The Oil Sands Developers Group (OSDG)
Co-Generation & Power Infrastructure Committee

2011 Oil Sands Co-Generation Report

Oil Sands Co-Generation Potential Survey

June 2011

Prepared by Genalta Power for the OSDG

THE OIL SANDS DEVELOPERS GROUP
Energy From Athabasca

2011 OIL SANDS CO-GENERATION REPORT

EXECUTIVE SUMMARY

This report is the 12th 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 in the future 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.

Compared to the 2010 survey results, additional projects were reported and more optimistic forecasts for projects previously reported resulted in increased forecast demand in the year 2019 of about 300 MW and increased co-generation capacity in 2019 of about 130 MW. Another year of robust oil prices appears to have provided optimism for oil sands developers to advance their projects. However, demand forecasts are increasing at a greater rate than generation capacity forecasts, reinforcing the point that areas like Fort McMurray will require more electricity from sources other than on-site co-generation.

The survey results show that reliability of power from grid (e.g. is co-generation required to ensure a reliable electricity source?) and the delivered price of grid power vs. cost of generating (e.g. will co-generation be economically viable?) 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 transmission capacity to the Fort McMurray and Cold Lake areas is developed in advance of industry requirements
- Provide greater certainty on the cost of new critical transmission development projects and the potential tariff impacts on oilsands projects both with and without on-site co-generation
- 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, oil sands mines (and associated upgraders) and from 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 and how generators that export power will be operated
    - for projects with on-site generation capacity, on-site demand stand-by requirements or electricity to be consumed from the provincial grid
- provide an estimate of the existing or forecast oil or bitumen electricity intensity
- 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. Compared to the 2010 survey results; however, new projects were reported and previously reported projects were advanced.

New data for the 2011 survey indicates that excess electricity from oil sands co-generation operations tend to be non price responsive. This data indicates that oil sands developers are not building excess generation capacity to actively participate in the wholesale electricity market and that the AESO should not be relying on increased generation output during times of high wholesale market (i.e. power pool) prices.

The report includes a detailed analysis of the potential impact of anticipated oil sands development projects on the Alberta transmission system serving the Fort McMurray area. The results show that the AESO's current transmission development plans that call for the addition of capacitor banks in 2012 and 500 kV lines from the Edmonton area to Fort McMurray to be completed in 2017 and 2019 will be required to provide timely supply capacity to oil sands projects.

The data presented in this report includes oil sands projects where the oil sands developer completed the 2011 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 2011 survey. It is anticipated that over 95% of the potential oil sands projects have been captured in the 2011 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 electricity 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 survey was completed in early 2011 when the oilsands industry was continuing to recover from the financial uncertainty of 2008 to 2010 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 *2011 Oil Sands Co-generation Report* contains the results of the 2011 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 and Power Infrastructure Committee of the Oil Sands Developers Group ("OSDG") manages the annual survey and issues this report. The committee looks at accessing and addressing the electricity transmission needs of the oil sands producers in Athabasca oil sands region and its linkages throughout the province. The committee provides a forecast report each year on Co-generation and Power Infrastructure. The mandate of the committee:

- Provide a forum to share, discuss and disseminate information about electricity transmission capabilities and delivery in the oil sands region of the province ensuring capacity needs to oil sands producers are met
- Assure that government regulatory processes are recognized and support the potential for new electrical generation in concert with oil sands development (the committee does not participate in regulatory proceedings)
- Explore issues, opportunities and new technologies in relation to the development and operation of co-generation and transmission in the oil sands region and province by engaging with the OSDG membership and key stakeholders

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

2.0 METHODOLOGY

The source of data for the *2011 Oil Sands Co-generation Report* is a survey of oil sands companies conducted in February to April 2011. The survey requested actual and forecasted data for co-generation operating capacity, on-site demand, requirements 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 Genalta Power Inc., and shared with a representative of the AESO.

The results were compiled with submissions from 12 participating oil sands companies who reported on 31 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 4,058 MW (Medium Range) by the year 2020. In addition, data was collected on an additional 23 oil sands projects where co-generation is not planned.

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 2011 survey and hence the information provided in this report may not be inclusive off all potential oil sands projects in Alberta.

3.0 RESULTS

3.1 Presentation of the Data

The results of the 2011 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 2011 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 4 on page 18).

The total number of planned or installed co-generation units reported in 2011 did not change from the 2010 survey. There were several cases of project sites increasing or decreasing the number of planned units, demonstrating an optimization of power needs. No new companies reported planning the use of co-generation. Four OSDG member companies and seven non-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 2010 is lower over the prior surveys. Similarly, prior surveys noted Medium Range co-generation operating reaching 3,500 MW by 2014, whereas the 2011 forecast does not reach 3,500 MW until 2017. 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 2011. 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 17 on page 20 in which the data for the year 2011 is extracted from the annual surveys conducted in the years 2002 to 2011.

An initiative to allow for the advancement of the construction of additional transmission capacity to the Fort McMurray area was approved in 2010 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 13 factors over five categories that could impact their decision to build or not build co-generation. The 13 factors, in order of importance ranked by the oil sands developers, were:

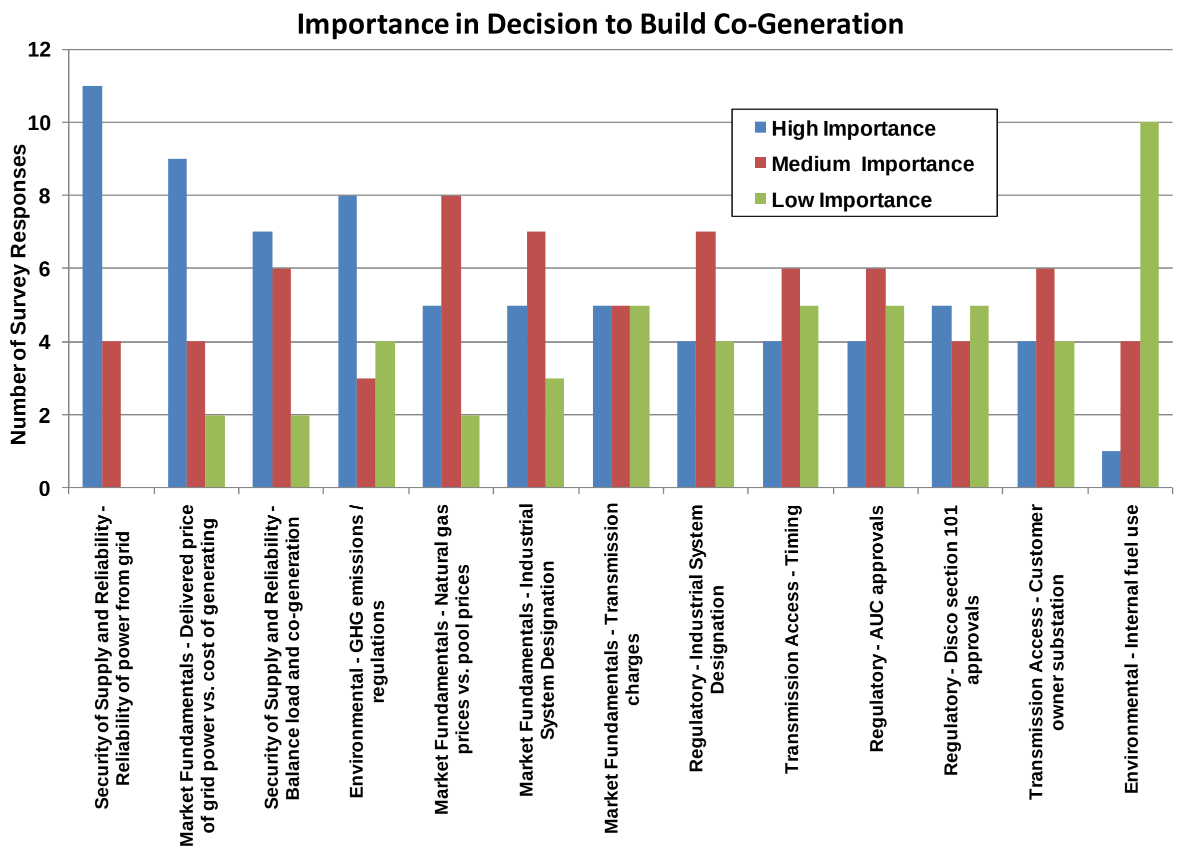
1. Security of Supply and Reliability - Reliability of power from grid[2]
2. Market Fundamentals - Delivered price of grid power vs. cost of generating[3]
3. Security of Supply and Reliability - Balance load and co-generation[4]
4. Environmental - GHG emissions / regulations[5]
5. Market Fundamentals - Natural gas prices vs. pool prices[6]
6. Market Fundamentals - Industrial System Designation[7]

[2] Transmission system is inadequate to provide the level of “up time” required for your projects
[3] Cost of electricity from cogeneration plus standby transmission charges compared to purchasing from third party suppliers plus transmission charges
[4] Ability to balance load and generation within your projects, including steam balance considerations
[5] Consideration of Greenhouse Gases (GHG) costs and regulations compliance (uncertainty and potential positive or negative impacts)
[6] Risks associated with the correlation between natural gas and electricity prices, or system heat rate (positive or negative)
[7] Potential AESO tariff savings associated with ISD (e.g. net metering)

7. Market Fundamentals - Transmission charges[8]
8. Regulatory - Industrial System Designation[9]
9. Transmission Access - Timing[10]
10. Regulatory - AUC approvals[11]
11. Regulatory - Disco section 101 approvals[12]
12. Transmission Access - Customer owner substation[13]
13. Environmental - Internal fuel use[14]

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 extent (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:

[8] AESO wires charges for delivery of electricity and/or stand-by capacity from the grid

[9] Consideration of time and resources required to obtain approvals from the Alberta Utilities Commission for an Industrial System Designation (ISD)

[10] Certainty or uncertainty to when transmission capacity will be available for your projects

[11] Ability or inability to obtain approval from the distribution company to become an AESO direct connect customer

[12] Ability or inability to obtain approval from the distribution company to become an AESO direct connect customer

[13] Ability to design, build and/or own the substation and control the development/construction process

[14] Ability to provide fuel from your project (e.g. syn-gas flared or turbine fuel source)

- 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
- Provide greater certainty on the cost of new critical transmission development projects and the potential tariff impacts on oilsands projects both with and without on-site co-generation
- Reduce environmental risks by providing clarity on future greenhouse gas emissions compliance obligations
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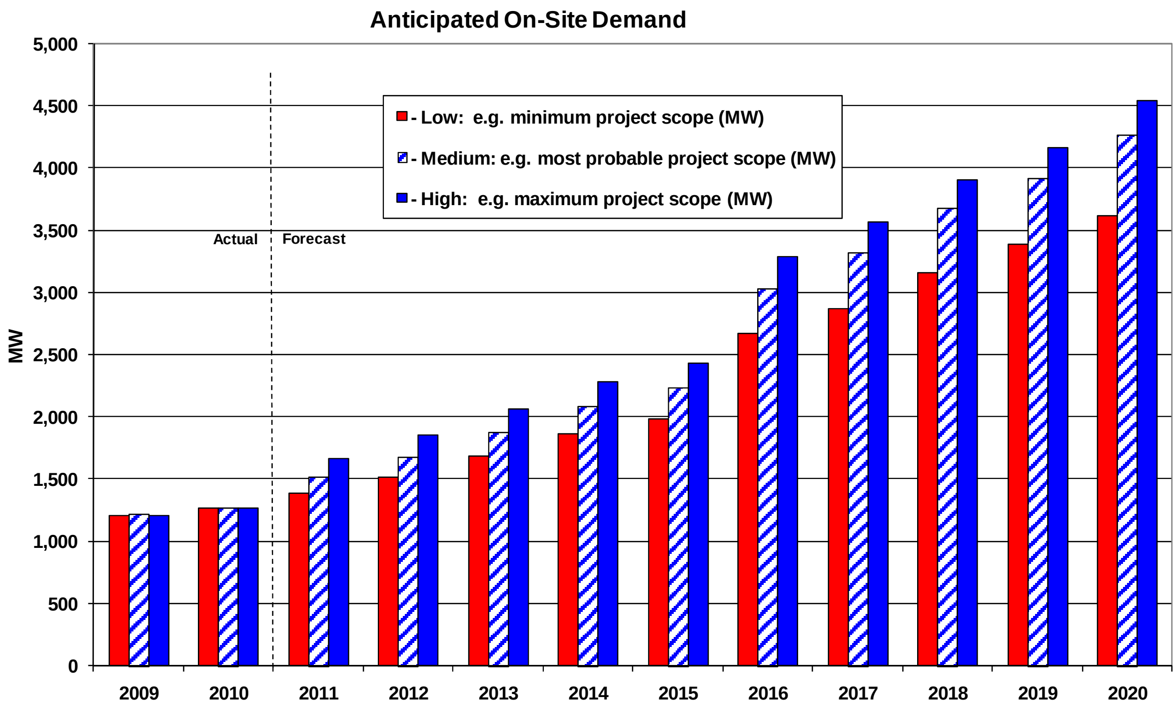
3.4 Detailed Survey Results

The following are the results for each question in the 2011 survey.

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

The 2011 survey results show an increase in on-site demand over the entire forecast period 2011 – 2020 (Figure 2). The rate of annual demand growth for the Medium Range averages about 12% per year until 2016 when an annual 35% growth spike is forecast (corresponding to a large oil sands mine coming on stream). A lower average 9% per year growth rate is forecast over the remaining years of the forecast (2017 to 2020). The total demand over the forecast period is about 300 MW higher than the 2010 report forecast (Medium, 2019).

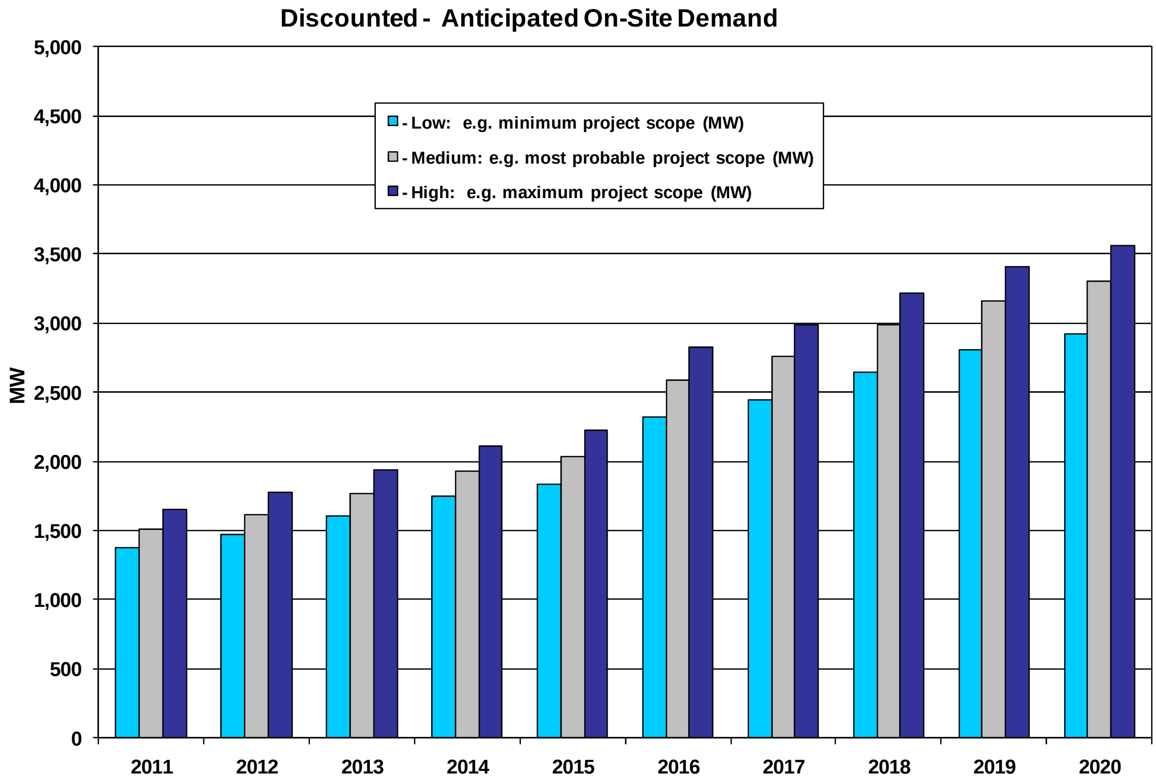
Figure 2 Anticipated On-Site Demand



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 section 7.0 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.

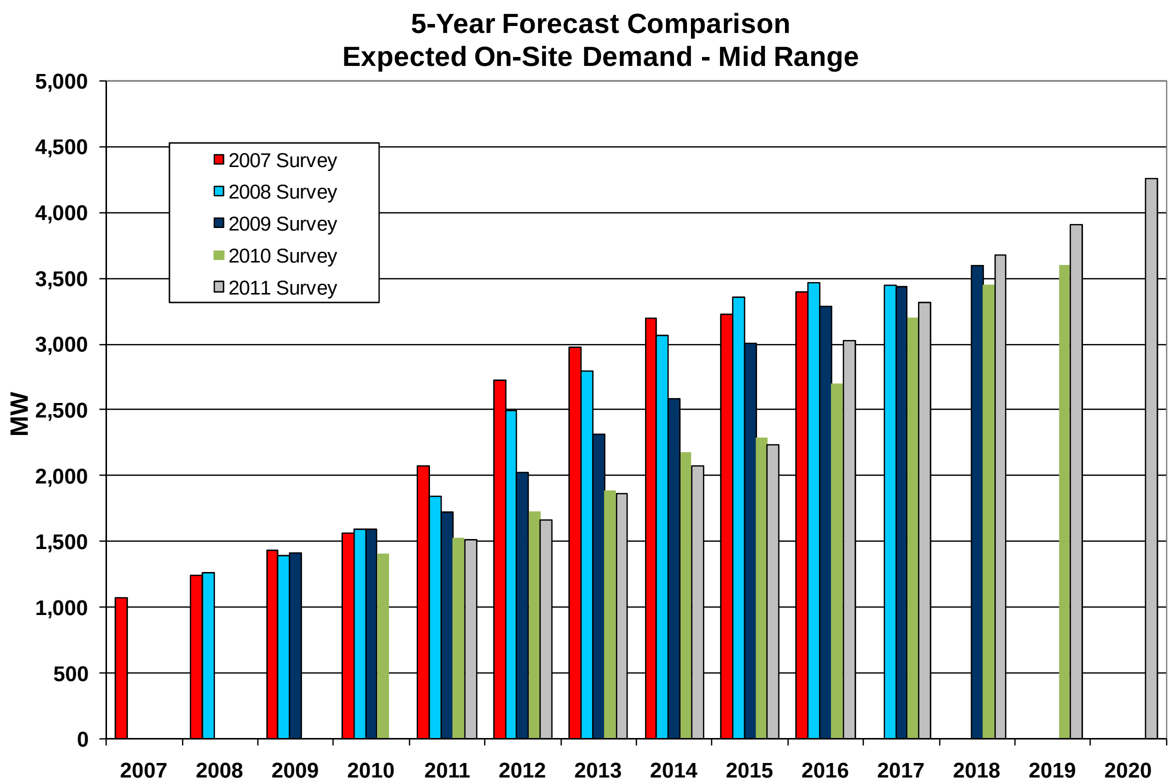
With discounting, the 2011 survey anticipated on-site demand is about 385 MW higher than the 2010 survey results for 2019, Medium Range (Figure 3).

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 from last year's survey up to the year 2016; however, about 300+ MW of new demand is forecast over the last five years of the forecast period compared to the 2010 survey results. Concerns noted in prior reports, including project capital costs, labour shortages, greenhouse gas emissions, etc. have likely lead to projects being delayed compared with earlier surveys up to the year 2016. However, oil sands developers continue to envision that their projects will proceed and in the 2011 survey demand growth in 2020 is forecast to eclipse all prior surveys by over 500 MW.

Figure 4 5 year Comparison of Expected On-Site Demand



3.4.2 What options for power supply are being considered?

Similar to the survey results over the last two years, respondents plan to use of both on-site co-generation and purchased power from the grid to meet their stand-by power needs. The rationale for the choice 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.

What is materially different in the 2011 survey results is that most of the new projects plan to purchase directly from the grid. In the 2010 survey, 41 projects responded to this question with 10 projects reporting that they planned to purchase from the grid at the end of the forecast period (24% Direct Purchase from grid (no co-gen)). In the 2011 survey, the number of reported projects increased to 55 and 30 reported that they only planned to purchase directly from the grid (54% from grid only). The results are presented in Table 1. Note that the options are not mutually exclusive as some respondents choose more than one option for a project.

Table 1 Options for Power Supply (number of projects)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Co-Generation only (no standby)	0	0	0	0	3	4	4	3	3	3	3	3
Direct purchase from grid (no co-gen)	5	6	6	12	18	23	25	26	29	30	30	30
Plan on doing both of the above	11	13	13	17	18	19	22	27	32	33	33	33

Quantitatively, the majority of the reported demand load plans on utilizing co-generation and purchases from the grid. The quantum of demand that completed this survey question diminished over time, presumably since some survey respondents were unsure of their longer term plans.

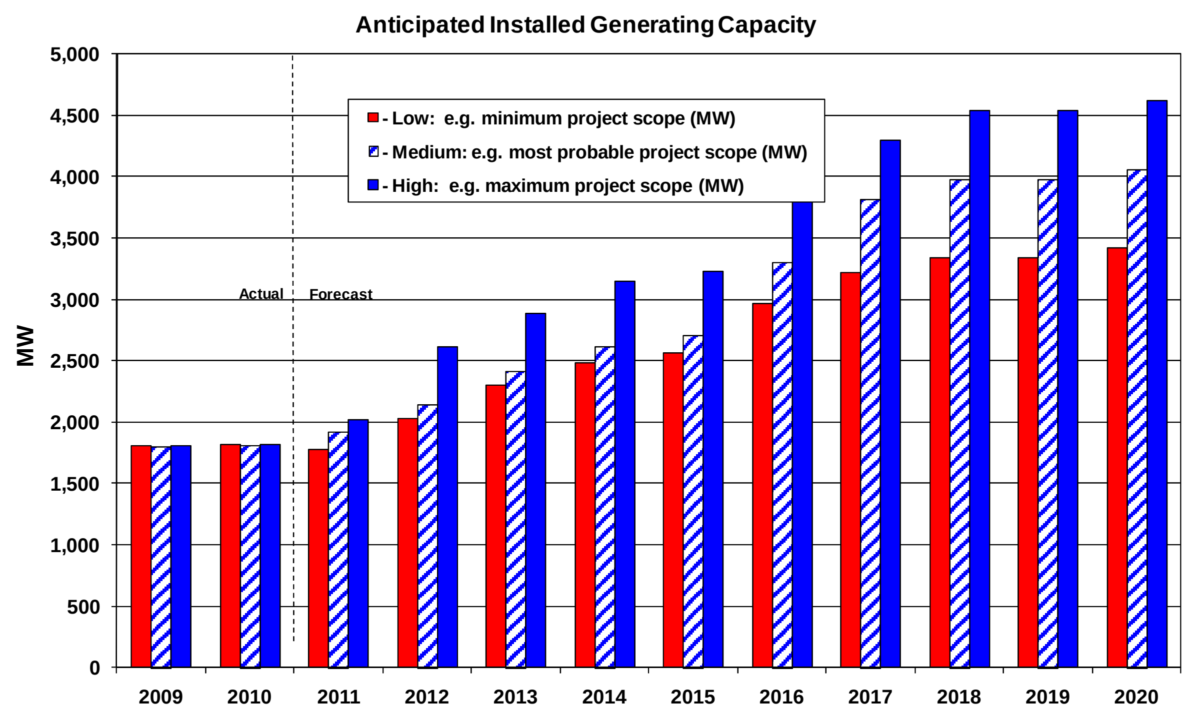
Table 2 Quantum of Demand Reported for Options for Power Supply (MW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Co-Generation only (no standby)	-	-	-	-	28	174	181	166	166	166	166	166
Direct purchase from grid (no co-gen)	57	67	62	78	156	279	367	647	690	793	841	881
Plan on doing both of the above	1,138	1,215	1,321	1,395	1,486	1,541	1,601	2,078	2,285	2,512	2,708	2,751
% of Total Demand Reported	94%	96%	87%	84%	80%	74%	72%	69%	69%	68%	69%	65%

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

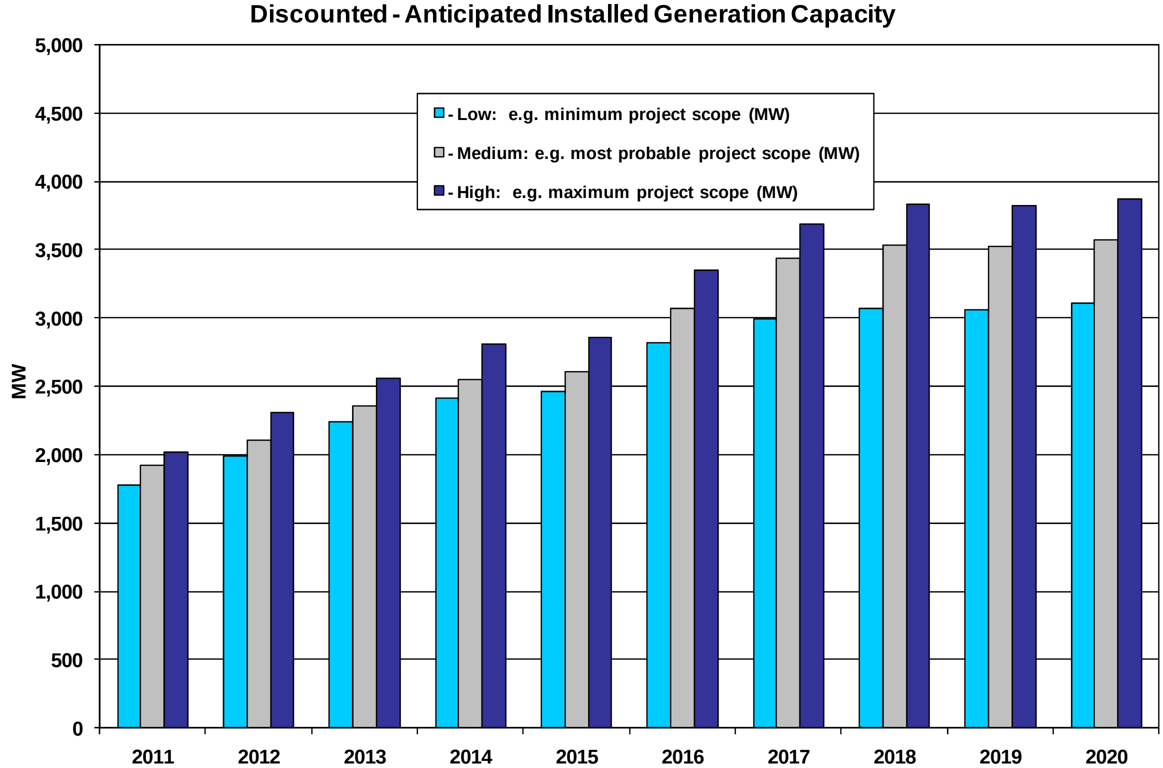
The 2011 survey range of operating generating capacity (Figure 5) indicates co-generation projects coming on line faster compared to the 2010 survey results, especially under the High Range. Over the survey horizon by 2019 about 130 MW of additional generation is forecast to be developed compared to the 2010 survey (compared to 300 MW of additional demand from Figure 4).

Figure 5 Anticipated Installed Operating Generation Capacity



Discounted results (Figure 6) are also higher than the 2010 survey, especially from 2016 to the end of the forecast period.

Figure 6 Discounted - Anticipated Installed Operating Generation Capacity



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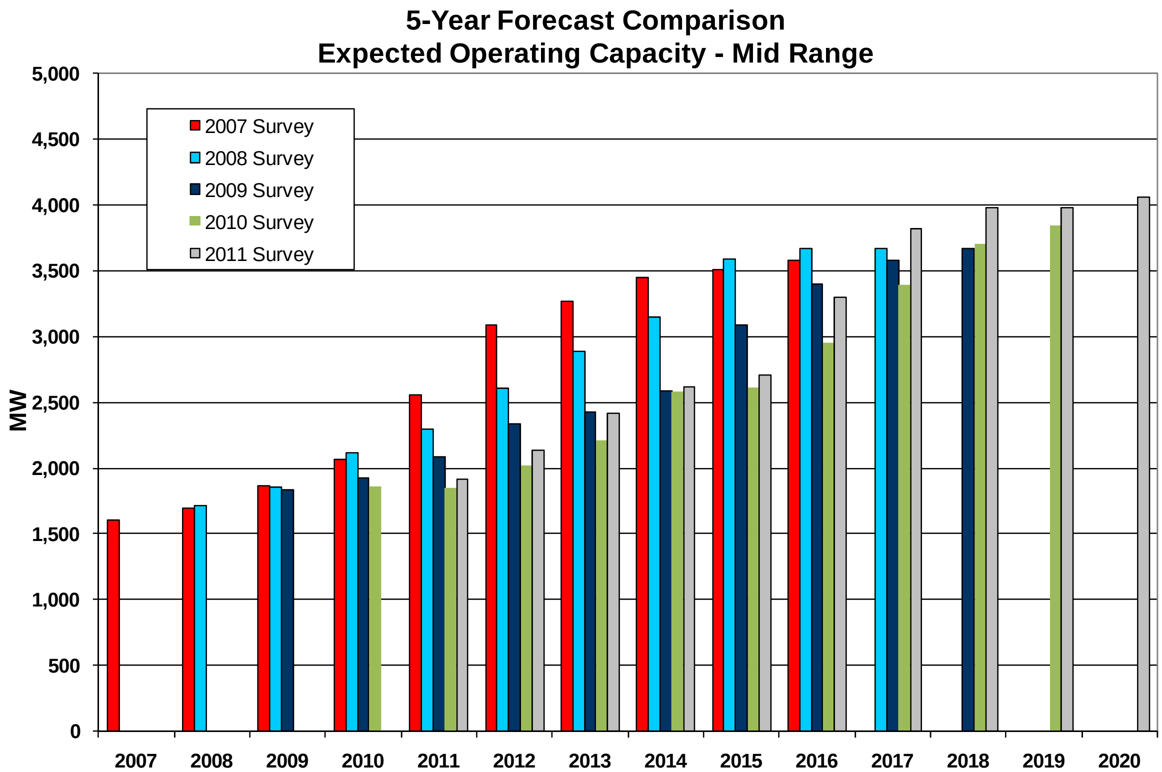
In each of the last four surveys, the actual operating co-generation capacity amounts are less than the previous year's forecast (Figure 7). It is not until near the end of the forecast period that the 2011 survey eclipses the values reported in the 2007 to 2010 surveys. Economic uncertainty is felt to be main reason for the delays in forecasting the installation of co-generation units.

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



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

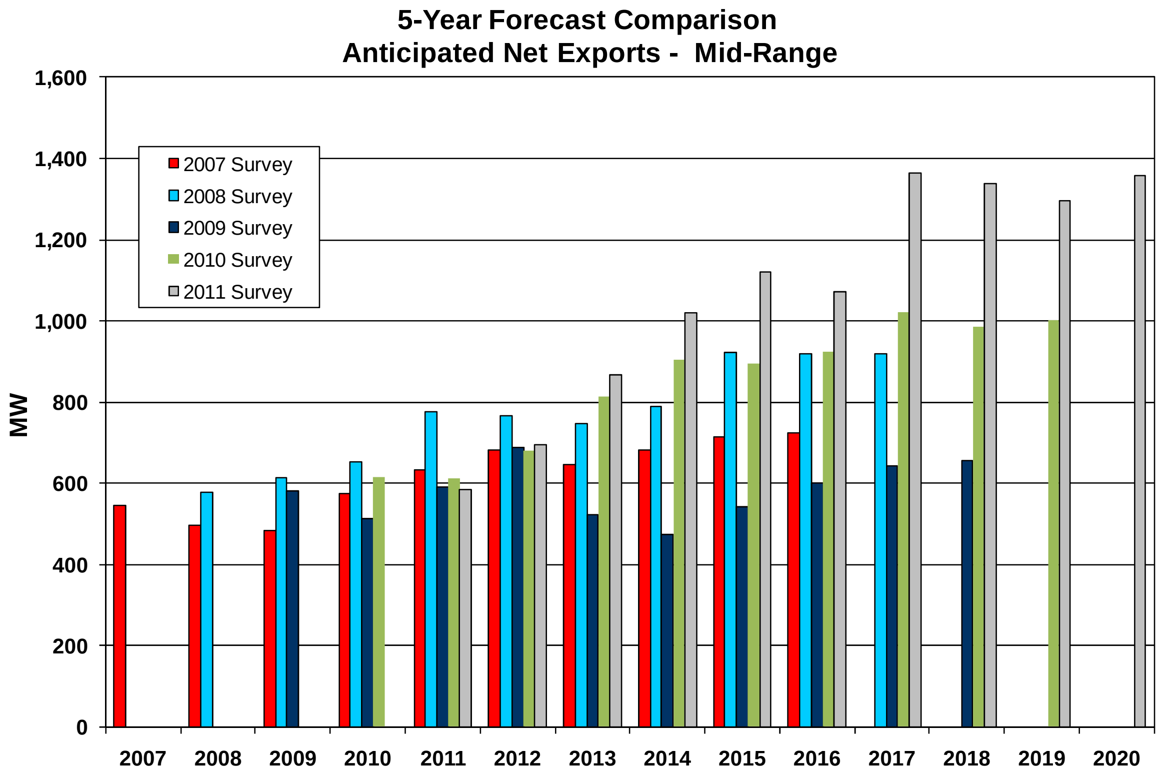
The 2011 survey forecast of net exports (Figure 8) are about 25% higher than the 2010 survey results starting in 2017. This result is counter intuitive as the forecast for demand has increased by about 300 MW, whereas the forecast for generation has only increased by about 130 MW.

However, one oil sands developer is planning on installing significant new generation capacity that produces the majority of the newly forecast net exports. Some existing developers are also forecasting to increase exports.

Most of the newly forecast demand is from projects that do not plan to install co-generation. The survey data suggests that the newly forecast load increases and export increases are primarily coming from different sets of projects.

The five year trend shows that the level of power exports envisioned in prior surveys is eclipsed as early as 2013, with over 250 MW of increased net exports forecast in the later years of the forecast.

Figure 8 5 year Comparison of Anticipated Net Exports



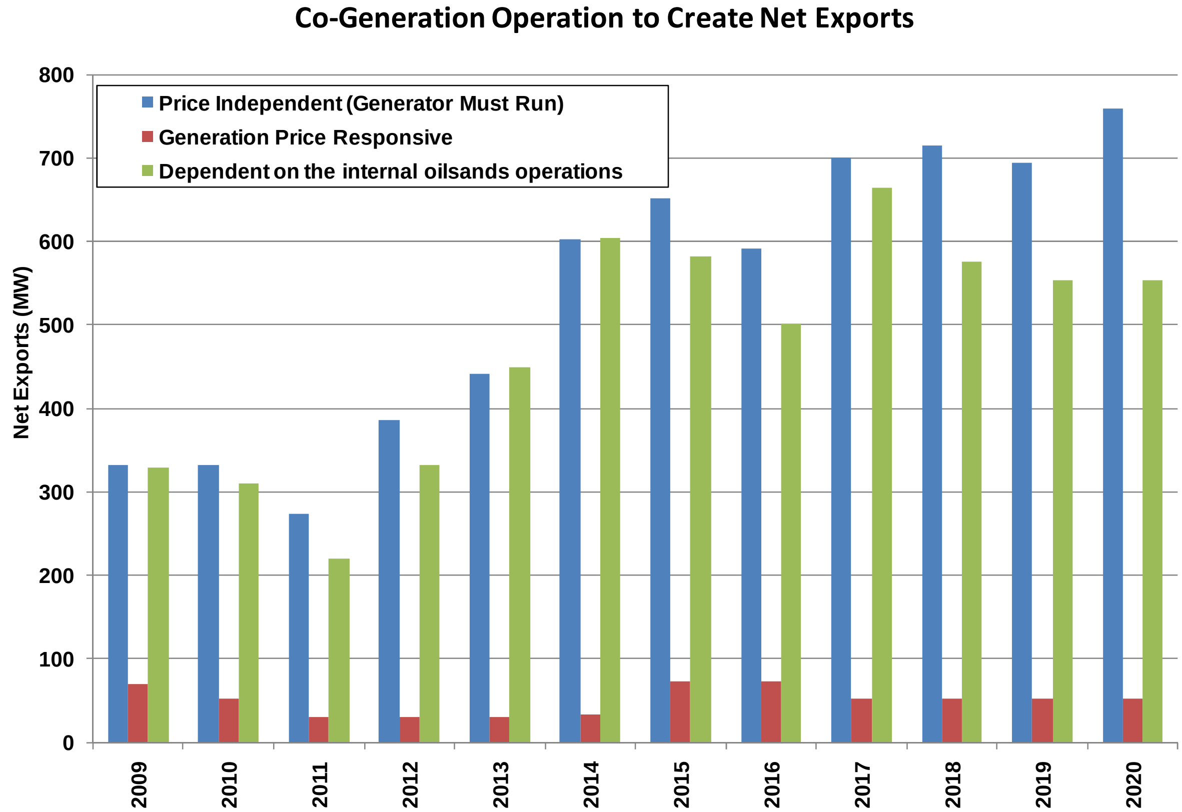
3.4.5 If anticipating power exports how do you plan to operate?

New for the 2011 survey was a question asking oilsands developers who were planning to export electricity how they plan to operate. Three options were provided:

1. Price Independent (Generator Must Run) - Net exports to the grid will continue regardless of the power pool price (net exports are a "price taker")
2. Generation Price Responsive - Net exports to the grid will generally increase when pool prices are high (e.g. pool price is above variable costs) and generally decrease when pool prices are low (e.g. pool price is below variable costs)
3. Dependent on the internal oilsands operations - The quantum of net exports will be a function of internal operations and may or may not depend on the power pool price.

The survey results are shown in Figure 9:

Figure 9 Co-Generation Operations to Create Net Exports



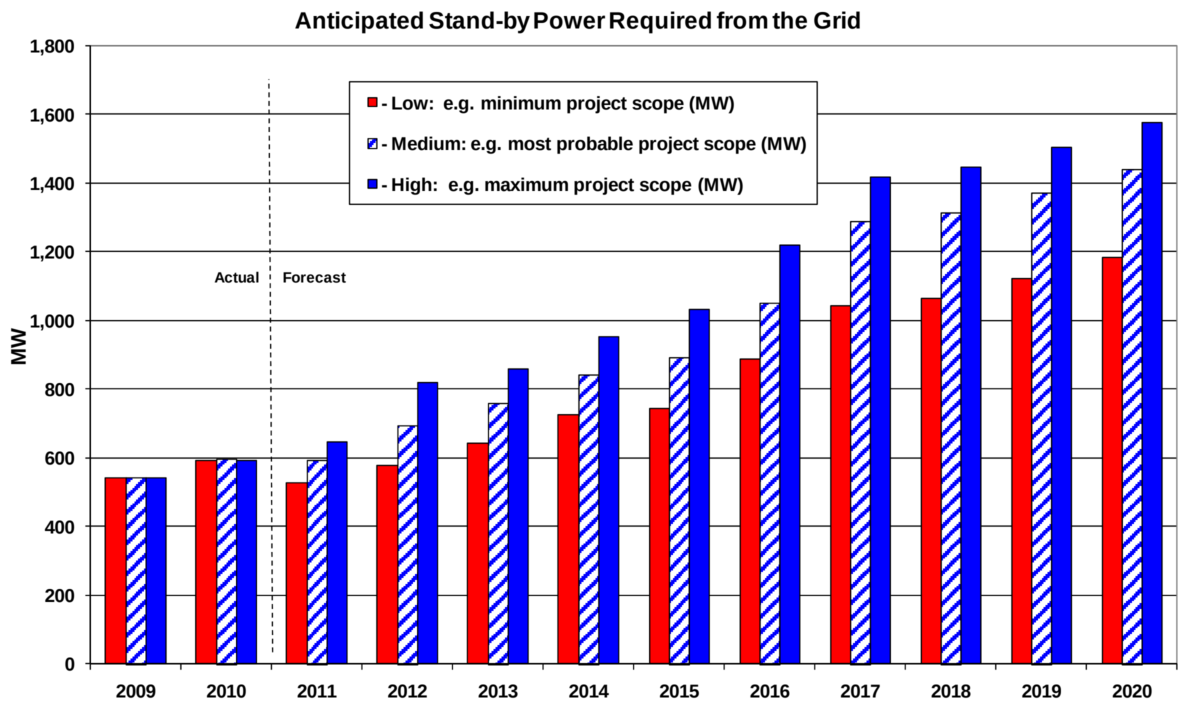
Generally, about 95% of all exports from oil sands projects are forecast to be non price responsive, that is, the net exports will be created based on factors other than the wholesale market price for electricity. This is a significant result as it indicates that some oil sands developers are not building excess generation capacity to actively participate in the wholesale electricity market and extract economic rent during periods of high wholesale power prices. Only three oil sands developers reported that they plan to be price responsive with a portion of their co-generation capacity.

From an electric system operation perspective, the non price responsiveness of excess co-generation capacity also indicates that the AESO should not be relying on increased generation output during times of high wholesale market (i.e. power pool) prices.

3.4.6 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 2011 results reflect a significant change with stand-by requirements (Figure 10) reported to be about 25% lower than the 2010 survey results. Closer examination revealed that three major oil sands projects with on-site generation plan to reduce their stand-by requirements compared with their prior year forecasts. Perhaps the anticipated increases in transmission tariff costs, resulting from the proposed transmission infrastructure build over the next 5 to 8 years, has resulted in oil sands developers re-evaluating the cost of stand-by capacity vs. risk of reduced production during generation outages. An alternative explanation is that as more co-generation units are built at a single location the need for stand-by from the grid is reduced.

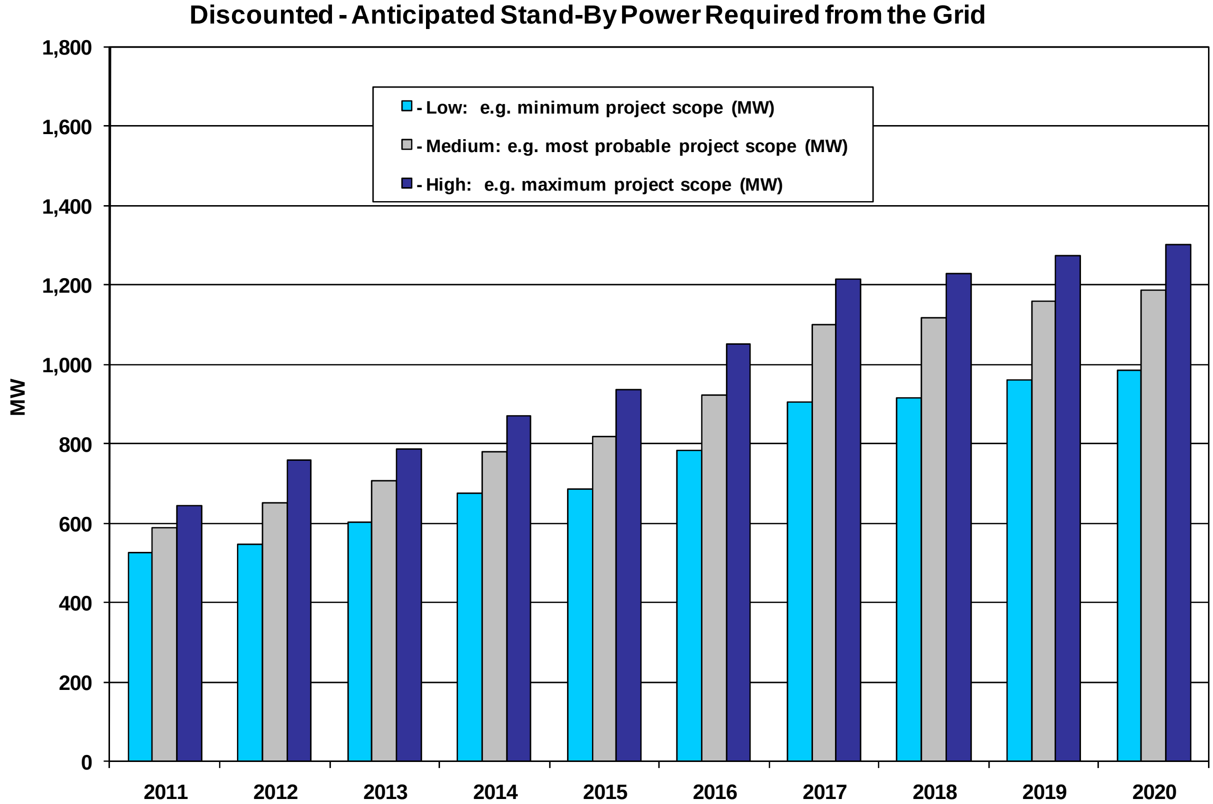
Figure 10 Anticipated Stand-By Power Requirements



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 10 must be used with caution as each project's stand-by power requirements are not fully 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 7.0 below entitled **Duration Curve Analysis** which suggests the **average** Medium Range co-incident requirement from all loads net of generation in the Fort McMurray area will be about 525 MW in 2020 under the 100% case (Figure 24, blue 2020 line) and about 200 MW under the discounted case (Figure 25, blue 2020 line), compared to over 1,400 MW in Figure 10 (Medium Range, 2020.

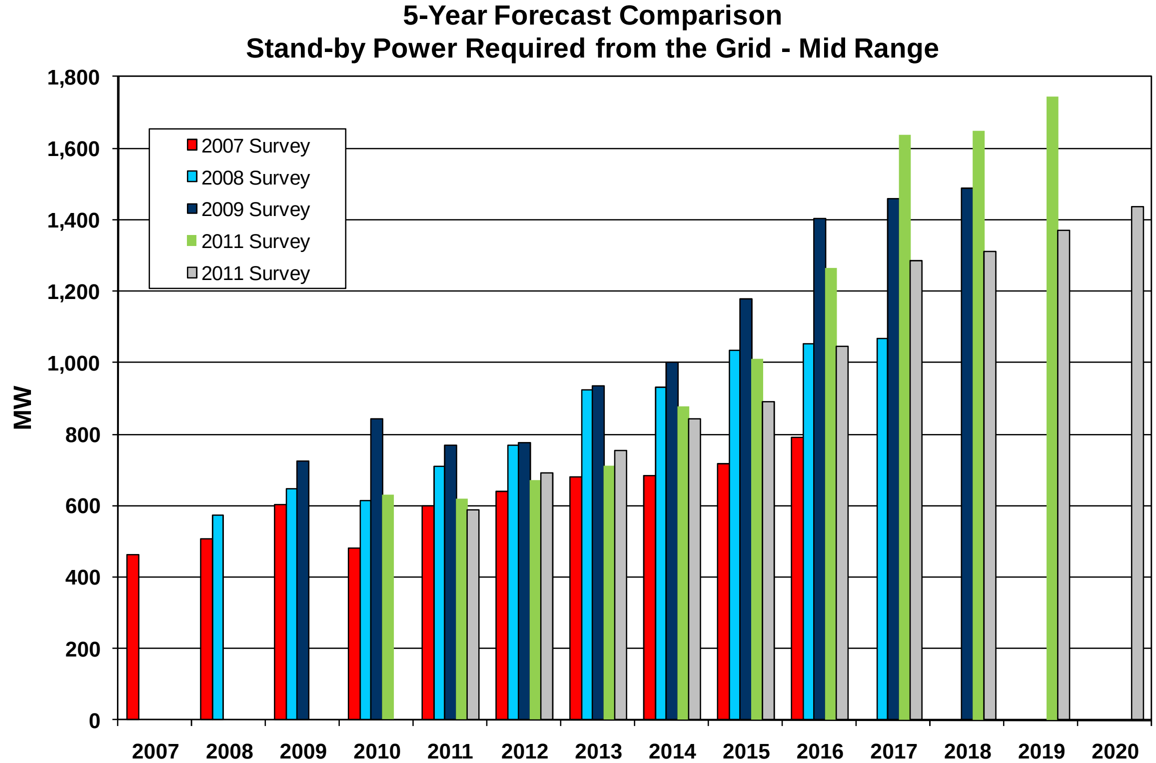
On a discounted basis (Figure 11), the anticipated stand-by requirements are about 1,200 MW by 2020. Again, this does not mean that 1,200 MW of stand-by will be required at any one time. Rather, this is the cumulative stand-by requirement over 30+ projects.

Figure 11 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 12). Starting in about 2014 the 2011 surveys show an anticipated lower reliance on stand-by compared to prior forecasts.

Figure 12 5 year Comparison of Stand-By Power Requirements



3.4.7 Oil Sands Mining vs. In-Situ Developments.

In the 2011 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 50% of the load growth is forecast to come from in-situ projects (Figures 13 & 14).

Figure 13 In-situ Projects Anticipated Demand

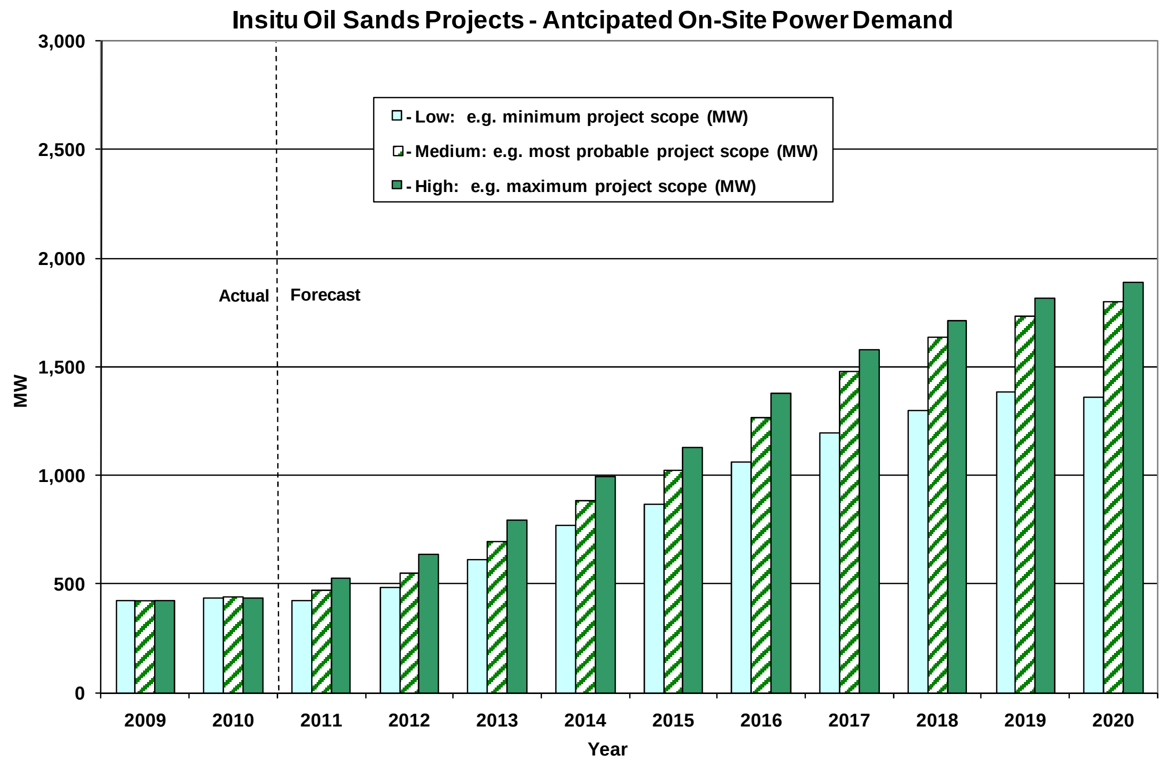
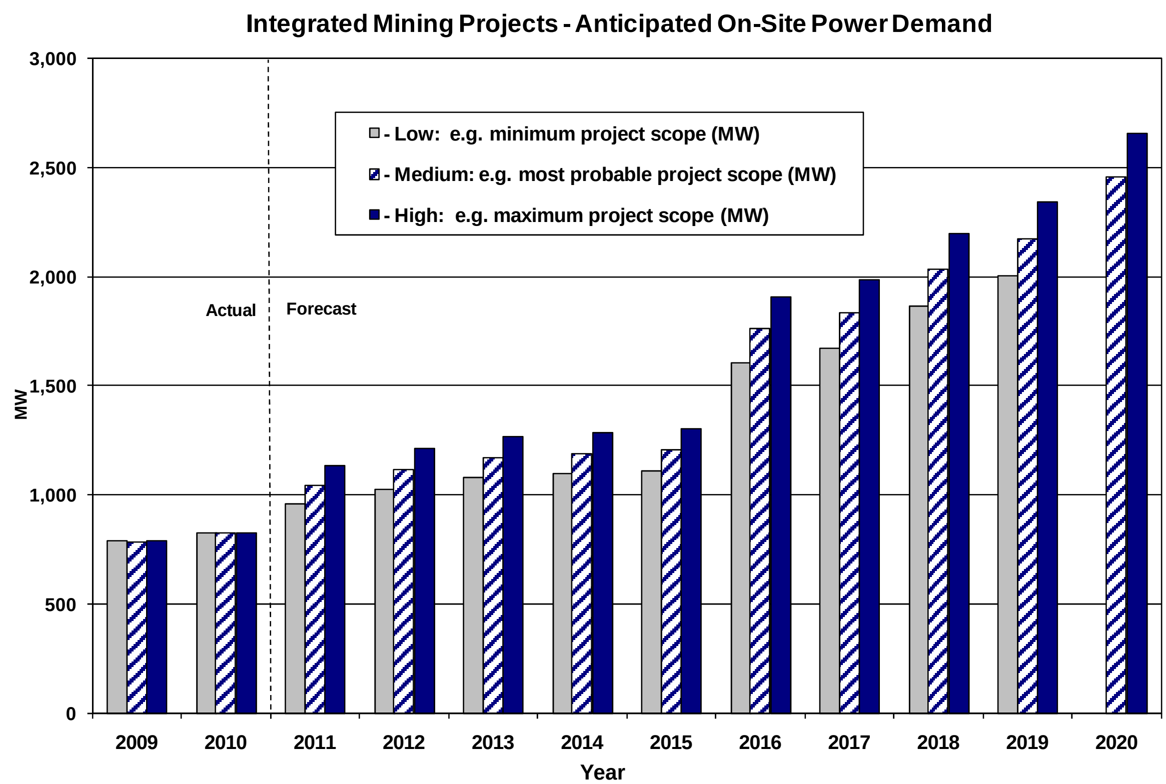


Figure 14 Oil Sand Mine Projects Anticipated Demand



About 60% of the co-generation is forecast to come from in-situ projects. Again the large increase in 2016 is the result of the next large oil sands mine commencing operation.

Figure 15 In-situ Projects Anticipated Co-generation

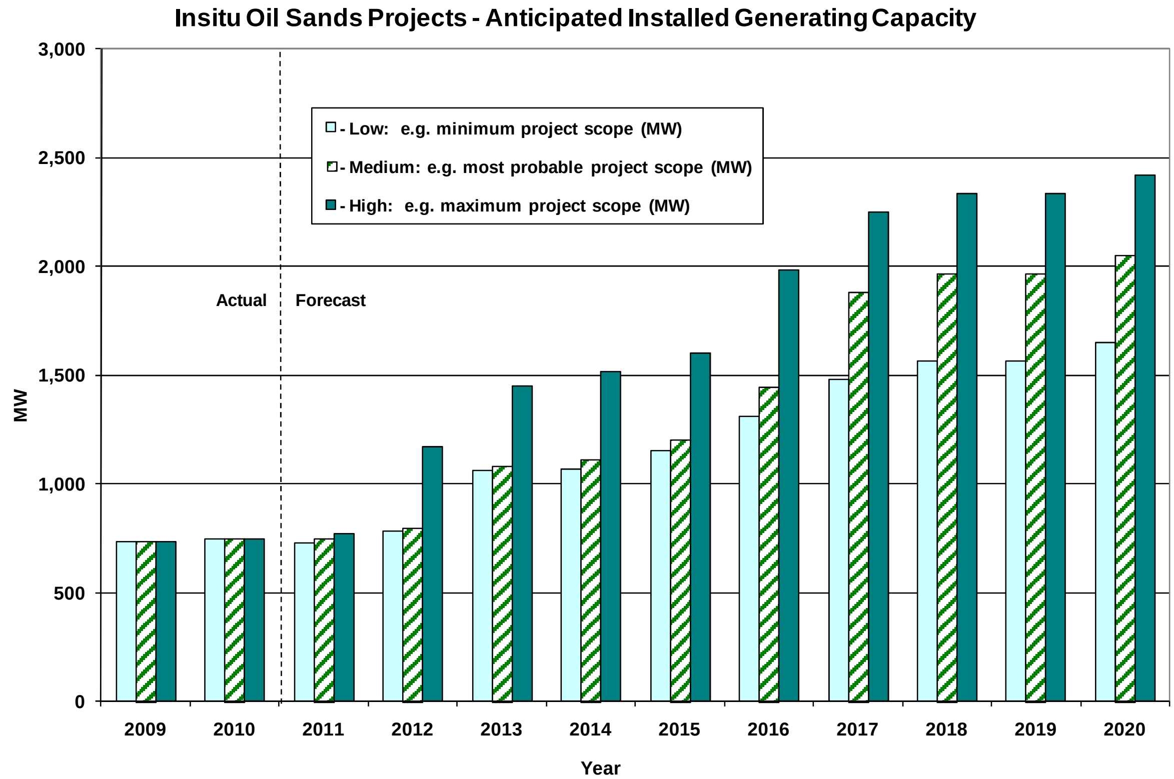
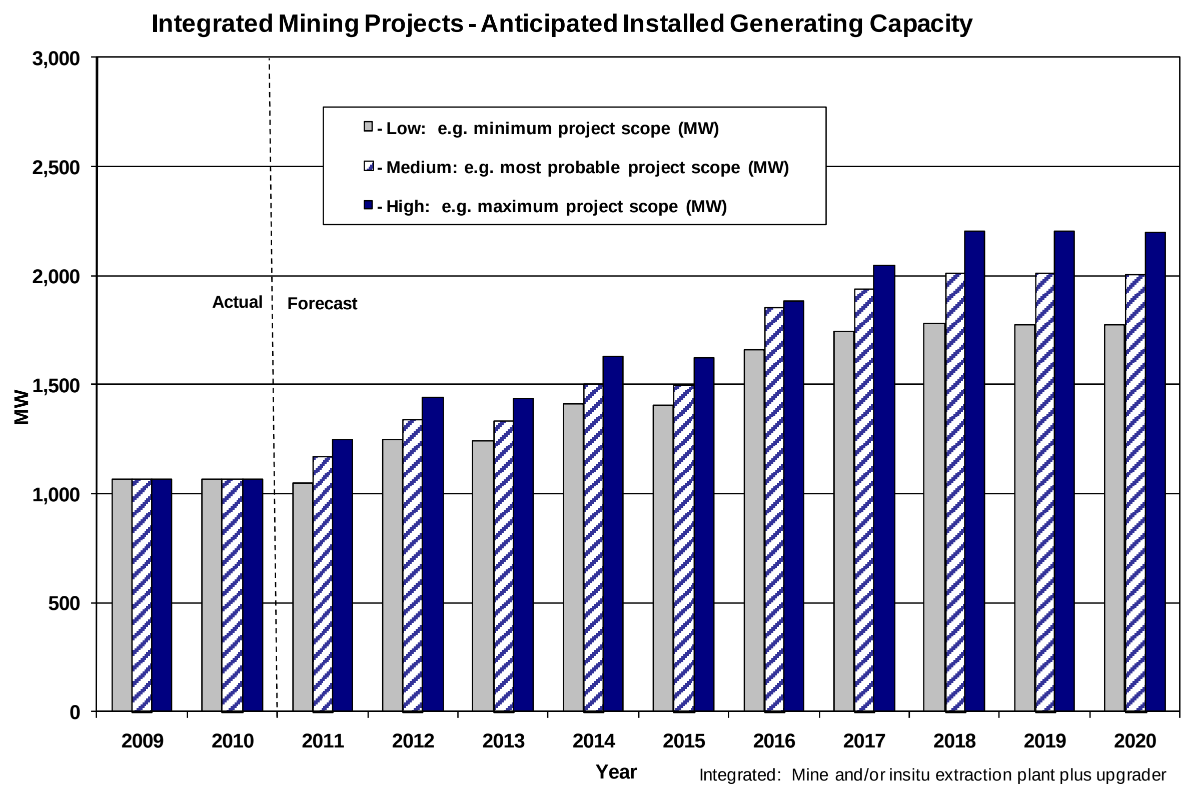


Figure 16 Oil Sand Mine Projects Anticipated Co-generation



Additional co-generation capacity from in-situ projects tends to be forecast near the latter part of the forecast horizon, with higher forecast levels in the High Range.

3.4.8 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 2020, ten years out.

Table 3 Location of Co-generation Projects – Operating Capacity, Nameplate Capacity and Number of Projects

Your Project is located in the Athabasca Region:	Operating MW in 2010	Operating MW in 2020	Nameplate Capacity in 2020	# Projects with Co-gen in 2010	# Projects with Co-gen in 2020
- South of Fort McMurray	278	863	1,253	3	12
- North of Fort McMurray and East of the Athabasca River	315	550	1,007	2	5
- North of Fort McMurray and West of the Athabasca River	915	1,907	1,934	4	8
Your Project is located in the Wabasca area	0	0	0	0	0
Your Project is located in the Cold Lake area	305	610	1,175	3	7
Your Project is located in Peace River area	0	180	180	0	1
Your Project is located in other areas, please specify	0	0	0	0	0
TOTAL	**1,813**	**4,110**	**5,549**	**12**	**33**

3.4.9 What is the status of your project as of January 1, 2011?

The purpose of this question was also to gather information on the development status of the various cogeneration units. Installed capacity is taken as the Medium Range in 2020, ten years out. Data was provided for a total of 32 projects with existing or planned co-generation units. Note that the forecast 2020 installed capacity is 4,445 MW (Table 4), higher than the co-generation operating MW shown in Table 3 of 4,110 MW.

However, the total 2020 forecast installed nameplate capacity is 5,349 MW over 36 projects with co-generation units (36 projects with a total of 66 generating units). Some survey respondents indicated that installed nameplate capacity was forecast for the year 2020, but did not indicate on the survey the status of the proposed co-generation unit or the anticipated operating capacity. Therefore, the statistics in Table 4 should be considered to be conservative and indicative only as they do not reflect all of the projects identified on the 2011 survey.

Table 4 Status of Co-generation Projects – Installed Capacity and Number of Co-generation Units

	Capacity MW	# Cogen Units
Built and/or operating	2,045	30
Under construction	85	1
Has been fully approved by the Regulatory Boards	465	6
Has been fully approved by the Company Boards	91	2
In the approval stage	107	4
Announced only	305	3
Conceptual Planning Stage	1,347	20
TOTAL	**4,445**	**66**

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 overall use of natural gas. In the earlier years of the 2000's 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 last 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 2011, forecast pool prices for electricity are relatively comparable to prior years and the existing transmission lines to export power from the Fort McMurray area are restricted. However, in 2009 the Alberta government passed the *Electric Statutes Amendment Act* that provides greater certainty that Alberta's transmission infrastructure will be upgraded over the forecast horizon, including a higher import limit by 2012 and new 500 kV lines from the Edmonton area to Fort McMurray (currently planned for 2017 and 2019).

Oil Sands developers in the 2010 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 2011 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 17 plots data for the year 2011 from surveys conducted for the years between 2001 and 2010 and demonstrates the change in forecasts of on-site demand and co-generation operating capacity. In general, the annual forecasts over the past 10 years show a "tightening" of demand and supply in 2011, starting with the year 2007 survey results. The gap widened slightly in the year 2009 and 2010 survey results.

Figure 17 2011 Forecasts from 2001 to 2010 Survey Data

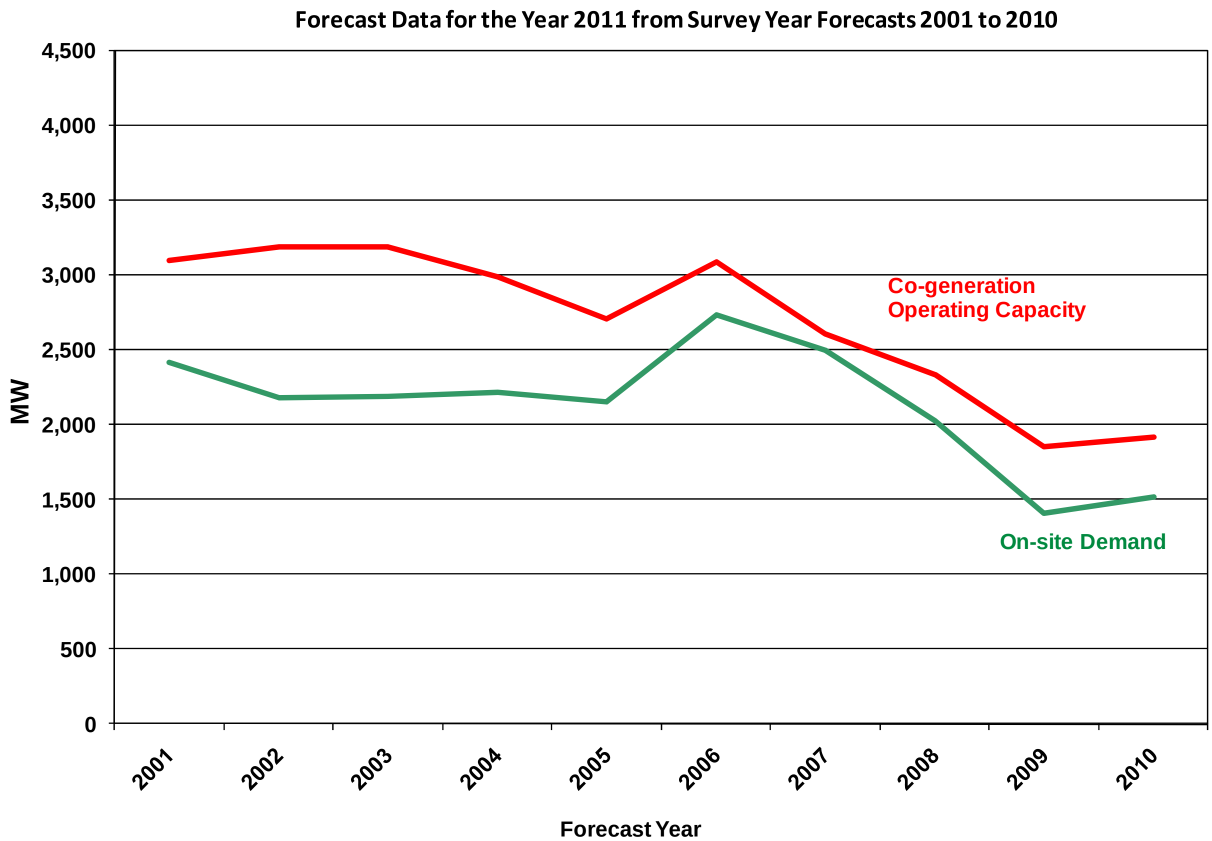
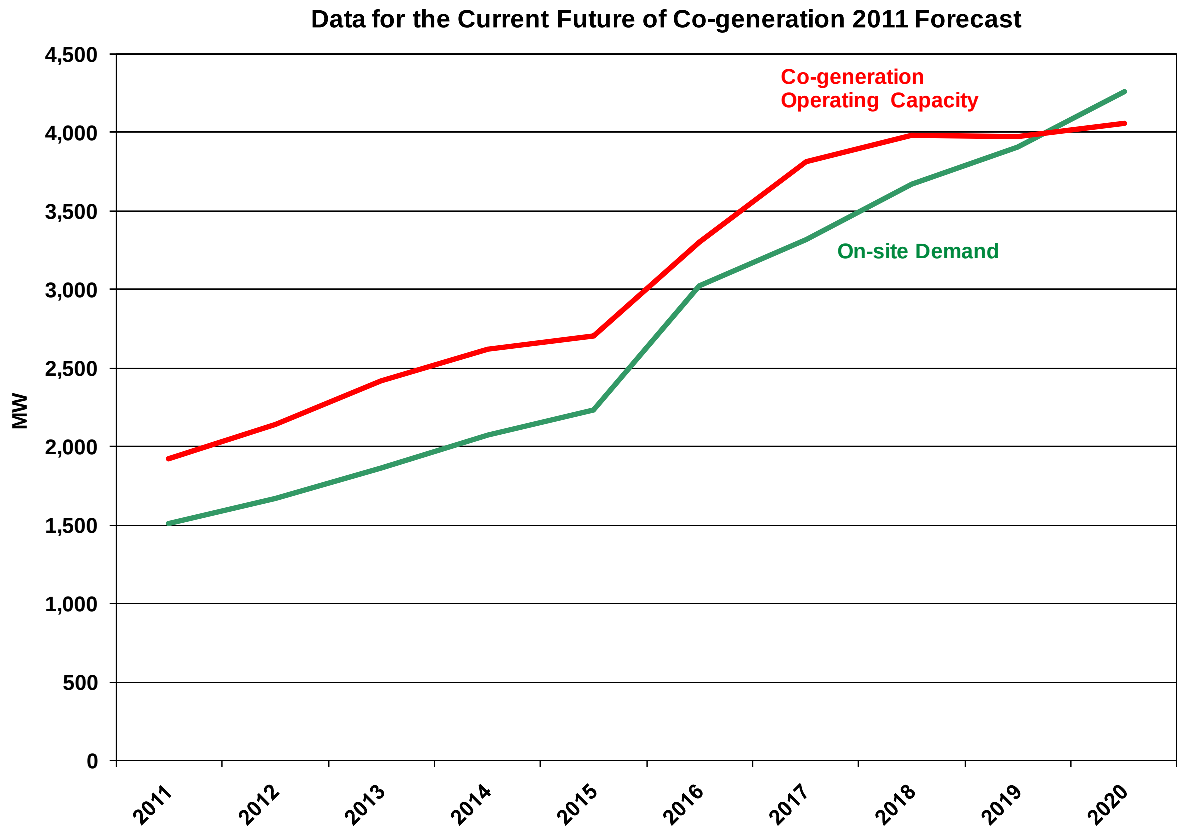


Figure 17 also provides a glimpse into the accuracy of prior forecasts. In general, if the lines are relatively flat then it would suggest that there have not been material changes in the surveys from year to year. One could surmise that the surveys in the earlier part of the last decade were more accurate as those from the last five years. Perhaps the changing economic conditions when the 2006 to 2010 survey data was collected are partly responsible for the revised forecast outlooks.

The decline in the forecast 2011 values for on-site demand and co-generation capacity from the 2007 survey to the 2011 survey are felt to be a result of projects being delayed in the wake of the higher capital cost estimates in 2005 to 2007 and the fallout from the financial crisis in 2008. As noted above, some oil sands developers are forecasting higher on-site demand and co-generation capacity in the coming years, to levels at or higher than those forecast in the mid-2000's.

Figure 18 demonstrates the 2011 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 and that the quantum of co-generation operating capacity and on-site demand will increase to levels above what was forecast for the year 2011 in prior surveys (Figure 17).

Figure 18 Forecasts from 2011 Survey



In comparison to the 2010 survey results, net exports are forecast to increase by about 300 MW or 30%. Perhaps oil sands developers are now anticipating that sufficient transmission capacity will in built to the Athabasca region and the level of net exports will be higher than forecast a year ago.

Future surveys may validate the premise that if the planned transmission reinforcements to the Athabasca region are built oil sands developers will plan to install more or larger co-generation units. While concerns over inadequate transmission capacity may have been addressed in the past two years, concerns including the high capital costs of installing new co-generation capacity, AESO tariff cost increases 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 or obtaining an Industrial Systems Designation ("ISD"), 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 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 2011 survey developers were asked to indicate if they have a section 101 approval, have filed for a section 101 approval or plan to file for an approval. Of the 31 projects that indicated plans for co-generation 20 respondents indicated a response with respect to an *EUA* section 101 approval:

Table 5 EUA Section 101

	Projects
Planned	5
Filed	5
Approved	10
	20

Of note, the number of projects that have a section 101 approval increased by five from the 2010 survey results.

Developers were also asked to indicate if they have an approved ISD, have filed an application with the AUC for an ISD or plan to file for an approval. Of the 127 identified projects (some of which include more than one phase of development), 36 indicated a response with respect to an ISD:

Table 6 Industrial System Designations

	Projects
Planned	13
Filed	5
Approved	18
	36

These statistics are skewed by projects being reported in phases. Even though only 30 projects indicated plans for co-generation with operating capacity, 36 projects indicated plans for an ISD. Obviously some load only project phases are planned to be incorporated into projects with co-generation to be part of an ISD. In most instances, all loads on a project site (which could include more than one phase) would be part of a single ISD.

Note that the number of approved ISDs increased by six from the 2010 survey results.

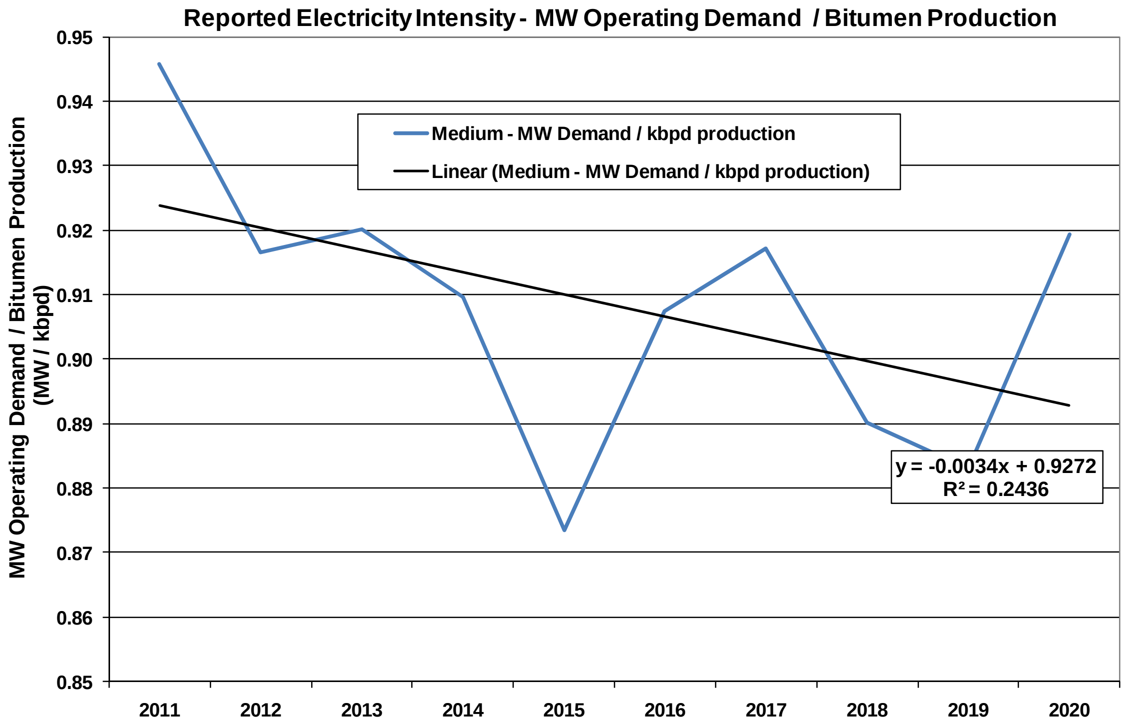
6.0 BITUMEN PRODUCTION

New on the 2011 survey was the request for developers to provide their estimated bitumen production under the High, Medium and Low Ranges. Several developers only provided their Medium Range production forecast, and some did not provide a response. Hence, the author is of the view that the data provided is incomplete and should not be used as a forecast of the total bitumen production from oil sands projects in Alberta.

Other organizations attempt to provide forecasts of bitumen production from oilsands projects. The Canadian Petroleum Producer's Association (CAPP) published the 2010-2025 Canadian Crude Oil Forecast and Market Outlook report that contains forecasts of bitumen production, see: http://www.capp.ca/forecast/Pages/default.aspx#tNCqWy8b5EWA

The data from the 2011 survey provided does suggest that bitumen production is expected to grow significantly, at an average rate of about 14% over the forecast horizon. For the projects where a bitumen production forecast was provided, the corresponding demand was determined and the ratio of demand to production was calculated. As shown in Figure 19, the average electricity demand per thousand barrels of bitumen production is about 0.9 MW / kbpd.

Figure 19 Bitumen Production Forecast



The trend over the forecast horizon is declining electricity intensity. As newer and more efficient oil sands operations are constructed, and expansions at existing facilities are added, it is anticipated that electrical intensity will decline.

7.0 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 over 30 at 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.

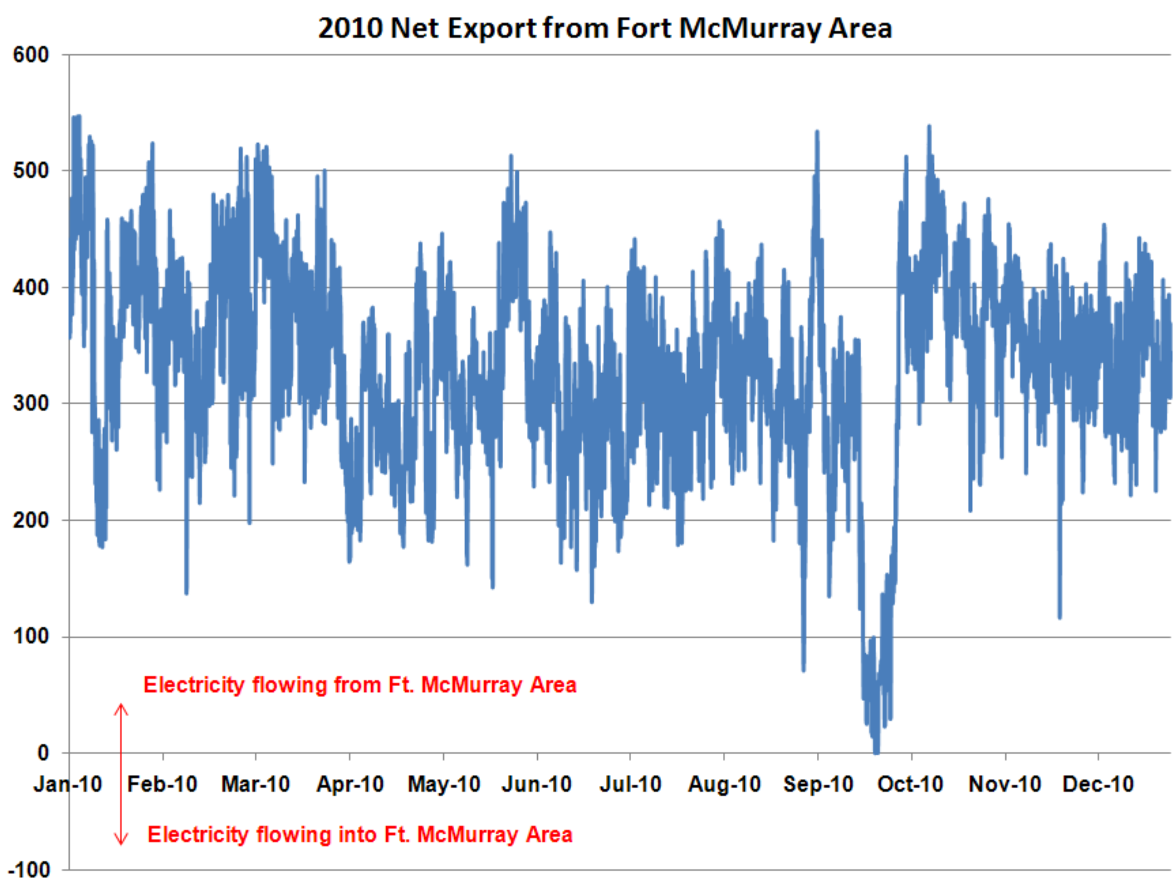
Conversely, the net export statistics may be more indicative since net exports are more likely to occur the majority of the time. Net exports typically fall into two categories: Surplus Net Exports and Merchant Net Exports.

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.

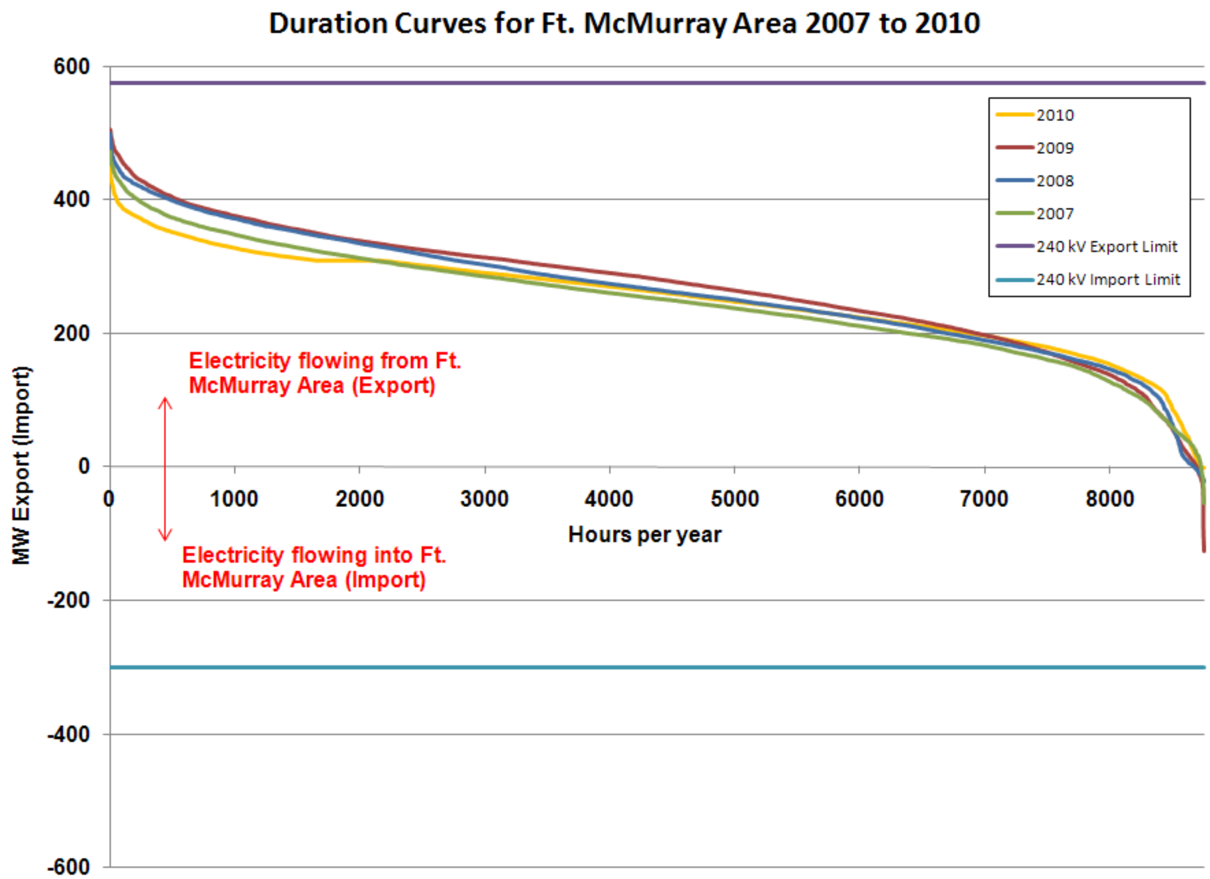
Planning for transmission capacity for net exports is more difficult as oilsands operations will dictate if net exports will occur. In order to investigate this issue further hourly transmission data for electricity flowing into and out of the Fort McMurray area was obtained from the AESO for all hours in 2007 to 2010. A plot of the 2010 data versus time (Figure 20) shows the random nature of the electricity flows and indicates that electricity flows out of the Fort McMurray area almost all of the time.

Figure 20 2010 Net Exports from Fort McMurray Area



A more representative way to view this data is via a duration curve. A duration curve can be used to illustrate the relationship between transmission capacity and capacity utilization. With a duration curve, data is ordered in descending order of magnitude and plotted against the number of hours in the time period (e.g. one year for 2010 data). The following duration curve (Figure 21) shows the same data as Figure 20 above, with data for 2007 to 2009 added for comparison purposes.

Figure 21 Duration Curves of Net Exports from the Fort McMurray Area



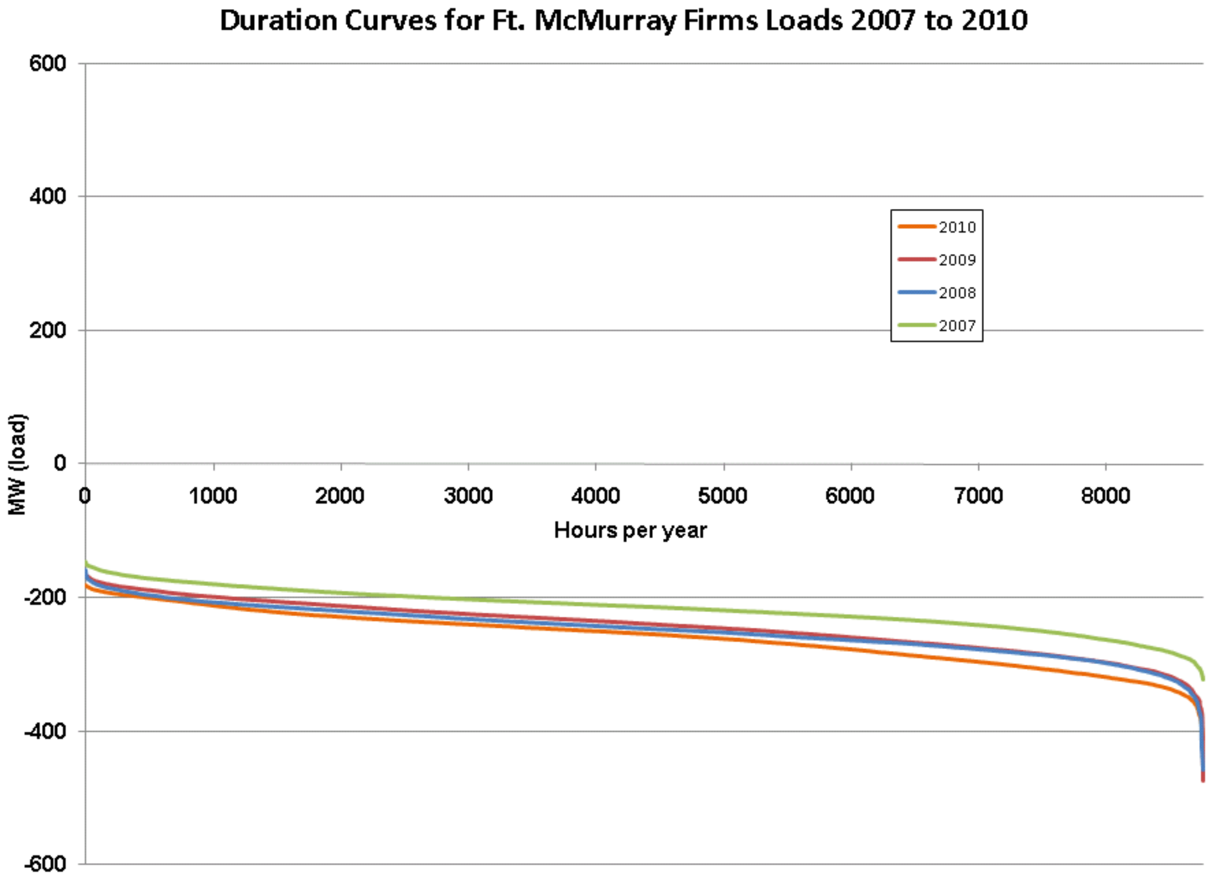
The Figure 21 duration curves show that generation in the Fort McMurray area (mainly oil sands co-generators) are producing more electricity than the area's total demand over 99% of the time. For all but a few hours per year there is a net export of electricity out of the Fort McMurray area. The duration curves also shows, for example, that in 2010 for about 2,600 hours per year (about 30% of the time) more than 300 MW was being exported from the Fort McMurray area.

Note that the quantum of exports from the Fort McMurray area is decreasing each year.

Also shown on the figure above are the current maximum 575 MW export and maximum 300 MW import limits with the existing three 240 kV lines into the Fort McMurray area. The AESO is planning to reinforce the reactive power capability in 2012, which is forecast to increase the maximum import limit from 300 to over 600 MW. Import and export capability is anticipated to be increased further in 2017 with the addition of the first of two 500 kV lines from the Edmonton area to Fort McMurray (the second 500 kV line is currently planned for 2019). If additional co-generation is added (or load is reduced) before additional transmission capacity becomes available as planned for 2012 and 2017, then there may be some hours per year where the AESO could potentially restrict generation output or curtail load due to transmission capacity limitations.

In order to utilize the 2011 survey data and project potential future transmission requirements, the 2010 data was segregated into demand related to the City of Fort McMurray and other smaller distribution loads (firm load) and load related to oil sands projects (including any other transmission connected loads). For the firm loads, the duration curves (Figure 22) show that the firm load varies between about 200 and 400 MW:

Figure 22 Duration Curves for Fort McMurray Firm Loads



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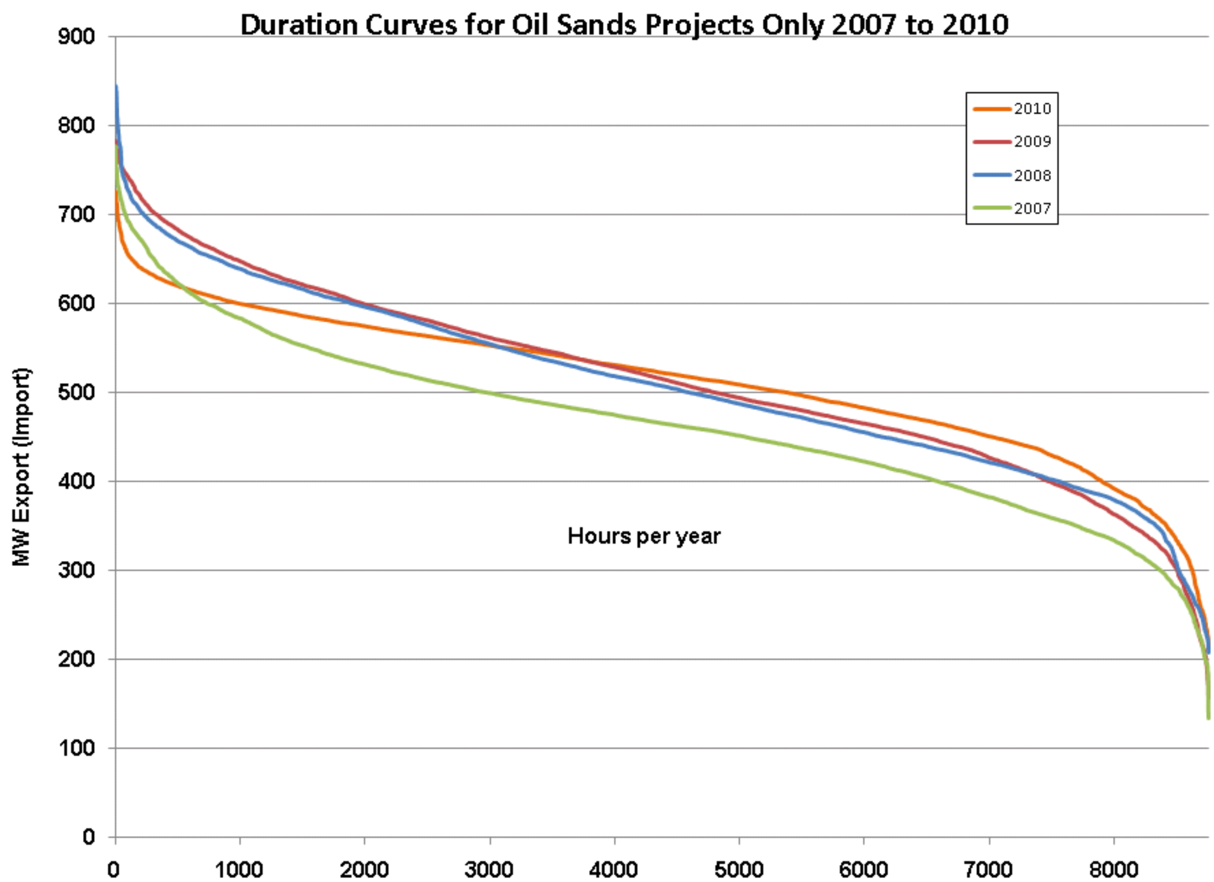
The oil sands related loads and generation alone have the following shape once the firm loads are removed. As can be seen, the oil sands projects in the Fort McMurray area provide a net export of electricity to the grid in every hour in 2007 to 2010, averaging just over 500 MW (Figure 23).

Figure 23 Duration Curves for Oil Sands Projects Only

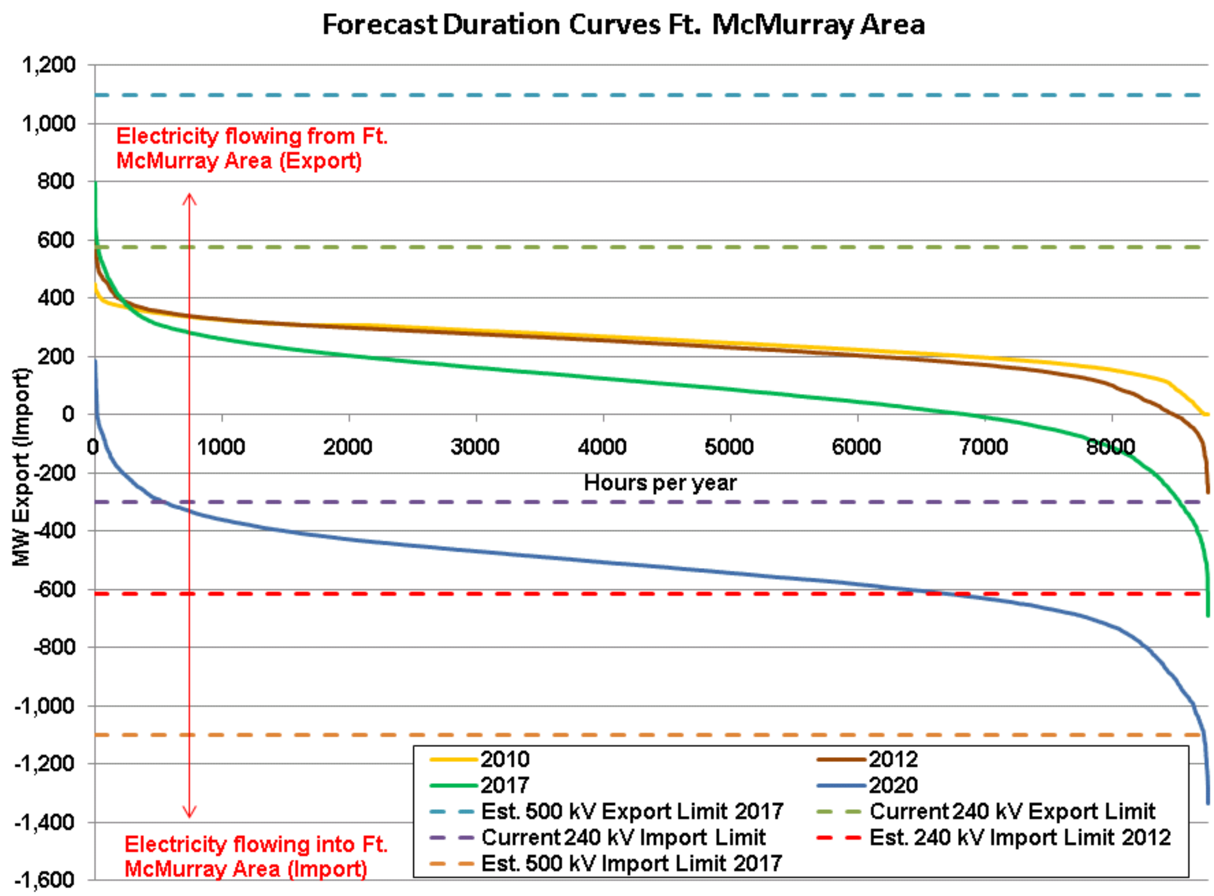


Forecasting into the future, it was assumed that the Fort McMurray firm load shape would not materially change and would grow at 2.0% per year. The oil sands related load and generation additions were derived from 2010 hourly flow data and the 2011 survey results with the following additional assumptions:

- 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 2011 survey, Medium Range
- 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 2012 (reactive power capability added), 2017 (1st 500 kV line added) and 2020 are shown below, with the 2010 data from Figure 21 shown for comparison purposes.

Figure 24 Forecast Flow Duration Curves for Fort McMurray Area



Unlike the current situation where transmission capacity is potentially limiting exports, the analysis suggests that by 2012 the key transmission limitation may be insufficient transmission capacity for electricity flowing into the Fort McMurray area (import). In 2012, the forecast is that the maximum import will be 265 MW, close to the current 300 MW import limit (brown line approaching the dotted red line). This is a direct result of oil sands developers forecasting that they do not intend 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. Under the AESO's policies, if imports are greater than the predefined transfer limits then oil sands projects may be required to involuntarily curtail load, potentially leading to reduced bitumen production.

Comparing the 2010 data (gold line) to the 2020 forecast (blue line), it is anticipated that imports into the Fort McMurray area will increase from about 0% of the time in 2010 to almost 100% in 2020.

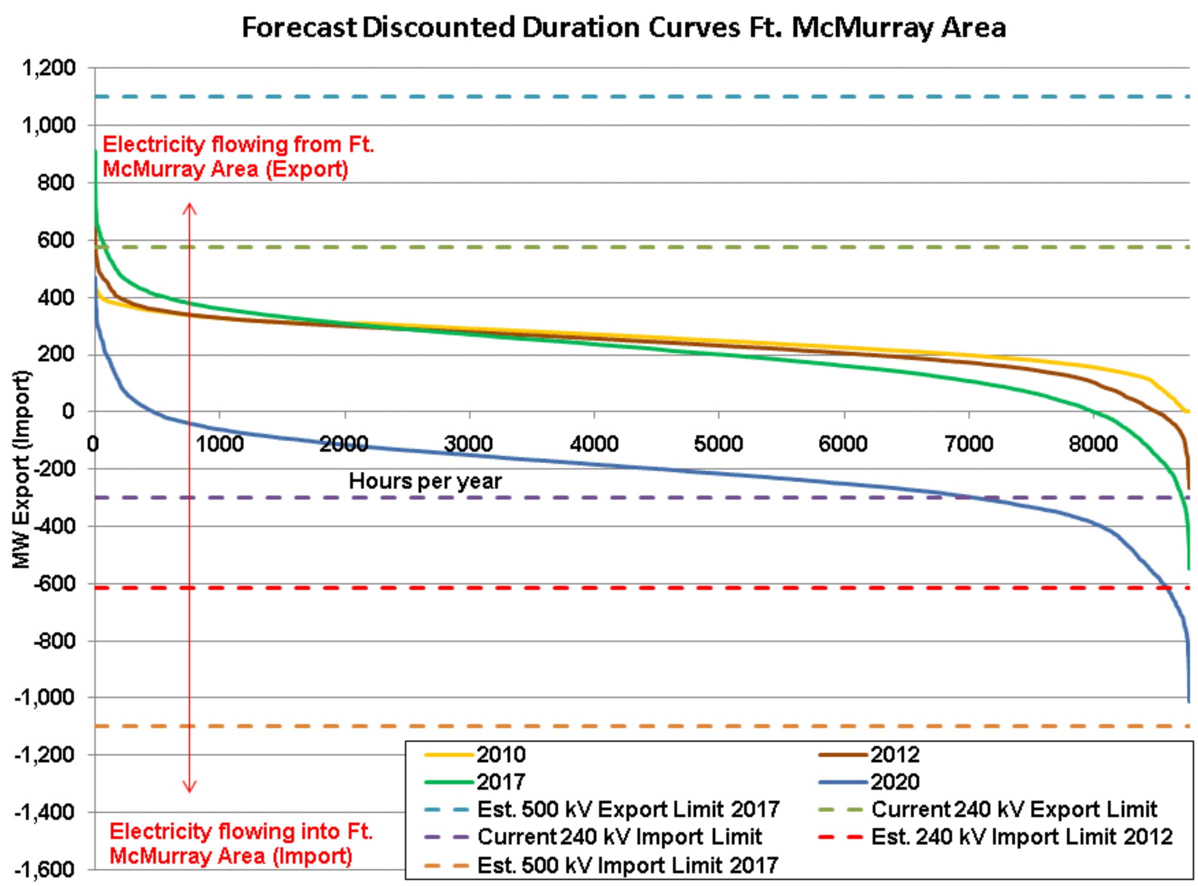
By 2012 the analysis suggests that there will be sufficient 240 kV transmission capacity for imports into the Fort McMurray. The addition of the reactive power capability will provide a significant buffer when the import limit is increased from the current 300 MW to the planned 614 MW.

The analysis does suggest that by 2012 the current 575 MW export limit could be reached about four hours per year. If this were to occur, under the AESO's policies generation could be required to ramp down. Presumably this level of generation output would include significant Merchant Net Exports which should not lead to reduced bitumen production.

For the 2017 forecast, imports are greater than the 614 MW limit only a few hours per year. With the 1st 500 kV line in place and the 1,100 MW import limit in place there will be ample transmission capacity. By 2020; however, forecast load additions in the Fort McMurray area (almost 2,100 MW by 2020, Medium Range) are much higher than generation additions (almost 1,200 MW by 2020, Medium Range). From 2017 to 2020, forecast load additions are almost 800 MW, whereas generation additions are only 70 MW. This leads to a 2020 forecast duration curve that suggests additional import capability will be required into the Fort McMurray area beyond that provided by the 1st 500 kV line for about 30 hours per year (0.3% of the time). With the addition of a 2nd 500 kV line proposed for 2019 additional transfer capacity is proposed; however, if one of the two 500 kV lines are out of service load customers could be curtailed.

Figure 24 assumes that all oil sands projects will proceed as reported in the 2011 survey. If the projects are discounted (as noted in section 3.1) the forecast load durations curves show a lower level of imports in 2017 and 2020 (Figure 25).

Figure 25 Forecast Discounted Load Duration Curves for Fort McMurray Area



For the 2012 discounted forecast duration curve, imports do not exceed the current 300 MW import limit. The import limit increase to 614 MW appears to be required in the 2012 to 2013 timeframe, consistent with the AESO's current plan to implement in Q1 2012.

With the 1st 500 kV line in place, the 2017 and 2020 discounted forecast duration curves are always above the estimated 500 kV line import capacity of 1,100 MW. This suggests that the first 500 kV line will be required by 2017 or 2018, consistent with the AESO's current plans.