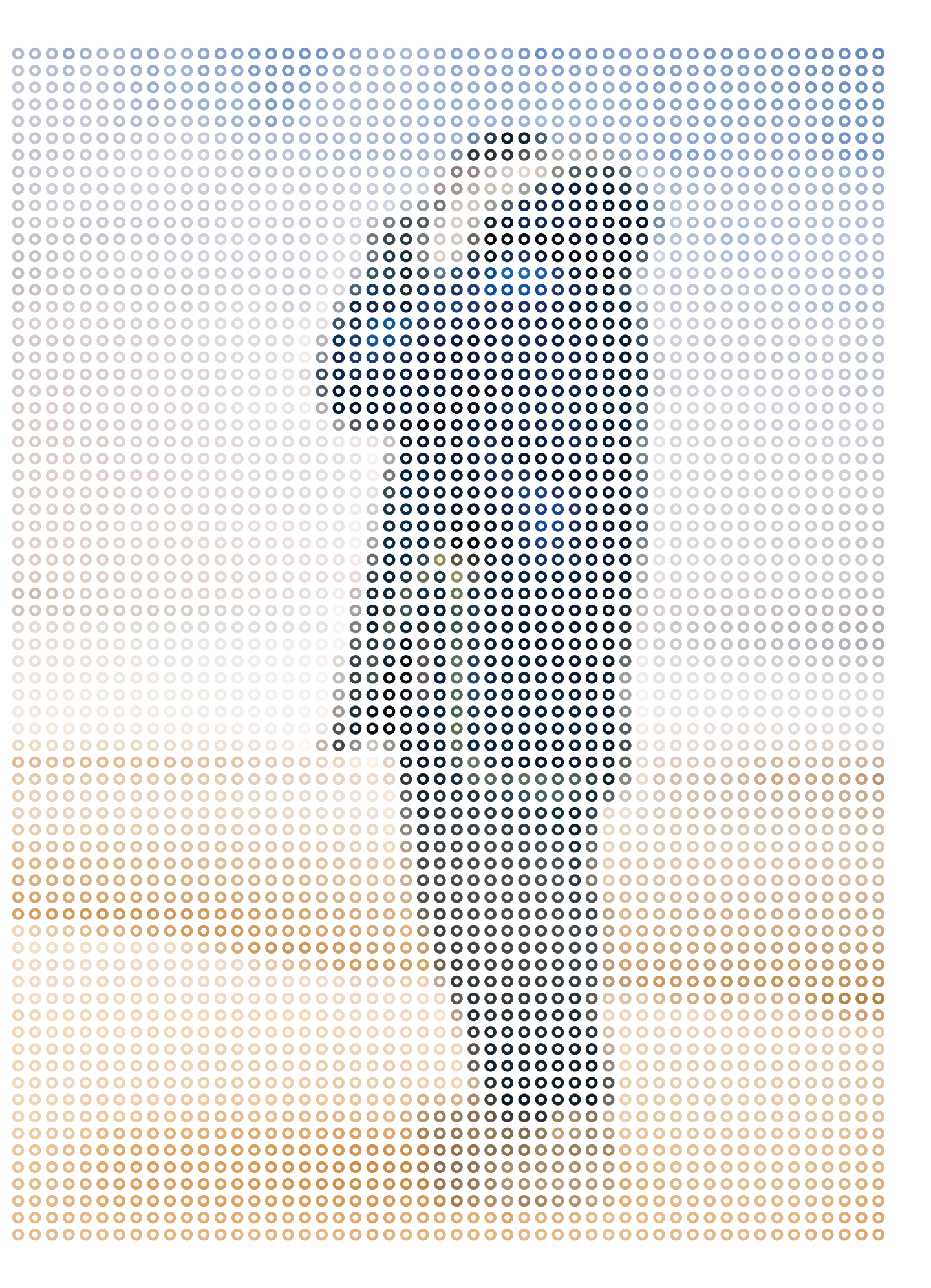


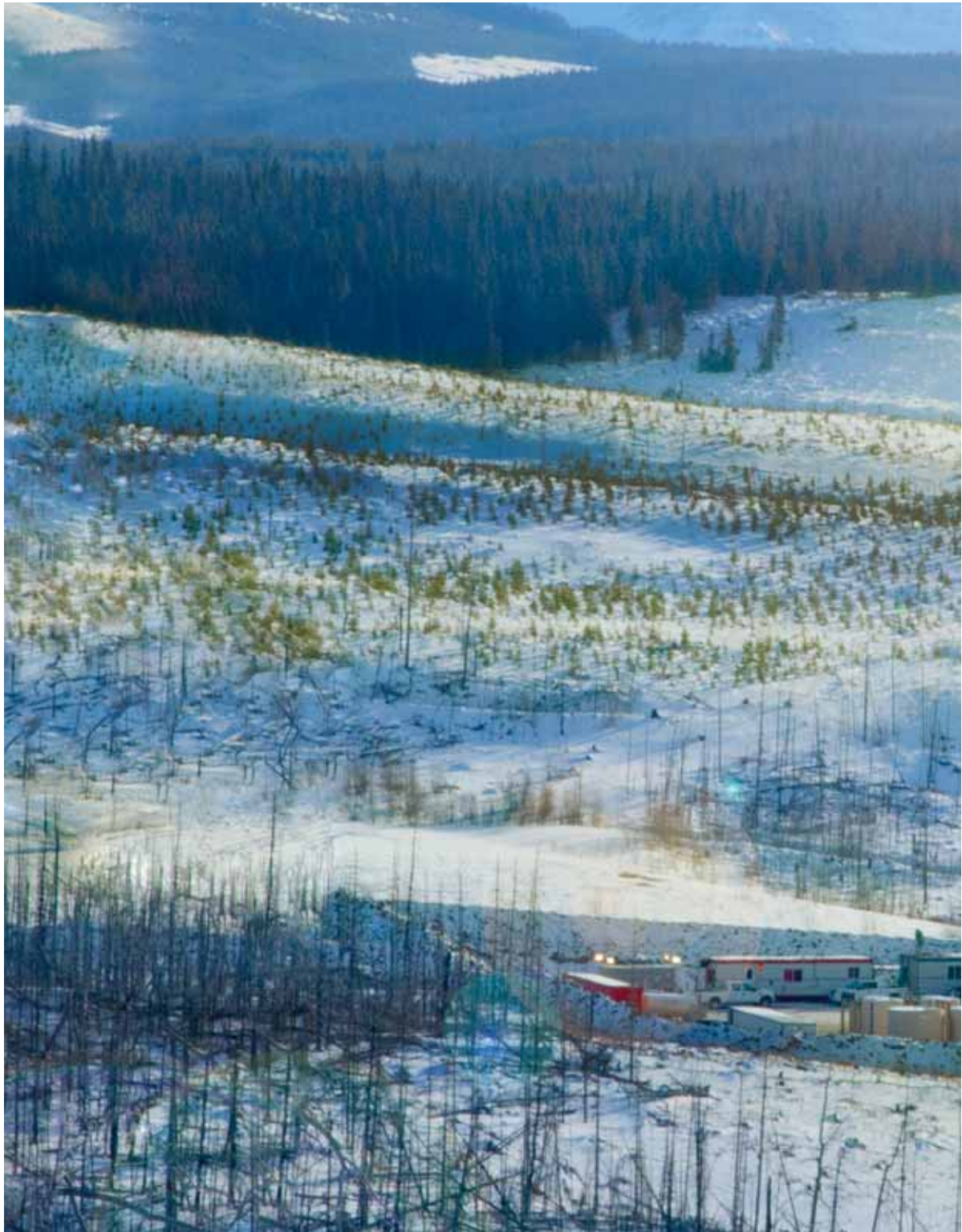
**MANITOK**  
ENERGY INC.



**Manitok is an Inuit word  
meaning rugged & enduring.**







**Manitok Stolberg  
Drill #1**



# Manitok Energy Inc.

**is a unique oil and gas company positioned to take maximum advantage of a once-in-a-generation opportunity in the foothills of the Western Canada Sedimentary Basin for the benefit of its shareholders.**

Oil and gas development in the Western Canadian Foothills has reached the point in its history where the majors have drilled enough of the large, deep gas structures to construct the necessary level of infrastructure to support further development of the hydrocarbon reserves in place at shallower depths. At the same time, the majors, all surprisingly acting in unison, have shifted their focus to other play types which have potential for vast new reserve additions like the Alberta oil sands and North American shale gas. During their drilling campaigns of the previous 20 years, the majors bypassed the shallower foothills reservoirs in the pursuit of the larger, deep structures where they had numerous drilling targets to pursue. They are now exiting the region before having fully exploited the deeper structures and leaving the shallower horizons relatively untouched. Declining production has also hit much of the foothills creating excess processing capacity in many areas. This 'perfect storm' creates an opportunity to generate enormous returns for those with the expertise and

Tim de Freitas & Massimo Geremia  
examining the Stolberg #1 drill site



willingness to be ‘early movers’ in the next stage of Western Canadian Foothills development;  
**the exploitation of the bypassed shallower horizons.**

We are currently one of the very few companies in the industry, including the majors, with the necessary geological and drilling experience to methodically and reliably exploit these bypassed reservoirs in the foothills. In our opinion, we have a world class structural geological team which can compete with anybody in industry.

## **Experience**

Manitok has been created specifically to focus on and succeed in the foothills. Our technical team has been assembled for their extensive drilling experience and successful track records in foothills exploration and development. **Prior to joining Manitok, much of our group spent many years at Talisman Energy, which had been the leader in foothills exploration and development for more than 20 years. Collectively, our technical team has more than 100 years of experience, involving billions of dollars of capital expenditures in foothills operations.**

**Now with Manitok, they are focused on shallower oil and liquids-rich natural gas plays that have been overlooked by the majors.** Energy companies are fond of saying their people are their biggest assets, but for us this is true in the most tangible and immediate sense. Our people are the cornerstone of our foothills strategy.

## The Focus Area

Unlike the plains, where today's focus is on unconventional, tight reservoirs, much of the opportunity in the foothills still lies in conventional reservoirs. These reservoirs, because of their physical properties, require much less capital to access the same reserves value. There is still a tremendous magnitude of reserves to be exploited in the foothills through vertical drilling with little fracture stimulation. However, where advantageous, horizontal drilling and today's new completion technologies can be applied to enhance returns.

We currently have an inventory of more than 40 prospective drilling targets, most of which can be effectively accessed with lower-cost vertical wells. We believe this drilling inventory gives us the ability, with adequate financing in place and the necessary time to execute the drilling, to exceed 5,000 barrels of oil equivalent production per day without adding any additional lands or acquisitions.

Admittedly, the foothills are no place for those without the requisite education, training and experience. The folding and faulting of reservoirs in the region makes it a significant challenge for most companies. With the knowledge and training gained by Manitok's technical team in the pursuit of deeper gas targets, we are now taking a different approach. We are pursuing the shallower, more modest oil and liquids-rich natural gas pools that the larger companies drilled through, and ignored, in their hunt for deep sour gas.

## Advantages to Manitok's Strategy

We are one of very few early entrants into the shallow foothills, which have to date, been largely underexploited. As a result, there are few competitors at this time and this will likely remain unchanged in the near future due to the technical experience required to understand and execute drilling programs in the foothills. Drilling experience in the foothills forms a substantial barrier to entry for companies. It takes many millions, if not billions, of dollars of drilling to understand what works and, more importantly, what doesn't work in the foothills. This low level of competition has enabled us to assemble more than 72,000 net acres of foothills leases, over the last 20 months, in the areas we consider the most prospective for early success.

There is plenty of running room for Manitok in the foothills, both because of the bypass opportunities and because the region is still substantially under-drilled, as compared with the rest of the basin. The previous exploration efforts of the majors have left the area substantially covered by 2-D and 3-D seismic surveys; much of which can be purchased at a fraction of the cost of acquisition. Similarly, the previous drilling of many deep wells means drill cuttings and well logs are readily available to provide a better understanding of the complex geology of our shallower targets.

Large tracts of crown land are still available for lease in the foothills and shallow rights reversions will make additional lands available in the coming years. Manitok anticipates that within the next several years, the reversions will begin to be enforced in the foothills which could ultimately lead

to tens of thousands of acres of shallower rights reverting back to the crown over time.

Finally, the previous activities of the majors, over more than 20 years, mean that infrastructure is already in place throughout our prospective areas. Roads, pipelines and processing plants have all been built which will significantly reduce the costs of future development. This means more of our capital will be allocated to drilling and completions, rather than to roads and facilities.

## **Proof of Concept**

The first major test of our foothills strategy was completed in the first quarter of 2011 with the drilling of our Stolberg #1 well, some 80 km west of Rocky Mountain House, Alberta.

We completed a successful liquids-rich natural gas well to a Cretaceous zone, at a depth of 3,200 metres. After initially perforating this zone, the flow test registered a rate of 739 barrels of oil equivalent per day, consisting of 75 barrels per day of 52° API wellhead condensate and four million cubic feet per day of sweet, liquids-rich natural gas. We have a 75% working interest in the well. After assessing the pressure build up data, getting an industry respected third party's opinion on that data, and our own internal evaluation involving other information like a nearby well analog, we believe that with a small volume fracture stimulation the well's production capability could be over 2,000 boe/d.

Based on the strong results of our first well, Manitok plans to follow up by drilling three locations near the discovery, likely beginning in the third quarter of this year. We hold a 97.7-per-cent working interest in a total of 17,600 acres in the area with multi-zone oil and liquids-rich natural gas potential.

Initial success at Stolberg demonstrates the efficacy of our approach to the foothills. It shows that risks can be managed and that our strategy can produce impressive rates of return.

## **Balance**

The Manitok management team fully understands that pursuing foothills oil and liquids-rich natural gas is a challenging undertaking that needs to be balanced by play type, as well as by product. Accordingly, we have developed several core areas other than Stolberg, which are prospective for oil, liquids-rich natural gas and dry natural gas.

Our first production was established in the heavy oil region of East Central Alberta. A discovery well was drilled in 2007 that resulted in a new-pool designation for Manitok near Vermilion, some 80 km west of Lloydminster, Alberta. We followed this in 2010 with five new wells that will give us a total of about 190 barrels of daily heavy crude oil production capability, all with a 100-per-cent working interest.

Our 24,960 acres at Fallen Timber are very prospective for liquids-rich gas and oil. Six competitor wells offsetting our Fallen Timber lands are currently producing both oil and liquids rich natural gas, some with a ten-year production

history. Production data from the area indicates that the natural gas wells could yield up to 70 barrels of natural gas liquids for every million cubic feet of natural gas. We have over 8 initial development locations, many with multi-zone potential.

While we are focusing our capital on oil and liquids rich natural gas for now, natural gas production in sufficient quantities is still a valuable commodity and will return to higher, economically sustainable, prices sometime in the near future. That is why we hold 14,240 net acres of natural gas-prone lands in the Coleman area. We hold a 50-per-cent working interest in two producing gas wells. Both of these wells are vertical and have not been able to effectively drain the reserves in place. ManitoK believes that there is over 40 Bcf of natural gas in place per section (640 acres) and the 2 wells have only produced 4 Bcf to date. Horizontal re-entries are required to exploit the significant amount of reserves still remaining. Each re-entry could have initial production rates of 6 to 12 Mmcf per day or 1,000 to 2,000 boe/d based on a 6:1 conversion rate. The re-entries also provide a low cost approach, relative to a drilling operation from surface, to proving the economics of the play. If the two re-entries are successful, there would be 6 to 10 future drills from surface.

The diversification of play type and product within our existing drilling inventory will allow ManitoK to quickly capitalize on opportunities created by large commodity price swings. Also, the ability to drill high rate wells, with development type risk, differentiates us from other junior oil and gas companies that have difficulty growing once they reach a certain corporate production threshold.

## The Future

Manitok has opened 2011 with an excellent demonstration of our foothills strategy at Stolberg. This success highlights our ability to acquire and economically drill foothills targets with substantial reserves in place which ultimately generates very high rates of return on our capital for our shareholders. The highly specialized skill set of our technical team, along with the many years of experience, provides Manitok with the competitive advantage needed to achieve continued success in the foothills.

As a result of our expertise, extensive land base and success to date, we have been able to attract a significant amount of new capital in a recent equity financing which has increased our cash position to over \$40 million at the time of this message. The Manitok team is very excited about the amount of shareholder value that we can create with further drilling on our lands over the next year. Manitok intends to continue to vigorously pursue the exceptional growth opportunities that exist in the foothills today. We have built this company with the right mix of specialized professional talent, an outstanding land base and the leadership required to achieve above-average growth for our shareholders, both immediately, and over the long term.



**Massimo M. Geremia**  
President & Chief Executive Officer



**The Canadian Foothills Belt as a unique underexploited area in Western Canada.**

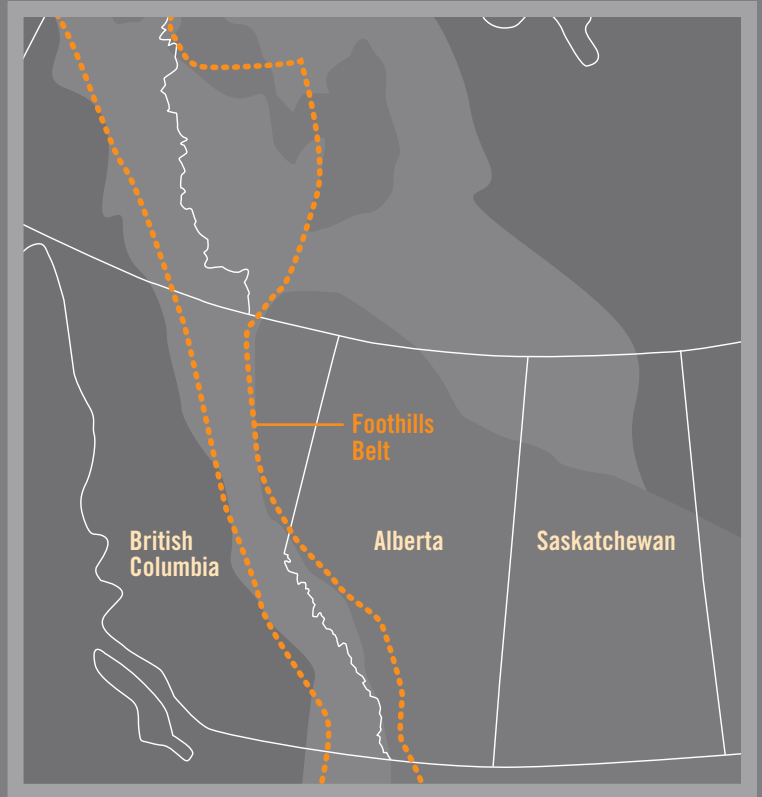
## **Manitok's Stolberg discovery is an example of a bypass reservoir in the foothills: it is a shallower conventional reservoir which was identified during a deeper drilling operation.**

The Foothills Belt covers a vast area of the Americas forming a continuous belt of oil and gas-bearing strata from the southern tip of South America to Canada's Arctic islands (Figure 1). The foothills form a narrow eastern band along the eastern part of the much wider fold belt and resulted from compressional forces brought upon by ancient collisions of rigid plates over the outer crust of the earth. Substantial reserves have been, and continue to be, found in the associated complex geological structures. Figure 2 features complex fold structures occurring in the central mountainous, parts of the fold belt, in areas typically not exploited by oil and gas companies. However, the mountains provide excellent models for predicting buried reservoir trends and geometries in the foothills, in areas that may have very limited surface relief. The foothills play comprises a unique (folded and faulted) geological character, and the associated surface can range from nearly flat land to rolling hills. In contrast, the Plains, from a geological standpoint, comprise horizontally layered rock covered by flat land or rolling hills. In other words, physiography, by itself, cannot be used to distinguish these two very different geological areas.

In the Plains areas of Western Canada, oil and gas has accumulated in very simple structures or in areas where a lateral reduction in permeability has halted leakage of the hydrocarbons to the surface. Early explorationists in Western Canada generally focused their efforts on conventional reservoirs in the Plains; that is, on reservoirs with adequate permeability, where associated hydrocarbons could flow to surface without stimulation. The typical picture that represent these early days of exploration are of drilling rigs with huge amounts of oil rushing from the ground due to uncontrolled outflow from a high permeability, conventional reservoir. This was a surprisingly common occurrence in the early stages of exploration in Alberta. While safe drilling practices have eliminated these type of outflows, the high permeability, large conventional reservoir discoveries have all but disappeared in the Plains. These older conventional fields of the Plains are now severely depleted, and operators have now moved on to either very small conventional pools and oil sands, or have focused their efforts on the "tighter" (low permeability) rocks in the Plains. While hydrocarbon accumulations in the tight rocks can still be large, hydrocarbons do not flow to surface unless subject to aggressive and expensive stimulation programs (commonly referred to as "multi-stage fracs"). Also, the amount of oil or gas that can be recovered from the rock is a fraction of what conventional reservoir rocks yield. Recoveries of the tighter rock can be increased with extensive additional drilling and fracture stimulation operations which forces finding and development ("F&D") costs higher. The low permeability reservoir has the additional characteristic of significantly higher decline rate, relative to conventional reservoirs, during the first year of production, and operators require ever increasing progression of drilling operations to offset these harsh declines. In some cases, proven booked reserves of high-decline unconventional wells may be unremarkable. In order to add value and lower F&D costs, operators may book a very high proportion of undeveloped reserves, which by nature, are risky, since commodity prices and drilling and operating costs are only estimates, which become less and less certain with every year that the reserves remain undrilled. In contrast, conventional pools have good permeability; the reserves per well tend to be much higher, and the decline rates can be very low.

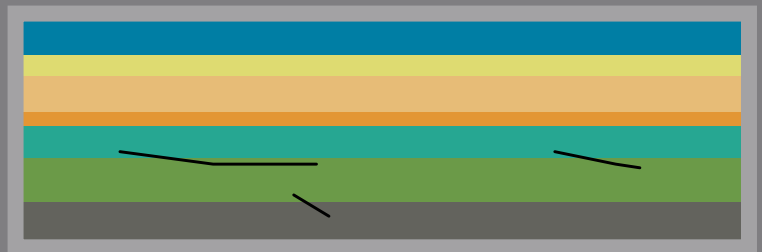
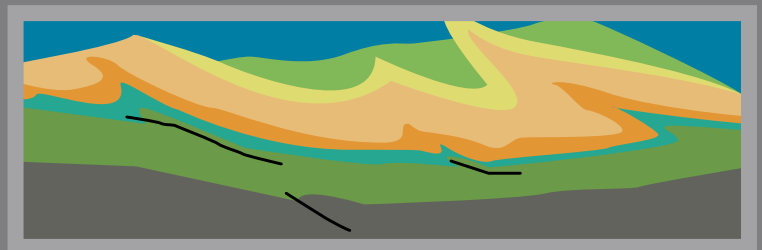
**Figure 1**

Map showing the distribution of the Foothills Belt (orange dotted line) in Alberta, British Columbia, Yukon, and Territories.



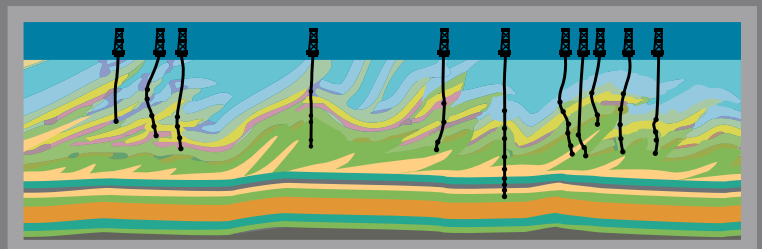
**Figures 2 & 3**

Folded character of the rock as a result of regional compression forces that created the Foothills Belt. Colour diagrams above and below showing deformed and undeformed state of the rock layers, respectively.



**Figure 4**

Regional cross section showing style of folding and faulting in the Manitok's Fallen Timber property. Vertical black lines are existing well bores. Coloured units represent the various rock layers, including reservoir intervals, in the Western Canada Sedimentary Basin.



While the mature state of development in the Plains requires these expensive stimulation operations, the foothills is decades behind, and extremely large conventional reservoirs can still be found. The first wave of major oil and gas producers, like Talisman Energy Inc. (“Talisman”), were a success story of discovery in the geologically complex, prolific foothills gas pools, some of which are the largest in North America. The majors participated in high capital drilling programs, which, because of the large reserves and low technical risk, were a focus for tremendous growth for a number of years. The abundant smaller reservoirs in the foothills still exist. However, in the past, they were too small to capture capital or to provide return on investment due to large infrastructure expenses. Now that this infrastructure has been installed, these smaller conventional reservoirs are extremely attractive targets. This pattern of major discovery and follow-up exploitation has been repeated a number of times over the last 50 years in the Plains. Manitok’s Stolberg discovery is an example of a bypass of reservoir in the foothills: it is a shallower conventional reservoir which was identified during a deeper drilling operation. While smaller in magnitude as compared to the deeper sour foothills gas reservoirs, the sweet Stolberg condensate and gas discovery is quite large when compared to recent conventional hydrocarbon discoveries over the last several years in the Plains. If explorationists of the past had tapped into the Stolberg reservoir using poor drilling practices of the time, an uncontrolled outflow of gas and condensate may have lasted for several weeks. In contrast, outflow from an unconventional well would be short lived or not occur at all.

The Foothills Belt has its challenges, and not every folded reservoir is the same. It is the most geologically and geophysically complex area in the Western Canada Sedimentary Basin. It requires operational and technical experience that few companies have mastered over the past decades. Talisman was an exception, and it developed a world class technical team, which yielded significant financial success for the company. Their knowledge of the structural complexity provided a competitive advantage over other operators. Members of the former Talisman foothills team, now at Manitok, pioneered the very challenging horizontal drilling in the foothills. We understand that the brittle reservoir rocks in the foothills fracture extensively as a result of folding and faulting. Once a particular structural model is resolved, fractures intensity and orientation can be predicted, and wells can be steered to exploit the natural fracture-enhanced permeability. Successful horizontal foothills wells of the past have yielded impressive initial production rates, and a large number of reserves were booked for each well, both of which drove very favourable economics. The knowledge gained from many years of seismic processing and interpretation, along with the experience of steering the wells through folded rocks in order to intersect the best part of the reservoir cannot be understated. With more than 250 tested foothills structures, we have also drilled enough wells to comprehend the role of borehole stability, which is a primary cause of some of the largest operational mishaps in foothills drilling programs.

**The fact that Talisman was a leading drilling operator for many years was a result of the very analytical approach to wellbore design. That same analytical approach on every aspect of a foothills drilling operation has been adopted by Manitok. All drilling projects at Manitok will certainly benefit from the knowledge gained by many years of hands-on experience along with this thorough approach.**



## Operations Review

## Stolberg/Cordel

### Manitok's operational focus swung dramatically to Alberta's west-central foothills following a game-changing, liquids-rich natural gas discovery at Stolberg in January, 2011.

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<b>Location:</b>	25 km north of Nordegg, Alberta	<b>Working Interest:</b>	1 well @ 75%
<b>Production:</b>	Beginning approx. Q3 2011 net 1,350 boe/d gas & liquids	<b>Depth:</b>	Approx. 3,200 metres
<b>Formation:</b>	Ostracod	<b>Land Position:</b>	17,920 acres @ 97% WI

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Latest analysis by Manitok and third-party indicates our discovery well, north of Nordegg, Alberta, is capable of producing 13-to-15 Mmcf/d of gas and liquids or 2,350 to 2,800 boe/d, with a stimulation treatment to remove near wellbore damage.

This includes 52° API field condensate at a rate of 16 barrels per Mmcf of gas. Gas will be delivered through the Stolberg unit gas gathering system to the Husky Ram River gas plant. While the rich gas will sell at a premium due to heating value, liquids recovery at the Ram Plant is low efficiency. Pending results of future drilling operations at Stolberg, Manitok will look at options to maximize the economic value of the production including alternate delivery points for better liquids recovery.

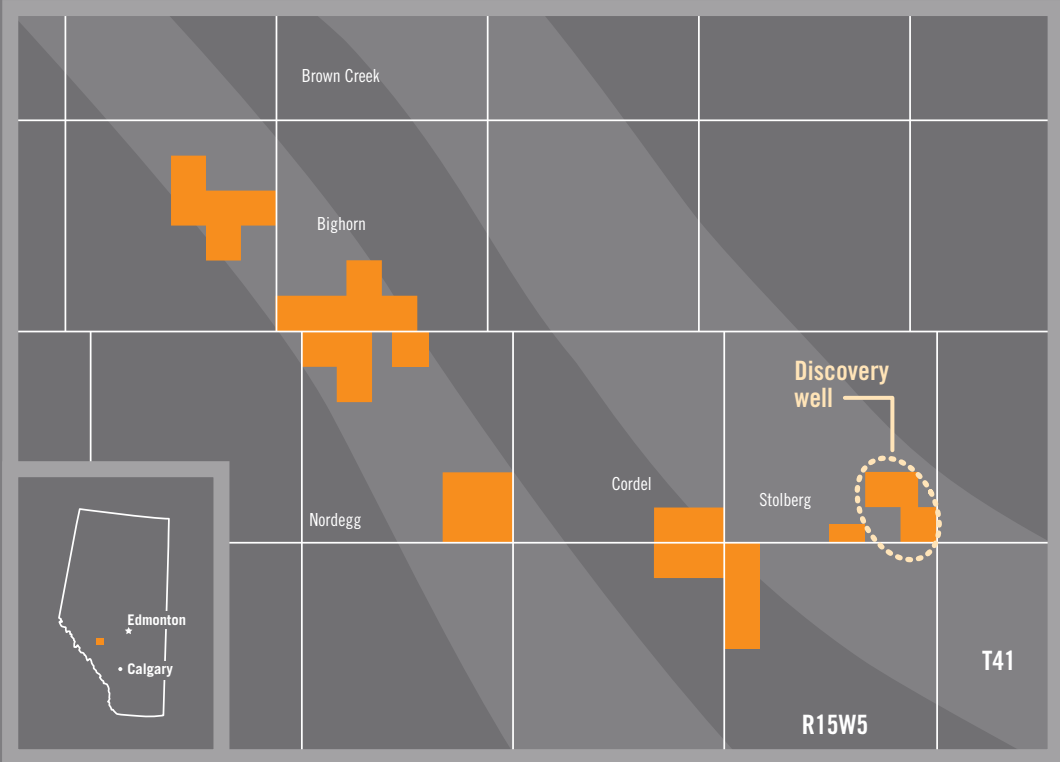
In order to avoid over-capitalizing the Stolberg well, we will install facilities sufficient for 1,800 boe/d gross production. With our 75-per-cent working interest in the well, this is expected to give us net production of 1,350 boe/d.

The discovery well is scheduled to begin production in the third quarter of 2011, and anticipated rates from this single well would increase our production more than four to five times our current levels.

Based on this success, Manitok will follow up with three additional vertical wells (net 2.25) starting in the third quarter of 2011, near the discovery, again targeting multiple, shallow Cretaceous zones with strong potential for sweet, liquids-rich natural gas and light oil discoveries. The complex structural geology of this foothills region is such that various Cretaceous targets may be stacked vertically (structural repeats, Figure 5), and a single vertical well may intersect a pay zone multiple times, thus increasing economic returns in each drilling project. Furthermore, reservoir zones are extensively fractured due to folding and faulting, which results in increased permeability and initial production rates. For this reason, each of the three follow-up wells is planned to test up to four zones, offsetting the risk of failure in any single zone.

We anticipate each well will cost about \$4-5 million to drill to depths of about 3,200 metres. Manitok holds 17,440 net acres of leases in the Stolberg/Cordel area and we see at least five additional, multi-zone targets in future drilling programs.

# Stolberg/Cordel



**Figure 5** – Thrust repeated Cardium in the central Alberta Foothills. This is a representative example of the type of projects Manitok has, and will, undertake in the Canadian Foothills. The light brown layer in the cliff is the Cardium Formation, which has been stacked vertically in a series of fault-bounded blocks. With a single well bore (blue line), three Cardium units could be intersected, significantly increasing reserves and thus economic returns on the drill project.

## Other Foothills Assets and Activities

### Fallen Timber

<b>Location:</b>	Approx. 75 km northwest of Calgary	<b>Working Interest:</b>	97%
<b>Production:</b>	Cretaceous oil play / no production	<b>Depth:</b>	To be determined
<b>Formation:</b>	Cardium / Viking	<b>Land Position:</b>	24,960 acres @ 97%

Fallen Timber is another thrustured Cretaceous play for oil and natural gas liquids. Here, as in Stolberg, conventional Cretaceous reservoirs are caught in a series of complex structures (Figure 5 on page 19). Drill projects will target up to three reservoir intervals, including multiple Cardium and Viking zones. Where multiple reservoirs are intersected with a single vertical well, economics are significantly improved.

The structural geology at Fallen Timber is similar to that at Stolberg, and Manitok is operationally and technically well staffed to handle this area. We plan to drill up to two wells in the fourth quarter of 2011, depending on capital availability.

Manitok has no current production at Fallen Timber but holds a 97% working interest in 24,960 acres, including 11,520 along a conventional, proven oil- and gas-prone Cardium trend, which already features six producing wells owned by others.

We see at least eight potential Cardium targets on our leases, including four with two Cardium formations and potential in the Viking Formation. Deliberately targeting this stacked, multi-zone reservoir is an important strategy in reducing our risk of dry holes in foothills development drilling.

Throughout the foothills, Manitok's exploration and development activities are significantly de-risked by the availability of well logs, cores, and chips, as well as three-dimensional and two-dimensional seismic surveys, all left over from the previous activities of major energy companies pursuing deeper gas plays in the region. Risks are further reduced by the fact that these previous activities were, in many cases, led by people who are now part of the Manitok team and therefore have a deep understanding of foothills geoscience. Major oil and gas firms have also invested significant capital on roads, pipelines, and gas plants which are currently underutilized. We can, therefore, exploit spare capacity and existing infrastructure, significantly enhancing economic returns.

### Coleman

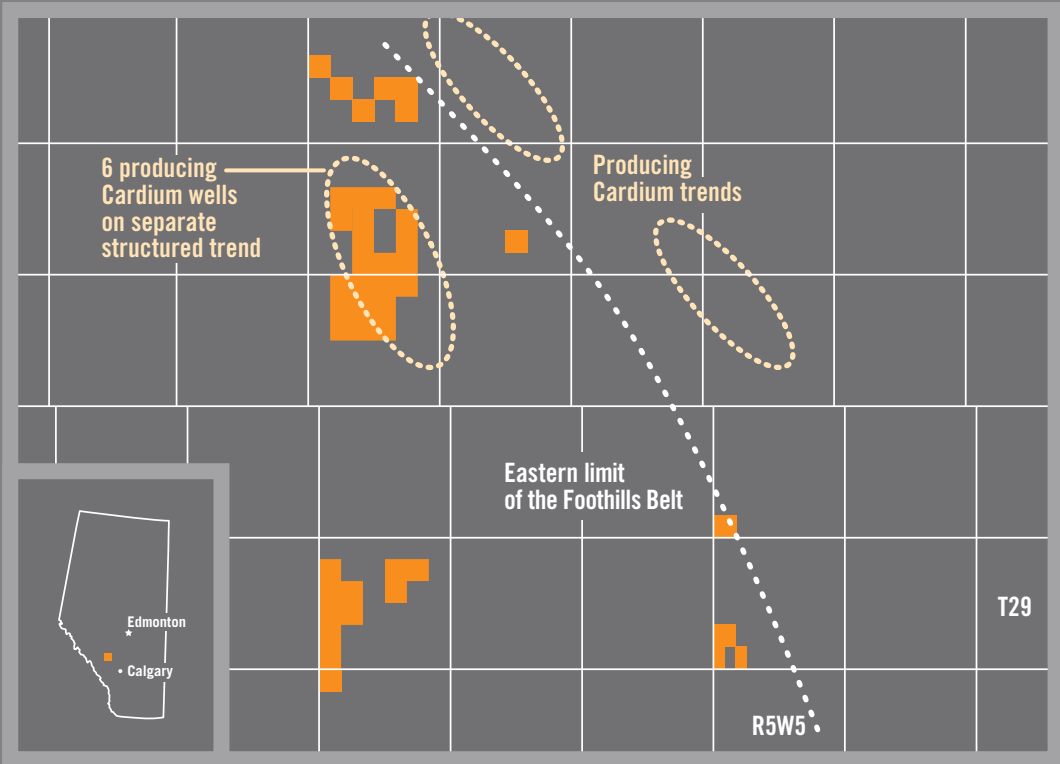
<b>Location:</b>	SW Alberta, Crowsnest Pass, east of BC border	<b>Working Interest:</b>	2 producing wells at 50%
<b>Production:</b>	Net 30 to 40 boe/d, slightly sour gas	<b>Depth:</b>	Approx. 3,400 metres
<b>Formation:</b>	Mount Head, Turner Valley & Wabamun	<b>Land Position:</b>	16,800 acres @ 85%

Prior to the Stolberg discovery and land acquisition at Fallen Timber, our flagship property was our Coleman foothills play north of the Crowsnest Pass in Southwest Alberta.

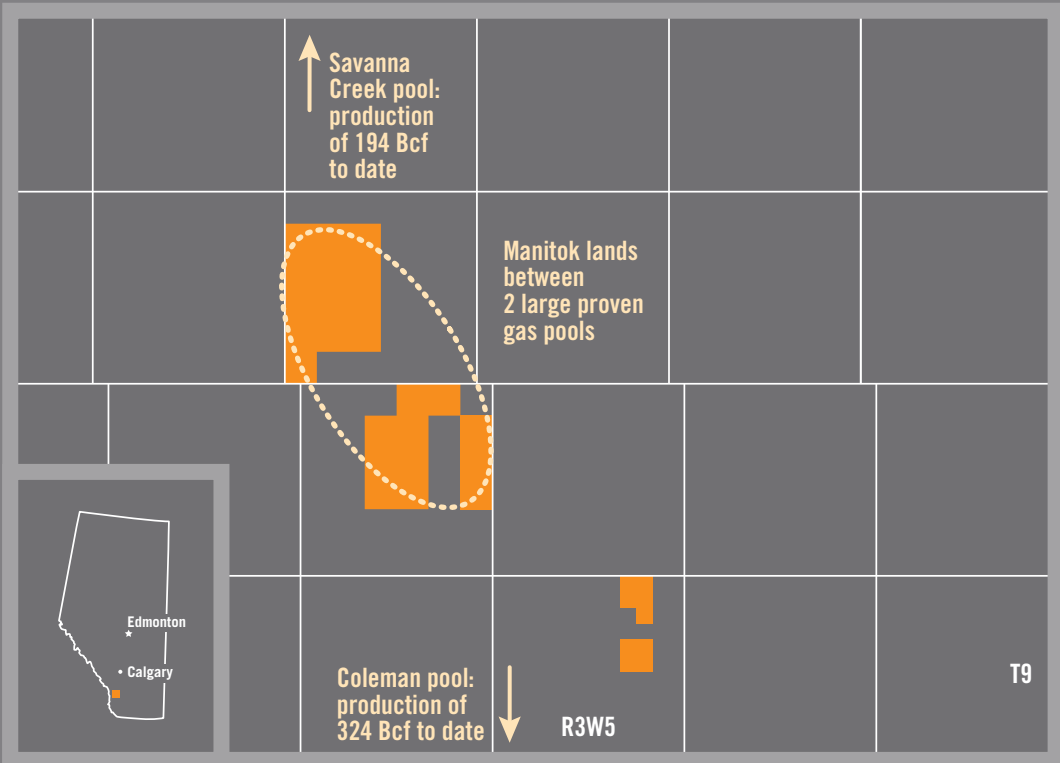
This property currently produces about 30 to 40 boe/d of dry sour gas, net to Manitok. Our two non-operated wells are about 3,400 metres in depth and tied in to Devon's Coleman gas plant.

Manitok holds 22.25 net sections (14,240 acres) in the Coleman trend and believes gas in place in Mount Head, Turner Valley, and Wabamun formations exceeds 40 billion cubic feet per section, of which only about four billion cubic feet has so far been produced. But further commercial extraction requires horizontal wells, and development is on hold while we devote resources elsewhere.

# Fallen Timber



# Coleman



## Plains Assets and Activities

### Swimming

<b>Location:</b>	80 km west of Lloydminster, Alberta	<b>Working Interest:</b>	8 producing wells/ 1 shut in @ 100%
<b>Production:</b>	150 bbls/d heavy oil	<b>Depth:</b>	Approx. 600 metres
<b>Formation:</b>	Cummings, GP & Sparky	<b>Land Position:</b>	7,726 acres @ 100%

Manitok closed 2010 with exit-rate production of 150 bbls/d of heavy oil (11°-13° API) from eight well locations on our Swimming property, some 80 km west of Lloydminster, Alberta. Our oil is currently processed on site to remove water and sand, and trucked to nearby facilities. Following staffing changes in the field, most shipped oil is now at pipeline specifications and sent to a Gibson's facility for pipeline delivery to refineries.

Current producing zones include the Cummings, GP, and Sparky formations from one section of our significant Swimming land base. This section is covered by a propriety 3-D seismic survey, which images numerous potential follow-up drill locations targeting the same producing sands.

In late 2010, we acquired additional extensive 2-D and 3-D seismic data and identified two significant anomalies on adjacent lands, which will be the target of our 2011 drilling campaign. We hold a 100% working interests in 10,560 acres at Swimming and are planning to drill at least five wells after spring breakup this year.

### Hairy Hill/Mannville

<b>Location:</b>	Approx. 100 km east of Edmonton	<b>Working Interest:</b>	5 producing wells @ 80%
<b>Production:</b>	Net 65 boe/d lean gas	<b>Depth:</b>	Approx. 600-700 metres
<b>Formation:</b>	Viking and Mannville	<b>Land Position:</b>	7,102 acres @ 66%

Manitok has interest in five producing gas wells (all non-operated or operated under contract), on the Hairy Hill and Mannville leases west of Swimming. Current production averages about net 65 boe/d of lean gas. No new activity is planned for this property in 2011.

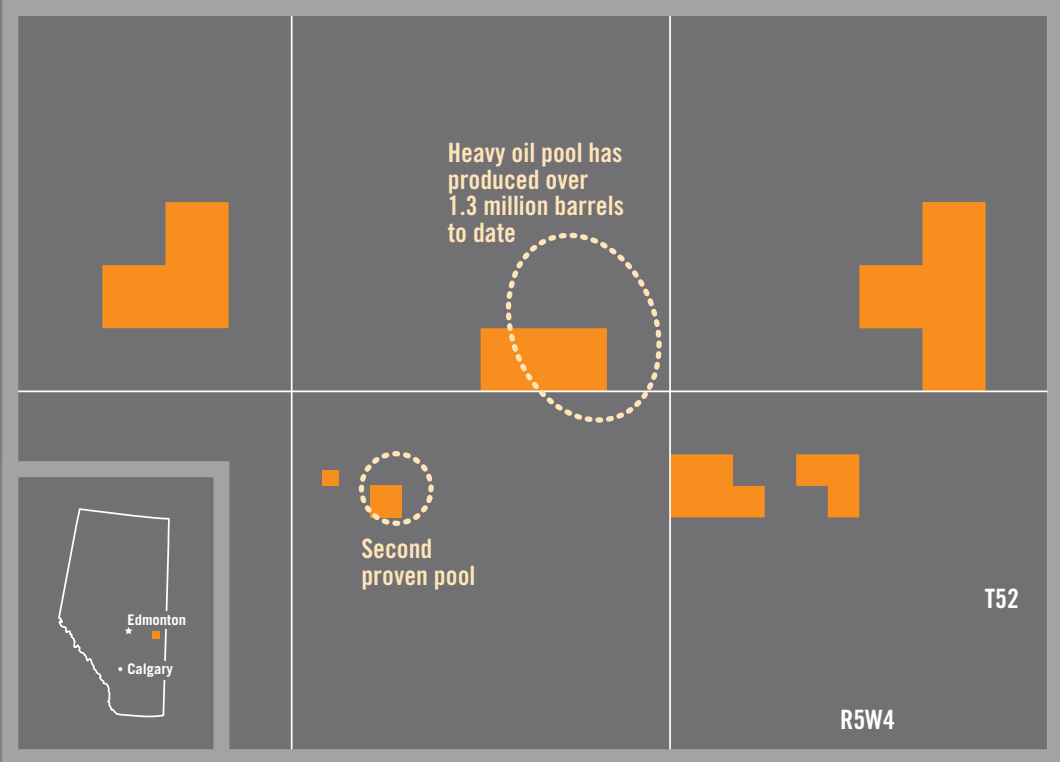
### Bolton

<b>Location:</b>	Near Grande Prairie, Alberta	<b>Working Interest:</b>	1 producing well @ 100%
<b>Production:</b>	Net 30 boe/d, lean gas	<b>Depth:</b>	Approx. 3,500 metres
<b>Formation:</b>	Gething	<b>Land Position:</b>	640 acres @ 100%

Our Bolton lean gas well, near Grande Prairie, Alberta, is producing about 30 boe/d on an intermittent basis from the Gething formation at a depth of about 3,500 metres. Production issues are due mainly to liquids loading related to condensate and water production. We are currently working with the contract operator in order to maximize production hours.

The well was tied in during the first quarter of 2011 and no new activity is planned during 2011.

# Swimming



## Land

	Total		Developed		Undeveloped	
	Gross	Net	Gross	Net	Gross	Net
<b>June 30, 2010</b>						
Foothills - Alberta	50,720	47,402	2,560	1,482	48,160	45,920
Other - Alberta	12,423	10,023	6,663	4,903	5,760	5,120
<b>Total</b>	<b>63,143</b>	<b>57,425</b>	<b>9,223</b>	<b>6,385</b>	<b>53,920</b>	<b>51,040</b>
<b>Dec 31, 2010</b>						
Foothills - Alberta	79,977	75,939	2,560	1,802	77,417	74,137
Other - Alberta	14,506	12,106	7,303	5,223	7,203	6,883
<b>Total</b>	<b>94,483</b>	<b>88,045</b>	<b>9,863</b>	<b>7,025</b>	<b>84,620</b>	<b>81,020</b>
<b>March 31, 2011</b>						
Foothills - Alberta	80,937	76,819	3,200	2,282	77,737	74,537
Other - Alberta	17,666	15,266	7,303	5,223	10,363	10,043
<b>Total</b>	<b>98,603</b>	<b>92,085</b>	<b>10,503</b>	<b>7,505</b>	<b>88,100</b>	<b>84,580</b>

From June 30, 2010 to December 31, 2010, Manitek increased its undeveloped land holdings by 57%. Manitek strategically posted acreage in its focus areas and monitored and bid on competitor postings. By posting land prior to industry being active in the areas, Manitek was able to achieve this increase in its undeveloped land at an average price of \$60 per acre. Among Manitek's acquisitions was the location for the Stolberg well and the proposed follow up locations. Manitek intends to continue to expand its undeveloped land position in its current focus areas where possible and to post and purchase land in new areas while activities are still quiet.

## RESERVES EVALUATION

Sproule Associates Limited ("Sproule") prepared an independent evaluation of Manitek's oil and natural gas reserves effective December 31, 2010 in accordance with the Canadian Oil and Gas Evaluation Handbook ("COGEH") and National Instrument 51-101 ("NI 51-101"). The results were provided to Manitek in an Evaluation Report dated March 30, 2011 (the "Sproule Evaluation"). Information provided in this annual report is based on Sproule's December 31, 2010 price forecast of commodity prices and costs (the "Sproule Price Forecast"). Additional data on reserves is contained in the Corporation's "Statement of Reserves and Other Oil and Gas Information", which is filed on SEDAR at [www.sedar.com](http://www.sedar.com). Columns may not add due to rounding of individual items.

## Oil and Natural Gas Reserves by Product Type

The following table summarizes Sproule's estimates of Manitek's oil and natural gas reserves at December 31, 2010 using the Sproule Price Forecast.

### Summary of Oil and Natural Gas Reserves as of December 31, 2010 – Forecast Prices and Costs

Reserve Category	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Total	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mmcf)	Net (Mmcf)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mboe)	Net (Mboe)
Proved										
Developed Producing	–	–	190.5	172.0	1,269	1,108	0.2	0.1	402.2	356.8
Developed Non-Producing	–	–	40.0	38.7	300	277	1.6	1.1	91.6	86.0
Undeveloped	–	–	165.0	152.8	–	–	–	–	165.0	152.8
<b>Total Proved</b>	–	–	<b>395.5</b>	<b>363.4</b>	<b>1,569</b>	<b>1,385</b>	<b>1.8</b>	<b>1.3</b>	<b>658.8</b>	<b>595.5</b>
Probable	–	–	133.4	118.6	629	549	1.7	1.2	239.9	211.3
<b>Total Proved Plus Probable</b>	–	–	<b>528.9</b>	<b>482.0</b>	<b>2,197</b>	<b>1,935</b>	<b>3.5</b>	<b>2.4</b>	<b>898.7</b>	<b>806.8</b>

(1) Estimates of reserves of natural gas include both associated and non-associated gas.

Proved developed producing reserves increased by 109.4 Mboe to 402.2 Mboe, which is an increase of 37% compared to its proved developed producing reserves of 292.8 Mboe as at June 30, 2010. Its proved reserves increased by 113.9 Mboe to 658.8 Mboe, which is an increase of 21% compared to its proved reserves of 544.9 Mboe as at June 30, 2010. Total proved plus probable reserves remained relatively consistent with the June 30, 2010 Sproule evaluation as the reserve additions related to the heavy oil wells brought on production in November 2010, offset the production in the period of 32.9 Mboe, technical revisions of 37.3 Mboe and the asset disposition in the Garrington area of Alberta of 47.2 Mboe. Total probable reserves decreased by 32%, but the majority of this reduction was due to reserves being reallocated to the proved reserves category as a result of the heavy oil drilling program.

Approximately 59% of ManitoK's proved plus probable reserves are comprised of heavy crude oil on a boe basis. On a valuation basis, proved plus probable heavy crude oil reserves make up approximately 73% of the total reserves value on a net present value ("NPV") 10% basis.

### Net Present Values of Future Net Revenues

The following table is a summary of the net present values of future net revenues associated with ManitoK's reserves at December 31, 2010, using the Sproule Price Forecast, before income taxes, without discount and using various discount rates.

#### Net Present Values of Future Net Revenue as of December 31, 2010 – Forecast Prices and Costs

Reserve Category	Before Income Taxes Discounted at (% per year)				
	0% (\$000s)	5% (\$000s)	10% (\$000s)	15% (\$000s)	20% (\$000s)
Proved					
Developed Producing	10,357	9,170	8,248	7,513	6,916
Developed Non-Producing	2,092	1,447	1,041	776	597
Undeveloped	2,651	2,017	1,511	1,101	767
Total Proved	15,100	12,635	10,799	9,390	8,280
Probable	7,064	5,223	3,995	3,141	2,525
Total Proved Plus Probable	22,164	17,858	14,795	12,531	10,805

(1) National Instrument 51-101 requires the inclusion of the following statement: estimates of future net revenues whether discounted or not do not represent fair market value.

The net present value of total proved plus probable reserves was approximately \$14.8 million, which is a decrease of 2% from \$15.1 million as at June 30, 2010. The net present value of total proved reserves amounted to \$10.8 million, which is an increase of 14% from \$9.5 million as at June 30, 2010. Each of these net present value amounts is calculated using the pre-tax present value of the reserves estimated by Sproule discounted at 10% without including any additional value for ManitoK's undeveloped land base.

## Forecast Prices Used in the Sproule Evaluation

The following table sets out the forecast price assumptions used by Sproule for the Sproule Evaluation. The pricing and cost assumptions used were determined by Sproule using information available from numerous government agencies, industry publications, oil refineries, natural gas marketers and industry trends. These forecast prices are subject to many uncertainties that exist in both the domestic and international petroleum industry.

### Sproule December 31, 2010 price forecast

Year	WTI			Natural Gas AECO (\$/CDN/Mmbtu)	Natural Gas Liquids			Currency Exchange Rate (\$US/\$CDN)	Inflation Rate (%)
	Cushing Oklahoma 40° API (\$US/bbl)	Edmonton Par Price 40° API (\$/CDN/bbl)	Hardisty Heavy 12° API (CDN\$/bbl)		Edmonton Propane (\$/CDN/bbl)	Edmonton Butane (\$/CDN/bbl)	Edmonton Pentanes Plus (\$/CDN/bbl)		
2011	\$88.40	\$93.08	\$74.46	\$4.04	\$55.20	\$62.44	\$95.32	0.932	1.5%
2012	\$89.14	\$93.85	\$75.08	\$4.66	\$55.66	\$62.95	\$96.11	0.932	1.5%
2013	\$88.77	\$93.43	\$72.87	\$4.99	\$55.41	\$62.67	\$95.68	0.932	1.5%
2014	\$88.88	\$93.54	\$71.09	\$6.58	\$55.47	\$62.75	\$95.79	0.932	1.5%
2015	\$90.22	\$94.95	\$72.16	\$6.69	\$56.31	\$63.69	\$97.24	0.932	1.5%
2016	\$91.57	\$96.38	\$73.25	\$6.80	\$57.16	\$64.65	\$98.71	0.932	1.5%
2017	\$92.94	\$97.84	\$74.36	\$6.91	\$58.02	\$65.63	\$100.20	0.932	1.5%
2018	\$94.34	\$99.32	\$75.48	\$7.02	\$58.90	\$66.62	\$101.71	0.932	1.5%
2019	\$95.75	\$100.81	\$76.62	\$7.14	\$59.79	\$67.63	\$103.25	0.932	1.5%
2020	\$97.19	\$102.34	\$77.78	\$7.26	\$60.69	\$68.65	\$104.81	0.932	1.5%
thereafter	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	0.932	1.5%

## Reserves Reconciliation

The following tables set forth a reconciliation of the Corporation's gross reserves by product for the six months ended December 31, 2010 as derived from the Sproule Evaluation using the Sproule Price Forecast against Sproule's evaluation of such reserves for the fiscal year ended June 30, 2010, using the forecast prices and costs in the Sproule evaluation for the fiscal year ended June 30, 2010.

### Reconciliation of Gross Proved Reserves – Forecast prices and costs

Factors	Light and Medium Oil (MbbL)	Heavy Oil (MbbL)	Natural Gas (Mmcf)	NGL's (MbbL)	Oil Equivalent (Mboe)
<b>Total Proved</b>					
<b>Opening Balance June 30, 2010</b>	<b>2.9</b>	<b>252.5</b>	<b>1,688</b>	<b>8.3</b>	<b>545.0</b>
Extensions	–	74.9	–	–	74.9
Improved Recovery	–	–	–	–	–
Technical Revisions	(1.4)	83.2	12	(2.8)	81.0
Discoveries	–	–	–	–	–
Acquisitions	–	–	–	–	–
Dispositions <sup>(1)</sup>	(1.5)	–	(26)	(3.4)	(9.2)
Economic Factors	–	–	–	–	–
Production <sup>(2)</sup>	–	(15.1)	(105)	(0.3)	(32.9)
<b>Closing Balance December 31, 2010</b>	<b>–</b>	<b>395.5</b>	<b>1,569</b>	<b>1.8</b>	<b>658.8</b>

(1) On August 4, 2010, the Corporation sold a non-core asset for approximately \$1.8 million.

(2) Represents production from July 1, 2010 to December 31, 2010.

**Reconciliation of Gross Probable Reserves – Forecast prices and costs**

Factors	Light and Medium Oil (Mbbbl)	Heavy Oil (Mbbbl)	Natural Gas (Mmcf)	NGL's (Mbbbl)	Oil Equivalent (Mboe)
<b>Total Probable</b>					
<b>Opening Balance June 30, 2010</b>	<b>9.2</b>	<b>180.2</b>	<b>839</b>	<b>22.0</b>	<b>351.2</b>
Extensions	–	45.0	–	–	45.0
Improved Recovery	–	–	–	–	–
Technical Revisions	(9.2)	(91.8)	(84)	(3.3)	(118.3)
Discoveries	–	–	–	–	–
Acquisitions	–	–	–	–	–
Dispositions <sup>(1)</sup>	–	–	(126)	(17.0)	(38.0)
Economic Factors	–	–	–	–	–
Production	–	–	–	–	–
<b>Closing Balance December 31, 2010</b>	<b>–</b>	<b>133.4</b>	<b>629</b>	<b>1.7</b>	<b>239.9</b>

(1) On August 4, 2010, the Corporation sold a non-core asset for approximately \$1.8 million.

**Reconciliation of Gross Proved Plus Probable Reserves – Forecast prices and costs**

Factors	Light and Medium Oil (Mbbbl)	Heavy Oil (Mbbbl)	Natural Gas (Mmcf)	NGL's (Mbbbl)	Oil Equivalent (Mboe)
<b>Total Proved Plus Probable</b>					
<b>Opening Balance June 30, 2010</b>	<b>12.1</b>	<b>432.7</b>	<b>2,527</b>	<b>30.3</b>	<b>896.3</b>
Extensions	–	119.9	–	–	119.9
Improved Recovery	–	–	–	–	–
Technical Revisions	(10.6)	(8.6)	(72)	(6.1)	(37.3)
Discoveries	–	–	–	–	–
Acquisitions	–	–	–	–	–
Dispositions <sup>(1)</sup>	(1.5)	–	(152)	(20.4)	(47.2)
Economic Factors	–	–	–	–	–
Production <sup>(2)</sup>	–	(15.1)	(105)	(0.3)	(32.9)
<b>Closing Balance December 31, 2010</b>	<b>–</b>	<b>528.9</b>	<b>2,198</b>	<b>3.5</b>	<b>898.7</b>

(1) On August 4, 2010, the Corporation sold a non-core asset for approximately \$1.8 million.

(2) Represents production from July 1, 2010 to December 31, 2010.

On a proved plus probable basis, before considering decreases from production of 32.9 Mboe, there were positive reserves increases, totaling 119.9 Mboe, on Manito's Swimming, Mannville and Hairy Hill assets due to performance factors and the five heavy oil well drilling program. There was a net negative technical revision of 37.3 Mboe, mainly due to a downward revision at Coleman, due to increased operating costs, which more than offset upward revisions at Swimming. Reserves were further reduced by 47.2 Mboe after the disposition of the Garrington assets for \$1.8 million.

The following table sets forth future development costs associated with Manito's reserves as derived from the Sproule evaluations for the applicable periods:

(\$000s)	December 31, 2010	June 30, 2010	June 30, 2009
Total Proved	4,432	2,184	2,385
Total Proved Plus Probable	5,152	4,329	4,853

During the financial period ended December 31, 2010, Manitok incurred capital costs of approximately \$2.1 million on undeveloped land and seismic and \$1.3 million on initial drilling in the Stolberg area which were not reflected in any reserves additions in the Sproule reserves evaluation. The reserves attributed to the remaining \$3.3 million of capital expenditures, on drilling, completing and equipping the five heavy oil wells at Swimming by November 2010, were limited due to the short production history of the new wells.

### **Reserve Life Index**

Based on the reserves estimated by the Sproule Evaluation, Manitok has a reserve life index of 5.9 years on a proved basis versus 5.3 years at June 30, 2010 and 7.7 years on a proved plus probable basis versus 7.5 years at June 30, 2010.

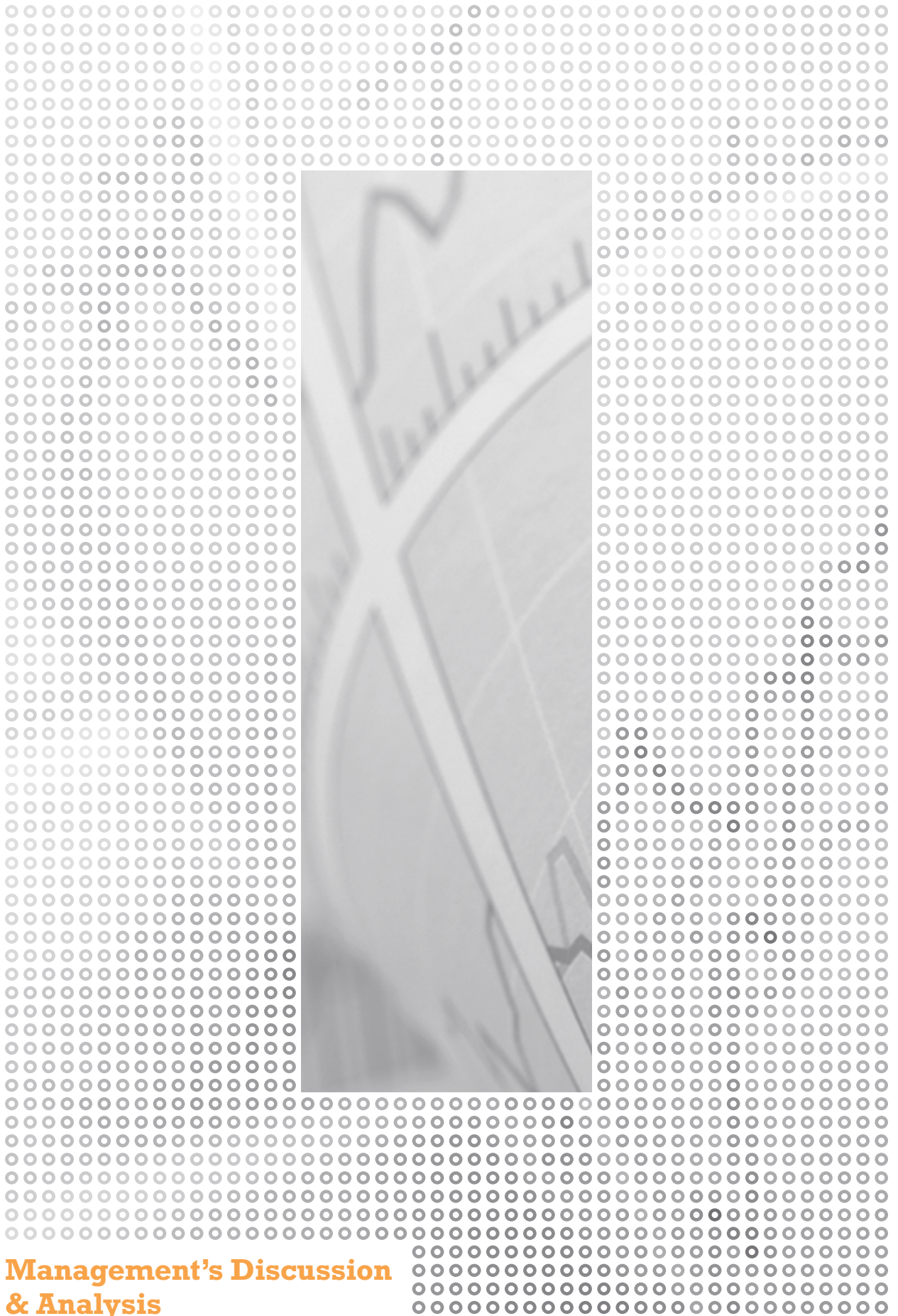
### **Advisory**

**Boe Conversions:** Barrels of oil equivalent (“boe”) amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet (6 mcf) of natural gas to one barrel of oil (1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

**Reserves Data:** All estimates of reserves volumes and future net revenues disclosed in this annual report are derived from the reserves evaluation dated March 30, 2011 which was prepared effective December 31, 2010 in accordance with National Instrument 51-101 by Sproule Associates Limited, an independent reserves evaluator. Estimates of reserves for each of June 30, 2009 and 2010 are derived from the evaluation of Manitok’s reserves prepared by Sproule Associates Limited.

**Reserves for Portion of Properties:** With respect to the disclosure of reserves contained in this annual report relating to portions of the Corporation’s properties, the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenues for all properties due to the effects of aggregation.

**Forward Looking Statements:** This Annual Report contains forward looking statements and forward looking information regarding the assets, business and operations of Manitok and the economic and regulatory environment in which it operates. The information, cautions, qualifications and disclosures made in Management’s Discussion and Analysis under the heading “Forward Looking Statements” in this annual report apply to all such forward looking statements in this annual report.



## **Management's Discussion & Analysis**

**MANITOK ENERGY INC.**  
**MANAGEMENT'S DISCUSSION & ANALYSIS**

**Manitok Energy Inc.** ("Manitok" or the "Corporation") is a junior oil and gas exploration, development and production company based in Calgary, Alberta. The Corporation formed as a result of an amalgamation between Manitok Exploration Inc. ("MEX") and Desco Resources Inc. ("Desco") pursuant to the Business Corporations Act (Alberta) on July 8, 2010 (the "Amalgamation") is listed on the TSX Venture Exchange under the symbol "MEI" and began trading on July 29, 2010. The Corporation's financial year end has been changed from June 30 to December 31, creating a six month fiscal year ended December 31, 2010. Additional information relating to the Corporation is available on the SEDAR website at [www.sedar.com](http://www.sedar.com).

The following Management's Discussion and Analysis ("MD&A") is dated April 20, 2011. The annual financial statements in respect of the three and six months ended December 31, 2010 (the "Reporting Periods") as compared to the three and twelve months ended June 30, 2010 (the "Comparable Prior Periods") and this MD&A have been prepared by management and approved by the Corporation's Audit Committee and Board of Directors. This MD&A should be read in conjunction with the unaudited interim financial statements of the Corporation and related notes for the Reporting Periods and Comparable Prior Periods, and the audited financial statements and related notes as at and for the six months ended December 31, 2010 and the twelve months ended June 30, 2010. All financial information (other than non-GAAP measures relating to terms used in the petroleum and natural gas industry) has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") and all dollar amounts are expressed in Canadian dollars unless otherwise stated.

**Selected Annual Information**

Period ended (\$, except for production and share information)	December 31, 2010	June 30, 2010
Average daily production (boe/d)	178.9	203.1
Petroleum and natural gas revenue	1,303,536	2,821,722
Total revenue, net royalties	1,205,794	2,394,365
Cash flow from operations	(633,824)	(141,868)
Per share – basic	(0.04)	(0.02)
Per share – diluted	(0.04)	(0.02)
Net earnings (loss)	(1,408,273)	(1,781,001)
Per share – basic	(0.08)	(0.26)
Per share – diluted	(0.08)	(0.26)
Capital expenditures, net <sup>(1)(2)</sup>	4,879,175	2,759,657
Total assets	43,884,291	17,591,508
Working capital deficiency (surplus)	(19,780,030)	(202,985)
Revolving credit facility	–	1,040,105
Total net debt <sup>(3)</sup>	–	837,120
Shareholders' equity	38,175,696	14,089,990
Common shares outstanding <sup>(4)</sup>		
End of period – basic	33,696,781	7,987,175
End of period – diluted	35,335,281	8,714,675
Weighted average shares for period – basic	17,402,916	6,948,060
Weighted average shares for period – diluted	17,402,916	6,948,060

(1) Included as a reduction of net capital expenditures in the period ended December 31, 2010 are proceeds of \$1.8 million relating to the disposition of a minor asset.

(2) Included as a reduction of net capital expenditures in the period ended December 31, 2010 is an expected recovery of \$0.1 million related to the Alberta Drilling Royalty Credit Program.

(3) Working capital (surplus) is only included in total net debt, if the Corporation is in a net debt position.

(4) All share balances in the prior period have been adjusted to reflect the 75% conversion factor of shares pursuant to the Amalgamation.

## Advisories

### Non-GAAP Measures

This MD&A and the Corporation's Quarterly and Annual Reports uses terms commonly used in the petroleum and natural gas industry, such as "cash flow", "netback", "operating netback" and "cash flow per share", which do not have standardized meanings prescribed by GAAP and therefore may not be comparable to measures by other companies where similar terminology is used. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding the Corporation's liquidity.

Cash flow appears as a separate line on the Corporation's Statements of Cash Flows above "changes in non-cash working capital" as cash provided by (used for) operating activities and is reconciled to net earnings (loss) and comprehensive earnings (loss). Operating netback denotes petroleum and natural gas revenue less royalties, less operating expenses and less transportation and marketing expenses.

### BOE Conversions

The oil and natural gas industry commonly expresses production volumes and reserves on a barrel of oil equivalent ("boe") basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved measurement of results and comparisons with other industry participants. Manitoq uses the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. However, boe's do not represent an economic value equivalency at the wellhead and therefore may be a misleading measure if used in isolation.

### Forward Looking Statements

This MD&A contains certain forward-looking statements and forward-looking information (hereinafter collectively referred to as "forward-looking statements") within the meaning of applicable Canadian securities laws. These statements relate to future events or future performance and are based upon the Corporation's current internal expectations, estimates, projections, assumptions and beliefs. All statements other than statements of historical fact are forward-looking statements. In some cases, words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "may", "will", "would", "potential", "proposed" and other similar words, or statements that certain events or conditions "may" or "will" occur, are intended to identify forward-looking statements.

Undue reliance should not be placed on these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions and known and unknown risks and uncertainties that the predictions, forecasts, projections and other forward-looking statements will not occur. Although the Corporation believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. The Corporation cannot guarantee future results, levels of activity, performance or achievements. Consequently, there is no representation by the Corporation that actual results achieved will be the same in whole or in part as those set out in the forward-looking statements. Such forward-looking statements in this MD&A speak only as of the date of this MD&A.

In particular, this MD&A contains forward-looking statements pertaining to the following: (i) cash flow and capital expenditures, (ii) drilling, completion and production matters, (iii) results of operations, (iv) financial position, and (v) other risks and uncertainties described from time to time in the Corporation reports. With respect to such forward-looking statements the key assumptions on which the Corporation relies are; that future prices for crude oil and natural gas, future currency exchange rates, interest rates and future availability of debt and equity financing will be at levels and costs that allow the Corporation to manage, operate and finance its business and develop its properties and meet its future obligations; that the regulatory framework in respect of royalties, taxes and environmental matters applicable to the Corporation will not become so onerous as to preclude the Corporation from viably managing, operating and financing its business and the development of its properties; and that the Corporation will continue to be able to identify, attract and employ qualified staff and obtain the outside expertise and other equipment it requires to manage, operate and finance its business and develop its properties.

All such forward-looking statements necessarily involve risks associated with oil and gas exploration, production and marketing which may cause actual results to differ materially from those anticipated in the forward-looking statements. Some of those risks include; general economic conditions in Canada, the United States and globally; industry conditions, including fluctuations in the price of oil and natural gas; uncertainties in the estimates of reserves and in the projection of future rates of production and timing of development expenditures, changes in governmental regulation of the oil and gas industry; geological, technical, drilling and processing problems and other difficulties in producing reserves; unanticipated operating events which can damage facilities or reduce production or cause production to be shut-in or delayed; failure to obtain regulatory approvals in a timely manner; adverse conditions in the debt and equity markets; and competition from others for scarce resources.

Readers are cautioned that the foregoing list of factors is not exhaustive. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement. The Corporation is not under any duty to update any of the forward-looking statements after the date of this MD&A to conform such statements to actual results or to changes in the Corporation's plans or expectations, except as otherwise required by applicable securities laws.

### Abbreviations

<b>Crude Oil and Natural Gas Liquids</b>		<b>Other</b>	
bbl	barrel	AECO	benchmark natural gas price determined at the AECO "C" hub in southeast Alberta
bbls	barrels		
bbls/d	barrels per day	WTI	West Texas Intermediate crude oil, a benchmark oil price determined at Cushing, Oklahoma
Mbbls	thousand barrels		
NGLs	natural gas liquids		
boe	barrels of oil equivalent	API	the measure of the density or gravity of liquid petroleum products
boe/d	barrels of oil equivalent per day		
Mboe	thousand barrels of oil equivalent		
<b>Natural Gas</b>			
mcf	thousand cubic feet		
mcf/d	thousand cubic feet per day		
Mmcf	million cubic feet		
Mmcf/d	million cubic feet per day		
Bcf	billion cubic feet		
mmbtu	million British thermal units		
GJ	Gigajoule		

## Overall Performance

### Production

Production in the six month Reporting Period averaged 178.9 boe/d, which is a 12% decrease from the average of 203.1 boe/d in the twelve month Comparable Prior Period. A portion of the decrease in production is due to normal production declines in the natural gas assets and an unusual amount of downtime in two areas and a sale of assets in a third area. A plant turnaround and compressor startup issue in August and September in the Hairy Hill area of Alberta resulted in a decrease of approximately 8 boe/d over the six month period and the production was shut-in for the majority of September in the Coleman area of Alberta, due to circumstances at the gas plant which were out of the Corporation's control, resulting in a decrease of approximately 5 boe/d over the six month period. The disposition of a property on August 4, 2010 in the Garrington area of Alberta represented approximately 10 boe/d over the six month period. The decline in natural gas production was partially offset by an increase in heavy oil production in the six month Reporting Period as it increased 12% from the twelve month Comparable Prior Period, due to five new heavy oil wells which began producing in November 2010.

For the six month Reporting Period, the Corporation's production consisted of approximately 53% natural gas and 47% crude oil and natural gas liquids. See "Results of Operations – Petroleum and Natural Gas Revenue".

### Commodity Prices

Average realized heavy oil prices in the six month Reporting Period were \$59.89 per barrel which is a 1% decrease from \$60.48 per barrel the Corporation averaged in the twelve month Comparable Prior Period. Average realized natural gas prices in the six month Reporting Period were \$3.69 per mcf which is an 11% decrease from \$4.14 per mcf the Corporation averaged in the twelve month Comparable Prior Period. The prices received for ManitoK's petroleum and natural gas sales are impacted by world events that dictate the level of supply and demand for crude oil and natural gas. ManitoK currently does not have any commodity hedges in place and thus is subject to fluctuations in commodity prices.

The 12° API heavy oil prices at Hardisty, Alberta averaged \$60.35 per barrel in the six month Reporting Period as compared to \$63.41 per barrel in the twelve month Comparable Prior Period. The AECO daily natural gas spot price averaged \$3.59 per mmbtu in the six month Reporting Period as compared to \$4.10 per mmbtu in the twelve month Comparable Prior Period. The reduction in commodity prices translated into reduced cash flow in the six month period.

### Cash Flow and Earnings

Cash flow is considered a non-GAAP measure commonly used in the oil and gas industry. Cash flow should not be considered an alternative to, or more meaningful than, cash provided by (used for) operating, investing and financing activities or net earnings (loss) as determined in accordance with Canadian GAAP, as an indicator of the Corporation's performance or liquidity.

The following schedule sets out the reconciliation of cash provided by (used for) operating activities to cash flow from operations:

Six and twelve months ended (\$)	December 31, 2010	June 30, 2010
Cash provided by (used for) operating activities	(893,234)	127,295
Asset retirement expenditures	53,945	—
Changes in non-cash working capital	205,465	(269,163)
Cash flow from operations	(633,824)	(141,868)
per share – basic	(0.04)	(0.02)
per share – diluted	(0.04)	(0.02)

Cash flow from operations<sup>(1)</sup> decreased to (\$633,824) (\$0.04 per share) for the six month Reporting Period as compared to (\$141,868) (\$0.02 per share) for the twelve month Comparable Prior Period. The decrease in cash flow for the six month Reporting Period as compared to the twelve month Comparable Prior Period was due mainly to an 86% increase in general and administrative costs per boe due to a significant increase in professional personnel levels in anticipation of the Corporation's future activity and additional legal, accounting and regulatory fees as a result of becoming a reporting issuer. Also affecting cash flow, to a lesser degree was a 12% decrease in average daily production volumes and an increase in processing and maintenance costs in the natural gas assets in the Coleman area of Alberta.

Manitok had a net loss of \$1,408,273 (\$0.08 per share) for the six month Reporting Period as compared to a net loss of \$1,781,001 (\$0.26 per share) for the twelve month Comparable Prior Period. The net loss for the Reporting Period was mainly attributable to the lower cash flow and higher stock-based compensation expense from the stock options granted in August 2010.

### Capital Expenditures

Capital expenditures before dispositions amounted to \$6,679,085 during the six month Reporting Period as compared to \$2,799,657 during the twelve month Comparable Prior Period. The increase in capital expenditures for the Reporting Period as compared to the Comparable Prior Period was due mainly to the drilling program of five heavy oil wells in east central Alberta and the commencement of a well in the Alberta Foothills. The majority of capital expenditures in the Comparable Prior Period were related to undeveloped land acquisitions at Alberta crown land sales that management believe were at a time of relatively weak land values in the Corporation's core areas. On August 4, 2010, the Corporation completed the sale of a minor property in the Garrington area of Alberta for approximately \$1.8 million which partially offset the Corporation's capital program.

Of the total capital spent before dispositions, for the six month Reporting Period, approximately 66% was directed to drilling, completion, and equipping costs for the Corporation's drilling program.

(1) Cash flow denoted with a "()", is negative throughout this MD&A.

## Major Transactions Affecting Financial Results

- On July 8, 2010, immediately prior to the Amalgamation, MEX completed a private placement of 4,311,700 Class “A” common shares of MEX (“MEX Shares”) (equivalent to 3,233,775 common shares of Manitek (“Manitek Shares”) issued at a price of \$1.15 per MEX Share (equivalent to \$1.53 per Manitek Share) and 3,846,000 MEX Shares on a “flow-through” basis under the Income Tax Act (Canada) (“MEX Flow-through Shares”) (equivalent to 2,884,500 Manitek Shares issued on a “flow-through” basis under the Income Tax Act (Canada) (“Manitek Flow-through Shares”) issued at a price of \$1.30 per MEX Flow-through Share (equivalent to \$1.73 per Manitek Flow-through Share) for total net proceeds of \$9.1 million. Proceeds of the private placement were used to repay the outstanding bank debt and fund the Corporation’s drilling program in late 2010.
- On July 8, 2010, MEX amalgamated with Desco, a TSX Venture Exchange listed reporting issuer, pursuant to the Business Corporations Act (Alberta) to form a new company under the name Manitek Energy Inc. Pursuant to the Amalgamation, each Desco shareholder received 0.375 of a Manitek Share for every one Desco common share and each MEX shareholder received 0.75 of a Manitek Share for every one MEX Share.
- On July 8, 2010, 702,500 of MEX stock options and 267,500 of MEX performance warrants were terminated and cancelled for nominal consideration, pursuant to the terms of the Amalgamation.
- On August 4, 2010, the Corporation completed the disposition of a minor oil & gas asset in the Garrington area of Alberta for approximately \$1.8 million. The proceeds were used to partially fund the Corporation’s capital program.
- On August 16, 2010 Manitek granted 1,588,500 stock options at a price of \$1.10 per share which vest over a three year period and expire on August 16, 2015.
- On December 22, 2010, Manitek completed the first tranche of a private placement of 10,031,500 Manitek Shares issued at a price of \$1.00 per Manitek Share and 6,618,559 Manitek Flow-through Shares issued at a price of \$1.15 per Manitek Flow-through Share for net proceeds of \$16.3 million. Proceeds of the private placement will be used to fund the Corporation’s drilling program in 2011.
- On December 30, 2010, Manitek completed the second and final tranche of a private placement of 325,400 Manitek Shares issued at a price of \$1.00 per Manitek Share and 110,130 Manitek Flow-through Shares issued at a price of \$1.15 per Manitek Flow-through Share for net proceeds of \$0.4 million. Proceeds of the private placement will be used to fund the Corporation’s drilling program in 2011.

## Major Transactions Subsequent to the Reporting Period

- On April 14, 2011 Manitek closed an equity financing, completed by way of a short form prospectus, for the sale of 17,968,750 Manitek Shares issued at a price of \$1.60 per Manitek Share for net proceeds of approximately \$26.8 million. Proceeds of the equity issue will be used to fund the Corporation’s drilling program and the acquisition of undeveloped land and seismic in 2011 and early 2012.

## Liquidity

### Working Capital

The Corporation's working capital surplus (current assets less current liabilities), which excludes any current portion of an amount drawn on the revolving credit facility, increased to \$19,780,030 at the end of the Reporting Period as compared to a \$202,985 working capital surplus at June 30, 2010. The increase in the working capital surplus at December 31, 2010 was due primarily to net cash proceeds of \$25.8 million received from the equity issuances in July 2010 and December 2010.

At December 31, 2010, the major components of ManitoK's current assets were: cash and cash equivalents (93%); joint venture billings (2%) to be received from its partners; and revenue (2%) to be received from its marketers in respect of December 2010 production, the majority of which was subsequently received in January 2011. In contrast, current liabilities largely consisted of trade payables (74%) and accrued capital costs (10%). Cash on hand at the end of 2010 was used to reduce outstanding trade payables in January 2011.

Manitok has invested the excess cash in a short-term interest bearing account with its lender. The Corporation can manage its working capital using its cash flow from operations, excess funds from its equity issuances and advances under its revolving credit facility. The Corporation did not have any liquidity issues with respect to the operation of its petroleum and natural gas business in the Reporting Period and the Comparable Prior Period.

### Bank Debt

The Corporation's revolving credit facility was \$NIL as at December 31, 2010, with an aggregate limit of \$2,500,000 as compared to \$1,040,105 as at June 30, 2010, when the aggregate limit was \$2,500,000. The outstanding bank debt was eliminated in the Reporting Period due to the net cash proceeds of \$9.1 million received from the equity issuances on July 8, 2010.

On October 20, 2010, the Corporation renewed the revolving credit facility with an authorized limit of \$2,500,000 with similar terms and conditions as the prior agreement. The Corporation's credit facilities are subject to the lender's redetermination of the borrowing base limit which is directly impacted by the value of the oil and natural gas reserves.

The Corporation is not permitted, without the prior written consent of the lender, to have a working capital ratio (current assets plus any undrawn portion of the facility divided by current liabilities excluding any current portion of an amount drawn on the credit facility) fall below 1:1. ManitoK was compliant with the covenant under its revolving credit facility throughout the Reporting Period and the Comparable Prior Period.

### Contractual Obligations

The Corporation enters into contractual obligations in the course of conducting its day-to-day business. The following table identifies ManitoK's estimated contractual obligations at December 31, 2010:

	< 1 Year	1-2 Years	3-5 Years	Thereafter
Accounts payable and accrued liabilities	3,579,357	—	—	—
Revolving credit facility	—	—	—	—
Office lease <sup>(1)</sup>	302,640	302,640	731,380	—
<b>Total estimated contractual obligations<sup>(2)</sup></b>	<b>3,881,997</b>	<b>302,640</b>	<b>731,380</b>	<b>—</b>

(1) The Corporation is committed under an operating lease relating to its office premises, which began on May 1, 2010 and expires on June 30, 2015. ManitoK does not presently use all of the leased premises and has sublet 5 offices to arms' length parties to recover a portion of the rental costs. The recovery of rental costs from the subleases is not reflected in the table.

(2) Contractual commitments that are routine in nature and form part of the normal course of operations for ManitoK are not included in the above table.

## Outstanding Share Data

The MEX Shares were the only class of shares outstanding and immediately prior to the Amalgamation on July 8, 2010, there were 18,807,267 MEX Shares outstanding, stock options to purchase 702,500 MEX Shares and performance warrants to purchase 267,500 MEX Shares. Subsequent to the Amalgamation, the Manitoq Shares are the only class of shares outstanding. Manitoq Shares began trading on the TSX Venture Exchange on July 29, 2010 under the symbol MEI. The following table summarizes the Manitoq Shares issued and outstanding:

	Common Shares
<b>MEX balance at June 30, 2009</b>	<b>8,176,826</b>
Issue of MEX Shares on December 31, 2009 <sup>(1)</sup>	1,235,741
Issue of MEX Shares on February 12, 2010 <sup>(2)</sup>	1,237,000
<b>MEX balance at June 30, 2010</b>	<b>10,649,567</b>
Issue of MEX Shares on July 8, 2010 <sup>(3)</sup>	8,157,700
<b>MEX balance at July 8, 2010 (prior to the Amalgamation)</b>	<b>18,807,267</b>
Issue of Manitoq Shares on the Amalgamation <sup>(4)</sup>	2,625,000
Conversion of MEX shareholders on the Amalgamation <sup>(5)</sup>	(4,701,807)
Issue of Manitoq Shares on December 22, 2010 <sup>(6)</sup>	16,650,059
Redemption of Manitoq Shares on December 23, 2010 <sup>(7)</sup>	(119,268)
Issue of Manitoq Shares on December 30, 2010 <sup>(8)</sup>	435,530
<b>Manitoq balance at December 31, 2010</b>	<b>33,696,781</b>

- (1) On December 31, 2009, MEX completed a private placement of 176,956 MEX Shares (equivalent to 132,717 Manitoq Shares) issued at a price of \$1.15 per MEX Share (equivalent to \$1.53 per Manitoq Share) and 1,058,785 MEX Flow-through Shares (equivalent to 794,089 Manitoq Flow-through Shares) issued at a price of \$1.30 per MEX Flow-through Share (equivalent to \$1.73 per Manitoq Flow-through Share) for total net proceeds of \$1.5 million. The proceeds of the equity issue were used primarily to pay the outstanding balance on the revolving credit facility.
- (2) On February 12, 2010, MEX completed a private placement of 1,237,000 MEX Shares (equivalent to 927,750 Manitoq Shares) issued at a price of \$1.15 per MEX Share (equivalent to \$1.53 per Manitoq Share) for total net proceeds of \$1.3 million. The proceeds of the equity issue were used primarily to fund the Corporation's capital program.
- (3) On July 8, 2010, MEX completed a private placement of 4,311,700 MEX Shares (equivalent to 3,233,775 Manitoq Shares) issued at a price of \$1.15 per MEX Share (equivalent to \$1.53 per Manitoq Share) and 3,846,000 MEX Flow-through Shares (equivalent to 2,884,500 Manitoq Flow-through Shares) issued at a price of \$1.30 per MEX Flow-through Share (equivalent to \$1.73 per Manitoq Flow-through Share) for total net proceeds of \$9.1 million. Proceeds of the equity issue were used to pay the outstanding balance on the revolving credit facility and fund the Corporation's drilling program in late 2010.
- (4) On the Amalgamation each Desco shareholder received 0.375 of a Manitoq Share for every one Desco share held. As of the Amalgamation date, Desco had 7,000,000 common shares issued and outstanding.
- (5) On the Amalgamation each MEX shareholder received 0.75 of a Manitoq Share for every one MEX Share held. As of the Amalgamation date, MEX had 18,807,267 MEX Shares issued and outstanding.
- (6) On December 22, 2010, Manitoq completed the first tranche of a private placement of 10,031,500 Manitoq Shares issued at a price of \$1.00 per Manitoq Share and 6,618,559 Manitoq Flow-through Shares issued at a price of \$1.15 per Manitoq Flow-through Share for net proceeds of \$16.3 million. Proceeds of the private placement will be used to fund the Corporation's drilling program in 2011.
- (7) On December 23, 2010, Manitoq purchased for cancellation 119,268 Manitoq Shares at a price of \$1.00 per Manitoq Share pursuant to an arrangement with a previous employee of the Corporation.
- (8) On December 30, 2010, Manitoq completed the second and final tranche of a private placement of 325,400 Manitoq Shares issued at a price of \$1.00 per Manitoq Share and 110,130 Manitoq Flow-through Shares issued at a price of \$1.15 per Manitoq Flow-through Share for net proceeds of \$0.4 million. Proceeds of the private placement will be used to fund the Corporation's drilling program in 2011.

At April 20, 2011 there were 51,665,531 Manitoq Shares outstanding and 2,915,500 stock options to purchase an equivalent number of Manitoq Shares. The increase in Manitoq Shares from December 31, 2010 relate to an equity financing on April 14, 2011 pursuant to a short form prospectus offering whereby it issued 17,968,750 Manitoq Shares issued at a price of \$1.60 per Manitoq Share for net proceeds of approximately \$26.8 million.

## Results of Operations

### Petroleum and Natural Gas Revenue

The following table details Manitok's petroleum and natural gas revenue ("P&NG"), production and average realized sales prices by category for the Reporting Periods and the Comparable Prior Periods:

	Three months ended December 31, 2010				Three months ended June 30, 2010			
	Total Revenue (\$)	Average Daily Production	%	Average (\$/unit)	Total Revenue (\$)	Average Daily Production	%	Average (\$/unit)
	Natural gas (mcf)	202,081	604.0	51	3.64	219,335	610.3	54
Heavy oil (bbls)	556,146	97.5	49	62.04	374,219	79.9	43	51.50
Light oil (bbls)	—	—	—	—	4,756	0.7	—	69.97
Natural gas liquids (bbls)	1,505	0.2	—	64.19	17,567	5.6	3	34.21
Total P&NG revenue (boe)	759,732	198.4	100	41.63	615,877	188.0	100	36.01

	Six months ended December 31, 2010				Twelve months ended June 30, 2010			
	Total Revenue (\$)	Average Daily Production	%	Average (\$/unit)	Total Revenue (\$)	Average Daily Production	%	Average (\$/unit)
	Natural gas (mcf)	386,019	568.8	53	3.69	1,117,241	739.1	61
Heavy oil (bbls)	906,234	82.3	46	59.89	1,615,964	73.2	36	60.48
Light oil (bbls)	1,808	0.1	—	70.64	28,616	1.1	—	71.83
Natural gas liquids (bbls)	9,475	1.7	1	29.58	59,901	5.6	3	29.28
Total P&NG revenue (boe)	1,303,536	178.9	100	39.59	2,821,722	203.1	100	38.07

The 23% increase in petroleum and natural gas revenue in the three month Reporting Period as compared to the Comparable Prior Period was primarily attributable to a 22% increase in the average daily production volume of heavy oil and a 20% increase in the average realized sales price of heavy oil during the Reporting Period. The 50% decrease in petroleum and natural gas revenue in the six month Reporting Period as compared to the twelve month Comparable Prior Period was due mainly to the shortened Reporting Period as a result of the change in year end and an 11% decrease in the average realized natural gas prices during the Reporting Period.

### Commodity Prices

Manitok's heavy oil pricing is based on Lloydminster Blend at Hardisty less a quality adjustment, blending costs, terminal charges and loss allowance. The Corporation sells virtually all of its natural gas production for prices based on the AECO daily spot price. The following table details the average reference price for the Reporting Periods and the Comparable Prior Periods:

	Three months ended			Six months ended			Twelve months ended		
	December 31			December 31			June 30		
	2010	2010	Change	2010	2010	Change	2010	2010	Change
Heavy oil – 12° API at Hardisty (\$/bbl)	<b>62.30</b>	59.70	4.4%	<b>60.35</b>	63.41	(4.8%)			
Natural gas – AECO (\$/mmbtu) <sup>(1)</sup>	<b>3.63</b>	3.90	(6.9%)	<b>3.59</b>	4.10	(12.4%)			
Light oil – Edmonton par (\$/bbl)	<b>80.71</b>	75.44	7.0%	<b>77.74</b>	76.05	2.2%			

(1) \$1.00/mmbtu = \$1.00/mcf based on a standard heat value mcf.

The price the Corporation receives for its commodity production depends on a number of factors, including AECO Canadian dollar spot market prices for natural gas, Hardisty Canadian dollar heavy oil prices, U.S. dollar oil prices, the U.S./Canadian dollar exchange rate, and transportation and product quality differentials. Manitok currently has no financial derivatives such as fixed commodity price contracts or other hedge type contracts, but it regularly considers managing the risks associated with fluctuating spot market prices for natural gas and U.S. dollar oil prices and the U.S./Canadian dollar exchange rate. The Corporation has no current intention to enter into any such contracts at this time.

### Royalties

Royalties are paid to the Alberta Government and other land and mineral rights owners. The following table illustrates the Corporation's royalty expense for the Reporting Periods and the Comparable Prior Periods:

	Three months ended			Six months ended			Twelve months ended		
	December 31			December 31			June 30		
	2010	2010	Change	2010	2010	Change	2010	2010	Change
Oil & natural gas royalties (\$)	<b>67,581</b>	80,745	(16.3%)	<b>133,341</b>	427,912	(68.8%)			
Oil & natural gas royalties (\$/boe)	<b>3.70</b>	4.72	(21.6%)	<b>4.05</b>	5.77	(29.8%)			
Effective royalty rate (%) <sup>(1)</sup>	<b>8.9%</b>	13.1%	(32.1%)	<b>10.2%</b>	15.2%	(32.9%)			

(1) The effective royalty rate is calculated by dividing the total aggregate royalties into P&NG revenue for the period.

The overall effective royalty rate in the three and six month Reporting Periods was 8.9% and 10.2% as compared to 13.1% and 15.2% in the Comparable Prior Periods, respectively. The decrease in the effective royalty rates in the Reporting Period as compared to the Comparable Prior Period is largely due to production royalty incentives for the new heavy oils wells brought on production in the fall of 2010 that are subject to a 5% royalty rate, a reduction in heavy oil volumes at one well location not subject to the incentive royalty rate which attracted a lower royalty rate and a reduction in natural gas volumes and natural gas prices which also attracts a lower royalty rate.

### *New Royalty and Drilling Incentives*

On July 9, 2009, the Government of Alberta approved an incentive royalty rate of 5% for the first year of production from each new conventional oil or natural gas well brought on production after April 1, 2009 and before March 31, 2011 up to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas per well.

On September 15, 2009, the Government of Alberta approved a Drilling Royalty Credit (“DRC”) incentive for new conventional oil and natural gas wells spud on or after April 1, 2009 and rig released before April 1, 2011. The Corporation is entitled to a DRC of \$200 per metre drilled, up to a maximum of 50% of the aggregate Crown royalties paid by the Corporation during the incentive period. Included as a reduction of net capital in the six month Reporting Period is an expected recovery of \$103,896 in DRCs related to this incentive program.

On March 11, 2010, the Alberta Government announced certain changes to the existing royalty framework based on the recommendations from the Investment Competitiveness Review. As a result of the competitiveness review, the existing Alberta Royalty Framework (“ARF”) will be adjusted to better reflect current industry conditions. The adjusted ARF will be effective for the January 2011 production month. Some of the highlights include:

- The current 5% front-end royalty rate on natural gas and conventional oil will become a permanent feature of the royalty system with the current time and volume limits as described above.
- The \$200 per metre DRC program will continue to remain in place as legislated until March 31, 2011. Credits not used prior to January 1, 2011 and credits established by drilling on or after that date until March 31, 2011 will be offset from net royalties calculated using adjusted ARF rates.
- The maximum royalty rate for conventional and unconventional natural gas will be reduced from 50% to 36%. For conventional oil, the maximum royalty will be reduced from 50% to 40%.
- The transitional royalty framework for oil and gas introduced in November 2008 will continue until December 31, 2013. Effective January 1, 2011, the government will not allow any new wells to elect the transitional royalty rates, but will allow an operator of wells for which transitional royalty rates have already been elected an option to switch to the new rates effective January 1, 2011.

On May 27, 2010 the Alberta government finalized the new royalty curves for oil and natural gas wells. A number of new incentive programs were also introduced for unconventional resource exploration and the use of high-cost technologies. Some of the highlights include:

- Wells defined as a “horizontal gas well” will receive a lower up-front maximum royalty rate of 5% to account for the high cost of horizontal drilling. This new horizontal gas well royalty rate will apply for 18 producing months up to a maximum of 500 million cubic feet of natural gas production per well, and is retroactive for wells that were spud on or after May 1, 2010.
- Wells defined as a “horizontal oil well” will receive a lower up-front maximum royalty rate of 5% at the start of production to facilitate the recovery of investment costs prior to imposing a higher royalty rate. This new horizontal oil well royalty rate will apply to all products, with varying volume and production month limits set according to the depth of the well, and is retroactive for wells that were spud on or after May 1, 2010.
- The Natural Gas Deep Drilling Program (“NGDDP”) will become an ongoing feature of Alberta’s royalty regime. Vertical depth requirements under this program were adjusted from 2,500 metres to 2,000 metres and will be applied retroactively for wells that were spud on or after May 1, 2010. Wells that

have producing intervals that exceed 2,000 metres of true vertical depth are eligible for a royalty credit adjustment. The royalty credit ranges from \$625 per metre to \$3,750 per metre drilled and depends on the type of well drilled and the depth ranges specified under the program.

These royalty incentive programs will create a lower cost structure for Manitek. Projects will have better economics under the new royalty framework as compared to the prior framework and therefore are more likely to be approved for capital spending during this current low natural gas commodity cycle.

### Operating Expense

The following table compares operating expenses for the Reporting Periods and the Comparable Prior Periods:

	Three months ended December 31, 2010		Three months ended June 30, 2010		Change	
	(\$)	\$/boe	(\$)	\$/boe	Amount	per boe
Field operating expenses	311,680	17.08	234,887	13.73	32.7%	24.4%
Expensed workovers	40,353	2.21	—	—	—	—
Total operating expenses	352,033	19.29	234,887	13.73	49.9%	40.5%

	Six months ended December 31, 2010		Twelve months ended June 30, 2010		Change	
	(\$)	\$/boe	(\$)	\$/boe	Amount	per boe
Field operating expenses	637,683	19.37	1,053,512	14.21	(39.5%)	36.3%
Expensed workovers	40,353	1.23	—	—	—	—
Total operating expenses	678,036	20.60	1,053,512	14.21	(35.6%)	45.0%

Total operating costs per boe increased by \$5.56 and \$6.39 in the three and six month Reporting Period as compared to the three and twelve month Comparable Prior Period. This was due partially to the expensed workovers on the heavy oil wells incurred in the Reporting Period. The remainder of the increase was due mainly to the higher proportion of heavy oil production relative to the total corporate production. Heavy oil operating costs are much higher on a per boe basis than natural gas operating costs. There were also additional expenses incurred in the start-up phase of the new heavy oil wells and an increase in processing and maintenance costs in the natural gas assets in the Coleman area of Alberta. Manitek will continue to monitor operating costs at all of its properties in an effort to reduce costs where possible.

### Transportation and Marketing Expense

The following table illustrates the Corporation's transportation and marketing expense for the Reporting Periods and the Comparable Prior Periods:

	Three months ended December 31 2010	Three months ended June 30 2010	Change	Six months ended December 31 2010	Twelve months ended June 30 2010	Change
	Transportation & marketing expenses (\$)	30,100	29,501	2.0%	58,399	131,175
Transportation & marketing expenses (\$/boe)	1.65	1.72	(4.1%)	1.77	1.77	—

These costs consist primarily of transportation costs and have remained relatively consistent in the Reporting Periods on a per boe basis as compared to the Comparable Prior Periods.

### General and Administrative Expense

The components of general and administrative costs ("G&A") for the Reporting Periods and the Comparable Prior Periods are as follows:

	Three months ended December 31, 2010		Three months ended June 30, 2010		Change
	(\$)	%	(\$)	%	
Salaries, benefits and consultants	356,463	59	253,376	83	40.7%
Other	245,969	41	50,830	17	383.9%
G&A expense, gross	602,432	100	304,206	100	98.0%
Overhead recoveries	(17,088)	(3)	64	—	—
Capitalized overhead	—	—	—	—	—
G&A expense, net	585,344	97	304,270	100	92.4%
G&A expense, net per boe	32.07		17.79		80.3%

	Six months ended December 31, 2010		Twelve months ended June 30, 2010		Change
	(\$)	(%)	(\$)	(%)	
Salaries, benefits and consultants	662,229	59	795,331	60	(16.7%)
Other	457,273	41	539,395	40	(15.2%)
G&A expense, gross	1,119,502	100	1,334,726	100	(16.1%)
Overhead recoveries	(17,088)	(2)	(426)	—	—
Capitalized overhead	—	—	—	—	—
G&A expense, net	1,102,414	98	1,334,300	100	(17.4%)
G&A expense, net per boe	33.49		18.00		86.1%

The increase in net G&A expenses of \$14.28 and \$15.49 per boe in the three and six month Reporting Period as compared to the three and twelve month Comparable Prior Period is due primarily to the costs incurred in anticipation of the Corporation's future growth. The costs included increased professional personnel levels and additional software requirements to accommodate an increase in capital spending, an increase in office rent due to larger space requirements, additional legal, accounting and regulatory fees as a result of becoming a public entity and a severance payment related to the settlement of a legal dispute with a former employee.

The capitalization of costs in the "overhead recoveries" category reflects an industry standard charge per Authorization for Expenditure to capitalize engineering, land, accounting and operations time related to overhead costs spent on capital projects that are not 100% owned by the Corporation, whereas the "capitalized overhead" category reflects a portion of costs relating to Manitok's exploration and geology department, which were \$NIL in the Reporting Period and Comparable Prior Period.

### Interest Expense

Interest expense for the three and six month Reporting Periods was \$1 (\$0.00 per boe) and \$769 (\$0.02 per boe) as compared to \$5,148 (\$0.30 per boe) and \$17,246 (\$0.23 per boe) for the Comparable Prior Periods. The overall effective interest rate applicable to the prime-based loans was 4.0% and 4.5% in the three and six Reporting Periods as compared to 3.9% and 3.7% in the Comparable Prior Periods.

The Corporation's average bank debt was approximately \$100 and \$38,000 in the three and six Reporting Periods as compared to \$406,000 and \$471,000 in the Comparable Prior Periods, calculated as a simple average of the daily amounts.

### Deferred Financing Fees

During the Reporting Period the Corporation charged \$327,947 in fees to share capital, which related to costs incurred in the fourth quarter of the June 30, 2010 fiscal period, for the issuance of MEX Shares and the Amalgamation completed on July 8, 2010.

### Depletion, Depreciation and Accretion Expenses

The components of depletion, depreciation and accretion (“DD&A”) expenses for the Reporting Periods and the Comparable Prior Periods are as follows:

	Three months ended December 31, 2010		Three months ended June 30, 2010		Change	
	(\$)	\$/boe	(\$)	\$/boe	Amount	per boe
Depletion & depreciation	546,448	29.94	459,781	26.88	18.8%	11.4%
Accretion for asset retirement obligations	17,860	0.98	14,800	0.87	20.7%	12.6%
Total DD&A	564,308	30.92	474,581	27.75	18.9%	11.4%

	Six months ended December 31, 2010		Twelve months ended June 30, 2010		Change	
	(\$)	\$/boe	(\$)	\$/boe	Amount	per boe
Depletion & depreciation	942,683	28.63	2,092,940	28.24	(55.0%)	1.4%
Accretion for asset retirement obligations	29,800	0.91	75,000	1.01	(60.3%)	(9.9%)
Total DD&A	972,483	29.54	2,167,940	29.25	(55.1%)	1.0%

DD&A expenses on a per boe basis remained relatively consistent in the six month Reporting Period as compared to the twelve month Comparable Prior Period. DD&A is a function of the estimated proved reserve additions, the associated future development capital required to recover those proved reserves, the cost of petroleum and natural gas properties in the full cost pool attributable to those proved reserves and production in the period. As at December 31, 2010, the Corporation excluded from its full cost pool \$4,003,802 (June 30, 2010 – \$3,354,945) of undeveloped land acquired by Manitok and \$2,063,914 (June 30, 2010 – \$NIL) for the drilling and seismic program in the Alberta Foothills which commenced in the Reporting Period, but was not assigned any proven reserves.

### Petroleum and Natural Gas Properties Impairment Test

The Corporation follows the full cost method of accounting which requires periodic review of capitalized costs to ensure that they do not exceed the recoverable value of the petroleum and natural gas properties and the fair value of the Corporation’s assets.

Manitok performed an impairment review at December 31, 2010 and June 30, 2010 on its petroleum and natural gas assets and based on this review, the Corporation determined there was no impairment of its petroleum and natural gas assets. The assumptions used in the impairment test are discussed in this MD&A in the “Critical Accounting Estimates” section.

### Stock-Based Compensation Expense

Manitok accounts for its stock-based compensation program which is stock options, using the fair value method. The related expense is recorded in the income statement over the vesting period.

The Corporation recorded a non-cash stock-based compensation expense of \$184,676 (\$10.12 per boe) for the three month Reporting Period and \$273,216 (\$8.30 per boe) for the six month Reporting Period as compared to (\$22,802) (\$1.33 per boe) and \$55,529 (\$0.75 per boe) for the Comparable Prior Periods.

The increase in stock-based compensation expense from the Comparable Prior Periods was due mainly to the issuance of 1,588,500 stock options to directors, officers, employees and key consultants of Manitok at an exercise price of \$1.10 per Manitok Share on August 16, 2010.

### Taxes

Manitok recorded a future income tax recovery of \$215,042 (\$11.78 per boe) for the three month Reporting Period and \$471,250 (\$14.31 per boe) for the six month Reporting Period, as compared to a recovery of \$134,684 (\$7.87 per boe) and \$584,336 (\$7.88 per boe) for the Comparable Prior Periods. These recoveries were attributed to the net losses recorded during the Reporting Periods and Comparable Prior Periods. Manitok incurred \$1,114 and \$3,792 Part XII.6 taxes in the three and six month Reporting Periods as compared to \$10,323 and \$17,205 in the Comparable Prior Periods.

### Capital Expenditures and Capital Resources

Capital expenditures amounted to \$3,205,267 and \$4,879,175 during the three and six month Reporting Periods as compared \$432,385 and \$2,759,657 during the Comparable Prior Periods. The significant increase in capital expenditures for the Reporting Period as compared to the Comparable Prior Period was due mainly to the Corporation's heavy oil drilling program which commenced in August and September of 2010 and the commencement of a well in the Alberta Foothills in December 2010. The drilling program was funded with the equity issuance in July 2010.

### Capital Expenditures

The following table sets forth a summary of the Corporation's capital expenditures incurred during the Reporting Periods and the Comparable Prior Periods:

Three months ended (\$)	December 31, 2010	June 30, 2010
Land	(234,197)	157,285
Seismic	526,274	213,234
Workovers and recompletions	136,123	73,319
Drilling and completions <sup>(1)</sup>	1,593,407	56,347
Well equipment and facilities	1,144,486	10,581
Total finding and development costs (F&D)	3,166,093	510,766
Acquisitions (dispositions), net	2,892	—
Total finding, development and acquisition costs (FD&A)	3,168,985	510,766
Administrative assets	36,282	(78,381)
Total capital expenditures	3,205,267	432,385

(1) Included in drilling and completions for the period ended December 31, 2010 is an expected recovery of \$0.1 million related to the Alberta Drilling Royalty Credit Program.

Six and twelve months ended (\$)	December 31, 2010	June 30, 2010
Land	1,420,100	2,212,543
Seismic	635,091	266,653
Workovers and recompletions	147,768	183,968
Drilling and completions <sup>(1)</sup>	3,199,100	103,119
Well equipment and facilities	1,234,254	5,039
Total finding and development costs (F&D)	6,636,313	2,771,322
Acquisitions (dispositions), net <sup>(2)</sup>	(1,799,910)	(40,000)
Total finding, development and acquisition costs (FD&A)	4,836,403	2,731,322
Administrative assets	42,772	28,335
Total capital expenditures	4,879,175	2,759,657

(1) Included in drilling and completions for the period ended December 31, 2010 is an expected recovery of \$0.1 million related to the Alberta Drilling Royalty Credit Program.

(2) On August 4, 2010, the Corporation sold a non-core asset in the Garrington area of Alberta for approximately \$1.8 million.

## Capital Resources

The following table sets forth a summary of the Corporation's capital resources for the Reporting Periods and the Comparable Prior Periods:

Three months ended (\$)	December 31, 2010	June 30, 2010
Cash flow from operations	(254,489)	(39,066)
Changes in non-cash working capital from operations	(395,172)	206,705
Asset retirement expenditures	(53,945)	–
Increase (decrease) in revolving credit facility	–	701,844
Proceeds from share issuances	18,094,892	–
Share issue costs	(1,340,741)	(99,060)
Cost of the Amalgamation	(449)	(229,586)
Redemption of common shares	(119,268)	–
Changes in non-cash working capital from investing	455,437	(108,470)
Total capital resources	16,386,265	432,367
Expenditures on petroleum and natural gas assets	(3,202,375)	(432,385)
Property acquisitions and dispositions	(2,892)	–
Net Change in Cash	13,180,998	(18)

Six and twelve months ended (\$)	December 31, 2010	June 30, 2010
Cash flow from operations	(633,824)	(141,868)
Changes in non-cash working capital from operations	(205,465)	269,163
Asset retirement expenditures	(53,945)	–
Increase (decrease) in revolving credit facility	(1,040,105)	424,336
Proceeds from share issuances	28,053,147	2,998,232
Share issue costs	(2,136,052)	(259,328)
Cash received from the Amalgamation	434,571	–
Cost of the Amalgamation	(48,304)	(229,586)
Redemption of common shares	(119,268)	–
Changes in non-cash working capital from investing	2,288,516	(301,409)
Total capital resources	26,539,271	2,759,540
Expenditures on petroleum and natural gas assets	(6,679,085)	(2,799,657)
Property acquisitions and dispositions	1,799,910	40,000
Net Change in Cash	21,660,096	(117)

## Summary of Quarterly Information

Quarters Ended	December 31 2010	September 30 2010	June 30 2010	March 31 2010
<b>OPERATING</b>				
Average daily production				
Natural gas (mcf/d)	604.0	533.5	610.3	730.6
Heavy oil (bbls/d)	97.5	67.1	79.9	73.7
Light oil (bbls/d)	—	0.2	0.7	0.6
NGLs (bbls/d)	0.2	3.3	5.6	5.1
Total (boe/d)	198.4	159.5	188.0	201.2
Average realized sales price				
Natural gas (\$/mcf)	3.64	3.75	3.95	5.08
Heavy oil (\$/bbls)	62.04	56.75	51.50	64.22
Light oil (\$/bbls)	—	70.64	69.97	76.01
NGLs (\$/bbls)	64.19	27.34	34.21	33.38
Total (\$/boe)	41.63	37.06	36.01	43.07
<b>OPERATING NETBACK (\$ per boe)</b>				
Petroleum and natural gas revenue	41.63	37.06	36.01	43.07
Royalties	(3.70)	(4.48)	(4.72)	(8.27)
Operating expense	(19.29)	(22.22)	(13.73)	(15.89)
Transportation and marketing expense	(1.65)	(1.93)	(1.72)	(1.97)
Operating netback	16.99	8.43	15.84	16.94
<b>FINANCIAL</b>				
Petroleum and natural gas revenue (\$)	759,732	543,804	615,877	779,933
Royalties (\$)	(67,581)	(65,760)	(80,745)	(149,725)
Interest and other revenue (\$)	20,840	14,759	(392)	539
Total revenues, net (\$)	712,991	492,803	534,740	630,747
Net earnings (loss) (\$)	(788,430)	(619,843)	(356,161)	(546,038)
Per share — basic and diluted (\$) <sup>(1)</sup>	(0.04)	(0.04)	(0.03)	(0.05)
Per share — basic and diluted (\$) <sup>(2)</sup>	(0.04)	(0.04)	(0.04)	(0.07)
Cash flow from operations (\$) <sup>(3)</sup>	(254,488)	(379,336)	(39,066)	(112,793)
Per share — basic and diluted (\$) <sup>(1)</sup>	(0.02)	(0.02)	(0.00)	(0.01)
Per share — basic and diluted (\$) <sup>(2)</sup>	(0.02)	(0.02)	(0.00)	(0.01)
Capital expenditures, net (\$)	3,205,267	1,673,908	432,385	1,704,100
Book value of total assets (\$)	43,884,291	26,996,311	17,591,508	17,100,015
Working capital deficiency (surplus) (\$)	(19,780,030)	(6,659,296)	(202,985)	(301,237)
Revolving credit facility (\$)	—	—	1,040,105	338,261
Total net debt (\$)	—	—	837,120	37,024
Shareholders' equity (\$)	38,175,696	23,059,697	14,089,990	14,469,651
Common shares outstanding <sup>(1)</sup>				
End of period — basic	33,696,781	16,730,460	10,649,567	10,649,567
End of period — diluted	35,335,281	18,318,960	11,619,567	11,619,567
Weighted average for the period — basic	18,538,049	16,267,784	10,649,567	10,072,300
Weighted average for the period — diluted	18,603,545	16,314,887	10,649,567	10,072,300
Common shares outstanding <sup>(2)</sup>				
End of period — basic	33,696,781	16,730,460	7,987,175	7,987,175
End of period — diluted	35,335,281	18,318,960	8,714,675	8,714,675
Weighted average for the period — basic	18,538,049	16,267,784	7,987,175	7,554,225
Weighted average for the period — diluted	18,603,545	16,314,887	7,987,175	7,554,225

(1) All per share and share balances prior to the September 30, 2010 period have not been adjusted to reflect the 75% conversion factor of shares, pursuant to the Amalgamation.

(2) All per share and share balances prior to the September 30, 2010 period have been adjusted to reflect the 75% conversion factor of shares, pursuant to the Amalgamation.

(3) Cash flow denoted with "( )", is negative cash flow throughout this MD&A.

## Summary of Quarterly Information

Quarters Ended	December 31 2009	September 30 2009	June 30 2009	March 31 2009
<b>OPERATING</b>				
Average daily production				
Natural gas (mcf/d)	789.8	824.0	862.6	879.3
Heavy oil (bbls/d)	66.8	72.5	49.0	52.5
Light oil (bbls/d)	1.3	1.7	1.9	3.1
NGLs (bbls/d)	4.4	7.3	7.1	6.1
Total (boe/d)	204.1	218.8	201.8	208.3
Average realized sales price				
Natural gas (\$/mcf)	4.78	2.86	3.55	5.00
Heavy oil (\$/bbls)	69.68	58.07	53.59	36.96
Light oil (\$/bbls)	74.48	68.99	63.91	51.78
NGLs (\$/bbls)	27.92	23.52	20.56	25.42
Total (\$/boe)	42.37	31.31	29.52	31.96
<b>OPERATING NETBACK (\$ per boe)</b>				
Petroleum and natural gas revenue	42.37	31.31	29.52	31.96
Royalties	(6.08)	(4.13)	(3.00)	(4.51)
Operating expense	(16.13)	(11.32)	(11.27)	(13.46)
Transportation and marketing expense	(1.52)	(1.86)	(1.32)	(1.51)
Operating netback	18.64	14.00	13.93	12.48
<b>FINANCIAL</b>				
Petroleum and natural gas revenue (\$)	795,693	630,219	542,184	599,274
Royalties (\$)	(114,205)	(83,236)	(55,027)	(84,571)
Interest and other revenue (\$)	203	206	945	9,650
Total revenues, net (\$)	681,691	547,189	488,102	524,353
Net earnings (loss) (\$)	(411,841)	(466,962)	(415,770)	(451,785)
Per share – basic and diluted (\$) <sup>(1)</sup>	(0.05)	(0.06)	(0.05)	(0.06)
Per share – basic and diluted (\$) <sup>(2)</sup>	(0.07)	(0.08)	(0.07)	(0.07)
Cash flow from operations (\$) <sup>(3)</sup>	52,495	(42,505)	14,539	14,821
Per share – basic and diluted (\$) <sup>(1)</sup>	0.01	(0.01)	0.00	0.00
Per share – basic and diluted (\$) <sup>(2)</sup>	0.01	(0.01)	0.00	0.00
Capital expenditures, net (\$)	502,849	120,323	328,313	825,484
Book value of total assets (\$)	16,410,692	16,200,041	16,559,077	17,505,864
Working capital deficiency (surplus) (\$)	(436,530)	(381,667)	(170,856)	131,140
Revolving credit facility (\$)	–	989,408	615,769	–
Total net debt (\$)	–	607,741	444,913	131,140
Shareholders' equity (\$)	13,981,458	12,845,404	13,297,172	13,680,455
Common shares outstanding <sup>(1)</sup>				
End of period – basic	9,412,567	8,176,826	8,176,826	8,176,826
End of period – diluted	10,382,567	9,146,826	9,146,826	9,294,326
Weighted average for the period – basic	8,190,258	8,176,826	8,176,826	8,176,826
Weighted average for the period – diluted	8,190,258	8,201,978	8,226,800	8,253,894
Common shares outstanding <sup>(2)</sup>				
End of period – basic	7,059,425	6,132,620	6,132,620	6,132,620
End of period – diluted	7,786,925	6,860,120	6,860,120	6,970,745
Weighted average for the period – basic	6,142,694	6,132,620	6,132,620	6,132,620
Weighted average for the period – diluted	6,142,694	6,151,484	6,170,100	6,190,421

(1) All per share and share balances prior to the September 30, 2010 period have not been adjusted to reflect the 75% conversion factor of shares, pursuant to the Amalgamation.

(2) All per share and share balances prior to the September 30, 2010 period have been adjusted to reflect the 75% conversion factor of shares, pursuant to the Amalgamation.

(3) Cash flow denoted with "( )", is negative cash flow throughout this MD&A

### **Discussion of Quarterly Results**

Manitok's average quarterly production in the quarter ended December 31, 2010 was 198.4 boe/d, which is a 24% increase from 159.5 boe/d in the quarter ended September 31, 2010 and a 6% increase from 188.0 boe/d in the quarter ended June 30, 2010. The quarter over quarter production increases are a direct result of increased heavy oil production due to improved operations of the Corporation's heavy oil properties and five new heavy oil wells which came on production in November 2010. Offsetting the heavy oil production increases were normal production declines in the natural gas assets along with the Corporation's two non-operated natural gas wells in the Coleman area of Alberta, which represent about 180 mcf/d being shut-in for a gas plant turnaround in June 2010 and for the majority of September 2010 due to circumstances at the third party gas plant which were out of the Corporation's control.

The Corporation's average realized commodity price has increased since the quarter ended June 30, 2010 from \$36.01 per boe to \$41.63 per boe, which is a 16% increase. This change was due to a 20% increase in the average realized sales price of heavy oil offset by an 8% decrease in the average realized sales price of natural gas.

Cash flow from operations generated by the Corporation in the quarter ended December 31, 2010 was (\$254,488), as compared to (\$379,336) in the quarter ended September 30, 2010 and (\$39,066) in the quarter ended June 30, 2010. The decrease in cash flow from operations in the quarter ended December 31, 2010 as compared to the quarter ended June 30, 2010 is due mainly to an increase in net general and administrative costs while the decrease in cash flow from operations in the quarter ended September 30, 2010 as compared to the quarter ended June 30, 2010 is due to lower average production volumes and an increase in net general and administrative costs.

Manitok spent \$3,205,267 on capital expenditures for the current quarter as compared to \$1,673,908 for the quarter ended September 30, 2010 and \$432,385 during the quarter ended June 30, 2010. The increase in capital expenditures from June 30, 2010 was due mainly to the five well drilling program in east central Alberta and the commencement of a well in the Alberta Foothills in December 2010. The Corporation's drilling program was funded by equity issuances in July 2010 and December 2010 as discussed in "Major Transactions Affecting Financial Results".

### **Mergers and Acquisitions**

The Corporation continues to review potential property acquisitions, joint venture opportunities and corporate mergers and acquisitions within its focus areas, with the intention of completing such a transaction if acceptable terms can be negotiated. As a result, Manitok may at any time be involved in discussions or negotiations with other parties or their agents in respect of property acquisitions and dispositions, joint venture opportunities and corporate merger and acquisition opportunities, but the Corporation is not committed to any such potential transaction and cannot be reasonably confident that it can complete any such potential transaction until appropriate legal documentation has been executed by relevant parties.

## New Accounting Pronouncements

### Transition to International Financial Reporting Standards

In February 2008, Canada's Accounting Standards Board ("AcSB") confirmed that International Financial Reporting Standards ("IFRS") will replace Canadian GAAP for Canadian public companies beginning January 1, 2011. Due to the short fiscal year ended December 31, 2010 and in accordance with National Instrument 52-107 and part 2.9 of Companion Policy 52-107CP, *Acceptable Accounting Principles and Auditing Standards*, the adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by ManitoK for the twelve months ended June 30, 2010, the six months ended December 31, 2010, and an opening balance sheet as at July 1, 2009.

ManitoK's transition plan includes training and development throughout the organization, and three key phases:

- **Phase 1 – Scoping and diagnostics**

This phase involves performing a high level diagnostic analysis to identify areas that may be affected by the transition to IFRS. The results of this analysis are priority ranked according to complexity and the amount of time required to assess the impact of changes in transitioning to IFRS.

- **Phase 2 – Impact analysis and evaluation**

During this phase, items identified in Phase 1 are addressed according to the priority levels assigned to them. This phase involves analysis of policy choices allowed under IFRS and their impact on the financial statements. In addition, certain potential differences are further investigated to assess whether there may be a broader impact to ManitoK's debt agreements, business processes or management reporting systems.

- **Phase 3 – Implementation phase**

This phase involves implementation of all changes approved in Phase 2 and will include changes to information systems, business processes, modification of agreements and training of all staff who are impacted by the conversion.

Management has essentially finalized its IFRS accounting policies for significant impact areas and has quantified the expected financial impact of these policies on the IFRS opening balance sheet at July 1, 2009 ("Transition Date"). The Audit Committee of the Board of Directors is in process of reviewing and approving all accounting policy choices as proposed by management. ManitoK has also implemented necessary changes to its business process and information systems for significant areas of impact, with internal control requirements taken into account. Communication of impacts to external stakeholders is expected to occur in the second quarter of 2011.

### IFRS Accounting Policies

ManitoK has evaluated all significant accounting policy differences between IFRS and Canadian GAAP and each of these differences is discussed in more detail below. ManitoK's analysis of chosen IFRS accounting policies specifically considers the current IFRSs that are in effect. As a result, any new or amended accounting standards that are issued by the International Accounting Standards Board ("IASB") in future periods may impact our current assessment of the chosen IFRS accounting policies and the expected financial impact on transition to IFRS.

### *Property, Plant & Equipment*

Property, Plant and Equipment ("PP&E") is the most significant area impacted by the adoption of IFRS. Manitok currently follows the Canadian GAAP guidelines on full cost accounting for oil and gas companies. IFRS has no equivalent guideline. In order to facilitate the transition to IFRS by full cost oil and gas companies, the IASB issued amendments to IFRS 1 *First-time Adoption of IFRS* allowing additional exemptions for first-time adopters of IFRS. Under these amendments, full cost oil and gas companies can elect to use the recorded amount under Canadian GAAP as the "deemed cost" for oil and gas assets on the Transition Date to IFRS. Companies that elect to use this IFRS 1 exemption on transition will need to decide whether to allocate based on reserve volumes or values using either proved or proved plus probable reserves. Without this exemption, the Corporation would have been required to retrospectively determine the carrying amount of oil and gas assets at the date of transition, or use the fair value or revaluation amount as the new deemed cost under IFRS. Manitok will use this exemption on transition to IFRS and allocate the existing net book value of its oil and gas full cost pool at the area level using proved plus probable reserve values. By using the exemption, the net book value of Manitok's PP&E at the date of transition to IFRS will be the same as it was under Canadian GAAP, subject to any potential IFRS impairments that are recognized at the date of transition.

In moving to IFRS, Manitok will be required to adopt different accounting policies for pre-exploration activities, Exploration and Evaluation ("E&E") activities, DD&A and the accounting for gains and losses on property dispositions, significant components of PP&E and other material non-monetary transactions.

Pre-exploration costs are costs incurred before the Corporation obtains the legal right to explore an area. Under Canadian GAAP, these costs are capitalized, while under IFRS, these costs must be expensed. At this time, Manitok does not anticipate that this accounting policy difference will have a significant impact on the Corporation's IFRS financial statements.

During the E&E phase, Manitok capitalizes costs incurred for these projects under Canadian GAAP. Under IFRS, the Corporation has the choice to either continue capitalizing E&E costs until technical feasibility and commercial viability of the project is determined, or to expense these costs as incurred. Once technical feasibility and commercial viability of an E&E project is determined, the related costs are transferred to the Developed and Producing ("D&P") category. If Manitok's policy choice is to continue capitalizing E&E project costs under IFRS, the Corporation has the alternative to either begin depleting the related costs when in the E&E phase or to deplete the costs once the project has demonstrated technical feasibility and commercial viability and is in the D&P category. Manitok will capitalize E&E project costs as incurred and begin depleting the related costs once technical feasibility and commercial viability of the E&E project is established and related costs are transferred to the D&P category. Technical feasibility and commercial viability of an E&E project is established when proved reserves are identified and the project yields production.

Under Canadian GAAP, Manitok calculates its DD&A rate at the country cost centre level. Under IFRS, this rate will be calculated at a lower unit of account. Under IFRS, the Corporation has the alternative to either continue depleting its assets over proved reserves (same as Canadian GAAP) or use another basis which more accurately reflects the useful life of Manitok's oil and gas assets. Manitok will calculate its DD&A rate at the area level and deplete its oil and gas assets over proved plus probable reserves on transition to IFRS.

Full cost oil and gas accounting under Canadian GAAP requires that gains or losses on divestitures of properties are only recognized when the disposal would affect the DD&A rate by 20% or more. Under IFRS, there is no such exemption, and therefore Manitok will be required to recognize all gains and losses on

property divestitures and from disposal of significant components of PP&E. There is no impact of adopting this IFRS accounting policy at July 1, 2009.

As a result of the additional IFRS 1 exemptions released by the IASB in July 2009, the Corporation anticipates that all changes to its PP&E accounting policies will be adopted prospectively at the Transition Date.

#### *Impairment Testing*

Under Canadian GAAP, the recoverable amount of ManitoK's oil and gas assets under the first step of the impairment test is determined using undiscounted future cash flow from proved reserves. Under IFRS, the recoverable amount is calculated using discounted future cash flow from proved plus probable reserves. In addition, impairment testing under Canadian GAAP is performed at the country cost centre level, while under IFRS, it will be performed at a lower level referred to as a cash-generating unit. Canadian GAAP prohibits reversal of impairment losses. Under IFRS, if the conditions giving rise to impairment have reversed, impairment losses previously recorded would be partially or fully reversed to eliminate write-downs recorded. ManitoK expects to adopt these changes in accounting policy prospectively. As ManitoK is in process of finalizing the impact of the revised standard on its transition to IFRS the impacts of the differences will not be disclosed at this time.

#### *Asset Retirement Obligations*

Under Canadian GAAP, the Corporation recognizes a liability for the estimated fair value of the future retirement obligations associated with PP&E. The fair value is capitalized and amortized over the same period as the underlying asset. ManitoK estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in wells and facilities, including an estimate for the timing of the costs to be incurred in future periods. These cash outflows are discounted using a credit-adjusted risk-free rate of 8% under Canadian GAAP. Changes in the net present value of the future retirement obligation are expensed through accretion as part of DD&A (same as IFRS).

Under IFRS, these liabilities are known as "decommissioning liabilities" and are included in the scope of IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*. Decommissioning liabilities are calculated at each reporting period by estimating the risk-adjusted future cash outflows, which are discounted using a risk-free rate. As ManitoK is in process of finalizing the impact of the revised standard on its transition to IFRS the impacts of the differences will not be disclosed at this time.

#### *Stock-based Compensation*

IFRS 2 *Share-Based Payments* requires the expense related to share-based payments to be recognized as the options vest. For options with different vesting periods, each vesting tranche must be treated as a separate option grant which accelerates the expense recognition in comparison to Canadian GAAP, which allows the expense to be recognized on a straight-line basis over the period the options vest. ManitoK must also apply an estimated forfeiture rate at the initial grant date for each option tranche. The forfeiture rate is taken into account by adjusting the number of stock options expected to vest under each tranche and subsequently revising this estimate throughout the vesting period, as necessary. When determining the fair value of each vesting tranche, ManitoK will apply an estimated option tranche life which reflects historical experiences in comparison to Canadian GAAP, which allows the life of the option to equal the five year expiry period. ManitoK expects to adopt this change in accounting policy prospectively. As ManitoK is in process of finalizing the impact of the revised standard on its transition to IFRS the impacts of the differences will not be disclosed at this time.

### *Income Tax*

In transitioning to IFRS, the carrying amount of Manitok's deferred tax balances will be directly impacted by the tax effects resulting from changes required by the above IFRS accounting policy differences. As Manitok is in process of finalizing the impact of the revised standard on its transition to IFRS the impacts of the differences will not be disclosed at this time.

### **Changes to IFRS Accounting Standards**

Manitok's analysis of accounting policy differences specifically considers the current IFRS standards that are in effect. The Corporation will continue to monitor any new or amended accounting standards that are issued by the IASB in future periods.

### **Information Systems**

Manitok has evaluated and implemented necessary changes to its information systems for significant areas of impact. Manitok's system updates were minimal, however, they were critical in order to allow for reporting of both Canadian GAAP and IFRS statements in 2010 as well as the updates required to track capital expenditures at a granular level for IFRS reporting in 2011 and thereafter.

### **Impacts to our Business**

Manitok does not expect that the adoption of IFRS in 2011 will have a significant impact or influence on its business activities, operations or strategies going forward. Management will continue to closely monitor the impact of IFRS on its business activities during 2011.

### **Critical Accounting Estimates**

Management is required to make judgments, assumptions and estimates in the application of GAAP that may have a significant impact on the financial results of the Corporation. The following summarizes the accounting estimates that are critical to determining Manitok's financial results.

#### **Estimates of P&NG Reserves, Depletion and Depreciation and Impairment Test**

The Corporation, at least annually, engages a qualified independent reserves evaluator to provide an estimate of the Corporation's year-end reserve volumes and associated future net revenues. These estimates are herein referred to as the "Reserve Estimates". To facilitate this process, the Corporation provides relevant production, financial and technical data to the reserves evaluator. The Corporation considers the Reserve Estimates to be critical estimates for the reasons discussed below.

The Reserves Estimates relating to the volume of reserves are utilized in the calculation of depletion and depreciation expense in the financial statements. The reserve volumes together with the production volumes for the relevant period are utilized in calculating a depletion rate for the Corporation. This depletion rate is used in conjunction with other accounting information to determine the depletion and depreciation for that period.

The Reserve Estimates relating to future net revenues of reserves are utilized in an impairment test calculation to determine if the costs capitalized under the full cost method of accounting have been impaired and thus should be written down. This potential impairment is based on a determination of whether the carrying value of petroleum and natural gas properties exceeds the estimated undiscounted future net cash flows from the proved reserves attributable to such properties.

Should the Reserve Estimates relating to the volume of reserves be materially incorrect, it could have a material impact on the Corporation's recorded amount of depletion and depreciation expense. Should the Reserves Estimates relating to the future net revenues of reserves be materially incorrect it may have a material impact on the determination of whether or not the Corporation is required to write down its petroleum and natural gas assets as a result of the impairment test. The Reserve Estimates will from time to time change based on changes in the many factors underlying the Reserve Estimates, which include but are not limited to: production performance, commodity prices, amount and timing of projected capital expenditures, revised technical interpretations based on activity and new information and the impact of additional activities not contemplated in the preparation of the Reserve Estimates.

The Reserve Estimates are also relied upon by the Corporation's lender in determining the amounts available to the Corporation under its credit facilities. The lender relies on all components of the Reserve Estimates and the underlying assumptions, except for the price forecast. The lender in most instances utilizes its own price forecast. The availability of these credit facilities is important to the Corporation because it relies on this source of capital to fund its capital budget in excess of its internally generated funds. Should the Reserves Estimates change materially and negatively, it may have a material adverse affect on the amount of capital available to the Corporation under the credit facilities, which may impair the Corporation's ability to pursue its business plans.

### Asset Retirement Obligations

Manitok records a liability for the fair value of legal obligations associated with the retirement of long-lived assets in the period in which they are incurred, normally when the asset is purchased or developed. In the oil and gas industry, this retirement obligation is normally associated with abandonment and reclamation costs relating to wells and facilities. On recognition of the asset retirement obligation there is a corresponding increase in the carrying amount of the related asset (an increase to petroleum and natural gas properties and equipment) which is recorded as the asset retirement cost. The total future asset retirement obligation is an estimate at a point in time based on the Corporation's net ownership interest in all wells (producing, shut-in, suspended and others) and facilities, the estimated cost to abandon and reclaim these wells and facilities, and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows required to settle the asset retirement obligation is the Corporation's best estimate at any given point in time that is subject to measurement uncertainty and any change may potentially impact the liability materially.

Manitok attempts to mitigate this risk by reviewing all of its wells and facilities included in the calculation and by utilizing the expertise of its reserve engineer in order to provide the best estimates possible at the time.

### Current Income Taxes

The Corporation is required to file a corporate income tax return annually and is required to pay any income tax liability in a timely manner. As a result of this requirement, Manitok must estimate at the end of each financial reporting period its potential current income tax liability for the particular fiscal year in question. In order to determine its income tax liability for the fiscal year, the Corporation must estimate revenue, royalties, other income, operating expenses, general and administrative expenses, interest expense, capital expenditures and other relevant items. The critical estimates in this process are production rates, commodity prices, capital expenditures and the tax category of these capital expenditures for the entire fiscal period. The risk of materially misstating the amount of current taxes payable is highest in respect of the first quarter and reduces for each quarter thereafter as more actual data is used and the estimated amounts apply to a shorter period.

To the extent that the estimate of current taxes payable varies materially from the actual amount of taxes payable, the Corporation may be required to pay an unexpected material amount of taxes which may adversely affect the Corporation's financial condition. The most critical part of this estimate is the estimate of the amount and tax category of capital expenditures that will be incurred during the relevant year as those expenditures form the basis of any new tax pools that Manitok can use as deductions in respect of that year. To the extent that a material amount of capital allocated to exploration drilling, which is 100% deductible in the fiscal year, is ultimately allocated to development drilling, which is only 30% deductible in the fiscal year, the Corporation's current taxes payable can change materially. There is a risk that wells that are drilled in an effort to encounter a new oil or natural gas accumulation can encounter an already discovered accumulation, thus changing the tax category from an exploration expenditure to a development expenditure. This risk is significant because many wells drilled by the Corporation are drilled in proximity to other wells and the tax category of the expenditures is not finally determined until drilling is completed. To mitigate this risk, the Corporation allocates its entire budget to tax categories based on discussions with its operations group and reviews the continuing validity of these categorizations at the end of each reporting period.

The determination of the Corporation's income and other tax liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ from that estimated and recorded by Management.

## **Risk Factors and Risk Management**

### **Commodity Price Risk**

Manitok's liquidity and cash flow are largely impacted by petroleum and natural gas commodity prices. Manitok has not hedged any of its oil and natural gas production at the date hereof and although it does monitor the hedge market, its strategy is to continue to sell its oil and natural gas production at the spot market rate. Management remains bullish about future commodity prices and believes Manitok is well positioned to take advantage of a rising oil and natural gas price environment. If there is a significant deterioration in the price it receives for oil and natural gas, Manitok will consider reducing its capital spending or access alternate sources of capital.

### **Foreign Currency Exchange Risk**

The Corporation is exposed to foreign currency fluctuations because its Canadian revenues are strongly linked to United States dollar denominated benchmark prices. Manitok has not hedged any of its foreign exchange risk at the date hereof.

### **Production Risk**

Manitok believes it has a stable production base and that an adverse event affecting production at any single well would not cause a liquidity issue. Nonetheless, Manitok remains subject to the risk that production rates of its most significant wells may decrease in an unpredictable and uncontrollable manner, which could result in a material decrease in the Corporation's overall production and associated cash flows.

All of Manitok's production passes through third party infrastructure prior to it being ready for transfer at designated commodity sales points. There is a risk that should this infrastructure fail and cause a significant portion of Manitok's production to be shut-in and unable to be sold, this could have a material adverse effect on Manitok's available cash flow.

### Reserve Replacement Risk

Oil and natural gas reserves naturally deplete as they are produced over time. The success of the Corporation's business is highly dependent on its ability to acquire and/or discover new reserves in a cost efficient manner. Substantially all of the Corporation's cash flow is derived from the sale of the petroleum and natural gas reserves it accumulates and develops. In order to remain financially viable, the Corporation must be able to replace reserves over time at a lesser cost on a per unit basis than its cash flow on a per unit basis. The reserves and costs used in this determination are estimated each year based on numerous assumptions and these estimates and costs may vary materially from the actual reserves produced or from the costs required to produce those reserves. In order to mitigate this risk, the Corporation employs a competent and experienced team of petroleum and natural gas professionals and closely monitors the capital expenditures made for the purposes of increasing its petroleum and natural gas reserves.

### Health, Safety & Environmental Risk

Health, safety and environment risks influence the workforce, operating costs and the establishment of regulatory standards. Manitok provides staff with the training and resources they need to complete work safely and effectively; incorporates hazard assessment and risk management as an integral part of everyday operations; monitors performance to ensure its operations comply with legal obligations and internal standards; and identifies and manages environmental liabilities associated with its existing asset base. Manitok carries insurance to cover a portion of property losses and liability to others resulting from unusual events.

Manitok is subject to the risk that the unexpected failure of its equipment used in drilling, completing or producing wells or transporting production could result in releases of fluid substances that pollute or contaminate lands at or near its facilities which could result in significant liability to the Corporation for costs of clean up, remediation and reclamation of contaminated lands. Manitok conducts its operations with due regard for the potential impact on the environment. This includes hiring skilled personnel, providing adequate training to all staff involved with operations, and by retaining expert advice and assistance to deal with environment remediation and reclamation work where such expertise is needed.

### Regulatory Risk

Government royalties, income tax laws, environmental laws and regulatory requirements can have a significant financial and operational impact on the Corporation. As an oil and natural gas producer, Manitok is subject to a broad range of regulatory requirements. Manitok hires and retains skilled personnel that are knowledgeable regarding changes to the regulatory regime under which it operates.

All of Manitok's properties are currently located within the province of Alberta. There is a risk that although the Corporation believes it is making an economic investment at the time all of the up-front capital is invested in facilities or drilling, completing and equipping an oil or natural gas well, the Government may at any point in the economic life of that project, expropriate without compensation a portion of the expected profit under a new royalty/tax regulation or regime with no grandfathering provisions. This may cause a particular project to become uneconomic once the new royalties or taxes take effect. This type of possible future government action is unpredictable and cannot be forecast by the Corporation.

### Counterparty Risk

Manitok assumes customer credit risk associated with oil and gas sales and joint venture participants. To mitigate this risk, the Corporation performs regular reviews of receivables to minimize default or non-payment and takes the majority of its production in kind. The Corporation may also put in place security arrangements with respect to amounts owed to it by others when reviews indicate it is appropriate to do so.

### Access to Credit Markets

Due to the nature of the Corporation's business it is necessary from time to time for the Corporation to access other sources of capital beyond its internally generated cash flow in order to fund the development and acquisition of its long term asset base. As part of this strategy the Corporation obtains some of this necessary capital by incurring debt and therefore the Corporation is dependent to a certain extent on continued availability of the credit markets.

The continued availability of the credit markets for Manitok is primarily dependent on the state of the economy and the health of the banking industry in Canada and United States. There is risk that the economy and banking industry experience unexpected and/or prolonged deterioration, then Manitok's access to credit markets may contract or disappear all together. The Corporation tries to mitigate this risk by dealing with reputable lenders and tries to structure its lending agreements to give it the most flexibility possible should these situations arise. However, the situations that may give rise to credit markets tightening or disappearing are beyond Manitok's control.

Manitok is also dependent to a certain extent on continued access to equity capital markets. The corporation is listed on the TSX Venture Exchange and maintains an active investor relations program. Continued access to capital is dependent on Manitok's ability to continue to perform at a level that meets market expectations.

### Climate Change Risks

North American climate change policy is evolving at both regional and national levels and recent political and economic events may significantly affect the scope and timing of new climate change measures that are ultimately put in place.

The Government of Alberta released its climate change strategy which sets a target to reduce greenhouse gas ("GHG") emissions in Alberta by 200 megatonnes or 50% by 2050. Implementing carbon capture and storage technology across industrial sectors is a large component of the strategy, along with energy-efficiency measures, clean energy technologies, and expanding the use of renewable sources of energy.

The Canadian government has expressed interest in pursuing the development of a North American cap and trade system for GHG emissions. In April 2007, the Government of Canada released the Regulatory Framework for Air Emissions ("Framework"). The Framework outlines short, medium and long-term objectives for managing both GHG emissions and air pollutants in Canada. It is uncertain how the Framework will fit within a North American cap and trade system and what the specific requirements for industrial emitters such as Manitok will be. Proposed regulations have not yet been released and therefore it is uncertain whether the impacts from such future regulations will be material to the Corporation.



**Financial Statements &  
Notes to the Financial Statements**

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## MANAGEMENT'S REPORT

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### To the Shareholders of Manitok Energy Inc.

The financial statements of Manitok Energy Inc. were prepared by management within the acceptable limits of materiality and are in accordance with accounting principles generally accepted in Canada. Management is responsible for ensuring that the financial and operating information presented in this annual report is consistent with that shown in the financial statements.

The financial statements have been prepared by management in accordance with the accounting policies as described in the notes to the financial statements. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. When necessary, such estimates are based on informed judgments made by management.

Management has designed and maintains an appropriate system of internal controls to provide reasonable assurance that all assets are safeguarded and financial records are properly maintained to facilitate the preparation of financial statements for reporting purposes.

Kenway Mack Slusarchuk Stewart LLP, an independent firm of Chartered Accountants appointed by shareholders, have conducted an examination of the corporate accounting records in order to express their opinion on the financial statements.

The Audit Committee, consisting of non-management directors, has met with representatives of Kenway Mack Slusarchuk Stewart LLP and management in order to determine if management has fulfilled its responsibilities in the preparation of the financial statements. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.



**Massimo M. Geremia**  
President and Chief Executive Officer

April 20, 2011



**Robert G. Dion**  
Vice President, Finance & Chief Financial Officer

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## INDEPENDENT AUDITORS' REPORT

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### To the Shareholders of Manito Energy Inc.

We have audited the accompanying financial statements of Manito Energy Inc. which comprise the balance sheet as at December 31, 2010 and June 30, 2010 and the statements of loss, comprehensive loss and deficit, and cash flows for the periods then ended, and a summary of significant accounting policies and other explanatory information.

### Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

### Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

### Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Manito Energy Inc. as at December 31, 2010 and June 30, 2010, and the results of its operations and its cash flows for the periods then ended in accordance with Canadian generally accepted accounting principles.



### Kenway Mack Slusarchuk Stewart LLP

Chartered Accountants  
Calgary, Alberta

April 20, 2011

## BALANCE SHEETS

As at (\$)	December 31 2010	June 30 2010
<b>Assets</b>		
<b>Current</b>		
Cash	21,730,744	70,648
Accounts receivable (note 8)	1,254,489	575,820
Prepaid and deposits	374,154	335,631
	23,359,387	982,099
Deferred financing fees (note 4)	–	327,947
Petroleum and natural gas properties and equipment (note 5)	20,524,904	16,281,462
	43,884,291	17,591,508
<b>Liabilities</b>		
<b>Current</b>		
Accounts payable and accrued liabilities	3,579,357	779,114
Revolving credit facility (note 6)	–	1,040,105
	3,579,357	1,819,219
Asset retirement obligations (note 9)	1,073,585	790,780
Future income taxes (note 10)	1,055,653	891,519
<b>Shareholders' Equity</b>		
Share capital (note 11)	42,145,786	16,954,840
Contributed surplus (note 12)	817,423	514,390
Retained earnings (deficit)	(4,787,513)	(3,379,240)
	38,175,696	14,089,990
Commitments and contingent liabilities (note 14)		
Subsequent events (note 16)		
	43,884,291	17,591,508

See accompanying notes to the financial statements

APPROVED BY THE BOARD



**Bruno P. Geremia CA**  
Director



**Massimo M. Geremia**  
Director

**STATEMENTS OF NET EARNINGS (LOSS),  
COMPREHENSIVE EARNINGS (LOSS) & RETAINED EARNINGS (DEFICIT)**

(\$, except share amounts)	For the six months ended December 31 2010	For the twelve months ended June 30 2010
<b>Revenue</b>		
Petroleum and natural gas	1,303,536	2,821,722
Royalties	(133,341)	(427,912)
Interest and other	35,599	555
	<b>1,205,794</b>	<b>2,394,365</b>
<b>Expenses</b>		
Operating	678,036	1,053,512
Transportation and marketing	58,399	131,175
General and administrative, net	1,102,414	1,334,300
Interest	769	17,246
Stock-based compensation (note 12)	273,216	55,529
Depletion, depreciation and accretion (note 5 and 9)	972,483	2,167,940
	<b>3,085,317</b>	<b>4,759,702</b>
<b>Earnings (loss) Before Income Taxes</b>	<b>(1,879,523)</b>	<b>(2,365,337)</b>
<b>Income Taxes</b>		
Future income taxes expense (recovery) (note 10)	(471,250)	(584,336)
	<b>(471,250)</b>	<b>(584,336)</b>
<b>Net Earnings (loss) &amp; Comprehensive Earnings (loss)</b>	<b>(1,408,273)</b>	<b>(1,781,001)</b>
<b>Retained Earnings (deficit), Beginning of Period</b>	<b>(3,379,240)</b>	<b>(1,598,239)</b>
<b>Retained Earnings (deficit), End of Period</b>	<b>(4,787,513)</b>	<b>(3,379,240)</b>
Net earnings (loss) per common share (note 13)		
Basic	(0.08)	(0.26)
Diluted	(0.08)	(0.26)
Weighted average common shares (note 13)		
Basic	17,402,916	6,948,060
Diluted	17,402,916	6,948,060

See accompanying notes to the financial statements

## STATEMENTS OF CASH FLOWS

(\$)	For the six months ended December 31 2010	For the twelve months ended June 30 2010
<b>Operating Activities</b>		
Net earnings (loss)	(1,408,273)	(1,781,001)
Adjustments for items not affecting cash:		
Depletion, depreciation and accretion	972,483	2,167,940
Stock-based compensation	273,216	55,529
Future income taxes expense (recovery)	(471,250)	(584,336)
	(633,824)	(141,868)
Changes in non-cash working capital (note 15)	(205,465)	269,163
Asset retirement expenditures	(53,945)	—
	(893,234)	127,295
<b>Financing Activities</b>		
Increase (decrease) in revolving credit facility (note 6)	(1,040,105)	424,336
Proceeds from share issuances (note 11)	28,053,147	2,998,232
Share issue costs	(2,136,052)	(259,328)
Cash received from amalgamation (note 2a)	434,571	—
Cost of amalgamation	(48,304)	(229,586)
Redemption of common shares (note 11)	(119,268)	—
	25,143,989	2,933,654
<b>Investing Activities</b>		
Expenditures on petroleum and natural gas assets	(6,679,085)	(2,799,657)
Proceeds from disposition of petroleum and natural gas assets	1,799,910	40,000
Changes in non-cash investing working capital (note 15)	2,288,516	(301,409)
	(2,590,659)	(3,061,066)
<b>Net Increase (decrease) in Cash</b>	<b>21,660,096</b>	<b>(117)</b>
<b>Cash, Beginning of Period</b>	<b>70,648</b>	<b>70,765</b>
<b>Cash, End of Period</b>	<b>21,730,744</b>	<b>70,648</b>
Cash interest paid	769	17,246
Cash taxes paid	—	—

See accompanying notes to the financial statements

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## NOTES TO THE FINANCIAL STATEMENTS

### FOR THE SIX MONTHS ENDED DECEMBER 31, 2010 AND THE TWELVE MONTHS ENDED JUNE 30, 2010

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01

#### NATURE OF OPERATIONS

**Manitok Energy Inc.** (“Manitok” or the “Corporation”) was formed as a result of an amalgamation between Manitok Exploration Inc. (“MEX”) and Desco Resources Inc. (“Desco”) pursuant to the Business Corporations Act (Alberta) on July 8, 2010 (the “Amalgamation”). MEX was a private entity, incorporated under the Business Corporations Act (Alberta) on April 20, 2005 and Desco was a reporting issuer, incorporated under the Business Corporations Act (Alberta) on July 8, 2009 which commenced trading on the TSX Venture Exchange on November 5, 2009 under the symbol “DSR.P”.

The Corporation is engaged in the exploration for, and the development, production and acquisition of, petroleum and natural gas reserves in Western Canada. Manitok is listed on the TSX Venture Exchange under the symbol “MEI” which commenced trading on July 29, 2010. Manitok’s financial year end has been changed from June 30 to December 31, creating a six month fiscal period ended December 31, 2010.

02

#### SIGNIFICANT ACCOUNTING POLICIES

The annual audited Financial Statements have been prepared by management in accordance with Canadian Generally Accepted Accounting Principles (“GAAP”), within an acceptable level of materiality, utilizing the framework of the accounting policies below. All dollar amounts are presented in Canadian dollars unless otherwise stated.

##### a) Basis of accounting

The Corporation’s Financial Statements include the accounts of Manitok and there are no subsidiary companies. As a result of the Amalgamation, control of Desco passed to the MEX shareholders. Accordingly, the share exchange is accounted for as a reverse takeover of Desco by MEX, pursuant to which MEX is deemed to be the acquirer and the continuing entity. The application of reverse takeover accounting results in the following:

- The financial statements are a continuation of MEX and are issued under the name of Manitok;
- As MEX is deemed to be the acquirer for accounting purposes, its assets and liabilities are included at historical carrying values;
- The capital structure of Manitok, being the capital structure of MEX, is different from that appearing in the financial statements of Desco in earlier periods; and
- The deemed consideration for the acquisition of Desco has been measured as the fair value of Desco’s net assets.

The net identifiable assets of Desco acquired with the reverse takeover as at July 8, 2010 were as follows:

(\$)	
Cash	434,571
Accounts receivable	20,582
Total net identifiable assets	455,153

##### b) Revenue recognition

Revenue associated with sales of petroleum and natural gas are recorded when the commodities are delivered and title passes to the purchaser. Revenue associated with sales of petroleum and natural gas is recorded gross of transportation and marketing charges.

##### c) Joint venture activities

Substantially all of the Corporation’s exploration and production activities are conducted jointly with others and, accordingly, the accounts reflect only the Corporation’s proportionate interest in such activities.

**d) Measurement uncertainty**

The preparation of timely Financial Statements necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. These estimates will affect assets, liabilities and the disclosure of contingent assets and liabilities at the date of the Financial Statements, as well as revenues and expenses during the reporting periods. Such estimates are based on informed judgments made by management. Actual results could differ materially from those estimated.

Amounts recorded for depletion, depreciation and accretion and amounts used for impairment test calculations are based on estimates of petroleum and natural gas reserves which include estimates of future commodity prices, future costs and other relevant assumptions. The Corporation's reserves are estimated and evaluated, at a minimum, annually by an independent engineering firm. Stock-based compensation is calculated using the Black-Scholes option-pricing model to determine the stock option's fair value which includes an estimate of the Corporation's share price volatility. The provision for income taxes is based on judgments in applying income tax law and estimates on the timing, likelihood and reversal of temporary differences between the accounting and tax basis of assets and liabilities. By their nature, these estimates are subject to measurement uncertainty and the impact of changes in such estimates on the Financial Statements of future periods could be material.

**e) Cash and cash equivalents**

Cash and cash equivalents includes cash, less outstanding cheques, and highly liquid short-term investments having a maturity date of not more than ninety days at the time of purchase.

**(f) Petroleum and natural gas properties and equipment**

*Capitalized costs*

The Corporation follows the full cost method of accounting whereby all costs relating to the exploration, acquisition and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre. Such costs include land acquisition costs, geological and geophysical expenses, production equipment, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells and corporate charges directly related to acquisition, exploration and development activities. Proceeds from the sale of properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would alter the rate of depletion and depreciation by 20% or more.

*Depletion and depreciation*

Depletion and depreciation of petroleum and natural gas properties and equipment, together with the estimated future costs to be incurred in developing proved reserves, are depleted or depreciated using the unit-of-production method based on the proved reserves before royalties as estimated by independent engineers. Petroleum and natural gas reserves and production are converted into equivalent units based upon estimated relative energy content of six thousand cubic feet of natural gas to one barrel of oil. The costs of undeveloped properties are excluded from the costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or the properties are considered to be impaired.

*Impairment*

Petroleum and natural gas properties are evaluated each reporting period through an impairment test to determine the recoverability of capitalized costs. The carrying amount is assessed as recoverable when the sum of the undiscounted cash flows expected from proved reserves plus the cost of unproved interests, net of impairments, exceeds the carrying amount. When the carrying amount is assessed not to be recoverable, an impairment loss is recognized to the extent that the carrying amount exceeds the sum of the discounted cash flows, using a risk free rate, from proved and probable reserves plus the cost of unproved interests, net of impairments. Reserves are determined pursuant to National Instrument 51-101, *Standards of Disclosures for Oil and Gas Activities*. Undeveloped land and unproved properties are assessed regularly to determine whether impairment has occurred.

### *Administrative assets*

The Corporation records depreciation on its office furniture and equipment, which includes computer equipment, on a straight-line basis using an expected useful life of four years. The Corporation records depreciation on its leasehold improvements, on a straight-line basis over the term of the building lease of five years.

### **(g) Asset retirement obligations**

The Corporation recognizes the estimated liability associated with future abandonment and reclamation costs in the Financial Statements when a well or related asset is drilled, constructed or acquired including facilities. Costs are estimated by management in consultation with the Corporation's engineers based on current costs and technology in accordance with current legislation and industry practices. The obligation is initially measured at fair value, and subsequently adjusted for the accretion of discount and any changes to the underlying cash flows. The asset retirement cost is capitalized to petroleum and natural gas properties and equipment and amortized into earnings in depletion expense on a basis consistent with depletion and depreciation. Actual site restoration and abandonment expenditures are applied directly against the asset retirement obligation. The Corporation reviews the obligation regularly and revisions to the estimated timing of cash flows, discount rates and estimated costs will result in an increase or decrease to the asset retirement obligation.

### **(h) Future income taxes**

The Corporation accounts for its income taxes using the liability method. Under this method, future income tax assets and liabilities are determined based on the differences between the accounting and tax basis of assets and liabilities using substantively enacted tax rates anticipated to apply in relevant future periods. Future income tax assets are recognized to the extent it is more likely than not that sufficient future taxable income will be available to allow the future income tax asset to be realized. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in the period of substantive enactment.

### **(i) Stock-based compensation**

The Corporation accounts for its stock-based compensation plan using the fair value method to value stock options granted to officers, directors, employees and key consultants. Under this method, compensation cost attributed to stock options granted is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the exercise of stock options, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital. In the event that vested stock options expire without being exercised, previously recognized compensation costs associated with such awards are not reversed.

### **(j) Flow-through shares**

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. The Corporation records the carrying value of the expenditures in petroleum and natural gas properties and equipment as incurred. The Corporation records the future income taxes associated with the renunciation of expenditures with a corresponding reduction to share capital when the expenditures are renounced.

### **(k) Financial instruments**

All financial instruments are initially recognized at fair value on the balance sheet. The Corporation has classified each financial instrument into the following categories: "held for trading" financial assets and financial liabilities; "loans or receivables"; and "other financial liabilities". Subsequent measurement of the financial instruments is based on their classification.

The Corporation has made the following classifications:

- Cash and cash equivalents are classified as financial assets held for trading and are measured at fair value. Gains and losses from revaluation are recognized in net income.
- Accounts receivable are classified as loans and receivables and are initially measured at fair value.
- Revolving credit facilities, accounts payable and accrued liabilities are classified as other liabilities and are initially measured at fair value.

Financial instruments measured at fair value on the balance sheet are classified according to the following hierarchy based on the amount of observable inputs used to value the instrument.

- **Level 1** – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- **Level 2** – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.
- **Level 3** – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level. The Corporation has categorized its financial instruments according to the hierarchy described above (see note 8).

#### **(l) Derivative financial instruments**

Derivative financial instruments may be used by the Corporation to manage economic exposure to market risks relating to commodity prices. Manitok's policy is not to utilize derivative financial instruments for speculative purposes.

Derivative financial instruments that do not qualify as hedges, or are not designated as hedges, are classified as held-for-trading and are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Balance Sheet as either an asset or liability with changes in fair value recognized in net income.

#### **(m) Per share information**

Per share information is computed using the weighted average number of common shares outstanding during the period. Diluted per share information is calculated using the treasury stock method, which assumes that any proceeds from the exercise of "in-the-money" stock options plus the unamortized stock-based compensation expense amounts would be used to purchase common shares at the average market price during the period. No adjustment to diluted income per share is made if the result of these calculations is anti-dilutive.

### 03

#### **TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS**

In 2006, the Accounting Standards Board ("AcSB") ratified a strategic plan to converge Canadian GAAP with International Financial Reporting Standards ("IFRS") by 2011 for public reporting entities. On February 13, 2008, the AcSB confirmed that IFRS will replace Canadian GAAP beginning January 1, 2011. Due to the short fiscal year ended December 31, 2010 and in accordance National Instrument 52-107 and part 2.9 of Companion Policy 52-107CP, *Acceptable Accounting Principles and Auditing Standards*, the adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by Manitok for the twelve months ended June 30, 2010, the six months ended December 31, 2010, and an opening balance sheet as at July 1, 2009.

04

**DEFERRED FINANCING FEES**

The fees incurred with respect to the issuance of common shares by MEX and the Amalgamation, before the transactions were completed had been deferred. The costs were charged to share capital upon completion of the issuance of shares and the Amalgamation on July 8, 2010.

At December 31, 2010, the balance of deferred financing fees was \$NIL (June 30, 2010 – \$327,947).

05

**PETROLEUM AND NATURAL GAS PROPERTIES AND EQUIPMENT**

As at (\$)	December 31, 2010		
	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas assets	28,006,040	(7,564,177)	20,441,863
Office furniture and equipment	162,978	(79,937)	83,041
	<b>28,169,018</b>	<b>(7,644,114)</b>	<b>20,524,904</b>

As at (\$)	June 30, 2010		
	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas assets	22,862,687	(6,638,552)	16,224,135
Office furniture and equipment	120,206	(62,879)	57,327
	<b>22,982,893</b>	<b>(6,701,431)</b>	<b>16,281,462</b>

At December 31, 2010, the cost of petroleum and natural gas properties and equipment includes \$6,067,716 (June 30, 2010 – \$3,354,945) relating to unproved properties which have been excluded from costs subject to depletion and depreciation. Estimated future development costs of \$4,432,000 (June 30, 2010 – \$2,184,000) associated with the development of the corporation's proved reserves were added to the Corporation's net book value in the depletion and depreciation calculation. Capitalized general and administrative costs at December 31, 2010 were \$NIL (June 30, 2010 – \$NIL)

On August 4, 2010, the Corporation completed and closed the sale of a minor property in the Garrington area of Alberta for \$1.8 million. The proceeds from the disposition were used to reduce the cost of petroleum and natural gas assets at December 31, 2010. No gain or loss was recorded on the sale.

On September 25, 2009, the Government of Alberta approved a drilling royalty incentive for new conventional oil and natural gas wells drilled on or after April 1, 2009, but before April 1, 2011. Included as a reduction of petroleum and natural gas assets at December 31, 2010 is an expected recovery of \$103,896 (June 30, 2010 – \$NIL) related to the Alberta Drilling Royalty Credit Program.

The Corporation performed an impairment test at December 31, 2010 to ensure the carrying value of its petroleum and natural gas properties and equipment is recoverable and does not exceed fair value. The petroleum and natural gas future prices are based on December 31, 2010 commodity price forecasts of the Corporation's independent reserve evaluators.

## NOTES TO THE FINANCIAL STATEMENTS

The following table summarizes the benchmark prices used in the impairment test calculation:

Year	WTI Oil (\$US/bbl)	US\$/CDN\$ Exchange Rate	Edmonton Par (\$CDN/bbl)	Hardisty Heavy (\$CDN/bbl)	AECO Gas (\$CDN/mmbtu)
2011	88.40	\$0.932	93.08	74.46	4.04
2012	89.14	\$0.932	93.85	75.08	4.66
2013	88.77	\$0.932	93.43	72.87	4.99
2014	88.88	\$0.932	93.54	71.09	6.58
2015	90.22	\$0.932	94.95	72.16	6.69
Thereafter	1.5%	\$0.932	1.5%	1.5%	1.5%

The benchmark prices were adjusted for quality and transportation in determining cash flow for purposes of the impairment test.

Based on the impairment test, Manitok concluded that its petroleum and natural gas properties and equipment were not impaired at December 31, 2010 and June 30, 2010.

### 06

#### REVOLVING CREDIT FACILITY

On October 20, 2010, the Corporation amended its agreement with a major Canadian lender for a demand revolving credit facility of \$2,500,000 with similar terms and conditions as the prior agreement. The revolving credit facility allows for prime-based loans in Canadian dollars which bear interest at the prime lending rate plus 1.5%.

The facility is subject to a review by the lender at any time in its sole discretion, and at least annually and any change in or redetermination of the borrowing base limit which results in a borrowing base shortfall must be eliminated by the Corporation. The next annual review date has been set for May 31, 2011, but may be set at an earlier or later date at the sole discretion of the lender. The revolving credit facility is secured by a general security agreement encompassing all of the Corporation's assets.

At December 31, 2010, the Corporation had drawn \$NIL (June 30, 2010 – \$1,040,105) on the credit facility and the overall effective interest rate applicable to the prime-based loans in the Credit Facility was 4.0% for the six months ended December 31, 2010 (for the twelve months ended June 30, 2010 – 3.7%).

### 07

#### CAPITAL MANAGEMENT

The Corporation's general policy is to maintain a sufficient capital base in order to manage its business in the most effective manner with the goal of increasing the value of its assets and thus its underlying share value. The Corporation's objectives when managing capital are to maintain financial flexibility in order to preserve its ability to meet financial obligations; to maintain a capital structure that allows Manitok the ability to finance its growth strategy using internally-generated cash flow and its available debt capacity; and to optimize the use of its capital to provide an appropriate investment return to its shareholders.

Manitok strives to properly exploit its current asset base and to acquire top quality assets. As such, the Corporation is not averse to maintaining a higher ratio of debt to total capital if management determines the assets it is acquiring or the projects it is drilling are of high quality. However, the Corporation manages its capital structure and makes adjustments considering changes in economic conditions and the risk characteristics of the assets. In order to maintain or adjust the capital structure, Manitok may issue new shares or debt, increase the credit facility limits, or adjust its capital spending to manage current and projected debt levels. Management expects to be able to continue to raise equity and obtain debt financing sufficient to meet both its short-term and long-term growth requirements in the current environment.

There were no changes in the Corporation's approach to capital management during the December 31, 2010 fiscal period. The capital structure of the Corporation is as follows:

As at (\$)	December 31, 2010	June 30, 2010	Change
Total shareholders' equity <sup>(1)</sup>	<b>38,175,696</b>	14,089,990	171%
Total shareholders' equity as a % of total capital	<b>100%</b>	94%	
Working capital deficiency (surplus) <sup>(2)</sup>	<b>(19,780,030)</b>	(202,985)	–
Revolving credit facility	–	1,040,105	–
Total net debt <sup>(2)</sup>	–	837,120	–
Total net debt as a % of total capital	<b>0%</b>	6%	
Total Capital	<b>38,175,696</b>	14,927,110	156%

(1) Shareholders' equity is defined as share capital plus contributed surplus plus retained earnings (deficit).

(2) Working capital deficiency (surplus) is defined as current assets less current liabilities excluding the current portion of the amount drawn on the revolving credit facility. Working capital (surplus) is only included in total net debt if the Corporation is in a net debt position.

During the year ended December 31, 2010, total shareholders' equity increased mainly due to the issuance of common shares (note 11h, 11i, 11n and 11o); recording of stock-based compensation expense (note 12); and offset by the net loss reported in the period.

Total debt decreased during the six month period ended December 31, 2010 due to the net equity proceeds of \$9,064,582 (note 11h and 11i) which were used to repay the outstanding amount of the Corporation's revolving credit facility.

The Corporation's lender requires quarterly compliance that the "working capital ratio" (as defined by the lender) is not less than the required ratio of 1:1. Manitok was in compliance with the financial covenant as at December 31, 2010 and June 30, 2010.

## 08

## FINANCIAL INSTRUMENTS & RISK MANAGEMENT

Manitok is exposed to credit risk, liquidity risk and market risk as part of its normal course of business. The Board of Directors has overall responsibility for the establishment and oversight of the Corporation's financial risk management framework and periodically reviews risk management activities and all outstanding positions, if any. Management identifies and analyzes the risks faced by the Corporation, monitors risks and market conditions and the Corporation's activities.

### Credit Risk

Cash consists of bank balances, but may also include short term investments. Counter-parties for the short term investments will be selected based on credit ratings and management will monitor all investments to ensure a stable return, and complex investment vehicles with higher risk will be avoided. The Corporation's exposure to cash credit risk at the balance sheet date is very low.

Credit risk is the risk of financial loss to the Corporation if a customer fails to meet its contractual obligations. A substantial portion of the Corporation's accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risks. The carrying amount of accounts receivable reflects management's assessment of the maximum credit risk associated with these customers. The following table illustrates the Corporation's maximum exposure for receivables:

As at (\$)	December 31, 2010	June 30, 2010
Marketers	<b>510,002</b>	230,943
Joint venture partners	<b>397,906</b>	76,876
Other	<b>346,581</b>	268,001
Total Receivables	<b>1,254,489</b>	575,820

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## NOTES TO THE FINANCIAL STATEMENTS

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At December 31, 2010, approximately 41% of the Corporation's significant individual accounts receivable was due from two marketers (June 30, 2010 – 39%, two marketers) and about 27% was related to a cash call for capital expenditures which were collected subsequent to December 31, 2010. For the period ended December 31, 2010, the Corporation received the majority of its revenue from two marketers which accounted for approximately 99% of its revenue (June 30, 2010 – 97%, two marketers). Receivables from marketers are normally collected on the 25th day of the month following production. Manitok mitigates the credit risk associated with these balances by establishing relationships with credit worthy companies. The Corporation historically has not experienced any material collection issues with its marketers.

Manitok attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to the commencement of the joint venture project. However, joint venture receivables are from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, further risks exist with joint venture partners as disagreements arise that increase the potential for non-collection.

The Corporation's accounts receivables are aged as follows:

As at (\$)	December 31, 2010	June 30, 2010
Current (less than 30 days)	1,148,610	445,422
30 to 60 days	36,871	5,766
61 to 90 days	5,766	3,771
Over 90 days	63,242	120,861
Total Receivables	1,254,489	575,820

At December 31, 2010, approximately 5% of Manitok's total accounts receivable are aged over 90 days and considered past due. Approximately 59% of this amount is due from a joint venture partner and the Corporation is currently in the process of resolving the outstanding balance.

Should Manitok determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If the Corporation subsequently determines an account is uncollectible, the account is written off with a corresponding charge to allowance for doubtful accounts. At December 31, 2010, Manitok's allowance for doubtful accounts balance was \$NIL (June 30, 2010 – \$NIL).

### Liquidity Risk

Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they become due. Manitok's approach to managing liquidity risk is to ensure, as much as possible, that it will have sufficient liquidity to meet its short-term and long-term financial obligations when due, under both normal and unusual conditions without incurring unacceptable losses or risking harm to the Corporation's reputation.

All of the Corporation's contractual financial liabilities at December 31, 2010 and June 30, 2010 are to be settled in cash. Manitok utilizes prudent cash and debt management to mitigate the likelihood of encountering difficulties in meeting its financial obligations. The Corporation also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month.

Typically, the Corporation ensures that it has sufficient cash on demand to meet expected operational expenses, including the servicing of financial obligations. To achieve this objective, the Corporation prepares annual capital expenditure budgets, which are approved by the Board of Directors and are reviewed and updated as considered necessary. Petroleum and natural gas production is monitored regularly and used to provide monthly current cash flow estimates. Also, Manitok utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures.

To facilitate the capital expenditure program, the Corporation has a reserve-based revolving credit facility, as disclosed in note 6, which is reviewed at least annually by the lender. At December 31, 2010, \$2,500,000 (June 30, 2010 – \$1,495,895) in unused credit was available to fund future obligations.

The following table lists the contractual obligations of the Corporation's financial liabilities as at December 31, 2010:

(\$)	< 1 Year	1 – 2 Years	2 – 5 Years	Thereafter
Accounts payable and accrued liabilities	3,579,357	–	–	–
Revolving credit facility <sup>(1)</sup>	–	–	–	–
<b>Total Financial Liabilities</b>	<b>3,579,357</b>	<b>–</b>	<b>–</b>	<b>–</b>

(1) The revolving credit facility bears interest at a floating rate.

### Market Risk

Market risk is the risk that changes in market conditions, such as commodity prices, exchange rates and interest rates, will affect the debt level of the Corporation, as well as its net earnings and cash flow from operations. The objective of market risk management is to manage and control exposures within acceptable limits, while maximizing returns. These risks are consistent with prior years.

All risk management transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

### Commodity Price Risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in market commodity prices. A significant change in commodity prices can materially impact the Corporation's borrowing base under its revolving credit facility and may reduce the Corporation's ability to raise capital. Commodity prices for crude oil and natural gas are not only impacted by the Canadian and U.S. dollar, but also by world economic events that dictate the levels of supply and demand.

From time to time, the Corporation may attempt to mitigate commodity price risk through the use of financial derivatives. Manitok did not have any price risk management contracts in place as at or during the six month period ended December 31, 2010 and the twelve month period ended June 30, 2010.

### Foreign Currency Risk

Foreign currency risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. Crude oil and to a certain extent natural gas prices are based upon reference prices denominated in U.S. dollars, while the majority of the Corporation's expenses are denominated in Canadian dollars. The exchange rate effect cannot be quantified but generally an increase in the value of the Canadian dollar as compared to the U.S. dollar will reduce the prices received by Manitok for its petroleum and natural gas sales.

When appropriate, Manitok may enter into agreements to fix the exchange rate of Canadian dollars to U.S. dollars to manage the risk. The Corporation did not have any forward exchange rate contracts in place as at or during the six month period ended December 31, 2010 and the twelve month period ended June 30, 2010.

### Interest Rate Risk

Interest rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in market interest rates. The Corporation is exposed to interest rate risk on its revolving credit facility which bears a floating rate of interest based on prime lending rates. The remainder of Manitok's financial assets and liabilities are not exposed to interest rate risk.

A 1% change in the Canadian prime interest rate in the six month period ended December 31, 2010 would have increased (decreased) net earnings (loss) and comprehensive earnings (loss) by approximately \$200 (twelve month period ended

## NOTES TO THE FINANCIAL STATEMENTS

June 30, 2010 – \$4,700), assuming that all other variables remain constant. A sensitivity of 1% is considered reasonable given the current level of the bank prime rate and market expectations for future movements. The Corporation considers this risk to be limited and thus does not hedge its interest rate risk.

Manitok did not have any interest rate swaps or financial contracts in place as at or during the six month period ended December 31, 2010 and the twelve month period ended June 30, 2010.

### Fair Value of Financial Instruments

Manitok's financial instruments include cash, accounts receivable, accounts payable and accrued liabilities and the revolving credit facility on the balance sheet. All of Manitok's financial instruments are transacted in active markets.

The carrying value and fair value of these financial instruments at December 31, 2010 is disclosed below by financial instrument category, as well as any related loss or interest expense for the period:

(\$)	Carrying Value	Fair Value	Loss	Interest Expense
Assets Held for Trading				
Cash <sup>(1)</sup>	21,730,744	21,730,744	–	–
Loans and Receivables				
Accounts receivable <sup>(2)</sup>	1,254,489	1,254,489	–	–
Other Liabilities				
Accounts payable and accrued liabilities <sup>(2)</sup>	3,579,357	3,579,357	–	–
Revolving credit facility <sup>(3)</sup>	–	–	–	769

(1) Cash is reported at fair value, based on a Level 1 designation as identified in note 2k.

(2) Accounts receivable and accounts payable and accrued liabilities are reported at amortized cost. Due to the short term nature of accounts receivable and accounts payable and accrued liabilities, their carrying values approximate their fair values.

(3) The Corporation's revolving credit facility bears interest at a floating rate and accordingly the fair market value approximates the carrying value.

09

### ASSET RETIREMENT OBLIGATIONS

The Corporation's asset retirement obligations result from net ownership interests in petroleum and natural gas properties and equipment including well sites, gathering systems, processing facilities and pipelines. Manitok estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations as at December 31, 2010 to be approximately \$2,430,840 (June 30, 2010 – \$1,476,080) which will be incurred at the end of the operating lives of the underlying petroleum and natural gas assets, estimated to be over the next 20 years, with the majority of costs estimated to be incurred between 2020 and 2030. A credit-adjusted risk-free interest rate of 8% (June 30, 2010 – 8%) and an inflation rate of 2% (June 30, 2010 – 2%) were used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

As at (\$)	December 31, 2010	June 30, 2010
Opening Balance	790,780	1,010,190
Obligations incurred	324,590	–
Obligations acquired (disposed), net	(16,160)	(32,490)
Actual expenditures	(53,945)	–
Changes in estimates	(1,480)	(261,920)
Accretion expense	29,800	75,000
Ending Balance	1,073,585	790,780

## 10

**FUTURE INCOME TAX**

The provision for income taxes differs from the result that would be obtained by applying the combined current year Canadian federal and provincial income tax rates in 2010 of 28.0% (June 2010 – 28.5%). The difference results from the following items:

For the six and twelve months ended (\$)	December 31, 2010	June 30, 2010
Net earnings (loss) before income taxes	(1,879,523)	(2,365,337)
Computed expected income tax expense (recovery)	(526,266)	(674,121)
Increase (decrease) in income taxes resulting from:		
Non-deductible stock-based compensation	76,500	15,828
Non-deductible expenses	1,787	2,881
Effect of tax rate changes and temporary differences recorded at future rates and other	(23,271)	71,076
Future income tax expense (recovery)	(471,250)	(584,336)

The components of the future income tax assets and liabilities are as follows:

As at (\$)	December 31, 2010	June 30, 2010
Future income tax liabilities:		
Petroleum and natural gas properties and equipment	(3,937,158)	(2,646,582)
Future income tax assets:		
Asset retirement obligations	268,396	197,695
Share issue costs	545,431	44,909
Non capital losses	2,013,462	1,512,459
Other	54,216	–
Net future income tax liability	(1,055,653)	(891,519)

At December 31, 2010, the Corporation's estimated non-capital losses for income tax purposes are approximately \$8.1 million (June 30, 2010 – \$6.2 million) available to shelter future taxable income. Management expects that future taxable income will be available to utilize non-capital losses.

The following table shows a breakdown of the Corporation's non-capital losses by year of expiry:

Year of Expiry	(\$)
2013	4,376
2024	119,892
2025	1,647,522
2026	630,435
2027	2,383,350
2028	1,438,194
2030	1,830,080
Total non-capital losses	8,053,849

## 11

## SHARE CAPITAL

(a) Authorized:

- Unlimited number of voting common shares
- Unlimited number of preferred shares issuable in series, with rights and privileges to be designated by the Board of Directors at the time of issuance

(b) Issued and outstanding:

	Number of common shares	Amount \$
<b>MEX balance, June 30, 2009</b>	<b>8,176,826</b>	<b>14,436,550</b>
Issued, net of costs (note 11c)	176,956	191,289
Issued, net of costs (note 11d)	1,058,785	1,303,336
Issued, net of costs (note 11e)	1,237,000	1,342,640
Tax effect of share issue costs (note 11f)	—	22,450
Tax effect of share issue costs (note 11g)	—	20,849
Tax effect of flow-through shares (note 11d)	—	(362,274)
<b>MEX Balance, June 30, 2010</b>	<b>10,649,567</b>	<b>16,954,840</b>
Issued, net of costs (note 11h)	4,311,700	4,513,474
Issued, net of costs (note 11i)	3,846,000	4,551,108
Tax effect of share issue costs (note 11j)	—	223,418
<b>MEX balance, July 8, 2010 (prior to the Amalgamation)</b>	<b>18,807,267</b>	<b>26,242,840</b>
Issuance on the Amalgamation, net of costs (note 11k)	2,625,000	157,131
Tax effect of costs of the Amalgamation (note 11l)	—	55,879
Conversion of MEX shareholders on the Amalgamation (note 11m)	(4,701,807)	—
Issued, net of costs (note 11n)	10,031,500	9,287,967
Issued, net of costs (note 11o)	6,618,559	7,047,192
Share redemption (note 11p)	(119,268)	(149,086)
Issued, net of costs (note 11q)	325,400	301,282
Issued, net of costs (note 11r)	110,130	117,262
Tax effect of share issue costs (note 11s)	—	335,269
Tax effect of flow through shares (note 11i)	—	(1,249,950)
<b>Manitok balance, December 31, 2010</b>	<b>33,696,781</b>	<b>42,145,786</b>

(c) On December 31, 2009, MEX issued a private placement of 176,956 Class "A" common shares of MEX ("MEX Shares") (equivalent to 132,717 common shares of Manitok ("Manitok Shares")) at a price of \$1.15 per MEX Share (equivalent to \$1.53 per Manitok Share) for total net proceeds of \$191,289.

(d) On December 31, 2009, MEX issued a private placement of 1,058,785 MEX Shares on a "flow-through" basis under the Income Tax Act (Canada) ("MEX Flow-through Shares") (equivalent to 794,089 Manitok Shares issued on a "flow-through" basis under the Income Tax Act (Canada) ("Manitok Flow-through Shares")) at a price of \$1.30 per MEX Flow-through Share (equivalent to \$1.73 per Manitok Flow-through Share) for total net proceeds of \$1,303,336. As at December 31, 2010 the Corporation had incurred the entire \$1,376,421 in renounced exploration expenditures.

(e) On February 12, 2010, MEX issued a private placement of 1,237,000 MEX Shares (equivalent to 927,750 Manitok Shares) at a price of \$1.15 per MEX Share (equivalent to \$1.53 per Manitok Share) for total net proceeds of \$1,342,640.

(f) MEX recognized a future income tax benefit of \$22,450 in respect of share issue costs of \$85,295 incurred with respect to the issuance of 176,956 MEX Shares and 1,058,785 MEX Flow-through Shares on December 31, 2009.

(g) MEX recognized a future income tax benefit of \$20,849 in respect of share issue costs of \$79,212 incurred with respect to the issuance of 1,237,000 MEX shares on February 12, 2010.

- (h) On July 8, 2010, immediately prior to the Amalgamation, MEX issued a private placement of 4,311,700 MEX Shares (equivalent to 3,233,775 Manitek Shares) at a price of \$1.15 per MEX Share (equivalent to \$1.53 per Manitek Share) for total net proceeds of \$4,513,474.
- (i) On July 8, 2010, immediately prior to the Amalgamation, MEX issued a private placement of 3,846,000 MEX Flow-through Shares (equivalent to 2,884,500 Manitek Flow-through Shares) at a price of \$1.30 per MEX Flow-through Share (equivalent to \$1.73 per Manitek Flow-through Share) for total net proceeds of \$4,551,108. The Corporation has until December 31, 2011 to incur the \$4,999,800 in exploration expenditures.
- (j) MEX recognized a future income tax benefit of \$223,418 in respect of share issue costs of \$893,673 incurred with respect to the issuance of 4,311,700 MEX Shares and 3,846,000 MEX Flow-through Shares on July 8, 2010.
- (k) On the Amalgamation each Desco shareholder received 0.375 of a Manitek Share for every one Desco share held on July 8, 2010. As of the Amalgamation date, Desco had 7,000,000 common shares issued and outstanding with \$157,131 in total net identifiable assets distributed to Manitek, net of costs incurred with respect to the Amalgamation.
- (l) Manitek recognized a future income tax benefit of \$55,879 in respect of \$298,022 in costs incurred with respect to the Amalgamation.
- (m) On the Amalgamation each MEX shareholder received 0.75 of a Manitek Share for every one MEX share held on July 8, 2010. As of the Amalgamation date, MEX had 18,807,267 MEX Shares issued and outstanding.
- (n) On December 22, 2010, Manitek issued the first tranche of a private placement of 10,031,500 Manitek Shares at a price of \$1.00 per Manitek Share for total net proceeds of \$9,287,967.
- (o) On December 22, 2010, Manitek issued the first tranche of a private placement of 6,618,559 Manitek Flow-through Shares at a price of \$1.15 per Manitek Flow-through Share for total net proceeds of \$7,047,192. The Corporation has until December 31, 2011 to incur the \$7,611,343 in exploration expenditures.
- (p) On December 23, 2010, Manitek purchased for cancellation 119,268 Manitek Shares at a price of \$1.00 per Manitek Share pursuant to an arrangement with a previous employee of the Corporation. The excess of the book value of share capital over the purchase price has been charged to contributed surplus.
- (q) On December 30, 2010, Manitek issued the second and final tranche of a private placement of 325,400 Manitek Shares at a price of \$1.00 per Manitek Share for total net proceeds of \$301,282 respectively.
- (r) On December 30, 2010, Manitek issued the second and final tranche of a private placement of 110,130 Manitek Flow-through Shares at a price of \$1.15 per Manitek Flow-through Share for total net proceeds of \$117,262. The Corporation has until December 31, 2011 to incur the \$126,650 in exploration expenditures.
- (s) Manitek recognized a future income tax benefit of \$335,269 in respect of share issue costs of \$1,341,190 incurred with respect to the issuance of 10,031,500 Manitek Shares and 6,618,559 Manitek Flow-through Shares on December 22, 2010 and the issuance of 325,400 Manitek Shares and 110,130 Manitek Flow-through Shares on December 30, 2010.

## 12

**STOCK-BASED COMPENSATION****Stock Options**

The Corporation established an Incentive Stock Option Plan (the "Plan") on June 25, 2010 whereby officers, directors, employees and key consultants may be granted options to purchase Manitek Shares at a fixed price not less than the fair market value of the stock at the time of grant, subject to certain conditions. Stock options granted under this Plan vest over a three year period at the rate of one-third on each anniversary date of the stock option grant. All stock options granted are for a five year term. The Corporation is authorized to issue stock options for a maximum of 10% of the issued and outstanding Manitek Shares pursuant to the Plan.

## NOTES TO THE FINANCIAL STATEMENTS

At December 31, 2010, the Corporation's Plan permitted the grant of options to a maximum of 3,369,678 Manitok Shares. At December 31, 2010, there remained available for issuance stock options in respect of 1,731,178 Manitok Shares.

A summary of the Corporation's outstanding stock options as at December 31, 2010 is presented below:

	Number	Weighted Average Exercise Price (\$)
<b>MEX balance, June 30, 2009</b>	<b>702,500</b>	<b>2.09</b>
Granted	—	—
Cancelled or forfeited	—	—
<b>MEX balance, June 30, 2010</b>	<b>702,500</b>	<b>2.09</b>
Granted <sup>(1)</sup>	1,638,500	1.10
Cancelled or forfeited <sup>(2)</sup>	(702,500)	(2.09)
<b>Manitok balance, December 31, 2010</b>	<b>1,638,500</b>	<b>1.10</b>

(1) Pursuant to the Plan, Manitok granted 1,588,500 stock options at an exercise price of \$1.10 per share on August 16, 2010 and 50,000 at an exercise price of \$1.00 per share on November 1, 2010.

(2) Pursuant to the Amalgamation, 702,500 of MEX's unexercised stock options had been terminated and cancelled for nominal consideration on July 8, 2010.

The range of exercise prices for stock options outstanding and exercisable under the plan at December 31, 2010 is as follows:

Exercise Prices		Awards Outstanding			Awards Exercisable		
Low	High	Quantity	Weighted Average	Weighted	Quantity	Weighted Average	Weighted
			Remaining Contractual Life (years)	Average Exercise Price		Remaining Contractual Life (years)	Average Exercise Price
\$1.10	\$1.10	1,638,500	4.6	\$1.10	—	—	—
		<b>1,638,500</b>	<b>4.6</b>	<b>\$1.10</b>	—	—	—

### Performance Warrants

On July 1, 2006, MEX issued performance warrants ("MEX Warrants") with an exercise price of \$2.00 that vest upon certain performance criteria and have an expiration date of July 1, 2011. The performance criteria would be met when the market price of the common shares equals or exceeds \$4.00 per common share and it is combined with a liquidity event. The liquidity event can be either an outright sale or merger of the Corporation or any event which causes the Corporation to become a public entity.

Pursuant to the Amalgamation on July 8, 2010, 267,500 of the MEX Warrants have been terminated and cancelled for nominal consideration. At December 31, 2010 there were no MEX Warrants outstanding (June 30, 2010 – 267,500).

### Stock-Based Compensation Expense

In order to calculate the compensation expense, the fair value of the stock options are estimated using the Black-Scholes option-pricing model that takes into account, as of the grant date: exercise price, expected life, current share price, expected volatility, expected dividends, and risk-free interest rates.

For the six month period ended December 31, 2010, the Corporation recorded \$273,216 (for the twelve month period ended June 30, 2010 – \$55,529) of non-cash stock-based compensation expense and a corresponding increase to contributed surplus.

The fair value of each option granted in the period is estimated using the Black-Scholes option-pricing model with weighted average assumptions for grants as follows:

For the six and twelve months ended	December 31, 2010	June 30, 2010
Weighted average fair value of options granted	\$0.75	—
Risk-free interest rate	2.04%	—
Expected life (years)	4.5	—
Expected volatility	90.3%	—
Expected dividends	0.0%	—

### Contributed Surplus Continuity

The following table presents the reconciliation of contributed surplus with respect to stock-based compensation:

As at (\$)	December 31, 2010	June 30, 2010
Opening Balance	514,390	458,861
Stock-based compensation expense	273,216	55,529
Share redemption (note 11p)	29,817	—
Ending Balance	817,423	514,390

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### PER SHARE INFORMATION

As at	December 31, 2010	June 30, 2010
MEX weighted average shares outstanding	—	9,264,080
Conversion factor of MEX Shares on the Amalgamation (note 11m)	—	(2,316,020)
Manitok weighted average shares outstanding – basic	17,402,916	6,948,060
Manitok weighted average shares outstanding – diluted	17,402,916	6,948,060

As the Corporation reported a loss for the six months ended December 31, 2010 and the twelve months ended June 30, 2010, the basic and diluted weighted average shares outstanding are the same for that period.

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### COMMITMENTS AND CONTINGENT LIABILITIES

The Corporation committed to incur exploration expenditures of \$1,376,421 related to the flow-through common share issuance completed on December 31, 2009, as indicated in note 11d. Manitok will be subject to Part XII.6 tax of approximately \$21,000 based on the prescribed rate on the balance of exploration expenditures not yet incurred at the end of each month subsequent to January 31, 2010. As at December 31, 2010, Manitok had satisfied its obligation.

The Corporation is committed to incur exploration expenditures of \$4,999,800 related to the flow-through common share issuance completed on July 8, 2010, as indicated in note 11i. Manitok will be subject to Part XII.6 tax based on the prescribed rate on the balance of exploration expenditures not yet incurred at the end of each month subsequent to January 31, 2011. As at December 31, 2010, the costs incurred for exploration expenditures were approximately \$738,000.

The Corporation is committed to incur exploration expenditures of \$7,737,993 related to the flow-through common share issuance completed on December 22, 2010 and December 30, 2010, as indicated in note 11o and 11r. Manitok will be subject to Part XII.6 tax based on the prescribed rate on the balance of exploration expenditures not yet incurred at the end of each month subsequent to January 31, 2011. As at December 31, 2010, the costs incurred for exploration expenditures were \$NIL.

## NOTES TO THE FINANCIAL STATEMENTS

On February 17, 2010, Manitok committed to an operating lease relating to its office premises beginning May 1, 2010 which expires on June 30, 2015. Under this commitment the Corporation will pay a monthly rate of approximately \$25,220, excluding occupancy costs, until the lease expires. The Corporation is committed to the following aggregate minimum lease payments:

Year	\$
2011	302,640
2012	302,640
2013	302,640
2014	302,640
2015	126,100

The Company was issued a statement of claim from a previous employee claiming wrongful dismissal and the Company had filed a statement of defense and counterclaim. On December 23, 2010 the issue was settled and Manitok agreed to pay the previous employee severance of \$31,500 and to redeem Manitok Shares held by the previous employee for \$1.00 per Manitok Share.

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### SUPPLEMENTARY CASH FLOW INFORMATION

The following table details the components of non-cash working capital:

As at (\$)	December 31, 2010	June 30, 2010
Provided by (used in)		
Accounts receivable	(678,669)	(288,225)
Prepaid and deposits	(38,523)	(44,069)
Accounts payable and accrued liabilities	2,800,243	300,048
	<b>2,083,051</b>	<b>(32,246)</b>
Provided by (used in)		
Operating	(205,465)	269,163
Investing	2,288,516	(301,409)
	<b>2,083,051</b>	<b>(32,246)</b>

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### SUBSEQUENT EVENTS

#### Stock Options

On January 3, 2011 Manitok granted 1,172,000 stock options at a price of \$1.23 per share which vest over a three year period and expire on January 3, 2016. On January 28, 2011 Manitok granted 140,000 stock options at a price of \$1.55 per share which vest over a three year period and expire on January 28, 2016.

#### Equity Financing

On April 14, 2011, the Corporation closed an equity financing, completed by way of a short form prospectus, for the sale of 17,968,750 Manitok Shares at a price of \$1.60 per Manitok Share for total gross proceeds of \$28.75 million and net proceeds of approximately \$26.8 million. Proceeds of the equity issue will be used to fund the Corporation's drilling program and the acquisition of undeveloped land and seismic in 2011 and early 2012.

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### RECLASSIFICATION

Certain amounts disclosed for prior periods have been reclassified to conform to the current period's presentation.

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## CORPORATE INFORMATION

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### DIRECTORS

**Bruno P. Geremia, C.A.** <sup>(1) (2) (3)</sup>  
Chairman of the Board  
Calgary, Alberta

**Robert J. Dales** <sup>(1) (2) (4)</sup>  
Calgary, Alberta

**Wilfred A. Gobert** <sup>(2) (3)</sup>  
Calgary, Alberta

**Gregory E. Peterson** <sup>(3)</sup>  
Calgary, Alberta

**Tom Spoletini** <sup>(2) (3)</sup>  
Calgary, Alberta

**Cameron G. Vouri, P. Eng.** <sup>(1)</sup>  
Calgary, Alberta

**Massimo M. Geremia** <sup>(1) (2)</sup>  
Calgary, Alberta

*(1) Reserve Committee Member*

*(2) Audit Committee Member*

*(3) Compensation Committee Member*

*(4) Added as director on July 8, 2010*

### OFFICERS

**Massimo M. Geremia**  
President and Chief Executive Officer

**Tim de Freitas, M.Sc., Ph.D.**  
Vice President, Exploration and  
Chief Operating Officer

**Robert G. Dion, C.A.**  
Vice President, Finance and  
Chief Financial Officer

**Dorothy Else**  
Vice President, Land

**Gregory E. Peterson**  
Corporate Secretary

### SOLICITORS

**Gowling Lafleur Henderson LLP**  
Calgary, Alberta

### AUDITORS

**Kenway Mack Slusarchuk Stewart LLP**  
Chartered Accountants  
Calgary, Alberta

### INDEPENDENT RESERVE EVALUATORS

**Sproule Associates Limited**  
Petroleum Consultants  
Calgary, Alberta

### BANKERS

**Alberta Treasury Branch**  
Calgary, Alberta

### TRANSFER AGENT

**Valiant Trust Company**  
Calgary, Alberta

### STOCK EXCHANGE LISTING

TSX Venture Exchange  
Symbol: MEI

### WEBSITE

[www.manitokenergy.com](http://www.manitokenergy.com)

### EMAIL

[info@manitok.com](mailto:info@manitok.com)

### HEAD OFFICE

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**Manitok Energy Inc.** is a junior energy company engaged in oil and gas exploration and production in Western Canada. The Company's primary area of focus is the Foothills Belt in Alberta. The Company's shares are listed for trading on the TSX Venture Exchange under the symbol: MEI

**Shareholders' Meeting** – Manitok Energy Inc. invites shareholders to attend the Annual and Special Meeting on June 22, 2011 at 2:30pm in the President's Room of the Calgary Petroleum Club, 319 – 5th Avenue S.W, Calgary, Alberta, Canada.



Photos by: Ilona Kohlmann of Peace of Art Photography

