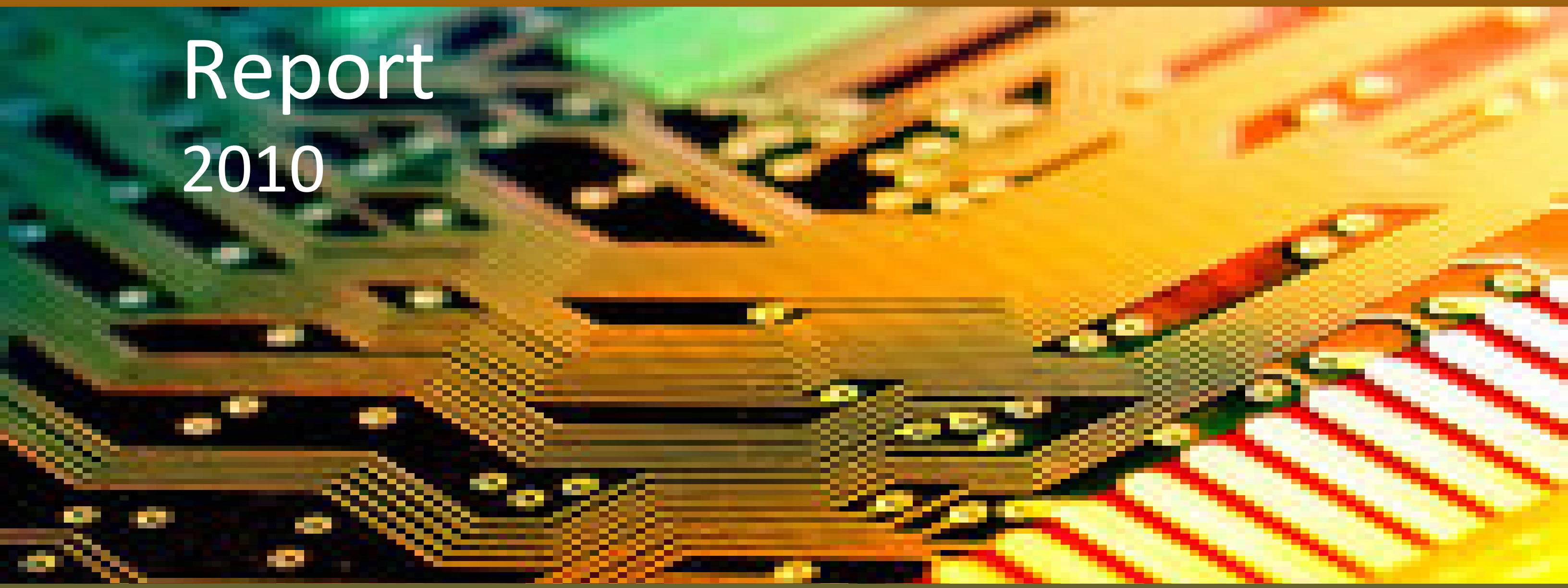
THE OIL SANDS DEVELOPERS GROUP
Energy From Athabasca

Oil Sands Co-Generation Report

2010



PRODUCED BY: THE OSDG
CO-GENERATION/TRANSMISSION COMMITTEE

OIL SANDS CO-GENERATION REPORT

OIL SANDS CO-GENERATION POTENTIAL
SURVEY RESULTS

May 2010

EXECUTIVE SUMMARY

This report is the 11th annual summary of a survey on the state and forecasts of electricity demand and co-generation development provided by oil sands developers in Alberta. The survey results show that oil sands developers either do not plan to install cogeneration or are planning to install cogeneration capacity to roughly match their on-site project load. The net result is that areas like Fort McMurray will move from being a net supplier or net exporter of electricity to the rest of the province to a net importer over the next decade.

The survey results show that Market Fundamentals (e.g. will co-generation be economically viable) and Security of Power Supply and Reliability (e.g. is co-generation required to ensure a reliably electricity source) were the most important factors for oil sands developers. Identified factors that policy makers could address to further encourage co-generation development include:

- Reduce security of supply and reliability risks and improve transmission access by ensuring that additional transmission capacity to the Fort McMurray and Cold Lake areas is developed in advance of industry requirements
- Reduce environmental risks by providing clarity on future greenhouse gas emissions compliance obligations
- Reduce development timelines with streamlined AESO connection and AUC approval processes and legislative changes to section 101 of the *EUA* to remove the requirement that transmission connected projects need approval from the local distribution company

The objectives of the co-generation survey are:

- determine the key factors that are important to oil sands developers in making decisions on the development of co-generation
- provide policy makers with an overview of the issues that may be promoting or hindering the development of co-generation at oil sands projects
- provide a quantitative overview of the current and potential:
    - on-site demand - electricity to be consumed by oil sands projects, either oil sands mines (and associated upgraders) and from the in-situ projects
    - co-generation capacity associated with oil sands projects
    - if on-site generation capacity is greater than on-site demand electricity exports to the provincial grid associated with oil sands projects
    - if on-site generation capacity is less than on-site demand stand-by requirements or electricity to be consumed from the provincial grid
- provide a comparison of the results from prior surveys and commentary on how government policies may be impacting co-generation development

A review of the survey's quantitative values indicates that prior surveys have been accurate such that the anticipated overall demand and co-generation capacity ten years out has not materially changed over the past five years; however, the timing of the development projects continues to be pushed further into the future. The high capital costs associated with oil sands development projects, the 2008 global financial issues and the subsequent recession are all cited as reasons for the slower than anticipated pace of oil sands development in Alberta.

An enhancement to this year's annual report includes a more detailed analysis of the potential impact of anticipated oil sands development projects on the Alberta transmission system. The results show that the AESO's current transmission development plans that calls for 500 kV lines from the Edmonton area to Fort McMurray to be completed in 2014 and 2015 will be required to provide stand-by service to oil sands projects.

The data presented in this report includes oil sands projects where the oil sands developer completed the 2010 survey. Not all oil sands developers completed the survey and hence this report should be viewed as somewhat conservative. The author is of the view the majority of the larger and higher probability of proceeding projects have been captured. Some oil sands developers working on some smaller or more speculative projects did not return the completed 2010 survey. It is anticipated that over 95% of the potential oil sands projects have been captured in the 2010 survey.

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1.0 INTRODUCTION

Co-generation has been employed by the oil sands industry in the commercial production of bitumen since the mid 1970's. Since then, co-generation capacity has grown as more projects are developed and operators seek self-sufficiency, improved electric energy reliability and optimization of power consumption by co-generating steam and power in a single, on-site facility. The Oil Sands Developers Group began tracking and forecasting the growth in co-generation in 1999 with the objective of providing information to operators, the Alberta Electrical System Operator ("AESO") and Alberta government policy makers on issues related to co-generation and transmission development.

The *2010 Oil Sands Co-generation Report* contains the results of the 2010 co-generation survey of companies operating or planning to operate oil sands mines and in-situ operations within the province of Alberta, Canada.[1] The purpose of the survey is to determine the current and potential electrical generation capacity of co-generation plants located within the oil sands projects. The Co-Generation/Transmission Committee of the Oil Sands Developers Group ("OSDG") manages the annual survey and issues this report.

The survey was completed in early 2010 when the oilsands industry was recovering from the financial uncertainty of 2008 and 2009 with renewed interest and plans for oil sands development. The survey results reflect the known changes in project schedules and scopes. Some of the participating companies have delayed projects and some are proceeding with caution with longer development term schedules.

The Oil Sands Developers Group deals with issues related to the development of bitumen resources within the Athabasca Oil Sands Deposit region of Alberta. The mandate of the Co-generation/Transmissions Committee is to provide a forum for oil sands developers to identify and address issues related to co-generation and to share, discuss and develop information in support of sufficient electrical transmission capability and regulatory processes for co-generation development in the Regional Municipality of Wood Buffalo and Cold Lake regions of Alberta.

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This report was prepared for The Oil Sands Developers Group by Desiderata Energy Consulting Inc. (www.desiderataenergy.com).

2.0 METHODOLOGY

The source of data for the *2010 Oil Sands Co-generation Report* is a survey of oil sands companies conducted in January and February of 2010. The survey requested actual and forecasted data for co-generation operating capacity, on-site demand, requirements

[1] Oil sands upgraders in the Heartland area near Fort Saskatchewan have been excluded from the survey.

for stand-by power from the grid and potential power sales or net exports. The data was requested for three ranges; low, medium and high. The ranges were defined as:

- **Low Range** - project would be built to the minimum anticipated scope - this may relate to a minimum capital spend, lower oil prices, higher priced carbon emissions and/or poorer economic conditions environments
- **Medium Range** - project would be built to the most probable or planned scope.
- **High Range** - project would be built to the maximum anticipated scope - this may relate to a higher capital spend, higher oil prices, lower priced carbon emissions and/or more robust economic conditions environments

The survey data were compiled, analyzed and adjusted by Desiderata Energy Consulting Inc., and shared with a representative of the AESO.

The results were compiled with submissions from 19 participating oil sands companies who reported on 30 operating or planned co-generation sites located in the Regional Municipality of Wood Buffalo, the Cold Lake and the Peace River regions of Alberta. A total of 59 generating units are either in operation or being planned, with a combined anticipated operating generating capacity of 3,845 MW of power (Medium Range) by the year 2019. In addition, data was collected on an additional 13 oil sands projects where cogeneration is not planned.

Not all oil sands developers completed the survey. The author is of the view the majority of the larger and higher probability of proceeding projects have been captured. Oil sands developers working on some smaller or more speculative projects did not return the completed 2010 survey. It is anticipated that over 95% of the potential oil sands projects have been captured in the 2010 survey.

This report contains forward-looking information. Actual results could differ materially due to market conditions, changes in law or government policy, changes in operating conditions and costs, changes in project schedules, operating performance, demand for oil and gas, commercial negotiations or other technical and economic factors. Not all oil sands companies completed the 2010 survey and hence the information provided in this report may not be inclusive off all potential oil sands projects.

3.0 RESULTS

3.1 Presentation of the Data

The results of the 2010 survey are shown in graph format in two cases; a 100 per cent all announced case and a risk factor based discounted case. The 100 per cent case assumes that all projects will proceed as announced, and the discounted case applies a percentage reduction to the reported data depending on the position of each project in the regulatory application/approval process. The discounted case is considered the most likely case as it includes a risk factor for project delays or cancellations. The discounting formula uses:

- 10 per cent of reported data for projects that are conceptual in nature
- 25 per cent for projects that have been announced
- 60 per cent for projects in the approval stage
- 90 per cent when regulatory approval has been received

- 100 per cent for projects with full company approval and/or under construction or operating

The 2010 results presented in the discounted case do not differ significantly from the 100 per cent case to the year 2015 as the generating units reported and discounted tend to be in the latter half of the survey horizon. A majority of the projects reported are in operation or are conceptual (see Table 3).

The total number of planned or installed co-generation units reported in 2010 increased by seven from the 2009 survey. There were several cases of project sites increasing or decreasing the number of planned units, demonstrating an optimization of power needs. Three new companies reported planning the use of co-generation. Four OSDG member companies declined to submit data as their projects are too early in the process to report meaningful data.

The five-year comparison of expected co-generation operating results indicate that actual operating co-generation capacity in 2009 is lower over the prior surveys. Similarly, prior surveys noted Medium Range co-generation operating reaching 3,500 MW by 2014, whereas the 2010 forecast does not reach 3,500 MW until 2018. In summary, the quantum of expected co-generation operating has not charged over the prior five surveys; however, the timing of the additions has been delayed by about 3 to 5 years.

3.2 Trends in the Use of Co-generation

A trend for oil sands companies to plan and build power generating capacity to primarily satisfy on-site power needs was first noted in the *2005 Co-generation Report*. This trend appears to persist in 2010. Prior to 2005, survey results indicated that companies made more allowance for net export capacity for projects located in the Athabasca region, near the city of Fort McMurray. The trend is illustrated in Figure 18 in which the data for the year 2011 is extracted from the annual surveys conducted in the years 2000 to 2010.

An initiative to allow for the advancement of the construction of additional transmission capacity to the Fort McMurray area was approved in 2009 in the form of the *Electric Statutes Amendment Act*. This initiative and additional changes to government policy (i.e. clarification on greenhouse gas emissions) could potentially reverse the trend to build capacity to meet on-site demand only and support the growth in net exports from co-generation by encouraging developers to install greater capacity.

3.3 What Factors are Critical in the Decision to Build or Not Build Co-Generation?

Survey respondents were asked to indicate the level of importance of five categories of factors that could impact their decision to build or not build co-generation. The five categories, in order of importance, were:

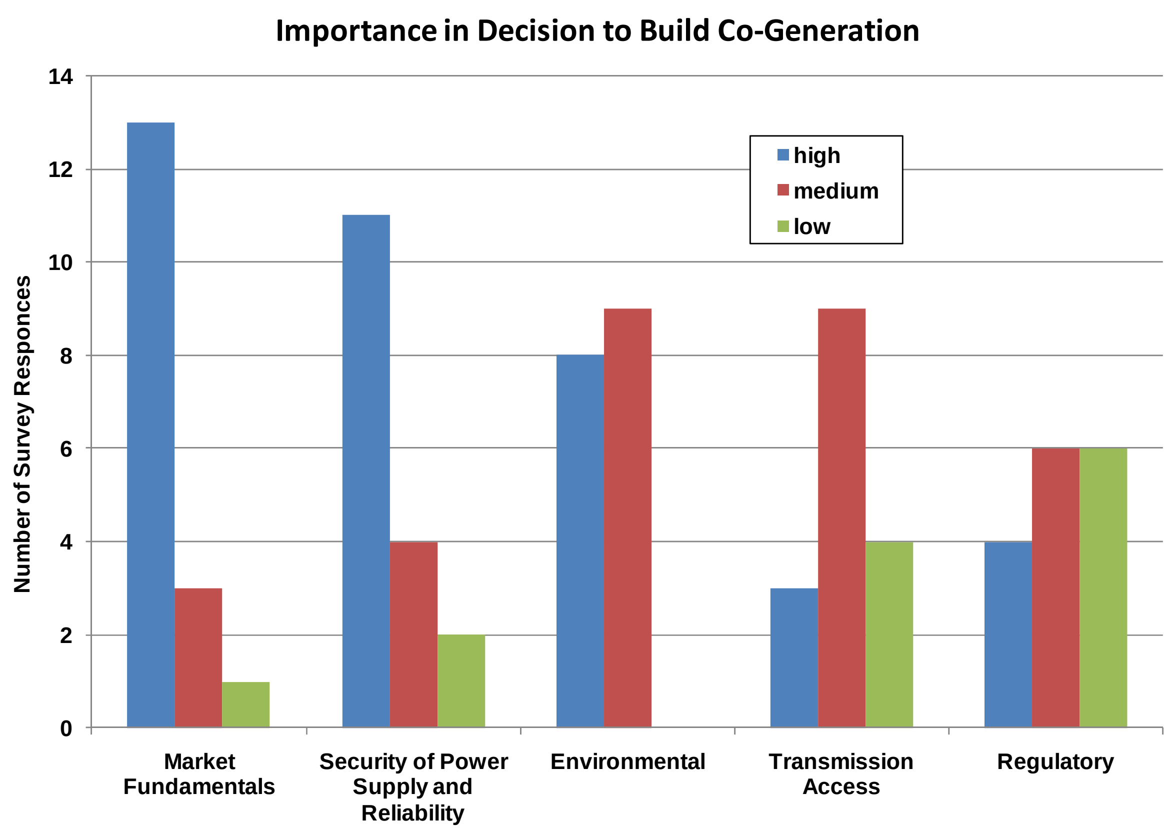
Market fundamentals

- Market price of power vs. cost of generating power
- Transmission costs
- Higher gas prices and lower pool prices reduce economic benefits
- Long term electrical prices
- Co-generation SAGD (Steam Assisted Gravity Drainage) steam balance

	• Non-fuel operating costs
Security of Supply and Reliability	• Market risk and reliability of power from grid • Balanced load and co-generation • Self sufficiency • Power supply security
Environmental	• GHG emissions/regulations • Internal fuel balance • Environmental performance
Transmission Access	• Available transmission capacity is a necessary but not sufficient condition • No export capacity from the Cold Lake area • Exceeding the limitations of existing equipment
Regulatory	• AESO connection process • Disco section 101 approvals • AUC transmission and power plant facility applications • Industrial System Designation approval

The following chart (Figure 1) shows the survey results graphically:

Figure 1 Factors Influencing Decision to Build Co-Generation



All of the factors were of high importance to some of the survey respondents. Some of the factors within Market Fundamentals are outside of the direct control of policy makers (e.g. wholesale natural gas and electricity prices) whereas other factors can be influenced to a greater extend (e.g. increased transmission costs via legislative requirements like the *Electric Statutes Amendment Act*). Other factors can be influenced to a greater extent by policy makers – for example:

- Reduce security of supply and reliability risks and improved transmission access by ensuring that additional transmission capacity to the Fort McMurray and Cold Lake areas is developed in anticipation of industry requirements
- Reduce environmental risks by providing clarity on future greenhouse gas emissions compliance obligations
- Reduce development timelines with streamlined AESO connection and AUC approval processes and legislative changes to section 101 of the *EUA* to remove the requirement that transmission connected projects need approval from the local distribution company

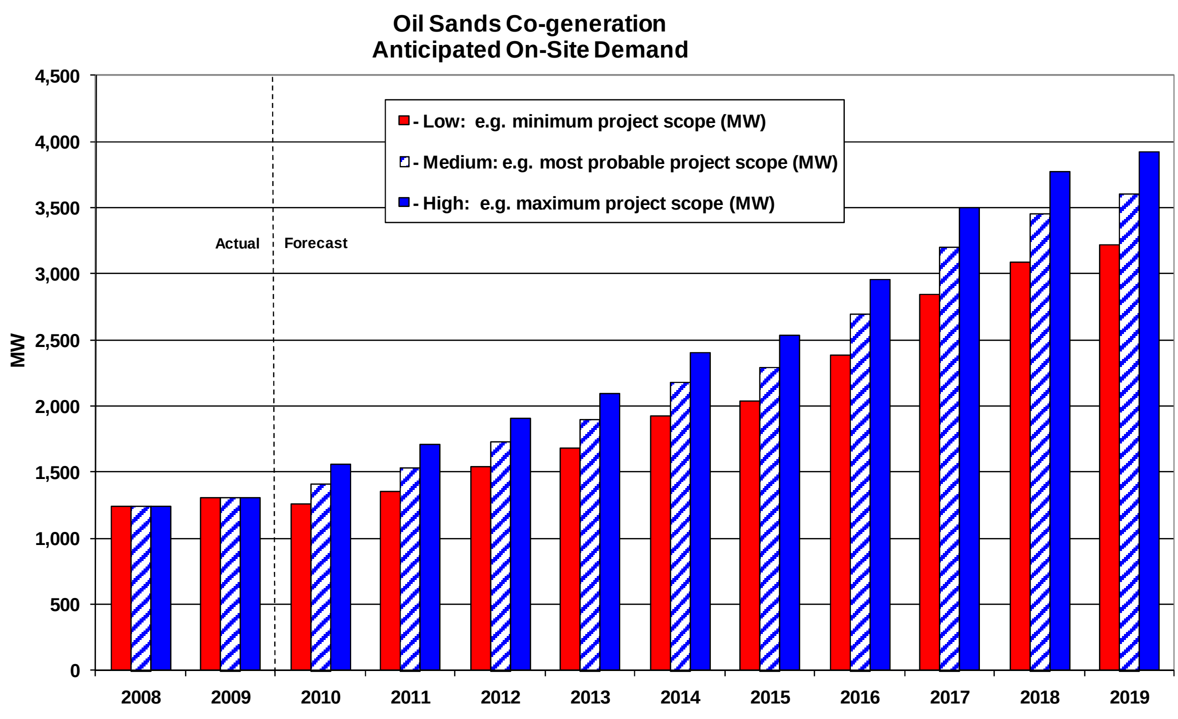
3.4 Detailed Survey Results

The following are the results for each question in the 2010 survey.

3.4.1 What is the expected range of on-site demand for each year?

The 2010 results show an increase in on-site demand over the entire forecast period 2010 – 2019 (Figure 2). The rate of annual demand growth for the Medium Range increases from about 8% per year in 2010 and 2011 to nearly 20% per year in 2017 before leveling off over the last few years of the forecast. The total demand over the forecast period is fairly similar to the 2009 forecast.

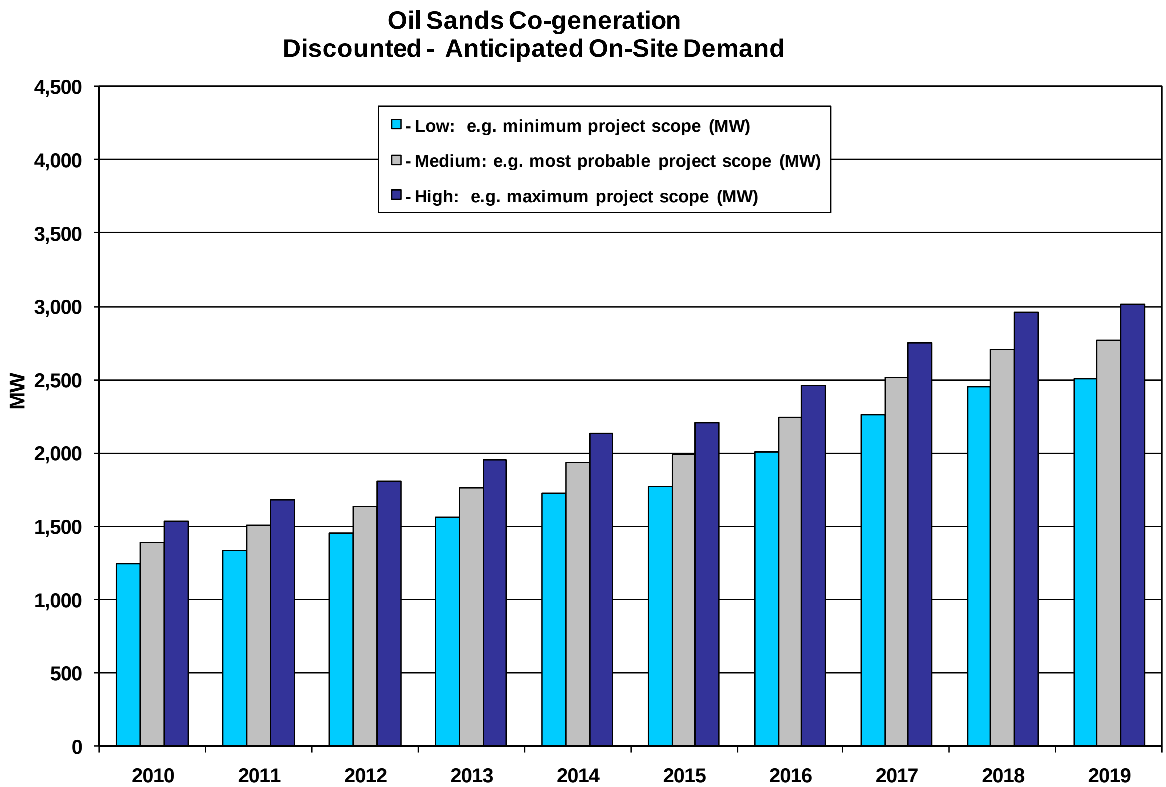
Figure 2 Anticipated On-Site Demand



Note that on-site demand is based on the level of contract demand or capacity each oil sands developer commits to with the AESO (i.e. DTS contract capacity). Most oil sands developers with co-generation on-site will contract for their maximum anticipated demand to ensure adequate capacity is available when their on-site generation units are off-line. Hence the data presented in this section of the report should not be taken as actual or average demand. As presented in the section below entitled **Duration Curve Analysis** actual demand is significantly lower than contract demand in most hours for oil sands projects that have on-site co-generation.

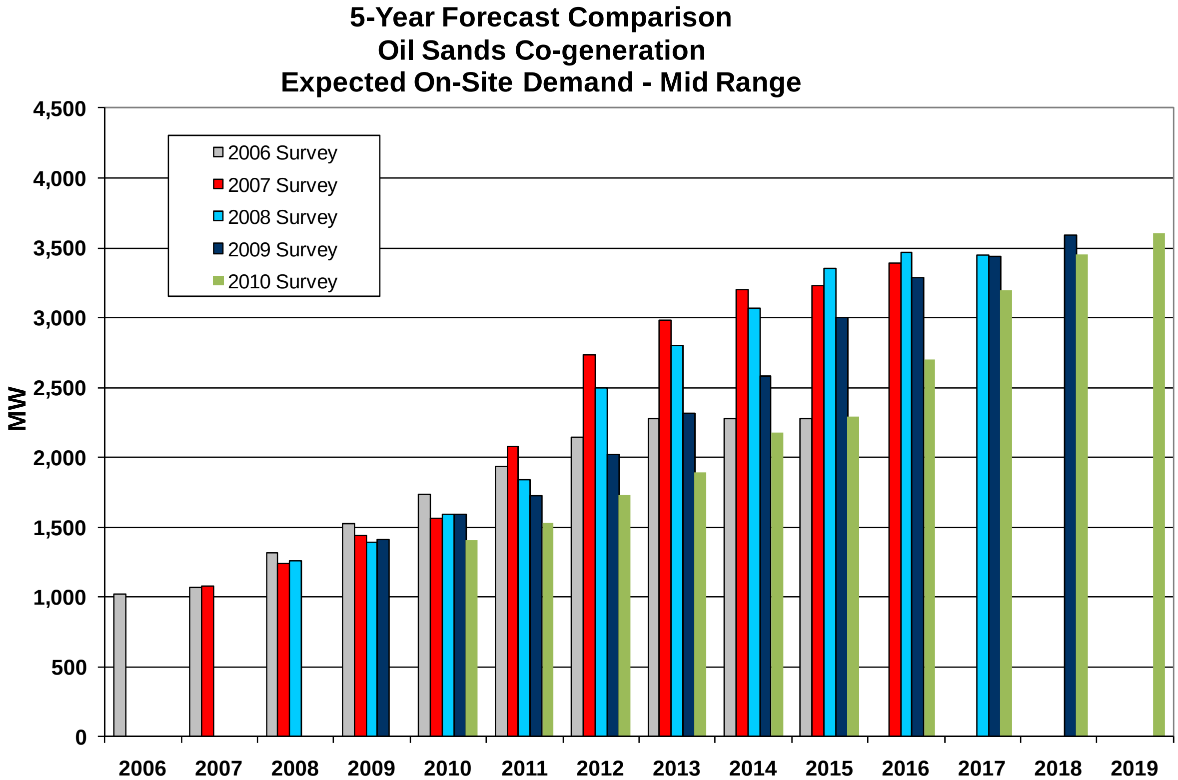
With discounting, the 2010 survey anticipated on-site demand is lower than the 2009 survey results (Figure 3). The rate of annual demand growth is similar at about 8% per year in 2010 and 2011; however, growth rates only reach 12% in 2017.

Figure 3 Discounted - Anticipated On-Site Demand



The five year comparison of annual surveys (Figure 4) shows that on-site demand growth has not materially changed; however, the timing has been delayed by about three to five years. Concerns over project capital costs, labour shortages, greenhouse gas emissions, etc. have likely lead to projects being delayed compared with earlier surveys. However, oil sands developers continue to envision that their projects will proceed.

Figure 4 5 year Comparison of Expected On-Site Demand



3.4.2 What options for power supply are being considered?

A noted change in the 2010 responses is the trend for companies to plan the use of both on-site co-generation and purchased power from the grid to meet their stand-by power needs. This trend was noted in the 2009 report and is even more prevalent with the 2010 survey results. The rationale for the change includes reducing capital costs by planning on-site generation to more closely meet on-site demand, willingness to assume higher risk with reliance on the grid and lower power pool prices.

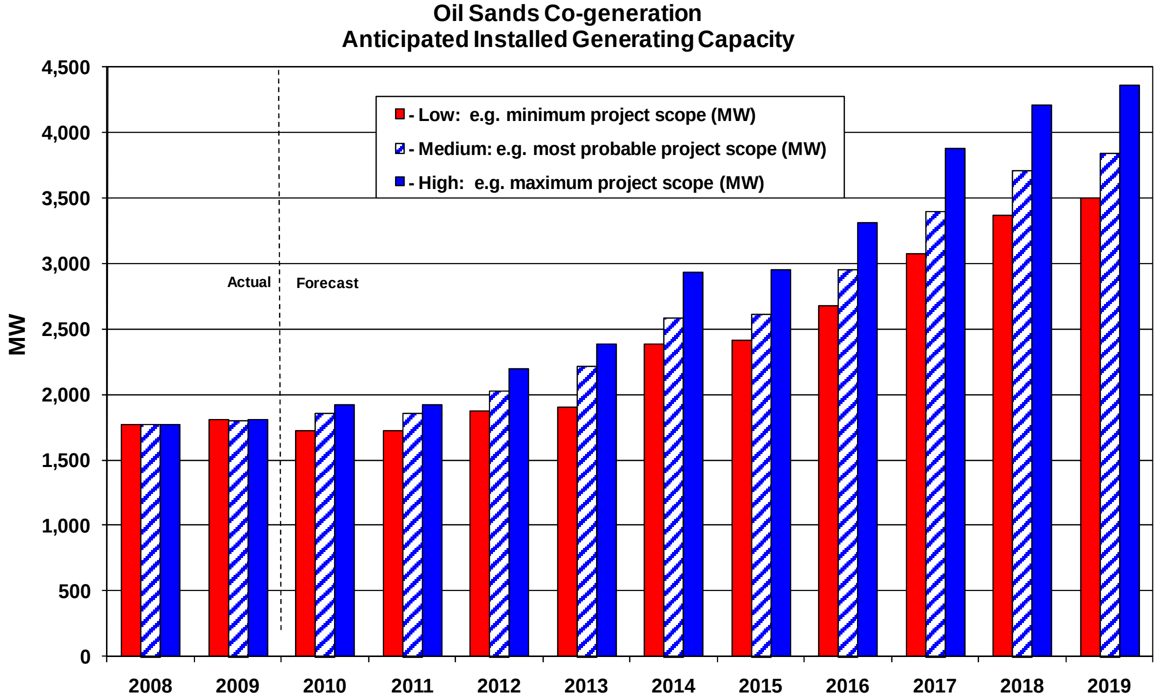
Table 1 Options for Power Supply (number of companies)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Co-Generation only	0	0	0	0	0	0	1	1	1	1	1	3
Direct purchase from the grid only	5	5	6	4	6	10	14	12	9	8	8	10
Plan on doing both of the above	13	13	13	15	17	18	19	22	26	30	30	31

3.4.3 If installing on-site co-generation power supply, please provide the anticipated range of your operating generating capacity.

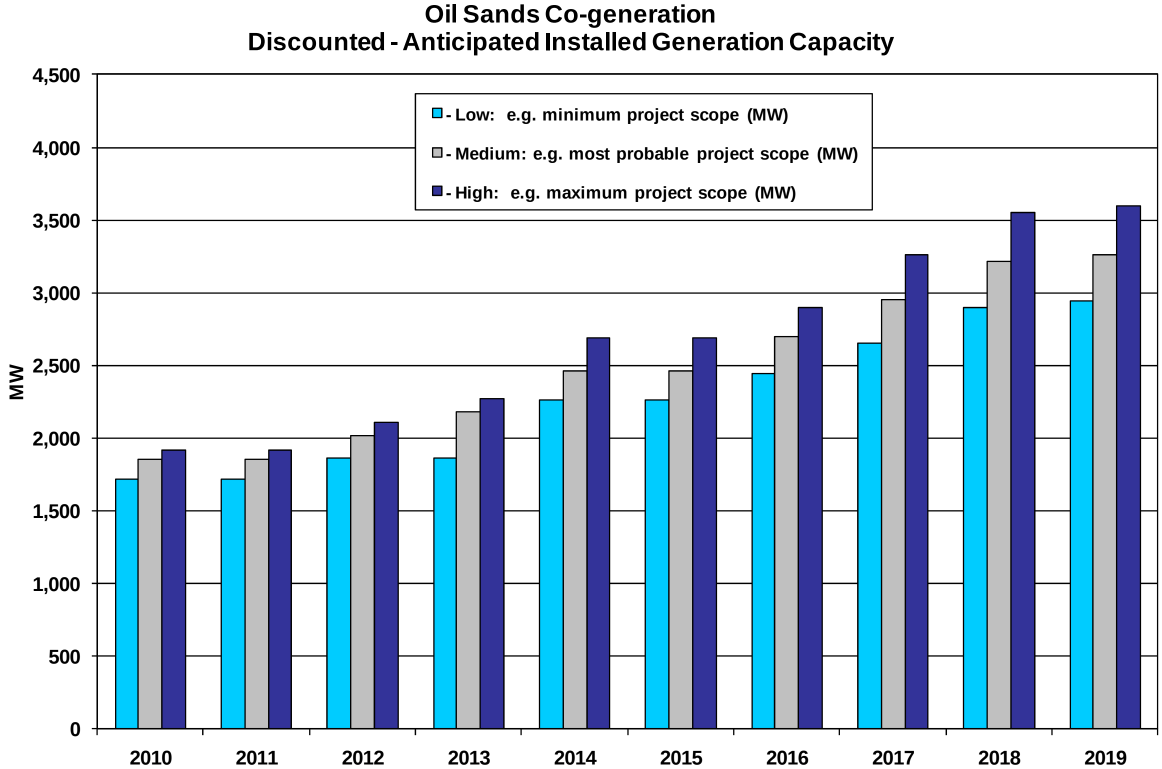
The 2010 survey range of operating generating capacity (Figure 5) indicates a delay in co-generation projects coming on line over the next three years compared to the 2009 survey results. Over the survey horizon slightly more generation is forecast to be developed.

Figure 5 Anticipated Installed Operating Generation Capacity



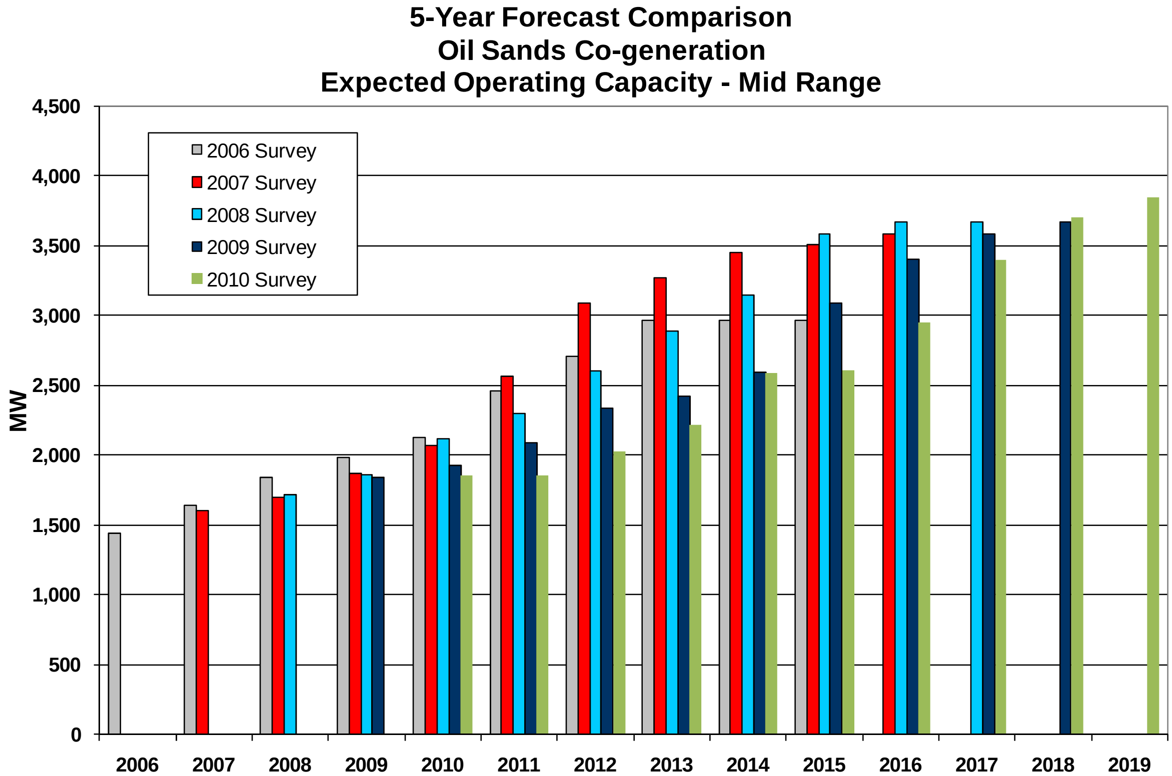
Discounted results (Figure 6) are slightly lower than the 2009 survey and reflect a lower level of additions in the later part of the forecast period.

Figure 6 Discounted - Anticipated Installed Operating Generation Capacity



In each of the last five surveys, the actual operating co-generation capacity amounts are less than the previous year's forecast (Figure 7), with the exception of the 2007 forecast. Economic uncertainty is felt to be main reason for the delays in forecasting the installation of co-generation units. Similarly to on-site demand, the overall level of expected co-generation operating by the end of the forecast period has not materially changed.

Figure 7 5 year Comparison of Expected Operating Co-generation Capacity

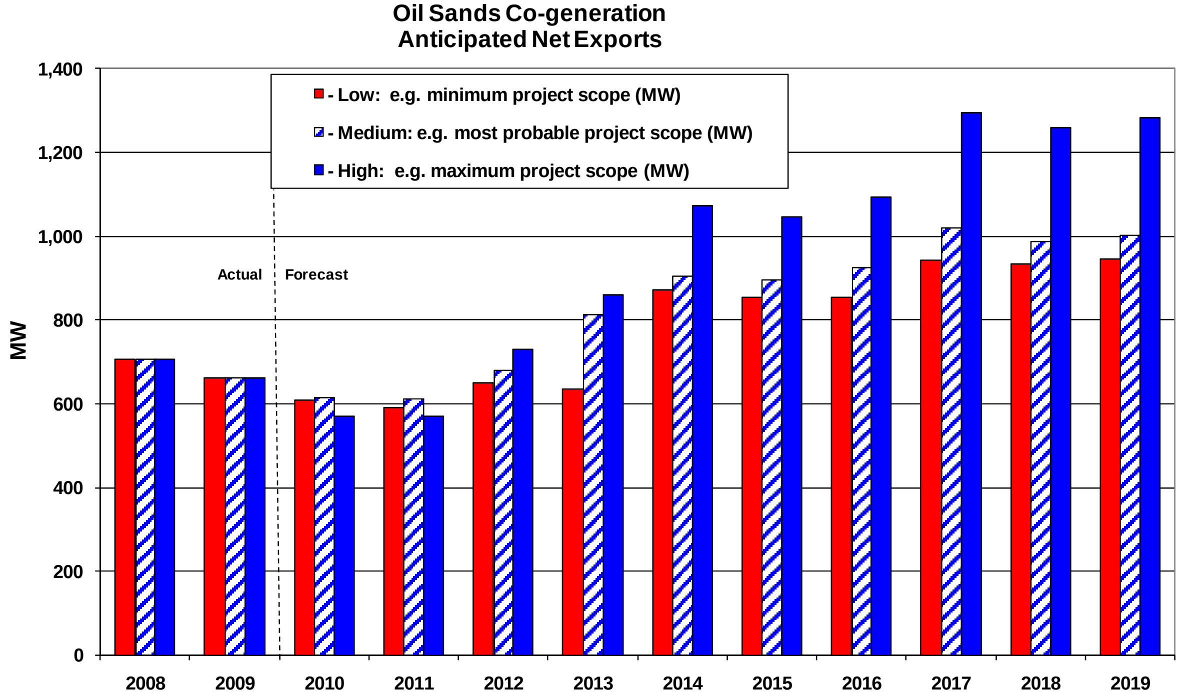


3.4.4 If installing co-generation, please provide the anticipated range of net exports.

The 2010 survey forecast of net exports (Figure 8) are higher than the 2009 survey results due primarily to a change in the survey. Prior surveys asked respondents to indicate the potential for net exports to the grid. It was anticipated that respondents provide values that reflected their forecast for "average" exports under the Low, Medium and High Ranges. The 2010 survey calculated net exports as the difference between respondent provided on-site operating generation capacity and load requirements. Survey respondents were asked to change the calculated value if appropriate.

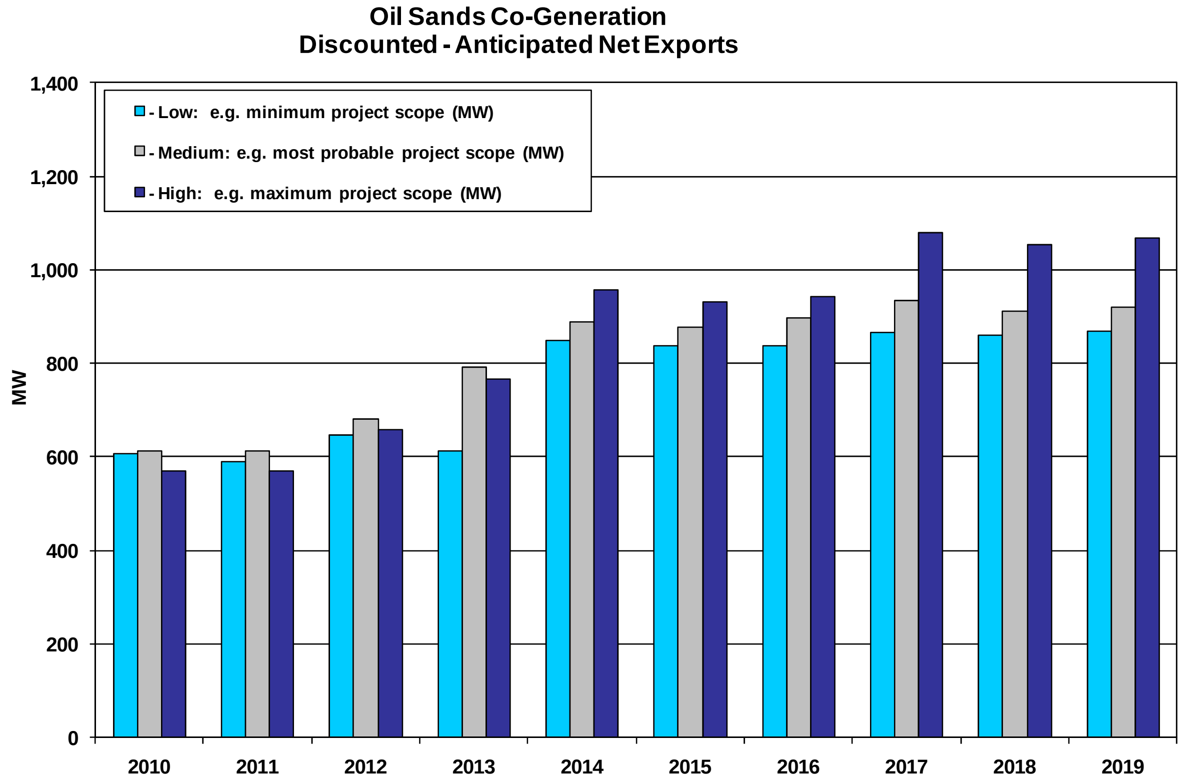
The net result of the survey change is less variation in the forecast values of net exports over the Low, Medium and High Ranges. For some respondents, the relative difference between forecast on-site demand and forecast on-site generation could lead to the Low Range having higher net exports than the High Range. In the latter part of the forecast horizon greater net exports are forecast in the High Range.

Figure 8 Anticipated Net Exports



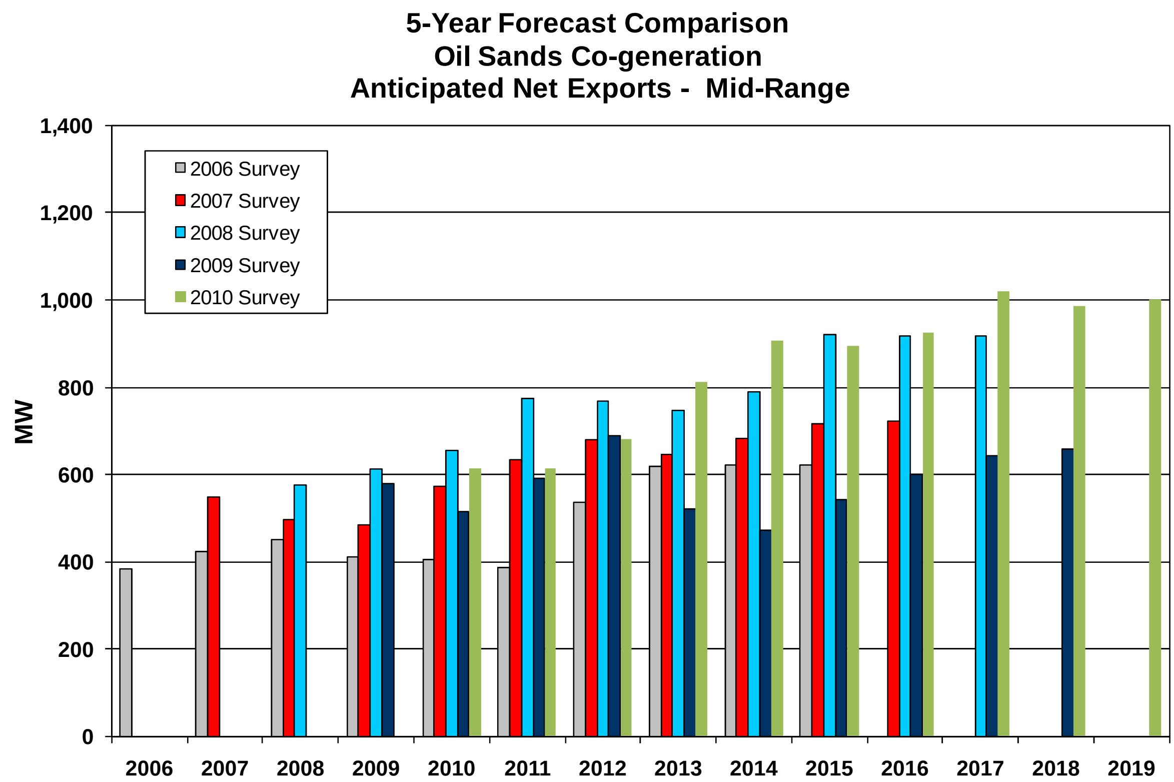
The discounted values (Figure 9) are not much lower that the un-discounted values since most of the projects with significant net exports are currently operating with planned future expansions.

Figure 9 Discounted - Anticipated Net Exports



The five year trend (Figure 10) shows that the level of power exports envisioned in prior surveys are still anticipated, albeit with a delay. Unlike the other five year comparisons, the overall level of forecast net exports has increased in the 2010 survey in the latter years of the survey's horizon.

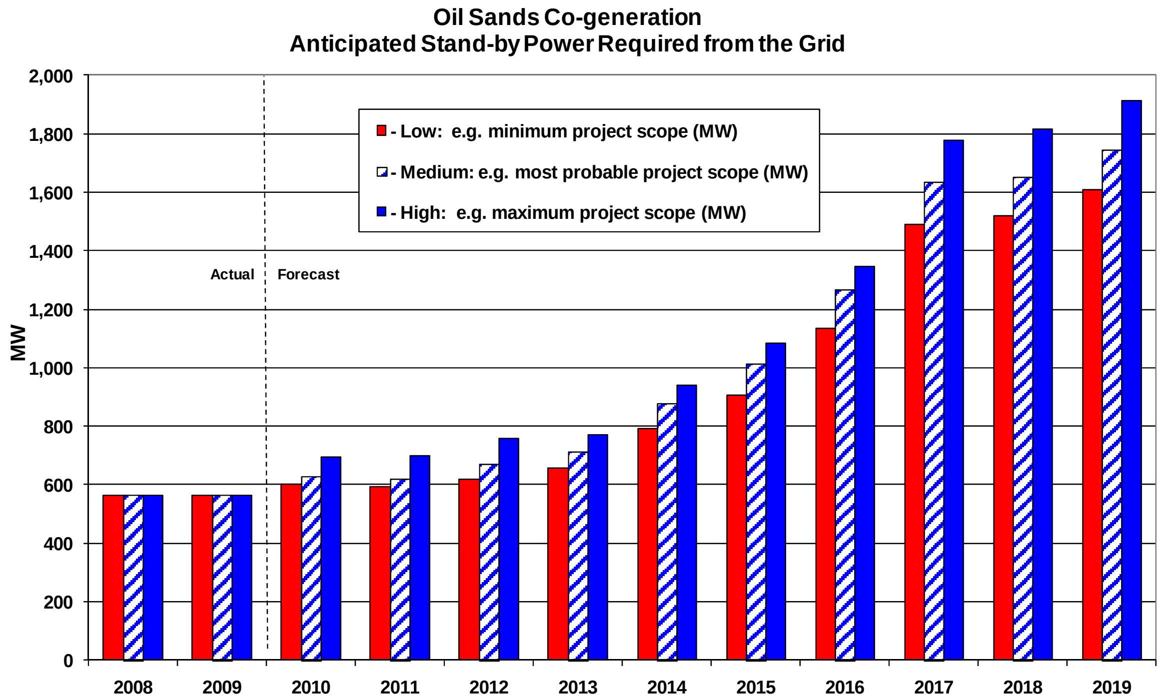
Figure 10 5 year Comparison of Anticipated Net Exports



3.4.5 If you are planning to construct a co-generation plant, how much stand-by power or back-up do you require from the grid each year?

The 2010 results reflect more consistent growth in demand for stand-by power (Figure 11) compared to the 2009 survey results. Similar to last year's survey, the total anticipated stand-by demand by 2019 is forecast to be about 1,800 MW.

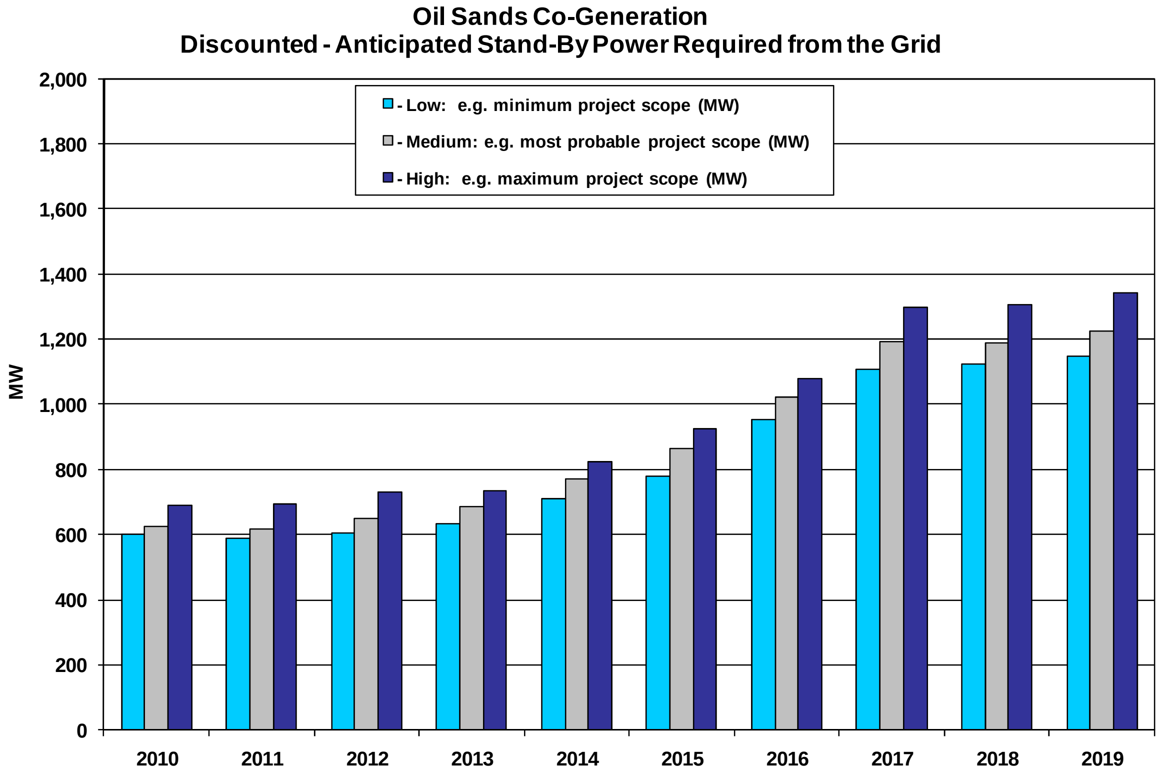
Figure 11 Anticipated Stand-By Power Requirements



Members of the Committee agree that the level of stand-by required is difficult to calculate on an annual basis as the range varies significantly for any given day in the year. Figure 11 must be used with caution as each project's stand-by power requirements are not additive with other projects. The requirement for stand-by from the transmission system is infrequent and the likelihood that all projects will require stand-by capacity at the same time is remote. Please see section 6 below entitled **Duration Curve Analysis** which suggests the maximum co-incident requirement from all loads in the Fort McMurray area will be about 700 MW in 2019 under the 100% case and about 930 MW under the discounted case.

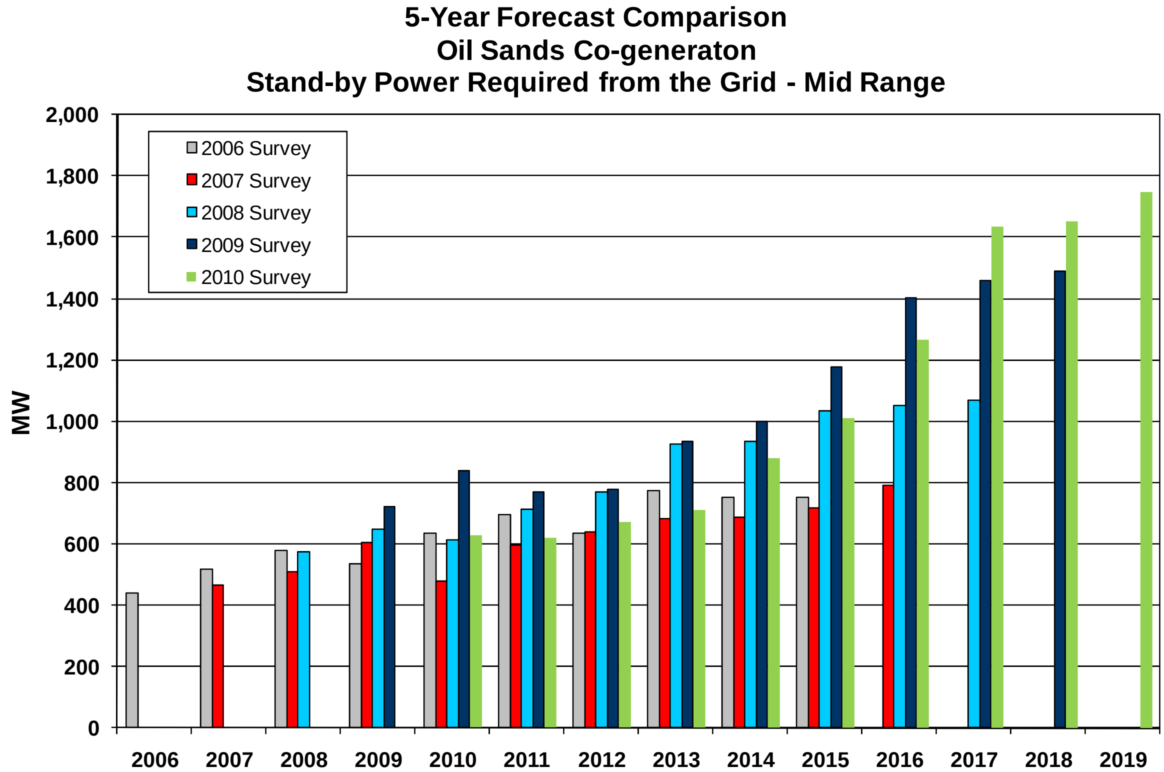
On a discounted basis (Figure 12), the anticipated stand-by requirements are about 1,300 MW by 2019. Again, this does not mean that 1,300 MW of stand-by will be required at any one time. Rather, this is the entire stand-by requirement over nearly 30 projects.

Figure 12 Discounted - Anticipated Stand-By Power Requirements



Similar to trends seen from the other five year forecast graphs above, the quantum of stand-by required is delayed from prior surveys (Figure 13). However, starting in about 2014 the 2009 and 2010 surveys show an anticipated greater reliance on stand-by in the latter part of the forecast horizon compared to previous surveys. It would appear that oil sands developers intend to not only install more on-site co-generation capacity, they also intend to purchase more stand-by capacity from the transmission system.

Figure 13 5 year Comparison of Stand-By Power Requirements



3.4.6 Oil Sands Mines vs. In-Situ Developments.

In the 2010 survey respondents were also asked to identify if their oil sands project was a mining operation or an in-situ development. With respect to demand, the results show that over the forecast horizon about 54% of the load growth is forecast to come from in-situ projects (Figures 14 & 15).

Figure 14 In-situ Projects Anticipated Demand

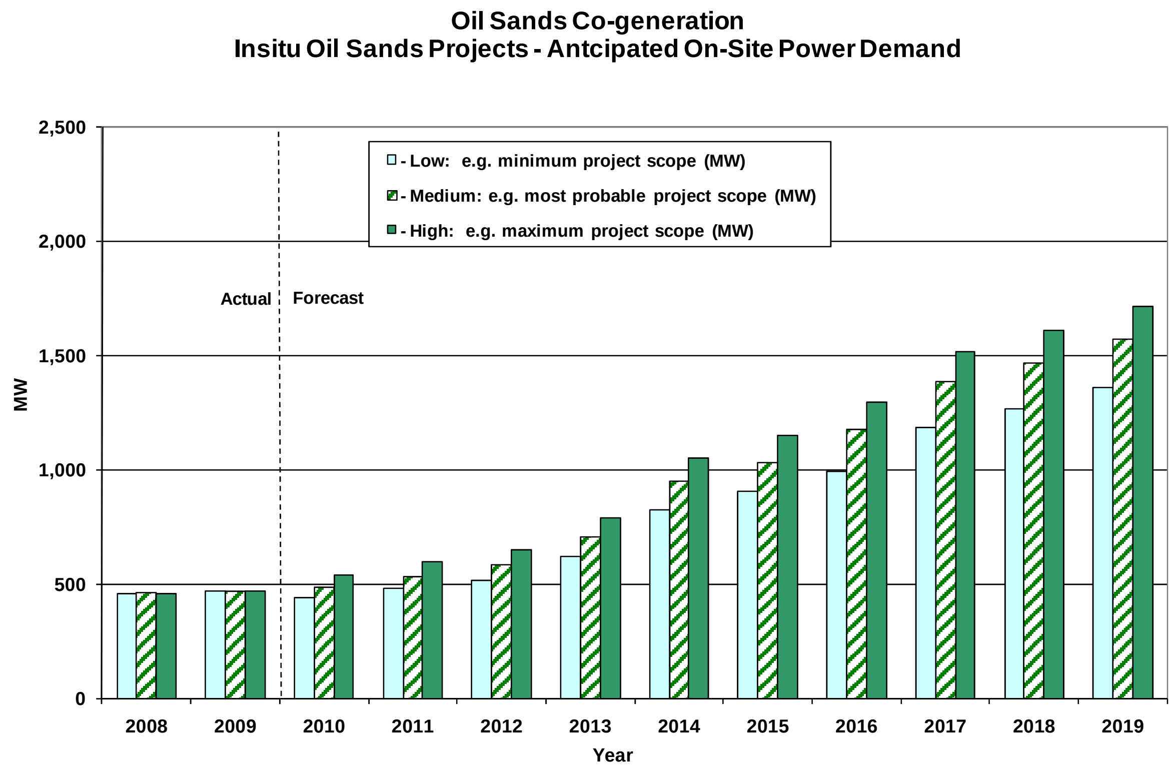
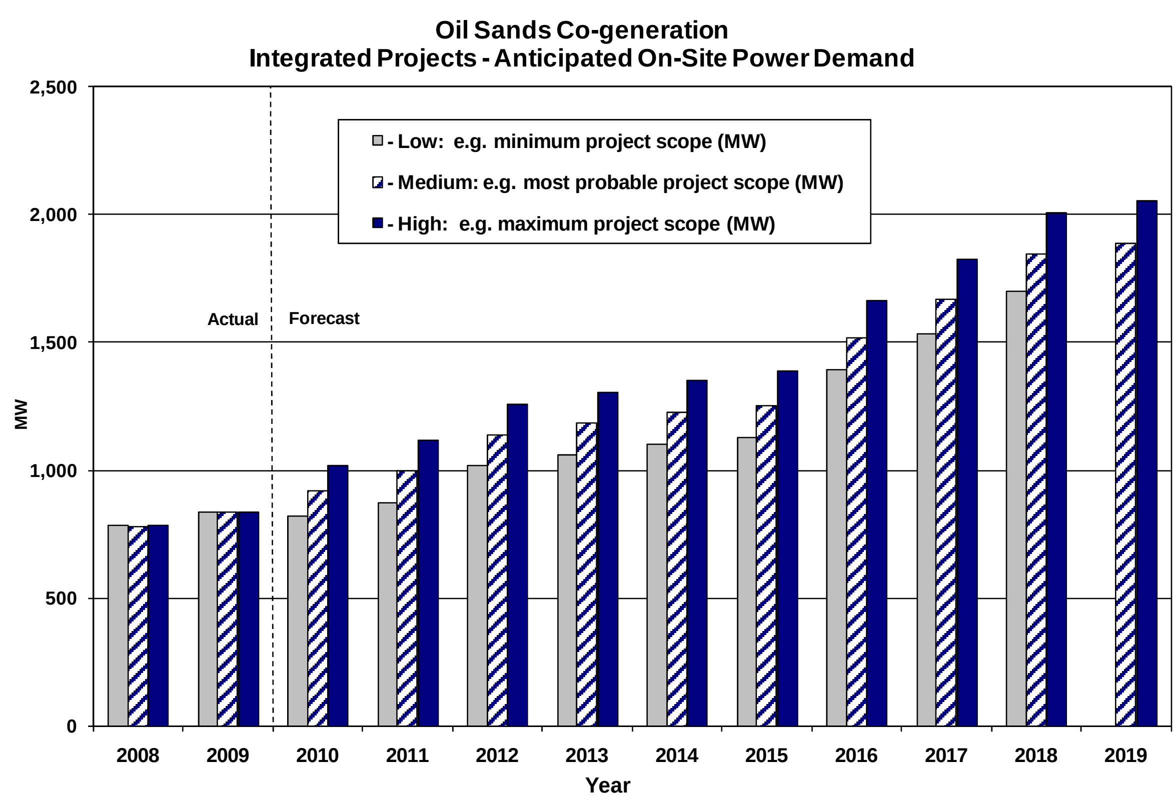


Figure 15 Oil Sand Mine Projects Anticipated Demand



About 59% of the co-generation is forecast to come from in-situ projects.

Figure 16 In-situ Projects Anticipated Co-generation

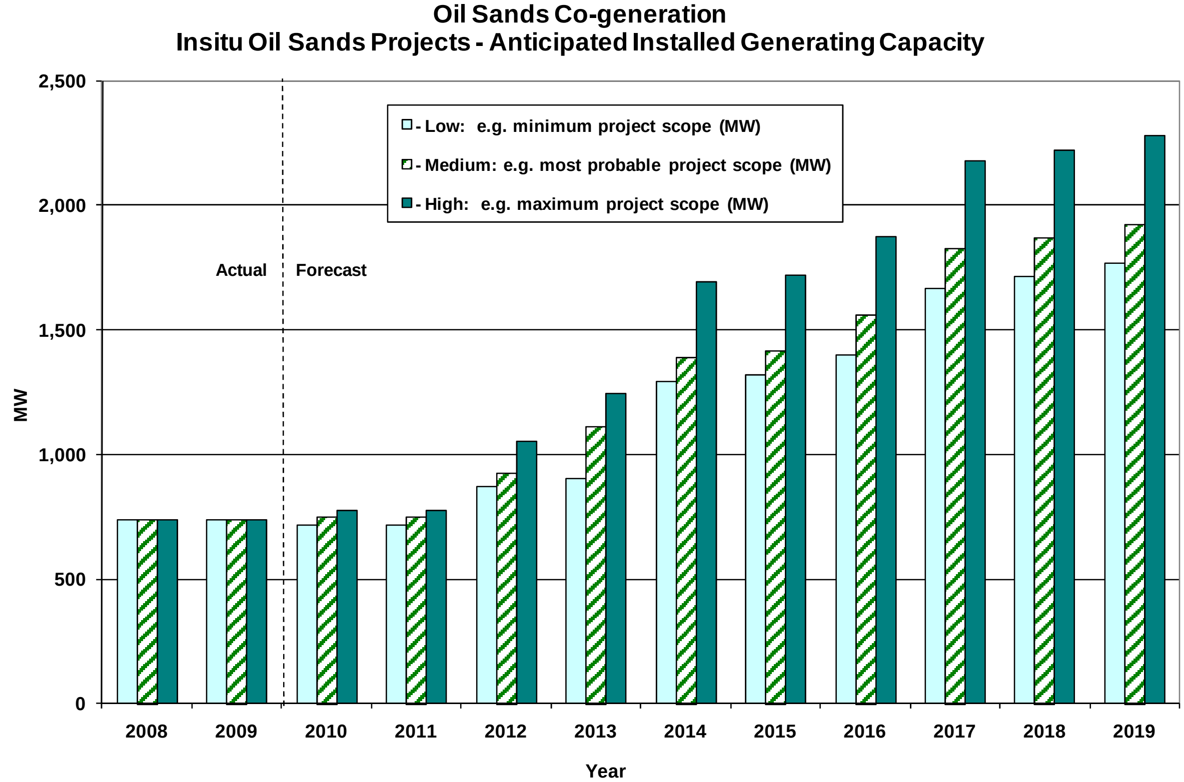
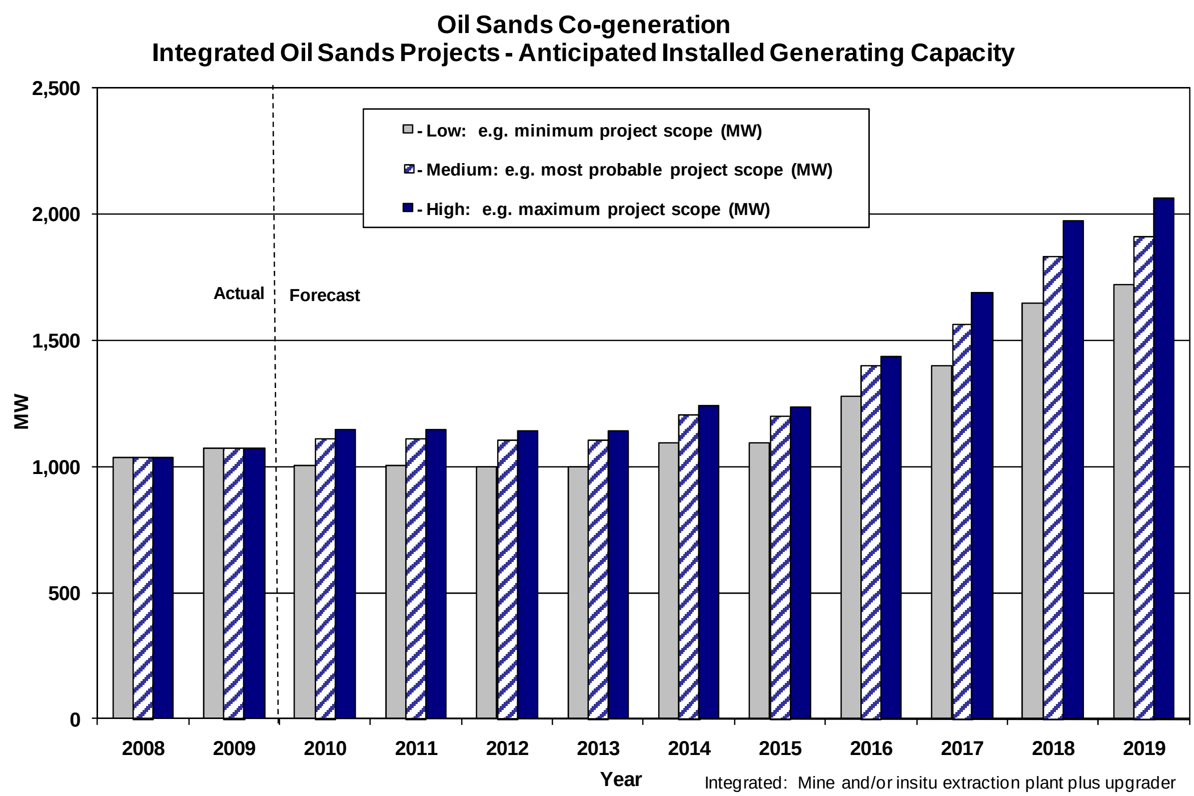


Figure 17 Oil Sand Mine Projects Anticipated Co-generation



Additional co-generation capacity from oil sand mines tends to be forecast near the latter part of the forecast horizon.

3.4.7 Your project is located in the following region.

The purpose of this question is to assist the AESO to plan for any future transmission lines by identifying the location and number of existing and forecasted co-generation units and the anticipated co-generating operating capacity in each area of the region. Co-generation operating capacity is taken as the Medium Range in 2019, ten years out.

Table 2 Location of Co-generation Projects

Your Project is located in the Athabasca Region:	Operarting MW -2019	# Projects with Co-gen
- South of Fort McMurray	331	5
- North of Fort McMurray and East of the Athabasca River	1,322	10
- North of Fort McMurray and West of the Athabasca River	1,662	11
Your Project is located in the Cold Lake area	530	4
Your Project is located in other areas, please specify	0	0
TOTAL	**3,845**	**30**

3.4.8 What is the status of your project as of January 1, 2010?

The purpose of this question is to assist the AESO in determining when new transmission lines may be required. Installed capacity is taken as the Medium Range in 2019, ten years out. Note that the forecast 2019 installed capacity is 4,433 MW, higher than the co-generation operating MW shown in Table 2 of 3,845 MW.

Table 3 Status of Co-generation Projects

Installed Capacity	2019 MW	# Units
Built and/or operating	2,229	31
Under construction	-	-
Has been fully approved by the Regulatory Boards	280	2
Has been fully approved by the Company Boards	114	2
In the approval stage	335	3
Announced only	160	2
Conceptual Planning Stage	1,315	19
TOTAL	**4,433**	**59**

4.0 NET EXPORT POTENTIAL

The potential for net exports from co-generation is significant if market conditions are favourable. Co-generation can generate excess power with relatively little increase in the use of natural gas. In the earlier years of the decade the power pool prices were generally higher and it was anticipated that transmission lines to move power out of the Athabasca region were going to be built. Developers planned for excess co-generation capacity from oil sands projects.

In the latter part of the decade it became apparent that transmission capacity to export surplus power from the Fort McMurray region was limited and power pool prices were volatile. Developers responded by lowering their forecasts for the development of surplus co-generation capacity from oil sands projects.

In 2010, pool prices for electricity are lower and the existing transmission lines to export power from the Fort McMurray area are restricted. However, in the past year the Alberta government has passed the *Electric Statutes Amendment Act* that provides greater certainty that Alberta's transmission infrastructure will be upgraded over the forecast horizon, including new 500 kV lines from the Edmonton area to Fort McMurray (currently planned for 2014 and 2015).

Oil Sands developers in the 2009 and earlier surveys were likely not planning for the generation of excess co-generation capacity and were planning to build only sufficient co-generating capacity to supply their own on-site power needs. It is anticipated that for the 2010 survey developers may not have fully modified their outlook to take into consideration the potential for increased transmission capacity into and out of the Fort McMurray area. While the *Electric Statutes Amendment Act* has passed, there is still some uncertainty regarding the potential cost and timing of the proposed 500 kV transmission upgrades within Alberta.

Figure 18 plots data for the year 2011 from surveys conducted between 2000 and 2010 and demonstrates the change in forecasts for net exports compared to forecasts of on-site demand and co-generation operating capacity. While the forecast for net exports in 2011 has remained relatively flat since the 2003 survey, 2011 forecasts for co-generation operating capacity and on-site demand have trended slightly downward.

Figure 18 2011 Forecasts from 2001 to 2010 Surveys

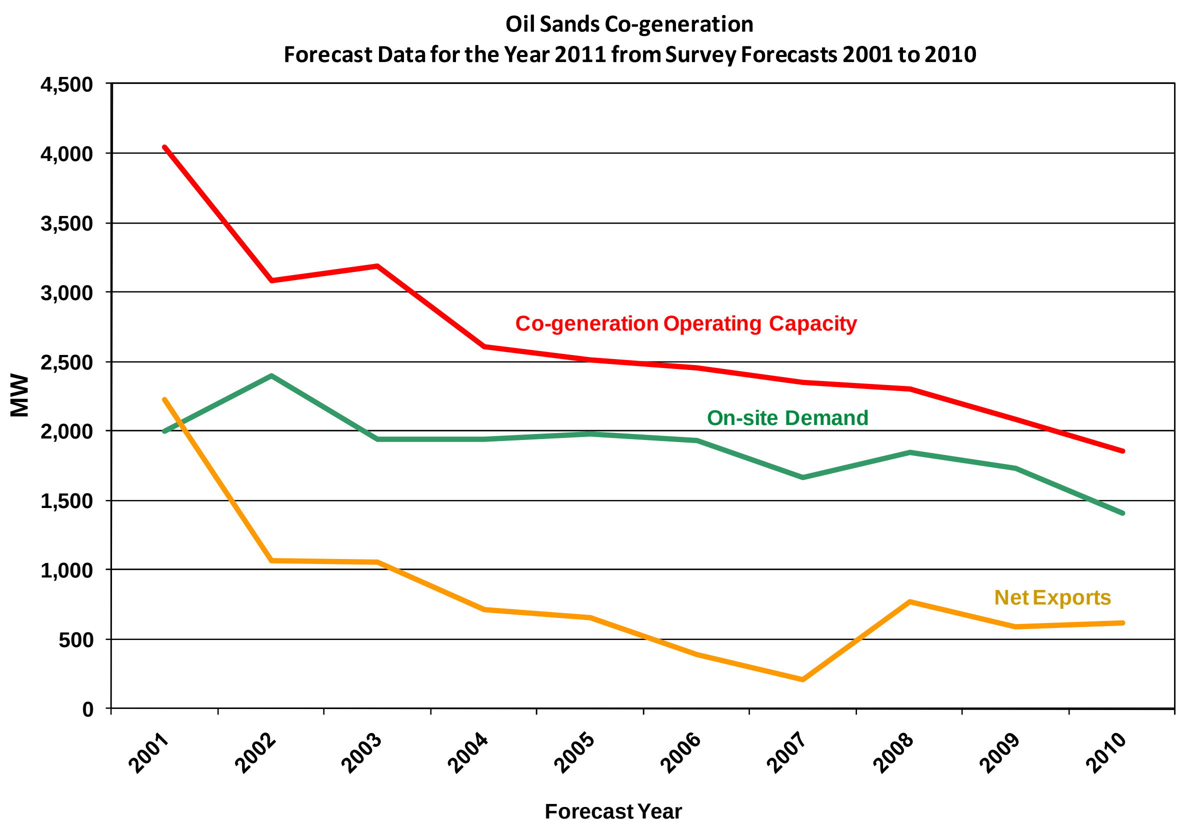
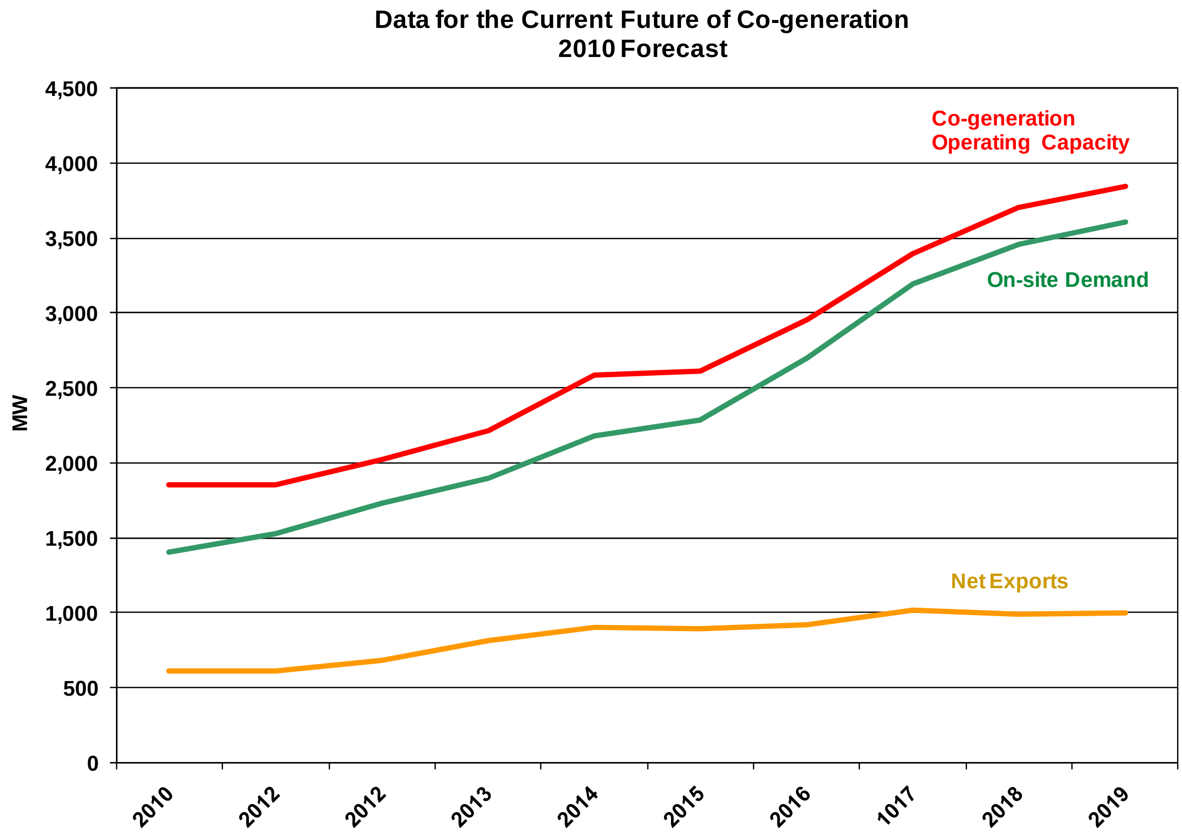


Figure 18 also provides a glimpse into the accuracy of prior forecast. In general, if the lines are relatively flat then it would suggest that there have not been material changes in the surveys from year to year. One could surmise that the surveys in the earlier part of the decade were not as accurate as those from the last five years. Perhaps more experience with Alberta's restructured and deregulated electricity industry has allowed oil sands developers to obtain a better understanding of the potential for co-generation projects.

Figure 19 demonstrates the 2010 survey results for on-site demand and co-generation operating capacity in relation to net exports. Looking forward, developers anticipate that additional projects will be built with co-generation; however, the quantum of excess generation operating capacity from these new projects is less than what was expected a decade ago when electricity deregulation was implemented in Alberta.

Figure 19 Forecasts from 2010 Survey



Future surveys will indicate if the planned transmission reinforcements will alter oil sands developer's plans to install larger co-generation units. While concerns over inadequate transmission capacity may have been addressed in the past year, concerns including the high capital costs of installing new co-generation capacity and greenhouse gas emissions remain.

5.0 REGULATORY APPROVALS

Most of the oil sands developers of the OSDG Co-generation Committee voiced concern that section 101 of the existing *Electric Utilities Act ("EUA")* is a deterrent to the development of co-generation. As a pre-requisite to the installation of co-generation, it is a requirement that a developer obtain an *EUA* section 101 approval from the local wire owning utility. Wire owners are reluctant to provide an approval under section 101 unless the oil sands developer has an Industrial Systems Designation ("ISD") order from the Alberta Utilities Commission ("AUC"). Recent regulatory precedents suggest that an ISD can only be obtained once a generating unit has been ordered. For many oil sands projects, preliminary development phases typically do not have generation as the focus of the development is to prove the reserves and not to optimize long run economics.

Unfortunately, without a section 101 approval and an ISD order an oil sands developer is not allowed to work directly with the AESO on transmission developments and owning distribution or transmission lines on-site is more onerous and expensive. Acquiring an ISD order can be onerous and inefficient, to the point where process delays may place a developer under significant scheduling constraints. In addition, once distribution or transmission lines are built by a wire owning utility the value of a future ISD can be diminished. These constraints could force the developer to either scale back the scope of a co-generation facility or cancel the cogeneration facility altogether. Streamlining section 101 approvals as they pertain to ISD's would enhance the efficient integration of co-generation facilities into an oil sands development.

As part of the 2010 survey developers were asked to indicate if they have a section 101 approval, have filed for a section 101 approval application or plan to file for an approval. Of the 29 projects that indicated plans for co-generation 13 respondents indicated a response with respect to an *EUA* section 101 approval:

Table 4 *EUA* Section 101

	Projects
Planned	5
Application Filed	3
Application Approved	5
	13

Developers were also asked to indicate if they have an ISD, have filed an application with the AUC for an ISD or plan to file for an approval. Of the 29 projects that indicated plans for co-generation 23 respondents indicated a response with respect to an ISD:

Table 5 Industrial System Designations

	Projects
Planned	7
Application Filed	4
Application Approved	12
	23

Of note, of the 16 ISDs that have been granted in Alberta 12 or 75% are for oil sands developments.

6.0 DURATION CURVE ANALYSIS

One of the shortcomings of the co-generation surveys is the static nature of the reported data. For example, a developer may forecast the anticipated need for 50 MW of stand-by capacity from the transmission grid. What is not captured in the surveys is that the stand-by capacity may only be required a few hours per year. With the number of oil sands projects with co-generation approaching 30 near the end of the forecast horizon, a significant amount of diversity will exist, or said another way, not all 30 projects will require standby capacity at the same time.

Planning for transmission capacity for stand-by assuming all co-generators will rely on the transmission grid at the same time is not reasonable. Since co-generation units tend to be in service 95% or more of the time, the reliance on the transmission grid for stand-by is significantly less than the survey numbers may indicate.

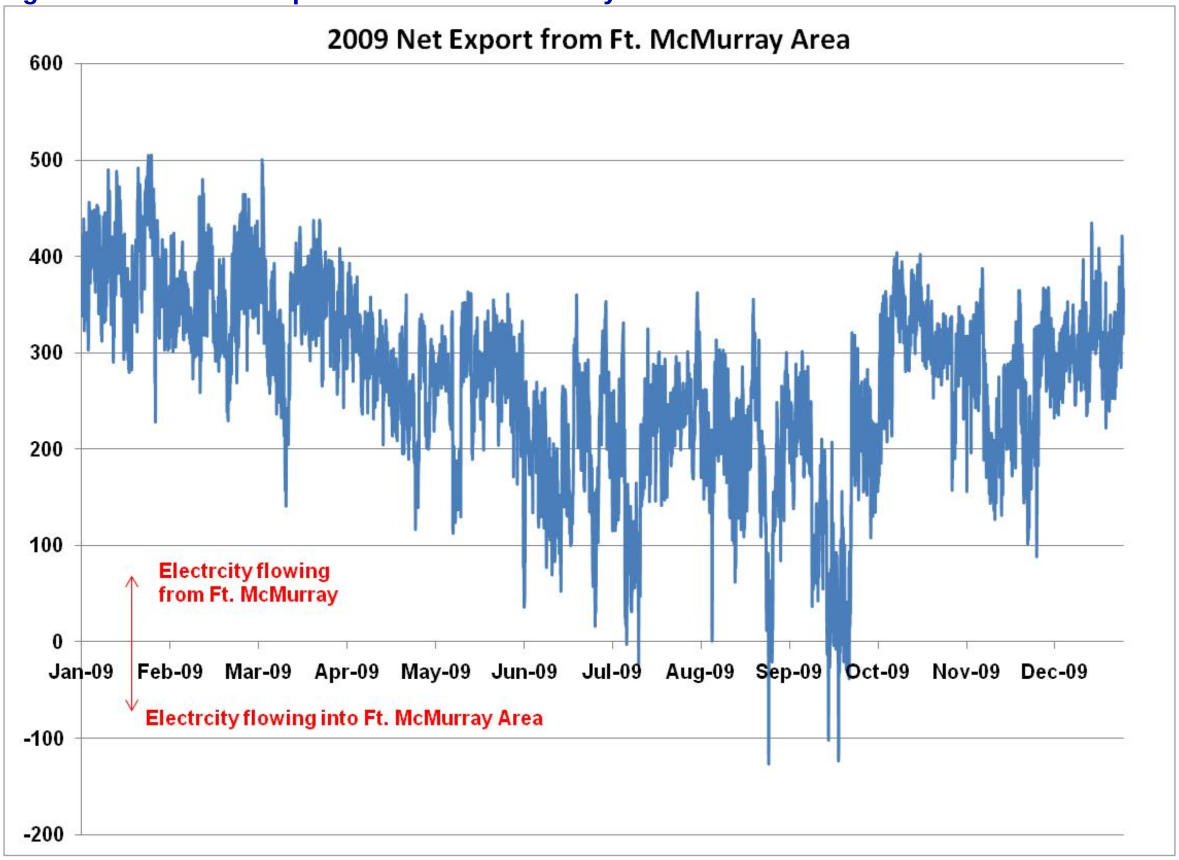
Conversely, the net export statistics may be more indicative since net exports are more likely to occur the majority of the time. Net exports typically fall into two categories: Surplus Net Exports and Merchant Net Exports.

Surplus Net Exports typically occur regardless of the wholesale or power pool price for electricity. An example is an oil sands mine that requires a certain amount of hot water for process that comes from a co-generation unit. Since the hot water is required for production, the co-generation unit must run to produce hot water and electricity is in essence a by-product. If the co-generation capacity is greater than on-site demand, the surplus electricity is sold to the power pool as a “price taker”.

Merchant Net Exports tend to be more closely tied to power pool prices. When power pool prices rise above the variable cost of electricity production generation owners have a profit motive to increase on-site generation and increase net exports. Within the limitations of the generation units and other operational factors, some generation owners increase generation output when power pool prices are higher.

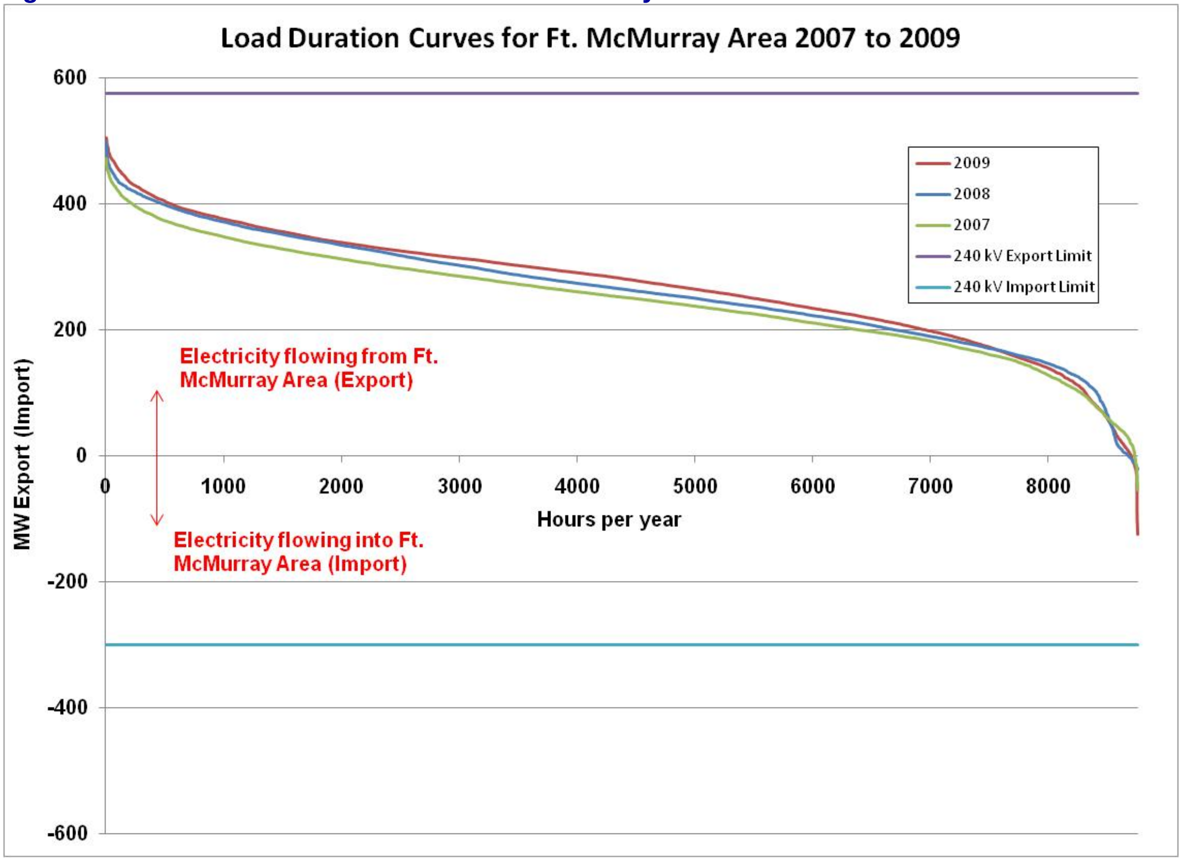
Planning for transmission capacity for net exports is more difficult as market conditions will dictate if additional net exports will occur. In order to investigate this issue further hourly transmission flow data for electricity flowing into and out of the Fort McMurray area was obtained from the AESO for all hours in 2007 to 2009. A plot of the 2009 data versus time (Figure 20) shows the random nature of the electricity flows and indicates that electricity flows out of the Fort McMurray area most of the time.

Figure 20 2009 Net Exports from Fort McMurray Area



A more representative way to view this data is via a load duration curve. A load duration curve can be used to illustrate the relationship between transmission capacity and capacity utilization. With a load duration curve, demand load data is ordered in descending order of magnitude and plotted against the number of hours in the time period (e.g. one year for 2009 data). The following load duration curve (Figure 21) shows same the data as Figure 20 above, with data for 2007 and 2008 data added for comparison purposes.

Figure 21 Load Duration Curves for Fort McMurray Area

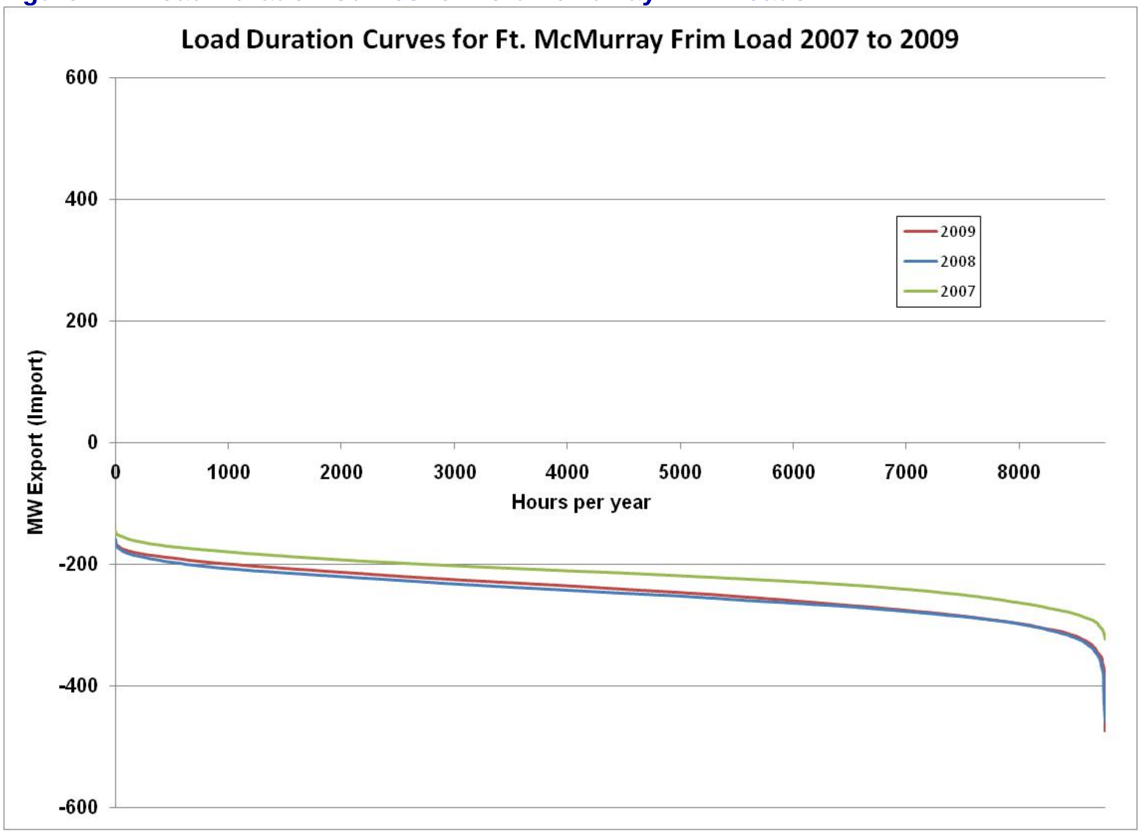


The Figure 21 load duration curves show that oil sands co-generators are producing more electricity than they need for their operations over 99% of the time. For all but about 50 hours per year (0.6% of the time) there is a net export of electricity out of the Fort McMurray area. The duration curves also shows, for example, that for about 550 hours per year (about 6% of the time) more than 400 MW was being exported from the Fort McMurray area.

Also shown on the figure above are the current 575 MW export and 300 MW import limits with the existing three 240 kV lines into the Fort McMurray area. If additional co-generation is added (or load is reduced) before additional transmission capacity becomes available as planned for 2014, then there may be some hours per year where the AESO could potentially restrict generation output due to transmission capacity limitations.

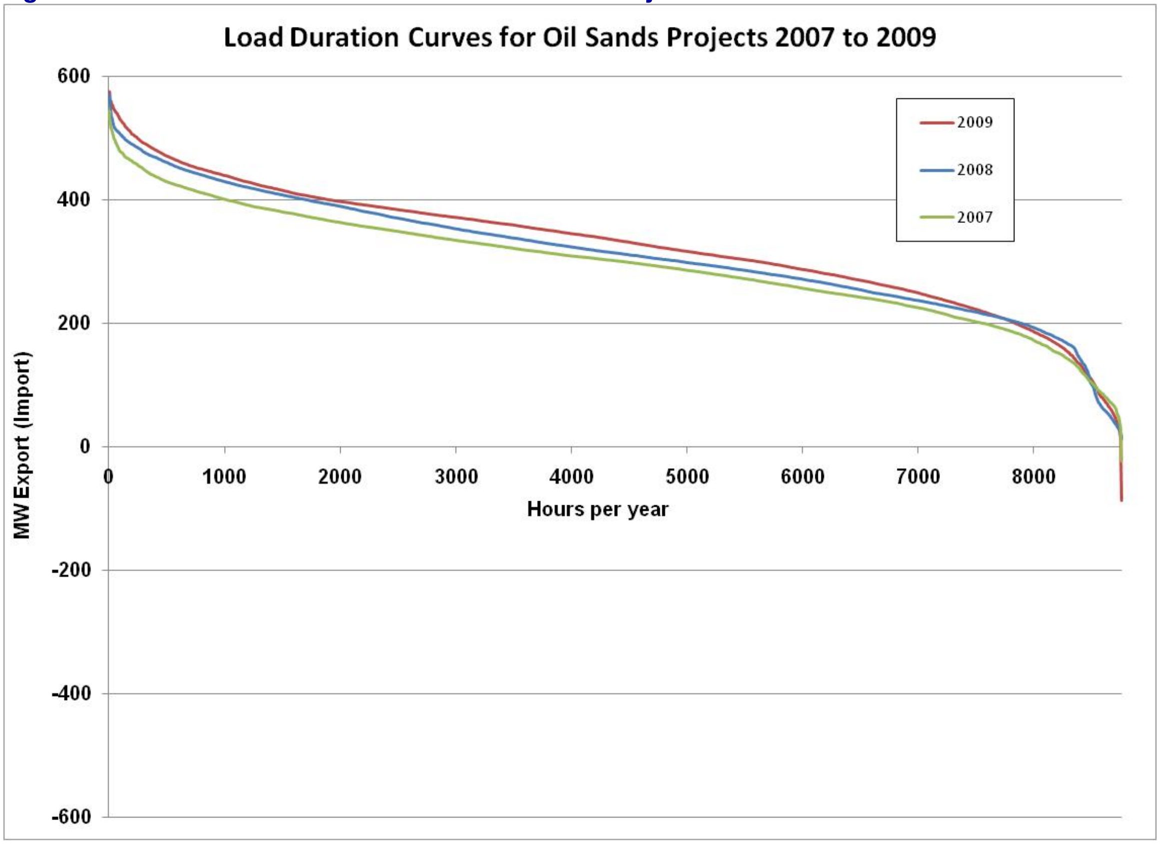
In order to utilize the 2010 survey data and project potential future transmission requirements, the 2009 data was segregated into demand related to the City of Fort McMurray and other smaller distribution loads (firm load) and generation related to oil sands projects (including any other transmission connected loads). For the firm loads, the load duration curves (Figure 22) show that the firm load varies between about 200 and 400 MW:

Figure 22 Load Duration Curves for Fort McMurray Firm Loads



The oil sands related loads and generation alone have the following shape once the firm loads are removed. As can be seen, the oils sands projects in the Fort McMurray area provide a net export of electricity to the grid in almost every hour (Figure 23).

Figure 23 Load Duration Curves for Oil Sands Projects

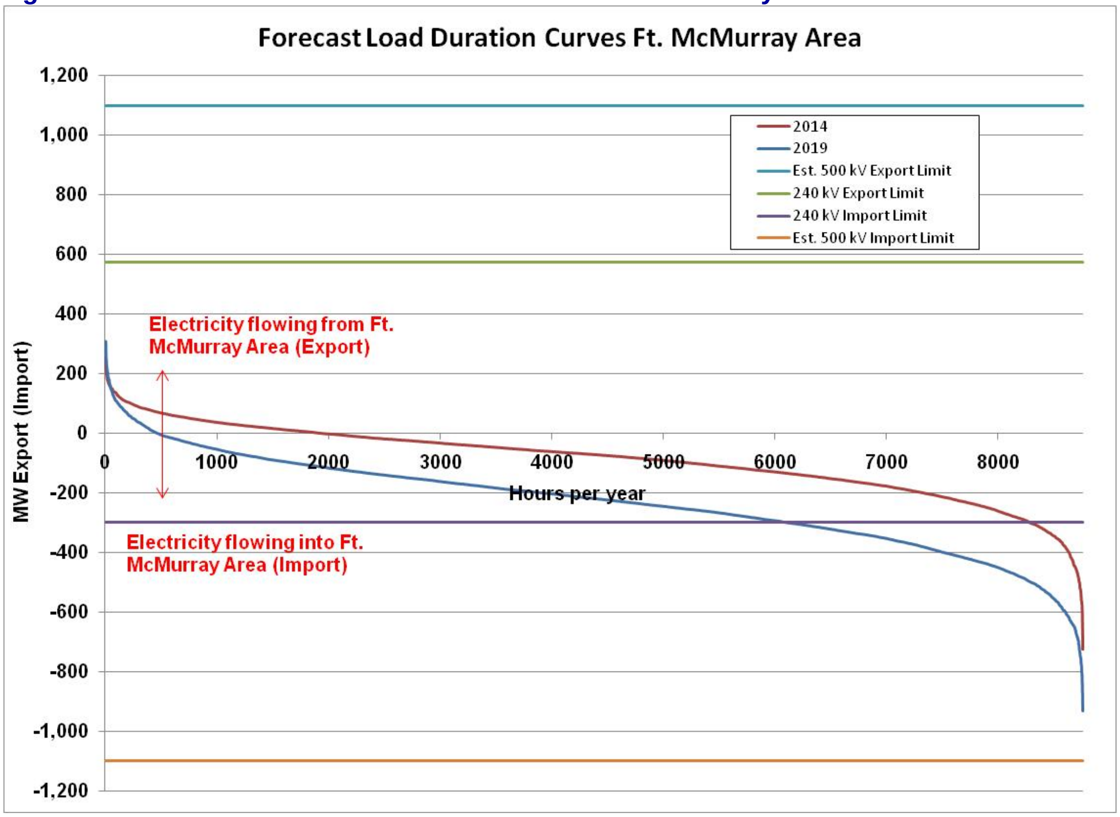


Forecasting into the future, it was assumed that the Fort McMurray firm load shape would not materially change and would grow at 2.0% per year. The oil sands related load and generation additions were derived from 2009 hourly load flow data and the 2010 survey results with the following additional assumptions:

- Each co-generation project operates 95% of the time (2.5% of the time down for planned maintenance and 2.5% of the time down for unplanned maintenance)
- Oil sands operations load factor of 85%
- Timing of stand-by requirements and generation exports for each hour determined on a probabilistic basis for each load and generation project included in the 2010 survey
- No consideration of wholesale power prices, i.e., all net exports assumed to be from Surplus Net Exports

The results of the analysis (Figure 24) for the years 2014 and 2019 are shown below.

Figure 24 Forecast Load Duration Curves for Fort McMurray Area



Unlike the current situation where transmission capacity is potentially limiting exports, the analysis suggests that by 2014 the key transmission limitation will be insufficient transmission capacity for electricity flowing into the Fort McMurray area (import). This is a direct result of oil sands developers forecasting that they do not intent to meet their on-site demand with co-generation capacity and they also intend to rely on the transmission grid for a greater portion of the their on-site demand.

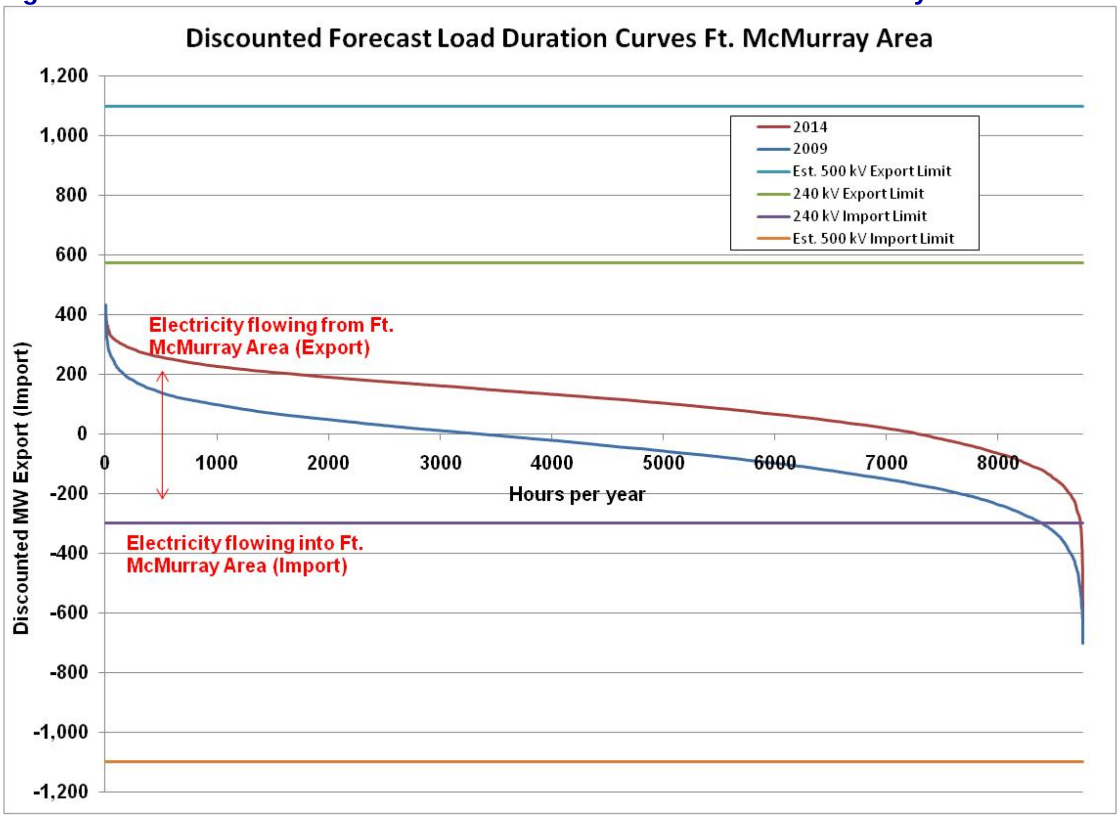
Comparing Figure 21 to Figure 24, it is anticipated that imports into the Fort McMurray area will increase from about 56 hours per year (0.6% of the time) in 2009 to about 8,302 hours per year (95% of the time) in 2019.

Note that by 2014 the analysis suggests that there will be insufficient 240 kV transmission capacity for imports into the Fort McMurray area in 2014. Under the AESO policies this means that if there is a transmission contingency (e.g. transmission line out of service due to lighting strike) during the forecast 470 hours (5% of the time) when imports are greater than the 300 MW limit then AESO customers may be required to involuntarily curtail load.

As noted section 3.4.5, the 2010 survey results indicate that up to 1,800 MW of stand-by capacity (with the majority required in the Fort McMurray area) will be required for oil sands projects by 2019. On a probabilistic basis (Figure 24), the maximum requirement for imports into the Fort McMurray area will be 700 MW – not all oil sands projects will require standby capacity at the same time due to the random nature of generation outages.

Figure 24 assumes that all oil sands projects will proceed as reported in the 2010 survey. If the projects are discounted (as noted in section 3.1) the forecast load durations curves show a lower level of imports in 2014 and 2019 (Figure 25).

Figure 25 Forecast Discounted Load Duration Curves for Fort McMurray Area



As noted above, if all projects proceed as reported on the survey then the analysis suggests by 2014 there would be 470 hours (5% of the time) when imports are greater than the 300 MW limit. Using discounted project values, there would only be 22 hours (0.3% of the time) when imports are greater than the 300 MW limit. The discounted analysis agrees with the AESO's current proposed timing for having the first 500 kV line to Fort McMurray in-service by 2014.

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