GREENSTONE-MARATHON INTEGRATED REGIONAL RESOURCE PLAN - APPENDICES

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Connecting Today. Powering Tomorrow.

Greenstone-Marathon 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 assumed 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

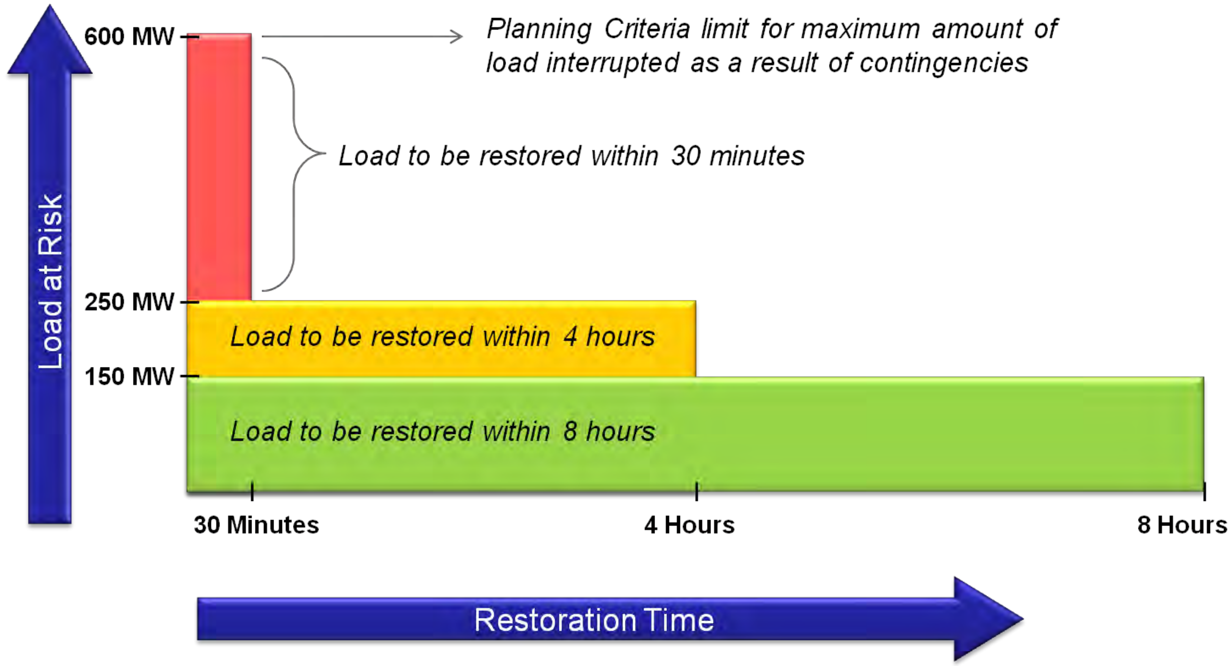
Table A-4: Summary of ORTAC Load Security Criteria

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 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

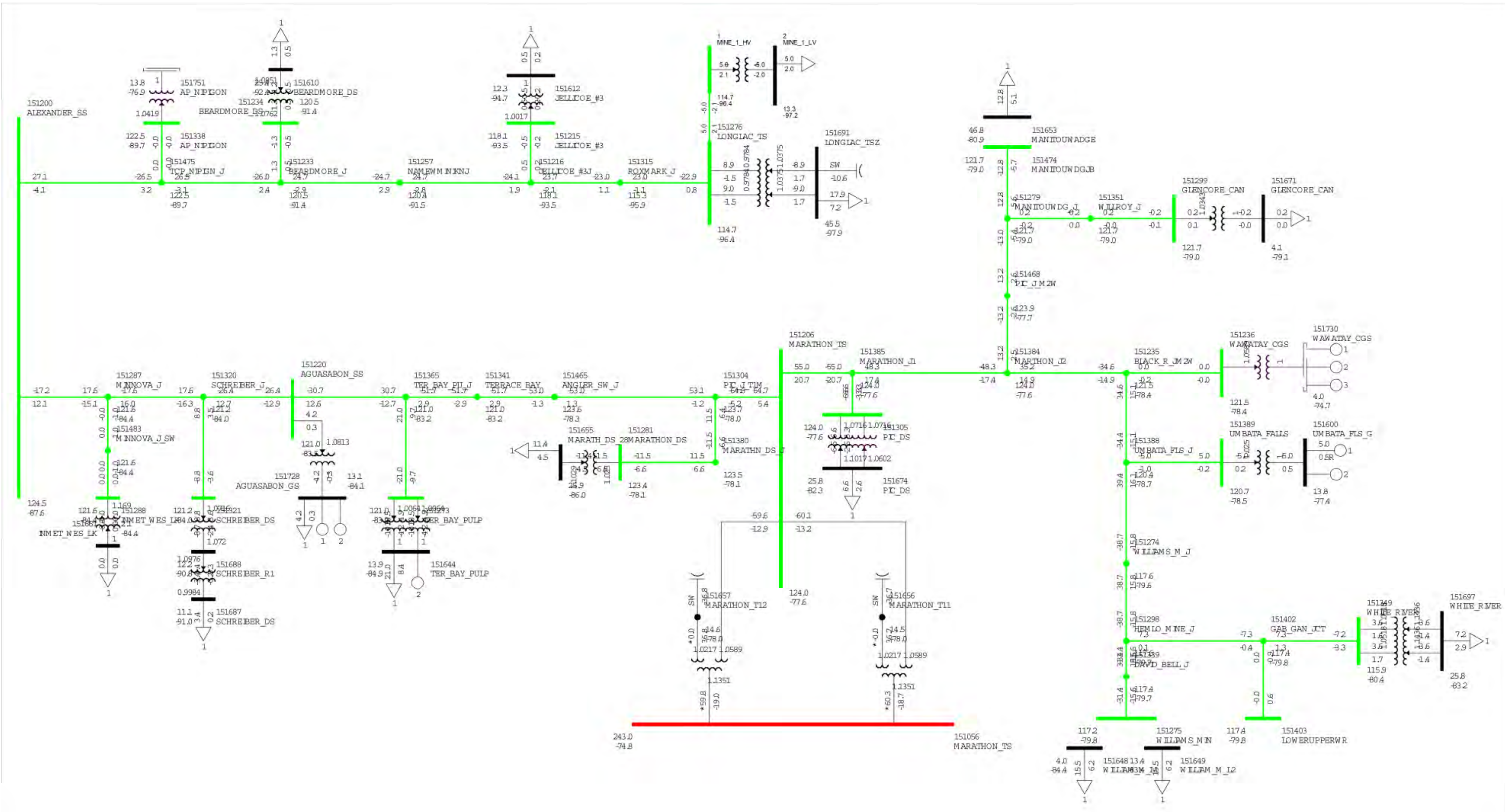
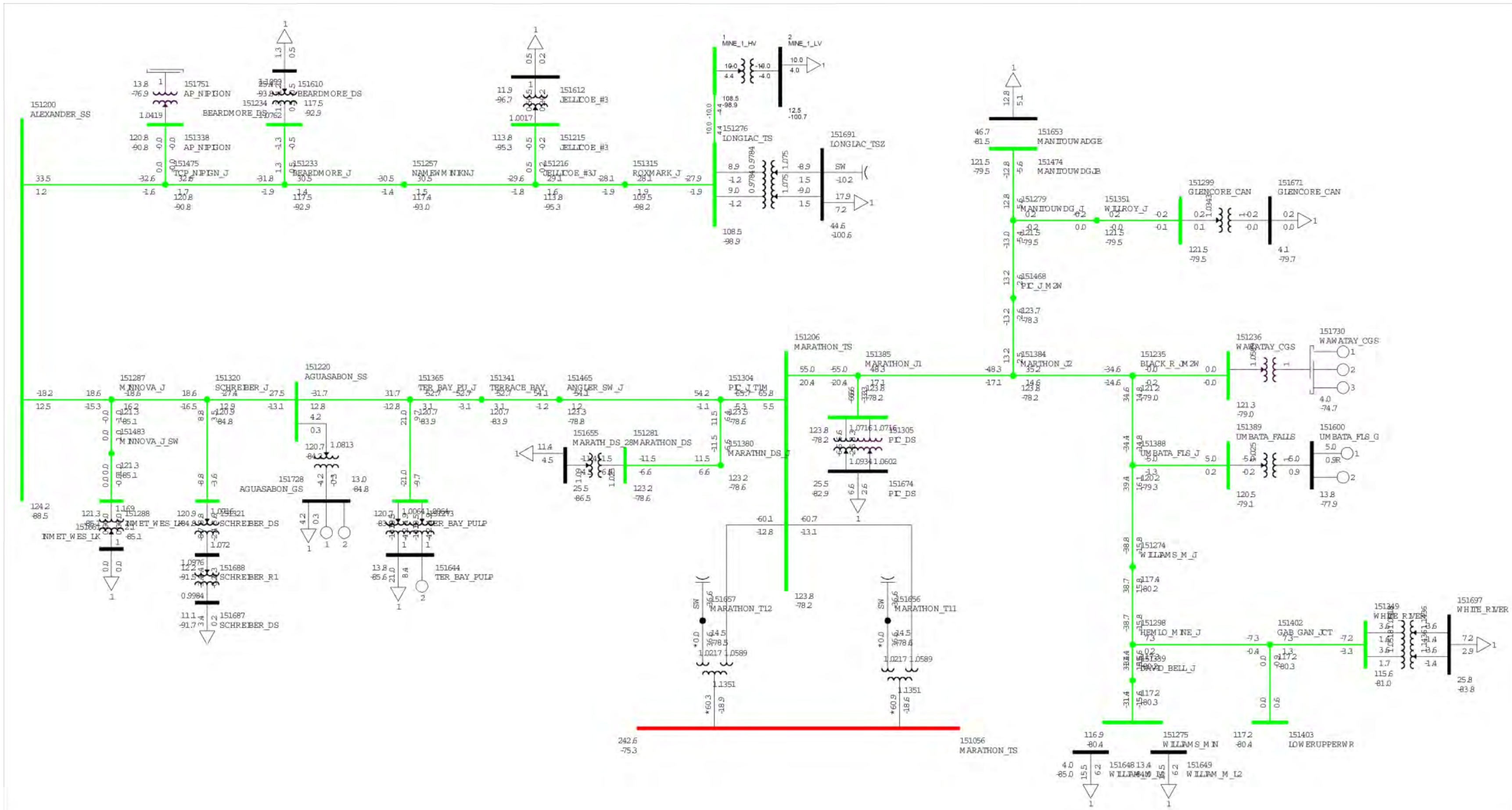


Figure B-2: Establishing Greenstone Sub-system LMC - 30 MW of Load Supplied by A4L



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
- 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

Bus	Voltage [kV]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Marathon TS (230 kV)	243.9	250	220
Marathon TS (115 kV)	124.6		
Terrace Bay SS	121.5	127	113
Aguasabon SS	121.5		
Alexander SS	124.8		

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 RAS 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>
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B.2.4 Load Flow Plots

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

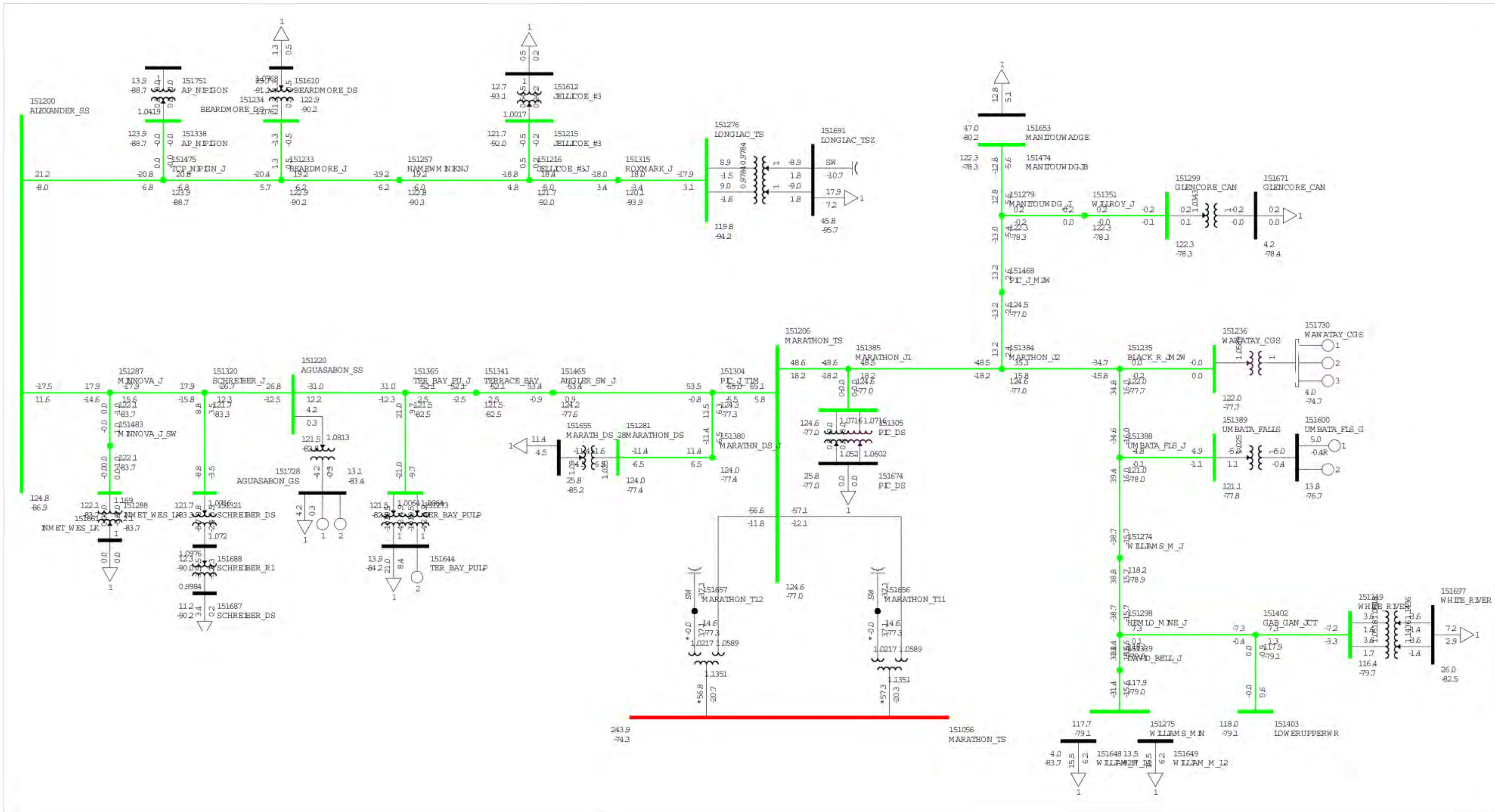


Figure B-4: Establishing North Shore LMC: Scenario A 2020 Forecast Post-contingency Pre-ULTC

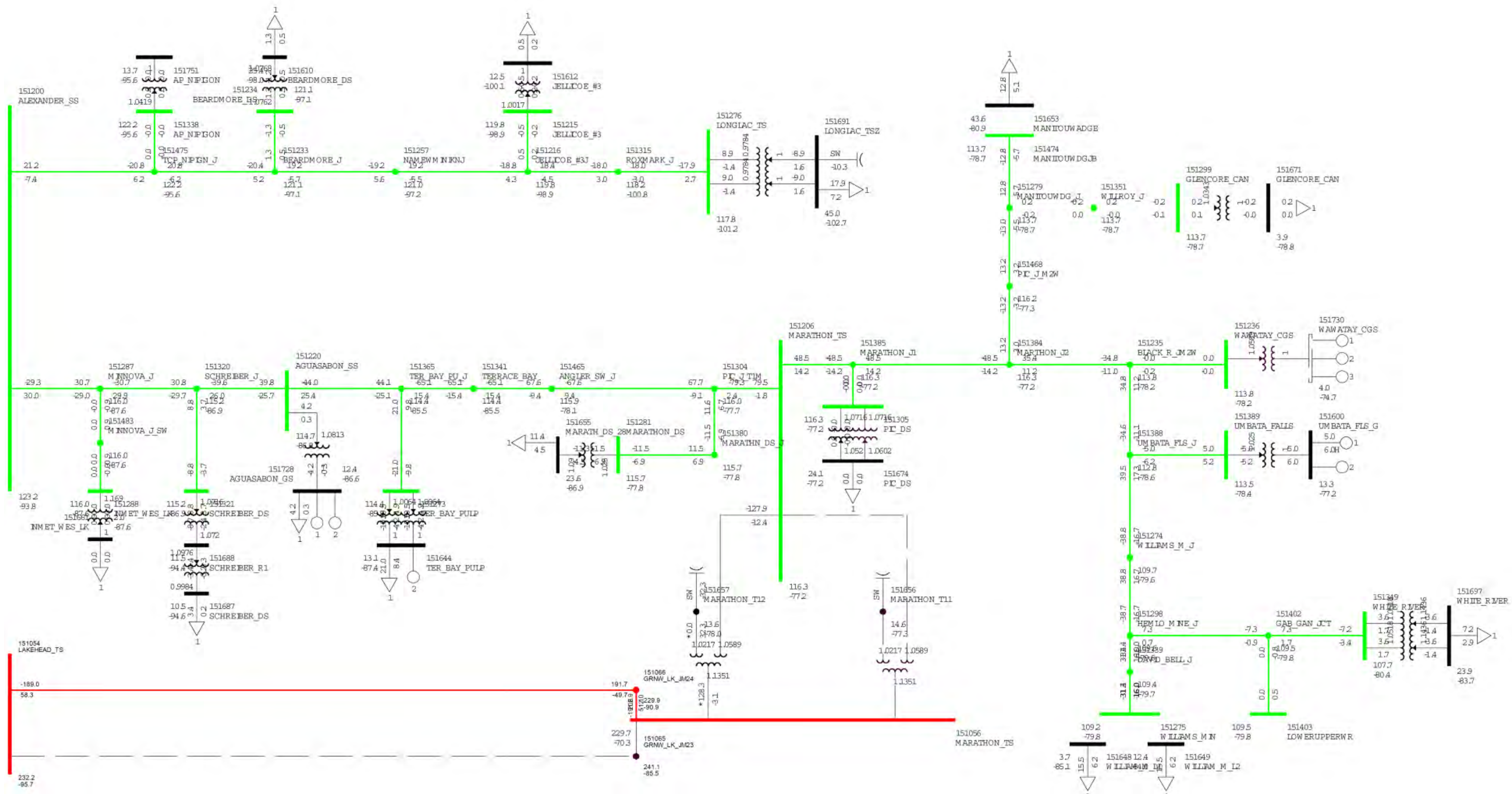
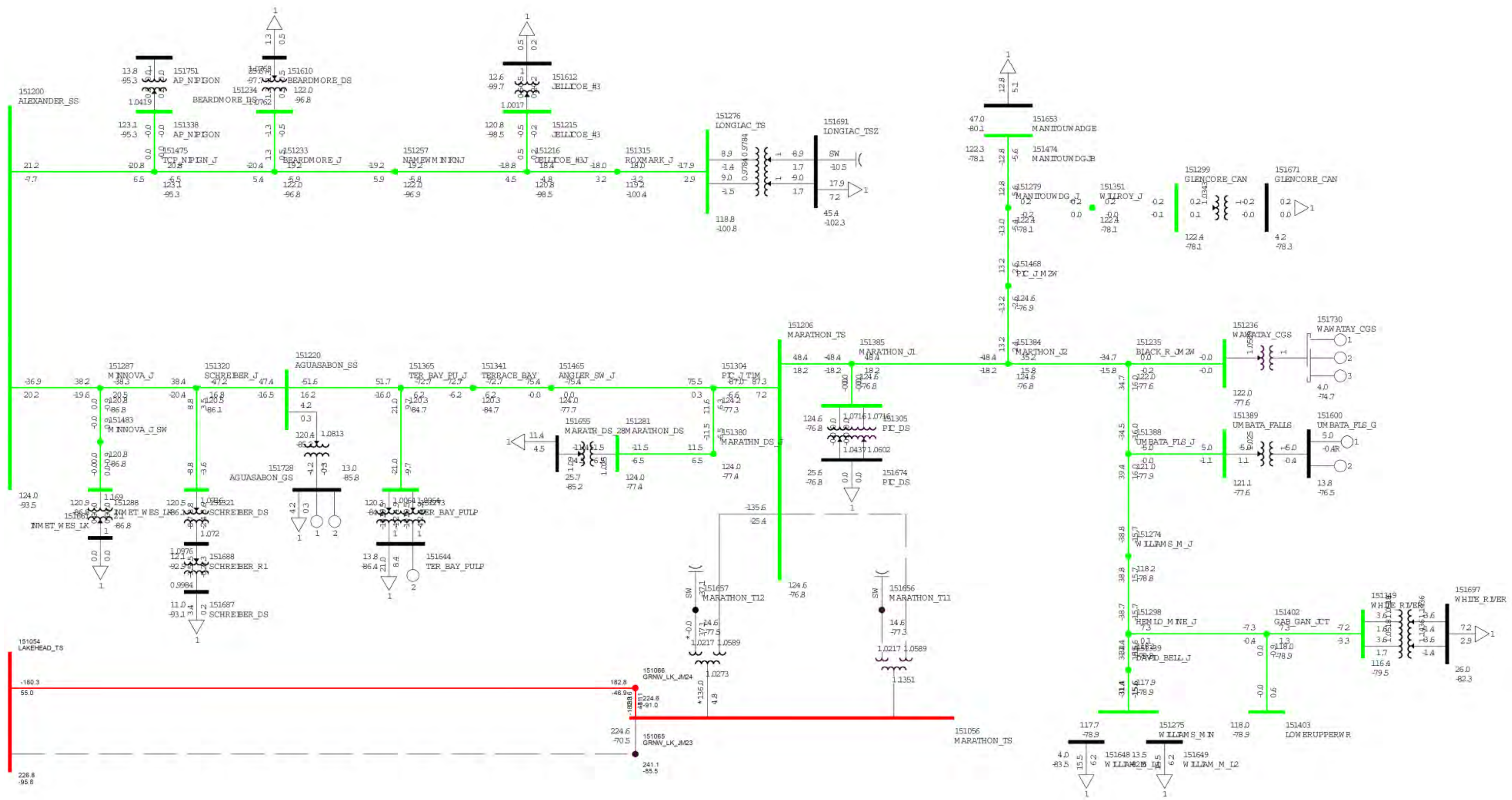


Figure B-5: Establishing North Shore LMC: Scenario A 2020 Forecast Post-contingency Post-ULTC



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	127	113
Manitouwadge TS	121.4		
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

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)	245.4	231.5 (-5.7%)	226.6 (-7.7%)	250	207	10
Marathon TS (115 kV)	125.5	116.6 (-7.1%)	124.8 (-0.6%)	127	108	10
Manitouwadge TS	121.4	112.1 (-7.1%)	120.7 (-0.6%)			
White River DS	117.3	108.1 (-7.8%)	116.6 (-0.6%)			

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B.3.4 Load Flow Plots

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

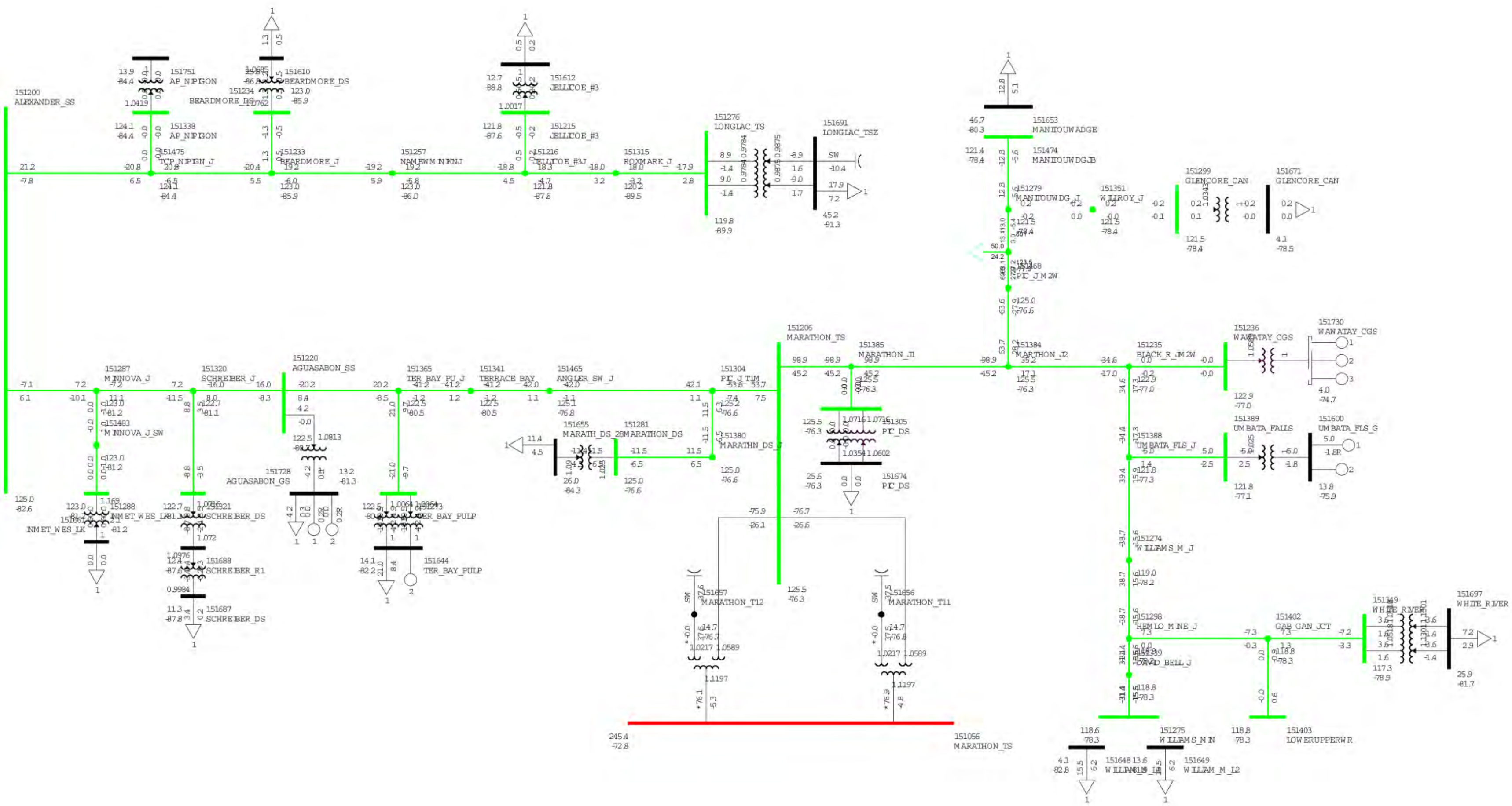


Figure B-7: Establishing Marathon Area LMC: Scenario C 2020 Forecast Post-contingency Pre-ULTC

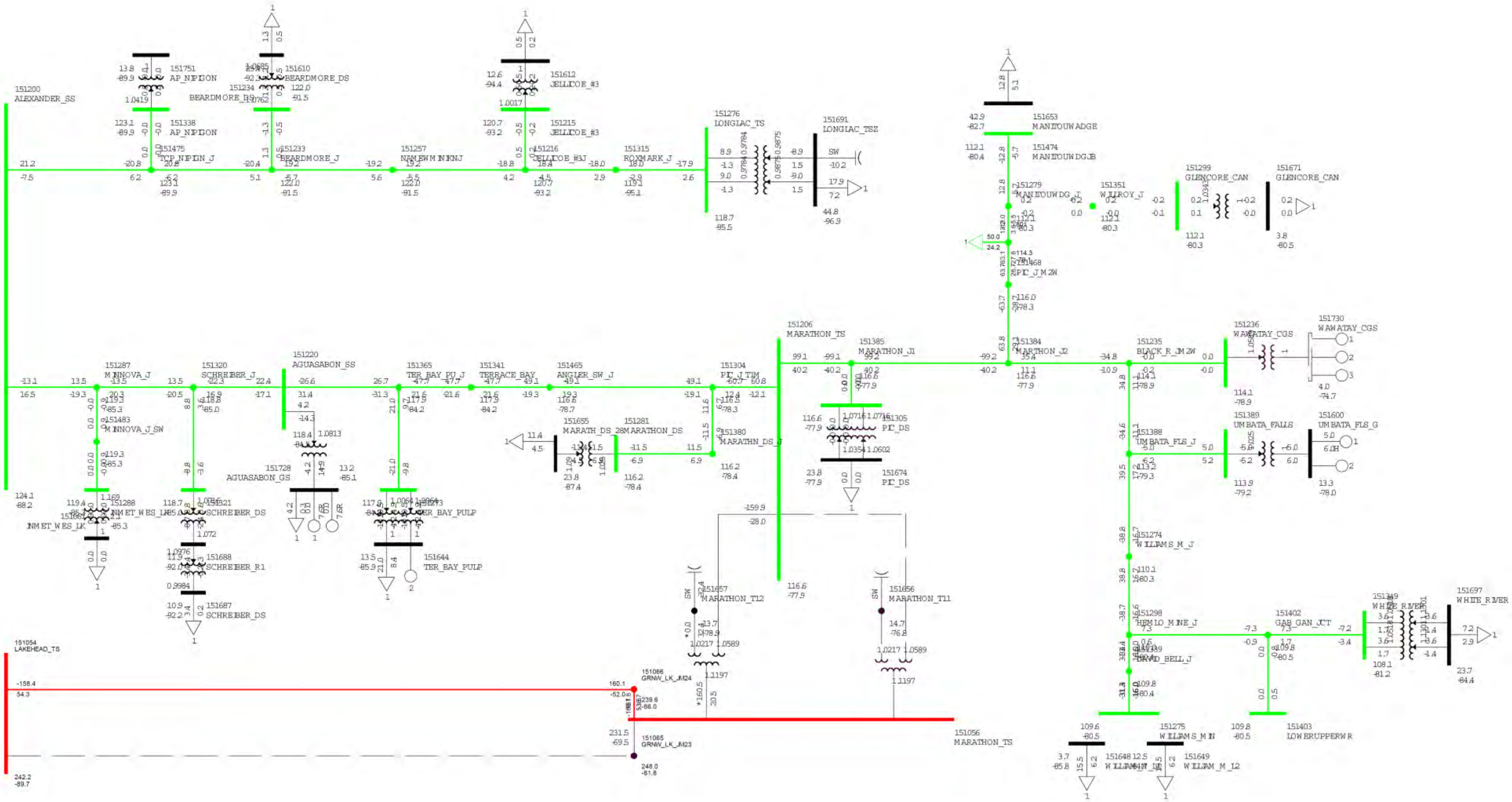
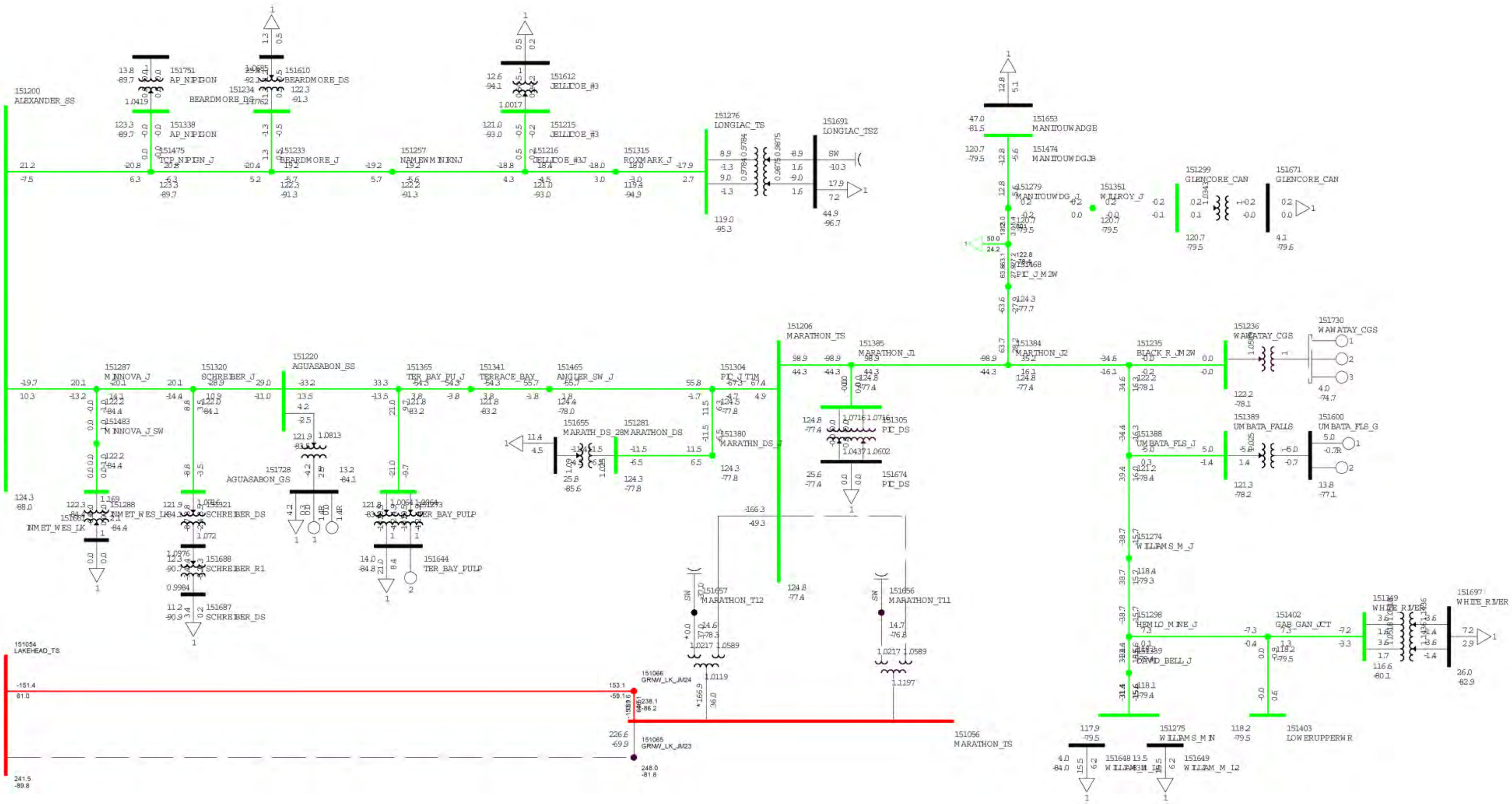


Figure B-8: Establishing Marathon Area LMC: Scenario C 2020 Forecast Post-contingency Post-ULTC



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Appendix C: Studies to Establish Technical Performance of Near-term Options

Appendix C: Studies to Establish Technical Performance of Near-term 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 RAS 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.

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

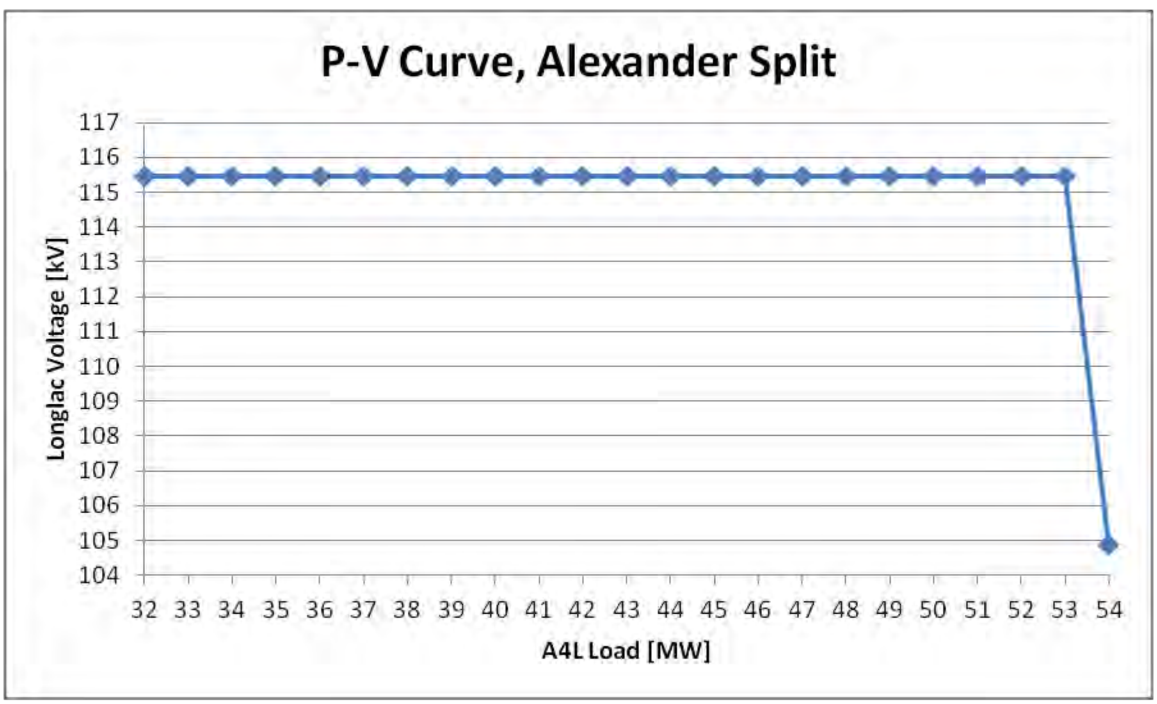
With an element out-of-service pre-contingency, 85-percentile hydroelectric output conditions are assumed. The outage of either breakers KL4 or L5L6 does not result in the splitting of

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 Remedial Action Scheme 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

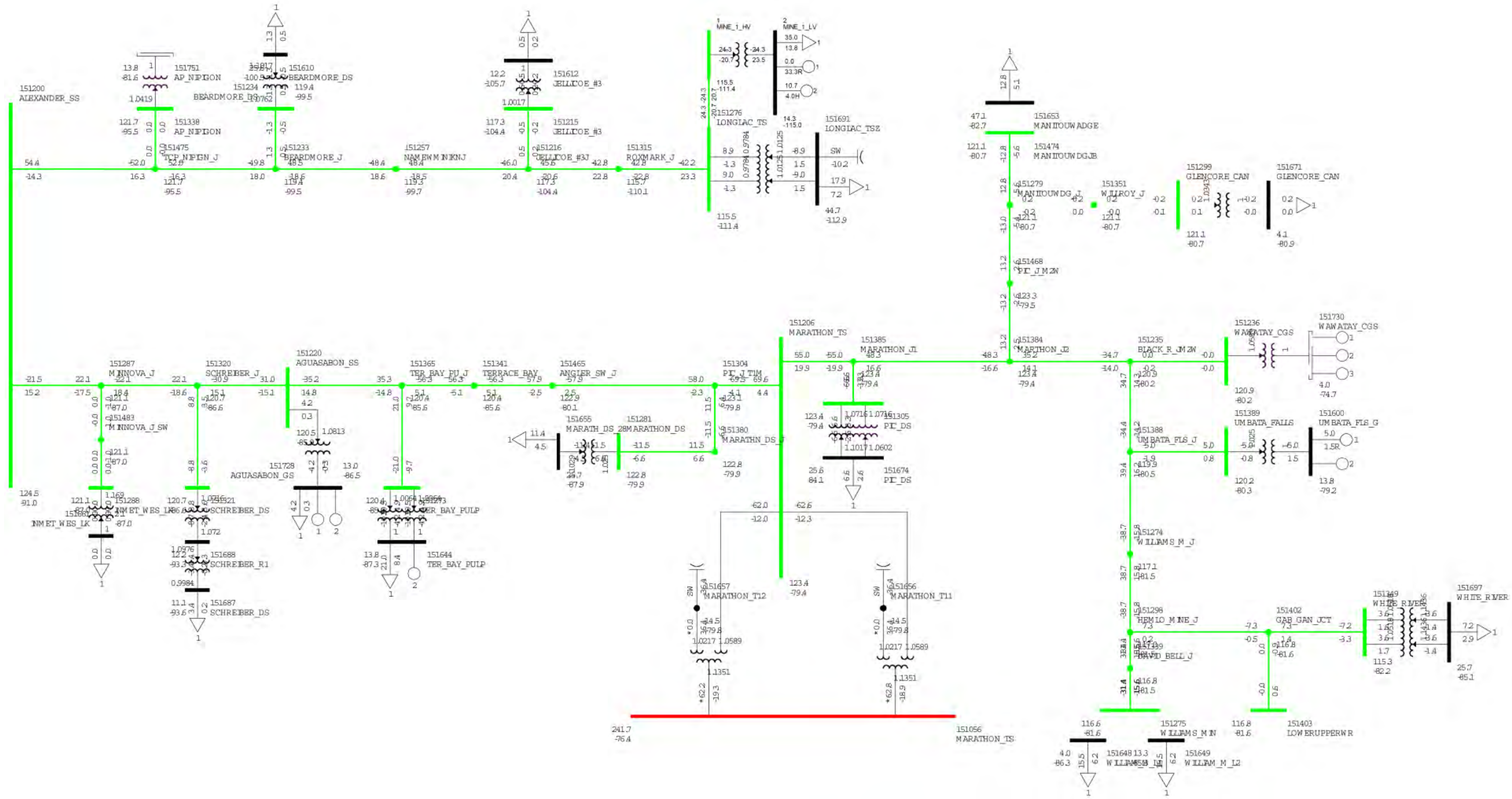
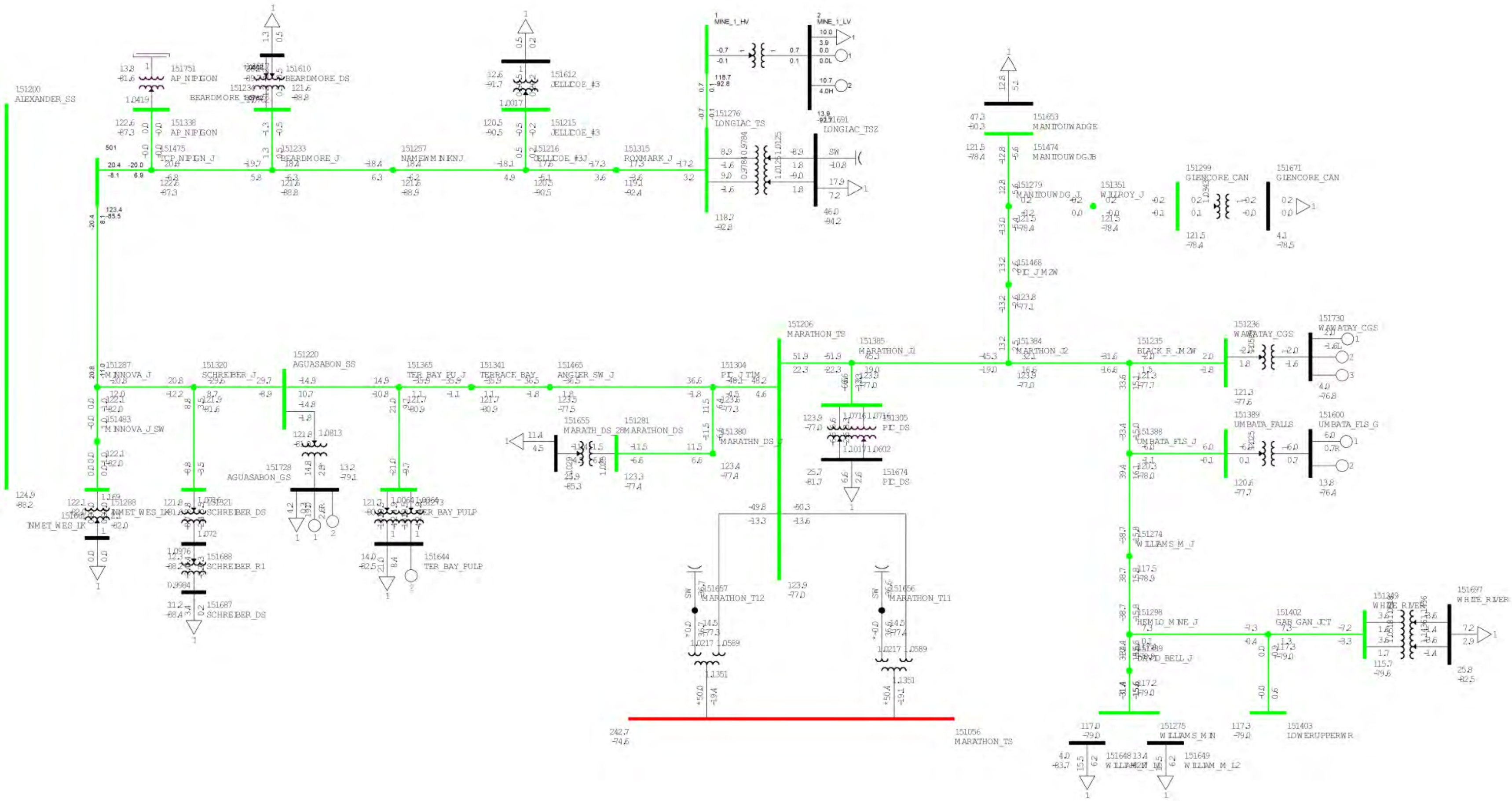


Figure C-3: With +40MVar Reactive Compensation and one of two 10 MW gas-fired generator in-service at Geraldton mine, Alexander SS split for P-V analysis



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.

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

Bus	Voltage [kV]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Alexander SS	124.5	127	113
Beardmore JCT	118.8		
Jellicoe JCT	118.2		
Longlac TS	118.1		

Breaker Outages at Alexander SS Pre-contingency

The breaker outages being considered are as follows:

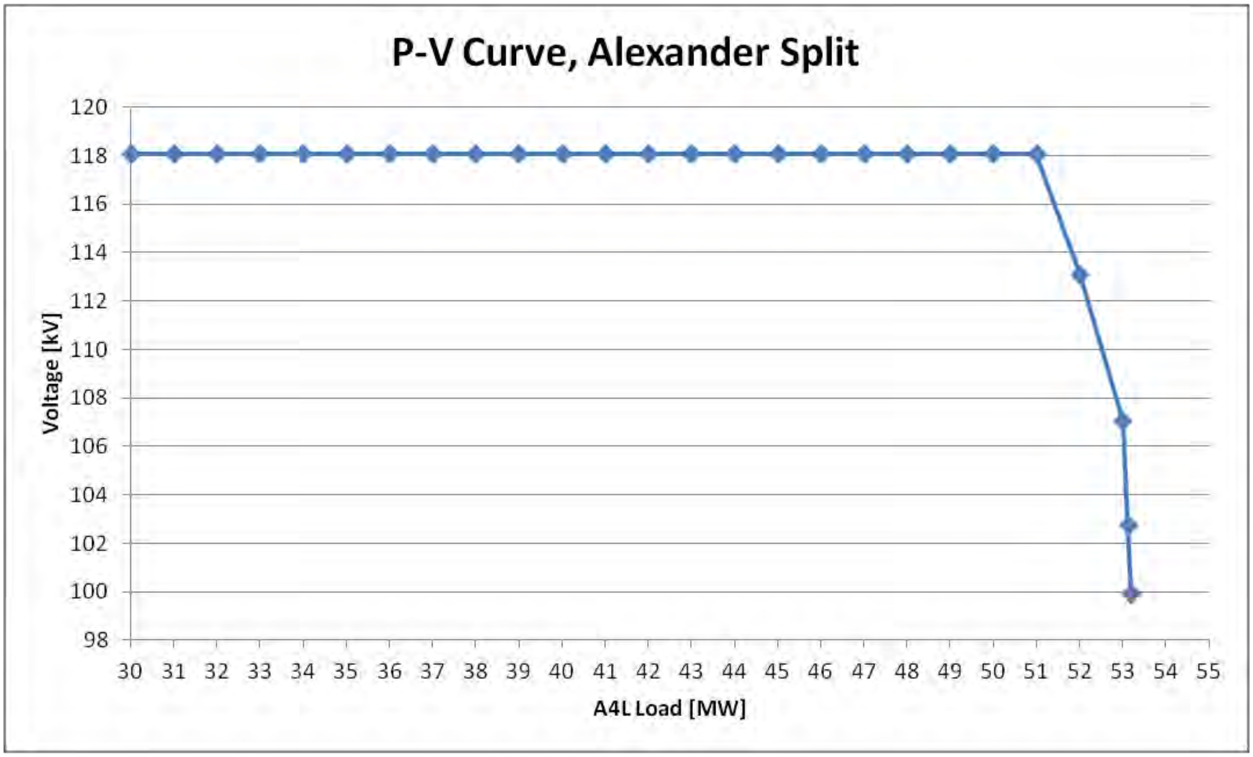
- Alexander SS breaker KL4 outage
- Alexander SS breaker L5L6 outage

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 Remedial Action Scheme 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

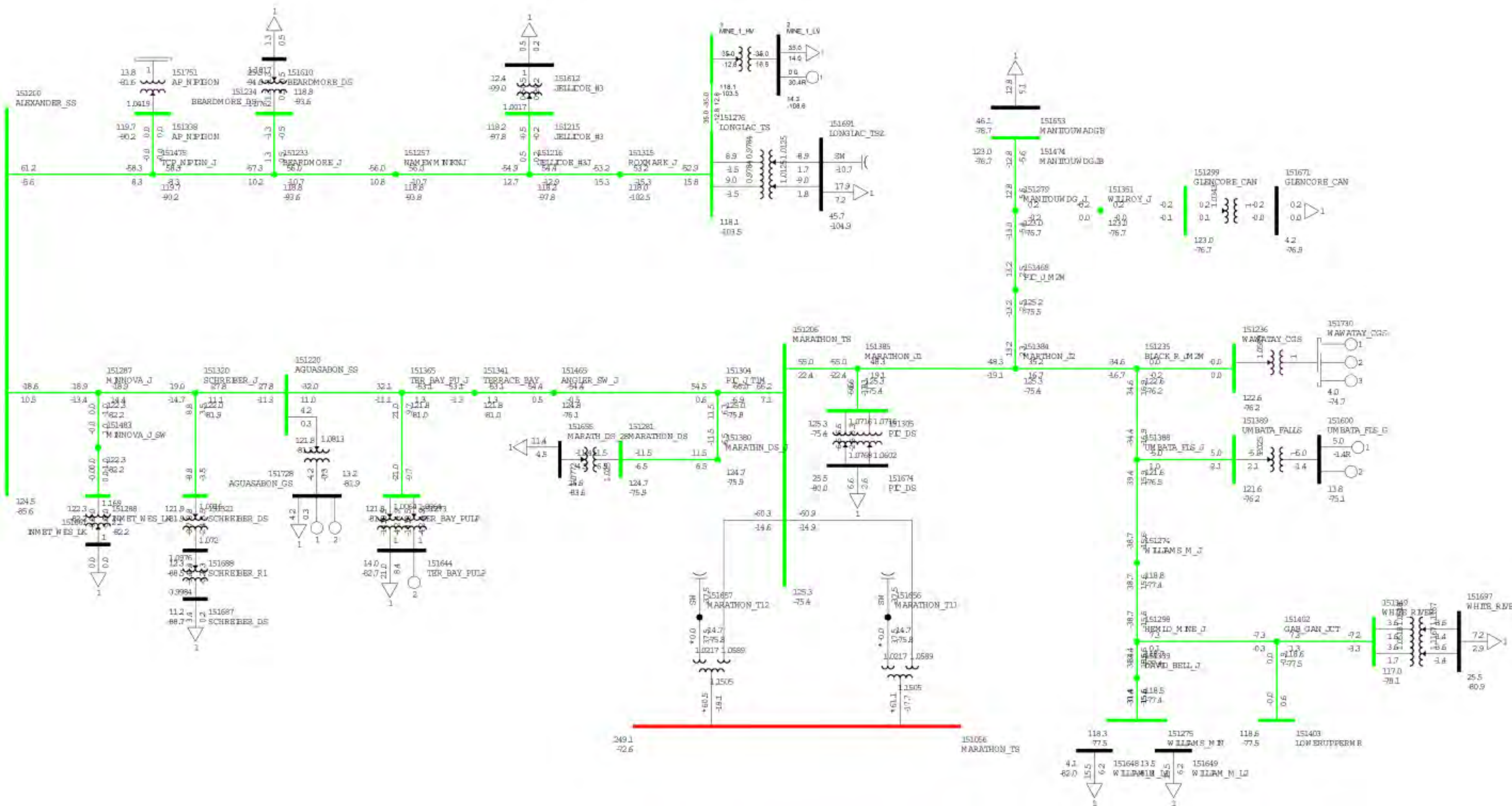
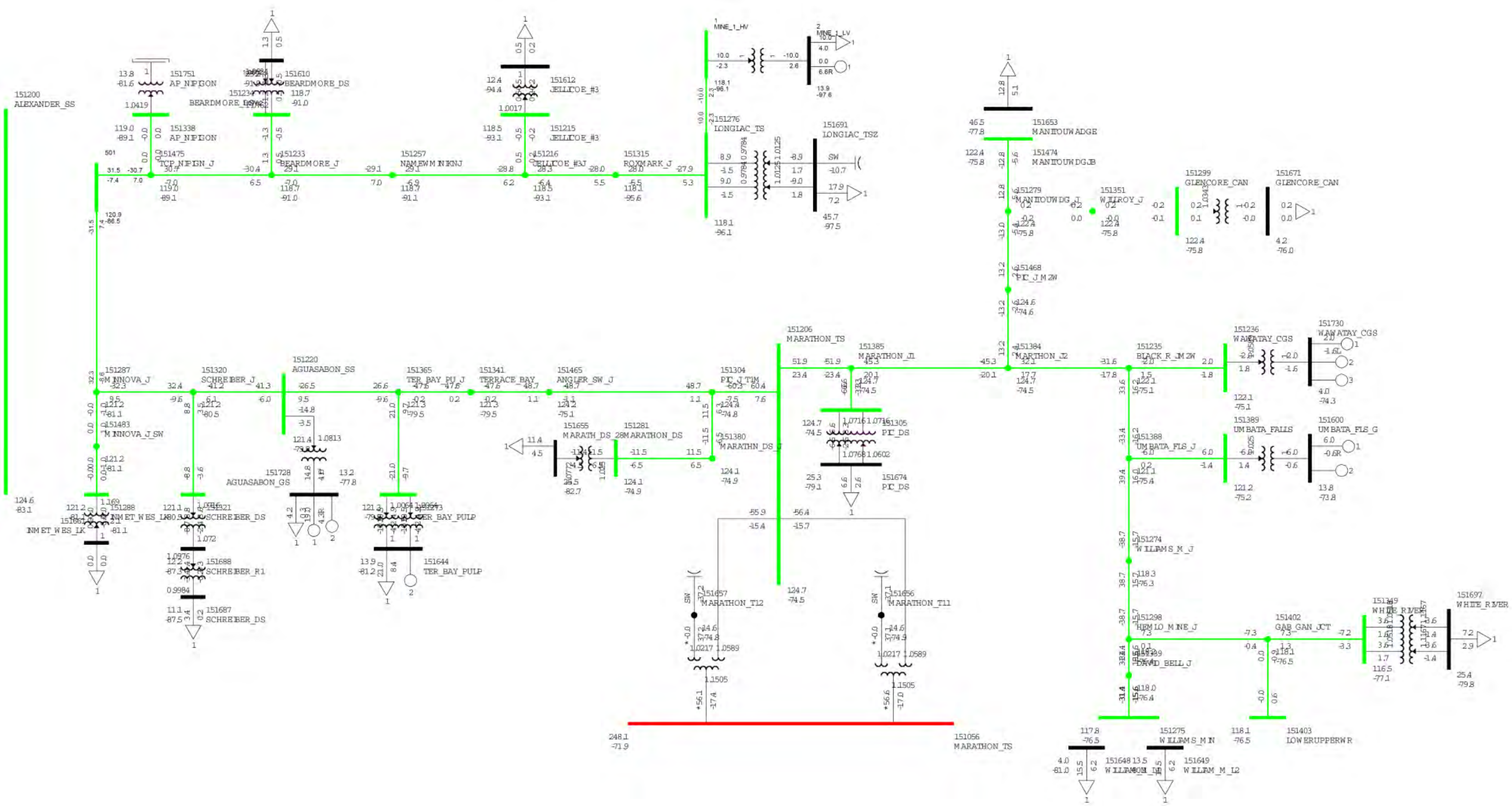


Figure C-6: With +40MVar Reactive Compensation and replacement of transmission line A4L, Alexander SS split for P-V analysis



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

Bus	Voltage [kV]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Marathon TS (230 kV)	248.6	250	220
Longlac TS (230 kV)	241.9		
Marathon TS (115 kV)	125.0	127	113
Longlac TS (115 kV)	125.7		
Jellicoe JCT	122.7		
Beardmore JCT	123.6		
Alexander SS	124.8		

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 Remedial Action Scheme. 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

<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>248.6</td><td>252.7 (+1.6%)</td><td>247.9 (-0.3%)</td><td rowspan="2">250</td><td rowspan="2">207</td><td rowspan="2">10</td></tr>
<tr><td>Longlac TS (230 kV)</td><td>241.9</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Marathon TS (115 kV)</td><td>125.0</td><td>127.0 (+1.6%)</td><td>122.9 (-1.7%)</td><td rowspan="5">127</td><td rowspan="5">108</td><td rowspan="5">10</td></tr>
<tr><td>Longlac TS (115 kV)</td><td>125.7</td><td>118.1 (-6.0%)</td><td>118.1 (-6.0%)</td></tr>
<tr><td>Jellicoe JCT</td><td>122.7</td><td>116.1 (-5.4%)</td><td>115.9 (-5.5%)</td></tr>
<tr><td>Beardmore JCT</td><td>123.6</td><td>118.8 (-3.9%)</td><td>118.5 (-4.1%)</td></tr>
<tr><td>Alexander SS</td><td>124.8</td><td>125.0 (+0.2%)</td><td>124.6 (-0.2%)</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 -25 MVar tertiary connected reactor 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.

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.

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

Scheme. 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 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.

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 Remedial Action Scheme 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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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

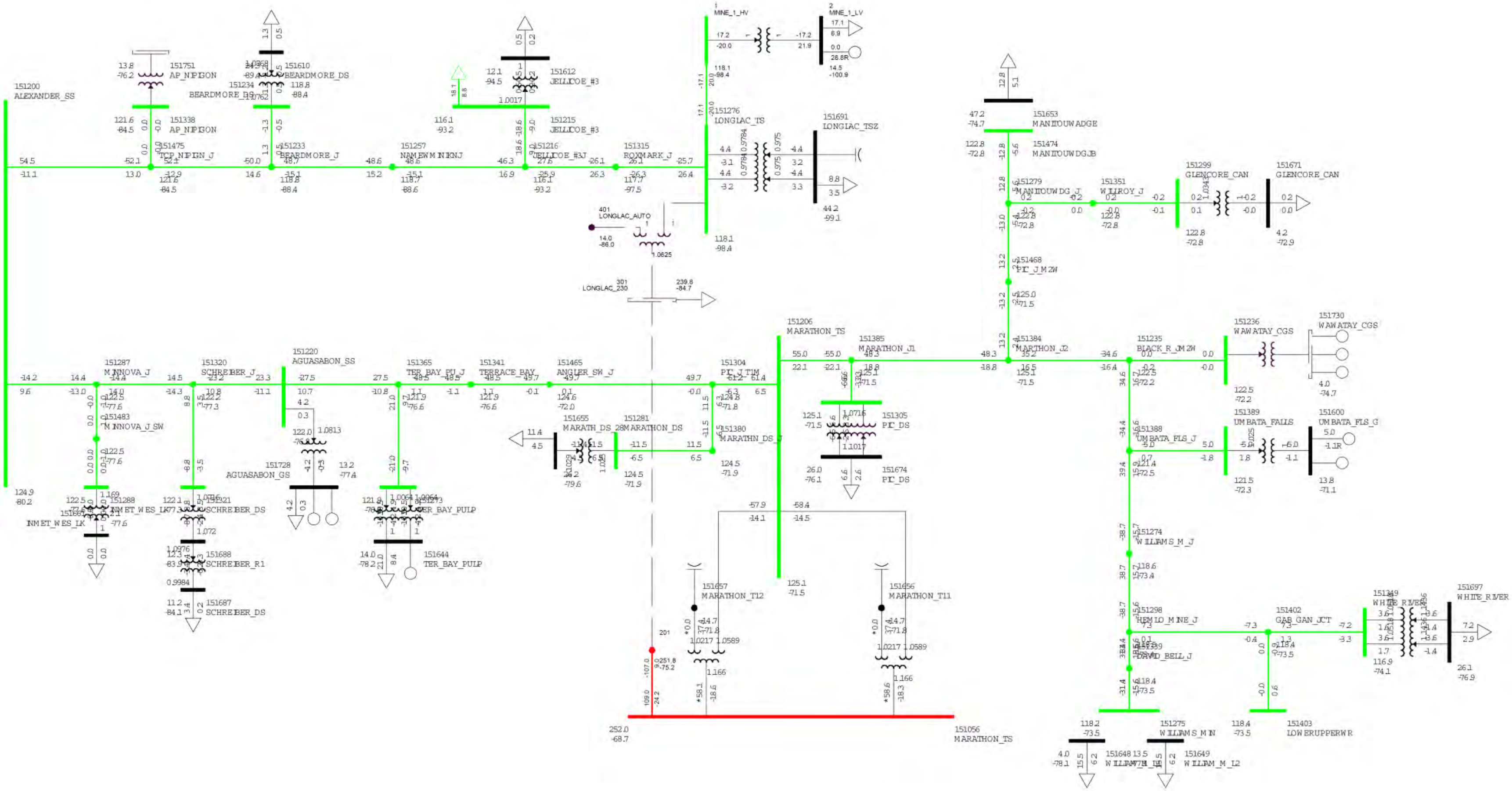


Figure C-9: With +40 MVar Reactive Compensation and new 230 kV single-circuit "West of Marathon" transmission line, post-contingency load flow plot post-ULTC with Marathon capacitor switched out

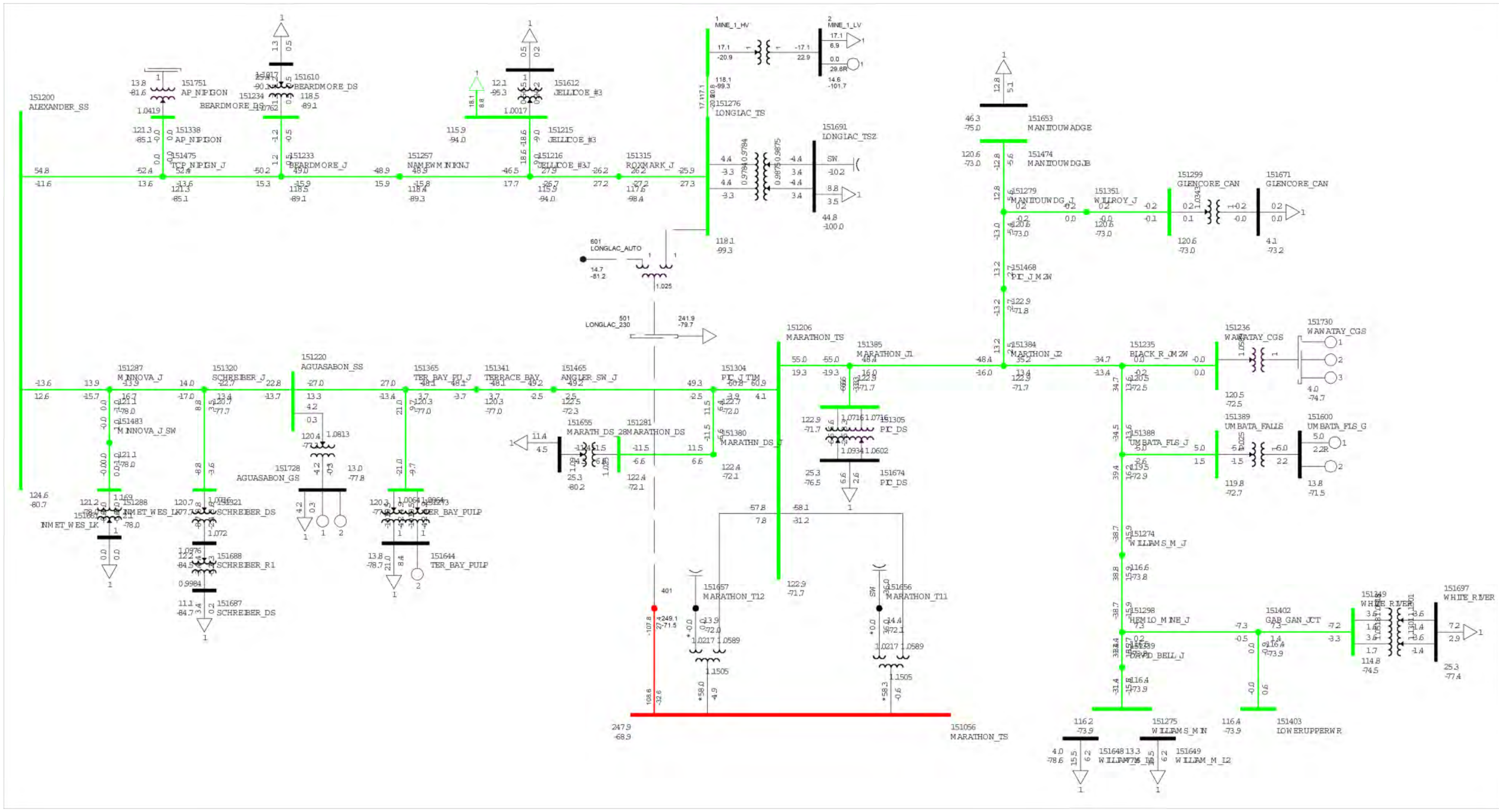
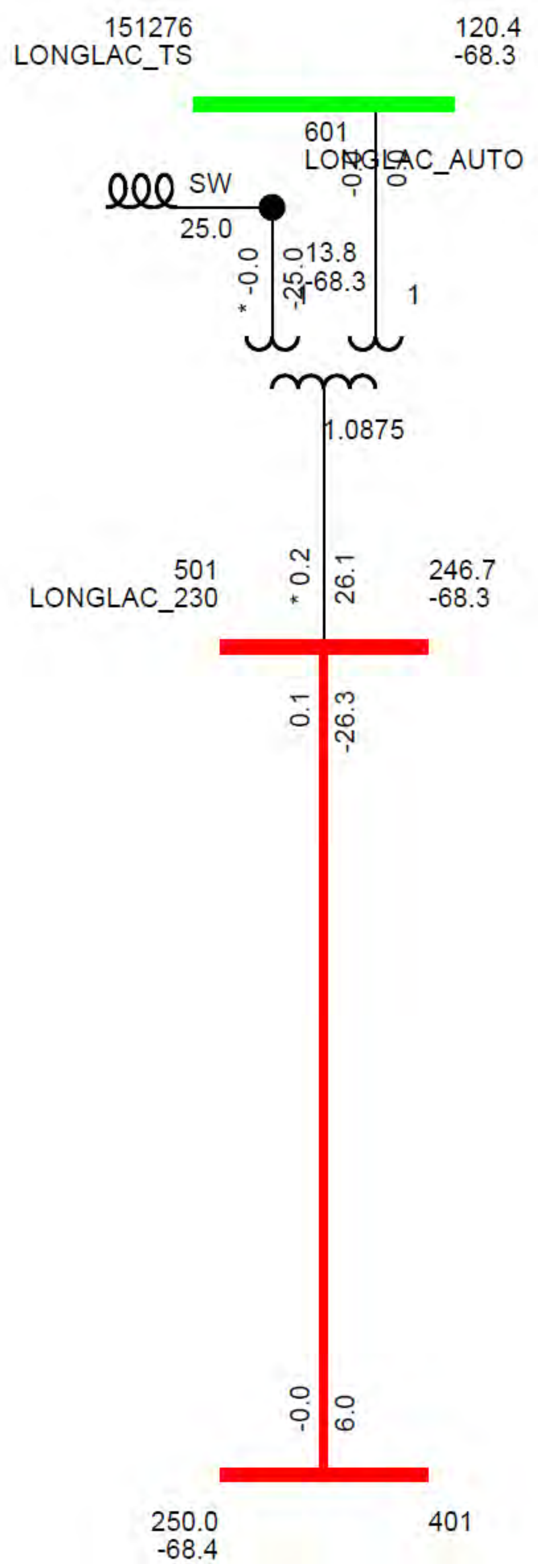


Figure C-10: New 230 kV single-circuit "West of Marathon" transmission line no load test with -25 MVar tertiary reactor



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

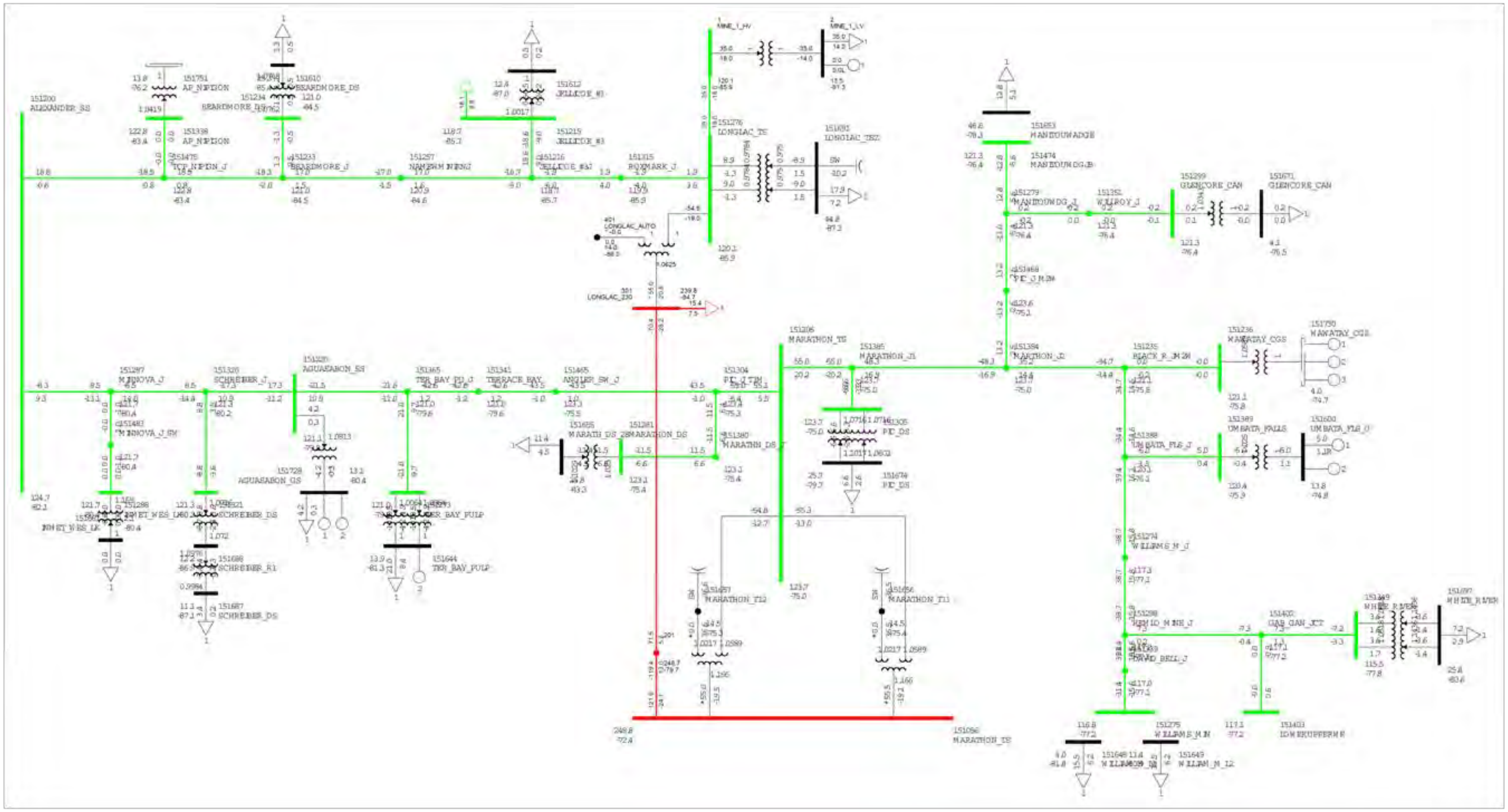


Figure C-12: With +40 MVar Reactive Compensation and new 230 kV single-circuit "East of Nipigon" transmission line, post-contingency load flow plot pre-ULTC

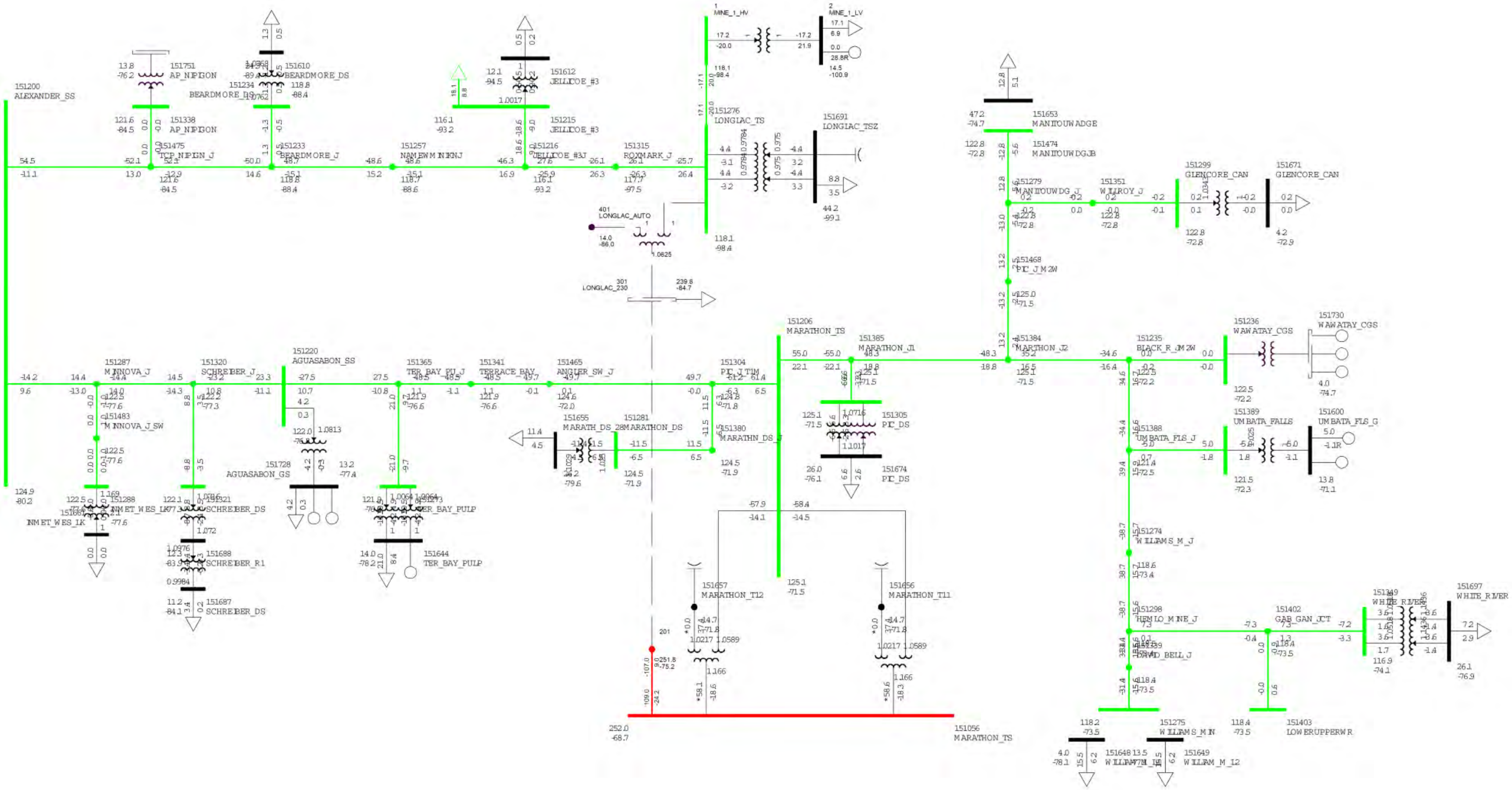


Figure C-13: With +40 MVar Reactive Compensation and new 230 kV single-circuit "East of Nipigon" transmission line, post-contingency load flow plot post-ULTC with Marathon capacitor switched out

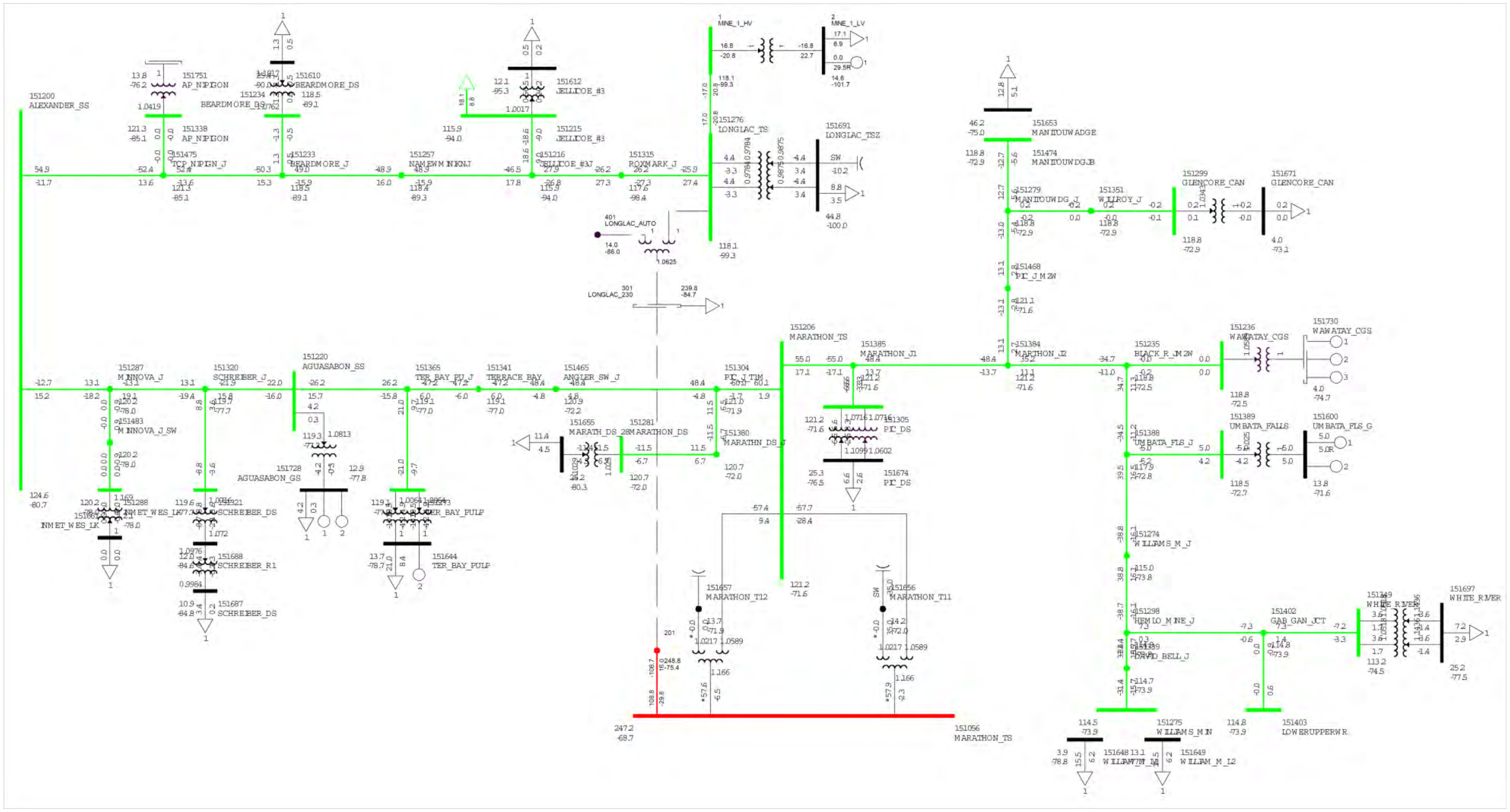
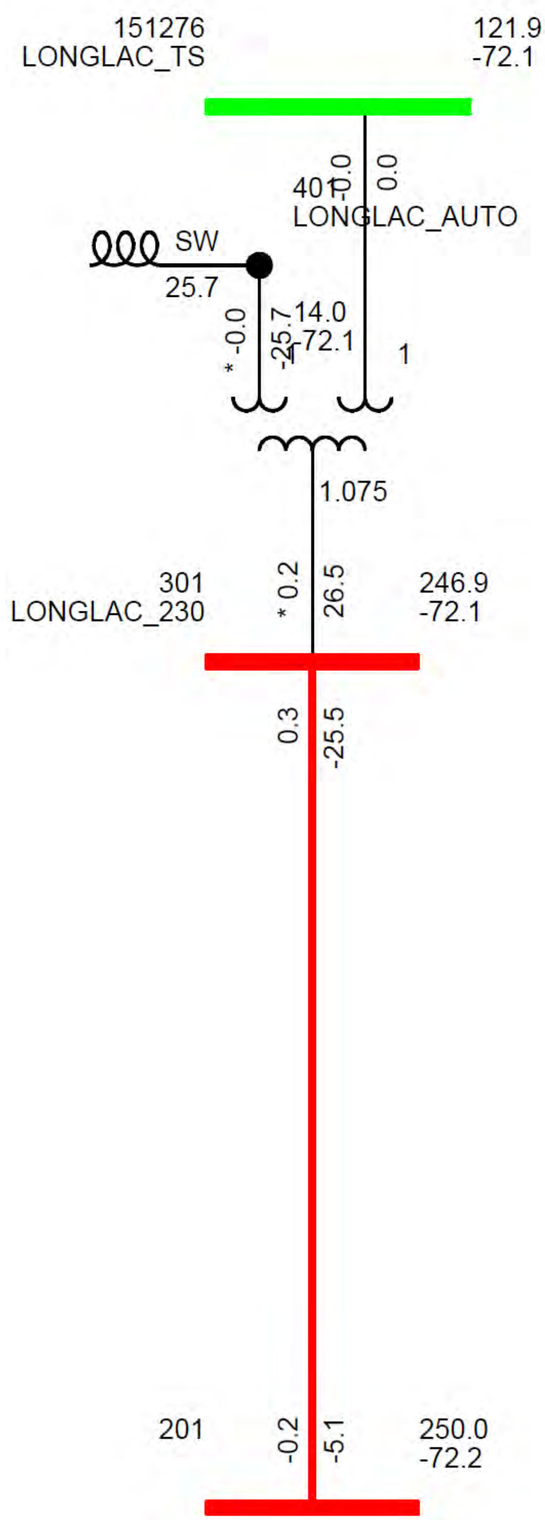


Figure C-14: New 230 kV single-circuit "East of Nipigon" transmission line no load test with -25 MVar tertiary reactor



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

<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>247.3</td><td rowspan="2">250</td><td rowspan="2">220</td></tr>
<tr><td>Longlac TS (230 kV)</td><td>238.5</td></tr>
<tr><td>Marathon TS (115 kV)</td><td>125.8</td><td rowspan="9">127</td><td rowspan="9">113</td></tr>
<tr><td>Longlac TS (115 kV)</td><td>123.5</td></tr>
<tr><td>Jellicoe JCT</td><td>121.1</td></tr>
<tr><td>Beardmore JCT</td><td>122.6</td></tr>
<tr><td>Alexander SS</td><td>124.8</td></tr>
<tr><td>#84</td><td>120.5</td></tr>
<tr><td>#86</td><td>119.7</td></tr>
<tr><td>Manitouwadge JCT</td><td>121.3</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. 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 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

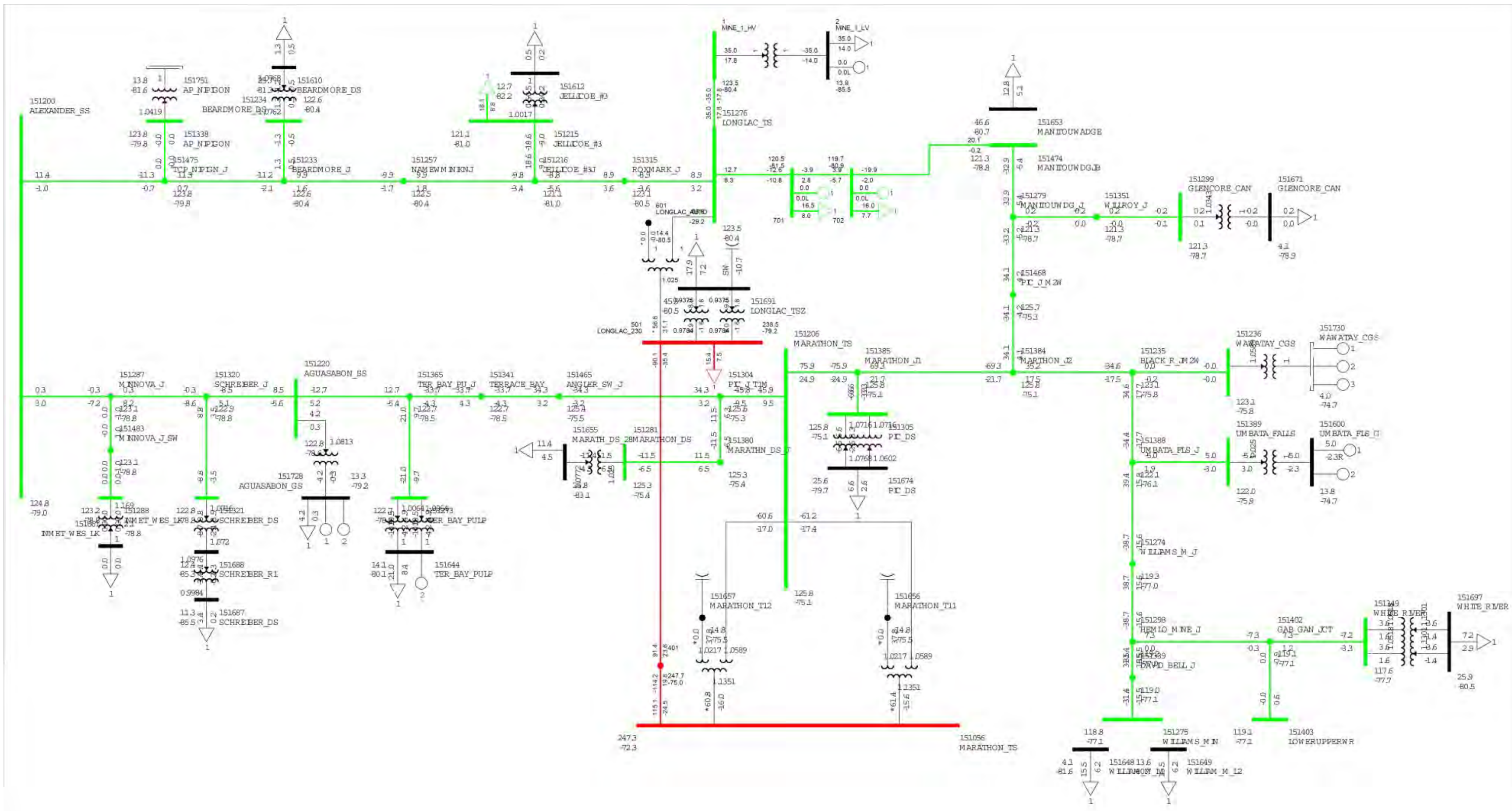


Figure C-16: With +40 MVar Reactive Compensation, new 230 kV single-circuit "West of Marathon" transmission line, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, post-contingency load flow plot pre-ULTC

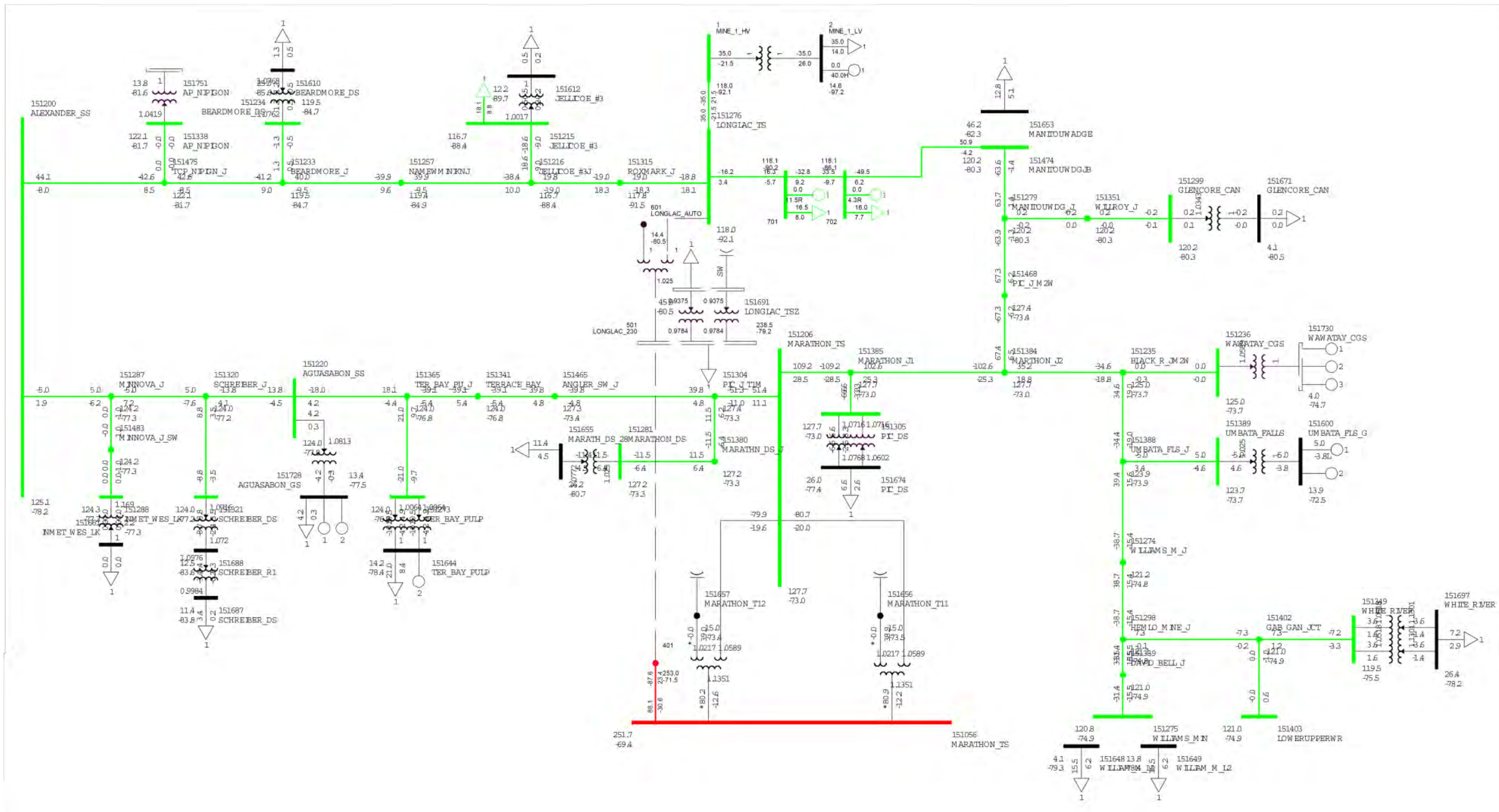


Figure C-17: With +40 MVar Reactive Compensation, new 230 kV single-circuit "West of Marathon" transmission line, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, post-contingency load flow plot post-ULTC

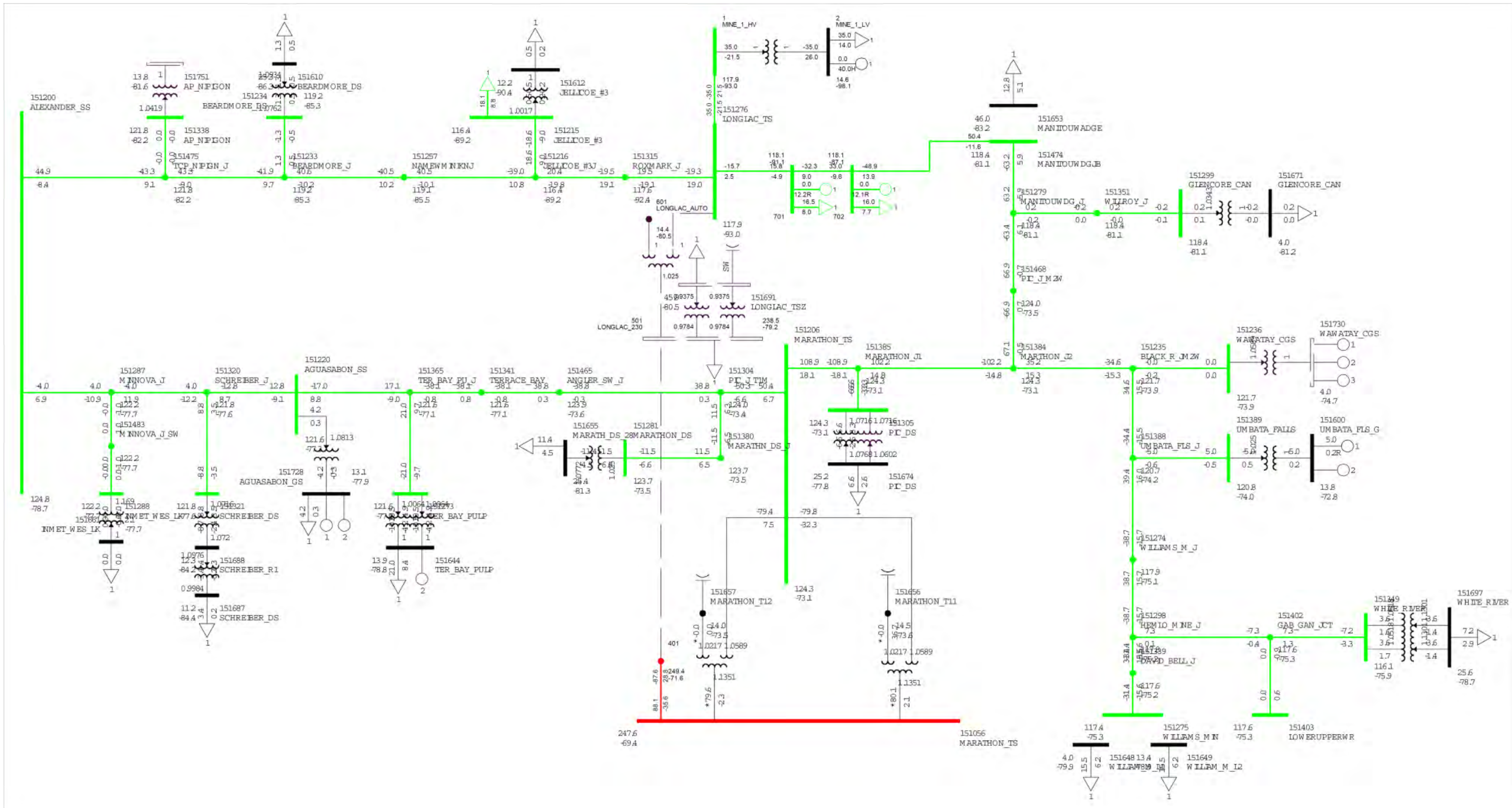


Figure C-18: New 230 kV single-circuit "West of Marathon" transmission line and new 115 kV single-circuit Longlac to Manitouwadge transmission line -25 MVar tertiary and 2x +/- 15 MVar SVCs, no load test

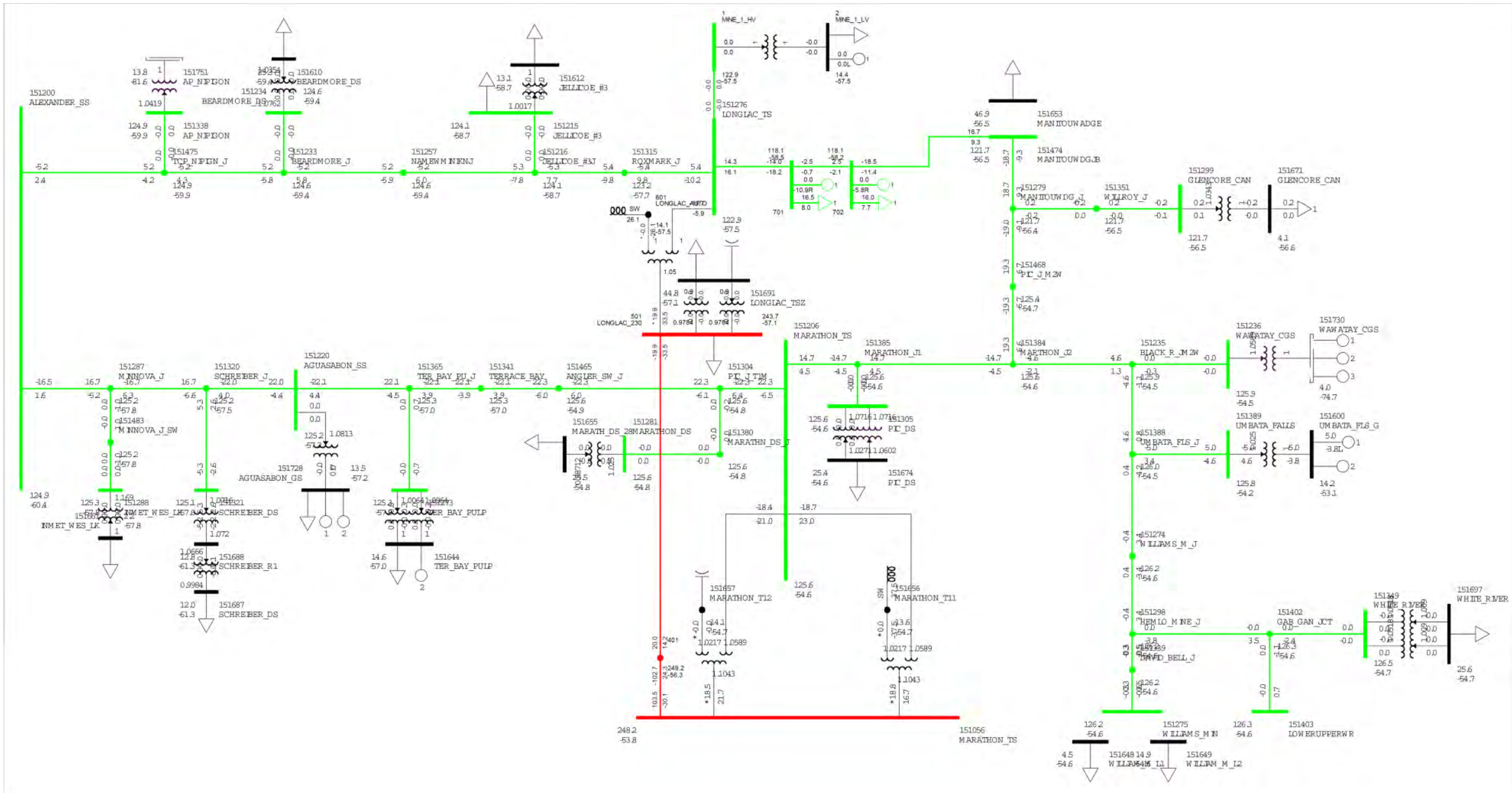


Figure C-19: With +40 MVar Reactive Compensation, new 230 kV single-circuit "East of Nipigon" transmission line, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, pre-contingency load flow plot

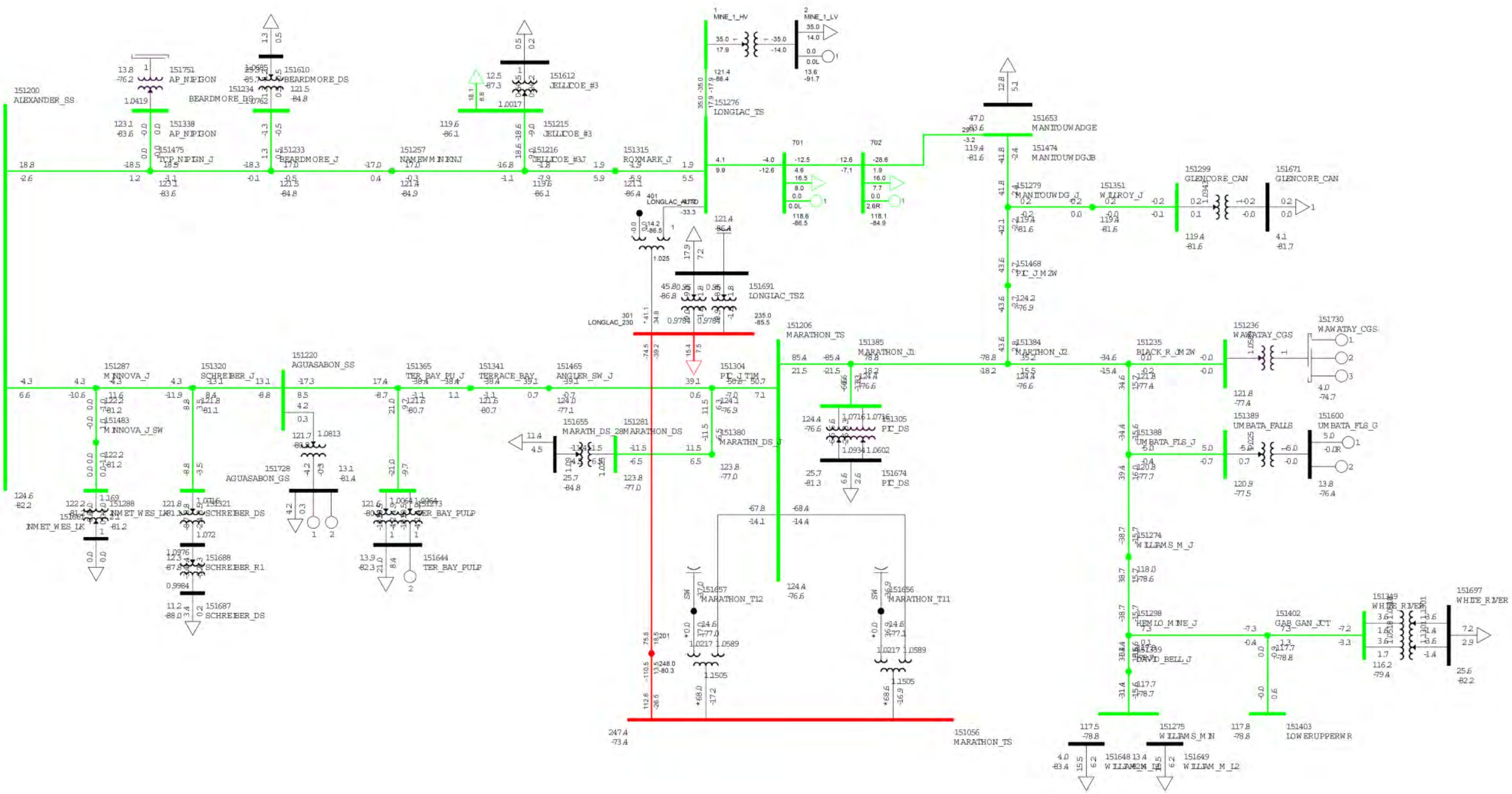


Figure C-20: With +40 MVar Reactive Compensation, new 230 kV single-circuit “East of Nipigon” transmission line, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, post-contingency load flow plot pre-ULTC

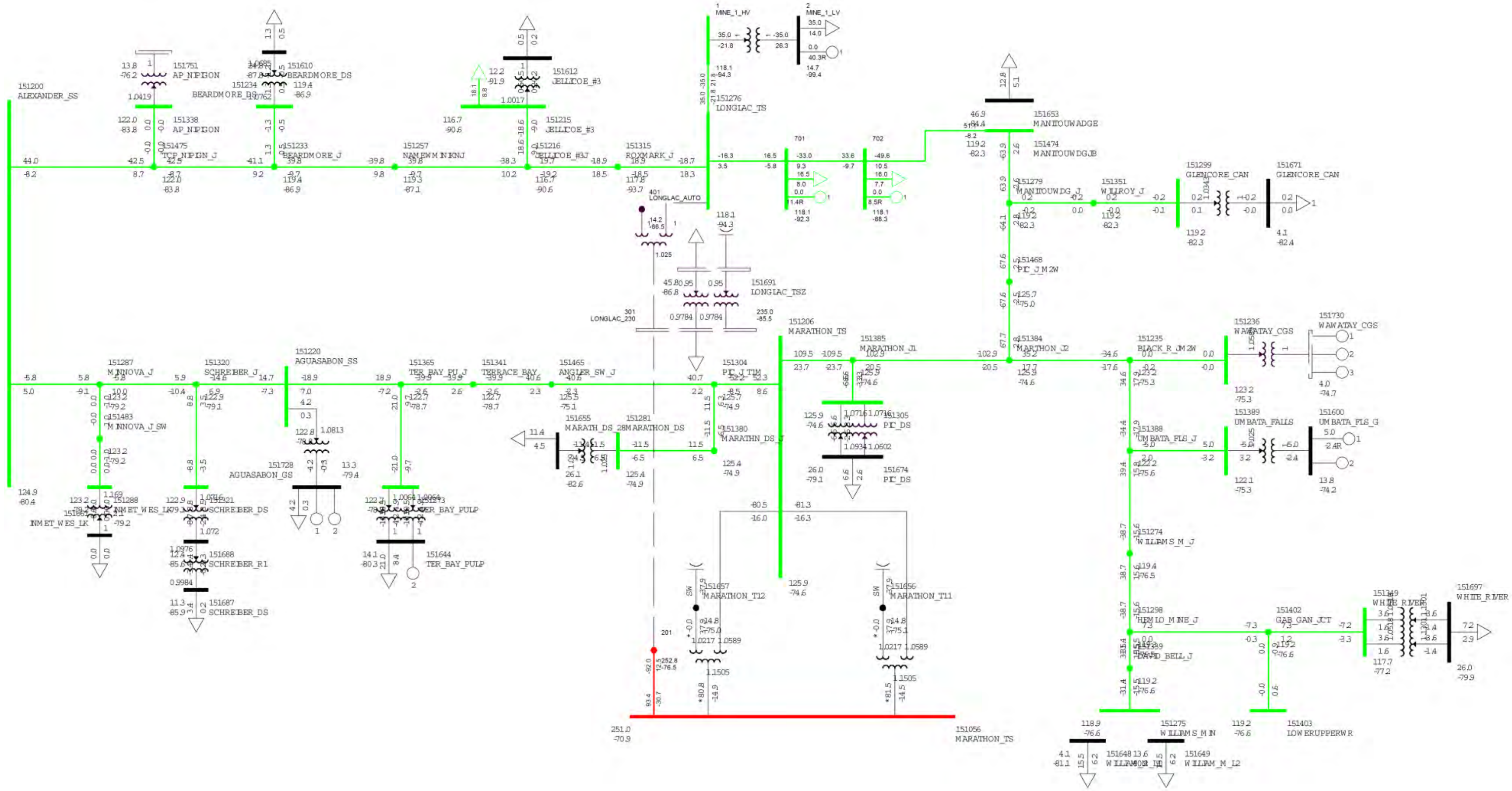


Figure C-21: With +40 MVar Reactive Compensation, new 230 kV single-circuit "East of Nipigon" transmission line, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, post-contingency load flow plot post-ULTC

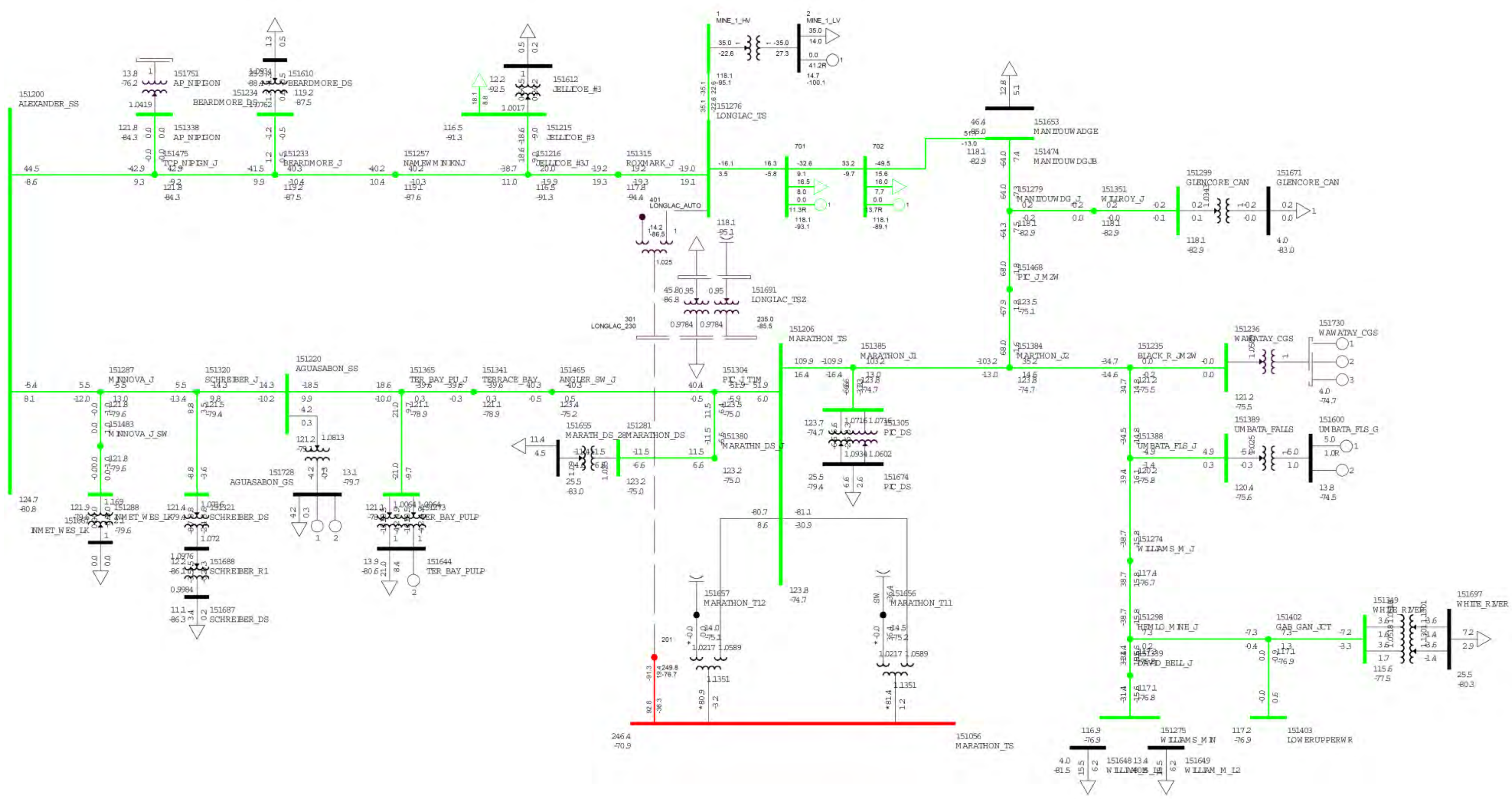
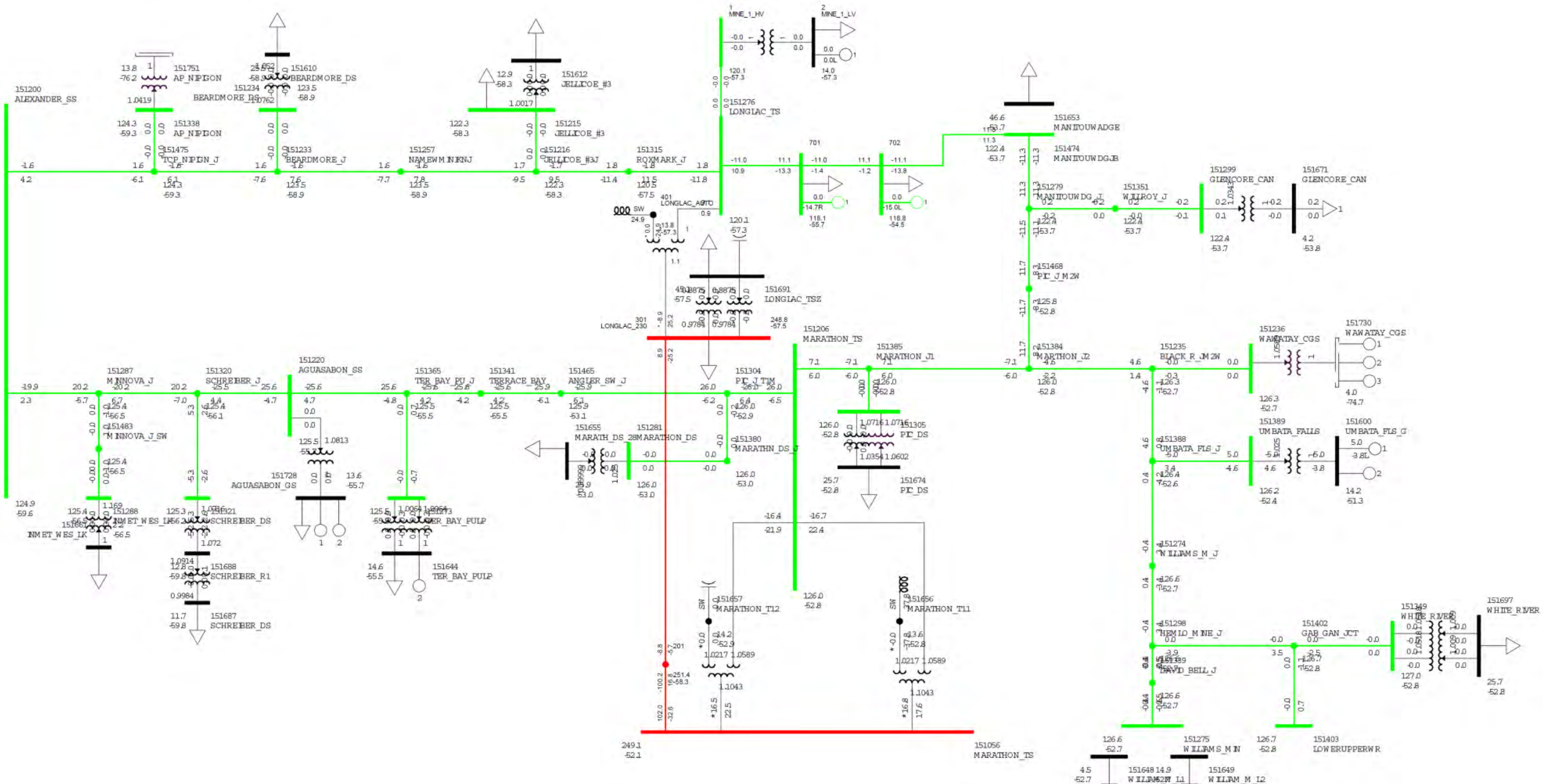


Figure C-22: New 230 kV single-circuit "East of Nipigon" transmission line and new 115 kV single-circuit Longlac to Manitouwadge transmission line -25 MVar tertiary and 2x +/- 15 MVar SVCs, no load test



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

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)	246.8	255.0	249.0	250	207	10
Marathon TS (115 kV)	125.5	131.0	126.1	127	108	10
Longlac TS	118.1	118.1	118.1			
Jellicoe JCT	117.1	116.4	116.1			
Beardmore JCT	119.7	119.0	118.7			
Alexander SS	124.0	124.7	124.2			
#84	118.1	118.1	118.1			
#86	118.1	118.1	118.1			
Manitouwadge JCT	120.0	N/A	N/A			

* 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

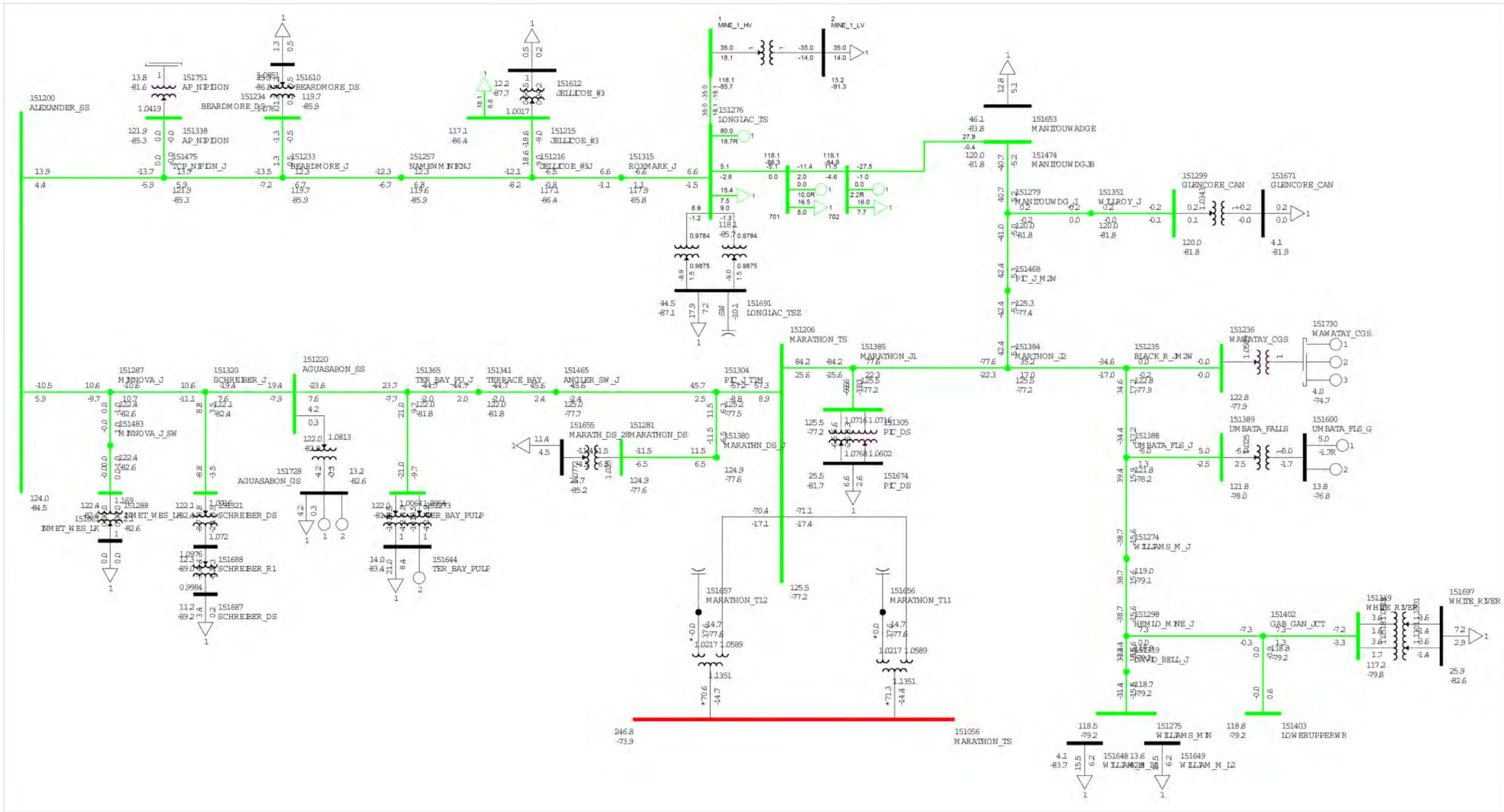


Figure C-24: With a new generating plant connected to Longlac TS outputting 80 MW, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, post-contingency load flow plot pre-ULTC

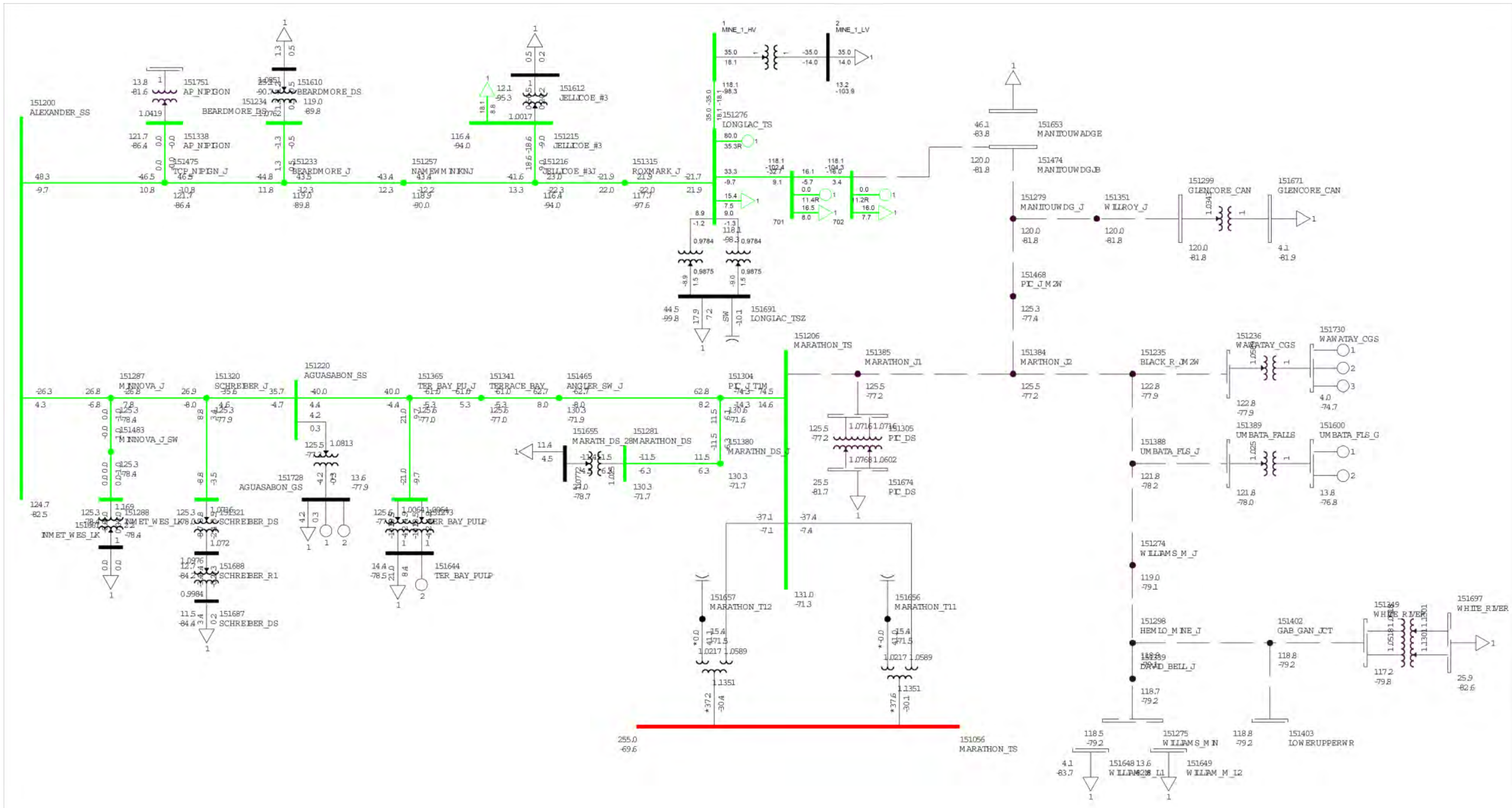
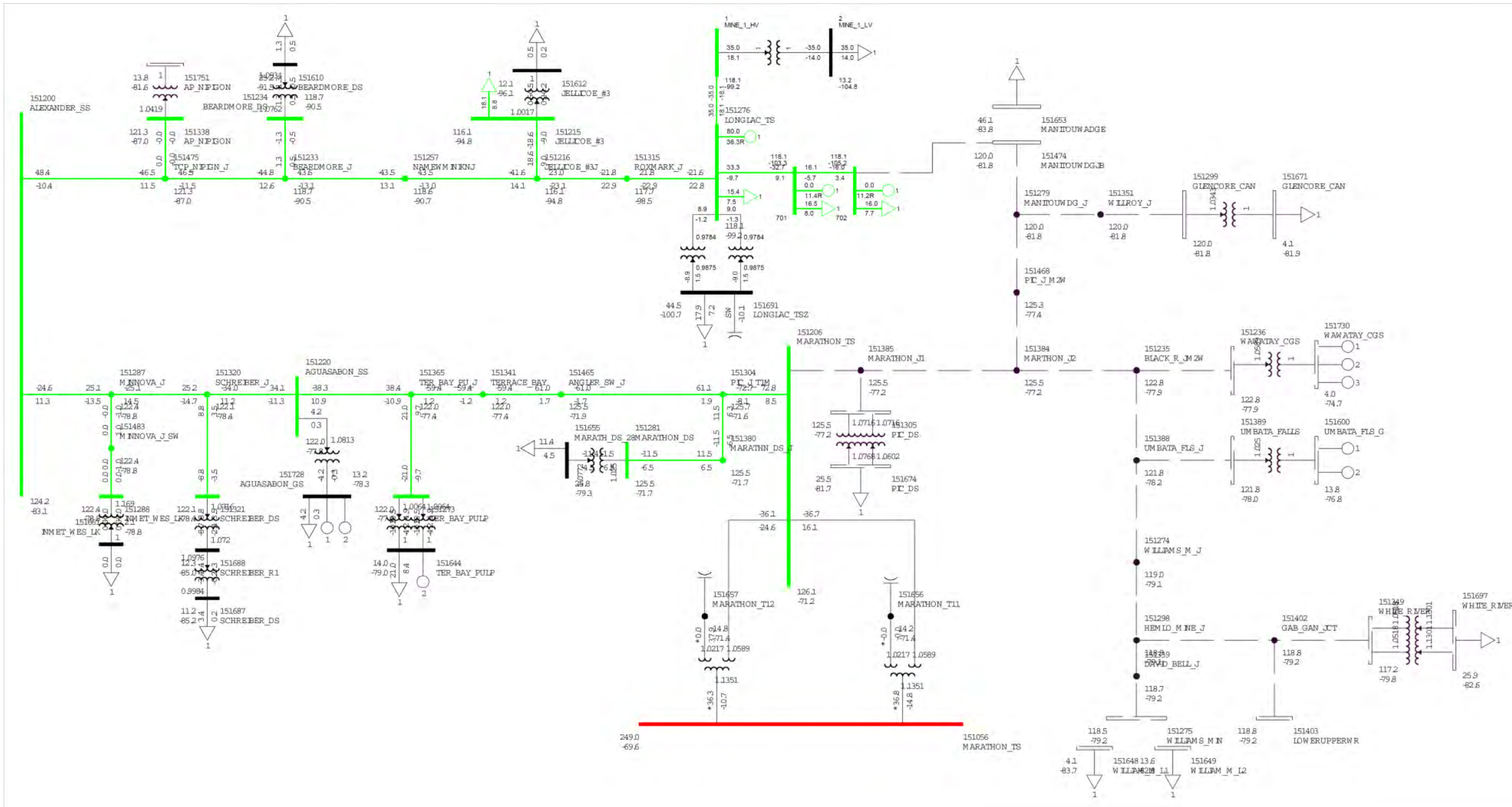


Figure C-25: With a new generating plant connected to Longlac TS outputting 80 MW, new 115 kV single-circuit Longlac to Manitouwadge transmission line, 2x +/- 15 MVar SVCs, post-contingency load flow plot post-ULTC



- 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 with dual-fuel capability is $2,752/kW
- 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 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

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[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

Greenstone-Marathon IRRP

Appendix D: Economic Analysis of Near-term Options

Appendix D: Economic Analysis of Near-term 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 with dual-fuel capability 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 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
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
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
Cumulative PV	-	-	-	-	0.4	0.7	1.0	1.4	1.7	2.0	2.3	2.5	2.8	3.1	3.3	3.5	3.8	4.0	4.2	4.4	4.6

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	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	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	2.1
Avoided System Gen Cost	-	-	-	-	(1.9)	(1.9)	(2.2)	(2.3)	(2.3)	(2.3)	(2.3)	(2.2)	(2.3)	(2.3)	(2.4)	(2.4)	(2.4)	(2.3)	(2.3)	(2.3)	(2.3)
Total Annual Gx Cost	-	-	-	-	59.4	1.9	1.6	1.5	1.5	1.5	1.5	1.6	1.5	1.6	1.5	1.4	1.4	1.5	1.5	1.5	1.5
Annual Amortized cost	-	-	-	-	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	5.6	5.6
Cumulative PV of Amortized cost	-	-	-	-	4.8	9.5	13.9	18.2	22.3	26.3	30.1	33.8	37.3	40.7	44.0	47.1	50.1	53.0	55.8	58.5	61.1

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 with dual-fuel capability 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 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	-	-	-	-	172.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed O&M	-	-	-	-	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
Variable O&M	-	-	-	-	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
Fuel Cost	-	-	-	-	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	12.8
Avoided System Gen Cost	-	-	-	-	(12.9)	(12.9)	(14.9)	(15.1)	(15.4)	(15.1)	(15.4)	(14.7)	(15.2)	(15.0)	(15.6)	(15.7)	(15.9)	(15.3)	(15.3)	(15.3)	(15.3)
Total Annual Gx Cost	-	-	-	-	178.8	6.2	4.2	4.0	3.7	4.0	3.7	4.5	3.9	4.1	3.6	3.4	3.3	3.8	3.8	3.8	3.8
Annual Amortized cost	-	-	-	-	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6
Cumulative PV of Amortized cost	-	-	-	-	15.1	29.5	43.5	56.9	69.7	82.1	94.0	105.5	116.5	127.1	137.2	147.0	156.4	165.5	174.2	182.5	190.6

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	-	-	-	-	0.6	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	0.6
Total Annual Cost	-	-	-	-	62.2	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
Annual Amortized Cost	-	-	-	-	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Cumulative PV	-	-	-	-	3.0	5.8	8.6	11.2	13.7	16.2	18.5	20.8	23.0	25.0	27.1	29.0	30.8	32.6	34.3	36.0	37.6

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 with dual-fuel capability 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 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:

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[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	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	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	-	-	-	-	-	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	6.0	6.0
Cumulative PV	-	-	-	-	-	5.1	10.0	14.7	19.2	23.6	27.8	31.8	35.7	39.4	43.0	46.4	49.7	52.9	56.0	58.9	61.7	64.5

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	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	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	-	-	-	-	-	6.5	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	6.5
Cumulative PV	-	-	-	-	-	5.6	10.9	16.0	21.0	25.7	30.3	34.7	38.9	43.0	46.9	50.6	54.2	57.7	61.0	64.2	67.3	70.3

[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)

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[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	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	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	-	-	-	-	-	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	-	-	-	-	-	12.1	23.8	35.0	45.8	56.2	66.2	75.8	85.0	93.9	102.4	110.6	118.5	126.0	133.3	140.3	147.1	153.6

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	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	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	-	-	-	-	-	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1
Cumulative PV	-	-	-	-	-	12.1	23.7	34.9	45.7	56.0	65.9	75.5	84.7	93.5	102.0	110.2	118.1	125.6	132.9	139.9	146.6	153.0

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 with dual-fuel capability is \$2,752/kW
- 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 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	-	-	-	-	-	-	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Cumulative PV	-	-	-	-	-	-	7.7	15.1	22.2	29.1	35.7	42.0	48.1	53.9	59.6	65.0	70.2	75.2	80.0	84.6	89.1	93.3

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
Variable O&M	-	-	-	-	-	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	3.7
Fuel Cost	-	-	-	-	-	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	20.8
Avoided System Gen Cost	-	-	-	-	-	(23.2)	(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	-	-	-	-	-	305.1	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	-	-	-	-	-	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
Cumulative PV of Amortized cost	-	-	-	-	-	19.6	38.5	56.7	74.2	91.0	107.1	122.6	137.6	151.9	165.7	179.0	191.8	204.0	215.8	227.2	238.1	248.6

[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 with dual-fuel capability 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 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	-	-	-	-	-	172.6	230.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed O&M	-	-	-	-	-	4.0	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
Variable O&M	-	-	-	-	-	2.3	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
Fuel Cost	-	-	-	-	-	12.8	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Avoided System Gen Cost	-	-	-	-	-	(18.7)	(29.1)	(33.3)	(33.8)	(34.5)	(33.8)	(34.4)	(32.9)	(34.0)	(33.6)	(34.8)	(35.1)	(35.4)	(34.2)	(34.2)	(34.2)	(34.2)
Total Annual Gx Cost	-	-	-	-	-	173.0	257.5	23.1	22.7	22.0	22.6	22.1	23.6	22.5	22.9	21.7	21.4	21.1	22.3	22.3	22.3	22.3
Annual Amortized cost	-	-	-	-	-	49.1	49.1	49.1	49.1	49.1	49.1	49.1	49.1	49.1	49.1	49.1	49.1	49.1	49.1	49.1	49.1	49.1
Cumulative PV of Amortized cost	-	-	-	-	-	42.0	82.4	121.3	158.6	194.5	229.0	262.3	294.2	324.9	354.4	382.8	410.1	436.3	461.5	485.8	509.1	531.6

D.8 Interim Gas Generation

D.8.1 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 with dual-fuel capability 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 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
- Linear depreciation is assumed

D.8.2 Methodology

To determine the annual NPV cost of carrying a interim gas generation option for the Geraldton mine, a 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
- After a single year, remaining asset value is assumed salvageable.
- Capital and annual costs and benefits were amortized over the life of the project
- NPV was calculated over the planning period (2015-2035)

D.8.3 Results

Figure D-13: Interim Gas Generation 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	-	-	-	-	-	57.5	(54.7)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed O&M	-	-	-	-	-	1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fuel Cost	-	-	-	-	-	2.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided System Gen Cost	-	-	-	-	-	(1.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Annual Gx Cost	-	-	-	-	-	59.4	(54.7)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual Amortized cost	-	-	-	-	-	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	0.5	0.5
Cumulative PV of Amortized cost	-	-	-	-	-	0.4	0.8	1.2	1.6	1.9	2.3	2.6	2.9	3.2	3.5	3.8	4.1	4.3	4.6	4.8	5.1	5.3

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Appendix E: A4L Performance Summary

Appendix E: Reliability Analysis of Greenstone Sub-system

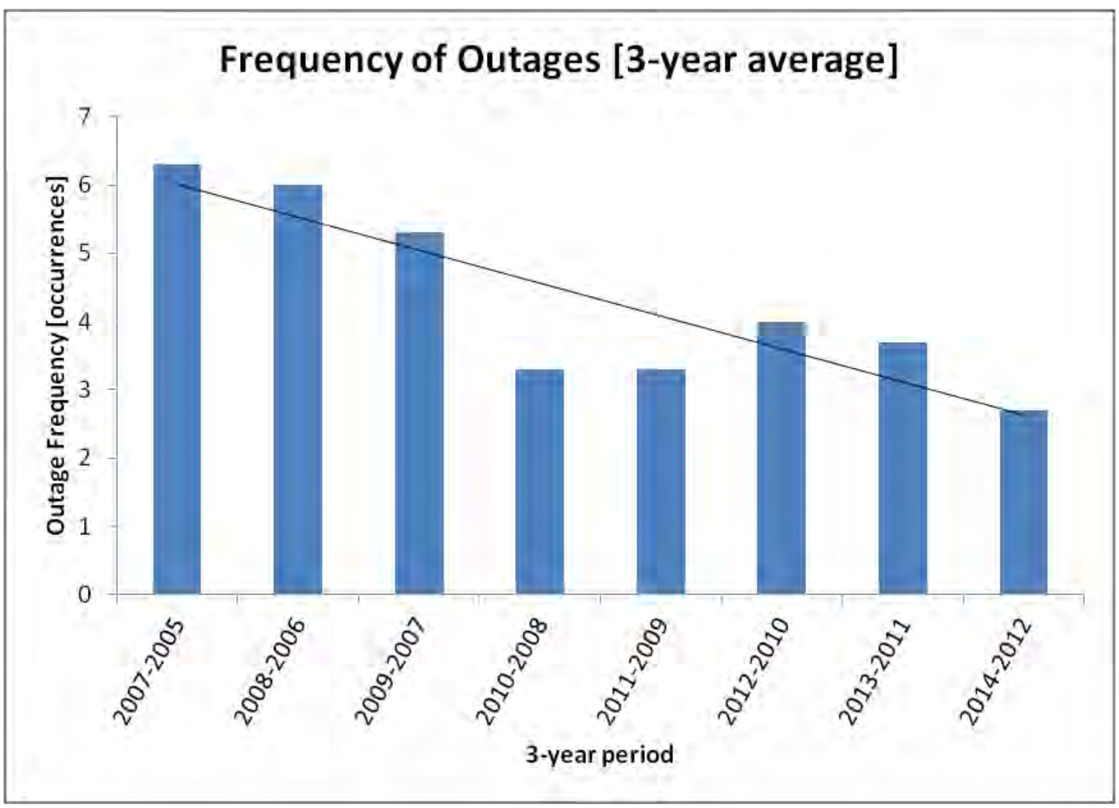
Under the Scenario A demand forecast, the LMC of the Greenstone sub-system is adequate to meet forecast demand. This appendix summarizes analysis of the past performance of circuit A4L, which supplies the Greenstone sub-system to determine if further reliability-based investments may be justified.

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.

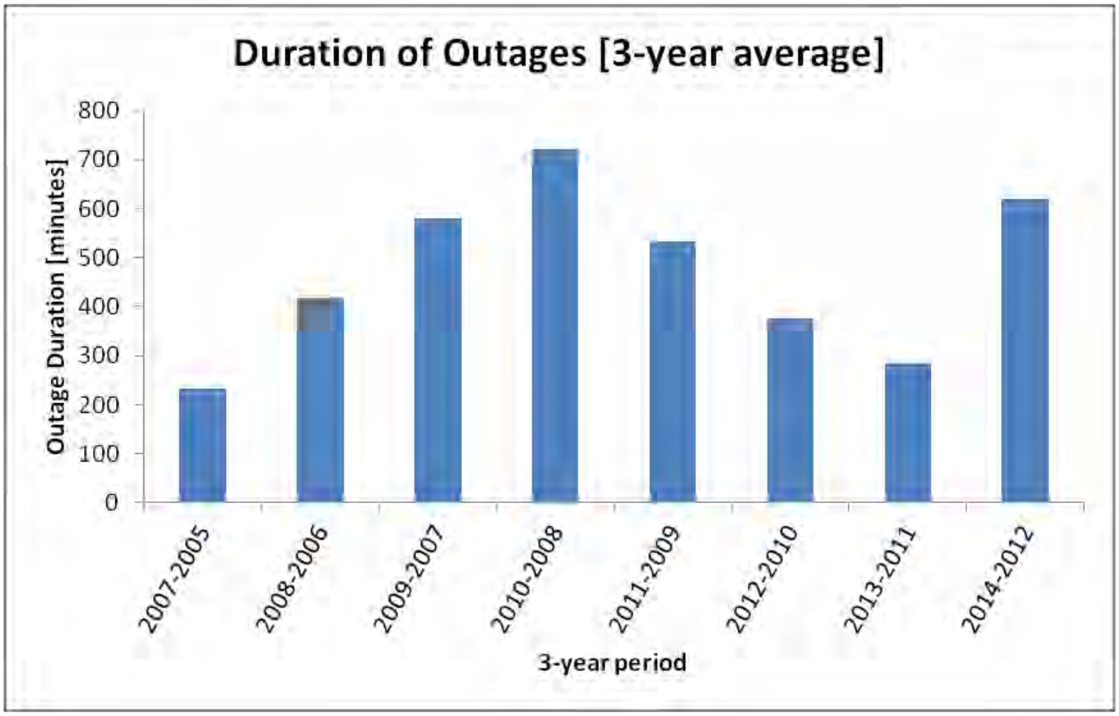
Figure E-1: Frequency of A4L Outages (3-year average)



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, in 2014 one incident of surge arrester failure occurred at 6:14 pm, and on March 8 2016 an incident of insulation failure occurred at 2:53 pm with multiple failed restoration attempts. 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

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[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.

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Appendix F: Studies to Establish Technical Performance of Medium- and Long-term Plan Elements

Appendix F: Studies to Establish Technical Performance of Medium- and Long-term Plan Elements

The following appendix summarizes power flow tests to support the technical performance of power system elements of the medium- and long-term plan horizons.

F.1 Supply to Beardmore Mine with 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

This section illustrates that Option C2 has sufficient margin to incorporate the Beardmore mine and that no further enhancements would be required.

F.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
- Scenario C 2035 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 F-1: 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 F-2: 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

F.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

F.1.3 Results – West of Marathon Route

All Elements In-Service Pre-contingency

Refer to Figure F-1 for load flow plot.

Table F-3: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
New 230 kV Line	880	243	28
Alexander SS x AP Nipigon JCT	310	71	23
AP Nipigon JCT x Beardmore JCT	260	73	28
Beardmore JCT x Jellicoe DS #3 JCT	260	42	16
Jellicoe DS #3 JCT x Roxmark JCT	260	58	22
Roxmark JCT x Longlac TS	260	54	21
Longlac TS x #84	620	79	13
#84 x #86	620	34	6
#86 x Manitouwadge JCT	620	98	16
Manitouwadge JCT x Pic JCT	350	164	47
Pic JCT x Marathon TS	620	161	26

Table F-4: 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>246.4</td><td rowspan="2">250</td><td rowspan="2">220</td></tr>
<tr><td>Longlac TS (230 kV)</td><td>237.1</td></tr>
<tr><td>Marathon TS (115 kV)</td><td>125.3</td><td rowspan="8">127</td><td rowspan="8">113</td></tr>
<tr><td>Longlac TS (115 kV)</td><td>122.7</td></tr>
<tr><td>Jellicoe JCT</td><td>119.9</td></tr>
<tr><td>Beardmore JCT</td><td>121.1</td></tr>
<tr><td>Alexander SS</td><td>124.7</td></tr>
<tr><td>#84</td><td>119.7</td></tr>
<tr><td>#86</td><td>119.0</td></tr>
<tr><td>Manitouwadge JCT</td><td>120.5</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. The load flow results are tabulated below.

Refer to Figure F-2 for pre-ULTC load flow plot and Figure F-3 for post-ULTC load flow plot with capacitor switching at Marathon.

Table F-5: 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	231	75
AP Nipigon JCT x Beardmore JCT	260	230	89
Beardmore JCT x Jellicoe DS #3 JCT	260	202	78
Jellicoe DS #3 JCT x Roxmark JCT	260	144	56
Roxmark JCT x Longlac TS	260	137	53
Longlac TS x #84	790	84	11
#84 x #86	790	174	22
#86 x Manitouwadge JCT	790	260	33
Manitouwadge JCT x Pic JCT	350	321	92
Pic JCT x Marathon TS	790	321	41

Table F-6: 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)	246.4	251.3 (+2.0%)	247.2 (+0.3%)	250	207	10
Longlac TS (230 kV)	237.1	N/A	N/A			
Marathon TS (115 kV)	125.3	127.5 (+1.8%)	124.0 (-1.0%)	127	108	10
Longlac TS (115 kV)	122.7	117.5 (-4.2%)	117.4 (-4.3%)			
Jellicoe JCT	119.9	115.6 (-3.6%)	115.3 (-3.8%)			
Beardmore JCT	121.1	118.0 (-2.6%)	117.7 (-2.8%)			
Alexander SS	124.7	124.9 (0.2%)	124.6 (-0.1%)			
#84	119.7	118.1 (-1.3%)	118.1 (-1.3%)			
#86	119.0	118.1 (-0.8%)	118.1 (0.8%)			
Manitouwadge JCT	120.5	119.9 (-0.5%)	118.1 (-2.0%)			

* Capacitor switching at Marathon required to remain below 250 kV

F.1.4 Results – East of Nipigon Route

All Elements In-Service Pre-contingency

Refer to Figure F-4 for load flow plot.

Table F-7: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
New 230 kV Line	880	214	24
Alexander SS x AP Nipigon JCT	310	104	34
AP Nipigon JCT x Beardmore JCT	260	105	40
Beardmore JCT x Jellicoe DS #3 JCT	260	74	28
Jellicoe DS #3 JCT x Roxmark JCT	260	47	18
Roxmark JCT x Longlac TS	260	38	14
Longlac TS x #84	620	58	10
#84 x #86	620	70	11
#86 x Manitouwadge JCT	620	144	23
Manitouwadge JCT x Pic JCT	350	207	59
Pic JCT x Marathon TS	620	207	33

Table F-8: Voltage Analysis

Bus	Voltage [kV]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Marathon TS (230 kV)	246.9	250	220
Longlac TS (230 kV)	234.1		
Marathon TS (115 kV)	124.1	127	113
Longlac TS (115 kV)	120.9		
Jellicoe JCT	118.5		
Beardmore JCT	120.1		
Alexander SS	124.5		
#84	118.3		
#86	118.1		
Manitouwadge JCT	119.1		

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 F-5 for pre-ULTC load flow plot and Figure F-6 for post-ULTC load flow plot with capacitor switching at Marathon.

Table F-9: 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	227	73
AP Nipigon JCT x Beardmore JCT	260	226	87
Beardmore JCT x Jellicoe DS #3 JCT	260	198	76
Jellicoe DS #3 JCT x Roxmark JCT	260	142	54
Roxmark JCT x Longlac TS	260	134	52
Longlac TS x #84	790	91	12
#84 x #86	790	178	23
#86 x Manitouwadge JCT	790	259	33
Manitouwadge JCT x Pic JCT	350	320	92
Pic JCT x Marathon TS	790	320	41

Table F-10: 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)	246.9	250.6 (+1.5%)	246.0 (-0.4%)	250	207	10
Longlac TS (230 kV)	234.1	N/A	N/A			
Marathon TS (115 kV)	124.1	125.7 (+1.3%)	123.5 (-0.5%)	127	108	10
Longlac TS (115 kV)	120.9	118.1 (-2.3%)	118.1 (-2.3%)			
Jellicoe JCT	118.5	115.9 (-2.2%)	115.8 (-2.3%)			
Beardmore JCT	120.1	118.2 (-1.6%)	118.0 (-1.7%)			
Alexander SS	124.5	124.8 (+0.2%)	124.5 (+0.0%)			
#84	118.3	118.1 (-0.2%)	118.1 (-0.2%)			
#86	118.1	118.1 (+0.0%)	118.0 (-0.1%)			
Manitouwadge JCT	119.1	119.0 (-0.1%)	117.8 (-1.1%)			

* Capacitor switching at Marathon required to remain below 250 kV

.

F.1.5 Load Flow Plots

Figure F-1: Option C2 "West of Marathon" route option for 230 kV line, with 5 MW at Beardmore mine, pre-contingency load flow plot

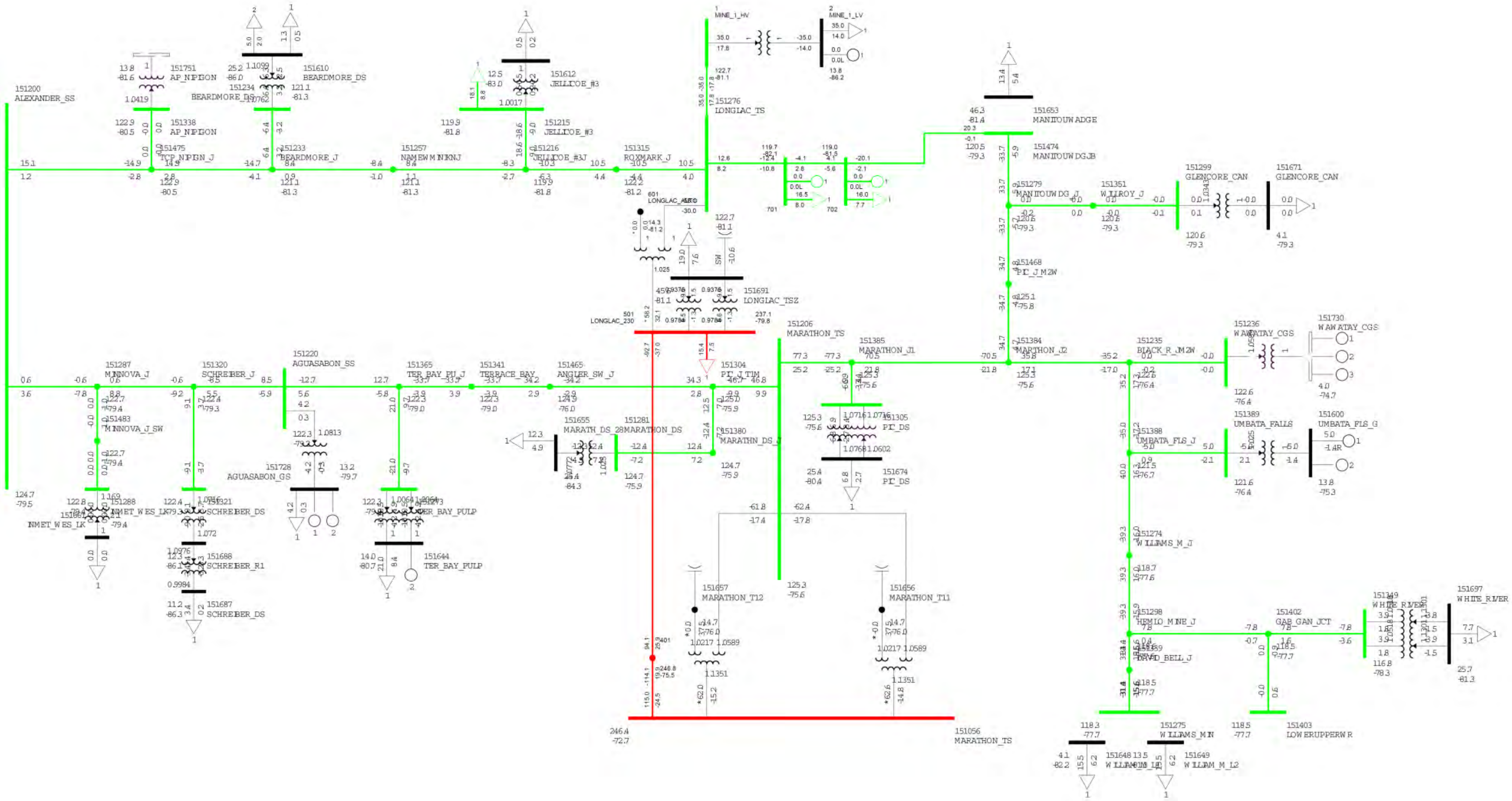


Figure F-2: Option C2 “West of Marathon” route option for 230 kV line, with 5 MW at Beardmore mine, post-contingency load flow plot pre-ULTC

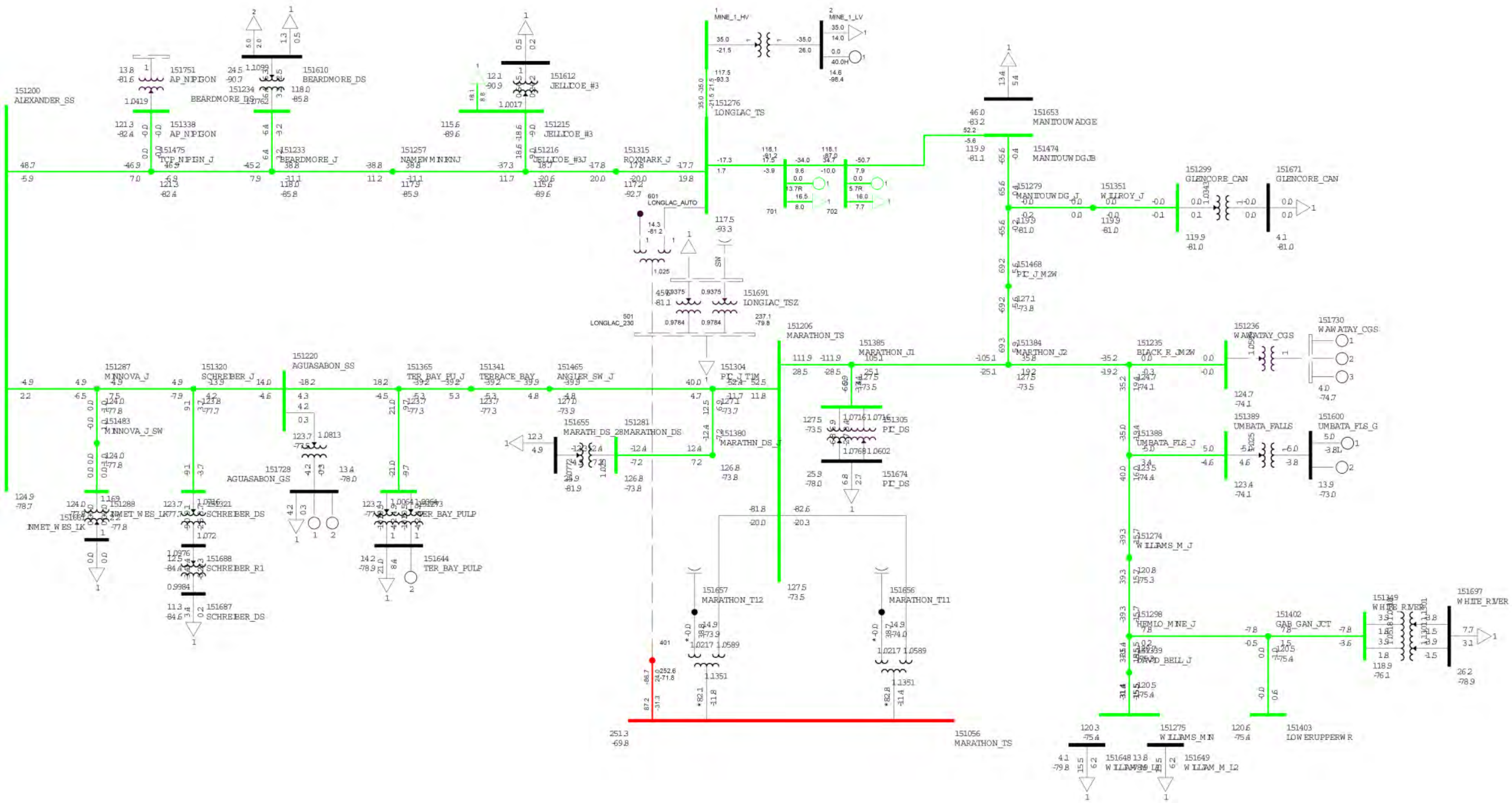


Figure F-3: Option C2 "West of Marathon" route option for 230 kV line, with 5 MW at Beardmore mine, post-contingency load flow plot post-ULTC

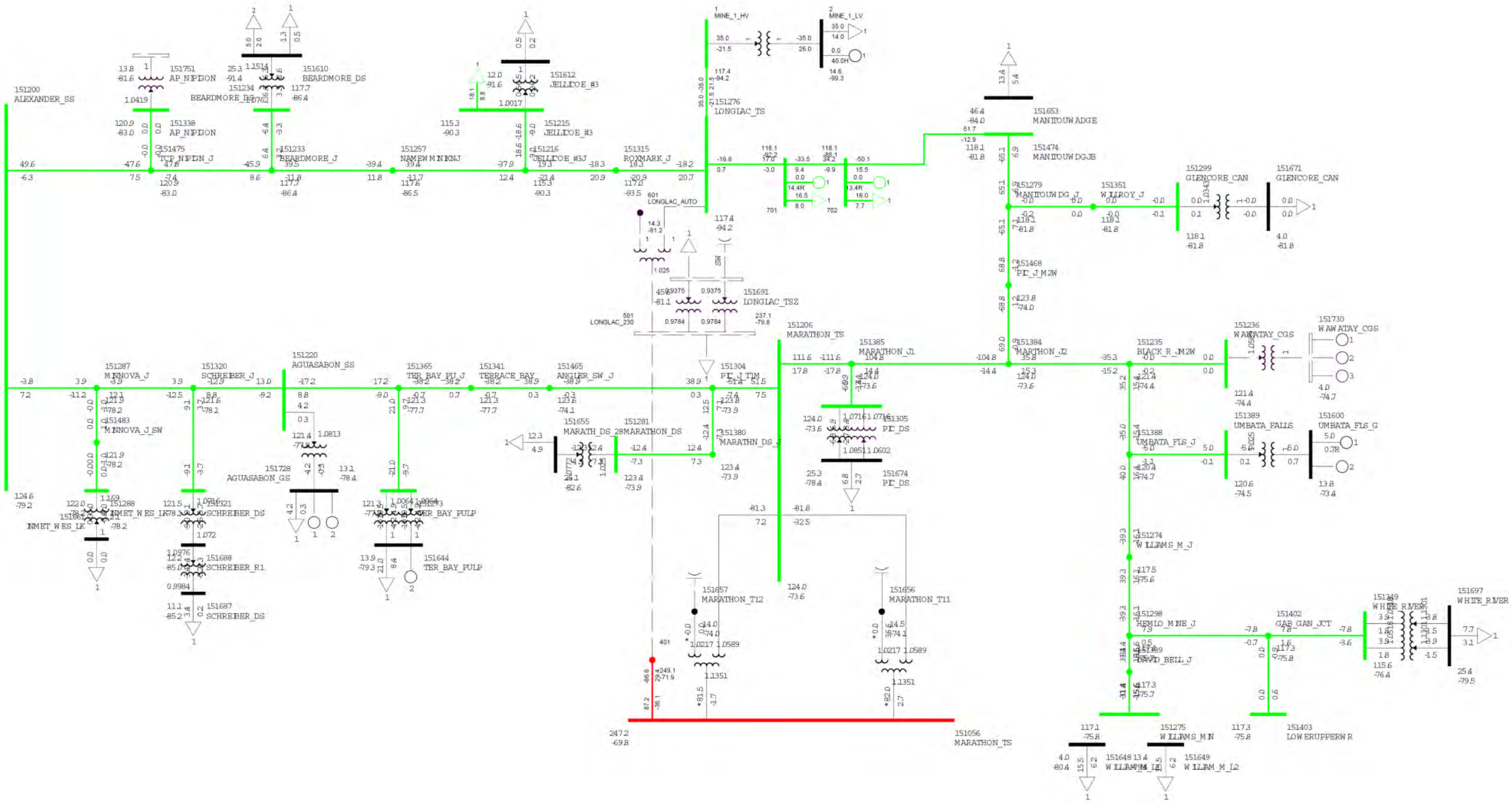


Figure F-4: Option C2 "East of Nipigon" route option for 230 kV line, with 5 MW at Beardmore mine, pre-contingency load flow plot

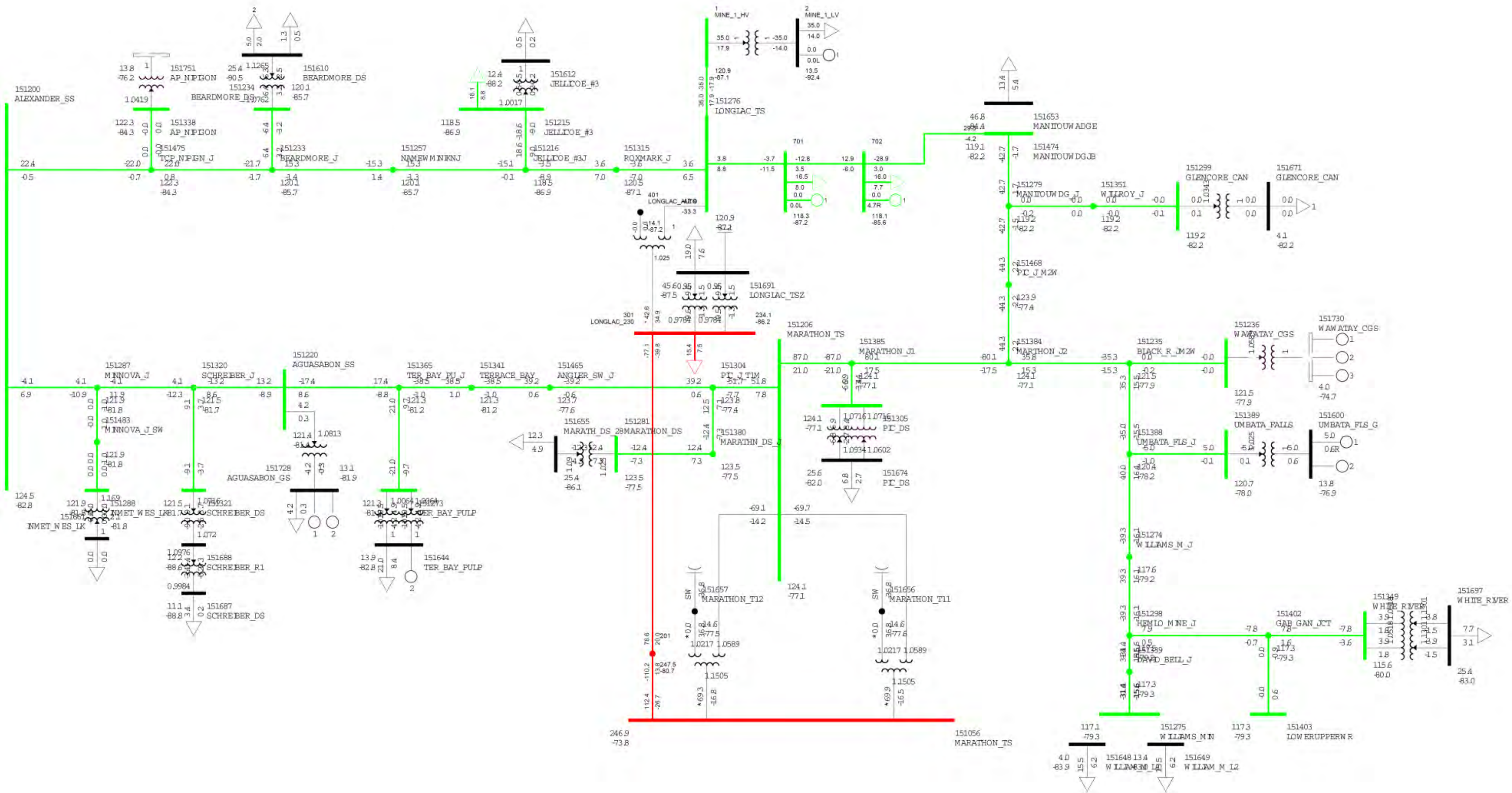


Figure F-5: Option C2 "East of Nipigon" route option for 230 kV line, with 5 MW at Beardmore mine, post-contingency load flow plot pre-ULTC

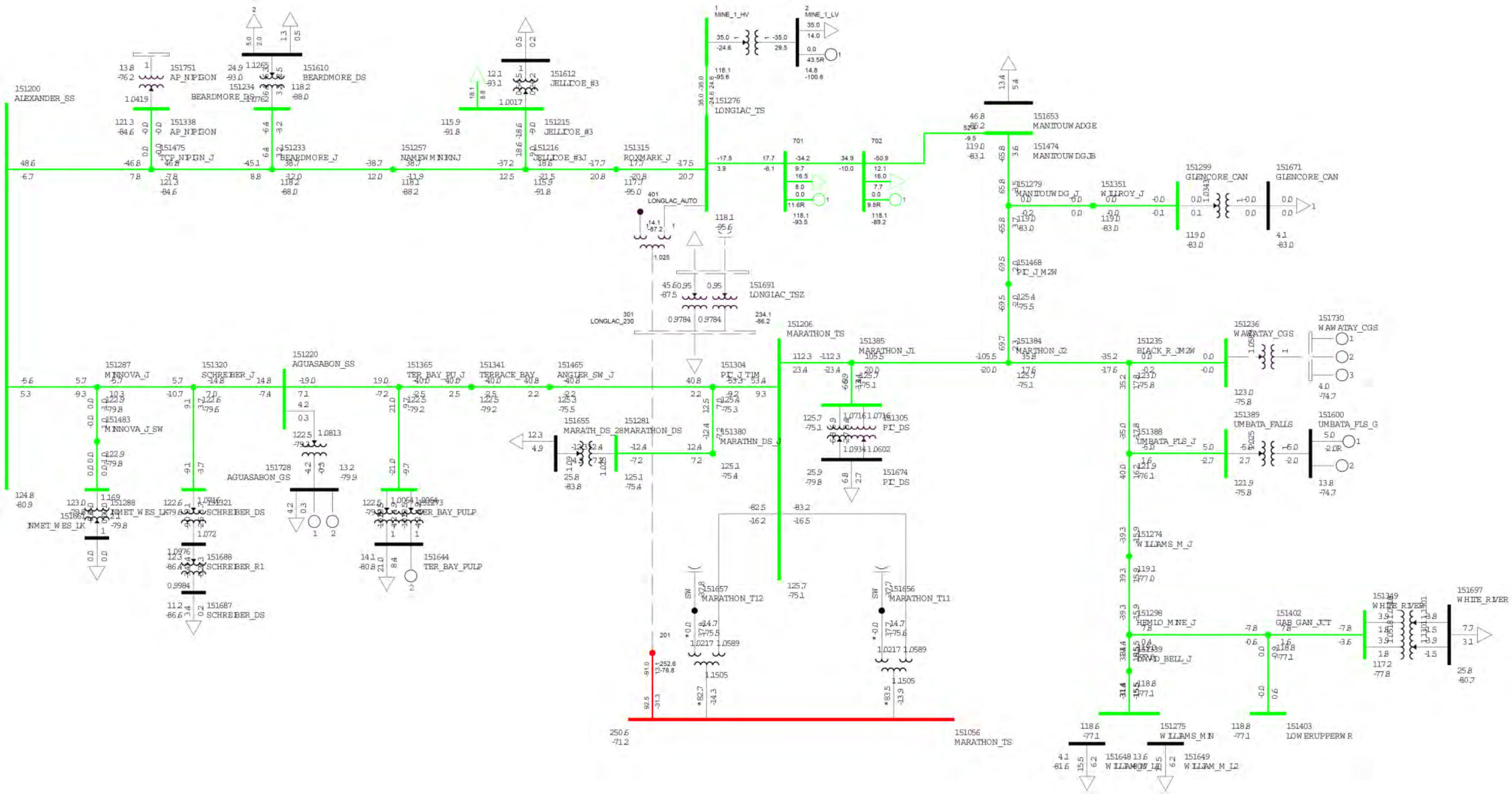
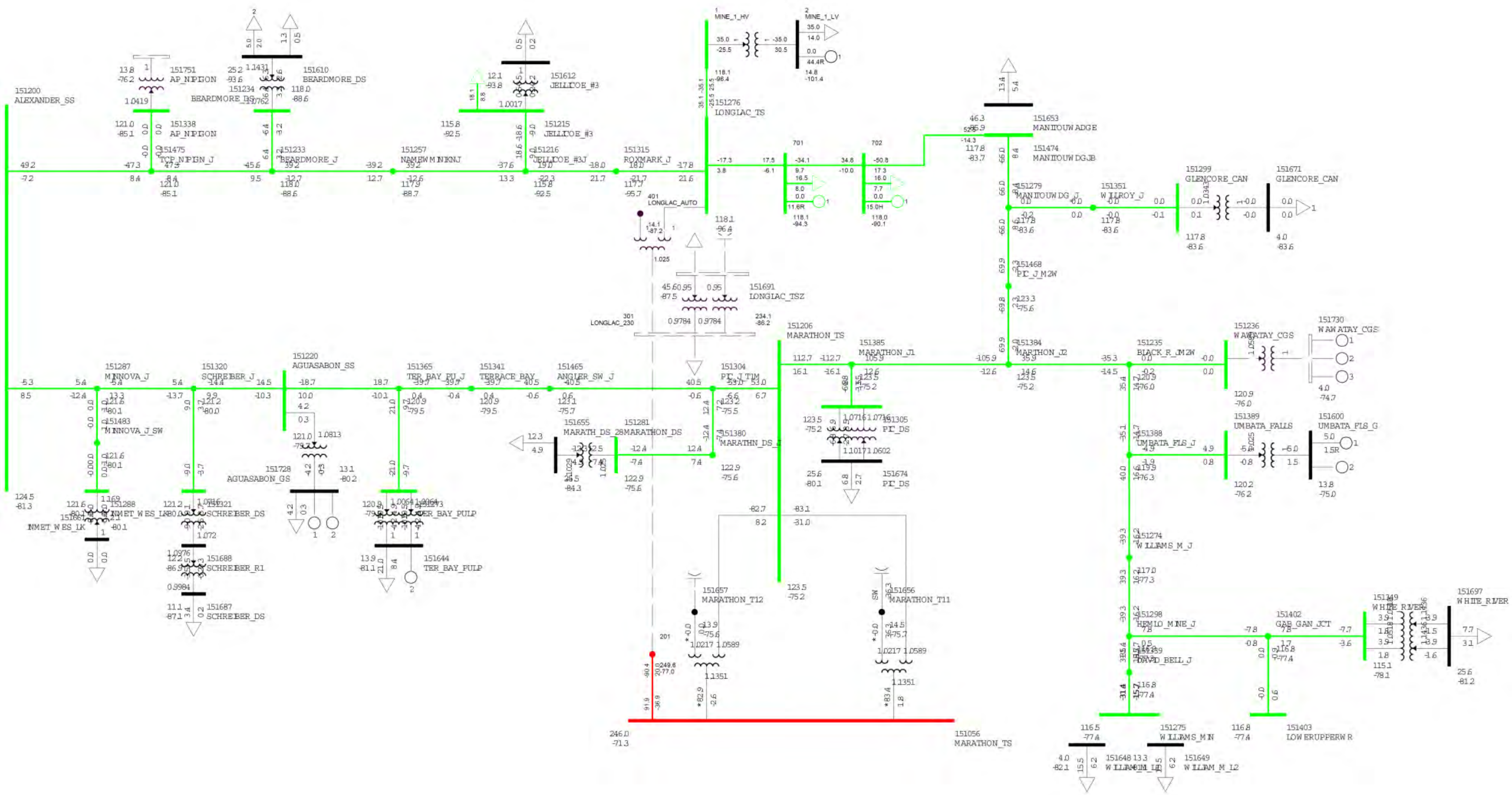


Figure F-6: Option C2 "East of Nipigon" route option for 230 kV line, with 5 MW at Beardmore mine, post-contingency load flow plot post-ULTC



F.2 Supply to Beardmore Mine with 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 RAS to account for low-probability high-consequence events

This section illustrates that Option B1 does not have sufficient margin to incorporate the Beardmore mine and that further enhancements would be required.

F.2.1 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 2035 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)

F.2.2 Methodology

- Assess system condition versus standards with all elements in-service pre-contingency. (Assessment of system condition versus standards considering the outage of a single element is accounted for by the assumption of one of the new gas-fired engines being out-of-service).

F.2.3 Results

All Elements In-Service Pre-contingency

Refer to Figure F-7 for load flow plot.

Table F-11: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
Alexander SS x AP Nipigon JCT	310	298	96
AP Nipigon JCT x Beardmore JCT	260	296	114
Beardmore JCT x Jellicoe DS #3 JCT	260	271	104
Jellicoe DS #3 JCT x Roxmark JCT	260	265	102
Roxmark JCT x Longlac TS	260	261	100

Table F-12: 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>124.7</td><td rowspan="4">127</td><td rowspan="4">113</td></tr>
<tr><td>Beardmore JCT</td><td>118.0</td></tr>
<tr><td>Jellicoe JCT</td><td>116.4</td></tr>
<tr><td>Longlac TS</td><td>115.5</td></tr>
</table>

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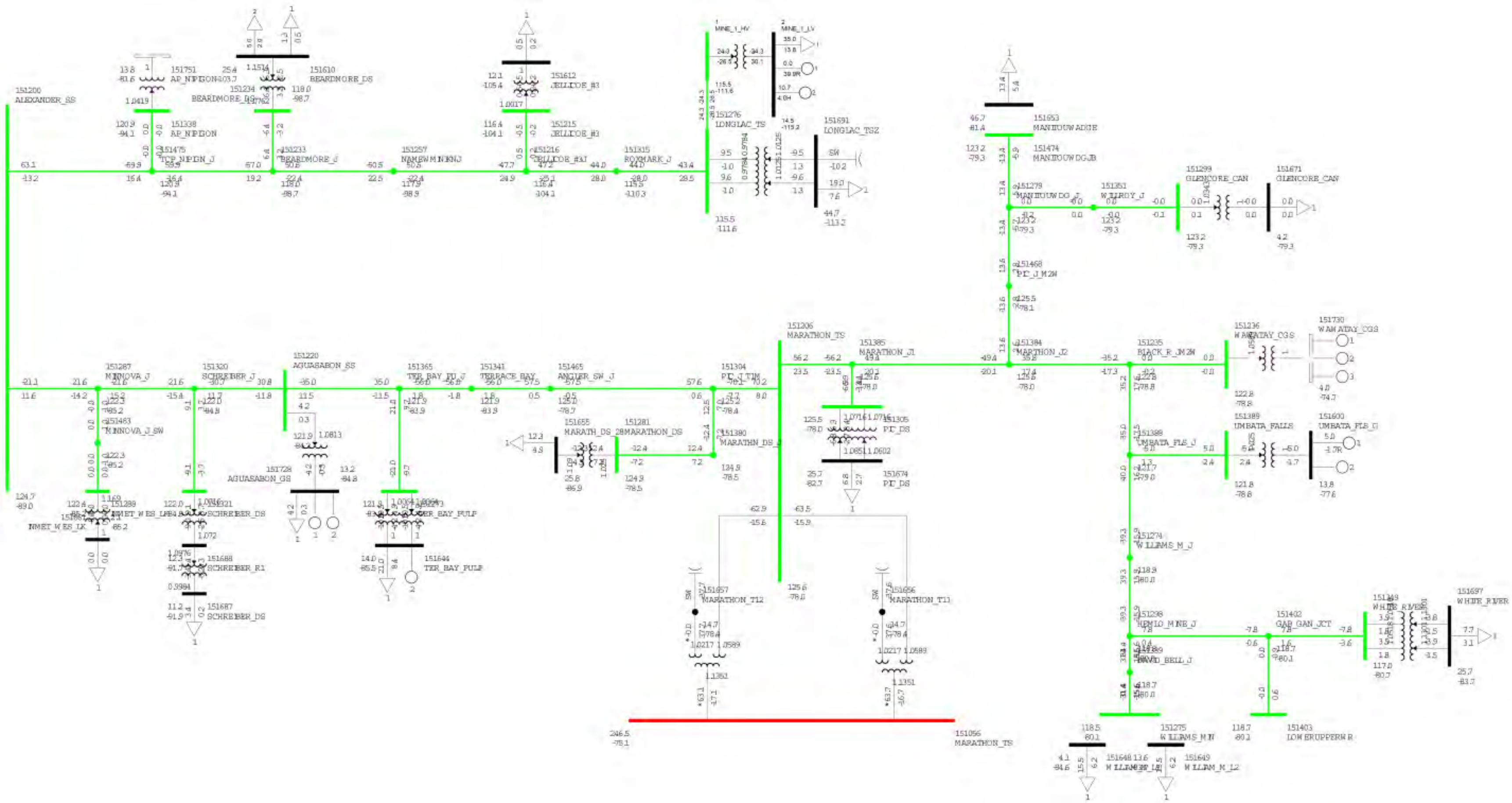
F.2.4 Load Flow Plots

Figure F-7: Option B1, with 5 MW at Beardmore mine, pre-contingency load flow plot



F.3 Supply to Beardmore Mine with 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 115 kV
- Replacing circuit A4L from Nipigon to Longlac with 477 kcmil conductors
- Installing a local RAS to account for low-probability high-consequence events

This section illustrates that Option B3 does not have sufficient margin to incorporate the Beardmore mine and that further enhancements would be required.

F.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 B 2035 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 F-13: 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

F.3.2 Methodology

- Assess system condition versus standards with all elements in-service pre-contingency. (Assessment of system condition versus standards considering the outage of a single element is not presented as it is less limiting that the scenario with all elements in-service).

F.3.3 Results

All Elements In-Service Pre-contingency

Refer to Figure F-8 for load flow plot.

Table F-14: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
Alexander SS x AP Nipigon JCT	310	320	103
AP Nipigon JCT x Beardmore JCT	620	319	51
Beardmore JCT x Jellicoe DS #3 JCT	620	290	47
Jellicoe DS #3 JCT x Roxmark JCT	620	286	46
Roxmark JCT x Longlac TS	620	283	46

Table F-15: Voltage Analysis

Bus	Voltage [kV]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Alexander SS	124.3	127	113
Beardmore JCT	117.6		
Jellicoe JCT	117.5		
Longlac TS	118.1		

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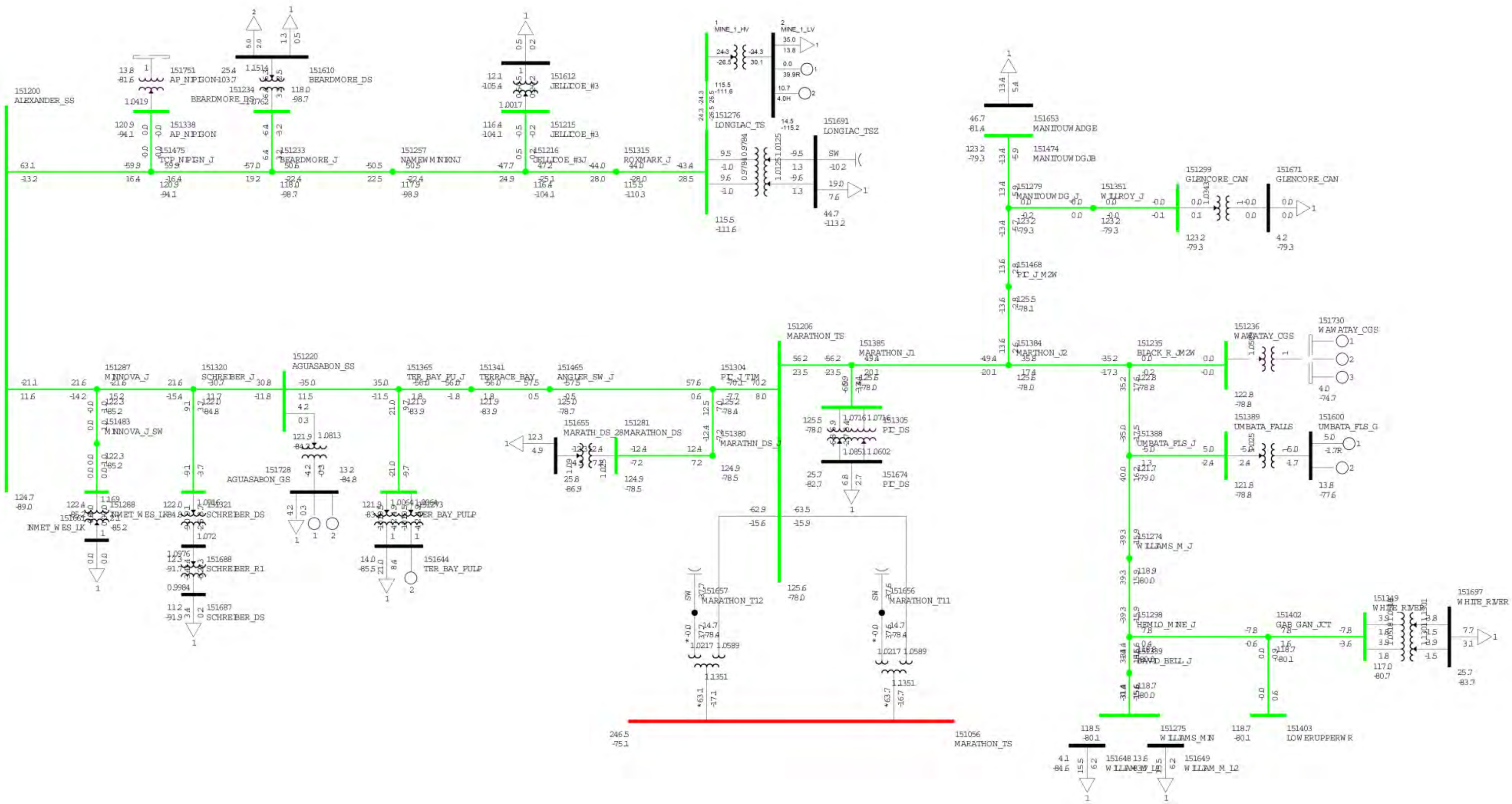
F.3.4 Load Flow Plots

Figure F-8: Option B3, with 5 MW at Beardmore mine, pre-contingency load flow plot



F.4 Supply to Beardmore Mine with Transmission Upgrades

As indicated in F.2 and F.3, Option B1 and Option B3 do not have sufficient margin to incorporate the Beardmore mine. This section illustrates the performance of the system supplying the Beardmore mine following upgrades to the transmission system. Transmission system upgrades are considered in addition to Option B1 and Option B3, respectively.

F.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 B 2035 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 F-16: 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

F.4.2 Methodology

- Assess system condition versus standards with all elements in-service pre-contingency.
- Assessment of system condition versus standards considering the outage of a single element is not presented as it is less limiting that the scenario with all elements in-service. However, the need for arming load rejection for breaker outages at Alexander SS presented in Appendix C.1.3 and C.2.3 would remain.

F.4.3 Results – Option B1 and Transmission Upgrade

<u>All Elements In-Service Pre-contingency</u>

If Option B1 is pursued, replacing sections of circuit A4L from Alexander SS to Beardmore TS with 477 kcmil conductors is considered for this option. Refer to Figure F-9 for load flow plot.

Table F-17: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
Alexander SS x AP Nipigon JCT	620	268	43
AP Nipigon JCT x Beardmore JCT	620	267	43
Beardmore JCT x Jellicoe DS #3 JCT	260	240	92
Jellicoe DS #3 JCT x Roxmark JCT	260	236	91
Roxmark JCT x Longlac TS	260	233	91

Table F-18: 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>122.3</td></tr>
<tr><td>Jellicoe JCT</td><td>119.1</td></tr>
<tr><td>Longlac TS</td><td>115.5</td></tr>
</table>

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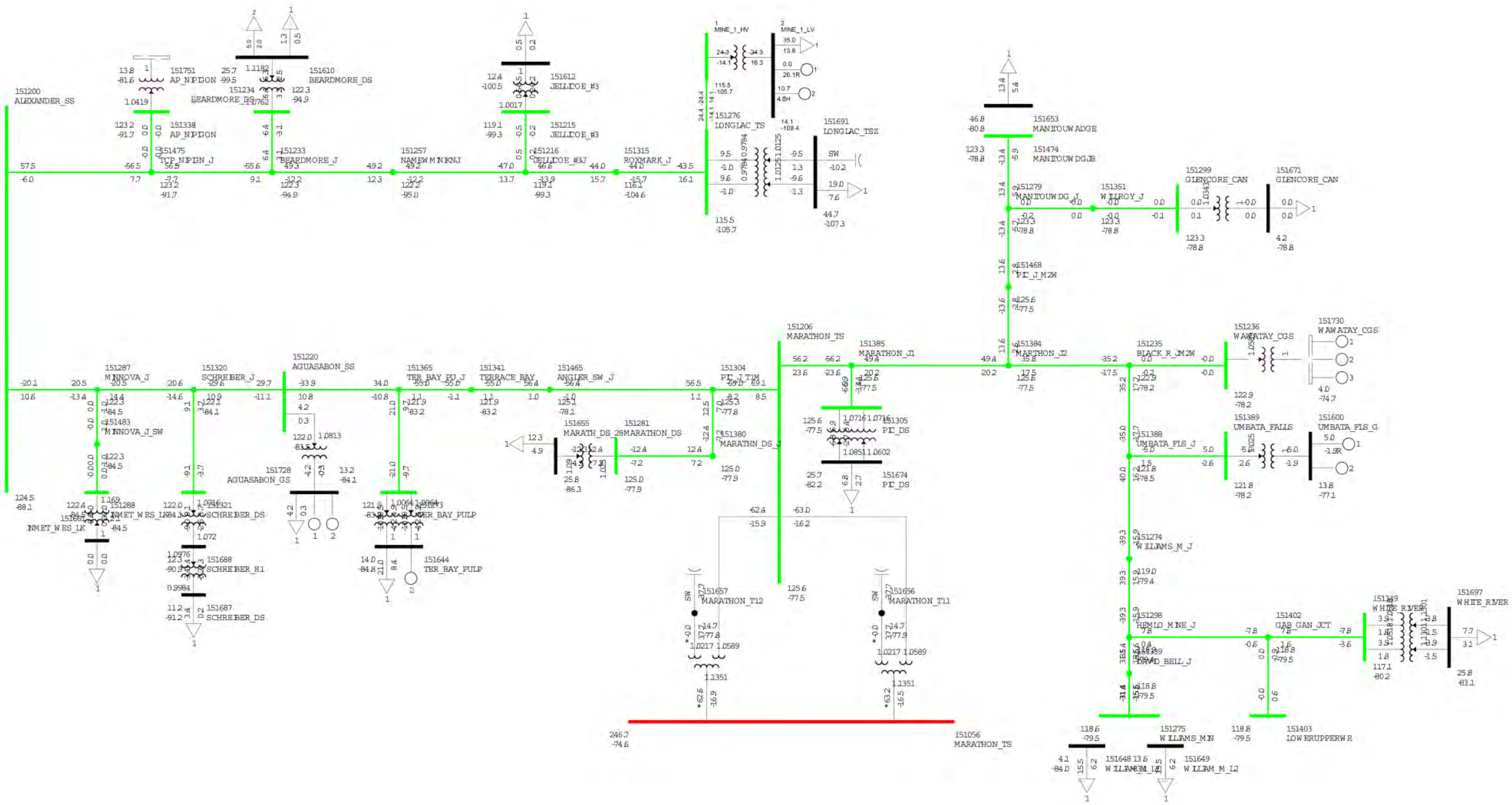
F.4.4 Load Flow Plots

Figure F-9: Option B1 with 5 MW at Beardmore mine and A4L replaced between Alexander SS and Beardmore TS with 477 kcmil conductors



F.4.5 Results – Option B3 and Transmission Upgrade

All Elements In-Service Pre-contingency

If Option B3 is pursued, replacing the remaining sections of circuit A4L from Alexander SS to Nipigon Junction with 477 kcmil conductors is considered for this option. Refer to Figure F-10 for load flow plot.

Table F-19: Thermal Analysis

Alexander SS x AP Nipigon JCT	620	307	50
AP Nipigon JCT x Beardmore JCT	620	307	50
Beardmore JCT x Jellicoe DS #3 JCT	620	278	45
Jellicoe DS #3 JCT x Roxmark JCT	620	274	44
Roxmark JCT x Longlac TS	620	272	44

Table F-20: Voltage Analysis

Bus	Voltage [kV]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Alexander SS	124.2	127	113
Beardmore JCT	120.0		
Jellicoe JCT	118.9		
Longlac TS	118.1		

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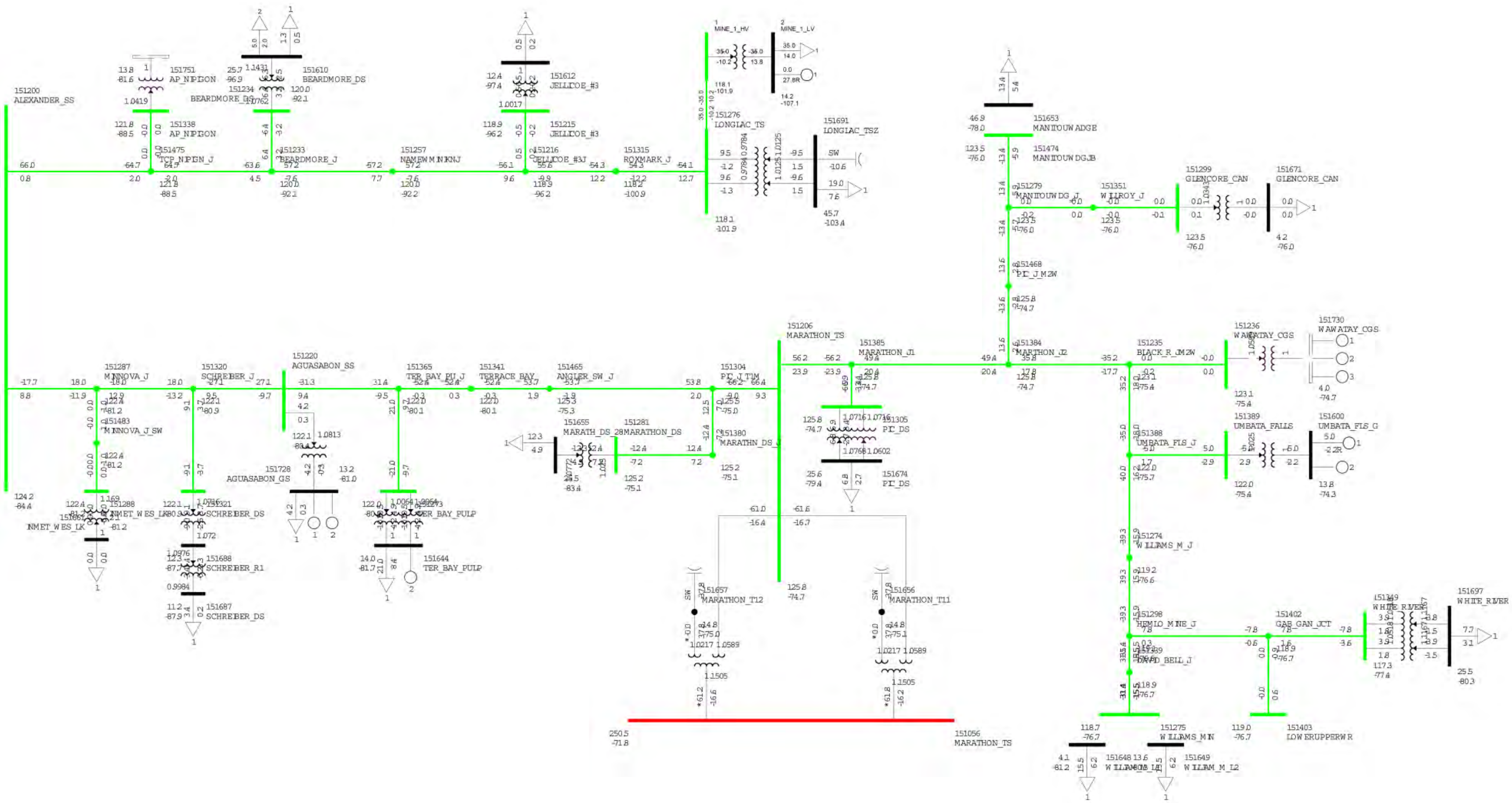
F.4.6 Load Flow Plots

Figure F-10: Option B3 with 5 MW at Beardmore mine and A4L replaced between Alexander SS and Nipigon Junction with 477 kcmil conductors



F.5 Supply to Beardmore Mine with Generation Resources

As indicated in F.2 and F.3, Option B1 and Option B3 do not have sufficient margin to incorporate the Beardmore mine. This section illustrates the performance of the system supplying the Beardmore mine following new or expanded generation resources. New or Expanded generation resources are considered in addition to Option B1 and Option B3, respectively.

F.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 B 2035 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)
- New 2x10 MW gas-fired engines at Beardmore mine, or expanded 1x10 MW gas-fired engine at Geraldton mine

F.5.2 Methodology

- Assess system condition versus standards with all elements in-service pre-contingency.
- Assessment of system condition versus standards considering the outage of a single element is not presented as it is less limiting that the scenario with all elements in-service. However, the need for arming load rejection for breaker outages at Alexander SS presented in Appendix C.1.3 and C.2.3 would remain.

F.5.3 Results – Option B1 and Expanded Generation at Geraldton Mine

All Elements In-Service Pre-contingency

If Option B1 is pursued, expansion of a generating plant at the Geraldton mine by adding 1x10 MW gas-fired engine is considered in this option. Refer to Figure F-11 for load flow plot.

Table F-21: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
Alexander SS x AP Nipigon JCT	310	228	74
AP Nipigon JCT x Beardmore JCT	260	226	87
Beardmore JCT x Jellicoe DS #3 JCT	260	200	77
Jellicoe DS #3 JCT x Roxmark JCT	260	195	75
Roxmark JCT x Longlac TS	260	191	74

Table F-22: Voltage Analysis

Bus	Voltage [kV]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Alexander SS	124.7	127	113
Beardmore JCT	119.0		
Jellicoe JCT	117.3		
Longlac TS	115.5		

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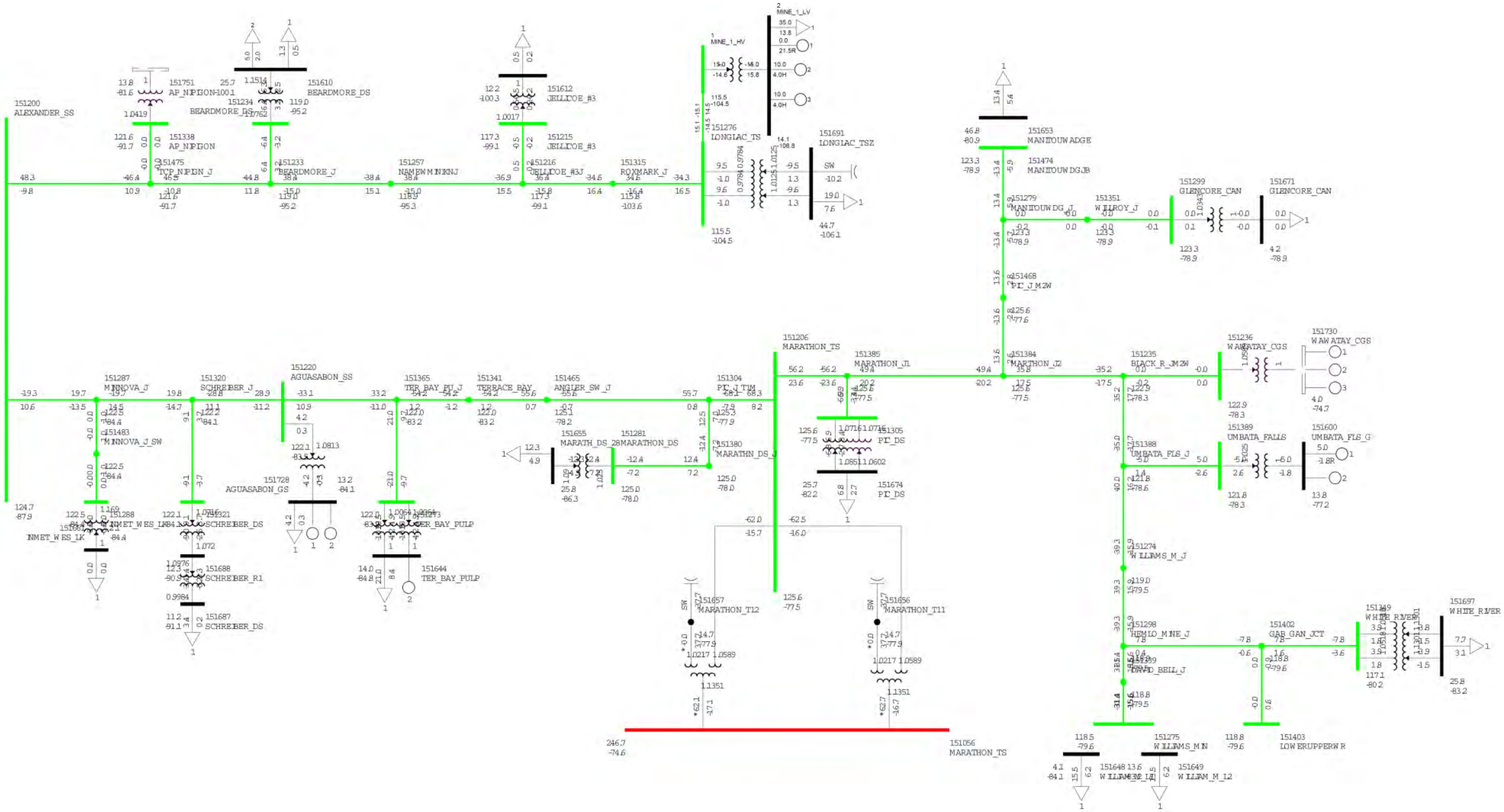
F.5.4 Load Flow Plots

Figure F-11: Option B1 with 5 MW at Beardmore mine and Geraldton mine generation expanded by 1x10 MW unit



F.5.5 Results – Option B3 and New Generation at Beardmore Mine

All Elements In-Service Pre-contingency

If Option B3 is pursued, installation of a new generating plant at the Beardmore mine by adding 2x10 MW (i.e a single redundancy) gas-fired engine plant is considered in this option. Refer to Figure F-12 for load flow plot.

Table F-23: Thermal Analysis

Circuit Section	Continuous Rating [A]	Loading [A]	Loading [% Rating]
Alexander SS x AP Nipigon JCT	310	265	86
AP Nipigon JCT x Beardmore JCT	620	265	43
Beardmore JCT x Jellicoe DS #3 JCT	620	283	46
Jellicoe DS #3 JCT x Roxmark JCT	620	280	45
Roxmark JCT x Longlac TS	620	277	45

Table F-24: Voltage Analysis

Bus	Voltage [kV]	Maximum Continuous Voltage [kV]	Minimum Continuous Voltage [kV]
Alexander SS	124.4	127	113
Beardmore JCT	118.8		
Jellicoe JCT	118.2		
Longlac TS	118.1		

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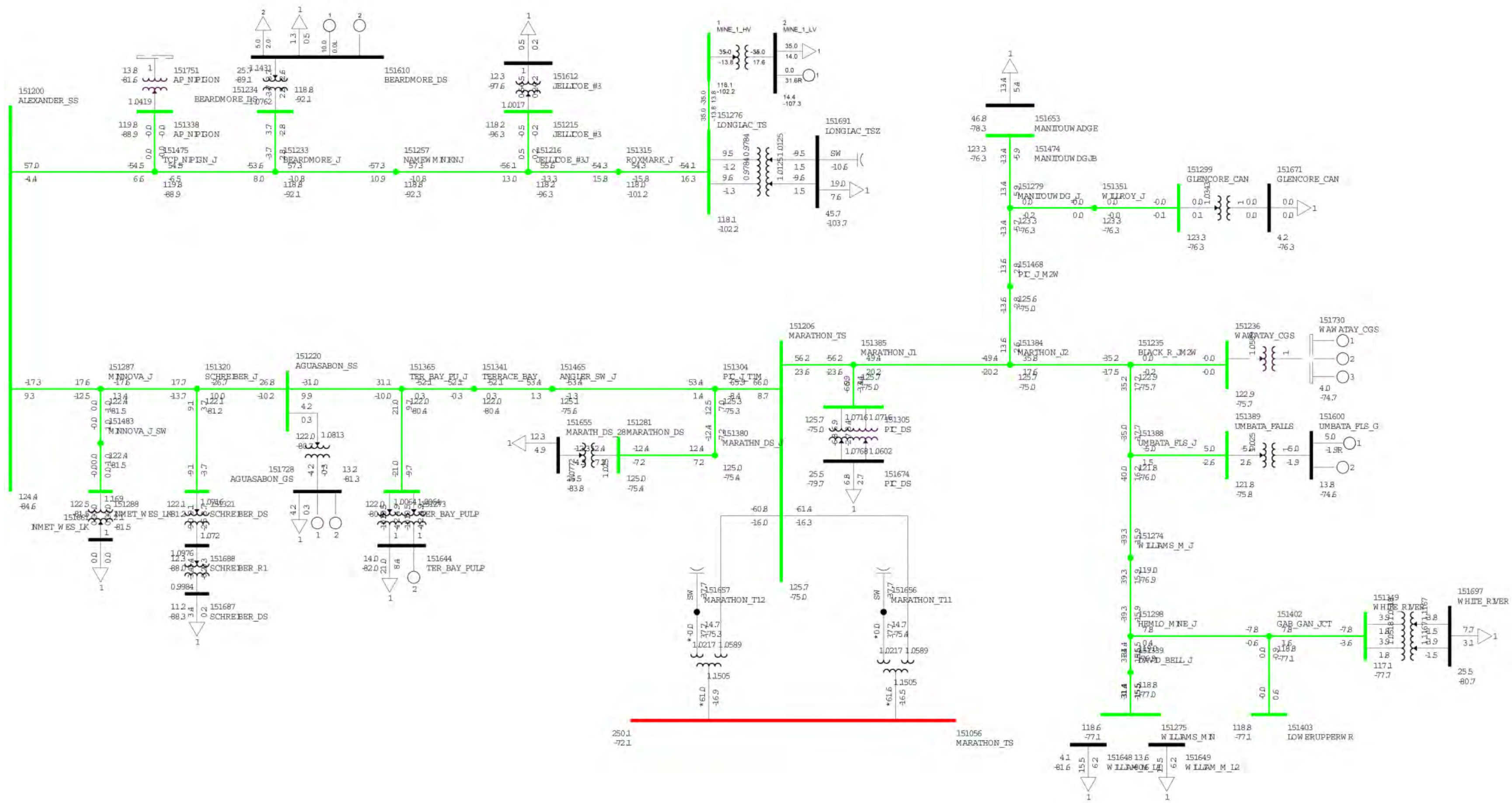
F.5.6 Load Flow Plots

Figure F-12: Option B3 with 5 MW at Beardmore mine and Geraldton 2x10 MW generation plant at Beardmore mine



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Appendix G: Economic Analysis of Medium- and Long-term Options

Appendix G: Economic Analysis of Medium- and Long-term Options

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

G.1 Supply to Beardmore Mine with Transmission Upgrades

G.1.1 Assumptions

- 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[19]
- 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

G.1.2 Methodology

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

- Based on the unit cost of the line and a length of either 35 km or 65 km for the Alexander SS to Nipigon Junction option or the Alexander SS to Beardmore option, the line capital cost was determined to be $16.2 million or $30 million respectively
- Based on capital, annual O&M costs were calculated as $2.4 million and $4.5 million respectively for the Alexander SS to Nipigon Junction option and the Alexander SS to Beardmore option respectively
- Capital and annual costs were amortized over the life of the project
- NPV was calculated over the planning period (2015-2035)

[19] 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

G.1.3 Results

Figure G-1: Replace A4L from Alexander SS to Nipigon Junction

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Line Cost								16.2														
O&M								0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total Annual Cost								16.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Annual Amortized Cost								0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Cumulative PV								**0.7**	**1.3**	**1.9**	**2.5**	**3.1**	**3.6**	**4.1**	**4.6**	**5.1**	**5.6**	**6.0**	**6.5**	**6.9**	**7.3**	**7.7**

Figure G-2: Replace A4L from Alexander SS to Beardmore TS

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Line Cost								30.0														
O&M								0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Annual Cost								30.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Annual Amortized Cost								1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Cumulative PV								**1.2**	**2.4**	**3.5**	**4.6**	**5.7**	**6.7**	**7.7**	**8.6**	**9.5**	**10.4**	**11.2**	**12.0**	**12.8**	**13.5**	**14.2**

G.2 Supply to Beardmore Mine with New or Expanded Generation

G.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 with dual-fuel capbability is $3,028/kW-installed
- Two 10 MW gas generating units are assumed to comprise on-site gas generating plant at the Beardmore mine project
- One 9.5 MW gas generating unit is assumed to comprise the expansions of an on-site gas generating plant at the Geraldton mine project
- Natural gas is assumed to be supplied by the existing TransCanada pipeline
- Pipeline capacity is assumed 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

G.2.2 Methodology

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

- Based on the unit cost for installing new generation capacity, the capital costs of installing a new 1x9.5 MW gas generator at Geraldton mine and installing 2x10 MW gas generators at Brookbank are $28.8 million and $60.6 million respectively
- Based on generator size, annual O&M costs were calculated as $10.0 million and $10.5 million for the Geraldton mine option and Brookbank mine option respectively
- Annual energy production is estimated from summing the forecast hourly demand for the Beardmore mine
- System generation credit associated with avoiding system generation cost by the annual energy produced by the Geraldton and Brookbank 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)

G.2.3 Results

Figure G-3: Install new 1x10 MW gas generating unit at Geraldton mine gas generating plant

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gx Capital Cost							28.8														
Fixed O&M							0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Variable O&M							0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cost							1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Avoided System Gen Cost							(2.1)	(2.1)	(2.2)	(2.2)	(2.2)	(2.1)	(2.2)	(2.1)	(2.2)	(2.2)	(2.3)	(2.2)	(2.2)	(2.2)	(2.2)
Total Annual Gx Cost							29.5	0.7	0.6	0.7	0.6	0.7	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Annual Amortized cost							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
Cumulative PV of Amortized cost							**2.0**	**4.0**	**5.9**	**7.7**	**9.4**	**11.1**	**12.7**	**14.2**	**15.7**	**17.1**	**18.5**	**19.8**	**21.1**	**22.3**	**23.5**

Figure G-4: Install new 2x10 MW gas generating plant at Beardmore mine

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gx Capital Cost							60.6														
Fixed O&M							0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Variable O&M							0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cost							1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Avoided System Gen Cost							(2.1)	(2.1)	(2.2)	(2.2)	(2.2)	(2.1)	(2.2)	(2.1)	(2.2)	(2.2)	(2.3)	(2.2)	(2.2)	(2.2)	(2.2)
Total Annual Gx Cost							61.3	0.7	0.7	0.7	0.7	0.8	0.7	0.7	0.6	0.6	0.6	0.7	0.7	0.7	0.7
Annual Amortized cost							4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Cumulative PV of Amortized cost							**3.8**	**7.5**	**11.1**	**14.5**	**17.7**	**20.9**	**23.9**	**26.8**	**29.6**	**32.3**	**34.9**	**37.4**	**39.8**	**42.1**	**44.3**

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Appendix H: Economic Assessment of the Little Jackfish Project

Appendix H: Economic Assessment of the Little Jackfish Project

The following appendix provides additional information regarding the economic attributes of the Little Jackfish hydroelectric project.

H.1 Overview

Little Jackfish is a proposed 78 MW hydroelectric project located on the northern tip of Lake Nipigon in Northwestern Ontario. It is capable of producing 385 GWh of energy (at a 56% capacity factor) with some storage capability. The project reflects a partnership between OPG and local First Nation communities as part of the WZI development corporation. Development of the project is currently on hold in light of the current supply and demand outlook.

H.2 Planning Considerations

The economics of the Little Jackfish project are influenced by a number of factors. These include:

- Regional and provincial load growth
- Electricity mix and planning outlook
- Need (amount, timing) for additional energy and capacity
- Transmission availability
- Economics in the context of alternative sources of supply

With respect to transmission, a portion of the investment associated with the Little Jackfish project includes the construction of a 180 km 230 kV transmission line from the project site to the provincial transmission grid, at Kama Bay.

The Greenstone-Marathon regional plan is considering a potential transmission route from Longlac to the provincial grid, at Kama Bay (referred to as the "East of Nipigon line option"). This transmission option is driven by potential load growth in the Greenstone area.

Both transmission investments (Little Jackfish and the East of Nipigon line option) have about 80 km of common transmission line routing. If a transmission line consistent with the route identified in the Greenstone-Marathon regional plan is pursued, it could potentially reduce the Little Jackfish transmission line length (and cost) from 180 km to 100 km. Under this scenario, the Little Jackfish transmission line would terminate in the Beardmore-Jellicoe area. This has the potential to reduce a portion of the costs associated with the Little Jackfish project and is considered in the economic assessment of supply options.

H.3 Economic Assessment: Methodology and Assumptions

The economics of the Little Jackfish project are compared to a number of alternative supply-side options, each providing similar quantities of energy and capacity.

Key assumptions include:

- Economic assumptions with respect to Little Jackfish were provided by OPG.
- Little Jackfish has a project lead time of 4.5 years to in-service. A 2019 in-service year is assumed based as this is the earliest in-service date of Little Jackfish. A 90 year service life is assumed.
- Full capacity value of 78 MW assumed for Little Jackfish, assumed to be enabled by its storage capability.
- Little Jackfish requires a 180 km transmission line to connect to the provincial grid. Potential reduction in line length due to the common routing with the East of Nipigon line option is about 80 km. Alternative supply options assumed to have no significant transmission costs since it is assumed supply can be located near load.
- Repowering and replacement cost of alternative resources, which have a shorter operating life than Little Jackfish, is also reflected. Gas technology is replaced three times over the 90 year study period. Each cycle, the gas technology operates for 20 years after which it is repowered (at 25% of initial capital cost) to operate for another 10 years.

A probabilistic analysis is conducted assessing the uncertainty associated with natural gas fuel price only as this is the variable deemed to influence the economics of generation resource options the most (i.e. assume all other costs remain unchanged and their associated uncertainty having a minimal impact on the relative economic merits of options). Gas prices follow a log-normal distribution reflecting historical gas prices between 1997 and 2014. Uncertainty analysis is conducted in @RISK™.

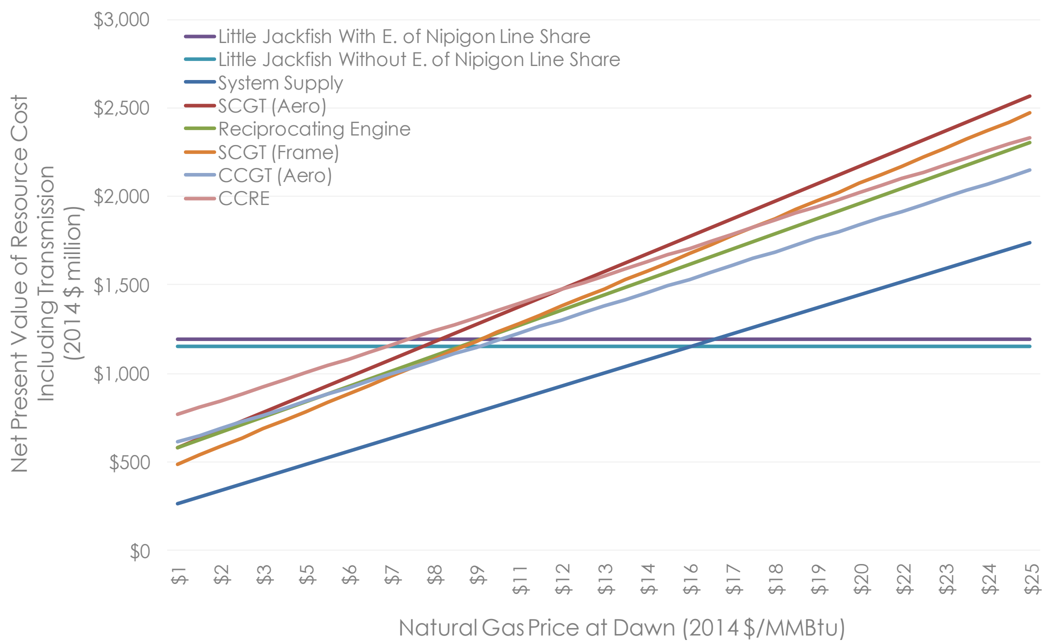
With respect to Little Jackfish, transmission costs are evaluated under two cases, considering with and without the East of Nipigon portion of line costs. Costs of each option are evaluated from a ratepayer perspective and include overnight capital cost, fixed and variable operating costs, and fuel costs. Financing costs are not considered and are assumed to be similar across resource options considered.

Costs are evaluated over 90 years (life of the Little Jackfish project), out to the year 2108, and are compared on an NPV and levelized unit energy cost basis assuming a 4% real social discount rate.

H.4 Economic Assessment: Summary of Results

The NPV of the Little Jackfish project ranges between $1.15 B and $1.20 B including transmission costs (without and with shared portion of East Of Nipigon line). It is break-even with the cost of alternative gas generation options at a gas price of $7-$9/MMBtu. It is break-even with the cost of system supply at a gas price of $15-16/MMBtu. This is illustrated in Figure H-1.

Figure H-1: Net Present Value of Resource Options as a Function of Natural Gas Price



Viewing the same results as a set of NPV probability distributions, Figure H-2, illustrates that the distribution of NPVs of system supply (as a function of natural gas price) has a cost range that is almost always lower than the cost of Little Jackfish. The NPV distribution of the cost of alternative gas generation options also tends to be lower although there are instances when costs are higher.

Expressed as a cumulative probability distribution of NPVs, Figure H-3, the cost of system supply is less than the cost of Little Jackfish (NPV $1.15B-$1.20B including transmission costs) almost 100% of time. The NPV cost of alternative gas generation options is less than the cost of the Little Jackfish project about 75%-95% of time.

Figure H-2: Probability Distribution of the Net Present Value of Resource Options as a Function of Natural Gas Price

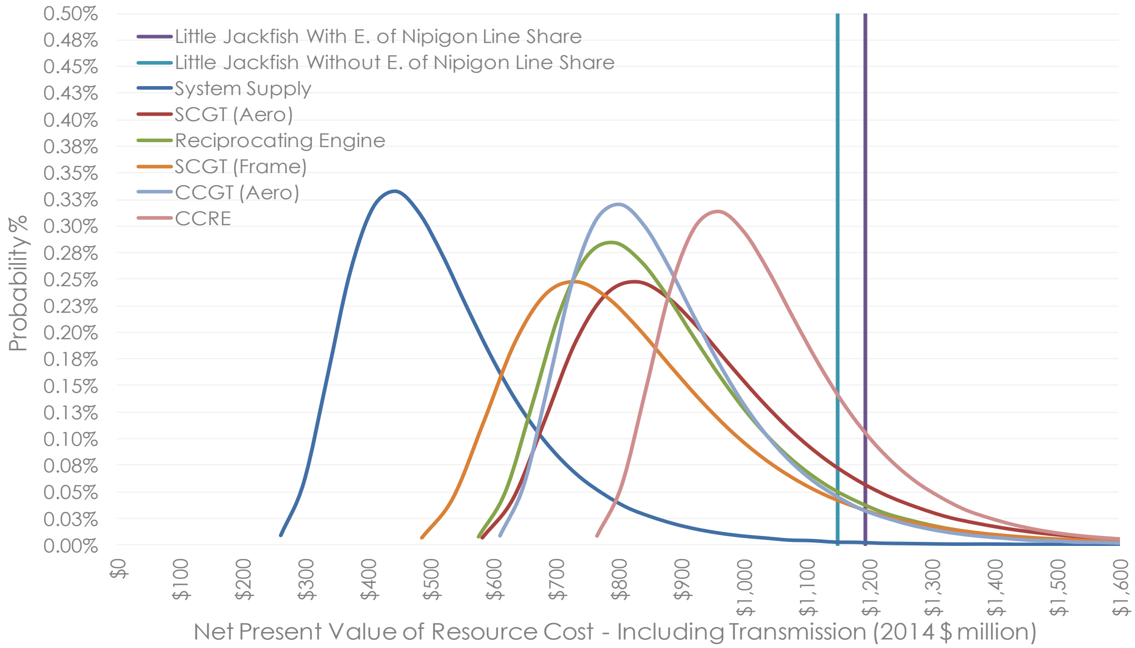
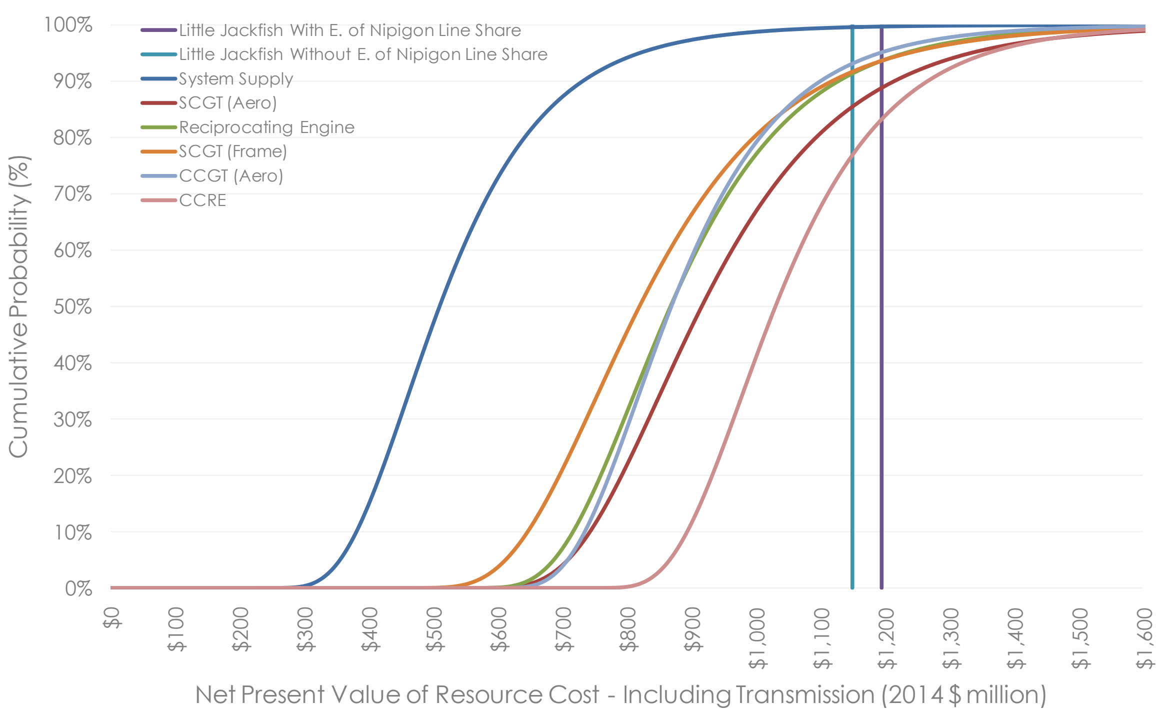
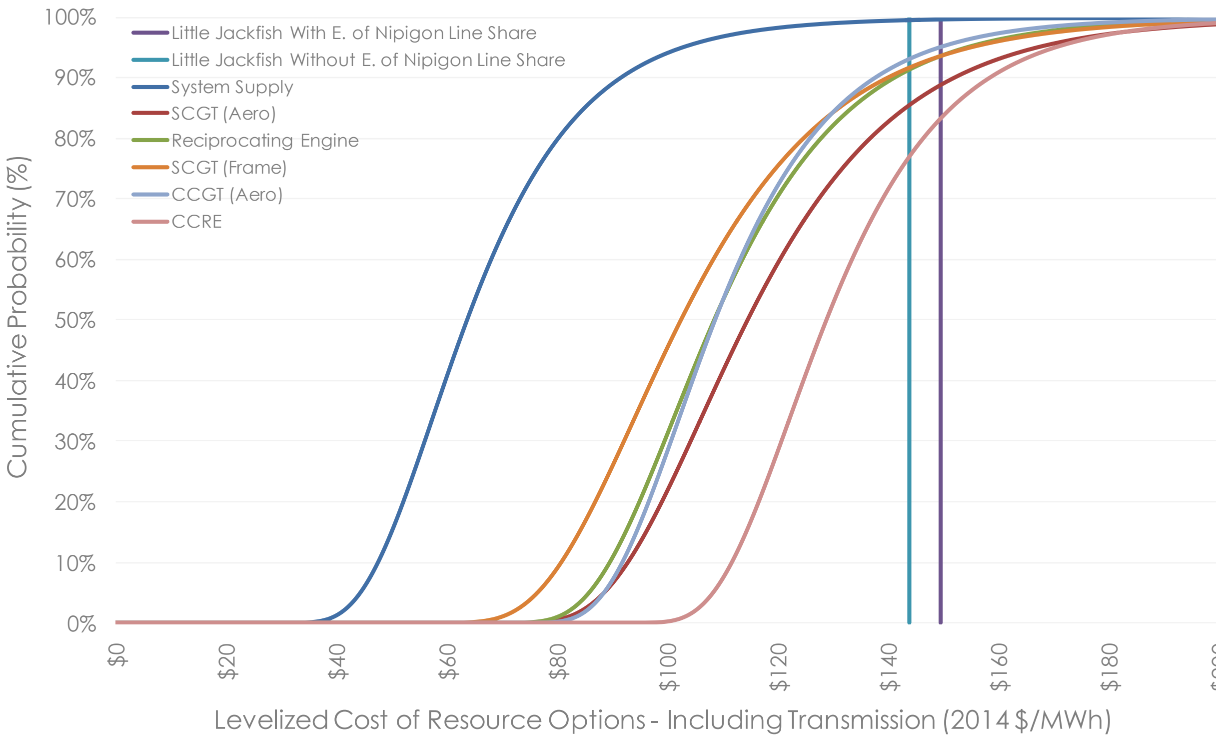


Figure H-3: Cumulative Probability of the Net Present Value of Resource Options as a Function of Natural Gas Price



Similarly, expressed as a cumulative probability distribution of levelized cost, Figure H-4, the cost of system supply is less than the cost of Little Jackfish ($144-$150/MWh including transmission costs) almost 100% of time. The levelized cost of alternative gas generation options is less than the cost of the Little Jackfish project about 75%-95% of time.

Figure H-4: Cumulative Probability of the Levelized Unit Energy Cost of Resource Options as a Function of Natural Gas Price



H.5 Planning Consideration

There are a number of benefits associated with the Little Jackfish project. These include:

- A shorter lead time, about 4.5 years, compared with other hydroelectric projects (6 to 8 years) given the progress made to date with respect to project development (the environmental assessment for project is near completion, concept level engineering design near completion, aboriginal, public, and agency consultation conducted);
- Site offers 56 GWh of monthly storage capability which might have some system operability value;
- Involvement of First Nation communities and associated economic development opportunities;
- Virtually no GHG emissions.

There are also challenges associated with the Little Jackfish project:

- The project has limited dispatchability and load following capability as compared to other supply resources;
- Supply from water power represents 60% of the supply in the Northwest. Given the impact low water conditions have on Northwest supply reliability, additional water power may require additional insurance supply in the northwest under low water events;
- Limited ability to contribute to the Provincial supply mix given the downstream transmission constraints that exist in the Northwest. Although this is true for any resource located in the Northwest, the fact that hydroelectric has limited dispatchability means the potential for spilling water to avoid surplus generation and transmission congestion;
- Higher line losses considering location of project from loads;
- The project is not expected to be economic as a merchant project under the current market price outlook. A power purchase agreement would need to be negotiated.

The reduction in Little Jackfish transmission costs due to the shared routing with the East of Nipigon line is $45M which is 4% of the total project cost. This has a minimal impact on the economic merits of the project as seen illustrated in the previous section.

A number of aspects would have to align for the project to be further considered as a supply option. These include higher demand growth in the region; development of the East of Nipigon transmission line; reduction in project costs or increase in the cost of alternatives (e.g., due to higher gas/carbon prices); and procurement mechanism would need to be established.

Greenstone-Marathon IRRP

Appendix I: Marathon Co-gen Options Assessment

Appendix I: Marathon Co-Generation Options Assessment

The following appendix outlines the planning level economic analysis of installing a co-generation facility in the Town of Marathon, including assumptions, methodology, and discounted cash flow analysis. The three options considered are Biomass, Diesel, and Propane engines.

I.1 Assumptions

- Costs represent planning level precision of ±50%
- Propane and diesel fuel generator options were assumed to have a capital cost of $4 million per MW of installed capacity
- Annual OM&A costs are estimated using a fixed and 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 fuel costs for diesel fuel and propane are assumed to be $1.1/L and $0.9/L respectively. The energy densities for diesel fuel and propane are assumed to be 43.1 MJ/kg and 50.35 MJ/kg respectively
- All generation options considered have a conversion efficiency of 30% and a thermal utilization efficiency of 80%
- The total annual electric load is the same as the existing load at 3.44 GWh
- The total annual thermal load is the same as the existing load at 2.75 GWh
- Cost of Carbon was not considered

I.2 Methodology

I.2.1 Identify Large Customers

From the Broader Public Sector Energy Consumption Reporting, which is publically available, the largest public sector energy consumers were identified. The locations of these consumers were then mapped to determine those that are located within close vicinity. Those located within close vicinity are considered as loads for the co-generation concept. The hospital, arena/theatre, high school, Fire Hall, Family Practise/Library, Pool, and EMS are located within 50 m and represent over 50% of the public sector energy demand.

I.2.2 Size the Option

The concept is sized to produce the less of the electrical or thermal energy demand to minimize the operating cost and maximize the avoided cost to the community. This resulted in sizing to the existing thermal energy demand.

Based on typical load curves for the consumers being included in the analysis, a notional 1 MW capacity is assumed to develop high-level fixed operating and maintenance costs.

I.2.3 Determine the Payback Period

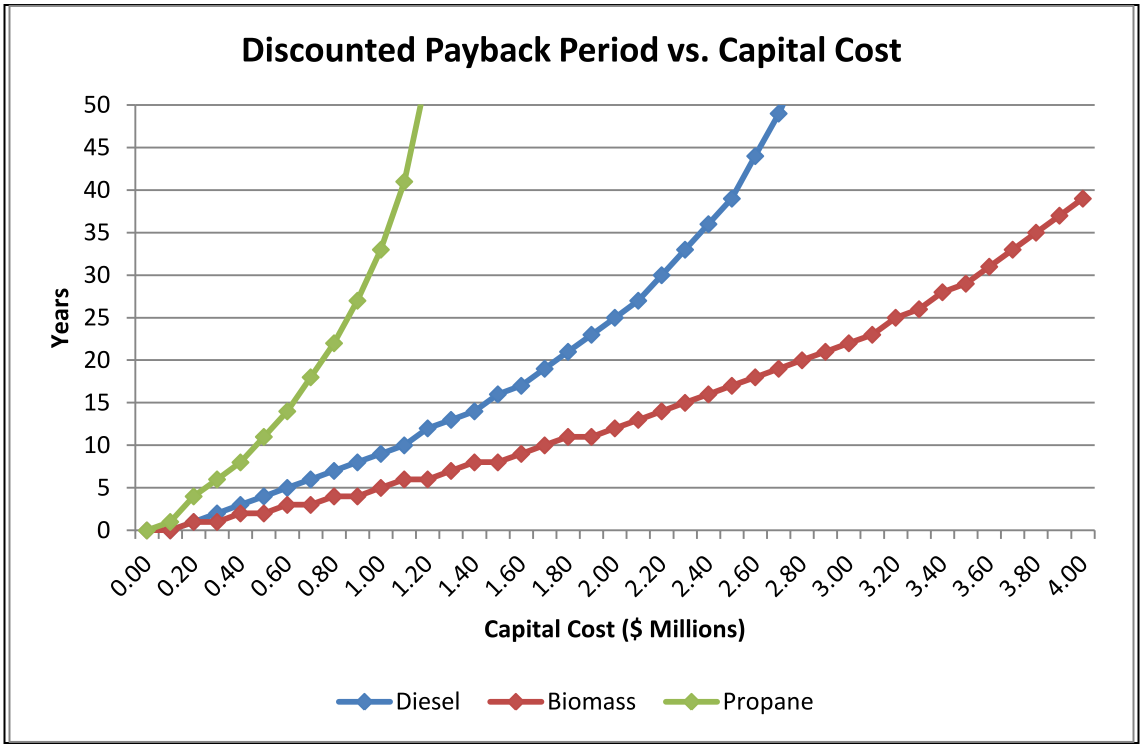
The payback period was calculated by taking the following steps

- The generation facility was sized to produce the existing thermal load of 2.75 GWh annually. The resulting electric energy produced is 1.03 GWh annually. The remaining electrical load is provided by the grid at an assumed price of $0.15/kWh
- The avoided cost, or benefit to the community, is calculated by taking the existing electric and fuel costs and subtracting the proposed electric and fuel costs for the co-generation facility
- The annual benefits were calculated as $250 thousand, $176 thousand, and $107 thousand for Biomass, Diesel, and Propane generation options, respectively
- The annual fixed and variable OM&A were calculated as $9,090 and $45,470 respectively
- The annual cash flows are calculated by subtracting the total annual costs from the annual benefit. For year one this includes the capital cost of the facility, and for every other year this includes fixed and variable OM&A only
- NPV was calculated over the planning period (2015-2035)
- The payback period is determined as the number of years before the NPV turns positive after the initial capital cost
- The payback period of each generation option was calculated for varying levels of initial capital cost

I.3 Results

The following shows the discounted payback period for Biomass, Diesel, and Propane generation options against varying initial capital cost.

Figure I-1: Discounted Payback Analysis



Greenstone-Marathon IRRP

Appendix J: Local Advisory Committee Report on the Socio-Economic Benefits of Electricity Options to Local Communities

Appendix J: Local Advisory Committee Report on the Socio-Economic Benefits of Electricity Options to Local Communities

As an outcome to the third General LAC meeting on May 12, 2016, the LAC members decided to produce a report outlining the local socio-economic impacts of the electricity solutions being explored in the Greenstone-Marathon IRRP and compliment the IESO and Working Group's technical and economic analyses.

Socio-economic impact analysis is not within the traditional scope of the IRRP, and is not in the mandate of the IESO. By including this LAC report as an appendix to the Greenstone-Marathon IRRP, this does not represent an endorsement of the results by the IESO. However, the IESO recognizes the LAC members as its best source of local socio-economic impact information.

The LAC report was not available at the time of publishing the IRRP, but is forthcoming and will be attached to this appendix when finalized.

Greenstone-Marathon IRRP

Appendix K: Documentation of Local Advisory Committee Meetings and Additional Feedback Received

Appendix K: Documentation of Local Advisory Committee Meetings and Additional Feedback Received

K.1 Local Advisory Committee Meeting Material

The following documents the Local Advisory Committee Meetings Agendas and Summaries.

Greenstone-Marathon Local Advisory Committee
Inaugural Meeting

Nipigon Community Centre
135 Wadsworth Drive, Nipigon, ON P0T 2J0

Monday, June 29, 2015

5:00 pm - 7:00 pm

AGENDA

AGENDA ITEM	TIME	TOPIC	LEAD	MATERIAL
1	4:45 p.m.	Public Registration		
2	5:00 p.m.	Opening Remarks & Roundtable Introductions	Luisa Da Rocha	
3	5:15 p.m.	Review of LAC Manual	Luisa Da Rocha	✔
4	5:30 p.m.	Presentation of Greenstone-Marathon Near-Term Plan and Discussion of Planning for Post-2020	Joe Toneguzzo/ Christopher Reali	✔
5	6:30 p.m.	Group Discussion of Other Local Electricity Priorities	Luisa Da Rocha	
6	6:45 p.m.	Public Questions	Luisa Da Rocha	
7	6:50 p.m.	Closing Remarks & Next Meeting	Luisa Da Rocha	
8	7:00 p.m.	Meeting Adjourns		

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Meeting Notes

Meeting Information	
Date:	June 29, 2015
Location:	Nipigon Community Centre – Nipigon, ON
Subject:	Inaugural Greenstone-Marathon Local Advisory Committee Meeting
Attendees:	**Committee Members** Rod Bosch President Desaulniers Larry Doran Armand Giguere William Gordon Harold Harkonen Mayor Richard Harvey President William Gordon Stan Johnson Christina Burk **IESO** Stephanie Aldersley Luisa Da Rocha Christopher Reali Joe Toneguzzo
Webinar Archive:	http://www.meetview.com/ieso20150629
LAC Meeting Materials:	http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/Greenstone-Marathon.aspx

	Key Topics	Follow up Actions
1	**Opening Remarks and Roundtable Introductions** • Luisa Da Rocha welcomed everyone and discussed the meeting focus • Roundtable introductions were made	
2	**Review of Local Advisory Committee Manual** • Ms. Da Rocha provided an overview of the LAC manuals - All materials are available publically on the IESO's website, and have been presented collectively as a resource	☐ LAC members to confirm their contact information

3	**Presentation of Greenstone-Marathon Interim IRRP and Discussion of Local Priorities/Next Steps** • **Presentation delivered by Joe Toneguzzo and Christopher Reali, IESO** - Introduction to the Ontario Electricity Sector - Electricity planning in Northwest Ontario - Summary of finding from the Greenstone-Marathon Integrated Regional Resource Plan - Community Engagement - Discussion of Long-term Needs and Community Priorities • **Questions and Feedback from Committee: (meeting summary in italics, questions and feedback in regular font)** *Demand Forecasting: The LAC discussed the demand forecast for the region and how it was developed. The IESO explained that it engages existing and new customers as soon as we are aware of new developments, CVNW, and other stakeholders as it develops and maintains the forecast.* - Does the plan address potential load growth including the LNG plant in the Nipigon vicinity, and how proactive the IESO is when it finds out about potential new loads (i.e. does the IESO contact the company or wait for the company to reach out) o Note: The plan does not include the LNG, because electrical demand is unknown at this time. - Load capacity for the mine in Phase 1 is 35 MW, not 25 MW as noted in the plan; does this difference mean changes need to be made to the interim plan o Note: Confirmed phase 1 of the Geraldton mine is 25 MW, phase 2 is an incremental 10 MW, making the total approximately 35 MW, - Is the Terrace Bay Mill included in the plan o Note Yes *Implementation, Costs and Cost Allocation: discussion of implementation process, especially cost allocation rules. The IESO explained that cost allocation is decided by the Ontario Energy Board and the general approach to cost recovery is that the beneficiary pays. In GM, since existing customers do not require any system reinforcements, new customers would bear the cost of new investment* - Discussion of the Net Present Value of the plans and the breakdown for the costs; Will customers be required to pay the full costs	☐ Adjustments to be made to the materials as noted ☐ Provide a brief update on the status of the Thunder Bay and West of Thunder Bay plans at the next meeting

- Is the decision for the new line based purely on whether the industrial load will pay for the new line as opposed to improving the quality of service to the residents in Greenstone; what are the requirements to make a ring connection

- Question about priority projects and the associated cost responsibility; it was suggested that the 230 kV line could go ahead if it was deemed a priority project

Timing: the LAC discussed project timing. The IESO explained that a 230 kV line has a lead time between 5-7 years. Timing can be met if customers and proponents move quickly to establish agreements of cost and service and initiate required approvals processes.

- Alternatives to serve the proposed oil pipeline pumping stations were discussed along with timing

- What lead time is required to build the 230kV line; the development of this line is a prime consideration

- Concerns that even if the 230 kV transmission line is declared a priority project, it will still not be available to meet the mid 2020 need date;

- Discussion of timing for the next meeting and its relation to moving forward on the transmission line to meet need dates

Miscellaneous Items

- *Discussion of the power equipment alternatives for the mine and the broader issues that need to be considered (i.e. stability it can bring to the system, storm events)*

- *Discussion of a possible second line from Manitouwadge to help create a looped system as recommended under Scenario C, in addition to a 230 kV line from the East-West Tie to near Longlac TS.*

- *Discussion regarding the future of Little Jackfish*

  Discussion re Forest fires as it relates to power outages

- *Discussion of how the East-West Tie project factor into meeting needs In the area. The project addresses needs for the entire Northwest, but forecasted Greenstone-Marathon demand is included in the need for the East-West Tie expansion.*

- *Discussion about Red Rock. Red Rock Township is part of the*

	Thunder Bay plan, but Red Rock Indian Band is being engaged in both Thunder Bay and GM plans. - *Discussion of the relationship between various plans in the Northwest. The Planners for each of the areas work closely together and coordinate the plans.* - Adjustments required to the materials: Maps - add a label for Greenstone; correct location of municipal labels along the Lake, correct location of Longlac TS Hornepayne should be added to the Northwest Ontario Scoping assessment	
5	**Discussion of Other Community Priorities** • The Committee was asked to identify any additional community priorities for discussion at the LAC meetings	☐ Committee members to identify other topics of interest
6	**Closing Remarks & Meeting Adjournment** • Luisa Da Rocha provided closing remarks	

Greenstone-Marathon Local Advisory Committee
Meeting #2

Red Rock Indian Band
2 Gas Rd., Lake Helen Reserve, Nipigon, ON P0T 2J0

Wednesday, November 26, 2015

1:00 pm - 4:00 pm

AGENDA

AGENDA ITEM	TIME	TOPIC	LEAD	MATERIAL
1	12:45 p.m.	Public Registration		
2	1:00 p.m.	Opening Remarks & Roundtable Introductions	Luisa Da Rocha	
3	1:15 p.m.	Review of Minutes from Inaugural Meeting	Luisa Da Rocha	✔
4	1:30 p.m.	Presentation and Discussion – Implementation of Near-Term Planning Elements	Joe Toneguzzo/ Christopher Reali	✔
5	2:15 p.m.	BREAK		
6	2:30 p.m.	Presentation and Discussion – Medium and Long-Term Drivers	Joe Toneguzzo/ Christopher Reali	✔
7	3:15 p.m.	Identification of Issues for Discussion	Luisa Da Rocha	
8	3:40 p.m.	Public Questions	Luisa Da Rocha	
9	3:55 p.m.	Closing Remarks & Next Meeting	Luisa Da Rocha	
10	4:00 p.m.	Meeting Adjourns		

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Meeting Notes

Date:	Wednesday, November 25, 2015
Location:	Nipigon, ON
Subject:	Greenstone-Marathon Local Advisory Committee Meeting #2
Attendees:	**Committee Members in Attendance** Rod Bosch Joe Donio Larry Doran Armand Giguere Harold Harkonen Stan Johnston **IESO** Christopher Reali Joe Toneguzzo Luisa Da Rocha Stephanie Aldersley
LAC Meeting Materials:	http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/Greenstone-Marathon.aspx

	Key Topics	Follow up Actions
1	**Opening Remarks and Roundtable Introductions** • Ms. Da Rocha welcomed everyone and discussed the meeting focus • Roundtable introductions were made	
2	**Review of Minutes from Inaugural LAC Meeting** *Summary: The LAC reviewed the minutes of the inaugural Committee meeting held on June 29, 2015 which focused on the role of the LAC and a presentation and discussion of the Greenstone-Marathon Interim Integrated Regional Resource Plan (IRRP).* • Concerns were raised about the statement regarding the timing for the 230 kV line. The minutes indicate that the timing for this line "can be met" in 5-7 years, however it is already late 2015 and the line is needed by 2020. It was noted that the minutes should not include a statement that the timing can be met when this is not known. ○ The IESO acknowledges this concern is valid if the electrical demand from both the mining customer and the pipeline company materialize by 2020. This note in the November meeting minutes, will serve as acknowledgement of this concern.	☐ Review timeline statements for in-service of the new 230Kv line from the last minutes

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Presentation on the Implementation of Near-Term Planning Elements

- Presentation delivered by Joe Toneguzzo and Christopher Reali, IESO. A copy of the presentation is available on the LAC Meeting Materials link above.
  - Review of LAC Meeting #1
  - Implementation of Near-Term Planning Elements

<u>**Review of LAC Meeting #1 – Near-Term Plan**</u>
Presentation Summary: The Interim IRRP report released in June 2015 includes three forecast scenarios: <u>Scenario A</u> includes Local Distribution Company (LDC) demand growth and two saw mill restarts; <u>Scenario B</u> builds off this base and adds the two-phased mining development in Geraldton; <u>Scenario C</u> includes all of the elements from the previous scenario and adds the pipeline conversion project. The Working Group has developed options to meet electricity needs in each scenario.

- Staff levels at the mine are expected to be approximately 400 people, which means an additional 1,200 people in Geraldton. Is this growth accounted for in the models? If the mine is to self-generate, does this create any issues for supplying this increased load in town given that there is only 1.5 MW left? In this scenario, the LDC will need to pay for any associated costs as community growth doesn't get funded by the proponents or customers?
  - IESO: Spin-off growth is accounted for in the LDC electricity forecast projection and is therefore considered in the plan

<u>**Near-term Needs and Recommendations**</u>
Presentation Summary - Stage One (for 2018): The need for new capacity is being driven by potential new industrial customers, not existing customers. For the first phase of the mining development, the near-term plan recommends two options to connect to the grid: synchronous condenser or a static synchronous compensator (STATCOM). Both make available 20MW and have an NPV cost of about $5 million.

- Is the Net Present Value (NPV) to the system or to the customer? The presentation includes a societal cost of $7million, however there are $millions (potentially $17 million) in additional costs for a new substation and line that the customer will need to connect to the grid; costs they don't have if they decide to self-generate. If these additional costs haven't been factored into the plan, this could account for pushback from the mine as they don't see the cost of connecting to the grid as just $7 million. The customer is also talking about moving the Longlac TS. Overall, the plan needs to look at costs from both societal and customer perspectives.
  - IESO: The NPV uses a societal perspective which includes social discount rates with capital costs of $7 million. How the mining customer chooses to connect will affect the costs – for example, there is some available capability at Longlac TS and connecting to this station is expected to result in lower costs than building another station. In comparison to the grid connection costs, the IESO analysis indicates that the self-generation option is in the $100s of millions. The IESO has had meetings with the customer and has performed the cost analysis for them taking a customer

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☐ Look into the growth assumed by the LDC for new jobs associated with mining activity

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	perspective. The costs and the technical characteristics of the synchronous condenser versus STATCOM options have been discussed with the customer. • From a societal perspective, the best device would be the synchronous condenser as it is far superior to a STATCOM. This is still a radial line in northern Ontario and it is more sensitive to voltage swings and sags that cause the customer to lose power. Is the customer aware of this difference? This choice also affects the power reliability for customers in Greenstone. o IESO: Yes, the IESO has discussed these technical characteristics in meetings with the customer. *Presentation Summary - Stage Two (for 2020): Scenario B includes the second phase of the mine, but no pipeline pumping stations. Recommendations to address this load include a line replacement of sections of the A4L or 20 MW of customer based on-site gas generation in the form of two 10 MW generating units to provide redundancy. Scenario C includes a larger build out to accommodate all mining and pipeline electrical demand requirements. Recommendations include installing a new 230kV line from the existing East-West Tie into the Longlac area as well as new 115kV facilities to connect the existing Longlac and Manitouwadge TS. Costs and in-service dates for both scenarios are included in the plan.* • Given that it's November, the earliest a 230kV line could be built is the beginning of 2021, with the more likely scenario being 2022 or 2023. For Scenario B, Stage 2, will the customer be required to put in a generator or pay to upgrade the existing line? o IESO: For Scenario B, the customer could put in a generator or upgrade the existing line for additional capacity. Benefits from small generation onsite being grid-connected, include the ability to load displace in terms of industrial rates, also avoiding peak-demand periods through the Industrial Conservation Initiative, which provides an opportunity for the customer to reduce the Global Adjustment portion of their rate. Individual customer connection requests are reviewed during the System Impact Assessment (SIA) with the IESO. • For Scenario C, under stage two, if the mine chooses to self-generate, what becomes of the pipeline? The customer's two options are that they pay the cost of the new 230kV/115kV, or they pay to self-generate? o IESO: The customer has started their SIA work with the IESO for assessment of only the pipeline and once finalized, it becomes a public document. • West of this area, the oil pipeline is looking at off-grid generation for pumping stations, which could also be the fallback solution here. o IESO: The customer is still looking at possibilities for electricity supply and an interim solution may be gas based self-generation to bridge to the transmission supply. It is up to customer to accommodate their timeline and costs. • For Scenario B, the A4L has 7-8MW of additional capacity. If the existing (LDC) load increases to greater than what has been projected, who pays? o IESO: Cost allocation would need to be discussed with Hydro One Distribution. • Northern Ontario needs to be on the same playing field as Southern Ontario	☐ Share more details on available support programs

	where there is capacity for development without major costs. ○ Note to Meeting Summary: The IESO believes that Northern Ontario is on the same playing field as southern Ontario, when it comes to capacity/reliability planning. The planning criterion, used by the IESO, does not distinguish between northern and southern Ontario. Comparable loads in southern Ontario are planned under the same criteria as the north. • First Nation communities are planning for growth and this information is available for Hydro One. AZA is looking at developing 50 homes in Greenstone in a five year period with a target of 75, and also business growth. Bingwi Neyaashi Anishinaabek is also growing. Growth is being constrained as a result of the existing infrastructure and Hydro One needs to be aware of the organic growth coming on as a result of development. From an economic development prospective, the community formerly participated in the Ministry of Natural Resources procurement for a wood pellet plus co-generation facility but was declined because of a lack of capacity on the A4L. White Sand also submitted a proposal at the same time. Studies are currently being undertaken to get a better handle on the community growth with people moving back and new businesses being established. Communities are working on economic development plans, for example, Bingwi Neyaashi is developing a saw mill. • Electrical task force (CVNW) is looking at the supply of advance biomass to Thunder Bay from somewhere other than Norway; supply within the region. • Connection timeframes are a catch 22 - the time frames for industrial or economic growth are faster than the timeframes for the system to respond • What is the driver for the 115Kv line from Manitouage to Longlac? ○ IESO: To connect two remote pumping stations. • Does the proponent pay for the whole circuit, or is it a shared cost since it will improve the reliability and power quality to customers in Greenstone. ○ IESO: Cost responsibility the mandate of the Ontario Energy Board. The proponent is the driver for the capacity need at this time. **<u>Recommendation Near-Term Plan Stage 1</u>** • The five year development time for an in-service date of 2020 on the 230kV is optimistic. The line is 150km in length and will require a full environmental assessment. At a certain point, options are eliminated because it is not realistic. ○ IESO: The 230 kV transmission line is required if the mine and all four pipeline pumping stations connect to the grid. Proponents are investigating connections to the grid so development work has progressed, which could shorten lead times. It is up to the proponent to find the service provider and build a line. Industrials can build lines faster. However, the IESO agrees it is challenging, if the pipeline company wants to be supplied by the 230kV. Options include delaying their in-service date or finding an interim solution. The IESO understands that the pipeline company views self-generation is an interim option, which buys time for eventual grid connection. • First Nation communities have been looking at development in the area and understand the timing and challenges – it is overly optimistic. Many FN	☐ Communicate to Hydro One the availability of First Nation community growth data

	communities have done substantial EA work for transmission and there is potential to use this development work and reduce the timeframe. Ideally, both customers would make a decision today. **<u>Implementation Considerations</u>** *Presentation Summary: Implementation of the plan elements are driven by industrial development and according to the Ontario Energy Board's Transmission System Code benefitting customers are responsible for related costs. IESO does not have a direct role in agreements between customers and proponents. We work with proponents and provide information as required and encourage solutions to align with recommendations so they are considered in broader planning. A description was provided on the role of the customer, proponent, communities and the IESO in implementation.* • Is there a mechanism in place to challenge the rules in the Transmission System Code that say that the benefitting customer has to incur the costs recognizing that work will benefit society, i.e. improvement of quality of life? ○ IESO: There are discussions with the Ontario Energy Board on this and a member of Common Voice Northwest is part of this group. • The priority project exemption allows the Minister of Energy to proclaim a project to go ahead and exempts it from the Transmission System Code. ○ IESO: Bill 135 has not yet passed. **<u>Medium and Long-term Planning Drivers</u>** *Presentation Summary: The Interim Plan looked at first five years; the full plan will look out 20 years. Medium and long-term planning drivers include additional mining claims in Greenstone area, Ring of Fire supply, cost considerations of Little Jackfish and community energy opportunities. Scenarios B and C consider phase two of the Geraldton mine. Incremental costs were provided for the Beardmore mine options.* **Additional Mining Claims** • Where is the location of the extra 5MW needed for processing for the Geraldton mine? If the Geraldton mine self-generates for the Hardrock portion, the extra 5MW could come off the grid, but would eliminate the ability of the LDC to supply the population growth from Longlac TS. ○ IESO: Phase 2 of Geraldton mine will accommodate a 10MW load increase which includes processing; 5MW would be supplied at Beardmore station. This will be confirmed. IESO is recommending that the customer pursue grid connection. We will look at additional scenarios where the Hardrock mine uses self-generation, Brookbank uses the capacity on the A4L and the accommodation of organic growth in the Greenstone area • Electrical Task Force estimates 35MW for the Hardrock portion and an additional 5MW for hoisting mechanisms, dewatering, etc. for a total load of 40MW. ○ IESO: We have assumed 35MW is the full phase. This will be confirmed. • At the recent open house for Greenstone Gold it was mentioned that the environmental assessment was studying hard rock for years 1-15 and extending the life of the mine past 15 years with Brookbank. The 5mw is tied to Brookbank for extraction purposes so the community expansion would	☐ Confirm which new mine and processing loads will be associated with the Beardmore mine and where they will be located ☐ Look into a scenario where Hardrock mine uses self-generation and Brookbank uses all capacity on A4L, and organic growth in Greenstone area associated with Hardrock cannot be accommodated without upgrades

come before the 5MW at Brookbank.

Ring of Fire

- Is the North-South recommendation the preferred source?
  - IESO: The IESO's recommendation from the North of Dryden plan still remains that both options are comparable in cost. For the east-west route, there are cost sharing opportunities with the line to Pickle Lake. For the north-south route, the case for the line to Greenstone would be made better by having more customers utilizing the facility.
- Does the proponent decide on the option?
  - IESO: Yes, the preferred option is selected by the proponent, but the option is also subject to an environmental assessment which would look at the alternatives.
- What is the timeline? This decision affects other decisions. If they choose the east-west route does that impact the 230 kV supply into Longlac? No.
  - IESO: Timing and decision will be based on the when the strongest economic case is made. The line to Longlac is still the IESO's recommended lowest cost solution for Scenario C. For north of Dryden, the line to Pickle Lake is the recommendation regardless of the Ring of Fire. These customers create greater utilization and therefore economic efficiency of the resources.
- The cost of the transportation corridor is ten times the cost of transmission. The SNC Lavalin study showed that building a transmission line alongside a corridor reduces costs by 2/3. Therefore, the transportation corridor will determine the line. There could be two corridors – road and rail.
- The line to Pickle Lake is considered a network asset. Will the line from Nipigon to Greenstone also be a network asset and what is the impact of this classification on costs? Will the line to Ring of Fire be a private line?
  - IESO: Classification of the line to Pickle Lake is yet to be determined by the Ontario Energy Board. The IESO may be called upon to provide information on the characteristics of the line and we are preparing evidence now. The line to Longlac is the same.
- The line to Pickle Lake has already been deemed a priority project, so it is going ahead. Building a line without an established need doesn't allow for classification and cost allocation - it is a catch 22.
  - IESO: The line is going ahead but that doesn't determine what rate pool it will go in to. This line is a prerequisite to remote community connection and the business case attributed costs for this line to remote communities.
- Routing and cost of transportation would be determined by the environmental assessment, which would include extensive Aboriginal consultation which will help drive routing. First Nations expect to be extensively involved. First Nations working with WZI would support development of a new line to Geraldton along an existing corridor as this would have less environmental impact.
- There is a lot of wind potential on the corridor to Greenstone.

	Little Jackfish • Is there a credit for cap and trade? The province has announced $20/ton in 2017 and $30/ton thereafter. The credit was calculated at $84 million capital cost credit. ○ IESO: A risk analysis was completed on the price of natural gas, which included carbon pricing either through cap and trade or a carbon adder. The $6/MWh figure represents an average, not a full probability curve. • How many MW are available at Little Jackfish as a peaking plant? If the 230kV circuit is in by 2020, is the expectation that OPG will not build Little Jackfish? ○ IESO: 70 MW is available for rating. The final report will consider the cost savings of a 230 kV line on the east shores of Lake Nipigon and whether it is enough to change the outcome. The savings are relatively small and they don't change the outcome relative to other options like supplying energy from the system or new natural gas generation. The future system need is projected to be capacity related and Little Jackfish is an energy resource. This will be included in the final report. **Community Energy Opportunities** • Is there an update on the liquid natural gas plant in the Nipigon area to supply the North Shore area? ○ IESO: The IESO has not received additional information. • An industrial client in Terrace Bay is also looking at high pressure natural gas, but not sure if project is still moving ahead.	☐ Confirm analysis for Little Jackfish includes current cap and trade figures
5	**Next Steps** • When will the final plan be released? ○ IESO: The final plan will be released in mid-2016. • There are three big things: Greenstone Gold, Energy East and Ring of Fire. If the proponents are going to reject the recommendations from the Interim Report and go with self-generation, this should be known before the IESO finalizes the regional plan. ○ IESO: The purpose of the Interim Report was so that customers could see the available options and IESO's recommendations. The plan is central to industrial demand and focuses on two customers (the mining development and the pipeline conversion). The customer has the right to choose any option they want. The report identified options that are prudent investments staged over time that could meet their needs. • If the planning is good for the proponent and not the local community then it's a lost opportunity to improve the reliability of the local area. Once a decision is made, especially if both customers implement self-generation, then the economic opportunities for the Ring of Fire are lost.	

6	**Next Meeting & Adjournment** Focus of the next meeting will be a review of the draft report. Next meeting to be held at the end of March/beginning of April and will be hosted an hour earlier from 12:00 – 3:00 p.m.	☐ Circulate draft IRRP for review by LAC

Greenstone-Marathon Local Advisory Committee
Meeting #3

Red Rock Indian Band
2 Gas Rd., Lake Helen Reserve, Nipigon, ON P0T 2J0

Thursday, May 12, 2016

12:00 pm - 3:00 pm

AGENDA

AGENDA ITEM	TIME	TOPIC	LEAD	MATERIAL
1	11:45 p.m.	Public Registration		
2	12:00 p.m.	Opening Remarks & Roundtable Introductions	Luisa Da Rocha	
3	12:10 p.m.	Review of Minutes from Meeting #2	Luisa Da Rocha	✔
4	12:20 p.m.	Presentation and Discussion – Draft Greenstone-Marathon IRRP	Joe Toneguzzo/ Christopher Reali	✔
5	1:45 p.m.	BREAK		
6	2:00 p.m.	Presentation and Discussion (cont'd) – Draft Greenstone-Marathon IRRP	Joe Toneguzzo/ Christopher Reali	✔
7	2:40 p.m.	Public Questions	Luisa Da Rocha	
8	2:55 p.m.	Discussion of LAC Role Going Forward	Luisa Da Rocha	
9	3:00 p.m.	Closing Remarks & Meeting Adjournment		

Meeting Notes

Meeting Information	
Date:	May 12, 2016
Location:	Red Rock Indian Band, Lake Helen Reserve, ON
Subject:	Greenstone-Marathon Local Advisory Committee Meeting #3
Attendees:	**<u>Committee Members in Attendance</u>** Rod Bosch Joe Donio Larry Doran (via webinar) Armand Giguere Harold Harkonen Jordan Hatton Stan Johnston **<u>IESO</u>** Christopher Reali Joe Toneguzzo Luisa Da Rocha Stephanie Aldersley
LAC Meeting Materials:	http://www.ieso.ca/Pages/Participate/Regional-Planning/Northwest-Ontario/Greenstone-Marathon.aspx

	Key Topics	Follow up Actions
1	**Opening Remarks and Roundtable Introductions** • Ms. Da Rocha welcomed everyone and discussed the meeting focus • Roundtable introductions were made	
2	**Review of Summary of Meeting #2 from November 25, 2015** *Summary: The LAC reviewed the minutes of the second Committee meeting held on November 25, 2015. This second Committee meeting was held to review the near-term plan as presented at the inaugural Committee meeting, with a focus on the requirements for successful implementation. The second Committee meeting also introduced some initial analysis of the medium and long-term planning drivers.* • The Municipality of Hornepayne is not listed in the plan. They should be since developments in Hornepayne would also affect the area. ○ IESO: The IESO will add Hornepayne to the list of municipalities for clarity. Hornepayne is supplied from Manitouwadge station and the forecasted demand of that station includes the forecasted demand for the Municipality of Hornepayne.	☐ IESO will add Hornepayne to the list of municipalities in the IRRP ☐ Summary from LAC Meeting #2 to be posted on IESO website

3	**Presentation on the Summary of the Draft IRRP** • Presentation delivered by Joe Toneguzzo and Christopher Reali, IESO. A copy of the presentation is available on the LAC Meeting Materials link above. ○ Review of Action Items from LAC meeting #2, and IESO's follow-up ○ Summary of draft IRRP Findings and Recommendations for feedback ○ Next Steps **<u>Review of LAC Meeting #2 Action Items for IESO</u>** *Summary: The IESO provided some background on the history of the Greenstone-Marathon IRRP: following the release of the IESO's Draft Scoping Assessment Report, the feedback from the Municipality of Greenstone indicated that the timelines of the IRRP were not conducive to the development the municipality is seeing. The IESO responded by including an Interim Report in the final Scoping Assessment Report. The Interim IRRP was published in June 2015 for the purpose of facilitating critical decision making for customers in a manner that accommodates near-term development timelines. The IESO has since met with customers, governments, and others, where updates were provided that were incorporated into the draft IRRP. The IESO reviewed their responses to eight Action Items it took back for additional analysis and confirmation after LAC meeting #2. The Action Items related to project lead times (1), demand forecast information (4), industrial rates (1), cost of carbon (1), and draft IRRP circulation (1).* • Does the 1 MW figure for new load associated with a population increase of 1,200 people include increase in the commercial load that could result from that increase in population. ○ IESO: The IESO's understanding is that a multi-variant econometric forecasting tool is used and that increased commercial activity would be something that is accounted for based on an increase in population and employment econometrics. The LDC forecast information is provided by Hydro One Distribution. Hydro One would be best to address the details. • The 1 MW figure seems small if it includes increased commercial activity, it would be appropriate if it is just for the population. ○ IESO: Hydro One would have to confirm, but the committee should note that there is about 20% of margin that exists in the forecast, and it should be clarified that the 1 MW is a coincident peak increase. What that means is that it is not equal to the increase in total connected load from increased population or increased commercial activity, but reflects that portion of the increased demand from the driver in population and employment that coincides with the peak for the area. Coincident demand is lower than total connected load. The IESO believes this is a reasonable number. • Can you translate that 20% margin figure to MW, where the 20% represents the margin on A4L following the connection of only the Beardmore mine. ○ IESO: In the range of 4-5 MW. • How can you accommodate 4-5 MW more load supplied to Geraldton if the Beardmore mine takes up all of the capacity on the line? It is not the station that is limiting, it is the line. ○ IESO: If the Beardmore mine were to connect to the grid at Beardmore, the circuit A4L would be able to supply more capacity than the 25 MW that is referenced in the IRRP. As indicated in the IRRP, the 25 MW of capacity on A4L is based on the assumption that all of the new load is	

connected at the end of the line. There would be less voltage drop contributed by the Beardmore mine compared to load at the end of the line. Since there is less voltage drop, you could supply more community load at Longlac TS.

Summary of Draft IRRP

Near-term Needs

Presentation Summary: The IESO provided an overview of the near and medium to long-term recommendations described in the draft IRRP made public prior to the LAC meeting. The three near-term demand forecast scenarios for the Greenstone Subsystem were reviewed. The IESO clarified an update to the near-term demand forecast related to the Geraldton mining project. Initially the project was communicated to the IESO as materializing in two stages: Stage 1 was 25 MW in 2018, and Stage 2 was an additional 10 MW in 2020. The update from the proponent indicated a single stage where all of the customer's electrical demand would materialize in 2019. The three near-term demand forecast scenarios indicate that (1) the existing system is sufficient to supply forecasted demand if no industrial customers materialize, (2) depending on if only the Geraldton mine materializes or if the Geraldton mine and the pipeline project materializes, different levels of expansion would be required.

- Is the Beardmore mine included in the forecast for scenario B?
  - IESO: The Beardmore mine is considered in the medium term, whereas the graph (slide 9) illustrates just the near-term. For the purpose of a conservative representation of the medium term, an in-service date of 2021 was used for the Beardmore mine.
- Could recommended upgrades for forecast scenarios B and C accommodate development of the Beardmore mine or would further upgrades be required?
  - IESO: Our Recommended Stage 2 for the near-term would fully accommodate the growth in the area for the near, medium, and long term. If the 230 kV line component of Stage 2 is not in place, then incremental enhancements would be required. The options are discussed later in the summary: upgrading a section of the existing circuit, and another option is installing additional gas generation.

Recommended Near-term Plan: Stage 1

Presentation Summary: The recommended first stage would coincide with the in-service of the Geraldton mine. This would include the installation of +40 Mvar of reactive compensation at the mine site, and grid-connected generation at the customer site with the level of redundancy acceptable to the customer. The IESO has used two 10 MW natural gas gensets as its assumption, which is consistent with Ontario reliability criteria. The assumed two 10 MW natural gas gensets were used in the Net Present Value (NPV) economic analysis. The IESO noted that the option to upgrade the existing 115 kV circuit continues to be more economic than installing customer generation, but the change in project schedule for the mine resulted in insufficient lead time. If the Geraldton mine timelines are delayed for certain reasons, the upgrade of the existing circuit should be considered.

- Is the IESO's recommendation that the mine install their own generation?
  - IESO: Yes – grid-connected customer-based generation. Based on the updated timing provided by the mine developer of a revised in-service date of a single stage in 2019, the option to upgrade the existing circuit would not be able to accommodate those lead times.
- We have been saying for the past two years that you cannot accommodate

the lead times.
  - IESO: An Interim Report was released in June of last year to facilitate the critical decision making of customers in the area. There was no response from the industrial customer to those recommendations at that time. The IESO cannot direct an industrial customer to pursue an option in a situation where the reliability of the interconnected system is not at risk. The Interim Report was released and if the customer wanted to pursue that option, they would have engaged Hydro One. This critical timing was outlined in the implementation requirements of the Report. The customer chose not to proceed, time passed and this is the current situation. The onus lies with the customer and the proponent. The IESO does not have the authority to direct this.
- The Minister of Energy could have declared this a priority project and that would have addressed this issue.
- Is the only benefit to connect to the grid for the mine backup power or are there any commercial incentives?
  - IESO: Some of the programs that were identified in the presentation include means of managing electricity costs. If a grid connected customer generation plant was used to peak clip, it could take advantage of the Industrial Conservation Initiative which allows them to avoid a portion of their Global Adjustment charge. If the generation is operated as a Combined Heat and Power (CHP) and is consistent with the rules of the Industrial Accelerator Program, they could be eligible for a capital incentive. The IESO met with the customer, made them aware of these benefits and connected them with the IESO's appropriate conservation contacts. The other possibility is that a third party generating company could own and operate the plant and establish a power purchase agreement with the mine. That generating company would then have the benefit of having access to the energy market and any future markets on the horizon, such as a capacity auction.
- I was not aware that a generator could have a separate power purchase agreement (with another customer) and also connect to the grid.
  - IESO: As long as the IESO is aware of those bilateral agreements when it comes to settlement.
- Isn't it cheaper for them to go off-grid? They would not have any global adjustment, and would avoid some costs for certain things to be built and be connected to the grid.
  - IESO: The IESO's analysis indicates that grid connection would be more economic. Not connecting to the grid would expose them to other costs, such as the cost of greater gas burn, and higher exposure to any cost of carbon. In terms of additional connection costs, it should be noted that as a part of the mining project's Environmental Assessment (EA) project description is the need to rebuild and relocate a Hydro One transformer station and dismantle the existing one as the facility is on top of where the mine pit would be. Since this essentially amounts to building a new station, with 44 kV feeders, which are relatively high capacity, it would be beneficial to take that opportunity to build that station in a way where the customer could make use of this activity. It is expected that the incremental cost would be low since the station would be rebuilt anyway. The alternative identified by the developer in their EA is a new 115 kV station with 2.5 km line tap. It is important to note that an additional

station with a 2.5 km tap would be more costly than making use of a rebuilt station and would require greater approvals such as a leave to construct due to the tap length. If the Longlac TS is going to be relocated and rebuilt anyway, providing a 44 kV grid supply point for the mine could be beneficial. This arrangement provides access to both the electricity and gas markets, offering diversity, which may be economically advantageous.

- Isn't the mine looking to start the mine first, then move the station later? Is there enough time to move the station in time for the 2019 start date?
    - IESO: We do not have the answer for that. A typical step-down DESN station would have a 2.5-3 year lead time. It is also important to note that there are a number of things that this project needs to get done to materialize, such as the realignment of the highway. It is important to recognize that these industrial projects are mega projects on their own with many challenging lead times and approvals, beyond those discussed regarding electrical supply.

Recommended Near-term Plan: Stage 2

Presentation Summary: The recommended second stage would coincide with the in-service of the pipeline conversion project. This includes the installation of a new 230 kV supply and a new 115 kV connection line. Although route analysis is not considered within the scope of an IRRP, it is necessary to assume routing for the purpose of establishing distances and develop cost estimates. The IESO considered two routing concepts for the purpose of costing, and as indicated in earlier LAC meetings, the IESO is indifferent to the two routing concepts as they have approximately the same cost. The IESO also noted that if timelines communicated by the Geraldton mine developer are delayed, it may be more economic to advance the 230 kV line to be in-service coincident with the mine, if there is certainty that the pipeline is proceeding.

- In this scenario, is it only if the pumping stations materialize that the 230 kV line is built?
    - IESO: Under the scenarios that were investigated, if the pipeline project materializes a major reinforcement would be needed and the 230 kV line is the most economic.
- Could you not just get a tap off the end for the 115 kV? Why is a line that goes down to Manitouwadge recommended?
    - IESO: The pipeline developer has communicated to the IESO that they have an additional reliability requirement that no two adjacent pumping stations can be lost for the same outage. The 115 kV line is needed in this particular arrangement to satisfy that requirement. A radial could not be established out of Longlac TS to prevent the loss of multiple pumping stations.
- Are there reasons why the pumping station could not go out to Hearst? Isn't that where the other pumping station is close to?
    - IESO: Yes, there are many technical challenges with interconnecting Longlac and Hearst stations. Therefore, the Manitouwadge option is preferred.
- Is there a cost breakdown between the 230 kV and 115 kV portions of the $160 million?
    - IESO: Yes, it is approximately $70 million for the 230 kV and $90 million for the 115 kV. It should also be noted that the NPV costs are only those costs that are incurred within the 20-year planning period for

	comparative purposes, and are not all-in costs. • Stage 2 greatly improves the reliability of supply. Greenstone would no longer be on the end of a radial supply, which has been a point of contention in the Northwest for years. Who would pay for this? o IESO: Ultimately the decision of cost allocation is up to the Ontario Energy Board. The likely scenario based on the beneficiary pay principle in Ontario is that the industrial customers triggering the enhancements would bear those costs. If any additional customers materialize within 15 years, regulations stipulate that those customers must also contribute to the costs. • Wouldn't it be cheaper to not connect those pumping stations that are far away from the grid and supply them with their own generation? o IESO: The pipeline developer has that option. The IRRP considers that option in the analysis and is identified in the report as "Option C1". The recommended Stage 2 is identified as "Option C2". The costs for Option C1 and Option C2 are comparable, but Option C2 provides greater reliability, so it was recommended (as Stage 2) on that basis. • If the 230 kV line is only \$70 million and could supply the mine's needs and most of what the pipeline needs, and Stage 1 is \$65 million, but the 230 kV line is superior, couldn't they just go with the 230 kV line? It would be clearer if the \$90M and the \$160M are not together in the report. o IESO: Yes, however the lead-times cannot accommodate the mine's communicated timeline. This is why the IESO has indicated that it may be advantageous if the mine's timeline ends up being delayed, to advance the 230 kV line. The IESO will further clarify this point in the IRRP report. • The mine has indicated that they want to move ahead in one stage by 2019 which means they are advancing the second half of the project. The recommendation for supply would not be in service until 2021 or 2022 given the 5-7 year development lead time. They are being delayed because there is no way to supply them. o IESO: The shift to one in-service date could also be viewed as a one-year delay on the first phase. The 5-7 year lead time is an average. Private companies can usually accelerate this. It is important to remember that just as the electricity infrastructure needs to go through the approval process to be brought in to service, so does the mine. • It was noted in the draft report that the OEB is looking into the cost allocation process. What is involved in that review? o IESO: The review is just commencing. It is in response to the Southern Essex County Transmission Reinforcement project, and is intended to ensure that there is consistency in the Transmission System Code and Distribution System Code in how costs are allocated. There are a number of parties that have chosen to participate in this process including the Energy Task Force and the Northern Ontario Chambers of Commerce. It is anticipated that cost allocation topics that have been brought up in the north will be brought up at the Board as part of this process. • Regarding the cost allocation review, it comes down to socio-economic issues. The north wants to be on same footing as southern Ontario. • Are there any private companies that have been able to build a line of this magnitude in under 5 years? o IESO: The supply to Detour Lake is a recent example of a new 230kV line built by a private developer. The IESO believes timelines may have been	☐ IESO to clarify that the 230 kV line option is only \$5 million NPV more than Stage 1, but is a superior supply option.

	shorter. • There are a lot of First Nations in the area that are interested in developing the new 230 kV line. The First Nations have met with the customers, but they have their own timelines and are not at the point where they can commit to anything to get a firm start date. **Implementation Considerations; from Plan to Project** *Presentation Summary: Implementation of the plan elements are driven by industrial development and according to the Ontario Energy Board's Transmission System Code benefitting customers are responsible for related costs. IESO does not have a direct role in agreements between customers and proponents. The IESO works with proponents, provides information as required and provides approvals support for solutions that align with recommendations. A description was provided on the role of the customer, proponent, communities and the IESO in implementation.* **Medium and Long-term Plan** *Presentation Summary: Medium and long-term planning drivers and recommendations were outlined including, additional mining claims in Greenstone, supply to the Ring of Fire, cost considerations of the Little Jackfish hydroelectric project, and community energy opportunities. The recommended actions by the IESO are: (1) mining developers retain the upgrading of circuit A4L as an economic option, (2) a new transmission line be considered when investigating a multi-use infrastructure corridor to the Ring of Fire, and (3) the Town of Marathon may wish to perform a detailed feasibility or engineering study of cogeneration.* • Is there an estimate of planned outages to Greenstone for the option of upgrading circuit A4L? o IESO: The IESO does not have firm details on planned outages. Some ideas to reduce the time of planned outages would be to build the replacement section alongside the existing circuit if there is right of way space available and then cut over afterward, or build a temporary bypass. • The Town of Marathon is interested in pursuing the cogeneration option. Is there a contact for information related to Save on Energy? o IESO: The IESO will take that as an action. Note that other factors should be considered such as cost of carbon, expanded natural gas supply to currently unserved communities, and Liquefied Natural Gas to be aware of when pursuing a cogeneration option. **Greenstone-Marathon IRRP Next Steps** *Presentation Summary: Customers are responsible for choosing their preferred options. The IESO will support customers and proponents where their choices align with the plan. The IESO does not have a direct role in implementation. A summary of possible implementation agreements were provided for information.* • Reiterating that the cost for Stage 1 is almost the same as the 230 kV line component of Stage 2, and this needs to come out more forcefully in the plan. o The action item has been noted previously. • If the mine chooses self-generation, does the near-term elements of the plan need to be revisited? Part of the plan is based on estimates - the $70 and $90 million figures sound reasonable, but the generation costs seem high. o IESO: If the mine chooses to go off-grid, it does not change the requirements significantly for the pumping station loads. The plan would not be revisited for this. However, more customers sharing the cost of	☐ IESO to provide details to Stan Johnson related to Save on Energy.

	facilities will be more economic from the perspective of any one customer compared to a single customer taking on the full cost. The IESO would need to consider a plan update if a significant event takes place. • Should the Committee not discuss the social aspects of the options? Option 1 allows little to no expansion in Greenstone, but option 2 has a lot of potential and more social value. Should there not be a recommendation in the report that discusses this? o IESO: The report includes a table that compares the options. If there are any changes to timing, the recommendations in the plan can change. The existing plan identifies where these changes may occur and forms a reference for future changes. • The socio-economic factors are not within the scope of the IESO. Could there be an appendix that indicates the socioeconomic factors that have been voiced by the LAC? When we have to make presentations to decision makers, it could be beneficial to have all of the analysis in one place. o IESO: This product is a good idea and the LAC may be the best equipped to produce the document. The IESO will include an opener in the report if the LAC report is produced after the IRRP publication to allow it to be slotted in without delaying the IRRP. • What is done with the plan? Is it presented to the customers? o IESO: Under the IESO license, the IRRP will be posted on the IESO website and OEB expects the IESO will use it as evidence to support regulatory process. Customers are made aware of the report through our individual discussions with them. • The LAC members will need to see the revised plan to create the LAC report.	☐ IESO to confirm how best to include the LAC's document in the final report.
5	**Next Steps** A discussion was held with the committee members about the role of the LAC following the publication of the IRRP. Options that were presented included: continuing the LAC to discuss the implementation of the plan, concluding the LAC, or meeting once a year to touch base on developments and discuss updates. The following was discussed in relation to the future role of the LAC. • Following the LAC's development of their report, the members will meet with the IESO to present the LAC's findings and discuss the future role of the LAC. This was agreed upon by the Committee members. • The Energy Task Force (ETF) has put together quite a bit on the societal factors and will contribute to the development of the addendum. • A committee member stated they will confirm the role that the community of Greenstone will contribute. • Perhaps feedback from the developers may be beneficial in the LAC report. • First Nations Committee members confirmed that their input will not represent the perspective of other communities including those not present at the LAC meetings. These committee members will make other First Nations LAC members aware of this opportunity. o IESO: The IESO can reach out to the communities that have not attended the LAC meetings to ensure that they are aware of their opportunity to provide input and let them know that this is a LAC-led product.	☐ IESO to reach out to other communities and inform them of the LAC document being developed.

	• How is government made aware of the plan? ○ IESO: The IESO briefs the Ministry of Energy on the plan. The IESO relies on the Ministry of Energy to discuss within government and invite the IESO when it requires support. • The ETF meets with government as well. • The First Nations have meetings with government and they are aware of what is being done. • The LAC probably won't start working on the report until there is a final IRRP. ○ IESO: It may not be necessary for the members to wait. The IESO is aware of the LAC's input. If the LAC wishes to move in parallel they can. • The LAC prefers to see the final wording at the end of June and the LAC will strive to produce a socioeconomic product following. ○ IESO: The IESO will include a placeholder in the final document to make sure it is known that the LAC's report is forthcoming. • The LAC prefers that their report be a direct appendix to the report and not a separate document. Having it as a direct appendix is critical to illustrating the input as an entire package. • The First Nations are very supportive of growth that can be supported by a 230kV line and will work with the ETF on the development of the LAC report once the IRRP is released. • It was noted by several members that it is important to include the LAC member report within the IRRP so that it is one document. Actions items were reviewed with the LAC members: • A two-week comment period will be provided for additional feedback. • The IRRP will be posted to the IESO website at the end of June and will include a placeholder for LAC submission. • IESO to determine how the LAC report will be included in the report. • The LAC members will provide a report on socio-economic factors and organize a LAC meeting to discuss the submission. The future role of the LAC will also be discussed at this meeting.	☐ IESO to confirm how the LAC report will be handled based on the expectation of what an IRRP can and cannot include.
	Public Questions • Has there been any change in the load assumptions for the 115 kV expansion east of Longlac? ○ IESO: No there has not been a change. There are some additional loads in certain scenarios in the Marathon area, but they would not directly share those connection facilities.	
6	**Next Meeting & Adjournment** • The next meeting will be called by the LAC when they are ready to brief the IESO on their socio-economic analysis and report.	

K.2 Additional Feedback Received

The following documents the comments submitted on the publically posted Draft IRRP during the comment period from May 12-27, 2016.

Comments on Draft Greenstone-Marathon
Integrated Regional Resource Plan (IRRP)

OPG was pleased to review the draft Greenstone-Marathon Integrated Regional Resource Plan (IRRP) posted in May 2016.

The Little Jackfish River Hydroelectric Project (the "Project") is considered in various sections of the IRRP for the synergies it could potentially provide to the system. As the lead proponent for the Project, OPG would like to further highlight the following benefits and synergies to ensure each is fully considered in the IESO's planning.

Project Benefits

- About 400 jobs (600 at peak) during the three-year construction period
  - For every direct construction job created, another 0.65 person years of employment will be generated elsewhere in Northwestern Ontario
- Approximately $300-400M in economic spin-offs
- $490M Gross Revenue Charges to the Province over its 90-year life
- Significant water storage capability in the Little Jackfish River system with minimal new flooding, providing renewable, dispatchable energy to meet daily and seasonal demand

First Nation Benefits

- Opportunity for equity ownership in the Project for Lake Nipigon First Nations
- Supports economic development and capacity building of area First Nations
- Compliments government and privately-funded training initiatives aimed at getting local Aboriginal People qualified to participate in construction activities
- Potential to provide renewable generation to the remote First Nation communities of Whitesand, Kiashke Zaaging Anishinaabek, Marten Falls, Eabametoong, and Neskantaga, removing costly and unhealthy diesel dependency

Synergy with other Economic Development in Northwestern Ontario

- Addresses the needs of mining proponents who require a cost-effective and reliable source of power for mining developments
- Acts as a job and business incubator, helping develop skills and business relationships needed to support future economic development initiatives in Northwestern Ontario, in the Greenstone-Marathon areas as well as potentially the Ring of Fire area
- Creates opportunity to share costs of new infrastructure (e.g. transmission, roads) with mining and other resource users in the region

Environmental Considerations

- Reduces diesel dependency and the associated environmental, health, and safety risks of such diesel dependency, related to mining operations and First Nation communities
- Provides a more environmentally responsible alternative to greenhouse gas emitting generation such as natural gas or diesel
- Aligns with provincial and federal climate change mitigation policy

- Utilizes a transmission corridor that has been studied under a formal environmental assessment, where plans have been developed to mitigate any significant environmental impacts

OPG recommends that the IESO include scenarios which recognize removal of diesel dependency to the extent possible and reduction of natural gas generation as currently under consideration by provincial policy and climate change mitigation strategies. Giving consideration to greenhouse gas concerns, environmental regulations and the expected upward trajectory of carbon prices, a project such as the Little Jackfish River Hydroelectric Project aligns with efforts to meet established provincial greenhouse gas reduction targets (e.g. 2020/2030/2050 targets).