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RESS/EMAIL & COURIER

Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4

Attention: Ms. K. Walli, Board Secretary

Dear Ms. Walli:

Re: Interrogatory Responses of Canadian Niagara Power Inc. (EB-2009-0283)

We are counsel to Canadian Niagara Power Inc. (CNP) in the above noted matter. Enclosed, please find CNP's responses to all interrogatories received in the above-noted matter. These include interrogatories from Board Staff (Attachment "A") and from Hydro One Networks Inc. (Attachment "B").

Yours truly,

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All Intervenors

ATTACHMENT "A"

Responses to the Interrogatories of Board Staff

RESPONSES TO THE INTERROGATORIES OF BOARD STAFF

1.0 PROJECT NEED

References

(1) Exhibit B, Tab 3, Sch. 1

(2) Exhibit B, Tab 1, Sch. 1

Preamble

Page 8 of Ref (1) indicates that:

- the average monthly peak load on CNP's transmission system was 48 MW in 2005, 49 MW in 2007 and 47 MW in 2008;
- the annual peak load was 56 MW in 2008 and exceeded 48 MW since 2002.
- CNP forecasts its load to grow at an annual rate of 0.5%.

Page 2 of Ref (2) provides the rating of the existing transmission line sections related to the Project. It is noted that the load levels indicated above are within the capability of all of the transmission line sections except for the 0.66 km line section between Queen St. Tower in Fort Erie and High Tower in Buffalo. This section is a double circuit line with a rating of 48 MW for each circuit. However, at this time only one of the two circuits is energized.

The Table on page 10 of Ref (1) shows performance data for the CNP transmission system in the period 2002 - 2008.

Pages 11-13 of Ref (1) provide a comparison of the performance of CNP's transmission system with values in a Canadian Electricity Association benchmarking report and Hydro One's Customer Delivery Point Performance Standards ("CDPPS"). It is noted that Hydro One's CDPPS data is provided on a "per delivery point" basis as per Section 4.5 of the Transmission System Code and excludes planned outages. CNP's statistics seem to be on a "total system" basis with no reference to the number and loading of delivery points.

Page 1 of Ref (1) states that the need for the Project is driven by the requirements of the Transmission System Code, which in turn requires the CNP transmission system to satisfy requirements found within the reliability standards of the North American Electric Reliability Corporation ("NERC"), as well as to meet the standards of good utility practice. On pages 3-4, it is stated that:

....the CNP Transmission System does not have N-1 contingency at present. By not having N-1 contingency, the system configuration is not in accordance with NERC standards or the Code. In support of its obligations to comply with the Code and NERC standards, CNP has initiated the Project to establish N-1 contingency for its system by upgrading its New York interconnection so as to establish a parallel and continuous supply source.

Page 1 of Ref (1) also states that "Because there are no viable alternatives, the Project in respect of this reliability concern is non-discretionary."

Board staff would like to get some clarification regarding the need for the Project and the criteria used to establish the need.

Questions / Requests

(i) Please explain CNP's rationale for submitting that its transmission system should be able to withstand the N-1 contingency criterion (i.e. uninterrupted supply upon loss of one element). In answering this question please consider: the size of the load (average monthly peak of 47MW and annual peak of 58 MW in 2008); the normal supply from Hydro One has ample capacity for the existing and expected future load; and there is some backup capability from USNG.

(ii) Is it CNP's interpretation that NERC Standard TOP-002-2 (Requirement #6) which states that "each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning)...." applies to CNP's current radial supply to the Fort Erie load? Please explain.

(iii) Does the IESO agree with CNP's submission that its transmission system should be able to withstand the N-1 contingency criterion and with CNP's response to (i) and (ii) above? Please provide verification from the IESO, with appropriate explanations.

(iv) If meeting of the N-1 contingency criterion was not a requirement, are there other reliability issues/concerns that need to be addressed? If so:

(A) Please describe the specific reliability issues/concerns that need to be addressed.

(B) What are the specific criteria or standards on which the need is based?

(C) Please provide an explanation of how the CNP transmission system does not meet the criteria or standards in (b) including any metrics or threshold levels used to establish the need.

(v) Does the IESO agree with CNP's response to (iv) above? Please provide verification from the IESO, with appropriate explanations.

(vi) Please explain why only one of the two circuits on the limiting Queen St. Tower to High Tower section of the 115 kV line is energized?

(vii) Please provide the performance data for CNP's transmission system similar to that provided on pages 10 & 13 of Ref (1) but with the following changes:

- Provide the data on a "delivery point" basis rather than the entire system and indicate the average load (in MW) at each delivery point.
- Exclude planned outages in the analysis.
- Include 2009 (year to date) in the analysis.

(viii) Please describe CNP's process for analyzing its system performance and comparison to Hydro One's CDPPS. Your answer should include the criteria used to establish the need for reliability improvement including any metrics or threshold levels used and the rationale.

(ix) What is CNP's rationale for using the average of the 3-year rolling averages instead of using the latest 3-year rolling average for comparison to Hydro One's CDPPS?

(x) How would consideration of the latest 3-year rolling average for comparison with Hydro One's CDPPS affect CNP's conclusions with respect to the adequacy of its transmission system?

(xi) Seeing that there were no outages on the CNP transmission system in 2007 and 2008 (see Table on page 10 of Ref 1):

(A) What, in CNP's opinion, is the reason for the high level of reliability in 2007 and 2008?

(B) Did CNP undertake any improvements to the transmission system prior to 2007 that likely contributed to the high level of reliability in 2007 and 2008? Please explain.

(xii) Does the IESO agree with CNP's criteria from (viii) and (ix) above and its application in determining the adequacy of CNP's transmission system? If not, what criteria does the IESO consider to be appropriate in determining the adequacy of a transmission system such as CNP's? Please provide verification from the IESO, with appropriate explanations.

(xiii) In comparing CNP's transmission performance data with the values in the CEA benchmarking report, CNP calculated an outage frequency of 8.75 outages per 100 km per year for CNP's system in the period 2002-2006.

(A) Please calculate CNP's transmission system outage frequency for the latest 4-year period, i.e., 2005-2008. Please exclude planned outages in this analysis.

(B) Does the performance metric from the CEA benchmarking report (1.0534 outages per 100 km per year) include outages to terminal equipment as is included in the CNP performance data? If not, please indicate what the comparable outage rate would be including outages to terminal equipment.

(C) Is the above noted performance metric based on the latest CEA benchmarking report? If not, please provide the outage frequency in the latest report.

(xiv) Regarding CNP's statement on page 1 of Ref (1) that "Because there are no viable alternatives, the Project in respect of this reliability concern is non-discretionary":

(A) Is this statement made with respect to Section 5.2.2 of the Ontario Energy Board's "Filing Requirements for Transmission and Distribution Applications"?

(B) Please explain the rationale for classification as a non-discretionary project.

(C) Are the IESO and/or the OPA in agreement with this classification? Please provide verification from the IESO and/or the OPA.

Responses

(i) As explained in Exhibit B, Tab 3, Schedule 1, section 5.1.2 of the Transmission System Code requires CNP, as a transmitter, to operate and maintain its transmission facilities in compliance with the Code, its licence, its operating agreement with the IESO, the Market Rules, all connection agreements, good utility practice, the standards of all applicable reliability organizations and any applicable law. Together, these obligations give rise to the need for CNP to provide transmission service with a high level of reliability.

To provide the requisite level of reliability, it is critical for CNP's transmission system to be able to provide uninterrupted supply upon the loss of one element. The current configuration does not enable CNP's transmission system to provide such uninterrupted supply upon the loss of its primary source of supply from Hydro One's system. As explained in Exhibit B, Tab 2, Schedule 1, loss of the primary supply may result from (1)

a fault on the Hydro One transmission system, (2) a fault on line A37 between Hydro One's Murray TS and CNP's Station #11, (3) a failure at Station #11, which is the sole supply point to line L2, or (4) a fault on line L2, between Station #11 and Station #18. An interruption to this primary supply necessarily results in the entire CNP transmission system going dark, adversely affecting all of the system's end-users.

While the CNP system has some limited backup capability from USNG through the use of the Emergency Tie Line, this backup capability is no longer capable of meeting average monthly peak load levels on the CNP system and cannot be engaged without there first being a significant interruption to supply (See Exhibit B, Tab 3, Schedule 1, pp. 5-9). This is because it takes a minimum of 4 hours to complete the co-ordination and switching over to this alternate supply source in the event of a forced outage. During this time, the entire CNP transmission system remains dark. For a planned outage, such as for purposes of carrying out maintenance on the CNP system, CNP can undertake some of the coordination activities in advance but the process of switching over to the Emergency Tie Line will still require an outage of approximately 30 minutes in duration. During such a planned outage, with limited exceptions, the entire CNP system must go dark. Moreover, in order to switch back from the Emergency Tie Line to the primary supply source following either a planned or forced outage, CNP's system experiences an additional 30 minute outage during which the entire system goes dark. In accordance with principles of good utility practice, it is unreasonable and unacceptable for CNP to subject the end-users of its system to forced and planned outages with the frequency, duration and, particularly, the scope that its end-users are subject to under the current configuration.

By providing a synchronous tie with New York, the project would enable CNP's system to withstand an N-1 contingency. The reliability standards applicable to the system would therefore be more fully achieved because two sources of supply will then be readily available in the event of an outage to the primary supply source.

In addition, CNP believes that, from a compliance perspective, it is obligated to ensure that its transmission system is able to withstand an N-1 contingency by providing uninterrupted supply upon the loss of one element. This obligation arises under section 5.1.2 of the Transmission System Code based on the requirement that a transmitter shall operate and maintain its system in compliance with good utility practice and the standards of all applicable reliability organizations (see response to 1.0(ii) below).

CNP believes that the size and type of load served by the CNP transmission system is significant enough to justify the investment needed to provide N-1 contingency. The CNP service territory is primarily urban in nature and includes a diverse group of end-users. These include residential, commercial, institutional and industrial end-users who depend on a reliable source of supply (See for example Exhibit B, Tab 4, Schedule 1, pp. 6-7). As noted in the pre-filed evidence at Exhibit B, Tab 4, Schedule 1, p. 15, among the

end-users that are served by CNP's system are large industrial users and the Peace Bridge Authority, which operates one of the busiest and most economically significant border crossings between Canada and the United States. The improved reliability that would result from the system being able to withstand an N-1 contingency is critical for these important end-users, as well as to be able to support future load growth from industrial end-users and potential generation, including renewable energy generation facilities, that wish to connect to CNP's transmission system or the distribution system that it serves.

With respect to the capacity of the Hydro One supply, while the Hydro One system has sufficient capacity to meet CNP's existing and future expected loads, the concern is that a disruption to this supply from Hydro One necessarily results in the entire CNP transmission system going dark. No matter how much capacity is available on the Hydro One system, CNP's reliability concern will not be mitigated. Because of the CNP system's configuration, the issue is reliability, not the capacity of this primary supply source.

(ii) Yes. As described in Exhibit B, Tab 3, Schedule 1 of CNP's pre-filed evidence and in the response to (i) above, CNP has a responsibility as an Ontario transmitter to provide improved reliability. In particular, given the circumstances described, CNP in accordance with good utility practice must provide improved reliability. Section 5.1.2 (and as reflected in section 8.1.1) of the Transmission System Code provides that "a transmitter shall operate and maintain its transmission facilities in compliance with this Code . . ., good utility practice, the standards of all applicable reliability organizations and any applicable law." The Code further defines "reliability organization" as meaning NERC, NERC's reliability councils and the IESO. As part of CNP's obligation under the Transmission System Code to operate and maintain its system in accordance with good utility practice, CNP regards Requirement #6 of NERC's reliability standard TOP-002-2, as providing a credible basis for its view that good utility practice with respect to the CNP transmission system demands that the system be able to withstand an N-1 contingency. There is no other viable mechanism by which CNP can remedy the circumstances described (See Exhibit B, Tab 6, Schedule 1).

(iii) The IESO's views with respect to CNP's submission that its transmission system should be able to withstand the N-1 contingency criterion, as well as with respect to CNP's responses to (i) and (ii) above, are as follows:

IESO

While the CNP transmission system is not currently classified as Bulk Electricity System from a NERC viewpoint, the IESO agrees with CNP's submission that the CNP transmission system should be able to withstand the N-1 contingency criterion, as a fundamental principle of good utility practice, and also agrees with CNP's response to 1.0(i).

(iv) The following response addresses the questions/requests set out in (iv)(a)-(c):

Notwithstanding the language or formal 'applicability' of the NERC standard, in substance and in the current circumstances of the CNP transmission system, the N-1 contingency criterion is the only viable solution to provide improved reliability and as such represents a fundamental element of good utility practice. There are significant reliability concerns that need to be addressed in accordance with good utility practice. As described in the pre-filed evidence and in response (i) above, CNP's load is subject to an unreasonable and unacceptable risk of going dark because of the current system configuration and the lack of a readily available second source of supply that is capable of providing uninterrupted service in the event of the loss of the primary supply source (See Exhibit B, Tab 3, Schedule 1, pp. 2-4).

As described in response (i), the need for the project is driven by CNP's responsibility to operate and maintain its system in accordance with good utility practice, which is defined in the Transmission System Code as:

> "the practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good utility practice is not intended to be limited to optimum practices, methods or acts to the exclusion of all others, but rather to include all practices, methods or acts generally accepted in North America."

Based on the use of this term in the Code, CNP has an obligation to operate and maintain its system in accordance with such generally accepted practices and/or through the exercise of reasonable judgment consistent with good business practices, reliability, safety and expedition. CNP's belief is that, for a system of the size and nature of CNP's transmission system, serving end-users with the diversity and economic significance of those served by CNP's system, good utility practice demands that such system have the ability to withstand the loss of one element such that a readily available secondary supply is available to provide uninterrupted service in the event of the unplanned loss of the system's primary supply. In addition, good utility practice suggests that CNP should have the ability to carry out planned outages for purposes of carrying out maintenance activities without incurring lengthy system-wide outages in the course of switching to and from an emergency supply source (See Exhibit B, Tab 3, Schedule 1, p. 14).

Aside from standards of good utility practice, CNP has considered its historical performance against the Hydro One Customer Delivery Point Standards (CDPPS) and against the findings of a Canadian Electricity Association Study on Forced Outages of Transmission System Equipment, 115-149 kV. This analysis, described in Exhibit B,

Tab 3, Schedule 1, pages 11-13 of the Application, generally indicates that the performance of the CNP transmission system has been below average. Consideration of the contributing factors behind these unfavourable comparisons shows that performance relative to these standards would have been significantly better if the CNP system had N-1 contingency. This is because virtually all outages in recent years would have been either prevented or significantly shortened.

With respect to the CDPPS, as shown in Figure 3.3 (b) on Page 13 of Exhibit B, Tab 3, Schedule 1 of the Application, CNP's performance from 2002 to 2008 fell below both the Minimum and Average Performance Standards for both frequency and duration of outages. With respect to the CEA Study, as described on pages 11-13 of Exhibit B, Tab 3, Schedule 1 of the Application, CNP's average outage frequency also fell below the average levels found in the CEA Study.

Outages to CNP end-users are disruptive and adversely impact businesses and institutions, as well as the economic well-being of the region served by CNP's transmission system. In addition to the risk of more frequent outages, the fact that it would take a minimum of four hours to activate the emergency supply from USNG contributes further to the adverse impacts on CNP's end-users. Moreover, with the exception of only a few minor circumstances, the system configuration causes outages on the CNP transmission system to be *system-wide* outages that in each instance affect over 15,000 end-users.

The frequency, duration and scope of outages that CNP's system and end-users are exposed to can curtail future growth and serve as a barrier for potential generation loads, including renewable energy generation facilities. With respect to the curtailment of future growth, potential industrial and institutional end-users will be deterred from connecting new facilities in the area unless they can be assured of a more reliable electricity transmission supply. Similarly, renewable generators will require reliable transmission both as a source of supply and as a means for delivering their generation output. This includes renewable energy generators proposing to connect to the distribution system that is served by CNP's transmission system. It is CNP's understanding that the distribution system that it serves has been the subject of several queries and expressions of interest from prospective renewable energy generators.

Moreover, at an Ontario system-wide level, the project has the ability to address a number of additional concerns, including providing the system operator with additional flexibility to evacuate surplus baseload or renewable generation or to import during periods of supply shortages. These benefits are associated with the additional intertie capacity that would be provided by the project.

(v) The IESO's views with respect to CNP's response to (iv) above, is as follows:

IESO

The IESO agrees with CNP's response to 1.0(iv). The IESO would like to emphasize the potential of the Project to enhance the overall Ontario import/export capability and, hence, to provide:

- *increased market activity and efficiency,*
- *flexibility to address situations of surplus baseload and/or renewable generation, and*
- *flexibility to import during periods of supply shortages.*

(vi) Both circuits were originally 25 cycle and energized and insulated at 41.6 kV. Under CNP's 1998 application to the National Energy Board to vary its permit, only one circuit was established as 60 cycle and re-insulated for 115 kV. This was sufficient at that time to act as an emergency tie line. The de-energized circuit is still registered as 25 cycle and insulated at 41.6 kV. To change this would require NEB approval. In any event, energizing the second circuit would not address the reliability issue.

(vii) CNP's performance data, with changes as requested, is provided in **Appendix "A"** (the "Modified Data"). However, CNP has not included the 2009 (year to date) data in the analysis as requested because all other data presented is for full years and using partial year data makes it problematic to calculate 3-year rolling averages. CNP does note that, for 2009, as of October 26 there have been no outages on the CNP transmission system.

As with the analysis provided in the pre-filed evidence at Exhibit B, Tab 3, Schedule 1, pp. 10-13, the Modified Data demonstrates that Station 18 does not meet the Standard Average Performance for both frequency and duration of outages. The Modified Data also indicates that Station 17 does not meet the Standard Average for interruption duration, but does meet the standard for outage frequency. However, this outcome arises only because the average load at Station 17 causes it to fall into a different load category with lower performance standards. Station 17 serves several industrial end-users and it would be unreasonable for those end-users to expect a lower level of reliability than those supplied from Station 18. Moreover, it should be noted that CNP supplies two delivery points only from a billing perspective. The two delivery points are connected to the same line and are inter-related. Any change in the line that impacts one of the delivery points will impact the other delivery point too. As a result, it is not appropriate to consider these delivery points in isolation. The more appropriate measure is for a single delivery point.

Although planned outages were excluded from the analysis for the Modified Data as requested, CNP does not believe it is appropriate to exclude this information. As the nature of CNP's system configuration unavoidably results in planned outages giving rise, in most circumstances, to system-wide outages of approximately 30 minutes in order to engage the Emergency Tie Line and additional system-wide outages of the same duration for switching back to the primary supply, planned outages are highly relevant to the

analysis of CNP's transmission system performance in the context of the Application. (See Exhibit B, Tab 3, Schedule 1, p. 14).

(viii) Since the Hydro One CDPPS sets standards based on load served and because Hydro One supplies the CNP transmission system, CNP felt that it was reasonable to use the Hydro One standards to measure the performance of the CNP system. The Minimum and Average standards defined by the Hydro One CDPPS were used as benchmarks for comparison with CNP performance. CNP performance statistics for the period 2002-08 were calculated on the basis of 3-year rolling averages and compared to the Hydro One CDPPS.

This analysis indicates that CNP performance has been below the Hydro One standards, both in terms of frequency and duration of outages. In terms of frequency of interruptions, CNP's average frequency of 2.9 outages per year exceeded the Hydro One average of 1.1 outages per year. CNP's maximum average of 4.3 outages per year exceeded the Hydro One minimum standard of 3.5 outages per year. In terms of outage duration, the CNP average of 184 minutes per year well exceeded the Hydro One average of 22 minutes per year and also greatly exceeded the Hydro One minimum performance standard of 140 minutes per year.

CNP's performance measured against the Hydro One standards is indicative of the need for reliability improvement on the CNP system.

CNP also notes that, while frequency and duration of outages are important measures of system performance, the scope of outages - which is not considered in this analysis - is also an important consideration and highly relevant to CNP's circumstances. As mentioned in previous responses, with very few exceptions, an outage on CNP's transmission system results in an outage to the entire CNP transmission system. This system serves approximately 15,600 end-users and includes a diverse range of residential, commercial, institutional and industrial end-users. As such, outage scope should be considered together with duration and frequency.

(ix) CNP recognizes that Hydro One's CDPPS are designed to use the previous 3 years of data to calculate a 3 year rolling average, which is then compared to the average and minimum standards of performance. On this basis, CNP's transmission system performed below Hydro One's CDPPS in 2004, 2005 and 2006, and performed above the standards in 2007 and 2008. It is not appropriate to look at a single, 3-year period for comparison. The purpose of presenting the average of the 3-year rolling averages was to demonstrate that, for the 5 year period from 2004 to 2008, CNP's transmission system has on average performed below Hydro One's CDPPS. Reliability trends, particularly at the transmission level, are more appropriately assessed over longer time periods.

(x) From a statistical perspective, the latest 3-year rolling averages would likely be indicative of better reliability performance than the information presented in Figure 3.3, referenced

above. However, this would not affect CNP's conclusions with respect to the adequacy of its transmission system. As noted in the previous response, reliability performance is better measured over a longer time-span than three years. Moreover, recent good performance does not excuse transmission operators such as CNP from the obligation to plan for contingency situations. The fact remains that the CNP system does not have a readily available supply in the event of a loss of the primary supply from Hydro One. This inherent weakness in the system needs to be addressed regardless of whether there were fewer outages on average in the most recent 3-year period as compared to the entire five year period from 2004-2008.

In contingency planning, it is pertinent to consider the potential exposure of the system to risk. Of particular note for CNP are the significant portions of the transmission system which consist of lines along wooden poles located on road allowances where there is a risk that vehicular accidents can cause service disruptions. These wooden poles are also subject to the possibility of burning due to insulator tracking. In addition to the vehicle accidents and burning pole incidents described in Figure 3.2 of the pre-filed evidence, which lists events that resulted in actual system outages, since in recent years there have also been a number of similar events on these portions of the system that gave rise to significant risks of lengthy, forced outages, but which did not actually result in service disruption:

1) A vehicle accident occurred in 2005 that resulted in a broken transmission pole;
2) A transmission pole burned in 2006 due to insulator tracking;
3) A vehicle accident occurred in 2009 that resulted in a broken transmission pole; and
4) A transmission pole burned in 2009 due to insulator failure on a 34.5 kV underbuild circuit.

While each of these incidents could very well have given rise to lengthy outages to CNP's entire transmission system, CNP and the end-users of the system were very fortunate that none of the above-noted incidents actually caused forced outages. Nevertheless, these incidents demonstrate the types of risks faced by CNP, any one of which poses a significant risk of causing a forced outage. Just as a prudent utility in measuring its safety performance would effectively regard a "near miss" in the worker safety context as though the injury or harm to the worker actually occurred, it is prudent in considering CNP's transmission system performance to, at least qualitatively, regard incidents such as those listed above as though outages actually resulted.

In summary, consideration of the latest 3-year rolling average does not affect CNP's conclusions with respect to the adequacy of its transmission system. Over the period from 2002 to 2008, CNP has consistently maintained and operated the transmission system and has not materially altered or made improvements to the system. With this in mind, it is CNP's view that the historical performance over the entire period provides a

more realistic indication of what can be expected in the future than consideration of the latest 3-year rolling average in isolation.

(xi) The following is responsive to (xi)(a) and (b):

In 2007 and 2008, favourable weather conditions were experienced and there were no vehicular accidents affecting CNP's transmission system. As part of its ongoing maintenance programs, CNP carried out activities that included the removal of trees that posed potential risks to transmission lines and the replacement of some older insulators. Prior to 2007, CNP also implemented more systematic line inspection and vegetation management programs. While these activities may have reduced some risk, there is no way to quantify their relative contributions, if any, to CNP's reliability performance in 2007 and 2008. In addition, a large portion of the system is subject to the risk of vehicle accidents. Due to the nature of the system, it would only take one such accident or incident to dramatically change CNP's performance for a given year. As noted above, one such vehicle accident did occur in 2008. In this example, while a transmission pole was dislodged and broken from the impact, CNP was able to stabilize and replace this pole without any loss of power to the system.

(xii) The IESO's views, with respect to CNP's responses to (viii) and (ix) above, are as follows:

IESO

The IESO is not in a position to comment on the criteria used by CNP to establish the need for reliability improvement, or on the application of those criteria in determining the adequacy of CNP's transmission system. However, in the IESO's opinion, CNP's responses to 1.0(viii) and 1.0(ix) appear reasonable.

(xiii)(a) The CNP outage frequency for this period, with planned outages excluded, is 1.5625 outages per 100 km year, which is 48% higher than the CEA reported average of 1.0534 outages per 100 km year.

(xiii)(b) The CNP performance metrics quoted in the Application and in (xiii)(a) above do not include terminal outages and are therefore direct comparisons to the CEA benchmark.

(xiii)(c) It is CNP's understanding that a 2007 Report was released by CEA in mid-October 2009. CNP has not acquired or reviewed this report, which would include one additional year of data as compared to the 2006 Report that was referenced in the pre-filed evidence. As a result, because this report presents multi-year averages, CNP does not expect there to be any material changes in the outage frequency data reported therein.

(xiv)(a) Yes.

(xiv)(b) CNP believes that the non-discretionary classification for the project is warranted by the recognition that the need for the project is driven significantly by a factor that is beyond the control of the Applicant. Specifically, the Transmission System Code requires CNP to operate and maintain its transmission system in accordance with good utility practice. As the current configuration of the CNP system does not allow for the provision of uninterrupted supply upon the loss of its primary supply source, and given that the entire system remains dark for a period of at least 4 hours before the emergency supply from USNG can be engaged, it would be good utility practice in these circumstances to provide the system with N-1 contingency. For these reasons, and because there are no viable alternative means of providing N-1 contingency (See Exhibit B, Tab 6, Schedule 1), CNP regards the project as non-discretionary. The inclusion of a requirement under NERC Standard TOP-002-2 for transmission operators to plan to meet unscheduled changes in system configuration and generation dispatch at a minimum N-1 contingency planning provides further support for the proposition that N-1 contingency planning is good utility practice in the circumstances of CNP's current system configuration. Moreover, this non-discretionary classification is consistent with section 5.2.2 of the Filing Requirements, which suggests that a non-discretionary project may be triggered or determined by, for example, requirements to satisfy obligations specified by regulatory organizations such as NERC.

CNP, in accordance with principles of good utility practice and applying its reasonable judgment, believes that it is unreasonable and unacceptable for CNP to subject the end-users of its system to planned or forced outages, including the risk of such outages, with the frequency, duration and scope that its end-users are subject to as a result of the current system configuration. Because the system has only a single supply, it is not able to withstand the loss of that one element. It is CNP's view that good utility practice demands that a system of the size and nature of CNP's transmission system be capable of withstanding the loss of a single element by having two readily available sources of supply. While the Emergency Tie Line is available for backup supply, the 4-hour duration for engaging this backup supply in the event of a forced outage - during which the entire system remains in the dark - is not acceptable for the end-users of CNP's system, which include residential, commercial, institutional and industrial, including large industrial, loads as well as the uniquely important Peace Bridge Authority. Similarly, it is not acceptable to subject these end-users to two separate system-wide outages of 30 minutes to enable CNP to carry out maintenance activities on the system. As such, from a system reliability perspective, this project is non-discretionary.

(xiv)(c) The IESO's views, with respect to project classification, are as follows:

IESO

As stated under 1.0(iii), the CNP transmission system is not currently classified as Bulk Electricity System under NERC, or as Bulk Power System under NPCC, and it is within the IESO's load restoration criteria. However, as also stated under 1.0(iii) and 1.0(v), the IESO agrees with the need for CNP system enhancements, given CNP's responses to 1.0(i) and 1.0(iv). The IESO is in no position to determine the classification of the Project.

2.0 ALTERNATIVES CONSIDERED

References

(1) Exhibit B, Tab 6, Sch. 1

(2) Exhibit B, Tab 3, Sch. 1

Preamble

CNP considered 5 alternatives to address the need. Three are variations of the Project and two involve new transmission lines connecting to alternate supply points and on different routes.

Based on the evidence:

- All of the 5 alternatives provide an increased level of reliability to the load in Fort Erie and associated benefits.
- All of the 5 alternatives meet the N-1 Contingency Criterion.
- Only the Project provides additional system-wide benefits to Ontario associated with an increase in the interconnection capability between Ontario and New York.
- The NPV of the Project is $10.4 million over the 30-year study period.
- The NPV of the other alternatives ranges from $ - 3.8 million to about $ -28.5 million.

CNP submitted on page 7 of Ref (2) that a forced outage requiring the initiation of the New York supply through the Emergency Tie Line would involve a 31-step switching process that could take a minimum of 4 hours.

Questions / Requests

(i) Does CNP agree with Board staff's approximation that the NPV of the alternatives which do not provide any system-wide benefits to Ontario would be in the order of $ -28.5 million? If not, what is the appropriate NPV?

(ii) Assuming that there was no requirement to meet the N-1 contingency criterion, please comment on the feasibility, scope, cost (approximate), expected benefits and impact on the reliability of supply to the Fort Erie load for each of the following options:

(A) Upgrade the 0.66 km limiting transmission line section between Queen St. Tower and High Tower so that it has sufficient capacity to supply the entire Fort Erie load.

(B) Reenergize the existing unenergized circuit in the limiting transmission line section between Queen St. Tower and High Tower so that the two circuits can supply the entire Fort Erie load.

(C) Improve the 31-step switching procedure by procedural and/or equipment changes/additions to reduce the 4-hour switching time, e.g. automated switching or other feasible measures.

(D) Any other alternative(s) that CNP can identify that would improve the reliability of supply to the Fort Erie load.

Responses

(i) No. It is not clear to CNP as to how Board Staff derived the $(28.5) million figure. As indicated on page 17 of Exhibit B, Tab 6, Schedule 1 of the pre-filed evidence, CNP has calculated the NPV for the Niagara Project Alternative as being $(3.8) million and the NPV for the Port Colborne Project Alternative as being $(12.4) million. These project alternatives do not provide any system-wide benefits.

(ii)(a) While an upgrade to the 0.66 km limiting transmission line section between Queen St. Tower and High Tower would improve line capacity, this would only be by a small margin. This is because the capacity available from USNG would then be limited to 53 MW because of capacity limitations on L46 and L47 on the USNG system (See Exhibit B, Tab 6, Schedule 1, page 3). Considered as a standalone project, the upgrade of this line section would have very limited reliability benefit. In particular, such a project would increase the capacity of the Emergency Tie Line from 48 MW to 53 MW. As CNP's annual peak demand has been as high as 56 MW (2008) and is consistently forecast to be greater than 55 MW in future, even the incremental 5 MW of capacity would not provide the Emergency Tie Line with sufficient capacity to fully serve CNP's emergency needs. An upgrade of this section of the line would cost an estimated $150K.

(ii)(b) Similar to the response to (ii)(a) above, the energizing of the second circuit in the limiting line section would provide additional line capacity, but the ability to use that additional capacity would similarly be limited by the capacity limitations on L46 and L47 on the USNG system. See also the response to 1.0(vi), above.

(ii)(c) The minimum four-hour timeframe referenced in the pre-filed evidence describes the period of time it would typically take from the time a forced outage occurs until the time that power supply can flow through the Emergency Tie Line from USNG to CNP's transmission system. The actual switching operation that is carried out to effect the change in supply from HONI to USNG (or vice-versa) takes approximately 30 minutes, while the remainder of the four-hour minimum timeframe is attributable to the need for USNG to perform switching operations on it's system and for necessary co-ordination among CNP, HONI, IESO and USNG. Such coordination is vital to preventing adverse

consequences to the USNG system that would otherwise result from the Emergency Tie Line being engaged. Switching devices involved in the operation are already automated and controlled via CNP's SCADA system. The switch at the normally open point on the Emergency Tie Line cannot be closed immediately upon loss of the HONI supply because of the need for co-ordination. As a result, CNP does not believe there are any equipment or procedural changes that would be able to materially expedite the procedure for engaging the emergency tie line in response to a forced outage. The time needed to activate the Emergency Tie Line is a function of the system's configuration.

(ii)(d) There is no other viable alternative for resolving the fundamental reliability problem associated with the CNP transmission system, as principally described in the pre-filed evidence at Exhibit B, Tab 3, Schedule 1, Exhibit B, Tab 6, Schedule 1 and in the response to 1.0(i) above. While CNP has a range of planned system improvements of a normal or ongoing nature, such as procedural improvements and capital or maintenance expenditures to enhance the robustness of the system, these will not solve the fundamental problem as described. Such initiatives will not address the issues of "load at risk" or the lack of N-1 contingency.

3.0 PROJECT ECONOMICS AND COST RESPONSIBILITY

References

(1) Exhibit B, Tab 2, Sch. 1, Page 2

(2) Exhibit B, Tab 4, Sch 1

(3) Exhibit B, Tab 5, Sch. 1

(4) Exhibit B, Tab 12, Sch 2, Page 31

Preamble

Based on CNP's Evidence:

- The estimated total cost of the Project is $30.9 million. Of this, $14.9 million is for facilities in Ontario and the remaining $16 million is for facilities in New York.
- Implementation of the Project will result in:
  - benefits associated with improved reliability of supply to the Fort Erie load estimated at $16.1 million (NPV over 30 years))
  - benefits due to Improved maintenance schedules estimated at $3.4 million (NPV over 30 years)
  - benefits to Ontario due to increased interconnection capability between Ontario and New York estimated at $36.6 million (NPV over 30 years)
- In Ref (1) CNP states that "Though not currently expected, Queen Street Tower and High Tower may need to be replaced to support the new conductors."
- On page 10 of Ref (2), CNP states the following:

  The Project is rated to provide 150 MW of intertie capacity in both directions at the Niagara interface with New York.

- The SNC Lavalin report (Ref 4) states the following:

  The New York to Ontario transfer capability will increase by more than 150 MW with the CNP tie.....

The Ontario to New York transfer capability will increase only by a small amount with the CNP tie, since the Ontario to New York transfer is constrained by the 345 kV systems in New York (as identified by the Limiting Circuit in the tables).

(underlining added)

- In calculating the benefits to Ontario ($36.6 million NPV) due to increased interconnection capability between Ontario and New York, CNP assumed that the Project would provide an additional 150 MW of interconnection capability which would avoid the need for 150 MW of new generation capacity. The avoided generation costs were then determined using CDM guidelines which would result in a value of $365.6 million over the life of the Project and reducing this amount by 90% to come up with $36.6 million. (Reducing the $365.6 million amount by 90% seems somewhat arbitrary.)

- The Project relates to network assets and CNP is proposing to pay the entire cost of the Project (estimated at $30.9 million) including the capital contribution that CNP will make to USNG to cover the costs of the work in New York and that this be ultimately added to rate base and recovered through the network charge of the Uniform Transmission Rates.

Board staff wishes to explore the reasonableness of the estimated Project costs and benefits as well as CNP's rationale for its proposal to pay the entire cost of the Project and seek recovery from Ontario ratepayers.

Questions / Requests

(i) Please provide cost breakdowns for the estimates shown in Figure 5.1 in Ref (1) for the facilities proposed on the Ontario side and to the extent possible those on the New York side based on the following categories:

- engineering;
- construction;
- equipment and materials
- commissioning:
- contingencies;
- overheads (break down into Direct Overheads and Indirect overheads); and
- AFUDC.

(ii) Please indicate the accuracy of the estimates shown in Figure 5.1 in Ref (1).

(iii) Has CNP determined yet whether the Queen Street Tower and High Tower need to be replaced to support the new conductors? If it is required, what is the estimated cost of carrying this out?

(iv) The $16.1 million benefit associated with the improved reliability of supply to the Fort Erie load is based on a value of lost load (VoLL) of $10,000/MWh and an interruption of the entire load one day every 10 years. The method does not seem to relate to reliability levels before and after the Project is implemented.

(A) How does this method compare with the methodology used by other transmitters in Ontario in evaluating the benefits of improved reliability of transmission systems?

(B) Please comment on the accuracy of the above-noted CNP calculation.

(C) Please comment on the accuracy of CNP's alternate calculation ($11.5 million) which considers the impact on specific customers and customer classes. (This method also does not seem to relate to reliability levels before and after the Project is implemented.)

(v) Please explain (with verification from the IESO) the apparent discrepancy in the calculation of the increase in the Ontario – New York interconnection capability between the CNP/IESO and SNC Lavalin calculations referred to in the preamble.

(vi) Please confirm (with verification from the IESO) what the appropriate increase in the import and export capability of the Ontario electricity market that should be used in calculating the benefits of the Project.

(vii) Please comment on the appropriateness of using CDM Guidelines for evaluating avoided generation in calculating the benefits to Ontario ($36.6 million NPV) associated the increased interconnection capability between Ontario and New York.

(viii) Does the IESO and/or the OPA agree with the methodology used by CNP (i.e. using CDM guidelines for avoided generation for valuing additional import capability in Ontario) to determine the value of the increased interconnection capability associated with the Project? Any comments/explanations from the IESO and/or OPA should be included in your reply.

(ix) If the IESO and/or OPA do not agree with the methodology in (viii):

(A) please advise what methodology is considered appropriate by the IESO and/or the OPA, including their rationale;

(B) please calculate the economic value of the increased interconnection capability associated with the Project based on the methodology in (a).

(x) Since the Project will increase the interconnection capability between Ontario and New York in both directions, and likely benefits both sides, why is CNP proposing to pay the entire cost of the Project, including the work in New York?

(xi) Has CNP attempted to negotiate a cost-sharing arrangement with USNG? If it didn't, why not? If it did, what was the outcome and rationale?

(xii) Please provide any policies, guidelines and examples of prior practice (both at CNP and other Ontario transmitters) that would support CNP's proposal to pay the entire cost of the Project (including work in New York) and recover the costs from the Ontario electricity ratepayers.

(xiii) Please advise what the cost-sharing arrangements were between Hydro One and U.S. jurisdictions (New York and Michigan) when the existing interconnections were established/reinforced. (In answering this, please consult with and provide verification from Hydro One.)

Responses

(i) The requested breakdown of the capital cost estimate is provided below. Please note that the amounts indicated in the table are CNP's estimates at this point in time and that commissioning costs are included within the construction costs as shown. While the estimated capital cost of $30.9 million as presented in the pre-filed evidence did not include AFUDC, all of the NPV and rate impact calculations provided in the pre-filed evidence do account for AFUDC.

	Ontario	**New York**	**Total**
Engineering	1.2	1.4	2.7
Construction	1.7	7.2	8.9
Equipment & Materials	8.5	5.0	13.6
Commissioning			
Contingencies	2.3	2.3	4.6
Overhead	1.1		1.1
Sub-total	**14.9**	**16.0**	**30.9**
AFUDC			2.3
Total			**33.2**

(ii) +/- 25%

(iii) No. This will be determined during the detailed engineering stage of the project. If required, it is estimated that replacement towers would cost approximately $400K each. However, in the event that detailed engineering determines that replacement towers may

be needed, consideration would then be given to the feasibility of using lighter weight composite conductors which may allow for continued use of the existing towers. The incremental cost of the composite conductor as compared to standard conductor would be considered against the incremental cost of replacing the existing towers.

(iv) (a) CNP is not aware of any other transmitter in Ontario that has sought leave from the Board to construct a transmission project where the primary justification for the project was driven by loss of load. CNP's approach to evaluating the local benefits of improved reliability is driven by its unique character as a transmitter that serves load that can be lost, in its entirety, for an extended period of time. These unique characteristics of the project led CNP to use the value of lost load ("VoLL") approach.

(b) The accuracy of the VoLL calculation is validated by the 'bottom-up' calculation of benefits, which was based on detailed customer information collected by CNP (see Exhibit B, Tab 4, Schedule 1, section 2(b) and Figure 4.2). Since the bottom-up approach identifies $11.5 million of benefits, which represents over 70% of the benefits indicated through the VoLL calculation, CNP concludes that the VoLL approach is reasonable and that the calculation is a reasonably accurate quantification of the local reliability benefits from the project (See response to (iv)(c) below).

(c) While the accuracy of CNP's bottom-up calculation is dependent upon the accuracy of the responses provided by the selected end-users who responded to CNP's questionnaire, CNP believes that there is a unique value in accounting for data collected directly from affected end-users who were asked to specifically consider the impacts of outages on their operations. However, while the use of such data 'from the field' lends credibility to the bottom-up approach, it is narrow in scope in that this calculation does not account for benefits to residential, commercial, institutional or industrial end-users other than the sample of industrial end-users surveyed. As such, it is reasonable to expect that this calculation would identify fewer benefits than the VoLL approach. In summary, this approach is accurate, but narrow in scope and therefore its value is in providing a basis, grounded in data from end-users, for validating the seemingly more abstract VoLL calculation of local reliability benefits.

(v) The IESO statement was based on the IESO's study of the Ontario system. The IESO did not perform an in-depth study of the technical aspects of the USNG system. As a result, the IESO analysis assumed that the interconnection capability would increase by the same amount in both directions. This is compared to the SNC Lavalin report, which is based on more detailed analysis of the USNG system. The analysis of the IESO and SNC are therefore not in conflict, but must be read together to get a more complete understanding of the implications for Ontario and for the USNG system in New York (see response to 3.0(vi) below).

The views of the IESO with respect to this explanation of the apparent discrepancy are as follows:

IESO

The IESO agrees with CNP's explanation in 3.0(v).

(vi) The inter-area transfer analysis in the SRIS has been carried out for purposes of evaluating the impact of the project on inter-area transfer capability. This study considered such impacts under the condition of there being 150 MW flowing in either direction, during peak periods on the system, as well as with certain assumptions concerning dispatch conditions. During all periods (peak and non-peak), the New York to Ontario transfer capability across all interties is expected to increase by 247 to 259 MW. Of this, 150 MW will be provided directly by the proposed intertie. The remaining 97 to 109 MW of incremental transfer capability, which will be made possible by the proposed intertie, would be added to existing interties.

With respect to Ontario to New York transfer capability, during periods other than peak periods, the increase in transfer capability is similarly expected to be in the order of 150 MW across the proposed intertie. However, during peak periods and under the assumed dispatch conditions, the flow south from Ontario to New York is expected to be constrained due to limitations on the New York system. Under the worst conditions (i.e. absolute peak periods), the proposed intertie would allow for the flow of 44 to 47 MW from Ontario to New York, as shown in Table 5.1 of the report provided in Exhibit B, Tab 12, Schedule 2 of the pre-filed evidence. During peak periods where system demand is something less than 'absolute' peak, the proposed intertie would allow for flows that are correspondingly greater than the range indicated for this worst case scenario.

The views of the IESO, with respect to this explanation of the incremental import and export capability expected from the proposed intertie, are as follows:

IESO

The IESO agrees with the description of on-peak transfer capabilities, as summarized in CNP's response to 3.0(vi). The IESO is not aware of any studies on off-peak transfer capabilities between Ontario and New York, hence it cannot comment on the Ontario to New York transfer capability improvement during off-peak periods.

(vii) As explained in Exhibit B, Tab 4, Schedule 1, beginning at p. 11, CNP used the CDM Guidelines because the project has the potential to provide avoided generation capacity benefits in a manner similar to that which would be provided by CDM initiatives. CDM initiatives have the potential to avoid the need for new generation resources. Likewise, an increase in transmission intertie capacity from a resource outside of Ontario has the potential to provide a similar benefit. As a result, the calculation under the CDM

Guideline provides a reasonable estimate of the value of this benefit. The avoided capacity values presented in the CDM Guidelines are appropriate because they are based on the avoided capacity cost for the OPA's Clean Energy Supply (CES) power purchase contracts for peaking generation (*Avoided Cost Analysis for the Evaluation of CDM Measures*, Navigant Consulting, January 14, 2005) and are not related in any way to specific CDM measures or social values.

Electricity system operators and industry experts will invariably view additional intertie capacity as a benefit. However, quantifying the value of these benefits can become difficult. In order to mitigate this uncertainty, CNP exercised a high degree of conservatism by de-rating or reducing the calculated value by 90% for the purposes of valuing the intertie benefits to Ontario.

(viii) The IESO's views, with respect to the methodology used by CNP to determine the value of the increased interconnection capability associated with the project, are as follows:

IESO

The IESO expresses no opinion on the CDM guideline itself, nor the methodology used by CNP to determine the value of the increased interconnection capability associated with the Project. In its resource adequacy/planning studies, the IESO does not assume reliance on any interconnection support from its neighbours.

(ix) The IESO's views, with respect to the appropriate methodology, are as follows:

IESO

The IESO is not in a position to recommend a methodology to determine the economic value of the additional interconnection capability.

(x) Increased intertie capacity is an ancillary benefit arising from the project, which is primarily intended to bring reliability on CNP's transmission system in line with good utility practices. While it is true that electricity will flow in both directions, USNG has not sought the benefits arising from the project because USNG already has adequate and reliable supply. Moreover, the USNG system already enjoys N-1 contingency and would therefore derive minimal local reliability benefit from the project.

(xi) CNP did attempt to negotiate a cost-sharing agreement with USNG, but as noted in (x) above, USNG was not receptive to the idea because they were of the view that the USNG system already enjoyed N-1 contingency and would therefore derive minimal benefit from the Project.

(xii) In 1998, CNP implemented the Emergency Tie Line with USNG. This project included the installation of 2.7 km of underground cable on the USNG system to connect USNG's

Line 46 to the CNP system. Because this project was intended to provide an emergency source from USNG and was solely for the benefit of CNP, the cost of facilities installed on the USNG system was borne by CNP and is being recovered from Ontario ratepayers as a rate base addition reflected in the asset value associated with its rights under the interconnection agreement between CNP and USNG, which gives CNP the right to an alternative source of supply for the benefit of its end-users.

(xiii) The following statement has been provided by Hydro One in response to the question of what cost-sharing arrangements were between Hydro One and U.S. jurisdictions when the existing interconnections were established or reinforced:

> "The cost sharing arrangements between Hydro One and U.S. jurisdictions for existing interconnections have generally been that each transmitter pays for the assets on their side of the border and is responsible for ordinary operation and routine maintenance costs. There have been arrangements in limited circumstances to share the costs of extraordinary maintenance and repair of certain transformers and phase-shifters."

Notwithstanding the response provided by Hydro One, CNP notes that such interconnections have typically been developed for the mutual benefit of both participating jurisdictions. In the circumstances of the Project, the reliability benefit will be enjoyed solely by Ontario and not by New York. Moreover, the existing interconnections between Hydro One and U.S. jurisdictions were established quite some time ago under a very different regulatory regime and under very different interconnection arrangements than at present. In particular, such interconnections would have been developed at times when there was minimal or no cross-border trade across interties except in the case of emergencies. While more recently Hydro One has been involved in developing an intertie between Ontario and Quebec, this would not be relevant to CNP's circumstances because the Ontario-Quebec intertie is expected to provide mutual benefits to both jurisdictions. It is also important to note that, if Hydro One were to propose a new interconnection project to connect with a jurisdiction in the United States, Hydro One would be faced with the same regulatory requirements in the United States as are being faced by CNP.

4.0 SYSTEM IMPACT ASSESSMENT (SIA)

References

(1) Exhibit A, Tab 3, Sch. 1, Pages 21-22

(2) Exhibit B, Tab 9, Sch. 1

(3) Exhibit B, Tab 9, Sch. 2

Preamble

CNP submitted a SIA, dated January 17, 2007 and labelled as "DRAFT Report" as well as "Final Report". The report concludes that Notification of Conditional Approval for connection be issued to CNP subject to subject to a list of requirements contained in the SIA.

There is no Notification of Conditional Approval included in the pre-filed evidence (as is generally required in a Section 92 application).

Based on information contained in the SIA:

- the short circuit analysis is not completed;
- the IESO is awaiting short circuit modeling data for the USNG system; and
- CNP is required to provide the data to the IESO to complete the analysis.

There is no evidence to indicate whether the above items have since been completed.

Board staff wishes to obtain information/verification regarding the status of the IESO's SIA and the Notification of Conditional Approval for the Project.

Questions / Requests

(i) Please advise whether the SIA report dated January 17, 2007 is the final SIA report or a draft. If it is not final, please provide the final version.

(ii) Please provide a signed copy of the IESO's Notification of Conditional Approval for the SIA.

(iii) Since the SIA filed is over 2 1/2 years old, please provide verification from the IESO that it is in agreement with the Project as now proposed and provide status of any outstanding requirements it has or new requirements due to changed conditions etc. e.g. status of short circuit studies.

(iv) Please confirm that CNP plans to implement all of the IESO's connection requirements in the contained in the SIA and any updates to it.

Responses

(i) The SIA report dated January 17, 2007 is a Final Report. A typographical error on the cover page has been corrected by the IESO and the full report is provided at **Appendix "B"**.

(ii) An executed copy of the IESO's Notification of Conditional Approval for the SIA is provided at **Appendix "C"**.

(iii) It is CNP's understanding that the outstanding requirements include the need for updates to short circuit studies from Hydro One, the provision by CNP to the IESO of technical details and specifications for the phase shifter and voltage regulator once this equipment is selected, as well as details of any material changes that may be made to the project design. It is CNP's further understanding, based on consultation with the IESO, that all of the above-mentioned outstanding requirements will require the issuance of an addendum to the SIA Final Report.

The IESO's views, with respect to the status of the SIA and outstanding requirements, are as follows:

IESO

The IESO confirms that it is supportive of the Project as now proposed and agrees with the description of outstanding requirements provided by CNP in its response to 4.0(iii).

(iv) CNP confirms that it plans to implement all of the IESO connection requirements contained in the SIA and any updates to the SIA.

5.0 CUSTOMER IMPACT ASSESSMENT (CIA)

References

(1) Exhibit A, Tab 3, Sch. 1, Pages 21-22

(2) Exhibit B, Tab 10, Sch. 1

(3) Exhibit B, Tab 10, Sch. 2

Preamble

CNP filed a CIA carried out by Hydro One, dated September 16, 2006 (Ref 2). The CIA indicates that:

- Hydro One carried out a short circuit analysis and concluded that, while the Project would result in a small increase in short circuit levels, the increased short circuit level is still within the capability of the existing facilities.

- Hydro One concluded that the Project is not expected to have a significant impact on the customers in the area.

Questions / Requests

(i) Since the CIA filed is over 3 years old, please provide verification from Hydro One that the results of the CIA are still valid and provide the status of any outstanding requirements or new requirements due to changed conditions etc.

(ii) Please confirm that any requirements in the current CIA and any updates to it will be implemented.

Responses

(i) Hydro One has verified that the results of the CIA remain valid, subject to the need to review the assumptions used for the Short Circuit Study in the CIA. This review may give rise to the need to recalculate some of the study results.

(ii) CNP confirms that any requirements in the current CIA and any updates to it will be implemented.

6.0 ENVIRONMENTAL ASSESSMENTS

References

(1) Exhibit B, Tab 7, Sch 1

Preamble

CNP submits that, for various reasons mentioned in Ref (1):

- CNP does not expect the Project to trigger any federal environmental assessment requirements.
- CNP "is confident that no provincial environmental assessment requirements will apply to the Project."

Questions / Requests

(i) Please provide verification from Environment Canada that no federal environmental assessment requirements will apply to the Project.

(ii) Please provide verification from the Ministry of the Environment that no provincial environmental assessment requirements will apply to the Project.

(iii) If the federal and/or provincial authorities in (i) and (ii) above indicate that there are environmental requirements, please indicate how CNP plans to fulfill the requirements including the timeframe for completion.

Responses

(i) The federal environmental assessment process is a proponent-driven process under which the question of whether a proposed project may be subject to federal environmental assessment requirements is determined by means of a self-evaluative process. The key points from CNP's self-evaluative process are discussed in Exhibit B, Tab 7, Schedule 1. This self-evaluative process involves consideration of the Canadian Environmental Assessment Act and the regulations thereunder, as well as guidance documents provided by the Canadian Environmental Assessment Agency that are designed to assist proponents in carrying out this self-evaluative process.

While carrying out this self-evaluative process is itself not a regulatory requirement, a project proponent will, from a practical perspective, have to follow such a process in order to determine for compliance purposes whether the federal environmental assessment requirements will apply to their project. Because of the self-evaluative nature of the process, CNP cannot provide verification from Environment Canada that such requirements will not apply to the project. Moreover, it is CNP's understanding that

Environment Canada does not normally provide any such verification for projects that do not trigger federal environmental assessment requirements.

(ii) The provincial environmental assessment process is a proponent-driven process under which the question of whether a proposed project may be subject to provincial environmental assessment requirements is determined by means of a self-evaluative process. The key points from CNP's self-evaluative process are discussed in Exhibit B, Tab 7, Schedule 1. This self-evaluative process involves consideration of the Environmental Assessment Act and Ontario Regulation 116/01 (Electricity Projects), as well as the Ministry of the Environment's *Guide to Environmental Assessment for Electricity Projects*, which is incorporated by reference into the regulation and assists proponents in carrying out the self-evaluative process.

While carrying out this self-evaluative process is itself not a regulatory requirement, a project proponent will, from a practical perspective, have to follow such a process in order to determine for compliance purposes whether the provincial environmental assessment requirements will apply to their project. Because of the self-evaluative nature of the process, CNP cannot provide verification from the Ministry of the Environment that such requirements will not apply to the project. Moreover, it is CNP's understanding that the Ministry of the Environment does not normally provide any such verification for projects that do not require environmental assessments. Finally, as explained in footnote 4 on page 5 of Exhibit B, Tab 7, Schedule 1, although CNP does not expect that provincial environmental assessment requirements will apply, in the course of carrying out detailed engineering work CNP will be able to confirm whether or not two new towers will be needed. If those towers are needed, then provincial environmental assessment requirements may arise. However, CNP currently believes that the towers will not be required. As such, it would be premature for CNP to express any final conclusions with respect to the applicability of provincial environmental assessment requirements at this time (See also the response to 3.0(iii), above).

(iii) In the event that any environmental assessment requirements under either the federal or provincial regime are found to apply, CNP would engage a qualified consultant to assist CNP in following all applicable steps and meeting all applicable requirements, including the determining the scope, timing and consultation requirements for such processes.

7.0 CNP / USNG OPERATIONAL AGREEMENTS

References

(1) Exhibit B, Tab 12, Sch 2

Preamble

Ref (1) refers to study carried out by SNC Lavalin as part of New York Independent System Operator's interconnection process. Page i of the reference states the following:

> *The Project allows for a maximum tie flow of 150MW in either direction. CNP is, however, expected to operate the tie largely consistent with its existing operating pattern (i.e. supplying its loads from Hydro One transmission under normal operating conditions and receiving power from NYISO side only when its Hydro One link is outaged) in keeping with its intrautility agreements.*

Board staff wishes to investigate the relevance of the above statement and its implication that power would be flowing into Ontario only when the Hydro One link is outaged. If this is the case, it seems unlikely that Ontario would derive the significant benefits associated with the increased interconnection capability ($36.6 million). Some clarification is required.

Questions / Requests

(i) Please explain the relevance of the above noted statement from Ref (1) and whether the significant benefits associated with the increased interconnection capability can be achieved under such restrictions.

(ii) Please provide verification from USNG that it is in agreement with the operation of the proposed synchronous tie between Ontario and New York as envisaged by CNP/IESO in a manner that will achieve the reliability benefits for the Fort Erie load as well as the benefits to Ontario associated with the increased interconnection capability.

Responses

(i) The phase shifter and voltage regulator will always be online and the intertie will always be energized. CNP anticipates that it will be scheduled so that, as a default, there will be a net flow of zero. By this, it is meant that flows from Ontario towards New York will be counterbalanced by the flows from New York toward Ontario (i.e. they will be in equilibrium), with the net result being that, as a default, there will be no flow in either direction. However, if at any time the flow from Ontario toward New York is interrupted, then the equilibrium will be compromised and the flow from New York towards Ontario will immediately become available to serve the CNP transmission system. Moreover, changes to the net flow of zero can be scheduled at any time by and at the direction of the IESO, in coordination with its U.S. counterparts. Ontario would

thereby still benefit from the full import capability of the intertie if and when the IESO, in concert with its U.S. counterparts, chooses to schedule the intertie differently from the default schedule.

(ii) Please see the letter from USNG provided in **Appendix "D"**, which sets out USNG's views with respect to the operation of the proposed synchronous tie between Ontario and New York in a manner that will achieve the reliability benefits for the Fort Erie load as well as the benefits to Ontario associated with the increased interconnection capability.

8.0 LAND RELATED MATTERS AND OTHER APPROVALS

References

(1) Exhibit B, Tab 2, Sch 1, Pages 2-3

Preamble

Based on CNP's evidence:

- The Ontario portion of the Project will take place on or be situated upon lands that already support the CNP Transmission System and which CNP already controls and, as a result no new land is required for the Project.

- Station #18 may need to be expanded by a minimal amount in order to accommodate the phase shifting transformer and voltage regulator.

Questions / Requests

(i) Please provide a list of all outstanding approvals and permits needed to complete construction of the proposed facilities.

(ii) Is CNP required to negotiate/renegotiate easement agreements with any of the affected property owners? If so, have the property owners been presented with a form of easement agreement? Please provide copies of any forms of easement agreements that have been or will be presented to the affected landowners.

(iii) Are there any landowner issues/concerns to be resolved with respect to the expansion of Station #18? If so, what is the status including CNP's plan and expected timing for resolution?

(iv) Are there any other outstanding landowner issues/concerns that need to be addressed? If so, what is the status including CNP's plan and expected timing for resolution?

Responses

(i) Required permits and approvals for construction are as follows:

- Leave to Construct from the Ontario Energy Board
- Notice of Project to the Ontario Ministry of Labour
- Amendment of Permit from the National Energy Board
- Amendment of Presidential Permit (by USNG on behalf of CNP)

In addition, there may be minor municipal approvals needed to facilitate work on the project and there may be permits or approvals required by USNG, which will be obtained by USNG on behalf of CNP.

(ii) No. CNP does not expect that it will require any additional lands for the project. However, in the event that additional lands are needed, CNP would plan to purchase that land. CNP does not need to negotiate or renegotiate any easement agreements in connection with the project.

(iii) In the event that the detailed engineering determines that such additional lands are required, CNP does not anticipate that any landowner issues or concerns would arise.

(iv) CNP served the notice of application on approximately 50 landowners along its transmission system. In response, CNP had only two calls by individuals seeking a basic explanation of what the notice was about and one email query as to whether the project would give rise to a service disruption. As such, CNP does not anticipate any other landowner issues or concerns.

9.0 ABORIGINAL PEOPLES CONSULTATIONS

References

(1) Exhibit B, Tab 6, Sch 1, Page 22

Preamble

There is no mention in the evidence regarding any aboriginal lands that may be affected by the Project or any consultations with any Aboriginal group. Ref (1) mentions Aboriginal involvement in other alternatives that were considered and rejected by CNP.

Board staff requires certain information/confirmation from CNP regarding potential impacts of the Project on any Aboriginal groups in Ontario.

Questions / Requests

(i) Has CNP made inquiries to determine if there are Aboriginal groups that may be affected by the Project?

(ii) If there are Aboriginal groups that are affected by the Project, has CNP consulted with them? If so please indicate:

- (A) when and how contact was first initiated;
- (B) the individuals within the Aboriginal groups who were contacted, and their position in or representative role for the group; and
- (C) a listing, including the dates, of any phone calls, meetings and other means that may have been used to provide information about the project and to hear any interests or concerns of Aboriginal groups with respect to the project.

(iii) Please provide any relevant written documentation regarding consultations, such as notes or minutes that may have been taken at meetings or from phone calls, or letters received from, or sent to, Aboriginal groups.

(iv) Please provide any relevant information gathered from or about the Aboriginal groups as to their treaty rights, any filed and outstanding claims or litigation concerning their treaty rights, treaty land entitlement or aboriginal title or rights, which may potentially be impacted by the project.

(v) Please identify any specific issues or concerns that have been raised by Aboriginal groups in respect of the Project and, where applicable, how those issues or concerns will be mitigated or accommodated.

(vi) Please explain whether any of the concerns raised by Aboriginal groups with respect to the Project have been discussed with any government department or agencies, and if so, identify when contacts were made and who was contacted.

(vii) Please provide details of any known Crown involvement in consultations with Aboriginal groups in respect of the Project.

(viii) If CNP has not made inquiries to determine if there are Aboriginal groups who may be affected by the Project, please advise what CNP's intentions are with respect to Aboriginal consultations as to process and expected timing.

Responses

(i) Yes. While there is a significant off-reservation Aboriginal population in the general vicinity of Fort Erie and the proposed project, there is, to the best of our knowledge, no formal Aboriginal representative council.

Representatives of Canadian Niagara Power spoke with the administrative staff at the Fort Erie Native Cultural Center and this was followed with formal notice to the Executive Director of the Cultural Center on August 13, 2009. This formal notice was referenced in the Affidavit of Service filed with the Board dated August 19, 2009.

It has been Canadian Niagara Power's experience, that Fort Erie Native Cultural Center which is associated with the federal and provincial association of Native Cultural Centers is a central point of contact with the Aboriginal population in the area. This was confirmed in a telephone conversation with the Executive Director on October 20, 2009. The Executive Director also confirmed in that telephone conversation that Canadian Niagara Power's Notice of Application was tabled at their most recent Board Meeting and that there were no adverse issues raised. The Board has asked that Canadian Niagara Power attend a future forum at the Cultural Center to provide first hand description of the project and its benefits to the area.

(ii) Based on Canadian Niagara Power's discussion with the Executive Director of the Fort Erie Cultural Center, referenced in Part (i), there are no Aboriginal groups that are affected by the Project.

(iii) Other than CNP's Notice of Application to the Fort Erie Cultural Center, there is no relevant documentation.

(iv) Not applicable.

(v) The Executive Director of the Fort Erie Aboriginal Cultural Center has requested on behalf of their Board that Canadian Niagara Power attend a future forum at the Cultural

Center to provide first hand description of the project and its benefits to the area. Canadian Niagara Power has agreed to this request.

(vi) There have been no concerns raised.

(vii) There have been no consultations required.

(viii) Not applicable.

APPENDIX "A"

Modified Data per Request in 1.0(vii)

Summary Table of Outage Event Statistics for CNPI Station 17

Year	DP Frequency (events /yr)	3 yr Rolling Average	DP Duration (Min / year)	3 yr Rolling Average
2002	1		54	
2003	2		165	
2004	7	3.3	375	198
2005	0	3.0	0	180
2006	2	**3.0**	203	**193**
2007	0	0.7	0	68
2008	0	0.7	0	68
Total or Average	12	**2.1**	797	**141**

Comparison of CNPI Outage History to Hydro One CDPPS

	Hydro One CDPPS EB 2002-0424 (Table 1) >0-15 MW		CNPI CDPPS Statistics	
	Standard (Average Performance)	Minimum Standard of Performance	Average 2002 to 2008	Maximum 2002 to 2008
DP Frequency of Interruptions (Outages/yr)	4.1	9	2.1	3.3
DP Interruption Duration (min/yr)	89	360	141	198

Summary Table of Outage Event Statistics for CNPI Station 18

Year	DP Frequency (events /yr)	3 yr Rolling Average	DP Duration (Min / year)	3 yr Rolling Average
2002	1		54	
2003	2		165	
2004	8	3.7	253	157
2005	0	3.3	0	139
2006	2	**3.3**	203	**152**
2007	0	0.7	0	68
2008	0	0.7	0	68
Total or Average	13	**2.3**	675	**117**

Comparison of CNPI Outage History to Hydro One CDPPS

	Hydro One CDPPS EB 2002-0424 (Table 1) >15-40 MW		CNPI CDPPS Statistics	
	Standard (Average Performance)	Minimum Standard of Performance	Average 2002 to 2008	Maximum 2002 to 2008
DP Frequency of Interruptions (Outages/yr)	1.1	3.5	2.3	3.7
DP Interruption Duration (min/yr)	22	140	117	157

APPENDIX "B"

Final SIA Report with Corrected Cover Page per Request in 4.0(i)

REPORT

ieso
Power to Ontario.
On Demand.

System Impact Assessment Report

CONNECTION ASSESSMENT & APPROVAL PROCESS

Issue 1.0

Project: Fort Erie Interconnection
Applicant: Canadian Niagara Power Inc.

CAA ID 2005-192

Transmission Assessments & Performance Department

Final Report

January 17, 2007

Document ID	IESO_REP_0323
Document Name	System Impact Assessment Report
Issue	Issue 1.0
Reason for Issue	First issue.
Effective Date	January 17, 2007

SYSTEM IMPACT ASSESSMENT REPORT
For
Fort Erie Interconnection

System Impact Assessment Report

115 kV Interconnection between Fort Erie and Huntley TS

Acknowledgement

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

Disclaimers

IESO

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

Approval of the proposed connection is based on information provided to the IESO by the connection applicant and the transmitter(s) at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by the transmitter(s) at the request of the IESO. Furthermore, the connection approval is subject to further consideration due to changes to this information, or to additional information that may become available after the approval has been granted. Approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed facility to the IESO-controlled grid. However, connection approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter(s) during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, you must be aware that the IESO may revise drafts

of this report at any time in its sole discretion without notice to you. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that it is using the most recent version of this report.

HYDRO ONE

Special Notes and Limitations of Study Results

The results reported in this preliminary feasibility study are based on the information available to Hydro One, at the time of the study, suitable for a preliminary assessment of a new generation or load connection proposal.

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

This study does not assess the short circuit or thermal loading impact of the proposed connection on facilities owned by other load and generation (including OPGI) customers.

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

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

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

Table of Contents

SIA Findings

Conclusions

Canadian Niagara Power Inc. is proposing to establish parallel operation of the IESO-controlled grid and New York Huntley station by installing a phase shifter and voltage regulator at Fort Erie. The new phase shifter and voltage regulator will be located at CNP#18 station and have a maximum capability of 150 MW.

This System Impact Assessment has examined the effect of closing of the existing 115 kV radial interconnection between CNP #18 station (Fort Erie, Ontario) and Huntley GS (Buffalo, New York) on the reliability of the IESO-controlled grid. The studies concluded that:

1. There is no overloading concern for the new tie line for contingencies associated with any one of the existing Niagara tie lines.

2. The new connection between Fort Erie and Huntley does not introduce any new limiting elements or contingencies for the Niagara tie lines.

3. The short section between the Niagara Murray and CNP #11 which is rated at 125 MVA will limit the export capability over the new interconnection to about 75 MVA.

4. The line section between Bertie Hill and the High Tower on the New York side which is rated at about 66 MVA will result in limitations that would restrict the full utilization of the new tie.

5. During high export conditions over the new interconnection, the voltage at CNP #18 station is below the minimum required operating voltage of 113 kV.

6. To respect the IESO voltage decline criteria upon contingencies resulting in the disconnection of Line 46 from Huntley GS, only up to 100 MVA of load could be isolated from Line 46 onto the Fort Erie tie.

7. Regulating Transformer must be rated at 150 MVA or more and have a ±10% on-load tap range in order to control reactive power flow. The transformer must push reactive power out of the Ontario Control Area when it is tapped down (i.e. moving from tap 2 to tap 1 pushes reactive power out of Ontario).

8. Phase Shifting Transformer must be able to provide at least an operating range of ± 40 degrees. The phase shifter must push power out of the Ontario Control Area when it is tapped down (i.e. moving from tap 2 to tap 1 pushes power out of Ontario).

It is concluded that with the transmission reinforcements identified in this assessment, the new interconnection at Fort Erie would increase the import and export capability of the Ontario electricity market by 150 MW, provided the limiting line sections are uprated, contingent on there being no short circuit limitations.

This assessment covered the IESO-Controlled grid and the proposed tie line equipment up to the Huntley station only. Niagara Mohawk must verify the capability of their upstream facilities.

Notification of Approval for Connection Proposal

It is recommended that Notification of Conditional Approval for connection be issued to Canadian Niagara Power Inc., subject to IESO's Requirements for Connection listed below, and any further requirements that may be identified by Hydro One Networks Inc. in the Customer Impact Assessment.

IESO's Requirements for Connection

The IESO's requirements for the connection of the proposed Fort Erie tie are as follows:

1. The short circuit analysis is not completed, awaiting short circuit modeling data for Niagara Mohawk system. CNP is required to provide the data to the IESO to complete the analysis.

2. The connection applicant is required to initiate the Customer Impact Assessment process with Hydro One.

3. The connection applicant is required to ensure that the performance of the phase shifter and voltage regulator that are eventually supplied and installed is similar to the predicted performance or exceeds the predicted performance observed in the simulation results.

4. All equipment and facilities being connected to the IESO-controlled grid adhere to the reliability standards set forth in the Market Rules regarding frequency and voltage variations. All equipment shall be capable of continuously operating in the range between 59.5 Hz - 60.5 Hz and have the capability to operate for 10 minutes in the range of 58 Hz – 61.5 Hz. Equipment must also be able to continuously operate in the range 113 kV – 127 kV. Following contingencies equipment must be capable of operating for up to 30 minutes at voltages as high as 132kV.

5. The connection applicant is required to check the status and ratings of the existing tie circuits on the New York side and upgrade the circuits to match the rating of 150 MVA if necessary.

6. The connection from Murray to CNP #11 station must be upgraded to at least 200 MVA to accommodate the maximum export capability on the new Fort Erie tie-line.

7. The voltage regulator R46 must be rated no less than 150 MVA and have an on-load tap range from 108 kV to 132 kV to control reactive power flow. R46 must push reactive power out of the control Area when it is tapped down (i.e. moving from tap 2 to tap 1 pushes reactive power out of Ontario).

8. The phase shifter PS46 must be able to provide an operating range of ± 40 degrees. PS46 must push power out of the control Area when it is tapped down (i.e. moving from tap 2 to tap 1 pushes active power out of Ontario).

9. The short term thermal overload capabilities of PS46 and R46 must be high enough to accommodate the post-contingency loading identified in Section 5.1. Equipment with a 4 hour rating as suggested in Table 2 would be adequate.

10. Operation of PS46 must be directed by the IESO. CNP requirements to make changes must be approved by the IESO.

11. During some combinations of outage at Huntley S.S. Huntley will be radially connected to Fort Erie tie and the load at Huntley must be limited to 100 MVA so that the voltage at CNP #18 will remain within acceptable levels. If the load surpasses this level, this new parallel path must be removed from service due to voltage decline concerns.

12. Prior to connection, the applicant must successfully complete the IESO's market entry process. All necessary permits and operating agreements must be in place prior to making this new parallel between Ontario and New York.

System Impact Assessment Report

1. Project Description

Canadian Niagara Power Inc. (CNP), a subsidiary of Fortis Ontario, is the Local Distribution Company operating transmission & distribution (T&D) assets at Fort Erie. The CNP distribution system at Fort Erie is interconnected with Hydro One's transmission at Murray station and the load is presently supplied by IESO-controlled grid. Alternatively, the CNP system at Fort Erie could be supplied by Huntley GS in NYISO grid in a radial manner. However, the connection to the NYISO grid can only be made after the CNP system is disconnected from the IESO-controlled grid. This results in undesirable power interruption to the CNP customers.

Canadian Niagara Power Inc. is proposing to establish parallel operation of the IESO-controlled grid and New York Huntley station by installing a phase shifter and voltage regulator at Fort Erie. The new phase shifter will be connected in series with the 115 kV circuit Line 2 at CNP #8 terminal station.

The target in-service date for the new interconnection is Q4 2007.

The connection applicant retained Acres International (Acres) to conduct a preliminary transmission planning studies for Fort Erie system. The report prepared by Acres contains analysis of Fort Erie tie power flows.

This System Impact Assessment (SIA) study has examined the impact of the proposed interconnection between Fort Erie and Huntley GS on the reliability of the IESO-controlled grid. The study also investigated the requirements for the phase shifter and voltage regulator and proposed permits prior to the interconnection between Fort Erie and Huntley GS.

– End of Section –

2. System Description and Connection Arrangement

2.1 Interconnections between Ontario and New York

The IESO controlled grid is synchronously connected with New York system at Niagara and St. Lawrence.

The Ontario – New York Niagara interconnection provides supply to 60 Hz and 25 Hz systems via circuits at various voltage levels. The supply to the 60 Hz system,is provided by two 230/345 kV circuits (PA301 and PA302), two 230 kV circuits (PA27, BP76) and one 115 kV circuit. The 25 Hz system is supplied, via one 115/69 kV circuit and one 69 kV circuit.

As indicated in IESO's Ontario Transmission System dated June 27, 2005, the New York (NY) Niagara interconnection, in the winter, is limited to 1,650 MW for flows into Ontario and 1,950 MW for flows out of Ontario. In the summer, the limit is 1,300 MW for flows into and out of Ontario. The interconnection is constrained by thermal limitations in the winter and summer.

The Queenston Flow West (QFW) interface is in series with the NY Niagara interconnection. All flows entering Ontario on the NY Niagara interconnection will also appear on the QFW interface; this includes imports and parallel path flows. Based on past experience and studies, the QFW interface limit is always reached before NY Niagara interconnection limit for flows entering Ontario; as a result, the capability of the NY Niagara interconnection is never fully utilized. The QFW interface is constrained by thermal limitations, which are very dependent on weather conditions. This will increased with the Niagara reinforcement.

Typically, when QFW hits its limit of 1,750 MW under summer conditions, the flow across the NY Niagara interconnection is 1,000 MW. Similarly, when QFW hits its limit of 1,950 MW under winter conditions, flow across the NY Niagara interconnection is 1,200 MW.

Similarly, at worst, internal constraints in New York can limit flows leaving Ontario to 700 MW and 1,000 MW during the summer and winter periods, respectively.

However, Hydro One obtained approvals for reinforcing the QFW interface and the project is scheduled for in service towards the end 2006. With the implementation of QFW reinforcement project the existing QFW limitations constraining NY Niagara imports to a level that is lower than the actual capability of the interconnection will be eliminated.

The Ontario – New York St. Lawrence interconnection consists of two 230 kV circuits, L33P and L34P. The interconnection is under the control of phase angle regulators. The limit on this interconnection is about 400 MW for flows into or out of Ontario, which is constrained by thermal limitations.

2.2 Allanburg – Beck and CNP 115 kV system

The CNP distribution system at Fort Erie consists of a switching station (CNP # 11) and two transformer stations (CNP # 17 and # 18). The CNP Fort Erie load can be connected to either A36N or A37N 115 kV circuit, which run from Allanburg TS to Beck GS, via a short tap from Murray TS and via Line No. 2. Both A36N and A37N are rated at approximately 270 MVA for summer weather conditions, and Line No. 2 at 210 MVA. It should be noted that the CNP system is connected to Hydro One transmission via a short section of line between the Niagara Murray and CNP #11 station. This section which belongs to Hydro One is only rated at 125 MVA. Since Murray and CNP #11 can be connected either via circuit A37N or circuit A36N but not both, this section would limit both the import capability on the Fort Erie tie-line.

After opening the connection between CNP and IESO-controlled grid at switching station #11, the system can be connected with NY grid through several circuit lines/cable by closing the breaker at transformer station #18. Therefore, the load can be radially supplied by either IESO-controlled grid or NY grid. The CNP system peak is about 50 MW with a power factor of approximate 0.92.

A schematic diagram of the 115 kV transmission system in the Fort Erie area is shown in Figure 1.

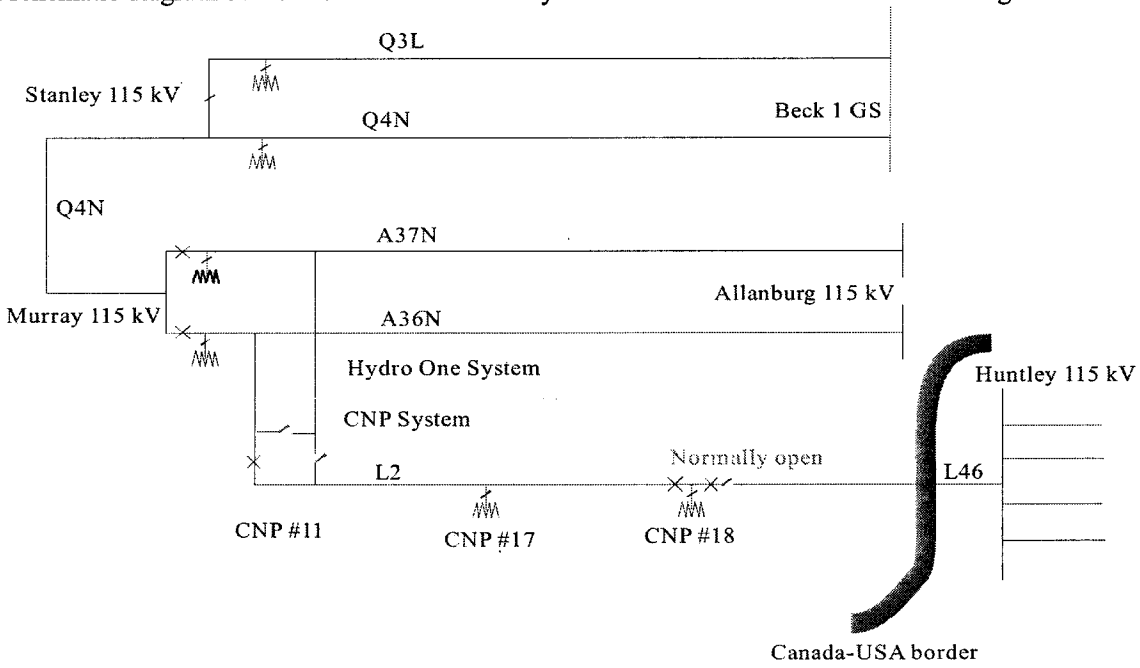

Figure 1. Allanburg – Beck and CNP 115 kV system

2.3 Proposed Interconnection

The proposed interconnection is to be located in CNP #18 TS as shown in Figure 2.

With the proposed interconnection, CNP load at Fort Erie would be supplied from both Allanburg/Beck and Huntley 115 kV systems. Consequently, for a contingency that interrupts the power supply from Allanburg, the CNP load will continue to be supplied by Huntley station, and vice versa.

The voltage regulator and phase shifter will be connected between CNP #18 station, adjacent to breaker 18R46, and L46 which ends at Huntley station.

The transmission line between Murray and Huntley GS consists of four sections as shown in Figure 2. The first section from CNP #18 to Bertie Hill (C to D) is a 3.23 km single circuit line with continuous rating of 180 MVA. The second section, (D to E) is a 0.5 km double circuit from Bertie Hill to the high tower crossing point at the Niagara River. The continuous rating is 66 MVA for each circuit. It should be noted that only one of the two circuits of the double circuit line is normally used. The third part (E to F) is a 0.66 km double circuit line crossing the river with a rating of 50 MVA for each. The last section is a 2.7 km cable with continuous rating of 137-165 MVA terminating at Huntley GS. The summary of circuit ratings provided by connection applicant is shown in Table 1.

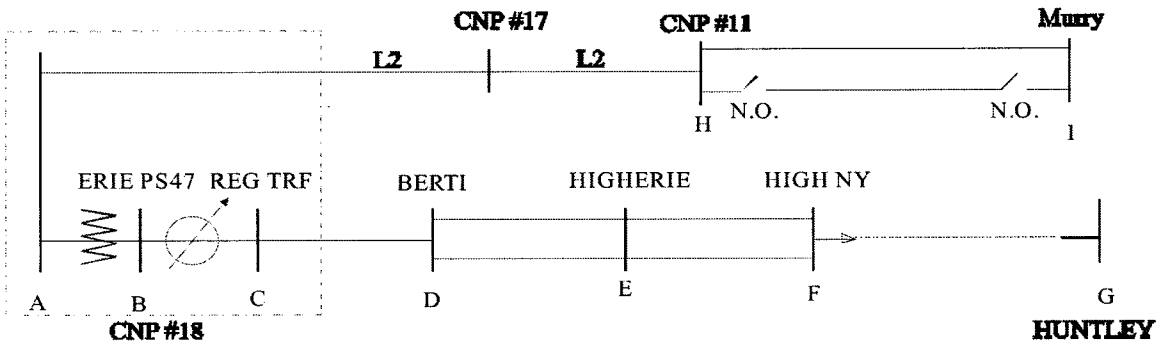

Figure 2. Transmission line between Murray and Huntley GS

Table 1 CNP Fort Erie Tie Line Data

Line Section	Description	Length [km]	Tower	Rating [MVA]
A to B	Voltage Regulator (R46)	N/A	N/A	ONAN/ON AF 100/150
B to C	Phase Shifter (PS46)	N/A	N/A	Not given
C to D	Double Circuit Line (1 circuit I/S only)	3.23	Double Circuit Pole	180
D to E	Bertie Hill to High Tower- Ft Erie side	0.5 (2 × ccts)	High Tower	66 / cct
E to F	Crossing Niagara River Ft Erie	0.66 (2 × ccts)	High Tower	50 / cct

F to G	U/G Cable to Huntley to Crossing Point NY side	2.7	Cable	137 - 165
A to H	CNP #18 to Rankine– Line No. 2	25.4		210
H to I	Rankine to Murray TS	2.0		125

*Ratings provided in amps converted to MVA at 115 kV
*When range given for ratings, lower value corresponds to summer conditions and upper value to winter conditions.

– End of Section –

3. Short Circuit Assessment

Because this project involves the paralleling of two transmission systems and connection of additional generation onto the IESO-controlled grid a short circuit assessment is required. Hydro One will be performing short circuit studies when more detailed technical specifications for the new voltage regulator, the phase shifter and the generation on the New York side will be provided by the proponent.

The short circuit analysis is not completed, awaiting short circuit modeling data for Niagara Mohawk system. CNP is required to provide the data to the IESO to complete the analysis.

– End of Section –

4. Phase Shifter and Voltage Regulator Assessments

This section describes the results of the studies performed to identify the requirements for the phase shifter (PS46) and voltage regulator (R46) which are to be installed at CNP #18. The load flow used in this study was based on the IESO's summer 2010 peak system conditions base case.

This study was performed assuming all existing facilities in service, together with any facilities that have already obtained connection approvals and are committed to come in service. In particularly, the Queenston Flow West (QFW) transmission reinforcement project, which has already been approved and is planned for in-service in late 2006, was assumed in service. Other improvements to the transmission system in Ontario expected during 2006 will alleviate some of the constraints restricting imports over the Niagara ties.

The following are the emergency transfer capabilities for the NY-ON interface at Niagara based on a 2005 forecast. These TTC values exclude the St. Lawrence ties.

- *Emergency Import = 1550 MW*
- *Emergency Export = 2325 MW*

With the addition of the new NY-ON tie, L46 will be the most thermally limiting of the NY-ON ties. As such, the emergency import and export transfer capabilities should effectively increase by 150 MW.

- *Emergency Import (with L46) = 1700 MW*
- *Emergency Export (with L46) = 2475 MW*

Due to the difference in voltage between the CNP system and the Huntley, a voltage regulator (R46) is required.

The voltage regulator must be rated at no less than 150 MVA and have a ±10% on-load tap range in order to control reactive power flow. The transformer must push reactive power out of the Area when it is tapped down (i.e. moving from tap 2 to tap 1 pushes reactive power out of Ontario).

The data provided by the proponent for the new phase shifter was the same as the existing phase shifter on L33P with a phase shift capability of ± 40 degrees. This L33P phase shifter is rated at 230 kV and 300 MVA and was not deemed to be a suitable model for this interconnection.

For this study the IESO used a different phase shifter model appropriate for a 115 kV interconnection. The new phase shifter is rated at 120 kV and 150 MVA. The overload capability for this transformer at 100% preload (150 MVA) can be found in Table 2. PS46 was also modeled with a small impedance in order to maximize the power flow over the interconnection. A complete listing of the load flow data for PS46 and R46 can be found in Appendix A.

Table 2. Overload Capability: 120 kV/ 150 MVA Phase Shifting Transformer

Ambient Temp. (degrees Celsius)	MVA					
	5 min	15 min	1h	2h	3h	4h
30	228	198	185	180	177	175
5	284	245	216	208	202	198

In order to determine the angle shift requirement for PS46, the flow on the new tie line was varied between ±150 MW for all cases previously described. The study results are illustrated in Figure 3.

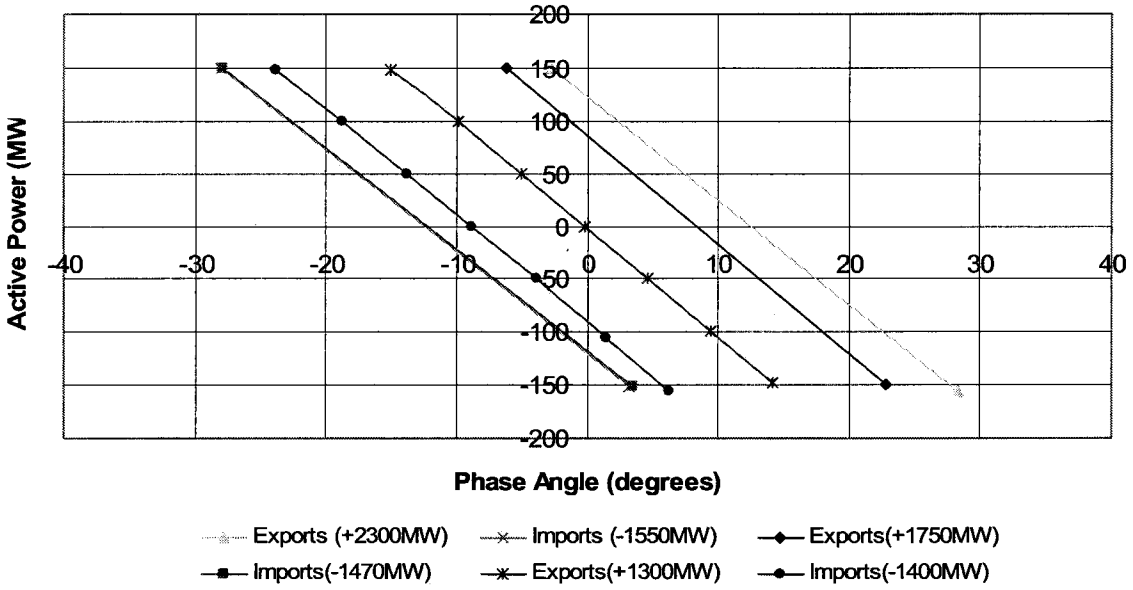

Figure 3. CNP Fort Erie Tie MW vs. PS46 Angle

The results indicate that an operating capability of ± 40 degrees for PS46 can control the active power flow on the new tie from import 150 MW to export 150 MW. This angle range proved to be feasible for the assessed conditions. Figure 3.0 also illustrates that a 1° change in phase angle results in a 10 MW change on this new tie.

Phase Shifting Transformer must be able to provide an operating range of ± 40 degrees. The phase shifter must push power out of the Area when it is tapped down (i.e. moving from tap 2 to tap 1 pushes power out of Ontario). Operation of PS46 must be directed by the IESO only therefore tap changes are not permissible unless directed by the IESO.

It should be noted that the data used in this assessment represent typical parameters for the phase shifter and voltage regulator. The applicant is required to supply the parameters to the IESO as soon as they are obtained from the manufacturers. If the data provided by the manufacturers differ materially from the data that was used in the assessment, then the analysis will need to be repeated.

After the installation of the new phase shifter and voltage regulator, the proponent is required to perform commissioning tests to validate the data. As soon as the commissioning tests are completed and actual data is available, the connection applicant is required to provide the results to the IESO. Using these data the IESO will verify the behaviour of the new equipment, as part of the Facility Registration Process.

The applicant is required to ensure that the performance of the equipment that is eventually supplied and installed is similar to the predicted performance or exceeds the predicted performance observed in the simulation results obtained using the above models.

In addition, the connection applicant must ensure that all equipment and facilities being connected to the IESO-controlled grid adhere to the reliability standards set forth in the Market Rules regarding frequency and voltage variations.

All equipment and facilities being connected to the IESO-controlled grid adhere to the reliability standards set forth in the Market Rules regarding frequency and voltage variations. All equipment shall be capable of continuously operating in the range between 59.5 Hz - 60.5 Hz and have the capability to operate for 10 minutes in the range of 58 Hz – 61.5 Hz. Equipment must also be able to continuously operate in the voltage range from 113 kV to 127 kV. Following contingencies equipment must be capable of operating for up to 30 minutes at voltages as high as 132kV.

– End of Section –

5. System Impact Studies

This connection assessment study is concentrated on identifying the effect of the proposed Fort Erie Tie on the reliability of the IESO –controlled grid. The studies investigated thermal loading of transmission lines and transformers, and system voltages for pre and post contingency situations. In addition, the adequacy of the CNP tie line was investigated.

The same base case with summer 2010 peak system conditions was used in these assessments. This study was performed assuming all existing facilities in service and various facility outage conditions, i.e., contingencies on the Ontario-New York Niagara interconnect ties, were considered.

5.1 Thermal Loading Assessment

The existing system configuration was described previously in Section 2.3. The ratings of those circuits are generally around 150 MVA except for the sections between Murray and CNP #11 and between Bertie Hill and the high tower on the New York side.

The short section between the Niagara Murray and CNP #11 is rated only at 52 MVA. As a result of, with summer loads at CNP #17 and #18 of about 60 MW, the import capability would be limited to approximately 115MW and the export capability would be limited to approximately zero. To achieve the designed import capability over the new interconnection, the line section between Niagara Murray and CNP #11 must be upgraded to a continuous rating of at least 200 MVA.

The connection applicant is required to upgrade the line section from Murray to CNP #11 to a continuous rating of at least 200 MVA to accommodate exports up to the capability on the new Fort Erie tie-line.

Sections between Bertie Hill and the High Tower on the New York side are of double circuit construction but only one of the two circuits between Bertie Hill and High Tower on the Fort Erie side is used. This circuit is rated at about 66 MVA. To achieve the designed export capability over the new interconnection, the line section between Bertie Hill and the High Tower must be upgraded to a continuous rating of 150 MVA.

The connection applicant is required to check the status and ratings of the existing tie circuits on the NY side. If the rating of the existing circuits is below the maximum design capability of the tie then CNP is required to obtain the necessary approvals and undertake the upgrading of these circuits to a continuous rating of 150 MVA.

Outage distribution factors (ODF's) were calculated for contingencies on the Ontario – New York Niagara tie lines: PA301, PA302, BP76, PA27 and L46.

Table 3 summarizes the ODF for various contingencies under an emergency import scenario on the Niagara Ties (import = 1550.3 MW) and with the Fort Erie-Huntley tie importing at its maximum capability of about 150 MW.

Table 3. ODF for Import Scenario

Contingency	Pre-Contingency Flow (MW) *	PA301	PA302	PA27	BP76	L46
PA301	-466.6	-1.00000	0.51717	0.32368	0.29363	0.22643
PA302	-466.9	0.51737	-1.00000	0.32394	0.29387	0.22662
PA27	-362.1	0.22290	0.22299	-1.00000	0.30332	0.21790
BP76	-254.7	0.16834	0.16841	0.25251	-1.00000	0.20454
L46	-150.9	0.02368	0.02369	0.03309	0.03731	-1.00000

The following table summarizes the ODF for various contingencies under an emergency export scenario on the Niagara Ties (export = 2306.6 MW) and with the Fort Erie-Huntley tie importing at its maximum capability of about 150 MW.

Table 4. ODF for Export Scenario

Contingency	Pre-Contingency Flow (MW) *	PA301	PA302	PA27	BP76	L46
PA301	868.7	-1.00000	0.51852	0.32464	0.29460	0.22800
PA302	869.8	0.51872	-1.00000	0.32490	0.29484	0.22818
PA27	277.2	0.22365	0.22374	-1.00000	0.30398	0.21894
BP76	290.9	0.16897	0.16904	0.25308	-1.00000	0.20546
L46	149.7	0.02399	0.02400	0.03345	0.03770	-1.00000

The post contingency flow on the Fort Erie tie is the pre-contingency flow plus the flow on the contingency circuit(s) multiplied with corresponding ODF(s). For example, the flow on the Fort Erie – Huntley tie post a single contingency on PA301 would be calculated as follows:

$$Ft\ Erie\ tie_{post\ PA301} = Ft\ Erie\ tie + ODF^{PA301} \times PA301.$$

If the initial flows on Ft Erie tie = -115 MW and PA301= -200 MW, then the post contingency flow on this new tie lie would be:

$$Ft\ Erie\ tie_{post\ PA301} = -115\ MW + 0.024 \times (-200\ MW)$$
$$= -119.8\ MW.$$

The results from the study showed that the ODFs for the CNP Fort Erie tie line ranged from 2% to 3% for the loss of any one of the Niagara tie lines. Due to the low ODFs, significant overloading of the new tie

line for the loss of the existing interconnection is not expected (i.e. 2%×1000 MW = 20 MW). It can be concluded that there is no overloading concern for the new tie line for contingencies associated with any one of Niagara tie lines.

Furthermore, the ODF on the Niagara ties for the loss of the CNP Fort Erie tie line was approximately 22% per line. Since the power flow on the Fort Erie tie is small in comparison to the capacity of the existing tie lines, its loss would not result in significant flow increases on the 230 kV Niagara tie lines.

Therefore, the new connection between Fort Erie and Huntley does not introduce any new limiting elements or contingencies for the Niagara tie lines.

5.2 Voltage Assessments

The Market Rules (Appendix 4.1) require that, for the 115 kV transmission system, the system voltage be maintained between 113 kV and 127 kV. The IESO Transmission Assessment Criteria (4.3 Voltage Change Limits) require that voltage declines be limited to less than 10% for a single-element contingency.

Appendix B contains the Single Line diagrams illustrating the voltages and power flow distribution on the system surrounding Fort Erie during high imports and exports on the new tie (approximately ±150 MW). It should be noted that during high export conditions, the voltage at CNP #18 station is under the minimum required operating voltage of 113 kV.

Certain contingencies at Huntley 115 kV station could cause load to be isolated from Line 46 onto Fort Erie and the IESO-controlled grid. When Breaker R242 or R245 at Huntley S.S. (south bus) is open, the load at Huntley must be limited to 100 MVA, so that following fault at line 38 or south bus, the voltage at CNP #18 will remain within acceptable levels. If the load surpasses this level, the Fort Erie – Huntley tie may be opened at Fort Erie for reliable operation of the IESO-controlled grid.

The loads affected by this restriction include:

- F.M.C. Corporation
- United Refining Company
- Dunlop Tire and Rubber Company
- Dupont Switching Station
- Chevrolet (Tonawanda)
- Praxair/Linde Company
- American Brass Company
- Encogen
- Kenmore T.S.
- Buffalo Sewer Authority

5.3 Impact on Import/Export Capability between ON-NY

It is concluded that with the transmission reinforcements identified in this assessment, the new interconnection at Fort Erie would increase the import and export capability of the Ontario electricity

market by 150 MVA, provided the limiting line sections are uprated, contingent on there being no short circuit limitations.

5.4 Permits

Prior to connection, the applicant must successfully complete the IESO's market entry process. All necessary permits and operating agreements must be in place prior to making this new parallel between Ontario and New York.

– End of Report –

Appendix A Load Flow Models for Phase Shifter and Voltage Regulator

```
 5674,'CNP 18  ', 118.0000,1,     0.000,     0.000,   1,   7,1.04455, -23.5013,   1
 9999,'ERIE PS1', 118.0500,1,     0.000,     0.000,   1,   7,0.99485, -22.6466,   1
10000,'REG TRF ', 118.0500,1,     0.000,     0.000,   1,   7,0.99516, -24.5178,   1
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0 / END OF LOAD DATA, BEGIN GENERATOR DATA
0 / END OF GENERATOR DATA, BEGIN BRANCH DATA
0 / END OF BRANCH DATA, BEGIN TRANSFORMER DATA
 9999, 5674,    0,'R46',1,1,1,   0.00034,  -0.00167,2,'        ',1,   1,0.5000,   2,0.5000
   0.00015,   0.01000,  100.00
0.95245,   0.000,   0.000,  150.00,  150.00,  150.00, 2,     0, 1.10217, 0.93696, 5.00000,-5.00000,  33,10,
0.00000, 0.00000
1.00000,   0.000
 9999,10000,    0,'P46',1,1,1,   0.00000,   0.00000,2,'        ',1,   1,1.0000
   0.00182,   0.00700,  100.00
1.00000,    0.000,    1.942,  150.00,  198.00,     0.00, 3,      0,40.0000,-40.000,-100.000,-120.000,9999, 4,
0.00000, 0.00000
1.00000,   0.000
0 / END OF TRANSFORMER DATA, BEGIN AREA DATA
0 / END OF AREA DATA, BEGIN TWO-TERMINAL DC DATA
0 / END OF TWO-TERMINAL DC DATA, BEGIN VSC DC LINE DATA
0 / END OF VSC DC LINE DATA, BEGIN SWITCHED SHUNT DATA
0 / END OF SWITCHED SHUNT DATA, BEGIN IMPEDANCE CORRECTION DATA
 4, -42.20, 0.21700,   0.00, 0.15700,  42.20
10,0.93700, 1.64100,1.00000, 1.00000,1.03000, 1.02000,1.10000, 1.42700
0 / END OF IMPEDANCE CORRECTION DATA, BEGIN MULTI-TERMINAL DC DATA
0 / END OF MULTI-TERMINAL DC DATA, BEGIN MULTI-SECTION LINE DATA
0 / END OF MULTI-SECTION LINE DATA, BEGIN ZONE DATA
0 / END OF ZONE DATA, BEGIN INTER-AREA TRANSFER DATA
0 / END OF INTER-AREA TRANSFER DATA, BEGIN OWNER DATA
0 / END OF OWNER DATA, BEGIN FACTS DEVICE DATA
0 / END OF FACTS DEVICE DATA
```
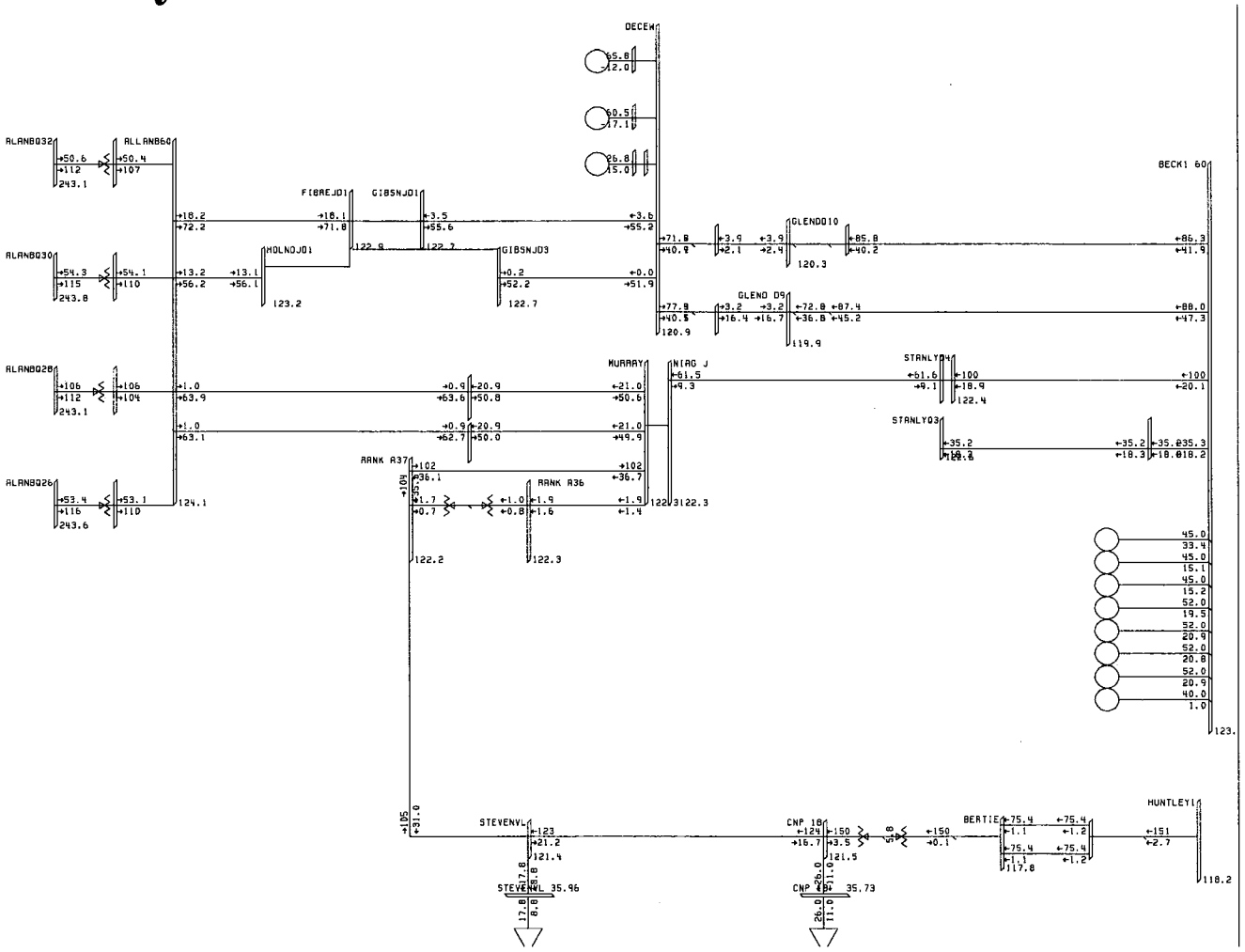
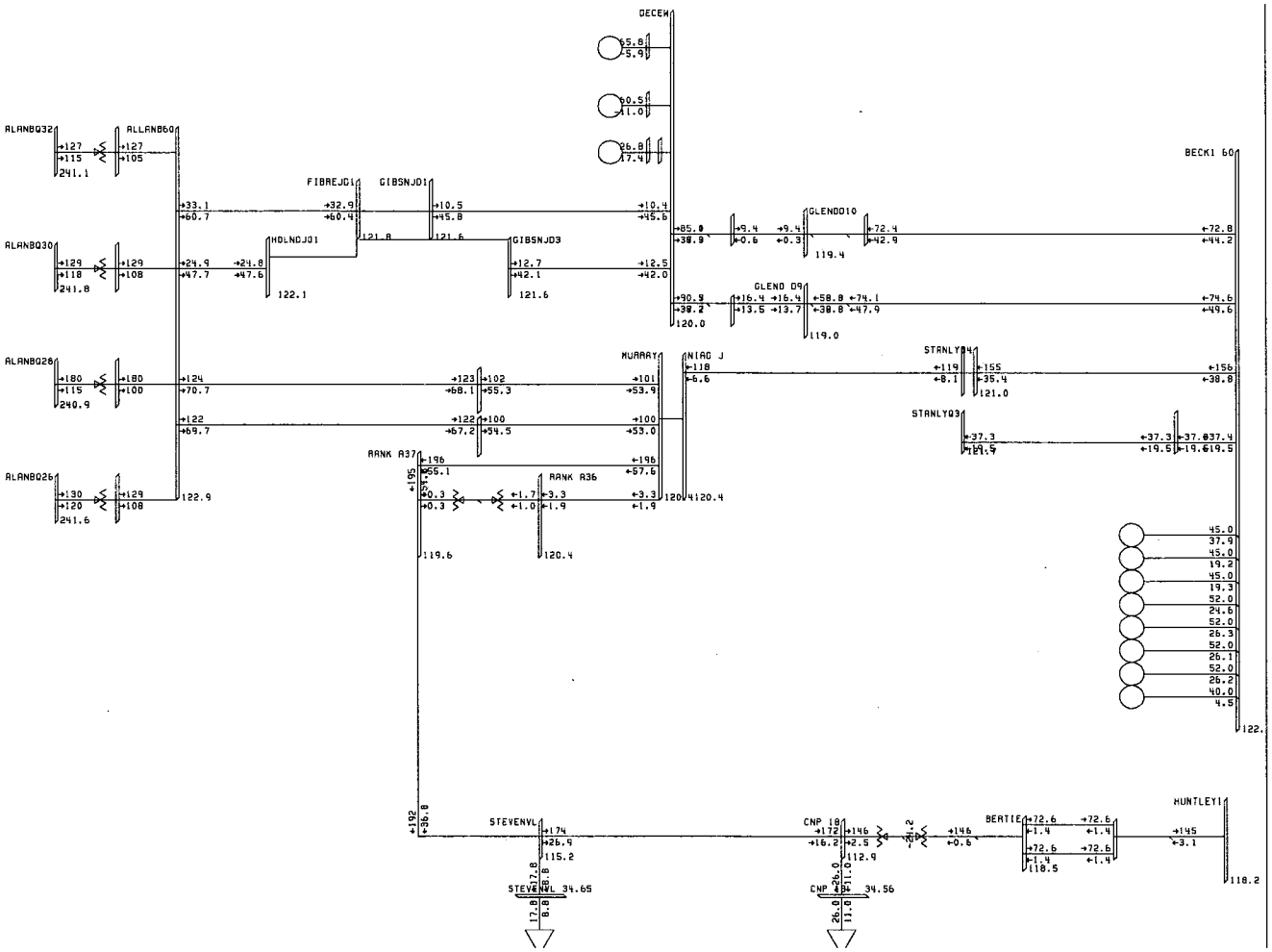

Appendix B Single Line Diagrams for ± 150 MW flow on Ft Erie – Huntley Tie




DECEW
ALANBQ32
ALLANB60
ALANBQ30
ALANBQ28
ALANBQ26
FIBREJD1
GIBSNJD1
HDLNDJD1
GIBSNJD3
GLENDD10
GLEND D9
BECK1 60
MURRAY
NIAG J
STANLYQ4
STANLYQ3
RANK A37
RANK A36
STEVENVL
STEVENVL 34.65
CNP 18
CNP 34.56
BERTIE
HUNTLEY1

APPENDIX "C"

Executed Notification of Conditional Approval from IESO per Request in 4.0(ii)

ieso
Power to Ontario.
On Demand.

January 17, 2007
Mr. Kazi A. Marouf
Manager–Transmission Planning
Canadian Niagara Power Inc.
1130 Bertie Street
Fort Erie, ON
L2A 5Y2

Dear Mr. Marouf,

115 kV Interconnection between Fort Erie System and Huntley Generating Station in NY/USA
Notification of Conditional Approval of Connection Proposal
CAA ID Number: 2005-192

Thank you for the detailed information regarding the115 kV Interconnection between Fort Erie System and Huntley Generating Station in NY/USA.

From the information provided, our review concludes that the proposed new interconnection and facilities will not result in a material impact on the reliability of the IESO-controlled grid. The IESO is therefore pleased to grant **conditional approval** for the interconnection between Fort Erie and Huntley. However, this approval is subject to the full implementation of the IESO's requirements, as detailed in the attached System Impact *Assessment* Report. Any material changes to your proposal may require re-assessment by the IESO in accordance with Market Manual 2.10, and may nullify your conditional approval.

Final approval will be granted upon successful completion of the IESO Facility Registration process. During facility registration you will be expected to demonstrate that you have fulfilled the requirements and the modification is in line with the proposal assessed by the IESO. Please contact market.entry@ieso.ca if you have not received a Facility Registration Summary package within the next 10 days.

For further information, please contact the undersigned.

Yours truly,

Michael Falvo
Manager - Transmission Assessments & Performance
Telephone: (:905) 855-6209
Fax: (905) 855-6129
E-mail: mike.falvo@ieso.ca
cc: IESO Record

Canadian Niagara Power Inc. acknowledges the IESO requirements in the subject report, and commits to fulfill these requirements, and all other applicable Market Rules, before receiving final approval to connect to the IESO-controlled grid and to participate in the IESO-administered market.

Dated: Nov 1, 2006

Per:

Name: KAZI MASRUF

Title: MANAGER OF TRANSMISSION DEVELOPMENT.

APPENDIX "D"

Letter from USNG per Request in 7.0(ii)

nationalgrid

Angus S. Orford
Vice President, Operations
Fortis Ontario
1130 Bertle Street
PO Box 1218
Fort Erie, Ontario L2A 5Y2

Subject: National Grid Comments on the Fortran 1 a.k.a. the Fort Erie Interconnection Project

Dear Angus:

In response to your request concerning the subject project, we provide the following.

Niagara Mohawk (d/b/a National Grid) anticipates minimal benefits for its interests from the Fort Erie Interconnection Project. We do not oppose the project and will cooperate with its sponsors based on the following considerations:

- The primary and stated purpose of the interconnection is to provide an emergency connection for Canadian Niagara Power.
- Canadian Niagara Power has advised National Grid of its intention to also use the interconnection for the purpose of allowing imports and exports into or from Ontario, for the benefit of Ontario and at the direction of the regional independent electricity system operators. Terms and conditions of the foregoing will be subject to the completion and execution of an interconnection agreement between National Grid and Canadian Niagara Power as well as the regional system operators, and other jurisdictional government and regulatory agencies as required.
- The upgrades to the affected National Grid 115 kv systems, as specified in Canadian and US studies, are to be subject to NYISO approval and will be installed by National Grid on behalf of CNP.
- The connection and its operation, no matter what purpose it serves, will not adversely affect National Grid's system, customers or other stakeholders in terms of reliability, performance and economics.
- Our position is subject to the negotiation and execution of a final Interconnection Agreement, the terms and conditions of which would govern the parties with respect to this interconnection.

Please feel free to call me to discuss our response.
Sincerely,

William Malee

William Malee,
Director,
Transmission Commercial Services

ATTACHMENT "B"

Responses to the Interrogatories of Hydro One Networks Inc.

RESPONSES TO THE INTERROGATORIES OF HYDRO ONE NETWORKS

Reference

Exhibit B, Tab 2, Schedule 1

Question / Request

1. Please provide any additional studies which show the impact (such as transfer capacity, reliability, voltage) of the new interconnection on the existing interconnections between U.S. National Grid and the Hydro One system in the Niagara Falls area.

Response

Apart from the SIA (IESO), CIA (Hydro One), Feasibility Study (NYISO), and SRIS (NYISO) filed with CNP's pre-filed evidence, there are presently no additional studies assessing the impact of the new interconnection that have been completed. Pursuant to NYISO Interconnection Procedures, an Interconnection Facilities Study is currently underway. This study will be forwarded to Hydro One when complete.

Reference

Exhibit B, Tab 2, Schedule 1

Question / Request

2. a) Please provide any additional information or studies on how the new interconnection could impact on the existing interconnection between CNP and Hydro One's Murray Transformer Station.

   b) Were any impacts identified?

   c) If so, what measures would be necessary to mitigate those impacts, what is the implementation schedule, and what is their cost?

Response

(a) CNP has no additional information or studies. A facilities study is currently underway by the NYISO, which may or may not be relevant to this request.

(b) Not applicable.

(c) Not applicable.

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Reference

Exhibit A, Tab 3, Schedule 1, Page 20

Preamble

It is CNP's intention to apply to the NEB for the required changes to its federal permit subsequent to receiving a final decision from the OEB in the present application.

Question / Request

3. Is it still CNP's intent to wait for OEB approval prior to applying to the National Energy Board for amendments to its federal permit?

Response

Yes. It continues to be CNP's intent to await OEB approval before applying to the NEB for revisions to the federal permit. CNP has consulted with NEB staff and has been advised that this would be the NEB's expected sequence of regulatory processes for a project of this nature.

Reference

Exhibit A, Tab 3, Schedule 1, Pages 19-20

Question / Request

4. There are three existing interconnection facilities between the Hydro One transmission system in Queenston, Ontario and the U.S. National Grid system which are operating below capacity. Has an economic study been conducted comparing the costs of utilizing the existing facilities versus building the proposed facilities? If so, please provide the results of the study. If not, why has this option not been considered?

   In lieu of building the proposed interconnection between CNP and U.S. National Grid, has the use of the existing interconnections between Hydro One and U.S. National Grid been discussed with U.S. National Grid?

Response

No economic study has been conducted by CNP to evaluate the costs of using Hydro One's existing facilities. This concern has not been considered for CNP because it does not address the reliability issues on the CNP transmission system.

CNP has had no discussions with USNG on the use of existing Hydro One-USNG interconnections. This option has not been considered because it does not address the reliability issues on the CNP transmission system.