Version caviardée

Rapport de l'expert Brian D. Evans-Mongeon

TESTIMONY
AND EXHIBITS
OF
BRIAN EVANS-MONGEON
ON BEHALF OF
HYDRO QUEBEC TRANSÉNERGIE

October 28, 2016

I. INTRODUCTION

Please state your name and address.

My name is Brian Evans-Mongeon. My address is 1080 Waterbury-Stowe Rd, Suite 2, Waterbury, Vermont 05676.

By whom are you employed?

I am the President and Chief Executive Officer of Utility Services, Inc. a consulting company specializing in regulatory compliance and support services to entities in Canada and the United States affected by the "Electric Reliability Organization" which the province of Quebec recognizes as the North American Electric Reliability Corporation (NERC).

On whose behalf are you appearing?

I am appearing on behalf of Hydro Quebec TransÉnergie (HQT).

II. QUALIFICATIONS

Please state your educational background.

I hold a Bachelor of Science in Business Administration from the University of Vermont. I also hold an Associates degree in Electric/Electronic Technology from Vermont Technical College. In addition, I have obtained Utility leadership certificates from Northeast Public Power Association and Electric Power Research Institute.

Please summarize your professional experience.

My career in the electric utility industry spans nearly thirty years. I spent eight and a half years at Green Mountain Power Corporation culminating as the Manager, Power Operations & Administration. My responsibilities included the management of the short-term power trading and planning activities. I also participated in the development of new rules and regulations for conducting transactions in the New England Power Pool and the company's development of an open-access transmission and market based pricing sales tariffs.

From 1996 to 2007 I worked for the Vermont Public Power Supply Authority as the Marketing Services Manager and Manager of Power Supply and Transmission. My job responsibilities are primarily directed toward the development of new business enterprises for the Authority, developing and analyzing new generation sites, developing power and transmission budgets and settlement, working with members to improve system dispatch and operations, and special projects. During my tenure, I have been successfully involved in bringing new clients to the Authority. Acting as Agent for the Authority's members and affiliates on matters relating to compliance with ISO New England and the state wide transmission providers.

In 2007, I founded Utility Services, Inc., a firm that assists companies in their compliance and reliability programs as administered by NERC. Currently we provide expert advice to over 60 electric utilities, generating facilities with approximately 5,000 MW of nameplate generation, transmission companies, energy marketing companies, with respect to compliance with the NERC reliability regime including the cyber and physical security requirements. In addition, recently, we have been permitted to use the EISAC's Cyber Risk Preparedness Assessment tool to develop our "Securing The Grid" program that helps entities develop a Culture of Security program within their organizations.

I also have been chair, co-chair or a member of over a dozen NERC committees relating to compliance, standard development, program design, audit, planning, and performance. Of note, I chaired the NERC Project on Disturbance and Sabotage Reporting, and am presently the Co-Chair the NERC Essential Reliability Services Working Group. In addition, I was a member of the NERC Risk Based Registration Technical Support Team. I spent two years on the NERC Project team developing NERC's current definition of Bulk Electric System (BES Definition) that became effective July 1, 2014 and July 1, 2016 for newly identified BES elements. As I discuss more below, an integral part of the development and discussions was "bright-line" concept. A complete list of the NERC projects and committee in which I participated is attached as an Exhibit to my testimony.

Please describe some of your experience applying NERC policies with respect to the definition of Bulk Electric System.

In addition to being a member of the NERC standard drafting team that developed the BES Definition, I have managed multiple Bulk Electric System inclusion and exclusion declarations and assisted with exception requests in the NERC process. I achieved this work through an examination of customer configurations using one or three-line diagrams and by analyzing them using NERC's hierarchical assessment approach as described below. I assessed diagrams based on the BES Definition and, if the conditions were met for an inclusion or exclusion, I worked with the customer on the submission of the determination request. If the examination produced a result of where an exception was warranted, I worked with the customer on the submission of the request and assisted them through the NERC exception process as required by the customer.

III. TESTIMONY

What is the purpose of your testimony?

I describe how the facilities of Rio Tinto Alcan, Inc. (RTA) would not be excluded from the NERC BES Definition, if they were located within the continental boundaries of the United States of America, and therefore subject to registration by NERC for compliance with relevant Reliability Standards. In doing so, I explain how NERC registers entities and applies the BES Definition to determine which entities must comply with the NERC Reliability Standards. I also describe the history of NERC's Critical Infrastructure Protection (CIP) Reliability Standards and the fundamental importance of security of the grid in developing and enacting those standards. In that light, I describe how RTA's facilities would be subject to higher impact classifications than what RTA argues for under the CIP Reliability Standards, specifically Reliability Standard CIP-002-5.1.

What Exhibits are you sponsoring?

Exhibit Number	Description
1	Resume of Brian Evans-Mongeon
2	NERC BES Definition
3	Reliability Standard CIP-002-5_1
4	Reliability Standard CIP-002-4
5	NERC Rationale and Implementation Document for CIP2004-2

6	NERC Frequently Asked Questions– CIP Version 5 Standards April 1, 2015 Posting
Exhibit Number	**Description**
7	Preuve Rio Tinto Alcan Inc.
8	AESI Report
9	Réponses de RTA à la DDR no 2 de la Régie
10	NPCC A-10 Criteria

Section 1 – NERC Registration Process

Please provide an overview of the NERC Registration Process.

NERC's starting point for monitoring and enforcing compliance with Reliability Standards is NERC's processes for identifying and registering owners, operators, and users of the bulk power system are responsible for performing reliability-related functions in accordance with the approved Reliability Standards. All bulk power system owners, operators and users are required to register with NERC. The process for registration is described in the NERC Rules of Procedure, Section 500 and Appendix 5A. The NERC Compliance Registry is a listing of all organizations registered and therefore subject to compliance with approved reliability standards. NERC developed a "Statement of Compliance Registry Criteria" (Registry Criteria) defined in the NERC Rules of Procedure Appendix 5B that delineates the selection criteria employed by NERC and regional entities to determine which organizations should be registered as owners, operators, or users of the interconnected transmission network and therefore included on the NERC Compliance Registry. The Registry Criteria provide a basis for identifying whether an entity should be subject to the NERC compliance and monitoring programs. These initial "bright-lines" determine whether an entity is an owner, operator, or user of the bulk power system as that term has been defined by the United States Congress. Once the entity is registered, the program then assesses the how and what kind of impact the entity has or can bring to the bulk power system.

Please describe NERC's Registry Criteria process.

NERC's Registry Criteria articulates a three-step process for determining whether bulk power system users, owners and operators must be registered in one or more functional categories for compliance with mandatory Reliability Standards. Section I provides that an entity that uses, owns or operates elements of the Bulk Electric System pursuant to NERC's definition is a candidate for registration. Section II of the Registry

Criteria categorizes registration candidates under fifteen functional entity categories. Section III provides threshold criteria for excluding entities identified as candidates for registration under Sections I and II.

In addition, NERC has published a guide, the "NERC Bulk Electric System Definition Reference Document Version 2.0 – April 2014," (NERC BES Reference Document) to assist entities with respect to determining whether any assets meet the BES Definition. Specifically, NERC created a hierarchical approach in applying the BES Definition to help entities. The approach is described in details with figures to give the guidance.

Please summarize a typical process for applying the BES definition.

The typical process flow is listed below:

- Application of the BES Definition to determine entities that use, own, or operate elements of the Bulk Electric System. The identified entities are classified as (i) owners, operators, and users of the bulk power system and (ii) candidates for Registration.
    - In the event that the BES Definition designates an element as part of the Bulk Electric System that an entity believes is not necessary for the reliable operation of the interconnected transmission network, Appendix 5C of the ERO Rules of Procedure, Procedure for Requesting and Receiving an Exception from the Application of the NERC Definition of Bulk Electric System (BES Exception Process), may be used on a case-by-case basis to ensure that the appropriate elements are classified as part of the Bulk Electric System.

- Entities identified as candidates for registration are considered for registration under one or more of the appropriate functional entity types based on a comparison of the functions the entity normally performs and the Registry Criteria.
- The registered entity bears the burden of proof with respect to the materiality assessment and must submit to NERC, in writing, details of the issues and identification of the Responding Entity and the applicable Regional Entity, Reliability Coordinator, Balancing Authority, Planning Authority and Transmission Operator that have (or will have upon registration of the entity) the entity whose registration status is at issue within their respective scope of responsibility.

Additionally, NERC can request information relating to the following types of questions to help outline what duties and responsibilities the entity will have in the performance of their duties.

- Does the entity have real-time authoritative control of BES elements?
- Is the entity specifically identified in the emergency operation plans and/or restoration plans of an associated Reliability Coordinator, Balancing Authority, Generator Operator or Transmission Operator?
- Will intentional or inadvertent removal of an element owned or operated by the entity, or a common mode failure of two elements as identified in the Reliability Standards (for example, loss of two elements as a result of a breaker failure), lead to a reliability issue on another entity's system (such as a neighboring entity's element exceeding an applicable rating, or loss of non-consequential load due to a single contingency). Conversely, will such contingencies on a neighboring entity's system result in Reliability Standards issues on the system of the entity in question?
- Can the normal operation, misoperation or malicious use of the entity's cyber assets cause a detrimental impact (e.g., by limiting the operational alternatives) on the operational reliability of an associated Balancing Authority, Generator Operator or Transmission Operator?
- Will the aggregate effect of eliminating functional registrations and/or reducing the compliance obligations (i.e. subset list of Reliability Standards/Requirements) for an entity within a portion of the Bulk Electric System result in a potential adverse reliability impact to that portion of the Bulk Electric System (e.g., where multiple entities considered individually are not necessary for the reliable operation of the system, but in aggregate the entities are material)?
- Will the aggregate effect of eliminating functional registrations and/or reducing the compliance obligations (i.e. subset list of Reliability Standards/Requirements) for an entity across the Bulk Electric System result in a potential adverse reliability impact to the Bulk Electric System (e.g., where all or many of a particular functional entity type would affect the reliable operation of the system during a wide-area disturbance)?

Please explain how the BES Definition identifies candidates for registration in Section I of the Registry Criteria.

The BES Definition includes bright-line core criteria with various enumerated inclusions and exclusions. As a result of the application of these provisions, all elements and facilities necessary for the reliable operation and planning of the interconnected transmission network will be included as elements of the Bulk Electric System. The BES

Definition consists of what NERC refers to as a "core" definition and a list of facilities configurations that will be included or excluded from the "core" definition.

Please explain how NERC applies the BES Definition.

NERC applies the BES Definition in a three step hierarchy. First, entities apply the core definition to establish the bright line of 100 kV, the overall demarcation point between Bulk Electric System and Non-Bulk Electric System elements. Second, entities apply the specific Inclusions to determine specific elements that are included in the Bulk Electric System, such as certain transmission elements and real power (generation) and reactive power resources. Third, entities evaluate specific situations for potential exclusion from the Bulk Electric System and should be applied. For example, exclusion E2 (behind-the-meter generation) provides for the specific exclusion of certain real power resources that reside behind the retail meter on the customer's side and supersedes the more general inclusion I2 (generating resources).

Please explain the "core" definition of the Bulk Electric System.

The "core" definition of the BES Definition:

> *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.*

Please explain whether the RTA facilities would be included in the core definition.

RTA's facilities would be included under the core definition because they contain Real Power resources connected at 100 kV or higher. In the AESI Report, AESI describes the RTA generation facilities as being connected at 161 kV or higher facilities (See AESI Report at 4, n. 13)

Please explain NERC BES Definition Inclusion I2.

Because the core definition cannot explicitly provide enough clarity on all electrical elements and how they would be recognized, NERC added several additional provisions to deal with specific needs. These provisions may either "include" or "exclude" assets to the BES Definition. Inclusion I2 provides supplemental detailed criteria for the inclusion of generation under the BES. Inclusion I2 states:

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:

- *Gross individual nameplate rating greater than 20 MVA. Or,*
- *Gross plant/facility aggregate nameplate rating greater than 75 MVA.*

The drawings below from the NERC BES Reference Document, illustrate how NERC applies Inclusion I2.

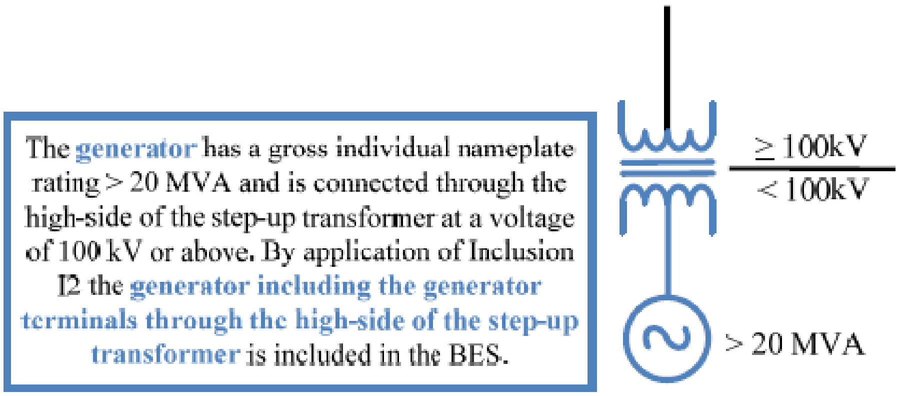

Figure I2-1: Single Generator (BES)

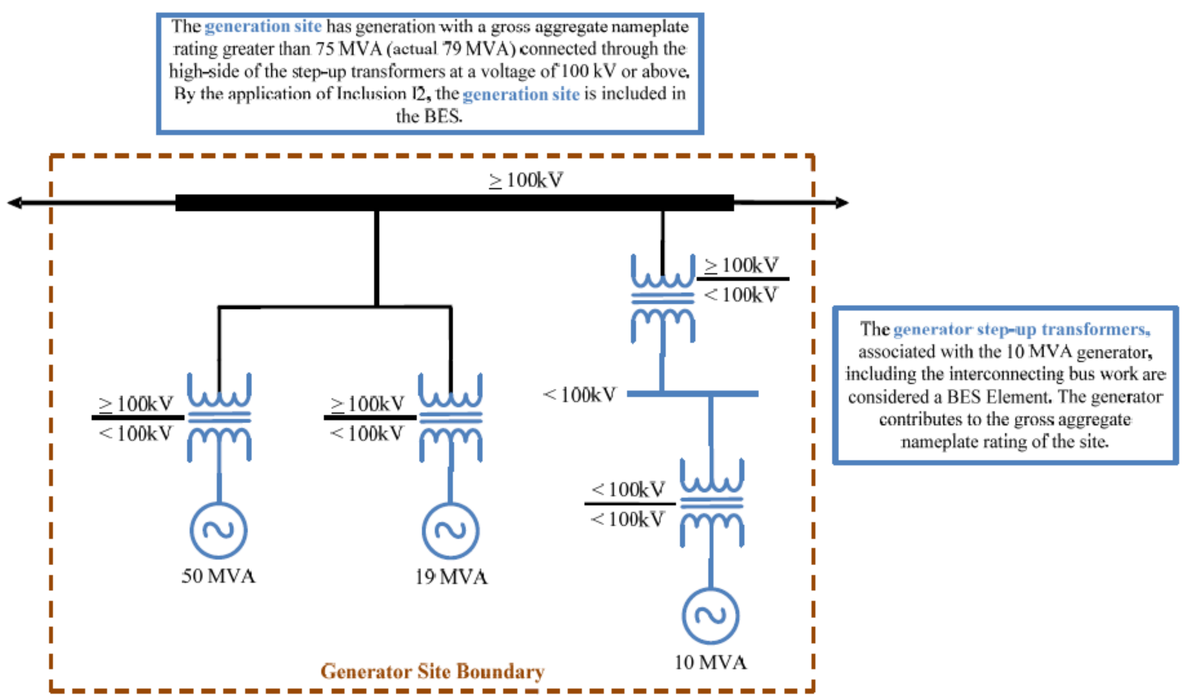

Figure I2-5: Multiple Generators at a Single Site (BES)

Would RTA's facilities be part of the BES pursuant to Inclusion I2 in the BES Definition?

Yes. RTA indicates [redacted] that it has seven generation units totaling at least 3000 MVA [redacted]

[redacted]

In addition, the operating voltage of the grid where this generation is connected appears to be 161 kV, which exceeds the BES Definition 100 kV threshold for the high side terminals of the step-up transformer. Given these parameters, all of the generation would meet the Inclusion I2 of the BES Definition.

You explain that RTA's facilities would fall under Inclusion I2 of the BES Definition. Would RTA's facilities have been subject to Reliability Standards prior to the effective date of the BES Definition?

Yes. While the BES Definition has only been in effect since 2014 with newly included Bulk Electric System elements become subject to relevant Reliability Standards July 1, 2016, the Northeast Power Coordinating Council, Inc (NPCC) has included generation at or above 20 MVA since the first set of NERC Reliability Standards became effective on June 21, 2007. From that day until May 4, 2009, NPCC criteria for determining whether generation should be subject to registration as a Generator Owner and Generator Operator was determined by whether the generation was at or above 20 MVA and directly connected to a what NPCC defined as an "A-10" transmission facility. NPCC defined specific requirements applicable to design, operation, and protection of the bulk power system in a document entitled "Classification of Bulk Power System Elements (Document A-10)" to provide the methodology to identify the bulk power system elements, or parts thereof, of the interconnected NPCC Region. As an exhibit to my testimony, I have included NPCC's entire A-10 criteria. This was in effect until May 4, 2009, when NPCC issued a "Compliance Guidance Statement" (CGS). The CGS provided additional guidance to all the entities in the NPCC footprint that revised the definition of generation materiality in the United States for use when NPCC assessed the need to register a Generator Owner and Generator Operator to the NPCC and NERC Compliance Registries. The CGS stated that all generating units (individual generating unit greater than 20 MVA (gross nameplate rating) or generating plant/facility greater than 75 MVA (gross aggregate nameplate rating)) that are connected via step up transformers to transmission facilities 100 kV and above were considered material to the reliability of the bulk electric system in the United States. In sum, since the inception of Reliability Standards, individual generation at or above 20 MVA has been subject to Reliability Standards in the NPCC region. Therefore, since the CGS in 2009, the A-10 criteria of NPCC to establish the bulk electric system was not the only criteria to establish the impact of an installation in the NPCC region.

Please explain Exclusion E2 of the BES Definition.

NERC established this exclusion to address those "physical" electrical installations where an end user's load also has generation that is owned by the same end user and the generation is co-located with the end user load behind a distribution utility's retail meter. Prior to the implementation of the BES Definition, NERC had previously recognized these physical installations as eligible for registration as part of its Registry Criteria. The language in the Registry Criteria and the BES Definition are materially the same. Additionally, these types of installations have been called "behind the meter" or "net metering" and have been mostly used by industrial customers. Industrial customers prefer local sources of generation and reliability services for their load requirements thus making the service of load more reliable at the local level.

Exclusions

Figure E2-2 depicts customer owned generation residing behind the retail meter. The cogeneration operation is resulting in a net capacity to the BES of 100 MVA.

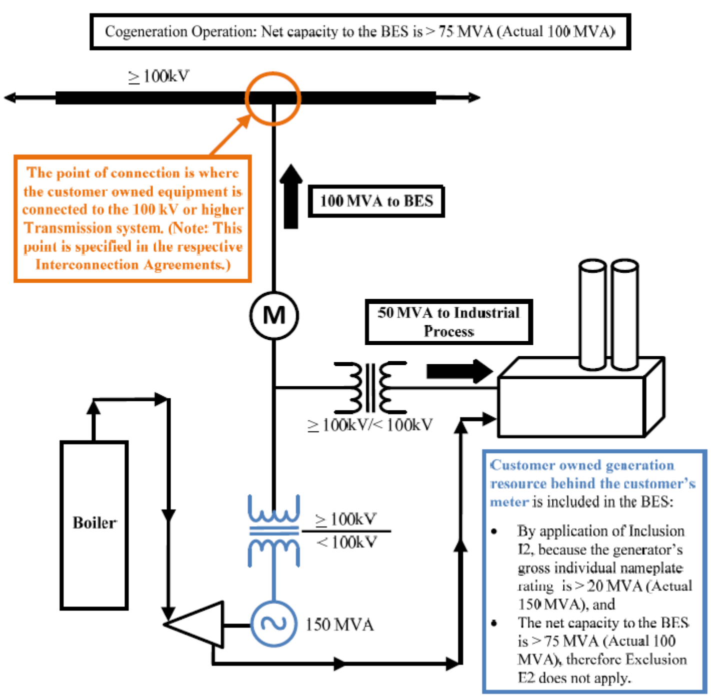

Figure E2-2: Behind-the-Meter Generation: Net Capacity to the BES Greater Than 75 MVA

NERC's basis for this exclusion comes from the setup of a common interconnection for the load and generation. This is illustrated in the figure above which is included in the NERC BES Reference Document. Thus a utility's retail metering records the net amount of the load and generation. This design provides for the customer to perform the coordination, balancing, and handling of operations at the location behind the designated metering point. The distribution entity is responsible for such actions based upon the net impact, on their side of the metering point.

When the net impact of the load and generation is less than 75 MVA, the generation is not subject NERC oversight. However, if the net impact to the interconnected transmission network is greater than 75 MVA to the distribution entity, the generation does not qualify for exclusion from the BES Definition and the customer must develop a compliance program to meet all of the Reliability Standards that are applicable to the Generator Owner and/or Generator Operator functional categories.

To determine netting, an entity must evaluate the hourly generation and load values for a 12-month period. If the amount of generation exceeds the hourly load by a value of 75 MVA or greater, the entity is not eligible for the E2 Exclusion. This is true even if there is only one hour of a 75 MVA exceedance.

Does the RTA meet this exclusion in the BES Definition?

No, the RTA facilities do not meet Exclusion E2 of the BES Definition.

Please explain why it does not meet the Exclusion.

Based upon my experience and knowledge of the exclusion as a member of the NERC BES Definition Standard Development Project Team, this installation would not meet the Exclusion for two reasons. First, as illustrated in the one-line diagram below, RTA is represented by the area within the dashed black lines. As shown, there is not a single interconnection point where all of the RTA generation and load is connected to the HQT bulk power system or the HQ- designated Reseau de transport principal (RTP). There are four interconnection points between HQT and RTA. Plus, there are interconnections from RTA to service areas that HQT is obligated to serve load. There are a total of seven generation plants located within the RTA footprint and the major RTA load points are located at Usine Alma and Usine Jonquiere. As seen elsewhere in the North American continent, this would be considered a virtual net-metering environment instead of the purely physical electrical configuration.

Redacted

Second, based on the RTA statements of its combined generation and load, the net input to the HQT RTP will exceed 75 MVA on a regular basis. As I explained above, if there is even one hour of injection of power to the interconnected transmission network, net metered generation is not eligible for the E2 Exclusion. As shown in the table below, RTP generation exceeds 75 MVA for a significant number of hours annually over the last few years.

Redacted

Given these reasons, RTA would not be able to claim an E2 Exclusion under the BES Definition.

Please explain NERC BES Definition Exclusion E1.

Exclusion E1 of the BES Definition provides for excluding radial systems from the Bulk Electric System. A radial system is a portion of the grid where there is a single interconnection and, absent a working interconnection, any generation or load would otherwise be isolated or blacked out from the rest of the interconnected transmission network. There are three types of radial systems eligible for exclusion under the BES Definition. They are load only, generation only, and combined load and generation. If there is more than one interconnection to serve a single area, it therefore cannot be considered a radial system. Exclusion E3 is as follows:

> *E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:*
>
> *a) Only serves Load. Or*
> *b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or, c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).*
>
> *Note – A normally open switching device between radial systems, as depicted on p prints or one-line diagrams for example, does not affect this exclusion.*

Does the RTA meet Exclusion E1 of the NERC BES Definition?

No. As I explained in my conclusions regarding Exclusion E2, RTA has four points of service interconnection with HQT, thus RTA cannot be viewed as a radial system.

Please explain BES Definition Exclusion E3.

Under Exclusion E3, local networks (LN) can be excluded from the Bulk Electric System. An LN could be considered multiple interconnected radial systems and is defined as "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." Whereas an Exclusion E1 radial system would have a single interconnection point to the grid, an LN would have two or more interconnections to what would be otherwise isolated portion of the system. LNs provide for an increased level of reliability because a single point could be shut down for maintenance or out-of-service for other reasons, but the remaining interconnections ensure adequate flows are maintained to serve the balance of the LN.

In order for an LN to be excluded, four conditions must be met. First, an LN cannot have transmission elements operated above 300 kV. Second, the total aggregate amount of generation within the LN system must be 75 MVA of nameplate generation or less. Third, all flows on all of the interconnections must be in toward the LN. At a minimum, entities would have to show, on an hourly basis that for a period of two years, there were no outward flows on the three main interconnects with the RTP. Fourth, the LN is not part of a flowgate or transfer path, where 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 Quebec Interconnections, and is not a monitored facility included in an Interconnection Reliability Operating Limit (IROL). Any one of these criteria can invalidate the Exclusion being taken.

Does the RTA meet this Exclusion Provision in the BES Definition?

The RTA does not meet the E3 Exclusion.

Please explain why it does not meet the Exclusion E3.

Based on the information presented by RTA, I conclude that NERC would not accept the RTA configuration as an LN because it fails to meet the Exclusion E3 criteria. While the initial configuration has the appearance of an LN, it fails to meet the following LN requirements. First, there are several 300 kV transmission elements included within the LN. Second, total nameplate generation exceeds 75 MVA. Third, [redacted] Thus, RTA would not be permitted to take Exclusion E3.

You have not indicated whether a control center is considered part of the Bulk Electric System. Please explain.

NERC defines a "Control Center" as

One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in realtime to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

NERC Reliability Standards outline certain performance obligations for control centers, but they are not recognized as BES assets under the BES Definition. When an entity owns or operates Bulk Electric Systems assets and they are subject to the standards outlining performance obligations for control centers, the entity must assess whether it is performing certain reliability obligations like balancing, dispatching, or having control on the operation of BES assets. If so, entities must then comply with all standards associated with control centers.

Would there be another option for RTA to seek removal from the Bulk Electric System?

Yes, NERC has established the BES Exception Process to add elements to, and remove elements from, the Bulk Electric System. The decision to approve or disapprove exception requests will be made by NERC thereby eliminating the potential for inconsistency and subjectivity. The exception process is not intended to be used to resolve ambiguous situations. Rather, the exception process is only available after an initial determination has been made regarding whether an element is part of or not part of the Bulk Electric System through the application of the definition to the element. An owner of an element may submit a request to the applicable Regional Entity to include the element in, or remove it from, the bulk electric system. In addition, a Regional Entity, planning authority, reliability coordinator, transmission operator, transmission planner, or balancing authority that has the elements covered by an exception request within its scope of responsibility may submit an exception request for the inclusion of an element or elements owned by a registered entity.

The requesting entity must assemble studies, engineering analyses, diagrams, and other evidence and submit the exception request to NERC. NERC regional and technical staffs will review the submitted data. Should additional data be necessary for the review, NERC can impose such requirements on the entity. It is up to the entity to present and justify a technical rationale why the request for Exception should be granted. The Exception process can take months to years to complete, depending upon the technical nature of the request.

Have you participated in an Exception Request for an entity?

Yes, my company worked with an entity on a specific case where they sought to have a LN exclusion exception.

Did NERC grant the exception?

No. The company presented all of the technical data, including engineering studies, documenting how they met the Exclusion criteria on all evaluative points. However, due to the unique nature of the interconnected transmission network and market conditions of this particular entity, NERC found that the flowgate criterion from Exclusion E3 was not met. As a result, the exception was not granted. In my opinion, this suggests that NERC, even in the case of strong technical data illustrating that there is little impact to the grid, holds tight to all bright-line threshold criteria in order to ensure reliability of the interconnected transmission network.

In your view, how would you believe a RTA exception request would fare at NERC?

Based upon my experience and in my follow up conversations with the NERC technical staff pertaining to that particular request I describe above, I do not believe that the RTA would be successful in being granted an Exception. As I explain above the RTA configuration fails to meet the criteria that are required for exclusion. I believe that NERC, if this case were presented, would not grant the exception.

What does it mean if RTA cannot secure an Exclusion under E1, E2, or E3?

RTA would become a candidate to be a NERC registered entity.

You previously explained that Section II of the Registry Criteria categorizes registration candidates under fifteen functional entity categories. Would RTA be registered for any of those categories in the United States?

As I explain in further detail below, based upon the information contained within the RTA filing, it is reasonable to conclude that the RTA would be registered (if they were located within the continental boundary of the United States of America), at a minimum as a Generator Owner, Generator Operator, and Transmission Owner. That said, with the tasks that RTA indicates it performs in coordination with the Reliability Coordinator, RTA could also be deemed to be a Balancing Authority and a Transmission Operator.

What are some of the responsibilities of a Balancing Authority and Transmission Operator that cause you to suggest this outcome?

As identified in the NERC Reliability Functional Model – Version 5 document, a Balancing Authority integrates resource plans ahead of time, maintains generation-load-interchange-balance within a Balancing Authority Area, and contributes to Interconnection frequency in real time. Specifically, some of the Ahead of Time and Real Time duties include, but aren't limited to:

- Receives operating and availability status of generating units and operational plans and commitments from Generator Operators (including annual maintenance plans) within the Balancing Authority Area.
- Receives annual maintenance plans from Generator Owners within the Balancing Authority Area.
- Receives final approval or denial of a request for an Arranged Interchange from the Interchange Coordinators.
- Implements generator commitment and dispatch schedules from the Load-Serving Entities and Generator Operators who have arranged for generation within the Balancing Authority Area.
- Receives dispatch adjustments from Reliability Coordinators to prevent exceeding limits.
- Provides generation dispatch to Reliability Coordinators.
- Receives operating information from Generator Operators.
- Provides Real-time operational information for Reliability Coordinator monitoring.
- Receives reliability alerts from Reliability Coordinator.
- Complies with reliability-related requirements (e.g., reactive requirements, location of operating reserves) specified by Reliability Coordinator.
- Directs resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in real time.
- Implements corrective actions and emergency procedures as directed by the Reliability Coordinator.
- Receives information of Implemented Interchange and Confirmed Interchange curtailments from Interchange Coordinator.

In the NERC Functional Model, a Transmission Operator has the following tasks:

- Monitor and provide telemetry (as needed) of all reliability-related parameters within the reliability area.
- Monitor the status of, and deploy, facilities classed as transmission assets, which may include the transmission lines connecting a generating plant to the

transmission system, associated protective relaying systems and Special Protection Systems.

- Develop system limitations such as System Operating Limits and Total Transfer Capabilities, and operate within those limits.
- Develop and implement emergency procedures.
- Develop and implement system restoration plans.
- Deploy reactive resources to maintain transmission voltage within defined limits.

Would RTA qualify as a Balancing Authority and Transmission Operator?

Yes. In my view of the RTA evidence and indications from discussions with HQT staff, these tasks are being performed on a regular basis by the RTA. As such, if the RTA were located in the United States of America, NERC might seek to register them as a Balancing Authority and Transmission Operator because they perform the following:

- Receives operating and availability status of generating units and operational plans and commitments from Generator Operators (including annual maintenance plans) within the Balancing Authority Area.
- Receives, for its own generators, annual maintenance plans from Generator Owners within the Balancing Authority Area.
- Receives final approval or denial of a request for an Arranged Interchange from the Interchange Coordinators.
- Receives, at the point of interconnection, dispatch adjustments from Reliability Coordinators to prevent exceeding limits.
- Receives operating information from Generator Operators.
- Provides Real-time operational information for Reliability Coordinator monitoring at the point of interconnection.
- Directs resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in real time.
- Per the "Common Instructions," implements corrective actions and emergency procedures as directed by the Reliability Coordinator.

<u>Section 2 – Protection of Critical Infrastructure</u>

What do you address in this section of your testimony?

I summarize the history of NERC's development of Reliability Standards for the protection of the North American interconnected transmission network. In doing so, I provide a background on the evolution of the need for cyber security protection and how NERC has addressed the evolving threats to the grid as the North American transmission network has become even more interconnected.

Explain the evolution of how the interconnected transmission network has been operated.

For many years, the control systems for the interconnected transmission network have operated in a stand-alone environment without computer or communication links to the external information technology infrastructure. However, more recently such stand-alone enclaves have been increasingly connected to both the corporate environment and the external world, and the interconnected transmission network is no exception. Indeed, these network connections bring the potential for cyber and physical attacks on these systems. The problem becomes particularly critical when several entities come under attack simultaneously.

What is the concern with cyber attacks on interconnected networks?

Attacks have the potential to impact the interconnected transmission network rather than to simply disrupt the operation of some components. Electronic access is the key to any successful cyber attack. Gaining physical access constitutes a major step toward achieving electronic access, but many other means are available. If an adversary can gain electronic access to a computer system, he may be able to gain control over that system and use it for his purposes. In today's environment, many infrastructure control systems have an electronic pathway that leads to the outside world, which can create a potential for access that is vulnerable to exploitation by an adversary. Indeed various industries have experienced computer exploitation of infrastructure control systems. To date, the majority of these intrusions have resulted in minimal disruption to the infrastructure itself. However, these episodes clearly illustrate that electronic pathways do exist that lead to the control systems of the most critical infrastructures. Prevention, or an expectation that one can prevent all attacks is unrealistic. In order to establish a "culture of security," an entity must develop tools, processes, and practices that will allow the entity to have information when an attack occurs and the ability to limit the hacker's attempt to disrupt the cyber systems. The NERC set of CIP Reliability Standards are designed to provide a structure for entities to meet those expectations.

What are some of the ways to mitigate cyber threats?

First and foremost is a strong cyber security posture by the entities that may be vulnerable to such attacks. To meet or minimize these risks, one widely recognized cyber security strategy is defense in depth. Defense in depth is a widely accepted, effective strategy to address cyber threats that is both comprehensive and flexible. This strategy involves layering of defense mechanisms in a way that discourages an attack and increases the potential that an entity will be alerted to the attack.

Compared to general grid operations, cyber security is in many ways as much, or even more, a matter of subjectively balancing physical and technical options rather than a purely objective task of achieving a single, steady, physical state. It does have a purely technical objective component, however, which consists of the various technologies that exist to defend computer systems. The task of balancing technical options comes into play as one selects and combines the various available technologies into a comprehensive architecture to protect the specific computer environment. The key to success is possessing cyber security standards that provide reliable direction on how to choose among alternatives to achieve an adequate level of security.

What steps has NERC taken to address cyber security of the grid?

To address these threats vis-à-vis the North American interconnected transmission network, NERC began development of the CIP Reliability Standards in June 2002. As an interim measure, NERC adopted an urgent action cyber security standard referred to as Urgent Action 1200 (UA 1200) in 2003. It was more limited in scope and applicability than the CIP Reliability Standards. The CIP Reliability Standards were approved by the NERC Board of Trustees in May 2006 to supersede UA 1200.

<u>Section 3 – Application of CIP Standards to RTA's facilities</u>

Please provide an overview of NERC's CIP Reliability Standards.

The CIP Reliability Standards recognizes "defense in depth," to address cyber threats that are both comprehensive and flexible by providing a set of requirements to protect the interconnected transmission network from malicious cyber attacks. In earlier versions, they required bulk power system users, owners, and operators to establish a risk-based vulnerability assessment methodology to identify and prioritize critical assets and critical cyber assets. Once the critical cyber assets were identified, the CIP Reliability Standards required, among other things, that the responsible entities establish plans, protocols, and controls to safeguard physical and electronic access, to train personnel on security matters, to report security incidents, and to be prepared for recovery actions. The first CIP standards, enacted in 2006, have evolved into the currently-effective "version 5" Standards. The version 5 standards require responsible entities to identify and categorize "BES Cyber Systems using a new methodology based on whether a BES Cyber System has a Low, Medium, or High Impact on the reliable operation of the bulk electric system. Once a BES Cyber System is categorized, a responsible entity must comply with the associated requirements of the CIP version 5 Standards that apply to the impact category.

Please explain how an entity identifies whether it has compliance obligations for its facilities under the CIP Reliability Standards.

The CIP Reliability Standards, starting with CIP-002-5.1, provide for a registered entity (e.g., a Generator Owner, Generator Operator, Balancing Authority, Transmission Owner and Transmission Operator) to assess whether or not their assets have what NERC refers to as BES Cyber Systems. NERC requires the identification and categorization of BES Cyber Systems according to specific criteria which are included "Attachment 1 – Impact Rating Criteria" (Attachment 1), that characterize their impact for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the bulk electric system. Under the CIP-002-5.1 method, a registered entity assesses assets against a series of "bright line" criteria to ascertain whether the asset can be identified as a High, Medium, or Low impact. The high impact category covers control centers having a wide area impact; the medium impact category that covers generation and transmission facilities, as well more localized control centers; and the low impact category that covers all other BES Cyber Systems.

Once the impact assessment has been completed, registered entities must review the cyber assets associated with the impact-identified asset against a set of BES Reliability Operating Services (BROS) and timing criteria (both of which are part of the CIP Reliability Standards) to determine whether the impact-identified asset contains BES Cyber Systems.

How does NERC define a BES Cyber Asset and BES Cyber System?

NERC defines a BES Cyber Asset as "[a] Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System." NERC defines a Cyber Asset as a "Programmable electronic devices, including the hardware, software, and data in those devices."

Second, NERC defines a BES Cyber System as "[o]ne or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity."

Would RTA's assets include BES Cyber System(s)?

Yes.

Please explain.

Per the guidance language in NERC CIP Reliability Standard starting on page 17, CIP-002-5.1 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, "…that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES." The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-5.1. The concept includes a number of named BES reliability operating services (BROS).

These named BROS include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

If any one of the BROS is performed and the timing intervals are identified as being appropriate, then the classified asset has a BES Cyber System. Based upon the evidence provided to date, the RTA Control Center would meet the Monitoring and Control BROS at a minimum as stated on pages 1 and 2 in Réponses de RTA à la DDR no 2 de la Régie. Other BROS that are likely are: Controlling Voltage, Balancing Load & Generation, and Dynamic Response.

Are Generator Owners, Generator Operators, Transmission Owners, Transmission Operators and Balancing Authorities subject to the NERC CIP Version 5 Reliability Standards?

Yes. The CIP standards contain a section outlining the applicability of the standard. This section identifies the various functional registrations that apply and if there are specific types of facilities that are subject to that standard. Generally, standards and their requirements apply only to Bulk Electric System recognized assets, unless the standard has detailed specific types of non- Bulk Electric System assets. Once an entity is recognized as having Bulk Electric System assets, the NERC mandatory standards for that functional registration associated with those Bulk Electric System assets apply. It is then up to the registered entity to develop programs, documentation, or other means to satisfy the obligation stated in the standard and its requirements.

In this case**,** in Section 4.2.2 of NERC CIP Reliability Standard CIP-002-5.1, all BES assets associated with entities registered as Generator Owner, Generator Operator, Transmission Owner, Transmission Operator and Balancing Authority are applicable and subject to the compliance obligations. This applicability language extends through all of the NERC CIP Reliability Standards.

As shown earlier, the each of RTA's seven generators would meet the I2 criteria and thus would be the basis for GO and GOP registration. As such, under the applicability of the NERC CIP Reliability Standard, all generation meeting the I2 criterion would need to be evaluated in the CIP Requirements.

Please explain the High and Medium Impact criteria in Attachment 1.

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories.

Attachment 1 Criterion 1 covers high impact assets for controls centers. The relevant criterion is:

Criterion 1.2 categorizes Control Centers used to perform the functional obligations of a Balancing Authority where there is an aggregation of 3000 MW in a single interconnection as High Impact. Assessment: This is based upon the total aggregate amount of generation as established by the net Real Power capability within or conducted through the RTA Control Center. In the United States of America, net Real Power capability under NERC does not provide for the reduction of retail load, but only for the on-site power requirements of the generation site.

Attachment 1 Criterion 2 covers medium impact assets for control centers. The relevant criterion is:

Criterion 2.1 categorizes 1500 MW of commissioned generation asset(s) at a single location as Medium Impact; or Criterion 2.11 categorizes asset(s) used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection as Medium Impact. Assessment: Depending how "single location" might be defined for RTA's facilities, one or the other of these criteria would likely identify the generation assets as Medium Impact.

How should the 3000 MW threshold for Control Centers used to perform the functional obligations of a Balancing Authority functions be calculated?

It is a bright line threshold. As NERC states in the Guidelines and Technical Basis for the CIP-002-5.1 standard, "In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1." This is consistent with NERC's broader use of the bright line concept throughout the BES process which provides consistency across systems and regions.

How did NERC derive the 3000 MW threshold?

In the Guidelines and Technical Basis section of CIP-002-5.1, NERC explains that the 3000 MW threshold for criterion 1.2 for BA Control Centers was derived from its analysis of Balancing Authority footprints which shows that a "majority of BAs with significant impact are covered under this criterion."

What was NERC's rationale for using the 1500 MW criterion?

When NERC implemented version 4 of the CIP Reliability Standards, it promulgated a "Rationale and Implementation Reference Document (NERC CIP Reference Document) as guidance for responsible entities in the application of the criteria in CIP-002-4 Attachment 1. It provides clarifying notes on the intent of the rationale of the development of the standard. The NERC CIP Reference Document explains that criterion 1.15 (now criterion 2.11 in the version 5 standards) designates generation control centers that control generation facilities designated as critical assets or used to control generation greater than an aggregate of 1500 MW in a single interconnection as critical assets. NERC explained that in the development of this criterion the drafting team derived the 1500 MW threshold from other Reliability Standards and intended it as a bright-line for aggregate generation controlled based on the used in Criterion 1.1. The drafting team specified a single interconnection because it is more likely that the span of control of the generation control center may cross multiple Balancing Authority areas or even regions and interconnections.

How does NERC instruct entities to calculate the 1500 MW?

In the use of "net Real Power capability," NERC team sought to use a value that could be verified through existing requirements. In that light, it selected NERC standard MOD-024 and current development efforts in that area. Please note that MOD-024 has since been combined with MOD-25 but as relevant here the material aspects of determining "net Real Power capability" remain the same. In MOD-025, the equation is as follows:

> Net Real Power Capability (*MW) equals Gross Real Power Capability (*MW) minus Aux Real Power connected at the same bus (*MW) minus tertiary Real Power connected at the same bus (*MW).

In other words, the calculation is the gross Real Power capability less any auxiliaries, station service, or other internal use of the output of generation units. Internal use does not include the service to any load external to the generation, such as in a net-metering configuration.

Please comment on RTA's "net generation injection" analysis.

Use of net generation injection is inconsistent with NERC policy and practice and with the plain words of Reliability Standard CIP-002-5.1. As I noted above, use of the bright line concept is to ensure consistency across systems and regions. To allow for a net injection analysis will create inconsistent application of standards which NERC rejected during the development process of the BES Definition. As previously stated in this testimony, I noted that the term "net Real Power Capability" has the definition of Real Power output minus Auxiliary and Tertiary Load. The provision for "net" does not provide for the subtraction of retail load in this equation.

Would RTA be subject to the High Impact classification under Reliability Standard CIP-002-5.1?

Based on my review of the RTA facilities, RTA performs Balancing Authority functions and thus, in the United States it is likely to be registered as a Balancing Authority. I[redacted] Consequently, the BES Cyber Systems need to be protected based upon the requirements of the NERC set of CIP Reliability Standards. Accordingly, RTA's Control Center that would be used to perform the functional obligations of a Balancing Authority where there is an aggregation of 3000 MW in a single interconnection would be designated as [redacted]

In my view and based upon the available information, if RTA were located within the continental boundary of the United States of America, they, as a registered entity, would be subject to NERC registrations for, at a minimum, Generator Owner, Generator Operator, and Balancing Authority[redacted]

[redacted]

Please summarize your conclusions.

RTA would be included as part of the Bulk Electric System by virtue of applying the BES Definition to its facilities, if they were located within the continental boundaries of the United States of America, and therefore subject to registration by NERC for compliance with relevant Reliability Standards. Its facilities fall under the "core" BES definition as well as the specific inclusion for generation at 20 MVA or higher. In addition, none of the exclusions would apply to RTA's facilities. Moreover even if they were excluded, they would be included by the inclusion process in the United States.

I also conclude that RTA performs functions that would cause NERC to register it as a Balancing Authority in the United States. [redacted] Finally, use of net generation injection is inconsistent with NERC policy and practice in using bright line criteria. Using a net injection analysis would create inconsistent application of standards which NERC has repeatedly rejected. It is also inconsistent with the rationale that NERC included with Reliability Standard CIP-002-5.1 which calls for a bright line test.