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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

September 4, 2009

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2008-0272 – Hydro One Networks 2009 and 2010 Electricity Transmission Revenue Requirements – Supplemental Filing of Material in Support of Capital Projects

Attached are three copies of additional evidence in support of the capital projects disallowed by the Board as part of its Decision with Reasons on Hydro One Network's 2009 and 2010 Transmission Revenue Requirement Application Proceeding EB-2008-0272.

Hydro One is providing this supplemental filing in advance of the November timeline set by the Board in order to provide time for a decision on this matter to be reflected in Hydro One's updated 2010 Revenue Requirement and proposed 2010 Uniform Transmission Rates to be submitted for approval by the Board in October 2009.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

c. EB-2008-0272 Intervenors (email)

EXHIBIT LIST

ONTARIO ENERGY BOARD

IN THE MATTER OF *the Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF an Application by Hydro One Networks Inc. For an Order or Orders approving rates for the transmission of electricity.

SUPPLEMENTAL EVIDENCE

1. The Applicant is Hydro One Networks Inc. ("Hydro One Networks"), a subsidiary of Hydro One Inc. Hydro One Networks is an Ontario corporation with its head office in Toronto. The Applicant carries on the business, among other things, of owning and operating transmission facilities in Ontario. The transmission business of Hydro One Networks will be referred to as "Hydro One Transmission".

2. In its Reasons for Decision in the EB-2008-0272 proceeding issued on May 28, 2009, the Ontario Energy Board (the "Board"), did not approve four of the Network capital projects proposed by Hydro One Transmission to be placed in-service in the 2010 test year. The Board did provide Hydro One Transmission with the opportunity to provide additional supporting evidence for these projects for purposes of setting 2010 rates providing such evidence is filed no later than November 30, 2009.

3. Pursuant to the Board's direction Hydro One Networks hereby requests the Board's approval of the capital costs and additional revenue requirement for the transmission of electricity associated with two of the four disallowed projects, to be placed in-service in 2010.

4. The projects requested for approval are:

    - Static Var Compensators (SVCs) at Porcupine TS and Kirkland Lake TS (D7)
    - Series Capacitors at Nobel SS (D8)

5. Approval of capital projects D7 and D8 will increase the previously approved capital program by $82.7 million to a total of $936.5 million in 2009, and by $62.0 million to a total of $1,057.6 million in 2010. Both projects are planned for in-service in 2010 and the resulting impact on the 2010 Revenue Requirement is estimated to be $7.1 million, using the same cost of capital assumptions as in the Order issued by the Board on July 3, 2009 approving the 2009 and 2010 Revenue Requirement arising from the EB-2008-0272 Decision with Reasons. As directed by the Board, the final 2010 test year cost of capital parameters will be set based upon September 2009 data. If approved by the Board, the associated $7.1 million revenue requirement for these projects and the $1,242.2 million previously approved will be adjusted to reflect the final cost of capital parameters issued by the Board.

6. Hydro One is providing this supplemental filing in advance of the November timeline set by the Board in order to provide time for a decision on this matter to be reflected in Hydro One's updated 2010 Revenue Requirement to be submitted for approval by the Board in October 2009 and as input into the finalization of 2010 Uniform Transmission Rates.

7. The persons affected by this supplemental evidence are the ratepayers of Hydro One's transmission business. It is impractical to set out their names and addresses because they are too numerous.

8. Hydro One Networks requests that a copy of all documents filed with the Board by each party to this submission be served on the Applicant and the Applicant's counsel as follows:

a) The Applicant:

Ms. Anne-Marie Reilly
Regulatory Coordinator
Hydro One Networks Inc.

Address for personal service:	8th Floor, South Tower 483 Bay Street Toronto, ON M5G 2P5
Mailing Address:	8th Floor, South Tower 483 Bay Street Toronto, ON M5G 2P5
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Electronic access:	Regulatory@HydroOne.com

b) The Applicant's counsel:

Mr. D.H. Rogers, Q.C.
Rogers Partners LLP

Address for personal service:	181 University Avenue Suite 1900, P.O. Box 97 Toronto, ON M5H 3M7
Mailing Address:	181 University Avenue Suite 1900, P.O. Box 97 Toronto, ON M5H 3M7
Telephone:	(416) 594-4500
Fax:	(416) 594-9100
Electronic access:	don.rogers@rogersmoore.com

DATED at Toronto, Ontario, this 4th day of September, 2009.

HYDRO ONE NETWORKS INC.

By its counsel,

____

D.H. Rogers, Q.C.

SUMMARY OF SUPPLEMENTAL EVIDENCE

This summary provides a brief description of the approvals being sought through this supplemental evidence submission.

1.0 BACKGROUND

In its May 28, 2009 Decision with Reasons on Hydro One Networks' 2009 and 2010 Transmission Revenue Requirement Application, Proceeding EB-2008-0272, the Ontario Energy Board (the "Board") did not approve four of the Network capital projects proposed by Hydro One Transmission to be in-service in the 2010 test year. The Board did state it "will keep this part of the proceeding open and will provide Hydro One with the opportunity to provide additional evidence on these projects for the purpose of setting 2010 rates" (page 48 of Decision with Reasons).

The Board required additional evidentiary support for the following projects:

- Static Var Compensators ("SVCs") at Porcupine TS and Kirkland Lake TS (D7)
- Series Capacitors at Nobel SS (D8)
- Shunt Capacitor Bank at Algoma TS (D9)
- Shunt Capacitor Banks at Mississagi TS (D10)

At the time Hydro One Transmission submitted the prefiled evidence, Hydro One used the best information available to forecast the timing of its capital expenditure program. As with all forecasts, circumstances change as market conditions and government initiatives evolve. Hence the timing of the need for projects D9 and D10 have now shifted by one year.

Projects D9 and D10, supplemented by the installation of an SVC at Mississagi TS, are required to provide the reactive power to increase the transfer capability of the Mississagi Flow-East Interface to enable incorporation of up to 300 MW of renewable generation in the area from Sudbury to eastern Lake Superior, including the Sault Ste. Marie/Algoma area. In a letter dated June 1, 2009, provided as Exhibit C, Tab 1, Schedule 3, the OPA expressed their support for Hydro One's plan to install the proposed facilities and stated the need for the increased transfer capability by December, 2011.

Given the shift in need of a year, Hydro One is no longer seeking inclusion of projects D9 and D10 in rate base as part of the current proceeding for the 2010 test year. Approval for rate base inclusion for these projects will now be requested as part of Hydro One Transmission's 2011 – 2012 transmission rate application given the OPA's current analysis of when these projects need to be in-service.

Hydro One Transmission is therefore providing the requested additional evidentiary support only for projects D7 and D8.

2.0 SUPPORTING EVIDENCE FOR PROJECTS D7 AND D8

Hydro One Transmission has noted the Board's concerns in its Decision respecting the need for additional supporting evidence from the Ontario Power Authority ("OPA") and the Independent Electric Systems Operator ("IESO") for transmission projects which do not require a section 92 approval and have yet to be approved as part of the OPA's IPSP.

Hydro One notes the Board's satisfaction with the level of supporting detail provided by the OPA in the Bruce to Milton Leave to Construct proceeding and has tried to balance the level of detail required for a section 92 application with the detail that can be provided for approval of a transmission project as part of a revenue requirement application.

Hydro One has worked closely with the OPA in the development of this supplemental evidence and will continue to work with both the OPA and the IESO in development of its capital plans for all future applications to ensure a satisfactory evidentiary record is provided to the Board.

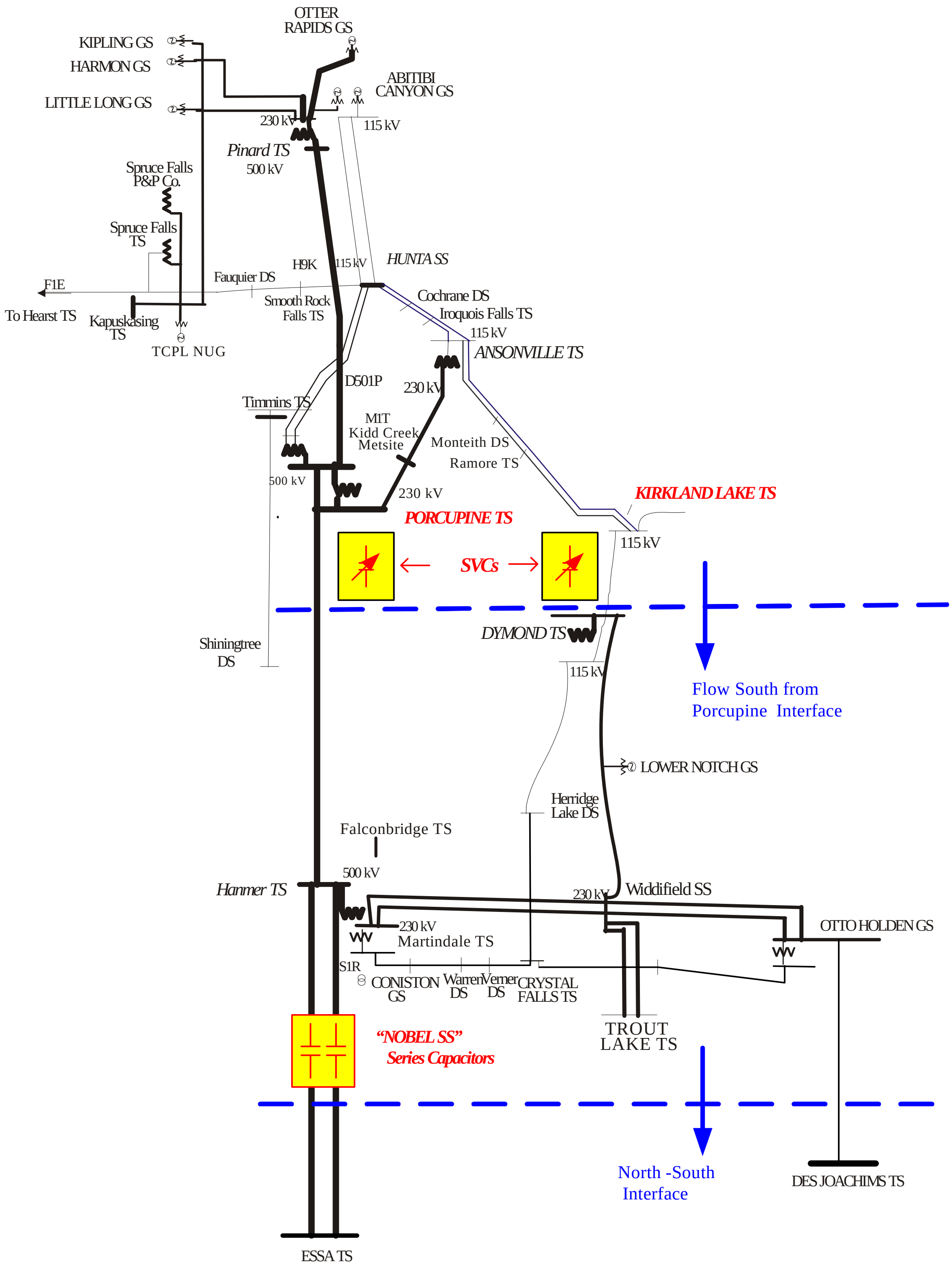
Additional supporting information from the Ontario Power Authority ("OPA") and Independent Electricity System Operator ("IESO") are provided in Exhibit C, Tab 1, Schedules 1 to 5.

The need for Project D7 is described at Exhibit B, Tab 1, Schedule 1, a detailed project description and cost are provided at Exhibit B, Tab 1, Schedule 2 and a consideration of alternatives is filed at Exhibit B, Tab 1, Schedule 3.

Similarly, the need for Project D8 is described at Exhibit B, Tab 2, Schedule 1, a detailed project description and cost are provided at Exhibit B, Tab 2, Schedule 2 and a consideration of alternatives is filed at Exhibit B, Tab 2, Schedule 3.

A schematic of the existing transmission system, proposed SVCs at Porcupine TS and Kirkland Lake TS (Project D7), and the series capacitors at Nobel SS (Project D8) is provided in Figure 1.

1 Figure 1. Existing and Proposed Transmission Facilities



NEED FOR STATIC VAR COMPENSATORS AT PORCUPINE TS AND KIRKLAND LAKE TS (PROJECT D7)

Project D7 consists of the installation of Static Var Compensators ("SVCs") at Porcupine TS and Kirkland Lake TS. Together with the installation of series capacitors at Nobel SS, which is part of Project D8, the installation of SVCs at Porcupine TS and Kirkland Lake TS is required to meet the following needs:

- Allow the OPA to successfully procure approximately 500 MW of hydroelectric generation north of Porcupine TS from four specific projects that were directed by the Minister of Energy.
- Promote the use and generation of electricity from renewable energy resources in a manner consistent with the policies of the Government of Ontario by providing for the timely reinforcement of the transmission system necessary to accommodate the connection of up to about 350 MW in additional generation to be procured in Northern Ontario.
- Provide dynamic reactive power support to maintain supply reliability to electricity consumers north of New Liskeard.

Details on the four specific generation projects directed by the Minister of Energy were provided in the OPA's letter of May 20, 2008 which is provided at Exhibit C, Tab 1, Schedule 1[1]. The "Hydroelectric Energy Supply Agreements" directive issued by the Minister of Energy on December 20, 2007 required the OPA to contract with Ontario Power Generation for the development of several hydroelectric facilities in northeastern and northwestern Ontario. These facilities have a combined capacity of approximately 500 MW.

[1] This letter was originally provided as Attachment 4 to the undertaking response Exhibit J1.3 filed February 26, 2009 in this proceeding(EB-2008-0272).

Details on the committed and other near-term generation projects originally expected to be developed in Northern Ontario are provided in Table 2 of the additional supporting material provided by the OPA included at Exhibit C, Tab 1, Schedule 2. These additional generation resources consisted of 246 MW in committed resources and 134 MW of other resources. These generation resources are a mix of hydro, wind, gas and biomass generation originally identified in Exhibit E, Tab 3, Schedule 1 in the Integrated Power System Plan ("IPSP") filed as application EB-2007-0707. The forecast of additional resources expected in Northern Ontario has subsequently been updated to 387 MW of in-service and committed resources, and 375 MW of other resources, as shown in Table 4 of the additional supporting material provided by the OPA.

These new generation resources will significantly increase the level of southbound flows on the North South ("N-S") Interface, which currently operates near its capability of about 1,300 MW without the use of post contingency generation rejection. The impact of the proposed facilities on the N-S Interface transfer capability is summarized on page 2 of the IESO Addendum provided at Exhibit C, Tab 1, Schedule 5. As shown in the IESO Addendum, Project D7 together with the series capacitors installed as part of Project D8 will increase the N-S Interface transfer capability by 500 MW to 1,800 MW. The transfer capability is further increased to 2,050 MW through use of the existing post contingency generation rejection scheme. The increased transfer capability will allow access to new renewable generation in the North and provide capacity congestion relief on this critical interface during critical peak load conditions.

The need with respect to maintaining supply reliability for customers north of New Liskeard stems from the fact that when there is a single-circuit contingency on the 500 kV line from Porcupine TS to Hanmer TS, the whole power system north of Timmins is connected to the rest of network via two weak 115 kV circuits connected to Kirkland Lake TS. Without the dynamic reactive power support from the proposed SVCs, instability could cause the transmission system to separate at Kirkland Lake TS. The SVC installation under Project D7 is split between Porcupine TS and Kirkland Lake TS so that it provides the dual benefit of increasing the transfer capacity of power flows south from Porcupine TS while mitigating the potential for significant interruptions to load customers north of New Liskeard.

The 200 Mvar of dynamic reactive power support provided by the Kirkland Lake SVC will also contribute to meeting the IESO's "Ontario Resource and Transmission Assessment Criteria", which are used by the IESO to assess connection proposals.[2] If the reliability to customers north of New Liskeard was not addressed by installing the SVC at Kirkland Lake TS, the power flow south from Porcupine TS would not be permitted to exceed its existing limit, which would restrict the Lower Mattagami Development directed by the Minister of Energy as noted in the OPA's letter of May 20, 2008.

While there have been some changes since Hydro One filed its pre-filed evidence requesting approval of both Projects D7 and D8, the additional supporting material provided by the OPA included as Exhibit C, Tab 1, Schedule 2 concludes on page 9 that "while some of the expected in-service dates of the generation resources have changed, the OPA expects a large amount of near-term resources to come into service that will require these transmission reinforcements" and further notes that without these projects "there will not be enough transmission capability available to allow new renewable resources to come into service in the near-term". Accordingly, the OPA continues to recommend Project D7 and Project D8, be implemented by 2010.

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[2] The transmission assessment criteria are posted on the IESO web site at:
http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

The IESO's System Impact Assessment ("SIA") report dated May 15, 2007[3] and addendum dated August 15, 2007 are provided as Exhibit C, Tab 1, Schedule 4 and Schedule 5, respectively. The IESO has confirmed the adequacy and necessity of the facilities proposed by Projects D7 and D8, noting on page 3 of the SIA that "the enhanced transfer capability provided by the installation of these new facilities would be adequate to accommodate all of the existing & committed generating facilities north of Sudbury together with an increase of 433MW in the output from the expanded Mattagami River plants". The SIA also shows that the proposed facilities will provide the dynamic reactive support that is required to control post-contingency voltages on the power system north of Sudbury.

[3] This SIA was originally submitted as Attachment 1 to interrogatory response Exhibit I, Tab 1, Schedule 61 under the current proceeding (EB-2008-0272).

DESCRIPTION, COST AND SCHEDULE FOR PROJECT D7

1.0 DESCRIPTION OF WORK

Project D7 consists of adding Static Var Compensators (“SVCs”) at Porcupine TS and Kirkland Lake TS. The scope of work required to integrate the SVC facilities into the two existing stations extends beyond simply the purchase and installation of the SVCs. The complete scope of work will include the following components at Porcupine TS and Kirkland Lake TS.

Porcupine TS:

- One -100/+300 Mvar SVC and associated coupling transformer to connect at the 230kV bus
- Two new 230kV breakers and associated bus work
- Protection, control and communication equipment
- Landscaping, fencing, grounding

Kirkland Lake TS:

- One -88/+200 Mvar SVC and associated coupling transformer to connect at the 115kV bus
- One new 115kV breaker and associated bus work
- A High Voltage line tap from the 115 kV D4 bus to the SVC
- Protection, control and communication equipment

The SVCs and associated coupling transformer at both TS sites will be purchased and installed via a turn-key contract. The balance of the work will be completed by Hydro One staff.

2.0 COST AND SCHEDULE

The total cost for the installation of SVCs at Porcupine TS and Kirkland Lake TS is estimated to be $109 million. $59 million of the project cost goes to the procurement and installation of SVCs as a turn-key project ($31 million for Porcupine TS SVC and $28 million for Kirkland Lake TS SVC). The turn-key contract cost is based on detailed tendering specifications and obtained from competitive bids. The remainder of the cost is for the work required to integrate these assets into the existing transformer stations, as well as associated interest charges ("AFUDC"), overheads and contingencies.

The planned in-service for the two SVCs is November 2010.

The anticipated cash flow and total cost for the project is shown in Table 1.

Table 1
Project D7 Cash Flow ($ million)

To end of 2008	2009	2010	Total
5	49	55	109

ALTERNATIVES FOR PROJECT D7

Hydro One planners, working in coordination with IESO and OPA staff, looked at a number of alternatives for increasing the transfer capabilities of the North-South ("N-S") Interface and the transmission system north of Sudbury. Different technologies were considered for the regions north of Sudbury (Shunt Compensation, Project D7), and south of Sudbury (Series Compensation, Project D8), as appropriate to the different nature of the problems and system topologies in these two regions.

The following transmission alternatives to Project D7 "Installation of SVCs at Porcupine TS and Kirkland Lake TS" were considered by Hydro One and rejected for the reasons detailed below:

Alternative 1: Do Nothing.

The "Do Nothing" alternative is not acceptable since the capacity of the existing transmission system is constrained and currently limits the ability to access all of the existing generation north of Sudbury. The "Do Nothing" alternative would constrain the development of planned renewable generation resources in Northern Ontario. This alternative would also not address the existing reliability concerns to customers north of New Liskeard, or address the deterioration in reliability once the new generation facilities come on line.

Alternative 2: Install Mechanically Switched Capacitor / Reactor Banks.

Unlike an SVC, a Mechanically Switched Capacitor/Reactor is normally used only to provide steady-state reactive power support. Under dynamic conditions mechanically switched devices may be automatically switched once at much slower speed. Although the mechanically switched devices cost relatively less than the SVCs, they do not provide the fast and dynamic reactive support required to ensure system stability during high N-S transfers and avoid risk of load interruption to customers north of New Liskeard. In addition, Hydro One is concerned about equipment risks associated with automatically switching high voltage capacitor banks in the system, especially in a relatively weaker northern Ontario system. The alternative of automatically switching off Mechanically Switched Reactors with Mechanically Switched Capacitor Banks on-line pre-contingency does not satisfy concerns about supply reliability for customers. This alternative also contravenes the IESO's "Ontario Resource and Transmission Assessment Criteria" during conditions when there is high flow south from Porcupine TS. Thus, this alternative will not sufficiently relieve the existing transmission restrictions and will result in continued and increasing operating restrictions.

Alternative 3: Install Series Capacitor on Porcupine TS to Hanmer TS 500kV Circuit.
While this alternative would increase the transfer limit from the perspective of the Flow South transfer on the N-S Interface, the interface limit for Flow-South-into-Sudbury would still be restricted to the existing level of about 650 MW in order to avoid adversely impacting the reliability to Hydro One customers following the loss of the 500 kV circuit P502X. Since this alternative does not address concerns about the existing transmission restrictions on the Flow-South-into-Sudbury Interface, there will be continued and increasing operating restrictions as new generation comes on line. This alternative would prevent incorporation of approximately 550 MW of renewable generation north of Porcupine TS and therefore is inconsistent with the OPA recommendation and the Government's direction regarding development of renewable generation in the north.

Alternative 4: New Parallel Single Circuit 500kV Line from Pinard TS to Hanmer TS.
This alternative would provide significantly greater increase in the transfer capability from the north into Southern Ontario and improve the overall system reliability in Northern Ontario. While this option remains a credible solution to provide for longer term requirements, a new line could not be built in time to meet the in-service date required by the OPA in their May 20, 2008 letter. In addition, at a cost of roughly $1 billion, a new line would be approximately ten times more costly that the recommended investments.

NEED FOR SERIES CAPACITORS AT NOBEL SS (PROJECT D8)

Project D8 consists of the installation of series capacitors at Nobel SS to provide 50% compensation of the Essa TS to Hanmer TS 500 kv lines. Together with the installation of Static Var Compensators ("SVCs") at Porcupine TS and Kirkland Lake TS as part of Project D7, the installation of series capacitors at Nobel SS is required to meet the following needs:

- Allow the OPA to successfully procure approximately 500 MW of hydroelectric generation north of Porcupine TS from four specific projects that were directed by the Minister of Energy.
- Promote the use and generation of electricity from renewable energy resources in a manner consistent with the policies of the Government of Ontario by providing for the timely reinforcement of the transmission system necessary to accommodate the connection of up to about 350 MW in additional generation to be procured in northern Ontario.

The new generation resources noted above will significantly increase the level of southbound flows on the North South ("N-S") Interface, which currently operates near its capability of about 1,300 MW without the use of post contingency generation rejection. The impact of the proposed facilities on the N-S Interface transfer capability is summarized on page 2 of the IESO Addendum provided at Exhibit C, Tab 1, Schedule 5. As shown in the IESO Addendum, Project D8 together with the SVCs installed as part of Project D7 will increase the N-S Interface transfer capability by 500 MW to 1,800 MW. The transfer capability is further increased to 2,050 MW through use of the existing post contingency generation rejection scheme. The increased transfer capability will allow access to new renewable generation in the North and provide capacity congestion relief on this critical interface during critical peak load conditions.

Supporting detail for the needs noted above, including a review of the supporting information provided by the OPA and the IESO, was previously covered in the discussion of the need for Project D7 in Exhibit B, Tab 1, Schedule 1.

DESCRIPTION, COST AND SCHEDULE FOR PROJECT D8

1.0 DESCRIPTION OF WORK

Project D8 will involve the construction of a new transmission switching station ("SS") to be located on Hydro One property approximately 20 km north of Parry Sound, northeast of the community of Nobel. The scope of work required to install the major facilities at the new station, to be called "Nobel SS", consists of the following:

- Two 750 Mvar, 500 kV series capacitor banks, one on each 500 kV lines from Hanmer TS x Essa TS (circuits X503E and X504E), associated protection and control equipment, as well as all station infrastructure facilities (e.g. fencing and grounding)
- Eight new 500kV tapping structures to bring the 500 kV circuits X503E and X504E into the new Nobel SS
- Protection, control and communication equipment at Hanmer TS and Essa TS
- Access roads to the Nobel SS station site and landscaping

The work required to purchase and install the facilities described in the first bullet above will be completed via a turn-key contract. The balance of the work will be completed by Hydro One staff.

2.0 COST AND SCHEDULE

The total cost for installation of Series Capacitors at Nobel SS is estimated to be $47 million. The bulk of the project cost, $28 million, goes to the procurement and installation of series capacitor at a new station site as a turn-key project. The turn-key contract for the construction of the new Nobel SS is based on detailed tendering specifications and obtained from competitive bids. The remainder of the cost is for the work required to build new infrastructure, such as new towers, to integrate the new Nobel SS into the existing transmission 500 kV circuits X503E and X504E, as well as associated interest charges ("AFUDC"), overheads and contingencies.

The planned in-service for the Nobel SS series capacitors is December 2010, and the anticipated cash flow is shown in Table 1.

Table 1
Project D8 Cash Flow and Total Cost ($ million)

To end of 2008	2009	2010	Total
6	34	7	47

ALTERNATIVES FOR PROJECT D8

Hydro One planners, working in coordination with IESO and OPA staff, looked at a number of alternatives for increasing the transfer capabilities of the North-South ("N-S") Interface and the transmission system north of Sudbury. Different technologies were considered for the regions north of Sudbury (Shunt Compensation, Project D7), and south of Sudbury (Series Compensation, Project D8), as appropriate to the different nature of the problems and system topologies in these two regions.

The following transmission alternatives to Project D8 were considered by Hydro One and rejected for the reasons detailed below:

Alternative 1: Do Nothing.

The "Do Nothing" alternative is not acceptable since the capacity of the existing transmission system is constrained and currently limits the ability to access all of the existing generation north of Sudbury. The "Do Nothing" alternative would constrain the development of planned renewable generation resources in Northern Ontario.

Alternative 2: Install a New 500kV Switching Station.

This alternative involves installing a new 500kV switching station mid-way between Hanmer TS and Essa TS. This alternative would cost about the same as the proposed investment but it would increase the transfer capability by only 100 MW, which is about 70% less than the improvement in transfer capability achieved by the proposed investment. As such, this alternative provides relatively lower benefits for costs that are of the same order of magnitude as the proposed investment.

Alternative 3: Build a New Single Circuit 500kV Line to the GTA.

This alternative involves building a new single circuit 500kV line to connect Hanmer TS to an existing or new 500kV TS in or near the greater Toronto area (GTA). This would increase the transfer capability on the N-S interface by about 1500 MW. Although this alternative provides considerable long-term benefits in terms of the transfer capability and system reliability, and it remains a credible option to provide for longer term requirements, it is about ten times more costly than the proposed investment. Further, this alternative cannot be built in time to meet the in-service date identified by the OPA due to the challenges in obtaining regulatory and environmental approvals.

Ontario Power Authority™

May 20, 2008

Mr. Geoff Ogram
Vice-president,
Asset Management
Hydro One Networks Inc.
483 Bay Street
Toronto, ON
M5G 2C9

Dear Geoff:

Re: Increasing the Transfer Capabilities of the North-South and Sudbury-North Transmission Systems

The purpose of this letter is to recommend Hydro One Networks Inc. to proceed with the installation of series compensation facilities on the Hanmer to Essa 500 kV circuits at Nobel SS, and static and dynamic reactive power resources at Hanmer TS, Kirkland Lake TS, Porcupine TS and Essa TS, for in-service in 2010. These facilities will permit increases in the power transfer capabilities between Sudbury and the GTA (the North-South Tie) and between Timmins and Sudbury to meet the near-term need for incorporating new renewable generation in northern Ontario. These projects are consistent with and a component of the longer term transmission development plan to increase the transfer capabilities along these two power delivery paths to facilitate the development of the large renewable generation potentials in northern Ontario.

The North-South Tie, which comprises two 500 kV circuits between Hanmer TS in Sudbury and Essa TS in Barrie and one 230 kV circuit from Holden GS (east of North Bay) and Des Joachims GS (near Chalk River), is the transmission path by which the surplus generation in northern Ontario is delivered to electricity consumers in southern Ontario. In the past few years, a number of resources developments that came into service in northern Ontario have increased the level of southbound flows on the North-South Tie so that it is operating near its capacity of about 1,300 MW, and occasionally to 1,400 MW with the use of generation rejection. The Ontario Power Authority (OPA) forecasts another 900 MW of new resources, much of it renewables, to be in-service in northern Ontario by 2013. They include:

- the Lac Seul hydroelectric project (12 MW) – 2008
- the Hound Chute hydroelectric project (10 MW) – 2009
- the Upper Mattagami River hydroelectric project (35 MW) – 2009/2010
- the Lower Mattagami River hydroelectric project (450 MW) – 2011/2013

These projects, totalling just over 500 MW, were directed by the Minster of Energy to the OPA with a letter dated December 20, 2007 to assume the responsibility of the Crown and negotiate a financial energy supply agreement with Ontario Power Generation Inc. Thus, there is a high certainty that the above four projects would proceed.

Beyond the projects listed above, other planned generation in that time frame includes additional hydroelectric, wind, and combined heat and power generation that totals to about 400 MW. Although, there are more uncertainties associated with these generation developments, much of these are expected to develop requiring increase in the transfer capability of the North-South Tie.

On the transmission system north of Sudbury, as most of the generation projects related to Minister of Energy direction are located north of Timmins, the transfers on the transmission path from Pinard TS (near Fraserdale) and Sudbury will be significantly increased when they come into service in the 2010 to 2013 period. At this time, this system is already operating at its capability and requires the use of generation and load rejection special protection measures. Additional power transfers will further aggravate the reliability of this regional network.

Thus, in order to facilitate the development of committed and planned renewable and other resources forecast for northern Ontario in the 2010 to 2013 time frame, reinforcement of the North-South Tie and the transmission system north of Sudbury to increase the power transfer capabilities of these systems is required. Because of the urgency to provide the required increased capabilities in the 2010/11 timeframe, options that involve new transmission lines were considered but rejected because of the lead times required to develop these projects. Hydro One Networks, working in coordination with the Independent Electricity System Operator and the OPA, identified the recommended near-term solution for increasing the capabilities of the North-South Tie and the transmission system north of Sudbury as follows:

- Installation of series capacitors for 50% compensation of the Essa TS x Hanmer TS 500 kV lines (X503E and X504E) at Nobel SS at an estimated cost of approximately $ 45 M.

- Installation of a static-var-compensator (SVC) at Porcupine 230 kV TS with +300/-100 MVAr rating and another SVC at Kirkland Lake 115 kV TS with +200/-100 MVAr rating at a total estimated cost of about $ 100 M.

- Installation of two shunt capacitor banks at Porcupine 230 kV TS (125 MVAr @ 220 kV each), one bank at Hanmer 230 kV TS (149 MVAr @220 kV), and one bank at Essa 230 kV TS (182 MVAr @220 kV) at a total estimated cost of about $ 25 M.

Dynamic reactive resources are required in this transmission reinforcement in order to control voltages on the system north of Sudbury and New Liskeard. Increased transfers from Timmins to Sudbury as the result of new renewable generation developments north of Timmins further aggravate the reliability of supply to customers in this area. Hydro One Networks' proposal is to split the SVC need into two installations as described above, one at Porcupine TS in the Timmins area and one at Kirkland Lake TS in the New Liskeard area. This arrangement will provide a dual benefit of being able to control voltages on the 500 kV system north of Sudbury under varying power transfer conditions and provide voltage support to the 115 kV system north of New Liskeard following transmission outages.

The facilities proposed by Hydro One Networks will increase the transfer capabilities of the North-South Tie by 750 MW, from 1,300 MW to 2050 MW, and facilitate the incorporation of planned generation developments in northern Ontario. They will also allow increase in the transfer capability of the transmission system north of Sudbury to facilitate the development of directed hydroelectric development north of Sudbury totalling about 500 MW. They will also be an integral part of long-term developments of this system which ultimately involves installation of new transmission lines to enable further development of renewable generation in northern Ontario.

The OPA recommends that Hydro One Networks Inc. proceeds with the installation of the above transmission facilities immediately to enable the target in-service date ranging from fall 2010 to spring 2011. We understand that the project involving shunt capacitor may involve locating the identified shunt capacitor banks at different transformer stations as further project development work takes place.

Please feel free to contact us should you require any clarification or additional information.

Yours truly,

Amir Shalaby
Vice-President
Power System Planning

cc. Ken Kozlik, the IESO

OPA
Ontario Power Authority

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T 416-967-7474
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August 21, 2009

Mr. Carmine Marcello
Senior Vice President, Asset Management
Hydro One Networks, Inc.
483 Bay Street, 14th floor-north
Toronto, Ontario M5G 2P5

Dear Carmine,

Please find attached the Ontario Power Authority's supporting evidence for the reinforcement projects to the transmission system between Timmins and Barrie. This evidence is provided in response to your June 30, 2009, letter requesting a more fulsome justification of the facilities that the Board did not approve in your 2009-2010 Transmission Revenue Requirement application. The attached evidence provides support for the committed projects that were of particular concern to Hydro One: the series capacitor banks at Nobel SS, and the static var compensators at Porcupine TS and Kirkland TS that the OPA recommended in the May 20, 2008, letter to Hydro One. The evidence also addresses the shunt capacitor banks at Porcupine TS, Hanmer TS, and Essa TS that were also recommended in the May 20, 2008, letter.

The supporting evidence details the information and analysis that the OPA used in its May 2008 recommendation, as well as changes since then that provide continued support for the need of these facilities.

Please feel free to contact us should you require any clarification or further information.

Yours Truly,

R.F. Chow

for Amir Shalaby
Vice-President
Power System Planning

Cc: Bob Chow, OPA
Michael Lyle, OPA
Bruce Campbell, IESO
Kim Warren, IESO
Allan Cowan, Hydro One
Bing Young, Hydro One

THE ONTARIO POWER AUTHORITY'S SUPPORTING ANALYSIS FOR INCREASING THE TRANSFER CAPABILITIES OF THE NORTH-SOUTH AND SUDBURY-NORTH TRANSMISSION SYSTEMS BY 2010

1.0 PURPOSE

The purpose of this document is to provide supporting evidence for the May 20, 2008, letter that the Ontario Power Authority ("OPA") sent to Hydro One Networks Inc. ("Hydro One") recommending that Hydro One proceed with the installation of reinforcements to the transmission system between Timmins and Barrie. This letter was filed in EB-2008-0272 at Exhibit J1.3, Attachment 4. This supporting evidence is filed in response to the Ontario Energy Board's ("OEB") May 28, 2009, decision to not approve the cost recovery of the two projects listed below due to insufficient evidence at that time. The details of these projects are as follows:

- Project D7: Installation of a static-var-compensator (SVC) at Porcupine 230 kV TS with +300/-100 MVAr and another SVC at Kirkland Lake 115 kV TS with +200/-100 MVAr rating
- Project D8: Installation of series capacitors for 50% compensation of the Essa TS x Hanmer TS 500 kV lines (X503E and X504E) at Nobel SS

In the same letter, the OPA also recommended the installation of shunt capacitor banks at three transformer stations, as follows:

- Project D12: Installation of two shunt capacitor banks at Porcupine 230 kV TS (125 MVAr @ 220 kV each)
- Future Project: Installation of one shunt capacitor bank at Hanmer 230 kV TS (149 MVAr @ 220 kV)
- Future Project: Installation of one shunt capacitor bank at Essa 230 kV TS (182 MVAr @ 220 kV)

These five projects will be referred to as the "Reinforcement Projects".

2.0 THE CONTEXT OF THE OPA'S LETTER

This section describes the generation forecast, transmission system limitations, and the rationale for the OPA's recommendation to Hydro One at the time that the letter was written.

2.1 Generation Forecast

On December 20, 2007, the “Hydroelectric Energy Supply Agreements” (“HESA”) directive was issued by the Ministry of Energy. This directive required the OPA to contract with Ontario Power Generation (“OPG”) for the development of several hydroelectric facilities in northeastern and northwestern Ontario. These facilities have a combined capacity of approximately 500 MW. At that time, these facilities were expected to come into service in the 2008 to 2013 timeframe. Table 1 provides the capacity and expected in-service date of the HESA facilities at the time that the OPA issued its letter.

Table 1
Capacity and Expected In-Service Date of HESA Facilities as of May 2008

Site	Capacity (MW)	Expected In-Service Date
Lac Seul	12	2008
Hound Chute	10	2009
Upper Mattagami	35	2009-2010
Lower Mattagami	450	2011-2013
Source: OPA		

The OPA also identified committed and other near-term generation projects that were expected to be developed in Northern Ontario by 2013 in its letter to Hydro One. These resources totaled almost 400 MW and are listed in Table 2 below. This information was included at Exhibit E, Tab 3, Schedule 1 in the Integrated Power System Plan (IPSP), which is application EB-2007-0707.

Table 2
Committed and Other Near-term Generation Projects in Northern Ontario as of May 2008

Site	Type	Capacity (MW)
Committed Resources		
RES I Umbata Falls	Hydro	23
CHP Algoma	Gas	63
Committed RESOP	Wind	140
RES II Island Falls	Hydro	20
Total Committed		**246**
Other Resources		
Alexander	Hydro	1
Espanola	Hydro	16
Cameron Falls	Hydro	4
Mattagami Lake Dam	Hydro	5
Pine Portage	Hydro	2
Ragged Chute	Hydro	4
Gravelle Chute	Hydro	3
At Highway 17	Hydro	3
Trowbridge Falls	Hydro	1
Northern Thunder Bay	Hydro	1
Newpost Creek	Hydro	25
Bentley Creek	Hydro	2
Biomass Atikokan	Biomass	35
Big Beaver Falls	Hydro	11
Biomass northwest	Biomass	10
25.6 – 19.2 km from mouth	Hydro	10
Timmins South	Hydro	1
Total Other Resources		**134**
Total Committed and Other Resources		**380**
Source: OPA		

2.2 Transmission System Limitations

The existing transmission system connection between Northern and Southern Ontario is referred to as the North-South Tie. It is comprised of two 500 kV circuits between Hanmer TS in Sudbury and Essa TS in Barrie and one 230 kV circuit between Holden GS (east of North Bay) and Des Joachims GS (near Chalk River). At the time of the letter, a number of generation resources had already come into service in Northern Ontario which had increased the level of southbound flows on the North-South Tie so that it was operating near its capability of about 1,300 MW. Occasionally, generation rejection had been armed on some generation units in Northern Ontario in order to increase the pre-contingency flows on the North-South Tie to 1,400 MW. As discussed above, the generation forecast indicated that there would be almost 900 MW of new generation resources in Northern Ontario and these additional resources would cause southbound flows on the North-South Tie to greatly exceed its capability.

On May 15, 2007, the Independent Electricity System Operator ("IESO") issued a System Impact Assessment ("SIA") report stating that the implementation of the Reinforcement Projects would allow the major HESA facilities listed in Table 1 to be connected to the system, as well as other near-term generation resources. In addition, these projects would provide the dynamic reactive support that is required to control post-contingency voltages on the power system North of Sudbury. The SIA was filed in Hydro One's rate case as Exhibit I-1-61, Attachment 1 and was also filed in the IPSP at Exhibit E-3-1, Attachment 1. An addendum to this SIA was issued by the IESO on August 15, 2007, and this was filed in the IPSP at Exhibit E-3-1, Attachment 2.

2.3 Rationale for the OPA's Recommendation

At the time that the OPA issued its recommendation to Hydro One, the HESA generation resources were intended to support meeting system adequacy after coal-fired generation was phased out. The June 13, 2006, directive to the OPA on the IPSP goals stated that the OPA should "[plan] for coal-fired generation in Ontario to be replaced by cleaner sources in the earliest practical time frame that ensures adequate generating capacity and electric system reliability in Ontario." Delays to transmission projects could delay the incorporation of the HESA facilities and other generation resources in Northern Ontario that were expected to replace coal-fired generation. The OPA aimed to mitigate the impact of delays to transmission projects by targeting for transmission projects to come into service in advance of when generation projects would require additional transmission capability to connect to the power system.

Furthermore, over 250 MW of the non-HESA generation resources were expected to come into service by 2010. These resources were expected to increase the southbound flow on the North-South Tie, which would require an increased capability by 2010.

Several directives also required the OPA to procure for, and plan for the utilization of, renewable resources. The June 13, 2006, directive on the IPSP goals required the OPA to plan to increase Ontario's use of renewable energy. The August 27, 2007, directive required the OPA to procure up to 2,000 MW of Renewable Energy Supply by 2011. It was expected that these targets for renewable development would be met in part by the development of resources in Northern Ontario. However, resources in Northern Ontario can only be developed and utilized if there is capability available on the North-South Tie.

For the above reasons, the OPA determined that the capability of the North-South Tie would need to be increased by 2010.

Next, the OPA considered two basic alternatives to increase the capability of the North-South Tie: (a) the implementation of the Reinforcement Projects, and (b) the construction of a new transmission line.

The OPA determined that the implementation of the Reinforcement Projects was preferable to a new transmission line for three major reasons. First, the Reinforcement Projects maximize the capability of the existing transmission system without the need for additional right-of-way. Second, these projects require a shorter timeline for installation than a new line, and therefore have a lower exposure to risks of delay that could prevent the incorporation of critical generation facilities. Finally, these projects provide more flexibility than a new transmission line because they provide a smaller incremental increase in transmission capability and do not prevent the installation of a new transmission line at a later time if it is needed. The Reinforcement Projects would continue to provide on-going value should the capability of the North-South Tie be scaled up to meet future development. Therefore, the OPA determined that the implementation of the Reinforcement Projects was preferable to the construction of a new transmission line.

On this basis, the OPA recommended that Hydro One proceed with the installation of the Reinforcement Projects by 2010.

3.0 CHANGES SINCE THE OPA ISSUED ITS RECOMMENDATIONS

Since the OPA issued its letter in May 2008, new government policies and changes in generation development timelines have continued to support the need to increase the capability of the North-South Tie. These changes are detailed below.

There have been revisions to the expected in-service dates of the HESA and other generation projects. These changes are summarized for the HESA resources in Table 3. The total capacity of the other generation resources expected to be in-service by 2013 has increased from about 400 MW to over 700 MW, including an increase in committed resources from about 250 MW to almost 400 MW, as shown in Table 4. In particular, OPG's intention to convert the Thunder Bay and Atikokan coal-fired generation plants to biomass facilities has resulted in a significant increase in the near-term generation capacity expected to come into service in Northern Ontario. The hydroelectric resources that could be developed in the longer-term, but are no longer expected to be in-service by 2013, are shown in Table 5 below. Note that the capacities of some of the sites listed in Tables 4 and 5 have been updated with the latest available information.

Table 3
Capacity and In-Service Date of the HESA Sites as of May 2008 and Today

Site	Capacity (MW)	Previous Expected In-Service Date	Current Expected In-Service Date
Lac Seul	12	2008	In-service
Hound Chute	10	2009	2010
Upper Mattagami	35	2009-2010	2010
Lower Mattagami	450	2011-2013	2014
Source: OPA			

Table 4
Committed and Other Near-Term Generation Projects in Northern Ontario as of Today

Site	Type	Capacity (MW)
In-Service and Committed Resources (Note 2)		
RES I Umbata Falls	Hydro	23
CHP Algoma	Gas	63
In-Service RESOP	Various	5
Committed RESOP	Various	177
RES II Island Falls	Hydro	20
Biomass northwest	Biomass	(Note 1)
RES III Greenwich Windfarm	Wind	99
Total Committed		**387**
Other Resources		
Cameron Falls	Hydro	4
Namewaminikan - 8 km & 12.8 km	Hydro	10
Alexander	Hydro	1
Mattagami Lake Dam	Hydro	6
Pine Portage	Hydro	4
Biomass Atikokan	Biomass	200
Thunder Bay Biomass	Biomass	150
Total Other Resources		**375**
Total by 2013		**762**

Source: OPA
Note 1: This site was included separate from the RESOP potential in the May 20, 2008 letter, but has since been contracted for through RESOP and is included in the committed RESOP site in this Table.
Note 2: Not all in-service resources are included in this Table. Only the resources that were included in May 20, 2008 letter that have since come into service are included in this Table.

Table 5
Hydroelectric Resources Included in the May 20, 2008, Letter that are no Longer Expected to Develop by 2013

Site	Type	Capacity (MW)
Espanola	Hydro	16
Ragged Chute	Hydro	4
Gravelle Chute	Hydro	2
At Highway 17	Hydro	2
Trowbridge Falls	Hydro	1
Northern Thunder Bay	Hydro	1
Newpost Creek	Hydro	25
Bentley Creek	Hydro	1
Big Beaver Falls	Hydro	11
25.6 - 19.2 km from mouth	Hydro	10
Timmins South	Hydro	1
	Total	**74**
Source: OPA		

The OPA has contracted for over 350 MW of generation resources in Northern Ontario that have come into service since May 2008 or are expected to come into service by 2010. These resources will increase southbound flows on the North-South tie beyond its capability and therefore require the Reinforcement Projects to be installed by 2010.

Furthermore, the Green Energy and Green Economy Act ("GEGEA") identifies the Government's goal "to increase the availability of renewable energy in Ontario and increase the use of renewable energy sources in Ontario." The expected launch of the Feed-in Tariff ("FIT") program, a component of the GEGEA, has increased the expectation for renewable generation development across the Province, including in Northern Ontario. Generation resources contracted through the FIT program could come into service as early as 2011 or 2012 if there is available transmission capability. As described in Section 2.2, the existing transmission system between Northern and Southern Ontario is already fully utilized and therefore any additional generation will require the reinforcement of this transmission system. The Reinforcement Projects are therefore required by 2010, as scheduled, to allow the connection and utilization of new renewable resources.

4.0 CONCLUSION

In May 2008, the OPA recommended that Hydro One proceed with the Reinforcement Projects based on the capability of the existing transmission system and the generation resources expected to come into service at that time. Although some of the expected in-service dates of the generation resources have changed, the OPA expects a large amount of near-term resources to come into service that will require these transmission reinforcements. Further, the OPA anticipates that the FIT program will yield significant interest in renewable generation development in Northern Ontario. Without the Reinforcement Projects, there will not be enough transmission capability available to allow new renewable resources to come into service in the near-term through this program. Therefore, the OPA still recommends that the Reinforcement Projects should be implemented by 2010.

OPA
Ontario Power Authority™

June 1, 2009

Mr. Carmine Marcello
Senior Vice-President
Asset Management & Corporate Projects
Hydro One Networks Inc.
483 Bay Street
Toronto, ON
M5G 2C9

Dear Carmine:

Re: Installation of Reactive Power Facilities at Mississagi TS and Algoma TS

The purpose of this letter is to express OPA's support of Hydro One Networks Inc.'s intent to install the following reactive power facilities to improve the transfer capability east of Mississagi TS, for in-service by December, 2011:

- a 90 MVAr 230 kV shunt capacitor bank at Algoma TS;
- 2 x 75 MVAr 230 kV shunt capacitor banks at Mississagi TS;
- a -100/+300 MVAr 230 kV Static Var Compensator (SVC) at Mississagi TS.

The transmission path between Mississagi TS (located in the Algoma District) and the Sudbury area comprises three 230 kV circuits and is referred to as the Sudbury-West transmission system. Together, these circuits provide the capability to transmit power surpluses from the Sault Ste. Marie/Algoma area west of Sudbury to Sudbury.

Presently, there is a sizeable level of power surplus in the Sault Ste. Marie/Algoma area. The forecast for this area is for more renewable resource development as well as other areas west of Sudbury, all heightened by the expected launch of the Feed-in Tariff Program for renewable resources in the coming months. These locations have considerable wind and other renewable resource potentials, and are supported by expressed interests of developers.

Existing renewable and co-generation resources in the Sault Ste. Marie/Algoma area total about 1,100 MW (not including another 120 MW of existing gas-fired generation located in Sault Ste. Marie). As well, the transmission line connecting the system in northwestern Ontario to the Sudbury-West system is capable of delivering another 325 MW into this area from the west. The demand in this area, mostly at Sault Ste Marie, peaks at about 400 MW. Thus, the range of peak power transfers that could flow along the Sudbury-West path into Sudbury is estimated to be between 700-1100 MW depending on the coincidental operation of wind, hydro and other generation in the area, transfers from the northwest along the East-West Tie and the demand in the Sault Ste. Marie/Algoma area.

The Independent Electricity System Operator (IESO) has established the transfer east capability of the Sudbury-West transmission system to be about 670 MW. This would be increased to about 800 MW when the Nobel SS series capacitors come in-service in 2010, assuming that adequate reactive power support is provided by existing local hydro units or other reactive resources connected to Mississagi TS.

Therefore, given the level of transfers that could prevail and the transfer capability that the Sudbury-West has, considerable congestion could result on this path. This could constrain the output from renewable generating resources if reinforcement to the Sudbury-West transmission system is not provided.

Furthermore, there has been significant interest with regard to new wind and other renewable generation developments in locations west of Sudbury. A possible long-term solution to increase the transfer capability for this area involves the construction of a new transmission line between Mississagi TS and Hanmer TS (located near Sudbury). This line would initially be operated at 230 kV and would then be converted to 500 kV operation when warranted. The implementation of the the first and second stages of the long-term solution would be determined by the level of renewable generation developed in the area. For the near-term, the installation of the subject reactive power facilities by Hydro One Networks will maximize the capability of the existing Sudbury-West transmission system. With these proposed facilities, the IESO has established that the Sudbury-West transfer capability would increase by about 300 MW, from 800 MW to 1,100 MW. The benefits of the proposed reactive facilities would endure for the longer term since these facilities would still be required even after the new line west of Sudbury is built but initially operated at 230 kV as proposed.

A joint study of the OPA, Hydro One Networks and the IESO has also established that the SVC needed at Mississagi does not need to have continuous variable control capability with their reactive power output. Therefore, the SVC could comprise mechanically switched reactors and thyristor-switched capacitor banks adjusting their reactive output in discrete steps. Minimal filtering would be required. Such device has a lower cost than those which provide a continuous variable controlled output.

The cost of the reactive power facilities estimated by Hydro One Networks is approximately $90 million, including contingencies, overhead and interest. The projected in-service date of these facilities is December 2011.

The OPA supports this proposed solution to provide reactive support and voltage regulation of transmission system west of Sudbury in a cost-effective and timely manner.

Please feel free to contact us should you require any clarification or additional information.

Yours truly,

Amir Shalaby

Vice-president, Power System Planning
Ontario Power Authority

cc.	Ken Kozlik	IESO
	Bob Chow	OPA

IESO_REP_0379

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CONNECTION ASSESSMENT & APPROVAL PROCESS

SYSTEM IMPACT ASSESSMENT REPORT

For the Proposed Installation of:

Series Capacitors in the 500kV Circuits X503E & X504E at Nobel TS
SVCs at Porcupine TS & Kirkland Lake TS

Applicant: *Hydro One Networks Inc.*

CAA ID Nos.	***2004-160***	*Series Capacitors at Nobel TS*
	2006-223	*SVCs at Porcupine TS & Kirkland Lake TS*

Transmission Assessments & Performance Department

FINAL Version

Date: *15th May 2007*

System Impact Assessment Report

For the Installation of:
Series Capacitors in the 500kV Hanmer TS to Essa TS circuits, and
Static VAr Compensators at Porcupine TS and Kirkland Lake TS

Acknowledgement

The IESO wishes 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 Hydro One Networks Inc. 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 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 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 the most recent version of this report is being used.

Hydro One

Special Notes and Limitations of Study Results

The results reported in this system impact assessment are based on the information available to Hydro One, at the time of the study, suitable for a system impact assessment of a new transmission facility.

HYDRO ONE NETWORKS Inc.

SYSTEM IMPACT ASSESSMENT REPORT

For the Installation of:

Series Compensation in the 500kV Hanmer TS to Essa TS Circuits, and
Static VAr Compensators at Porcupine TS and Kirkland Lake TS

EXECUTIVE SUMMARY

1. Introduction

With all transmission facilities in-service, operation of the generating facilities in North-eastern and North-western Ontario during peak periods is governed primarily by the existing transfer limits on the following transmission Interfaces that have been identified in Diagram Exec 1:

Interface		*Present Transfer Limit*
East-West Transfer East	[measured at Wawa TS]	325MW
Mississagi (East Circuits) Flow-East	[measured at Mississagi TS]	550MW
Flow-South	[measured at Essa TS & Otto Holden GS]	1400MW

A review of the *existing* generating facilities in the North-east of the Province, as far west as Wawa TS, indicates a total installed capacity of **3370MW**. This includes the two Prince Wind Farm Projects; the ongoing development of Yellow Falls GS; the proposed redevelopment of the Upper Mattagami River plants (27MW); as well as a nominal 25MW injection at Iroquois Falls from the Abitibi Price system.

With a transfer across the East-West Transfer East Interface at the present operating limit of 325MW, those facilities west of Mississagi TS would result in a transfer of approximately 1030MW across the Mississagi Flow-East Interface. This would exceed the operating limit of this Interface by 480MW.

The corresponding transfer across the Flow-South Interface would be approximately **2170MW**: this would exceed the present operating limit for this Interface by 770MW.

The proposed expansion of the generating facilities at the Lower Mattagami River plants, representing a net increase in capacity of 433MW, would increase the peak transfer across the Flow-South Interface to **2500MW**.

Even if the existing limit of 550MW for transfers across the Mississagi Flow-East Interface were to be respected, then the expansion of the generating facilities at the Lower Mattagami River plants could still result in a peak transfer of **2100MW** across the Flow-South Interface.

Hydro One has therefore submitted a proposal for review under the Connection Assessment process involving the installation of the following facilities:

- Static VAr Compensators (SVCs) at Porcupine TS and Kirkland Lake TS, and
- Series capacitors at Nobel SS in each of the 500kV circuits X503E & X504E between Hanmer TS and Essa TS. These are to provide 50% compensation for the line reactance.

These facilities are intended to increase the transfer capability across the Flow-South Interface to approximately 2100MW. This would then be sufficient to accommodate all of the existing generating facilities north of Sudbury together with the proposed expansion of the Mattagami River plants, while restricting transfers across the Mississagi Flow-East Interface to the present limit of 550MW.

2. *Expansion of the Mattagami River Plants*

To accommodate the additional output from the generating facilities on the Mattagami River it has been determined that a new 230kV busbar would be required at Little Long SS so that the two 230kV circuits to Pinard TS could be individually terminated on to the new busbar. This would then result in equal loading on each 230kV circuit and ensure that the flows would remain within their continuous summer rating.

Similarly the existing 230kV circuit that currently terminates at Harmon GS would need to be extended to Kipling GS so that the existing and the proposed generating facilities could then be distributed between the two 230kV circuits. Not only would this balance the loading on each circuit, but it would ensure that a contingency involving either of the circuits would not result in the isolation of all three generating units at any of the four generating plants.

In addition, to compensate for the increased transmission losses, it was determined that a 100MVAr shunt capacitor bank would need to be installed at both Little Long GS and Pinard TS.

These new facilities have been assumed to be an integral part of the facilities associated with the expansion of the Mattagami River plants and while they were included in the system models that were used for the analysis for this Assessment, they are not considered to be included in the facilities for which Hydro One is presently seeking connection approval.

3. *Transfers across the Mississagi Flow-East Interface*

The existing Mississagi Special Protection System (SPS) is presently only capable of initiating generation rejection in response to the simultaneous loss of the two of the 230kV circuits between Mississagi TS and Algoma TS (circuits A23P, A324P & X74P) or between Algoma TS and the Sudbury area (circuits S22A, X27A & X74P).

The proposed expansion of this SPS to allow generation rejection to be initiated in response to single-circuit contingencies would allow higher pre-contingency transfers to occur across the Mississagi Flow-East Interface.

However, analysis has shown that once the transfers across this Interface exceed 890MW, transient stability cannot be maintained between the generation capacity west of Sudbury and the rest of the system, following a contingency involving the 500kV circuit P502X between Hanmer TS and Porcupine TS.

This analysis has also shown that with additional reactive power support, consisting of a +300/-100MVAr SVC at Mississagi TS together with a 100MVAr shunt capacitor bank at both Mississagi TS and Algoma TS, the transfer capability across this Interface could be increased to approximately 1030MW.

This would be sufficient to accommodate all of the existing generating facilities west of Mississagi TS, including the Prince I & II Projects, together with a maximum transfer of 325MW across the East-West Transfer East Interface at Wawa TS.

4. *Transfers across the Flow-South Interface*

i. With the new facilities as originally proposed

With the following new facilities in-service, analysis has shown that, subject to the automatic rejection of approximately 500MW of generating capacity in the Moose River basin immediately post-contingency, transient stability for a contingency involving one of the Hanmer TS-to-Essa TS 500kV circuits could be maintained for a pre-contingency transfer of up to **2150MW** (after allowing for a margin of 10%) across the Flow-South Interface:

- the proposed series capacitors at Nobel SS, together with the SVCs at Porcupine TS and Kirkland Lake TS
- the local facilities identified for the proposed expansion of the Lower Mattagami River plants

  i.e. a new 230kV busbar at Little Long GS plus a 100MVAr shunt capacitor bank at both Little Long GS & Pinard TS

Following the automatic rejection of 500MW of generating capacity, the post-contingency transfer across the Flow-South Interface would be reduced to approximately 1780MW. Since the Power-Voltage analysis for the system conditions with the same facilities in-service as detailed above has shown that post-contingency voltage stability could be maintained for a post-contingency transfer of up to 1921MW, the requirements for maintaining transient stability would therefore be more limiting than those for voltage stability.

The enhanced transfer capability provided by the installation of these new facilities would be adequate to accommodate all of the **existing & committed** generating facilities north of Sudbury together with an increase of **433MW** in the output from the expanded Mattagami River plants, and with a simultaneous transfer of approximately **600MW** across the Mississagi Flow-East Interface i.e. approximately 50MW above the present operating limit of 550MW for this Interface.

ii. With the new facilities as originally proposed, together with additional reactive power support on the north-south corridor

With additional reactive power support at both Mississagi TS and Algoma TS, the analysis has shown that the transfer capability across the Mississagi Flow-East Interface could be increased to 1030MW. However, with the facilities as originally proposed by Hydro One, the transfers across the Flow-South Interface would still be limited to 2150MW. This would therefore mean that the transfers across the Mississagi Flow-East Interface would need to be restricted to only 600MW whenever peak transfers are being made from the generating facilities north of Sudbury.

To increase the transfer capability of the Flow-South Interface to 2500MW (after margin) so that all of the existing and committed generating facilities both north and west of Sudbury could be accommodated, together with a maximum transfer of 325MW across the East-West Transfer East Interface, the analysis has shown that additional shunt capacitor banks would be required at the following locations, with the ratings that have been indicated:

• Porcupine TS	2 x 125MVAr shunt capacitor banks	rated at 220kV
• Hanmer TS	a 2nd 149MVAr shunt capacitor bank	
• Essa TS	a 2nd 182MVArshunt capacitor bank	

With these additional facilities in place, 560MW of generating capacity in the Moose River basin would need to be rejected in response to an X503E (or X504E) contingency to maintain post-contingency transient stability. With this amount of generation capacity rejected, the resulting post-contingency transfer across the Flow-South Interface would be approximately 2040MW. Since the PV-analysis has shown that the maximum post-contingency transfer across the Flow-South Interface for which voltage stability could be maintained would be approximately 2238MW (after margin), the requirements for transient stability would therefore remain more restrictive than those for voltage stability.

Potential Impact on NPCC Utilities

For transfers of over 2000MW across the Flow-South Interface, a failure of the North-east Special Protection System (SPS) to initiate the required amount of generation rejection could result in transient and/or voltage instability, leading to separation of the system across the North-South Interface. Since the resulting resource deficiency in southern Ontario would be expected to have an adverse impact on the systems of our neighbouring utilities, this would result in that the portion of the SPS that responds to an X503E or X504E contingency being classified as a Type I SPS.

In anticipation of this future classification, it is therefore recommended that those facilities associated with X503E and X504E contingencies be fully duplicated to meet the NPCC requirements for a Type I SPS.

5. Transmission facilities north of Sudbury

With the expansion of the Mattagami River generating facilities and the incorporation of the 20MW facility at Yellow Falls GS, the flow via circuit H9K into Hunta SS was shown to increase. This has the effect of increasing the loading on circuits H6T & H7T into Timmins TS from Hunta SS so that their continuous summer ratings would be exceeded. This overloading could be further aggravated should the Upper Mattagami plants following their conversion from 25Hz to 60Hz operation be incorporated into La Forest DS, displacing some of the load supplied from this supply point.

It has therefore been recommended that the section of the 115kV circuits H6T & H7T between La Forest Junction and Timmins TS be uprated to at least 100^{o}C so that its rating would be comparable to that of the section between Tower 5 and Tower 280.

Furthermore, should the Upper Mattagami Plants be incorporated into the LV system of La Forest DS it may be prudent to increase the rating of this section of circuits H6T & H7T beyond 100^{o}C to accommodate a possible power injection into the 115kV system at La Forest DS.

5.1 Contingencies Involving the 500kV circuits north of Hanmer TS

500kV Circuit D501P between Porcupine TS and Pinard TS

The proposed expansion of the Mattagami River plants would result in a maximum transfer across this Interface of approximately **1300MW.**

With transfers at this level, generation rejection totalling approximately 1300MW would therefore be required in response to a contingency involving the 500kV circuit D501P. In addition, the 230kV circuits H22D, L20D & L21S would need to be cross-tripped. This would result in the capacitor banks at Little Long GS and Pinard TS being automatically disconnected.

In addition, the existing capacitor bank at Hanmer TS, together with the capacitor banks that have been proposed for installation at both Porcupine TS and Hanmer TS to achieve a Flow-South transfer capability of 2500MW, would also need to be tripped.

500kV Circuit P502X between Hanmer TS and Porcupine TS

Following the proposed expansion of the Mattagami River plants, the maximum transfer across this Interface would increase to approximately **1600MW**.

With transfers at this level, a subsequent contingency involving the 500kV circuit P502X would require approximately 1600MW of generation capacity to be rejected, together with the cross-tripping of the 500kV circuit D501P and the 230kV circuits H22D, L20D & L21S, to maintain post-contingency transient stability.

In addition, if further capacitor banks were to be installed to achieve a Flow-South transfer capability of 2500MW, then the new capacitor banks at Porcupine TS together with one of the capacitor banks at Hanmer TS would need to be tripped.

The rejection of 1600MW, which would represent a net resource deficiency of approximately 1500MW after taking account of the associated change in the transmission losses, would then represent the single largest contingency condition on the IESO-controlled grid and would require a corresponding increase in both the 10-minute and 30-minute operating reserves.

6. IESO-Requirements & Recommendations

As a result of the analysis performed for this Assessment, the following requirements were identified:

- Modify the existing Under-Frequency Load Shedding Schemes so that all of the loads in the area north of, and including Timmins are only associated with the Stage 2 portion of these Schemes.
- Review the protective relaying on the following circuits and modify as necessary to avoid inadvertent tripping in response to an external fault:

115kV Circuits:	D3K (Dymond TS to Kirkland Lake TS); A4H & A5H (Hunta SS to Ansonville TS); A8K & A9K (Ansonville TS to Kirkland Lake TS)
230kV Circuit:	W71D (Dymond TS to Widdifield SS)

- Obtain appropriate dynamic models for the SVCs that faithfully represent their behaviour so that additional studies can be performed to confirm that the recommended settings will avoid excessive post-contingency over-voltages at the associated busbars.
- Modify the NE Load & Generation Rejection Scheme to provide the required cross-tripping features, as well as the ability to arm the individual shunt capacitor banks for automatic tripping.

  In addition, the NE Load & Generation Rejection Scheme is to have the capability of initiating the rejection of each stage of the Prince Wind Farm development individually in response to a 500kV contingency involving either circuit X503E or circuit X504E.

  These new facilities, together with those existing facilities that are associated with an X503E or X504E contingency, are required to be fully duplicated to meet the requirements for possible future classification as a Type I SPS
- Perform tests on the NE Load & Generation Rejection Scheme to determine definitive time delays for the rejection of the various generating units covered by the Scheme for each of the contingency conditions that are respected.

  Should the time delays obtained from these tests vary significantly from those assumed in this assessment then it may be necessary to perform additional analysis to determine the effect that they would have on the post-contingency performance of the system.
- Uprate the 500kV circuits E510V & E511V between Essa TS and Claireville TS.
- Uprate the section of 115kV circuits H6T & H7T between La Forest Junction and Timmins TS.

7. Customer Impact Assessment

A Customer Impact Assessment is to be performed once a formal decision is made to proceed with the installation of the series capacitors at Nobel TS, together with the SVCs at Porcupine TS and Kirkland Lake TS.

Should any other major issues be identified through the CIA process then these will be addressed through an Addendum to this SIA Report.

8. Notification of Approval of the Connection Proposal

Subject to the completion of the Customer Impact Assessment and satisfying all of the requirements detailed in Section 6 above, the IESO has concluded that the following work will have no materially adverse effect on the IESO-controlled grid:

- the installation of series capacitors at Nobel TS in each of the Hanmer-to-Essa TS 500kV circuits to provide 50% compensation for the line reactance.

- the installation of a 230kV-connected SVC at Porcupine TS, rated at +300/-100MVAr
- the installation of a 115kV-connected SVC at Kirkland Lake TS, rated at +200/-100MVAr

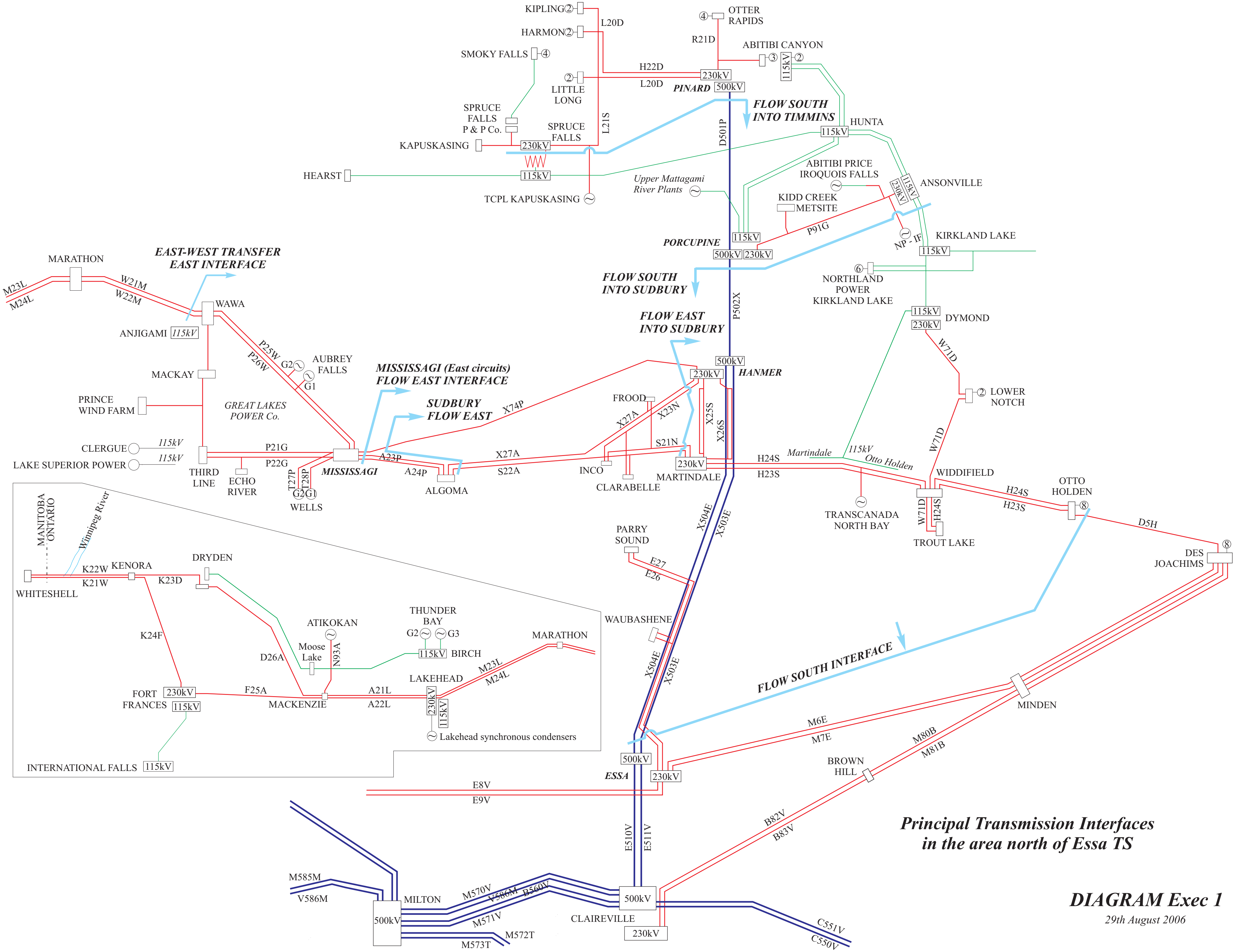
It is therefore recommended that a Notification of Conditional Approval to Connect be issued for this work.

This approval is also to cover the following work:

- The uprating of the 500kV circuits E510V & E511V between Essa TS and Claireville TS
- The uprating of the section of the 115kV circuits H6T & H7T between La Forest Junction and Timmins TS
- The modification of the NE Load & Generation Rejection Scheme
- The modification of the Under-Frequency Load-Shedding Schemes in the north-east

Approval for those facilities directly associated with the following are expected to be the subject of separate Assessments and are therefore not included in this Notification of Conditional Approval:

- The enhancement of the Mississagi Flow-East Interface
- The incorporation of the additional generating facilities at the expanded Mattagami River plants, and
- The installation of additional shunt capacitor banks to increase the Flow-South transfer capability from 2150MW to 2500MW.



Principal Transmission Interfaces in the area north of Essa TS

DIAGRAM Exec 1

29th August 2006

HYDRO ONE NETWORKS Inc.

SYSTEM IMPACT ASSESSMENT REPORT

For the Installation of:

Series Compensation in the 500kV Hanmer TS to Essa TS Circuits, and
Static VAr Compensators at Porcupine TS and Kirkland Lake TS

1. Introduction

Transfers to southern Ontario are already being constrained by the present operating limit of 1400MW for transfers across the Flow-South Interface. With the award of the following contracts under the Government of Ontario's initiative for new renewable resources in the north-east, the extent of the possible constraints will worsen:

- *Renewables I RFP*
    - The Prince I Wind Farm, with a capacity of 99MW, located in Prince Township near Sault Ste. Marie.
- *Renewables II RFP*
    - The Island Falls Hydroelectric Project, with a capacity of 20MW, located near Smooth Rock Falls on the Mattagami River.
    - The Prince II Wind Farm, with a capacity of 90MW, located adjacent to the Prince I Wind Farm in Prince Township.

Should approval be given to proceed with the planned expansion of the Mattagami River Plants then the transfer capability of the existing transmission facilities will need to be enhanced to address not only the existing constraints but also to accommodate the additional generating capacity from this hydroelectric development.

After accounting for the planned shut-down of the existing 52MW Smoky Falls generating station, the expansion of the Mattagami River plants is expected to result in a net increase of 432MW in the generating capacity in the north-east.

To achieve the necessary increase in the transfer capability over the transmission system south of Hanmer TS in Sudbury, Hydro One is proposing to install the following facilities:

- Series capacitors in each of the 500kV circuits X503E & X504E, to provide a 50% level of compensation. The series capacitors are to be located at Nobel TS, which is the approximate mid-point of these circuits.

- A Static VAr Compensator (SVC) at Porcupine TS, rated at +300/-100MVAr and connected to the 230kV busbar via a dedicated step-up transformer.

- A further SVC at Kirkland Lake TS, rated at +200/-100MVAr and connected to the 115kV busbar via a dedicated step-up transformer.

This assessment summarises the results of the IESO's analysis and identifies the IESO's requirements for incorporating the proposed facilities into the IESO-controlled grid.

1.1 Combined Heat & Power Contracts

Although not included in the analysis supporting this assessment, the 63MW co-generation facility at the Algoma Steel Mill in Sault Ste. Marie that was awarded a contract by the OPA on 16th October 2006 will further increase the transfers across the Flow-South Interface.

This Project is scheduled to be in full commercial operation during the second quarter of 2009.

2. *Operational Interfaces*

Diagram 1 shows the principal transmission facilities in the area north of Essa TS in Barrie. For clarity, most of the 115kV transmission facilities have been omitted together with most of the smaller generating facilities.

The principal Interfaces that govern the operation of the IESO-controlled Grid within this area are as follows:

i. Flow-South/Flow-North Interface -

Representing the combined flow on the 230kV circuit D5H, measured at Otto Holden GS, and on the 500kV circuits X503E & X504E, measured at Essa TS.

ii. East-West Transfer Interface -

Representing the combined flow on the 230kV circuits W21M & W22M, measured at Wawa TS

iii. Transfer at Mississagi Interface -

Representing the combined flow on the 230kV circuits A23P, A24P & X74P, measured at Mississagi TS.

iv. Sudbury Flow-East & Flow-West Interface - (Measured at both Mississagi TS and Algoma TS)

Representing the combined flow on the 230kV circuit X74P, measured at Mississagi TS, and on the 230kV circuits S22A & X27A, measured at Algoma TS.

This assessment has also adopted an arbitrary Interface to measure the combined flow into Sudbury from the west. This Interface has been designated the *Flow-East into Sudbury Interface* and it represents the combined flow on the following circuits:

v. Flow-East into Sudbury - (Measured at both Hanmer TS and Martindale TS)

Representing the combined flow on the 230kV circuits X74P & X27A, measured at Hanmer TS, and S22A, measured at Martindale TS.

In addition, the selection of appropriate responses within the North-east Load & Generation Rejection (NE LGR) Scheme for contingencies involving the 500kV system north of Sudbury is governed by the transfers over the following Interfaces:

vi. Flow-South (or Flow-North) into Sudbury:

Representing the combined flow on the 500kV circuit P502X, measured at Porcupine TS, and on the 115kV circuits A8K & A9K, measured at Ansonville TS.

vii. Flow-South (or Flow-North) into Timmins:

Representing the combined flow on the 500kV circuit D501P, measured at Pinard TS, and through the 230/115kV auto-transformer T7 at Spruce Falls TS.

Except for the new *Flow-East into Sudbury* Interface (item v), the present operating limits for each Interface, with all elements in-service, for the condition with flows eastwards on the East-West Ties and for flows southwards on the north-east system, are shown in the following Table:

Summary of Existing Operating Limits for the Study Area: *With all elements in-service pre-contingency*			
	Interface	***Present Limit***	***Critical Contingency***
•	Flow-South Transfer	*1400MW:* with 100MW of generation rejection *1300MW:* with no generation rejection	Loss of one of the 500kV circuits between Hanmer TS & Essa TS
•	East-West Transfer East	*325MW*	Loss of one of the 230kV circuits between Marathon TS & Wawa TS
•	Mississagi (East Circuits) Flow-East	*550MW*	Loss of the 230kV circuit X74P between Mississagi TS & Hanmer TS
•	Sudbury Flow-East	*No existing limit*	-
•	Flow-South into Timmins	*No existing limit -* Generation rejection required to maintain the post-contingency flow through Spruce Falls TS to the 115kV busbar to 75MW or to 20MW to the 230kV busbar AND/OR To maintain the post-contingency flow on 115kV circuit H9K to within ± 80MW.	Loss of the 500kV circuit D501P
•	Flow-South into Sudbury	*For Flow-South >650MW:* Cross-trip 500kV circuit D501P & 230kV circuit L21S and initiate generation or load rejection to maintain the post-contingency flow on circuits A8K & A9K to within 40MW south & 50MW north *For Flow-South >40MW & ≤ 650MW:* Initiate generation or load rejection to maintain the post-contingency flow on circuits A8K & A9K to between 0MW & 40MW south	Loss of the 500kV circuit P502X

3. *Thermal Ratings of the Existing Transmission Facilities*

The thermal ratings of the principal transmission facilities that were used in this assessment have been summarised in Appendix A.

For all of these facilities that are contained within the area north of Barrie (Essa TS), the ratings have been determined using an ambient temperature of **30^{o}C**, with a wind-speed of 4km/hr.

4. *System Conditions Recorded on 30th May 2006*

On 30th May 2006, when a transfer of 1411MW was recorded across the *Flow-South* Interface, a snapshot of the prevailing system conditions was taken. This Flow-South would have been slightly in excess of the existing operating limit of 1400MW for this Interface.

At the time that the snapshot was taken the primary demand was approximately 24100MW.

Diagram 2 shows the results from a load flow study that has attempted to reproduce the flows and the generation despatch that were recorded for this peak *Flow-South* transfer. For this condition, the recorded transfer across the *East-West Transfer East* Interface was **241MW**, while the net transfers into Ontario across the Manitoba/Minnesota Interconnections were 147MW

As shown, the generation capacity that was despatched within the north-east area totalled **2456MW** while for the north-west a total of 876MW of generation capacity was despatched.

As summarised below, the load flow results show a close correlation with the various transfers that were recorded:

Interface	*Recorded Transfers*	*Load Flow Results*
Flow-South Interface	1411MW	1411MW
Manitoba-Minnesota Transfer	147MW	149MW
East-West Transfer East	241MW	244MW
Mississagi (East Circuits) Flow-East	636MW	639MW
Flow-South into Hanmer	760MW	761MW
Flow-West from Dryden & Fort Frances	190MW	194MW

The Diagram also shows the loads that had to be assumed for both the north-east and the north-west, together with the resulting transmission system losses, to achieve flow distributions similar to those recorded on 30th May 2006.

For the north-west, the total load from the study was 701MW, which together with the transmission losses of 71MW, would result in a primary demand of 772MW for the area. This is approximately 11MW less than the primary demand that was actually recorded.

Similarly for the north-east, the total load from the study was 1132MW. With losses of 145MW, this would result in a primary demand of 1277MW. Since the primary demand that was recorded for the north-east was 1329MW, this suggests that the load in the load flow is understated by approximately 50MW.

It should also be noted that although the transfer of 636MW that was recorded across the *Mississagi (East Circuits) Flow-East* Interface on 30th May 2006 would have exceeded the present operating limit of 550MW for this Interface, a temporary, emergency operating limit of 650MW had been introduced specifically for the condition when all four generating units at Aubrey GS and Wells GS were in-service. Furthermore, this transfer occurred when the corresponding *East-West Transfer West* was only 241MW. Had this latter transfer been at its limiting value of 325MW, then this would have increased the *Mississagi Flow-East* transfer to approximately 720MW; approximately 170MW over the present operating limit, and 70MW over the emergency limit.

It is also worth noting that at the time the snapshot of the various system flows was taken, the Abitibi Price mill at Iroquois Falls was injecting 19MW into the system from their generating facilities.

5. Examination of the Existing System Constraints

The preceding load flow study that attempted to replicate the system conditions of 30th May 2006 was performed with the generating resources that were actually dispatched at the time the snapshot was taken. For the north-east these resources totalled 2456MW, with a further transfer of 241MW eastwards across the East-West Ties.

Since the available resources in the north-east are significantly higher and since the transfer capability of the East-West Ties is 325MW eastwards, a study was performed to determine the *Flow-South* potential of the existing generating facilities if they were not to be constrained by the present system operating limits.

For this study, and also for all subsequent studies, the IESO's reference base case for the summer-2006 was used with the load in the north-east adjusted to a value of 1192MW. This value was selected to comply with the load of 1132MW that was shown in Diagram 2, with further adjustments to account for the following:

- the discrepancy between the computed primary demand shown in Diagram 2 and the actual value that was recorded for this area, and
- the expected changes in the area load by the summer-2010, when the expanded facilities on the Mattagami River are expected to be operational.

For the north-west, no adjustment of the load was deemed to be necessary since the critical parameter in the study was the transfer on the East-West Ties. This transfer was maintained at the Interface limit of 325MW.

The generating resources that were assumed to be dispatched in this study together with the other resources that were assumed to contribute to the *Flow-South* transfer are described in the following sections.

5.1 Existing Generating Resources:

North-eastern Ontario - North & East of Sudbury

The peak outputs from the existing generating facilities in the north-east are summarised in Table 1. These include the increase in the capacity of the existing units at Little Long GS and Harmon GS resulting from the planned upgrade of their turbine runners. Once the runner upgrades have been complete, the combined capacity of the existing generating facilities in north-eastern Ontario will be **2157MW**.

North-eastern Ontario - West of Sudbury & including GLP

Table 2 summarises the peak output from the existing generating facilities in the remainder of north-eastern Ontario between Wawa TS and Sudbury. The capacity of these facilities totals **934MW**.

Total Existing Capacity in North-eastern Ontario

The existing generating facilities in north-eastern Ontario therefore have a combined capacity of **3091MW**.

TABLE 1	***NE Generation Capacity: North & East of Sudbury***		
Station	*Units*	*Total Generation*	*Summated Capacity*
Abitibi Canyon GS	230kV: 3 x 65MW	195MW	998MW *Following runner upgrades: 1019MW*
	115kV: G2 67MW G3 62MW	129MW	
Otter Rapids GS	4 x 47MW	188MW	
Little Long GS	2 x 68MW	136MW	
	Runner Upgrade: + 4MW	*140MW*	
Harmon GS	2 x 70MW	140MW	
	Runner Upgrade: + 17MW	*157MW*	
Kipling GS	2 x 79MW	158MW	
Smoky Falls GS	4 x 13MW	52MW	
Lower Notch GS	2 x 131MW	262MW	584.7MW
Otto Holden GS	4 x 28.1MW	112.4MW	
	4 x 32.6MW	130.4MW	
Coniston GS	3 x 5MW	15MW	
Crystal Falls GS	4 x 1.9MW	7.6MW	
TCPL North Bay	30.8MW + 26.5MW	57.3MW	
TCPL Calstock	43.2MW	43.2MW	524.7MW
Carmichael Falls	2 x 9.3MW	18.6MW	
Nagagami & Shekak	2 x 9.3MW	18.6MW	
TCPL Kapuskasing	30.8MW + 26.5MW	57.3MW	
Long Sault Rapids	4 x 5MW	20MW	
Cochrane	28.2MW + 14.3MW	42.5MW	
Tunis	52.7MW + 19.8MW	72.5MW	
Northland - Iroquois Falls	2 x 49.9MW +	133.5MW	
	33.7MW		
Northland - Kirkland Lake	3 x 17.9MW + 14MW	118.5MW	
	+ 19MW + 31.8MW		
Domtar-Eddy Espanola	2 x 8MW + 14MW	30MW	30MW
		Total *(after runner upgrades)*	***2158.4MW***

TABLE 2	**NE Generation Capacity: GLP & West of Sudbury**		
Station	*Units*	*Total Generation*	*Summated Capacity*
McPhail GS	2 x 5.5MW	11MW	76MW
R.A. Dunford GS (High Falls)	2 x 22.5MW	45MW	
Scott GS	2 x 10MW	20MW	
Steephill GS	15MW	15MW	40.1MW
Harris GS	11.2MW	11.2MW	
Mission Falls GS	13.9MW	13.9MW	
Gartshore GS	22MW	22MW	75.7MW
Hogg GS	15MW	15MW	
Andrews GS	2 x 8.1MW + 22.5MW	38.7MW	
Hollingsworth GS	22MW	22MW	22MW
Mackay GS	2 x 9.5MW + 26MW	45MW	45MW
Clergue GS	3 x 17.3MW	51.9MW	51.9MW
Lake Superior Power	2 x 47MW + 26.1MW	120.1MW	120.1MW
		Sub-Total	***430.8MW***
Aubrey GS	2 x 81.8MW	163.6MW	163.6MW
Wells GS	2 x 120.3MW	240.6MW	240.6MW
Rayner GS	2 x 23.3MW	46.6MW	88.2MW
Red Rock GS	2 x 20.8MW	41.6MW	
Serpent River	2 x 3.6MW	7.2MW	11.2MW
Aux Sable GS	4MW	4MW	
		Sub-Total	***503.6MW***
		Total	***934.4MW***

Upper Mattagami River Plants

The existing generating facilities at Lower Sturgeon GS, Sandy Falls GS & Wawaitin GS on the upper reaches of the Mattagami River have an installed capacity of 24.3MVA. These facilities are operating at 25Hz and are incorporated into Martindale TS via the 25/60Hz frequency converter.

In the study replicating the 30th May snapshot of the system, and for which the results have been summarised in Diagram 2, it was assumed that the net injection into Martindale TS from these facilities totalled 10MW.

Ontario Power Generation has recently submitted an application for a Connection Assessment for the planned conversion of these generating facilities to 60Hz operation and for their incorporation directly into the existing 27.6kV busbar at Timmins TS. The new facilities are to have a combined capacity of 27MW and they are expected to be operational by the end-2009.

Since the redeveloped Upper Mattagami Plants are scheduled to be operational before the expansion of the plants on the lower reaches of the Mattagami River is planned to be completed, it was therefore decided to include the new facilities in all of the subsequent studies. This was done to ensure consistency between the respective study results.

Table 3 provides details of the new generating facilities that are to be installed at each of the existing stations.

TABLE 3	**NE Generation Capacity: Redevelopment of the Upper Mattagami River Plants**	
Conversion of the Upper Mattagami Plants		
Wawaitin GS	2 x 6.75MW	13.5MW
Sandy Falls GS	1 x 4.95MW	5.0MW
Lower Sturgeon GS	1 x 8.8MW	8.8MW
Total Output from the Upper Mattagami Redevelopment		***27MW***

Abitibi Price - Iroquois Falls

Abitibi Price at Iroquois Falls operates the following three generating stations that have a combined output of approximately 90MW:

- Island Falls GS Incorporated via the Abitibi Price 110kV double-circuit line into the mill
- Iroquois Falls GS Incorporated directly into the local 12kV busbar at the mill
- Twin Falls GS Incorporated directly into the local 12kV busbar at the mill

A 75MVA 230/110kV auto-transformer provides a connection to these generating facilities and to the paper-machine portion of the load at the mill from the IESO-controlled grid. The thermal-mechanical pulping load at the mill is supplied directly from the 230kV system via three 72MVA 230/13.8kV step-down transformers.

A review of Abitibi Price's operations over the past year shows that there are frequent periods, particularly during the peak winter and summer periods, as well as during freshet, when the mill is injecting up to 60MW into the IESO-controlled grid.

All of the studies apart from the initial 'snapshot' study which included a 19MW injection have therefore included a nominal injection of 25MW via the Abitibi Price connection at Ansonville TS.

Tembec Mill in Smooth Rock Falls

On 24th April 2006, Tembec announced that their paper mill in Smooth Rock Falls is to cease operations at the end of July 2006.

The mill presently has two 4MVA hydroelectric generating units and two 15MVA steam-turbine generating units providing the majority of the power requirements.

It has been assumed that once the existing steam load at the mill disappears, that the two steam-turbine units will no longer be operated. However, there would be no similar restrictions on the operation of the hydroelectric units and it has therefore been assumed that these two units will continue to operate, providing an injection of approximately 6.4MW into the system at Smooth Rock Falls.

Atikokan GS & Thunder Bay GS

When this study was started, the stated objective of the Government of Ontario was for Atikokan GS to cease operations in 2007 and for the boilers for the two steam-turbine units at Thunder Bay GS to be converted for operation on gas.

However, in mid-June 2006 the government referred the question of how best to replace the existing coal plants in the earliest practical time frame to the OPA. The future status of both Atikokan GS & Thunder Bay GS is therefore being reviewed.

Since this assessment has assumed a fixed transfer eastwards of 325MW across the East-West Ties, measured at Wawa TS, it has been assumed that it will not be especially sensitive to the particular generating facilities that are operating in the north-west.

5.2 Potential Flow-South Transfer from the Existing Generating Facilities

Diagram 3 shows the results of a study with all of the existing generating facilities operating at their maximum output; with the other resources describe above in-service; and with transfers on the East-West Ties at their maximum value of 325MW.

The total capacity of all of the generation facilities in the north-east is shown as **3151MW**. This represents the combined totals from Tables 1 & 2 (2158MW & 934MW, respectively), together with the 27MW from the Upper Mattagami Plants; 25MW from Abitibi Price Inc. in Iroquois Falls; and 6MW from the Tembec facility in Smooth Rock Falls.

This generation despatch scenario would result in a transfer of 1999MW across the Flow-South Interface; approximately 600MW over the present operating limit of 1400MW.

It should be emphasised that this scenario does not include either of the two stages of the Prince Wind Farm or the committed generating facility at Yellow Falls.

For this case, with no series compensation installed in the 500kV circuits between Hanmer TS & Essa TS, it was necessary to add the following shunt capacitor banks in order to respect minimum voltages and maintain an acceptable voltage profile:

• Mississagi TS	96MVAr	} Σ 245MVAr -Rated at 220kV
• Hanmer TS	149MVAr	

Items of Note:

Although this study represents a condition that would not normally be allowed to persist because it would result in the *Flow-South* limit being violated, it does indicate some other potential limitations on the system:

- *Mississagi Flow-East*

  The flow across this Interface is shown as 840MW which would be well in excess of the present operating limit of 550MW.

  However, since this limit is based on the post-contingency voltage declines at Mississagi TS and Algoma TS following the loss of the Hanmer-Mississagi 230kV circuit, the installation of the additional shunt capacitor bank at Mississagi TS, and to a lesser extent the additional shunt capacitor bank at Hanmer TS, would be expected to improve this limit.

  In addition, the expansion of the existing Mississagi Special Protection System (SPS) to allow it to respond to single-circuit contingencies as well as to the double-circuit contingencies that are presently addressed by this SPS would further increase the transfer capability of this Interface.

- *Flows on the Hunta to Timmins 115kV circuits*

  The continuous rating for the major portion of each of these circuits is 104MVA. However, this is reduced to just 78MVA for the final spans into Timmins TS.

  The flows on these circuits are not evenly distributed due to the presence of single connections to the Kidd Creek Mine (from circuit H7T) and to LaForest DS (from circuit H6T). Consequently, at their respective Hunta terminals the flow on circuit H7T is higher than that on circuit H6T. This reverses at their respective terminations into Timmins TS with circuit H6T being more heavily loaded than circuit H7T.

While the flow on circuit H7T at Hunta SS would be marginally within its continuous rating, the flow on circuit H6T at Timmins TS would exceed its continuous rating (86MVA versus a rating of 78MVA).

5.3 Proposed Expansion of the Mattagami River Plants

The proposed expansion of the Mattagami River plants would involve the installation of a third generating unit at each of the three existing generating stations: Little Long GS, Harmon GS & Kipling GS. In addition the existing Smoky Falls generating station would be decommissioned and replaced with a new facility consisting of three new generating units.

An integral part of this plan would involve the development of a new 230kV busbar at Little Long GS as shown in Diagram 4. Not only would this new busbar ensure balanced loading on the two circuits into Pinard TS but it would also provide a suitable location for connecting a 230kV shunt capacitor bank to supply the increased reactive power losses on the 230kV system into Pinard TS.

The Diagram also shows the proposed connection of the generating facilities at each of the Mattagami River plants to the two radial circuits from Little Long SS. The arrangement that has been selected is intended to satisfy a number of objectives:

i. Achieving an approximate balance between the amounts of generating capacity incorporated on to each radial circuit.

ii. Maintaining a connection to each generating station whenever one of the two radial circuits from Little Long SS is out-of-service, and

iii. Managing the river flows following a contingency involving either of the 230kV radial circuits that would result in the automatic removal from service of all of the generating facilities connected to it.

Although not included in the new facilities covered by this Assessment for an increase in the Flow-South transmission capability, the new 230kV switching station at Little Long GS, together with a new 100MVAr shunt capacitor bank at the same location, has been assumed to be in-service in all of the subsequent analysis.

It is intended to address the development of this new 230kV switching station at Little Long GS in the companion Connection Assessment for the Expansion of the Lower Mattagami Plants.

Table 4 provides details of the new generating units that are to be installed to provide an increase in capacity of 485MW. After allowing for the retirement of the existing Smoky Falls GS, the net increase in capacity will be **433MW**.

TABLE 4	***NE Generation Capacity: Proposed Expansion of the Mattagami River Plants***		
Mattagami Expansion			
Little Long GS	1 x 70MW	70MW	*Total: 485MW*
Harmon GS	1 x 78MW	78MW	
Kipling GS	1 x 79MW	79MW	
Smoky Falls GS	3 x 86MW	258MW	
		Less existing Smoky Falls GS	*- 52MW*
		Net Increase from Mattagami Expansion	***433MW***

Modelling of the New Generating Units

The data used in this assessment to model the new generating units at each of the three existing generating stations were assumed to be the same as that for the existing equipment at these locations.

For the 86MW units that are to be installed at the new Smoky Falls generating station, the data for the existing 79MW units at Kipling GS were used and pro-rated accordingly.

6. *Reference Load Flow Study*

Diagram 5 shows the results of the load flow study with the following changes implemented to correspond to the expected peak operational condition during the summer-2010:

- The addition of a new 230kV busbar at Little Long GS
- The addition of a third generating unit at Little Long GS, Harmon GS & Kipling GS
- The incorporation of the new Smoky Falls GS and the retirement of the existing facility.
- The incorporation of both stages of the Prince Wind Farm - 189MW
- The incorporation of Yellow Falls GS - 20MW
- The installation of series capacitors in circuits X503E & X504E at Nobel SS to provide 50% compensation
- The addition of a 230kV-connected SVC at Porcupine TS with a rating of +300/-100MVAr
- The addition of a 115kV-connected SVC at Kirkland Lake TS with a rating of +200/-100MVAr

In addition, in order to respect minimum voltage requirements and to obtain an acceptable voltage profile, as well to minimise the reactive power output from the new SVCs and the generating units, it was found necessary to include the following shunt capacitor banks:

• Mississagi TS	96MVAr	*Σ 245MVAr* Identified Previously	*Total: Σ 952MVAr* Rated at 220kV
• Hanmer TS	149MVAr		
• Porcupine TS	250MVAr	Additional Requirements: *Σ 707MVAr*	
• Pinard TS	100MVAr		
• Little Long GS	100MVAr		
• Algoma TS	75MVAr		
• Essa TS	182MVAr		

This study has been adopted as the reference for all subsequent analysis

For this study the total generating capacity that was despatched in the north-east totalled **3804MW**.

This represents an increase of 653MW over the generation despatch that was assumed for the study whose results have been summarised in Diagram 3. This increase accounts for the incorporation of the following new generating facilities:

• The expansion of the Mattagami River plants and the retirement of the existing Smoky Falls GS	433MW	Σ 653MW
• The incorporation of the Prince Wind Farm	200MW	
• The incorporation of Yellow Falls GS	20MW	

For this study the Flow-South transfer has increased to **2514MW** and this value has been adopted as the reference flow for the transient stability analysis that is discussed in Section 7 of this report.

Although a further 642MW of additional resources have been incorporated, the increase in the transfer across the Flow-South Interface shows an increase of only 515MW over that shown in Diagram 3. The difference is accounted for primarily through the increased transmission system losses within the north-east (from 281MW to 415MW)

Items of Note:

- Reactive Power Requirements

  The incorporation of the additional 642MW of generating capacity in the north-east is shown to increase the transmission system reactive power losses by almost 1000MVAr.

  While approximately 625MVAr of this (at an assumed voltage of 240kV) will be provided by the 525MVAr of additional shunt capacitor banks north of Sudbury (707MVAr minus the 182MVAr capacitor at Essa TS), the bulk of the remaining increase in the reactive power requirements will be supplied from the series capacitors at Nobel SS together with the additional shunt capacitor bank at Essa TS. These will result in a transfer of approximately 700MVAr into Hanmer TS via the two 500kV circuits: an increase of 320MVAr.

- Flows on the 230kV circuits H22D & L20D

  The projected flows on these circuits (1138A) will be only marginally within their continuous rating of 1140A for an ambient temperature of 30^{O}C and a wind speed of 4km/hr.

  Any further decrease in the combined load at the Spruce Falls mill; at Kapuskasing TS; and at Hearst TS beyond that which has been assumed in this study could therefore result in these circuits being overloaded.

  Although these circuits are not part of the existing NE LGR Scheme, they will need to be included in it once the new busbar is established at Little Long GS. This would then allow generation to be rejected following a single-circuit contingency involving either of these circuits so that the companion circuit is not overloaded.

- Flows through the 500/230kV auto-transformers at Pinard TS

  The combined transfer through these two auto-transformers is approximately 1300MVA, which with both auto-transformers in-service would be within their continuous ratings. However, an outage involving either auto-transformer would require the output from the generating facilities to be constrained so that the 10-day limited-time-rating of the companion unit is not exceeded.

  [Since the 500kV circuit-switcher associated with each auto-transformer at Pinard TS is not used for fault interrupting duty, a contingency that involves either auto-transformer would therefore result in both units being isolated due to the tripping of the 500kV circuit D501P. Consequently, the NE LGR Scheme is not required to recognise the loss of each individual auto-transformer.]

- Mississagi Flow-East

  With the GLP generating facilities operating at their maximum output and with the incorporation of the Prince Wind Farm, the flow across this Interface is expected to increase to approximately 1030MW. This would be well in excess of the present operating limit of 550MW.

  However, as mentioned earlier, the installation of the additional reactive support at both Mississagi TS and Algoma TS through a combination of SVCs and shunt capacitor banks would be expected to improve this limit by providing post-contingency voltage support at both Mississagi TS and Algoma TS following the loss of the Hanmer-Mississagi 230kV circuit or both Mississagi-Algoma 230kV circuits.

  For this transfer of 1030MW, the pre-contingency flows on the individual 230kV circuits between Mississagi TS and the Sudbury area are shown to remain within their continuous ratings. However, since any contingency involving one of these circuits would result in severe overloading of the remaining two circuits, a generation rejection Scheme would therefore need to be available if serious congestion of this Interface is to be avoided.

- Flows on the Hunta to Timmins 115kV circuits, H6T & H7T

  Although the flows on these circuits are shown to increase, primarily as a result of the incorporation of the Yellow Falls facility at Smooth Rock Falls, they still remain within the thermal ratings of these circuits at the Hunta terminals. However, the flow on the limiting section of circuit H6T into Timmins TS is shown to be approximately 50A over its continuous rating of 370A.

  It is therefore recommended that the section of circuits H6T & H7T between La Forest Junction and Timmins TS be uprated to at least 100^{o}C so that its rating is comparable to that for the section between Tower 5 and Tower 280.

  Furthermore, should it be decided to incorporate the Upper Mattagami Plants into the La Forest DS LV system it may be prudent to increase the rating of this section of circuits H6T & H7T beyond 100^{o}C to accommodate a possible power injection into the 115kV system at La Forest DS.

7. Transient Stability Analysis

Contingency Conditions

The Reference Load Flow Study has identified the Transfer Limits that would be required across each of the individual Interfaces to allow all of the planned, as well as all of the existing, resources to be accommodated without applying any restrictions under normal system conditions with all elements in-service.

Transient Stability Analysis was therefore performed for the following contingency conditions using these Interface Transfers, together with the appropriate margin, to determine whether the proposed facilities would allow these transfer levels to be achieved:

- A normally-cleared three-phase fault applied at the Hanmer terminal of the 500kV circuit X503E (or X504E)
- A normally-cleared three-phase fault applied at the Hanmer terminal of the 500kV circuit P502X
- A normally-cleared three-phase fault applied at the Porcupine terminal of the 500kV circuit D501P

For the D501P contingency, studies were also performed with the fault located at the Pinard terminal to confirm that applying a fault at the Porcupine terminal would represent the more severe condition.

Fault clearing and generation rejection times

The following times were used for each of the 500kV contingency conditions that were examined:

Fault clearance & G/R times for a contingency involving circuit X503E (or X504E):

•	Clearance of the fault at the Hanmer TS terminal		66msec
•	Clearance of the fault at the Essa TS terminal	+ 25msec	91msec
•	Rejection of the Moose River generating facilities	+ 89msec	180msec
•	Rejection of the NE non-utility generating facilities & the Prince wind farm	+ 50msec	230msec

Fault clearance & G/R times for a contingency involving circuit P502X:

For this contingency it was determined that cross-tripping of both the 500kV circuit D501P & the 230kV circuit L21S would be necessary

•	Clearance of the fault at the Hanmer TS terminal		66msec
•	Clearance of the fault at the Porcupine TS terminal & Cross-tripping of the Porcupine terminal of circuit D501P	+ 25msec	91msec
•	Cross-tripping of the 230kV breakers associated with circuit D501P at Pinard TS	+ 29msec	120msec
•	Cross-tripping of the 230kV circuit L21S at Kapuskasing TS & Rejection of the Moose River generating facilities	+ 60msec	180msec
•	Rejection of the NE non-utility generating facilities	+ 50msec	230msec

Fault clearance & G/R times for a contingency involving circuit D501P:

1.	*For a fault at the Porcupine terminal*		
•	Clearance of the fault at the Porcupine TS terminal		66msec
•	Clearance of the fault at the Pinard TS terminal (3-cycle breakers) & Cross-tripping of the 230kV circuit L21S at Kapuskasing TS	+ 42msec	108msec
2.	*For a fault at the Pinard terminal*		
•	Clearance of the fault at the Pinard TS terminal (3-cycle breakers) & Cross-tripping of the 230kV circuit L21S at Kapuskasing TS		83msec
•	Clearance of the fault at the Porcupine TS terminal	+ 8msec	91msec
•	Rejection of the Moose River generating facilities		180msec
•	Rejection of the NE non-utility generating facilities	+ 50msec	230msec

Provision of a 10% Margin on the Limiting Transfers

The IESO's Transmission Assessment Criteria require that -

'all stability limits should be shown to be stable if the most critical parameter is increased by 10%'.

In Diagram 5 the *reference* peak transfer across the Flow-South Interface, with all generating facilities in-service and with a maximum transfer of 325MW on the East-West Ties was shown to be 2514MW.

Consequently, to provide the required 10% margin, negative load was therefore added at the following busbars to increase this transfer to approximately 2765MW:

Location of Negative Load to Provide a Margin of 10% on the Flow-South Transfer			
•	Pinard 500kV busbar	100MW	To account for the additional transmission losses, the amount of negative load had to be increased by approximately 50MW
•	Porcupine 500kV busbar	100MW	
•	Mississagi 230kV busbar	100MW	

Sequence of Generation Rejection

For consistency between the study results, the following sequence was adopted for the order in which generation capacity is to be rejected in response to the various contingency conditions that were examined:

<table>
<tr><td colspan="6">Sequence used for Rejecting the Negative Loads & the Generating Units</td></tr>
<tr><td rowspan="3">1.</td><td colspan="2" rowspan="3">Trip the Negative Load</td><td>For an X503E or X504E contingency</td><td colspan="2">All three 100MW loads</td></tr>
<tr><td>For a P502X contingency</td><td colspan="2" rowspan="2">Only the 100MW loads at Pinard TS & Porcupine TS</td></tr>
<tr><td>For a D501P contingency</td></tr>
<tr><td>2.</td><td colspan="2">Trip the Prince 200MW Wind Farm</td><td>For an X503E (or X504E) contingency</td><td colspan="2">200MW</td></tr>
<tr><td>3.</td><td>Harmon GS</td><td>G1</td><td rowspan="8">For all three contingency conditions examined</td><td>79MW</td><td rowspan="6">Maximum Capacity Rejected: 426MW</td></tr>
<tr><td>4</td><td>Kipling GS</td><td>G1</td><td>79MW</td></tr>
<tr><td>5</td><td>Smoky Falls GS</td><td>G1</td><td>86MW</td></tr>
<tr><td>6</td><td>Little Long GS</td><td>G1</td><td>70MW</td></tr>
<tr><td>7</td><td>Otter Rapids GS</td><td>G1</td><td>47MW</td></tr>
<tr><td>8</td><td>Canyon GS</td><td>G1</td><td>65MW</td></tr>
<tr><td>9 to 14</td><td colspan="2">Repeat sequence from 3 to 8 with the 2nd unit at each Mattagami River GS</td><td colspan="2">Maximum Capacity Rejected: 426MW</td></tr>
<tr><td>15 to 20</td><td colspan="2">Repeat sequence from 3 to 8 with the 3rd unit at each Mattagami River GS</td><td colspan="2">Maximum Capacity Rejected: 426MW</td></tr>
</table>

In addition, selected non-utility generation capacity was also rejected to respect the thermal limits on the 115kV transmission system.

For contingencies involving the 500kV system north of Sudbury (circuits P502X & D501P) only those negative loads at Pinard TS and Porcupine TS were rejected post-contingency. This would result in the negative load at Mississagi TS remaining connected following either of these contingency conditions.

Since the retention, post-contingency, of the negative load at Mississagi TS and the lack of any associated dynamic capability was considered to be too onerous, it was therefore decided to replace the negative load at Mississagi TS with a fictitious 100MW generating unit for the P502X & D501P contingencies.

Models Used for the SVC

For the load flow studies, each SVC was modelled as a generator with only a reactive power output equivalent to the rating proposed by Hydro One.

The generator representing the proposed SVC to be installed at Porcupine TS therefore had a range of -100MVAr to 300MVAr, while the range of the generator representing the Kirkland Lake SVC was set at -100MVAr to 200MVAr.

For the transient analysis, the CSVGN1 model shown in Diagram 6 was used to represent each SVC. Conservative parameters were selected for use in the model, on the expectation that the performance of the actual SVCs will be superior to that obtained in the analysis.

Once the supplier(s) of the SVCs have been selected, appropriate dynamic models that faithfully represent the behaviour of the SVCs are to be obtained to allow additional studies to be performed to confirm that the recommended settings will avoid excessive over-voltages at the associated busbars.

7.1 Preliminary Results for a P502X Contingency

Flow-East at Mississagi TS

The initial analysis indicated that once the Prince Wind Farm becomes fully operational and the peak transfer across the Mississagi Flow-East Interface could then exceed 1000MW, it would not be possible to maintain transient stability of the generating facilities associated with the East-West Tie following a contingency involving the 500kV circuit P502X.

The maximum transfer across the Mississagi Flow-East Interface for which stability could be maintained in response to a three-phase fault at the Hanmer terminal of the 500kV circuit P502X was found to be 980MW. After applying a margin of 10%, this would be equivalent to a transfer limit of **890MW;** 140MW less than the reference transfer of 1030MW. The corresponding flow on circuit P502X into Hanmer TS was 1670MW and the Flow-South transfer for this study was approximately 2700MW, or 2460MW after allowing for the 10% margin.

The upper portion of Diagram 7 shows the corresponding voltage at each of the critical busbars west of Sudbury in response to the P502X contingency. This shows the maximum voltage decline occurring at Marathon TS, with those at Algoma TS and Mississagi TS being the next most severe, respectively. It is also worth noting that the minimum voltages at Algoma TS and Mississagi TS occur approximately a half cycle earlier than that at Marathon TS.

The lower portion of Diagram 7 shows the post-contingency voltages for the condition with the transfer across the Mississagi Flow-East Interface increased by 25MW to 1002MW. This results in post-contingency instability.

The maximum voltage decline is shown to occur at Algoma TS, with that at Mississagi TS being the next most severe.

A study with a reduced transfer into Hanmer TS via circuit P502X was performed to determine whether the size of the flow into Hanmer TS was the cause of the instability. For this study the flow on circuit P502X into Hanmer TS was reduced to 1347MW, resulting in a Flow-South transfer of 2390MW.

The post-contingency voltages obtained from this study are shown in the lower half of Diagram 8. The results from the earlier study with a Flow-South into Hanmer TS of 1670MW have been reproduced in the upper half of this Diagram. [These are the same results that were shown in the lower half of Diagram 7, but with an expanded horizontal time scale to aid in the comparison of the two sets of results.]

Comparing the results for the two flow conditions shows that they are remarkably similar, with the only significant difference being a delay of approximately 0.1 seconds for the case with the lower flow into Hanmer TS, before the voltages hit their minimum values.

It has therefore been concluded that the low post-contingency voltages on the system west of Sudbury, together with the attendant instability of the generating units is primarily the result of the high transfers across the Mississagi East Interface rather than the level of the flow into Hanmer TS via the 500kV circuit P502X.

Diagram 9 shows the rotor angle response of the generating units to a P502X contingency for the same operating condition for which the post-contingency voltages are shown in the lower half of Diagram 8. The divergence between those generators associated with the system west of Algoma TS and those to the east of Algoma TS is clearly shown.

Installation of an additional SVC on the system west of Sudbury

Studies were performed with a single +300/-100MVAr SVC installed at various locations on the system west of Sudbury to examine the effect that it would have on the post-contingency performance of the system west of Sudbury.

Since Diagram 7 showed the minimum voltage occurring at Marathon TS, a study was performed with the SVC installed on the 230kV busbar at that location. The results, which are shown in Diagram 10, indicate that although the SVC would provide adequate post-contingency support for the voltage at Marathon TS, excessive voltage declines would still occur at both the Algoma and Mississagi 230kV busbars, leading to a loss of stability.

Diagram 11 shows the results with an SVC installed at Algoma TS (the upper half) or at Mississagi TS (the lower half). For both studies the post-contingency voltages are shown to recover and transient stability was maintained. Although either location for the SVC would be acceptable, the results show a marginally superior response, especially with respect to the voltage at Marathon TS, with the SVC located at Mississagi TS.

Furthermore, siting the SVC at Mississagi TS rather than Algoma TS would be preferable for a double-circuit contingency involving the Mississagi-to Algoma 230kV circuits since it would then remain available to provide the maximum post-contingency support to the flows across the remaining 230kV circuit, X74P, between Mississagi TS and Hanmer TS.

Diagram 12 shows the effect that an SVC at Algoma TS (or Mississagi TS) would have on reducing the accelerating power from all of the in-service generating units in north-western Ontario.

All of the subsequent analysis was therefore performed with a +300/-100MVAr SVC located at Mississagi TS.

7.2 Response to a P502X Contingency

With the system model modified to include an SVC at Mississagi TS, in addition to those that are to be installed at Porcupine TS and Kirkland Lake TS, a study was performed with the transfers on the principal interfaces set to represent those shown in the reference case (Diagram 5) with a further margin of 10%.

Interface	*Transfers in the Study with a 10% Margin*	*Equivalent Transfers with no margin*	*Reference Case Transfers from Diagram 5*
Mississagi Flow-East	1126MW	1024MW	1030MW
Flow into Hanmer on P502X	1672MW	1520MW	1503MW
Flow-South	2777MW	2525MW	2514MW

Diagram 13 shows the rotor angle response of the generating units to the P502X contingency and Diagram 14 shows the responses of the three SVCs together with their associated busbar voltages.

In Diagram 13 there is a clear distinction between the responses of those generating facilities associated with the 230kV system in the Sudbury area and those associated with the system north of Sudbury. With an SVC assumed at Mississagi TS, more rapid damping of the generating facilities in the former group is shown to occur, while for the latter group the oscillations are more pronounced, although adequately damped.

In Diagram 14, the SVCs are shown to result in stabilised voltages at their associated busbars within approximately 1.5 seconds of the fault being applied, although significant variations in the output of each of the SVCs is shown to continue for up to 7 seconds after the application of the fault.

Diagram 15 shows the same information as in Diagram 14 but on an expanded time scale. This has allowed the following switching activities to be identified and also provides a better view of the responses of the individual SVCs:

•	At 0.2 seconds, the fault is applied	Time A
•	After 66 milliseconds the fault is cleared at the local terminal: at Hanmer TS	Time B
•	After a further 25msec (91msec), the fault is cleared at the remote terminal & circuit D501P is cross-tripped: at Porcupine TS	Time C
•	After a further 29msec (120msec), circuit D501P is isolated at its remote terminal: at Pinard TS	Time D
•	After 180msec following the application of the fault, the Moose River generating facilities are rejected	Time E
•	After 230msec following the application of the fault, the NUG facilities in the north-east (excluding Northland Power-Kirkland Lake) are rejected	Time F
•	After 250msec following the application of the fault, the Northland Power-Kirkland Lake facility is rejected	Time G
•	After 1sec following the application of the fault, the shunt capacitor banks are tripped	Time H

The plot for the voltage at Porcupine TS shows that it momentarily increases to 3.1 pu immediately following isolation of the faulted circuit P502X at its remote terminal at Porcupine TS. During the subsequent 30 milliseconds, before the cross-tripping of circuit D501P at its Porcupine terminal can be completed, the principal path for the output of the generating units is through circuits D501P and P91G via Porcupine TS and the SVC at that location responds by producing its maximum reactive power output of 300MVAr.

An over-voltage of this magnitude would not be acceptable. However, since it is of very short duration it is assumed that it arises as a result of the particular model that was used to represent the SVC in the analysis.

Similarly, for the SVC at Kirkland Lake TS the voltage is shown to increase momentarily to a maximum of 1.6 pu in response to the same actions.

Consequently it will be necessary to ensure that the designs selected for the SVCs will not allow excessive over-voltages to occur in practice.

Load Flow Results

The load flow results following a P502X contingency, with the initial system conditions as shown in Diagram 5 (the Reference Case), have been summarised in Diagram 16. The principal responses that were initiated were as follows:

- Rejection of 1660MW of generating capacity in the north-east, north of Sudbury
- Cross-tripping of the 500kV circuit D501P and the 230kV circuits L21S, H22D & L20D
- Tripping of the following shunt capacitor banks:
    - 150MVAr at Porcupine TS
    - 150MVAr at Hanmer TS

The post-contingency transfers on the Interconnections, assuming no post-contingency contribution from the generating facilities in Ontario, are shown to total 1557MW. However, since the pre-contingency flow on the Interconnections was 50MW, the net change would be 1507MW. Although this would exceed the TLIC (Tie Line Inrush Current) limit of 1500MW, experience has shown that approximately 15% of any resource deficiency is automatically supplied from the Ontario generation facilities.

It is also worth noting that in order to respect the long-term emergency rating of circuit D3K between Kirkland Lake TS and Dymond TS, the entire Northland Power-Iroquois Falls facility had to be rejected. However, should it be feasible to increase the operating temperature of this line from its present 82^{O}C to 127^{O}C this would increase its LTE rating from 115MVA to 166MVA. This would allow half the Northland Power-Iroquois Falls facility to remain in-service post-contingency, while respecting the increased LTE rating of circuit D3K, as shown in Diagram 17.

With a total of 1594MW of generation capacity rejected, the combined transfers on the Interconnections would be 1515MW, representing a net change of 1465MW.

Diagrams 16 & 17 also show increased post-contingency transfers on the Manitoba and Minnesota Interfaces as follows:

Transfers on the Interconnections before & after a contingency involving the 500kV circuit P502X					
	Diagram No.	*Transfers on Interconnections*		*Voltage Angles*	
		With Manitoba	*With Minnesota*	*Kenora*	*Fort Frances*
Pre-contingency Transfers	5	282.0MW	-147.0MW	99.3^o	85.3^o
Post-contingency Transfers	16	319.4MW	-96.3MW	60.2^o	44.0^o
	Change	*+37.4MW*	*+50.7MW*	*-39.1^o*	*-41.3^o*
	17	318.6MW	-98MW	61.4^o	45.3^o
	Change	*+36.6MW*	*+49.0MW*	*-37.9^o*	*-40.0^o*

The angular change at Kenora TS is shown to exceed the -5^o setting of the $\Delta\theta$ element that supervises both the ΔP1 and the ΔP2 relays on the Ontario-Manitoba Interconnection and would therefore be sufficient to enable the relays. However, the change in the transfer across the Interconnections of approximately +50MW would not be sufficient to trigger operation of the ΔP1 relay which is normally set at +300MW. It would however be marginally sufficient to trigger operation of the ΔP2 relay if the minimum setting of +50MW were in effect. Since this setting is only deployed when one of the Kenora-Whiteshell circuits is out-of-service at the same time that transfers north across the US-Manitoba Interface exceed 900MW, it is not expected to be a concern. Should this very rare situation arise then the possible operation of the ΔP2 relay could be avoided by temporarily limiting the transfers into Hanmer TS on circuit P502X. This would limit the amount of generation rejection that would need to be initiated in response to a P502X contingency and hence reduce the post-contingency flows that would occur over the Ontario-Manitoba Interconnections.

However, it should be noted that, subject to agreement with Manitoba Hydro, there is an expectation that these facilities will soon be disabled so that this will no longer be an issue.

Increase in Operating Reserve

The transmission system losses for the reference case shown in Diagram 5 total 1134MW, while those for the condition following a P502X contingency total 1034MW, as shown in Diagram 16; a difference of 100MW. Consequently the net effect on the system of rejecting 1660MW of generating capacity in response to a P502X contingency would be a resource deficiency of approximately 1560MW [1660MW - 100MW].

This would represent the single worst contingency for the system and would be expected to require an increase in the 30-minute operating reserve. This operating reserve is presently maintained at 1350MW to cover the 900MW deficiency resulting from the loss of one Darlington unit together with a further 450MW to cover half the loss in output from a second Darlington unit.

Frequency Response

Diagram 18 shows the frequency response at various busbars following a P502X contingency with subsequent cross-tripping of the 500kV circuit D501P.

This shows that the frequency at all of the monitored busbars would fall below the 59.3Hz threshold and for longer than the 300 milliseconds necessary for the first stage of the automatic low shedding to be triggered.

While the frequency at Hearst TS is also shown to fall below 58.8Hz, the second stage of load shedding is not expected to be initiated because the frequency is shown to be below this threshold for far less than the required 300 milliseconds.

It is therefore recommended that those loads that are part of the Under-Frequency Load-Shedding (UFLS) scheme in the area north of, and including, Timmins should only be associated with the Stage 2 portion of the Scheme so as to avoid any unintentional loss of load in response to a P502X contingency.

Relay Protection

Diagrams 19 & 20 show the apparent impedance loci for the 115kV circuits D3K and A8K, respectively, for a three-phase fault at the Hanmer terminal of the 500kV circuit P502X.

The apparent impedance loci for circuit D3K, as determined at the Kirkland Lake terminal and as reproduced in Diagram 19, is shown to enter the Zone 2 characteristic of the protective relaying. Since this would not provide the required margin of zero percent for relays having a time delay setting of less than or equal to 0.4 seconds, the existing protective relaying on this circuit would therefore not be acceptable.

For circuit A8K, the apparent impedance loci as shown in Diagram 20 would respect the margin criterion. Although not reproduced here, the results obtained for the companion 115kV circuit A9K were similar to those shown in Diagram 19.

7.3 Response to a D501P Contingency

Diagrams 21 & 22 show the rotor angle response of the generating units to contingencies involving the 500kV circuit D501P for the conditions with the fault located either at the Porcupine TS or at the Pinard TS terminal, respectively. The generators north and west of Sudbury have been grouped separately, with those north of Sudbury in the upper half of each Diagram.

The Diagrams show that the generating units north of Sudbury exhibit a marginally more pronounced swing for the condition with the fault located at the Porcupine terminal of circuit D501P. Furthermore, the effect is greatest on those units west of Timmins that are more remote from the moderating influence of the SVCs at Porcupine TS and Kirkland Lake TS.

They also show that the units remain stable with acceptable damping.

Load Flow Results

Diagram 23 shows the results from a load flow study that examined the post-contingency conditions following a D501P contingency and for which the principal responses that were initiated were as follows:

- Rejection of all of those generating facilities that are associated with the 230kV system connected to Pinard TS. The capacity of these facilities totals 1347MW.
- Cross-tripping of the 230kV circuits L21S, H22D & L20D
- Tripping of the following shunt capacitor banks:
    - 150MVAr at Porcupine TS
    - 300MVAr at Hanmer TS

As before, the initial system conditions for this study were as shown in Diagram 5 (the Reference Case).

With a lesser amount of generating capacity rejected, the study showed that the transfers on the Manitoba and Minnesota Interfaces would be reduced correspondingly:

	Diagram No.	*Transfers on the Interconnections*		*Voltage Angles*	
		With Manitoba	*With Minnesota*	*Kenora*	*Fort Frances*
Pre-contingency Transfers	5	282.0MW	-147.0MW	99.3^{o}	85.3^{o}
Post-contingency Transfers	23	315.2MW	-105.8MW	68.3^{o}	52.5^{o}
	Change	*+ 33.2MW*	*+ 41.2MW*	*- 31.0*^{o}	*- 32.8*^{o}

However, the high post-contingency flows on circuits H6T & H7T between Hunta SS and Timmins TS, and particularly over the final section into Timmins TS from Structure No. 284, are shown to exceed the LTE ratings of these circuits and could therefore require additional generation capacity to be rejected.

The post-contingency flows and the corresponding ratings are summarised below:

Post-contingency Flows following a 500kV contingency involving circuit D501P			
	115kV Circuits	*H6T*	*H7T*
Flow at Hunta SS		523A	485A
Long-Term Emergency Rating	*Limiting Section:* Structure 5 to 280 - op. temp: 99^{o}C	*520A*	*520A*
Flow at Timmins		**456A**	**408A**
Long-Term Emergency Rating	*Limiting Section:* Structure 284 to Timmins TS - op. temp: 70^{o}C	*370A*	*370A*

Since the entire line is equipped with 336.4kcmil conductors, uprating the section between Structure 284 to Timmins TS to raise its operating temperature to around 100^{o}C would increase the LTE rating of circuits H6T & H7T to more than 500A and this would be more than adequate to accommodate the project post-contingency flows.

Diagram 24 shows the response of the various SVCs together with their effect on the local voltages.

As expected in view of their close proximity to the fault location, the SVCs at Porcupine TS and Kirkland Lake TS are shown to provide a significant reactive power contribution during the post-fault period which helps stabilise the voltages in the area. However, it is also worth noting that even though the SVC at Mississagi TS is relatively remote from the faulted element, it continues to provide an important reactive power contribution.

Diagram 25 shows the SVC responses on an expanded time scale, with the following switching activities identified:

• At 0.2 seconds, the fault is applied	Time A
• After 66 milliseconds the fault is cleared at the local terminal: at Porcupine TS	Time B
• After a further 42msec (108msec), the fault is cleared at the remote terminal via the 230kV breakers at Pinard TS	Time C
• After 180msec following the application of the fault, the Moose River generating facilities are rejected	Time D
• After 230msec following the application of the fault, the NUG facilities in the north-east are rejected	Time E
• After 1sec following the application of the fault, the shunt capacitor banks are tripped	Time F

For this contingency condition the maximum voltages that were recorded were much more moderate, as shown below, reflecting the improved connectivity that is maintained post-contingency, between Porcupine TS and the rest of the system:

Porcupine TS:	Maximum voltage	1.14 pu
Kirkland Lake TS:	Maximum voltage	1.19 pu
Algoma TS:	Maximum voltage	1.20 pu

Relay Protection

Diagrams 26 & 27 show the apparent impedance loci for the 115kV circuits D3K and A4H, respectively, for a three-phase fault at the Porcupine terminal of the 500kV circuit D501P. In both instances, the loci remain well clear of the operating ranges defined by the relay characteristics and would therefore meet the margin requirements.

7.4 Response to an X503E (or X504E) Contingency

For a contingency involving the 500kV circuit X503E (or its companion circuit, X504E) with an initial transfer south across the Flow-South Interface of 2770MW (equivalent to 2518MW after allowing for the required margin of 10%), it was determined that 860MW of capacity, including the 300MW of negative load required to provide the margin, would need to be rejected to maintain post-contingency stability.

The rotor angle responses of selected generating units are shown in Diagram 28. Again, those units north of Sudbury have been grouped in the upper half of the Diagram while those west of Sudbury are shown in the lower half.

All of the units are shown to remain stable with adequately damped oscillations.

Diagram 29 shows the corresponding responses of the SVCs. As before, all three SVCs are shown to make considerable contributions, with the greatest contribution coming from the unit at Porcupine TS. Furthermore, the reactive contributions from the Porcupine SVC are shown to continue at a high level for a longer period than was the case for either a P502X contingency (Diagram 14) or a D501P contingency (Diagram 24). This is due in part to the greater amount of generation capacity that remains in-service in the area north of Timmins following an X503E (orX504E) contingency (approximately 1600MW after the rejection of 360MW of capacity).

Diagram 30 shows the SVC responses on an expanded time scale, with the following switching activities identified:

• At 0.2 seconds, the fault is applied	Time A
• After 66 milliseconds the fault is cleared at the local terminal: at Hanmer TS	Time B
• After a further 25msec (91msec), the fault is cleared at the remote terminal: at Essa TS	Time C
• After 180msec following the application of the fault, the Moose River generating facilities are rejected	Time D
• After 230msec following the application of the fault, the NUG facilities in the north-east are rejected	Time E
• After 1sec following the application of the fault, the shunt capacitor banks are tripped	Time F

The voltage plots in this Diagram show that for this contingency condition the maximum, transitory voltages that would be expected to occur would remain within an acceptable range:

Porcupine TS:	Maximum voltage	1.15 pu
Kirkland Lake TS:	Maximum voltage	1.23 pu
Algoma TS:	Maximum voltage	1.13 pu

Load Flow Results

The load flow results following an X503E (or X504E) contingency, with the initial system conditions as shown in Diagram 5 (the Reference Case), have been summarised in Diagram 31. The principal responses that were initiated were as follows:

- Rejection of 560MW of generating capacity in the north-east, north of Sudbury.
- Tripping of the following shunt capacitor banks:
    - 100MVAr at Porcupine TS
    - 100MVAr at Pinard TS
    - 100MVAr at Little Long GS

With this amount of generation rejection initiated, the post-contingency flow on the companion circuit X504E would be 2130A (1869MW/290MVAr at 512.7kV). This would exceed the continuous rating of 2080A for a section of circuit X504E and would require either of the following measures to be implemented:

- Uprate the critical section of circuit X504E that is equipped with quad 495kcmil conductors and presently has a sag temperature of 73^{o}C to a sag temperature of at least 76^{o}C.
- Increase the amount of generation capacity to be rejected during those periods when the transfers south across the Flow-South Interface are at their peak of approximately 2500MW by about 65MW to a total of 625MW.

The results with an additional 65MW 230kV-connected generating unit at Abitibi Canyon GS rejected in response to an X503E (or X504E) contingency are shown in Diagram 32.

With the additional generating capacity rejected, the flow on circuit X504E would then be reduced to 1977A which would be sufficient to respect its continuous rating of 2080A.

Frequency Response

Diagram 33 shows the frequency response at various busbars following an X503E (or X504E) contingency.

This shows that of the busbars that were monitored, the frequency recorded at both Hearst TS and Spruce Falls TS would fall below the 59.3Hz threshold. Furthermore, since the frequency at Hearst TS is shown to remain below the 59.5Hz threshold for approximately 300 milliseconds, this would therefore be expected to trigger the first stage of the automatic under-frequency load shedding.

This therefore supports the earlier recommendation that those loads that are part of the Under-Frequency Load-Shedding (UFLS) scheme in the area north of, and including, Timmins should only be associated with the Stage 2 portion of the Scheme so as to avoid any unintentional loss of load in response to either a P502X or an X503E (or X504E) contingency.

7.4.1 Power-Voltage Analysis

Diagram 34 shows the results of the PV-analysis for the post-contingency condition shown in Diagram 31 following the loss of circuit X503E (and the rejection of 560MW of generation capacity, together with the tripping of a 100MVAr capacitor bank at Porcupine TS, at Pinard TS and at Little Long SS).

As shown in Diagram 31, the post-contingency Flow-South transfer for this condition would be 2041MW.

Diagram 34 shows that for the voltages at Pinard TS, Porcupine TS and Hanmer TS, the respective voltage instability points (or knees) of their PV-curves would occur at a Flow-South transfer of approximately 2345MW. After applying a margin of 5%, the maximum Flow-South transfer that would be acceptable to ensure that the criterion for post-contingency voltage stability is respected would be approximately 2230MW. This would be well in excess of the projected post-contingency transfer of 2041MW (2145MW after allowing for the margin of 5%).

7.4.2 Delayed Generation Rejection

In all of the preceding analysis, the time interval that was assumed for completing the rejection of each individual generating unit via the NE Load & Generation Rejection Scheme was 180 milliseconds following the initial occurrence of the fault.

Since it has not been verified whether the NE Load & Generation Rejection Scheme is capable of achieving this response in practice, a study was therefore performed with the rejection time increased to 200 milliseconds to determine what effect, if any, a slower rejection time would have on the transient response.

Diagram 35 shows the rotor angle responses of selected generating units to a 3-phase fault at the Hanmer terminal of the 500kV circuit X503E (or X504E). The responses of those units north of Sudbury have been grouped in the upper half of the Diagram while those to the west of Sudbury are shown in the lower half.

All of the units are shown to remain stable with adequately damped oscillations.

If the responses in Diagram 28 (for a rejection time of 180msec) are compared with those in Diagram 35 (for a rejection time of 200msec), it is apparent that the increased G/R time has only a negligible effect of the magnitudes of the angular deviations for the respective generating units that were monitored. The delayed rejection time is, however, shown to affect the timing of the angular swings experienced by the respective generating units

To determine the magnitude of this delay, the time taken for the monitored unit at Little Long GS to reach its maximum angular deviation on its second swing has therefore been used as the reference:

Comparison of Generation Rejection Times: Rotor Angles at Little Long GS		
Rejection Time	*Diagram No.*	*Time taken by the Little Long Unit from fault occurrence*
180 milliseconds	28	1.90 seconds
200 milliseconds	35	2.20 seconds
	Difference	*0.30 seconds*

Consequently, the increase of 20 milliseconds in the rejection time is shown to result in a 300 millisecond delay in the angular deviation of the generating units.

Diagram 36 shows the corresponding responses of the SVCs for a rejection time of 200msec. As with the rotor angle responses, the responses of the individual SVCs are shown to be very similar in magnitude to those shown in Diagram 29, but with a similar delay before each SVC reaches is maximum output.

To determine the extent of this delay, the time taken for the SVC at Porcupine TS to reach its first ‘unconstrained’ peak output has been used as the reference:

Comparison of Generation Rejection Times: Porcupine SVC		
Rejection Time	*Diagram No.*	*Time taken by the Porcupine SVC from fault occurrence*
180 milliseconds	29	3.33 seconds
200 milliseconds	36	3.63 seconds
	Difference	*0.30 seconds*

These results therefore show an identical delay of 300msec in the associated response of the SVC at Porcupine TS to the 20msec increase in the generation rejection time.

The conclusion from this single study is that a rejection time of up to 200msec would not materially affect the post-contingency performance of the generating units nor adversely affect the transfer capability of the system. Whether this would remain valid for any additional delay in the generation rejection time beyond the 200msec that was examined would require further analysis. However, rather than make further assumptions, tests would need to be conducted by Hydro One to confirm the actual generation rejection times for the various components of the NE Load & Generation Rejection Scheme so that these could be used in all future analysis.

8.0 Performance of the System with no additional Shunt Capacitor Banks in-service

Hydro One's original proposal included only the SVCs at Porcupine TS and Kirkland Lake TS and the series capacitors at Nobel TS in the 500kV circuits between Hanmer TS and Essa TS. These additional facilities were intended to provide a sufficient increase in the transfer limit across the Flow-South Interface to accommodate only the increased capacity from the expanded generating facilities on the Mattagami River. Furthermore, the new 230kV busbar at Little Long GS as well as the additional capacitor banks that are required at Little Long GS and Pinard TS to compensate for the increased reactive power losses were considered to be part of this plan to expand the Mattagami River plants.

The analysis summarised in this section of the Report is therefore intended to quantify the improvement in the Flow-South transfer capability that would be provided by only those facilities in the original Hydro One proposal.

8.1 Analysis

8.1.1 Voltage Stability Analysis

PV-Analysis: With series capacitors at Nobel SS & SVCs at Porcupine TS and Kirkland Lake TS

The results from this study for the post-contingency condition following the loss of the 500kV circuit X 503E (or X504E) are shown in Diagram 37. The knee-points of the PV-curves are shown to occur at a Flow-South transfer of 2023MW. After applying a margin of 5%, the corresponding voltage stability limit for *post-contingency* transfers across the Flow-South Interface would therefore be **1921MW**.

Load Flow Analysis

Diagrams 38 & 39 show the results from the pre- and post-contingency load flow studies, respectively, for the condition that would result in a post-contingency transfer at the limiting value of 1921MW.

To achieve this post-contingency transfer of 1921MW, a pre-contingency Flow-South transfer of approximately 2000MW was found to be necessary to account for the increased post-contingency transmission losses and the reduced transfers across the Minnesota and Manitoba Interfaces. In Diagram 38, the pre-contingency transfers across the Flow-South and East-West Transfer East Interfaces are therefore shown to be 1996MW and 325MW, respectively.

For this study, in order to maintain a transfer across the Mississagi Flow-East Interface within the existing limit of 550MW (with no generation rejection initiated in response to a single-circuit contingency) while maintaining the East-West Transfer East flow at 325MW, it was necessary to assume the following facilities were out-of-service:

• Aubrey Falls GS	one generating unit	82MW
• Wells GS	one generating unit	120MW
• Lake Superior Power	the entire facility	120MW
• Prince I & II Wind Farms	the entire facilities	200MW
	Total Capacity	*522MW*

With these facilities out-of-service, the transfer across the Mississagi Flow-East Interface is shown to be reduced to 524MW.

With this transfer across the Mississagi Flow-East Interface, it was also found to be necessary to assume that the 20MW facility at Yellow Falls GS was out-of-service and that the net injection into the system from Abitibi Price facility at Iroquois Falls was reduced from 25MW to 10MW in order to achieve the required pre-contingency transfer of approximately 2000MW across the Flow-South Interface.

The results summarised in Diagram 38 for this particular loading condition show that an output of 231MVAr would be required from the SVC at Porcupine TS to maintain a voltage of 242kV on the Porcupine 230kV busbar.

In Diagram 39, with circuit X503E out-of-service and a post-contingency transfer across the Flow-South Interface of 1921MW, the SVC at Porcupine TS is shown to be at its maximum output of 300MVAr. Since it is no longer able to support the voltage on the 230kV busbar, it is shown to decline to 239kV, while that on the 500kV busbar at Porcupine TS falls to 505kV. However, the greatest decline is shown to occur at Hanmer TS, with the voltages falling to 498kV and 233kV on the 500kV and 230kV busbars, respectively. This is consistent with the results obtained from the PV-analysis, as shown in Diagram 37, with progressively lower voltages recorded at Pinard TS, Porcupine TS and at Hanmer TS.

This Diagram also shows a reduction of 17MW in the East-West Transfer East together with an increase of 63MW in the transmission system losses in the North-east from 292MW to 355MW: a net change of 80MW.

8.1.2 Transient Stability Analysis

A further series of transient stability studies were performed for the same system conditions with a transfer across the Mississagi Flow-East Interface of approximately 550MW, but with no additional shunt capacitor banks at Porcupine TS, Hanmer TS or Essa TS. For these studies that examined a contingency involving the 500kV circuit X503E (or X504E), the transfer across the Flow-South Interface was increased incrementally, with different amounts of generating capacity being rejected at the plants in the Moose River basin until stability could no longer be maintained. In addition, to provide the required margin of 10%, appropriate amounts of negative load were added at Pinard TS, Porcupine TS and Mississagi TS.

The limiting condition at which stability could be maintained corresponded to a Flow-South of 2427MW, which included 275MW of negative load. After deducting the negative load to account for the required margin, the maximum pre-contingency transfer across the Flow-South Interface for which stability could be maintained would therefore be 2152MW. For this transfer, 425MW of generating capacity would need to be automatically rejected in response to a contingency involving either of the 500kV circuits X503E or X504E.

Diagram 40 shows the rotor angle response of selected generating units to this contingency condition. The generating units north of Sudbury have been grouped in the upper half of the Diagram, while those west of Sudbury are shown in the lower half of the Diagram.

All of the units are shown to remain stable with adequately damped oscillations.

Diagram 41 shows the corresponding responses of the SVCs and their effect on the local voltages.

All three SVCs are shown to respond up to their maximum rated capability during the post-fault period as shown in the following Table:

SVC Outputs in response to an X503E (or X504E) contingency			
Location	*Initial Output prior to the Contingency*	*Final Output after 10 seconds*	*Maximum : Minimum Rated Output*
Porcupine TS	+300MVAr	+100MVAr	300MVAr : -100MVAr
Kirkland Lake TS	+20MVAr	-10MVAr	200MVAr : -40MVAr
Mississagi TS	-40MVAr	-50MVAr	300MVAr : -100MVAr

For this contingency condition, the maximum voltages that were recorded were as follows:

Porcupine TS:	Maximum 230kV voltage	1.09 pu
Kirkland Lake TS:	Maximum 115kV voltage	1.19 pu
Algoma TS:	Maximum 230kV voltage	1.14 pu

Transient Stability Analysis with no SVC at Mississagi TS

In earlier analysis it had been determined that in order to maintain post-contingency transient stability in response to a three-phase fault on circuit P502X at its Hanmer terminal, an SVC would be required at either Mississagi TS or Algoma TS once transfers across the Mississagi Flow-East Interface exceeded 890MW. Further details are given in Section 7.1 of this Report.

Consequently, for the conditions examined in the preceding Section, where the transfer across the Mississagi Flow-East Interface was only 550MW, an SVC at Mississagi TS would not be necessary.

The analysis was therefore repeated without an SVC at Mississagi TS.

The limiting Flow-South transfer for which stability could be maintained in response to a contingency involving the 500kV circuit X503E (or X504E) was found to remain at 2427MW which included 275MW of negative load. This reflects the minimal impact that the omission of an SVC at Mississagi TS would be expected to have on the initial acceleration of the generating units following the contingency.

However, to compensate for the loss of the post-contingency voltage support provided by the SVC at Mississagi TS, it was found that the amount of generating capacity that would need to be automatically rejected would need to be increased by 80MW to 505MW.

Diagram 42 shows the rotor angle response of selected generating units to this contingency condition. As before, the generating units north of Sudbury were grouped in the upper half of the Diagram, while those west of Sudbury were grouped in the lower half of the Diagram.

The responses shown in Diagram 42 are virtually identical to those shown in Diagram 40, with the principal difference being the lower rotor angles at which the generating units stabilise as a result in the increase in the amount of generation capacity rejected. All of the units remain stable with adequately damped oscillations.

Diagram 43 shows the corresponding responses of the SVCs and their effect on the local voltages. The maximum voltages that were recorded at the monitored busbars, together with their respective changes from those obtained from the preceding study with an SVC at Mississagi TS, were as follows:

Porcupine TS:	Maximum 230kV voltage	1.09 pu	-	no change
Kirkland Lake TS:	Maximum 115kV voltage	1.18 pu	-	a reduction of 0.01 pu (-1.2kV)
Algoma TS:	Maximum 230kV voltage	1.19 pu	-	an increase of 0.05 pu (+11kV)

Apart from this small increase in the post-contingency transient voltage at Algoma TS, the principal difference between Diagrams 41 and 43 is a reduction of approximately 25MVAr in the steady-state output of the SVC at Porcupine TS. This occurs because of the reduced reactive power losses as a result of the need to reject an additional 80MW of generating capacity in the Moose River basin to maintain transient stability.

Load Flow Results

Diagram 44 shows the pre-contingency load flow results for the condition with a Flow-South of 2152MW, representing the transient stability limit after allowing for the 10% margin. To achieve this transfer all the identified generating facilities, north of Sudbury, were assumed to be in-service, and generation capacity at Aubrey Falls GS and Wells GS was then added until the required Flow-South transfer was obtained. The additional generation capacity is shown to result in a transfer of 594MW across the Mississagi Flow-East Interface. Although this would exceed the present limit, it is expected that it would be within the revised limit once enhancements to the Mississagi SPS can be implemented to allow generation rejection to be initiated for single-circuit contingencies.

At this transfer level across the Flow-South Interface the output from the SVC at Porcupine TS is shown to be 276MVAr, which is close to its maximum rating of 300MVAr.

The results of the post-contingency load flow, following the loss of the 500kV circuit X503E (or X504E) and the rejection of 425MW of generating capacity at the Moose River plants, is shown in Diagram 45.

The post-contingency flow across the Flow-South Interface is shown as 1778MW which represents a reduction of 374MW from the pre-contingency value. This is less than the 425MW of generating capacity that has been rejected, primarily as a result of the reduced transmission losses due to lower amount of generating capacity in-service post-contingency (the losses in the North-east are shown to change from 327MW pre-contingency, to 283MW post-contingency).

Also, with the reduced amount of generating capacity in-service post-contingency following the initiation of the generation rejection, the output from the SVC at Porcupine TS is shown to fall to 180MVAr.

Since the post-contingency flow of 1778MW following the rejection of 425MW of generating capacity is less than the 1921MW transfer limit at which post-contingency voltage-stability can be maintained, these studies confirm that transient stability will therefore be more limiting than voltage stability.

8.2 Conclusions from the studies with no additional Shunt Capacitor Banks in-service

These studies demonstrate that the proposed series capacitors at Nobel SS together with the SVCs at Porcupine TS and Kirkland Lake TS would allow a maximum Flow-South of 2150MW to be achieved. This would be sufficient to accommodate all of the existing generating facilities north of Sudbury together with the planned expansion of the Mattagami River plants as well as the development of the 20MW Yellow Falls facility.

With all of the facilities north of Sudbury in-service, both existing and planned, the transfers across the Mississagi Flow-East Interface would therefore need to be limited to approximately 600MW.

9. Conclusions and Recommendations

A review of the *existing* resources in the north-east and north-west of the Province has indicated a potential transfer over the Flow-South Interface of approximately **2000MW**, as shown in Diagram 3. This assumes a transfer of approximately 840MW across the Mississagi Flow-East Interface. To achieve a transfer of this level, the existing Mississagi SPS would need to be expanded to allow generation rejection to be initiated in response to single-circuit contingencies and an SVC would need to be installed at Mississagi TS, together with an additional shunt capacitor bank at both Mississagi TS and Algoma TS, so that the present transfer limit for the Mississagi Flow-East Interface could be increased.

With the transfer limit for the Mississagi Flow-East Interface increased sufficiently to allow the output of the 200MW Prince Wind Farm to be accommodated, the potential transfer across the Flow-South Interface could therefore increase to **2150MW,** assuming a corresponding increase of approximately 50MW in the transmission losses.

The proposed 433MW expansion of the generating facilities at the Mattagami River Plants would then be expected to increase the potential Flow-South transfer to approximately **2500MW**, as shown in Diagram 5.

Local Enhancements to the Mississagi - Sudbury Interface

In order to increase the transfer limit on the Mississagi Flow-East Interface to approximately **1030MW** to accommodate all of the existing resources west of Mississagi TS, together with the maximum permissible transfers on the East-West Ties of 325MW, it has been determined in a companion study that the following facilities would need to be installed:

- an SVC rated at +300/-100MVAr at Mississagi TS, together with
- a 96MVAr (at 220kV) shunt capacitor bank at Mississagi TS, and
- a 75MVAr (at 220kV) shunt capacitor bank at Algoma TS

While all of the facilities listed above were included in the system model used for this Assessment, it should be noted that the approvals required for their connection to the IESO-controlled grid are to be the subject of a separate Assessment.

Local Enhancements to the Little Long - Pinard Interface

Similarly, in order to accommodate the proposed expansion of the Mattagami River Plants, the following facilities would need to be installed:

- a 230kV busbar at Little Long GS, together with
- a 100MVAr (at 220kV) shunt capacitor bank at Little Long GS
- a 100MVAr (at 220kV) shunt capacitor bank at Little Long GS

Again, although these facilities have been included in the system model used for this Assessment, the approvals required for their connection to the IESO-controlled grid are to be the subject of a further, separate Assessment.

9.1 Increase in the Flow-South Transfer Limit

i. With the series capacitors at Nobel SS together with the SVCs at Porcupine TS and Kirkland Lake TS

- ***together** with the local facilities identified for the expansion of the Mattagami River plants:*

  i.e. a new 230kV busbar at Little Long GS plus a 100MVAr shunt capacitor bank at both Little Long GS & Pinard TS

Subject to automatically rejecting 505MW of generating capacity in the Moose River basin immediately post-contingency, these facilities would allow the limit for pre-contingency transfers across the Flow-South Interface to be increased to ***2150MW.***

This would be adequate to accommodate all of the **existing & committed** generating facilities north of Sudbury together with an increase of **433MW** in the output from the expanded Mattagami River plants, and with a simultaneous transfer of approximately **600MW** across the Mississagi Flow-East Interface i.e. approximately 50MW above the present operating limit of 550MW for this Interface.

ii. With the series capacitors at Nobel SS together with the SVCs at Porcupine TS and Kirkland Lake TS

- ***together** with the local facilities identified for the expansion of the Mattagami River plants:*

  i.e. a new 230kV busbar at Little Long GS plus a 100MVAr shunt capacitor bank at both Little Long GS & Pinard TS

- ***together** with the local facilities identified for enhancing the transfer capability across the Mississagi Flow-East Interface:*

  i.e. a +300/-100MVAr SVC at Mississagi TS plus a 100MVAr shunt capacitor bank at both Mississagi TS & Algoma TS

- ***together** with additional 230kV shunt capacitor banks at the following locations:*

• Porcupine TS	2 x 125MVAr shunt capacitor banks	}	rated at 220kV
• Hanmer TS	a 2nd 149MVAr shunt capacitor bank		
• Essa TS	a 2nd 182MVAr shunt capacitor bank		

These facilities would allow the limit for transfers across the Flow-South Interface to be increased to ***2500MW.***

This would be adequate to accommodate all of the **existing & committed** generating facilities both north and west of Sudbury together with the increased output from the expanded Mattagami River plants, and with a simultaneous transfer of approximately **1030MW** across the Mississagi Flow-East Interface.

This increase in the transfer capability across the Mississagi Flow-East Interface would be adequate to accommodate all of the **existing** generating facilities between Wawa TS and the Sudbury area, including the Prince I & II Projects, together with a transfer of **325MW** across the East-West Transfer East Interface.

9.2 Increased Transfers into Timmins & Sudbury

Flow-South Into Timmins

The proposed expansion of the Mattagami River plants would result in a maximum transfer across this Interface of approximately **1300MW.** (see Diagram 5)

With transfers at this level, generation rejection totalling approximately 1300MW (see Diagram 23) would be required in response to a contingency involving the 500kV circuit D501P. In addition, the 230kV circuits H22D, L20D & L21S would need to be cross-tripped. One of the shunt capacitor banks at Porcupine TS together with both capacitor banks at Hanmer TS would also need to be tripped: the capacitor banks at Little Long GS and Pinard TS would be automatically disconnected with the cross-tripping of the 230kV circuits.

Flow-South Into Sudbury

The maximum transfer across this Interface would be approximately **1600MW** following the proposed expansion of the Mattagami River plants.

With transfers at this level, generation rejection totalling approximately 1600MW (see Diagram 17), together with the cross-tripping of the 500kV circuit D501P and the 230kV circuits H22D, L20D & L21S would be required in response to a contingency involving the 500kV circuit P502X. In addition, one of the shunt capacitor banks at Porcupine TS together with one of the capacitor banks at Hanmer TS would need to be tripped.

The rejection of 1600MW, which after taking account of the associated change in the transmission losses would translate into a net resource deficiency of approximately 1500MW (as shown in Diagram 17), would then represent the single largest contingency condition on the IESO-controlled grid and would require a corresponding increase in both the 10-minute and 30-minute operating reserves.

Potential Effect on NPCC Utilities

i. For Contingencies involving either of the 500kV circuits P502X & D501P

None of the analysis that has been performed for this Assessment has indicated that the increased levels of generation rejection that are expected to be necessary in response to either a P502X or a D501P contingency would have an adverse effect on either the IESO-controlled grid or on the systems of our neighbouring utilities.

Consequently, for contingencies involving either of the 500kV circuits P502X or D501P, it is expected that the North-east Load & Generation Scheme will continue to be classified as a Type III SPS by NPCC (the North-east Power Co-ordinating Council).

The continued application of generation rejection in response to a first contingency would therefore not violate the IESO's Ontario Resource & Transmission Criteria that prohibit the reliance on a Type I Special Protection System, when all transmission elements are in-services, except during the transitional period while new transmission reinforcements are being brought into service.

ii. For contingencies involving either of the 500kV circuits X503E or X504E

Without the additional shunt capacitor banks at Porcupine TS, Hanmer TS and Essa TS, the maximum Flow-South transfer that could be achieved while maintaining a transient stability margin of 10% would be 2150MW. This would, however, require the automatic rejection of 425MW of generating capacity.

With the additional shunt capacitor banks at Porcupine TS, Hanmer TS and Essa TS, the maximum Flow-South transfer that could be achieved would increase to 2518MW. The amount of generating capacity that would need to be automatically rejected would also increase to 560MW.

For Flow-South transfers at either of these levels, a failure of the SPS to initiate generation rejection would be expected to result in transient and/or voltage instability with a potential risk that the system would separate across the North-South Interface. This would result in a resource deficiency in southern Ontario of either 2150MW (less the net change in the transmission losses) or 2518MW (less the net change in the transmission losses).

A resource deficiency of either of these magnitudes would be expected to have an adverse effect on the systems of our neighbouring utilities and could therefore result in that part of the SPS that responds to an X503E or X504E contingency being classified as a Type I SPS by NPCC.

In anticipation of this future classification, it is therefore recommended that those facilities associated with an X503E or X504E contingency be fully duplicated to meet the NPCC requirements for a Type I SPS.

Reliance on a Type I SPS

In Section 2.3.4 of the OPA's Discussion Paper No.5: Transmission - for the Integrated Power Supply Plan, reference is made to the development of additional transmission facilities between Barrie and the GTA to enhance the Flow-South capability, with a lead-time of between five and seven years. Since continued reliance on a Type I Special Protection System, when all transmission elements are in-services, is permitted during the transitional period while new transmission reinforcements are being brought into service, there would therefore be no violation of the IESO's Ontario Resource & Transmission Criteria.

9.3 IESO-Requirements & Recommendations

The analysis performed for this Assessment has also identified the following requirements:

- The frequency responses for both a P502X and a D501P contingency have shown that the frequency at selected busbars is expected to fall below the 59.3Hz threshold for longer than the 300 milliseconds that would trigger load rejection via the first stage of the Under-Frequency Load-Shedding (UFLS) Scheme. The IESO therefore requires that all of the loads in the area north of, and including Timmins should only be associated with the Stage 2 portion of the UFLS Scheme.

- The apparent impedance loci for the 115kV circuit D3K in response to a P502X contingency is shown to enter the Zone 2 characteristic of the protective relaying. Since this would not provide the required margin, the IESO requires the protective relaying on this circuit to be reviewed, and if necessary modified to ensure that this circuit is not tripped for external faults.

  Since each of the following circuits are considered to be critical to the post-contingency performance of the system north of Sudbury, it is also recommended that the protective relaying on these circuits be reviewed, even though the analysis has indicated that the required margin would be met:

Circuits	*Terminal Stations*	*Contingency Condition*
A4H & A5H	Hunta SS to Ansonville TS	D501P & P502X (with D501P cross-tripped)
A8K & A9K	Ansonville TS to Kirkland Lake TS	P502X (with & without D501P cross-tripped)
D3K	Kirkland Lake TS to Dymond TS	P502X (with & without D501P cross-tripped)
W71D	Dymond TS to Widdifield SS	P502X (with & without D501P cross-tripped)

- Once the supplier(s) of the SVCs have been selected, appropriate dynamic models are to be obtained that faithfully represent the behaviour of the devices so that additional studies can be performed to confirm that the recommended settings will avoid excessive over-voltages at the associated busbars.

- Modifications to the NE Load & Generation Rejection Scheme are required to provide the required cross-tripping features as detailed below, as well as the ability to arm the following shunt capacitor banks for automatic tripping:

Circuits to be separately Cross-tripped	*Contingency Conditions*
500kV circuit D501P	P502X
230kV circuit H22D	P502X & D501P
230kV circuit L20D	P502X & D501P
230kV circuit L21S	P502X & D501P
Shunt Capacitor Banks to be tripped	
Little Long GS	P502X, D501P, X503E & X504E
Pinard TS	P502X, D501P, X503E & X504E
1st & 2nd cap banks individually at Porcupine TS	P502X, D501P, X503E & X504E
1st & 2nd cap banks individually at Hanmer TS	P502X, D501P, X503E & X504E

In addition, the NE Load & Generation Rejection Scheme is to have the capability of initiating the rejection of each stage of the Prince Wind Farm development individually in response to a 500kV contingency involving either circuit X503E or circuit X504E.

These new facilities, together with those existing facilities that are associated with an X503E or X504E contingency, are required to be fully duplicated to meet the requirements for possible future classification of part of the NE Load & Generation Rejection Scheme as a Type I SPS.

- The IESO requires tests to be conducted on the NE Load & Generation Rejection Scheme to determine definitive time delays for the rejection of the various generating units covered by the Scheme for each of the contingency conditions that are respected.

  Should the time delays obtained from these tests vary significantly from those assumed in this assessment then it may be necessary to perform additional analysis to determine the effect that they would have on the post-contingency performance of the system.

- Uprate the 500kV circuits E510V & E511V between Essa TS and Claireville TS.

- Uprate the section of the 115kV circuits H6T & H7T between La Forest Junction and Timmins TS.

10. Customer Impact Assessment

Once a formal decision is made to proceed with the installation of the series capacitors at Nobel TS, together with the SVCs at Porcupine TS and Kirkland Lake TS, Hydro One Networks Inc. is proposing to conduct a Customer Impact Assessment for this Project to determine whether the proposed facilities could have a material adverse effect on their customers.

Should any major issues be identified through the CIA process then these will be addressed through an Addendum to this Report.

11. Notification of Approval of the Connection Proposal

Subject to the completion of the Customer Impact Assessment and the satisfactory resolution of any issues that it may raise, as well meeting all of the requirements identified in Section 8.2, the IESO has concluded that the following work will have no materially adverse effect on the IESO-controlled grid:

- the installation of series capacitors at Nobel TS in each of the Hanmer-to-Essa TS 500kV circuits to provide 50% compensation for the line reactance.
- the installation of a 230kV-connected SVC at Porcupine TS, rated at +300/-100MVAr
- the installation of a 115kV-connected SVC at Kirkland Lake TS, rated at +200/-100MVAr

It is therefore recommended that a Notification of Conditional Approval to Connect be issued for this work.

This approval also covers the following work:

- The uprating of the 500kV circuits E510V & E511V between Essa TS and Claireville TS
- The uprating of the section of the 115kV circuits H6T & H7T between La Forest Junction and Timmins TS
- The modification of the NE Load & Generation Rejection Scheme, including the duplication of those facilities associated with an X503E or X504E contingency to meet the requirements for possible classification as a Type I SPS.
- The modification of the Under-Frequency Load-Shedding Scheme in the north-east

Approval for those facilities directly associated with the following are expected to be the subject of separate Assessments, and are therefore not included in this Notification of Approval:

- The enhancement of the Mississagi Flow-East Interface
- The incorporation of the additional generating facilities at the expanded Mattagami River plants, and
- The installation of additional shunt capacitor banks to increase the Flow-South transfer capability from 2150MW to 2500MW.

APPENDIX A Line Ratings									
500kV Line Ratings: North-East			*Ratings at 30^{o}C Ambient: 4km/hr wind: MVA at 520kV*						
Circuit	*Conductor (Limiting Section)*	*Sag Temp*	*Continuous at 93^{o}C or Sag Temperature, if lower*		*Long-Term 'Emergency' at 127^{o}C or Sag Temperature, if lower*		*15-min LTR at Sag Temperature*		
D501P: Pinard TS to Porcupine TS									
Pinard TS to Structure 1 ***(East)***	Quad 583.2 18/7	71^{o}C	2210A	1990MVA	2210A	1990MVA	2210A	1990MVA	*Pre-load of 2210A*
Structure 1 Dead-end Loops ***(E)***	Twin 795.0 26/7	127^{o}C	1780A	1603MVA	2280A	2054MVA	2510A	2261MVA	*Pre-load of 1780A*
Pinard TS to Structure 1 ***(West)***	Quad 585.0 26/7	127^{o}C	2950A	2657MVA	3750A	3377MVA	4020A	3621MVA	*Pre-load of 2950A*
Structure 1 Dead-end Loops ***(W)***	Twin 3640 91/0	127^{o}C	4070A	3666MVA	5330A	4800MVA	6940A	6251MVA	*Pre-load of 4070A*
Structure 1 ***(East)*** to ***(West)***	Twin 795.0 26/7	127^{o}C	1780A	1603MVA	2280A	2054MVA	2510A	2261MVA	*Pre-load of 1780A*
Str 1 ***(East)*** to Porcupine TS	Quad 583.2 18/7	71^{o}C	2210A	1990MVA	2210A	1990MVA	2210A	1990MVA	*Pre-load of 2210A*
P502X: Porcupine TS to Hanmer TS									
Porcupine TS to Hanmer TS	Quad 583.2 18/7	71^{o}C	2210A	1990MVA	2210A	1990MVA	2210A	1990MVA	*Pre-load of 2210A*
X503E: Hanmer TS to Essa TS									
Hanmer TS to Junction Point	Quad 495.0 22/7	79^{o}C	2270A	2045MVA	2270A	2045MVA	2270A	2045MVA	*Pre-load of 2270A*
Junction Point to Junction Point	Quad 520.2 18/7	79^{o}C	2330A	2099MVA	2330A	2099MVA	2330A	2099MVA	*Pre-load of 2330A*
Junction Point to Essa TS	Quad 495.0 22/7	79^{o}C	2270A	2045MVA	2270A	2045MVA	2270A	2045MVA	*Pre-load of 2270A*
X504E: Hanmer TS to Essa TS									
Hanmer TS to Junction Point	Quad 520.2 18/7	73^{o}C	2130A	1918MVA	2130A	1918MVA	2130A	1918MVA	*Pre-load of 2130A*
Junction Point to Junction Point	Quad 495.0 22/7	73^{o}C	2080A	1873MVA	2080A	1873MVA	2080A	1873MVA	*Pre-load of 2080A*
Junction Point to Junction Point	Quad 495.0 22/7	76^{o}C	2180A	1963MVA	2180A	1963MVA	2180A	1963MVA	*Pre-load of 2180A*
Junction Point to Essa TS	Quad 468.3 26/7	78^{o}C	2180A	1963MVA	2180A	1963MVA	2180A	1963MVA	*Pre-load of 2180A*

APPENDIX A (Continued) Line Ratings

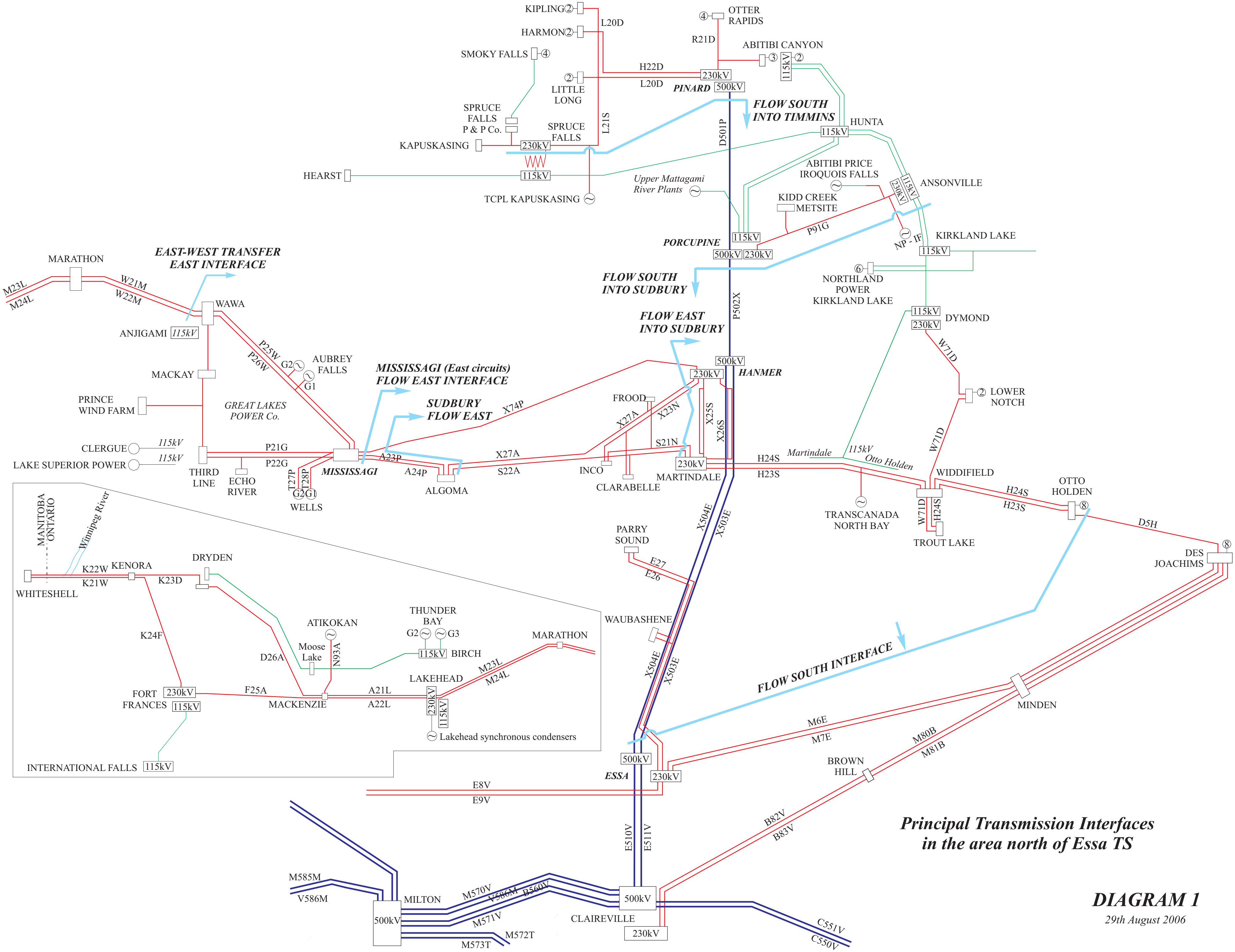
230kV Line Ratings: North-East			*Ratings at 30°C Ambient: 4km/hr wind: MVA at 240kV*						
Circuit	*Conductor (Limiting Section)*	*Sag Temp*	*Continuous at 93°C or Sag Temperature, if lower*		*Long-Term 'Emergency' at 127°C or Sag Temperature, if lower*		*15-min LTR at Sag Temperature*		
H22D & L20D: Pinard TS to Little Long GS									
Pinard TS to Little Long GS	1277.5kcmil 42/7	93°C/127°C	1140A	474MVA	1470A	611MVA	1680A	698MVA	*Pre-load of 1140A*

115kV Line Ratings: North-East				*Ratings at 30°C Ambient: 4km/hr wind: MVA at 121kV*						
Circuit		*Conductor (Limiting Section)*	*Sag Temp*	*Continuous at 93°C or Sag Temperature, if lower*		*Long-Term 'Emergency' at 127°C or Sag Temperature, if lower*		*15-min LTR at Sag Temperature*		
D3K: Dymond TS to Kirkland Lake TS										
Dymond TS to Kirkland Lake TS		477kcmil 26/7	82°C	550A	115MVA	550A	115MVA	550A	115MVA	*Pre-load of 550A*
H9K: Hunta SS to Kapuskasing TS										
Kapuskasing TS to O'Brien Jct		795kcmil 26/7	110°C	850A	178MVA	980A	205MVA	1050A	220MVA	*Pre-load of 850A*
O'Brien Jct to Structure 585		336.4kcmil 26/7	150°C	490A	103MVA	630A	132MVA	740A	155MVA	*Pre-load of 490A*
Structure 585 to Carmichael Jct		211.6kcmil 6/1	71°C	280A	59MVA	280A	59MVA	280A	59MVA	*Pre-load of 280A*
Carmichael Jct to Fauquier Jct			144°C	370A	78MVA	460A	96MVA	510A	107MVA	*Pre-load of 370A*
Fauquier Jct to Malette Jct			88°C	350A	73MVA	350A	73MVA	350A	73MVA	*Pre-load of 350A*
Malette Jct to Structure 127			150°C	370A	78MVA	460A	96MVA	530A	111MVA	*Pre-load of 370A*
Str 127 to Hunta Jct	D/C Line Parallelled		66°C	260A	54MVA	260A	54MVA	260A	54MVA	*Pre-load of 260A*
Str 127 to Str 116			68°C	270A	57MVA	270A	57MVA	270A	57MVA	*Pre-load of 270A*
Str 116 to Hunta Jct			68°C	270A	57MVA	270A	57MVA	270A	57MVA	*Pre-load of 270A*
Hunta Jct to Hunta SS		795kcmil 26/7	150°C	850A	178MVA	1090A	228MVA	1400A	293MVA	*Pre-load of 850A*

APPENDIX A (Continued) Line Ratings									
115kV Line Ratings: North-East			*Ratings at 30^{o}C Ambient: 4km/hr wind: MVA at 121kV*						
Circuit	*Conductor (Limiting Section)*	*Sag Temp*	*Continuous at 93^{o}C or Sag Temperature, if lower*		*Long-Term 'Emergency' at 127^{o}C or Sag Temperature, if lower*		*15-min LTR at Sag Temperature*		
H6T & H7T:Hunta SS to Timmins TS									
Hunta SS to Tower No. 5	336.4kcmil 30/7	150^{o}C	500A	104MVA	630A	132MVA	750A	157MVA	*Pre-load of 500A*
Tower No. 5 to Tower No. 280		99^{o}C	500A	104MVA	520A	109MVA	530A	111MVA	*Pre-load of 500A*
Tower No. 280 to Tower No. 284	336.4kcmil 26/7	150^{o}C	500A	104MVA	630A	132MVA	750A	157MVA	*Pre-load of 500A*
Tower No. 284 to Timmins TS	336.4kcmil 30/7	70^{o}C	370A	78MVA	370A	78MVA	370A	78MVA	*Pre-load of 370A*
A4H: Ansonville TS to Hunta SS									
Ansonville TS to Hunta SS	203.2kcmil 16/19	60^{o}C	260A	54MVA	260A	54MVA	260A	54MVA	*Pre-load of 260A*
A5H: Ansonville TS to Hunta SS									
Ansonville TS to Str 210	795kcmil 26/7	150^{o}C	850A	178MVA	1090A	228MVA	1400A	293MVA	*Pre-load of 850A*
Str 210 to Str 206	468.3kcmil 26/7	150^{o}C	610A	128MVA	780A	163MVA	940A	197MVA	*Pre-load of 610A*
Str 206 to Str 200	336.4kcmil 26/7	150^{o}C	500A	104MVA	630A	132MVA	750A	157MVA	*Pre-load of 500A*
Str 200 to Str 8									
Str 8 to Str 4	203.2kcmil 16/19	150^{o}C	380A	88MVA	490A	103MVA	580A	122MVA	*Pre-load of 380A*
Str 4 to Iroquois Falls Jct	336.4kcmil 26/7	130^{o}C	500A	104MVA	630A	132MVA	750A	157MVA	*Pre-load of 500A*
Iroquois Fall Jct to Str 186	336.4kcmil 26/7	150^{o}C	500A	104MVA	630A	132MVA	750A	157MVA	*Pre-load of 500A*
Str 186 to Str 123	500kcmil 30/7	73^{o}C	500A	104MVA	500A	104MVA	500A	104MVA	*Pre-load of 500A*
Str 123 to Str 51	500kcmil 30/7	76^{o}C	520A	109MVA	520A	109MVA	520A	109MVA	*Pre-load of 520A*
Str 51 to Fournier Jct	477kcmil 26/7	150^{o}C	620A	130MVA	790A	166MVA	960A	201MVA	*Pre-load of 620A*
Fournier Jct to Str 50									
Str 50 to Hunta SS	500kcmil 30/7	66^{o}C	440A	92MVA	440A	92MVA	440A	92MVA	*Pre-load of 440A*

APPENDIX A (Continued) Line Ratings									
115kV Line Ratings: North-East			*Ratings at 30^{o}C Ambient: 4km/hr wind: MVA at 121kV*						
Circuit	*Conductor (Limiting Section)*	*Sag Temp*	*Continuous at 93^{o}C or Sag Temperature, if lower*		*Long-Term 'Emergency' at 127^{o}C or Sag Temperature, if lower*		*15-min LTR at Sag Temperature*		
A8K: Ansonville TS to Kirkland Lake TS									
Ansonville TS to Tower No. 271	468.3kcmil 26/7	60^{o}C	420A	88MVA	420A	88MVA	420A	88MVA	*Pre-load of 420A*
Tower No. 271 to Junction Point	167.8kcmil 6/1	60^{o}C	220A	46MVA	220A	46MVA	220A	46MVA	*Pre-load of 220A*
Junction Point to Tower No. 408	211.6kcmil 6/1	60^{o}C	260A	54MVA	260A	54MVA	260A	54MVA	*Pre-load of 260A*
Tower No. 408 to Tower No. 648	133.2kcmil 7/0 Cu	60^{o}C	250A	52MVA	250A	52MVA	250A	52MVA	*Pre-load of 250A*
Tower No. 648 to Tower No. 652	203.2kcmil 16/19	150^{o}C	380A	88MVA	490A	103MVA	580A	122MVA	*Pre-load of 380A*
Tower 652 to Kirkland Lake SS	167.8kcmil 6/1	60^{o}C	220A	46MVA	220A	46MVA	220A	46MVA	*Pre-load of 220A*
A9K: Ansonville TS to Kirkland Lake TS									
Ansonville TS to Junction Point	795kcmil 26/7	127^{o}C	850A	178MVA	1090A	228MVA	1210A	254MVA	*Pre-load of 850A*
Junction Point to Junction Point	468.3kcmil 26/7	60^{o}C	420A	88MVA	420A	88MVA	420A	88MVA	*Pre-load of 420A*
Junction Point to Junction Point	336.4kcmil 26/7	60^{o}C	340A	71MVA	340A	71MVA	340A	71MVA	*Pre-load of 340A*
Jct Pt to Monteith Jct to Jct Pt	167.8kcmil 6/1	82^{o}C	280A	59MVA	280A	59MVA	280A	59MVA	*Pre-load of 280A*
Junction Point to Junction Point	477kcmil 26/7	82^{o}C	550A	115MVA	550A	115MVA	550A	115MVA	*Pre-load of 550A*
Junction Point to Junction Point	167.8kcmil 6/1	82^{o}C	280A	59MVA	280A	59MVA	280A	59MVA	*Pre-load of 280A*
Junction Point to Junction Point	211.6kcmil 6/1	82^{o}C	330A	69MVA	330A	69MVA	330A	69MVA	*Pre-load of 330A*
Junction Point to Junction Point	167.8kcmil 6/1	82^{o}C	280A	59MVA	280A	59MVA	280A	59MVA	*Pre-load of 280A*
Junction Point to Ramore Jct	167.8kcmil 7/0 Cu	82^{o}C	360A	75MVA	360A	75MVA	360A	75MVA	*Pre-load of 360A*
Ramore Jct to Ramore TS	167.8kcmil 7/0 Cu	150^{o}C	400A	84MVA	500A	105MVA	570A	119MVA	*Pre-load of 400A*
Ramore TS to Structure 316	167.8kcmil 7/0 Cu	150^{o}C	400A	84MVA	500A	105MVA	570A	119MVA	*Pre-load of 400A*
Structure 316 to Kirkland Lake TS	167.8kcmil 7/0 Cu	60^{o}C	290A	61MVA	290A	61MVA	290A	61MVA	*Pre-load of 290A*

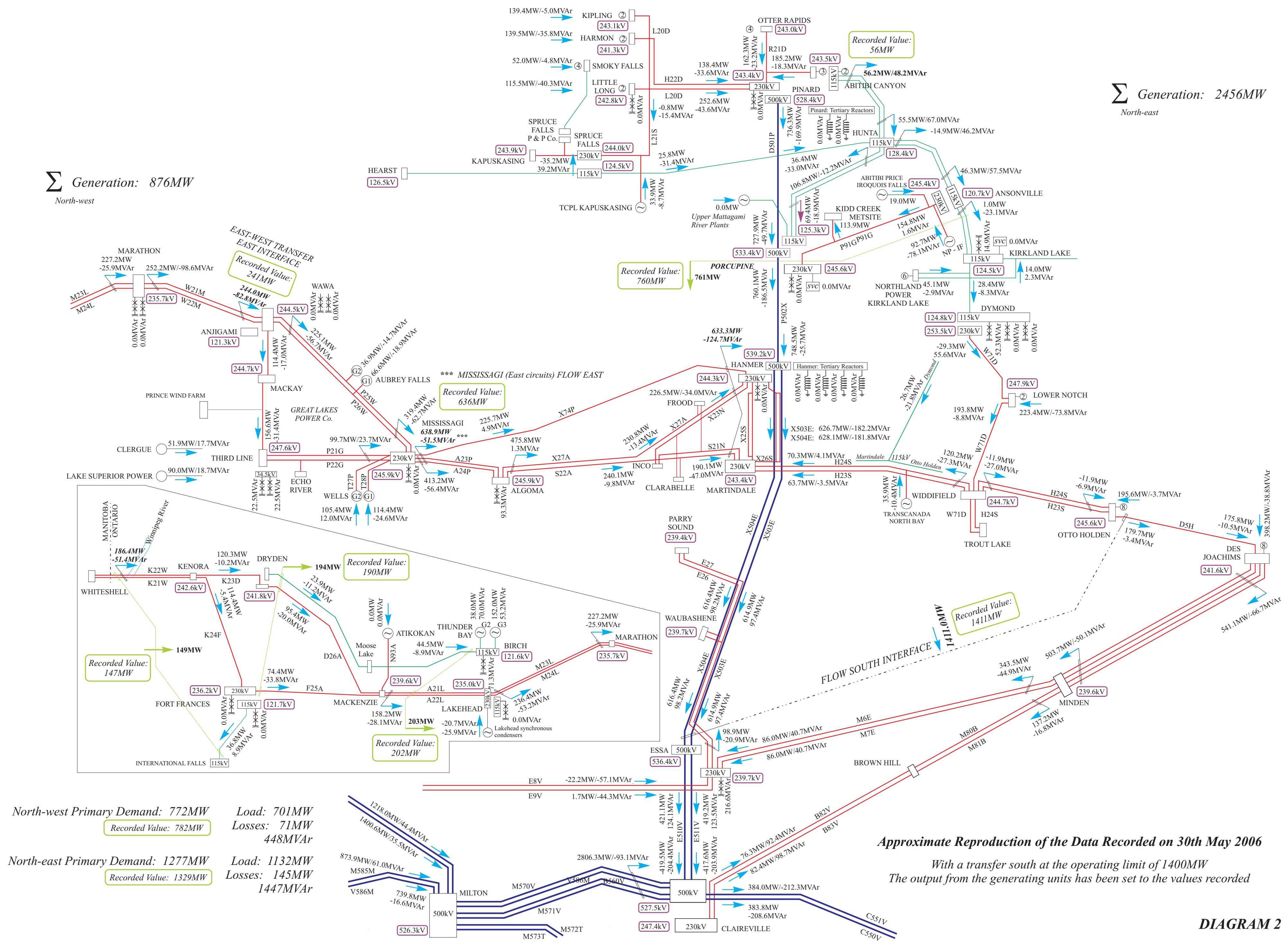
APPENDIX A (Continued) Line Ratings									
115kV Line Ratings: North-East			*Ratings at 30^{o}C Ambient: 4km/hr wind: MVA at 121kV*						
Circuit	*Conductor (Limiting Section)*	*Sag Temp*	*Continuous at 93^{o}C or Sag Temperature, if lower*		*Long-Term 'Emergency' at 127^{o}C or Sag Temperature, if lower*		*15-min LTR at Sag Temperature*		
D2L: Dymond TS to Crystal Falls GS									
Dymond TS to Structure 84	477kcmil 26/7	60^{o}C	420A	88MVA	420A	88MVA	420A	88MVA	*Pre-load of 420A*
Structure 84 to Structure 85	795kcmil 26/7	150^{o}C	850A	178MVA	1090A	228MVA	1400A	293MVA	*Pre-load of 850A*
Structure 85 to Structure 261	477kcmil 26/7	60^{o}C	420A	88MVA	420A	88MVA	420A	88MVA	*Pre-load of 420A*
Structure 261 to Structure 95	167.8kcmil 6/1 **TWIN**	60^{o}C	450A	94MVA	450A	94MVA	450A	94MVA	*Pre-load of 450A*
Structure 95 ***(N)*** to Cassels SS	795kcmil 26/7	150^{o}C	850A	178MVA	1090A	228MVA	1400A	293MVA	*Pre-load of 850A*
Cassels SS to Structure 95 ***(S)***	795kcmil 26/7	150^{o}C	850A	178MVA	1090A	228MVA	1400A	293MVA	*Pre-load of 850A*
Structure 95 ***(S)*** to Str 105 ***(N)***	167.8kcmil 6/1 **TWIN**	60^{o}C	450A	94MVA	450A	94MVA	450A	94MVA	*Pre-load of 450A*
Str 105 ***(N)*** to Herridge Lake DS	477kcmil 26/7	150^{o}C	620A	130MVA	790A	166MVA	960A	201MVA	*Pre-load of 620A*
Herridge Lake DS to Str 105 ***(S)***	477kcmil 26/7	150^{o}C	620A	130MVA	790A	166MVA	960A	201MVA	*Pre-load of 620A*
Str 105 ***(S)*** to Str 263 to Str 409	167.8kcmil 6/1 **TWIN**	60^{o}C	450A	94MVA	450A	94MVA	450A	94MVA	*Pre-load of 450A*
Structure 409 to Crystal Falls SS	477kcmil 26/7	150^{o}C	620A	130MVA	790A	166MVA	960A	201MVA	*Pre-load of 620A*



Principal Transmission Interfaces in the area north of Essa TS

DIAGRAM 1

29th August 2006



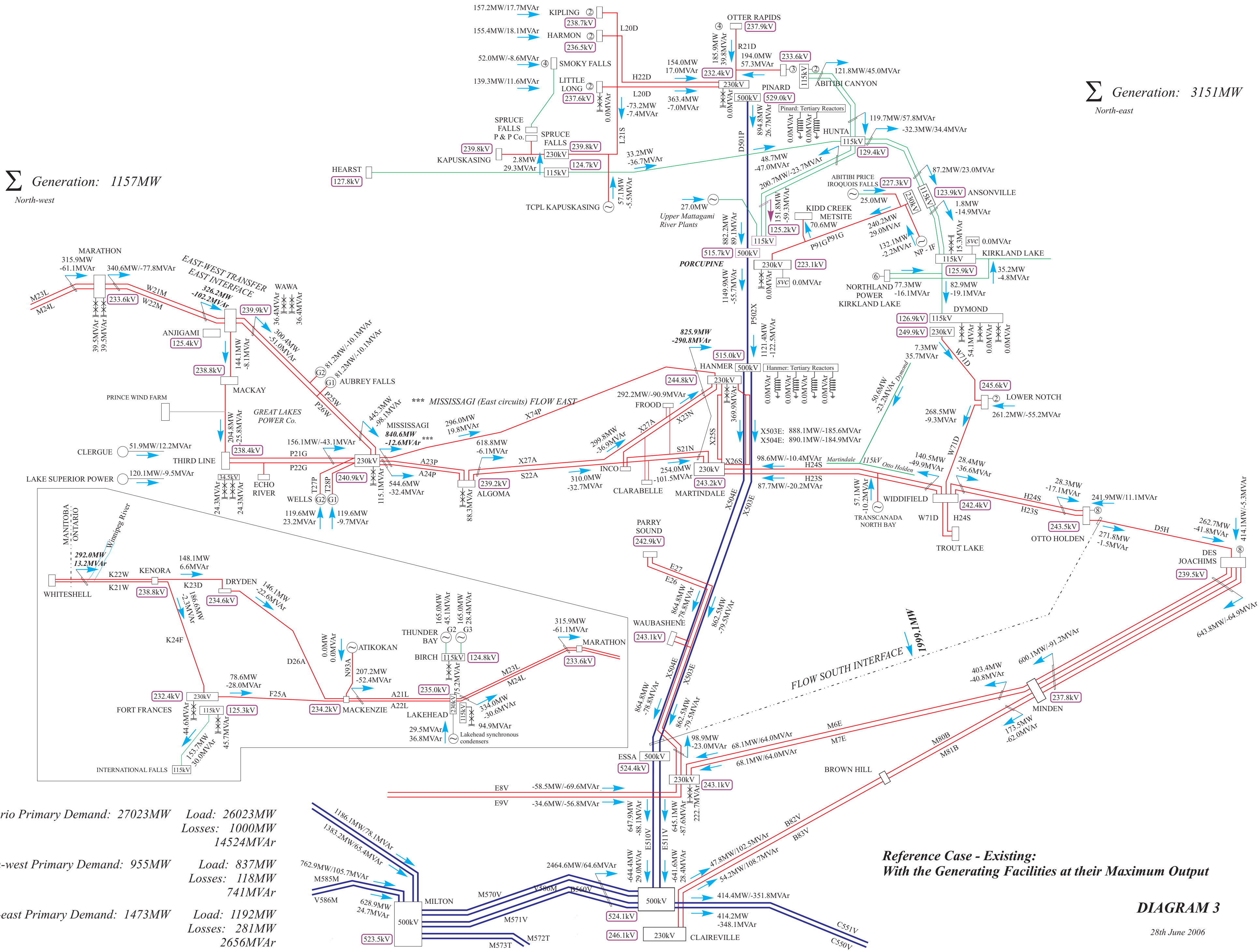
Approximate Reproduction of the Data Recorded on 30th May 2006

With a transfer south at the operating limit of 1400MW

The output from the generating units has been set to the values recorded

DIAGRAM 2

26th June 2006



Ontario Primary Demand: 27023MW *Load: 26023MW*
Losses: 1000MW
14524MVAr

North-west Primary Demand: 955MW *Load: 837MW*
Losses: 118MW
741MVAr

North-east Primary Demand: 1473MW *Load: 1192MW*
Losses: 281MW
2656MVAr

Reference Case - Existing:
With the Generating Facilities at their Maximum Output

DIAGRAM 3

28th June 2006

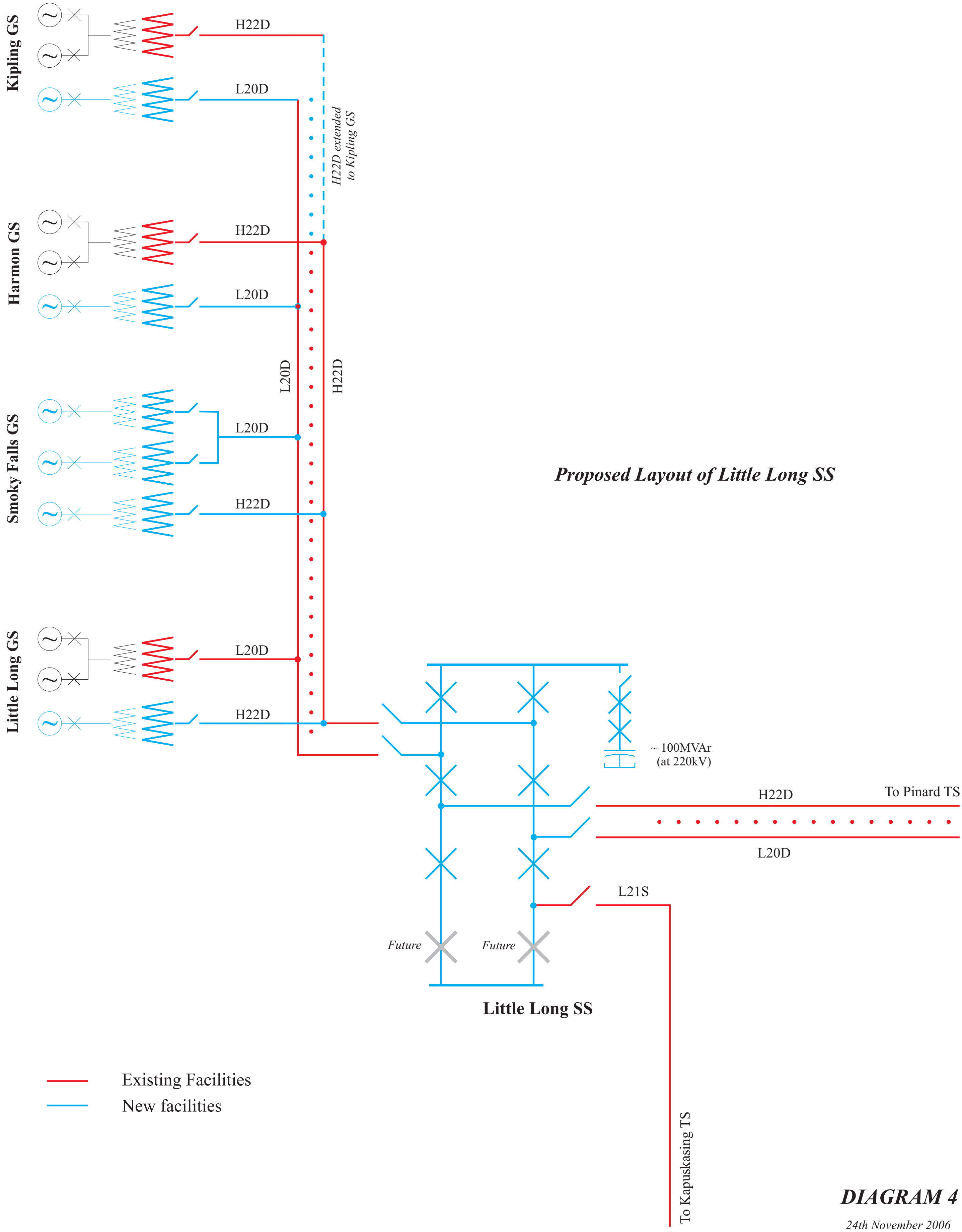
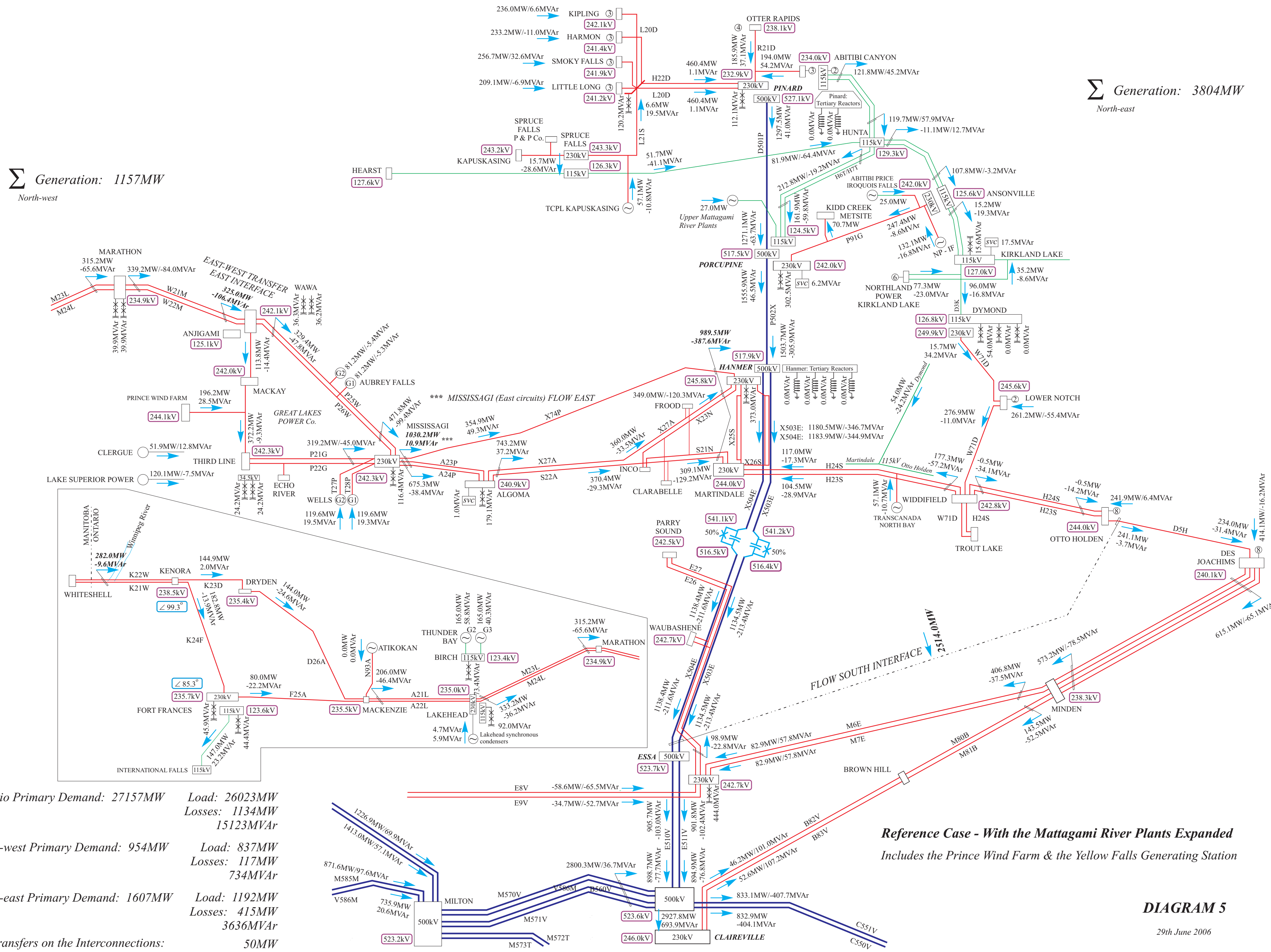


DIAGRAM 4

24th November 2006



Ontario Primary Demand: 27157MW — *Load: 26023MW*, *Losses: 1134MW*, *15123MVAr*

North-west Primary Demand: 954MW — *Load: 837MW*, *Losses: 117MW*, *734MVAr*

North-east Primary Demand: 1607MW — *Load: 1192MW*, *Losses: 415MW*, *3636MVAr*

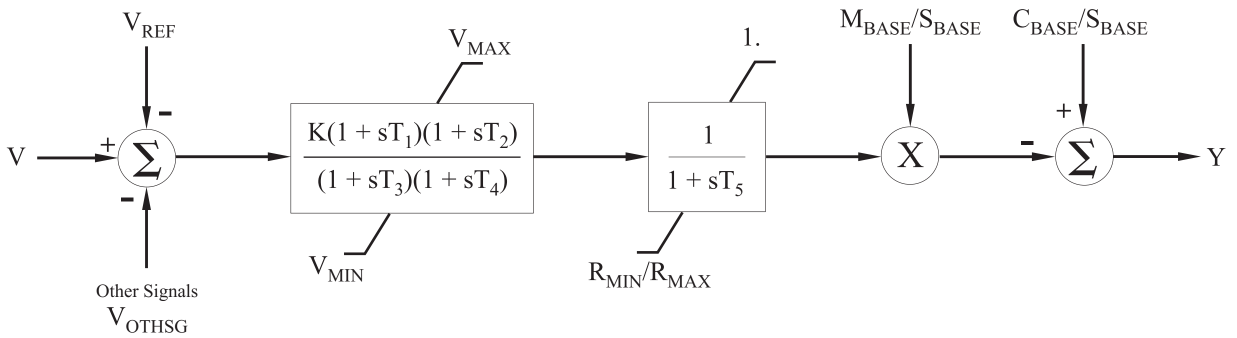
Net Transfers on the Interconnections: 50MW

Reference Case - With the Mattagami River Plants Expanded

Includes the Prince Wind Farm & the Yellow Falls Generating Station

DIAGRAM 5

29th June 2006



Values used in the Transient Stability Analysis

K	32	
R_{MIN} Reactor Minimum MVAr Output	0.0MVAr	
V_{MAX}	1.0	
V_{MIN}	0.0	
T_1	0.00 sec	
T_2	0.00 sec	
T_3	0.02 sec	
T_4	0.00 sec	
T_5	0.00 sec	
	Porcupine TS	Kirkland Lake TS
C_{BASE} Capacitor MVAr Output	300MVAr	200MVAr
M_{BASE} MVAr Range of SVC	400MVAr	300MVAr

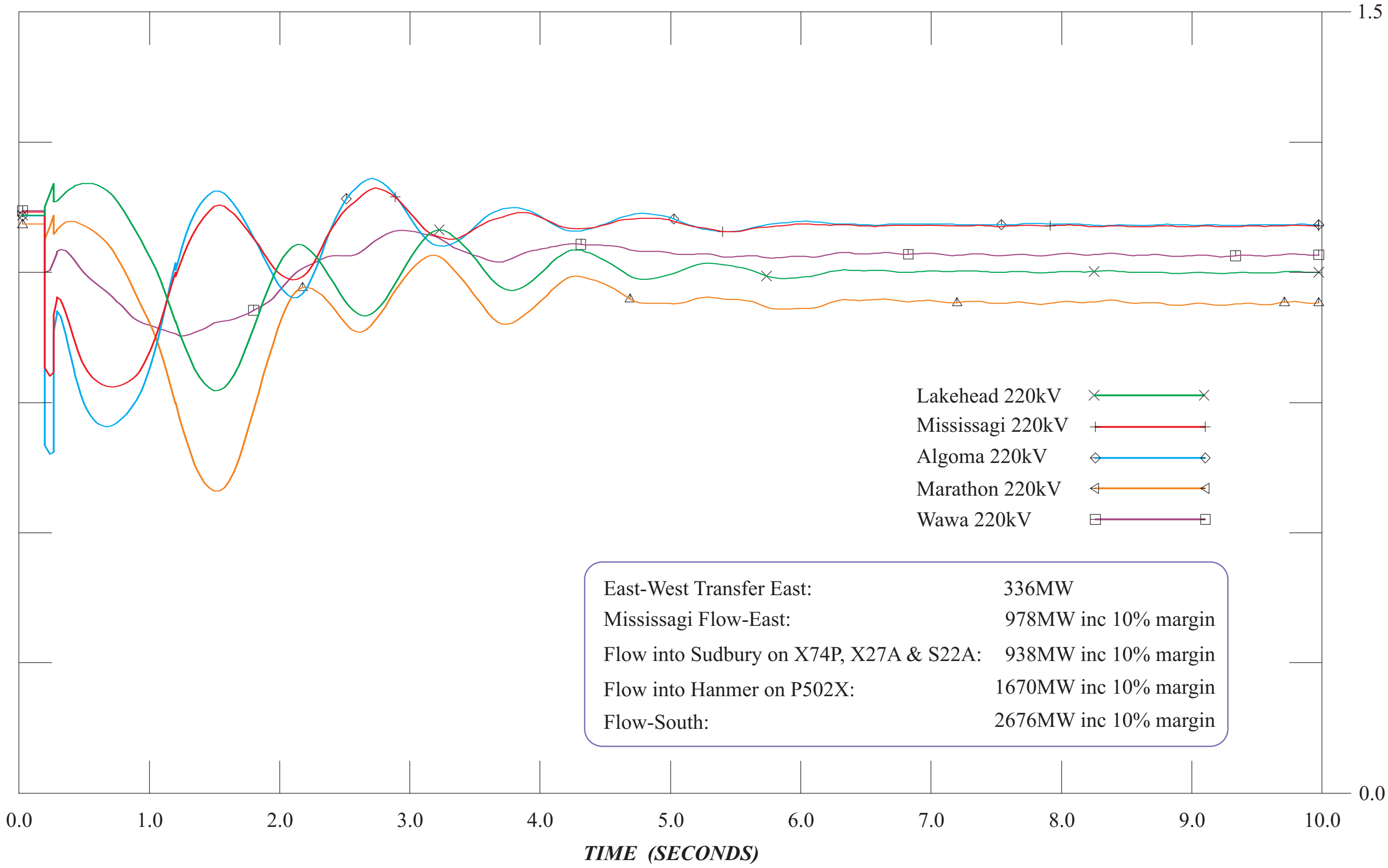
CSVGN1 Static VAr Compensator Model

Data assumed for the Transient Analysis

DIAGRAM 6

5th July 2006

Voltages with the Output from the Prince Wind Farm at 150MW



Voltages with the Output from the Prince Wind Farm at 175MW

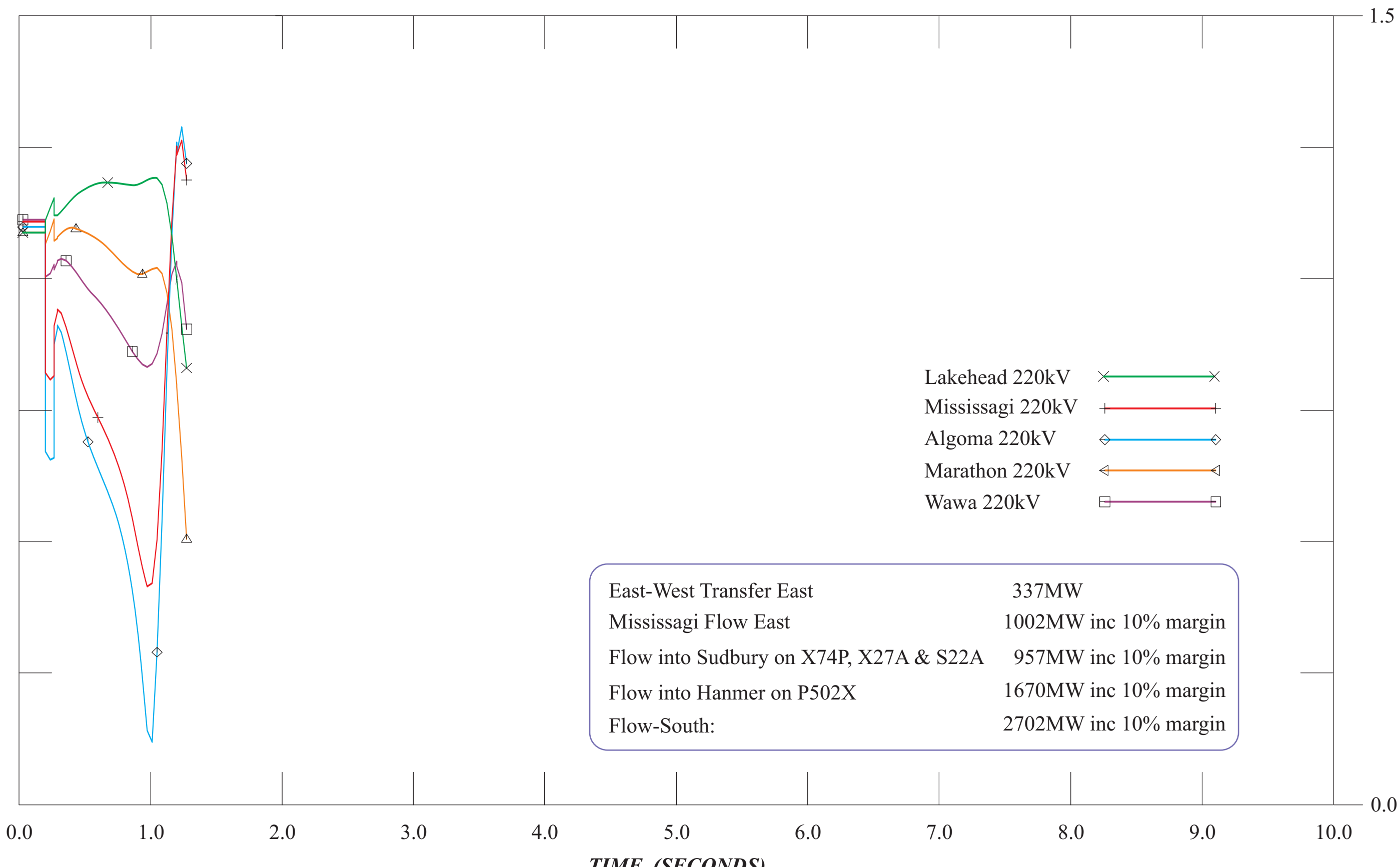
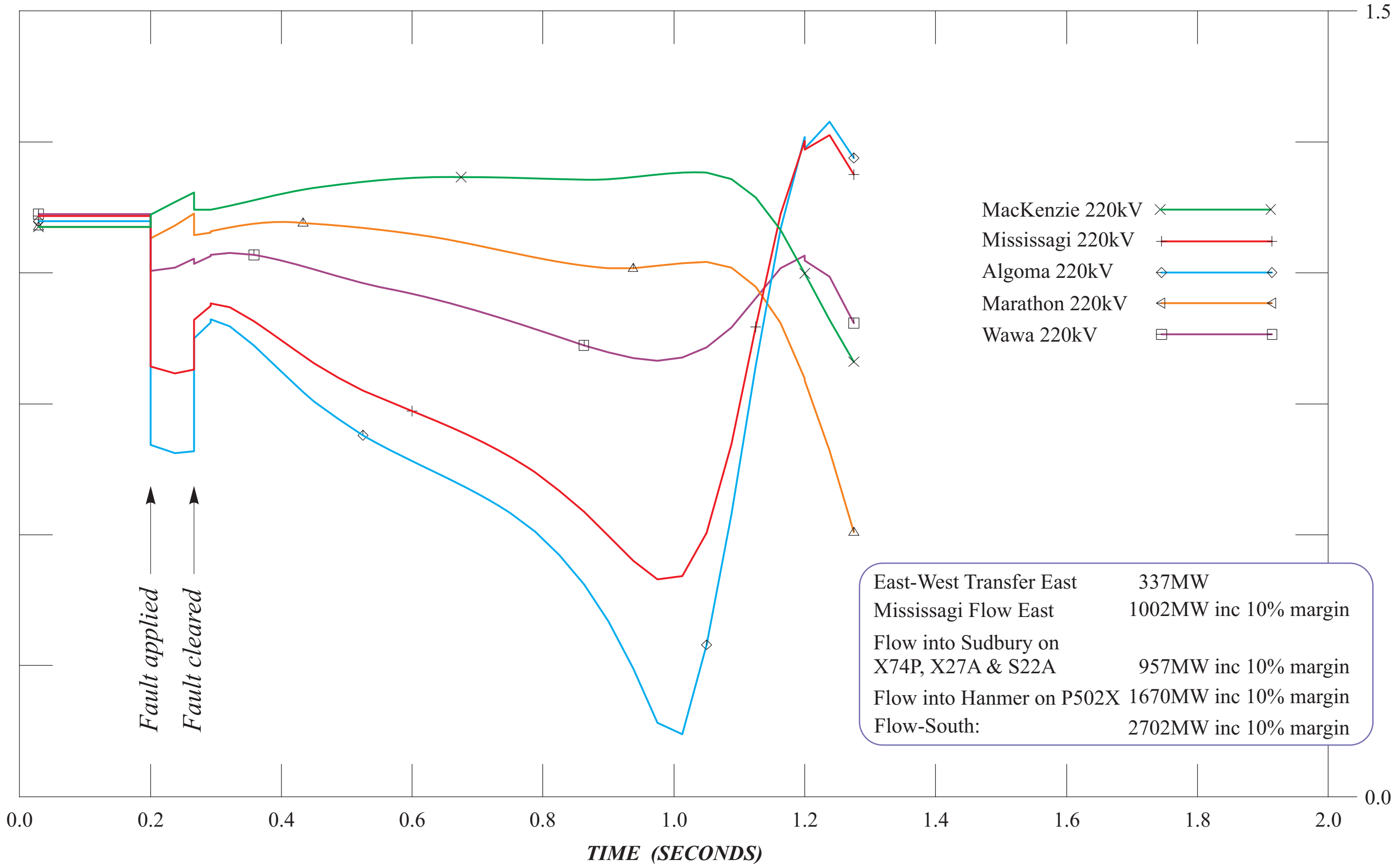


DIAGRAM 7

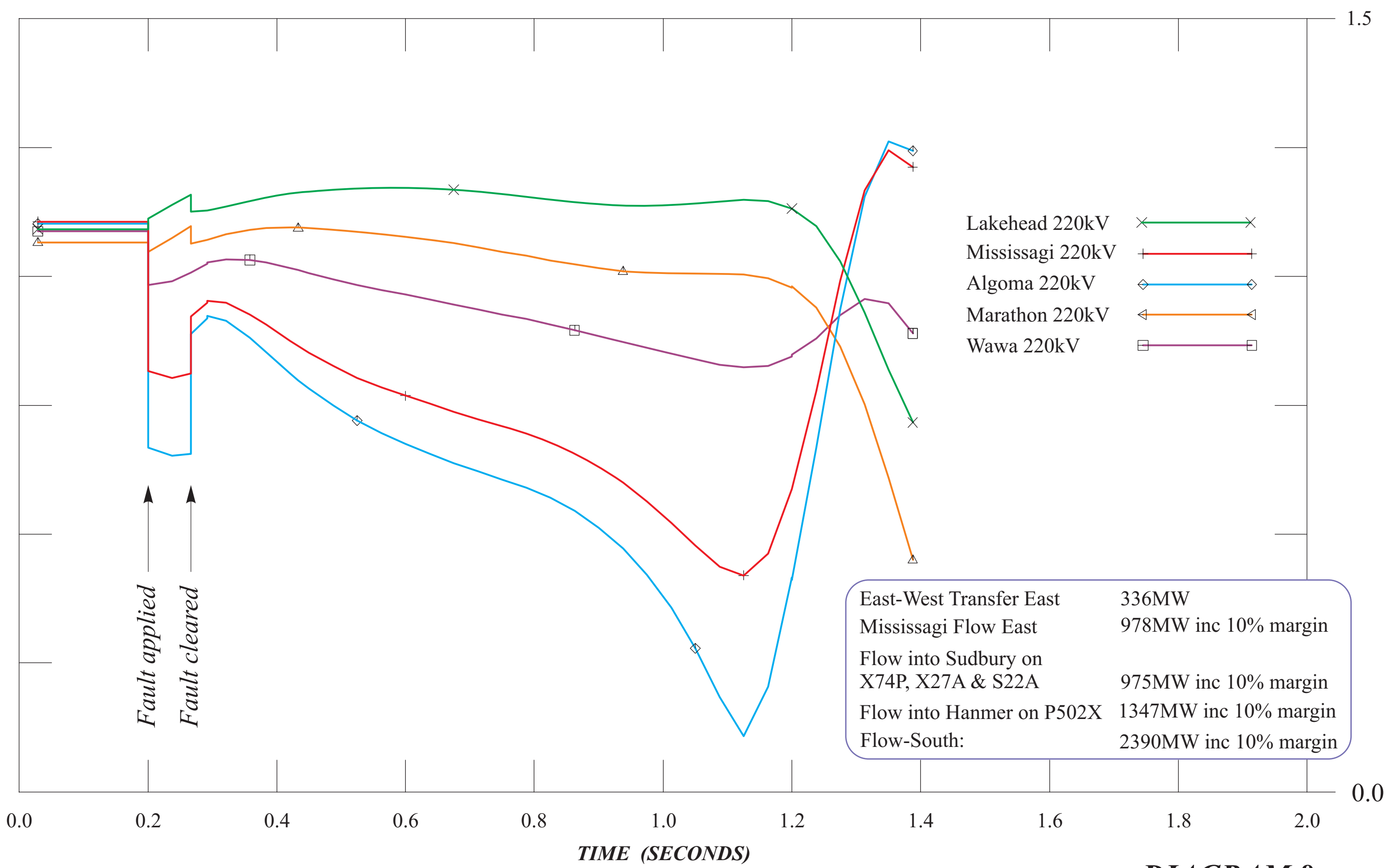
Transient Voltages in Response to a Contingency Involving the 500kV Circuit P502X

17th July 2006

Copy of the lower half of Diagram 7



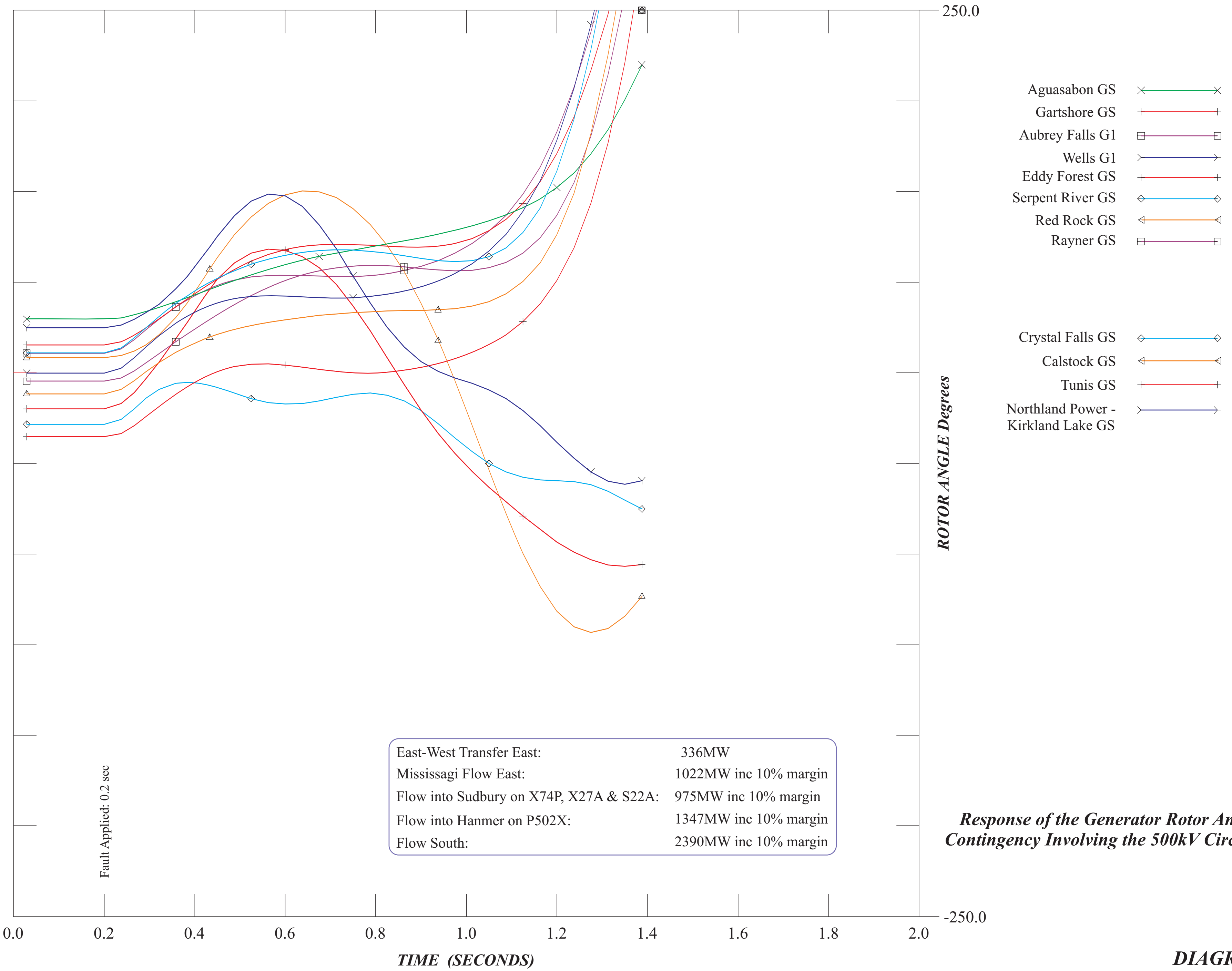
With reduced Flow-South into Sudbury



Transient Voltages in Response to a Contingency Involving the 500kV Circuit P502X

DIAGRAM 8

17th July 2006



Response of the Generator Rotor Angles to a Contingency Involving the 500kV Circuit P502X

DIAGRAM 9

19th August 2006

Voltages West of Sudbury with a +300/-100MVAr SVC at Marathon TS

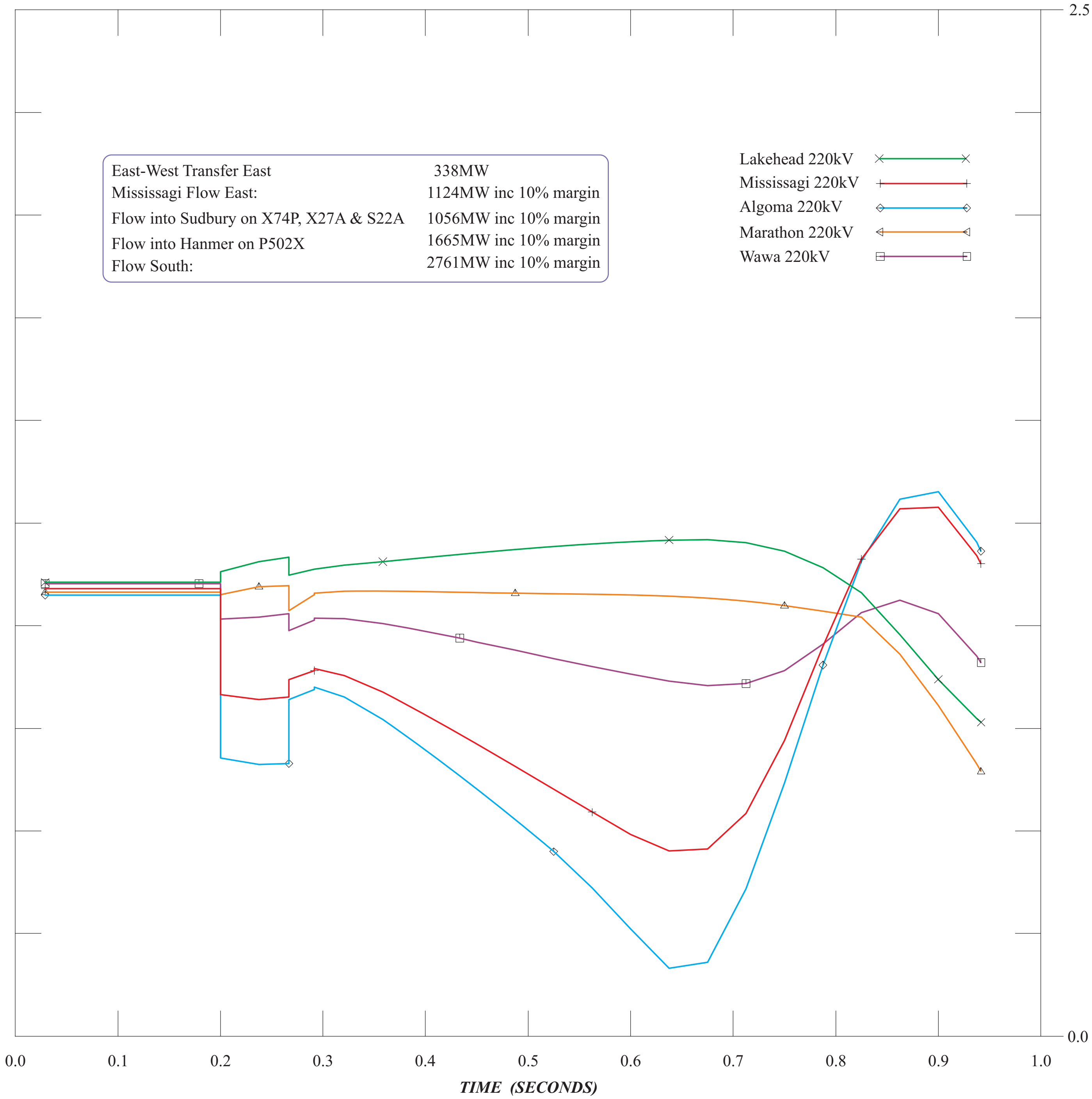
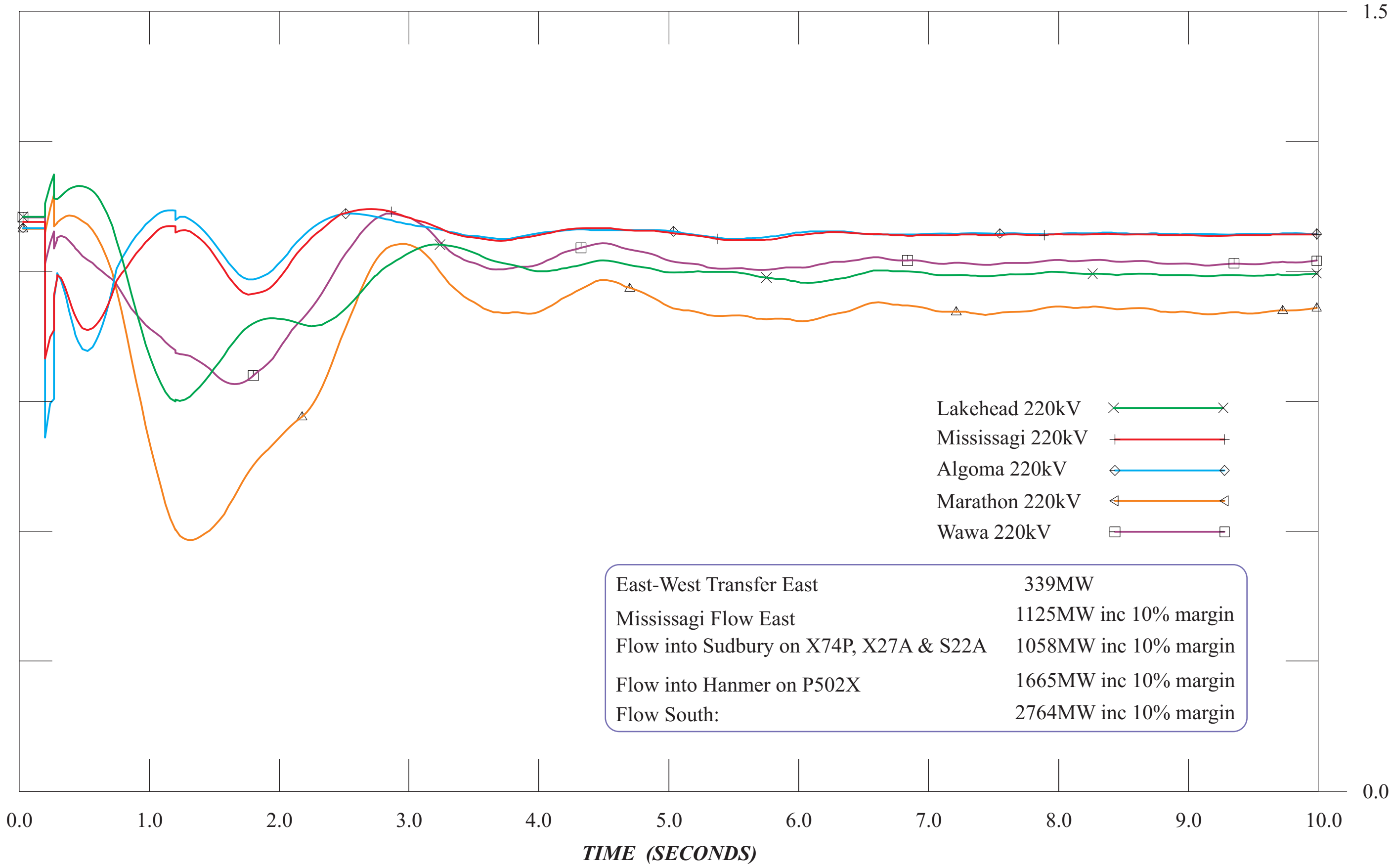


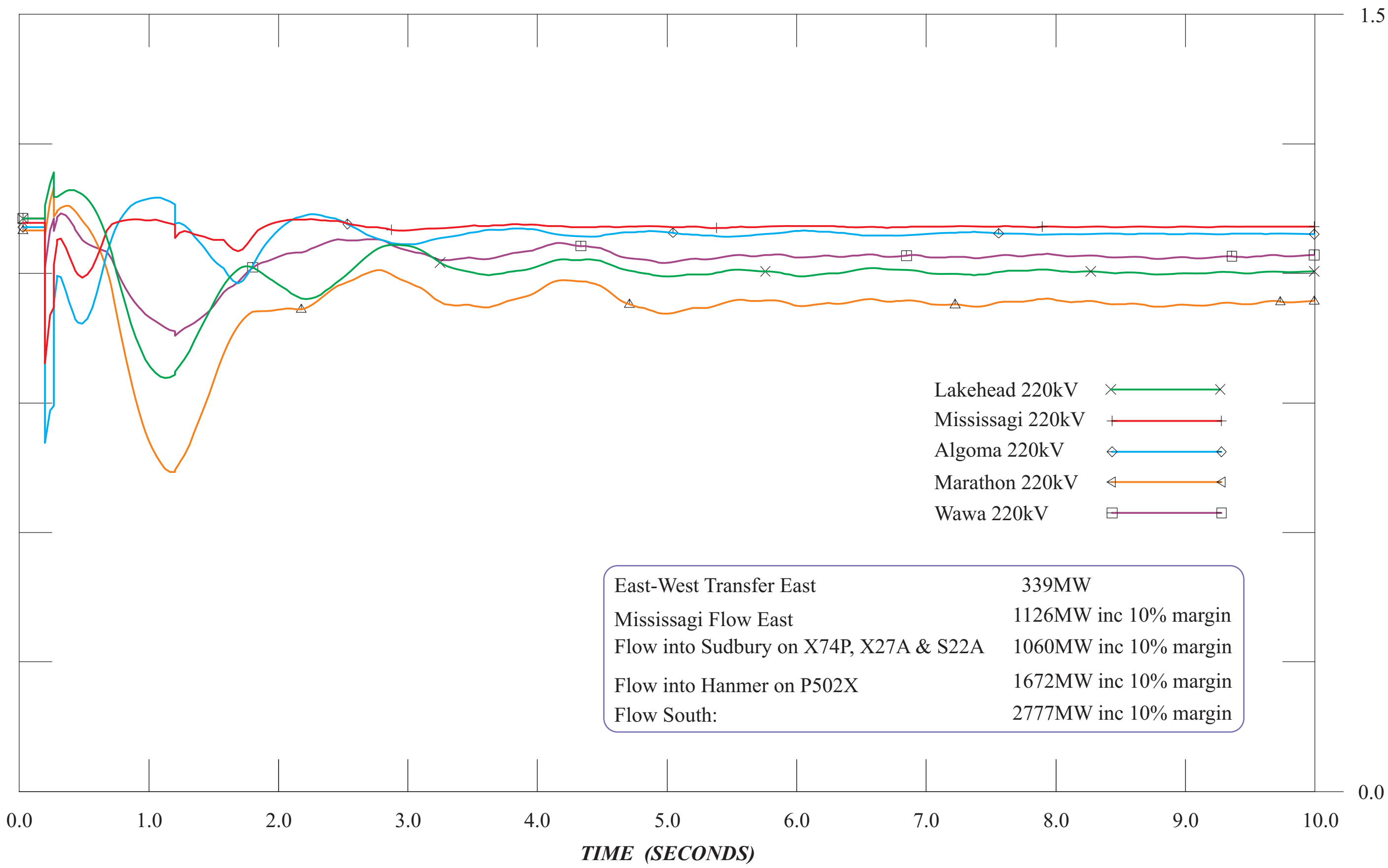
DIAGRAM 10

17th July 2006

Voltages West of Sudbury with a +300/-100MVAr SVC at Algoma TS



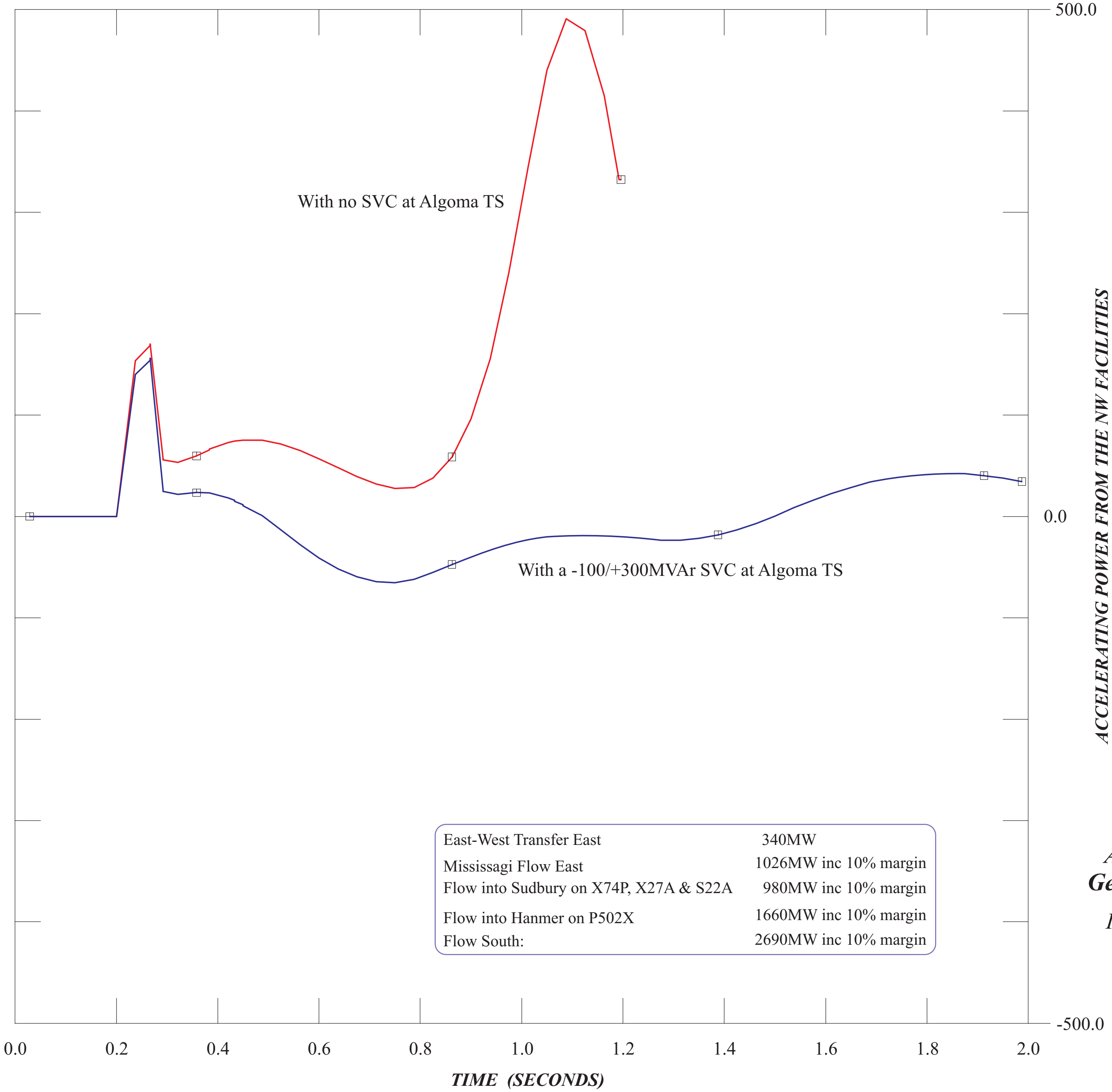
Voltages West of Sudbury with a +300/-100MVAr SVC at Mississagi TS



Transient Voltages in Response to a Contingency Involving the 500kV Circuit P502X

DIAGRAM 11

17th July 2006

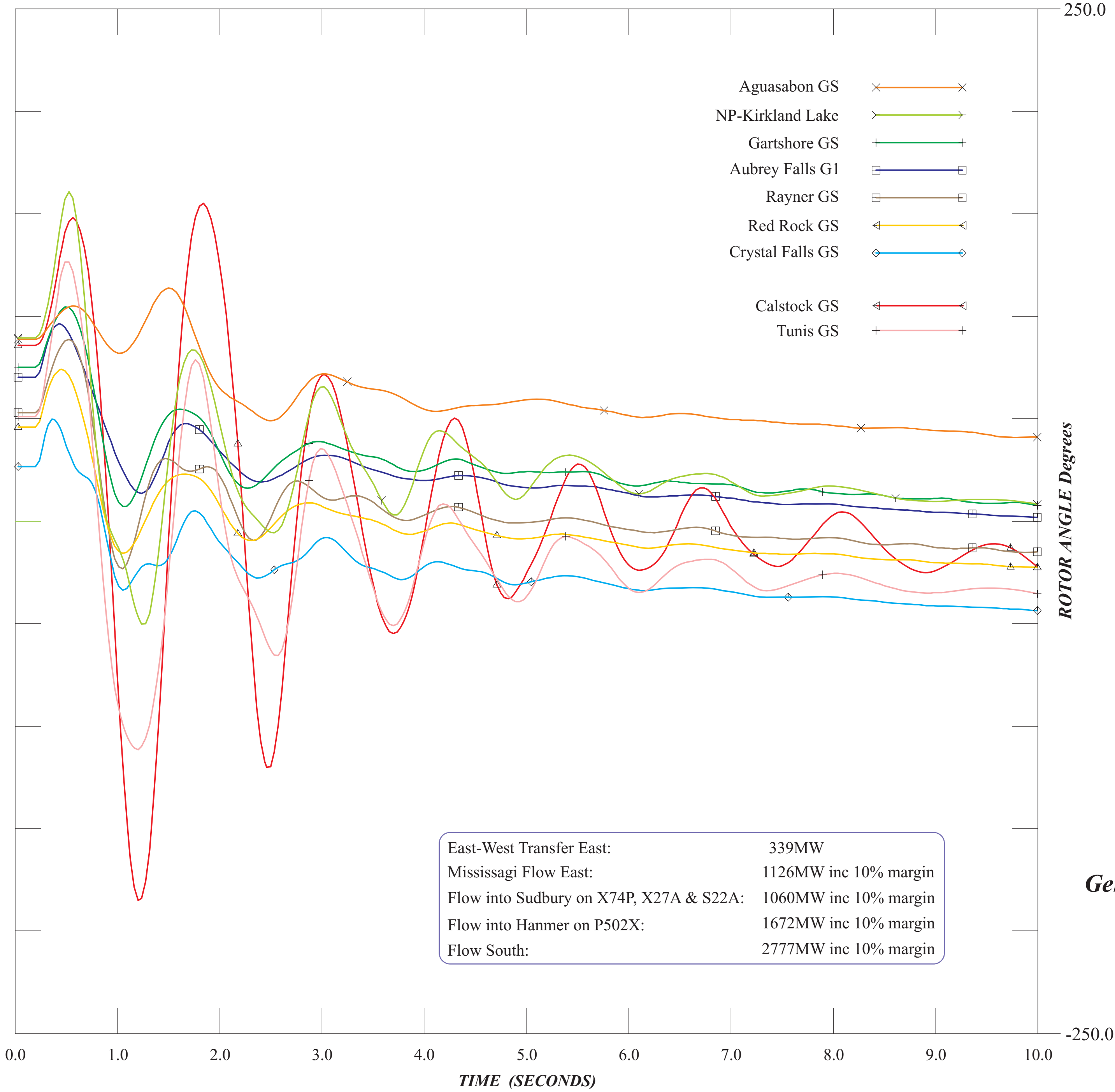


Accelerating Power from the Generating Facilities in the NW

In response to a 3-phase fault at Hanmer TS on circuit P502X

DIAGRAM 12

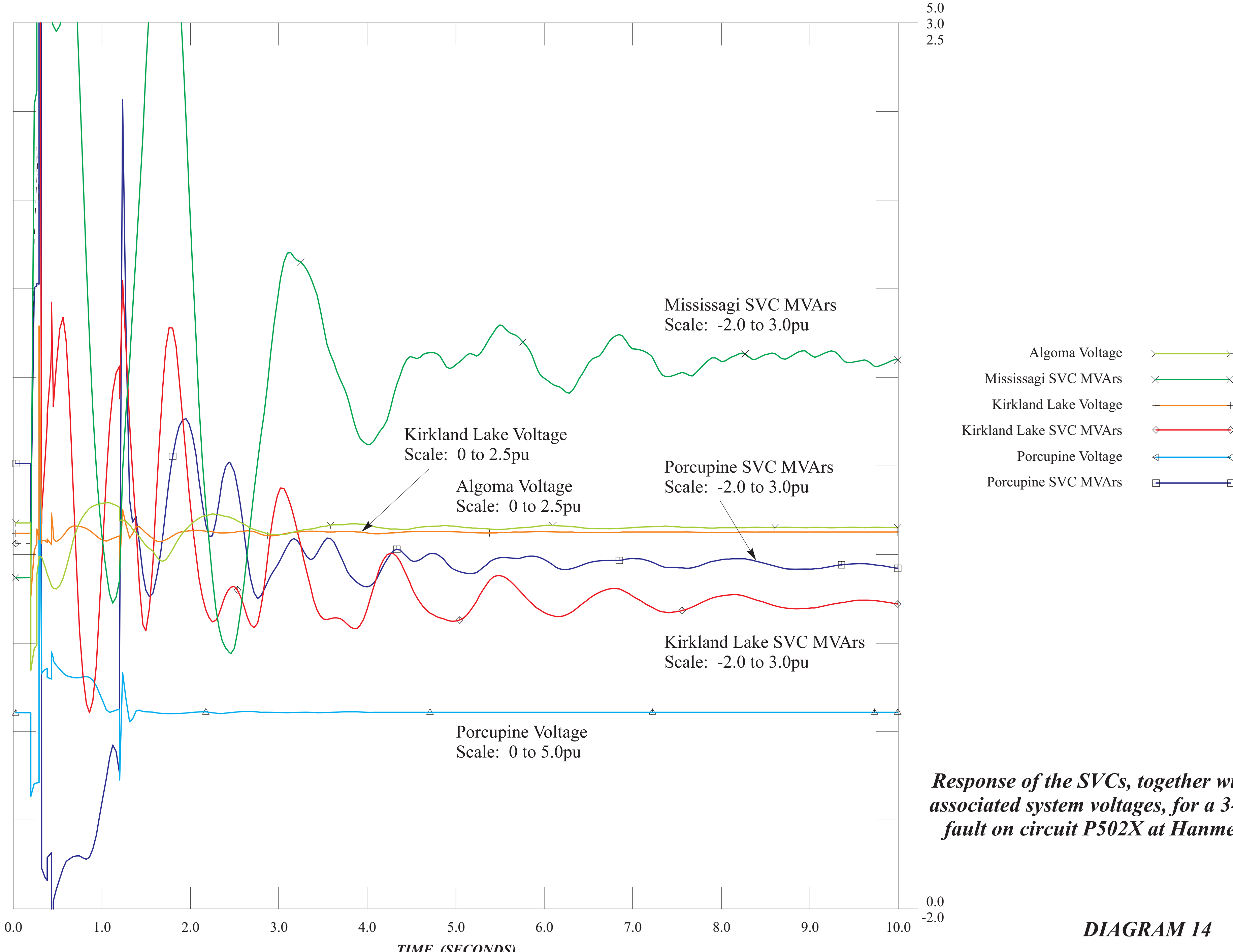
5th July 2006



Generator Rotor Angle Responses to a 3-phase fault on circuit P502X at Hanmer TS

DIAGRAM 13

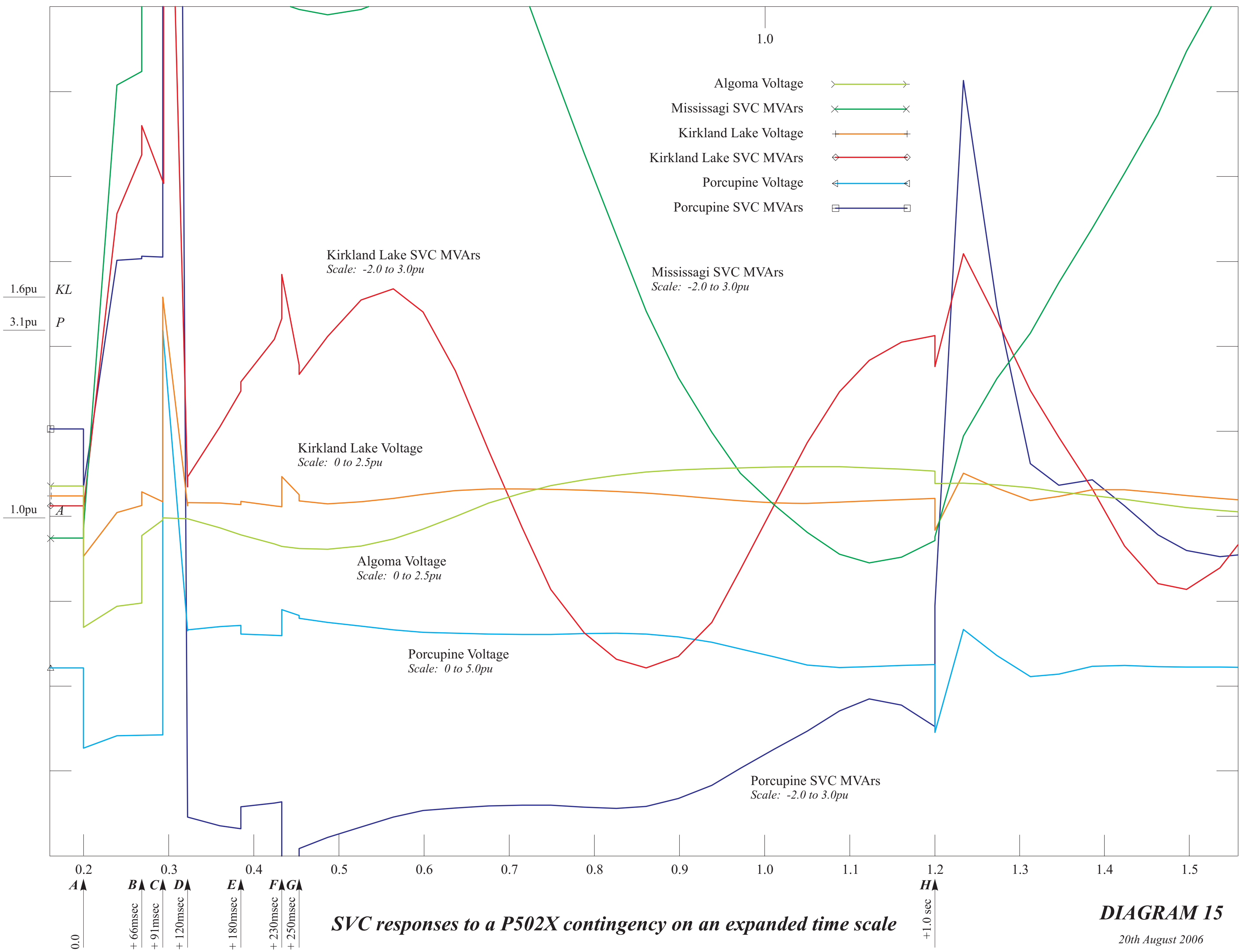
20th August 2006



Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit P502X at Hanmer TS

DIAGRAM 14

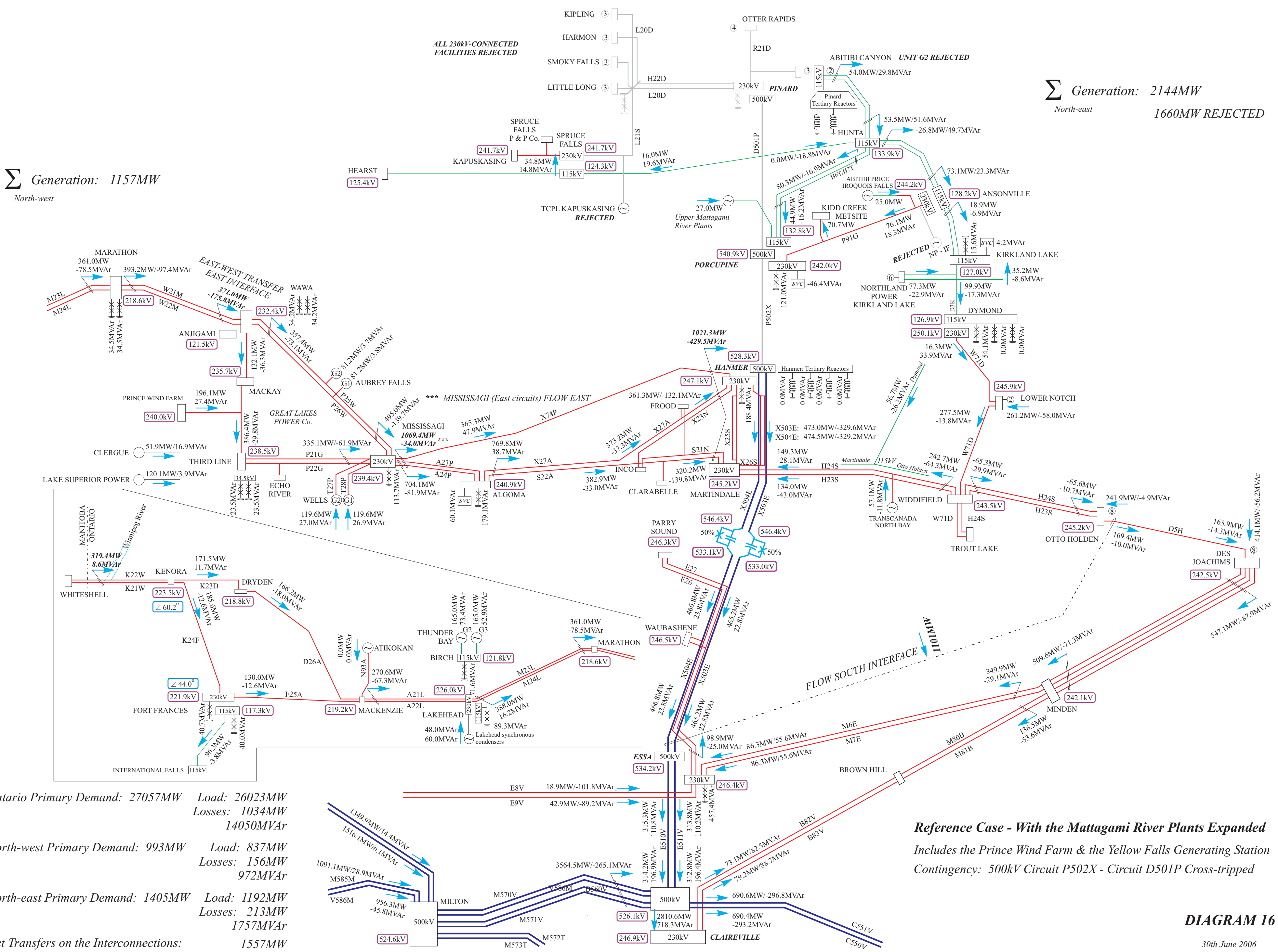
20th August 2006



SVC responses to a P502X contingency on an expanded time scale

DIAGRAM 15

20th August 2006



Ontario Primary Demand: 27057MW — *Load: 26023MW*
Losses: 1034MW
14050MVAr

North-west Primary Demand: 993MW — *Load: 837MW*
Losses: 156MW
972MVAr

North-east Primary Demand: 1405MW — *Load: 1192MW*
Losses: 213MW
1757MVAr

Net Transfers on the Interconnections: 1557MW

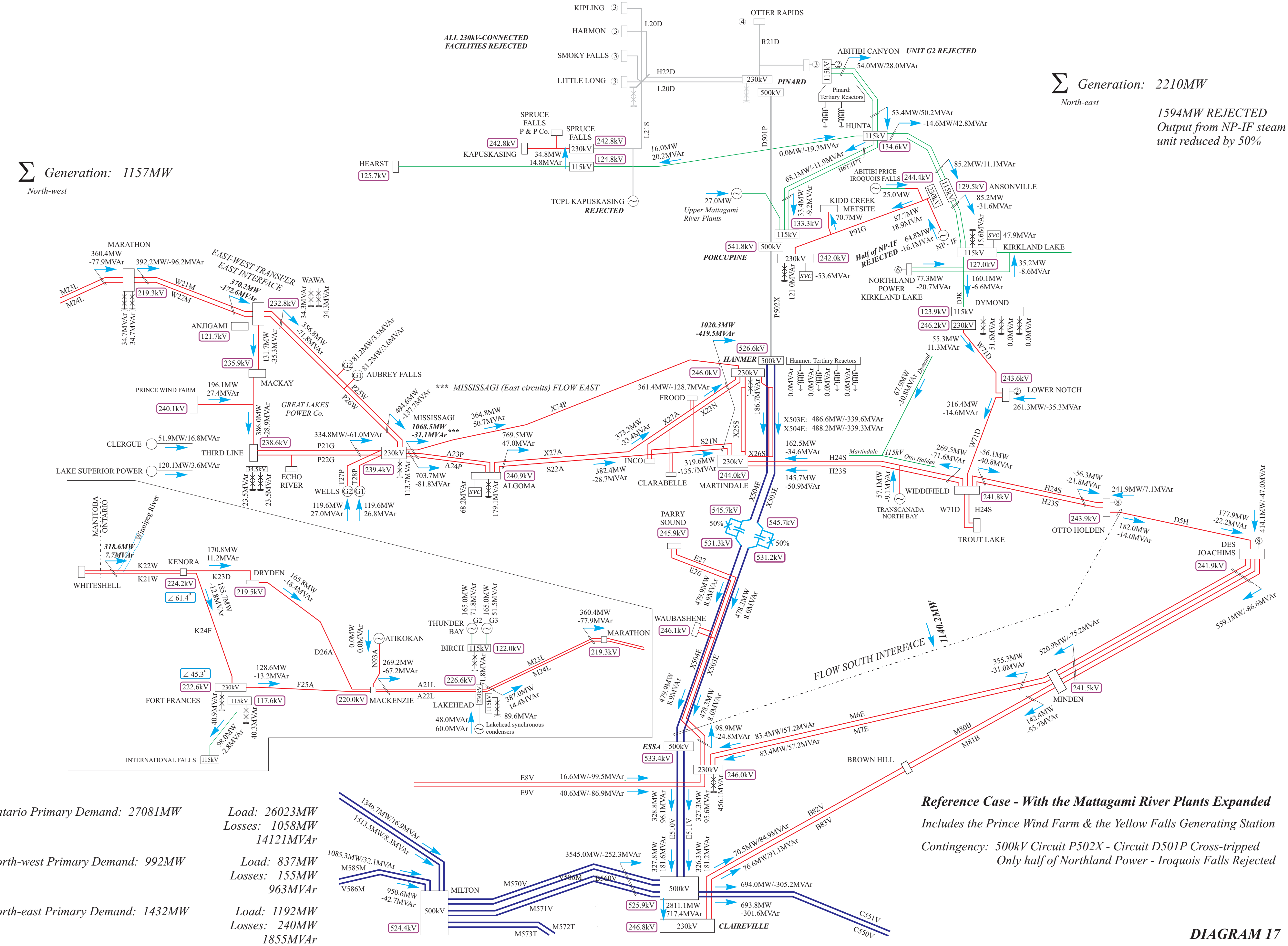
Reference Case - With the Mattagami River Plants Expanded

Includes the Prince Wind Farm & the Yellow Falls Generating Station

Contingency: 500kV Circuit P502X - Circuit D501P Cross-tripped

DIAGRAM 16

30th June 2006



Ontario Primary Demand: 27081MW — *Load: 26023MW*, *Losses: 1058MW*, *14121MVAr*

North-west Primary Demand: 992MW — *Load: 837MW*, *Losses: 155MW*, *963MVAr*

North-east Primary Demand: 1432MW — *Load: 1192MW*, *Losses: 240MW*, *1855MVAr*

Net Change in the Transfers on the Interconnections: 1515MW

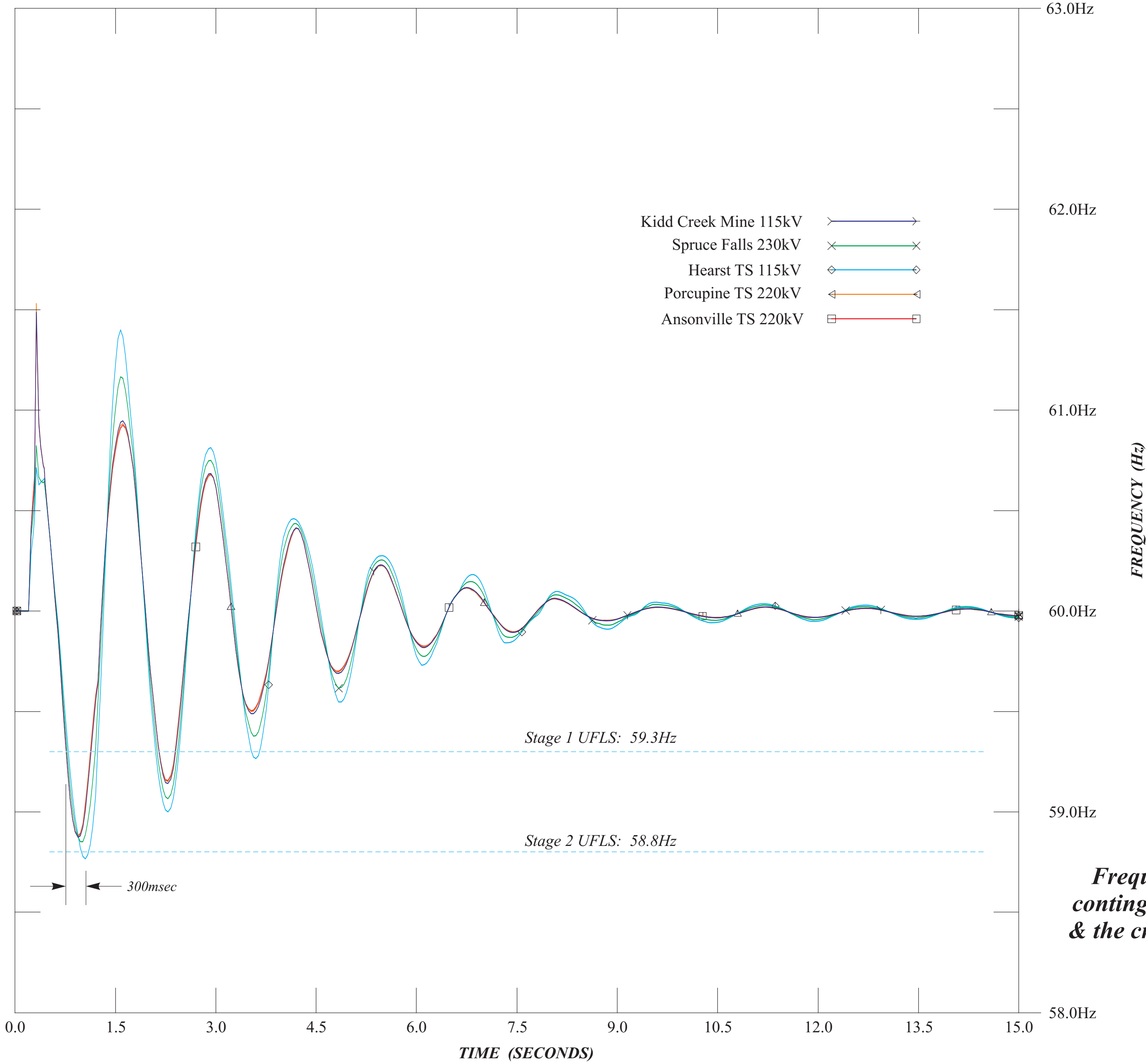
Reference Case - With the Mattagami River Plants Expanded

Includes the Prince Wind Farm & the Yellow Falls Generating Station

Contingency: 500kV Circuit P502X - Circuit D501P Cross-tripped
Only half of Northland Power - Iroquois Falls Rejected

DIAGRAM 17

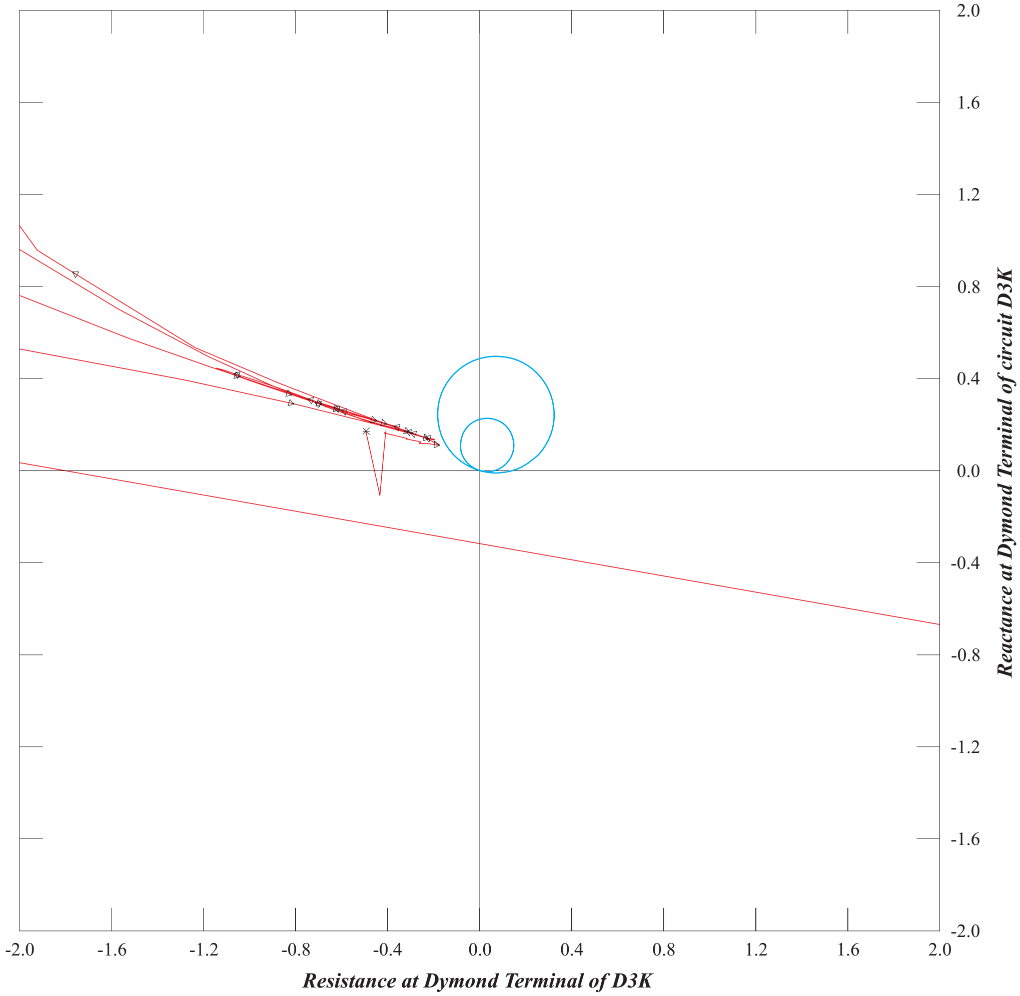
30th June 2006

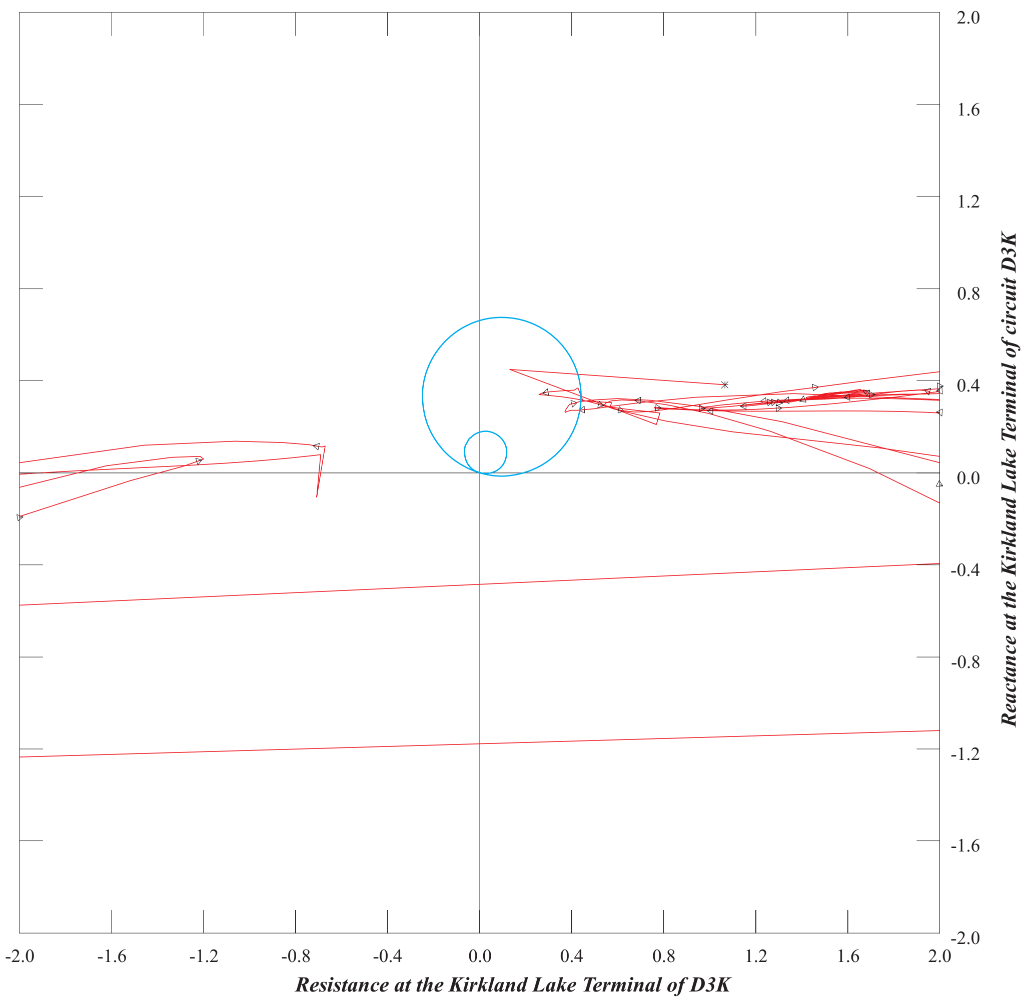


Frequency Response following a contingency involving circuit P502X & the cross-tripping of circuit D501P

DIAGRAM 18

20th August 2006



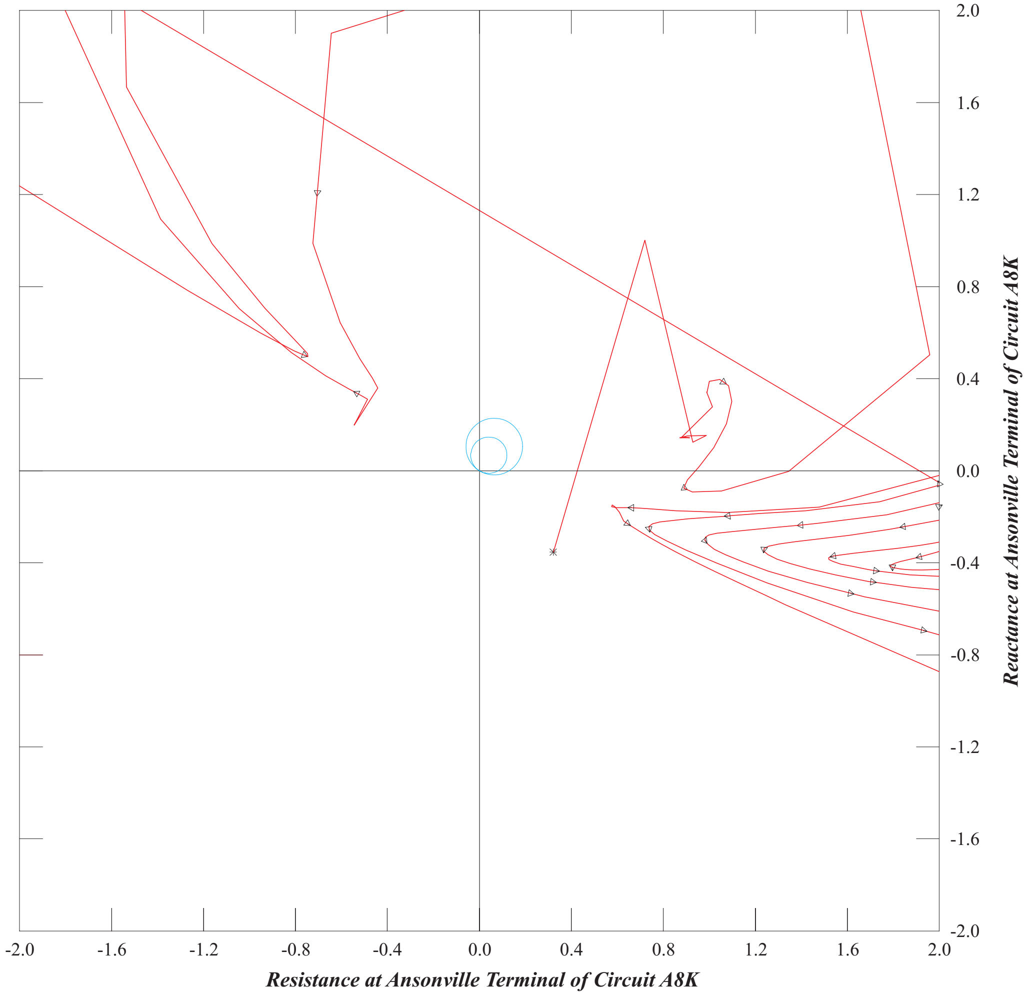


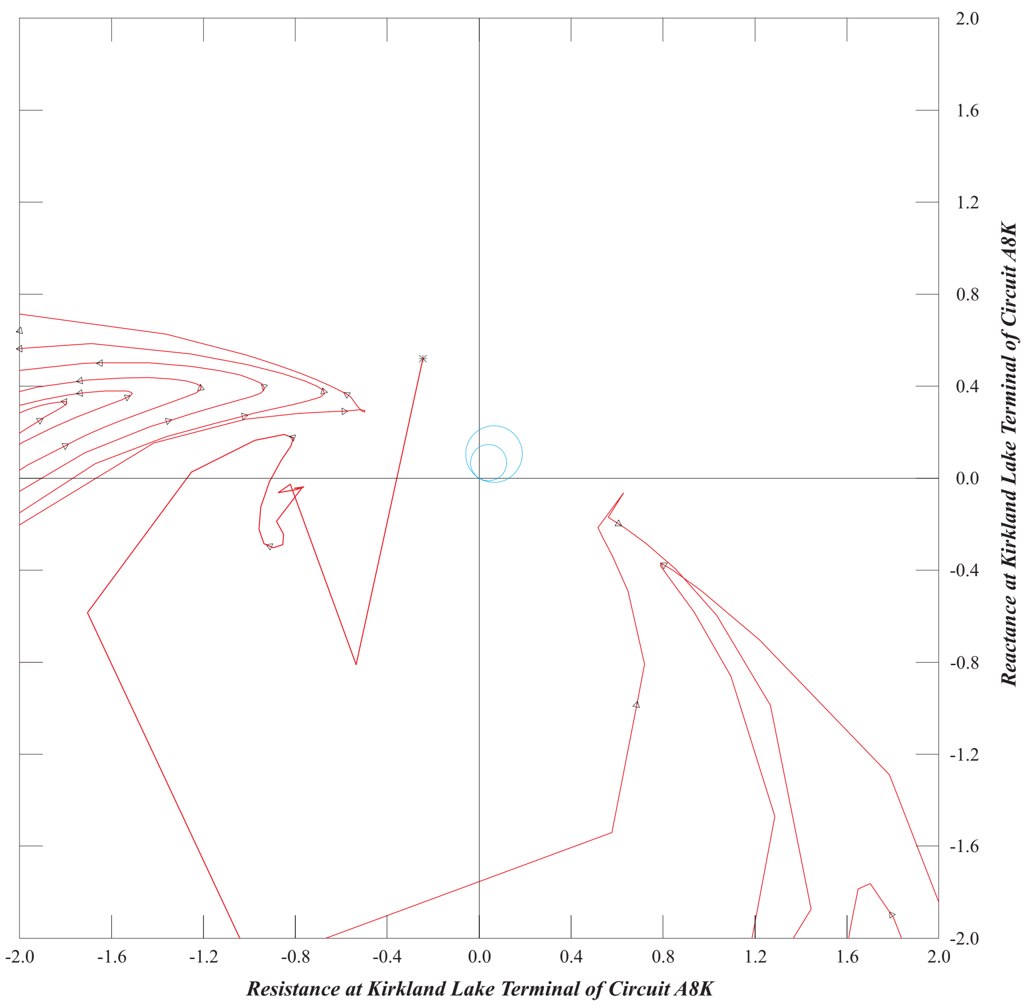
Apparent Impedance Loci for 115kV circuit D3K

For a 500kV 3-phase fault on circuit P502X at Hanmer TS

DIAGRAM 19

20th December 2006



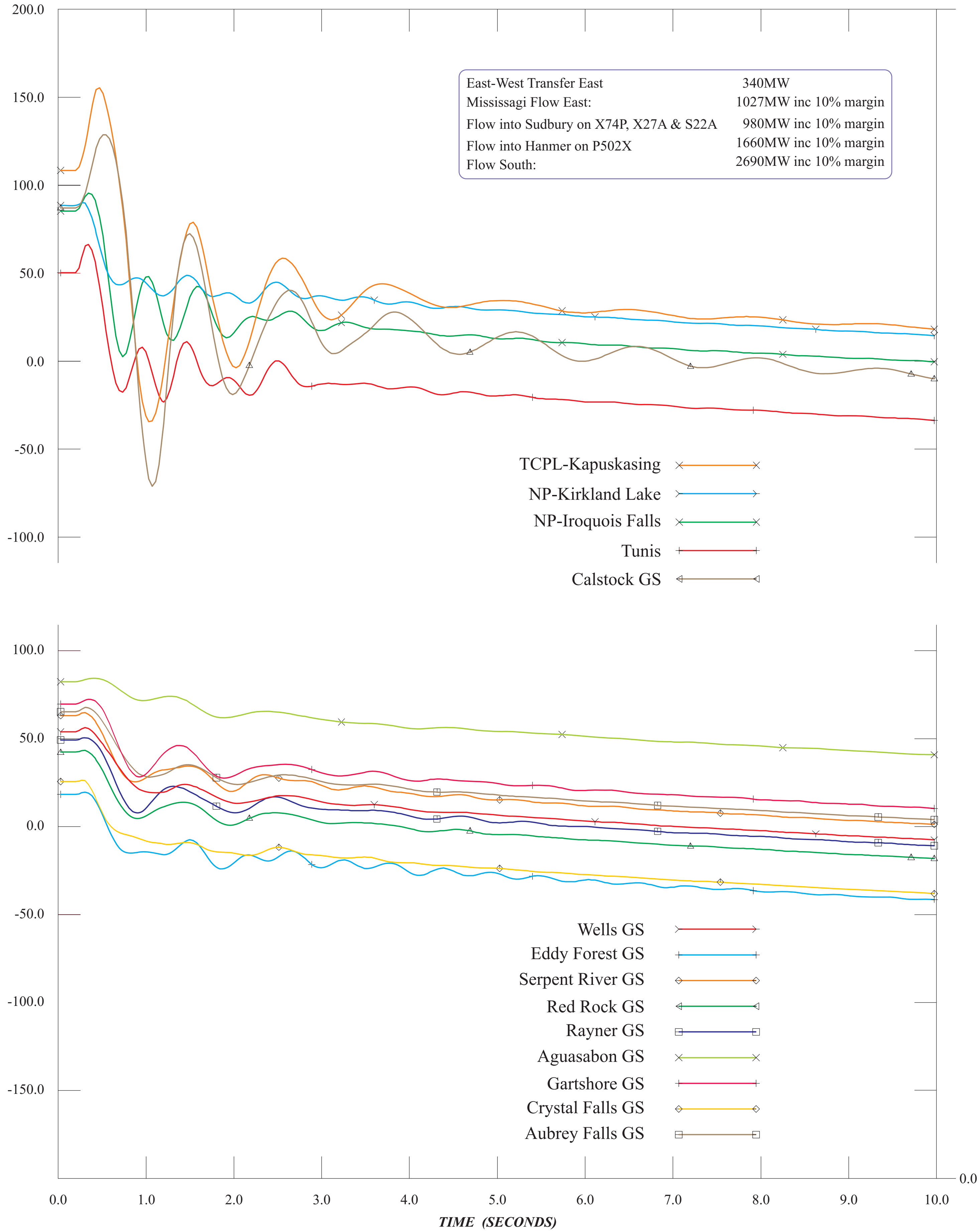


Apparent Impedance Loci for 115kV Circuit A8K

For a 500kV 3-phase fault on circuit P502X at Hanmer TS

DIAGRAM 20

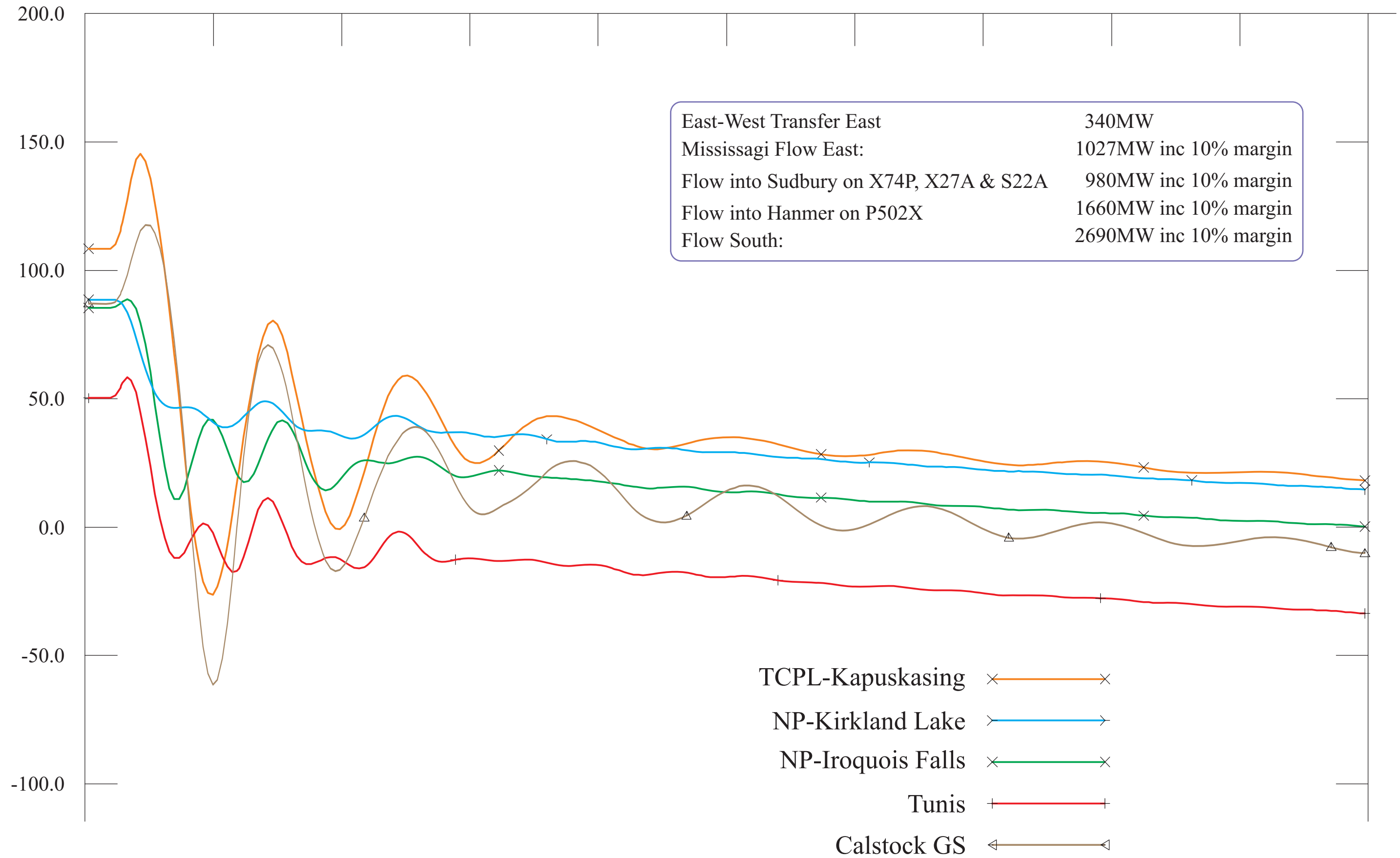
20th December 2006

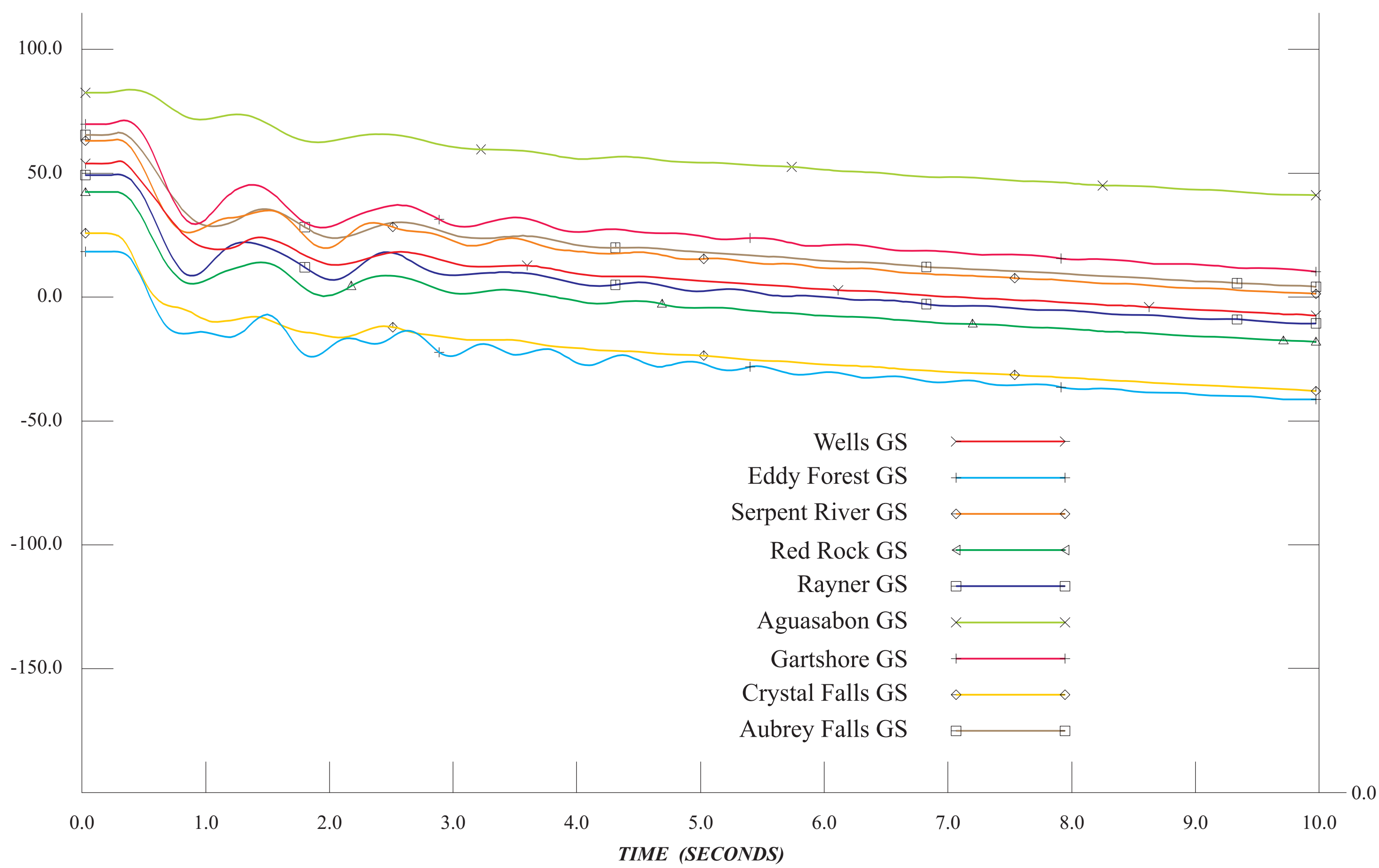


Generator Rotor Angle Responses to a 3-Phase fault on circuit D501P at Porcupine TS

DIAGRAM 21

17th July 2006

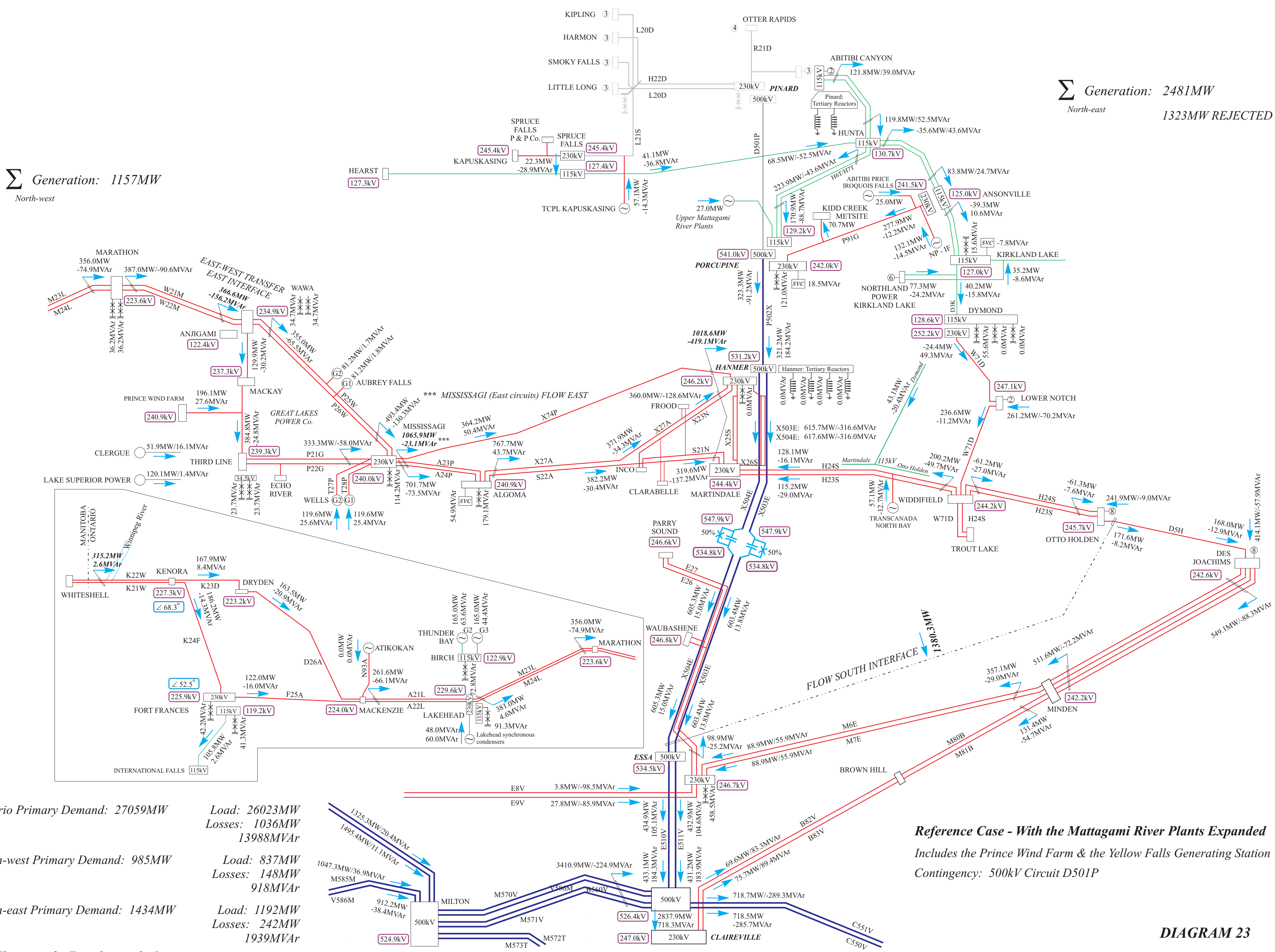




Generator Rotor Angle Responses to a 3-Phase fault on circuit D501P at Pinard TS

DIAGRAM 22

23rd August 2006



Ontario Primary Demand: 27059MW

Load: 26023MW
Losses: 1036MW
13988MVAr

North-west Primary Demand: 985MW

Load: 837MW
Losses: 148MW
918MVAr

North-east Primary Demand: 1434MW

Load: 1192MW
Losses: 242MW
1939MVAr

Net Change in the Transfers on the Interconnections: 1246MW

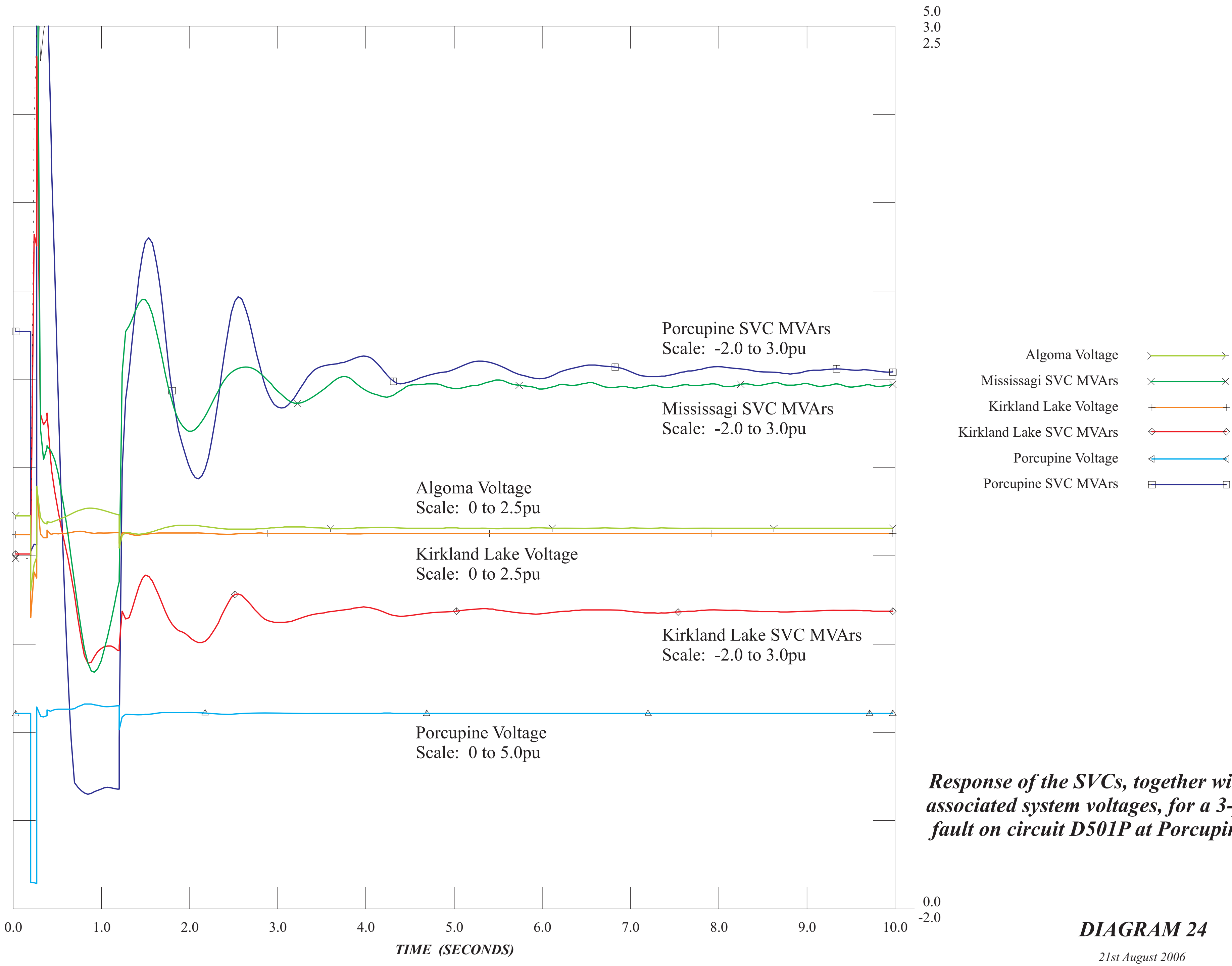
Reference Case - With the Mattagami River Plants Expanded

Includes the Prince Wind Farm & the Yellow Falls Generating Station

Contingency: 500kV Circuit D501P

DIAGRAM 23

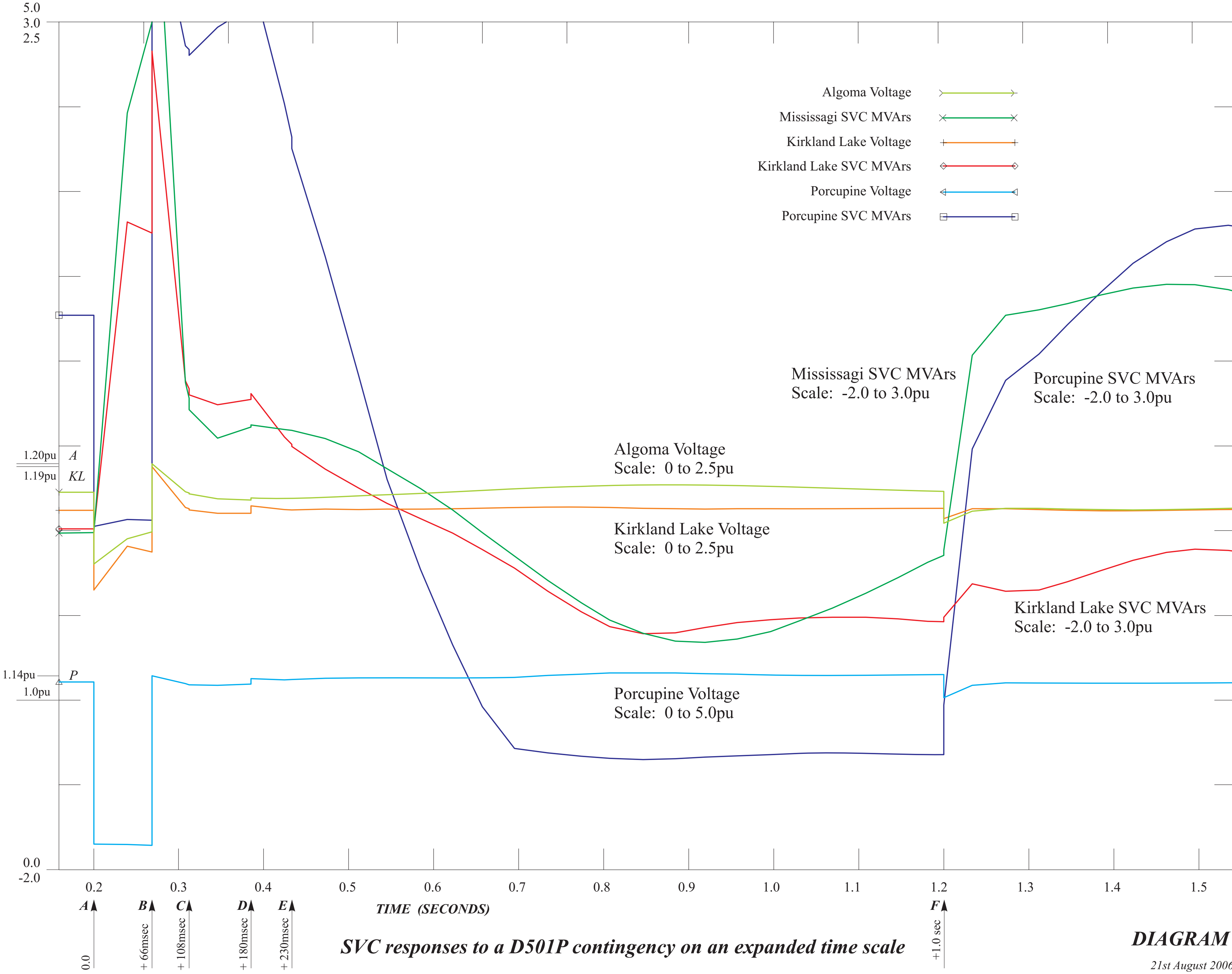
4th July 2006



Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit D501P at Porcupine TS

DIAGRAM 24

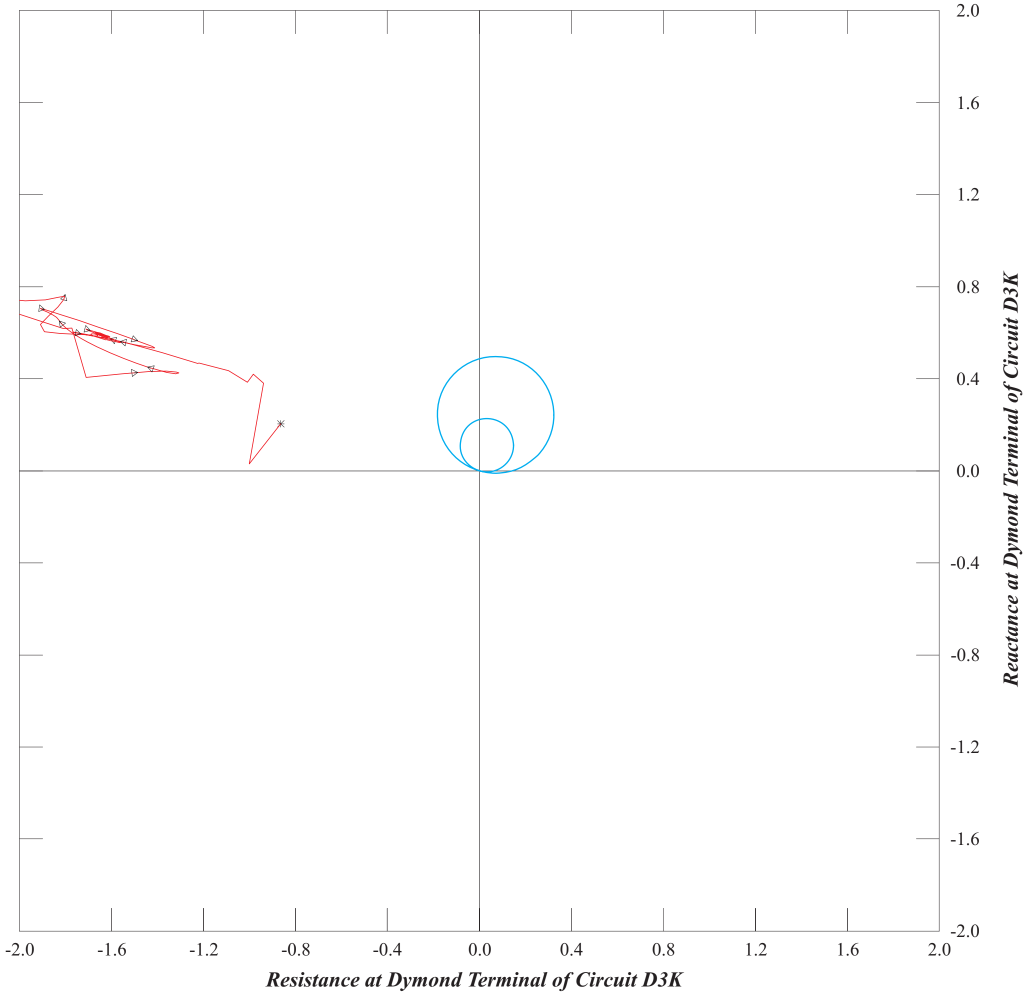
21st August 2006

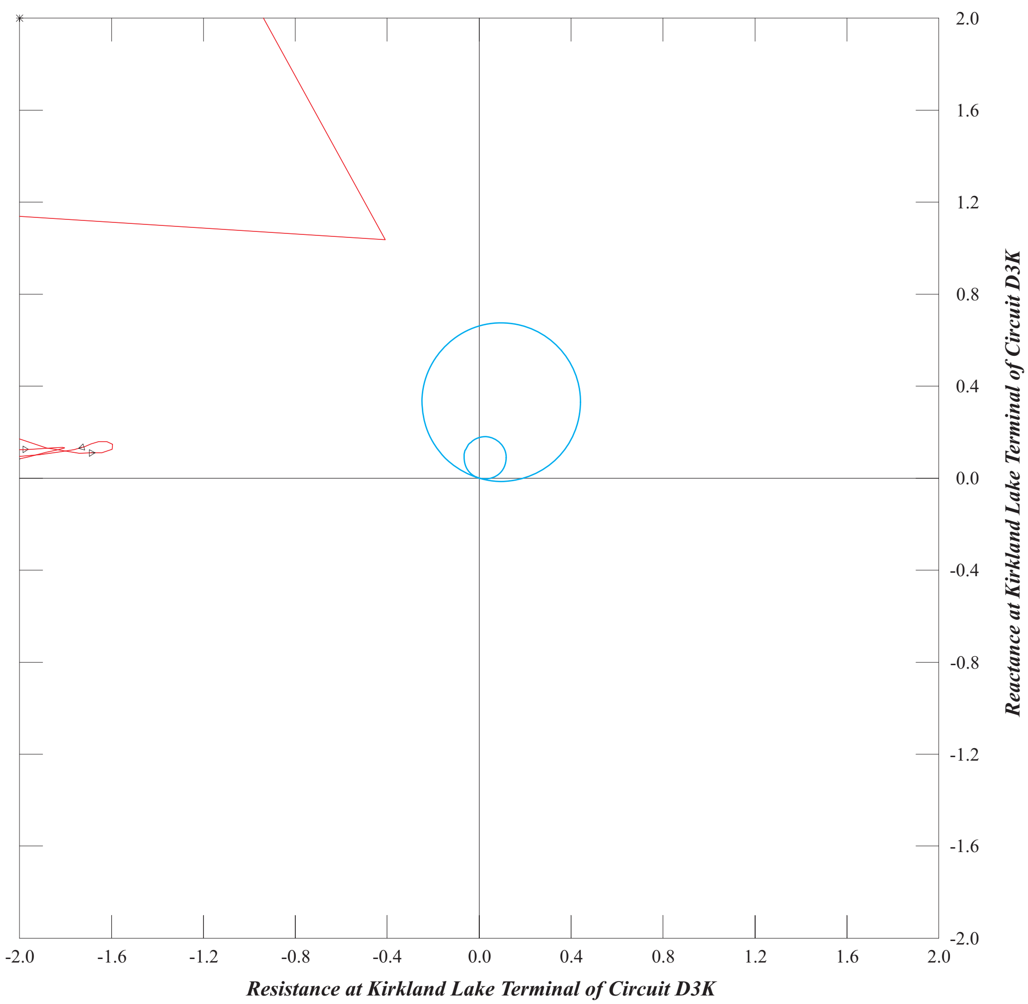


SVC responses to a D501P contingency on an expanded time scale

DIAGRAM 25

21st August 2006



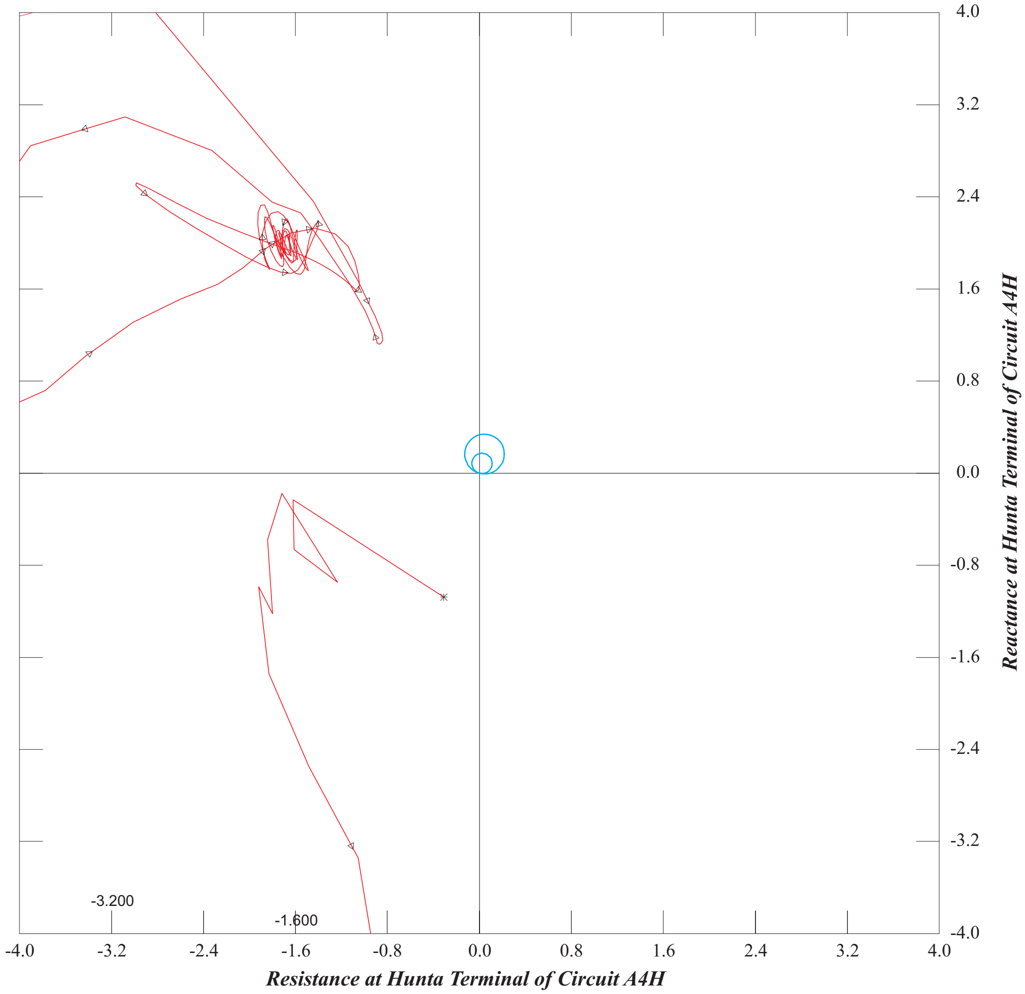


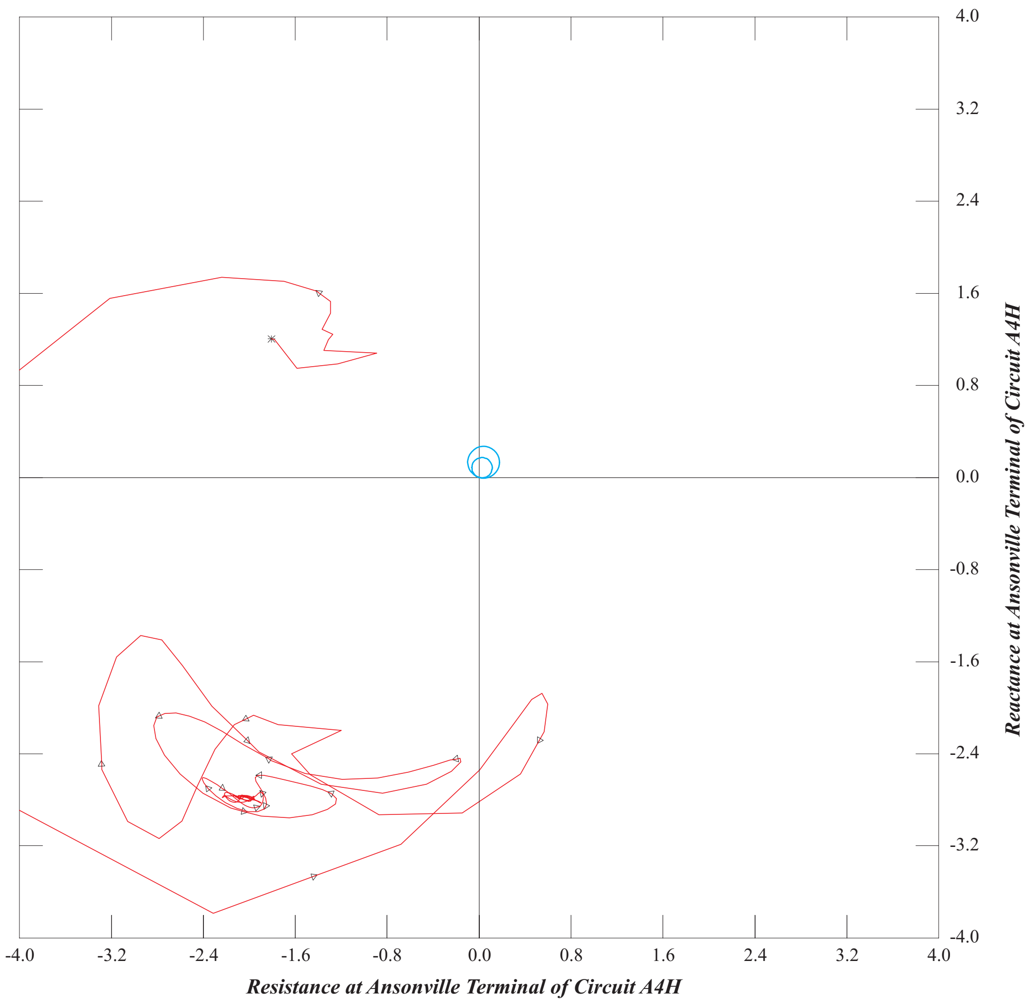
Apparent Impedance Loci for 115kV circuit D3K

For a 500kV 3-phase fault on circuit D501P at Pinard TS

DIAGRAM 26

20th December 2006



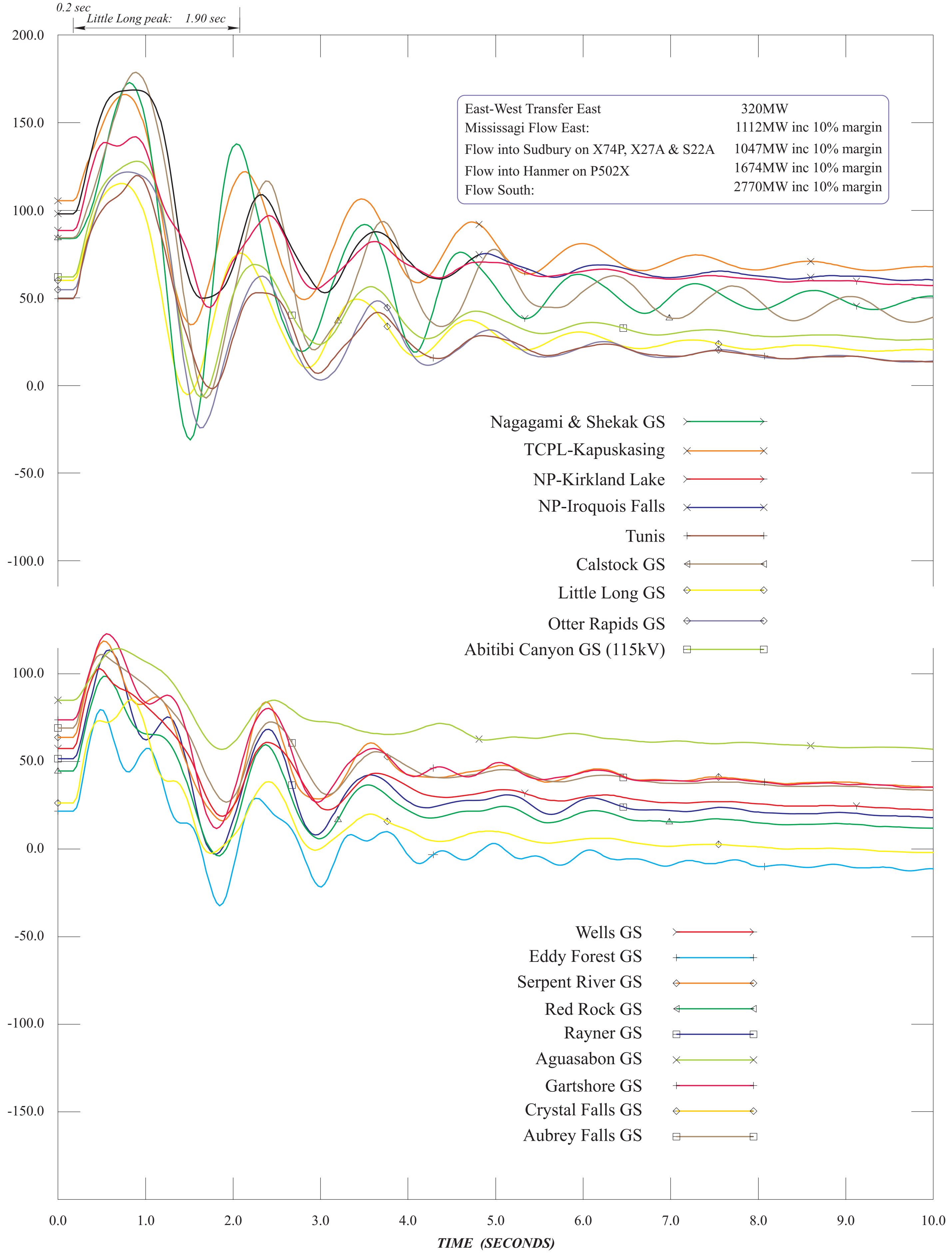


Apparent Impedance Loci for 115kV circuit A4H

For a 500kV 3-phase fault on circuit D501P at Porcupine TS

DIAGRAM 27

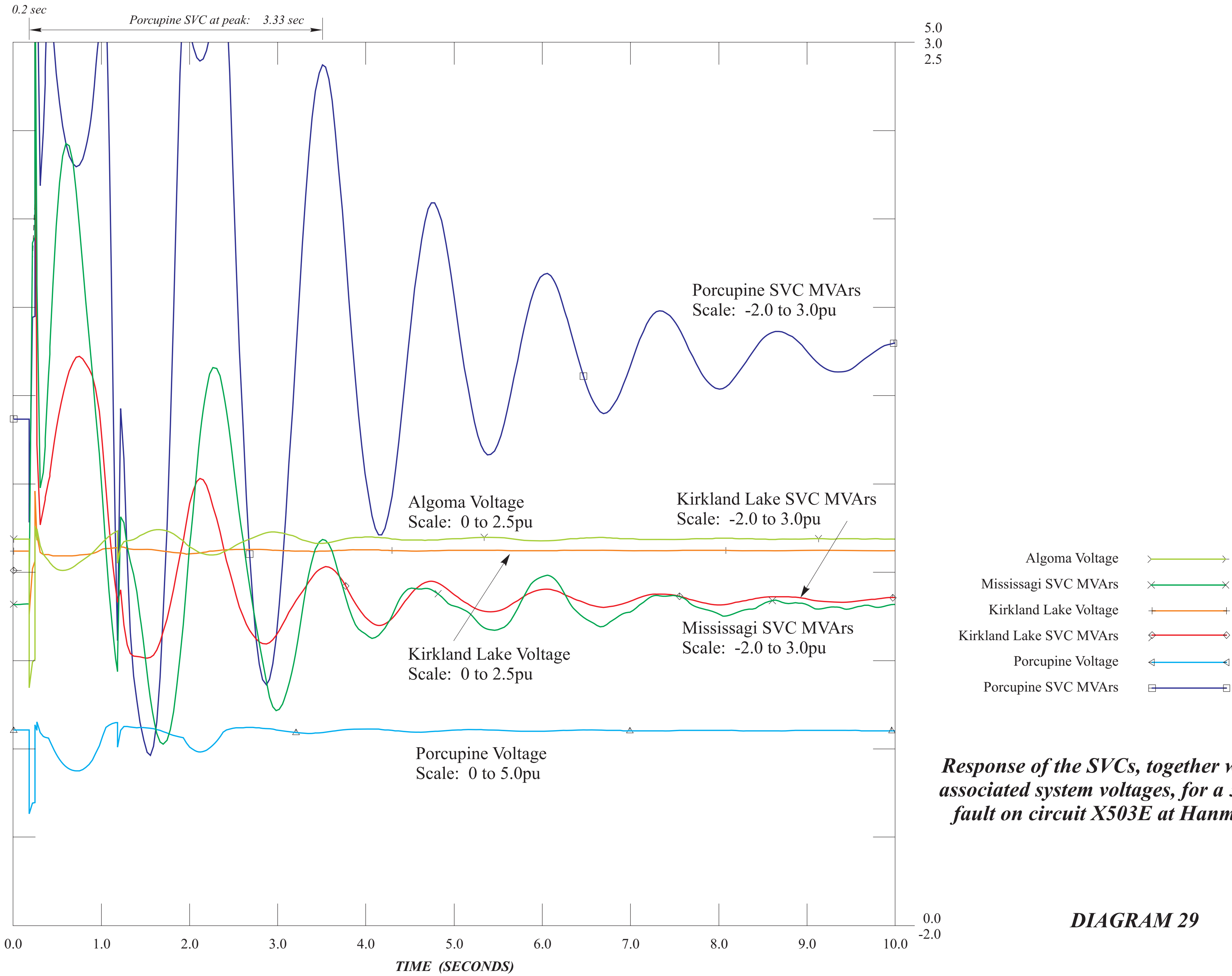
20th December 2006



Generator Rotor Angle Responses to a 3-Phase fault on circuit X503E at Hanmer TS

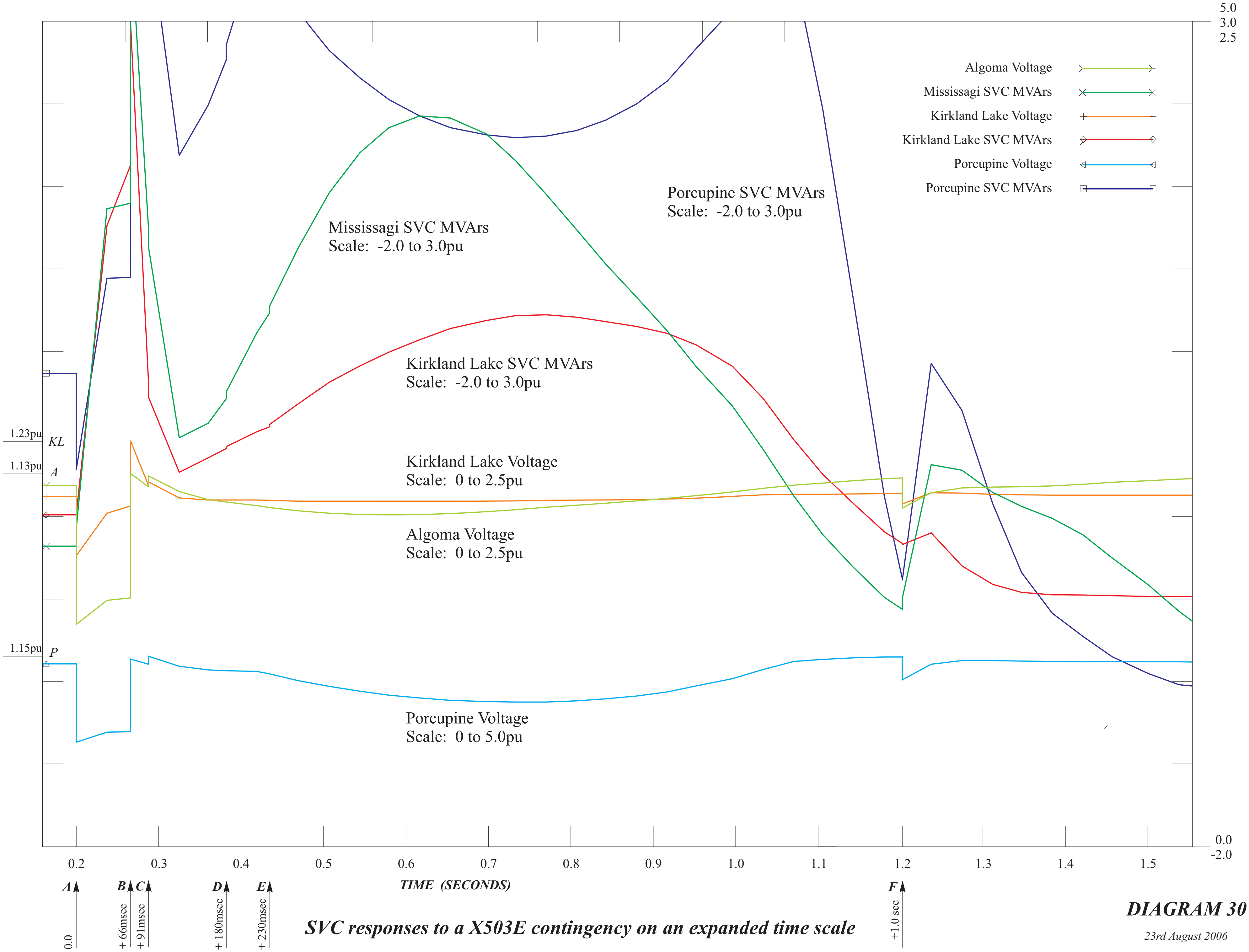
DIAGRAM 28

23rd August 2006



Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit X503E at Hanmer TS

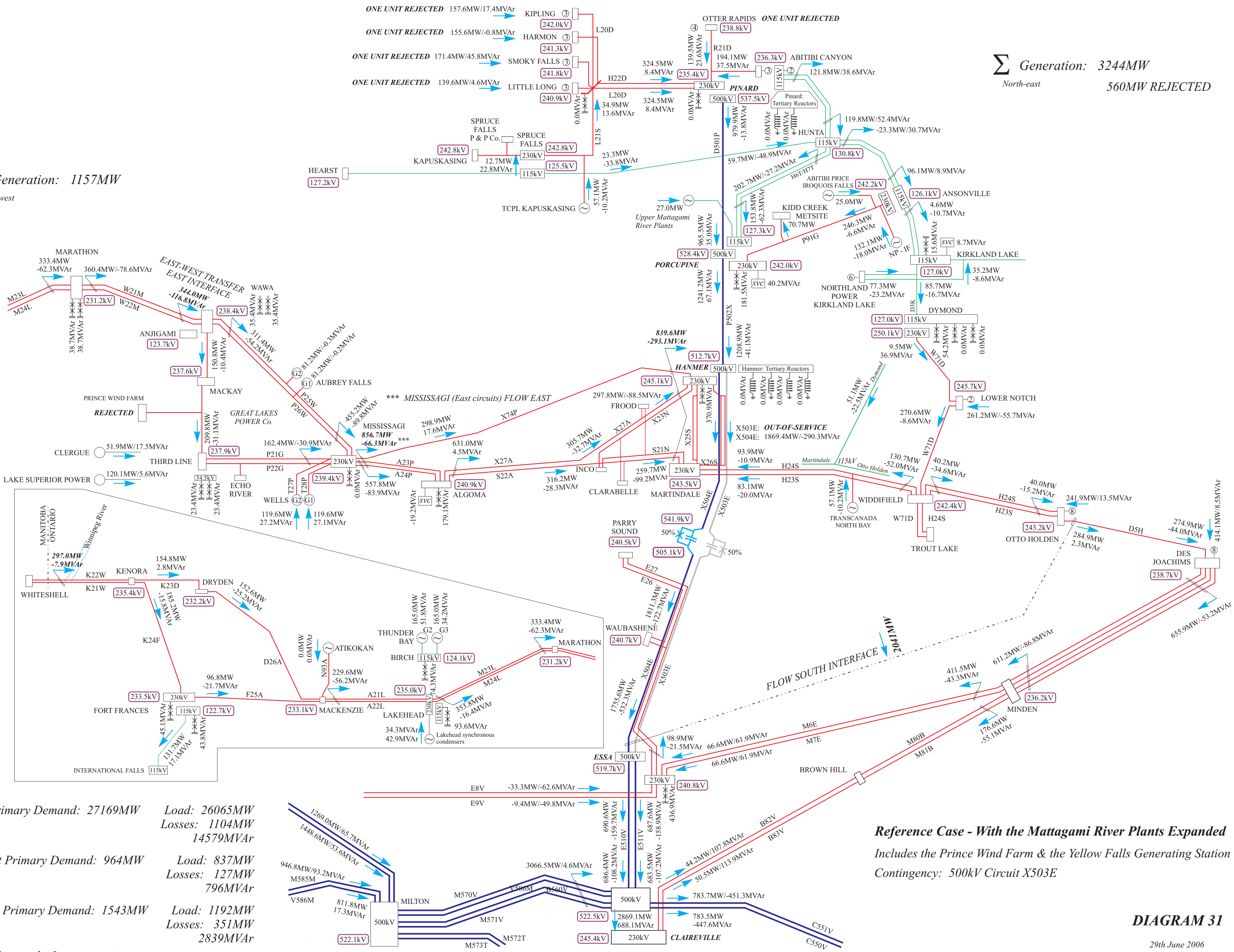
DIAGRAM 29



SVC responses to a X503E contingency on an expanded time scale

DIAGRAM 30

23rd August 2006



Ontario Primary Demand: 27169MW — Load: 26065MW; Losses: 1104MW; 14579MVAr

North-west Primary Demand: 964MW — Load: 837MW; Losses: 127MW; 796MVAr

North-east Primary Demand: 1543MW — Load: 1192MW; Losses: 351MW; 2839MVAr

Net Transfers on the Interconnections: 580MW

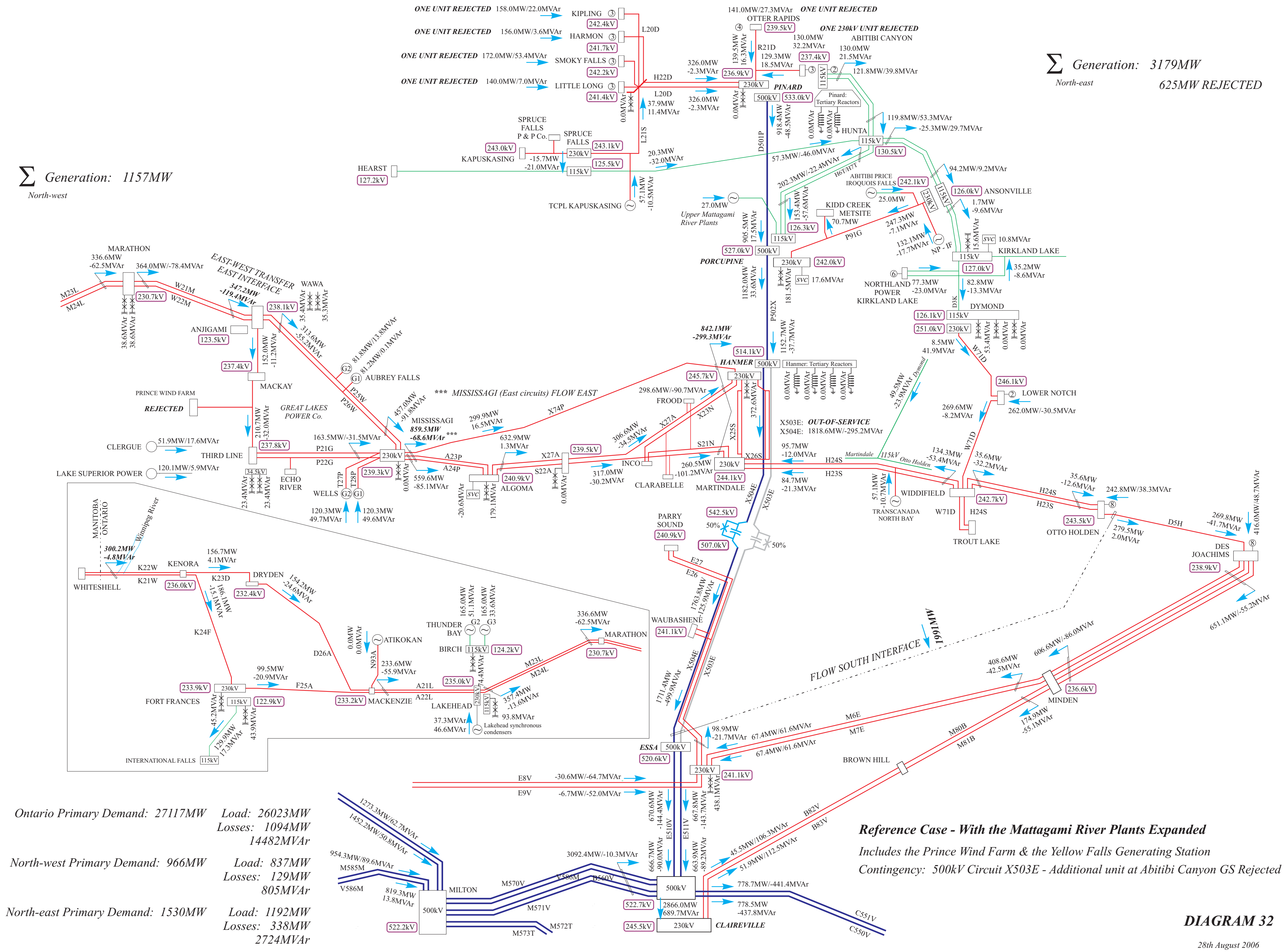
Reference Case - With the Mattagami River Plants Expanded

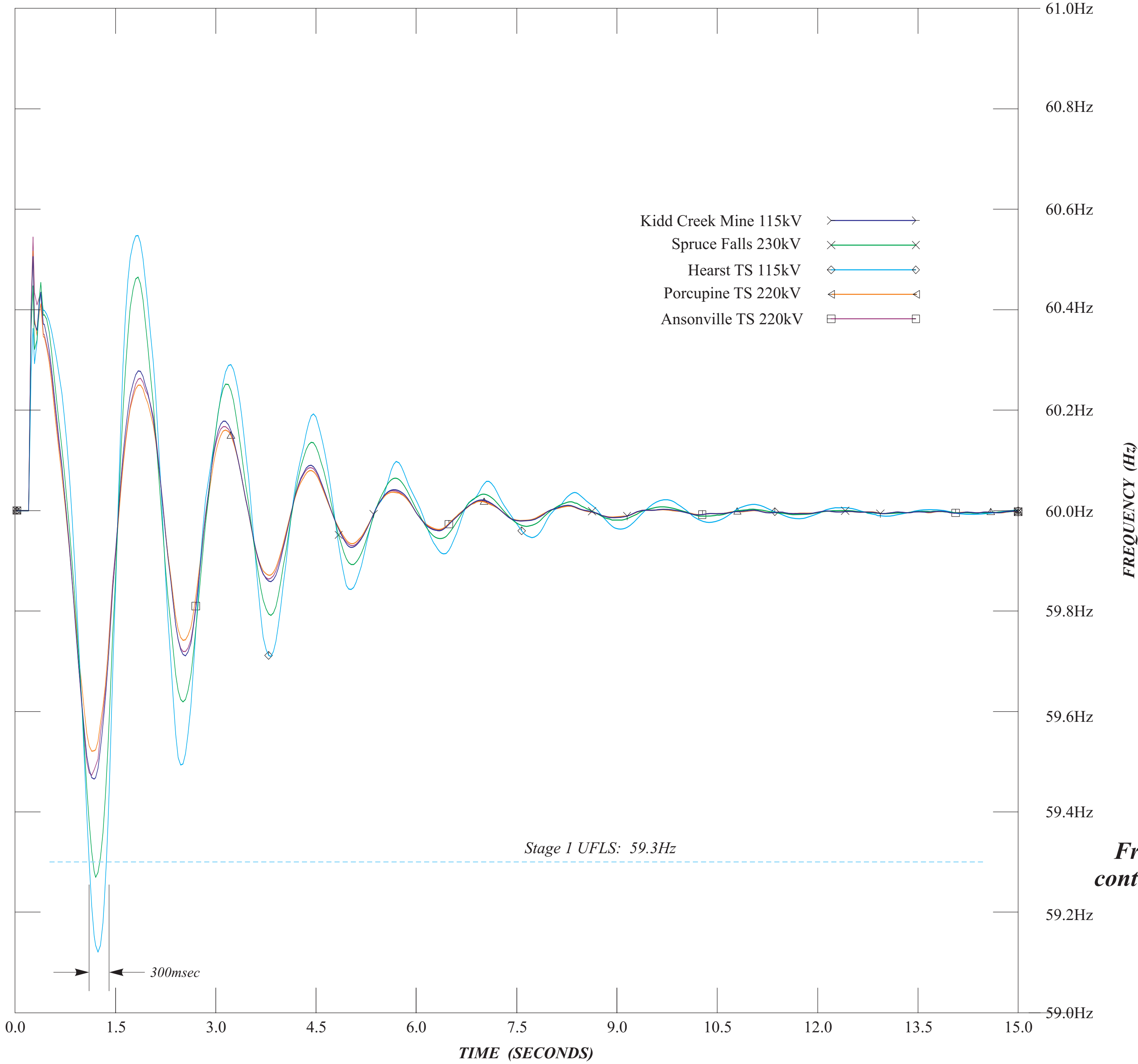
Includes the Prince Wind Farm & the Yellow Falls Generating Station

Contingency: 500kV Circuit X503E

DIAGRAM 31

29th June 2006

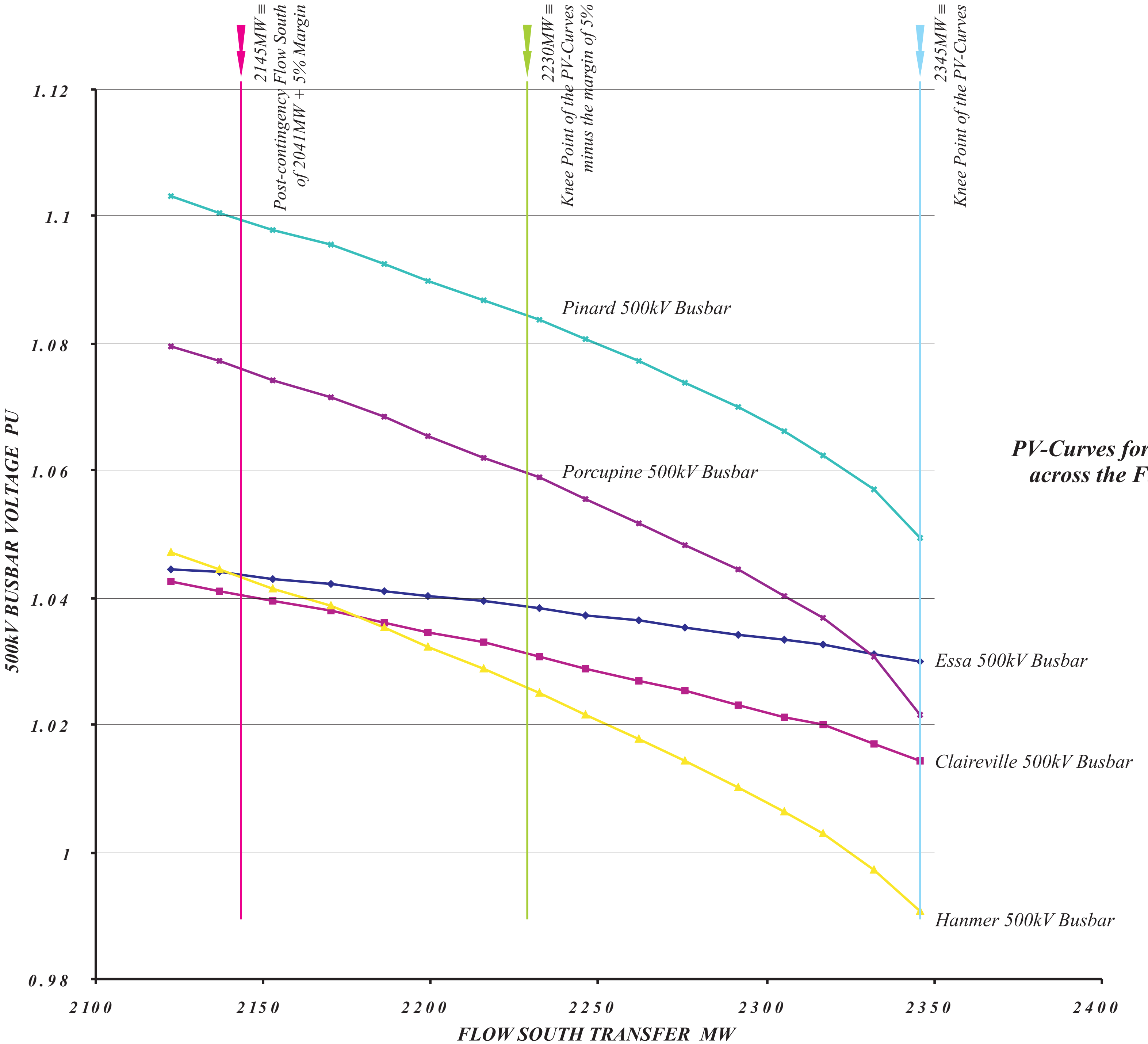

Reference Case - With the Mattagami River Plants Expanded
Includes the Prince Wind Farm & the Yellow Falls Generating Station
Contingency: 500kV Circuit X503E - Additional unit at Abitibi Canyon GS Rejected
DIAGRAM 32
28th August 2006
Σ Generation: 3179MW
North-east
625MW REJECTED
Σ Generation: 1157MW
North-west
Ontario Primary Demand: 27117MW
Load: 26023MW
Losses: 1094MW
14482MVAr
North-west Primary Demand: 966MW
Load: 837MW
Losses: 129MW
805MVAr
North-east Primary Demand: 1530MW
Load: 1192MW
Losses: 338MW
2724MVAr
ONE UNIT REJECTED 158.0MW/22.0MVAr
KIPLING
242.4kV
ONE UNIT REJECTED 156.0MW/3.6MVAr
HARMON
241.7kV
ONE UNIT REJECTED 172.0MW/53.4MVAr
SMOKY FALLS
242.2kV
ONE UNIT REJECTED 140.0MW/7.0MVAr
LITTLE LONG
241.4kV
141.0MW/27.3MVAr ONE UNIT REJECTED
OTTER RAPIDS
239.5kV
ONE 230kV UNIT REJECTED
ABITIBI CANYON
PINARD
500kV
533.0kV
Pinard: Tertiary Reactors
HUNTA
130.5kV
SPRUCE FALLS P & P Co.
SPRUCE FALLS
243.1kV
125.5kV
243.0kV
KAPUSKASING
HEARST
127.2kV
TCPL KAPUSKASING
Upper Mattagami River Plants
ABITIBI PRICE IROQUOIS FALLS
242.1kV
ANSONVILLE
126.0kV
KIDD CREEK METSITE
126.3kV
NP - IF
KIRKLAND LAKE
127.0kV
NORTHLAND POWER KIRKLAND LAKE
PORCUPINE
527.0kV
242.0kV
DYMOND
126.1kV
251.0kV
LOWER NOTCH
246.1kV
HANMER
514.1kV
245.7kV
Hanmer: Tertiary Reactors
842.1MW
-299.3MVAr
X503E: OUT-OF-SERVICE
X504E: 1818.6MW/-295.2MVAr
FROOD
INCO
CLARABELLE
MARTINDALE
244.1kV
WIDDIFIELD
TRANSCANADA NORTH BAY
TROUT LAKE
242.7kV
OTTO HOLDEN
243.5kV
DES JOACHIMS
238.9kV
MARATHON
230.7kV
EAST-WEST TRANSFER EAST INTERFACE
347.2MW
-119.4MVAr
WAWA
238.1kV
ANJIGAMI
123.5kV
MACKAY
237.4kV
PRINCE WIND FARM
REJECTED
AUBREY FALLS
GREAT LAKES POWER Co.
*** MISSISSAGI (East circuits) FLOW EAST
MISSISSAGI
859.5MW
-68.6MVAr
CLERGUE
THIRD LINE
237.8kV
LAKE SUPERIOR POWER
ECHO RIVER
WELLS
239.3kV
ALGOMA
240.9kV
239.5kV
PARRY SOUND
240.9kV
542.5kV
507.0kV
WAUBASHENE
241.1kV
MANITOBA
ONTARIO
Winnipeg River
300.2MW
-4.8MVAr
WHITESHELL
KENORA
236.0kV
DRYDEN
232.4kV
ATIKOKAN
THUNDER BAY
BIRCH
124.2kV
MARATHON
230.7kV
FORT FRANCES
233.9kV
122.9kV
MACKENZIE
233.2kV
LAKEHEAD
235.0kV
Lakehead synchronous condensers
INTERNATIONAL FALLS
FLOW SOUTH INTERFACE
1691MW
MINDEN
236.6kV
BROWN HILL
ESSA
520.6kV
241.1kV
MILTON
522.2kV
CLAIREVILLE
522.7kV
245.5kV
2866.0MW
689.7MVAr



Frequency Response following a contingency involving circuit X503E

DIAGRAM 33

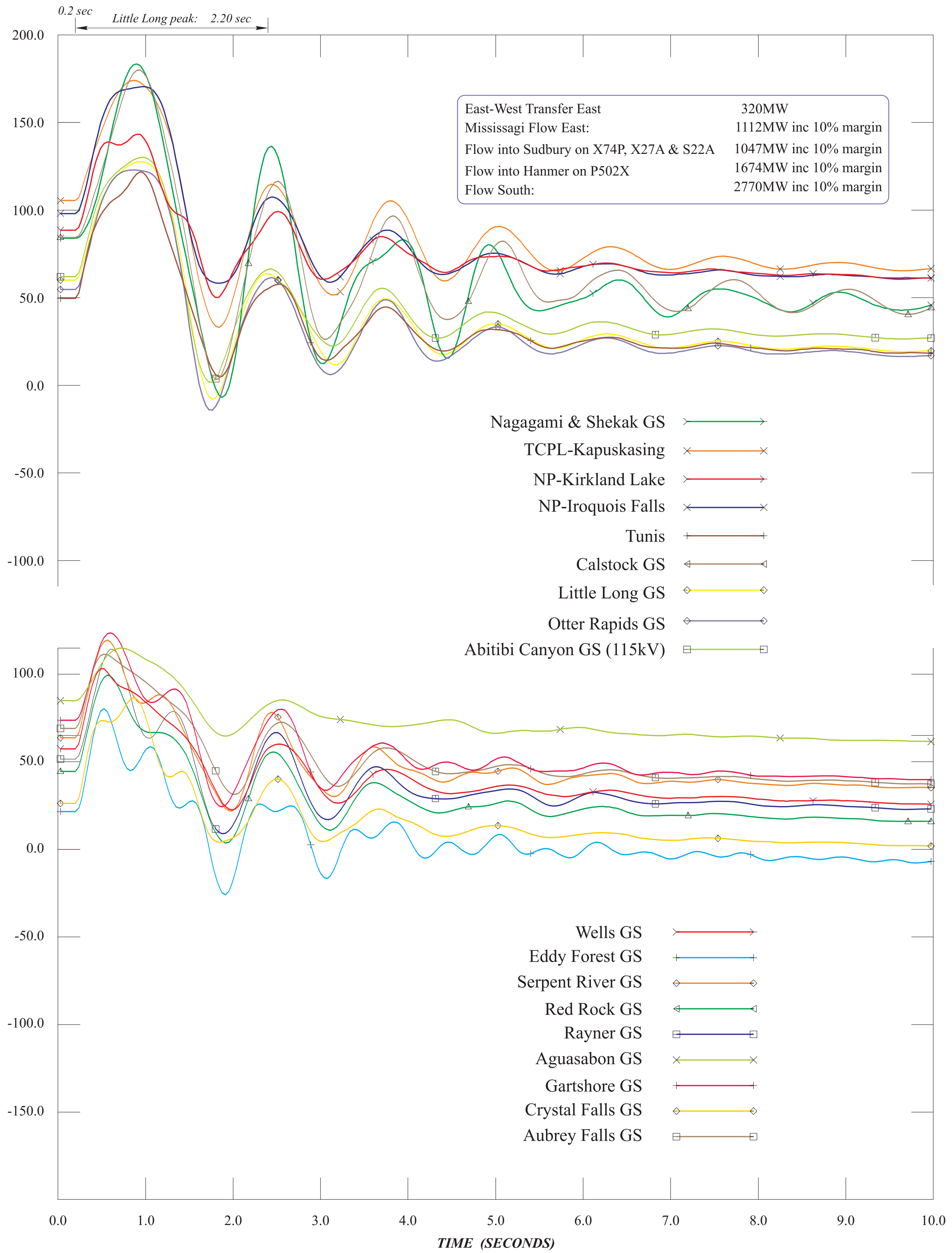
7th September 2006



PV-Curves for Increasing Transfers across the Flow-South Interface

DIAGRAM 34

29th November 2006

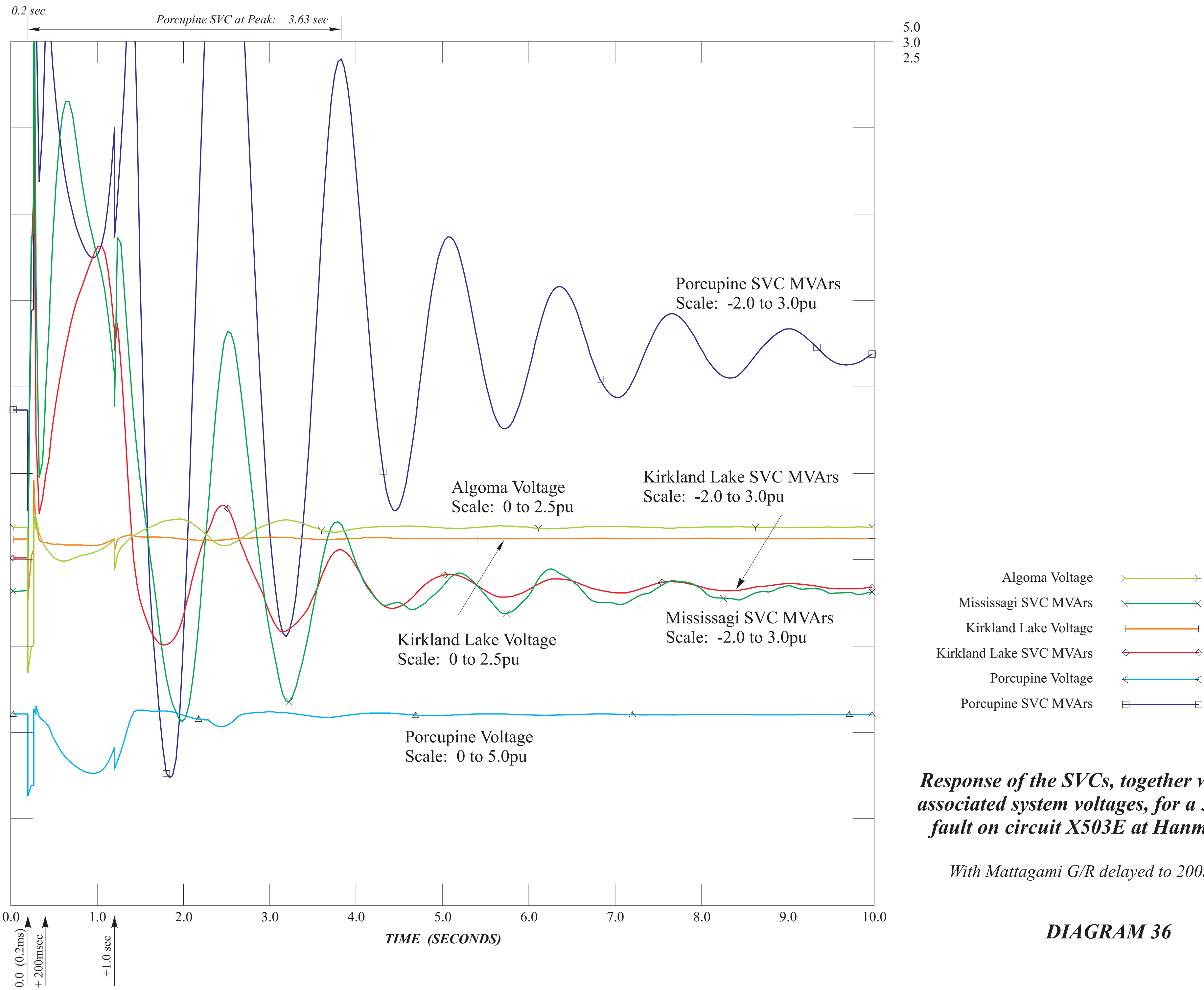


Generator Rotor Angle Responses to a 3-Phase fault on circuit X503E at Hanmer TS

(with the rejection time for the generation in the Moose River basin increased to 200msec)

DIAGRAM 35

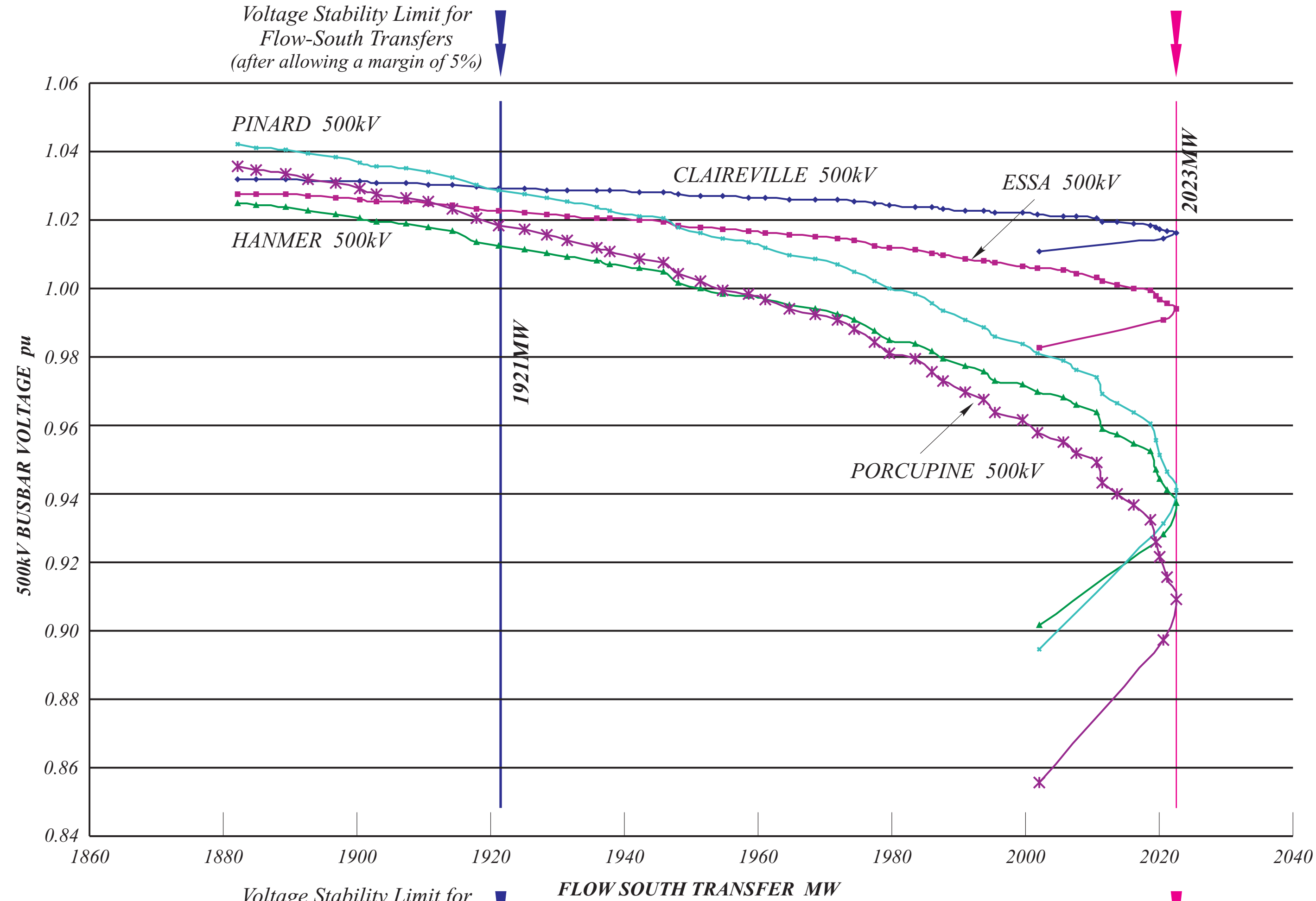
8th January 2007

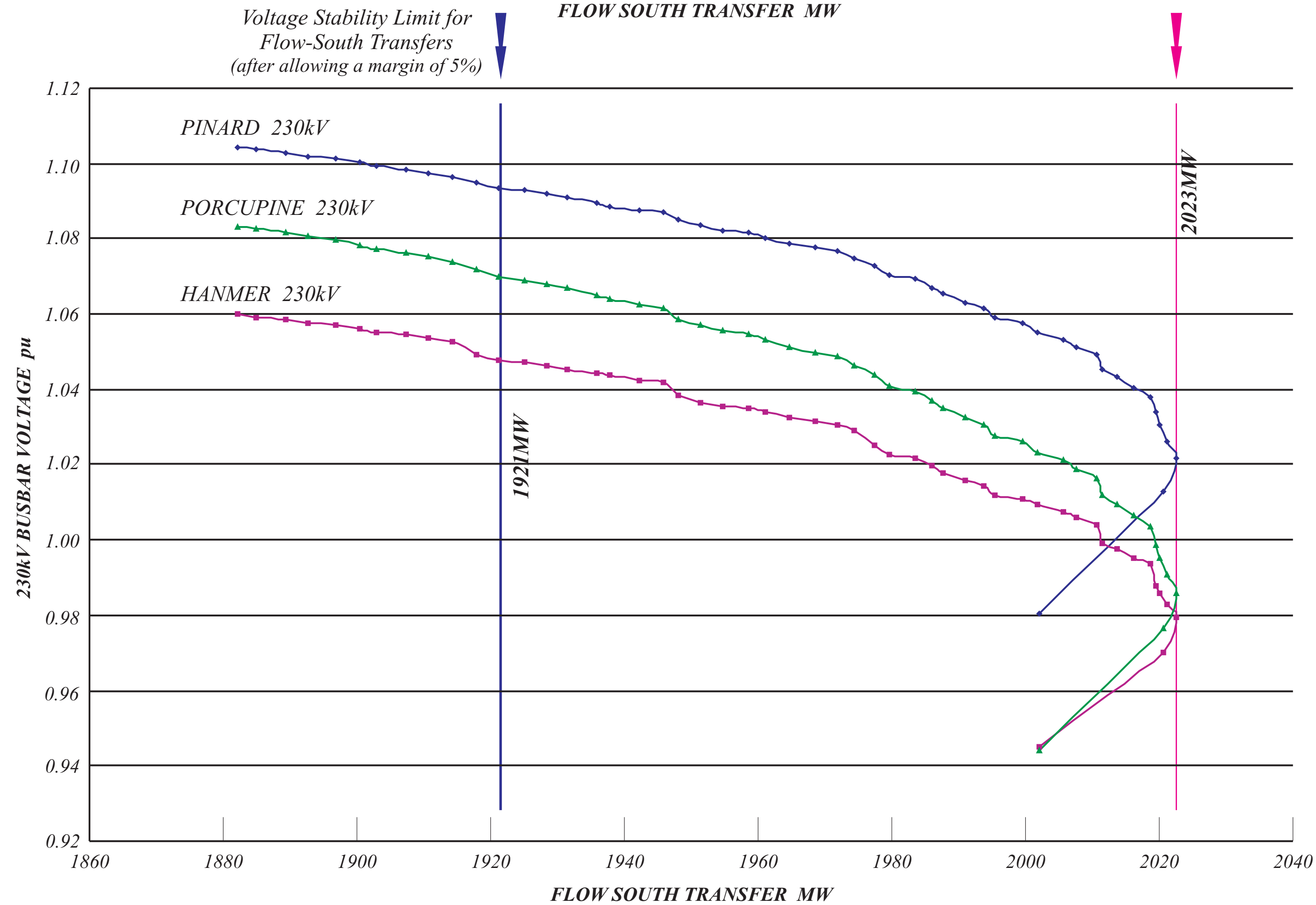


Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit X503E at Hanmer TS

With Mattagami G/R delayed to 200msec

DIAGRAM 36

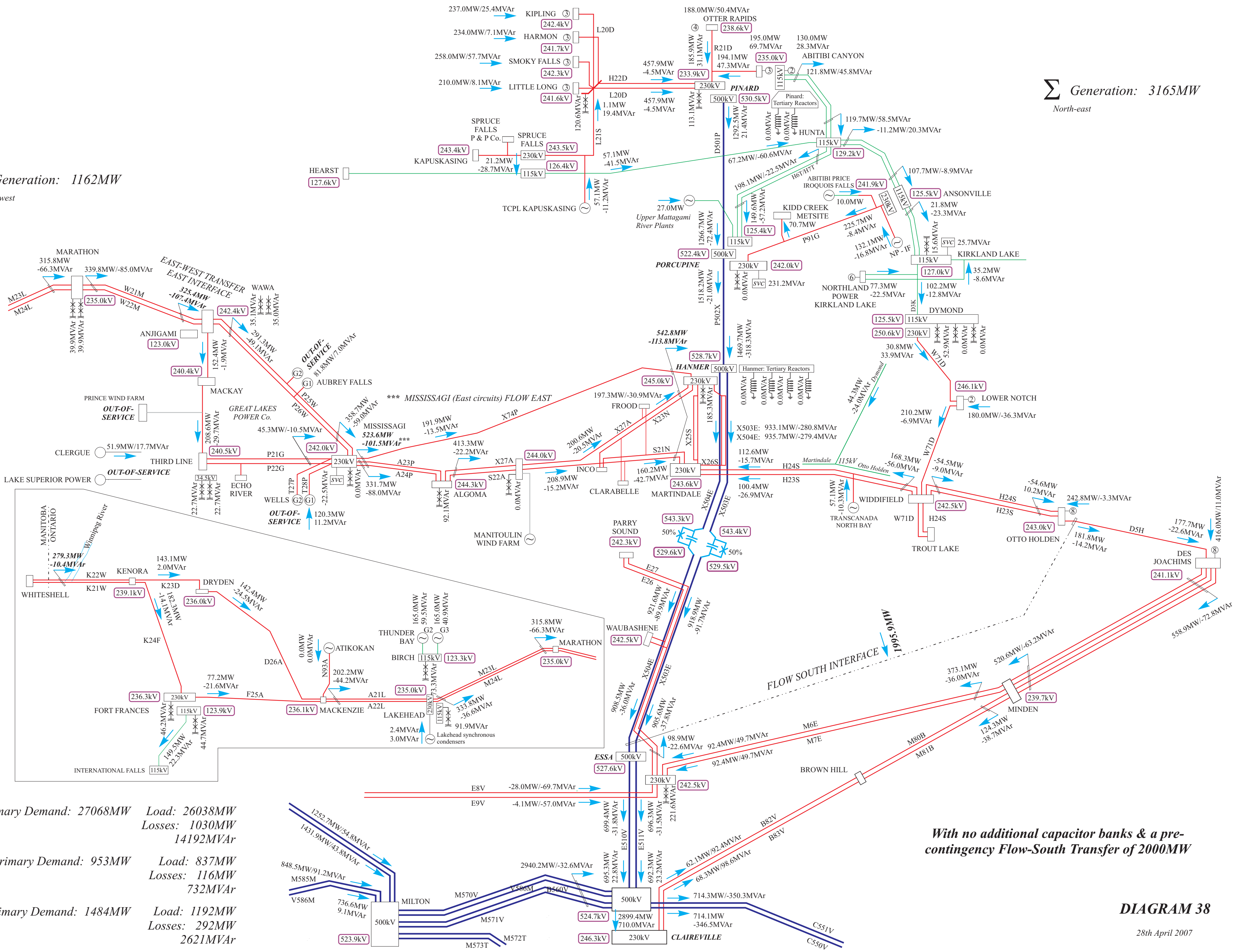




Post-Contingency PV-Curves for Increased Transfers across the Flow-South Interface

DIAGRAM 37

24th April 2007



∑ Generation: 1162MW
North-west

∑ Generation: 3165MW
North-east

Ontario Primary Demand: 27068MW Load: 26038MW
Losses: 1030MW
14192MVAr

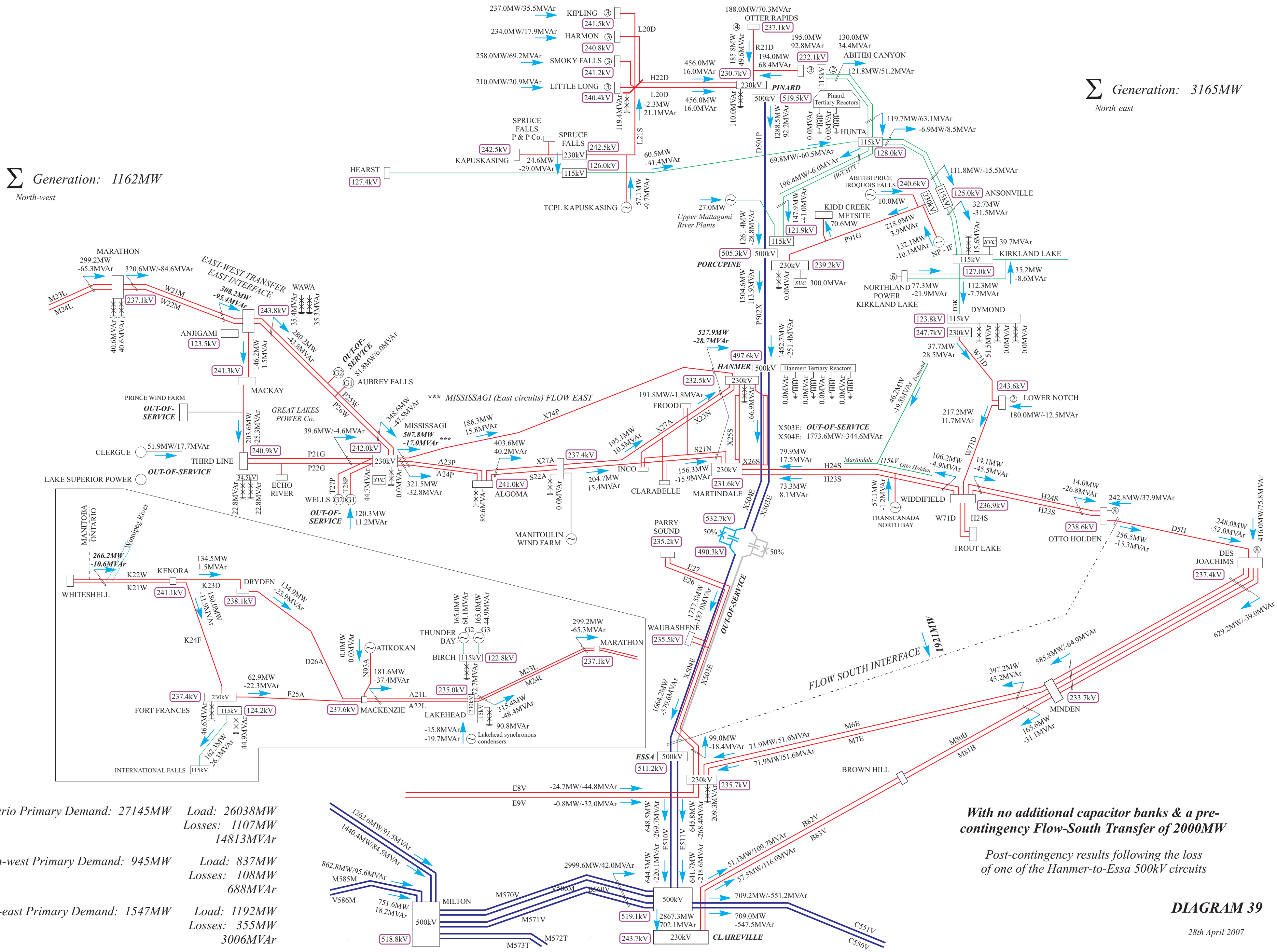
North-west Primary Demand: 953MW Load: 837MW
Losses: 116MW
732MVAr

North-east Primary Demand: 1484MW Load: 1192MW
Losses: 292MW
2621MVAr

With no additional capacitor banks & a pre-contingency Flow-South Transfer of 2000MW

DIAGRAM 38

28th April 2007



Ontario Primary Demand: 27145MW *Load: 26038MW*
Losses: 1107MW
14813MVAr

North-west Primary Demand: 945MW *Load: 837MW*
Losses: 108MW
688MVAr

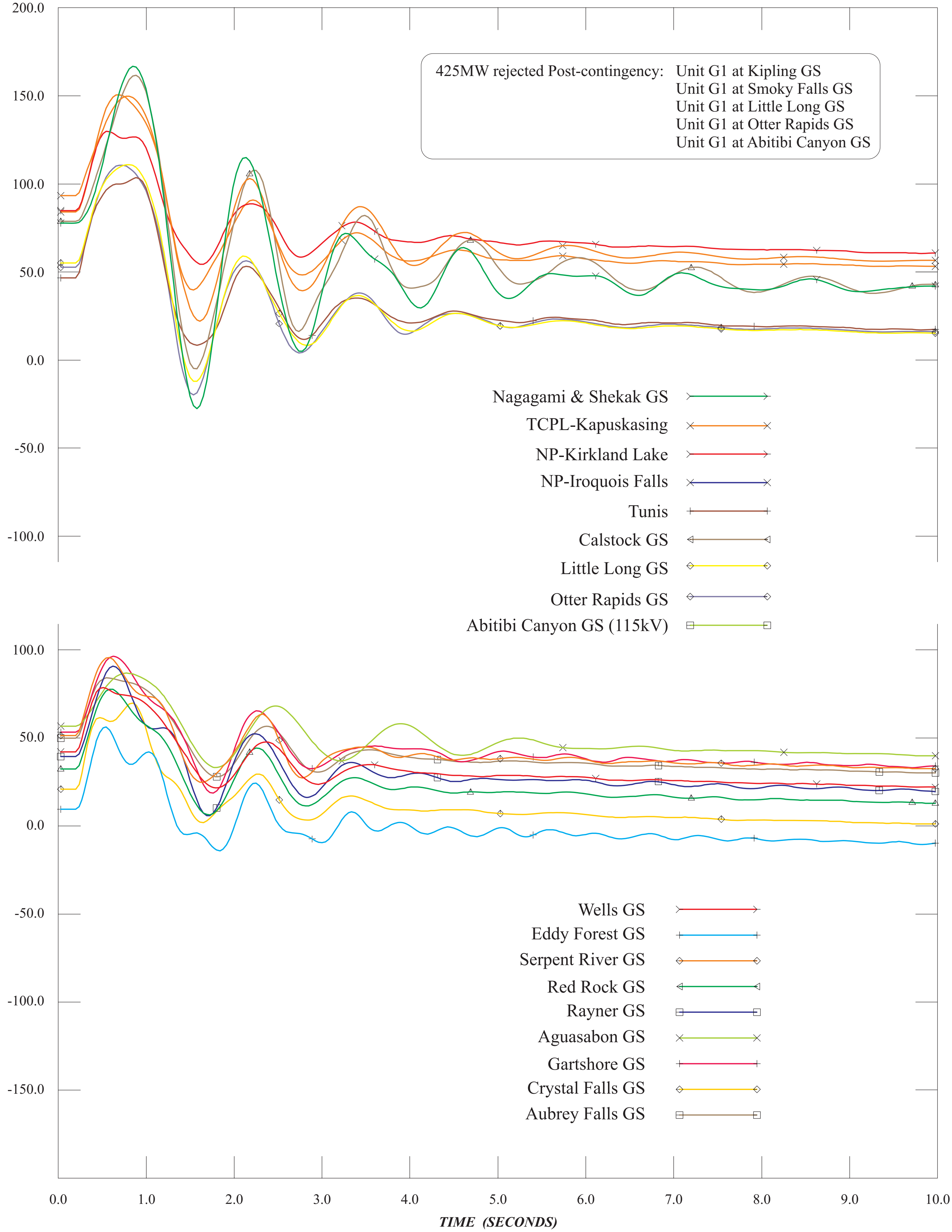
North-east Primary Demand: 1547MW *Load: 1192MW*
Losses: 355MW
3006MVAr

With no additional capacitor banks & a pre-contingency Flow-South Transfer of 2000MW

Post-contingency results following the loss of one of the Hanmer-to-Essa 500kV circuits

DIAGRAM 39

28th April 2007

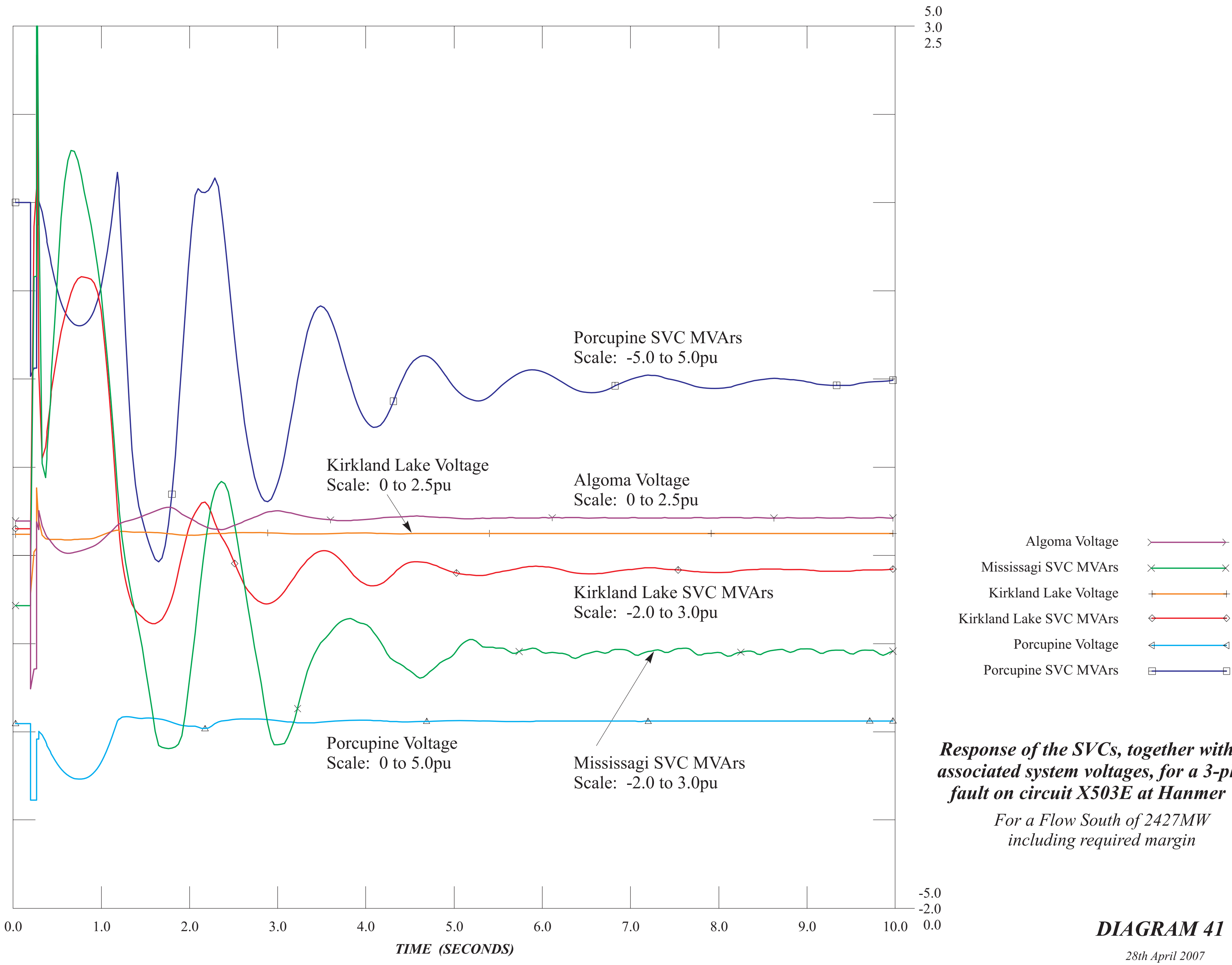


Generator Rotor Angle Responses to a 3-Phase fault on circuit X503E at Hanmer TS

DIAGRAM 40

For a Flow South of 2427MW including the required margin

28th April 2007

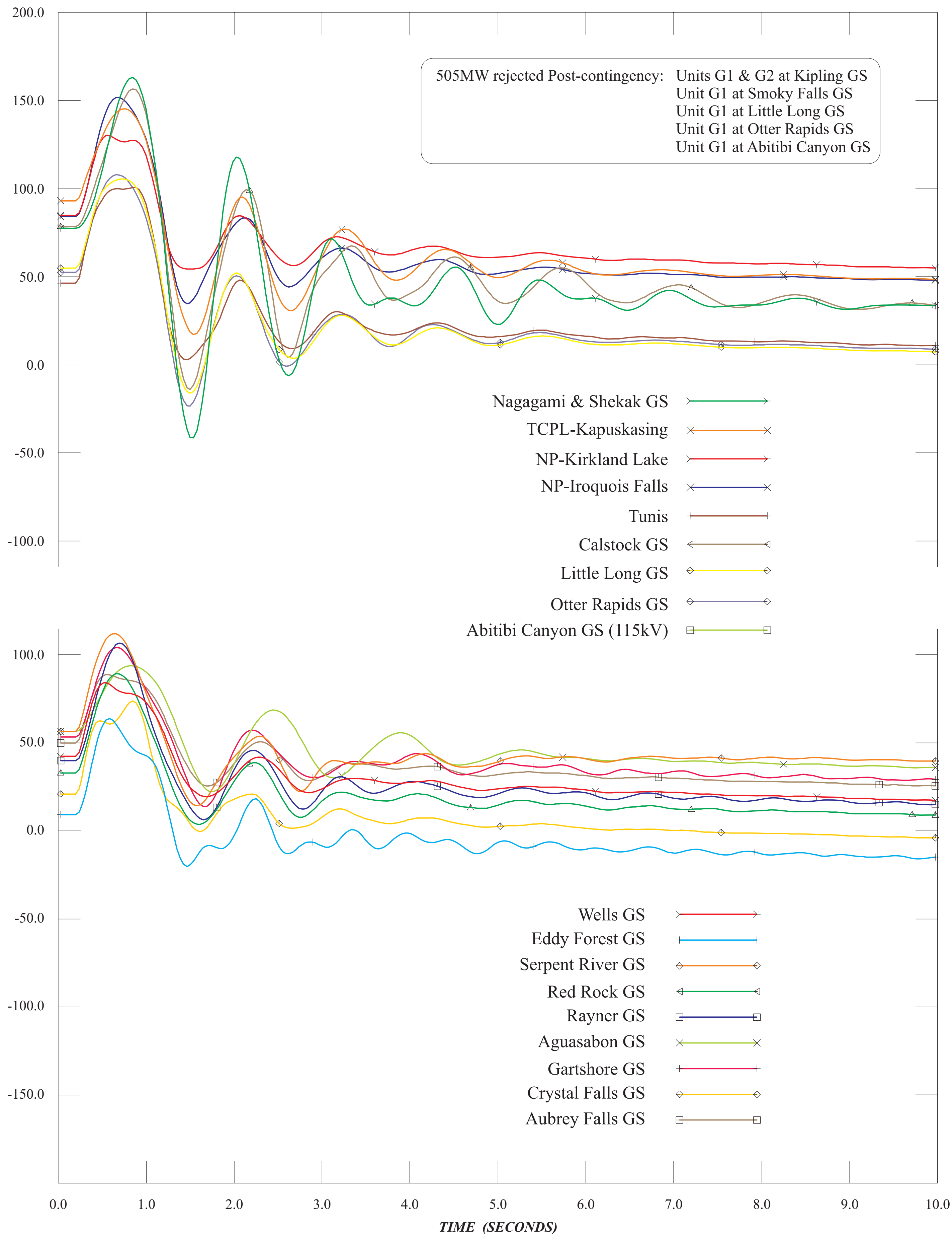


Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit X503E at Hanmer TS

For a Flow South of 2427MW including required margin

DIAGRAM 41

28th April 2007

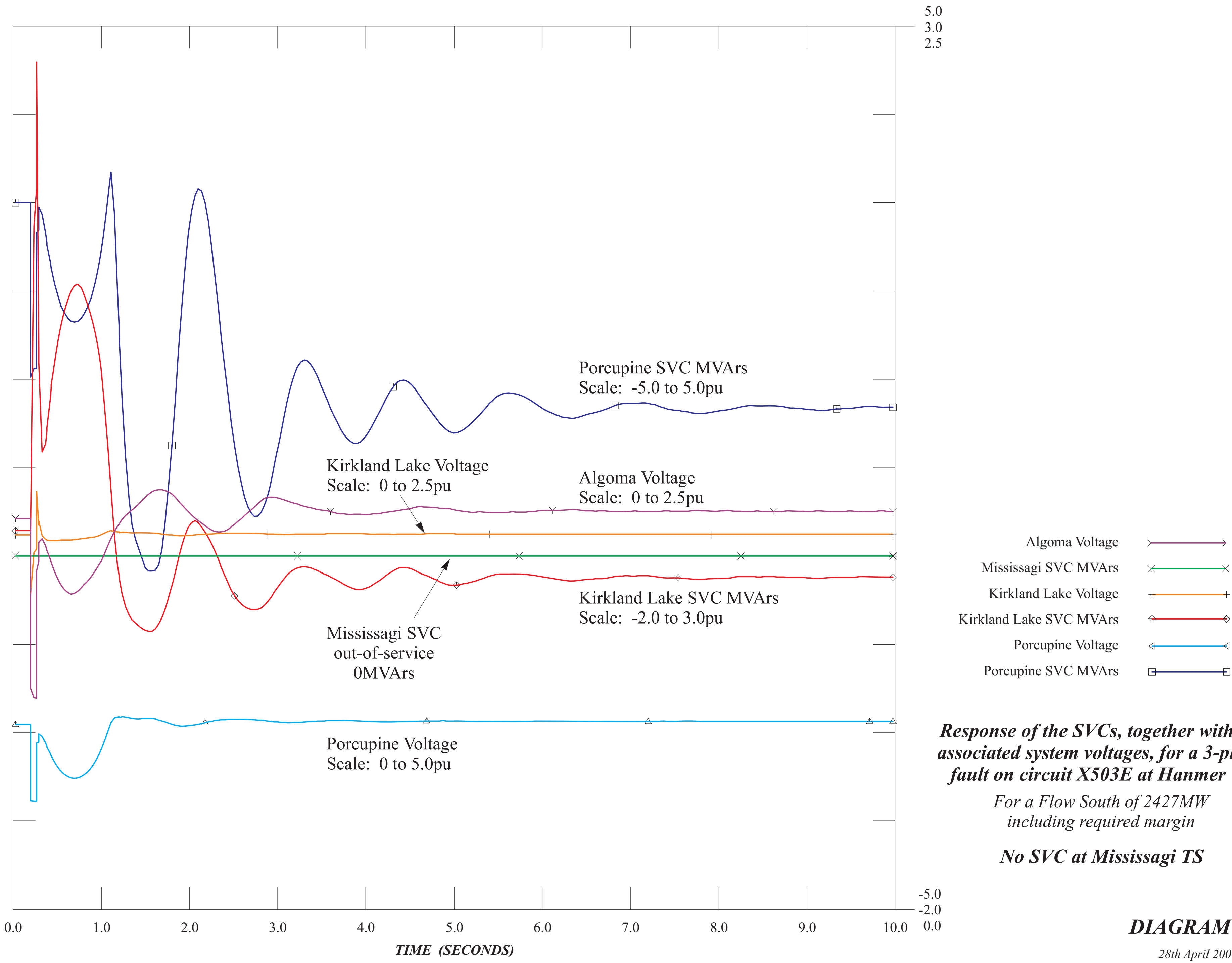


Generator Rotor Angle Responses to a 3-Phase fault on circuit X503E at Hanmer TS

With no SVC at Mississagi TS & a Flow South of 2427MW including the required margin

DIAGRAM 42

3rd May 2007



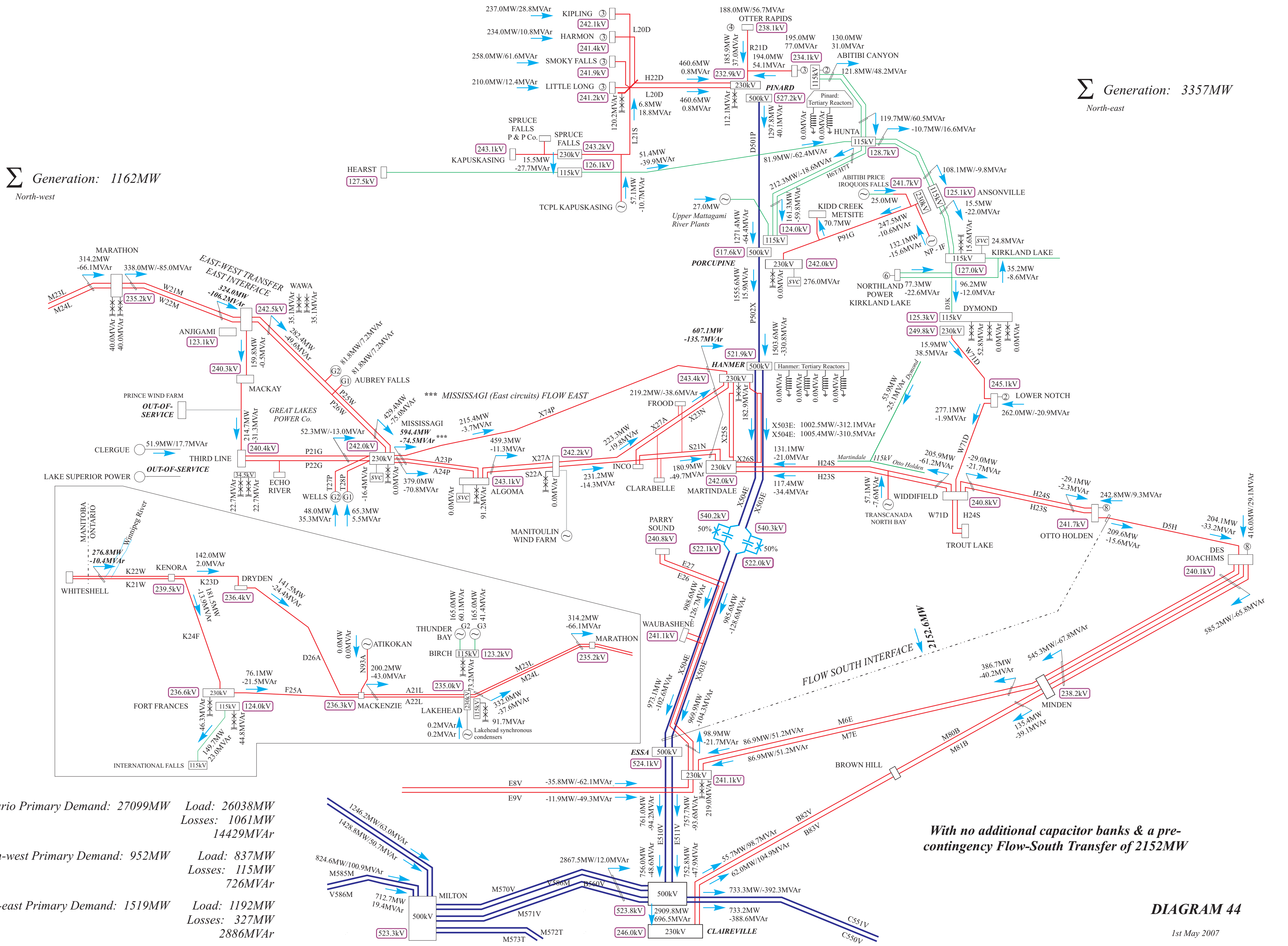
Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit X503E at Hanmer TS

For a Flow South of 2427MW including required margin

No SVC at Mississagi TS

DIAGRAM 43

28th April 2007



Ontario Primary Demand: 27099MW *Load: 26038MW*
Losses: 1061MW
14429MVAr

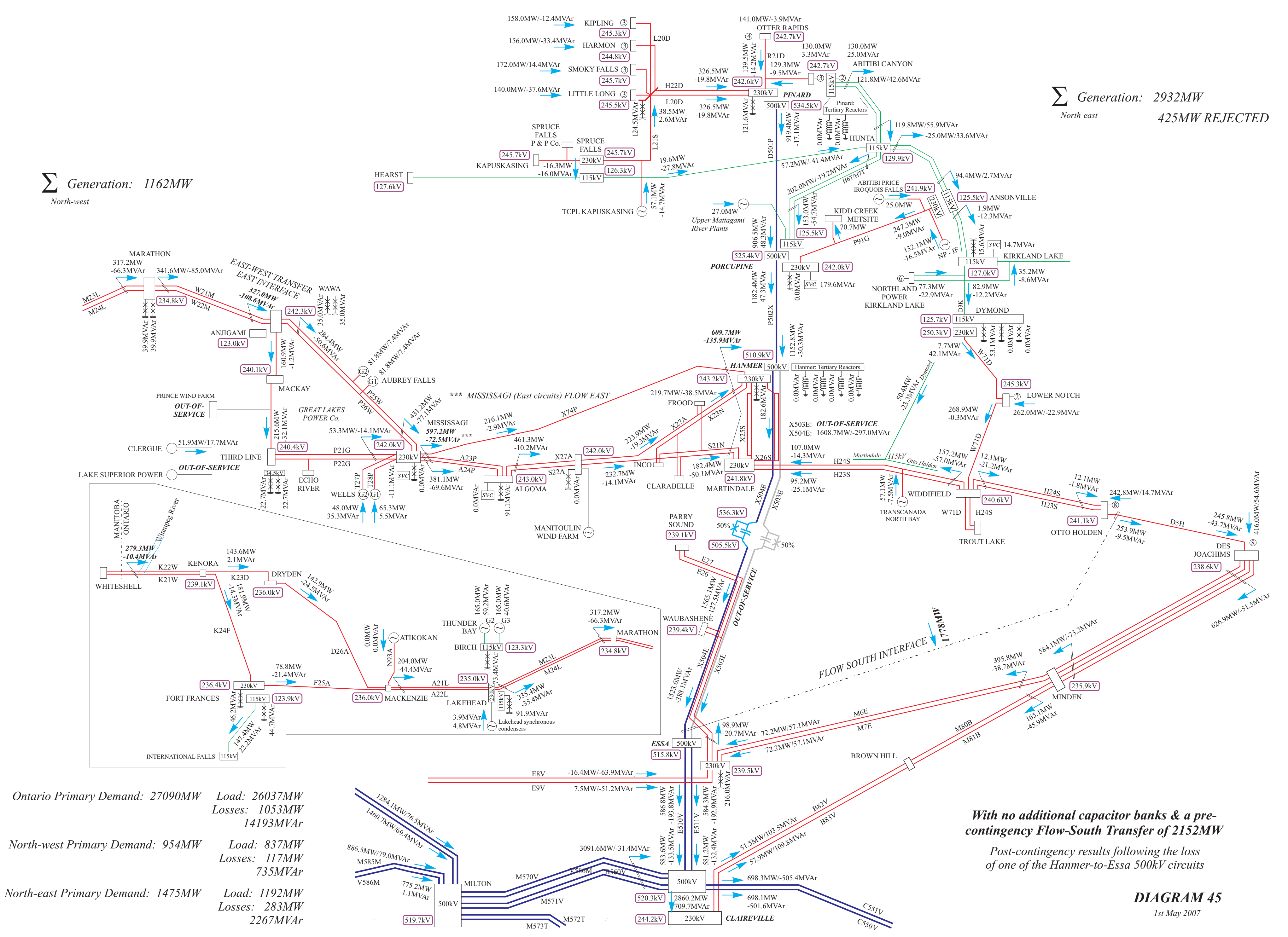
North-west Primary Demand: 952MW *Load: 837MW*
Losses: 115MW
726MVAr

North-east Primary Demand: 1519MW *Load: 1192MW*
Losses: 327MW
2886MVAr

With no additional capacitor banks & a pre-contingency Flow-South Transfer of 2152MW

DIAGRAM 44

1st May 2007



With no additional capacitor banks & a pre-contingency Flow-South Transfer of 2152MW

Post-contingency results following the loss of one of the Hanmer-to-Essa 500kV circuits

DIAGRAM 45

1st May 2007

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CONNECTION ASSESSMENT & APPROVAL PROCESS

SYSTEM IMPACT ASSESSMENT REPORT: 1st Addendum

For the Proposed Installation of:

Series Capacitors in the 500kV Circuits X503E & X504E at Nobel TS
SVCs at Porcupine TS & Kirkland Lake TS

Review of the effect on the transfer capability across the Flow-South Interface of not using generation rejection in response to first contingencies

Applicant: Hydro One Networks Inc.

CAA ID Nos.	***2004-160***	*Series Capacitors at Nobel TS*
	2006-223	*SVCs at Porcupine TS & Kirkland Lake TS*

Transmission Assessments & Performance Department

FINAL Version

Date: 15th August 2007

System Impact Assessment Report: ***1st Addendum***

For the Installation of:
Series Capacitors in the 500kV Hanmer TS to Essa TS circuits, and
Static VAr Compensators at Porcupine TS and Kirkland Lake TS

Review of the effect on the transfer capability across the Flow-South Interface of not using generation rejection in response to first contingencies

Acknowledgement

The IESO wishes 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 Hydro One Networks Inc. 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 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 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 the most recent version of this report is being used.

Hydro One

Special Notes and Limitations of Study Results

The results reported in this system impact assessment are based on the information available to Hydro One, at the time of the study, suitable for a system impact assessment of a new transmission facility.

HYDRO ONE NETWORKS Inc.

SYSTEM IMPACT ASSESSMENT REPORT:

For the Installation of:

Series Compensation in the 500kV Hanmer TS to Essa TS Circuits, and
Static VAr Compensators at Porcupine TS and Kirkland Lake TS

1st Addendum:

Review of the effect on the transfer capability across the Flow-South Interface of not using generation rejection in response to first contingencies

Summary

The results from the analysis that was performed for this Addendum have been combined with those summarised in the original SIA Report and presented in the following Table.

This Table shows that without using automatic post-contingency generation rejection in response to contingencies involving either of the 500kV Hanmer-to-Essa circuits, the maximum transfer that could be supported across the Flow-South Interface would be restricted to **2110MW.**

This would represent a reduction of approximately *390MW* from the **2500MW** transfer that could be accommodated if generation rejection were to be employed.

The Table also shows that the incremental effect on the transfer capability across the Flow-South Interface of the proposed additions to the transmission facilities in the north-east would be as follows:

	Proposed New facilities	*Transfer Capability across the Flow-South Interface*	
		Incremental Increase	*Cumulative Increase*
1.	Installation of series capacitors at Nobel SS in the 500kV circuits X503E & X504E to provide 50% compensation	340MW	-
2.	Installation of SVCs at Porcupine TS & Kirkland Lake TS	160MW	*500MW*
3.	Installation of additional shunt capacitor banks at Porcupine TS, Hanmer TS & Essa TS	250MW	*750MW*
4.	Installation of an SVC at Mississagi TS, and shunt capacitor banks at Mississagi TS & Algoma TS	60MW	*810MW*

Summary of the maximum transfers that could be supported across the Flow-South Interface

With all elements in-service pre-contingency

Critical Contingency: Loss of one of the 500kV circuits between Hanmer TS & Essa TS

	Reinforcement Scenario		***Transfer Across the Flow-South Interface***		
			With no G/R	***With G/R***	***Amount of G/R***
•	Existing Transmission Facilities		1300MW	1400MW	100MW
•	With the addition of series capacitors at Nobel SS for 50% compensation		1640MW		
		Increase	*340MW*		
•	With the addition of 50% series capacitors at Nobel SS *plus* SVCs at Porcupine TS & Kirkland Lake TS	*Facilities proposed by Hydro One for installation on the North-South corridor*	1800MW	2150MW	505MW
		Increase	*160MW*	*750MW*	
•	With the addition of series capacitors at Nobel SS for 50% compensation *plus* SVCs at Porcupine TS & Kirkland Lake TS *plus* Shunt capacitor banks at Hanmer TS, Porcupine TS & Essa TS		2050MW		
		Increase	*250MW*		
•	With the addition of series capacitors at Nobel SS for 50% compensation *plus* SVCs at Porcupine TS & Kirkland Lake TS *plus* Shunt capacitor banks at Hanmer TS, Porcupine TS & Essa TS *plus* SVC at Mississagi TS and shunt capacitor banks at Mississagi TS & Algoma TS		2110MW	2500MW	560MW
		Increase	*60MW*	*450MW*	

1. *Introduction*

The original SIA Report had concluded that with the installation of the following facilities on the North-South corridor, as proposed by Hydro One, it would be possible to increase the maximum transfers that could be supported across the Flow-South Interface to **2150MW**:

- Series capacitors in each of the 500kV circuits X503E & X504E, to provide a 50% level of compensation. The series capacitors are to be located at Nobel TS, which is the approximate mid-point of these circuits.
- A Static VAr Compensator (SVC) at Porcupine TS, rated at +300/-100MVAr and connected to the 230kV busbar via a dedicated step-up transformer.
- A further SVC at Kirkland Lake TS, rated at +200/-100MVAr and connected to the 115kV busbar via a dedicated step-up transformer.

To achieve pre-contingency transfers of this level, it was assumed that generation rejection would continue to be used, albeit on an interim basis until major new transmission reinforcement could be installed. For a pre-contingency transfer of 2150MW, the analysis had shown that approximately 500MW of generating capacity would need to be rejected immediately post-contingency.

With the maximum transfer that could be accommodated across the Flow-South Interface increased to 2150MW, it would be possible to incorporate the additional 430MW of new generating capacity proposed under the expansion of the Mattagami River plants. However, with all the existing and committed generating facilities north of Sudbury in-service and operating at their maximum output, it would be necessary to restrict the simultaneous transfers across the Flow-into-Sudbury Interface to approximately 600MW.

The analysis had also shown that a further increase to **2500MW** in the maximum transfer that could be accommodated across the Flow-South Interface could be achieved through the installation of the following facilities on both the North-South corridor and on the Mississagi-to-Sudbury corridor:

•	Porcupine TS	2 x 125MVAr shunt capacitor banks	
•	Hanmer TS	a 2nd 149MVAr shunt capacitor bank	} rated at 220kV
•	Essa TS	a 2nd 182MVAr shunt capacitor bank	
•	Mississagi TS	an SVC rated at +300/-100MVAr	
•	Mississagi TS	a 96MVAr shunt capacitor bank	} rated at 220kV
•	Algoma TS	a 2nd 75MVAr shunt capacitor bank	

For a pre-contingency transfer of 2500MW, approximately 560MW of generating capacity would need to be rejected immediately post-contingency.

With the maximum transfer across the Flow-South Interface increased to 2500MW, this would be sufficient to allow simultaneous transfers across the Flow-into-Sudbury Interface (from the west) of approximately 1000MW to be accommodated. This would allow unrestricted operation of all of the existing and committed generating facilities between Wawa TS and Sudbury, as well as allowing maximum transfers of 325MW eastwards across the East-West Ties.

The transfer capabilities that had been determined in the original SIA Report have been summarised in Table 1.

Transfer Capabilities with no generation rejection

This Addendum identifies that maximum transfers that it would be possible to support across the Flow-South Interface without resorting to the use of generation rejection.

TABLE 1	From the Original SIA Report: Summary of the maximum transfers that could be supported across the Flow-South Interface			
With all elements in-service pre-contingency *Critical Contingency:* Loss of one of the 500kV circuits between Hanmer TS & Essa TS				
	Reinforcement Scenario	***Maximum Transfers Across the Flow-South Interface***		
		With no G/R	***With G/R***	***Amount of G/R***
•	Existing Transmission Facilities	*1300MW*	*1400MW*	*100MW*
•	**Facilities proposed by Hydro One for installation on the North-South corridor:** The addition of series capacitors providing 50% compensation at Nobel SS *plus* The installation of SVCs at Porcupine TS & Kirkland Lake TS	-	*2150MW*	*505MW*
	Increase		*750MW*	
•	The addition of series capacitors providing 50% compensation at Nobel SS *plus* The installation of SVCs at Porcupine TS & Kirkland Lake TS *plus* The installation of shunt capacitor banks at Hanmer TS, Porcupine TS & Essa TS *plus* The installation of an SVC at Mississagi TS & shunt capacitors at Mississagi TS & Algoma TS	-	*2500MW*	*560MW*
	Increase		*350MW*	

2. *Operational Interfaces*

The principal Interfaces that govern the operation of the IESO-controlled Grid within the area under review are as follows:

i. *Flow-South/Flow-North Interface -*

Representing the combined flow on the 230kV circuit D5H, measured at Otto Holden GS, and on the 500kV circuits X503E & X504E, measured at Essa TS.

ii. *East-West Transfer Interface -*

Representing the combined flow on the 230kV circuits W21M & W22M, measured at Wawa TS

iii. *Mississagi Flow-East Interface -*

Representing the combined flow on the 230kV circuits A23P, A24P & X74P, measured at Mississagi TS.

An additional, arbitrary Interface had also been adopted in the original SIA to measure the combined flow into Sudbury from the west. This Interface had been designated the *Flow-East into Sudbury Interface* and it represents the combined flow on the following circuits:

iv. *Flow-East into Sudbury -* *(Measured at both Hanmer TS and Martindale TS)*

Representing the combined flow on the 230kV circuits X74P & X27A, measured at Hanmer TS, and S22A, measured at Martindale TS.

3. *Transient Stability Analysis for a Contingency involving either of the 500kV Hanmer-to-Essa circuits*

All of the analysis was performed for a normally-cleared three-phase fault applied at the Hanmer terminal of circuit X503E (or X504E).

The fault was applied after 0.2 seconds and cleared at the Hanmer terminal of the 500kV circuit after a further 66msec.

Clearance of the fault at the remote terminal at Essa TS was assumed to occur after a further 25msec. The total elapsed time from the occurrence of the fault, to the line being removed from service, would therefore be 91msec.

Flow-into-Sudbury

For this analysis, the Flow-into-Sudbury was maintained at approximately 750MW for the cases without the additional SVC at Mississagi TS. This would be equivalent to a transfer across the Mississagi Flow-East Interface of approximately 765MW.

After applying a margin of 10%, this transfer would remain within the voltage-stability limit for transfers across the Mississagi Flow-East Interface once additional facilities have been added to the North-South corridor that would provide crucial voltage support at Hanmer TS.

For the case with the additional SVC assumed to be installed at Mississagi TS, the Flow-into-Sudbury was increased by a nominal 50MW to 823MW.

In the transient stability studies for each of the development scenarios considered, the Flow-South into Sudbury was increased by dispatching additional generating capacity at the Moose River plants until instability of the generating units north of Sudbury occurred.

Provision of a 10% Margin on the Limiting Transfers

The IESO's Transmission Assessment Criteria require that -

> 'all stability limits should be shown to be stable if the most critical parameter is increased by 10%'.

The limiting transfer beyond which the units were shown to be unstable was therefore reduced by 10% to obtain the maximum transfer capability across the Flow-South Interface for the particular development scenario under review.

3.1 With series capacitors installed at Nobel SS in the 500kV circuits X503E & X504E

Diagrams 1 & 2 shows the results from the last transient stability study for which the generating units remained stable.

In Diagram 2, while the minimum voltage at Porcupine TS is shown to decline to a value that is only marginally above the 70% of nominal voltage that is permitted under the IESO's Ontario Resource & Transmission Assessment Criteria, the voltage is also shown to remain below the 80% of nominal voltage threshold for 525msec. This would be well in excess of the 250msec permitted under the IESO's criteria.

The study was therefore repeated with reduced transfers into Sudbury until the 250msec criterion was satisfied. Diagram 3 shows the voltage responses at the monitored busbars for a transfer of 1270MW into Sudbury (Hanmer) via the 500kV circuit P502X. This would correspond to a transfer of 1807MW across the Flow-South Interface. At this transfer level, the voltage at Porcupine TS is shown to remain below the 80% of nominal voltage threshold for 210msec, which would satisfy the criterion.

After applying a margin of 10%, the effective transient-stability limit for transfers across the Flow-South Interface, with only the new series capacitors at Nobel SS in place and without employing post-contingency generation rejection, would therefore be **1642MW**.

This would represent an increase of approximately *340MW* over the present limit of 1300MW for the condition with no generation rejection initiated post-contingency.

3.2 With series capacitors installed at Nobel SS and SVCs at Porcupine TS & Kirkland Lake TS

The results for the last transient stability study for which the generating units remained stable with the additional SVCs assumed at Porcupine TS and Kirkland Lake TS are summarised in Diagrams 4 & 5.

In Diagram 5, the minimum transient voltage recorded at Porcupine is shown to remain above approximately 77% of the nominal voltage, and would therefore meet the IESO's criteria. However, since the voltage is shown to remain below the 80% threshold for 270msec it would therefore exceed the permitted time of 250msec.

It is worth noting that during this interval, the corresponding reactive power output from the SVC at Porcupine TS is shown to decline. This occurs because the SVC has already reached its maximum rating and it is then unable to control the voltage at the Porcupine 230kV busbar. Under these operating conditions its output then becomes voltage-dependent.

The marginal violation in the time that the voltage remains below the 80% threshold could therefore be addressed either through the provision of a short-term overload capability for the SVC or through a very small reduction (<10MW) in the Flow-South transfer.

After applying the required margin of 10%, the addition of the SVCs at Porcupine TS and Kirkland Lake TS would therefore increase the transient-stability limit for transfers across the Flow-South Interface to **1800MW.**
The installation of the SVCs at Porcupine TS and Kirkland Lake TS would therefore achieve a further increase of approximately *160MW* in the transfer limit over that provided through the installation of the series capacitors at Nobel SS, for the condition with no generation rejection initiated post-contingency.

3.3 With series capacitors installed at Nobel SS; SVCs installed at Porcupine TS & Kirkland Lake TS; and additional shunt capacitor banks installed at Porcupine TS, Hanmer TS & Essa TS

The analysis in the original SIA Report had shown that one of the consequences of increasing the power transfers across the North-South corridor would be a significant increase in the reactive power losses. The installation of additional shunt capacitor banks at Porcupine TS, Hanmer TS and Essa TS was therefore proposed to achieve an improvement in the voltage profile over the North-South corridor.

The results from the transient-stability study for a contingency involving one of the Hanmer-to-Essa 500kV circuits with these additional shunt capacitor banks in-service are shown in Diagrams 6 & 7.

While the response shown in Diagram 7 for the SVC at Porcupine is similar to that shown in Diagram 5, the voltage recorded at Porcupine TS only remains below the 80% threshold for 185msec and would therefore satisfy the IESO's criterion.

The addition of the shunt capacitor banks at Porcupine TS, Hanmer TS and Essa TS would therefore increase the transient-stability limit for transfers across the Flow-South Interface to **2053MW.**

This would represent a further increase of approximately *250MW* in the transfer limit over that which would be provided through the installation of the series capacitors at Nobel SS and the SVCs at Porcupine TS and Kirkland Lake TS, for the condition with no generation rejection initiated post-contingency.

3.4 With series capacitors installed at Nobel SS; SVCs installed at Porcupine TS & Kirkland Lake TS; additional shunt capacitor banks installed at Porcupine TS, Hanmer TS & Essa TS; and an SVC at Mississagi TS and shunt capacitors at Mississagi TS & Algoma TS

In the original SIA Report it had been identified that the transfer into the Sudbury area from the west would need to be restricted to approximately 890MW to avoid instability of the generating units west of Algoma in response to a contingency involving the 500kV circuit P502X, between Hanmer TS and Porcupine TS.

Analysis had shown that the installation of an SVC at Mississagi TS together with shunt capacitor banks at Mississagi TS and Algoma TS would permit higher transfers into Sudbury while maintaining stability in the event of a P502X contingency.

Diagrams 8 & 9 show the results from the transient-stability study for a contingency involving one of the Hanmer-to-Essa 500kV circuits with the additional SVC at Mississagi TS together with the shunt capacitor banks at Mississagi TS and Algoma TS in-service.

In Diagram 9, the behaviour of the SVC at Porcupine TS stays essentially unchanged, with the result that the voltage at Porcupine TS is shown to remain below the 80% threshold for 260msec. As before, this marginal violation could be addressed either through the provision of a short-term overload capability for the SVC or through a minor reduction in the Flow-South transfer.

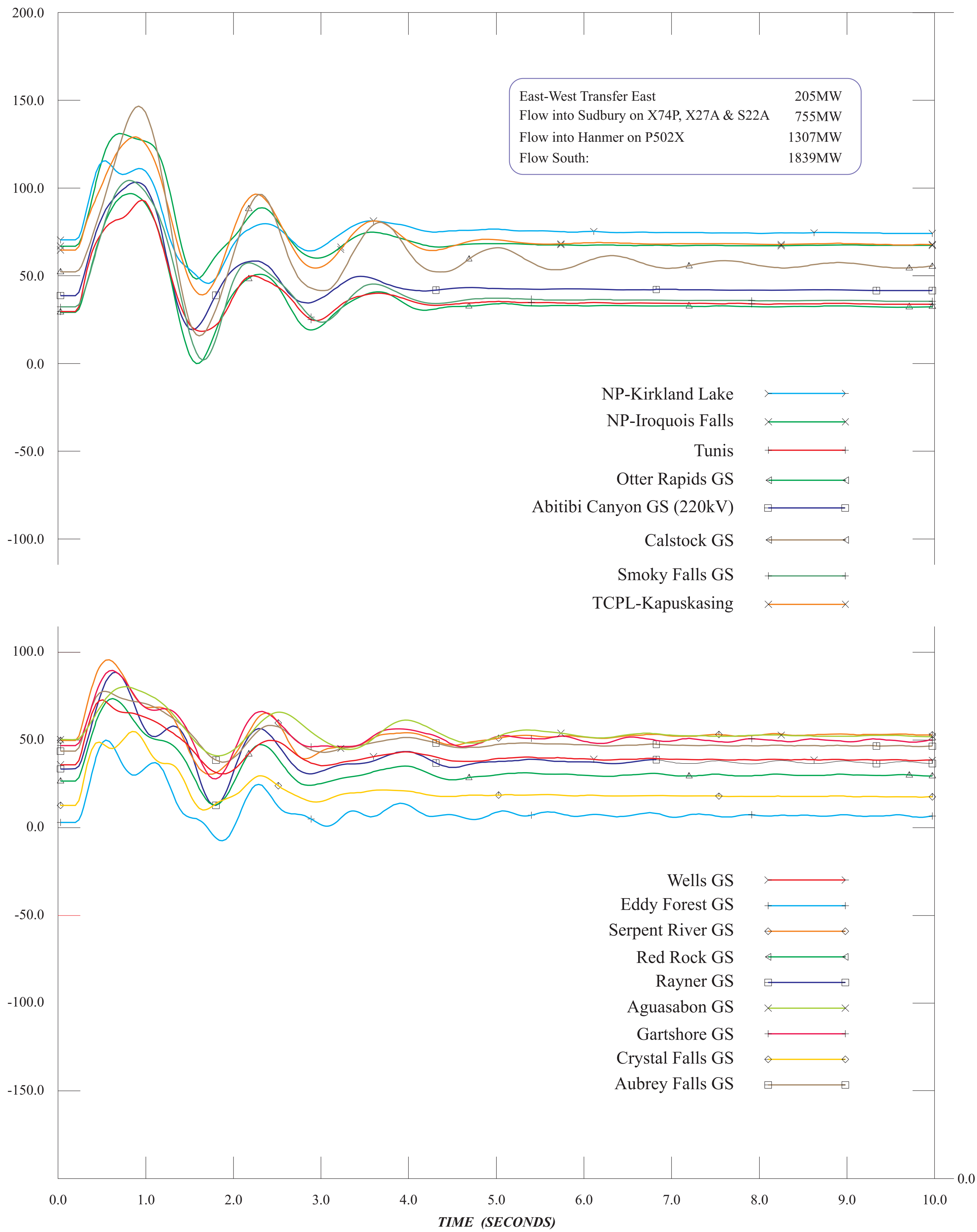
The addition of the SVC at Mississagi TS, together with the shunt capacitor banks at Mississagi TS and Algoma TS would therefore increase the transient-stability limit for transfers across the Flow-South Interface to **2110MW**, after applying the required margin of 10%**.**

This would represent a further increase of approximately *60MW* in the transfer limit over that which would be provided through the installation of the series capacitors at Nobel SS; the SVCs at Porcupine TS and Kirkland Lake TS; and the additional shunt capacitor banks at Porcupine TS, Hanmer TS and Essa TS, for the condition with no generation rejection initiated post-contingency.

3.5 Summary of the transfer capabilities across the Flow-South Interface

The following Table summarises the transfer capabilities that were presented in the original SIA Report together with the results obtained from the analysis performed for this Addendum.

TABLE 2	***Summary of the maximum transfers that could be supported across the Flow-South Interface***				
With all elements in-service pre-contingency *Critical Contingency:* Loss of one of the 500kV circuits between Hanmer TS & Essa TS					
	Reinforcement Scenario		***Transfer Across the Flow-South Interface***		
			With no G/R	***With G/R***	***Amount of G/R***
•	Existing Transmission Facilities		1300MW	1400MW	100MW
•	With the addition of series capacitors at Nobel SS for 50% compensation		1640MW		
		Increase	*340MW*		
•	With the addition of 50% series capacitors at Nobel SS *plus* SVCs at Porcupine TS & Kirkland Lake TS	*Facilities proposed by Hydro One for installation on the North-South corridor*	1800MW	2150MW	505MW
		Increase	*160MW*	*750MW*	
•	With the addition of series capacitors at Nobel SS for 50% compensation *plus* SVCs at Porcupine TS & Kirkland Lake TS *plus* Shunt capacitor banks at Hanmer TS, Porcupine TS & Essa TS		2050MW		
		Increase	*250MW*		
•	With the addition of series capacitors at Nobel SS for 50% compensation *plus* SVCs at Porcupine TS & Kirkland Lake TS *plus* Shunt capacitor banks at Hanmer TS, Porcupine TS & Essa TS *plus* SVC at Mississagi TS and shunt capacitor banks at Mississagi TS & Algoma TS		2110MW	2500MW	560MW
		Increase	*60MW*	*450MW*	

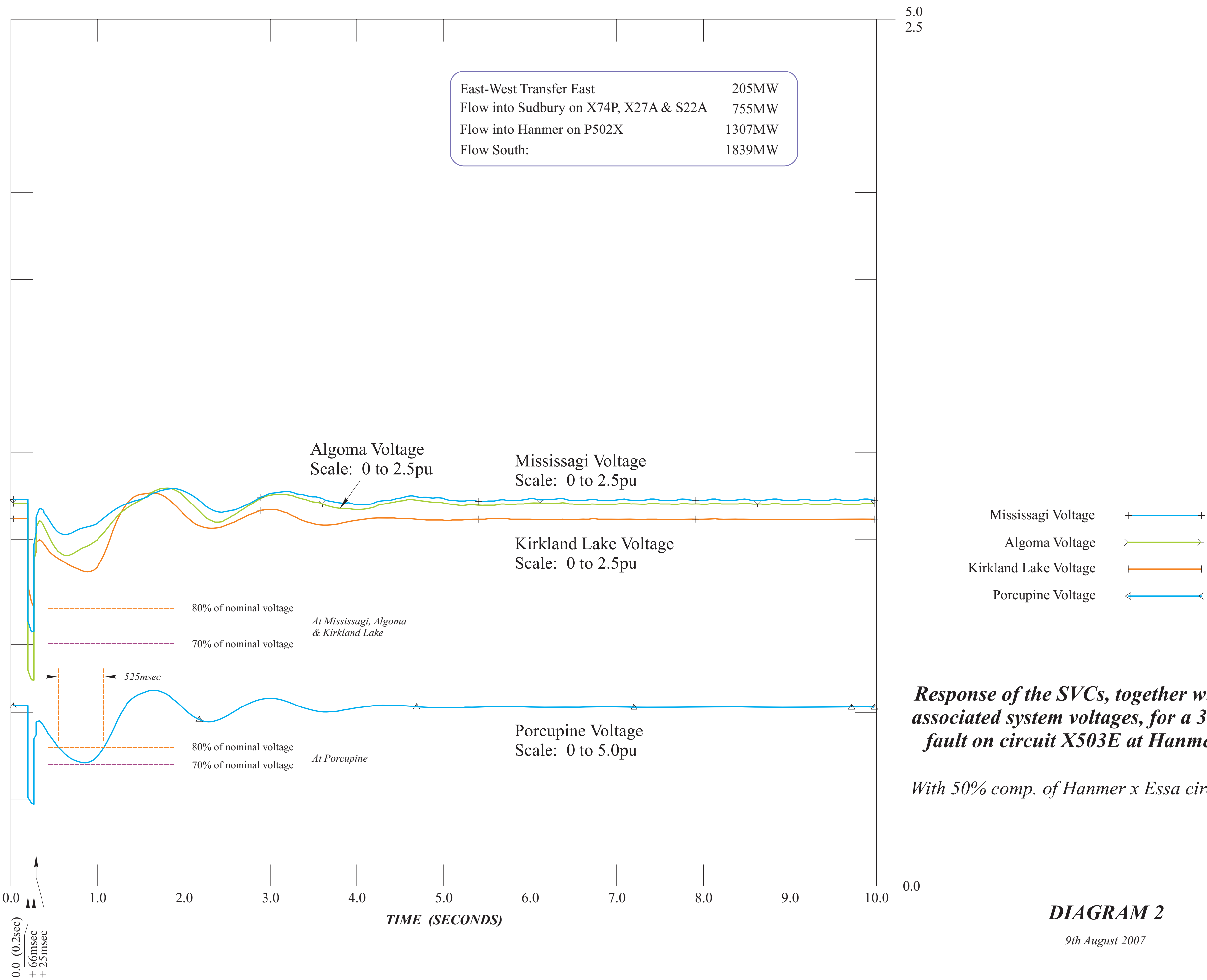


Generator Rotor Angle Responses to a 3-Phase fault on circuit X503E at Hanmer TS

With 50% compensation on the two Hanmer x Essa 500kV circuits

DIAGRAM 1

9th August 2007

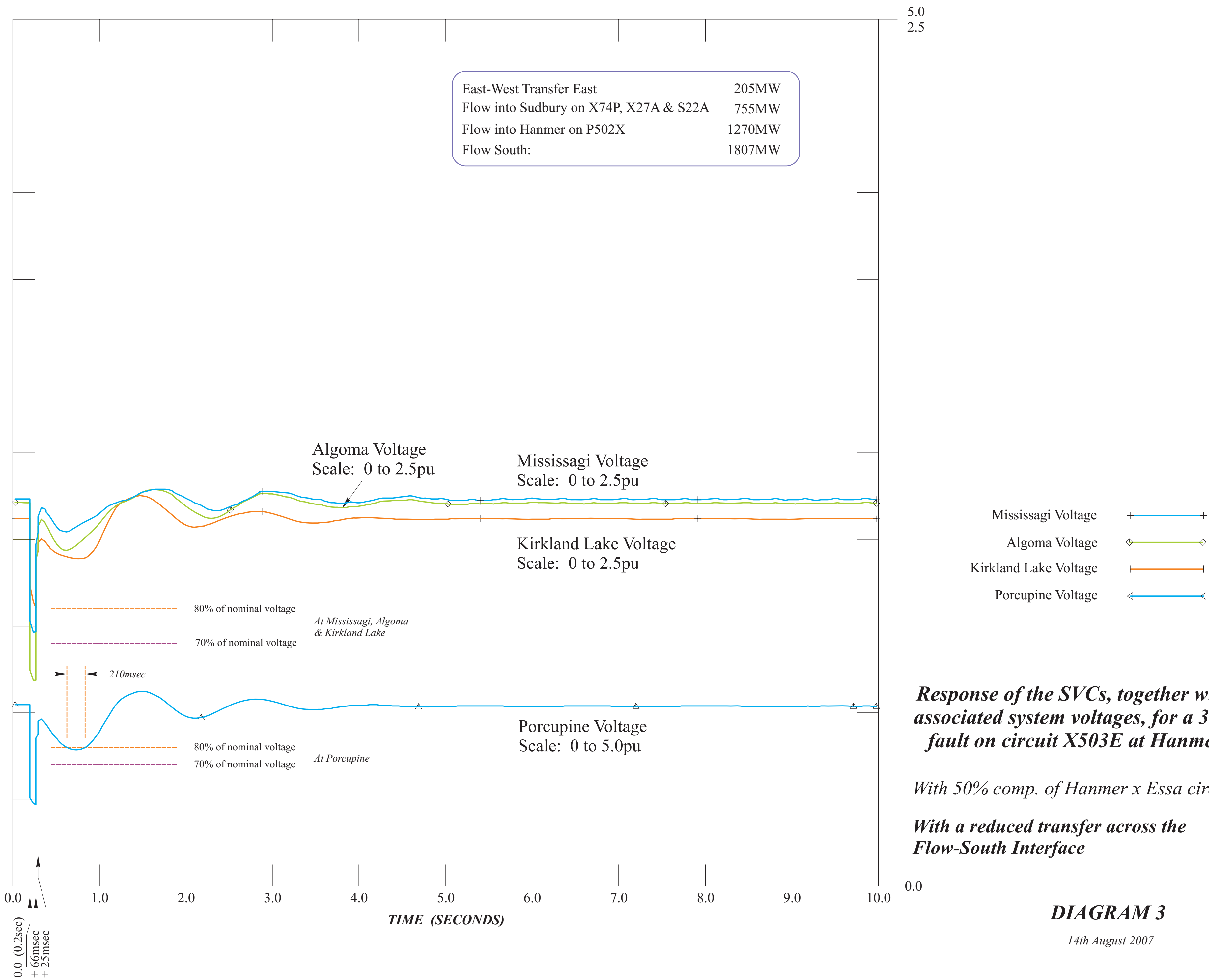


Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit X503E at Hanmer TS

With 50% comp. of Hanmer x Essa circuits

DIAGRAM 2

9th August 2007



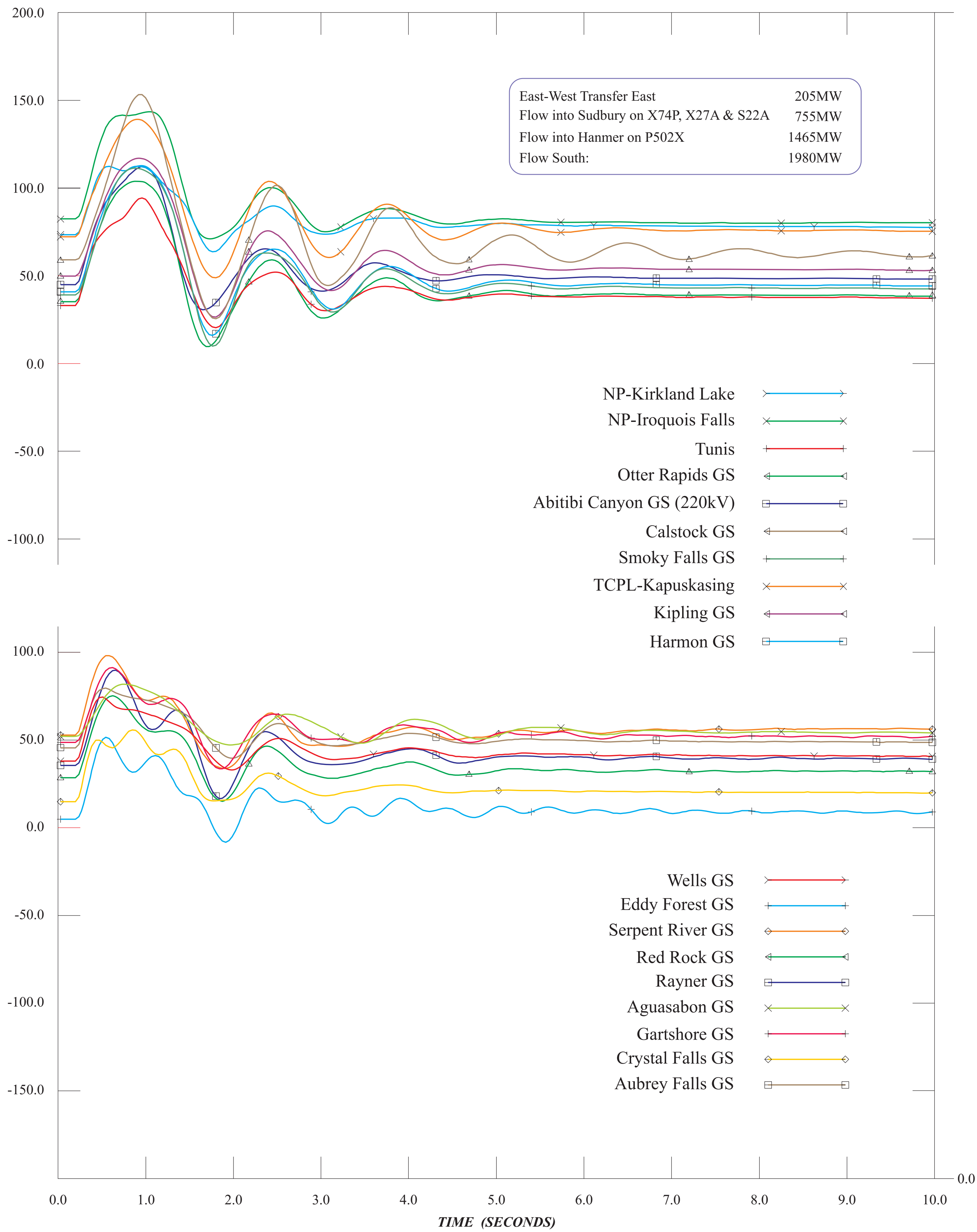
Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit X503E at Hanmer TS

With 50% comp. of Hanmer x Essa circuits

With a reduced transfer across the Flow-South Interface

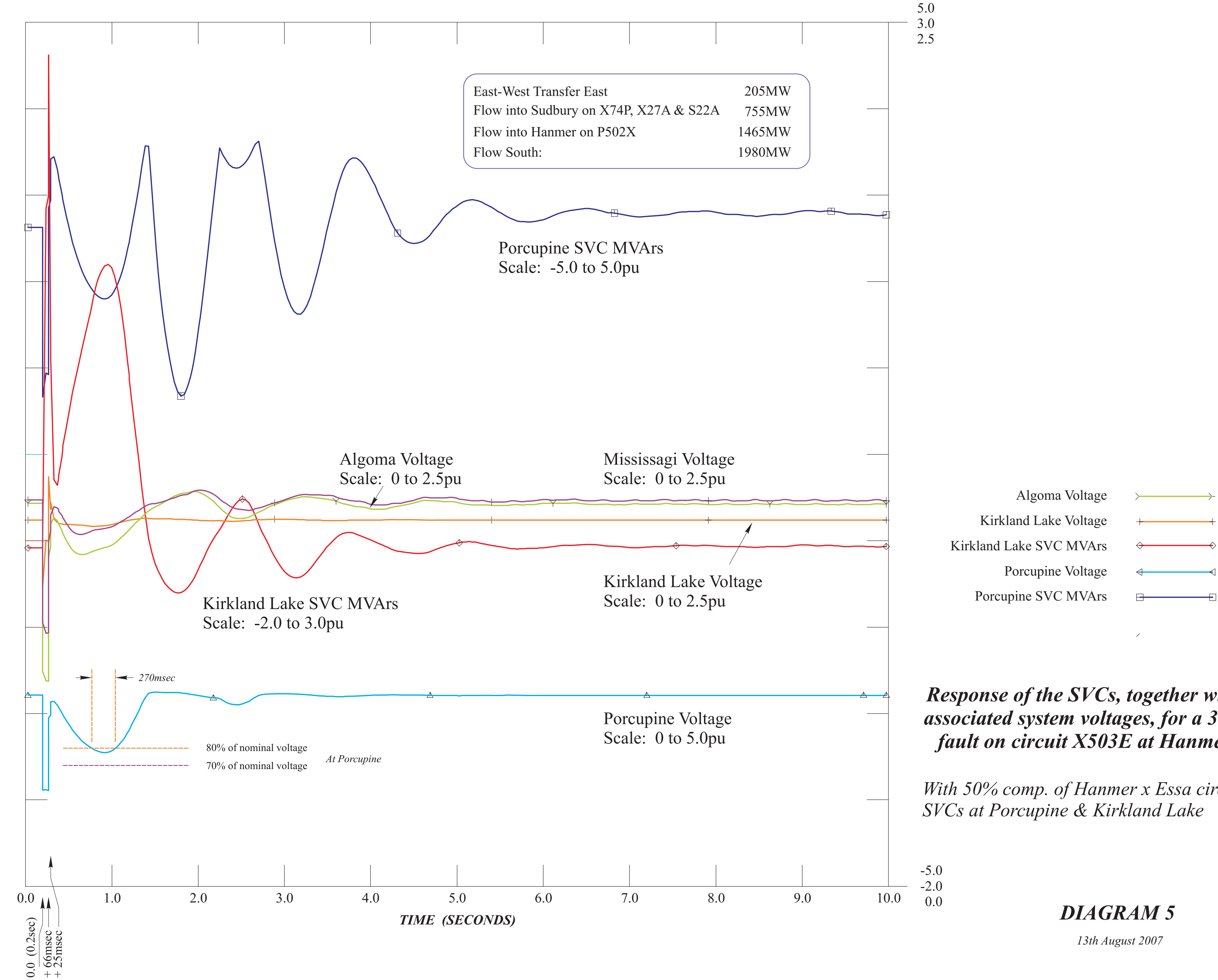
DIAGRAM 3

14th August 2007



Generator Rotor Angle Responses to a 3-Phase fault on circuit X503E at Hanmer TS
With 50% compensation of Hanmer x Essa circuits + SVCs at Porcupine & Kirkland Lake

DIAGRAM 4
9th August 2007

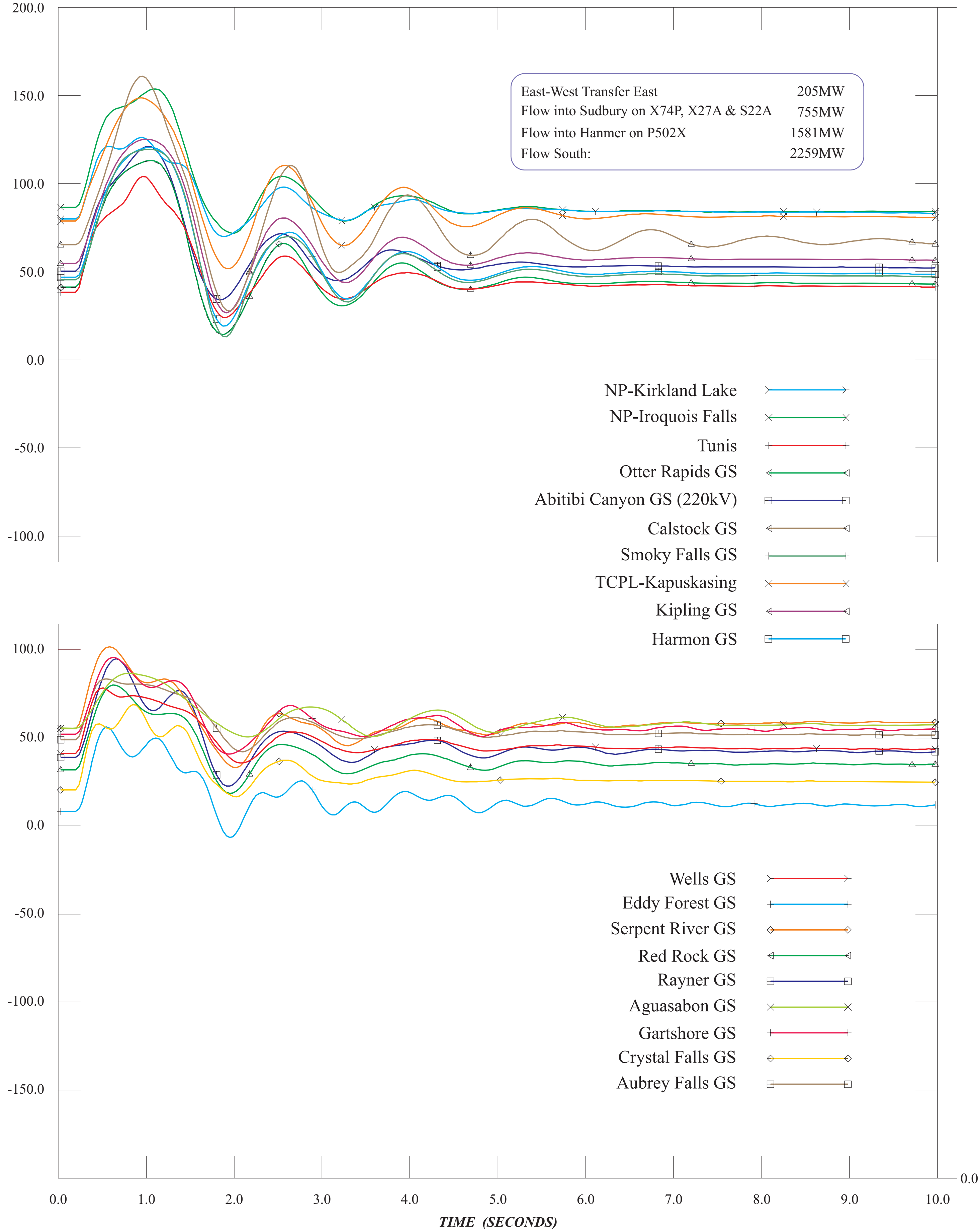


Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit X503E at Hanmer TS

With 50% comp. of Hanmer x Essa circuits + SVCs at Porcupine & Kirkland Lake

DIAGRAM 5

13th August 2007

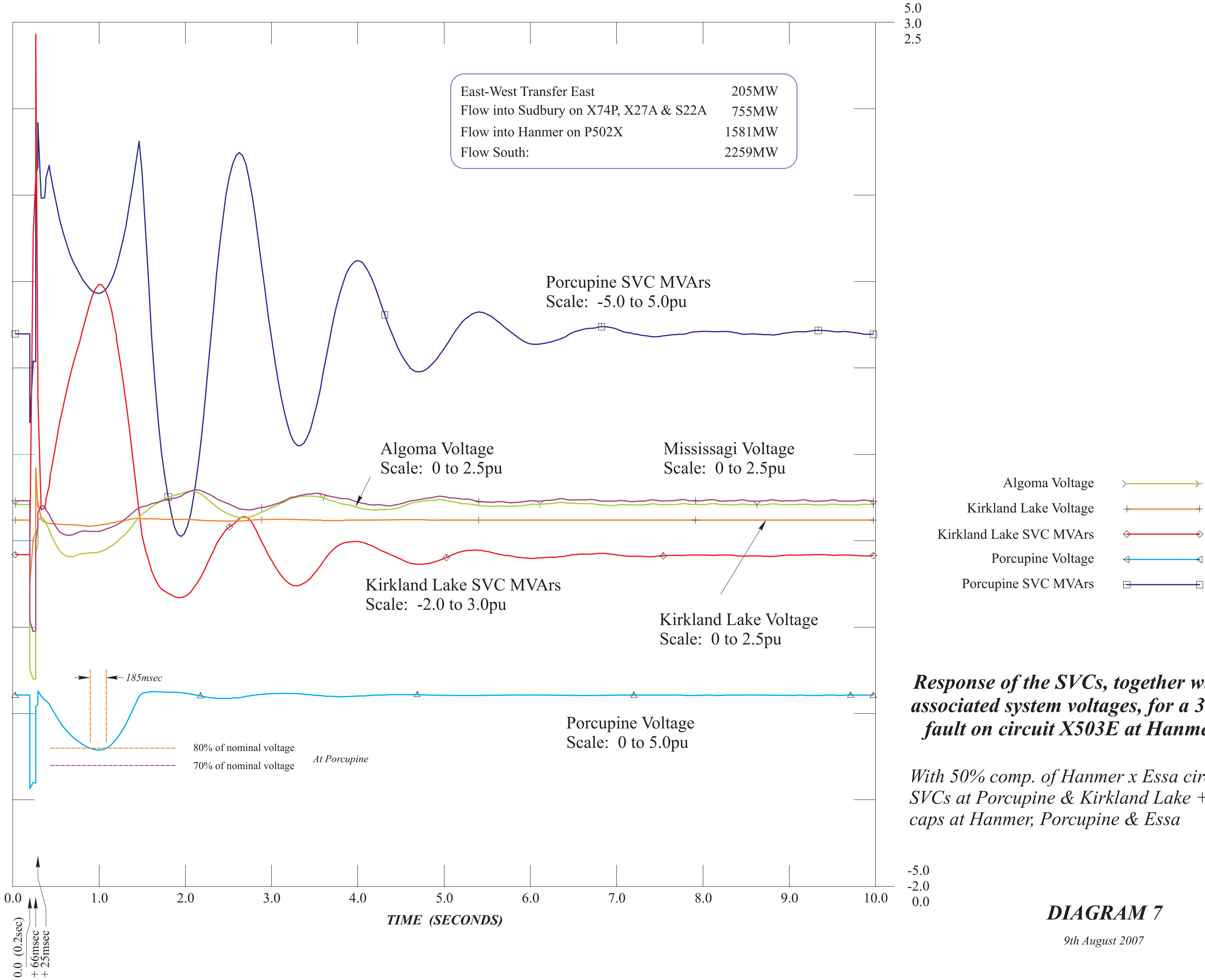


Generator Rotor Angle Responses to a 3-Phase fault on circuit D501P at Porcupine TS

With 50% comp. of Hanmer x Essa circuits + SVCs at Porcupine TS & Kirkland Lake TS + shunt capacitors at Hanmer TS, Porcupine TS & Essa TS

DIAGRAM 6

13th August 2007

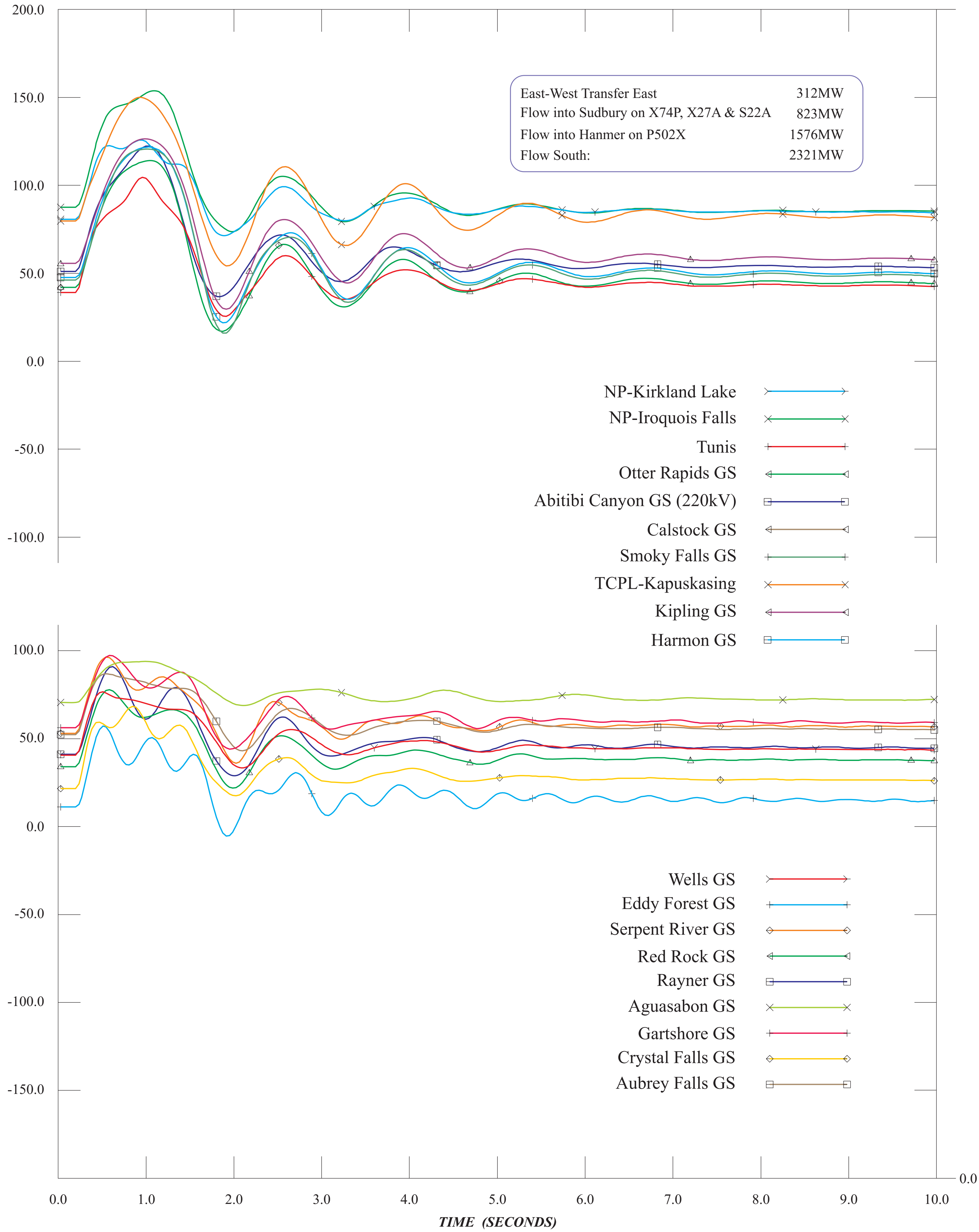


Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit X503E at Hanmer TS

With 50% comp. of Hanmer x Essa circuits + SVCs at Porcupine & Kirkland Lake + shunt caps at Hanmer, Porcupine & Essa

DIAGRAM 7

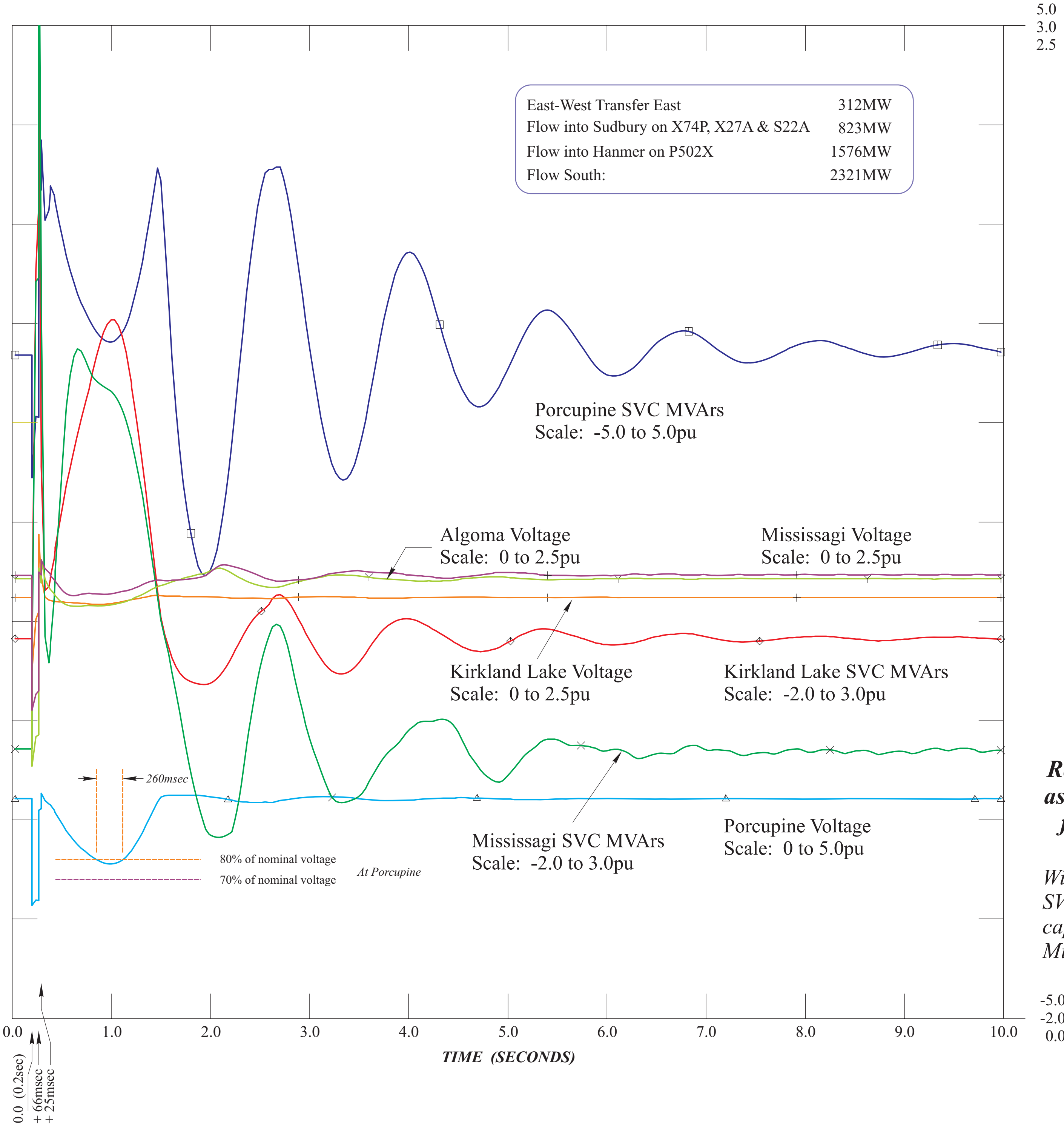
9th August 2007

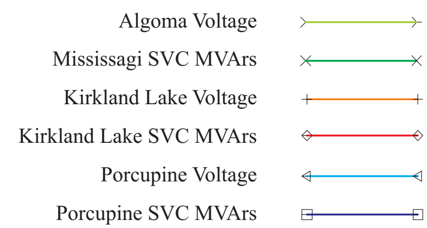


Generator Rotor Angle Responses to a 3-Phase fault on circuit X503E at Hanmer TS
With 50% comp. of Hanmer x Essa circuits + SVCs at Porcupine & Kirkland Lake + shunt caps at Hanmer, Porcupine & Essa + SVC at Mississagi & caps at Mississagi & Algoma

DIAGRAM 8

13th August 2007





Response of the SVCs, together with the associated system voltages, for a 3-phase fault on circuit X503E at Hanmer TS

With 50% comp. of Hanmer x Essa circuits + SVCs at Porcupine & Kirkland Lake + shunt caps at Hanmer, Porcupine & Essa + SVC at Mississagi & caps at Mississagi & Algoma

DIAGRAM 9

13th August 2007