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March 21, 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. 2

On November 19, 2018, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-43-19 setting out a further Regulatory Timetable for review of the Application, FBC respectfully submits the attached response to ICG IR No. 2.

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-2, BCUC IR 1.1

"Transmission line 10L has been de-energized since 2010 due to its poor condition and must be visually assessed and, if necessary, rehabilitated before it can be placed in service."

1.1 Please provide information that identifies the periods when and for how long 10L has been energized since 2010.

Response:

The 10L circuit between the CHR tap and CSC was in service and supplying Grand Forks area load from WTS on the following dates between 2011 and 2018. Data is not available for 2010.

Year	Date and Time	
	Start	End
2010	No data available	
2011	06/04/2011 8:35:00 AM	06/04/2011 3:15:00 PM
2012	22/08/2012 8:20:00 AM	22/08/2012 8:30:00 AM
2013	10L did not serve GFT area load from WTS	
2014	03/09/2014 2:35:00 PM	31/10/2014 11:35:00 AM
2015	05/10/2015 11:30:00 AM	09/10/2015 2:00:00 PM
2016	10L did not serve GFT area load from WTS	
2017	10L did not serve GFT area load from WTS	
2018	10L did not serve GFT area load from WTS	

2.0 Reference: Exhibit B-2, BCUC IR 1.2.2

"FBC has operated the GFT T1 load tap changer in manual control since April 2016, which appears to have resulted in stable dissolved hydrocarbon and hydrogen gases. However, the load tap changer may not be the actual cause of the high acetylene levels. Therefore, FBC selected the worst case scenario for the risk of failure (RoF) as 2.6 percent."

2.1 Please confirm that elevated acetylene levels are common, and indeed expected, for on-load tap changers.

Response:

For the type of load tap changer in GFT T1, high acetylene levels are common.

2.2 Please confirm that acetylene in transformer oil indicates an arcing fault, which would be readily identifiable if it was present in elsewhere in the transformer other than the on-load tap changer.

Response:

Confirmed. The presence of acetylene is a clear indicator of arcing. It is abnormal to find acetylene dissolved in transformer insulating oil. However, acetylene can be produced inside the main tank during short duration events, which may lead to an immediate transformer failure.

2.3 Please confirm there are no indications at this time that either GFT T1 or OLI T1 would be unable to remain in useful service for at least another 15 years with prudent maintenance.

Response:

Based on the GFT T1 Condition Assessment and OLI T1 Field Inspection Assessment reports performed by ABB, which assumed preventive maintenance, FBC concluded that the transformers could last 10 to 15 years. However, FBC cannot predict this outcome with certainty and has no reason to revise its conclusion.

3.0 Reference: Exhibit B-2, BCUC IR 1.2.3

"FBC considers that an acceptable risk of failure (RoF) for a transmission station should be no higher than 2 percent based on industry standards."

3.1 Please provide a reference for the industry standard that specifies a risk of failure threshold of 2 percent.

<u>Response:</u>

Please refer to the response to BCUC IR 2.17.1.1.

4.0 Reference: Exhibit B-2, BCUC IR 1.2.8

"Additionally, OLI T1 has the following known issues:

-An oil leak between the load tap changer and main tank.

-Load tap changer with an excessive number of operations and arcing contact issues.

-The load tap changer motor and gear mechanism is loose."

4.1 Please confirm whether the OLI T1 on-load tap changer contacts, motor and gear mechanism are able to be replaced.

Response:

Please refer to the response to BCUC IR 2.20.1.

4.2 Please describe how an oil leak between the on-load tap changer and the main tank will increase the risk of failure of OLI T1.

Response:

Oil migration between the Load Tap Changer (LTC) tank and the main tank will result in cross contamination of the main tank. The migration of oil polluted with suspended particles from the LTC tank to the main tank will reduce the dielectric properties of the oil in the main tank and will lead to an unforeseen transformer failure. The cross contamination will also skew the dissolved gas analysis results for the main tank, which will prevent the identification of an issue before it turns into a failure.

5.0 Reference: Exhibit B-2, BCUC IR 1.3.5

5.1 Please explain why outages in excess of 500 hours were allowed to remain for that period of time without repair.

Response:

Of the outages exceeding 500 hours, two were attributed to 10L and resulted in no customer outages. The remaining outage was on 9L and was due to a tree on the line. While it took approximately 686 hours to repair 9L, Christina Lake customers were returned to service within approximately 3 hours by transferring the load to 10L as Christina Lake can be supplied from either 9L or 10L.

6.0 Reference: Exhibit B-2, BCUC IR 1.3.6

"However, the parallel operation of 9L and 10L significantly reduces the outage times in the event of a GFT T1 outage. … Conversely, with only a single line in service and depending on the Grand Forks area, customer outages may be required until GFT T1 is restored."

6.1 Please explain that with the parallel operation of 9L and 10L FBC meets the single contingency (N-1) planning criteria for the 63 kV system in the Grand Forks area even if only a single line is in service and GFT T1 is not in service?

Response:

Parallel operation would mean that both 9L and 10L are in service. With a single line out of service, the lines would not be in parallel operation.

Both 9L and 10L must be operated in parallel to support the Grand Forks area seasonal peak loads during a GFT T1 outage. The N-1 planning criteria cannot be met with a single line in service because either 9L or 10L alone cannot support the seasonal peak load during a GFT T1 outage.

6.2 Please explain why the parallel operation of 9L and 10L with GFT T1 does not meet the single contingency planning criteria when the second transformer, GFT T2, does meet the single contingency planning criteria?

Response:

Please refer to the response to ICG IR 2.6.1.

7.0 Reference: Exhibit B-2, BCUC IR 1.1.1

"… FBC cannot meet the single contingency (N-1) planning criteria for the 63 kV system in the Grand Forks area since parallel operation of 9L and 10L cannot be relied upon."

Reference: Exhibit B-2, BCUC IR 1.3.7

"The reliability that is driving the Project, however, is not the overall duration or frequency of outages to customers. It is the inability of the 63 kV system in the Grand Forks area to meet the N-1 contingency planning criteria, as required by FBC's standards for an interconnected system."

7.1 Please explain why the single contingency (N-1) planning criteria also requires reliability criteria to be applied to each element of the system? Specifically, what reliability criteria are applied to the operation of 9L and 10L?

Response:

The single contingency (N-1) planning criteria is defined on page 11 of the Application (footnote 7):

> Single contingency reliability, also referred to as N-1 reliability, means that an outage of a single element with all other elements of the power system in service (a single transmission line, transformer, generating unit, power conditioning unit like a shunt capacitor bank, a shunt reactor bank, a series capacitor, a series reactor, etc.) will result in no load loss.

The criterion does not apply to the individual elements. With respect to Grand Forks area reliability, this means that upon the loss of GFT T1, FBC must be able to supply 100 percent of the Grand Forks area load from an alternate supply, either 9L and 10L operating in parallel or a second 63kV transformer at GFT. Because both lines are required to meet peak demand, 9L and 10L together are considered to be a single element when operating in parallel.

7.2 Please explain why Alternative C was considered an option to meet the single contingency (N-1) planning criteria if it does not meet the forecast load growth in the Grand Forks area during the 20-year planning horizon?

Response:

Alternative C, rehabilitating 9L and 10L, was included as an option to ensure all possible alternatives were considered.

The current 20-year load forecast indicates the Grand Forks area load will exceed 45 MW by 2031 (45 MW is the maximum Grand Forks area load that can be supported from both 9L and 10L during a GFT T1 outage). FBC considered whether reactive compensation could be added to supply the needed voltage support but concluded this would not be a feasible long term solution because the increase in reactive compensation is disproportionately large compared to the increase in load.

8.0 Reference: Exhibit B-2, BCUC IR 1.4.4

8.1 Please discuss whether, at the time of the Kettle Valley Substation Project, there was any analysis of retaining either 9L or 10L from the Kettle Valley Substation to GFT as a secondary source, and if not, why not?

Response:

The Kettle Valley substation project eliminated the 63 kV voltage between GFT and Rock Creek, therefore there was no value in keeping 9L and 10L lines as a secondary source, given that 9L and 10L were in very deteriorated condition. Portions of the lines were re-built to distribution lines where it was economical and feasible to do so.

9.0 Reference: Exhibit B-2, BCUC IR 1.15.2

"Using the detailed condition assessment report for 9L and 10L, the Class 2 estimate for the transmission and distribution portion of the project is $7.452 million. The total project cost is $13.171 million…"

9.1 Please confirm that the total project cost of $13.171 million of Alternative B should be used when comparing the total project cost of Alternative B to the total project cost of Alternatives A and C?

Response:

BCUC IR 1.15.2 (Exhibit B-2) reference in the preamble should read "…the Class 3 estimate for the transmission and distribution portion of the project is $7.452 million".

Confirmed, the total project capital cost of $13.171 million for Alternative B is the total project capital cost to compare against Alternatives A and C.

10.0 Reference: Exhibit B-4, BCOAPO IR 1.2.1

"FBC has prepared a preliminary contingency plan designed to address the unforeseen failure of GFT T1."

10.1 Please provide the referenced preliminary contingency plan.

Response:

As part of the preliminary contingency plan, FBC prepared the following scope of work to install OLI T1 in case of a failure to GFT T1:

- Disconnect GFT T1.
- Drain oil from GFT T1, remove surge arrestors and neutral CT and relocate to OLI T1.
- Disconnect Voltage Transformers (VTs) and Current Transformers (CTs), and remove the structure to make room for OLI T1.
- Physically remove GFT T1 and replace with OLI T1.
- Install cable tray from OLI T1 to nearby cable trench.
- Install new control cables from OLI T1 to control building.
- Complete OLI T1 oil processing.
- Test and commission OLI T1 and protection.
- Complete high voltage connections and energize.
- Re-install the VTs and CTs.

FBC also prepared general arrangement drawings, section drawings, AC schematic drawings for GFT T1, a single line diagram, and a materials listing for the required scope of work. FBC notes that these drawings are completed internally and are still in the process of validation by key stakeholders and contain sensitive system information. Further, FBC believes that examination of the preliminary contingency plan is not necessary to facilitate the BCUC's decision on the Application. For all these reasons, FBC respectfully declines to provide the preliminary contingency plan.

10.2 Please describe any analysis of the contingency plan FortisBC has undertaken to identify any pre-work that could be performed to reduce the time to install the on-site spare transformer.

Response:

Please refer to the response to ICG IR 2.10.1.

10.3 What is the fastest turnaround time to install the on-site spare transformer on a "best efforts" basis?

Response:

As stated in the response to BCOAPO IR 1.2.1 (Exhibit B-4), it would take approximately 3 to 4 weeks to install the on-site spare transformer.

11.0 Reference: Exhibit B-4, BCOAPO IR 1.3.1

11.1 Please provide the actual summer and winter peak loads from 2010 onwards, the forecasted summer and winter peaks for the years 2010 to 2019, and the annual forecasted summer and winter peaks to 2038.

Response:

The forecast summer and winter peak loads for GFT T1 from 2011 to 2018 as prepared for the 2012 Integrated System Plan were as shown in the first table below (no forecast data was available for 2010, the year in which the forecast was prepared). FBC's system load forecast is a "1-in-20" load forecast, which produces forecast peak loads that are expected to be higher than the actual peak loads in 19 out of 20 years. It is a non-coincident peak load forecast used to determine the substation, distribution and transmission infrastructure needed in order to supply all FBC customers during peak demand periods and adverse weather conditions. As can be seen from the first two tables below, this has resulted in a higher peak load forecast for GFT T1 than actually recorded.

Year	Summer Peak (MVA)	Winter Peak (MVA)
2010	No Data	No Data
2011	34.87	40.11
2012	35.56	40.49
2013	36.14	41.12
2014	36.43	41.39
2015	36.89	41.52
2016	37.16	41.71
2017	37.56	41.97
2018	37.90	42.20

The actual summer and winter peak loads for GFT T1 from 2010 to 2018 were recorded as follows:

Year	Summer Peak (MVA)	Winter Peak (MVA)
2010	26.19	32.60
2011	25.49	32.24
2012	No Data	29.23*
2013	28.23	29.12
2014	29.58	32.57
2015	28.81	31.28
2016	28.76	30.60
2017	29.00	33.58
2018	33.01	31.22
* No GFT T1 load data available for 2012		

The forecast summer and winter peak loads for GFT T1 from 2019 to 2038 are as follows,

Year	Summer Peak (MVA)	Winter Peak (MVA)
2019	38.67	40.54
2020	39.06	40.95
2021	39.36	41.29
2022	39.67	41.62
2023	39.97	41.99
2024	40.34	42.41
2025	40.72	42.78
2026	41.04	43.16
2027	41.41	43.57
2028	41.77	43.99
2029	42.14	44.36
2030	42.47	44.74
2031	42.84	45.15
2032	43.20	45.57
2033	43.57	45.94
2034	43.89	46.36
2035	44.26	46.78
2036	44.63	47.19
2037	45.00	47.61
2038	45.36	48.02

12.0 Reference: Exhibit B-5, CEC IR 1.7.1

"The Grand Forks area has 3,750 residential and commercial customers, 2,200 City of Grand Forks customers, and 2 industrial customers."

12.1 Please provide the amount of load the single largest customer contributed to the forecast summer and winter peak loads in 2010, 2018, 2025 and 2031.

<u>Response:</u>

The largest customer in the Grand Forks area is the City of Grand Forks electric utility. The measured peak demand for the City of Grand Forks was 6.96 MVA in summer 2010, 8.63 MVA in winter 2010, 8.98 MVA in summer 2018, and 7.76 MVA in winter 2018.

In the 2016 Long Term Electric Resource Plan, the City of Grand Forks peak load was forecast at 7.12 MVA in summer 2025, 9.94 MVA in winter 2025, 7.38 MVA in summer 2031, and 10.30 MVA in winter 2031. Since the load forecast was prepared in 2016, it does not include recent customer additions in the Grand Forks area.

13.0 Reference: Exhibit B-6, ICG IR 1.1.3

13.1 Please explain the reason for the 40 MVA peak load in the 2010 annual load profile. What was the duration of the 40 MVA peak?

Response:

The GFT T1 load momentarily spiked to 40.031 MVA on January 5th, 2010 at 4:00 AM. The peak was recorded as the maximum value over a 15 minute interval. Since this was likely a transient event, it is not considered the peak load. FBC confirmed there were no faults recorded at the nearby stations and as such it is unclear what may have caused this event.

13.2 Please confirm the average load carried by GFT T1 in 2017 was less than 50% of the maximum nameplate rating. In what year is the average annual load expected to reach 50% of the nameplate rating.

Response:

Confirmed. The average load carried by GFT T1 in 2017 was approximately 21.05 MVA. The nominal rating of GFT T1 is 60 MVA. Therefore, the average load carried by GFT T1 in 2017 was less than 50 percent of the nominal nameplate rating.

FBC does not forecast the average annual load. Please refer to the response to ICG IR 2.11.1, which provides the forecast peak loads for GFT T1 from 2019 to 2038.

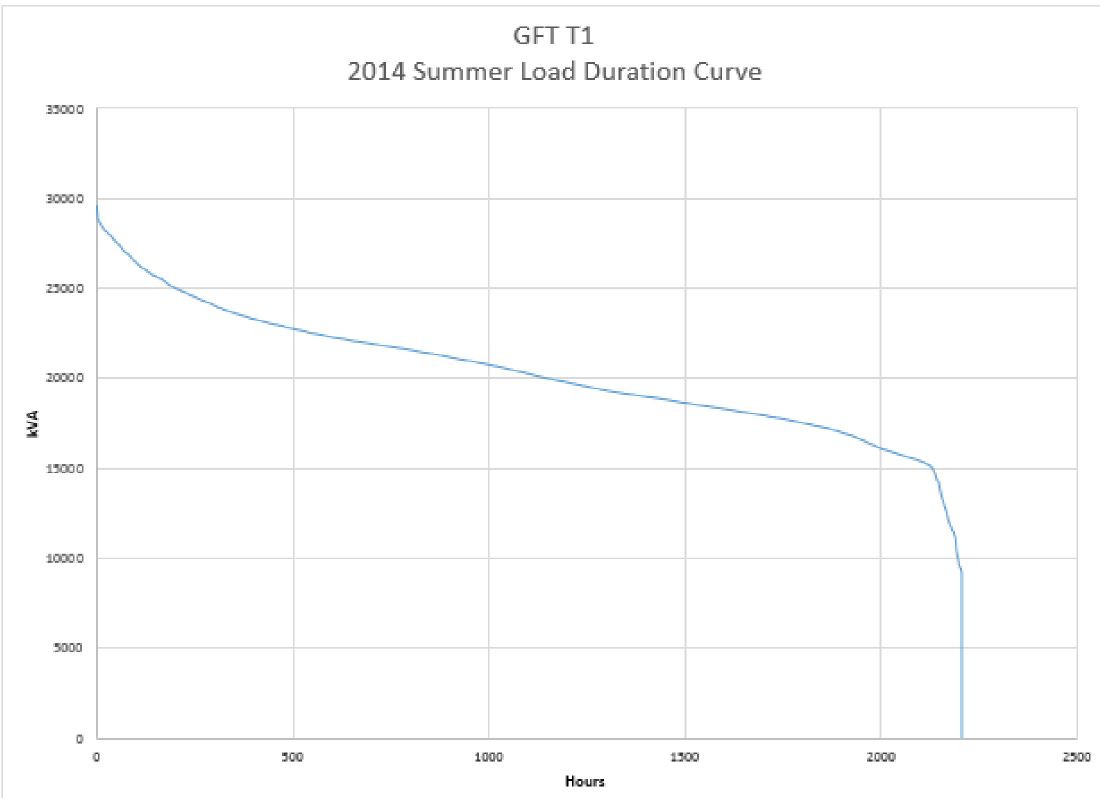
The GFT T1 transformer has sufficient capacity to meet the forecast distribution demand for the Grand Forks area load over the system planning horizon of 20 years. The GFT Reliability Project is not being proposed to address a capacity issue in the Grand Forks area.

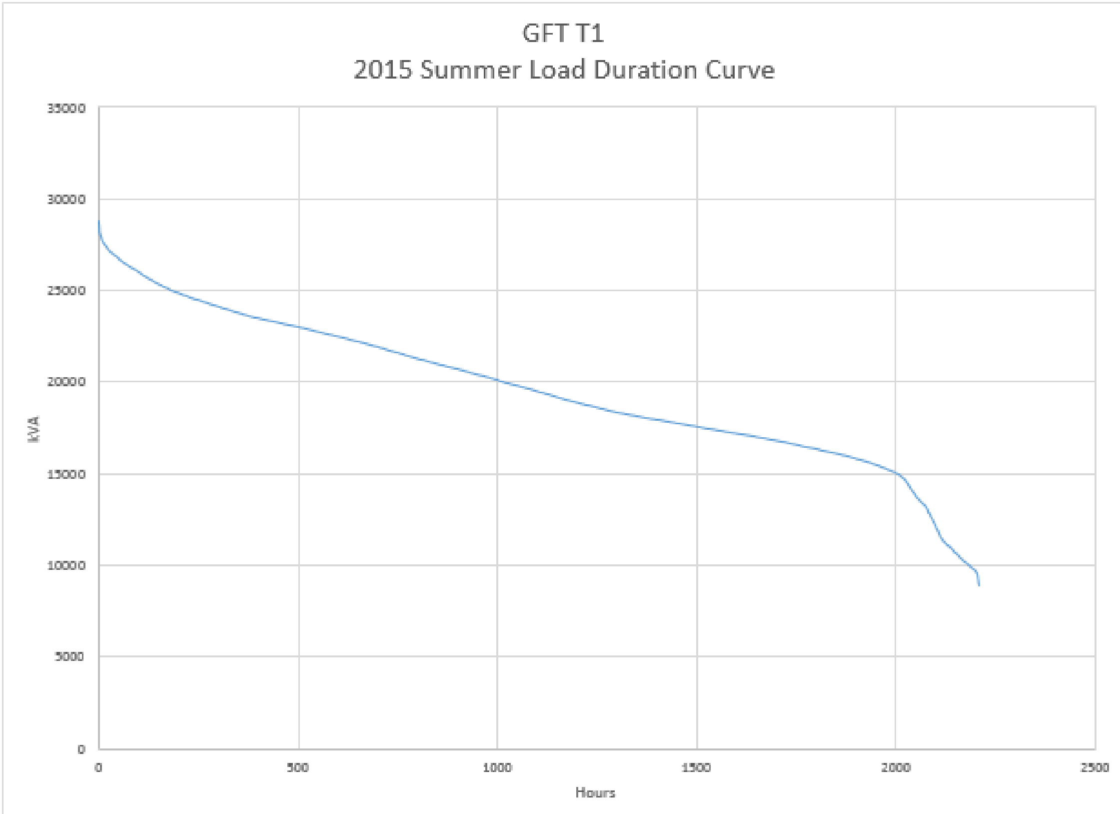
14.0 Reference: Exhibit B-6, ICG IR 1.2.1

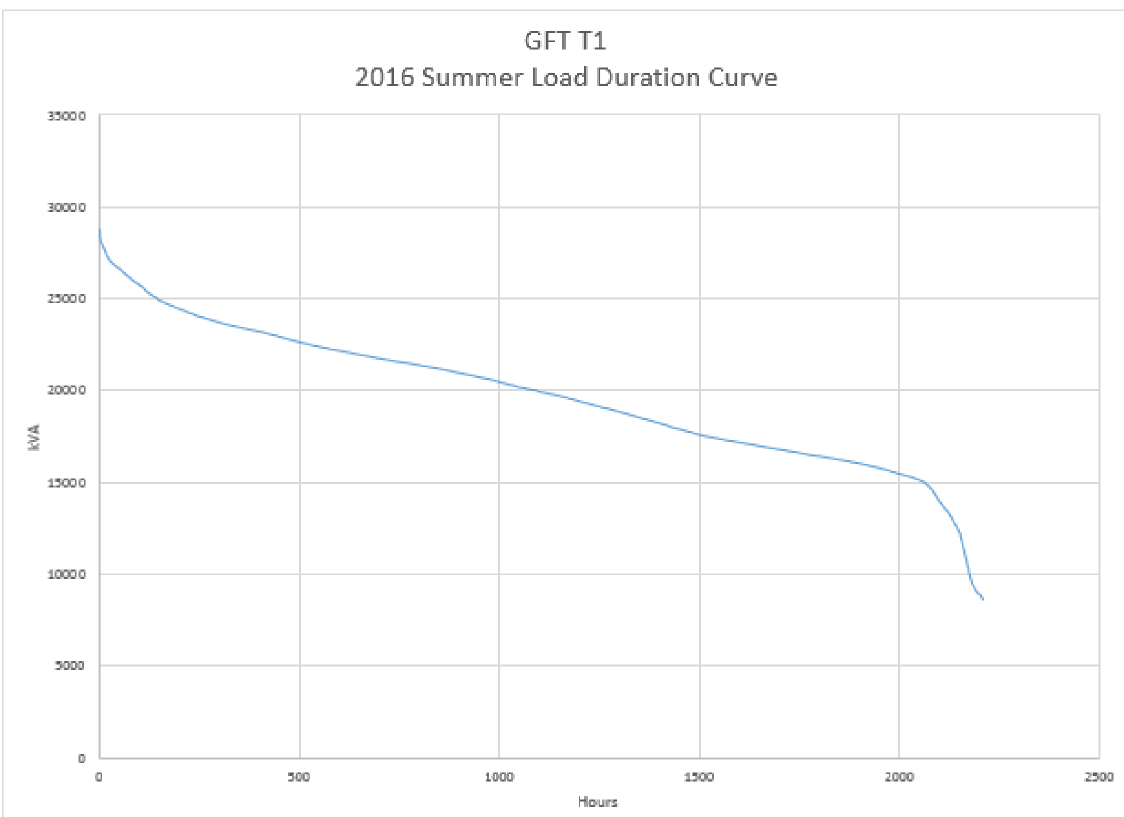
14.1 Please re-format the data supplied in the spreadsheets submitted in Exhibit B-5, CEC IR 1.7.1 as traditional load-duration curves so that the number of hours where the transformer was carrying above a given load can be readily determined.

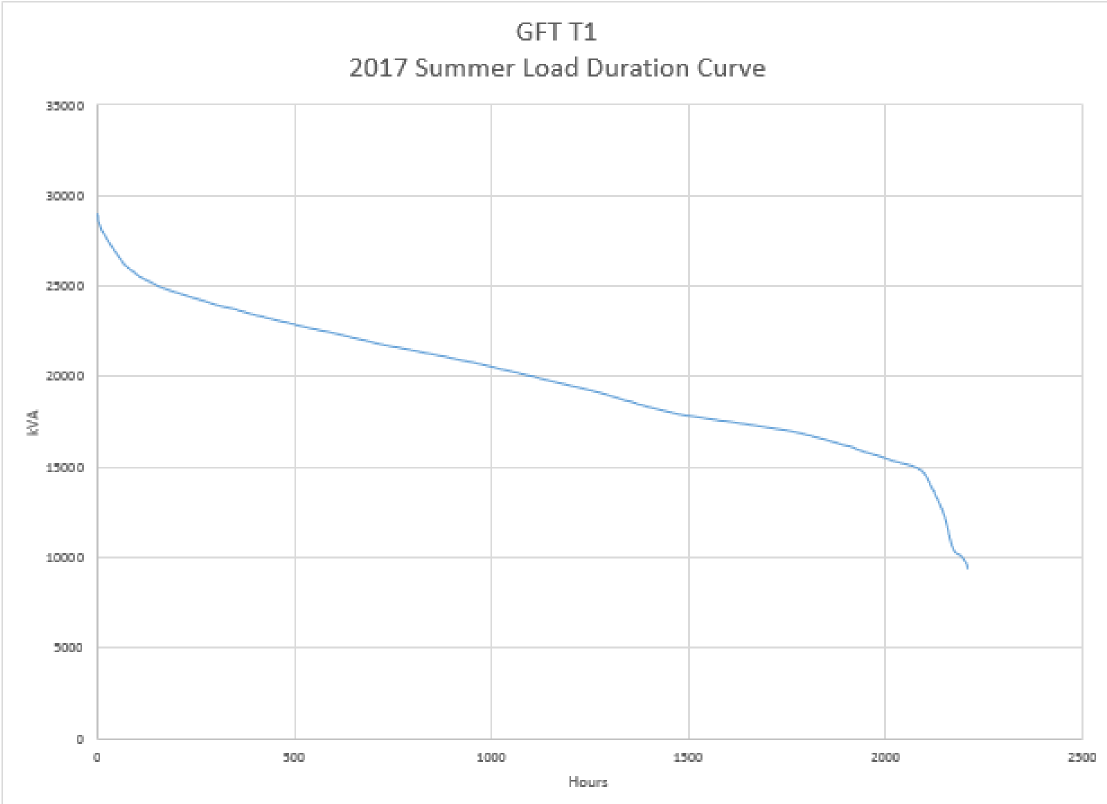
Response:

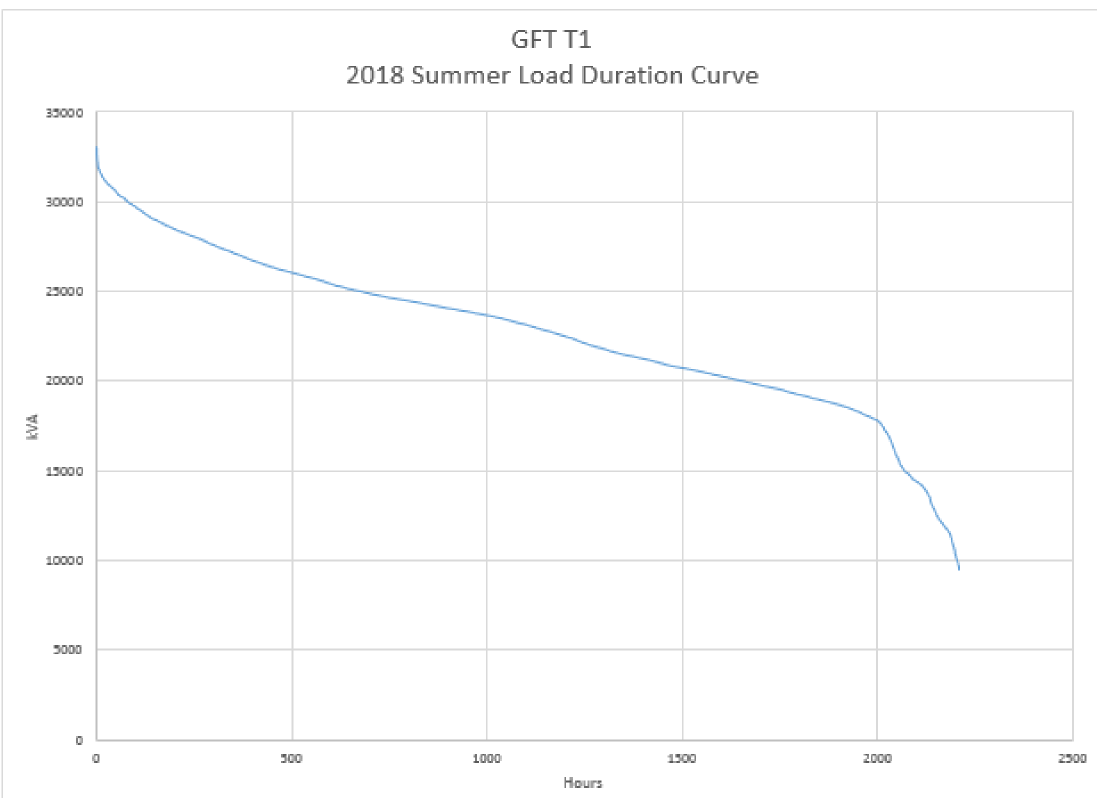
The summer season load duration curves for GFT T1 over the past five years are provided below.



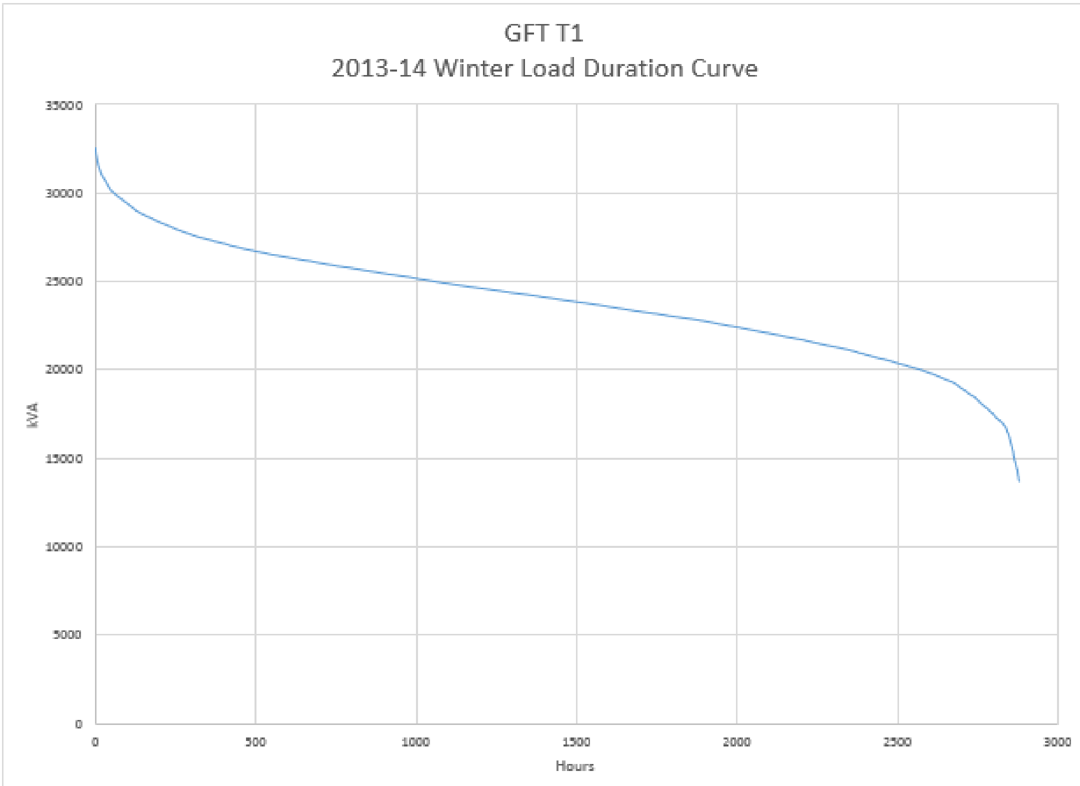

GFT T1
2015 Summer Load Duration Curve
kVA
35000
30000
25000
20000
15000
10000
5000
0
0
500
1000
1500
2000
2500
Hours

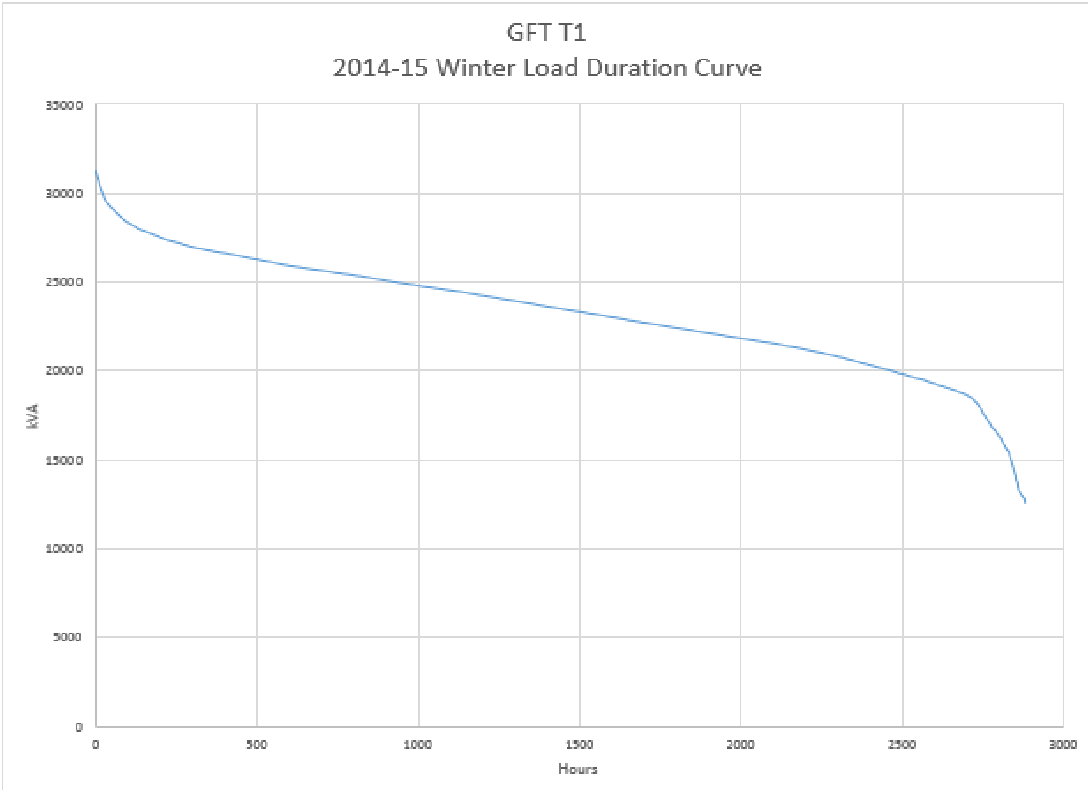

GFT T1
2016 Summer Load Duration Curve
kVA
35000
30000
25000
20000
15000
10000
5000
0
0
500
1000
1500
2000
2500
Hours

1 
GFT T1
2017 Summer Load Duration Curve
kVA
35000
30000
25000
20000
15000
10000
5000
0
0
500
1000
1500
2000
2500
Hours

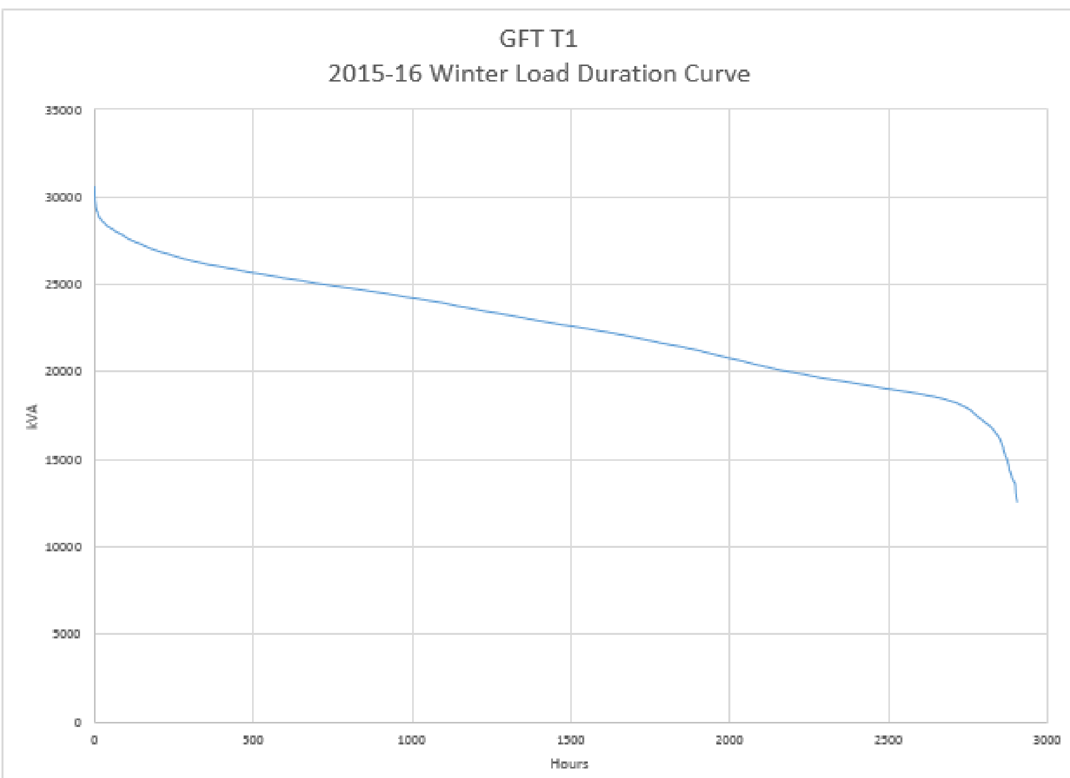
2 
GFT T1
2018 Summer Load Duration Curve
kVA
35000
30000
25000
20000
15000
10000
5000
0
0
500
1000
1500
2000
2500
Hours

The winter season load duration curves for GFT T1 over the past five years are provided below.

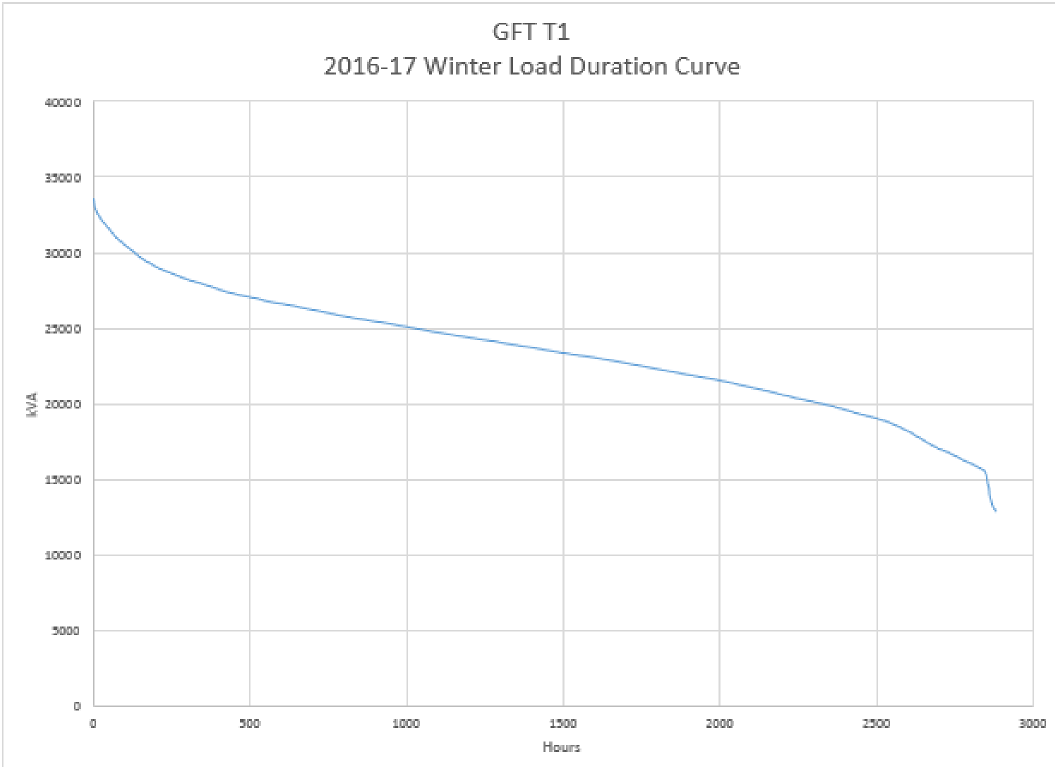


1 

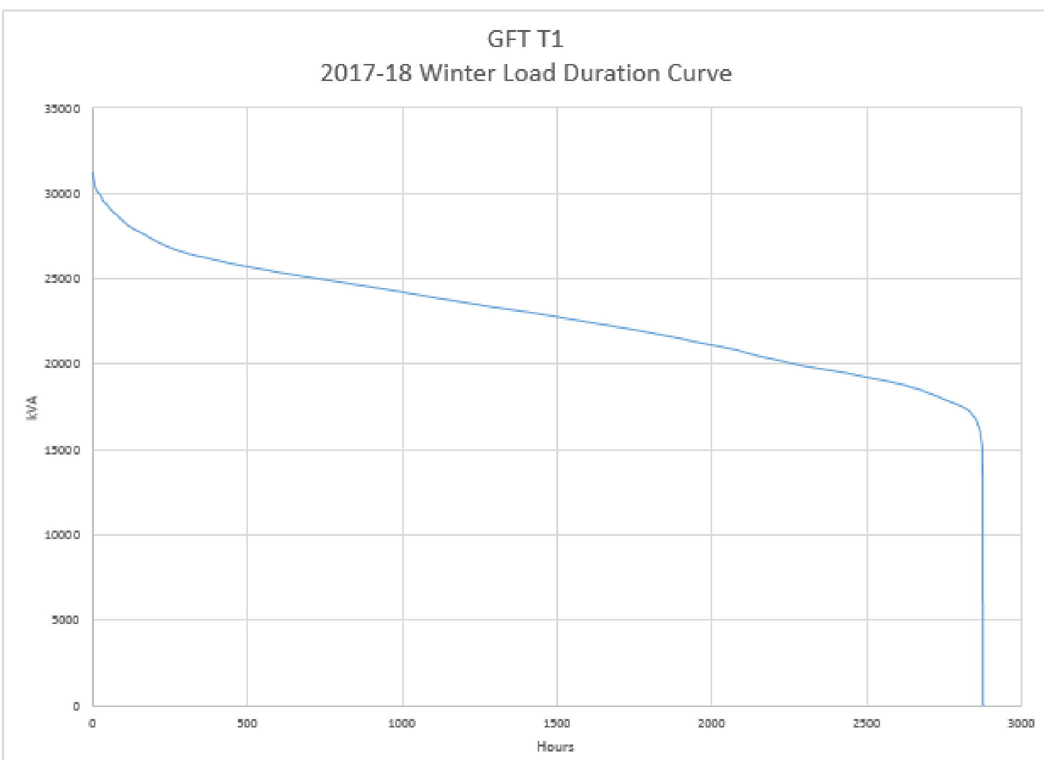
GFT T1
2014-15 Winter Load Duration Curve
kVA
35000
30000
25000
20000
15000
10000
5000
0
0
500
1000
1500
2000
2500
3000
Hours

2 

GFT T1
2015-16 Winter Load Duration Curve
kVA
35000
30000
25000
20000
15000
10000
5000
0
0
500
1000
1500
2000
2500
3000
Hours



GFT T1
2016-17 Winter Load Duration Curve
kVA
Hours



GFT T1
2017-18 Winter Load Duration Curve
kVA
Hours