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July 16, 2009

RESS & 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: Canadian Niagara Power Inc. - Application for Leave to Construct and Reinforce Transmission Facilities - EB-2009-0283

We are counsel to Canadian Niagara Power Inc. ("CNPI"). On behalf of CNPI, we are enclosing two copies of an application, pursuant to section 92 of the *Ontario Energy Board Act*, for leave to construct and reinforce transmission facilities in and around Fort Erie, Ontario (the "Application"). The Board has assigned file no. EB-2009-0283 to the Application.

The Application has been submitted electronically via the Board's Regulatory Electronic Submission System (RESS). A copy of the confirmation page is attached.

Yours truly,

Jonathan Myers

Tel 416.865.7532
Fax 416.865.7380
jmyers@torys.com

cc: Mr. A. Orford, CNPI
Mr. D. Bradbury, CNPI
Mr. C. Keizer, Torys LLP

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ONTARIO ENERGY BOARD

EB-2009-0283

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Sched. B);

AND IN THE MATTER OF an application by Canadian Niagara Power Inc. for an Order or Orders pursuant to section 92 of the *Ontario Energy Board Act, 1998* (as amended) granting leave to construct and reinforce transmission facilities in and around Fort Erie, Ontario.

Canadian Niagara Power Inc.

July 15, 2009

EXHIBIT A - ADMINISTRATIVE

Exhibit A, Tab 1, Schedule 1

Exhibit List

EXHIBIT LIST

Exh	**Tab**	**Sch**	**Title**
A - ADMINISTRATIVE			
A	1	1	Exhibit List
	2	1	Application
	3	1	Summary of the Pre-Filed Evidence
	4	1	Procedural Orders/Affidavits/Correspondence
	5	1	Notices of Motion
	6	1	Curriculum Vitae of Witnesses
B – APPLICANT'S PRE-FILED EVIDENCE			
B	1	1	Existing Distribution System
			Appendix A - Detailed Single Line Diagram of Existing CNP Transmission System
	2	1	Project Description
			Appendix A - Map of Existing System and Proposed Project Facilities
	3	1	Project Need
			Appendix A - Switching Procedure to Supply Fort Erie Load from the Emergency Tie Line
			Appendix B - Switching Procedure to Supply Fort Erie Load from Line 2 when Emergency Tie Line is Engaged
	4	1	Project Benefits
	5	1	Project Costs, Rate Impact and Treatment
			Appendix A - Calculation of the Rate Impact of the Project
	6	1	Project Alternatives

Exhibit A, Tab 2, Schedule 1

Application

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Sched. B);

AND IN THE MATTER OF an application by Canadian Niagara Power Inc. for an Order or Orders pursuant to section 92 of the *Ontario Energy Board Act, 1998* (as amended) granting leave to construct and reinforce transmission facilities in and around Fort Erie, Ontario.

APPLICATION

1. The Applicant is Canadian Niagara Power Inc. ("CNP"). CNP is an Ontario corporation with its head office located in Fort Erie, Ontario. CNP is a licenced transmitter (ET-2003-0073) and operates a transmission system in and around Fort Erie, Ontario including an international interconnection to Buffalo, New York under a National Energy Board Permit.

2. CNP hereby applies to the Ontario Energy Board (the "Board") pursuant to Section 92 of the *Ontario Energy Board Act* (the "Act") for an order or orders granting:

   (a) leave to reinforce 2.0 km of line (being CNP's lines A36 and A37) to accommodate the maximum capability of an upgraded interconnection between CNP's transmission system in Fort Erie, Ontario and US National Grid's ("USNG") transmission system in Buffalo, New York;

   (b) leave to construct and reinforce 0.66 km of Conductor from the Bertie Hill Tower to Queen Street Tower in Fort Erie with 795 MCM conductor to provide capacity of at least 150 MW; and

   (c) leave to construct and reinforce 0.66 km of Conductor from the Queen Street Tower in Fort Erie, Ontario, across the Niagara River, to the High Tower forming part of the USNG transmission system in Buffalo, New York.

Fundamental and integral to the completion of the forgoing is:

(a) installation of an additional 115 kV breaker adjacent to the Murray taps on A36N and A37N;

(b) installation of two additional breakers at Station #17 in Stevensville for enhanced sectionalizing and zone control;

(c) installation of a 150 MVA phase shifting transformer and voltage regulator at Station #18 in Fort Erie;

(d) construction of a 115 kV three-breaker ring station located at switch SW 998 in Buffalo, New York, that will tie L46, L47 and USNG's Canada Bus; and

(e) removal and replacement of approximately 10 km of conductor from the Huntley Station to a new 115 kV Paradise Station being planned by USNG in Buffalo, with a new 115 kV three-phase transmission circuit.

All of the aforementioned is defined as the "Project".

3. No new land will be acquired for the construction of the Project.

4. Attached as Schedule "A" is a map showing the general location of the Project.

5. The purpose of the Project is to address transmission reliability concerns and to provide overall system benefits to Ontario through an expanded and synchronous interconnection.

6. The Independent Electricity System Operator ("IESO") has conducted a connection assessment in respect of the Project. A copy of the IESO's System Impact Assessment Report is filed in support of this Application.

7. This Application is supported by written evidence that includes details of the Project. The written evidence is pre-filed and may be amended from time to time, prior to the Board's final decision on this Application.

8. The persons affected by this application are the ratepayers of Ontario. It is impractical to set out the names and addresses of all the ratepayers of Ontario because they are too numerous.

9. CNP requests that, pursuant to Section 34.01 of the Board's *Rules of Practice and Procedure*, this proceeding be conducted by way of written hearing.

10. CNP requests that a copy of all documents filed with the Board by each party be served on the Applicant and the Applicant's counsel, as follows:

(a) The Applicant:

Canadian Niagara Power Inc.
1130 Bertie Street
P.O. Box 1218
Fort Erie, Ontario L2A 5Y2

Attention: Mr. Angus Orford
Vice President, Operations
Telephone: (905) 994-3639
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Attention: Mr. Douglas Bradbury
Director, Regulatory Affairs
Telephone: (905) 994-3634
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(b) The Applicant's Counsel:

Torys LLP
Suite 3000
79 Wellington Street West
Box 270, TD Centre
Toronto, Ontario M5K 1N2

Attention: Mr. Charles Keizer
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Attention: Mr. Jonathan Myers
Telephone: (416) 865-7532
Fax: (416) 865-7380
Email: jmyers@torys.com

DATED at Toronto, Ontario, this 16th day of July, 2009.

Canadian Niagara Power Inc.,
By its counsel,

Per: ______________________
Charles Keizer

Schedule 'A' - Map of Existing CNP Transmission System and Proposed Project Facilities

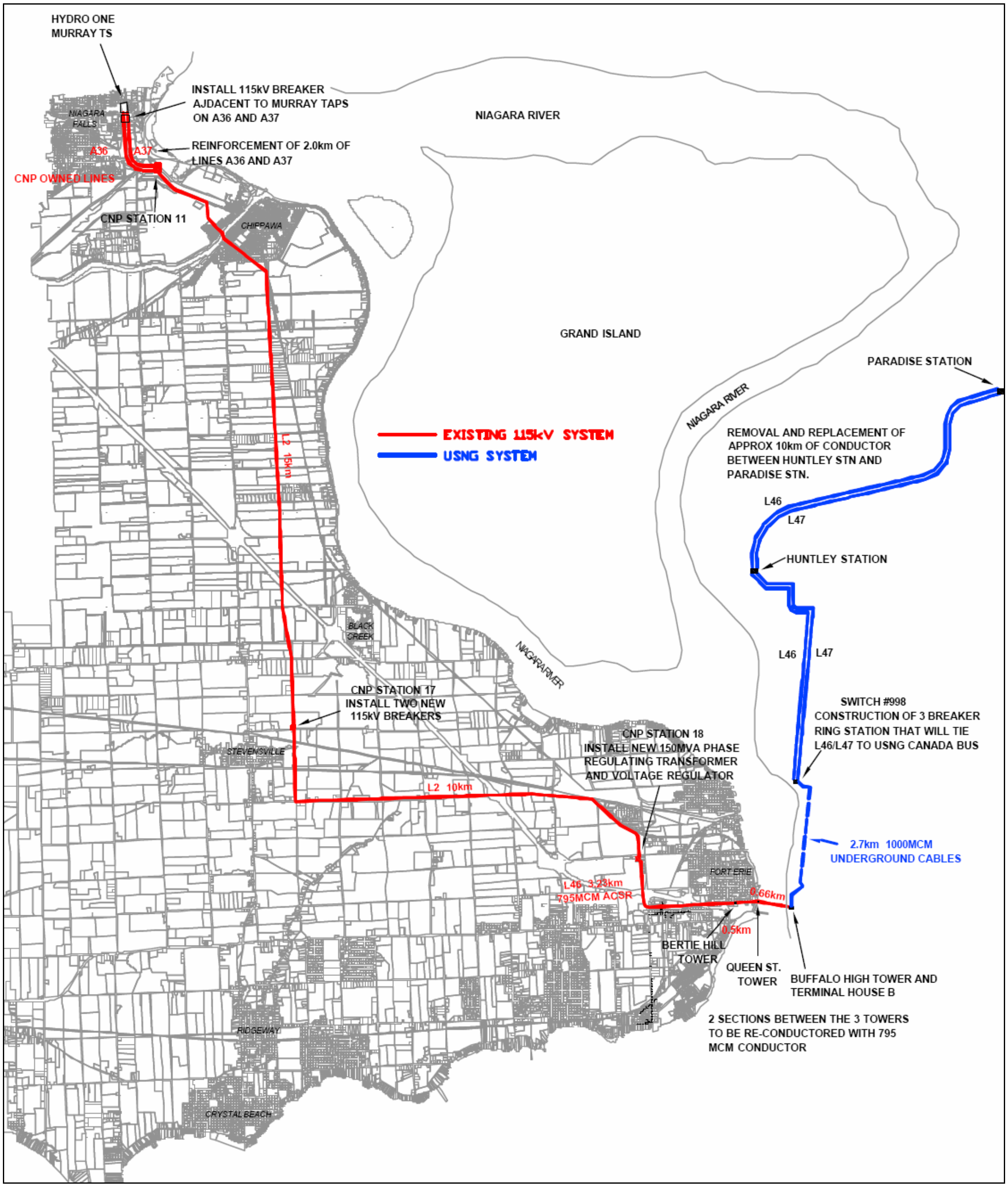


Exhibit A, Tab 3, Schedule 1

Summary of the Pre-Filed Evidence

SUMMARY OF THE PRE-FILED EVIDENCE

1. The Application and the Project

Canadian Niagara Power Inc. ("CNP") is a licensed transmitter pursuant to transmission license ET-2003-0073. CNP is an Ontario corporation with its head office in Fort Erie, Ontario. CNP operates its transmission system in and around Fort Erie, Ontario.

This is an application by CNP for a leave to construct and reinforce a transmission line under Section 92 of the *Ontario Energy Board Act*, 1998 (as amended) (the "Act"). In particular, CNP seeks:

(a) *to reinforce 2.0 km of line being lines A36 and A37 to accommodate the maximum capability of the interconnection between Fort Erie, Ontario and Buffalo, New York;*

(b) *to replace 0.5 km of conductor from the Bertie Hill Tower to the Queen Street Tower in Fort Erie with 795 MCM conductor to provide capacity of at least 150 MW; and*

(c) *to replace 0.66 km of conductor from the Queen Street Tower in Fort Erie, Ontario, across the Niagara River, to the High Tower adjacent to Terminal House B in Buffalo, New York, with 795 MCM conductor to provide capacity of at least 150 MW.*

Fundamental and integral to the completion of the Project (as hereinafter defined) is:

(d) *the installation of an additional 115 kV breaker adjacent to the Murray taps on A36N and A37N;*

(e) *the installation of two additional breakers at Station #17 in Stevensville for enhanced sectionalizing and zone control;*

(f) *the installation of a 150 MVA phase shifting transformer and voltage regulator at Station #18 in Fort Erie, Ontario;*

(g) *the construction of a 115 kV three-breaker ring station located at switch SW 998 in Buffalo, New York, that will tie L46, L47 and US National Grid's ("USNG") Canada Bus; and*

(h) *the replacement of approximately 10 km of conductor from the Huntley Station to a new 115 kV Paradise Station being planned by USNG in Buffalo, New York, with a new 115 kV three-phase transmission circuit.*

All of the aforementioned is defined as the "Project".

2. Purpose of the Project

As noted in **Exhibit B, Tab 1, Schedule 1**, and **Exhibit B, Tab 3**, **Schedule 1**, there are important reliability concerns for the CNP Transmission System. Because there are no viable alternatives, the Project in respect of this reliability concern is non-discretionary. 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. The Project will bring CNP Transmission, as a licensed transmitter, in line with minimum standards for reliability established under the Transmission System Code and realize the benefits associated with achieving those standards (See Section 2 of **Exhibit B, Tab 4, Schedule 1**). The Project will also provide a range of important benefits to Ontario and the IESO-controlled grid that will arise from establishing an upgraded intertie that operates in parallel with the Ontario and New York systems (See Section 3 of **Exhibit B, Tab 4, Schedule 1**). This includes a system of sufficient reliability to meet the needs of renewable generators that may seek connection as a consequence of the Ontario Power Authority's feed-in tariff program and the *Green Energy and Green Economy Act, 2009*.

3. Existing CNP Transmission System

As shown in the system map provided at **Figure 1.1** and as depicted in the single line diagram in **Figure 1.2**, the existing CNP Transmission System is interconnected with the Hydro One Networks Inc. ("Hydro One") transmission system by two CNP-owned 115 kV transmission lines (Lines A36 and A37) extending from Hydro One's Murray Transmission Station ("Murray TS") in Niagara Falls, Ontario to CNP's Switching Station #11 ("Station #11"), also located in Niagara Falls, Ontario. Station #11 is connected to CNP Transmission Station #17 ("Station #17") in Stevensville, Ontario by a single 15 km, 115 kV line known as L2. Beyond Station #17, line L2 extends 10 km to CNP Transmission Station #18 ("Station #18") in Fort Erie, Ontario.

Figure 1.1 CNP Transmission System (Existing)

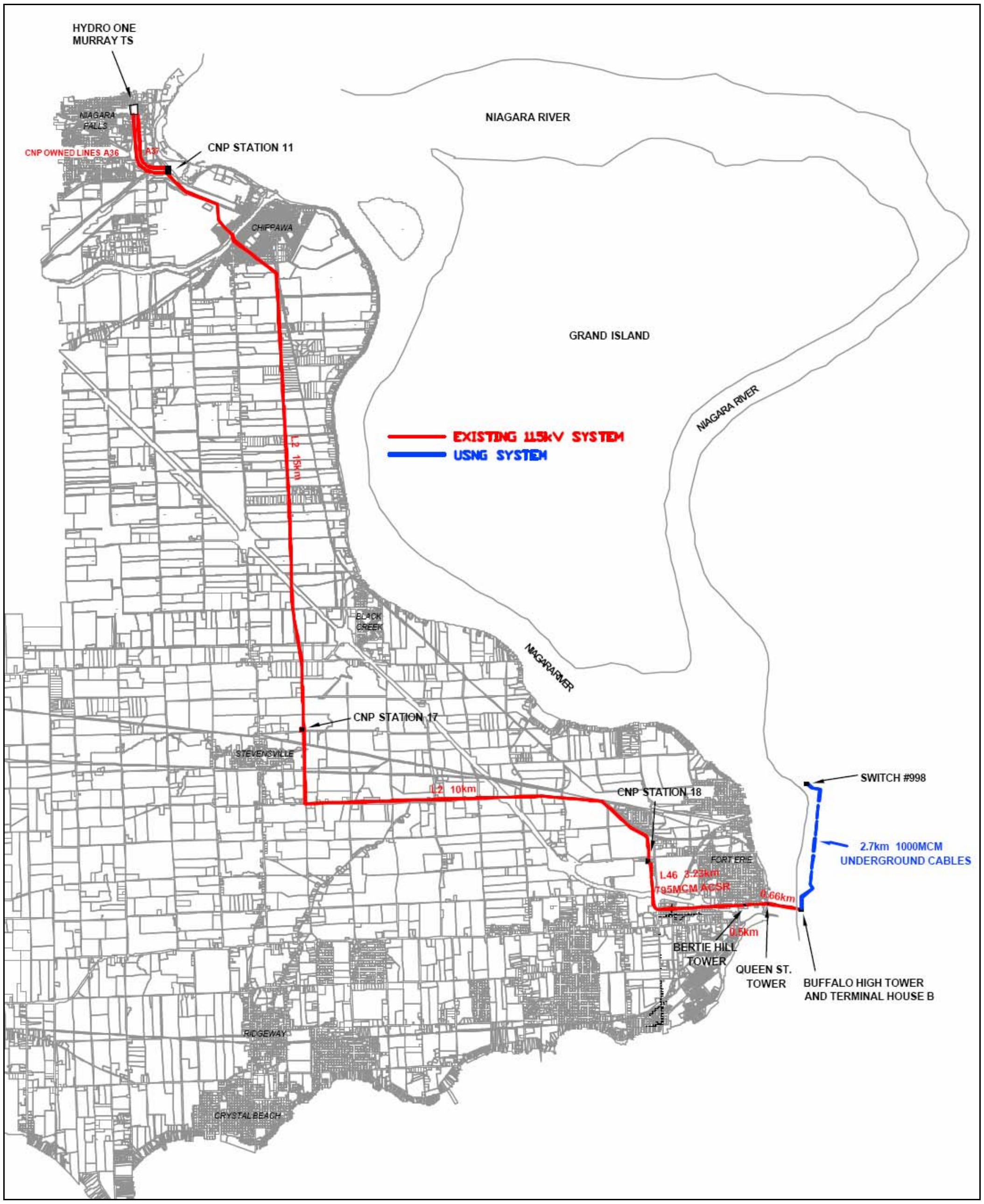
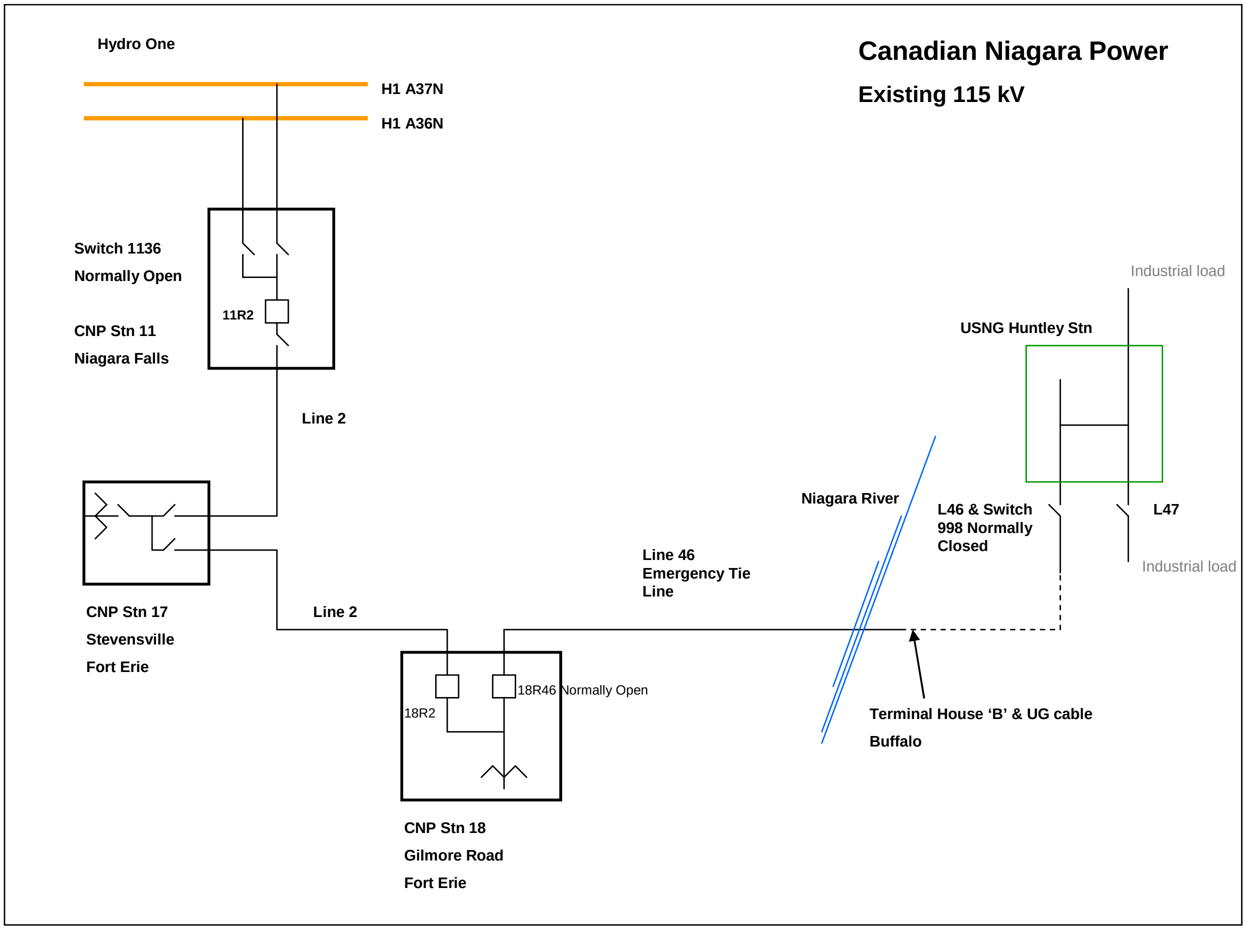


Figure 1.2 Simplified Single Line Diagram of the CNP Transmission System (Existing)



The transmission line connecting Station #18 in Fort Erie and the Canada bus (owned by USNG) in Buffalo, New York[1] consists of the four following sections:

(a) *Station #18 to Bertie Hill Tower (both in Fort Erie and owned by CNP) – a 3.23 km single circuit 115 kV (795 MCM ACSR) line with a continuous rating of 169 MW known as Line 46;*

[1] The Canada bus owned by USNG is within the control area of the New York Independent System Operator ("NYISO")

(b) *Bertie Hill Tower to Queen Street Tower (both in Fort Erie and owned by CNP) – a 0.5 km 115 kV double circuit span with a continuous rating of 62 MW for each circuit (however, at this time only one circuit is energized);*

(c) *Queen Street Tower (in Fort Erie and owned by CNP) to High Tower (in Buffalo and owned by USNG) extending into Terminal House 'B' – a 0.66 km 115 kV double circuit line crossing the Niagara River with a continuous rating of 48 MW for each circuit (however, at this time only one circuit is energized); and*

(d) *Terminal House 'B' to Switch 998 (both in Buffalo and owned by USNG) – a 2.7 km 1,000 MCM underground cable with a continuous rating of 159 MW. The interconnection into the Buffalo system, which is owned and controlled by USNG, occurs at Switch 998.*[2]

The transmission facilities from Station #18 to Switch 998 in Buffalo (the "Emergency Tie Line") are energized but no energy flows over those lines. This is because the Hydro One system and the USNG system are not synchronous, i.e. they cannot be run in parallel. As a result, switches at Station #18 are normally open (i.e. no energy flows). Under normal operations the CNP Transmission System is interconnected with and supplied only from the Hydro One system via Station #11 and line L2. As the Ontario and New York systems are out of phase at the Fort Erie-Buffalo connection point, running them in parallel would result in large flows of reactive power across the closed tie. If this were to occur, the thermal ratings of the CNP Transmission System would be exceeded and significant equipment damage would result or protective systems would operate to interrupt power supply. In either case, significant outages would result, including potentially to the USNG system.

[2] USNG plans transmission system extensions and reconfiguration in the Buffalo area on account of the anticipated retirement of the Huntley generating station. The extension and reconfiguration involve connection of lines 46 and 47 at a new Paradise substation, rather than at Huntley, by 2012.

At present, the entire CNP Transmission System is vulnerable to outages due to the occurrence of any one of the following events:

(a) *A fault on the Hydro One transmission system;*

(b) *A fault between Hydro One's Murray TS and Station #11;*

(c) *A catastrophic failure at Station #11; and*

(d) *A fault on CNP's Line L2, between Station #11 and Station #18.*[3]

In any of these circumstances, the entire CNP Transmission System would "go dark" until the problem is resolved or service is established with New York over the Emergency Tie Line. The Emergency Tie Line is the interconnection with New York that was upgraded in 1998 to permit emergency services.

4. Local Need for the Project

(a) *N-1 Contingency*

As a licensed transmitter, CNP Transmission is obliged to abide by the Transmission System Code (the "Code"). Section 5.1.2 of the Code provides that "a transmitter shall 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."

[3] A fault between Station #11 and Station #17 would cause all of the CNP load to be interrupted and require use of the Emergency Tie Line. A fault between Station #17 and Station #18 would cause all of the CNP load to be interrupted until distribution feeders in the system were switched so as to isolate and pick up load.

Section 8.1.1 of the Code provides that "a transmitter shall ensure compliance with the standards of all applicable reliability organizations," referring to the standards of NERC, NERC's reliability councils and Ontario's Independent Electricity System Operator ("IESO").

NERC Standard TOP-002-2, entitled *Normal Operations Planning*, provides at Requirement #6 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) . . ."[4]

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.

By establishing an N-1 configuration, the Project would enable the provision of continuous service to the CNP Transmission System and, thereby, to the customers it ultimately serves, in the event of a failure on the CNP Transmission System or in the event of a failure on the Hydro One transmission system that supplies the CNP Transmission System. At present, the entire CNP Transmission System is vulnerable to outages due to the occurrences noted above.

At best, in the event an outage causes the CNP Transmission System to "go dark" due to one of the circumstances described above, the Emergency Tie Line may only be operated on a temporary basis for emergency purposes. The time required to engage the Emergency Tie Line in such a situation involves a minimum of four hours due to the need to take all necessary precautions to engage the interconnection safely and the need to coordinate with the IESO,

[4] NERC Standard TOP-002-2, *Normal Operations Planning* (parentheses in original).

Hydro One and USNG. Making a request for service from New York then requires CNP Transmission to follow a 31-step switching procedure. A copy of this switching procedure is provided in **Appendix A** of **Exhibit B, Tab 3, Schedule 1.** Once the fault has been repaired and service from Murray TS can recommence, CNP must initiate a process similar to the above in order to switch supply back from New York to Ontario.

While the Emergency Tie Line is important, its effectiveness is limited to remedying outages of a sufficient duration to justify taking all of the steps needed to energize the line. As such, the Emergency Tie Line would typically only be engaged where an outage is expected to continue for a period of at least 4 hours.

Another significant limitation of the Emergency Tie Line is its capacity to provide an alternative source of supply during emergency situations, relative to current and forecast loads on the CNP Transmission System. The capacity of the Emergency Tie Line is 48 MW. The average monthly peak load on the CNP Transmission System in 2008 was 47 MW, but was 48 MW in 2005 and 49 MW in 2007. CNP forecasts annual load growth on the system of 0.5%. As such, there is no certainty that the Emergency Tie Line will be able to provide sufficient capacity to meet average monthly peak loads in the near term and, when factoring in forecast demand, it is expected that the Emergency Tie Line will consistently fail to meet average monthly peak system needs within a few years. As good utility practice calls for systems to be designed on the basis of peak loads rather than average loads, it is also important to recognize that annual peak demand on the CNP system, which was 56 MW in 2008, has consistently exceeded the capacity provided by the Emergency Tie Line since at least 2002. As such, there is a need to provide N-1 contingency in order to provide an instantaneous supply alternative in the event of any unplanned outage to the CNP Transmission System.

(b) ***Reliability Concerns***

The CNP Transmission System has experienced 16 outages or an average of 2.3 outages per year during the period from 2002 to 2008. Over the same period, the CNP Transmission System has experienced 1009 minutes, or an annual average of 144.1 minutes of service interruption per year.

As an accepted principle of good utility practice, ensuring N-1 contingency would provide CNP with the ability to deal with such outage events when they inevitably arise. As a result, almost all of the outages listed in **Exhibit B, Tab 3, Schedule 1, Figure 3.2** would not have occurred if the CNP Transmission System had N-1 contingency in place. While all of the line outages related to line faults would have been completely avoided if the Project had been in place, terminal outages would have been mitigated such that the system as a whole would not have gone dark. The Project will enable CNP Transmission to isolate problems and perform the necessary repairs while the remainder of the system is energized continuously from either from Ontario or New York. Following implementation of the Project, CNP Transmission will be able to consistently achieve a high level of system reliability and performance.

When 2002-2006 performance data for the CNP Transmission System is compared with data in the Canadian Electricity Association's ("CEA") *2006 Forced Outage Performance of Transmission Equipment* benchmarking report,[5] for the same period and the same voltage class

[5] Available at http://www.canelect.ca/en/aboutcea/aboutcea_documents_reports_benchmarking.html for purchase from the Canadian Electricity Association.

(110-149 kV), the analysis indicates that outage frequency on the CNP Transmission System of 8.75 outages per 100 km per year is far greater than the CEA average frequency of 1.0534 outages per 100 km per year. Implementation of the Project will significantly reduce the frequency of outages and bring the CNP Transmission System more in line with other well-performing electricity transmitters.

(c) ***Accommodating Renewable Generation***

The *Green Energy and Green Economy Act, 2009* ("GEGEA") received Royal Assent on May 14, 2009. While the Ontario Power Authority's feed-in-tariff program is no doubt central to achieving this policy objective, there is also a strong recognition among the Province and electricity sector agencies that significant investments in transmission and distribution systems will be needed in order to support and facilitate the development of renewable resources. However, for CNP Transmission to be considered as a potential host for renewable generation facilities, before the question of expansion or reinforcement can be considered, the reliability concerns associated with the lack of N-1 contingency on the CNP Transmission System must first be addressed.

Furthermore, under GEGEA amendments to the *Ontario Energy Board Act*, the transmission licence held by CNP Transmission will soon be deemed to contain a condition that requires CNP Transmission to prepare, for Board approval, a plan for the expansion or reinforcement of the its transmission system to accommodate the connection of renewable energy generation facilities. CNP Transmission would then be required to implement such expansion or reinforcement in accordance with its approved plan. Looking ahead to when CNP Transmission is required to develop its plan, it may not be possible for CNP Transmission to provide the Board with a satisfactory plan for expansion or reinforcement to accommodate the connection of renewable generation facilities unless the reliability issues associated with the lack of N-1 contingency on the CNP Transmission System have by that point been addressed.

5. Ontario System-Wide Need for the Project

As explained beginning at page 10 of **Exhibit B, Tab 4, Schedule 1**, the Project would represent an improvement of at least 10% in the Niagara interface capacity with the NYISO-controlled grid. This additional intertie capacity would:

(a) reduce capacity requirements for Ontario,

(b) provide insurance against generation maintenance outages during shoulder seasons and in other circumstances,

(c) allow for greater exports of surplus baseload generation, and

(d) enhance opportunities for trade with New York.

6. Project Benefits

The Project will provide significant reliability benefits to the CNP Transmission System. The Project will also provide significant benefits to the Ontario electricity system by virtue of the resulting increased intertie capacity with New York at the 115 kV voltage level.

(a) *Reliability Benefits*

In each type of unplanned outage listed above and described on page 3 of **Exhibit B, Tab 3, Schedule 1**, the Project would prevent or significantly reduce the loss of load and eliminate the risk of the entire CNP Transmission System "going dark". The Project would also prevent the system from going dark during certain planned maintenance outages. The Project would enable the CNP Transmission System to withstand an outage of a major element, including an outage to the Hydro One system from which it is exclusively supplied at present. With respect to those benefits that can be quantified, there are two basic approaches available. The first approach relates to establishing the value of lost load in relation to the average load on the CNP Transmission System. While this approach does not necessarily account for unique local circumstances, it does have the benefit of attributing a value to benefits that would otherwise not be easily quantifiable. The second approach would be to attempt to identify key cost implications through a 'bottom-up' analysis of key end users and the costs they would expect to incur absent the Project.

As set out in **Exhibit B, Tab 4, Schedule 1**, the approach that has been adopted here has been to use the value of lost load as the basis for quantifying the local reliability benefits of the Project. The results of 'bottom-up' calculations based on local circumstances are then used for comparison purposes to validate the value of lost load derived from industry literature. Based on this methodology, conservatively applied, the quantitative reliability benefits expected from the Project have a net present value of $16.1 million.

(b) ***Intertie Capacity Benefits***

The Project is rated to provide 150 MW of intertie capacity in both directions at the Niagara interface with New York. In addition, the Project could provide an incremental 100 MW of intertie capacity on the Niagara ties in certain circumstances, therefore resulting in a total of 250

MW of intertie capacity being added to Ontario.[6] Based on the normal circumstances where the Project provides 150 MW of additional intertie capacity, this would represent an improvement of approximately 10% in the Niagara interface capacity with the NYISO-controlled grid. The benefits related to reduced capacity requirements, which CNP has been able to quantify, would provide benefits with an estimated net present value of $36.5 million.

(c) ***Generation Maintenance Outage Benefits***

The increased intertie capacity provided by the Project would also help relieve constraints during shoulder seasons when generation facilities may not be available due to maintenance activities. These constraints occur during peak periods in shoulder seasons when planned generation maintenance outages take place. At these times, the remaining generating capacity in Ontario may not be sufficient to meet peak demand and, as a result, the ability for Ontario generators to undertake maintenance activities can be constrained. The Project would help relieve this constraint by allowing for a higher level of imports, thereby enabling Ontario generators to implement improved maintenance schedules. The value of this benefit is estimated at $179,110 per year (2008 dollars), which has an estimated NPV of $3.4 million over the 30-year life of the Project.

(d) ***Qualitative Benefits***

In considering the Project, there are a host of important qualitative factors that merit attention. Most of these qualitative benefits arise from the increased intertie capacity provided by the Project and, therefore, are to the benefit of the Ontario electricity system as a whole.

---

[6] See Part 5 of *System Reliability Impact Study* (SRIS) *for Fortran Project of Canadian Niagara Power* (February 2009), at Exhibit B, Tab 12, Schedule 1.

(i) ***Outages to the Peace Bridge***

One unique entity that is impacted by outages to the CNP Transmission System is the Buffalo and Fort Erie Public Bridge Authority, which is responsible for operating and maintaining the Peace Bridge that connects Buffalo, New York to Fort Erie, Ontario.

During outage events to the CNP Transmission System, the ability of Canadian authorities to carry out their duties on the Fort Erie side of the bridge is adversely and significantly affected. One impact of an outage is the delay of truck traffic until electricity service resumes. The delay of truck traffic gives rise to direct costs for truck owners and operators, as well as indirect costs to the economy as a whole on both sides of the border due to delays in the movement of goods.

(ii) ***Insurance Against Supply Shortages***

With respect to long-term supply needs, the increased intertie capacity provided by the Project would provide some increased protection against potential delays in the availability of new resources within Ontario, or against higher than anticipated load growth in the province.

(iii) ***Surplus Baseload Generation***

In times of low Ontario demand, the additional intertie capacity provided by the Project would allow for greater exports of electricity to New York to take place relative to current tie line limitations. This provides the IESO with incremental flexibility to manage situations where there is a surplus of either baseload or renewable generation.

(iv) ***Maximizing use of Land and Few Regulatory Risks***

As described in **Exhibit B, Tab 2, Schedule 1**, the Project involves the replacement and reinforcement of certain existing lines and the installation of certain new equipment at existing stations. No new transmission towers or lands would be required. In doing so, the Project maximizes the use of existing infrastructure while minimizing costs and impacts on the community. By employing existing land and infrastructure, CNP Transmission does not reasonably anticipate material concerns about adverse impacts on stakeholders. From a regulatory and permitting perspective, these characteristics of the Project can be very significant.

(v) ***Comparatively Inexpensive New Intertie Capacity***

Relative to the cost of other recent large-scale intertie developments in Ontario, the Project would provide a low-cost supply of intertie capacity for the province. In particular, a 1250 MW transmission intertie between Ontario and Quebec near Ottawa is scheduled for completion in 2010. This project is being undertaken jointly by Hydro One and Hydro-Québec TransÉnergie. As reported by the Ministry of Energy and Infrastructure on its website, this project requires investments of $124 million by Ontario and $684 million from Quebec, for a total project cost of $808 million,[7] or $646,000 for each megawatt of new intertie capacity. By comparison, CNP Transmission's proposed intertie with New York at Fort Erie/Buffalo carries an estimated cost of $206,000 for each megawatt of new intertie capacity.

[7] See http://www.mei.gov.on.ca.wsd6.korax.net/english/energy/electricity/index.cfm?page=transmission-projects.

7. Project Costs and Rate Impacts

The estimated costs of the Project are as set out in **Figure 1.3**.[8] The amounts set out are broken down by project component, and reflect the estimated future costs of materials, labour, engineering, project management, owner's administration and contingency.[9] The project cost estimates are based on pre-engineering work undertaken in support of project development and the preparation of estimates.

With respect to the costs shown in Figure 1.3 for the construction of the three-breaker ring station and the removal and replacement of approximately 10 km of conductor from Huntley Station to Paradise Station, these costs are based on preliminary, good faith estimates from USNG and are subject to more detailed engineering and negotiation.

The Project has a positive net present value of nearly $10.4 million, which accounts for the reliability benefits to the CNP Transmission System and the intertie capacity benefits to Ontario, but does not capture the numerous qualitative benefits highlighted above.

[8] In addition to the items listed in Figure 5.1, the NYISO has suggested that CNP Transmission also install a 30 MVA capacitor bank at Station #18 for purposes of controlling voltage. This was not identified by the IESO or Hydro One as being required for any reason and CNP does not believe this work will be necessary. However, this will not be confirmed until the detailed engineering phase of the Project. If this work is required, it would be estimated to cost $400,000.

[9] The costs listed as "Project development costs" in Figure 5.1 reflect costs already incurred in the development stage of the Project.

Figure 1.3 Estimated Project Costs

Project Component	Cost (Million CAD $)
Project development costs	1.1
Reinforcement of 2.0 km of line sections from Murray Tap to Station #11 (forming lines A36 and A37)	Included in Station #11 costs, below
Installation of one additional breaker and disconnect switches near Station #11 (and reinforcement of 2.0 km of line sections)	2.9
Installation of two additional breakers and disconnect switches at Station #17	1.9
Installation of a 150 MW phase shifting transformer and voltage regulator at Station #18	8.8
Replacement of 0.5 km of conductor from the Bertie Hill Tower to the Queen Street Tower, and 0.66 km of conductor from the Queen Street Tower across the Niagara River to the High Tower	0.2
Construction of a three-breaker ring station near Switch 998[10]	6.0
Removal and replacement of approximately 10 km of conductor from Huntley Station to Paradise Station[11]	10.0
Total	**$30.9**

CNP Transmission proposes that the Project costs, including the capital contribution that CNP Transmission will make to USNG to cover the costs of the three-breaker ring station and the rebuild of lines L46 and L47, be ultimately added to rate base and recovered through the network charge of the Uniform Transmission Rates. The Project relates to network assets and is necessary in order for CNP Transmission to maintain compliance with its obligations as a licenced electricity transmitter, in particular its obligations under the Transmission System Code and NERC requirements that are incorporated by reference into the Code. In addition, the

[10] US $5.75M @ 1.05% (CIBC forecast average rate for 2011, as of July 14, 2009) = CAD $6.0375 million.

[11] US $9.5M @ 1.05% (CIBC forecast average rate for 2011, as of July 14, 2009) = CAD $9.975 million.

Project gives rise to a wide range of significant, system-wide benefits and helps the CNP Transmission System achieve the level of reliability that will be necessary to support the future connection of renewable generation facilities arising from the Province's *Green Energy and Green Economy Act* and related initiatives.

The NPV of the transmission rate impact over the life of the Project would be approximately $46 million. As a percentage of the existing Transmission Network Pool revenue requirement, the Project would represent an average increase over the entire Project life of 0.48%. In terms of the actual rate impact of the Project, based on the currently approved Network load of 258,509 MW, it is expected that Network rates would increase by an average of 1.2 cents per kilowatt, per month, over the life of the Project. As a result, the expected impact of the Project on a typical residential customer would be 2.7 cents per month, which represents an estimated increase of 0.024%.

8. Project Alternatives

To address the need for N-1 contingency on the CNP Transmission System, CNP considered five different options. Of the five options considered, three are variations of the proposed Project in that they all involve establishing a synchronous connection with New York at Buffalo, but differ in their capacity. The analysis of these variations resulted in a determination that the proposed Project is the only viable option among the three for establishing the interconnection with New York.

The remaining two options, involve the development of new transmission lines to connect the CNP Transmission System to the IESO-controlled grid at additional locations within Ontario, being either at Station #11 in Niagara (the “Niagara Project Alternative”) or at Hydro One’s Crowland Transmission Station in Port Colborne (the “Port Colborne Project Alternative”). While the Project Alternatives would provide N-1 contingency for the CNP Transmission System, neither of the Project Alternatives would provide CNP Transmission with the opportunity to offer any benefits to Ontario through the provision of additional intertie capacity between Ontario and New York. It is very important to note, however, that the viability of each Project Alternative is uncertain because each would entail significantly greater permitting and stakeholder risk, as well as the use of new lands for new transmission facilities. In addition, the Project Alternatives each have negative NPV’s, while the Project has a positive NPV.

9. Other Regulatory Approvals

Given that the Project includes the removal and replacement of conductors along the international portion of the system that spans the Niagara River between Fort Erie and Buffalo, CNP is required to obtain prior approval for the project from the National Energy Board (“NEB”). Such approval to change the international power line will need to be sought under section 21 of the National Energy Board Act, under which the NEB has authority to vary a permit issued under that Act. No oral hearing would be required for such an application. 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.

The need for a permit amendment from the NEB does not trigger any requirements under the *Canadian Environmental Assessment Act*. CNP Transmission does not anticipate that any other potential federal environmental assessment “triggers” will apply to the project.

Similarly, CNP Transmission does not expect that provincial environmental assessment requirements will apply to the proposed Project. As the Project constitutes “minor modifications” to facilities that were initially constructed without the need for a provincial environmental assessment, the Project is exempt from the requirements of the *Environmental Assessment Act* and associated regulations.

10. Construction and In-Service Schedule

The proposed construction and in-service schedule for the Project is provided at **Exhibit B, Tab 8, Schedule 1, Appendix A**. The schedule assumes a start date of December 15, 2009, which would result in a project completion date of September 30, 2012. This represents a total of 33.5 months. As indicated by the proposed schedule, this timeframe is driven primarily by long lead-times for key equipment, particularly the phase shifting transformer and voltage regulator, as well as permitting and regulatory approvals processes associated with work to be carried out on CNP’s behalf by USNG.

11. System and Customer Impact Assessments

CNP Transmission applied for, and the Independent Electricity System Operator (“IESO”) completed, a System Impact Assessment for the Project. The IESO issued a final System Impact Assessment Report (the “SIA Report”) for the Project on January 17, 2007. The SIA Report, which is provided in **Exhibit B, Tab 9, Schedule 2**, concludes that the installation of a 150 MVA phase shifter and voltage regulator, in combination with the various transmission reinforcements that are part of the Project (which are needed to address limiting line sections), would increase the import and export capability of the Ontario electricity market by 150 MW.

The SIA Report also confirms that “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.”[12] The SIA Report recommends that a Notification of Conditional Approval be issued to CNP Transmission.

CNP Transmission also applied for, and Hydro One completed, a Customer Impact Assessment for the Project. Hydro One issued a final Customer Impact Assessment Report (the “CIA Report”) for the Project on September 16, 2006. The CIA Report, which is provided in **Exhibit B, Tab 10, Schedule 2**, concludes that the Project is not expected to have significant adverse impacts on Hydro One or on customers in the area, including during the construction period.

12. Feasibility and System Reliability Impact Studies

The New York Independent System Operator’s (“NYISO”) interconnection process requires that, as an initial step, a feasibility study be conducted. The feasibility study involved a power flow analysis and a short circuit analysis on the New York State Transmission System, including the local transmission system owned by USNG. The results of the analysis are presented in the Feasibility Study Final Report (the “Feasibility Study Report”), issued on October 16, 2007, which is provided at **Exhibit B, Tab 11, Schedule 2**. The Feasibility Study Report concludes that the Project would result in acceptable voltages. The Feasibility Study Report also identifies key transfer limits, which the Project has been designed to overcome.

[12] Exhibit B, Tab 9, Schedule 2, SIA Report, p. 8.

NYISO's interconnection process further requires that a system reliability impact study ("SRIS") be carried out for purposes of assessing the impact of an interconnection project on the connecting transmission owner's transmission system. While this is the same basic purpose as the Feasibility Study Report, the SRIS is more comprehensive, more detailed and considers impacts on potentially affected neighbouring systems. The SRIS involved a power flow analysis (including of thermal and voltage performance), a power transfer analysis, a short circuit analysis and a dynamic stability analysis on the New York State Transmission System and the local transmission systems of CNP Transmission and USNG. The results of this analysis are presented in the SRIS Final Report, issued in February 2009, which is provided in **Exhibit B, Tab 12, Schedule 2**. The SRIS Final Report concludes that, while upgrades would be needed to overcome limitations in the thermal ratings of certain line sections, the Project would increase the New York-Ontario interface transfer capability by more than 150 MW and would not have any adverse impacts on system stability. These upgrades, which include the construction of the three-breaker ring station and upgrading 10 km of lines L46 and L47, are part of the Project. The SRIS also sets out preliminary cost estimates for these two elements of the Project.

Exhibit A, Tab 4, Schedule 1

Procedural Orders / Affidavits / Correspondence

Exhibit A, Tab 5, Schedule 1

Notices of Motion

Exhibit A, Tab 6, Schedule 1

Curriculum Vitae of Witnesses

EXHIBIT B - APPLICANT'S PRE-FILED EVIDENCE

Exhibit B, Tab 1, Schedule 1

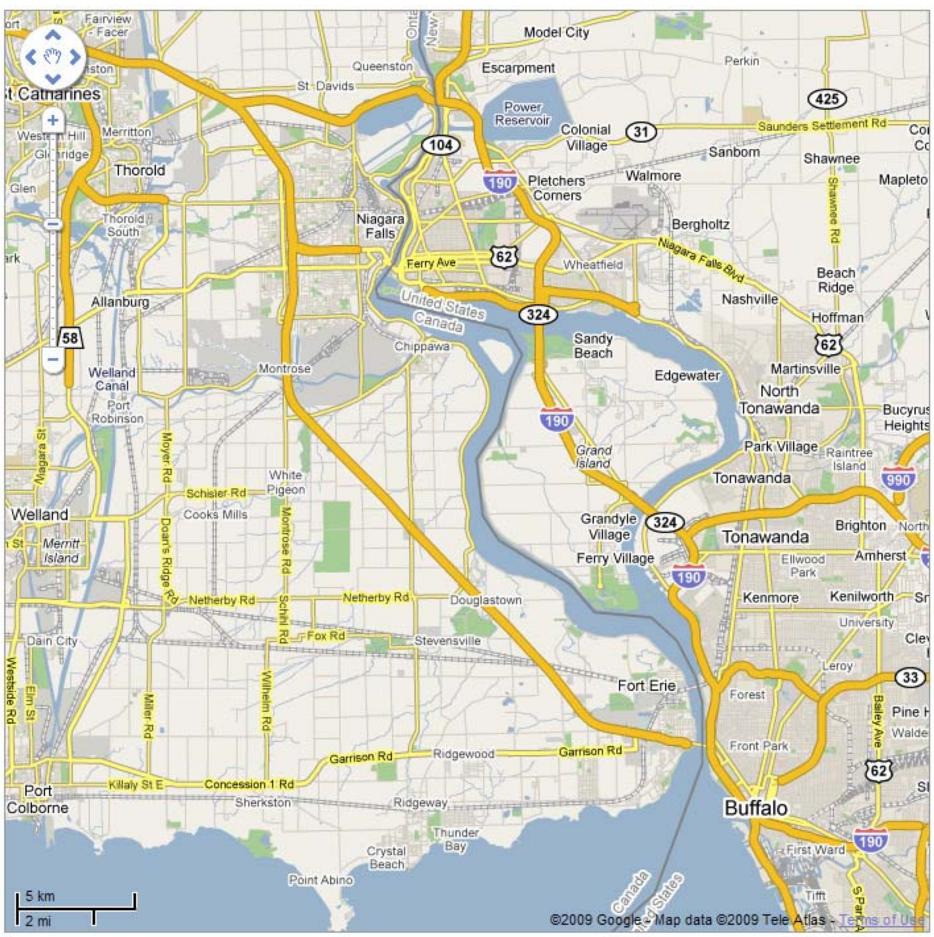
Existing Distribution System

EXISTING SYSTEM DESCRIPTION

1. Location

The Project involves activities to be undertaken and facilities to be constructed in and around the Town of Fort Erie, Ontario, as well as in the City of Buffalo, New York, and along the existing international power line that spans the Niagara River between these two locations. Fort Erie is a town with a population of nearly 30,000 people and is located on the Niagara River in the southern Niagara region of Ontario. It is located directly across the Niagara River from Buffalo, New York. A general map of the region is provided at **Figure 1.1**.

Figure 1.1 - Regional Map of Fort Erie, Buffalo, Niagara Falls and Port Colborne



2. Description and Location of Existing Facilities

As shown in the system map provided at **Figure 1.2** and as depicted in the simplified single line diagram in **Figure 1.3** (as well as in the detailed single line diagram in **Appendix A**), the existing CNP Transmission System is interconnected with the Hydro One Networks Inc. ("Hydro One") transmission system by two CNP-owned 115 kV transmission lines (Lines A36 and A37) extending from Hydro One's Murray Transmission Station ("Murray TS") in Niagara Falls, Ontario to CNP's Switching Station #11 ("Station #11"), also located in Niagara Falls, Ontario. Station #11 is connected to CNP Transmission Station #17 ("Station #17") in Stevensville, Ontario by a single 15 km, 115 kV line known as L2. Beyond Station #17, line L2 extends 10 km to CNP Transmission Station #18 ("Station #18") in Fort Erie, Ontario.

The transmission line connecting Station #18 in Fort Erie and the Canada bus (owned by U.S. National Grid ("USNG")) in Buffalo, New York[1] consists of the four following sections:

(a) Station #18 to Bertie Hill Tower (both in Fort Erie and owned by CNP) – a 3.23 km single circuit 115 kV (795 MCM ACSR) line with a continuous rating of 169 MW known as Line 46;

(b) Bertie Hill Tower to Queen Street Tower (both in Fort Erie and owned by CNP) – a 0.5 km 115 kV double circuit span with a continuous rating of 62 MW for each circuit (however, at this time only one circuit is energized);

(c) Queen Street Tower (in Fort Erie and owned by CNP) to High Tower (in Buffalo and owned by USNG) extending into Terminal House 'B' – a 0.66 km 115 kV double circuit line crossing the Niagara River with a continuous rating of 48 MW for each circuit (however, at this time only one circuit is energized); and

(d) Terminal House 'B' to Switch 998 (both in Buffalo and owned by USNG) – a 2.7 km 1,000 MCM underground cable with a continuous rating of 159 MW. The

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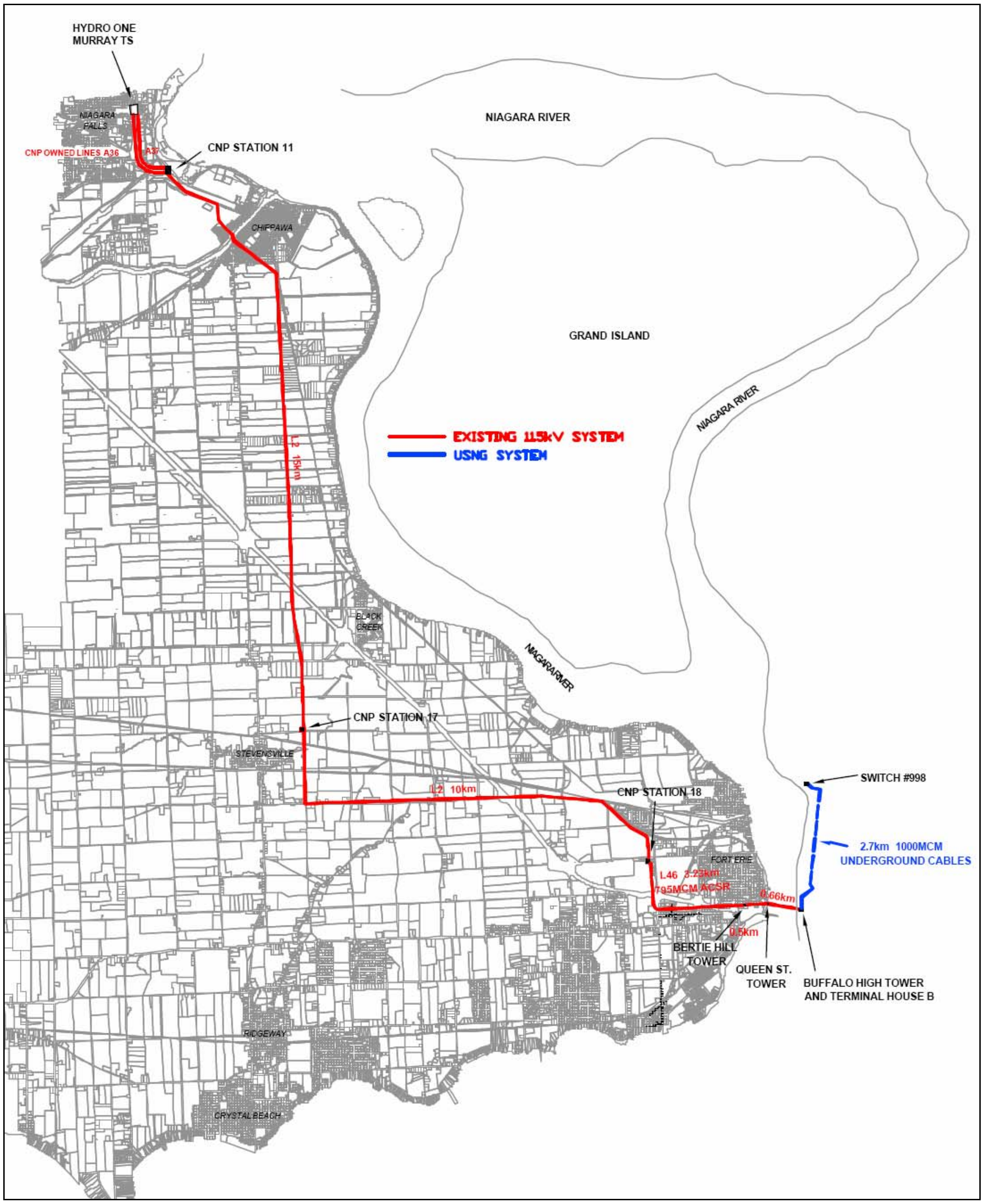
[1] The Canada bus owned by USNG is within the control area of the New York Independent System Operator ("NYISO")

interconnection into the Buffalo system, which is owned and controlled by USNG, occurs at Switch 998.[2]

Figure 1.2 - Transmission System Map (Current)



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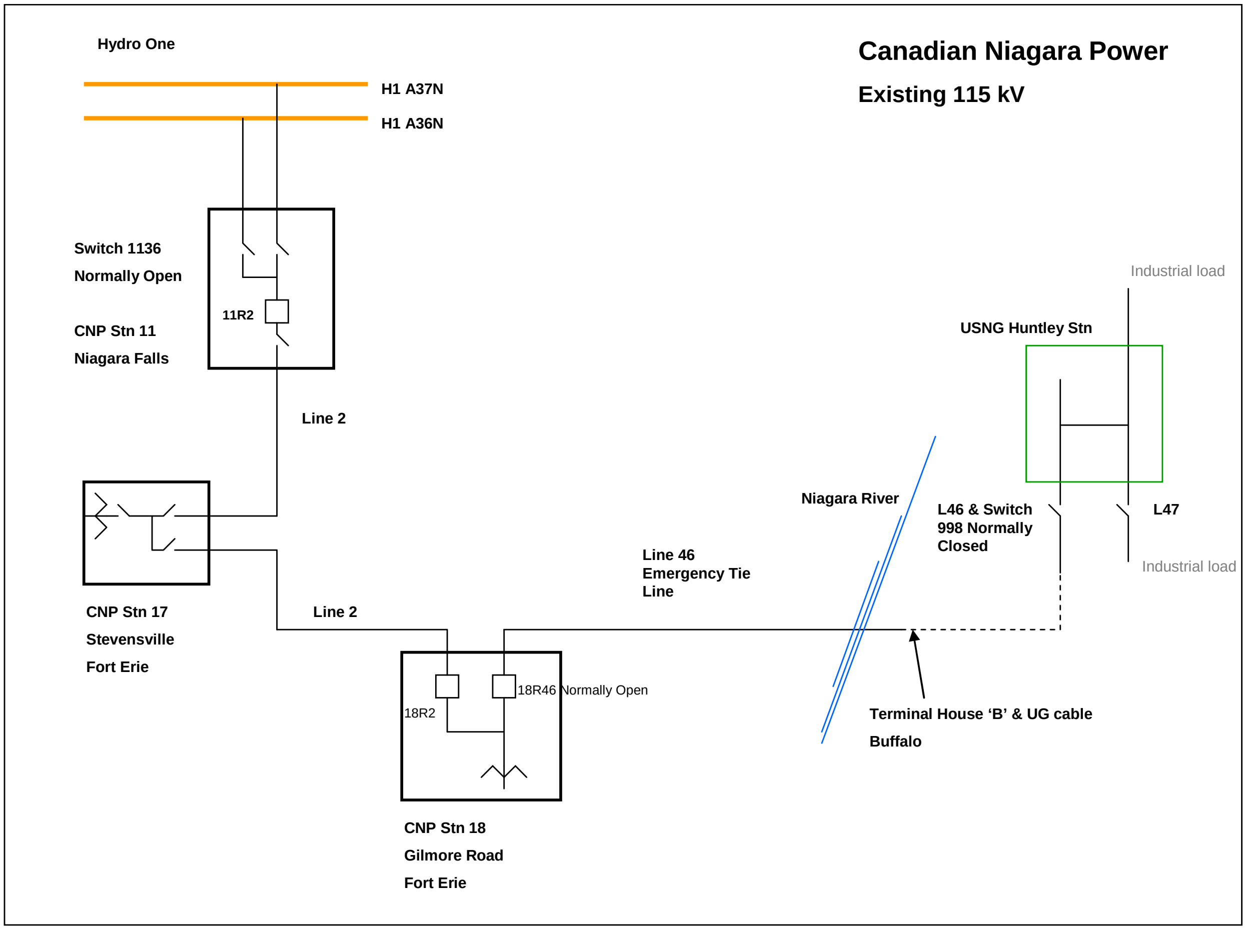
[2] USNG plans to reconfigure its transmission system in the Buffalo area on account of the anticipated retirement of the Huntley generating station. The reconfiguration involves connection of lines 46 and 47 at a new Paradise substation, rather than at Huntley, by 2012.

Figure 1.3 - Transmission System Single Line Diagram (Current)



The transmission facilities from Station #18 to Switch 998 in Buffalo (the "Emergency Tie Line") are energized but no energy flows over those lines. This is because the Hydro One system and the USNG system are not synchronous, i.e. they cannot be run in parallel. As a result, switches at Station #18 are normally open (i.e. no energy flows). Under normal operations the CNP Transmission System is interconnected with and supplied only from the Hydro One system via Station #11 and line L2. The interconnection with New York was upgraded in 1998 to enable it to operate as an emergency tie line in the event that:

(a) supply on the Hydro One side of Station #11 is lost,

(b) there is a fault affecting the connection between Station #11 and Murray TS, or

(c) there is a fault downstream of Station #11 on line L2.[3]

In any of these circumstances, the entire CNP Transmission System would "go dark" until the problem is resolved or service is established with New York over the Emergency Tie Line. The capacity of the Emergency Tie Line is 48 MW. As the Ontario and New York systems are out of phase at the Fort Erie-Buffalo connection point, running them in parallel would result in large flows of reactive power across the closed tie. If this were to occur, the thermal ratings of the CNP Transmission System would be exceeded and significant equipment damage would result or protective systems would operate to interrupt power supply. In either case, significant outages would result, including potentially to the USNG system. The Emergency Tie Line is discussed in greater detail at **Exhibit B, Tab 3, Schedule 1**.

[3] A fault between Station #11 and Station #17 would cause all of the CNP load to be interrupted and require use of the Emergency Tie Line. A fault between Station #17 and Station #18 would cause all of the CNP load to be interrupted until distribution feeders in the system were switched so as to isolate and pick up load.

APPENDIX A

Detailed Single Line Diagram of Existing CNP Transmission System

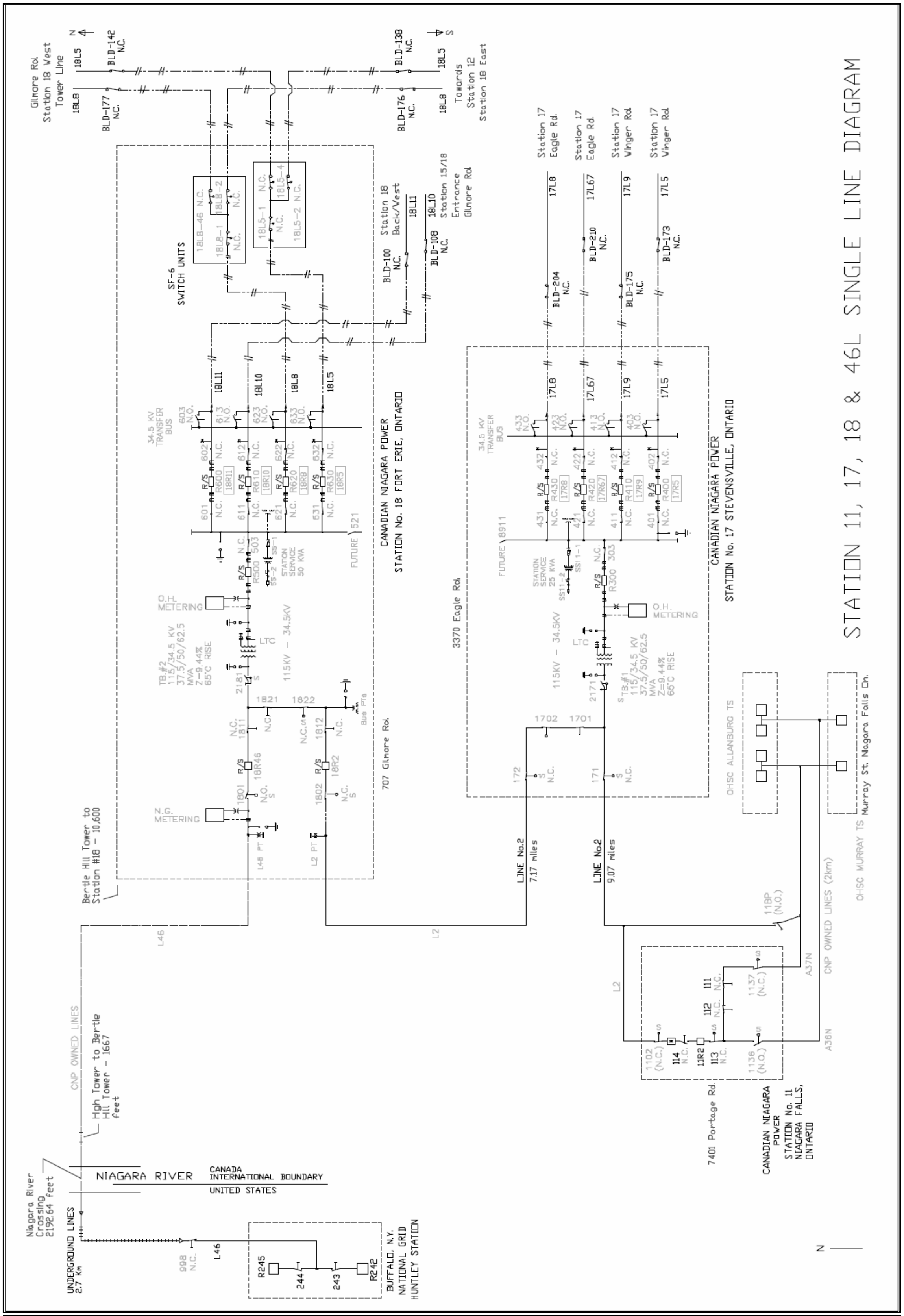

STATION 11, 17, 18 & 46L SINGLE LINE DIAGRAM
CANADIAN NIAGARA POWER
STATION No. 18 FORT ERIE, ONTARIO
CANADIAN NIAGARA POWER
STATION No. 17 STEVENSVILLE, ONTARIO
CANADIAN NIAGARA POWER
STATION No. 11
NIAGARA FALLS,
ONTARIO
BUFFALO, N.Y.
NATIONAL GRID
HUNTLEY STATION
NIAGARA RIVER
CANADA
INTERNATIONAL BOUNDARY
UNITED STATES
SF-6
SWITCH UNITS
LINE No.2
7.17 miles
LINE No.2
9.07 miles
707 Gilmore Rd.
3370 Eagle Rd.
7401 Portage Rd.

Exhibit B, Tab 2, Schedule 1

Project Description

PROJECT DESCRIPTION

The CNP Transmission System is currently served by a single supply point on the IESO-controlled grid. The Project involves developing a synchronous connection between the CNP Transmission System, the IESO-controlled grid and the NYISO-controlled grid for the purpose of establishing N-1 contingency for the CNP Transmission System, thereby bringing the CNP Transmission System in line with minimum reliability standards and providing benefits to the system as a whole. Reliability benefits are set out in Section 2 of **Exhibit B, Tab 4, Schedule 1**. The Project will also provide Ontario and the IESO-controlled grid with additional intertie capacity with New York. These system-wide benefits are discussed in Section 3 of **Exhibit B, Tab 4, Schedule 1**. Section 4 of **Exhibit B, Tab 4, Schedule 1** provides a discussion of qualitative benefits related to both reliability and intertie capacity.

With reference to **Figure 2.1**, which provides a map showing the various components of the Project (see **Appendix A** for a large scale version), and the simplified single line diagram depicting the components of the Project in **Figure 2.2**, the Project would involve the following work activities:

a) Reinforcement of 2.0 km of line forming Lines A36 and A37 in order to accommodate the maximum capability of the new Fort Erie interconnection;

b) Installation of an additional 115 kV breaker adjacent to the Murray taps on A36N and A37N;

c) Installation of two additional breakers at Station #17 in Stevensville for enhanced sectionalizing and zone control;

d) Installation of a 150 MVA phase shifting transformer and voltage regulator at Station #18 in Fort Erie;

e) Replacement of 0.5 km of conductor from the Bertie Hill Tower to the Queen Street Tower in Fort Erie with 795 MCM conductor to provide capacity of at least 150 MW;

f) Replacement of 0.66 km of conductor from the Queen Street Tower in Fort Erie, across the Niagara River, to the High Tower adjacent to Terminal House B in Buffalo, New York, with 795 MCM conductor to provide capacity of at least 150 MW;[1]

g) Construction of a 115 kV three-breaker ring station located at switch SW 998 in Buffalo, New York, that will tie L46, L47 and USNG's Canada Bus; and

h) Replacement of approximately 10 km of conductor from the Huntley Station to the planned USNG 115 kV Paradise Station in Buffalo, with a new 115 kV three-phase transmission circuit,

all of which are defined as "the Project".

The work activities in respect of paragraphs (a) to (f) will be completed by CNP Transmission. The work activities described in paragraphs (g) and (h) above would be carried out by USNG upon receipt of a capital contribution from CNP. All work and all new facilities associated with the Project in Ontario would take place on or be situated upon lands that already support the CNP Transmission System and which CNP already controls. As a result, no new land is required

[1] Though not currently expected, Queen Street Tower and High Tower may need to be replaced to support the new conductors.

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

Figure 2.1 - Map of Project Components

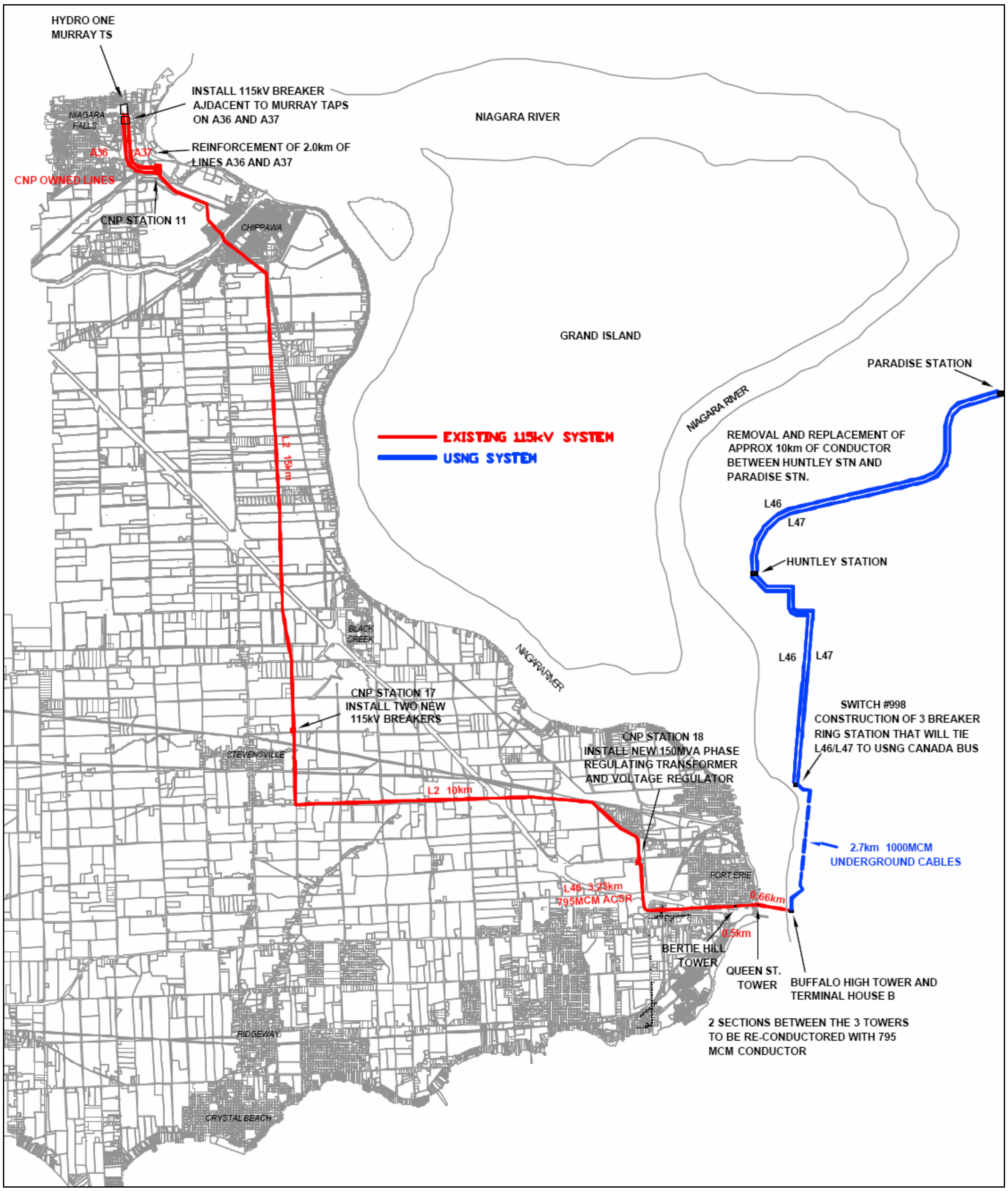
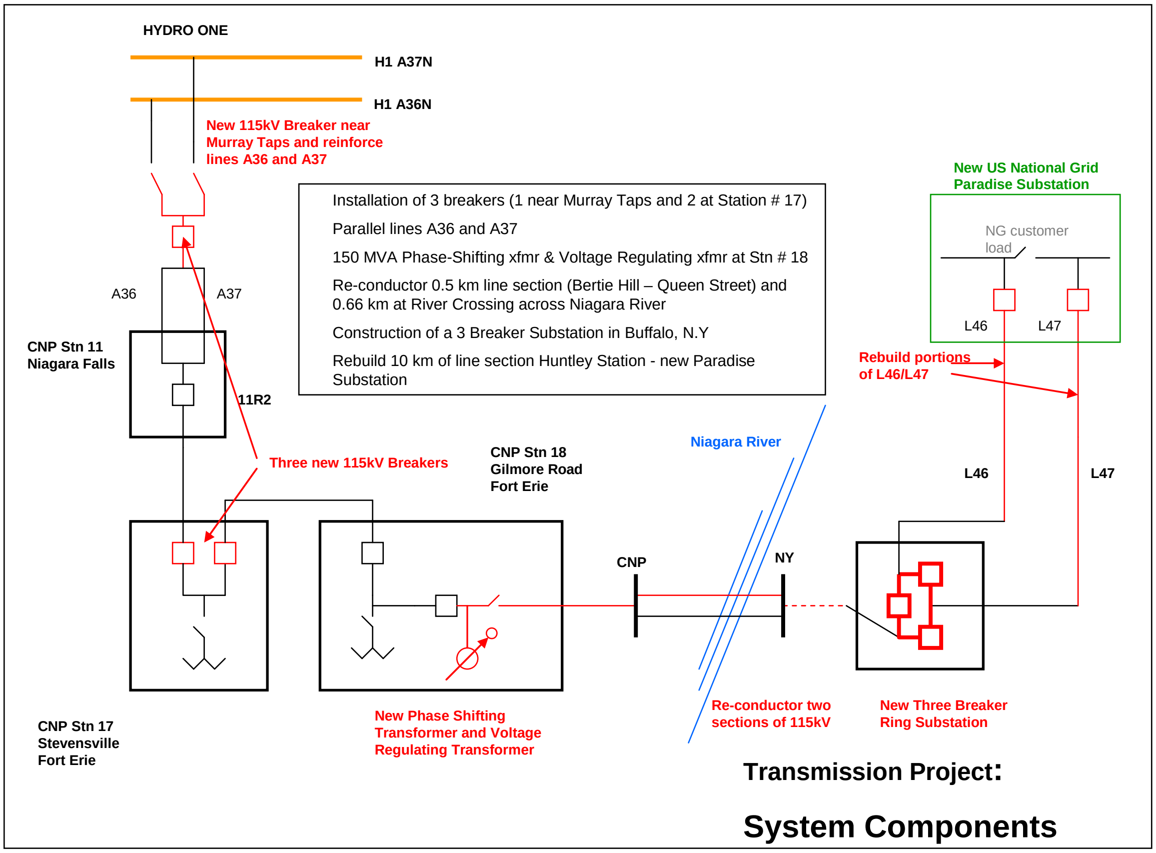


Figure 2.2 - Single Line Diagram of Project Components



A discussion of other permitting and regulatory requirements for the Project, including environmental approvals and National Energy Board approvals, is provided in **Exhibit B, Tab 7, Schedule 1**.

As shown in the proposed construction and in-service schedule for the Project in **Exhibit B, Tab 8, Schedule 1**, it is estimated that the Project will take 33.5 months to complete, due primarily to long lead-times for key equipment.

In respect of the work activities to be carried out by CNP Transmission, a copy of the System Impact Assessment from the IESO is included in **Exhibit B, Tab 9, Schedule 2** and a copy of the Customer Impact Assessment from Hydro One is included in **Exhibit B, Tab 10, Schedule 2**. In addition, with respect to the work activities to be carried out by USNG on behalf of CNP Transmission, a copy of the preliminary Feasibility Study is provided in **Exhibit B, Tab 11, Schedule 2** and a copy of the more detailed and comprehensive System Reliability Impact Study is provided in **Exhibit B, Tab 12, Schedule 2**.

APPENDIX 'A'

Map of Existing System and Project Components

[Folded map contained in original document]

Exhibit B, Tab 3, Schedule 1

Project Need

PROJECT NEED

As noted in **Exhibit B, Tab 1, Schedule 1**, and as set out below, there are important reliability concerns for the CNP Transmission System. Because there are no viable alternatives, the Project in respect of this reliability concern is non-discretionary. 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. The purpose of the Project is twofold: (1) to bring CNP Transmission, as a licensed transmitter, in line with minimum standards for reliability established under the Transmission System Code and realize the benefits associated with achieving those standards (See Section 2 of **Exhibit B, Tab 4, Schedule 1**), and (2) to provide a range of important benefits to Ontario and the IESO-controlled grid that arise from establishing an upgraded intertie that operates in parallel with the Ontario and New York systems (See Section 3 of **Exhibit B, Tab 4, Schedule 1**).

1. N-1 Contingency

As a licensed transmitter, CNP Transmission is obliged to abide by the Transmission System Code (the "Code"). Section 5.1.2 of the Code provides that "a transmitter shall 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."

Section 8.1.1 of the Code provides that "a transmitter shall ensure compliance with the standards of all applicable reliability organizations," referring to the standards of NERC, NERC's reliability councils and Ontario's Independent Electricity System Operator ("IESO").

NERC Standard TOP-002-2, entitled *Normal Operations Planning*, provides at Requirement #6 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) . . ."[1]

Moreover, the principle that a transmission system should provide N-1 contingency, particularly in more highly populated urban areas, is generally accepted as being consistent with good utility practice. Therefore, the necessity of meeting the NERC standard and good utility practice are fundamental to the Code. As such, through the Project, CNP Transmission is endeavouring to maintain this fundamental requirement of the Code.

By establishing an N-1 configuration, the Project would enable the provision of continuous service to the CNP Transmission System and, thereby, to the customers it ultimately serves, in the event of a failure on the CNP Transmission System or in the event of a failure on the Hydro One transmission system that supplies the CNP Transmission System. At present, the entire CNP Transmission System is vulnerable to outages due to the occurrence of any one of the following events:

[1] NERC Standard TOP-002-2, *Normal Operations Planning* (parentheses in original).

- *A fault on the Hydro One transmission system*: Faults could occur at Murray TS, at Allanburg TS, or on the A37N circuit between Murray TS and Allanburg TS, any one of which would result in an outage to the entire CNP Transmission System;

- *A fault between Hydro One's Murray TS and Station #11*: As noted in the description of the existing system in **Exhibit B, Tab 1, Schedule 1**, the CNP Transmission System is connected to Murray TS by two kilometres of 115 kV circuit Line A36 and Line A37. Line A37 is energized. Line A36 is also energized up to Station #11, but is connected to Station #11 by a switch that remains open during normal operations and is not run in parallel with Line A37. If a fault results in an outage to A37 (the normal feed to Station #11) then the switch to A36 (the backup feed) must be made manually and in coordination with Hydro One. This process could take several hours and requires an outage to the entire CNP Transmission System;

- *A catastrophic failure at Station #11*: As the sole supply point to Line L2, a major equipment failure would result in an outage to the entire CNP Transmission System; and

- *A fault on CNP's Line L2, between Station #11 and Station #18*: Line L2 is a single radial 115 kV circuit of approximately 25 km in length with no backup source. A fault would result in a loss of supply to the entire CNP Transmission System.

As demonstrated by these potential events, each of which would give rise to system-wide outages, 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.

In essence, having an N-1 configuration means that the system will be able to withstand an outage of one major element. Because the CNP Transmission System is only supplied from a single source, it is not currently able to withstand an outage to that supply. At best, in the event an outage causes the CNP Transmission System to "go dark" due to one of the circumstances described above, the portion of the CNP Transmission System extending from Station #18 in Fort Erie to Switch 998 in Buffalo, New York (the "Emergency Tie Line") may only be operated on a temporary basis for emergency purposes. The time required to engage the Emergency Tie Line in such a situation involves a minimum of four hours due to the need to take all necessary precautions to engage the interconnection safely and the need to coordinate with the IESO, Hydro One and USNG. During the intervening period, while efforts to engage the Emergency Tie Line are underway, the CNP Transmission System would remain dark because, at present, the Hydro One transmission system and the USNG system cannot be run in parallel.

As long as the Hydro One and USNG systems are not run in parallel, line L2 can only be energized via the Emergency Tie Line. This would feed all of the CNP Transmission System load using supply from the Emergency Tie Line during periods of average load. However, as explained below, the Emergency Tie Line has significant limitations. Among these limitations is that the Emergency Tie Line is not capable of meeting CNP's peak demand levels and will soon be incapable of meeting CNP's annual average demand levels (See Figure 3.1).

2. Shortcomings of the Emergency Tie Line

Recognizing the exposure of the system to supply loss, CNP Transmission took steps in 1998 to establish the current Emergency Tie Line between Fort Erie, Ontario and Buffalo, New York. Historically, transmission lines of 46 kV (25Hz) ran from Fort Erie across the Niagara River to Buffalo as part of a closed 25 Hz system. The 25 Hz system was decommissioned in Buffalo. As part of efforts to establish the Emergency Tie Line, an underground cable was installed in Buffalo to connect the intertie with Line 46, which was part of what was then known as the Niagara Mohawk system. After this connection was made, the intertie could be operated at 60 Hz and 115 kV. However, the Emergency Tie Line system was not designed to run in parallel with the Ontario grid. When the CNP Transmission System is taking supply from Ontario, the Emergency Tie Line must remain open (i.e., no flows of electricity across the Emergency Tie Line) so that no uncontrolled flows occur from either the Ontario or New York system.

As the Ontario and New York systems are out of phase at the Fort Erie-Buffalo connection point, running them in parallel would result in large flows of reactive power across the closed tie. If this were to occur, the thermal ratings of the CNP Transmission System would be exceeded and significant equipment damage would result or protective systems would operate to interrupt power supply. In either case, significant outages would result, including potentially to the USNG system. Therefore, the Emergency Tie Line is under-utilized and can only be energized in limited emergency circumstances.

Because the systems interconnected by the Emergency Tie Line cannot be run in parallel, an interruption to supply from Hydro One because of any of the circumstances listed on page 3 of this schedule would result in the CNP Transmission System "going dark" or remaining out of service until either (1) the fault causing the event is investigated and repaired, or (2) CNP Transmission initiates and completes a request for emergency response over the Emergency Tie Line.

When the CNP Transmission System experiences an outage, CNP's standard operating practice is as follows: (1) CNP would communicate with Hydro One to determine if there is a loss of supply on the Hydro One network; (2) for suspected faults on CNP's transmission system, CNP would dispatch resources such as line and substation crews to inspect line sections and stations; (3) once the source of the fault is known, CNP would assess the timeframe necessary for repair and initiate steps to repair the fault; and (4) if the time period to effect the repair is expected to take at least 4 hours, then CNP would initiate a request to close the Emergency Tie Line and take service from New York. Making a request for service from New York then requires CNP to follow a 31-step switching procedure, which essentially involves: contacting Hydro One to confirm the estimated duration of the outage; contacting the IESO and USNG to inform each of these parties that the CNP Transmission System needs to be fed by the Emergency Tie Line; sending out CNP Transmission crews to check breakers and switches at Stations #11, #17 and #18; having the system control operator conduct a number of tasks; and informing the IESO and USNG once all steps are completed. A copy of this switching procedure is provided in **Appendix A**.

Once the fault has been repaired and service from Murray TS can recommence, CNP must initiate a process similar to the above in order to switch supply back from New York to Ontario. The procedure for switching back to supply through Station #11 involves 36 steps and further coordination with Hydro One, the IESO and USNG. A copy of this switching procedure is provided in **Appendix B**. Essentially, this process involves CNP Transmission initiating an outage at Station #18 to disconnect from the New York grid. Supply from the Ontario system is then reinstated at Station #11, which permits Stations #17 and #18 to be energized. This process requires an outage to the entire CNP Transmission System of at least 20-30 minutes in duration.[2]

Where the Emergency Tie Line is engaged to allow for scheduled maintenance activities, CNP endeavours to schedule any necessary outages during off-peak periods so as to minimize the cost and inconvenience to those served by the system. This is subject to consideration of whether the Emergency Tie Line will have the capacity to supply the expected load until such off-peak period. Where the Emergency Tie Line is engaged, USNG prefers that CNP Transmission disengage from the Emergency Tie Line at the earliest possible opportunity.

With respect to timing, a forced outage requiring the initiation of New York supply through the Emergency Tie Line would involve a process that could take a minimum of 4 hours. This includes time for the investigation and assessment of required repairs arising from the fault and time related to orchestrating the establishment of supply from New York over the Emergency Tie Line. If a decision is made not to engage the Emergency Tie Line, then the duration of an outage could be longer, depending on the length of time required to complete the repairs and restoration.

While the Emergency Tie Line is important, its effectiveness is limited to remedying outages of a sufficient duration to justify taking all of the steps needed to energize the line. As such, the

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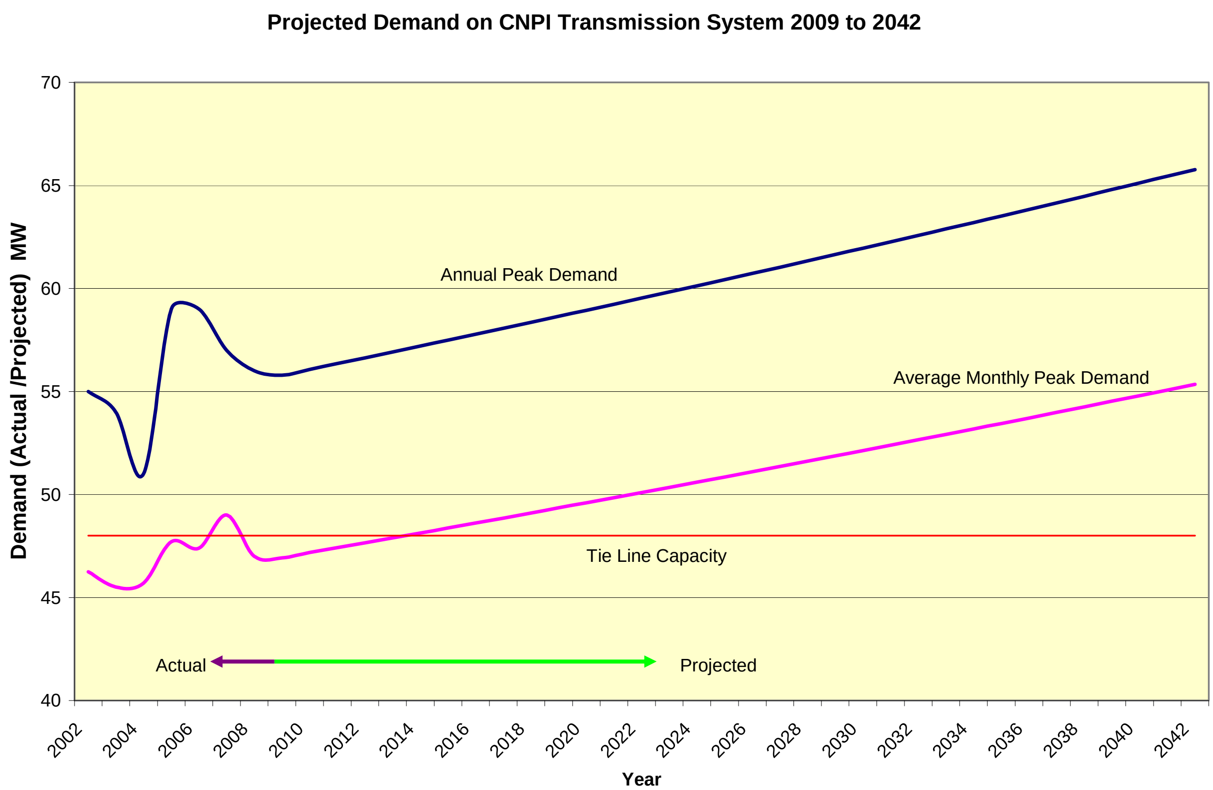
[2] The duration of an outage required for switching back to Ontario supply is much shorter than that required to engage the Emergency Tie Line because the required co-ordination and communications activities can be undertaken while the Emergency Tie Line is in service.

Emergency Tie Line would typically only be engaged where an outage is expected to continue for a period of at least 4 hours.

Another significant limitation of the Emergency Tie Line is its capacity to provide an alternative source of supply during emergency situations, relative to current and forecast loads on the CNP Transmission System. The capacity of the Emergency Tie Line is 48 MW. The average monthly peak load on the CNP Transmission System in 2008 was 47 MW, but was 48 MW in 2005 and 49 MW in 2007. CNP forecasts annual load growth on the system of 0.5%. As such, there is no certainty that the Emergency Tie Line will be able to provide sufficient capacity to meet average monthly peak loads in the near term and, when factoring in forecast demand, it is expected that the Emergency Tie Line will consistently fail to meet average monthly peak system needs within a few years (See **Figure 3.1**). More importantly, as good utility practice calls for systems to be designed on the basis of peak loads rather than average loads, Figure 3.1 further shows that annual peak demand on the CNP system, which was 56 MW in 2008, has consistently exceeded the capacity provided by the Emergency Tie Line since at least 2002. Therefore, where an outage occurs during a period of higher than average demand on the CNP Transmission System, the Emergency Tie Line will generally be incapable of meeting system needs. As such, there is a need to provide N-1 contingency in order to provide an instantaneous supply alternative in the event of any unplanned outage to the CNP Transmission System. This would help prevent outages on the CNP Transmission System and mitigate the shortcomings of the Emergency Tie Line in its present configuration.

Figure 3.1 - Forecast Loads on the CNP Transmission System



3. **Reliability**

(a) ***Industry Performance Measures***

<u>IESO Local Area Performance Benchmarks</u>

As a market participant and licensed transmitter, CNP Transmission files a monthly interruption report with the IESO which includes duration and load supply details for each outage event. **Figure 3.2** summarizes CNP Transmission's service interruption history from 2002 to the present, which lists all outages directly attributable to both planned and unplanned events on the existing 115 kV transmission system. As shown in Figure 3.2, the CNP Transmission System has experienced 16 outages or an average of 2.3 outages per year during the period from 2002 to

2008. Over the same period, the CNP Transmission System has experienced 1009 minutes, or an annual average of 144.1 minutes of service interruption per year.

Figure 3.2 - Summary of CNP Transmission System Service Interruptions (2002-2008)

Year	Date	Outage Duration (Min)	Cause	Type of Outage L = line T= terminal
2002	June 1	54	Car accident - guy wire broke and contacted phase conductor between Stns. 11 & 17.	L
2003	Oct. 15	75	Conductors slapped together during windstorm	L
	Nov. 13	90	Fault on Line 2 between Stns. 17 and 18 - unknown cause	L
2004	January 17	36	Bad weather.	L
	February 8	8	Planned outage to replace pole damaged by fire.	L
	February 22	6	Tree contact during wind storm.	L
	March 3	2	Poor weather - high winds.	L
	March 16	27	Vehicle accident - broken pole.	L
	March 22	18	Animal contact on HV bus at Stn. 17	L
	March 26	106	Ligntning arrester failure at Stn. 18	T
	July 1	50	Failed PT at Stn. 18	T
	August 8	278	Failed PT at Stn 17	L
2005			*No transmission outages in 2005*	
2006	May 12	53	Tree contact between Stns. 11 & 17.	L
	October 13	150	Severe snow storm.	L
	November 12	31	Planned outage to transfer Fort Erie load to L46 from New York to facilitate transmission line maintenance.	L
	November 13	25	Planned outage to transfer Fort Erie load from L46 from New York after completion of transmission line maintenance.	L
2007			*No transmission outages in 2007*	
2008			*No transmission outages in 2008*	
Total		**1,009**	**Minutes**	
Yearly Average		**144.1**	**Minutes**	
Number of Outages		**16**		
Yearly Average		**2.3**		

Based on this data, the IESO assesses local area performance, as it is required to do pursuant to the *Market Rules*.[3] Under the IESO's Local Area Performance benchmarks, the performance of a transmission system is rated as "Red", "Yellow" or "Green" based on system performance in relation to performance in recent years. Red indicates poorer performance than threshold and Green indicates better than threshold performance. Since 2002, the rating of the CNP Transmission System has gone from Yellow (2002) to Red (2003 and 2004) to yellow (2005 and

[3] See Rule 5.4.3 of the Market Rules.

2006) to Green (2007 and 2008). The inconsistency in the performance record for the CNP Transmission System is indicative of the fact that in some years CNP is fortunate that no major equipment failures or supply outages occur but in other years, despite its good management, CNP is exposed to potentially serious reliability concerns.

As an accepted principle of good utility practice, ensuring N-1 contingency would provide CNP with the ability to deal with such outage events when they inevitably arise. As a result, almost all of the outages listed in Figure 3.2 would not have occurred if the CNP Transmission System had N-1 contingency in place. While all of the line outages related to line faults would have been completely avoided if the Project had been in place, terminal outages would have been mitigated such that the system as a whole would not have gone dark. The Project will enable CNP to isolate problems and perform the necessary repairs while the remainder of the system is energized continuously from either from Ontario or New York. Following implementation of the Project, CNP Transmission will be able to consistently achieve a green rating for the IESO's Local Area Performance Benchmarks.

Canadian Electricity Association Transmission Benchmarking

Another basis for considering performance of the CNP Transmission System is with reference to performance data set out in the Canadian Electricity Association's ("CEA") *2006 Forced Outage Performance of Transmission Equipment* benchmarking report.[4] When 2002-2006 performance data for the CNP Transmission System is compared with data in this report for the same period

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[4] Available at http://www.canelect.ca/en/aboutcea/aboutcea_documents_reports_benchmarking.html for purchase from the Canadian Electricity Association.

and the same voltage class (110-149 kV), the analysis indicates that outage frequency on the CNP Transmission System of 8.75 outages per 100 km per year is far greater than the CEA average frequency of 1.0534 outages per 100 km per year. Implementation of the Project will significantly reduce the frequency of outages and bring the CNP Transmission System more in line with other well-performing electricity transmitters.

Hydro One's Customer Delivery Point Performance Standards

One further means of considering the performance of the CNP Transmission System is to consider its performance against the Customer Delivery Point Performance Standards (CDPPS) of Hydro One. While CNP does not have its own CDPPS, the Hydro One CDPPS for the same load class (>15-40 MW) provides a good benchmark for comparison.[5] Hydro One's CDPPS reflects its performance over a 10-year period, against which it compares performance based on a three-year rolling average. The frequency and duration of delivery point outages on the CNP Transmission System for the past seven years are set out at **Figure 3.3(a)**. Over this period, the average of the three-year rolling averages for the frequency of interruptions on the CNP Transmission System has been 2.9 outages per year, with a maximum of 4.3 outages per year. This can be compared to Hydro One's average benchmark of 1.1 outages per year and its minimum standard of performance of 3.5 outages per year (See **Figure 3.3(b)**). With respect to outage duration over the same period, the analysis indicates that the CNP Transmission System experienced an average of 184 minutes of outages per year based on the average of three-year

[5] The CNP Transmission System has an average load of 36 MW for purposes of determining the appropriate load class under Hydro One's CDPPS. With forecast load growth, the CNP Transmission System will soon move into the next load class (>40-80 MW), for which the Hydro One CDPPS outage frequency and duration standards are even more strict (average frequency of outages 0.5 per year / average duration of outages 11 minutes per year) than for the >15-40 MW load class to which CNP now belongs.

rolling averages, as indicated by Figure 3.3(a), which is far greater than the average standard of 22 minutes of outages per year under Hydro One's CDPPS and greater than the minimum standard of performance of 140 minutes per year.[6] As noted, implementation of the Project will significantly reduce the frequency and duration of outages on the CNP Transmission System.

Figure 3.3 - Comparison of CNP Performance to Hydro One's CDPPS

(a) Summary Table of Outage Events for CNP

Year	**DP Frequency** (events /yr)	**3 yr Rolling Average**	**DP Duration** (Min / year)	**3 yr Rolling Average**
2002	1		54	
2003	2		165	
2004	9	4.0	531	250
2005	0	3.7	0	232
2006	4	**4.3**	259	**263**
2007	0	1.3	0	86
2008	0	1.3	0	86
Total or Average	16	**2.9**	1,009	**184**

(b) Comparison of CNP Outage History to Hydro One's 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**	**2.9**	**4.3**
DP Interruption Duration (min/yr)	**22**	**140**	**184**	**263**

Source Data: Hydro One CDPPS - EB 2002-0424, revised February 7, 2008.

[6] See Hydro One Networks' Revised Customer Delivery Point Performance Standards filed February 7, 2008 pursuant to the Ontario Energy Board's January 17, 2008 Decision and Order in the EB-2002-0424 proceeding.

(b) ***Vulnerability to Planned Outages***

In addition to forced or unplanned outages due to circumstances such as those described above, the CNP Transmission System and customers in Fort Erie are also vulnerable to planned outages that are necessary for maintenance purposes. Due to the design of the CNP Transmission System and the lack of N-1 contingency, some planned maintenance activities between Station #11 and Station #17 require outages to the entire CNP Transmission System. While the Emergency Tie Line can be engaged in such circumstances to provide power while the relevant portions of the CNP Transmission System are isolated for maintenance, outages will still occur before the Emergency Tie Line can be energized, due to the current configuration. As shown in Figure 3.2, two such outages occurred in November 2006 to allow for maintenance activities.

4. **Accommodating Renewable Generation in Support of the *Green Energy and Green Economy Act, 2009***

The *Green Energy and Green Economy Act, 2009* ("GEGEA") received Royal Assent on May 14, 2009. Through the GEGEA, the Province is attempting to spur a significant increase in the development of renewable energy generation in Ontario. While the Ontario Power Authority's feed-in-tariff program is no doubt central to achieving this policy objective, there is also a strong recognition among the Province and electricity sector agencies that significant investments in transmission and distribution systems will be needed in order to support and facilitate the development of renewable resources. To date, most of the discussion concerning the transmission and distribution investments needed to support renewable generation has focused on the expansion and reinforcement of systems in order to accommodate new generation. However, before the question of expansion or reinforcement can be considered, the reliability concerns associated with the lack of N-1 contingency on the CNP Transmission System must first be addressed. For CNP Transmission or the distribution system that it serves to be considered as a potential host for renewable generation facilities, prospective generators will need to be confident that the transmission system will offer a high level of reliability in order to support and maximize the generation output from their planned facilities. Moreover, certain renewable technologies, including wind and solar generation, require a power source to generate electricity. The lack of N-1 contingency on the CNP Transmission System would therefore be a significant barrier to the connection of such renewable generation facilities.

Furthermore, under GEGEA amendments to the *Ontario Energy Board Act*, the transmission licence held by CNP Transmission will soon be deemed to contain a condition that requires CNP Transmission to prepare, for Board approval, a plan for the expansion or reinforcement of its transmission system to accommodate the connection of renewable energy generation facilities. CNP Transmission would then be required to implement such expansion or reinforcement in accordance with its approved plan. Looking ahead to when CNP Transmission is required to develop its plan, it may not be possible for CNP Transmission to provide the Board with a satisfactory plan for expansion or reinforcement to accommodate the connection of renewable generation facilities unless the reliability issues associated with the lack of N-1 contingency on the CNP Transmission System have by that point been addressed. Once the CNP Transmission System has N-1 contingency, through the implementation of the proposed Project, CNP Transmission would be in a position to then consider, in developing its plan, what expansion or reinforcement work might be needed so that the CNP Transmission System could better accommodate renewable energy generation facilities in support of the Province's policy objectives.

5. Ontario System-wide Needs

As explained beginning at page 10 of **Exhibit B, Tab 4, Schedule 1**, the Project would represent an improvement of at least 10% in the Niagara interface capacity with the NYISO-controlled grid. This additional intertie capacity would:

- Reduce capacity requirements for Ontario,
- Provide insurance against generation maintenance outages during shoulder seasons and in other circumstances,
- Allow for greater exports of surplus baseload generation, and
- Enhance opportunities for trade with New York.

In support of the need for increased intertie capacity, the IESO's December 2008 *Ontario Reliability Outlook* states the following with respect to the New York ties at Niagara:

> The import capability from New York via the two 345 kV and the two 230 kV interconnections at Niagara is often restricted by the thermal ratings of the existing transmission facilities of the QFW Interface. These limitations are even more pronounced during outage conditions. Completion of the reinforcement of this interface is necessary for improved utilization of the interconnection with New York at Niagara Falls.
>
> Once the QFW work is complete, it becomes appropriate to explore further expansion of the interface capability at Niagara. Since three of the eight river crossings at Beck GS are presently idle, these would appear to present an opportunity to establish an additional interconnection at this location. *Increasing the capability of this interface would address these limitations and further augment any future moves toward a more regional approach to balancing supply. This need will become even more prominent with increased renewable resources associated with variable operating characteristics*.[7] (emphasis added)

[7] IESO's December 2008 *Ontario Reliability Outlook*, page 15.

The same IESO report also notes, in relation to the challenges of surplus baseload generation, that:

> As more variable generation comes online, new tools and processes will be needed to balance this supply against other types of supply during periods of low demand. For example, high levels of wind generation during periods of low demand could create surplus baseload generation concerns. Surplus baseload generation currently occurs only a few times a year and is resolved through the rescheduling of outages to take advantage of these conditions, *or through increased exports*.[8] (emphasis added)

More recently, in it's *18-Month Outlook: From June 2009 to November 2010,* the IESO commented on the recent phenomenon of negative pricing due to surplus baseload generation, noting in particular the important role of export capacity in mitigating such circumstances:

> Prior to 2008, there had only been five instances of negative pricing in the province . . . So far from January to March 2009, there have been 58 instances of negative pricing with a new peak low of -$51.00; all of which occurred during the last week of March. The negative prices can be attributed to lower demand conditions and low-priced baseload generation. *The phenomenon was further exacerbated by a significant transmission outage which limited Ontario's ability to export. This outage resulted in a zero MW schedule with NY and a reduced scheduling limit with Michigan, limiting exports out of the province. The IESO, during these times, was required to dispatch down baseload generation that is not typically manoeuvred.*[9] (emphasis added)

The Project would assist in meeting these needs identified by the IESO. In addition, as discussed in **Exhibit B, Tab 4, Schedule 1**, with the expected surge in renewable resources with variable operating characteristics in Ontario arising from the *Green Energy and Green Economy Act, 2009*, the Project would represent a timely contribution to this recognized need for increased intertie capacity. Moreover, the Project offers additional protection against long-term supply

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[8] IESO, December 2008 *Ontario Reliability Outlook*, page 9.

[9] IESO, *18-Month Outlook: From June 2009 to November 2010*, pages 30-31.

shortages that could result, for instance, from delays in the availability of new resources within Ontario or from higher than anticipated load growth in the province.

APPENDIX A

Switching Procedure to Supply Fort Erie Load from the Emergency Tie Line

Switching Procedure to Supply Fort Erie Load from 46 Line

Purpose: In the event that a Section of 2 Line between Station #17 and Niagara Falls and or both A37N and A36N are defective for an extended period of time

(Last Revised May 1, 2008)

THESE INSTRUCTIONS SHOULD BE E-MAILED TO ALL FIELD STAFF INVOLVED WITH THESE SWITCHING OPERATIONS

☑	Seq. No	Apparatus Designation	Operation	Comments
	1.	Fort Erie Distribution Load	Confirm that Line 2 (115KV) is de-energized	Contact Hydro One at 1-866-384-4743 (Access Code 41135), Reason Code = 05*, Station Code =591#. Confirm with Hydro One operator estimated length of outage if outage is from Hydro One's side System Control Operator to notify CNP staff to assist at both Station #17 and Station #18
	2.		Prepare for load transfer	The System Control Operator will contact **IESO** at Clarkson at (905)-855-6410 and will contact **National Grid** at 1-315-460-2475 and will inform both that Fort Erie will be fed from 46 Line
	3.	Breaker 11R2, 11BP, Switch 1102 at Station #11	Open via SCADA and Check to be opened	Have CNP staff at Station #11 check open Breaker 11R2, 11BP, Switch 1102
	4.	Breaker R300	Open via SCADA and Check to be opened	Have CNP staff at Station #17 check Breaker R300 open
	5.	Breakers 17R5,17R9,17R8 & 17R67	Open via SCADA and Check to be opened	Have CNP staff at Station #17 check Breakers 17R5,17R9,17R8 & 17R67 open
	6.	Breakers 17R5,17R9,17R8 & 17R67	Via SCADA secure Hold-Off	System Control Operator to secure hold-off on Breakers 17R5,17R9,17R8 & 17R67
	7.	Switch 171 at Station #17	Open via SCADA and Check Open	Have CNP staff at Station #17 check switch 171 open

	8.	Switch 171 at Station #17	Lock and Tag	Have CNP staff at St. #17 de-clutch switch 171, Lock in the open position and place 'DO NOT OPERATE TAG"
	9.	Breaker R500	Open via SCADA and Check to be opened	Have CNP staff at Station #18 check Breaker R500 open
	10	Breakers 18R5,18R8,18 R10 & 18R11	Open via SCADA and Check to be opened	Have CNP staff at Station #18 check Breakers 18R5,18R8,18R10 & 18R11 open
	11.	Breakers 18R5,18R8,18 R10 & 18R11	Via SCADA secure Hold-Off	System Control Operator to secure hold-off on Breakers 18R5,18R8,18R10 & 18R11
	12	Station #17 Bank Tap Changer	Via SCADA, Place in Manual Mode	System Control Operator to place in manual mode
	13	Station #18 Bank Tap Changer	Via SCADA, Place in Manual Mode	System Control Operator to place in manual mode
	14.	43 By-Pass at Station #18	Close	Have CNP staff at Station #18 change 43 By-Pass switch from normal to 43-By-Pass
	15.	Switch 1801 at Station #18	Close via SCADA and Check Close	Have CNP staff at Station #18 check switch 1801 is closed
	16.	Breaker 18R2 at Station #18	Open via SCADA and Check Open	Have CNP staff at Station #18 check breaker 18R2 open
	17.	18R46 at Station #18	Close via SCADA and Check close	Have CNP staff at Station #18 check breaker 18R46 closed
	18.	Breaker 18R500 at Station #18	Close via SCADA and Check Close	Have CNP staff at St. #18 check breaker 18R500 close. (Station Service must be energized to operate taps)
	19.	Transformer Bank#1 at Station #18	Adjust voltage to 125 volts via SCADA	System Control Operator to Adjust voltage to 125 volts via SCADA
	20	Breakers 18R5,18R8,18 R10 & 18R11	Close via SCADA	System Control Operator check for load pick up on SCADA
	21.	Breakers 18R5,18R8,18 R10 & 18R11	Via SCADA surrender Hold-Off	System Control Operator to surrender hold-off on Breakers 18R5,18R8,18R10 & 18R11

	22.	Transformer Bank #1 at Station #18	Place tap Changer in Auto Mode via SCADA	Done by System Control Operator in Control Room.
	23.	Breaker 18R2 at Station #18	Close via SCADA and Check Close	Have CNP staff at Station #18 check breaker 18R2 close
	24.	Breaker 17R300 at Station #17	Close via SCADA and Check Close	Have CNP staff at Station #17 check breaker 17R300 is close. (Station Service must be energized to operate taps)
	25.	Transformer Bank#1 at Station #17	Adjust voltage to 125 volts via SCADA	System Control Operator to Adjust voltage to 125 volts via SCADA
	26.	Breakers 17R5,17R9,17R8 & 17R67	Close via SCADA	System Control Operator check for load pick up on SCADA
	27.	Breakers 17R5,17R9,17R8 & 17R67	Via SCADA surrender Hold-Off	System Control Operator to surrender hold-off on Breakers 17R5,17R9,17R8 & 17R67
	28.	Transformer Bank #1 at Station #17	Place tap Changer in Auto Mode via SCADA	Done by System Control Operator in Control Room.
	29	Meters	Record	Record start meter reading on 46 line for billing purposes
	30.	43 By-Pass at Station #18	Open	Have CNP staff at Station #18 change 43 By-Pass switch from 43-By-Pass to normal
	31.	Fort Erie Distribution Load	Notifications	The System Control Operator will contact Hydro One at 1-866-384-4743 (Access Code 41135), Reason Code = 05*, Station Code =591#, as well as the **IESO** at Clarkson at (905)-855-6410 and will contact **National Grid** at 1-315-460-2475 and will inform all that Fort Erie is now being fed from 46 Line

APPENDIX B

Switching Procedure to Supply Fort Erie Load from Line 2 when Emergency Tie Line is Engaged

Switching Procedure to Supply Fort Erie Load from 2-Line When Fed From 46-Line

Purpose: At this time, 46-Line can only be used under emergency circumstances. Once the Fort Erie load can be safely supplied from Station #11, the Fort Erie load must be transferred from 46-Line to 2-Line. This will be done at an agreed upon time when the Fort Erie load is minimal. Several wholesale customers will need to be warned in advance of the load transfer.

(Last Revised May 1, 2008)

THESE INSTRUCTIONS SHOULD BE E-MAILED TO ALL FIELD STAFF INVOLVED WITH THESE SWITCHING OPERATIONS

☑	Seq. No	Apparatus Designation	Operation	Comments
	1.	Fort Erie Distribution Load	Confirm that Line 2 (115KV) is de-energized	Contact Hydro One at 1-866-384-4743 (Access Code 41135), Reason Code = 05*, Station Code =591#. Inform them that CNPI will now be transferring the load back to 2-Line System Control Operator to notify CNP staff to assist at both Station #17 and Station #18
	2.		Prepare for load transfer	The System Control Operator will contact **IESO** at Clarkson at (905)-855-6410 and will contact **National Grid** at 1-315-460-2475 and will inform both that Fort Erie will be transferring from 46-Line to 2-Line
	3.	Station #17 Bank Tap Changer	Via SCADA, Place in Manual Mode	System Control Operator to place in manual mode
	4.	Station #18 Bank Tap Changer	Via SCADA, Place in Manual Mode	System Control Operator to place in manual mode
	5.	Breakers 17R5,17R9,17R8 & 17R67	Open via SCADA and Check to be opened	Have CNP staff at Station #17 check Breakers 17R5,17R9,17R8 & 17R67 open
	6.	Breakers 17R5,17R9,17R8 & 17R67	Via SCADA secure Hold-Off	System Control Operator to secure hold-off on Breakers 17R5,17R9,17R8 & 17R67
	7.	Breaker R300	Open via SCADA and Check to be opened	Have CNP staff at Station #17 check Breaker R300 open

	8.	Breakers 18R5,18R8,18 R10 & 18R11	Open via SCADA and Check to be opened	Have CNP staff at Station #18 check Breakers 18R5,18R8,18R10 & 18R11 open
	9.	Breakers 18R5,18R8,18 R10 & 18R11	Via SCADA secure Hold-Off	System Control Operator to secure hold-off on Breakers 18R5,18R8,18R10 & 18R11
	10.	Breaker R500	Open via SCADA and Check to be opened	Have CNP staff at Station #18 check Breaker R500 open
	11.	43 By-Pass at Station #18	Close	Have CNP staff at Station #18 change 43 By-Pass switch from normal to 43-By-Pass
	12.	Breaker 18R2 at Station #18	Open via SCADA and Check Open	Have CNP staff at Station #18 check breaker 18R2 open
	13.	18R46 at Station #18	Open via SCADA and Check open	Have CNP staff at Station #18 check breaker 18R46 open. contact **National Grid** at 1-315-460-2475
	14.	Switch 1801 at Station #18	Open via SCADA and Check Open	Have CNP staff at Station #18 check switch 1801 is Open
	15.	Switch 11-BP at Station #11	Check Open	Have CNP staff at Station #11 check switch 11-BP is Open
	16.	Switch 1102 at Station #11	Check Open	Have CNP staff at Station #11 check switch 1102 is Open
	17.	Breaker 11R2 at Station #11	Check Open	Have CNP staff at Station #11 check Breaker 11R2 is Open
	18.	Switch 1102 at Station #11	Close via SCADA and Check Close	Have CNP staff at Station #11 check switch 1102 is Closed
	19.	Switch 171 at Station #17	Remove Tag	Have CNP staff at St. #17 Unlock, re-couple switch 171, Remove 'DO NOT OPERATE TAG" and Lock in the open position
	20.	Switch 171 at Station #17	Close via SCADA and Check Closed	Have CNP staff at Station #17 check switch 171 closed
	21.	Breaker 11R2 at Station #11	Notify HONI and IESO before closing 11R2	Contact Hydro One at 1-866-384-4743 (Access Code 41135), Reason Code = 05*, Station Code =591#. The System Control Operator will contact **IESO** at Clarkson at (905)-855-6410

	22	Breaker 11R2 at Station #11	Close via SCADA and Check Closed	Have CNP staff at Station #11 check Breaker 11R2 is Open
	23	Breaker 17R300 at Station #17	Close via SCADA and Check Close	Have CNP staff at Station #17 check breaker 17R300 is close. (Station Service must be energized to operate taps)
	24	Transformer Bank#1 at Station #17	Adjust voltage to Normal Line 2 voltage via SCADA	System Control Operator to Adjust voltage to Normal Line 2 voltage via SCADA
	25	Breakers 17R5,17R9,17R8 & 17R67	Close via SCADA	System Control Operator check for load pick up on SCADA
	26	Breakers 17R5,17R9,17R8 & 17R67	Via SCADA surrender Hold-Off	System Control Operator to surrender hold-off on Breakers 17R5,17R9,17R8 & 17R67
	27	Transformer Bank #1 at Station #17	Place tap Changer in Auto Mode via SCADA	Done by System Control Operator in Control Room.
	28	Breaker 18R2 at Station #18	Close via SCADA and Check Close	Have CNP staff at Station #18 check breaker 18R2 close
	29	Breaker 18R500 at Station #18	Close via SCADA and Check Close	Have CNP staff at St. #18 check breaker 18R500 close. (Station Service must be energized to operate taps)
	30	Transformer Bank#1 at Station #18	Adjust voltage to 125 volts via SCADA	System Control Operator to Adjust voltage to 125 volts via SCADA
	31	Breakers 18R5,18R8,18R10 & 18R11	Close via SCADA	System Control Operator check for load pick up on SCADA
	32	Breakers 18R5,18R8,18R10 & 18R11	Via SCADA surrender Hold-Off	System Control Operator to surrender hold-off on Breakers 18R5,18R8,18R10 & 18R11
	33	Transformer Bank #1 at Station #18	Place tap Changer in Auto Mode via SCADA	Done by System Control Operator in Control Room.
	34	Meters	Record	Record stop meter reading on 46-Line for billing purposes

	35	43 By-Pass at Station #18	Open	Have CNP staff at Station #18 change 43 By-Pass switch from 43-By-Pass to normal
	36	Fort Erie Distribution Load	Notifications	The System Control Operator will contact Hydro One at 1-866-384-4743 (Access Code 41135), Reason Code = 05*, Station Code =591#, as well as the **IESO** at Clarkson at (905)-855-6410 and will contact **National Grid** at 1-315-460-2475 and will inform all that Fort Erie is now being fed from 2- Line

Exhibit B, Tab 4, Schedule 1

Project Benefits

PROJECT BENEFITS

1. Introduction

The Project, as described in **Exhibit B, Tab 2, Schedule 1**, will provide a parallel and continuous connection between the Ontario 115 kV transmission system and the New York system via the CNP Transmission System, which is described in **Exhibit B, Tab 1, Schedule 1**. This configuration will provide significant reliability benefits to the CNP Transmission System. The Project will also provide significant benefits to the Ontario electricity system by virtue of the resulting increased intertie capacity with New York at the 115 kV voltage level. After discussing the quantitative local reliability benefits and the quantitative intertie capacity benefits of the Project to Ontario, the final section of this Exhibit provides a discussion of the many significant qualitative benefits that are expected.

2. Quantitative Reliability Benefits

For each type of unplanned outage described on page 3 of **Exhibit B, Tab 3, Schedule 1**, the Project would prevent or significantly reduce the loss of load and eliminate the risk of the entire CNP Transmission System “going dark”. The Project would also prevent the system from going dark during certain planned maintenance outages. Because the system would no longer have to rely upon the “break-before-make” Emergency Tie Line as its source of contingency, once the Project comes into service, flows from New York would instantaneously replace any loss of service to the CNP Transmission System, thereby providing the CNP Transmission System with N-1 contingency.

The primary purpose of the Project, therefore, is to establish N-1 contingency for the CNP Transmission System in accordance with the Transmission System Code, NERC standards and established principles of good utility practice, thereby improving system reliability significantly. The Project would enable the CNP Transmission System to withstand an outage of a major element, including an outage to the Hydro One system from which it is exclusively supplied at present. In the event of such an outage, the Project would allow for the CNP Transmission System to be seamlessly supplied from New York, without the resource-intensive and lengthy process (during which the system remains dark) now needed to engage the Emergency Tie Line (See **Exhibit B, Tab 3, Schedule 1, Appendix A**). As noted, almost all of the historical outages shown in **Exhibit B, Tab 3, Schedule 1, Figure 3.2** would have been prevented had there been N-1 contingency on the CNP Transmission System.[1] Having this contingency would improve the performance and reliability of the system and ensure that a high level of system performance can be achieved on a consistent basis going forward.

Most importantly, the improved reliability that would result from the Project would bring significant benefits to end users. With respect to those benefits that can be quantified, there are two basic approaches available.

The first approach relates to establishing the value of lost load in relation to the average load on the CNP Transmission System. While this approach does not necessarily account for unique local circumstances, it does have the benefit of attributing a value to benefits that would otherwise not be easily quantifiable.

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[1] As noted in Exhibit B, Tab 3, Schedule 1, while all of the line outages related to line faults would have been completely avoided if the Project had been in place, terminal outages would have been mitigated such that the system as a whole would not have gone dark. The Project will enable CNP to isolate problems and perform the necessary repairs while the remainder of the system is energized continuously from either from Ontario or New York.

The second approach would be to attempt to identify key cost implications through a 'bottom-up' analysis of key end users and the costs they would expect to incur absent the Project. While this approach has the advantage of taking into account local circumstances, it does not provide sufficient breadth and ignores many of the expected benefits, particularly to residential end users and small businesses and institutions.

As set out below, the approach that has been adopted here has been to use the value of lost load as the basis for quantifying the local reliability benefits of the Project. Based on this methodology, conservatively applied, the quantitative reliability benefits expected from the Project have a net present value of $16.1 million. The results of 'bottom-up' calculations based on local circumstances are then used for comparison purposes to validate the value of lost load derived from industry literature.

(a) Value of Lost Load to Fort Erie

The average load on the CNP Transmission System is currently 36 MW (2009).[2] Average load is used here because it is the best measure of the average benefit related to improved reliability. Based on forecasts, the average load is expected to rise at a rate of 0.5% per year to 42.4 MW over the expected 30-year life of the Project (See **Exhibit B, Tab 3, Schedule 1, Figure 3.1**). The Project will provide 150 MW of supply capacity. In the analysis that follows, 36 MW (2009) plus annual growth is assumed to be for reliability purposes for Fort Erie[3] while the remaining capacity in each year is assumed to be for the benefit of the rest of Ontario[4]. As such, the Project would allow the average Fort Erie load in any given year to be served in

[2] The average load differs from the "monthly average peak load" of 48 MW, which is referred to elsewhere in this Application, including in Figure 3.1 of Exhibit B, Tab 3, Schedule 1.
[3] 36.7 MW in 2013, increasing to 42.4 MW in 2042.
[4] 113.3 MW in 2013, decreasing to 107.6 MW in 2042.

circumstances where such load would otherwise not be served due to a resource deficiency or supply failure affecting the CNP Transmission System. To provide a conservative estimate, the methodology is only applied to the average load of Fort Erie.

The value of lost load ("VoLL") is the average value that consumers place on one MWh of unsupplied energy based on the value of the commercial and personal opportunities lost due to one MWh of electricity not being delivered as expected. Based on a review of literature, we have assumed a VoLL of $10,000/MWh.[5] Because industry standards generally require electricity systems to be designed so that the probability of any area within that system having to disconnect firm load due to resource deficiencies is, on average, no more than one day in 10 years,[6] it is possible to estimate the value of added capacity, for system reliability reasons, provided by the Project. As shown in **Figure 4.1**, based on there being one day in 10 years that Fort Erie requires supply from an alternate source, and assuming a VoLL of $10,000/MWh, the expected cost that would be avoided by having the Project in place would be $24,000 per MW of demand. This assumes that 24 hours would be lost every 10 years. Based on this planning

[5] This value is in-line with the range of estimates reported in the literature. See: (1) Wacker, Garry and Roy Billinton. "Consumer Cost of Electric Service Interruptions," *Proceedings of the IEEE*, 77 (6), pp. 919 – 930, 1989, which reports results from a Canadian Preparatory Action study conducted in the early 1980's and reports estimates of the VoLL, during peak demand periods, of approximately $20000/MWh and $2500/MWh for business and residential consumers, respectively (year 2008 dollars); (2) Kariuki, K. K. and R. N. Allan. "Evaluation of Reliability Worth and Value of Lost Load," *IEE Proceedings, Generation, Transmission and Distribution*, 143, pp. 171 – 180, 1996, which reports the result of a British study conducted in 1993 and that estimates the energy-consumption-weighted-average of value of lost load to be greater than $20000/MWh; and (3) Willis, K. G. and G. D. Garrod. "Electricity Supply Reliability – Estimating the Value of Lost Load," *Energy Policy*, 25, pp. 97–103, 1997, which uses British data collected in 1996 and estimates the value of lost load to be approximately $10000/MWh.

[6] Northeast Power Coordinating Council, Document A-2, *Basic Criteria for Design and Operation of Interconnected Power Systems*, revised May 6, 2004 at Section 3.0 Resource Adequacy - Design Criteria: "Each Area's probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criteria shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

construct, reliability has a high value. The discounted net present value of these avoided costs over the 30-year life of the Project would be $16.1 million, assuming a real discount rate of 4.19%[7].

Figure 4.1 - Value of Lost Load (VoLL)

Value of Lost Load (VoLL)

Value of Lost Load (VoLL) Assumed value based on literature review (assume $ 2013)	A	**10,000**	**$/MWh**
Probability of disconnecting load due to resource deficiencies shall on average not be greater than 1 day (24 hours) in 10 years.	B	**24**	**hours**
Annual Probability (1 in 10 years)	C	**0.10**	
VoLL per MW (annual)	(A x B x C)	**$24,000**	**per MW**
CNPI Average Demand Growth Rate	0.5%		
Discount Rate (real)	4.19%		
Inflation Rate	2.0%		
CNPI WACC	6.27%		

Year	Project Year	CNP Avg Demand (MW)	VoLL per MW ($ 000's	VoLL ($ 000's	Present Value ($ 000's
2009		36.0			
2010		36.2			
2011		36.4			
2012		36.5			
2013	1	36.7	24	881	864
2014	2	36.9	24	886	833
2015	3	37.1	24	890	803
2016	4	37.3	24	895	775
2017	5	37.5	24	899	748
2018	6	37.7	24	904	721
2019	7	37.8	24	908	696
2020	8	38.0	24	913	671
2021	9	38.2	24	917	647
2022	10	38.4	24	922	624
2023	11	38.6	24	926	602
2024	12	38.8	24	931	581
2025	13	39.0	24	936	560
2026	14	39.2	24	940	541
2027	15	39.4	24	945	521
2028	16	39.6	24	950	503
2029	17	39.8	24	955	485
2030	18	40.0	24	959	468
2031	19	40.2	24	964	451
2032	20	40.4	24	969	435
2033	21	40.6	24	974	420
2034	22	40.8	24	979	405
2035	23	41.0	24	984	391
2036	24	41.2	24	989	377
2037	25	41.4	24	993	364
2038	26	41.6	24	998	351
2039	27	41.8	24	1,003	338
2040	28	42.0	24	1,008	326
2041	29	42.2	24	1,014	315
2042	30	42.4	24	1,019	304
				VoLL NPV $	**16,121**

7 The real discount rate of 4.19% assumes CNP Transmission's Weighted Average Cost of Capital (WACC) of 6.27% and 2.0% inflation.

(b) Local Costs of Service Interruption

To validate the results of the VoLL analysis, which determined the reliability benefit to Fort Erie to have a net present value of $16.1 million, it is helpful to consider the cost impacts of outages with regard to local circumstances through a bottom-up approach. Two local circumstances, discussed below, were considered - the costs of outages to local businesses that would have been avoided by the Project, as well as the costs to a certain group of residential end users in Fort Erie whose homes are uniquely susceptible to flooding during loss of power situations. This bottom-up approach identified total costs of $11.5 million that would be avoided if the Project is put in place and N-1 contingency is established ($8.7 million for local businesses and $2.7 million due to flooding).[8] This approach provides validation for the VoLL approach because, even with its narrow scope - which accounts only for the cost implications of outages to a sample of businesses and to one residential area in one particular type of circumstance - this bottom-up approach shows costs of $11.5 million. As this represents over 70% of the amount determined using the VoLL, it would not be unreasonable to assume that, if the bottom-up approach were expanded, costs would be shown to be in the range of the $16.1 million identified using the VoLL approach. As a result, the VoLL approach - which captures a far wider range of costs - is found to be a reasonable and appropriate means of quantifying the local benefits of the Project.

(i) Costs to Fort Erie Businesses

Figure 4.2(a) sets out the results of power interruption questionnaires completed by the larger industrial and commercial end users in Fort Erie.[9] These questionnaires asked businesses to estimate their costs in the event of an interruption to electricity service. For this selection of

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[8] Numbers do not add up due to rounding.
[9] Excluding retail businesses.

commercial and industrial businesses only, it is estimated that each momentary outage gives rise to over $22,000 in costs on average for the group. For each 30-minute outage, the estimated cost to these businesses rises to just over $80,000. For an outage of up to 4 hours, the estimated costs are nearly $275,000 and for an outage greater than 4 hours the costs are estimated at $1.6 million. These costs result, for instance, from impacts such as spoilage at a printing facility and lost production at a food processing facility. As shown from **Figures 4.2(b) and (c)**, when the probability of each outage event type (based on CNP's outage event history from 2002 to 2008, as shown in **Exhibit B, Tab 3, Schedule 1**, Figure 3.2) is applied to these costs, it is estimated that these businesses lose $464,000 annually (based on 2008 dollars). Assuming 2% inflation and no change in the amount of business outage costs, the net present value ("NPV") of these losses, which would be avoided over the 30-year life of the Project, is an estimated $8.7 million (See **Figure 2(c)**).

Figure 4.2 - Costs to Large Industrial and Commercial End Users in Fort Erie

4.2(a) Summary of Large Industrial and Commercial End User Survey Data

	Customer	Outage Duration Category & Cost ($ 2008)			
		Momentary	**30 minutes**	**4 hours**	**More than 4 hours**
1	AeroSafe	5,000	10,000	***10,000***	***10,000***
2	American Color	1,600	2,400	8,000	1,000,000
3	Canadian Gasket	-	1,220	9,685	19,370
4	Canadian Tire - *not quantified*				
5	DMI Industries	1,383	4,225	9,500	25,000
6	Durez Plastics	-	-	7,100	23,250
7	Eurocopter	3,800	3,800	30,000	***30,000***
8	Fleet		32,500	34,500	34,500
9	Fort Erie Race Track and Slots - *not quantified*				
10	Garrison Tool & Die		1,150	9,200	10,200
11	Metcor	150	6,450	15,600	21,600
12	Peace Bridge - *not quantified*	-			
13	Peninsula Alloy		2,750	55,000	255,000
14	Pharmetics	7,500	2,400	13,000	26,000
15	Rich Products		7,500	60,000	120,000
16	S&S Plastics - *not quantified*				
17	Sherwin Williams	3000	6000	12,500	25,000
18	Shur Grain - *not quantified*	-	-	-	-
A	**Outage Cost Sub-totals**	**22,433**	**80,395**	**274,085**	**1,599,920**

Note: sample survey of CNPI industrial and commercial electricity distribution customers (excludes residential and retail customer impacts)
Indicates assumed values ***(Italics and Bold)***

4.2(b) Calculation of Outage Costs

Year	Date	Outage Duration (Min)	Outage Event Categorization (Min)			
			Momentary (< 10 min)	30 minutes (< 60 min)	4 hours (up to)	More Than 4 Hours
2002	June 1	54		54		
2003	Oct. 15	75			75	
	Nov. 13	90			90	
2004	January 17	36		36		
	February 8	8	1 outage			
	February 22	6	1 outage			
	March 3	2	1 outage			
	March 16	27		27		
	March 22	18		18		
	March 26	106			106	
	July 1	50		50		
	August 8	278				278
2005						
2006	May 12	53		53		
	October 13	150			150	
	November 12	31		-		
	November 13	25		-		
2007						
2008						
Number of Events			**3**	**6**	**4**	**1**
B. Outage Event Probability (in any given year) (Number of events divided by 7 years of history)			**0.43**	**0.86**	**0.57**	**0.14**

Note : Planned outages of Nov 12 & 13, 2006 have been excluded for the purposes of this calculation i.e. customer cost impact would be minimized due to notification and scheduling during off peak hours

4.2(c) Net Present Value of Outage Costs

	Momentary Per Event	30 minutes	4 hours	More than 4 hours	Total
A. Outage Cost	22,433	80,395	274,085	1,599,920	
B. Outage Event Probability	0.43	0.86	0.57	0.14	
Outage Cost per Year (A x B)	**$ 9,614**	**$ 68,910**	**$ 156,620**	**$ 228,560**	**$ 463,704**

Net Present Value of Customer Outage Costs		
Inflation Rate	2.0%	
Discount Rate (CNPI WACC)	6.27%	
Real Discount Rate	4.19%	
Project Life	30 years	
Outage Cost per Year	**$ 2008**	**$ 463,704**
	$ 2013	**$ 511,967**
Net Present Value of Annual Outage Costs		**$ 8,746,921**

(ii) Costs to Fort Erie Residents

Due to the difficulty of quantifying the costs of outages to all affected residential end users, it is only the costs of a unique group of residential end users in a unique set of circumstances that has been considered. Specifically, in October 2006 a lengthy outage led to flooding in two particular residential areas within Fort Erie, which are ultimately served by CNP's Transmission System. This circumstance provides a means for estimating the quantitative impact of one type of potential harm to residential customers of a service interruption. What is unique about these two residential areas is that they are prone to flooding. Drainage for these neighbourhoods is provided by municipal pump stations and force mains. When a major storm event coincides with a power outage, as it did in October 2006, these neighbourhoods are without drainage and homes become susceptible to flooding as residential sump pumps are also without power.

The maximum potential amount of flood damages that could reasonably be claimed as a result of a single recurrence of such a flood, and which costs would therefore be avoided upon the Project coming into service, is estimated at $14.5 million. This figure is based on there being a total of 1450 residences in these susceptible communities and data indicating that the average claim for each residence that made a claim following the 2006 event was $10,000. It is conservatively estimated that such a coincidence of events leading to such losses would occur only one time within 100 years, which gives rise to a present value cost over the 30-year period of approximately $2.7 million. Based on information obtained from the Insurance Bureau of Canada, the assumption that each claim would be for $10,000 is also conservative.[10]

[10] According to the Insurance Bureau of Canada, severe rains in the Greater Toronto Area in August 2005 resulted in over 13,000 sewer backup claims, for which insurers paid out an average of nearly $19,000 per claim. Severe rains in Edmonton in July 2004 resulted in approximately 9,500 sewer backup claims, for which insurers paid out an average of nearly $15,500 per claim. Finally, flooding in Peterborough in 2004 resulted in over 5,000 claims, for which insurers paid out an average of nearly $17,000 per claim.

3. Quantitative Intertie Capacity Benefits to Ontario

The Project is rated to provide 150 MW of intertie capacity in both directions at the Niagara interface with New York. In addition, the Project could provide an incremental 100 MW of intertie capacity on the Niagara ties in certain circumstances, therefore resulting in a total of 250 MW of intertie capacity being added to Ontario.[11] Based on the normal circumstances where the Project provides 150 MW of additional intertie capacity, this would represent an improvement of approximately 10% in the Niagara interface capacity with the NYISO-controlled grid. The need for this additional intertie capacity, which is recognized by the IESO, is discussed beginning on page 16 of **Exhibit B, Tab 3, Schedule 1**. As will be discussed below, the increased intertie capacity provided by the Project would:

- Reduce capacity requirements for Ontario,
- Provide insurance against generation maintenance outages during shoulder seasons and in other circumstances,
- Allow for greater exports of surplus baseload generation, and
- Enhance opportunities for trade with New York.

The benefits related to reduced capacity requirements and insurance against generation maintenance outages, both of which CNP has been able to quantify, would provide benefits with an estimated total value of $39.9 million, as explained below. Benefits related to the export of surplus baseload generation and opportunities for trade with New York are discussed in the context of qualitative benefits beginning at page 15 of this **Exhibit B, Tab 4, Schedule 1**.

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[11] See Part 5 of *System Reliability Impact Study* (SRIS) *for Fortran Project of Canadian Niagara Power* (February 2009), at Exhibit B, Tab 12, Schedule 2.

(a) Reliability and Adequacy / Avoided Generation Capacity Costs

One way to value the reliability improvements that would result from the additional intertie capacity provided by the Project is to determine the cost of building equivalent new generating capacity. In this analysis, such additional generating capacity represents an alternative means of providing similar system-wide reliability benefits as provided by the Project. The cost of meeting the need for increased reliability through the development of new generating capacity can then be considered in the analysis as a cost that could be *avoided* by instead choosing to meet this need for increased system-wide reliability through development of the Project.

The methodology used to value the avoided capacity requirements employs the OEB's *Guidelines for Electricity Distributor Conservation and Demand Management* (the "CDM Guidelines"). The CDM Guidelines provide a basis for local electricity distribution companies (LDCs) in Ontario to measure the feasibility of CDM initiatives for approval by the OEB. Among other values, the CDM Guidelines include a forecast of avoided costs for generation capacity on a $/kW basis, forecast to the year 2025.[12] This set of data applies to initiatives that provide capacity benefits only (with no avoided energy savings). The figures used from the CDM Guidelines assume a load factor of 5%, which is consistent with the expected load factor of the intertie. Attachment 1 from the CDM Guidelines is presented in **Figure 4.3**, below.

[12] Ontario Energy Board, *Guidelines for Electricity Distributor Conservation and Demand Management*, EB-2008-0037, March 28, 2008, Attachment 1 - "Avoided Cost of Energy, and of Generation, Transmission and Distribution Capacity", Column M.

Figure 4.3 - Avoided Cost of Generation Capacity - Attachment 1 of CDM Guidelines

Avoided cost of Generation Capacity

Source: Avoided Cost of Energy, and of Generation, Transmission and Distribution Capacity - March 28, 2008, Attachment 1
http://www.oeb.gov.on.ca/documents/cases/EB-2008-0037/Avoided_Costs_20080328.pdf

a	*b*	*c*	*d*	*e*	*f*	*g*	*h*	*i*	*j*	*k*	*l*	*m*
	Energy								Avoided	Avoided	Avoided	Avoided
	Winter			Summer			Shoulder		Generation	Transmission	Distribution	Capacity
Year	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak	(CAD$/kW-yr)	(CAD$/kW-yr)	(CAD$/kW-yr)	(CAD$/kW-yr)
2006	120.8	83.9	45.4	112.9	81.4	47.5	84.2	42.3	0	0	0	0
2007	124.6	84.3	45.2	111.5	79.6	45.9	81.4	40.8	0	0	0	0
2008	115.4	86.8	48.9	110.6	83.6	50.1	90.4	44.9	74.65	5.62	0	144.84
2009	111.9	77.1	48.9	104.5	79.5	47.6	85.8	43.4	83.57	5.76	0	146.7
2010	113.5	77.4	52.1	107	80.5	48.2	83.5	43.4	71.49	5.9	0	148.55
2011	110.2	77.3	52.7	103.2	81.3	48.5	84.2	43	85.42	6.05	0	150.41
2012	112.4	78.9	53.3	113.1	84.6	51.2	88.5	47.8	81.2	6.2	0	152.27
2013	125.2	86.4	59.9	116.9	91.3	54	92.5	51.9	61.6	6.36	0	**154.25**
2014	125.7	92.4	62.8	127.9	96.8	56.7	98.9	54.4	46.63	6.52	0	**156.23**
2015	127.4	94.7	69.6	151.6	106.7	62.5	102.8	59.9	23.16	6.68	0	**158.22**
2016	131.7	97.3	70.9	152.5	108.1	63.9	104.5	61.4	26.88	6.85	0	**160.21**
2017	136	100	72.1	153.5	109.5	65.3	106.2	62.8	29.94	7.02	0	**162.33**
2018	140.3	102.7	73.4	154.4	110.9	66.8	108	64.3	31.66	7.19	0	**164.32**
2019	144.6	105.4	74.6	155.3	112.3	68.2	109.7	65.7	32.41	7.37	0	**166.59**
2020	148.9	108.1	75.9	156.3	113.6	69.6	111.4	67.2	31.85	7.56	0	**168.73**
2021	152.4	110.4	78	157.1	116.5	71.5	114.7	69.1	38.27	7.74	0	**170.87**
2022	155.8	112.7	80	157.9	119.4	73.4	117.9	71	41.97	7.94	0	**173.16**
2023	159.3	115	82.1	158.7	122.4	75.3	121.1	72.9	44.22	8.14	0	**175.46**
2024	162.7	117.3	84.2	159.5	125.3	77.2	124.3	74.8	44.56	8.34	0	**177.77**
2025	166.1	119.7	86.3	160.3	128.2	79.1	127.5	76.7	42.02	8.55	0	**180.08**

For measures which provide summer on-peak period demand response but no energy savings,
distributors should use the avoided generation capacity values in column M only.

Inflation of 2.5% - see note 1 on Attachment 1

It is reasonable to use the CDM Guidelines for the purposes of valuing the avoided generation capacity benefit of the Project because the Project has the potential to provide incremental reductions in system-wide capacity requirements similar to CDM initiatives. This similarity arises from the fact that neither CDM programs nor the Project are equivalent in impact to the construction of a physical generation facility located in Ontario.

Based on the CDM Guidelines, the net present value ("NPV") of the avoided generation costs for 150 MW of generation capacity over the life of the project is $365.6 million. For purposes of valuing the Project the avoided generation costs from the CDM Guidelines have been reduced by a highly conservative factor of 90%, which, as shown in **Figure 4.4**, results in a NPV of the avoided generation costs for 150 MW of generation capacity over the life of the project of $36.5 million.

Figure 4.4 - Calculation of Avoided Generation Capacity Benefit

Calculation of Avoided Generation Capacity Benefit

Capacity of Intertie 150 MW
Discount Rate 6.27%

Year	Project Year	Avoided * Capacity (CAD$/kW-yr)	% ** Change	Avoided Capacity MW	Value of Avoided Generation	Present Value ($ 000's
2013	1	154.25	-	150	23,138	22,444
2014	2	156.23	1.3%	150	23,435	21,391
2015	3	158.22	1.3%	150	23,733	20,385
2016	4	160.21	1.3%	150	24,032	19,423
2017	5	162.33	1.3%	150	24,350	18,519
2018	6	164.32	1.2%	150	24,648	17,640
2019	7	166.59	1.4%	150	24,989	16,828
2020	8	168.73	1.3%	150	25,310	16,038
2021	9	170.87	1.3%	150	25,631	15,283
2022	10	173.16	1.3%	150	25,974	14,574
2023	11	175.46	1.3%	150	26,319	13,896
2024	12	177.77	1.3%	150	26,666	13,248
2025	13	180.08	1.3%	150	27,012	12,628
2026	14	*182.42*		150	27,363	12,037
2027	15	*184.79*		150	27,718	11,474
2028	16	*187.19*		150	28,078	10,937
2029	17	*189.62*		150	28,443	10,425
2030	18	*192.08*		150	28,812	9,938
2031	19	*194.57*		150	29,186	9,473
2032	20	*197.10*		150	29,565	9,029
2033	21	*199.66*		150	29,949	8,607
2034	22	*202.25*		150	30,338	8,204
2035	23	*204.88*		150	30,732	7,820
2036	24	*207.54*		150	31,131	7,454
2037	25	*210.24*		150	31,535	7,105
2038	26	*212.97*		150	31,945	6,773
2039	27	*215.73*		150	32,360	6,456
2040	28	*218.53*		150	32,780	6,154
2041	29	*221.37*		150	33,206	5,866
2042	30	*224.25*		150	33,637	5,591
		Average (2013 to 2025)	1.3%			
					Generation Capacity NPV $	**365,643**
					Capacity Derating	**90%**
					Generation Capacity NPV for Project Valuation	**36,564**

Notes:
* Source: Avoided Cost of Energy, and of Generation, Transmission and Distribution Capacity - March 28, 2008, Attachment 2, for values to year 2025

** % Change - average from 2013 to 2025 used to forecast avoided capacity for years 2026 to 2042

(b) Generation Maintenance Outages

The increased intertie capacity provided by the Project would also help relieve constraints during shoulder seasons when generation facilities may not be available due to maintenance activities. These constraints occur during peak periods in shoulder seasons when planned generation maintenance outages take place. At these times, the remaining generating capacity in Ontario may not be sufficient to meet peak demand and, as a result, the ability for Ontario generators to undertake maintenance activities can be constrained. The Project would help relieve this constraint by allowing for a higher level of imports, thereby enabling Ontario generators to implement improved maintenance schedules. Improved maintenance schedules help prevent damage to generation facilities and lower the probability of forced outages, along with all of the adverse impacts associated with such forced outages. As shown in **Figure 4.5**, the value of this benefit is estimated at $179,110 per year (2008 dollars), which has an estimated NPV of $3.4 million over the 30-year life of the Project. This calculation assumes that cost savings can be realized for an average of eight hours per day, 20 days per year. The hourly cost savings of $7.46 per MWh is based on the average price differential of the hourly Ontario energy price ("HOEP") between April and June, over the past five years.

Figure 4.5 - Generation Maintenance Outage Benefits

Generation Maintenance Benefit

Estimated value of an additional 150 MW of intertie capacity during spring and fall maintenance (additional insurance)

Assume:	Utilized 4 weeks per year (weekdays only)				20	days
	Hours per day				8	hours
	Total Hours			**A**	**160**	**hours per year**

Summary of HOEP Price Differential (April to June)

Year	April	June	Difference			
2009	$ 32.63	$ 34.06	$ 1.42			
2008	$ 70.00	$ 84.97	$ 14.97			
2007	$ 61.68	$ 67.92	$ 6.24			
2006	$ 60.39	$ 61.05	$ 0.66			
2005	$ 75.38	$ 89.40	$ 14.02			
Average				**B**	**$ 7.46**	**$ / MWh**
Intertie Capacity				**C**	**150**	**MW**
Annual Value (A x B x C)					**$ 179,110**	**per Year ($ 2008)**
					$ 197,752	**per Year ($ 2013)**

Present Value of Generation Maintenance Benefit

Inflation Rate	2.0%	
Discount Rate (CNPI WACC)	6.27%	
Real Discount Rate	4.19%	
Project Life	30	years

Net Present Value of Annual Outage Costs **$ 3,378,586**

4. Qualitative Benefits

In considering the Project, there are a host of important qualitative factors that merit attention. Most of these qualitative benefits arise from the increased intertie capacity provided by the Project and, therefore, are to the benefit of the Ontario electricity system as a whole.

(a) Outages to the Peace Bridge

One unique entity that is impacted by outages to the CNP Transmission System is the Buffalo and Fort Erie Public Bridge Authority, which is responsible for operating and maintaining the Peace Bridge that connects Buffalo, New York to Fort Erie, Ontario. The Peace Bridge is a critical infrastructure link for trade and includes facilities where immigration, security and trade requirements, among other matters, are administered for both Canada and the United States. During outage events to the CNP Transmission System, the ability of Canadian authorities to carry out their duties on the Fort Erie side of the bridge is adversely and significantly affected. One impact of an outage is the delay of truck traffic until electricity service resumes. The delay of truck traffic gives rise to direct costs for truck owners and operators, as well as indirect costs to the economy as a whole on both sides of the border due to delays in the movement of goods.

The direct costs to truck owners and operators can be understood in part using the findings of a study by Transport Canada, which estimates the cost of delay at $60-$75 per truck per hour (2005 dollars).[13] This accounts for the costs of the drivers and the trucks, including fuel, but has no regard for the value of the goods that are on-board. While it may be possible to quantify the impact of outages on truck drivers and operators based on available figures of truck traffic at the Peace Bridge, because these costs do not fall to Ontario ratepayers it is more appropriate to consider these costs on a qualitative basis. Nevertheless, to demonstrate the magnitude of the impact, it is worth noting that current truck traffic on the Peace Bridge travelling into Fort Erie is approximately 800,000 trucks per year. This is forecast to increase between 2-3% per year up to approximately 1.5 million trucks per year in 30 years.

With respect to the indirect costs to the economy as a whole of power outages affecting the Peace Bridge, while it is possible to quantify these costs to an extent and the numbers are informative, it is more appropriate to consider these costs from a qualitative perspective. The environmental assessment for a proposed new Peace Bridge states that “in 2005, exports via truck (using all area bridges) to Canada passing through the Port of Buffalo-Niagara Falls customs district totaled US$28.7 billion. Imports from Canada via truck totaled US$24.9 billion,

[13] Transport Canada. *The Cumulative Impact of U.S. Import Compliance Programs at the Canada/U.S. Land Border on the Canadian Trucking Industry* (Final Report), May 24, 2005 (prepared by DAMF Consultants Inc. in association with L-P Tardif & Associates Inc. for Transport Canada), p. 34.

for a total trade value of close to US$54 billion. The Peace Bridge accounts for 57% of the total commercial traffic along the Niagara Frontier bridge crossing options, equating to US$30.6 billion in total trade value annually."[14] Based on these figures, it can be estimated that total trade across the Peace Bridge is valued at approximately US$82 million per day or US$3.4 million per hour, which works out to approximately US$57,000 per minute. While the value of this trade is not the same as the cost or value of delays in the movement of goods, the data provides an indication of the importance of this facility to the broader economy, the potential impacts of an outage affecting the flow of such goods and the importance of ensuring reliable electricity supply to this critical facility.

(b) Eliminating Interruptions for CNP Planned Maintenance Outages

The Project would eliminate the need to impose system-wide service interruptions in order for CNP Transmission to implement planned maintenance outages. The two such planned maintenance outages in November 2006 were each approximately 30 minutes in duration due to the break-before-make configuration of the system (See **Exhibit B, Tab 3, Schedule 1, Figure 3.2**). While CNP Transmission strives to mitigate the impacts of such outages by scheduling them, when possible, late at night, they do have cost and operational impacts for businesses whose operations are 24-hours per day[15] and represent a significant inconvenience to businesses and residential end users within Fort Erie. In addition, there is a significant amount of time and effort involved in planning and preparing for such outages due to the need to coordinate

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[14] Buffalo and Fort Erie Peace Bridge Authority, *Peace Bridge Expansion Project - Capacity Improvements to the Peace Bridge, Plazas and Connecting Roadways*, Draft Design Report, Draft Environmental Impact Statement, Appendix G - Socioeconomic Report (prepared by Ecology and Environment, Inc.), September 2007, p. 4.

[15] These include a major food products producer, a casino, an aerospace company, water and wastewater treatment facilities, various restaurants, retail stores and gas stations, as well as the Buffalo and Fort Erie Public Bridge Authority in respect of the Peace Bridge.

activities with the IESO, Hydro One and USNG. By eliminating the system-wide service interruptions in order to implement planned maintenance outages on the CNP Transmission System, resources at CNP and these other entities could instead maintain their focus on core functions and priorities.

(c) **Insurance Against Supply Shortages**

With respect to long-term supply needs, the increased intertie capacity provided by the Project would provide some increased protection against potential delays in the availability of new resources within Ontario, or against higher than anticipated load growth in the province. Ontario's long-term electricity system plans include various assumptions, including with respect to the timing of projects coming on line and projections of load growth. While difficult to quantify, in the event these assumptions and projections do not prove correct then, to the extent that such inaccuracies result in supply deficiencies beyond the in-service date of the Project, Ontario would benefit from having the protection afforded by the additional 150 MW of intertie capacity provided by the Project.

With respect to short-term supply needs, the increased intertie capacity provided by the Project would also provide some increased protection against unexpected reductions in Ontario-based generation supply, such as which might result from renewable energy facilities with intermittent sources (i.e. wind). With the recent emphasis in the *Green Energy and Green Economy Act, 2009* on expanding such generation with intermittent sources, the importance of this benefit is expected to grow over the life of the Project (See excerpts from IESO reports on pp. 16-17 of **Exhibit B, Tab 3, Schedule 1**).

(d) **Facilitating Surplus Baseload and Renewable Generation Exports**

In times of low Ontario demand, the additional intertie capacity provided by the Project would allow for greater exports of electricity to New York to take place relative to current tie line limitations. This provides the IESO with incremental flexibility to manage situations where there is a surplus of either baseload or renewable generation. The need for additional export capacity in Ontario is evident in the market price for electricity, which was negative on a number of occasions during the spring of 2009. Baseload generators will typically offer negative electricity prices into the market to ensure they will be dispatched at a constant level of output and will not be required to cycle on and off. The negative prices for electricity represent situations where demand has fallen below the level of supply from baseload generators. Such a situation may arise in circumstances where renewable generation sources provide electricity supply at times where such supply is not needed. In these circumstances, the excess baseload generation, or the excess renewable supply, will need to be evacuated from Ontario. Given the recent passing of the *Green Energy and Green Economy Act, 2009* which is designed to facilitate the Province of Ontario's desire to increase intermittent generation such as wind and solar power, the increased operating flexibility furnished by the Project will provide incremental benefits.

(e) **Facilitating Trade with New York**

Interties between Ontario and New York are often congested. The additional intertie capacity with New York would provide benefits associated with the possibility of increased trade between Ontario and New York.

(f) **Maximizing Use of Existing Land and Infrastructure**

As described in **Exhibit B, Tab 2, Schedule 1**, the Project involves the replacement and reinforcement of certain existing lines and the installation of certain new equipment at existing stations. It is not expected that any new transmission towers or lands would be required. As such, the Project maximizes the use of existing infrastructure while minimizing costs and impacts on the community. By employing existing land and infrastructure, CNP Transmission does not reasonably anticipate material concerns about adverse impacts on stakeholders. From a regulatory and permitting perspective, these characteristics of the Project can be very significant.

(g) **Comparatively Few Regulatory Risks**

The Project would make use of existing lands and optimize the use of existing infrastructure in order to provide all of the benefits described above to Fort Erie and to Ontario. It is a unique situation that allows such significant benefits to be realized without requiring additional lands or rights of way, without affecting people or their communities and without environmental impacts. While the need for other regulatory approvals is discussed in **Exhibit B, Tab 7, Schedule 1**, it is sufficient to state here that these characteristics are expected to assist the Project in obtaining all necessary approvals on a timely basis and in minimizing the environmental approvals required for the project.

(h) **Comparatively Inexpensive New Intertie Capacity**

Relative to the cost of other recent large-scale intertie developments in Ontario, the Project would provide a low-cost supply of intertie capacity for the province. In particular, a 1250 MW transmission intertie between Ontario and Quebec near Ottawa is scheduled for completion in

2010. This project is being undertaken jointly by Hydro One and Hydro-Québec TransÉnergie. As reported by the Ministry of Energy and Infrastructure on its website, this project requires investments of $124 million by Ontario and $684 million from Quebec, for a total project cost of $808 million,[16] or $646,000 for each megawatt of new intertie capacity. By comparison, CNP Transmission's proposed intertie with New York at Fort Erie/Buffalo carries an estimated cost of $206,000 for each megawatt of new intertie capacity.

[16] See http://www.mei.gov.on.ca.wsd6.korax.net/english/energy/electricity/index.cfm?page=transmission-projects.

Exhibit B, Tab 5, Schedule 1

Project Costs, Rate Impact and Treatment

PROJECT COSTS, RATE IMPACT AND TREATMENT

1. Project Costs

The estimated costs of the Project are as set out in **Figure 5.1**.[1] The amounts set out in Figure 5.1 are broken down by project component, as per the description of the Project in **Exhibit B, Tab 1, Schedule 1**. The amount shown for each project component reflects the estimated future costs of materials, labour, engineering, project management, owner's administration and contingency.[2] The project cost estimates are based on pre-engineering work, which was undertaken to allow for project development and the preparation of estimates.

With respect to the costs shown in Figure 5.1 for the construction of a three-breaker ring station and the removal and replacement of approximately 10 km of conductor from Huntley Station to Paradise Station, these costs are based on preliminary, good faith estimates from USNG and are subject to more detailed engineering and negotiation. These USNG estimates were made in US currency and have been converted to Canadian dollars for purposes of Figure 5.1.

[1] In addition to the items listed in Figure 5.1, the NYISO has suggested that CNP Transmission also install a 30 MVA capacitor bank at Station #18 for purposes of controlling voltage. This was not identified by the IESO or Hydro One as being required for any reason and CNP does not believe this work will be necessary. However, this will not be confirmed until the detailed engineering phase of the Project. If this work is required, it would be estimated to cost $400,000.

[2] The costs listed as "Project development costs" in Figure 5.1 reflect costs already incurred in the development stage of the Project.

Figure 5.1 - Estimated Project Costs

Project Component	Cost (Million CAD $)
Project development costs	1.1
Reinforcement of 2.0 km of line sections from Murray Tap to Station #11 (forming lines A36 and A37)	Included in Station #11 costs, below
Installation of one additional breaker and disconnect switches near Station #11 (and reinforcement of 2.0 km of line sections)	2.9
Installation of two additional breakers and disconnect switches at Station #17	1.9
Installation of a 150 MVA phase shifting transformer and voltage regulator at Station #18	8.8
Replacement of 0.5 km of conductor from the Bertie Hill Tower to the Queen Street Tower, and 0.66 km of conductor from the Queen Street Tower across the Niagara River to the High Tower	0.2
Construction of a three-breaker ring station near Switch 998[3]	6.0
Removal and replacement of approximately 10 km of conductor from Huntley Station to Paradise Station[4]	10.0
Total	**$30.9**

2. Positive Net Present Value

As shown in **Figure 5.2**, the Project has a positive NPV of $10,367,499. This is based on a comparison of the NPV of the rate impact to the Transmission Network Pool over the life of the Project (see **Appendix A**) against the NPV for the reliability benefits to the CNP Transmission

[3] US $5.75M @ 1.05% (CIBC forecast average rate for 2011, as of July 14, 2009) = CAD $6.0375 million.
[4] US $9.5M @ 1.05% (CIBC forecast average rate for 2011, as of July 14, 2009) = CAD $9.975 million.

System and the NPV for the system-wide benefits of the Project for Ontario.[5] The reliability and system-wide benefits of the Project are discussed in **Exhibit B, Tab 4, Schedule 1**. Moreover, the positive NPV for the Project does not take into account the numerous qualitative benefits associated with the Project, which are also described in **Exhibit B, Tab 4, Schedule 1**.

Figure 5.2 Calculation of the Project Net Present Value

Net Present Value (NPV) of Costs and Benefits	**Proposed Project "N-1" Intertie to NYISO**	
1. Transmission Network Pool Rate Impact (cost)		**$ (45,695,988)**
2. Customer Avoided Costs (CNPI Customers)		
VoLL for CNPI Customers		**$ 16,120,647**
Sub-total		**$ (29,575,340)**
3. Intertie Benefits (Ontario)		
Reliability and Adequacy (avoided generation capacity)	$36,564,254	
Generation Maintenance Benefit	$ 3,378,586	**$ 39,942,839**
NPV Total		**$ 10,367,499**

3. **Proposed Rate Treatment**

CNP Transmission proposes that the Project costs, including the capital contribution that CNP Transmission will make to USNG to cover the costs of the three-breaker ring station and the rebuild of lines L46 and L47, be ultimately added to rate base and recovered through the network charge of the Uniform Transmission Rates. The Project relates to network assets and is necessary in order for CNP Transmission to maintain compliance with its obligations as a

[5] As shown in Appendix A, the discount rate used is 6.27%, which is the after tax weighted average cost of capital for CNP Transmission.

licenced electricity transmitter, in particular its obligations under the Transmission System Code and NERC requirements that are incorporated by reference into the Code. In addition, the Project gives rise to a wide range of significant, system-wide benefits and helps the CNP Transmission System achieve the level of reliability that will be necessary to support the future connection of renewable generation facilities arising from the Province's *Green Energy and Green Economy Act* and related initiatives.

4. Rate Impact

As shown in **Appendix A**, CNP Transmission's revenue requirement would increase by an average of $3.2 million per year over the life of the Project, with a maximum revenue requirement increase of $3.95 million expected in 2014. The NPV of the transmission rate impact over the life of the Project would be approximately $46 million. As a percentage of the existing Transmission Network Pool revenue requirement, the Project would represent an average increase over the entire Project life of 0.48%. In terms of the actual rate impact of the Project, based on the currently approved Network load of 258,509 MW, it is expected that Network rates would increase by an average of 1.2 cents per kilowatt, per month, over the life of the Project. As shown in **Figure 5.3**, the expected impact of the Project on a typical residential customer would be 2.7 cents per month, which represents an estimated increase of 0.024%.

Figure 5.3 Impact on a Typical Residential Customer Bill

	Existing Rates	%	Estimated Rate Increase	%
Electricity	$59.43	51.5%	$59.43	51.5%
Transmission	**$9.24**	**8.00%**	**$9.26**	**8.02%**
Distribution	$27.84	24.1%	$27.84	24.1%
Regulatory Charges	$6.78	5.9%	$6.78	5.9%
Debt Retirement Charge	$6.66	5.8%	$6.66	5.8%
GST	$5.50	4.8%	$5.50	4.8%
Total	**$115.45**		**$115.48**	
Cost Impact - $ per month			**$0.027**	
Cost Impact - %			**0.024%**	

Note: calculation based on levelized rate impact

APPENDIX A

Calculation of the Rate Impact of the Project

Transmission Network Pool Rate Impact

($ 000's)

Revenue Sufficiency (deficiency)		1	2	3	4	5	6	7	8	9	10	15	20	25	30
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2027	2032	2037	2042
Investment Carrying Costs															
Rate Base		16,066	31,579	30,471	29,363	28,255	27,147	26,039	24,931	23,823	22,715	17,174	11,634	6,094	554
LT Debt Component of Rate Base	56.0%	8,997	17,684	17,064	16,443	15,823	15,202	14,582	13,961	13,341	12,720	9,618	6,515	3,413	310
ST Debt Component of Rate Base	4.0%	643	1,263	1,219	1,175	1,130	1,086	1,042	997	953	909	687	465	244	22
Equity Component of Rate Base	40.0%	6,427	12,631	12,188	11,745	11,302	10,859	10,415	9,972	9,529	9,086	6,870	4,654	2,438	222
Return o LT Debt Cost	7.62%	686	1,348	1,300	1,253	1,206	1,158	1,111	1,064	1,017	969	733	496	260	24
ST Debt Cost	1.33%	9	17	16	16	15	14	14	13	13	12	9	6	3	0
Equity	8.01%	515	1,012	976	941	905	870	834	799	763	728	550	373	195	18
Return on Rate Base	**7.52%**	**1,209**	**2,376**	**2,293**	**2,209**	**2,126**	**2,043**	**1,959**	**1,876**	**1,793**	**1,709**	**1,292**	**875**	**459**	**42**
Cost of Service - after tax															
Add Operating & Maintenance x (1 - t)		307	307	307	307	307	307	307	307	307	307	307	307	307	307
Federal Capital Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Provincial Capital Taxes x (1 - t)		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Municipal Tax - Grants in Lieu x (1 - t)		75	149	149	149	149	149	149	149	149	149	149	149	149	149
Depreciation & Amortization		1,108	1,108	1,108	1,108	1,108	1,108	1,108	1,108	1,108	1,108	1,108	1,108	1,108	1,108
Less CCA tax shield		-386	-740	-681	-627	-576	-530	-488	-449	-413	-380	-250	-165	-109	-72
Interest tax shield		-201	-396	-382	-368	-354	-340	-326	-312	-298	-285	-215	-146	-76	-7
Revenue Requirement - after tax	**Sub-total**	2,112	2,804	2,794	2,779	2,760	2,737	2,709	2,679	2,645	2,609	2,391	2,129	1,838	1,527
Revenue Requirement - before tax		**2,974**	**3,950**	**3,936**	**3,914**	**3,887**	**3,854**	**3,816**	**3,773**	**3,726**	**3,675**	**3,368**	**2,999**	**2,588**	**2,151**
Incremental Project Revenue		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sufficiency (deficiency)		**-2,974**	**-3,950**	**-3,936**	**-3,914**	**-3,887**	**-3,854**	**-3,816**	**-3,773**	**-3,726**	**-3,675**	**-3,368**	**-2,999**	**-2,588**	**-2,151**
Average		-3,205													
NPV of Transmission Rate Impact @	6.27%	**-45,998**													

Rate Impact		Base Year[1]	1	2	3	4	5	6	7	8	9	10	15	20	25	30
			2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2027	2032	2037	2042
Revenue Requirement for Total Network Pool ($ 000's)		663,674	**666,625**	**667,601**	**667,587**	**667,566**	**667,538**	**667,505**	**667,467**	**667,424**	**667,377**	**667,326**	**667,019**	**666,650**	**666,240**	**665,802**
Approved Network Load (MW)		258,509	**258,509**	**258,509**	**258,509**	**258,509**	**258,509**	**258,509**	**258,509**	**258,509**	**258,509**	**258,509**	**258,509**	**258,509**	**258,509**	**258,509**
Network Pool Rate ($ /kw /month)		$ 2.57	**2.579**	**2.583**	**2.582**	**2.582**	**2.582**	**2.582**	**2.582**	**2.582**	**2.582**	**2.581**	**2.580**	**2.579**	**2.577**	**2.576**
Rate Impact ($ /kw /month)	**Average**	**0.012**	**0.011**	**0.015**	**0.015**	**0.015**	**0.015**	**0.015**	**0.015**	**0.015**	**0.014**	**0.014**	**0.013**	**0.012**	**0.010**	**0.008**
Rate Impact - % relative to base year	**Average**	**0.48%**	**0.44%**	**0.59%**	**0.59%**	**0.59%**	**0.58%**	**0.58%**	**0.57%**	**0.57%**	**0.56%**	**0.55%**	**0.50%**	**0.45%**	**0.39%**	**0.32%**

Note 1: Based on OEB approved rates for Jan 1, 2009, EB-2008-0113

Exhibit B, Tab 6, Schedule 1

Project Alternatives

PROJECT ALTERNATIVES

To address the need for N-1 contingency on the CNP Transmission System, CNP considered five different options. Of the five options considered, three are variations of the proposed Project in that they all involve establishing an synchronous connection with New York at Buffalo, but differ in their capacity. The analysis of these variations, which will be discussed below, resulted in a determination that the proposed Project is the only viable option among the three for establishing the interconnection with New York. The remaining two options, which involve the development of new transmission lines to connect the CNP Transmission System to the IESO-controlled grid at additional locations within Ontario, are the "Project Alternatives" and are discussed below.

1. The Status Quo

Given the non-discretionary nature of the Project, the status quo was not considered as an alternative. If the status quo remains, the CNP Transmission System would continue to suffer from its lack of N-1 contingency. As explained in **Exhibit B, Tab 3, Schedule 1** and as shown in Figure 3.3 thereof, peak load on the CNP Transmission System already exceeds the capacity of the Emergency Tie Line on a consistent basis. As a result, from a planning perspective, in peak periods the Emergency Tie Line does not function adequately. In addition, based on load growth forecasts for the CNP Transmission System, it is expected that within a few years the average monthly peak will consistently exceed the capacity of the Emergency Tie Line. At such time, the Emergency Tie Line will not be functional as a means of providing a sufficient alternative supply during emergency periods.

2. Project Variations

Given the need for N-1 contingency on the CNP Transmission System, together with the recognition that sufficient emergency supply will not be available and the recognition that the emergency supply is already deficient in respect of the CNP Transmission System's peak load, CNP identified as an option the development of a synchronous connection with the USNG-controlled grid at Buffalo. The feasibility of several variations of such an undertaking was considered. The conclusion of this analysis was that variation (c), being the Project, described below, is by far the most prudent approach to developing a synchronous connection with New York at Buffalo. These variations are as follows.

(a) ***Intertie to New York Using 60 MVA Phase Shifter***

This variation of the synchronous connection with New York would employ a phase shifter that is sized at 60 MVA so as to meet the CNP Transmission System's current peak load. On a "stand-alone" basis, this variation of the intertie would require the installation of a 60 MVA phase shifting transformer and voltage regulator at Station #18 in Fort Erie, along with the following necessary work components:

- Installation of an additional 115 kV breaker adjacent to the Murray taps on A36N and A37N to improve reliability and system operations;
- Installation of two additional breakers at Station #17 in Stevensville for better sectionalizing and zone control; and
- Construction of a 115 kV three-breaker ring station located at switch SW 998 in Buffalo, New York, that will tie L46, L47 and the Canada Bus.

This variation would have an estimated cost of $20.7 million.[1] However, thermal studies carried out for CNP Transmission show that the transfer limit from the USNG system to the CNP Transmission System is approximately 53 MW. The critical contingency driving this transfer limit is the outage of either L46 or L47. The limitation is the low thermal rating for sections of L46 and L47 near Paradise Station. Due to this limitation, even if a synchronous connection with New York were developed using a 60 MVA phase shifter, the synchronous connection would effectively be limited in its capacity to below 53 MW during outages to either of L46 or L47. To overcome this limitation so as to make use of the entire 60 MVA capacity of the phase shifter in these circumstances, in addition to the key components listed above, this variation would have to also include:

- Replacement of 0.5 km of conductor from the Bertie Hill Tower to the Queen Street Tower in Fort Erie with conductor of sufficient capacity at 115 kV;
- Replacement of 0.66 km of conductor from the Queen Street Tower in Fort Erie, across the Niagara River, to the High Tower adjacent to Terminal House B in Buffalo, New York, with conductor of sufficient capacity at 115 kV; and
- Replacement of the 10 km conductor from Huntley Station to the new Paradise Station, both of which are in Buffalo.

As a result of the need for these additional work components, costs of this variation would increase to approximately $29.3 million if the phase shifter is to be properly utilized. In any event, however, long-term potential would not be realized. While such an intertie would be capable of serving in the short term, this variation would only provide a temporary solution. Though the phase shifter would have a 30-year life, average load growth over that period would

[1] The cost estimates for all project variations, including the Project, account for currency exchange with respect to those components initially estimated by USNG in US dollars, as well as project development costs, as set out in Exhibit B, Tab 5, Schedule 1, Figure 5.1.

reach the limits of the capacity of the phase shifter. Moreover, as demonstrated by Figure 3.3 of **Exhibit B, Tab 3, Schedule 1**, peak demand levels would be expected to exceed the capacity of a 60 MVA phase shifter even sooner. At such time, this variation would cease to provide N-1 contingency sufficient to address the needs of the CNP Transmission System. Moreover, by virtue of being sized only to meet the immediate needs of Fort Erie, this variation would not provide any incremental intertie capacity for Ontario and those benefits would not be obtained.

(b) ***Intertie to New York Using 80 MVA Phase Shifter***

This variation of the synchronous connection with New York would employ a phase shifter that is sized at 80 MVA so as to accommodate expected load growth on the CNP Transmission System and in particular expected peak load. On a "stand-alone" basis, this variation of the intertie would require the installation of an 80 MVA phase shifting transformer and voltage regulator at Station #18 in Fort Erie, along with the following necessary work components:

- Installation of an additional 115 kV breaker adjacent to the Murray taps on A36N and A37N to improve reliability and system operations;
- Installation of two additional breakers at CNP transmission station #17 in Stevensville for better sectionalizing and zone control; and
- Construction of a 115 kV three-breaker ring station located at switch SW 998 in Buffalo, New York, that will tie L46, L47 and Canada Bus.

This variation would have an estimated cost of approximately $21.2 million. However, as indicated above, thermal studies carried out for CNP Transmission show that the transfer limit from the USNG system to the CNP Transmission System is approximately 53 MW. As with variation (a), even if a synchronous connection with New York were developed using an 80 MVA phase shifter, the synchronous connection would effectively be limited in its capacity to below 53 MW during outages to either of L46 or L47 if the line capacity of the sections between Huntley Station and the Paradise Station are not increased. To overcome this limitation so as to make use of the entire 80 MVA capacity of the phase shifter, in addition to the key components listed above, this variation would have to include:

- Replacement of 0.5 km of conductor from the Bertie Hill Tower to the Queen Street Tower in Fort Erie with conductor of sufficient capacity at 115 kV;
- Replacement of 0.66 km of conductor from the Queen Street Tower in Fort Erie, across the Niagara River, to the High Tower adjacent to Terminal House B in Buffalo, New York, with conductor of sufficient capacity at 115 kV; and
- Replacement of the 10 km conductor from Huntley Station to the new Paradise Station, both of which are in Buffalo.

As a result of the need for these additional work components, costs of this variation would increase to approximately $29.8 million if the 80 MVA phase shifter is to be properly utilized. While such an intertie would be capable of providing N-1 contingency for the CNP Transmission System over the expected life of the phase shifter, by virtue of being sized only to meet the immediate and expected needs of Fort Erie, this variation would not provide any incremental intertie capacity for the benefit of Ontario.

(c) ***Intertie to New York Using 150 MVA Phase Shifter***

This variation, being the Project, is the preferred alternative and is described in greater detail in **Exhibit B, Tab 2, Schedule 1**. In summary, this variation would employ a phase shifter that is sized at 150 MVA so as to meet the current and expected needs of the CNP Transmission System during the life of the equipment associated with the project, while also providing for additional intertie capacity with New York to be made available for the benefit of Ontario. As compared to variations (a) and (b), if those variations were to be constructed so as to make use of the entire 60 MVA or 80 MVA capacity of the phase shifting transformer and voltage regulators associated with those variations, this variation (c) of the intertie with New York would require virtually no incremental work components. The only significant difference is the capacity of the phase shifting transformer and voltage regulator itself. As described in **Exhibit B, Tab 2, Schedule 1**, the Project would entail the following key work components:

- Reinforcement of 2.0 km of line forming Lines A36 and A37 in order to accommodate the maximum export capability on the new Fort Erie interconnection;
- Installation of an additional 115 kV breaker adjacent to the Murray taps on A36N and A37N to improve reliability and system operations;
- Installation of two additional breakers at CNP transmission station #17 in Stevensville for better sectionalizing and zone control;
- Installation of a 150 MVA phase shifting transformer and voltage regulator at Station #18 in Fort Erie;
- Replacement of 0.5 km of conductor from the Bertie Hill Tower to the Queen Street Tower in Fort Erie with conductor of sufficient capacity at 115 kV;
- Replacement of 0.66 km of conductor from the Queen Street Tower in Fort Erie, across the Niagara River, to the High Tower adjacent to Terminal House B in Buffalo, New York, with conductor of sufficient capacity at 115 kV;
- Construction of a 115 kV three-breaker ring station located at switch SW 998 in Buffalo, New York, that will tie L46, L47 and Canada Bus; and
- Replacement of approximately 10 km of conductor from the Huntley Station to a new 115 kV Paradise Station being planned by US National Grid in Buffalo, with a new 115 kV three-phase transmission circuit.

As shown in **Exhibit B, Tab 5, Schedule 1**, This variation, being the Project, has an estimated cost of $30.9 million. Given the limitations associated with variations (a) and (b) and the need to carry out the full array of work activities in order to address the limitations of variations (a) and (b), this variation (c) provides significantly greater utility in providing N-1 contingency for the CNP Transmission System. In particular, unlike variation (a), this variation would provide N-1 contingency to the CNP Transmission System for the entire life of the phase shifter, thereby maximizing use of the installed infrastructure and ensuring N-1 contingency would be provided at least for the next 30 years. While variation (b) would also be expected to provide N-1 contingency for the next 30 years or more, variation (b) would not provide any new intertie capacity for the benefit of Ontario. As such, for a relatively small incremental cost in comparison with variation (b), this variation would provide CNP Transmission with the opportunity to offer significant benefits to Ontario through the availability of additional intertie capacity between Ontario and New York (See discussions of Quantitative Intertie Capacity Benefits to Ontario, as well as Qualitative Benefits, in **Exhibit B, Tab 4, Schedule 1**). For these reasons and others described throughout this Application, this variation was selected as the preferred variation.

3. Project Alternatives

While the preferred variation discussed above represents the best form of a synchronous connection with New York, the Project Alternatives would each involve the development of a new transmission line along transmission rights of way in order to connect the CNP Transmission System to the IESO-controlled grid at a second location, being either at Station #11 in Niagara (the "Niagara Project Alternative") or at Hydro One's Crowland Transmission Station in Port Colborne (the "Port Colborne Project Alternative"). In doing so, the Project

Alternatives would be expected to provide substantially the same reliability benefits to the CNP Transmission System as would the proposed Project (See discussion of Quantitative Reliability Benefits beginning on page 1 of **Exhibit B, Tab 4, Schedule 1**), albeit through a fundamentally different approach. While the Project Alternatives would provide N-1 contingency for the CNP Transmission System, neither of the Project Alternatives would provide CNP Transmission with the opportunity to offer any benefits to Ontario through the provision of additional intertie capacity between Ontario and New York. It is also important to note that the viability of each Project Alternative is highly uncertain because each would entail significantly greater permitting and stakeholder risk, as well as the use of new lands for new transmission facilities.

(a) ***Niagara Project Alternative***

The Niagara Project Alternative would involve the construction of an 18 km, 115 kV transmission line from Station #11 to Station #18 (See **Appendix A**). In addition, the Niagara Project Alternative would require installation of one breaker at Station #11 and one breaker at Station #18, along with all related facilities. The route would be subject to regulatory approvals and related community consultation processes. It could be possible for the Niagara Project Alternative to be constructed generally along an unused 25 Hz right of way currently owned by CNP Transmission. However, the Niagara Project Alternative would have to include removal of the old, unused 25 Hz line. The new line would feature single pole towers of approximately 65 feet in height, approximately every 100 meters along the route. By comparison, the existing unused lines along the 25 Hz right of way feature substantially shorter towers that are approximately 45 feet in height.

As shown in **Appendix B**, the route for the Niagara Project Alternative along the existing 25 Hz right of way would bring this new 115 kV transmission line into close proximity with residential areas and various other land use designations that would be expected to add significant permitting and stakeholder risk to this Project Alternative. Land use planning in this area is the joint responsibility of the Regional Municipality of Niagara and each of the relevant local municipalities. The route of the Niagara Project Alternative would be situated partly within the Town of Fort Erie and partly within the City of Niagara Falls, both of which are within the Regional Municipality of Niagara. Land use plans in the Town of Fort Erie and in the City of Niagara Falls must be consistent with the plans from the Regional Municipality of Niagara, which are set out in the Regional Niagara Policy Plan.[2]

As shown in **Appendix B**, assuming that the Niagara Project Alternative were developed along the former 25 Hz right of way currently owned by CNP Transmission, the route would run through or directly adjacent to a number of areas that are designated as environmentally significant based on the Core Natural Heritage Map that forms part of the Regional Niagara Policy Plan. In particular, the route would run through or directly adjacent to approximately eleven “Environmental Conservation Areas”,[3] ten areas designated as “Fish Habitat”, as well as seven designated “Environmental Protection Areas”[4]. Generally, the Regional Niagara Policy

[2] Regional Niagara Policy Plan (July 2007), incl. Regional Policy Plan Amendment 187 - Environmental Policies and the associated Core Natural Heritage Map. See http://www.niagararegion.ca/living/icp/policy-plan.aspx

[3] “Environmental Conservation Areas” are defined in the Regional Niagara Policy Plan as including significant woodlands; significant wildlife habitat; significant habitat of species of concern; regionally significant Life Science ANSIs; other evaluated wetlands; significant valleylands; savannahs and tallgrass prairies; and alvars; and publicly owned conservation lands (Policy 7.B.1.4).

[4] “Environmental Protection Areas” are defined in the Regional Niagara Policy Plan as includes provincially significant wetlands; provincially significant Life Science Areas of Natural and Scientific Interest (ANSIs); and

Plan provides that development or site alteration may be permitted on or near any of these areas, but only if it can be demonstrated through the preparation of an Environmental Impact Study that there will be no long-term significant negative impacts. In addition, virtually the entire route of the Niagara Project Alternative would fall within areas that are designated as "Potential Natural Heritage Corridors". In these areas, Policy 7.B.1.12 of the Regional Niagara Policy Plan requires that the Corridor be considered in the development review process and that development should be located, designed and constructed to maintain and, where possible, enhance the ecological functions of the Corridor in linking Core Natural Areas.

Based on the foregoing, these land use considerations would very likely give rise to potential complexity, public opposition, delay, increased cost and uncertainty for the Niagara Project Alternative. This gives rise to the real risk that this Project Alternative would not be able to proceed and would therefore not be a certainty for comparison purposes. A discussion of the approvals processes (common to the Niagara Project Alternative and the Port Colborne Project Alternative) through which many of these issues would be addressed, is provided below.

The Niagara Project Alternative would have an estimated cost of $13.4 million, excluding any costs that might arise from delays, permitting and approvals, or required consultation processes, including with First Nations, if applicable.

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significant habitat of threatened and endangered species. In addition, within the Greenbelt Natural Heritage System, Environmental Protection Areas also include wetlands; significant valleylands; significant woodlands; significant wildlife habitat; habitat of species of concern; publicly owned conservation lands; savannahs and tallgrass prairies; and alvars (Policy 7.B.1.3).

(b) ***Port Colborne Project Alternative***

The Port Colborne Project Alternative would involve the construction of a 25 km, 115 kV transmission line from a site adjacent to Hydro One's Crowland Transmission Station ("Crowland TS") in Port Colborne to Station #18. An existing railway right of way (concerning which CNP Transmission does not have any interests) in combination with other lands might provide a potential route (See **Appendix C**). However, it is not clear as to whether such a route is possible. In addition, the Port Colborne Project Alternative would require installation of one breaker at Crowland TS, two breakers at Station #17 and one breaker at Station #18, along with all related facilities. It would also be expected that additional lands would be required adjacent to Crowland TS in Port Colborne. Along the 25 km transmission line contemplated by this Project Alternative, where no transmission facilities are currently in place, new 65-foot tall transmission towers would be required approximately every 100 m along the length of the line.

As shown in **Appendix B**, the potential route for the Port Colborne Project Alternative would bring this new 115 kV transmission line into close proximity with residential areas and various other land use designations that would be expected to add significant permitting and stakeholder risk to this Project Alternative. As indicated above, land use planning in this area is the joint responsibility of the Regional Municipality of Niagara and each of the relevant local municipalities. The route of the Port Colborne Project Alternative would be situated partly within the Town of Fort Erie and partly within the Town of Port Colborne, both of which are within the Regional Municipality of Niagara. Land use plans in the Town of Fort Erie and the Town of Port Colborne must be consistent with the Regional Niagara Policy Plan.

Assuming that the Port Colborne Project Alternative were developed along the railway right of way and such other lands as indicated, then the route would run through or directly adjacent to a number of areas that are designated as environmentally significant based on the Core Natural Heritage map that forms part of the Regional Niagara Policy Plan. Specifically, the route would run through or directly adjacent to approximately eleven “Environmental Conservation Areas”, five areas designated as “Fish Habitat”, three designated “Environmental Protection Areas”, as well as ten areas in three main swaths that are designated as “Potential Natural Heritage Corridors”. The meanings and significance of these designations are as stated above with respect to the Niagara Project Alternative.

As with the Niagara Project Alternative, the land use considerations for the Port Colborne Project Alternative would be very likely to give rise to potential complexity, public opposition, delay, increased cost and uncertainty for this Project Alternative. This gives rise to the real risk that this Project Alternative would not be able to proceed and would therefore not be a certainty for comparison purposes. A discussion of the approvals processes (common to the Niagara Project Alternative and the Port Colborne Project Alternative) through which many of these issues would be addressed is provided below.

The Port Colborne Project Alternative would have an estimated cost of $19.4 million, which includes $3.5 million associated with the acquisition of land rights. The cost of acquiring land rights, however, is highly uncertain. A conservative estimate has therefore been used. As with the cost estimate for the Niagara Project Alternative, this estimate does not include potential costs due to delay, permitting and approvals, or required consultation processes, including with First Nations, if applicable.

(c) *Additional Regulatory Requirements for the Project Alternatives*

With respect to permitting and approvals, the environmental assessment requirements that would be applicable to the Niagara Project Alternative and the Port Colborne Project Alternative are worth noting. As discussed in **Exhibit B, Tab 7, Schedule 1**, it is not expected that provincial or federal environmental assessment requirements will apply to the proposed Project. This is primarily due to the fact that the proposed Project involves upgrades and work on existing facilities and involves only minimal physical changes to the existing system within Ontario. However, as explained below, the addition of new lines associated with the Project Alternatives would give rise to environmental assessment requirements. As such, this is a key difference between the Project and the Project Alternatives.

Under Ontario's *Environmental Assessment Act* ("EA Act"), regulations may authorize certain project proponents to proceed with undertakings in accordance with approved class environmental assessment requirements.[5] Ontario Regulation 116/01 (Energy Projects) under the EA Act requires that, for certain transmission projects, proponents follow the Class Environmental Assessment process for Minor Transmission Facilities, which was first developed

[5] A person may apply to the Minister of the Environment to approve a class environmental assessment process for a particular class of undertakings. Once approved, that class environmental assessment process may be followed by any proponent who is proposing an undertaking that falls within approved class of undertakings.

by Ontario Hydro.[6] In particular, Regulation 116/01 provides that a proponent who is engaged in the planning, designing, establishing, construction, operating, changing, expanding or retiring of a transmission line that is more than 2 km in length, designed to operate at a nominal voltage of 115 kV, and that is not associated with a generation facility, is subject to the Class Environmental Assessment process for Minor Transmission Facilities (the "Class EA Process").

The Class EA Process generally requires that a proponent of a project that falls within the approved class complete the following steps:

1. Establish the need for their project,
2. Identify project options,
3. Define their study area,
4. Provide notice to and consult with affected ministries, the public, affected local and regional municipalities, the Niagara Escarpment Commission if applicable, any affected conservation authority, Environment Canada if federal lands or interests may be affected, as well as Band Councils or appropriate organizations in respect of potentially affected First Nations,
5. Collect data related to impacts on agricultural resources, landscape/aesthetics, biological resources, forest resources, heritage resources, human settlements, mineral resources and recreational resources,
6. Evaluate alternative routes or sites using qualitative and quantitative methods and select the preferred alternative,

[6] Class Environmental Assessment for Minor Transmission Facilities, Rev. 6, approved pursuant to the *Environmental Assessment Act* by Order-in-Council No. 1173/92, April 23, 1992. Note: While the Ministry of the Environment's Guide to EA Requirements for Electricity Projects (March 2001) states at section A.5.2 that "the Class EA for Minor Transmission Facilities will be revised to reflect the roles and responsibilities of participants in the restructured electricity market," such revisions do not appear to have been made to date. As a result, the environmental assessment requirements that would be applicable to the Project Alternatives may differ from the process described in the current approved Class Environmental Assessment document.

7. Notify affected ministries, agencies and the interested public while providing an opportunity for further comments to be received and for the public to request a “bump-up” to the individual environmental assessment process,

8. Endeavour to address any outstanding concerns expressed,

9. Prepare and file a final Environmental Study Report,

10. Where opposition remains and “bump-up” requests are made so as to require a more comprehensive individual environmental assessment under the Act then, subject to the Minster’s decision on the request, the proponent would have to conduct an individual environmental assessment, and

11. Where changes are made to the project subsequent to completing the environmental assessment process, the proponent must then complete an addendum to their Environmental Study Report documenting the changes and their impacts and providing an opportunity for further comment and review.

In addition to the above process, if the route gives rise to potential impacts on such federally-regulated matters as fisheries, aboriginal lands, navigable waters or federal lands, to name just a few, then there would be a risk that the Project Alternative could also trigger federal environmental assessment requirements under the *Canadian Environmental Assessment Act*.

A particular challenge specific to the Port Colborne Project Alternative would be considerations associated with the need to cross the Welland Canal, which is operated on behalf of Transport Canada by the St. Lawrence Seaway Management Corporation. While this matter would require further study and consideration, it is the Applicant’s understanding that a licence from the St. Lawrence Seaway Management Corporation would need to be obtained and that such a crossing would need to provide a minimum of 150 feet of clearance for passing ships. While not insurmountable, this factor would add cost and complexity to the development of the Port Colborne Project Alternative, while providing an additional potential source for delay.

Finally, as suggested by the notification requirements in the Class Environmental Assessment process,[7] there are potential approvals that would be required from the local conservation authorities or from affected municipalities. With respect to conservation authorities, regulations under the *Conservation Authorities Act* require proponents to obtain approval for developments (i.e. construction or erection of structures) that are close to shorelines, in or on river or stream valleys, hazardous lands, wetlands or other sensitive areas, or where removal of vegetation and other activities are carried out within conservation areas. The routes for either of the Project Alternatives would be very likely to require such approvals. With respect to municipal approvals, detailed reviews of land use policies, plans and by-laws as well as discussions with all affected municipalities would be required in order to determine concerns and to identify acceptable means of mitigating those concerns in order to secure the necessary municipal approvals for the Project Alternatives.

4. Net Present Value Comparison of the Project and Project Alternatives

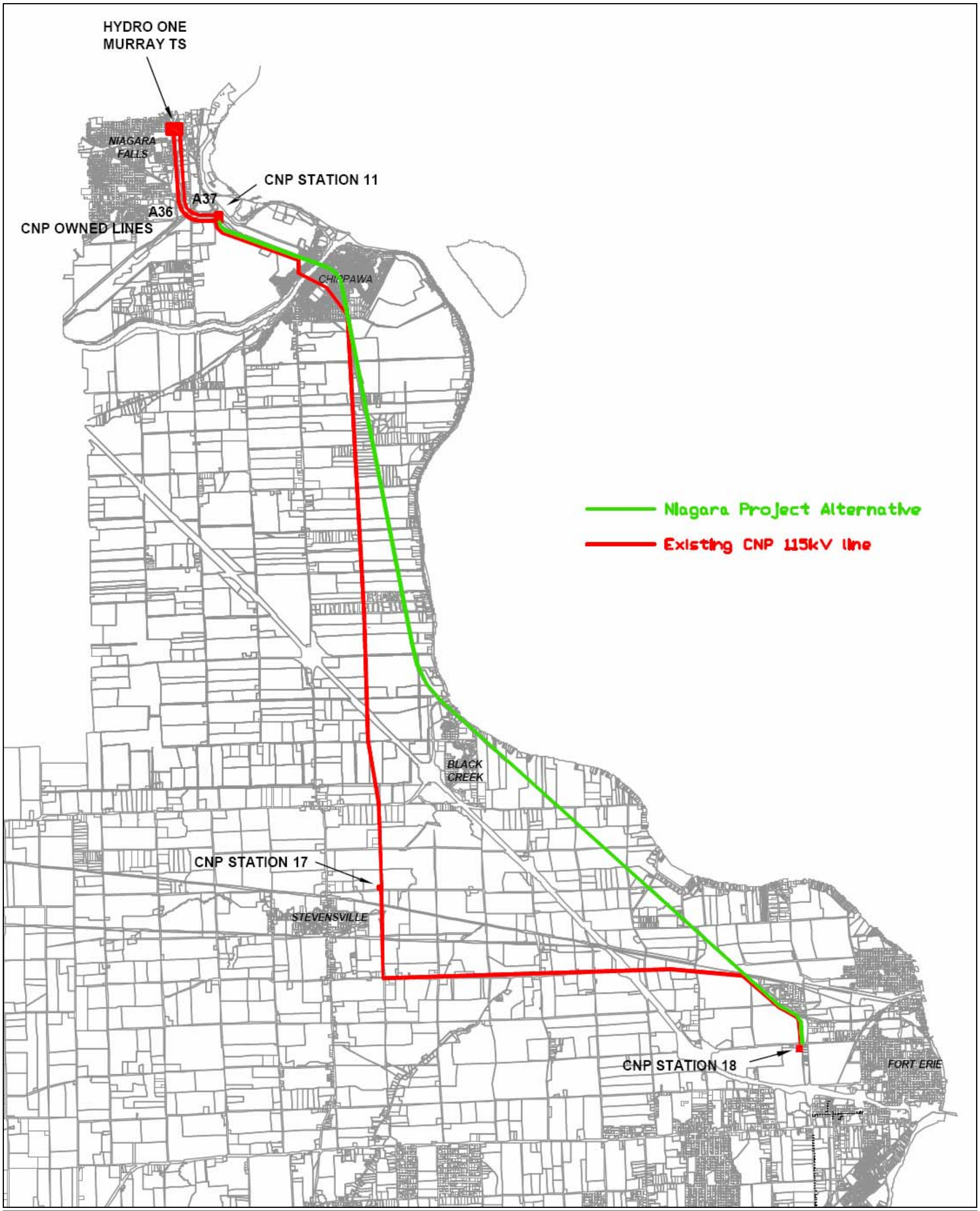
As set out in **Exhibit B, Tab 5, Schedule 1**, the NPV for the preferred alternative, being the Project, is $10,367,499. The NPV for the Project accounts for the local reliability benefits of the Project, as well as the system-wide benefits to Ontario that are associated with the increase in intertie capacity that would be provided by the Project. For the Project Alternatives, which do

[7] Section 3.3.2 of the Class EA Process provides that the proposed project would be publicly announced, that each of the following will be notified: every potentially affected local, county, regional, district and metropolitan municipality; the Niagara Escarpment Commission (where the study area includes any part of the area under the jurisdiction of the Commission); any conservation authority that has jurisdiction over watersheds that may be affected by a project; Environment Canada if federal lands, mandates or interests may be affected; and Band Councils of any potentially affected Indian Reserves or the appropriate Aboriginal or Metis organization in respect of non-Reserve Aboriginals or Metis communities.

not provide any system-wide benefits to Ontario, it is only the local reliability benefits that are accounted for in the NPV calculation. As such, the NPV for the Niagara Project Alternative is $(3,806,921) and the NPV for the Port Colborne Project Alternative is $(12,546,166).

APPENDIX A

Map of Niagara Project Alternative Potential Route


HYDRO ONE
MURRAY TS
NIAGARA
FALLS
CNP STATION 11
A37
A36
CNP OWNED LINES
CHIPPAWA
Niagara Project Alternative
Existing CNP 115kV line
BLACK
CREEK
CNP STATION 17
STEVENSVILLE
CNP STATION 18
FORT ERIE

APPENDIX B

Map of Land Use Designations Affecting the Project Alternatives

[Folded map in original document]

APPENDIX C

Map of Port Colborne Project Alternative Potential Route

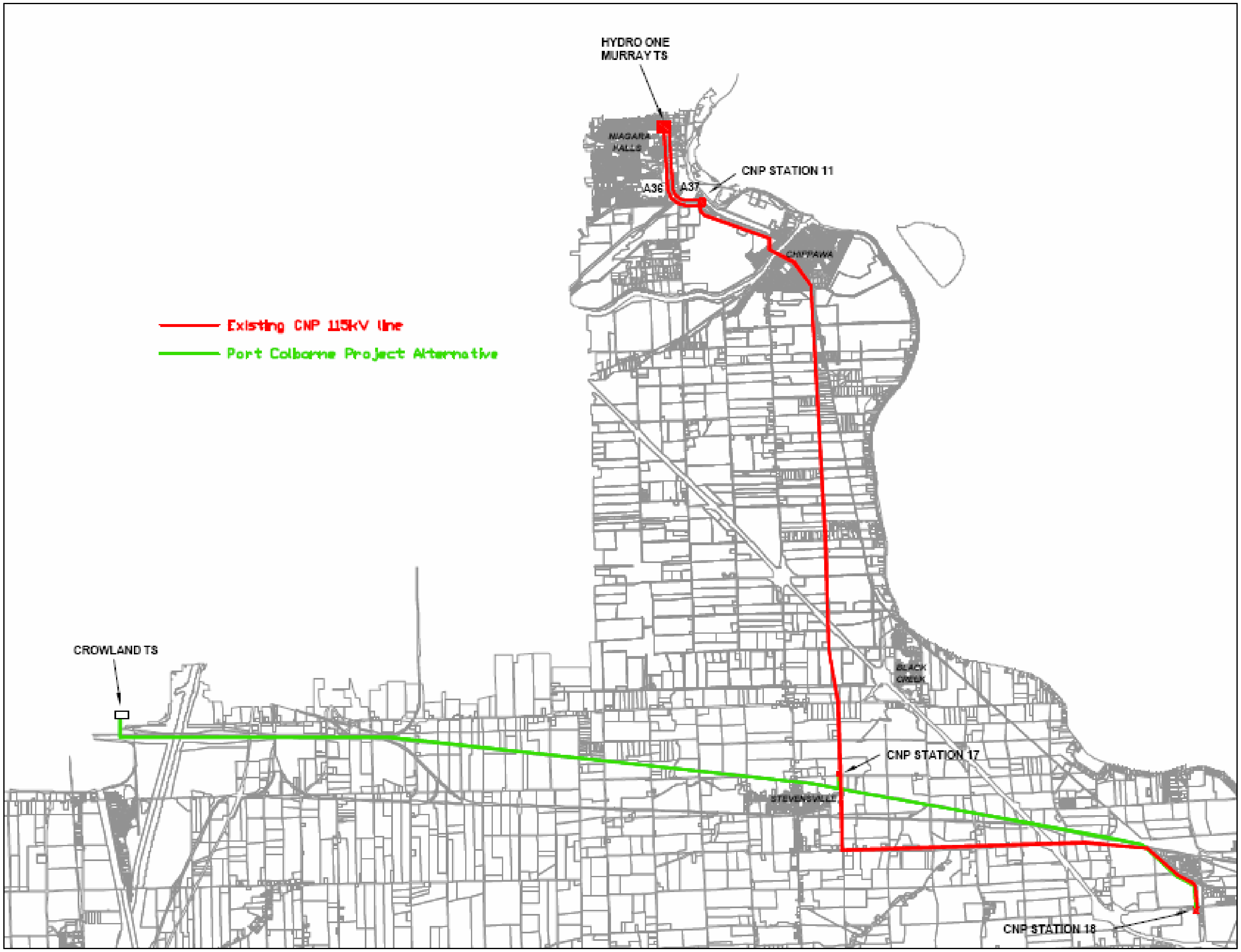

HYDRO ONE
MURRAY TS
NIAGARA FALLS
A36
A37
CNP STATION 11
CHIPPAWA
Existing CNP 115kV line
Port Colborne Project Alternative
CROWLAND TS
BLACK CREEK
CNP STATION 17
STEVENSVILLE
CNP STATION 18

Exhibit B, Tab 7, Schedule 1

Other Regulatory Approvals

OTHER REGULATORY APPROVALS

This section describes key permits and approvals that are expected to be required for the Project from regulators other than the Ontario Energy Board. These include approvals from federal authorities in Canada, other provincial authorities, municipal authorities, as well as various authorities in the United States in respect of the portions of the project that will be carried out on CNP's behalf by USNG.

1. Canadian Approvals

(a) Federal

(i) *National Energy Board*

CNP holds an electricity permit (EP-137) from the National Energy Board ("NEB"), issued in May 1999 under 58.11 of the *National Energy Board Act* ("NEB Act"). Permit EP-137 authorized CNP to rehabilitate and to subsequently operate the international power line at Fort Erie. In addition, permit EP-137 revoked and replaced a Certificate of Public Service and Necessity (EC-22), which had been issued in 1959. Section 9 of permit EP-137 requires that CNP obtain prior approval from the NEB for any change to the international power line. Given that the Project includes the removal and replacement of conductors along the international portion of the system that spans the Niagara River between Fort Erie and Buffalo, CNP is therefore required to obtain prior approval for the project from the NEB. Such approval to change the international power line will need to be sought under section 21 of the NEB Act, under which the NEB has authority to vary a permit issued under that Act.

The process for obtaining a such a variation to the permit, as confirmed with NEB staff, is to file an application under Section 21 of the NEB Act for prior approval of the changes that are needed on the international power line that is the subject of permit EP-137. The content requirements for the application will be guided by the NEB's Electricity Regulations as well as its Filing Manual, but will generally have to address issues such as potential reliability implications for other Canadian jurisdictions and potential environmental impacts (though not to the extent of an environmental assessment). No oral hearing would be required for such an application. It is CNP's intention to apply to the NEB for the required changes to its permit subsequent to receiving a final decision from the OEB in the present Application.

(ii) ***Environmental Assessment***

For the reasons that follow, CNP does not expect the Project to trigger any federal environmental assessment requirements.

First, an application under Section 21 of the NEB Act does not trigger federal environmental assessment requirements under the Law List Regulations of the *Canadian Environmental Assessment Act* ("CEAA") and does not fall within the scope of undertakings for which comprehensive study environmental assessments are required under CEAA.

Another potential "trigger" would be an approval under the *Navigable Waters Protection Act* in respect of the installation of works over navigable waters. However, although the Project would require the removal and replacement of the portion of the system that spans the Niagara River, CNP's experience[1] suggests that no such approval would be needed because the vertical clearance of the line would be no different than the vertical clearance of the existing line. Moreover, this work component can be carried out using methods that require only that a boat be in the water for purposes of observation and safety. The actual replacement work is carried out from the shore.

Finally, where there is no such prescribed "trigger" giving rise to federal environmental assessment requirements, the only potentially relevant basis for requiring a federal environmental assessment for the Project would be if the federal Minister of the Environment were of the opinion that the Project may cause significant adverse environmental effects occurring outside Canada. Given the low impact nature of the construction activities associated with the Project, particularly as it relates to the portion of the system that spans the Niagara River, CNP does not believe the Project is at risk of such a finding.

(b) Provincial

(i) *Environmental Assessment*

As explained below, CNP Transmission does not expect that provincial environmental assessment requirements will apply to the proposed Project.

The basic scheme under Ontario's *Environmental Assessment Act* (the "EA Act"), is that the EA Act applies only to undertakings where (a) the proponent is the Province, a municipality or a public body, (b) a person enters into an agreement under which they commit to being subject to the EA Act, or (c) a regulation designates certain major commercial enterprises or activities as

[1] A federal environmental screening report was required when CNP developed the emergency tie line in 1998.

being subject to the EA Act. Consistent with this third category, Ontario Regulation 116/01 (Electricity Projects) designates a wide range of energy projects as being subject to the EA Act. Among these, section 3(1) of the regulation designates (a) transmission lines that are more than 2 km in length, which are designed to operate at 115 kV or more and which are not associated with a generation facility, as well as (b) transformer stations that are designed to operate at 115 kV or more and which are not associated with a generation facility, as being undertakings to which the EA Act applies. On this basis, the Project - which involves activities associated with transmission lines as well as transformer stations - falls within the ambit of the EA Act and the regulation.

However, O. Reg. 116/01 also provides for various exemptions from the requirements of the EA Act and the regulation. Of particular relevance to the Project are the exemptions associated with modifications to existing facilities. It is important to understand that modifications are classified under the regulation as either "significant modifications" or "minor modifications". "Minor modifications" are modifications that are not "significant modifications". "Significant modifications" are, with respect to transmission lines of 115 kV or more, any expansion of or change in the line that includes (a) the replacement of a pole or tower, or (b) a change in a right-of-way for the line, if after the expansion or change the transmission line would still be designed to operate at 115 kV or more.[2] With respect to transformer stations, a "significant modification" would be any expansion of or change in the station that includes the installation of additional transformer equipment if (a) the installation of the additional equipment requires an extension of

[2] Section 1(1), O. Reg. 116/01 (Electricity Projects), subparagraph (j) in the definition of "significant modification".

the site where the station is located and, after installation the station would operate at 115 kV or more, or (b) the installation of the additional equipment would increase the nominal voltage at the station to greater than 230 kV.[3]

CNP Transmission expects that (a) the Project is not likely to require the replacement of any poles or towers or any changes in rights-of-way, and (b) the installation of additional equipment at CNP transformer stations, including the installation of the phase shifting transformer and voltage regulator at Station #18, is not likely to require the extension of any transformer station site and will not increase the voltage of any station to greater than 230 kV. As such, CNP Transmission has a strong basis for its expectation that the Project will represent only a "minor modification" for purposes of the EA Act and O. Reg. 116/01. This is significant because, under the regulation, "minor modifications" to facilities that were constructed before O. Reg. 116/01 came into force and which therefore did not initially require EA Act approval (which is the case for the CNP Transmission System), are grandparented from all environmental assessment requirements. It is for this reason that CNP Transmission is confident that no provincial environmental assessment requirements will apply to the Project.[4]

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[3] Section 1(1), O. Reg. 116/01 (Electricity Projects), subparagraph (k) in the definition of "significant modification".

[4] As noted in Exhibit B, Tab 2, Schedule 1, despite its expectation that no environmental assessment requirements will apply to the Project, CNP Transmission acknowledges that in the course of performing the detailed engineering for the Project it could be determined that one or two transmission towers may need replacement and/or that a very minor expansion of Station #18 may be needed to accommodate the installation of the phase shifting transformer and voltage regulator. In the event that such a determination is made, CNP Transmission would ensure that it meets all applicable environmental assessment requirements.

(c) **Municipal**

CNP does not expect that any significant municipal approvals would be required for the Project. While minor approvals may be needed to allow for construction processes to take place, no changes to land use designations are needed.

2. **U.S. Approvals**

USNG will be responsible for obtaining all approvals on CNP’s behalf, which may be necessary to allow for the construction and operation of works in the United States. Based on indications from USNG, such work will not require an environmental assessment to be undertaken. However, an amendment to the existing Presidential Permit (PP-190), issued in December 1998, would be required.

Exhibit B, Tab 8, Schedule 1

Construction and In-service Schedule

CONSTRUCTION AND IN-SERVICE SCHEDULE

The proposed construction and in-service schedule for the Project is provided at **Appendix A**. The schedule assumes a start date of December 15, 2009, which would result in a project completion date of September 30, 2012. This represents a total of 33.5 months, which begins with preparations for the tendering process in respect of the phase shifting transformer and voltage regulator and concludes with the testing and commissioning of the Project facilities. As indicated by the proposed schedule, this timeframe is driven primarily by long lead-times for key equipment, as well as permitting and regulatory approvals processes associated with work to be carried out on CNP's behalf by USNG.

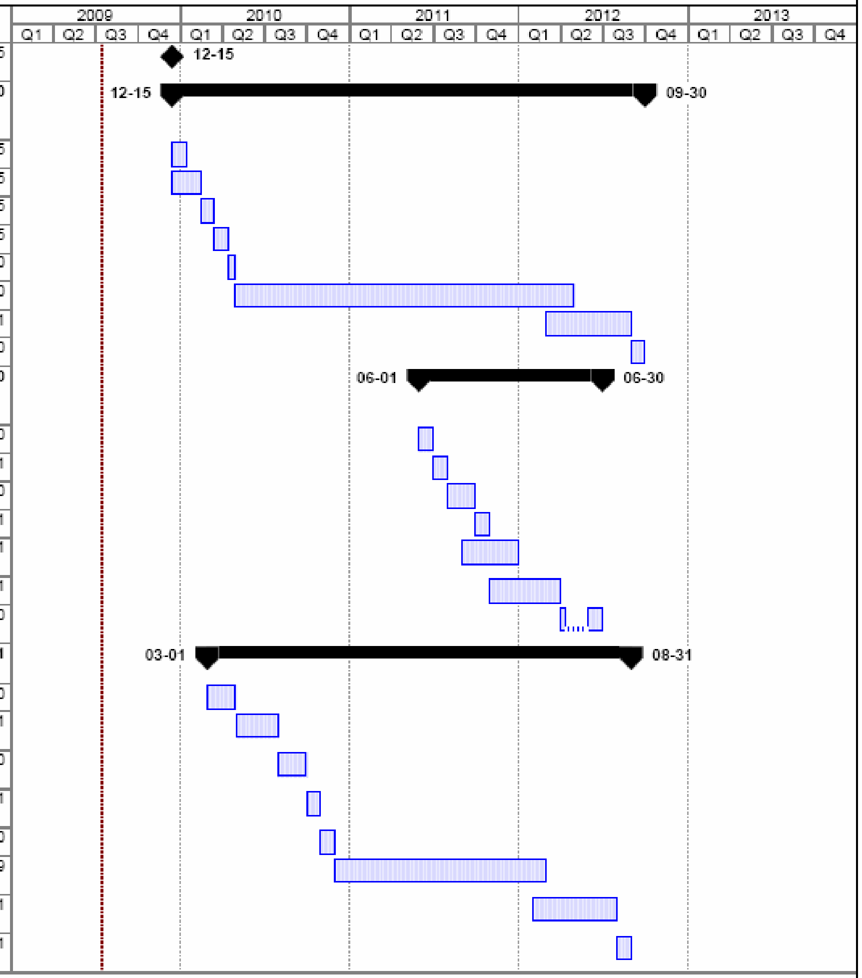
APPENDIX A

Proposed Construction and In-service Schedule

SNC·LAVALIN T & D

Canadian Niagara Power (CNP): Proposed Schedule for Fortran Project

ID	Task Name	Start	Finish
1	Project Start	Tue 09-12-15	Tue 09-12-15
2	**Task 1: Phase Shifting Transformer and Voltage Regulator (115 KV, +/- 150MVA) at CNP #18**	**Tue 09-12-15**	**Sun 12-09-30**
3	Design and Engineering Period	Tue 09-12-15	Fri 10-01-15
4	Preparation of Technical Specifications	Tue 09-12-15	Mon 10-02-15
5	Tendering and Bidding period	Mon 10-02-15	Mon 10-03-15
6	Clarification of Bids, Bid Evaluation	Mon 10-03-15	Thu 10-04-15
7	Award of Contract	Thu 10-04-15	Fri 10-04-30
8	Delivery Period	Fri 10-04-30	Mon 12-04-30
9	Construction Start	Thu 12-03-01	Fri 12-08-31
10	Testing and Commissioning	Sat 12-09-01	Sun 12-09-30
11	**Task 2: Reconductor 115 KV River Crossing Point (Terminal House B to Bertie Hill Tower) 1.2KM**	**Wed 11-06-01**	**Sat 12-06-30**
12	Design and Engineering	Wed 11-06-01	Thu 11-06-30
13	Preparation of Technical Specifications	Fri 11-07-01	Sun 11-07-31
14	Tendering and Bidding Period	Mon 11-08-01	Fri 11-09-30
15	Bid Evaluation and Award	Sat 11-10-01	Mon 11-10-31
16	Coordinate Outage Plan with NYISO, IESO, HONI, Others	Thu 11-09-01	Sat 11-12-31
17	Delivery Period	Tue 11-11-01	Sat 12-03-31
18	Construction (Conductor Replacement)	Mon 12-04-02	Sat 12-06-30
19	**Task 3: Miscellaneous (Cap Bank at Stn # 18, P&C Modification, Other System Upgrade, etc)**	**Mon 10-03-01**	**Fri 12-08-31**
20	Design and Engineering Period	Mon 10-03-01	Fri 10-04-30
21	Preparation of Technical Specifications	Sat 10-05-01	Sat 10-07-31
22	Tendering and Bidding period	Sun 10-08-01	Thu 10-09-30
23	Clarification of Bids, Bid Evaluation	Fri 10-10-01	Sun 10-10-31
24	Award of Contract	Mon 10-11-01	Tue 10-11-30
25	Delivery Period	Wed 10-12-01	Wed 12-02-29
26	Construction Start	Wed 12-02-01	Tue 12-07-31
27	Testing and Commissioning	Wed 12-08-01	Fri 12-08-31



Proposed Schedule for Fortran Project
Run Day: July 13-09

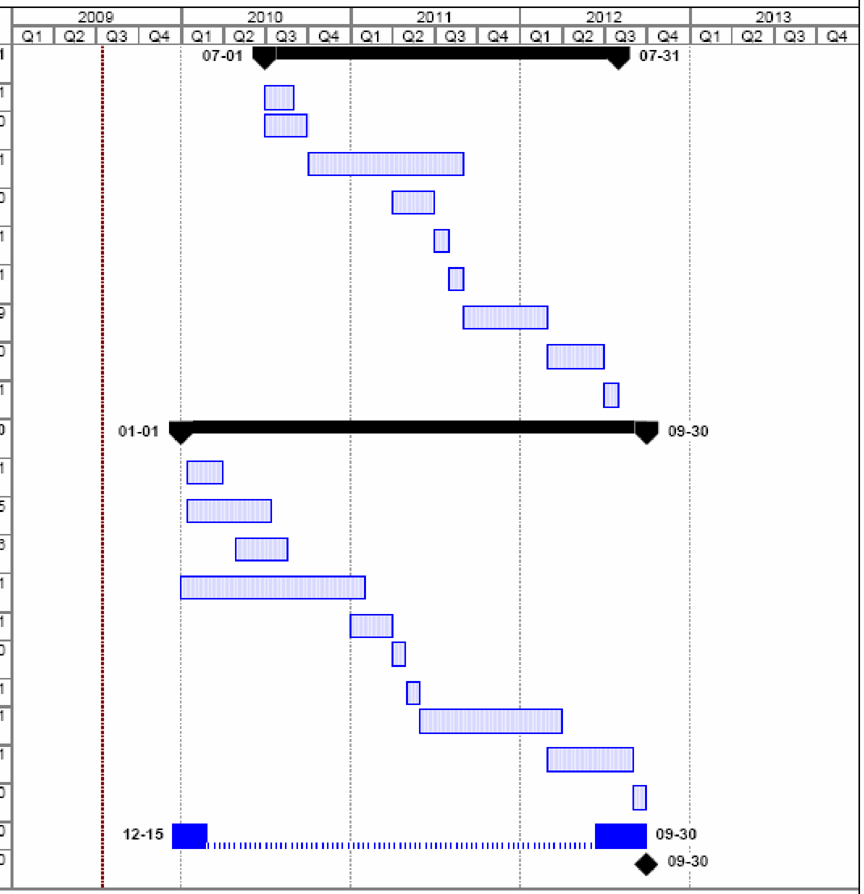
Task		Milestone		External Tasks	
Split		Summary		External Milestone	
Progress		Project Summary		Deadline	

Date printed: Mon 09-07-13

SNC•LAVALIN T&D

Canadian Niagara Power (CNP): Proposed Schedule for Fortran Project

ID	Task Name	Start	Finish
28	**Task 4: Upgrade115 KV: L46 and L47 (6.3 Miles)**	**Thu 10-07-01**	**Tue 12-07-31**
29	Design and Engineering Period	Thu 10-07-01	Tue 10-08-31
30	Preparation of Technical Specifications	Thu 10-07-01	Thu 10-09-30
31	Permitting Approvals	Fri 10-10-01	Wed 11-08-31
32	Tendering and Bidding period	Fri 11-04-01	Thu 11-06-30
33	Clarification of Bids, Bid Evaluation	Fri 11-07-01	Sun 11-07-31
34	Award of Contract	Mon 11-08-01	Wed 11-08-31
35	Delivery Period	Thu 11-09-01	Wed 12-02-29
36	Construction Start	Thu 12-03-01	Sat 12-06-30
37	Testing and Commissioning	Mon 12-07-02	Tue 12-07-31
38	**Task 5: Construction of 3-Breaker Ring Substation in Buffalo**	**Fri 10-01-01**	**Sun 12-09-30**
39	Selection of Site	Fri 10-01-15	Wed 10-03-31
40	Design and Engineering Period	Fri 10-01-15	Thu 10-07-15
41	Preparation of Technical Specifications	Fri 10-04-30	Mon 10-08-16
42	Permitting and Regulatory Approvals	Fri 10-01-01	Mon 11-01-31
43	Tendering and Bidding period	Sat 11-01-01	Thu 11-03-31
44	Clarification of Bids, Bid Evaluation	Fri 11-04-01	Sat 11-04-30
45	Award of Contract	Mon 11-05-02	Tue 11-05-31
46	Delivery Period	Wed 11-06-01	Sat 12-03-31
47	Construction Start	Thu 12-03-01	Fri 12-08-31
48	Testing and Commissioning	Sat 12-09-01	Sun 12-09-30
49	**Project Management**	Tue 09-12-15	Sun 12-09-30
50	Project Completion	Sun 12-09-30	Sun 12-09-30



Proposed Schedule for Fortran Project
Run Day: July 13-09

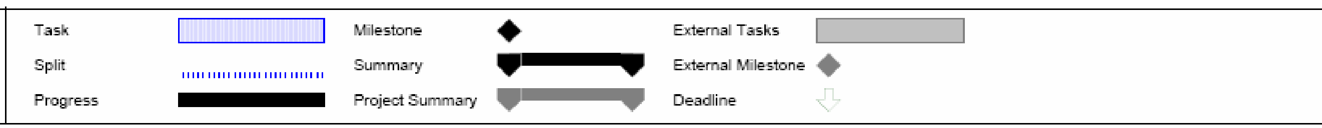


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Exhibit B, Tab 9, Schedule 1

Overview - System Impact Assessment

OVERVIEW - SYSTEM IMPACT ASSESSMENT

CNP Transmission applied for, and the Independent Electricity System Operator ("IESO") completed, a System Impact Assessment for the Project. The IESO issued a final System Impact Assessment Report (the "SIA Report") for the Project on January 17, 2007. The purpose of the SIA Report is to assess the impacts of the proposed connection with the IESO-controlled grid on the reliability of the integrated power system and whether the IESO should approve or disapprove of the proposed connection.

The SIA Report, which is provided in **Exhibit B, Tab 9, Schedule 2**, concludes that the installation of a 150 MVA phase shifter and voltage regulator, in combination with the various transmission reinforcements that are part of the Project (which are needed to address limiting line sections), would increase the import and export capability of the Ontario electricity market by 150 MW. The IESO's analysis covers the impacts of the Project on the IESO-controlled grid up to the Huntley station in Buffalo and, as such, the conclusions are subject to USNG confirming the capability of their upstream facilities (See **Exhibit B, Tab 12, Schedule 1**). The conclusions are also subject to any further requirements identified by Hydro One in the Customer Impact Assessment (See **Exhibit B, Tab 10, Schedule 1**). As such, the SIA Report recommends that a Notification of Conditional Approval be issued to CNP Transmission.

With respect to local reliability, the SIA Report also confirms that "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."[1]

[1] Exhibit B, Tab 9, Schedule 2, SIA Report, p. 8.

Exhibit B, Tab 9, Schedule 2

IESO's System Impact Assessment Report

IESO_REP_0323

REPORT

System Impact Assessment Report

CONNECTION ASSESSMENT & APPROVAL PROCESS

Issue 1.0
DRAFT Report

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.

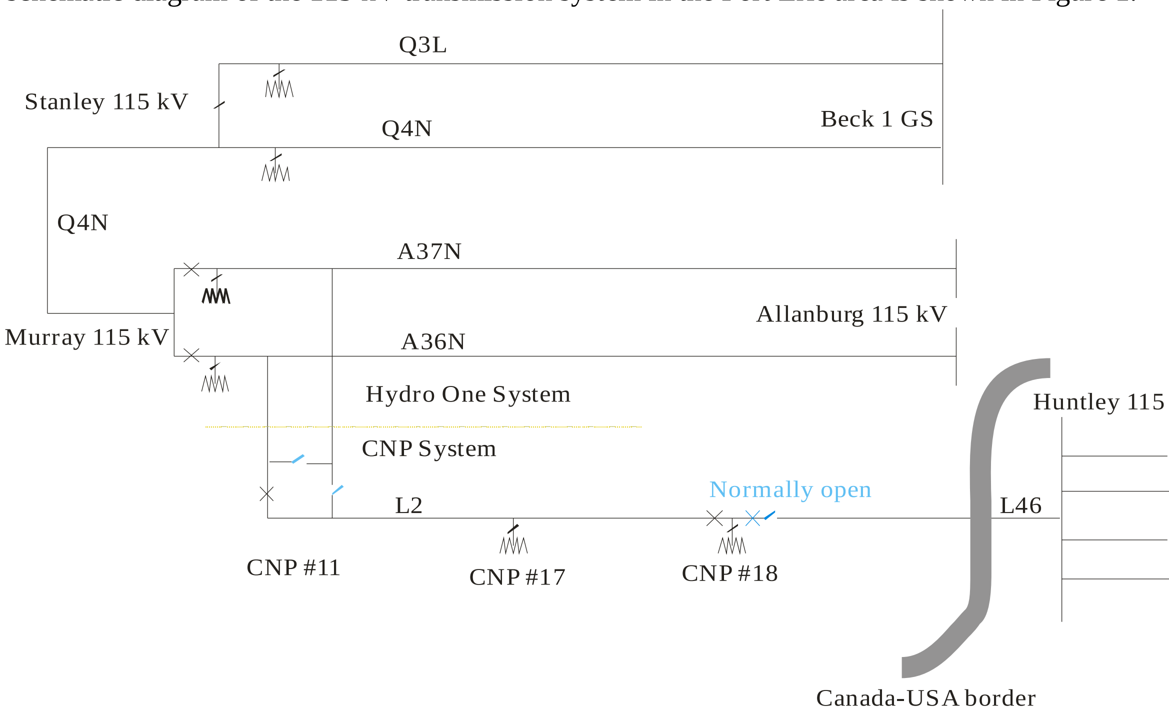

Figure 1. Allanburg – Beck and CNP 115 kV system

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.

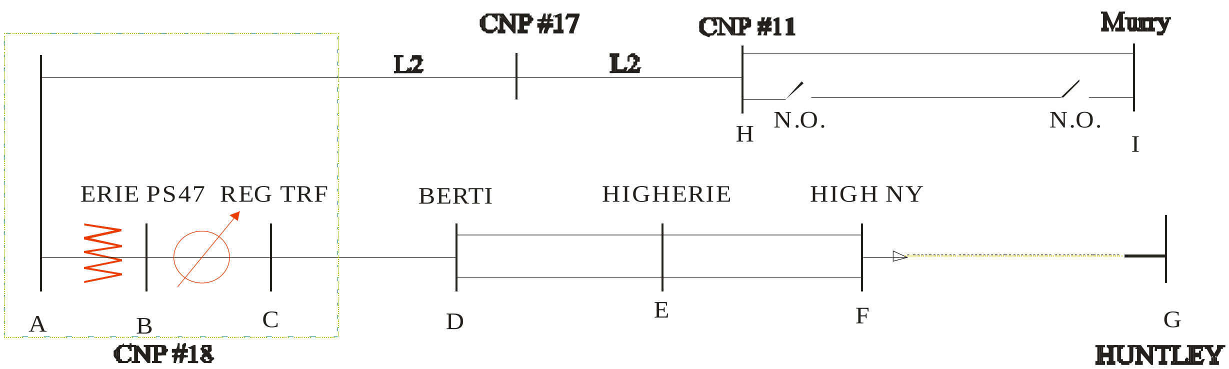

Figure 2. Transmission line between Murray and Huntley GS

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/ONAF 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 particular, 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.

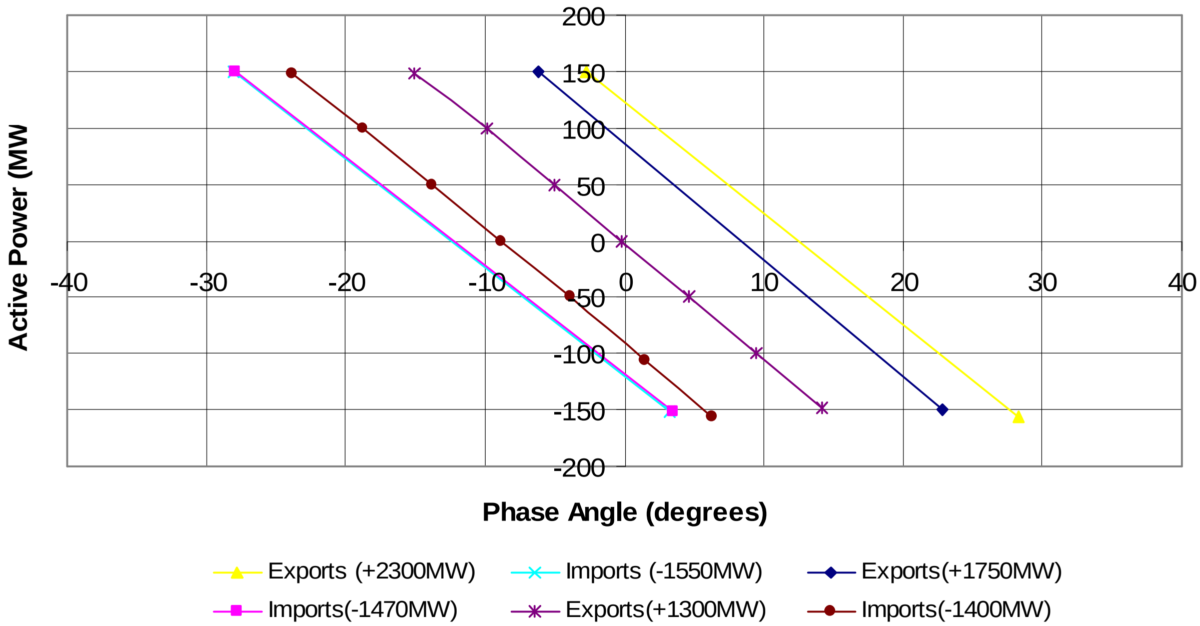

Figure 3. CNP Fort Erie Tie MW vs. PS46 Angle

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 1º 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:

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

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:

$$\begin{aligned}\textit{Ft Erie tie}_{\textit{post PA301}} &= -115\ \textit{MW} + 0.024 \times (-200\ \textit{MW}) \\ &= -119.8\ \textit{MW}.\end{aligned}$$

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
```
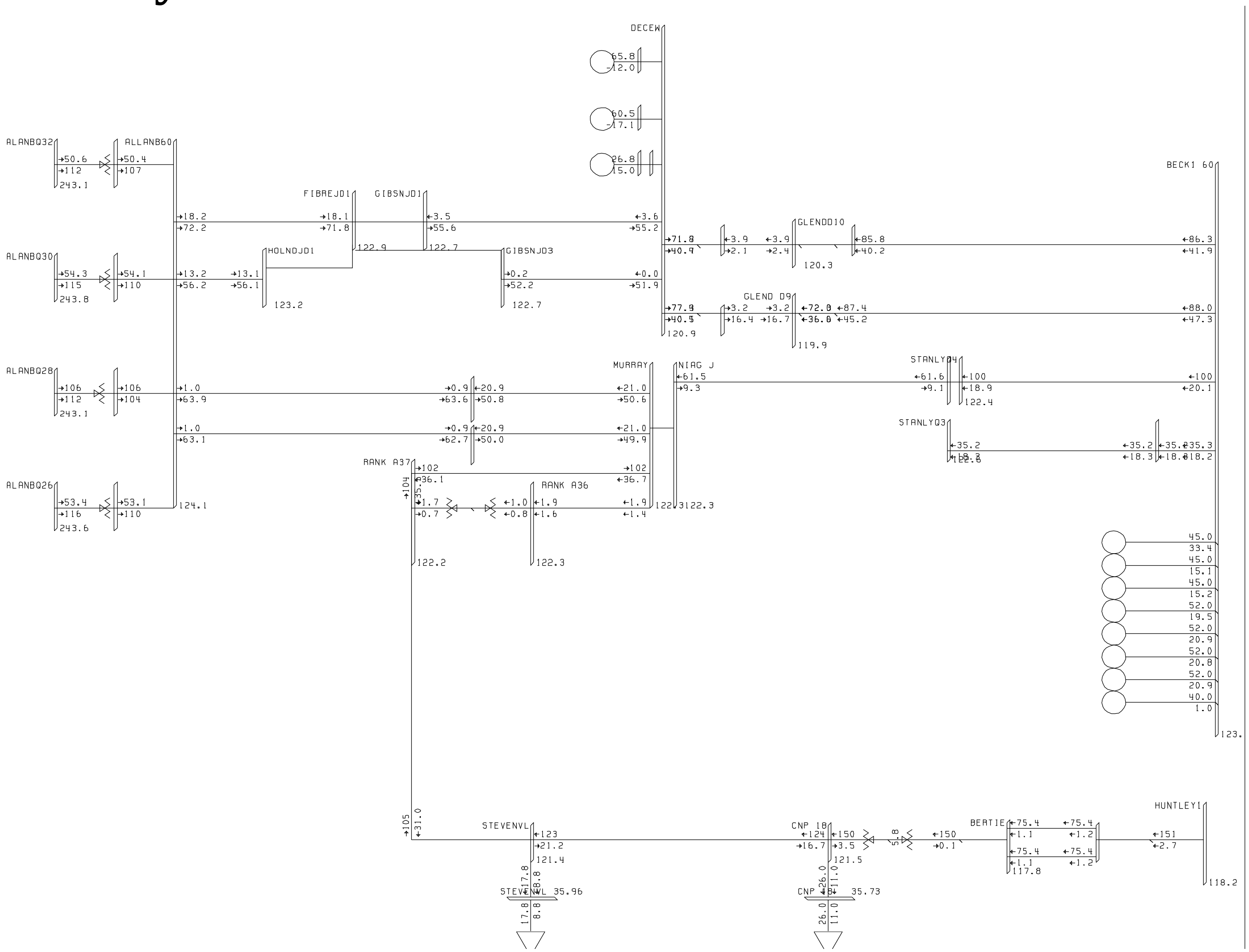

Appendix B Single Line Diagrams for ± 150 MW flow on Ft Erie – Huntley Tie



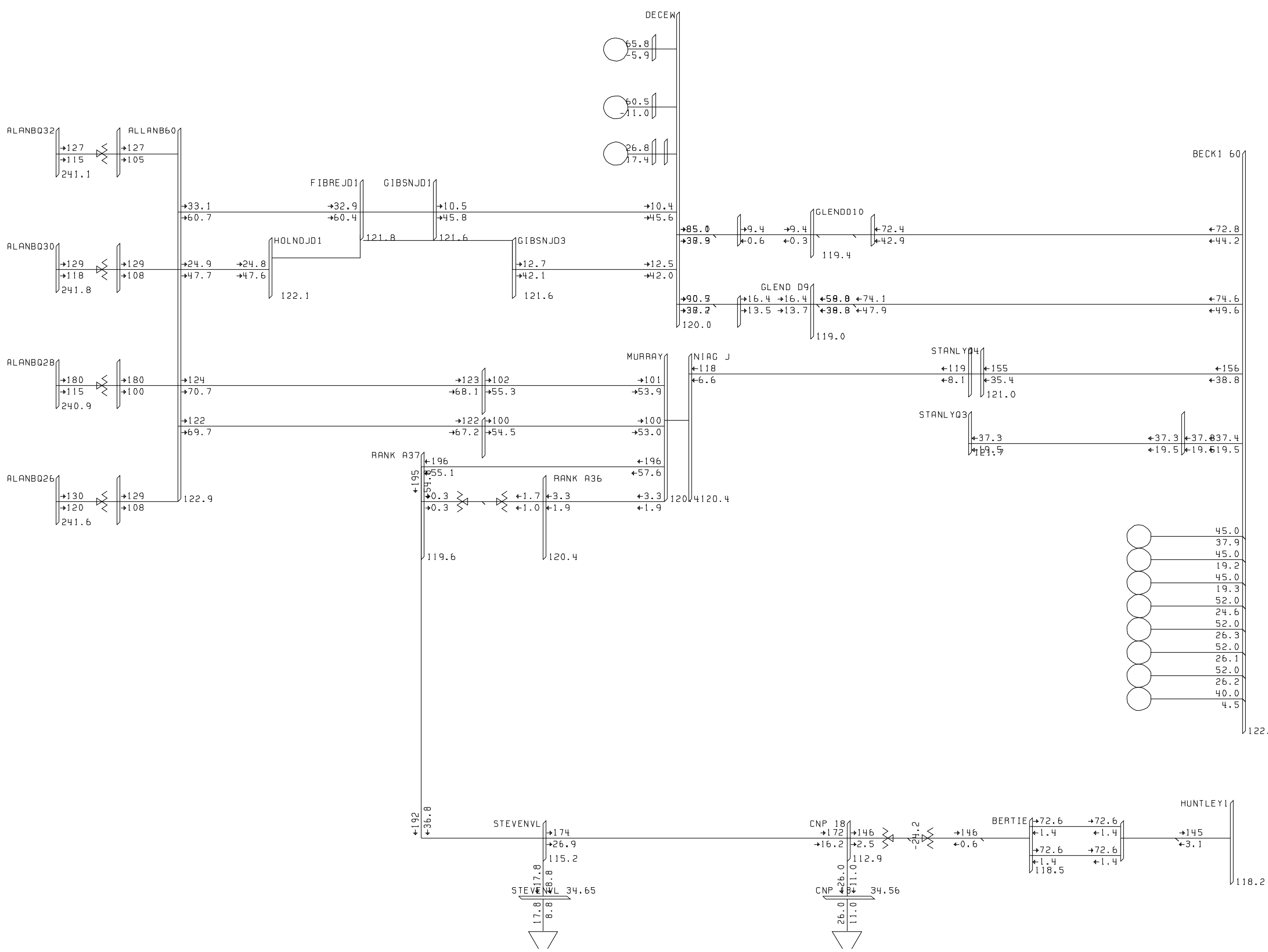

DECEW
ALANBQ32
ALLANB60
FIBREJD1
GIBSNJD1
BECK1 60
GLENDD10
ALANBQ30
HOLNDJD1
GIBSNJD3
GLEND D9
ALANBQ28
MURRAY
NIAG J
STANLYQ4
STANLYQ3
RANK A37
RANK A36
ALANBQ26
STEVENVL
CNP 18
BERTIE
HUNTLEY1
STEVENVL 34.65
CNP
34.56

Exhibit B, Tab 10, Schedule 1

Overview - Customer Impact Assessment

OVERVIEW - CUSTOMER IMPACT ASSESSMENT

CNP Transmission applied for, and Hydro One completed, a Customer Impact Assessment for the Project. Hydro One issued a final Customer Impact Assessment Report (the "CIA Report") for the Project on September 16, 2006. The purpose of the CIA Report is to assess the potential impacts on the existing transmission connected customers in the vicinity of the proposed new interconnection facility at their connection point to the Hydro One system.

The CIA Report, which is provided in **Exhibit B, Tab 10, Schedule 2**, concludes that the Project is not expected to have significant adverse impacts on Hydro One or on customers in the area, including during the construction period.

Exhibit B, Tab 10, Schedule 2

Hydro One's Customer Impact Assessment Report

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

CUSTOMER IMPACT ASSESSMENT

CANADIAN NIAGARA POWER INC.

FORT ERIE INTERCONNECTION

Revision: R2

Date: September 16, 2006

Issued by: **System Investment Division**
Hydro One Networks Inc.

Prepared by:

Peter Huang
Assistant Network Engineer/Officer
Transmission System Development
Hydro One Networks Inc.

Reviewed by:

John Sabiston
Transmission Plans Manager - West
Transmission System Development
Hydro One Networks Inc.

Disclaimer

This Draft Customer Impact Assessment was prepared based on information available about the connection of the proposed Canadian Niagara Power Inc.'s (CNP) Fort Erie Interconnection. It is intended to highlight significant impacts, if any, to affected transmission customers early in the project development process and thus allow an opportunity for these parties to bring forward any concerns that they may have. Subsequent changes to the required modifications or the implementation plan may affect the impacts of the proposed connection identified in Customer Impact Assessment. The results of this Customer Impact Assessment are also subject to change to accommodate the requirements of the IESO and other regulatory or municipal authority requirements.

Hydro One shall not be liable to any third party which uses the results of the Customer Impact Assessment under any circumstances whatsoever for any indirect or consequential damages, loss of profit or revenues, business interruption losses, loss of contract or loss of goodwill, special damages, punitive or exemplary damages, whether any of the said liability, loss or damages arises in contract, tort or otherwise. Any liability that Hydro One may have to CNP in respect of the Customer Impact Assessment is governed by the Agreement between CNP and Hydro One dated April 21, 2006.

CUSTOMER IMPACT ASSESSMENT
CNP FORT ERIE INTERCONNECTION

1.0 INTRODUCTION

1.1 Background

Canadian Niagara Power Inc. (CNP), a subsidiary of FortisOntario, is the local transmitter and distributor in the Fort Erie area. CNP's transmission system is presently connected to the Hydro One 115kV system at Murray TS, and it is also connected to the New York grid at Huntley TS. The load served by CNP can be either supplied from Ontario through Hydro One interconnected transmission system or the New York side. However, the existing system is setup in a "break before make" fashion, resulting in power interruption to the local customers due to the radial nature of the system setup.

CNP is proposing to establish a permanent interconnection between Hydro One transmission system and the New York Huntley station by installing a phase shifter and voltage regulator at CNP Station #18. The permanent interconnection can provide dual supply routes for the local loads served by CNP thus improving local supply reliability.

1.2 Fort Erie Interconnection

To maintain control of the flow across the proposed interconnection, a phase shifter, rated at approximately 150MVA, is proposed. A similar sized voltage regulator is also proposed in order to offset the minor voltage difference across two transmission systems and control the MVAR flow between the two systems. With this proposed interconnection, loads served by CNP can be simultaneously supplied from the Ontario system and the New York system. The single line diagram for the interconnection can be found in Appendix A.

1.3 Customer Connections

The purpose of this CIA is to assess the potential impacts on the existing transmission connected customer(s) in the vicinity of the proposed new interconnection facility at their connection point to the Hydro One system. The primary focus of this study was on customers supplied by stations directly connected to circuit A36N/A37N and Q4N. Table 1 provides a list of the customers connected at each station:

Table 1: Customers Connected to A36N, A37N, and Q4N

Station	Customers
Kalar MTS, 115kV	- Niagara Falls Hydro Inc.
Murray TS	- Niagara Falls Hydro Inc.
Stanley TS	- Niagara Falls Hydro Inc. - Niagara-on-the-Lake Hydro Inc. - Ontario Power Generation Inc.
Rankine CTS, 115kV (CNP Station #11)	- Canadian Niagara Power Inc.

2.0 METHODOLOGY & CRITERIA

2.1 Planning Criteria

To establish the adequacy of Hydro One transmission system incorporating the proposed additional generation facilities, the following post-fault voltage decline criteria were applied as per "IESO Transmission Assessment Criteria":

http://www.theimo.com/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

- The loss of a single transmission circuit should not result in a voltage decline greater than 10% for pre-transformer tap-changer action (including station loads) and 10% post-transformer tap-changer action (5% for station loads) ;
- The loss of a double transmission circuit should not result in a voltage decline greater than 10% for pre-transformer tap-changer action (including station loads) and 10% post- transformer tap-changer action (5% for station loads) ;
- Voltages below 50 kV shall be maintained in accordance with CSA 235.

2.2 Study Assumptions

July 2006 summer basecase was used. The following system conditions are present or added to the voltage study to ensure proper modeling of the area:

- QFW reinforcement is assumed in-service
- Local 115kV circuit parameters are updated using data provided by CNP
- Phase shifter and voltage regulator are added using assumed data from IESO
- New 115kV circuit connection is established by connecting the Ontario system to the phase shifter, CNP Station #18, and Huntley TS using data provided by CNP
- Local station loads are checked against historical loading to ensure proper modeling
- All loads are modeled as constant MVA load

Nanticoke GS units are backed off to allow for import from the New York interconnection when setting up the import case.

2.3 Power System Analysis

Power system analysis is an integral part of the transmission and distribution planning process. It is used by Hydro One to evaluate the capability of the existing network to deliver power and energy from generating stations to provide a reliable supply to customers.

a. Load Flow Studies: The PTI PSS/E AC load flow program was used to set up detailed base cases with the proposed Fort Erie Interconnection.

b. Short-Circuit Studies: Short circuit studies are used to determine the impact of the proposed interconnection at its point of connection to Hydro One.

3.0 ASSESSMENT OF HYDRO ONE NETWORKS SHORT CIRCUIT LEVELS AT CUSTOMER CONNECTION

Short-circuit studies were carried out to assess the fault contribution of the new Fort Erie Interconnection. The study area encompasses the stations connected to 115kV A36N, A37N, and Q4N and end stations. The following are study assumptions used for short circuit studies:

- Base case assumes existing & committed generating facilities in-service.
- Pre-fault voltage of 250 kV at 220 kV stations is assumed.
- Pre-fault voltage of 127 kV at 115 kV stations is assumed.
- Pre-fault voltage of 14.2 kV at 13.8kV stations is assumed.
- New York short circuit equivalent is given by CNP. The maximum interconnection condition is used to assess the worst short circuit level.

The studies results are summarized in Table 2 to Table 5 below show both symmetric and asymmetric (3-cycle) fault currents and percentage increase. The study also assumes maximum contribution from all the planned generation additions.

3.1 Present Systems

Table 2: Present Fault Levels

Area Customers	Fault Levels (kA)			
	Symmetrical		Asymmetrical	
	3-Phase	L-G	3-Phase	L-G
Allanburg TS 115kV	35.9	37.0	45.0	38.9
Beck1 TS 115kV	26.2	29.0	31.0	36.3
Kalar MTS 115kV A36N	22.5	19.5	25.3	19.6
Kalar MTS 115kV A37N	22.6	19.7	25.5	19.8
Murray TS 115kV	22.7	19.0	25.8	19.5
Rankine CTS (CNP #11) 115kV	17.6	14.0	18.4	14.3
Stanley TS 115kV Q4N	20.7	17.6	21.6	17.6
Murray TS 13.8kV B Bus	15.2	4.3	19.7	6.1
Murray TS 13.8kV Y Bus	15.3	7.2	20.0	10.1
Murray TS 13.8kV J Bus	13.7	7.1	17.7	9.9
Murray TS 13.8kV K Bus	13.7	7.1	17.7	9.9
Stanley TS 13.8kV BY Bus	16.8	8.0	21.1	10.2
Stanley TS 13.8kV JQ Bus	16.9	5.1	22.6	6.0

3.2 With Interconnection using Maximum Condition for New York Equivalent

Table 3: Fault Levels with Interconnection

Area Customers	Fault Levels (kA)			
	Symmetrical		Asymmetrical	
	3-Phase	L-G	3-Phase	L-G
Allanburg TS 115kV	38.3	38.8	47.3	40.8
Beck1 TS 115kV	27.5	30.0	32.3	37.5
Kalar MTS 115kV A36N	24.3	20.6	26.9	20.8
Kalar MTS 115kV A37N	24.5	20.8	27.0	21.0
Murray TS 115kV	25.8	21.1	28.9	21.4
Rankine CTS (CNP #11) 115kV	20.9	16.2	21.7	16.5
Stanley TS 115kV Q4N	22.2	18.5	23.0	18.5
Murray TS 13.8kV B Bus	15.4	4.3	20.0	6.1
Murray TS 13.8kV Y Bus	15.5	7.2	20.1	10.1
Murray TS 13.8kV J Bus	13.8	7.1	17.9	10.0
Murray TS 13.8kV K Bus	13.8	7.1	17.9	10.0
Stanley TS 13.8kV BY Bus	16.9	8.0	21.2	10.2
Stanley TS 13.8kV JQ Bus	17.0	5.1	22.7	6.0

Table 4: Station Breaker Capability

Station	Fault Levels (kA)			
	Station Maximum		Lowest Breaker Capability	
	Symmetrical	Asymmetrical	Symmetrical	Asymmetrical*
Allanburg TS 115kV	38.8	47.3	40.0	48.0
Beck1 TS 115kV	30.0	37.5	36.0	43.2
Murray TS 115kV	25.8	28.9	40.0	48.0
Murray TS 13.8kV	15.5	20.1	31.5	37.8
Stanley TS 13.8kV	17.0	22.7	25.0	30.0

* The asymmetrical breaker capability is a calculated value based on 1.2 x symmetrical capability

Table 5: The Incorporation of Fort Erie Interconnection

Area Customers	Percentage Increase (%)			
	Symmetrical		Asymmetrical	
	3-Phase	L-G	3-Phase	L-G
Allanburg TS 115kV	6.7%	4.9%	5.3%	4.7%
Beck1 TS 115kV	5.0%	3.4%	4.2%	3.6%
Kalar MTS 115kV A36N	8.0%	5.6%	6.4%	6.0%
Kalar MTS 115kV A37N	8.4%	5.6%	5.9%	6.0%
Murray TS 115kV	13.7%	11.1%	12.1%	9.9%
Rankine CTS (CNP #11) 115kV	18.8%	15.7%	18.1%	15.0%
Stanley TS 115kV Q4N	7.2%	5.1%	6.5%	4.9%
Murray TS 13.8kV B Bus	1.3%	0.0%	1.6%	0.0%
Murray TS 13.8kV Y Bus	1.3%	0.0%	0.5%	0.0%
Murray TS 13.8kV J Bus	0.7%	0.0%	1.2%	1.0%
Murray TS 13.8kV K Bus	0.7%	0.0%	1.2%	1.0%
Stanley TS 13.8kV BY Bus	0.6%	0.0%	0.5%	0.0%
Stanley TS 13.8kV JQ Bus	0.6%	0.0%	0.5%	0.0%

Table 2 study results show that existing fault levels meet maximum symmetrical three-phase and single line-to-ground faults (kA) of 115 kV and 13.8 kV for all equipment connected to Hydro One transmission system as set out in Appendix 2 of the *Transmission System Code* (TSC). The maximum symmetrical three-phase and single line-to-ground faults given in the TSC may be summarized as follows:

Nominal Voltage (kV)	*Max. 3-Phase Fault (kA)*	*Max. SLG Fault (kA)*
230	63	80
115	50	50
44	20	19
27.6	17	12 (4 wire)/ 0.45 (3 wire)
13.8 and under	21	10

Table 5 shows that there is a maximum of 18.8 % increase in short circuit level at Rankine CTS (CNP Station #11) as a result of the Fort Erie Interconnection. The maximum short circuit increase in other non-CNP station is Murray TS, with an increase of 13.7%. However, the fault current observed is still below the capability rating of the installed breakers at the stations. Table 4 also shows that there is very limited increase in short circuit level at other locations, especially the 13.8kV buses.

Overall, the increased short circuit level is below the TSC limit and the existing equipment rating. However, customers are encouraged to verify the capability of their installed equipment to ensure safe operation.

4.0 ASSESSMENT OF HYDRO ONE NETWORKS VOLTAGE PERFORMANCE AT CUSTOMER CONNECTION

Load flow studies were carried out for the new interconnection at Fort Erie. These studies reviewed the voltage performance on the local 115 kV system and customer stations in the vicinity. The area under study encompasses Allanburg TS, Beck 1 TS (115kV, 60Hz), Kalar MTS, Murray TS, Stanley TS, and the CNP interconnection station Rankine CTS (also known as CNP Station #11).

Local voltage impact was assessed using post-contingency load flows. The following operating conditions and generator-associated connections were assumed for testing the local voltage impact:

The following *scenarios* were used to assess the local voltage impact:

1. Scenario 1: existing system without Fort Erie Interconnection
2. Scenario 2: Interconnection is established. No net power flow between Ontario and other jurisdictions. The Fort Erie phase shifter is regulating and allowing 0 MW to flow.
3. Scenario 3: An IESO documented maximum import of 1300MW flows across the Ontario-New York interface at Niagara (excluding Fort Erie Interconnection). The Fort Erie phase shifter is regulating and allowing a maximum import of 150 MW (limited by equipment ratings).

Tests for the voltage impact were conducted using the following contingencies:

a) A single contingency loss of A37N (performed on scenario 1, 2, and 3)
b) A single contingency loss of A36N (performed on scenario 3)
c) A single contingency loss of Q4N (performed on scenario 1 and 3)
d) A single contingency loss of the Fort Erie Interconnection (performed on scenario 3)
e) A single contingency loss of Q30M (performed on scenario 3)
f) A single contingency loss of BP 27 (performed on scenario 3)

Scenario 3 is tested extensively because it represents the most heavily loaded case in the local area. Results for these tests are shown in Tables 6-14:

Table 6: Loss of A37N (scenario 1)

	Pre-C Voltage	Before ULTC Post-C Voltage		After ULTC Post-C Voltage	
		Voltage	% Change	Voltage	% Change
Allanburg TS 115kV	125.60	125.94	0.3%	126.04	0.4%
Beck1 TS 115kV	124.22	124.20	0.0%	124.25	0.0%
Kalar MTS 115kV A36N	124.58	124.33	-0.2%	124.44	-0.1%
Kalar MTS 115kV A37N	124.59	124.59	0.0%	124.59	0.0%
Murray TS 115kV	123.91	123.46	-0.4%	123.54	-0.3%
Rankine CTS (CNP #11) 115kV	123.61	123.61	0.0%	123.61	0.0%
Stanley TS 115kV Q4N	123.87	123.64	-0.2%	123.70	-0.1%
Murray TS 13.8kV B Bus	14.22	13.35	-6.1%	13.91	-2.2%
Murray TS 13.8kV Y Bus	14.18	13.25	-6.6%	13.97	-1.5%
Murray TS 13.8kV J Bus	14.22	14.63	2.9%	14.39	1.2%
Murray TS 13.8kV K Bus	14.33	13.74	-4.1%	13.93	-2.8%
Stanley TS 13.8kV BY Bus	14.16	14.14	-0.1%	14.15	-0.1%
Stanley TS 13.8kV JQ Bus	14.13	14.12	-0.1%	14.12	-0.1%

Table 7: Loss of A37N (scenario 2)

	Pre-C Voltage	Before ULTC Post-C Voltage		After ULTC Post-C Voltage	
		Voltage	% Change	Voltage	% Change
Allanburg TS 115kV	125.61	125.95	0.3%	125.95	0.3%
Beck1 TS 115kV	124.23	124.20	0.0%	124.20	0.0%
Kalar MTS 115kV A36N	124.59	124.34	-0.2%	124.36	-0.2%
Kalar MTS 115kV A37N	124.60	124.60	0.0%	124.60	0.0%
Murray TS 115kV	123.93	123.46	-0.4%	123.47	-0.4%
Rankine CTS (CNP #11) 115kV	123.62	119.61	-3.2%	119.38	-3.4%
Stanley TS 115kV Q4N	123.89	123.64	-0.2%	123.65	-0.2%
Murray TS 13.8kV B Bus	14.22	13.35	-6.1%	13.90	-2.3%
Murray TS 13.8kV Y Bus	14.18	13.25	-6.6%	13.96	-1.6%
Murray TS 13.8kV J Bus	14.22	14.63	2.9%	14.39	1.2%
Murray TS 13.8kV K Bus	14.14	13.55	-4.2%	13.92	-1.6%
Stanley TS 13.8kV BY Bus	14.16	14.14	-0.1%	14.14	-0.1%
Stanley TS 13.8kV JQ Bus	14.14	14.12	-0.1%	14.12	-0.1%

Table 8: Loss of A37N (scenario 3)

	Pre-C Voltage	Before ULTC Post-C Voltage		After ULTC Post-C Voltage	
		Voltage	% Change	Voltage	% Change
Allanburg TS 115kV	125.03	125.26	0.2%	125.27	0.2%
Beck1 TS 115kV	123.97	123.84	-0.1%	123.85	-0.1%
Kalar MTS 115kV A36N	124.13	123.71	-0.3%	123.74	-0.3%
Kalar MTS 115kV A37N	124.14	124.14	0.0%	124.14	0.0%
Murray TS 115kV	123.55	122.90	-0.5%	122.91	-0.5%
Rankine CTS (CNP #11) 115kV	123.58	124.14	0.5%	124.14	0.5%
Stanley TS 115kV Q4N	123.53	123.16	-0.3%	123.17	-0.3%
Murray TS 13.8kV B Bus	14.18	13.28	-6.3%	13.82	-2.5%
Murray TS 13.8kV Y Bus	14.33	13.35	-6.8%	13.88	-3.1%
Murray TS 13.8kV J Bus	14.18	14.56	2.7%	14.32	1.0%
Murray TS 13.8kV K Bus	14.29	13.66	-4.4%	13.85	-3.1%
Stanley TS 13.8kV BY Bus	14.24	14.21	-0.2%	14.21	-0.2%
Stanley TS 13.8kV JQ Bus	14.30	14.27	-0.2%	14.27	-0.2%

Table 9: Loss of A36N (scenario 3)

	Pre-C Voltage	Before ULTC Post-C Voltage		After ULTC Post-C Voltage	
		Voltage	% Change	Voltage	% Change
Allanburg TS 115kV	125.03	125.11	0.1%	125.02	0.0%
Beck1 TS 115kV	123.97	123.73	-0.2%	123.64	-0.3%
Kalar MTS 115kV A36N	124.13	124.13	0.0%	124.13	0.0%
Kalar MTS 115kV A37N	124.14	123.53	-0.5%	123.39	-0.6%
Murray TS 115kV	123.55	122.65	-0.7%	122.43	-0.9%
Rankine CTS (CNP #11) 115kV	123.58	122.74	-0.7%	122.45	-0.9%
Stanley TS 115kV Q4N	123.53	122.96	-0.5%	122.80	-0.6%
Murray TS 13.8kV B Bus	14.18	13.44	-5.2%	13.85	-2.3%
Murray TS 13.8kV Y Bus	14.33	13.59	-5.2%	14.00	-2.3%
Murray TS 13.8kV J Bus	14.18	14.54	2.5%	14.26	0.6%
Murray TS 13.8kV K Bus	14.29	13.63	-4.6%	13.97	-2.2%
Stanley TS 13.8kV BY Bus	14.24	14.19	-0.4%	14.18	-0.4%
Stanley TS 13.8kV JQ Bus	14.30	14.25	-0.3%	14.23	-0.5%

Table 10: Loss of Q4N (scenario 1)

	Pre-C Voltage	Before ULTC Post-C Voltage		After ULTC Post-C Voltage	
		Voltage	% Change	Voltage	% Change
Allanburg TS 115kV	125.60	125.53	-0.1%	125.53	-0.1%
Beck1 TS 115kV	124.22	124.00	-0.2%	123.99	-0.2%
Kalar MTS 115kV A36N	124.58	124.57	0.0%	124.57	0.0%
Kalar MTS 115kV A37N	124.59	124.58	0.0%	124.58	0.0%
Murray TS 115kV	123.91	123.97	0.0%	123.97	0.0%
Rankine CTS (CNP #11) 115kV	123.61	123.67	0.0%	123.67	0.0%
Stanley TS 115kV Q4N	123.87	123.87	0.0%	123.87	0.0%
Murray TS 13.8kV B Bus	14.22	14.22	0.0%	14.22	0.0%
Murray TS 13.8kV Y Bus	14.18	14.19	0.1%	14.19	0.1%
Murray TS 13.8kV J Bus	14.22	14.23	0.1%	14.23	0.1%
Murray TS 13.8kV K Bus	14.33	14.34	0.1%	14.34	0.1%
Stanley TS 13.8kV BY Bus	14.16	13.51	-4.6%	13.94	-1.6%
Stanley TS 13.8kV JQ Bus	14.13	12.91	-8.6%	13.85	-2.0%

Table 11: Loss of Q4N (scenario 3)

	Pre-C Voltage	Before ULTC Post-C Voltage		After ULTC Post-C Voltage	
		Voltage	% Change	Voltage	% Change
Allanburg TS 115kV	125.03	124.96	-0.1%	124.96	-0.1%
Beck1 TS 115kV	123.97	123.76	-0.2%	123.75	-0.2%
Kalar MTS 115kV A36N	124.13	124.09	0.0%	124.09	0.0%
Kalar MTS 115kV A37N	124.14	124.10	0.0%	124.10	0.0%
Murray TS 115kV	123.55	123.55	0.0%	123.54	0.0%
Rankine CTS (CNP #11) 115kV	123.58	123.58	0.0%	123.58	0.0%
Stanley TS 115kV Q4N	123.53	123.53	0.0%	123.53	0.0%
Murray TS 13.8kV B Bus	14.18	14.17	-0.1%	14.17	-0.1%
Murray TS 13.8kV Y Bus	14.33	14.33	0.0%	14.33	0.0%
Murray TS 13.8kV J Bus	14.18	14.18	0.0%	14.18	0.0%
Murray TS 13.8kV K Bus	14.29	14.29	0.0%	14.29	0.0%
Stanley TS 13.8kV BY Bus	14.24	13.50	-5.2%	13.90	-2.4%
Stanley TS 13.8kV JQ Bus	14.30	13.02	-9.0%	13.81	-3.4%

Table 12: Loss of Interconnection (scenario 3)

	Pre-C Voltage	Before ULTC Post-C Voltage		After ULTC Post-C Voltage	
		Voltage	% Change	Voltage	% Change
Allanburg TS 115kV	125.03	124.90	-0.1%	124.94	-0.1%
Beck1 TS 115kV	123.97	123.85	-0.1%	123.87	-0.1%
Kalar MTS 115kV A36N	124.13	123.93	-0.2%	123.96	-0.1%
Kalar MTS 115kV A37N	124.14	123.94	-0.2%	123.97	-0.1%
Murray TS 115kV	123.55	123.30	-0.2%	123.33	-0.2%
Rankine CTS (CNP #11) 115kV	123.58	123.00	-0.5%	123.03	-0.4%
Stanley TS 115kV Q4N	123.53	123.36	-0.1%	123.39	-0.1%
Murray TS 13.8kV B Bus	14.18	14.14	-0.3%	14.15	-0.2%
Murray TS 13.8kV Y Bus	14.33	14.30	-0.2%	14.31	-0.1%
Murray TS 13.8kV J Bus	14.18	14.15	-0.2%	14.15	-0.2%
Murray TS 13.8kV K Bus	14.29	14.26	-0.2%	14.26	-0.2%
Stanley TS 13.8kV BY Bus	14.24	14.22	-0.1%	14.23	-0.1%
Stanley TS 13.8kV JQ Bus	14.30	14.28	-0.1%	14.28	-0.1%

Table 13: Loss of Q30M (scenario 3)

	Pre-C Voltage	Before ULTC Post-C Voltage		After ULTC Post-C Voltage	
		Voltage	% Change	Voltage	% Change
Allanburg TS 115kV	125.03	123.92	-0.9%	123.68	-1.1%
Beck1 TS 115kV	123.97	123.38	-0.5%	123.22	-0.6%
Kalar MTS 115kV A36N	124.13	123.13	-0.8%	122.86	-1.0%
Kalar MTS 115kV A37N	124.14	123.14	-0.8%	122.87	-1.0%
Murray TS 115kV	123.55	122.65	-0.7%	122.36	-1.0%
Rankine CTS (CNP #11) 115kV	123.58	122.74	-0.7%	122.39	-1.0%
Stanley TS 115kV Q4N	123.53	122.78	-0.6%	122.56	-0.8%
Murray TS 13.8kV B Bus	14.18	14.06	-0.8%	14.03	-1.1%
Murray TS 13.8kV Y Bus	14.33	14.22	-0.8%	14.18	-1.0%
Murray TS 13.8kV J Bus	14.18	14.07	-0.8%	14.04	-1.0%
Murray TS 13.8kV K Bus	14.29	14.18	-0.8%	14.14	-1.0%
Stanley TS 13.8kV BY Bus	14.24	14.16	-0.6%	14.13	-0.8%
Stanley TS 13.8kV JQ Bus	14.30	14.21	-0.6%	14.19	-0.8%

Table 14: Loss of PA27 (scenario 3)

	Pre-C Voltage	Before ULTC Post-C Voltage		After ULTC Post-C Voltage	
		Voltage	% Change	Voltage	% Change
Allanburg TS 115kV	125.03	124.92	-0.1%	124.99	0.0%
Beck1 TS 115kV	123.97	123.90	-0.1%	123.94	0.0%
Kalar MTS 115kV A36N	124.13	124.01	-0.1%	124.09	0.0%
Kalar MTS 115kV A37N	124.14	124.01	-0.1%	124.10	0.0%
Murray TS 115kV	123.55	123.42	-0.1%	123.52	0.0%
Rankine CTS (CNP #11) 115kV	123.58	123.46	-0.1%	123.55	0.0%
Stanley TS 115kV Q4N	123.53	123.43	-0.1%	123.50	0.0%
Murray TS 13.8kV B Bus	14.18	14.16	-0.1%	14.17	-0.1%
Murray TS 13.8kV Y Bus	14.33	14.32	-0.1%	14.33	0.0%
Murray TS 13.8kV J Bus	14.18	14.17	-0.1%	14.18	0.0%
Murray TS 13.8kV K Bus	14.29	14.27	-0.1%	14.29	0.0%
Stanley TS 13.8kV BY Bus	14.24	14.23	-0.1%	14.24	0.0%
Stanley TS 13.8kV JQ Bus	14.30	14.29	-0.1%	14.30	0.0%

The maximum and minimum phase-to-phase voltages given in the IESO's Transmission Assessment Criteria and Canadian Standard Association document CAN-3-C235-83 are as follows:

Nominal Voltage (kV)	*Maximum Voltage (kV)*	*Minimum Voltage (kV)*
115	127 *	113
13.8	+6% nominal = 14.63	+6% nominal = 12.97

*Certain buses can be assigned specific maximum and minimum voltages as required for operations. In northern Ontario, the maximum continuous voltage for the 230 and 115kV systems can be as high as 260kV and 132kV respectively. *[from IESO document IMO_REQ_0041 Issue 2.0]*

The voltage study indicated there is no voltage violation except at two locations where excessive voltage drop can occur. One location is Murray TS, particularly the 13.8kV B Bus and Y Bus. Another location is the 13.8kV JQ Bus at Stanley TS. The voltage drop at Murray TS can be as great as 6.8% immediately post contingency while the voltage change in Stanley TS can be as great as 9%.

As noted in the tests on Scenario 1 (existing facilities), the voltage violation already exists at Murray TS's B Bus and Y Bus due to increased load in the area. When compared to other scenarios, the new Fort Erie Interconnection is shown to have only contributed an additional 0.2% under the maximum transfer condition. Another test on Scenario 1 (as shown in Table 10) shows that the existing system setup will result in a voltage drop of 8.6% at Stanley TS JQ Bus. The new Fort Erie Interconnection contributed 0.4% of increase of voltage drop at Stanley TS.

Since there are existing voltage violations, Hydro One will further investigate these problems and implement solutions if appropriate to correct the situation to ensure that post contingency voltage changes fall within the mandated limit. Therefore, the additional Fort Erie Interconnection will not result in substantial change in the voltage profile of customers supplied by neighbouring 115kV circuits.

5.0 CONNECTION LINE RELIABILITY

The new interconnection will add one phase shifter, one voltage regulator, and one disconnect switch in series onto the existing circuit. There is an existing breaker at Rankine CTS (CNP Station #11) that can isolate faults occurring within the CNP's circuit. There are also breakers in CNP Station #18 that can maintain CNP Line #2 if there are problems with the added equipment. Therefore, the additional equipment is not expected to materially reduce the reliability of Hydro One's circuit.

6.0 PRELIMINARY OUTAGE IMPACT ASSESSMENT

Outages associated with the construction work to install the new phase shifter and voltage regulator does not interfere with the operation of Hydro One's circuits. There is no expected outage to be taken by Hydro One to facilitate CNP to install the new phase shifter and voltage regulator. Only minor impact is expected during commissioning period for the interconnection facility.

7.0 CONCLUSIONS

The overall findings of this Customer Impact Assessment are summarized below:

- The results of short circuit studies show that the neighbouring stations encountered small amount of increases in fault level. However the increased fault level is still within the capability of the existing facilities.

- The new interconnection, under heavy flow condition, contributes minor amount of voltage drop in the area. However, the increase is not significant as there are existing voltage performance violations, which will be addressed by Hydro One under separate projects.

- The new interconnection is not expected to materially reduce the reliability of the customers connected in the area. In addition, there is no expected outage impact to Hydro One and its connected customers during construction period of the interconnection.

Overall, the new Fort Erie Interconnection is not expected to have a significant impact on the customers in the area.

Appendix A: CNP Fort Erie Interconnection SLD

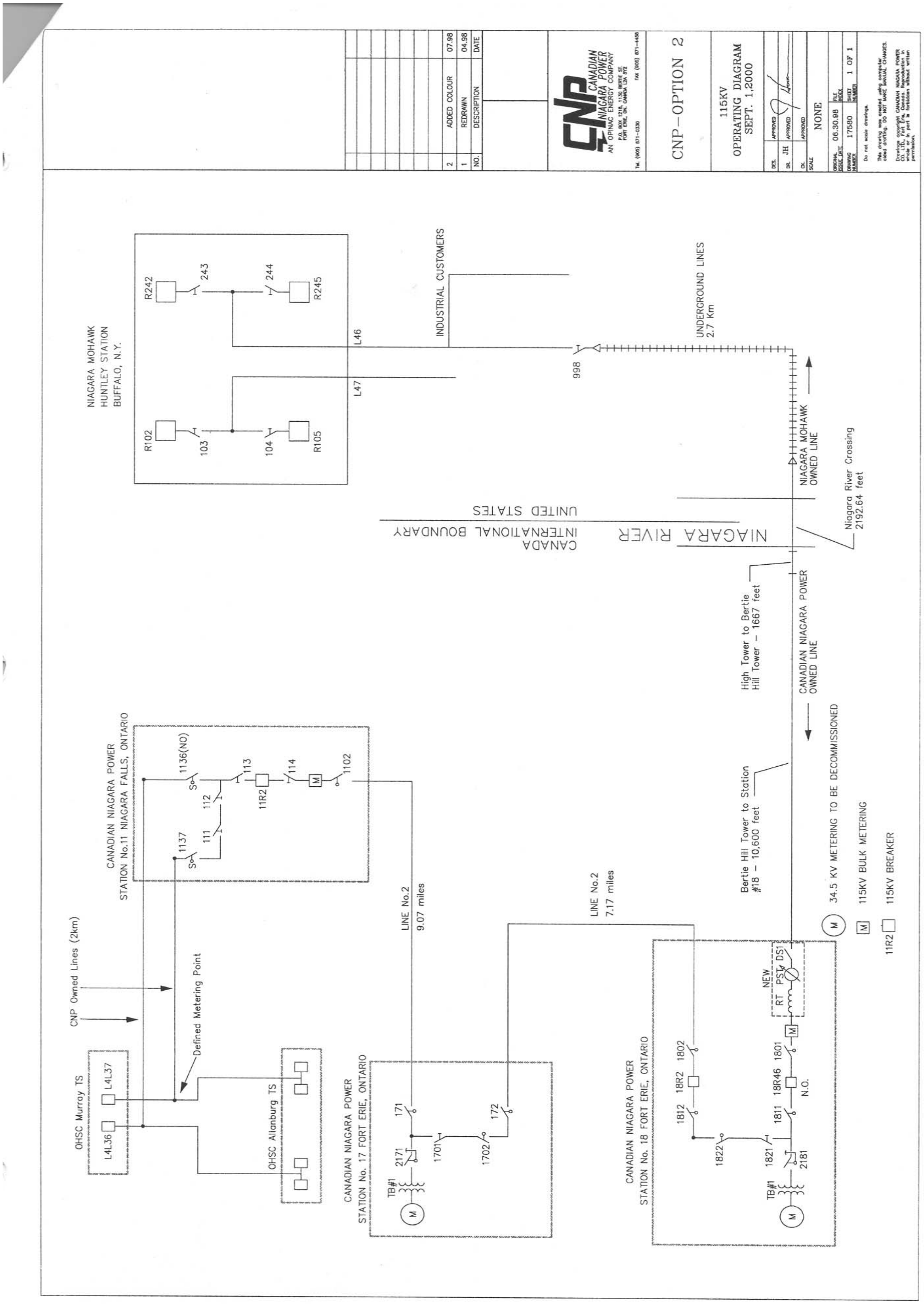


Exhibit B, Tab 11, Schedule 1

Overview - Feasibility Study

OVERVIEW - FEASIBILITY STUDY

The New York Independent System Operator's ("NYISO") interconnection process requires that a feasibility study be conducted to determine the impact of a proposed project on the connecting transmission owner's system and on potentially affected, neighbouring systems. To meet this requirement, SNC-Lavalin Power Ontario Inc., NYISO staff and USNG staff jointly conducted an interconnection feasibility study for the Project. The feasibility study involved a power flow analysis and a short circuit analysis on the New York State Transmission System, including the local transmission system owned by USNG. The results of the analysis are presented in the Feasibility Study Final Report (the "Feasibility Study Report"), issued on October 16, 2007, which is provided at **Exhibit B, Tab 11, Schedule 2**.

The Feasibility Study Report concludes that the Project would result in acceptable voltages. The Feasibility Study Report also identifies key transfer limits, which the Project has been designed to overcome. In addition, the Feasibility Study Report made preliminary estimates (a) that the necessary upgrade of 10 km of 115 kV transmission lines L46 and L47 at the Paradise Station would cost US $9 million (+/- 25%) and require 3 years for engineering, permitting and construction, and (b) that the development of the three breaker ring station in Buffalo would cost $4.5 million and require 18-24 months to engineer.

Exhibit B, Tab 11, Schedule 2

Feasibility Study - Final Report

Feasibility Study for

FORTRAN PROJECT
Queue #210
Paradise – Ft. Erie Tie Closed at Buffalo 3-Breaker Ring Station

Prepared by:

SNC-Lavalin Power Ontario Inc.
For NYISO and
Canadian Niagara Power Inc.

Reviewed by:
National Grid and Niagara Mohawk Power Corporation

Final Report

October 16, 2007

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Executive Summary

Executive Summary

CNP's (Canadian Niagara Power Inc.) transmission system is presently connected to the Hydro One 115kV system at Murray substation, and it can also be connected to the New York grid via line L46 to the Huntley substation. The load served by CNP can be either supplied from Ontario through Hydro One's interconnected transmission system or from the New York transmission grid of Niagara Mohawk Power Corporation/National Grid. The existing system is setup in a "break before make" fashion, resulting in power interruption to the local customers due to the radial nature of the system setup whenever a change over of supply is required.

National Grid has planned transmission system extensions and reconfiguration in the region on account of expected retirement of Huntley generating station. The extension and reconfiguration involve connection of lines 46 and 47 at a new Paradise Substation (instead of Huntley) by the year 2010. The study has therefore been carried out for the year 2011.

CNP, as the developer, is proposing to establish a permanent interconnection between Hydro One transmission system and the proposed Paradise station by installing a phase shifter and voltage regulator at CNP Station #18. The tie line from New York ISO system to CNP is proposed to be modified by setting up a 3 Breaker Ring Station in Buffalo to which lines L46, L47 and the tie to CNP would be connected. This arrangement resulted in balanced local customer transformers power flows. The permanent interconnection (termed the 'Fortran Project') can provide dual supply routes for the local loads served by CNP thus improving supply reliability. The IESO Ontario has proposed the parameters of the phase-shifter suitable for control of the tie power flow under a range of system conditions.

The NYISO Interconnection process (Attachment X of the NYISO OATT) required that a feasibility study be conducted to determine the impact of the project on the Connecting Transmission Owner's system and on potentially Affected Systems (neighboring systems).

SNC-Lavalin Power Ontario Inc. (SLPO), NYISO Staff and National Grid's staff have jointly conducted this Interconnection Feasibility study of the Fortran Project to satisfy the above NYISO tariff requirement. This study involved a power flow analysis and a short circuit analysis on the New York State Transmission System including the local transmission system owner's system. The study was conducted with and without the project to determine the local impact of the project.

Thermal and Voltage Studies have been completed for CNP-NYISO transfers up to 150 MW in both directions. The base case and contingency studies showed that the voltages were acceptable in all cases. Voltage changes due to contingencies were small in all cases. Thermal Studies showed that:

- The transfer limit from NYISO to CNP is limited to about 53 MW. The critical contingency is the outage of either L47 or L46 with the limitation being the low thermal rating of these circuits for line sections near Paradise Station. A temporary SPS scheme is proposed, to enable 150 MW pre-contingency transfers to CNP until the required line uprating is completed (as noted below).

- The power transfer on the CNP tie towards NYISO is limited to about 150 MW by the rating of internal circuits in CNP, but is not limited by circuits in New York ISO. All the voltage criteria were satisfied.

- 60 MW of CNP loads can be supplied radially from the 3 Breaker Ring Station in Buffalo with the line to Hydro One open.

- The Niagara River crossing of the CNP tie is rated at about 100 MVA. It is understood that the rating of these circuits will need to be increased to above 100 MVA if higher transfers are contemplated.

- The three-phase fault at the Paradise 115 kV bus was the most severe of the fault types showing an increase from 39 kA (without project) to 42 kA (with project). The value is within the rating of the lowest rated (50 kA) breaker at this location. The impact of the project was less than 2.6 kA in all cases. The three-phase fault level at the CANADA bus and 3 Breaker tie point was only 16 kA (Post-CNP tie).

- NG's Cost and Implementation time estimates are shown below

    1. **Upgrade of 6.3 miles of 115 kV transmission line L46 and L47 at the Paradise Station end**
       The cost to complete this upgrade is expected to be $9,000,000 (+/-25%) and will require 3 years for the engineering, permitting and construction. This upgrade will result in the ratings of the Paradise – FMC, FMC – Dunlop and Dunlop – DuPont sections of both line #46 and #47 increasing to 271 MVA summer normal, 313 MVA summer LTE, 359 MVA summer STE, 331 MVA winter normal, 364 MVA winter LTE and 404 MVA winter STE.

    2. **Create the 3 breaker Ring Station in Buffalo**:

       It is expected that the station will require 18-24 months to engineer and cost $4.5M.

3. NG's estimates of the earliest possible schedule for this project will be:

Spring 2008 – SRIS and Facility study would need to be complete, IA signed
Spring 2008 – Begin work on 3 breaker ring station
Spring 2009 – Begin work for reconductoring
Spring 2010 – 3 breaker ring station complete, SPS in service
Spring 2012 – Reconductoring complete, SPS removed from service

1 Introduction

Canadian Niagara Power Inc. (CNP), a subsidiary of FortisOntario, is the local transmitter and distributor in the Fort Erie area. CNP's transmission system is presently connected to the Hydro One 115kV system at Murray TS (Transformer Station), and it can also be connected to the National Grid (NG) system at Huntley station. The load served by CNP can be either supplied from Ontario through Hydro One interconnected transmission system or from the NYISO system of National Grid under an agreement between CNP and NG. The existing system is setup in a "break before make" fashion, resulting in power interruption to the local customers due to the radial nature of the system setup whenever a changeover is necessary.

National Grid has planned transmission system extensions and reconfiguration in the region on account of expected retirement of Huntley generating station. The extension and reconfiguration involve connection of lines 46 and 47 at a new Paradise Substation (instead of Huntley) by the year 2010. The study has therefore been carried out for the year 2011. The new line sections introduced as part of the new connection to Paradise station are rated at Rate B of 185 MW and this will lower the rating of circuits L46 and L47.

CNP is proposing to establish a permanent interconnection between Hydro One transmission system and the proposed NG Paradise station by installing a phase shifter and voltage regulator at CNP Station #18. The permanent interconnection can provide dual supply routes for the local loads served by CNP thus improving local supply reliability in the two systems. The estimated in service for the project is 2010.

According to the Standard Large Facility Interconnection Procedures (Attachment X of the NYISO OATT), a Feasibility Study is required (unless waived by a three-party agreement) to assess the impact of the project on the base case electrical system, and to determine a good-faith non-binding cost estimates and time to construct the facilities needed to interconnect the project in the NY Transmission System. The facilities include any System Upgrade Facilities (SUFs) and the Transmission Owner's Attachment Facilities (AFs) that are needed solely due to the project.

The feasibility study has been carried out to meet the above requirements and includes a Power Flow Analysis (reported in Section 4) and a Short Circuit Analysis (reported in Section 5) - both without and with the project to determine the incremental impact of the project on the system. These analyses were conducted in accordance with the applicable NERC, NPCC, NYSRC criteria, and NYISO and CTO's guidelines, procedures and practices.

2 Description of the FORTRAN Project

2.1 CNP Transmission System

The CNP distribution system at Fort Erie consists of a switching station (Rankine or CNP # 11) and two transmission stations Stevenville (CNP # 17) and CNP# 18. CNP#11 is fed from Murray substation of Hydro One. Line L2 connects the CNP#11 substation to CNP#17 substation in Fort Erie.

Hydro One's Murray Substation is connected to Allanburg TS (Transformer Station) and Beck GS. The CNP Fort Erie load may be connected to either A36N or A37N 115 kV circuits at CNP#11; by the switch arrangement shown in Figure 2.1. Both A36N and A37N are rated at approximately 270 MVA (summer weather conditions), and Line No. 2 is rated at 210 MVA. The CNP system can be fed radially from the NYISO grid by closing of a breaker at transformer station #18 (after opening the connection between CNP and IESO-controlled grid at CNP #11). The CNP system peak in this future study is assumed to be 60 MW at 0.92 power factor for the study year.

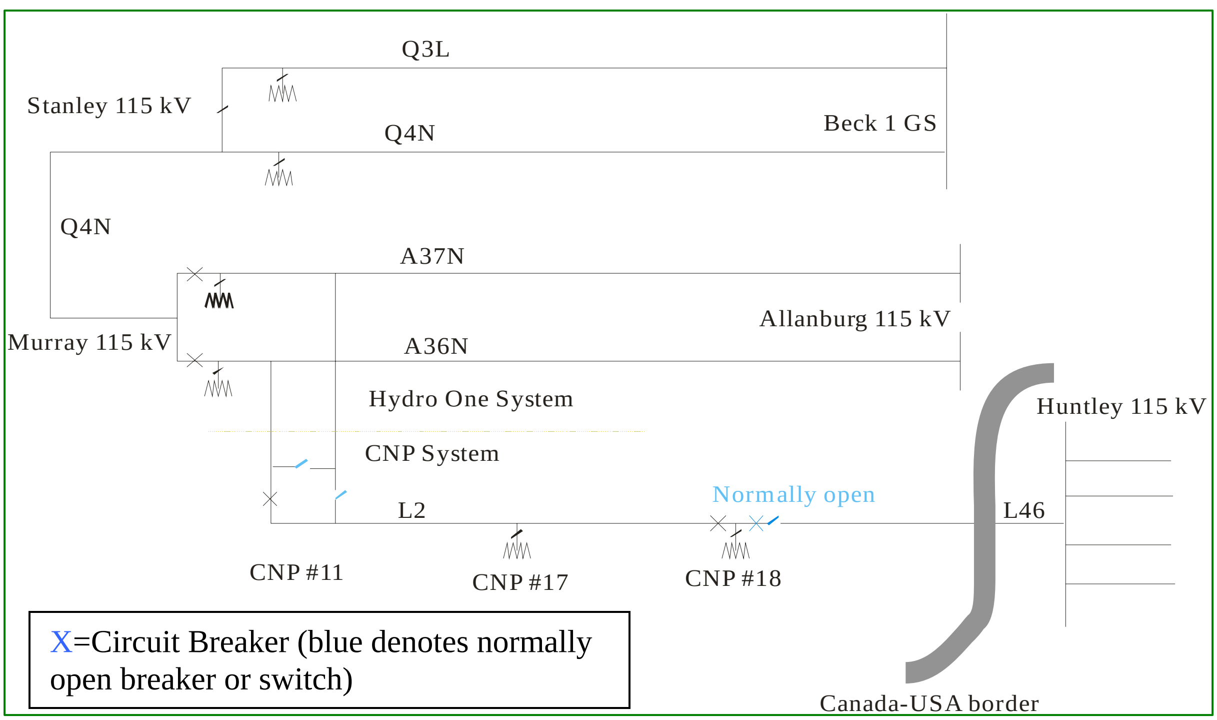


Figure 2.1 Present Arrangement - Allanburg and CNP 115 kV system

2.2 Proposed Interconnection

With the proposed interconnection, CNP load at Fort Erie can be supplied from both Murray TS and the proposed Paradise 115 kV station or its predecessor, the existing Huntley Substation. Consequently, for a contingency that interrupts the power supply from Murray, the CNP load will continue to be supplied by Paradise station, and vice versa. The voltage regulator and phase shifter will be connected between CNP #18 station and Line 46 in New York.

The transmission line between CNP #18 and NYISO Canada bus consists of the following four sections as shown in Figure 2.2:

- CNP #18 to Bertie Hill (C to D); a 3.23 km single circuit line with continuous rating of 180 MVA.
- Point D to E; This is a 0.5 km double circuit from Bertie Hill to the high tower crossing point at the Niagara River. The continuous rating is 68 MVA for each circuit.
- Point E to F is a 0.66 km double circuit line crossing the river with a rating of 51 MVA for each.
- The last section is a 2.7 km cable with continuous rating of 169 MVA terminating at ‘Canada’ bus in NYISO on Line 46.

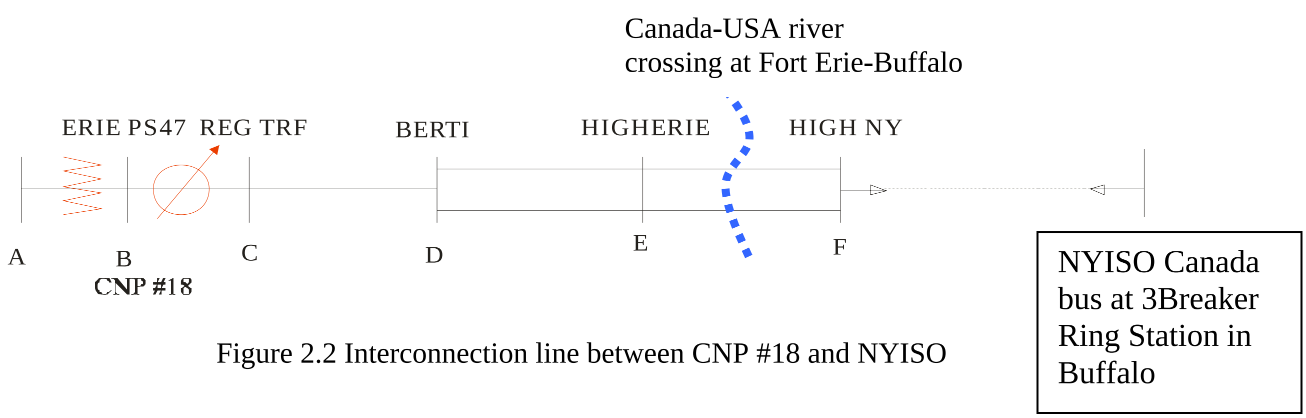
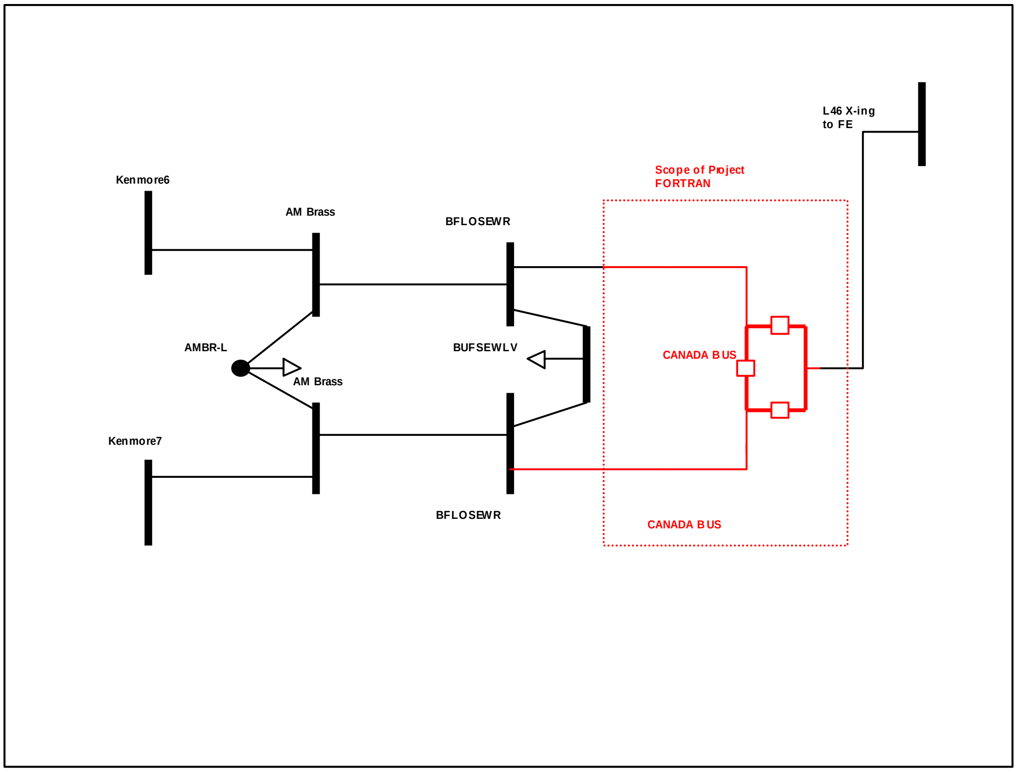


Figure 2.2 Interconnection line between CNP #18 and NYISO

On the New York side, the proposed Paradise Station and the existing Huntley Station are shown in NG Diagrams in Appendix B. Lines 46 and 47 that connect to Huntley Station are proposed to connect to the new Paradise Station. Lines 46 and 47 will have 5 miles of 636 aluminum (37 strand) and 1 mile of 500 copper (37 strand) conductor. The aluminum conductor is at the Paradise end of the line. The CNP tie will connect as shown in Figure 2.3 where the tie and Lines 46 and 47 will connect into a 3 Breaker Ring near the Buffalo Sewer Station. This connection will ensure that the tapped customer transformer loads are balanced. In this arrangement, both lines 46 and 47 will be in parallel, so that the outage of either line will be critical. Loss of Line 46 will also result in the loss of the Dupont generator (that is tapped on this line).

Figure 2.3
Proposed 3 Breaker Ring Station (in New York) to Connect CNP tie line



2.2.1 Proposed Voltage Regulator and Phase Shifter

The Fort Erie to NYISO 115 tie line is (proposed to be) closed via a Voltage Regulator (R46) and Phase Shifting transformer (PS46). Due to the difference in voltage between the CNP system and the Huntley, a voltage regulator (R46) is required to have the prevailing voltage on both sides of the interconnection and to control MVAR flows. IESO in Ontario stated that the voltage regulator should be rated at 150 MVA and have a ±10% on-load tap range in order to control reactive power flow.

The proposed phase shifter is rated at 120 kV and 150 MVA (similar rating to R46). The overload capability for this transformer at 100% preload (150 MVA) can be found in Table 2.1. 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. A complete listing of the load flow data for PS46 and R46 (as provided by IESO) can be found in Appendix B.

Table 2.1 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

3 Study Assumptions

The following key assumptions were used in performing this study. These assumptions were acceptable to the NYISO, the Transmission Owner (TO) and the Project Developer, and have been incorporated in the Scope of Study (Appendix A).

Study Period:

The study period is taken as 2011 after completion of the Paradise Substation and other system extensions/reconfigurations proposed by NG in the area. NYISO staff created the Power flow and Short Circuit base cases for the summer 2011 peak load conditions to be used in this study. All projects listed in the Scope of Study (Appendix A) were modeled in these base cases. There are many relevant planned changes to the Ontario System since the NYISO power flow case was created. The power flow case was partially updated by the addition of a new 230 kV double circuit line at Allanburg and was considered adequate for the purposes of results of this study.

Study Area: NG plans to replace the Huntley Station with the new Paradise station nearby. The Study was focused on the Point of Interconnection of the existing tie at the proposed Paradise Station and the tapped loads and surrounding local transmission system within the upstate New York System.

Base Case Conditions:

'Pre-CNP' Base case without the project: The base case included all proposed projects listed in Appendix A. In the power flow base case, some generators were taken out of service and some were dispatched at lower than maximum output to create a balance between load and generation. Generation dispatch was done in accordance with NYISO operating practices. In the short circuit case, however, all existing and proposed projects were kept in service in accordance with NYISO Short Circuit Methodology.

'Post CNP' Base Case with the project: The CNP tie was modeled in with NG-Ontario flows using the phase shifter controls. The same level of generation and load is in the system. Reactive power flow was controlled and minimized using the voltage regulator. This is also required since different voltage levels exist on the two sides of the tie. Other interconnection flows were also studied. Flows of up to 150 MW in either direction were to be studied. Tie line Flows North (NYISO to CNP) and Flows South (CNP to NYISO) were studied.

Modeling:

- Phase Angle Regulators (PARs), switched shunts, and LTC transformers were modeled as regulating pre-contingency and non-regulating post-contingency. The PAR schedules used in the study were those modeled in the NYISO 2005 FERC 715 power flow base cases.
- SVC and FACTS devices were set to zero pre-contingency and allowed to operate to full range post-contingency.

Impacts of the Fortran project on the Ontario System

The IESO[1] and Hydro One[2] studied of the System Impact of the project on the Ontario System and found that the proposed project is acceptable from an Hydro One/IESO/CNP perspective. The termination point in New York was at Huntley station in those studies.

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[1] Fort Erie Interconnection
Canadian Niagara Power Inc. IESO ***CAA ID 2005-192***

[2] Draft Customer Impact Assessment Canadian Niagara Power Inc. Sep 2006

4 Power Flow Analysis

Power flow analysis was conducted to determine the impact of the project (overloads, voltage violations, etc.) within the study area under normal and contingency conditions. The analysis was first done without the project and then with the project to identify the incremental impact of the project.

For this feasibility study, the power flow analysis was limited to Thermal and Voltage analysis as defined in the Scope of Study (Appendix A) and as outlined in the Appendix. All projects higher in the queue were modeled in the base cases (with very few exceptions on transition projects that have been inactive). These modeled projects are also described in the Scope of Study. Generation dispatch was done in accordance with NYISO and local Transmission Owner's (TO) operating practices.

PTI (Siemens) PSS/E Power flow program was used to conduct Thermal and Voltage analysis for pre-contingency and design criteria contingency conditions, focusing on the study area. Table PF-A and Appendix B detail the relevant contingencies. With the 3 Breaker Ring Station in Buffalo, both lines L46 and L47 are connected to the CNP tie line. Therefore both line outages L46 and L47 become critical contingencies. The loss of L46 results in the dropping of the Dupont generator and the Linde load. Tie line Flows North (NYISO to CNP of 150 and because of limitations, a lower transfer of 60 MW was studied) and Flows South (CNP to NYISO of 150 MW) were studied.

Thermal limits were assessed using normal ratings for pre-contingency conditions and applicable emergency ratings (Long Term Emergency, LTE, ratings) for post- contingency conditions. They are entered as Rate A and Rate B in the Power Flow. The STE rating (Rate C) was not used in this study.

Voltage limits were assessed, pre and post contingency, using NYISO voltage limits for the Bulk Power System and 0.95 –1.05 p.u. at other system buses unless specified otherwise. No buses from Exhibit A-3 of the NYISO System Operation Procedures were in the study system.

Table PF-A
List of Power flow Design Contingencies

New York	Contingency Description
Autos	Packard CONTINGENCY 'PK TB3' TRIP auto 1 CONTINGENCY 'PK TB4' TRIP auto 2 Gardenville CONTINGENCY 'GV TB1' CONTINGENCY 'GV TB2' CONTINGENCY 'GV TB3'
Single Line Outage	115 kV lines 36 to 39; 46,47,129,130,133 181,182
Double Line Outage	36&37 ; 38&39; '54+182GV', '102+180', '129+130', '130+133', '180NI+182PK', '180GV+181/922', TRANSFORMERS & BUS TIES (see Appendix)
Ontario	**Contingency Description affecting New York**
Single Line Outage	115 kV line outage of CNP Murray line L2 will result in the power supply to the CNP loads (about 60 MW) being supplied radially from the New York System.

4.1 Pre CNP tie Analysis

4.1.1 Base Case Power Flows Pre CNP tie

Table PF1-1 displays the line flows on lines out of Paradise Station pre-CNP project and Table PF1-2 shows the voltages on the tap points of Lines 46 and 47 and important NYISO stations. The Dupont L46 generator is on-line at 56 MW. The demand of the system connected to L46 and L47 is estimated to be 136 MW. The Paradise voltage is near 1 per unit or 115 kV. Tables PF1-3 and PF1-4 show CNP side voltages. The plot shown in Appendix displays the tapped customer transformer power flows pre-project.

Table PF1-1 Pre-CNP Project Flows out of Paradise Station

FROM BUS	76701	PARADISE	115	CKT	MW	MVAR	MVA	% I RATE A
TO	CAPACITOR BANK				0	-105.5	105.5	
TO	76503	S224-36	115	1	46.5	2.1	46.6	27
TO	76504	S224-37	115	1	48	1.9	48	28
TO	76655	DUNLOP	115	1	52.9	31.2	61.4	36
TO	76677	FMC CORP	115	1	27.3	23.3	35.9	21
TO	76683	AMHST-38	115	1	36.8	5.8	37.2	26
TO	76684	AMHST-39	115	1	32.5	4.1	32.8	23
TO	76700	GRDNVL1	115	1	19.1	-2	19.2	12
TO	76708	NI.B-181	115	1	46.8	16.7	49.6	31
TO	76709	NI.B-182	115	1	52.9	14.3	54.8	31
TO	76710	PACK(N)E	115	1	-82.3	-3.2	82.3	51
TO	76722	S129-38	115	1	-74.6	-7.5	75	37
TO	76723	S129-39	115	1	-61.5	-0.5	61.5	31
TO	76747	ZRMN-133	115	1	-91.1	3.9	91.2	54
TO	76748	ZRMN-130	115	1	-53.2	15.5	55.4	33

Table PF-1-2 Pre-CNP Project Bus Voltages

	NAME	Pre-CNP P.U Voltages
75456	GARDV115	1.0023
76710	PACK(N)E	1.0199
76711	PACK(S)W	1.0199
79591	NIAGAR2E	1.02
79592	NIAGAR2W	1.02
76701	PARADISE	1.0022
76677	FMC CORP	0.9929
76654	DUNLOP	0.9927
76656	DUPONT46	0.9924
76657	CHEVY	0.9913
76659	LINDE	0.9906
76803	KENMORE6	0.9903
76805	AM BRASS	0.9897
76808	BFLOSEWR	0.9893
76807	CANADA	0.9895
76655	DUNLOP	0.9882
76613	DUPONT7	0.9878
76658	CHEVY	0.987
76804	KENMORE7	0.9862
76806	AM BRASS	0.9857

Table PF1-3 Pre Project CNP Line Flows

CNP Line Flows					MW/MVAR Tie Open
81657	CNP 18	83556	STEVENVL	1	-40.1
					-21.62
83556	STEVENVL	83509	RANK A37	1	-60.29
					-31.47

Table PF1-4 Pre Project CNP Voltages

	NAME	**Pre-CNP P.U Voltages**
81657	CNP 18	0.9662
83556	STEVENVL	0.9764
83509	RANK A37	0.9968
81725	MURRAY	1.0006

4.1.2 Contingency Study - Pre CNP tie

The Dupont generator (on Line 46) is rarely used and it is also a conservative assumption to assume that that generator is off-line in most of these studies with flows to CNP The contingency list, subsystem and monitoring files are listed in the Appendix B. In the Pre CNP tie situation, even with the Dupont Generator off-line, none of the circuits in the monitored subsystem (for the NYISO WEST subsystem and the Ontario system to Allanburg) were loaded above the 95% of Rate B when subjected to the contingencies in that list. None of those transmission elements were above Rate A in this Base Case. Table PF1-5 shows the L46 Line Flows and Table PF1-6 shows voltages, pre and post-contingency; after an outage of L47 (with the Dupont Generator off-line). It is observed that the power flows on the line L46 at 123 MW is only 61 MW below the L46 Rate B rating of 185 MVA (after the L47 outage). Voltages are above the limits in all cases.

Table PF1-5
Pre Project L46 Line Flows Pre Project after outage of L47 - Dupont Generator Off-line

Line Flows					MW/MVAR Base Case	MW/MVAR L47 Outage
76701	PARADISE	76677	FMC CORP	1	75.98	123.72
					39.79	79.25
76677	FMC CORP	76654	DUNLOP	1	66.5	113.33
					37.1	71.93
76654	DUNLOP	76656	DUPONT46	1	59.97	113.3
					31.53	71.77
76656	DUPONT46	76657	CHEVY	1	53.11	106.41
					27.83	67.89
76657	CHEVY	76659	LINDE	1	27.51	53.52
					12.05	27.8
76659	LINDE	76803	KENMORE(	1	22.82	48.81
					10.69	26.34
76803	KENMORE6	76805	AM BRASS	1	17.3	36.99
					9.16	22.29

Table PF1-6 Voltages Pre Project– Outage of L47 - Dupont Generator Off-line

NAME		Base Case Voltages	L47 Outage Voltages
75456	GARDV115	1.0007	1.0006
76710	PACK(N)E	1.0194	1.0193
76711	PACK(S)W	1.0194	1.0193
79591	NIAGAR2E	1.02	1.02
79592	NIAGAR2W	1.02	1.02
76701	PARADISE	0.9988	0.9987
76677	FMC CORP	0.9813	0.9657
76654	DUNLOP	0.9809	0.9649
76656	DUPONT46	0.9804	0.9638
76657	CHEVY	0.9794	0.9614
76659	LINDE	0.9787	0.96
76803	KENMORE6	0.9784	0.9593
76805	AM BRASS	0.9779	0.9581
76808	BFLOSEWR	0.9777	0.9574
76807	CANADA	0.9778	0.9578

4.1.3 Radial Supply to CNP Loads from NYISO

Agreements (NG/CNP) allow for radial supply of CNP loads in the event that supply from the Hydro One grid is interrupted. A power flow study was carried out with the 3 Breaker Ring, the voltage regulator and phase-shifter, and the forecast demand of 60 MW CNP loads supplied from the proposed Paradise station, with the line ‘L2’ to Hydro One opened. With all lines in service, and the Dupont Generator in-service, the loadings and voltages were acceptable as shown in Tables PF2-1 and PF2-2.

Table PF2-1 CNP Load Radial on NYISO System – Voltages

NAME		Voltages/ Radial
75456	GARDV115	1
76710	PACK(N)E	1.0191
76711	PACK(S)W	1.0191
79591	NIAGAR2E	1.02
79592	NIAGAR2W	1.02
76701	PARADISE	0.9973
76677	FMC CORP	0.9793
76654	DUNLOP	0.9788
76656	DUPONT46	0.9783
76657	CHEVY	0.9765
76659	LINDE	0.9748
76803	KENMORE6	0.974
76805	AM BRASS	0.9724
76808	BFLOSEWR	0.9702
76807	CANADA	0.9702
76655	DUNLOP	0.9765
76613	DUPONT7	0.9758
76658	CHEVY	0.9745
76804	KENMORE7	0.9727
76806	AM BRASS	0.9715

NAME		Voltages/ Radial
81657	CNP 18	0.9833
83556	STEVENVL	0.9788

Table PF2-2 CNP Load Radial on NYISO System – Line Flows

Line Flows					MW/MVAR Radial
76701	PARADISE	76677	FMC CORP	1	64.82
					43.05
76677	FMC CORP	76654	DUNLOP	1	55.43
					40.77
76654	DUNLOP	76656	DUPONT46	1	48.16
					34.79
76656	DUPONT46	76657	CHEVY	1	97.3
					49.51
76657	CHEVY	76659	LINDE	1	70.18
					32.6
76659	LINDE	76803	KENMORE6	1	65.46
					31.04
76803	KENMORE6	76805	AM BRASS	1	59.4
					29.18
76701	PARADISE	76655	DUNLOP	1	76.63
					46.93
76655	DUNLOP	76613	DUPONT7	1	69.56
					39.13
76613	DUPONT7	76658	CHEVY	1	69.54
					39.07
76658	CHEVY	76804	KENMORE7	1	43.78
					23.18
76804	KENMORE7	76806	AM BRASS	1	38.01
					21.49
76806	AM BRASS	76809	BFLOSEWR	1	24.79
					13.02
76691	L46 NY	81647	L46 CNP	1	30.2
					15.61
76691	L46 NY	81647	L46 CNP	2	30.2
					15.61

CNP Line Flows					MW/MVAR
81647	L46 CNP	81648	BERTIHLL	1	30.19
					15.58
81647	L46 CNP	81648	BERTIHLL	2	30.19
					15.58
81648	BERTIHLL	81649	ERIEPS46	1	60.37
					31.12
81657	CNP 18	83556	STEVENVL	1	20.08
					9.23

4.1.4 Ontario Contingencies affecting NYISO

The 115 kV line outage of CNP17 to Murray TS line ‘L2’ will result in the power supply to the CNP loads (about 60 MW) being supplied from the New York System in the proposed Fortran project configuration. This is similar to the situation studied in Section 4.1.3 - radial supply.

4.2 Contingency Study – Post CNP with 150 MW to CNP

4.2.1 Thermal and Voltage Study – Dupont Generator Offline

The incoming power flow case from the NYISO was set up for about 150 MW power flow across the CNP tie at the border at Fort Erie by adjusting the phase-shifter and voltage regulator. The Dupont Generator was assumed to be off-line. In any case, the outage of L46 would result in the dropping of the tapped Dupont generator. It was found that the post-contingency loadings were a little higher with the Dupont generator initially off-line. The voltage regulator at CNP was set to minimize reactive power flows in the pre-contingency power flows. The power flows and voltages are displayed below in Tables 3.1a and 3.1b (Paradise Station Power Flows), Tables PF3-2 (Local Voltages) and Tables PF3-3 (Local Line Power Flows). NYISO 115 kV local voltages are about 2% lower when compared to the Pre CNP case. It is seen that the flow on circuit Paradise to FMC Corp is at 95% of the Rate A, prior to any outage. Table PF3-3 displays the power flows on critical circuits L46 and L47 relative to the Pre CNP Case. Figures B1 and B2 in Appendix B show load flow plot diagrams of the local system. The local tapped transformers show balanced flows.

A Thermal Study and Voltage study was carried out on this power flow case using the ACCC feature of PSSE. The Thermal study results table below (Table PF4.1) shows the branches that exceeded 90% of Rate A in the Base Case and 90% of Rate B in the Contingency Case. Lines 46 and 47 overloads are about 50% given the low rating of the first section of line after the connection to Paradise Station. The next section, Dunlop to FMC Corp, has an 8% overload. The CNP river crossing circuits are rated at about 100 MVA. It is understood that the rating of these circuits will need to be increased to above 150 MVA if transfers above that rating is contemplated.

The Voltage results table (Table PF4.2) shows buses that were below 0.95 or above 1.05 either in the Base Case or in the Contingency cases. The voltage change is also shown for these buses and shows that voltage changes are small. The voltages are within the allowable range for the base case and for the contingencies. Voltage changes are also well below the allowable 5% change.

The Thermal study shows that three sections of line 46 are loaded above Rate B for the contingency loss of line 47 and one section of Line 47 is loaded above Rate B for the outage of Line 46. The most severe overload is on the first line section out of Paradise Station that has a Rate B of only 185 MVA. The same section is near its Rate A of 168 MVA in the base case. A 50% uprating of this section is required if the 150 MW flow to CNP is to be achieved. The next section of line on L46 (FMC Corp to Dunlop) also needs uprating but by a smaller amount. Most sections of lines 46 and 47 are rated at 220/252 MVA (Rate A/Rate B). The cable circuit L46NY to Canada is at the thermal rating limit of 169 MVA. There is some reduction in the level of CNP tie power flows during L47 or L46 outages due to the change in loop impedance and angles of the buses. With the Dupont Generator on-line, the situation is not much improved, since with the 3 breaker ring arrangement, the outage of L46 (and with it the tapped Dupont Generator) becomes the most critical outage.

Table PF 3.1a
Flows from Paradise Station - 150 MW to CNP – Dupont Gen Off-line

FROM BUS	76701	PARADISE	115	CKT	MW	MVAR	MVA	% I RATE A
	CAPACITOR BANK				0	-103.6	103.6	
TO	76503	S224-36	115	1	28.4	-2.3	28.5	16
TO	76504	S224-37	115	1	29.4	-2.7	29.6	17
TO	76655	DUNLOP	115	1	142.5	47	150.1	**90**
TO	76677	FMC CORP	115	1	151.1	49.5	159	**95**
TO	76683	AMHST-38	115	1	20.9	3.8	21.3	15
TO	76684	AMHST-39	115	1	16.6	2.1	16.8	12
TO	76700	GRDNVL1	115	1	-0.5	-4.6	4.6	3
TO	76708	NI.B-181	115	1	33	15.8	36.6	23
TO	76709	NI.B-182	115	1	33.5	11.9	35.5	21
TO	76710	PACK(N)E	115	1	-101.1	-7.7	101.4	64
TO	76722	S129-38	115	1	-90.2	-12.6	91.1	46
TO	76723	S129-39	115	1	-78.8	-5.7	79	40
TO	76747	ZRMN-133	115	1	-111.3	-1.2	111.3	67
TO	76748	ZRMN-130	115	1	-73.6	10.2	74.3	45

Table PF 3.1b
Paradise Station Line Flow Differences (150 MW to CNP - Pre Project)
150 MW North – Dupont Gen Off-line

FROM BUS	76701	PARADISE	115	CKT	Post-Pre MW	Post-Pre MVAR
TO	CAPACITOR BANK					1.2
TO	76503	S224-36	115	1	-13.3	-2.3
TO	76504	S224-37	115	1	-13.7	-2.5
TO	76655	DUNLOP	115	1	81.8	11.2
TO	76677	FMC CORP	115	1	75.1	9.7
TO	76683	AMHST-38	115	1	-11.2	-1
TO	76684	AMHST-39	115	1	-11.2	-1
TO	76700	GRDNVL1	115	1	-13.8	-1.3
TO	76708	NI.B-181	115	1	-9.4	-0.4
TO	76709	NI.B-182	115	1	-13.7	-1.2
TO	76710	PACK(N)E	115	1	-14.4	-2
TO	76722	S129-38	115	1	-12	-2.7
TO	76723	S129-39	115	1	-13.3	-2.7
TO	76747	ZRMN-133	115	1	-15.4	-2.4
TO	76748	ZRMN-130	115	1	-15.6	-2.6

Table PF3-2 Voltages Pre and Post CNP 150 MW North – Dupont Gen Off-line

Bus		CNP-OFF	CNP150N	DIFF%
75456	GARDV115	1.0023	0.998	-0.4
76710	PACK(N)E	1.0199	1.0185	-0.1
76711	PACK(S)W	1.0199	1.0185	-0.1
79591	NIAGAR2E	1.02	1.02	0.0
79592	NIAGAR2W	1.02	1.02	0.0
76701	PARADISE	1.0022	0.9931	-0.9
76677	FMC CORP	0.9929	0.9683	-2.5
76654	DUNLOP	0.9927	0.9678	-2.5
76656	DUPONT46	0.9924	0.967	-2.5
76657	CHEVY	0.9913	0.9656	-2.6
76659	LINDE	0.9906	0.9644	-2.6
76803	KENMORE6	0.9903	0.9638	-2.7
76805	AM BRASS	0.9897	0.9628	-2.7
76808	BFLOSEWR	0.9893	0.9616	-2.8
76807	CANADA	0.9895	0.9616	-2.8
76655	DUNLOP	0.9882	0.9686	-2.0
76613	DUPONT7	0.9878	0.9679	-2.0
76658	CHEVY	0.987	0.9664	-2.1
76804	KENMORE7	0.9862	0.9644	-2.2
76806	AM BRASS	0.9857	0.9631	-2.3

Table PF 3.3 L46/L47 Flows - 150 MW North – Dupont Gen Off-line

Line Flows					MW/MVAR CNP OFF	MW/MVAR CNP 150 N	MW/MVAR Increase
76701	PARADISE	76677	FMC CORP	1	75.98	151.09	75.11
					39.79	49.54	9.75
76677	FMC CORP	76654	DUNLOP	1	66.5	140.45	73.95
					37.1	40.94	3.84
76654	DUNLOP	76656	DUPONT46	1	59.97	133.68	73.71
					31.53	35.1	3.57
76656	DUPONT46	76657	CHEVY	1	53.11	126.79	73.68
					27.83	31.21	3.38
76657	CHEVY	76659	LINDE	1	27.51	100.61	73.1
					12.05	14.69	2.64
76659	LINDE	76803	KENMORE6	1	22.82	95.86	73.04
					10.69	12.95	2.26
76803	KENMORE6	76805	AM BRASS	1	17.3	90.06	72.76
					9.16	11.13	1.97
76701	PARADISE	76655	DUNLOP	1	60.68	142.54	81.86
					35.77	46.99	11.22
76655	DUNLOP	76613	DUPONT7	1	53.07	133.97	80.9
					28.63	33.89	5.26
76613	DUPONT7	76658	CHEVY	1	53.06	133.93	80.87
					28.6	33.66	5.06
76658	CHEVY	76804	KENMORE7	1	25.83	107.14	81.31
					11.95	16.74	4.79
76804	KENMORE7	76806	AM BRASS	1	19.56	101.01	81.45
					10.13	14.35	4.22
76806	AM BRASS	76809	BFLOSEWR	1	5.54	87.41	81.87
					1.36	5.31	3.95

Table PF4.1
Thermal Loading MVA >90% rating – 150 MW to CNP – Dupont Gen Off-line

MONITORED BRANCH						CONTINGENCY	RATING	FLOW	%
75465	HINMN115	115	76261	HARIS115	1	BASE CASE	238	233.8	96.8
76655	DUNLOP	115	76701	PARADISE	1	BASE CASE	168	146.5	90
76677	FMC CORP	115	76701	PARADISE	1	BASE CASE	168	155.2	95.4
76691	L46 NY	115	76807	CANADA	1	BASE CASE	169	153.6	94.7
76613	DUPONT7	115	76655	DUNLOP	1	46	252	232.8	97.6
76613	DUPONT7	115	76658	CHEVY	1	46	252	232.1	97.6
76655	DUNLOP	115	76701	PARADISE	1	46	185	250.1	**142.7**
76654	DUNLOP	115	76656	DUPONT46	1	47	252	240.3	101.1
76654	DUNLOP	115	76677	FMC	1	47	252	257.5	108.2
76656	DUPONT46	115	76657	CHEVY	1	47	252	232	97.9
76677	FMC CORP	115	76701	PARADISE	1	47	185	266.7	**152.5**
76691	L46 NY	115	76807	CANADA	1	36+37	169	159.8	98.6
75449	ERIE 115	115	75451	PAVMT115	1	GV115 BUSTIE	179	165.2	92.7
75451	PAVMT115	115	75507	STOLE115	1	GV115 BUSTIE	179	178.2	99.2

Table PF4.2 Voltage Conditions – 150 MW to CNP – Dupont Gen Off-line

Contingency	Bus			V-CONT	V-INIT
46	76613	DUPONT7	115	0.94635	0.96795
46	76655	DUNLOP	115	0.94761	0.96865
46	76658	CHEVY	115	0.94357	0.96641
46	76691	L46 NY	115	0.93718	0.95937
46	76804	KENMORE7	115	0.94077	0.96443
46	76806	AM BRASS	115	0.93907	0.96314
46	76807	CANADA	115	0.93801	0.96164
46	76809	BFLOSEWR	115	0.93801	0.96164
47	76654	DUNLOP	115	0.94425	0.96776
47	76656	DUPONT46	115	0.94293	0.96705
47	76657	CHEVY	115	0.94015	0.9656
47	76659	LINDE	115	0.93827	0.96439
47	76677	FMC CORP	115	0.94535	0.96833
47	76691	L46 NY	115	0.93434	0.95937
47	76803	KENMORE6	115	0.93742	0.96384
47	76805	AM BRASS	115	0.93583	0.96276
47	76807	CANADA	115	0.93498	0.96164
47	76808	BFLOSEWR	115	0.93498	0.96164

4.3 Contingency Study – Post CNP with 60 MW to CNP

4.3.1 Thermal and Voltage Study

It is apparent, from the Pre Contingency study that there is only about 60 MW of available transmission capacity to CNP, with the ‘3 breaker ring’ arrangement that is under study here. The incoming power flow case from the NYISO was therefore set up for a 60 MW flow north to CNP. Tables PF5.2 and PF5.3 show the local line flows and voltages compared with the Pre Project system.

A thermal and voltage contingency study was carried out on this case. The thermal study shows (Table PF5.1) that one section of line 46 is still 9% above Rate B for the contingency loss of line 47. The voltages are within the allowable range for the base case and for the contingencies. Voltage changes are small for this transfer level as shown in Table PF 5.3.

The limiting value of Post CNP Flow North to CNP is about 53 MW. The 150 MW to CNP flow may be possible in the pre-contingency system, if an SPS scheme is used after a critical contingency on L46 or L47. National Grid will find the use of such an SPS acceptable as a temporary measure. It is expected that the phase angle regulator will normally provide any necessary adjustment to the flow on the circuits, and the SPS will protect the National Grid circuits from overloads during outage conditions only if adjustment of the phase angle regulator cannot be done quickly enough. The SPS will monitor the flow on circuits #46 and #47 at Paradise and for outage conditions will trip the breakers at the three breaker ring station opening the tie to CNP. For power flow greater than or equal to the STE ratings of the circuit, the trip would be immediate. For power flow greater than or equal to the LTE rating, 15 minutes will be allowed. For power flow greater than the normal rating but less than the LTE rating, 4 hours will be allowed.

Table PF5.1
Thermal Loading > 90% – 60 MW to CNP – Dupont Generation Off-line

MONITORED BRANCH						CONTINGENCY	RATING	FLOW	%
75465	HINMN115	76261	HARIS115	115	1	BASE CASE	238	227.4	94.1
76655	DUNLOP	76701	PARADISE	115	1	46	185	176	99.1
76677	FMC CORP	76701	PARADISE	115	1	47	185	192.7	108.7
75451	PAVMT115	75507	STOLE115	115	1	GV115 BUSTIE	179	173.3	96.2

Table PF5.2
L46 Flows Comparison to Pre Project - L47 outage – 60 MW to CNP Dupont Generation Off-line

Line Flows					MW/MVAR CNP OFF l47 Outage	MW/MVAR 60 N L47 Outage
76701	PARADISE	76677	FMC CORP	1	123.72	173.16
					79.25	84.76
76677	FMC CORP	76654	DUNLOP	1	113.33	161.76
					71.93	72.35
76654	DUNLOP	76656	DUPONT46	1	113.3	147.91
					71.77	59.41
76656	DUPONT46	76657	CHEVY	1	106.41	141
					67.89	55.43
76657	CHEVY	76659	LINDE	1	53.52	88.07
					27.8	14.93
76659	LINDE	76803	KENMORE6	1	48.81	83.34
					26.34	13.28
76803	KENMORE6	76805	AM BRASS	1	36.99	71.5
					22.29	9.13

Table PF5.3 Voltages – 60 MW to CNP – Dupont Generation Off-line

Bus		CNP-OFF Dupont Off L47 out	60N L47 out	DIFF%
75456	GARDV115	1.0006	0.9999	-0.1
76710	PACK(N)E	1.0193	1.0191	0.0
76711	PACK(S)W	1.0193	1.0191	0.0
79591	NIAGAR2E	1.02	1.02	0.0
79592	NIAGAR2W	1.02	1.02	0.0
76701	PARADISE	0.9987	0.9971	-0.2
76677	FMC CORP	0.9657	0.9598	-0.6
76654	DUNLOP	0.9649	0.9589	-0.6
76656	DUPONT46	0.9638	0.9579	-0.6
76657	CHEVY	0.9614	0.9557	-0.6
76659	LINDE	0.96	0.9545	-0.5
76803	KENMORE6	0.9593	0.954	-0.5
76805	AM BRASS	0.9581	0.9531	-0.5
76808	BFLOSEWR	0.9574	0.9534	-0.4
76807	CANADA	0.9578	0.9534	-0.4

4.4 Contingency Study – Post CNP with 150 MW to NYISO

4.4.1 Thermal and Voltage Study

The incoming power flow case from the NYISO was set up for a 150 MW flow south from CNP to NYISO. The Dupont Generator was assumed to be on-line in this case as this would increase the line loadings. Tables PF6-1 and PF6-2 show voltages and thermal loadings with the 150 MW transfer to NYSIO and a comparison to the Pre Project conditions. Voltages in NYISO system are marginally better in this situation.

Voltages at the CNP buses show that capacitive support would be necessary and capacitors were added to the case at CNP 18 bus, to facilitate the transfer.

A thermal and voltage contingency study was carried out on this case. The thermal study results showed that there are no overloads for the conditions studied. Similarly, the voltage results showed that there were no voltage violations.

Ontario circuits feeding CNP are approaching their thermal limit at this transfer level, namely circuit L2, the voltage regulator and phase-shifter and other circuits between Berthill and L46 New York bus.

Table PF6-1 Voltages – 150 MW to NYISO compared with Pre Project Voltages

Bus		CNP-OFF	150 S	DIFF%
75456	GARDV115	1.0023	1.0034	0.1
76710	PACK(N)E	1.0199	1.0194	0.0
76711	PACK(S)W	1.0199	1.0194	0.0
79591	NIAGAR2E	1.02	1.02	0.0
79592	NIAGAR2W	1.02	1.02	0.0
76701	PARADISE	1.0022	1.0046	0.2
76677	FMC CORP	0.9929	0.9987	0.6
76654	DUNLOP	0.9927	0.9986	0.6
76656	DUPONT46	0.9924	0.9985	0.6
76657	CHEVY	0.9913	0.9976	0.6
76659	LINDE	0.9906	0.9971	0.6
76803	KENMORE6	0.9903	0.997	0.7
76805	AM BRASS	0.9897	0.9967	0.7
76808	BFLOSEWR	0.9893	0.9969	0.8
76807	CANADA	0.9895	0.9969	0.7
76655	DUNLOP	0.9882	0.9964	0.8
76613	DUPONT7	0.9878	0.9961	0.8
76658	CHEVY	0.987	0.9956	0.9
76804	KENMORE7	0.9862	0.9957	1.0
76806	AM BRASS	0.9857	0.9959	1.0
76809	BFLOSEWR	0.9855	0.9969	1.1
81657	CNP 18	0.9662	0.975	0.9
83556	STEVENVL	0.9764	0.9768	0.0
83509	RANK A37	0.9968	0.9937	-0.3
81725	MURRAY	1.0006	0.9984	-0.2

Table PF6-2 Power Flows – 150 MW to NYISO compared with Pre Project Flows

Line Flows					MW/MVAR CNP OFF	MW/MVAR 150 S
76701	PARADISE	76677	FMC CORP	1	27.29	-39.65
					23.33	26.18
76677	FMC CORP	76654	DUNLOP	1	18.19	-48.8
					22.61	25.17
76654	DUNLOP	76656	DUPONT46	1	10.57	-56.05
					16.47	19.23
76656	DUPONT46	76657	CHEVY	1	59.71	-6.91
					31.24	33.95
76657	CHEVY	76659	LINDE	1	31.76	-33.95
					14.1	17.48
76659	LINDE	76803	KENMORE6	1	27.07	-38.64
					12.73	16.11
76803	KENMORE6	76805	AM BRASS	1	20.6	-44.68
					10.76	14.33
76701	PARADISE	76655	DUNLOP	1	52.89	-26.74
					31.17	29.75
76655	DUNLOP	76613	DUPONT7	1	46.46	-33.4
					25.07	24.19
76613	DUPONT7	76658	CHEVY	1	46.46	-33.41
					25.06	24.18
76658	CHEVY	76804	KENMORE7	1	21.58	-59.18
					9.86	8.54
76804	KENMORE7	76806	AM BRASS	1	16.26	-64.96
					8.5	6.82
76806	AM BRASS	76809	BFLOSEWR	1	3.9	-78.21
					0.56	-1.7
81657	CNP 18	83556	STEVENVL	1	-40.1	-187.82
					-21.62	35.31
83556	STEVENVL	83509	RANK A37	1	-60.29	-210.26
					-31.47	13.03
83509	RANK A37	81725	MURRAY	1	-72.49	-225.07
					-39.58	-14.42

4.5 *Summary of Study*

4.5.1 CNP-NYISO Transfer Limits with 3 Breaker Ring Station

Thermal and Voltage Studies have been completed for CNP-NYISO transfers up to 150 MW in both directions. The base case and contingency studies showed that the voltages were acceptable in all cases. Voltage changes due to contingencies were small in the cases. Thermal Studies showed that the transfer limit from NYISO to CNP is restricted to below 60 MW mainly by the thermal rating of the section between Paradise and the next station towards the tie point. The transfer limit from CNP to NYISO is about 150 MW, although some circuits in Ontario approach their thermal limits. The ‘3 breaker Ring’ station does balance the power flows on the tapped transformer stations.

4.5.2 Radial Supply to CNP from Paradise - 3 Breaker Ring Station

60 MW of CNP loads can be supplied radially on L46 from NYISO’s proposed Paradise Station via the 3 Breaker Ring Station, with the connection to Hydro One Open. Voltages and Line loadings were acceptable.

5 Short Circuit Analysis

Short Circuit analysis was performed to determine the fault current at the buses within the Study Area with and without the project, and to identify if rating of any of the circuit breakers is exceeded. This has been done in accordance with the NYISO Guideline for Fault Current Assessment (Appendix E). 230 and 115 kV buses within the study area were selected to determine fault duties. The following fault types were evaluated:

- Three phase fault,
- Double line to ground fault, and
- Single line to ground fault
- Line to line to ground fault

The highest of these three faults was compared against the lowest rated circuit breaker at each of these buses to determine whether or not the circuit breaker may be overdutied.

The following ratings of circuit breakers were provided for the subject stations. The study was performed using an ASPEN system representation provided by NYISO both without and with the 3 Breaker Ring and Fortran project in service. All generation projects listed in the “Scope of Study” (Appendix A) were modeled in the base cases.

The results are summarized in tables below as follows:

- Table SC-1 shows the results without the project (Pre-CNP tie),
- Table SC-2 with the project (Post-CNP tie), and
- Table SC-3 shows comparison of the two cases.

The three-phase fault at the Paradise 115 kV bus was the most severe of the fault types showing an increase from 39 kA (without project) to 42 kA (with project). The value is within the rating of the lowest rated (50 kA) breaker at this location. The impact of the project was less than 2.6 kA in all cases. The three-phase fault level at the CANADA bus and 3 Breaker tie point was only 16 kA (Post-CNP tie).

Table SC1 Fault Currents – Pre CNP Tie

off			Fault Current Amps			
BUS	KV	Rating kA	3LG(A)	2LG(A)	1LG(A)	LL(A)
Paradise	115	50	39729	38901	33690	34016
Packard	230	50	41607	40881	36276	35438
Packard	115	50	52486	51789	46520	44290
Niagara	230	63	48732	52462	53616	41271
Niagara E	115	50	48164	47232	46202	40439
Gardenville	230	37.5	24163	23315	21093	20793
Gardenville	115	43	42257	41843	40575	36304
Huntley	230	50	26969	26374	24678	23186
Lockport	115	40	33239	30777	23384	28699

Table SC2 Fault Currents – Post CNP - tie with '3 Breaker Ring'

ON			Fault Current Amps			
BUS	KV	Rating kA	3LG(A)	2LG(A)	1LG(A)	LL(A)
Paradise	115	50	42390	41216	35113	36322
Packard	230	50	41833	41071	36397	35643
Packard	115	50	53463	52597	47066	45148
Niagara	230	63	48933	52669	53836	41499
Niagara E	115	50	48773	47908	46602	40976
Gardenville	230	37.5	24389	23503	21212	20995
Gardenville	115	43	42967	42417	41025	36931
Huntley	230	50	27094	26477	24750	23299
Lockport	115	40	33565	30875	23494	28814

Table SC3   Fault Currents – Comparison 'Post minus Pre' CNP tie

ON			Fault Current Amps			
BUS	KV		3LG(A)	2LG(A)	1LG(A)	LL(A)
Paradise	115		2661	2315	1423	2306
Packard	230		226	190	121	205
Packard	115		977	808	546	858
Niagara	230		201	207	220	228
Niagara W	115		609	676	400	537
Gardenville	230		226	188	119	202
Gardenville	115		710	574	450	627
Huntley	230		125	103	72	113
Lockport	115		326	98	110	115

6 Preliminary Cost Estimates and Schedules

6.1 Estimates

The following estimates were provided by NG:

- The Power flow study for the 150 MW transfer to CNP, showed that first line sections out of Paradise (Lines 46 and 47) will require a 300 MVA (Rate B) rating and FMC Corp to Dunlop will require about 270 MVA (Rate B) rating. Estimates this rating increase are shown below.

  Cost of Upgrade Facilities
  Upgrading the capacity of 115 kV circuits #46 and #47 to at least 300 MVA will require modification of existing structures and replacement of approximately 6.3 miles of conductor. Use of 1113 ACSR conductor was needed to achieve the necessary 300 MVA of capacity. The cost to complete this upgrade is expected to be $9,000,000 (+/- 25%) and will require 3 years for the engineering, permitting and construction. This upgrade will result in the ratings of the Paradise – FMC, FMC – Dunlop and Dunlop – DuPont sections of both line #46 and #47 increasing to 271 MVA summer normal, 313 MVA summer LTE, 359 MVA summer STE, 331 MVA winter normal, 364 MVA winter LTE and 404 MVA winter STE.

- NG's estimates for modifications to create the 3 Breaker Ring Station in Buffalo are shown below.

  National Grid has prepared a conceptual cost for the installation of the 3 breaker ring station connecting lines #46, #47 and the river crossing. As always these are +/-25%, assume all necessary property for the station or the right of way is acquired by the developer and do not include cost to obtain any necessary permits. This estimate also does not include any protection modifications that may be required at the CNP Ontario station to coordinate with Paradise and the new 3 breaker ring station. It is expected that the station will require 18-24 months to engineer and construct and cost $4.5M.

6.2 Temporary Use of an SPS Scheme

National Grid will find the use of an SPS acceptable as a temporary measure until the permanent upgrades can be completed so long as the developer agrees to pay for the system upgrades. The SPS will be allowed to remain in operation no more than 2 years. It is expected that the phase angle regulator will normally provide any necessary adjustment to the flow on the circuits, and the SPS will protect the National Grid circuits from overloads during outage conditions only if adjustment of the phase angle regulator cannot be done quickly enough.

The SPS will monitor the flow on circuits #46 and #47 at Paradise and for outage conditions will trip the breakers at the three breaker ring station opening the tie to CNP. For power flow greater than or equal to the STE ratings of the circuit, the trip would be immediate. For power flow greater than or equal to the LTE rating, 15 minutes will be allowed. For power flow greater than the normal rating but less than the LTE rating, 4 hours will be allowed.

The communication and relaying necessary to make the SPS operational will require that the interconnection between National Grid and CNP not be completed until after Paradise station is in service in the late spring of 2010.

6.3 Project Schedules

NG's estimates of the earliest possible schedule for this project will be:

Spring 2008 – SRIS and Facility study would need to be complete, IA signed
Spring 2008 – Begin work on 3 breaker ring station
Spring 2009 – Begin work for reconductoring
Spring 2010 – 3 breaker ring station complete, SPS in service
Spring 2012 – Reconductoring complete, SPS removed from service

7 Conclusions

The tie line from New York ISO system to CNP was modified by setting up a 3 Breaker Ring Station in Buffalo to which lines L46, L47 and the tie to CNP were connected. This arrangement resulted in balanced tapped customer transformers flows. Thermal and Voltage Studies have been completed for CNP-NYISO transfers up to 150 MW in both directions. The base case and contingency studies showed that the voltages were acceptable in all cases. Voltage changes due to contingencies were small in all cases. Thermal Studies showed that:

- The transfer limit from NYISO to CNP is limited to about 53 MW. The critical contingency is the outage of either L47 or L46 with the limitation being the companion circuit – sections near Paradise Station. A temporary SPS Scheme is proposed (to trip off the CNP tie for critical L46 and L47 outages which would overload L46 or L47) until the required line uprating can be completed so that up to150 MW transfers to CNP to be made pre-contingency.

- The power transfer on the CNP tie towards NYISO is limited to about 150 MW by the rating of internal circuits in CNP, but is not limited by circuits in New York ISO. All the voltage criteria were satisfied.

- 60 MW of CNP loads can be supplied radially from the 3 Breaker Ring in Buffalo with the line to Hydro One open.

- The Niagara River crossing of the CNP tie is rated at about 100 MVA. It is understood that the rating of these circuits will need to be increased to above 100 MVA if higher transfers are contemplated.

- NG's Cost and Implementation time estimates are shown below

  1. **Upgrade of 6.3 miles of 115 kV transmission line L46 and L47 at the Paradise Station**
     The cost to complete this upgrade is expected to be $9,000,000 (+/-25%) and will require 3 years for the engineering, permitting and construction. This upgrade will result in the ratings of the Paradise – FMC, FMC – Dunlop and Dunlop – DuPont sections of both line #46 and #47 increasing to 271 MVA summer normal, 313 MVA summer LTE, 359 MVA summer STE, 331 MVA winter normal, 364 MVA winter LTE and 404 MVA winter STE.

2. **Create the 3 breaker Ring Station in Buffalo**:

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It is expected that the station will require 18-24 months to engineer and cost $4.5M.

Short Circuit analysis:

The three-phase fault at the Paradise 115 kV bus was the most severe of the fault types showing an increase from 39 kA (without project) to 42 kA (with project). The value is within the rating of the lowest rated (50 kA) breaker at this location. The impact of the project was less than 2.6 kA in all cases. The three-phase fault level at the CANADA bus and 3 Breaker tie point was only 16 kA (Post-CNP tie).

Time to Construct CTO's Attachment facilities:

NG's estimates of the earliest possible schedule for this project will be:

Spring 2008 – SRIS and Facility study would need to be complete, IA signed
Spring 2008 – Begin work on 3 breaker ring station
Spring 2009 – Begin work for reconductoring
Spring 2010 – 3 breaker ring station complete, SPS in service
Spring 2012 – Reconductoring complete, SPS removed from service

Appendices

Appendix A: Scope of Study

EXHIBIT 1:

Scope of the Interconnection Feasibility Study for the Fortran Project – Fort Erie, Ontario

1. **Purpose**
The purpose of this study is to make a preliminary evaluation of the feasibility of the proposed interconnection of the Canadian Niagara Power Inc. Fortran Project (the "Project") to the New York State Transmission System. The Project will close the Line 2/46 inter-tie between the Canadian Niagara Power ("CNP") #18 station in Fort Erie, Ontario and National Grid's ("NGrid") Huntley 115 kV substation in Buffalo, NY. This will be done by operating breaker 18R46 normally closed and installing a phase shifting transformer on Line 2/46. The Project is expected to have a maximum rating of 150 MW. The Project will be located in the Town of Fort Erie, Ontario and has a proposed in-service date of the first quarter of 2008.

   The study will assess the impact of the Project on the base case electric system, including potentially Affected Systems, and will provide a list of the facilities (NGrid Attachment Facilities and System Upgrade Facilities) required to make the interconnection and a non-binding good faith estimates of cost and time to construct those facilities. The study will be conducted in accordance with the applicable NERC, NPCC, NYSRC, NGrid, and Affected Systems (if applicable) reliability and design standards; and in accordance with applicable, New York Independent System Operator ("NYISO"), NGrid, and Affected Systems (if applicable) study guidelines, procedures and practices.

2. **Interconnection Plan**
The study will include a description of the proposed facilities and the conceptual design of the Interconnection to the transmission system. The description will include a one-line diagram depicting the proposed facilities (to include both Developer and Transmission Owner Attachment Facilities) and their integration with the existing facilities.

3. **Study Period**
The study will focus on the period of five years in the future. The study will be conducted using appropriate Power Flow and Short Circuit base cases provided by the NYISO and/or NGrid, and will include the representation of other proposed projects listed in Appendix A.

4. **Study Area**
The study will focus on the Point of Interconnection (Huntley 115 kV substation) and the surrounding 115 kV, 230 kV, and local transmission systems within the West Region (Zone A) in western New York that are most likely to be affected by the Project (the "Study Area").

5. **Base Case Conditions**
The preliminary impact of the proposed Project will be evaluated for summer peak load conditions for the following base case conditions.

Case 1 – Base case without the Project. The base case will include the proposed projects listed in Appendix A. The Short Circuit base case will model all the projects as in-service. The Power Flow base case will normally model all projects in-service at full output, but may model some projects as out-of-service or less than full output as necessary to establish a feasible base dispatch. Generation will be dispatched in accordance with NYISO practices.

Case 2 – Case 1 with the Project modeled. The Project will be modeled as in-service at full output. Generation will be re-dispatched in the Power Flow case in accordance with NYISO practices.

6. **Analysis**
Limited thermal, voltage and short circuit analyses will be conducted to assess the performance of the power system within the Study Area, with and without the Project, in accordance with applicable reliability standards and study practices. Modifications to base cases, during analyses, will be documented in the Study report.

6.1 Power Flow Analyses
Thermal and voltage analyses, using the PSS/E load flow program, will be conducted for pre-contingency and design criteria contingency conditions, and will be limited to the Study Area. Thermal Limits will be assessed using normal ratings pre-contingency, and applicable emergency ratings (Long-Term-Emergency, LTE, ratings or Short-Term-Emergency, STE, ratings) post-contingency. Voltage limit will be assessed, pre and post contingency, using NYISO voltage limits for the bulk power system and 0.95 – 1.05 pu for other transmission system buses, unless specified otherwise.

6.2 Short Circuit Analysis
Short Circuit analysis will be performed to determine the fault duty of buses within the Study Area, and to identify if any circuit breaker ratings have been exceeded as a result of the Project. This analysis will be performed in accordance with the NYISO Guideline for Fault Current Assessment, and NGrid and Affected Systems (if applicable) criteria.

7. **Modeling Assumptions**

7.1 Phase angle regulators (PARs), switched shunts, and LTC transformers will be modeled as regulating pre-contingency and non-regulating post-contingency. The study will use PAR schedules established by the NYISO in coordination with the neighboring ISOs through the NERC and NPCC base case development processes, and were modeled in the NYISO 2005 FERC 715 power flow base cases.

7.2 SVC and FACTS devices will be set to zero pre-contingency and allowed to operate to full range post-contingency.

8. **Evaluation and Identification of System Upgrade Facilities (SUFs)**
If study results indicate that the Project, as proposed, would result in violations of reliability standards, analyses will be performed to identify any SUFs that would be required to meet the NYISO's Minimum Interconnection Standard..

9. **Preliminary Cost Estimates of Facilities**
A preliminary description of facilities (NGrid Attachment Facilities and System Upgrade Facilities, if any) required to interconnect the Project to the New York State Transmission System, and non-binding good faith estimates of cost and time to construct those facilities, will be provided.

10. **Report**
A report will be prepared to document the feasibility study results and supporting information.

Appendix A

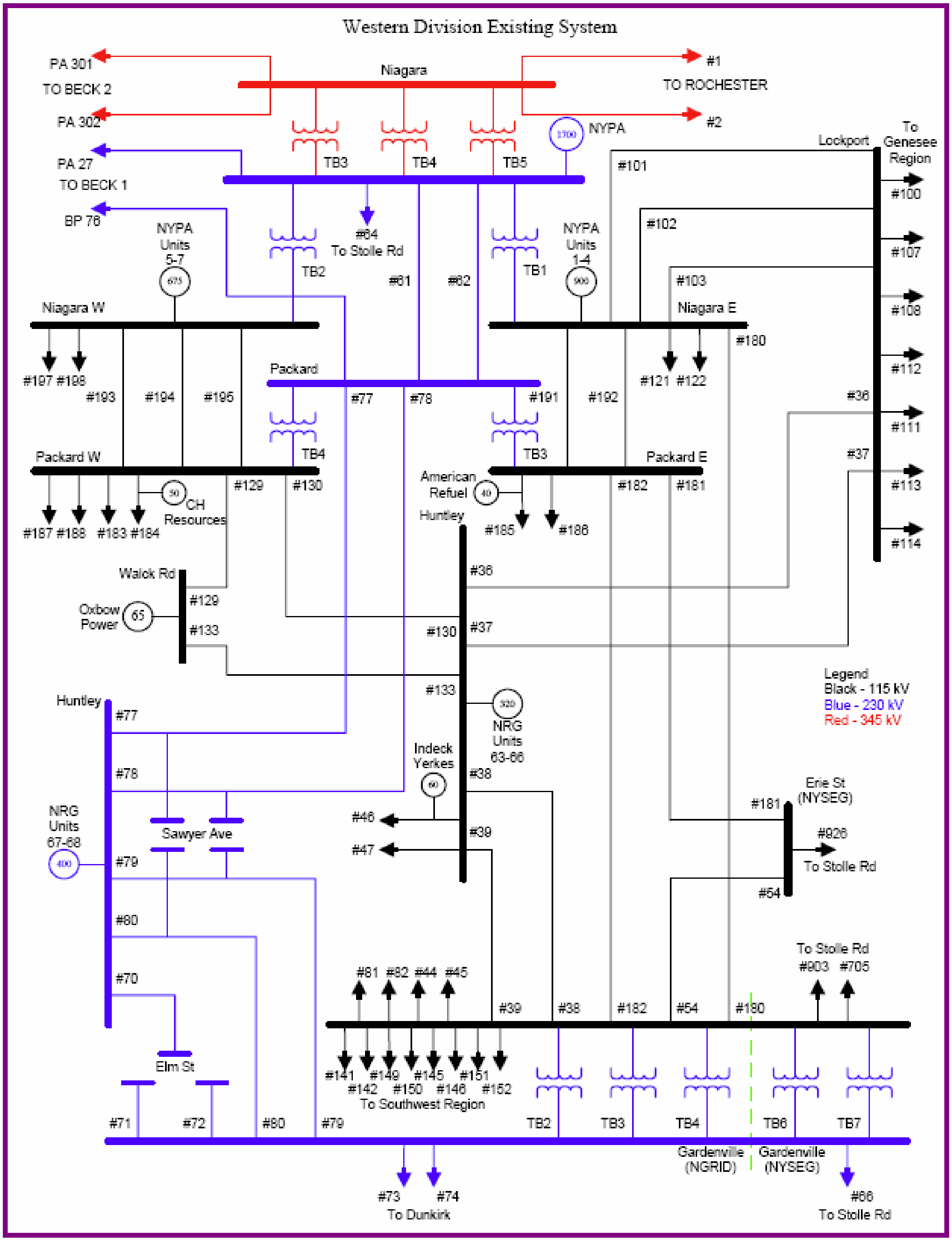
List of Other Proposed Projects to be Modeled in the Base Case For Fortran Project

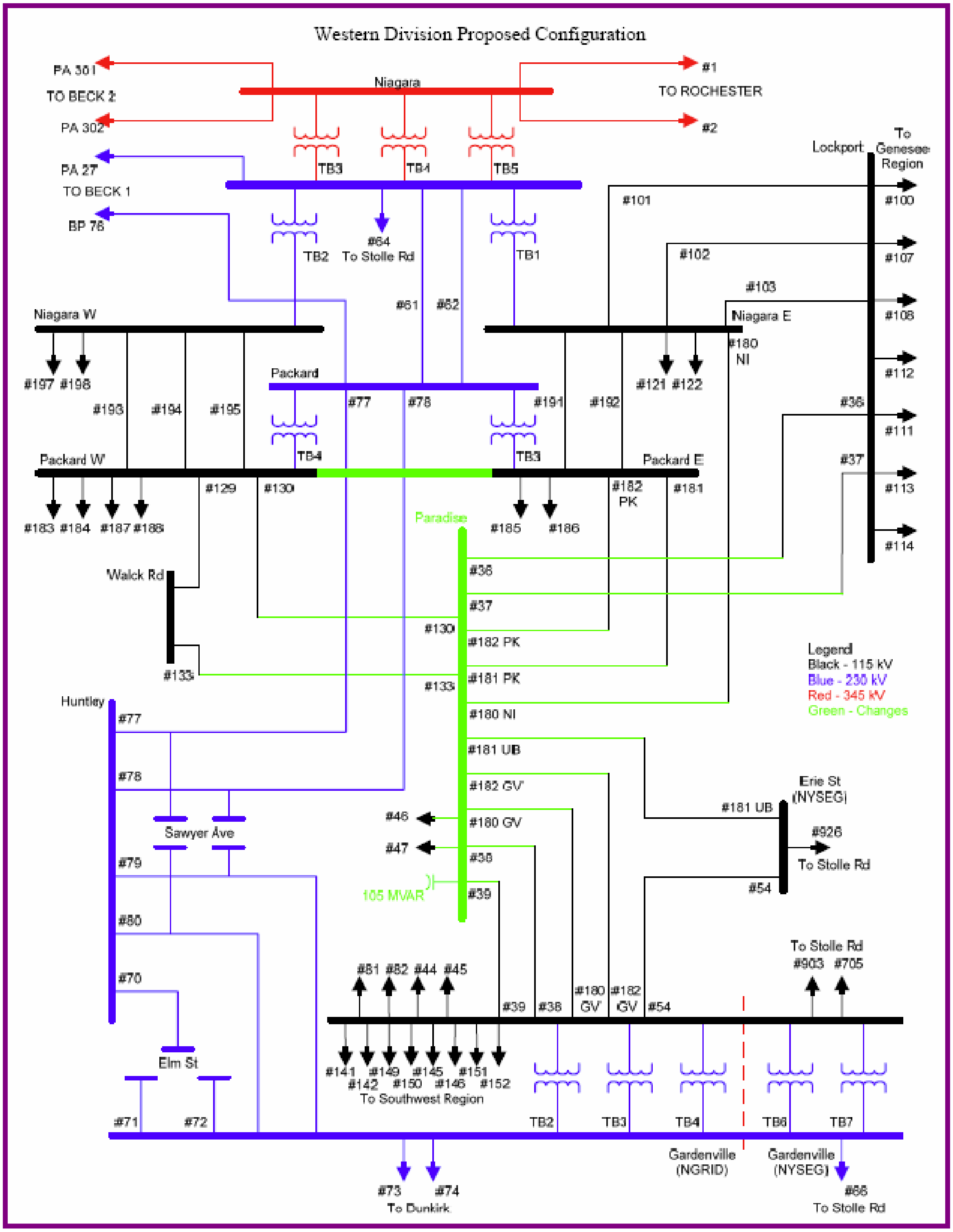
Queue Pos.	Developer/Project Name	Size (MW)
18	NYPA Poletti Project	500
19	NYC Energy Kent Ave	79.9
20	KeySpan Spagnoli Road CC Unit	250
22	Calpine Wawayanda Energy Center	500
24	Reliant Astoria Repowering Phase 1	367
25	ConEd East River Repowering	288
29	Mirant Bowline Point 3	750
31	SCS Astoria Energy	1000
65	Fortistar LMA Lockport II	79.9
69	Besicorp Empire State Newsprint	660
70	Reliant Astoria Repowering Phase 2	173
90	Fortistar VP	79.9
91	Fortistar VAN	79.9
93	PSEG Cross Hudson Project	550
94	Atlantic Energy Neptune PJM-LI DC	660
96	Calpine JFK Expansion	45
107	Caithness Long Island	310
113	Global Winds Prattsburgh Project	75
117	Chautauqua Windpower Project	50
119	ECOGEN Prattsburgh Wind Farm	79.5
125	Linden VFT Inter-Tie	300
127A	Airtricity Munnsville	40
135	UPC Wind Canandaigua Wind	81
136	Rochester Transmission Project	N/A
139	Entergy Indian Point 3 Uprate	38
141	Flat Rock Wind Power	300
142	Airtricity Hartsville Wind	50
143	Constellation Ginna Plant Uprate	95
144	Invenergy High Sheldon Windfarm	198
146	Con Edison Mott Haven Substation	N/A
147	NY Windpower West Hill Windfarm	40
150	Reunion Power Cherry Valley Wind	70
152	Invenergy Stamford Wind	129
153	ConEd Sprain Brook-Sherman Crk (M-29)	500
155	Invenergy Canisteo Hills Windfarm	149
156	AREC Fairfield Wind Project	120
157	Orion Energy NY I	100
160	AREC Burke Wind Project	102
161	NY Windpower Marble River Wind Project	76
163	Clipper Windpower Pine Hills Wind Project	100
164	FPL Energy Long Island Offshore Wind	140
166	AES New York St. Lawrence Wind Farm	130

Queue Pos.	Developer/Project Name	Size (MW)
168	Zilka Perry Wind Farm (Dairy Hills)	132
169	Zilkha Batavia Wind Farm	90.8
170	Zilkha Machias Wind Farm	90
171	Zilkha Clinton County	123.8
172	Noble Clinton Wind Field	80
173	Noble Bliss Wind Field	71
174	Noble Altona Wind Field	99
175	Noble Ellenburg Wind Field	79.5
177	Noble Wethersfield Wind Field 230kV option	129
178	Noble Allegany Wind Field	99
179	Noble Malone Wind field	159
180	Invenergy Buffalo Rd. Wind Farm 230 kV	165
182	Everpower Howard Wind	102.3
185	NYPA Blenheim Gilboa Storage	120
186	Community Energy Jordanville Wind	150
187	NY Windpower North Slope Wind	109.5
189	PPM Energy Clayton Wind	132
190	PPM Energy Mixer Road Wind	66
191	New York Regional DC	1200
193	Orion Wyoming	60
195	TransEnergie Harbor Cable Project II	500
196	Roaring Brook Windpower Roaring Brook	79.5
197	Tug Hill Windpower LLC Tug Hill	79.5
198	Picket Brook Windpower/Picket Brook	79.5
199	UPC Wind Canandaigua II	42
201	NRG Energy/ Berrians GT	200
203	UPC Wind Genesee Wind Farm	500
206	Hudson Transmission	660
207	Greenlight Energy/ Cape Vincent	210
208	CRC Development/ Roundhouse Renewable	36
209	SUEZ Energy / Nassau Generating	88

Appendix B: Thermal Analysis

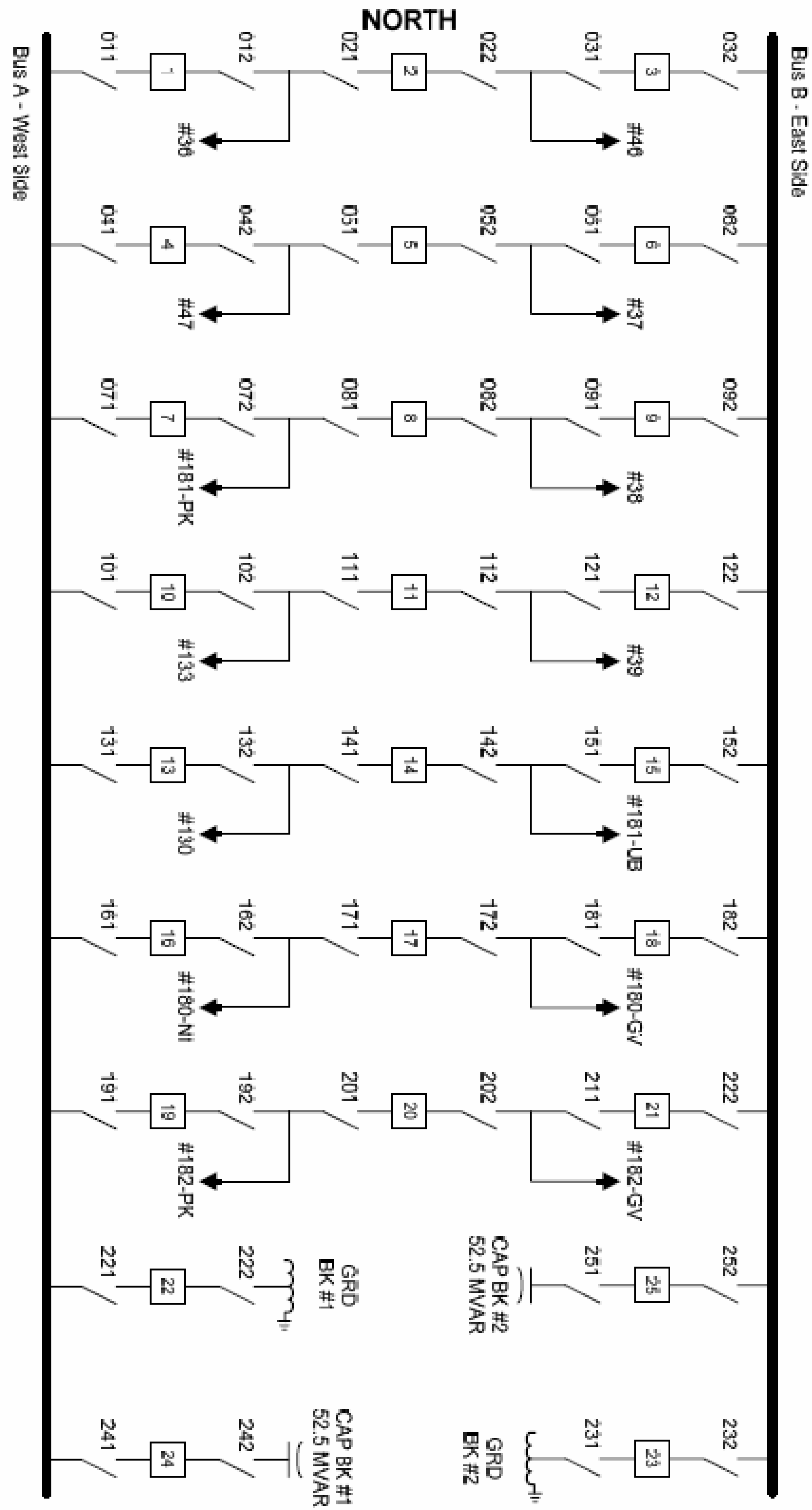
NG Western Division Diagrams





Western Division Proposed Configuration
PA 301
TO BECK 2
PA 302
Niagara
#1
TO ROCHESTER
#2
PA 27
TO BECK 1
BP 76
TB3
TB4
TB5
Lockport
To Genesee Region
#64 To Stolle Rd
TB2
TB1
#101
#100
#102
#107
#103
#108
#61
#62
Niagara W
Niagara E
#180 NI
#112
#197 #198
#193
#194
#195
Packard
#77
#78
#191
#192
#121 #122
#36
#111
#37
#113
#114
Packard W
TB4
TB3
Packard E
#129
#130
#182 PK
#181
#183 #184 #187 #188
Paradise
#185
#186
Walck Rd
#36
#37
#130
#182 PK
#133
#133
#181 PK
Huntley
#180 NI
#77
#181 UB
#78
#182 GV
Erie St (NYSEG)
#181 UB
Sawyer Ave
#46
#180 GV
#926
#47
#38
To Stolle Rd
#79
105 MVAR
#39
#54
#80
To Stolle Rd
#903 #705
#70
#81 #82 #44 #45
#39
#38
#180 GV
#182 GV
#54
Elm St
#141 #149 #145 #151
#142 #150 #146 #152
To Southwest Region
#71
#72
TB2
TB3
TB4
TB6
TB7
Gardenville (NGRID)
Gardenville (NYSEG)
#73
#74
To Dunkirk
#66
To Stolle Rd
Legend
Black - 115 kV
Blue - 230 kV
Red - 345 kV
Green - Changes

Paradise Station Configuration



Draft 2/27/2007

Contingencies Tested & Area Monitored

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COM ***************************** /
COM *        LINE OUTAGE        * /
COM ***************************** /

CONTINGENCY '36'
TRIP BUS 76787
TRIP BUS 76740
TRIP BUS 77092
TRIP BUS 76696
TRIP BUS 76503
END

CONTINGENCY '37'
TRIP BUS 76724
TRIP BUS 76739
TRIP BUS 77093
TRIP BUS 76697
TRIP BUS 76504
END

CONTINGENCY '38'
TRIP BUS 76683
TRIP BUS 76727
TRIP BUS 76731
TRIP BUS 76735
TRIP BUS 76729
TRIP BUS 76742
TRIP BUS 76753
END

CONTINGENCY '39'
TRIP BUS 76684
TRIP BUS 76728
TRIP BUS 76732
TRIP BUS 76736
TRIP BUS 76730
TRIP BUS 76754
END

CONTINGENCY '46'
TRIP BUS 76677
TRIP BUS 76654
TRIP BUS 76656
TRIP BUS 76657
TRIP BUS 76659
TRIP BUS 76803
TRIP BUS 76805
TRIP BUS 76808
END

CONTINGENCY '47'
TRIP BUS 76655
TRIP BUS 76613
TRIP BUS 76658
TRIP BUS 76804
TRIP BUS 76806
TRIP BUS 76809
```

```
END

CONTINGENCY '129'
TRIP BUS 76704
TRIP BUS 76685
END

CONTINGENCY '130'
TRIP BUS 76705
TRIP BUS 76719
TRIP BUS 76748
TRIP BUS 76738
END

CONTINGENCY '133'
TRIP BUS 76747
TRIP BUS 76737
END

CONTINGENCY '180PK'
TRIP BUS 76703
TRIP BUS 76506
TRIP BUS 76722
END

CONTINGENCY '180GV'
TRIP BRANCH FROM BUS 76700 TO BUS 76701 CKT 1
END

CONTINGENCY '181PK'
TRIP BRANCH FROM BUS 76710 TO BUS 76701 CKT 1
END

CONTINGENCY '181GV/922'
TRIP BUS 76708
TRIP BUS 76692
TRIP BUS 76745
TRIP BUS 76687
TRIP BUS 75484
CHANGE BUS 76688 LOAD BY 100 PERCENT
END

CONTINGENCY '182PK'
TRIP BUS 76699
TRIP BUS 76788
TRIP BUS 76723
END

CONTINGENCY '182GV'
TRIP BUS 76709
TRIP BUS 76693
TRIP BUS 76746
TRIP BUS 76633
TRIP BUS 76755
TRIP BUS 76682
CLOSE LINE FROM BUS 76199 TO BUS 76198 CKT 1
END

COM ***************************** /
COM *    DOUBLE LINE OUTAGE     * /
COM ***************************** /
```

CONTINGENCY '36+37'
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TRIP BUS 76787
TRIP BUS 76504
TRIP BUS 76503
END

CONTINGENCY '38+39'
TRIP BUS 76683
TRIP BUS 76684
TRIP BUS 76753
TRIP BUS 76754
TRIP BUS 76742
END

CONTINGENCY '54+182GV'
TRIP BRANCH FROM BUS 76701 TO BUS 76709 CKT 1
TRIP BRANCH FROM BUS 76709 TO BUS 77054 CKT 1
TRIP BRANCH FROM BUS 76693 TO BUS 77080 CKT 1
TRIP BRANCH FROM BUS 76746 TO BUS 76800 CKT 1
TRIP BRANCH FROM BUS 76682 TO BUS 76700 CKT 1
TRIP BRANCH FROM BUS 76577 TO BUS 76700 CKT 1
TRIP BRANCH FROM BUS 76741 TO BUS 76798 CKT 1
TRIP BUS 75445
CHANGE BUS 76687 LOAD BY 100 PERCENT
END

CONTINGENCY '102+180'
TRIP BUS 76718
TRIP BUS 76760
TRIP BUS 76703
TRIP BUS 77059
TRIP BUS 76722
END

CONTINGENCY '129+130'
TRIP BUS 76704
TRIP BUS 76705
TRIP BUS 76748
TRIP BUS 76738
TRIP BRANCH FROM BUS 76685 TO BUS 76802 CKT 1
END

CONTINGENCY '130+133'
TRIP BUS 76705
TRIP BUS 76719
TRIP BUS 76748
TRIP BUS 76747
END

CONTINGENCY '180NI+182PK'
TRIP BUS 76703
TRIP BUS 76506
TRIP BUS 76722
TRIP BUS 76788
TRIP BUS 76699
TRIP BUS 76723
END

CONTINGENCY '180GV+181/922'
TRIP BUS 76708
TRIP BUS 76692

```
TRIP BUS 76745
TRIP BUS 76687
TRIP BUS 75484
CHANGE BUS 76688 LOAD BY 100 PERCENT
TRIP BRANCH FROM BUS 76701 TO BUS 76700 CKT 1
END

COM ***************************** /
COM *  TRANSFORMERS & BUS TIES  * /
COM ***************************** /

CONTINGENCY 'PK TB3'
TRIP BRANCH FROM BUS 76665 TO BUS 76710 CKT 1
END

CONTINGENCY 'PK TB4'
TRIP BRANCH FROM BUS 76665 TO BUS 76711 CKT 2
END

CONTINGENCY 'GV TB2'
TRIP BRANCH FROM BUS 76663 TO BUS 76700 CKT 1
END

CONTINGENCY 'GV TB3'
TRIP BRANCH FROM BUS 76663 TO BUS 76700 CKT 2
END

CONTINGENCY 'GV TB4'
TRIP BRANCH FROM BUS 76663 TO BUS 76700 CKT 3
END

CONTINGENCY 'GV NYTB6'
TRIP BUS 76153
END

CONTINGENCY 'GV NYTB7'
TRIP BUS 76152
END

CONTINGENCY 'GV230 BUSTIE'
TRIP BRANCH FROM BUS 75412 TO BUS 76663 CKT 1
END

CONTINGENCY 'GV115 BUSTIE'
TRIP BRANCH FROM BUS 76700 TO BUS 75456 CKT 1
END

CONTINGENCY 'PK115 BUSTIE'
TRIP BRANCH FROM BUS 76710 TO BUS 76711 CKT 1
END

END
END

SUBSYSTEM cnp
JOIN 1
AREA 1
BUSES 81725 81680 83556 81657 81650 81649 81648 81647
KVRANGE 115 345
END
END
END
```

MONITOR BRANCHES IN SUBSYSTEM cnp
VOLTAGE RANGE SUBSYSTEM cnp .95 1.05
END
END

IESO Load Flow Models for Phase Shifter and Voltage Regulator

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 5674,'CNP 18  ', 118.0000,1,     0.000,     0.000,   1,   7,1.04455, -23.5013,   1
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5.00000,-5.00000,  33,10, 0.00000, 0.00000
1.00000,   0.000
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   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
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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
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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
```

Figure A Pre CNP Project Showing Tapped Transformer Power Flows

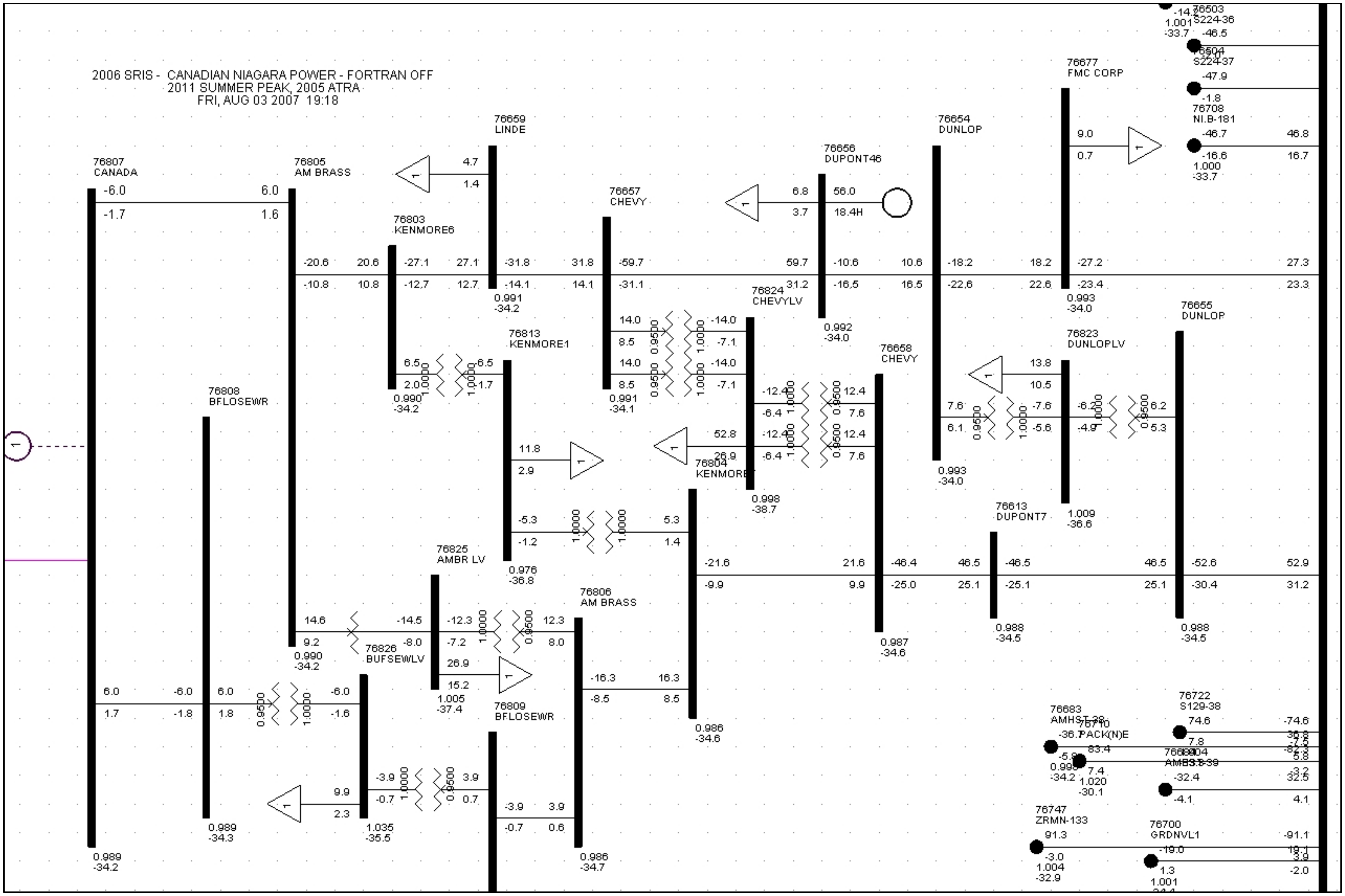


Figure B1 Post CNP Project 150 MW Flow to CNP - Showing Tapped Transformer Power Flows

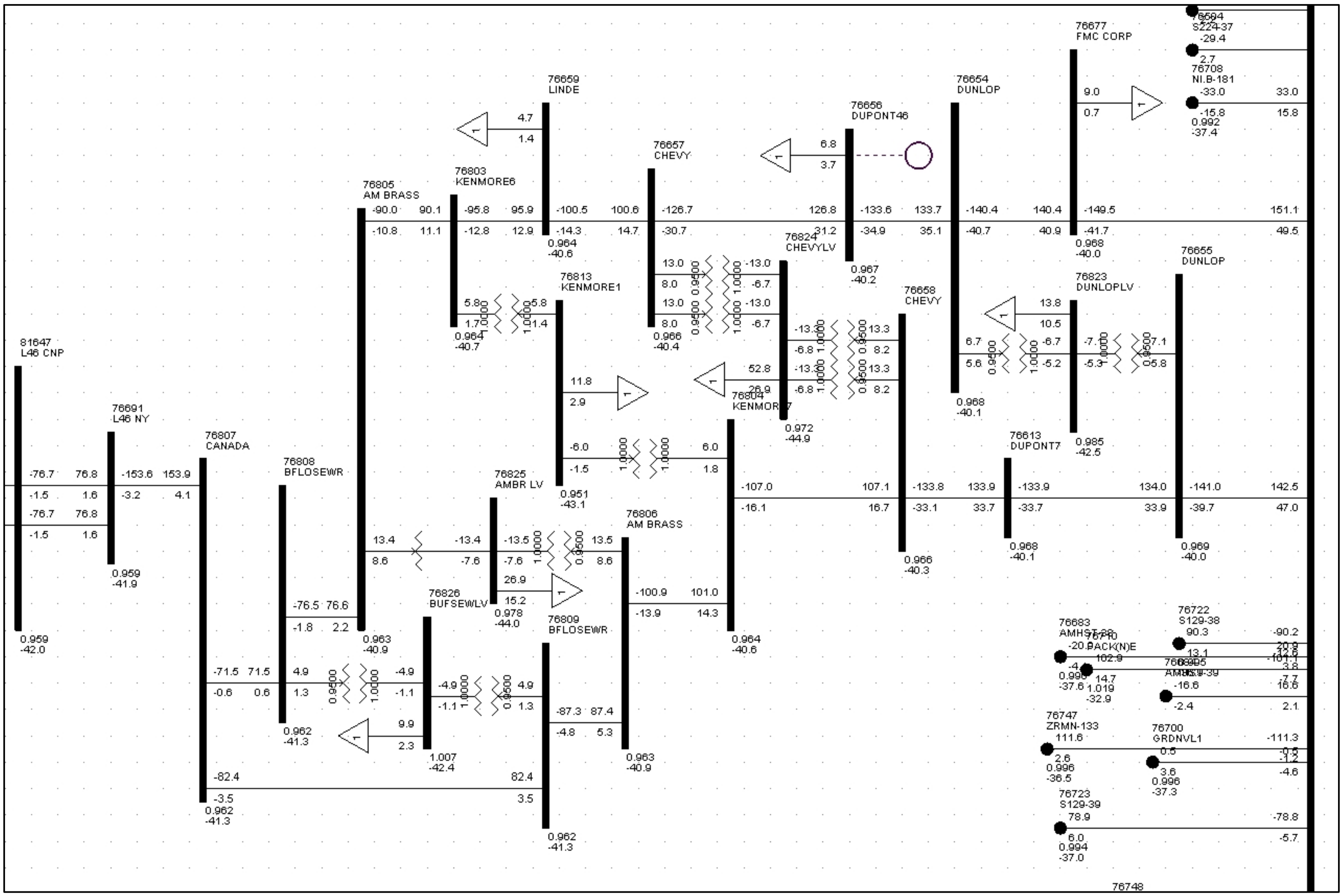
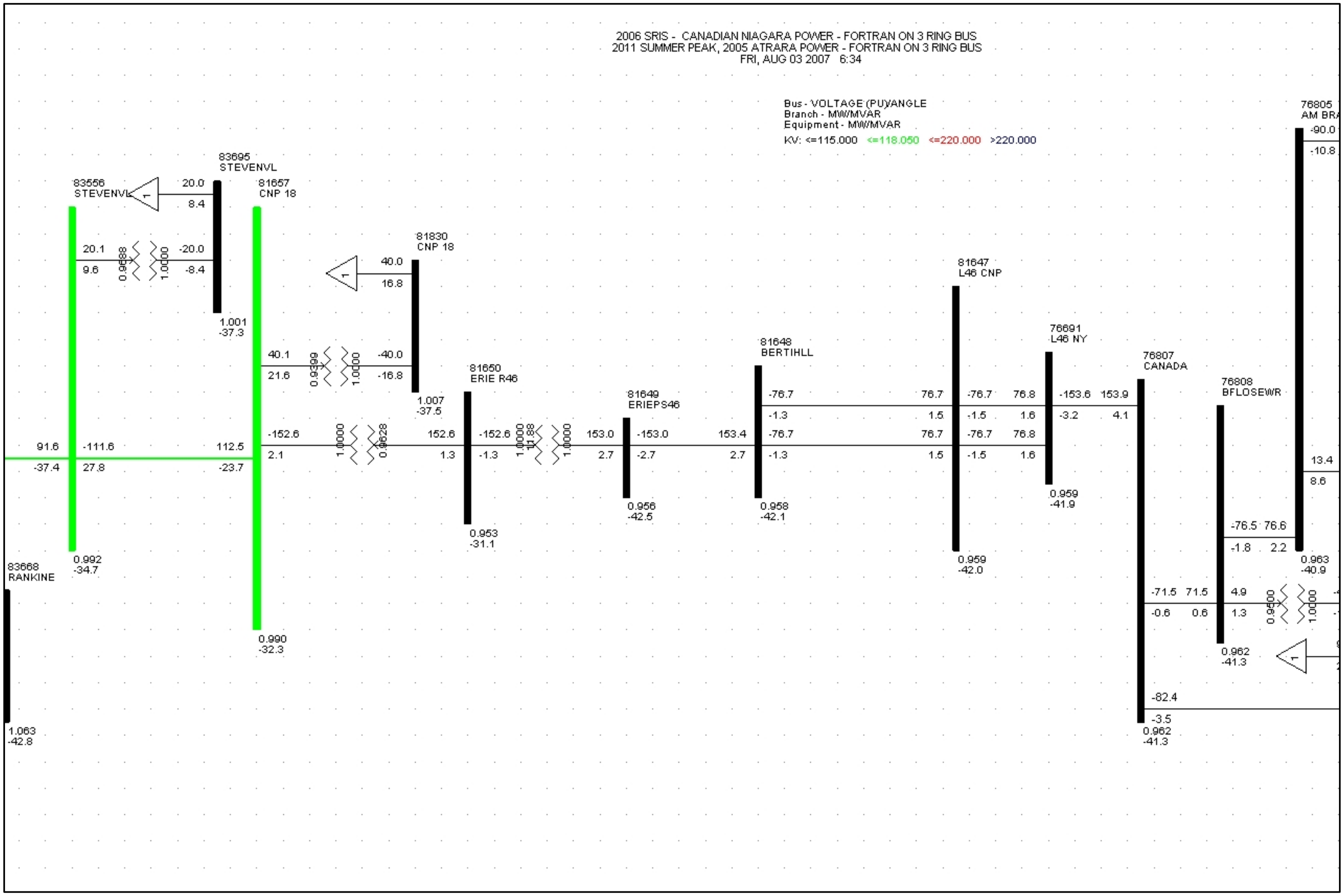


Figure B2 Post CNP Project 150 MW Flow to CNP



Appendix C: Voltage Analysis

1.0 Transmission Owner's Voltage Criteria

TO	Pre-Contingency		Post-Contingency		Allowable Voltage Drop
	Low	High	Low	High	
CH	0.95	1.05	0.9	1.05	10%
ConEd	.95	1.05	0.9	1.05	N/A
LIPA	0.95	1.05	0.9	1.05	N/A
NIMO	0.95	1.05	0.9	1.05	**5%**
NYSEG	0.90/0.95*	1.05	0.90/0.95*	1.05	N/A
O&R	0.95	1.05	0.9	1.05	N/A
NYPA	**	**	**	**	N/A
RGE	0.95	1.05	0.95	1.05	N/A

* - The voltage criteria of 0.95 p.u. is applied to non-regulated buses, while the voltage criteria of 0.90 p.u. is applied to regulated buses (TO control buses). A regulated customer/bus has an LTC or voltage regulator at the substation that supplies the load. For example, you may have customer xyz that is supplied from a 115/12.5 kV substation. If this station has an LTC transformer or some type of bus or line regulation, then this would be considered a regulated bus or substation. If the station did not have any type of voltage regulation, then it would be considered an unregulated station.

** - according to OP1 limit

Appendix D: Short Circuit Analysis

(Not Used)

Appendix E: NYISO Guideline for Fault Current Assessment

NYISO Guideline for Fault Current Assessment

Introduction

This document outlines a recommended approach for fault current assessments using ASPEN One Liner™/Batch Short-Circuit program and the NYISO short circuit representation base case. Use of programs other than ASPEN One Liner™ is not recommended at this time as the NYISO representation uses equipment short-circuit models (in ASPEN format) that are not readily available in other program(s) at this time. Fault current assessment is necessary in several areas of power system analysis including:

- breaker adequacy assessment
- assessment of fault levels for use in dynamics analysis
- fault levels to assess reclosing cycles and impact of the reclosing on breaker duty.

Operation of circuit breakers within specified fault interruption capabilities is essential for safe and reliable production, transmission, and delivery of electrical energy within the NYISO Interconnected bulk power system. This need has been heightened in recent years by the evolution of the open and competitive market structure and operation and the numerous requests from market participants and developers for interconnection to the grid.

Breaker adequacy assessments involve two complementary evaluations:

(i) that of fault interrupting duties expected to exist at stations due to prospective developer sites and other locations associated with planned system changes,
and

(ii) appraisal of present operating capabilities of the affected circuit breakers, including associated relay times.

Both evaluations involve judgment and, therefore, are guided by long-standing industry practices and standards.

The NYISO short circuit representation base case was developed with the assistance and cooperation of the transmission owner representatives on the NYISO System Protection Advisory Subcommittee (SPAS), and is maintained by the NYISO Operations Engineering Staff in accordance with the "Procedure for Developing and Maintaining the NYISO Short Circuit Representation" and the NYISO "Manual for System Analysis Data". The base case representation is maintained in ASPEN One Liner™ format and provides a uniform representation to perform fault current studies of the NYISO bulk power system as required by the NYISO "Transmission Expansion and Interconnection Manual".

Fault Current Calculations

The NYISO shall employ the methodology detailed below, consistent with the system conditions being studied, when evaluating short circuit currents on New York State transmission system facilities.

A. The following system-wide assumptions shall normally be applied to the base case representation for NYISO analysis:

1. All generating units are in service.[1] Synchronous machines (e.g., generators, synchronous condensers, and large motor groups) are modeled using subtransient saturated reactance (X_{dv}”). Machine zero-sequence reactance (X_{0v}) generally is not required in short-circuit studies because the GSU transformer HV/LV windings are normally specified with YG/D connections, blocking the flow of machine zero-sequence currents during system faults; generator X_{0v} can be omitted or set to the actual value, if readily available.
2. Transmission line models include positive- and zero-sequence inductive impedances. Negative-sequence impedance is equal to the positive-sequence impedance and hence not entered separately. Zero-sequence mutual impedances between mutually-coupled line sections, such as those on common rights-of-way, are also included. Positive-sequence mutuals are normally ignored, but can be combined with line impedance in some situations, if needed. Capacitive admittances of lines (line charging), both positive- and zero-sequence, are omitted.
3. Initially, fault levels will be determined with all transmission lines that are normally in service represented as such, and those transmission lines that are normally open (e.g. a “normally open” bus tie) shall be represented as such. However, all reasonably realizable system configurations that yield the highest fault current shall be considered, consistent with local operating practice and procedure as determined by the NYISO. System facilities represented in the studies reflect information obtained from equipment vendors, design records, and operating data (or best estimates) processed into suitable models using proven tools and techniques. Since resistance values are generally more difficult to secure than reactance values, although both are important in breaker duty assessments, References 1-3 can be used to estimate typical X/R ratios for principal system components.
4. All transformers are modeled using leakage reactance and load-loss based resistances corresponding to the present or planned operating tap positions, as appropriate. Tap ratios for load-tap changing transformers are assumed to be 1:1 (or center tap); phase-angle regulating transformers are assumed on the lowest impedance setting (typically center tap and / or 0-degree shift), and magnetizing branches are omitted. Impedances of mismatched, single-phase transformers operating in a common bank are averaged. Transformer positive- and negative sequence impedances are identical, and zero-sequence impedances are assumed identical to positive-sequence impedances unless test data indicate otherwise. All windings are modeled with proper winding/grounding connections, keeping in

mind that some GSU transformers operate with ungrounded neutrals to reduce fault duties. Fixed tap and GSU transformers should be represented on the tap ratio consistent with the connecting transmission owner practice, or the normal operating condition if tap and impedance data are readily available; otherwise they shall be represented on nominal.

5. All fault current- limiting series reactors are in service. Load current- limiting series reactors are represented only if switched permanently into service. Series capacitors are bypassed during close- in faults that exceed the capacitor normal rating (consistent with the series element protection); otherwise, they remain in service.
6. All loads, shunt capacitors, and shunt reactors are ignored except those shunts used in the representation of three winding transformers. Static VAr Compensators, Static Shunt or Series Compensators (FACTs devices), traditional HVdc converters, and other power-electronic devices are normally omitted, except that any transformers integrating these facilities into a power system are included. Voltage Source Converter HVdc is represented as an equivalent generator source, where appropriate.
7. All generator interna l voltages are set at 1.0 p.u. and no phase displacement due to load (i.e., Flat Gen pre- fault starting conditions are assumed[2]).

B. The following types of faults shall be considered:

- Three Line to Ground
- Double Line to Ground
- Single Line to Ground

All faults are assumed to be a zero- impedance (bolted) fault with no current limiting effect due to the fault itself.

C. Fault currents through each interrupting device shall be analyzed for the following fault conditions under all normal system and single contingency system configurations:

- Bus Fault
- Close- in Line-end Open Fault

Individual breaker analysis will be performed consistent with the station breaker arrangement.

References

[1] ANSI/IEEE C37.5-1979, "IEEE Guide for Calculation of Fault Currents for Application of AC High-Voltage Circuit Breakers Rated on a Total Current Basis."

[2] ANSI/IEEE C37.04-1979, "IEEE Standard Rating

Exhibit B, Tab 12, Schedule 1

Overview - System Reliability Impact Study

OVERVIEW - SYSTEM RELIABILITY IMPACT STUDY

NYISO's interconnection process requires that a system reliability impact study ("SRIS") be carried out for purposes of assessing the impact of an interconnection project on the connecting transmission owner's transmission system. While this is the same basic purpose as the Feasibility Study Report referred to in **Exhibit B, Tab 11, Schedule 1**, the SRIS is more comprehensive, more detailed and considers impacts on potentially affected neighbouring systems. SNC-Lavalin T&D Inc. was selected to conduct the SRIS, which involved a power flow analysis (including of thermal and voltage performance), a power transfer analysis, a short circuit analysis and a dynamic stability analysis on the New York State Transmission System and the local transmission systems of CNP Transmission and USNG. The results of this analysis is presented in the SRIS Final Report, issued in February 2009, which is provided in **Exhibit B, Tab 12, Schedule 2**.

The SRIS Final Report concludes that, while upgrades would be needed to overcome limitations in the thermal ratings of certain line sections, the Project would increase the New York-Ontario interface transfer capability by more than 150 MW and would not have any adverse impacts on system stability. As described in the Project Description at **Exhibit B, Tab 2, Schedule 1**, these upgrades, which include the construction of the three-breaker ring station and upgrading 10 km of lines L46 and L47, are part of the Project.

Exhibit B, Tab 12, Schedule 2

System Reliability Impact Study - Final Report

SNC·LAVALIN

Submitted to:

New York Independent System Operator

Final Report

Original

System Reliability Impact Study for Fortran Project of Canadian Niagara Power Fort Erie, Ontario (Queue # 210)

February 2009

SNC·LAVALIN

EXECUTIVE SUMMARY

Canadian Niagara Power Inc. (CNP) is a subsidiary of Fortis Ontario, operating as the local transmitter and distributor of power in the Fort Erie area. The transmission system of CNP is presently connected to the Hydro One 115kV system at Murray Transformer Station (TS). Under an inter-utility agreement, it can also be connected to the Niagara Mohawk Power Corporation d/b/a National Grid (NG) system at the end of the radial line L46. The NG system is part of the NYISO interconnection and is operated based on the NYISO operating guidelines.

CNP has proposed closing the Normally Open (N/O) tie between CNP and NG, creating a permanent "CNP-NG inter-tie". The proposed inter-tie, henceforth referred to as the Fortran Project, would establish continuous flow of power between CNP #18 sub-station in Fort Erie, Ontario, and "Canada bus" of NG in Buffalo, NY, providing two independent sources of power for the loads served by CNP.

The earlier studies have determined that the Fortran Project will include: 1) installation of a phase shifting transformer; and, 2) a voltage regulator in series with the tie line. The Point of Interconnection ("POI") will be a new 3-breaker ring station, connecting the Canada bus at the termination of the 115 kV lines L46 and L47.

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 intra-utility agreements. The tie's active power flow will be controlled via the phase shifting transformer's angle, which will be scheduled by coordinated operation planning of IESO and NYISO. The voltage regulating transformer will be operated with the goal of minimizing the tie's reactive power flow. Both the phase shifting transformer and the voltage regulator will be housed at CNP#18 substation.

The Interconnection process of NYISO, described in Attachment X of the NYISO OATT, requires conducting a System Reliability Impact Study (SRIS) to assess the impact of an interconnection project on the Connecting Transmission Owner's system and on potentially Affected Systems (neighboring systems). SNC-Lavalin T&D Inc. has been selected to conduct the Fortran Project SRIS, to satisfy the above NYISO regulatory requirement based on the base case information supplied by NYISO. The study is performed in accordance with applicable NYISO, Connecting Transmission Owner ("CTO") (i.e.: NM-NG), and Affected System(s) study guidelines, procedures and practices as well as applicable NERC, NPCC, NYSRC, NM-NG and Affected System(s) reliability and design standards.

The SRIS involved a power flow analysis (thermal and voltage performance), a power transfer analysis, a short circuit analysis and a dynamic stability analysis on the New York State Transmission System and the local transmission systems of CNP and NG. The impact of the project was determined by conducting these analyses with and without the project and comparing the results against each other.

Thermal studies conducted for the new CNP-NYISO inter-tie indicate that that the power transfers in both directions are restricted only by the thermal ratings of the two parallel river crossing circuits running between L46 NY and BERTIHILL buses. The study recommends reconductoring of the existing tie at the river crossing and approximately six miles of L46 and L47 lines. Studies performed on the system voltage/Var performance, for the same system loading conditions and inter-tie power transfers, indicate that, in addition to the voltage regulator, a capacitor bank is needed at the CNP #18 substation for transfer of +/-150 MW to maintain acceptable voltages at buses surrounding the Project.

The SRIS study has confirmed that the addition of the CNP tie (and associated facilities) does not adversely impact the transfer capability and that NY-Ontario interface at Niagara transfer capability will increase by more than 150 MW. The voltage and angle changes on the NY bulk power system due to the CNP tie flows are very small and voltage and stability limits are shown to be unaffected. The intra-area analysis showed that some of the NYISO intra-area transfer limits are increased by a small amount with the CNP tie.

Simulations of system dynamic response to the selected events indicated that: 1) the differences without and with the CNP tie are very small and the resulting oscillations are well-damped or remain unchanged; 2) There is no need for any upgrade of the existing protection system, as none of the simulated events lead to system dynamic instabilities; and, 3) For both single and complex contingencies, differences between system responses obtained with and without the Fortran Project are very small. In brief, the Fortran Project does not have any adverse impact on the system stability.

Steady-state and dynamic simulations were performed on a set of extreme cases. These events did not produce noticeable changes in the overall system response due to the addition of the new CNP tie.

Short Circuit analyses were conducted for key equipment surrounding the Project. The simulated faults indicating inadequate breaker IC were at NY Niagara Station. The short circuit current level rises could be attributed to Fortran Project as well as other projects added from the queue. The assignment of the responsibility is left to the Facility Study process.

To implement the Project, CNP has to take on the following activities over a period of about three and a half year:

1. Installing a phase angle regulating transformer and a voltage regulating transformer on the new inter-tie at CNP #18, at estimated cost of $8,800,000;

2. Re-conductor 0.7 miles length from the River Crossing Point NY side (Terminal House B) to CNP side Bertie Hill Tower with 795 ACSR conductor, at the estimated cost of $200,000.

3. Installing a 30MVA capacitor bank at CNP #18, at estimated cost of $400,000.

As part of the upgrades of the NG system, construction/upgrading of the following facilities within the next three and a half years have been proposed:

1. Upgrading of 6.3 miles of 115 kV transmission line L46 and L47 at the Paradise Station end. This upgrade will result in the ratings of the Paradise – FMC, FMC – Dunlop and Dunlop – DuPont sections of both L46 and L47 lines to increase to:

    a. 271 MVA for summer normal,
    b. 313 MVA for summer LTE,
    c. 359 MVA summer STE,
    d. 331 MVA winter normal,
    e. 364 MVA winter LTE; and,
    f. 404 MVA winter STE.

    The good faith estimate of this upgrade provided by NG is $9,500,000.

2. Constructing the 3-breaker Ring Station in Buffalo. The estimated cost of the 3-breaker ring station provided by NG is $ 5,750,000.

To enter into service, Fortran Project will require changes to the existing Presidential Permit that governs CNP energy transfers. The revised permit could address changes both in the transfer capacity and operation of the tie.

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1 Introduction

Canadian Niagara Power Inc. (CNP) is a subsidiary of Fortis Ontario, operating as the local transmitter and distributor of power in the Fort Erie area. The transmission system of CNP is presently connected to the Hydro One 115kV system at Murray Transformer Station (TS). Under an intra-utility agreement, it can also be connected to the Niagara Mohawk Power Corporation d/b/a National Grid (NG) system via a Normally Open (N/O) breaker at the end of the radial line L46. The NG system is part of the NYISO interconnection and its operation is governed by the NYISO guidelines.

The existing CNP system has a radial configuration and its breakers/switches are operated in accordance with "break before make" procedures. Therefore, switching the supply of power from the Hydro One to NYISO system or vice-versa results in interruptions of power to CNP local customers lasting several hours.

CNP has proposed operating the tie switch between CNP and NG as Normally Closed (N/C), effectively creating a permanent "CNP-NG inter-tie". The proposed inter-tie would establish continuous flow of power between the CNP #18 sub-station in Fort Erie, Ontario, and "Canada bus" of NG in Buffalo, NY, providing two independent sources of power for the local loads served by CNP.

Assuming it maintains its present operating pattern, under normal operating conditions CNP will be receiving power from Hydro One Murray TS to cater for its loads and to transmit as little power as possible to the NYISO side (please see Fig. 2-1). The amount of transmitted active power can be controlled via the phase shifting transformer that will be installed at CNP#18. The reactive power transfers will be influenced by the voltage regulator that will be also housed in CNP#18. For maintaining acceptable voltages at CNP and NG buses, installing a capacitor bank at CNP#18 is suggested.

As a participant in Electricity Markets, CNP can operate the inter-tie by submitting its Day Ahead (D/A) operation plan to IESO and/or NYISO for receiving daily operating schedules for its phase shifting transformer. The schedules of the phase shifting transformer will be determined as part of the Coordinated Operation Scheduling effort of the two ISOs. The resulting schedules will be passed to CNP to be implemented by CNP operators/dispatchers on a timely basis during the day .

Under emergency conditions, CNP will operate the tie in accordance with its intra-utility agreement. The existing agreement allows the tie to be disconnected from one side (presumably the side most affected by the emergency) and connected to the other side. Situations may arise during emergencies where CNP can assist the overall system operation by keeping the tie operational and transferring power to the impacted side. The details of such operations have to be worked out as part of revising the existing intra-utility agreements.

The MVAr flow direction on the tie may not necessarily coincide with that of the active power flow. Typically the voltage magnitude at Murray TS is higher than that of Canada bus and Var flows from the CNP side to the NG side. However, to operate the tie consistent with the current CNP operating pattern,, when possible, one would like to keep the Var transfers low. The voltage regulator can be deployed for that purpose.

The National Grid has planned to retire the Huntley 115kV Switching Station and has planned a new 115kV Substation called Paradise to rearrange the 115kV transmission lines that are now terminating at Huntley.

The goal of this System Reliability Impact Study (SRIS) is to evaluate the impact of the proposed inter-tie on the reliability of the New York State Transmission System for maximum power transfers of +/-150MW. The SRIS report provided here is based on the report outline specified in the NYISO Transmission Planning Guideline #1.0.

2 FORTRAN Project Description

2.1 The Project

CNP is proposing to establish a permanent interconnection between Hydro One transmission system and the planned NG Paradise station by installing a phase shifter and a voltage regulator at CNP Station #18. The permanent interconnection can provide dual supply routes for the local loads served by CNP, improving local supply reliability. The estimated in service for the project is Fall of 2012.

2.2 CNP Transmission System

At 115kV level, the CNP distribution system consists of:

1. CNP # 11 (or Rankin) switching station
2. Transmission stations CNP # 17 (Stevensville) and CNP# 18
3. Line L2, which connects CNP#11 and CNP#17 substations
4. Line L46 CNP, connecting CNP #18 to Huntley GS.

Note that line L46 has an underground cable section, which runs from bus L46 NY at the end of river crossing to the Canada bus tap point on the circuit L46 (see Figure 2.1). CNP#11 is fed from Murray substation of Hydro One.

Hydro One's Murray Substation is connected to Allanburg TS and Beck GS. The CNP Fort Erie load may be connected to either A36N or A37N 115 kV circuits at CNP#11; by the breaker arrangement shown in Figure 2.1. The ratings of both A36N and A37N are roughly 270 MVA for summer weather conditions while L2 is rated at 210 MVA.

The CNP system can be fed radially from the NYISO grid by closing a N/O breaker at station #18 (after opening the CNP and IESO-controlled grid connection at CNP #11). The CNP system peak load in this future study is assumed to be 60 MW at 0.92 power factor for the study year.

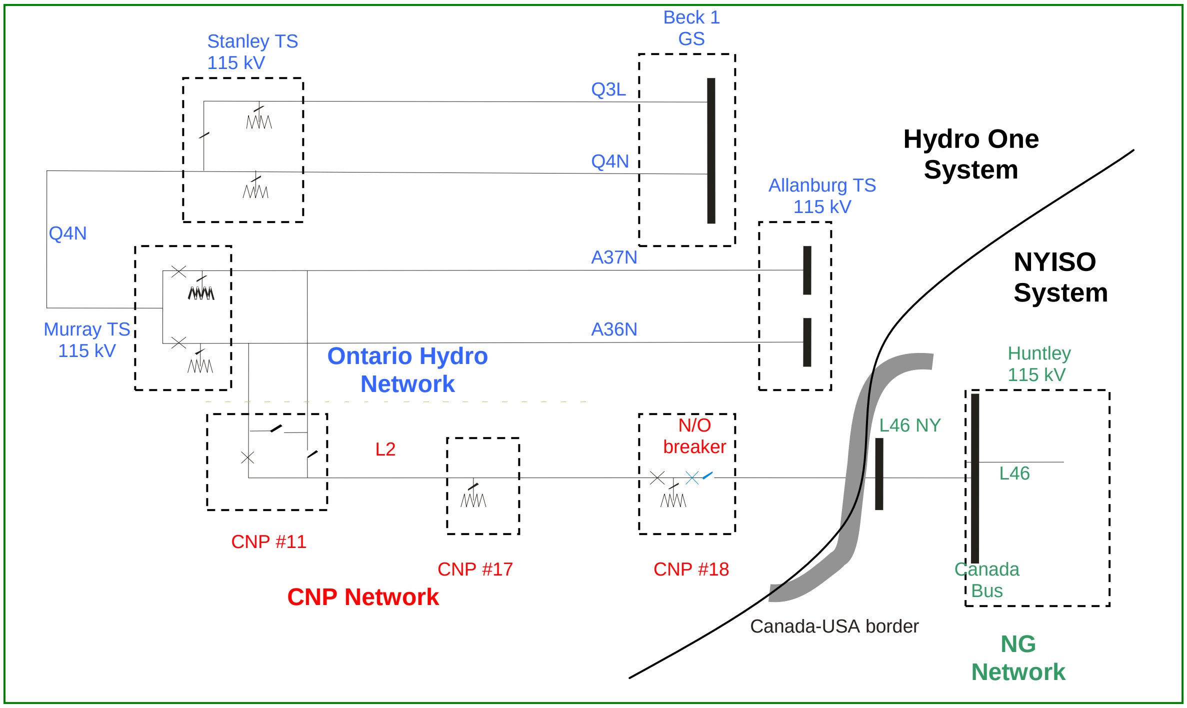

Figure 2-1: Present Arrangement – CNP system and portions of NG and Hydro One 115kV networks

2.3 Proposed Interconnection

With the proposed interconnection, CNP load at Fort Erie can be supplied from both Murray TS and the proposed Paradise 115 kV station or its predecessor, the existing Huntley Substation. Consequently, for a contingency that interrupts the power supply from Murray, the CNP load will continue to be supplied by Paradise station and vice versa. The voltage regulator and phase shifter will be connected between CNP #18 station and 'Canada' bus of NYISO system.

The transmission line between CNP #18 and NYISO 'Canada' bus consists of the following four sections, shown in Figure 2.2:

- CNP #18 to Bertie Hill (C to D); a 2.0 miles single circuit line with continuous rating of 180 MVA.
- Point D to E; This is a 0.3 miles double circuit from Bertie Hill to the high tower crossing point at the Niagara River. The continuous rating is 68 MVA for each circuit.
- Point E to F is a 0.4 miles double circuit line crossing the river with a rating of 51 MVA for each.
- The last section is a 1.7 miles cable with continuous rating of 169 MVA terminating at 'Canada' bus in NYISO

In this study, these four sections will be collectively referred to as "the new inter-tie".

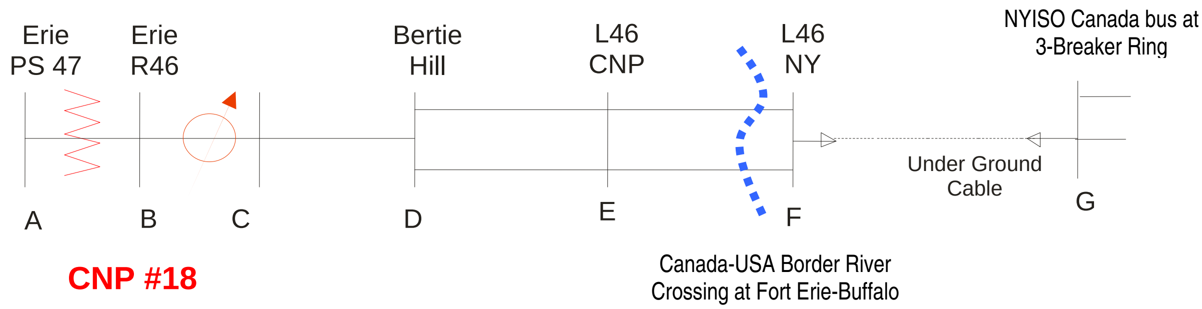

Figure 2-2: Interconnection line between CNP #18 and NYISO

On the New York side, the proposed Paradise Station and the existing Huntley Station are shown in one-line Diagrams in Appendix C. Lines 46 and 47 that connect to Huntley Station are proposed to be connected to the new Paradise Station. Lines 46 and 47 will have 5 miles of 636 aluminum (37 strand) and 1 mile of 500 copper (37 strand) conductor. The aluminum conductor is at the Paradise end of the line. The portion of the lines (6 miles long) that uses 795 ACSR (Drake) conductors will be left intact.

As shown in Figure 2.3 the CNP tie will connect to Lines 46 and 47 via a 3 Breaker Ring near the Buffalo Sewer Station. This connection will ensure that the tapped customer transformer loads are balanced. In this arrangement, lines 46 and 47 will be in parallel; thus outage of either line will be critical to the tie operation. Loss of Line 46 will also result in the loss of the DuPont generator (that is tapped on this line). The new 3-Breaker Ring station will introduce a stuck breaker contingency case that would interrupt both lines L46 and L47.

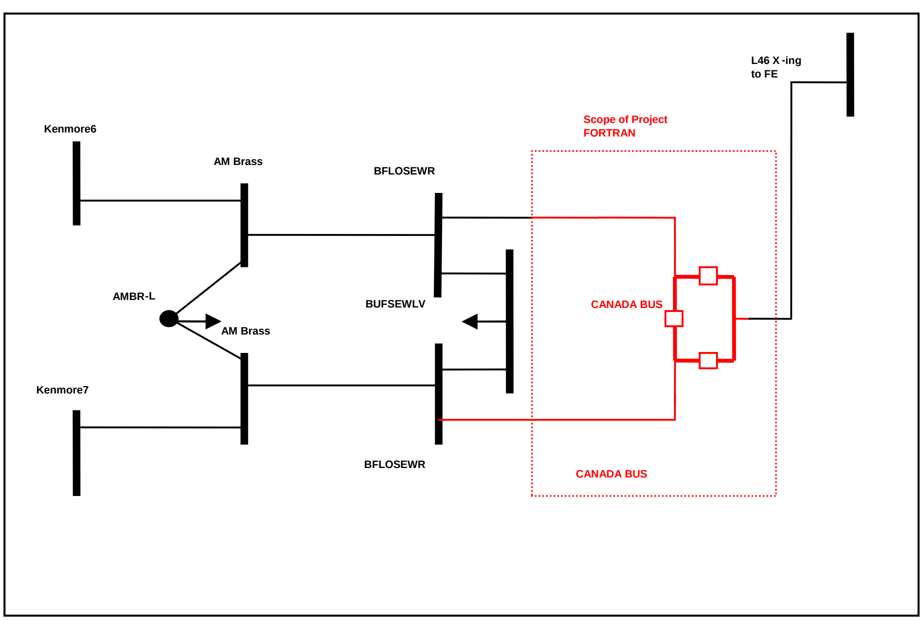

Figure 2-3: Proposed 3-breaker ring station (in New York) connecting CNP tie to Canada bus

2.4 Proposed Inter-tie Equipment

Based on earlier studies, the CNP-NG inter-tie will be connected at CNP#18 to:

- a voltage regulator (R46);
- a phase shifting transformer (PS46).

Due to the difference in voltage between the CNP system and the Huntley, a voltage regulator (R46) is required to bridge voltages on both sides of the interconnection. An IESO study suggests that the voltage regulator should be rated at 150 MVA and should have a ±10% on-load tap changing capability.

The proposed phase shifter is rated at 120 kV and 150 MVA (similar rating to R46). The overload capability for this transformer at 100% preload (150 MVA) can be found in Table 2.1. 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. A complete listing of the load flow data for PS46 and R46 (as provided by IESO) can be found in Appendix B.

Table 2-1: Overload capab120 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 addition to the voltage regulator, the results of this study (Please see Section 4) indicate that a 30 MVA capacitor bank is needed at CNP#18 to maintain acceptable voltages at NG customer buses.

3 Study Scope, Methodology and Assumptions

This section outlines methodologies, assumptions and basic principles that are employed to conduct this SRIS.

3.1 Interconnection Plan

The study addresses the proposed facilities and their conceptual interconnection to the transmission system. The descriptions provided here include one-line diagrams, which indicate the proposed facilities within the area of interest and their connection to the existing transmission facilities (see also Appendix A).

3.2 Study Period

The study is based on the system loads, generation mix, and network configuration representing 2012 power flow base cases submitted as part of the NYISO 2007 FERC 715 filing. The study uses the applicable Power Flow, Short Circuit and a Stability base cases provided by the NYISO, and includes representations of other proposed projects. These projects are listed in Appendix D.

3.3 Study Area

The study has evaluated the impact of the Project on:

- The bulk power system in the West Region (Zone A) which is most likely to be affected by the Project; and,
- The lower voltage systems local to the Project.

The focus of the study has been placed on the POI and the surrounding underlying (115 and 34.5 kV) network elements, directly impacted by the Project.

3.4 Methodology

In conducting the SRIS, the Consultant has deployed the study cases representing system conditions in 2012 that incorporated the FORTRAN project both in service and out of service. The Power Flow and Transfer Limits as well as Dynamic Stability analyses were performed using PTI PSS/E software package. The Short-Circuit Analysis was performed using the ASPEN software package. These analyses were intended to establish compliance of the Project, or lack thereof, with the bulk power system applicable reliability standards.

The following analyses have been performed as part of the SRIS and the results are presented in the indicated sections of this report:

- Power flow analysis – Conducted to assess the project's impact on branch loading as well as bus voltages in the study area under normal and contingency steady-state conditions. The results are provided in Section 4 and Appendix G and H;

- Interface Power Transfer Limit – Carried out to identify incremental impacts of the proposed project on power transfer limits at key interfaces. Summary of the results are given in Section 5 and the details are in Appendix I;

- Transient and Dynamic Stability analysis – Performed to evaluate the impact of the project on system performance in the study area. For the basic and extreme events, the results are given in Sections 6 and 7 and Appendices J and K respectively. Stability analysis has been also performed to detect a change in the system Critical Clearing Time due to the Fortran Project;

- Short Circuit Analysis – Performed to establish the impact of the project on the adequacy of the existing circuit breakers and related protection equipment vis-à-vis various faults. The results are given in Section 8 and Appendix L.

3.5 System Study Scenarios

3.5.1 Base Cases

The impact of the proposed Project is evaluated for three different operating scenarios, corresponding to different system loads, generations, interchanges and network topologies. These are:

- Winter Peak (WP) Load,

- Summer Peak (SP) Load, and

- Summer Light (SL) Load

Henceforth, the above operating scenarios will be referred to simply as WP, SP, and SL. Each scenario has been studied for the following cases:

<u>Case 1</u> – Without the Project

The base case includes the baseline system, Fortran Project under normal operation, and other proposed projects listed in Appendix D. The Short Circuit base case models all other projects as in-service. The Power Flow base case has modeled all projects in-service at full output. Generations are dispatched based on participation factors provided by NYISO.

Case 2 – With the Project

The Project is modeled as in-service, transferring $\pm$150MW. Additional facilities required by the Project are fully represented. Generators are re-dispatched in the Power Flow and Power Transfer cases.

3.5.2 Convention for Designating Tie Flow Direction and Schedules

Henceforth, the following convention is used to designate CNP-NG inter-tie flows:

- Northbound active power flows on the inter-tie (that is power flowing from Canada bus to CNP #18 or simply "NY to ON") are identified by "N".
- Southbound active power flows (that is power flowing from CNP #18 to Canada bus or simply from "ON to NY") are identified by "S".

Thus, "150N" implies 150MW flowing from NY to Ontario on the Fortran inter-tie. The reactive flow on the tie does not necessarily have the same direction as its active flow.

3.5.3 Meeting Voltage/Var Requirements

When the tie is carrying 150S, it influences the CNP and NG transmission systems differently. At CNP, it is seen as doubling or tripling the load (depending on the season) served by the company. Transfer of this relatively large power (for the CNP system) through the CNP equipment requires higher reactive power, which Hydro One cannot currently supply. This leads to reduced voltages at the CNP side, in particular at the CNP#18 bus. Raising this voltage to an acceptable level by deploying the voltage regulating transformer would be at the expense of losing control on the tie reactive power flow. At the NG side, however, the tie can be viewed as a new generating station, injecting around 100MW into the Canada bus. When the tie reactive flow happens to be in the same direction (which, in this case, normally is), the effect is an increase in NG bus voltages in immediate vicinity of Canada bus. Essentially, the tie can be viewed as a back up for the DuPont generator, when it becomes unavailable.

Conversely, when the tie carries 150N, the NG system can view the tie as a new 150MW load added to its system at Canada bus. Supply of this demand causes voltages at a number of buses on the NG system to drop. The magnitudes of voltage drops vary with the location of the generator(s) supplying the new demand. When DuPont generator is used for this purpose, as it is located close to Canada bus, the voltage drops are relatively small. However, in the absence of DuPont generator, the reactive power has to be brought into the NG system either from distant power plants or from the CNP side, via the tie. The latter option is more attractive, as it avoids additional loading of the NG transmission equipment and increasing their losses.

The above discussion points to the following:

- There is need for a Var resource at the CNP#18. It will support the voltage at the CNP#18 bus and can supply Var to the NG via the tie, when required;

- While it is generally desirable to keep the tie Var flows as small as possible, when the tie is scheduled for 150N, some reactive power has to be supplied via the tie to the NG side to maintain its customer bus voltages;

- The reactive power source at the CNP#18 complements the voltage regulating transformer by extending the VR reactive power control range.

Based on the above views, when performing the thermal and voltage performance analysis, a shunt capacitor bank is assumed to be connected to the CNP#18 bus. The size of this capacitor bank was not initially fixed and was allowed to be set by the CNP and NG voltage requirements. The capacitor bank step size (size of individual capacitors in the bank) was set to 5MVAr, as the voltage regulator is allowed to provide smooth control over +/-5 MVAr.

3.5.4 Re-dispatching Generators

In this study, base case generations are modified to enforce scheduled active power flows on the inter-tie. Re-dispatching involves three steps:

- Increasing/decreasing generations on the NY side

- Decreasing/increasing generations on the Ontario side

- Adjusting phase shifting transformer angle, to route the resulting interface flow changes to the CNP-NG inter-tie

The following table summarizes the studied scenarios in relation to the status of the Fortran Project, the type of studies performed, active power tie flow and the CNP demand, and the need for generation scheduling.

Table 3- 1: Studied scenarios and required generation re-dispatch

Operating Scenario	FORTRAN Project Status	Studies Performed	Tie Schedule (MW)	CNP Demand (MW)	Generation Rescheduled
WP	OFF	NCA	N/A	60	N/A
	ON	NCA	150S	60	Yes
	ON	NCA	150N	60	Yes
SP	OFF	NCA, XCA, TDA, TLC	N/A	60	N/A
	ON	NCA, XCA, TDA, TLC	150S	60	Yes
	ON	NCA, XCA, TDA, TLC	150N	60	Yes
SL	OFF	TDA	N/A	39.5	N/A
	ON	TDA	150S	39.5	Yes
	ON	TDA	150N	39.5	Yes

NCA: Normal Contingency Analysis; XCA: Extreme Contingency Analysis
TDA: Transient and Dynamic Analysis; TLC: Transfer Limit Calculation

As generation re-dispatch can be different for different studies, its details are separately given as part of each study's section.

3.6 Modeling Assumptions

In the conducted SRIS:

1. Phase angle regulators ("PARs"), switched shunts, and LTC transformers are modeled as regulating under pre-contingency conditions and as non-regulating in the post-contingency states. The study uses PAR schedules established by the NYISO, in coordination with the neighboring ISOs through the NERC and NPCC base case development processes, as represented in the NYISO FERC 715 power flow base cases filed in 2007;

2. Controls of the SVC and FACTS devices are fixed in the pre-contingency state but allowed to operate to full range under post-contingency conditions;

3. To determine MW transfer limits for NYISO interfaces, the SRIS has simulated generation re-dispatches based on the standard participation factors used in NYISO transmission planning and operating studies. Where applicable, for local (Transmission Owner) interfaces, generation re-dispatching is done in conformance with standards and practices of the Transmission Owner.

4. Previous NYISO studies have indicated the need for upgrading Niagara breakers. Some identified upgrades to Niagara breakers may have been reflected in the specified breaker interruption capacities, but not necessarily all;

5. Thermal limits for the line sections connecting Paradise to Dunlop Stations were based on the information in Table 3.2 below:

Table 3-2: Line upgrades – Required thermal limit increases for the Project

From BUS		To BUS		CKT	FORTRAN-OFF (MVA)		FORTRAN-ON (MVA)	
Bus No.	Bus Name	Bus No.	Bus Name		Rate A	Rate B	Rate A	Rate B
76701	PARADISE	76677	DUNLOP	L46	168	185	266	308
76701	PARADISE	76655	DUNLOP	L47	168	185	266	308

3.7 System Upgrades

Whenever the study results indicate that the Project, as proposed, results in violations of reliability standards, required System Upgrade Facilities has been identified.

3.8 Cost Estimates of Facilities/Time to Construct

When required, the SRIS has provided a description of facilities (Connecting Transmission Owners' Attachment Facilities and System Upgrade Facilities) needed to interconnect the Project to the New York State Transmission System. A non-binding good faith estimate of cost and time to construct the identified facilities has also been included.

4 Power Flow Analysis

The power flow analysis was conducted to evaluate the impacts of the Fortran Project on the transmission system. Thermal and voltage analyses were performed to establish system performance, focusing on the areas potentially affected by the Project. The analysis assumes that, when the Project is ON, all its facilities (including the PAR and VR transformers and the capacitor bank) are in service and the ratings of the lines L46 and L47 are those given in Table 3-2.

The thermal limits used in the study were normal limits (A Rating) for pre-contingency conditions and long time emergency limits (B Rating) for the post-contingency conditions. Buses were monitored for voltages deviations beyond +/-5 percent of their rated voltages.

Tables 4-1 and 4-2 provide re-dispatching of Hydro One and NYISO generations that is needed under SP loading to establish 150N and 150S, respectively. Note that the changes are restricted to generators belonging to specific power plants.

Table 4- 1: Generation re-dispatch for 150N tie flow under SP loading

System	Bus No.	Generator	Pre-Dispatch (MW)	Post-Dispatch (MW)	Generation Shift (MW)
Ontario	80906	PIC A G2	540	465	-75
	80907	PIC A G3	540	465	-75
	Total Generation Shift				-150
New York	78706	ATHESC1	188.5	250	+63.5
	78707	ATHESS1	48.5	110	+61.5
	78708	ATHESC2	189.5	215	+25.5
	Total Generation Shift				+150.5

Table 4- 2: Generation re-dispatch for 150S tie flow under SP loading

System	Bus No.	Generator	Pre-Dispatch (MW)	Post-Dispatch (MW)	Generation Shift (MW)
Ontario	81759	BECK25G7	0	45	+45
	81748	BECK2G25-1	42.8	80.8	+38
	81748	BECK2G25-1	42.8	80.8	+38
	81749	BECK2G23-1	75	81	+6
	81749	BECK2G23-2	75	81	+6
	81750	BECK2G21-1	77	81	+4
	81750	BECK2G21-2	77	81	+4
	81751	BECK2G19-1	77	81	+4
	81751	BECK2G19-2	77	81	+4

System	Bus No.	Generator	Pre-Dispatch (MW)	Post-Dispatch (MW)	Generation Shift (MW)
	81750	BECK2G15-1	77	81	+4
				Total Generation Shift	+153
New York	78706	ATHESC1	188.5	113.5	-75
	78708	ATHESC2	189.5	114.5	-75
				Total Generation Shift	-150

The re-dispatching of NYISO and Hydro One units for enforcing tie flow schedules of 150N and 150S, under WP loading are given in Tables 4-3 and 4-4, respectively. Again, the changes involve two specific power plants.

Table 4- 3: Generation re-dispatch for 150N tie flow under WP loading

System	Bus No.	Generator	Pre-Dispatch (MW)	Post-Dispatch (MW)	Generation Shift (MW)
Ontario	80908	PIC A G1	540	450	-90
	80909	PIC A G4	500	440	-60
				Total Generation Shift	-150
New York	78708	ATHESC2	205.5	250	+44.5
	78709	ATHESS2	65.5	110	+44.5
	78710	ATHESC3	220.5	250	+29.5
				Total Generation Shift	+148

Table 4- 4: Generation re-dispatch for 150S tie flow under WP loading

System	Bus No.	Generator	Pre-Dispatch (MW)	Post-Dispatch (MW)	Generation Shift (MW)
Ontario	80906	PIC A G2	0	150	+150
				Total Generation Shift	+150
New York	78708	ATHESC2	205.5	130.5	- 5
	78710	ATHESC3	220.5	145.5	-75
				Total Generation Shift	-150

This study was conducted using the ACCC (AC Contingency Constraint) function of the PSS/E software package. The results are organized to highlight:

- Operational requirements of the Local Transmission System (the Fortran Project)
- Changes in operating ranges of the equipment forming the bulk power system due to the Project.

4.1 Normal Operation of Local Transmission System

In this section, normal operation of the Fortran Project is examined. Three operating situations are examined:

- Unscheduled flow under Summer Peak (SP) and Winter Peak (WP) loadings
- 150S and 150N tie flows under SP loading
- 150S and 150N tie flows under WP loading

4.1.1 Unscheduled Flows

The Project's unscheduled flow corresponds to the existing situation when the N/O switch between CNP and NG is closed, establishing a tie but with no specific schedule for the tie flow. Under this condition, the tie flow is governed by loads and generations in the Hydro One and NYISO systems.

Here, the phase shifting transformer angle is used to reestablish the net flow which would have existed between IESO and NY systems in the absence of the Project. The capacitor bank and the VR transformer are used to control the reactive power flow on the tie. Table 4-5 shows the resulting tie flows under SP and WP loading conditions. For comparison, information on the net flows between IESO and NY in the absence of the Project is included. For both SP and WP loading conditions, the net flows between the two systems are restored only approximately.

Table 4- 5: Unscheduled tie operation under SP and WP loading conditions

System Loading Case	PAR Angle (deg.)	Tie Flow (MW)	Tie Flow (MVAr)	Tie Flow (MVA)	IESO Net Flow to NY (MW)
SP-OFF	N/A	N/A	N/A	N/A	15.0
SP-ON	6.0	70.5	0.6	70.50	12.3
WP-OFF	N/A	N/A	N/A	N/A	-3.1
WP-ON	10.0	91.1	5.5	91.27	-5.2

N/A: Not Applicable

Note that the PAR angles have a range of +/- 40 degrees.

4.1.2 SP Scheduled Flows

The operation of the tie controls, when it is scheduled to carry 150N and 150S under SP load, is shown Table 4-6. The status of the DuPont generator is chosen to make the operation difficult. The loading of the tie is generally very close to 150MVA, which is the rating of the two transformers. As the MW flow on the tie is very close to 150MW, the tie loading indicates that the reactive flows are relatively small.

Table 4-6 also indicates that, for 150N and DuPont OFF, there will be large voltage deviations at buses on both sides of the tie and there is need for Var support at CNP#18. This is in addition to the Voltage/Var control provided by the VR transformer. The study suggests a capacitor bank of 20MVA rating is needed to get the voltage deviation on the NG side down to about 1%. The PS transformer angle range needed to enforce tie flows of +/-150MW is (13.6, -19.0) degrees, which is well within the PAR transformer angle range of +/-40 degrees.

Table 4- 6: Tie operation for SP loading

Case	DuPont Status	Tie Controls			Tie Flow (MVA)	Canada Bus Voltage		
		Cap. Bank (MVAr)	PAR Angle (deg.)	RG Ratio		Pre-	Post	% change
150N	OFF	0	13.6	0.94	149.91	1.00	0.98	-2
		20	13.57	0.96	152.32	1.00	0.989	-1.1
150S	ON	0	-19.00	1.050	150.44	1.00	1.006	0.6
		20	-18.80	1.037	150.80	1.00	1.009	0.9

4.1.3 WP Scheduled Flows

Table 4-7 contains the same information as in Table 4-6, but under WP loading condition. Once more, in the worst case, the tie loading is only a few percent higher than the specified rating of 150MVA of the two transformers.

As in the SP case, for 150N and DuPont OFF, there is need for Var support at CNP#18 to bring voltage deviations on the NG side down to reasonable values. To have the voltage deviation at Canada bus down to 0.7%, the capacitor bank has to generate 30MVA The angle of the phase shifting transformer has to be set to +17.2 and -15.3 degrees to force the tie flow to 150N and 150S, respectively. These angles fall well inside the transformer angle range. Note that for 150S with DuPont ON, the capacitor bank output is effectively diverted from the NG side by the VR control actions, helping to raise voltages on the CNP side.

Table 4- 7: Tie operation for WP loading

Case	DuPont Status	Tie Controls			Tie Flow (MVA)	Canada Bus Voltage		
		Cap. Bank (MVAr)	PAR Angle (deg.)	RG Ratio		Pre-	Post	% change
150N	OFF	0	17.2	0.93	150.12	0.999	0.976	-2.3
		30	17.1	0.96	155.11	0.999	0.992	-0.7
150S	ON	0	-15.6	1.050	150.31	0.999	1.007	0.8
		30	-15.3	1.0105	150.71	0.999	1.007	0.8

4.2 Emergency Operation of the Local Transmission System

The results provided below for thermal contingency analysis are specific to NG, as it is the local system directly affected by the Project. The impact of the Project on the CNP system, for the same loading conditions and contingency cases, are given in Appendix G.

Tables 4-8 to 4-11 summarize overloads of the inter-tie due to outage of specific equipment in the NG system under SP and WP loading conditions. In the pre-contingency state, Hydro One and NYISO generations are scheduled as for normal operations (see Tables 4-3, 4-4 and 4-6 and 4-7) to enforce tie flow schedules of 150N and 150S.

Table 4- 8: Tie contingency overloads for SP loading with 150N schedule

From Bus		Base kV	To Bus		Base kV	Name	Contingency Case	Tie Flow (MVA)	% of Rating
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L36	153	102
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L37	153	102
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L38	152.1	101.4
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L39	151.7	101.2
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	180GV	151.7	101.2
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	181GV/922	151.7	101.2
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	182GV	151.8	101.2
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L36+L37	165.8	110.6
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L38+L39	156.2	104.2
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L54+182GV	153.7	102.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	180GV+181/92	151	100.7
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	PK TB3	150.7	100.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	PK TB4	150.7	100.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV TB3	150.8	100.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV TB4	150.7	100.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV NYTB6	150.8	100.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV NYTB7	151.1	100.7
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV230 BUSTIE	150.7	100.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	PK115 BUSTIE	152	101.4

Table 4- 9: Tie contingency overloads for SP loading with 150S schedule

From Bus		Base kV	To Bus		Base kV	Name	Contingency Case	Tie Flow (MVA)	% of Rating
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L38	150.6	100.4
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L39	150.9	100.6
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L129	153.3	102.2
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L130	154.7	103.1

From Bus		Base kV	To Bus		Base kV	Name	Contingency Case	Tie Flow (MVA)	% of Rating
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L133	155.7	103.8
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	180PK	153.4	102.3
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	180GV	150.7	100.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	181PK	154.4	103
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	181GV/922	150.9	100.6
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	182PK	152.7	101.8
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	182GV	150.6	100.4
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L102+L180	154.1	102.7
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L129+L130	156.2	104.1
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L130+L133	156.4	104.3
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	180NI+182PK	154.6	103.1
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	PK TB3	151.6	101.1
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	PK TB4	151.6	101.1
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV TB2	152.9	101.9
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV TB3	152.4	101.6
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV TB4	152.4	101.6
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV NYTB6	152.9	101.9
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV NYTB7	152.6	101.7
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV230 BUSTIE	153.2	102.2
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV115 BUSTIE	155.1	103.4
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	PK115 BUSTIE	151.7	101.2

Table 4- 10: Tie contingency overloads for WP loading with 150N

From Bus		Base kV	To Bus		Base kV	Name	Contingency Case	Tie Flow (MVA)	% of Rating
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L36	153.7	102.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L37	153.6	102.4
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L38	156.9	104.6
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L39	156.6	104.4
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L129	150.8	100.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	180PK	150.3	100.2
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	180GV	157	104.6
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	181PK	150.1	100.1
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	182PK	151.4	101
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	182GV	157.1	104.7
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L54+182GV	158	105.3
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	PK TB3	153.7	102.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	PK TB4	153.7	102.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV TB2	153	102
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV TB3	153.9	102.6
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV TB4	153.9	102.6

From Bus		Base kV	To Bus		Base kV	Name	Contingency Case	Tie Flow (MVA)	% of Rating
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV NYTB6	153.2	102.1
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV NYTB7	153.6	102.4
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV115 BUSTIE	153.8	102.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	PK115 BUSTIE	155.5	103.7

Table 4- 11: Tie contingency overloads under WP loading with 150S

From Bus		Base kV	To Bus		Base kV	Name	Contingency Case	Tie Flow (MVA)	% of Rating
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L36	152.1	101.4
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L37	152.1	101.4
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L129	154.9	103.3
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L130	156	104
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L133	156.8	104.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	180PK	155.5	103.7
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	181PK	155.6	103.7
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	182PK	154.4	103
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L102+L180	156.2	104.1
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L129+L130	159.1	106.1
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	L130+L133	159.6	106.4
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	180NI+182PK	158.4	105.6
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	PK TB3	152.1	101.4
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	PK TB4	152.1	101.4
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV TB2	153.5	102.3
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV TB3	152.9	102
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV TB4	152.9	102
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV NYTB6	153.8	102.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV NYTB7	153.4	102.3
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV230 BUSTIE	153.7	102.5
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	GV115 BUSTIE	152.9	101.9
81650	ERIE R46	115	81657	*CNP 18	118.05	RG	PK115 BUSTIE	151.9	101.2

The above tables indicate that, under SP and WP loading conditions,

- The most severe contingency case is the simultaneous loss of the lines L36 and L37. It results in 10.6% over load of the tie;
- There are 5 contingency cases resulting in overloads exceeding 5%;
- Most tie overloads following loss of equipment are below 3%.

The overloading capabilities allowed for both the Phase Shifting and Voltage Regulating transformers, listed in Table 2-1, indicate that the these transformers can readily withstand overloads exceeding 15% of their ratings for over 4 hours.

The base case and contingency studies show that the existing equipment thermal ratings will not be exceeded as long as the power transfers from NYISO to CNP stay below +/-150 MW. As the MVAr flow on the tie is minimized, the tie MVA requirement for such power transfers stays in the neighborhood of 150 MVA.

The resulting tie flow for the case when L36 and L37 are simultaneously lost amounts to 166 MVA. It is understood that the combined rating of these circuits needs to be increased beyond 150 MVA if higher power transfers are contemplated. The PAR and RG have sufficient overload ratings to handle 166 MVA tie flow for four hours or more.

4.3 West-Area Bulk Power System Thermal Analysis

The tables below summarize those branch power flows that exceed their thermal limits for SP and WP loading conditions, without and with the Fortran Project, within the West-Area of the NYISO system. The results indicate that no lines or transformers exceed 100% of their LTE loading levels. The results of the CNP System are provided in Appendix G,

Without the Project

Table 4.12 lists branch flows exceeding 90% of their thermal limits for SP loading without the Fortran Project (i.e. with the N/O breaker at CNP #18 open).

Table 4- 12: Pre-Fortran West-Area contingency results under SP loading

Monitored Element						Contingency Reference	Rating (MVA)	Flow (MVA)	% Rating
From Bus			To Bus						
75465	HINMN115	115	76261	HARIS115	115	BASE CASE	238	226.3	94.2
75465	HINMN115	115	76702	LOCKPORT	115	BASE CASE	220	200.4	90.3
76504	S224-37	115	76701	PARADISE	115	36	181	163.7	90.5
76503	S224-36	115	76701	PARADISE	115	37	181	163.9	90.6

For WP loading, the loading of all branches in the power grid were below 90% of their thermal limits.

4.3.1 With the Project

Power flows were run with the N/O breaker at CNP #18 closed for SP and WP cases. In each case, two flow directions were considered for the power on the planned CNP-NYISO tie:

- 150 MW north (150N); and
- 150 MW south (150S).

For SP loading with the new tie flow set to 150N, one branch loading approached its thermal limit. The results for this case is given in Table 4-13.

Table 4- 13: West-Area contingency for 150N under SP loading

Monitored Element						Contingency Reference	Rating (MVA)	Flow (MVA)	% Rating
From Bus			To Bus						
75465	HINMN115	115	76261	HARIS115	115	BASE CASE	238	237.3	98.8
75465	HINMN115	115	76702	LOCKPORT	115	BASE CASE	220	211.8	95.5
76691	L46 NY	115	76807	CANADA	115	BASE CASE	169	152.5	91.3
76691	L46 NY	115	76807	CANADA	115	36	169	153.2	91.8
76691	L46 NY	115	76807	CANADA	115	37	169	153.1	91.8
76691	L46 NY	115	76807	CANADA	115	38	169	152.3	91.2
76691	L46 NY	115	76807	CANADA	115	39	169	151.9	91
76806	AM BRASS	115	76809	BFLOSEWR	115	46	147	135.8	94.6
76805	AM BRASS	115	76808	BFLOSEWR	115	47	147	130.3	91.1
76691	L46 NY	115	76807	CANADA	115	180GV	169	151.9	91
76691	L46 NY	115	76807	CANADA	115	181GV/922	169	151.9	91
76691	L46 NY	115	76807	CANADA	115	182GV	169	151.9	91
76691	L46 NY	115	76807	CANADA	115	36+37	169	166.3	98.8
76691	L46 NY	115	76807	CANADA	115	38+39	169	156.5	93.6
76691	L46 NY	115	76807	CANADA	115	54+182GV	169	153.9	92.1
75465	HINMN115	115	76702	LOCKPORT	115	102+180	252	230.2	91.1
76691	L46 NY	115	76807	CANADA	115	180GV+181/92	169	151.1	90.6
76691	L46 NY	115	76807	CANADA	115	PK TB3	169	150.9	90.3
76691	L46 NY	115	76807	CANADA	115	PK TB4	169	150.9	90.4
76691	L46 NY	115	76807	CANADA	115	GV TB2	169	150	90
76691	L46 NY	115	76807	CANADA	115	GV TB3	169	150.9	90.5
76691	L46 NY	115	76807	CANADA	115	GV TB4	169	150.9	90.4
76691	L46 NY	115	76807	CANADA	115	GV NYTB6	169	151.1	90.2
76691	L46 NY	115	76807	CANADA	115	GV NYTB7	169	151.3	90.4
76691	L46 NY	115	76807	CANADA	115	GV230 BUSTIE	169	151	90.2
76691	L46 NY	115	76807	CANADA	115	PK115 BUSTIE	169	152.2	91.1

For WP loading with a tie flow of 150N the maximum loading of branches occurs on the 115kV line connecting AM BRASS (bus 76806) to BFLOSEWR (bus 76809), at 96.6 % of the line thermal limit. The corresponding results are summarized in Table 4-14.

Table 4- 14: West-Area contingency for 150N under WP loading

Monitored Element						Contingency Reference	Rating (MVA)	Flow (MVA)	% Rating
From Bus			To Bus						
76691	L46 NY	115	76807*	CANADA	115	BASE CASE	169	155.2	92.5
76691	L46 NY	115	76807*	CANADA	115	36	169	153.4	91.6
76691	L46 NY	115	76807*	CANADA	115	37	169	153.3	91.6
76691	L46 NY	115	76807*	CANADA	115	38	169	156.6	93.5

Monitored Element						Contingency Reference	Rating (MVA)	Flow (MVA)	% Rating
From Bus			To Bus						
76691	L46 NY	115	76807*	CANADA	115	39	169	156.3	93.3
76613	DUPONT7	115	76658*	CHEVY	115	46	252	226.6	91.5
76806*	AM BRASS	115	76809	BFLOSEWR	115	46	147	139.3	96.6
76656	DUPONT46	115	76657*	CHEVY	115	47	252	223.6	90.9
76805*	AM BRASS	115	76808	BFLOSEWR	115	47	147	133.2	92.8
76691	L46 NY	115	76807*	CANADA	115	180GV	169	156.7	93.5
76691	L46 NY	115	76807*	CANADA	115	182PK	169	151.1	90.2
76691	L46 NY	115	76807*	CANADA	115	182GV	169	156.8	93.6
76691	L46 NY	115	76807*	CANADA	115	54+182GV	169	157.7	94.1
76691	L46 NY	115	76807*	CANADA	115	PK TB3	169	153.4	91.6
76691	L46 NY	115	76807*	CANADA	115	PK TB4	169	153.4	91.6
76691	L46 NY	115	76807*	CANADA	115	GV TB2	169	152.6	91.3
76691	L46 NY	115	76807*	CANADA	115	GV TB3	169	153.5	91.8
76691	L46 NY	115	76807*	CANADA	115	GV TB4	169	153.5	91.7
76691	L46 NY	115	76807*	CANADA	115	GV NYTB6	169	152.9	91.1
76691	L46 NY	115	76807*	CANADA	115	GV NYTB7	169	153.4	91.4
76691	L46 NY	115	76807*	CANADA	115	GV115 BUSTIE	169	153.6	91.3
76691	L46 NY	115	76807*	CANADA	115	PK115 BUSTIE	169	155.2	92.6

For SP loading with the tie flow fixed at 150S, branch loadings above 90% of their thermal limits are given in Table 4.15. Two branches approach their loading limits following the loss of the line L36 and L37.

Table 4- 15: West-Area contingency for 150S under SP loading

Monitored Element						Contingency Type	Rating (MVA)	Flow (MVA)	% Rating
From Bus			To Bus						
75465	HINMN115	115	76261	HARIS115	115	BASE CASE	238	219.5	91.4
76504	S224-37	115	76701	PARADISE	115	36	181	180.2	99.3
76503	S224-36	115	76701	PARADISE	115	37	181	179.9	99.2
76806	AM BRASS	115	76809	BFLOSEWR	115	46	147	136.1	93.3
76691	L46 NY	115	76807*	CANADA	115	130	169	153.2	90.1
76691	L46 NY	115	76807*	CANADA	115	133	169	154.1	90.8
76691	L46 NY	115	76807*	CANADA	115	129+130	169	154.7	91
76691	L46 NY	115	76807	CANADA	115	130+133	169	155.2	91

Again, for WP loading with the tie flow at 150S, only a small number of branch loadings exceed 90% of their thermal limits. This is shown in Table 4.16.

Table 4- 16: West-Area contingency for 150S under WP loading

Monitored Element						Contingency Type	Rating (MVA)	Flow (MVA)	% Rating
From Bus			To Bus						
76806	AM BRASS	115	76809	BFLOSEWR	115	46	147	135.8	93.2
76691	L46 NY	115	76807*	CANADA	115	129	169	153.4	90.1
76691	L46 NY	115	76807*	CANADA	115	130	169	154.4	90.8
76691	L46 NY	115	76807*	CANADA	115	133	169	155.3	91.4
76691	L46 NY	115	76807*	CANADA	115	180PK	169	154	90.5
76691	L46 NY	115	76807*	CANADA	115	181PK	169	154.1	90.6
76691	L46 NY	115	76807*	CANADA	115	102+180	169	154.7	91
76691	L46 NY	115	76807	CANADA	115	129+130	169	157.9	92.7
76691	L46 NY	115	76807	CANADA	115	130+133	169	158.4	92.9
76691	L46 NY	115	76807	CANADA	115	180NI+182PK	169	157.2	92.3

4.3.2 Summary of Thermal Studies

Thermal studies have been conducted for power transfers up to 150 MW between CNP and NYISO in both directions. The base case and contingency studies showed that, for the present equipment thermal ratings, power transfer from NYISO to CNP has to stay just below 150 MW. At this power transfer level, there is 151 MVA power flow on the transmission lines between L46 NY and BERTIHILL bus. It is understood that the combined rating of these circuits needs to be increased beyond 150 MVA if higher power transfers are contemplated.

When the power transfer between Hydro One and NYISO over the new inter-tie is below 150 MW, all NYISO equipment would be operating within their limits except for the river crossing and line sections L46 and L47. Therefore, the study recommends reconductoring of the existing river crossing tie and approximately six miles of L46 and L47 lines.

Also, with Fortran Project in place, the power flows on both pairs of transformers at Buffalo Station become balanced.

4.4 Bulk Power System Steady-State Voltage Analysis

Voltage performance of the system was evaluated using the same base cases that were developed for thermal limit studies. No new generation re-scheduling or setting of the Phase Shifting Transformer angle were required.

4.4.1 Pre-Project Voltages

Normal operation results

Table 4.17 shows the pre-project base case voltages on the tap points of lines L46 and L47 as well as other important NYISO stations for both SP and WP loading conditions. Note that the table is organized based on bus Base Voltages and then, within each Base Voltage, the last column of the table is sorted in a descending order. This applies to Tables 4-17 to 4-20.

Table 4- 17: Pre-project bus voltages under SP and WP loading conditions

Bus No.	Bus Name	Base Voltage (kV)	SP Voltages (pu)	WP Voltages (pu)
75456	GARDV115	115	1.018	1.019
76710	PACK(N)E	115	1.027	1.019
76711	PACK(S)W	115	1.027	1.019
76701	PARADISE	115	1.012	1.013
76677	FMC CORP	115	1.003	1.002
76654	DUNLOP	115	1.003	1.002
76656	DUPONT46	115	1.003	1.002
76657	CHEVY	115	1.002	1.001
76659	LINDE	115	1.001	1.000
76803	KENMORE6	115	1.001	1.000
76805	AM BRASS	115	1.000	0.999
76808	BFLOSEWR	115	1.000	0.999
76655	DUNLOP	115	0.999	0.999
76613	DUPONT7	115	0.999	0.999
76658	CHEVY	115	0.998	0.998
76804	KENMORE7	115	0.997	0.997
76806	AM BRASS	115	0.997	0.997
76807	CANADA	115	1.000	0.999
76809	BFLOSEWR	115	0.997	0.996
79591	NIAGAR2E	230	1.020	1.020
79592	NIAGAR2W	230	1.020	1.020

On the CNP side, for the same system condition, the pre-project bus voltages are given in Table 4.18. Note that, because of the radial nature of the CNP network, it is normal to have relatively high voltages at bulk power delivery points (in this case at the 115kV Murray transformer substations).

Table 4- 18: Pre-project, base case CNP bus voltages for SP and WP loading conditions

Bus No.	Bus Name	Base Voltage (kV)	SP Voltages (pu)	WP Voltages (pu)
81725	MURRAY	118	1.051	1.060
83509	RANK A37	118	1.048	1.057
83556	STEVENVL	118	1.028	1.037
81657	CNP 18	118	1.019	1.028

4.4.2 Post-Project Voltages

Normal operation results

Table 4.19 shows post-project voltages on the CNP and NG buses as well as on some key buses in NYISO and Hydro One systems when the tie is transmitting 150N. For comparison purposes, the pre-project voltages and their percent changes are also tabulated.

Table 4- 19: Pre- and post-project voltages for SP and WP loadings with 150N (DuPont generator is offline)

Bus No.	Bus Name	Base Voltage (kV)	SP Voltages (p.u.)			WP Voltages (p.u.)		
			Pre-CNP	150N	DIFF%	Pre-CNP	150N	DIFF%
76657	CHEVY	115	1.002	0.991	-1.110	1.001	0.993	-0.806
76656	DUPONT46	115	1.003	0.992	-1.109	1.002	0.994	-0.805
76654	DUNLOP	115	1.003	0.992	-1.109	1.002	0.994	-0.805
76807	CANADA	115	1	0.989	-1.112	0.999	0.992	-0.706
76807	CANADA	115	1	0.989	-1.112	0.999	0.992	-0.706
76805	AM BRASS	115	1	0.99	-1.010	0.999	0.992	-0.706
76808	BFLOSEWR	115	1	0.989	-1.112	0.999	0.992	-0.706
76659	LINDE	115	1.001	0.99	-1.111	1	0.993	-0.705
76803	KENMORE6	115	1.001	0.99	-1.111	1	0.993	-0.705
76677	FMC CORP	115	1.003	0.993	-1.007	1.002	0.995	-0.704
76701	PARADISE	115	1.012	1.007	-0.497	1.013	1.008	-0.496
76809	BFLOSEWR	115	0.997	0.989	-0.809	0.996	0.992	-0.403
76804	KENMORE7	115	0.997	0.991	-0.605	0.997	0.993	-0.403
76806	AM BRASS	115	0.997	0.99	-0.707	0.997	0.993	-0.403
76658	CHEVY	115	0.998	0.992	-0.605	0.998	0.994	-0.402
76613	DUPONT7	115	0.999	0.993	-0.604	0.999	0.995	-0.402
75456	GARDV115	115	1.018	1.015	-0.296	1.019	1.015	-0.394
76655	DUNLOP	115	0.999	0.993	-0.604	0.999	0.996	-0.301
76710	PACK(N)E	115	1.027	1.026	-0.097	1.019	1.018	-0.098
76711	PACK(S)W	115	1.027	1.026	-0.097	1.019	1.018	-0.098
81725	MURRAY	118	1.051	1.051	0.00	1.060	1.059	0.09
83509	RANK A37	118	1.048	1.049	0.10	1.057	1.057	0.00
83556	STEVENVL	118	1.028	1.036	0.78	1.037	1.043	0.58
81657	CNP 18	118	1.019	1.031	1.18	1.028	1.039	1.07
79591	NIAGAR2E	230	1.020	1.020	0.00	1.020	1.020	0.00
79592	NIAGAR2W	230	1.020	1.020	0.00	1.020	1.020	0.00

Table 4.19 indicates that, for SP loading condition, the post-project voltages on the NYISO 115kV buses can drop by as much as 1.1%, relative to their Pre-project values, when the tie is set to 150N. Most voltage drops are occurring at buses that terminate on branches carrying

significant portions of the 150N. For WP loading case, voltage changes on the NYISO side are generally smaller than their SP counter-parts, with the largest change being about 0.8%. These voltages are obtained with the help of the voltage regulator and the capacitor bank at CNP #18.

The impact of power transfer direction on voltage changes was studied using SP and WP base cases with the inter-tie schedule set to 150S. Again, the DuPont Generator was taken offline as this corresponds to a more severe operating condition. Table 4.20 shows the resulting voltages and their comparison with the Pre-project voltage values.

Table 4- 20: Pre- and post-project voltages for SP and WP loadings with 150S (DuPont generator is offline)

Bus No.	Bus Name	Base Voltage (kV)	SP Voltages (pu)			WP Voltages (pu)		
			Pre-Project	Post Project	Diff %	Pre Project	Post Project	Diff %
75456	GARDV115	115	1.018	1.018	0.000	1.019	1.016	-0.295
76656	DUPONT46	115	1.003	1.001	-0.200	1.002	1	-0.200
76657	CHEVY	115	1.002	1.001	-0.100	1.001	1	-0.100
76677	FMC CORP	115	1.003	1.002	-0.100	1.002	1.001	-0.100
76654	DUNLOP	115	1.003	1.002	-0.100	1.002	1.001	-0.100
76710	PACK(N)E	115	1.027	1.027	0.000	1.019	1.019	0.000
76711	PACK(S)W	115	1.027	1.027	0.000	1.019	1.019	0.000
76701	PARADISE	115	1.012	1.012	0.000	1.013	1.013	0.000
76659	LINDE	115	1.001	1.001	0.000	1	1	0.000
76803	KENMORE6	115	1.001	1.001	0.000	1	1	0.000
76805	AM BRASS	115	1	1.001	0.100	0.999	1	0.100
76808	BFLOSEWR	115	1	1.003	0.299	0.999	1.002	0.299
76807	CANADA	115	1	1.003	0.299	0.999	1.002	0.299
76655	DUNLOP	115	0.999	1.003	0.399	0.999	1.002	0.299
76613	DUPONT7	115	0.999	1.003	0.399	0.999	1.002	0.299
76807	CANADA	115	1	1.003	0.299	0.999	1.002	0.299
76658	CHEVY	115	0.998	1.002	0.399	0.998	1.001	0.300
76804	KENMORE7	115	0.997	1.002	0.499	0.997	1.001	0.400
76806	AM BRASS	115	0.997	1.002	0.499	0.997	1.001	0.400
76809	BFLOSEWR	115	0.997	1.003	0.598	0.996	1.002	0.599
81657	CNP 18	118	1.019	0.99200	-2.65	1.028	1.002	-2.53
83556	STEVENVL	118	1.028	1.00500	-2.24	1.037	1.016	-2.03
83509	RANK A37	118	1.048	1.03700	-1.05	1.057	1.048	-0.85
81725	MURRAY	118	1.051	1.04300	-0.76	1.06	1.054	-0.57
79591	NIAGAR2E	230	1.020	1.020	0.00	1.020	1.020	0.00
79592	NIAGAR2W	230	1.020	1.020	0.00	1.020	1.020	0.00

Comparing voltage changes given in Tables 4.19 and 4.20, while the largest voltage change is clearly smaller in this case, there is also a mix of both voltage rises and voltage drops on the NYISO side. Again, the relatively high voltage level maintained at CNP #18 by the capacitor bank has maintained relatively higher voltages on its neighboring buses.

Contingency results

The voltage analyses results under pre- and post-contingency conditions are summarized in Appendix H. The listed bus voltages are those that fall outside the 0.95pu - 1.05pu range, as well as voltage deviations that are beyond +/- 5 percentages.

In Tables 4-21 voltage deviation beyond 2% for post–contingency conditions are listed for pre-Fortran project in West-Area under SP loading condition. The corresponding post-Fortran results for 150N and 150S are provided in Tables 4-23 and 4-24 respectively. Comparing the data in the Table 4-21 with those in Table 4-23 or Table 4-24 reveals that, except for voltages at or in the vicinity of the tie terminations, all significant voltage deviations are repeated in both tables. In other words, the Fortran Project does not noticeably impact the post-contingency behavior of the bulk power system.

Similar statements can be made with regard to the pre- and post-contingency conditions under the WP loading condition. The pre-Fortran data are provided in Table 4-22, while the post-Fortran results are given in Table 4-25 (150N) and Table 4-26 (150S).

Table 4- 20: Pre-Fortran voltage deviations > 2% in West-Area for SP loading

Contingency Description				Bus No.	Bus Name	kV	Post Contingency Voltage	Pre-Contingency Voltage
WEST	DEVIATION		46	76613	DUPONT7	115	0.97494	0.99895
WEST	DEVIATION		46	76655	DUNLOP	115	0.97588	0.99932
WEST	DEVIATION		46	76658	CHEVY	115	0.97283	0.99812
WEST	DEVIATION		46	76804	KENMORE7	115	0.971	0.99741
WEST	DEVIATION		46	76806	AM BRASS	115	0.9699	0.99698
WEST	DEVIATION		46	76809	BFLOSEWR	115	0.96929	0.99679
WEST	DEVIATION		47	76659	LINDE	115	0.98087	1.00114
WEST	DEVIATION		47	76803	KENMORE6	115	0.98028	1.00085
WEST	DEVIATION		47	76805	AM BRASS	115	0.9792	1.00032
WEST	DEVIATION		47	76807	CANADA	115	0.9789	1.00014
WEST	DEVIATION		47	76808	BFLOSEWR	115	0.9786	0.99995
WEST	DEVIATION	GV230 BUSTIE		75412	GARDV230	230	1.0461	1.01013
WEST	DEVIATION	GV230 BUSTIE		75417	STOLE230	230	1.03734	1.01363
WEST	DEVIATION	GV115 BUSTIE		75425	BIGTR115	115	0.99973	1.02395
WEST	DEVIATION	GV115 BUSTIE		75456	GARDV115	115	0.99088	1.01819
WEST	DEVIATION	GV115 BUSTIE		76117	LANGN115	115	0.99402	1.02021

Table 4- 21: Pre-Fortran voltage deviations > 2% in West-Area for WP loading

Contingency Description				Bus No.	Bus Name	kV	Post Contingency Voltage	Pre-Contingency Voltage
WEST	DEVIATION		46	76613	DUPONT7	115	0.97347	0.99883
WEST	DEVIATION		46	76655	DUNLOP	115	0.9745	0.99923
WEST	DEVIATION		46	76658	CHEVY	115	0.97118	0.99792
WEST	DEVIATION		46	76804	KENMORE7	115	0.96919	0.99714
WEST	DEVIATION		46	76806	AM BRASS	115	0.96801	0.99666
WEST	DEVIATION		46	76809	BFLOSEWR	115	0.96735	0.99643
WEST	DEVIATION		47	76654	DUNLOP	115	0.98181	1.00212
WEST	DEVIATION		47	76656	DUPONT46	115	0.98105	1.00191
WEST	DEVIATION		47	76657	CHEVY	115	0.97873	1.00084
WEST	DEVIATION		47	76659	LINDE	115	0.97732	1.00013
WEST	DEVIATION		47	76803	KENMORE6	115	0.97668	0.99983
WEST	DEVIATION		47	76805	AM BRASS	115	0.97551	0.99927
WEST	DEVIATION		47	76807	CANADA	115	0.97519	0.99909
WEST	DEVIATION		47	76808	BFLOSEWR	115	0.97486	0.9989
WEST	DEVIATION	GV230 BUSTIE		75412	GARDV230	230	1.02619	1.00204
WEST	DEVIATION	GV115 BUSTIE		75456	GARDV115	115	0.99862	1.01904

Table 4- 22: Post-Fortran voltage deviations > 2% in West-Area for SP 150N loading

Contingency Description			Bus No.	Bus Name	kV	Post Contingency Voltage	Pre-Contingency Voltage
WEST	DEVIATION	GV230 BUSTIE	75412	GARDV230	230	1.04339	1.00764
WEST	DEVIATION	GV230 BUSTIE	75417	STOLE230	230	1.03578	1.01226
WEST	DEVIATION	GV115 BUSTIE	75425	BIGTR115	115	0.99598	1.02
WEST	DEVIATION	GV115 BUSTIE	75456	GARDV115	115	0.98758	1.01473
WEST	DEVIATION	GV115 BUSTIE	76117	LANGN115	115	0.99055	1.01656

Table 4- 23: Post-Fortran voltage deviations > 2% in West-Area for SP 150S loading

Contingency Description			Bus No.	Bus Name	kV	Post Contingency Voltage	Pre-Contingency Voltage
WEST	DEVIATION	46+47	76691	L46 NY	115	1.08234	1.01049
WEST	DEVIATION	GV230 BUSTIE	75412	GARDV230	230	1.04697	1.01122
WEST	DEVIATION	GV230 BUSTIE	75417	STOLE230	230	1.03741	1.01379
WEST	DEVIATION	GV115 BUSTIE	75425	BIGTR115	115	1.00168	1.02594
WEST	DEVIATION	GV115 BUSTIE	75456	GARDV115	115	0.99253	1.01981
WEST	DEVIATION	GV115 BUSTIE	76117	LANGN115	115	0.99579	1.02197

Table 4- 24: Post-Fortran voltage deviations > 2% in West-Area for WP 150N loading

Contingency Description			Bus No.	Bus Name	kV	Post Contingency Voltage	Pre-Contingency Voltage
WEST	DEVIATION	GV115 BUSTIE	75425	BIGTR115	115	0.99087	1.0118
WEST	DEVIATION	GV115 BUSTIE	75456	GARDV115	115	0.99094	1.01449
WEST	DEVIATION	GV115 BUSTIE	76117	LANGN115	115	0.99101	1.01363

Table 4- 25: Post-Fortran voltage deviations > 2% in West-Area for WP 150S loading

Contingency Description			Bus No.	Bus Name	kV	Post Contingency Voltage	Pre-Contingency Voltage
WEST	DEVIATION	46+47	76691	L46 NY	115	1.07891	1.00944
WEST	DEVIATION	GV230 BUSTIE	75412	GARDV230	230	1.03232	1.00386
WEST	DEVIATION	GV115 BUSTIE	75425	BIGTR115	115	0.99202	1.01471
WEST	DEVIATION	GV115 BUSTIE	75456	GARDV115	115	0.99209	1.01725
WEST	DEVIATION	GV115 BUSTIE	76117	LANGN115	115	0.99216	1.01644

4.4.3 Summary of Voltage Analysis Results

Studies on voltage performance have been conducted for transfers of up to ±150MW between CNP and NYISO in both directions for SP and WP loading conditions. The base case and contingency studies showed that, in all normal and contingency cases, all voltages were above 95%. Furthermore, those voltage deviations that can be viewed as operationally significant appear both in pre- and post-contingency conditions. The results for CNP systems are listed in Appendix G.

5 Inter-Area Transfer Analysis

The Fortran Project inserts a 115 kV tie line in parallel with the Niagara tie lines. The CNP tie line includes a phase-shifter and a voltage regulator so that the MW and MVAR flows can be controlled. The power from the tie line, at its limit towards New York, will insert 150 MW into lines L46 andL47 from the proposed Canada 3-breaker ring bus. This power becomes dispersed into the 230 and 345 kV systems.

The objective of this Transfer Analysis is to study the impact of the FORTRAN tie on the transfer capability between Ontario and New York and the transfer capability across the Dysinger Interface. The CNP tie is scheduled at the rating of 150 MVA. Ontario.

CNP Tie Flow 150 MW towards New York

The CNP closed (through the phase-shifter) tie is scheduled in the direction of the power transfer. The closed CNP tie line would not be scheduled in a direction opposite to the transfer and the phase angle limits will not allow a transfer in the opposite direction to the main transfer flow. This situation is also noted in Tables 5.1 and 5.2.Therefore, the CNP tie is scheduled at 150 MW towards New York for the analysis of the Ontario to New York and Dysinger East interfaces.

CNP Tie Flow 150 MW towards Ontario

Also, the CNP tie is scheduled at 150 MW towards Ontario for the analysis of the New York to Ontario transfers and not against the flow due to angle limits. But, a situation can arise when the line between CNP and Hydro one is out of service and CNP must rely on assistance from New York ISO via the tie. This is also the current situation so that the two cases are identical (with and without the CNP tie). This situation is also noted in Tables 5.1 and 5.2

With a closed CNP tie: The synchronous tie will enable CNP to be fed from the NYISO with the CNP to Hydro One line out of service and without any interruption.

Without a closed CNP tie: The current tie will enable CNP to be fed from the NYISO with the CNP to Hydro One line out of service and after an interruption while the CNP load is transferred to the New York System.

Appendix I contains the detailed results of the PSSE TLTG runs for each case. A summary spreadsheet in this Appendix lists the details of the transfer limit and the limiting circuits and related contingencies. Also separate results are given in Appendix I for evaluating the Transfer Limit in the Base Cases without contingencies and with phase-shifters active in controlling the respective flows. Phase-shifters are set at the Base Case fixed angle in the contingency cases. The transfers are shown to be limited by the indicated contingency cases.

5.1 Inter-Area Bulk Power System Transfers

This part of the analysis examines the transfer capability between Ontario and New York. The results are shown in Table 5.1. The results in Table 5.1 show the following:

- The New York to Ontario transfer capability will increase by more than 150 MW with the CNP tie. The limiting circuit in the Normal Case is the Niagara-PA27 circuit for the shown stuck breaker contingency that results in the loss of two circuits (Niagara 230/345 and Niagara 345-Beck 345).

- 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).

Table 5- 1: Inter-area Transfer Limits

Interface	Fortran ON Transfers		Fortran Off Transfers		Transfer Difference (ON-OFF)	
	Normal (MW)	Emerg'cy (MW)	Normal (MW)	Emerg'cy (MW)	Normal (MW)	Emerg'cy (MW)
Base Case Tie flow = 150N						
New York - Ontario	1614	2056	1367	1797	247	259
Limiting Circuit	Niagara-PA27 230	Niagara-PA27 230	Niagara-PA27 230	Niagara-PA27 230		
Contingency Case	'SB:NIAG_345_3008'	Niagara-Beck 345	'SB:NIAG_345_3008'	Niagara-Beck 345		
Base Case Tie flow = 150 S						
New York - Ontario	Flow 150 S is not feasible due to phase angle limits on the CNP tie Phase Shifter (against the transfer direction)					
Base Case Tie flow = 150S						
Ontario - New York	923	1248	879	1201	44	47
Limiting Circuit	Niagara-Rochester 345	Niagara-Rochester 345	Niagara-Rochester 345	Niagara-Rochester 345		
Contingency Case	Kintigh-Rochester 345	Kintigh-Rochester 345	Kintigh-Rochester 345	Kintigh-Rochester 345		
Base Case Tie flow = 60 MW N to CNP						
Ontario - New York	Flow 150 N is not feasible due to phase angle limits on the CNP tie Phase Shifter (against the transfer direction). However radial assistance NYISO to CNP is possible when the CNP tie to Hydro One is on outage and is open. This is also the current arrangement so that the two cases are the same.				Cases are identical	Cases are identical

5.2 Intra-Area Transfer Limits

This part of the analysis examines the impact on the Dysinger interface (open and closed definitions) transfer capability in New York for Ontario to New York transfers. The results are shown in Table 5.2. As shown in Table 5.2, the Dysinger interface transfer capability will increase by a small amount with the CNP tie. In all cases, the transfer is constrained by the 345 kV systems in New York.

Table 5- 2: Intra-area Transfer Limits for Ontario to New City Transfers

Interface	Fortran ON Transfers		Fortran Off Transfers		Transfer Difference	
	Normal (MW)	Emerg. (MW)	Normal (MW)	Emerg. (MW)	Normal (MW)	Emerg. (MW)
Base Case Tie flow = 150 S to New York						
Dysinger-open	2721.8	3040.6	2701.9	2973	19.9	67.6
Limiting Circuit	Niagara-Rochester 345	Niagara-Rochester 345	Niagara-Rochester 345	Niagara-Rochester 345		
Contingency	Kintigh-Rochester 345	Kintigh-Rochester 345	Kintigh-Rochester 345	Kintigh-Rochester 345		
Dysinger-Close	4947.6	5332	4924.4	5257.7	23.2	74.3
Limiting Circuit	Niagara-Rochester 345	Niagara-Rochester 345	Niagara-Rochester 345	Niagara-Rochester 345		
Contingency	Kintigh-Rochester 345	Kintigh-Rochester 345	Kintigh-Rochester 345	Kintigh-Rochester 345		
Base Case CNP tie 60 MW N to CNP						
Dysinger-open	Flow 150 N is not feasible due to phase angle limits on the CNP tie Phase Shifter (against the transfer direction). However radial assistance 60 MW NYISO to CNP is possible when the CNP tie to Hydro One is on outage and is open. This is also the current arrangement so that the two cases are the same.				Cases are identical	Cases are identical
Dysinger-Close					Cases are identical	Cases are identical

5.3 Dysinger East Thermal Voltage and Stability Limits

It was apparent from the thermal studies that by the CNP tie addition the Dysinger interface transfer capability will increase by a small amount. The 345 kV system voltage and angle conditions are also similar in cases without and with the CNP tie on and loaded to the 150

MW towards New York. Therefore the Dysinger East Voltage stability limit will be unchanged as will the Angle stability limit when comparing voltage and stability performance with and without the CNP tie. Procedures only require studies to be carried out in situations where there is impact on this interface and it is clear that there is no impact on the 345 and 230 kV system voltages and angles. The reason is that the CNP tie feeds power into the network at 115kV voltage level and that is dispersed into the higher voltage network such that downstream interfaces are unaffected from thermal, voltage or stability viewpoint.

5.4 Summary of Transfer Analysis Study

The SRIS study has confirmed that the addition of the CNP tie (and associated facilities) does not adversely impact the transfer capability and that NY-ON Niagara interface transfer capability will increase by more than 150MW. The intra-area analysis showed that some of the NYISO intra-area transfer limits are increased by a small amount with the CNP tie. The voltage and angle changes on the NY bulk power system due to the CNP tie flows are very small and voltage and stability limits are unaffected.

6 Dynamic Analysis

System dynamic response to specific events (contingency cases), with and without the Fortran Project, were simulated for SP and SL loading conditions to assess the impact of the Project on dynamic behavior of the system.

With Fortran Project in service, the inter-tie was set to draw +/-150MW. The required generator re-dispatch for SP is given in Tables 6-1 and 6-2. For SL, generation re-dispatch information is provided in Tables 6-3 and 6-4.

Table 6- 1: Generation re-dispatch for 150N tie flow under SP loading condition

System	Bus Number	Generator	Pre-Dispatch (MW)	Post-Dispatch (MW)	Generation Shift (MW)
Ontario	81766	NANTICG5	500	350	-150
				Total Generation Shift	-150
New York	74702	RAV 3	422.8	429.3	+6.5
	76640	DUNKGEN3	64.55	98.5	+24
	77051	HNTLY68G	75.3	95.3	+20
	78963	BETHGT3	0	100	+100
				Total Generation Shift	+150.5

Table 6- 2: Generation re-dispatch for 150S tie flow under SP loading condition

System	Bus Number	Generator	Pre-Dispatch (MW)	Post-Dispatch (MW)	Generation Shift (MW)
Ontario	80906	PIC A G2	142	217	+75
	80907	PIC A G3	142	217	+75
	81748	BECK2G25	144.5	153.5	+9
				Total Generation Shift	+159
New York	78708	ATHESC2	260	110	-150
				Total Generation Shift	-150

Table 6- 3: Generation re-dispatch for 150N tie flow under SL loading condition

System	Bus Number	Generator	Pre-Dispatch (MW)	Post-Dispatch (MW)	Generation Shift (MW)
Ontario	80906	PIC A G2	447	372	-75
	80907	PIC A G3	447	372	-75
				Total Generation Shift	-150
New York	78708	ATHESC2	110	240	+130
	78709	ATHESS1	80	100	+20
				Total Generation Shift	+150

Table 6- 4: Generation re-dispatch for 150S tie flow under SL loading condition

System	Bus Number	Generator	Pre-Dispatch (MW)	Post-Dispatch (MW)	Generation Shift (MW)
Ontario	80906	PIC A G2	371.9	446.9	75
	80907	PIC A G3	371.9	446.9	75
				Total Generation Shift	150
New York	78708	ATHESC2	260	110	-150
				Total Generation Shift	-150

6.1 Event Definition

Events occurring on the 345kV level are listed in Table 6.5. Definitions of these events are provided to the Consultant as part of the system base cases and include response of the protection system to the event as well as the required simulation periods. These events are of interest as they can be used to evaluate the Project's impacts on the NYISO bulk power system.

Table 6- 5: Dynamic events on NYISO Bulk transmission system

No.	Name	Type	Location	Description
1	WC01	3 Ph	Niagara 345kV	- Fault at Niagara-Roch NR-2 /N.C. - Clear near 3.5 cycles, far 4.5 cycles
2	WC01AR	3 Ph	Niagara 345kV	- WC01 with Automatic Reclosing

No.	Name	Type	Location	Description
3	WC02	3 Ph	Niagara 345kV	- Fault at Niagara-RochNSR-2/N.C. - Clear near 3 cycles, far 5.5 cycles
4	WC02	3 Ph	Niagara 345kV	- WC02 with Automatic Reclosing
5	WC03	3 Ph	Niagara 345kV	- Fault at Niagara-Kintigh NS-1/38 - Clear near 3.5 cycles, far 4 cycles
6	WC03AR	3 Ph	Niagara 345kV	- WC03 with Automatic Reclosing
7	WC04	3 Ph	Rochester 345kV	- Fault at Kintigh-Rochester SR-1/39 - Clear near 3 cycles, far 4.5 cycles
8	WC04AR	3 Ph	Rochester 345kV	WC04 with Automatic Reclosing
9	WC05	SLG/STK	Niagara 345kV	- Fault at Niagara-Roch NR-2 - Clear Roch 3 cycles, Niag 13 cycles
10	WC06	SLG/STK	Kintigh 345kV	- Fault at Niagara-Kintigh NS-1/38 - Clear Niag. 5.5 cycles, Kintigh 10.1 cycles
11	WC07	3 Ph	Rochester 345kV	- Fault at Rochester-Pannell RP-1 - Clear Roch 3 cycles, Pannell 4.5 cycles
12	WC07AR	3 Ph	Rochester 345kV	- WC07 with Automatic Reclosing
13	WC08	3 Ph	Pannell 345kV	- Fault at Pannell-Clay PC-1 - Clear Pannell 3 cycles, Clay 6 cycles
14	WC08AR	3 Ph	Pannell 345kV	- WC08 with Automatic Reclosing
15	WC09	3 Ph	Pannell 345kV	- Fault at Rochester-Pannell RP-1 - Clear Pannell 3 cycles, Roch 4.5 cycles
16	WC09AR	3 Ph	Pannell 345kV	- WC09 with Automatic Reclosing
17	WC10	SLG	Rochester 345kV	- Fault at Rochester-Pannell RP-1 - Clear Pannell 4.5 cycles, Roch16.25 cycles
18	WC11	SLG/STK	Pannell 345kV	- Fault at Rochester-Pannell RP-1 - Clear Roch 5.5 cycles, Pannell 15.25 cycles
19	WC12	SLG/STK	Rochester 345kV	- Fault at Rochester-Kintigh SR-1/39 - Clear Kintigh 4.5 cycles, Roch 16.25 cycles
20	WC13	3 Ph	Niagara 345kV	- Fault at Beck-Niagara - Clear Niagara 3.5 cycles, Beck 6.5 cycles
21	WC14	SLG/STK	Rochester 345kV	- Fault at Rochester-Kintigh SR-1/39 - Clear Kintigh 4.5 cycles, Roch 16.5 cycles
22	WC15	LLG	Beck 220kV	- Fault at Niagara-Packard - Clear Beck 4.5 cycles

The event names indicate presence of two distinct types of events; namely,

- Events involving no Automatic Reclosing (AR) actions
- Events with Automatic Reclosing (AR)

For the first group of events the specified simulation times are typically 15s, while for the second group it is around 35s.

6.2 Results Summary

Simulation results, obtained for the listed events under SL and SP loading conditions, without and with the Fortran Project and for tie flows of +/-150MW, are presented graphically in Appendix J-1 to J-8. A close examination of the results indicates that:

1. For both types of events, differences in system responses obtained with and without the Fortran Project for SL and SP loading conditions are relatively small.

2. System responses for the simulated events are generally acceptable; i.e. their rotor angle and MW output oscillations are on the whole well-damped. The exception appears to be JAFITZ1G generator whose output has a small poorly-damped oscillatory component. The frequency of that oscillation is close 1.0 Hz, suggesting that it is excited by inertial swings between generator groups;

3. There seems to be no need for any upgrade of the existing protection system, as none of the simulated events lead to run-away dynamic instabilities. The small oscillations of JAFITZ1G generator can be damped by introducing new Power System Stabilizers (PSS) at strategically located generators or proper tuning of the existing PSSs;

In brief, there are no indications that Fortran Project adversely affects either the transient or dynamic behavior of the system.

It is important to note that there are in fact changes in system response for the same events in the pre- and post-project stages. But, in most cases, these changes are numerically small (relative to the actual values), making the resulting graphs appear identical.

6.3 Critical Clearing Time Simulations

Dynamic stability simulations have been carried out to study the system Critical Clearing Time (CCT) of without and with the Fortran Project. Both SP and SL Cases were studied.

The CCT evaluation has been based on introducing a three-phase fault at 115kV Canada bus, and its removal after 1s. The simulation was performed for 150S and 150N, with Fortran inter-tie in service.

Angle Spreads were evaluated using the PSSE PSSPLTSCAN function to monitor generator angles in West, NYC, and IESO Area. The first ten largest machine angle spreads were recorded as shown in the Appendix J7 in three tables.

The graphs in Appendix J7 show dynamics of machines and bus voltages in the vicinity of the fault. They indicate:

- Generator Rotor Angles (NIAG. G9, PIC A G4, DUNKGEN G3, HNTLY67G, LEW 1-3, and KINTI G24).
- Bus Voltage Magnitudes (115kV voltages at Canada, Paradise, L47 NY, Murray,L46CNP, and Bertihill)

As indicated in Table 6-6 (150S case) and Table 6-7 (150N Case), the system remains stable in all cases for a clearing time of more than one second (It is expected that local customers would trip out due to the fault duration. DuPont generator was tripped out at 0.2s.) It is therefore established that the project's 115 kV POI is remote enough from the bulk 230 kV and 345 kV systems that it does not exhibit stability problems for a long-duration fault – both with the CNP tie in service and also without the CNP tie.

Table 6- 6: Dynamic responses for 150S

Case	Fault Type	Faulted Element	Event Description	Result
1.. Summer Peak- Tie Closed (150S)	3 Phase	Canada Bus	3-PH fault at CANADA BUS & 0.2 sec drop DuPont generator, clearing fault after 1 sec.	System remains stable
2. Summer Peak - Tie Open	3 Phase	Canada Bus	3-PH fault at CANADA BUS & 0.2 sec drop DuPont generator, clearing fault after 1 sec.	System remains stable

Table 6- 7: Dynamic responses for 150N

Case	Fault Type	Faulted Element	Event Description	Result
1.. Summer Peak- Tie Closed (150N)	3 Phase	Canada Bus	3-PH fault at CANADA BUS & 0.2 sec drop DuPont generator, clearing fault after 1 sec.	System remains stable
2. Summer Peak - Tie Open	3 Phase	Canada Bus	3-PH fault at CANADA BUS & 0.2 sec drop DuPont generator, clearing fault after 1 sec.	System remains stable

7 Extreme Contingency Analysis

As part of the SRIS, the project's influence on the system response to extreme events was examined. The impacts were studied under both steady-state and dynamic conditions. The post-event steady-state is calculated by running a power flow, after introducing event-related changes on the system. When an extreme event involves loss of large generating units or entire power plants, it becomes essential to shed an appropriate amount of load to restore mathematical feasibility to the power flow problem.

Because of the broad nature of these events, one expects them to have severe impacts on the system dynamics, with or without the Project. However, the goal here is not to assess the "acceptability" of the resulting system responses, but to detect changes in them due to the addition of the Project.

7.1 Selected Extreme Dynamic Events

The selected extreme contingency cases are listed in Table 7.1. They all involve drastic changes in the system generation, load, and/or network connectivity, leading to highly stressed systems. As such, they serve as bench marks, for measuring robustness of the bulk power system.

Table 7- 1: Extreme contingency case descriptions

No.	Name	Type	Location	Description
1	EC01	Complex Contingencies	Niagara 345kV	- Loss of NYPP-OH tie at Niagara - Loss of PA27, BP26 and Beck-Niagara
2	EC02	Complex Contingencies	Niagara 345kV	- Loss of Niagara 345, 230 and 115 buses - Loss of Niagara Power Plant - Loss of Lewiston Generations
3	EC03	Complex Contingencies	Rochester 345kV	- Loss Corridor West of Rochester - Loss of Niagara-Rochester - Loss of Kintigh-Rochester
4	EC04	Complex Contingencies	Rochester 345kV	- Loss Corridor East of Rochester - Loss of Rochester-Pannell lines (2)

Below, results of simulating system responses to the above events, with and without the Fortran Project, are presented and changes attributable to the new interconnection are identified.

7.2 Extreme Contingency EC01

7.2.1 EC01 Steady-State Analysis

In the steady-state, the impacts of the event EC01 on the bulk power system appears in the form of changes in bus voltage magnitudes and angles, with corresponding line flow changes. Table 7.2- Table 7.4 identifies post-event buses voltage magnitudes with changes exceeding 0.005p.u. As the size of the Table 7.2- Table 7.4 indicates, for the event EC01 under SP loading condition, the introduction of the Fortran Project affects the voltage only on a very small number of buses. Note that the identified buses are all in the vicinity of the event's location.

Table 7- 2: Voltage changes due to EC01 for SP loading without Fortran

Bus No.	Bus Name	Base kV	Pre-Event		Post-Event		Change	
			Voltage pu	Angle (deg.)	Voltage pu	Angle (deg.)	Voltage pu	Angle (deg.)
79507	[NIAG. 8	13.800]	1.00133	-27.37	1.01039	-27.55	0.00906	-0.19
79508	[NIAG. 9	13.800]	1.00132	-27.36	1.01038	-27.55	0.00906	-0.19
79509	[NIAG. 10	13.800]	0.99724	-28.63	1.00451	-28.78	0.00727	-0.16
79510	[NIAG. 11	13.800]	0.99723	-28.62	1.0045	-28.78	0.00727	-0.16
79511	[NIAG. 12	13.800]	0.99723	-28.62	1.0045	-28.78	0.00727	-0.16

Table 7- 3: Voltage changes due to EC01 for SP loading with 150N

Bus No.	Bus Name	Base kV	Pre-Event		Post-Event		Change	
			Voltage pu	Angle (deg.)	Voltage pu	Angle (deg.)	Voltage pu	Angle (deg.)
79507	[NIAG. 8	13.800]	1.00147	-29.25	1.01012	-30.43	0.00864	-1.18
79508	[NIAG. 9	13.800]	1.00147	-29.24	1.01011	-30.42	0.00865	-1.18
79509	[NIAG. 10	13.800]	0.99735	-30.51	1.00429	-31.66	0.00694	-1.15
79510	[NIAG. 11	13.800]	0.99735	-30.5	1.00428	-31.65	0.00694	-1.15
79511	[NIAG. 12	13.800]	0.99735	-30.5	1.00428	-31.65	0.00694	-1.15

Table 7- 4: Voltage changes due to EC01 for SP loading with 150S

Bus No.	Bus Name	Base kV	Pre-Event		Post-Event		Change	
			Voltage pu	Angle (deg.)	Voltage pu	Angle (deg.)	Voltage pu	Angle (deg.)
79507	[NIAG. 8	13.800]	1.00397	-26.88	1.01154	-26.55	0.00757	0.34
79508	[NIAG. 9	13.800]	1.00397	-26.88	1.01154	-26.54	0.00757	0.34
79509	[NIAG. 10	13.800]	0.99936	-28.13	1.00543	-27.77	0.00608	0.36
79510	[NIAG. 11	13.800]	0.99935	-28.13	1.00543	-27.77	0.00608	0.36
79511	[NIAG. 12	13.800]	0.99935	-28.13	1.00543	-27.77	0.00608	0.36

Comparing voltage magnitude changes in Tables 7-2 to 7-4, it is clear that, for EC01, the Fortran Project does not alter the system voltage performance noticeably. The angle of the bus representing the Niagara Power Plant is reduced following the event, as the event leads to reduced generation at that plant.

For SP loading, with and without the Fortran Project, branch loadings above 95% of their thermal limits are listed in Tables 7.5 to 7.7. The results indicate that no lines or transformers exceed 95% of their LTE loading levels in the absence of the Project. In the presence of the Project, for tie flows of 150S and 150N, only CNP to NG tie cable are overloaded.

Table 7- 5: Line overloads due to EC01, without Fortran

Monitored Element						Contingency Type	Rating (MVA)	Flow (MVA)	% Rating
From Bus			To Bus						
	NONE					EC01			

Table 7- 6: Line overloads due to EC01, with the inter-tie carrying 150N

Monitored Element						Contingency Type	Flow (MVA)	Rating (MVA)	% Rating
From Bus			To Bus						
76691	L46 NY	115	81647	L46 CNP	115.00*	EC01	63.2	51	123.9
76691	L46 NY	115	81647	L46 CNP	115.00*	EC01	63.2	51	123.9

Table 7- 7: Line overloads due to EC01, with the inter-tie carrying 150S

Monitored Element						Contingency Type	Flow (MVA)	Rating (MVA)	Flow (MVA)
From Bus			To Bus						
76691	L46 NY	115	81647	L46 CNP	115.00*	EC01	71.1	51	139.4
76691	L46 NY	115	81647	L46 CNP	115.00*	EC01	71.1	51	139.4

Tables 7.8 to 7.10 contain pre- and post EC01 line MW flows. The selected flows are those that indicate changes exceeding 20 MW. The biggest line MW flow change for pre- Fortran Project is 96.2 MW. With FORTRAN, they become 107.1MW and 109.3 MW for the tie flows of 150S and 150N, respectively.

Table 7- 8: Line flow changes > 20 MW due to EC01, without FORTRAN

From Bus			To Bus			CKT	Pre-Event MW	Post Event MW	Flow Change	
No.	Name	Base kV	No.	Name	Base kV				MW	%
81500	BECK2 DK	220.00	81516	PA27 REG	230.00	27	-96.1	0.1	96.2	100.1
81500	BECK2 DK	220.00	81501	BECK2PA2	220.00	1	88.7	0.2	-88.5	99.8
81501	BECK2PA2	220.00	81508	BECK B	345.00	2	88.7	0.2	-88.5	99.8
81500	BECK2 DK	220.00	81502	BECK2PA1	220.00	1	88.7	0.3	-88.5	99.7
81502	BECK2PA1	220.00	81509	BECK A	345.00	1	88.7	0.3	-88.5	99.7
79591	NIAGAR2E	230.00	79592	NIAGAR2W	230.00	1	-53.9	-133.4	-79.4	147.3
79584	NIAG 345	345.00	79592	NIAGAR2W	230.00	1	-351.4	-430.5	-79.1	22.5
81500	BECK2 DK	220.00	81515	BP76 REG	230.00	76	-65.6	0.1	65.7	100.1
79584	NIAG 345	345.00	79591	NIAGAR2E	230.00	1	-178.8	-218.8	-40	22.4
79584	NIAG 345	345.00	79591	NIAGAR2E	230.00	2	-178.8	-218.8	-40	22.4
76665	PACKARD2	230.00	79592	NIAGAR2W	230.00	1	-79.4	-48.7	30.6	38.6
76665	PACKARD2	230.00	79592	NIAGAR2W	230.00	2	-77.7	-47.6	30	38.7

Table 7- 9: Line flow changes > 20 MW due to EC01, with the inter-tie carrying 150N

From Bus			To Bus			CKT	Pre-Event MW	Post Event MW	Flow Change	
No.	Name	Base kV	No.	Name	Base kV				MW	%
81500	BECK2 DK	220.00	81501	BECK2PA2	220.00	1	107.3	0.2	-107.1	99.8
81501	BECK2PA2	220.00	81508	BECK B	345.00	2	107.3	0.2	-107.1	99.8
81500	BECK2 DK	220.00	81502	BECK2PA1	220.00	1	107.4	0.3	-107.1	99.7
81502	BECK2PA1	220.00	81509	BECK A	345.00	1	107.4	0.3	-107.1	99.7
79584	NIAG 345	345.00	79592	NIAGAR2W	230.00	1	-312.9	-394.3	-81.4	26
79591	NIAGAR2E	230.00	79592	NIAGAR2W	230.00	1	-28.4	-100.8	-72.4	255
81500	BECK2 DK	220.00	81516	PA27 REG	230.00	27	-70.6	0.1	70.7	100.1
79584	NIAG 345	345.00	79591	NIAGAR2E	230.00	1	-159.3	-200.5	-41.2	25.9
79584	NIAG 345	345.00	79591	NIAGAR2E	230.00	2	-159.3	-200.5	-41.2	25.9
81500	BECK2 DK	220.00	81515	BP76 REG	230.00	76	-40.5	0.1	40.6	100.2
76665	PACKARD2	230.00	79592	NIAGAR2W	230.00	1	-100.3	-66	34.2	34.1
76665	PACKARD2	230.00	79592	NIAGAR2W	230.00	2	-98.1	-64.6	33.6	34.2
76691	L46 NY	115.00	76807	CANADA	115.00	1	-150	-122.8	27.3	18.2
81648	BERTIHLL	115.00	81649	ERIEPS46	115.00	1	149.9	122.6	-27.2	18.2
81649	ERIEPS46	115.00	81650	ERIE R46	115.00	PS	149.5	122.4	-27.1	18.1
81657	CNP 18	118.05	83556	STEVENVL	118.05	1	108.9	81.9	-26.9	24.7
81650	ERIE R46	115.00	81657	CNP 18	118.05	RG	149	122.1	-26.9	18.1
83509	RANK A37	118.05	83556	STEVENVL	118.05	1	-87.3	-61	26.3	30.1
81725	MURRAY	118.05	83509	RANK A37	118.05	1	-87.1	-61	26.2	30.1

Table 7- 10: Line flow changes > 20 MW due to EC01, with the inter-tie carrying 150S

From Bus			To Bus			CKT	Pre-Event MW	Post Event MW	Flow Change	
No.	Name	Base kV	No.	Name	Base kV				MW	%
81500	BECK2 DK	220.00	81516	PA27 REG	230.00	27	-109.2	0.1	109.3	100.1
79591	NIAGAR2E	230.00	79592	NIAGAR2W	230.00	1	-73.3	-159.2	-85.9	117.2
81500	BECK2 DK	220.00	81501	BECK2PA2	220.00	1	83.8	0.2	-83.6	99.8
81501	BECK2PA2	220.00	81508	BECK B	345.00	2	83.8	0.2	-83.6	99.8
81500	BECK2 DK	220.00	81502	BECK2PA1	220.00	1	83.9	0.3	-83.6	99.7
81502	BECK2PA1	220.00	81509	BECK A	345.00	1	83.9	0.3	-83.6	99.7
79584	NIAG 345	345.00	79592	NIAGAR2W	230.00	1	-377.3	-459.1	-81.7	21.7
81500	BECK2 DK	220.00	81515	BP76 REG	230.00	76	-79.2	0.1	79.2	100.1
79584	NIAG 345	345.00	79591	NIAGAR2E	230.00	1	-191.9	-233.3	-41.4	21.5
79584	NIAG 345	345.00	79591	NIAGAR2E	230.00	2	-191.9	-233.3	-41.4	21.5
76665	ACKARD2	230.00	79592	NIAGAR2W	230.00	1	-65.9	-34.9	30.9	47
76665	ACKARD2	230.00	79592	NIAGAR2W	230.00	2	-64.4	-34.1	30.3	47

Comparing flow changes for the same transmission line or the same transformer in the three cases represented by the above three tables, it is clear that the changes are generally the same for all three cases. The exceptions can be traced back to differences in loadings of nearby generators due to their re-dispatch, which was performed to establish 150N or 150S tie flow.

7.2.2 EC01 Dynamic Analysis

For SP loading condition, dynamics of some generators are simulated, with and without the Fortran Project, for the event EC01. The results of the simulations are given in Appendix K. With Fortran Project in service, the tie was set to draw 150N.

A comparison between the two simulations indicates that the dynamics of the angles remain largely unchanged. There are, however, shifts in the rotor angle values that can be traced back to differing initial conditions, which are the result of generation re-dispatch and/or introduction of the Fortran Project.

The same simulation is repeated for 150S cases and, as shown in Appendix K, the same conclusions can be drawn.

7.3 Extreme Contingency EC02

7.3.1 EC02 Steady-State Analysis

This contingency involves:

LOSS OF NIAGARA SUBSTATION AND GENERATION PLANT

LOSS OF NIAGARA 345, NIAGARA 230, NIAGARA 115
LOSS OF NIAGARA AND LEWISTON GENERATION.

It turned out that for the SP load, with 150N and 150S, with and without the Fortran Project, the power flow algorithm did not converge to a solution. That could imply that the introduction of the Fortran Project into the system does not alter the difficult operating condition facing the system, following the event EC02.

7.3.2 EC02 Dynamic Analysis

For the event EC02, dynamics of some generators, with and without the Fortran Project, are simulated for the SP loading condition. As shown in Appendix K, the system dynamics with and without the project, for 150N or 150S, are practically the same. The shifts in the rotor angle values can be attributed to differences in initial conditions due to the Fortran Project or generation re-dispatch.

7.4 Extreme Contingency EC03

7.4.1 EC03 Steady-State Analysis

This contingency involves:

LOSS OF R.O.W. WEST OF ROCHESTER
LOSS OF NIAGARA-ROCH, AND KINTIGH-ROCH

For the SP load, with and without the Fortran Project and for 150N or 150S, the power flow algorithm did not converge to a solution. One may conclude that the Fortran Project does not alter difficult system operating condition that follows event EC03.

7.4.2 EC03 Dynamic Analysis

For SP loading condition with a tie flow of 150N, dynamics of some generators are simulated for EC03, with and without the Fortran Project. As shown in Appendix K, dynamics of generator rotors remain practically unchanged. There are, however, shifts in the rotor angle values that are associated with different initial conditions, due to generation re-dispatch or introduction of the Fortran Project.

The same simulation is repeated for SP load with 150S. As shown in Appendix K, it leads to largely to similar results and the same conclusion.

7.5 Extreme Contingency EC04

7.5.1 EC04 Steady-State Analysis

For SP loading condition, the steady-state impact of the event EC04 on the bus voltage magnitudes and angles, before and after the Project, has been shown in Tables 7.11 to 7.13. Only those buses whose post-event voltage magnitudes change by more than 0.005pu are shown. As Tables 7.11 to 7.13 indicate, the introduction of the Fortran Project does not markedly change the impacts of the event EC04 on bus voltages. This remains true, regardless of the direction of the flow on the inter-tie. Note that the listed buses are all in the vicinity of the event's location.

Table 7- 11: Voltage changes due to EC04 for SP loading without Fortran

Bus No.	Bus Name	Base kV	Pre-Event		Post-Event		Change	
			Voltage (pu)	Angle (deg.)	Voltage (pu)	Angle (deg.)	Voltage (pu)	Angle (deg.)
77204	BURT	34.500	0.97735	-53.94	0.97228	-52.05	-0.00507	1.89

Table 7- 12: Voltage changes due to EC04 for SP loading with 150N

Bus No.	Bus Name	Base kV	Pre-Event		Post-Event		Change	
			Voltage (pu)	Angle (deg.)	Voltage (pu)	Angle (deg.)	Voltage (pu)	Angle (deg.)
	NONE							

Table 7- 13: Voltage changes due to EC04 for SP loading with 150S

Bus No.	Bus Name	Base kV	Pre-Event		Post-Event		Change	
			Voltage (pu)	Angle (deg.)	Voltage (pu)	Angle (deg.)	Voltage (pu)	Angle (deg.)
77204	BURT	34.500	0.97425	-53.32	0.96833	-51.26	-0.00593	2.06

For the event EC04, Tables 7.14 to 7.16 lists branch loadings that are above 95% of their thermal limits, before and after the Project for 150N and 150S under SP loading. The results indicate that no branch exceeds 95% of its LTE loading level in the absence of Fortran Project. With the Fortran Project, event EC04 causes overloads in the CNP-NG tie cable, for both 150S and 150N tie flows.

Table 7- 14: Line overloads due to EC04, without Fortran

Monitored Element						Contingency Type	Flow (MVA)	Rating (MVA)	% of Rating (MVA)
From Bus			To Bus						
	NONE					EC04			

Table 7- 15: Line overloads due to EC04, with the inter-tie carrying 150N

Monitored Element						Contingency Type	Flow (MVA)	Rating (MVA)	% of Rating (MVA)
From Bus			To Bus						
76691	L46 NY	115	81647	L46 CNP	115.00*	EC04	76.3	51	149.5
76691	L46 NY	115	81647	L46 CNP	115.00*	EC04	76.3	51	149.5

Table 7- 16: Line overloads due to EC04, with the inter-tie carrying 150S

Monitored Element						Contingency Type	Flow (MVA)	Rating (MVA)	% of Rating (MVA)
From Bus			To Bus						
76691	L46 NY	115	81647	L46 CNP	115.00*	EC04	75.3	51	147.7
76691	L46 NY	115	81647	L46 CNP	115.00*	EC04	75.3	51	147.7

Tables 7.17 to Table 7.19 list pre- and post EC04 branch MW flows. Again, the selected flows are those that indicate changes exceeding 20 MW. The biggest line MW flow change for pre- Fortran Project is 71.7 MW. With FORTRAN, they become 63.6MW and 80.3 MW for the tie flows of 150S and 150N, respectively.

Table 7- 17: Line flow changes > 20 MW due to EC04, without FORTRAN

From Bus			To Bus			CKT	Pre-Event MW	Post-Event MW	Line Flow Change	
Bus No.	Bus Name	kV	Bus No.	Bus Name	kV				MW	%
75404	KINTI345	345.00	79584	NIAG 345	345.00	1	-216.8	-145.1	71.7	33.1
81500	BECK2 DK	220.00	81502	BECK2PA1	220.00	1	88.7	41.8	-47	52.9
81502	BECK2PA1	220.00	81509	BECK A	345.00	1	88.7	41.8	-47	52.9
79584	NIAG 345	345.00	81509	BECK A	345.00	1	-88.5	-41.5	46.9	53.1
79584	NIAG 345	345.00	81508	BECK B	345.00	1	-88.5	-41.6	46.9	53
81500	BECK2 DK	220.00	81501	BECK2PA2	220.00	1	88.7	41.7	-46.9	52.9
81501	BECK2PA2	220.00	81508	BECK B	345.00	2	88.7	41.7	-46.9	52.9
79584	NIAG 345	345.00	79592	NIAGAR2W	230.00	1	-351.4	-310.4	41	11.7
81258	ST LAWRE	220.00	81259	STLAWR34	230.00	34	0	32.7	32.7	999.9

From Bus			To Bus			CKT	Pre-Event MW	Post-Event MW	Line Flow Change	
Bus No.	Bus Name	kV	Bus No.	Bus Name	kV				MW	%
81255	STLAWL34	230.00	81259	STLAWR34	230.00	34	0.4	-32.3	-32.7	999.9
81256	STLAWL33	230.00	81257	STLAWR33	220.00	33	0.4	-25.7	-26.1	999.9
81257	STLAWR33	220.00	81258	ST LAWRE	220.00	33	0.1	-26	-26.1	999.9
76500	DUNKIRK	230.00	76501	S RIPLEY	230.00	1	11.3	36.9	25.6	226.6
79591	NIAGAR2E	230.00	79592	NIAGAR2W	230.00	1	-53.9	-28.4	25.6	47.4
76665	PACKARD2	230.00	79592	NIAGAR2W	230.00	1	-79.4	-102.2	-22.9	28.8
76665	PACKARD2	230.00	79592	NIAGAR2W	230.00	2	-77.7	-100.1	-22.4	28.9
81258	ST LAWRE	220.00	81261	RAISNJ24	220.00	1	362.6	341.4	-21.2	5.8
79584	NIAG 345	345.00	79591	NIAGAR2E	230.00	1	-178.8	-158	20.8	11.6
79584	NIAG 345	345.00	79591	NIAGAR2E	230.00	2	-178.8	-158	20.8	11.6
81190	HAWTHORN	220.00	81261	RAISNJ24	220.00	1	-356.7	-336.1	20.5	5.8
80006	CHERRYWD	500.00	80192	C550 77J	500.00	1	1386.9	1366.6	-20.3	1.5
80006	CHERRYWD	500.00	80215	C551 77J	500.00	1	1389	1368.7	-20.3	1.5

Table 7- 18: Line flow changes > 20 MW due to EC04, with the inter-tie carrying 150N

From Bus			To Bus			CKT	Pre-Event MW	Post-Event MW	Line Flow Change	
Bus No.	Bus Name	kV	Bus No.	Bus Name	kV				MW	%
75404	KINTI345	345.00	79584	NIAG 345	345.00	1	-199.3	-135.7	63.6	31.9
79584	NIAG 345	345.00	81508	BECK B	345.00	1	-107.1	-65.1	42	39.2
79584	NIAG 345	345.00	81509	BECK A	345.00	1	-107.1	-65.1	42	39.2
81500	BECK2 DK	220.00	81501	BECK2PA2	220.00	1	107.3	65.3	-42	39.1
81500	BECK2 DK	220.00	81502	BECK2PA1	220.00	1	107.4	65.3	-42	39.1
81501	BECK2PA2	220.00	81508	BECK B	345.00	2	107.3	65.3	-42	39.1
81502	BECK2PA1	220.00	81509	BECK A	345.00	1	107.4	65.3	-42	39.1
79584	NIAG 345	345.00	79592	NIAGAR2W	230.00	1	-312.9	-276.8	36.1	11.5
81258	ST LAWRE	220.00	81259	STLAWR34	230.00	34	-22.1	6.7	28.9	130.4
81255	STLAWL34	230.00	81259	STLAWR34	230.00	34	22.5	-6.4	-28.9	128.3
81257	STLAWR33	220.00	81258	ST LAWRE	220.00	33	17.8	-5.3	-23.1	129.8
81256	STLAWL33	230.00	81257	STLAWR33	220.00	33	18.1	-5	-23.1	127.7
76500	DUNKIRK	230.00	76501	S RIPLEY	230.00	1	-10.2	12.6	22.8	223.7
79591	NIAGAR2E	230.00	79592	NIAGAR2W	230.00	1	-28.4	-5.9	22.5	79.2
76665	PACKARD2	230.00	79592	NIAGAR2W	230.00	1	-100.3	-120.4	-20.1	20

Table 7- 19: Line flow changes > 20 MW due to EC04, with the inter-tie carrying 150S

From Bus			To Bus			CKT	Pre-Event MW	Post-Event MW	Flow Change	
Bus No.	Bus Name	kV	Bus No.	Bus Name	kV				MW	%
75404	KINTI345	345.00	79584	NIAG 345	345.00	1	-233.4	-153.2	80.3	34.4
79584	NIAG 345	345.00	81509	BECK A	345.00	1	-83.6	-30.6	53	63.4
79584	NIAG 345	345.00	81508	BECK B	345.00	1	-83.6	-30.6	53	63.3
81500	BECK2 DK	220.00	81501	BECK2PA2	220.00	1	83.8	30.8	-53	63.2
81500	BECK2 DK	220.00	81502	BECK2PA1	220.00	1	83.9	30.8	-53	63.2
81501	BECK2PA2	220.00	81508	BECK B	345.00	2	83.8	30.8	-53	63.2
81502	BECK2PA1	220.00	81509	BECK A	345.00	1	83.9	30.8	-53	63.2
79584	NIAG 345	345.00	79592	NIAGAR2W	230.00	1	-377.3	-331.8	45.5	12.1
81258	ST LAWRE	220.00	81259	STLAWR34	230.00	34	9.6	46.4	36.8	384.3
81255	STLAWL34	230.00	81259	STLAWR34	230.00	34	-9.2	-46	-36.8	399.3
81256	STLAWL33	230.00	81257	STLAWR33	220.00	33	-7.3	-36.6	-29.4	404.2
81257	STLAWR33	220.00	81258	ST LAWRE	220.00	33	-7.6	-36.9	-29.4	388.5
76500	DUNKIRK	230.00	76501	S RIPLEY	230.00	1	30.5	59.2	28.7	93.9
79591	NIAGAR2E	230.00	79592	NIAGAR2W	230.00	1	-73.3	-44.8	28.5	38.9
76665	PACKARD2	230.00	79592	NIAGAR2W	230.00	1	-65.9	-91.2	-25.3	38.5
76665	PACKARD2	230.00	79592	NIAGAR2W	230.00	2	-64.4	-89.2	-24.8	38.5
81258	ST LAWRE	220.00	81261	RAISNJ24	220.00	1	356.4	332.5	-23.9	6.7
81190	HAWTHORN	220.00	81261	RAISNJ24	220.00	1	-350.6	-327.5	23.1	6.6
79584	NIAG 345	345.00	79591	NIAGAR2E	230.00	1	-191.9	-168.9	23	12
79584	NIAG 345	345.00	79591	NIAGAR2E	230.00	2	-191.9	-168.9	23	12
80006	CHERRYWD	500.00	80192	C550 77J	500.00	1	1380.7	1357.7	-23	1.7
80006	CHERRYWD	500.00	80215	C551 77J	500.00	1	1382.8	1359.8	-23	1.7
80041	CLAIRVIL	500.00	81305	C550 82J	500.00	1	-865.6	-844.2	21.4	2.5
80041	CLAIRVIL	500.00	81327	C551 82J	500.00	1	-864.3	-842.8	21.4	2.5

Again, by comparing line flow changes for the same device in the cases represented by the above three tables, one can conclude that the changes are mostly similar. Those that are not can be traced back to differences in generator loadings due to generation re-dispatch, which was done to establish 150N or 150S tie flow.

7.5.2 EC04 Dynamic Analysis

For SP loading condition, dynamics of some generators without and with the Fortran Project supporting a tie flow of 150N, are simulated following the event EC01. The results are shown in Appendix K. A comparison of the simulations for the two cases indicates that the dynamics of the angles remain practically the same. There are, however, shifts in their initial values that can be attributed to the generation re-dispatch or introduction of the Fortran Project.

The same simulation is repeated for 150S and, as shown in Appendix K, it leads to the same conclusions.

7.6 Summary

Based on above analyses, the introduction of the Fortran Project affects bus voltages and corresponding line flow changes on only few cases. Table 7.20 indicates the results of simulating system steady-state conditions following each extreme event, for different system loading conditions. The cases for which there was initially no power solution, mostly involved large load-generation imbalances. In these cases, after dropping large loads, the solution feasibility was restored.

Table 7- 20: Infeasible cases resulting from different extreme events, with and without the Fortran Project, under SP loading condition

Extreme Event	SP without Fortran	SP with 150S	SP with 150N
EC01	Power FlowConverged	Power Flow Converged	Power Flow Converged
EC02	Power Flow No-Converged	Power Flow No-Converged	Power Flow No-Converged
EC03	Power Flow No-Converged	Power Flow No-Converged	Power Flow No-Converged
EC04	Power Flow Converged	Power Flow Converged	Power Flow Converged

As the above table covers both Pre- and Post-Project cases, it is an indication that, from a steady-state perspective, the Fortran Project does not influence difficult operating conditions that would emerge in the wake of the extreme events, under SP loading condition. It is important to note that, in an actual power system, the power flow problem is always feasible, as the "fixed power injections" concept does not hold under abnormal operating conditions. The resulting system state, however, may not be controllable.

When there is a steady-state solution, for all extreme events, the areas which behave differently are mostly in the vicinity of the new project. Comparing bus voltages and line flows before and after the Project, the Fortran Project impact is seen to be local.

The dynamic simulation of the extreme events points to the same conclusions. That is, addition of the Fortran Project to the system, does not noticeably change dynamic behavior of the system. Observed changes are limited to shifts due to differences in initial conditions.

8 Short Circuit Analysis

8.1 Methodology

Short Circuit analysis was performed to determine the fault currents at the buses within the Study Area with and without the Project, and to establish whether any circuit breaker Interruption Capacity (IC) would be exceeded due to the project. This has been done in accordance with the NYISO Guideline for Fault Current Assessment.

Within the study area 230 and 115 kV buses were selected to evaluate breakers fault duties. The following fault types were evaluated:

- Three phase fault (3LG)
- Double line to ground fault (LLG)
- Single line to ground fault (SLG)
- Line to line fault (LTL)

The highest current for these faults was compared against the lowest breaker IC rating at each selected bus to determine the breakers' performance.

The study was performed using ASPEN system representation provided by NYISO both without and with the Fortran Project in service. Generation projects listed in the "Study Scope" (Appendix D) were modeled in the base cases.

8.2 Results

The results are summarized in three tables, as follows:

- Table 8-1 shows breaker performances in the absence of the Project (Pre-project) at selected buses
- Table 8-2 indicates the same but in the presence of the Project (Post-project)
- Table 8-3 compares breaker performances for 115kV and 230kV buses.

Table 8- 1: Pre-project breaker performances for selected fault categories

Bus Name	Voltage Rating (kV)	Lowest Breaker IC Rating (A)	3LG Faults (A)	LLG Faults (A)	SLG Faults (A)	LTL Faults (A)
BUFSEWER46	115	N/A	7916	7119	4709	6842
BUFSEWER47	115	N/A	7487	6701	4107	6471
CNPSTA18	115	N/A	6511	5870	3816	5630
DUPONT46	115	N/A	12488	11301	8209	10784
DUPONT47	115	N/A	11342	10169	6514	9793

Bus Name	Voltage Rating (kV)	Lowest Breaker IC Rating (A)	3LG Faults (A)	LLG Faults (A)	SLG Faults (A)	LTL Faults (A)
GARDENVILLE1	115	43800	41422	41104	40593	35612
GARDENVILLE1	230	35900	23760	22922	20983	20458
GARDENVILLE2	115	43800	41384	41066	40556	35579
GARDENVILLE2	230	35900	23736	22898	20963	20437
HUNTLEY	230	35900	27067	26729	25544	23286
KENMOR46	115	N/A	10672	9634	6652	9219
KENMOR47	115	N/A	9869	8846	5504	8525
LOCKPORT E	115	40000	34944	32232	24677	30012
LOCKPORT W	115	40000	35075	32346	24748	30123
MURRAY	115	N/A	21460	20856	17470	18585
NIAGRA E	115	40000	48375	47367	46384	40664
NIAGRA E	230	51000	50696	55107	56460	42994
NIAGRA W	115	40000	43278	41870	40581	36477
NIAGRA W	230	51000	50695	55107	56459	42993
PACKARD	230	50000	43211	43176	39082	36851
PACKARD NTH	115	63000	52446	51532	46488	44322
PACKARD STH	115	63000	52411	51494	46462	44292
PARADISE	115	50000	40103	36571	26649	34357

N/A: Not available

Table 8- 2: Post-project breaker performances for selected fault categories

Bus Name	Voltage Rating (kV)	Lowest Breaker IC Rating (A)	3LG Faults (A)	LLG Faults (A)	SLG Faults (A)	LTL Faults (A)
BUFSEWER46	115	N/A	15959	14289	8584	13787
BUFSEWER47	115	N/A	15955	14286	8582	13784
CNPSTA18	115	N/A	11158	10068	6513	9654
DUPONT46	115	N/A	16661	15047	10598	14387
DUPONT47	115	N/A	15789	14211	9619	13635
GARDENVILLE1	115	43800	42140	41697	41090	36244
GARDENVILLE1	230	35900	23988	23116	21114	20660
GARDENVILLE2	115	43800	42101	41658	41052	36210
GARDENVILLE2	230	35900	23963	23091	21094	20639
HUNTLEY	230	35900	27191	26832	25622	23399
KENMOR46	115	N/A	15815	14235	9396	13661
KENMOR47	115	N/A	15349	13793	8942	13258
LOCKPORT E	115	40000	35265	32504	24804	30298
LOCKPORT W	115	40000	35399	32621	24876	30412
MURRAY	115	N/A	24523	23589	19366	21236
NIAGRA E	115	40000	48988	47854	46796	41203
NIAGRA E	230	51000	50946	55317	56686	43219

Bus Name	Voltage Rating (kV)	Lowest Breaker IC Rating (A)	3LG Faults (A)	LLG Faults (A)	SLG Faults (A)	LTL Faults (A)
NIAGRA W	115	40000	43776	42261	40897	36917
NIAGRA W	230	51000	50945	55317	56685	43219
PACKARD	230	50000	43437	43369	39217	37056
PACKARD NTH	115	63000	53406	52330	47041	45162
PACKARD STH	115	63000	53369	52290	47014	45130
PARADISE	115	50000	42763	38929	27928	36661

N/A: Not available

The results of comparing pre- and post-project breaker performances for 115kV and 230kV buses are given in Table 8-3. The table shows only the first 30 largest current changes for the 3LG fault. The LTL fault current changes are relatively small and are not shown in the table.

Table 8- 3: Comparison of pre- and post-project breaker performances for the first 30 largest current changes (115kV and 230kV)

Bus Name	Voltage Rating (kV)	Fault Current Change		
		3LG Faults (A)	LLG Faults (A)	SLG Faults (A)
BUFSEWER47	115	8468	7585	4475
BUFSEWER46	115	8043	7169	3875
AM BRASS 47	115	6082	5473	3597
ENCOGEN	115	6041	5433	3545
AM BRASS46	115	5707	5092	2913
CNPSTA18	115	4647	4198	2697
PRAXAIR 46	115	4259	3810	2265
CHEVY 47	115	4210	3819	2821
DENEMOURSW	115	4008	3589	2303
CHEVY46	115	3916	3511	2153
DUNLOP 47	115	3683	3325	2572
CNPSTA11	115	3198	2860	1893
DUPONT	115	3195	2843	1879
MURRAY	115	3064	2734	1896
FMC	115	2684	2415	1476
PARADISE	115	2660	2358	1280
PACKARD NRTH	115	960	799	553
PACKARD STH	115	958	796	551
AIRCO84*	115	868	721	477
AIRCO83*	115	866	719	475
GARDENVILLE1	115	718	593	497
NGARDNV(NY)	115	717	593	496

Bus Name	Voltage Rating (kV)	Fault Current Change		
		3LG Faults (A)	LLG Faults (A)	SLG Faults (A)
NGARDENV(NY)	115	717	592	496
GARDENVILLE2	115	716	592	496
WALCK RD	115	626	551	150
ECWA 182	115	615	546	270
STA 78 133	115	615	542	124
NIAGRA E 115	115	613	518	412
STA 78 130	115	609	538	97
WALCK129	115	595	524	148

The above tables contain only buses that are impacted by the project by more than 594A for a 3LG fault. The full list of breakers whose fault current changes exceed 100A for different faults is given in Appendix L2.

8.3 Results Summary

According to the above Tables, for pre-Fortran Project, the significant faults are those occurring at NY Niagara Station, for the resulting fault currents exceed the current interruption capacity (IC) of breakers in that station.

With Fortran Project in service, the same fault currents increase by 200 to 600 Amps. Although other listed bus fault currents also exceed 200Amps (the largest being 115kV BUFSEWER buses exceeding 8 kA), unlike Niagara Falls breakers, their fault currents remain below their breakers' ICs.

A Short Circuit study, defined by a 3-phase fault at NGardenv(NY) 115kV bus with breaker 705 open at Girdle Road, was performed by NYSEG. The results indicated that the short-circuit current of NYSEG New Gardenville breaker 50712 would rise from 42,283A without the Fortran Project to 43,019A with the Fortran Project. Note that NYSEG uses 1.05pu flat operating bus voltages for assessing adequacy of breaker IC

In short, there seems to be some difficulties with IC of certain breakers in particular in the Niagara Falls area. The short circuit current level rises could be attributed to Fortran Project as well as other prior projects added from the queue. The assignment of responsibility can be properly assessed in the Facility Study process.

9 Preliminary Cost Estimates and Schedules

9.1 *Estimated Costs*

The expected schedule for the upgrading/construction activities to implement the Fortran Project as well as their good faith estimates are given below:

9.1.1 CNP activities

The activities listed in Table 9.1 are identified for CNP as part of this SRIS:

Table 9- 1: CNP activities and estimated costs

Activity	Description	Estimated Cost ($M)
1	Installing a phase angle regulating transformer and a voltage regulating transformer on the new inter-tie at CNP #18	$ 8.8
2	Re-conductor 0.7 miles length (one circuit) from the Crossing Point NY side (Terminal House B) to CNP side Bertie Hill Tower with 795 ACSR conductor	$ 0.2
3	Installing a 30 MVA (6x5MVA) capacitor bank at CNP #18	$ 0.4
	Total Estimated Cost for CNP in Millions	$ 9.4

9.1.2 NG activities

The activities that have been already identified for NG *in the project feasibility stage* and their estimated costs are given in Table 9.2, below.

Table 9- 2: NG activities and estimated costs

Activity	Description	Estimated Cost ($M)
1	Re-conductor 6.3 miles length of Lines 46 and 47 with 1113mcm ACSR conductor	$9.5
2	Constructing the 3-breaker Ring Station in Buffalo .	$ 5.75
	Total Estimated Cost for NG in Millions	$ 15.25

9.2 Excluded Cost

The cost estimate does not include any taxes or duties, Owner's administration, interest during construction, permitting and licensing, environmental and land acquisition cost.

9.3 Schedules

It is expected that CNP requires close to three years after finalization of the SRIS to complete its Fortran related activities, as listed in Table 9.3, below.

Table 9- 3: CNP Fortran project implementation schedules

Activity	Description	Start date	End Date
1	Conclude SRIS and Facility study, IA signed	Fall 2008	Fall 2009
2	Order phase shifter, voltage regulator and Cap bank	Fall 2009	
3	Do structural reinforcements	Summer 2010	Summer 2010
4	Do reconductoring	Summer 2010	Summer 2010
5	Install phase shifter and voltage regulator	Spring 2012	Fall 2012
6	Install the capacitor bank	Spring 2012	Fall 2012
7	Put the Project in Service	Fall 2012	Fall2012

Based on the Feasibility Study conducted for NG, its estimates of the earliest possible schedule for Fortran related activities are those given in Table 9.4.

Table 9- 4: NG Fortran related schedules

Activity	Description	Start date	End Date
1	Construct 3 Breaker Ring station	Fall 2009	Fall 2011
2	Do reconductoring	Fall 2009	Fall2012
3	Putting the project in Service	Fall 2012	Fall 2012

10 Conclusions

Thermal studies have been conducted on CNP-NYISO power transfers up to 150MW in both directions for summer and winter peak loading conditions. The base case and contingency studies showed that the power transfers from NYISO to CNP are largely restricted by the thermal ratings of the old line sections (at river crossing) running between L46 NY and BERTIHILL buses. The study recommends reconductoring of the existing tie and approximately six miles of L46 and L47 lines. Studies on the system voltage/Var performance conducted for the same system loading conditions and inter-tie power transfers indicate that the voltages were acceptable when a 30MVA capacitor bank is added to the CNP system at CNP#18. Voltage deviations following contingency cases were small in all cases.

The SRIS study has confirmed that the addition of the CNP tie (and associated facilities) does not adversely impact the transfer capability and that NY-Ontario interface transfer capability will increase by more than 150 MW. The voltage and angle changes on the NY bulk power system due to the CNP tie flows are very small and voltage and stability limits are shown to be unaffected. The intra-area analysis showed that some of the NYISO intra-area transfer limits are increased by a small amount with the CNP tie.

Simulations of system dynamic response to the selected events indicated that: 1) the differences without and with the CNP tie are very small and the resulting oscillations are well-damped or unchanged; 2) There is no need for any upgrade of the existing protection system, as none of the simulated events lead to system dynamic instabilities; and, 3) For both single and complex contingencies, differences between system responses obtained with and without the Fortran Project are very small. In brief, the Fortran Project does not have any adverse impact on the system stability.

Steady-state and dynamic simulations were performed on a set of extreme cases, involving drastic changes to the system generation, load, and/or network connectivity, to measure any change in the robustness of the bulk power system. The results indicated that, for different system loading conditions, these events did not produce noticeable changes in the overall system response due to the presence of the new inter-tie. There were naturally changes in the line flows and bus voltages local to the project subsystem. There were also cases for which initially there were no power flow solutions, with and without the Fortran Project. In these cases, after dropping some loads, solution feasibility were restored. In such cases, no conclusions were drawn from the resulting power flows and bus voltages as different load shedding strategies lead to different line flows and bus voltages.

Short Circuit analyses were conducted for key equipment surrounding the Project. The significant faults are those occurring at NY Niagara Station In most cases, when fault currents approached or exceeded the current interruption capacity of their associated breakers, they occurred consistently both with and without the CNP inter-tie. The short circuit current level rises could be attributed to Fortran Project as well as other projects added from the queue. The assignment of the responsibility is left to the Facility Study process.

To implement the Project, CNP has to take on the following activities over a three year period after finalization of the SRIS,

1. Installing a phase angle regulating transformer and a voltage regulating transformer on the new inter-tie at CNP #18, at estimated cost of $8,800,000;

2. Re-conductor 0.7 miles length from the River Crossing Point NY side (Terminal House B) to CNP side Bertie Hill Tower with 795 ACSR conductor, at the estimated cost of $200,000;

3. Installing a 30MVA capacitor bank at CNP #18, at estimated cost of $400,000.

As part of the upgrades of the NG system, construction/upgrading of the following facilities within about the next three and a half years have been proposed:

1. Upgrading of 6.3 miles of 115 kV transmission line L46 and L47 at the Paradise Station end. This upgrade will result in the ratings of the Paradise – FMC, FMC – Dunlop and Dunlop – DuPont sections of both L46 and L47 lines to increase to 271 MVA for summer normal, 313 MVA for summer LTE, 359 MVA summer STE, 331 MVA winter normal, 364 MVA winter LTE and 404 MVA winter STE. The good faith estimate of this upgrade provided by NG is $9,500,000.

2. Constructing the 3-breaker Ring Station in Buffalo. The estimated cost of the 3-breaker ring Station provided by NG is $ 5,750,000

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