Rapport de l'expert Kim Warren

(version caviardée)

Testimony and Exhibits of Kim Warren

on behalf of

Hydro Quebec TransEnergie

September 15, 2017

INTRODUCTION

Please state your name and address.

My name is Kim Warren. My address is 2085 Innkeeper Court, Oakville, Ontario. My postal code is L6M 3A2.

By whom are you employed?

Since retiring on January 1 of this year I am a self-employed consultant within the energy sector. I have recently joined the Board of Directors for NRStor. NRStor is a privately held energy storage project developer based out of Toronto, Ontario. I am also employed by the Sussex Strategy Group in Toronto as Senior Counsel. Sussex provides a variety of services related to government relations and communications. My focus is in support of the energy and environmental aspects of their activities and client services.

On whose behalf are you appearing?

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

QUALIFICATIONS

Please state your education and professional experience.

I began my career in the summer of 1978 as an electrical operator with Ontario Hydro, working at numerous hydro electric and high voltage transformer stations across the province. After completing their apprenticeship program, I progressed through the operating ranks and moved into the Ontario System Control Centre in the fall of 1982.

From 1982 to 1998 I worked as a system operator at the control centre. During my tenure, I held every position with the room, both production and transmission oriented. I left the control room to become their first line supervisor which quickly saw me rise to Manager of System Operations in 2000. I held that position until mid 2005 when I moved to the position of Manager of Regulatory Affairs for the IMO/IESO as part of a corporate development program. In 2008, I returned to power system operations as the Director of Planning and Assessments. In that position I oversaw all IESO planning and engineering functions, including connection applications, near term reliability assessments, limit derivations and power system modeling. I moved to the position of Chief Operating Officer, Vice President of Market and System Operations in May of 2011. I held that position through the IESO/OPA merger and retired from the IESO on January 1, 2017. As COO I was responsible for all engineering, near term planning and operating functions of the IESO. As COO, I was also chair of the provinces task groups responsible for both the planning and activation with respect to electricity related emergency operations and reporting to the Provincial Emergency Operating Centre. More details can be seen in my attached resume.

Other notable contributions during this time include being directly responsible for the response and restoration of the Ontario power system following the 2003 blackout. After the fact, I was asked by NERC and successfully championed the emergency rewrite of then NERC Policy 9 (predating NERC standards) that focussed on interconnected reliability and power system coordination needs and obligations. I also co-chaired the rewrite of NERC Policy 5 on emergency operations. As an active member on numerous NPCC and NERC task forces and committees I chaired the first coordination agreement between PJM and MISO. I was an active member within the CEA as well, chairing their regulatory group for over two years and spoke at two FERC Commissioner panels on the international aspects of interconnected power system planning, operations and standards.

During my time in the sector I have travelled extensively, visited many of the major control centres across North America. If memory serves me correctly that would include 11 of the 13 Reliability Coordinator Operating Centres on the continent. I also travelled and visited major operating centres in areas such as The Republic of South Korea and Denmark.

Lastly, following my retirement, at the direct request of the Ontario Deputy Minister of Energy, I worked with his staff in support of the development of the provinces Long Term Energy Plan. I concluded that support this past May.

TESTIMONY

What is the purpose of your testimony?

The purpose of my testimony is to support Hydro Quebec TransEnergie's position to terminate the exemptions relating to Rio Tinto Alcan Inc. (RTA), and possibly other entities with respect to the data and information needs of HQT staff in the execution of their duties to support the reliable operation of their footprint. I will describe the needs of system operators, the foundation of those needs, uses of this information, the present-day concerns, issues and risks as well as the possible consequences of continued operations in this environment.

What exhibits are you sponsoring?

1. My resume
2. The Relevant NERC standards in which the exemptions are founded
3. The Southwest Disturbance Report of 2011

Please describe the role of a Balancing Authority (BA), a Transmission Operator (TOP) and a Reliability Coordinator (RC).

The detailed roles of the above entities have been presented earlier on this file, including the testimony of Mr. Brian Evans-Mongeon in October, 2016. They are also included in the Southwest Disturbance Report (pages 16 – 17). For ease of reference I have included a brief summary of the roles here.

- A Balancing Authority develops resource plans, balances their areas generation/load, manages interchange and supports interconnected frequency.

- A Transmission Operator is responsible for the real-time operations of the transmission system under his purview. They perform reliability assessments in both planning and real-time environments. They develop contingency plans for system events and have the responsibility to take corrective actions to ensure reliable operations. They coordinate their operations with neighbouring BA's and TOP's. They are also expected to operate within established system operating limits and monitor operations within their area.

- A Reliability Coordinator is the highest level of authority within NERC and therefore has a larger scope than that of other entities. The RC is expected to have a wide area view of its and neighbouring areas and is to ensure operations within what NERC terms as Interconnected Reliability Operating Limits or IROL's. The RC oversees other entities such as BA's and TOP's and has the responsibility to direct other functional entities to ensure reliable interconnected operations. RC's also assist Transmission Operators in restorations and in developing contingency plans.

Please describe the need and use for data and information by the above entities in the management of an integrated power system.

As you are aware integrated power systems are highly complex systems where the need for accurate, timely and complete information and data is of paramount importance. This information is the foundation for all decision making, whether that be months or days ahead or in actual real-time operations.

Within the power system industry, much like the airline industry, this environment is often referred to as ones "situational awareness". The achievement of situational awareness does not occur by chance. Operations staff invests heavily in ensuring their staff are properly trained, have appropriate knowledge and experience as well as the processes, tools and procedures to surgically plan and operate the system effectively and efficiently under any and all circumstances, around the clock.

This information is then used by planners and operators of the system to determine boundary or “safe” conditions. It will be used in engineering studies, the development of system operating limits (local) and interconnected reliability operating limits (those beyond a local level). It determines the critical elements that when removed from service further limits system transfer capabilities – perhaps all together. It also determines both pre-contingency operating conditions and post contingency operating constraints. Based on available time and the asset portfolio and its characteristics this information would then assist in defining post contingency control action plans used in re-preparing the system following disturbances or unplanned events.

For example, following major disturbances, real-time data is used to validate study models (and those models are then used to provide SOL/IROL limits). Thus, the lack of real-time data from RTA system could lead to inaccurate limits since the study model could not have been validated with these real-time data.

There are also several other areas where this information is utilized. Often done in the longer-term planning horizon and connection related studies they would include areas such as inertia, frequency response, short circuit limitations, fault current infeed, relay coordination and System Protection Scheme coordination.

As you can see the output of these studies and analysis is used extensively across many areas of control centre operations. It is utilized in both near term, day ahead and real-time timeframes. It is used to set outage schedules, the basis for adequacy assessments and is critical in defining a valid operating plan that will be used in the days and hours that follow, ensuring reliable and efficient dispatch and contingency response capabilities.

The need for complete, accurate and timely data is the very core of a TOP or RCs toolset. In real-time Supervisory Control and Data Acquisition systems receive available data from assets in the field. This information is gathered and used by state estimation software to calculate real time values for the entire system. In conjunction with real time contingency analysis software it then calculates hundreds if not thousands of “what if” or contingency scenarios across the system. This information is then passed through to automated dispatch systems and presented and alarmed as necessary to operations staff who utilize this knowledge to avoid trouble areas before they occur or to redeploy assets quickly should trouble develop. These critical software systems are intended to be available at all times. The information they derive is constantly being refined and updated as power system conditions change. As you may imagine the loss of this capability is one of the most serious events a control centre can face.

Please describe the consequences associated with lack of information and data in the application of the above needs.

The loss of state estimation capabilities is one of the most serious events that can happen in our industry. Loss of state estimation renders operations staff blind to the operating environment around them. It generates the highest priority of repair, stopping all planned activities until remedied. State estimation failures are expected to be immediately announced to neighbouring jurisdictions so that they can provide assistance if possible. Prolonged events are the subject of industry led reviews and analysis as the industry, as a whole, views these failures or disruptions as a most serious event. In the business of interconnected power system operations, a company's ability to deliver reliable service is driven by many things, including its ability to appropriately manage its core capabilities, like state estimation.

Degraded state estimation can be just as troublesome since it leads to degraded or unavailable contingency solutions. This can happen due to corrupt data or the loss of key data and is more likely to happen in cases where limited data is available at the onset. Loss of data which is limited to begin with compounds issue resolution. Missing or corrupted data has a greater effect than would normally be the case where complete sets of data, perhaps even redundant data sets, are available for state estimation use. Poor or missing data corrupts the information used by control centre systems and its staff. If identified by staff the degraded outputs become an unnecessary concern that could be confusing until they are resolved. It often leads to more conservative operations and cost increases as the system cannot be operated as efficiently until better information about pre and post contingency conditions is known. If not quickly identified, which is of paramount concern, staff will be provided with inaccurate information about both present system conditions and an unrealistic portrayal of potential events, jeopardizing reliability.

The lack of situational awareness will lead to poorly developed and incomplete operating plans, both in the planning and real-time operating environments. As it is doubtful that operating staff will fully recognize a given situation it will likely evolve into inefficient or ineffective actions, jeopardizing the asset base, reliability and the ability to serve loads. It is doubtful the action plan brought forward, when an issue surfaces, will be complete or timely. It could easily fail in its mitigation efforts, jeopardizing the area of concern and perhaps neighbouring areas. It will likely also mean the efforts of the RC and TOP will be more reactionary in nature than proactive. That they will fail to foresee and avoid problems in advance and that they will find themselves in difficult scenarios, and do so more than necessary. Frankly it is akin to a game of roulette or chance. It is certainly not the basis for the sound planning and operation of a power system.

Power systems are never expected to be operated in an unstudied state. Significant engineering and analysis is done years, if not months and days ahead to ensure and area is operated under known and acceptable conditions. When unplanned events happen, such as loss of a generator or transmission line, the system is expected to be returned to acceptable operating conditions as soon as possible but in any case, less than 30 minutes. For decades that is and has been the basic principle of interconnected power system operations. If the limit violation in question is the basis of an IROL the shedding of firm load is expected to be utilized to meet these obligations. Should system operators face extreme conditions, such as the loss of multiple system elements in very short period of time, then these control actions may be implemented immediately in order to preserve major portions of the system. The studies that underpin this work requires a thorough set of detailed information, not broad assumptions, in order to accurately and completely understand the possible ramifications of respected contingencies, including planned outage scenarios. Doing otherwise would mean a system is being operated in an unstudied state. Operating in an unstudied state is often, if not always, a major contributing factor to every major disturbance that I am aware of.

Please provide a brief summary of the Southwest (Arizona – Sothern California) Disturbance of 2011, its major findings and describe any comparable issues or risks with what you see in this instance.

The 2011 disturbance originated within Arizona. It spread across the southwest negatively impacting areas as far wide as San Diego and Baja California in Mexico. The cause of the outage was the loss of a single 500 kV line. Loss of this single element resulted in cascade tripping and uncontrolled loss of transmission and generating assets including sub-100 kV facilities. In totality, the contingency resulted in ~ 7,000 MW of load loss affecting ~ 2.5 million customers. Most of the customer load was restored within 6 to 12 hours. Had the entities responsible been planning and operating their systems within industry based reliability standards the cascade tripping and load losses that occurred following the initial contingency would have been completely avoidable. Loss of the single 500 kV line should and could have been contained to that element alone.

Every interconnection within North America has its own characteristics and idiosyncrasies. That said lessons learned are always valuable and certain basic principles can often be applied across boundaries to assist the interconnections in the evolution of reliability and reliability related services. Although very different systems the similarities relating to the deficiencies surrounding the Southwest event and what could potentially happen in the area we are discussing today are significant.

What follows is a few excerpts from the disturbance reports findings/recommendations that hold a striking resemblance to the issues and concerns of HQT with respect to the RTA area.

Finding/recommendation 1.

Failure to conduct and share next day studies. TOPs should share results with neighbouring TOPs to ensure that all contingencies that could impact the BPS ae studied. (I noted in the initial review of these standards earlier witnesses established that RTA may well be defined as a TOP in other jurisdictions).

Finding /recommendation 2

Lack of updated external networks in next-day models. Some TOPs use models for external networks that are not updated to reflect next-day operating conditions external to their systems, such as generation and transmission outages. As a result, these TOPs next day studies do not adequately predict the impact of external contingencies on their systems or internal contingencies on external systems.

Finding/recommendations 3 and 6

Sub 100 kV facilities. TOPs and RCs should ensure that their next-day and seasonal studies include all internal and external facilities (including those below 100 kV) that can impact BPS[1] reliability.

Finding /recommendation 11

Lack of real-time external visibility. They (TOPs) should obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the SOLs of other TOPs. TOPs should review their real-time monitoring tools,

[1] This is the BPS defined as section 215 of the Federal Power Act “facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability “ and not BPS defined as NPCC A-10 criteria

such as State Estimation and Real Time Contingency Analysis (RTCA), to ensure that such tools represent critical facilities needed for the reliable operation of the bulk power system.

Finding/recommendation 12

Inadequate real-time tools. TOPs 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.

Finding /recommendation 13

Post contingency mitigation plans. TOPs should review existing operating processes and procedures to ensure that post contingency mitigation plans reflect the time necessary to take mitigating actions, including control actions, to return the system to a secure N-1 state as soon as possible but no longer than 30 minutes following a single contingency.

Finding/recommendation 16

Addressing discrepancies between real time contingency analysis and planning models. Review all model parameters on a consistent basis to make sure discrepancies do not occur.

Finding /recommendation 17

Impact of sub 100 kV facilities on reliability. Ensure that all facilities that can adversely impact bulk power system reliability are either designated as part of the bulk electrical system or otherwise incorporated into planning and operations studies and actively alarmed in RTCA systems.

Lastly, to provide further evidence in its areas of concern, the report also looked at the Blackout of 2003 and its findings and compared them to the events of 2011. Similarities existed in areas such as insufficient analysis and seasonal studies, inadequate identification of critical facilities and inaccurate dynamic models. I believe those same deficiencies exist in this instance as well. To what degree and potential consequences remain unclear until the associated studies by HQT have been completed.

Based on your understanding please describe the present-day operations of the Hydro Quebec system and Rio Tinto Alcan (RTA).

It is my understanding that RTA owns and operates a substantial network at 161 kV with some assets at 345 kV. These assets connect to the HQT via two 161kV lines and one 315 kV line to two different 735 kV stations and via a single 230 kV line to a 230 kV station. The RTA system includes a large fleet of hydro-electric generation of approximately 3,500 MVA.

Most importantly the RTA system is one of a fluid, two-way transfer of energy environment. Power system transfers can range between roughly [redacted] MW towards the HQT network to [redacted] MW from the HQT network (Radial black box model).

As currently in effect, the TOP-IRO standards assure that certain basic information is already provided, such as net load and injection forecasts.

However, HQT experience has now proven this to be inadequate for an RC, TOP or BA to carry out their obligations and duties. The two-way flows that are occurring can and have negatively and directly impacted HQT operations including at least three instances of IROL violations on the [redacted] 735 kV autotransformers, a very troubling concern. As you are aware should the limiting contingency occur its very possible an asset such as this would be permanently faulted and require replacement. As the [redacted] autotransformers represent an IROL interface, by definition, limit violations here can lead to cascade tripping and potential system separations outside of a local area. IROL's are the most serious system violations to manage.

The lack of necessary information surrounding RTA assets has corrupted HQT state estimation capabilities. After discussion with HQT staff, modeling RTA's interface with fictitious generators and loads currently mitigates state estimation failures. However, this leads to the degradation of its contingency analysis capabilities, not only for the area around RTA but for the entire footprint of HQT. As troubling as that is it is also my understanding that without the provision of additional information from RTA, failures of HQT state estimation are expected to reoccur.

The fact that RTA can and already has impacted HQT in the above two scenarios is very serious and most disturbing.

The position that RTA should be viewed only as a large industrial load, one that is largely self supported by its own fleet, is irrelevant to a TOP or RC in instances such as this. The concerns of these entities lie in the fact that RTA can and have had negative impacts outside of their local area. Because of their size, the two way and parallel flow aspects of their operations on the HQT system including the transmission of a large amount of voltage supportive reactive power, the need for information and data from this subsystem is just as vital to HQT as any other part of their system.

Please describe any comparable circumstances that you may be aware of.

I am not aware of any comparable circumstance with respect to any entity in any jurisdiction within North America similar to what is being reviewed here. The needs of Hydro Quebec TransEnergie represent the minimum set of basic, foundational needs of a Reliability Coordinator and Transmission Operator.

Please summarize your testimony.

The present day exemptions with respect to industrial based information and data provisions to HQT are bringing significant and unnecessary risks to HQT operations. HQT believe these exemptions should now end and I am fully supportive of that position.

More granularity is needed than what is being provided for today to address the IROL violations and degraded state estimation and contingency analysis capabilities that presently plague HQT operations and to ensure the system is planned and operated under known and studied conditions. Additionally, it is critical for HQT to have timely, accurate and complete situational awareness capabilities and at present that capability is in doubt.

In earlier reviews there was a call for more evidence to support the need for the enhanced provision of information to the system operator. The IROL and degraded state estimation being managed by HQT have now provided that evidence. The deficiencies are clear. The risks are substantial. Power systems are constantly evolving, as are the needs of system operators. In order for HQT operations to meet their obligations it is now appropriate that these deficiencies be addressed.