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February 14, 2019

Industrial Customers Group
c/o #301 – 2298 McBain Avenue
Vancouver, BC V6L 3B1

Attention: Mr. Robert Hobbs

Dear Mr. Hobbs:

Re: FortisBC Inc. (FBC)

Project No. 1598987

Application for a Certificate of Public Convenience and Necessity (CPCN) for the Grand Forks Terminal Station Reliability Project (the Application)

Response to the Industrial Customers Group (ICG) Information Request (IR) No. 1

On November 19, 2018, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-250-18 setting out the Regulatory Timetable for review of the Application, FBC respectfully submits the attached response to ICG IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Doug Slater

Attachments

cc (email only): Commission Secretary
Registered Parties

1.0 Reference: Exhibit B-1, Section 3.2.1, Facilities Condition Assessment, page 15

1.1 Please provide an inventory of those transformers in FortisBC's asset base with at least one terminal rated at 60 kV or greater, and for each transformer provide the age and expected remaining life. Please identify those transformers with less than 15 years remaining expected life.

Response:

The remaining life of transformers cannot be accurately estimated, as explained in the response to BCUC IR 1.2.1. All FBC transformers participate in the transformer maintenance program and only if unusual results are discovered through the regular testing will further analysis be done to estimate the remaining life of the unit.

Please refer to Attachment 1.1 for a list of all FBC transformers with at least one terminal rated at 60 kV or greater, which FBC considers may need to be replaced in the next 15 years.

1.2 FortisBC states the expected lifespan of both GFT T1 and OLI T1 is 40 years. Please discuss the relationship between loading of the transformers and expected lifespan and describe the basis upon which the 40 year lifespan calculated?

Response:

Please refer to the response to BCUC IR 1.2.1.

1.3 Please provide the historical daily, seasonal and annual loading profiles on both GFT T1 and OLI T1 over the last ten years and describe how this loading compares to the rated load carrying capability of the transformers?

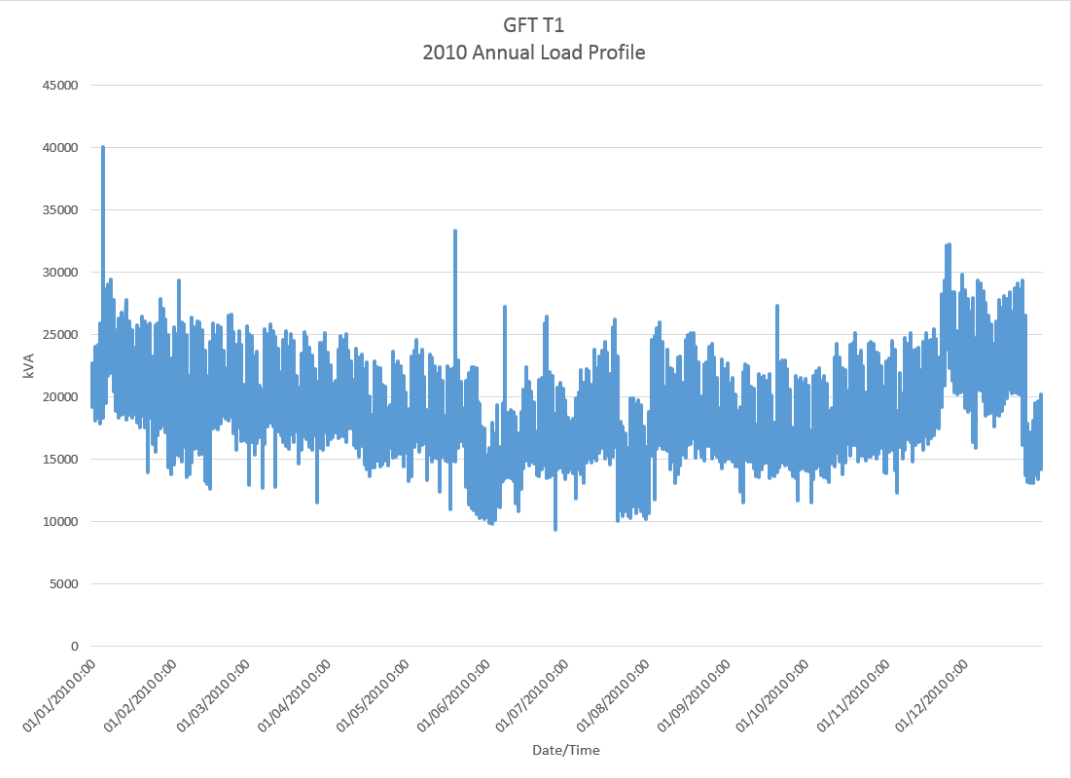
Response:

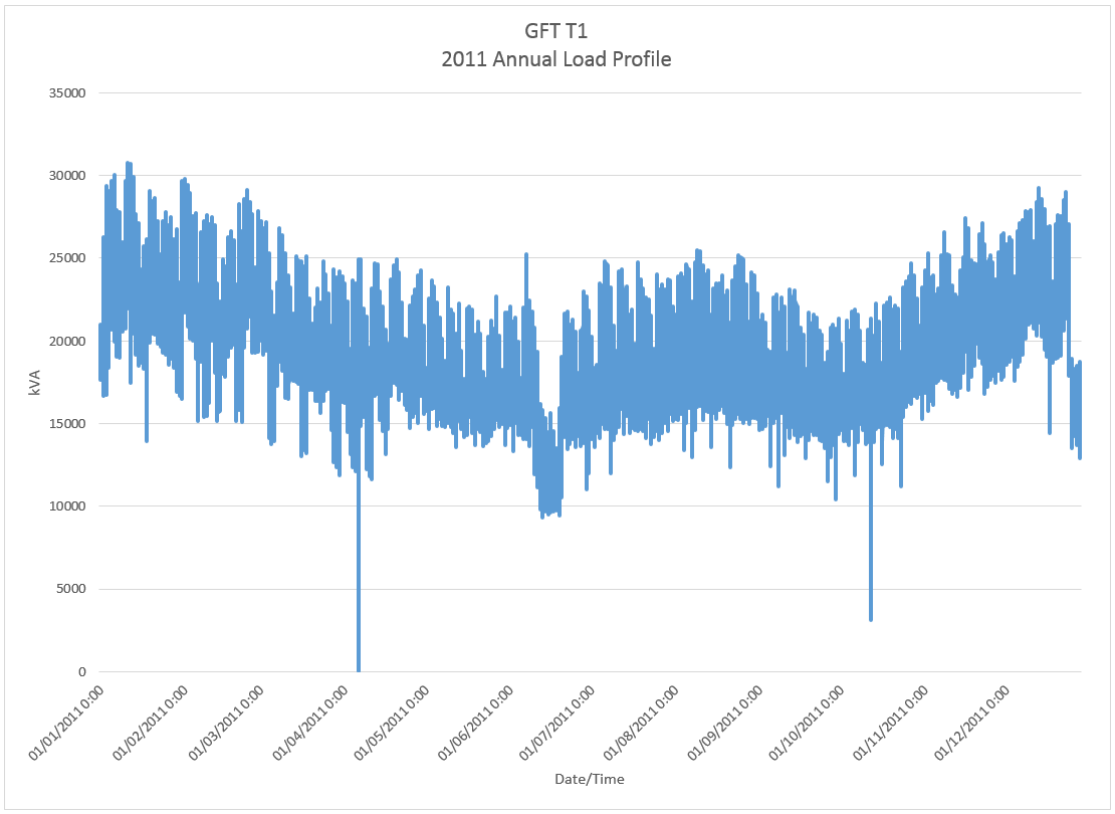
The annual and seasonal load profiles for GFT T1 between 2009 and 2018 are provided below. No load profiles are provided for 2012 due to unavailability of data.

Due to the large volume of data that would be required to provide daily load profiles over ten years, FBC has provided the daily load profiles for GFT T1 on the day of the the summer 2018 peak and the winter 2017-18 peak are provided below. Additionally, the third Monday of April 2018 and October 2018 have been included to show the daily load profile during the shoulder seasons in 2018.

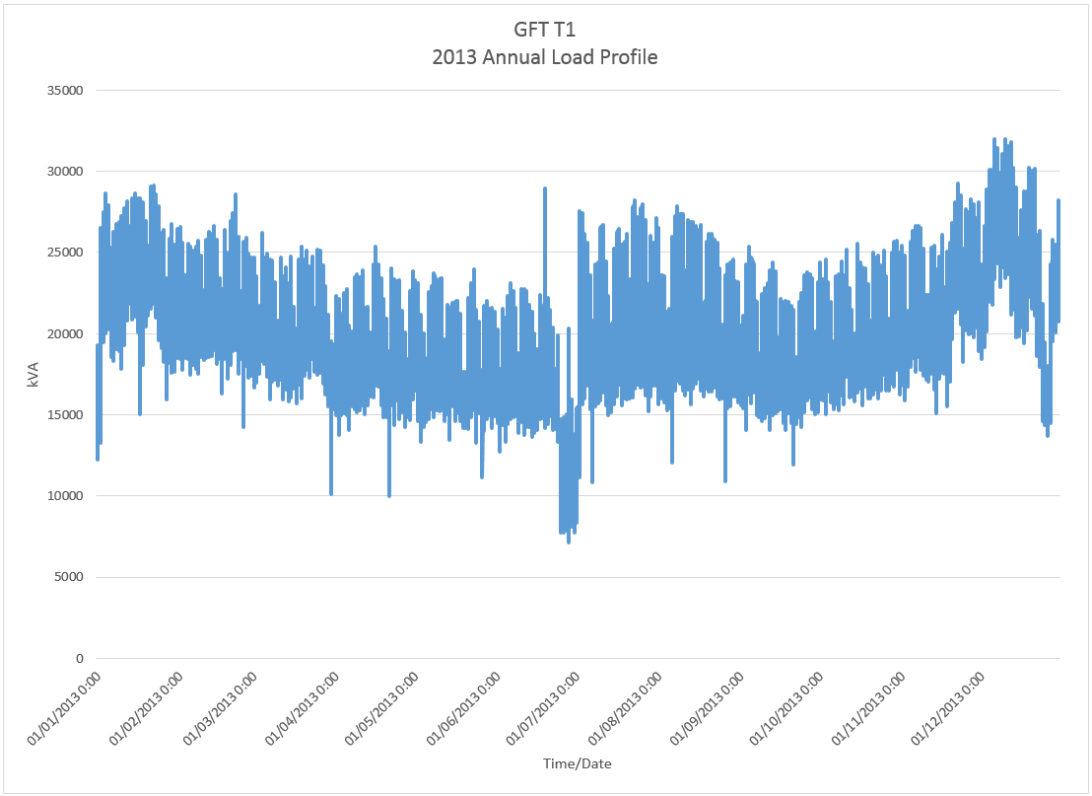
The historical profile indicates that GFT T1 loading has been below the nominal rating of the transformer (60 MVA).

<u>GFT T1 Annual Load Profiles:</u>

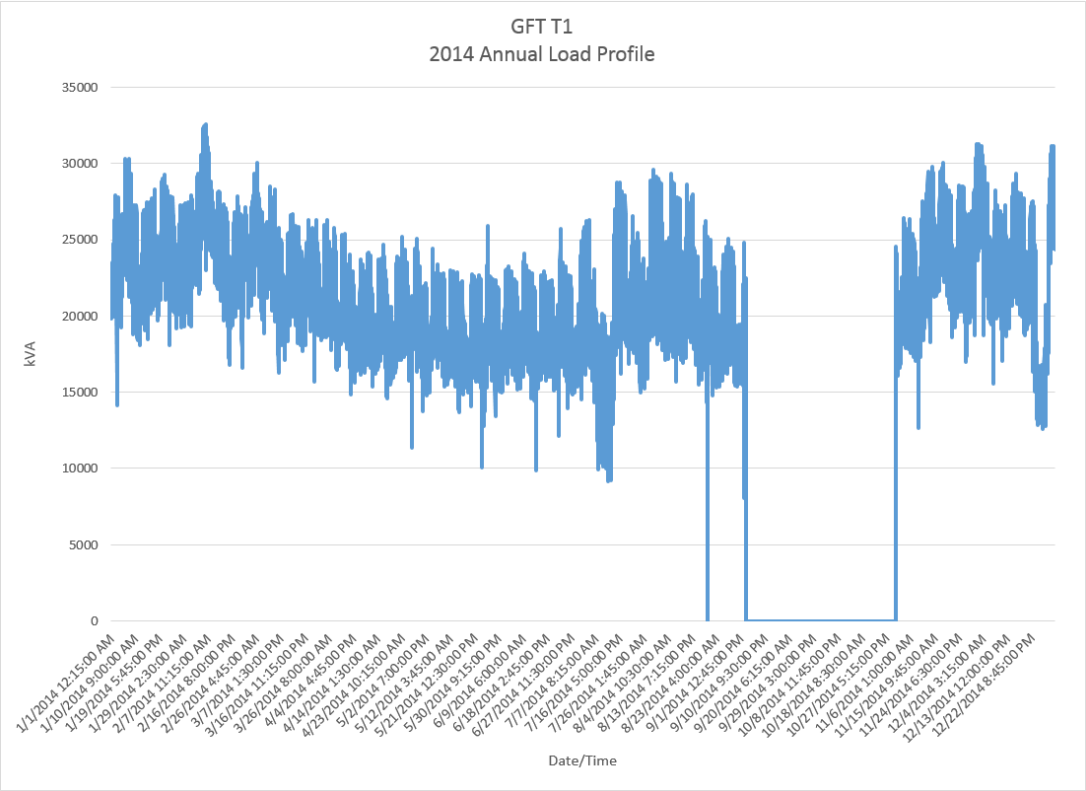



GFT T1
2011 Annual Load Profile
35000
30000
25000
20000
15000
10000
5000
0
kVA
01/01/2011 0:00
01/02/2011 0:00
01/03/2011 0:00
01/04/2011 0:00
01/05/2011 0:00
01/06/2011 0:00
01/07/2011 0:00
01/08/2011 0:00
01/09/2011 0:00
01/10/2011 0:00
01/11/2011 0:00
01/12/2011 0:00
Date/Time

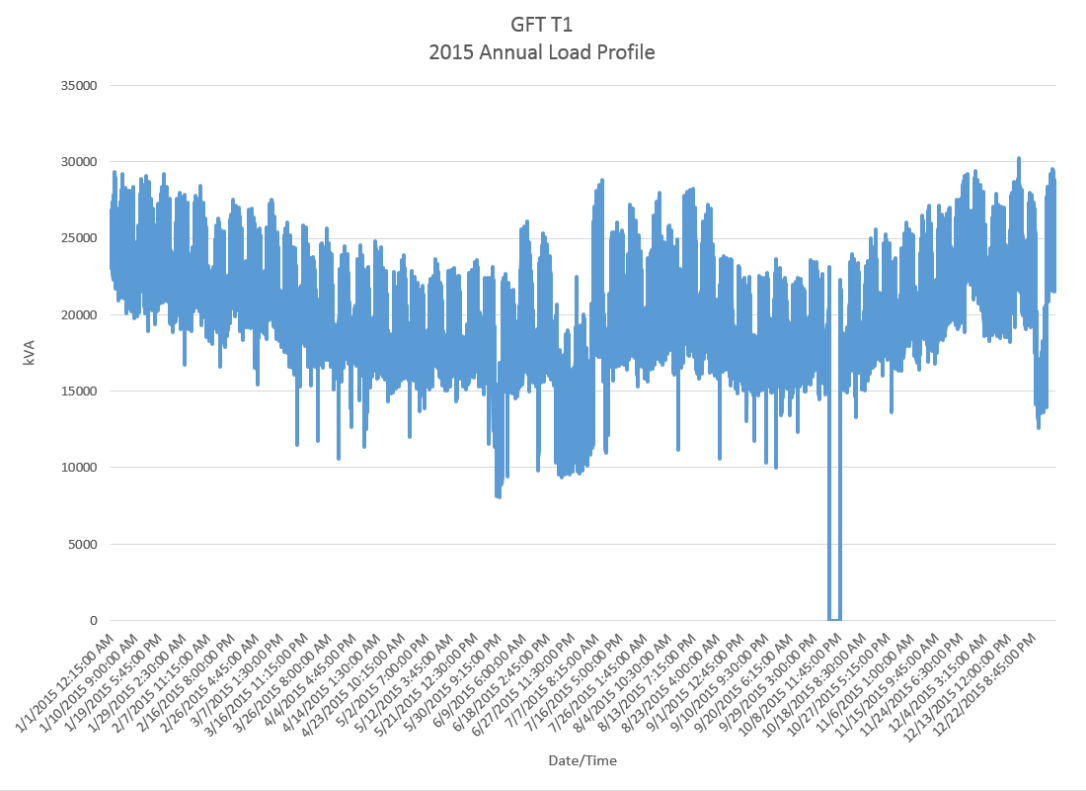
1


GFT T1
2013 Annual Load Profile
35000
30000
25000
20000
15000
10000
5000
0
kVA
01/01/2013 0:00
01/02/2013 0:00
01/03/2013 0:00
01/04/2013 0:00
01/05/2013 0:00
01/06/2013 0:00
01/07/2013 0:00
01/08/2013 0:00
01/09/2013 0:00
01/10/2013 0:00
01/11/2013 0:00
01/12/2013 0:00
Time/Date

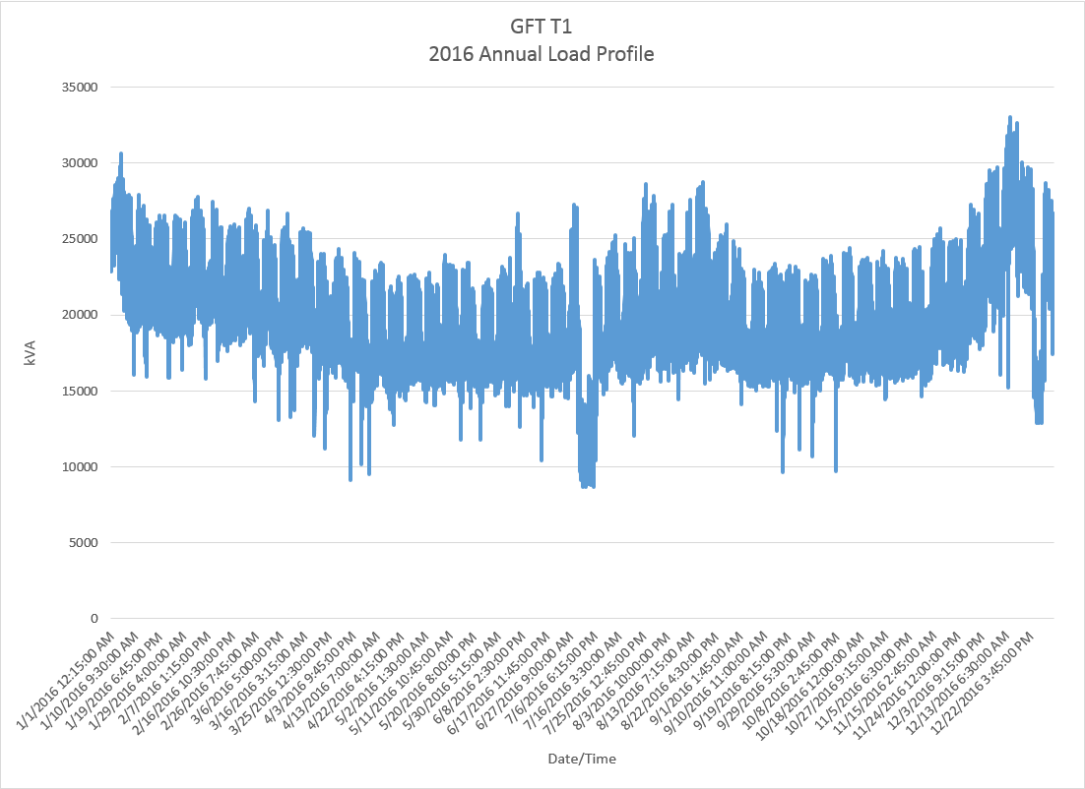
2


GFT T1
2014 Annual Load Profile
kVA
Date/Time

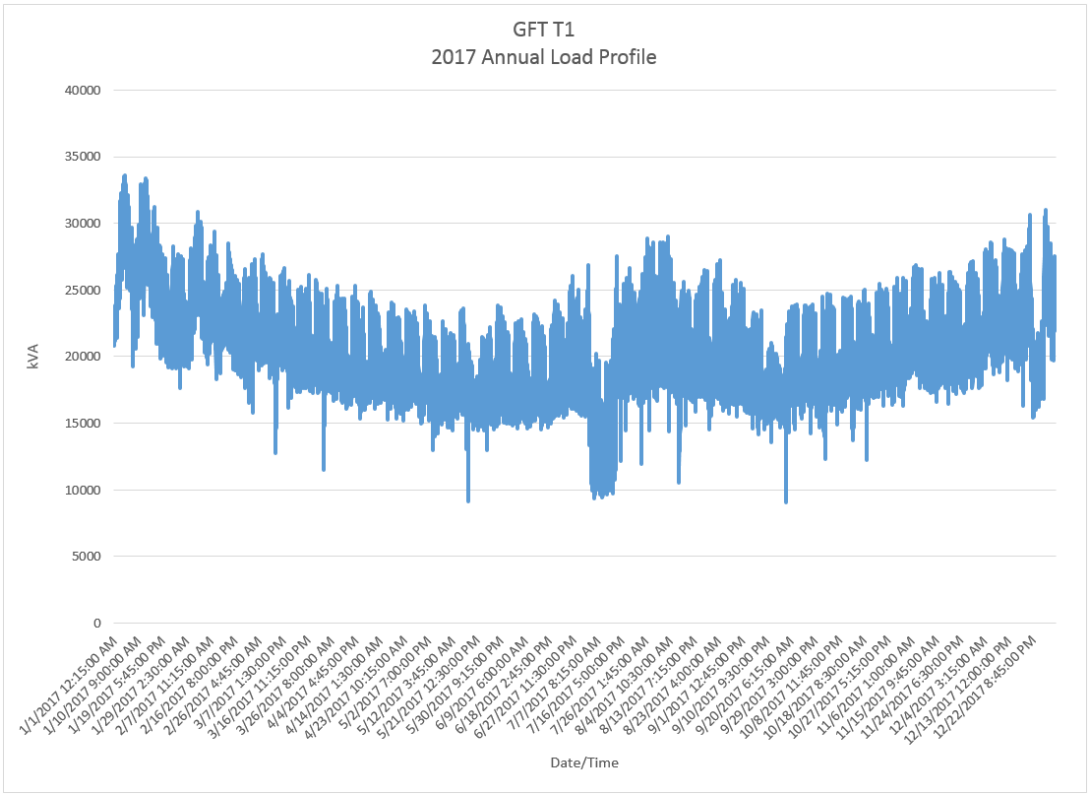
1


GFT T1
2015 Annual Load Profile
kVA
Date/Time

2

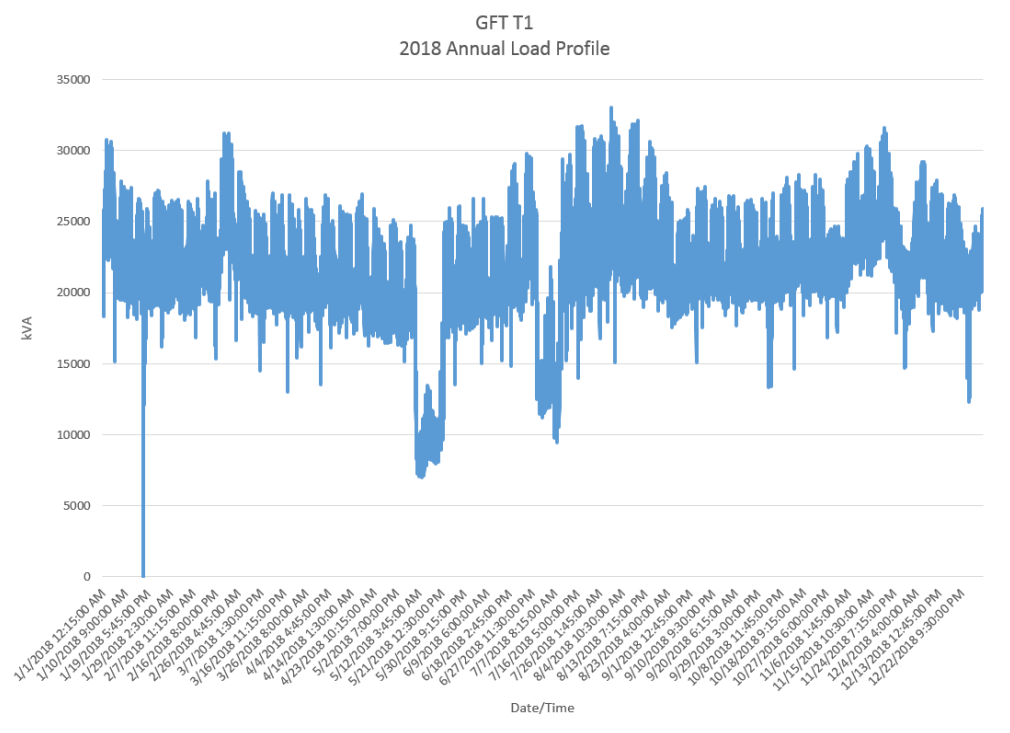

GFT T1
2016 Annual Load Profile
kVA
35000
30000
25000
20000
15000
10000
5000
0
1/1/2016 12:15:00 AM
1/10/2016 9:30:00 AM
1/19/2016 6:45:00 PM
1/29/2016 4:00:00 AM
2/7/2016 1:15:00 PM
2/16/2016 10:30:00 PM
2/26/2016 7:45:00 AM
3/6/2016 5:00:00 PM
3/16/2016 3:15:00 AM
3/25/2016 12:30:00 PM
4/3/2016 9:45:00 PM
4/13/2016 7:00:00 AM
4/22/2016 4:15:00 PM
5/2/2016 1:30:00 AM
5/11/2016 10:45:00 AM
5/20/2016 8:00:00 PM
5/30/2016 5:15:00 AM
6/8/2016 2:30:00 PM
6/17/2016 11:45:00 PM
6/27/2016 9:00:00 AM
7/6/2016 6:15:00 PM
7/16/2016 3:30:00 AM
7/25/2016 12:45:00 PM
8/3/2016 10:00:00 PM
8/13/2016 7:15:00 AM
8/22/2016 4:30:00 PM
9/1/2016 1:45:00 AM
9/10/2016 11:00:00 AM
9/19/2016 8:15:00 PM
9/29/2016 5:30:00 AM
10/8/2016 2:45:00 PM
10/18/2016 12:00:00 AM
10/27/2016 9:15:00 AM
11/5/2016 6:30:00 PM
11/15/2016 2:45:00 AM
11/24/2016 12:00:00 PM
12/3/2016 9:15:00 PM
12/13/2016 6:30:00 AM
12/22/2016 3:45:00 PM
Date/Time

1


GFT T1
2017 Annual Load Profile
kVA
40000
35000
30000
25000
20000
15000
10000
5000
0
1/1/2017 12:15:00 AM
1/10/2017 9:00:00 AM
1/19/2017 5:45:00 PM
1/29/2017 2:30:00 AM
2/7/2017 11:15:00 AM
2/16/2017 8:00:00 PM
2/26/2017 4:45:00 AM
3/7/2017 1:30:00 PM
3/16/2017 11:15:00 PM
3/26/2017 8:00:00 AM
4/4/2017 4:45:00 PM
4/14/2017 1:30:00 AM
4/23/2017 10:15:00 AM
5/2/2017 7:00:00 PM
5/12/2017 3:45:00 AM
5/21/2017 12:30:00 PM
5/30/2017 9:15:00 PM
6/9/2017 6:00:00 AM
6/18/2017 2:45:00 PM
6/27/2017 11:30:00 PM
7/7/2017 8:15:00 AM
7/16/2017 5:00:00 PM
7/26/2017 1:45:00 AM
8/4/2017 10:30:00 AM
8/13/2017 7:15:00 PM
8/23/2017 4:00:00 AM
9/1/2017 12:45:00 PM
9/10/2017 9:30:00 PM
9/20/2017 6:15:00 AM
9/29/2017 3:00:00 PM
10/8/2017 11:45:00 PM
10/18/2017 8:30:00 AM
10/27/2017 5:15:00 PM
11/6/2017 1:00:00 AM
11/15/2017 9:45:00 AM
11/24/2017 6:30:00 PM
12/4/2017 3:15:00 AM
12/13/2017 12:00:00 PM
12/22/2017 8:45:00 PM
Date/Time

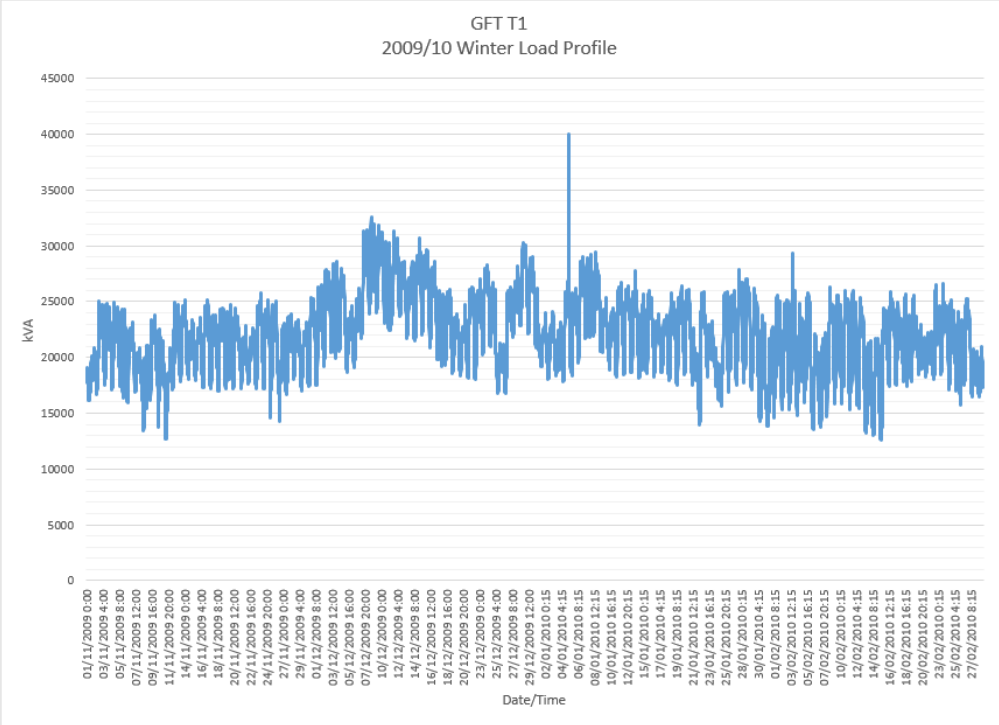
2

1



2

3 GFT T1 Seasonal Load Profiles:



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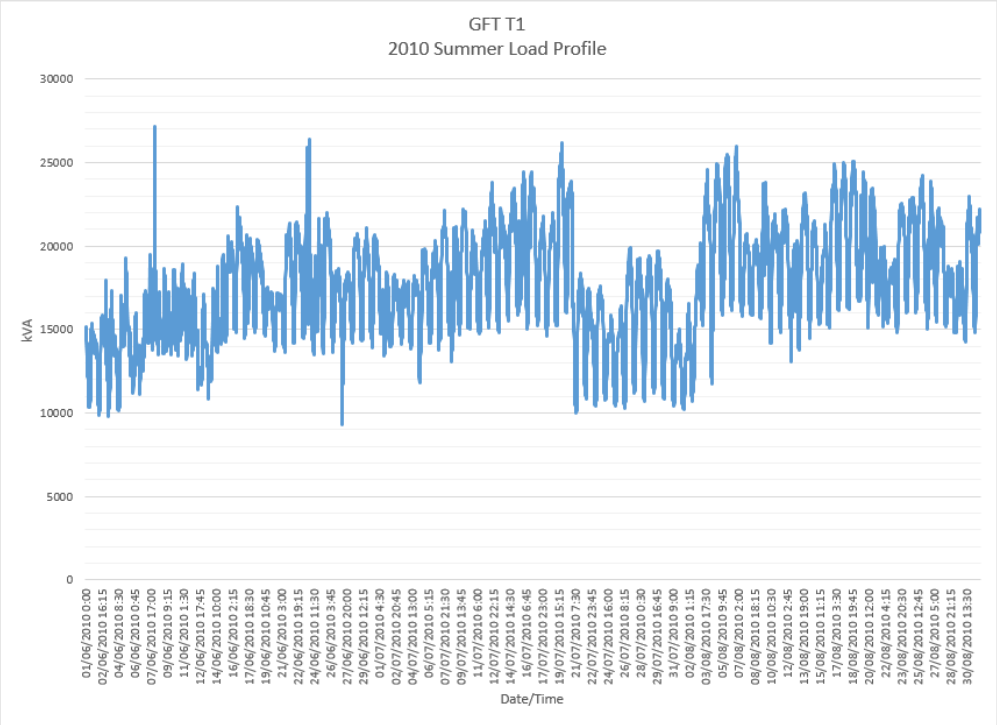
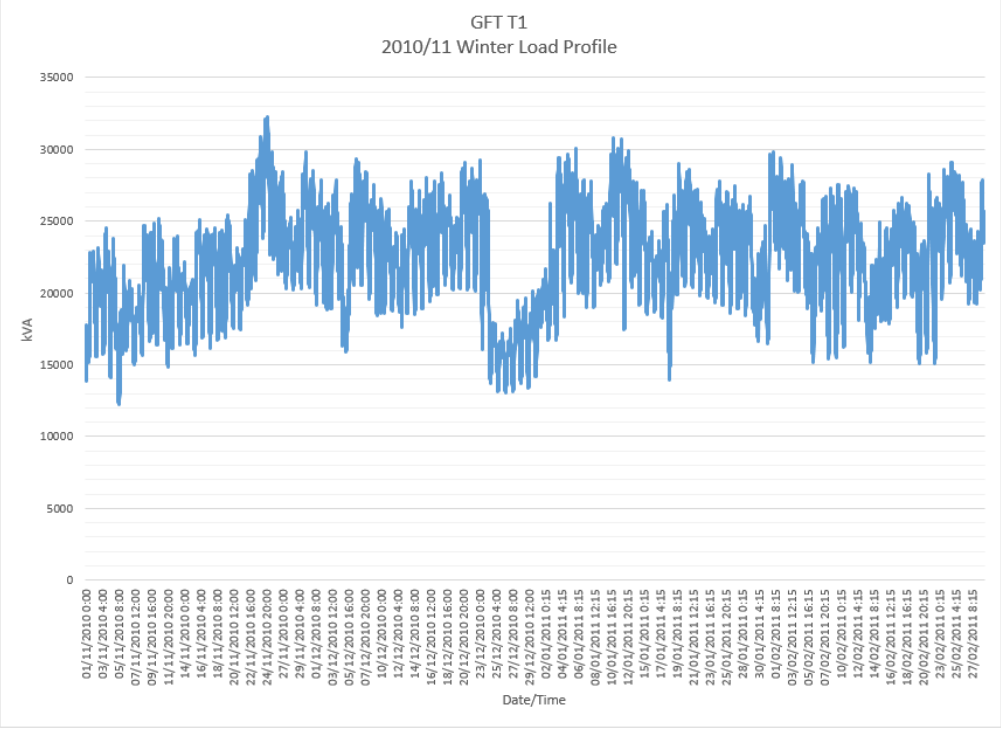
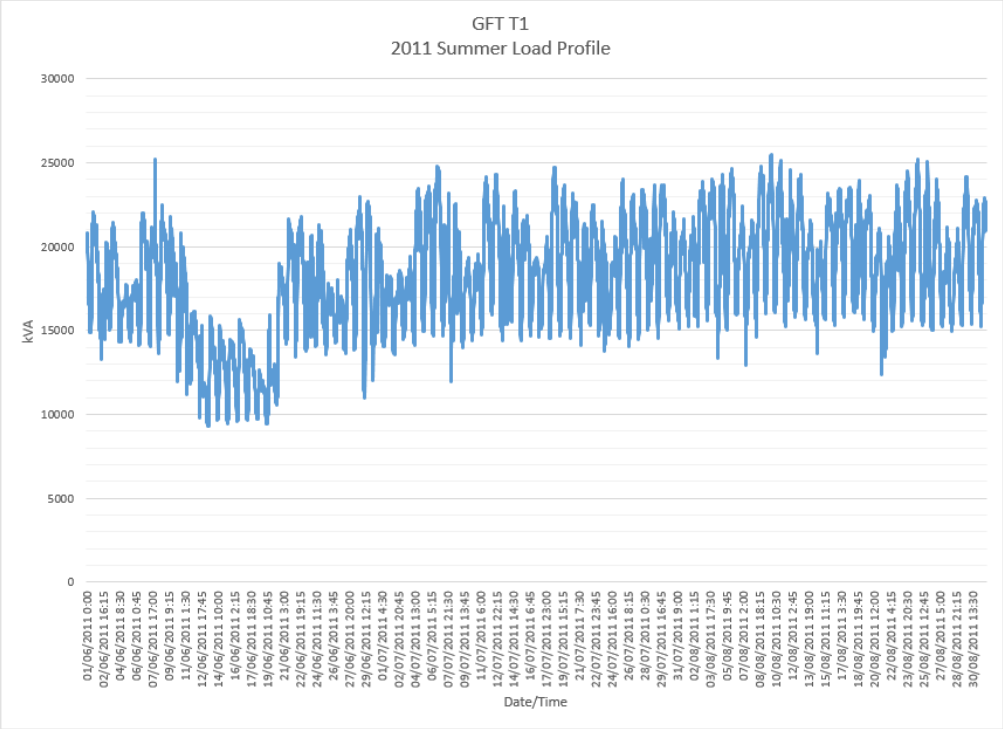

GFT T1
2010 Summer Load Profile
kVA
Date/Time

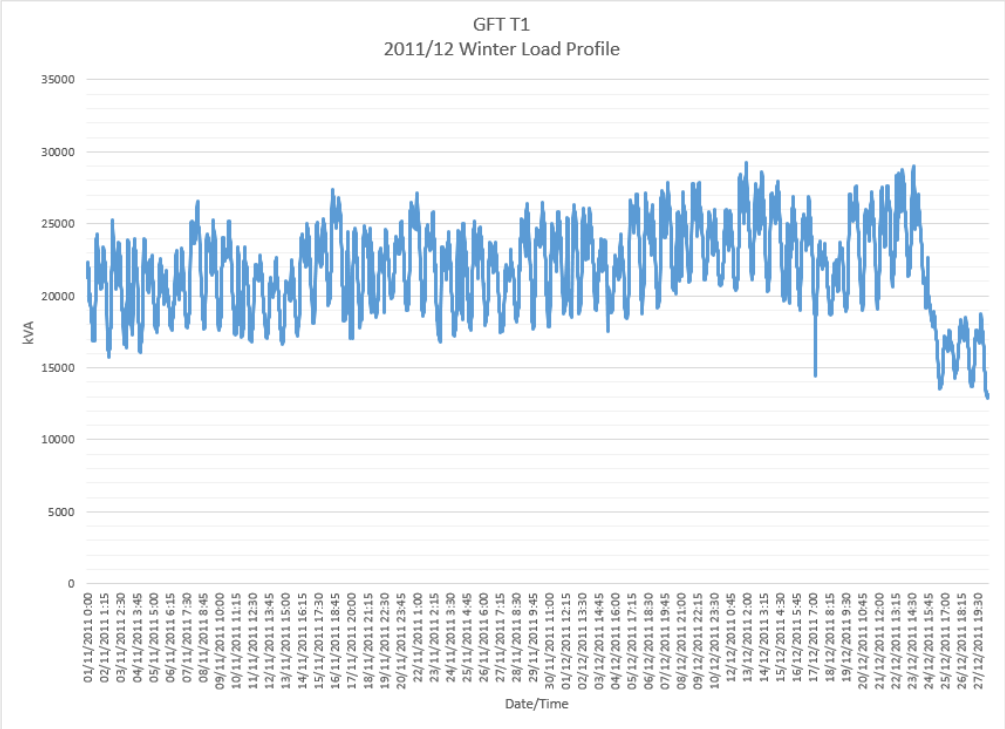
1


GFT T1
2010/11 Winter Load Profile
kVA
Date/Time

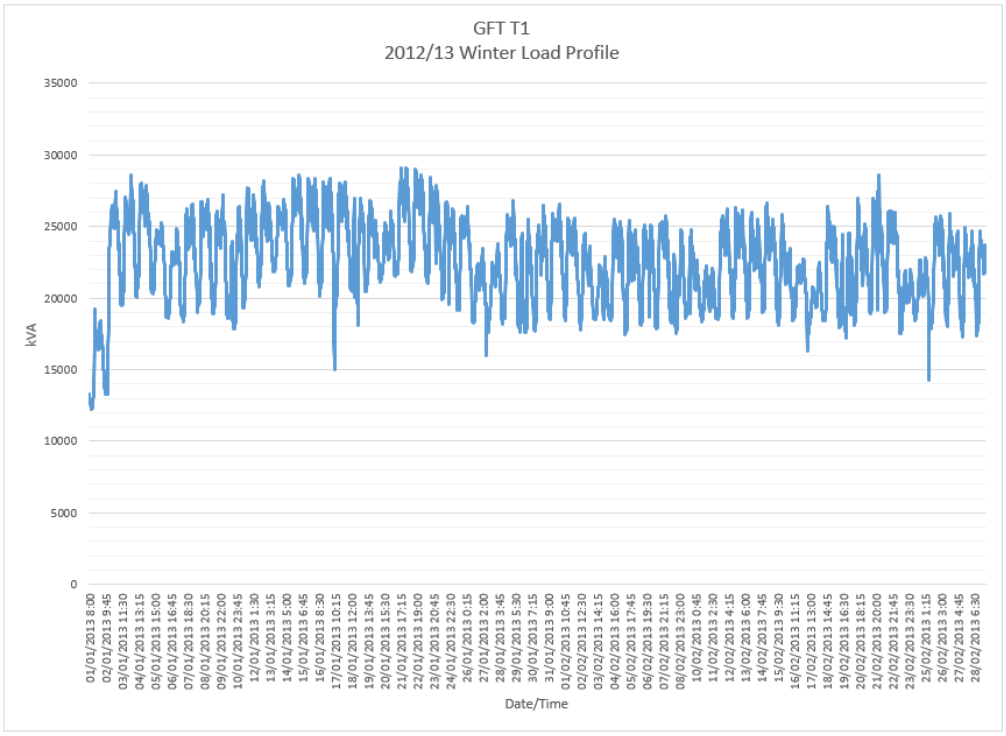
2


GFT T1
2011 Summer Load Profile
kVA
Date/Time

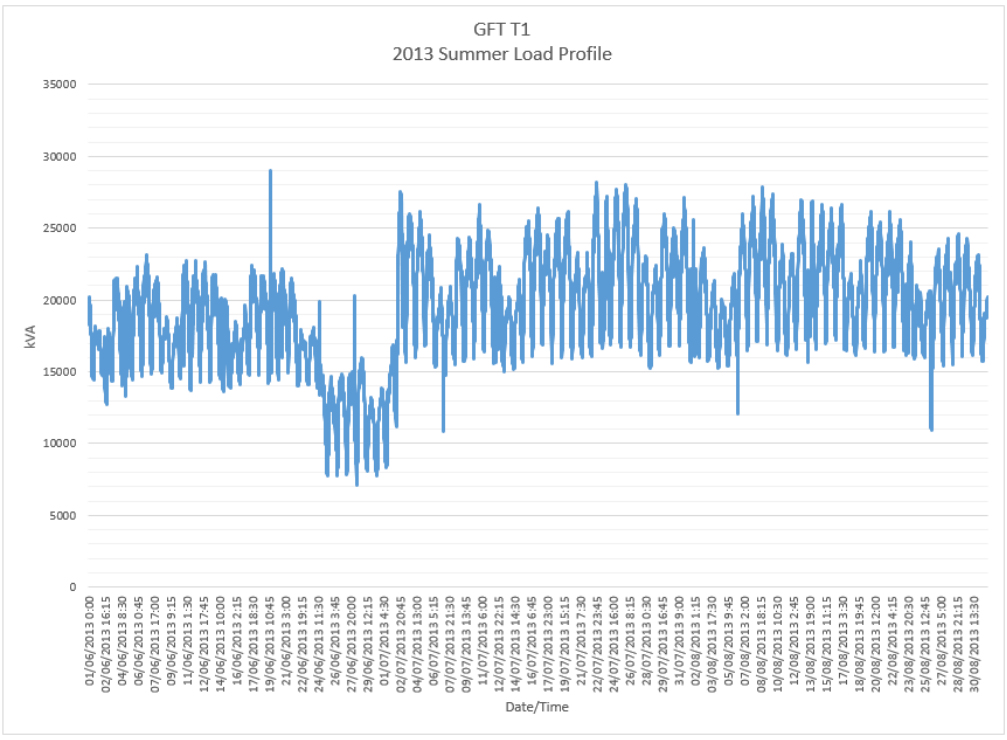
1


GFT T1
2011/12 Winter Load Profile
kVA
Date/Time

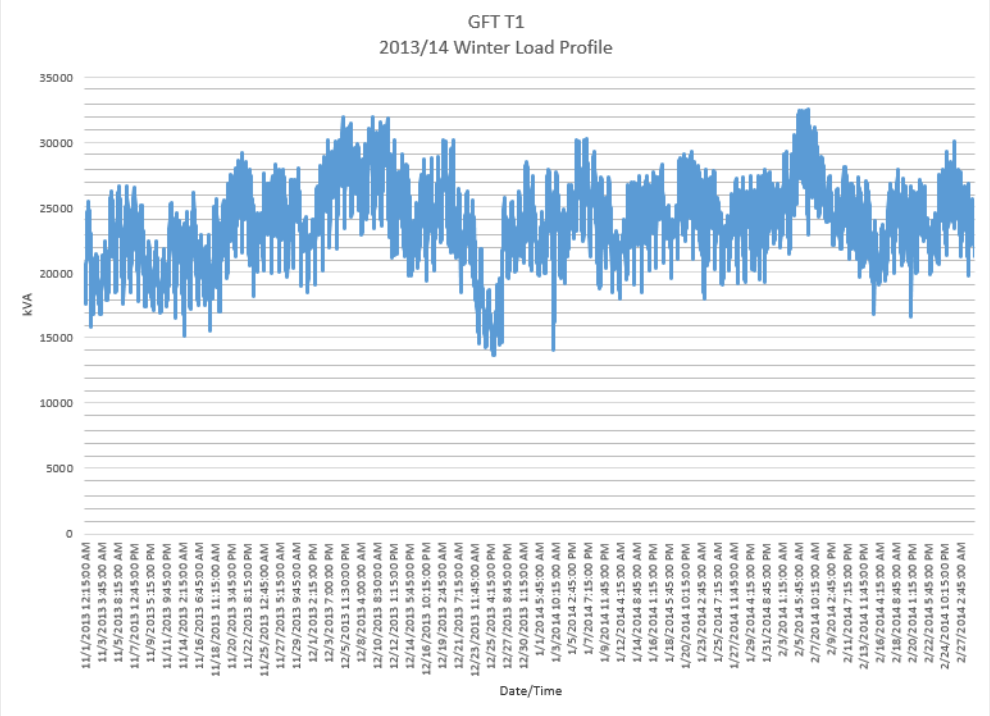
2


GFT T1
2012/13 Winter Load Profile
kVA
Date/Time

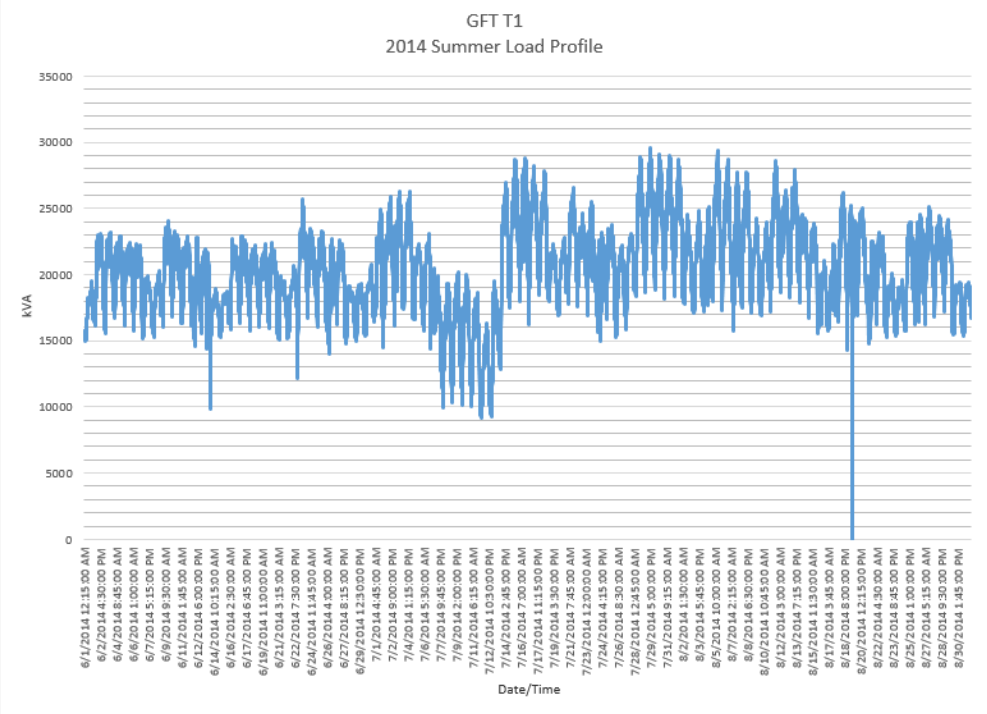
1


GFT T1
2013 Summer Load Profile
kVA
Date/Time

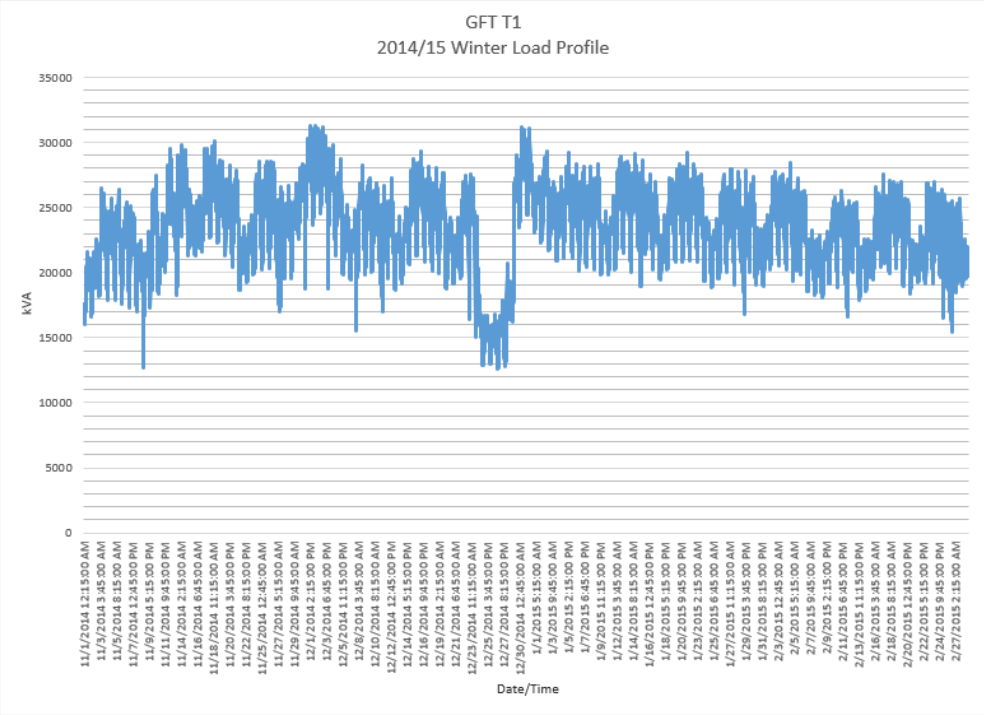
2


GFT T1
2013/14 Winter Load Profile
kVA
Date/Time

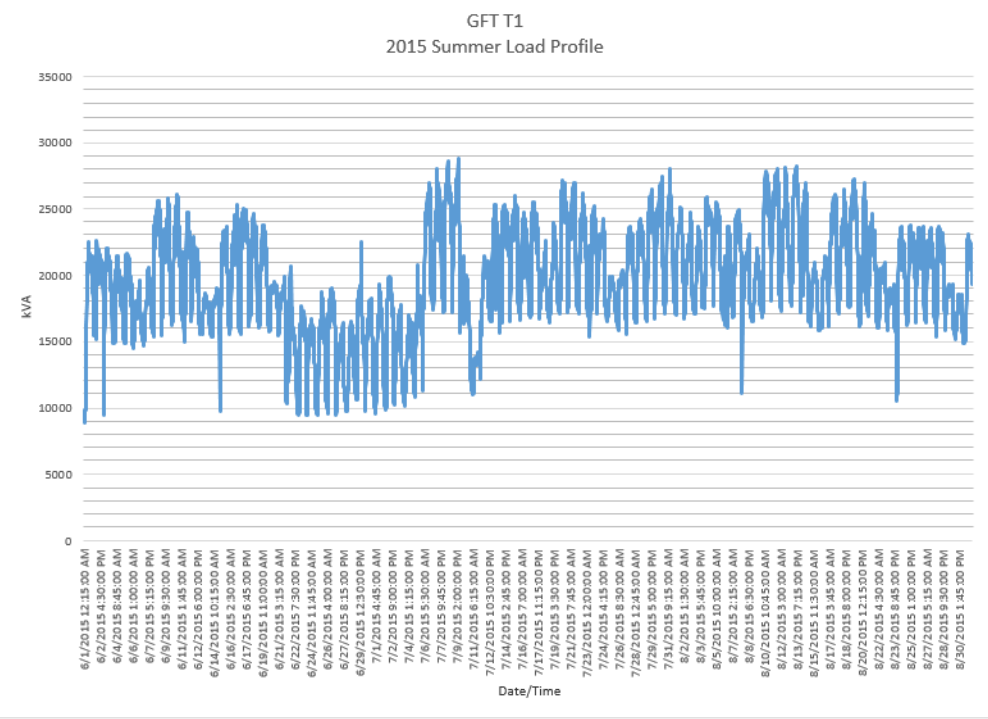
1


GFT T1
2014 Summer Load Profile
kVA
Date/Time

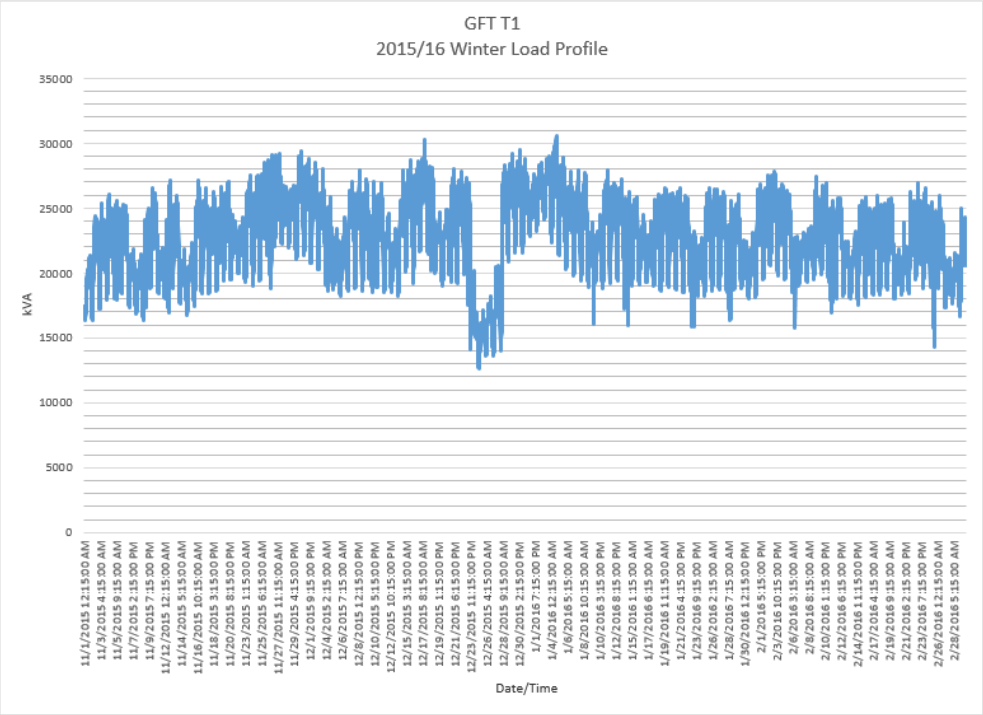
2


GFT T1
2014/15 Winter Load Profile
kVA
Date/Time

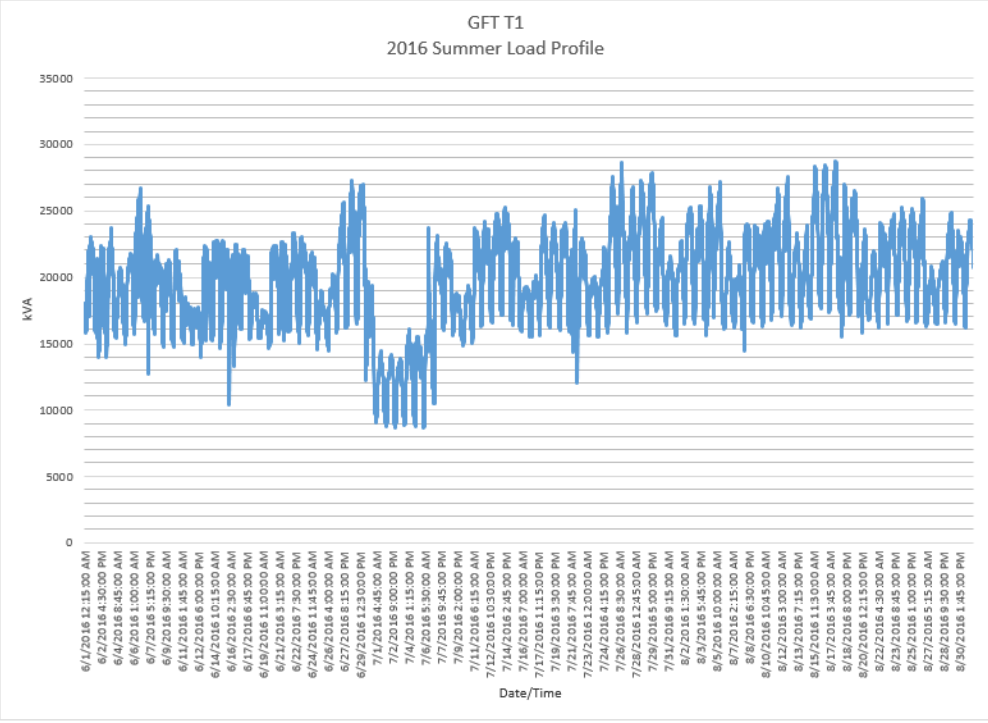
1


GFT T1
2015 Summer Load Profile
kVA
Date/Time

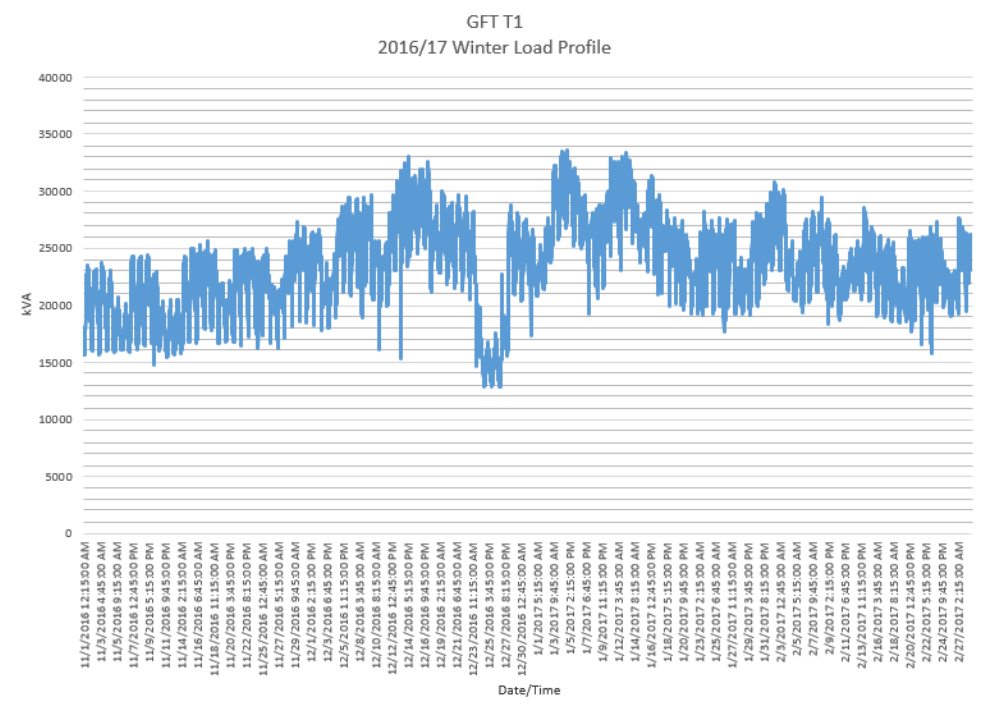
2


GFT T1
2015/16 Winter Load Profile
kVA
Date/Time

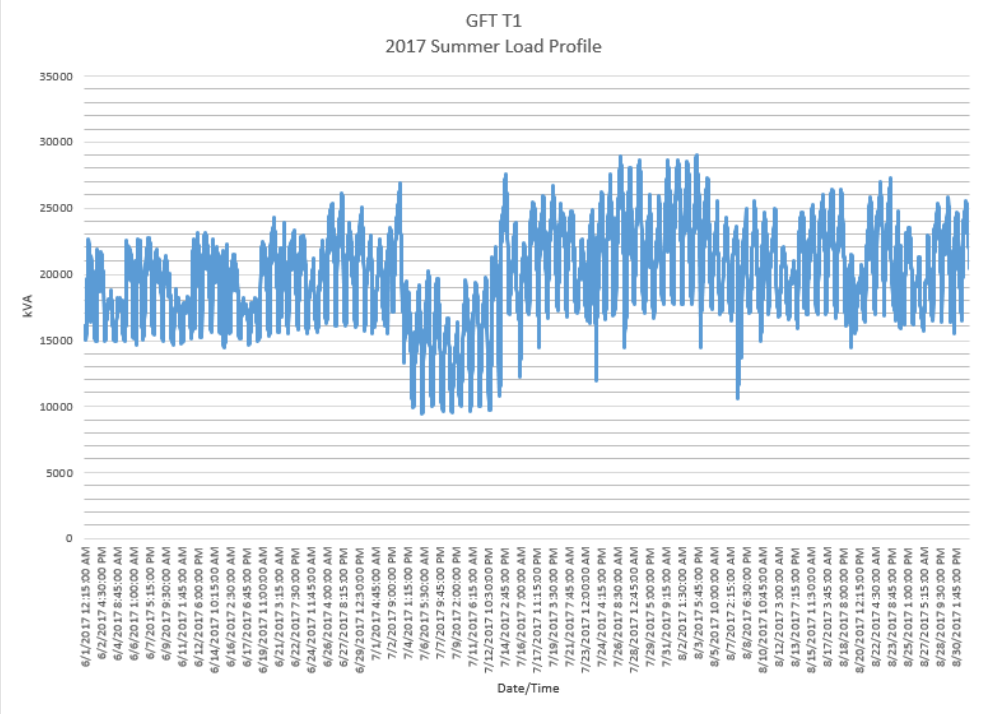
1


GFT T1
2016 Summer Load Profile
kVA
Date/Time

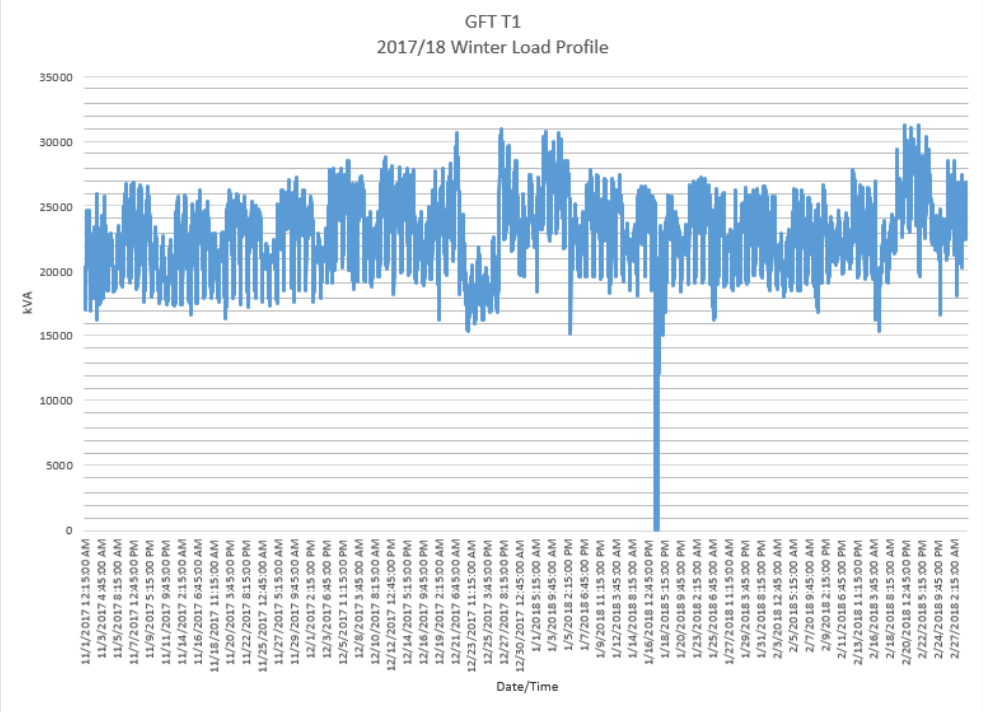
2


GFT T1
2016/17 Winter Load Profile
kVA
Date/Time

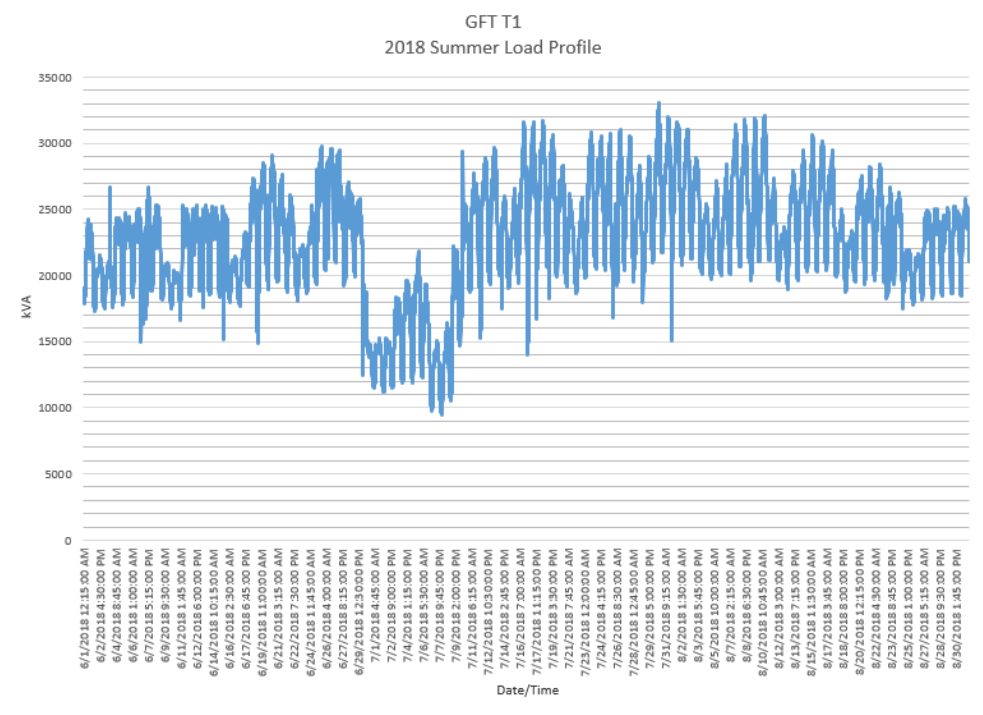
1


GFT T1
2017 Summer Load Profile
kVA
Date/Time

2


GFT T1
2017/18 Winter Load Profile
kVA
Date/Time

1

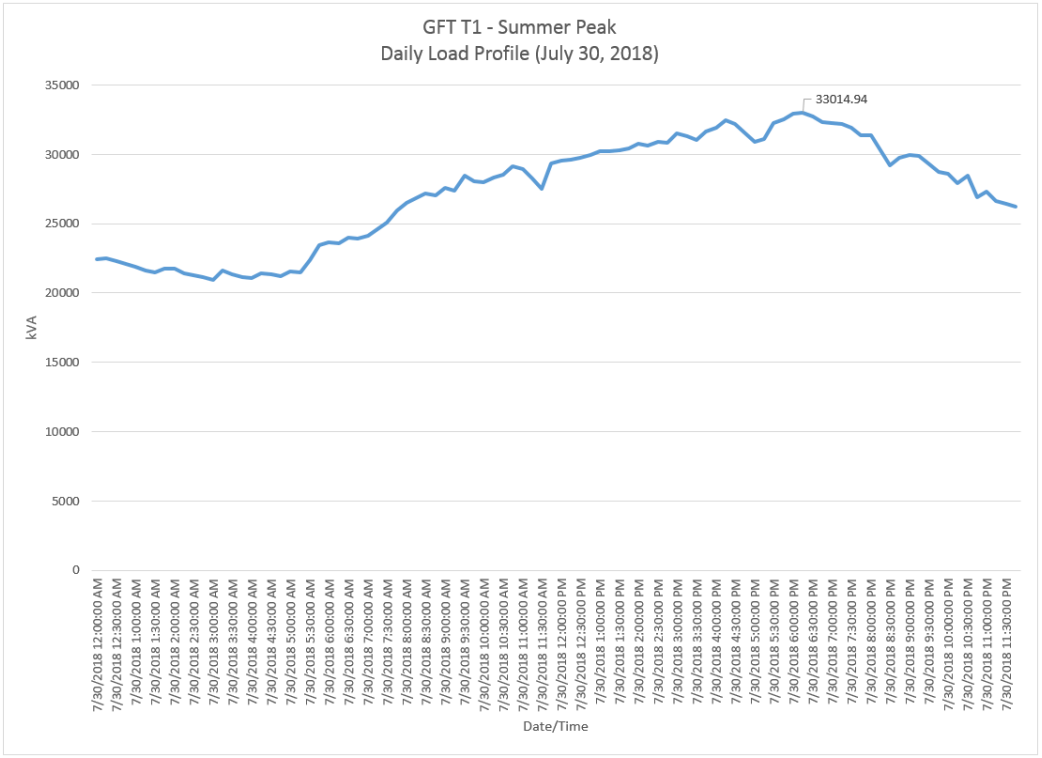

GFT T1
2018 Summer Load Profile
kVA
Date/Time

2

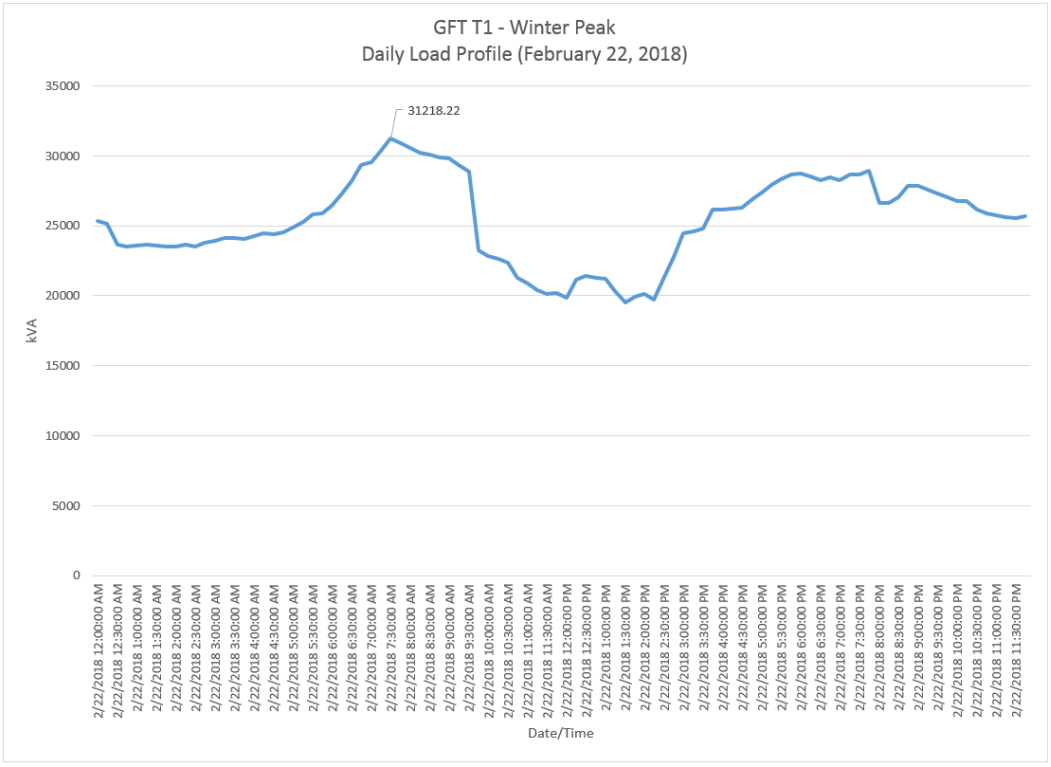
3

4

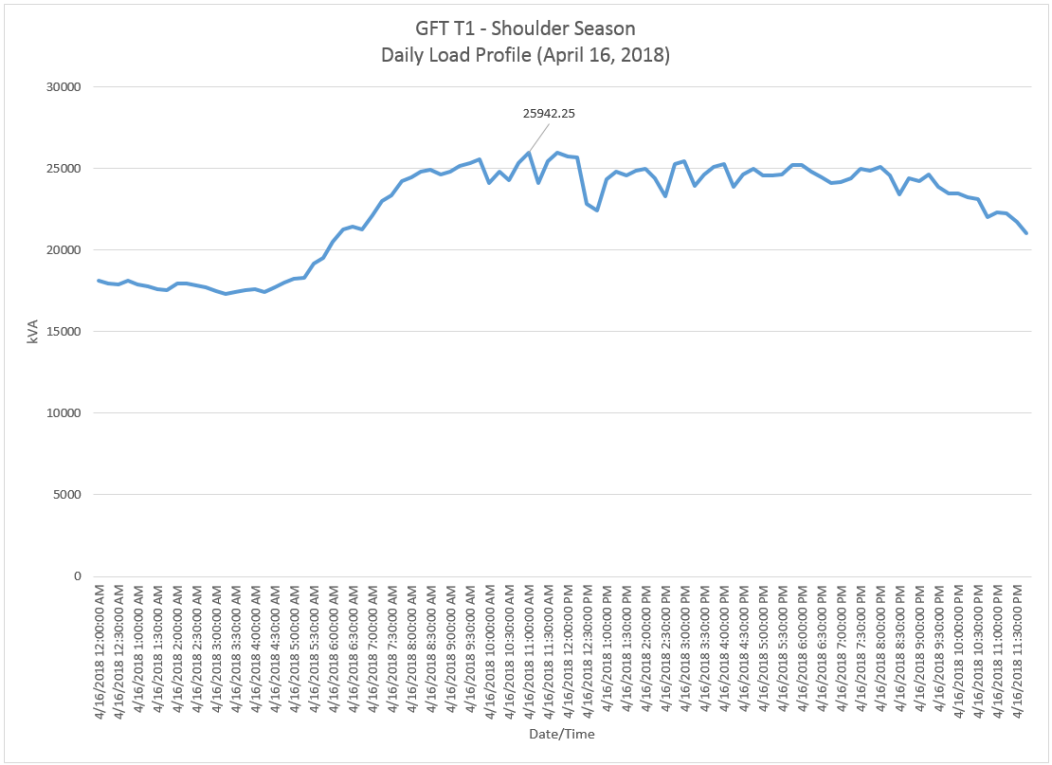
1 GFT T1 Daily Load Profiles:



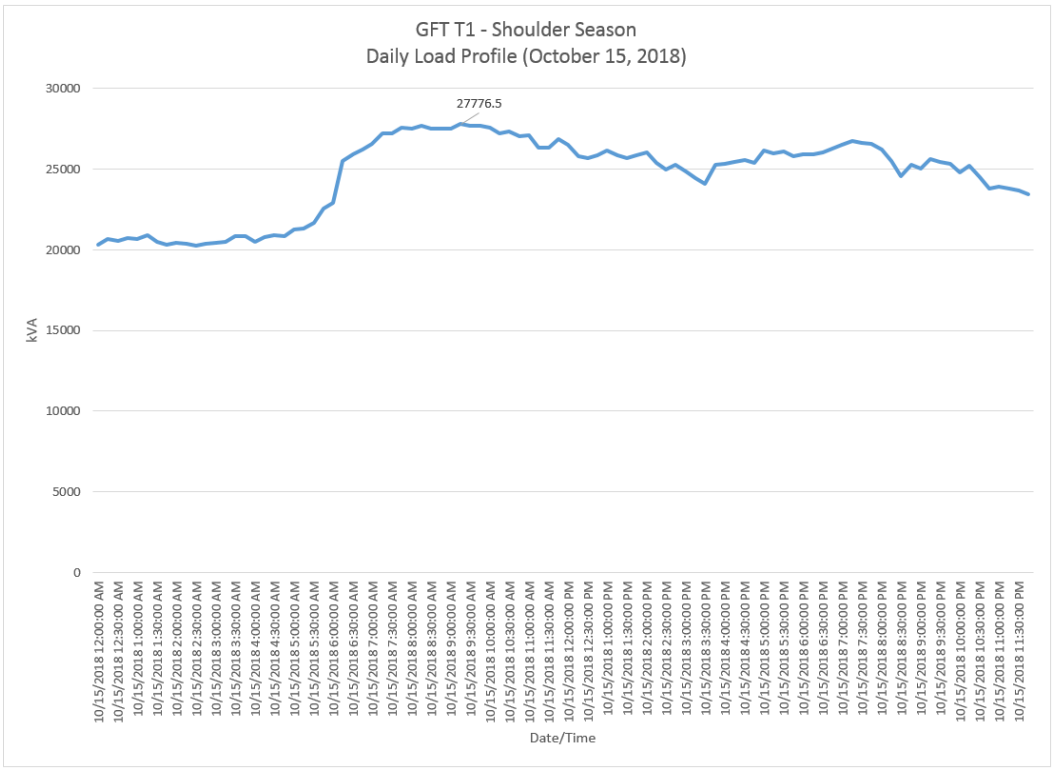
2



3


GFT T1 - Shoulder Season
Daily Load Profile (April 16, 2018)
25942.25
kVA
Date/Time

1


GFT T1 - Shoulder Season
Daily Load Profile (October 15, 2018)
27776.5
kVA
Date/Time

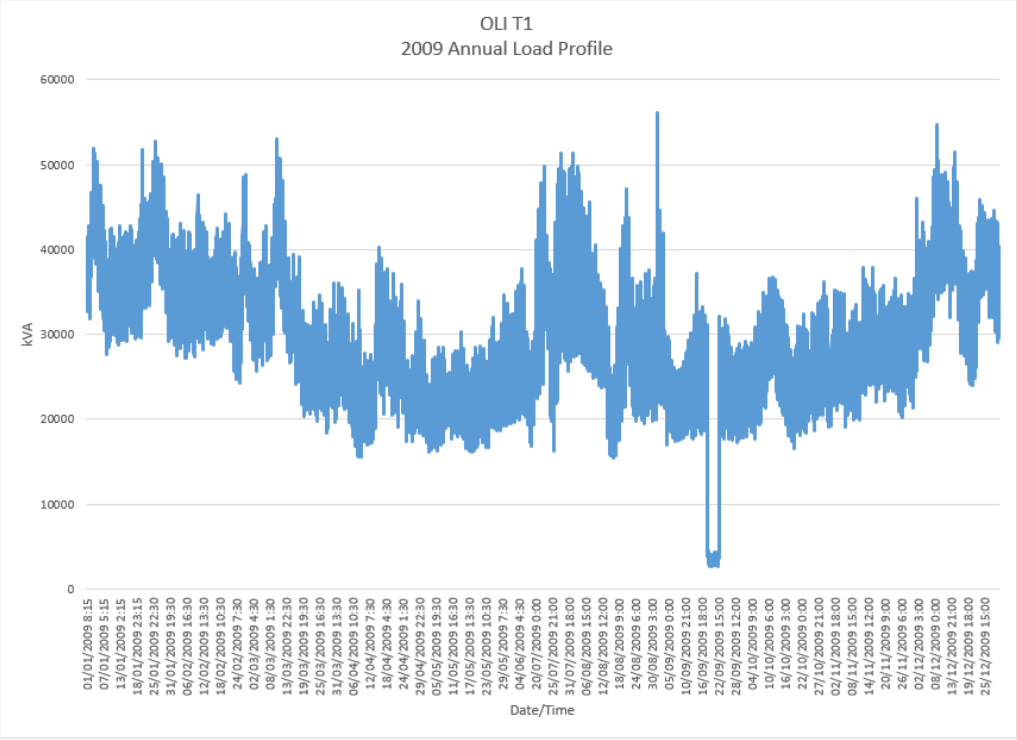
2

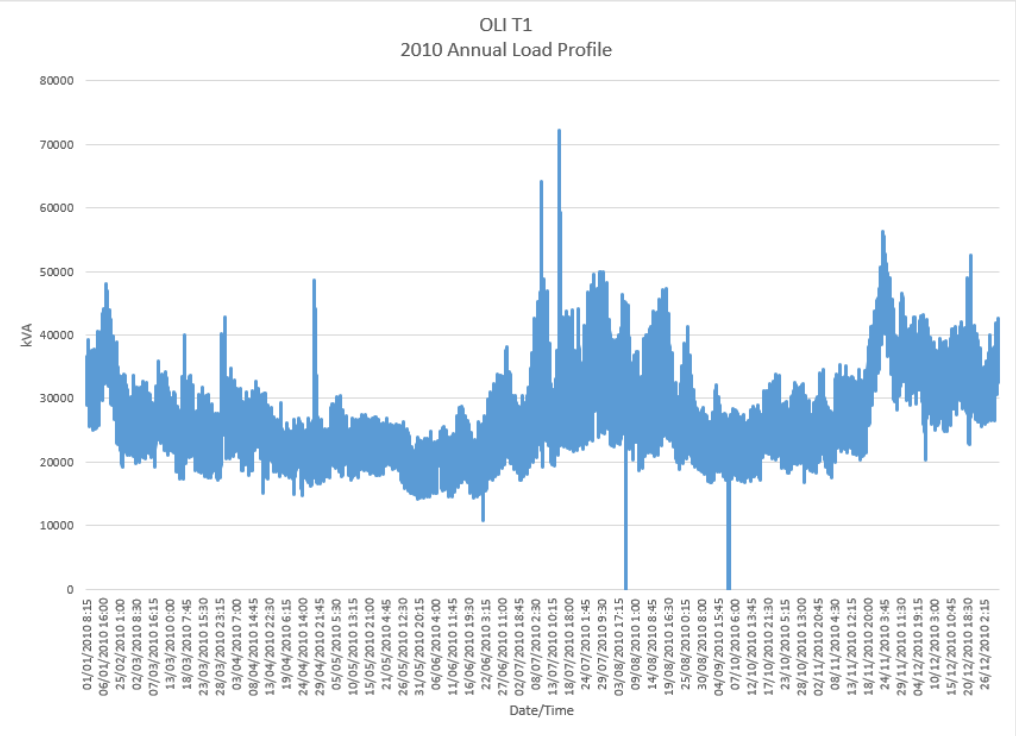
3

The annual load profiles for OLI T1 between 2009 and 2011 are provided below. There is no load profile provided from 2011 to 2018 because OLI T1 was removed from service in 2011.

The historical profile indicates that OLI T1 loading was primarily below the nominal rating of the transformer (60 MVA). However, the loading on OLI T1 momentarily spiked above the nominal rating in 2010.

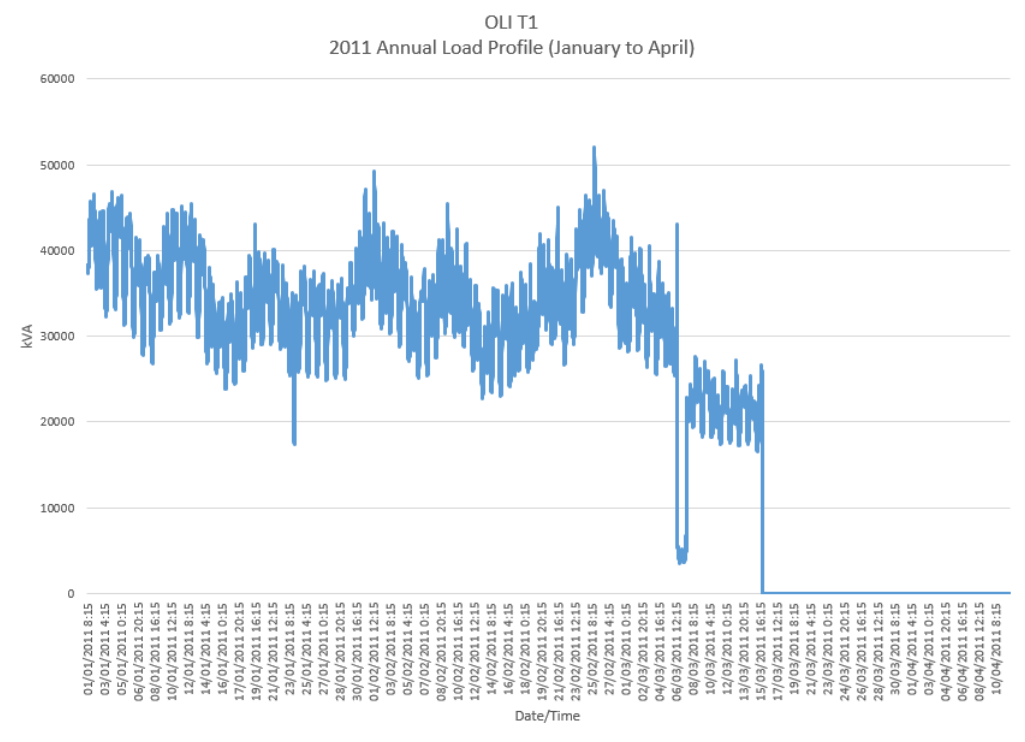
<u>OLI T1 Annual Load Profile:</u>




OLI T1
2010 Annual Load Profile
kVA
Date/Time

1
2

3


OLI T1
2011 Annual Load Profile (January to April)
kVA
Date/Time

4

1.4 How long was the longest-serving transformer in FortisBC's (or predecessor's) asset base in service?

Response:

The oldest transformer in the FBC fleet was UBO T1B which was in service at the Upper Bonnington generating plant for 105 years and failed in 2016. The single phase unit that failed was part of a three phase transformer bank. The unit had a very small MVA rating, was water-cooled, and had no load tap changer. After the BC Hydro Kootenay Canal hydro power plant was built, these transformers were only loaded during the freshet, which contributed to the long life of the unit.

2.0 Reference: Exhibit B-1, Section 3.1, page 12

"Over the past five years, the maximum winter and summer peak loads on GFT T1 were approximately 34 MW and 29 MW, respectively. GFT T1, with a nominal rating of 45/60 MVA has sufficient capacity to meet the forecasted distribution demand for the Grand Forks area load over the system planning horizon of 20 years."

2.1 Please provide the load-duration curves for the summer load and winter load served by GFT T1 for each of the last five years.

Response:

Please refer to the response to CEC IR 1.7.1.

3.0 Reference: Exhibit B-1, Section 3.1, page 14

"The maximum load that can be supplied by either 9L or 10L is 27 MW, which is insufficient to meet peak load conditions for the Grand Forks area."

3.1 Please provide the most recent two versions of FortisBC's facility ratings document as required by mandatory reliability standard FAC-008-3, and discuss any differences between the ratings of infrastructure in those documents and this Application.

Response:

The Mandatory Reliability Standards, including FAC-008-3, do not apply to 9L and 10L since these lines are not part of the Bulk Electric System. Further, the facility ratings documented in FBC Operating Order 7TR-101 (Facility Ratings) contain ratings based on equipment and line conductor limitations only. Operating parameters are determined by System Operating Limits (SOLs) which include facility ratings, system stability, and voltage limits which are not captured in the 7TR-101 document.

When GFT T1 is out of service and the Grand Forks area is being supplied by 9L and 10L, there are SOLs required to ensure the voltage remains above contingency limits. With both 9L and 10L closed from WTS to GFT, the maximum load able to be supplied is 45 MW without violating the voltage SOL. With only one of 9L or 10L closed from WTS to GFT, the maximum load able to be supplied is 27 MW without violating the voltage SOL.

Please refer to Confidential Attachment 3.1 for the last two versions of the FBC's facility ratings document (7TR-101 operating order).

FBC is requesting that Attachment 3.1 be filed on a confidential basis pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents adopted by Order G-15-19, because it contains sensitive operational and third party information.

4.0 Reference: Exhibit B-1, Section 3.2.1.2, page 15

"Although OLI T1 is on-site, it may take several weeks to install due to substation reconfiguration and civil work required to accommodate the spare transformer."

4.1 Please describe the scope and cost of the work and preparations that would be required to enable OLI T1 to be put into service within 48 hours of a failure of GFT T1. How much of that work can be done in the next year?

Response:

FBC has prepared a preliminary contingency plan designed to address the unforeseen failure of GFT T1. Please refer to the response to BCOAPO IR 1.2.1.

Given the layout of OLI T1 and the inherent complications with the protection circuitry, FBC would not be able to place OLI T1 into service within a 48-hour timeframe if GFT T1 failed.

4.2 Is OLI T1 currently located in the second (spare) bay at GFT?

Response:

No, OLI T1 is currently located in the north west corner of Grand Forks Terminal station. Please refer to the figure in the response to BCOAPO IR 1.10.2.

5.0 Reference: Exhibit B-1, Section 3.2.1.3, page 17

"In winter this can be nearly impossible, as 10L cannot be accessed from the ground due to the snowy and mountainous terrain."

5.1 Please describe and provide photos of the specialized equipment owned or used by FortisBC for winter ground access to remote right-of-way locations.

Response:

The typical winter vehicles used by FBC to access distribution and transmission line right of ways (ROW) are shown in the image below. For sections that cannot be accessed by either vehicle, field staff rely on snowshoes.

The vehicle on the left is a tracked side by side vehicle capable of hauling in material such as gear, insulators, cross arms, etc. The vehicle can carry two people. In the winter months, travel can be limited by snow type and depth. Creston, Grand Forks, and Warfield all have tracked side by sides for winter. In the summer months, the tracks are exchanged for rubber tires.

The vehicle on the right is a snowcat. It can carry the same amount of gear as a side by side, but it is a four passenger vehicle. The blade is capable of pushing some snow, but travel can be limited by snow type and depth. Only Warfield has a snowcat, which is shared across the Kootenay service territory.

5.2 How many specific locations on 10L are impossible to access from the ground in winter?

Response:

Access to 10L will depend on snow depth and conditions so FBC is unable to estimate which locations cannot be accessed. For periods of time during the year, and depending on prevailing conditions, helicopter access may be the only way to access some of the structures. However, there are several locations that would be extremely difficult to attempt to access in the winter. The figures below illustrate access to 10L.

5.3 Please describe whether recreational snow-mobiles routinely use the 9L and 10L right-of-way in the winter.

Response:

There are a small number of areas that may see some recreational snowmobile activity but most of the right of way (ROW) is not conducive to snowmobile riding. Large lengths of the ROW can have quite extreme conditions, making it not easily accessible by snowmobile.

6.0 Reference: Exhibit B-1, Table 3-2, page 19

6.1 Please describe the criteria for an outage to be included in FortisBC's SAIFI and SAIDI reliability indicators.

Response:

As per the Canadian Electricity Association (CEA) reporting standards, SAIDI and SAIFI are calculated as follows. FBC does not include momentary outages in its reliability metrics.

System Average Interruption Frequency Index (SAIFI):

This index is defined as the average number of interruptions per customer served per year.

$$\textbf{SAIFI} = \frac{\text{Total Customer-Interruptions}}{\text{Total Customers Served}}$$

System Average Interruption Duration Index (SAIDI):

This index is defined as the system average interruption duration for customers served per year.

$$\textbf{SAIDI} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$$

6.2 What was the impact of the GFT T1 transformer outage identified in Table 3-2 on that year's SAIFI and SAIDI reliability indicators?

Response:

The outage to GFT T1 only lasted for 10 seconds, therefore, it would not have been included in the 2014 SAIDI and SAIFI reliability indicators.

7.0 Reference: Exhibit B-1, Section 3.3, Alternatives Considered, page 20, lines 29-30

"Do nothing or Status Quo was not considered an option because FBC cannot currently meet the N-1 transmission planning criteria in the event of a GFT T1 failure during seasonal peaks."

7.1 Please identify when the N-1 transmission planning criteria was established for supply to the Grand Forks area?

Response:

FBC has reviewed its internal planning documents for the last twenty years. In its 1998 Transmission and Distribution Master Plan, the installation of a second 161/63kV transformer was selected as the preferred means of securing supply in the area (following reinforcement of the Okanagan transmission system, which was accomplished in the Okanagan Transmission Reinforcement project approved by Order C-5-08). The document directly referenced the need to maintain conformance with the N-1 planning criterion for the Boundary area supply, thus the N-1 planning criterion has been applied to the Grand Forks area for at least twenty years.

7.2 Please comment on whether FortisBC expects to meet the N-1 transmission planning criteria for all events on the transmission system?

Response:

Please refer to the responses to BCOAPO IR 1.7.1 and CEC IR 1.5.1.1.

7.3 Please provide evidence of the duration of the seasonal peaks when a GFT T1 failure will not meet the N-1 transmission planning criteria?

Response:

The seasonal peaks are instantaneous maximum values, and FBC assumes the question to ask for the duration of time surrounding the seasonal peaks that the load of GFT T1 exceeded the 27 MW limit. (Please refer to the response to CEC IR 1.7.1, which provides the GFT T1 winter and summer load data for the past five years.)

1 Based on the 15-minute interval readings, the duration of time around the seasonal peak for
2 which the GFT T1 load exceeded the 27 MW limit is presented in the table below.

Season	Date (mm/dd/yyyy)	Peak Load (MW)	Duration (hrs)	Season	Date (mm/dd/yyyy)	Peak Load (MW)	Duration (hrs)
Winter 2013/14	02/06/2014	32.6	6.5	**Summer 2014**	07/29/2014	29.6	5.75
Winter 2014/15	01/12/2014	31.3	15.75	**Summer 2015**	07/09/2015	28.8	4.5
Winter 2015/16	01/04/2016	30.6	6.25	**Summer 2016**	08/17/2016	28.8	4.25
Winter 2016/17	01/05/2017	33.6	20.0	**Summer 2017**	08/03/2017	29.0	4.25
Winter 2017/18	02/22/2018	31.2	3.25	**Summer 2018**	07/30/2018	33.0	14.0

3
4

8.0 Reference: Exhibit B-1, Section 3.3, Alternatives Considered, page 20

"FBC also considered consolidating 9L and 10L into a single circuit using 477 ACSR (Aluminium Conductor Steel-Reinforced) but rejected this option because the capacity of the new line could not support the Grand Forks area load."

8.1 Please provide the rating of the replacement single circuit that was considered and identify those conditions for which it could not support the Grand Forks area load.

Response:

On page 10 of Confidential Appendix C, the ampacity of 477 ACSR Pelican conductor is provided as 717A (summer) or 961A (winter). The response to BCUC Confidential IR 1.2.1 calculates the thermal capacity of this conductor. However, the thermal capacity of 9L and 10L is not the limiting factor in supplying Grand Forks area load during a GFT T1 outage.

Consolidating 9L and 10L into a single circuit with a larger conductor size would not be a feasible option because the voltage in the Grand Forks area would be below the acceptable contingency limits in the event of a GFT T1 outage under peak load conditions.

9.0 Reference: Exhibit B-1, Section 3.3.3, Alternative C: Transmission Rehabilitation of 9L and 10L, page 23

9.1 Please discuss the time period over which the $9.259 million capital cost of Alternative C could be expended if limiting capital expenditure was a priority.

Response:

From an efficiency point of view, FBC would try to implement the project in the shortest period of time possible. However, it is expected it would take place over a two to three year period due to the terrain and related conditions. Construction on 9L and 10L is limited by seasonal construction windows.

If capital expenditures are limited further, it will lengthen the project timeline beyond what is contemplated in Alternative C and also result in lower efficiency. This may be expected to translate into an increase in overall cost by 20 percent or more.

9.2 Are the failing or damaged insulation and cross arms all associated with failing poles? Are the insulators and cross-arms typically replaced when a pole is replaced?

Response:

No, failing or damaged insulation and cross arms are not necessarily associated with failing poles. However, due to the average pole life along the line, most poles are nearing end of life at the same time the cross arms are at the end of their lifecycles. Poles that are in good condition would not be expected to be changed out if only requiring arm and insulation replacements.

With respect to the second question, yes, the insulators and cross-arms are replaced when a pole is replaced, in particular when they are nearing the end of their lives together. This makes for more efficient construction replacements.

9.3 From the detailed condition assessment, how many structures have poles in acceptable condition with failing or damaged insulation or cross arms?

Response:

There are a total of 44 structures on 9L and 10L which DBS could identify that had failing insulation or arms, and which had poles in acceptable condition to reasonably accept refurbishment. These have been accounted for as repairs only and not replacements.

10.0 Reference: Exhibit B-1, Section 3.5.1, Technical Evaluation, page 27

"Load transfer would take longer under Alternative C, as field staff would have to manually close the normal open switches on 9L and 10L in order to reconfigure the 63 kV supply from WTS."

10.1 Please discuss the scope and costs of installing remotely operated disconnect switches on 9L. Is this technically feasible?

Response:

A portion of this response is being filed confidentially with the BCUC. FBC is requesting that this information be filed on a confidential basis pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents adopted by Order G-15-19, as it contains commercially sensitive information that if disclosed, could negatively impact future contract negotiations.

Adding a motor operator to the existing switches may be technically feasible. To meet the communication requirements to operate it remotely either fibre or cell communications would be required. Since there is no fibre network at these sites, it would be necessary to use cell communications. However, due to the remoteness of these areas, even cell communications may have limited reliability at these sites. Additionally, FBC has historically had issues with cell communication networks being used on remote switching applications.

FBC estimates that a high level cost for the installation of remote disconnect switches on the 63kV system would be approximately [redacted]

11.0 Reference: Exhibit B-1, Section 3.3, Alternatives Considered, page 28, lines 1-4

"The land risk is lowest for Alternative C since the distribution and transmission routes will not be changing, while Alternative A and Alternative B both require distribution rights-of-way to be confirmed for the portions of 9L and 10L that will not be removed."

11.1 Please explain the phrase "distribution rights-of-way to be confirmed"? For example, will it be necessary for FortisBC to procure or otherwise obtain new rights-of-way? If so, please provide the number of new rights-of-way that are necessary?

Response:

Please refer to the response to BCUC IR 1.9.2.

11.2 If the "distribution rights-of-way" are not confirmed, please comment on the consequences to the project? For example, will FortisBC then further consider Alternative C. If so, would FortisBC object to project approval being conditional on "distribution rights-of-way to be confirmed"?

Response:

FBC believes that obtaining the distribution Statutory Right of Way (SRW) is a low risk. At this time, there are only approximately 15 properties that have been identified as potentially requiring land rights for distribution SRW. Further, FBC believes the ownership mix of these properties (Crown and private) supports its assessment of risk.

FBC does not expect landowners to be any worse off than before given the Transmission ROW would effectively be replaced with a Distribution ROW. However, in the event that some of the necessary SRWs could not be obtained through negotiation, FBC would consider its options to complete the project. Given this and the above assessment of risk, FBC does not foresee further considering Alternative C, nor does it believe that a conditional project approval is required.

11.3 Please explain why a change from transmission facilities to distribution facilities on the same property might require new distribution rights-of-way, assuming FortisBC held the necessary transmission rights-of-way for the transmission

facilities? Please also comment on whether FortisBC will discharge transmission facility rights-of-way?

Response:

Please refer to the response to BCUC IR 1.9.2. Release of transmission rights-of-way are not planned as part of the GFT Reliability project as these right of ways may be required for long term planning.

11.4 Please explain why it is necessary to "confirm" distribution rights-of-way for portions of 9L and 10L that will not be removed? Is it necessary to "confirm" such distribution rights-of-way because FortisBC is concerned that it currently has distribution facilities on properties where there are no registered rights-of-way? If so, please provide an estimate of the number of properties on which distribution facilities may be located with no rights-of-way?

Response:

Please refer to the response to BCUC IR 1.9.2 explaining that FBC will confirm the rights of way following approval of the Project. At this time FBC is aware of approximately 15 properties where there are either no SRWs or acquiring an updated SRW would be preferred.

11.5 Please provide a route map for Alternative A and Alternative B that identify the distribution rights-of-way that need to be "confirmed"?

Response:

FBC considers its discussions and agreements with property owners to be private and confidential. Therefore, FBC respectfully declines to provide a route map that identifies individual properties for which distribution right of ways are in place or will be pursued.

11.6 Please confirm that the transmission routes for all three alternatives remain the same? If not confirmed, please identify the portion of the transmission routes that will change for each alternative?

Response:

In Alternative A and Alternative B, 44.6 km of the transmission lines 9L and 10L are proposed to be salvaged and 20.8 km repurposed to distribution lines. For a detailed map identifying the proposed transmission removal and distribution repurposing, please refer to the condition assessment report in Confidential Appendix C (Appendix VII - Option 2 Layout 9L/10L (CSC to CHR) - 63 kV Salvage & Re-use as Dx).

In Alternative C, the transmission route does not change.

11.7 Please comment on whether Alternative C requires consultation with Indigenous communities. Are there any physical impacts of Alternative C?

Response:

Alternative C does require consultation with Indigenous communities. While Alternative C was discussed in the meeting with the Osoyoos Band, further consultation would be required regarding the specific locations of the structure replacements if this alternative were to go forward.

Regarding the second question, FBC confirms that there are physical impacts caused by Alternative C as a result of structure replacements.

11.8 Please provide the estimates, on a confidential basis, of payments to Indigenous communities for consultation and accommodation for each of the alternatives. Please also comment on whether such estimates are AACE Class 3 estimates.

Response:

A portion of this response is being filed confidentially with the BCUC. FBC is requesting that this information be filed on a confidential basis pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents adopted by Order G-15-19, as it contains commercially sensitive information that if disclosed, could negatively impact future contract negotiations.

FBC confirms that no payments have been made to Indigenous Communities to date in connection with the Project. The estimate for consultation and accommodation for Alternative A

and B are [redacted], while Alternative C has an estimate of [redacted]. The estimates are based upon the amount of land disturbance and previous work with the Indigenous Communities in the area.

The estimate for these costs are not AACE Class 3. However, given the overall quantum of these estimates, the overall AACE Class 3 estimate for the project is not expected to be impacted.

11.9 Please provide the estimates, on a confidential basis, of payments to property owners for new statutory rights-of-way for each of the alternatives. Please also comment on whether such estimates are AACE Class 3 estimates.

Response:

A portion of this response is being filed confidentially with the BCUC. FBC is requesting that this information be filed on a confidential basis pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents adopted by Order G-15-19, as it contains commercially sensitive information that if disclosed, could negatively impact future contract negotiations.

The preliminary estimated aggregate lands costs including documentation and survey for Alternative A and Alternative B is [redacted], which is not an AACE Class 3 estimate (please also refer to the response to ICG IR 1.11.8).

There is no estimate for lands costs related to Alternative C as it does not contemplate changing the existing transmission route.

11.10 Please further explain why Alternative B is the recommended alternative when Alternative C has the lowest land risk and both Alternative B and Alternative C meet FBC transmission planning criteria?

Response:

As discussed in Section 3.5.1 and Section 3.5.2 of the Application, upon comparison of all technical and financial criterion, it was determined that Alternative B was a better solution than Alternative C. The lands risk is only one component of the "Project Risk" technical criterion. While Alternative C has no lands risk, the lands risk associated with Alternative B is considered

low as only a small number of rights of way additions or amendments are required. Alternative C had the highest present value of incremental cost of service because it had no reduction in transmission O&M or rehabilitation costs. As such, Alternative C had the highest rate impact to customers based on the basis of a levelized lifecycle analysis over a 40 year period.

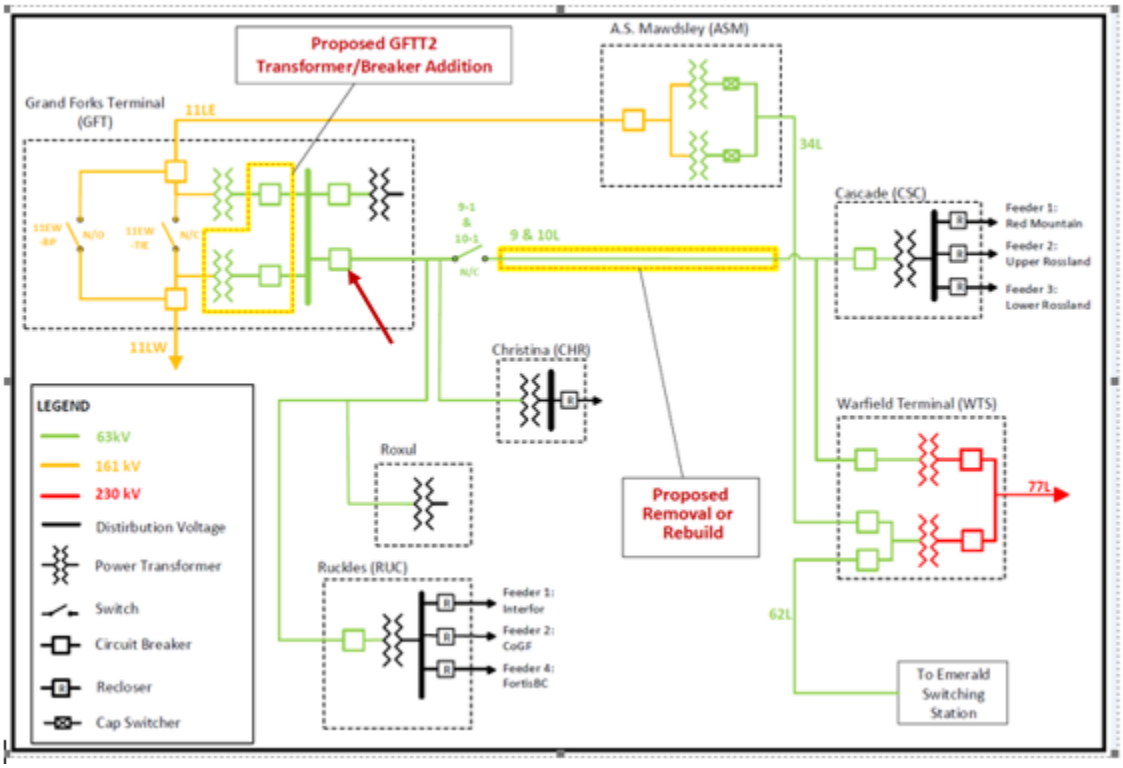
12.0 Reference: Exhibit B-1, Figure 5-1, page 34

12.1 Please confirm whether Figure 5-1 correctly depicts the Grand Forks Terminal with both 9L and 10L connected to the 63 kV bus at a single point with no circuit breaker.

Response:

Figure 5-1 does not correctly depict the Grand Forks Terminal. First, the figure has been simplified, showing 9L and 10L as a single line. Second, in both the existing and proposed configurations, each of 9L and 10L is connected to the 63 kV bus separately with individual circuit breakers. Figure 5-1 omitted breakers where 9L and 10L connect to the 63 kV bus at GFT. A corrected version of Figure 5-1 is provided below. The circuit breakers omitted in the original figure are identified by the red arrow (note that the square represents two separate breakers connected to the bus). FBC is filing an errata to correct this, concurrent with the filing of these IR responses.

Figure 5-1 Revised: Grand Forks Area Single Line Drawing



Attachment 1.1

Location	ID	HV Nominal	In Service Year
UBO - Upper Bonnington (MRS)	T1-A	63	1932
UBO - Upper Bonnington (MRS)	T1-B	63	1932
UBO - Upper Bonnington (MRS)	T1-C	63	1932
HER - Hearns	T1-A	63	1950
HER - Hearns	T1-B	63	1950
HER - Hearns	T1-C	63	1950
YMR - Ymir	T1	63	1950
M12 - 12 MVA Mobile	T1	63	1973
SAL - Salmo	T1	63	1968
TRC - Trout Creek	T1	63	1969
BEP - Beaver Park	T1	63	1965
PAS - Passmore	T1	63	1965
PLA - Playmor	T1	63	1966
STC - Stoney Creek	T1	63	1968
ASM - (A.S.) Mawdsley Terminal (MRS)	T1	161	1965
CRA - Crawford Bay	T4	63	1961
KAL - Kaleden	T1	63	1959
BLU - Blueberry	T1	63	1968
KER - Keremeos	T1	63	1974
GFT - Grand Forks Terminal (MRS)	T1	161	1965
ASM - (A.S.) Mawdsley Terminal (MRS)	T2	161	1971
DUC - Duck Lake	T1	138	1967
UBO - Upper Bonnington (MRS)	T4	63	1965
CRE - Creston	T1	63	1974
COF - Coffee Creek	T3-A	63	1971
COF - Coffee Creek	T3-B	63	1971
COF - Coffee Creek	T3-C	63	1971
CHR - Christina Lake	T1	63	1975
UBO - Upper Bonnington (MRS)	T3	63	1969
VAL - Valhalla	T2	63	1973
WES - Westminster	T1	63	1975
FRU - Fruitvale	T1	63	1986

Attachment 3.1

FILED CONFIDENTIALLY