Table of Contents

INTERROGATORY: OEBSTAFF-1

Ref:

1. Entegrus Powerlines Inc. – Application for a Service Area Amendment, October 17, 2022
2. Ontario Energy Board – Distribution System Code, Definitions, October 1, 2022

Entegrus states (Ref. 1, p. 3 of 32) that "the Subject Area is currently listed as an exclusion in the Entegrus Distribution Licence, although Entegrus acts as the physical distributor for the Customer…"

The DSC definition of a physical distributor (Ref 2) states that a: "physical distributor", with respect to a load transfer, means the distributor that provides physical delivery of electricity to a load transfer customer, but is not responsible for connecting and billing the load transfer customer directly.

The DSC definition of a geographic distributor (Ref 2) states that a: "geographic distributor," with respect to a load transfer, means the distributor that is licensed to service a load transfer customer and is responsible for connecting and billing the load transfer customer.

Question:

Please explain how Entegrus meets the OEB's definition of a physical distributor.

Response

Entegrus understands that the St. Thomas PUC and St. Thomas Energy Inc. ("STEI") have delivered the requisite Customer load from Edgeware TS to the Customer demarcation point since the inception of the M7/M8 feeders in the late 1990s. Entegrus has continued to deliver the Customer load since the April 1, 2018 merger with STEI, while not being responsible for billing the Customer directly. Accordingly, Entegrus is the physical distributor for the Customer.

INTERROGATORY: OEBSTAFF-2

Ref:
1. Entegrus Powerlines Inc. – Application for a Service Area Amendment, October 17, 2022

Questions:

a) Has Hydro One made any payments to Entegrus for use of the feeders since January 1, 2018?

b) Entegrus stated (Ref 1, p. 10-11 of 32) that the January 1, 2018 book value of the feeders excluding the book value of the poles was $116,431.
   - What was the book value of the feeders including the poles on January 1, 2018? Please show how this value was calculated relative to the capital cost.

Response

a) No payments have been received from Hydro One for the use of the feeders since January 1, 2018.

b) The net book value ("NBV") of the M7/M8 feeders inclusive of poles on January 1, 2018 was $224,869. Please refer to the calculation below.

Customer Feeders
NBV Analysis
Value as at December 31, 2017

Year	Cost	Amortization	NBV	Useful Life
1997	$ 739,699.75	$ 29,587.99	$ 710,111.76	25 Years
1998		$ 29,587.99	$ 680,523.77	25 Years
1999		$ 29,587.99	$ 650,935.78	25 Years
2000		$ 29,587.99	$ 621,347.79	25 Years
2001		$ 29,587.99	$ 591,759.80	25 Years
2002		$ 29,587.99	$ 562,171.81	25 Years
2003		$ 29,587.99	$ 532,583.82	25 Years
2004		$ 29,587.99	$ 502,995.83	25 Years
2005		$ 29,587.99	$ 473,407.84	25 Years
2006		$ 29,587.99	$ 443,819.85	25 Years
2007		$ 29,587.99	$ 414,231.86	25 Years
2008		$ 29,587.99	$ 384,643.87	25 Years
2009		$ 29,587.99	$ 355,055.88	25 Years
2010		$ 29,587.99	$ 325,467.89	25 Years
2011		$ 29,587.99	$ 295,879.90	25 Years
2012		$ 11,835.20	$ 284,044.70	40 Years
2013		$ 11,835.20	$ 272,209.51	40 Years
2014		$ 11,835.20	$ 260,374.31	40 Years
2015		$ 11,835.20	$ 248,539.12	40 Years
2016		$ 11,835.20	$ 236,703.92	40 Years
2017		$ 11,835.20	$ 224,868.72	40 Years

Notes:
1) useful life change in 2012 upon adoption of IFRS
2) does not include any capital or maintenance costs arising after 1997

INTERROGATORY: OEBSTAFF-3

Ref:
1. Entegrus Powerlines Inc. – Application for a Service Area Amendment, October 17, 2022
2. Entegrus Powerlines Inc. – Application for a Service Area Amendment, Attachment 3, October 17, 2022

Entegrus states (Ref 1, p. 16 of 32) that "In the event that Entegrus were to retain and control the feeders, in consultation with the Customer, the underutilized capacity on the M7 and M8 feeders could be used to address the immediate needs in St. Thomas (beyond which the focus would become a second additional feeder between 2024- 2027)."

Questions:

a) If Entegrus were to retain control of the feeders, would Entegrus reimburse Hydro One for the contribution that Hydro One has made to the cost of the feeders? Please explain and include information regarding the source of the funds to be used for reimbursement, and any planned treatment of that reimbursement for future ratemaking purposes.
b) Please explain Entegrus' plans to use the underutilized capacity on the M7 and M8 feeders for the capacity needs in the St. Thomas area.
    a. How will this plan impact Entegrus ratepayers?

Response

a) Based on the structure of the 1997 Letter and Addendum, the arrangement was an operating lease, since the purchase option associated with the M7/M8 feeders was at Net Book Value and was therefore not a bargain purchase option. Further, in the July 23, 2004 letter to the OEB (see EB-2002-0523, the first attachment to the July 23, 2004 letter, which is dated June 4, 2004) the former CEO of STEI stated that, "It was never the intention of St. Thomas Public Utilities Commission to enter into a distribution services agreement (under the resident terms of that lease agreement) that would survive the post market opening regime established by Bill 35." Accordingly, the monthly rental and maintenance (operating lease) payments from Hydro One to St. Thomas PUC / STEI / Entegrus represented reimbursement from Hydro One for the use of the facilities in order to keep St. Thomas PUC / STEI / Entegrus customers whole, since St. Thomas PUC / STEI / Entegrus has used the M8/M8 feeders to act as the physical distributor to the Customer. Consequently, Entegrus does not plan to reimburse Hydro One for the monthly rental and maintenance (operating lease) payments, particularly as Hydro One recovered substantially more in distribution charges from the Customer than Hydro One paid for the use of the M7/M8 feeders.

b) Entegrus intends to connect to the M7 and M8 feeders to address growth and redistribute a portion of its existing distribution system load. This will enable Entegrus to more evenly distribute customer load across its expanded pool of supply points. This will reduce peak loading on the existing feeders and simplify maintenance and restoration switching within the community, ultimately allowing Entegrus to best optimize its system to serve all St. Thomas customers, both existing and new.

a. The plan described in part b) will enable the full utilization of assets owned by Entegrus that currently have underutilized (stranded) capacity. This is a highly cost-effective way to meet the immediate capacity needs within the community. As a result, Entegrus ratepayers will receive more capacity at the least cost option.

INTERROGATORY: OEBSTAFF-4

Ref:
1. Entegrus Powerlines Inc. – Application for a Service Area Amendment, October 17, 2022
2. Entegrus Powerlines Inc. – Application for a Service Area Amendment, Attachment 3, October 17, 2022

Entegrus states (Ref 1, p. 11 of 32) that "Specifically, it would be contrary to regional planning objectives and OEB Act Section (1), regarding the protection of customers in terms of pricing and promoting economic efficiency and cost effectiveness in the transmission and distribution of electricity."

Questions:

a) Please explain this statement.

b) Please explain what discussions have occurred between Hydro One and Entegrus, regarding the regional planning process and when those discussions occurred.

c) Please provide references to any regional planning reports or documents that describe these discussions, such as an Integrated Regional Resource Plan.

Response

a) Hydro One seeks to purchase the M7/M8 feeders from Entegrus at a fraction of replacement value of the feeders. Hydro One then would allocate only 5 MW of the underutilized capacity back to Entegrus, while proposing to charge Entegrus for the use of this capacity at many multiples higher than the monthly rental and maintenance (operating lease) payments St. Thomas PUC / STEI charged Hydro One for the equivalent capacity. Thus, the Hydro One proposal does not promote economic efficiency.

   In addition, the following evidence suggests there is more than the 5 MW of underutilized (stranded) capacity on the M7/M8 feeders originally offered by Hydro One to Entegrus:

   (i) In the Entegrus 2023-05-12 Supplementary Evidence at Table 3-2, Entegrus presented an Alternative Connection Topology that met the Customer capacity requirements while providing additional capacity benefits for other St. Thomas customers. Entegrus Table 3-2 was premised on a Customer peak load of [redacted] and a maximum capacity rating of up to [redacted] per feeder. In the Hydro One 2023-05-19 Supplementary Evidence, Hydro One advanced a Customer peak load of [redacted] and a maximum capacity rating of up to [redacted] per feeder. Based on these Hydro One parameters, Hydro One then restated the Original Connection Topology (Entegrus 2023-05-12 Supplementary Evidence Table 3-1) to show only [redacted] of underutilized (stranded) capacity. However, Hydro One did not present a restated version of the Alternative Connection Topology (Entegrus 2023-05-12 Supplementary Evidence Table 3-2). Entegrus presents a restated Table 3-2 below utilizing Hydro One parameters (which, as described below in points ii) and iii), are untested). The updated table below shows there is in excess of [redacted] of underutilized (stranded) capacity, even under the Hydro One parameters.

this table has been filed separately in confidence

The aggregate availability of [redacted] of capacity, even under Hydro One parameters, is implicitly acknowledged by the Customer in Formet-2 part 3).

(ii) The typical Customer load used by Hydro One for its billing analysis in the Hydro One 2023-04-17 Evidence was [redacted], not the [redacted] Customer requirement now used in Table 1 of the Hydro One 2023-05-19 Supplementary Evidence.

(iii) The Customer's 2023-04-17 Evidence at Exhibit E, Section B-1 and at paragraph 27, confirmed that the capacity of the M7/M8 feeders was established to be [redacted]. Subsequently, Hydro One revealed in its 2023-05-19 Supplementary Evidence that the Hydro One in line switches at Edgeware TS are each rated at 600A, which limits the maximum capacity rating to approximately [redacted] for the feeders. Entegrus has sought additional clarity on the impact of Hydro One equipment on the capacity of the M7/M8 feeders in Entegrus Interrogatory #3 to Hydro One to determine how easily the maximum capacity rating could become [redacted]

The path proposed by Hydro One would result in Entegrus paying unreasonable rates to Hydro One to access a limited amount of capacity on Entegrus' own feeders to serve other customers in St. Thomas. Even if Entegrus was to accept this option, it would leave substantial available and unused (stranded) capacity on the M7/M8 feeders. This is particularly inefficient in the scenario where Entegrus has anticipated capacity requirements in St. Thomas that will imminently require new facilities, the size and cost of which would be reduced if Entegrus could access the capacity on its own M7/M8 feeders.

b) It is important to note that the regional planning process is a transmission-focused exercise, designed to identify impending needs in the bulk system, rather than a distribution feeder level needs assessment. The first cycle of regional planning for the London Area Region (of which St. Thomas is a subset) began in February 2015. The second regional planning cycle for London Area Region was officially initiated in April 2020 and the most recent update to the process was the completion of the "Regional Infrastructure Plan" published in August 2022.

Entegrus actively participates in the regional planning process led by the IESO for all regions relating to its service territories. Entegrus, at a minimum, holds annual meetings with Hydro One to review changes impacting local needs and/or the bulk transmission system and its operations. Additional meetings occur as material issues arise with several meetings being held in the 2017-2023 timeline. An example of this occurred in 2022, where Entegrus, having received a connection request for a large customer who was constrained in their ability to connect, worked proactively with the IESO and Hydro One Transmission to identify planning assumption errors that were restricting growth in the region. This resulted in the release of approximately [redacted] of capacity in the region and avoided the need to construct costly alternatives. More recently, in 2023, Entegrus met with Hydro One Distribution to discuss significant plans Hydro One had in the St. Thomas region. At that meeting, Entegrus was informed, for the first time, that Hydro One Distribution intended to build out "temporary" Edgeware TS M11 and M12 feeders for an "indefinite" period through a Municipal Consent process. Portions of the associated plan involve running new lines through Entegrus' service territory. These new feeders, if built to the standards of the M7 and M8, would materially reduce capacity at Edgeware TS. Hydro One noted that this "temporary" build out of the M11 and M12 would leave only the M9 available at Edgeware TS for future build out. Entegrus expressed concern about the lack of notification associated with the M11/M12 build out, as Entegrus has typically received advance notifications of such construction. Entegrus understands from review of the IESO website that the M11/M12 construction is now the subject of a 2023-initiated IESO System Impact Assessment process, but the IESO website does not provide any visibility into this process (reference 2023-748 Edgeware TS: Temporary Load Addition).

c) For regional planning purposes, St. Thomas is part of the "London Area", which includes the municipalities of Oxford County, Middlesex County, Elgin County, London, Woodstock and St. Thomas. Regional planning for the London area is divided into five sub-regions: Greater London, Alymer-Tillsonburg, Strathroy, Woodstock and St. Thomas. The most recent regional planning document related to the St. Thomas sub-region is shown at: https://www.hydroone.com/about/corporate-information/regional-plans/london. Published in August 2022, this report is transmission-focused and does not identify distribution asset needs in the St. Thomas region over the planning horizon of 10 years.

INTERROGATORY: OEBSTAFF-5

Ref:
1. Entegrus Powerlines Inc. – Application for a Service Area Amendment, October 17, 2022
2. Entegrus Powerlines Inc. – Application for a Service Area Amendment, Attachment 3, October 17, 2022

Entegrus states (Ref 1, p. 18 of 32) "Since, by way of the new feeder, Entegrus would be directly connected to the Edgeware TS, Entegrus does not believe it would incur any Low Voltage charges under this scenario."

Questions:

a) Please describe Entegrus' plan to pay for low voltage charges, if they occurred.

b) Please explain if and how paying for low voltage charges will impact Entegrus ratepayers.

Response

a) The Entegrus-St. Thomas rate zone does not currently incur Hydro One low voltage charges because the Entegrus feeders in St. Thomas (including the M7/M8 feeders) are all connected directly to Edgeware TS. If low voltage charges from Hydro One were to occur, these payments would be funded out of working capital and captured in Account 1550 Low Voltage Group 1 Deferral and Variance Account ("DVA"), in accordance with the Accounting Procedures Handbook ("APH"). Entegrus would subsequently propose disposition of Account 1550 as a charge to customers in a future rate application before the OEB.

b) Based on the monthly cost per 5 MW of capacity provided by Hydro One in Attachment 1 of the Entegrus 2023-05-12 Supplementary Evidence, adjusted for 2023 rates, Entegrus anticipates that Entegrus ratepayers would be subject to incremental costs of $92,652 ($7,721 X 12) per annum via eventual Account 1550 DVA disposition. However, as noted in the Entegrus response to OEB Staff-4 a) above, evidence suggests that there is [redacted] or more of underutilized (stranded) capacity on the M7/M8 feeders, which would [redacted] to an incremental cost of [redacted] per annum to Entegrus ratepayers. This annual cost for the use of only a portion of the feeders approximates the NBV of the feeders.

   Please note that in Interrogatory #15 to Hydro One, Entegrus has requested that Hydro One show the charge to Entegrus per month for [redacted] of feeder capacity on the M7 and M8 feeders.

INTERROGATORY: OEBSTAFF-6

Ref:
1. Entegrus Powerlines Inc. – Application for a Service Area Amendment, October 17, 2022
2. Entegrus Powerlines Inc. – Application for a Service Area Amendment, Attachment 3, October 17, 2022

The left column of Table 6-1 (Ref.1, p. 27 of 32) shows the costs that Entegrus would incur if Entegrus services the customer and accesses additional capacity.

Question:

a) What impact will these costs have on Entegrus ratepayers?

Response

a) The costs in the left column of Table 6-1 would be treated as capital costs and would be proposed to be added to rate base in the next Entegrus Cost of Service, planned for 2026. These costs are significantly less than the $1.7M costs for the construction of a new Edgeware TS Station Bus, Breaker Position and Station Egress (plus feeders) as shown in Table 5-1 of the Application. Accordingly, the costs in Table 6-1 would have a favourable impact on Entegrus ratepayers and these costs are far less than the Low Voltage charges that Hydro One proposes to charge Entegrus for equivalent capacity, as described above at OEBStaff-5 b).

INTERROGATORY: OEBSTAFF-7

Ref:
1. Entegrus Powerlines Inc. – Service Area Supplementary Evidence, May 12, 2023

Question:

a) Please explain the statement that "If additional St. Thomas customers were connected, operational flexibility and ease of customer restoration would increase." (Ref 1, p. 2 of 10)

Response

a) One of the reasons that distribution networks are built with loops and tie-in points is that as the density of these interconnections grow, the number of opportunities to switch around failed equipment or optimize a planned outage increases. This reduces the scope of sustained outages (either through automation or by enabling staged restorations).

Consider the impact of equipment failure or planned maintenance in the following two extreme scenarios:

(i) A rural community with a single feeder supplying it.
(ii) A high-rise located in downtown Toronto, provided with multiple concurrent connections.

In the case of the rural community with a single supply and no alternative supply available, customers downstream of the asset experience an outage for the duration of the restoration period. Alternatively, the high-rise customers experience no outage at all, as the remaining connections seamlessly carry the load to serve the high-rise. This illustrates the impact of the availability of alternate supply points on customer reliability and maintenance activities.

By interconnecting the M7 and M8 feeders to the existing four feeders serving the community, the number of supply points available to service the broader community of St. Thomas increases by 25%-50%, while the Customer will experience a 50% -100% increase in available supply points (depending on if the proposed or alternate connection topology is adopted).

This increases the number of interconnections within the distribution grid, providing additional points of alternate supply and increasing the density of interconnection within the distribution system. This improves Entegrus' ability to minimize or avoid outages due to maintenance activities or asset failures, increases operational flexibility, and eases customer restoration activities.

INTERROGATORY: OEBSTAFF-8

Ref:
1. Entegrus Powerlines Inc. – Service Area Supplementary Evidence, May 12, 2023

Question:

a) Please explain the statement that "No requirement is included in the DSC that a load transfer must always be billed by the local distributor on behalf of the physical distributor." (Ref. 1, p. 9 of 10)

Response

a) This statement was included in response to the 2023-04-17 Hydro One Evidence at p. 6. The intent of the statement was to note that in accordance with the DSC, Entegrus need not have billed the Customer directly in order for this situation to qualify as a load transfer (which requires elimination under the OEB's 2015 LTLT Elimination regulations). Please also see the response at OEBStaff-1.

INTERROGATORY: OEBSTAFF-9

Ref:
1. Entegrus Powerlines Inc. – Service Area Supplementary Evidence, May 12, 2023

Entegrus states (Ref. 1, p. 4 of 10) "…the purpose of the intelligent system featuring reclosers on the M7 and M8 feeders is to mitigate reliability issues, including momentary outages, while allowing additional St. Thomas customers to access currently unutilized capacity."

Question:

a) What is the expected cost of the proposed upgrades to M7 and M8 and how will this cost be recovered?

Response

a) Please see the table below, which represents Figure 6-1 from Entegrus' 2022-10-17 Application, updated for the items highlighted in Hydro One 2023-04-17 Evidence, page 24, related to connection costs. Entegrus would capitalize these incremental costs to the existing cost of the M7/M8 feeders for proposed inclusion in rate base in the 2026 Cost of Service.

Connection Component	Entegrus Services the Customer and Accesses Additional Capacity ($000s)			The Application: Hydro One Purchases the Entegrus Feeders and Services the Customer
	The Application (1 Entegrus Feeder Tie-in)	Entegrus 2023-05-12 Supplemental Evidence Topology Figure A (1 Entegrus Feeder Tie-In Plan)	Entegrus 2023-05-12 Supplemental Evidence Topology Figure B (2 Entegrus Feeder Tie-In Plan)	
Wholesale Meters Installation Cost	$ 150	$ 150	$ 150	
Reclosers Cost ($50 each)	$ 100	$ 150	$ 200	
Tie Points Contingency	$ -	$ 20	$ 40	
Hydro One Proposed Cost of Purchasing Both Feeders to Serve Customer (at Replacement Cost) (Note 1)				$3M - $4M
Net (Savings) Costs	**$ 250**	**$ 320**	**$ 390**	**$3M - $4M**

Note 1: *Hydro One proposes to purchase the Entegrus M7 and M8 express feeders for $116,431. As detailed in Section 5.5.1, Entegrus proposes that the replacement cost of the feeders of $3M-$4M is a more appropriate determinant.*

INTERROGATORY: OEBSTAFF-10

Ref:
2. Entegrus Powerlines Inc. – Service Area Supplementary Evidence, May 12, 2023
3. Entegrus Powerlines Inc. – Application for a Service Area Amendment, Attachment 3, October 17, 2022

Entegrus states (Ref 1, p. 9 of 10) that "Entegrus customers are being deprived of a benefit and will have to incur the consequences of additional costs for new capacity to serve St. Thomas."

Questions:

a) What benefit are Entegrus customers being deprived of? Please explain why Entegrus customers would be deprived of this benefit?

b) What is the net cost that Entegrus customers have paid for feeders M7 and M8 considering the payments made by Hydro One?

Response

a) The M7/M8 feeders are owned by Entegrus. St. Thomas PUC / STEI / Entegrus have delivered load to the Customer since the late 1990s and St. Thomas PUC / STEI received monthly rental and maintenance (operating lease) payments from Ontario Hydro / Hydro One. If the M7/M8 feeders are sold to Hydro One for $116,000, Entegrus will incur equivalent replacement costs of $3M-$4M and Entegrus customers will be deprived of the benefit of the two feeders currently owned by Entegrus. Please note that Entegrus Interrogatory #1 to Hydro One seeks an update on the comparative feeder replacement cost in 2023 dollars.

b) Considering the payments made by Hydro One, Entegrus customers have not paid costs for the M7/M8 Feeders, as the revenue requirement was reduced by a revenue offset for Other Revenue, which included the annual charges to HONI for the use of the feeders.

INTERROGATORY: FORMET-1

Ref:
Formet Peak Load

Entegrus Powerlines Inc. ("Entegrus") recognizes at Section 3.2 of its Service Area Amendment Supplementary Evidence that Formet Industries' ("Formet") peak load has reached [redacted].

The "Updated Scenario" found in Section 3.3 of the supplementary evidence and the calculations which follow in Tables 3-1 and 3-2 are based on an assumed peak load of [redacted], not [redacted].

Formet' past peak and expected future peak load at the facility at 1 Cosma Court ("Facility") is [redacted].

Table 1 in Hydro One Networks Inc.'s ("Hydro One") Supplementary Evidence provides Capacity Allocation in MVA.

Question:

Please provide revised versions of Table 3-1 and 3-2 found in Entegrus' Service Area Amendment Supplementary Evidence in MVA assuming the Facility's peak load to be [redacted]

Response

Table 3-1 and 3-2 are recreated in MVA below. Entegrus caveats that these tables use numbers provided by Hydro One at Section 3.0 of its 2023-05-19 Supplementary Evidence [redacted] Entegrus has asked Hydro One for back-up regarding these numbers at Interrogatory #4. Descriptions of the scenarios below are provided at Entegrus 2023-05-12 Supplementary Evidence Section 3.2.

TABLE 3-1: ORIGINAL CONNECTION TOPOLOGY - CAPACITY BY OPERATING SCENARIO (REVISED)

This table has been filed separately in confidence

TABLE 3-2: ALTERNATIVE CONNECTION TOPOLOGY – CAPACITY BY OPERATING SCENARIO (REVISED)

This table has been filed separately in confidence

INTERROGATORY: FORMET-2

Ref:
Capacity Allocation

Attachment 2-A to the Customer's Supplementary Evidence confirms that Hydro One has assigned the Facility a total capacity of [redacted] It also confirms that Hydro One has approved peak load of [redacted] for each feeder.

According to Section 3.0 of Hydro One's Supplementary Evidence, this [redacted] equates to [redacted], meaning that Hydro One would connect no more than [redacted] of other load to each feeder.

Section 3 of Entegrus' Service Area Amendment Supplementary Evidence refers to potential interconnection topology and operating scenarios.

Questions:

1(1). Will Entegrus agree as part of the order made in this application to match the capacity allocation commitment made by Hydro One by assigning (1) a total capacity of [redacted] (or [redacted] MVA) from the M7 and M8 feeders, and (2) up to [redacted] (or [redacted] MVA) for each feeder?

1(2). For clarity, is Entegrus prepared to assign the Formet Facility a total capacity of [redacted] (or [redacted] MVA) and to approve a peak load of [redacted] (or [redacted] MVA) by Formet on each feeder, and to have such commitment form part of the OEB's order in this application?

2. If the answer to (1)(1) and/or (1)(2) above is yes, for what duration will Entegrus make such a commitment, and what if any conditions are attached to such commitment or duration?

3. Will Entegrus agree as part of the order made in this application to connect no more than [redacted] MVA of other (non-Formet) load to each of M7 and M8?

4. If the answer to (3) above is yes, for what duration will Entegrus make such a commitment, and what if any conditions are attached to such commitment or duration?

5. If the answer to (3) above is yes, please revise the Connection Topology Figures in Attachment 2 to Entegrus' Supplementary Evidence to show a maximum of [redacted] MVA of other (non-Formet) load being connected to each of M7 and M8 (as opposed to the entire existing Entegrus Distribution system load being connected to each of M7 and

M8).

6. If the answer to (3) above is no, is there some other maximum amount of other (non-Formet) load, expressed in MVA, which Entegrus would agree as part of the order made in this application to be the maximum Entegrus could connect to each of M7 and M8?

7. If the answer to (6) above is yes, what is that proposed maximum load, expressed in MVA?

8. If the answer to (6) above is yes, for what duration will Entegrus make such a commitment, and what if any conditions are attached to such commitment or duration?

9. If the answer to (6) above is yes, please revise the Connection Topology Figures in Attachment 2 to Entegrus' Supplementary Evidence to show such maximum of other (non-Formet) load being connected to each of M7 and M8 (as opposed to the entire existing Entegrus Distribution system load being connected to each of M7 and M8).

10. What specific customers, other than Formet, does Entegrus intend to connect to the M7 and/or M8 feeders, and what are their projected peak loads in MVA over the next 2, 5 and 10 year periods?

11. If Entegrus intends to connect the Entegrus Distribution system in general to either or both of M7 and M8, rather than specific customers, what is the projected peak load in MVA over the next 2, 5 and 10 year periods, of such system, or of such part of the system as would be connected to either or both of M7 and M8?

Response

These interrogatories relate to the May 17, 2023, Capacity Allocation Commitment Letter between the Customer and Hydro One, filed in the Customer's 2023-05-19 Supplementary evidence as Attachment 2-A.

Entegrus has posed various interrogatories to Hydro One and the Customer related to the above-noted Capacity Allocation Commitment Letter to clarify the commitments that were just made by Hydro One in May 2023. Further, the load Entegrus would connect to the M7 and M8 feeders would require a detailed engineering analysis completed prior to the connection of any incremental load. Entegrus cannot respond to the Customer's interrogatories until this information is provided.

Conceptually, Entegrus could offer the same service (which would limit the available capacity available to other St. Thomas customers), subject to the answers to the interrogatories. What Entegrus does not yet understand, and what may be clarified by the interrogatory responses, is how Entegrus could [redacted] Such arrangements are typically subject to standby charges (also referred to as "gross load billing"). Currently, the Entegrus-St. Thomas rate zone tariff sheet does not include standby charges, although the Entegrus-Main rate zone tariff sheet does include standby charges. It is noted that standby charges are included as a priority for adjudicative policy review by the OEB in 2023/24 per the OEB 2023-2026 Business Plan. As such, any standby arrangements are subject to future policy change.

INTERROGATORY: FORMET-3

Ref:
Other Loads on M7 and M8

Entegrus admits in Section 5 of its Service Area Amendment Supplementary Evidence that new capacity is required in light of the [redacted] announcement.

Questions:

1. What is the projected peak load to be required by the [redacted] plant in MW or MVA, over the next 2, 5 and 10 year periods?

2. Has Entegrus made any written or verbal representations or commitments to [redacted] or its agents regarding Entegrus' ability to provide service [redacted]?

3. If the answer to (2) is yes, what written or verbal representations or commitments, if any, has Entegrus expressed to [redacted] or its agents regarding Entegrus' ability to provide service to [redacted]?

4. Has Entegrus provided any written or verbal cautions or limitations to [redacted] or its agents regarding Entegrus' ability to provide service to [redacted]?

5. If the answer to (4) is yes, what written or verbal cautions or limitations, if any, has Entegrus expressed to [redacted] or its agents regarding Entegrus' ability to provide service to [redacted]?

6. Please provide copies of all written communications, and summaries of all verbal communications, between representatives of Entegrus and representatives of Volkswagen or its agents prior to April 17, 2023 about Entegrus' ability to satisfy the power requirements at the proposed new battery plant. If such communications include confidential or commercially sensitive information belonging to Volkswagen, please provided redacted copies or summaries of same.

7. Without naming the [redacted] from whom Entegrus "recently received a request … for significant additional capacity" (as described in Section 5 of Entegrus' Supplementary Evidence), please state the volume of additional capacity in MW or MVA, so requested [redacted].

Response

(1-6)

[redacted] Nonetheless, as noted in the Entegrus 2023-05-12 Supplementary Evidence at Attachment 1 (iv), Entegrus expects the [redacted] will prompt further growth and need for distribution (and feeder) capacity in St. Thomas. Entegrus expects this to occur via economic spin-off from [redacted]

(7) This reference is to an existing Entegrus-St. Thomas GS>50 kW customer which recently requested an additional [redacted] of capacity.

INTERROGATORY: FORMET-4

Ref:
Rates

Entegrus has filed "Attachment 3, Estimated Monthly Bill" as part of its Service Area Amendment Supplementary Evidence, which refers to two different rate classes: [redacted]. Section 4 of Entegrus' Supplementary Evidence, entitled "Relative Costs to the Customer from Each Distributor", addresses rate classes.

Questions:

1. Would [redacted] initially be applied [redacted] should Entegrus be successful in this application?

2. If the answer to (1), above, is yes, which [redacted] rate classes would [redacted]

3. If the answer to (1), above, is yes, for what duration would the rate class described in the response to (1) above apply (ie. until rate harmonization in 2026, or until some other date)?

4. If the answer to (1), above, is yes, following the date described in response to (ii) above (for example, following rate harmonization in 2026), what rate class would apply [redacted]

5. Are the rates which are in effect today (June 2, 2023) under the rate class described in the response to (2) above, or is any single component of such rates, higher than the rates (or similar components) which are in effect and being charged to the Customer today as a Hydro One customer? Please provide details by listing the applicable Entegrus rates or rate components in effect today, and the comparable rates or rate components in effect today being charged by Hydro One to Formet.

6. Are the rates which are in effect today (June 2, 2023) under the rate class described in the response to (4) above, or is any single component of such rates, higher than the rates (or similar components) which are in effect and being charged to the Customer today as a Hydro One customer? Please provide details by listing the applicable Entegrus rates or rate components in effect today, and the comparable rates or rate

components in effect today being charged by Hydro One to Formet.

7. Section 6.5.4 of the Distribution System Code, which was enacted by the Board's decision in EB-2015-0006, states as follows:

> *If the transfer to the physical distributor results in the load transfer customer(s) paying higher delivery charges, the physical distributor shall apply rate mitigation in a manner that is approved by the Board.*

If Entegrus asserts that the Formet situation constitutes a Long Term Load Transfer to which EB-2015-0006 applies (which assertion Formet rejects), [redacted] in order to comply with the DSC?

8. If the answer to (7) above is yes, please:

- Describe such [redacted] that Entegrus proposes to apply [redacted]?
- Describe over what period of time has Entegrus proposed, or would Entegrus propose, [redacted]?
- Provide all rate and tariff details and implications [redacted]
- Demonstrate how such [redacted] would, if approved by the Board, [redacted] to Hydro One as a Hydro One customer.
- Is Entegrus content for the specifics of such [redacted] to be reflected in the Board's order?

9. If the answer to (7) above is no, why does Entegrus believe that Section 6.5.3 applies to [redacted] but Section 6.5.4 does not?

10. The purported bill comparisons provided by Entegrus in Attachment 3 to its Supplementary Evidence assume different consumption volumes in each scenario [redacted] In order to be able to compare the potential bill impacts to Formet from each of the options available to the Board, please provide four (4) different sample bills for the month of February 2023, based on the following assumptions from February 2023 (which assumptions reflect Formet's actual data), and the four Rate Scenarios described below:

- Formet consumption of [redacted] for the month
- Average commodity price of [redacted] per kWh
- Peak Demand during the month of [redacted] kW
- Global Adjustment Peak Demand Factor of [redacted]
- Provincial Global Adjustment of [redacted]
- HST Rate: 13%
- Applicable Rates/Tariff:

- Rate Scenario 1: General Service > 50 - 4999 kW in the Entegrus St. Thomas Rate Zone, as it was in effect February 28, 2023.
- Rate Scenario 2: Large Use Rate Class in the Entegrus Main Rate Zone, as it was in effect February 28, 2023.
- Rate Scenario 3: Same as Scenario 1, but applying any rate mitigation described in response to (8) above.
- Rate Scenario 4: Same as Scenario 2, but applying any rate mitigation described in response to (8) above.

Response

1. Yes, [redacted] Upon rate rebasing in 2026, Entegrus plans to harmonize its St. Thomas and Main rate zones. [redacted]

2. Please see the response at part 1 above.

3. Please see the response at part 1 above.

4. Please see the response at part 1 above.

5. Entegrus has reviewed the rates provided in Hydro One's 2023-04-17 evidence at Attachment 6, and the only base rate component of Entegrus' [redacted] rates that is higher than what the Customer is currently charged as a Hydro One customer is the distribution volumetric charge. Note that this excludes the impact of rate riders as these generally change every year and are not a valuable measure of comparison.

6. The 2026 Entegrus [redacted] rate class has not yet been designed. Currently, the closest estimate to the 2026 Entegrus [redacted] rate class is the Entegrus-Main [redacted] rate class. In comparison to the rates provided in Hydro One's 2023-04-17 evidence at Attachment 6, the only components that are higher for the Entegrus-Main [redacted] rate class include the fixed monthly service charge and the distribution volumetric charge. Although these two components are higher, the overall bill impact of the Entegrus-Main [redacted] rate class to the Customer would be lower in comparison to the Hydro One Sub Transmission rate class, please see HONI-24 Attachment 1.

7. When the 2022-10-17 Application was submitted, Entegrus did not anticipate [redacted] would be required based on the expectation that Entegrus distribution rates

[redacted] than those of Hydro One. Specifically, Entegrus did not anticipate that the Customer would reside in the Hydro One Sub-Transmission rate class. Entegrus continues to seek information in its 2023-06-02 interrogatories to Hydro One regarding differences in distribution charges between Entegrus and Hydro One (see Interrogatories #4 and #5). Entegrus is aware that [redacted] has occurred in the case of past LTLT eliminations involving [redacted][1] and therefore confirms its understanding that the OEB may approve [redacted], subject to its approval of the elimination of this LTLT.

8. As noted in part 1) above, Entegrus anticipates that in 2026, the Customer would fall under the harmonized Entegrus [redacted] rate class, and as shown at HONI-24 Attachment 1, the Customer would currently enjoy lower charges of approximately $208,000 per annum in the current Entegrus-Main [redacted] rate class, compared to those currently provided by Hydro One. Notably, it is recognized that both Entegrus and Hydro One rates will change over time. Accordingly, Entegrus proposes that, subject to the OEB granting the relief requested in this Application, and assuming that the rates currently paid by the Customer to Hydro One are appropriate and properly calculated (see the response to 7) above) and the difference is reasonable and in line with Entegrus' interpretation of the Formet charges with Hydro One, [redacted]

9. N/A. Please see the response at parts 7 and 8 above.

10. Please see Formet-4-10 Attachment 1 for Scenarios 1 and 2. In order to accurately calculate [redacted] Scenarios 3 and 4, Entegrus would require the corresponding Formet bills from Hydro One for February 2023 that use the same billing determinants. This request was made in Entegrus' Interrogatory #4 to Hydro One.

[1] June 14, 2017 Elimination of Load Transfer Arrangements between Hydro One Networks Inc. and Alectra Utilities Corporation.
August 9, 2016 Elimination of Long Term Load Transfers between Enersource Hydro Mississauga and Oakville Hydro Electricity Distribution Inc.

Formet-4 Attachment 1

this Attachment has been filed separately in confidence

INTERROGATORY: FORMET-5

Ref:
Reliability

Formet has highlighted the importance of reliability and consequential harm from outages at the Facility in its evidence. Entegrus has filed evidence about [redacted] reliability issues, including [redacted] in Section 3.4 of Entegrus' Supplementary Evidence.
In the event of an outage to either M7 or M8 (but excluding concurrent outages or curtailments of both M7 and M8), Entegrus requires that the entirety of its electricity needs, [redacted] be serviced by the other feeder.

Questions:

1. Will Entegrus guarantee that in the event [redacted] (assuming no concurrent [redacted] no matter what other uses are being made of M7 or M8 [redacted] will immediately shift to and be served by M8, without any [redacted]?

2. Will Entegrus guarantee that in the event [redacted] no matter what other uses are being made of M7 or M8, [redacted] without any [redacted]?

3. Will Entegrus guarantee that in the event [redacted] if and to the extent necessary, [redacted] will be served by M8 for the duration of the M7 [redacted]?

4. Will Entegrus guarantee that in the event [redacted]) no matter what other uses are being made of [redacted] will immediately shift to and be served by M7, [redacted]?

5. Will Entegrus guarantee that in the event [redacted] no matter what other uses are being made of M7 or M8, [redacted]

[redacted] without [redacted]?

6. Will Entegrus guarantee that in the event [redacted] if and to the extent necessary, all other (non-Formet) loads will be [redacted] will be served by M8 for the duration of the M8 [redacted]?

7. If the answers to (1) and/or (4) above are yes, please explain how that will happen, technically. As part of such response, please advise whether the process of [redacted] and whether Entegrus will guarantee that there will not be any [redacted]

8. Is Entegrus content for the foregoing commitments to be reflected in the Board's order?

Response

Entegrus strives to provide customers with reliable electricity supply and believes that as the Customer's physical distributor since 1997, St. Thomas PUC / STEI / Entegrus have provided reliable electricity supply, consistent with the reliability statistics noted in the Customer's 2023-04-17 Evidence at Exhibit K. This said, Entegrus cannot guarantee an uninterrupted supply of electricity at all times (i.e. [redacted]. The Distribution System Code acknowledges that occasional interruptions to the supply of electricity may occur beyond the control of distributors, such as severe weather events, accidents and other unforeseen circumstances.

Entegrus has posed various interrogatories to Hydro One and the Customer related to the May 17, 2023 Capacity Allocation Commitment Letter between the Customer and Hydro One. Conceptually, subject to the answers to these questions, Entegrus could offer the same service, which would limit the capacity available to other St. Thomas customers. What Entegrus does not yet understand, and what may be clarified by the interrogatory responses, is how Entegrus could offer [redacted]

In terms of mitigating outages through the use of reclosers, please see the response at HONI-4 g). In terms of matching the assurances apparently provided by Hydro One in the May 17, 2023 Capacity Allocation Commitment Letter, please also see the response at Formet-2.

INTERROGATORY: FORMET-6

Ref:
Entegrus' application and Attachment 1 to its Supplementary Evidence refer [redacted]

Question:

Why did Entegrus not agree to accept [redacted] from the M8 feeder?

Response

Entegrus owns the M7/M8 feeders and therefore does not recognize the ability for Hydro One to contract the capacity as described. In any event, the price at which [redacted] capacity was offered to Entegrus by Hydro One on the M8 feeder was many multiples beyond what Hydro One paid for the same equivalent capacity and would result in significant Hydro One Low Voltage charges to Entegrus customers in the future. Please see the response at HONI-16(a). Hydro One's proposed option described above would impact reliability in a way that the Entegrus plan mitigates, since the Entegrus plan provides additional redundancy by tying into multiple feeders as described in the response at OEBStaff-7.

INTERROGATORY: HONI-1

Ref:
1."The Subject Area is currently listed as an exclusion in the Entegrus Distribution Licence, although Entegrus acts as the physical distributor for the Customer and the Subject Area is surrounded by the Service Area of Entegrus and falls within the longstanding municipal boundaries of the City of St. Thomas." - Application, p. 3

Question:

Please confirm that the Subject Area was never in the service territory of either Entegrus or the former St. Thomas Energy Inc. ("STEI") since the Ontario Energy Board commenced issuing distribution licences i.e., the Subject Area has always been listed as an exclusion in the current Entegrus and STEI Distribution Licence. If not confirmed, please provide a copy of the OEB issued distribution licence that includes the Subject Area in the service area of the Applicant.

Response

Confirmed. Prior to Market Opening, circa 1997, the Subject Area was excluded from the St. Thomas PUC's distribution license. At that time, Ontario Hydro acted as the defacto economic regulator for Ontario electrical distributors such as St. Thomas Energy. Prior to this, the Subject Area was part of the distribution service territory of the St. Thomas PUC.

INTERROGATORY: HONI-2

Ref:

1. "Entegrus owns and maintains the feeders that serve the Customer and thereby continues to act as the physical distributor." Application, page 3
2. 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29 1998 Addendum) - Hydro One Intervenor Evidence – Attachment 3 – April 17, 2023

Questions:

a) Please confirm that Entegrus' position of "owning" the Feeders is predicated on the language of the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum). If not confirmed, please provide an explanation on what basis Entegrus advances that it owns the Feeders.

b) Please provide a breakdown of the costs that have been incurred by Entegrus, the previous STEI and the former St. Thomas PUC to construct the Feeders. Please provide a breakdown of the costs that have been incurred by Entegrus, STEI and the former St. Thomas PUC to maintain the Feeders. Please confirm how much of these costs have been recovered to date from current Entegrus ratepayers (or the previous STEI's and St. Thomas PUC ratepayers). In so doing, please address where these costs can be found in any Entegrus or STEI revenue requirement application.

Response

a) Not confirmed. Entegrus has continually owned the assets. Hydro One's documents consistently affirm Entegrus' ownership. This is supported by STEI's Transmission Connection Agreement (see below) dated November 27, 2001. This agreement identifies that the M7 and M8 feeders are owned by STEI (Entegrus). This is further supported by the Edgeware TS single line diagrams posted on Hydro One's customer portal, and the Hydro One Capacity Evaluation Tool (updated 2023-05-30).

D.6

EDGEWARE T.S. (NAW27)	
HON1 owns the following: **Note: * Indicates Controlling Authority belongs to ST. THOMAS ENERGY INC**	**ST. THOMAS ENERGY INC (STEI) owns the following:** **Note: * Indicates Controlling Authority belongs to HON INC.**
Transformers 27T1, 27T2	**Transformers** NONE – No transformers within T.S.
Breakers 27T1B, T1Y, T2B, T2Y, BY, 27M1, 27M2,27M3, 27M4, 27M5, 27M6, 27M7, 27M8, 27M10	**Breakers** NONE – No breakers within T.S.
Switches M1-L, M2-L, M1-M2, M3-L, M4-L, M3-M4, M5-L, M6-L, M5-M6, M7-L, M8-L, M7-M8, M10	**Switches** There are tie points between the St. Thomas Energy Inc owned feeders and Hydro One owned feeders. The connection point(s) is under the Operating Control of the Buchanan Operator even though ownership may rest with the Utility. Tie Switch 27M6-27M4 – Edward St. at Centennial Ave. (Owned by STEI) Tie Switch 27M5-27M3 – Fairview Ave. at Elm St. (Owned by STEI)
Current/Voltage Transformers **BVT, YVT**	**Current/Voltage Transformers** Ownership of CT's and PT's to be resolved
Feeders	**Feeders** Underground 27.6kV feeders M1, M5, M6, M7, M8 and M10 up to and including the associated terminators at NAW27.
Protection Systems	**Protection Systems**

b) Construction of the feeders cost $739,699.75 in 1997 dollars and Entegrus does not have a breakdown of this amount.

Based on a pro-ration of Entegrus St. Thomas service area feeder maintenance costs per km from 2002 – 2022, it is estimated that the cost to maintain the feeders was approximately $4,400 per annum (approximately $110,000 from 1997 – 2022).

The costs have not been recovered from current Entegrus ratepayers (or the previous STEI / St. Thomas PUC ratepayers) as the revenue requirement was reduced by a revenue offset for Other Revenue which included the annual charges to HONI for the use of the feeders[2].

As there is no adjustment to the rate base, depreciation or OM&A for the Customer feeders in the above noted applications, the costs can be found in the NBV used to determine rate base (please see the response at OEB Staff-2) which is subject to the cost of capital parameters. Further, OM&A incorporated in the revenue requirement would have included amounts for depreciation and maintenance of the feeders.

[2] EB-2010-0141 Exhibit 3 Tab 3 Schedule 6 Attachment 1 p.3 of 4 and EB-2014-0113 Exhibit: 3 Tab: 1 Schedule: 6 p.4 of 5

INTERROGATORY: HONI-3

Ref:
1.“Additionally, it cannot be said that the two dedicated Entegrus feeders that serve the Customer are “surplus to the utility’s needs”. If the Customer and the use of the feeders is transferred to Entegrus, then the utility can use some of the capacity on the feeders to serve growing demand in St. Thomas. This will save ratepayers money, by reducing the need for new infrastructure.” – Application, p. 3

Questions:

a) Please explain in detail what existing utility need the Feeders serve, i.e., are the Feeders currently required to serve Entegrus’ existing customers in St. Thomas?

b) With respect to the OEB’s Filing Requirements for Electricity Distribution Rate Applications, please provide Entegrus’ materiality threshold.

Response

a) In Entegrus’ 2021-2025 DSP (see HONI-10 Attachment 1), p.221 shows that between 2018 and 2019 Entegrus reached its planning capacity on the four existing feeders. Adding the sought after capacity meets system design targets and resolves the immediate capacity issue.

b) The materiality of the Entegrus-St. Thomas rate zone from its most recent Cost of Service (EB-2014-0113) was $50,000. The materiality of the Entegrus-Main rate zone from its most recent Cost of Service (EB-2015-0061) was $90,000.

INTERROGATORY: HONI-4

Ref:
1.“The reason for the urgency is that Entegrus has current capacity constraints in its St. Thomas service area, and it is important to have clarity about whether the excess capacity from the breaker positions currently dedicated to the Customer will be available for Entegrus to serve other capacity requirements in St. Thomas. If this will not be the case, then Entegrus needs to pursue alternative solutions (which will take some time).” – Application p. 4

2.“To address the fact that Entegrus is already running above design capacity of the existing four feeders available to the general public, Entegrus requires the equivalent of a feeder’s worth of capacity (i.e. 14 MW) in the immediate term (i.e. 2023).” – Application p. 16

3.Figure 5-2 – Application p. 15

4.The recent load growth in St. Thomas has resulted in the need to utilize emergency capacity (i.e. operate the assets at above design capacity at certain points in time) on these four feeders. Emergency capacity is defined as the difference between the maximum rating of the equipment and the design capacity (or operational rating) of the equipment. The difference between design capacity and emergency capacity is typically maintained to ensure that the distribution system can respond to contingency situations, for example when one or more assets are out of service due to maintenance activities or failure, as well as unexpected customer-driven load spikes.--Application p. 14

5. “Further, Entegrus would seek to access the pre-constructed, underutilized capacity on the feeders through the construction of a tap point. This point would include two reclosers (costing approximately $50,000 each), one on each feeder, which would be coordinated with the station breakers to allow for diversity of supply to the Entegrus system while protecting the Customer from power disturbances and maintaining reliability. In the event one feeder was unavailable, the other feeder would run a maximum capacity and could pick up the Customer load. A single line diagram of this design is shown below in Figure 5-3. Further, an additional tie-in to other existing nearby Entegrus assets could be made to further enhance reliability for both the Customer and other Entegrus customers.” – Application p. 21

“No incremental expansion of Entegrus’ distribution system will be required, as the two dedicated feeders owned by Entegrus already connect the Customer to the Edgeware TS.” – Application p. 28

7. Figure 5-3 – Application p. 22

8. Attachment 2, Figure B – Entegrus’ Supplementary Evidence

9. Table 6-1: Comparison of Costs (Savings) – Application p. 27

10. "As shown in Attachment 2, in this scenario, Entegrus deploys an intelligent system featuring reclosers on the M7 and M8 feeders, to feed a common line to tie in to the Entegrus system. The reclosers would be configured to dynamically select (with appropriate controls) the lower utilized feeder to supply additional St. Thomas customers." - Entegrus Supplementary Evidence p.4

11. Figure A - Entegrus Supplementary Evidence, Attachment 2

12. Section 4.3 of Hydro One Intervenor Evidence, p. 24

Questions:

a) Please provide all Entegrus SAIDI and SAIFI data since 2017. Similarly, please provide the SAIDI and SAIFI data for the area limited to the former STEI service territory.

b) Please explain in detail why there is an immediate term (i.e., 2023) need if the St. Thomas system design capacity has been exceeded since about 2018.

c) Please provide information regarding the forecast load growth utilized in Figure 5-2. Specifically, please provide information on any real customers (i.e. non-coincident peak load per customer and connecting feeder) that have requested a connection to Entegrus' distribution system that supports the forecast growth, and information on the capital contribution(s) these customers have made towards addressing such capacity needs.

d) Please confirm that the demand forecast provided in Figure 5-2 does not contemplate the Customer's demand and does not accommodate any change in forecast demand for the Customer over the time horizon.

e) Please discuss in detail and elaborate on what Entegrus will do if the transfer of the Feeders, once the Customer's load is accounted for, will not provide Entegrus with 14MW of design capacity. Please outline and discuss what alternatives have been considered and when those alternatives can be implemented.

f) Please clarify if the growth rate sensitivity range is 3.36%/year to 5.36%/year based on the historical growth rate of 3.86% between 2017 and 2021.

g) Please describe and provide any documentation demonstrating what reliability and quality of service impacts will be faced by Entegrus' distribution system and the Customer when one feeder is unavailable and the other feeder would need to run at maximum capacity as described in Reference 5.

h) With respect to Reference 5, please detail the scope, schedule and cost of the additional tie-in to other existing nearby Entegrus assets that would further enhance reliability for both the Customer and other Entegrus customers.

i) With respect to Reference 5 and the evidence that further enhancements to reliability could be experienced, please confirm that the evidence is relative to the currently contemplated Entegrus proposal and not the reliability the Customer currently enjoys with Hydro One. If not confirmed, please detail how the Entegrus proposal will enhance reliability beyond the reliability levels currently enjoyed by the Customer.

j) Please address the inconsistency between Entegrus' evidence at Reference 6 and Entegrus' evidence in Reference 5 that an additional tie-in to other existing nearby Entegrus assets could be made to further enhance reliability for both the Customer and other Entegrus customers.

k) With respect to Reference 4, please provide the longest period that Entegrus has needed to utilize emergency capacity. Please provide details as to when these events occurred and what triggered the event.

l) With respect to Reference 8, please clarify what is meant by Assets Included in the Application. Please confirm whether the cost associated with all these "Assets Included in the Application" has been included in the cost table provided at Reference 9. If not, please update the Table to reflect this cost.

m) With respect to Reference 8, please clarify what is meant by New Supply to Entegrus Customers. Please confirm whether the cost associated with the "New Supply to Entegrus Customers" has been included in the cost table provided at Reference 9. If not, please update the Table to reflect this cost. Please also detail the scope and schedule of these new facilities.

n) Please clarify if the intelligent reclosers in Reference 10 are the same as those in Reference 5. If not, please provide the costs for the intelligent reclosers.

o) Please clarify the discrepancy between Reference 5 and Reference 11 as to the number of reclosers required. Please provide the same for Reference 5 and 10.

p) Please clarify if there will be load connected between the 3 reclosers as per Reference 3. Please provide a map of this feeder expansion along with the customer connections, if any.

q) Please provide the costs of this feeder expansion.

r) Please update the costs identified Reference 9 in the column entitled Entegrus Services the Customer and Accesses Additional Capacity of Table 6-1 of the Entegrus Application to show all forecast costs documented in Reference 12.

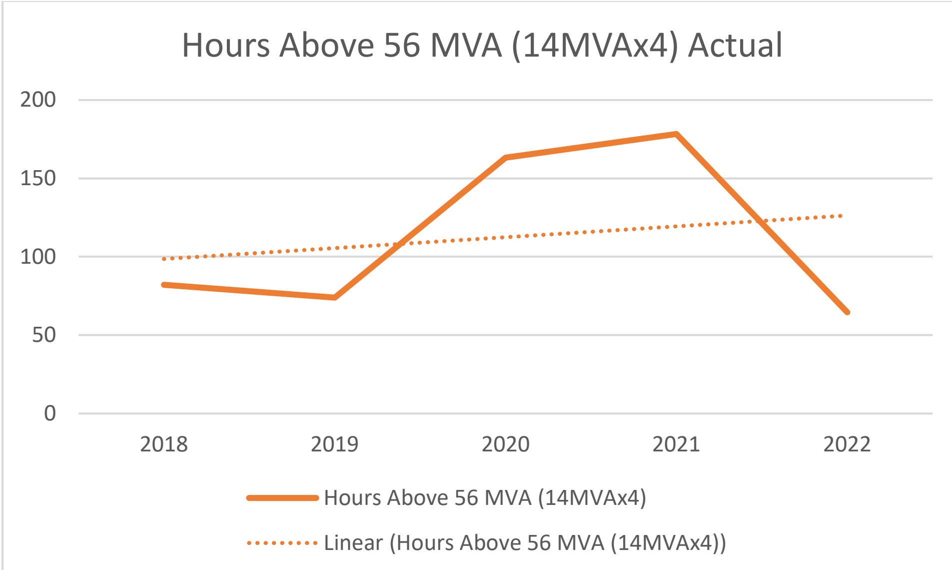
s) Please update Reference 9 to include the cost of the additional reclosers, feeder expansion costs, per annum LTLT mitigation costs, and any other costs not currently considered in the initial Application that Entegrus may consider necessary.

Response

a) EPI includes both Main and St. Thomas regions.

YEAR	EPI				St. Thomas			
	Excluding Loss of Supply		Including Loss of Supply		Excluding Loss of Supply		Including Loss of Supply	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
2017	1.72	1.07	3.66	2.21	0.47	0.58	0.72	1.57
2018	1.89	1.21	3.53	2.07	0.76	0.55	0.60	0.76
2019	1.73	1.02	3.37	1.99	0.73	0.36	0.73	0.36
2020	1.47	1.18	2.22	1.74	1.50	1.54	1.59	1.54
2021	1.09	1.02	2.87	2.01	0.25	0.51	0.26	0.51
2022	1.76	1.18	3.42	2.67	0.44	0.65	2.06	1.65

b) Consistent with Reference 4, the system peak has exceeded the planning capacity of the four feeders. As the system peak demand trends upward, so too does average demand. The number of hours per year where the demand exceeds planning capacity is also growing (see chart below).



The combination of hours above planning, and the intensity of the demand during those hours places constraints on Entegrus' ability to provide alternative supply points for its customers to mitigate the impact of outages. Section 4.4.5.2.5 Capacity Enhancements of Entegrus' 2021-2025 DSP contemplates the impact of both of these factors, and determines that 2023 was the appropriate time to add capacity to the Distribution system.

c) Figure 5-2 in the 2022-10-17 Application used actual data for the years 2017-2021 and applied a regression model to forecast growth in 2022 and beyond. In 2022 and 2023 year-to-date, Entegrus has added or received commitments related to approximately 850 St. Thomas service area customers with an associated estimated demand of 4.6 MW. The level of contributed capital is not relevant to this application. Entegrus notes that the more recent demands related to the above is subject to change since peak load usually occurs during the summer months and some of the initial peak load data is based on the construction phase.

d) The forecast provided in Figure 5-2 of the Application does not include the Customer's load. The premise of the "Max Design Capacity" lines in Figure 5-2 is that [redacted]

e) Entegrus addressed this in its 2021-2025 DSP and at Section 5.5 of the SAA Application. The load situation in St. Thomas is not static. Depending how much capacity is available based on the actual Formet requirements, and depending upon the load impacts from community growth expected to accompany the establishment of the [redacted], Entegrus will update its DSP and identify the most efficient solution.

f) The growth rate sensitivity range (based on Figure 5-2 of the Application) is between 2.36%/year and 5.36%/year.

g) Historically, when either the M7 or the M8 is out of service, the Customer load has been served from the remaining in-service feeder. This condition persists until the repairs or maintenance activities are completed.

Under either interconnection topology proposed by Entegrus at Section 3.4 and at Attachment 2 (Figure A and Figure B) of the Entegrus 2023-05-12 Supplementary Evidence, in the event that the M7 or M8 feeder becomes unavailable, the Customer will continue to receive service from the other feeder (i.e. the M7 or the M8). In addition, the Customer will also receive a backfeed (as needed), via switching from one of the other four Entegrus feeders to mitigate the outage. In that scenario, other St. Thomas customers will also receive service from the other four Entegrus feeders.

The incremental Entegrus load would not impact the reliability to the Customer, as the reclosers insulate the Customer from interruptions from other Entegrus assets/customers in this situation, just as they do when both feeders are in service.

h) Please see Section 5.8 of the Application and the update to Table 6.1 of the Application as shown at r) below.

i) The Customer 2023-04-17 Evidence at Exhibit K provides the following Customer reliability information: [redacted] The Entegrus proposals shown at Attachment 2 (Figure A and Figure B) of the Entegrus 2023-05-12 Supplementary Evidence would provide tie-in to alternative sources of power and thereby enhance reliability. Specifically, Figure A would tie-in to one additional Entegrus feeder and Figure B would tie-in to two additional feeders.

j) There is no inconsistency. As noted above in (i), the proposed connection topology (Application Figure 5-3, updated in the Entegrus 2023-05-12 Supplementary Evidence at Attachment 2, Figure A and Figure B) will provide increased reliability to the Customer and increased capacity to other Entegrus customers.

k) Entegrus was required to utilize emergency capacity for approximately 12.5 hours on July 9, 2020. High temperatures on that day contributed to elevated loading levels in St. Thomas.

l) While the correct number of reclosers were shown in the Entegrus 2023-05-12 Supplementary Evidence at Attachment 2 (three reclosers for Topology Figure A and four reclosers for Topology Figure B), a clerical error occurred in the pink highlight reference, which inferred that these were included in the 2022-10-17 Application (i.e. terminology “Assets Included in the Application”). In fact, Table 6-1 of the 2022-10-17 Application showed only two reclosers, and this was updated to reflect additional reclosers in the Entegrus 2023-05-12 Supplementary Evidence at Attachment 2 (Topology Figures A and B). Table 6-1 has been updated at r) below to correct for this.

m) In the Entegrus 2023-05-12 Supplementary Evidence at Attachment 2, the terminology “New Supply to Entegrus Customers” was used as an illustrative term to reference that the M7/M8 feeders would be used to supply the existing Entegrus distribution system in order to serve other Entegrus customers in St. Thomas. Figure A showed tie-in to one existing Entegrus feeder and Figure B showed tie-in to two existing Entegrus feeders. These illustrative terms do not represent new costs beyond those already shown in r) below.

n) Confirmed.

o) Please see the response at part l) above.

p) Feeder expansion for tie-in of the M7/M8 feeders to other Entegrus feeders is not required, although this may have been misinterpreted by Hydro One based on the expanded scale (for illustrative purposes) of the single line diagrams shown in the Entegrus 2023-05-12 Supplementary Evidence at Attachment 2. Feeder expansion is not required because other Entegrus feeders largely travel together with the M7/M8 feeders from Edgeware TS to the Customer.

q) A contingency cost for tie points has been added in (r) below to reflect any minor construction required to tie in these other Entegrus feeders to the M7/M8 feeders. As noted in (p) above, feeder expansion is not required.

r) Please see the response at OEBStaff-10. Note that some of the items raised by Hydro One in Section 4.3 of Hydro One Intervenor Evidence, p. 24 are rate-related matters and do not pertain to connection costs.

s) Please see the response at r) above. A contingency cost for tie points has been added in r) above to reflect any minor construction required to tie in the other adjacent Entegrus feeders to the M7/M8 feeders.

INTERROGATORY: HONI-5

Ref:
1. "This will result in the termination of the existing load transfer agreement, consistent with the mandatory direction in Section 6.5.3 of the Distribution System Code." – Application p. 5

Questions:

a) Please confirm that Entegrus has never filed a compliance complaint with the OEB regarding this alleged outstanding LTLT despite taking over STEI in 2018.

b) Please confirm that this connection has never been settled as an LTLT. If Entegrus takes the position that it has, please provide all documentation that reflects that type of settlement arrangement.

Response

(a) Entegrus Powerlines Inc. and STEI merged effective April 1, 2018 and continued thereafter as Entegrus Powerlines Inc. This SAA Application was filed by Entegrus after years of discussion with Hydro One on this matter and seeks relief in the form of the termination of the existing load transfer agreement, consistent with the mandatory direction in Section 6.5.3 of the Distribution System Code.

(b) Beyond the 1997 Letter and Addendum between Ontario Hydro and the St. Thomas PUC described in Section 5.2 of the Application and the associated monthly rental and maintenance (operating lease) payments (and the information described in the EB-2002-0523 record), Entegrus does not have further information as to how this connection has been settled in the past. As described in the Entegrus 2023-05-12 Supplementary Evidence, there are no management representatives of STEI still working with Entegrus to be able to provide information, nor has review of available STEI records provided further detail.

INTERROGATORY: HONI-6

Ref:
1. "In late 2017, Hydro One engaged STEI in discussions to purchase the M7 and M8 feeders, relying on the 1997 Letter between Ontario Hydro and the St. Thomas PUC. Specifically, Hydro One proposed to continue to serve the Customer and purchase the M7 and M8 feeders at their January 1, 2018 book value from Entegrus. STEI expressed its reluctance, due to the strong load growth in St. Thomas." – Application p. 10

2. "In doing so, it appears that STEI did not recognize that the purchase option cited by Hydro One had been frustrated by the OEB's December 2015 Distribution System Code amendments (EB-2015-0006), as described below in Section 5.4. Further, apparently STEI did not recognize, nor did Hydro One appear to recognize, the requirement of an OEB Section 86(1)(b) application and OEB approval in order to proceed with any sale of assets from STEI to Hydro One." - Application p. 10

Questions:

a) Please confirm that strong load growth or a change in load growth in St. Thomas, is not a term in the agreement which would permit Entegrus, or its predecessors, to resile from the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum). If Entegrus disagrees, please identify the term(s) in the agreement that supports the position that it can.

b) With respect to Reference 2, please confirm that it is equally plausible that STEI and Hydro One did not consider that the 1997 Supply Facilities Agreement (which for greater certainty, includes the May 29, 1998 Addendum) was not frustrated by the OEB's December 2015 Distribution System Code Amendments.

c) Hydro One does not recall that STEI showed any reluctance in respect of the sale of the M7 and M8 feeders once Hydro One agreed that STEI could keep the poles and that Hydro One would enter into a joint use arrangement with STEI for the Feeders. With respect to Reference 1, please provide evidence supporting the supposition that there was reluctance.

Response

(a) As per Section 5.4 of the Application, Entegrus submits that the 1997 Letter and Addendum is no longer applicable. In legal terms, the contract has been frustrated and can, or should, no longer be performed. Accordingly, Entegrus considers the terms of the 1997 Letter and

Addendum null and void.

(b) As described in the Entegrus 2023-05-12 Supplementary Evidence, there are no management representatives of STEI still working with Entegrus. Accordingly, Entegrus is not aware of whether STEI and Hydro One considered, or did not consider, that the 1997 Letter and Addendum had been frustrated by the OEB's December 2015 Distribution System Code Amendments.

(c) The reluctance is evident when Entegrus considers both the provisional agreement that STEI could keep the poles and that Hydro One would enter into a joint use arrangement with STEI for the feeders (as described in Section 5.3 of the Application) and the fact that no agreement was consummated with Hydro One prior to the STEI merger with Entegrus, which has led to this Application.

INTERROGATORY: HONI-7

Ref:
1. "In doing so, it appears that STEI did not recognize that the purchase option cited by Hydro One had been frustrated by the OEB's December 2015 Distribution System Code amendments (EB-2015-0006), as described below in Section 5.4. Further, apparently STEI did not recognize, nor did Hydro One appear to recognize, the requirement of an OEB Section 86(1)(b) application and OEB approval in order to proceed with any sale of assets from STEI to Hydro One." - Application p. 10

2. "Entegrus serves the area surrounding the Subject Area and accordingly has distribution infrastructure within close proximity, in addition to the M7 and M8 feeders that currently serve the Customer, and can provide the required electrical service with minimal additional investment (see Section 6.3)" – Application p. 24.

Questions:

a) Please provide any jurisprudence relied upon to support Entegrus' position that the commercial agreement, namely, the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) has been frustrated by the issuance of the DSC amendments referenced.

b) Please discuss how the treatment of the Customer in EB-2017-0192 as jointly filed by Hydro One and STEI. and consented to by these parties, can be resiled from if the OEB finds the 1997 Supply Facilities Agreement has not been frustrated.

c) Please confirm that applicability of a s.86 (1)(b) application to sell or lease an asset is the responsibility of the divesting or leasing distributor not the purchaser or lessee of such assets.

d) Please discuss Entegrus' position with regard to any amounts owing to Hydro One and its ratepayers in the case where the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) is not complied with, including Hydro One's right to be made whole in a civil recovery for the payments under the agreement. If it is Entegrus' position that no amounts would be owing to Hydro One, please explain why.

Response

(a) This is a matter for argument. At a high level, Entegrus relies on the general principles of frustration of contract. See, for, example, *Petrogas Processing Ltd. v. Westcoast Transmission Co.*, 1988 CanLII 3462 (AB KB) which cites leading textbooks.

(b) Entegrus has not resiled from anything that was included in the earlier LTLT elimination filing. Rather, Entegrus has identified another LTLT that should be eliminated. Supplementary LTLT eliminations between Hydro One and Entegrus have previously occurred after June 21, 2017, namely the transfer of a customer in the joint EB-2017-0326 application. There are also examples of other distributors and Hydro One filing supplementary or additional LTLT elimination applications following the main applications filed in response to the OEB's EB-2015-0006 Notice[3].

(c) Confirmed.

(d) Entegrus takes the position that the 1997 Letter was frustrated by the requirement to eliminate LTLTs. Under applicable legal principles, no damages are owed by either party when a contract is frustrated and can no longer be performed. The payments to date constitute an operating lease and are for the use of the Entegrus assets (primarily the M7/M8 feeders). Hydro One has enjoyed the use of the assets and has benefitted from the distribution revenue from the Customer. There are no amounts to be recovered.

Similarly, should the OEB decline to approve the transfer of the assets to Hydro One, because this transaction is not in the public interest, then Entegrus would be unable to complete the transfer and would take the position that the 1997 Letter is frustrated.

[3] For example EB-2017-0326.

INTERROGATORY: HONI-8

Ref:
1. "In 2021, Entegrus management conducted further in-depth analysis of the upcoming St. Thomas capacity challenges. The initial concept to address the St. Thomas capacity challenges is described herein as Scenario 1 (see Section 5.5.1), and involved the sale of the two underutilized dedicated feeders to Hydro One, followed by Entegrus investing approximately $1.7M (including a $1.1M payment to Hydro One) to build a new breaker position and egress at the Edgeware TS. Under this scenario, Entegrus would also incur significant feeder construction costs." - Application p. 11

Question:

a) Please confirm that the further in-depth analysis referenced in the extract occurred more than three years after Hydro One had exercised the option to purchase these facilities.

Response

(a) It is confirmed that the analysis took place after Hydro One attempted to exercise the purchase option.

INTERROGATORY: HONI-9

Ref:
1. "At that time, Entegrus came to the realization that the sale of the assets to Hydro One would require OEB Section 86(1)(b) approval from the OEB. Entegrus recognized that under the circumstances, it could not make such an application because such a sale of assets was contrary to the public interest. Specifically, it would be contrary to regional planning objectives and OEB Act Section (1), regarding the protection of customers in terms of pricing and promoting economic efficiency and cost effectiveness in the transmission and distribution of electricity. Entegrus would not be able to complete the application form in a way that would support approval. Challenges included, but were not limited to, the following application questions:

- Question 2.3: Are the assets surplus to the applicant's needs?
- Question 3.4: Would the proposed transfer impact the distribution rates of the applicant?" - Application p. 11

Questions:

a) Please confirm whether these assets currently reside in Entegrus' rate base.

b) Please confirm and provide documentation demonstrating how Entegrus and its predecessor, St. Thomas Energy Inc. reported the revenue collected from Hydro One under the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) in OEB-approved rates.

Response

(a) Confirmed.

(b) The last Cost of Service related to Entegrus-St. Thomas assets was EB-2014-0113, for rates effective January 1, 2015. Please refer to the Customer 2023-04-17 Evidence at Exhibit I, wherein the Customer has provided an excerpt of Exhibit 3 of the EB-2014-0113 Application, which shows that the monthly rental and maintenance (operating lease) payments collected from Ontario Hydro / Hydro One under the 1997 Letter and Addendum were treated as Other Revenue in the derivation of OEB-approved rates.

INTERROGATORY: HONI-10

Ref:
1."In June 2021, Entegrus released invoices to Hydro One in error that should have been held internally. The first invoice related to the purchase price of the conductor (and not the poles) on the M7 and M8. The second invoice related to charges for Hydro One feeder use in 2018-2020. These invoices would have reflected the sale of assets without OEB approval and Entegrus senior management was not aware that they had been released. Thereafter, in August 2021, after further study of alternatives for the 2021-2025 DSP, Entegrus verbally notified Hydro One that it would not sell the assets and sought an immediate meeting with Hydro One representatives. Hydro One was unable to schedule a meeting until October 2021, prior to which Hydro One paid the invoices (which were cancelled and refunded shortly thereafter by Entegrus)." - Application p. 12

Questions:

a) Please explain why the first invoice related to the purchase of the facilities was just for the conductor and not the poles. In so doing, please confirm that this is a deviation from the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) and address in the response why Entegrus invoiced just that amount?

b) Please confirm that Hydro One's (and its predecessor, Ontario Hydro's) leasing cost was predicated on the St. Thomas PUC's cost to construct the M7 and M8 which included the poles and conductor in accordance with the terms of the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum). If Entegrus disagrees, please explain why and provide the documentation it seeks to rely on to support how the leasing cost was arrived at.

c) Please confirm why the second invoice (related to charges for Hydro One feeder use in 2018-2020) was refunded? Did that invoice also require OEB approval? Please provide a copy of both refunded invoices for the purposes of completing the record.

d) Please provide a copy of the Entegrus 2021-2025 DSP.

Response

(a) As noted by Hydro One in HONI-6 c), Hydro One and STEI provisionally agreed that STEI could keep the poles (on which STEI and now Entegrus have other feeders beyond the M7/M8 feeders) and that Hydro One would enter into a joint use arrangement with STEI for the feeders. In any event, as per Section 5.4 of the Application, Entegrus submits that the 1997 Letter and Addendum is no longer applicable. In legal terms, the contract has been frustrated and can, or should, no longer be performed. Accordingly, Entegrus considers the terms of the 1997 Letter and Addendum to be null and void.

(b) Entegrus does not have any information beyond what is provided in the 1997 Letter and Addendum.

(c) Entegrus cancelled and refunded both invoices pending a resolution or determination of the matters of issue in this Application. No official cancelled invoices were issued. However, clear communications were issued to Hydro One to indicate that Entegrus did not intend to proceed with any sale. Hydro One chose to pay the invoices regardless. Entegrus refunded the amounts paid by Hydro One. Copies of the refunded invoices are already provided in the Hydro One 2023-04-17 Evidence at Attachment 8.

(d) Please see the response at HONI-10 Attachment 1, which has been filed separately from these responses due to file size.

INTERROGATORY: HONI-11

Ref:
1."In legal terms, the contract has been frustrated and can or should no longer be performed. The 1997 Letter no longer applies because Section 6.5.3 of the Distribution System Code ("DSC") established that where load transfers existed, the associated customer would be transferred from the geographic distributor to the physical distributor prior to June 21, 2017. Accordingly, Hydro One cannot rely on the 1997 Letter as obliging Entegrus to sell the two dedicated feeders to Hydro One. Entegrus submits that the transfer of the Customer to Entegrus, by way of this SAA Application, is the best means to address the unique situation that continues to exist." - Application p.12-1314

Questions:

a) Please confirm that the onus to prove frustration of the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) rests with Entegrus.

b) If the contract is not frustrated, please confirm that pursuant to the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) Entegrus is obligated under the terms therein to complete the transfer of ownership as HONI exercised its option to purchase in 2017. If Entegrus disagrees, please explain why and on what grounds it maintains a refusal to transfer ownership.

Response

a) Confirmed.

b) Entegrus is required to follow the direction of the OEB. Before transferring the M7/M8 feeders, Entegrus will have to obtain OEB approval under section 86(1)(b) of the OEB Act. One of the requirements in the OEB's application form for approval of transfer of assets under Section 86(1)(b) of the OEB Act is for the applicant (which would be Entegrus) to answer the question of "Will the transaction adversely impact the safety, reliability, quality of service, operational flexibility or economic efficiency of the applicant". Entegrus strongly believes that the transfer would have negative consequences for its ratepayers. Should the OEB decline to provide approval for the transfer of the assets under Section 86(1)(b) of the OEB Act, or otherwise decide that the ongoing servicing of the Customer by Hydro One is not in the public interest and direct Entegrus not to sell the M7/M8 feeders, then Entegrus will not be permitted to transfer ownership of the assets. In that circumstance, Entegrus would be unable to complete the transfer and would take the position that the 1997 Letter is frustrated.

INTERROGATORY: HONI-12

Ref:
1.“As a result of this strong growth, loading has reached the point where all four feeders available to the general public in St. Thomas are, on average, loaded beyond design capacity during peak periods. Accordingly, Entegrus occasionally experiences periods of time in St. Thomas where no transfer capacity remains in the event of certain single points of failure during peak loading, which can lead to extended outages... This continued growth above design capacity will drive an increasing number of failure points and lack of transfer capacity over time. To address the fact that Entegrus is already running above design capacity of the existing four feeders available to the general public, Entegrus requires the equivalent of a feeder’s worth of capacity (i.e. 1438 MW) in the immediate term (i.e. 2023).
Figure 5-2 also shows that dependent upon the growth scenario, a second additional 1 feeder will be required between 2024-2027.”- Application p. 15-16

2.“In many cases, the interests of the individual customer will align with the interests of other customers, and the system as a whole. Each market participant must accept the interdependence which is fundamental to the system. Each participant has a right to expect that others engaged in the same system meet their respective costs, without subsidization or penalty. That is as true for new customers as it is for others.” – Para. 230 – OEB Decision with Reasons, RP-2003-00449

Questions:

a) Please clarify/elaborate on how transferring the directly impacted Customer is advantaged by the Entegrus system with respect to reliability and quality of service?

b) Please clarify how the Entegrus proposal is consistent with the OEB statement provided at Reference 2.

c) Please confirm if Entegrus has identified the limitations in Reference 1 when applying for recent SAAs? If not, please elaborate why not?

d) Please clarify/elaborate why Entegrus has pursued new connections in Hydro One service territory despite the capacity constraints and potential reliability concerns outlined in Reference 1?

Response

a) Please see the response at HONI-4 i). Moreover, the relief sought from the Application supports the rational use of the M7/M8 feeders, which includes providing underutilized (stranded) capacity to other St. Thomas customers who require the capacity.

b) Entegrus believes that the relief sought from the Application is consistent with paragraph 230 of the OEB Decision with Reasons (RP-2003-0044) cited by Hydro One, as well as paragraph 229, wherein the OEB states that, "… the interest of any particular market participant must cede to the system's requirements…", and, "in its consideration of service area amendments, it will favour those applications which show that a given connection proposal represents the most economically efficient use of existing resources within the distribution system."

c) Recent Uncontested SAAs involving Entegrus and Hydro One have been initiated at the request of developers/customers residing in what was previously Hydro One service territory. Recent SAAs have not involved meaningful loads (i.e. the loads have been less than 1MW combined). As outlined in the 2021-2025 DSP (please see HONI-10 Attachment 1), Entegrus has been taking steps to expand capacity to serve St. Thomas, targeted for 2023. Some of this capacity could be provided by the M7/M8 feeders owned by Entegrus. In the meantime, Entegrus has been able to continue reliable service to St. Thomas customers (please see the response at HONI-4a).

d) Please see the response at c) above.

INTERROGATORY: HONI-13

Ref:
1.“Entegrus is not billed for these two additional, separate breakers associated with the Entegrus M7 and M8 feeders.”- Application p. 14

Question:

a) Please discuss who Entegrus understands is billed for these separate breakers.

Response

a) Entegrus confirms that it is not billed transmission charges for the breakers. Based on the Hydro One 2023-04-17 Evidence at Attachment 9, it appears that the Customer is typically billed for [redacted] of transmission charges (in aggregate) by the IESO on the two breakers.

INTERROGATORY: HONI-14

Ref:
1."In advance of this Application, Entegrus requested information on the status of the M7 and M8 breakers and if both breakers were currently reserved for the exclusive use of the Customer, or alternatively, whether a portion of the M7 and M8 capacity was reserved or utilized for other purposes. Hydro One declined to provide this information, aside from indicating that 5 MW of capacity from the M8 breaker position was allocated to Entegrus (see Section 5.5.2 for additional detail)"- Application p. 16

2. Hydro One recently indicated that this 5 MW of capacity is allocated to Entegrus. To date, Entegrus has not utilized any of this capacity.-Application p.19

Questions:

a) Please confirm that Entegrus never accepted and/or utilized this available capacity offer from Hydro One and therefore there is no contracted capacity for Entegrus on the M8 breaker position.

b) Please confirm why, to date, Entegrus has not utilized any of the capacity that was offered despite exceeding its system max design capacity since 2018?

c) Please clarify whether the 5MW of design capacity would assist with meeting Entegrus' imminent needs. If the amount is insufficient, please articulate what other investments will be required by Entegrus to address the imminent (2023) needs described in the Application. Please provide any analysis or study Entegrus has taken to address this need aside from what is already in evidence.

Response

a) Confirmed. Entegrus owns the M7/M8 feeders and therefore does not recognize the ability for Hydro One to contract the capacity as described. In any event, the price at which the 5 MW on the M8 was offered was many multiples beyond what Hydro One paid for the same equivalent capacity. Please see the response to OEBStaff-5 for a discussion of the impact to Entegrus customers.

b) Please see the response at part a) above.

c) As noted in Section 5.5 of the Application, Entegrus requires the equivalent of a feeder's worth of capacity (14 MW in the immediate term). This was also documented in the 2021-

2025 DSP. The relief sought, resulting in the integration of the M7/M8 into Entegrus' distribution system, would address the current forecast requirements in St. Thomas and may assist in meeting incremental requirements expected to arise in the community as the [redacted] is established.

INTERROGATORY: HONI-15

Ref:
1.“Under this scenario, Entegrus would sell the underutilized feeders to Hydro One at the January 1, 2018, net book value of the feeders of $116,431, which is substantially less than the estimated replacement cost of $3M -$4M for the two feeders (and associated breaker positions). In order to meet its St. Thomas load capacity requirements, Entegrus would then incur estimated aggregate costs of $1.7M for the construction of a single additional Edgeware station bus and breaker position, station egress and metering (as well as significant feeder construction costs). The cost of the additional breaker position would be paid to Hydro One”. - Application p. 17

2.Table 5-1 – Application p. 17

3.“Entegrus received the Bus and Breaker estimate of $1.1M per Table 5-1 above via an email from Hydro One in September 2019, which indicated that an estimation threshold range of -50% to +100% applies to this figure.” – Application p. 17

4.“In addition to the estimated construction costs above, Entegrus would also incur feeder construction costs. Since, by way of the new feeder, Entegrus would be directly connected to the Edgeware TS, Entegrus does not believe it would incur any Low Voltage charges under this scenario.” – Application p. 18

5.“Simply put, it does not make sense for Entegrus customers to bear $1.7M of cost to Hydro One (plus significant additional feeder construction costs), when there are existing underutilized assets already owned by Entegrus in proximity that could remedy the situation.” – Application p. 18

Questions:

a) Please confirm that Entegrus and/or STEI and/or St. Thomas PUC received payment for the construction of the feeders in accordance with the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum).

b) Please confirm that the terms and conditions of the 1997 Supply Facilities Agreement(which for greater certainty, includes, the May 29, 1998 Addendum) specify the monthly leasing costs and purchase option cost of the feeders (including the poles).

c) Please clarify whether Entegrus is of the opinion that all of the other terms and conditions of the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) would have remained unchanged if the purchase option was ultimately to be "replacement cost" rather than "net book value" as currently defined by the 1997 Supply Facilities Agreement.

d) Please clarify that the cost of the additional breaker position and all other costs associated with Edgeware TS in Scenario 1 would be paid to Hydro One Transmission, i.e., the transmitter that owns Edgeware TS, not Hydro One Distribution.

e) Please confirm that Entegrus' ownership position of the Feeders is predicated on the terms and conditions of the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum).

Response

a) Entegrus has no evidence to suggest that STEI and/or St. Thomas PUC did not receive monthly rental and maintenance (operating lease) payments from Ontario Hydro/Hydro One starting in September 1997 as per the 1997 Letter and Addendum. Entegrus (which merged with STEI on April 1, 2018), has never received monthly rental and maintenance (operating lease) payments from Hydro One in this regard.

b) The 1997 Letter and Addendum are on the record and available for the OEB to interpret. As per Section 5.4 of the Application, Entegrus submits that the 1997 Letter and Addendum is no longer applicable. In legal terms, the contract has been frustrated and can, or should, no longer be performed. Accordingly, Entegrus considers the terms of the 1997 Letter and Addendum null and void.

c) Please see the response at part b) above.

d) It is acknowledged that Hydro One Transmission owns Edgeware TS.

e) The M7/M8 feeders have been owned by St. Thomas PUC / STEI since their construction and Ontario Hydro / Hydro has paid monthly rental and maintenance (operating lease) payments to St. Thomas PUC / STEI. The M7/M8 feeders are included in the Entegrus rate base.

INTERROGATORY: HONI-16

Ref:
1."Hydro One indicated that 5 MW (from the M8 breaker position) was the maximum capacity that could be allocated to Entegrus from the two dedicated feeders. As can be seen in Figure 5-2, this additional 5 MW capacity is insufficient to address the Entegrus supply needs in St. Thomas. And as shown in Table 5-2, this 5 MW of capacity would come at a very high cost to Entegrus customers…To date, Entegrus has not utilized any of this capacity. Hydro One further indicated that, should Entegrus eventually transfer ownership of the M7/M8 feeders to Hydro One, based on Hydro One's current 2022 rates, to the extent that Entegrus uses this 5 MW in allocated capacity, Entegrus would be subject to Low Voltage ("LV") charges, plus Retail Transmission Service Rates ("RTSRs"). Hydro One notes that the charges are subject to change. The Hydro One LV and RTSRs – plus any additional Hydro One rate riders –would result in this scenario being a very expensive option for Entegrus customers, as shown below in Table 5-2." – Application p. 19

2. Table 5-2 – Application, p.19

3."The Hydro One charges shown above in Table 5-2 are significantly in excess of the monthly charges paid by Hydro One to St. Thomas PUC/STEI/Entegrus; these monthly charges to Hydro One were $5,828 per month for 28 MW of design capacity (on two feeders) for 1997-2007, followed by a reduction to $5,528 per month for the period 2008- 2017. In comparison, when normalizing for equivalent capacity (i.e. 28 MW vs. 5 MW) the equivalent charges which Hydro One proposes to charge Entegrus would be $252,773 (i.e. $45,138 X 28 MW / 5MW) per month. This means that Hydro One proposes to charge Entegrus 45 times more per month than Entegrus has historically charged Hydro One, on an equivalent capacity basis. And future additional Hydro One rate riders could make the proposition even more expensive for Entegrus customers." – Application, p. 19-20

Questions:

a) Please confirm that the rates documented in Table 5-2 are Entegrus' understanding of the OEB-approved charges for the services being requested by Entegrus of in this scenario.

b) Please confirm, that with respect to the comparison provided at Reference 3, Entegrus has never provided Hydro One with any capacity. In other words, please confirm, Entegrus is not, and has never been, a host distributor to Hydro One on these Feeders.

c) Please clarify the rationale for including the Deferred Tax Asset Vol. Rider in Table 5-2.

Response

a) Entegrus notes that the 5 MW of capacity on the M8 feeder was offered by Hydro One to Entegrus, as described in Section 5.3 of the Application. The rates documented in Table 5-2 of the Application contain both Hydro One Distribution Low Voltage (Common ST) charges and transmission-related charges. Entegrus acknowledges that the transmission-related charges can be excluded when comparing at a distribution level with Hydro One Distribution. In this context, the comparative pricing is as follows:

- Hydro One pricing to Entegrus[4]: $7,721 per month for 5 MW of capacity = $1,544.20 per month per MW
- Entegrus pricing to Hydro One at planning capacity for 2 feeders: $5,527.93 per month for 28 MW of capacity = $197.43 per MW
- Entegrus pricing to Hydro One at maximum operating capacity for 2 feeders: $5,527.93 per month for 56 MW of capacity = $98.71 per MW

It is thus evident that when comparing at a distribution level, Hydro One seeks to charge Entegrus 7.8X to 15.6X the Entegrus price for the same assets.

b) Entegrus has historically provided the complete use of the full capacity M7/M8 feeders to Hydro One in exchange for monthly rental and maintenance (operating lease) payments.

c) Entegrus acknowledges that the focus should be on base rates since rate riders are temporary in nature. Accordingly, Entegrus acknowledges that the Deferred Tax Asset Vol. Rider should be excluded.

[4] Common ST rate of $1.5442/kW per EB-2021-0110 Tariff Sheet, Sub Transmission - ST rate class.

INTERROGATORY: HONI-17

Ref:
1.“The SAA further reduces potential public confusion regarding the servicing of the Subject Area and would reduce an unnecessary layer of co-ordination between Entegrus and Hydro One.” - Application p. 22

2.“Further, in terms of reliability, the Customer would benefit from the proposed SAA by the removal of an unnecessary layer of coordination between Hydro One and Entegrus, in the event that a reliability event were to occur.” – Application p. 24

Questions:

a) Please clarify whether “potential public confusion” is limited to the distributors that are parties to this proceeding and the Customer. If not, please provide instances of potential public confusion beyond the aforementioned parties.

b) Please confirm that if Entegrus divested the Feeders in accordance with the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum), that would also eliminate the potential public confusion and reduce an unnecessary layer of coordination between Entegrus and Hydro One.

Response

a) Entegrus confirms that the examples of public confusion detailed at Section 5.5.4 of the Application involved the parties to this proceeding (and the Customer’s consultant). In addition, as described at Section 5.5 of the Application, Hydro One initiated [redacted]

b) Potential public confusion and the reduction of an unnecessary layer of coordination between Entegrus and Hydro One would be achieved by either: (i) the relief requested in the Application, specifically, a licence amendment pursuant to Section 74(1) of the Ontario Energy Board Act, 1998 for the purpose of amending the licensed service area of Entegrus to include the Customer, or (ii) by the divesture of the M7/M8 feeders by Entegrus to Hydro One, as sought by Hydro One. However, (ii) would create a “Swiss Cheese” effect, similar to that with which Hydro One is concerned with in the Hydro One 2023-05-19 Supplementary

Evidence at Attachment 3, since the Customer would remain fully embedded within what is otherwise Entegrus service territory.

INTERROGATORY: HONI-18

Ref:
1.“Approval of this SAA will not result in any negative impacts on cost, service quality, and reliability. As more fully described in Section 7.4, it is anticipated that the Customer will enjoy a distribution rate benefit from being served by Entegrus.” – Application p.28

2.“Approval of this SAA will not result in any negative impacts on cost, service quality, or reliability. It is anticipated that the Customer will enjoy a distribution rate benefit from being served by Entegrus.” – Application p. 29

3.“Entegrus anticipates that no mitigation is required, as Entegrus believes that the Customer would enjoy a distribution rate benefit if this Application were approved.” – Application p. 30

4.“…Entegrus could not confirm which Hydro One rate class the Customer resided in and did not anticipate that the Customer would reside in the Hydro One Sub-Transmission rate class based on Entegrus’ understanding that the rate class requires that a customer be connected to Hydro One-owned assets.” – Entegrus Letter Regarding Description of Supplementary Evidence – p. 3

5.Hydro One Intervenor Evidence, Section 3.1.1.1 –p.20

Questions:

a) Hydro One understands, based on Reference 4, that Entegrus erred in its understanding of the rate class the Customer qualifies for and Hydro One accepts that Entegrus could not confirm this with the Customer directly given it has no relationship with the Customer to be able to contact them in accordance with the DSC. Accordingly, please update References 1 through 3 of the Entegrus Application to account for the impacts to the Customer and all other Entegrus customers based on the mitigation that is necessary for Entegrus to serve the Customer.

b) With respect to References 1 through 4, please confirm that Entegrus is not licenced by the OEB to own these Feeders.

Response

a) As noted in the Entegrus 2023-05-12 Supplementary Evidence at Attachment 1, at the time of filing the Entegrus evidence in October 2022, Entegrus could not confirm which Hydro

One rate class the Customer resided in and did not anticipate that the Customer would reside in the Hydro One sub-transmission rate class, based on Entegrus' understanding that this rate class requires that a customer be connected to Hydro One-owned assets. Please also see the response at Formet-4.

b) Not confirmed. These assets are part of the Entegrus rate base. Please also see the response at HONI-2 b).

INTERROGATORY: HONI-19

Ref:
1.“Hydro One asserts that the facts show that the Customer is not served by an LTLT, and section 6.5.3 of the Distribution System Code (“DSC”) does not apply. Hydro One further states that the parties have not treated the arrangement as an LTLT, as evidenced by the fact that it was not included in the 2017 Joint LTLT elimination application from Hydro One and St. Thomas Energy (“STEI”). Load transfers were described in the Combined Proceeding on SAAs. In the Decision in that case, the OEB noted that “Load transfers are arrangements whereby an incumbent distributor permits an adjacent distributor to serve a load located in the incumbent’s service territory.” That is exactly the case here.” – Entegrus Supplementary Evidence p. 8

2.“Because of the LTLT, Entegrus customers are being deprived of a benefit and will have to incur the consequences of additional costs for new capacity to serve St. Thomas. That capacity requirement is imminent, with the recent Volkswagen announcement. For instance, Entegrus recently received a request from a St. Thomas customer for significant additional capacity. Effectively, the Entegrus assets are providing service for the Customer, yet the LTLT is preventing those assets from being fully utilized for all St. Thomas customers.” - Entegrus Supplementary Evidence p.8

3.“Entegrus is not aware of why the Customer load transfer was not historically billed through STEI, nor why the parties did not include the LTLT in the 2017 Joint LTLT application. There are no management representatives of STEI still working with Entegrus to be able to provide such information. However, that does not change the fact that this is a load transfer, and under section 6.5.3 of the DSC the OEB has directed parties to eliminate load transfers. No requirement is included in the DSC that a load transfer must always be billed by the local distributor on behalf of the physical distributor.” - Entegrus Supplementary Evidence p. 9

4.“Hydro One also points to a 2004 decision of OEB Market Operations, which held that the 1997 Letter is a lease agreement that was not impacted by section 26(3) of the Electricity Act. 22 The implication is that it is also unaffected by the LTLT elimination rules. While Entegrus had not been aware of this decision, its position is unchanged. The 1997 Letter is inextricably linked with the load transfer arrangement. As of 2015, distributors are required to eliminate load transfers – this means that the commitments in the 1997 Letter Agreement cannot be completed. The direction to eliminate LTLTs came much later than the 2004 decision cited by Hydro One and does not appear to have been a factor under consideration.” - Entegrus Supplementary Evidence pp. 9-10

5. Hydro One Supplementary Evidence, Attachment 1 (July 2000 DSC) and 2 (Notice of Proposed Amendments to the DSC issued February 2015).

6. Retail Settlement Code, section 3.2 – July 1, 2022

Questions:

a) With respect to Reference 2, please confirm where the St. Thomas customer that made a request for significant additional capacity is sited and whether Entegrus is stating that they cannot connect the customer. Please clarify whether Entegrus is outlining that it cannot serve new customer connection requests and whether Entegrus has reached out to Hydro One to determine whether Hydro One could service this other potential connection.

b) With respect to Reference 1 and 2, please elaborate on how the supposed LTLT is preventing those assets from being fully utilized for all St. Thomas customers. In so doing, please clarify Entegrus' position of how asset ownership is prohibiting and/or limiting a customer connection.

c) With respect to Reference 3, the DSC defines geographic distributor as "with respect to a load transfer, means the distributor that is licensed to service a load transfer customer and is responsible for connecting and billing the load transfer customer". This definition has not materially changed since the release of the initial DSC, provided at Reference 5. Please provide any examples of an LTLT that Entegrus is aware of that a load transfer customer was not billed by a geographic distributor and then settled between distributors.

d) With Respect to Reference 3, please address whether Entegrus has received information whether oral or in writing to explain why the Customer load transfer was not historically billed through STEI from non-management STEI or Entegrus employees and if applicable, to provide same.

e) With respect to Reference 3, please address whether Entegrus has received information whether oral or in writing to explain why the parties did not include the LTLT in the 2017 LTLT application from non-management STEI or Entegrus employees and if applicable, to provide same.

f) With respect to Reference 6 as well as Entegrus' position that this connection is an LTLT, please provide all documentation that supports that this connection has been accounted for as an LTLT in Entegrus' (and the former STEI's) in compliance with the Retail Settlement Code.

g) Based on Reference 5, please clarify whether Entegrus' position remains the same as that documented in Reference 4 with respect to its supposition that the direction to eliminate LTLTs was not a factor in the OEB's 2004 decision regarding this connection because the direction to eliminate LTLTs was provided in 2015.

Response

a) The request for significant additional capacity was received from an existing Entegrus St. Thomas customer. See the response at HONI-4 e) for the additional detail requested.

b) Entegrus believes that there is more than the [redacted] originally offered to Entegrus. Please see the response at OEBStaff-3 a).

c) Entegrus is not aware of scenarios that would match the unique facts of this case, where a customer in a distributor's territory was assigned to Ontario Hydro more than 20 years ago. Accordingly, Entegrus has not searched for other examples.

d) Entegrus has not received any information, whether oral or in writing, from any STEI or Entegrus employees in this regard.

e) Entegrus has not received any information, whether oral or in writing, from any STEI or Entegrus employees in this regard.

f) Please see the response at c) above.

g) The Entegrus position is unchanged.

INTERROGATORY: HONI-20

Ref:
1.“Further, as noted above, the Application also references Section 6.5.3 of the Distribution System Code, which established that where load transfers existed, the associated customer would be transferred from the geographic distributor to the physical distributor prior to June 21, 2017. Entegrus / St. Thomas Energy Inc. (“STEI”) / the St. Thomas PUC has always been the Customer's physical distributor.” – Application p. 4

2.“The feeders would be rented to Ontario Hydro from September 1997 through December 2007 for $5,827.93 per month. This rental charge would decrease by $300 per month (to $5,527.93 per month) from December 2007 to December 2017” - Application p.10

Question:

a) Please clarify Entegrus' position as to why Entegrus has always been the physical distributor when the Feeders were rented to Hydro One with the condition that Hydro One had the option to own the feeders at the end of the term of the lease agreement.

Response

a) The arrangement whereby Hydro One paid monthly rental and maintenance fees to Entegrus was an operating lease arrangement. Please also see the responses at OEBStaff-1 and OEBStaff-3 a). In any case, as noted in the Application at Section 5.4, the purchase option was frustrated by the OEB’s December 2015 Distribution System Code amendments (EB-2015-0006).

INTERROGATORY: HONI-21

Ref:
1."The relief sought in this Application meets the requirements and expectations of the Elimination of Load Transfer Arrangements process as set out in the EB-2015-0006 proceeding. That was true in 2017, when distributors were directed to make Load Transfer Elimination applications, and it remains true now. Additionally, the scenario outlined in this Application meets the requirements and expectations of the OEB in relation to SAAs more generally, as outlined in the RP-2003-0044 Combined Proceeding Decision with Reasons (February 27, 2004), including the fact that the transfer of the Customer and the use of the subject feeders by Entegrus is the most efficient use of existing distribution resources." - Application p. 13

Question:

a) Please confirm if Entegrus has made a comparison with Hydro One on the use of these distribution resources? If not, please explain how Entegrus concludes this would be the most efficient use of existing distribution resources.

Response

a) As described in Section 5.3 of the Application, the Entegrus M7/M8 feeders are underutilized and stranded capacity exists. While Hydro One offered Entegrus 5 MW of capacity on the M8 feeder, there have been continued indications throughout this process that additional underutilized capacity exists. Entegrus ownership would provide the opportunity to increase the capacity of the M7/M8 feeders (see Entegrus Interrogatory #3 to Hydro One) at less cost than the alternative, while tying to other Entegrus feeders to enhance reliability (see response at OEBStaff-7). Lastly, in terms of economic efficiency, the price at which the 5 MW on the M8 feeder was offered by Hydro One to Entegrus was many multiples beyond what Hydro One paid for the same equivalent capacity. Please also see the response at OEBStaff-3a).

INTERROGATORY: HONI-22

Ref:

1.“The design intent of being able to supply the Customer [redacted] is supported by the documentation filed by the Customer and the Customer’s claims. As constructed, the feeders feature materials with a safe operating rating [redacted] without equipment degradation, which is significantly higher than Entegrus’ initial assessment.” - Entegrus Supplementary Evidence p. 2

2.“Hydro One assumes that Entegrus planning capacity is 14 MW. This is too low in terms of how the M7 and M8 feeders were constructed. The use of 14 MW planning capacity in the Application was due to the limited information available to Entegrus at the time the Application was filed and was based on recent feeder construction practice. It is now known that the M7 and M8 feeders built by the St. Thomas PUC in 1997 each have a safe operating rating [redacted] and thus a higher planning capacity than the originally stated 14 MW.” -Entegrus Supplementary Evidence p.3

3.“Further, after leaving a 10% contingency [redacted] in the remaining safe operating rating to cover load increases or an abnormally high peak [redacted] remains, which Entegrus asserts is available capacity for all St. Thomas customers.” - Entegrus Supplementary Evidence p.4

4.Table 3-1 - Entegrus Supplementary Evidence p.4

5.Table 3-2 - Entegrus Supplementary Evidence p.5

6.Figure 5-2 – Application p.15

Questions:

a) Please identify the specific statements and documents in evidence that supports the [redacted] capacity of these feeders? Please also confirm this referenced value is what Entegrus assumes is the “safe operating rating” and not the “planning capacity” of the facilities.

b) Please specify what Entegrus supposes the safe operating rating value for the M7 and M8 feeder.

c) Please specify the feeder materials being referenced in the assertion that [redacted] would not cause equipment degradation.

d) Please confirm that Entegrus had built these feeders? If so, why was Entegrus unaware of the feeder ratings in its initial application?

e) Please confirm that Entegrus made the statement that Entegrus' planning capacity was 14MW in the application and therefore not an assumption made by Hydro One.

f) Please clarify/elaborate how the M7 and M8 feeders differ from the other Entegrus' feeders which have a 'planning capacity' of [redacted] and 'safe operating rating' of [redacted].

g) Please confirm reference 6 uses "planning capacity" for the feeders.

h) Conversely, it appears that Reference 3, 4 and 5, utilize the "safe operating rating" of the feeders. Please confirm, and, if so, please clarify why it is appropriate to use "safe operating rating" of the feeders for Reference 3, 4 and 5. Please update Reference 3, 4 and 5 based on the "planning capacity" of the Feeders.

Response

a) Entegrus relied upon the submission in the Formet evidence for the [redacted] capacity of the feeders. Specifically paragraphs 27, 29, 36 and Exhibit E, Section B-1. Entegrus confirms that [redacted] relates to a "safe operating rating" for the facilities.

b) Based on the information in Hydro One's supplementary evidence, Section 3.0, Entegrus understands that [redacted], consistent with Entegrus' original application. Entegrus is awaiting information on [redacted] (submitted via its Interrogatories) and [redacted]

c) Please see the response at part a).

d) As described in Attachment 3 of the Application, the M7/M8 feeders were constructed by St. Thomas PUC. Entegrus' 2022-10-17 Application considered an "approximate capacity of [redacted] each for emergency loading purposes" (p. 10), consistent with the information in the Hydro One Supplementary Evidence. See part a) for additional information.

e) Confirmed, although 14 MW represents a practice rather than an attribute of any equipment or physical restriction. As such it is subject to change as the distribution system grows in the number of sources available, the density of interconnection, and the level of automation present in the distribution network.

f) Entegrus acknowledges that the Application, filed 2022-10-17, was based on available information at the time and cited the standard Entegrus planning capacity of 14 MW.

However, thereafter, based on the Customer's 2023-04-17 Evidence at Exhibit E, Section B-1 and at paragraph 27, Entegrus confirmed that the capacity of the M7/M8 feeders [redacted] Entegrus noted the [redacted] at Section 3.2 of the Entegrus 2023-05-12 Supplementary Evidence. In response, Hydro One revealed in its 2023-05-19 Supplementary Evidence that the Hydro One in line switches at Edgeware TS are each rated at 600A, which, in turn, limits the maximum capacity rating to [redacted] for the feeders. Entegrus has sought additional clarity on the impact of Hydro One equipment on the capacity of the M7/M8 feeders in Entegrus Interrogatory #3 to Hydro One.

g) Confirmed.

h) Confirmed. References 3-5 do utilize the "safe operating rating" of the feeders. This is appropriate as the purpose of the margin between "planning capacity" and "safe operating rating" is to allow for contingency and operational flexibility. Both of these elements are shown explicitly in Tables 3-1 and Table 3-2. As such it is inappropriate to restate these in planning capacity as it would result in a double count.

INTERROGATORY: HONI-23

Ref:
1.“As a result of this strong growth, loading has reached the point where all four feeders available to the general public in St. Thomas are, on average, loaded beyond design capacity during peak periods. Accordingly, Entegrus occasionally experiences periods of time in St. Thomas where no transfer capacity remains in the event of certain single points of failure during peak loading, which can lead to extended outages.” - Application p.15

2.“For Entegrus, planning capacity represents 50% of the “safe operating rating” of the equipment as defined by the manufacturer. This definition of planning capacity has been adopted widely within the industry as a way to allow operational flexibility and to ensure adequate capacity […] is available in adjacent feeders to quickly restore customers during unplanned outages.” - Entegrus Supplementary Evidence p.1

3.“In this scenario, an additional downstream recloser is added (total of four) to allow load to be connected to the M7 and M8 feeders independently. This results in enhanced utilization of existing Entegrus assets for the purposes of Customer supply resiliency by providing two additional alternate supplies (rather than one alternate supply in Attachment 2, Figure A). The updated connection alternative is presented at Attachment 2, Figure B. This allows Entegrus to backfeed the M7 and M8 simultaneously, providing two alternate feeds to the Customer and mitigating a double M7 and M8 failure, which accordingly increases the reliability.” - Entegrus Supplementary Evidence p.5

4.“Entegrus can connect between [redacted] to [redacted] (column c and d in Table 3-2) while meeting current customer capacity requirements and remaining within safe operating rating of the feeders.” - Entegrus Supplementary Evidence p.5

Questions:

a) Please describe the capability of Entegrus Distribution feeders to take additional new load on the proposed connection to the M7 and/or M8, when, on average, the existing Entegrus Distribution feeders have already exceeded their design capacity of 14MW per feeder.

b) Given current constraints, please elaborate on how the safe operating rating of Entegrus Distribution feeders is maintained under 28MW if connecting an additional [redacted] to [redacted].

Response

a) The connection of the M7 and M8 feeders to Entegrus distribution system will result in a *reduction* of average feeder loading, as existing customers are migrated to the newly available M7/M8 supply.

b) The statements made in Reference 4 consider different parameters assumptions, which are being mixed by Hydro One above. This is further discussed in the Entegrus response to OEBStaff-4 a). In response to the information being sought, please see the updated tables provided in the response at Formet-1.

INTERROGATORY: HONI-24

Ref:
1. Attachment 3 – Entegrus Supplementary Evidence

Questions:

a) Please provide a live excel document of this Attachment.

b) Please provide a source (rate order and corresponding page) for all line loss rates utilized in the rate comparison completed.

c) Please describe how and why the loss rates have been applied in the manner proposed in the reference.

[redacted]

Response

a) Please see HONI-24, Attachment 1 filed in Excel. The Attachment has been updated to reflect part d).

b) Both loss factors can be found in the EB-2022-0026, Decision and Rate Order. The St. Thomas Rate Zone General Service 50 to 4,999 kW Service Classification loss factor used is for a Primary Metered Customer > 5,000 kW and can be found at p. 9 of the Entegrus-St. Thomas Rate Zone Tariff Sheets. The Main Rate Zone Large Use Service Classification loss factor used is for a Primary Metered Customer > 5,000 kW and can be found at p. 14 of the Entegrus-Main Rate Zone Tariff Sheets.

c) The loss rates were applied to the estimated non-loss-adjusted kWh per Hydro One's 2023-04-17 evidence, Attachment 6. As the non-loss-adjusted kWh were not provided in Hydro One's analysis at Attachment 6, Entegrus used the loss-adjusted Hydro One quantity of [redacted] and applied the corresponding Sub-Transmission - ST loss factor of 1.034 (EB-2021-0021) to arrive at the non-loss-adjusted kWh of [redacted]. Entegrus then applied the respective loss factors in part b) above to determine the loss-adjusted kWh under each Entegrus scenario.

d) Please see the response at part a) above.