September 16, 2016

Mtre Pierre Grenier
Dentons Canada LLP
1 Place Ville Marie, Suite 3900
Montréal, Québec H3B 4M7

Re:
- **Hydro-Québec Direction Contrôle des mouvements d'énergie's application for adoption of the version 5 critical infrastructure protection ("CIP") reliability standards for electric power transmission in Québec and for approval of the updated register identifying entities and installations subject to these version 5 CIP reliability standards**
- **Régie de l'énergie: R-3947-2015**

Dear Sir:

The attached report is to be submitted to the Régie de l'énergie (the "**Régie**") on behalf of Rio Tinto Alcan Inc. ("**RTA**") in connection with its Saguenay-Lac-Saint-Jean hydro-electric facilities and related installations (the "**RTA Installations**").

The report conveys our findings, positions and opinions based on:

(i) our knowledge and expertise regarding the implementation and application of the critical infrastructure protection ("**CIP**") reliability standards in the electrical industry;

(ii) our knowledge and understanding of the RTA Installations (facilities, configuration and electrical system), including their connections to Hydro-Quebec's transmission system;

(iii) our review and understanding of Hydro-Québec Direction Contrôle des mouvements d'énergie's ("**HQCMÉ**") application[1] to the Régie under file R-3947-2015 (the "**Application**") for the adoption of the version of the 5 CIP reliability standards to the installations listed in the Register of Entities subject to Reliability Standards[2] (the "**Register**") in Québec; and

(iv) our review and understanding of the Decision D-2016-119, issued by the Régie on July 29, 2016.

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1 R-3947-2015 : HQCMÉ Demande (B-0002, B-0004 and B-0015).

2 The Register of Entities subject to Reliability Standards 2016-07-29 (*Registre des entités visées par les normes de fiabilité*).

More specifically, this report is intended to:

(i) assess the rationality of HQCMÉ's proposal, in its Application, to categorize the RTA Installations, listed in the Register, as anything other than installations containing "low" Impact BES Cyber Systems, subject to version 5 of the CIP reliability standards accordingly;

(ii) review the potential consequences of HQCMÉ's proposal on the RTA Installations;

(iii) provide an assessment of comparability of HQCMÉ's proposed application of the CIP reliability standards with other jurisdictions within North-America subject to the NERC[3] reliability standards, primarily those within Canadian jurisdiction's regarding:

(a) the alignment of the definition of "**Main Transmission System**" (*Réseau de transport principal*)[4] ("**RTP**") that is used to establish the Register with that of the newly revised NERC bulk electrical system ("**BES**") definition; and

(b) the appropriateness of the proposed applicability of CIP reliability standards with respect to the RTA Installations, more specifically for generating facilities for industrial use [known as "*Producteurs à vocation industrielle*" ("**PVI**"), as defined in this file], as proposed in the Application; and

(iv) offer possible alternatives or enhancements where warranted to better align with other NPCC Canadian provincial jurisdictions.

For the reasons set out in our report, we assert that the RTA Installations listed in the Register only meet "low" impact ratings pursuant to the criteria defined in CIP-002-5.1 Attachment 1. Moreover, we are concerned that extending the immensely administratively burdensome program requirements for either a "high" or "medium" impact rating categorization of the RTA Installations that have little to no impact to the RTP will be costly, will serve little benefit to improving reliability, will needlessly increase risks by tying up limited resources that are in short supply, and is inconsistent in application of the CIP standards by other jurisdiction's within Canada and the United States for other installations of Local Networks ("LN") or industrial customers with generation behind the retail meter, that are applied in accordance with the NERC BES definition[5] exclusions E3 and E2 respectively, and within the context of the reliability objective[6] of CIP-002-5.1, Attachment 1 criterion for a 1500 MW or greater impact to the Interconnection.

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[3] North American Electric Reliability Corporation ("**NERC**").

[4] R-3947-2015: Glossary of Terms and Acronyms used in Reliability Standards (B-0044 and B-0045), at p 20.

[5] BES Definition Reference Document, Exclusion E2, at p 51; having a meaning similar to a PVI Installation and E3 at p 54 for LN.

[6] NERC Petition for the Approval version 4 of the CIP reliability standards, at p 15 and at p 27.

Therefore, we respectfully submit to the Régie in our report that:

(i) the RTP definition should be refined to be more precise for PVI installations, by including exclusions or other criteria appropriate for Québec, to better align with the new NERC BES definition, which is used extensively when establishing the reliability standards applicability, and for establishing the Register;

(ii) the total generating capability assigned to PVI installations when assessing the applicability of Reliability Standards and/or their requirements, should be solely based on the ”net” injection capability of the PVI installations at the interconnection(s) with the Hydro-Québec transmission system rather than including the PVI installations generating capability for servicing its own loads and/or any local loads served from its network;

(iii) the proposed CIP exclusion criteria for a production facility of 300MVA or less should not only be applied to an individual production facility, but should also be applied against the PVI installations as a whole using the aggregate ”net” injection capability of the PVI installations at the interconnection(s) with the Hydro-Québec transmission system;

(iv) the proposed CIP exclusion criteria discussed in (iii) above could be revised as follows:

- Any production facility or PVI installations that meets the following two conditions:
  (1) nominal net power injection to the Hydro-Québec transmission system of the installation is 300 MVA or less; and
  (2) no group of the installation can be synchronized with a neighboring network;

(v) the Register should specifically identify RTP production facilities and PVI Installations that are excluded from application of version 5 of the CIP reliability standards, in a similar fashion to how facilities are currently identified as critical assets or not;

(vi) the Register should specifically identify RTP facilities and PVI installations that meet criterion 2.3, 2.6, 2.7 and/or 2.9 from CIP-002-5.1 Attachment 1;

the total generating capability assigned to PVI installations when assessing the 1500 MW threshold of criterion 2.1, 2.11 and 2.13 from CIP-002-5.1 Attachment 1, should be solely based on the ”net” injection capability of the PVI installations at the interconnection(s) with the Hydro-Québec transmission system rather than including the PVI installations capability for servicing its own loads and/or any local loads served from its network; this would be consistent with the reliability objective of the NERC CIP standards drafting team when establishing the 1500 MW threshold based on the most significant Contingency

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FERC Order 761 Approving version 4 of the CIP reliability standards, at para 35 at p 20.

Reserve[7] requirements of the various Balancing Authorities in all regions in accordance with the NERC BAL-002 reliability standard[8]; and

(vii) in accordance with the application of each criterion from CIP-002-5.1 Attachment 1 to the RTA Installations listed in the Register using the principles discussed herein, none of the RTA Installations meet the "high" or "medium" impact ratings and only meet "low" impact ratings pursuant to those criteria.

Respectfully,

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7 R-3947-2015: Glossary of Terms and Acronyms used in Reliability Standards (B-0044 and B-0045), at p 8.

8 NERC Petition for the Approval version 4 of the CIP reliability standards, at p 15, which established the 1500 MW threshold.

REVIEW OF THE QUÉBEC CRITICAL INFRASTRUCTURE PROTECTION (“CIP”)
RELIABILITY STANDARDS AND
THE PROPOSED REGISTER OF ENTITIES AND INSTALLATIONS
SUBJECT TO THESE STANDARDS
IN THE CONTEXT OF RIO TINTO ALCAN INC.’S
SAGUENAY-LAC-SAINT-JEAN HYDRO-ELECTRIC
FACILITIES AND RELATED INSTALLATIONS

RÉGIE DE L’ÉNERGIE

R- 3947-2015

Re: **Hydro-Québec Direction Contrôle des mouvements d’énergie’s application for adoption of the version 5 critical infrastructure protection (“CIP”) reliability standards for electric power transmission in Québec and for approval of the updated register of entities and installations subject to these V5 CIP reliability standards**

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SEPTEMBER 16, 2016

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Article I. Terms of Reference

The following report is submitted to the Régie de l'énergie (the "**Régie**") on behalf of Rio Tinto Alcan Inc. ("**RTA**"). It conveys our findings, positions and opinions based on:

(i) our knowledge and expertise[1] regarding the implementation and application of critical infrastructure protection ("**CIP**") reliability standards in the electrical industry;

(ii) our knowledge and understanding of RTA's Saguenay-Lac-Saint-Jean hydro-electric facilities and related installations (the "**RTA Installations**")[2] as well as its facilities, configuration and electrical system, including their connections to Hydro-Québec's ("**HQ**") transmission system;

(iii) our review and understanding of Hydro-Québec Direction Contrôle des mouvements d'énergie's ("**HQCMÉ**") application to the Régie under file R-3947-2015[3] (the "**Application**") for the adoption of version 5 CIP reliability standards to the installations listed in the Register of Entities subject to Reliability Standards[4] (the "**Register**") in Québec; and

(iv) our review and understanding of the Decision D-2016-119, issued by the Régie on July 29, 2016.

This report is intended to:

(i) assess the rationality of HQCMÉ's proposal, in its Application, to categorize the RTA Installations, listed in the Register, as anything other than installations containing "low" Impact BES Cyber Systems, subject to version 5 of the CIP reliability standards accordingly;

(ii) review the potential consequences of HQCMÉ's proposal on the RTA Installations;

(iii) provide an assessment of comparability of HQCMÉ's proposed application of the CIP reliability standards with other jurisdictions within North-America subject to the NERC[5] reliability standards, primarily those within Canadian jurisdiction's regarding:

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1 See Section 6.03 Appendix C – Expert's Background, Qualifications, Training and Experience.

2 See Section 1.03(b) of this report.

3 R-3947-2015 : HQCMÉ Demande (B-0002, B-0004 and B-0015).

4 The Register of Entities subject to Reliability Standards 2016-07-29 (*Registre des entités visées par les normes de fiabilité*).

5 North American Electric Reliability Corporation ("**NERC**").

a. the alignment of the definition of "**Main Transmission System**" (*Réseau de transport principal*)[6] ("**RTP**") that is used to establish the Register with that of the newly revised NERC bulk electrical system ("**BES**") definition; and

b. the appropriateness of the proposed applicability of CIP reliability standards with respect to the RTA Installations, more specifically for generating facilities for industrial use [known as "*Producteurs à vocation industrielle*" ("**PVI**"), as defined in this file], as proposed in the Application; and

(iv) offer possible alternatives or enhancements where warranted to better align with other NPCC Canadian provincial jurisdictions.

The other Canadian jurisdictions that were considered, have adopted the new BES definition for the application of the version 5 CIP reliability standards to industrial customers with generation serving their own load, and are as follows:

- The province of Ontario where the reliability standards are approved by the Ontario Energy Board (OEB) and monitored and enforced by the Market Assessment and Compliance Division (MACD), a division of the Independent Electric System Operator (IESO);
- The province of New Brunswick where the reliability standards are approved by the New Brunswick Energy and Utilities Board (NBEUB) and monitored and enforced by the Northeast Power Coordinating Council (NPCC) under contract by the NBEUB.

The authors of this report are from AESI Acumen Engineered Solutions International Inc. ("**AESI**"). In connection with the Application before the Régie, AESI was retained by RTA to review applicable documentation pertaining to file R-3947-2015 and to submit our findings, positions, and opinions on three major aspects of the Application:

(i) the appropriateness of HQCME's proposal for the use of existing RTP definition to establish the Register rather than a more precise definition to better align with the new BES definition, which was used by the NERC standards drafting team in developing version 5 of the CIP reliability standards;

(ii) the comparison of this proposed application of version 5 of the CIP reliability standards to those used in other jurisdictions listed above; and

(iii) the appropriate categorization of reliability impact ratings (high, medium or low) of the RTA Installations in accordance with the criteria established within CIP-002-5.1

[6] R-3947-2015: Glossary of Terms and Acronyms used in Reliability Standards (B-0044 and B-0045), at p 20.

Attachment 1 entitled "Impact Rating Criteria" and the review of their applicability for any installations of a PVI and related facilities (the "**PVI Installations**").

Section 1.02 List of Sources and Documents Reviewed

To achieve the stated objectives of this report and formulate our opinions and positions, the information and documentation listed in the Appendix B of Section 6.02 herein were reviewed.

Section 1.03 Background

(a) The Application

On October 15, 2015, HQCMÉ, in its capacity as Reliability Coordinator for electric power transmission in Québec, filed the Application to the Régie seeking, amongst other things:

(i) the adoption of version 5 of the following CIP reliability standards: CIP-002-5.1, CIP-003-5, CIP-004-5.1, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1 and CIP-CIP-011-1, and their respective attachments;

(ii) the retirement (repeal) of the existing version 1 of the CIP reliability standards;

(iii) the adoption of changes to the Glossary of Terms and Acronyms[7] related reliability standards;

(iv) the approval of amendments to the Register; and

(v) establish the appropriate effective date of the reliability standards pursuant to those proposed by HQCMÉ.[8]

The Application was submitted under sections 31(5), 85.2, 85.6, 85.7, 85.8 and 85.13 of the *Act respecting the Régie de l'énergie*.

In its submissions to the Régie, the register of entities subject to reliability standards filed by HQCMÉ's[9] lists RTA as an entity that will be subject to version 5 of the CIP reliability standards. More importantly, HQCMÉ has submitted to the Régie[10] that, given the size of its generating capability, the RTA Installations would be subject to a reliability categorization, pursuant to CIP-002-5.1 Attachment 1 criteria, other than a "low" impact installation. However, under the existing version 1 of the CIP reliability standards, HQCMÉ did not identify RTA as an entity owning or operating facilities classified as "Critical

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7 See note 6.

8 R-3947-2015: Informations relatives aux normes (B-0005), p 10. Note that the Régie, in its decision D-2016-119, adopted version 5 of the CIP reliability standards at various dates, except for the PVI Installations (para 48 et 64).

9 R-3947-2015: Registre des entités visées par les normes de fiabilité (B-0024 and B-0025).

10 Decision D-2016-119, at para 26 and 76.

Assets"[11] for CIP reliability standards[12] and thus not subject to the existing version 1 of the CIP reliability standards.

Given this new implication of being subject to version 5 of the CIP reliability standards, RTA requested that the Régie hold off in its decision regarding HQCMÉ's application with respect to PVI Installations.

On July 29, 2016, in its Decision D-2016-119, the Régie placed a temporary suspension on the application of CIP standards on PVI Installations, until the Régie decided on the appropriate implementation rules for the standards applicable to these facilities.

(b) The RTA Installations

RTA owns and operates a distribution system, albeit at high tension voltages[13], in the Saguenay-Lac-Saint-Jean region that was exclusively designed to transport power from RTA's seven (7) power plants in the region to service RTA's load. Additionally, pursuant to a transmission service agreement entered into between RTA and Hydro-Québec TransÉnergie ("**HQT**") and approved by the Régie[14], RTA's distribution system transports energy from HQT's network to service HQ's area load [redacted].

RTA's electricity generation in the Saguenay region consists of seven (7) power plants, three (3) on the Péribonka River and four (4) on the Saguenay River. These installations have the capacity to produce, on average, approximately 2000 MW (installed capacity of approximately 3100 MW), representing approximately 90% of RTA's aluminum production power requirements for the region. The balance of RTA's electrical needs is provided by HQ, through three (3) interconnects with HQT. Occasionally, within the physical limitation and established System Operating Limits ("**SOL**"), RTA will transmit energy to HQ during freshet and high water level periods, when generation availability from the seven (7) power plants exceeds RTA's own load requirements.

Article II. Analysis and General Comments

AESI acknowledges the Régie's affirmative action in establishing a meaningful and mandatory "reliability" framework in the Province of Québec, within the context of Québec's legal and regulatory environment. It also supports the Régie's continued consultative approach with affected parties in determining the appropriate application of reliability standards for Québec. Moreover, AESI commends the Régie for taking a deliberate and cautious approach, soliciting input from affected parties and weighing the appropriates of the various reliability standards accordingly, prior to making its final decision on the Applications to adopt the reliability standards and the installations subject to these standards (specifically,

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11 Asset as established by the HQCMÉ methodology for defining installations if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the RTP.

12 Decision D-2016-119, at para 60.

13 RTA's distribution network consists primarily of an array of 161 kV facilities, with the exception of the 345 kV facilities from transformer station at Delisle to Chute-Des-Passes generating Facility.

14 Decision D-2014-145.

for this file R-3947-2015, the applicability of version 5 of the CIP reliability standards to the RTA Installations listed in the Register of entities subject to reliability standards[15] and the applicability of version 5 of the CIP reliability standards for PVI Installations, as proposed in the Application).

Given the purpose and configuration of PVI Installations, it is AESI's opinion, based on our extensive experience and tracking of the evolution of the new NERC BES definition, in conjunction with the CIP standards evolution as well as our expertise with respect to its predecessor term bulk power system (BPS)[16] as used within NPCC in the application of all NERC standards to Facilities that truly impact its Interconnection, that they should be viewed no differently than a large industrial customer with load displacement generation utilizing its own distribution network, irrespective of the voltage level of its distribution system. Furthermore, PVI Installations should be considered with respect to the applicability of reliability standards within a similar context of the current bulk electrical system (BES) NERC definition that became effective July 1, 2014 and enforceable July 1, 2016 in the United States and most Canadian jurisdictions. Specifically, those in the Northeast within the NPCC area such as Ontario, New Brunswick, and Nova Scotia.. The NERC BES definition, which was used by the NERC CIP standards drafting team and the industry in establishing the appropriate criteria for categorizing reliability impact importance and the degree to which protection is required. In other words, version 5 of CIP reliability standards applied within a more precise definition of RTP for PVI installations, more aligned with their reliability objectives that incorporates considerations for defined exclusions for specific installations.

The current RTP (*Réseau de transport principal*) definition [17] as noted further below and approved by the Régie, is less precise with respect to the NERC criteria for registering generation installations serving load only or forming part of a local network and connected to the bulk electrical system (BES under the NERC definition)[18] (*Système de production-transport d'électricité*) and as currently defined by HQCMÉ[19] for the Québec reliability framework.

AESI is a strong advocate of the more precise "bright line" BES definition that now lists a set of specific Facilities for inclusion and a specific set of Facilities for exclusion to ensure clarity of application of the NERC reliability standards. As such, it is AESI's view that the Québec reliability framework would be greatly enhanced, eliminating further ambiguity with respect to the application of Québec reliability standards, including the CIP reliability standards, if similar exclusion was specifically defined for the RTP. More importantly, this approach would provide for better consistency with respect to the application of reliability standards with all other jurisdictions in North America, albeit within the Québec reliability framework.

15 R-3947-2015: Registre des entités visées par les normes de fiabilité (B-0024 and B-0025).

16 R-3947-2015: Glossary of Terms and Acronyms used in Reliability Standards (B-0044 and B-0045), at p 6.

17 R-3947-2015: Glossary of Terms and Acronyms used in Reliability Standards (B-0044 and B-0045), at p 20.

18 NERC Glossary of Terms Dated August 17, 2016.

19 R-3947-2015: Glossary of Terms and Acronyms used in Reliability Standards (B-0044 and B-0045), at p 6.

"**Main Transmission System**" (*Réseau de transport principal*) (**RTP**)[20]

The transmission system comprised of equipment and lines generally carrying large quantities of energy and of generating facilities of 50 MVA or more, providing control over reliability parameters:

- Generation/load balancing
- Frequency control
- Level of operating reserves
- Voltage control of the system and tie lines
- Power flows within operating limits
- Coordination and monitoring of interchange transactions
- Monitoring of special protection systems
- System restoration

*(**Réseau de transport principal**)*

It is important to emphasize that the current RTP approved definition will now result in certain reliability standards and requirement being applicable to installations beyond their reliability objective as established by the new NERC BES definition, enforceable through sanctions under the Québec compliance program, inconsistent with other jurisdictions. Specifically, this can occur because the RTP definition does not include exclusion criteria analogous to the NERC BES definition, which were used in the development of the version 5 CIP reliability standards and its related criteria in CIP-002-5.1 Attachment 1, such as the 1500 MW threshold impact to an Interconnection defined in criterion 2.1, 2.11 and 2.13, a MW threshold which was based on the average Contingency Reserves required for each Interconnection to be carried by Balancing Authorities in accordance with the NERC BAL-002 reliability standard to cover the most severe single contingency. Installations with less than 1500 MW impact to an Interconnection are meant to be excluded from criterion 2.1, and similarly Control Centers with less than 1500 MW impact to the Interconnection are meant to be excluded from 2.11 and 2.13.

Additionally, it is AESI's expectations and opinion that HQCMÉ's proposed exclusion(s), with respect to the application of version 5 of the CIP reliability standards for PVI Installations, ought to be applied, consistent with the Application for other generator installations, currently before the Régie, and as outlined in the Régie decision D-2016-119[21], as follows:

- Any production facility that meets the following two conditions:
  (1) nominal power of the installation is 300 MVA or less; and
  (2) no group of the installation can be synchronized with a neighboring network.

Specifically, the exclusion applied to any PVI Installations when its aggregate net capacity provided to (injected into) the RTP network does not exceed 300 MVA, similar to the NERC BES "E2", exclusion as noted below, unless specifically defined within the standards applicability standards.

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[20] R-3947-2015: Glossary of Terms and Acronyms used in Reliability Standards (B-0044 and B-0045), at p 20.

[21] Decision D-2016-119, at para 30.

More importantly, such exclusion for PVI Installations be applied within the same spirit of the specific MW thresholds that considers the Contingency Reserve implications to the BA, as is used within the CIP-002-5.1 Attachment 1 criteria from the net injection to the Québec Interconnection perspective. The same value that is used when establishing the Contingency Reserve requirements for Québec Interconnections.

NERC BES is now defined as follows in the NERC Glossary of Terms Used in reliability standards[22] (the "**NERC Glossary**"):

> **"bulk electrical system (BES)"**
>
> Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.
>
> Inclusions:
>
> - I1 Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under Exclusion E1 or E3.
> - I2 Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
>   (a) Gross individual nameplate rating greater than 20 MVA. Or,
>   (b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.
> - I3 Blackstart Resources identified in the Transmission Operator's restoration plan.
> - I4 Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
>   (a) The individual resources, and
>   (b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.
> - I5 Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or

[22] NERC Glossary of Terms, August 17, 2016.

higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions (in pertinent part to this File):

- E1 exclusion for Radial system, not relevant for these discussions.
- E2 A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.
- E3 Local networks (LN): A group of contiguous transmission Elements operated at less than 300 KV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

  (a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of nonretail generation greater than 75 MVA (gross nameplate rating);

  (b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

  (c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Québec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).
- E4 Reactive Power devices installed for the sole benefit of a retail customer(s).

AESI reiterates its opinion that similar exclusions, as is listed above, be considered for the RTP definition, to ensure consistent application of the version 5 CIP reliability standards for PVI Installations as applied in other jurisdictions and as was used in the development of these standards.

Article III. Application of NERC CIP reliability standards to the RTA Installations

AESI fully endorses and supports the arguments that HQCMÉ has presented to the Régie[23] with respect to the version 5 of the CIP reliability standards, which include the new CIP-010-1 and CIP-011-1 reliability standards, noting that they represent a significant improvement compared to existing CIP standards adopted by the Régie. That is within the context of the application of version 5 of the CIP reliability standards, in accordance with CIP-002-5.1 Attachment 1 and as intended by the CIP standards draft team as articulated in the guidance documentation, responses during the development of version 5 of the CIP reliability standards and the revised BES definition.

A position strongly supported by NERC and the FERC, notwithstanding FERC issuing a number of Directives to NERC for further refinements, some of which have already been included in the FERC approved version 6 and version 7 currently in draft of the CIP reliability standards.

The Régie has also acknowledged[24] the importance it places on this family of reliability standards, which are designed to require cyber security measures to protect infrastructure and are essential to the reliability of the electricity transmission system in Quebec. In this regard, the Régie believes that the public interest requires the adoption of reliability standards designed to protect the electric system against malicious acts and ensure implementation of cyber security measures required by the standards without delay and accordingly have approved version 5 of the CIP reliability standards, as filed by HQCMÉ, in its decision D-2016-119.

CIP reliability standard CIP-002-5.1 Attachment 1, as approved by the Régie, includes a list of criteria to be used to categorize the reliability impact rating (high, medium or low) of the identified BES Cyber Systems at the specific installations (facilities) impacting the reliability of the RTP. This impact rating (high, medium or low) categorization then defines the specific level of application and implementation of CIP reliability standard requirements on the entities subject to the standards, as established by the RTP definition. A key metric defined in the impact rating criteria related to generating facilities is the total generating capability of a single installation that is controlled by a common BES Cyber System, potentially subject to intrusion or being compromised. The NERC standards drafting team established a value of 1500 MW as a “threshold value” from a single generating facility or the Generator Operator (GOP) control center[25] that could be removed from a single Interconnection[26]. This is a principle which appears to be

[23] Decision D-2016-119, at para 44.

[24] Decision D-2016-119, at para 46.

[25] R-3947-2015: Glossary of Terms and Acronyms used in Reliability Standards (B-0044 and B-0045), at p 9.

lost within the current HQCMÉ proposal before the Régie with respect to installations subject to version 5 of the CIP reliability standards. While AESI supports the principle of using the 1500 MW generation loss (within an Interconnection) through a common BES Cyber System from a generation installation, it believes that applying such principles to any PVI Installations must be considered from the net generation injection to the affected Interconnection and not from the generating capability of the local network serving its own loads, periodically having excess capability available for the Balancing Authority (BA).

It is AESI's view that such PVI Installations must be assessed on the merits of their capability to impact the Interconnection and specifically, in this case, the Québec Interconnection Contingency Reserve requirements, with the threshold value of 1500 MW or more considered when establishing impact ratings and related scope of applicability of version 5 of the CIP reliability standards to any PVI Installations. To do so otherwise would extend the reach of version 5 of the CIP reliability standards, in AESI's view, beyond those intended by the CIP standard and accordingly approved by FERC, when establishing the 1500 MW threshold impact for the affected Interconnection[27].

A position consistent with and supported by the Régie in its decision D-2015-059[28] with respect to HQCMÉ assertions of the information required by HQCMÉ with respect to GOP whose facilities are mainly used to supply industrial loads. Specifically, regarding the generating capability information required, it has been established as "*(i) in the planning time horizon, the net power at the connection points of its system, total production of its generation facilities and its system load and (**ii) in real time, the net power at the connection points of its system**" [emphasis added]*. It is not required to inform the BA and the Transmission Operator (TOP) of all generation resources available as required under requirement TOP-006-2 R1.1[29].

Section 3.01 1500 MW Threshold Criterion

With respect to the application of version 5 of the CIP reliability standards to the RTA Installation, it is AESI's understanding that the physical limitations of the three (3) interconnections with HQT would preclude the RTA network from ever approaching the 1500 MW threshold, irrespective of the RTA network generating capability, as listed in the Register.

As outlined earlier, RTA's electricity generation in the Saguenay region consists of seven (7) power plants. These installations have the capacity to produce, on average, approximately 2000 MW (installed capacity of approximately 3100 MW), representing approximately 90% of RTA's aluminum production

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26 Interconnection (with capital I) as established by the NERC Glossary of Terms and adopted by HQCMÉ in its Glossary (B-0044 and B-0045) at p 18, meaning the geographical areas of the Eastern, Western, ERCOT (Texas) and Québec Interconnections.

27 The Québec Interconnection, within the meaning of the NERC and HQCMÉ Glossary of Terms.

28 Decision D-2015-059, at para 303 to 307, and para 705 with respect to HQCMÉ's application to the Régie for approval of the TOP-006-2 reliability standard.

29 TOP-006-2 Appendix QC-TOP-006-2 (approved by the Régie's decision D-2016-059).

power requirements for the region. The balance of RTA's electrical needs is provided by HQ, through three (3) interconnects with HQT. Occasionally, within the physical limitation and established SOL, RTA will transit energy to HQ during freshet and high water level periods, when generation availability from the seven (7) power plants exceeds RTA's own load requirements.

HQCMÉ has established a SOL of [redacted] for the three (3) interconnects and during spring freshet RTA may provide to HQT the [redacted][30]. However, more importantly, at no time can these three (3) interconnections continue operations above [redacted] for any extended period of time, nor approach the 1500 MW threshold injection value (for example after internal RTA load loss contingency), before HQT and/or RTA operator intervention to return the interconnections to below the SOL through generation rejections/runbacks or initiates separations of the affected interconnections exceeding its line rating or SOLs.

With respect to MW withdrawals from the HQT network during periods of low water levels typically during the winter periods to service RTA loads and for transferring energy to service the various HQT local loads, a current applied SOL of [redacted][31] during the winter ([redacted] during the warmer summer periods) period has been established by HQCMÉ for the three (3) interconnections. Here again, operator intervention occurs and is required whenever, this SOL is exceeded.

Importantly, there is no realistic or plausible contingency within the RTA network or under the control of RTA's control center, in which 1500 MW or more of its generation can be lost without also losing various loads served by such generation, either through transmission network configuration, due to under-voltage trips and/or separation of the RTA interconnections with HQT due to the line loading exceedances. In other words, it is implausible to have a generation loss of 1500 MW impact on the Quebec Interconnection, triggering equivalent Contingency Reserves[32], the genesis of the 1500 MW threshold.

Within this context, it is AESI's opinion that the RTA Installations listed in the Register, do not meet the 1500 MW threshold for applicability of criterion 2.1 and 2.11 of CIP-002-5.1 Attachment 1.

Accordingly, it is our view that HQCMÉ's proposal to expand the scope of coverage of the NERC CIP reliability standards to the RTA Installations as either a "high" or "medium" impact rating, based on this criterion, given its limitations on total MW generation implications to HQT system is unjustified and inconsistent with the reliability objective of the CIP reliability standards. Specifically, the 1500 MW threshold that was established by the NERC standards drafting team, based on the most significant

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30 Historically, this upper SOL limit of [redacted] Injection is only achieved [redacted].

31 [redacted]

32 R-3947-2015: Glossary of Terms and Acronyms used in Reliability Standards (B-0044 and B-0045), at p 8.

Contingency Reserve requirements in an Interconnection and approved accordingly by FERC[33] as acceptable justification. Further, AESI submits that the RTA Installations only meet the “low” impact rating pursuant to these criteria.

RTA is fully aware of, recognizes the importance of, and supports the need to maintain system reliability, including local area reliability as well as the need to protect its RTA Installations from malicious cyber attacks. However, RTA remains committed that any such obligations should be balanced and applied consistently with other jurisdictions within Canada and the USA.

Further, given the importance of protecting the RTA Installations, RTA already has in place a cyber security program that aligns with good utility practices and, to various degrees, many of the listed requirements of the CIP reliability standards, and will continue to do so in order to enhance the protection of the RTA Installations from cyber attacks. Nonetheless, these requirements should not be subject to the rigorous and administratively burdensome Québec Reliability Standards Compliance Monitoring and Enforcement Program[34] and its related sanctions.

Section 3.02 RC, TOP and BA Criterion

Within the reliability framework established for Québec, HQT, including HQCMÉ, have been established as the Reliability Coordinator (RC), Balancing Authority (BA) and Transmission Operator (TOP) for the Québec Interconnection[35] and is the only entity in the Register subject to the reliability standard requirements listed for the RC, BA and TOP, including those related to version 5 of the CIP reliability standards assigned to those functions. Given the aforementioned, the following CIP-002-5.1 Attachment 1 Criterion do not apply to the RTA Installations and only apply to HQT in its role as RC, BA and TOP.

i) Criterion 1.1; specific to the RCs;

ii) Criterion 1.2; specific to the BAs;

iii) Criterion 1.3; specific to the TOPs;

iv) Criterion 2.12; specific to the TOPs not included by criterion 1.3; and

v) Criterion 2.13 specific to the BAs not included by criterion 1.2.

Section 3.03 Generation Installation Criterion

AESI has reviewed and applied the various other CIP-002-5.1 Attachment 1 Section 1 – *High Impact Rating* criterion specifically applicable to Generator Operator and Section 2 – *Medium Impact Rating*

33 NERC Petition for the Approval version 4 of the CIP reliability standards, at p 15 and at p 27; FERC Order 761 Approving version 4 of the CIP reliability standards, at para 35 p 20.

34 As established for the Québec reliability framework.

35 Interconnection (with capital I) as established by the NERC Glossary of Terms and adopted by HQCMÉ in its Glossary (B-044 and B-045) at p 18, meaning the geographical areas of the Eastern, Western, ERCOT (Texas) and Québec Interconnections.

criterion specifically applicable to generation installation assets, comparing those with the RTA Installations to establish the appropriate categorization of these installations, as follows:

(a) Criteria 1.4

This criteria does not apply. RTA's Control Center or backup Control Center used to perform the functional obligations of the Generator Operator (GOP) does not include any of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9, as detailed below.

(b) Criteria 2.1

This criteria does not apply. RTA's does not have any commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

(c) Criteria 2.3

HQT, as the Planning Coordinator (PC) and Transmission Planner (TP), has not informed RTA that any of its RTA Installations (i.e. any of RTA's generating facilities) are necessary to avoid an Adverse Reliability Impact[36] in the planning horizon of more than one year. Nor has HQCMÉ, in its application before the Régie, identified that RTA's Installations are necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

In fact, it is AESI's view that, from a planning perspective, RTA's network is simply viewed as a generation resource with a maximum injection to the HQT network of [redacted], or as a load during low water levels. A position consistent with and supported by the Régie in its decision D-2015-059[37] with respect to HQCMÉ assertions of the information required by HQCMÉ with respect to GOP whose facilities are mainly used to supply industrial loads. Specifically, regarding the generating capability information it has been established as "(*i*) ***in the planning time horizon, the net power at the connection points of its system, total production of its generation facilities and its system load*** *and (ii) in real time, the net power at the connection points of its system.*" *[emphasis added]* It is not required to inform the BA and the TOP of all generation resources available as required under requirement TOP-006-2 R1.1[38].

(d) Criteria 2.6

HQT, as the Planning Coordinator (PC), Transmission Planner (TP) and Reliability Coordinator (RC), has not informed RTA that any of its RTA Installations (i.e. any of its transmission or generating

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36 R-3947-2015, HQCMÉ-2, Document 5, at page 2 (B-0044 and B-0045).

37 Decision D-2015-059, at para 303 to 307, and para 705 with respect to HQCMÉ's application to the Régie for approval of the TOP-006-2 reliability standard.

38 TOP-006-2 (approved by the Decision D-2016-059).

facilities) are critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

(e) Criteria 2.11

Within the context of the net injection principle as outlined above in Section 3.01, this criteria does not apply. While RTA's Control Center or backup Control Center is used to perform the functional obligations of the GOP for an aggregate highest rated net Real Power[39] capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection, the generation is to supply only RTA's load, as a PVI Installation and various other local loads, nor does RTA provide net generation to the Québec Interconnection through its three (3) interconnections with the HQT transmission system equal to or exceeding 1500 MW at any time therefore does not impact, in AESI's view, the Québec Interconnection Contingency Reserve requirements (See Section 3.01 above).

Section 3.04 Transmission Installation Criterion

AESI has reviewed and applied the various other remaining CIP-002-5.1 Attachment 1 Section 2 – *Medium Impact Rating* criterion specifically applicable to Transmission type assets comparing those with the RTA Installations to establish the appropriate categorization of these installations, as follows:

(a) Criteria 2.2

This criteria does not apply. RTA's reactive resources (excluding generating installations (Facilities) per the criteria) are well below the maximum Reactive Power[40] nameplate rating of criterion threshold of 1000 MVAR.

(b) Criteria 2.4

This criteria does not apply. RTA does not own any Transmission Facilities that are operated at 500 KV.

(c) Criteria 2.5

This criteria does not apply. While RTA owns Transmission Facilities that are operating between 200 kV and 499 kV at a single substation, they are <u>not</u> connected to three (3) or more other Transmission stations or substation at 200 kV or higher, and have an "aggregate weighted value" exceeding 3000 according to the table listed in Attachment 1.

[39] NERC Glossary of Terms, August 17, 2016.

[40] NERC Glossary of Terms, August 17, 2016.

(d) Criteria 2.6

HQT, as the Planning Coordinator (PC), Transmission Planner (TP) and Reliability Coordinator (RC), has not informed RTA that any of its RTA Installations (i.e. any of its transmission or generating facilities) are critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

(e) Criteria 2.7

This criteria does not apply. RTA does not own or operate any Transmission Facilities essential to meeting Nuclear Plant Interface Requirements (NPIRs). There are no nuclear facilities in operation in Québec.

(f) Criteria 2.8

This criteria does not apply. RTA does not own or operate any Facilities that meet the requirements of criterion 2.1 and 2.3 and as such there are no Transmission facilities, including generation interconnection facilities if destroyed, degraded, misused, or otherwise rendered unavailable, that would result in the loss of the generation facilities identified by criterion 2.1 or criterion 2.3.

(g) Criteria 2.9

RTA does not own or operate any Special Protection Systems (SPS) or equipment that impact Interconnection Reliability Operating Limits (IROLs).

(h) Criteria 2.10

RTA does not own or operate any Under-Voltage Load Shedding (UVLS) or under frequency load shedding (UFLS)[41] systems or equipment that will shed load equal to or greater than 300 MW.

(i) Criteria 2.12

Refer to Section 3.02 - RC, TOP and BA Criterion.

(j) Criteria 2.13

Refer to Section 3.02 - RC, TOP and BA Criterion.

Therefore, based on the principles discussed above in section 3.01 and the application of each criterion from CIP-002-5.1 Attachment 1, as approved by the Regie,[42] to the RTA Installations listed in the Register, as outlined above in Sections 3.02, 3.03 and 3.04 of this report, the RTA Installations do not meet “high” or “medium” impact ratings, and only meet “low” impact ratings pursuant to those criterion.

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[41] As defined by the NERC Glossary of Terms and forming part of the Québec Interconnection UFLS or UVLS programs.

[42] Decision D-2016-119.

Article IV. Cost Effectiveness

It has been estimated by RTA that it would cost for RTA some 2.5 M$ for the implementation of the CIP reliability standards and will include an annual cost of some $200k for ongoing maintenance activities. This estimate is pursuant to RTA's preliminary cost assessment for implementation of version of the CIP reliability standards and based on RTA's understanding of the implementation requirements for a "medium" impact reliability categorization. While RTA appreciates the need for the implementation costs that truly support reliability of the Québec transmission system, it is our view that such expenditures would provide little to no true reliability benefits to that system.

AESI notes that NERC, the Regional Entities[43], and many industry stakeholders, including US Federal, state and Canadian provincial regulatory authorities, have expressed interest in the identification of the costs incurred from implementing NERC Reliability Standards compared to risks addressed. The desire is to balance costs and risks during the standards development and revision process. It is equally important that once reliability standards are established that a just and reasonable application of such standards is ensured. To this end, NERC and the Regions[44] are incorporating processes during the standard development stages to assess the cost compared against reliability benefits and to ensure consistent application of the standards in all Regions within NERC control.

Article V. Conclusions

The RTA Installations should be viewed no differently than a large industrial customer with load displacement generation and an extensive distribution system, albeit a very large industrial customer with significant generation for its installed load carried over a "high tension" distribution network.

Notwithstanding the size and the voltage of the RTA Installations' distribution network, any faults and disturbances, including those created through malice or cyber intrusion of its network continue to have local impact implications only.

RTA understands the importance of, and remains committed to, helping assure the reliability of its network and three (3) interconnections with HQT as well as the protection of its RTA Installations against cyber intrusions and malicious attacks. RTA further recognizes that it is in its best interest to take such measures and has a long standing history and proven track record of maintaining a reliable system in the Saguenay-Lac-Saint-Jean region and has implemented an extensive cyber security program to protect its RTA Installations.

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43 As defined by the NERC Rules of Procedure, Appendix 2, dated April, 2016.

44 R-3947-2015: "Regional Reliability Organizations" in the Glossary of Terms and Acronyms used in Reliability Standards (B-0044 and B-0045), at p 28.

We assert that the RTA Installations listed in the Register only meet “low” impact ratings pursuant to the criterion in CIP-002-5.1 Attachment 1, consistent with the reliability objective of the NERC CIP standards drafting team.

However, we remain concerned that extending the immensely administratively burdensome of version 5 of the CIP reliability standards program requirements for “high” and “medium” impact ratings, for the identification and categorization of the identified BES Cyber Systems located at any RTA Installations, to facilities that have little to no impact to the HQT network, will be costly and will serve little benefit to improving reliability of the RTP. In addition, it will tie up limited resources that are already in short supply; these resources would be better served if focussed on reliability matters that do have a direct impact to the reliability of the RTP.

Therefore, we respectfully submit to the Régie that:

(i) the RTP definition should be refined to be more precise for PVI Installations, by including exclusions or other criteria appropriate for Québec, to better align with the new NERC BES definition, which is used extensively when establishing the reliability standards applicability, and for establishing the Register;

(ii) the total generating capability assigned to PVI Installations when assessing the applicability of Reliability Standards and/or their requirements, should be solely based on the “net” injection capability of the PVI Installations at the interconnection(s) with the Hydro-Québec transmission system rather than including the PVI Installations generating capability for servicing its own loads and/or any local loads served from its network;

(iii) the proposed CIP exclusion criteria for a production facility of 300MVA or less should not only be applied to an individual production facility, but should also be applied against the PVI Installations as a whole using the aggregate “net” injection capability of the PVI Installations at the interconnection(s) with the Hydro-Québec transmission system;

(iv) the proposed CIP exclusion criteria discussed in (iii) above could be revised as follows:

- Any production facility or PVI Installations that meets the following two conditions:
  (1) nominal net power injection to the Hydro-Québec transmission system of the installation is 300 MVA or less; and
  (2) no group of the installation can be synchronized with a neighboring network;

(v) the Register should specifically identify RTP production facilities and PVI Installations that are excluded from application of version 5 of the CIP reliability standards, in a similar fashion to how facilities are currently identified as critical assets or not;

(vi) the Register should specifically identify RTP facilities and PVI Installations that meet criterion 2.3, 2.6, 2.7 and/or 2.9 from CIP-002-5.1 Attachment 1;

(vii) the total generating capability assigned to PVI Installations when assessing the 1500 MW threshold of criterion 2.1, 2.11 and 2.13 from CIP-002-5.1 Attachment 1, should be solely based on the "net" injection capability of the PVI Installations at the interconnection(s) with the Hydro-Québec transmission system rather than including the PVI Installations capability for servicing its own loads and/or any local loads served from its network;

this would be consistent with the reliability objective of the NERC CIP standards drafting team when establishing the 1500 MW threshold based on the most significant Contingency Reserve[45] requirements of the various Balancing Authorities in all regions in accordance with the NERC BAL-002 reliability standard[46]; and

(viii) in accordance with the application of each criterion from CIP-002-5.1 Attachment 1 to the RTA Installations listed in the Register using the principles discussed herein, none of the RTA Installations meet the "high" or "medium" impact ratings and only meet "low" impact ratings pursuant to those criterion.

Respectfully:

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[45] R-3947-2015: Glossary of Terms and Acronyms used in Reliability Standards (B-044 and B-045), at p 8.

[46] NERC Petition for the Approval version 4 of the CIP reliability standards, at p 15, which established the 1500 MW threshold.

Article VI. Appendices

Section 6.01 Appendix A – Affirmation and Statement of Independence

The information contained in this report is based on information provided by RTA and information contained in the list of sources and documents referred to in Appendix B of Section 6.02 (some documents were translated to English), and the knowledge and extensive expertise of the authors on the subject. This information is, to the best of AESI's knowledge, factually correct.

Further, AESI and the undersigned have no relationship or association with RTA, and have provided these paid professional services at the request of RTA, as independent consultants with established expertise in the electricity industry.

AESI Acumen Engineered Solutions International Inc.

R. J. Falsetti

By: Ronald J. Falsetti, P.Eng.
Title: Senior Regulatory Policy Advisor

J Charlebois

Joel Charlebois, P.Eng.
Vice President, Regulatory Services

Loreto Sarracini

Loreto Sarracini, P.Eng.
President

Section 6.02 Appendix B – List of Sources and Documents Reviewed

a) Our comprehensive knowledge of (i) cyber security reliability standards application and related compliance programs within North America; (iii) implementation requirements and associated known issues with the NERC criteria, specifically within the context of the BES[47];

b) Detailed review with RTA's representatives of the RTA Installations as well as their operational processes and strategies;

c) AESI's discussions with RTA's representatives of the operational agreements/arrangements between RTA and Hydro-Québec and the RTA Installations limitations, capabilities, controls and activities to support system reliability;

d) Decision D-2016-119;

e) Decision D-2014-145;

f) Decision D-2015-059;

g) R 3947-2015: HQCMÉ Demande (B-0002, B-0004 and B-0015);

h) R-3947-2015: Glossary of Terms and Acronyms used in Reliability Standards;

i) *The* Register of Entities subject to Reliability Standards *2016-07-29 (Registre des entités visées par les normes de fiabilité*);

j) R-3947-2015: HQCMÉ-1, Document 2 (B-0005);

k) NERC Glossary of Terms, August 17, 2016; (RTA-5)

l) BES Definition Reference Document, Exclusions E2 and E3; (RTA-6)

m) NERC reliability standard TOP-006-2 Appendix QC-TOP-006-2 (approved by the Decision D-2016-059);

n) [redacted]; (RTA-7)

o) NERC Petition for the Approval version 4 of the CIP reliability standards; (RTA-8)

p) FERC Order 761 Approving version 4 of the CIP reliability standards. (RTA-9)

[47] See *Curriculum Vitae* attached.

Section 6.03 Appendix C – Expert's Background, Qualifications, Training and Experience

(a) Joel Charlebois

AESI

Joel Charlebois, P.Eng.

Professional Summary

Joel Charlebois is a proven leader and respected mentor of a strong team of NERC compliance professionals. He successfully manages numerous client engagements covering a wide range of regulatory and technical requirements. Joel maintains an extensive understanding and practical experience in all aspects of NERC regulatory compliance for both CIP and Non-CIP regulatory compliance projects (governance, mock audits, compliance tools, etc.). His experience and broad perspective bridges the gap into technical solutions for proactive compliance. Joel's aptitude and acumen transcends boundaries to support a multitude of Information Technology applications and implementation projects (SCADA/EMS, web applications, software design and development, systems integration, databases, etc.), and into business analytics, that guarantees delivery of effective and comprehensive solutions to complex problems.

Relevant Project Experience

NERC – Regulatory Compliance Management Systems

- Managed the installation, configuration, customization and operational deployment of the SigmaFlow NERC Compliance Manager solution to facilitate NERC CIPv5/6 compliance for Ontario Power Generation (OPG)
- Performed assessment and gap analyses of NERC Compliance Management Systems (CMS) and tools
- Conducted an extensive evaluation of a large Transmission Owner/Operator's CMS and related methodologies used for monitoring, complying with, and storing evidence for NERC and regional regulatory requirements
- Developed guidelines for transitioning compliance programs towards a proactive, integrated and highly automated compliance management, monitoring, and reporting solution

NERC CONSULTING SERVICES

- Reviewed, interpreted and/or advised clients on:
  - Reliability Assurance Initiative
  - Internal Controls & Evaluations
  - NERC Standards development
  - FERC NOPRs and Orders
  - Requirement obligations & evidentiary artifacts
  - Requirement interpretation requests
  - Standard & requirement enforcement dates
  - Market rules & obligations
  - Rules of Procedure and audit processes
  - Enforcement actions and penalties
  - NERC publications
  - Recommendations for balloting
- Registered Entity Types include: BA, IA, PA, RC, RP, RSG, TOP, TSP, GO, GOP, TO, TP, DP, LSE, RP, PSE

Areas of Expertise

- NERC Compliance
- Systems Integration
- Project Management
- Software Design and Development
- SCADA/EMS

Education

- Bachelor of Engineering Science, Electrical Engineering, University of Western Ontario, 2003
- Bachelor of Science, Computer Science, University of Western Ontario, 2003

Professional Associations

- PEO - Professional Engineers of Ontario

AESI

Joel Charlebois, P.Eng.

- Clients include: BC Hydro, Brookfield Renewable Power, ElectriCities (represents ~50 municipalities), Cobra Thermosolar Plants, Hydro One, Hydro Quebec TransÉnergie and Production, Independent Electricity System Operator (IESO), Indianapolis Power & Light, Lower Colorado River Authority (LCRA), Muscatine Power and Water, New Brunswick Power (NBP), Ontario Power Generation (OPG), Oglethorpe Power Company (OPC), TransCanada, and more

NERC - Regulatory Compliance Audit Support

- Conducted and participated in several NERC Non-CIP and CIP Compliance Mock Audits and Compliance Posture Assessments covering a wide range of NERC Registered Entity Types for several organizations including:
  - Grid Operational Control Centers
  - Municipal Utilities & Vertically Integrated Utilities
  - Generator & Transmission Owners/Operators
- Prepared extensive and detailed NERC Audit & Compliance Posture Assessment Reports that provided both NERC & Regional (NPCC, ERCOT, SERC, etc.) compliance gap analyses along with recommendations for remedying any perceived gaps and that described opportunities to enhance existing documentation to ensure continued successful regulatory compliance
- Developed RSAW narratives, compliance responses, and evidentiary documentation lists for submission to Compliance Enforcement Authorities
- Assisted with the identification of relevant and high quality evidentiary and supporting documentation
- Reviewed evidentiary and supporting documentation packages prior to submission to Compliance Enforcement Authorities
- Drafted responses to Requests for Information (RFIs) received during the audit process
- Identified instances when auditors went out of scope of the requirement language and carefully crafted responses that were provided to the audit team addressing such

NERC – Regulatory Compliance Programs

- Developed NERC Regulatory Compliance program documentation, complete with descriptions of compliance analyses and actions, evidentiary requirements, and accountability assignments that enable Entities to establish a strong culture of compliance, including but not limited to:
  - Overall Governance
  - Compliance Policies
  - Methodologies (e.g., Facility Ratings)
  - Programs (e.g., Protection System Maintenance)
  - Emergency Operations Plans (e.g. Event Reporting)
  - Operator Level Procedures, Instructions, Handbooks, etc.
  - Internal Controls
- Assessed and performed gap analyses of NERC Regulatory Compliance program documentation while providing recommendations to remedy any identified gaps
- Developed and conducted general and standards specific NERC compliance training

NERC – Industry Participation

- Attended and participated in NPCC Reliability Standards Committee (RSC) meetings, compliance workshops, and conferences

AESI

Joel Charlebois, P.Eng.

- Speaker and panelist on the topic of NERC compliance

SCADA/EMS WORK

- Assisted a Transmission Owner and Operator with the development of a Request for Proposal for a new SCADA/EMS system to upgrade the existing system. The RFP included requirements for the following new SCADA/EMS systems components:
  - Primary Control System (PCS)
  - Backup Control System (BCS)
  - Quality Assurance System (QAS)
  - Program Development System (PDS)
  - Operator Training Simulator (OTS)
  - High Speed Data Historian

- Provided technical support in the specification and selection of a Transmission Operations System (SCADA/EMS) for a new Transmission Operations Center:
  - Requirements Analysis
  - Development of a Request For Proposal
  - Participation in the Vendor Analysis process

- Participation in the implementation of a SCADA System and Metering Settlement System to enable the participation of a set US Electric Cooperatives in multiple energy markets. Participation involved:
  - Market Protocols Analysis
  - SCADA and Metering billing/settlement tool requirements
  - Cost Analysis
  - SCADA System procurement and implementation
  - Revenue Meter procurement and implementation

POWER SYSTEMS IT WORK

- Implementation of a web-enabled system for Power Scheduling and Settlement by multiple Power Marketers for Georgia Systems Operations Corporation. These roles include:
  - Functional and Policy Analysis
  - Establishment of Business Rules and Requirements to govern scheduling activities
  - Design, development, documentation and installation of the necessary environment & software components
  - Project Management for product enhancements and upgrades
  - Integration with EMS/SCADA, Load Forecasting, OATI Tagging, PI and eDNA Historians, etc.
  - Virtualization and migration from a Solaris & Oracle environment to a Microsoft Windows, SQL Server, and VM Ware environment

- Defined and prepared specifications for Market Participation IT Tools for MISO, PJM and NYISO markets
- Design & Development experience with several IT infrastructure & software products, as well a strong programming skills in multiple languages, including:
  - VMware Virtualization Software
  - Databases & SQL (Oracle, SQL Server, etc.)
  - JAVA, JavaScript, JQuery, JSP, C, Visual Basic, HTML, etc.

- Web Application Infrastructure Installation, Configuration and Administration:

- Application Servers, Secure FTP Servers, LDAP Directory Servers, Proxies, Firewalls, etc.

- Experience with an electric distribution utility in Ontario involving:
  - Detailed designs, materials lists & estimates for overhead and underground work relating to customer projects
  - Prepare and review Residential, Industrial/Commercial development design drawings
  - Preparation of cost estimates and bill of material for project service orders
  - Field verification of existing site/electrical plant condition
- Prepared software specification and requirements for software tools to provide data editing and report generation capabilities for a XA/21 Energy Management System (EMS)
- On-going system support for a major US Electric Systems Operations Company

MANUFACTURING IT WORK

- Trained and Performed Radiographic Quality Inspection of various die cast metal parts for the Power Industry
- Performed maintenance and assembly of NASAT MC Actuator Reclosers and Power Units and became familiar with several products used in various applications for High Power Transmission
- Performed installation and configuration of several types of hardware and software components for IBM laptops, workstations, and servers
- Support and troubleshooting methodology for several hardware and software components

Continuing Education

- eDNA Historian User and Administrator Courses: InStep Software LLC, 2014
- Fundamentals of Auditing for NERC Compliance Team Leaders: North American Electric Reliability Corporation, 2011
- Fundamentals of Auditing: North American Electric Reliability Corporation, 2011
- Gathering Quality Evidence During Compliance Audits: North American Electric Reliability Corporation, 2011
- Generation Controls Course: Kestrel Power Engineering Ltd., 2008
- Project Management for Software Development: Learning Tree International, 2007
- Locational Marginal Pricing (LMP): PJM Interconnection, 2005
- ICCP: Survalent Technologies, 2004

(b) Ron Falsetti

AESI

Ron Falsetti, P.Eng., B.Sc.

Professional Summary

Ron Falsetti has an extensive career in the electric utility operation at both plant and system levels attained throughout his 39 year tenure leading to comprehensive knowledge of North American Reliability Standards, and intimate and practical knowledge of NPCC criteria. Ron was involved in the implementation and operation of the Ontario market and had direct responsibility for managing the Ontario Reliability Compliance Program - to establish and ensure compliance of both the IESO and its 200 Ontario market participants, with the NERC Standards and NPCC Criteria. He was also responsible for managing and preparing the IESO readiness, as a Reliability Coordinator, Transmission Operator, Balancing Authority, Interchange Authority, Planning Coordinator and Transmission Planner, for NERC compliance audits and readiness reviews. Building on his credibility, Ron has been active in numerous NERC and NPCC Compliance Committees and with Standards Committees with the IESO, ISO/RTO Council (IRC) and NPCC. He has led and prepared several mock audits and assessments, preparing reports on the status of clients' compliance, actions required to correct and mitigate areas of non-compliance, as well as the assessment, development, and implementation of Internal Compliance Programs and Organizational constructs to manage such programs.

EMPLOYMENT HISTORY

Nov 2008 – Current *AESI Acumen Engineered Solutions International*

- Nov 2014 – Current Senior Regulatory Policy Advisor
- 2010 – Nov 2014 Vice President - Regulatory Services
- Nov 2008 – 2010 Associate – Senior Consultant

1998-Sept - 2008 *INDEPENDENT ELECTRICITY SYSTEM OPERATOR*

- 1999 – 2008 Compliance Manager, Ontario Market Participants & IESO

1997 - 2008 *Ontario Hydro*

- 2000 – 2008 Accounts Manager, Wholesale Power; Industrial & Municipal Utilities
- 1997 – 2008 Electrical Engineer, Bruce Nuclear Power Complex

Areas of Expertise

- NERC Compliance
- FERC 693
- Ontario Regulations
- Market Rules

Education

- Electrical Engineering, University of Western Ontario, 1977

Professional Associations

- PEO - Professional Engineers of Ontario

Relevant Project Experience

NERC Standards Compliance

- Responsible for regulatory project oversight and development/maintenance of regulatory sustainment services
- Compliance validation and audit readiness review of various clients that include Independent System Operator (ISO), fully integrated utilities and Transmission owners and operators
- Provided expert guidance on: i) the application of Standards in other jurisdictions within the NPCC; ii) filings and rulings at NPCC and FERC regarding application of reliability standards etc. Working closely with the client management and lawyers, preparing expert testimony for filing for regulatory hearings

AESI

Ron Falsetti, P.Eng., B.Sc.

- Provided expertise and technical guidance to Registered Entity compliance investigations, responding to requests for information by the Regional Entity regarding reliability standard violations
- Member of a fully integrated utility Reliability Compliance Steering Committee providing an independent object view of its Reliability Compliance Program and on regulatory developments affecting it; a committee of senior management established to provide oversight and guidance of its Reliability Compliance Program on behalf of the Board Audit Committee

NERC – Regulatory Compliance Programs

- Developed NERC Regulatory Compliance program documentation, complete with descriptions of compliance analyses and actions, evidentiary requirements, and accountability assignments that enable Entities to establish a strong culture of compliance, including but not limited to:
    - Overall Governance
    - Compliance Policies
    - Compliance Program Oversight Manuals
    - Methodologies (e.g., CIP Critical Assets)
    - Emergency Operations Plans
    - Operator Level Procedures, Instructions, Handbooks, etc.
    - Internal Controls
- Assessed and performed gap analyses of NERC Regulatory Compliance program documentation while providing recommendations to remedy any identified gaps
- Developed and conducted general and standards specific NERC compliance training

NERC CONSULTING SERVICES

- Reviewed, interpreted and/or advised clients on:
    - Reliability Assurance Initiative
    - Internal Controls & Evaluations
    - NERC Standards development
    - FERC NOPRs and Orders
    - Requirement obligations & evidentiary information
    - Requirement interpretation requests
    - Standard & requirement enforcement dates
    - Program Effectiveness Assessment
    - Rules of Procedure and audit processes
    - Enforcement actions and penalties
    - NERC publications
    - Recommendations for balloting
- Registered Entity Types include: RC, TOP, BA, IA, PA, RP, RSG, TSP, GO, GOP, TO, TP, DP, LSE, RP, PSE

NERC - Regulatory Compliance Audit Support

- Conducted and participated in numerous NERC Non-CIP Compliance Mock Audits and Compliance Posture Assessments covering a wide range of NERC Registered Entity Types for several organizations as listed below including:
    - Grid Operational Control Centers
    - Municipal Utilities & Vertically Integrated Utilities
    - Generator & Transmission Owners/Operators

AESI

Ron Falsetti, P.Eng., B.Sc.

- Prepared extensive and detailed NERC Audit & Compliance Posture Assessment Reports that provided both NERC & Regional (NPCC, MRO, ERCOT, SERC, WECC, etc.) compliance gap analyses along with recommendations for remedying any perceived gaps and that described opportunities to enhance existing documentation to ensure continued successful regulatory compliance
- Hydro One Networks Inc.: conducted an assessment and detailed report of Hydro One's ICP and organization construct, and managed /oversaw the development and implementation of a comprehensive ICP to address identified gaps and recommended enhancements.
- Ontario Power Generation (OPG): conducted a Hydro Plant Group audit readiness review and assisted in preparation of the required compliance filing documentation in preparation of an IESO Market Assessment and Compliance Division (MACD) audit.
- Hydro Québec – TransÉnergie (HQT): conducted an RC, TOP, BA, PC and TO audit readiness review and assisted in preparation of the required compliance filing documentation in preparation of an Northeast Power Coordination Council (NPCC) audit.
- Independent Electricity System Operator (IESO): conducted a RC, TOP and BA audit readiness review and assisted in preparation of the required compliance filing documentation in preparation of an Northeast Power Coordination Council (NPCC) audit.
- New Brunswick Power(NBP): conducted a RC, TOP BA, PC, TO, GO and GOP audit readiness review and assisted in preparation of the required compliance filing documentation in preparation of an Northeast Power Coordination Council (NPCC) audit.
- Oglethorpe Power Corporation (OPC): Provided expertise and technical guidance to a Protection System standard "deep dive" review in responding to a request for information by the SERC Region Entity in regards to PRC-005 self-report compliance investigation
- Rio Tinto Alcan Inc. (RTA): Developed a report for filing with the Québec regulator; the Régie de l'énergie (the "Régie") on behalf of RTA presenting technical arguments against the Hydro-Québec's Direction – Contrôle des mouvements d'énergie (HQCME) group's proposed Québec Compliance Monitoring and Enforcement Program (QCMEP) for its Saguenay Lac-Saint Jean Installation
- Brookfield Power: Developed a report for filing with the Québec regulator; the Régie de l'énergie (the "Régie") on behalf of Brookfield Power presenting technical arguments against the Hydro-Québec's Direction – Contrôle des mouvements d'énergie (HQCME) group's proposed Québec Compliance Monitoring and Enforcement Program (QCMEP) for its Lièvre installation. Assisted in developing responses to the Régie's subsequent request for information on the above filing
- Nova Scotia Power Incorporated (NSPI): Project lead for the gap analysis /compliance readiness assessment for this fully integrated utility
- Greenfield Energy Center (GEC): Developed GEC's Transmission Vegetation Management Program and related documentation

NERC – Industry Participation

- Managed IESO Reliability Compliance Program (IRCP); monitoring, assessing and reporting Ontario marker participant and its compliance to North American Electric Reliability Corporation (NERC) standards and Northeast Power Coordinating Council (NPCC) Inc. criteria
- Managed IESO reliability standards and criteria review program providing consolidated comments to NERC and NPCC standards and criteria under development
- Managed IESO readiness for NERC compliance audits and readiness reviews
- Chair of ***IESO Reliability Standards Standing Committe***e (RSSC); a stakeholder forum designed to:
    - Manage and maintain the NPCC Standards Development Procedure and processes

- Notify stakeholders of reliability related information on new and developing reliability standards, NPCC criteria and Electric Reliability Organization (ERO) matters
- Discuss, provide advice and to the extent possible, develop consensus comments on new and developing reliability standards and criteria
- Engage stakeholders in the standard development process of NPCC Inc. and NERC

- IESO representative and Vice-Chair (2005-2008) of ***NPCC Compliance Committee*** a committee of the NPCC Board responsible for overseeing NPCC's compliance program and registered entity compliance with NERC Standards and NPCC Criteria, with notable responsibility to:
  - Review and approve NPCC Compliance Staff procedures for implementing the compliance program
  - Review and endorse processes used, by NPCC Compliance Staff, for noncompliance assessments and determination of sanctions
  - Provide final approval of compliance assessments done by NPCC Compliance Staff related to NPCC Reliability Criteria, including approval of non-monetary sanction recommendations
  - Provide a pre-hearing forum for the resolution of contested compliance and /or sanction determinations
  - Conduct annual evaluations of the NPCC Compliance Staff's CMEP implementation

- Chair of ***NPCC Registration Sub-Committee***, responsible for providing direction to the Compliance Committee and NPCC Compliance staff on entity registration. Specifically, with respect to developing the strategy and registration methodology for generator owners/operators and transmission owners/operators as it pertains to NPCC definition of bulk power system
- IESO representative on ***NPCC Regional Standards Committee***. A committee of the NPCC Board, charged with:
  - Management and maintenance of the NPCC Standards Development Procedure and processes
  - Providing consolidated NPCC Regional review and comment to the existing and proposed NERC standards and participate in the NERC Reliability Standards Development Process
  - Identification of upcoming issues associated with new NERC reliability standards and their potential impact to the NPCC Region, (i.e. Regional difference). Proposing solutions or guide the development of the standards through effective and timely comments and soliciting NPCC participation on the standard authorization requests (SAR) and reliability standards drafting teams

- ISO/RTO Council (IRC) representative on ***NERC Compliance and Certification Committee***; a committee of the NERC Board with a mandate to engage, support and advise the Board and NERC Compliance staff regarding all facets of the NERC Compliance Monitoring and Enforcement Program, the Organization Registration program and the Organization Certification program
- Coordinating System Operation's strategic reliability and business risk management process
- Accountable for managing and facilitating market participant's registration and market entry prior to market opening
- Project coordinator for NERC's Electronic Interchange Transaction (e-tags) implementation

Account Management - Wholesale Power ;Industrial & Municipal Consumers

- Responsible for key industrial & municipal utility accounts, providing regulatory, financial and technical guidance to plant managers and utility Commissions and for managing overall customer relationship

- Identified, developed and facilitated implementation of innovative energy solutions and energy supply contracts with key Industrial & municipal utility accounts
- Responsible for developing municipal utility rates cases for Ontario Hydro Board approval

Electrical Engineer, Bruce Nuclear Power Complex

- Site Energy Coordinator, Electrical Systems & Process Control Engineer - Bruce Nuclear Power Complex
- Responsible for the coordination of Bruce Complex outages with Ontario generation and Transmission outages
- Responsible for electrical systems commissioning, diagnostic and ongoing maintenance programs for emergency power combustion turbine units, HP steam system controls and site electrical protection system
- Nuclear System Engineer, responsible for the main electrical power system from the Bruce B Facility
- Chair - "BNPD Strategic Operating Planning Committee" responsible for developing optimum short and long-term energy production deployment objectives, strategies, guidelines, plans and software applications to maximize site electrical output based on bulk electrical system limitations impacting Bruce flows (locked in energy and spring freshet)

Continuing Education

- NERC Compliance Team Leader - Fundamentals of Auditing, NERC 2011
- NERC Auditor Training:
  - Fundamentals of Auditing
  - Gathering Quality Evidence
  - Violation Investigation
- Ontario Market Operations Training
- Relay Protection, Control and Metering Training
- Combustion Turbine Control Logic
- Industrial Application of Gas Turbines
- Strategic Account Management Training
- Major Account Management Training and Problem Solving
- Coaching Skills and Cooperative Coordination
- Effective Negotiating Skills; Key Account Business Relations and Effective Team Building

(c) Loreto Sarracini

Loreto Sarracini, P.Eng.

Professional Summary

Loreto Sarracini has been immersed in the electrical power industry for almost 40 years, both working in and supporting electrical utilities across North America achieve their operational and management goals. His experience is founded in Power System Operations and complemented with projects such as NERC Regulatory Compliance, EMS/SCADA, system operations, Information Communication and Technology, automation, generating plant construction, operations and maintenance, cyber and physical security, and establishing Smart Grid strategies and roadmaps.

His NERC Regulatory Compliance projects include: NERC/Region readiness audit and mock audit for both the CIP and Non-CIP Standards for all NERC registered entity types, assisted in the development of Polices, Guidelines and Procedures for NERC/Regions Reliability Standards Compliance, helped to identify the required evidence to demonstrate compliance, and developed and conducted Training and Compliance programs for NERC Compliance.

In the area of EMS/SCADA, Loreto has been involved in managing the implementation of new and upgrades of EMS/SCADA system, from system definition phase through to system implementation and cutover, including the integration of EMS/SCADA system with Data Historians, Energy Tagging system, Corporate IT Enterprises systems and external control centers with neighboring utilities.

Relevant Project Experience

NERC Standards Compliance

- Conducted NERC/Region readiness audit and mock audit for both the CIP and non-CIP Standards for all NERC registered entity types (BA, RP, GO, GOP, TO, TOP, LSE, PSE, DP, RC, TSP, IA, TP, PA and RSG) and in all NERC Regions
- Assisted Utilities in the development of Polices, Guidelines and Procedures for NERC/Regions Reliability Standards Compliance and helped to identify the required evidence to demonstrate compliance
- Assist Utilities to prepare for their actual NERC/Regional Audit, from developing their RSAWs to representing the Utility at the actual audit as their SME
- Developed Training programs and Compliance programs for NERC Compliance
- Develop and conduct training for CIP and Non-CIP standards
- Assist clients with understanding the new BES definition and CIP V5 categorization, and the associated impacts
- Assist clients with strategy development and implementation of a program to meet the new CIP 5 requirements
- Assisted a number of Utilities to establish and implement a CIP Cyber and Physical Security Program for Power Plants, Substations and Control Centres
- Conducted assessments of utilities systems/tools/processes for managing compliance and assisted in identifying and developing new systems/tools/processes to manage compliance
- Conducted assessments of Utility's Internal Compliance Program (staffing/program structure/strategy/tools) and provide a report identifying the GAPs and process improvements

Areas of Expertise

- Power System Operations & Planning
- NERC Compliance (CIP and Non-CIP)
- EMS/SCADA
- Project Management
- Systems Integration

Education

- Bachelor of Applied Science, Electrical Engineering, University of Toronto, 1976

Professional Associations

- PEO - Professional Engineers of Ontario

AESI

Loreto Sarracini, P.Eng.

- Assisted utilities to implement the recommendations from the GAP analysis of their Internal Compliance Program assessment
- Developed a NERC Compliance Overview document, a Compliance Plan User Guide on how to develop an Internal Compliance Program, and a sample Internal Compliance program; prepared and delivered training workshops and webinars on how to implement the developed materials; National Rural Electric Cooperative Association (NRECA) and the American Public Power Association (APPA) to share with their members, numbering over 2000 utilities
- Developed and Conducted several NERC CIP Cyber and Physical Security Workshops and Non-CIP Workshops to utilities in Canada and United States
- Provided services to a number of Utilities to establish and implement a Physical Security Program to secure their Bulk Electric System (BES) assets to meet the NERC CIP standards
- Conducted a BA study to identify what it would take for a utility to register and operate as a Balancing Authority
- Lead a project team to implement all of the necessary policies, procedures, systems and tools and get them approved by FERC/NERC/SERC to register as a Control Area/Balancing Authority
- Conducted a study to determine what it would take for a Utility to establish a complete regulatory framework to support their registration as a RC, BA, TOP, TO, TP, TSP, GO, GOP, PA and RP

EMS/SCADA/SmartGrid

- Supported utilities with the development of SmartGrid strategies and roadmaps
- Provided an Acting Managers role for the Energy Control System department for Georgia System Operations Corporation (GSOC) (formerly Oglethorpe Power Corporation) based in Atlanta Georgia (USA). Responsible for the management of GSOC's Energy Control System, which includes all development and support staff (System & Database administrators) and all Dispatching Center tools (Hardware and Software) used by the System Dispatchers. This position was provided for approximately 2 years until GSOC hired a permanent Manager
- As Manager of GSOC's Energy Control System, additional responsibilities included designing an infrastructure to allow GSOC's EMS/SCADA system to be integrated with other internal and external systems while ensuring the security, reliability and performance of the EMS/SCADA system and developing an overall maintenance and disaster recovery strategy for the system. Their internal systems included their Corporate Network, Data Historian and the Remote Revenue Metering System. The external systems included dedicated data links (ICCP) with other control centres and the internet to support various functions such as: OASIS, OATI Electronic tagging, Web based Custom Energy Market Application to provide data to Power Marketers and for remote database support (utilizing Virtual Private Network (VPN) technology)
- Established GSOC's EMS/SCADA maintenance strategy
- Provided both management and technical services for a number of Utilities in managing the implementation of new and upgrades of EMS/SCADA system, from system definition phase through to system implementation and cutover, including the integration of EMS/SCADA system with internal and external systems and ensuring that the system delivered were NERC CIP Compliant.
- Prepared and delivered an Information Technology strategic planning seminar to the Alabama Municipal Electric Authority (AMEA) and their 11 member Utilities. The majority of the utilities are electric, but some are also responsible for water and gas. The seminar included their SCADA systems and Corporate IT infrastructure
- Provided Project Management and Technical assistance to Georgia System Operations (formerly Oglethorpe Power Corporation (OPC)) based in Atlanta Georgia (USA) in the implementation of their

new state of the art EMS/SCADA system being supplied by GE (formerly Harris Corporation). Continued to provide Project Management and Technical assistance for the upgrade of GSOC's EMS/SCADA system since the installation of their first system

- Developed the Data Logging and Reporting requirements for Oglethorpe Power Corporation's (OPC) System Control Department to ensure that the associated information needs of OPC and other external agencies are adequately met. Also designed the required reports for development and implementation by the EMS/SCADA vendor based on the reporting requirements
- Oglethorpe Power Corporation operations staff on the use of EMS/SCADA applications supplied by the vendor of their state of the art EMS/SCADA system for the effective operation of the Power System
- Established the infrastructure between the EMS/SCADA computing environment and the Corporate Computing environment for the transfer of information using Replication Server to other business within the Corporation
- Provided both management and technical services for a number of Utilities in managing the implementation of new and upgrades of EMS/SCADA system, from system definition phase through to system implementation and cutover (participating in the FAT and SAT), including the integration of EMS/SCADA system with internal and external systems, ensuring that the system delivered were NERC CIP Compliant and providing the necessary training on the system and applications
- Canada, Ontario Hydro Power System Operations staff, developed real-time applications for the Ontario Hydro energy management system (i.e. System Control Centre - Data Acquisition Computing System DACS) for monitoring operating reserves and the simulation of the activation of operating reserve
-

Owner's Engineer and Technical Support

- Construction of Generation Facilities for various Utilities and IPPs:
  - Alabama Municipal Electric Authority
  - Costal Power Corporation
  - Conectiv
  - Doyle 1 LLC
  - Florida Power and Light
  - Greater Toronto Airport Authority
  - Oglethorpe Power Corporation
    - Smarr Energy Facility – 2-120 MW Siemens/Westinghouse Simple Cycle Gas Turbines
    - Sewell Creek Energy Facility – 1-120 MW and 2-140 MW Siemens/Westinghouse Simple Cycle Gas Turbines
    - Talbot Country Energy Facility – 6-120 MW Siemens/Westinghouse Simple Cycle Gas Turbines
    - Chattahoochee Energy Facility – 550 MW Siemens/Westinghouse Combined Cycle Gas Turbines

IT Services

- Designed an IT system (Hardware and Software) to allow a newly formed company providing services to Electrical Utilities to effectively carry out their business functions. The system included remote access for staff, the capability to allow the company to provide services to host web pages, database server, file server and network redundancy, RAID technology and the necessary firewalls to ensure the system security. Prepared a Request for Quotation (RFQ) for the procurement of the IT system (Hardware, Software, System Network, Support & Maintenance Services)

AESI

Loreto Sarracini, P.Eng.

- Developed software products covering all aspects of utility operations and administrations in such diverse fields as:
  - Project and Work Management
  - Expert Design Systems
  - Water Management
  - Demand Side Management
  - Power System Planning and Operations
  - Computer Network Management
  - Nuclear, Thermal and Hydraulic Generation
- Design, development and maintenance of all power system application programs:
  - Identification of the computational techniques to be used in the development of application programs
  - Design of the man/machine interface and procedures
  - Software design, coding and testing
  - Documentation
  - User training and support
  - Integration and acceptance of new or modified software into the live environment
  - Developing, commissioning and maintaining production (economy) and control oriented application programs
  - Developing, commissioning and maintaining security related application programs
  - Determining the requirements, methods and cost/benefit of new applications in close liaison with other departments

Bulk Electricity System (BES)

- Responsible for the outage coordination of all of Ontario Hydro generating fleet (Nuclear, Thermal and Hydro)
- Responsible for the coordination of generating resources outages with the Transmission outages
- Conducted system performance studies for establishing thermal and system stability limits on the Ontario Hydro power system
- Responsible for providing post event analysis of BES operation and related consulting services
- Supervised a group of professional and technical personnel responsible for providing a regular evaluation results service for the financial costs attributable to those relevant BES limitations encountered in the:
  - efficient dispatch of Ontario Hydro generation resources
  - sale of electrical capacity and energy to other organizations, both within and outside of Ontario
  - purchase of electrical capacity and energy from other organizations, both within and outside of Ontario
- Provided a regular evaluation results service for the financial benefit resulting from identified operational practices and procedures
- Responsible for reviewing, analyzing, and making recommendations related to the on-going reliable and economic operation of the BES
- Identification of new areas where monitoring and the subsequent feedback of post event evaluation data would be beneficial
- Identification and development of new methods for the monitoring of BES operation to meet changing operational circumstances
- Provided appropriate guidance/direction within and outside Ontario Hydro with operating experience

and assessments to improve planning, design, and operation of the interconnected system

- Advised management regarding past, present, and future operating matters
- Developed power system operating procedures for overall power system operations

Coordination Section – Resource Utilization

- Provided coordinated generator outage and test plans
- Developed and supplied coordinated generator maintenance and test schedules
- Provided representation on interconnection sub committees, advised management and wrote reports for management regarding past, present, and future operating matters
- Supplied management instructions to Power System Operations Division, management and accounting
- Liaised with all Ontario Hydros' coal, nuclear and hydraulic stations in the provision of coordinated generator outage plans for work program planning and budget planning purposes

Hydro Electric Power Plant Resource Planning

- Provided near term policies and procedures and short and mid-term program for hydraulic storage inventories
- Provided policies and procedures for operation of hydraulic resources and utilization of hydraulic storage inventories for use in the near-term to the System Operation Department
- Provided the program for operation of hydraulic resources and utilization of hydraulic storage inventories for the short and mid-term to all of Ontario Hydro
- Represented Ontario Hydro on external boards and committees involving external regulatory agencies or other governmental, corporate, or private users of water, in regard to near term policies and procedures and short and mid-term program relative to hydraulic resources and hydraulic storage inventories
- Provided actual results of hydraulic resource utilization to all of Ontario Hydro
- Provided forecasted results in the short and mid-term for hydraulic storage inventories utilization to all of Ontario Hydro
- Provided information on operating experience and made assessments and recommendations to both inside and outside Ontario Hydro, regarding hydraulic resource utilization to improve planning and design of the bulk electricity system generating capacity in the short-term
- Canada, Ontario Hydro Regional and Station operating staff on water management, river and reservoir utilization for the generation of power

International

- International consulting services in the following areas:
  - System Planning
  - Power System Operations
  - Distribution Planning
  - Information Technology
  - EMS/SCADA
- Sarawak Electric Supply Corporation (SESCo) - (Malaysia):
  - Developed and implemented into their Energy Management System a generation operation optimization model (Hydro-Thermal Coordination)

- Defined the requirements for connecting the EMS/SCADA system into the corporate network in order to provide operational data to other business within the corporation while maintaining the security and integrity of their EMS/SCADA system
- Established policies, procedures and guidelines in the area of Generation Optimization and Power System Operation
- Conducted an organization study of their System Operation Function (staff resources and tools). Produced a report recommending a restructure and the phased development of resources (staffing, tools, equipment) to meet the utilities current and future needs
- Developed, designed and implemented a Pilot Management Reporting System in order to provide management with key information required by them in a timely and consistent manner
- Established and implemented Corporate Performance measures and indices, to be integrated into the Management Reporting System
- Participated in a Management Information System (MIS) project for the planning and development of a computer-based information acquisition, processing and reporting system to provide management with operational and planning information
- Developed Data Logging and Reporting requirements for Sarawak Electric Supply Corporation

- Pakistan, Water and Power Development Authority of Pakistan trainees on generator outage coordination and load dispatch training
- Malaysia, Sarawak Electricity Supply Corporation staff on Power Systems Operations and Corporate and general performance measures for electrical utilities
- Malaysia, Tenaga Nasional Berhad operations and engineering staff on the integrated operations of Power Systems, operating tools and methodologies, and EMS/SCADA applications