Rapport de l'expert Brian Evans-Mongeon

(version caviardée)

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

September 15, 2017

I. INTRODUCTION

1. Please state your name and address.

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

2. 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).

II. QUALIFICATIONS

3. 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.

4. 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, including, as of August 2017, the NERC Planning Committee. 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. A complete list of the NERC projects and committee in which I participated is attached as an Exhibit to my testimony.

5. 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.

6. What experience do you have with the Transmission Operations (TOP) and Interconnection Reliability Operations and Coordination (IRO) Reliability Standards?

As an industry participant and an active member of the NERC Ballot Body, I have reviewed, discussed, developed comments and balloted on the TOP and IRO family of Reliability Standards, including the most recent update during NERC Project 2014-03. As I discuss in detail below, this project was a review and consolidation of much of the TOP and IRO Standards to simplify and streamline the requirements. Discussions and comment development activities include participation in industry and trade organizations, most notably the NPCC Regional Standards Committee. This Committee is comprised of participants representing all segments of the NERC program. Through vetting in this group, the Standards were generally viewed as supportive of and necessary for BES reliability. This included significant discussions of the monitoring of non-BES elements to support the reliability of the BES.

My practical experience with implementation of the Standards involves assisting clients in the satisfaction of data requests and information requirements from the Transmission Operator and Reliability Coordinator for those entities to maintain situational awareness of grid operations. Providing the data and information necessary to the Transmission Operator and Reliability Coordinator to maintain situational awareness is critical to interconnected transmission network operations and in the best interest of all interconnected utilities to ensure operation within system limitations. Explaining this reasoning to the entities subjected to the data requests and ensuring their compliance with these requests is a significant portion of my experience with these specific Standards.

7. Have you testified previously before the Regie?

Yes, I have testified at the Régie de l'énergie in the hearing held for the second phase of file R-3947-2015 regarding the NERC Critical Infrastructure Protection (CIP) Reliability Standards.

III. TESTIMONY

8. What is the purpose of your testimony?

The first section of my testimony describes NERC registration process and how the BES Definition is used to determine which entities must comply with the NERC Reliability Standards. That section is very similar to my report filed in the second phase of file R-3947-2015. I then describe how the facilities of Rio Tinto Alcan, Inc. (RTA) would not be excluded from the NERC BES Definition, if RTA 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. As a result of RTA's facilities being part of the BES, I also conclude that RTA would be required to comply with the NERC TOP and IRO Reliability Standards due to the significance of their facilities in the interconnected transmission network. Further, if there is a markets concern on the potential for information sharing within Hydro-Quebec by Hydro-Quebec TransEnergie, then this issue would be addressed outside of NERC as it is not a reliability concern. Under reliability requirements, an entity recognized as an individual Balancing Authority, Generator Operator, Transmission Operator, or a Transmission Planner, which I believe to be a valid case for them to be registered as such, then the data required is just as significant and it must be shared between the areas.

9. What exhibits have you reviewed in the preparation of your testimony?

Exhibit Number	Description
HQCF-5, document 2.2	Resume of Brian Evans-Mongeon
HQCF-5, document 5	NERC BES Definition
HQCF-5, document 2.3	TOP and IRO Standards
HQCF-5, document 2.4	FERC Proposal to Remand TOP and IRO Standards (November 21, 2013)
HQCF-5, document 2.5	FERC Order 817 Approving Revised TOP and IRO Standards

HQCF-5, document 1.2	Reliability Coordinator's Report
C-RTA-0024 (R-3947-2015 phase II)	AESI Report in docket R-3947-2015 phase II
HQCF-5, document 2.6	Hydro Quebec TransÉnergie Register of Entities Subject to Reliability Standards April 2017
HQCF-5, document 3	Kim Warren's report
HQCMÉ-2017-1, Document 6	Arizona-Southern California outages on September 8, 2011 (Causes and Recommendations) – FERC/NERC Staff Report
HQCF-5, document 8	Reliability Functional Model Technical Document Version 5
HQCF-5, document 9	Bulk Electric System Definition Reference Document

<u>Section I – NERC Registration Process</u>

10. 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 ensure users of the interconnected transmission network are responsible for performing reliability-related functions in accordance with the approved Reliability Standards. All owners, operators and users of the interconnected transmission network 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 Electric System" as that term has been defined by NERC. Once the entity is registered, the program then assesses the how and what kind of impact the entity has or can bring to the interconnected transmission network.

11. Please describe NERC's Registry Criteria process.

NERC's Registry Criteria articulates a three-step process for determining whether interconnected transmission network 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 (BES 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 including and 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.

12. 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 interconnected transmission network 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)?

13. 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.

14. Comment on how the BES Definition is applied in the U.S.

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).

15. 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.

16. Comment on whether the core definition applies to RTA's facilities.

RTA's facilities would be included under the core definition because they contain "Transmission Elements operated at 100 kV or higher" as well as "Real Power resources connected at 100 kV or higher." In addition, RTA owns more than 3000 MW of generating resources and a control center. 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).

17. 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.

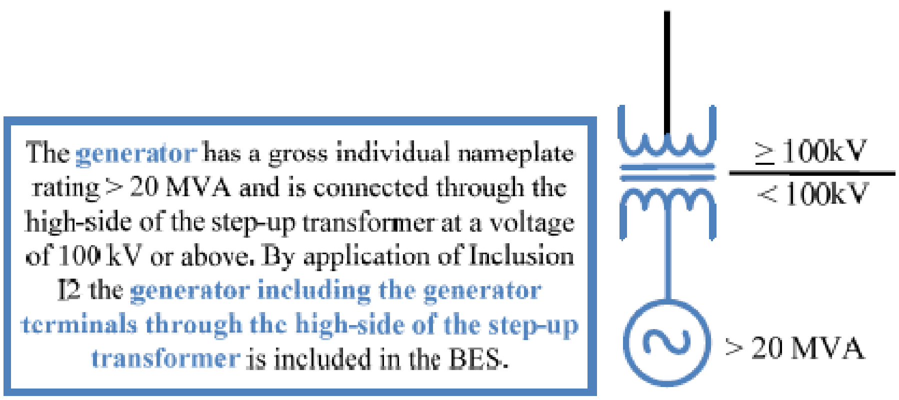

Figure I2-1: Single Generator (BES)

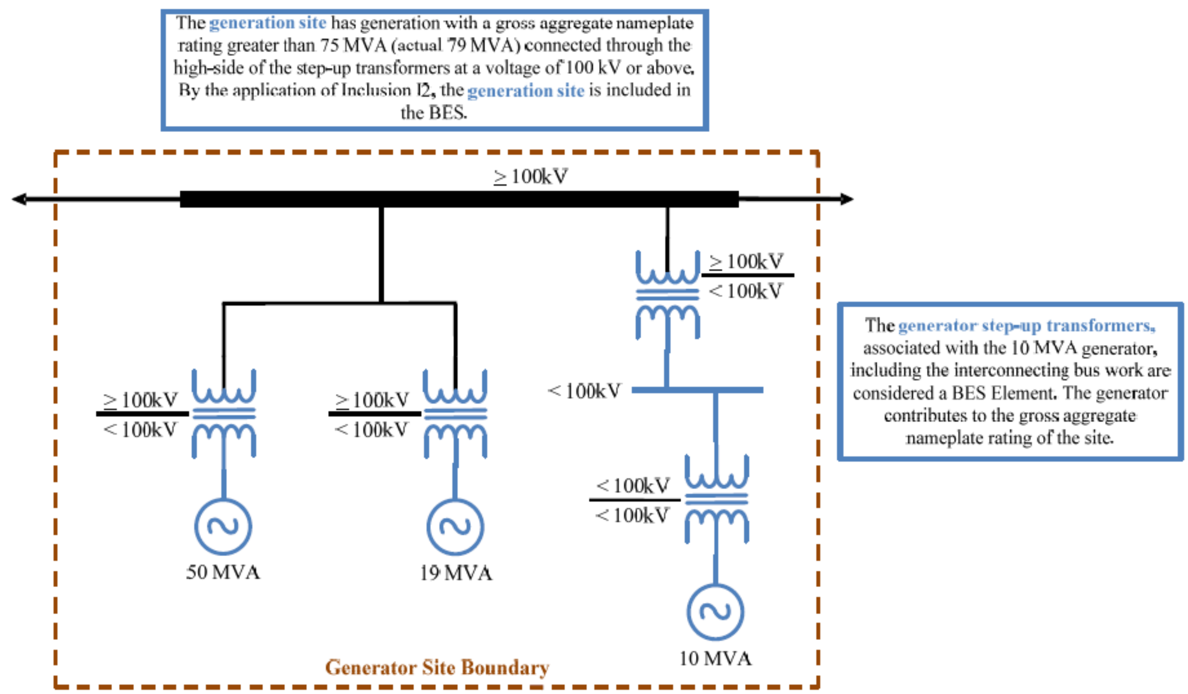

Figure I2-5: Multiple Generators at a Single Site (BES)

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

Yes. RTA has seven generation facilities totaling at least 3000 MVA of generation within a generation site boundary based on the one line diagram with a dashed black line. The nameplate capacity for each of RTA's seven generation facilities exceeds 75 MVA, with each generating unit exceeding 20 MVA.[1]

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.

19. 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?

---

[1] http://www.regie-energie.qc.ca/en/audiences/NormesFiabiliteTransportElectricite/R-3947-2015-B-0083-D%C3%A9pos%C3%A9-2017_04_04_EN.pdf page 62.

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 BPS 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.

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.

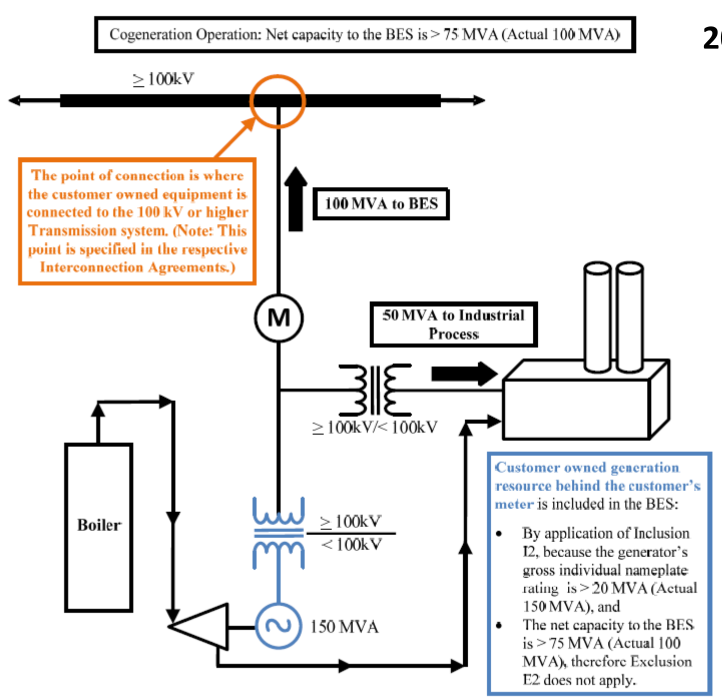

Figure E2-2: Behind-the-Meter Generation: Net Capacity to the BES Greater Than 75 MVA

20. 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.

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.

21. Does RTA meet this exclusion in the BES Definition?

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

22. Please explain why.

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. 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 Réseau 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 [redacted] and [redacted]. 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, as shown in the table below, RTP generation exceeds 75 MVA for a significant number of hours annually over the last few years. 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,[2] RTP generation exceeds 75 MVA for a significant number of hours annually over the last few years.

[2] HQCF-5, document 1.2

	Energy exchanged (GWh)		Hourly net energy exported from RTA to HQ > 75 MW	
	Total export by RTA	Net exchange between RTA and HQ[3]	Total hours	% hours
2009	[redacted]	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]
2017[4]	[redacted]	[redacted]	[redacted]	[redacted]

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

23. 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).*

---

[3] A negative energy value means RTA was a net buyer in that year.
[4] The data for 2017 are for January 1, 2017 through to June 30, 2017.

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.

24. Does 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.

25. 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.

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

RTA does not meet the E3 Exclusion.

27. Please explain why.

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, as presented by the RC in its report (HQCF-5, document 1.2), there are significant transfers of power to and from the HQT RTP. Thus, RTA would not be permitted to take Exclusion E3.

28. Comment on whether there are other options for an entity to seek removal from the Bulk Electric System?

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.

29. Comment on whether an Exception Request could benefit RTA.

Based on my experience, I do not believe it would. My company worked with an entity on a specific case where they sought to have a LN exclusion exception. 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.

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. Thus, in my view, RTA would become a candidate to be a NERC registered entity.

30. Please explain the functional registration process.

The process of entity registration begins at the regional level regardless of who identifies the entity to be registered (NERC, FERC, Regional Entity or an entity itself). The NERC Regional Enforcement Authority assesses the prospective entity using the NERC Statement of Compliance Registration Criteria Appendix 5B and if it meets those criteria forwards the application to NERC. NERC and the Regional Entities have identified two principles they believe are key to the entity selection process. These include needs to be consistency between regions and across the continent with respect to which entities are registered, and; plus any entity reasonably deemed material to the reliability of the interconnected transmission network will be registered, irrespective of other considerations.

To address the second principle, the Regional Entities, working with NERC, will identify and register any entity they deem material to the reliability of the interconnected transmission network. If NERC or a Regional Entity encounters an organization that is not listed in the Compliance Registry, but which should be subject to the Reliability Standards, NERC, or the Regional Entity, is obligated to initiate actions to add that organization to the Compliance Registry. The Regional Entity considering registration of an organization not meeting (e.g., smaller in size than) the criteria may propose registration of that organization if the Regional Entity believes and can reasonably demonstrate that the organization is an interconnected transmission network owner, or operates, or uses interconnected transmission network assets, and is material to the reliability of the interconnected transmission network. Similarly, the Regional Entity may exclude an organization that meets the criteria described above as a candidate for registration if it believes and can reasonably demonstrate to NERC that the interconnected transmission network owner, operator, or user does not have a material impact on the reliability of the interconnected transmission network.

NERC maintains the organization registration and organization certification programs that identify the roles and authority of Regional Entities in the programs are delegated from NERC pursuant to the Rules of Procedure through regional delegation agreements or other applicable agreements; as well as processes for the programs shall be administered by NERC and the Regional Entities. Materials that each Regional Entity uses are subject to review and approval by NERC.

For all geographical or electrical areas of the interconnected transmission network, the registration process ensures that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage.

In particular the process ensures that all areas are under the oversight of one and only one Reliability Coordinator, ensure that all Balancing Authorities and Transmission Operator entities are under the responsibility of one and only one Reliability Coordinator, ensure that all transmission Facilities of the interconnected transmission network are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator, and ensure that all loads and generators are under the responsibility and control of one and only one Balancing Authority.

31. You previously explained that Section II of the Registry Criteria categorizes registration candidates under fifteen functional entity categories. Comment on how RTA would qualify under those categories in the United States?

As I explain in further detail below, 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 and Transmission Planner. 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 Transmission Operator.

A Balancing Authority is defined as "The responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real-time. "

A Transmission Operator is defined as "The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission Facilities."

The Transmission Operator operates or directs the operation of transmission facilities, and maintains local-area reliability, that is, the reliability of the system and area for which the Transmission Operator has responsibility. The Transmission Operator achieves this by operating the transmission system within its purview in a manner that maintains proper voltage profiles and System Operating Limits, and honors transmission equipment limits established by the Transmission Owner. The Transmission Operator is under the Reliability Coordinator's direction respecting wide-area reliability considerations, that is, considerations beyond those of the system and area for which the Transmission Operator has responsibility and that include the systems and areas of neighboring Reliability Coordinators. The Transmission Operator, in coordination with the Reliability Coordinator, can take action, such as implementing voltage reductions, to help mitigate an Energy Emergency, and can take action in system restoration.

A Transmission Planner is defined as "The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area." For reference, a Planning Authority is defined as "The responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems." Today, within the ERO region that includes RTA, Hydro-Quebec is already recognized as the Planning Authority and typically, there is only one Planning Authority within a Balancing Authority. In many cases, and I feel that in the situation of RTA where they maintain substantive influence over the transmission Facilities within their operations, it is practical for there to be multiple Transmission Planners.

The boundaries for the Transmission Planner area are basically defined by the location of the Bulk Electric System facilities under the purview of the Transmission Planner, i.e. those facilities for which the Transmission Planner develops reinforcement and corrective action plans resulting from studies and analysis of system performance and interconnection of facilities. This means that the Transmission Planner's area is not defined by the extent of the models it uses or studies that it performs since any planner can assess and perform simulations on readily available interconnection wide models. The BES facilities in its area, i.e. under its purview, are generally contiguous. Traditionally transmission planning has been associated with one or more Transmission Owners, i.e. reinforcement and corrective action plans must be associated with the facilities of certain Transmission Owners. In some cases where transmission ownership crosses a state line, the BES facilities on one side of a geographic boundary line may be in one Transmission Planner Area while the remaining facilities may be in another. As such, the Transmission Planner Area is not constrained to fit within one Reliability Coordinator or Transmission Operator Area. However, the Transmission Planner Area can only be smaller than or equal to the area of its related Planning Coordinator.

32. What are the responsibilities of a Balancing Authority, Transmission Operator and Transmission Planner that cause you to suggest this outcome?

As identified in the NERC Reliability Functional Model, 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.

33. Please describe Transmission Operator tasks.

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.

34. Please describe Transmission Planner tasks.

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

- Maintain and develop, in cooperation with adjacent and overlapping Transmission Planners, methodologies and tools for the analysis and simulation of the transmission systems in the evaluation and development of transmission expansion plans related to resource adequacy plans.

- Define, consolidate and collect or develop, in cooperation with adjacent and overlapping Transmission Planners, information required for planning purposes including:
    - Transmission facility characteristics and ratings.
    - Demand and energy forecasts, capacity resources, and demand response programs.
    - Generator unit performance characteristics and capabilities.
    - Long-term capacity purchases and sales

- Maintain transmission system models (steady state, dynamics, and short circuit) to evaluate Bulk Electric System performance.

- Coordinate with adjacent and overlapping Transmission Planners so that system models and resource and transmission expansion plans take into account modifications made to adjacent and overlapping Transmission Planner areas.

- Evaluate, develop, document, and report on expansion plans for the Transmission Planner area. Assess whether the integrated plan meets reliability needs, and, if not, report on potential network conditions or configurations that do not meet performance requirements and provide potential alternative solutions to meet performance requirements.
    - Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for transmission service.
    - Evaluate and plan for all requests required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.
    - Determine transfer capability values (generally one year and beyond) as appropriate.
    - Monitor, evaluate and report on transmission expansion plan and resource plan implementation.
    - Coordinate projects requiring transmission outages that can impact reliability and firm transactions.

- Notify Generation Owners, Resource Planners, Transmission Planners and Transmission Owners of any planned transmission changes that may impact their facilities.

- Define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.

35. Would RTA qualify as a Balancing Authority and Transmission Operator and Transmission Planner?

Yes. In my view of the RTA evidence submitted in the file R-3947-2015 regarding the CIP standards, 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, Transmission Operator and Transmission Planner 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.
- 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.
- Maintains and develops methodologies and tools for the analysis and simulation of the transmission systems in the evaluation and development of transmission expansion plans.
- Defines and develops information required for planning purposes including: Transmission facility characteristics and ratings, Demand and energy forecasts, and capacity resources, Generator unit performance characteristics and capabilities, Long-term capacity purchases and sales.
- Coordinates with adjacent Transmission Planners so that system models and resource and transmission expansion plans.
- Appears to evaluate plans that are in response to long-term (generally one year and beyond) for transmission service.
- Evaluates and plans to integrate new (End-use Customer, generation, and transmission) facilities into the bulk electric system.
- Determines transfer capability values (generally one year and beyond) as appropriate.
- Coordinates projects requiring transmission outages that can impact reliability and firm transactions.
- Notifies others any planned transmission changes that may impact their facilities.
- Defines system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.

While the Quebec reliability framework is slightly different from how NERC identifies entities for registration, the Québec Reliability Coordinator, whom the Régie designates, can seek registration of entities which perform the aforementioned functional tasks. The Régie then approves the registry and puts it into force. Both regimes are focused on reliability and on rigorous registration of entities and are supported by thorough processes.

<u>Section II – TOP-IRO Reliability Standards</u>

36. What do you address in this section of your testimony?

In this section, I discuss the history and development of the TOP and IRO Reliability Standards. I discuss the original standards, the impetus for changing the standards and the improvements in the standards. I also discuss how the standards address the 2011 Southwest Outage particularly with respect to lower voltage (sub-100 kV or non-BES)) facilities. In addition, I discuss why the TOP Reliability Standards would be applicable to RTA as a Balancing Authority, Transmission Operator and Transmission Planner.

37. Please describe the history and background of the NERC Reliability Standards.

NERC has been promoting and evaluating interconnected transmission network reliability and developing reliability standards for over 40 years. Since its inception, NERC has adopted operating policies and planning standards to ensure the reliability of the interconnected transmission network in North America. In response to the blackout of August 2003, NERC transformed its existing operating policies and planning standards into Reliability Standards. NERC contemplated that collectively the reliability standards should provide a comprehensive and complete set of technically sound requirements that establish an acceptable threshold of performance necessary to ensure reliability of the interconnected transmission network. NERC envisioned that an adequate level of reliability would entail both a complete set of standards addressing all aspects of interconnected transmission network design, planning, and operation that materially affect reliability, and for the technical efficacy of each standard. It is primarily for this reason that NERC proposed that all of operating policies and standards be used initially as the base set of standards.

38. Please provide a timeline and the purpose and need for the development of the TOP and IRO Standards.

In June 2002, the NERC Board of Trustees approved a new, consensus-based standards development procedure founded on the American National Standards Institute (ANSI) principles of openness, inclusiveness, balance, and fairness. At that time there were sixteen reliability standards in some stage of development: eleven originally proposed standards covering a minimum set of requirements for reliable planning and operation of bulk electric systems; four additional standards addressing certification criteria for reliability service providers; and a standard on cyber security.

NERC accelerated the transition from operating policies and planning standards to a single set of reliability standards under the ANSI-accredited process for several reasons:

1. The August 14, 2003 blackout has challenged NERC and the industry to demonstrate that its reliability standards are unambiguous and measurable immediately.

2. The U.S./Canada Power System Outage Task Force final report of April 5, 2004 states in Recommendation 25: "NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards."

3. An April 14, 2004 FERC order stated a policy objective addressing the need to expeditiously modify NERC reliability standards in order to make these standards clear and enforceable.

4. The continued use of multiple formats, processes and forums for developing and maintaining reliability rules is an inefficient dilution of industry and staff resources.

5. The transition to new standards and retiring of existing operating policies and planning standards will be too complex for industry implementation if taken one standard at a time over several years. The August 14, 2003 blackout has created an urgent need for NERC to ensure that its reliability standards are clear and measurable. This need has been reinforced by Recommendation 25 of the U.S./Canada Power System Outage Task Force and FERC's reliability policy objective.

39. Did NERC include the initial version of the TOP and IRO Reliability Standards in the 2002-2005 timeframe?

Yes, NERC worked on the development of the TOP and IRO standards during this time, and it adopted the Version 0 Standards on February 8, 2005. As part of implementing the Version 0 Standards, NERC developed a 2006 work plan to ensure the standards were ready to be effective on January 1, 2007. The plan addressed three areas of work: a) modifications to the standards necessary to make them ready for implementation by the ERO; b) modifications to NERC procedures that must be approved and in place prior to operation as the ERO. The NERC reliability standards process requires each standard to be reviewed at least once every five years. This periodic review ensured that even the least significant standards will receive appropriate scrutiny and necessary improvements over time.

The process for transferring to a new reliability standard and concurrently retiring applicable sections of the operating policies and planning standards was always recognized to be complex, particularly for the entities that must follow the reliability rules and the Regional Councils who are implementing the compliance programs. A protracted, multi-year transition would be confusing and more difficult than a more abbreviated effort to replace the operating policies and planning standards in a single step. This implies that the Version 0 standards were a first step in maintaining an adequate level of reliability and that further changes could be expected.

40. Comment on subsequent revisions to the "Version 0" TOP and IRO Reliability Standards.

NERC began revision of the Version 0 of the TOP and IRO Reliability Standards in 2007. NERC Project 2007-03 was established to revise the TOP Standards to specifically clarify requirements for real-time operations of the interconnected transmission network and consider stakeholder comments from the Version 0 development and comments from FERC. The revisions to the TOP and IRO standards were completed in 2013, however, FERC had concerns about the revisions and remanded the standards back to NERC.

41. You mentioned "concerns" from FERC. Can you please elaborate?

NERC submitted revised TOP and IRO Reliability Standards to FERC in 2013. The Commission issued a Notice of Proposed Rulemaking (FERC Remand NOPR) in which it proposed to remand the standards citing concerns that the changes in the proposed standards create reliability gaps in the standards that are critical to reliable operation of the interconnected transmission network and that NERC has removed critical reliability aspects without adequately addressing these aspects in the proposed standards. One area of concern that FERC noted was that, unlike the currently-effective TOP Reliability Standards, there was no requirement in the proposed standards for transmission operators to plan and operate within all System Operating Limits (SOLs). FERC also observed that the provisions in the proposed Reliability Standards that require transmission operators to operate only within a subset of SOLs offset the potential improvements.

42. Where there other concerns?

Yes, FERC described nearly one dozen concerns. These can be found in the FERC Remand NOPR which I attach as an exhibit to my testimony. Notably, FERC was concerned with NERC's proposal to retire TOP and IRO Reliability Standards that require reliability coordinators and transmission operators to maintain and use certain models and analysis capabilities and monitoring. Specifically, FERC was concerned that NERC proposed to delete requirements for transmission operators to (1) maintain accurate computer models utilized for analyzing and planning system operations; (2) use monitoring equipment to bring to the attention of operating personnel important deviations; (3) use sufficient metering to ensure accurate and timely monitoring; and (4) have sufficient information and analysis tools to determine the cause(s) of SOL violations.

43. Did FERC raise any concerns about sub-100 kV facilities?

Yes. FERC noted it was unclear whether NERC's proposal would require transmission operators to include updated external networks to reflect operating conditions external to their systems and (internal and external) sub-100 kV facilities in their operational planning analyses. In Order 693, FERC directed a modification to planned outage coordination to require consideration of facilities below 100 kV that, in the opinion of the registered entity (such as a transmission operator) will have a direct impact on the reliability of the interconnected transmission network. The 2011 Southwest Outage Blackout Report includes similar recommendations, which I discuss below, that transmission operators should ensure their next-day studies include updated external networks and internal and external facilities (including those below 100 kV) that can impact interconnected transmission network reliability. Although NERC proposed to require the transmission operator to consider "projected system conditions," FERC stated that it was is unclear whether "projected System conditions" include the relevant updated external networks and (internal and external) sub-100 kV facilities.

44. What steps did NERC take to address FERC's concerns?

In response to the aforementioned concerns raised by FERC, NERC initiated Project 2014-03 to provide clear, unambiguous Reliability Standards to allow Reliability Coordinators, Transmission Operators, and Balancing Authorities operate the interconnected transmission system in a safe and reliable manner. In addition, the Project 2014-03 standard drafting team considered recommendations from the Independent Experts Review Panel ("IERP"). In sum, the development of the Reliability Standards was informed by industry reports and initiatives, including two NERC-sponsored technical conferences in March 2014, the Southwest Outage Report, the IERP Report, the NERC Operating Committee consideration of the IERP report and feedback from FERC.

45. On the basis of your experience in Reliability Standards, describe the general improvements regarding the TOP and IRO standards from NERC Project 2014-03.

The Reliability Standards stemming from these projects improved the then effective TOP and IRO Reliability Standards by eliminating gaps, ambiguities, and redundancies, and by improving the overall quality of the TOP and IRO Reliability Standards. The Reliability Standards included improvements over the Version 0 TOP and IRO Reliability Standards in key areas such as: (1) operating within system operating limits and interconnection reliability operating limit) (SOLs and IROLs); (2) outage coordination; (3) situational awareness; (4) improved clarity and content in foundational definitions; and (5) requirements for operational reliability data.

Specifically, the Reliability Standards address matters that are fundamental to grid reliability as they pertain to the coordinated efforts to plan and operate the Bulk Electric System in a reliable manner under both normal and abnormal conditions. The Reliability Standards provide a comprehensive framework for reliable operations, with important improvements to ensure the Bulk Electric System is operated within pre-established limits while enhancing situational awareness and strengthening operations planning. The Reliability Standards establish or revise requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities, and operational reliability data. Among other things, the Reliability Standards help to ensure that Reliability Coordinators and Transmission Operators work together, and with other functional entities, to operate the Bulk Electric System within System Operating Limits ("SOLs") and Interconnection Reliability Operating Limits ("IROLs").

46. Please discuss the currently-effective TOP and IRO Reliability Standards.

The TOP Reliability Standards generally address real-time operations and planning for next-day operations, and apply primarily to the responsibilities and authorities of Transmission Operators, although certain requirements apply to the roles and responsibilities of the Balancing Authority. The IRO Reliability Standards set forth the responsibility and authority of Reliability Coordinators to provide for reliable operations. Reliability Coordinators have an essential role in ensuring reliable operations, as they are the functional entities with the highest level of authority and have the wide-area view of the Bulk Electric System.

The Reliability Standards improve upon existing obligations for Transmission Operators and Reliability Coordinators to help ensure the Bulk Electric System is operated within predetermined operating limits. Specifically, SOLs, which must be monitored by Transmission Operators, include Ratings and limits necessary to ensure reliable operation within acceptable reliability criteria, as determined pursuant to Facilities Design, Connections and Maintenance ("FAC") Reliability Standards. In the IRO Reliability Standards, Reliability Coordinators must continue to monitor SOLs in addition to their obligation in the currently effective Reliability Standards to monitor and analyze IROLs. These obligations require the Reliability Coordinator to have the wide-area view necessary for situational awareness and provide them the ability to respond to system conditions that have the potential to negatively affect reliable operations.

47. Please discuss the improvements to the operations planning and outage coordination aspects of the Reliability Standards.

The Reliability Standards also improve upon operational planning requirements for Reliability Coordinators and Transmission Operators. Reliability Standards IRO-008-2 and TOP-002-4 contain requirements for performing day-ahead studies and developing plans to operate within operating limits. Certain operational planning requirements are applicable to the Balancing Authorities as well, as discussed below. Further, the revised definition for Operational Planning Analysis incorporates recommendations from the Southwest Outage Report that are designed to address operations planning shortfalls with the potential to cause repeat occurrences of similar events. For example, the revised definition of Operational Planning Analysis includes use of external system data such as transmission or generation outages, interchange prediction, and projected system conditions to improve the scope, accuracy, and quality of the analysis.

Operations planning relies on timely and accurate information of transmission and generation outages. Consequently, Reliability Standard IRO-017-1 addresses the coordination of outages in advance. Reliability Standard IRO-017-1 establishes operational planning requirements for each Reliability Coordinator to implement an outage coordination process for its area that will identify and resolve issues with the potential to impact reliable operations. Reliability Standard IRO-017-1 thus addresses a reliability gap identified in the IERP Report and the Southwest Outage Report.

48. What changes were made to the standards with respect to operational reliability data?

The Reliability Standards establish requirements for the provision of information and data needed by the Transmission Operator and Balancing Authority for reliable operations. Reliability Standard TOP-003-3 (Operational Reliability Data) establishes requirements for the provision of information and data needed by the Transmission Operator and Balancing Authority for reliable operations, replacing relevant requirements from Reliability Standard TOP-003-1. The purpose of Reliability Standard

TOP-003-3 is to ensure that Transmission Operators and Balancing Authorities have the data needed to fulfill their operational and planning responsibilities. TOP-003-3 is derived from the approach for Reliability Coordinators in Reliability Standard IRO-010-2 to improve the flow of operational reliability data needed by Transmission Operators and Balancing Authorities. Effective operations planning and accurate assessment of system conditions in real-time rely on complete, current, and timely data and information.

49. Please describe the specific requirements of Reliability Standard TOP-003-3.

The Reliability Standard consists of five Requirements, including requirements for Balancing Authorities and Transmission Operators to maintain and distribute to relevant entities data specifications needed to perform various analyses and assessments. The Reliability Standard also requires entities receiving data specifications to respond according to mutually agreed upon parameters. The following is a description of each of the Requirements in TOP-003-3.

Requirement R1 requires each Transmission Operator to maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification must include, but is not limited to:

• a list of data and information needed to support these analyses, monitoring, and assessments;
• provisions for the notification of current Protection System and Special Protection System status or degradation that impacts System reliability;
• a periodicity for providing data; and
• the deadline by which the respondent (i.e., recipient) is to provide the indicated data.

Requirement R2 requires each Balancing Authority to maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification must include:
• a list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring;
• provisions for the notification of current Protection System and Special Protection System status or degradation that impacts System reliability;
• a periodicity for providing data; and
• the deadline by which the respondent (i.e., recipient) is to provide the indicated data.

Requirements R3 and R4 require each Transmission Operator (Requirement R3) and Balancing Authority (Requirement R4) to distribute its data specification to the entities that have the necessary data.

Requirement R5 requires each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification pursuant to Requirement R3 or R4 to satisfy the obligations of the documented data specification using:

(i) a mutually agreeable format;
(ii) (ii) a mutually agreeable process for resolving data conflicts; and
(iii) (iii) a mutually agreeable security protocol. Data specification and collection for Reliability Coordinators is addressed in Reliability Standard IRO-010-2 (Reliability Coordinator Data Specification and Collection).

50. Please describe the specific requirements of Reliability Standard IRO-010-2.

Reliability Standard IRO-010-2 (Reliability Coordinator Data Specification and Collection) provides a mechanism for the Reliability Coordinator to obtain the information and data it needs for reliable operations and to help prevent instability, uncontrolled separation, or cascading outages. Reliability Standard IRO-010-2 reflects recommendations from Southwest Outage Report, including more clearly identifying necessary data and information to be included in the Reliability Coordinator's data specification.

The Reliability Standard consists of the following three requirements:

Requirement R1 provides that the Reliability Coordinator must maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification must include:

- a list of data and information necessary to support Reliability Coordinator Operational Planning Analyses, Real-time monitoring, and Real-time Assessments, including non-Bulk Electric System data and external network data, as deemed necessary by the Reliability Coordinator;
- provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability;
- a periodicity for providing data; and
- the deadline by which the respondent is to provide the indicated data.

Requirement R2 provides that the Reliability Coordinator must distribute its data specification to entities that have the required data.

Requirement R3 provides that each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification must satisfy the obligations of the documented specifications using a mutually-agreeable format, process for resolving data conflicts, and security protocol.

I understand from Hydro Quebec TransÉnergie that Hydro Quebec TransÉnergie, as the Quebec Interconnection Reliability Coordinator transmitted its specification on January 1st, 2017.[5]

<u>Section III - The Arizona-Southern California Outage on September 8, 2011 (2011 Southwest Outage</u>

51. Please describe the 2011 Southwest Outage.

On the afternoon of September 8, 2011, an 11-minute system disturbance occurred in the Pacific Southwest, leading to cascading outages and leaving approximately 2.7 million customers without power. The outages affected parts of Arizona, southern California, and Baja California, Mexico. All of the San Diego area lost power, with nearly 1.5 million customers in the region losing power, some for up to 12 hours.

52. Comment on NERC's investigation on the 2011 Southwest Outage.

Following the 2011 Southwest Outage, NERC and FERC conducted a joint investigation. The investigation concluded that the cause of the disturbance stemmed primarily from weaknesses in operations planning and real-time situational awareness, which, if conducted properly, would have allowed system operators to proactively operate the system in a secure state during normal system conditions and to restore the system to a secure state as soon as possible.

On April 27, 2012, FERC and NERC issued the "Arizona-Southern California Outage on September 8, 2011, Causes and Recommendations" (Southwest Outage Report),

[5] http://www.hydroquebec.com/reliability-coordinator/documentation.html. And the document is: http://www.hydroquebec.com/data/transenergie/pdf/specification-for-data-and-information.pdf

outlining the investigators' findings and making recommendations for reliability improvements. The Southwest Outage Report made twenty-seven findings and associated recommendations applicable mostly to Transmission Operators, Balancing Authorities, and Reliability Coordinators. These findings and recommendations addressed the lack of adequate operations planning and real-time situational awareness of contingency conditions.

The Southwest Outage Report concluded that several other factors contributed to the 2011 Southwest Outage. For example, the Reliability Coordinator and the affected entities did not consistently recognize the adverse impact that sub-100 kV facilities can have on the reliability. Furthermore, there were significant issues with protection system settings.

53. How does the lack of real-time situational awareness affect reliability?

Transmission Operators, Balancing Authorities and Reliability Coordinators have system operators who constantly monitor their networks to maintain situational awareness of system conditions, identify potential system disturbances, and institute mitigating measures, as necessary. The affected entities use a range of tools to perform these functions. All of the entities use SCADA systems as their main monitoring tool. SCADA systems typically consist of a central computer that receives information from various RTUs and intelligent electronic devices (IEDs), located throughout the system. SCADA systems provide control center operators with real-time measurements of system conditions and can send alarms to signal a problem. Most of the affected entities also use several other tools to study and analyze the information received from their SCADA systems. Two of the most important tools are State Estimator and RTCA. State Estimator gathers the available measurements from the SCADA system and calculates estimated real-time values for the whole system. RTCA then takes the information from State Estimator and studies "what if" scenarios. For example, RTCA determines the potential effects of losing a specific facility, such as a generator, transmission line, or transformer, on the rest of the system. In addition to studying the effects of various contingencies, RTCA can prioritize contingencies. It can also provide mitigating actions and send alarms (visual and/or audible) to operators to alert them to potential contingencies. While most entities have and use these tools, the Southwest Outage Report identified several concerns with entities' ability to adequately monitor, identify, and plan for the next most critical contingency in real time.

54. Can you specify the findings of the SW Outage Report on this issue?

Yes. The September 8th event exposed the negative consequences of Transmission Operators having limited external visibility into neighboring systems. The South West Outage demonstrated that more expansive visibility into neighboring systems is necessary for these Transmission Operators to maintain situational awareness of external conditions and contingencies that could impact their systems and internal conditions and contingencies that could impact their neighbors' systems. During the 11-minute time span of the Southwest Outage, entities observed changes in flows into their systems, but were unable to understand the cause or significance of these changes and lacked sufficient time to take corrective actions. If affected entities had seen and run studies based on real-time external conditions prior to the event, they could have been better prepared to redispatch generation or take other control actions and deal with the impacts when the event started.

The Southwest Outage Report found that affected Transmission Operators had limited real-time visibility outside their systems, typically monitoring only one external bus. As a result, they lacked adequate situational awareness of external contingencies that impacted their systems. They also may not fully understand how internal contingencies could affect SOLs in their neighbors' systems. The specific situation related to this finding is described in the Southwest Outage Report as follows (page 87-88):

> IID [Imperial Irrigation District], for example, is adjacent to APS [Arizona Public Service, and the changes in flows on APS's system, especially on its 500 kV lines, can affect the flows on IID's system and vice versa. Yet, IID's visibility into APS's system is limited to information about the tie line between them. In fact, IID's visibility into all of its neighbors is limited to one or two buses outside its system. As a result, IID did not learn in real-time that H-NG tripped. IID also did not understand prior to the event how changes in flows or the loss of H-NG would affect its system. Immediately after H-NG tripped, IID observed loading on its CV transformers escalate rapidly, but it had not been prepared for this escalation. If IID had greater visibility into APS's system and IID had an equivalent on its RTCA that modeled the external network using APS's real-time data instead of pseudogenerators modeled at the end of each tie line, IID's RTCA could have more accurately studied the results of a post-contingency loss of H-NG on its system before it occurred. After seeing the more accurate RTCA results, IID could have initiated appropriate control actions before H-NG tripped. Also, having real-

time status of the H-NG would have better prepared IID to deal with the effects of its loss in real time.

In addition to IID not having adequate situational awareness of APS's system, the affected Transmission Operators and Balancing Authorities external to IID were not aware in real time of the effect of the post-contingency loss of IID's three 230/92 kV transformers on their systems. Losses of the CV and Ramon transformers can cause SOL violations on neighboring systems. These transformer outages had a significant ripple effect and led to the cascading nature of the event. Yet, entities outside IID's footprint were not prepared for these outages and, except for WECC RC, were unaware of the outages in real time because of a lack of adequate visibility into IID's system. For example, at the time of the event, CAISO's visibility into IID's system stopped at the tie line into IID's El Centro station.

Providing Transmission Operators with the ability to observe and model external system conditions and events on a continuous real-time basis will allow them to study and plan for the impact of external conditions and contingencies before it is too late to react, as was the case with the Southwest Outage.

55. How did NERC address the concerns and recommendations of the SW Outage Report when it revised the TOP and IRO Reliability Standards in 2014?

As part of the 2014 revision to the TOP and IRO Reliability Standards, NERC considered the Southwest Outage Report findings and recommendations applicable to Transmission Operators, Balancing Authorities and Reliability Coordinators, and addressed these recommendations in the language of the Reliability Standards. Below I describe some of the pertinent findings and recommendations identified in the Southwest Outage Report, and an explanation of how NERC revised the Reliability Standards to address the reliability issues identified following the 2011 Southwest Outage.

56. Please discuss the Southwest Outage Report findings and recommendations on situational awareness.

NERC and FERC staff concluded in the Southwest Outage Report that Transmission Operators have limited real-time visibility outside their systems and lack adequate situational awareness of external contingencies. Accordingly, recommendation #11 proposed that Transmission Operators engage in more real-time data sharing and obtain sufficient data to monitor significant external facilities in real-time. In addition, recommendation #11 advised that Transmission Operators review their real-time monitoring tools, such as state estimator and real-time contingency analysis (“RTCA”), to ensure that such tools reflect the critical facilities needed for the reliable operation of the interconnected transmission network.

57. Comment on how NERC revised the standards to address the lack of situational awareness.

Reliability Standard TOP-001-3, Requirement R13 addresses this reliability concern by requiring Transmission Operators to perform a Real-time Assessment at least once every 30 minutes. Furthermore, the definition of Real-time Assessment includes an assessment of potential post-contingency operating conditions.

58. Please discuss the Southwest Outage Report Findings with respect to inadequate real-time tools and NERC’s fix in the TOP and IRO Reliability Standards.

In recommendation #12, FERC and NERC staff advised that Transmission Operators should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.

Reliability Standard TOP-001-3, Requirement R13, is designed to resolve this specific issue by requiring Transmission Operators to ensure a Real-time Assessment is performed at least once every 30 minutes.

In addition, the Southwest Outage Report determined that post-contingency mitigation plans are not viable under all circumstances and suggested that Transmission Operators review existing operating processes and procedures to ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions to return the system to a secure state.

Reliability Standards TOP-002-4, Requirement R2 and TOP-001-3, Requirement R14 resolve this issue by requiring Transmission Operators to have an Operating Plan to address SOL exceedances, and initiate the Operating Plan to mitigate an exceedance as part of its real-time monitoring or assessment. In addition, the standard drafting team has developed a white paper on SOL definition and exceedance criteria (the “SOL White Paper”), which clarified the standard drafting team’s position on establishing and exceeding SOLs, and on implementing Operating Plans to mitigate exceedances. The SOL White Paper provides important linkages between relevant reliability standards and reliability concepts to establish a common understanding necessary for developing effective Operating Plans to mitigate SOL exceedances.

Finally, recommendation #13 advised that as part of the review of existing operating processes and procedures, Transmission Operators should consider the effect of relays that automatically isolate facilities without providing operators sufficient time to take mitigating measures.

NERC addressed this in Reliability Standard TOP-003-3, Requirement R1, and the definitions of Operational Planning Analysis and Real-time Assessment, which collectively require the acquisition of protection system data, such as relays that automatically isolate facilities, as an item to be included in the Transmission Operator studies.

59. The Southwest Outage Report found that the Reliability Coordinator and the neighboring transmission operators were not notified that upon losing Real Time Contingency Analysis (RTCA) capability, at least one affected transmission operator lost the ability to conduct RTCA more than 30 minutes prior to, and throughout the course of the event. What did it recommend and what was NERC's response?

Recommendation #15 suggested that Transmission Operators should ensure procedures and training are in place to notify WECC Reliability Coordinator and neighboring Transmission Operators and Balancing Authorities promptly after losing RTCA capabilities. TOP-001-3, Requirement R9, which requires Transmission Operators to notify affected registered entities of outages to monitoring and assessment capabilities, addresses this recommendation.

60. Please describe pertinent findings and recommendations with respect to operations planning.

Several findings in the Southwest Outage Report relate to operations planning. The Southwest Outage Report noted that not all Transmission Operators conducted studies or shared studies with other transmission operators or the Reliability Coordinator. In addition, the Southwest Outage Report determined that when conducting next-day studies, some affected Transmission Operators used models that do not reflect next-day operating conditions external to their systems. Recommendation #2 stated that Transmission Operators and Balancing Authorities update their studies to reflect these conditions. Such external operating conditions include generation and transmission outages and scheduled Interchanges.

61. What changes did NERC make to the Reliability Standards to address this?

NERC revised TOP-002-4, Requirements R1, R3, and R6 directly to address this recommendation by requiring Transmission Operators to conduct next-day studies (Requirement R1), share the results of the studies with the registered entities identified in the operating plans (Requirement R3), and provide the results to the Reliability Coordinator (Requirement R6).

Reliability Standards TOP-002-4, Requirement R1 and TOP-003-3 Requirement R1, Part 1.1, and the definition of Operational Planning Analysis address the need for accurate models. Specifically, TOP-002-4 Requirement R1 requires the Transmission Operators to have Operational Planning Analysis for the next day, which under the definition includes external operating conditions like Interchange data, transmission and generator outages, and identified equipment limitations. In addition, Reliability Standard TOP-003-3 Requirement R1, Part 1.1 requires Transmission Operators to maintain a documented specification for the data they need to support Operational Planning Analyses, including external network data. Furthermore, recommendation #2 suggested that Transmission Operators and Balancing Authorities should take the necessary steps to allow free exchange of next-day operational data between operating entities. TOP-003-3 Requirements R1, R2 and R5 address this reliability issue. Requirement R1 directs Transmission Operators to maintain data specification for the data necessary to perform Operational Planning Analysis, and Requirement R2 establishes a similar obligation for Balancing Authorities. Requirement R5 requires Transmission Operators, Balancing Authorities, Generator Owners, Generator Operators, Load-Serving Entities, Transmission Owners, and Distribution Providers to satisfy any requests for information included in the Reliability Standard that are necessary for completion of the required Operational Planning Analysis. The same recommendation also concluded that the Reliability Coordinators should review the procedures for coordinating next-day studies within their region, ensure adequate data exchange among Balancing Authorities and Transmission Operators, and facilitate the next-day studies conducted by Balancing Authorities and Transmission Operators. This issue is addressed in IRO-008-2 Requirement R2, which directs Reliability Coordinators to have coordinated Operating Plans(s) for next-day operations. These coordinated Operating Plans aim to timely and adequately address reliability issues identified in the next-day Operational Planning Analysis.

The Southwest Outage Report does not define the limits of which sub-100 kV facilities impact reliability. It recognizes that many facilities below 100 kV do not impact reliability but that the sub-100 kV facilities in this event affected the interconnected transmission network because they were in parallel to significant transmission corridors.

62. What are the Report's findings with regard to sub-100 kV facilities?

In the Southwest Outage Report, NERC and FERC staff determined that in conducting next-day studies, some Transmission Operators do not adequately consider lower-voltage facilities below 100 kV. They recommended that Transmission Operators and Reliability Coordinators should ensure their next-day studies include all internal and external facilities (including those below 100 kV) that can affect interconnected transmission network reliability.

NERC revised Reliability Standard TOP-003-3 Requirement R1.1 and IRO-010-2 Requirement R1.1 by specifically requiring Transmission Operators and Reliability Coordinators to incorporate any non-Bulk Electric System data deemed necessary into their Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

63. What did the Southwest Outage Report find with respect to providing adequate data for external and lower-voltage facilities in seasoning planning?

The Southwest Outage Report concluded in that the focus of Transmission Operator seasonal planning should be expanded to include external facilities and internal and external sub-100 kV facilities that affect Bulk Electric System reliability.

64. Did NERC modify the TOP-IRO Reliability Standards to address this recommendation?

Yes. This reliability concern was addressed in TOP-003-3, Requirement R1, which requires Transmission Operators to obtain external network and sub-100 kV data deemed necessary for use in Operational Planning Analyses. Additionally, the outage coordination process established by Reliability Coordinators, as required by IRO-017-1, must specifically address wide-area issues. In this manner, the Reliability Standards collectively ensure that the scope of operations planning from day-ahead up to and including seasonal planning extends beyond the individual Transmission Operator Area and is coordinated across the Reliability Coordinator Area. Furthermore, Reliability Standard IRO-017-1, Requirement R1 specifies that the Reliability Coordinator's outage coordination process must include a process for resolving planned outage conflicts with other Reliability Coordinators.

65. Has NERC made any subsequent modifications to the TOP and IRO Standards since 2014 to address sub-100 kV facilities?

Yes. Reliability Standard TOP-001-3 Requirement R10 required the Transmission Operator to monitor facilities and the status of special protection systems within its Transmission Operator area, and to obtain and use status, voltages, and flow data for Facilities and the status of special protection systems outside of its area, for the purpose of determining SOL exceedances within its Transmission Operator area. In Order 817, FERC expressed concern that in some instances the absence of real-time monitoring of non-BES (i.e. sub-100 kV) facilities by the transmission operator within and outside its TOP areas as necessary for determining SOL exceedances in TOP-001-3, Requirement R10 creates a reliability gap. Monitoring of such facilities, FERC explained, could protect reliability while these non-BES facilities are considered for inclusion in the BES through the BES inclusion process. Further, FERC noted that certain non-BES facilities may not qualify as candidates for inclusion in the BES Definition but should be monitored for reliability purposes because they are occasional SOL exceedance performers. FERC therefore directed NERC to revise TOP-001-3 Requirement R10 to require real-time monitoring of non-BES facilities.

Consistent with the Commission's directive, NERC revised the standard (now Reliability Standard TOP-001-4 Requirement R10 to become effective June 2018) to ensure that all facilities that can adversely impact reliability are monitored. The non-BES facilities that the Transmission Operator is required to monitor are those that are necessary for the Transmission Operator to determine SOL exceedances within its Transmission Operator Area. The requirement corresponds to Reliability Standard IRO-002-5 Requirement R5 which requires Reliability Coordinators to monitor non-BES facilities to the extent necessary. The requirement allows Transmission Operators flexibility for identifying the non-BES facilities that should be monitored for determining SOL exceedances. Transmission Operators perform various analyses and studies that could lead to the identification such facilities. These analyses and studies include, for example, the Operational Planning Analysis required by TOP-002-4 Requirement R1, the Real-time Assessments required by TOP-001-4 Requirement R13, any analysis performed by the Transmission Operator as part of BES exception processing, and analysis which may be specified in the Reliability Coordinator's outage process that leads the Transmission Operator to identify a non-BES facility that should be monitored temporarily for determining SOL exceedances.

66. Please comment on any anticipated changes to the Reliability Standards regarding data collection.

In 2017, NERC and its Technical Committees are considering amending their data collection requirements in a variety of standards, including the TOP and MOD standards. The data requirements involve the so-called distribution energy resources (DER). Presently, the industry is experiencing a change in the resource mix due to the deepening penetration of the inverter based resources, such as wind and solar within the distribution system footprints. Historically, these non-BES resources have been behind the meter and netted against the local distribution demands. Due to the deepening penetrations, the amount of generation is growing to a potentially significant amount of megawatts. As a result, NERC's initial research in this area has indicated that netting of DER against demand is no longer appropriate and needs to be collected and analyzed based upon the gross nameplates and total demand. NERC's DER data collection and modeling proposals will be acted upon in late 2017 and 2018.

With NERC is looking at the significance of distribution based generation for modelling purposes because netting is inappropriate, I believe RTA, which is netting at least 10-fold more generation compared to DER, should no longer be allowed to net its generation and load. It should have to communicate real-time data from inside its network to its host operator (Balancing Authority, Transmission Operator, and Reliability Coordinator) or to its neighboring operator if it assumes the operator functions.

67. What changes did NERC make regarding contingencies in operational planning analysis?

The previous TOP/IRO Standards were unclear on the need for including external networks or sub-100 kV facilities in the Operational Planning Analysis conducted by Transmission Operators. The new TOP Reliability Standards addressed this concern as follows. Reliability Standard TOP-003-3 requires each applicable entity to develop a data specification that would cover its data needs for monitoring and analysis purposes, including non-Bulk Electric System data and external network data deemed necessary by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments (see Requirement R1, Part 1.1). Further TOP-003-3, Requirement R5 requires Transmission Operators to supply data to Transmission Operator, thus making it clear that a Transmission Operator may request and receive data from outside of its immediate area. A similar requirement is in Reliability Standard IRO-010-2, Requirement R1, Part 1.1 for Reliability Coordinators. In addition, as discussed above, Reliability Standard TOP-001-4, Requirement R10 (which goes into effect in June 2018) has been revised to require the transmission operator to monitor non-BES facilities for determining system operating limit exceedances within its transmission operator area. NERC states that this revision helps to ensure that all facilities (i.e. BES and non-BES) that can adversely impact reliability are monitored.

I would also note that FERC Order No. 693 contained a directive to modify the TOP Reliability Standards for planned outage coordination to consider sub-100 kV facilities that the registered entity viewed as having a direct impact on interconnected transmission network reliability. The Southwest Blackout Report recommended similar treatment of sub-100 kV facilities and external networks to ensure that Transmission Operators' next-day studies include all external networks and facilities that could affect the reliability of the interconnected transmission network. Reliability Standard IRO-017-1 addresses outage coordination among the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner. Together with the data specification requirements in Reliability Standards TOP-003-3 and IRO-010-2, Reliability Standard IRO-017-1 would help ensure that the outage coordination process established by Reliability Coordinator will consider sub-100 kV facilities that the relevant entities view as having a direct impact on interconnected transmission network reliability.

68. Please discuss the other findings and recommendations in the Southwest Outage Report that NERC addressed in revising the TOP and IRO Reliability Standards.

NERC and FERC staff determined that the Reliability Coordinator process for estimating scheduled Interchanges was not adequate to ensure that such values were accurately reflected in the Reliability Coordinator's next-day studies. Along the same lines, The Southwest Outage Report concluded that due to a lack of coordination in the seasonal planning processing the WECC region, Transmission Operators may fail to identify contingencies in one subregion that could affect other Transmission Operators in the same or another subregion.

The Southwest Outage recommended that the Reliability Coordinator involved in the event should improve its process for predicting Interchanges in the day-ahead timeframe. In the definition of Operational Planning Analysis, Interchange data is an included input of next-day studies, which addresses this recommendation. The Report also recommended that the individual Transmission Operators should conduct a full contingency seasonal analysis to identify contingencies outside their own systems and share the analysis with the other affected Transmission Operators.

69. What did NERC revise in the TOP and IRO standards to address the issues?

Reliability Standards TOP-003-3, Requirement R1 and TOP-002-4, Requirement R3 address coordination of operational planning among Transmission Operators by requiring Transmission Operators to gather external data deemed necessary to perform analysis and share the results of the studies with the affected entities. Furthermore, Reliability Standard IRO-017-1 requires Reliability Coordinators to establish an outage coordination process that will identify and resolve transmission and generation planned outage issues in the Operations Planning Time Horizon, which includes next-day and seasonal planning periods that have the potential to impact the Reliability Coordinator's wide-area.

70. The Southwest Outage Report advised that Reliability Coordinators study IROLs in the day-ahead timeframe and monitor potential IROL exceedances in real-time. How did NERC address this issue?

While Reliability Standard FAC-014-2, Requirement R1 directs the Reliability Coordinator to establish SOLs and IROLs, NERC addressed the recommendation in Reliability Standard IRO-008-2, Requirement R1 which further specifies that each Reliability Coordinator must shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed SOLs and IROLs within its wide-area. In addition, IRO-008-2, Requirement R4 requires the Reliability Coordinator to perform a Real-time Assessment of system conditions at least once every 30 minutes.

71. The Southwest Outage Report determined that Transmission Operators in WECC do not always conduct their individual planning studies based on multiple base cases, and as a result, some contingencies could be missed and excluded from the studies. How did NERC address this in the standards?

In recommendation #7 it was suggested that Transmission Operators include in their seasonal studies multiple base cases and generation maintenance outages, as well as dispatch scenarios during high-load shoulder periods. NERC addressed this issue by including a broader definition of Operational Planning Analysis, under which projected system conditions such as load forecasts and generation output levels must be considered by Transmission Operators and Reliability Coordinators. Such projected system conditions would include generator outages and high-load periods. Additionally, the outage coordination process established by Reliability Coordinators as required by IRO-017-1 must specifically define a process to evaluate the impact of transmission and generation planned outages within the wide-area. The Reliability Coordinator's outage coordination process covers the operations planning time horizon, which spans from day-ahead up to and including seasonal planning.

72. In Recommendation #8, the Southwest Outage Report recommended that Transmission Operators include in the information they share during the seasonal planning process the overload relay trip settings on transformers and transmission lines that affect the interconnected transmission network. How did NERC address this?

This reliability concern is addressed in Reliability Standards TOP-003-3, Requirement R1 and TOP-002-4, Requirement R3, and in the associated definition of Operational Planning Analysis. TOP-003-3, Requirement R1 requires Transmission Operators to maintain provisions for notification of current protection system and special protection system status or degradation that affects system reliability. The Reliability Standard TOP-002-4, Requirement R3 requires sharing of the study results among the Transmission Operators. Furthermore, the definition of Operational Planning Analysis explicitly requires that protection systems be included in the pre-and-post contingency studies. Additionally, the Reliability Coordinators must specifically define a process to evaluate the impact of transmission and generation planned outages within the wide-area as required by IRO-017-1. This process would include relevant system inputs necessary to evaluate the impact of transmission and generation planned outages on the reliable operation of the interconnected transmission network. The Reliability Coordinator's outage coordination process covers the Operations Planning Time Horizon, which spans from day-ahead up to and including seasonal planning.

<u>Section IV – Analysis of RTA Facilities and the Need for Information Sharing</u>

73. Comment on whether the requested data and monitoring of facilities required by the TOP and IRO Reliability Standards apply to facilities similar to RTA's in the U.S.

If RTA were elsewhere within the ERO, it would be required to meet the performance obligations outlined in the NERC Reliability Standards. Once an entity is registered with NERC under a particular registration, the entity must comply with all applicable standards, unless at the time of an audit, the entity can demonstrate that the standard(s) are not material to their situation. But this is only achieved at the time of an audit, not in advance. Once an entity is registered, it is mandatory for the entity to document and demonstrate its performance. In this particular instance, where the oversight of the Reliability Coordinator is essential to understanding the complete activities occurring within their area, RTA must provide data to the RC. In order for the completion coordination of reliable operations, the RC must be able to see, in its entirety, what is occurring within its wide area view, which in this case, is the Quebec Interconnection. Absent this information, the RC may not be in a position to act, as highlighted in the testimony of Mr. Kim Warren, in the most prudent manner to maintain reliable grid operations.

74. Comment on whether there are alternatives to RTA providing information to the Reliability Coordinator.

If RTA is not willing to provide such information to HQT, then RTA needs to be accountable for its activities to ensure grid reliability. The operation of the North American grid is only as strong as its weakest organization. If any electrical organization doesn't contribute to keeping and maintaining the integrity of the grid with its neighbors and surrounding organizations, then the entity must stand up and be recognized for its independence, but still needs to be involved. Put another way, it is imperative that RTA share data and information to protect grid reliability and to avoid the circumstances that caused the Southwest Outage due to a lack of information sharing. As such, RTA would need to be registered as a Balancing Authority, Transmission Operator and Transmission Planner and would be required to provide data of its operations and monitoring to other organizations like the regional entity or even NERC. This data sharing ensures and is consistent with the functional registration I discussed in my response to Question 32, namely that no areas should be lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical. In particular this process ensures that all areas are under the oversight of one and only one Reliability Coordinator, ensure that all Balancing Authorities and Transmission Operator entities are under the responsibility of one and only one Reliability Coordinator, ensure that all transmission facilities of the interconnected transmission network are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator, and ensure that all loads and generators are under the responsibility and control of one and only one Balancing Authority. In short, there should be no gaps in coverage.

75. What is the purpose of monitoring and data collection of interconnected systems?

Each Reliability Coordinator, Balancing Authority and Transmission Operator is required to be cognizant of what is happening within their responsible areas. This gives them each an "area-wide perspective or wide area perspective." They have planning and modeling requirements to their respective NERC regional entity, as well as NERC itself. When questions arise about events, or modeling scenarios, the Reliability Coordinator, Balancing Authority and Transmission Operator must be able to address the scenario discussions. The only way they can do this is by having the data from the various entities within their respective areas.

76. In what way it mitigates operational issues of interconnected systems?

As highlighted by Mr. Kim Warren in his report, the availability and delivery of operational data is essential to the planning and modeling requirements of the interconnected transmission network. In order to assess future conditions, having detailed and representative data makes or breaks future projections. Without such data, planners are making potentially invalid and inaccurate assessments, which may have adverse impacts, such as those seen in the 2011 Southwest Outage.

77. Identify and comment on any entity comparable to RTA, in a jurisdiction outside Québec, which would not have to send generation or transmission operations data to its RC, BA and TOP.

I am not aware of any case where an entity similar to RTA, a single industrial based registered entity, would be excluded from the data submission requirements. There are several industrial based entities in Texas and California where they have to submit their data. So, if RTA were located anywhere outside of Quebec, they will be subject to the data submission requirements under the NERC Reliability Standards and reliability programs.

78. 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 for 100 kV or higher transmission elements as well as the specific inclusion for generation at 20 MVA or higher. In addition, none of the BES Definition exclusions would apply to RTA's facilities. Moreover even if they were excluded by application of the definition, they would be included by the BES Definition inclusion process in the United States.

I also conclude that RTA performs functions that would require it to be registered as a Balancing Authority, Transmission Operator, and Transmission Planner in the United States, 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.

- 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.
- Maintains and develops methodologies and tools for the analysis and simulation of the transmission systems in the evaluation and development of transmission expansion plans.
- Defines and develops information required for planning purposes including: Transmission facility characteristics and ratings, Demand and energy forecasts, and capacity resources, Generator unit performance characteristics and capabilities, Long-term capacity purchases and sales.
- Coordinates with adjacent Transmission Planners so that system models and resource and transmission expansion plans.
- Appears to evaluate plans that are in response to long-term (generally one year and beyond) for transmission service.
- Evaluates and plans to integrate new (End-use Customer, generation, and transmission) facilities into the bulk electric system.
- Determines transfer capability values (generally one year and beyond) as appropriate.
- Coordinates projects requiring transmission outages that can impact reliability and firm transactions.
- Notifies others any planned transmission changes that may impact their facilities.
- Defines system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.

The data acquisition of all elements whether Bulk Electric System or non-BES is crucial for the reliability of system operation. The Southwest Outage established the importance of the need for a wide-area view and for Reliability Coordinators and Transmission Operators to obtain these data. To maintain grid reliability and protect against the potential for a similar event as the Southwest Outage, it is my opinion that RTA needs to share these real-time data (including all internal and external facilities' data, whether from facilities above or below 100 kV, that can affect interconnected transmission network reliability), with HQT so it can perform real-time analysis and maintain reliable operation of the interconnected transmission network. If RTA were not to share the data, it should be registered as a Balancing Authority and Transmission Operator so that an appropriate entity is performing real-time tasks and thus avoid a reliability gap.