Application Exhibit List

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ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998, S.O. 1998*, c. 15, Sch. B, as amended (the "**OEB Act**")**;**

AND IN THE MATTER of an application by White River Hydro LP and Pic Mobert First Nation for an order under section 92 and subsection 96(2) of the OEB Act granting leave to construct an electricity transmission line and related facilities.

APPLICATION FOR LEAVE TO CONSTRUCT

1. The Applicants hereby apply to the Ontario Energy Board (the "**Board**") pursuant to section 92 of the OEB Act for an order or orders granting leave to construct the proposed transmission facilities (the "**Transmission Facility**"), as further described below and more particularly described in Exhibit B-1-1.

2. The Applicants in this application are White River Hydro Limited Partnership ("**White River Hydro LP**") and Pic Mobert First Nation ("**Pic Mobert**"), which entities are partners in the Pic Mobert Hydro Power Joint Venture (the "**Joint Venture**"). An ownership chart is contained in Exhibit A-1-2. The Joint Venture was formed on May 2, 2005 to provide for the development, permitting, construction and operation of the Gitchi Animki Hydroelectric Project (the "**Project**"), which project is comprised of the transmission facilities that are the subject of this application and certain hydro electric generating facilities, all as further described below.

3. As a federally recognized band within the meaning of the *Indian Act*, Pic Mobert, via band council, holds a 35% direct legal interest in the Joint Venture. Pic Mobert is a First Nation community of 828 members of which 325 reside on reserve. The reserve is located on 286 ha of federal reserve property on the southeast corner of White Lake. The members of Pic Mobert are Anishinabek and their ancestors have lived on the north shore of Lake Superior and used the White River watershed for fishing, transportation, trapping and trade prior to, and following the arrival of Europeans in the area.

4. White River Hydro LP holds the remaining 65% interest in the Joint Venture. White River Hydro LP is a subsidiary of Regional Power Inc. ("**Regional Power**"), which company is a subsidiary of Manulife Financial. White River Hydro LP was created by Regional Power on October 21, 2009 for the purpose of developing, constructing and operating the Project. Regional Power holds a 99.9% interest in White River Hydro LP,

while White River Hydro GP, which is also wholly owned by Regional Power, holds a 0.001% interest and acts as the general partner to White River Hydro LP.

5. Regional Power, via its subsidiary Regional Power Opco Inc., and its predecessor companies has been in the business of developing and operating hydroelectric power plants since 1985, and has developed three greenfield hydroelectric plants. Two of these, the 16 MW Sechelt Creek GS[1] and the 3 MW Dease Lake GS, are located in British Columbia. The third is the 13.5 MW Wawatay GS located on the Black River near the Town of Marathon, Ontario approximately 100 km west of White River. Regional Power is completing construction on three of its other projects in British Columbia, namely the Upper Bear, Lower Bear and Long Lake Hydro project. The Bear projects are 10 MW each and are scheduled to be online December 2011 (Lower Bear) and March 2012 (Upper Bear). The 35 MW Long Lake Hydro project is under construction and is scheduled to be online December 2012. Regional Power has also rehabilitated three existing generating stations located in Dryden, Ontario.

6. The Joint Venture is developing two hydroelectric generating facilities on the White River, being the lower Gitchi Animki Niizh facility (the "**Niizh Facility**", 10 MW) and the upper Gitchi Animki Bezhig facility (the "**Bezhig Facility**", 8.9 MW, the Niizh and Bezhig Facilities referred to collectively as the "**Hydro Facilities**").

7. The Project will be the first major commercial undertaking for the Pic Mobert community and revenue from the Project will positively impact various social development initiatives being considered by the community in its move toward self sufficiency. The installation of the Bezhig Facility will also improve river habitat and help resolve flooding issues.

8. In addition to providing significant benefits to Pic Mobert, the Project is being developed to further the provincial government's policy objective to increase the amount of renewable energy generation being added to the provincial grid. In particular, the government's policy regarding renewable energy is outlined in the *Green Energy and Green Economy Act, 2009,* S.O. 2009, c. 12, which act amended key pieces of legislation to promote the use and generation of electricity from renewable energy sources, including the *OEB Act*. The *Electricity Act,* 1998 was also amended to provide for the creation of Ontario's first Feed-in-tariff program for renewable energy development, which was subsequently developed by the Ontario Power Authority.

9. The Hydro Facilities each have power purchase agreements associated with them, which agreements were awarded to the Joint Venture under the Feed-in-tariff Program.

10. The Transmission Facility will be used to connect the Hydro Facilities to the bulk provincial electricity system and consist of the following elements:

[1] The Sechelt Creek GS, developed and operated by Regional Power, won the 2005 UNESCO International Hydropower Association (IHA) Blue Planet Prize at the United Nations Conference of Parties on Climate Change in Montreal on December 4, 2005. the Blue Planet Prize, which is awarded every 2 years for up to three Hydro Facilities, recognizes good practice in the development and operation of a hydropower scheme on the basis of environmental, technical, social and economic criteria developed by the IHA and UNESCO.

I. A single 115 kV electricity transmission line (the "**Transmission Line**") approximately 23.5 km in length, which will connect the Hydro Facilities to the IESO-controlled grid and begin at the downstream Niizh Facility, connect the Bezhig Facility and terminate at the interconnection point (the "**Interconnection Point**") with Hydro One's M2W, 115 kV circuit (the "**M2W Circuit**");

II. A switching station (the "**Switching Station**") will be located adjacent to the M2W Circuit;

III. A switchyard (the "**Niizh Switchyard**") located adjacent to the Niizh Facility powerhouse that will connect the Niizh Facility to the Transmission Line; and

IV. A switchyard (the "**Bezhig Switchyard**") located adjacent to the Bezhig Facility powerhouse that will connect the Bezhig Facility to the Transmission Line.

11. The Transmission Line will also carry a fibre-optic communication cable that will provide control and protection telemetry, unit status and SCADA information and control between each of the Hydro Facilities and to the Interconnection Point to provide with remote operation, monitoring and interconnection to the Hydro One control and protection scheme on the M2W Circuit. The fibre-optic cable will also interconnect to the existing Bell Canada fibre-optic telephone cable running along Highway 17.

12. The lands (the "**Facility Lands**") upon which the Transmission Facility will be built are entirely Crown lands, with the exception for a small portion of land that is privately owned by Canadian Pacific Rail ("**CP Rail**"), for which a crossing is being sought. In addition to being Crown lands, the Facility Lands are also provincial park lands. The Applicants have obtained all necessary permits and approvals for the development of the Project within provincial park lands.

13. The Project, including the Transmission Facility, is subject to the environmental screening process for hydro electric projects prescribed by *Ontario Regulation 116/01, Electricity Project Regulation* (the "**Regulation**"). Accordingly, the Applicant has conducted extensive consultation with interested stakeholders and concluded the environmental screening process on November 5, 2010. No requests for elevation were received. In addition to the environmental approvals, the Applicants have received the final interconnection reports issued by the IESO and Hydro One Networks Inc. ("**Hydro One**"), both of which conclude that the Project, as proposed, is acceptable from an interconnection standpoint.

14. The individuals below are the authorized representatives of the Applicants for the purpose of serving documents throughout this proceeding:

Kristyn Annis
McCarthy Tétrault LLP
Toronto Dominion Bank Tower
66 Wellington St. W
Toronto, ON M5K 1E6

Tel: 416.601.7624
Fax: 416.868.0673
Email: kannis@mccarthy.ca

Babar Khan, P.Eng.
Regional Power OPCO Inc.
6755 Mississauga Road, Suite 308
Mississauga, ON L5N 7Y2

Tel: 905-363-4200 Ext 209
Fax: 905-363-4202
Email: babark@regionalpower.com

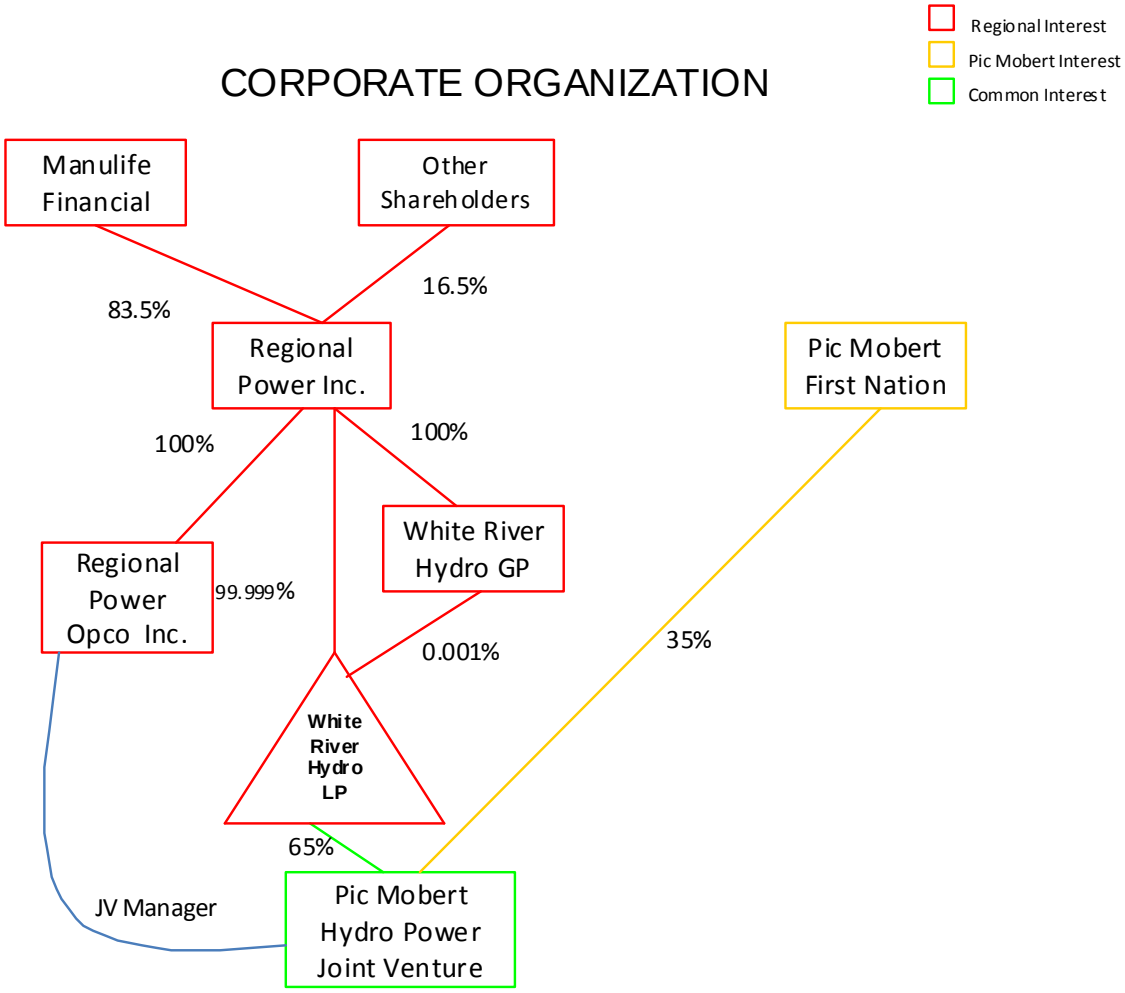
Dated December 6, 2011 at Toronto, Ontario

White River Hydro LP and Pic Mobert First Nation, by its counsel, McCarthy Tétrault LLP

Per:

Kristyn Annis

A-1-2 – Ownership Structure



Doc# 10057094

B-1-1 Project Overview

Project Description – Hydro Facilities

15. The Applicants are proposing to construct the Hydro Facilities on the White River in north western Ontario. The Project is publicly referred to as the Gitchi Animki Hydroelectric Project.

16. The Bezhig Facility will be located approximately 3.2 km downstream from the site of the existing White Lake Dam. The Bezhig Facility will replace the function of the current White Lake Dam, which is currently owned and operated by the Ministry of Natural Resources ("**MNR**"). The Bezhig Facility has a total installed capacity of 8.9 MW and will be operated to maintain the White Lake water levels to optimize renewable hydroelectric power production, while facilitating recreation and improving flood management capabilities.

17. The Niizh Facility is located approximately 1.6 km downstream from Chicagonce Falls on the White River and approximately 12 km downstream from the Bezhig Facility. The Niizh Facility will be operated as a run-of-the river facility[2] dependent on the flows from the Bezhig Facility and will have a total installed capacity of 10 MW.

18. The existing White Lake Dam will be decommissioned as part of the Project, and the function of lake level and flood control will be carried out by the new Bezhig Facility. It is anticipated that a new modern control structure will provide for more effective and consistent control of water levels on White Lake and flows along the White River with the added advantage of lowering the potential for flooding within the built areas of White Lake Provincial Park, within the Pic Mobert community and along the course of the White River.

19. The Joint Venture was awarded two separate power purchase agreements for each of the Hydro Facilities under the OPA's FIT Program in April 2010.

Project Description - Transmission Facility

20. The Hydro Facilities will be connected to the bulk transmission system via the Transmission Facility, which is comprised of the elements previously described above in paragraph 10, Section A-1-1, being the Transmission Line, the Switching Station, the Niizh Switchyard and the Bezhig Switchyard.

21. The Transmission Line will run from the Niizh Facility along the south side of the White River along Route 700 for approximately 12 km and then north along Route 729C for approximately another 1 km where it will connect at the Bezhig Facility. Both Route 700 and Route 729C (collectively, the "**Forest Service Roads**") are forestry roads that are

[2] A run-of-the-river facility is one which has minimal forebay storage that passes some or all of the inflow through one or more turbines on a continuous basis, with the remainder, if any, going over an existing falls or spillway.

currently licensed to White River Forest Products Limited ("**WRFP**"). The Transmission Line will then run from the Bezhig Facility where it will cross the White River and then traverse Crown land generally in a north westerly direction for approximately 10.5 km, before terminating at the Switching Station located next to the Interconnection Point on the north side of Highway 17. Apart from a right of way parcel of land owned by CP Rail located approximately 6 km northwest of the Bezhig Facility, the Transmission Line will be built entirely on Crown land.

22. The Switching Station will consist of motorised and manual disconnect switches, transmission line breaker, transmission line control and protection equipment, fibre-optic communication terminus equipment and take-off structures to the line and Hydro One sides. The Switching Station will consist of a gravel foundation, grounding grid and fencing. An access road will be constructed from the Switching Station to Highway 17. Hydro One is finalising the design of the T-Tap interconnection with indication from Hydro One that they will provide a pole structure adjacent to the Switching Station with taps to the M2W Circuit for interconnection to the WRHI Switching Station. The Switching Station will be located on the south side of the Hydro One M2W Circuit with the final location finalised after detailed design of the Transmission Line as well as of the Hydro One's portion of the interconnection.

23. The Niizh Switchyard will consist of motorised and manual disconnect switches, line breaker, transmission line and transformer control and protection equipment, fibre-optic communication terminus equipment, powerhouse main step-up transformer and take-off structure to the Transmission Line. The Niizh Switchyard will consist of a gravel foundation, grounding grid and fencing.

24. The Bezhig Switchyard will consist of motorised and manual disconnect switches, line breaker, transmission line and transformer control and protection equipment, fibre-optic communication terminus equipment, powerhouse main step-up transformer and take-off structures to the Niizh to Bezhig and the Bezhig to Switching Station sides. The Bezhig Switchyard will consist of a gravel foundation, grounding grid and fencing and is adjacent to the Bezhig Facility powerhouse.

25. A 50-m wide ROW will be required to allow passage of the Transmission Line from the Bezhig Facility to the Interconnection Point and the portions of Transmission Line that run along the 700 Series Road. The total length of the Transmission Line will be approximately 23.5 km. A map of the Transmission Facility is attached as Exhibit B-1-3.

B-1-2 Project Location

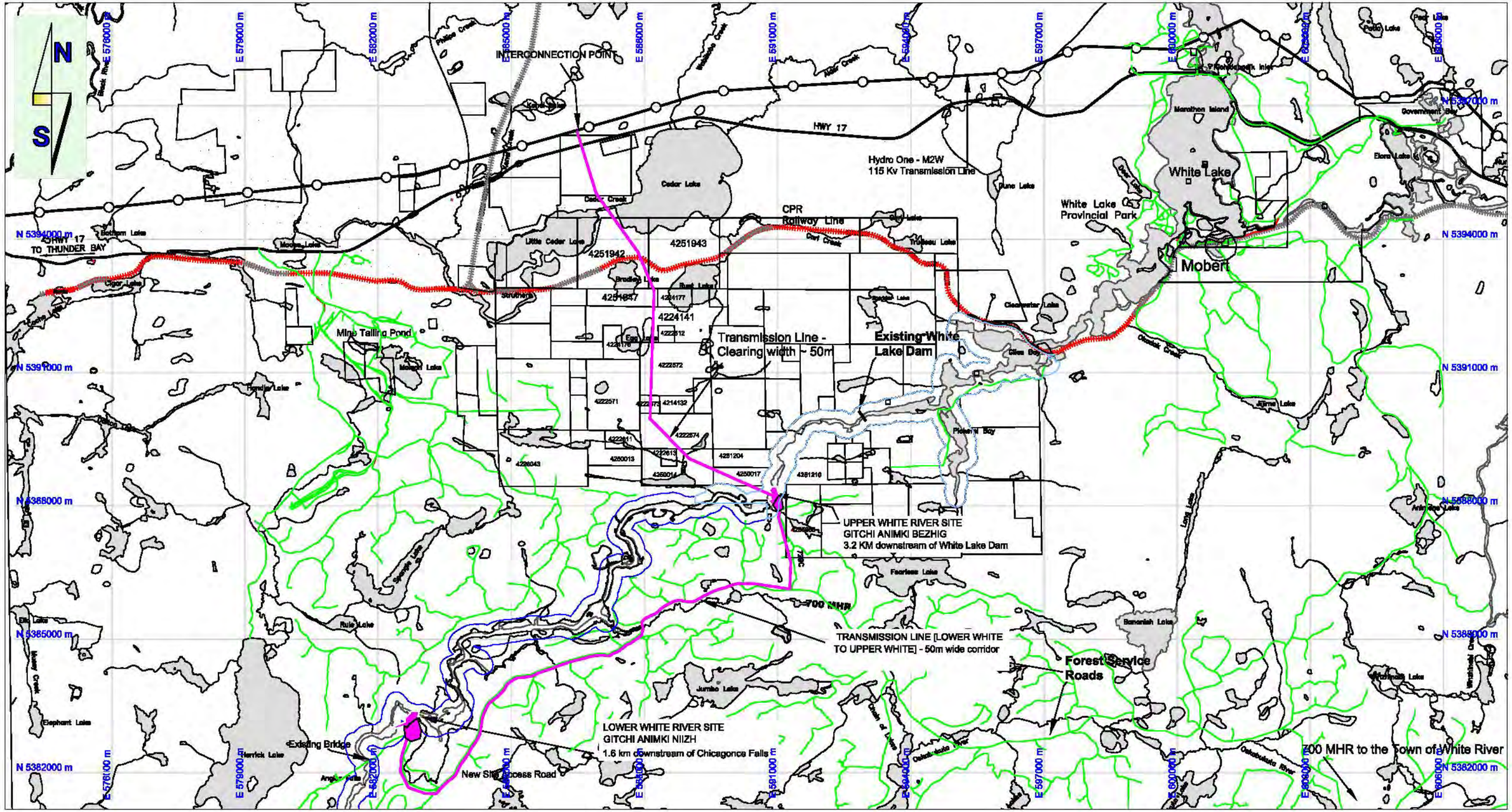
26. White River has its head waters southeast of the Town of White River. The river spans a distance of approximately 130 km and flows into White Lake approximately 70 km downstream of its source into White Lake for approximately 62 km before flowing into Lake Superior, approximately 18 km south of the Town of Marathon. The final 13.8 km of the lower reach of the White River flows through Pukaskwa National Park. The main features of the river and the immediate surrounding area are displayed in Exhibit B-1-4. They include:

- White Lake and White Lake Dam
- White Lake Provincial Park
- Pic Mobert First Nation Community
- Pic River First Nation Community
- Pukaskwa National Park
- Towns of White River and Marathon.

27. The upstream and more northerly site (Bezhig Facility) is situated approximately 12 km southwest of the community of Mobert, occupied by the Pic Mobert. The Town of White River lies approximately 30 km southeast (70 km by road) of the Project area.

28. The coordinate of the Niizh Facility's Switchyard is 48º 35'39" N; 85º 52'41" W. The coordinate of the Bezhig Facility's Switchyard is 48º 38'24" N; 85º 46'06" W. The preliminary coordinate of the Switching Station is 48º 42'53" N; 85º 49'27" W. The Transmission Line will run between the aforementioned coordinates, beginning at the Niizh Facility, traversing generally north easterly to the Bezhig Facility and then generally north westerly to the Switching Station.

B-1-3 Map of Transmission Facility



Notes:

1. All Dimensions are in meters and coordinates in NAD83 UTM Zone 16
2. Road Network shown on this drawing has the following sources:
   a) Domtar Inc. GIS dataset - provided by Domtar Inc. on Feb 8, 2007 - rd0508 / wr700rds shape files
   b) 1:50,000 NTDB vector dataset

LEGEND

- PROPOSED TRANSMISSION LINE
- CROWN LAND
- WHITE LAKE PARK EXTENSION
- FOREST RESERVE / WHITE LAKE PARK EXTENSION
- MINING CLAIMS
- HIGHWAY #17
- HYDRO ONE 115 Kv TRANSMISSION LINE
- EXISTING ROAD NETWORK (FOREST SERVICE ROADS)
- CP RAILWAY RIGHT OF WAY

SCALE

0 600 1200 1800 2400 3000

Meters

REV	Y	M	D	REVISION DESCRIPTION	DES	DRN	CHK
A	11	11	10		BK	BK	BK

REGIONAL POWER INC.

GITCHI ANIMKI HYDRO PROJECT - WHITE RIVER

LAND MAP

PROJECT NUMBER	134
CAD NUMBER	W005
DRAWING NUMBER	260

B-1-4 Map of Project Area

Study Area

Marathon

Gitchi Animki, Bezhig

Gitchi Animki, Niizh

Umbata Falls
Umbata Hydro Power
Generating Station

White River

PUKASKWA NATIONAL PARK

0 5 10
Kilometres

Legend

White Lake Provincial Park Extension

H016864_rm_May_2010

Figure 1.2
Pic Mobert Hydro Power Joint Venture
Gitchi Animki Hydroelectric Project
Project Study Area and Surrounding Features

HATCH

B-1-5 Transmission Line Alternatives

29. Prior to finalizing the routing for the Transmission Facility that is submitted as part of this Application, the Applicants examined two alternatives (the "**Transmission Alternatives**") for the portion (the "**Niizh Portion**") of the Transmission Line that runs from the Niizh Switchyard south of the White River prior to joining up with the Bezhig Facility. A map of the Transmission Alternatives is attached as Exhibit B-1-6.

30. An Environmental Review Report (ERR) for the Project that includes the Transmission Alternatives was prepared and submitted under the requirements of the *Electricity Project Regulation (O. Reg. 116/01)* environmental screening process. The public/agency review period ended on November 5, 2010 without any elevation requests being received. A statement of completion was subsequently filed with the Ministry of Environment (MOE). Following the filing of the Statement of Completion, the Applicants decided to consider an additional transmission line routing option that was not among the Transmission Alternatives considered and presented in the ERR. Only the Niizh Portion was altered in this new route, and is the route proposed in this Application that follows the Forest Service Roads. This preferred route for the Niizh Portion is considered to be a "minor" modification to the Project as it was proposed in the ERR.

31. Discussions were held with representatives of WRFP, the Sustainable Forest Licence ("**SFL**") holder for the White River Forest. As the SFL holder, WRFP is responsible for both forest and road management within the area. WRFP stated that it had no objections to the proposed use of the Forest Service Road ROW for the Transmission Line. In any event, WRFP is merely a licensee and does not have any legal right to object to third party use of the Forest Service Roads, which are owned by the MNR.

32. The proposed route for the Niizh Portion is preferred as it would remove the need to clear portions of the White River Forest north of the river, make use of existing common corridors, and would ensure that road infrastructure in this area is properly maintained and preserved while harvesting operations are occurring in other locales within the SFL. A road use agreement already exists between WRFP and the Applicant to cover the costs of maintenance on the Forest Service Roads.[3]

33. Technical review of the preferred route for the Niizh Portion concluded that there would be a considerably lower cost associated therewith, when compared to the Transmission Alternatives. The lowered cost is due mainly to the fact that the intensive clearing of trees and surface preparation that would be required for sections of the Transmission Alternatives would not be required for the proposed Niizh Portion route. Furthermore, the existing access to the Niizh Portion will allow the rapid deployment of equipment and personnel both for construction as well as for transmission line maintenance, which translates into more efficient execution of transmission line erection. The Niizh Portion can be erected with minimal impact to any users of the Forest Service Roads.

[3] PIP Addendum, Appendix A, at p. 5.

34. Following the assessment exercise, the Applicants concluded that there is no need for the preparation of an Addendum for public review under the environmental screening process. This is due to the following:

- The new proposed route reduces the number of river crossings by the Transmission Line by one.
- The new proposed route reduces the number of required water crossings by one.
- The new proposed route is considered an improvement over the previous one by the MNR, Ontario Parks, the SFL holder and the technical review personnel of the Applicants.
- The potential negative impacts identified through the completion of the criteria checklist are all significantly less than the similar impacts associated with the previously presented preferred route.
- No objections were raised by the public to the previously proposed route, and it is evident that the new route will have considerably less impact, so it is reasonable to conclude that no objections would be raised for the new route.
- The new proposed route does not bisect the SFL to the north.
- The new proposed route minimizes the impacts to river-bank-right (for river travelers).
- The new proposed route eliminates encroachment near lodge owner on Spangler Lake.

B-1-6 – Map of Transmission Alternatives

N

S

HWY 17

HWY 17
TO THUNDER BAY

CPR
Railway Line

Hydro One - M2W
115 Kv Transmission Line

White Lake

White Lake
Provincial Park

Mobert

Transmission Line - Option 1

Transmission Line Option 2

Existing White
Lake Dam

Mine Tailing Pond

UPPER WHITE RIVER SITE
GITCHI ANIMKI BEZHIG
3.2 KM downstream of White Lake Dam

700 MHR

Alternate to Transmission Line Option 1
from Lower Site to Upper Site. Generally
follows 700 series road.

LOWER WHITE RIVER SITE
GITCHI ANIMKI NIIZH
1.6 km downstream of Chicagonce Falls

Existing Bridge

New Site Access Road

700 MHR to the Town of White River

SCALE

0 600 1200 1800 2400 3000

Meters

REV	Y	M	D	REVISION DESCRIPTION	DES	DRN	CHK
A	11	05	9		BK	BK	BK

REGIONAL
POWER
INC.

GITCHI ANIMKI HYDRO PROJECT - WHITE RIVER

TRANSMISSION LINE OPTIONS

PROJECT NUMBER	134
CADD NUMBER	W005
DRAWING NUMBER	150

B-2-1 Design Specifications of Transmission Facility

35. The Applicants will be relying on subcontractors to design and construct the Transmission Facility. In addition, the same subcontractor will be responsible for constructing the Hydro Facilities, although Regional Power will be responsible for the design of such facilities.

36. The Applicants developed a single request for proposal (RFP) for the design-build of the Transmission Facility and the build of the Hydro Facilities. The RFP was sent to select contractors on or about November 15, 2011. The bidding process will close January 2012. The RFP document includes the design specifications for the Transmission Facility, which any successful bidder will be required to meet. A copy of the design specifications for the Transmission Facility is included at Exhibit B-2-2.

37. In addition to the design specifications, attached at Exhibit B-2-3 are drawings of typical cross sections of two types of poles that may be used. However, the Applicants note that the ultimate decision with respect to pole design lies with the successful bidder in the above-mentioned RFP.

38. The Transmission Facility will be integrated with the Hydro Facilities according to the single line diagrams for each of the Hydro Facilities, copies of which are provided at Exhibit B-2-4.

B-2-2 Excerpt from Transmission Line RFP

SECTION 018000

ENGINEERING & DESIGN CRITERIA

TABLE OF CONTENTS

PART 1 – GENERAL

1.1. Description

This Engineering Section outlines the design criteria specification requirements of the transmission line in terms of desired function, limitations, operating conditions, performance, material design selection requirements, and compliance with applicable codes, standards, regulations, and acceptable industry practices.

Also refer to the scope of work for the general Contract for details pertaining to the description of the overall transmission line specifications.

1.2. Submittals

The Scope of Work for the Engineering design of the overhead Transmission line includes preparing several documents that shall be submitted in two parts prior to construction; one as a preliminary design package for review and approval by the Owner, and secondly a formal construction package intended for release.

A. The following documents shall be issued for construction.

1. Construction Summary & Scope of Work
2. Structure List
3. Plan & Profile Drawings
4. Finalized Permitting/Crossing Drawings
5. Structure/Assembly Drawings
6. Stringing Tables
7. Sag/Tension Data
8. Bill of Materials
9. Phasing Drawing
10. Foundation Drawings/Designs
11. Anchoring Drawings
12. Dampering Data & Installation Drawings
13. Staking Table

Upon completion of the Work, the Contractor shall submit as-built copies of the above documentation as referenced in Section 017853 – Project As-Builts and Turnovers. Contractor shall also submit an as-built backup copy of the finalized PLS-CADD file.

1.3. Permitting

A. Contractor to complete finalized crossing drawings and permit applications for all regulatory crossings of the Transmission line. Crossing permits shall be expected, but not limited to the following:

1. Ontario Ministry of Transportation (MTO) for Highway 17
2. Canadian Pacific Railway (CPR)
3. White River Navigable Waterway
4. Forestry MNR Road crossings

Contractor shall meet or exceed all applicable codes and standards pertaining to each crossing jurisdiction. Note that there may be further requirements that exceed CSA specifications.

Preliminary permit drawings for the MTO and CPR crossing have been created by t he Owner and will need to be incorporated for acceptable requirements during detailed design of the transmission line.

1.4. References

Requirements of the applicable codes and standards that shall be adopted for the Design of the Transmission line can be found in Section 014113 – Codes and Standards.

PART 2 – CLIMATIC DATA

2.1. General

Equipment shall function without violating guaranteed values under existing ambient conditions. The following climatic data are based on Environment Canada data "Canadian Climate Normals 1970-2000" for Wawa, Ontario (approximately 110km south-east of the White River site).

Elevation	287 m above sea level (ASL)
Conductor Loading Condition:	
radial ice	12.5 mm (1/2 in.)
wind pressure	400 Pa (8.35 psf)
Max., wind pressure 1/100 year probability	750 Pa (15.6 psf)
Extreme minimum temperature	-50 °C
Extreme maximum temperature	33.1 °C
Max., ambient design temperatures	40 °C
Degree days below 18°C, average	5962.5
Rainfall average (annual)	727.4 mm

Snowfall, average (annual)	328.6 cm
Total precipitation, average (annual)	1002.2 mm
Extreme Snow Depth	145 cm
Extreme daily rainfall	101.4 mm
Extreme daily snowfall	40.8 cm
Days with measurable rainfall	105.4 days per year average
Days with measurable snowfall	78.6 days per year average
Days with measurable precipitation	172.3 days per year average

2.2. Rime Icing

Contractor to include rime icing in the design for determining adequate clearances and structural strength considerations. The rime icing specifications for wind pressure, radial ice/snow, and ice/snow density is provided in Section 4.2 Weather Loadings, but may be revised by Contractor with the acceptance from Owner.

2.3. Lightning

Environment Canada climatic data for the closest area, indicates a keraunic level of 23 thunderstorm days per year average based on a 30 year period (1971-2000). It should be anticipated that designs should expect and average flash density from 0.5 to 1 flashes/sq.km./yr.

2.4. Seismic Activity

While Seismic activity for the area is not expected to be a significant issue, the design shall review and take into consideration typical seismic levels that may impact the line designs. For more significant expected seismic levels, the phase spacing should be increased, insulation levels increased (i.e.: dust cloud contamination) and foundations used that will be more resilient to shock wave oscillations.

PART 3 – ELECTRICAL DESIGN CRITERIA

3.1. Description

Overhead line description.

Line Designation	To Be Determined
Nominal Voltage	115 kV

Minimum Operating Voltage	~112kV (Nominal – 2.5%)
Maximum Operating Voltage	~124kV (Nominal + 7.5%)
Number of Circuits	1
Transmission Conductor	266.8 ACSR Partridge
Number of Conductors per Phase	1
OHSW Conductor	3/8” Steel Grade 180
Communication Type	OPGW
Approximate Line Length	23.5 km

3.2. Clearances

A. Ground Clearance

The typical minimum vertical ground clearances of 115kV transmission conductors are specified below. The clearances provided in the table below are based on CSA 22.3 No.1-10, Table 2 and Table 3.

Ensure clearance buffers specified in Section 3.2.vii are added to the below table minimum design clearances – these clearance buffers are intended to allow for: minor construction deviations, survey errors, and design errors. Additional clearances shall be allowed for to account for mean annual snow falls.

Conductor Location	**Clearance For 115kV (m)**
Over ground normally accessible only to pedestrians, snowmobiles, and all-terrain vehicles (no reasonable vehicle access). *	4.0
Alongside roads in areas unlikely to be traveled by road vehicles and within 1.5m of the limit of the road right-of-way. *	4.6
Over or alongside areas likely to be traveled by road vehicles. **	5.2
Over right-of-ways of underground pipelines.	5.2
Above top of rail at railway crossings. **	8.4
Waterway crossings – small lakes and rivers **	10.7
Waterway crossings – small lakes, medium rivers, rivers connecting lakes, and adjacent to bridges. **	12.7

* Clearance areas shall only be allowed under very special and specific circumstances and must be approved by Owner

B. Special Crossing Clearance Requirements

For areas where governing agencies/jurisdictions have dictated clearances in excess of the CSA 22.3 No.1-10 code requirements include the following. All required clearances shall be measured to the worst-case maximum final sag positions and shall include the clearance buffers specified in Section 3.2.vii.

1. MTO Highway 17
2. CP Railway
3. Navigable Waterways
4. Forestry MNR Roads
5. Powerhouse Access Roads

C. Circuit Spacing

1. Crossing vertically and attached to different structures

Shall be evaluated with upper circuit at maximum worst-case final sag position and with the bottom circuit at the conductor cord (straight line) between attachments points. Clearances based on CSA 22.3 No.1-10, Table 13.

1. Crossing vertically and attached to the same structures (or underbuilt circuit – 115kV to OPGW/OHSW)

Shall be evaluated with the upper circuit (OPGW/OHSW) at worst case maximum final sag position, and the lower circuit (transmission phase conductor) at -20°C, bare sag position.

D. Phase-to-Phase Conductor Spacing (115kV)

Phase spacing calculations shall be completed using Percy Thomas methods. The spacing of transmission conductor phases shall provide adequate clearances, both at the structure and in-span locations. The phase spacing is generally accounted for in structure framing design; however, Contractor is responsible to check that adequate phase clearances are maintained in the design for the particular span lengths being implemented.

E. Structure Clearance (Air Gap)

The minimum distance between the phase conductor (or closest energized portion thereof) and the structure (pole, cross arm, guys,etc.) is the minimum wet flashover distance of 970mm for 115kV phase-to-phase voltage. This minimum structure clearance shall be checked for all load conditions. This clearance is meant to incorporate surge voltages that may occur during switching or system disturbances.

F. Insulator Swing

On suspension structure types (i.e. H-frames), Contractor must ensure that the maximum allowable horizontal swing of all suspension insulators meet the required horizontal clearances for a minimum of 970mm for 115kV phase-to-phase voltage. The actual horizontal clearances of the energized phase to the pole/crossarm shall be based on the

calculated values using PLS-CADD software at extreme wind (0°C, 750Pa, bare) conditions.

G. Design Clearance Buffers

To ensure that the ground clearances specified are maintained under all conditions and taking into account the errors that can occur during construction, wire sagging, survey, switching surges, etc., a clearance buffer shall be added to the values specified in the CSA code and relevant jurisdiction standards. The resulting clearances shall be used for line design.

Location	Min Design Clearance
Spans crossing high-risk areas such as Highway, roads, pipelines, railways, critical areas, etc.	Code + 1.2m
Spans crossing cultivated & pasture lands and brushed Right of Way where off road vehicles or other traffic may have access.	Code + 0.9m
Spans crossing other locations such as pedestrian access only or very rugged terrain unlikely accessible with vehicles.	Code + 0.6m
Circuit spacing calculations – Crossing vertically and attached to different support structures.	Code + 0.9m
Circuit spacing calculations – Crossing vertically and attached to the same support structures (or underbuilt).	Code + 0.6m

3.3. Conductor Data

A. Transmission Phase Conductors

The phase conductors shall be single 266.8kcmil ACSR "Partridge" having the following characteristics:

Diameter 0.642" (16.3 mm)
Weight 0.3669 lbs/ft (4.92 N/m)
Stranding 26/7
Rated tensile strength (RTS) 11.3 kips (50.3 kN)

The conductor design shall be as per CSA Standard C61089-03, "Round Wire Concentric Lay Overhead Electrical Stranded Conductors".

B. Shield Wire

The shield wire shall consist of one optical fibre ground wire (OPGW), and the use of one overhead shield wire (OHSW) for 2-pole and 3-pole structure types.

The OPGW shall provide both lightning protection and communications between the switchyards or substations. Fibre Optic cables are to provide for a Single Mode, 24 fibre strand design and the following properties:

Attenuation Coefficient at 1310 nm	<0.40 dB/km
Attenuation Coefficient at 1550 nm	<0.30 dB/km
Minimum Bending Radius (Dynamic)	20x Cable Dia. + 50mm
Minimum Bending Radius (Static)	10x Cable Diameter

For further details on the fibre cable communications refer to Section 338253 – Fibre Communication Installation.

The OHSW shall consist of a single 3/8" Grade 180 galvanized Steel cable having the following characteristics:

Diameter	0.375" (9.5 mm)
Weight	0.273 lbs/ft (3.98 N/m)
Stranding	7
Rated tensile strength (RTS)	13.5 kips (60.1 kN)

3.4. Ampacity Rating

The transmission conductor (266.8kcmil ACSR Partridge) expected steady-state ampacity ratings for Summer and Winter calculations were completed using the following general assumptions:

Based on IEEE Std. 738-199 calculation method

Wind Speed	0.61 m/s (2 ft/s)
Angle of Wind to Wire	90°
Frequency	60 Hz
Atmospheric Conditions	Clear
Altitude (above sea level)	400m (approximate)
Latitude of Location	48.6° North
Circuit Voltage	115kV Nominal
Coefficient of Absorption	0.5
Coefficient of Emissivity	0.5

The maximum transmission conductor thermal rating and related circuit capacity calculations are:

Season	Ambient Air Temperature	Maximum Conductor Temperature	Conductor Ampacity Rating	Circuit Transmission Capacity
Summer	40 °C	100 °C	488 A	97 MVA
Winter	5 °C	100 °C	642 A	129 MVA

3.5. Sag/Tension Criteria

The limiting conductor tensions for producing sag and tension charts are shown in the following table.

Weather Conditions	Condition	Temp. (°C)	Wind (Pa)	Radial Ice (mm)	**% UTS**
CSA Heavy (900 kg/m^3)	Final	-20º	400	12.5	**50%**
Rime Icing (350 kg/m^3)	Final	-15º	230	50	**60%**
Max Cold - Uplift	Initial	-50º	0	bare	**50 %**
Cold - Vibration	Initial	-30º	0	bare	**30 %**

Mean Annual	Final	0º	0	bare	**20 %**
Mean Annual	Initial	0º	0	bare	**25 %**

The tension limits for the OPGW shall be as recommended by the OPGW manufacturer. The OPGW and OHSW conductors shall be sagged to match the transmission at an everyday weather condition; as well as meeting the circuit spacing requirements for all load cases.

3.6. Vibration Control

Contractor shall use Stockbridge “dog bone” type vibration dampers to mitigate Aeolian vibration problems on the transmission phase conductors and the OHSW/OPGW wires. The dampering design and installation locations shall be as per the damper manufacturer specifications or upon the CIGRE vibration criteria which ever may be more stringent. The OPGW damper type and installation locations shall be as per the OPGW manufacturer specifications.

3.7. Galloping

A galloping review shall be completed for consideration of the transmission to OPGW/OHSW spacing requirements. The “Double Loop” calculation methodology shall be applied for the calculations with clearances checked at 25% and 75% of the span length with wind from either direction. Weather conditions to be used for the galloping calculations are 0°C, 1/2" ice, 100Pa wind (final after creep) for the swing angle loop and 0°C, 1/2" ice (final after creep) for the sag loop.

3.8. Corona & Electric Field Effects

Corona and field effects are not expected to be an issue for the 115 kV transmission line located in remote area. The size of the selected conductor exceeds the anticipated electrical requirements for transmission of the power. Corona rings are not generally expected to be required on the 115kV transmission insulation.

The transmission line shall be designed to meet the radio interference levels specified in the Industry Canada Standard ICES-004 Spectrum Management and Telecommunications Policy - Interference Causing Equipment Standard Alternating Current High Voltage Power Systems.

3.9. Obstruction Marking

All navigable water crossings shall be permitted through Nav Canada under the Navigable Waters Protection Act federal legislation. The White River crossing is to be designed with marker balls.

The White River waterway is required to maintain a particular clearance as defined in Section 3.2. This clearance height is measured from the lowest point of the conductor under worst-case sag conditions to the ordinary high water mark of the water. The markers balls to be installed are to be a minimum of 30 inch diameter (or more typical available 36 inch diameter) and must be approved by Transport Canada. The markers are to be attached on the OHSW/OPGW at a maximum interval of 45m alternating on each wire with international white and international orange in accordance with Canadian Standard 621.19 “Standards Obstruction Markings”.

3.10. Lightning Protection

The lightning performance of this line shall be accomplished through the use of OHSW/OPGW framed with the appropriate structure geometry. The lightning protection angle for positioning the OHSW/OPGW shall be 30° for the outside angle. For multiple OHSW installations (H-frame structures), the inside angle must be 40° or less.

3.11. Grounding

All structures shall have all metallic hardware bonded together using a #4 solid copper bond wire and tied into a #2 ACSR (or copper equivalent) type conductor used for the pole downlead. Typical hardware bonding shall be done with either a special crimp-on connection lug or by wrapping through a double flat washer assembly.

All structures shall have ground rods installed, and shall be ¾” x 10’ copper clad type rods. At the base of the pole for connection to the ground rod, the downlead shall change again to a #4 solid copper wire and be connected with squeeze-on or ampact type connectors. The top of the grounding rod shall be at a minimum of 300mm below the ground level. At locations where grounding rods are impractical or not effective, the grounding system may include radial counterpoise wires and/or equipotential rings.

After installation of the grounding system and prior to the installation of any overhead conductors or wires, the grounding resistance shall be measured at several structure locations along the route. The grounding resistance at each site shall be 25 ohms or less. If 25 ohms grounding resistance is not achievable with a single grounding rod, additional ground rods shall be required.

3.12. Transposition

The transposition of phase conductors may be required if the voltage unbalance exceeds the tolerance limit. The White River Transmission line is relatively shorter in length, and therefore the transposition of the transmission phases are likely not required.

3.13. Clipping Offsets

The need for clipping offsets should be taken into account for all suspension applications with significant elevation transitions.

3.14. Charging Current

All switch installations must have charging current calculations completed and approved by Owner to be within acceptable limits.

PART 4 – STRUCTURAL DESIGN CRITERIA

4.1 Design Methodology

The Transmission line shall be designed using deterministic design methods. The minimum load factors for non-linear analysis are provided in Section 4.4, and shall be applied to the appropriate grade of construction for the area.

Contractor shall use non-linear analysis, including stability (buckling) check, for the method of analysis of all structures.

Contractor shall use PLS-CADD for all design calculations using method 4 for all structural loads and clearances. The PLS-CADD criteria file shall be reviewed and approved by Regional Power. Upon completion of the detailed design, a copy of the PLS-CADD backup file shall be provided.

4.2 Weather Loadings

The following are weather load cases for CSA requirements and recommended added design loadings that are be used for detailed design of the Transmission line. All structures shall be designed for all load cases provided below as applied to the wires and poles themselves.

Loading Conditions	Temp. (°C)	Wind (Pa)	Radial Ice/Snow (mm)	Ice/Snow Density (kg/m^3)
CSA Heavy	-20º	400	12.5	900
Rime Icing & Wind	-15º	230	50	450
Max Cold (Uplift)	-50º	0	bare	-

Extreme Wind	0º	750	bare	-
Mean Annual	0º	0	bare	-

4.3 Structure Types

Wood pole structure types are selected for use on the Transmission line. Either single pole or H-frame structures types may be used for the detailed design. Structure type selection is the discrepancy of Contractor with final approvals from Regional Power. Typical structure type drawings showing and framing can be found in Section 337116.43 Structure and Assemblies. Any "special" structure types that may be required for detailed design must be submitted and approved by Regional Power prior to implementing.

4.4 Structural Load Case

A. CSA Heavy

White River is located within the CSA Heavy area as per the CSA C22.3 No. 1-10 Loading Maps (Figure C.1). The deterministic CSA Heavy weather load condition is for 12.5mm radial ice with 400Pa horizontal wind at -20°C, and shall be applied to all structure types and components.

B. Uplift

Contractor to ensure there is no uplift loads on all tangent structures at -50°C initial weather conditions with no wind and bare conductor.

C. Everyday Working Stress

Contractor shall check the everyday allowable working stress and deflection limits for all self-supporting (un-anchored) angle and deadend wood pole structures. The wood properties for select structural grade wood pole members need to be de-rated for safe allowable wood working stress of the wood fibers at mean annual everyday (0°C) tensions with 100Pa wind.

D. Broken Wire Condition

Deadend and angle structures shall be designed to withstand a torsional load equal to the static load caused by the tension release of any one broken wire load (one phase or one OHSW/OPGW) in an adjacent span. The loading conditions shall be taken at worst-case CSA Heavy load lases without Safety Factors. The torsion loads should take into account the insulator swing, structure deflection, and interaction with other phases or wires.

E. Failure Containment

For all deadend structures with loads on one side (all wires) completely removed from the double deadend structure. Loads on the opposing side (all wires – phase and OHSW/OPGW) shall be checked at CSA Heavy conditions and includes all applicable safety factors.

Cascade failure prevention structures shall be added to any section of line that extends for more than 30 tangent structures or 8kms, whichever is more stringent. The Cascade failure prevention structures may consist of double deadend (in line) structures or a special guyed or support that could absorb all of the expected energy from a complete structure failure.

F. Unbalanced Ice Loading

All structure types shall be designed for an unbalanced longitudinal load. Structures are to be checked for unbalanced loads resulting from all iced weather conditions (CSA Heavy and Rime Icing) with one span (all wires – phase and OHSW/OPGW) loaded with the iced condition and the other span (all wires on the opposing side of the structure) at the equivalent temperature with bare conditions. Structural flexibility and insulator swing should be taken into account to calculate the resulting longitudinal forces.

G. Construction & Maintenance

All structures shall be designed to account for any loads imposed by assembly and erection, wire stringing and sagging, tie-down, and maintenance operations. The strength of all lifting points and related components will be designed to withstand at least three times the static wire loads.

All structures shall be designed to withstand wire tensions equal to 1.5 times the sagging tensions and/or 2.0 times the stringing (pulling) tensions. Checked at -20º C initial tensions with no wind and bare wire.

For conductor tie-down operations, a maximum wire slope of 1 vertical to 3 horizontal shall be assumed from the structure. All tie-down wires loads shall be designed to withstand tensions 2.0 times and checked at -40º C initial tensions with no wind and bare wire.

4.5 Load Factors & Grade of Construction

All facilities shall be built to Grade 2 Construction Standards, with the exception of the CP Railway crossing area, which is to be built to Grade 1 Standards. All structures

within the deadend section containing the CPR crossing are to be built to Grade 1 Standards.

A. Wood Poles

The wood pole minimum load factors are in accordance with the requirements of CSA C22.3 No. 1-10 deterministic values, and additional recommended specifications.

WOOD POLE – MINIMUM LOAD FACTORS							
Load Case	Structure Types	Grade 2 Load Factors			Grade 1 Load Factors		
		Vert	Trans	Long	Vert	Trans	Long
CSA Heavy	Tang/Angle	1.50	1.30	1.00	2.00	1.90	1.20
	Deadend	1.50	1.30	1.30	2.00	1.90	1.90
Rime Icing & Wind	Tang/Angle	1.50	1.30	1.00	2.00	1.90	1.20
	Deadend	1.50	1.30	1.30	2.00	1.90	1.90
Max Cold (Uplift)	Tang/Angle	1.50	1.30	1.00	2.00	1.90	1.20
	Deadend	1.50	1.30	1.30	2.00	1.90	1.90
Extreme Wind	Tang/Angle	1.50	1.30	1.00	2.00	1.90	1.20
	Deadend	1.50	1.30	1.30	2.00	1.90	1.90
Allowable Wood Working Stress	Un-anchored Angle & DE	1.0	1.0	1.0	1.0	1.0	1.0
Sagging (no wind, bare, -20º C initial)	All	1.5	1.5	1.5	1.5	1.5	1.5
Stringing (no wind, bare, -20º C initial)	All	2.0	2.0	2.0	2.0	2.0	2.0
Tie-down (no wind, bare, -40º C initial)	Tang/Angle	2.0	2.0	2.0	2.0	2.0	2.0

B. Structural Components

The minimum load factors for the structural components are in accordance with the requirements of CSA C22.3 No. 1-10 deterministic values and typical recommended standards.

STRUCTURAL COMPONENTS – MINIMUM LOAD FACTORS			
Structural Component	**Applies to**	**Grade 2 Load Factor**	**Grade 1 Load Factor**
Foundation (typical)	Poles & Anchors	2.0	2.0
Foundation (saturated soils)	Poles & Anchors	Site specific soil calculations required	
Insulator String	Suspension	2.0	2.0

(SML)	& Deadends		
Insulator Posts (MDCL)	Tangents & Light Angles (max design combined loadings)	1.0	1.0
Insulator Posts (MDCL)	Tangents & Light Angles (everyday combined loadings)	3.0	3.0
Crossarms	Steel	Vert=1.15 Long=1.10	Vert=1.30 Long=1.20
Crossarms	Wood	Vert=2.00 Long=1.60	Vert=2.00 Long=1.60
Guy Assemblies	All guy hardware	1.25	1.60
Guy Strain Insulator	All	2.0	2.0

All structural members (e.g. crossarms) capable of supporting a lineman shall be designed for an additional vertical load of 1.0 kN, in addition to supporting the mass of conductors without ice covering for all load cases.

4.6 Substation A-Frame Loading Limits

The conductor loading on the A-frame shall be adjusted for reduce tensions on the A-frame. The actual design loadings shall be determined and provided by Contractor during detailed design stage.

4.7 Structure Spotting

Multiple considerations will be taken into account when spotting structure positions. These conditions include but are not limited to the following:

1. Clearances – Refer to Section 3.2.
2. Uplift – Checked at -50°C initial tensions.
3. Pole/Materials Strength Limitations
4. Maximum Allowable Line Deflections & Insulator Swing
5. Environmental Concerns – See Section F.
6. Right of Way and Accessibility – See Section O.
7. Survey (terrain) – See Section P.

4.8 Structure Foundation Design

Wood poles are to be set in the ground plumb and are intended to be installed at the typical industry standard of 10% of the pole height plus two feet for normal ground conditions, and at 10% for poles set in rock. For areas where the soil is saturated and of poor bearing capacity, additional foundation support and/or safety factors shall be provided in order to obtain adequate structural capacity at ground line.

The technique for excavations of the poles is somewhat flexible and if culverts are used, they should be fully buried after backfilling. Any backfilling of excavations shall be done to at least 90% proctor or the same compaction as the surrounding native soils.

All tangent pole holes and/or culverts shall be a minimum of 300mm larger than the diameter of the pole butt. Poles being set in culverts are to allow for no less than 75mm of distance from the pole to the edge of hole/culvert. Any culverts used in the pole excavations shall have a bonding jumper that shall be attached to the pole downlead and to the culvert.

All backfill shall be approved (in-situ or non-native material), well graded, free of snow, free of frozen lumps, free of organic materials, trash, well drained, and shall be well compacted. Compaction of backfill shall be typically done in 150mm lifts (and never allowed to be more than 300mm) and shall use power compacting equipment to meet the required specification. Backfill shall also be typically required to be mounded 300mm above the ground line to allow for future settling and drainage.

4.9 Guying/Anchoring

Standard earth anchors for wood pole structure types shall be utilized for design. Refer to Section 337116.43 – Structures and Assemblies for typical anchor drawings expected for design.

A minimum strength factor reduction of 0.5 shall be applied to the bearing capacity of the native soil and backfill material. Site specific areas that have had a detailed soil analysis completed may use a reduction strength factor of 0.7. For soils that will be subject to saturated conditions for even part of a year must apply the saturated soil condition parameters with additional strength factors used.

4.10 Right of Way

A Transmission line corridor area has been reserved for the right of way. All structures, foundations, and anchors shall be designed within the boundary of right of way unless

otherwise approved by Owner. Refer to Section 017329 – Right of Way & Brushing for further details.

PART 5 – MATERIAL PROPERTIES

5.1 General

All hardware material strengths shall be coordinated with its associated parts. Deadend hardware shall be capable of full design conductor tensions while still within the component "yield" strengths and related safety factors.

All bolt and nut hardware shall be typically 3/4" Utility grade, galvanized or better and shall have specific cold weather rated properties (with associated Charpy tests) by the manufacturer for use in extreme low temperature environments.

All metal components shall be specified using the CSA Standard C83-96 as a minimum and shall also allow for cold weather properties in the metal to accommodate temperatures of -50ºC. Conductor hardware (excluding suspension clamps), shall be forged steel with impact properties of at least 20 joules at -200 C.

5.2 Insulators

The insulation to be used for all applications on the 115kV Transmission line shall be synthetic silicone rubber type and shall meet the requirements of CSA C411.1-M89 and C411.4-98 standards. It is intended that all insulation shall be limited to the use of Type J (ANSI 52-5) hardware unless special circumstances dictate; in which case special approval must be granted by Owner.

A. Insulator Requirements

Insulation specifications shall be as per the following minimum mechanical and electrical characteristics.

Line Post Insulators – For use on tangent and light angle single pole applications. End fittings shall be drop-eye for horizontal posts and trunion clamps for vertical posts.

Insulation Properties	Horizontal	Vertical
Voltage Rating	115kV	115 kV
Min. Length (Section)	1400mm	1400mm
Leakage Distance Min.	2790mm	2490mm
60Hz Dry V50 (kV)	425	425
60Hz Wet V50 (kV)	390	390

CIFO (negative) V50 (kV)	650	650
CIFO (positive) V50 (kV)	600	600
MDCL Strength (kN)	6.2	6.2

Suspension Insulators – Tangent applications shall use insulators with y-clevis-ball end fittings; deadend and heavy angle applications shall use insulators with ball-socket end fittings. All deadend and heavy angle applications shall utilize 27" y-clevis-ball extensions on the pole/tower side, and 10" ball-socket hotline extensions on the conductor side of the insulator.

Insulation Properties	**Type J (ANSI 52-5)**	
	Tangent	**Deadend**
Voltage Rating	115kV	115 kV
Min. Length (Section)	1300mm	1300mm
Insulators per phase	1	1
Leakage Distance Min.	2600mm	3300mm
Dry Arcing Distance	1000mm	1100mm
60Hz Dry V50 (kV)	420	470
60Hz Wet V50 (kV)	370	420
CIFO (negative) V50	690	780
CIFO (positive) V50	660	750
SML Strength (kN)	111	133
Routine Test Load (kN)	55	67

Electrical strength rating as specified above is based on National Electrical Safety Code C2-2002, CSA CAN3-C308-M85, CSA C411.4 and ANSI C29.12.

B. Contamination Level

The transmission line is located in an area of low contamination.

C. Guy Strain Insulators

All guys passing through the 115kV transmission conductors for anchoring of the OHSW/OPGW shall include a guy strain insulator installed into the guy wire at the transmission phase height. There shall be isolation of the guy wire above and below the phase conductor. The strength reduction factor of the guy strain insulator shall be 0.5. The guy strain insulator shall be selected so that the factored strength rating is matched to the guy wire capacity.

5.3 Poles

The poles shall be full length Pentachlorophenol treated wood poles with butt incising above ground line. Any poles installed deeper than the standard 10% +2ft depth shall have additional butt incising for 2ft above ground level or have pole ground line treated wrap installed.

The height and class of the poles shall be determined based on the structural and electrical design criteria. The pole information shall be tagged and installed at the appropriate readable height above ground on the pole.

Wood pole dimensions are to meet the specifications as per the CAN/CSA-O15-90 Wood Utility Poles and Reinforcing Stubs standard.

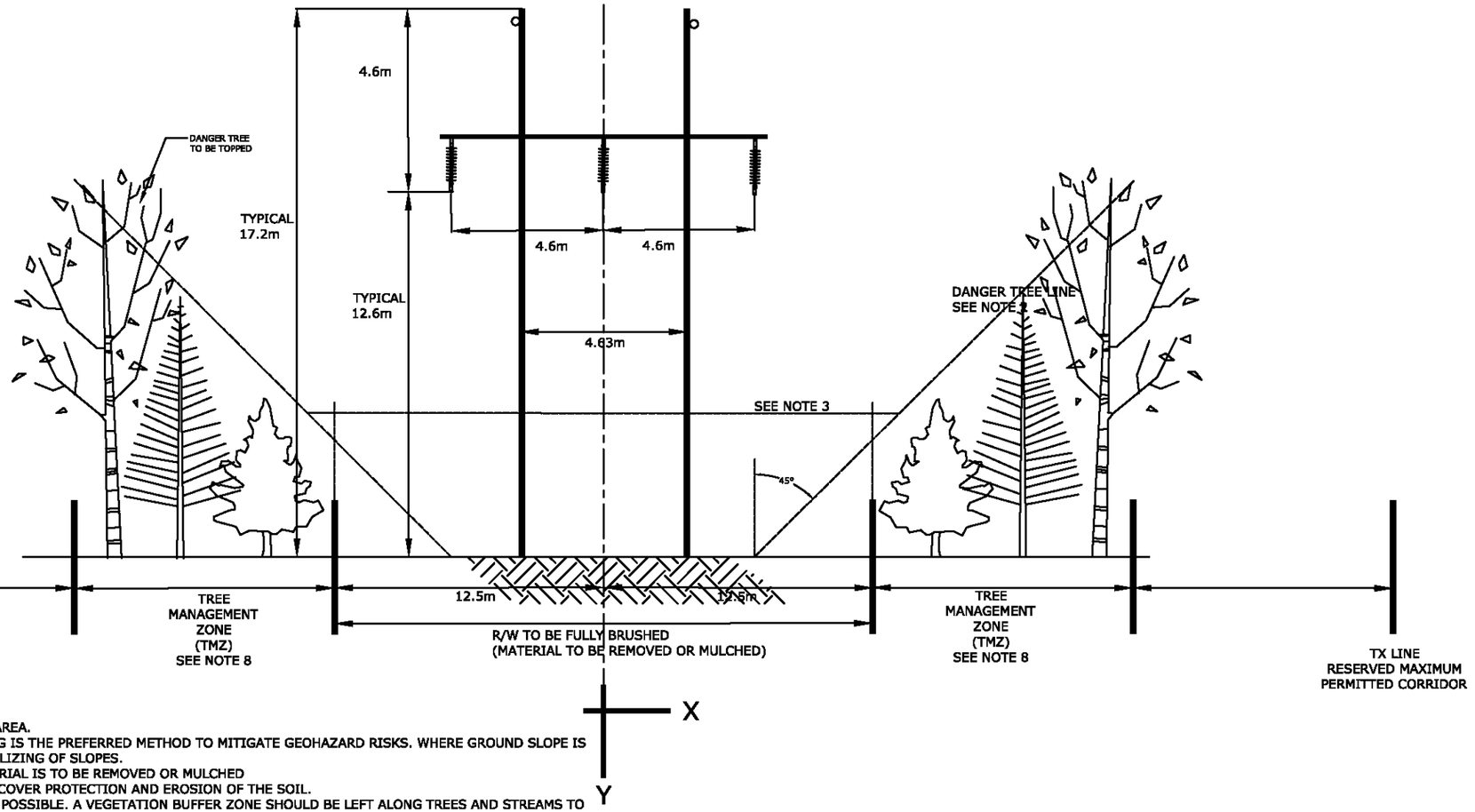
5.4 Structure Tags

All structures are to be field labeled with the corresponding line and structure number as assigned by Regional Power. These structure labels are to be installed at approximately 1/3 of the pole height above ground with 6" polyethylene tags. This labeling is to be separate and additional to any switch/equipment labeling that is required.

****END OF SECTION****

B-2-3 Cross Sectional Drawings of Typical Poles

OHSW	⅜" EHS GRADE 180
	X Y
OHSW	2.4m 12.6m
RULING SPAN	220m
OHSW SAG @ 0°C	1.8m
R (DC@ 20°C) =	4.118 Ω/km
R (60Hz @ 10 AMPS) =	4.2298 Ω/km
Xa (60Hz REACTANCE @ 1' SPACING) =	0.6584 Ω/km
X'a (60Hz REACTANCE @ 1' SPACING) =	0.2003 MΩ-km
CONDUCTOR	266 ACSR PARTRIDGE
	X Y
OUTSIDE LEFT PHASE	-4.6m 12.6m
MIDDLE PHASE	0 12.6m
OUTSIDE RIGHT PHASE	+4.6m 12.6m
SINGLE OR BUNDLED	SINGLE
PARTRIDGE	
R (DC@ 20°C) =	0.2089 Ω/km
R (60Hz @ 25°C) =	0.2135 Ω/km
Xa (60Hz REACTANCE @ 1' SPACING) =	0.2888 Ω/km
X'a (60Hz REACTANCE @ 1' SPACING) =	0.1729 MΩ-km
RULING SPAN	220m
CONDUCTOR SAG @ 100°C	6.3m (APPROX)
OPERATING VOLTAGE RANGE:	109kV TO 121kV
NOMINAL DESIGN VOLTAGE:	115kV
THERMAL RATING (SUMMER)	97MVA
THERMAL RATING (WINTER)	125MVA
GROUND RESISTANCE:	VARIES - 100 TO 5000 Ω-m EXPECTED VALUES.
APPROX. LIGHTNING FLASH DENSITY:	0.5 - 1 fl / km² / yr



NOTES:
1. 50m MAXIMUM R/W WIDTH ALLOWED; AND MUST FIT WITHIN THE RESERVED AREA.
2. ALL DANGER TREES SHALL BE REMOVED OR TOPPED BY CONTRACTOR. TOPPING IS THE PREFERRED METHOD TO MITIGATE GEOHAZARD RISKS. WHERE GROUND SLOPE IS MORE THAN 30°, TOPPING IS THE ONLY ALLOWED METHOD TO AVOID DESTABILIZING OF SLOPES.
3. TREES WITHIN THE LEGAL FORMAL R/W ARE TO BE FULLY BRUSHED AND MATERIAL IS TO BE REMOVED OR MULCHED
4. CARE MUST BE TAKEN TO PREVENT DESTROYING OR DEGRADING OF GROUND COVER PROTECTION AND EROSION OF THE SOIL.
5. AVOID CLEARING VEGETATION IN RIPARIAN AREAS TO THE GREATEST EXTENT POSSIBLE. A VEGETATION BUFFER ZONE SHOULD BE LEFT ALONG TREES AND STREAMS TO MINIMIZE SILTATION AND SEDIMENTATION AND PREVENT ADVERSE IMPACTS TO RIPARIAN HABITATS.
6. THE CONTRACTOR SHALL SUBMIT THE PLAN FOR THE DISPOSAL OF TREES, BRUSH, BRANCHES AND REFUSE BEFORE START OF CLEARING.
7. ADDITIONAL TREE REMOVAL OR MAINTENANCE OF THE TRANSMISSION LINE CORRIDOR SHOULD ONLY BE ALLOWED AFTER ENVIRONMENTAL REVIEW AND APPROVAL.
8. TMZ BRUSHING EXTENT IS TO BE DICTATED BY GENERAL TREE HEIGHTS AND DISTANCES FROM THE TRANSMISSION LINE AS INDICATED.

REV	DATE	BY	DESCRIPTION
R0	31-10-13	AM	NEW DRAWING

SCALE N/A

WARNING 0 1/2 1 IF THIS BAR DOES NOT MEASURE 1cm THEN DRAWING IS NOT TO SCALE

DESIGNED
DRAWN AM
CHECKED DBS

SUBMITTED BY
(PROJECT MANAGER'S NAME) LICENSE NO. DATE
(COMPANY OFFICER'S NAME) LICENSE NO. DATE

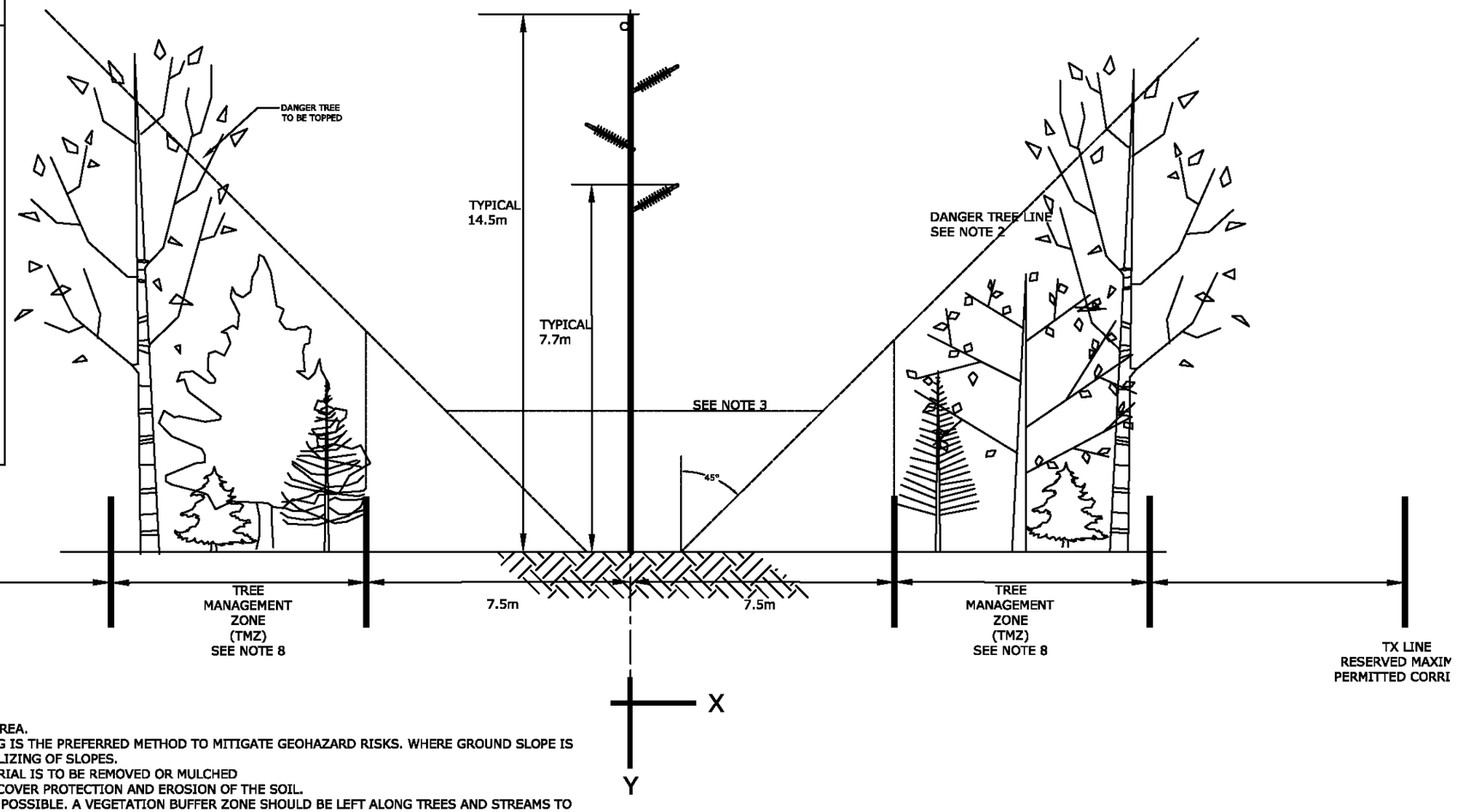
DBS ENERGY SERVICES INC. MWH

White River Hydro Inc.
Gitchi Animki (White River)
Hydroelectric Project

TYPICAL H-FRAME STRUCTURE - 115kV
WHITE RIVER PROJECT
RIGHT OF WAY & BRUSHING PLAN WITH STRUCTURE LAYOUT
266 PARTRIDGE ACSR
- TYPICAL LAYOUT PLAN -

Project No. 6680149
Drawing No. T11-CR-P1116.007 R0
Sheet No. 1 of 1

OHSW	⅜" EHS GRADE 180
	X Y
OHSW	+/- 0.3m 14.2m
RULING SPAN	130m
OHSW SAG @ 0°C	0.7m
R (DC@ 20°C) =	4.118 Ω/km
R (60Hz @ 10 AMPS) =	4.2298 Ω/km
Xa (60Hz REACTANCE @ 1' SPACING) =	0.6584 Ω/km
X'a (60Hz REACTANCE @ 1' SPACING) =	0.2003 MΩ-km
CONDUCTOR	266 ACSR PARTRIDGE
	X Y
TOP PHASE	-1.5m 10.7m
MIDDLE PHASE	0 9.2m
BOTTOM PHASE	+1.5m 7.7m
SINGLE OR BUNDLED	SINGLE
PARTRIDGE	
R (DC@ 20°C) =	0.2089 Ω/km
R (60Hz @ 25°C) =	0.2135 Ω/km
Xa (60Hz REACTANCE @ 1' SPACING) =	0.2888 Ω/km
X'a (60Hz REACTANCE @ 1' SPACING) =	0.1729 MΩ-km
RULING SPAN	130m
CONDUCTOR SAG @ 100°C	3.1m (APPROX)
OPERATING VOLTAGE RANGE:	109kV TO 121kV
NOMINAL DESIGN VOLTAGE:	115kV
THERMAL RATING (SUMMER)	97 MVA
THERMAL RATING (WINTER)	125 MVA
GROUND RESISTANCE:	VARIES - 100 TO 5000 Ω-M EXPECTED VALUES
APPROX LIGHTNING FLASK DENSITY:	0.5 - 1 fl. / km² / yr



TES:
50m MAXIMUM R/W WIDTH ALLOWED; AND MUST FIT WITHIN THE RESERVED AREA.
ALL DANGER TREES SHALL BE REMOVED OR TOPPED BY CONTRACTOR. TOPPING IS THE PREFERRED METHOD TO MITIGATE GEOHAZARD RISKS. WHERE GROUND SLOPE IS MORE THAN 30°, TOPPING IS THE ONLY ALLOWED METHOD TO AVOID DESTABILIZING OF SLOPES.
TREES WITHIN THE LEGAL FORMAL R/W ARE TO BE FULLY BRUSHED AND MATERIAL IS TO BE REMOVED OR MULCHED
CARE MUST BE TAKEN TO PREVENT DESTROYING OR DEGRADING OF GROUND COVER PROTECTION AND EROSION OF THE SOIL.
AVOID CLEARING VEGETATION IN RIPARIAN AREAS TO THE GREATEST EXTENT POSSIBLE. A VEGETATION BUFFER ZONE SHOULD BE LEFT ALONG TREES AND STREAMS TO MINIMIZE SILTATION AND SEDIMENTATION AND PREVENT ADVERSE IMPACTS TO RIPARIAN HABITATS.
THE CONTRACTOR SHALL SUBMIT THE PLAN FOR THE DISPOSAL OF TREES, BRUSH, BRANCHES AND REFUSE BEFORE START OF CLEARING.
ADDITIONAL TREE REMOVAL OR MAINTENANCE OF THE TRANSMISSION LINE CORRIDOR SHOULD ONLY BE ALLOWED AFTER ENVIRONMENTAL REVIEW AND APPROVAL.
TMZ BRUSHING EXTENT IS TO BE DICTATED BY GENERAL TREE HEIGHTS AND DISTANCES FROM THE TRANSMISSION LINE AS INDICATED.

REV	DATE	BY	DESCRIPTION
R0	11-10-13	AM	NEW DRAWING

SCALE N/A

WARNING 0 1/2 1 IF THIS BAR DOES NOT MEASURE 1cm THEN DRAWING IS NOT TO SCALE

DESIGNED
DRAWN AM
CHECKED DBS

SUBMITTED BY
(PROJECT MANAGER'S NAME) LICENSE NO. DATE
(COMPANY OFFICER'S NAME) LICENSE NO. DATE

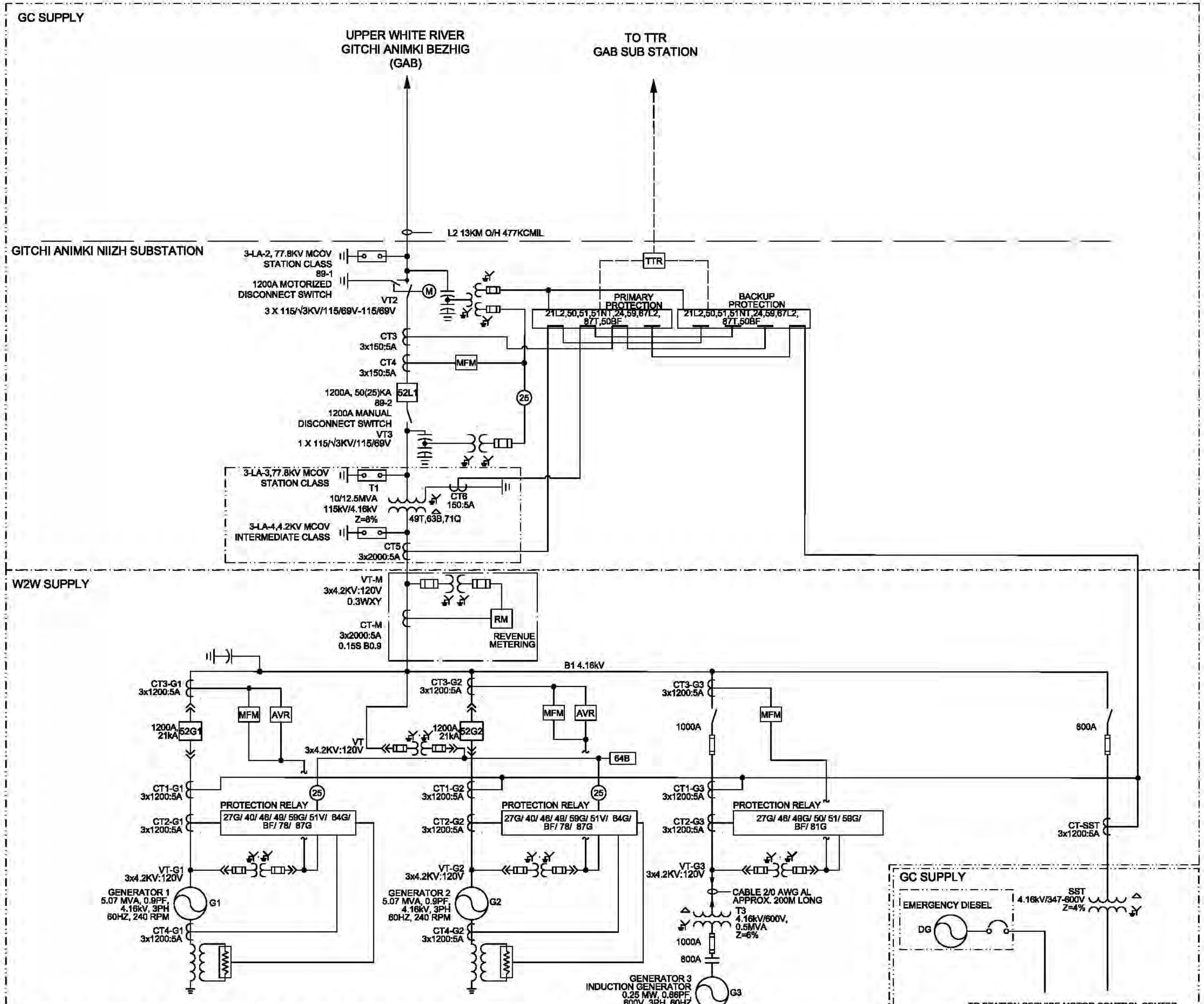
DBS ENERGY SERVICES INC. MWH

White River Hydro Inc.
Gitchi Animki (White River)
Hydroelectric Project

TYPICAL SINGLE POLE STRUCTURE - 115kV
WHITE RIVER PROJECT
RIGHT OF WAY & BRUSHING PLAN WITH STRUCTURE LAYOUT
266 PARTRIDGE ACSR
-TYPICAL LAYOUT PLAN-

Project No. 6680149
Drawing No. T11-CR-P1116.008 R0
Sheet No. 1 of 1

B-2-4 Single Line Diagrams of Niizh and Bezhig Facilities



GENERAL SHEET NOTES

1. ALL 115kV EQUIPMENT WILL BE CAPABLE OF CONTINUOUS OPERATION BETWEEN 113kV AND 132 kV.
2. 89-1,89-2 WILL BE MANUAL OPERATED DISCONNECT SWITCHES, WITH A SHORT CIRCUIT CAPABILITY OF 50kA.
3. 52L1 WILL BE A CIRCUIT SWITCHER OR A CIRCUIT BREAKER (TO BE DETERMINED IN CONSULTATION WITH HYDRO ONE).
4. 52G1 AND 52G2 WILL BE WITHDRAWABLE CIRCUIT BREAKERS APPROVED FOR GENERATOR BREAKER OPERATION AND TRV CAPABILITIES PER IEEE C37.013a.
5. THE SYNCHRONIZING BREAKERS (52L1,52L2, 52G1,2) WILL BE CAPABLE OF WITHSTANDING AT LEAST 2p.u. VOLTAGE ACROSS THEIR OPEN TERMINALS.
6. THE REQUIREMENT FOR TRANSFER TRIP WILL BE DETERMINED IN CONSULTATION WITH HYDRO ONE.
7. PROTECTION 21 MAY BE REPLACED BY 87L DEPENDING ON HYDRO ONE DECISION.

REV	DATE	BY	DESCRIPTION
0	MM/DD/YY	X.X.	ISSUED FOR ???

SCALE: NO SCALE

WARNING: 0 1/2 1 — IF THIS BAR DOES NOT MEASURE 1cm THEN DRAWING IS NOT TO SCALE

DESIGNED

DRAWN R NAIR

CHECKED

SUBMITTED BY

(PROJECT MANAGER'S NAME) LICENSE NO. DATE

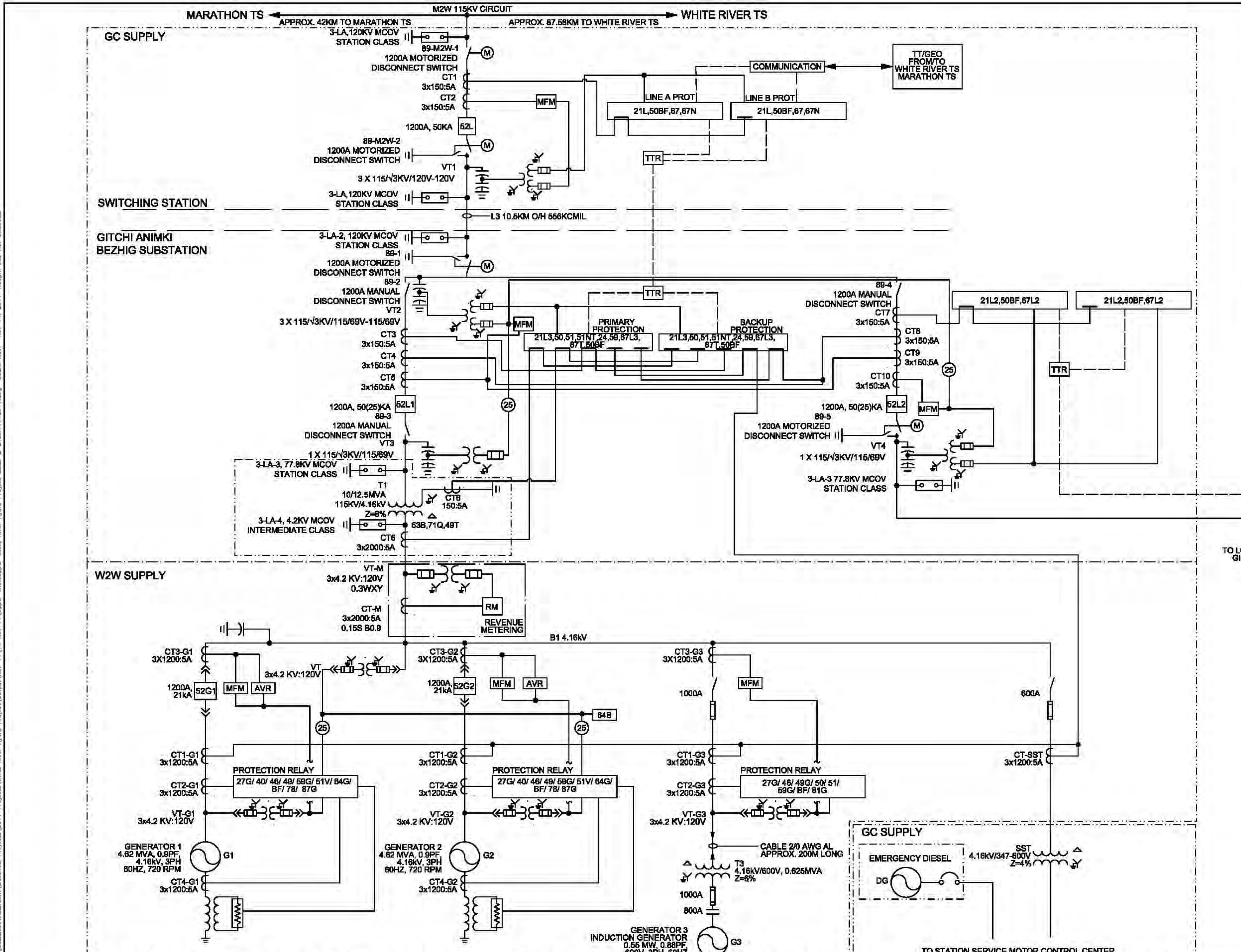
(COMPANY OFFICER'S NAME) LICENSE NO. DATE

MWH VANCOUVER BRITISH COLUMBIA

White River Hydro Inc.
Gitchi Animki (White River) Hydroelectric Project

GITCHI ANIMKI NIIZH (LOWER) SITE
ELECTRICAL
SINGLE LINE DIAGRAM DRAFT

Project No. 6680149
Drawing No. LO-E-1D
Sheet No. of



GENERAL SHEET NOTES

1. ALL 115kV EQUIPMENT WILL BE CAPABLE OF CONTINUOUS OPERATION BETWEEN 113kV AND 132 kV.
2. 89-M2W-1, 89-M2W-2, 89-1 WILL BE MOTORIZED DISCONNECT SWITCH, WITH A SHORT CIRCUIT CAPABILITY OF 50kA.
3. 52L WILL BE A CIRCUIT BREAKER WITH 50kA INTERRUPTING CAPABILITY (3 PHASE AND SINGLE PHASE TO GROUND).
4. 89-2, 89-3, 89-4 & 89-5 WILL BE MANUAL OPERATED DISCONNECT SWITCH, WITH A SHORT CIRCUIT CAPABILITY OF 50kA.
5. 52G1 AND 52G2 WILL BE WITHDRAWABLE CIRCUIT BREAKERS APPROVED FOR GENERATOR OPERATION AND TRV CAPABILITIES PER IEEE C37.013a.
6. THE SYNCHRONIZING BREAKERS (52L1,52L2, 52G1, 2) WILL BE CAPABLE OF WITHSTANDING AT LEAST 2p.u. VOLTAGE ACROSS THEIR OPEN TERMINALS.
7. THE REQUIREMENT FOR TRANSFER TRIP WILL BE DETERMINED IN CONSULTATION WITH HYDRO ONE.
8. PROTECTION 21 MAY BE REPLACED BY 87L DEPENDING ON HYDRO ONE DECISION.

REV	DATE	BY	DESCRIPTION
0	MM/DD/YY	X.X.	ISSUED FOR ???

SCALE: NO SCALE

WARNING: 0 1/2 1 — IF THIS BAR DOES NOT MEASURE 1cm THEN DRAWING IS NOT TO SCALE

DESIGNED
DRAWN R NAIR
CHECKED

SUBMITTED BY
(PROJECT MANAGER'S NAME) LICENSE NO. DATE
(COMPANY OFFICER'S NAME) LICENSE NO. DATE

MWH VANCOUVER BRITISH COLUMBIA

White River Hydro Inc.
Gitchi Animki (White River) Hydroelectric Project

GITCHI ANIMKI BEZHIG (UPPER) SITE
ELECTRICAL
SINGLE LINE DIAGRAM DRAFT

Project No. 8880149
Drawing No. UP-E-21D
Sheet No. of

B-3-1 Land Matters

39. As demonstrated at Exhibit B-1-3, the Project will be built almost entirely on Crown lands with the exception of the CP Rail crossing north of the White River.

40. Regarding the Hydro Facilities, the Bezhig Facility falls within an Ontario Living Legacy forest reserve (the "**Forest Reserve**") slated for eventual regulation and inclusion in the White Lake Provincial Park. The Forest Reserve and surrounding land falls under the jurisdiction of the *Crown Forest Sustainability Act* with respect to forest operations.

41. The lower Niizh Facility falls within the Park Addition (further defined below, within 200 m of the White River) and on Crown land outside the park (lands >200 m from the White River). The Park Addition falls under the jurisdiction of the *Provincial Parks and Conservation Reserve Act* while the surrounding Crown land falls under jurisdiction of the *Crown Forest Sustainability Act* with respect to forest operations.

42. With the exception of a crossing over the CP Rail-owned railway corridor, the Facility Lands (i.e. those lands required to develop and construct the Transmission Facility) will also be located on the Crown lands. The Applicants will enter into a lease with the Crown, the form of which is attached at Exhibit B-3-2, for the portions of the Transmission Line that traverse Crown lands, including the Forest Reserve, as well as for Crown lands on which the Switching Stations and Hydro Facilities are located.

43. In addition to the Park Addition and the Forest Reserve, a portion of the Transmission Line will traverse the Forest Service Roads ROW. The Applicant will enter into an easement (the "**Crown Easement**") with the Crown, the form of which is attached at Exhibit B-3-3, for the portion of the Transmission Line that falls within the Forest Service Road ROW.

44. Mining rights have been issued to a third party, all as further described below, on some of the Crown lands located outside of the Park Addition and outside of the Forest Reserve.

Forest Service Roads

45. The Niizh Portion of the Transmission Line will traverse the Forest Service Roads. The Forest Service Roads are owned by the MNR, and have been licensed to WRFP pursuant to SFL #550399. Pursuant to the SFL, WRFP is responsible for the maintenance and operation of the Forest Service Roads. The Joint Venture has entered into a road use agreement (the "**Road Use Agreement**") dated March 26, 2010, pursuant to which the Joint Venture is permitted to use the Forest Service Roads for the purposes of developing, constructing and operating the Project in exchange for covering a certain portion of the maintenance services fees. The term of the Road Use Agreement is 40 years beginning on the commercial operation date of the Project. Access is also provided throughout the development and construction stage of the Project.

46. As iterated in Exhibit B-1-5, WRFP stated that it had no objections to the proposed use of the Forest Service Roads for the Transmission Line. In any event, WRFP does not have a veto over the Applicants' use of the Forest Service Roads ROW for the purposes of constructing the Transmission Line. Legal rights to use the Forest Service ROW for the Transmission Line will be granted to the Applicants via the Crown Easement.

Park Addition

47. In 1999, Ontario's Living Legacy Land Use Strategy recommended that the existing White Lake Provincial Park be expanded southward along the White River to the northern boundary of Pukaskwa National Park. Specifically, the expansion (the "**Park Addition**") included all areas within 200 m of either side of the White River between White Lake Provincial Park (main site) and Pukaskwa National Park. However, White River's potential for hydroelectric development has been under consideration for several decades and in 1993, the rights to development of three sites were allocated to Pic Mobert. This proposed expansion led to the inclusion of three previously allocated sites within the new park boundary. The earlier commitments made to Pic Mobert remained in effect and the intended use of the three sites for hydroelectric development was deemed to be "a permitted, non-conforming use" under the Crown Land Use Policy Report for the park. The Park Addition was regulated in June 2006.

48. As noted in Exhibit B-1-3, the Park Addition extends along either side of White River providing a linkage with Pukaskwa National Park, which is located approximately 50 km to the southwest of White Lake Provincial Park (not shown on the map). The Project was approved for development within the White Lake Provincial Park (including the Park Addition) pursuant to section 19(3) of the *Provincial Parks and Conservation Reserves Act, 2006* on July 19, 2011. As part of the Project, the Transmission Facility is also considered permitted development. The Transmission Line falls within the Park Addition at the point where the Transmission Line crosses the White River at the Bezhig Facility.

Mining Rights

49. Metalcorp Limited ("**Metalcorp**") is the holder of unpatented mining claims on certain portions of the Crown Lands north of the White River. The Joint Venture and Metalcorp entered into an agreement dated October 29, 2009, as amended[4] January 25, 2010 and September 16, 2011, in which Metalcorp agreed to consent to the disposition of surface rights over certain mining claims held by Metalcorp. The mining claim identifiers and areas are shown in Exhibit B-1-3.

[4] The Metalcorp Agreement was amended in September 2011 in order to provide the Joint Venture the Additional surface rights it required for the amended Transmission Line route along the Forest Service Roads.

Crossings

50. The Transmission Facility will require the following crossing permits; others may be identified as development details are finalized:

    (i) CP Rail transportation corridor

    (ii) MTO Highway 17

    (iii) White River Navigable Waterway

    (iv) Forest MNR Road Crossings.

51. The CP Rail's Heron Bay Subdivision provides east-west freight transportation and passes to the south of Highway 17. The subdivision is located approximately 14.5 km north of the proposed Bezhig Facility. A transmission line crossing permit application along with associated crossing drawings is being prepared based on the specifications provided by CP Rail and will be submitted for processing in December 2011. The approvals are expected by February 2012.

52. Ministry of Transportation controlled Highway 17 requires encroachment, entrance and land use permit to construct transmission line crossing. An application and associated drawings will be submitted to MTO for these approvals. These permits are expected to be received by February 2012.

B-3-2 Form of Crown Lease

Legal Document;

**Do not date stamp,
mark, change,
staple, punch or
initial.**

Legal Document;

**Do not date stamp,
mark, change,
staple, punch or
initial.**

Ministry of Natural Resources

PROVINCE OF ONTARIO

MINISTRY OF NATURAL RESOURCES

WATERPOWER LEASE AGREEMENT

NO. [redacted]

THIS LEASE AGREEMENT made in duplicate as of the [redacted] day of [redacted], [redacted], pursuant to the Public Lands Act,

BETWEEN:

HER MAJESTY THE QUEEN in right of Ontario, as represented by the Minister of Natural Resources for the Province of Ontario, hereinafter referred to as the "Crown"

OF THE FIRST PART

- and -

[redacted] incorporated under the laws of [redacted] hereinafter referred to as the "Company",

OF THE SECOND PART

WHEREAS the Company desires to lease from the Crown certain waterpowers or privileges and the public lands and lands under water necessary for the development thereof;

AND WHEREAS the Company represents that it has the technical and financial ability to construct, repair, maintain and operate a hydro-electric generating facility on the premises hereinafter described;

AND WHEREAS the Crown has agreed to lease the said premises and to grant a waterpower or privilege described to the Company on the terms and conditions herein contained;

WITNESSETH that in consideration of the premises and mutual agreements and undertakings reserved and contained herein, the Crown and the Company agree to and with each other as follows

1. In this lease agreement,

   (a) "Affiliate" means an affiliate body corporate within the meaning of subsection 1(4) of the Business Corporations Act (Ontario), as amended from time to time;

(b) "gross revenue" means the amount received, or deemed to be received, by the producer for hydro-electric production, excluding any revenue attributable to transmission and distribution, but before any other adjustment for any cost, fee or charge, as set out below:

(i) For sales of hydro-electricity through the Independent Electricity System Operator (IESO), gross revenue means the actual amount received or receivable by the producer for such production;

(ii) For sales through bilateral contracts, gross revenue means the amount received or receivable under the contract for such power;

(iii) For hydro-electricity produced for own use, gross revenue means the amount that would have been received if the power were purchased from a third party at the average annual price as determined by the IESO;

(iv) For bilateral contracts between related parties, gross revenue means the higher of the amounts determined under (ii) and (iii).

(c) "Minister" means the Minister of Natural Resources;

(d) "rental year" means calendar year;

(e) "production" means the amount of hydro-electric power, measured in gigawatt hours, generated in Ontario by the hydro-electric generating station; plus,

(i) The amount of electricity or other equivalent compensation received from other producers, including those in other jurisdictions, in compensation for the use of the water associated with the Ontario hydro-electric generating station; less,

(ii) The amount of electricity or other equivalent compensation delivered to other producers, including those in other jurisdictions, in compensation for the use of the water associated with the other producers hydro-electric generating station.

(f) "water rental charge" means the waterpower rental charge calculated in accordance with paragraphs 3 and 4 of this lease agreement;

(g) "works" means all buildings, dams, weirs, tunnels, races, flumes, sluices, pits, wingwalls, spillways, control gates, intake headwork, fish passages, fish guards, by-pass channels and other structures constructed or erected on the premises for producing, generating, utilizing and transmitting power, together with all plant, machinery and equipment affixed thereto.

2. The Crown, pursuant to the Public Lands Act as amended from time to time, and the regulations made thereunder and subject to the limitations thereof, and in consideration of the sum of [redacted] now paid by the Company to the Crown, the receipt whereof is hereby acknowledged, doth DEMISE AND LEASE unto the Company, its successors and assigns for the purpose of production of electrical power thereon ALL AND SINGULAR those certain parcels or tracts of land and land under water situate, lying and being in the Geographic Township of [redacted], in the Town of [redacted], in the Territorial District of [redacted] and Province of [redacted], more particularly described in the Schedule attached hereto, heretofore and hereinafter referred to as the "premises";

TOGETHER WITH the right or privilege to develop the waterpower thereon for the generation of electrical energy and for such purpose to construct, operate, maintain and repair, in accordance with the provisions hereof, all necessary works;

TO HAVE AND TO HOLD the premises with the appurtenances thereunto belonging for a term as described in paragraph 16 to be computed from the [redacted] day of [redacted], [redacted] and from thenceforth next ensuing and fully to be complete and ended.

3. The Company shall pay such water rental charge in such manner as required by the Electricity Act, 1998 as amended from time to time and provide such information in such a manner as required by that Act.

4. In the event that the Electricity Act, 1998 is repealed or no longer provides for the payment of water rentals, the Company shall

   (a) file an annual return with the Crown in respect of the parent company and any of their subsidiaries situated in Ontario on or before March 16th of each year in the form and at such time as directed by the Ministry in writing,

   (b) In the event that the Company does not furnish to the Crown the return required by sub-paragraph (a) the waterpower rental charge for the month and each subsequent month in respect of which the return was to be furnished shall be subject to a penalty equivalent to the interest rate set for overdue accounts by the Ministry of Finance or any successor responsible for setting such interest rate and such penalty will be added to the waterpower rental charge payable for that month in the preceding year.

   (c) Notwithstanding sub-paragraph (b), the return required by sub-paragraph (a) shall be furnished to the Crown no later than the end of the third month in respect of which the return is to be made, and the failure to furnish the said statement by the said due date may constitute a breach of this lease agreement.

   (d) Commencing on the first day of the month in which energy is first produced, the Company covenants and agrees to pay monthly to the Crown in lawful money of Canada, without prior demand therefore and upon the conditions and at the

time hereinafter set forth a waterpower rental charge comprised of:

(i) a waterpower rental charge calculated at 9.5% on gross revenue derived from the generation of hydro-electricity from the premise.

(ii) any additional charge imposed pursuant to regulations, as amended, made under sub-paragraph (a) of subsection (3) of section 42 of the Public Lands Act, R.S.O. 1990, Chapt. P-43.

(e) The waterpower rental charge payable hereunder for the year commencing with the [redacted] day of [redacted], [redacted] and ending with the [redacted] day of [redacted], [redacted], and for each and every subsequent rental year during the term of this lease agreement, shall be subject to annual review by the Minister, and if it shall appear necessary or desirable to the Minister that the waterpower rental charge should be adjusted, the Minister shall so notify the Company on or before the 30th day of June of the rental year immediately preceding the year in respect of which the adjustment is to be made and the waterpower rental charge may be adjusted by the Minister.

(f) Should the generation of electrical power on the premises be discontinued for the purposes of repairing or maintaining the works, the Company shall continue to be responsible for all rentals required to be paid under this lease agreement.

5. The Company further covenants and agrees to pay the Crown in lawful money of Canada, without any prior demand therefor on the [redacted] day of [redacted], [redacted], and on the first day of January in each and every subsequent rental year of the term of this lease agreement, an annual land rental in the amount of [redacted].

(a) The land rental may be reviewed annually by the Minister, and if it shall appear necessary or desirable to the Minister that the land rental should be adjusted, the Minister shall notify the Company on or before the 30th day of June of the year immediately preceding the year in respect of which the adjustment is to be made and the land rental may be adjusted by the Minister.

6. (a) In the event that the Company fails to pay any sum of money owing to the Crown under this lease agreement on or before the day such sum is due, interest on such sum shall accrue from the due date at the interest rate set for overdue accounts by the Ministry of Finance or any successor responsible for setting such interest rate and such interest shall be a debt owing by the Company to the Crown.

(b) In the event that any sum of money payable by the Company under this lease agreement remains unpaid for one year after the date by which the sum of money is due and payable, the Minister may cancel this lease agreement after giving the Company thirty (30) days notice in writing and the Crown may, without further notice of any

kind or any form of legal process whatsoever, forthwith re-enter upon the premises or any part thereof.

7. The Minister or any person authorized by him in that behalf may enter the premises at any reasonable time to inspect the books and records of the Company or to inspect the condition of the premises and the works thereon or any of them.

8. (a) The Company shall, during the term of this lease agreement, operate and maintain the works on the premises in accordance with all federal, provincial and municipal legislation, in particular, laws related to health, safety and the environment as well as the requirements of the Ministry of Natural Resources dam safety standards, any applicable dam operating plan and/or any applicable water management plan approved by the Minister.

(b) The Minister or any person authorized by him in that behalf may enter the premises and effect repairs to any works where the Company has been directed in writing by the Minister to effect repairs and the Company fails or neglects to effect such repairs and the costs and expenses incurred by the Minister in so doing shall be a debt owing by the Company to the Crown.

9. The Company covenants and agrees with the Crown, and it is understood that it is a condition of this lease agreement:

(a) that it will not, except to an affiliate of the Company, assign or sublet, sell or transfer the premises or any part thereof, either for the whole or any part of the term, without first obtaining the written consent of the Crown and the granting of such consent shall be within the discretion of the Crown. Where such assignment, sublet, sale or transfer has been made by the Company to an affiliate, the Company guarantees that the affiliate will satisfactorily perform the terms and conditions of this lease agreement.

(b) that the Company will not mortgage or charge or grant security in the works for the balance of the term of the lease agreement without first obtaining the consent of the Crown and the granting of such consent shall be within the discretion of the Crown;

(c) that the Company will furnish the Crown with a summary of the proposed transaction, certified as accurate by a director or an officer of the Company who has authority to bind the Company, so as to enable the Crown to properly consider the Company's application for the Crown's consent, and shall also furnish such additional information and materials as the Crown may request for the purpose and shall pay such fee for assignment, subletting, mortgaging, charging, transfer or sale as is fixed from time to time by the Minister;

(d) the Company will, in addition to the above, furnish the Crown with a copy of the original registered documentation of all such transactions within fourteen (14) days of the conclusion of each transaction with registration particulars endorsed thereon;

(e) the Company shall furnish the Crown with a covenant by the assignee, subtenant, transferee or purchaser as the case may be, directly with the Crown, to observe and perform the terms and conditions of this lease agreement and be subject to the provisos herein contained;

(f) in the case of a charge or mortgage, the Crown agrees that if the mortgagee or chargee assumes possession or control of the premises, the mortgagee or chargee shall observe and perform the terms and conditions of this lease agreement and be subject to the provisos herein contained for so long as the mortgagee or chargee shall continue in possession or control of the premises, providing that there has been no breach of the lease agreement while the mortgagee or chargee has been in possession;

(g) that it shall pay all taxes, rates, duties and assessments whatsoever, whether municipal, parliamentary or otherwise, unless the same are being contested expeditiously and in good faith, now charged or hereafter to be charged upon the premises or the works on account thereof or upon the interest of the Company therein that would, if unpaid, constitute a lien or encumbrance on the premises or on the lands of the Crown. Where the Company is contesting taxes, rates, duties or assessments the Company shall give notice to the Crown.

(h) that should the Company fail to pay, when due, any taxes, rates, duties or assessments referred to in paragraph (g) unless the same are being contested expeditiously and in good faith, the Minister shall have the right to terminate this lease agreement after giving the Company thirty (30) days notice in writing;

(i) that it will pay all rates and charges for public and other utilities including water, gas, electricity, telephone and fuel, unless the same are being contested expeditiously and in good faith, that would, if unpaid, constitute a lien or encumbrance on the premises or on the lands of the Crown;

(j) that it will immediately pay and discharge any sheriff's executions filed against the premises for which it is responsible, and also any liens or other charges attaching thereto by reason of any act or omission on its part, whether caused by any work, services, or materials which it has had performed or supplied in connection with any of the works on the premises, or by failure to pay any tax for which it is responsible;

(k) the Company shall assume all liability and obligation, if any, and all loss, damage or injury, including death, to persons or property that would not have happened but for this lease agreement or anything done or omitted to be done or maintained by the Company thereunder or intended so to be and the Company shall at all times indemnify and save harmless the Crown from and against all such loss, damage, or injury, and all actions, suits, proceedings, costs,

charges, damages, expenses, claims or demands arising therefrom or connected therewith; and

(l) that the Company shall throughout the term of this lease agreement provide and keep in force for the benefit of the Crown and the Company general liability insurance in an amount of not less than ten million dollars ($10,000,000.00) in respect of injury to or death of any persons or property damage.

The Company shall, throughout the term of this lease agreement, put in effect and maintain, at its own cost and expense, with insurers having a secure A.M. Best rating of B + or greater, or the equivalent, all the necessary and appropriate insurance that a prudent person in the business of the Company would maintain, including but not limited to, the following:

(a) commercial general liability insurance on an occurrence basis for third-party bodily injury, personal injury and property damage, to an inclusive limit of not less than Ten Million Dollars ($10,000,000.00) (Canadian (CAD) per occurrence.

Insurance coverage must be endorsed:

(i) to name the Indemnified Parties as additional insureds with respect to liability insurance;
(ii) to provide cross-liability and severability of interest clauses;
(iii) to provide 30 day written notice of cancellation;
(iv) to provide contractual liability coverage, and
(v) to provide products and completed operation

All such insurance shall be primary and not require the sharing of any loss by any insurer of any Indemnified Party.

Proof of Insurance

The Company shall provide MNR with proof of the insurance required by this lease agreement in the form of valid certificates of insurance that reference this lease agreement and confirm the required coverage, within one (1) day of the issuance of this lease agreement, and renewal replacements on or before the expiry of any such insurance. Upon the request of the Ministry, a copy of each insurance policy shall be made available to it. The Company shall ensure that each of its subcontractors obtains all the necessary and appropriate insurance that a prudent person in the business of the subcontractor would maintain and that the Indemnified Parties are named as additional insureds with respect to any liability arising in the course of performance of the subcontractor's obligations under any subcontract for operation, repair or maintenance of the facility/dam.

10. In the event that any of the works or any alteration, renovation, enlargement, or reconstruction of the works should be destroyed by fire or other calamity, or be demolished, or by reason of any other occurrence become incapable of being utilized for the purpose of producing electricity then, unless the Company, within six (6) months of the happening of any such event, or such longer time as may be approved by the Crown, gives to the Crown written notice of its intention to rebuild, replace or reinstate the works, or reconstruct the works so destroyed, demolished or rendered unusable, in a manner satisfactory to the Crown and actually carries out such intention through to completion to the Crown's satisfaction within thirty six (36) months of the date of the notice referred to in this paragraph or such longer time approved by the Crown, then the Crown may at its option terminate this lease agreement.

11. It is expressly agreed that any failure by the Crown to enforce, either in part or in whole, the rights and remedies available to the Crown under these presents for any breach or failure by the Company to observe the provisions of any covenant or other matter herein contained shall not be deemed to be a waiver or acquiescence of same on the part of the Crown, nor shall such failure preclude the Crown from enforcing such rights and remedies against the Company for any subsequent breach or nonobservance. Any waiver of any of the Crown's rights under this lease agreement shall not have any force or any validity unless the Crown has consented thereto in writing.

12. (1) (i) The Company, when requested by the Minister, will develop a decommissioning plan within twelve (12) months of the request by the Minister. The Company agrees to comply with the decommissioning plan approved by the Minister.

(ii) The approved decommissioning plan shall specify the work necessary to leave the premises in a safe condition, together with a timetable for completing the decommissioning work and such work will be completed not later than twelve (12) months after the expiration or termination of this lease agreement or such longer period as may be approved by the Minister.

(2) Upon the expiration or earlier termination of this lease agreement:

(i) if notice to remove is not given by the Crown to the Company or such notice is given less than 30 days before the expiration or earlier termination of this lease agreement, all works or other assets remaining on the premises upon the expiration or sooner termination of this lease agreement automatically become the property of the Crown unless expressly rejected by the Crown, or its delegate, and the Crown has no obligation whatsoever to pay compensation for them and the Crown assumes no liability for them to the Company;

(ii) where the Company fails to restore the premises to a mutually agreed clean and safe condition within 12 months from the expiration or sooner termination of this lease agreement where notice to remove was given by the Crown to the Company not less than 30 days before the expiration or earlier termination of this lease agreement, the Company will pay to the Crown a sum in lawful money of Canada sufficient to cover the costs, if any, incurred by the Crown in selling, disposing of or destroying the works or other assets and in restoring the premises to a clean and safe condition; these costs shall be a debt due the Crown and may be recovered at the suit of the Crown in any court of competent jurisdiction.

13. Wherever in this lease agreement the word "Crown" occurs it shall be construed as including the Assigns, Heirs and Successors of the Crown and any person, corporation or commission hereafter exercising the powers now vested in the Crown and wherever in this lease agreement the word "Company" occurs it shall be construed as including assigns, heirs, executors, administrators, corporations, successors and other legal representatives of the Company; and this lease agreement is to be read with all changes in gender or number as required by the context. It is agreed that every covenant, proviso and agreement herein contained shall enure to the benefit of and be binding upon the parties hereto.

14. If the Company is in breach of any condition, agreement, affirmative covenant, negative covenant or any other obligation contained herein, the Crown shall give written notice of the breach and shall specify a reasonable time within which the breach must be remedied, taking into account the nature of the breach and the consequence thereof.

If the Company fails to remedy the breach within the time specified in the notice:

(i) The Company may be subject to prosecution pursuant to section 69.1 of the Public Lands Act; and/or,

(ii) The Crown shall have the right, but not the obligation to remedy the breach and take steps to rectify or mitigate the consequences of the breach, and recover its reasonable expenses in relation thereto from the Company as additional rent; and/or

(iii) The Crown may exercise a right of re-entry and may terminate the lease agreement.

15. (a) The Minister may terminate the lease agreement if he deems the termination to be in the public interest.

(b) In the event that the Minister terminates the lease agreement pursuant to sub-paragraph 15 (a), the Company shall be entitled to such compensation as agreed to by the parties or by arbitration under the Arbitration Act 1991.

16.(a) The initial term of this lease agreement shall be for a period of 20 years, commencing on the date indicated in paragraph 2.

(b) After completion of the 10th year of the initial term of the lease agreement the Minister shall conduct a review to ensure that the Company has complied with the terms and conditions of this lease agreement. If the review satisfies the Minister that the Company has complied with the terms and conditions of this lease agreement, the Minister shall extend the term of the lease agreement for an additional ten (10) years upon the same terms and conditions. If the review does not satisfy the Minister that the Company has complied with the terms and conditions of this lease agreement, the term of the lease agreement will not be extended and the lease agreement shall, subject to being terminated pursuant to paragraph 15, remain in effect until the date of expiry of the lease agreement.

(c) At each subsequent date when only 10 years remain before the expiry of the lease agreement, the Minister shall conduct a review to ensure that the Company has complied with the terms and conditions of this lease agreement. If the review satisfies the Minister that the Company has complied with the terms and conditions of this lease agreement, the Minister shall extend the term of the lease agreement for an additional ten (10) years upon the same terms and conditions or new terms and conditions that the Minister considers appropriate. If the review does not satisfy the Minister that the Company has complied with the terms and conditions of this lease agreement, the term of the lease agreement will not be extended and the lease agreement shall, subject to being terminated pursuant to paragraph 15, remain in effect until the date of expiry of the lease agreement.

(d) The Company agrees to give notice to the Crown of its intention to extend the term of the lease agreement not less than six months before the completion of the 10th year of its initial term and before each subsequent date when only 10 years remain before its expiry.

18. It is agreed that access to the premises is strictly the responsibility of the Company unless otherwise provided herein. Prior written approval from the Crown must be obtained before any construction of any road or other access facilities on the premises. The Crown reserves the right to use any access facilities so constructed without payment of any compensation to the Company.

The Company agrees and confirms that:

(a) nothing contained herein grants the Company more than a leasehold interest in the premises for the period specified, and that period is subject to compliance with the terms of this lease agreement;

(b) the successive granting of a lease agreement for the use of the premises will not create any

future rights or interest whatsoever in the premises for the benefit of the Company or any one else;

(c) should any improvements whatsoever be made to or on the premises this will not confer upon the Company any right to use the premises other than within the terms of this lease agreement nor will it give the Company any right to, or any expectation of, future lease agreements;

(d) there are no representations or warranties between the Crown and the Company for the use of the premises;

(e) there are no conditions, covenants, agreements, or obligations other than those imposed by law, regulation, or the terms of this lease agreement, between the Crown and the Company for the use of the premises.

18. All rent due under this lease agreement shall be payable to the Crown at the address specified in the rental notice, or in such other manner or place as the Crown may from time to time in writing direct.

19. It is further understood and agreed that this lease agreement is granted subject to:

(a) the right of Her Majesty the Queen in right of Canada to control navigation and shipping; and

(b) the right of Her Majesty the Queen in right of Canada, Her Majesty the Queen in right of Ontario, or any authorized Board, Commission, Corporation or person to control water levels, flood and overflow the premises.

20. Saving, excepting and reserving unto Us, Our Heirs and Successors, all ores, mines or minerals which are or shall hereafter be found on or under the premises hereby demised.

21. Also saving, excepting and reserving the surface rights only in and over any public or colonization roads or any highways crossing the said premises at the date of this lease agreement and not flooded as a result of the works contemplated hereby.

22. Also saving, excepting and reserving the surface rights only in ten percent of the acreage hereby granted for roads and the right to lay out the same where the Crown or its officers may consider necessary, subject to the Company's right to flood the area granted under this lease agreement for the purpose of the works contemplated hereby.

23. The Crown specifically reserves its rights under s.65 of the Public Lands Act, R.S.O. 1990, c.P.43.

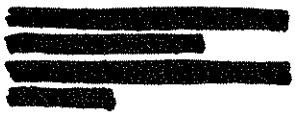
24. Whenever in this lease agreement notice is given by:

(a) the Company to the Crown, such notice shall be given in writing and forwarded by registered mail addressed to the District Manager at:

Ministry of Natural Resources
P.O. Box 730
2 Third Avenue
Cochrane, Ontario
P0L 1C0

or served personally to the District Manager or sent by fax or telecopier, to the District Manager followed by confirmation of delivery by telephone;

(b) the Crown to the Company, such notice shall be given in writing and forwarded by registered mail addressed to the Company at



or by delivering it to the Company personally to the Company with a copy to any mortgagee or chargee that has obtained the consent of the Crown to mortgage or charge this lease agreement at the address provided by such mortgagee or chargee to the Crown, but no copy is required to be provided where the mortgagee or chargee has failed to provide an accurate and current address to the Crown;

(c) any notice given under this lease agreement shall be validly received on the date of such personal service, or if mailed, delivered on the third business day after the mailing of the same in Canada, delivery or posting;

(d) any person may change the address for delivery of notices by notice given in accordance herewith.

SCHEDULE

Part of Location [redacted],

Being part of the bed of the [redacted] River

Lying opposite Blocks [redacted] and [redacted], Registered Plan [redacted],

And part of Lot [redacted], Concession [redacted],

Now being part of Block [redacted], Plan [redacted],

Geographic Township of [redacted],

Town of [redacted],

Territorial District of [redacted],

Containing [redacted] hectares, more or less,

Designated as Parts [redacted] and [redacted], on Reference Plan [redacted].

Office of the Surveyor General
CSK/10-Mar-11/

IN WITNESS WHEREOF the parties hereto have executed this lease agreement, the Crown under the hand of the Minister of Natural Resources and the Company under its corporate seal under the hands of its proper officers duly authorized in that behalf.

SIGNED, SEALED and DELIVERED in the presence of

[redacted]

Witness as to execution by Minister

HER MAJESTY THE QUEEN in right of [redacted]

[redacted]

Minister of Natural Resources for the Province of [redacted]

I have the authority to bind the Crown.

[redacted]

By: [redacted]
Name: [redacted]
Position: [redacted]

and: _____
Name:
Position:

I/We have the authority to bind the Corporation.

Waterpower Lease Agreement No. [redacted]

Main Office File No. [redacted]

Land Registrar,
Ministry of Government Services,
will mail duplicate to:

[redacted]

B-3-3 Form of Crown Easement

PROVINCE OF ONTARIO

MINISTRY OF NATURAL RESOURCES

GRANT OF EASEMENT

NO. «EasementNumber»

THIS INDENTURE made in duplicate the «DatedDay» day of «DatedMonth» in the year of Our Lord two thousand and «DatedYear» pursuant to the Public Lands Act,

BETWEEN:

THE MINISTER OF NATURAL RESOURCES
for the Province of Ontario,
hereinafter called the "Grantor",

OF THE FIRST PART;

- and -

«NAME»
hereinafter called the "Grantee",

OF THE SECOND PART;

WITNESSETH that under the Public Lands Act and in consideration of the sum of ONE THOUSAND DOLLARS ($1,000.00) now paid by the Grantee to the Minister of Finance of Ontario, the receipt whereof is hereby acknowledged, and the annual payments hereinafter mentioned, and the covenants and agreements hereinafter contained on the part of the Grantee to be paid, observed and performed, the Grantor doth hereby grant, convey, transfer, and confirm unto the Grantee, its successors and assigns, as and from the «DayOfEffectiveCommencementDate» day of «MonthOfEffectiveCommencementDate», «YearOfEffectiveCommencementDate», the right, licence, liberty, privilege and easement on, over, under and through the public lands situate, lying and being in the «SchATownshipGeographicDist» «SchATerritorialDist» and Province of Ontario, being more particularly described in Schedule "A" attached hereto, and which public lands are hereinafter referred to as the "right of way".

(a) to lay down, construct, operate, maintain, inspect, patrol, alter, remove, replace, re-locate, re-construct and remove at any time and from time to time an electrical transmission line or lines consisting of all necessary towers, poles and anchors with guys, braces, wires, cables and related material and equipment, hereinafter referred to as the "works";

(b) to maintain and use bridges and such gates in all fences that are now on the right-of-way as the Grantee may from time to time consider necessary;

(c) to install at a minimum depth of twelve inches below the surface of the right-of-way and maintain and use an underground conductor or conductors for grounding purposes when and where required on the right-of-way;

(d) to mark the location of the works under the right-of-way by suitable markers at such place or places on the land as are approved by the Grantor;

(e) to cut and prune selectively, trees and brush on the right-of-way and to keep the right-of-way clear of all trees, brush and shrubs that may interfere with the safe operation of the works;

(f) subject to the payment of Crown Stumpage charges under the Crown Forest Sustainability Act, to cut, prune and remove any Crown-owned trees standing or growing on land adjacent to the right-of-way where the condition thereof will interfere with the safe operation of the works;

(g) to keep the right-of-way clear of any buildings, structures or other improvements not otherwise permitted by the terms of this easement that may interfere with the safe operation of the works;

(h) to conduct engineering and legal surveys and make soil tests, on or over the right-of-way; and the Grantee shall have access to the right-of-way at any and all times for itself and its servants, agents, contractors and subcontractors with or without vehicles, supplies, machinery and equipment for all purposes necessary and convenient for the exercise and enjoyment of the right, privilege and easement granted herein on the following terms and conditions which are hereby mutually covenanted and agreed to by and between the Grantor and the Grantee:

1. The right, licence, liberty, privilege and easement hereby granted shall be coterminious with and cease and determine immediately upon the determination of the term created by Waterpower Lease Agreement No. <> dated <> , as the same may be amended, extended or replaced from time to time, or until the Grantee shall surrender, execute and deliver a transfer and release thereof.

2. The Grantee shall pay, subject to paragraph 3, to the Minister of Finance of Ontario for the time being in advance yearly and every year on or before the «DayOfEffectiveCommencementDate» day of «MonthOfEffectiveCommencementDate» of each year that this easement remains in force the sum of «Fee» DOLLARS ($«FeeNumeric»).

3. The amount of the annual payments mentioned in paragraph 2 is subject to annual review and adjustment, each such adjustment shall take effect on the first day of January in the year next following; the adjusted rent shall be determined by the Grantor or by arbitration under the Arbitrations Act where within thirty days of the Grantee being given notice of the Grantor's determination of the adjusted payment, the Grantee gives the Grantor notice that the adjusted payment shall be determined under the Arbitrations Act. It is agreed that this easement is not subject to rent review legislation.

4. Subject to the rights granted herein to the Grantee, Her Majesty the Queen in right of Ontario shall have charge of the administration, management, sale and disposition of the land and shall have the right to fully use and enjoy it.

5. (1) Where Her Majesty the Queen in right of Ontario makes a disposition of public lands comprising in whole or in part any part of the right-of-way, the person to whom the disposition is made, his heirs, executors, administrators, successors and assigns or any of them, may use the surface layer of the right-of-way:

   (a) with the consent of the Grantee, for the growing of crops and the grazing of live-stock;

   (b) with the consent of the Grantee, for the purposes of a road, trail or lane crossing the right-of-way or any other crossing, provided that where the right-of-way is owned by a municipal corporation, commission, public utility or other agency or authority of a public nature, the consent of the Grantee shall not be required except as to the location thereof;

   (c) with the consent of the Grantee for any purpose consistent with municipal zoning.

   (2) The owner or lessee of the mines or minerals lying in, on or under the right-of-way may work and prospect for mines or minerals, provided that the safe operation of the works of the Grantee is not interfered with or endangered.

6. The Grantee agrees to restore at its own expense the right-of-way to its approximate condition as the same existed immediately prior to the installation of the works and to restore all fences damaged during such installation or during any subsequent operations by the Grantee, to the satisfaction of the Grantor so far as is consistent with the use of the easement hereby granted and the Grantee will compensate the Grantor for any trees, shrubs, and crops or any of them destroyed or fences not restored at a valuation determined by the Grantor.

7. The Grantee will compensate Her Majesty the Queen in right of Ontario for any loss, damage or expense resulting from, caused by or in any manner connected with the exercise of the rights granted herein or which would not have happened but for the existence of the works or this easement, provided that the obligation to compensate Her Majesty shall not apply if a court of competent jurisdiction has ruled that such loss, damage or expense is attributable to the acts of the Grantor, Her Majesty the Queen in right of Ontario, Her officers, servants and agents or any of them, in deliberate or reckless disregard for the rights granted herein.

8. Notwithstanding any rule of law or equity, the works shall at all times remain the property of the Grantee notwithstanding that the same may be annexed or affixed to the land and shall at any time and from time to time be removable in whole or in part by the Grantee, its successors and assigns.

9. In the event that the Grantee abandons the works, the Grantee may, with the consent of the Grantor, leave any part thereof in place.

10. (i) If the Grantee is in breach of any condition, agreement, affirmative covenant, negative covenant or any other obligation contained herein, the Grantor shall give written notice of the breach and shall specify a reasonable time within which the breach must be remedied, taking into account the nature of the breach and the consequences thereof.

(ii) If the Grantee fails to remedy the breach within the time specified in the notice:

(a) The Grantee may be subject to prosecution pursuant to Section 69.1 of the Public Lands Act; and/or,
(b) The Grantor shall have the right but not the obligation to remedy the breach and take steps to rectify or mitigate the consequences of the breach and recover its reasonable expenses in relation thereto from the Grantee as additional rent; and/or,
(c) The Grantor may exercise a right of re-entry and may terminate the easement.

11. The Grantee performing and observing the covenants and conditions on its part to be performed and observed, shall and may peaceably hold and enjoy the rights, liberties, privileges and easement hereby granted, without let, hindrance, molestation or interruption on the part of the Grantor or of any person claiming by, through, under or in trust for the Grantor.

12. All notices to be given hereunder may be given by registered letter, addressed to the Grantee at

«ApplicantMailingAddress»
«ApplicantMailingAddress1»
«ApplicantMailingAddress2»
«ApplicantMailingAddress3»
«ApplicantMailingAddress4»

or to the Grantor at the

Ministry of Natural Resources
<district office>
<town, province>
<postal code>

or such other address as the Grantor or Grantee may respectively, from time to time designate by letter, and any such notice shall be deemed to have been given to and received by the addressee on the third business day after mailing thereof, postage prepaid and registered.

13. The right, licence, liberty, privilege and easement herein granted is pursuant to Section 42.1 of the Electricity Act.

14. The Grantee covenants to indemnify, keep indemnified and save harmless the Grantor, Her Majesty the Queen in right of Ontario, Her officers, servants and agents or any of them, hereinafter collectively referred to as "the Grantor" from and against all claims, demands, costs, suits, actions or proceedings, causes of action, loss, damage, expense or injury including death, of any nature or kind whatsoever, resulting from, caused by or in any manner connected with the exercise of any right granted herein or which would not have happened but for the existence of the works or this easement, and the Grantee hereby waives, releases and forever discharges, the Grantor from all claims, demands, costs, suits, actions or proceedings, causes of action, loss, damage, expense or injury including death, of any nature or kind whatsoever, which the Grantee has or hereafter shall or may have resulting from, caused by or in any manner connected with the exercise of any right granted herein or which would not have happened but for the existence of the works or this easement, provided that the indemnity and release herein shall not apply if a court of competent jurisdiction has ruled that such claims, demands, costs, suits, actions or proceedings, causes of action, loss, damage, expense or injury including death, of any nature or kind whatsoever are attributable to acts of the Grantor in deliberate or reckless disregard for the rights granted herein.

15. The rights, liberties, privileges and easement hereby granted are and shall be of the same force and effect to all intents and purposes as a covenant running with the land, and this Indenture, including all the covenants and conditions herein contained, shall extend to be binding upon and enure to the benefit of the successors and assigns of the parties hereto respectively.

IN WITNESS WHEREOF the parties hereto have hereunto set their hands and seals.

xxxxxxxx
Provincial Lands Specialist - Crown Land Registry
Land Management Section
Ministry of Natural Resources
for and on behalf of the
Minister of Natural Resources

BY:_____

AND:_____

Grant of Easement No. «EasementNumber»

Main Office File No. «MOFileNo»

«ApplicantName»
«AdviseAddress1»
«AdviseAddress2»
«AdviseAddress3»
«AdviseAddress4»

B-4-1 CONNECTION IMPACT OF TRANSMISSION FACILITY ON GRID

53. A single system impact assessment ("**SIA**") was performed for both the Bezhig and Niizh Facilities as they are interconnected to the common transmission line at the Bezhig Facility which is interconnected to the M2W Circuit. A Copy of the SIA report is attached as Exhibit B-4-2.

54. The IESO recommended in the SIA report that "From the information provided, our review concludes that the proposed connection of the White River Generation Facility, subject to the requirements specified in this report, will not result in a material adverse effect on the reliability of the IESO-controlled grid. It is recommended that a Notification of Conditional Approval for Connection be issued for the White River Generation Facility subject to the implementation of the requirements listed in this report."

55. A single Customer impact assessment ("**CIA**") was performed by Hydro One for the Hydro Facilities. A copy of the CIA is attached as Exhibit B-4-3. The purpose of the CIA is to highlight significant impacts, if any, to affected transmission customers early in the project development process and thus allow an opportunity for these parties to bring forward any concerns that they may have including those needed for the review of the connection and for any possible application for leave to construct.

56. The CIA noted that the Hydro Facilities are connected to the M2W Circuit at a point of common coupling protected by a single high voltage 115 kV breaker. Consequently, the connection of the Hydro Facilities does not expose the existing Hydro One customers to increased interruptions or diminish the reliability and performance of supply. The CIA further concluded that the Hydro Facilities will not adversely affect transmission customers from the load flow or short circuit perspective. The draft CIA was provided to all of the affected transmission customers in the area and no comments were received within the provided review period.

57. The Applicant confirms that all of the recommendations listed in the SIA reports and CIA will be met prior to connecting the Transmission Facility to the IESO-controlled grid.

Exhibit B-4-2 – SIA Report

REPORT

Power to Ontario.
On Demand.

System Impact Assessment Report

Gitchi Animki Niizh GS and Gitchi Animki Bezhig GS

CONNECTION ASSESSMENT & APPROVAL PROCESS

Final Report

CAA ID 2010-384, 2010-385

Applicant: Regional Power OPCO Inc.

Market Facilitation Department

February 28, 2011

Document ID	IESO_REP_0678
Document Name	System Impact Assessment Report
Issue	Issue 1.0
Reason for Issue	Final Report
Effective Date	February 28, 2011

System Impact Assessment Report

Gitchi Animki Niizh GS and Gitchi Animki Bezhig GS

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

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, you must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to you. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that it is using the most recent version of this report.

HYDRO ONE

Special Notes and Limitations of Study Results

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

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

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

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

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

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

Table of Contents

Executive Summary

Description

Regional Power OPCO Inc. is proposing to develop Gitchi Animki Niizh (Lower White River) and Gitchi Animki Bezhig (Upper White River), two new hydro-electric plants near the town of Mobert, Ontario with a combined maximum capacity of 20 MW.

- Lower White River consists of 2 x 4.8 MW synchronous units and 1x 0.4 MW induction unit
- Upper White River consists of 2 x 4.725 MW synchronous units and 1x 0.55 MW induction unit

Two contracts were awarded under the government Feed-In Tariff (FIT) program. Upper White River is expected to start commercial operation in January 2013 and Lower White River is expected to start commercial operation in March 2013.

This assessment examined the impact of injecting 20 MW of hydro-electric generation from the White River Generation Facility into the provincial grid via the 115 kV circuit M2W on the reliability of the IESO-controlled grid.

Findings

The following conclusions are achieved based on this assessment:

(1) The proposed connection arrangement and equipment for the White River Generation Facility does not have a material adverse impact on the reliability of the IESO-controlled grid.

(2) The system fault levels after the incorporation of the White River Generation Facility will not exceed the interrupting capabilities of the existing breakers on the IESO-controlled grid near this facility.

(3) Pre-Contingency Thermal Analysis: No pre-contingency overloads were identified under high transfer east conditions. Under high transfer west conditions, the in-service of the White River Generation Facility plus additional committed generation on M2W (20 MW) and A4L (10 MW) could result in congestion in order to respect continuous ratings of the 115 kV circuit A7L.

(4) Post-Contingency Thermal Analysis under High Transfer East Conditions: Existing congestion (pre-White River Facility connection) on the 115 kV circuits A7L, T1M was identified for high transfers east under summer conditions as post contingency loadings were found to exceed the long term emergency ratings.

The connection of the White River Generation Facility may slightly (i) increase the overload on the 115 kV circuit A7L for the loss of A6P/A8L (at most by 2% from existing conditions) and (ii) reduce the overload on 115 kV circuit T1M for the loss of M23L/M24L, R1LB/R2LB and loss of Umbata Falls GS (at most by 5% from existing conditions).

(5) Post-Contingency Thermal Analysis under High Transfers West Conditions: Existing congestion (pre- White River Facility connection) on the 115 kV circuit A7L was identified for high transfers west under summer conditions as post contingency loadings were found to exceed the long term emergency ratings. The connection of the White River Generation Facility may slightly increase the overload on the 115 kV circuit A7L for the loss of M23L/M24L, A6P/A8L, R1LB/ R2LB (at most by 2% from existing conditions).

Under current conditions, without the White River Generation Facility in-service, for the loss of A7L, the 115 kV circuit A8L is loaded post-contingency with a margin of 3 MW from its long term emergency rating. Similarly, for the loss of M23L, the 115 kV circuit A5A is loaded post-contingency with a margin of 2 MW from its long term emergency rating. As such, any additional generation incorporated east of Alexander would likely cause congestion on these circuits for such contingencies, as observed in this assessment.

(6) For now, based on historical East West Transfer West flow patterns it is not necessary for the White River Generation Facility to participate in any existing or new Special Protection System. Nevertheless, if future flow patterns on East West Transfer West show an increasing trend, the White River Generation Facility may be required to participate in a new Special Protection System.

(7) The maximum voltage declines for the loss of White River Generation Facility were found to be within the 10% pre and post-ULTC action limit.

(8) The White River Generation Facility is capable of meeting reactive power range requirements at the point of common coupling given an off-load tap setting of 124 kV on the step up transformers at both Lower and Upper sites.

(9) Based on the information provided by the applicant, the excitation systems at both Upper and Lower sites do not meet the Market Rule performance requirements with regards to ability to reach specified negative ceiling values and ability to reach positive and negative ceiling within defined response times.

(10) Based on the information provided by the applicant, the governor systems at both Upper and Lower sites meet the Market Rule performance requirements.

(11) The incorporation of the White River Generation Facility does not cause any material adverse impact on the transient performance of the IESO-controlled grid.

(12) The Protection Impact Assessment conducted by the transmitter identified the following:

(a) Existing protection scheme at Marathon TS will have to be modified and hardware addition is required to incorporate blocking, Generator End Open (GEO) and breaker failure signals from the White River Generation Facility switching station.
(b) New telecommunication link(s) will need to be established to transmit signals among all stations on M2W that are required for reliable fault clearing. The provision of new telecommunication facilities at Lower and Upper White River is the responsibility of the applicant.
(c) Existing Zone 1 reach will remain unchanged, while the Zone 2 reach will increase to cover the new maximum apparent impedance due to the White River Generation Facility.

Other Findings

(1) Under certain operating conditions, transient instability could occur for the loss of A6P, loss of L3P or loss of L4P with or without the new generation in-service. New generation refers to units at the White River Generation Facility, committed generation on A4L (10 MW) and additional committed generation on M2W (20 MW).

It was found that no transient instability would occur for the 115 kV contingencies involving loss of A6P, L3P or L4P, if PLC communication is installed between Port Arthur TS and Alexander SS and Port Arthur TS and Lakehead TS, which would reduce the clearing time to 149 ms after fault inception.

Hydro One is required to investigate if PLC transfer trip telecommunication can be installed between (i) Port Arthur TS and Alexander SS for circuit A6P, (ii) Lakehead and Port Arthur TS for circuit L3P and (iii) Lakehead and Port Arthur TS for circuit L4P. Connection to the grid of the White River Generation Facility is not dependent on these installations; however, output restrictions may have to be imposed on all generation within the pocket bounded by Alexander 115 kV and Marathon T11 and T12, including the White River Generation Facility under certain system conditions until the PLC facilities are installed.

IESO's Requirements for Connection

Transmitter Requirements

The following requirements are applicable to Hydro One for the incorporation of the White River Generation Facility:

(1) The transmitter is required to change the relay settings of the 115 kV circuit M2W at Marathon TS to account for the effect on apparent impedance due to power injection from the hydro-electric generation facility.

Modifications to protection relays after this SIA is finalized must be submitted to IESO as soon as possible or at least six (6) months before any modifications are to be implemented on the existing protection systems. Mitigation solutions to address modifications resulting in adverse impact on reliability must be jointly developed with the applicant.

Connection Applicant Requirements

Specific Requirements: The following specific requirements are applicable to the applicant for the incorporation of the White River Generation Facility. Specific requirements pertain to the level of reactive compensation needed, operation restrictions, Special Protection Systems, upgrading of equipment and any project specific items not covered in the general requirements:

(1) The exciters at Upper and Lower White River sites are rotating AC exciters and have limited performance capability when compared to the Market Rule requirements. In the event that the applicant is unable to adopt a different exciter, the applicant is required to apply to the IESO for an exemption from the Market Rule exciter performance requirements prior to connection. The final approval to connect the facility is conditional upon a successful award of an exemption.

General Requirements: The proposed connection must comply with all the applicable requirements from the Transmission System Code (TSC), IESO Market Rules, and standards and criteria. The most relevant requirements are summarized below and presented in more detail in **Section 2** of this report.

(1) The proposed facility must satisfy the Generator Facility Requirements in Appendix 4.2 of the Market Rules.

(2) As this facility is in northern Ontario, all new 115 kV equipment must have a maximum continuous voltage rating and the ability to interrupt fault current at a voltage of at least 132 kV.

(3) If revenue metering equipment is being installed as part of this project, it must comply with Chapter 6 of the IESO Market Rules.

(4) The new equipment must sustain the fault levels in the area where the equipment is installed. Should future system enhancements result in fault levels exceeding equipment capability, the applicant is required to replace equipment at its own expense with higher rated equipment, up to 50 kA as per the Transmission System Code for the 115 kV system.

(5) The 115 kV breaker must meet the required interrupting time of less than or equal to 5 cycles as per the Transmission System Code.

(6) The connection equipment must be designed such that adverse effects due to failure are mitigated on the IESO-controlled grid.

(7) The connection equipment must be designed for full operability in all reasonably foreseeable ambient temperature conditions.

(8) The facility must satisfy telemetry requirements as per Appendices 4.15 and 4.19 of the Market Rules. The determination of telemetry quantities and telemetry testing will be conducted during the IESO Facility Registration/Market entry process.

(9) Protection systems must satisfy requirements of the Transmission system code and specific requirements from the transmitter. New protection systems must be coordinated with existing protection systems.

(10) Protective relaying must be configured to ensure transmission equipment remains in service for voltages between 94% of minimum continuous and 105% of maximum continuous values as per Market Rules, Appendix 4.1.

(11) Although the SIA has found that a Special Protection Scheme (SPS) is not currently required for the White River Generation Facility, provisions must be made in the design of the protections and controls at the facility to allow for the installation of Special Protection Scheme equipment. Should a future SPS be installed to improve the transfer capability in the area or to accommodate transmission reinforcement projects, the White River Generation Facility, will be required to participate in the SPS and to install the necessary protection and control facilities to affect the required actions.

(12) Protection systems within the generation facility must only trip the appropriate equipment required to isolate the fault. After the facility begins commercial operation, if an improper trip of the transmission facilities occurs due to events within the generation facility, the new facility may be required to be disconnected from the IESO-controlled grid until the problem is resolved.

(13) The autoreclosure of the new 115 kV breaker at the connection point must be blocked. Upon its opening for a contingency, it must be closed only after IESO approval is granted. The IESO will require reduction of power generation prior to the closure of the breaker followed by gradual increase of power to avoid a power surge.

(14) The generation facility must operate in voltage control mode and shall regulate automatically voltage at a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal based within ±0.5% of any set point within ±5% of rated voltage. If the AVR target voltage is a function of reactive output, the slope $\Delta V / \Delta Q_{max}$ shall be adjustable to 0.5%.

(15) Mathematical models and data, including any controls that would be operational, must be provided to the IESO through the IESO Facility Registration/Market Entry process at least seven months before energization from the IESO-controlled grid. That includes both PSS/E and DSA software compatible mathematical models representing the new equipment for further IESO, NPCC and NERC analytical studies. The connection applicant may need to contact the software manufacturers directly, in order to have the models included in their packages. If the data or assumptions supplied for the registration of the facilities materially differ from those that were used for the assessment, then some of the analysis might need to be repeated.

(16) The registration of the new facilities will need to be completed through the IESO's Market Entry process before IESO final approval for connection is granted and any part of the facility can be placed in-service.

(17) As part of the IESO Facility Registration/Market Entry process, the connection applicant must provide evidence to the IESO confirming that the equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in this assessment. Until this evidence is provided and found acceptable to the IESO, the Facility Registration/Market Entry process will not be considered complete and the connection applicant must accept any restrictions the IESO may impose upon this project's participation in the IESO administered market or connection to the IESO-controlled grid. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

(18) During the commissioning period, a set of IESO specified tests must be performed. The commissioning report must be submitted to the IESO within 30 days of the conclusion of commissioning. Field test results should be verifiable using the PSS/E models used for this SIA.

(19) The proposed facility must be compliant with applicable reliability standards set by the North American Electric Reliability Corporation (NERC) and the North East Power Coordinating Council (NPCC) prior to energization to the IESO controlled grid.

(20) The applicant may meet the restoration participant criteria as per the NERC standard EOP-005. Further details can be found in section 3 of Market Manual 7.8 (Ontario Power System Restoration Plan).

Notification of Conditional Approval

From the information provided, our review concludes that the proposed connection of the White River Generation Facility, subject to the requirements specified in this report, will not result in a material adverse effect on the reliability of the IESO-controlled grid.

It is recommended that a *Notification of Conditional Approval for Connection* be issued for the White River Generation Facility subject to the implementation of the requirements listed in this report.

1. Project Description

Regional Power OPCO Inc. has proposed to develop Gitchi Animki Niizh (Lower White River) and Gitchi Animki Bezhig (Upper White River), two new hydro-electric plants with a combined capacity of 20 MW near the town of Mobert, Ontario.

Each project was awarded a contract under the government Feed-In Tariff program. Upper White River is expected to start commercial operation in January 2013 and Lower White River is expected to start commercial operation in March 2013. Collectively, these two projects are referred to as the "White River Generation Facility" throughout this report.

The proposed White River Generation Facility will tap onto Hydro One's existing 115 kV circuit M2W at a distance of 42 km from Marathon via a single 6.25 km 115 kV circuit. Each plant will be connected to this 115 kV line tap via a 8.75 km circuit (Lower White River) and 3 km circuit (Upper White River).

The Lower White River plant will consist of two identical 5.33 MVA, 4.16 kV synchronous generators with a maximum power output of 4.8 MW each and a 0.465 MVA, 0.6 kV induction generator with a maximum power output of 0.4 MW. Each of the synchronous generators will be connected to the 4.16 kV bus with a 4.16 kV breaker. The induction generator will be connected to the 4.16 kV bus via a 0.5 MVA 4.16/0.6 kV step-up transformer and 200 meters of 4.16 kV cable with a 4.16 kV breaker. The combined power from the three generators is transferred towards the 8.75 km circuit and M2W line tap through a 10MVA, 115/4.16 kV step-up transformer with a 115 kV breaker.

The Upper White River plant will consist of two identical 5.25 MVA, 13.8 kV synchronous generators with a maximum power output of 4.725 MW each and a 0.625 MVA, 0.6 kV induction generator with a maximum power output of 0.55 MW. Each of the synchronous generators will be connected to the 13.8 kV bus with a 13.8 kV breaker. The induction generator will be connected to the 13.8 kV bus via a 0.625 MVA 13.8/0.6 kV step-up transformer and 200 meters of 13.8 kV cable with a 13.8 kV breaker. The combined power from the three generators is transferred towards the 3 km circuit and M2W line tap through a 10 MVA, 115/13.8 kV step-up transformer with a 115 kV breaker.

The proposed synchronous generators are salient pole machines with rated speeds of 240 rpm (Lower White River) and 720 rpm (Upper White River).

– End of Section –

2. General Requirements

Generators

The proposed facility must satisfy the generator facility requirements in Appendix 4.2 of Market Rules.

The generation facility requirements for a hydro-electric facility primarily include:

- the generation facility shall have the capability to operate continuously between 59.4Hz and 60.6Hz and for a limited period of time in the region above straight lines on a log-linear scale defined by the points (0.0s, 57.0Hz), (3.3s, 57.0Hz), and (300s, 59.0Hz);
- the generation facility shall respond to frequency increase by reducing the active power with an average droop based on maximum active power adjustable between 3% and 7% and set at 4%. Regulation dead band shall not be wider than ± 0.06%. A sustained 10% change of rated active power after 10 s in response to a constant rate of change of frequency of 0.1%/s during interconnected operation shall be achievable;
- speed shall be controlled in a stable fashion in both interconnected and island operation. Certain types of generation, such as hydro-electric generation will require different governor control settings to achieve both a rapid response during interconnected operation and a stable response during island operation. The switch between these two settings must be automatically triggered by conditions that are subject to IESO approval. Normally either frequency alone or a combination of frequency and rate of change of frequency would be acceptable.
- the generation facility shall be able to ride through routine switching events and design criteria contingencies assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times unless disconnected by configuration;
- the generation facility directly connecting to the IESO-controlled grid shall have the minimum capability to supply continuously all levels of active power output for 5% deviations in terminal voltage. Rated active power is the smaller output at either rated ambient conditions (e.g. temperature, head, wind speed, solar radiation) or 90% of rated apparent power. To satisfy steady-state reactive power requirements, active power reductions to rated active power are permitted;
- the generation facility must have the capability to inject or withdraw reactive power continuously (i.e. dynamically) at a connection point up to 33% of its rated active power at all levels of active power output except where a lesser continually available capability is permitted by the IESO. If necessary, shunt capacitors must be installed to offset the reactive power losses within the facility in excess of the maximum allowable losses. If generators do not have dynamic reactive power capabilities as described above, dynamic reactive compensation devices must be installed to make up the deficient reactive power;
- the generation facility shall regulate automatically voltage at a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal based within ±0.5% of any set point within ±5% of rated voltage. If the AVR target voltage is a function of reactive output, the slope $\Delta V / \Delta Q_{max}$ shall be adjustable to 0.5%. The equivalent time constants shall not be longer than 20 ms for voltage sensing and 10 ms for the forward path to the regulator output.

Connection Equipment (Breakers, Disconnects, Transformers, Buses)

Appendix 4.1, reference 2 of the Market Rules states that under normal conditions voltages in northern Ontario are maintained within the range of 113 kV to 132 kV.

The 115 kV equipment in the facility must have a maximum continuous voltage rating of at least 132 kV.
Fault interrupting devices must be able to interrupt fault current at the maximum continuous voltage of 132 kV.

If revenue metering equipment is being installed as part of this project, please be aware that revenue metering installations must comply with Chapter 6 of the IESO Market Rules for the Ontario electricity market. For more details the connection applicant is encouraged to seek advice from their Metering Service Provider (MSP) or from the IESO metering group.

The Transmission System Code (TSC), Appendix 2 establishes maximum fault levels for the transmission system. For the 115 kV system, the maximum 3 phase symmetrical fault level is 50 kA and the single line to ground (SLG) symmetrical fault level is 50 kA.

The TSC requires that new equipment be designed to sustain the fault levels in the area where the equipment is installed. If any future system enhancement results in an increased fault level higher than the equipment's capability, the connection applicant is required to replace the equipment at their own expense with higher rated equipment capable of sustaining the increased fault level, up to the TSC's maximum fault level of 50 kA for the 115 kV system.

The Transmission System Code (TSC), Appendix 2 states that the maximum rated interrupting time for 115 kV breakers must be $\leq$ 5 cycles. The connection applicant shall ensure that the new breakers meet the required interrupting time as specified in the TSC.

The connection equipment must be designed so that the adverse effects of failure on the IESO-controlled grid are mitigated. This includes ensuring that all circuit breakers fail in the open position.

The connection equipment must be designed so that it will be fully operational in all reasonably foreseeable ambient temperature conditions.

IESO Monitoring and Telemetry Data

In accordance with the telemetry requirements for a generation facility (see Appendices 4.15 and 4.19 of the Market Rules) the connection applicant must install equipment at this project with specific performance standards to provide telemetry data to the IESO. The data is to consist of certain equipment status and operating quantities which will be identified during the IESO Market Entry Process.

As part of the IESO Facility Registration/Market Entry process, the connection applicant must also complete end to end testing of all necessary telemetry points with the IESO to ensure that standards are met and that sign conventions are understood. All found anomalies must be corrected before IESO final approval to connect any phase of the project is granted.

Protection Systems

Protection systems must be designed to satisfy all the requirements of the Transmission System Code as specified in Schedules E, F and G of Appendix 1 (version B) and any additional requirements identified by the transmitter. New protection systems must be coordinated with existing protection systems.

Protective relaying must be set to ensure that transmission equipment remains in-service for voltages between 94% of the minimum continuous and 105% of the maximum continuous values in the Market Rules, Appendix 4.1.

The Applicant is required to have adequate provision in the design of protections and controls at the facility to allow for future installation of Special Protection Scheme (SPS) equipment. Should a future SPS be installed to improve the transfer capability in the area or to accommodate transmission reinforcement projects, the project will be required to participate in the SPS system and to install the necessary protection and control facilities to affect the required actions.

Any modifications made to protection relays by the transmitter after this SIA is finalized must be submitted to the IESO as soon as possible or at least six (6) months before any modifications are to be implemented on the existing protection systems. If those modifications result in adverse impacts, the connection applicant and the transmitter must develop mitigation solutions.

Send documentation for protection modifications triggered by new or modified primary equipment (i.e. new or replacement relays) to connection.assessments@ieso.ca.

For protection modifications that are not associated with new or modified equipment (i.e. protection setting modifications) please send documentation to protection.settings@ieso.ca.

Protection systems within the generation facility must only trip the appropriate equipment required to isolate the fault. After the facility begins commercial operation, if an improper trip of the 115 kV circuit M2W occurs due to events within the facility, the facility may be required to be disconnected from the IESO-controlled grid until the problem is resolved.

The autoreclosure of the new 115 kV breaker at the connection point must be blocked. Upon its opening for a contingency, it must be closed only after the IESO approval is granted. The IESO will require reduction of power generation prior to the closure of the breaker followed by gradual increase of power to avoid a power surge.

Facility Registration/Market Entry Requirements

Mathematical models and data, including any controls that would be operational, must be provided to the IESO through the IESO Facility Registration/Market Entry process at least seven months before energization to the IESO-controlled grid. That includes both PSS/E and DSA software compatible mathematical models representing the new equipment for further IESO, NPCC and NERC analytical studies. The connection applicant may need to contact the software manufacturers directly, in order to have the models included in their packages

The registration of the new facilities will need to be completed through the IESO's Market Entry process before IESO final approval for connection is granted and any part of the facility can be placed in-service. If the data or assumptions supplied for the registration of the facilities materially differ from those that were used for the assessment, then some of the analysis might need to be repeated.

As part of the IESO Facility Registration/Market Entry process, the connection applicant must provide evidence to the IESO confirming that the equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in this assessment. Until this evidence is provided and found acceptable to the IESO, the Facility Registration/Market Entry process will not be considered complete and the connection applicant must accept any restrictions the IESO may impose upon this project's participation in the IESO administered market or connection to the IESO-controlled grid. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

During the commissioning period, a set of IESO specified tests must be performed. The commissioning report must be submitted to the IESO within 30 days of the conclusion of commissioning. Field test results should be verifiable using the PSS/E models used for this SIA.

Reliability Standards

Prior to connecting to the IESO controlled grid, the proposed facility must be compliant with the applicable reliability standards set by the North American Electric Reliability Corporation (NERC) and the North East Power Coordinating Council (NPCC).

A list of applicable standards, based on the connection applicant's market role/OEB licence can be found here:

http://www.ieso.ca/imoweb/ircp/reliabilityStandards.asp

In support of the NERC standard EOP-005, the connection applicant may need to meet the restoration participant criteria. Please refer to section 3 of Market Manual 7.8 (Ontario Power System Restoration Plan) to determine its applicability to the proposed facility.

The IESO monitors and assesses market participant compliance with these standards as part of the IESO Reliability Compliance Program. To find out more about this program, visit the webpage referenced above or write to ircp@ieso.ca.

Also, to obtain a better understanding of the applicable reliability obligations and find out how to engage in the standards development process, we recommend that the connection applicant join the IESO's Reliability Standards Standing Committee (RSSC) or at least subscribe to their mailing list at rssc@ieso.ca. The RSSC webpage is located at: http://www.ieso.ca/imoweb/consult/consult_rssc.asp.

– End of Section –

Review of Connection Proposal

3.1 Proposed Connection Arrangement

The proposed connection arrangement of the White River Generation Facility is shown in **Figure 1**.

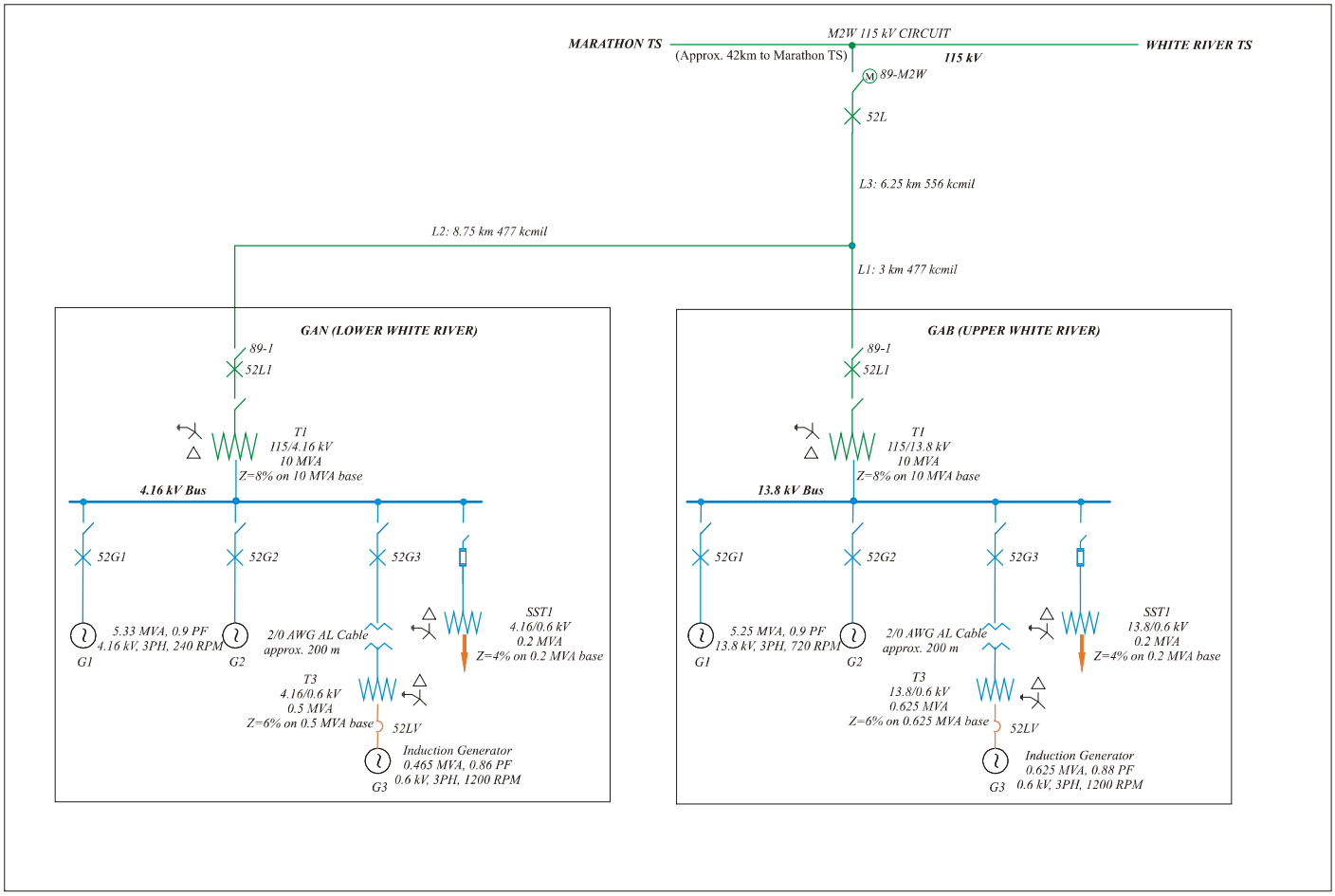


Figure 1: Proposed connection arrangement

The 115 kV system and 230 kV system within the vicinity of the White River Facility is shown in **Figure 2**.

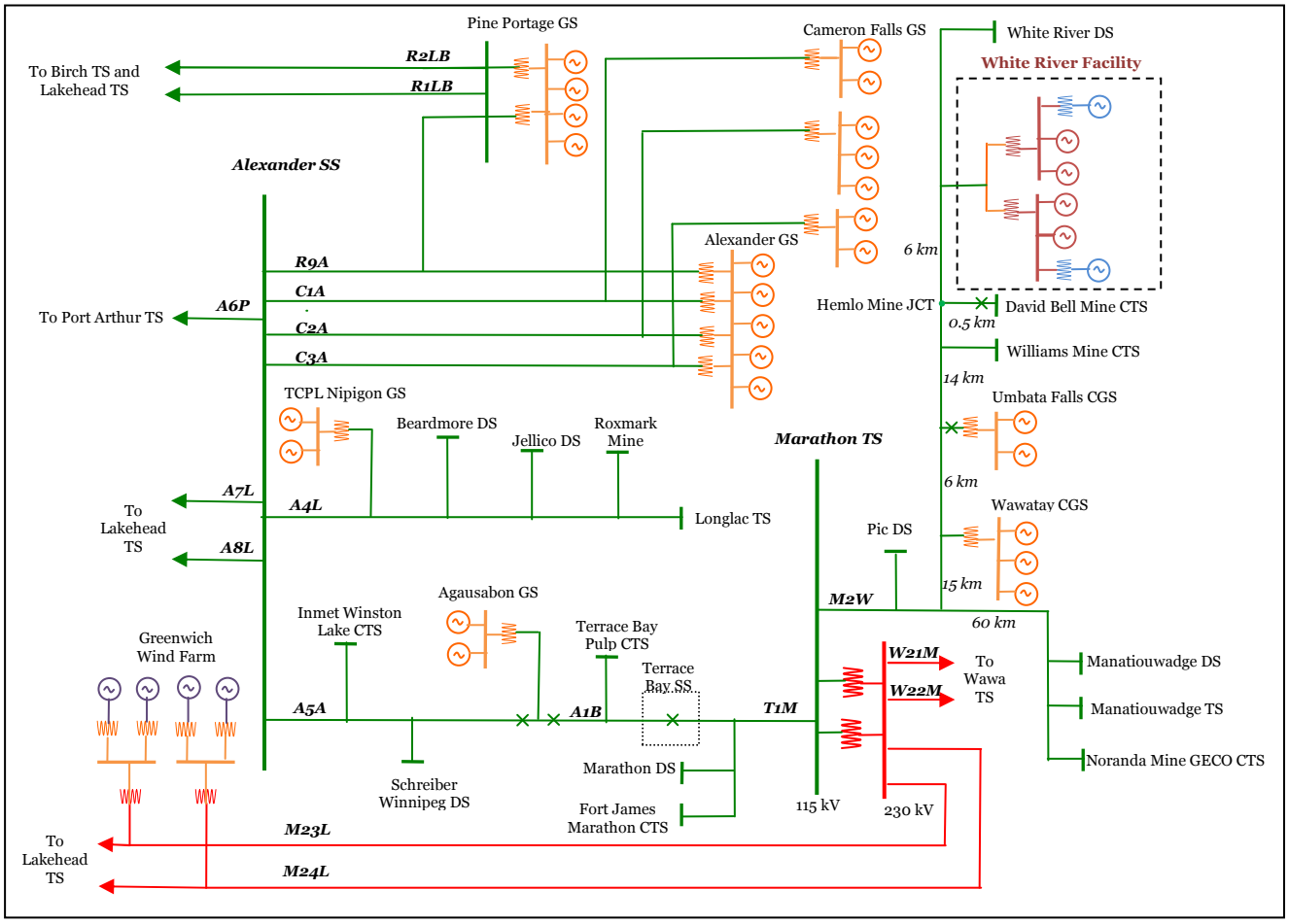


Figure 2: 230 kV and 115 kV System surrounding White River

3.2 Existing System

The White River Generation Facility has proposed to connect to the existing Hydro One 115 kV circuit M2W between Hemlo Mine JCT and White River DS. This circuit has two generation stations, Wawatay and Umbata Falls and seven load stations connected to it, including Pic DS, Manitouwadge DS, Manitouwadge TS, Noranda Mine GECO CTS, Williams Mine CTS, David Bell Mine CTS and White River DS.

Historical data consisting of hourly average samples between Jan 1 to Dec 31, 2009 were obtained from IESO real-time data for the following quantities:

- Active Power flow on M2W at Marathon (MW)
- Active Power flow on T1M at Marathon (MW)
- Active Power flow on A5A at Alexander (MW)
- Active Power flow on A6P at Alexander (MW)
- Active Power flow on A7L at Alexander (MW)
- Active Power flow on A8L at Alexander (MW)
- Voltages at Alexander SS 115 kV, Lakehead TS 115 kV, Marathon TS 115 kV
- Total Generation at Umbata Falls (MW)
- Total Generation at Pine Portage, Cameron Falls and Alexander GS (MW)
- Total Generation at TCPL Nipigon (MW)
- Total Generation at Aguasabon (MW)
- Interface flows on East West Transfer East (MW)

Graphs for these quantities are shown in **Figures 3 to 16**. Note, for active and reactive power flows, positive values represent flows out of the station.

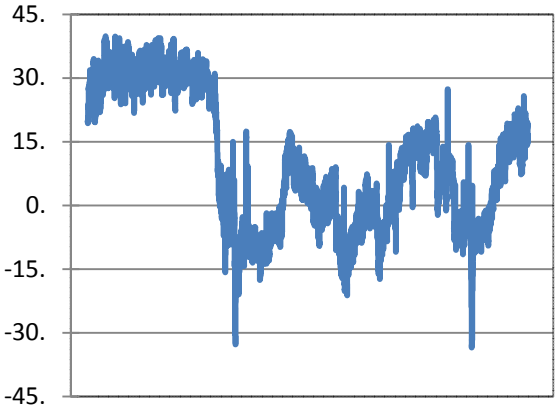


Figure 3: MW flow on M2W at Marathon

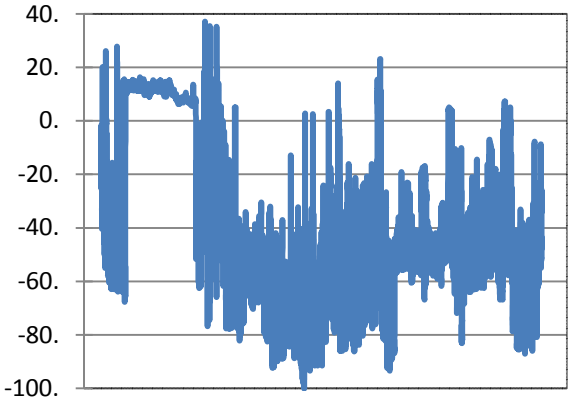


Figure 4: MW flow on T1M at Marathon

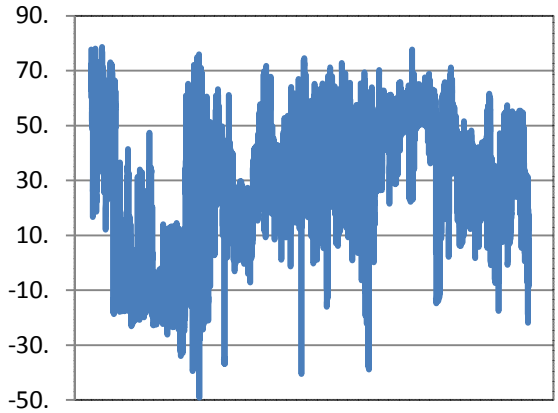


Figure 5: MW flow on A5A at Alexander

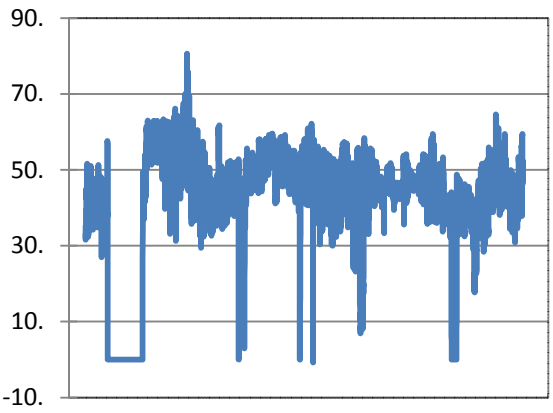


Figure 6: MW flow on A6P at Alexander

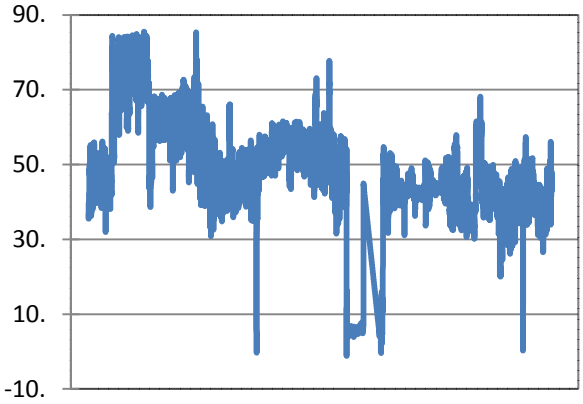


Figure 7: MW flow on A7L at Alexander

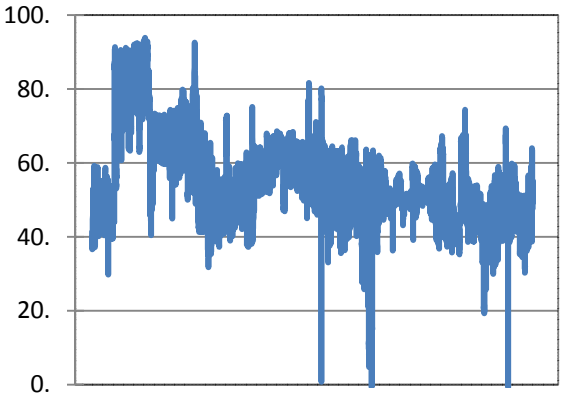


Figure 8: MW flow on A8L at Alexander

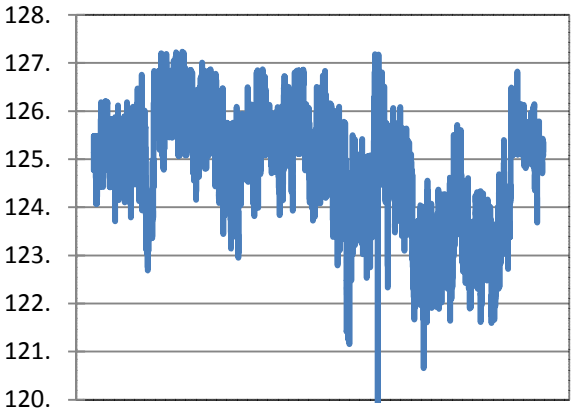


Figure 9: Voltage at Alexander SS 115 kV

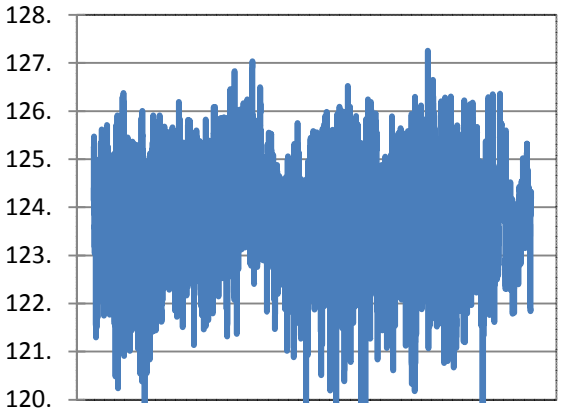


Figure 10: Voltage at Lakehead TS 115 kV

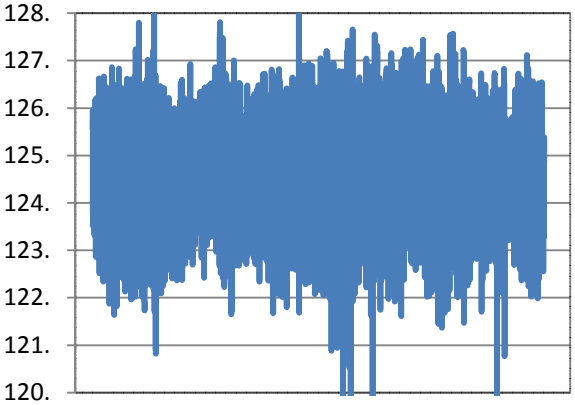


Figure 11: Voltage at Marathon TS 115 kV

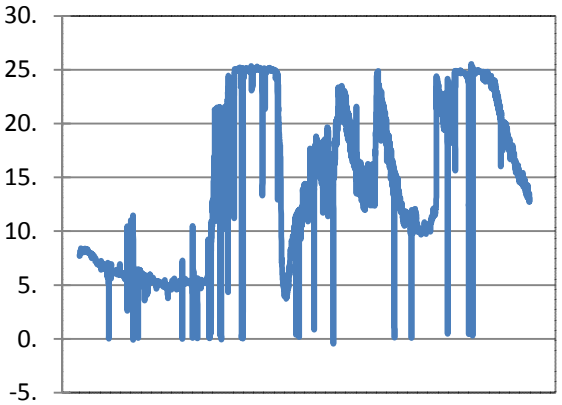


Figure 12: Total Generation at Umbata Falls (MW)

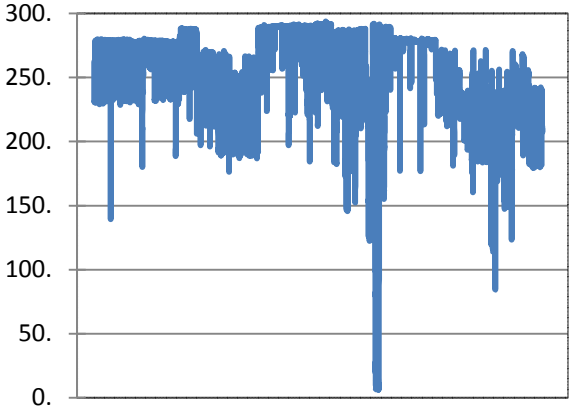


Figure 13: Total Generation at Pine Portage, Cameron Falls and Alexander GS (MW)

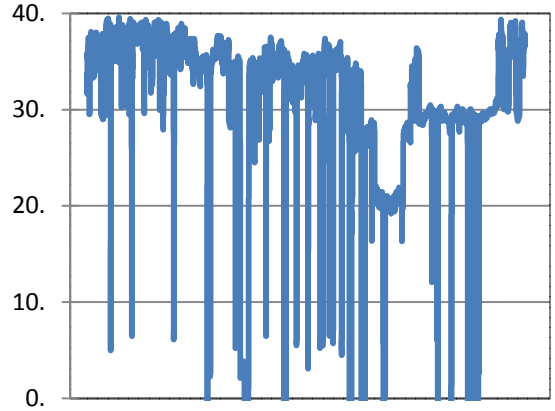


Figure 14: Total Generation at TCPL Nipigon (MW)

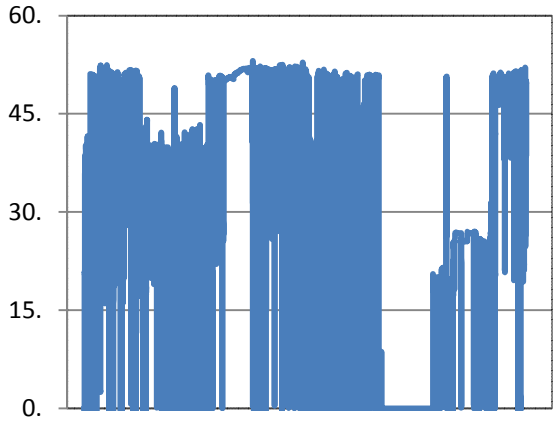


Figure 15: Total Generation at Aguasabon (MW)

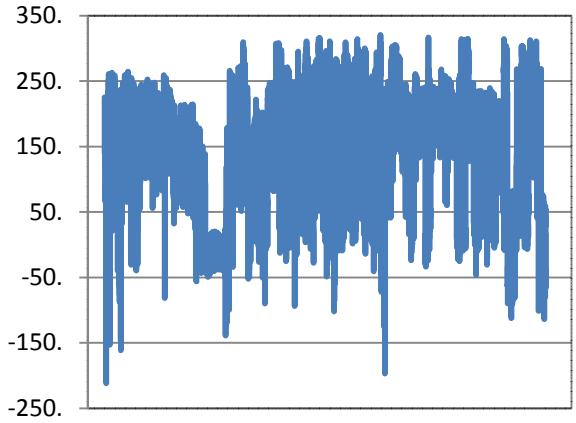


Figure 16: East West Transfer East (MW)

The following can be observed:

Station	Average voltage
Alexander SS	124.8 kV
Lakehead TS	123.7 kV
Marathon TS	124.6 kV

Quantity	Maximum	Minimum
Flow on M2W out of Marathon TS	40 MW	-30 MW
Flow on T1M out of Marathon TS	36 MW	-95 MW
Flow on A5A out of Alexander SS	77 MW	-50 MW
Flow on A6P out of Alexander SS	80 MW	20 MW
Flow on A7L out of Alexander SS	85 MW	20 MW
Flow on A8L out of Alexander SS	93 MW	20 MW
Generation at Umbata Falls	25 MW	0 MW
Generation at Pine Portage, Cameron Falls and Alexander GS	292 MW	116 MW
Generation at TCPL Nipigon	39 MW	0 MW
Generation at Aguasabon	52 MW	0 MW
East West Transfer East	318 MW	-210 MW

The above quantities were accounted for when determining the study scenarios and assumptions for the System Impact Assessment. For the list of assumptions, please refer to **Section 6.1** of this report.

– End of Section –

4. Data Verification

4.1 Generator

A generator connecting to the IESO-controlled grid must have the capability to perform the following unless specified otherwise.

- Supply continuously all levels of active power output for 5% deviations in terminal voltage. Rated active power is the smaller output at either rated ambient conditions (e.g. temperature, head, wind speed, solar radiation) or 90% of rated apparent power. To satisfy steady-state reactive power requirements, active power reductions to rated active power are permitted.

- Inject or withdraw reactive power continuously (i.e. dynamically) at a connection point up to 33% of its rated active power at all levels of active power output except where a lesser continually available capability is permitted by the IESO. A conventional synchronous unit with a power factor range of 0.9 lagging to 0.95 leading at rated active power connected via a main output transformer impedance not greater than 13% based on generator rated apparent power is acceptable.

The following table shows the required leading and lagging reactive capability for the synchronous units at Lower White River and Upper White River Falls at rated active power. A verification of the generator capability curves provided by Regional Power OPCO Inc. indicates that these units are capable of meeting the required reactive capability range.

Generator Reactive Capability Data						
Unit	MVA	Rated MW	kV	Z_{source} (Xd")	Q_{MAX} required @ rated MW & 0.9 lagging PF	Q_{MIN} required @ rated MW & 0.95 leading PF
Lower White River	5.333	4.800	4.16	0.232	2.325 Mvar (43.6%)	-1.578 Mvar (29.6%)
Upper White River	5.250	4.725	13.8	0.160	2.288 Mvar (43.6%)	-1.553 Mvar (29.6%)

The following table shows the calculation of the impedance between White River Generation Facilities terminals and point of connection to the IESO-controlled grid (ICG).

Collector System Impedance Calculation based on 115 kV							
		R (p.u.)	X (p.u.)	MVA base	R (p.u.)	X (p.u.)	MVA base
115 kV Lines	Interconnection	0.00513	0.02025	100	0.00114	0.00451	22.256
	Lower White River	0.00838	0.02835		0.00187	0.00631	
	Upper White River	0.00287	0.00972		0.00064	0.00216	
Transformers	115/4.16 kV	0.0080	0.0800	10	0.01781	0.17805	
	115/13.8 kV	0.0080	0.0800	10	0.01781	0. 17805	
Lower White– Line + 115/4.16 kV transformer	Total R & X				0.01968	0.18436	
	Impedance				***Z1***	***0.18541***	
Upper White – Line + 115/13.8 kV transformer	Total R & X				0.01845	0.18021	
	Impedance				***Z2***	***0.18155***	
Interconnection line	Total R & X				0.00114	0.00451	
	Impedance				***Z3***	***0.00465***	
Total Impedance	***Z = (Z1 // Z2) + Z3***					***0.09638***	

The impedance between the White River Generation Facilities terminals and point of connection to the IESO-controlled grid calculated on total MVA rating of the generation facilities of 22.256 MVA is 9.64%. This impedance is within the maximum impedance of 13% required to achieve the necessary reactive capability of ±33% of rated active power (± 6.6 Mvar at the point of connection).

Tests were done to verify whether the facility can achieve this reactive capability at the point of connection. Further studies were performed by changing the off-load tap setting on the Lower White River 115/4.16 kV and Upper White River 115/13.8 kV step-up transformers and varying the facility output to examine the effect on the reactive injection/withdrawal capability at the White River Generation Facility's point of connection. For these tests, the respective Lower White River and Upper White River induction unit step-up transformers were assumed to operate at the nominal tap position. A constant voltage of 124.5 kV was assumed at the 115 kV terminal of the White River Generation Facility. Results are summarized in the following table:

Examination of Connection Point Reactive Capability at Various Operating Points						
Cases	Lower and Upper 115 Transformer Tap Position	V_{term} (pu)	$Qgen_{total}$ (Mvar)	PCC Injection (Mvar)	Mvar losses	Reactive Requirement
Pgen=20 MW	121 kV	1.05	1.9	1.1	0.8 Mvar	Lagging requirement: Deficient by 5.5 Mvar
Pgen=20 MW	124 kV	1.045	8.7	7.7	1 Mvar	Lagging requirement is met
Pgen=20 MW	121 kV	1.01	-6.9	-7.9	1 Mvar	Leading requirement is met
Pgen=20 MW	124 kV	1.01	-6.9	-8.0	1 Mvar	Leading requirement is met
Pgen=0 MW	121 kV	0.96	-16.3	-16.8	0.5 Mvar	Leading requirement is met
Pgen=0 MW	124 kV	0.95	-11.7	-11.7	0.0 Mvar	Leading requirement is met

It can be observed that at the 124 kV tap position on the 115 transformers, the leading and lagging requirements are met.

4.3 Transformer

Specifications for the Lower White River 115/4.16 kV transformer and 4.16/0.6 kV transformer are listed below.

Transformation	115/4.16 kV
Rating	10 MVA ONAN
Impedance	0. 008+0.08 p.u. based on 10 MVA
Configuration	3 phase, high side: wye grounded, low side: delta
Tapping	Off-load tap changers at HV (121 ± 6 kV in 4 steps)

Transformation	4.16/0.6 kV
Rating	0.5 MVA ONAN
Impedance	0. 006+0.06 p.u. based on 0.5 MVA
Configuration	3 phase, high side: delta, low side: wye grounded

Specifications for the Upper White River 115/13.8 kV transformer and 13.8/0.6 kV transformer are listed below.

Transformation	115/13.8 kV
Rating	10 MVA ONAN
Impedance	0. 008+0.08 p.u. based on 10 MVA
Configuration	3 phase, high side: wye grounded, low side: delta
Tapping	Off-load tap changers at HV (121 ± 6 kV in 4 steps)

Transformation	13.8/0.6 kV
Rating	0.625 MVA ONAN
Impedance	0. 006+0.06 p.u. based on 0.625 MVA
Configuration	3 phase, high side: delta, low side: wye grounded

4.4 Circuit Breakers and Switches

Specifications of the isolation devices provided by the connection applicant are listed below.

Breakers and switches	**4.16 kV**	**13.8 kV**	**115 kV**
Rated line-to-line voltage	4.16 kV	13.8 kV	132 kV
Interrupting time	5 cycles	5 cycles	5 cycles
Rated continuous current	1200 A	1200 A	1200 A
Rated short circuit breaking current	25 kA	25 kA	50 kA

The interrupting time of the 115 kV breakers are 5 cycles, which satisfies the Transmission system code interrupting requirement of 5 cycles or less.

The symmetrical rated short circuit breaking current of the 115 kV breakers are 50 kA which satisfies the maximum 3 phase symmetrical fault level of 50 kA established by the Transmission System Code for the 115 kV system.

4.5 Dynamic Models

The performance of the equipment proposed for the installation and their transient behavior was evaluated using the data provided/confirmed by Regional Power OPCO Inc.; results are presented in Sections 6.5 and 6.6. The dynamic models of the generator, excitation systems, power system stabilizer and governor are given below.

1) GENERATOR

The proposed synchronous generators are modeled with the Salient Pole Generator Model (GENSAL) with the following parameters and values:

MODEL : GENSAL – *Generator Parameters*			
CON's	Value		Description
	Lower White River	Upper White River	
J	2.62	2.40	T'_{D0} (>0) (sec)
J+1	0.04	0.03	T''_{D0} (>0) (sec)
J+2	0.042	0.080	T''_{Q0} (>0) (sec)
J+3	1.59	1.87	Inertia, H
J+4	0.0	0.0	Speed damping, D
J+5	1.094	1.460	X_D
J+6	0.672	0.860	X_Q
J+7	0.335	0. 250	X'_D
J+8	0.232	0.160	$X''_D=X''_Q$
J+9	0.175	0.070	X_L
J+10	0.137	0.137	S(1.0)
J+11	0.393	0.393	S(1.2)

The proposed induction generators are modeled with the Induction Generator Model (CIMTR1) with the following parameters and values:

MODEL : CIMTR1 – *Generator Parameters*			
CON's	Value		Description
	Lower White River	Upper White River	
J	1.219	0.689	T' (sec) (>0)
J+1	0.0	0.0	T" (sec)
J+2	5.80	2.80	Inertia, H
J+3	3.127	4.058	X
J+4	0.240	0.264	X'
J+5	0.0	0.0	X"
J+6	0.090	0.113	X_1
J+7	1.0	1.0	E_1 ($\geq$0)
J+8	0.05	0.05	$S(E_1)$
J+9	1.2	1.2	E_2
J+10	0.30	0.30	$S(E_2)$
J+11	0	0	Switch

2) AUTOMATIC EXCITATION SYSTEMS

The exciters for both Lower White River and Upper White River synchronous generators are modeled with the Basler DECS rotating AC Exciter Model (ESAC8B) with the following parameters and values:

MODEL : ESAC8B – *Exciter Parameters*		
CON's	Value	Description
J	0.01	T_R (sec)
J+1	80	K_P
J+2	20	K_I
J+3	10	K_D
J+4	0.01	T_D (sec)
J+5	1.0	K_A
J+6	0.01	T_A
J+7	11	V_{RMAX}
J+8	0	V_{RMIN}
J+9	1.8	$T_E > 0$ (sec)
J+10	1.0	K_E
J+11	2.3	E_1
J+12	0.03	$S(E_1)$
J+13	3.1	E_2
J+14	0.3	$S(E_2)$

3) STABILIZER

A power system stabilizer installation is not a part of this project, as rotating exciters are being employed. No power system stabilizer model at the White River Generation Facility is assumed for the transient assessment in **Section 6.6**.

4) GOVERNOR

The governors for the synchronous generators are modeled with the Woodward P.I.D. Hydro Governor Model (WPIDHY) with the following parameters and values:

MODEL : WPIDHY - *Governor Parameters*			
CON's	Value		Description
	Lower White River	Upper White River	
J	0.25	0.25	T_{REG} (sec)
J+1	-0.04	-0.04	REG
J+2	1.38	1.63	K_P
J+3	0.277	0.325	K_I
J+4	0.46	0.54	K_D
J+5	0.15	0.15	T_A (>0) (sec)
J+6	0.15	0.15	T_B (>0) (sec)
J+7	0.2	0.2	VELMX
J+8	-0.2	-0.2	VELMN (<0)
J+9	1.0	1.0	GATMX
J+10	0.0	0.0	GATMN
J+11	1.0	1.0	T_W (>0) (sec)
J+12	1.0	1.0	P_{MAX}
J+13	0.1	0.1	P_{MIN}
J+14	0.0	0.0	D
J+15	0.0	0.0	G_0
J+16	0.4	0.4	G_1
J+17	0.36	0.36	P_1
J+18	0.6	0.6	G_2
J+19	0.55	0.55	P_2
J+20	1.0	1.0	P_3

– End of Section –

5. Fault Level Assessment

Fault level studies were completed by Hydro One to examine the effects of the White River Generation Facility on fault levels at existing facilities in the area. Studies were performed to analyze the fault levels with and without the White River Generation Facility and other committed generation in the surrounding area. The short circuit study was carried out with the following facilities and system assumptions:

Niagara, South West, West Zones

- All hydraulic generation
- 6 Nanticoke
- 2 Lambton
- Brighton Beach (J20B/J1B)
- Greenfield Energy Centre (Lambton SS)
- St. Clair Energy Centre (L25N & L27N)
- East Windsor Cogen (E8F & E9F) + existing Ford generation
- TransAlta Sarnia (N6S/N7S)
- Imperial Oil (N6S/N7S)
- Thorold GS (Q10P)

Central, East Zones

- All hydraulic generation
- **6 Pickering units**
- **4 Darlington units**
- **4 Lennox units**
- GTAA (44 kV buses at Bramalea TS and Woodbridge TS)
- Sithe Goreway GS (V41H/V42H)
- Portlands GS (Hearn SS)
- Kingston Cogen
- TransAlta Douglas (44 kV buses at Bramalea TS)

Northwest, Northeast Zones

- All hydraulic generation
- 1 Atikokan
- 2 Thunder Bay
- NP Iroquois Falls
- AP Iroquois Falls
- Kirkland Lake
- 1 West Coast (G2)
- Lake Superior Power
- Terrace Bay Pulp STG1 (embedded in Neenah paper)

Bruce Zone

- 8 Bruce units (Bruce G1 and Bruce G2 maximum capacity @ 835 MW)
- 4 Bruce B Standby Generators

All constructed wind farms including

- Erie Shores WGS (WT1T)
- Kingsbridge WGS (embedded in Goderich TS)
- Amaranth WGS – Amaranth I (B4V) & Amaranth II (B5V)
- Ripley WGS (B22D/B23D)
- Prince I & II WGS (K24G)
- Underwood (B4V/B5V)
- Kruger Port Alma (C24Z)
- Wolf Island (injecting into X4H)

New Generation Facilities:
Committed generation

- Greenwich Wind Farm (M23L and M24L)
- Gosfield Wind Project (K2Z)
- Kruger Energy Chatham Wind Project (C24Z)
- Raleigh Wind Energy Centre (C23Z)
- Talbot Wind Farm (W45LC)
- Greenfield South GS (R24C)
- Halton Hills GS (T38B/T39B)
- Oakville Generating Station (B15C/B16C)
- York Energy Centre (B82V/B83V)
- Island Falls (H9K)
- Becker Cogeneration (M2W)
- Wawatay G4 (M2W)
- Beck 1 G9: increase capacity to 68.5 MVA (Beck #1 115 kV bus)
- Lower Mattagami Expansion
- All renewable generation projects awarded FIT contracts were included

Transmission System Configuration

Existing system with the following upgrades:

- Bruce x Orangeville 230 kV circuits up-rated
- Burlington TS: Rebuild 115 kV switchyards
- Leaside TS to Birch JCT: Build new 115 kV circuit. Birch to Bayfield: Replace 115 kV cables.
- Uprate circuits D9HS, D10S and Q11S
- Hurontario SS in service with R19T+V41H open from R21T+V42H (230 kV circuits V41H and V42H extended and connected from Cardiff TS to Hurontario SS). Hurontario SS to Jim Yarrow 2x3km 230 kV circuits in-service
- Cherrywood TS to Claireville TS: Unbundle the two 500 kV super-circuits (C551VP & C550VP)
- Allanburg x Middleport 230 kV circuits (Q35M and Q26M) installed
- Claireville TS: Reterminate circuit 230 kV V1RP to Parkway V71P. Reterminate circuit 230 kV V72R to Cardiff(V41H)
- One 250 Mvar (@ 250 kV) shunt capacitor bank installed at Buchanan TS

- LV shunt capacitor banks installed at Meadowvale
- 1250 MW HVDC line ON-HQ in service
- Modeling of Michigan system with short circuit equivalent provided by International Transmission Company (ITC).
- Tilbury West DS second connection point for DESN arrangement using K2Z and K6Z
- Second 500kV Bruce-Milton double-circuit line in service. Double-circuit line from the Bruce Complex to Milton TS with one circuit originating from Bruce A and the other from Bruce B
- Windsor area transmission reinforcement:
    - 230 kV transmission line from Sandwich JCT (C21J/C22J) to Lauzon TS
    - New 230/27.6 DESN, Leamington TS, that will connect C21J and C22J and supply part of the existing Kingsville TS load
    - Replace Keith 230/115 kV T11 and T12 transformers
    - 115 kV circuits J3E and J4E upgrades
- Woodstock Area transmission reinforcement:
        - Karn TS in service and connected to M31W & M32W at Ingersol TS
        - W7W/W12W terminated at LFarge CTS
        - Woodstock TS connected to Karn TS
- Nanticoke and Detweiler SVCs
- Series capacitors at Nobel SS in each of the 500 kV circuits X503 & X504E to provide 50% compensation for the line reactance
- Lakehead TS SVC
- Porcupine TS & Kirkland Lake TS SVC
- Porcupine TS: Install 2x125 Mvar shunt capacitors
- Essa TS : Install 250 Mvar shunt capacitor
- Hanmer TS: Install 149 Mvar shunt capacitor
- Pinard TS: Install 2x30 Mvar LV shunt capacitors
- Upper Mattagami expansion
- Fort Frances TS: Install 22 Mvar moveable shunt capacitor
- Dryden TS: Install shunt capacitors
- Lower Mattagami Expansion – H22D line extension from Harmon to Kipling.

System Assumptions

- Lambton TS 230 kV operated **open**
- Claireville TS 230 kV operated **open**
- Leaside TS 230 kV operated **open**
- Leaside TS 115 kV operated **open**
- Middleport TS 230 kV bus operated **open**
- Hearn SS 115 kV bus operated **open –** as required in the Portlands SIA
- Napanee TS 230 kV operated **open**
- Cherrywood TS north & south 230kV buses operated **open**
- Cooksville TS 230 kV bus operated **open**
- Richview TS 230 kV bus operated **open**
- All capacitors in service
- All tie-lines in service and phase shifters on neutral taps
- Maximum voltages on the buses

The following table summarizes the symmetric and asymmetrical fault levels near the White River Generation Facility against the corresponding breaker ratings.

Bus	New generation O/S				New generation I/S				Breaker Ratings	
	Total Fault Current Symmetrical (kA)		Total Fault Current Asymmetrical (kA)		Total Fault Current Symmetrical (kA)		Total Fault Current Asymmetrical (kA)		Symmetrical (kA)	Asymmetrical (kA)
	3-ph fault	L-G	3-ph fault	L-G	3-ph fault	L-G	3-ph fault	L-G		
Alexander 115 kV	8.944	9.018	9.888	10.231	9.049	9.089	9.988	10.298	10.50	11.40
Pine Portage 115 kV	7.094	7.434	7.961	8.700	7.130	7.461	7.995	8.726	10.50	11.40
Lakehead 115 kV	17.982	20.401	20.043	23.989	18.153	20.547	20.209	24.132	29.50	34.10
Port Arthur 115 kV	13.632	13.120	14.470	13.949	13.732	13.185	14.566	14.010	14.20	15.90
Aguasabon 115 kV	4.518	3.933	5.195	4.874	4.553	3.951	5.228	4.893	40.00	47.90
Terrace Bay 115 kV	4.668	3.684	5.534	4.290	4.708	3.701	5.573	4.306	14.60	14.70
Marathon 115 kV	6.454	7.746	6.878	8.461	6.759	8.07	7.184	8.786	39.62	45.44
Umbata Falls 115 kV	3.221	2.988	3.229	3.061	3.336	3.071	3.343	3.145	40.00	40.20
White River GS 115 kV	N/A	N/A	N/A	N/A	2.807	2.565	2.871	2.641	50.00	Not provided
Lakehead 230 kV	8.180	8.203	9.861	10.664	8.244	8.246	9.926	10.712	39.70	46.20
Marathon 230 kV	5.129	5.022	5.661	5.733	5.260	5.123	5.800	5.841	39.70	46.20

The results show that fault levels in the area surrounding the White River Generation Facility are within the symmetrical and asymmetrical breaker ratings. Fault levels increase when all the proposed generators are in service with the highest increase at Marathon of 0.325 kA (Asymmetrical current for L-G fault).

Note the breakers at Port Arthur are at 97% of their symmetrical breaker rating capability with all the proposed generation in service.

Therefore, it can be concluded that increases in fault levels, due to the White River Generation Facility will not exceed the interrupting capabilities of the existing breakers on the IESO-controlled grid.

– End of Section –

6. System Impact Studies

This connection assessment was carried out to identify the effect of the proposed facility on thermal loading of transmission interfaces in the vicinity, the system voltages for pre/post contingencies, the ability of the facility to control voltage and the transient performance of the system.

6.1 Assumptions and Background

Various summer and winter peak load conditions within the 115 kV pocket bounded by Lakehead TS and Marathon TS were studied for this assessment with Transfer East and Transfer West flow conditions. For winter load conditions, winter 2013 peak loads along A5A, A1B, T1M and M2W were used for the study. For summer load conditions, summer 2013 peak loads along A5A, A1B and T1M were used and minimum load values along M2W were used for the study. The following describes the study scenarios, system conditions and modeling assumptions.

Study Scenarios

A total of eight scenarios were studied for this assessment:

S1 – High Transfer East flows under summer peak load conditions (2010 existing system)
S2 – High Transfer East flows under summer peak load conditions + White River generation I/S
S3 – High Transfer East flows under summer peak load conditions + White River generation I/S + committed generation on M2W (20 MW) [1] + committed generation on A4L (10 MW) [2]+ embedded generation at Fort William and Red Rock DS I/S
S4 – High Transfer West flows under summer peak load conditions (2010 existing system)
S5 – High Transfer West flows under summer peak load conditions + White River generation I/S
S6 – High Transfer West flows under summer peak load conditions + White River generation I/S + Becker cogeneration on M2W
S7 – High Transfer West flows under summer peak load conditions + White River generation I/S + committed generation on M2W (20 MW) [1]+ committed generation on A4L (10 MW) [2]
S8 – High Transfer West flows under winter peak load conditions + White River generation I/S + committed generation on A4L (10 MW) [2]

Note: (1) Becker Cogeneration (CAA ID 2009-367)
(2) Namewaminikan Hydro project (CAA ID 2010-393)

The following table summarizes the various flows, loads and interface values for each of the scenarios.

Summary of Scenarios Studied for Assessment								
Scenarios	S1	S2	S3	S4	S5	S6	S7	S8
Interface Flows								
OMTE - Ontario Manitoba Transfer East	293 MW	294 MW	293 MW	-295 MW	-295 MW	-295 MW	-295 MW	-295 MW
MPFN - Minnesota Power Flow North	25 MW	25 MW	25 MW	-50 MW	-50 MW	-50 MW	-50 MW	-50 MW
EWTE - East West Transfer East	329 MW	332 MW	333 MW	-353 MW	-349 MW	-350 MW	-350 MW	-350MW
Line Flows								
M2W at Marathon TS	-19 MW	-38 MW	-56 MW	-19 MW	-38 MW	-56 MW	-56 MW	22 MW
T1M at Marathon TS	-73 MW	-71 MW	-69 MW	15 MW	18 MW	22 MW	21 MW	14 MW
A5A at Alexander SS	60 MW	56 MW	54 MW	-35 MW	-38 MW	-42 MW	-41 MW	-22 MW
A6P at Alexander SS	51 MW	52 MW	53 MW	61 MW	61 MW	62 MW	64 MW	62 MW
A7L at Alexander SS	51 MW	52 MW	55 MW	62 MW	63 MW	63 MW	65 MW	59 MW
A8L at Alexander SS	58 MW	59 MW	62 MW	70 MW	71 MW	72 MW	74 MW	67 MW
A6P + A7L + A8L at Alexander SS *	160 MW	163 MW	170 MW	193 MW	195 MW	197 MW	203 MW	188 MW
Marathon and Alexander Area Generation								
White River GS	0 MW	20 MW	20 MW	0 MW	20 MW	20 MW	20 MW	20 MW
	0 MX	-3.5 MX	-3.3 MX	0 MX	-3.1 MX	-2.5 MX	-2.5 MX	8.7 MX
Umbata Falls CGS	23 MW	23 MW	23 MW	23 MW	23 MW	23 MW	23 MW	12 MW
Wawatay CGS	13 MW	13 MW	13 MW	13 MW	13 MW	13 MW	13 MW	13 MW
Aguasabon GS	40 MW	40 MW	40 MW	40 MW	40 MW	40 MW	40 MW	40 MW
TCPL Nipigon GS	40 MW	40 MW	40 MW	40 MW	40 MW	40 MW	40 MW	0 MW
Alexander GS	68 MW	68 MW	68 MW	68 MW	68 MW	68 MW	68 MW	68 MW
Cameron Falls GS	92 MW	92 MW	92 MW	92 MW	92 MW	92 MW	92 MW	92 MW
Pine Portage GS	129 MW	129 MW	129 MW	64 MW	64 MW	64 MW	64 MW	129 MW
Greenwich Lake Wind Farm	100 MW	100 MW	100 MW	0 MW	0 MW	0 MW	0 MW	0 MW
Marathon Area Load								
Inmet Winston Lake CTS	0.1 MW	0.1 MW	0.1 MW	0.1 MW	0.1 MW	0.1 MW	0.1 MW	0.1 MW
Schreiber Winnipeg DS #2	1.6 MW	1.6 MW	1.6 MW	1.6 MW	1.6 MW	1.6 MW	1.6 MW	4.7 MW
Terrace Bay Pulp CTS	0.9 MW	0.9 MW	0.9 MW	0.9 MW	0.9 MW	0.9 MW	0.9 MW	8.6 MW
Marathon DS	3.3 MW	3.3 MW	3.3 MW	3.3 MW	3.3 MW	3.3 MW	3.3 MW	8.5 MW
Fort James Marathon CTS	9.8 MW	9.8 MW	9.8 MW	9.8 MW	9.8 MW	9.8 MW	9.8 MW	6.5 MW
Pic DS	0.8 MW	0.8 MW	0.8 MW	0.8 MW	0.8 MW	0.8 MW	0.8 MW	5.7 MW
Manitouwadge DS	0.2 MW	0.2 MW	0.2 MW	0.2 MW	0.2 MW	0.2 MW	0.2 MW	1.5 MW
Manitouwadge TS	1.9 MW	1.9 MW	1.9 MW	1.9 MW	1.9 MW	1.9 MW	1.9 MW	12.8 MW
Geco CTS	0.1 MW	0.1 MW	0.1 MW	0.1 MW	0.1 MW	0.1 MW	0.1 MW	0.3 MW
Williams Mine CTS	11.4 MW	11.4 MW	11.4 MW	11.4 MW	11.4 MW	11.4 MW	11.4 MW	29.4 MW
David Bell Mine CTS	1.2 MW	1.2 MW	1.2 MW	1.2 MW	1.2 MW	1.2 MW	1.2 MW	5.3 MW
White River DS	1.3 MW	1.3 MW	1.3 MW	1.3 MW	1.3 MW	1.3 MW	1.3 MW	8.2 MW

* Note that A6P + A7L + A8L values are consistent with historical values coincident with high EWTE and high EWTW flows

System Conditions

All transmission system elements were in service.

Load stations in the Marathon area were set to operate at 0.9 power factor.

The demand in the Northwest was scaled to the 2013 extreme weather summer coincident peak load of 630 MW (Forecasted normal weather coincident peak is 588 MW).

Modeling Assumptions

For both load flow and transient studies, the IESO 2010 summer base case was used as a starting point. The Northwest demand was first scaled to the 2013 extreme weather coincident peak. Transfers east and west were created by scheduling generation between Manitoba, Minnesota and Ontario. Afterwards, the 115 kV pocket bounded by Lakehead TS and Marathon TS were scaled to either summer or winter peak values to produce **Scenarios S1 to S8**. The following other changes were implemented into the base case in the Northwest:

- Addition of Fort Frances Capacitor (CAA 2005-195)
- Addition of Dryden Capacitor (CAA 2008-352)
- Longlac Refurbishment (CAA 2007-EX360)
- Greenwich Wind Farm (CAA 2008-337)
- Cameron Falls G7 Excitation System Replacement (CAA 2010-EX471)
- Alexander G5 Excitation System & Runner Replacement (CAA 2010-EX482)
- Kenora Power/Angle Relay Deregistration (CAA 2009-EX448)
- A6P Refurbishment Project (CAA 2010-EX490)
- Loads were represented by constant MVA loads for thermal and voltage analysis and as voltage dependent loads with P being modeled as 50% constant current and 50% constant impedance ($P \alpha V^{1.5}$) and Q being modeled as 100% constant impedance ($Q \alpha V^2$) for transient analysis.
- The Ontario-Manitoba and Ontario-Minnesota phase shifters were operated as per Northwest SCO: On manual (blocked), if the change in the interface flows is equal or less than 26 MW and 10 MW respectively. For the changes greater than described above, the phase shifters at Whiteshell (Manitoba) are controlling the flow within the $\pm$26 MW of scheduled interchange flow or until 4 operations have been called for. At International Falls, phase shifters move until the error is less than 10 MW.
- Thunder Bay G2 and G3 units were assumed out of service
- Atikokan G1 was assumed in-service.

6.2 Protection Impact Assessment

A Protection Impact Assessment (PIA) was completed by Hydro One to examine the impact of the new generators on existing transmission system protections. The existing protections for M2W at Marathon TS were described in the PIA report and the proposed protection settings were analyzed based on preliminary fault calculation. Finally, the proposed protection solutions and recommendations were presented. A copy of the Protection Impact Assessment summary can be found in **Appendix C** of this report.

The existing protection scheme at Marathon TS will have to be modified and hardware addition is required to incorporate blocking, generator end open and breaker failure signals from the White River Generation Facility switching station.

New telecommunication link(s) will need to be established to transmit signals among all stations on M2W that are required for reliable fault clearing. The provision of new telecommunication facilities required to incorporate the connection of the White River Generation Facility is the responsibility of the applicant.

The existing Zone 1 reach setting at Marathon TS will remain unchanged. The existing Zone 2 reach setting will need to be extended to cover the new maximum apparent impedance due to the connection of the White River Generation Facility.

The IESO concluded that the proposed protection adjustments will have no material adverse impact on the IESO-controlled grid.

6.3 Thermal Analysis

The assessment examined the effect the proposed facility would have on the thermal loadings of the 115 kV and 230 kV transmission area elements within its vicinity.

The *Ontario Resource and Transmission Assessment Criteria* requires that all line and equipment loads be within their continuous ratings with all elements in service, and within their long-term emergency ratings with any element out of service. Lines and equipment may be loaded up to their short-term emergency ratings immediately following the contingencies to effect re-dispatch, perform switching, or implement control actions to reduce the loading to the long-term emergency ratings.

Hydro One provided the Continuous, Long Term Emergency and Short Term Emergency planning thermal ratings for various circuits under summer weather conditions. The algorithm for deriving these ratings is as follows:

- *Ambient conditions*: 30ºC temperature , 4 km/hr wind speed, daytime
- *Continuous*: Rating obtained at the lesser of conductor temperature of 93 ºC or sag temperature
- *Long Term Emergency*: Rating obtained at the lesser conductor temperature of 127ºC or sag temperature
- *Short Term Emergency*: Rating obtained at the sag temperature with a pre-contingency loading of 100% of the continuous rating.

Note: the A6P line section from Reserve junction to Port Arthur TS was obtained from the System Impact Assessment performed for the A6P Refurbishment Project (CAA 2010-EX490).

Planning Ratings for transformers were obtained from the Hydro One secure website.

Planning Ratings provided by Hydro One were compared against Operational Ratings. In cases where the operational rating of an element was found to be more limiting than its planning rating, the operational rating was used instead for the thermal analysis.

The following table summarizes the ratings for various circuits and transformers monitored for the thermal analysis. Unless indicated, the values provided are assumed to be planning ratings.

Element	Monitored Element		Rating		
	From	To	Continuous	Long Term Emergency	Short Term Emergency
Lakehead T7	LAKEHEAD_TS 220	LAKEHEAD_TS 118	250 MVA	286 MVA	383.2 MVA
Lakehead T8	LAKEHEAD_TS 220	LAKEHEAD_TS 118	250 MVA	286 MVA	383.2 MVA
Marathon T11	MARATHON_TS 220	MARATHON_TS 118	125 MVA	197.3 MVA	240.3 MVA
Marathon T12	MARATHON_TS 220	MARATHON_TS 118	125 MVA	197.3 MVA	240.3 MVA
A21L	MACKENZIE_TS220	LAKEHEAD_TS 220	861 A *	880 A	880 A
A22L	MACKENZIE_TS220	LAKEHEAD_TS 220	861 A *	880 A	880 A
M23L	LAKEHEAD_TS 220	GREENWICH1 220	880 A	890 A	900 A
	GREENWICH1 220	MARATHON_TS 220	880 A	890 A	900 A
M24L	LAKEHEAD_TS 220	GREENWICH2 220	880 A	890 A	900 A
	GREENWICH2 220	MARATHON_TS 220	880 A	890 A	900 A
W21M	MARATHON_TS 220	WAWA_TS 220	861 A *	880 A	880 A
W22M	MARATHON_TS 220	WAWA_TS 220	880 A	1020 A	1080 A
P3B	PT_ARTH_#1A2118	BIRCH_TS 118	620 A	740 A	780 A
P7B	PT_ARTH_#1A1118	BIRCH_TS 118	620 A	790 A	870 A
L3P	LAKEHEAD_TS 118	PT_ARTH_#1A2118	720 A	920 A	1130 A
L4P	LAKEHEAD_TS 118	PT_ARTH_#1A1118	620 A	790 A	960 A
R1LB	LAKEHEAD_JR1118	BIRCH_TS 118	620 A	790 A	870 A
	PINE_PORTAGE118	LAKEHEAD_JR1118	301 A *	324 A *	324 A *
R2LB	LAKEHEAD_JR2118	BIRCH_TS 118	620 A	790 A	890 A
	PINE_PORTAGE118	LAKEHEAD_JR2118	375 A *	420 A	420 A
A6P	ALEXANDER_SS118	RESERVE_JA6P118	490 A	490 A	490 A
	RESERVE_JA6P118	PT_ARTH_#1A1118	550 A	700 A	750 A
A7L	ALEXANDER_SS118	RESERVE_JA7L118	310 A	310 A	310 A
	RESERVE_JA7L118	LAKEHEAD_TS 118	308 A *	340 A	340 A
A8L	ALEXANDER_SS118	LAKEHEAD_TS 118	430 A	430 A	430 A
A5A	ALEXANDER_SS118	MINNOVA_J 118	430 A	430 A	430 A
	SCHREIBER_J 118	AGUASABON_SS118	430 A	430 A	430 A
A1B	AGUASABON_SS118	TER_BAY_PU_J118	570 A	570 A	570 A
	TER_BAY_PU_J118	TERRACE_BAY 118	620 A	790 A	960 A
T1M	PIC_J_T1M 118	MARATHON_TS 118	620 A	790 A	960 A
	TERRACE_BAY 118	PIC_J_T1M 118	460 A	460 A	460 A
M2W	MARATHON_TS 118	MARATHON_J1 118	620 A	790 A	840 A
	MARATHON_J1 118	MARTHON_J2 118	620 A	790 A	840 A
	MARTHON_J2 118	MANITOUWDG_J118	349 A *	350 A	350 A
	MANITOUWDG_J118	MANITOUWADGE118	199 A *	230 A	230 A
	MARTHON_J2 118	BLACK_R_JM2W118	370 A	470 A	500 A
	BLACK_R_JM2W118	UMBATA_FLS_J118	370 A	470 A	500 A
	HEMLO_MINE_J118	WHITE_RVRTAP118	330 A	330 A	330 A

Note: (*) Operational Rating

The following table summarizes the pre-contingency loading as a percentage of the continuous rating for **Scenarios S1 to S7**. The pre-contingency active and reactive power output level at the White River Generation Facility can be found in the "Assumptions and Background" section of this report (**Section 6.1**)

Element	Monitored Element		% of Continuous Rating						
	From	To	Flow East			Flow West			
			S1	S2	S3	S4	S5	S6	S7
Lakehead T7	LAKEHEAD_TS 220	LAKEHEAD_TS 118	17.4	18.3	22.0	9.2	9.2	10.5	10.9
Lakehead T8	LAKEHEAD_TS 220	LAKEHEAD_TS 118	17.9	18.7	22.4	9.6	9.5	10.8	11.2
Marathon T11	MARATHON_TS 220	MARATHON_TS 118	37.7	43.2	49.8	8.7	9.9	14.6	14.9
Marathon T12	MARATHON_TS 220	MARATHON_TS 118	37.6	43.2	49.7	11.7	11.8	15.4	15.8
A21L	MACKENZIE_TS220	LAKEHEAD_TS 220	20.8	18.7	13.6	43.0	42.9	43.0	43.2
A22L	MACKENZIE_TS220	LAKEHEAD_TS 220	20.8	18.7	13.6	43.0	42.9	42.9	43.2
M23L	LAKEHEAD_TS 220	GREENWICH1 220	25.1	23.3	21.5	44.9	46.9	48.8	48.9
	GREENWICH1 220	MARATHON_TS 220	36.7	34.8	32.9	46.6	48.8	50.8	50.9
M24L	LAKEHEAD_TS 220	GREENWICH2 220	24.0	22.2	20.3	44.9	46.8	48.7	48.8
	GREENWICH2 220	MARATHON_TS 220	36.9	35.0	33.1	46.7	48.8	50.8	51.0
W21M	MARATHON_TS 220	WAWA_TS 220	46.9	47.3	47.7	48.9	48.9	48.8	48.8
W22M	MARATHON_TS 220	WAWA_TS 220	45.9	46.3	46.7	47.9	47.9	47.8	47.8
P3B	PT_ARTH_#1A2118	BIRCH_TS 118	47.8	48.2	46.0	61.2	59.0	56.7	55.6
P7B	PT_ARTH_#1A1118	BIRCH_TS 118	43.4	43.8	42.3	58.2	58.9	59.5	60.1
L3P	LAKEHEAD_TS 118	PT_ARTH_#1A2118	25.5	25.7	23.3	41.5	48.3	55.1	58.5
L4P	LAKEHEAD_TS 118	PT_ARTH_#1A1118	50.5	50.5	49.3	62.8	63.6	64.3	64.6
R1LB	LAKEHEAD_JR1118	BIRCH_TS 118	40.9	41.2	38.9	55.1	55.7	56.3	56.6
	PINE_PORTAGE118	LAKEHEAD_JR1118	72.5	73.2	75.7	70.8	71.7	72.5	74.3
R2LB	LAKEHEAD_JR2118	BIRCH_TS 118	39.1	39.4	37.2	52.7	53.3	53.9	54.2
	PINE_PORTAGE118	LAKEHEAD_JR2118	66.3	66.9	69.3	64.8	65.5	66.3	67.9
A6P	ALEXANDER_SS118	RESERVE_JA6P118	49.1	49.7	51.2	58.7	59.4	60.1	61.7
	RESERVE_JA6P118	PT_ARTH_#1A1118	40.7	41.3	43.3	49.3	49.9	50.6	52.0
A7L	ALEXANDER_SS118	RESERVE_JA7L118	79.2	80.3	84.5	95.6	97.0	98.3	**101.3**
	RESERVE_JA7L118	LAKEHEAD_TS 118	79.3	80.5	84.7	95.9	97.2	98.5	**101.5**
A8L	ALEXANDER_SS118	LAKEHEAD_TS 118	63.2	64.1	67.4	76.4	77.5	78.5	80.9
A5A	ALEXANDER_SS118	MINNOVA_J 118	64.6	61.1	59.4	41.0	45.4	49.5	48.3
	SCHREIBER_J 118	AGUASABON_SS118	61.9	58.3	56.6	43.1	47.5	51.6	50.4
A1B	AGUASABON_SS118	TER_BAY_PU_J118	78.4	75.7	74.4	0.7	3.7	7.1	6.2
	TER_BAY_PU_J118	TERRACE_BAY 118	71.5	69.0	67.8	1.7	3.8	6.8	6.0
T1M	PIC_J_T1M 118	MARATHON_TS 118	64.3	61.7	60.4	11.7	13.8	16.4	15.7
	TERRACE_BAY 118	PIC_J_T1M 118	96.4	93.1	91.4	1.8	6.5	10.6	9.6
M2W	MARATHON_TS 118	MARATHON_J1 118	14.4	29.1	43.2	14.5	29.1	43.1	43.1
	MARATHON_J1 118	MARTHON_J2 118	15.0	29.6	43.7	15.0	29.6	43.6	43.6
	MARTHON_J2 118	MANITOUWDG_J118	4.6	4.5	22.6	4.5	4.5	22.7	22.7
	MANITOUWDG_J118	MANITOUWADGE118	5.5	5.5	40.0	5.6	5.6	40.2	40.3
	MARTHON_J2 118	BLACK_R_JM2W118	28.8	53.6	53.5	28.9	53.5	53.2	53.1
	BLACK_R_JM2W118	UMBATA_FLS_J118	11.8	36.9	36.8	15.9	39.9	39.4	39.3
	HEMLO_MINE_J118	WHITE_RVRTAP118	3.4	25.8	25.8	3.3	25.8	25.7	25.6

No pre-contingency overloads were identified under high transfer east conditions. With high East West Transfer West (EWTW) flows, it was found that under existing conditions the pre-contingency loading on A7L is 95.9% (**Scenario S4**). With the addition of the White River Generation Facility, the pre-contingency loading on A7L is 97.2% (**Scenario S5**), and with the further addition of 20 MW of committed generation on M2W and 10 MW of committed generation on A4L, the pre-contingency loading on A7L was found to be 101.5% (**Scenario S7**). Therefore, the addition of generation at White River and additional generation on M2W and A4L may result in pre-contingency congestion on A7L.

As such, under summer conditions some re-dispatch of generation may be required such that the new generation is constrained and generation west of Lakehead is increased in order to avoid pre-contingency overloads on A7L with high EWTW flows.

The following table summarizes the post-contingency loading as a percentage of the Long Term Emergency rating for **Scenarios S1**, **S2** and **S3** (High Transfers East).

Element	Monitored Element		% of Long Term Emergency Rating											
			Scenario S1				Scenario S2				Scenario S3			
	From	To	M24L	R2LB	A8L	Loss of Umbata	M24L	R2LB	A8L	Loss of Umbata	M24L	R2LB	A8L	Loss of Umbata
Lakehead T7	LAKEHEAD_TS 220	LAKEHEAD_TS 118	8.5	14.8	14.7	14.9	9.7	15.7	15.5	16.0	12.8	18.4	18.1	19.1
Lakehead T8	LAKEHEAD_TS 220	LAKEHEAD_TS 118	9.0	15.3	15.1	15.3	10.1	16.1	16.0	16.4	13.3	18.8	18.6	19.4
Marathon T11	MARATHON_TS 220	MARATHON_TS 118	27.2	24.7	25.2	18.7	30.8	28.3	28.8	22.2	34.8	32.5	33.1	26.3
Marathon T12	MARATHON_TS 220	MARATHON_TS 118	27.2	24.7	25.2	18.7	30.8	28.3	28.8	22.2	34.8	32.5	33.1	26.3
A21L	MACKENZIE_TS220	LAKEHEAD_TS 220	20.3	20.6	20.8	21.4	18.2	18.4	18.5	19.2	13.6	13.6	13.8	14.4
A22L	MACKENZIE_TS220	LAKEHEAD_TS 220	20.3	20.6	20.8	21.4	18.2	18.4	18.5	19.2	13.6	13.6	13.8	14.4
M23L	LAKEHEAD_TS 220	GREENWICH1 220	41.0	24.0	23.7	25.7	37.9	22.1	21.9	23.9	35.1	20.5	20.2	22.2
	GREENWICH1 220	MARATHON_TS 220	53.2	35.4	35.1	37.2	50.0	33.4	33.1	35.2	47.1	31.6	31.3	33.4
M24L	LAKEHEAD_TS 220	GREENWICH2 220	0.0	22.9	22.6	24.6	0.0	21.0	20.7	22.7	0.0	19.2	18.9	21.0
	GREENWICH2 220	MARATHON_TS 220	0.0	35.6	35.3	37.4	0.0	33.6	33.3	35.4	0.0	31.8	31.5	33.7
W21M	MARATHON_TS 220	WAWA_TS 220	39.3	45.6	45.6	43.8	39.7	45.8	45.9	44.1	40.5	46.4	46.4	44.6
W22M	MARATHON_TS 220	WAWA_TS 220	33.9	39.3	39.4	37.8	34.3	39.5	39.6	38.0	34.9	40.0	40.0	38.5
P3B	PT_ARTH_#1A2118	BIRCH_TS 118	39.8	51.0	39.7	40.0	40.1	51.3	40.0	40.3	38.2	48.7	38.1	38.4
P7B	PT_ARTH_#1A1118	BIRCH_TS 118	33.4	44.5	35.2	33.8	33.8	44.9	35.6	34.2	32.5	43.1	34.4	33.0
L3P	LAKEHEAD_TS 118	PT_ARTH_#1A2118	20.2	28.6	19.7	19.9	20.3	28.8	19.8	20.1	18.4	26.4	17.9	18.2
L4P	LAKEHEAD_TS 118	PT_ARTH_#1A1118	40.2	47.8	40.8	39.7	40.2	47.7	40.9	39.6	39.1	46.1	40.5	38.6
R1LB	LAKEHEAD_JR1118	BIRCH_TS 118	32.0	41.8	31.7	32.0	32.2	42.1	31.9	32.2	30.4	39.7	30.1	30.4
	PINE_PORTAGE118	LAKEHEAD_JR1118	63.8	88.5	81.1	66.9	64.7	89.4	82.0	67.5	67.3	92.5	85.1	69.9
R2LB	LAKEHEAD_JR2118	BIRCH_TS 118	30.6	0.0	30.3	30.6	30.8	0.0	30.6	30.8	29.1	0.0	28.8	29.1
	PINE_PORTAGE118	LAKEHEAD_JR2118	56.0	0.0	71.4	58.8	56.8	0.0	72.2	59.4	59.1	0.0	74.9	61.4
A6P	ALEXANDER_SS118	RESERVE_JA6P118	45.4	58.7	62.3	48.6	46.3	59.5	63.2	49.3	48.0	61.2	65.3	50.7
	RESERVE_JA6P118	PT_ARTH_#1A1118	29.4	38.7	41.2	31.6	30.1	39.2	41.8	32.1	31.9	41.1	43.9	33.7
A7L	ALEXANDER_SS118	RESERVE_JA7L118	72.8	95.7	**103.3**	78.4	74.5	97.0	**104.8**	79.5	79.0	**101.7**	**110.2**	83.6
	RESERVE_JA7L118	LAKEHEAD_TS 118	66.0	86.9	93.9	71.1	67.5	88.1	95.3	72.2	71.7	92.5	**100.1**	75.9
A8L	ALEXANDER_SS118	LAKEHEAD_TS 118	58.0	76.4	0.0	62.5	59.4	77.5	0.0	63.5	63.0	81.3	0.0	66.8
A5A	ALEXANDER_SS118	MINNOVA_J 118	85.4	70.2	73.0	67.2	80.0	66.5	69.3	63.5	77.1	65.2	68.3	62.0
	SCHREIBER_J 118	AGUASABON_SS118	82.7	67.4	70.3	64.4	77.4	63.8	66.7	60.7	74.4	62.4	65.5	59.2
A1B	AGUASABON_SS118	TER_BAY_PU_J118	93.7	82.4	84.5	80.3	89.7	79.7	81.8	77.5	87.5	78.6	80.9	76.3
	TER_BAY_PU_J118	TERRACE_BAY 118	67.2	59.1	60.6	57.6	64.3	57.1	58.6	55.5	62.7	56.3	58.0	54.7
T1M	PIC_J_T1M 118	MARATHON_TS 118	61.7	53.5	55.0	52.0	58.7	51.3	52.9	49.9	57.1	50.5	52.2	49.0
	TERRACE_BAY 118	PIC_J_T1M 118	**115.4**	**101.5**	**104.0**	98.8	**110.5**	98.0	**100.7**	95.3	**107.7**	96.7	99.5	93.9
M2W	MARATHON_TS 118	MARATHON_J1 118	11.3	11.3	11.3	2.7	22.9	22.8	22.8	10.2	33.9	33.9	33.9	20.8
	MARATHON_J1 118	MARTHON_J2 118	11.8	11.7	11.7	2.2	23.3	23.2	23.2	10.5	34.3	34.3	34.3	21.2
	MARTHON_J2 118	MANITOUWDG_J118	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	22.5	22.5	22.6	22.4
	MANITOUWDG_J118	MANITOUWADGE118	4.7	4.8	4.8	4.7	4.8	4.8	4.8	4.7	34.6	34.7	34.7	34.4
	MARTHON_J2 118	BLACK_R_JM2W118	22.7	22.6	22.6	4.4	42.3	42.2	42.1	21.3	42.2	42.0	42.0	21.0
	BLACK_R_JM2W118	UMBATA_FLS_J118	9.3	9.3	9.2	14.5	29.1	29.0	29.0	11.3	29.0	28.9	28.8	11.1
	HEMLO_MINE_J118	WHITE_RVRTAP118	3.4	3.4	3.4	3.4	25.9	25.8	25.8	25.6	25.8	25.8	25.8	25.5

Studies performed show that under existing High Transfer East summer conditions (**Scenario S1**) there may be overloads on circuit (i) A7L for the loss of A6P/A8L and (ii) T1M for loss of M23L/M24L. Note the table above only shows results for the loss of M24L, loss of R2LB and the loss of A8L as these contingencies result in a greater overload than the loss of their respective companion/parallel path.

Overloads on Circuit A7L

As shown from **Scenario S1**, under existing conditions, the A7L line section from Alexander SS to Reserve Junction was found to have the largest overload for the loss of A8L (103.3 % of the long term emergency rating). With the addition of the White River Generation Facility, the overload on A7L is increased slightly to 104.8% (**Scenario S2**). The addition of the White River Generation Facility *plus* 20 MW of additional committed generation on M2L *plus* 10 MW of committed generation on A4L *plus* new embedded generation within the vicinity may cause the overload on A7L to increase to 110.2 % (**Scenario S3**).

Overloads on Circuit T1M

Under existing conditions (**Scenario S1**), the T1M line section from Terrace Bay SS to Picton junction was found to have the largest overload for contingency M24L (115.4 % of the long term emergency rating). With the addition of the White River Generation Facility, the overload on T1M is reduced to 110.5% (**Scenario S2**). The addition of White River Generation Facility *plus* 20 MW of additional committed generation on M2L *plus* 10 MW of committed generation on A4L *plus* new embedded generation within the vicinity may cause the overload on T1M to further decrease to 107.7 % (**Scenario S3**).

The following table summarizes the post-contingency loading as a percentage of the Long Term Emergency rating for **Scenarios S4**, **S5**, **S6** and **S7** (High Transfers West).

Element	Monitored Element		% of Long Term Emergency Rating															
			Scenario S4				Scenario S5				Scenario S6				Scenario S7			
	From	To	M23L	R2LB	A7L	A8L	M23L	R2LB	A7L	A8L	M23L	R2LB	A7L	A8L	M23L	R2LB	A7L	A8L
Lakehead T7	LAKEHEAD_TS 220	LAKEHEAD_TS 118	3.3	8.4	8.6	8.9	3.5	9.2	9.3	10.0	4.5	10.6	10.9	11.6	3.7	10.9	11.2	11.9
Lakehead T8	LAKEHEAD_TS 220	LAKEHEAD_TS 118	3.0	8.7	8.9	9.2	3.1	9.4	9.5	10.2	4.2	10.8	11.1	11.8	3.3	11.2	11.4	12.1
Marathon T11	MARATHON_TS 220	MARATHON_TS 118	0.0	5.8	6.1	6.3	0.0	7.3	7.9	8.2	0.0	10.0	10.7	11.0	0.0	10.3	11.0	11.4
Marathon T12	MARATHON_TS 220	MARATHON_TS 118	24.0	7.6	7.7	7.8	20.4	8.4	8.7	9.0	17.8	10.4	11.0	11.3	17.4	10.6	11.3	11.6
A21L	MACKENZIE_TS220	LAKEHEAD_TS 220	42.8	41.8	41.6	41.4	43.0	41.9	41.6	41.5	43.1	42.2	41.9	41.9	43.5	42.5	42.2	42.1
A22L	MACKENZIE_TS220	LAKEHEAD_TS 220	42.8	41.8	41.6	41.4	43.0	41.9	41.6	41.5	43.1	42.2	41.9	41.9	43.5	42.5	42.2	42.1
M23L	LAKEHEAD_TS 220	GREENWICH1 220	0.0	45.3	45.6	45.9	0.0	47.3	47.6	47.9	0.0	49.3	49.5	49.9	0.0	49.4	49.7	50.1
	GREENWICH1 220	MARATHON_TS 220	0.0	47.0	47.3	47.6	0.0	49.1	49.5	49.8	0.0	51.1	51.5	51.8	0.0	51.3	51.7	52.0
M24L	LAKEHEAD_TS 220	GREENWICH2 220	83.6	45.3	45.5	45.8	87.4	47.2	47.5	47.8	91.0	49.2	49.4	49.8	91.2	49.3	49.6	50.0
	GREENWICH2 220	MARATHON_TS 220	86.2	47.1	47.4	47.7	90.1	49.2	49.5	49.8	93.7	51.2	51.5	51.8	94.0	51.4	51.7	52.0
W21M	MARATHON_TS 220	WAWA_TS 220	49.7	48.1	48.0	48.1	50.2	48.1	48.0	48.1	50.6	47.8	47.7	47.8	50.5	47.8	47.7	47.8
W22M	MARATHON_TS 220	WAWA_TS 220	42.9	41.5	41.4	41.5	43.3	41.5	41.4	41.5	43.6	41.2	41.1	41.2	43.6	41.2	41.2	41.3
P3B	PT_ARTH_#1A2118	BIRCH_TS 118	55.2	66.0	50.8	50.7	54.1	64.7	49.0	49.0	53.2	63.5	47.5	47.5	52.4	62.7	46.7	46.6
P7B	PT_ARTH_#1A1118	BIRCH_TS 118	49.0	59.6	46.7	46.9	50.2	60.5	47.2	47.5	51.5	61.6	48.1	48.5	52.0	62.1	48.5	48.9
L3P	LAKEHEAD_TS 118	PT_ARTH_#1A2118	31.4	44.3	32.2	32.1	37.7	49.8	37.4	37.4	44.5	55.5	42.9	42.8	47.5	58.0	45.4	45.3
L4P	LAKEHEAD_TS 118	PT_ARTH_#1A1118	52.7	60.5	50.7	50.7	52.8	62.2	51.5	51.3	52.9	62.3	52.3	51.8	53.4	62.6	52.8	52.3
R1LB	LAKEHEAD_JR1118	BIRCH_TS 118	45.3	56.5	42.8	42.7	46.2	57.4	43.3	43.3	47.3	58.4	44.1	44.0	47.6	58.6	44.3	44.2
	PINE_PORTAGE118	LAKEHEAD_JR1118	75.3	86.6	80.3	82.6	77.1	87.6	81.3	83.5	79.0	88.5	82.2	84.4	80.8	90.7	84.4	86.7
R2LB	LAKEHEAD_JR2118	BIRCH_TS 118	43.3	0.0	41.0	40.9	44.2	0.0	41.5	41.5	45.3	0.0	42.2	42.1	45.6	0.0	42.4	42.3
	PINE_PORTAGE118	LAKEHEAD_JR2118	66.3	0.0	70.6	72.6	67.9	0.0	71.5	73.5	69.6	0.0	72.3	74.3	71.2	0.0	74.2	76.3
A6P	ALEXANDER_SS118	RESERVE_JA6P118	68.7	68.3	72.5	74.7	70.5	69.1	73.4	75.6	72.4	70.1	74.4	76.7	74.1	72.0	76.5	78.8
	RESERVE_JA6P118	PT_ARTH_#1A1118	45.4	45.4	48.4	49.9	46.6	46.0	49.0	50.6	47.9	46.6	49.7	51.3	49.1	48.0	51.2	52.8
A7L	ALEXANDER_SS118	RESERVE_JA7L118	**112.1**	**111.8**	0.0	**124.8**	**115.0**	**113.3**	0.0	**126.5**	**118.1**	**114.7**	0.0	**128.2**	**121.2**	**118.1**	0.0	**132.0**
	RESERVE_JA7L118	LAKEHEAD_TS 118	**102.1**	**101.6**	0.0	**113.5**	**104.8**	**103.0**	0.0	**115.1**	**107.6**	**104.3**	0.0	**116.6**	**110.4**	**107.4**	0.0	**120.1**
A8L	ALEXANDER_SS118	LAKEHEAD_TS 118	89.7	89.4	96.7	0.0	92.1	90.6	98.1	0.0	94.6	91.7	99.4	0.0	97.0	94.5	**102.4**	0.0
A5A	ALEXANDER_SS118	MINNOVA_J 118	96.4	35.7	32.1	31.2	**105.8**	40.0	36.4	35.5	**115.5**	44.3	40.6	39.8	**114.4**	43.0	39.2	38.3
	SCHREIBER_J 118	AGUASABON_SS118	98.4	37.7	34.2	33.3	**107.9**	42.1	38.5	37.6	**117.6**	46.4	42.7	41.9	**116.5**	45.1	41.2	40.4
A1B	AGUASABON_SS118	TER_BAY_PU_J118	42.9	4.0	6.6	7.4	50.1	1.5	3.4	4.3	57.4	3.0	0.4	1.2	56.6	2.1	1.1	2.0
	TER_BAY_PU_J118	TERRACE_BAY 118	31.4	2.6	4.5	4.9	36.6	0.4	1.9	2.5	41.9	2.5	0.6	0.1	41.3	1.8	0.5	0.8
T1M	PIC_J_T1M 118	MARATHON_TS 118	39.2	6.9	5.8	5.4	44.5	8.1	6.5	5.9	49.8	10.5	8.7	8.1	49.2	9.9	8.1	7.5
	TERRACE_BAY 118	PIC_J_T1M 118	54.4	4.5	7.7	8.5	63.3	0.6	3.3	4.3	72.2	5.7	2.8	0.2	71.2	4.6	0.9	1.4
M2W	MARATHON_TS 118	MARATHON_J1 118	11.3	11.4	11.3	11.3	22.6	22.7	22.7	22.7	33.9	33.9	33.9	33.9	33.9	33.9	33.9	33.9
	MARATHON_J1 118	MARTHON_J2 118	11.7	11.8	11.8	11.8	23.0	23.1	23.1	23.1	34.3	34.3	34.3	34.3	34.3	34.3	34.3	34.3
	MARTHON_J2 118	MANITOUWDG_J118	4.5	4.5	4.5	4.5	4.4	4.5	4.5	4.5	22.7	22.6	22.6	22.6	22.7	22.6	22.6	22.6
	MANITOUWDG_J118	MANITOUWADGE118	4.9	4.8	4.8	4.8	4.9	4.9	4.9	4.9	34.8	34.7	34.7	34.7	34.8	34.7	34.7	34.7
	MARTHON_J2 118	BLACK_R_JM2W118	22.3	22.7	22.7	22.6	41.7	41.9	42.0	41.9	41.8	42.1	42.1	42.0	41.9	42.0	42.1	42.0
	BLACK_R_JM2W118	UMBATA_FLS_J118	11.4	12.3	12.2	12.2	30.8	31.1	31.2	31.0	31.0	31.3	31.4	31.2	31.0	31.3	31.3	31.1
	HEMLO_MINE_J118	WHITE_RVRTAP118	3.3	3.3	3.3	3.3	25.6	25.7	25.7	25.7	25.7	25.8	25.8	25.8	25.7	25.8	25.8	25.7

The table above shows that under existing summer conditions, with High Transfer West flows, there may be overloads on circuit A7L for the loss of M23L/M24L, R1LB/R2LB, A6P/A8L. Note the table above only shows results for the loss of M23L, loss of R2LB and loss of A8L, as these contingencies result in an overall greater overload than the loss of their respective companion/parallel path.

Note, in all transfer west scenarios, the Greenwich wind farm was assumed to be out of service, as it is expected that during its operation, it will oppose westbound flows on the EWTW interface. In the event, however, that Greenwich is in-service and EWTW flows are at 350 MW, the post-contingency loadings may be higher than those presented in the table above, resulting in higher congestion in the area.

Overloads on Circuit A7L

Under existing conditions, the A7L line section from Alexander SS to Reserve junction was found to have the greatest overload for the loss of A8L with a loading of 124.8 % of the long term emergency rating (**Scenario S4**). With the incorporation of the White River Generation Facility, the overload on A7L is increased slightly to 126.5 % (**Scenario S5**). The addition of the White River Generation Facility *plus* 20 MW of additional committed generation on M2L causes the overload to increase slightly to 128.2 % (**Scenario S6**), while the further addition of 10 MW of committed generation on A4L causes the overload on A7L to increase to 132.0 % (**Scenario S7**).

Overloads on Circuit A8L

Under existing conditions, circuit A8L is the most impacted circuit for the loss of A7L with a loading of 96.7 % of the long term emergency rating (**Scenario S4**). With the incorporation of the White River Generation Facility, the loading on A8L is increased slightly to 98.1 % of the long term emergency rating (**Scenario S5**). The addition of the White River Generation Facility *plus* 20 MW of additional committed generation on M2L causes the overload to increase slightly to 99.4 % (**Scenario S6**), while the further addition of 10 MW of committed generation on A4L causes the overload on A7L to increase to 102.4 % (**Scenario S7**).

It should be noted that under existing conditions, in which the post-contingency loading on A8L for the loss of A7L is 96.7 % (**Scenario S4**), the margin from the long term emergency rating is only 3 MW. As such any scenario with additional generation east of Alexander would likely cause overloads on A8L post-contingency for loss of A7L.

Overloads on Circuit A5A

Under existing conditions, the loading on A5A line section from Schreiber junction to Aguasabon SS for the loss of M23L was found to be 98.4% of the circuit's long term emergency rating. With the addition of the White River Generation Facility, the loading on A5A is increased to 107.9 % of the long term emergency rating (**Scenario S5**). The addition of the White River Generation Facility *plus* 20 MW of additional committed generation on M2L causes the overload on A5A to increase to 117.6 % (**Scenario S6**), while the further addition of 10 MW of committed generation on A4L causes the overload on A7L to increase to 116.5 % (**Scenario S7**).

It should be noted that under existing conditions, in which the post-contingency loading on A5A is 98.4% (**Scenario S4**), the margin from the long term emergency rating is only 2 MW. As such, any scenario with additional generation east of Alexander would likely cause overloads on A5A post-contingency for the loss of M23L.

Increased congestion on circuit A5A would affect the transfer west capability of the A5A@Alexander+M23L@Lakehead+M24L@Lakehead interface. The *Ontario Resource and Transmission Assessment Criteria* states that new or modified connections to the IESO-controlled grid may increase congestion on transmission facilities but will not be permitted to lower power transfer capability or operating security limits by 5% or more.

- As shown with **Scenario S4**, studies found that under existing 2010 conditions there is no overload on A5A post-contingency for loss of M23L with an A5A+M23L+M24L flow of 366.8 MW. The corresponding EWTW flow was 350 MW.
- With the addition of White River Generation Facility, studies found that the A5A+M23L+M24L flow must be lowered to 365.3 MW and EWTW reduced to 338 MW in order to avoid overloading A5A post-contingency for loss of M23L. This is a reduction of 0.4% of the A5A+M23L+M24L transfer capability.
- With the addition of Becker Cogeneration (the 20 MW of additional committed generation on M2L), studies found that A5A+M23L+M24L flow must be lowered to 363.6 MW and EWTW flow reduced to 336.6 MW. This is a reduction of 0.9 % of the A5A+M23L+M24L transfer capability.
- With the addition of White River Generation Facility *plus* 20 MW of additional committed generation on M2L, studies found that the A5A+M23L+M24L flow must be lowered to 363.1 MW and EWTW flow reduced to 315.4 MW. This is a reduction of about 1% of the A5A+M23L+M24L transfer capability.

Therefore the reduction in transfer capability with the incorporation of the White River Generation Facility *plus* the Becker Cogeneration will not exceed the 5% limit reduction permitted by the *Ontario Resource and Transmission Assessment Criteria*.

Under winter conditions, the planning long term emergency rating for circuit A5A is 580 A. Should thermal loadings for **Scenario S6** be compared with winter ratings, there would be no overload post contingency, thus indicating that under winter conditions, the transfer capability of the A5A+M23L+M24L interface will not be reduced due to the incorporation of the White River Generation Facility and 20 MW of additional committed generation on M2W. Therefore, thermal concerns on A5A are limited to summer conditions.

For the time being, based on recent historical EWTW summer flows, it will not be necessary for White River Generation Facility to participate in a new Special Protection Scheme (SPS) that would reject or run-back generation at the facility for the loss of M23L/M24L and associated contingencies. The highest EWTW summer flow since 2009 was found to be 223 MW, which occurred during the summer of 2010. Nevertheless, should future flow patterns change, the IESO may require that an SPS be installed and, at that time, would require the White River Generation Facility to participate.

In conclusion, the addition of the White River Generation Facility, as well as additional committed generation on M2W and A4L will likely cause increased congestion on some of the 115 kV circuits in the area. This will have to be alleviated by generation re-dispatch in the area.

6.4 Voltage Analysis

The assessment of the voltage performance in the Marathon 115 kV area was done in accordance with the IESO's *Ontario Resource and Transmission Assessment Criteria.* The criteria states that with all facilities in service pre-contingency, 115 kV and 230 kV system voltage declines following a contingency shall be limited to 10% both before and after transformer tap changer action. The study was done for peak load conditions and constant MVA model in both immediate pre-contingency state and in post-ULTC state.

A voltage decline analysis was performed with **Scenario S8** (High Transfer West flows under winter peak load conditions) to observe the effect of the loss of the White River Generation Facility. For conservative results, it was assumed that one Umbata Falls unit was in-service pre-contingency and that all the White River synchronous units were operating at 0.9 lagging power factor prior to the contingency. The pre-contingency active and reactive power output level at the White River Generation Facility under **Scenario S8** can be found in the "Assumptions and Background" section of this report (**Section 6.1**)

The study results under pre-ULTC and post-ULTC conditions are summarized in the following table.

Scenario S8 Voltage Declines					
Monitored Busses	Loss of White River with all White River synchronous units at 0.9 lag and one Umbata Falls unit in-service pre-contingency				
Bus Name	Pre-Cont Voltage (kV)	Pre-ULTC		Post-ULTC	
		kV	%	kV	%
LAKEHEAD TS 230 kV	240.00	240.00	0.00%	240.00	0.00%
MARATHON TS 230 kV	240.92	239.63	-0.54%	239.61	-0.55%
WAWA TS 230 kV	242.72	242.02	-0.29%	242.01	-0.29%
LAKEHEAD TS 115 kV	123.22	123.20	-0.01%	123.22	0.00%
ALEXANDER SS 115 kV	124.61	124.59	-0.02%	124.60	-0.01%
MARATHON TS 115 kV	124.48	123.65	-0.66%	123.64	-0.67%
PIC DS 115 kV	124.47	123.65	-0.66%	123.63	-0.67%
MANITOUWADGE TS 115 kV	121.94	121.08	-0.71%	121.06	-0.72%
GECO CTS 115 kV	121.96	121.09	-0.71%	121.08	-0.72%
WAWATAY CGS 115 kV	124.04	122.06	-1.59%	122.08	-1.58%
UMBATA FALLS CGS 115 kV	123.50	121.38	-1.72%	121.39	-1.71%
WILLIAMS MINE CTS 115 kV	120.43	116.30	-3.43%	116.34	-3.40%
DAVID BELL MINE CTS 115 kV	120.62	116.50	-3.42%	116.53	-3.39%
WHITE RIVER GS 115 kV	121.19	116.47	-3.89%	116.50	-3.87%
WHITE RIVER DS 115 kV	119.05	114.20	-4.08%	114.23	-4.05%

For the loss of the White River Generation Facility, the maximum voltage change of 4.08 % was recorded at White River DS. These voltage changes are within the IESO's criteria of 10%.

6.5 Control Systems Assessment

6.5.1 GOVERNOR SYSTEM PERFORMANCE TESTING

The proposed synchronous generators at Lower White River and Upper White River are to be equipped with the Woodward P.I.D. Hydro Governor modeled by WPIDHY PTI model.

As per Appendix 4.2 of Market Rules, each generation facility directly connected to the IESO-controlled grid shall have the capability to:

- Regulate speed with an average droop based on maximum active power adjustable between 3% and 7% and set at 4% unless otherwise specified by the IESO.

Lower White River

To evaluate governor performance at Lower White River, the Governor Droop test was performed with an initial loading of 50% of the machine MVA (0.5 * 5.333 MVA = 2.67 MVA) and zero speed with a step change of 1%.

Figure 17 shows that the governor droop is 3.98 % which meets the Market Rule requirements.

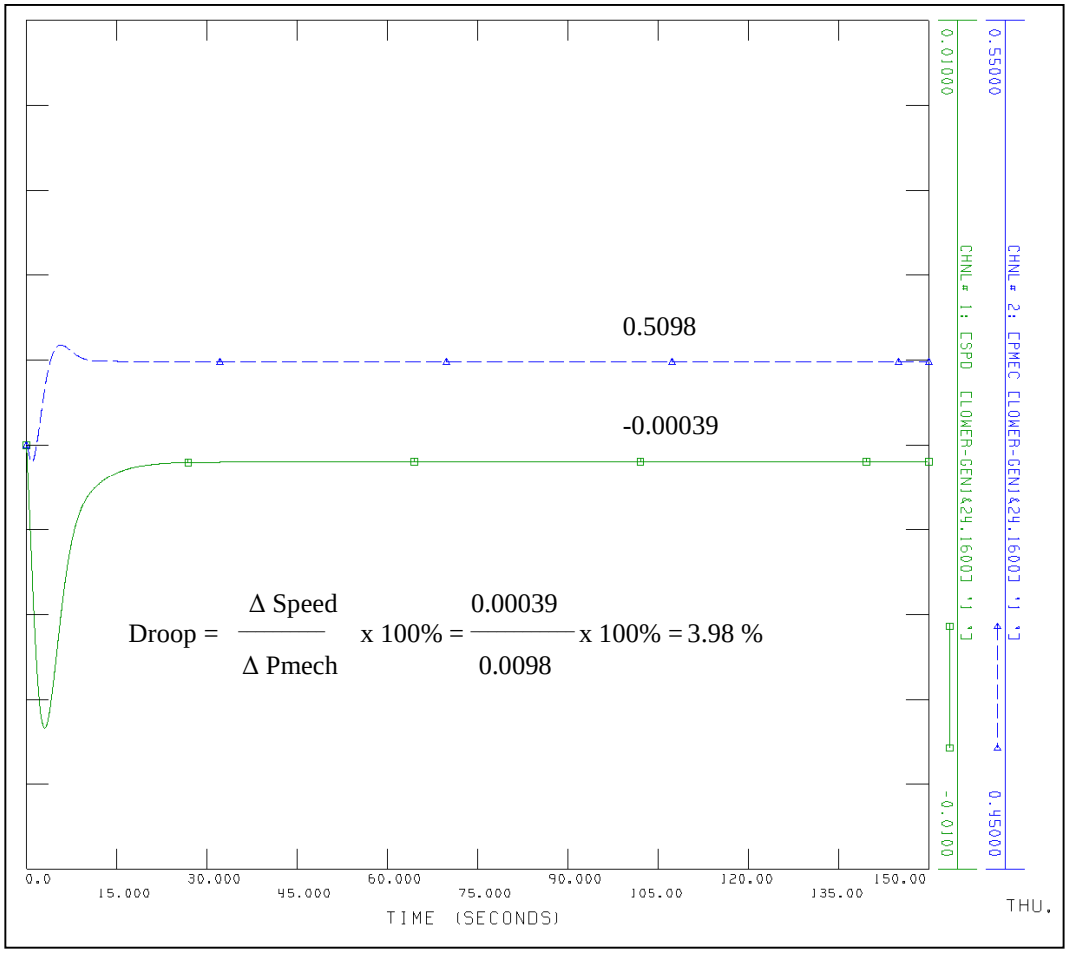


Figure 17: Lower White River Governor Response

Upper White River

To evaluate governor performance at Upper White River, the Governor Droop test was performed with an initial loading of 50% of the machine MVA (0.5 * 5.25 MVA = 2.625 MVA) and zero speed with a step change of 1%.

Figure 18 shows that the governor droop is 4.02 % which meets the Market Rule requirements.

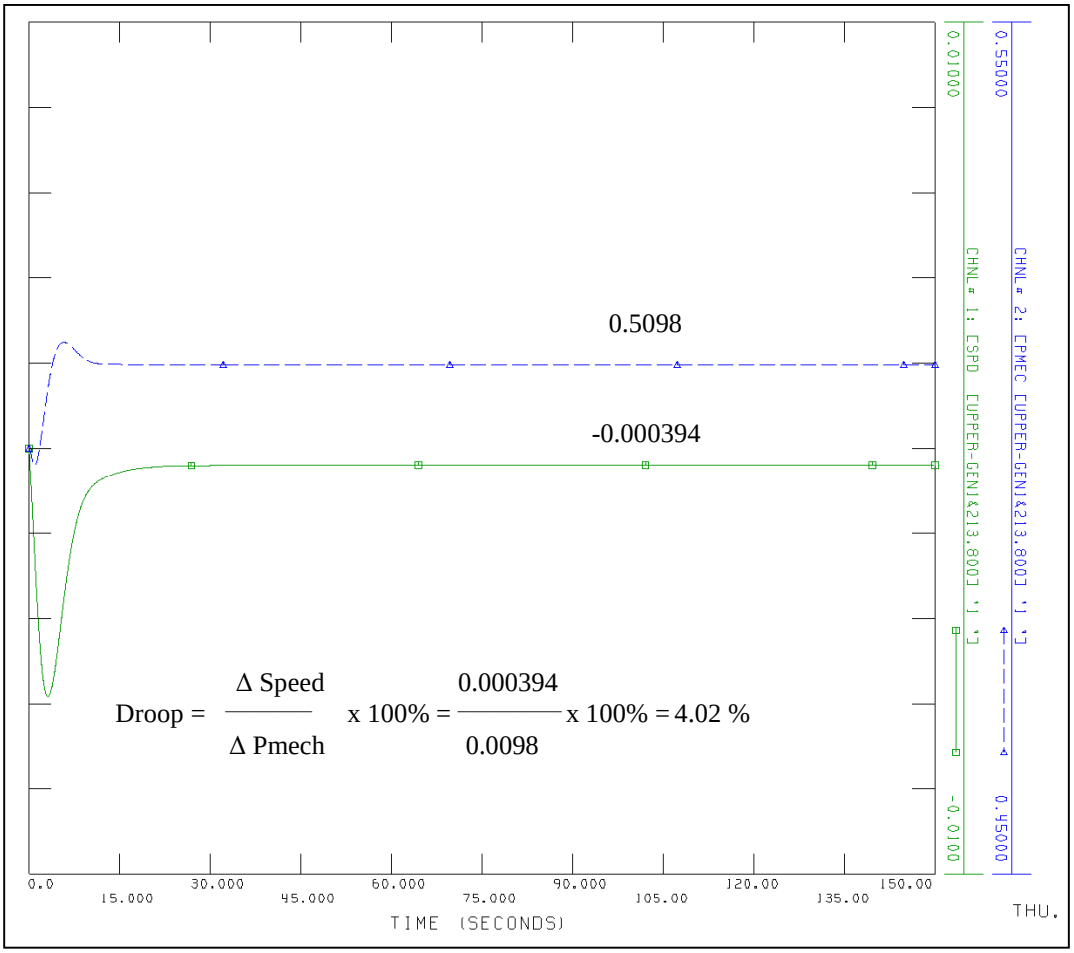


Figure 18: Upper White River Governor Response

6.5.2 EXCITATION SYSTEM PERFORMANCE TESTING

The proposed generators at Lower White River and Upper White River are to be equipped with the Basler DECS rotating AC Exciter modeled by the ESAC8B PTI model. For the Lower White synchronous units, the excitation system test was performed with a generator output of 4.80 MW. For the Upper White synchronous units, the excitation system test was performed with a generator output of 4.725 MW.

As per Appendix 4.2 of Market Rules, each generation facility directly connected to the IESO-controlled grid shall have an Automatic Voltage Regulator with the following capability:

- Equivalent time constants shall not be longer than 20 ms for voltage sensing and 10 ms for the forward path to the exciter output. i.e. (Tr ≤ 20ms and Ta ≤ 10 ms).

In order to meet the above requirement with the ESAC8B exciter, Tr must be less than or equal to 0.02 s and Ta must be less than or equal to 0.010 s. The exciters at Lower White River and Upper White River Falls have Tr = 0.01 and Ta = 0.01 and therefore meet this requirement.

EXCITATION SYSTEM RESPONSE RATIO TEST

As per Appendix 4.2 of Market Rules, each generation facility directly connected to the IESO-controlled grid shall have an Excitation System with the capability to:

- Provide positive and negative ceilings not less than 200% and 140% of rated field voltage at rated terminal voltage and rated field current

To evaluate the positive and negative ceilings, response ratio tests were performed.

The positive ceiling test automatically raises the reference setting of the voltage regulator by a large amount at time equal zero, with the generator initialized to its rated output at rated power factor.

The negative ceiling test automatically lowers the reference setting of the voltage regulator by a large amount at time equal zero, with the generator initialized to its rated output at rated power factor.

The open circuit response tests for the Lower White River synchronous units are shown below.

Lower White River

Figure 19 shows that for the positive ceiling response ratio test, the Lower White River exciter field voltage increased from rated value of 2.155 p.u. to ceiling voltage of 4.832 p.u which is 224% of rated field voltage.

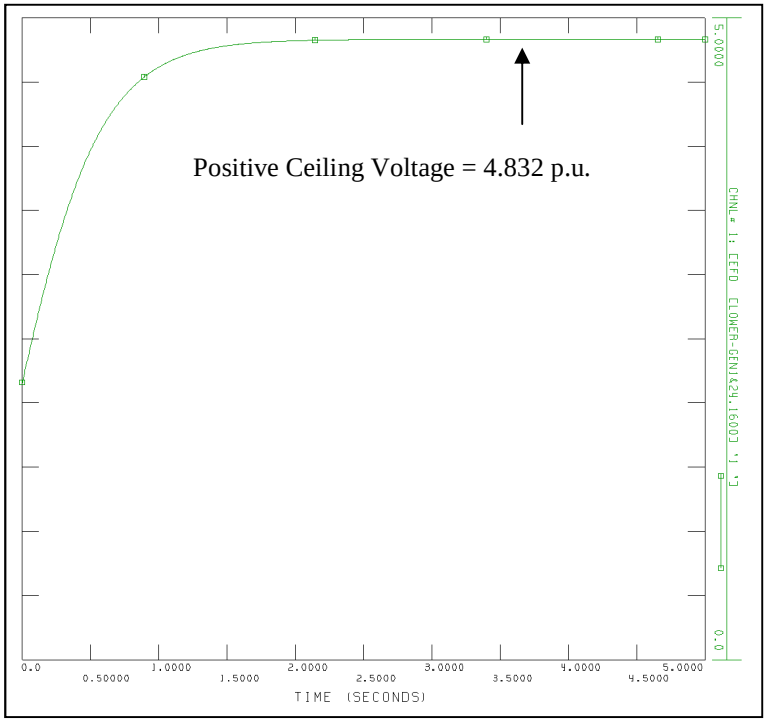


Figure 19: Lower White River Response Ratio Test for Positive Ceiling

Hence the exciter at Lower White River meets the 200% positive ceiling requirement.

Figure 20 shows that for the negative ceiling response ratio test, the Lower White River exciter field voltage decreased from rated value of 2.155 p.u. to negative ceiling voltage of 0 p.u which does not meet the negative ceiling requirements.

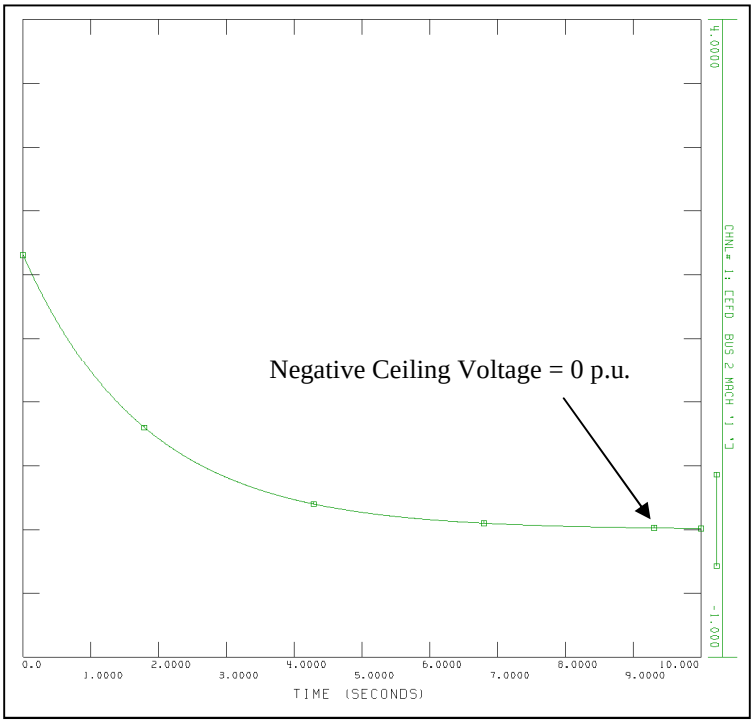


Figure 20: Lower White River Response Ratio Test for Negative Ceiling

Hence the exciter at Lower White River does not meet the 140% negative ceiling requirement.

The open circuit response tests for the Upper White River synchronous units are shown below.

Upper White River

Figure 21 shows that for the positive ceiling response ratio test, the Upper White River exciter field voltage increased from rated value of 2.312 p.u. to ceiling voltage of 4.832 p.u which is 209% of rated field voltage.

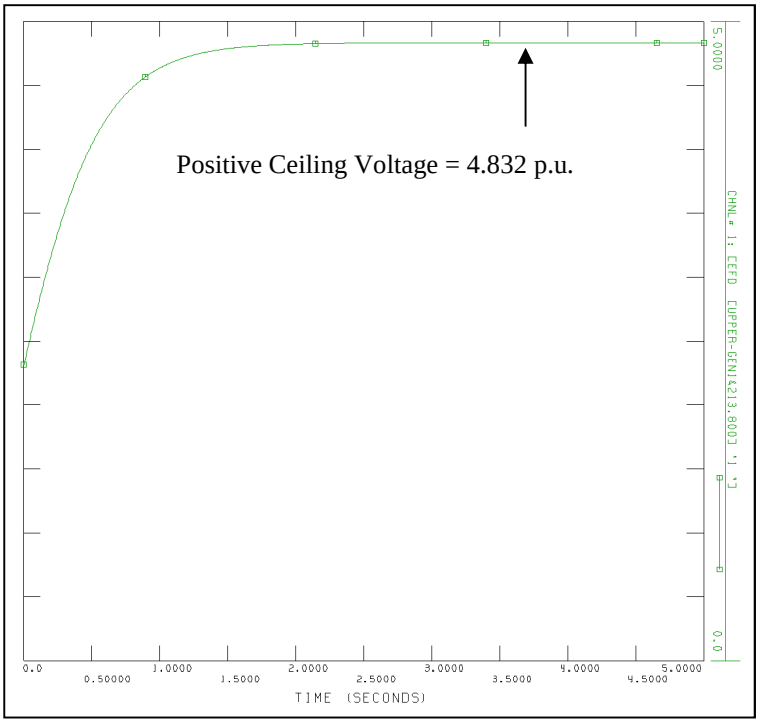


Figure 21: Upper White River Response Ratio Test for Positive Ceiling

Hence the exciter at Upper White River meets the 200% positive ceiling requirement.

Figure 22 shows that for the negative ceiling response ratio test, the Upper White River exciter field voltage decreased from rated value of 2.312 p.u. to negative ceiling voltage of 0 p.u which does not meet the negative ceiling requirements.

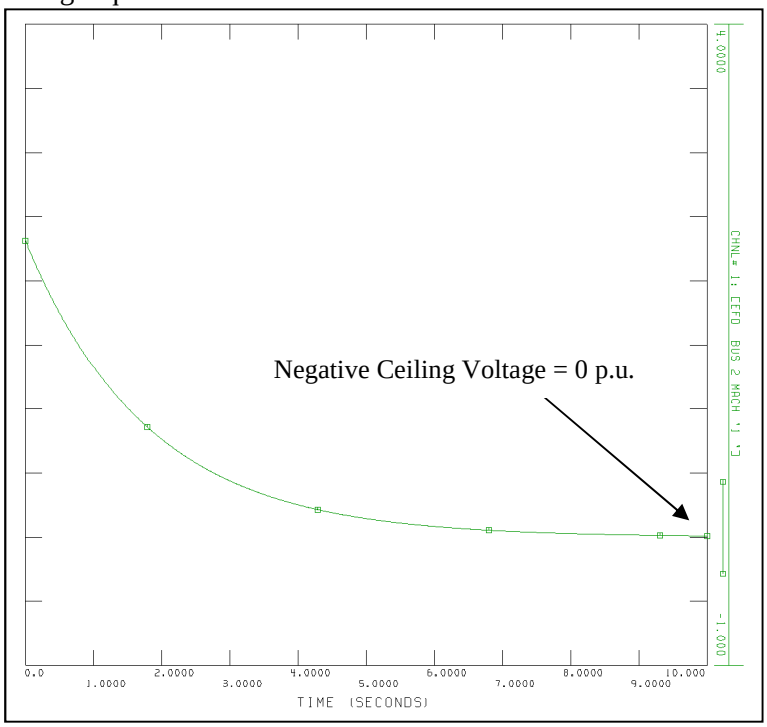


Figure 22: Upper White River Response Ratio Test for Negative Ceiling

Hence the exciter at Upper White River does not meet the 140% negative ceiling requirement.

EXCITATION SYSTEM OPEN CIRCUIT RESPONSE TEST

As per **Appendix 4.2** of Market Rules, each generation facility directly connected to the IESO-controlled grid shall have an excitation system with the capability to:

- Provide a voltage response time to either ceiling not more than 50 ms for a 5% step change from rated voltage under open-circuit conditions

Open circuit test for +5% step change in reference voltage was performed to verify if the exciter has the capability of reaching 1.95 * Efd_{rated} starting from Efd = Efd_{rated} within 50 ms.

Open circuit test for -5% step change in reference voltage was performed to verify if the exciter has the capability of reaching -1.28 * Efd_{rated} starting from Efd = Efd_{rated} within 50 ms.

The open circuit response tests for the Lower White River synchronous units are shown below.

Lower White River

Figure 23 shows the open circuit test results for a +5% step change in reference voltage for the Lower White River units.

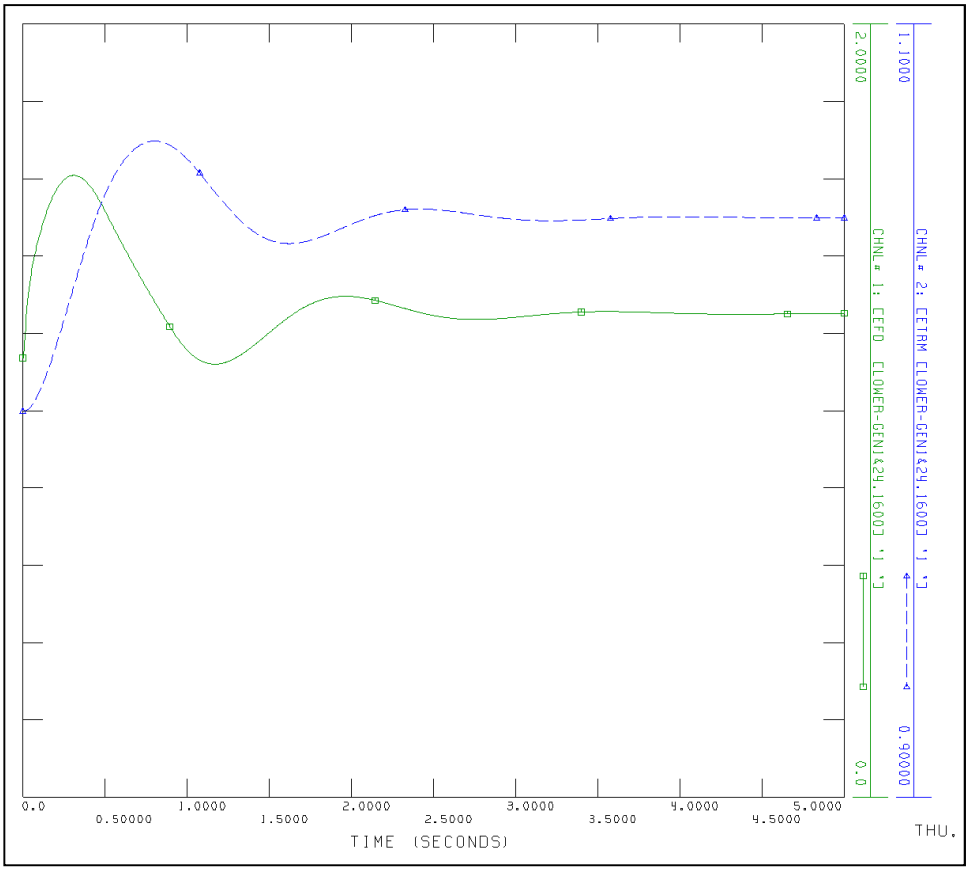


Figure 23: Lower White River Open Circuit Test for +5% Reference Voltage Change

From the graph it was observed that $Efd_{initial}$ (t=0) = 1.137= Efd_{oc}. Efd_{rated} = 2.155 p.u.

Therefore the required time to reach 1.95 * Efd_{rated} = 4.202 p.u is:

$$RT_{OC\_pos} = 50 * \frac{1.95\ Efd_{rated} - Efd_{oc}}{1.95\ Efd_{rated} - Efd_{rated}} = 74.86\ ms$$

From the graph it was observed that Efd is only able to reach no more than 1.609 p.u and hence the exciter does not meet the required voltage response time for the positive ceiling.

Figure 24 shows the open circuit test results for a -5% step change in reference voltage for the Lower White River units.

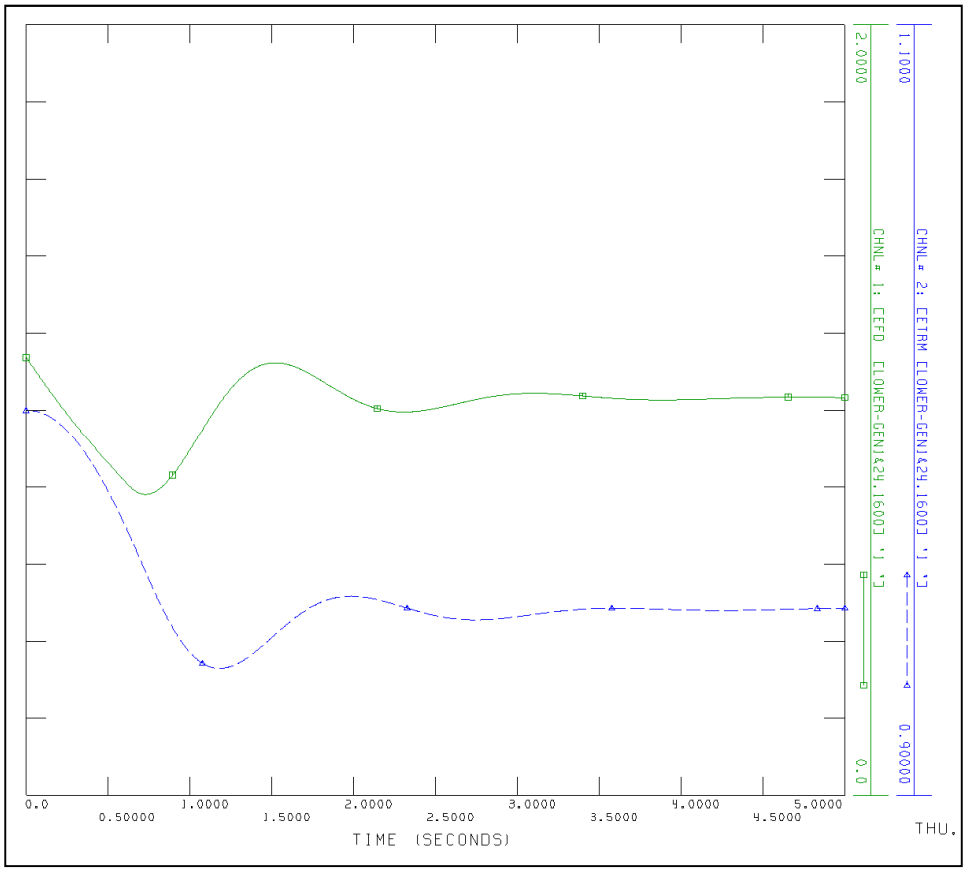


Figure 24: Lower White River Open Circuit Test for -5% Reference Voltage Change

From the graph it was observed that $Efd_{initial}$ (t=0) = 1.137 = Efd_{oc}. Efd_{rated} =2.155 p.u.

Therefore the required time to reach -1.28 * Efd_{rated} = -2.758 p.u is:

$$RT_{OC\_neg} = 50 * \frac{1.28\ Efd_{rated} + Efd_{oc}}{1.28\ Efd_{rated} + Efd_{rated}} = 39.64\ ms$$

From the graph it was observed that Efd is only able to reach 0.78 p.u and hence the exciter does not meet the required voltage response time for the negative ceiling.

The open circuit response tests for the Upper White River synchronous units are shown below.

Upper White River

Figure 25 shows the open circuit test results for a +5% step change in reference voltage for the Upper White River units.

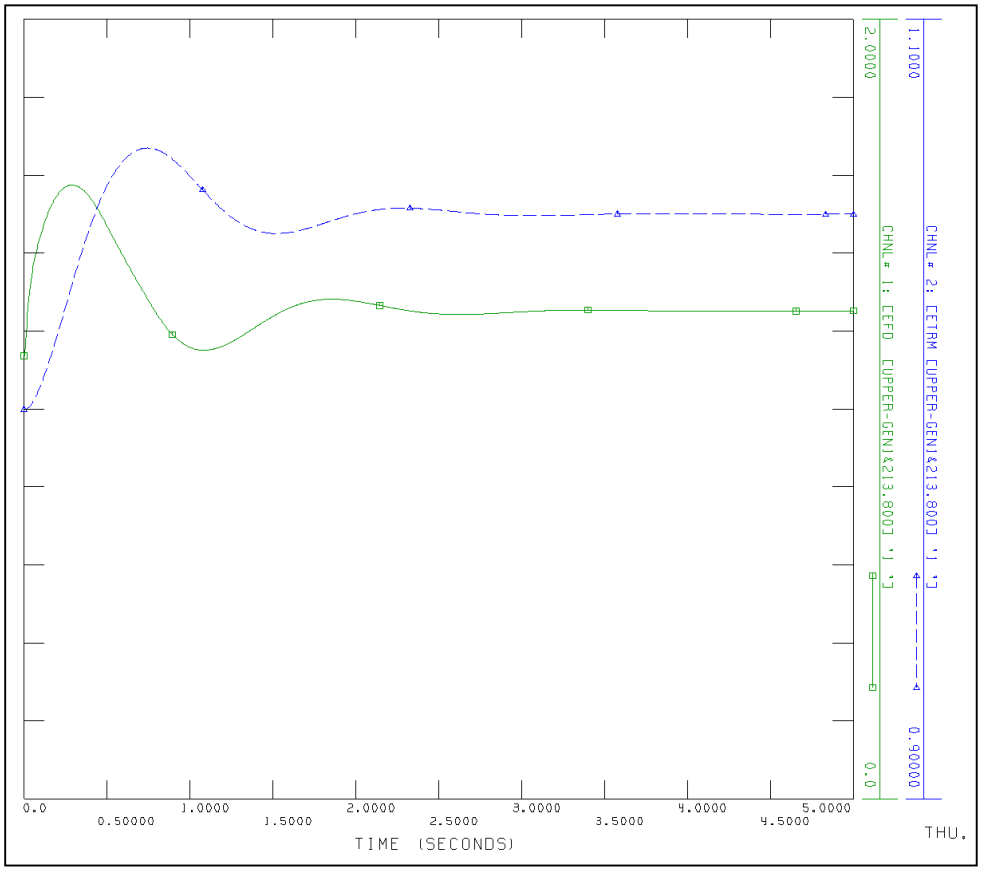


Figure 25: Upper White River Open Circuit Test for +5% Reference Voltage Change

From the graph it was observed that $Efd_{initial}$ (t=0) = 1.137= Efd_{oc}. Efd_{rated} = 2.312 p.u.

Therefore the required time to reach 1.95 * Efd_{rated} = 4.509 p.u is:

$$RT_{OC\_pos} = 50 * \frac{1.95\ Efd_{rated} - Efd_{oc}}{1.95\ Efd_{rated} - Efd_{rated}} = 76.75\ \text{ms}$$

From the graph it was observed that Efd is only able to reach no more than 1.57 p.u and hence it does not meet the required voltage response time for the positive ceiling.

Figure 26 shows the open circuit test results for a -5% step change in reference voltage for Upper White River units.

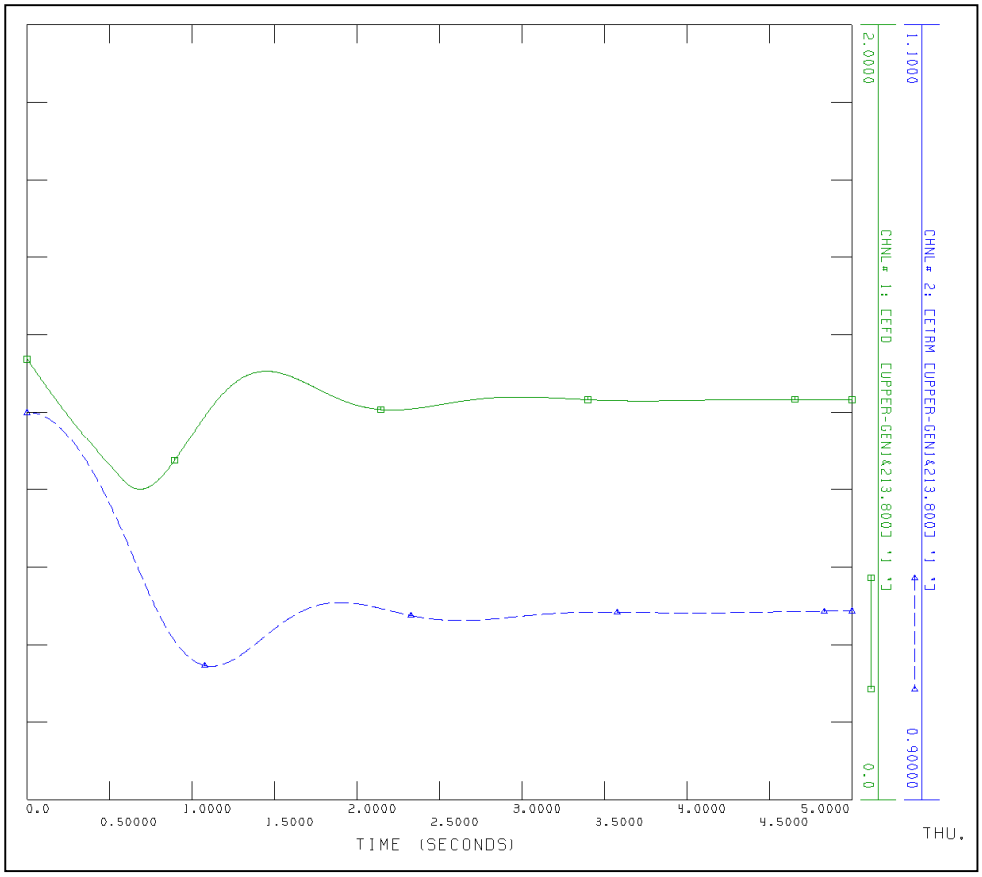


Figure 26: Upper White River Open Circuit Test for -5% Reference Voltage Change

From the graph it was observed that $Efd_{initial}$ (t=0) = 1.137 = Efd_{oc}. Efd_{rated} = 2.312 p.u

Therefore the required time to reach -1.28 * Efd_{rated} = - 2.96 p.u is:

$$RT_{OC\_neg} = 50 * \frac{1.28\ Efd_{rated} + Efd_{oc}}{1.28\ Efd_{rated} + Efd_{rated}} = 38.85\ ms$$

From the graph it was observed that Efd is only able to reach no more than 0.8 p.u. and hence it does not meet the required voltage response time for the negative ceiling.

As per **Appendix 4.2** of Market Rules, each generation facility directly connected to the IESO-controlled grid shall have an Excitation System with the capability to:

- Provide a positive ceiling not less than 170% of rated field voltage at rated terminal voltage and 160% of rated field current

Lower White River

This test was performed by modelling one Lower White River synchronous unit connected to an infinite bus system at rated terminal voltage. The reference voltage was raised to 1.01 p.u. in order to achieve a steady state where field current and field voltage were equal to 160% of rated values. A step change of 4% was then applied to the reference voltage. **Figure 27** shows this test.

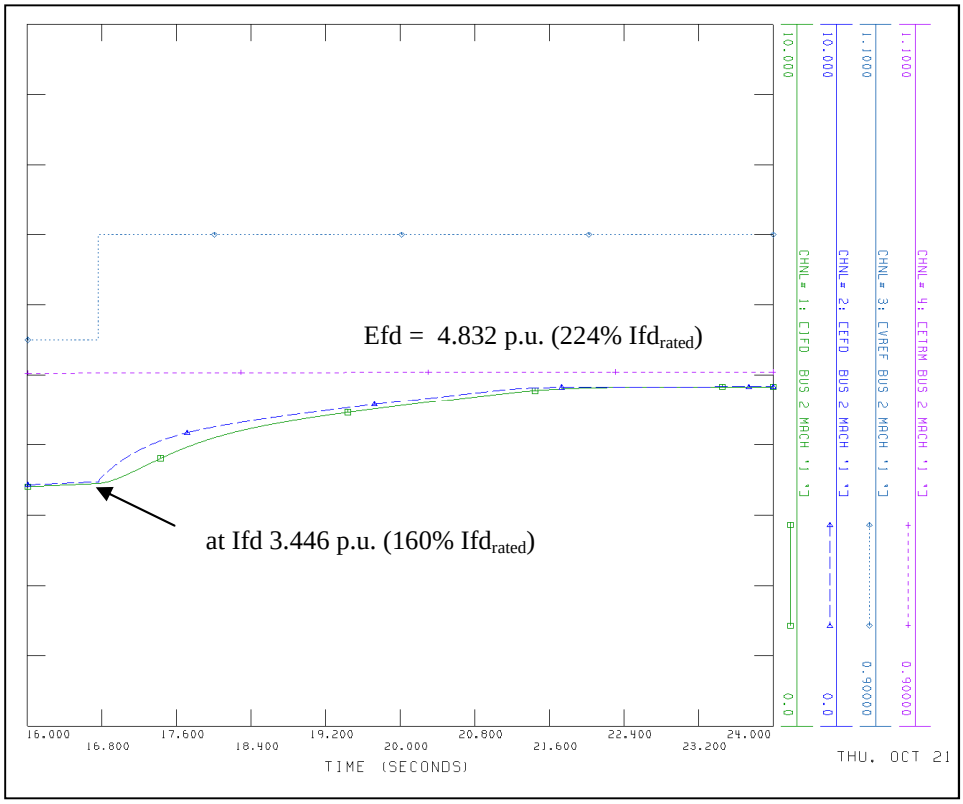


Figure 27: Lower White River Field Voltage Response under rated terminal voltage and 160% of rated field current conditions for a 4% step change

From the above graph, it was noticed that field voltage reached 224% of rated field voltage at rated terminal voltage and 160% of rated field current for a reference voltage step change of 4%. This exceeds the Market Rule requirement of 170%.

Upper White River

This test was performed by modelling one Upper White River synchronous unit connected to an infinite bus system at rated terminal voltage. The reference voltage was raised to 1.015 p.u. in order to achieve a steady state where field current and field voltage were equal to 160% of rated values. A step change of 3.5% was then applied to the reference voltage. **Figure 28** shows this test.

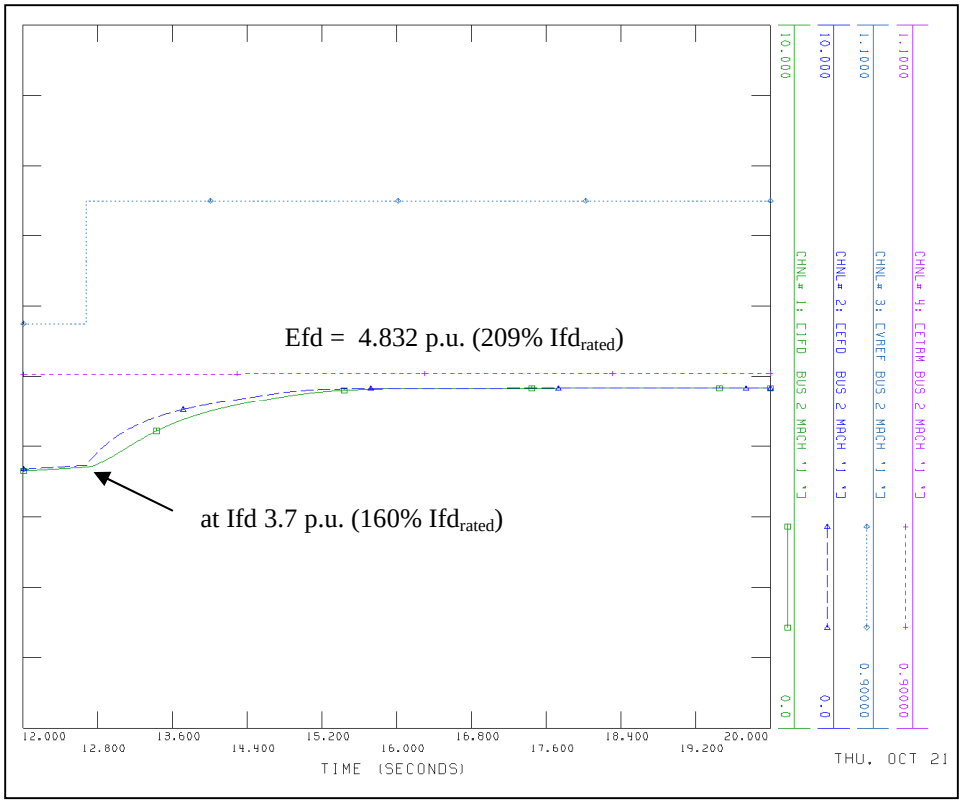


Figure 28: Upper White Field Voltage Response under rated terminal voltage and 160% of rated field current conditions for a 3.5% step change

From the above graph, it was noticed that field voltage reached 209% of rated field voltage at rated terminal voltage and 160% of rated field current for a reference voltage step change of 3.5%. This exceeds the Market Rule requirement of 170%.

In conclusion, the excitation system at the White River Generation Facility does not meet the Market Rule requirements for negative ceiling and requirements for positive and negative ceiling response times. This is due to the fact that the exciters that have been proposed are rotating AC exciters. While this is the case, dynamic simulations found in **Section 6.6**, in which the White River excitation models are used, do not show any material adverse impact on the transient performance of the IESO-controlled grid as a result of the incorporation of White River Generation Facility.

In the event that Regional Power OPCO Inc. is unable to change exciter technology to meet the Market Rule requirements, Regional Power OPCO Inc. will need to apply to the IESO for an exemption from the excitation requirements. The final approval to connect the White River Generation Facility will be contingent on the successful award of an exemption.

6.6 Transient Analysis

Transient stability analysis was performed considering faults in the Lakehead by Marathon area with the following scenarios:

Scenario S3: High Transfer East flows under summer peak load conditions *plus* White River generation I/S *plus* committed generation on M2W (20 MW) *plus* committed generation on A4L (10 MW) *plus* embedded generation at Fort William and Red Rock DS I/S

Scenario S7: High Transfer West flows under summer peak load conditions *plus* White River generation I/S *plus* committed generation on M2W (20 MW) + committed generation on A4L (10 MW)

For **Scenarios S3** and **S7**, the pre-contingency active and reactive power output level at the White River facility can be found in the "Assumptions and Background" section of this report (**Section 6.1**)

In addition, two additional scenarios were created to examine the effect of the loss of M23L+ M24L under storm conditions. This contingency was simulated under the following transfers east and west flows:

Scenario	East West Transfer East (EWTE)	Lakehead Flow East (LFE)	White River Facility Generation Output
Flow $East_{storms}$	303 MW	110 MW	P=20 MW; Q= -2.9 Mvar
Flow $West_{storms}$	-250 MW	N/A	P=20 MW; Q= -2.3 Mvar

The following twelve LLG contingencies for transfer east and transfer west conditions were tested:

ID	Contingency	Voltage (kV)	Location	LLG Fault MVA	Fault Clearing Time (ms)[1]	
					Near	Remote
SC1,SC13	LLG fault on T1M	115 kV	Marathon	458-j4079 MVA	83 ms	133 ms
SC2,SC14	LLG Fault on A5A	115 kV	Alexander	552-j3603 MVA	116 ms	183 ms
SC3,SC15	LLG Fault on A8L	115 kV	Lakehead	944-j8922 MVA	116 ms	149 ms
SC4,SC16	LLG Fault on R9A	115 kV	Alexander	552-j3603 MVA	116 ms	149 ms
SC5, SC17	LLG Fault on R1LB	115 kV	Lakehead	944-j8922 MVA	116 ms	133 ms at Birch 149 ms at Pine Portage
SC6,SC18	LLG Fault on A6P	115 kV	Alexander	552-j3603 MVA	116 ms	716 ms
SC19				544-j3577 MVA	116 ms	716 ms
SC20				552-j3603 MVA	116 ms	149 ms
SC7,SC21	LLG Fault on L3P	115 kV	Lakehead	944-j8922 MVA	116 ms	188 ms
SC22				931-j8848 MVA	116 ms	188 ms
SC23				944-j8922 MVA	116 ms	149 ms
SC8,SC24	LLG fault on M23L	230 kV	Marathon	451-j3427 MVA	91 ms[2]	124 ms
SC9,SC25	LLG fault on M24L	230 kV	Lakehead	641-j6206 MVA	83 ms	116 ms
SC10,SC26	LLG fault on W21M	230 kV	Marathon	451-j3427 MVA	91 ms[2]	124 ms
SC11,SC27	LLG fault on W22M	230 kV	Wawa	492-j4218 MVA	91 ms[2]	124 ms at Wawa 115 and Marathon 220
SC12,SC28	Simultaneous LG faults on different phases of M23L & M24L	230 kV	Marathon	451-j3427 MVA	83 ms	116 ms

Note: (1) Fault applied at t=0.1 seconds
(2) Near end fault cleared by transformer differential protection

The transient responses are shown in **Appendix B** of the report. From the results, it was found that under the high transfer west conditions as seen in **Scenario S7**, transient instability may occur due to the loss of A6P (SC18) and loss of L3P (SC21). An examination of this scenario shows that the total flow on A6P+A7L+A8L out of Alexander was 203 MW and the East West Transfer West (EWTW) flow was 352 MW.

To examine the loss of A6P and L3P under existing conditions, sensitivity studies were performed under conditions in which the White River Generation facility and the 20 MW of additional generation on M2W were not in-service. The total flow on A6P+A7L+A8L out of Alexander was 220 MW and the EWTW flow was 333 MW. To achieve this A6P+A7L+A8L flow, units at Pine Portage were placed at maximum output. Again, responses for the loss of A6P (SC19) and loss of L3P (SC22) show that transient instability may occur. Therefore, this demonstrates that instability for the loss of A6P, loss of L3P and loss of L4P is an existing issue, which newly proposed generation could slightly exacerbate.

For the above simulations, a fault on A6P is cleared in 716 ms after inception, as currently there are no communication channels between Port Arthur TS and Alexander SS. It was found that if PLC communication is installed between the two terminals, the fault could be cleared in 149 ms after inception. Transient responses for this simulation are shown in contingency SC20. As shown, responses are well damped and stable.

Similarly, a fault on L3P or L4P is cleared in 188 ms after inception, as currently, the communications between Lakehead TS and Port Arthur TS are metallic dual channel communication. It was found that if PLC communication is installed between the two terminals, the fault could be cleared in 149 ms after inception. Transient responses for this simulation are shown in contingency SC23. As shown, responses are well damped and stable.

An examination of historical data since 2006 indicates that at high transfers west, the A6P+A7L+A8L out of Alexander flows levels are not as high as the flow levels that were studied in the unstable cases indicated above. A sensitivity test was performed in which **Scenario S7** was adjusted such that the A6P+A7L+A8L flow out of Alexander was 173 MW and the EWTW flow was 300 MW – flows representing a more probable scenario of high transfers west. No modifications to the communications (i.e. implementation of PLC) were assumed. The transient responses for the loss of A6P, loss of L3P and loss of L4P were all found to be stable for this case. Nevertheless, since future flow patterns may change, an investigation into shortening the fault clearing time on A6P, L3P and L4P is still necessary.

Hydro One is required to investigate if PLC transfer trip telecommunication can be installed between (i) Port Arthur TS and Alexander SS for circuit A6P and (ii) Lakehead and Port Arthur TS for circuits L3P and L4P. Connection to the grid of the White River Generation Facility is not dependent on these installations; however, output restrictions may have to be imposed on all generation within the pocket bounded by Alexander 115 kV and Marathon T11 and T12, including the White River Generation Facility and 20 MW of additional committed generation on M2W and 10 MW of committed generation on A4L under certain system conditions until the PLC facilities/reactive resources are installed.

For all of the other simulated contingencies, transient responses are stable and well damped.

– End of Report –

Appendix A: Market Rules – Appendix 4.2

Appendix 4.2 – Generation Facility Requirements

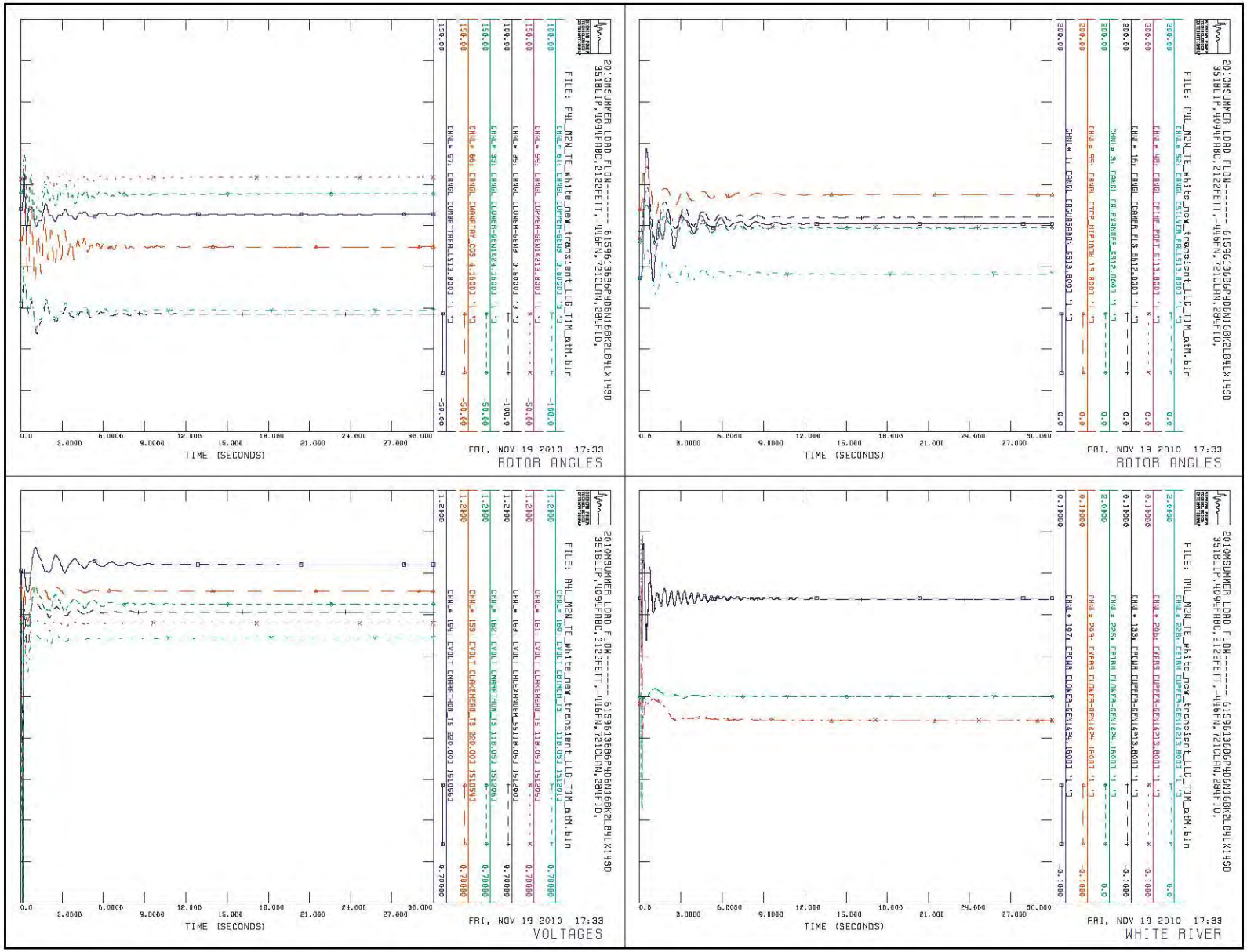
The performance requirements set out below shall apply to *generation facilities* subject to a *connection assessment* finalized after March 6, 2010. Performance of alternative technologies will be compared at the point of connection to the *IESO-controlled grid* with that of a conforming conventional synchronous *generation unit* with an equal apparent power rating to determine whether a requirement is satisfied.
Each *generation facility* that was authorized to connect to the *IESO-controlled grid* prior to March 6, 2010 shall remain subject to the performance requirements in effect for each system at the time of its authorization to connect to the *IESO-controlled grid* was granted or as agreed to by the *market participant* and the *IESO* (i.e. the "original performance requirements"). These requirements shall prevail until the main elements of an associated system (e.g. governor control mechanism, main exciter) are replaced or substantially modified. At that time, the replaced or substantially modified system shall meet the applicable performance requirements set out below. All other systems, not affected by replacement or substantial modification, shall remain subject to the original performance requirements.

Category	***Generation facility* directly connected to the *IESO-controlled grid, generation facility* greater than 50 MW, or *generation unit* greater than 10 MW shall have the capability to:**
1. Off-Nominal Frequency	Operate continuously between 59.4 Hz and 60.6 Hz and for a limited period of time in the region above straight lines on a log-linear scale defined by the points (0.0 s, 57.0 Hz), (3.3 s, 57.0 Hz), and (300 s, 59.0 Hz).
2. Speed/Frequency Regulation	Regulate speed with an average droop based on maximum active power adjustable between 3% and 7% and set at 4% unless otherwise specified by the *IESO*. Regulation deadband shall not be wider than ± 0.06%. Speed shall be controlled in a stable fashion in both interconnected and island operation. A sustained 10% change of rated active power after 10 s in response to a constant rate of change of speed of 0.1%/s during interconnected operation shall be achievable. Due consideration will be given to inherent limitations such as mill points and gate limits when evaluating active power changes. Control systems that inhibit governor response shall not be enabled without *IESO* approval.
3. Low Voltage Ride Through	Ride through routine switching events and design criteria contingencies assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times unless disconnected by configuration.
Category	***Generation facility* directly connected to the *IESO-controlled grid* shall have the capability to:**
4. Active Power	Supply continuously all levels of active power output for 5% deviations in terminal voltage. Rated active power is the smaller output at either rated ambient conditions (e.g. temperature, head, wind speed, solar radiation) or 90% of rated apparent power. To satisfy steady-state reactive power requirements, active power reductions to rated active power are permitted.
5. Reactive Power	Inject or withdraw reactive power continuously (i.e. dynamically) at a *connection point* up to 33% of its rated active power at all levels of active power output except where a lesser continually available capability is permitted by the *IESO*. A conventional synchronous unit with a power factor range of 0.90 lagging and 0.95 leading at rated active power connected via a main output transformer impedance not greater than 13% based on generator rated apparent power is acceptable.
6. Automatic Voltage Regulator (AVR)	Regulate automatically voltage within ±0.5% of any set point within ±5% of rated voltage at a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal. If the AVR target voltage is a function of reactive output, the slope ΔV /ΔQmax shall be adjustable to 0.5%. The equivalent time constants shall not be longer than 20 ms for voltage sensing and 10 ms for the forward path to the exciter output. AVR reference compensation shall be adjustable to within 10% of the unsaturated direct axis reactance on the unit side from a bus common to multiple units.

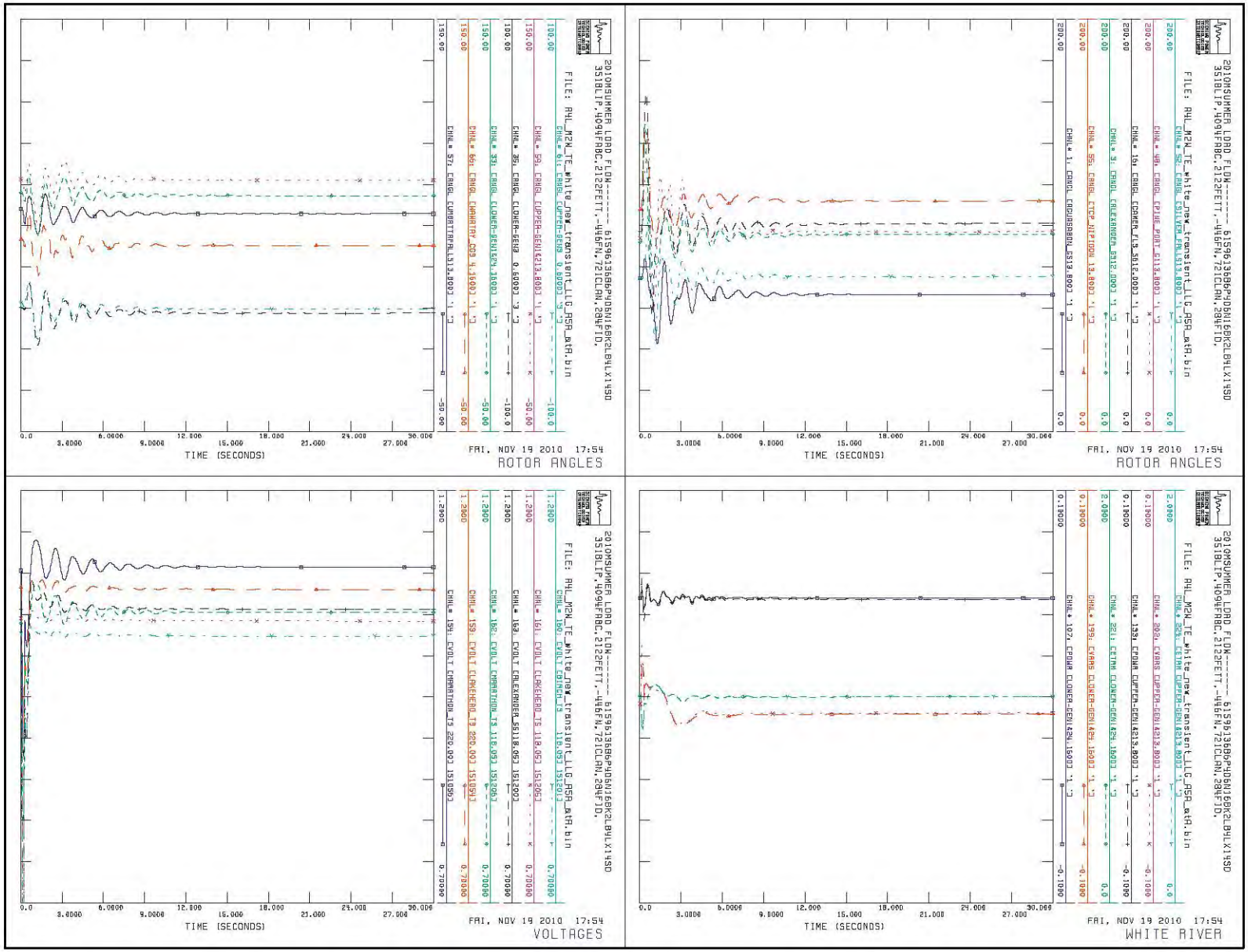
7. Excitation System	Provide (a) Positive and negative ceilings not less than 200% and 140% of rated field voltage at rated terminal voltage and rated field current; (b) A positive ceiling not less than 170% of rated field voltage at rated terminal voltage and 160% of rated field current; (c) A voltage response time to either ceiling not more than 50 ms for a 5% step change from rated voltage under open-circuit conditions; and (d) A linear response between ceilings. Rated field current is defined at rated voltage, rated active power and required maximum continuous reactive power.
8. Power System Stabilizer (PSS)	Provide (a) A change of power and speed input configuration; (b) Positive and negative output limits not less than ±5% of rated AVR voltage; (c) Phase compensation adjustable to limit angle error to within 30° between 0.2 and 2.0 Hz under conditions specified by the IESO, and (d) Gain adjustable up to an amount that either increases damping ratio above 0.1 or elicits exciter modes of oscillation at maximum active output unless otherwise specified by the *IESO*. Due consideration will be given to inherent limitations.
9. Phase Unbalance	Provide an open circuit phase voltage unbalance not more than 1% at a *connection point* and operate continuously with a phase unbalance as high as 2%.
10. Armature and Field Limiters	Provide short-time capabilities specified in IEEE/ANSI 50.13 and continuous capability determined by either field current, armature current, or core-end heating. More restrictive limiting functions, such as steady state stability limiters, shall not be enabled without *IESO* approval.
11. Performance Characteristics	Exhibit *connection point* performance comparable to an equivalent synchronous *generation unit* with characteristic parameters within typical ranges. Inertia, unsaturated transient impedance, transient time constants and saturation coefficients shall be within typical ranges (e.g. H > 1.2 Aero-derivative, H > 1.2 Hydraulic less than 20 MVA, H > 2.0 Hydraulic 20 MVA or larger, H > 4.0 Other synchronized units, X'd < 0.5, T'do > 2.0, and S1.2 < 0.5) except where permitted by the *IESO*.

Appendix B: Diagrams for Transient Simulations

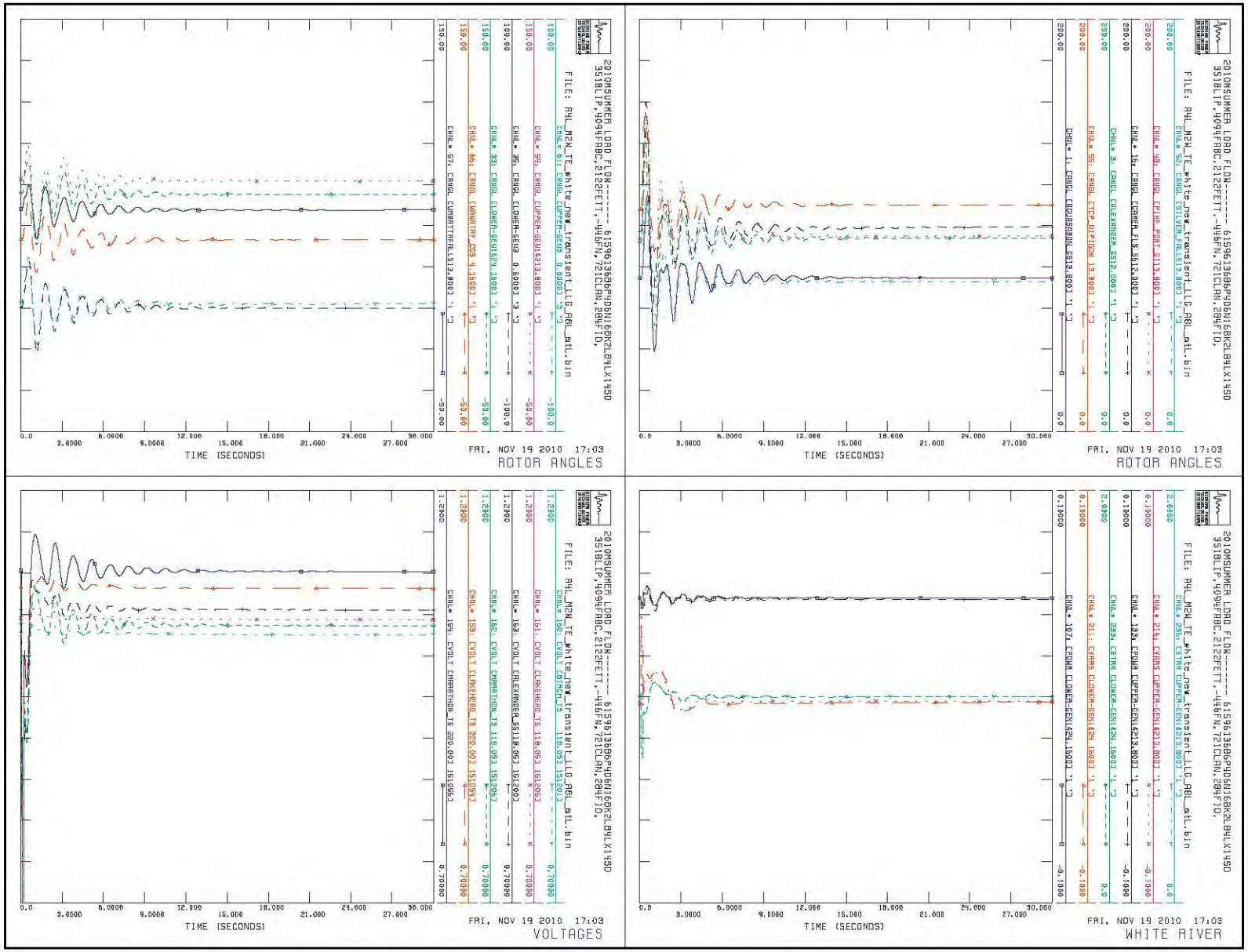
SC1– Scenario S3: LLG Fault on T1M at Marathon 115 kV



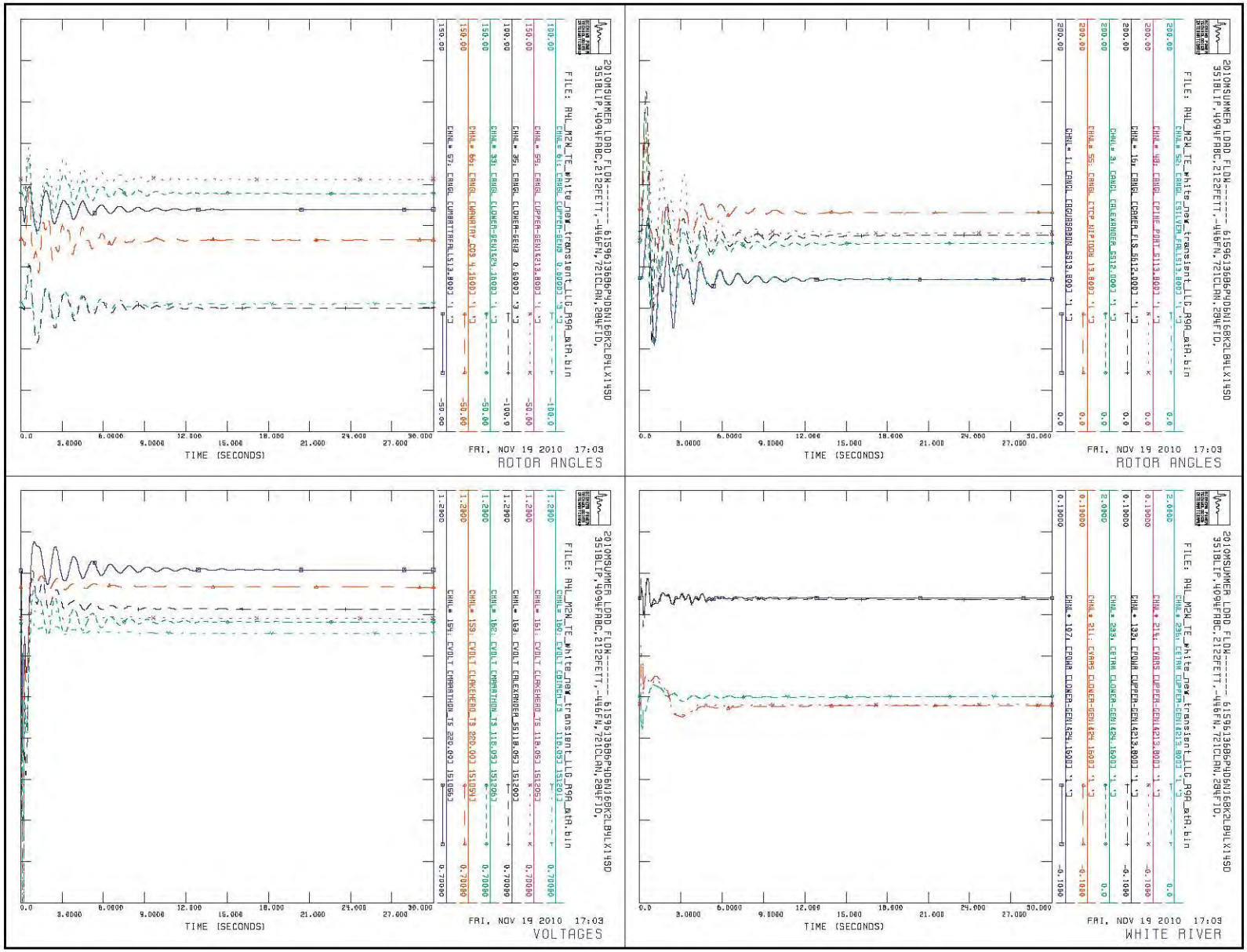
SC2– Scenario S3: LLG Fault on A5A at Alexander SS 115 kV



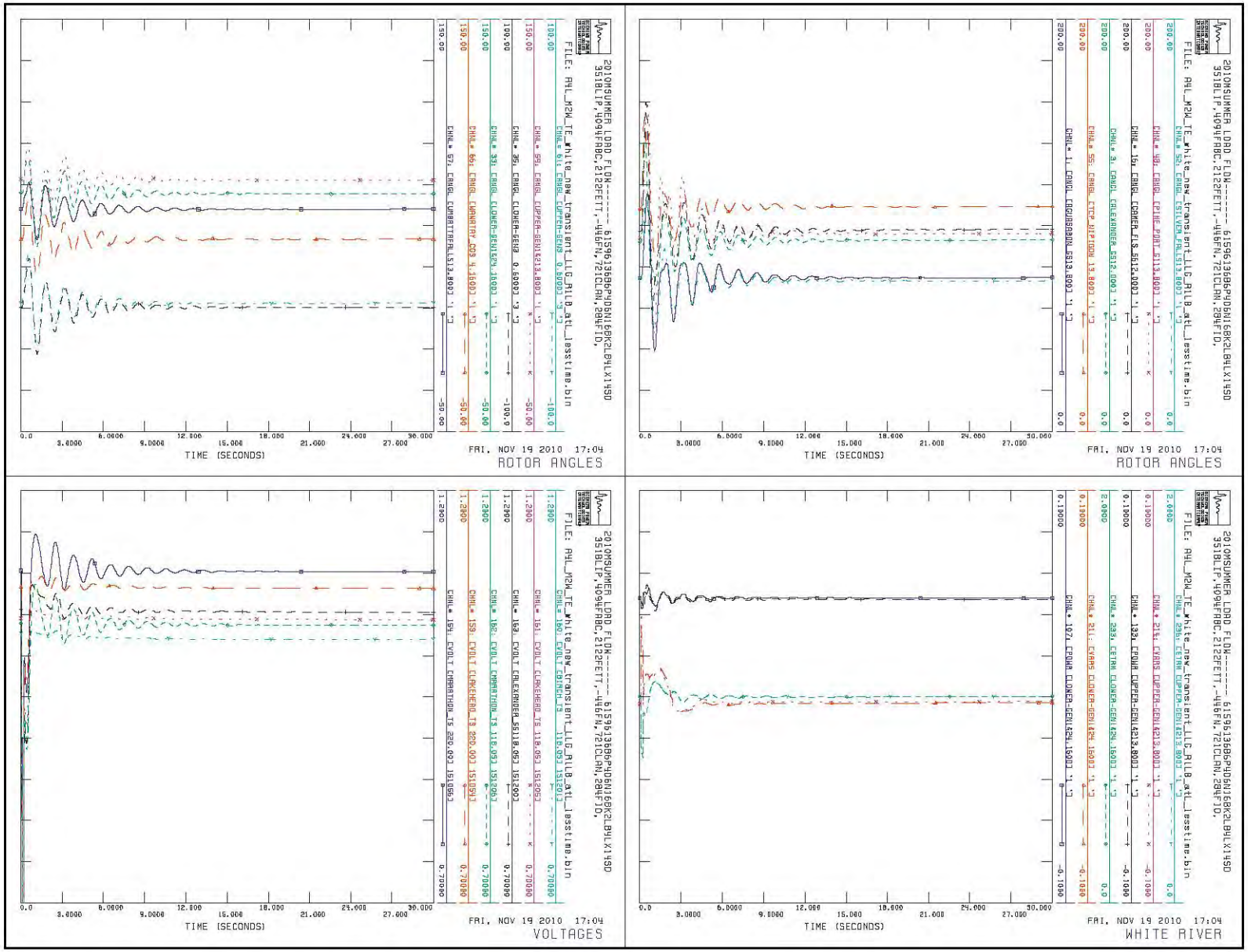
SC3– Scenario S3: LLG Fault on A8L at Lakehead 115 kV



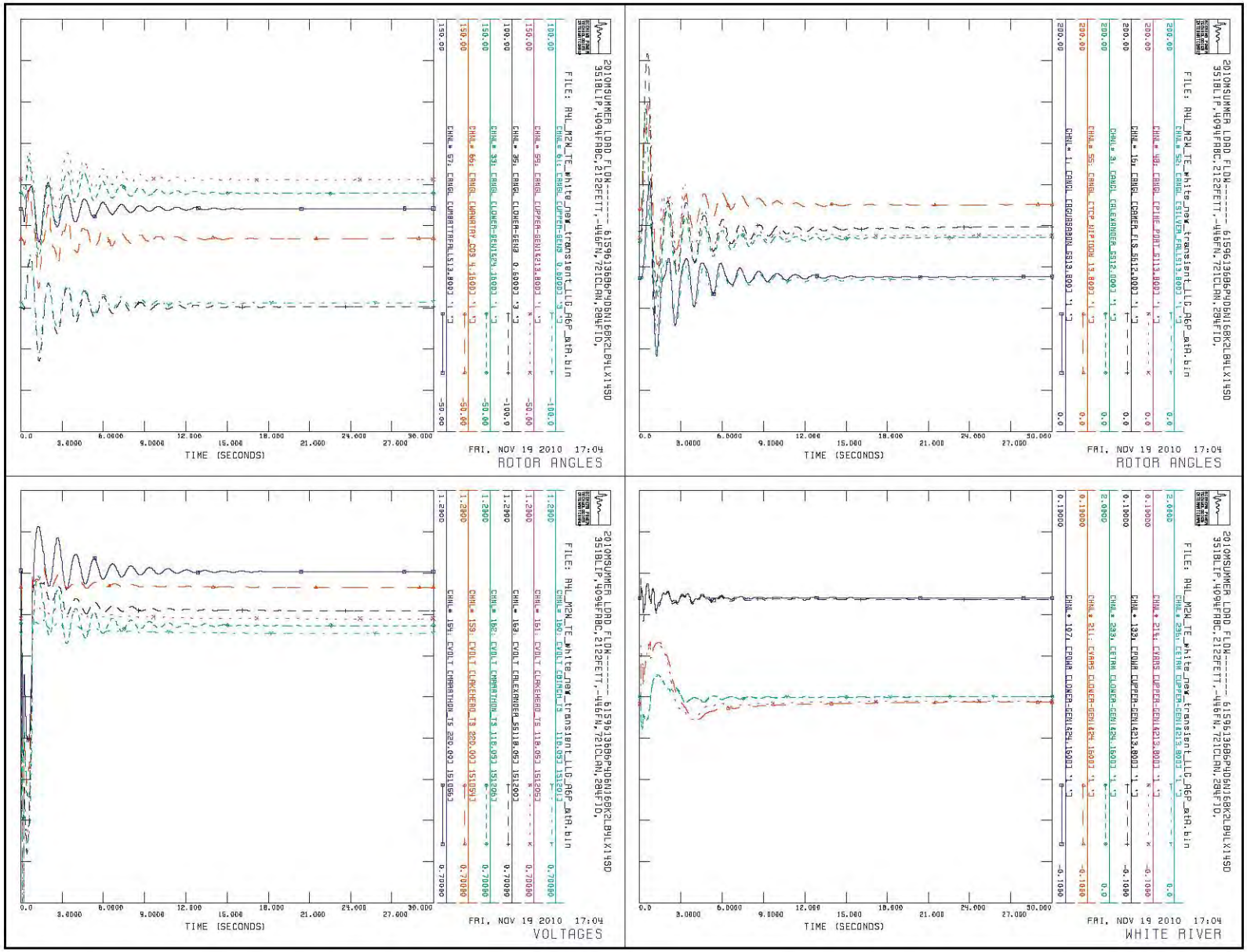
SC4– Scenario S3: LLG Fault on R9A at Alexander SS 115 kV



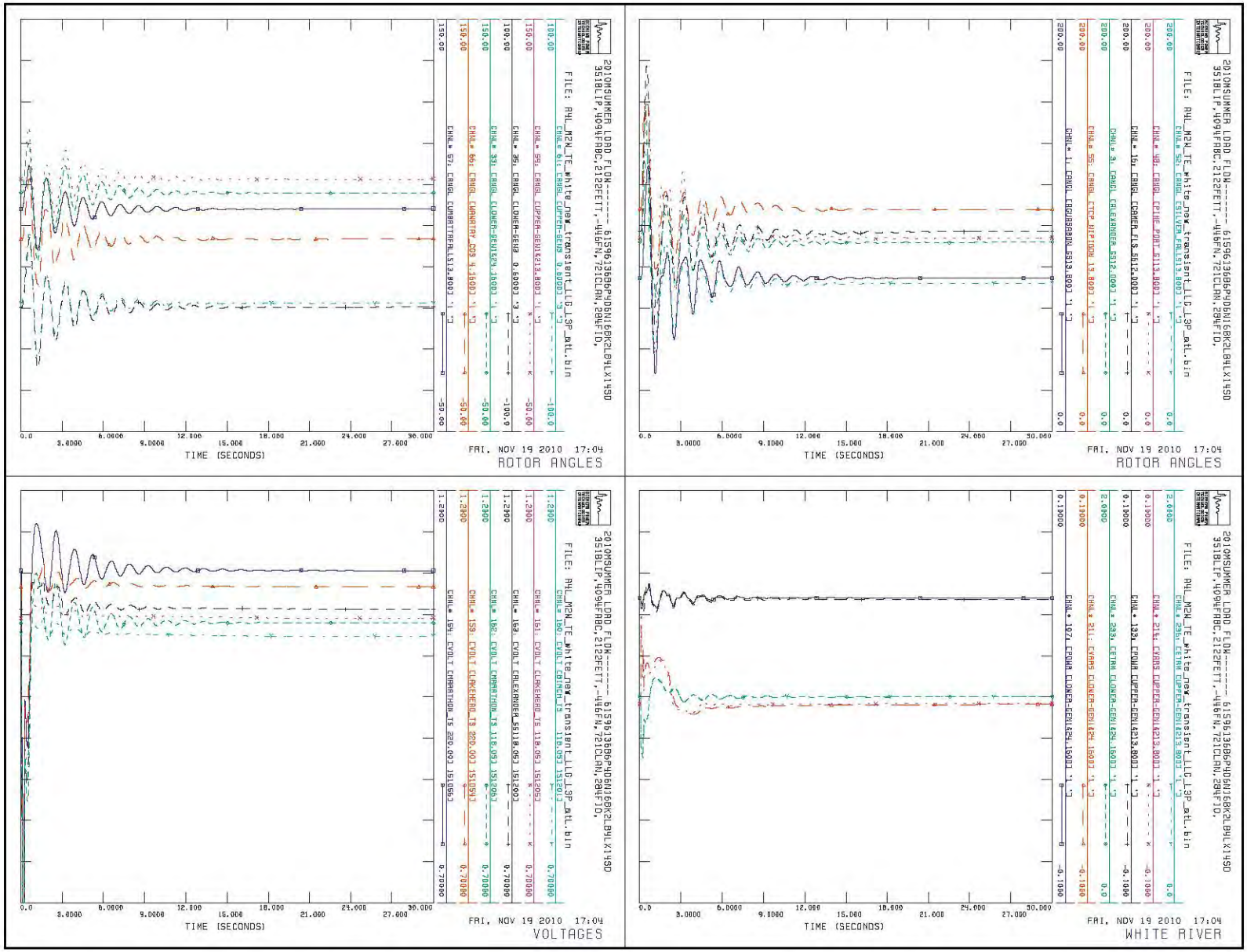
SC5– Scenario S3: LLG Fault on R1LB at Lakehead 115 kV



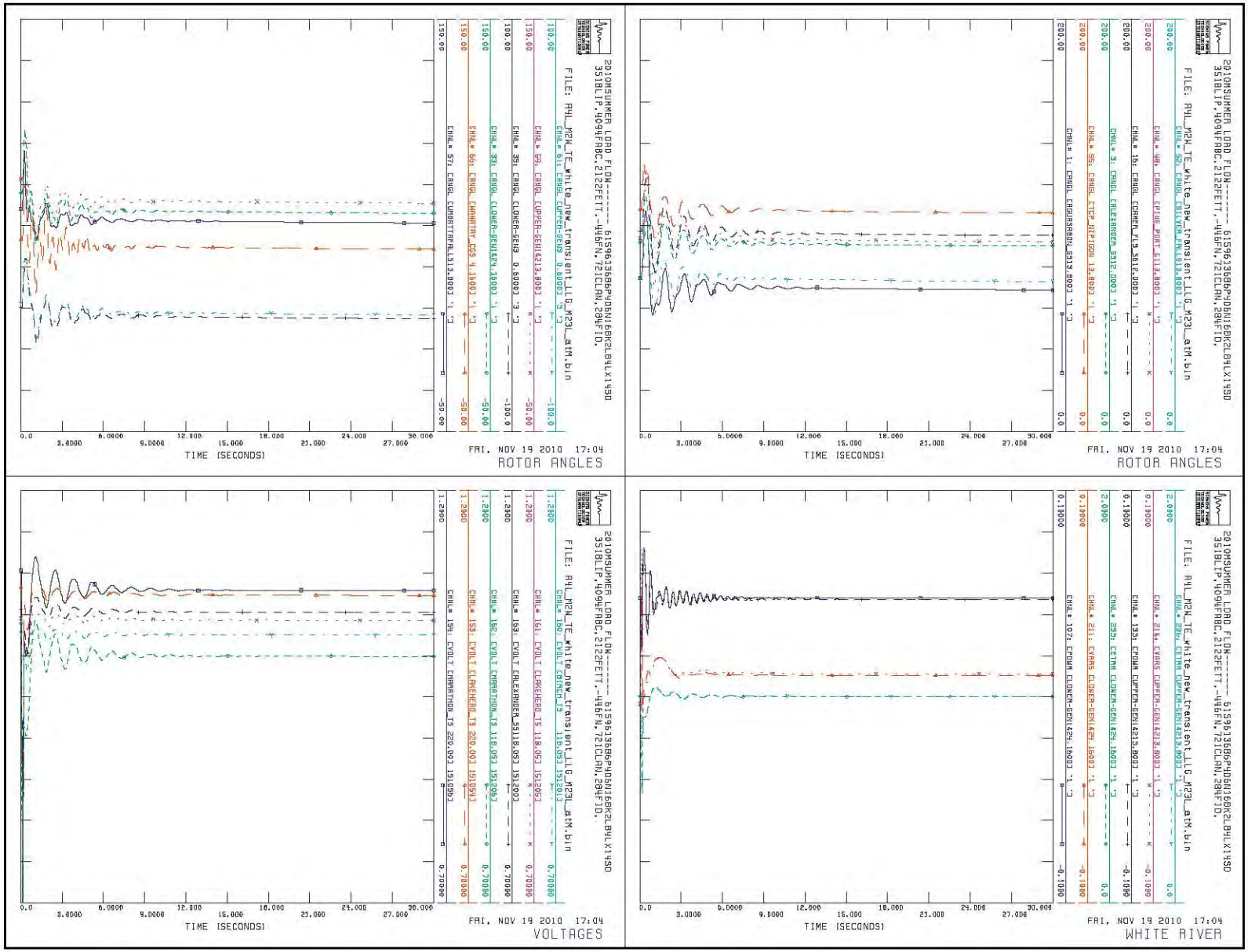
SC6– Scenario S3: LLG Fault on A6P at Alexander SS 115 kV



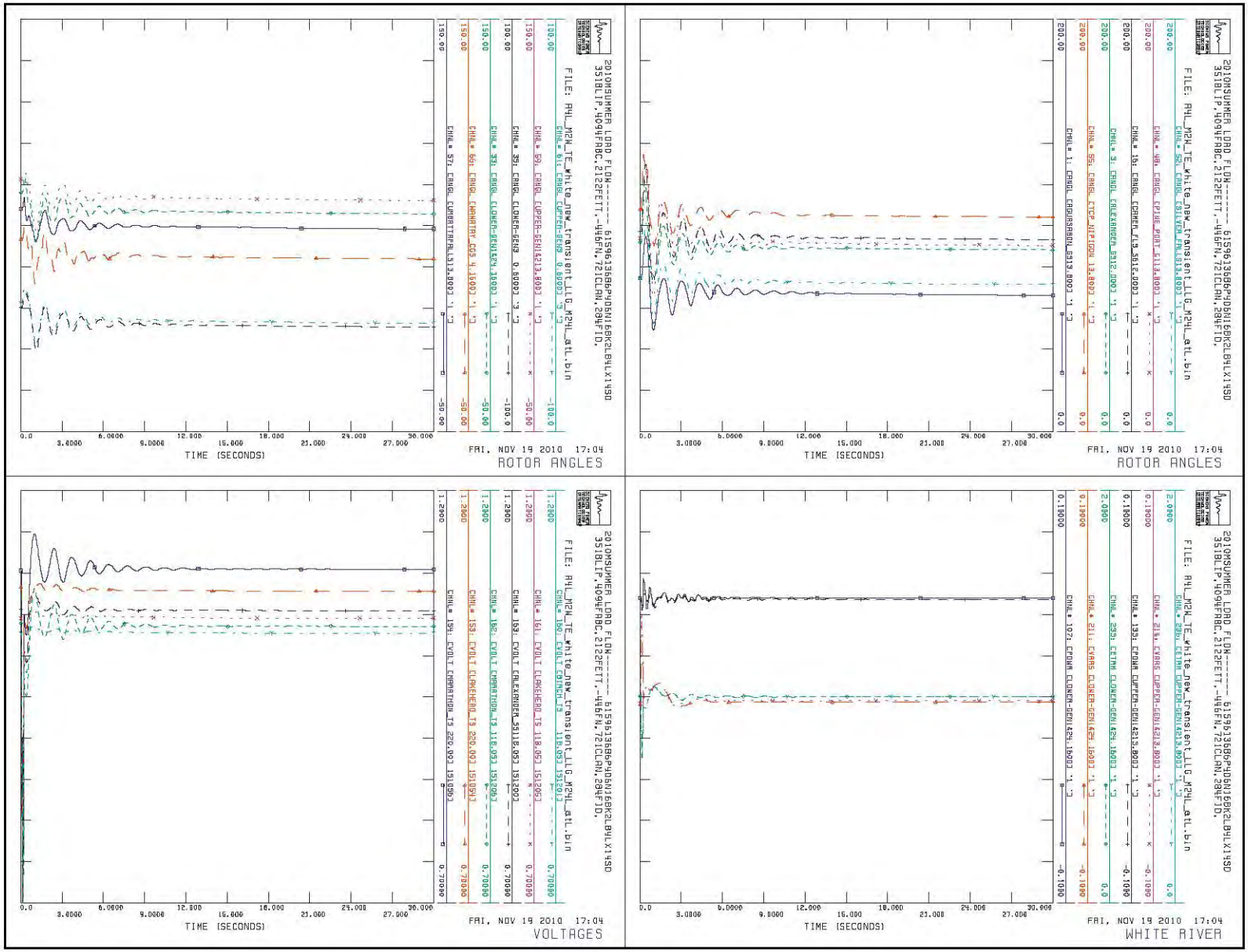
SC7– Scenario S3: LLG Fault on L3P at Lakehead 115 kV



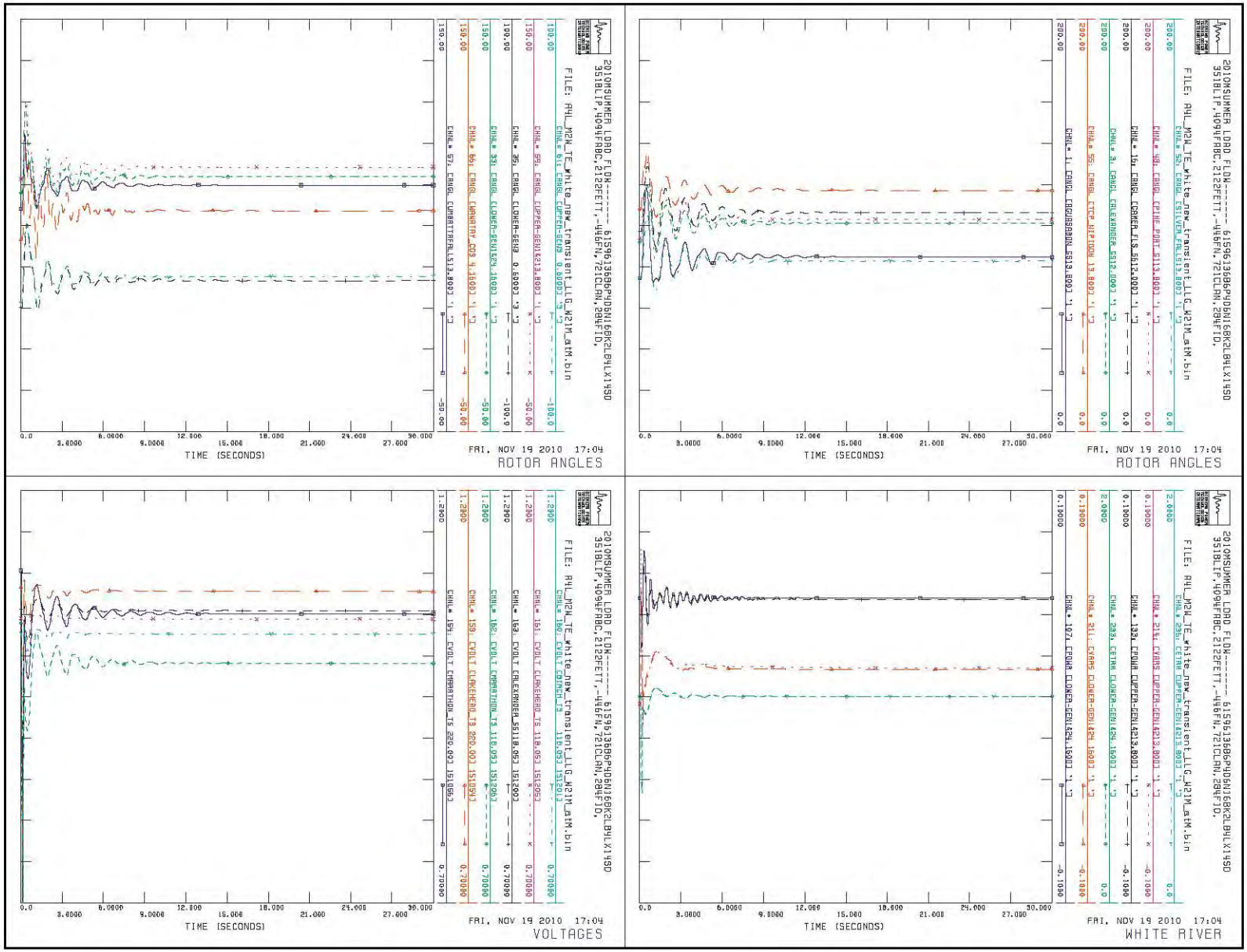
SC8– Scenario S3: LLG Fault on M23L at Marathon 230 kV



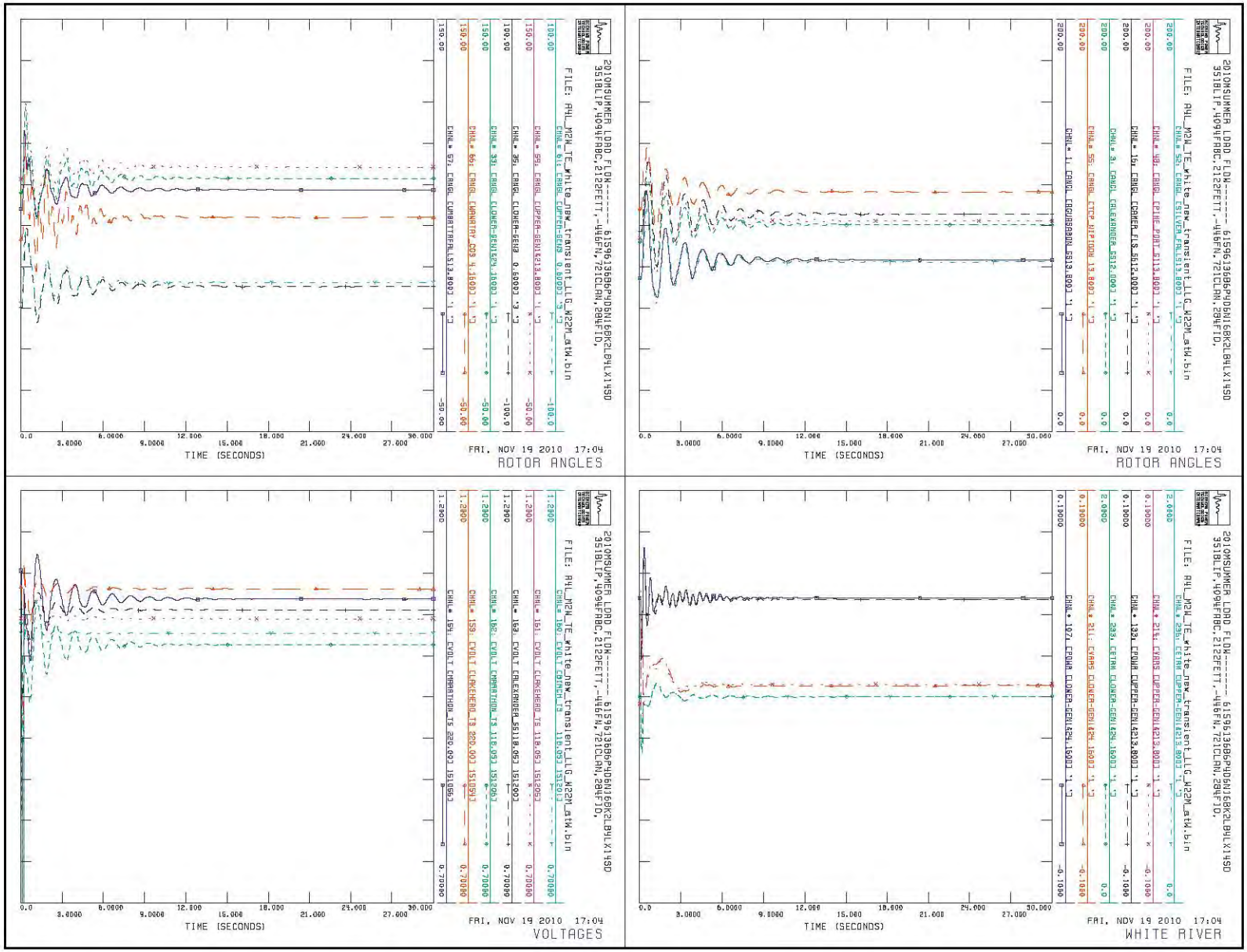
SC9– Scenario S3: LLG Fault on M24L at Lakehead 230 kV



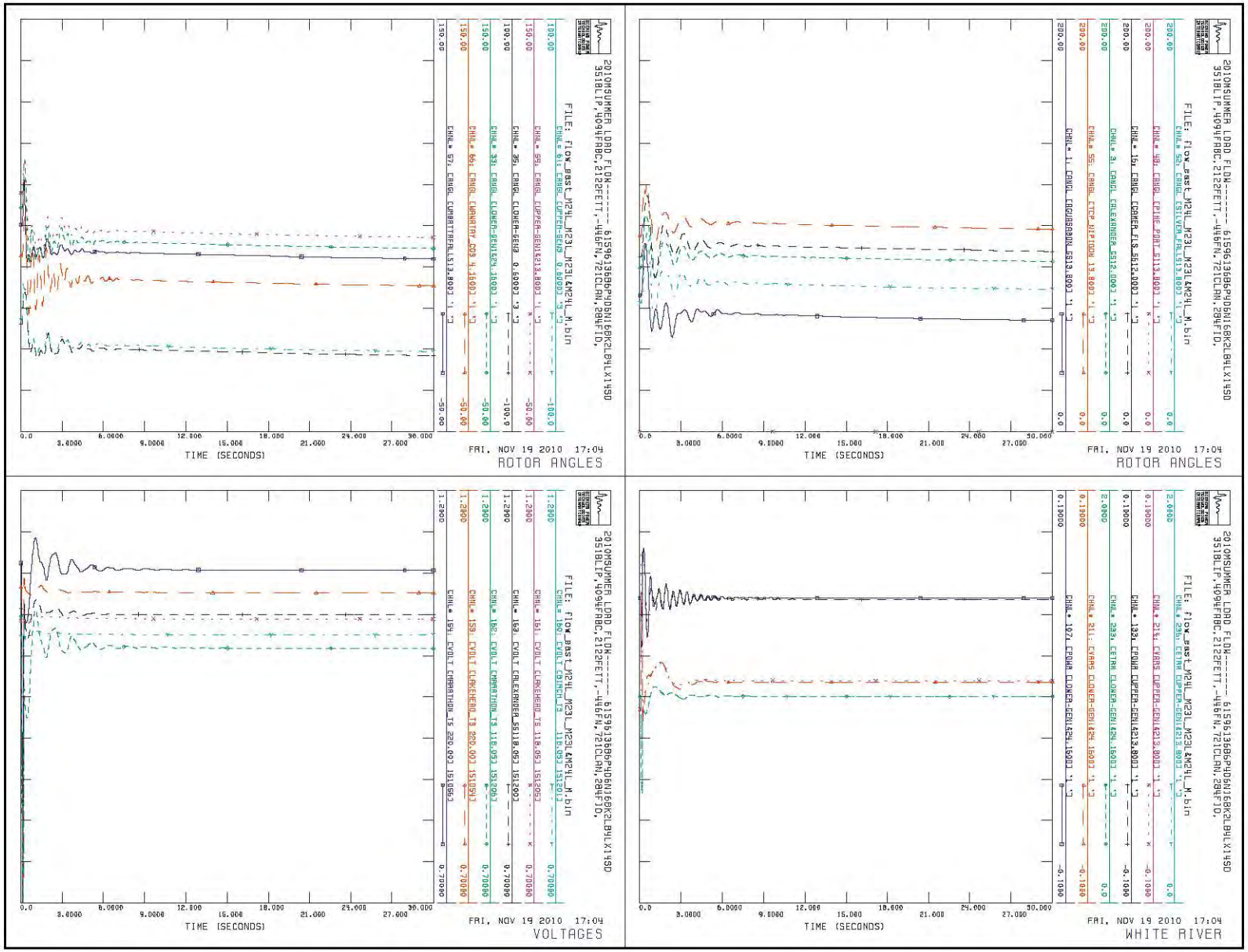
SC10– Scenario S3: LLG Fault on W21M at Marathon 230 kV



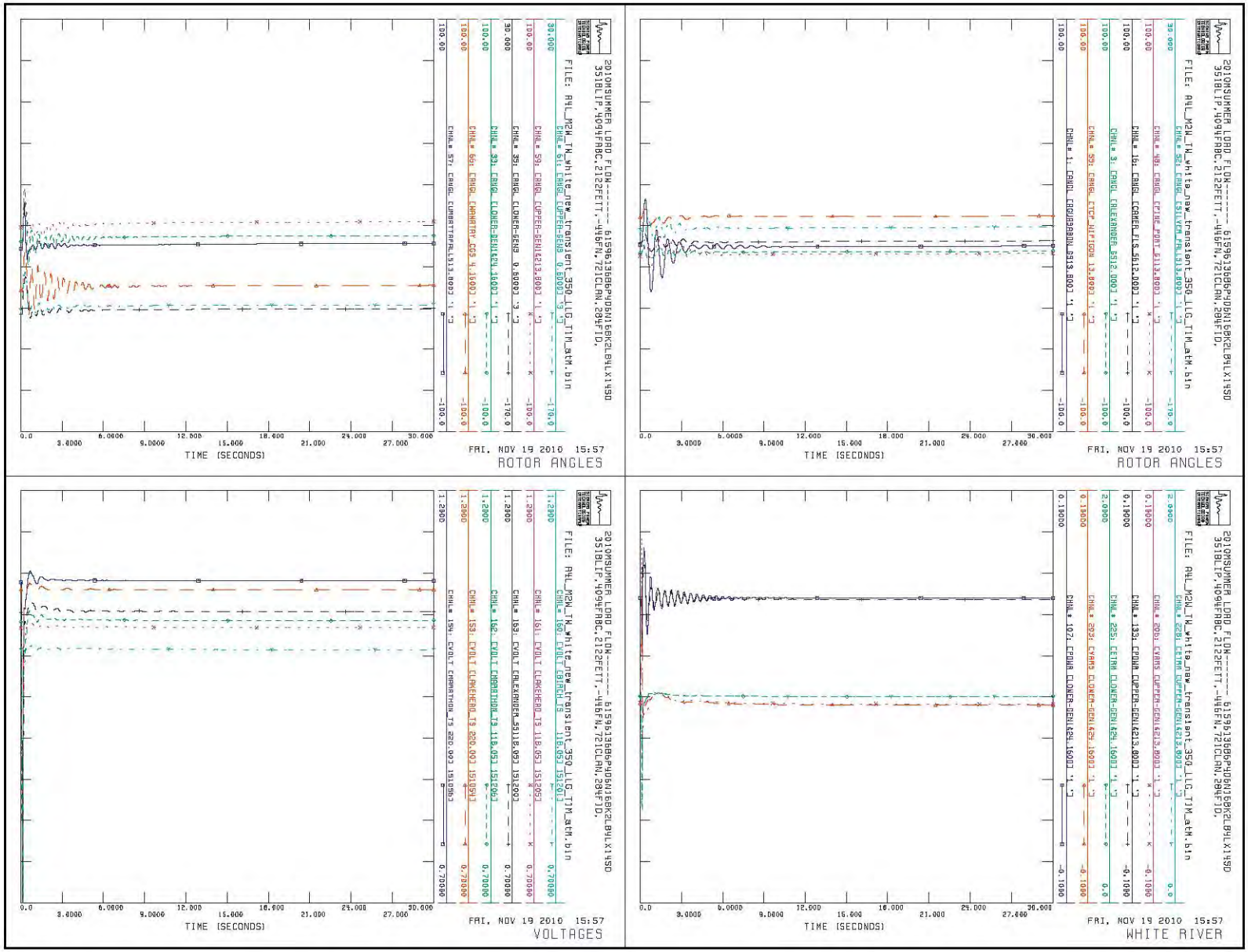
SC11– Scenario S3: LLG Fault on W22M at Wawa 230 kV



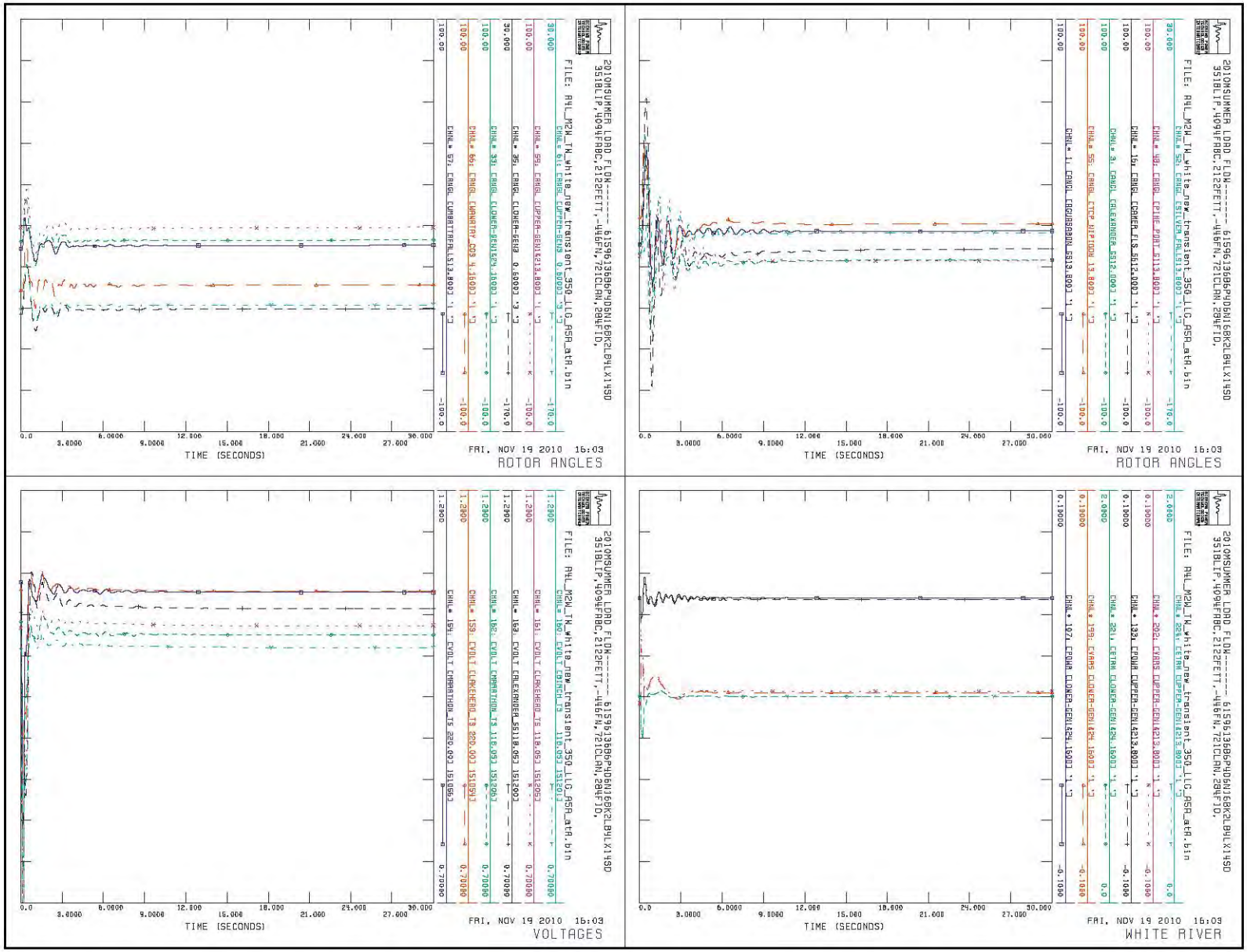
SC12– Scenario EWTE=303 MW, LFE=110 MW: Simultaneous LG Faults on M23L and M24L at Marathon 230 kV



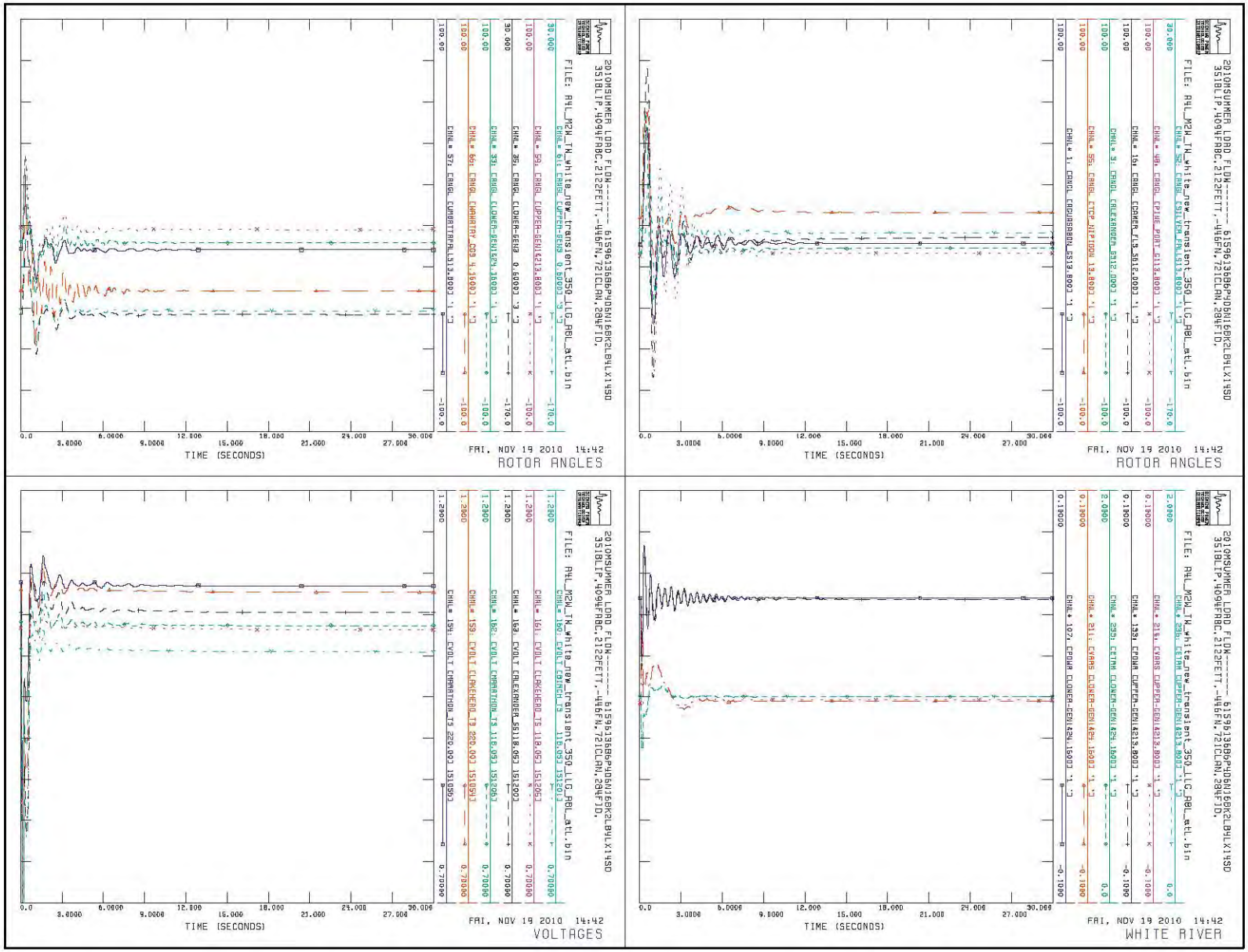
SC13– Scenario S7: LLG Fault on T1M at Marathon 115 kV



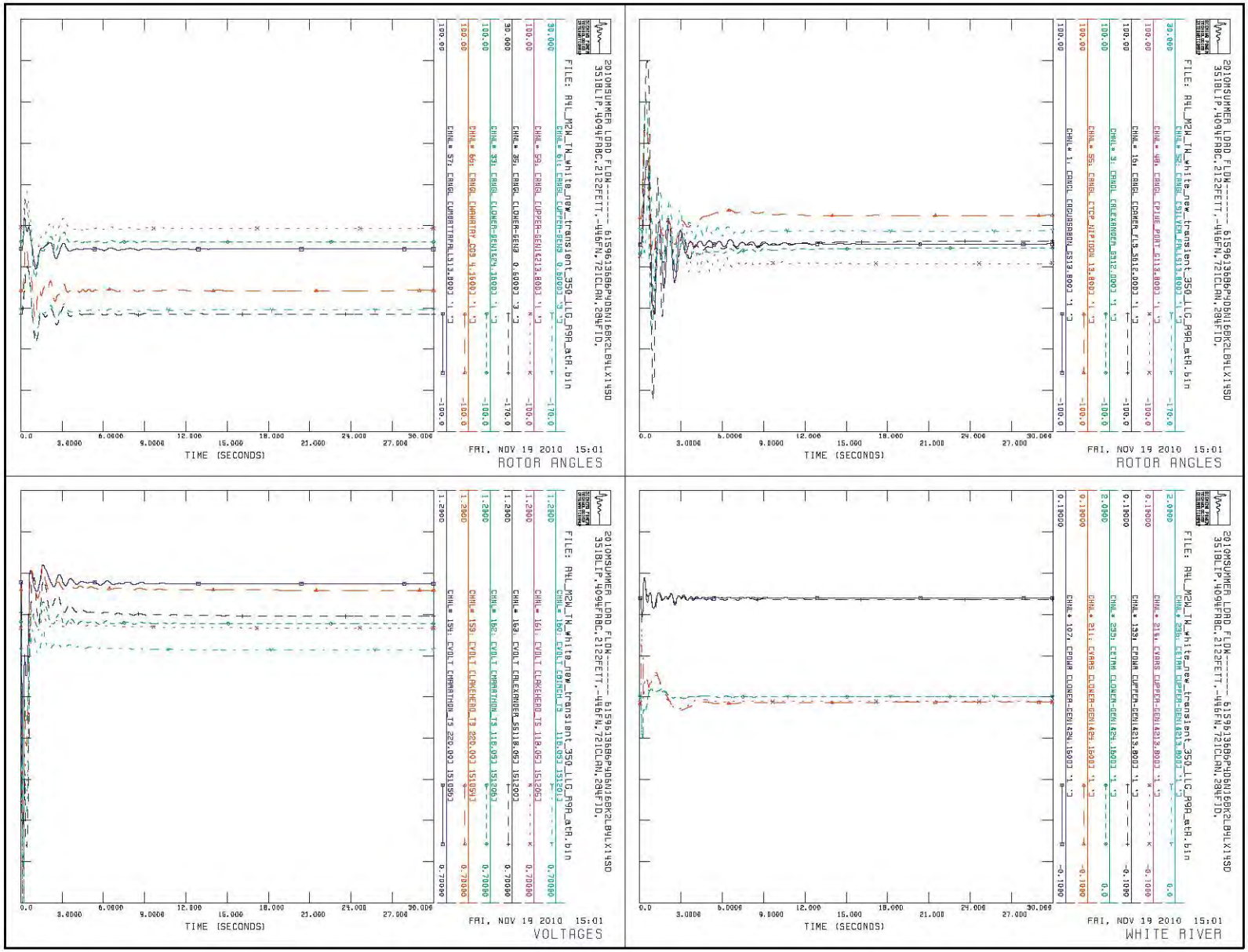
SC14– Scenario S7: LLG Fault on A5A at Alexander SS 115 kV



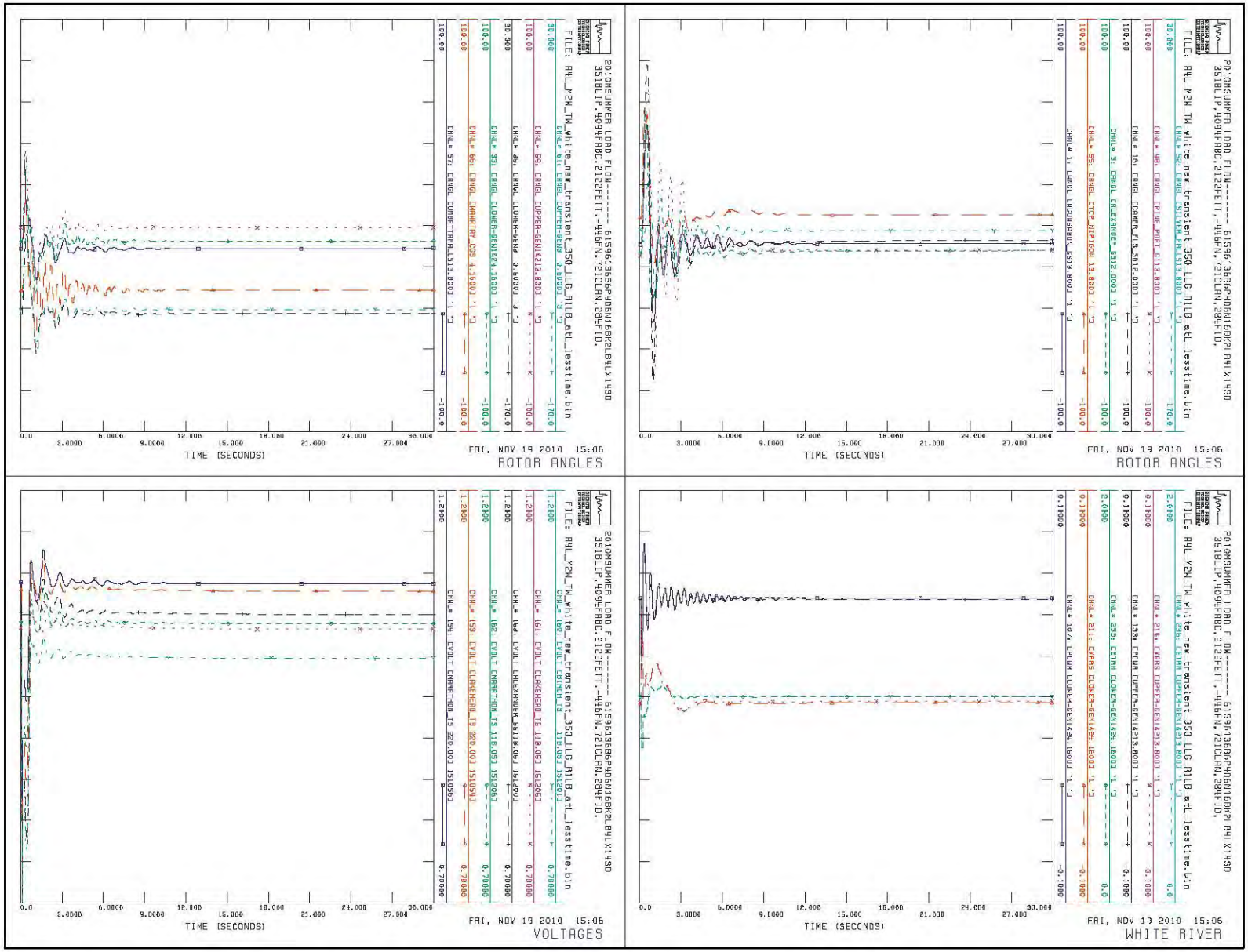
SC15– Scenario S7: LLG Fault on A8L at Lakehead 115 kV



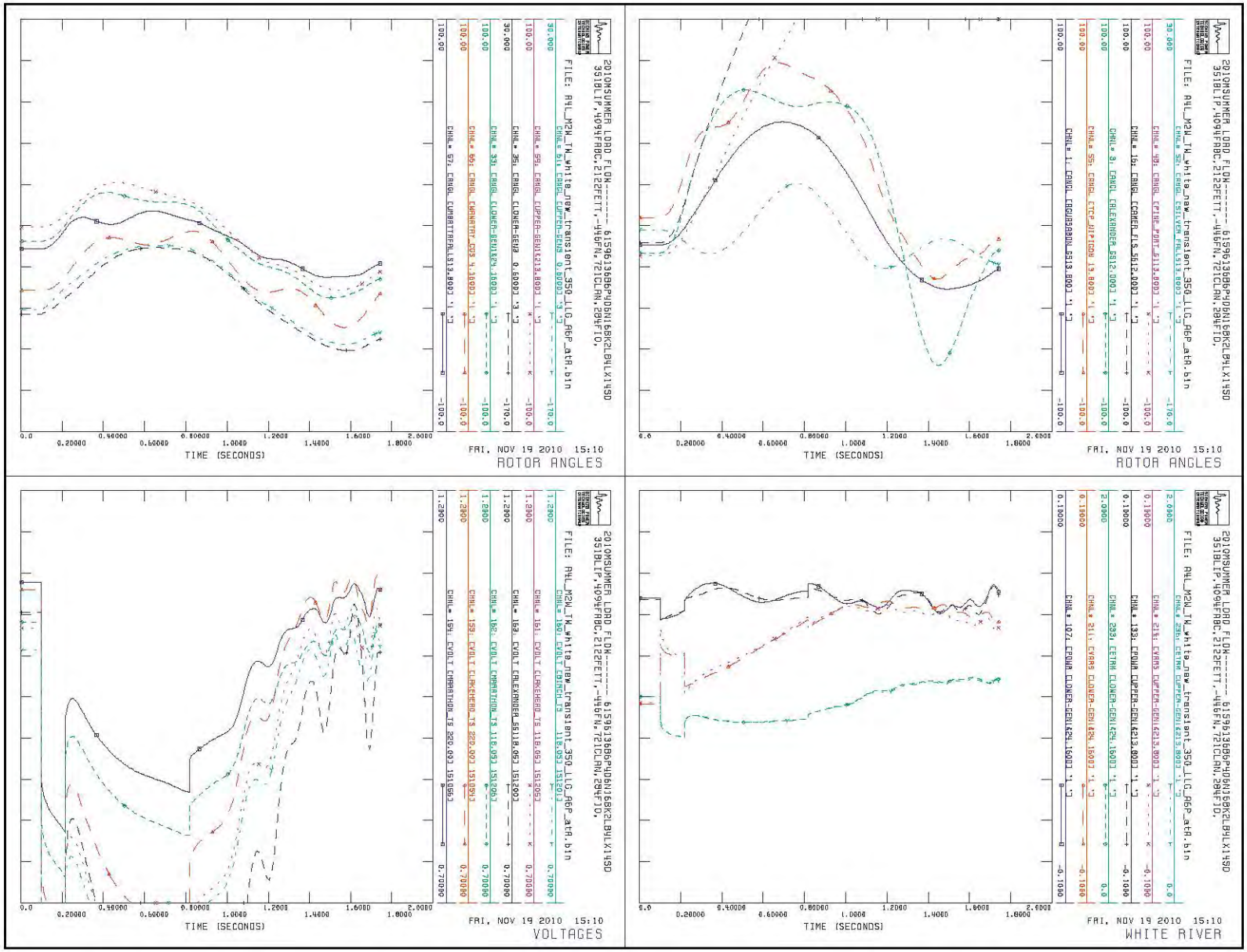
SC16– Scenario S7: LLG Fault on R9A at Alexander SS 115 kV



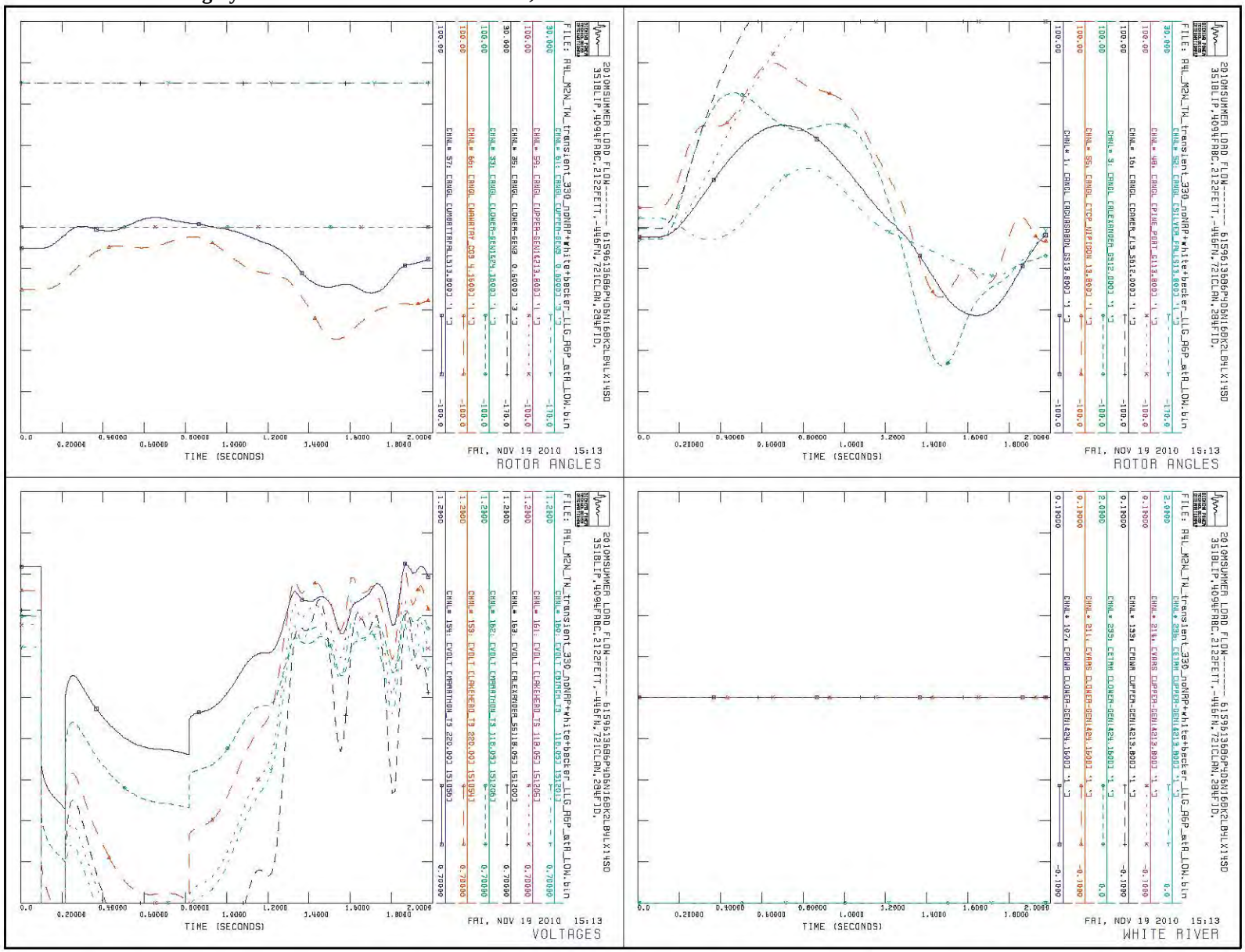
SC17– Scenario S7: LLG Fault on R1LB at Lakehead 115 kV



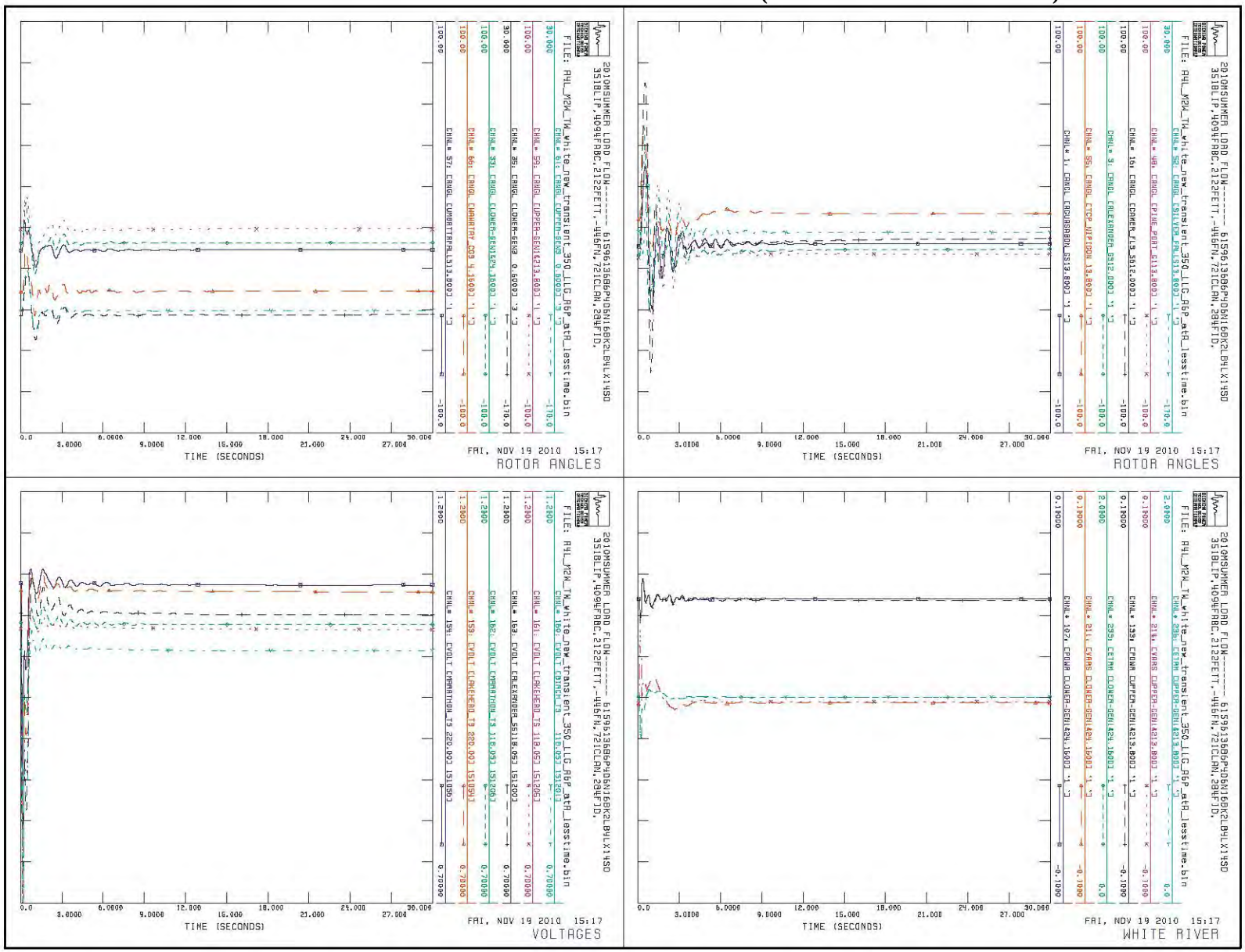
SC18– Scenario S7: LLG Fault on A6P at Alexander SS 115 kV



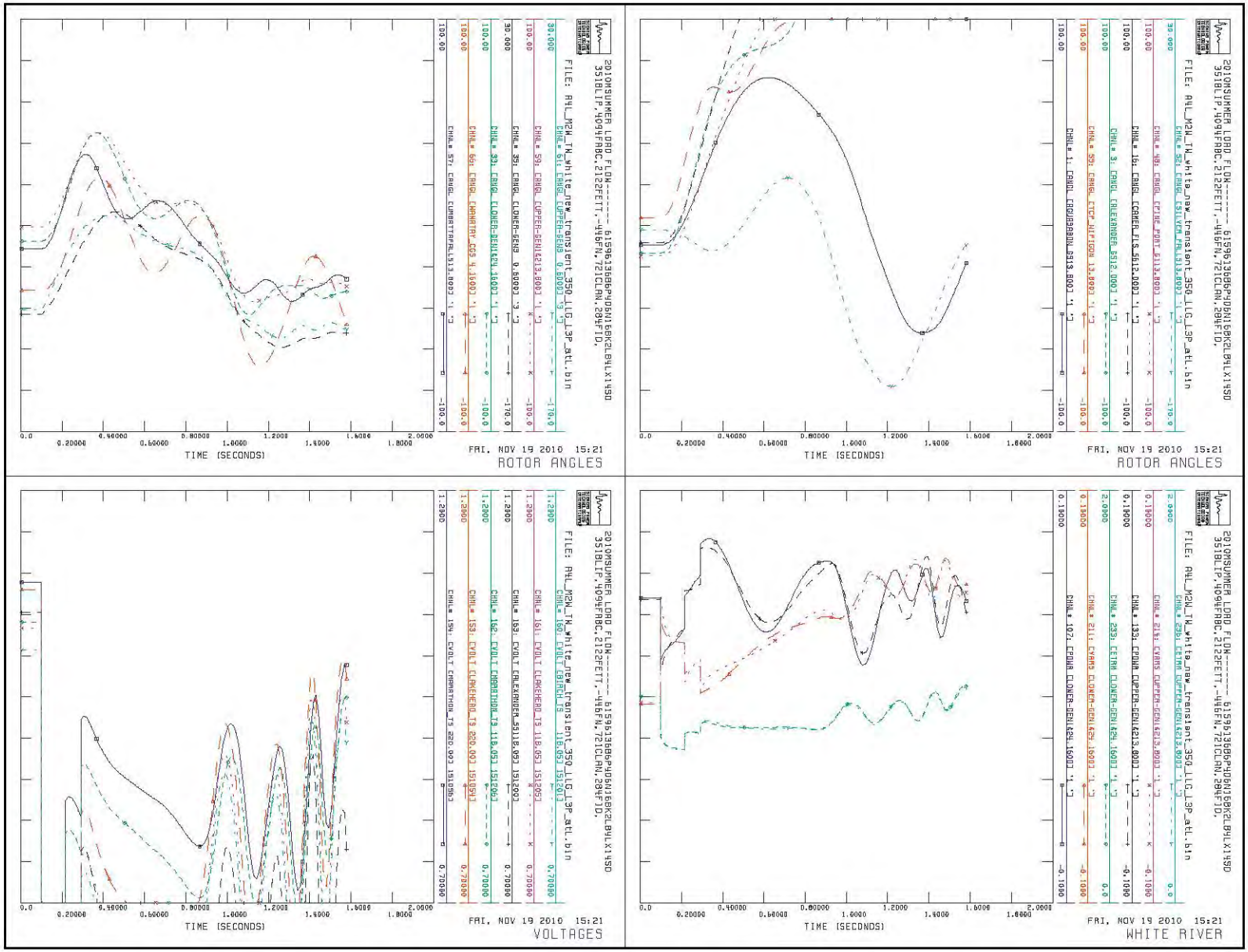
SC19– Existing System Scenario EWTW=333 MW; A6P+A7L+A8L=220 MW: LLG Fault on A6P at Alexander SS 115 kV



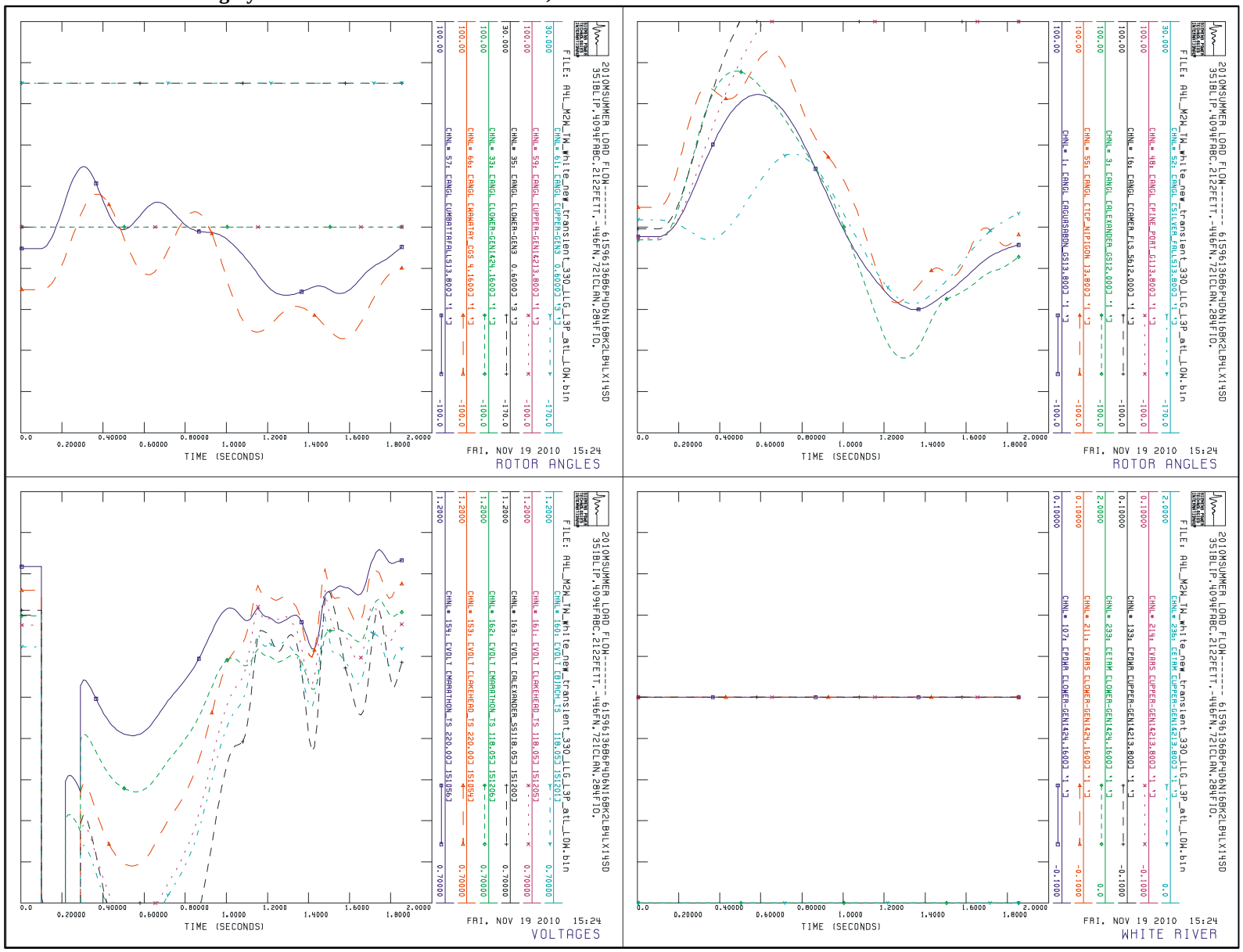
SC20– Scenario S7: LLG Fault on A6P at Alexander SS 115 kV (PLC Communications Assumed)



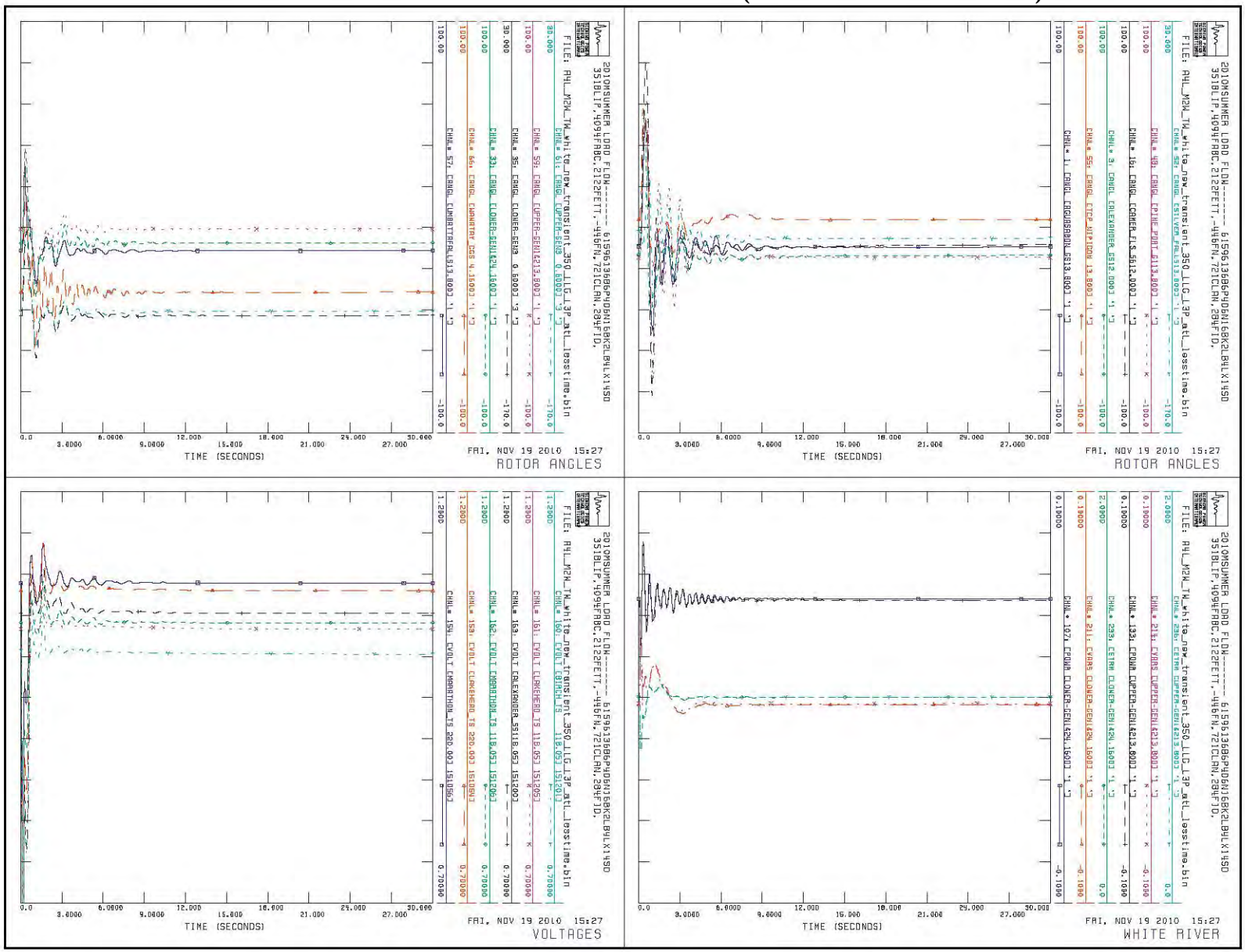
SC21– Scenario S7: LLG Fault on L3P at Lakehead 115 kV



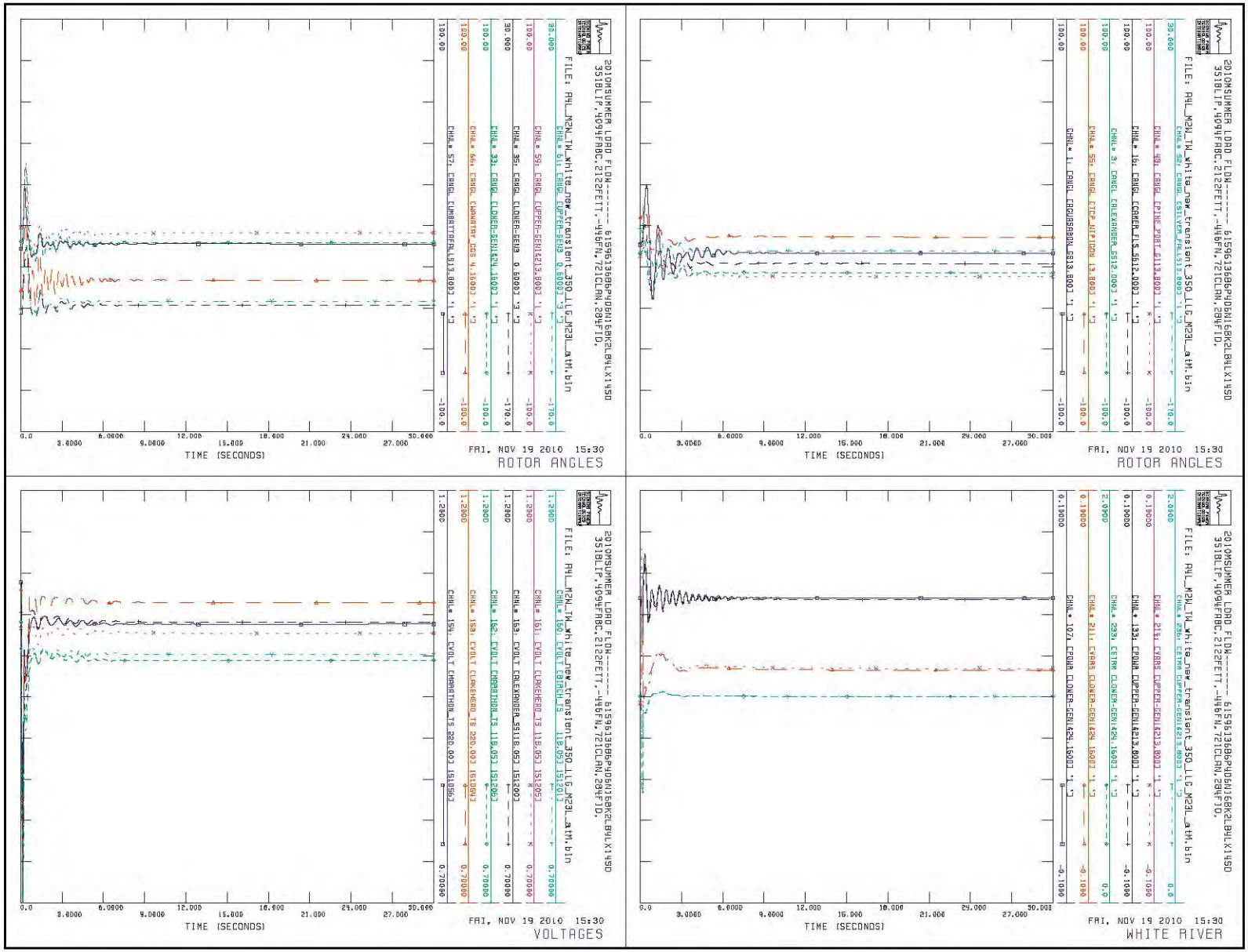
SC22– Existing System Scenario EWTW=333 MW; A6P+A7L+A8L=220 MW: LLG Fault on L3P at Lakehead 115 kV



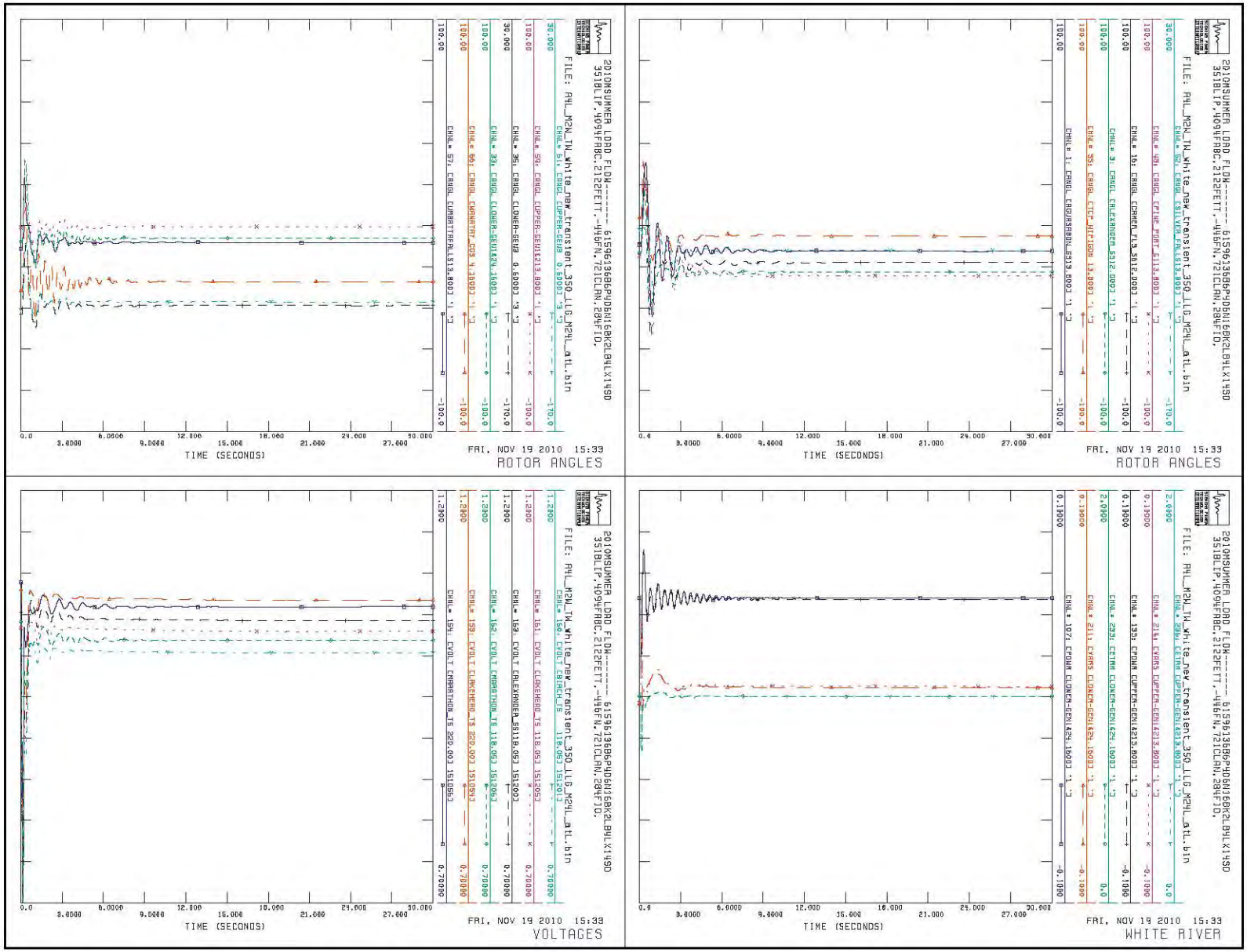
SC23– Scenario S7: LLG Fault on L3P at Lakehead 115 kV (PLC Communications Assumed)



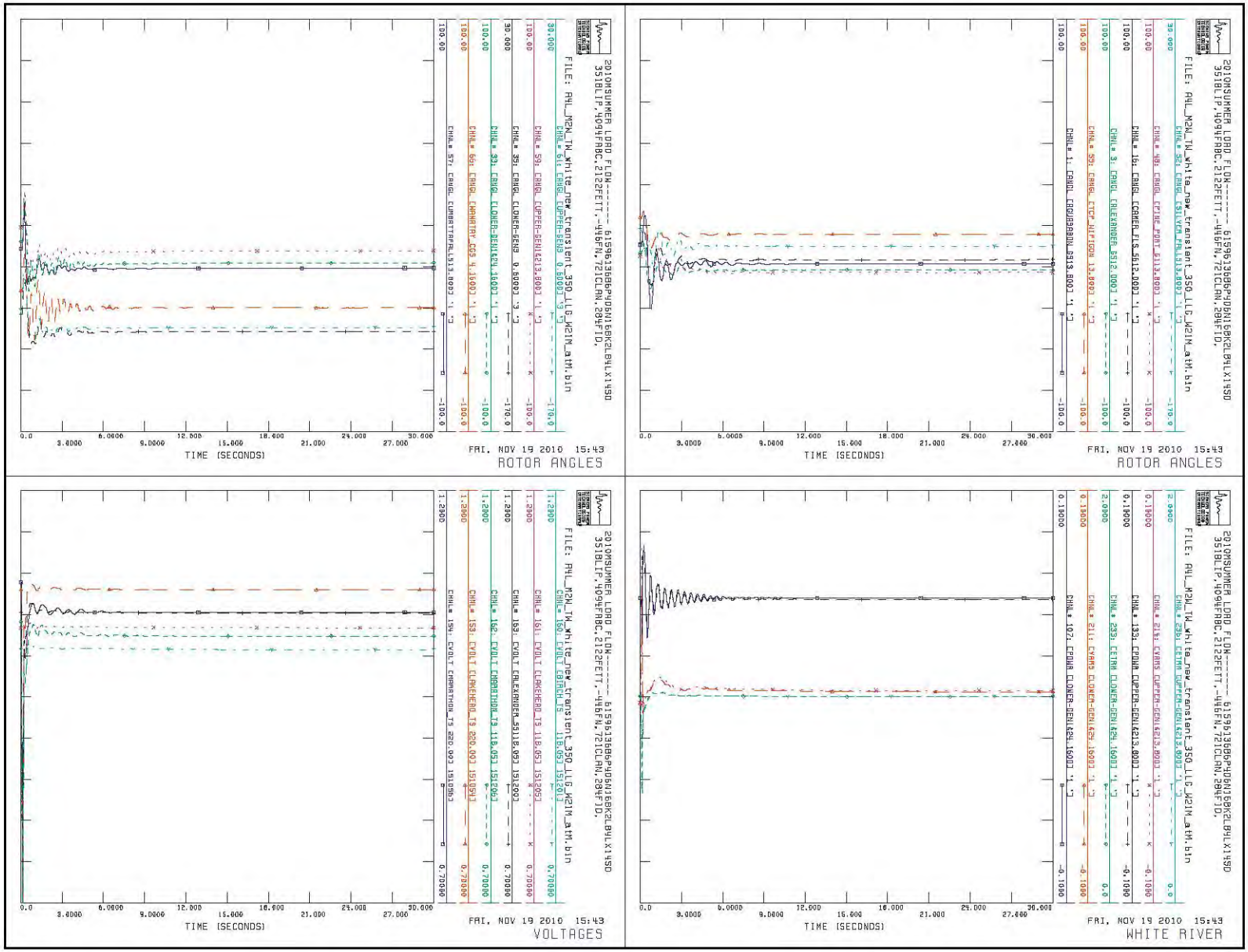
SC24– Scenario S7: LLG Fault on M23L at Marathon 230 kV



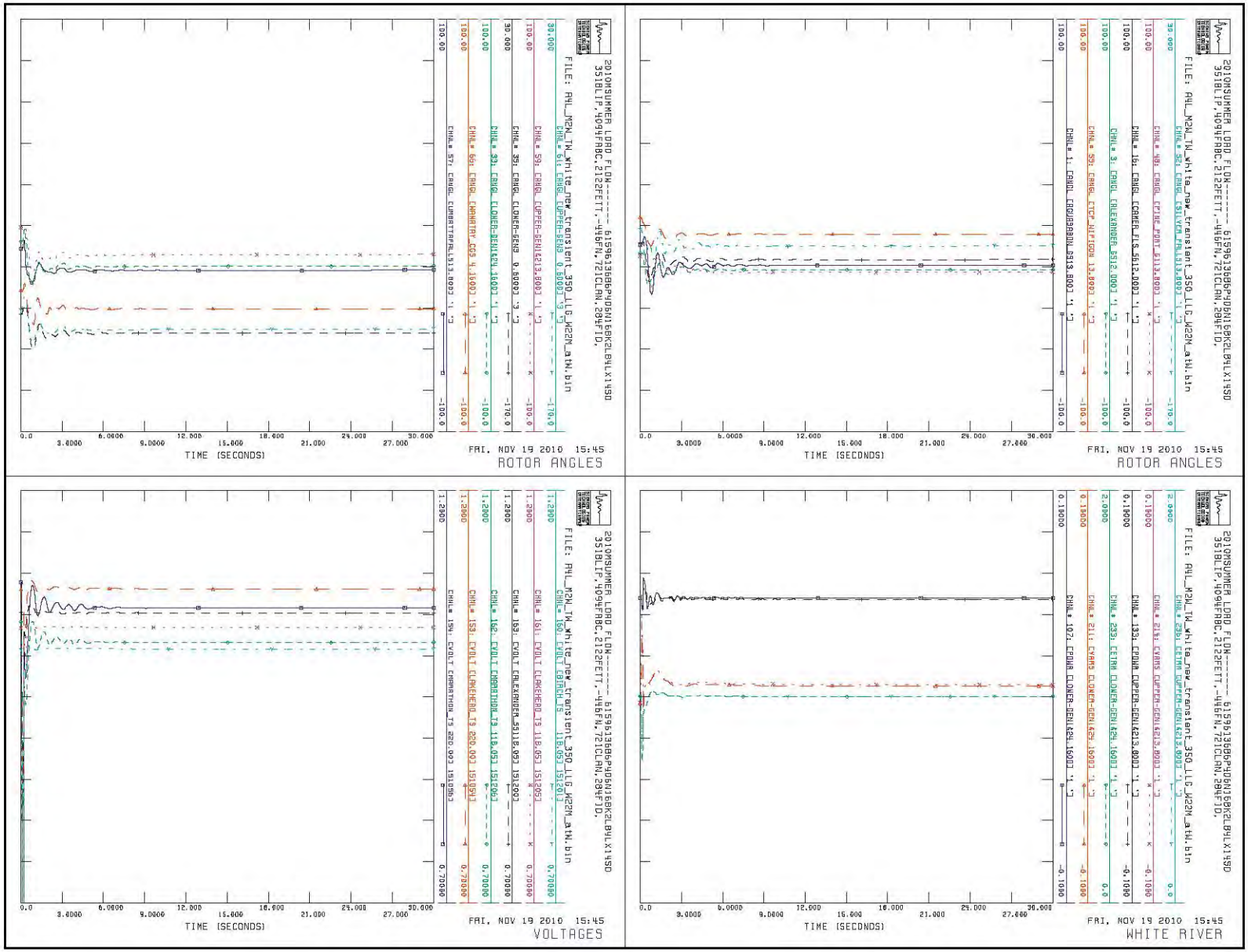
SC25– Scenario S7: LLG Fault on M24L at Lakehead 230 kV



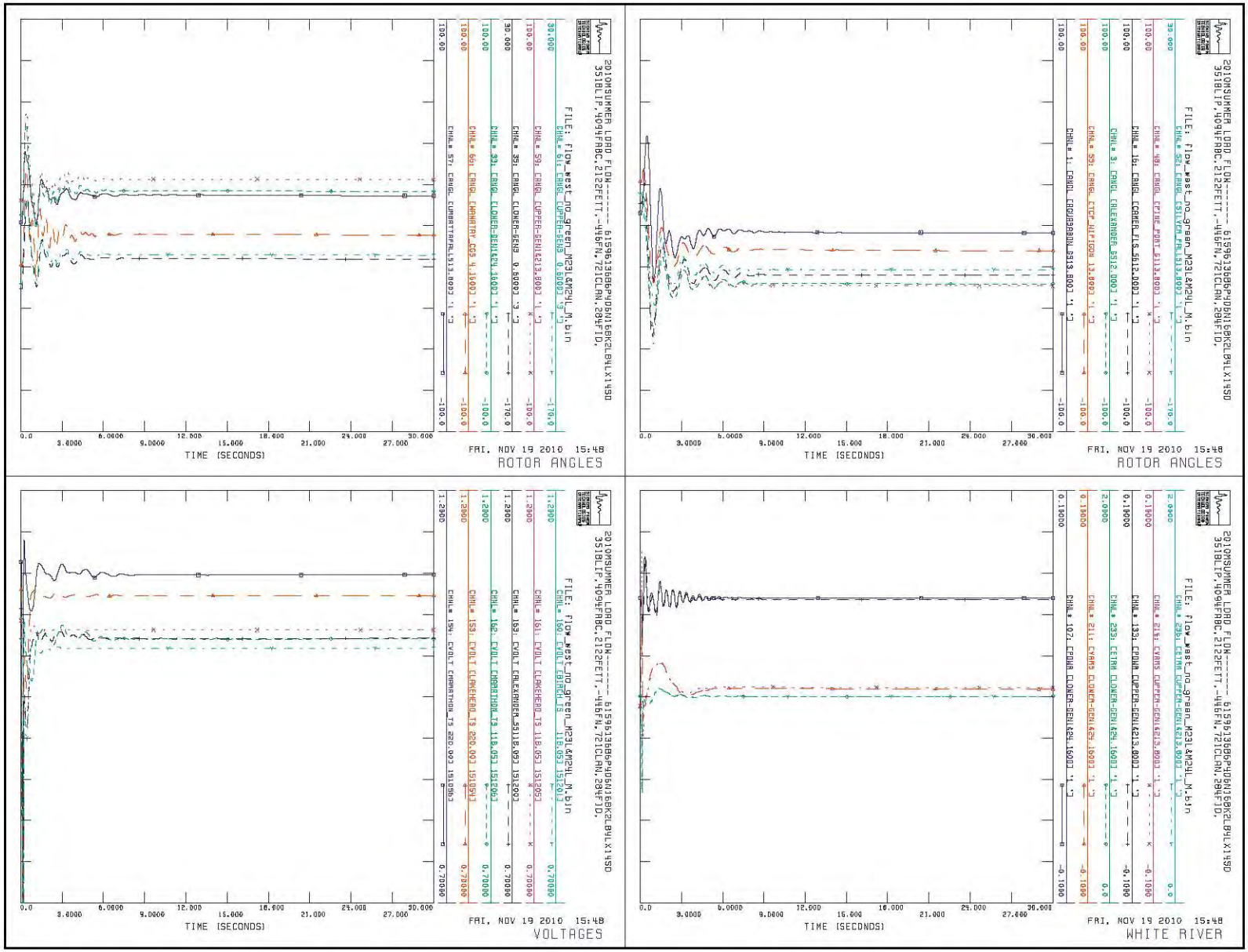
SC26– Scenario S7: LLG Fault on W21M at Marathon 230 kV



SC27– Scenario S7: LLG Fault on W22M at Wawa 230 kV



SC28– Scenario EWTW=250 MW: Simultaneous LG Faults on M23L and M24L at Marathon 230 kV



Appendix C: Protection Impact Assessment

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

PROTECTION IMPACT ASSESSMENT

LOWER AND UPPER WHITE RIVER HYDRO PROJECTS

2 X 5.25 MVA HYDRO GENERATORS (UPPER)
2 X 5.33 MVA HYDRO GENERATORS (LOWER)

Date: November 17, 2010
P&C Planning Group Project #: PCT-165-PIA, PCT-166-PIA

Prepared by

Hydro One Networks Inc.

Disclaimer

This Protection Impact Assessment has been prepared solely for the IESO for the purpose of assisting the IESO in preparing the System Impact Assessment for the proposed connection of the proposed generation facility to the IESO–controlled grid. This report has not been prepared for any other purpose and should not be used or relied upon by any person, including the connection applicant, for any other purpose.

This Protection Impact Assessment was prepared based on information provided to the IESO and Hydro One by the connection applicant in the application to request a connection assessment at the time the assessment was carried out. It is intended to highlight significant impacts, if any, to affected transmission protections early in the project development process. The results of this Protection Impact Assessment are also subject to change to accommodate the requirements of the IESO and other regulatory or legal requirements. In addition, further issues or concerns may be identified by Hydro One during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with the Transmission System Code legal requirements, and any applicable reliability standards, or to accommodate any changes to the IESO-controlled grid that may have occurred in the meantime.

Hydro One shall not be liable to any third party, including the connection applicant, which uses the results of the Protection Impact Assessment under any circumstances, whether any of the said liability, loss or damages arises in contract, tort or otherwise.

EXECUTIVE SUMMARY

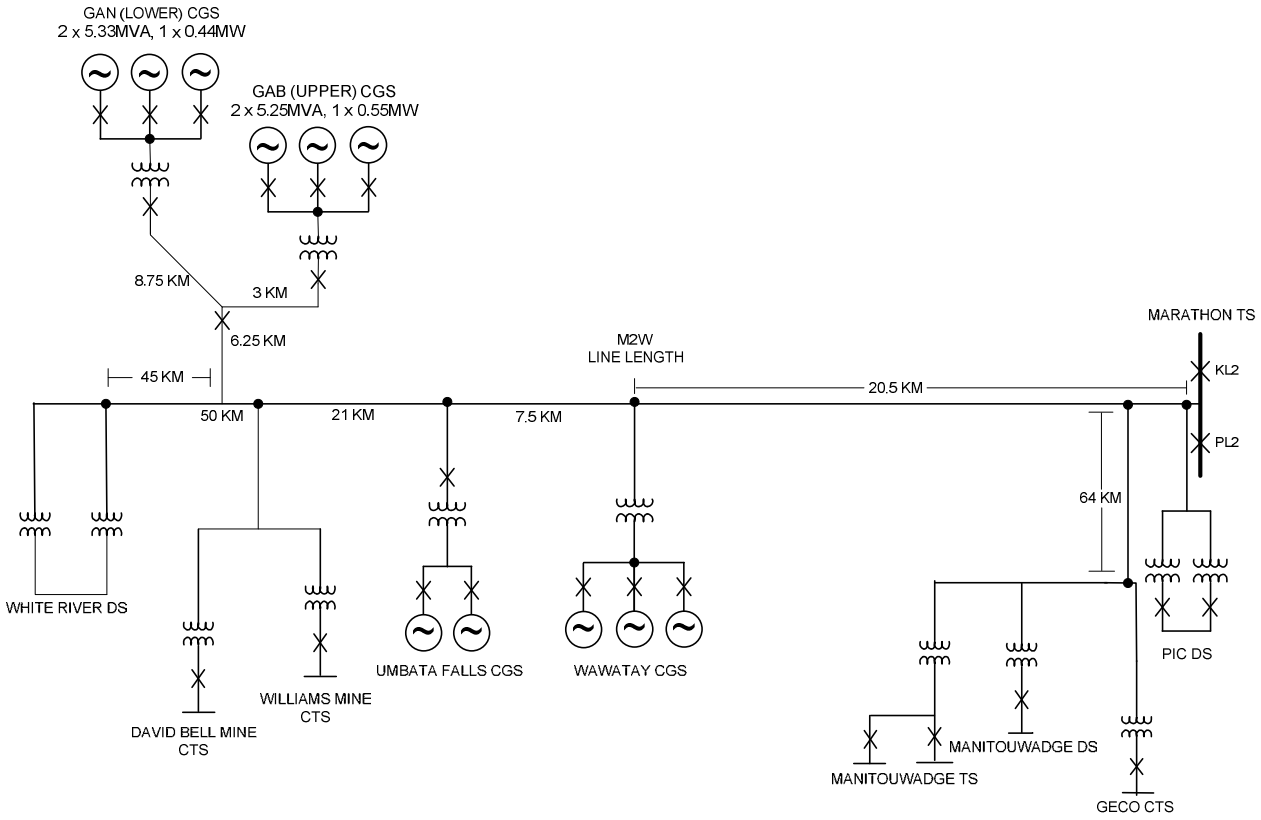


Figure 1: ~21 MVA Hydro Generation Connection to HONI Transmission System

It is feasible for Pic Mobert Hydro Power Joint Venture (PMHP) to connect the proposed ~21 MVA generation at the location in Figure 1 as long as the proposed changes are made:

PROTECTION HARDWARE

The present protections on M2W will continue to function with the existing teleprotection scheme for the Marathon TS terminal. The Protection scheme will have to be modified and hardware addition is required for a blocking, GEO and breaker failure signal from the new PMHP switching station to be incorporated into the existing scheme.

PROTECTION SETTING

The existing Zone 2 reach will be adjusted to cover the maximum apparent impedance due to the connection of the PMHP generators.

TELECOMMUNICATIONS

New telecommunication link(s) need to be established to transmit protection signals among all stations that are required for the reliable fault clearing. The provision of new telecommunication facilities that are required to facilitate this connection (subject to final design considerations) is responsibility of the proponent.

Exhibit B-4-3 – CIA report

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

CUSTOMER IMPACT ASSESSMENT

Proposed

Gitchi Animki Niizh (GAN) 10.0 MW Generation Project
(OPA Ref. # FIT – FSH5DP3)
And
Gitchi Animki Bezhig (GAB) 10.0 MW Generation Project
(OPA Ref. # FIT – F2L095E)

Revision: **Rev 0**

Date: **February 10, 2011**

Issued by: Transmission Plans North Department
Transmission System Development Division
Hydro One Networks Inc.

Prepared by:

Khurram Makhdoom
Transmission System Development
Hydro One Networks Inc.

Approved by:

Ibrahim El Nahas
Transmission System Development
Hydro One Networks Inc.

Disclaimer

This Customer Impact Assessment was prepared based on preliminary information available about the connection of the proposed generations near the town of Mobert in Marathon area, Ontario. It is intended to highlight significant impacts, if any, to affected transmission customers early in the project development process and thus allow an opportunity for these parties to bring forward any concerns that they may have including those needed for the review of the connection and for any possible application for leave to construct. Subsequent changes to the required modifications or the implementation plan may affect the impacts of the proposed connection identified in this Customer Impact Assessment. The results of this Customer Impact Assessment and the estimate of the outage requirements are also subject to change to accommodate the requirements of the IESO and other regulatory or municipal authority requirements.

Hydro One Networks shall not be liable to any third party which uses the results of the Customer Impact Assessment under any circumstances whatsoever, for any indirect or consequential damages, loss of profit or revenues, business interruption losses, loss of contract or loss of goodwill, special damages, punitive or exemplary damages, whether any of the said liability, loss or damages, arises in contract, tort or otherwise.

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CUSTOMER IMPACT ASSESSMENT

Proposed Gitchi Animki Niizh 10.0 MW Hydro Electric Generation Project and Gitchi Animki Bezhig 10.0 MW Hydro Electric Generation Project both located near the town of Mobert in Marathon area, Ontario Site.

1.0 EXECUTIVE SUMMARY

Under the Ontario's Green Energy Green Environment initiative Ontario Power Authority's (OPA) received two applications of 10.0 MW each to connect a total of 20.0 MW hydroelectric generations under its Feed-In-Tariff (FIT) program. This report presents the results of assessment to connect the above two generations to Hydro One's transmission system.

Both generations are intended to connect to Hydro One's 115 kV M2W circuit through a single line tap at tower number 244 approximately 42 km from Marathon TS. The impact of these new generation projects was analyzed by comparing the voltages in the area before and after incorporation of the Gitchi Animki Niizh and Gitchi Animki Bezhig hydroelectric generation projects. Ontario Energy Board's Transmission system code was primary 'Planning Criteria' to observe any voltage or short circuit level violations. The impact assessment of the proposed generation on thermal loading of transmission facilities is a part of IESO's SIA.

The proposed Gitchi Animki Niizh Hydro Electric Generation Project and Gitchi Animki Bezhig Hydro Electric Generation Project each of 10 MW intend to connect to Hydro One's circuit M2W through a single 115 kV line tap. Both these projects are connected to the M2W circuit at the point of common coupling protected by a single high voltage 115 kV breaker. Consequently, this connection does not expose the existing Hydro One customers to increased interruptions or diminish the reliability and performance of supply.

The load flow and short circuit analysis of the system concluded that incorporating the proposed Gitchi Animki Niizh and Gitchi Animki Bezhig hydroelectric generation projects each of 10.0 MW into the Hydro One's transmission system at the proposed location will not materially cause adverse impact on the existing Hydro One's transmission system and customers. The draft of this report was provided to all the affected customers in the area and no comments were received within the provided review period.

2.0 INTRODUCTION

2.1 Scope of the Study

Pic Mobert Hydro Power joint Venture has applied to connect the proposed Gitchi Animki Niizh (GAN) and Gitchi Animki Bezhig (GAB) both of 10.0 MW each hydroelectric generations to Hydro One's transmission system under Ontario Power Authority's (OPA) Feed-In-Tariff (FIT) program. The generation facilities are to be connected to the existing Hydro One's 115 kV M2W circuit approximately 42 km from Marathon TS in the Marathon area of northwestern Ontario. Each of these generation facilities consists of multiple hydroelectric units. The GAN (10.0 MW) and GAB (10.0 MW) generations intend to connect to the M2W circuit through a single high voltage breaker and through a single line tap on the M2W 115 kV circuit. Both facilities are scheduled to be in-service by January 2013 as per customer's applications.

The scope of this Customer Impact Assessment (CIA) is to access jointly the impact of both the proposed generation facilities on the Hydro One's transmission system in the Marathon area. The primary focus of this study is to identify the impact on the transmission customer connected facilities and operating constraints based on facility voltage performance. The study also assists in determining if any transmission system upgrade will be required for integrating the proposed generations for all possible system conditions.

It is worth noting that this CIA does not take into account the impact of any other project under the FIT program, which will not go in-service before the GAN and GAB projects or is not ahead of this project in queue.

The impact of the new generation on the bulk system is not included in the scope of this study and is to be assessed as part of the System Impact Assessment (SIA) issued by the Independent Electricity System Operator (IESO). In addition, this study does not evaluate the impact of the Gitchi Animki Niizh and Gitchi Animki Bezhig Hydro Electric Generation Projects on the existing network's Protection and Control facilities. Review of the Protection and Control aspects will be covered under the Protection Impact Assessment (PIA) and during the preparation of the Connection Cost Estimate stage of the project reflected in the Connection Cost Agreement (CCA).

Figure 1 shows a geographical overview of the project area, Figure 2 and 3 provide the geographical location and connection points of the projects. Figure 4 is the single line diagram of the power system in the area, including the proposed generation projects.

3.0 AREA TRANSMISSION OVERVIEW

The transmission system in the area of the proposed generation projects consists of the radial 115 kV single circuit transmission line M2W, from the 230/115 kV Marathon TS to White River DS. This circuit is tapped at Marathon Junction to supply the loads of Manitouwadge TS, Manitouwadge DS and GECO CTS. In addition, it supplies a number of transmission-connected generations and load customers between Marathon TS and White River DS.

Fig 1 – Existing Transmission System Overview of Project Area

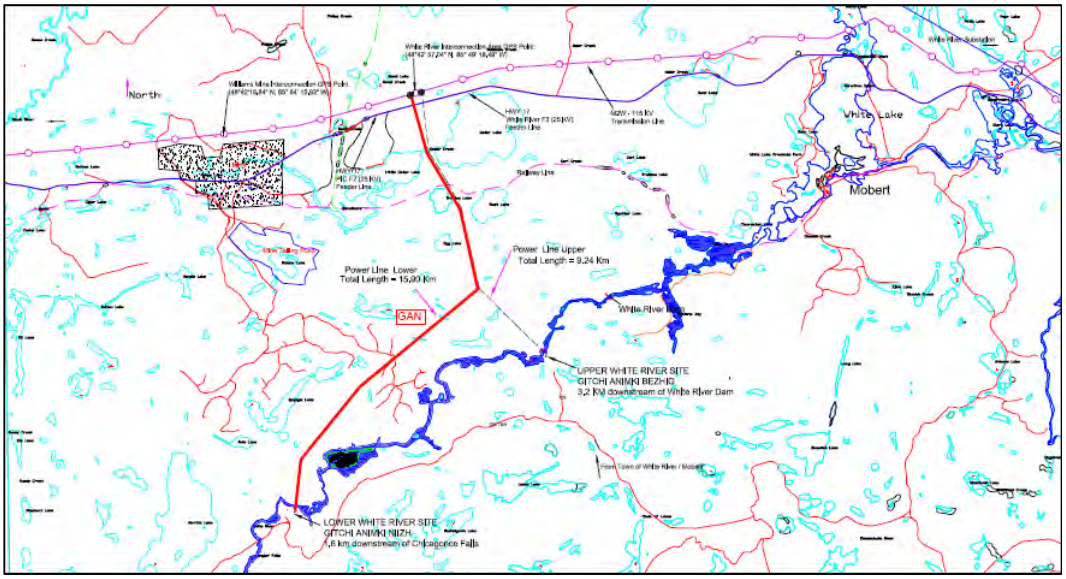


Fig 2 – Geographical Location of Gitchi Animki Niizh (GAN) Hydro Electric Project

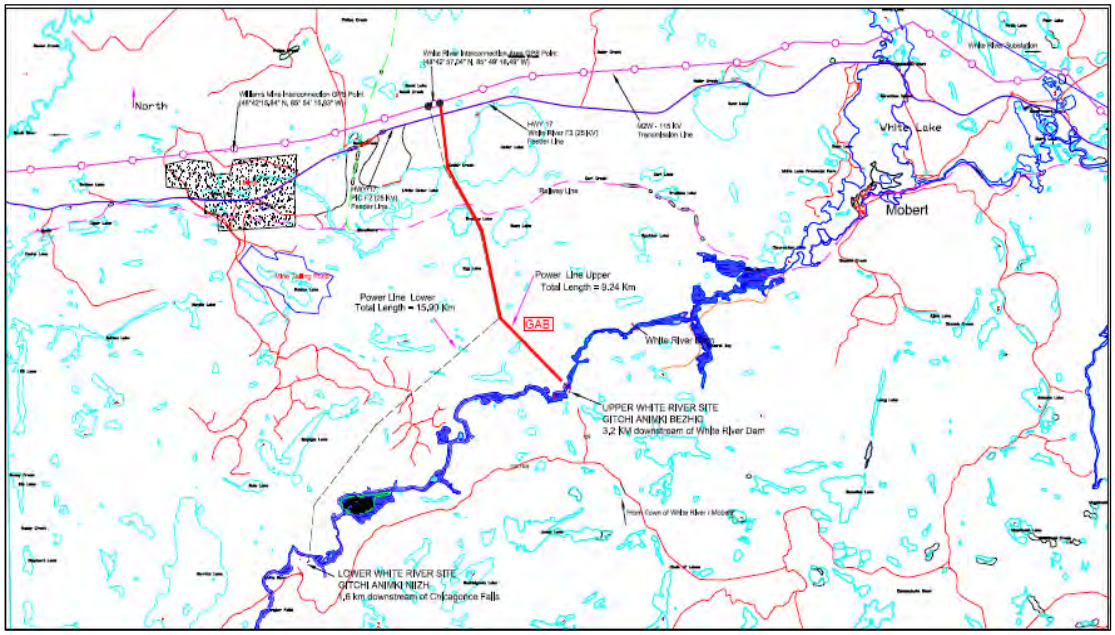


Fig 3 – Geographical Location of Gitchi Animki Bezhig (GAB) Hydro Electric Project

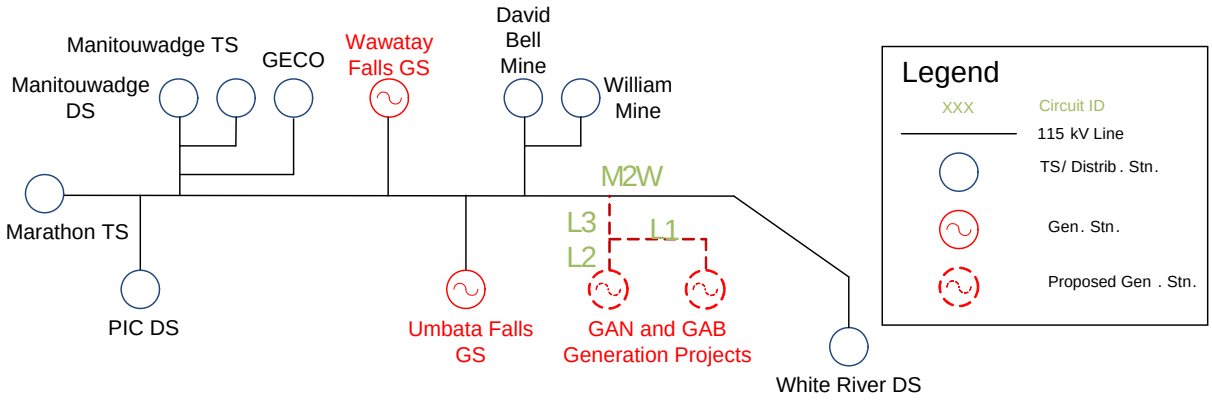


Fig 4 – Single Line Diagram of circuit M2W with GAN and GAB projects

4.0 PLANNING CRITERIA

4.1 Voltage Performance

After the addition of the GAN and GAB hydroelectric generating stations to the Hydro One's system, the voltages in the Hydro One's Transmission system in the immediate vicinity of the proposed generation is required to remain within limits as shown below in Table 1.

With all planned facilities in service pre-contingency, system voltage changes in the period immediately following a contingency shall not result in a voltage decline greater than 10% for pre-transformer tap-changer action (including station loads less than 50kV) and 10% post-

transformer tap-changer action (5% for station loads less than 50kV). In addition, the steady state voltage at station loads less than 50kV are to remain within 6% of the nominal voltage.

Table 1: Voltage Limit Criteria

Contingency Voltage Change Limits						
Nominal Bus Voltage (kV)	**500**	**230**	**115**	**Transformer Station Voltages**		
				44	**27.6**	**13.8**
% voltage change *before* tap changer action	10%	10%	10%	10%	10%	10%
% voltage change *after* tap changer action	10%	10%	10%	5%	5%	5%
AND within the range						
Maximum* (kV)	550	250	127 (132)	112% of nominal		
Minimum* (kV)	470	207	108	88% of nominal		

4.2 Transformer Tap-Changers

Supply point transformers at 115 kV level are assumed to have automatic tap-changers as per simulation model used for this evaluation.

4.3 Base Case

Two base cases were prepared to simulate high and light load system operating conditions.

4.4 Power System Analysis

Power System Analysis is an integral part of the transmission planning process. It is used by Hydro One to evaluate the capability of the existing network to deliver power and energy from generating stations to provide a reliable supply to customers. Two relevant aspects of Power System Analysis used in this assessment are:

a. Load Flow Studies: An AC load flow program was used to set up the base case and compute the voltages before incorporating the generation in the system and after incorporating the generation in the system at the desired location and operating conditions. The assessment criterion is provided above in section 4.1.

b. Short-circuit Studies: A Short Circuit Analysis program was used to determine the impact of the new generation on the short-circuit levels in the area. The short-circuit level limits, as per Transmission System Code, for the 115 kV system are the following:

Nominal Voltage (kV)	***Max. 3-Phase Fault (kA)***	***Max. SLG Fault (kA)***
115	50	50
44	20	19
25/ 27.6	17	12

Notes:

Effective September 1, 2010, Hydro One requires a 5 % margin on the acceptable TSC limits at voltage levels of <50kV to account for other sources of fault current on the distribution system such as un-modeled synchronous motors and data inaccuracies.

5.0 LOAD FLOW STUDIES

Load flow studies were carried out to analyze the impact of the new facilities on the voltage performance of Hydro One's transmission system and customers in the vicinity of the proposed GAN and GAB Hydro Electric Projects. No voltage violations were observed under normal operating conditions with the incorporation of these two-generation projects. At the connection point, the proposed GAB and GAN generations were assumed running close to unity power factor in the simulation model.

The following buses in the area were observed for potential voltage violations with the inclusion of the new generations:

- Marathon TS (115 kV)
- Pic DS (115 kV)
- Manitouwadge Jct (115 kV)
- Umbata Falls Jct (115 kV)
- Black River Junction (115 kV)
- Hemlo Mine Junction (115 kV)
- Generators PCC (115 kV) on M2W
- White River DS (115 kV)
- Marathon DS (115 kV)
- Marathon Pulp CTS (115 kV)

The analysis results for both pre and post generations under light and high load conditions are shown in Appendix A. With the incorporation of the GAB and GAN hydroelectric generation projects the analysis revealed about 2.5% change in voltage levels which is well within the acceptable range of $\pm$10% and the voltages in the area remain within the acceptable levels.

6.0 SHORT- CIRCUIT STUDIES

Short-circuit studies were carried out to assess the impact of change in short circuit levels when the GAB and GAN hydroelectric generation projects were placed in-service. The impact of the new facilities on the fault levels on Hydro One customers supplied through the 115 kV M2W circuit was analyzed.

The current short circuit levels in the immediate vicinity of the proposed generation projects are shown in Table 2.

Table 2: Present Short-Circuit Levels

Bus Name	Voltage Level (kV)	Existing Fault Levels			
		Symmetrical (kA)		Asymmetrical (kA)	
		3Ph Fault	LG Fault	3Ph Fault	LG Fault
Marathon TS	115	6.5	7.7	6.9	8.5
Pic DS	115	6.4	7.7	6.8	8.3
Pic DS	25	1.7	1.8	1.9	2.1
Manitouwadge TS	115	1.7	1.1	1.7	1.1
Manitouwadge TS	44	1.5	2.0	1.6	2.1
Manitouwadge DS1	12.5	2.7	2.9	2.9	3.1
Willroy Jct	115	1.7	1.0	1.7	1.0
Black River Jct	115	4.2	3.7	4.2	3.8
Umbata Falls Jct	115	5.1	5.0	5.2	5.1
Hemlo Mine Jct	115	2.6	1.8	2.6	1.8
White River	115	1.4	0.8	1.4	0.8
White River	25	2.9	2.4	2.9	2.5

After incorporating the GAB and GAN hydroelectric generations at the proposed location, the short circuit levels at 115 kV buses in the area will increase to the values shown in Table 3.

Table 3: Short-Circuit Levels after Incorporating GAN and GAB Projects

Bus Name	Voltage Level (kV)	Fault Levels with GAN and GAB Generation Projects			
		Symmetrical (kA)		Asymmetrical (kA)	
		3Ph Fault	LG Fault	3Ph Fault	LG Fault
Marathon TS	115	6.8	8.1	7.2	8.8
Pic DS	115	6.7	8.0	7.1	8.6
Pic DS	25	1.7	1.8	1.9	2.1
Manitouwadge TS	115	1.8	1.1	1.8	1.1
Manitouwadge TS	44	1.5	2.0	1.6	2.1
Manitouwadge DS1	12.5	2.7	2.9	2.9	3.1
Willroy Jct	115	1.7	1.0	1.7	1.0
Black River Jct	115	4.5	4.2	4.6	4.3
Umbata Falls Jct	115	5.5	5.4	5.6	5.5
Hemlo Mine Jct	115	3.0	2.7	3.1	2.7
White River	115	1.6	1.0	1.6	1.0
White River	25	2.9	2.4	3.0	2.5

The new short circuit levels show a slight increase on the buses in the immediate vicinity of the proposed generations, however there is no material change in the short circuit levels in the area and no violation of short circuit limits were observed.

The results of the fault levels studies shown on these tables above show that the impact of the GAN and GAB projects does not have a measurable (>=0.01kA) impact at the fault level at any of the stations (Windsor Walker #1, Kingsville or Martindale) where mitigation measures are necessary to limit fault levels to acceptable values.

7.0 RELIABILITY

As per customer's applications, both GAB and GAN hydroelectric generations will have a high voltage 115 kV circuit breaker on their joint line tap near the point of common coupling on M2W circuit. This breaker will clear the faults along the line taps and inside the generation facilities resulting in minimum impact on other customers in the area. With the incorporation of these new generations, there will be an insignificant change in the performance and reliability of the 115 kV M2W circuit.

8.0 CONCLUSIONS AND RECOMMENDATIONS

After conducting load flow and short circuit analysis of the system, the simulation results confirm that incorporating the proposed GAN and GAB hydroelectric generation projects into Hydro One's transmission system at the proposed location will not cause any adverse impact on the system and customers.

References

[1] Independent Electricity System Operator (IESO), ***IESO Transmission Assessment Criteria,*** Issue 2.0.

[2] Ontario Energy Board, **Transmission System Code**, July 25, 2005

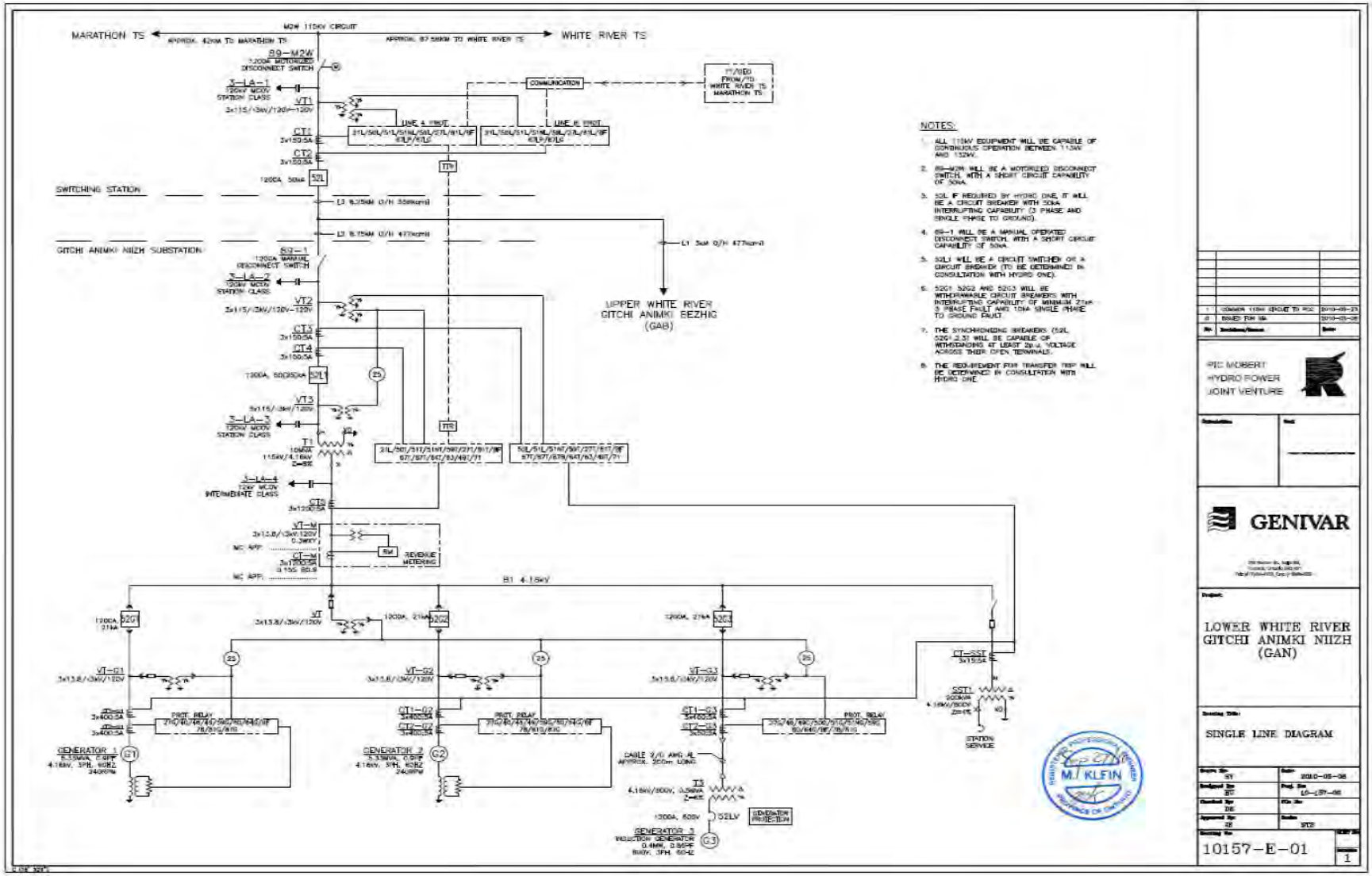
APPENDIX A – *LOAD FLOW ANALYSIS*

Load Flow Analysis

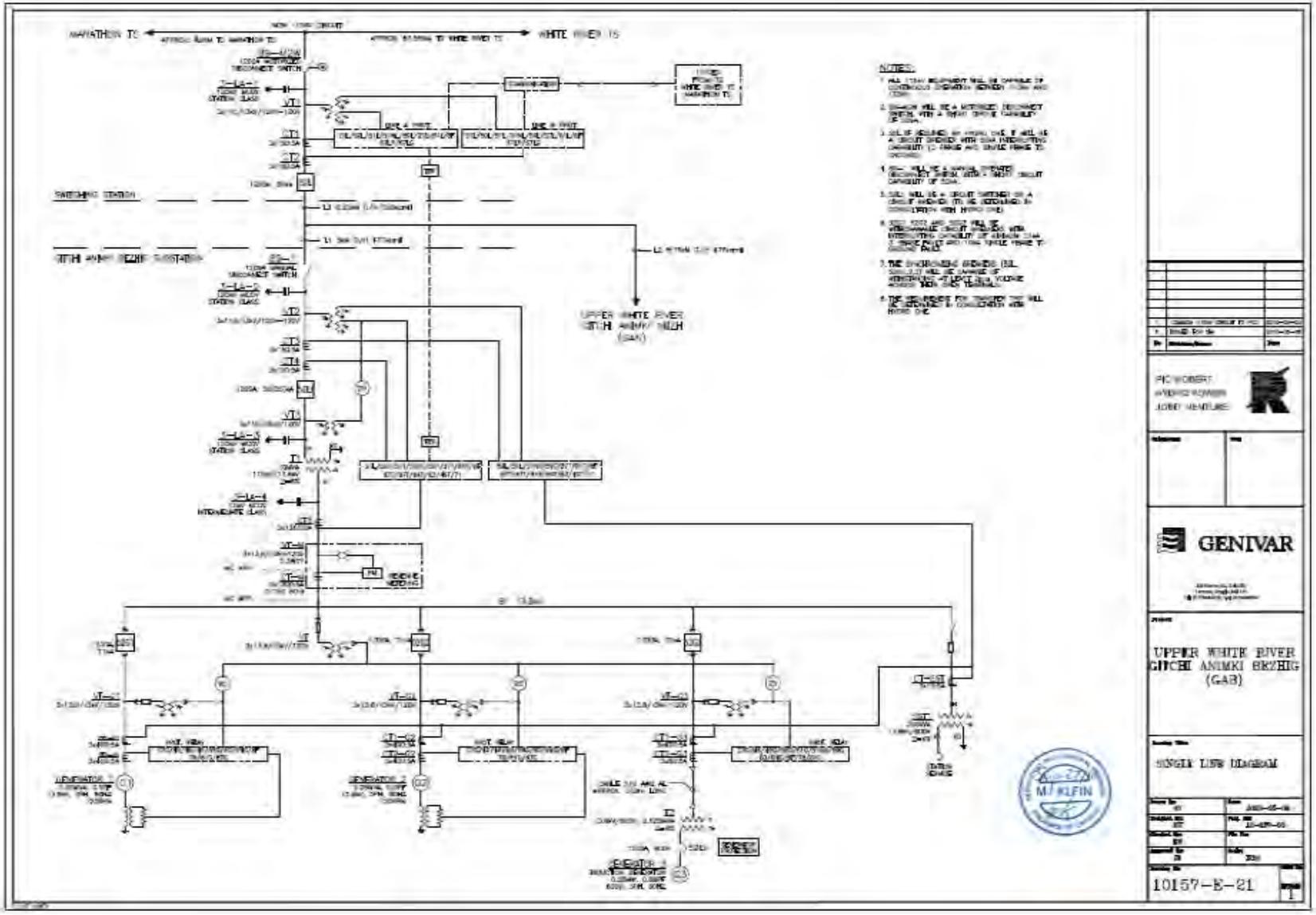
Bus Voltages		Loading Conditions on M2W			
		Light Load		High Load	
		Before Generation Addition	After Generation Addition	Before Generation Addition	After Generation Addition
Flows on M2W @ Marathon *	MW/ MVAr	29.2/ 7.1	48.5/ 5.5	0.5/ -3.5	20.4/ -9.0
Flows on M2W @ White River DS (White River DS load)		1.1/ 0.5		3.8/ 1.7	
Bus Name	Units	(V)	(V)	(V)	(V)
Marathon TS (115 kV)	kV	125.7	122.8	125.8	124.9
Pic DS (115 kV)	kV	125.7	122.8	125.8	124.9
Manitouwadge Jct (115 kV)	kV	126.4	123.6	125.5	124.2
Umbata Falls Jct (115 kV)	kV	127.0	124.9	125.8	125.5
Black River Junction (115 kV)	kV	127.1	125.0	125.7	125.5
Hemlo Mine Junction (115 kV)	kV	126.4	125.6	123.0	123.8
Generators PCC (115 kV)	kV	126.5	126.1	122.9	124.2
White River DS (115 kV)	kV	126.5	126.1	122.3	123.6
Marathon DS (115 kV)	kV	125.3	122.3	125.4	124.4
Marathon Pulp CTS (115 kV)	kV	125.3	122.3	125.4	124.4

* + ive for flows for flows towards Marathon TS and White River DS

Appendix B - ***Single Line Diagrams of GAN and GAB Projects***



GAN Project - Single Line Diagram



GAB Project - Single Line Diagram

B-5-1 Construction & In Service Schedule

58. Following issuance of the Statement of Completion on November 8, 2010 and Location Approval under Lands and Rivers Improvement Act received on November 16, 2011, the Applicants began securing the required federal and provincial permits/approvals to facilitate Project construction.

59. February 2012 is being targeted as the timeline to secure the majority of the pre-construction permits/approvals. The location approval for the Hydro Facilities pursuant to Section 14 of the *Public Lands Act* was obtained on November 16, 2011 after satisfying EA approval requirements by Ministry of Natural Resources. Construction is expected to commence with some ground clearing, and access road upgrade/construction in March/April 2012 and continuing throughout the year. In-water works such as coffer dam placement and subsequent dam construction are expected to commence in the summer of 2012 following completion of the detail design, tender document preparation and selection of a qualified contractor to construct the Project.

60. Construction of the Hydro Facilities and the Transmission Facility is planned to be conducted simultaneously, enabling both Hydro Facilities to be brought on line at or about the same time. The schedule as described above is dependent on reviews and approvals being completed in time to allow the projected milestones to be achieved and deadlines to be met. Further details regarding the Hydro Facilities' and the Transmission Facility's development schedule and phasing of construction are provided in Exhibit B-5-2.

61. The Hydro Facilities will be constructed using a traditional design-build approach whereby the Applicants will perform design drawings for the majority of the works and the successful contractor will construct the works. There are also aspects of the construction where the contractor will be solely responsible for final design, subject to performance criteria set out by the Joint Venture. This includes the Transmission Facility components and other ancillary works.

B-5-2 Gantt Chart

Activity/Description	Year 1 (2011)												Year 2 (2012)												Year 3 (2013)												Year 4 (2014)												Year 5 (2015)				
	Winter and Freshet												Winter and Freshet												Winter and Freshet																												
	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M
1. EPC Contract Award					Submission of EA Addendum	Location Approval/Permit																			General Contractor, Engineering																							Demob					
2. Mobilization etc.																																																				
3. Upgrading and Construction of Access Roads																																																				
4. Clearing of 2 Sites (all areas)																																																			
5. Excavation of Diversion Channel																																																			
6. Construction of Diversion Works (Headworks)																																																			
7. Excavation of Headrace Canals																																																			
8. Excavation and Construction of Intake and Excavation of Powerhouse Area																																																			
9. Penstocks and Powerhouses																																																			
10. Excavation of Tailraces																																																			
11. Installation of Mechanical and Electrical Equipment																																																			
12. Equipment Commissioning and Testing																																																			
13. Transmission Lines, Switchyards and Substations																																																			
14. In-River-Cofferdams																																																			
15. Clearing of Riverbanks and Damsites																																																			
16. Completion of Temporary Cofferdams																																																			
17. Clearing of Damsites (foundation,excavation, etc.)																																																			
18. Construction of Dams and Spillways																																																			
19. Installation of Spillway Gates																																																			
20. Construction of Compensation Flow Powerhouse (lower site)																																																			
21. Installation of Compensation Turbines, Penstock, Gates, Valves, etc.																																																			
22. Removal of Cofferdams																																																			
23. Removal of all Rock Plugs in Headrace and Tailrace Canals																																																			
24. Close Diversion Works (stop-logs and concrete plugs)																																																			
25. Site Clean-up																																																			
26. Reservoir Filling																																																			
27. Fish Habitat Work																																																			
28 Decommissioning of White Lake Dam																																																			
29. Reservoir Rim Clearing of Trees																																																			
30. Generation at Two Stations																																																			

Legend

- Winter Months
- Spring Freshet
- In-Water Work Period

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Figure 2.6
Pic Mobert Hydro Power Joint Venture
Gitchi Animki Hydroelectric Project
Schedule of Project Construction Activities

HATCH™

B-6-1 Consultation

Community and Stakeholder Consultation

62. Public, agency and stakeholder consultation was an integral component of the environmental assessment process for the Project, which environmental assessment process includes review of the Transmission Facility. The consultation process facilitated the exchange of pertinent information between interested parties and the Applicants, and served to identify issues and areas of concern. The establishment of open communication between the Applicants and interested stakeholders facilitated early and ongoing resolution of issues pertaining to the Project. Consultation, transparency and disclosure have been key components of the Project's planning and development activities, mainly through direct mailings, newspaper ads, and several public open houses.

63. A number of meetings were held with various stakeholders such as local educational institutions and recreational organizations to discuss the Project. Where possible, the Applicants provided opportunities to educate these stakeholders about the environmental assessment process and the Project. Communication continued throughout the environmental assessment process and is expected to be ongoing as the Project proceeds to development.

64. Consultation with tourism outfitters was also undertaken to obtain additional information on the use of the area by these parties and to evaluate potential impacts to their respective operations and activities. A number of such organizations and businesses were formally contacted in June of 2007 and February of 2008. In January of 2009, cottagers on Little Cedar and Cedar Lakes were also sent information regarding the proposed Project in the form of a letter.

65. Four public information centers ("**PICs**") were held on May 14, 15, 16, 2007 and on March 24, 2009 to present and receive public input on the Project. More specifically, the purpose of these PICs was to provide information to the public regarding the proposed Project and the environmental screening process, to provide an opportunity for the public to express any issues and concerns with the proposed Project and to provide information on the existing conditions within the study area, the potential impacts associated with the construction and operation of the Project, and prescribed mitigation measures to minimize anticipated impacts. The PICs followed an Open House display format, where display boards were exhibited. Attendees were able to observe the display boards and interact directly with representatives of the Applicants in an effort to obtain clarification on various aspects of the Project. Comments were garnered via written comment sheets, verbal discussion during the PICs and e-mails after the PICs. All four PICs were advertised both in local newspapers and by mass mailing in the weeks leading up to the PICs.

66. Communications with the local community will continue during the construction and operation phases of the Project. The purpose of these activities is to ensure that any unforeseen impacts on the community or the environment are quickly identified and

properly addressed. In the event the Project is decommissioned following termination of their life cycle, appropriate communications with the local community will be carried out.

First Nation Consultation

67. First Nation consultation helps to ensure that First Nation views, issues, and concerns are given due consideration during the environmental assessment process. As such, First Nations that were contacted during the environmental assessment process included, in addition to members of the Joint Venture partner, Pic Mobert, the Ojibways of the Pic River First Nations. The following principles were developed at the outset to guide the First Nations consultation effort:

- Respect for traditional knowledge and values of First Nations and other Aboriginal communities
- Inclusion of First Nations and other Aboriginal communities and their traditional knowledge throughout the environmental assessment process
- Understanding and flexibility in the environmental assessment process when engaging First Nations and other Aboriginal community members and in determining consultation approach
- Transparency when communicating information and utilizing traditional knowledge as part of the environmental assessment process.

68. The purpose of the First Nations consultation plan was to consult with each respective First Nation via written correspondence and meetings. A key component of the plan was to gather and compile information pertinent to the environmental assessment process including as a minimum:

- use of lands and resources within the Project's study area for traditional purposes
- any Aboriginal Traditional Knowledge of the Project's study area, such as historical use, any cultural resources including ossuaries and information related to the natural environment
- concerns regarding any potential negative effects resulting from the Project's construction and operation.

69. The Pic Mobert community has been informed of and consulted on numerous matters concerning the Project and the community's participation in the Project dates back to the early 1990's. Consultation with the community in regards to potential impacts of the Project (both positive and negative) has been an important part of the consultation process to ensure members of the Band Council and the Band membership have had numerous opportunities to learn about water power in general, as well as matters specific to the Project.

70. The creation of the Joint Venture was approved by the Pic Mobert community in 2005. Since that time, the Pic Mobert Council and community have been informed of and consulted on matters concerning the design and business matters associated with the Hydro Facilities through a variety of means including presentations at closed and open (public) meetings of the Band Council, presentations at community meetings and public and First Nation Information Centres, information posted on the community's website (www.picmobert.ca), as well as newsletters issued by the Band Council and/or by the Applicants jointly with the Band Council.

71. The Applicants have also considered the information needs of the First Nations communities by effectively engaging them in the environmental assessment process. This has included providing community members with clear, concise and accessible information regarding the construction and operation phases of the Project throughout the environmental assessment process.

72. In addition, Indian and Northern Affairs Canada was consulted to determine whether there are First Nation land claims, or lands subject to litigation within the Project's study area. Consultation with the Crown Law Office revealed a claim covering the area of the Project. However, the Ojibways of the Pic River have indicated and stated during the Elders Meeting of August 27, 2007 that while the Project would be constructed within traditional territory, they would not interfere with traditional use.

73. The Applicant also hosted a community consultation meeting on June 18, 2005 at the Pic Mobert First Nation Community Hall. During the meeting, display boards were presented, and representatives were available to answer questions from the community.

74. In May 2007 and March 2009, during the environmental assessment process, two separate sets of First Nations Information Centres were held on four different days to consult with and engage the Pic Mobert and Pic River First Nations. Both the 2007 and the 2009 First Nations Information Centres were advertised in local newspapers and the 2009 Information Centres were also advertised via mass mailing. In advance of the 2009 First Nation Information Centres, representatives of the Applicant also met with the Pic Mobert Chief and Council in Thunder Bay on March 15, 2009, to inform and prepare the Council.

75. The purpose of the May 2007 First Nations Information Centres was to provide information to the community regarding the proposed Project and the environmental screening process and to provide an opportunity for the community to express any issues and concerns with the proposed Project. The purpose of the March 2009 sessions was to introduce the Project and their objectives, Regional Power's project team, the environmental assessment process followed, the existing conditions within the Project's study area, and the potential environmental impacts associated with the construction and operation of the Project. Details regarding the benefits of the Project as well as the prescribed mitigative measures to minimize anticipated impacts were also presented at the March 2009 Information Centres.

76. Both sets of First Nations Information Centres used a drop-in centre format to allow participants to discuss the Project on an individual basis. Display panels were provided to present information on the Project and to encourage dialogue and the two-way exchange of information.

77. On August 21, 2007, a meeting was held at the Ojibways of the Pic River First Nation to discuss Traditional Aboriginal Values present in the vicinity of the Project. No objections to the Project were raised during the meeting, and Chief Couchie expressed support for the proposed Hydro Facilities. It was understood and stated that the Project would be constructed within traditional territory, and no objection was raised.

78. On October 3, 2007, a meeting was held at the Pic Mobert to discuss Traditional Aboriginal Values present in the vicinity of the Project. Items discussed during the meeting included the background and history of the Project, the proposed organization including the structure of the Applicant, as well as the proposed community trust model. Details on site locations, proposed development strategies and an overview of consultation conducted to date were provided. A question-and-answer period followed the description of various components of the Project. No objections to the Project were raised during the meeting and the Elders expressed their support for the Project. Moreover, they praised the effort by Pic Mobert Council and Community in moving toward self-support through the clean energy Project.

79. Participation and engagement of the Pic Mobert in review and decision-making with respect to the Project will continue through provision of information to Band Members by the Chief and Council and through the Applicants' Management Committee, which includes an appointed Council representative. It is noted that the Regional Power has and continues to fund a Community Liaison person who acts as the Pic Mobert community's advocate on internal and external day-to-day matters, as well as ensuring that the Council and community are informed of development matters regarding the Project. The Community Liaison has already participated in various conference calls, meetings and presentations with Pic Mobert Band Council. This will continue throughout the life of the Project.

Exhibit B-7-1 Regulatory

Permits and Approvals

80. Under the Canada-Ontario Agreement on Environmental Assessment Coordination (November 2004), a single harmonized report which addresses both the federal and provincial EA processes was prepared. The Project Information Report/Environmental Screening Review Report (the "**PIP**") is a harmonized report, and served as the basis for review by the relevant federal and provincial agencies. The PIP was prepared by Hatch on behalf of the Applicants.

Permit/Approval	Description	Status
MOE Environmental Screening/CEAA federal environmental screening/ MNR WPPG PIP	Completion required before other permits and approvals granted	**Completed**
Transport Canada Approval under Section 5(1) of the NWPA	Protection of public right to navigation; approval of any works built in, on, over, under, through or across a navigable water	Notice of application in newspapers. The permits to be awarded post 30 days public review period. Expected to be received in January 2012.
DFO Authorization for Works Affecting Fish Habitat	Fish Habitat Mitigation Plan to ensure No Net Loss of Productivity	Modelling simulation underway to satisfy the conditions of DFO. Permit is expected to be received in March 2012.
DFO Authorization for Destruction of Fish by Means Other than Fishing	Required if blasting in or near fish habitat	Pending
NRCan Temporary Magazine License,	Required for the purchase and storage of explosives required for blasting	Pending
MNR Burn Permit	Permit required from MNR for any burning of slash	Pending
MNR Work Permit	Required for construction on Crown land including roads and trails, water crossings, works on shorelands	Pending
MNR Aggregate Resources Act	Permit to operate a pit or quarry on Crown land or any land under water Licence on private land in areas designated under Section 5 of the ARA	Pending

Permit/Approval	Description	Status
MNR Crown Forest Sustainability Act	Forest Resource Licence to harvest or cut merchantable timber when clearing Crown land for construction	Pending
MNR Endangered Species Act	No permit or approval, however, MNR should advise proponent of responsibilities under the Act – namely that no person shall wilfully kill, injure or take any species or destroy or interfere with the habitat of any species regulated under the ESA	Pending
MNR Fish and Wildlife Conservation Act	Authorization to destroy beaver dams, dens of fur-bearing mammals or bears and the nests or eggs of birds	To be applied by contractor (if required)
MNR Lakes and Rivers Improvement Act (LRIA)	Section 14 Approval – for the location and plans and specifications is required to construct a dam, considering other users of the water and riparian owners, the protection of persons of property as well as other environmental values	Completed
MNR – LRIA	Section 16 Approval – for the plans and specifications is required for the alteration, repair or modification of any part of a dam, considerations as stated above in Section 14 approval	Pending
MNR – LRIA	Section 23.1 Approval of the Water Management Plan describing the operation of flows and levels for the river system	Pending
MNR	Class EA for Resource Stewardship Facility Development (MNR Class EA-RSFD)	Completed
MNR	Class EA for Provincial Parks and Conservation Reserves (MNR Class EA-PPCR)	Completed
MNR Public Lands Act	Waterpower Lease Agreement, Land Use Permit, Crown Lease or Easement – tenure issued to dispose of the rights to use Crown land	Pending
MNR Public Lands Act	Work Permit for construction activities on Crown land	Pending
MNR Forest Fires Prevention Act	A fire permit will be required for any burning to be done	Pending
MNR Waterpower Lease	Waterpower Lease required to operate facilities	Pending

Permit/Approval	Description	Status
MOE Permit to Take Water (required when more than 50,000 L/d of water is taken from a watercourse)	Required for hydroelectric power generation May be required during construction (temporary diversion, excavation pumping)	Pending
MOE Certificate of Approval (C of A) (Industrial Sewage Works)	Settling pond discharges	Pending
Ministry of Labour (MOL) Notice of Project	Required prior to start of construction	Pending
MTO	Permit to allow an access road leading off Highway 17 Permit to allow the crossing of Highway 17 by the Transmission Line	Pending
CP Rail	Authorization to cross their right of way (ROW)	Pending

81. Adequate fire safety clearance will be provided along the Transmission Line routes. In addition, a maintenance program will be implemented to ensure that the Transmission Line ROW is kept clear to reduce the fire risk and to allow access by fire fighters if needed. Transmission Line ROW clearance widths will be determined based on adjacent flammable fuel types in order to ensure a defensible space of the line. Clearance width will also ensure the line cannot be struck by falling trees causing a short in the line and the possible ignition of a forest fire.

82. Clearing of the line and regular fuel maintenance will be done in accordance with the conditions of the work permit and should resultant slash require burning that process will be carried out under the authority and conditions of a fire permit and a prescribed burn plan prepared as required. Wawa AFFES Headquarters staff will be contacted for discussions and advice on all forest fire management issues related to operations.

Codes and Standards

83. The RFP document specifies that the Transmission Facility will be built to meet all applicable codes and standards, laws, regulations of the national, provincial and municipal building codes and any other acts pertinent to the Transmission Facility.

84. In the event of a conflict between any of the applicable codes and standards, the Transmission Facility shall conform to the standard of the authority having the stricter requirement.

85. The following codes and standards have been identified in the RFP document as applicable. To the extent the successful bidder identifies others, such codes and standards will also be followed.

- ANSI C29.1, “Test Methods for Electrical Power Insulators”
- ANSI C29.12, “Standard For Insulators Composite – Suspension Type”
- ANSI/IEEE Std 524-2003, “IEEE Guide to the Installation of Overhead Transmission Line Conductors”
- IEEE C135.1-1999 “Standard for Zinc-Coated Steel Bolts and Nuts for Overhead Line Construction”
- ASTM C136 - 06 “Standard Test Method for Sieve Analysis of Fine and Coarse Aggregates”
- ASTM A153 / A153M - 05 “Standard Specification for Zinc Coating (Hot-Dip) on Iron and Steel Hardware”
- Canadian Aviation Regulations, Standard 621.19 “Standards Obstruction Markings”
- Canadian Pacific Railway, “Crossing Manual”
- CSA-015-90, “Wood Utility Poles and Reinforcing Stubs”
- CSA-080.8-97, “Wood Preservation”
- CSA-086-01 “Engineering Design in Wood”
- CSA-C22.2 No. 41-M1987, “Grounding and Bonding Equipment”
- CSA-C22.2 No. 232-M1988 “Optical Fiber Cables”
- CSA-C22.3 No. 1-10, “Overhead Systems”
- CSA-C22.3 No. 5.1-93 “Recommended Practices for Electrical Protection-Electric Contact Between Overhead Supply and Communications Lines”
- CSA-C22.3 No. 6-M91, “Principles and Practices of Electrical Coordination Between Pipelines and Electric Supply Lines”
- CSA-C22.3 No 60826-10 “Transmission Design Criteria”
- CSA-C49.1-M87 “Round Wire, Concentric Lay, Overhead Electrical Conductors”
- CSA-C57-1966, “Electric Power Connectors for Use in Overhead Line Conductors”
- CSA-C83-96 (R2000), “Communication and Power Line Hardware”

- CSA G164-M92-CAN/CSA “Hot Dip Galvanizing of Irregularly Shaped Articles Metals and Metal Products”
- CSA-C411.1-M89 “AC Suspension Insulators”
- CSA-C411.4-98, “Composite Suspension Insulators for Transmission Applications”
- CSA-C61089-03, “Round Wire Concentric Lay Overhead Electrical Stranded Conductors”
- CSA-CAN3-C308-M85, “The Principles and Practice of Insulation Coordination”
- CSA-G12-92 (R1998), “Zinc-Coated Steel Wire Strand”
- IEEE 738-1993, “Standard for Calculating Current-Temperature Relationship of Bare Overhead Conductors”
- IEEE P1222-1997, “Standard for All Dielectric Self-Supporting Fiber Optic Cable (ADSS) for Use on Overhead Utility Lines”
- IEEE Standard 1313.2-1999, IEEE Guide for the Application of the Insulation Coordination”
- Industry Canada ICES-004, “Interference Causing Equipment Standard, AC High Voltage Power Systems”
- TIA/EIA 598C Optical Fiber Cable Color Coding
- IEEE P977 9/2006 “Guide to Installation of Foundations for Transmission Line Structures”
- IEEE 691-2001 “Guide for Transmission Structure Foundation Design and Testing”
- Ontario Energy Board, “Transmission System Code” (2010)
- Ontario Electricity Act
- Hydro One Standards for Distribution crossings and Transmission interconnection.
- Independent Electricity System Operator (IESO) requirements.