



Fort McMurray Area Service Requirements Forecast

April 2, 2007

Executive Summary

The oil sands industry is the catalyst for significant growth in northeast Alberta and has created a need for new electricity infrastructure development. Reliable electrical supply is of considerable importance to oil sands producers as these facilities typically require a combination of Supply Transmission Service (STS) and Demand Transmission Service (DTS) with varying degrees of usage to help balance operations and for reliability purposes. The Alberta Electric System Operator (AESO) is in the process of preparing an area transmission plan for the Fort McMurray area.

A forecast of the load and generation potential is necessary to comprehend the Transmission Service requirements for the area. This forecast information has been obtained through consultation with the regional stakeholders. According to the forecast, the Fort McMurray area will have significant on-site load and generation. By 2016, this area is forecasted to have 2,827 MW of load and 3,192 MW of installed generation. The total DTS requirement in this area is expected to increase from the present 577 MW to 2,038 MW by 2016. Similarly the STS is expected to increase from 645 MW to 1,447 MW. It was observed that approximately 55% of the forecast DTS and STS requirements were low load factor (LF) requests (i.e. less than 40% load factor). The low LF DTS and STS components for 2016 are 1,187 MW and 721 MW respectively. Apart from the DTS and STS requirements, the size of the Fort McMurray load and generation is significant from a system planning perspective and may be another driver for future transmission development.

The transmission service requirements are unique for this region of the province. This area can shift from being a load center to a generation surplus region as indicated by magnitude of the DTS and STS requirements. To determine the transmission system capability that would be necessary to support the service requirements, different forecasting approaches were considered. These approaches were based on deterministic and probabilistic methods. The AESO is recommending a transmission transfer capability of approximately 1,700 MW by 2016 which is obtained by the probabilistic approach using Monte Carlo simulations and is higher than the deterministic approaches.

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1.0 Background

The Fort McMurray area is bounded to the north by the Northwest Territories, east by the Saskatchewan border, west by the fifth meridian and to the south by Athabasca/Lac La Biche and Cold Lake areas. The landscape is heavily forested and covered with vast bogs and muskeg. The main industries in this area are dominated by bitumen extraction, heavy oil processing, pipelines and forestry.

This report presents the service requirements forecast for the Fort McMurray area over the next ten years. The forecast was based on discussions held with the major oilsands lease holders, distribution facility owners (DFO), information extracted from Athabasca Regional Infrastructure Working Group (RIWG) reports, the AESO's own data from interconnection applications and planned projects.

This area is forecasted to have significant components of Demand Transmission Service (DTS) and Supply Transmission Service (STS). The DTS is the contractual value of the load that the AESO is obligated to serve to a customer. Similarly the STS is the contractual value of the generation supply for which the AESO is obligated to provide transmission capacity. At an industrial site, it is possible that the total physical on-site load or generation be equal to or higher than the DTS or STS contractual value. This concept is explained in detail in Section 3.4. The AESO has investigated a number of different forecasting approaches that can be employed to ensure that the transmission system in the Fort McMurray area is adequate to meet the needs of the area and are further elaborated in this report document.

1.1 Northeast Transmission Development Drivers

The oil sands industry is continuing its unprecedented growth and has created a need for new electricity infrastructure development in the northeast part of the province. Since 1996 over \$34 billion has been invested in Alberta's oil sands with a current production level of one million barrels a day. According to a March 29, 2005 "Oil Sands Co-Generation Potential" report produced by the Athabasca Regional Infrastructure Working Group (RIWG), total oil sands industry and investment could reach \$80 billion by 2013 with an expected production of over two million barrels a day. Other estimates note that with additional investments, the industry could produce up to three to four million barrels a day by 2021.

Reliable electrical supply is of considerable importance to bitumen producers for extraction to transportation and upgrading the bitumen to oil. There are currently two processes used for extracting bitumen from the oil sands, mining and in-situ. The mining process, used by companies like Syncrude, consumes a significant amount of both electrical energy and steam. Co-

generation facilities are commonly installed to offset electrical usage with modest amounts of electricity being available for export onto the grid.

The in-situ process used by companies like Petro-Canada employs a SAGD (Steam Assisted Gravity Drainage) technology to retrieve the bitumen. A significant amount of steam is required for this process while the electrical load is relatively small. This process is well suited for co-generation development. Regardless of process, these facilities typically require a combination of STS and DTS with varying degrees of usage to help balance operations and for electric supply reliability.

With the amount of bitumen extraction in Fort McMurray and Cold Lake areas, transportation for remote upgrading or shipping locally refined oils to market requires extensive development of pipelines. These pipelines require a series of pumping stations to maintain adequate pressures. The preferred prime mover is an electric motor due to its simplicity and ease of operation. The selection of an electric drive rests on the availability and capacity of nearby electrical infrastructure. These pumping stations are generally located south of Ft. McMurray and Athabasca areas.

Oil sands operations encompassing bitumen extraction, heavy oil upgrading and refining facilities also have an impact on the electricity requirements of municipalities in the area who often support corresponding growth in secondary industries such as oilfield services, manufacturing and transportation. These industries are generally located along the Fort McMurray to Fort Saskatchewan corridor.

1.2 Overview of Load and Generation

The existing load in the Fort McMurray area as well as the future load growth is dominated by oil sands mining and SAGD operations. The oil sands developments in the area are expected to continue the practice of installing on-site generation to supply all or part of their plant electrical requirements while at the same time contracting for system capacity for all or part of this load.

The analysis of the historical load data of industrial loads with on-site generation in the area has revealed a number of characteristics which are significantly different than the majority of load on the system. The characteristics of on-site loads require a different approach when forecasting the expected area peak load compared to other areas where historical coincidence between loads is used to forecast the future coincident demand of a region. The major differences are:

- no correlation between individual plant loads
- no correlation between the plant loads and system load

- no correlation between the plant on-site generation and the system load or pool price
- on-site generation runs at a high capacity factor but still varies randomly compared to system load or pool price over a fairly wide range of operation
- very weak correlation between the on-site generation and the on-site load

The implications of these unique characteristics are as follows:

- 1) Because the variation of the plant loads is random between plants (high diversity), the regional peak will be the result of random chance and therefore historical coincidence can not be used to predict the areas peak load.
- 2) Because the loads have no correlation with system load, the peak of the area could occur at any time. The system could be at peak, light load or anywhere in-between. This means that the system must be planned to handle a peak in this area at all times.
- 3) Because the generation output at the on-site facilities is random, the normal practice of economic dispatching the generation can not be followed.

In other words, the on-site customer's net-to-grid generation/load could be high, low or anywhere in between at the time of a regional or system load peak.

1.3 Existing System

The existing transmission system in the Northeast region is shown in Figure 1.3-1. As shown, there are three 240 kV lines connecting the Fort McMurray region to the rest of the Alberta Interconnected Electric System (AIES). The underlying 144/138 kV transmission network is weak and serves as a sub-transmission network. To facilitate the analysis of the region, a "South of Fort McMurray" or SFM cut-plane is defined and all the power flows are measured with respect to the SFM cut-plane. Previous studies had established a power export limit of 600 MW out of and an import limit of 300 MW to the Fort McMurray area.

With the recent plans for load and generation development north and south of Fort McMurray area, these export and import limits may change over time. The new generation in the area will tend to increase the export capability limit by providing the necessary voltage support whereas the increase in load will tend to reduce the power import capability into the area.

The northeast (NE) cut plane is another interface defined in the northeast region. As shown in Figure 1.3-1, this cut plane includes 240 kV transmission line flows on 9L913 south of Mitsue 732S, 920L and 921L south of Lamoureux 71S. At present there is a power export out of the northeast region at this cut plane for most of the time of the year. In 2005, a maximum power export of approximately 400 MW was observed. Flows on this cut plane are being addressed in a separate study.

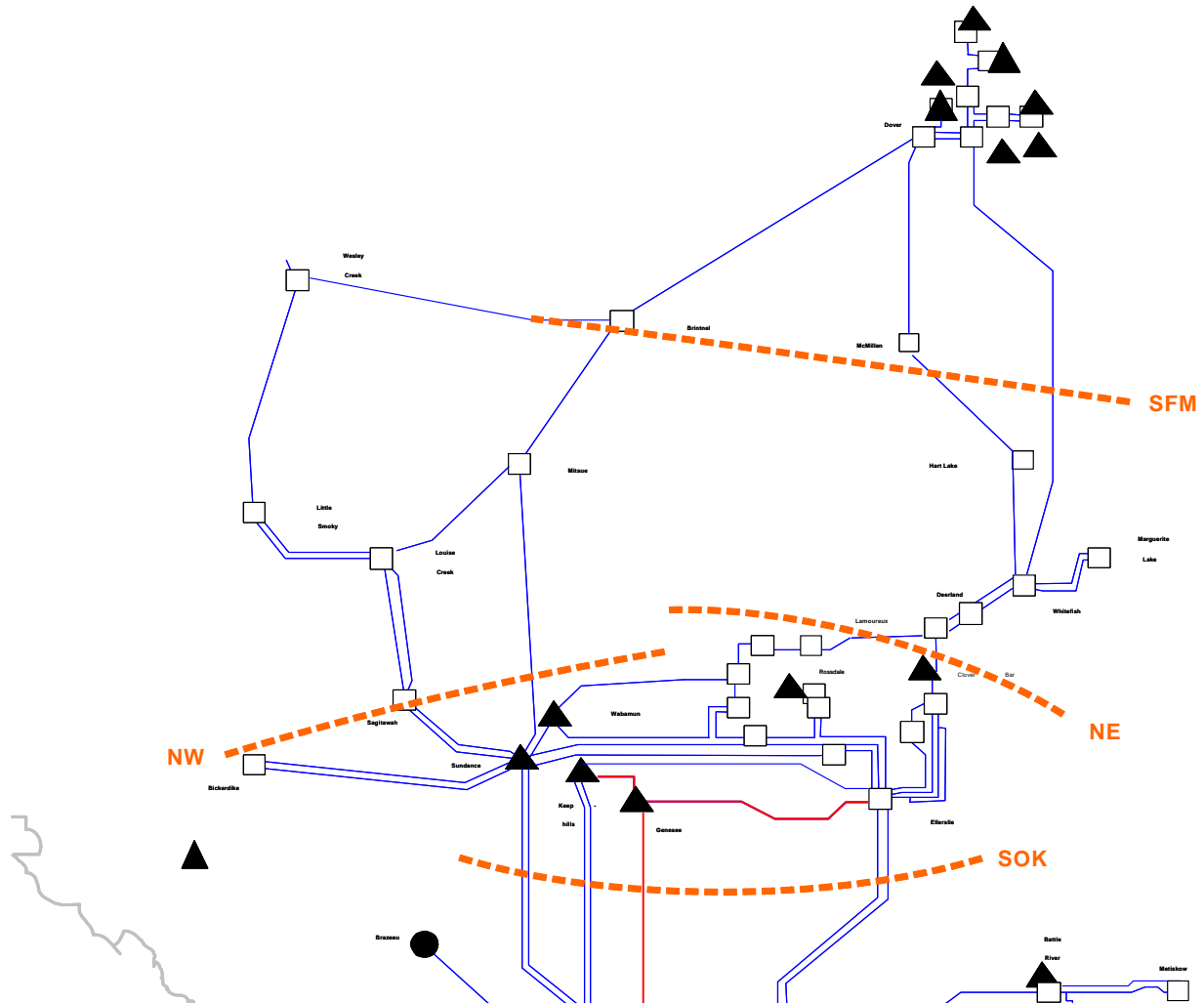


Figure 1.3-1: Existing Northeast Transmission System

1.4 Existing SFM Path Flow Duration Curve

Figure 1.4-1 shows the values of export and import in to the Fort McMurray area for the year 2005. These values were measured on the power flowing across the south of Fort McMurray (SFM) cut-plane as shown in Figure 1.3-1. As evident from the 2005 historical data, Fort McMurray area has been an export area almost all the time with a maximum export of 388 MW. The maximum import level in to the Fort McMurray area was 136 MW and the duration for which the area imported power was only 182 hours. The 2005 sum of STS contracts was 645 MW and the sum of DTS contracts was 353 MW. This shows that an actual maximum flow out of FMM area of 388 MW always remained lower than the maximum contractual value of 645 MW. Similarly the maximum import value of 136 MW always remained lower than the maximum contractual value of 353 MW.

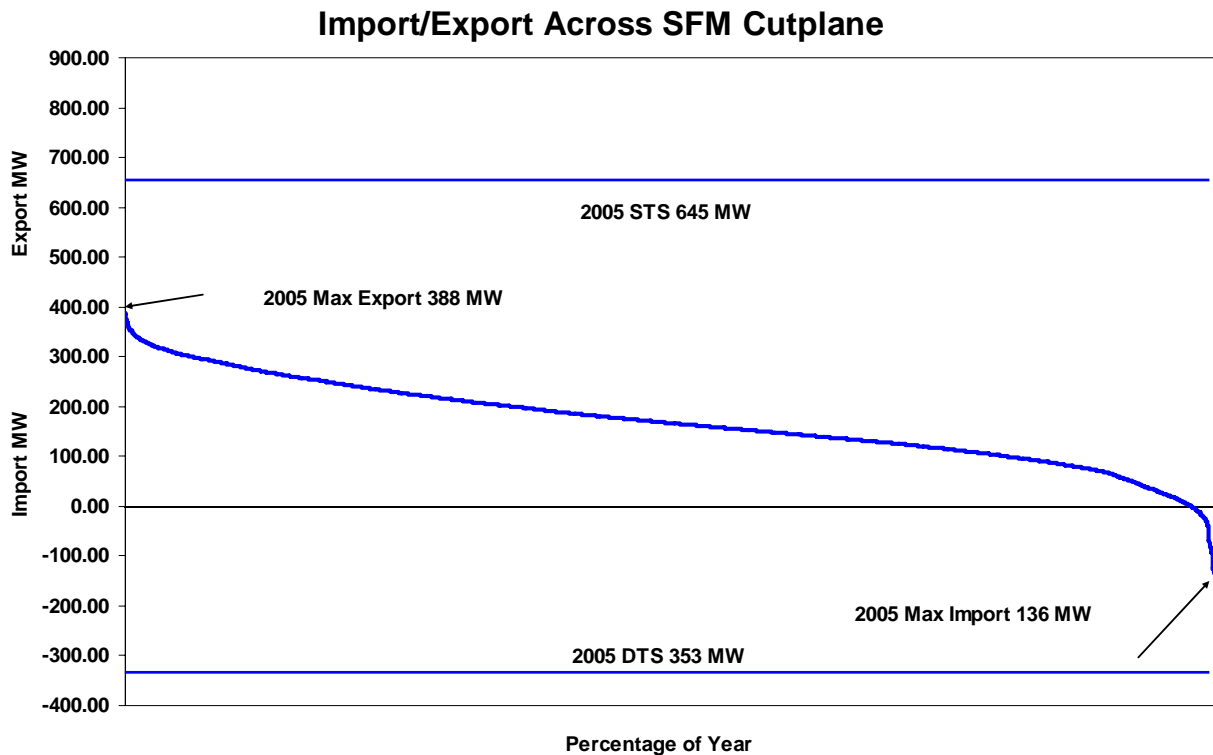


Figure 2.4-1: 2005 Fort McMurray Export and Import Values

1.5 Stakeholder Consultation

The assessment of load and generation scenarios for the Fort McMurray and adjacent areas is necessary to comprehend the transmission system requirements for the region. Information about the major individual customers such as the electrical load, generation, future plans, operational patterns, upgrading facilities etc. has been obtained through consultation with the stakeholders. A list of the major stakeholders consulted for this assessment is included in the Appendix A. The questionnaires used for collecting information are shown in Appendix B.

2.0 Growth of Load and Generation

The load forecast for the Fort McMurray region must address three unique features of the loads being added in the region. These are:

- The new PODs are exclusively supplying industrial type loads which have high load factors but at the same time exhibit a very low correlation between PODs.
- Many of the existing and future PODs rely on on-site generation and are only contracting for a part of their load.
- Many of the new PODs, even though contracted to supply all of their proposed load, have also indicated the intent to add generation at the same site.

The AESO has prepared these forecasts in consultation with the DFO and the stakeholders in the area.

2.1 Types of Load Customers

For the forecasting of both growth and the regional coincident peak, the Fort McMurray load customers have been divided into three types: Distribution, Industrial and Net Onsite Load. The detail definitions are included in Table 2.1-1. Each of these load types has distinctly different characteristics which influence how both growth and coincidence are forecast.

Table 2.1 1: Definitions for POD load categories

Distribution Load	Substations supplying a mix of distributed residential, farms, small commercial and oil and gas fields served by the Distribution Facility Owner (DFO) via a distribution power system.
Industrial Load	Large industrial load customer substations including industrial plants, compressor and pumping loads. This substation category also includes those customers with generation on site which have contracted (DTS) for 100% of their total gross load.
Net Onsite Load	Large industrial load customers which have onsite generation and have not contracted (DTS) for all of the gross (total physical) loads at the site. The demand forecasted for these sites is the "net load" which is the total physical load minus the on site generation production.

2.2 Distribution Load Forecast

The Fort McMurray region currently has only a minimal amount of Distribution type PODs. Only the PODs which supply the actual City of Fort McMurray and the immediate surrounding area are considered to fall within this classification. No new distribution type PODs are forecast to be added. Table 2.2-1 shows the DFO Point of Delivery (POD) coincident winter peak load forecast for Fort McMurray region.

Table 2.2 1: Fort McMurray Area – DFO Load Forecast (MW)

Substation	2006	2007	2008	2009	2010	2011	2016
Wabasca 720S	11	12	13	13	14	14	15
Brintnell 876S	24	27	31	35	37	37	42
Ruth Lake 848S	27	28	33	35	36	40	53
Parsons Creek 718S	35	39	44	47	50	53	66
Hangingstone 820S	30	19	20	21	22	23	28
Gregoire 883S	6	6	6	1	1	1	5
Algar 875S	8	8	11	11	11	12	14
Mariana 833S	3	8	10	10	12	12	17
Crow 860S	6	7	7	3	3	8	21
Kinosis 856S	19	24	24	25	26	27	34
Joslyn 849S	23	28	14	16	19	20	29
Leismer 72S	5	5	5	5	5	5	5
Christina Lake 723S	7	23	33	34	35	36	42
Total	204	234	251	256	271	288	371

2.3 Industrial Load Forecast

The industrial load forecast consists of large industrial loads only. Typically these are dedicated substations for a specific industrial plant, compressor or pipeline pumping stations. The demand and energy at existing substations only changes significantly if the plant expands or makes changes. This forecast, shown in Table 2.3-1, has been built up from a forecast of the average load of individual plant expansions or new plant sites and aggregated into a total for the region. The load has a high load factor compared to a distribution POD but because the individual station demands are typically driven by variations in the processing, there is virtually no correlation between plants or with the distribution coincidental peak.

New industrial plants which have indicated they will be adding on-site generation but will contract for the full plant load have had their entire load included in the industrial customer type forecast. Because they have also provided a forecast of the generation to be added at these sites, this generation has been included in all generation scenarios studied. Both the load and generation forecast for the industrial load is shown in Figure 2.3-1.

Table 2.3 1: Average Industrial Load in Fort McMurray Area (MW)

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016
Average Load	288	295	432	491	863	1204	1247	1268	1314

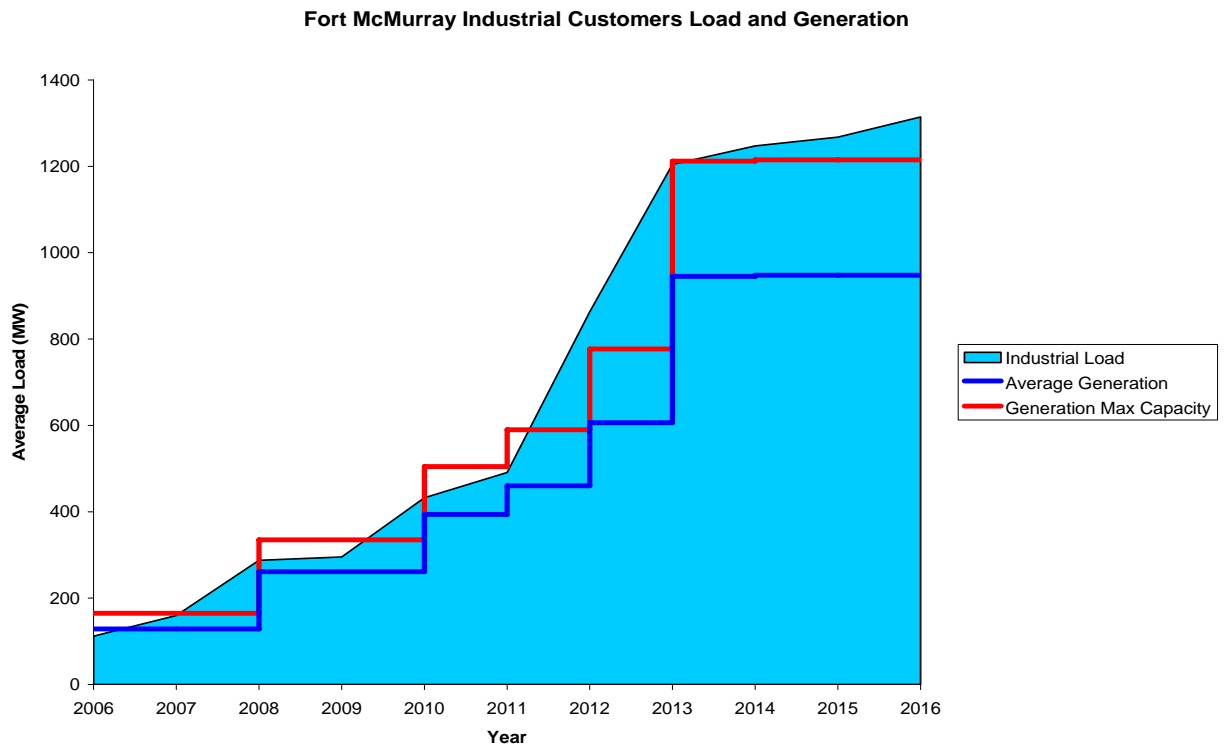


Figure 2.3 1: Fort McMurray Region Industrial Load and Generation Forecast

2.4 Net Onsite Load Forecast

The industrial sites with onsite generation who intend to contract for only part of their gross (total physical) load are forecast as a net load but also require a forecast of both total load and total generation in order to forecast a peak load for the region. The average load and average generation forecast for the Net Onsite customer type are shown in Figure 2.4-1 and Table 2.4-1.

Because the load is not fully covered by a contract for the capacity, the load less the generation at a site are treated as a positive or negative net load when planning the system for load service adequacy. This net load is variable with little or no correlation to other loads on the system due to the variability of the load, generation outages, and seasonal generator de-rates weak correlation of generation to load, and variability of generation output due to varying process requirements for steam. The peak load at these sites exhibits higher variability than industrial load alone due to the added randomness of generator outages.

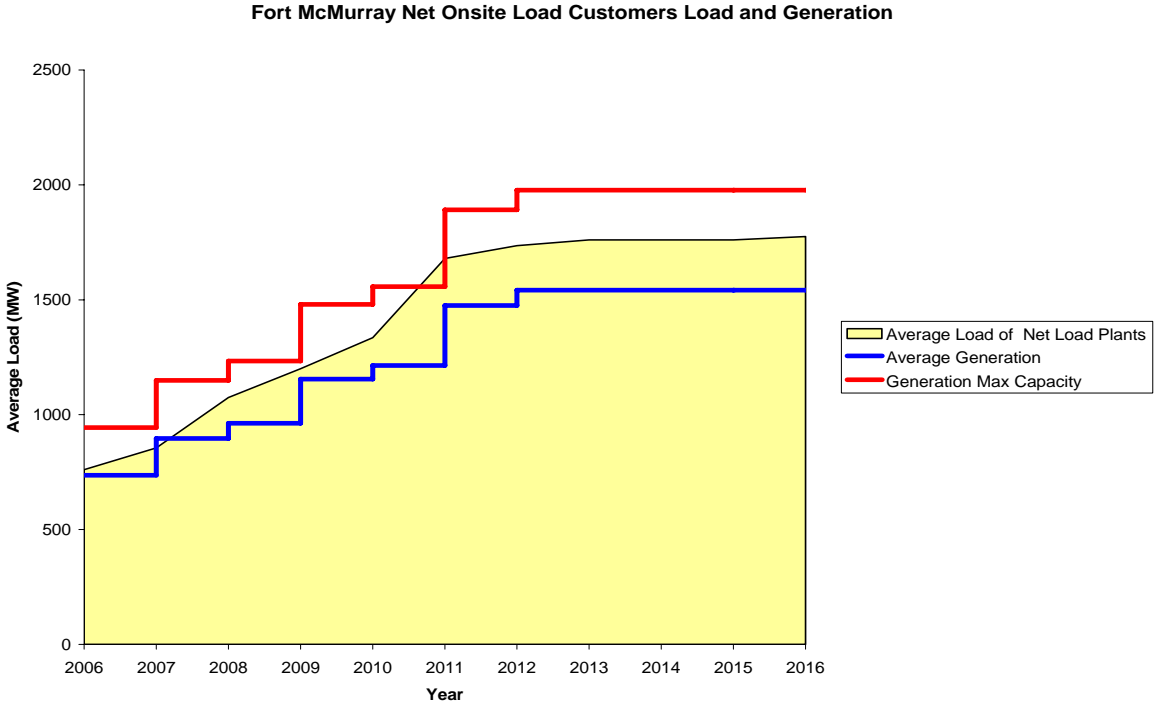


Figure 2.4 1: Fort McMurray Average Net Onsite Customers Load and Generation Forecast

Table 2.4 1: Load and Generation for Net Load Plants Customer (MW)

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016
Average Load	1,075	1,200	1,335	1,680	1,735	1,761	1,761	1,761	1,775
Generation MCR	1,234	1,480	1,557	1,892	1,977	1,977	1,977	1,977	1,977

2.5 Estimated SFM Path Flow Duration Curve

One method to estimate the expected 2016 import/export duration curve is to extrapolate the 2005 duration curve with the 2016 forecast values for the DTS and STS using the following formula.

- $2016\ import = (2005\ import / total\ 2005\ DTS) \times total\ (2016)DTS$
- $2016\ export = (2005\ export / total\ 2005\ STS) \times total\ (2016)STS$

This results in a projected maximum export of 870 MW and a maximum import of 785 MW. The projected import and export duration curve for the year 2016 is shown in Figure 2.4-2.

Projected 2016 STS/DTS

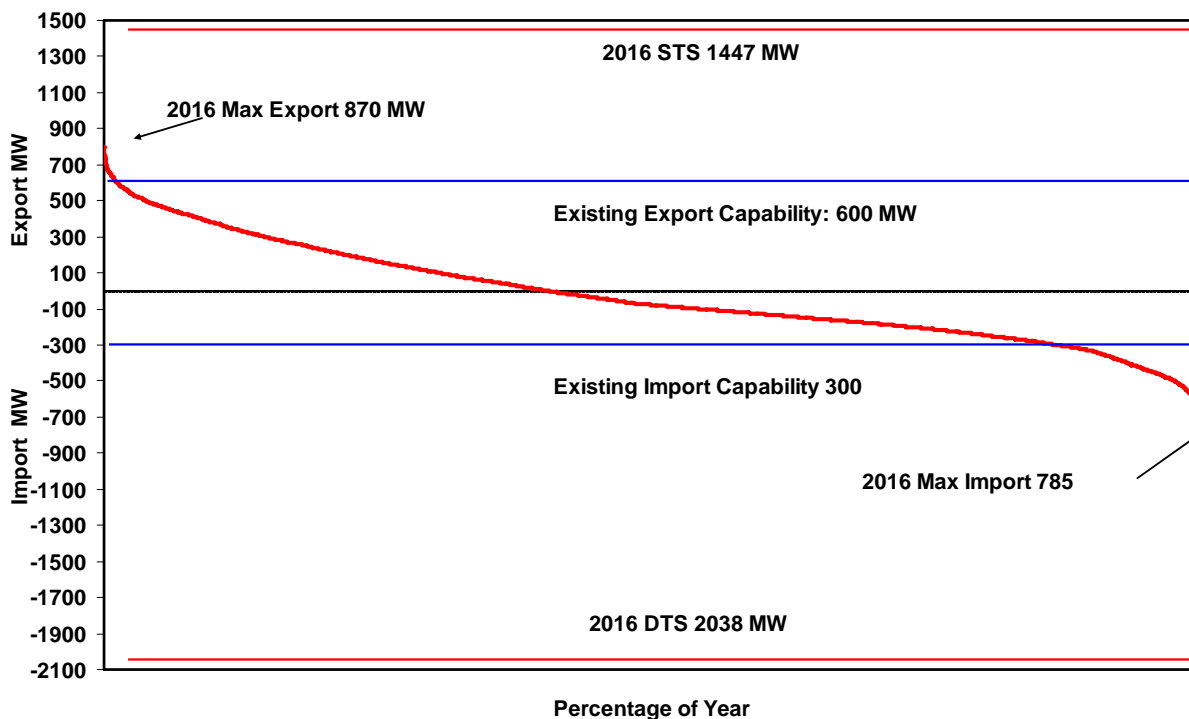


Figure 2.4 2: Projected 2016 Fort McMurray Export and Import Values

Given that the load duration curve represents one year and may differ for other years, further analysis is required to determine the expected maximum values of export and import for this region. It is important to recognize not only the magnitude of export and import of the region but also the duration for which the exports and imports occurred. In 2005, an export out of the Fort McMurray area was observed for most of the time during the year with a median export magnitude of 170 MW. This pattern is expected to gradually change in the future due to DFO load growth in the region. The projected 2016 power flow pattern shows that for slightly more than half the time, the Fort McMurray area will be an import area. The median import value, however, during the year is expected to be close to 0 MW.

3.0 Forecast Methodologies for Coincident Regional Peak

As mentioned before, the Fort McMurray region is unique from a forecasting perspective as it has a number of customers that will be contracting both DTS as well as STS. Planning for a transmission system that is capable of handling the full range of all contracted DTS and STS without consideration of any diversity will result in large capital investments. On the other hand

planning for only the normal system conditions can result in congestion and possible violation of the AESO's Reliability Criteria. The solution is to find the most likely maximum load and supply scenarios that the Fort McMurray region will experience during the next ten years. This likely load and supply scenarios would then be the basis for which the transmission system will be planned.

A suitable approach can be obtained by employing deterministic or probabilistic methods to determine the transfer capability for the Fort McMurray area. Three approaches have been considered to determine load and supply expectancy for the Ft. McMurray area. These are:

- Deterministic
- Capacity Outage Probability
- Probabilistic Analysis Using Monte Carlo Method

3.1 Major Assumptions

The major assumptions used in all the approaches are as follows:

- all the approaches are based on the load and generation forecast provided in Section 2;
- all the approaches assume no transmission or generation constraints outside of the Fort McMurray area;
- the outage rates considered for the two probabilistic approaches (based on Canadian Electrical Contractors Association (CECA) generation report are as follows:
 - Forced outage rate of 5.5% for gas turbine cogeneration units and steam turbine units
 - Forced outage rate of 3.6% for gas turbines units
 - Maintenance outage rate of 4% for all units;
- load duration curve assumed to be as per 2005/2006 as shown in Figure 3.1-1

2005_06 Ft McMurray Load Duration Curve

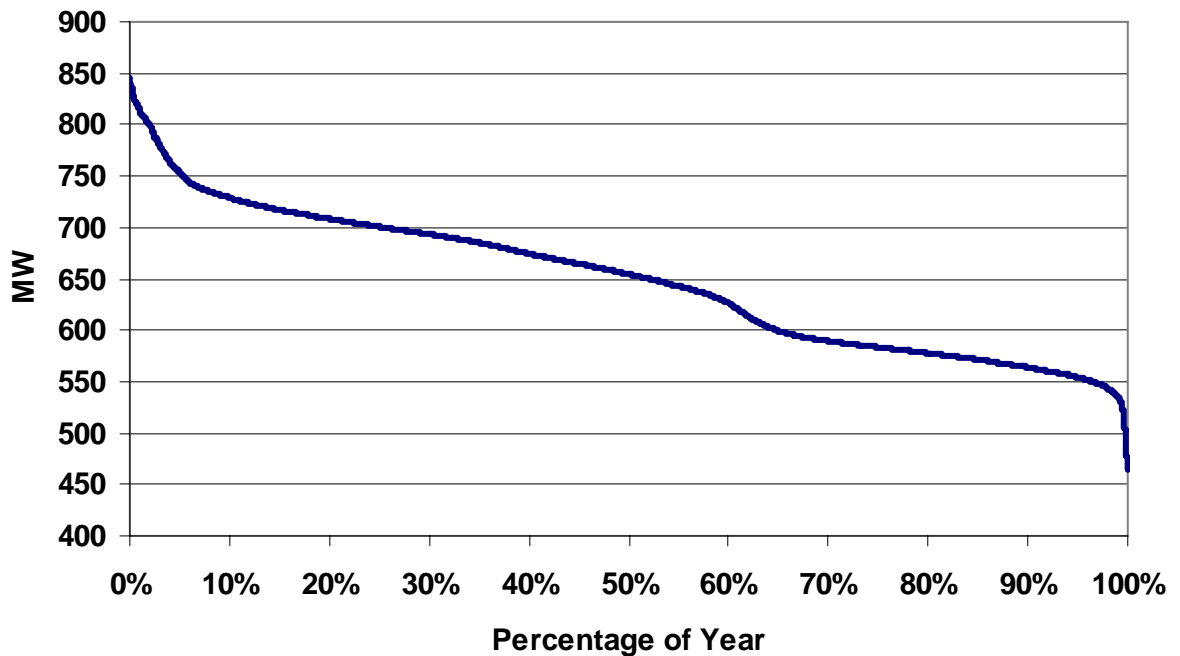


Figure 3.1 1: 2005-06 Fort McMurray Load Duration Curve

3.2 Deterministic Approach

Two individual deterministic approaches have been considered to calculate the transfer requirements for the Fort McMurray area. The first approach is based on the fact that the loads and generation in the area can be divided into high and low load factor categories. The second and more traditional approach is where all the physical load and generation is considered regardless of their operational characteristics (high or low load factor) or contractual (DTS/STS) values. The two approaches are discussed as follows;

3.2.1 High and Low Load Factor Load and Generation

Customers with on-site generation typically require a combination of STS and DTS with varying degrees of usage to help balance operations and for electric supply reliability. Their services can be divided into high load factor and low load factor categories. Table 3.2-1 shows the DTS and STS forecast split into high and low load factor categories for the Fort McMurray area customers with on-site generation. High load factor DTS & STS represents the normal

load and generation conditions that will be present most (40% or more) of the time. Whereas low load factor DTS represents load that could appear due to a loss of one or more generators due to maintenance or forced outages. Similarly, low load factor STS represents excess generation output that could be present due to change or loss of processing load.

Table 3.2 1: Fort McMurray Area – STS & DTS Forecast (MW)

Year	2006	2007	2008	2009	2010	2011	2016
Low LF DTS	297	377	512	542	534	594	1187
Total DTS	577	687	888	928	1,006	1,112	2,038
Low LF STS	251	361	441	365	456	541	721
Total STS	645	805	880	930	1,081	1,321	1,447

As evident from Table 3.2-1, the sum of DTS contracts will increase from a present value of approximately 577 MW to 2,038 MW by 2016. Similarly the total STS contracts will also increase from 645 MW at present to 1,447 MW by 2016. However the values of average generation and load on the system are much higher than just the STS and DTS values. This is because the physical generation/load at a site could be higher than the STS/DTS contractual values as explained in Section 2. At present the average generation in Fort McMurray area is approximately 1,109 MW whereas the average load is 799 MW. By 2016, these values are expected to increase to 3,192 MW and 2,827 MW for generation and load respectively as shown in Table 3.2-2. The total Alberta Interconnected Electric System (AIES) generation and load are of the order of 12,000 MW and 9,000 MW respectively which shows that the Fort McMurray system represents a significant part of the AIES.

Table 3.2 2: Fort McMurray Area – On-site Generation & Load Forecast

Year	2006	2007	2008	2009	2010	2011	2016
Avg. Generation (MW)	1,109	1,314	1,569	1,815	2,062	2,482	3,192
Avg. Load (MW)	799	913	1252	1377	1597	1992	2827

3.2.2 DTS/STS Deterministic Approach

This deterministic approach is based on factors such as:

- the total amount of high load factor (LF) DTS and STS;
- the total amount of low LF DTS and STS;
- Maintenance schedule of generators;
- Most significant contingency

A consideration in ascertaining the maximum load and supply scenarios is the maintenance outage schedule of the generators in the Fort McMurray region. The AESO receives information about the maintenance schedule of individual generators but does not have a role in coordinating the outage schedules between these units unless these outages pose a risk to the system. A maintenance outage of two or more generators may put the system at risk and therefore has to be considered in the various planning approaches.

Generation unavailability due to derated capacities is another factor to consider. The main reason for derates is the ambient temperature although process driven capacity reduction can sometime occur in the system. This phenomenon is more prominent in the gas turbines during summer months. In the formulation of the planning approach for Fort McMurray area, it was assumed that all the gas turbine unit capacities in 2016 were derated by 10% which is in the order of 300 MW. Therefore this magnitude of unavailable generation will have to be considered to determine the target transfer in capability for planning requirements.

For simplification purposes, it has been observed that the present import capability into the Fort McMurray area is approximately half of the export capability out of the region. It was concluded that planning the transmission system capable of import will also provide export capability out of this area. As discussed earlier, the requested DTS contract level exceeds the STS level by over 25% in 2016. Therefore, the deterministic forecasting approach will

focus on meeting the DTS requirements and then ensure that the STS requirements can also be served.

Within the DTS/STS deterministic methodology, several individual approaches were considered that were derived from typical utility practices, planning criteria and actual events. These approaches are based on the assumption that the profile of the on-site load is flat. Usually the on-site load profile has a +/- 20% variation and is not totally flat. In the following possible approaches, different types of contingencies or additional loads are added to the flat load profile to cover the possible load spikes. The following are listed from maximum coverage to the minimum transmission development:

(a) Total Forecasted DTS

This approach will result in a strong transmission network but at the same time will be the most capital intensive solution in order to supply the fully contracted DTS. It assumes that all the customers that have on-site generation will concurrently have their generators out for maintenance or unavailable due to a forced outage.

(b) High LF DTS + percentage of Low LF DTS

This approach plans to support high load factor DTS load on the system as well as a percentage of the low load factor DTS. This analysis will determine the likelihood of the Ft. McMurray area generation being susceptible to multiple generator outages (maintenance and forced). The results can be translated to a percentage of low LF DTS that should be supported. This approach requires generator maintenance and performance data. The amount of low LF support to be selected is subjective and open to debate.

(c) High LF DTS + maintenance outage of the largest generator + largest low LF DTS

In this approach, it is assumed that the largest generator is out for maintenance and the planning is to be done for the high load factor DTS plus the largest low load factor individual DTS load. This is a comprehensive approach and is realistic as this type of a scenario has already occurred in the AIES system.

(d) High LF DTS + maintenance/forced outage of the two largest generators

This approach will support high load factor DTS load on the system plus the loss of the two largest generators in the Ft. McMurray area on either maintenance or forced outage.

(e) High LF DTS + Largest Low LF DTS

This approach will support high load factor DTS load on the system plus the largest low load factor DTS in the Ft. McMurray area.

(f) High LF DTS + maintenance/forced outage of the largest generator

This approach will support high load factor DTS load on the system plus the loss of the two largest generators in the Ft. McMurray area on either maintenance or forced outage.

(g) High LF DTS

This represents the DTS scenario that would be prevalent most of the time on the system. It however fails to cover the possible contingencies that can and have occurred on the Fort McMurray transmission system. For this reason, this approach has not been considered.

After completing a review of the various individual deterministic forecasting approaches for the Fort McMurray area, the AESO would favor the approach outlined in (c) above which plans for high load factor DTS; plus the highest individual low load factor DTS; while the largest generator in the Fort McMurray area is out for maintenance and adjusted for generation unavailability. This approach represents a realistic level of load and generation scenario and also takes care of the worst possible contingency conditions that have actually occurred in the system. With this approach, the target transfer in capability in the year 2016 would be as follows:

- high load factor DTS = 851 MW
- largest individual low load factor DTS = 250 MW
- largest unit out for maintenance = 165 MW
- derated generation = 300 MW

The total target transfer in capability would be 1,566 MW. As previously stated, planning the Fort McMurray system for the above mentioned transfer in level will also be adequate for all the reasonable STS requirements for the next ten years. Table 3.2-3 shows the transfer in capability obtained for each year up to 2016 with the deterministic approach.

Table 3.2 3: Transfer Capability (MW) Using DTS/STS Approach

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016
High LF DTS	376	386	472	518	663	699	747	797	851
Gen. Derates	157	182	206	248	275	300	300	300	300
Largest Low LF DTS	250	250	250	250	250	250	250	250	250
Largest Gen.	165	165	165	165	165	165	165	165	165
Transfer Capability	948	983	1,093	1,181	1,353	1,414	1,462	1,512	1,566

3.2.3 Traditional Deterministic Approach

This traditional approach considers the actual physical generation and loads instead of using STS and DTS contractual values. The load forecast presented in Table 3.2-2 shows the average loads in the Fort McMurray area. In view of the characteristics of the loads in the area, it is assumed that the average loads are approximately 80% of their peak values. Therefore, all the loads need to be converted into the peak values. The required transfer in capability is calculated as the difference between the peak load and average generation while considering the contingency of the largest unit as well as the generation derates. For the year 2016, the target transfer capability would be as follows:

- peak load = 4,003 MW
- average generation = 3,192 MW
- largest unit = 165 MW
- generation derates = 300 MW

Table 3.2 4: Transfer Capability (MW) Using The Traditional Approach

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016
Peak Load	1,813	1,975	2,311	2,816	3,341	3,800	3,862	3,922	4,003
Avg. Gen	1,569	1,815	2,062	2,482	2,754	3,189	3,192	3,192	3,192
Largest Unit	165	165	165	165	165	165	165	165	165
Gen. Derates	157	182	206	248	275	300	300	300	300
Transfer Capability	566	507	620	747	1,027	1,076	1,135	1,195	1,276

3.3 Capacity Outage Probability Approach

The forecasting approach discussed in the previous sections is based on a deterministic methodology. The weakness of deterministic approaches is that these do not account for the probabilistic or stochastic nature of system behavior, customer demand or of component failures. Also these approaches do not precisely define the true risk of not meeting the load in the system. In this section, a Capacity Outage Probability approach¹ is employed. This probabilistic approach is widely used due to its flexibility and simplicity of application. This method uses a capacity outage probability table derived from the average power production of the generators with their associated maintenance and forced outage rates. The average generator production, while operating, was determined to be approximately 84% of maximum continuous ratings (MCR) based on the historical data for the Fort McMurray area generators. The outage probability is combined with the local area system load characteristics to give an expected risk of loss of load.

The capacity outage table is built to evaluate the probability of outage of unit capacity in the system. Based on forecasted load and generation provided in Sections 2.1 to 2.4 and the assumptions stated in Section 3.1, the cumulative probability of outage of 400 MW or more for a generating system of 3,192 MW is very low as illustrated in Figure 3.3-1. In building the capacity outage probability table, the cumulative probabilities lower than E-07 were truncated.

¹ Reliability Evaluation of Power Systems, 2nd Edition; Roy Billinton, R.N. Allan; Section 2.2.4 A Recursive Algorithm for Capacity Model Building

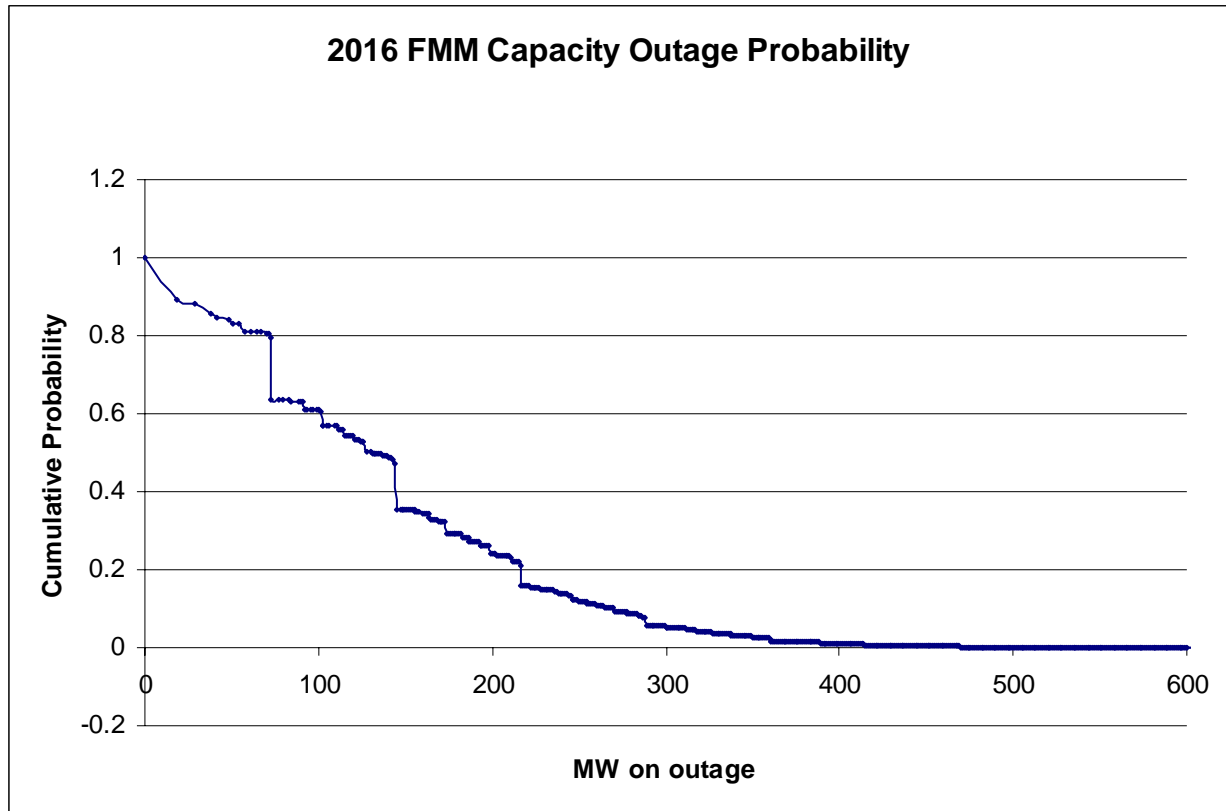


Figure 3.3 1: Capacity Outage Probability

The load duration curve for 2016 is shown in Figure 3.3-2. This duration curve is based on the 2005/06 load data and has been extrapolated for the year 2016 using information about the DFO and behind-the-fence load growth rates. In this method the underlying assumption is that the load duration curve for the year 2016 will have a similar shape as that of 2005/06. The installed capacity of the Fort McMurray generation is also shown in Figure 3.3-2. This capacity takes into account the unavailable generation due to maintenance considerations. As mentioned earlier, the import capability of the existing transmission system has been established to be 300 MW which is also shown in the figure.

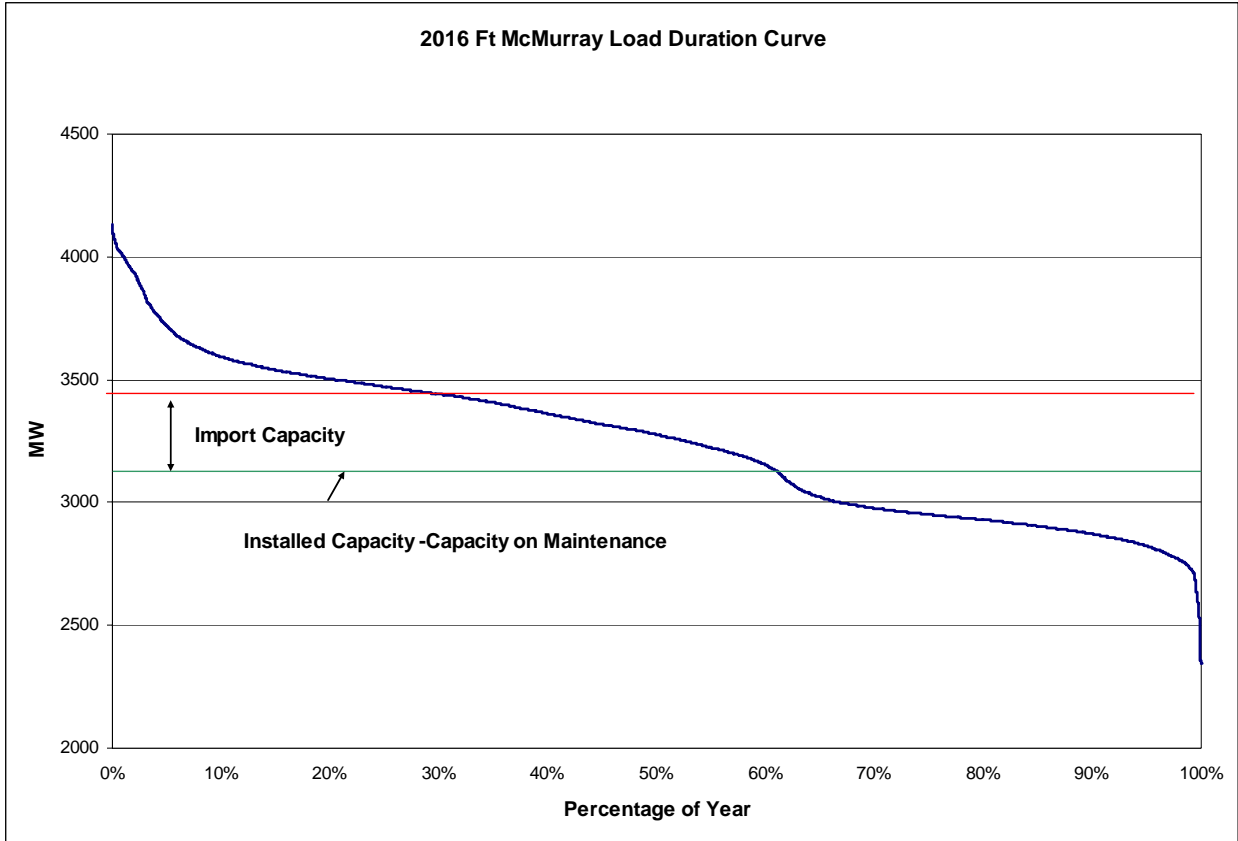


Figure 3.3 2: Fort McMurray Load Duration Curve

From the capacity outage table, individual probabilities of different generation levels were obtained. Similarly a total load probability table was built using the load duration curve shown in Figure 3.3-2. Using the generation and load probabilities, a net load (Load – generation) probability curve was developed which is shown in Figure 3.3-3. A probability of 1 in 5 years would yield a net load of approximately 1,500 MW. Adding a value of 100 MW of losses for 2016, a target transfer in capability of approximately 1,600 MW was obtained.

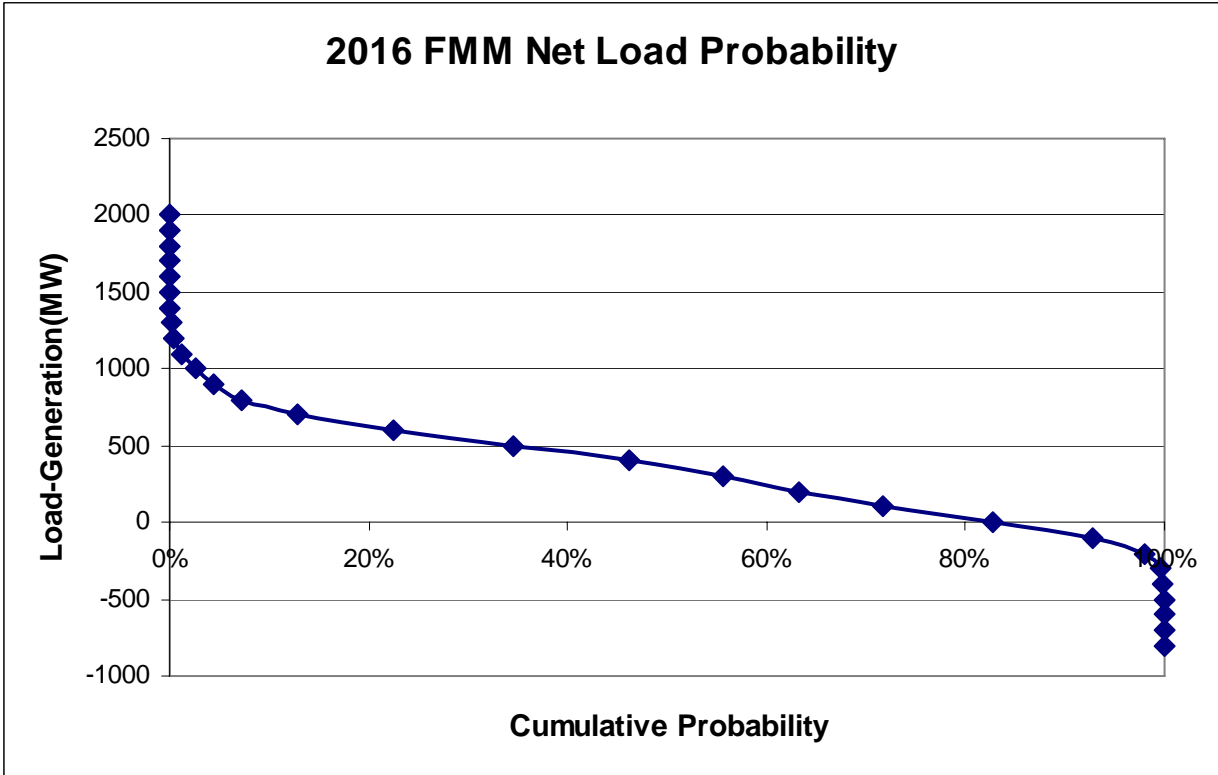


Figure 3.3 3: Net Load Probability Curve

3.4 Probabilistic Method Using Monte Carlo

Monte Carlo is a type of simulation which uses randomly generated values for uncertain variables over and over to simulate a model. It is widely used in industry to perform reliability analysis, forecast load and analyze risk.

As discussed in section 2.0, the on-site loads at different stations historically have been shown to be uncorrelated. The normal practice for predicting coincidental peak demand in an area is to use historical coincidence of the loads to predict the future. This is a sound approach if the load mix within the region remains the same in the future as in the past and if the regions loads have a high degree of correlation which is usual when peak load demand is driven by weather. But for plants whose load has been shown to have no correlation with each other and whose load has no relation to weather, the historical behavior of the loads provides no indication of future behavior. In addition to the random nature of the plant load the problem is further complicated by random outages of the on-site generators which are used to supply part of the load for “Net Load” customers. Monte Carlo simulation techniques are ideally suited for the forecasting of the coincident peak demand of this type of area because the random nature of the interrelationships between plants can be modeled.

3.4.1 *Modeling of Different Customer Types*

a) **Distribution Load**

Because the loads for the “Distribution” type PODs do correlate with each other, the hourly load is assumed to keep the same characteristic in the future as it has historically. This is modeled by applying growth rates to historical hourly data at all “Distribution” PODs.

b) **Industrial Load**

To simplify the simulation, all of the “Industrial” type PODs are combined into a single load with a characteristic load factor curve based on the historical behavior of all of the industrial loads in the Fort McMurray region. By using total of the hourly data of all of the industrial load, diversity between individual plants is already included in the representative curve. Because there is little or no correlation between this type of load and either “Distribution” load or the load at “Net Load” customers, the load factor of the total regional industrial load for each hour of the year is randomly selected from the possible states which the characteristic load factor curve represents.

The historical load data shows a fairly consistent degree of variability year over year and it is therefore assumed to have a repeating annual behavior rather than the state of each hour being independent of what has previously occurred in that year. A simple way of envisioning this type of simulation is to

think of it as a deck of 8760 cards (one card for each hour of the year) with each card having one of the 8760 load factors which make up the load duration curve for a typical year. The simulation shuffles the entire deck and then draws from the deck as each hour of the year is simulated. By the end of the year all of the cards (states) within the deck (the load duration curve in this case) will have occurred but the order which they occur is random.

c) Net Onsite Load Forecast

Because this type of load is not fully covered by a contract for the capacity, it is treated as positive or negative net load made up of a combination of on-site generation and physical load. These types of load make up a significant proportion of the load but only have a minor effect on the region peak because they supply most of their load themselves with their on-site generation.

The total physical load of the Net Onsite Load” customers has been forecasted separately substation by substation. The Monte Carlo simulation randomly assigns a load at each station using the same “card deck” method as is used for the industrial loads.

For the on-site generation of the “Net Onsite Load” customer types, different capacity factor duration curves based on historical data are used for gas turbine (“GT”) and steam turbine (“ST”) units. These curves are applied individually to all existing as well as future on-site generators. At each station, a random state is used to assign a capacity factor to each generator.

The unplanned forced outages of each generator are also included in the calculation of the total load of the “Net Onsite Load” customers. The CECA competitive model planned and unplanned outage rates are used to simulate generator maintenance and random forced outages.

The DTS and STS limits forecast for each customer site are applied in the simulation for each hour at each station. This means the net positive load is never permitted to exceed the DTS contract level and the negative net load is limited to the STS contract.

3.4.2 Monte Carlo Results

To test the reasonableness of the Monte Carlo model, the actual historical load data from 2005 was compared to the simulated results. The results from ten Monte Carlo runs are shown in Figure 3.4-2 along with the actual regional load data for 2005.

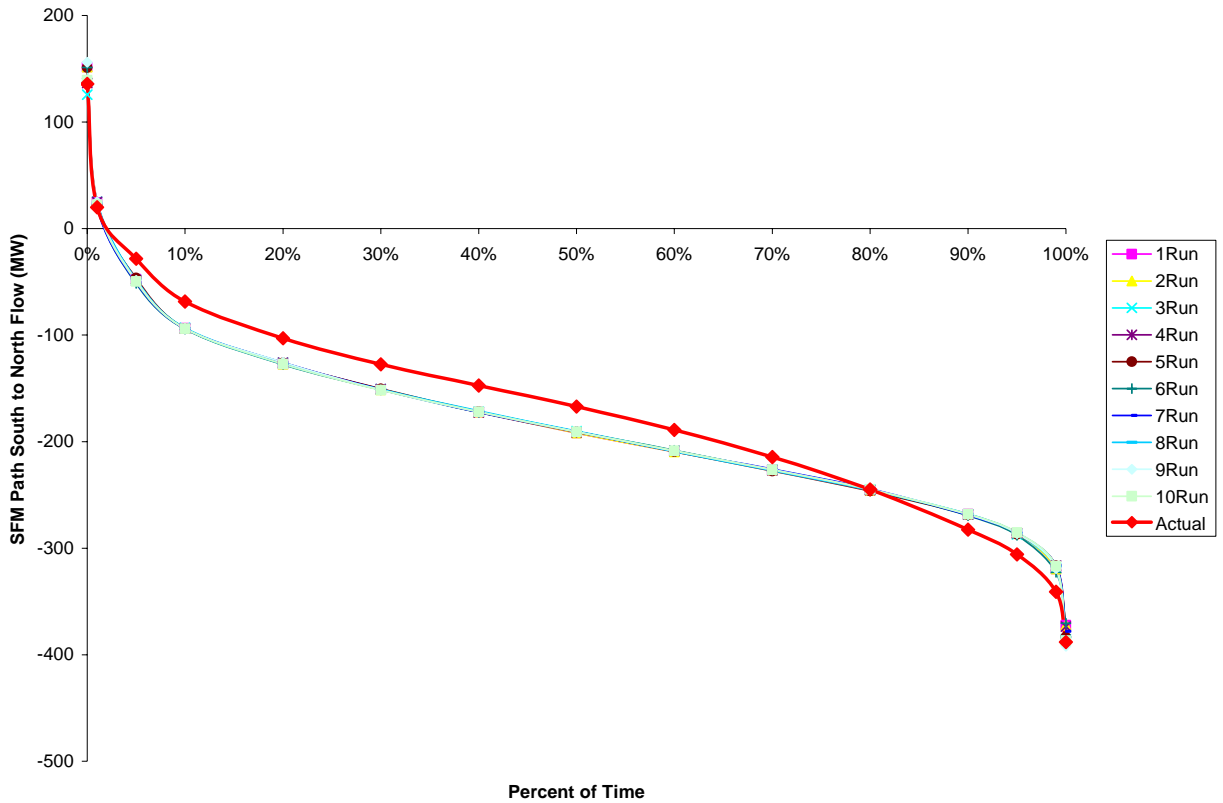


Figure 3.4 1: Monte Carlo Simulated Load Duration Curves for Fort McMurray

3.4.3 Fort McMurray Peak Demand Forecast

Table 3.4-4 shows the area peak for demand for a 1 in 5 year coincidental peak, based on ten Monte Carlo runs for each year. This is the 20th percentile of multiple Monte Carlo runs performed for the same year. For the years 2011 and 2016, 100 simulations were run to verify that ten runs for each year was sufficient for an accurate prediction of the 20th percentile. The forecasted peak demands with different types of loads are shown in Figure 3.4-1.

Table 3.4 1: Fort McMurray peak demand forecast

Year	Fort McMurray Peak Demand (MW)
2008	705
2009	837
2010	1050
2011	1256
2012	1706
2013	2160
2014	2217
2015	2260
2016	2393

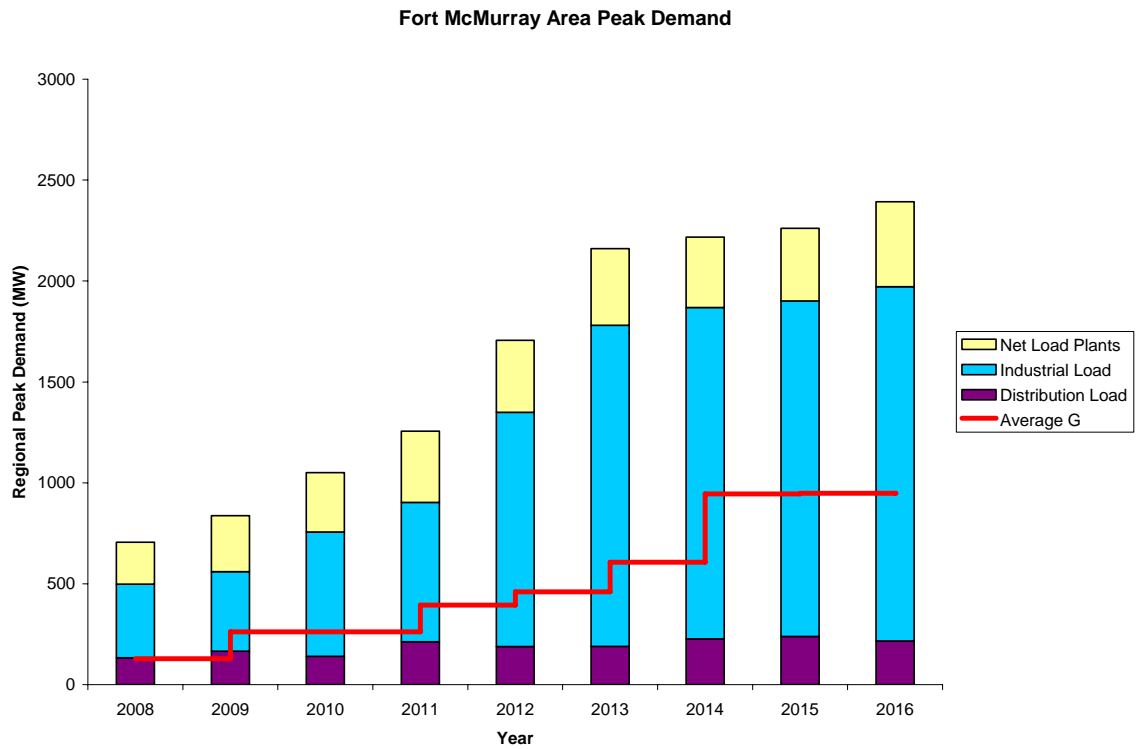


Figure 3.4 2: Fort McMurray peak demand forecast by Customer Type

4.0 Path Capability Requirement

The Transmission Reliability Criteria requires that;

“The transmission supply to each predominantly load area will be planned so that a Category B event will result in acceptable performance with the most critical generator out of service, for commercial or maintenance reasons, and with the system readjusted after re-dispatching the remaining generation according to the forecast merit order.”¹

Therefore the path capability required to supply a region can be estimated by establishing the coincidental peak of a region, adding the estimated system losses within the region and subtracting the total in-merit generation dispatched within the region assuming the single largest generator is unavailable. This requires that both the peak load forecast as well as a generation scenario forecast be done to evaluate the path capability required.

4.1 Generation Scenarios

As discussed in section 2.4, the onsite generators at “Net Onsite Load” customer sites have already been included (dispatch) in the calculation of the coincidental peak load. Therefore, only the part of generation is treated as available generation to supply peak demand of this area. Table 4.1-1 shows the forecasted available generation levels in Fort McMurray area for future years.

Table 4.1 1: Available Generation in Fort McMurray Area (MW)

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016
Average Generation	261	261	394	460	606	945	948	948	948

4.2 Comparison of Forecasting Methodologies

The required transfer in capability calculated from the two deterministic and one probabilistic approach is provided in Table 4.2-1 and shown graphically in Figure 4.2-1. It can be observed that the power transfer requirements obtained from these approaches range from approximately 1300 MW to 1700 MW.

¹ Page 3, Transmission Reliability Criteria, Part II, System Planning

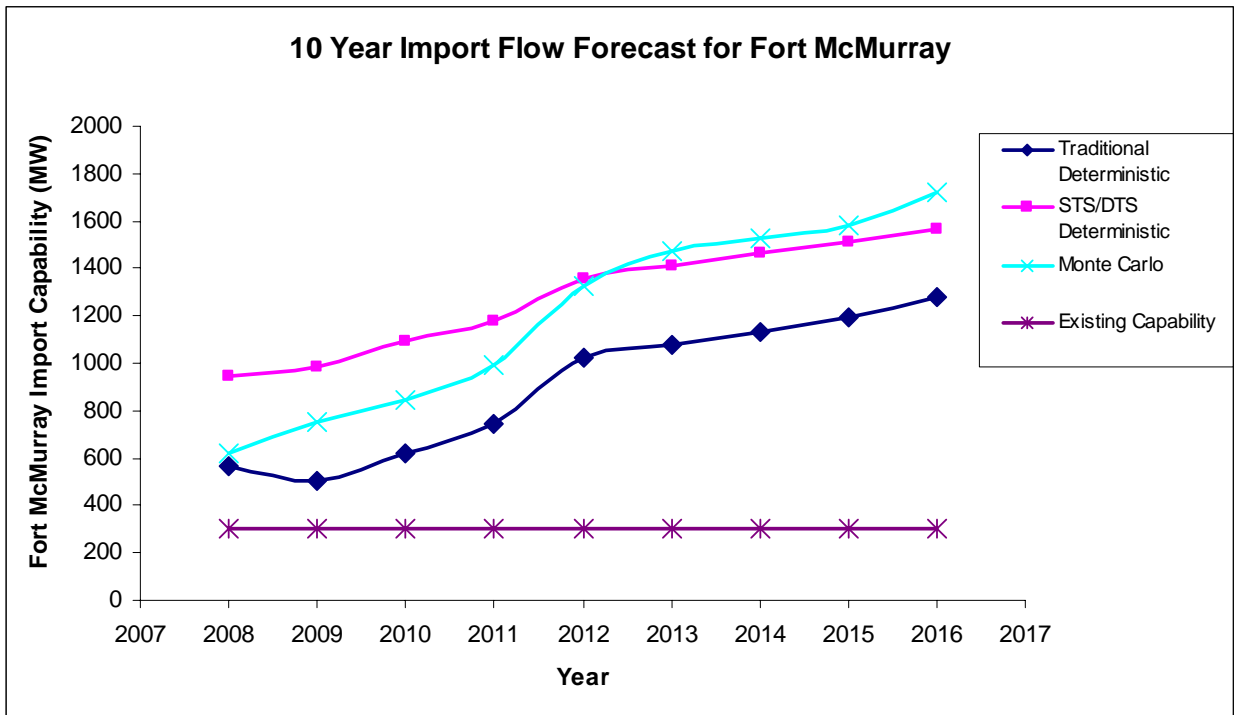


Figure 4.2 1: 10 Year Transfer In Forecast

Table 4.2 1: Target Transfer In Capability (MW)

Year	Traditional Deterministic	DTS/STS Deterministic	Monte Carlo
2008	566	948	619
2009	507	983	755
2010	620	1,093	843
2011	747	1,181	992
2012	1,027	1,353	1,322
2013	1,076	1,414	1,472
2014	1,135	1,462	1,531
2015	1,195	1,512	1,578
2016	1,276	1,566	1,723

4.3 Recommendation

From Figure 4.2-1, it can be recommended that a reasonable transfer in capability for the year 2016 would be approximately 1,700 MW which is obtained by the monte carlo approach. This target transfer capability into the Ft. McMurray area will reasonably supply over 80% of the expected total DTS requirements of 2,038 MW in 2016. This transfer capability would be in excess of what is required to support the expected STS requirements of 1,447 MW.

APPENDIX A.

List of Stakeholders Consulted for the Northeast Planning Study

Albian Sands Energy

ATCO Electric

ATCO Power

Canadian Natural Resources Limited

Compton Petroleum

Connacher Oil and Gas

Conocophillips

Devon Energy

EPCOR

Husky

Imperial Oil Limited

JACOS

Opti-Nexen

Petro-Canada

Shell

Syncrude

Suncor

Synenco

TransAlta

TransCanada Power

APPENDIX B.

Sample Questionnaires

**Northeast Transmission Development Plan
Existing Oil Sands Producer Questionnaire
2015 – 2021 Forecast
(Confidential)**

Company Name: _____

Project Name: _____

Interconnection Point: _____

Attending from Company: _____

Attending from AESO: _____

Date: _____

A. Current Electricity Requirements

The current DTS and STS contract for this interconnection is _____ MW and _____ MW respectively.

1. What would be the normal range of DTS/STS usage?
2. Under what conditions will the maximum DTS/STS would be utilized?

B Fuel Supply:

1. What is your current fuel supply situation (natural gas, synthetic gas, bitumen, coke, etc.) and supplier (TransCanada, ATCO, other) for thermal requirements?
2. If externally supplied, what would be your course of action in the event of loss of gas supply?

C Future Expansion Plans:

1. In general, please describe the potential to expand operations for bitumen extraction, upgrading and transportation beyond 2015?

2. Will your future facility employ mining, SAGD in-situ or a combination of mining & SAGD operations to extract bitumen?

3. Would you ever consider moving to boiler firing (beyond what you may already have in the way of supplemental firing) after the retirement of existing cogeneration facilities and purchase from the grid?

D Incremental and/or New Facility Electricity Requirements

1. What is size and timing of future expansions and anticipated electric energy consumption and generation capacity that would be associated with the expansion within the ISD?

2. Can you please provide a conceptual description of new transmission development within the ISD as a result of expanded operations?

Northeast Transmission Development Plan

Oil Sands Producer (New) Questionnaire

2010 – 2021 Forecast

(Confidential)

Company Name: _____

Project Name: _____

Location of Main Plant: _____

Attending from Company: _____

Attending from AESO: _____

Date: _____

A **General Questions:**

1. Will your facility employ mining, SAGD in-situ or a combination of mining & SAGD operations or some other technology to obtain bitumen?
2. In general, please describe the timing of permitting, construction, staging of bitumen extraction, upgrading and transportation requirements?
3. In general, describe your planned electrical load and generation profile for the operations described above?
4. If installing a co-generation facility, how will it be powered (gas or steam)?

B **Fuel Supply:**

1. What will be the fuel supply of choice (natural gas, synthetic gas, bitumen, coke, etc.) and supplier (TransCanada, ATCO, other) for thermal requirements?
2. If externally supplied, what would be your course of action in the event of loss of fuel supply?

C **Electricity Requirements:**

1. Will your facility purchase power from the grid, partial self- supply, wholly self supply or export onto the grid?

2. What would be the maximum DTS and/or STS requirements for the project and timing?

3. What would be the normal range of DTS/STS usage?

4. Under what conditions will the maximum DTS/STS would be utilized?

C. Other:

1. Upgrading:

(a) Are you planning upgrade on-site as production levels rises.

(b) If not, do you plan to transport to Edmonton or elsewhere for upgrading.?

2. Industrial Site Designation

a) Are you planning to apply for ISD status?

(b) If yes, can you please provide a description of new transmission development within the ISD?

