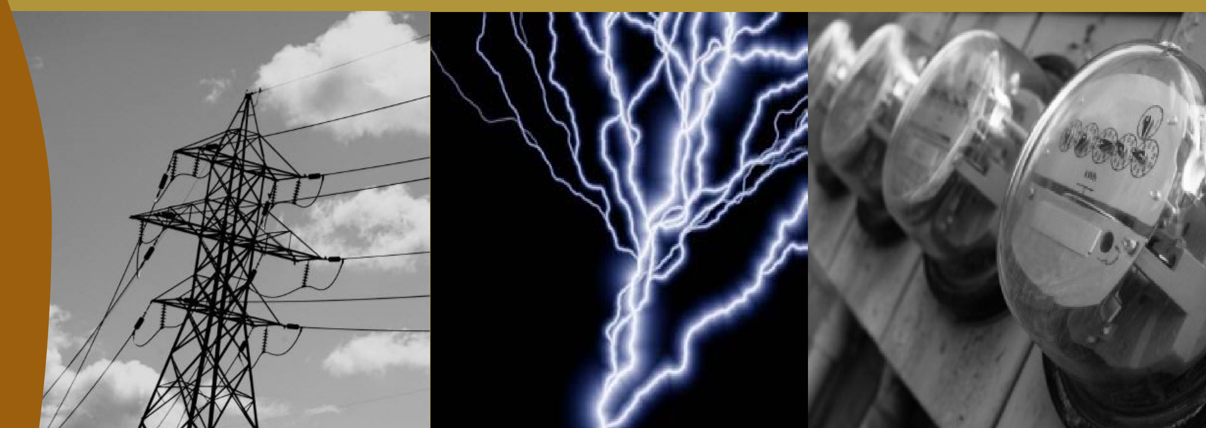
2013 Oil Sands

Co-generation and Connection Report

Issued July 2013



Prepared for the OSDG by Desiderata Energy Consulting Inc.

desiderata ENERGY CONSULTING INC

THE OIL SANDS DEVELOPERS GROUP

Energy From Athabasca

Executive Summary

Since 1999, the Oil Sands Developers Group (OSDG) has facilitated an annual Oil Sands Co-generation and Connection Survey to assess the existing and future electricity demand requirements and on-site co-generation potential of the oil sands industry in Alberta. Oil sands production and extraction are electric intensive processes and require forward looking analysis to ensure sufficient electricity supply and transmission capacity are available.

The survey results were compiled from 25 oil sands companies, reporting on 136 oil sands projects, of which, 54 projects have or plan to develop on-site co-generation. Mining projects amounted to 15% of all projects reported while the remaining 85% comprise some form of in-situ development. Oil sands developers provided feedback on projects in the three oil sands regions in Alberta, Peace River, Athabasca, and Cold Lake, with the majority of existing and planned projects located in the Athabasca region. Participation in the survey was consistent with the previous year's study.

Developers were asked to provide feedback on the influential factors impacting the decision to build on-site co-generation. Of the 16 influential factors identified, respondents indicated <u>delivered price of power versus cost of generating</u> was the most influential variable impacting the decision to build on-site co-generation. This was followed by <u>reliability of power from the grid</u> and <u>balance of load and co-generation</u>.

The delivered price of power reflects both electricity commodity prices as well as wires tariff charges; both of which are expected to increase over the forecast period. At the time of writing, the Alberta Electric System Operator (AESO) was preparing the 2014 tariff, which will include further increases in transmission charges over the next ten years. The prevalence of transmission related influential factors amongst those ranked with "high importance" provides an indication of how vital reasonable, reliable, and timely access to the provincial transmission grid is for oil sands developers.

While some factors influencing the decision to develop on-site co-generation are outside the direct control of policy makers, others can be influenced to a greater extent. The following outlines some factors policy makers could influence, potentially assisting on-site co-generation decision making:

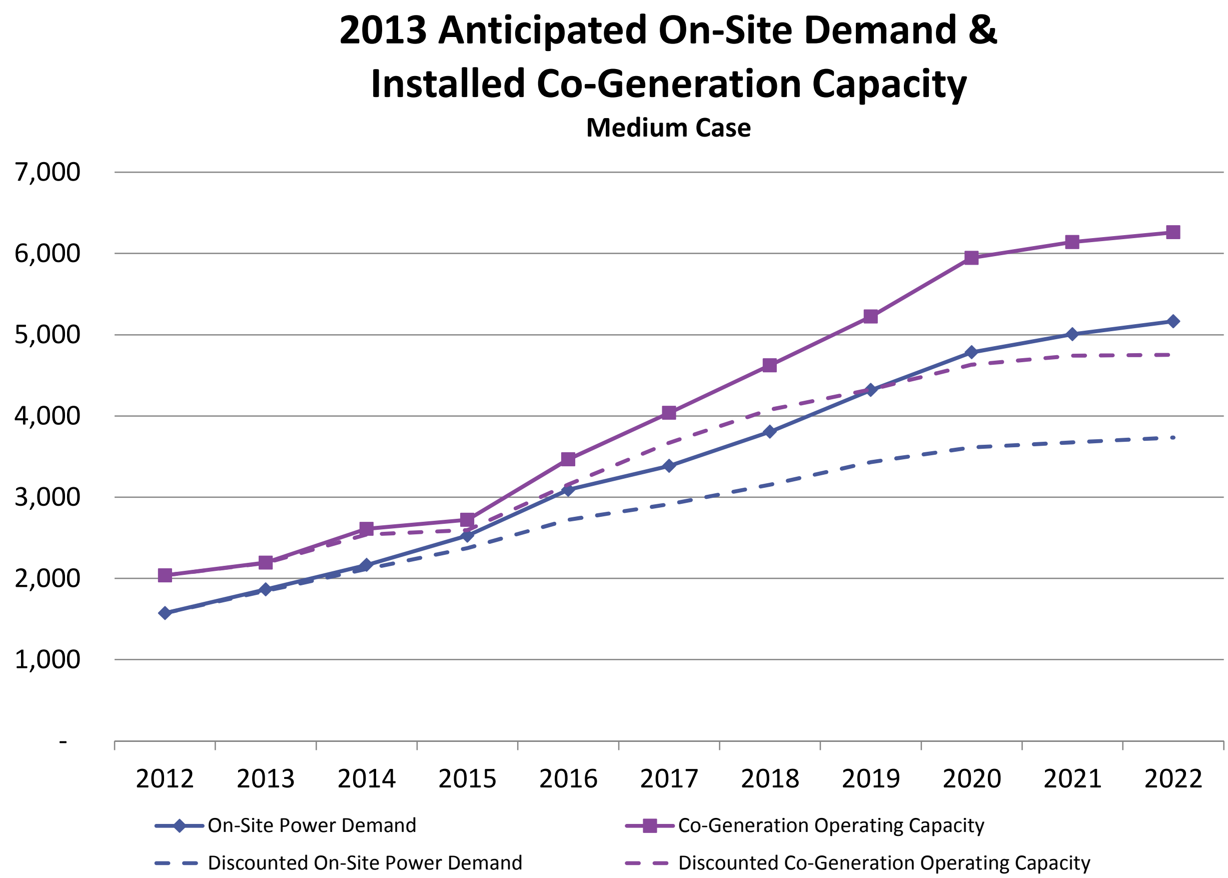
- Reduce security of supply risk, reliability risk, and improve transmission access by ensuring additional transmission capacity (i.e. 500 kV lines under the AESO's competitive procurement process) to/from the Athabasca, Cold Lake and Peace River oil sands areas is developed in advance of industry requirements.
- Continue to provide greater transparency on the cost of new critical transmission development projects and the potential tariff impacts on oil sands projects both with and without on-site cogeneration.
- Reduce environmental risks by providing clarity on future greenhouse gas emissions compliance obligations, credit allowances, and emissions policy.
- Reduce development timelines with a more streamlined AESO connection and Alberta Utilities Commission (AUC) approval processes and make changes to Section 101 of the *Electric Utilities Act (EUA)*, to remove the requirement that transmission connected projects need approval from the local distribution company.
- Encourage the use of Industrial System Designations (ISDs) and the development of efficient and economic industrial systems for oil sands operations.

- Continue to provide a consistent set of market parameters and operating policies, providing clarity and confidence that the current electric market design will not be modified, allowing oil sands developers to make 20+ year investment decisions with greater certainty.

The environmental and economic benefits associated with on-site co-generation are significant and quantifiable. Government policies should be formulated to support development of co-generation with oil sands projects.

Similar to survey results from the past four years, the majority of respondents plan to use both on-site co-generation and purchased power from the grid to meet their power needs. Figure 1 illustrates the Medium Range on-site demand and on-site co-generation survey results (all oil sands regions) along with the corresponding discounted or adjusted forecasts.

Figure 1 – Anticipated On-Site Demand & Installed Co-Generation Forecast (Medium Range)



In the very near term, on-site demand will increase from around 1,800 MW in 2013 to over 2,500 MW in 2015, averaging around 340 MW of load additions each year. Increased on-site demand can be the result of new projects coming on-line, increases or ramping up of existing projects, and development of additional phases or streams. The largest increase in demand growth over the forecast period occurs in 2016, registering a 22% increase in anticipated on-site demand over 2015. Of this increase, around 40% is associated with eight new projects or phases scheduled to come on-line that year and the remaining 60% the result of ramping up of existing operations. Following 2016, anticipated on-site demand grows at an average of 9% per year.

The discounted anticipated on-site demand forecast is also shown in Figure 1. With discounting, on-site demand has a considerably lower annual growth rate, averaging 9% in the Medium Range over the forecast period. The average discount factor applied to oil sands projects was 59% with almost half of the projects receiving a discount factor of 25% or less (i.e. projects announced or in conceptual stages).

Relative to last year's report, the 2013 forecast of anticipated on-site demand is in line with previous expectations in the very near term. Starting in 2016, the 2013 survey results begin to fall below the 2012 survey, continuing to grow at a lower rate over the remainder of the forecast period. This result is primarily due to the removal of two, electric intensive projects from the forecast. These two projects account for over half of the decrease in anticipated on-site demand relative to the previous study; had these two projects remained in the forecast, there would have been a net increase in demand expectations year-over-year.

In 2012, on-site co-generation capacity amounts to just over 2,000 MW, accounting for roughly 14% of total installed generation capacity in the province. On-site co-generation supply is forecast to increase to almost 2,200 MW in 2013, with the installation of a few generators at new or existing oil sands projects. By 2022, on-site co-generation supply is forecast to amount to over 6,200 MW in the Medium Range. The forecast of on-site co-generation has an average growth rate of 12% per year, with the largest increase occurring in 2016; in line with on-site demand growth expectations. In the near term (2013 to 2015), on-site co-generation records an average growth rate of 10%, increasing to 13% over the remainder of the forecast period.

Consistent with demand, discounts were applied based on current status of the project with the heaviest discount applied to those projects in the earlier stages. Discounted on-site co-generation is expected to amount to over 4,700 MW by 2022 (Medium Range), recording an average growth rate of 9% over the forecast period. An average discount factor of 61% was applied, with under half the projects receiving a discount factor of 25% or less.

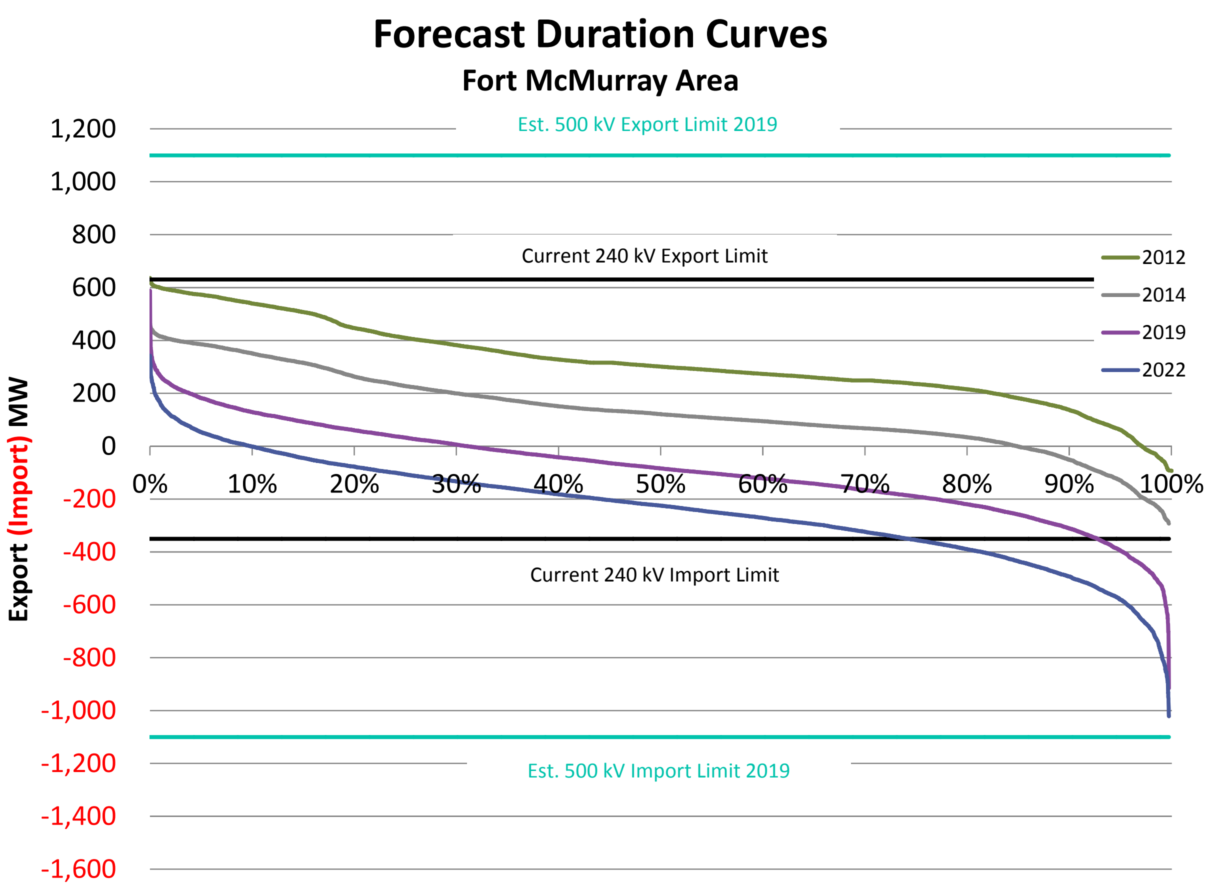
Compared with the 2012 report, the near term results are relatively consistent. This is to be expected as those projects in the near term are likely already under construction or in an advanced stage of planning. Starting around 2017, the 2013 survey results show growth at a stronger rate than 2012, with around 15% (or 800 MW) more co-generation capacity scheduled to come on-line by 2021. New co-generation projects planned for the forecast period are being developed by both existing, established oil sands producers and new entrants. Very few projects recorded lower on-site co-generation capacities year-over-year with most differences assumed to be the result of delay or revisions to existing estimates.

As to be expected, a decrease in on-site power demand and an increase in on-site co-generation capacity results in an overall net increase in the amount of capacity <u>available</u> for export to the provincial grid from the oil sands regions. The supply/demand balance in each of the three oil sands regions will dictate net power flows to the provincial grid. Significant amounts of excess electricity can be produced when on-site co-generation is sized to meet steam loads (i.e. larger gas turbines and HRSG configurations) versus when on-site generation is sized to meet anticipated demand with standalone steam generators installed to produce additional steam (over and above what a smaller co-generation configuration could produce). Of the 136 projects included in the 2013 survey results, 34 indicated varying amounts of excess electricity for export. Excess capacities ranged from as low as a couple megawatts to as high as a stand-alone natural gas-fired generator. It is anticipated each oil sands region (Peace, Athabasca, and Cold Lake) will transition from periods of excess generation supplies (i.e. net exports to the provincial grid) to period of increased demand (i.e. net imports from the provincial grid over time).

There was a significant increase in anticipated surplus generation in the 2013 survey. For the most part, this increase is associated with three oil sands developers with hundreds of megawatts of on-site excess co-generation capacity each. Together these three producers account for almost 65% of the year-over-year change by the end of the forecast period. Anticipated surplus generation begins to show rapid growth during the second half of the forecast, a period which includes many projects in earlier stages of development.

An estimate of hourly flows into and out of the Athabasca/Fort McMurray region only, was calculated based on historical duration curves and the 2013 survey forecasts for on-site demand and co-generation in the region. The results of the analysis are shown in Figure 2 for the years 2014, 2019 (after the first stage of the 500 kV line is scheduled for completion) and 2022. This figure illustrates the results of the unadjusted on-site demand and co-generation values.

Figure 2 – Forecast Power Flow Duration Curves for Fort McMurray Area



The analysis suggests the current 240 kV line limits are sufficient to meet export and import needs in the near future. Actual export volumes in 2012 were above the N-1 export line limit shown in Figure 2, a circumstance that can occur in a few hours but would not be a preferred operating condition. Over time, as power flows in and out of the Athabasca/Fort McMurray region increase and become more exaggerated, the results indicate import capacity of the existing transmission system will become insufficient. The Figure suggests this could occur as early as 2014 when import requirements are forecast to approach 300 MW. Between 2014 and 2015 the Athabasca/Fort

McMurray region is expected to transition to a net importer and by 2019 and 2022, import requirements into the region are substantial, approaching the planned 500 kV limit (shown by the teal "Est. 500 kV Import Limit, 2019" line).

There are several factors that cause the increase in regional imports, despite the forecast of excess on-site co-generation supply from all three regions. The majority of oil sands developers plan some form of on-site generation with support from the Alberta transmission grid serving a portion of on-site demand. Multi-phase projects, generation maintenance, and on-site operating conditions can also influence electricity flows creating periods of energy imbalance. The majority of the increase in imports is associated with firm load growth from the Urban Service Area of Fort McMurray, which is anticipated to average 8% electricity demand growth over the forecast period. This load will effectively be served from excess on-site co-generation supply within the Athabasca/Fort McMurray area.

Consistent with previous years, the Athabasca/Fort McMurray region will transition from a net exporter of electricity to a net importer. Imports are forecast to occur 15% of the time in 2014, up from 3% in 2012 and 7% in 2011, increasing to 70% of the time by 2019 and 90% by 2022. Additional co-generation development, above that shown in this study, could eliminate and reverse the power flows forecast.

In the case of the discounted or adjusted demand and supply forecast, while the magnitude of exports and imports is lower than the unadjusted case, the end result is consistent. The existing 240 kV line limits will be insufficient to serve power flows and the Athabasca/Fort McMurray area will transition to become a net importer, expected sometime between 2015 and 2016. Under both the discounted and undiscounted results, continued improvements to the existing transmission infrastructure will support increased power flows; however, the 500 kV lines to Fort McMurray will be required by the end of the decade.

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Introduction

Co-generation in the oil sands is the simultaneous generation of electricity and useful heat, either steam or hot water. Co-generation applications include the use of a gas turbine to drive an electric generator. The exhaust heat from the gas turbine is captured in a boiler or Heat Recovery Steam Generator (HRSG) to produce steam for injection in in-situ operations or process heat for oil sands mining operations. Co-generation is more efficient at producing electricity and steam or hot water when compared with other technologies (e.g. coal or natural gas fired facilities) and standalone boilers.

Co-generation has been employed by the oil sands industry to assist with the production of bitumen since the mid 1970's. Over the past 40+ years, co-generation capacity has grown as more projects come on-line and seek self-sufficiency, improved electric reliability, and optimization of on-site steam and electricity needs. Despite the efficiencies and other benefits associated with co-generation, not all oil sands operators elect to install co-generation as part of their oil sands facilitates.

The Oil Sands Developers Group (OSDG) began tracking and forecasting the growth in co-generation in 1999, with the objective of providing information to operators, the AESO, and Alberta government policy makers on issues related to co-generation and transmission development. The *2013 Oil Sands Co-Generation & Connection Report* contains the results of the 2013 co-generation survey of companies operating or planning to operate oil sands mines and in-situ operations within the province of Alberta, Canada. The purpose of the study is to determine the current and potential electrical capacity of co-generation plants located within oil sands projects. The OSDG Co-Generation and Power Infrastructure Committee manages the annual survey and issues this report. The Committee looks at assessing and addressing the electricity transmission needs of the oil sands producers and the linkages throughout the province. Each year the committee provides a forecast report on Co-generation and Power Infrastructure. The mandate of the committee is to:

- 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 developers (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 the province by engaging with the OSDG membership and key stakeholders.

If you have any comments on this report please contact:

Dianne Farkouh, Operations Manager
Oil Sands Developers Group (OSDG)
617 – 8600 Franklin Avenue
Fort McMurray, Alberta Canada T9H 4G8
Phone: (780) 790-1976
dianne.farkouh@oilsandsdevelopers.ca
www.OilSandsDevelopers.ca

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Use of Cogeneration Trends

The development of co-generation associated with oil sands operations has gone through several build cycles. The earliest oil sands developers began operations in the late 1960s and involved on-site electricity generation and steam production, typically burning coke to heat boilers and run steam generators. As oil sands operations were developed throughout the 1970s to 1990s various co-generators were brought on-line. In some cases, these units were developed in partnership with electric utilities or independent power producers, eventually leading to some oil sands companies creating internal co-generation divisions. During this period, co-generation was typically sized to meet on-site steam requirements, resulting in excess electric capacity.

The deregulation of the Alberta electricity market was, in part, influenced by the desire for a visible and open system to sell co-generated electricity at a market-established price. The change in trend to develop power generation primarily to satisfy on-site power needs was first noted in the *2005 Co-Generation Report*.

Today, oil sands operators are facing significant increases in operating costs, including transmission tariffs, with some developers concerned that transmission infrastructure may not be developed in a timely manner, leading to renewed interest in on-site co-generation development. However, the high cost of construction in remote oil sands areas, long-term commodity price uncertainty, operational considerations, and other factors have caused some oil sands producers to be reluctant to development co-generation. The current trend seems to be developing and sizing co-generation on a project-by-project basis, with companies making decisions tailored to their development plans.

Methodology

The *2013 Oil Sands Co-Generation & Connection Report* summarizes the results of a survey of oil sands companies conducted during Q1-2013 from all three oil sands regions; Peace River, Athabasca, and Cold Lake. The survey requested actual and forecast values 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 reflect a minimum capital spend, lower oil prices, higher operating costs, and/or poor economic conditions.
- **Medium Range** – project would be built to the most probable or planned scope in a business-as-usual environment.
- **High Range** – project would be built to the maximum anticipated scope. This may relate to a larger capital spend, higher oil prices, lower operating costs, and/or more robust economic conditions.

The survey data was complied, analyzed, and adjusted by Desiderata Energy Consulting Inc. and shared with a representative of the AESO. Participation in this year's study involved 25 oil sands development companies, reporting on 136 oil sands projects (some new projects, expansions or phases of existing or planned installations), of which, 54 projects have developed or are expecting to develop on-site co-generation. The number of respondents and projects in this year's survey results are relatively consistent with 2012, while the number of projects considering the use of co-generation has increased.

The 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. The results included in this report reflect the information shared by participating companies. Not all oil sands developers completed the 2013 survey, hence the information provided in this report is not inclusive of all potential oil sands projects in Alberta.

Presentation of the Data

The results of the 2013 survey are summarized throughout the report in two ways. The first reflects the un-adjusted values of the survey respondents, assuming all projects will proceed at their announced capacity and timing. The second applies a percentage-based adjustment to the survey responses creating a discounted data set. The discount is applied based on the development status of each project, focusing particularly on the regulatory application/approval process. Table 1 illustrates each development stage and its corresponding discount. There is no adjustment made to timing assumptions of planned developments.

Table 1 – Development Stage Discounts

Status	Discount
Cancelled	0%
Conceptual	10%
Announced	25%
Approved	60%
Regulatory	90%
Construction	100%
Operating	100%

The discounted results reflect a more likely outcome as projects in the initial stages of development have been adjusted to incorporate the increased risk of delays or cancellations. As many of the oil sands projects included in the 2013 study are in the earlier stages of development, there is a significant difference between the un-adjusted survey results and the discounted analysis. This difference increases over the forecast period as projects scheduled for the second half of the forecast period tend to be in earlier stages of development and therefore receive heavier discounts. This methodology is consistent with previous reports.

Typically, the Medium Range survey responses are discussed throughout with most figures illustrating the results of all three ranges (Low, Medium and High). Five-year comparisons of survey responses are included for some result areas.

Similar to the 2012 study, oil sands development of carbonate reservoirs containing bitumen have been excluded. While the concept of producing oil from carbonates has existed for many years, the extremely large amounts of electricity required to extract bitumen from these formations, using electric heating technologies has, in part, prevented commercial development. Several companies have expressed an interest in carbonate oil sands projects with estimates of 500 MW to 5,000 MW of on-site generation required. For now, carbonate developments have been excluded from the survey while these projects remain in the early development stages.

The use of electricity for bitumen extraction from carbonate reservoirs would have a significant impact on the Alberta electricity market, as multiple, large on-site natural gas-fired generation developments, most likely combined-cycle, would be required to meet the large downhole electric heating loads. These projects may elect to secure firm transmission supply contracts (AESO Demand Transmission Service or DTS rate) for a portion of their requirements which would likely coincide with some form of transmission upgrades. This study will continue to monitor oil sands carbonate development and ensure future forecasts acknowledge and/or incorporate these potential developments.

Survey Results

Critical Factors Influencing the Decision to Develop Co-Generation

Survey respondents were asked to indicate the level of importance of 16 factors over six categories that could impact their decision to build or not to build co-generation. The "Corporate Policy" category is new to this year's survey, attempting to capture the influence of internal policies on co-generation development. Table 2 lists the 16 factors and provides a brief overview of each factor.

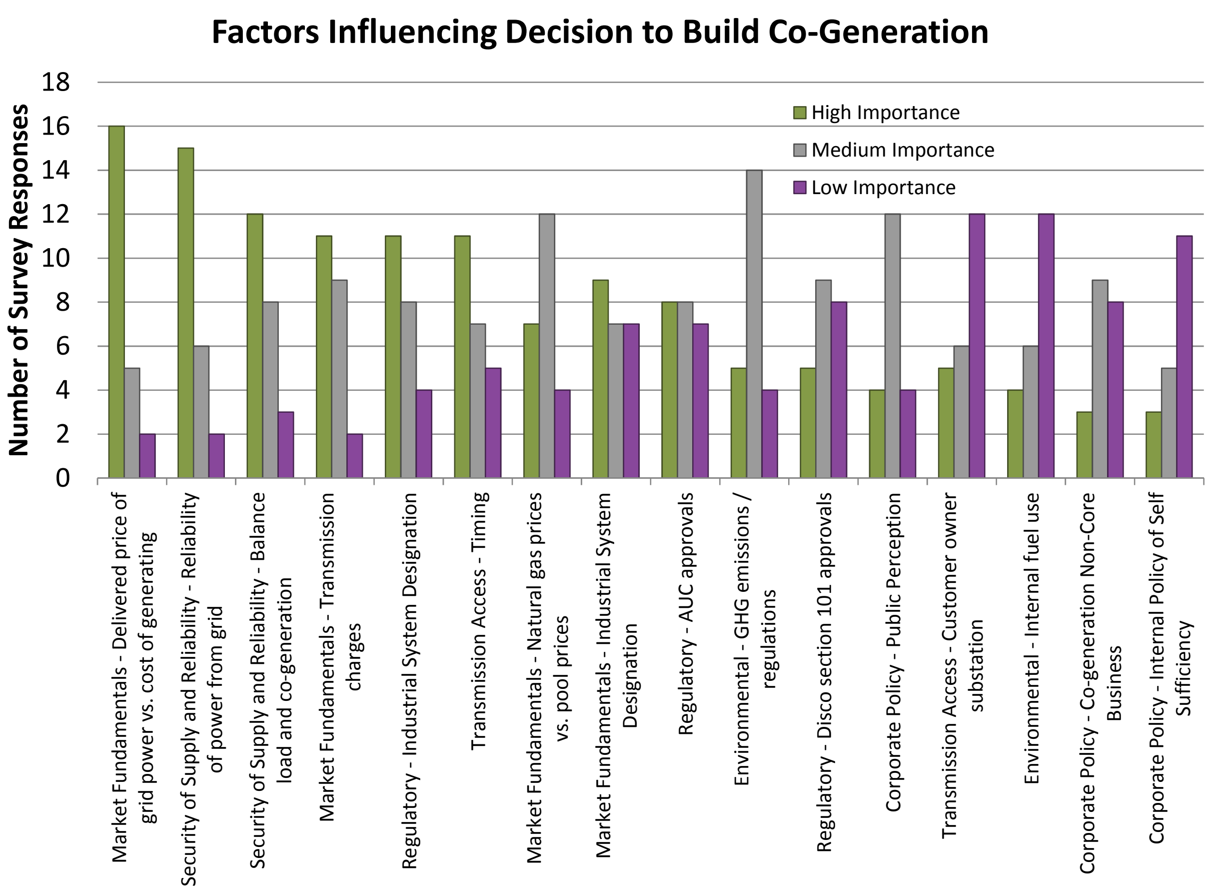
Table 2 – Factors Influencing Co-Generation Development Decisions

Category	Factor	Description
Security of Supply & Reliability	Reliability of power from grid	Transmission system is inadequate to provide the level of "up time" required for oil sands projects.
	Balance load & co-generation	Ability to balance load and generation within oil sands projects, including steam balance considerations.
Environmental	GHG emissions/ regulations	Consideration of GHG cost and regulation compliance (uncertainty and potential positive/ negative impacts).
	Internal fuel use	Ability to provide fuel from the oil sands operations, (e.g. syn-gas fueled or turbine fuel source).
Transmission Access	Timing	Certainty (or uncertainty) to when transmission capacity will be available for oil sands projects.
	Customer owned substation	Ability to design, build, and/ or own the substation and control the development/ construction process.
Market Fundamentals	Delivered price of grid power versus cost of generating power	Cost of electricity from co-generation plus stand-by transmission charges compared to purchasing from third party suppliers plus transmission charges.
	Natural gas prices versus power pool prices	Risks associated with the correlation between natural gas and electricity prices, or system heat rate (positive/ negative).
	Transmission Charges	AESO wires charges for delivery of electricity and/ or stand-by capacity from the grid.
	Industrial System Designation	Potential AESO tariff savings associated with ISD (e.g. net metering).
Regulatory	DISCO Section 101 approvals	Ability (or inability) to obtain approval from the distribution company to become an AESO direct connect customer.

Category	Factor	Description
	Alberta Utilities Commission approvals	Consideration of time and resources required to obtain approvals from the AUC for a co-generation power plant.
	Industrial System Designation	Consideration of time and resources required to obtain approvals from the AUC for an ISD.
Corporate Policy	Co-generation non-core business	Ability (or inability) in co-generation or utility development.
	Internal policy of self sufficiency	Corporate policy to control/ manage/ generate electric energy supply.
	Public perception	Public and/or environmental implications of co-generation or other electric energy supplies.

The following chart (Figure 3) illustrates the survey results, sorted by on a hierarchical value assigned to each level of importance. This methodology prevents ranking of importance based purely on those factors with the most number of "high importance" responses and can allow for instances with a number of "medium importance" responses to have a higher overall ranking.

Figure 3 – Factors Influencing Decision to Build Co-Generation

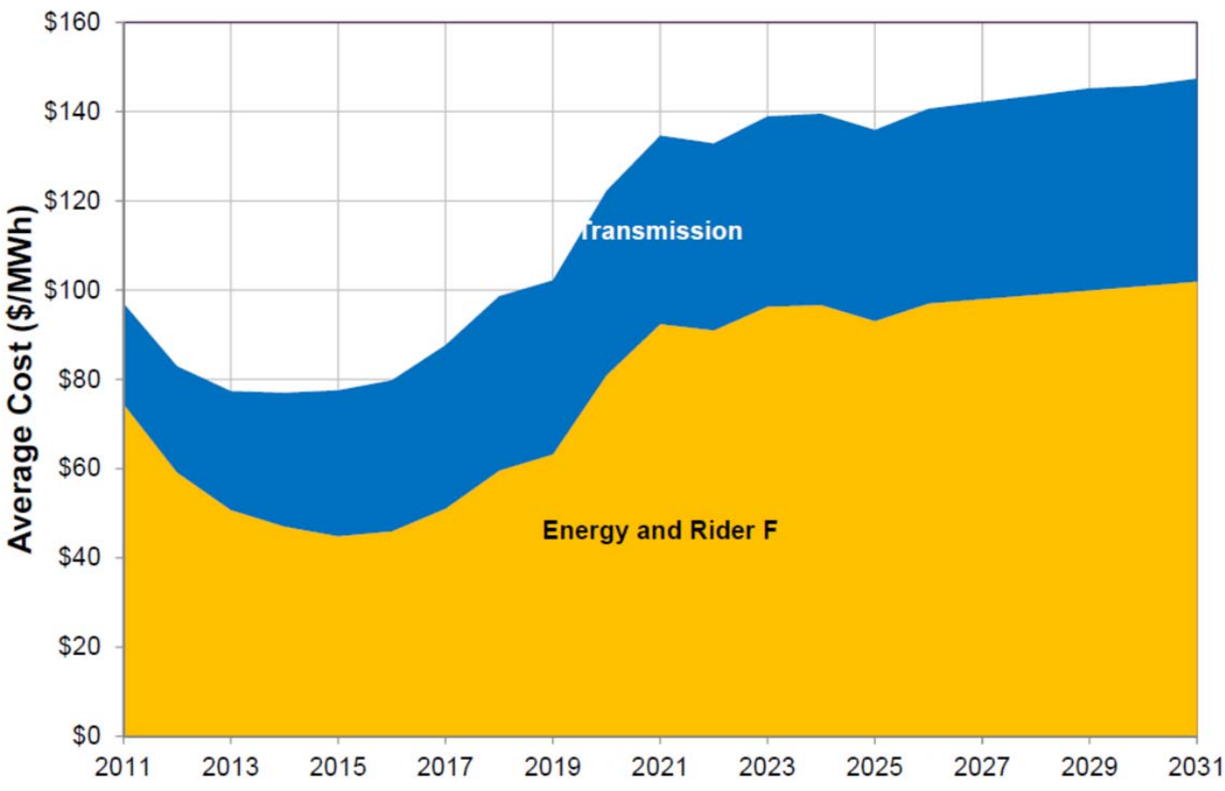


For the second consecutive year, 2013 survey respondents have identified delivered price of power versus cost of generating on-site as the most important factor influencing the decision to build on-site generation, with 16 of 24 oil sands companies responding to this section of the survey indicating this factor was of high importance.

The delivered price of power reflects both electricity commodity prices as well as wires tariff charges; both of which are expected to increase over the forecast period. Over the past five years (2008-2012), Alberta's annual power prices have ranged between $48/MWh (2009) and $90/MWh (2008). It is anticipated annual average power prices will, in general, increase as the supply demand balance in the Alberta electricity market evolves. Over the same time period (2008 – 2012), average transmission tariff costs have doubled to about $20/MWh and are anticipated to double again by 2018.

At the time of writing, the AESO was preparing the 2014 tariff, which will include significant additional increases in transmission charges over the next ten years. The increase in transmission tariffs impacts direct connect and distribution customers and is the result of large infrastructure builds/upgrades on both the bulk (500 kV & 240 kV) and local (144 kV & 138 kV) transmission systems. Figure 4 shows an estimate of future delivered power price based on models prepared for the AESO's 2014 tariff filing.

Figure 4 – Average Delivered Costs of Electricity ($/MWh)[1]



[1] Source: AESO. 2014 Tariff Consultation – Information Session Slides. 24 May 2013. Slide 31. Commodity price source EDC Associates, escalated after 2027 by average annual growth rate (2021 to 2027).

At the most basic level, if on-site co-generation can be developed and operated for a lower $/MWh rate than the delivered price of power, there would be an economic incentive to build co-generation, all other things being equal. In reality, the decision to build on-site generation is a combination of many influential factors with the delivered price of power being one aspect of the decision.

Survey respondents again listed reliability of power from the grid as the second most influential factor in the decision to develop on-site co-generation. The third most influential factor was balance of load and co-generation; up one position from last year's results. The loss of power or steam supply could result in a significant cost in terms of lost bitumen production, potentially encouraging the development of on-site redundancy.

Transmission charges moved up three ranks to the fourth most influential factor. As previously mentioned, this response is likely the result of forecast increases in wires tariff charges proposed in the AESO's 2014 tariff. Avoiding a portion of these tariff charges through the development of on-site co-generation, with an ISD, can amount to significant savings for oil sands developers. Transmission access – timing also moved up three ranks, to the sixth most influential factor. The prevalence of transmission related influential factors amongst those ranked with "high importance" should provide an indication of how important access to the provincial transmission grid is for oil sands developers.

The "Corporate Policy" category, new to this year's survey, had all three factors ranked near the lower level of influence, with public perception being the fifth lowest influential factor. All of the factors were deemed to be of high importance to some of the survey respondents, with at least three participants listing internal policy of self-sufficiency (the lowest ranked factor) of high importance when making the decision to develop co-generation.

Some of the factors within each category are outside the direct control of policy makers, such as wholesale natural gas and electricity prices, whereas other factors, like increased transmission costs, via legislative requirements in the *EUA* and emissions compliance policy can be influenced to a greater extent. The following list outlines some factors that policy makers could influence, potentially assisting on-site co-generation decision making:

- Reduce security of supply risk, reliability risk, and improve transmission access by ensuring additional transmission capacity (i.e. 500 kV lines under the AESO's competitive procurement process) to/from the Fort McMurray, Cold Lake and Peace River oil sands areas is developed in advance of industry requirements.
- Continue to provide greater transparency on the cost of new critical transmission development projects and the potential tariff impacts on oil sands projects both with and without on-site cogeneration.
- Reduce environmental risks by providing clarity on future greenhouse gas emissions compliance obligations, credit allowances, and emissions policy.
- Reduce development timelines with a more streamlined AESO connection and AUC approval processes and make changes to Section 101 of the *EUA*, to remove the requirement that transmission connected projects need approval from the local distribution companies.
- Encourage the use of ISDs and the development of efficient and economic industrial systems for oil sands operations.
- Continue to provide a consistent set of market parameters and operating policies, providing clarity and confidence that the current electric market design will not be modified, allowing oil sands developers to make 20+ year investment decisions with greater certainty.

Regulatory Approvals

Consistent with previous studies, survey respondents were asked to provide insight into their plans for two specific regulatory aspects of co-generation development; *EUA* Section 101 approval and Industrial System Designations. Figure 3 identified these two regulatory aspects of being of some importance when developing on-site co-generation, with nine respondents indicating ISDs were of high importance and 5 indicating Section 101 approval was of high importance. The relative position of these factors is unchanged from the previous study.

Section 101 of the *EUA* states oil sands developers must arrange for distribution service from the distribution system owner in the area (ATCO Electric and FortisAlberta are the distribution owners in the oil sands areas). If the facility wishes to receive service directly from the transmission system, approval from the distribution system owner and the AESO must be obtained.

An ISD is approved by the AUC for integrated industrial operations, where the development of on-site generation is integrated with on-site processes and is an economic and efficient option. ISDs are not intended to create an independent electric market or duplicate the transmission and distribution system. Acquiring an ISD is an important aspect of early regulatory approvals and delays in ISD approvals can impact project development timing and overall project economics. When assessing a project for Section 101 approval, it is generally preferred that a site have an ISD order from the AUC, and so these two regulatory aspects go, somewhat, hand-in-hand. Failure to obtain Section 101 approval and an ISD can have a detrimental impact on co-generation development.

Developers were asked to indicate if they have a Section 101 approval, have filed for Section 101 approval, or plan to file for approval. Of the 54 projects with plans for co-generation, 25 projects provided a response to this question, summarized in Table 3.

Table 3 – *EUA* Section 101

Stage	*EUA* Section 101 Projects	
Planned	9	36%
Filed	3	12%
Approved	13	52%
Total	**25**	

The majority of respondents indicated Section 101 approval had been received with three applications ongoing and the remainder planning to seek approval. This breakdown is relatively consistent with the 2012 study. For those projects scheduled to come on-line in the latter years of the forecast period, it is likely that a Section 101 approval has yet to be considered in great detail. Developers seeking ISD approval will likely also apply for a Section 101 approval.

Table 4 provides the status of any planned ISD applications. Developers were asked to indicate if they have an approved ISD, filed an ISD application, or plan to apply. Of the 54 projects with existing or planned on-site co-generation capacity, 42 provided a response to this question.

Table 4 – Industrial System Designations

Industrial System Designations		
Stage	**Projects**	
Planned	24	57%
Filed	1	2%
Approved	17	40%
Total	**42**	

The majority of oil sands developers intend to seek an ISD, implying that there are economic and efficiency benefits to this regulatory aspect. Both tables above include only the information provided by respondents only and thus does not include a full sample of those considering co-generation. In addition, these statistics may be skewed by projects being reported in phases. In most instances, all sources of demand and supply on a project site, which could include more than one phase of development, could be part of a single ISD.

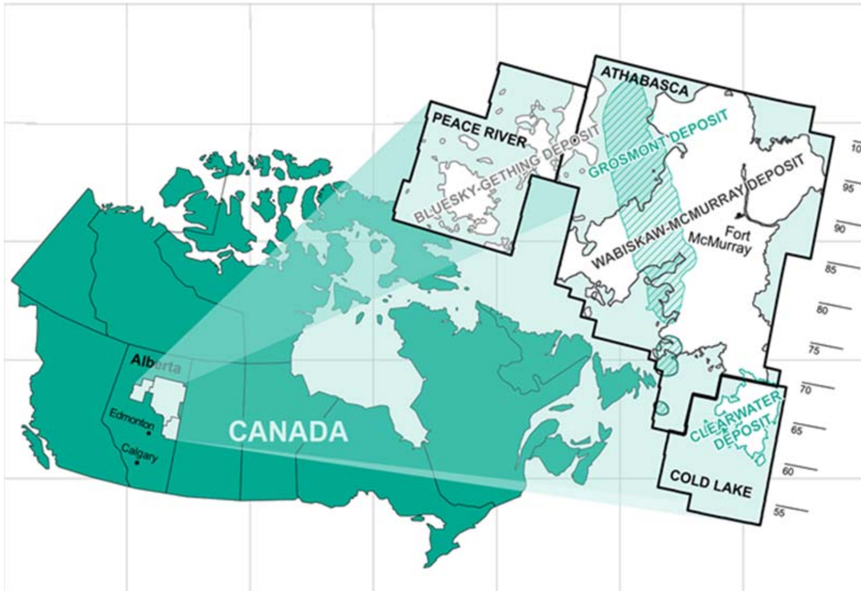
Detailed Survey Results

The following section presents the results for each question of the 2013 survey. The results were compiled from 25 oil sands companies reporting on 136 oil sands projects (some multi-stage/phase), of which, 54 projects have developed or are expecting to develop on-site co-generation. 15% of the projects reported were identified as mining projects with the remaining 85% a form of in-situ development (based on total number of projects, including staged developments). While oil sands mines may represent a smaller number of projects, they are typically larger than in-situ projects, both in terms of on-site power demand and production (bbl/d). Some oil sands projects are multi-phase developments, adding demand and potentially on-site co-generation through a staged approach. The impact of multi-phase developments can be seen throughout the forecast. Oil sands developers provided feedback on projects in the three oil sands regions in Alberta, Peace River, Athabasca, and Cold Lake, with the majority of existing and planned projects located in the Athabasca region. While the number of survey participants and projects is consistent with the 2012 study, there has been an increase in the number of co-generators scheduled to come on-line over the forecast period.

Question: Your project is located in the following region:

There are three oil sands deposit regions in Alberta; Peace River, Athabasca, and Cold Lake (shown in Figure 5). The Athabasca region contains both heritage and new mining and in-situ developments. This region is the largest and most action. For the purposes of this study, the Athabasca region has been further divided into three areas; North of Fort McMurray and East of the Athabasca River, North of Fort McMurray and West of the Athabasca River, and South of Fort McMurray. The Cold Lake region is found to the southeast of the Athabasca region while the Peace River region is located to the west. The Cold Lake and Peace River areas have a tendency towards in-situ operations. The Wabasca and Red Earth/Other regions contain those few outliers not located in the traditional three oil sands areas.

Figure 5 – Alberta's Oil Sands Regions[2]



The results of this question assist the AESO in planning for future transmission growth by identifying the location and number of existing and forecast co-generation units and the anticipated co-generation operating capacity in each region. Values shown in the table below reflect un-adjusted Medium Range survey results and are consistent with the results shown in Figure 9.

Table 5 – Location, Number & Operating Capacity of Co-Generation Projects

Project Location	No. of Projects with Co-Gen		Operating Capacity (MW)	
	2012	2022	2012	2022
Athabasca Region -				
South of Fort McMurray	3	14	278	1,186
North of Fort McMurray and East of the Athabasca River	3	10	954	2,009
North of Fort McMurray and West of the Athabasca River	3	20	485	1,584
Wabasca Area	-	-	-	-
Cold Lake	3	5	317	647
Peace River	1	2	3	700
Red Earth / Other	-	3	-	135
Total	**13**	**54**	**2,037**	**6,261**

As can be seen from Table 5, the majority of projects are located in the Athabasca region, followed by the Cold Lake area. Survey respondents indicated there were 13 projects with co-generation operating in the province in 2012 with one new project in the Peace River area. Operating capacity in 2012 is estimated at 2,037 MW; an increase of 198 MW year-over-year, the result of increased co-generation capacity at new and existing oil sands developments. By 2022, the number of projects

[2] Source: Energy Resources Conservation Board (ERCB). ST98-2013: Alberta's Energy Reserves 2012 and Supply/Demand Outlook 2013-2022. May 2013.

with on-site co-generation is expected to quadruple, with over 6,200 MW of operating capacity from 54 projects.

Relative to the 2012 study, there was a 17% (or 8 project) increase in the number of co-generation projects expected to come on-line over the forecast period. Both new and existing oil sands developers have added planned co-generation to the forecast, implying installation of on-site generation is not limited to larger developers/projects.

Question: What is the status of your project as of January 1st, 2013?

The purpose of this question is to gather information on the development status of the various co-generation units. There is a significant difference between a conceptual project and steel in the ground. The status of each co-generator provides insight into both the timing and probability of the project coming on-line. Table 6 lists the operating capacity for the Medium Range and the number of co-generation units in 2022.

Table 6 – Co-Generation Status, Operating Capacity, & Number of Units (Medium Range, 2022)

Status	Operating Capacity (MW)	No. Co-Gen Units
Operating	2,037	29
Under Construction	982	15
Regulatory Approval	926	13
In Approval Stage	1,051	11
Announced	863	23
Conceptual	402	7
Total	**6,261**	**98**

The 2013 survey results imply that over 6,200 MW of co-generation is planned to be operating by 2022. Currently, these co-generators are in various stages of development from conceptual projects to existing operations. Almost 30% of co-generation units were identified as "Operating" with 15% listed as "Under Construction". Note, the number of co-generation units may reflect more than one co-generator located at a single facility or project. Compared to the 2012 survey results, both installed generation capacity and the number of units are higher by the end of the forecast period.

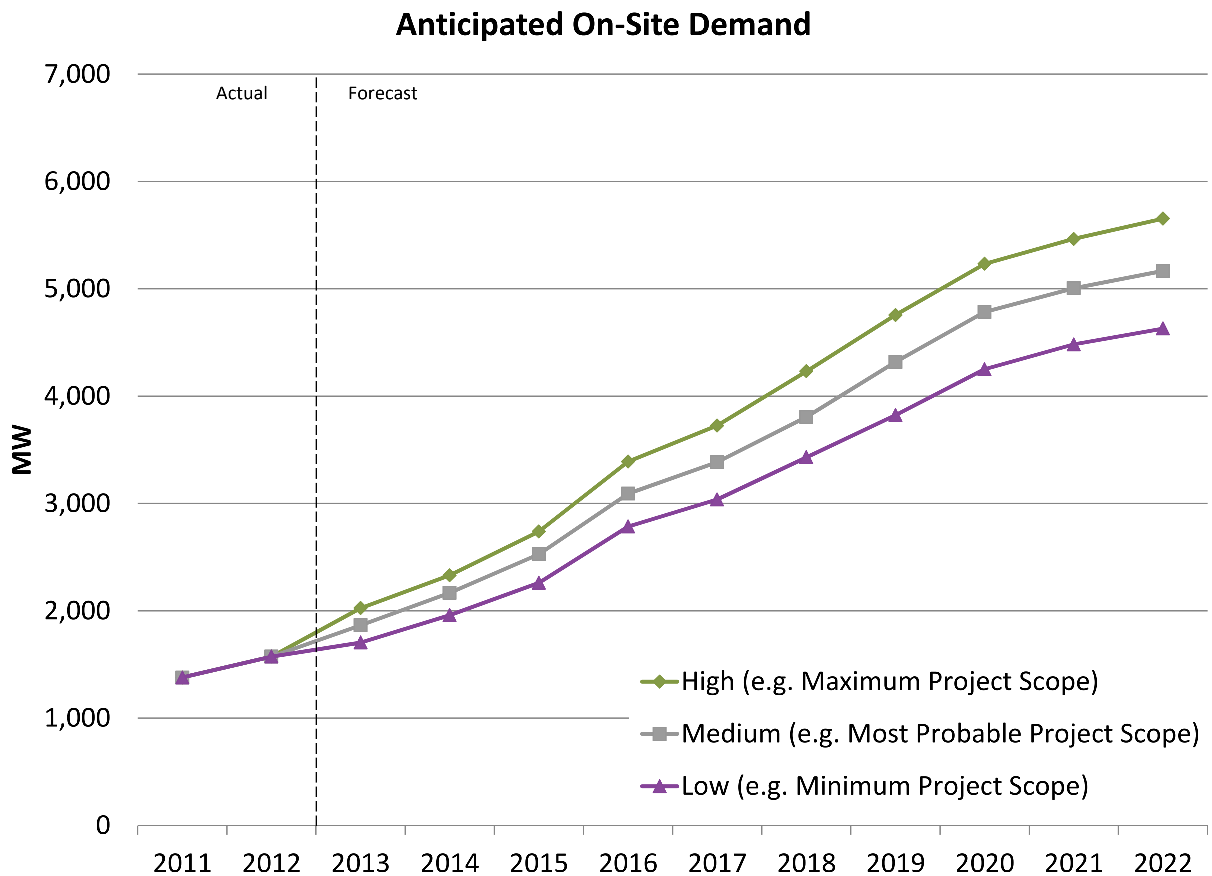
Question: What is the typical range of on-site power demand in MW for each year?

Figure 6 illustrates anticipated on-site demand for developments in all three oil sands regions which is expected to record a 13% growth rate over the forecast period (Medium Range). In the very near term, on-site demand increases from around 1,800 MW in 2013 to over 2,500 MW in 2015, averaging around 340 MW load additions each year. Increased on-site demand can be the result of new projects coming on-line, increases or ramping up of existing projects, and/or development of additional phases or streams.

The largest increase in demand growth over the forecast period occurs in 2016, registering a 22% increase in anticipated on-site demand over 2015. Of this increase, around 40% is associated with the 8 new projects or phases scheduled to come on-line that year. The remaining 60% is the result of ramping up of existing operations. The 2012 study also forecast a high growth rate in 2016. While the growth projected in this year's survey results is slightly lower, 2016 remains a significant year in terms of anticipated on-site demand growth. Following 2016, anticipated on-site demand grows at an average of 9% per year.

The spread between High and Medium Ranges and Medium and Low Ranges is relatively consistent across the forecast period, with Medium Range results tend to be slightly closer the High Range. By 2022, the High Range is 487 MW above the Medium Range forecast while the Low Range is 536 MW below.

Figure 6 – Anticipated On-Site Demand

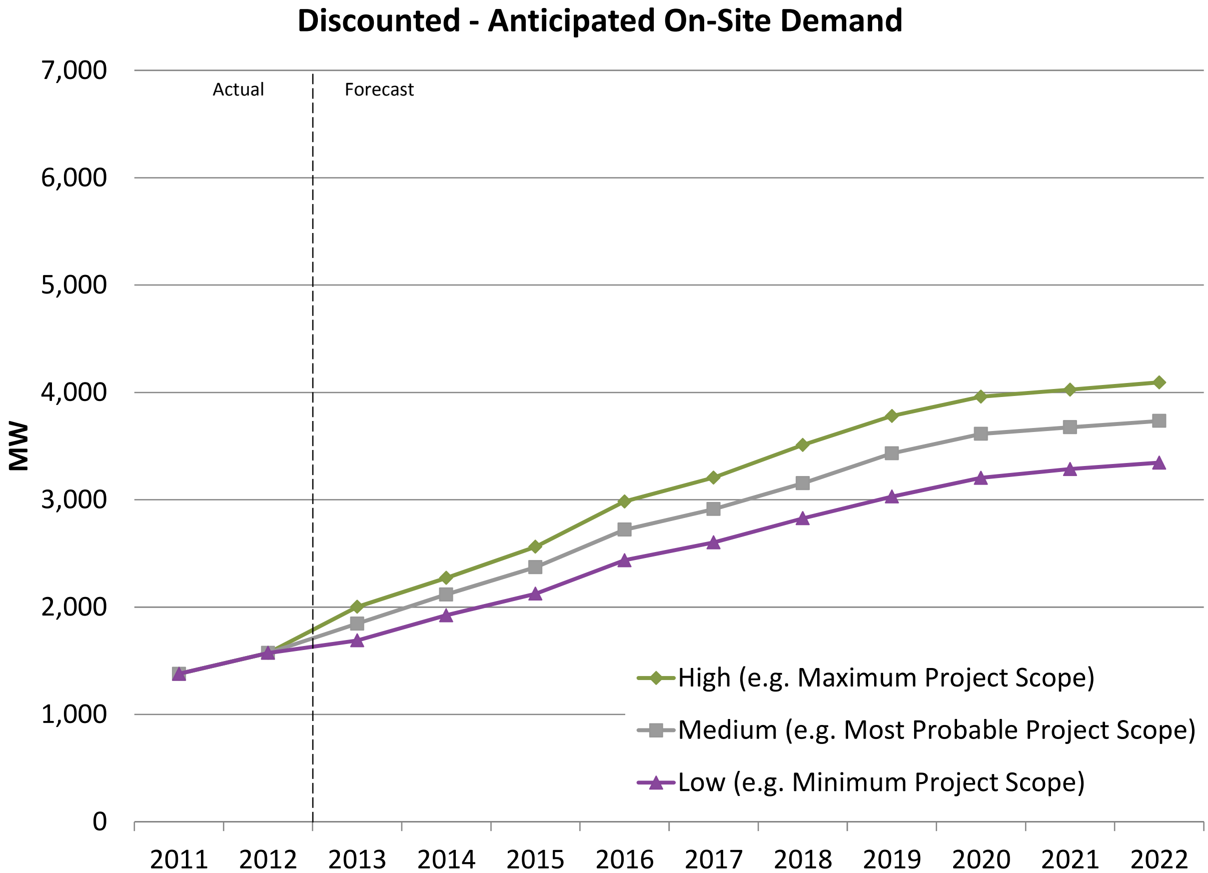


Oil sands developers may choose to consume electricity from the provincial grid, install on-site generation, or some combination of the two to meet on-site electricity requirements or electric demand. Figure 6 illustrates aggregate anticipated on-site demand but does not distinguish between the differing methods of serving this load. In reality, there will be few instances where the majority of developers would be consuming electricity from the grid at their highest anticipated on-site demand capacities at the same time due to differing on-site operations. Figure 14, which illustrates the forecast of Stand-by Power requirements (i.e. DTS Contract Capacity), and the Duration Curve Analysis section, detailing electricity flows over the year, provide more insight into electricity consumption patterns.

The discounted anticipated on-site demand forecast is shown in Figure 7. With discounting, the 2013 survey anticipated on-site demand results show a considerably lower annual growth rate, averaging

9% in the Medium Range over the forecast period. The average discount applied to oil sands projects was 59% with almost half of the projects receiving a discount of 25% or less.

Figure 7 – Discounted – Anticipated On-Site Demand



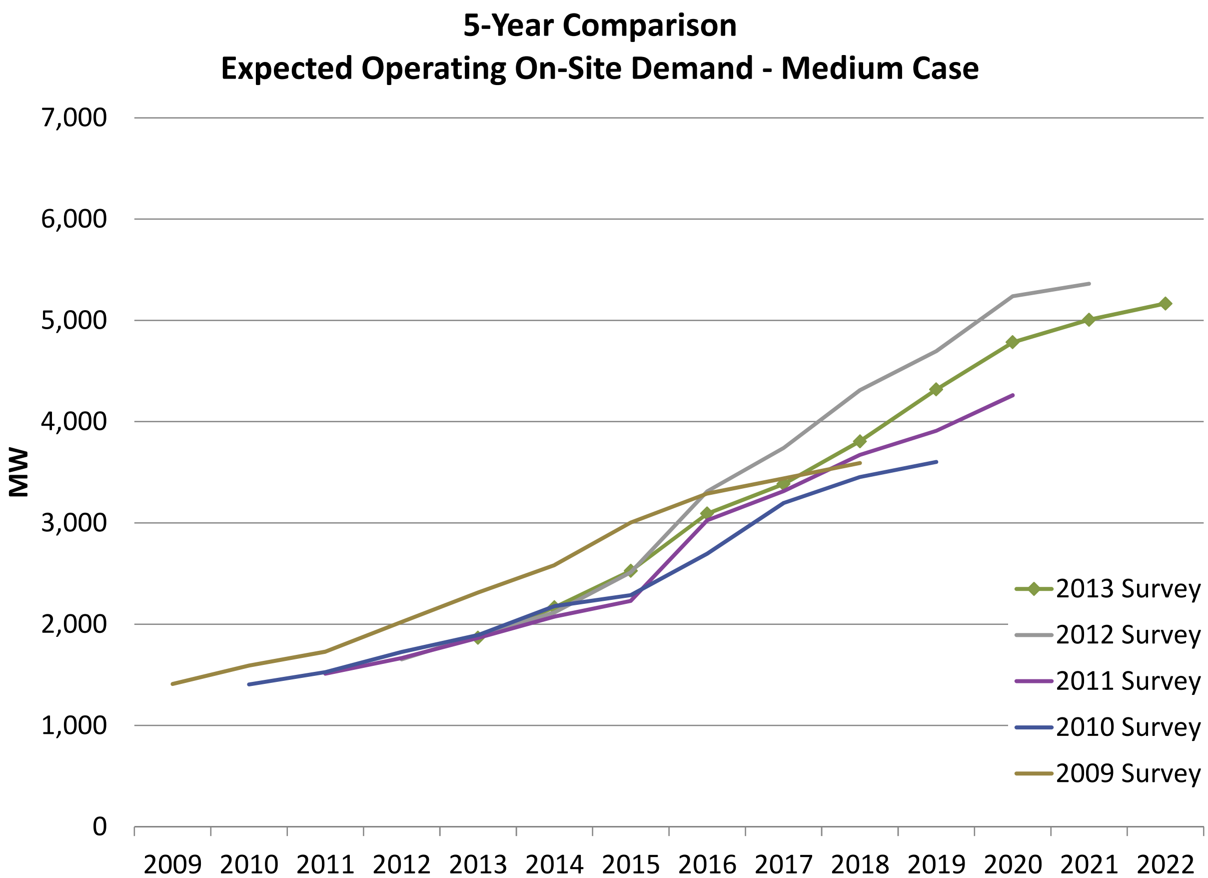
By the end of the forecast period, discounted anticipated on-site demand is expected to amount to just over 3,700 MW in the Medium Range; 28% (or 1,400 MW) lower than the unadjusted anticipated on-site demand forecast for the same period.

A five year comparison of annual survey results for anticipated on-site demand is shown in Figure 8. In the very near term, the 2013 forecast of anticipated on-site demand is in line with the 2012 forecast. This result is to be expected as projects scheduled to come on-line or ramp up in the near term are likely already under construction or in final engineering stages and so have more certainty around demand capacity and timing.

Starting in 2016, the 2013 survey results begin to fall below the 2012 survey and continue to grow at a lower rate over the remainder of the forecast period. This result is primarily due to the removal of two, electric intensive projects from the forecast. These two projects account for over half of the decrease in anticipated on-site demand relative to the 2012 study; had these two projects remained in the forecast, there would have been a net increase in demand expectations year-over-year. The remaining differences between the 2013 and 2012 survey results are assumed to be due to improved demand expectations and estimated start dates.

In the Medium Range, anticipated on-site demand is expected to amount to just over 5,000 MW in 2021; 7% (or around 350 MW) lower than the 2012 survey results for the same year.

Figure 8 – 5-Year Comparison of Anticipated On-Site Demand



New to this year's survey was a question which asked respondents to provide insight into on-site electric loads. Of the 136 projects surveyed, Table 7 summarizes the results from 33 projects (or phases of projects) that responded to this question. Note, some projects provide multiple responses (i.e. had more than one additional large electric load on-site).

Table 7 – Large Electric Loads

Large Electric Loads Load	Projects
Water Evaporation Treatment	19
Pumping Station or Facility	14
Camp Site with Electric Space Heating	17

The low response to this question (24%) as well as the possibility of multiple large electric loads on-site prevents any material conclusions. In time, it is anticipated on-site demand estimates will be better understood with additional insight into large electric loads.

Question: What options for power supply are being considered?

On-site power demand can be served through the provincial electricity market, the installation of on-site generation, or a combination of the two. The majority of respondents indicated a combination of co-generation and grid supply would be utilized to meet their power needs with 40%, on average over the forecast period, indicating they would rely on direct purchases from the grid only (i.e. no on-site cogeneration) and 8% utilizing on-site co-generation only. Table 8 provides the annual breakdown.

Table 8 – Options for Power Supply (Number of Projects)

Options for Power Supply	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Co-Generation Only (No Grid Stand-By)	-	-	1	1	4	7	7	9	9	8	9	9
Direct Purchase from Grid (No On-Site Generation)	14	15	16	19	26	25	24	27	23	22	21	19
Both of the Above	14	14	14	17	20	25	32	35	45	51	54	54

Relative to the 2012 study, more projects have indicated a combination of on-site generation and grid supply will be used to serve power demand. Table 9 shows the electricity source for the quantum of demand in terms of MW, with 13% of demand reported, on average over the forecast period, planning to make direct purchases from the grid and 2% to develop on-site co-generation only. Again, the majority of demand is planning on some combination of supply ("Both of the Above") with almost 85% of demand planning for utilizing co-generation and purchases from the grid.

Table 9 – Options for Power Supply (Quantum of Demand Reported)

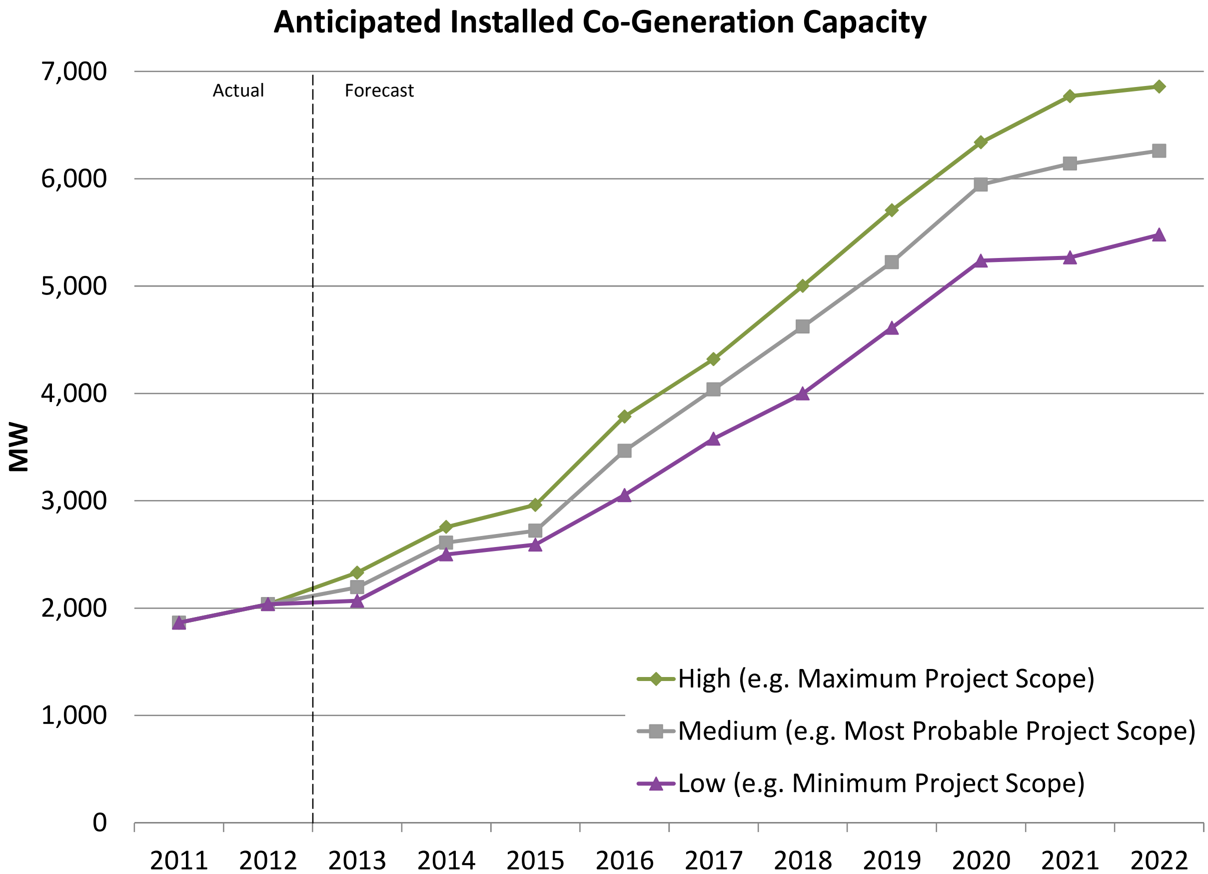
Demand for Power Supply (MW)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Co-Generation Only (No Grid Stand-By)	-	-	6	6	50	85	116	158	158	143	173	173
Direct Purchase from Grid (No On-Site Generation)	78	121	209	252	396	477	449	607	588	670	660	685
Both of the Above	1,294	1,442	1,619	1,882	2,013	2,442	2,731	2,953	3,484	3,883	4,085	4,180
% of Total Demand Reported	100%	99%	98%	99%	97%	97%	97%	98%	98%	98%	98%	98%

Some respondents chose not to provide a response to this question, therefore only a portion of the projects and forecast demand is presented in the tables above. It is clear, given the results shown in Table 9, oil sands developers have indicated on-site co-generation with additional service or support from the provincial grid will serve the majority of on-site power demand.

Question: If installing (or installed) on-site co-generation power supply, please provide the average of your installed generating capacity.

Anticipated on-site co-generation capacity from all oil sands regions is illustrated in Figure 9. In 2012, on-site co-generation capacity amounted to just over 2,000 MW, accounting for roughly 14% of total installed generation capacity in the province. On-site co-generation capacity is forecast to increase to almost 2,200 MW in 2013, with the installation of a few generators at new or existing oil sands developments. By 2022, on-site co-generation capacity is forecast to be over 6,200 MW in the Medium Range.

Figure 9 – Anticipated Installed Co-Generation Capacity

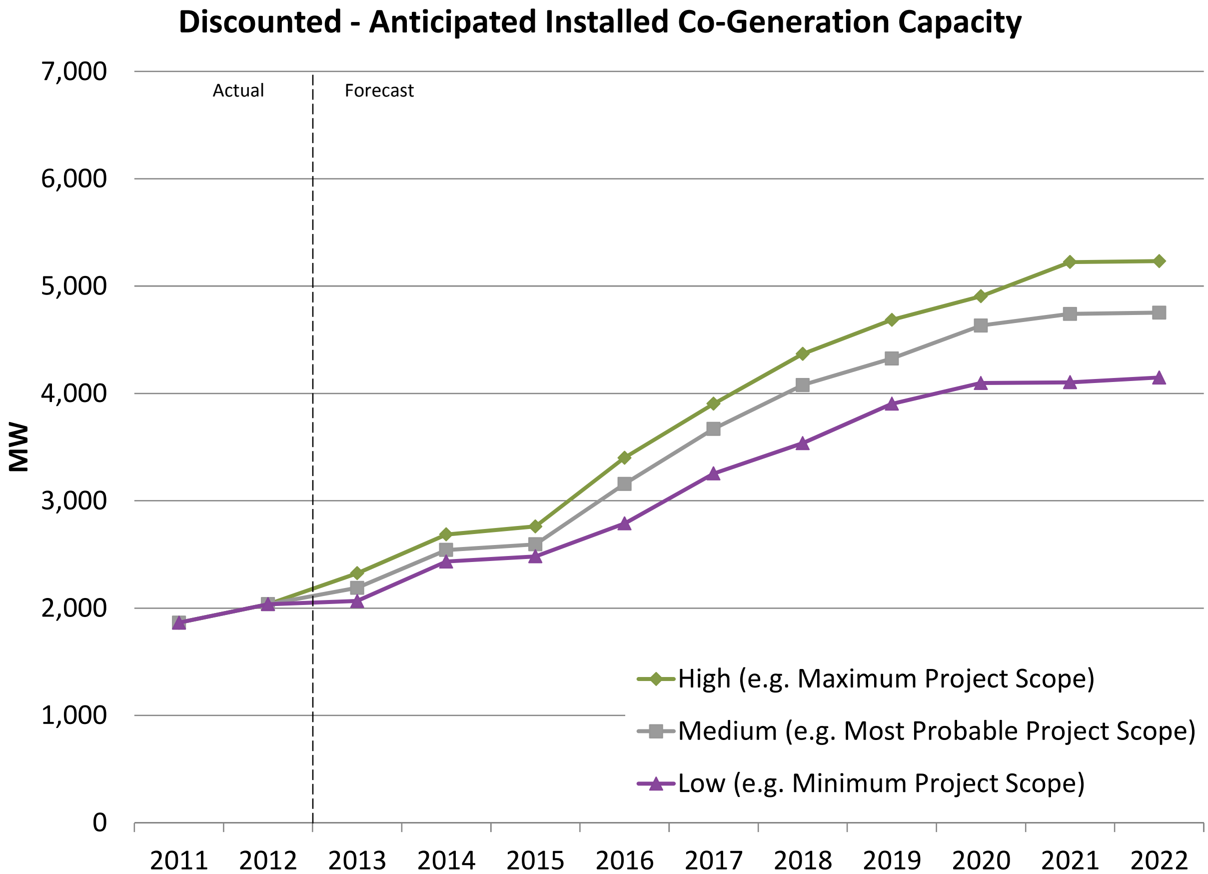


The forecast of on-site co-generation has an average growth rate of 12% with the largest increase occurring in 2016, in line with on-site demand growth expectations. In the near term (2013 to 2015), on-site co-generation records an average growth rate of 10%, increasing to 13% over the remainder of the forecast period. Near the end of the forecast, generation additions slow as electricity supply sources for projects scheduled to come on-line later in the forecast period become more uncertain.

The spread between the High and Medium Range and Low and Medium Range is relatively consistent until the second half of the forecast period. At this point, the Low Range forecast grows at a slower rate. Recall, in the Low Range respondents are asked to provide the minimum anticipated scope, potentially reflecting minimal capital spend, lower oil prices, higher operating costs, and/or poorer economic conditions. While co-generation capacity continues to increase over the forecast period, under the Low Range scenario fewer and/or smaller on-site generators are forecast to be developed.

Figure 10 illustrates the results of the discount applied to anticipated on-site co-generation. Consistent with demand, the discount was applied based on current status of the project with the heaviest discount applied to those projects in the earlier stages. Discounted on-site co-generation is expected to amount to over 4,700 MW by 2022 (Medium Range), recording an average growth rate of 9% over the forecast period.

Figure 10 – Discounted – Anticipated Installed Co-Generation Capacity

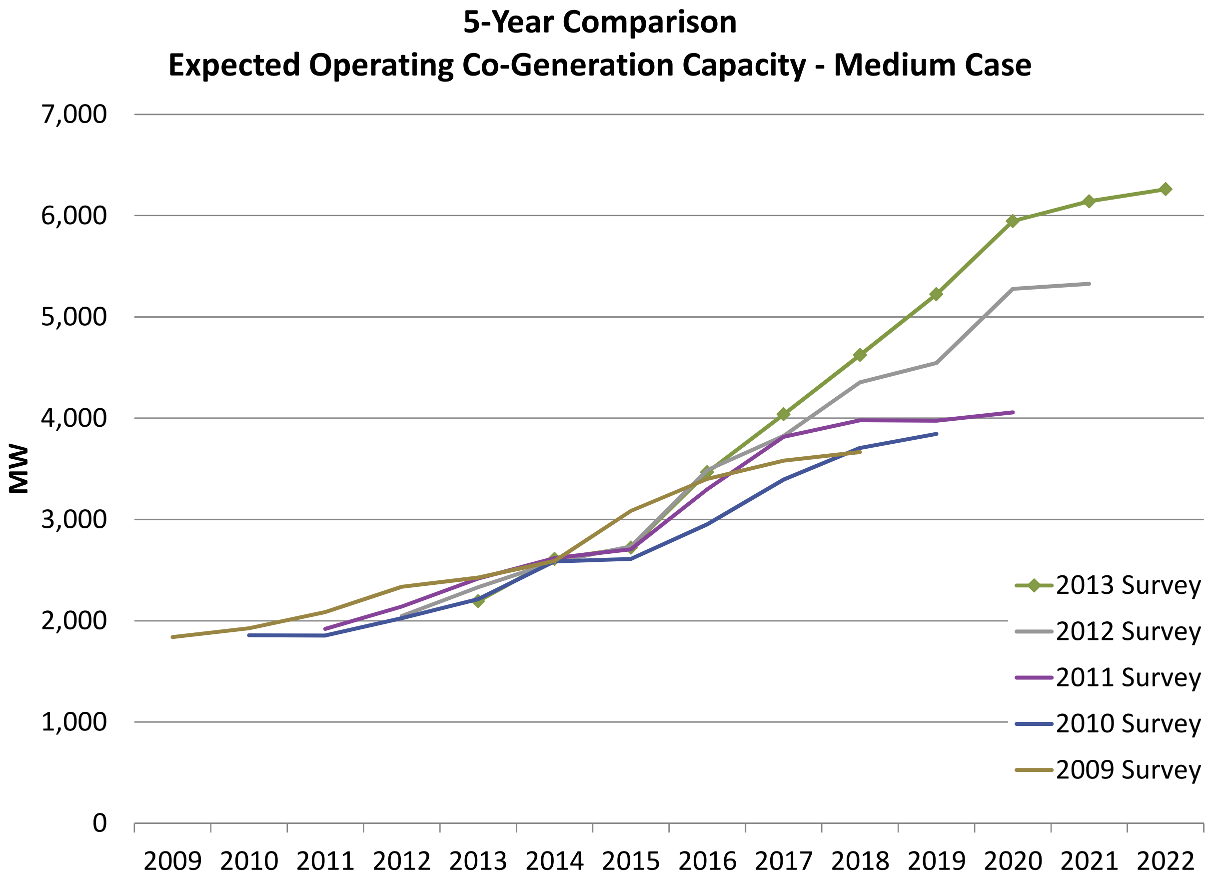


An average discount of 61% was applied, with under half the projects receiving a discount of 25% or less (i.e. projects announced or in conceptual stages).

The 2013 survey results are compared to the 2012 results in Figure 11. In the near term, the results are relatively consistent with previous years' studies. This is to be expected as projects in the near term are likely already under construction or in an advanced stage of planning. Starting around 2017, the 2013 survey results begin to grow at a stronger rate than 2012, with around 15% (or 800 MW) more scheduled to come on-line in 2021. Unlike demand, the removal of two large and electric intensive projects has had a limited impact on the co-generation capacity forecast.

New co-generation projects planned for the forecast period are being developed by both existing, established oil sands producers and new entrants. Very few projects recorded lower on-site co-generation capacities year-over-year with most differences assumed to be the result of delay or revisions to existing estimates.

Figure 11 – 5-Year Comparison of Expected Installed Operating Co-Generation Capacity



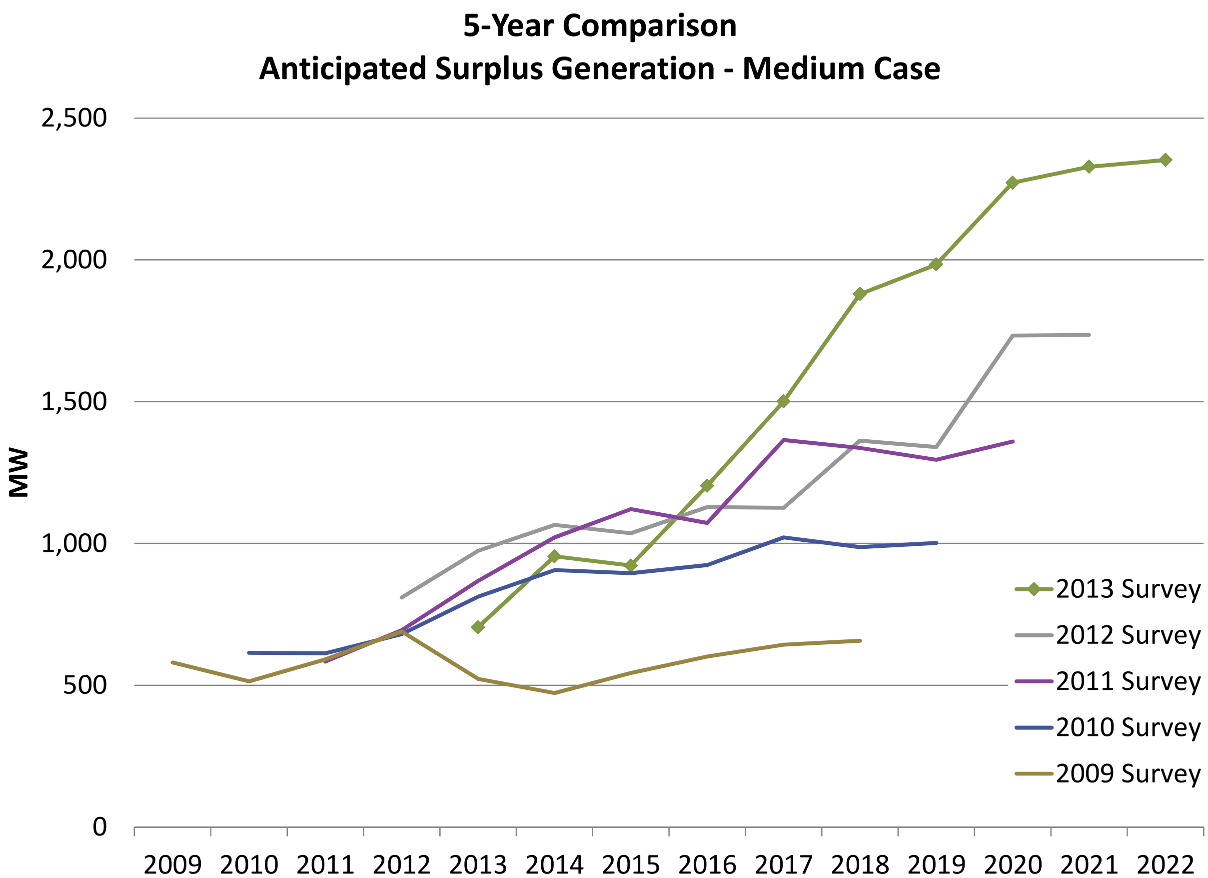
Additional on-site co-generation capacity results are consistent with the results of the other survey questions; implying oil sands developers are increasingly open to the idea of on-site generation, in light of the importance of reliable and cost effective power and steam supply. The next section will discuss the sizing of co-generation relative to on-site load and the potential for increased power exports to the provincial grid.

Question: If installing co-generation, please confirm anticipated range of power exports to the grid (i.e. surplus generation).

As to be expected, a decrease in on-site power demand and an increase in on-site co-generation capacity results in an overall net increase in the amount of capacity available for export to the provincial grid from all three oil sands regions. The supply/demand balance in each of the three oil sands regions will dictate net power flows to the provincial grid. Significant amounts of excess electricity can be produced when on-site co-generation is sized to meet steam loads versus when on-site generation is sized to meet anticipated demand. Figure 12 illustrates anticipated surplus generation, calculated as the difference between on-site co-generation and anticipated on-site demand from all projects with excess co-generation capacity, across all three oil sands regions.

Of the 136 projects included in the 2013 survey results, 34 indicated varying amounts of excess electricity for export. Excess capacities ranged from as low as a couple of megawatts to as high as a stand-alone natural gas-fired generator.

Figure 12 – 5-Year Comparison of Anticipated Surplus Generation



There was a significant increase in anticipated surplus generation in the 2013 survey. This increase is associated with three oil sands developers with hundreds of megawatts of on-site excess co-generation capacity each. Together these three producers account for almost 65% of the year-over-year change by the end of the forecast period. Anticipated surplus generation begins to grow rapidly during the second half of the forecast, a period which includes many projects in earlier stages of development. Figure 12 illustrates un-adjusted anticipated exports. The forecast would be quite a bit different if discounts were applied and surplus generation capacity was categorized by oil sands region.

Question: If anticipating power exports, how do you plan to operate?

The Alberta power market requires generators to provide price-quantity offers to determine dispatch to meet provincial demand. Oil sands developers with export capacity have the option to submit offers which may alter how the co-generator operates. Exports can be split into two categories; Surplus Net Exports and Merchant Net Exports. Surplus Net Exports typically occur regardless of electricity prices and are associated with co-generators sized to meet on-site steam requirements, often producing excess electricity as a by-product. Merchant Net Exports tend to respond to movements in the power market where co-generators can adjust operations without detrimentally impacting steam supplies or bitumen production. While there were would be minor hourly adjustments to Surplus Net Exports, Merchant Net Exports could change by hundreds of MW from one time period to another.

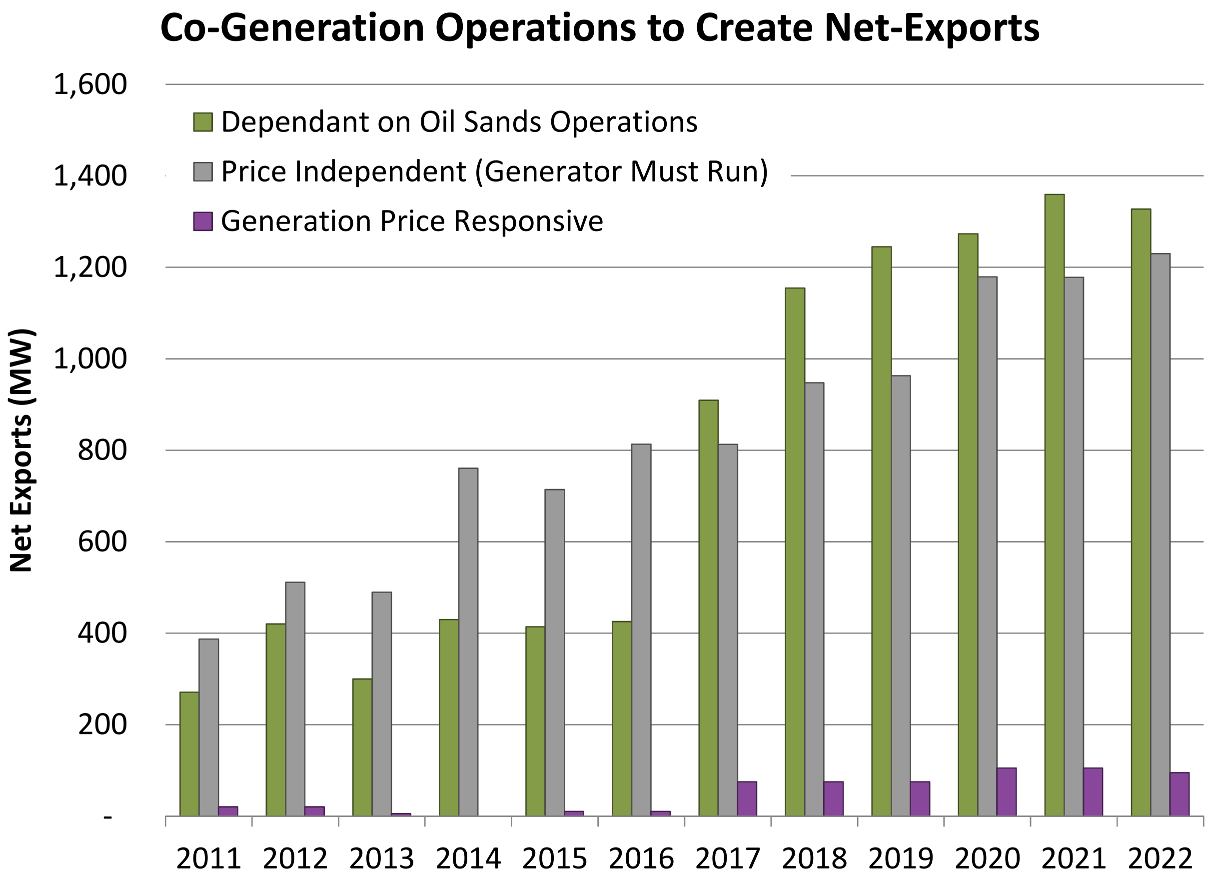
Currently, the majority of co-generation net exports from the oil sands are Surplus Net Exports or non-price responsive, in that excess capacity is offered into the Alberta market near the $0/MWh floor. This ensures steam or hot water required for the oil sands process is available, with no changes to on-site operations in response to hourly spot market electricity prices. In essence, most of the excess electricity produced on-site is a by-product and would be produced regardless of spot wholesale electricity prices.

Survey participants were asked how excess electricity, if any, would be offered into the market. 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 "price takers" bidding near the $0/MWh floor).
2. Generation Price Responsive – net exports to the grid will generally increase when pool prices are high (e.g. pool price is above marginal operating costs) and generally decrease when pool prices are low (e.g. pool price is below marginal operating costs).
3. Dependent on Internal Oil Sands Operations – the quantum of net exports will be a function of internal operations and may or may not change with power pool prices.

The survey results are shown in Figure 13.

Figure 13 – Co-Generation Operations to Create Net Exports



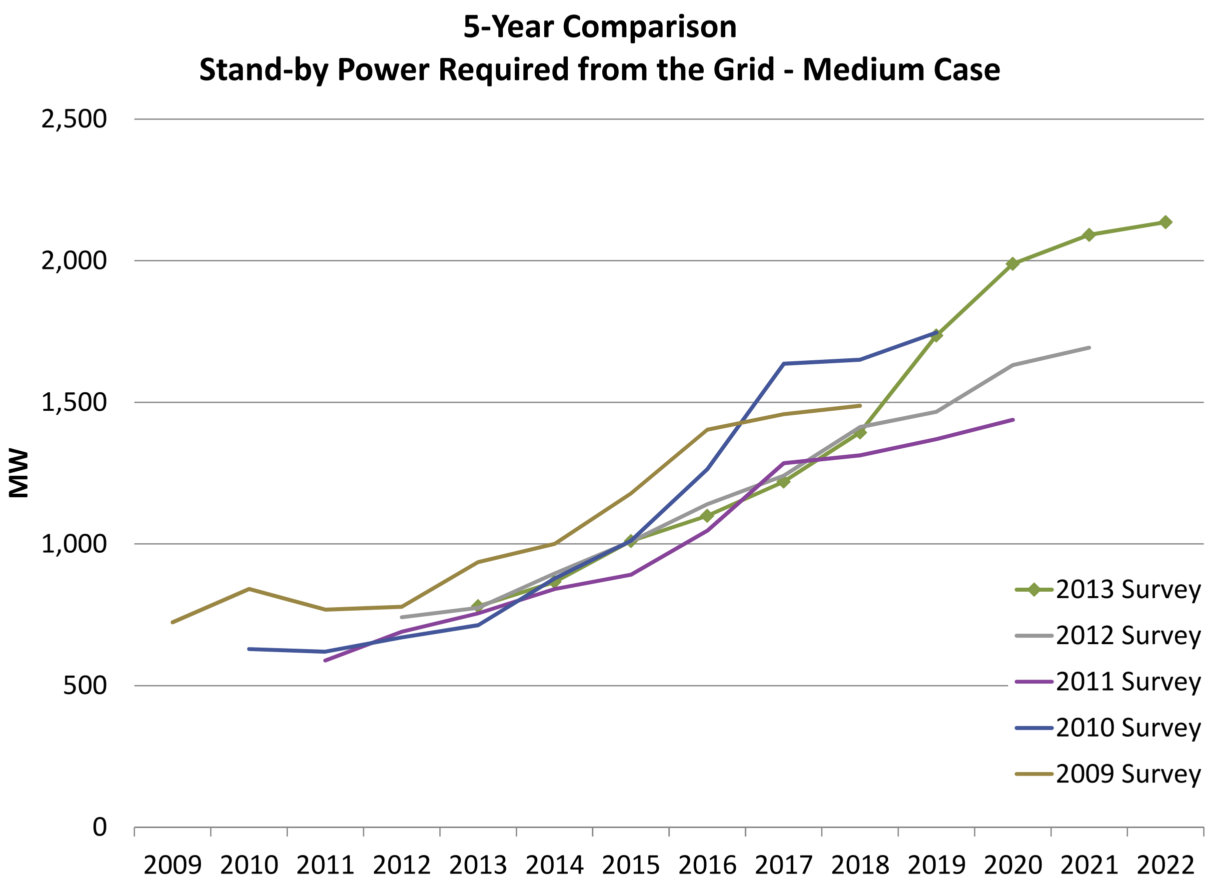
Most oil sands developers indicated co-generation operations would be either Price Independent or Dependent on Oil Sands Operations, a result consistent with the 2012 study results. For the majority of the excess capacity, net exports to the provincial grid will be determined based on numerous factors, one of which may be the wholesale price of electricity. Few developers indicated exports would be responsive to power prices; a continuation of existing behavior. Some producers provided more than one response; implying portions of generation capacity could be operated in different modes.

Question: If you are planning to construct co-generation, how much stand-by power or back-up do you require from the grid each year (i.e. DTS Contract Capacity)?

Stand-by or back-up power requirements refer to the amount of Demand Transmission Service (DTS) Contract Capacity oil sands developers intend to receive from the AESO. Typically, this value would reflect the amount of power capacity a project would require to operate if any on-site generation was unavailable (e.g. offline for routine maintenance). Some developers choose to contract for the full amount of on-site power demand while others may contract for a portion of on-site demand (often called standby power). There are monthly fixed costs associated with DTS Contract Capacity and pros and cons of selecting a particular DTS contract capacity value.

In the near term, stand-by power requirements are consistent with previous years' expectations, increasing significantly in 2019 with the start-up of six projects, averaging around 50 MW of stand-by requirements each. Despite increasing wires tariff costs, oil sands developers continue to indicate need for stand-by or back-up power from the provincial grid. The cost associated with lost production due to a power outage would justify some redundant power supplies. It should be noted that reducing stand-by capacity and relying more on on-site generation would have a quantifiable, positive impact on co-generation economics, all other things being equal.

Figure 14 – 5-Year Comparison of Stand-by Power Requirements

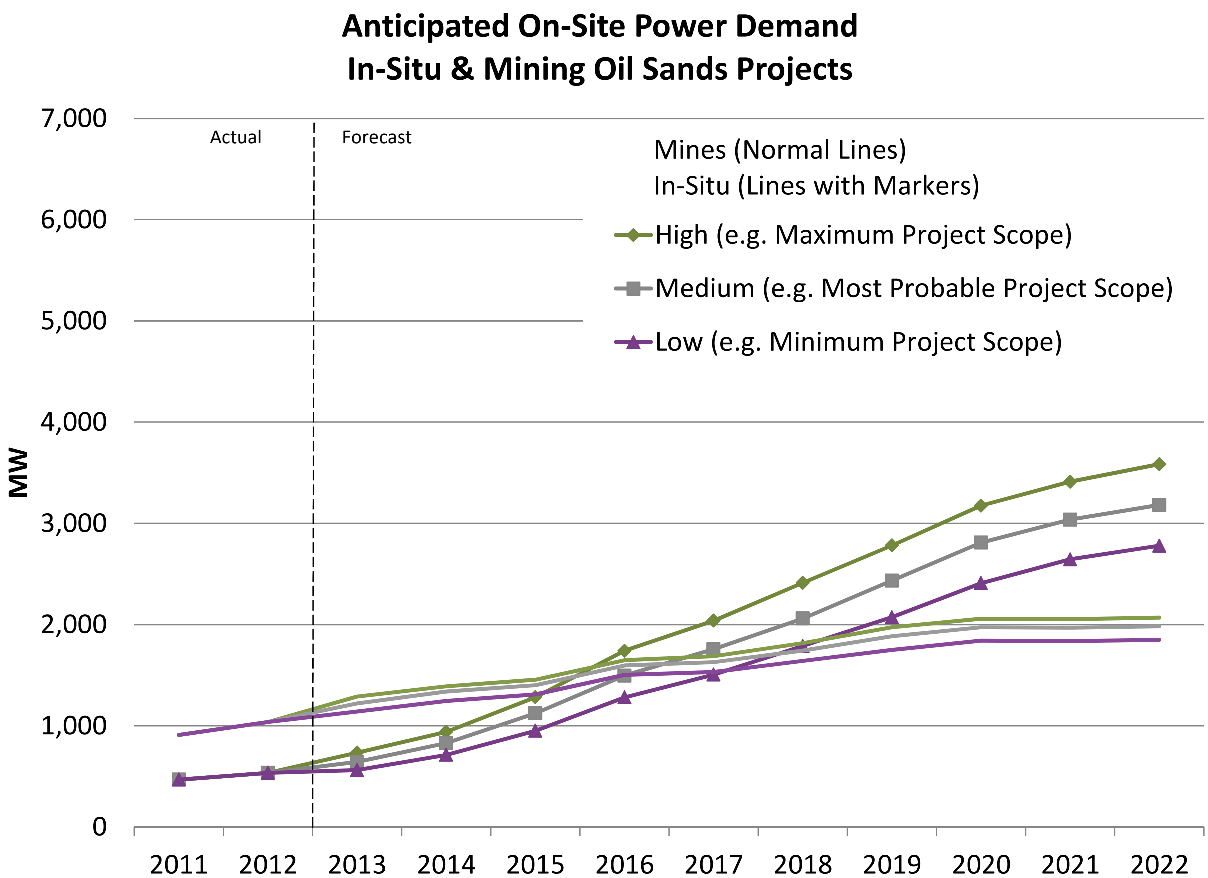


The variables are somewhat difficult to estimate and the results should be interpreted with some caution. Power requirements can vary drastically over the course of a year and, as previously mentioned, oil sands developers will individually select their DTS Contract Capacity, which could be affected by other variables such as utility capital investments. The results in Figure 14 do not reflect coincident power demand in a given hour, nor does it reflect typical imports into a specific oil sands region. For analysis and commentary on power flows in and out of the Athabasca region, refer to the Duration Curve Analysis section below.

Question: Oil Sands Mining vs. In-Situ Developments

Survey respondents were asked to identify the type of oil sands development; mining or in-situ. Of the 136 projects included in this study, 15% were mining projects with the remaining 85% a form of in-situ development. Figure 15 presents the results of the 2013 survey with respect to on-site demand separated into oil sands development type. Forecast power demand for mining operations are shown by straight lines and in-situ projects are illustrated by lines with markers.

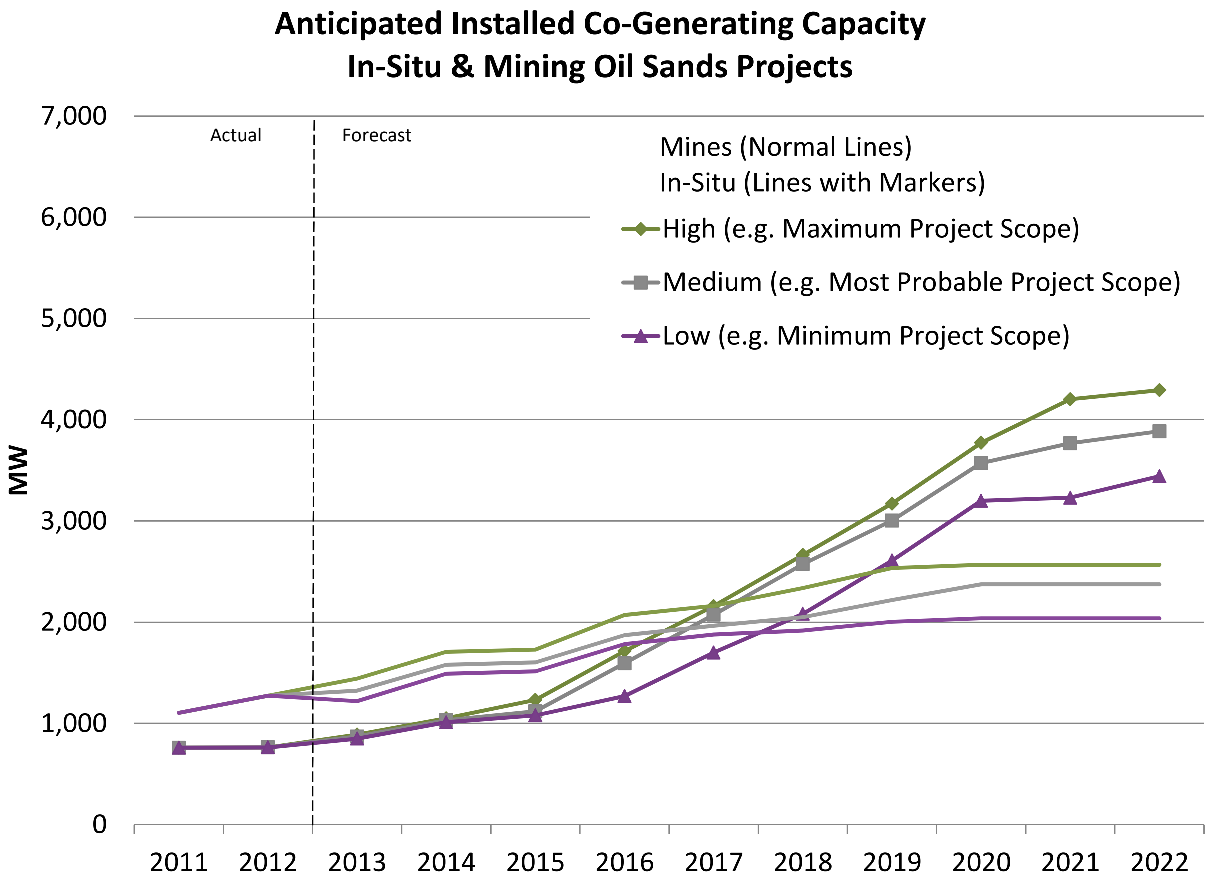
Figure 15 – Anticipated On-Site Power Demand – In-Situ & Mining



While mining operations tend to be more electric intensive, the growth in the number of in-situ developments over the forecast period allows in-situ related electricity consumption to overtake mining power consumption, starting as early as 2016 (Medium Range). Mining related on-site power demand is expected to record an average growth rate of 7% over the forecast period, compared to a 19% growth rate for in-situ developments.

The breakdown of mining versus in-situ on-site co-generation developments is shown in Figure 16. Similar to Figure 15 above, mining projects account for the majority of the existing oil sands co-generation fleet, with co-generation capacity associated with in-situ developments becoming the majority as early as 2017 (Medium Range).

Figure 16 – Anticipated Installed Co-Generating Capacity – In-Situ & Mining



It is interesting to note the tight spread between the three ranges forecast for in-situ on-site co-generation capacity. The High and Low Range forecasts are only 20 MW apart from the Medium Range forecast up to 2015, when the High Range increases at a greater rate. This result is assumed to be due to greater certainty of near term plans as well as the lead time to build additional or larger on-site co-generation. In the case of mining co-generation capacity, a wider spread is forecast in the near term, assumed to be the result of larger amounts of already installed capacity which could be uprated or improved upon in a more timely fashion.

Net Export Potential

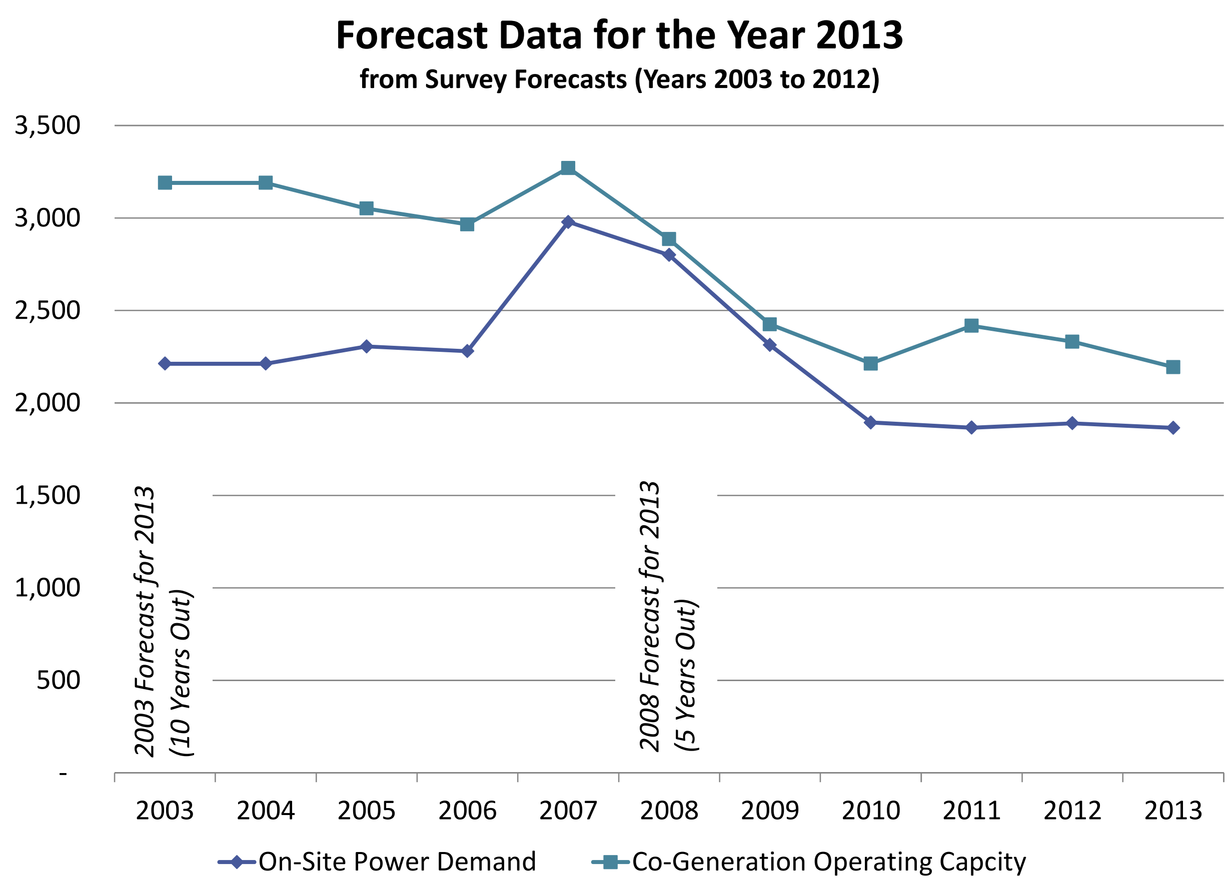
Exporting excess electricity to the Alberta power market has been an important aspect of on-site co-generation development. There is potential for positive benefits to both generation owners, in the form of revenues streams to offset costs associated with power and steam production, and Alberta electricity consumers in the forms of lower electricity prices. Oil sands co-generation tends to be supplied to the market at low prices (as discussed with Figure 13).

The three main oil sands regions, Peace River, Athabasca, and Cold Lake, each have unique supply/demand balances that dictate if the region is a net importer or net exporter. The Athabasca region, with the majority of existing and planned oil sands projects, is the biggest region with the largest quantity of net power flows to the provincial market.

The potential for net exports, has, in part, influenced trends in on-site co-generation development. In the early 2000s, power pool prices were generally higher and a transmission build, to move power out of the Athabasca region, was anticipated. During this time, oil sands developers planned for excess co-generation capacity from oil sands projects in order to take advantage of these favorable market conditions. However, in the latter part of the last decade, it became apparent that transmission capacity to export surplus power from the oil sands regions was limited and power pool prices were more volatile. Developers responded by sizing their co-generation projects closer to on-site conditions, effectively lowering the forecast of net exports from oil sands developments to the provincial grid. Looking forward, oil sands developers are faced with higher forecast power prices, increasing transmission tariff costs, and promise of a significant transmission build, including a higher import limit by 2019 from the first stage (stage 1A, 1B and 2) of the two new 500 kV lines from the Edmonton area to Fort McMurray[3].

Developing on-site co-generation can represent a significant undertaking, in a potentially non-core area for most oil sands developers. It is anticipated oil sands developers will move with caution when deciding whether or not to build on-site co-generation and will seriously investigate the risk factors associated with excess supply.

Figure 17 – 2013 Forecasts from Survey Results (2003 to 2012)



[3] Source: Alberta Electric System Operator (AESO). Fort McMurray West 500 kV Transmission Project. Project Information Brief. May 9th, 2013. Section 2.1(b).

Historical survey results for the year 2013 are shown in Figure 17. These responses, gathered from the 2003 to 2012 surveys, demonstrate the change in on-site demand and co-generation capacity forecasts. The values shown for 2003 reflect the expectations of demand and supply growth ten years out, with each survey value moving closer to a forecast of one year out, as shown with the 2012 survey results.

The results indicate oil sands related co-generation capacity has always been anticipated to be larger than on-site demand with the difference between the two lessening between 2007 and 2009. From 2010 on, demand expectations for 2013 have somewhat settled while on-site co-generation development has increased. The variance in installed capacity between 2010 and 2013 is anticipated to be the result of timing changes to planned developments. Purchase of equipment and construction of co-generation can be a 2 to 4 year process, thus forecasts of 2013 installed capacity from 2010 would be a relatively known value, versus 10 years ago (2003) when projects could still be in early stages of development.

Figure 17 demonstrates the accuracy of prior forecasts. In general, if the lines were relatively flat, it would suggest there may not have been material changes in the survey results from year to year (as noted above). Both on-site power demand and co-generation operating capacity are well below forecasts from 10 years ago, reflecting how forecasts near the end of the study period, as the year 2013 would have been in the 2003 survey, are based on projects in early stages of development and subject to change.

Figure 18 – 2013 On-Site Demand & Co-Generation Capacity Forecast

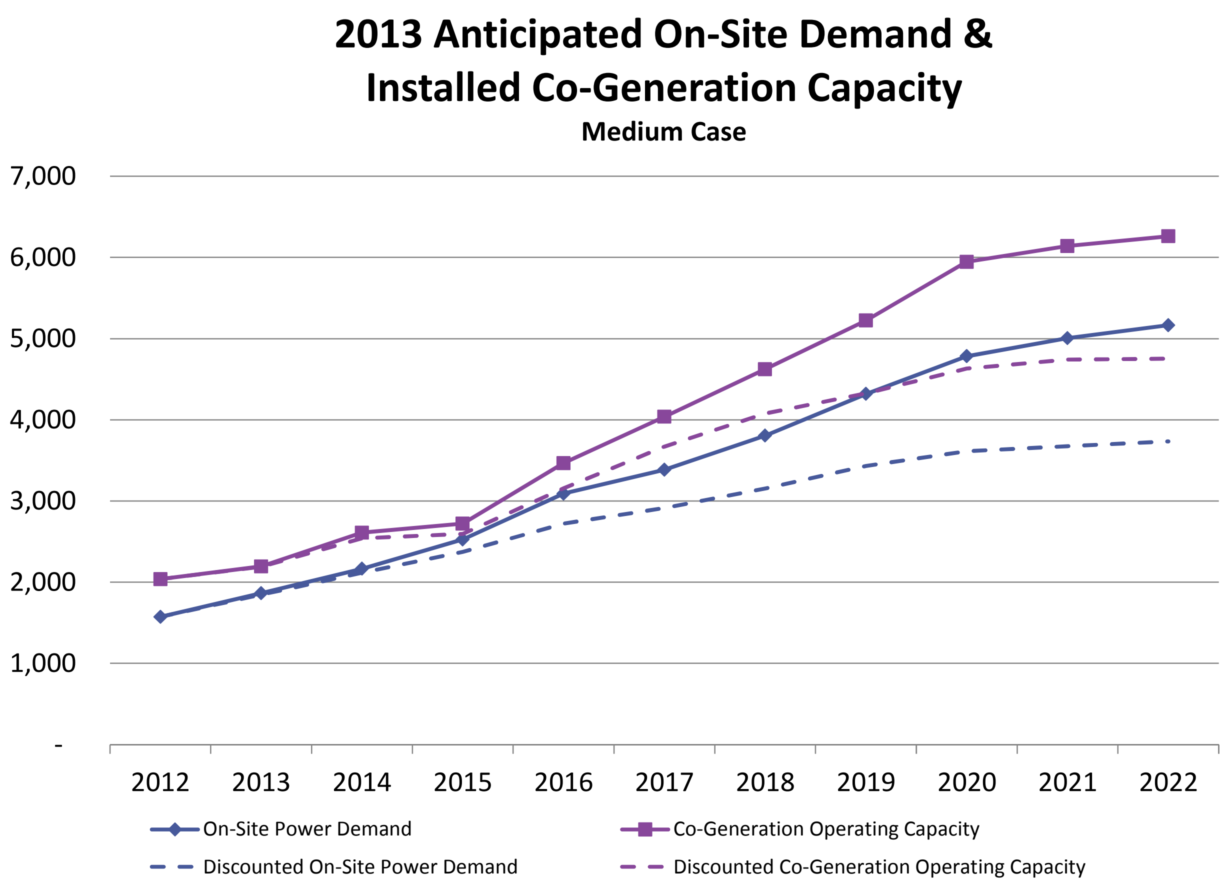


Figure 18 illustrates the 2013 survey results of anticipated on-site demand and installed co-generation capacity (Medium Range) for all three oil sands regions. Over the forecast period, co-generation capacity is expected to exceed on-site demand with co-generation additions growing at a faster rate than on-site demand. By the end of the forecast period, installed co-generation is anticipated to be just over 1,000 MW higher. However, as Figure 17 demonstrated, the supply/demand balance is anticipated to narrow as industry approaches 2022.

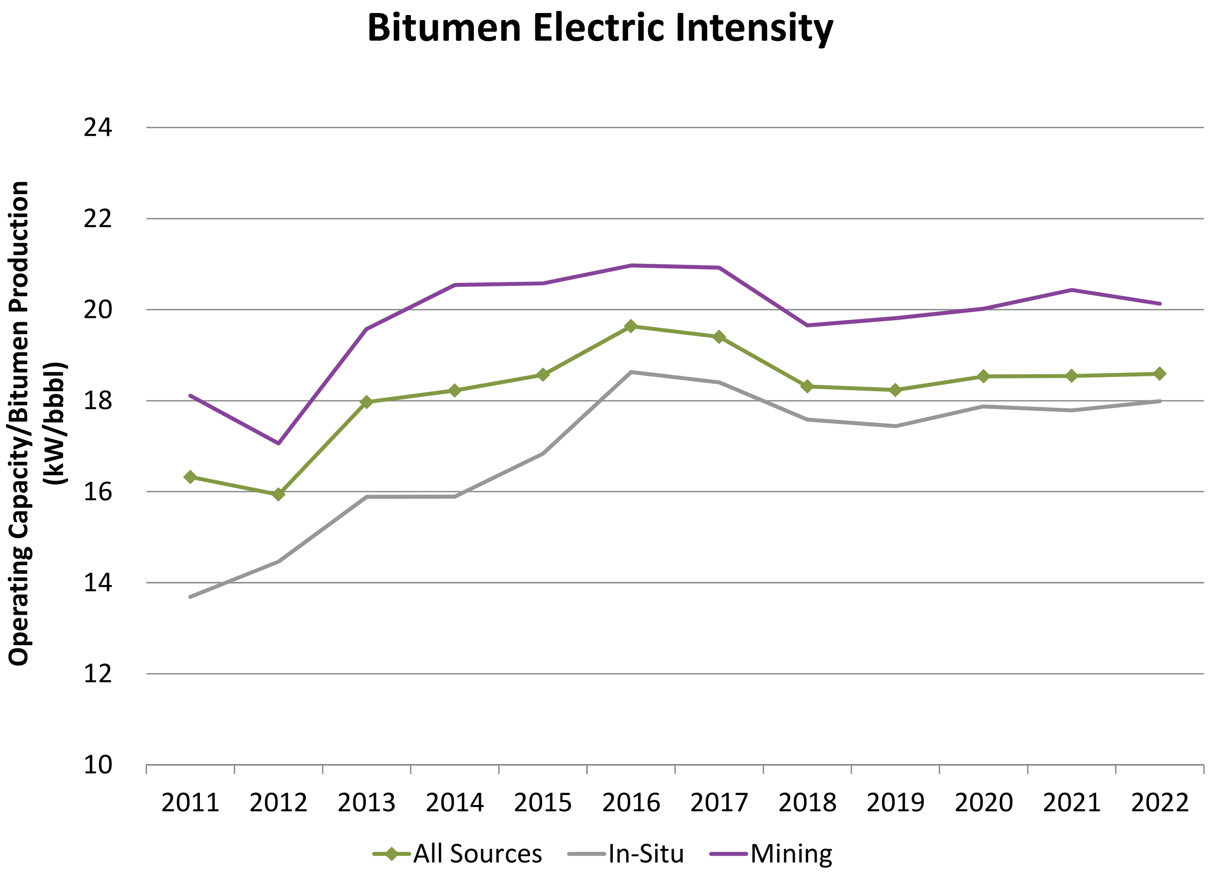
In terms of net export potential, the regional supply/demand balances will dictate net power flows to/from the provincial grid. For both the demand and supply forecasts, a few large projects account for the majority of the change year-over-year, demonstrating the impact of large oil sands developments.

Bitumen Production

Consistent with past surveys, an estimate of bitumen production under the three ranges was requested. Some respondents chose not to provide a bitumen production forecast and so caution should be used when interpreting the following results. In aggregate, bitumen production is anticipated to grow by 15% over the forecast period (Medium Range), with mining bitumen production growing at an average rate of 7% and in-situ production recording annual average growth of 21%.

Figure 19 illustrates the Medium Range electric consumption (kW) per barrel of production (i.e. kbpd per hour) split by oil sands mining and in-situ projects. This value was calculated as the sum of anticipated on-site demand in a given year divided by aggregate bitumen production for mining or in-situ projects. This methodology should lessen the influence of any outliers. Again, only those projects that provided a bitumen forecast were included in this analysis. As can be seen from the figure, the value varies over the years as new developments come on-line, existing projects ramp-up, and efficiencies are achieved. This "saw-tooth" electric intensity is consistent with previous studies. The calculated electric intensity from all sources averages around 18 kW/bbl with mining operations recording an average electricity intensity of 20 kW/bbl and in-situ operations averaging 17 kW/bbl. Mining operations, with materially handling and on-site processing, tend to be more electric intensive.

Figure 19 – Reported Electric Intensity



On a project by project basis, there was a large deviation in calculated electric intensities. Some projects reported extremely high electric intensities while others reported extremely low electric intensities, in both cases, the results were well beyond one standard deviation from the mean. There are some existing and planned oil sands operations that are expected to have high electric intensities, specifically those with on-site upgrading as well as projects using electricity in bitumen recovery processes. However, there is an electric intensity floor.

Duration Curve Analysis

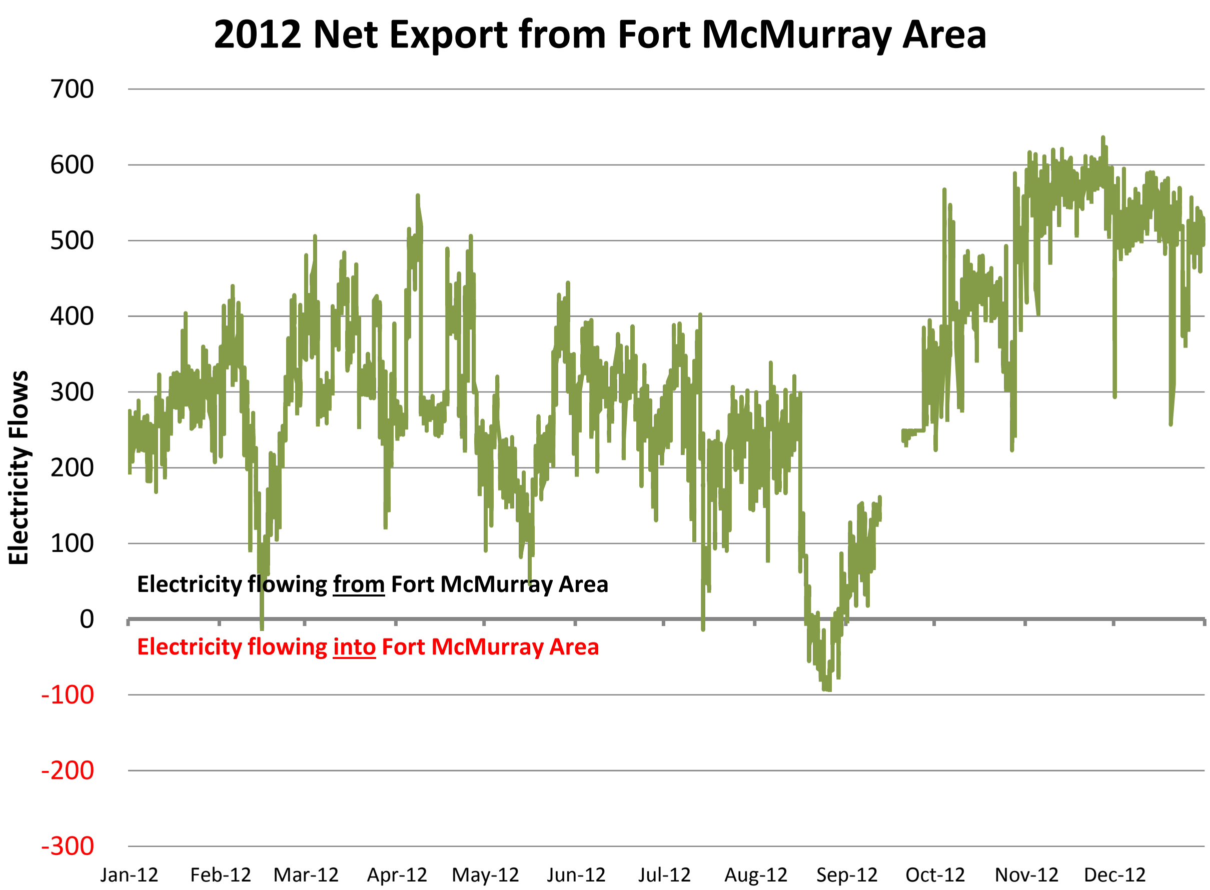
Oil sands developers were asked to provide in-the-hour or instantaneous demand and supply capacities; however, over time capacities will fluctuate based on on-site operations. As the number of oil sands projects increase over the forecast period, energy flows in and out of the Athabasca region also increase and become more exaggerated.

Anticipated stand-by capacity provides an example of how hourly requirements can differ from annual energy flows. A developer may forecast the need for 50 MW of stand-by capacity, but may only draw this capacity from the transmission grid during a few hours in the year. Figure 14 illustrated aggregate anticipated stand-by capacity; an estimate which is unlikely to occur in a given hour as not all oil sands projects will draw from the grid, at their maximum capacity, at the same time.

Planning for transmission capacity is complicated by ever changing demand and supply volumes and forecasts. The following analysis focuses on energy flows over the course of the year and provides an estimate of typical electricity movements based on forecast demand and supply capacities and historical energy patterns. While Figure 12 illustrated anticipated surplus co-generation capacity from all three oil sands regions, the following analysis focuses on flows in and out of the Athabasca/Fort McMurray region only.

Hourly net energy flows into and out of the Fort McMurray area were provided by the AESO and are shown in Figure 20. During 2012, the Fort McMurray cutplane definition was changed, now measuring power flows at the Dover and Ruth Lake substations (causing a one week gap in missing data during September 2012).[4]

Figure 20 – 2012 Net Export from Fort McMurray Area



For the majority of the year, the Fort McMurray region was a net exporter to the provincial grid, averaging 316 MW. Following the change in cutplane definition, exports were generally higher; however, this increase in export volumes was mostly the result of the commissioning of a new co-generator with large quantities of excess capacity. Consistent with 2012, there were few instances of imports into the region, assumed to be the result of lower on-site generation production.

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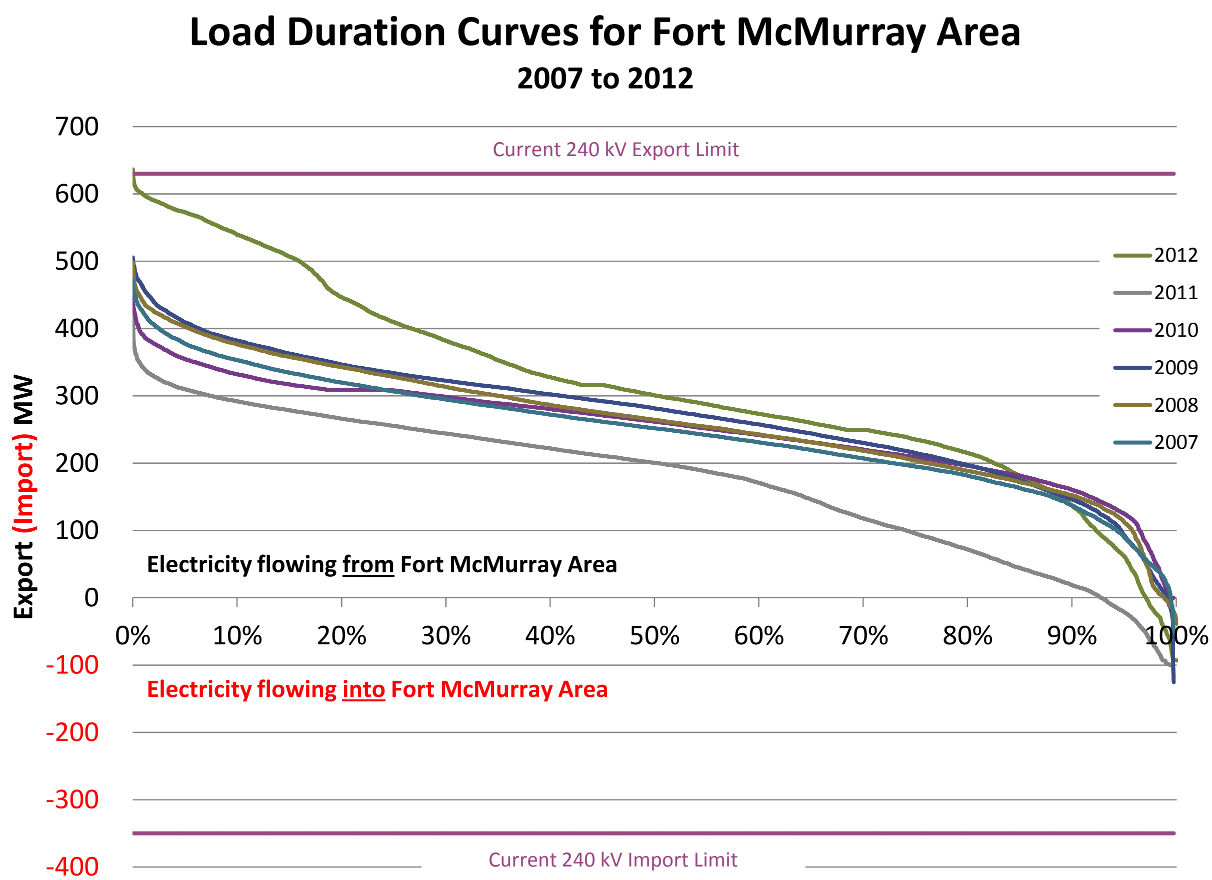
[4] Source: Alberta Electric System Operator (AESO). Information Document Northeast Area Transmission Constraint Management ID# 2011-008(R). Effective 2012-12-04.

A duration curve provides another view of annual energy flows, presenting the data in descending order of magnitude plotted against the number of hours in the year. Organizing the data in this manner more clearly illustrates the relationship between transmission capacity and capacity utilization. Figure 21 shows the same data as the Figure above, with data for 2007 to 2011 added for comparison purposes. Note, 2012 annual average flows were used as a proxy for the missing data in September 2012.

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



In 2012 increased excess co-generation capacity significantly increased exports out of the region, well above previous years. Exports averaged 327 MW, occurring over 97% of the year, with imports averaging 42 MW over the remaining 3%. If the increased export capacity associated with new co-generation was removed, the duration curve of net exports out of the Athabasca region would be more consistent with previous years.

The current 240 kV export and import limits, shown in Figure 21 (N-1 line limits), have been updated this year to reflect the AESO's Northeast Area Transmission Constraint Management Information Document.[5] Continued improvements to existing transmission lines and substations as well as planned developments will impact current transmission line losses in and out of the Fort McMurray

[5] Source: Alberta Electric System Operator (AESO). Information Document Northeast Area Transmission Constraint Management ID# 2011-008(R). Effective 2012-12-04.

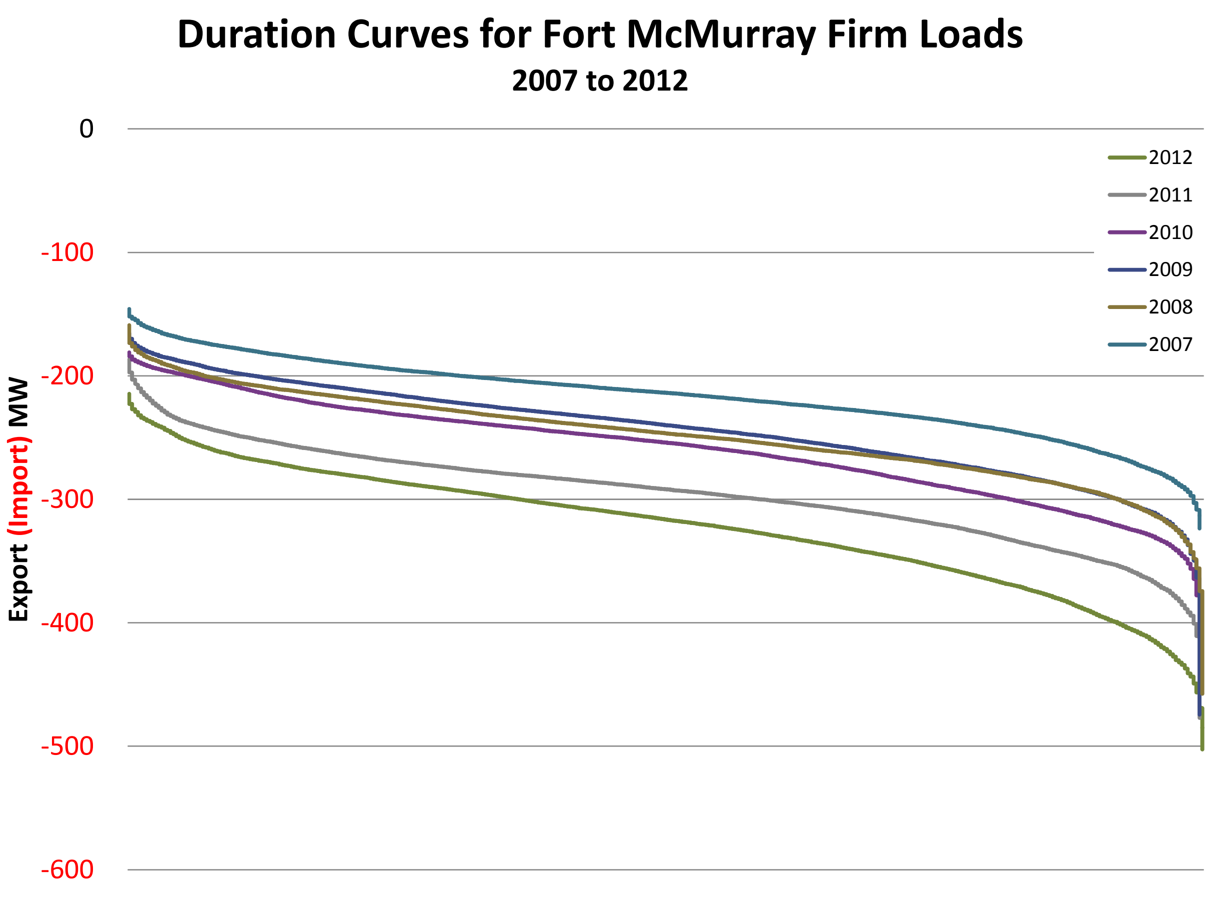
region. The addition of the 500 kV transmission lines should, all other things being equal, improve line losses resulting in slightly increased amounts of energy available to serve electricity load. Regional line losses are very much dependent on the supply/demand balance and often vary as existing and planned developments change.

The increase in capacity (55 MW exports & 50 MW imports) over last year's report is the result of AESO efforts to reinforce the reactive power capability of the three 240 kV lines running south from the Fort McMurray transmission loop. There were two hours in 2012 where export capacity was rated 1% (or 5 MW) over the reported export limit. Import and export capability is anticipated to increase further in 2019 with the completion of the first stage of the 500 kV bulk system additions from the Edmonton area to Fort McMurray (the second 500 kV line is planned for 2020+).

The 2011 duration curve illustrates one end of the spectrum, a year with increased imports and decreased net exports, potentially the result of lower on-site production and/or increased regional demand. The 2012 duration curve provides an example of the opposite end of the spectrum, increased export capacity due to new co-generation development. Going forward, as supply and demand capabilities evolve, annual duration curves are expected to behave in a similar manner.

In an effort to separate oil sands related load from non-oil sands load, the firm load (i.e. Urban Service Area of Fort McMurray load) was isolated. Figure 22 shows the duration curves of the firm loads from 2007 to 2012, which tend to vary between 200 MW and 500 MW.

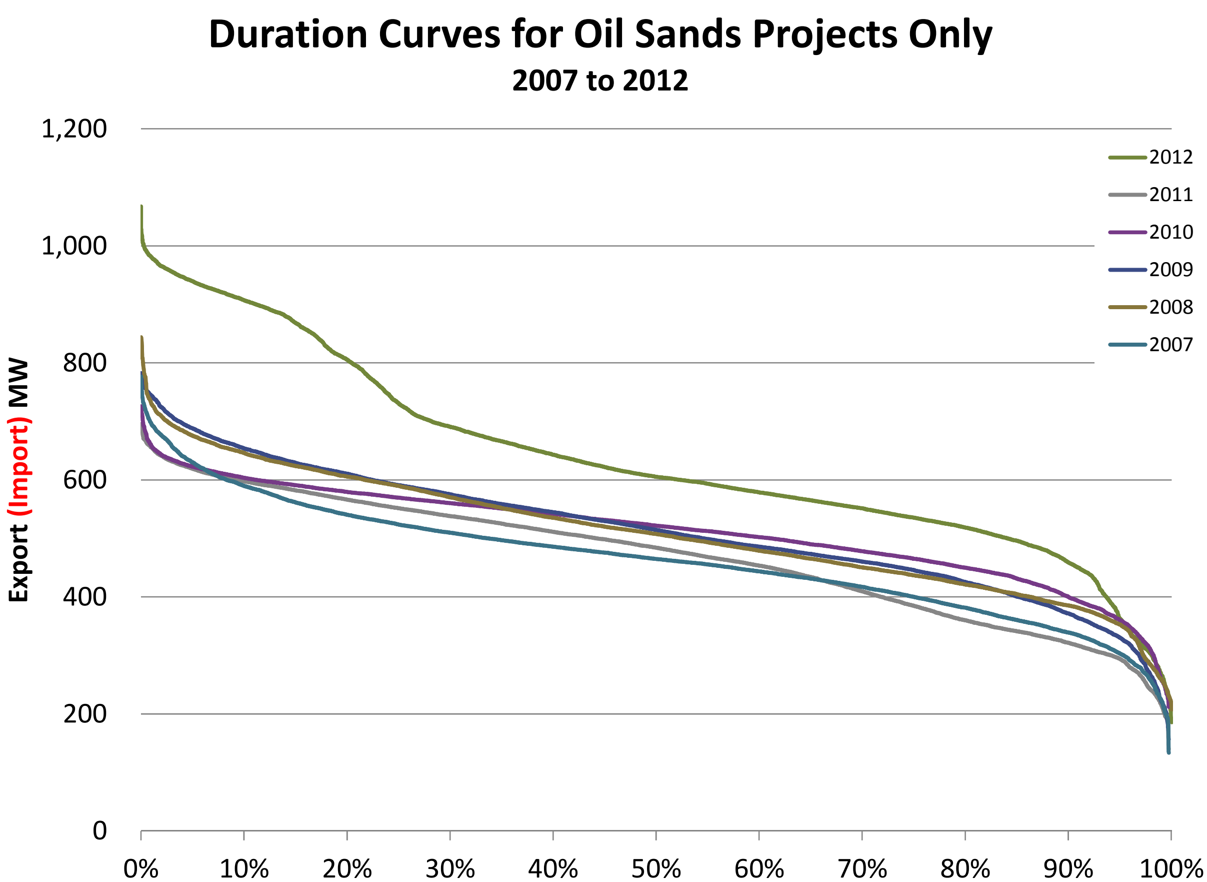
Figure 22 – Duration Curves for Urban Service Area of Fort McMurray Firm Loads



Continuing the trend from previous years, firm load from the Urban Service Area of Fort McMurray has increased, assumed to be the result of increased demand associated with economic growth. The city imports all electricity from the provincial grid, drawing on average around 320 MW in 2012; 9% (or 27 MW) above the 2011 average import capacity. This is the sixth consecutive year of increased firm load growth, a trend which is expected to continue going forward as the region experiences strong economic growth.

Extracting the firm loads from net exports provides an indication of oil sands related electricity flows (Figure 23). Oil sands projects in the Athabasca/Fort McMurray area provided net exports of electricity to the grid in every hour in 2007 to 2012; averaging just over 630 MW in 2012. Again, the increase in oil sands related exports has been attributed, in part, to increased excess co-generation capacity.

Figure 23 – Duration Curves for Oil Sands Projects Only



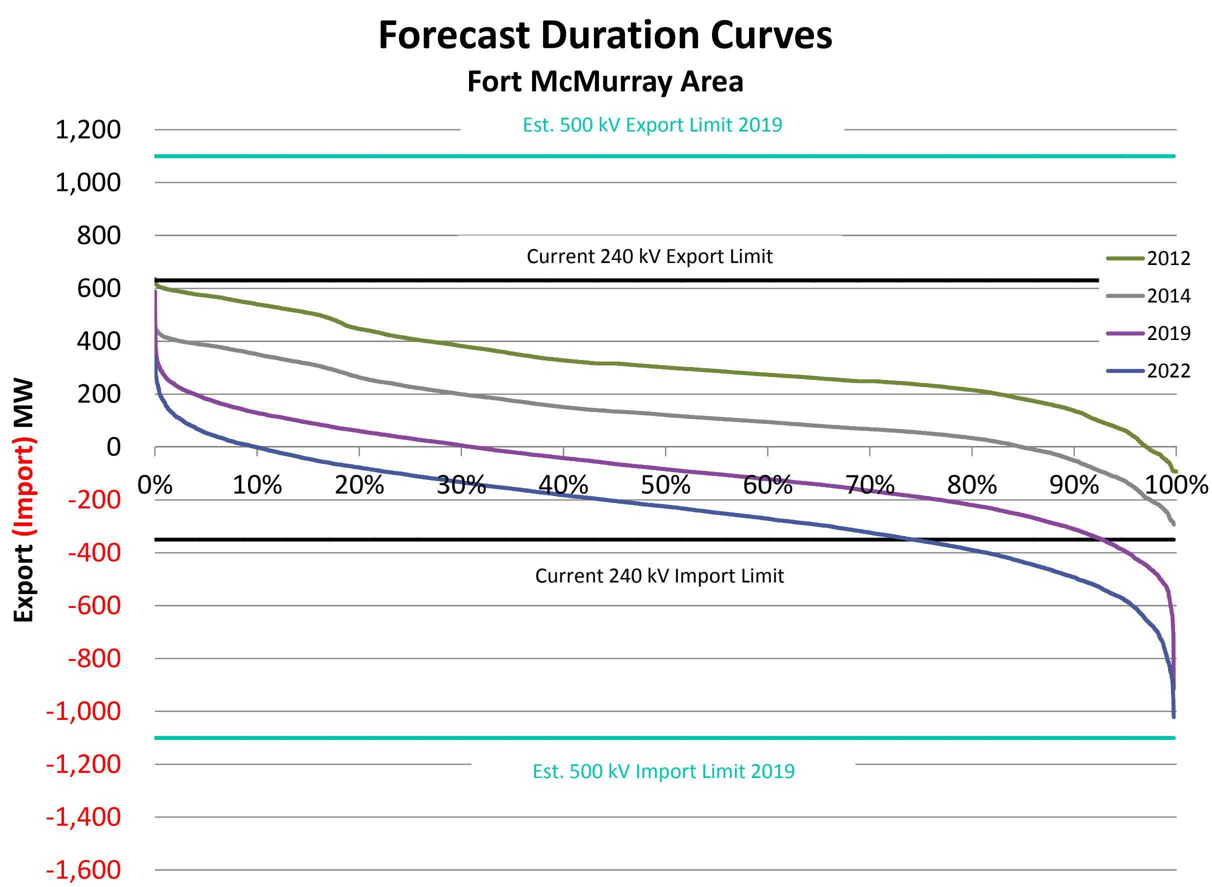
An estimate of hourly flows into and out of the Fort McMurray region in 2019 and 2022 was calculated using historical duration curves and the 2013 survey forecasts for on-site demand and co-generation. The following methodology was used:

Based on the consistent nature of firm load from Fort McMurray over the past six years (Figure 22), it is assumed the firm load shape will not materially change over time and grow at 8% per year. Oil sands related load and generation hourly behavior and additions were derived from 2012 hourly data and the 2013 survey results for the Athabasca/Fort McMurray region. As well, the following assumptions were included:

- 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 have a load factor of 85%.
- Capacity and timing of stand-by requirements and generation exports were determined hourly, on a probabilistic basis, for each load and generation project included in the 2013 survey (Medium Range).
- No consideration of wholesale power prices was allowed to influence the results (i.e. all net exports were assumed to be from surplus on-site generation behaving as price takers, with no additional electricity produced as a result of higher market prices).

The results of the analysis are shown in Figure 24 for the years 2014, 2019 (after the first stage of the 500 kV line is scheduled for completion) and 2022, with the 2012 data from Figure 21 shown for comparison purposes (including Urban Service Area of Fort McMurray firm load). The figure illustrates the results of the unadjusted on-site demand and co-generation values.

Figure 24 – Forecast Power Flow Duration Curves for Fort McMurray Area



The analysis suggests the current 240 kV line limits are sufficient to meet export and import needs in the near future. Actual export volumes in 2012 were above the N-1 export line limit shown in Figure 24, a circumstance that can occur in a few hours but would not be a preferred operating condition. Over time, as power flows in and out of the Fort McMurray region increase and become more exaggerated, the results indicate import capacity of the existing transmission system will become insufficient. The analysis suggests this insufficiency could occur as early as 2014 when import requirements are forecast to approach 300 MW. Between 2014 and 2015 the region is expected to transition to a net importer and by 2019 and 2022, import requirements into the region are substantial, approaching the planned 500 kV limit (shown by the teal "Est. 500 kV Import Limit, 2019" line).

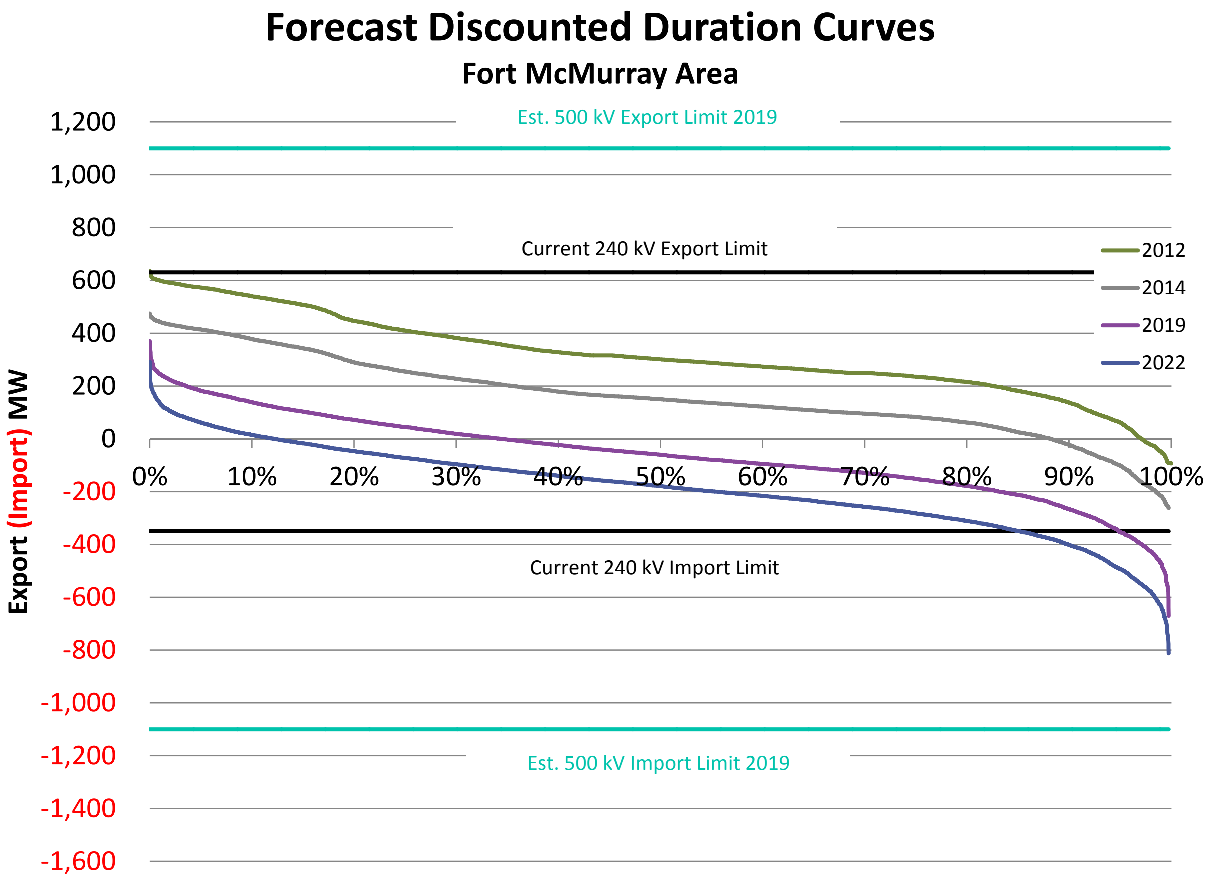
There are several factors that cause the increase in regional imports despite the forecast of excess on-site co-generation supply from all three regions. Table 8 and Table 9 indicated the majority of oil sands developers plan some form of on-site generation with support from the Alberta transmission grid serving a portion of on-site demand. During periods of planned or unplanned generator maintenance oil sands operations may import electricity from the transmission grid. The majority of the increase in imports is associated with firm load growth from the Urban Service Area of Fort McMurray, which is anticipated to record 8% growth over the forecast period. This load will effectively be served from excess on-site co-generation supply within the Ft. McMurray area.

Over the forecast period, there are a number of bulk and regional transmission development plans proposed by the AESO, including the 500 kV transmission line builds. Continued development of new assets and improvements/capacity additions to existing assets will impact the import/export capacity to the Fort McMurray area. The current 240 kV line limits (shown in Figure 24 and Figure 25) will most likely gradually increase over time, comparable to the year-over-year increases previously mentioned.

Consistent with previous years' reports, the Fort McMurray region will transition from a net exporter of electricity to a net importer. Imports are forecast to occur 15% of the time in 2014, up from 3% in 2012 and 7% in 2011, increasing to 70% of the time by 2019 and 90% by 2022.

Figure 24 above assumes all oil sands projects will proceed as reported in the 2013 survey. Applying the discount factor provides an alternative power flow forecast (Figure 25).

Figure 25 – Forecast Power Flow Duration Curves for Fort McMurray Area (Discounted)



Both anticipated on-site demand expectations and forecast installed co-generation capacity were adjusted in Figure 25 based on the development status of the project. While the magnitude of exports and imports is lower than the unadjusted case, the end result is consistent. The existing 240 kV line limits will be insufficient to serve power flows and the Fort McMurray area will transition to become a net importer, expected sometime during 2015 to 2016. Under both the discounted and undiscounted results continued improvements to the existing transmission infrastructure will support increased power flows; however, the 500 kV lines to Ft. McMurray will be required by the end of the decade.