GREENSTONE-MARATHON AREA
INTEGRATED REGIONAL RESOURCE PLAN - APPENDICES
Interim Report for the Near-Term (2015-2020)

Part of the Northwest Ontario Planning Region | June 22, 2015

ieso
Independent Electricity System Operator

Greenstone-Marathon Interim IRRP

Appendix A: Summary of Planning Criteria Applied to the Greenstone-Marathon IRRP Studies

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A.1 Pre-contingency Outages and Hydroelectric Conditions

For local area supply studies different credible combinations of reasonable worst-case conditions for generation output and pre-contingency facility outages[1] are considered:

Table A-1: Hydroelectric Generation Output Assumptions (General)

Hydroelectric Output	Pre-contingency State
98th Percentile	Normal – no elements on outage
85th Percentile	Single element outage

The local hydroelectric generation output assumed for study purposes are summarized below and based on 20 years of historical hydroelectric data:

Table A-2: Hydroelectric Generation Output Assumptions (by Station)

Station	98th Percentile [MW]	85th Percentile [MW]
Aguasabon GS	0	19
Umbata Falls GS	5	6
Wawatay GS	0	2
New Contracted Hydro[2]	0	0

A.2 Equipment Loading Criteria

Section 7.1 of ORTAC specifies the following criteria for load security related to equipment loading and level of load loss allowed under the applicable credible contingencies defined in ORTAC 2.7.1 and 2.7.2, and NERC TPL-001-4:

- **Criterion I**: With all the transmission facilities in service, equipment loading must be within continuous ratings.

[1] Pre-contingency facility outages: Refers to the outage of a power system facility in the initial condition. Additional contingencies are considered on top of the outage.
[2] Until drought hydroelectric performance is established for new hydroelectric facilities, the IESO assumes that new hydroelectric facilities cannot be counted on to supply load during drought conditions.

- **Criterion II**: With one element out of service, equipment loading must be within applicable long-term ratings and not more than 150 MW of load may be interrupted. Planned load curtailment or load rejection, excluding voluntary demand management, is permissible only to account for local generation outages.
- **Criterion III**: With two elements out of service, equipment loading must be within applicable short-term emergency ratings. The equipment loading must be reduced to the applicable long-term emergency ratings in the time afforded by the short-term ratings. Planned load curtailment or load rejection exceeding 150 MW is permissible only to account for local generation outages. Not more than 600 MW of load may be interrupted by configuration and by planned load curtailment.

A.3 Voltage Criteria

Voltage criteria applied can be sub-categorized as: voltage magnitude/change, and voltage stability.

A.3.1 Voltage Magnitude/Change Criteria

The voltage magnitude and change criteria indicate the allowable range of pre-contingency and post-contingency voltage magnitudes as well as the allowable post-contingency voltage change before and after under load tap changer ("ULTC") action.

Table A-3: Summary of ORTAC Voltage Magnitude/Change Criteria

Nominal Bus Voltage [kV]	Pre-contingency		Post-contingency			
	Maximum	**Minimum**	**Maximum**	**Minimum**	**Pre-ULTC Voltage Change**	**Post-ULTC Voltage Change**
500	550	490	550	470	10%	10%
230	250	220	250	207	10%	10%
115	127	113	127	108	10%	10%
Transformer Station Secondary (e.g. 44, 27.6, 13.8 kV)	106% of nominal	98% of nominal	112% of nominal	88% of nominal	10%	5%

After the system is re-dispatched and system adjustments are made following a contingency condition, the system must return back to within acceptable pre-contingency limits.

A.3.2 Voltage Stability Criteria

Voltage stability analysis is carried out by generating pre- and post-contingency P-V curves for the system. Power transfer is limited to the lesser of the following:

- A pre-contingency transfer that is 10% lower than the voltage instability point of the pre-contingency P-V curve, or
- A pre-contingency transfer that results in a post-contingency power flow that is 5% lower than the voltage instability point of the post-contingency curve

A.4 Load Security and Restoration

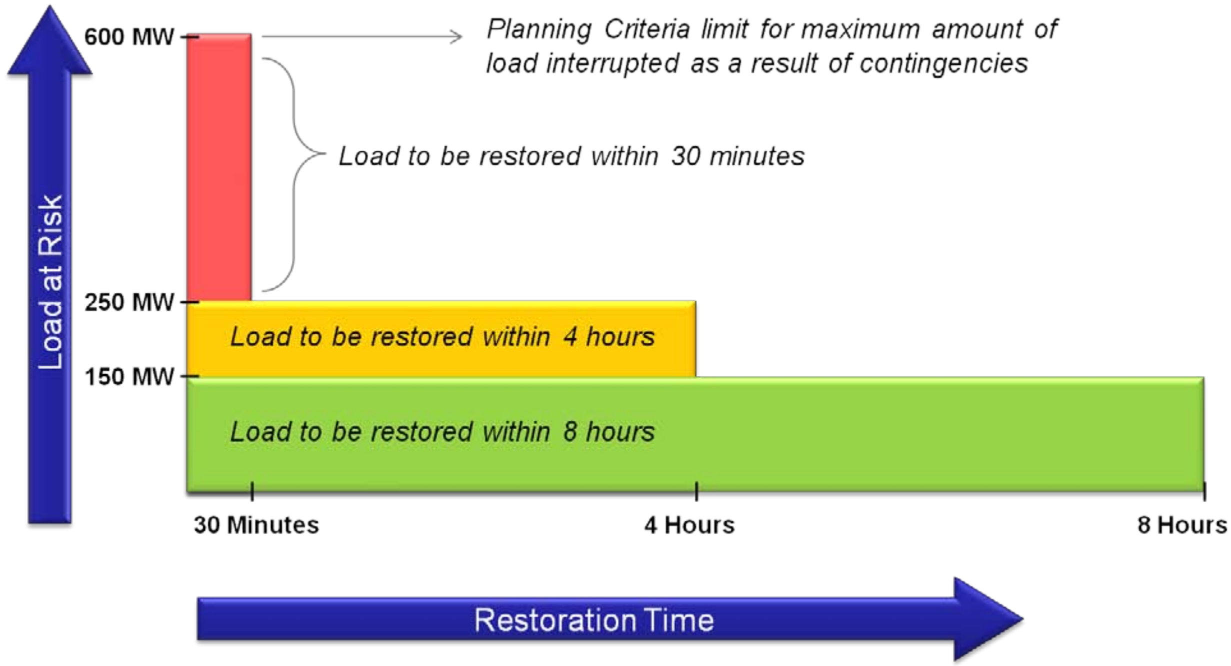
Table A-4: Summary of ORTAC Load Security Criteria

Condition	Load Curtailment Allowed [MW]	Total Load Loss Allowed (Load Curtailment + Lost by Configuration) [MW]
All transmission facilities in-service	N/A – All Load Must Be Continuously Supplied	
One element out-of-service	0*	150
Two elements out-of-service	150*	600

* Greater load curtailment is allowable to account for local generation outages, up to the magnitude of the respective generator(s). The total load loss does not change.

If the condition being studied results in an acceptable level of load loss, the load should be restored within the following timeframes.

Figure A-1: Summary of ORTAC Load Restoration Criteria



These approximate restoration times apply to design criteria conditions and are intended for locations that are near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility.

Greenstone-Marathon Interim IRRP

Appendix B: Studies to Establish Needs

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B.1 Greenstone Sub-system Load Meeting Capability

The following describes the analysis used to determine the LMC for the Greenstone sub-system.

B.1.1 Assumptions

- AP Nipigon GS out-of-service
- Drought hydroelectric conditions
- Longlac TS capacitor banks in-service (2x5 MVar)
- Summer planning ratings applied for transmission facilities
- Load supply stations service LDC load as per Scenario A 2020 forecast demand
- Load Q/P ratio of 0.4 assumed (to give at least 0.9 power factor on HV winding of step-down transformer, consistent with the Market Rules)

B.1.2 Methodology

- Load increased at Geraldton Mine location in 5 MW increments until criteria violation is observed
- The total load supplied by circuit A4L prior to the criteria violation is established as the LMC

B.1.3 Results

The supply to the Greenstone sub-system via circuit A4L was found to be limited by pre-contingency minimum voltage. Other system conditions were found to be less limiting and have therefore not been reported. The following table summarizes the magnitude being supplied by circuit A4L, and the corresponding voltage performance.

Table B-1: Voltage Analysis

Figure Reference	A4L Load [MW]	Longlac TS 115 kV Voltage [kV]	Minimum Pre-contingency Voltage Criterion [kV]
Figure B-1	25	114.7	113
Figure B-2	30	108.5	

Therefore, the LMC for the Greenstone sub-system is established as 25 MW.

B.1.4 Load Flow Plots

Figure B-1: Establishing Greenstone Sub-system LMC - 25 MW of Load Supplied by A4L

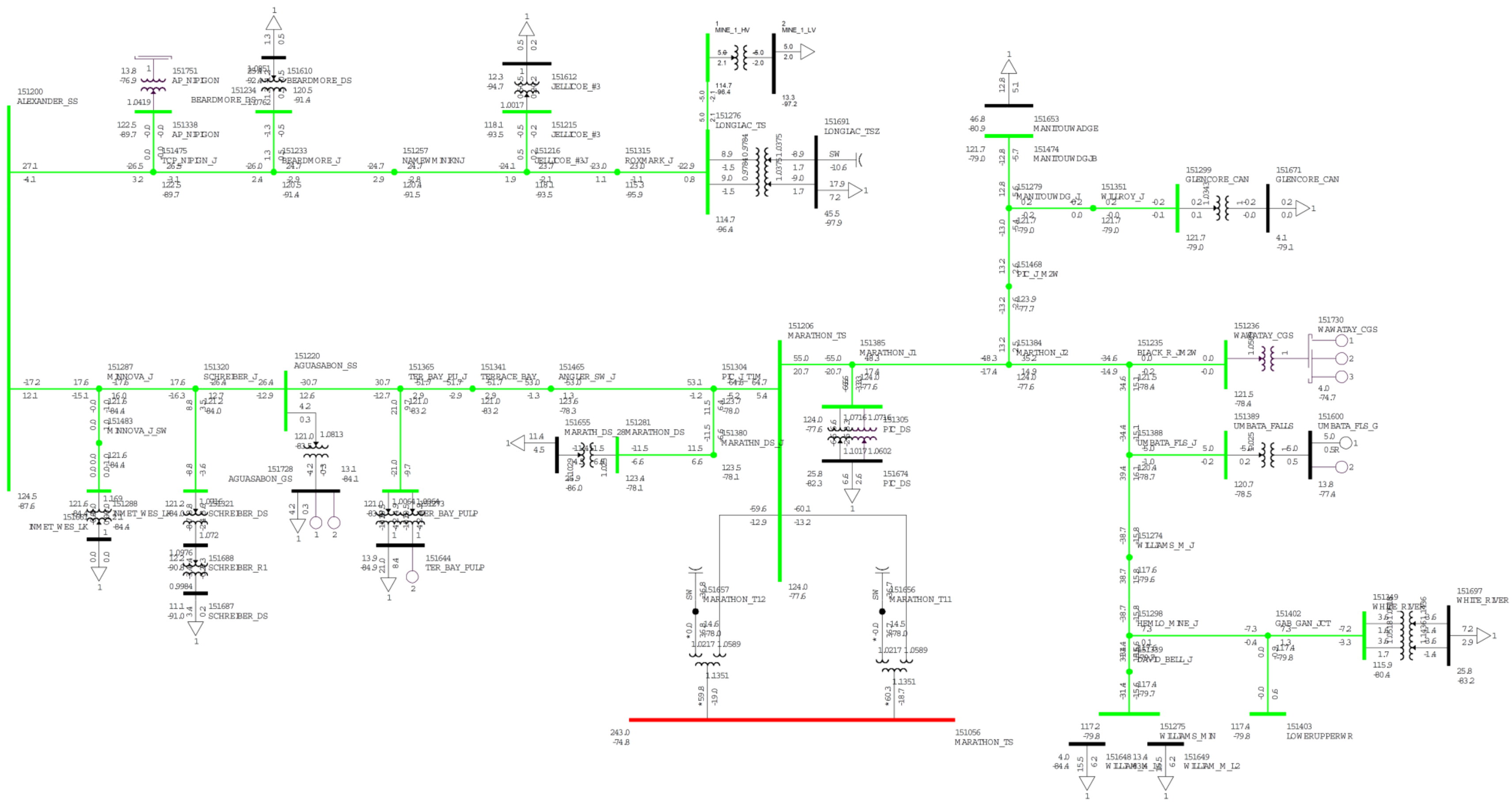
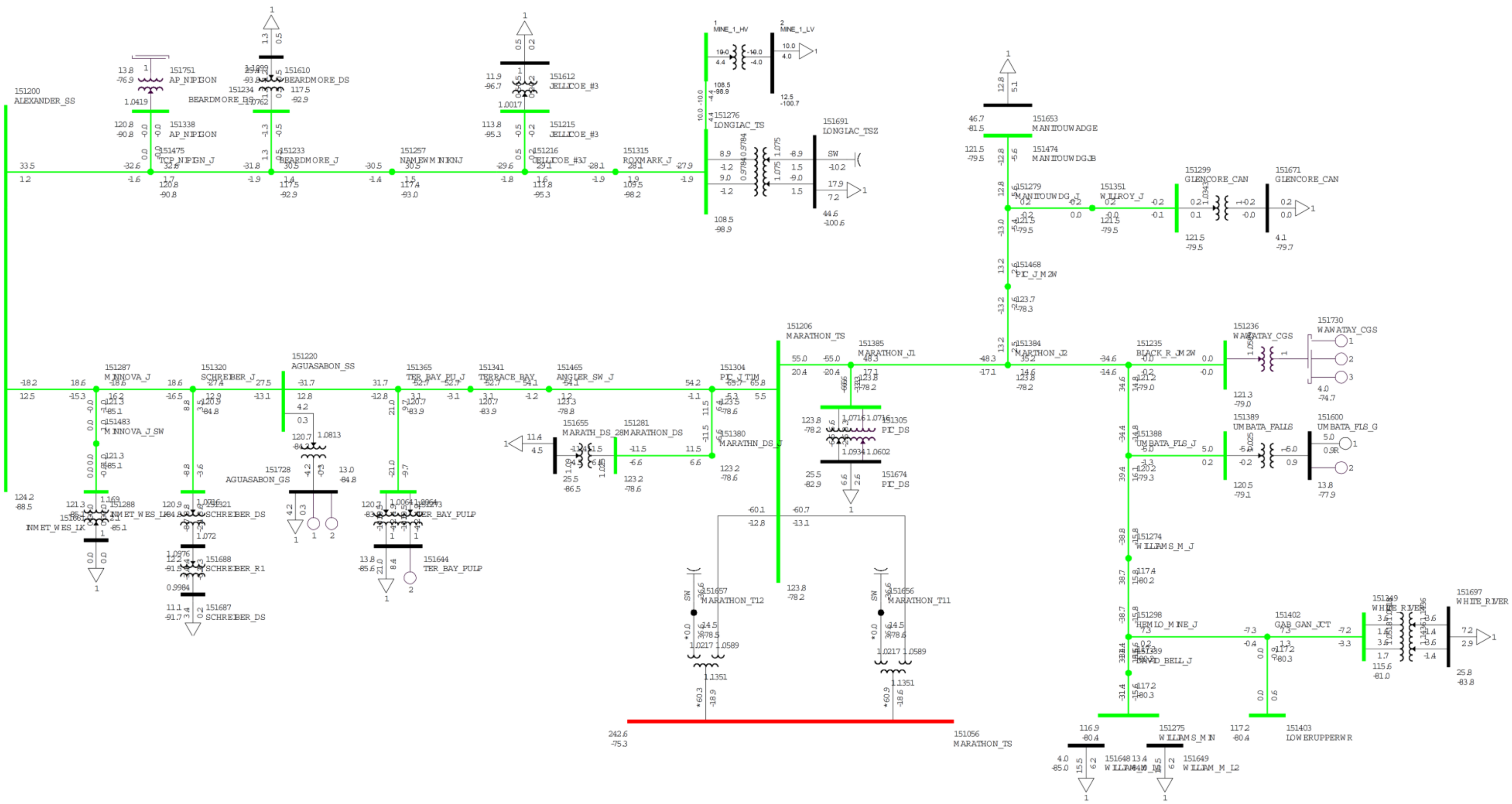


Figure B-2: Establishing Greenstone Sub-system LMC - 30 MW of Load Supplied by A4L



B.2 North Shore Sub-system Load Meeting Capability

The following describes the analysis used to determine the LMC for the Greenstone sub-system.

B.2.1 Assumptions

- AP Nipigon GS out-of-service
- Drought hydroelectric conditions
- Summer planning ratings applied for transmission facilities
- Load supply stations service LDC load as per Scenario A 2020 forecast demand, which is the highest of the forecast scenarios
- Load Q/P ratio of 0.4 assumed (to give at least 0.9 power factor on HV winding of step-down transformer, consistent with the Market Rules)

B.2.2 Methodology

- Compare loading to ratings and voltages to standards for:
    - Pre-contingency condition with the East-West Tie at maximum westbound fair weather transfer
    - Post-contingency conditions for loss of M23L and/or M24L with the East-West Tie at maximum westbound fair weather transfer prior to the contingency

B.2.3 Results

The supply to the North Shore sub-system was not found to be limiting:

Pre-contingency

Refer to Figure B-3 for load flow plot.

Table B-2: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
Marathon TS x Pic JCT	620	303	49
Pic JCT x Angler Switch JCT	460	248	54
Angler Switch JCT x Terrace Bay SS	460	248	54
Terrace Bay SS x Terrace Bay JCT	620	248	40
Terrace Bay JCT x Aguasabon SS	570	159	28
Aguasabon SS x Schreiber JCT	430	141	33
Schreiber JCT x Minnova JCT	430	114	26
Minnova JCT x Alexander SS	430	109	25

Table B-3: Voltage Analysis

<table>
<tr><th>Bus</th><th>Voltage [kV]</th><th>Maximum Continuous Voltage [kV]</th><th>Minimum Continuous Voltage [kV]</th></tr>
<tr><td>Marathon TS (230 kV)</td><td>243.9</td><td>250</td><td>220</td></tr>
<tr><td>Marathon TS (115 kV)</td><td>124.6</td><td rowspan="4">127</td><td rowspan="4">113</td></tr>
<tr><td>Terrace Bay SS</td><td>121.5</td></tr>
<tr><td>Aguasabon SS</td><td>121.5</td></tr>
<tr><td>Alexander SS</td><td>124.8</td></tr>
</table>

Post-contingency

Refer to Figure B-3, Figure B-4 and Figure B-5 for load flow plots.

The loss of circuit M23L is the most severe single element contingency for the North Shore sub-system as it removes Marathon TS auto-transformer T11 and shunt capacitor bank SC29 from service, resulting in a significant voltage change, and also increases the loading of the North Shore circuits.

The loss of both circuits M23L and M24L are recognized by the Northwest SPS for the interim, and addressed by the East-West Tie reinforcement for the long term. Further analysis of this condition was not required.

Table B-4: Thermal Analysis

Circuit Section	Long-term Emergency Rating [A]	Loading [A]	Loading [% Rating]
Marathon TS x Pic JCT	790	406	51
Pic JCT x Angler Switch JCT	460	351	76
Angler Switch JCT x Terrace Bay SS	460	351	76
Terrace Bay SS x Terrace Bay JCT	790	350	44
Terrace Bay JCT x Aguasabon SS	570	260	46
Aguasabon SS x Schreiber JCT	430	241	56
Schreiber JCT x Minnova JCT	430	208	48
Minnova JCT x Alexander SS	430	205	48

Table B-5: Voltage Analysis

<table>
<tr><th>Bus</th><th>Pre-contingency Voltage</th><th>Post-contingency Voltage (Pre-ULTC)</th><th>Post-contingency Voltage (Post-ULTC)</th><th>Maximum Voltage [kV]</th><th>Minimum Voltage [kV]</th><th>Voltage Change Limit [%]</th></tr>
<tr><td>Marathon TS (230 kV)</td><td>243.9</td><td>229.7 (-5.8%)</td><td>224.6 (-7.9%)</td><td>250</td><td>207</td><td>10</td></tr>
<tr><td>Marathon TS (115 kV)</td><td>124.6</td><td>116.3 (-6.7%)</td><td>124.6 (0.0%)</td><td rowspan="4">127</td><td rowspan="4">108</td><td rowspan="4">10</td></tr>
<tr><td>Terrace Bay SS</td><td>121.5</td><td>114.4 (-5.8%)</td><td>120.3 (-1.0%)</td></tr>
<tr><td>Aguasabon SS</td><td>121.5</td><td>114.7 (-5.6%)</td><td>120.4 (-0.9%)</td></tr>
<tr><td>Alexander SS</td><td>124.8</td><td>123.2 (-1.3%)</td><td>124 (-0.6%)</td></tr>
</table>

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B.2.4 Load Flow Plots

Figure B-3: Establishing North Shore LMC: Scenario A 2020 Forecast Pre-contingency

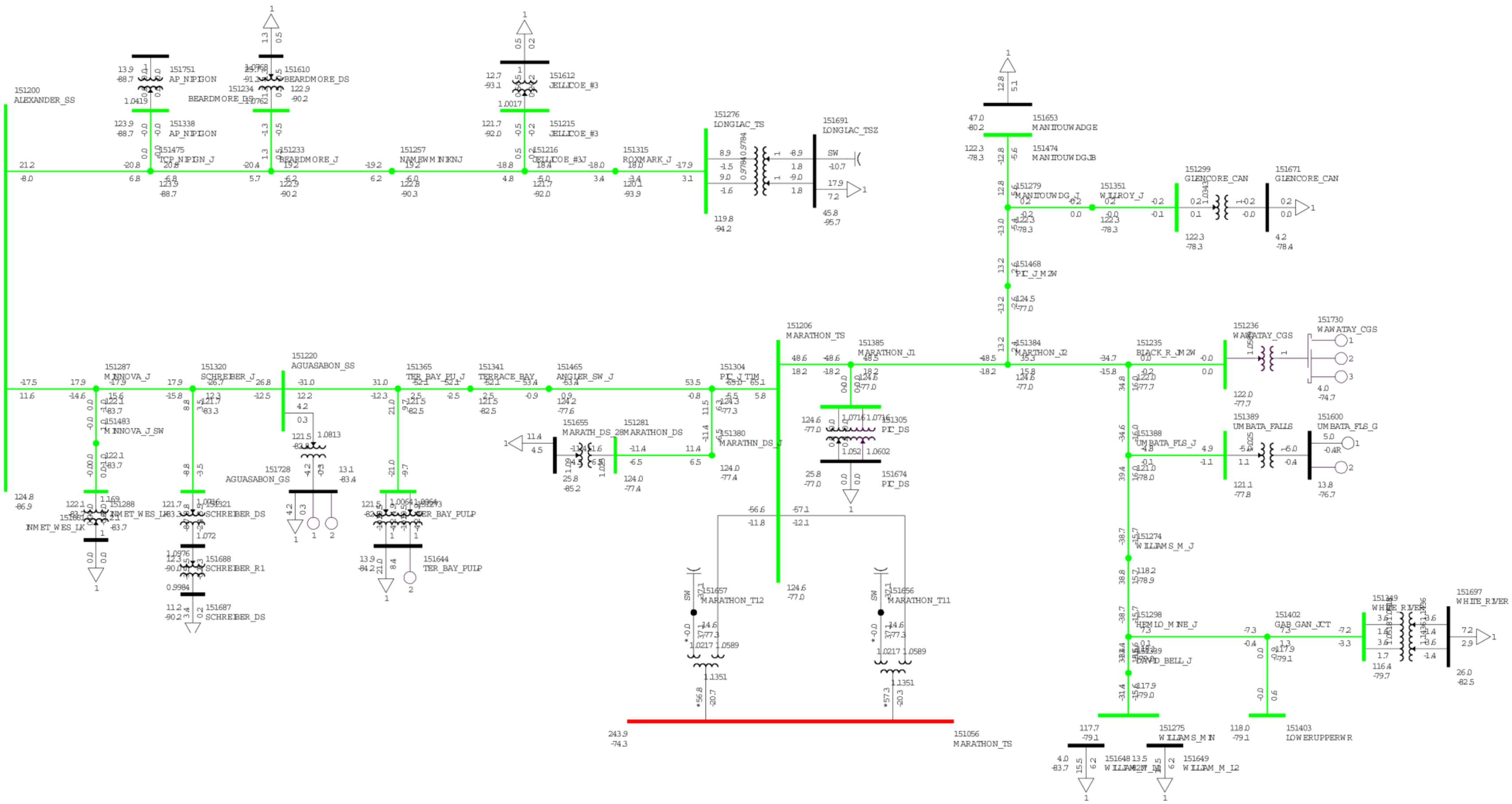


Figure B-4: Establishing North Shore LMC: Scenario A 2020 Forecast Post-contingency Pre-ULTC

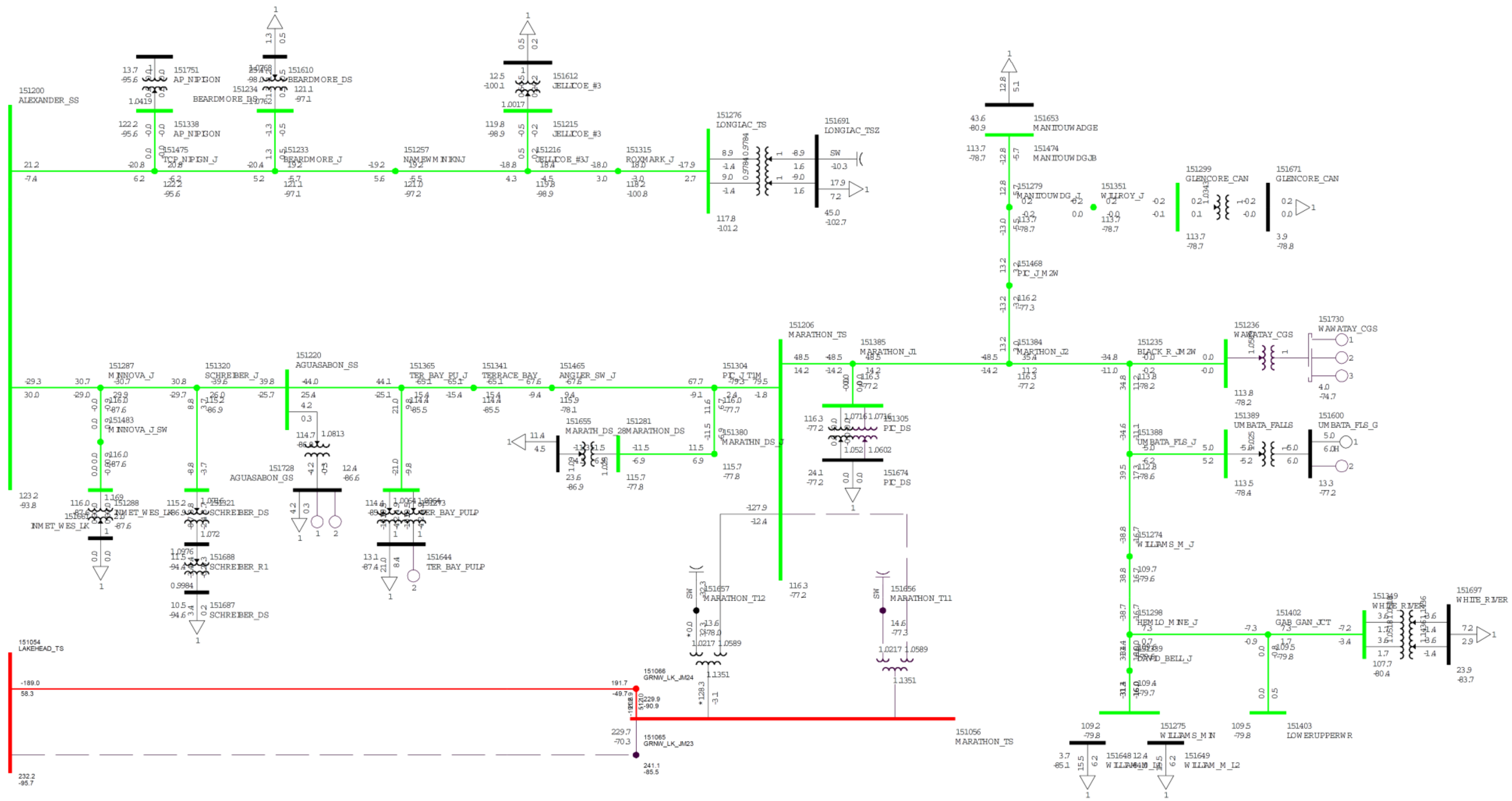
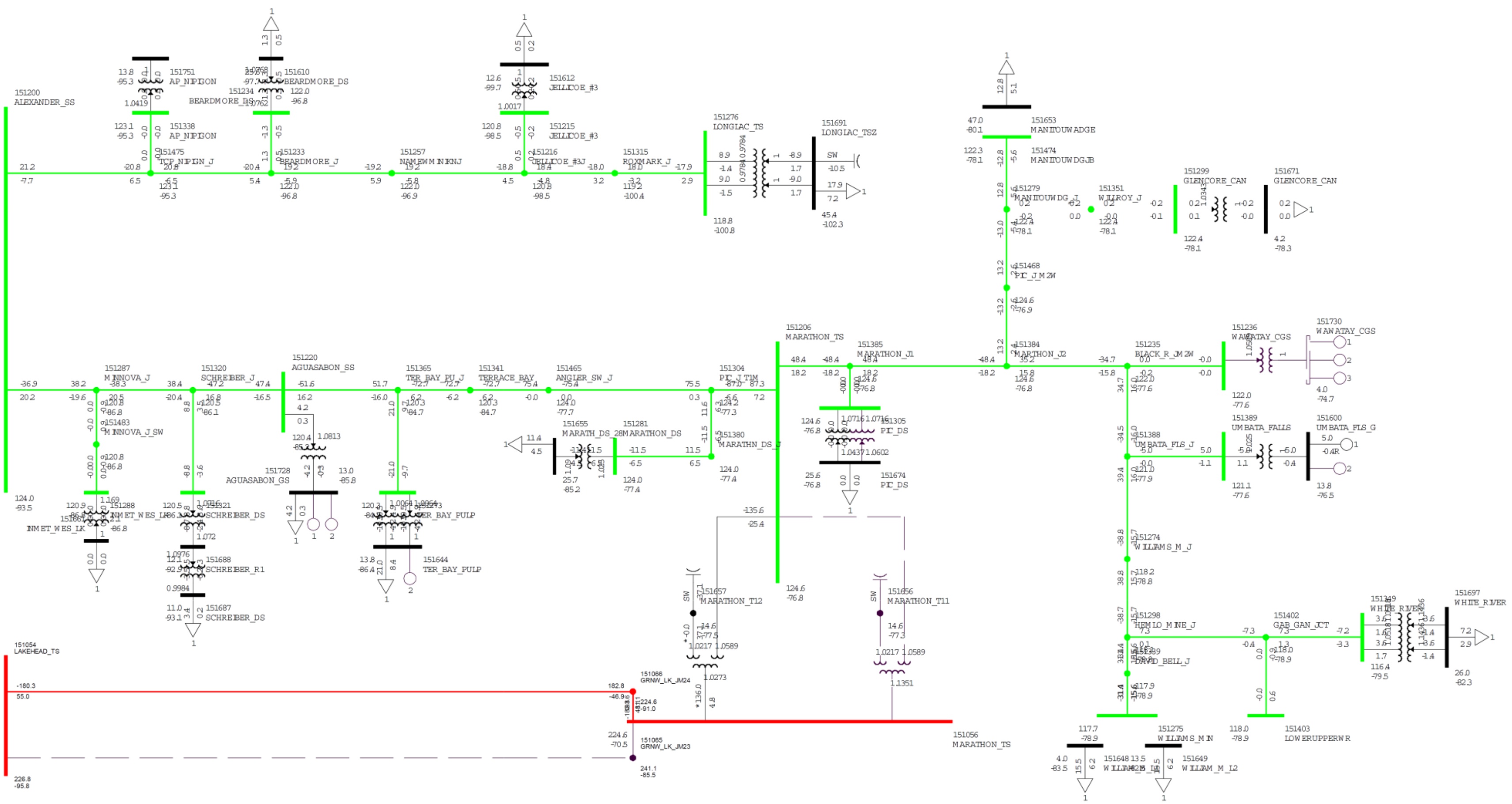


Figure B-5: Establishing North Shore LMC: Scenario A 2020 Forecast Post-contingency Post-ULTC



B.3 Marathon Area Sub-system Load Meeting Capability

The following describes the analysis used to determine the LMC for the Greenstone sub-system.

B.3.1 Assumptions

- AP Nipigon GS out-of-service
- Drought hydroelectric conditions
- Aguasabon GS operating in condense-mode
- Summer planning ratings applied for transmission facilities
- Demand forecast as per Scenario C 2020 forecast demand, which is the highest of the forecast scenarios
- Load Q/P ratio of 0.4 assumed (to give at least 0.9 power factor on HV winding of step-down transformer, consistent with the Market Rules)

B.3.2 Methodology

- Compare loading to ratings and voltages to standards for:
  - Pre-contingency condition with the East-West Tie at maximum westbound fair weather transfer
  - Post-contingency conditions with the East-West Tie at maximum westbound fair weather transfer prior to the contingency

B.3.3 Results

The supply to the Marathon area sub-system was not found to be limiting:

Pre-contingency

Refer to Figure B-6 for load flow plot.

Table B-6: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
Marathon TS x Pic JCT	620	321	52
Pic JCT x Manitouwadge JCT	350	322	92
Marathon TS x Black River JCT	370	181	49
Black River JCT x Umbata Falls JCT	370	183	49
Umbata Falls JCT x Williams Mine JCT	370	203	55
Williams Mine JCT x Hemlo Mine JCT	370	203	55
Hemlo Mine JCT x Animki JCT	330	35	11
Animki JCT x White Fiver DS	330	39	12

Table B-7: Voltage Analysis

Bus	Voltage [kV]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Marathon TS (230 kV)	245.4	250	220
Marathon TS (115 kV)	125.5		
Manitouwadge TS	121.4	127	113
White River DS	117.3		

Post-contingency

Refer to Figure B-6, Figure B-7 and Figure B-8 for load flow plots.

The loss of circuit M23L is the most severe single element contingency for the Marathon area sub-system as it removes Marathon TS auto-transformer T11 and shunt capacitor bank SC29 from service, resulting in a significant voltage change. All facilities are expected to perform within limits. However, it is noted that in order to maintain post-contingency voltages at White River DS under peak demand conditions coincident with drought hydroelectric conditions, Aguasabon GS should be called on for reactive power services by operating in condense mode.

Other contingency conditions were found to be less limiting and are not presented in this report.

Table B-8: Thermal Analysis

Circuit Section	Long-term Emergency Rating [A]	Loading [A]	Loading [% Rating]
Marathon TS x Pic JCT	790	323	41
Pic JCT x Manitouwadge JCT	350	323	92
Marathon TS x Black River JCT	470	180	38
Black River JCT x Umbata Falls JCT	470	181	39
Umbata Falls JCT x Williams Mine JCT	470	203	43
Williams Mine JCT x Hemlo Mine JCT	470	204	43
Hemlo Mine JCT x Animki JCT	330	36	11
Animki JCT x White Fiver DS	330	39	12

Table B-9: Voltage Analysis

<table>
<tr><th>Bus</th><th>Pre-contingency Voltage</th><th>Post-contingency Voltage (Pre-ULTC)</th><th>Post-contingency Voltage (Post-ULTC)</th><th>Maximum Voltage [kV]</th><th>Minimum Voltage [kV]</th><th>Voltage Change Limit [%]</th></tr>
<tr><td>Marathon TS (230 kV)</td><td>245.4</td><td>231.5 (-5.7%)</td><td>226.6 (-7.7%)</td><td>250</td><td>207</td><td>10</td></tr>
<tr><td>Marathon TS (115 kV)</td><td>125.5</td><td>116.6 (-7.1%)</td><td>124.8 (-0.6%)</td><td rowspan="3">127</td><td rowspan="3">108</td><td rowspan="3">10</td></tr>
<tr><td>Manitouwadge TS</td><td>121.4</td><td>112.1 (-7.1%)</td><td>120.7 (-0.6%)</td></tr>
<tr><td>White River DS</td><td>117.3</td><td>108.1 (-7.8%)</td><td>116.6 (-0.6%)</td></tr>
</table>

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B.3.4 Load Flow Plots

Figure B-6: Establishing Marathon Area LMC: Scenario C 2020 Forecast Pre-contingency

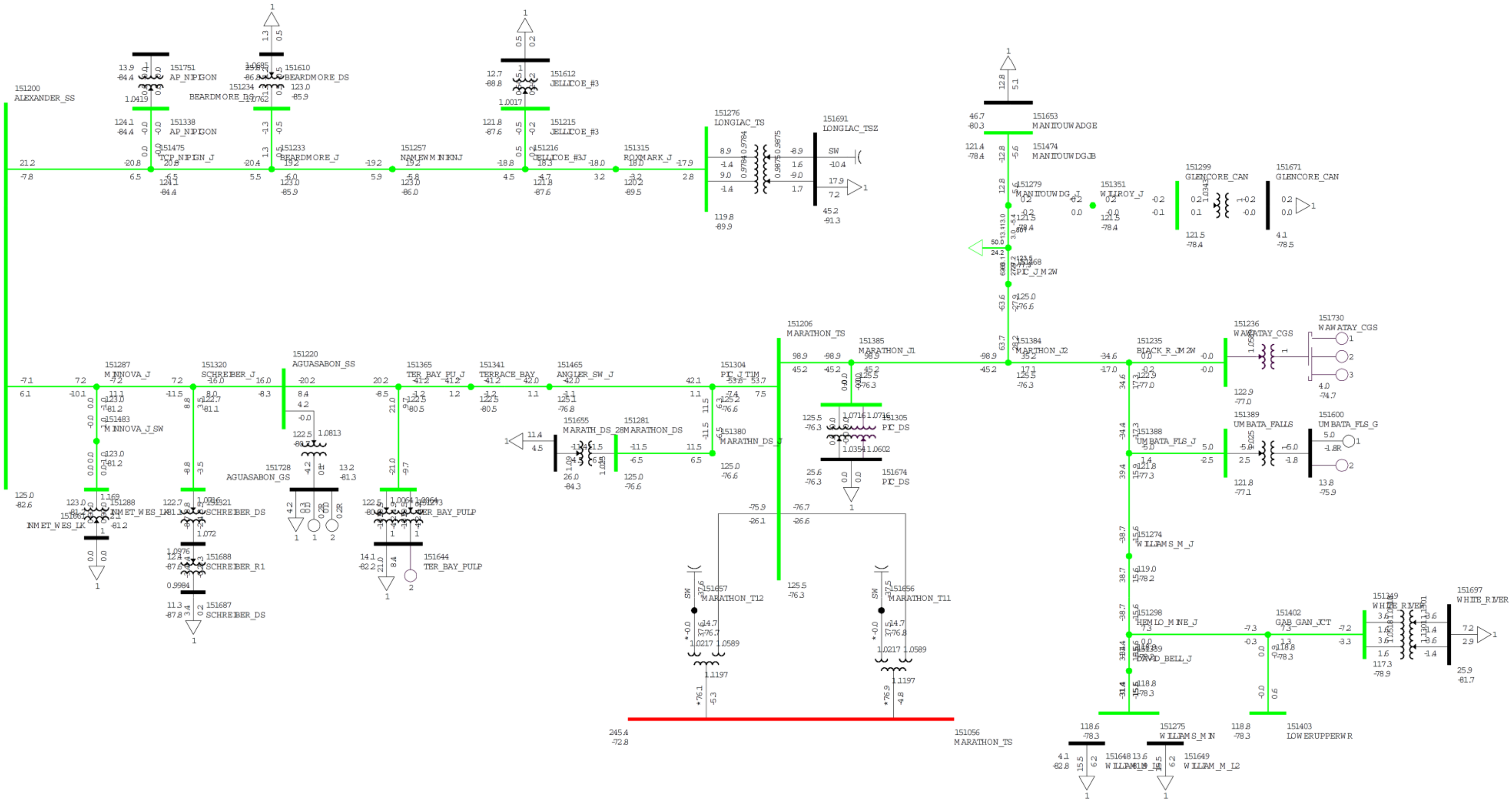


Figure B-7: Establishing Marathon Area LMC: Scenario C 2020 Forecast Post-contingency Pre-ULTC

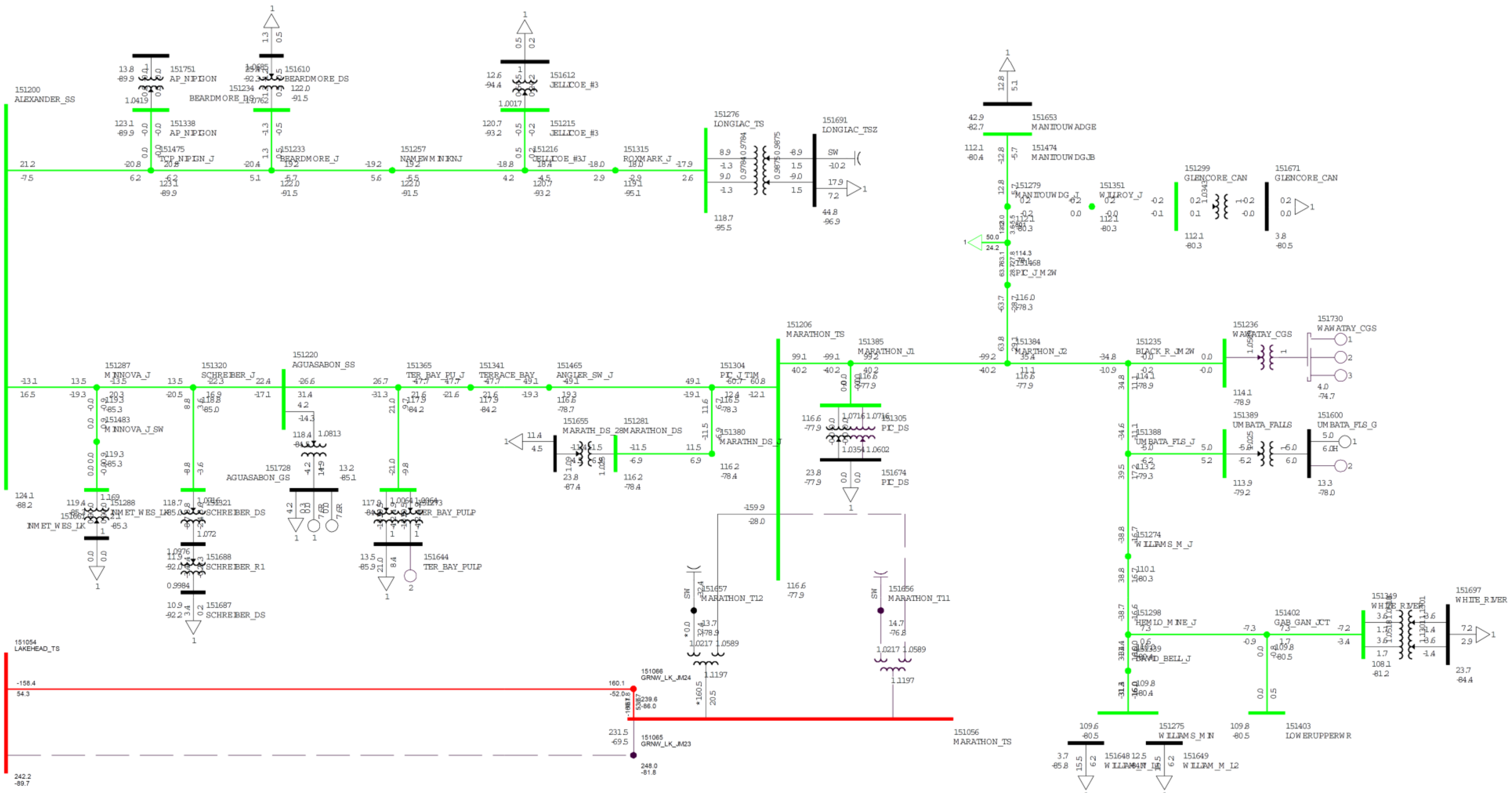
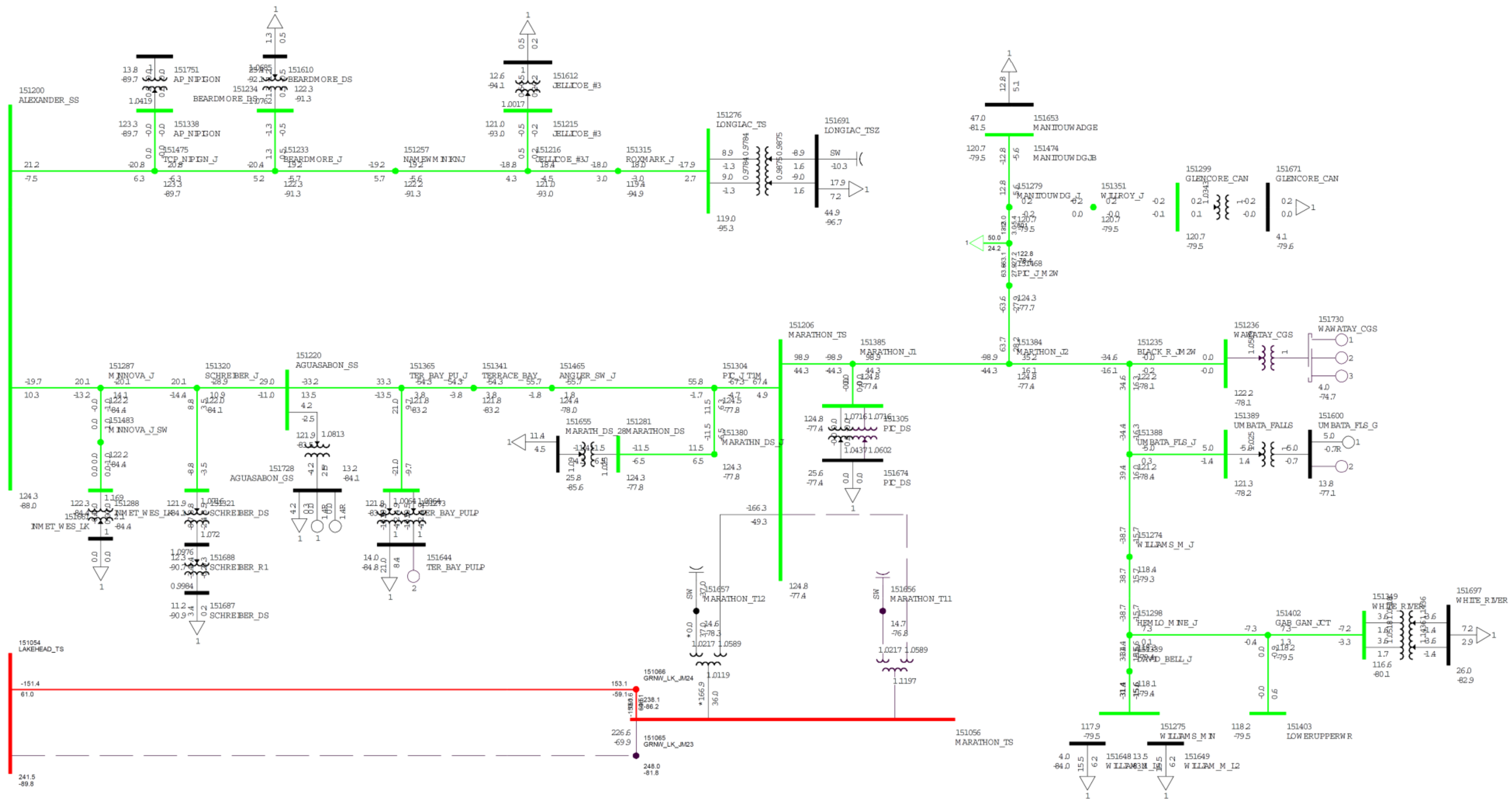


Figure B-8: Establishing Marathon Area LMC: Scenario C 2020 Forecast Post-contingency Post-ULTC



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Appendix C: Studies to Establish Technical Performance of Options

Appendix C: Studies to Establish Technical Performance of Options

The following appendix summarizes power flow tests to support the technical performance of power system options.

C.1 Option B1

Option B1 was established to meet up to the near-term forecast demand under Scenario B. This option consists of the following:

- Installing +40 MVar of new reactive compensation, in either the form of a synchronous condenser or a STATCOM, modeled as remote voltage control at Longlac TS to 115 kV
- Installing 2x10 MW gas-fired engines
- Installing a local SPS to account for low-probability high-consequence events

C.1.1 Assumptions

- AP Nipigon GS out-of-service
- One of the new gas-fired engines out-of-service
- Drought hydroelectric conditions
- Longlac TS capacitor banks in-service (2x5 MVar)
- Summer planning ratings applied for transmission facilities
- Scenario B 2020 forecast demand
- Load Q/P ratio of 0.4 assumed (to give at least 0.9 power factor on HV winding of step-down transformer, consistent with the Market Rules)

C.1.2 Methodology

- Assess system condition versus standards with all elements in-service pre-contingency
- Assess system condition versus standards considering the outage of a single element. Outage conditions that are most severe are:
    - Alexander SS breaker KL4 outage
    - Alexander SS breaker L5L6 outage
- Breaker outage conditions pre-contingency are not identified in NPCC Directory #1 or NERC TPL-001-4, however, given the ring bus design of Alexander SS, they are credible outage conditions that need to be considered.
- Voltage Stability analysis is performed by generating a P-V curve and comparing with ORTAC voltage stability criteria. This is achieved by initially using the Scenario A 2020 forecast demand (i.e. only LDC station load), and incrementing the load at the Geraldton

mine site by 1 MW and 0.4 MVar up to the critical point of the P-V curve. This would establish a point on the curve that would represent Scenario B 2020 demand once the load at the Geraldton mine site is incremented to 35 MW and 14 MVar.

C.1.3 Results

All Elements In-Service Pre-contingency

Refer to Figure C-2 for the load flow plot.

Table C-1: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
Alexander SS x AP Nipigon JCT	310	261	84
AP Nipigon JCT x Beardmore JCT	260	258	99
Beardmore JCT x Jellicoe DS #3 JCT	260	251	97
Jellicoe DS #3 JCT x Roxmark JCT	260	246	95
Roxmark JCT x Longlac TS	260	242	93

Table C-2: Voltage Analysis

Bus	Voltage [kV]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Alexander SS	124.5	127	113
Beardmore JCT	119.4		
Jellicoe JCT	117.3		
Longlac TS	115.5		

Breaker Outages at Alexander SS Pre-contingency

The breaker outages being considered are as follows:

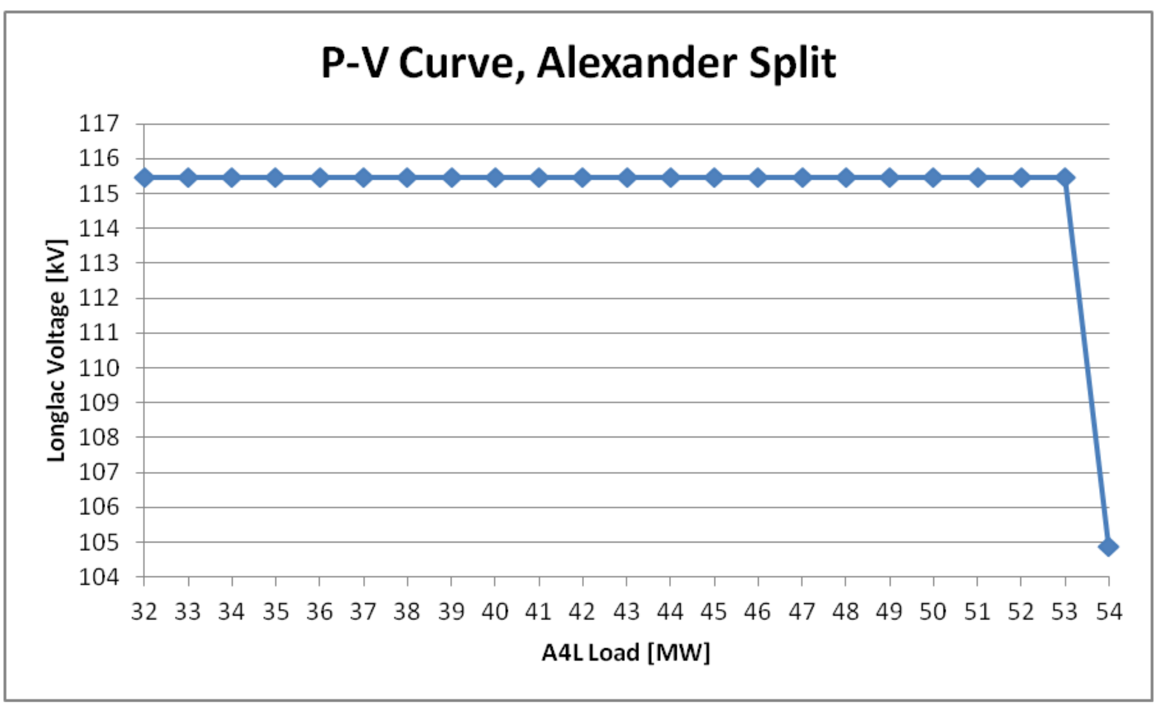
- Alexander SS breaker KL4 outage
- Alexander SS breaker L5L6 outage

With an element out-of-service pre-contingency, 85-percentile hydroelectric output conditions are assumed. The outage of either breakers KL4 or L5L6 does not result in the splitting of Alexander SS on its own. Therefore, the pre-contingency condition is not limiting as it represents the same system configuration as assessed with all elements in service, but with additional hydroelectric output. Therefore the pre-contingency condition is not reported on its own.

The limiting condition arises in the event that a fault occurs coincident with the specified breaker outage conditions above, and is the focus of the following analysis. In the event that circuit A6P experiences a fault while breaker KL4 is out-of-service, or C3A experiences a fault while breaker L5L6 is out-of-service, this would split the ring bus at Alexander SS in such a way that circuit A4L is only connected in series with circuit A5A.

The following illustrates the Voltage Stability analysis considering the condition where Alexander SS is split. In order to generate the P-V curve, initially only 10 MW and 4 MVar of load is modeled at the Geraldton mine site, and increased in 1 MW and 0.4 MVar increments. The system condition is illustrated in the load flow plot given in Figure C-3. Figure C-1, below, illustrates the P-V curve under this configuration.

Figure C-1: P-V Curve with Alexander Split, 40 MVar Reactive Compensation, and 10 MW of local generation



The P-V curve generated above for the voltage stability of circuit A4L is typical for a heavily compensated line. As indicated in the P-V curve, the voltage operates at the setpoint of the compensating device (synchronous condenser or STATCOM), until the maximum rated output of the compensating device is reached. Once, the compensating device reaches maximum output, any further increase in load will result in a severe voltage drop, which is observed.

Table C-3: Voltage Stability Analysis

Parameter	[MW]
Voltage Stability Critical Load	54
Stability Limit	50
Scenario B 2020 Forecast Load	53
Post-contingency load reduction required	3

In order to manage this low-probability high-consequence system condition, a special protection system may be installed to ensure load is continuously supplied during an outage of breaker KL4 or L5L6. Alternatively, the customer may opt to dispatch their own local generation, if available, following an IESO order in preparation for the contingency, in accordance with the Market Rules and System Operating Procedures.

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C.1.4 Load Flow Plots

Figure C-2: With +40MVar Reactive Compensation and one of two 10 MW gas-fired generator in-service at Geraldton mine

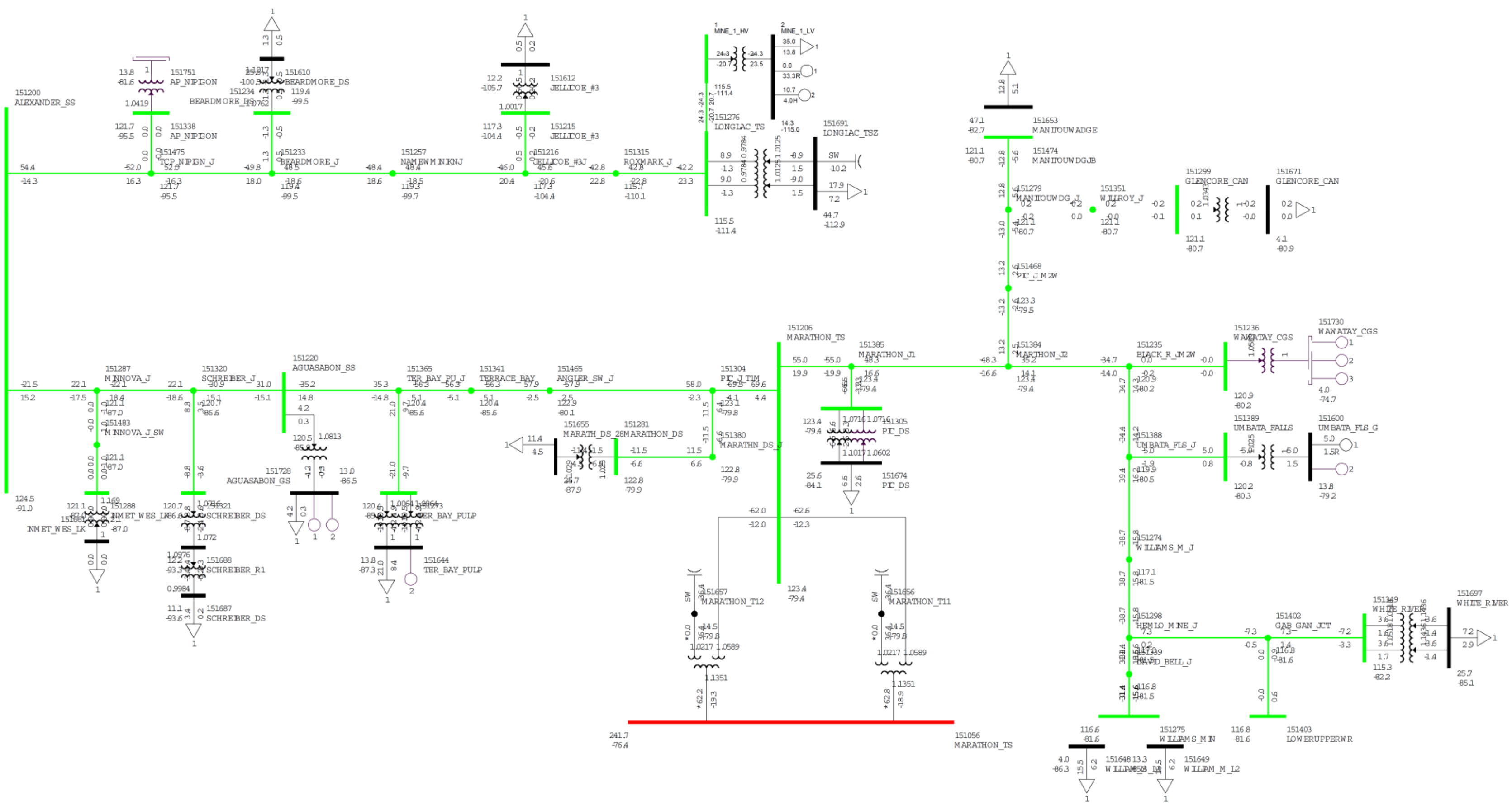
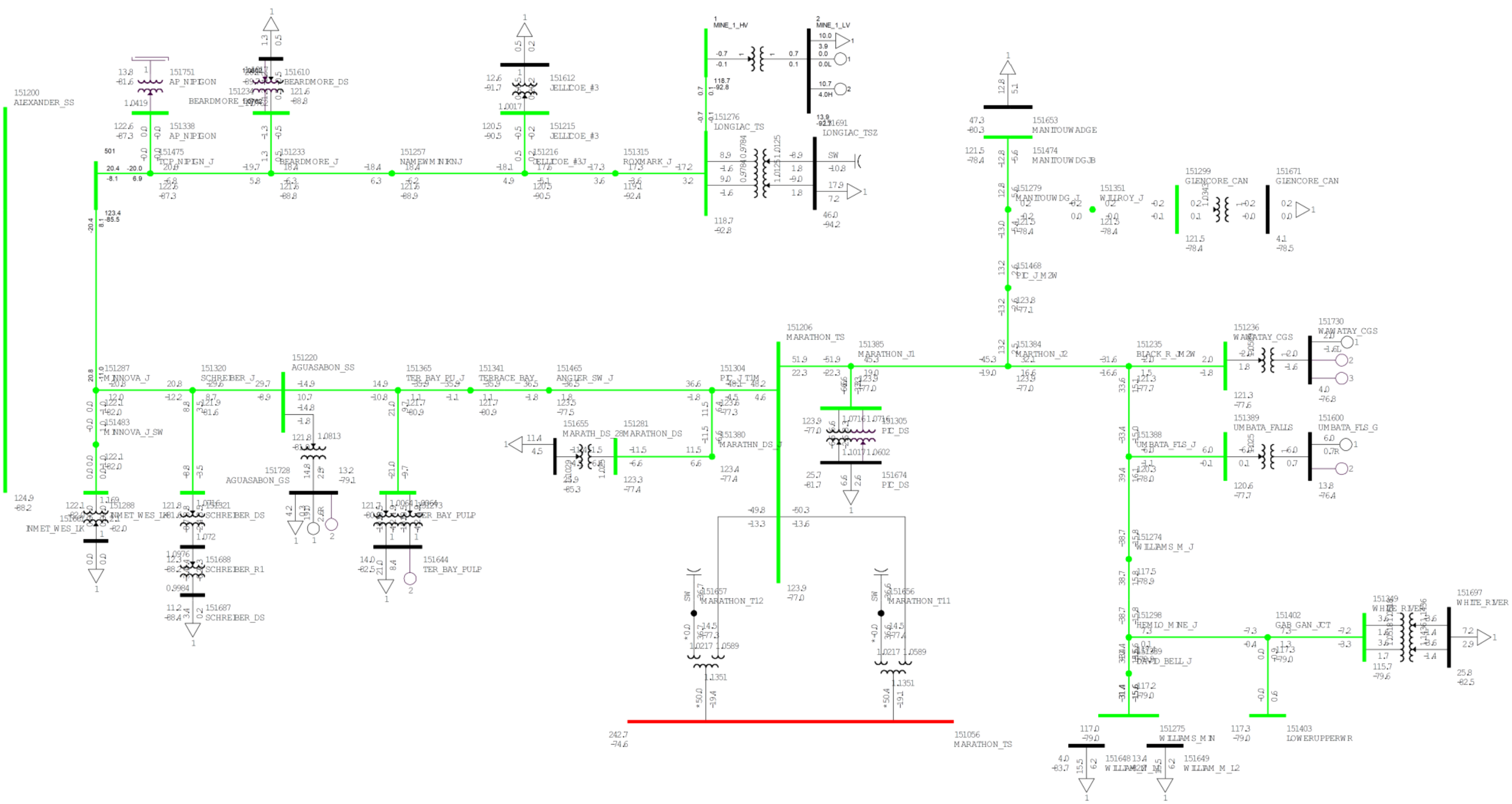


Figure C-3: With +40MVar Reactive Compensation and one of two 10 MW gas-fired generator in-service at Geraldton mine, Alexander SS split for P-V analysis



C.2 Option B3

Option B3 was established to meet up to the near-term forecast demand under Scenario B. This option consists of the following:

- Installing +40 MVar of new reactive compensation, in either the form of a synchronous condenser or a STATCOM, modeled as remote voltage control at Longlac TS to 118 kV
- Replacing circuit A4L from Nipigon to Longlac with 477 kcmil conductors

C.2.1 Assumptions

- AP Nipigon GS out-of-service
- Drought hydroelectric conditions
- Longlac TS capacitor banks in-service (2x5 MVar)
- Summer planning ratings applied for transmission facilities
- Scenario B 2020 forecast demand
- Load Q/P ratio of 0.4 assumed (to give at least 0.9 power factor on HV winding of step-down transformer, consistent with the Market Rules)
- The replacement circuit has the following characteristics (on a 100 MVA base and 118.05 kV base):

Table C-4: Replacement 115 kV Circuit Parameters

R [p.u./km]	X [p.u./km]	B [p.u./km]	Continuous Rating [A]	Long-term Emergency Rating [A]	Short-term Emergency Rating [A]
0.000966	0.003385	0.000490	620	790	960

C.2.2 Methodology

- Assess system condition versus standards with all elements in-service pre-contingency
- Assess system condition versus standards considering the outage of a single element. Outage conditions that are most severe are:
    - Alexander SS breaker KL4 outage
    - Alexander SS breaker L5L6 outage
- Breaker outage conditions pre-contingency are not identified in NPCC Directory #1 or NERC TPL-001-4, however, given the ring bus design of Alexander SS, they are credible outage conditions that need to be considered.
- Voltage Stability analysis is performed by generating a P-V curve and comparing with ORTAC voltage stability criteria. This is achieved by initially using the Scenario A 2020

forecast demand (i.e. only LDC station load), and incrementing the load at the Geraldton mine site by 1 MW and 0.4 MVar up to the critical point of the P-V curve. This would establish a point on the curve that would represent Scenario B 2020 demand once the load at the Geraldton mine site is incremented to 35 MW and 14 MVar.

C.2.3 Results

All Elements In-Service Pre-contingency

Refer to Figure C-5 for load flow plot.

Table C-5: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
Alexander SS x AP Nipigon JCT	310	285	92
AP Nipigon JCT x Beardmore JCT	620	284	46
Beardmore JCT x Jellicoe DS #3 JCT	620	277	45
Jellicoe DS #3 JCT x Roxmark JCT	620	273	44
Roxmark JCT x Longlac TS	620	271	44

Table C-6: Voltage Analysis

<table>
<tr><th>Bus</th><th>Voltage [kV]</th><th>Maximum Continuous Voltage [kV]</th><th>Minimum Continuous Voltage [kV]</th></tr>
<tr><td>Alexander SS</td><td>124.5</td><td rowspan="4">127</td><td rowspan="4">113</td></tr>
<tr><td>Beardmore JCT</td><td>118.8</td></tr>
<tr><td>Jellicoe JCT</td><td>118.2</td></tr>
<tr><td>Longlac TS</td><td>118.1</td></tr>
</table>

Breaker Outages at Alexander SS Pre-contingency

The breaker outages being considered are as follows:

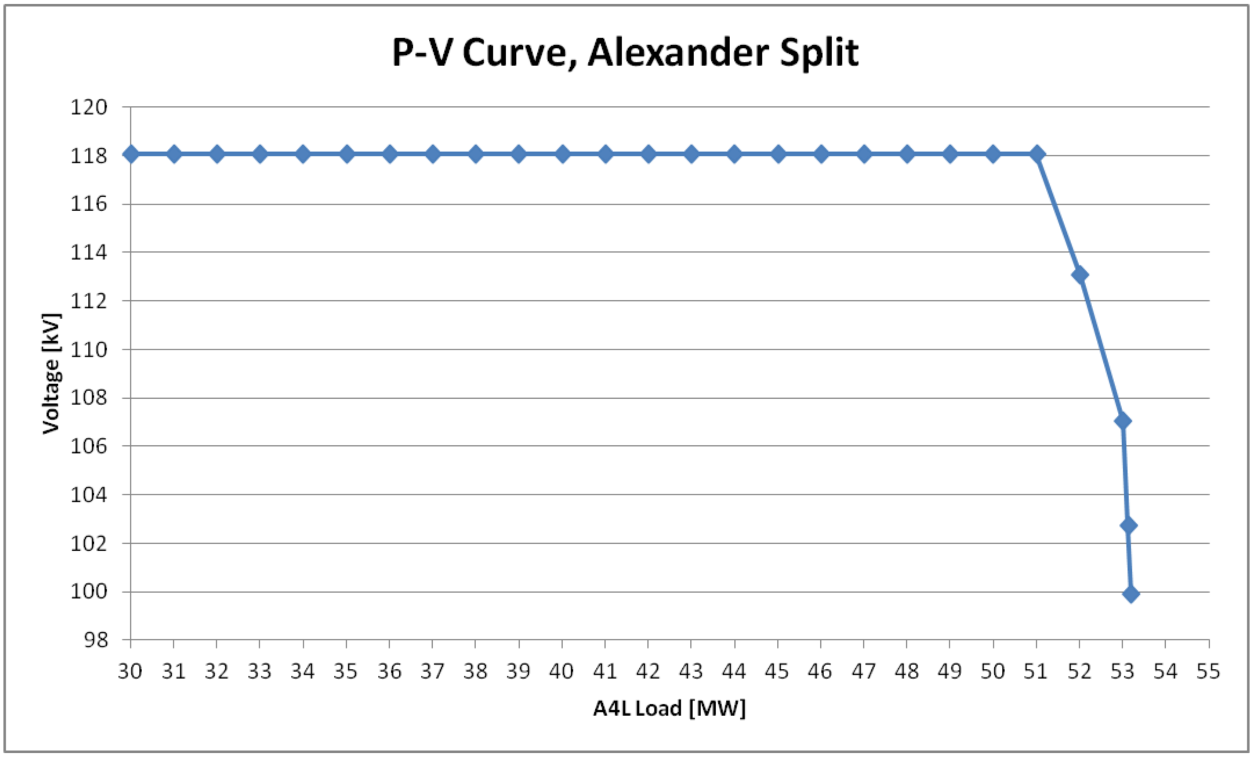
- Alexander SS breaker KL4 outage
- Alexander SS breaker L5L6 outage

With an element out-of-service pre-contingency, 85-percentile hydroelectric output conditions are assumed. The outage of either breakers KL4 or L5L6 does not result in the splitting of Alexander SS on its own. Therefore, the pre-contingency condition is not limiting as it represents the same system configuration as assessed with all elements in service, but with additional hydroelectric output. Therefore the pre-contingency condition is not reported on its own.

The limiting condition arises in the event that a fault occurs coincident with the specified breaker outage conditions above, and is the focus of the following analysis. In the event that circuit A6P experiences a fault while breaker KL4 is out-of-service, or C3A experiences a fault while breaker L5L6 is out-of-service, this would split the ring bus at Alexander SS in such a way that circuit A4L is only connected in series with circuit A5A.

The following illustrates the Voltage Stability analysis considering the condition where Alexander SS is split. In order to generate the P-V curve, initially only 10 MW and 4 MVar of load is modeled at the Geraldton mine site, and increased in 1 MW and 0.4 MVar increments. The initial system condition is illustrated in the load flow plot given in Figure C-6. Figure C-4, below, illustrates the P-V curve under this configuration.

Figure C-4: P-V Curve with Alexander Split, 40 MVar Reactive Compensation, and A4L replaced



The P-V curve generated above for the voltage stability of circuit A4L is typical for a heavily compensated line. As indicated in the P-V curve, the voltage operates at the setpoint of the compensating device (synchronous condenser or STATCOM), until the maximum rated output of the compensating device is reached. Once, the compensating device reaches maximum output, any further increase in load will result in a severe voltage drop, which is observed.

Table C-7: Voltage Stability Analysis

Parameter	[MW]
Voltage Stability Critical Load	53
Stability Limit	50
Scenario B 2020 Forecast Load	53
Post-contingency load reduction required	3

In order to manage this low-probability high-consequence system condition, a special protection system may be installed to ensure load is continuously supplied during an outage of breaker KL4 or L5L6. Alternatively, the customer may accept this risk, but be prepared that following an IESO order to curtail demand in preparation of the contingency, they would be required to comply consistent with the Market Rules and System Operating Procedures.

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C.2.4 Load Flow Plots

Figure C-5: With +40MVar Reactive Compensation and replacement of transmission line A4L from Nipigon to Longlac with 477 kcmil conductors

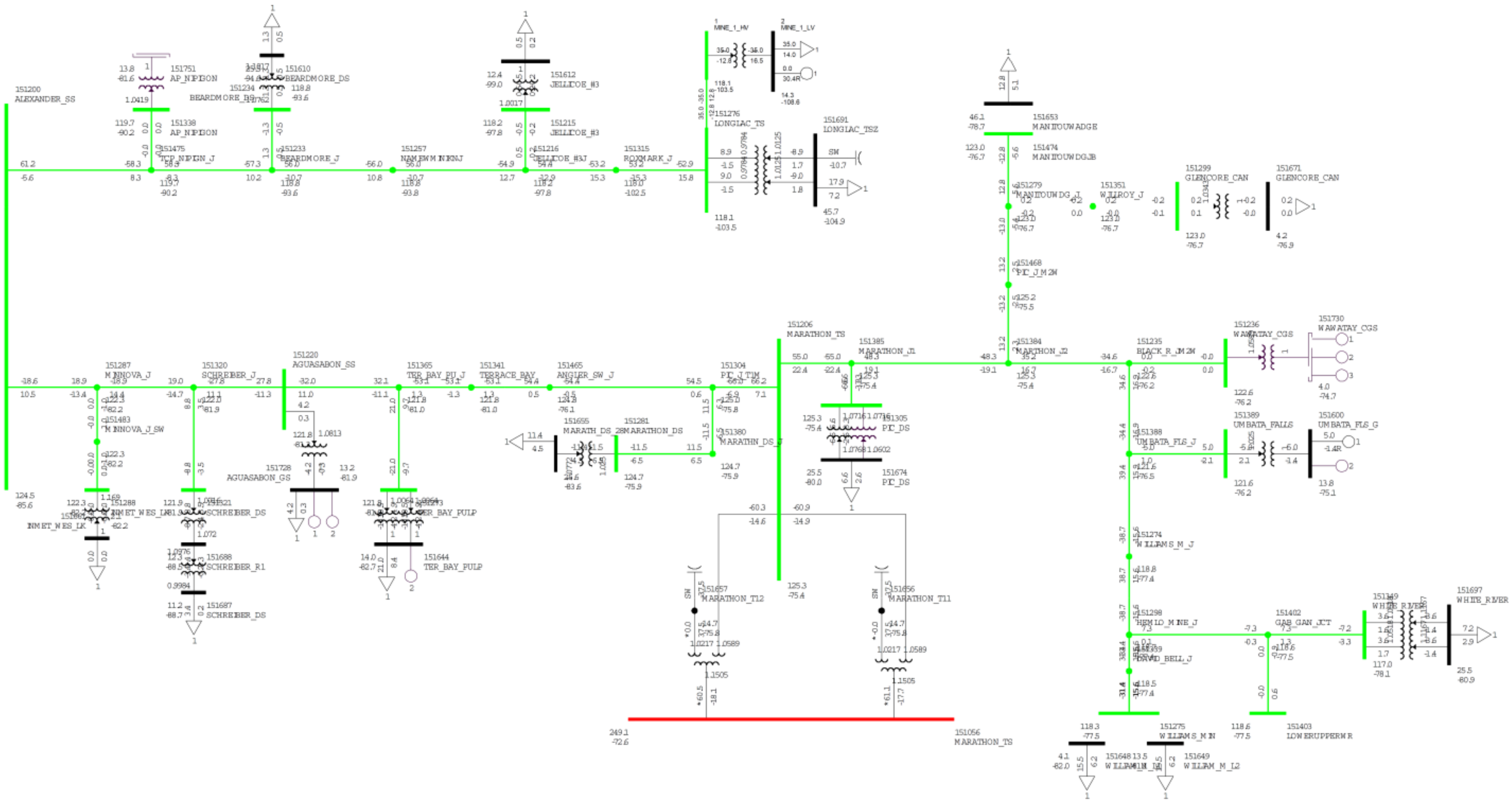
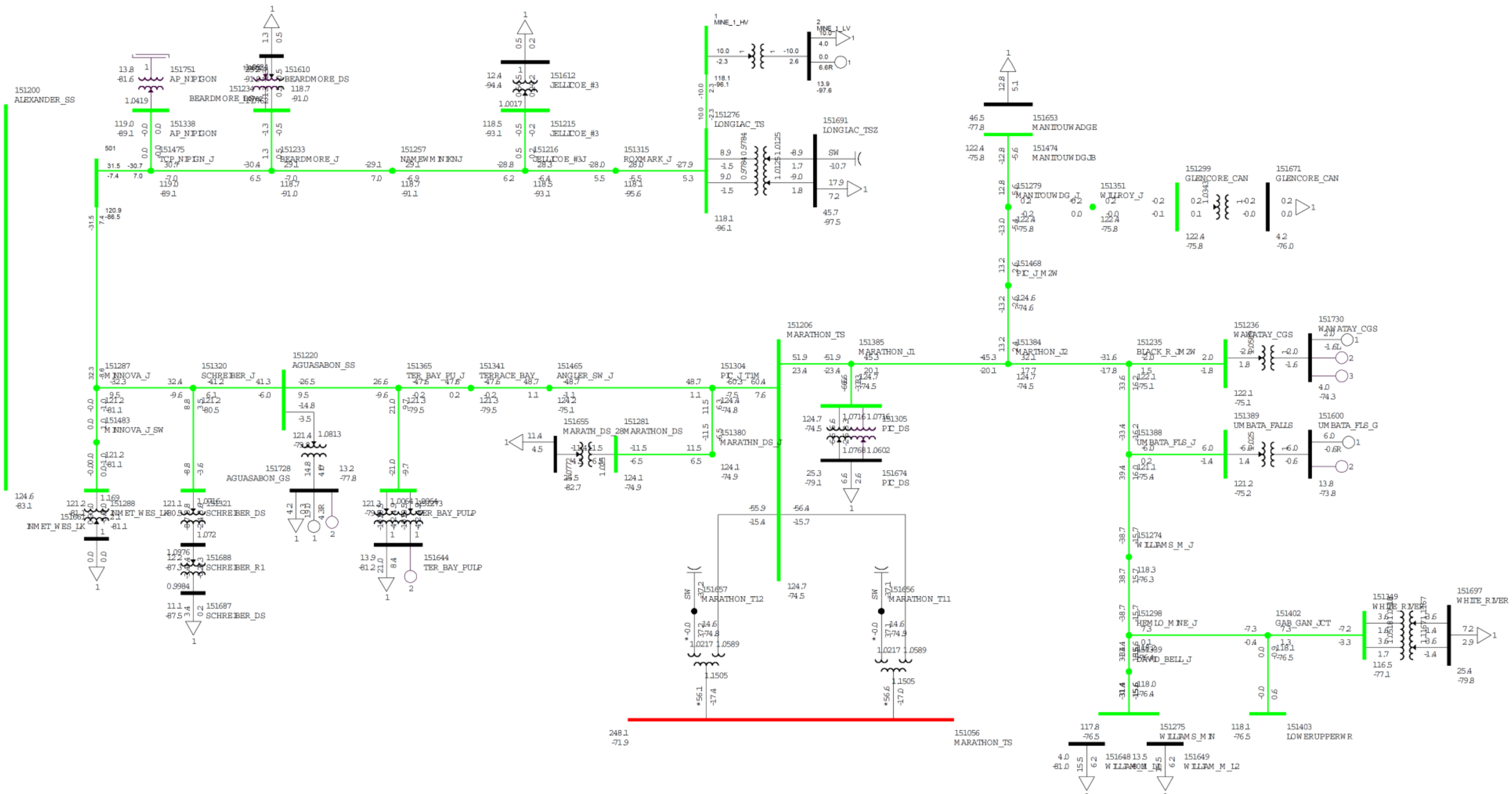


Figure C-6: With +40MVar Reactive Compensation and replacement of transmission line A4L, Alexander SS split for P-V analysis



C.3 Option C1

Option C1 was established to meet up to the near-term forecast demand under Scenario C.

- Installing a new 230 kV single-circuit 795 kcmil transmission line via one of the following routes:
  - West of Marathon Route:
    - 100 km from a new switching station along the East-West Tie to Longlac TS
  - East of Nipigon Route:
    - 150 km from a new switching station along the East-West Tie to Longlac TS
- Installing 1 new 230/115 kV auto-transformer and associated switching at Longlac TS
- Installing 1 new circuit tap along the East-West tie
- Installing +40 MVar of new reactive compensation, in either the form of a synchronous condenser or a STATCOM, modeled as remote voltage control at Longlac TS to 118 kV
- Installing -25 MVar reactive compensation connected to tertiary winding of new auto-transformer

C.3.1 Assumptions

- AP Nipigon GS out-of-service
- Drought hydroelectric conditions
- Longlac TS capacitor banks in-service (2x5 MVar)
- Summer planning ratings applied for transmission facilities
- Scenario C 2020 forecast demand
- Load Q/P ratio of 0.4 assumed (to give at least 0.9 power factor on HV winding of step-down transformer, consistent with the Market Rules)
- The new circuit has the following characteristics (on a 100 MVA base and 220.0 kV base):

Table C-8: New 230 kV Circuit Parameters

R [p.u./km]	X [p.u./km]	B [p.u./km]	Continuous Rating [A]	Long-term Emergency Rating [A]	Short-term Emergency Rating [A]
0.000166	0.001035	0.001607	880	1120	1430

C.3.2 Methodology

- Assess system condition versus standards with all elements in-service pre-contingency

- Assess system condition versus standards considering the outage of a single element
- Assess no-load condition to determine inductive reactive compensation requirement

C.3.3 Results – West of Marathon Route

All Elements In-Service Pre-contingency

Refer to Figure C-7 for load flow plot.

Table C-9: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
New 230 kV Line	880	206	24
Alexander SS x AP Nipigon JCT	310	33	11
AP Nipigon JCT x Beardmore JCT	260	33	13
Beardmore JCT x Jellicoe DS #3 JCT	260	30	11
Jellicoe DS #3 JCT x Roxmark JCT	260	68	26
Roxmark JCT x Longlac TS	260	64	25

Table C-10: Voltage Analysis

<table>
<tr><th>Bus</th><th>Voltage [kV]</th><th>Maximum Continuous Voltage [kV]</th><th>Minimum Continuous Voltage [kV]</th></tr>
<tr><td>Marathon TS (230 kV)</td><td>248.6</td><td rowspan="2">250</td><td rowspan="2">220</td></tr>
<tr><td>Longlac TS (230 kV)</td><td>241.9</td></tr>
<tr><td>Marathon TS (115 kV)</td><td>125.0</td><td rowspan="5">127</td><td rowspan="5">113</td></tr>
<tr><td>Longlac TS (115 kV)</td><td>125.7</td></tr>
<tr><td>Jellicoe JCT</td><td>122.7</td></tr>
<tr><td>Beardmore JCT</td><td>123.6</td></tr>
<tr><td>Alexander SS</td><td>124.8</td></tr>
</table>

Loss of New 230 kV Circuit

The most limiting contingency for the system following the enhancement of a new 230 kV circuit is the loss of that new circuit. Following the loss of the new 230 kV circuit, the resulting system is the same as the existing system, where A4L is the only circuit supplying load in the Greenstone sub-system. Therefore, following the contingency load must be immediately reduced to 45 MW. This may be achieved by configuration, or through a special protection system. The load flow results below correspond to post-contingency load of 45 MW, and indicate the system would be at its post-contingency limit.

Refer to Figure C-8 for pre-ULTC load flow plot and Figure C-9 for post-ULTC load flow plot with capacitor switching at Marathon.

Table C-11: Thermal Analysis

Circuit Section	Long-term Emergency Rating [A]	Loading [A]	Loading [% Rating]
New 230 kV Line	1120	Out-of-service	N/A
Alexander SS x AP Nipigon JCT	310	260	84
AP Nipigon JCT x Beardmore JCT	260	258	99
Beardmore JCT x Jellicoe DS #3 JCT	260	251	97
Jellicoe DS #3 JCT x Roxmark JCT	260	193	74
Roxmark JCT x Longlac TS	260	186	71

Table C-12: Voltage Analysis

Bus	Pre-contingency Voltage	Post-contingency Voltage (Pre-ULTC)	Post-contingency Voltage (Post-ULTC)*	Maximum Voltage [kV]	Minimum Voltage [kV]	Voltage Change Limit [%]
Marathon TS (230 kV)	248.6	252.7 (+1.6%)	247.9 (-0.3%)	250	207	10
Longlac TS (230 kV)	241.9	N/A	N/A			
Marathon TS (115 kV)	125.0	127.0 (+1.6%)	122.9 (-1.7%)	127	108	10
Longlac TS (115 kV)	125.7	118.1 (-6.0%)	118.1 (-6.0%)			
Jellicoe JCT	122.7	116.1 (-5.4%)	115.9 (-5.5%)			
Beardmore JCT	123.6	118.8 (-3.9%)	118.5 (-4.1%)			
Alexander SS	124.8	125.0 (+0.2%)	124.6 (-0.2%)			

* Capacitor switching at Marathon required to remain below 250 kV

No Load Condition

The no load condition is assessed to determine if the installation of -25 MVar tertiary connected reactor (which is a standard size) is sufficient to suppress voltages at the Longlac terminal of the new line. For this condition, it is assumed that the sending-end voltage of the new line is maintained at the maximum allowable voltage of 250 kV, and that A4L is open at Longlac. This is to ensure the reactor is sized for reasonable worst-case conditions.

Operational measures such as removing circuits from service to suppress voltages were not considered for this condition. It is assumed that such measures would only be reserved for outage conditions, for example if reactor(s) are unavailable.

It is observed that -25 MVar is sufficient and would suppress voltages at Longlac to within ratings. Refer to Figure C-10 for load flow plot.

C.3.4 Results – East of Nipigon Route

All Elements In-Service Pre-contingency

Refer to Figure C-11 for load flow plot.

Table C-13: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
New 230 kV Line	880	183	21
Alexander SS x AP Nipigon JCT	310	87	28
AP Nipigon JCT x Beardmore JCT	260	88	34
Beardmore JCT x Jellicoe DS #3 JCT	260	83	32
Jellicoe DS #3 JCT x Roxmark JCT	260	31	12
Roxmark JCT x Longlac TS	260	22	8

Table C-14: Voltage Analysis

<table>
<tr><th>Bus</th><th>Voltage [kV]</th><th>Maximum Continuous Voltage [kV]</th><th>Minimum Continuous Voltage [kV]</th></tr>
<tr><td>Marathon TS (230 kV)</td><td>248.8</td><td rowspan="2">250</td><td rowspan="2">220</td></tr>
<tr><td>Longlac TS (230 kV)</td><td>239.8</td></tr>
<tr><td>Marathon TS (115 kV)</td><td>123.7</td><td rowspan="5">127</td><td rowspan="5">113</td></tr>
<tr><td>Longlac TS (115 kV)</td><td>120.1</td></tr>
<tr><td>Jellicoe JCT</td><td>118.7</td></tr>
<tr><td>Beardmore JCT</td><td>121.0</td></tr>
<tr><td>Alexander SS</td><td>124.7</td></tr>
</table>

Loss of New 230 kV Circuit

The most limiting contingency for the system following the enhancement of a new 230 kV circuit is the loss of that new circuit. Following the loss of the new 230 kV circuit, the resulting system is the same as the existing system, where A4L is the only circuit supplying load in the Greenstone sub-system. Therefore, following the contingency load must be immediately reduced to 45 MW. This may be achieved by configuration, or through a special protection system. The load flow results below correspond to post-contingency load of 45 MW, and indicate the system would be at its post-contingency limit.

Refer to Figure C-12 for pre-ULTC load flow plot and Figure C-13 for post-ULTC load flow plot with capacitor switching at Marathon.

Table C-15: Thermal Analysis

Circuit Section	Long-term Emergency Rating [A]	Loading [A]	Loading [% Rating]
New 230 kV Line	1120	Out-of-service	N/A
Alexander SS x AP Nipigon JCT	310	260	84
AP Nipigon JCT x Beardmore JCT	260	258	99
Beardmore JCT x Jellicoe DS #3 JCT	260	251	97
Jellicoe DS #3 JCT x Roxmark JCT	260	193	74
Roxmark JCT x Longlac TS	260	186	72

Table C-16: Voltage Analysis

Bus	Pre-contingency Voltage	Post-contingency Voltage (Pre-ULTC)	Post-contingency Voltage (Post-ULTC)*	Maximum Voltage [kV]	Minimum Voltage [kV]	Voltage Change Limit [%]
Marathon TS (230 kV)	248.8	252.0 (+1.3%)	247.2 (-0.6%)	250	207	10
Longlac TS (230 kV)	239.8	N/A	N/A			
Marathon TS (115 kV)	123.7	125.1 (+1.1%)	121.2 (-2.0%)	127	108	10
Longlac TS (115 kV)	120.1	118.1 (-1.7%)	118.1 (-1.7%)			
Jellicoe JCT	118.7	116.1 (-2.2%)	115.9 (-2.4%)			
Beardmore JCT	121.0	118.8 (-1.8%)	118.5 (-2.1%)			
Alexander SS	124.7	124.9 (+0.2%)	124.6 (-0.1%)			

* Capacitor switching at Marathon required to remain below 250 kV at Marathon TS

No Load Condition

The no load condition is assessed to determine if the installation of -25 MVar tertiary connected reactor (which is a standard size) is sufficient to suppress voltages at the Longlac terminal of the new line. For this condition, it is assumed that the sending-end voltage of the new line is maintained at the maximum allowable voltage of 250 kV, and that A4L is open at Longlac. This is to ensure the reactor is sized for reasonable worst-case conditions.

Operational measures such as removing circuits from service to suppress voltages were not considered for this condition. It is assumed that such measures would only be reserved for outage conditions, for example if reactor(s) are unavailable.

It is observed that -25 MVar is sufficient and would suppress voltages at Longlac to within ratings. Refer to Figure C-14 for load flow plot.

C.3.5 Load Flow Plots

Figure C-7: With +40 MVar Reactive Compensation and new 230 kV single-circuit "West of Marathon" transmission line, pre-contingency load flow plot

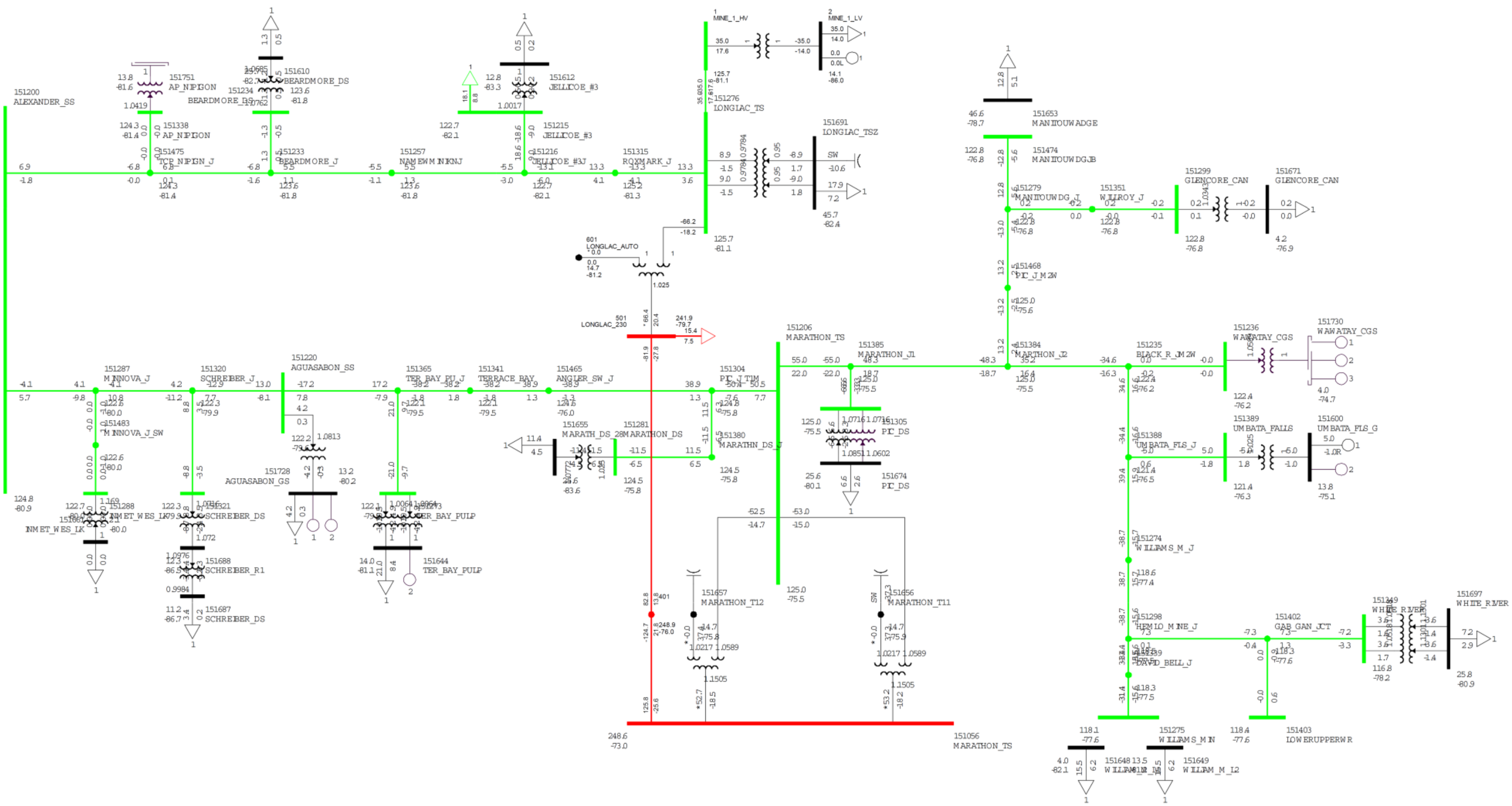


Figure C-8: With +40 MVar Reactive Compensation and new 230 kV single-circuit "West of Marathon" transmission line, post-contingency load flow plot pre-ULTC

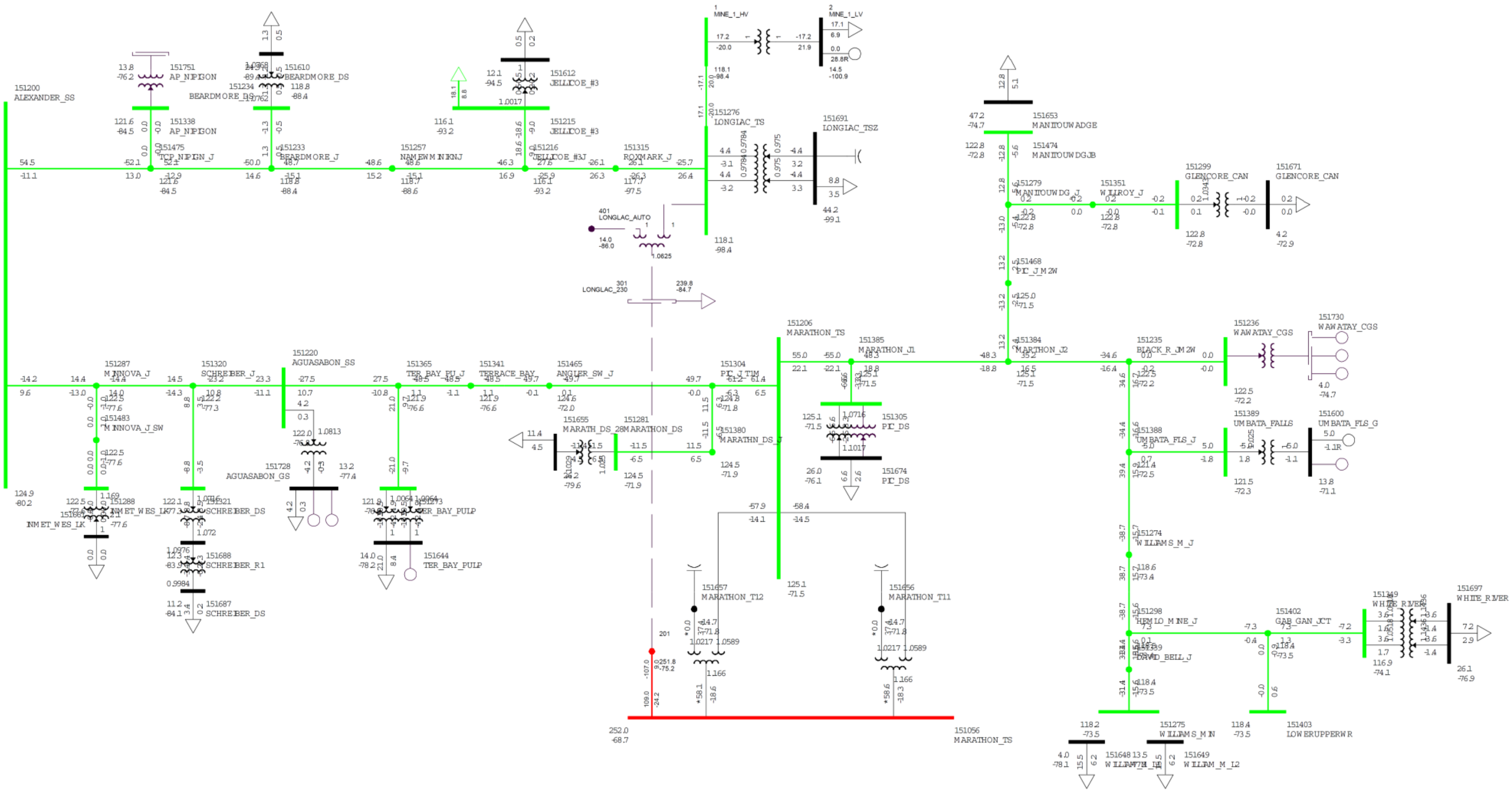


Figure C-9: With +40 MVar Reactive Compensation and new 230 kV single-circuit "West of Marathon" transmission line, post-contingency load flow plot post-ULTC with Marathon capacitor switched out

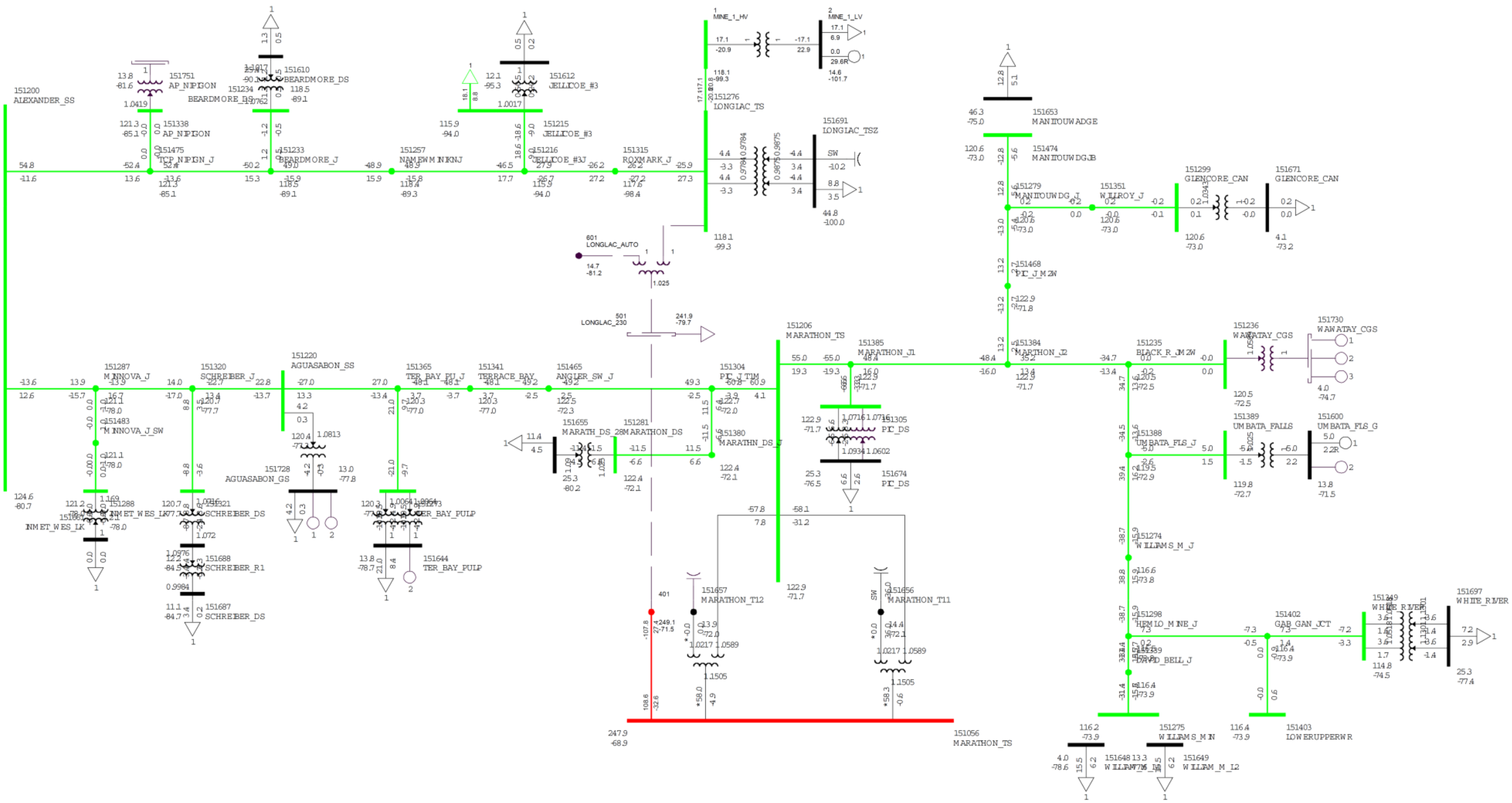
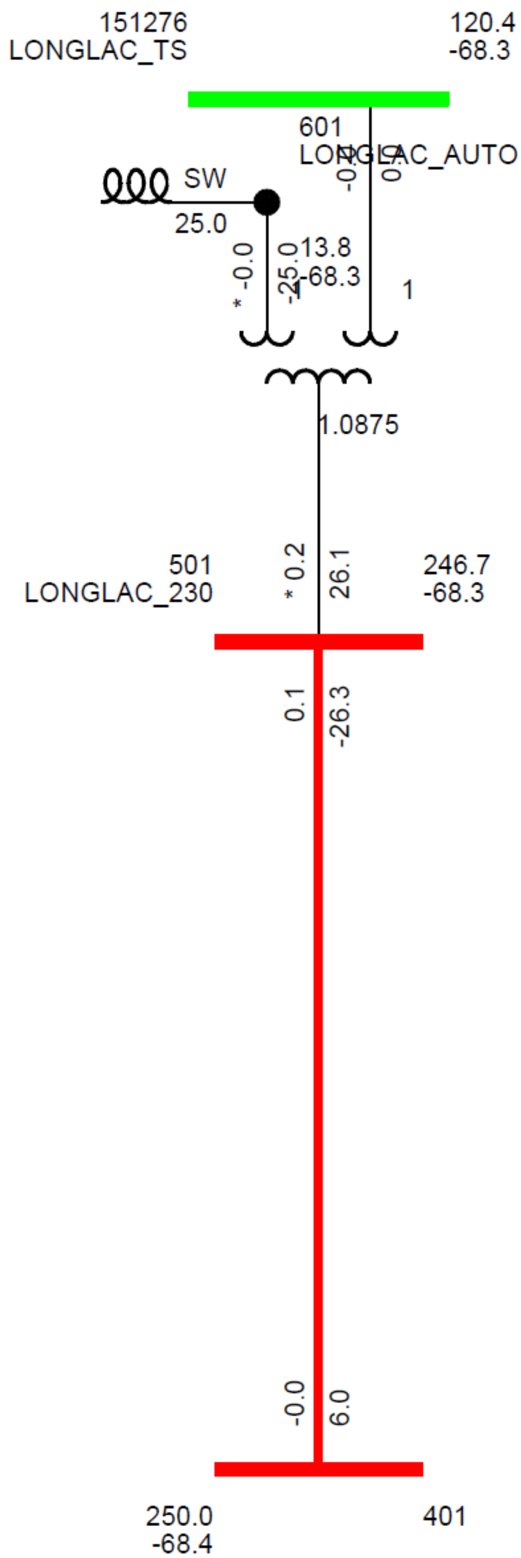


Figure C-10: New 230 kV single-circuit "West of Marathon" transmission line no load test with -25 MVar tertiary reactor



C.3.6 Load Flow Plots

Figure C-11: With +40 MVar Reactive Compensation and new 230 kV single-circuit "East of Nipigon" transmission line, pre-contingency load flow plot

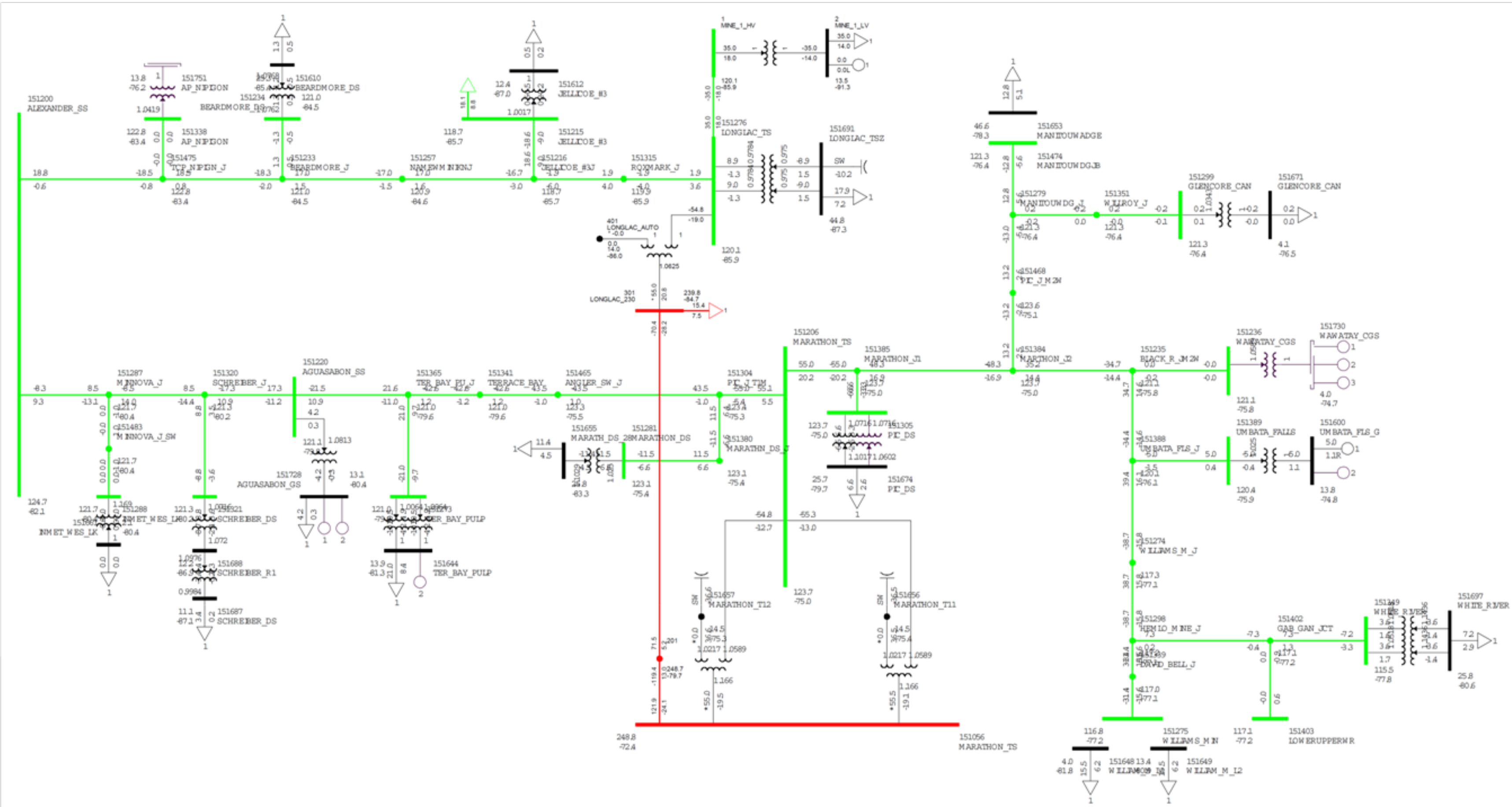


Figure C-12: With +40 MVar Reactive Compensation and new 230 kV single-circuit "East of Nipigon" transmission line, post-contingency load flow plot pre-ULTC

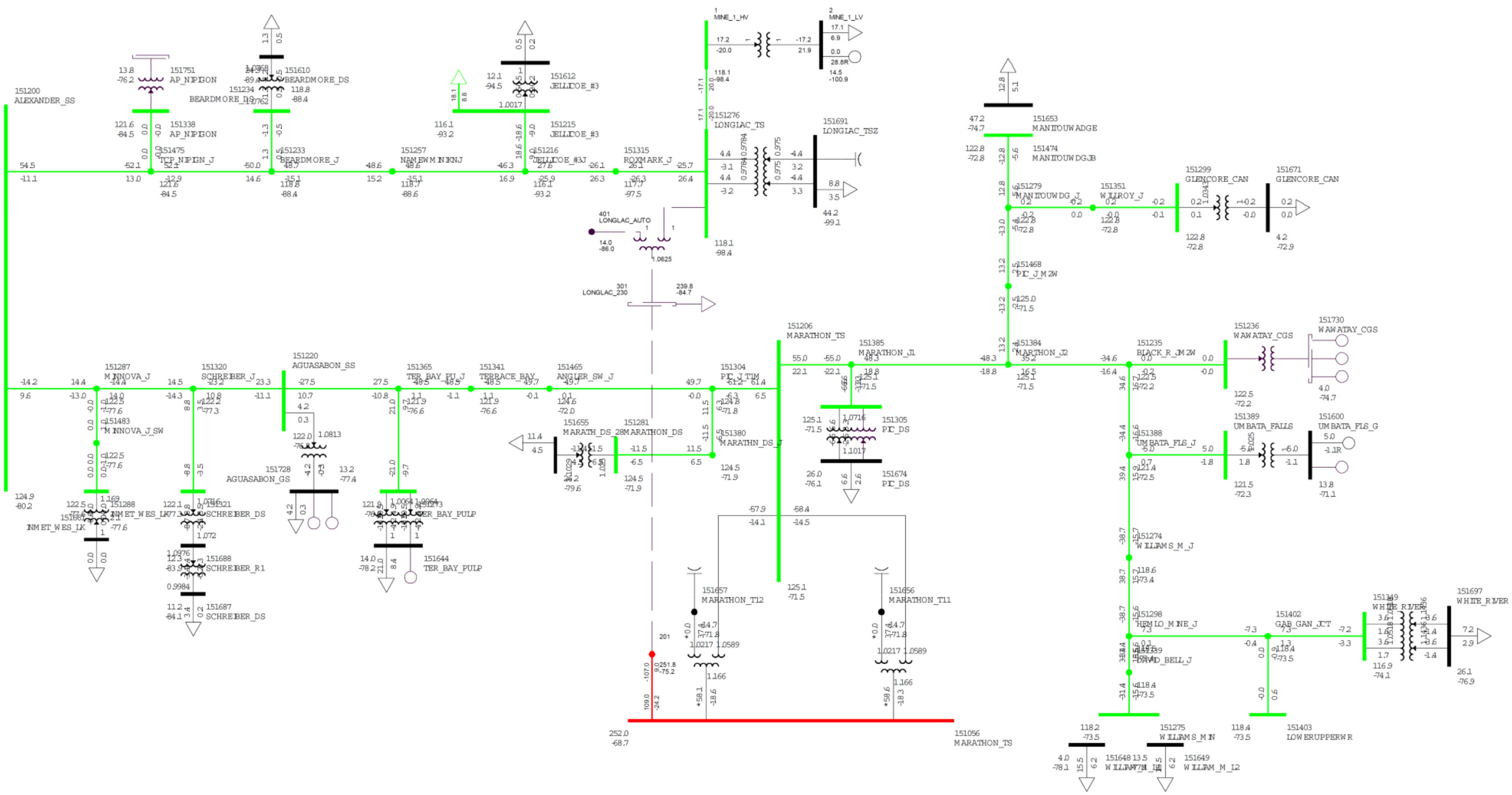


Figure C-13: With +40 MVar Reactive Compensation and new 230 kV single-circuit "East of Nipigon" transmission line, post-contingency load flow plot post-ULTC with Marathon capacitor switched out

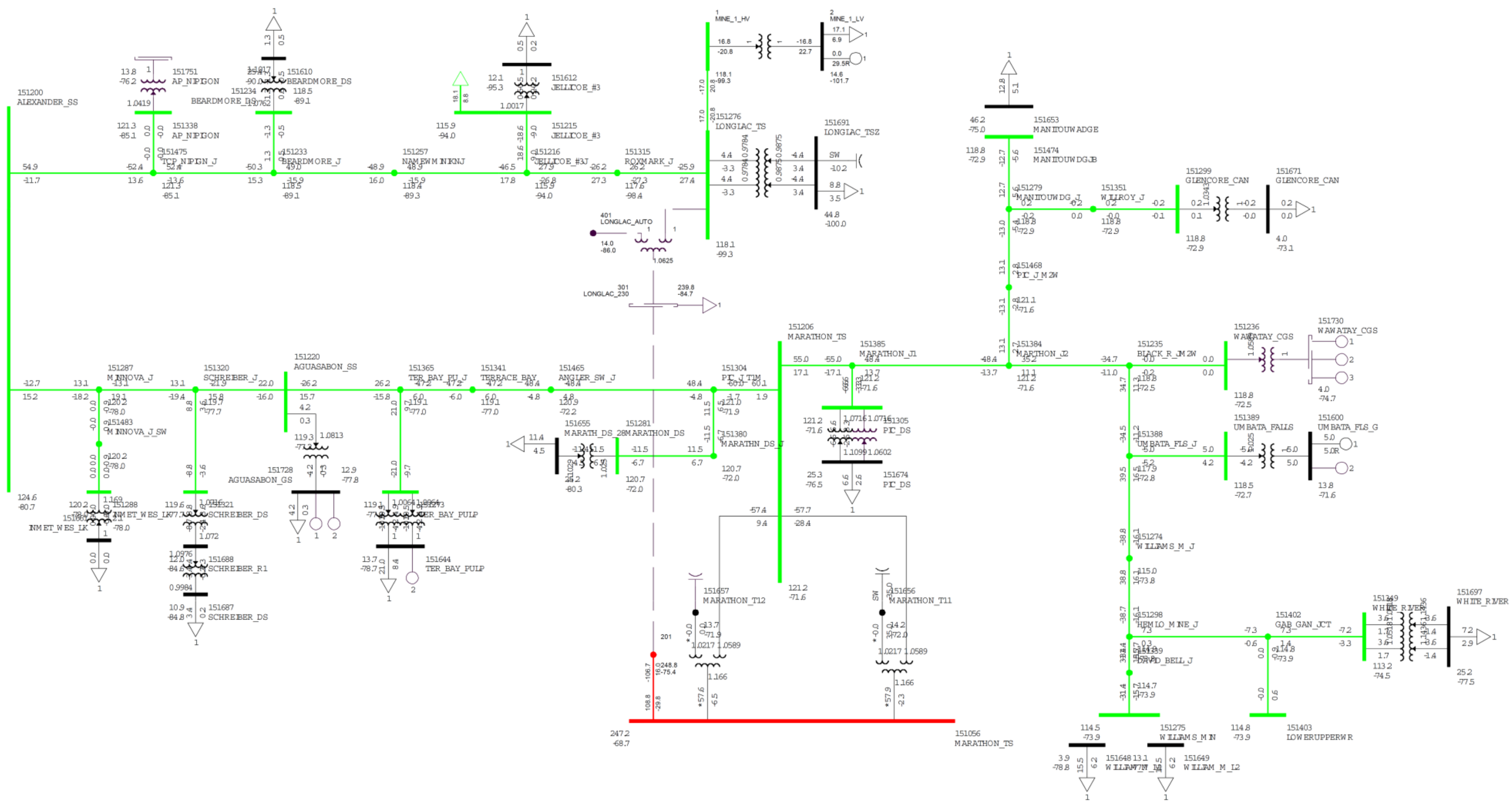
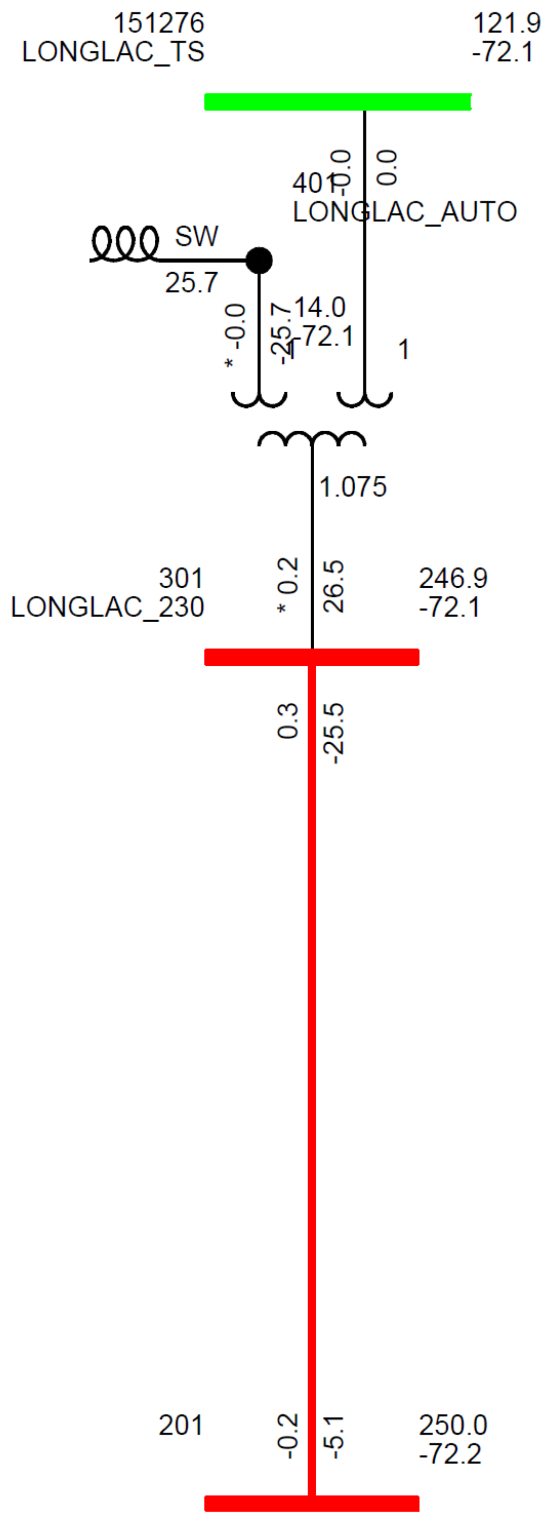


Figure C-14: New 230 kV single-circuit "East of Nipigon" transmission line no load test with -25 MVar tertiary reactor



C.4 Option C2

Option C2 was established to meet up to the near-term forecast demand under Scenario C.

- Installing a new 230 kV single-circuit 795 kcmil transmission line via one of the following routes:
  - West of Marathon Route:
    - 100 km from a new switching station along the East-West Tie to Longlac TS
  - East of Nipigon Route:
    - 150 km from a new switching station along the East-West Tie to Longlac TS
- Installing 1 new 230/115 kV auto-transformer and associated switching at Longlac TS
- Installing 1 new circuit tap along the East-West tie
- Installing +40 MVar of new reactive compensation, in either the form of a synchronous condenser or a STATCOM, modeled as remote voltage control at Longlac TS to 118 kV
- Installing -25 MVar reactive compensation connected to tertiary winding of new auto-transformer
- Installing a new approximately 175 km 115 kV single-circuit 477 kcmil transmission line from Manitouwadge to Longlac
- Installing 2 +/-15 MVar SVCs along the new 115 kV circuit
- Reterminating Longlac TS from the existing 115 kV to the new 230 kV bus, requiring the installation of new 230/44 kV step-down transformers

C.4.1 Assumptions

- AP Nipigon GS out-of-service
- Drought hydroelectric conditions
- Longlac TS capacitor banks in-service (2x5 MVar)
- Summer planning ratings applied for transmission facilities
- Scenario C 2020 forecast demand
- Load Q/P ratio of 0.4 assumed (to give at least 0.9 power factor on HV winding of step-down transformer, consistent with the Market Rules)
- The new 230 kV circuit has the following characteristics (on a 100 MVA base and 220.0 kV base):

Table C-17: New 230 kV Circuit Parameters

R [p.u./km]	X [p.u./km]	B [p.u./km]	Continuous Rating [A]	Long-term Emergency Rating [A]	Short-term Emergency Rating [A]
0.000166	0.001035	0.001607	880	1120	1430

- The new 115 kV circuit has the following characteristics (on a 100 MVA base and 118.05 kV base):

Table C-18: New 115 kV Circuit Parameters

R [p.u./km]	X [p.u./km]	B [p.u./km]	Continuous Rating [A]	Long-term Emergency Rating [A]	Short-term Emergency Rating [A]
0.000966	0.003385	0.000490	620	790	960

C.4.2 Methodology

- Assess system condition versus standards with all elements in-service pre-contingency
- Assess system condition versus standards considering the outage of a single element
- Assess no-load condition to determine inductive reactive compensation requirement

C.4.3 Results – West of Marathon Route

All Elements In-Service Pre-contingency

Refer to Figure C-15 for load flow plot.

Table C-19: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
New 230 kV Line	880	234	27
Alexander SS x AP Nipigon JCT	310	53	17
AP Nipigon JCT x Beardmore JCT	260	54	21
Beardmore JCT x Jellicoe DS #3 JCT	260	50	19
Jellicoe DS #3 JCT x Roxmark JCT	260	50	19
Roxmark JCT x Longlac TS	260	45	17
Longlac TS x #84	620	80	13
#84 x #86	620	33	5
#86 x Manitouwadge JCT	620	97	16
Manitouwadge JCT x Pic JCT	350	160	46
Pic JCT x Marathon TS	620	158	25

Table C-20: Voltage Analysis

Bus	Voltage [kV]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Marathon TS (230 kV)	247.3	250	220
Longlac TS (230 kV)	238.5		
Marathon TS (115 kV)	125.8	127	113
Longlac TS (115 kV)	123.5		
Jellicoe JCT	121.1		
Beardmore JCT	122.6		
Alexander SS	124.8		
#84	120.5		
#86	119.7		
Manitouwadge JCT	121.3		

Loss of New 230 kV Circuit

The most limiting contingency for the system following the enhancement of a new 230 kV circuit is the loss of that new circuit. The load flow results are tabulated below.

Refer to Figure C-16 for pre-ULTC load flow plot and

Figure C-17 for post-ULTC load flow plot with capacitor switching at Marathon.

Table C-21: Thermal Analysis

Circuit Section	Long-term Emergency Rating [A]	Loading [A]	Loading [% Rating]
New 230 kV Line	1120	Out-of-service	N/A
Alexander SS x AP Nipigon JCT	310	211	68
AP Nipigon JCT x Beardmore JCT	260	210	81
Beardmore JCT x Jellicoe DS #3 JCT	260	203	78
Jellicoe DS #3 JCT x Roxmark JCT	260	141	54
Roxmark JCT x Longlac TS	260	134	52
Longlac TS x #84	790	81	10
#84 x #86	790	168	21
#86 x Manitouwadge JCT	790	252	32
Manitouwadge JCT x Pic JCT	350	312	89
Pic JCT x Marathon TS	790	312	39

Table C-22: Voltage Analysis

Bus	Pre-contingency Voltage	Post-contingency Voltage (Pre-ULTC)	Post-contingency Voltage (Post-ULTC)*	Maximum Voltage [kV]	Minimum Voltage [kV]	Voltage Change Limit [%]
Marathon TS (230 kV)	247.3	251.7 (+1.8%)	247.6 (+0.1%)	250	207	10
Longlac TS (230 kV)	238.5	N/A	N/A			
Marathon TS (115 kV)	125.8	127.7 (+1.5%)	124.3 (-1.2%)	127	108	10
Longlac TS (115 kV)	123.5	118.0 (-4.5%)	117.9 (-4.5%)			
Jellicoe JCT	121.1	116.7 (-3.6%)	116.4 (-3.9%)			
Beardmore JCT	122.6	119.5 (-2.5%)	119.2 (-2.8%)			
Alexander SS	124.8	125.1 (+0.2%)	124.8 (0.0%)			
#84	120.5	118.1 (-2.0%)	118.1 (-2.0%)			
#86	119.7	118.1 (-1.3%)	118.1 (-2.0%)			
Manitouwadge JCT	121.3	120.2 (-0.9%)	118.4 (-2.4%)			

* Capacitor switching at Marathon required to remain below 250 kV

No Load Condition

The no load condition is assessed to determine if the installation of -25 MVar tertiary connected reactor (which is a standard size) on the Longlac auto-transformer and the 2 +/-15 MVar SVCs along the 115 kV connection line is sufficient to suppress voltages during light load periods for this option. For this condition, voltages at Marathon and Alexander are assumed to operate close to the 250 kV and 127 kV limits in order to establish a reasonable worst-case condition.

Operational measures such as removing circuits from service to suppress voltages were not considered for this condition. It is assumed that such measures would only be reserved for outage conditions, for example if reactor(s) are unavailable.

It is observed that the reactive power resources considered for this option are sufficient and would suppress voltages to within ratings. Refer to Figure C-18 for load flow plot.

C.4.4 Results – East of Nipigon Route

All Elements In-Service Pre-contingency

Refer to Figure C-19 for load flow plot.

Table C-23: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
New 230 kV Line	880	207	24
Alexander SS x AP Nipigon JCT	310	88	28
AP Nipigon JCT x Beardmore JCT	260	87	34
Beardmore JCT x Jellicoe DS #3 JCT	260	81	31
Jellicoe DS #3 JCT x Roxmark JCT	260	39	15
Roxmark JCT x Longlac TS	260	30	11
Longlac TS x #84	620	64	10
#84 x #86	620	71	11
#86 x Manitouwadge JCT	620	142	23
Manitouwadge JCT x Pic JCT	350	204	58
Pic JCT x Marathon TS	620	203	33

Table C-24: Voltage Analysis

Bus	Voltage [kV]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Marathon TS (230 kV)	247.4	250	220
Longlac TS (230 kV)	235.0		
Marathon TS (115 kV)	124.4	127	113
Longlac TS (115 kV)	121.4		
Jellicoe JCT	119.6		
Beardmore JCT	121.5		
Alexander SS	124.6		
#84	118.6		
#86	118.1		
Manitouwadge JCT	119.4		

Loss of New 230 kV Circuit

The most limiting contingency for the system following the enhancement of a new 230 kV circuit is the loss of that new circuit. The load flow results are tabulated below.

Refer to Figure C-20 for pre-ULTC load flow plot and Figure C-21 for post-ULTC load flow plot with capacitor switching at Marathon.

Table C-25: Thermal Analysis

Circuit Section	Long-term Emergency Rating [A]	Loading [A]	Loading [% Rating]
New 230 kV Line	1120	Out-of-service	N/A
Alexander SS x AP Nipigon JCT	310	210	68
AP Nipigon JCT x Beardmore JCT	260	208	80
Beardmore JCT x Jellicoe DS #3 JCT	260	201	77
Jellicoe DS #3 JCT x Roxmark JCT	260	139	54
Roxmark JCT x Longlac TS	260	133	51
Longlac TS x #84	790	83	13
#84 x #86	790	169	27
#86 x Manitouwadge JCT	790	258	42
Manitouwadge JCT x Pic JCT	350	318	91
Pic JCT x Marathon TS	790	317	51

Table C-26: Voltage Analysis

Bus	Pre-contingency Voltage	Post-contingency Voltage (Pre-ULTC)	Post-contingency Voltage (Post-ULTC)*	Maximum Voltage [kV]	Minimum Voltage [kV]	Voltage Change Limit [%]
Marathon TS (230 kV)	247.4	251.0 (+1.5%)	246.4 (-0.4%)	250	207	10
Longlac TS (230 kV)	235.0	N/A	N/A			
Marathon TS (115 kV)	124.4	125.9 (+1.2%)	123.8 (-0.5%)	127	108	10
Longlac TS (115 kV)	121.4	118.0 (-2.8%)	117.9 (-2.9%)			
Jellicoe JCT	119.6	116.6 (-2.5%)	116.4 (-2.7%)			
Beardmore JCT	121.5	119.4 (-1.7%)	119.1 (-2.0%)			
Alexander SS	124.6	124.9 (+0.2%)	124.7 (+0.1%)			
#84	118.6	118.1 (-0.4%)	118.1 (-0.4%)			
#86	118.1	118.1 (0.0%)	118.1 (0.0%)			
Manitouwadge JCT	119.4	119.2 (-0.2%)	118.1 (-1.1%)			

* Capacitor switching at Marathon required to remain below 250 kV

No Load Condition

The no load condition is assessed to determine if the installation of -25 MVar tertiary connected reactor on the Longlac auto-transformer and the 2 +/-15 MVar SVCs along the 115 kV connection line is sufficient to suppress voltages during light load periods for this option. For this condition, voltages at Marathon and Alexander are assumed to operate close to the 250 kV and 127 kV limits in order to establish a reasonable worst-case condition.

Operational measures such as removing circuits from service to suppress voltages were not considered for this condition. It is assumed that such measures would only be reserved for outage conditions, for example if reactor(s) are unavailable.

It is observed that the reactive power resources considered for this option are sufficient and would suppress voltages to within ratings. Refer to Figure C-22 for load flow plot.

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C.4.5 Load Flow Plots

Figure C-15: With +40 MVar Reactive Compensation, new 230 kV single-circuit "West of Marathon" transmission line, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, pre-contingency load flow plot

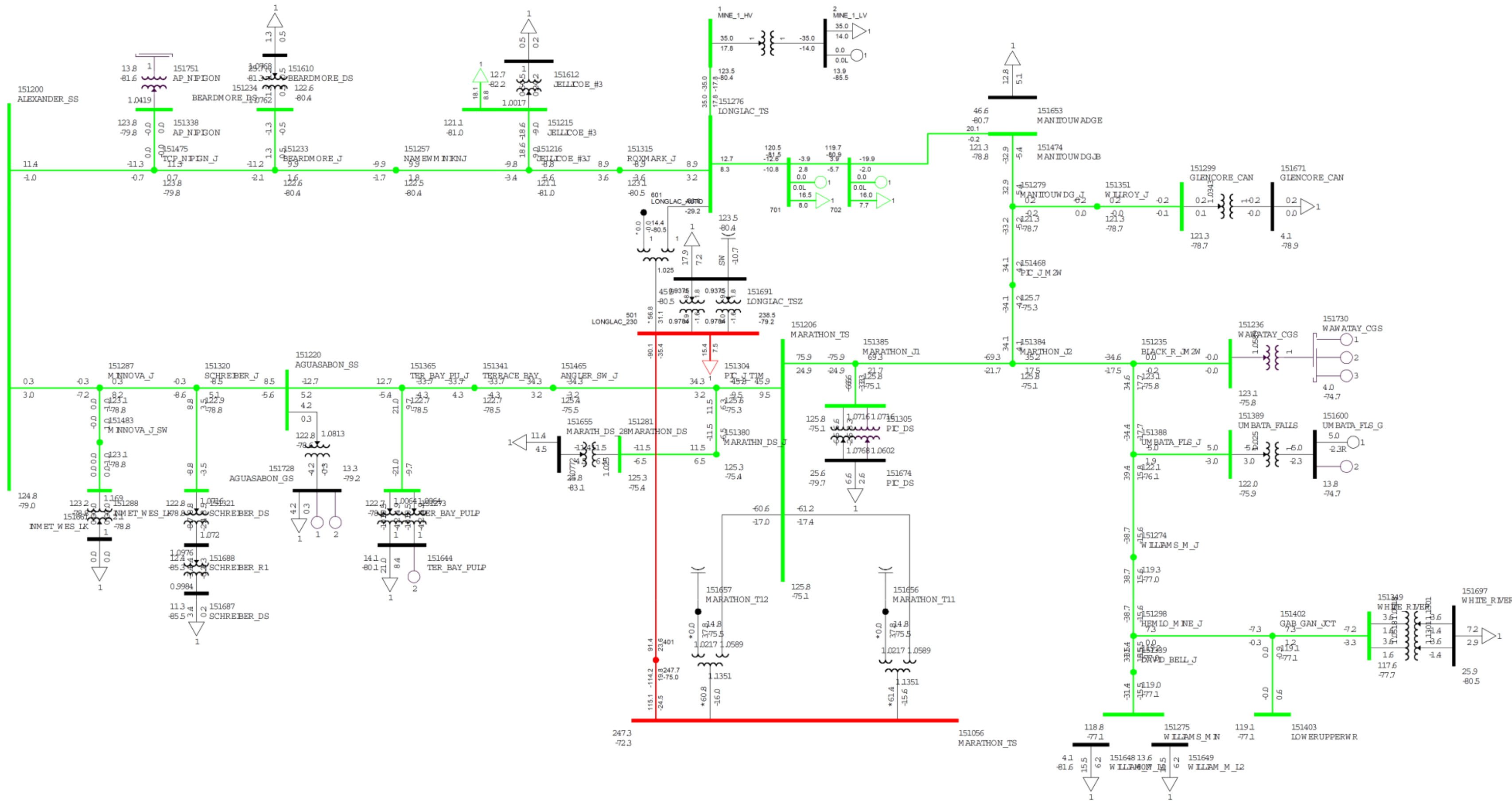


Figure C-16: With +40 MVar Reactive Compensation, new 230 kV single-circuit "West of Marathon" transmission line, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, post-contingency load flow plot pre-ULTC

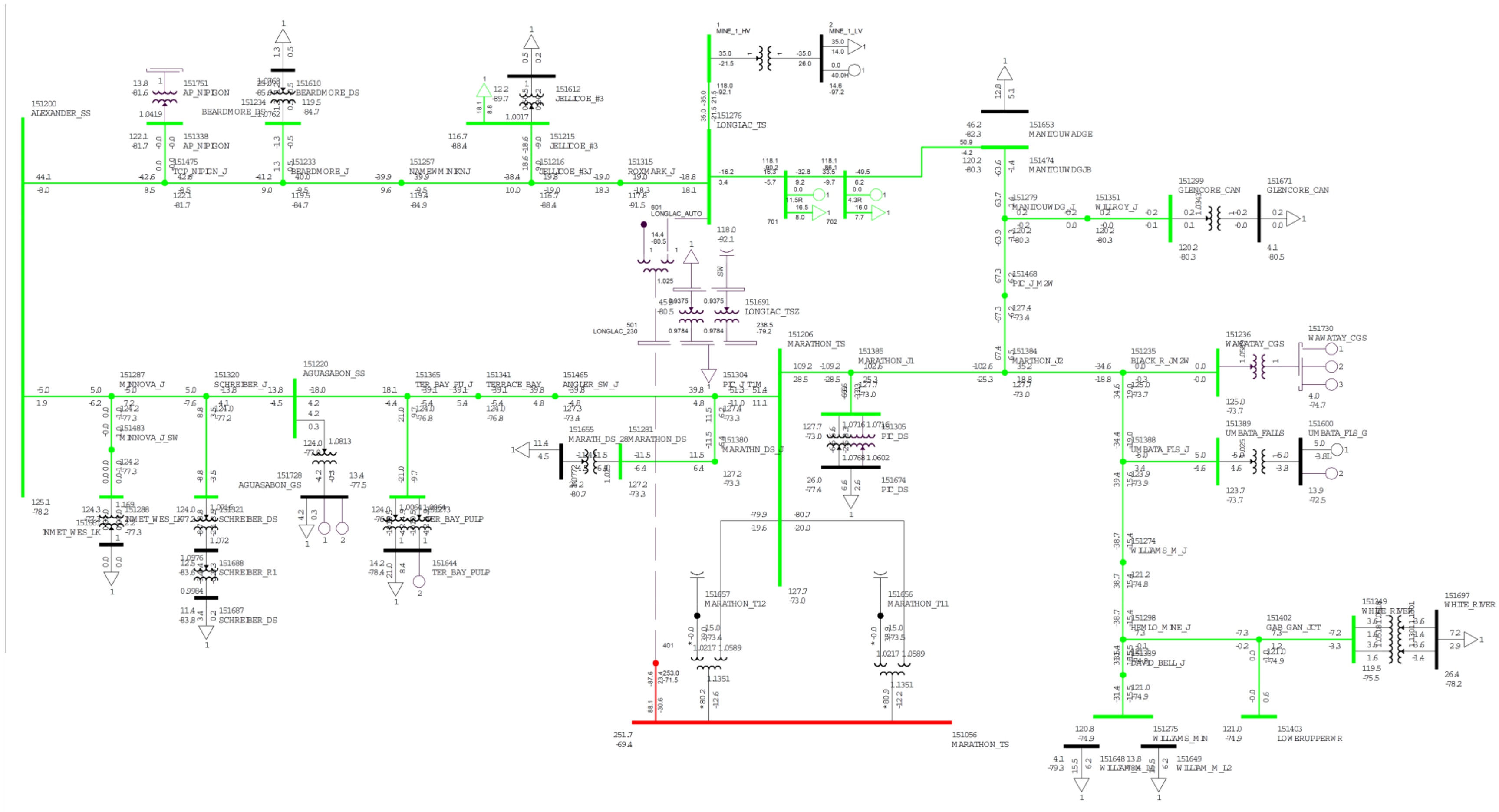


Figure C-17: With +40 MVar Reactive Compensation, new 230 kV single-circuit "West of Marathon" transmission line, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, post-contingency load flow plot post-ULTC

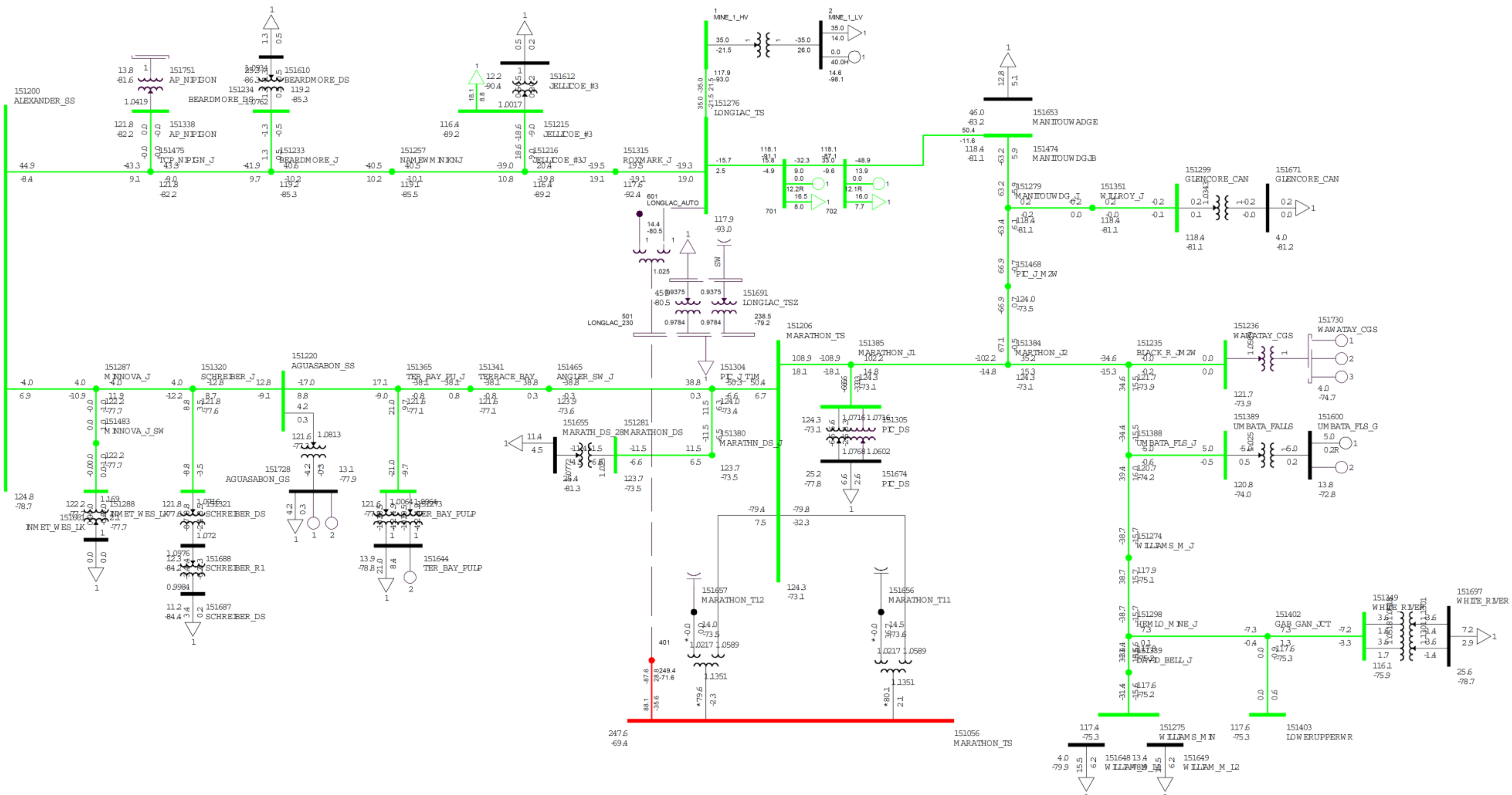


Figure C-18: New 230 kV single-circuit "West of Marathon" transmission line and new 115 kV single-circuit Longlac to Manitouwadge transmission line -25 MVar tertiary and 2x +/- 15 MVar SVCs, no load test

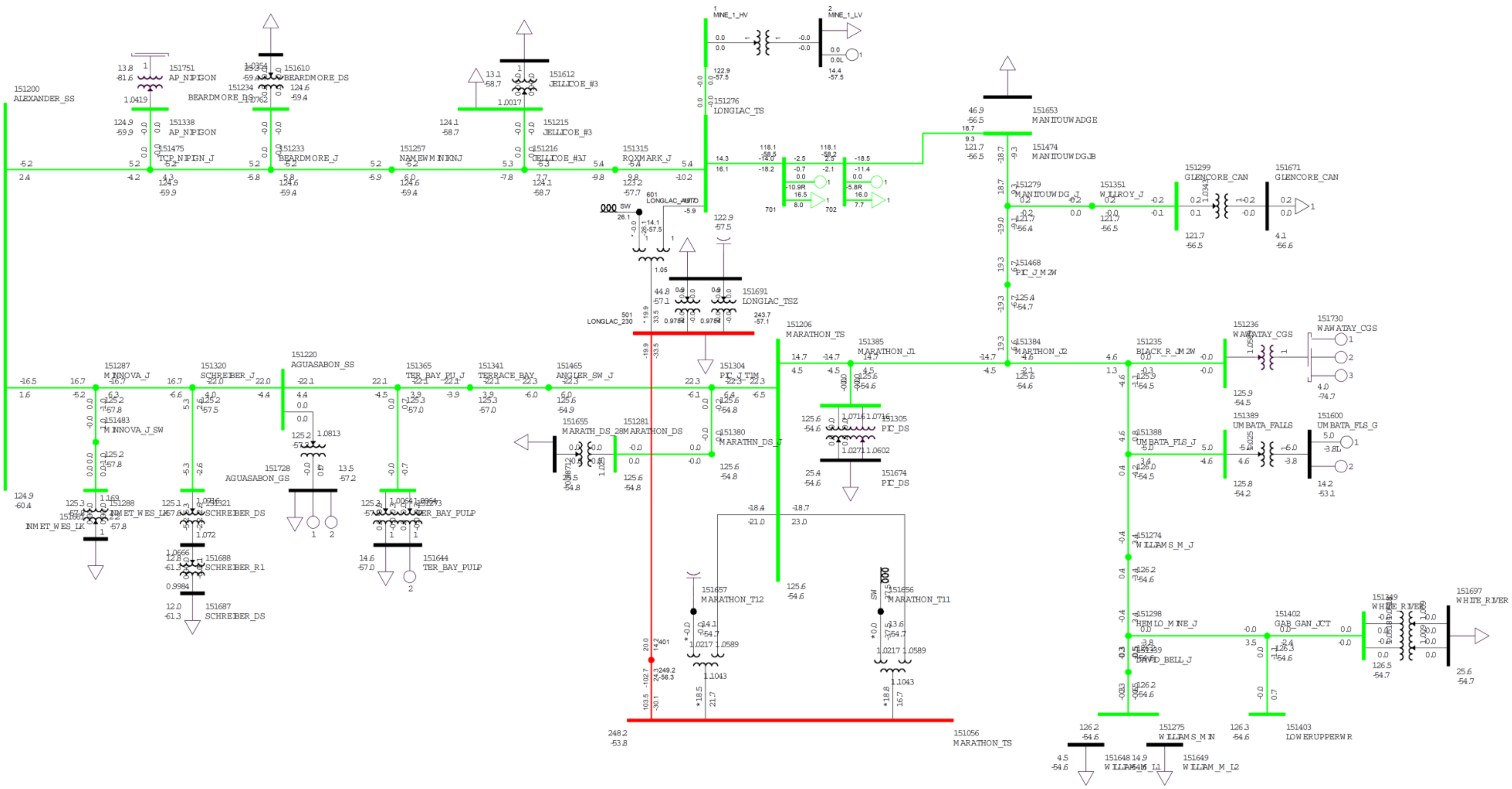


Figure C-19: With +40 MVar Reactive Compensation, new 230 kV single-circuit "East of Nipigon" transmission line, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, pre-contingency load flow plot

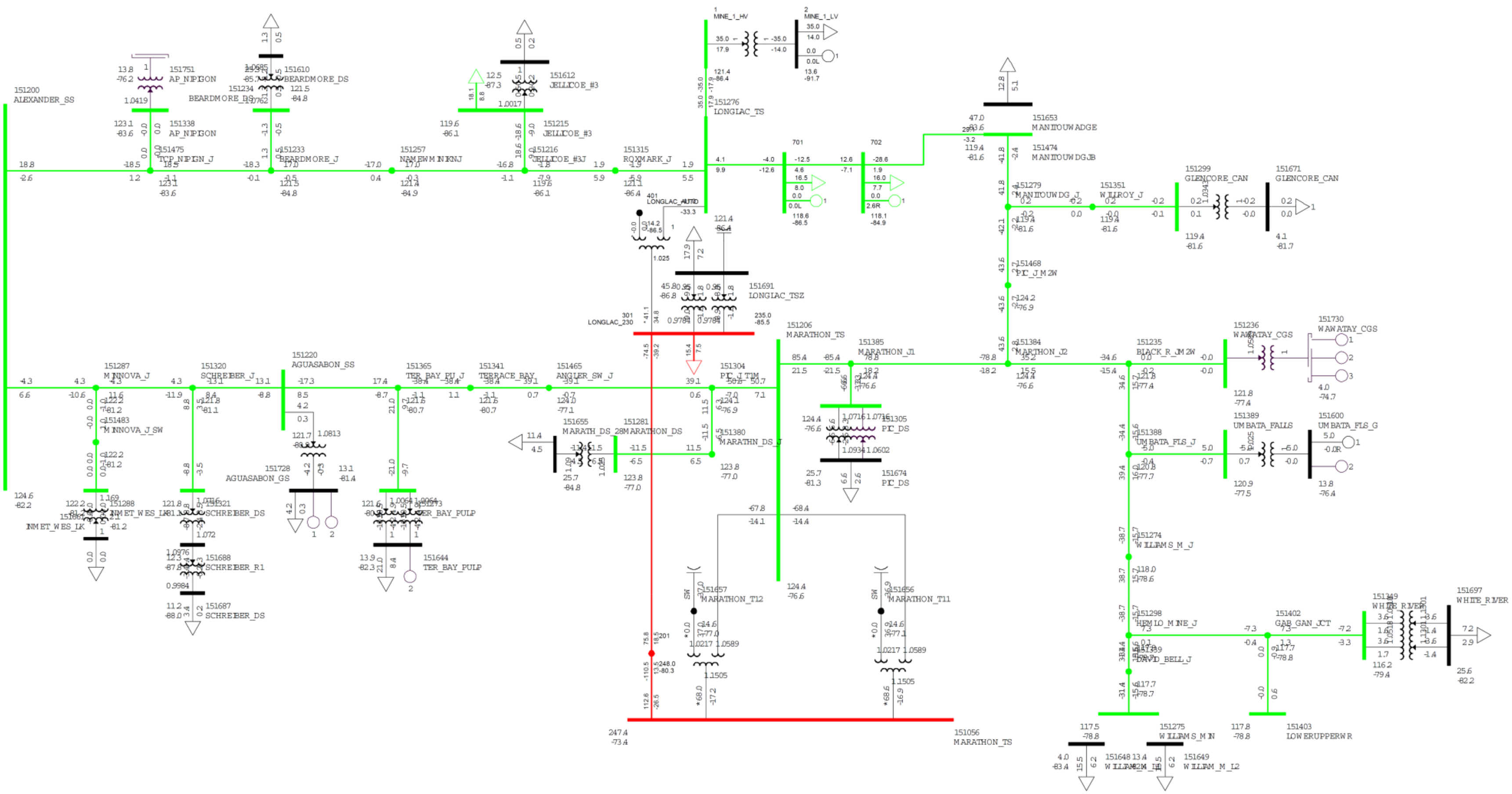


Figure C-20: With +40 MVar Reactive Compensation, new 230 kV single-circuit "East of Nipigon" transmission line, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, post-contingency load flow plot pre-ULTC

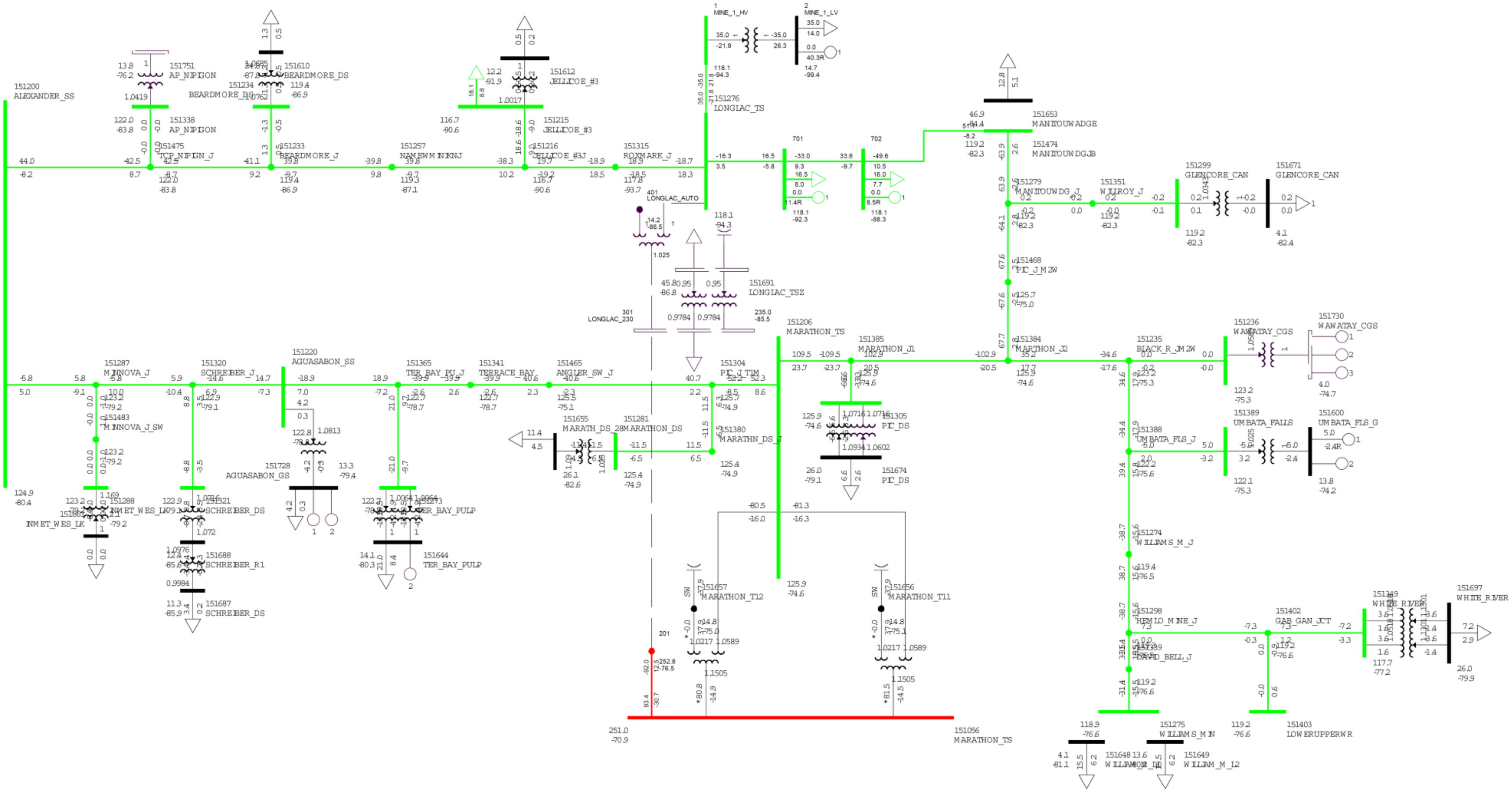


Figure C-21: With +40 MVar Reactive Compensation, new 230 kV single-circuit "East of Nipigon" transmission line, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, post-contingency load flow plot post-ULTC

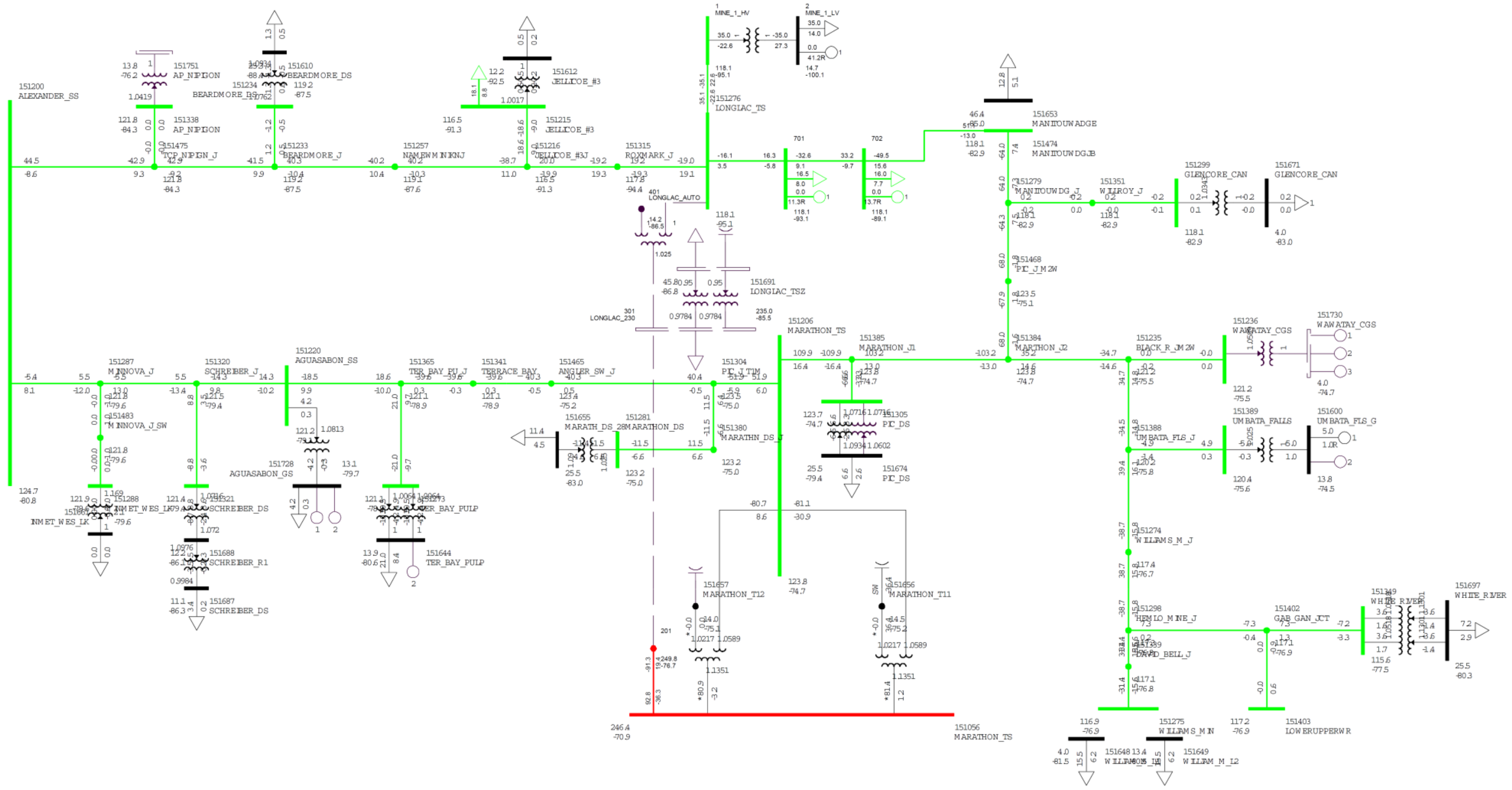
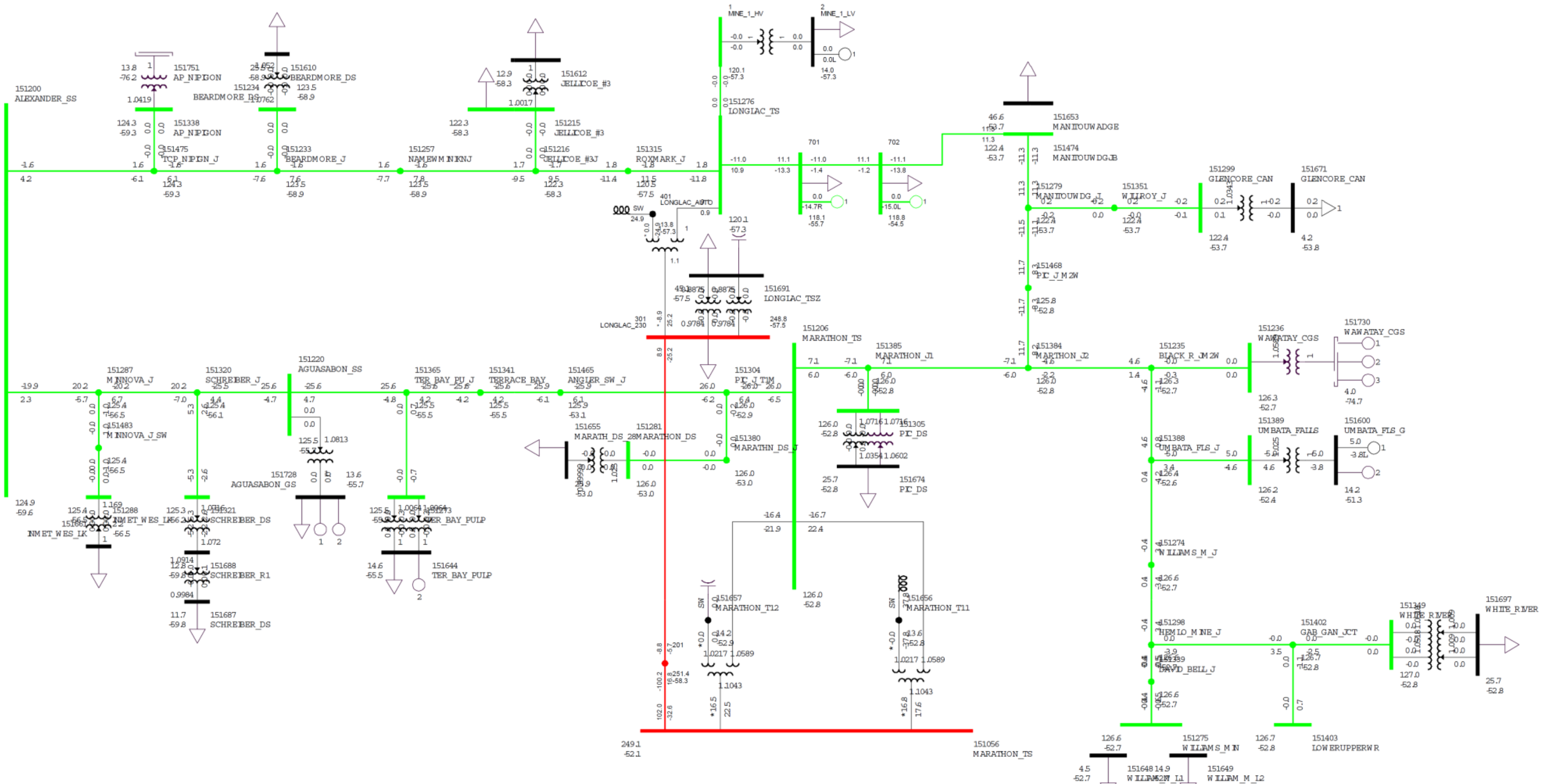


Figure C-22: New 230 kV single-circuit "East of Nipigon" transmission line and new 115 kV single-circuit Longlac to Manitouwadge transmission line -25 MVar tertiary and 2x +/- 15 MVar SVCs, no load test



C.5 Option C3

Option C3 was established to meet up to the near-term forecast demand under Scenario C.

- Installing a new generating facility connecting to Longlac TS with a firm capacity of 80 MW
- Installing a new approximately 175 km 115 kV single-circuit 477 kcmil transmission line from Manitouwadge to Longlac
- Installing 2 +/-15 MVar SVCs along the new 115 kV circuit

C.5.1 Assumptions

- AP Nipigon GS out-of-service
- Drought hydroelectric conditions
- Longlac TS capacitor banks in-service (2x5 MVar)
- Summer planning ratings applied for transmission facilities
- Scenario C 2020 forecast demand
- Load Q/P ratio of 0.4 assumed (to give at least 0.9 power factor on HV winding of step-down transformer, consistent with the Market Rules)
- The new 115 kV circuit has the following characteristics (on a 100 MVA base and 118.05 kV base):

Table C-27: New 115 kV Circuit Parameters

R [p.u./km]	X [p.u./km]	B [p.u./km]	Continuous Rating [A]	Long-term Emergency Rating [A]	Short-term Emergency Rating [A]
0.000966	0.003385	0.000490	620	790	960

C.5.2 Methodology

- Assess system condition versus standards with all elements in-service pre-contingency
- Assess system condition versus standards considering the outage of a single element
- Assess no-load condition to determine inductive reactive compensation requirement

C.5.3 Results

All Elements In-Service Pre-contingency

Refer to Figure C-23 for load flow plot.

Table C-28: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
Alexander SS x AP Nipigon JCT	310	71	23
AP Nipigon JCT x Beardmore JCT	260	74	28
Beardmore JCT x Jellicoe DS #3 JCT	260	72	28
Jellicoe DS #3 JCT x Roxmark JCT	260	33	13
Roxmark JCT x Longlac TS	260	33	13
Longlac TS x #84	620	29	5
#84 x #86	620	61	10
#86 x Manitouwadge JCT	620	135	22
Manitouwadge JCT x Pic JCT	350	199	57
Pic JCT x Marathon TS	620	197	32

Table C-29: Voltage Analysis

Bus	Voltage [kV]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Marathon TS (230 kV)	246.8	250	220
Marathon TS (115 kV)	125.5	127	113
Longlac TS	118.1		
Jellicoe JCT	117.1		
Beardmore JCT	119.7		
Alexander SS	124.0		
#84	118.1		
#86	118.1		
Manitouwadge JCT	120.0		

Loss of M2W

The most limiting contingency for the system following the enhancement of a new generation plant injecting near Longlac TS is the loss of circuit M2W. The load flow results are tabulated below.

Refer to Figure C-24 for pre-ULTC load flow plot and Figure C-25 for post-ULTC load flow plot with capacitor switching at Marathon.

Table C-30: Thermal Analysis

Circuit Section	Long-term Emergency Rating [A]	Loading [A]	Loading [% Rating]
Alexander SS x AP Nipigon JCT	310	230	74
AP Nipigon JCT x Beardmore JCT	260	228	88
Beardmore JCT x Jellicoe DS #3 JCT	260	221	85
Jellicoe DS #3 JCT x Roxmark JCT	260	162	62
Roxmark JCT x Longlac TS	260	155	60
Longlac TS x #84	790	170	27
#84 x #86	790	84	14
#86 x Manitouwadge JCT	790	Out-of-service	N/A
Manitouwadge JCT x Pic JCT	350	Out-of-service	N/A
Pic JCT x Marathon TS	790	Out-of-service	N/A

Table C-31: Voltage Analysis

<table>
<tr><th>Bus</th><th>Pre-contingency Voltage</th><th>Post-contingency Voltage (Pre-ULTC)</th><th>Post-contingency Voltage (Post-ULTC)*</th><th>Maximum Voltage [kV]</th><th>Minimum Voltage [kV]</th><th>Voltage Change Limit [%]</th></tr>
<tr><td>Marathon TS (230 kV)</td><td>246.8</td><td>255.0</td><td>249.0</td><td>250</td><td>207</td><td>10</td></tr>
<tr><td>Marathon TS (115 kV)</td><td>125.5</td><td>131.0</td><td>126.1</td><td rowspan="8">127</td><td rowspan="8">108</td><td rowspan="8">10</td></tr>
<tr><td>Longlac TS</td><td>118.1</td><td>118.1</td><td>118.1</td></tr>
<tr><td>Jellicoe JCT</td><td>117.1</td><td>116.4</td><td>116.1</td></tr>
<tr><td>Beardmore JCT</td><td>119.7</td><td>119.0</td><td>118.7</td></tr>
<tr><td>Alexander SS</td><td>124.0</td><td>124.7</td><td>124.2</td></tr>
<tr><td>#84</td><td>118.1</td><td>118.1</td><td>118.1</td></tr>
<tr><td>#86</td><td>118.1</td><td>118.1</td><td>118.1</td></tr>
<tr><td>Manitouwadge JCT</td><td>120.0</td><td>N/A</td><td>N/A</td></tr>
</table>

* Capacitor switching at Marathon required to remain below 250 kV

No Load Condition

The no load condition is assessed to determine if the installation of the 2 +/-15 MVar SVCs along the 115 kV connection line is sufficient to suppress voltages during light load periods for this option. For this condition, voltages at Marathon and Alexander are assumed to operate close to the 250 kV and 127 kV limits in order to establish a reasonable worst-case condition.

Operational measures such as removing circuits from service to suppress voltages were not considered for this condition. It is assumed that such measures would only be reserved for outage conditions, for example if reactor(s) are unavailable.

It is observed that the reactive power resources considered for this option are sufficient and would suppress voltages to within ratings. Refer to Figure C-26 for load flow plot.

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C.5.4 Load Flow Plots

Figure C-23: With a new generating plant connected to Longlac TS outputting 80 MW, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, pre-contingency

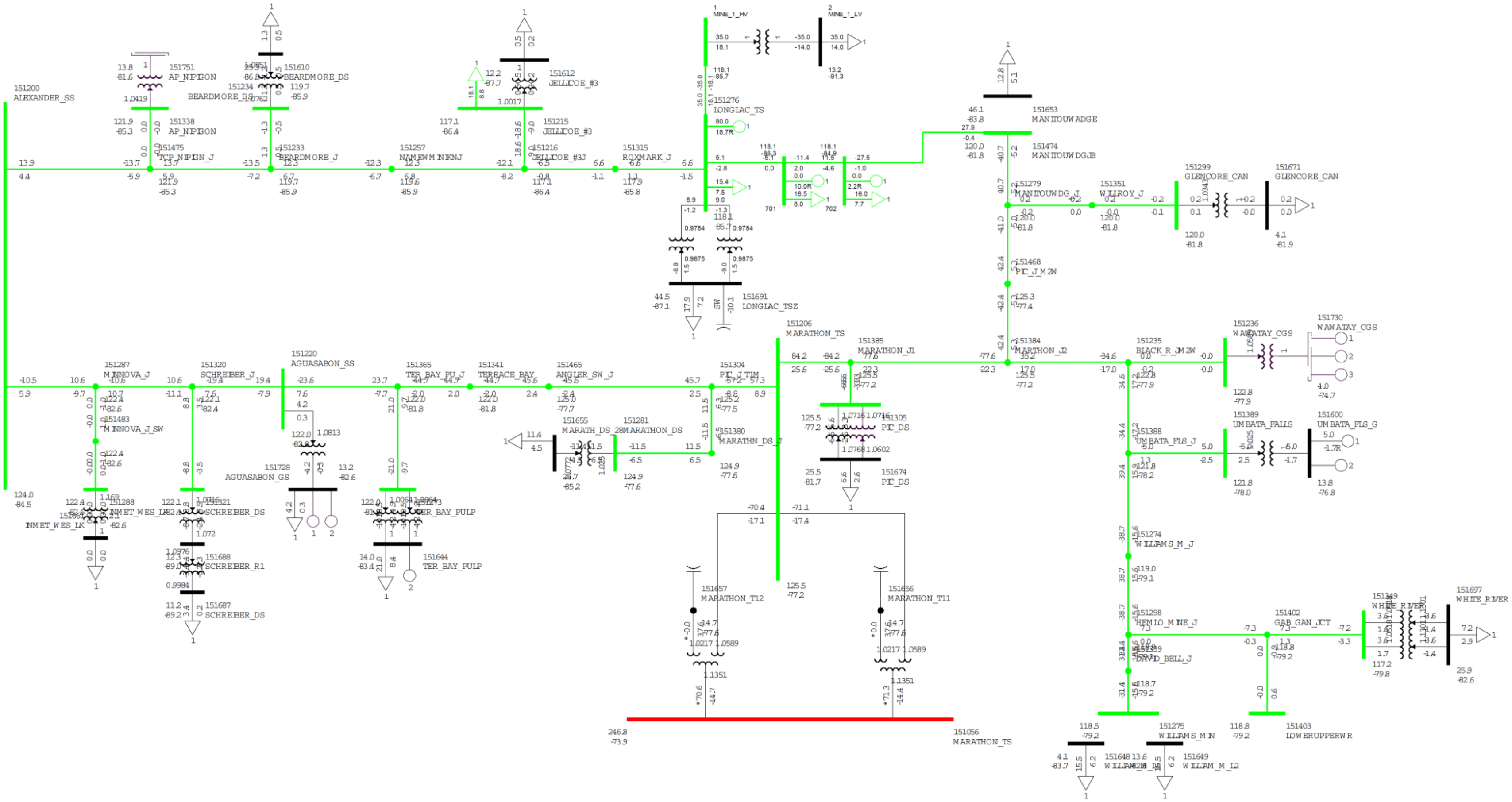


Figure C-24: With a new generating plant connected to Longlac TS outputting 80 MW, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, post-contingency load flow plot pre-ULTC

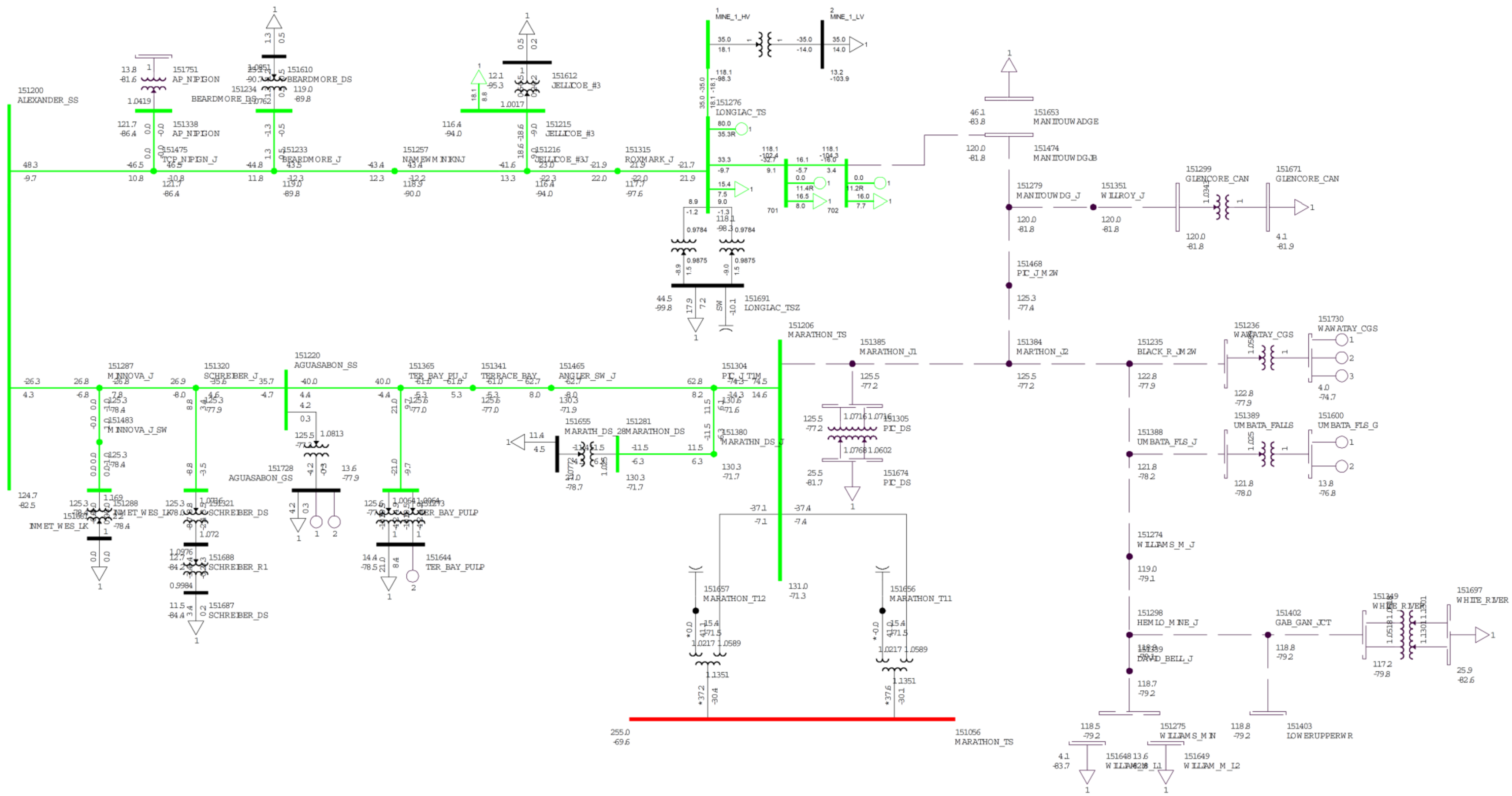


Figure C-25: With a new generating plant connected to Longlac TS outputting 80 MW, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, post-contingency load flow plot post-ULTC

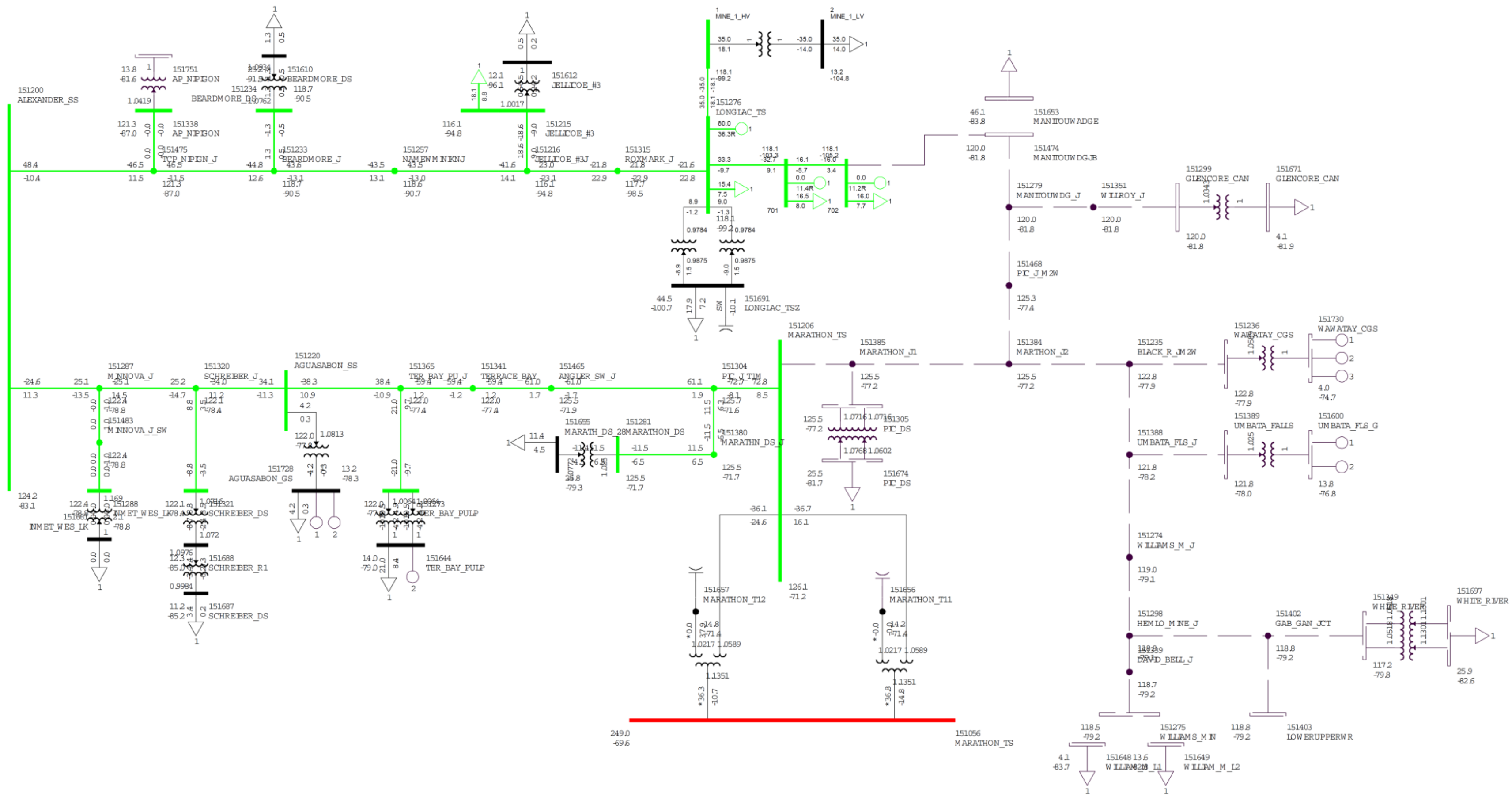
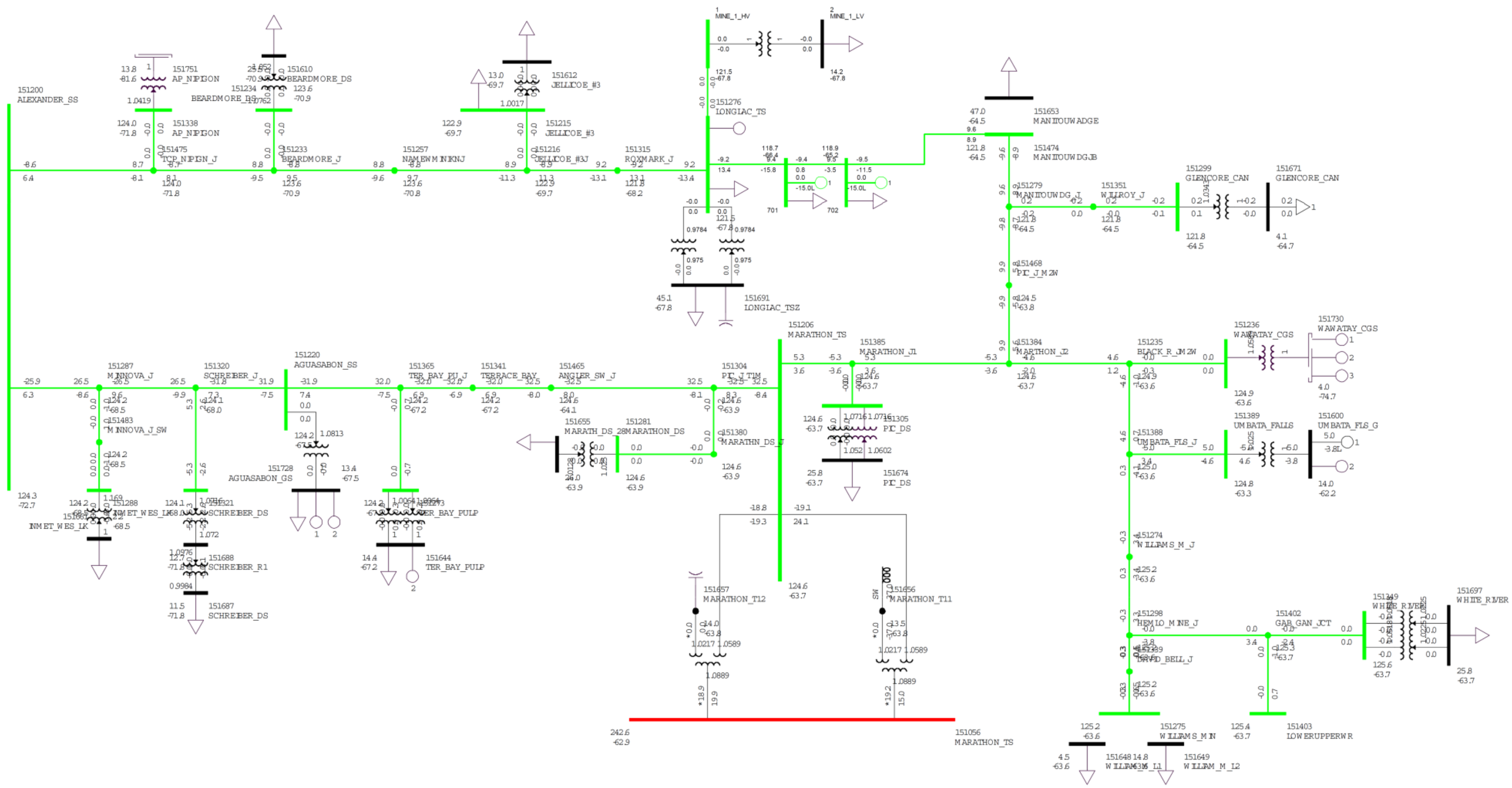


Figure C-26: With a new generating plant connected to Longlac TS (out-of-service), new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, no Load test



Greenstone-Marathon Interim IRRP

Appendix D: Economic Analysis of Options

Appendix D: Economic Analysis of Options

The following appendix outlines the planning level economic analysis of options, including assumptions, methodology, and discounted cash flow analysis.

D.1 Option B1

D.1.1 Assumptions

- Costs represent planning level precision of ±50%
- Capital cost for installing +40 MVar of reactive compensation on-site of the Geraldton mine project (i.e. customer-owned distribution) is $7.5 million[3]
- Discrete gas generator unit sized of 9.5 MW
- Unit cost for installing a 9.5 MW gas generator unit is $3,028/kW-installed
- Two 9.5 MW gas generating units are assumed to comprise on-site gas generating plant for the Geraldton mine project
- Natural gas is assumed to be supplied by the existing TransCanada pipeline
- Pipeline capacity is assumed to be available and only gas management charges are assumed
- Annual O&M costs are estimated using a fixed and a variable component. The fixed component is based on the installed capacity of the generator and is assumed to be $45/kW annually. The variable component is based on the energy production in a given year and is assumed to be $9/MWh
- The energy cost is assumed to be $49/MWh with delivery cost of $25/kW annually for pipeline capacity allocation
- Land cost not included in estimate

D.1.2 Methodology

Discounted cash flow analysis was performed by taking the following steps:

- Based on generator size, annual O&M costs were calculated as $1.7 million
- Annual energy production is estimated from summing the forecast hourly demand greater than 25 MW (amount that would be allocated by grid connection) for every hour of the year for the Geraldton mine
- System generation credit associated with avoiding system generation cost by the annual energy produced by the Geraldton mine on-site generation facility is calculated
- Capital and annual costs were amortized over the life of the project
- NPV was calculated over the planning period (2015-2035)

[3] Hydro One Transmission received quote from ABB for synchronous condenser

D.1.3 Results

Figure D-1: Option B1 Transmission Facilities Cash Flow

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Condenser	-	-	-	7.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Annual Cost	-	-	-	7.6	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Annual Amortized Cost	-	-	-	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Cumulative PV	-	-	-	0.4	0.7	1.1	1.4	1.7	2.1	2.3	2.6	2.9	3.2	3.4	3.7	3.9	4.1	4.3	4.6	4.8	5.0

Figure D-2: Option B1 Generation Facilities

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gx Capital Cost	-	-	-	-	-	57.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed O&M	-	-	-	-	-	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Variable O&M	-	-	-	-	-	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Fuel Cost	-	-	-	-	-	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Avoided System Gen Cost	-	-	-	-	-	(2.5)	(2.9)	(2.9)	(2.9)	(2.9)	(2.9)	(2.8)	(2.9)	(2.9)	(3.0)	(3.0)	(3.0)	(2.9)	(2.9)	(2.9)	(2.9)
Total Annual Gx Cost	-	-	-	-	-	58.8	1.0	0.9	0.9	0.9	0.9	1.0	0.9	1.0	0.9	0.8	0.8	0.9	0.9	0.9	0.9
Annual Amortized cost	-	-	-	-	-	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Cumulative PV of Amortized cost	-	-	-	-	-	4.1	8.1	11.9	15.5	19.0	22.4	25.7	28.8	31.8	34.7	37.5	40.1	42.7	45.2	47.6	49.8

D.2 Option B2

D.2.1 Assumptions

- Costs represent planning level precision of ±50%
- Discrete gas generator unit sized of 9.5 MW
- Unit cost for installing a 9.5 MW gas generator unit is $3,028/kW-installed
- Seven 9.5 MW gas generating units are assumed to comprise the gas generating plant
- Natural gas is assumed to be supplied by the existing TransCanada pipeline
- Pipeline capacity is assumed to be available and only gas management charges are assumed
- Annual O&M costs are estimated using a fixed and a variable component. The fixed component is based on the installed capacity of the generator and is assumed to be $45/kW annually. The variable component is based on the energy production in a given year and is assumed to be $9/MWh
- The energy cost is assumed to be $49/MWh with delivery cost of $25/kW annually for pipeline capacity allocation
- Land cost not included in estimate

D.2.2 Methodology

Discounted cash flow analysis was performed by taking the following steps:

- Based on capital cost, annual O&M costs were calculated as $6.3 million
- Annual energy production is equal to the annual energy demand of the Geraldton mine
- System generation credit associated with avoiding system generation cost by the annual energy produced by the Geraldton mine on-site generation facility is calculated
- Capital and annual costs were amortized over the life of the project
- NPV was calculated over the planning period (2015-2035)

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D.2.3 Results

Figure D-3: Option B2 Generation Facilities Cash Flow

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gx Capital Cost	-	-	-	143.8	-	28.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed O&M	-	-	-	3.3	3.3	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Variable O&M	-	-	-	1.6	1.6	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Fuel Cost	-	-	-	9.2	9.2	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8
Avoided System Gen Cost	-	-	-	(9.7)	(10.1)	(12.8)	(14.8)	(15.0)	(15.3)	(15.0)	(15.3)	(14.6)	(15.1)	(14.9)	(15.4)	(15.6)	(15.8)	(15.2)	(15.2)	(15.2)	(15.2)
Total Annual Gx Cost	-	-	-	148.2	4.0	35.1	4.3	4.1	3.8	4.1	3.8	4.6	4.0	4.2	3.7	3.5	3.4	3.9	3.9	3.9	3.9
Annual Amortized cost	-	-	-	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
Cumulative PV of Amortized cost	-	-	-	15.1	29.6	43.5	56.9	69.8	82.2	94.1	105.6	116.6	127.2	137.4	147.2	156.6	165.7	174.4	182.8	190.8	198.6

D.3 Option B3

D.3.1 Assumptions

- Costs represent planning level precision of ±50%
- Capital cost for installing +40 MVar of reactive compensation on-site of the Geraldton mine project (i.e. customer-owned distribution) is $7.5 million[4]
- Unit cost for installing a new 115 kV single-circuit wood pole line with 477 kcmil conductor is $462,000/km[5]
- Right-of-way space is available to build the new line while the existing line remains operating[6]
- Annual O&M costs estimated as 1% of the capital cost of the project, and would be incurred every year from the in-service date to the end of the project useful life
- Land cost not included in estimate

D.3.2 Methodology

Discounted cash flow analysis was performed by taking the following steps:

- Based on the unit cost of the line and a length of 117 km from Nipigon to Longlac, the line capital cost was determined to be $54 million
- Based on capital cost of $7.5 million for the compensation and $54 million for the line, annual O&M costs were calculated as $0.6 million
- Capital and annual costs were amortized over the life of the project
- NPV was calculated over the planning period (2015-2035)

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[4] Hydro One Transmission received quote from ABB for synchronous condenser
[5] From October 2011 SNC Lavalin Transmission Unit Cost Study Report, escalated by 2% per year for three years to convert from end of 2011 to end of 2014 dollars
[6] If right-of-way space is not available, a temporary by-pass would be required

D.3.3 Results

Figure D-4: Option B3 Transmission Facilities Cash Flow

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Line Cost	-	-	-	-	-	54.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Condenser	-	-	-	7.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	0.1	0.1	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total Annual Cost	-	-	-	7.6	0.1	54.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Annual Amortized Cost	-	-	-	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Cumulative PV	-	-	-	2.9	5.6	8.3	10.9	13.3	15.7	18.0	20.1	22.2	24.3	26.2	28.1	29.9	31.6	33.3	34.8	36.4	37.9

D.4 Option C1

D.4.1 Assumptions – Transmission Facilities

- Costs represent planning level precision of ±50%
- Capital cost for installing +40 MVar of reactive compensation on-site of the Geraldton mine project (i.e. customer-owned distribution) is $7.5 million[7]
- Unit cost for installing a new 230 kV single-circuit H-frame wood pole line with 795 kcmil conductor with road access is $486,000/km and with no road access is $630,000/km[8]
- Cost for installing a -25 MVar reactor is $5 million
- Cost for an auto-transformer station of $14.3 million[9]
- Annual O&M costs estimated as 1% of the capital cost of the project, and would be incurred every year from the in-service date to the end of the project useful life
- Land cost not included in estimate

D.4.2 Assumptions – Generation Facilities

- Costs represent planning level precision of ±50%
- Discrete gas generator unit sized of 9.5 MW
- Unit cost for installing a 9.5 MW gas generator unit is $3,028/kW-installed
- Four 9.5 MW gas generating units are assumed to comprise the gas generating plant
- Natural gas is assumed to be supplied by the existing TransCanada pipeline
- Pipeline capacity is assumed to be available and only gas management charges are assumed
- Annual O&M costs are estimated using a fixed and a variable component. The fixed component is based on the installed capacity of the generator and is assumed to be $45/kW annually. The variable component is based on the energy production in a given year and is assumed to be $9/MWh
- The energy cost is assumed to be $49/MWh with delivery cost of $25/kW annually for pipeline capacity allocation
- Land cost not included in estimate

D.4.3 Methodology – Transmission Facilities

Discounted cash flow analysis was performed by taking the following steps:

[7] Hydro One Transmission received quote from ABB for synchronous condenser
[8] From October 2011 SNC Lavalin Transmission Unit Cost Study Report, escalated by 2% per year for three years to convert from end of 2011 to end of 2014 dollars
[9] From October 2011 SNC Lavalin Transmission Unit Cost Study Report, escalated by 2% per year for three years to convert from end of 2011 to end of 2014 dollars

- Based on the unit cost of the line and a length of either 100 km for the West of Marathon option or 150 km for the East of Nipigon option, the line capital cost was determined to be $63 million and $73 million respectively
- Based on capital cost, annual O&M costs were calculated as $1 million and $1.1 million respectively for the West of Marathon and East of Nipigon options
- Capital and annual costs were amortized over the life of the project
- NPV was calculated over the planning period (2015-2035)

D.4.4 Methodology – Generation Facilities

Discounted cash flow analysis was performed by taking the following steps:

- Based on capital cost, annual O&M costs were calculated as $4 million
- Annual energy production is equal to the annual energy demand of the major pipeline
- System generation credit associated with avoiding system generation cost by the annual energy produced by the major pipeline on-site generation facility is calculated
- Capital and annual costs were amortized over the life of the project
- NPV was calculated over the planning period (2015-2035)

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D.4.5 Results[10]

Figure D-5: Option C1 West of Marathon Transmission Facilities Cash Flow

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Line Cost	-	-	-	-	-	-	63.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Lac Station Cost	-	-	-	-	-	-	19.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EWT Switching	-	-	-	-	-	-	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Condenser	-	-	-	-	7.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	0.1	0.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Total Annual Cost	-	-	-	-	7.6	0.1	103.3	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Annual Amortized Cost	-	-	-	-	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Cumulative PV	-	-	-	-	5.1	10.0	14.7	19.2	23.5	27.7	31.7	35.5	39.3	42.8	46.2	49.5	52.7	55.8	58.7	61.5	64.2	66.8

Figure D-6: Option C1 East of Nipigon Transmission Facilities Cash Flow

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Line Cost	-	-	-	-	-	-	72.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Lac Station Cost	-	-	-	-	-	-	19.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EWT Switching	-	-	-	-	-	-	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Condenser	-	-	-	-	7.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	0.1	0.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Total Annual Cost	-	-	-	-	7.6	0.1	113.4	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Annual Amortized Cost	-	-	-	-	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
Cumulative PV	-	-	-	-	5.6	10.9	16.1	21.0	25.8	30.3	34.7	38.9	43.0	46.9	50.7	54.3	57.8	61.1	64.3	67.4	70.4	73.2

[10] Total option C1 cash flow is equal to the sum of the transmission facilities cash flow for the applicable route and the generation facilities (following page) cash flow.

Figure D-7: Option C1 Generation Facilities Cash Flow

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gx Capital Cost	-	-	-	-	-	-	115.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed O&M	-	-	-	-	-	-	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Variable O&M	-	-	-	-	-	-	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Fuel Cost	-	-	-	-	-	-	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Avoided System Gen Cost	-	-	-	-	-	-	(8.2)	(9.3)	(9.4)	(9.6)	(9.4)	(9.6)	(9.2)	(9.5)	(9.4)	(9.7)	(9.8)	(9.9)	(9.5)	(9.5)	(9.5)	(9.5)
Total Annual Gx Cost	-	-	-	-	-	-	118.0	1.8	1.7	1.5	1.7	1.5	1.9	1.6	1.8	1.4	1.4	1.3	1.6	1.6	1.6	1.6
Annual Amortized cost	-	-	-	-	-	-	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
Cumulative PV of Amortized cost	-	-	-	-	-	-	8.1	15.9	23.3	30.5	37.5	44.1	50.5	56.6	62.6	68.2	73.7	79.0	84.0	88.9	93.5	98.0

D.5 Option C2

D.5.1 Assumptions

- Costs represent planning level precision of ±50%
- Capital cost for installing +40 MVar of reactive compensation on-site of the Geraldton mine project (i.e. customer-owned distribution) is $7.5 million[11]
- Unit cost for installing a new 230 kV single-circuit H-frame wood pole line with 795 kcmil conductor with road access is $486,000/km and with no road access is $630,000/km[12]
- Unit cost for installing a new 115 kV single-circuit wood pole line with 477 kcmil conductor is $462,000/km with road access and $600,000/km with no road access[13]
- Cost for installing a -25 MVar reactor is $5 million
- Cost for an auto-transformer station of $14.3 million[14]
- Unit cost for installing 2 x ± 15 MVar SVCs is $0.25 million/MVar
- Unit cost for installing inline breaker switching station is $12 million per 2-breaker station
- Annual O&M costs estimated as 1% of the capital cost of the project, and would be incurred every year from the in-service date to the end of the project useful life
- Land cost not included in estimate

D.5.2 Methodology

Discounted cash flow analysis was performed by taking the following steps:

- Based on the unit cost of the 230 kV line and a length of either 100 km for the West of Marathon option or 150 km for the East of Nipigon option, the line capital cost was determined to be $63 million and $73 million respectively
- Based on the unit cost of the line and a length of 100 km with road access and 75 km with no road access, the line capital cost was determined to be $91 million
- Based on capital, annual O&M costs were calculated as $2.6 million and $2.7 million respectively for the West of Marathon and East of Nipigon options
- Capital and annual costs were amortized over the life of the project
- NPV was calculated over the planning period (2015-2035)

[11] Hydro One Transmission received quote from ABB for synchronous condenser
[12] From October 2011 SNC Lavalin Transmission Unit Cost Study Report, escalated by 2% per year for three years to convert from end of 2011 to end of 2014 dollars
[13] From October 2011 SNC Lavalin Transmission Unit Cost Study Report, escalated by 2% per year for three years to convert from end of 2011 to end of 2014 dollars
[14] From October 2011 SNC Lavalin Transmission Unit Cost Study Report, escalated by 2% per year for three years to convert from end of 2011 to end of 2014 dollars

D.5.3 Results

Figure D-8: Option C2 West of Marathon Cash Flow

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Line Cost (230)	-	-	-	-	-	-	63.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Lac Station Cost	-	-	-	-	-	-	19.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EWT Switching	-	-	-	-	-	-	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Line cost (115 kV)	-	-	-	-	-	-	91.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
In-line breakers	-	-	-	-	-	-	36.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Condenser	-	-	-	-	7.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SVC (+/- 30 Mvar)	-	-	-	-	-	-	15.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
230kV/LV Transformer	-	-	-	-	-	-	10.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	0.1	0.1	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Total Annual Cost	-	-	-	-	7.6	0.1	257.0	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Annual Amortized Cost	-	-	-	-	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6
Cumulative PV	-	-	-	-	12.1	23.8	35.0	45.8	56.2	66.2	75.7	85.0	93.8	102.4	110.6	118.4	126.0	133.3	140.3	147.0	153.5	159.8

Figure D-9: Option C2 East of Nipigon Cash Flow

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Line Cost	-	-	-	-	-	-	72.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Lac Station Cost	-	-	-	-	-	-	19.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EWT Switching	-	-	-	-	-	-	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Line cost (115 kV)	-	-	-	-	-	-	91.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
In-line breakers	-	-	-	-	-	-	36.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Condenser	-	-	-	-	7.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SVC (+/- 30 Mvar)	-	-	-	-	-	-	15.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
230kV/LV Transformer	-	-	-	-	-	-	10.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	0.1	0.1	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Total Annual Cost	-	-	-	-	7.6	0.1	267.0	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Annual Amortized Cost	-	-	-	-	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2
Cumulative PV	-	-	-	-	12.6	24.7	36.3	47.5	58.3	68.7	78.6	88.2	97.4	106.2	114.7	122.9	130.8	138.3	145.6	152.6	159.3	165.8

D.6 Option C3

D.6.1 Assumptions – Transmission Facilities

- Costs represent planning level precision of ±50%
- Unit cost for installing a new 115 kV single-circuit wood pole line with 477 kcmil conductor is $462,000/km with road access and $600,000/km with no road access[15]
- Unit cost for installing 2 x ± 15 MVar SVCs is $0.25/MVar
- Unit cost for installing inline breaker switching station is $12 million for 2-breaker station
- Annual O&M costs for transmission facilities estimated as 1% of the capital cost of the project, and would be incurred every year from the in-service date to the end of the project useful life
- Land cost not included in estimate

D.6.2 Assumptions – Generation Facilities

- Costs represent planning level precision of ±50%
- Unit cost for installing a 20 MW gas generator unit is $2,752
- Six 18 MW gas generating units are assumed to comprise the gas generating plant
- Natural gas is assumed to be supplied by the existing TransCanada pipeline
- Pipeline capacity is assumed to be available and only gas management charges are assumed
- Annual O&M costs are estimated using a fixed and a variable component. The fixed component is based on the installed capacity of the generator and is assumed to be $40/kW annually. The variable component is based on the energy production in a given year and is assumed to be $9/MWh
- The energy cost is assumed to be $49/MWh with delivery cost of $20/kW annually for pipeline capacity allocation
- Land cost not included in estimate

D.6.3 Methodology – Transmission Facilities

Discounted cash flow analysis was performed by taking the following steps:

- Based on the unit cost of the line and a length of 100km with road access and 70 km with no road access, the line capital cost was determined to be $91 million

[15] From October 2011 SNC Lavalin Transmission Unit Cost Study Report, escalated by 2% per year for three years to convert from end of 2011 to end of 2014 dollars

- Based on capital, annual O&M costs for transmission facilities were calculated as $1.7 million
- Capital and annual costs were amortized over the life of the project
- NPV was calculated over the planning period (2015-2035)

D.6.4 Methodology – Generation Facilities

Discounted cash flow analysis was performed by taking the following steps:

- Based on capital cost, annual O&M costs for generation were calculated as $4.5 million
- Annual energy production is equal to the annual energy demand of the Geraldton mine
- System generation credit associated with avoiding system generation cost by the annual energy produced by the Geraldton mine on-site generation facility is calculated
- Capital and annual costs were amortized over the life of the project
- NPV was calculated over the planning period (2015-2035)

D.6.5 Results[16]

Figure D-10: Option C3 Transmission Facilities Cash Flow

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Line cost (115 kV)	-	-	-	-	-	-	91.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
In-line breakers	-	-	-	-	-	-	60.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SVC (+/- 30 Mvar)	-	-	-	-	-	-	15.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	-	-	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Total Annual Cost	-	-	-	-	-	-	167.8	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Annual Amortized Cost	-	-	-	-	-	-	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
Cumulative PV	-	-	-	-	-	-	7.6	15.0	22.1	28.9	35.4	41.7	47.7	53.6	59.1	64.5	69.7	74.6	79.4	84.0	88.4	92.7

Figure D-11: Option C3 Generation Facilities Cash Flow

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gx Capital Cost	-	-	-	-	300.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed O&M	-	-	-	-	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Variable O&M	-	-	-	-	0.7	0.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Fuel Cost	-	-	-	-	4.1	4.1	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
Avoided System Gen Cost	-	-	-	-	(10.9)	(11.1)	(23.3)	(26.5)	(26.8)	(27.4)	(26.9)	(27.3)	(26.2)	(27.0)	(26.7)	(27.6)	(27.8)	(28.1)	(27.1)	(27.1)	(27.1)	(27.1)
Total Annual Gx Cost	-	-	-	-	297.7	(2.5)	5.0	1.8	1.5	0.9	1.4	1.0	2.2	1.3	1.7	0.7	0.5	0.2	1.2	1.2	1.2	1.2
Annual Amortized cost	-	-	-	-	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
Cumulative PV of Amortized cost	-	-	-	-	19.7	38.7	56.9	74.5	91.4	107.6	123.2	138.2	152.6	166.5	179.8	192.6	204.9	216.8	228.2	239.1	249.7	259.8

[16] Total option C3 cash flow is equal to the sum of the transmission facilities cash flow and the generation facilities cash flow.

D.7 Option C4

D.7.1 Assumptions

- Costs represent planning level precision of ±50%
- Unit cost for installing a 9.5 MW gas generator unit is $3,028/kW
- Fourteen 9.5 MW gas generating units are assumed to comprise the gas generating plants
- Natural gas is assumed to be supplied by the existing TransCanada pipeline
- Pipeline capacity is assumed to be available and only gas management charges are assumed
- Annual O&M costs are estimated using a fixed and a variable component. The fixed component is based on the installed capacity of the generator and is assumed to be $45/kW annually. The variable component is based on the energy production in a given year and is assumed to be $9/MWh
- The energy cost is assumed to be $49/MWh with delivery cost of $25/kW annually for pipeline capacity allocation
- Land cost not included in estimate

D.7.2 Methodology

Discounted cash flow analysis was performed by taking the following steps:

- Based on capital cost, annual O&M costs were calculated as $10.7 million
- Annual energy production is equal to the annual energy demand of the major pipeline and Geraldton mine
- System generation credit associated with avoiding system generation cost by the annual energy produced by the major pipeline and Geraldton mine on-site generation facilities is calculated
- Capital and annual costs were amortized over the life of the project
- NPV was calculated over the planning period (2015-2035)

D.7.3 Results

Figure D-12: Option C4 Cash Flow

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gx Capital Cost	-	-	-	-	143.8	-	258.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed O&M	-	-	-	-	-	9.3	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7
Variable O&M	-	-	-	-	-	1.6	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Fuel Cost	-	-	-	-	-	9.2	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.3
Avoided System Gen Cost	-	-	-	-	(15.2)	(15.6)	(28.7)	(32.9)	(33.4)	(34.1)	(33.4)	(34.0)	(32.5)	(33.6)	(33.2)	(34.4)	(34.7)	(35.0)	(33.8)	(33.8)	(33.8)	(33.8)
Total Annual Gx Cost	-	-	-	-	128.6	4.5	283.6	20.5	20.1	19.4	20.0	19.5	21.0	19.9	20.3	19.1	18.8	18.5	19.7	19.7	19.7	19.7
Annual Amortized cost	-	-	-	-	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7	43.7
Cumulative PV of Amortized cost	-	-	-	-	38.8	76.2	112.1	146.6	179.8	211.8	242.5	272.0	300.4	327.6	353.9	379.1	403.4	426.7	449.1	470.7	491.4	511.4

Greenstone-Marathon Interim IRRP

Appendix E: A4L Performance Summary

Appendix E: Reliability Analysis of Greenstone Sub-system

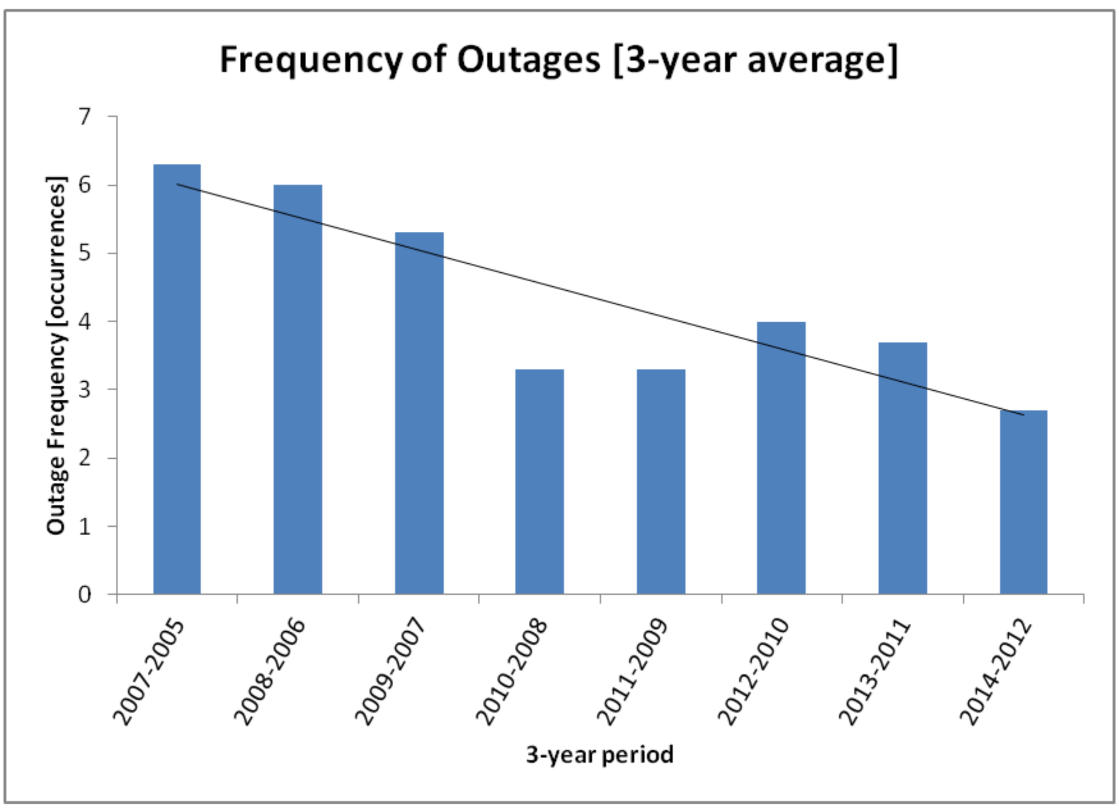
Under the Scenario A demand forecast, the LMC of the Greenstone sub-system is adequate to meet forecast demand. This appendix summarizes analysis of the past performance of circuit A4L, which supplies the Greenstone sub-system to determine if further reliability-based investments may be justified.

E.1 A4L Performance Summary

E.1.1 Frequency of Outages

The frequency (occurrences per year) of forced outages for the customer delivery points along circuit A4L have been within the OEB-approved standard, and have been decreasing over the past ten years. Since 2009, the frequency of forced outages has been below the target for its group, i.e., better than the standard. The rolling 3-year average of outage frequencies has decreased from 6.3 in 2005-2007 to 2.7 in 2012-2014.

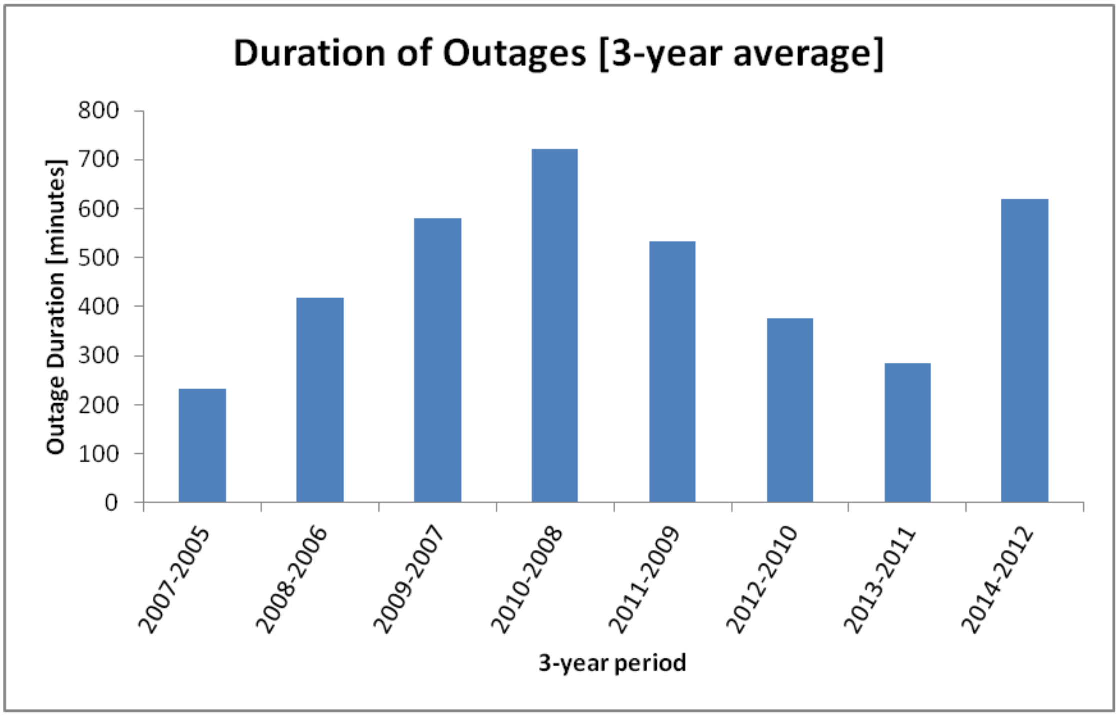
Figure E-1: Frequency of A4L Outages (3-year average)



E.1.2 Duration of Outages

The rolling 3-year average of outage durations at Longlac TS had decreased to 284 minutes in 2011-2013, which is within the standard for its group. However, one relatively long outage in 2013 and one in 2014 caused the rolling 3-year average outage durations to exceed the standard for its group in 2012-2014.

Figure E-2: Duration of A4L Outages (3-year average)



In 2013 an incident of insulation failure occurred at 9:41 pm, and in 2014 one incident of surge arrester failure occurred at 6:14 pm. As a result of remoteness and accessibility difficulties for locating and repairing damaged equipment during the night, these outages lasted for several hours. The intent of the 8-hour restoration criterion due to forced outages is that these outages should be addressed in a working day. The issues of level of staffing and remoteness are recognized in ORTAC, indicating that "approximate restoration times are intended for locations that are near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility."

There have also been one or two planned outages in each of the past few years for repair or maintenance work on circuit A4L or its terminal stations. When work is not urgent, planned outages are scheduled and the customers are informed in advance.

E.2 A4L Sustainment Planning Summary

Hydro One monitors the number (frequency) and duration of outages at customer delivery points and measures them against performance standards approved by the OEB. This information is used to allocate resources for maintaining or improving the customer deliver point performance. In addition, as a part of routine maintenance, Hydro One inspects the poles and insulators of circuit A4L on a regular basis and plans for testing and replacement of facilities that are not in good condition.

To improve the performance of circuit A4L, Hydro One has had an extensive sustainment program for this circuit.

The following summarizes past sustainment investments:

Table E-1: Past Sustainment Investments

Timeframe	Poles Replaced
2005-2009	246
2010-2014	122

Continued sustainment activities are planned for circuit A4L to maintain reliability performance of the circuit for the area.

Table E-2: Planned Sustainment Investments

Timeframe	Poles to be Replaced
2015-2016	113

E.3 Economic Analysis of Outages

Many jurisdictions within the electricity industry rationalize reliability improvements to transmission and distribution systems by conducting a cost-benefit analysis which accounts for the monetized risk of the existing reliability performance in comparison with the cost and benefit of improving the performance.

This is accomplished by:

1. Assessing the expected reliability performance (frequency and duration of outages) of the existing facilities
2. Determining the expected level of customer electrical supply affected (MW and MWh)
3. Monetizing the cost of a supply interruptions to the affected customers
4. Determining the cost of mitigating solutions and their impact on supply interruptions to the affect customers
5. Comparing (3) and (4) for the existing system versus an upgraded system through a cost-benefit analysis

In order to quantify reliability performance of the supply to the Greenstone area, a probabilistic reliability assessment has been performed. This analysis takes the historical average unavailability of the supply to the Greenstone area from circuit A4L and determines the Expected Unserved Energy ("EUE"). EUE is defined as the average annual energy that is not supplied due to outages in the area. It is a reliability metric that is commonly established for asset management assessments.

Depending on the different customer classes present in the area, the EUE can be converted to a monetized risk ($/year) through use of the appropriate Value of Customer Reliability ("VCR") or synonymously Value of Lost Load ("VOLL"). VCR is a metric that establishes the value of reliability per unit energy ($/kWh). The Australian Energy Market Operator ("AEMO") is one of the leaders in VCR analysis and has published in their September 2014[17] Value of Customer Reliability Review a sector breakdown of Australia's VCRs:

Table E-3: AEMO VCR Results

Customer Class	Residential	Agriculture	Commercial	Industrial
VCR [2014$AUS/kWh]	25.95	47.67	44.72	44.06

17 http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/SAAF/VCR%20final%20report%20%20PDF%20update%2027%20Nov%2014.ashx

In June 2013, London Economics International LLC developed a briefing paper titled *Estimating the Value of Lost Load*[18] for the Electric Reliability Council of Texas ("ERCOT"). The paper illustrated that a broad range of VOLLs exist and found that:

> "Average VOLLs for a developed, industrial economy range from approximately $9,000/MWh to $45,000/MWh…residential customers generally have a lower VOLL ($0/MWh - $17, 976/MWh) than commercial and industrial ("C/I") customers (whose VOLLs range from about $3,000/MWh to $53,907/MWh)"

VCRs may be used to determine the amount of investment that is justified to reduce the loss of load by 1 kWh. Without specific VCR data established for Greenstone, the Greenstone-Marathon IRRP Working Group has assumed a VCR of $30/kWh. This $30/kWh VCR assumption is comparable to the AEMO VCRs assuming 50% residential and 50% C/I (which gives $33.41 CAD/kWh), and falls within the ERCOT VOLL ranges. Only forced outages are considered for EUE analyses using VCRs.

The following uses the mean three year average outage frequency and duration data of 2010-2012, 2011-2013, and 2012-2014.

Table E-4: Reliability Analysis Results

Average Annual Outage Frequency [occ/year]	Average Outage Duration [hrs/occ]	Forecast Peak Demand [MW]	Assumed Load Factor [Avg/Peak %]	Average VCR [2014CAD /kWh]	25% Reliability Value [$K/year]	50% Reliability Value [$K/year]	100% Reliability Value [$K/year]
3.467	2.22	20	70	30	800	1600	3200

The analysis indicates that the monetized risk of outages (reliability value) is not sufficient for the customer to justify further investment, beyond continued routine maintenance and planned sustainment activities.

E.4 Reliability Analysis Conclusion

From the above analysis the Working Group believes that past sustainment activities have been adequate and future sustainment plans are appropriate to ensure performance of circuit A4L is

[18] http://www.puc.texas.gov/industry/projects/electric/40000/40000_427_061813_ERCOT_VOLL_Literature_Review_and_Macroeconomic_Analysis.pdf

maintained. The Greenstone-Marathon IRRP Working Group does not believe further reliability-based investments are justified based on the incremental reliability that would be provided. However, if customers wish to pursue further reliability investments independently, then they may do so.