Exemption Application Form

Submit this form by e-mail to: exemptions@ieso.ca

All information submitted in this process will be used by the *IESO* solely in support of its obligations under the *Electricity Act, 1998,* the *Ontario Energy Board Act, 1998,* the *market rules* and associated policies, standards and procedures and its licence. All submitted information will be assigned the appropriate confidentiality level upon receipt.

Terms and acronyms used in this Form that are italicized have the meanings ascribed thereto in Chapter 11 of the *market rules*.

Part 1 – General Information

Date Submitted to the IESO:	September 27, 2024
Organization Name:	Algoma Steel Inc.
Address:	105 West Street
City/Town:	Sault Ste. Marie
Province:	Ontario
Postal/Zip Code:	P6A 7B4
Email Address:	gordon.lees@algoma.com

Part 2 – Information About the Exemption Application

Please specify the duration for which you would like the exemption granted in days, months or years:	Algoma requests that the Exemption remain in effect concurrently until the in-service date of the project known as the Northeast Bulk System Reinforcement.
Please cite the *market rules* section number(s) or the *market manual*, policy, standard or procedure to which this *exemption application* relates:	Market Rules, Chapter 9, s.2.4A.2. Algoma understands that the relevant requirements will continue following the Market Renewal Project pursuant to the forthcoming version of Chapter 9, Section 2.5.2.

Part 3 – Type of Exemption Application Request

☒ The *exemption applicant* requests an *exemption* pursuant to section 1.6.3 of Market Manual 2.2: Exemption Applications

OR

☐ The *exemption applicant* requests an interim *exemption* pursuant to section 1.6.2 of Market Manual 2.2: Exemption Applications staying the *exemption applicant's* obligation to comply with the following *market rules* listed in Part 2 of this form

*The *IESO* recommends that the *exemption applicant* contact the *IESO's* Market Assessment and Compliance Division regarding the compliance and enforcement measures the *IESO* intends to take pending the hearing of the *exemption* as in some cases it may not be necessary for the *exemption applicant* to seek an interim *exemption*.

Part 4 – Supporting Documentation to be Attached by Exemption Applicant

The *exemption applicant* shall attach a plan detailing:

- The manner and time within which the *exemption applicant* will become compliant;
- The manner in which the *exemption applicant* proposes to modify its equipment or *facilities* or otherwise conduct its operations during the period of time for which the *exemption* would be in effect; and
- The *exemption applicant's* estimate of any costs that may be imposed on the *IESO* or on other *market participants*, if the *exemption* were granted.

Additionally, the criteria listed in section 1.5.2 of Market Manual 2.2: Exemption Applications should be considered and detailed in the *exemption applicant's* plan and as appropriate, supported by additional documentation.

1. Schedule "A" – Algoma Steel Inc.'s Submissions
2. Attachment 1— *Exemption Applicant's* Plan
3. Attachment 2 – Financial Analysis (Confidential) (Public/Redacted version attached hereto)
4. Attachment 3 – System Impact Assessment (Public)

Part 5 – Certification

The *exemption applicant* hereby declares that the information contained in and submitted in support of this document is, to the best of the *exemption applicant's* knowledge, complete and accurate.

Gordon Lees

Name

Sr Project Manager, Algoma Steel Inc.

Title

Part 6 – Confidentiality

☐ The *exemption applicant* agrees that information in this *exemption application* may be posted in its entirety on the *IESO* website

OR

☒ The *exemption applicant* claims confidentiality over parts of this *exemption application* in accordance with Section 1.6.4 of Market Manual 2.2: Exemption Applications*.* The parts of this *exemption application* over which confidentiality is claimed are highlighted. The balance of the information in this *exemption application* may be posted on the *IESO* website.

<u>**Schedule "A"**</u>

Introduction

1. Algoma Steel Inc. ("**Algoma**") is a corporation carrying out business as a steelmaker, based out of Sault St. Marie, Ontario.

2. Algoma is a market participant registered as a consumer, capacity auction participant, and capacity market participant.

3. Pursuant to the Market Rules, Chapter 1, Section 14, Algoma is applying for exemptive relief from the application of Chapter 9, Section 2.4A.2 to permit Algoma to settle energy withdrawals from its forthcoming electric arc furnaces net of injections from its 110 MW combined cycle generation facility Lake Superior Power Generation Station (the "**LSP**"), during each five-minute metering interval within a settlement hour. Further details of the exemptive relief sought is set out herein.

Background

4. Algoma is introducing two electric arc furnaces as a key element of its transition to sustainable steel production. This initiative will create 500 construction-related jobs and reduce emissions by 3 million tonnes per year by 2030, and has received support commitments from the Federal Government's Net Zero Accelerator initiative for up to $420 million**.**

5. Algoma intends to register the electric arc furnaces as a load facility consisting of an aggregated non-dispatchable load (collectively, the "**EAF**") in the IESO-administered markets ("**IAM**").

6. Algoma intends to register LSP as a generation facility consisting of the following three registered facilities that are each self-scheduling generation units:

   (a) LAKESUPERIOR-LT.STG1 ("**STG1**");

   (b) LAKESUPERIOR-LT.GTG1 ("**GTG1**"); and

   (c) LAKESUPERIOR-LT.GTG2 ("**GTG2**").

   Collectively, EAF, STGI, GTGI and GTG2 are hereby referred to as the "**Resources**".

7. The EAF and LSP are being introduced as an expansion to Algoma's existing steel mill facility which has been in operation since 1901. The steel mill is part of a contiguous site that is connected to the ICG at the following three delivery points, which are each interconnected by Algoma's internal 34 kV distribution system:

   (a) Patrick Street TS;

   (b) ASI Tube TS; and

(c) LSP.

8. Algoma acquired LSP in 2018, before which it operated as a non-utility generator, as Algoma understands.

(a) From 2018 to 2023, GTG1 operated to provide load displacement to Algoma's non-dispatchable load facility (associated with the steel mill) referred to as Patrick St. TS;

(b) In 2022 and 2023, new gas turbines were purchased as part of the EAF project, which was required for the EAF to operate in accordance with the parameters set out by the SIA;

(c) From 2018 to 2023, GTG2 and STG1 were not in operation;

(d) Since the spring of 2024, GTG1 and GTG2 have provided load displacement to Patrick St. TS;

(e) STG1 is currently being recommissioned, for the primary purpose of upgrading its controls.

9. The IESO issued a System Impact Assessment in respect of the EAF and LSP on April 21, 2023 (the "**SIA**"), the public version of which is attached hereto as Attachment 3. As a condition of authorizing for Algoma to proceed with the process of connecting the EAF, LSP and associated facilities to the IESO-controlled grid ("**ICG**"), the IESO required, among other things, that:

(a) Algoma will minimize the impact caused by the EAF's on the system by offsetting load and providing voltage support from LSP; and

(b) Each of the Resources must remain directly connected to the ICG.

10. LSP and EAF buses will be connected by a new 0.6 km underground 115 kV cable referred to as SMR 1. For the purposes of this Application, the LSP bus, EAF bus and SMR 1 circuit will be collectively referred to as the "**Bus**". The Bus is owned by Algoma; however, because it is within the operational control of the IESO, it forms part of the ICG.

11. The LSP bus connects to Hydro One Inc.'s ("**Hydro One**") Clergue TS through two underwater 115 kV circuits referred to as "**Cogen 1**" and "**Cogen 2**". Cogen 1 and Cogen 2 are each 1.5 km. Cogen 1 and Cogen 2 are also owned by Algoma, but are within the operational control of the IESO and therefore form part of the ICG.

12. The LSP and the EAF are designed in a highly integrated manner:

(a) they will be located within the geographical boundary of the existing steel mill facility;

(b) they will be connected by the Bus, which we wish to emphasize is owned by Algoma and wholly located on its premises; and

(c) they will share the same two common connections to the high voltage transmission system, which will each include a metering installation.

13. Despite that Algoma owns the Bus, which is wholly located on its real property, because it forms part of the ICG, Algoma understands that it will be responsible for incurring certain charges for withdrawing energy therefrom, including Global Adjustment and uplift.

14. Algoma intends to commission LSP for the primary purpose of mitigating the EAF's load on the ICG, notably during arcing, consistent with the terms of the SIA. Under these circumstances, energy will flow from LSP directly to the EAF via the Bus. A further requirement as per the SIA's voltage control requirements is for LSP to be connected and synchronized to the ICG during and between arcing, which consequently requires that between arcing periods LSP will inject energy into the ICG. However, there is the potential that the LSP may be used for other purposes, including for the injection and sale of electricity into the IAM or to backfeed Patrick St TS., to the extent that such energy is not required to fulfill its primary purpose of providing electricity to the EAF.

15. In the event that Algoma opts for LSP to backfeed Patrick St. TS, it anticipates achieving this mode of operation by isolating LSP from Clergue TS and by connecting the EAF bus to existing bus no 318 (which is connected to Patrick St TS) by opening switches no. 1502 and 1509 (associated with Cogen 1 and Cogen 2, respectively) and closing a 34.5KV tie between Patrick St TS and EAF systems.

16. If certain contingency events arise, namely an outage for Cogen 1 or Cogen 2, Algoma expects to configure its plant by implementing the following modes of operation:

(a) feed the EAF from Cogen 1 by opening switch no. 1509 when Cogen 2 is out of service;

(b) feed the EAF from Cogen 2 by opening switch no. 1502 when Cogen 1 is out of service;

(c) while Algoma expects for the LSP bus tie breaker 1505 to remain closed in the absence of equipment failure, in the event that there is equipment failure in respect of breaker no. 1505 or its associated isolation switches nos. 1504 and 1506, Algoma would be forced to open breaker 1505. Under this contingency scenario, GTG2 would supply EAF via the Hydro One Clergue TS substation. Algoma does not expect this to have any material impact on upstream transmission line limitations as, under these circumstances, electricity would only flow through the Hydro One tie breaker no. 205 and not impact the three 115kV upstream circuits (known as Algoma 1, Algoma 2 and Algoma 3) which are the limiting elements in the local 115kV system. Algoma does not propose to implement this mode of operation unless it receives prior approval from the IESO and Hydro One.

17. In the course of discussions with IESO staff, Algoma previously requested that the IESO provide settlement treatment for the EAF so that generation from LSP is used to offset the load from the EAF (i.e., settled on a 'net' basis, as if the LSP generators were behind the meter of EAF or vice-versa). The IESO has referred such request as one for a "by- directional station".

18. Further to discussions between Algoma and IESO staff, IESO staff has taken the position that <u>in the absence of an exemption</u>, under the operation of the Market Rules, notably Chapter 9, s.2.4A.2,

(a) the load withdrawn from the EAF must be settled on its gross consumption based on its uniquely designated delivery point rather than on a net basis from the injections of LSP; and

(b) resource aggregation between the LSP and EAF is not an available option under Section 2.3 of Chapter 7 of the Market Rules because they are different classes of registered facilities.

19. Algoma acknowledges that under the Market Rules, the IESO determines settlement amounts for each "uniquely identifiable reference point" known as a "delivery point", which is associated with one or more registered wholesale meters ("**RWMs**") associated with a registered facility/Resource.[1] As Algoma understands, Chapter 9, Section 2.4A.2 requires that, in the event that a delivery point is associated with multiple RWMs, those RWMs must correspond to a *single* registered facility. Further, Algoma understands that Section 2.3 of Chapter 7 does not permit for load equipment and generation units to be registered as an aggregated multi-directional registered facility. As such, to achieve the desired settlement outcome, as described below, Algoma is requesting that the IESO designate two delivery points to form the basis of the settlement for the Resources.

20. Under the proposed configuration, (a) a generation delivery point will be designated for all of the Resources and will be the subject of settlement charges when there is a <u>net injection</u> over the course of a 5-minute metering interval. Similarly, (b) a second delivery point, a load delivery point, will also correspond to all of the Resources, and will be the subject of settlement charges when there is a <u>net withdrawal</u> over the course of a 5-minute metering interval. As Algoma understands, this configuration would otherwise be unavailable due to Chapter 9, Section 2.4A.2 because the Resources consist of four registered facilities (i.e., more than one registered facility), and because aggregating load resources with generation resources is not available under the IESO's interpretation of Chapter 7, Section 2.3.

21. Algoma proposes to continue participating in the Capacity Market as a physical hourly demand response ("**HDR**") resource. Algoma currently participates in the capacity market as an HDR resource associated with Patrick St. TS. To facilitate Patrick St. TS's participation in the capacity market, Algoma backfeeds Patrick St TS from the LSP. After the EAF is in service, Algoma may wish to register the EAF as a physical HDR resource as well. Algoma understands that if EAF participates as an HDR resource, generation supplied from LSP to the EAF will be considered as part of the calculation of its baseline consumption determined for the purposes of participating in the capacity market**.**

Exemptive Relief Sought

22. Algoma requests that the IESO grant exemptive relief from the application of Chapter 9, Section 2.4A.2, to the extent necessary to permit the Resources to share two by-directional delivery points, one to be used for a net injection scenario, and another to be used for a net withdrawal scenario, as described in paragraph 20, so that the EAF's real-time market settlement amounts are derived based on the difference between (1) injections from STG1, GTG1, GTG2, and (2) withdrawals from the EAF (i.e., aggregated EAF-LT-LOAD1 and EAF-LT.Load2), during each

[1] Market Rules, Chapter 9, Section 2.4A.2; Chapter 11, "delivery point".

five-minute metering interval, summed during the settlement hour (collectively, the "**Exemption**"). For the avoidance of doubt, Algoma is *not* requesting the IESO to register the Resources as single aggregated by-directional registered facility. The settlement treatment sought by the Exemption is depicted in the following formula:

222737 – LAKESUPERIOR-LT.GTG1: DP/RWM=$(MC_{cogen1} + M_{cogen2})_{\text{INJECTED Quantity}}$

– EAF-LT.LOAD1: DP/RWM=$(M_{cogen1} + M_{cogen2})_{\text{WITHDRAWN Quantity}}$

23. Algoma requests that the Exemption remain in effect concurrently until the in-service date of the project known as the Northeast Bulk System Reinforcement. To the best of Algoma's knowledge, the Northeast Bulk System Reinforcement is expected to go in service in 2029.

24. To the extent that Chapter 9, Section 2.4A.2 is amended as part of the IESO's Market Renewal Program, the Exemption shall apply *mutatis mutandis* to the equivalent obligations. To this end, Algoma understands that the relevant requirements will continue following the Market Renewal Project pursuant to the forthcoming version of Chapter 9, Section 2.5.2.

Analysis: Criteria provided by Market Manual 2.2, section 1.4.2

25. Algoma submits that, on balance, the criteria provided by section 1.4.2 of Market Manual 2.2 overwhelmingly militate in favour of granting the Exemption.

The Exemption will not result in an adverse impact to the ICG or the IAM

26. The Exemption will not impact the ability of the IESO to direct the operations and maintain the reliability of the ICG. The Exemption deals uniquely with the settlement treatment of the specified generation facility and load facility and does not seek to derogate from requirements relating to the operation of such facilities or any equipment. Further, Algoma does not propose to depart from the requirements set out in the SIA, which the IESO determined would allow for the EAF and LSP to operate without material adversely impacting the reliability of the integrated power system.[2]

27. Further to discussions with IESO staff, Algoma understands that allowing netting between the resources for each five-minute metering interval is compatible with the IESO's settlement tools and processes which establish RWM readings for every five-minute metering interval.

28. For the same reasons described in paragraph 26, Algoma submits that the Exemption will not impact the ability of the IESO to ensure non-discriminatory access to the ICG, nor will it affect the ability of the IESO to operate the IAM in an efficient, competitive and reliable manner.

The Exemption will not result in undue preference in the IAM

29. The Exemption will not result in Algoma receiving unduly preferential treatment in the IAM relative to similarly situated market participants. Rather, for the reasons that follow, Algoma submits the Exemption will create a fair settlement outcome that accurately and fairly reflects the quantity of energy that Algoma withdraws from the ICG. To this end, the Exemption would

[2] SIA, p.8.

function to assign Algoma an accurate proportion of the total monthly Global Adjustment charges assessed by IESO based on Algoma's net use, but the Exemption would not change the total Global Adjustment collected by IESO on a monthly or annual basis.

30. By seeking the Exemption, Algoma is merely intending to remedy what it submits is an inequitable outcome caused by the self-contained nature of LSP's primary mode of operation which is ultimately required to mitigate the shortcomings of the ICG. Algoma is seeking for the EAF to be settled net of injections provided by LSP to ensure that certain settlement charges, including to Global Adjustment and uplift, reflect energy that it purchases from the IAM from *other* market participants. In other words, Algoma is seeking to pay settlement charges based on its *net* energy withdrawals, which is exclusive of quantities supplied by LSP.

31. Conversely, in the absence of the Exemption, Algoma will be forced to incur these incremental settlement charges for buying back its own energy which Algoma,

(a) holds title to;

(b) generates on the same geographical boundary, and, shares the same connections to the ICG, as the load (i.e., the EAF); and

(c) directly conveys to the EAF by the Bus owned by Algoma and wholly located on its real property.

Adding to the inequity of this outcome, incurring the incremental settlement charges on the EAF's gross withdrawals would be tantamount to requiring Algoma to provide a subsidy to other market participants for the maintenance of the broader ICG and for the IESO's acquisition of electricity under contract. This is particularly troublesome in light of the self- contained nature of Algoma's primary use of LSP, and of the reality that Algoma is commissioning LSP because the ICG cannot support the EAF without it, as described above.

32. The Exemption will not provide Algoma with a competitive advantage over other market participants. Given that Algoma's generation facilities are registered self-scheduling generation resources – which act as price takers in the IAM – their production is based on the operation of the EAF and is not tied to the market signals in the IAM. Similarly, on the load side, Algoma's load facilities, including the EAF, will operate as a non-dispatchable load, as a price taker. As such, the proposed exemption will not place Algoma in a preferential position by displacing otherwise competitive offers from dispatchable generators or competitive bids from dispatchable loads. The financial consequences of the proposed exemption are self-contained to Algoma.

33. Further, the settlement outcome sought by the Exemption is appropriate because it is consistent with LSP's uniquely self-contained operational characteristics in the ICG, notably, by performing the following functions in accordance with the requirements of the SIA:

(a) mitigating the system impacts of the EAF arcing;

(b) operating in manner that is highly integrated with EAF; and

(c) operating in a manner that is self-contained to Algoma with limited, if any, operational and financial impacts to the broader ICG or other market participants.

In addition, given LSP's unique role vis-à-vis the EAF, it is not similarly situated to merchant generation facilities which participate in the IAM with commercial purposes. In other words, the proposed difference in treatment is justified by a difference in circumstances from other market participants.

Algoma would incur unreasonable costs with the Market Rules in the absence of the Exemption

34. For all of the reasons discussed above, Algoma submits it is unreasonable and inequitable in the circumstances for Algoma to incur settlement charges for EAF's consumption without offsetting the energy that LSP will convey to the EAF via the Bus during the relevant five-minute metering interval.

35. Further, the extent of the unreasonable and inequitable outcome of incurring these costs in the circumstances is heightened by the exorbitant incremental costs that Algoma would expect to incur in the absence of the Exemption, which is expected to amount to approximately $35M over the course of a year. Details supporting this analysis is set out in Attachment 2. This analysis does not consider transmission-related charges, which are not within the scope of the Exemption.

The Exemption Plan is complete

36. The Exemption Plan is complete as it contains all of the information required by Market Manual 2.2, section 1.6.3.

Timing considerations

37. Algoma recognizes that the regime under Section 2.4A.2 of Chapter 9 predates the operation of the facilities subject to the Exemption. Algoma only received commitments for Federal funding for the EAF in 2021, and the proposed configuration of LSP is intended to allow the EAF to operate without adverse system impacts, as detailed in the SIA. However, the considerations provided by Market Manual 2.2, s.4.2 are criteria that the IESO must holistically consider, and they do not constitute a list of cumulative requirements which must each be met. On balance, the factors overwhelmingly militate in favour of granting the proposed exemption.

Algoma will be capable of operating the EAF and LSP in accordance with the terms and conditions of the Exemption

38. Algoma will be capable of operating the EAF and LSP in accordance with requirements provided in the SIA.

The Exemption furthers the statutory objective of promoting cleaner sources of energy in accordance with provincial policy

39. Noting that the following consideration is not explicitly provided by section 1.4.2 of Market Manual 2.2, Algoma submits that the Exemption should be granted because it furthers the

statutory objective of the *Electricity Act, 19*98 "to promote the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources, in a manner consistent with the policies of the Government of Ontario."[3] The EAF is being introduced to replace a high-emitting coal furnace. Ontario's climate change strategy[4] contemplates the policy goal of "[f]inish[ing] the phase out of coal by supporting efforts of Ontario industry to reduce their greenhouse gas emissions by reducing and phasing out their use of coal."[5] Further, the Provincial Government has expressed support for replacing coal facilities with electric facilities in the steel sector, and has contributed to financing the introduction of electric steelmaking equipment to this end.[6]

40. Given that Algoma is introducing the EAF as a cornerstone of its a broader decarbonization policy initiative, and that LSP is being configured for the primary purpose of supporting the EAF, the Exemption will alleviate the above-noted financial prejudice to Algoma for responsibly implementing provincial decarbonization policy, which it would otherwise incur due to a likely unintended technicality in the Market Rules. Therefore, Algoma submits that granting the Exemption represents the exercise of discretion that is most consistent with the relevant purpose of the IESO's enabling statute.

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[3] Electricity Act, 1998, S.O. 1998, c. 15, Sched. A (the "***Electricity Act, 1998***"), s.1(g).
[4] Ministry of the Environment, Conservation and Parks, *Preserving and Protecting our Environment for Future Generations: A Made-in-Ontario Environment Plan* (November 2018).
[5] *Ibid*.
[6] Ontario, "Ontario Secures Major Investment in Clean Steelmaking Technology in Sault Ste. Marie", News Release (November 12, 2021).

Attachment 1 – Exemption Plan

1. *The manner in which the exemption applicant proposes to operate or modify its equipment or facilities or otherwise conduct its operations, or in the case of the IESO, to operate the IESO-administered markets or direct the operations and maintain the reliability of the IESO-controlled grid, during the period of time for which the exemption would be in effect so as to operate in a manner that achieves, as closely as possible, the objectives of the obligation or standard to which the exemption application relates*

   N/A as Algoma does not propose to operate its facilities or equipment in a manner that is prohibited by the Market Rules. Rather, the Exemption seeks to derogate from Market Rules that pertain to market settlement, which do not have any implications on Algoma's physical operations in the IAM or on the ICG. As stated in the body of Schedule "A", the Exemption seeks settlement treatment to be based on EAF's withdrawals net of any offsetting injections from LSP for each five-minute metering interval. This reflects the unique and self-contained role of LSP to mitigate system impacts of the EAF. Given that the Exemption is merely seeking to remedy what Algoma alleges is an unjust settlement outcome, Algoma believes that it is not appropriate for Algoma to modify its facilities or equipment or conduct in the circumstances.

2. *The manner and time within which the exemption applicant will become compliant with the obligation or standard to which the exemption application relates*

   Algoma expects to be able to comply with the requirements of Section 2.4A.2 of Chapter 9 following the in- service date of the project known as the Northeast Bulk System Reinforcement. To the best of Algoma's knowledge, the Northeast Bulk System Reinforcement is expected to go in service in 2029.

3. *The exemption applicant's estimate of any costs that may be imposed on the IESO or on other market participants, if the exemption were granted.*

   Algoma does not believe that the Exemption will impose any cost on other market participants or the IESO. Rather, Algoma is merely requesting that its settlement reflect the net quantity of energy withdrawn from EAF, rather than including the gross quantities which are inclusive of its own energy injected by LSP.

Attachment 2 - Financial Analysis
(Public/Redacted Version)

Scenarios	Description	Load Profile (Note 1)	Energy Purchased (1hr) (MWH's)	Energy Sold (1hr) (MWH's)	Energy Charge (HOEP)	Misc Energy Charges	GA Charges (Note 2)	Total
No Exemption	LSP sells all MW's into the Market	[redacted]			Same in all scenarios	$	$	$
With Exemption	Cogen 1 & 2 Settle as a bi-directional delivery points each hour	[redacted]			Same in all scenarios	$	$ [redacted]	$
							Delta	$ 34,979,235

Notes: 1	This is a typical profile during Phase 1 operation but there will be a wide variation of actual hourly profiles. This "typical" profile provides a good approximation of average operation over a year for cost estimation and comparison.
2	Assumes

Charge Rates Used:

Misc. Energy Charges $ 5.00 2023 actual $/MWh

GA $6.7 Billion Estimate for 2026

Attachment 3 –System Impact Assessment (Public)

System Impact Assessment Report

Final Report - Public

CAA ID: 2021-694 and 2021-695
Project: Algoma Steel – New Load Facility and Lake Superior Power CGS – Generation Reconfiguration
Connection Applicant: Algoma Steel Inc.

April 21, 2023

Connecting Today.
Powering Tomorrow.

Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of conditional approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Conditional approval of the project is based on information provided to the IESO by the connection applicant and Hydro One at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by Hydro One at the request of the IESO. Furthermore, the conditional approval is subject to further consideration due to changes to this information, or to additional information that may become available after the conditional approval has been granted.

If the connection applicant has engaged a consultant to perform connection assessment studies, the connection applicant acknowledges that the IESO will be relying on such studies in conducting its assessment and that the IESO assumes no responsibility for the accuracy or completeness of such studies including, without limitation, any changes to IESO base case models made by the consultant. The IESO reserves the right to repeat any or all connection studies performed by the consultant if necessary to meet IESO requirements.

Conditional approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed project to the IESO-controlled grid. However, the conditional approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter(s) during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. This report does not in any way constitute an endorsement of the proposed connection for the purposes of obtaining a contract with the IESO for the procurement of supply, generation, demand response, demand management or ancillary services.

The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, the connection applicant must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to the connection applicant. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used.

Hydro One

The results reported in this report are based on the information available to Hydro One, at the time of the study, suitable for a System Impact Assessment of this connection proposal.

The short circuit and thermal loading levels have been computed based on the information available at the time of the study. These levels may be higher or lower if the connection information changes as a result of, but not limited to, subsequent design modifications or when more accurate test measurement data is available.

This study does not assess the short circuit or thermal loading impact of the proposed facilities on load and generation customers.

In this report, short circuit adequacy is assessed only for Hydro One circuit breakers. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One circuit breakers and identifying upgrades required to incorporate the proposed facilities. These results should not be used in the design and engineering of any new or existing facilities. The necessary data will be provided by Hydro One and discussed with any connection applicant upon request.

The ampacity ratings of Hydro One facilities are established based on assumptions used in Hydro One for power system planning studies. The actual ampacity ratings during operations may be determined in real-time and are based on actual system conditions, including ambient temperature, wind speed and facility loading, and may be higher or lower than those stated in this study.

The additional facilities or upgrades which are required to incorporate the proposed facilities have been identified to the extent permitted by a System Impact Assessment under the current IESO Connection Assessment and Approval process. Additional facility studies may be necessary to confirm constructability and the time required for construction. Further studies at more advanced stages of the project development may identify additional facilities that need to be provided or that require upgrading.

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Project Description

Algoma Steel Inc. (the "connection applicant") is proposing to connect a new load facility for two new Electric Arc Furnaces (EAF), namely EAF CTS (CAA 2021-694), and re-connect the load displacement generators GTG-1 (42.5 MW of gas) and STG-1 (25 MW of steam) from Patrick St. TS (CAA 2021-695) back to their original configuration at the 115 kV Lake Superior Power (LSP) CGS bus. These two generator units along with the existing LSP CGS GTG-2 (42.5 MW) gas unit, which is not currently operating, will be in-service during EAF operation to offset the EAF's load and provide voltage support. All the above changes will be referred to as the "project" in this report.

EAF CTS will connect to LSP CGS via one new 0.6 km underground 115 kV cable. It will be supplied by two 115/34.5 kV 200 MVA step-down transformers with associated circuit breakers and disconnect switches, including switches intended for future connection to a 230 kV system supply. Figure 1, included in Appendix B: Project Data (Confidential), shows the single line diagram of the project and surrounding area.

The instantaneous peak load at EAF CTS can be as high as 140 MW and will ramp up and down between 0 and 140 MW between 30-60 times per day. Each ramping operation will occur within seconds. The power factor of the EAF load remains constant at 0.97 lagging at all times, including during ramping.

A new auxiliary load of 20 MW required for the EAFs operation will be added at the connection applicant's Patrick St. TS facility, while 8 MW of existing load at Patrick St. will be removed.

The connection applicant intends to operate EAF CTS, LSP CGS and Patrick St. TS facilities such that the net sum of the instantaneous peak load from all three facilities, as measured at their low voltage side of the 115 kV transformers at these three facilities, under normal operating conditions ("Algoma load") will not exceed 188 MW without the EAFs operating, and 218 MW during EAF operation.

When the EAF is not operating, the connection applicant plans to utilize the full capability of LSP to offset 110 – 120 MW of load at its Patrick St. TS facility by opening the 115kV connection to Clergue TS, and connecting to Patrick St. TS through a normally open low voltage tie circuit stemming from the EAF 34.5 kV bus.

The LSP CGS bus connects to Hydro One Inc.'s ("H1 transmitter") Clergue TS through COGEN#1 and COGEN #2 115 kV circuits, which are owned by the connection applicant.

In addition, as part of this project, all LSP CGS units will have their governors upgraded; GTG-1 and GTG-2 will have their rotors and stators rewound. Once these upgrades are complete, GTG-1 and STG-1 will initially be reconnected to their existing low-voltage bus at Patrick St. TS prior to being reconfigured to connect at the LSP 115 kV bus in Q4, 2023.

The in-service date of the EAF is expected to be Q1 2024.

Notification of Conditional Approval

This assessment concludes that the proposed connection of the project is expected to have no material adverse impact on the reliability of the integrated power system, provided that all requirements in this report are implemented. Therefore, the assessment supports the release of the Notification of Conditional Approval for connection of the project.

Assessment Findings

System impact studies were carried out to assess the impact of the project in accordance with Chapter 8 of Market Manual 1.4. The studied scenarios and main assumptions are available in Appendix D and detailed study results are available in Appendix E of this report. Based on the assessment results, we have identified the following findings:

1. The project load will reduce steady-state voltage performance in the Hydro One Sault Ste. Marie system during all elements in-service and outage conditions. This can be addressed by adding 75 MVar of reactive compensation. Installing two steps of 37.5 MVar each would satisfy the voltage change criteria of 4% for capacitor switching.
2. With any two transmission elements out of service, the addition of the project exacerbates or creates new post-contingency low-voltage violations and thermal overloading violations, which require up to 350 MW of total load interruption to address. Today, without the project, up to 310 MW of load interruption is required to address similar violations. The amounts of load that would need to be interrupted both today and with the project in-service are greater than the 150 MW allowed by the ORTAC (Ontario Resource and Transmission Assessment Criteria) load security requirement for two transmission elements out of service. For the current system, this has been grandfathered, given the system in this area was not originally designed meet all of today's ORTAC requirements. The IESO is currently in the process of addressing this issue through a Northeast bulk system planning study and an Integrated Resource Regional Plan (IRRP). In the interim, project's contribution to the thermal and voltage issues will be addressed through automatic load rejection by Remedial Action Schemes (RAS)s.
3. As a result of the amount of automatic load rejection required to resolve thermal and voltage issues for two elements out of service conditions, high voltages up to 263 kV could occur at Hanmer TS, Algoma TS, Wawa TS, Mississagi TS and Third Line TS. These voltages are acceptable for up to 30 minutes and there are control actions available within 30 minutes to reduce the voltages below the maximum continuous voltages.
4. At Mississagi Flow West (MISSW) flows above 700 MW, which may be needed to supply future loads connecting west of Mississagi, the system could inadvertently separate east of Mississagi TS following the loss of A23P and A24P under all-in-service conditions or the loss of S22A or X27A under outage conditions because of encroachment on protective relays on circuits X74P, S22A and X27A.

5. For certain recognized planning events involving transmission elements near the project, e.g. Breaker Fail (BF) of Third Line breaker 402, excessive area wide voltage decline occurs due to the addition of the project. This issue can be addressed by a voltage-based load rejection scheme located at the project.
6. In the SSM area, the system is operated within a tighter voltage range, 118-124 kV, than the rest of the system. The changes to voltages introduced by the ramping of the EAF will make operating within this range even more challenging.
7. The ramping of the EAF from 0 to 140 MW and vice versa results in material local voltage changes in the SSM area. Because of the frequency of voltage changes, both H1 transmitter and SSM PUC concluded that voltage changes in excess of 2% are not acceptable. This constraint is aligned with the Transmission System Code (TSC) Appendix 2 requirements.

   Our studies identified that 105 MVar of fast-response dynamic Vars would maintain the local voltage changes within 2% for a 140 MW load fluctuation. This amount of dynamic reactive power could be sourced from the LSP generators and other devices. Please note this amount of reactive power is not in addition to, and would satisfy, the reactive power compensation mentioned in Finding #1 above.
8. The ramping of the EAF results in material voltage changes at transmission stations in the bulk system as far east as Hanmer TS. Because of the frequency of voltage changes, H1 transmitter has confirmed that, in order to maintain acceptable voltage performance for the existing customers and avoid excessive wear and tear on their equipment, voltage changes in excess of 2% are not acceptable.

   Studies indicate that excessive voltage changes occur under heavy flows on the MISSW interface. While the IESO will deploy available resources to minimize grid voltage changes, there may be times when those resources are insufficient. At those times, EAF operation will be restricted. Based on historical flows and system conditions, EAF operation would be restricted for about 2% of the time annually. More information regarding system conditions under which EAF will be restricted and the degree of EAF restriction will be determined during the Market Registration stage, and will be subject to updates during operations planning and real-time operation as system conditions change.
9. The ramping of the EAF load will cause significant swings in active power (MW) flow through critical interfaces in Northeastern and Northwestern Ontario. Maintaining power flows within the operating security limits will require careful coordination of EAF operation with IESO's operations planning and real-time operations teams.
10. The full ramping of the EAF load could result in a change of 12.7 MW on the Minnesota interconnection and a total of 20 MW on the Manitoba interconnection. Minnesota phase shifters will automatically change tap positions should the difference between the actual and scheduled flows exceed 10 MW. Manitoba phase shifters will automatically change tap positions should the difference between the actual and scheduled flows exceed 25.6 MW. Minnesota Power and Manitoba Hydro have been informed of the results of this study and have agreed to

monitor the additional duty on the phase shifters once the project goes in-service to determine whether further investigation is needed.

11. For an outage to the main protection of T6 at Patrick St. TS, which has no fast redundant protection, a three phase fault or line-ground fault close to the Patrick St. TS bus, will cause the LSP CGS units to go unstable as the fault will remain on the bus until cleared by back-up protection after 1.3 seconds. If backup protection timing can be improved to clear a fault within 120 ms, units at LSP CGS will remain stable.

IESO Requirements for Connection

Specific Requirements:

The following specific requirements are applicable for the incorporation of the project and its connection facilities. Specific requirements pertain to the level of reactive power compensation needed, operation restrictions, remedial action scheme, upgrading of equipment and any project specific items not covered in the general requirements.

Requirements for the Connection Applicant

1. Ensure that the instantaneous peak Algoma load does not exceed 188 MW without EAF operation, or 218 MW during EAF operation with LSP generation in-service. The connection applicant must have measures in place to reduce its load within 5 minutes in the event the 188 MW, or 218 MW limit, are inadvertently exceeded; exceedance of these limits during normal operations is not allowed.
2. To support the levels of Algoma load described in requirement #1 above, LSP units must operate in voltage control mode and the connection applicant must install the equivalent of 75 MVar additional reactive support at its facilities. Two 37.6 MVar shunt capacitors rated at 34.5 kV would be acceptable.
3. Operate at voltages between 118 kV and 124 kV at its connection point. However, if current local voltage restrictions are relaxed or lifted in the future, the connection applicant shall be able to operate within normal voltage ranges, i.e., 113 kV to 127 kV.
4. Ensure that the operation of the EAF does not result in a local voltage change that exceeds H1 transmitter's and SSM PUC's 2% voltage change threshold. This could be achieved by installing locally placed fast-acting reactive compensation device(s) (i.e. SVC, Statcom, etc.) or, if feasible, by coordinating its own local reactive devices in a manner that is acceptable to the IESO, H1 transmitter and SSM PUC. The solution to satisfy the local voltage change needs shall be presented to the IESO and H1 transmitter for evaluation at least twelve months before the in-service date of the project.

5. Provide single points of contact to the IESO, reachable 24/7, and have those contacts participate in operations planning and real-time operations processes to allow for:
   a. the IESO be aware of the intended next-day and real-time operations of the facility, and
   b. the connection applicant to be aware when EAF operation needs to be restricted to accommodate system conditions, including outages, as communicated by the IESO market forecasts and integration team (MFI) or the IESO control room.
6. Have a demand management procedure acceptable to the IESO and H1 transmitter that ensures that the EAF operation can be curtailed within 5 minutes. The need for load curtailment could occur when H1 transmitter's 2% voltage change criterion is at risk of being violated, during outages to LSP CGS units, or during any other operating situations where the IESO cannot manage the power or voltage fluctuations triggered by the EAF's operation.

   The demand management procedure must be subject to the following conditions:

   a. Reduce up to the entire project load, upon direction by the IESO, within 5 minutes; failure to follow the direction could result in immediate disconnection of the project from the transmission grid;

   b. Set up a dedicated direct line for the IESO and H1 transmitter to reach the facility control room, which will be staffed at all times when the EAF is in-service; and,

   c. Prepare a detailed procedure outlining how the EAF load reduction and/or EAF shutdown will be implemented. The procedure is to be approved by IESO and H1 transmitter.
7. The connection applicant shall install RAS facilities to participate in the following Remedial Action Schemes (RAS) that will automatically disconnect the EAF load for system events: Third Line Instantaneous Load Rejection Scheme and Northwest RAS. EAF loads must be rejected within 66 ms upon receipt of the signal from the applicable schemes.

   The connection applicant shall ensure that the RAS facilities comply with NPCC Reliability Reference Directory #7 as per the RAS type classification which will be finalized during the Market Registration process. To avoid any delay to the project, it is strongly recommended the RAS facilities be designed to meet NPCC Reliability Reference Directory #7 for NPCC Type I RAS before the RAS type classification is finalized. If deemed or expected to be a Type II or Limited Impact RAS, the connection applicant shall ensure the RAS facilities have provisions to comply with NPCC Reliability Reference Directory #7 for Type I RAS in case the RAS is re-classified as NPCC Type I RAS in the future as the system evolves.

   Telemetry, including but not limited to, MW, MVar and breaker status for the feeders/equipment tripped by the RAS, as specified by the IESO at the time of registration, shall be provided.
8. To prevent area wide voltage decline, install a voltage-based tripping scheme that will automatically disconnect one or all of its EAF(s) for voltages below 108 kV at the EAF 115 kV

bus within 1 second. All capacitors and LSP generator units shall remain in-service. Any other proposed settings will need to be approved by the IESO.

9. Ensure the LSP generators, exciters and power system stabilizers of GTG-1, GTG-2 and STG-1 meet, at a minimum, the original performance requirements applicable to them when the units were once connected directly to the 115 kV LSP CGS bus, in the event they are not able to meet the prevailing performance requirements as per Market Rules Appendix 4.2.
10. Be prepared to re-incorporate LSP units GTG-1 and STG-1 into the Mississagi Generation Scheme in the future if there is a need, upon request from the IESO.
11. To address Finding 11, the backup protection timing for Patrick St. T6 needs to be improved to clear a fault within 120 ms; otherwise T6 must be removed from service should the main protection be out-of-service. The connection applicant must work with H1 transmitter and SSM PUC to confirm what other equipment at the Patrick St. 115 kV bus may also be required to be taken out of service should equipment have similar protections to T6 in place, if improvements to back-up timing allowing the LSP CGS units to remain stable, cannot be made.

    This requirement must be fulfilled prior to LSP CGS being reconfigured in Q4, 2023.
12. The connection applicant shall provide the missing governor model for STG-1 during the Market Registration process.

Requirements for H1 Transmitter

1. H1 transmitter shall include the project in the Third Line Instantaneous Load Rejection Scheme, and NW RAS (formerly Northwest SPS2) as per Appendix F of this report. During the IESO Market Registration process, a revised Facility Description Document (FDD) for both the Third Line Instantaneous Load Rejection Scheme and NW RAS (formerly Northwest SPS2), must be provided and finalized at least twelve months prior to in-service. The FDD must contain the finalized RAS matrix as well as expected operating times. The actual operating times must be measured during commissioning and documented as a Performance Validation Record.

    If the FDD or performance testing as per the Performance Validation Record indicates a change in design or slower than expected operating times, as compared to what was assumed in this assessment, then further analysis of the project will need to be done by the IESO. This may delay the grant of IESO final approval to place the project in-service.

    The H1 transmitter shall ensure that the RAS facilities comply with NPCC Reliability Reference Directory #7 as per the RAS type classification which will be finalized during the Market Registration process. To avoid any delay to the project, it is strongly recommended the RAS facilities be designed to meet NPCC Reliability Reference Directory #7 for NPCC Type I RAS before the RAS type classification is finalized. If deemed or expected to be a Type II or Limited Impact RAS, the transmitter shall ensure the RAS facilities have provisions to comply with NPCC Reliability Reference Directory #7 for Type I RAS in case the RAS is re-classified as NPCC Type I RAS in the future as the system evolves.

Telemetry, as specified by the IESO at the time of registration, shall be provided.

This requirement must be fulfilled prior to the EAF coming into service in Q1 2024.

2. Patrick St. T6 must be removed from service should the main protection be out-of-service, unless backup protection timing can be improved to clear a fault within 120 ms. H1 transmitter must work with the connection applicant and SSM PUC to confirm what other equipment at the Patrick St. 115 kV bus may also be required to be taken out of service or require protection timing improvement should equipment have similar protections to T6 in place.

   This requirement must be fulfilled prior to LSP CGS being reconfigured in Q4, 2023.

General Requirements:

The connection applicant shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code (TSC) and reliability standards. Some of the general requirements that are applicable to this project are presented in detail in Appendix A: General Requirements of this report.

Recommendation

1. To relieve the number of times static reactive devices may need to be switched, it is recommended that H1 transmitter and SSM PUC examine possible solutions to addressing the operating voltage limitations at Third Line TS. Today, the acceptable continuous voltage range at the station is 118 kV to 124 kV whereas the ORTAC requirement should be between 113 kV to 127 kV.

2. The transmitter is recommended to modify the relay characteristics of circuits X74P, X27A and S22A and/or decrease the timing of the Third Line RAS L/R function. This will enable higher MISSW transfers without the risk of post-contingency system separation mentioned in finding 4.

Appendix A: General Requirements

The connection applicant shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code and reliability standards. This section highlights some of the general requirements that are applicable to the project.

The following requirements, i.e. (1) – (9), apply to both Algoma Steel – New Load Facility (CAA 2021-694) and Lake Superior Power CGS – Generation Reconfiguration (2021-695) portions of the project:

1. The connection applicant must notify the IESO at connection.assessments@ieso.ca as soon as they become aware of any changes to the project scope or data used in this assessment. The IESO will determine whether these changes require a re-assessment.

2. The connection applicant shall ensure that the BPS elements are in compliance with the applicable NPCC criteria and the BES elements in compliance with the applicable NERC reliability standards. To determine the standard requirements that are applicable, the IESO provides mapping tools titled "NPCC Criteria Mapping Spreadsheet" for BPS elements and "NERC Reliability Standard Mapping Tool/Spreadsheet" for BES elements at the IESO's website of Applicability Criteria for Compliance with Reliability Requirements.

   Note, the connection applicant may request an exception to the application of the BES definition. The procedure for submitting an application for exemption can be found in Market Manual 11.4: "Ontario Bulk Electric System (BES) Exception" at the IESO's website.

   The IESO's criteria for determining applicability of NERC reliability standards and NPCC Criteria can be found in the Market Manual 11.1: "Applicability Criteria for Compliance with NERC Reliability Standards and NPCC Criteria" at the IESO's website.

   Compliance with these reliability standards will be monitored and assessed as part of the IESO's Ontario Reliability Compliance Program. For more details about compliance with applicable reliability standards reliability standards, the connection applicant is encouraged to contact orcp@ieso.ca and also visit the Ontario Reliability Compliance Program webpage.

   However, like any other system element in Ontario, the BPS and BES classifications of the project will be periodically re-evaluated as the electrical system evolves. Newly identified BPS and BES facilities associated with this project are listed in Appendix C.

3. The connection applicant shall ensure that the project's equipment meet the voltage requirements specified in section 4.2 and section 4.3 of the Ontario Resource and Transmission Assessment Criteria (ORTAC).

4. According to Section 6.1.2 of the TSC, the connection applicant must ensure the project's transmission connection equipment is designed to withstand the fault levels in the area. According to Section 6.4.4 of the TSC, if any future system changes result in an increased fault level higher than the project's equipment capability, the connection applicant is required to

replace that equipment with higher rated equipment capable of withstanding the increased fault level, up to the maximum fault level specified in Appendix 2 of the TSC.

It is the connection applicant's responsibility to verify that all equipment and circuit breakers within the project are appropriately sized for the local fault levels.

The connection applicant shall ensure that the circuit breakers/switchers installed at the project have rated interrupting time that satisfies Appendix 2 of the TSC. Fault interrupting devices installed at the project must be able to interrupt fault currents at the applicable maximum continuous voltage as specified in Section 4.2 and Section 4.3 of ORTAC.

5. The connection applicant shall ensure that the protection systems are designed to satisfy all the requirements of the TSC. New protection systems must be coordinated with existing protection systems. Protection systems within the project shall only trip the appropriate equipment isolating the fault.

   Associated overvoltage protective relaying must be set to ensure that the project's equipment does not automatically trip for voltages up to 5% above the equipment's corresponding maximum continuous voltage as specified in section 4.2 of the ORTAC.

   BPS elements are deemed by the IESO to be essential to system reliability and security and must be protected by redundant protection systems in accordance with Section 8.2 of the TSC. These redundant protection systems must satisfy all requirements of the TSC, and in particular, they must be physically separated and not use common components, common battery banks, or common instrument transformer secondary windings.

   The protection systems for transmission voltage BES elements (whose rated voltage is higher than 100 kV) must be redundant. Redundancy must be present in protective relaying for normal fault clearing and control circuitry associated with protective functions including trip coils of the circuit breakers or other interrupting devices. These redundant protection systems must not use common instrument transformer secondary windings. A single communication system, if used, must be monitored and reported and a single DC supply, if used, must be monitored and reported for both low voltage and open circuit.

   As the electrical system evolves, transmission voltage non-BPS or non-BES elements (whose rated voltage is higher than 100 kV) within the project, may be re-classified as BPS elements or BES elements. The connection applicant is recommended to design the protection systems for these elements according to the protection requirements for BPS elements or have adequate provisions for future upgrade to meet those requirements.

   The connection applicant shall ensure that the project's automatic reconnection capability, if available, be disabled. Upon its disconnection following a contingency, the connection applicant must obtain the IESO's approval before reconnecting the project to the IESO-controlled grid.

6. The connection applicant shall ensure that the connection equipment is designed to be fully operational in all reasonably foreseeable ambient conditions. Failures of the connection

equipment must be contained within the project and have no adverse impact on the IESO-controlled grid.

7. The connection applicant must initiate the IESO's Market Registration process at least eight months prior to the commencement of any project related outages.

   The connection applicant is required to provide "as-built" equipment data for the project during the IESO Market Registration process. If the submitted equipment data differ materially from the ones used in this assessment, then further analysis of the project may need to be done by the IESO before final approval to connect is granted.

   Models and data, including any controls that would be operational, must be provided to the IESO. This includes both PSS/E and DSA software standard library models representing the new equipment for further IESO, NPCC and NERC analytical studies. The models and data may be shared with other reliability entities in North America as needed to fulfill the IESO's obligations under the Market Rules, NPCC and NERC rules. The connection applicant may need to contact the software manufacturers directly, in order to have the models included in their packages. This information should be submitted at least eight months before energization to the IESO-controlled grid, to allow the IESO to incorporate this project into IESO work systems and to perform any additional reliability studies.

   As part of the IESO Market Registration process, the connection applicant must also provide evidence to the IESO confirming that the project's equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in this assessment. This evidence shall be either type tests done in a controlled environment or commissioning tests done on-site. In either case, the testing must be done not only in accordance with widely recognized standards, but also to the satisfaction of the IESO. Until this evidence is provided and found acceptable to the IESO, the Market Registration process will not be considered complete and the connection applicant must accept any restrictions the IESO may impose upon this project's participation in the IESO-administered markets or connection to the IESO-controlled grid. The evidence must be supplied to the IESO within 30 days after completion of commissioning tests. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

   If the submitted models and data differ materially from the ones used in this assessment, then further analysis of the project may need to be done by the IESO before final approval to connect is granted.

   At the sole discretion of the IESO, performance tests may be required at generation and transmission facilities. The objectives of these tests are to demonstrate that equipment performance meets the IESO requirements, and to confirm models and data are suitable for IESO purposes. The H1 transmitter may also have its own testing requirements. The IESO and the H1 transmitter will coordinate their tests, share measurements and cooperate on analysis to the extent possible.

   Once the IESO's Market Registration process has been successfully completed, the IESO will provide the connection applicant with a Registration Approval Notification (RAN) document, confirming that the project is fully authorized to connect to the IESO-controlled grid. For more details about this process, the connection applicant is encouraged to contact IESO's Market Registration at market.registration@ieso.ca.

8. The connection applicant shall ensure that wholesale revenue metering installations comply with Chapter 6 of the Market Rules. This includes any intermediate project stages such as installation of temporary equipment or the use of mobile transformers. For more details, the connection applicant is encouraged to seek advice from their Metering Service Provider (MSP) or from the IESO metering group in early stages of project design.

9. As per Market Manual 1.4: Connection Assessment and Approval (formerly Market Manual 2.10), the connection applicant will be required to provide a status report of its proposed project with respect to its progress upon request of the IESO using the project status report form on the IESO website. Failure to comply with project status requirements listed in Market Manual 1.4: Connection Assessment and Approval (formerly Market Manual 2.10) will result in the project being withdrawn.

   The connection applicant will be required to also provide updates and notifications in order for the IESO to determine if the project is "committed" as per Section 3.3 of Market Manual 1.4: Connection Assessment and Approval (formerly Market Manual 2.10).

The following requirements, i.e. (10) – (13), apply to only Algoma Steel – New Load Facility (CAA 2021-694):

10. In accordance with Appendix 4.3 of the Market Rules, the connection applicant shall ensure the project have the capability to maintain the power factor within the range of 0.9 lagging and 0.9 leading as measured at the defined meter point of the project by adjusting its reactive compensation at any time, upon the IESO's or the transmitter's request. However, it is recognized that the project with its reactive compensation required by the IESO in-service may normally operate outside this range.

11. The connection applicant has a total peak load at all its owned facilities, including the project, which is greater than 25 MW. According to Section 10.4.6 of Chapter 5 of the Market Rules and Section 11.3 of the Market Manual 7.1, the connection applicant is required to participate in the automatic Under-Frequency Load Shedding (UFLS) program and must select 35% of total peak load among its owned facilities for under-frequency tripping, based on a date and time specified by the IESO that approximates system peak, according to Section 10.4 of Chapter 5 of the Market Rules.

    The UFLS relay connected loads shall be set to achieve the amounts to be shed as stated in Section 11.3 of Market Manual 7.1. Table 1 summarizes UFLS relay settings as a function of the total peak load of all facilities, including the project, owned by the connection applicant.

Table 1: UFLS relay settings

Aggregate Summer Peak Load	UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)	Load Shed at stage as % of Connection Applicant's Load	Cumulative Load Shed at stage as % of Connection Applicant's Load
25 MW or more and less than 50 MW	1	59.5	0.3	≥ 35	≥ 35
50 MW or more and less than 100 MW	1	59.5	0.3	≥ 17	≥ 17
	2	59.1	0.3	≥ 18	≥ 35
100 MW or greater	1	59.5	0.3	7 – 9	7 – 9
	2	59.3	0.3	7 – 9	15 – 17
	3	59.1	0.3	7 – 9	23 – 25
	4	58.9	0.3	7 – 9	32 – 34
	Anti-Stall	59.5	10.0	3 – 4	35 – 37

The connection applicant, in conjunction with the H1 transmitter, must also ensure that capacitor banks connected to the same station bus as the load are shed by UFLS facilities at 59.5 Hz with a time delay of 3 seconds.

The maximum load that can be connected to any single UFLS relay is 150 MW to ensure that the inadvertent operation of a single under-frequency relay during the transient period following a system disturbance does not lead to further system instability.

The IESO will review the requirements annually and inform the relevant market participants of their automatic UFLS obligations.

12. In accordance with Section 7.5 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.17 of the Market Rules on a continual basis. The data shall be provided in accordance with the performance standards set forth in Appendix 4.22, subject to Section 7.6A of Chapter 4 of the Market Rules. The whole telemetry list will be finalized during the IESO's Market Registration process.

    The connection applicant must install monitoring equipment that meets the requirements set forth in Appendix 2.2 of Chapter 2 of the Market Rules. As part of the IESO's Market Registration process, the connection applicant must also complete end to end testing of all necessary telemetry points with the IESO to ensure that standards are met and that sign conventions are understood. All found anomalies must be corrected before IESO's final approval to connect any phase of the project is granted.

13. The ORTAC states that the transmission system must be planned such that, following design criteria contingencies on the transmission system, affected loads can be restored with the restoration times listed below:
    a. All load must be restored within approximately a target of 8 hours;
    b. When the amount of load interrupted is greater than 150MW, the amount of load in excess of 150MW must be restored within approximately a target of 4 hours;
    c. When the amount of load interrupted is greater than 250MW, the amount of load in excess of 250MW must be restored within a target of 30 minutes.

The following requirements, i.e. (14) – (19), apply to only Lake Superior Power CGS – Generation Configuration (CAA 2021-695). In the event that LSP CGS generators, exciters and power system stabilizers are not able to meet the prevailing performance requirements as per Market Rules Appendix 4.2 and outlined below, the connection applicant must ensure they meet, at a minimum, the original performance requirements applicable to them when the units were once connected directly to the 115 kV LSP CGS bus.

14. As per Appendix 4.2 of the Market Rules, the connection applicant shall ensure that the generation facility has the capability to operate continuously between 59.4 Hz and 60.6 Hz and for a limited period of time in the region bounded by straight lines on a log-linear scale defined by the points (0.0 s, 57.0 Hz), (3.3 s, 57.0 Hz), and (300 s, 59.0 Hz) and the straight lines on a log-linear scale defined by the points (0.0 s, 61.8 Hz), (8 s, 61.8 Hz), and (600 s, 60.6 Hz).

    The facility has to have the capability to Regulate speed/frequency with an average droop based on maximum active power adjustable between 3% and 7% and set at 4% unless otherwise specified by the IESO. Regulation dead-band shall not be wider than ±0.06%. Speed/frequency shall be controlled in a stable fashion in both interconnected and island operation. A sustained 9% change of rated active power after 10 s in response to a step change of speed of 0.5% during interconnected operation shall be achievable. Due consideration will be given to inherent limitations such as mill points and gate limits when evaluating active power changes. Control systems that inhibit primary frequency response shall not be enabled without IESO approval.

15. The project is directly connected to the IESO-controlled grid, and thus, according to Appendix 4.2 of the Market Rules, the connection applicant shall ensure that the project has the capability to:

    - continuously supply all levels of active power output within a +/- 5% range of its rated terminal voltage. Rated active power is the smaller output at either rated ambient conditions (e.g. temperature, head, wind speed, solar radiation) or 90% of rated apparent power. To satisfy steady-state reactive power requirements, active power reductions to rated active power are permitted.;
    - Continuously (i.e., dynamically) inject or withdraw reactive power at the high-voltage terminal of the main output transformer up to 33% of rated active power at all levels of

active power output, and at the typical transmission system voltage, except where a lesser continually available capability is permitted with the IESO's approval. A conventional synchronous unit with a power factor range of 0.90 lagging and 0.95 leading at rated active power connected via a main output transformer impedance not greater than 13% based on generation unit rated apparent power is acceptable. Reactive power losses or charging between the high-voltage terminal of the main output transformer and the connection point shall be addressed in a manner permitted by IESO approval;

Regulate voltage automatically within ±0.5% of any set point within ±5% of rated voltage at the low-voltage terminal of the main output transformer if the transformer impedance is not more than 13% based on the rated apparent power of the generation facility, or at a point approved by the IESO. Reactive power-voltage droop or AVR reference load current compensation shall not be enabled without IESO approval. The equivalent time constants shall not be longer than 20 ms for voltage sensing and 10 ms for the forward path to the exciter output. AVR reference compensation shall be adjustable to within 10% of the unsaturated direct axis reactance on the unit side from a bus common to multiple units.

16. In accordance to Appendix 4.2 of the Market Rules, the connection applicant shall ensure that the excitation systems of the project shall have (a) Positive and negative ceilings not less than 200% and 140% of rated field voltage, respectively, while supplying the field winding of the generation unit operating at nominal voltage under open circuit conditions; (b) An excitation transformer impedance not greater than 10% on excitation system base; (c) A voltage response time to either ceiling not more than 50 ms for a 5% step change from rated voltage under open-circuit conditions; and (d) a linear response between ceilings. Rated field current is defined at rated voltage, rated active power and required maximum continuous reactive power.

    In accordance to Appendix 4.2 of the Market Rules, the connection applicant shall ensure that the Power System Stabilizers (PSS) of the project shall have (a) a change of power and speed input configuration; (b) positive and negative output limits not less than ±5% of rated AVR voltage; (c) phase compensation adjustable to limit angle error to within 30° between 0.2 Hz and 2.0 Hz under conditions specified by the IESO, and (d) gain adjustable up to an amount that either increases damping ratio above 0.1 or elicits exciter modes of oscillation at maximum active output unless otherwise specified by the IESO. Due consideration will be given to inherent limitations.

17. In accordance to Appendix 4.2 of the Market Rules, the connection applicant shall ensure the project shall have the capability to ride-through routine switching events and design criteria contingencies assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times, unless disconnected by configuration.

    The connection applicant will be required to demonstrate the project's voltage ride-through capability during commissioning by either providing manufacturer test results or monitoring several variables under a set of IESO specified field tests, and the test results must be verifiable using the dynamic models provided for the project.

18. The connection applicant shall install a permanent device for disturbance recording that meets the technical specifications provided in Section 2.7 of Market Manual 1.6: Performance Validation (formerly Market Manual 2.20). The quantities to be recorded and the trigger settings will be provided by the IESO during the Market Registration process.

19. If applicable according to Section 7.3 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.15 of the Market Rules on a continual basis. The data shall be provided with equipment that meets the requirements set forth in Appendix 2.2, Chapter 2 of the Market Rules, in accordance with the performance standards set forth in Appendix 4.19, subject to Section 7.6A of Chapter 4 of the Market Rules. The whole telemetry list will be finalized during the IESO's Market Registration process.

    As part of the IESO's Market Registration process, the connection applicant must also complete end to end testing of all necessary telemetry points with the IESO to ensure that standards are met and that sign conventions are understood. All found anomalies must be corrected before IESO's final approval to connect any phase of the project is granted.

Appendix B: Project Data (Confidential)

Appendix C: Facility Classification (Confidential)

Appendix D: Study Scope of Work (Confidential)

Appendix E: Detailed Study Results (Confidential)

Appendix F: Remedial Action Scheme Selection Matrices (Confidential)

Appendix G: Commissioning Tests (Confidential)

Appendix H: Protection Impact Assessments (Confidential)

Appendix I: Telemetry Requirements (Confidential)

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/IESO

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