REPORT

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System Impact Assessment Report

Connection Assessment & Approval Process

Issue 1.0

CAA ID 2008-356

Applicant: Ontario Power Generation Inc.
Project: Beck 1 G9 Rehabilitation
Proposed in service date: December 31, 2010

Market Facilitation Department

August 20, 2009

Final Report

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System Impact Assessment Report

Beck 1 G9 Rehabilitation

Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

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

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

HYDRO ONE

Special Notes and Limitations of Study Results

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

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

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

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

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

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

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Reference (Section and Paragraph)	Description of Change

1. SIA Findings

1.1 SIA Conclusions

Ontario Power Generation Inc. plans to upgrade Sir Adam Beck Generation Station #1, unit G9 to increase its capacity to 68.5 MVA. The SIA concluded that the project, subject to the requirements specified in this report, is expected to have no material adverse impact on the reliability of the IESO controlled grid.

1.1.1 Study Results and Conclusions

This study determined that additional capacity at Beck #1 GS is beneficial for reducing the flow through the Allanburg autotransformers. Additional renewable capacity is generally beneficial for the whole Ontario system given the scheduled de-registration of coal fired generators.

The tests identified that the 115kV circuit Q4N from Beck #1 GS to Stanley junction, with all elements in service, may currently be utilized close to its planning criteria capacity under extreme conditions. Hydro One recently increased the circuit rating (CAA ID#2008-EX406) to accommodate more power out of the Beck#1 complex. Under severe weather conditions combined with high water levels, the post-contingency flow may exceed the circuit's continuous rating at this junction but not its short term emergency rating. If such a remote condition occurs the generation at Beck#1 will have to be reduced to bring the post contingency Q4N flow within applicable ratings.

The power transfer capability of the existing or future reinforced Queenston Flow West (QFW) transmission interface is not affected by the increased output of Beck#1 G9.

Without the QFW transmission reinforcement, the power transfer capability of the existing QFW interface can cause congestion. If dispatch instructions from the IESO cause Beck#1 G9 to deviate from its market schedule due to congestion on the interface, Ontario Power Generation would be eligible to receive congestion management settlement credit (CMSC) payments.

In the future, if the frequency of constraints or associated electricity market congestion costs increases materially, the IESO may require Beck#1 G9 to participate in a special protection system (SPS) and to install the necessary protection and control facilities to effect the required actions.

There is sufficient breaker capability margin to accommodate the fault level increase due to Beck#1 G9 rehabilitation.

1.1.2 Recommendations

OPG is encouraged to officially submit preliminary applications to Hydro One and IESO for all upgrades they're intending to perform at Beck#1 GS. This will facilitate appropriate planning of necessary transmission upgrades that, when finalized, will allow the full output of Beck#1 GS be delivered under all weather conditions.

1.2 IESO's Requirements for Connection

The proposed generation facility shall comply with all applicable requirements of Market Rules, Chapter 4, Appendix 4.2.

1.2.1 QFW interface – Special Protection System

Transmission flows are determined by the pattern of loads and generation, and the characteristics of the transmission system at any given time. These factors are inherently somewhat unpredictable due to the random availability of transmission and generation facilities, the effect of weather on load levels and the dispatch of generation based on market mechanisms.

Congestion is the condition under which the trades that market participants wish to implement exceed the capability of the IESO-controlled grid. It usually requires the IESO to adjust the output of generators, decreasing it in one area to relieve the constraint and increasing it in another area to meet the load requirements.

The power transfer capability of the QFW transmission interface needs to be greater than 2,300 MW to avoid constraining existing generation facilities east of the interface and New York – Niagara imports. Without the QFW transmission reinforcement, the existing QFW interface with its summer power transfer capability of about 1,750 MW can cause congestion. The addition of Beck#1 G9 and any other new generation east of the interface may aggravate conditions where constraints occur.

If dispatch instructions from the IESO cause Beck#1 G9 to deviate from its market schedule due to congestion on the interface, Ontario Power Generation would be eligible to receive congestion management settlement credit (CMSC) payments.

In the future, if the frequency of constraints or associated electricity market costs to relieve congestion on the QFW interface increase materially, the IESO may recommend the installation of a special protection system (SPS) capable of rejecting generation east of the QFW interface. The installation of an SPS would be expected to increase the power transfer capability of the interface and thereby, relieve any congestion.

Should a SPS be installed, Beck#1 G9 will be required to connect and to participate in the SPS by installing appropriate protection and control facilities at Beck#1 G9.

Therefore, the design of protection and control facilities at Beck#1 G9 must not preclude the installation of protection and control facilities for a SPS should it be required in the future.

1.3 Notification of Conditional Approval for Connection Proposal

From the information provided, our review concludes that the proposed changes will not result in a material adverse impact on the reliability of the IESO-controlled grid. It is recommended to issue a Notification of Conditional Approval for the rehabilitation of Beck#1 G9.

Ontario Power Generation must complete the IESO Market Entry/Facility Registration process in a timely manner before IESO final approval to connect is granted. As part of the IESO Market Entry process, Ontario Power Generation must provide evidence to the IESO confirming that the equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in this assessment. This evidence shall be either type tests done in a controlled environment or commissioning tests done on-site. In either case, the testing must be done not only in accordance with widely recognized standards, but also to the satisfaction of the IESO. Until this evidence is provided and found acceptable to the IESO, the Market Entry process will not be considered complete and Ontario Power Generation must accept any restrictions the IESO may impose upon Beck#1 G9's participation in the IESO-administered markets or connection to the IESO-controlled grid.

The evidence must be supplied to the IESO within 30 days after completion of commissioning tests. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

– End of Section –

2. Introduction

Ontario Power Generation Inc. plans to rehabilitate Sir Adam Beck Generation Station #1, unit G9 generator. After rehabilitation, G9 will be able to generate 68.5 MVA. The G9 rehabilitation also requires replacement of its transformer T9. Breaker 52-M34 and associated disconnect switches will be retained. The scheduled permanent in service date is December 31, 2010.

2.1 Purpose

This report summarized the assessment of the data and models for the proposed G9, the intended mode of operation, the impact of the upgraded generating facility on the local transmission facilities and reviewed the dynamic performance of the new generating facility to ensure compliance with the Market Rules. The assessment was based on appropriate assumptions for generation and transmission projects, and related procedures and guidelines that are in force at the time of the application. The system model included existing generators and all new facilities (including new capacity at existing *generating facilities*) that have either signed a contract with a purchaser or have signed a connection cost recovery agreement with a transmitter.

2.2 Scope

All scenarios considered for this study focused on the Niagara 115 kV area where the new generator is connected.

2.3 Requirements and limitations

The pre-contingency base cases are assuming the system in normal operating configuration. The information supplied for the new generator assumes similarities to the newly upgraded G7 unit:

- The proponent is responsible for ensuring that the performance of the equipment that is eventually supplied and installed in this generation facility is similar to the predicted performance or exceeds the predicted performance observed in the simulation results obtained using provided equipment models and data.
- The proponent is required to provide type test data that validates parameters already used in the analysis or perform commissioning tests to find new parameters of the models.

– End of Section –

3. Project Description

Ontario Power Generation is planning to rehabilitate Beck#1 G9 to increase the output to 68.5 MVA. The new unit remains connected to the 115 kV 60 Hz “E9” bus located at Beck#1 GS through:

- T9 – 115 kV / 13.2 kV, 3 phase, 68.5 MVA ONWF transformer;
- 52-M34 – 115 kV, rated current 2500 A, rated symmetrical short circuit capability 40 kA, SF6 circuit breaker;
- 20HT9-T9 and 20HT9-E – 115/121 kV, continuous rated current 1200 A disconnect switches.

The “E9” bus can be isolated from “E8” bus by the existing 8E-9 switch and from “E10” bus by the existing 9E-10 switch, both locked closed.

Unit parameters supplied by the proponent and used for this study:

- Generator: Salient pole, 60 Hz, 68.5 MVA, 13.8 kV, 0.9 PF

Values for GENSAL parameters:

T’do = 7.64, T”do = 0.073, T”qo = 0.091, Inertia = 3.4, Speed dumping = 0, Xd = 0.812, Xq = 0.59, X’d = 0.306, X”d = X”q = 0.23, Xl = 0.11, S(1.0) = 0.107, S(1.2) = 0.327

The proponent provided the generator reactive power capability curves for G7 that are shown in Appendix A. For the rated output of 61.6 MW the generator can supply about 30 Mvar and absorb about 30 Mvar at its terminals thus meeting the Market Rules, Chapter 4, Appendix 4.2, Ref 1 requirements for reactive power capability.

- Excitation system: Potential or Compound Source Controlled Rectifier Exciter

Values for ESST4B parameters:

Tr = 0.01, KPR = 33.7, KIR = 3.37, VRMAX = 1, VRMIN = -0.87, TA = 0.01, KPM = 1, KIM = 0, VMMAX = 1, VMMIN = -0.87, KG = 0, KP = 4.45, KI = 0, VBMAX = 5.34, KC = 0.072, XL = 0, THETAP = 0

- Power system stabilizer: Dual-Input Stabilizer

Values of PSS2A parameters:

ISC1 = 1 (rotor speed deviation), REMBUS1 = 0, ICS2 = 3 (generator electrical power on MBASE PU), REMBUS 2 = 0, M = 5, N = 1, Tw1 = 15, Tw2 = 15, T6 = 0, Tw3 = 15, Tw4 = 0, T7 = 15, KS2 = 2.206, KS3 = 1, T8 = 0.5, T9 = 0.1, KS1 = 10, T1 = 0.08, T2 = 0.02, T3 = 0.08, T4 = 0.02, Vstmax = 0.1, Vstmin = -0.05

- Speed governor: Double-Derivative Hydro Governor

Values of WSHYDD parameters:

Db1 = 0, err = 0, Td = 0.1, K1 = 6.3, Tf = 0.1, K2 = 1.9, Ki = 0.25, R = 0.04, Tt = 1, Kg = 1.4, Tp = 0.2, Velopen = 0.07, Velclose = 0.07, Pmax = 1, Pmin = 0, db2 = 0, GV1 = 0.1, Pgv1 = 0, GV2 = 0.6, Pgv2 = 0.7, GV3 = 0.7, Pgv3 = 0.82, GV4 = 0.8, Pgv4 = 0.9, GV5 = 0.9, Pgv5 = 0.95, Aturb = -1, Bturb = 0.5, Tturb = 0.9, Trate = 61.6

– End of Section –

4. General requirements

4.1 Voltage requirements:

Appendix 4.1, reference 2 of the Market Rules states that equipment on the 115 kV grid in southern Ontario may be exposed to voltages as high as 127 kV. In addition, some recognized contingencies (e.g. load shedding, open line end) can cause a temporary voltage increase above the maximum continuous voltage. For these conditions, connection equipment may be exposed to voltages approximately 5% above the maximum continuous operating voltage for the period of time that it takes the IESO to direct operations to restore a normal voltage profile and to prepare for the next contingency. This re-preparation period will be as short as possible but it should not take longer than 30 minutes. Therefore, the IESO requires that 115 kV connection equipment in southern Ontario:

- must have a maximum continuous voltage rating of at least 127 kV; and
- must be able to remain in-service at voltages up to 133 kV for up to 30 minutes.

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

4.2 Maximum fault levels:

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

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

4.3 Protection Requirements:

New protection systems must be coordinated with existing protection systems and must be designed to satisfy the requirements of the Transmission System Code (TSC). Facilities designated as essential to power system reliability must be protected by two redundant protection systems according to section 8.2.1a of the TSC. These redundant protections systems must satisfy all requirements of the TSC but in particular they may not use common components, common battery banks or common secondary CT or PT windings.

As currently assessed, this facility is not designated as essential to power system reliability and therefore the above protection requirements do not apply. In the future, as the electrical system evolves, this facility may be designated as such and at that time the above requirements will apply.

To allow sufficient time to assess the impact on power system reliability, the connection applicant must submit any proposed protection changes to the IESO at least six (6) months before any actual changes are to be implemented on the existing protection systems.

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

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

The design of protection and control facilities at Beck#1 GS – G9 must not preclude the installation of protection and control facilities for generation rejection should they are required in the future.

Provided that all requirements of the Transmission System Code as specified in Schedules E, F and G of Appendix 1 (Version B) and any additional requirements identified by the applicable Transmitter (Hydro One) are satisfied, the IESO does not have additional requirements.

4.4 Monitoring Requirements:

The Market rules (Chapter 4 section 7.4) require that the generator shall provide the IESO with on-line monitored quantities on a continual basis as specified in Appendix 4.15 and achieving the performance standards specified in Appendix 4.19. End to end telemetry testing must be completed by the applicant along with the IESO to ensure that standards are met and sign conventions are well understood.

4.5 Reliability Requirements:

Prior to connecting to the IESO controlled grid, the proposed facility must be compliant with the applicable reliability standards set by the North American Electric Reliability Corporation (NERC) and the North East Power Coordinating Council (NPCC). A list of applicable standards, based on the proponent's/applicant's market role/OEB license can be found here:

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

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

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

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

– End of Section –

5. Review of connection proposal

5.1 Connection Arrangement

The new generator will be connected on the 115 kV, 60 Hz "E-9" Bus in Beck#1 GS as illustrated by the following figure:

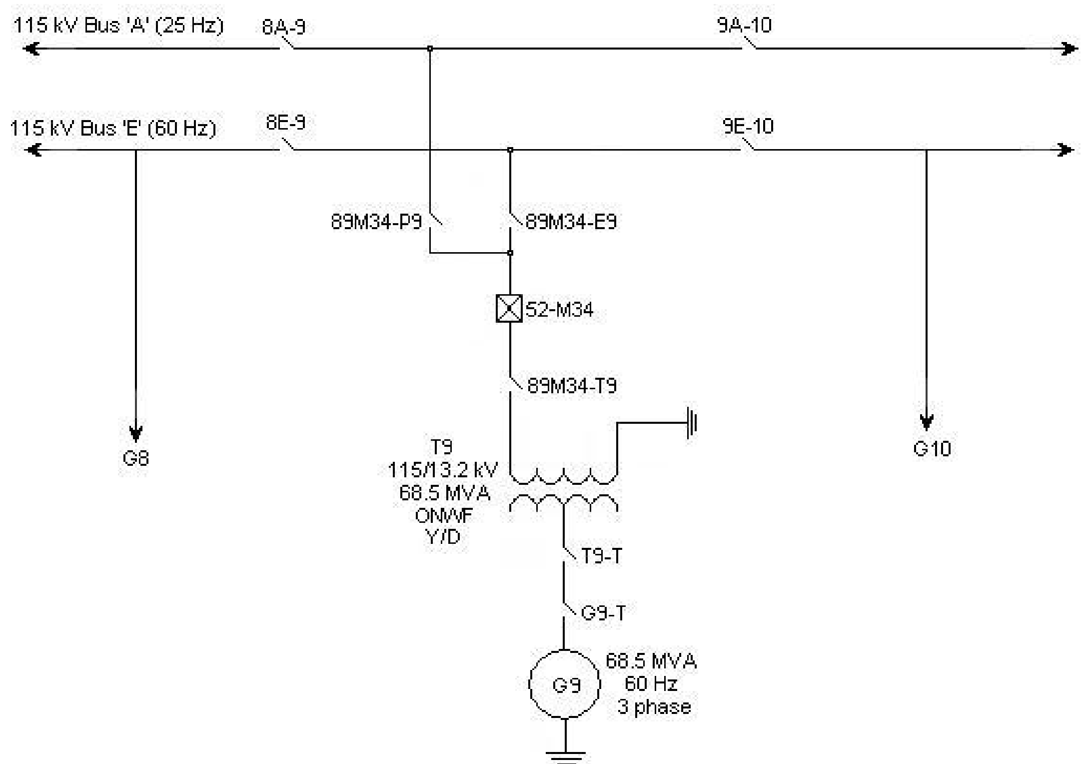


Figure 1: Location of Beck#1 G9

5.2 Data verification

The specifications for the generator and major electrical components as provided by Ontario Power Generation are listed below:

Table 1: Generator data

Identifier	G9	
Type	Salient Pole	
Frequency (Hz)	60	
Maximum Continuous Rating (summer, winter)	61.6	61.6
Rated capability (MVA)	68.5	
Rated voltage (kV)	13.8	
Power factor	0.9	
Total rotational inertia of generator and turbine	3.4	
Speed (RPM)	225	
Normal loading ramp rates (MW/min)	61.6	
Emergency loading ramp rates (MW/min)	61.6	
Armature and field resistance (Ohm)	0.0064	0.1312
Saturation at rated voltage (S1.0) and 20% above rated voltage (S1.2)	0.107	0.327
Base field current (A)	578	
Base field voltage (V)	75.9	
Excitation system model	ESST4B	
Power system stabilizer model	PSS2A	
Speed governor model	WSHYDD	

Generation facilities shall be able to operate continuously at full power in the range 59.4 to 60.6 Hz. Each generation facility shall be capable of operating at full power for a limited period of time at frequencies as low as 58.8 Hz. Each generation facility shall not trip for under-frequency excursions that are above a straight line defined on a linear-log plot of time and frequency by the points (300s, 59.0Hz) and (3.3s, 57.0 Hz) unless the *IESO* accepts other trip settings. Immediate tripping is allowed below 57.0 Hz. – Chapter 4, Appendix 4.2, Ref 3. The generator capability curve (Appendix A) indicates the proposed unit meets this requirement.

A synchronous generation unit shall have the capability to supply at its terminal reactive power within the range 90% lagging (overexcited) to 95% leading (underexcited) power factor based on rated active power and rated voltage. – Chapter 4, Appendix 4.2, Ref 1.

Table 2: Step-up Transformer data

Identifier	T9		
Station	Beck # 1 GS		
Configuration	3-phase		
Temperature rise (degC)	65		
Cooling types	ONWF		
Thermal rating (MVA)	68.5		
Summer 30degC continuous, 15 minute and 10 day thermal ratings (MVA)	68.5	68.5	68.5

Connection type	H-wye			L-delta	
Rated voltage for each winding (kV)	115			13.2	
Positive sequence impedance/base MVA	9.39/68.5				
Off load taps	123.63	120.75	117.88	115.00	112.13
On load taps	Not available				
In service off-load tap position (kV)	115.00				

Table 3: Breaker data (existing)

Identifier	HT9
Station	SAB# 1
Rated voltage (kV)	145
Interrupting time (ms)	38.5
Interrupting media	SF6
Rated continuous current (A)	2500
Rated symmetrical short circuit capability (kA)	40*

* The highest short-circuit current on the 115kV bus in Beck#1 GS, according to Hydro One short circuit estimation is below 32 kA so the proposed 40 kA rating of this breaker should be sufficient.

Table 4: Disconnect Switches data (existing)

Identifier	HT9-E/-T9
Station	SAB# 1
Voltage rating (kV)	135
Type	Disconnect
Continuous rating current (A)	1200

The proposed equipment satisfies the IESO requirements for connection.

– End of Section –

6. System description

6.1 Existing Transmission

Allanburg 115 kV Local Area is the portion of 115 kV system bounded by Allanburg TS 230/115 kV autotransformers (T1, T2, T3 and T4), Beck#1 GS E bus and DeCew Falls GS including Vineland TS and Beamsville TS. Details of Allanburg 115 kV area are provided in the figure below:

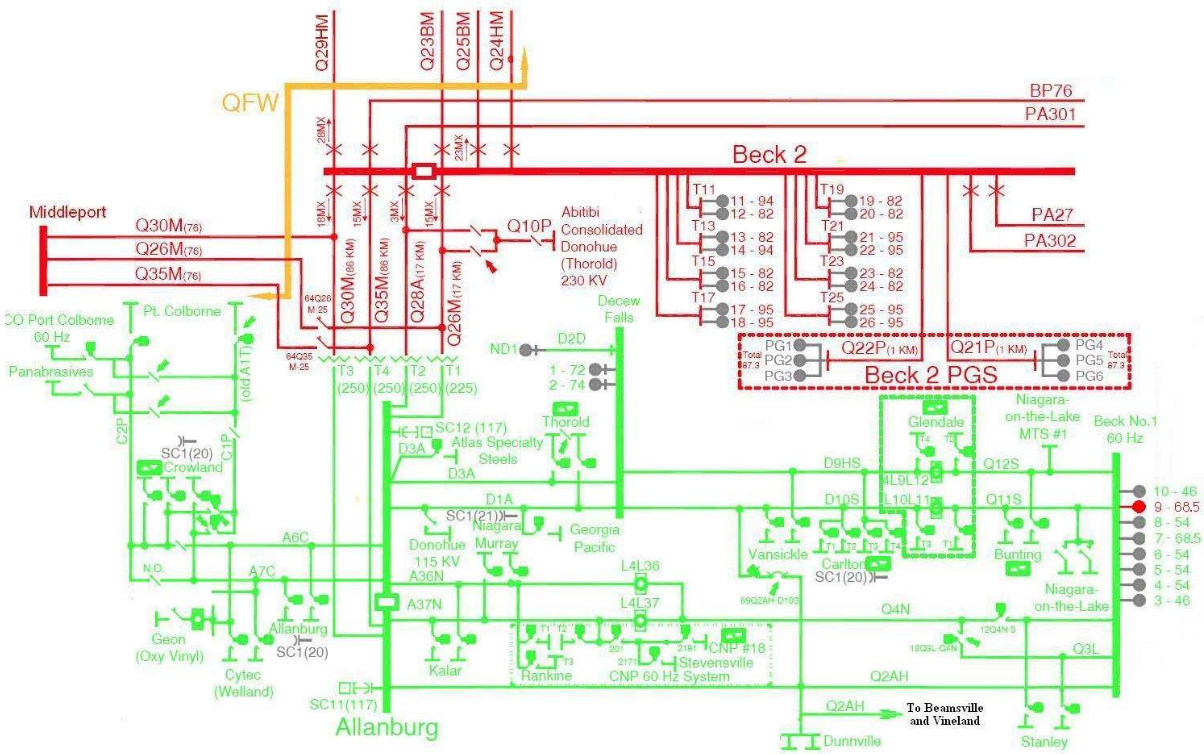


Figure 2: Niagara 115 kV Local Area

The proposed generator (in red) is connected to Beck#1 GS 60 Hz "E" bus. The Niagara area is considered summer critical.

– End of Section –

7. System impact studies

7.1 Short Circuit Assessment

Hydro One indicates that the highest short circuit increase due to Beck#1 G9 rehabilitation is symmetrical 0.22 kA and asymmetrical 0.42 kA for a three phase short circuit, symmetrical 0.21 kA and asymmetrical 0.4 kA for a line to ground short circuit. This increase is not expected to raise the short circuit level above any breaker's capability in the area. Previous studies (CAA ID# 2006-252 Beck#1 G7 conversion) indicate the lowest margin of 2.3 kA at Allanburg; the increase due to G9 rehabilitation is well within this margin.

7.2 Study Assumptions

The study base case contains all existing generation and transmission facilities that have been committed or are under construction.

Two base cases were prepared for this study:

- Summer high load – based on values collected on Aug 01, 2007 hour 16:00. According to the best predictions currently available these values would represent an all time peak for the zone.
- Summer low load – based on values collected on Aug 01, 2007 hour 06:00. For non industrial loads hour 06:00 is on average 60% of hour 16:00, which represents a good approximation for a low load scenario.

For both base cases the following scenarios were studied to verify the impact of the new generator:

(a) Loss of circuit Q12S from Beck#1 GS to Glendale TS;
(b) Loss of circuit Q11S from Beck#1 GS to Glendale TS;
(c) Loss of circuit Q4N from Beck#1 GS to Murray TS;
(d) Loss of circuit Q2AH from Beck#1 GS to Allanburg TS;
(e) Loss of Beck#1 G9;
(f) Breaker failure T4H at Allanburg TS associated with loss of Q2AH;
(g) Breaker failure L4L36 at Murray TS associated with loss of Q4N.

Transient analysis was performed for the following contingencies/scenarios:

(a) Loss of Q4N from Beck#1 GS to Murray TS for a short circuit located close to Beck#1 GS;
(b) Loss of Q12S from Beck#1 GS to Glendale TS for a short circuit located close to Beck#1 GS;

7.3 Power System Analysis

Load flow studies were performed to determine the impact of the proposed upgrade on the local transmission facilities and confirm that all transmission facilities ratings, with consideration to the various modes of operation particular to the area, will be adequate to accommodate the proposed development, as well as whether generation rejection or generation run-back facilities will be required to respond to contingency conditions and to avoid overloading the remaining transmission facilities following a system contingency.

The thermal ratings of the existing transmission facilities were verified against simulated load flows to identify the system upgrades that may be required to allow the new facility output be accommodated with all existing transmission elements in-service.

The analysis pointed out that Q4N's section between Beck# 1 GS and Stanley TS still is the highest loaded element in the zone. The line's rating, after the recent upgrades, is lower than other lines emerging from Beck#1 115 kV bus and also Q4N shares a larger part of the flow out of Beck#1 GS, respectively about 33%. Some of the flow can be diverted onto Q11S and Q12S, both having sufficient spare capability, by reducing the output at DeCew Falls GS.

The following graph shows that over the last two years the Q4N flow was constantly below the continuous (real time) rating. The Q4N upgrade per CAA ID# 2008-EX406 was effective May 2009 so most of this period the real time rating is lower, being the pre-upgrade value. Analysis of the data revealed that less than 50 MVA margin occurred for only about 1.6% of the time, most of it before the upgrade, which is a good indication of the potential constraints Q4N limitation may impose on Beck#1 during operation.

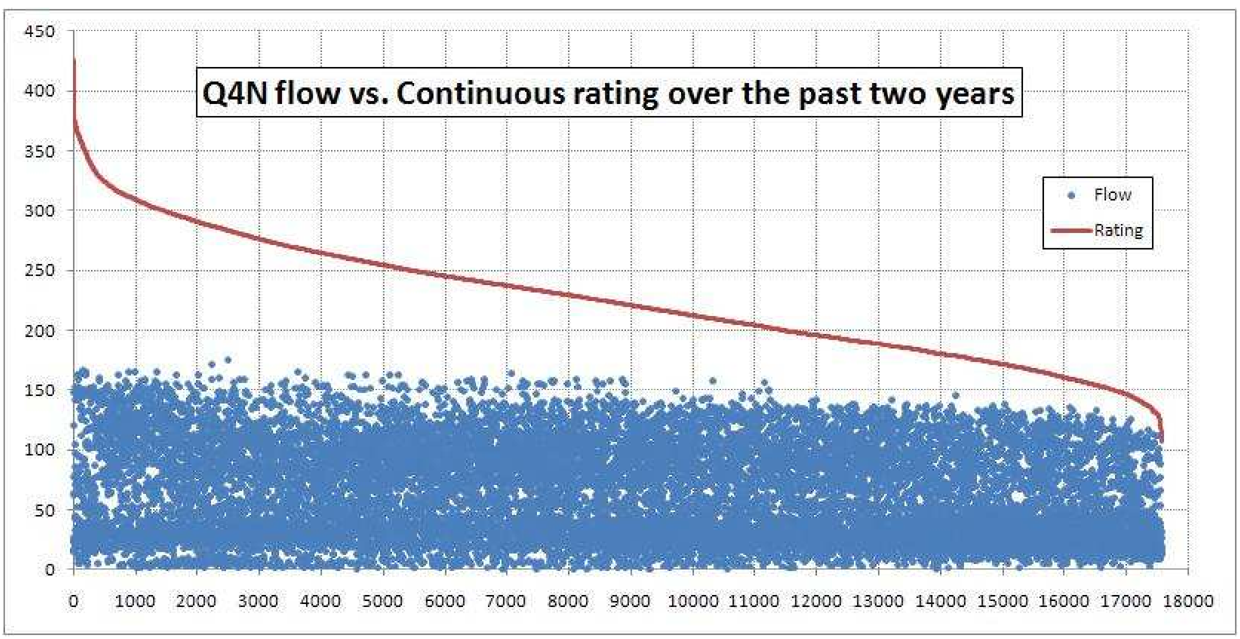


Figure 3: Q4N flow and real time continuous rating for two years

The generation increase in the Niagara 115 kV zone reduces the Allanburg autotransformers flow under high load conditions:

Table 5: Beck#1 – G9 influence over Allanburg autotransformers

Element	Rate	G9 - O/S Flow (MVA)	%	G9 - I/S Flow (MVA)	%	Change[1] Flow (MVA)	%
Allanburg T1	225	146	65%	134	59%	13	6%
Allanburg T2	250	135	54%	123	49%	13	5%
Allanburg T3	250	108	43%	98	39%	10	4%
Allanburg T4	250	111	44%	100	40%	11	4%

The rehabilitation of Beck#1 – G9 will have a beneficial impact over the Allanburg autotransformers loading.

7.4 Voltage Decline Studies

Voltage decline studies were performed to examine the effect of the loss of the new generation facility on local voltages to determine if the voltage declines are in excess of the voltage change limits specified in the IESO Transmission Assessment Criteria document and the effect of transmission contingencies resulting in the loss of the new generating facility on local voltages.

All elements in and connected to Allanburg 115 kV area were monitored for low range and voltage deviations per the Ontario Resource and Transmission Assessment Criteria, Section 4.3:

- 115 kV nominal voltage buses: 10% change before tap action, 10% change after tap action and within the range 108 kV to 127 kV
- Buses with less than 50 kV nominal voltage: 10% change before tap action, 5% change after cap action and within the range 88% of nominal to 112% of nominal.

No out of range voltages were detected during the simulations. The calculated voltage deviation range for the studied scenarios was:

- High load, pre tap action [-0.08% to 0.205%];
- High load, post tap action [-0.142% to 0.274%];
- Low load, pre tap action [-0.100% to 0.008%];
- Low load, post tap action [-0.080% to 0.018%].

All values are well within the criteria.

7.5 Transient Stability Analysis

Transient studies were performed to demonstrate that the generator control systems (excitation and governor) meet following performance standard requirements:

[1] The value accounts for the entire Beck#1 G9 output, only part of this change is due to the rehabilitation.

- Each synchronous generation unit rated at 10 MVA or higher shall be equipped with an excitation system with a voltage response time not longer than 50 ms for a voltage reference step change not to exceed 5%, a positive ceiling voltage of at least 200% of the rated field voltage and a negative ceiling voltage of at least 140% of the rated field voltage – Chapter 4, Appendix 4.2, Ref 12.
- Each synchronous generator connected to the IESO-controlled grid rated at or above 10 MVA shall be equipped with a speed governor that has permanent speed droop between 3 % and 7% – Chapter 4, Appendix 4.2, Ref 16.

The proponent is responsible for ensuring that the performance of the equipment that is installed in this generation facility has similar performance or exceeds the predicted performance observed in the simulation results.

7.5.1 Exciter test results

Transient simulations were performed to determine the response ratio and open-circuit of the exciter. The rated field voltage, field voltage ceiling and voltage response time were determined. The results are shown below:

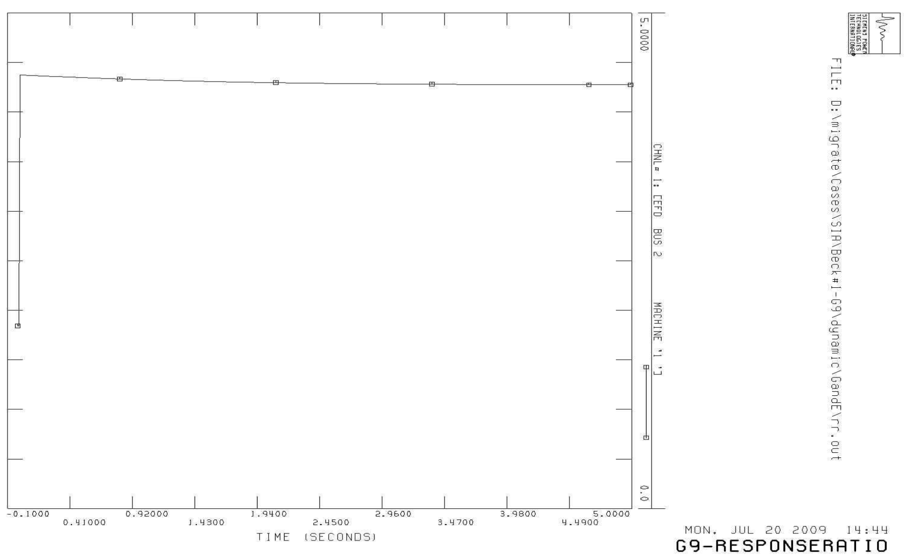


Figure 4: Response ratio test for Beck#1 G9

According to this test the rated field voltage of the proposed generator is 1.84314 pu. The positive ceiling voltage of G9 should be at least 3.616 pu, and a negative ceiling voltage of at least -2.531 pu.

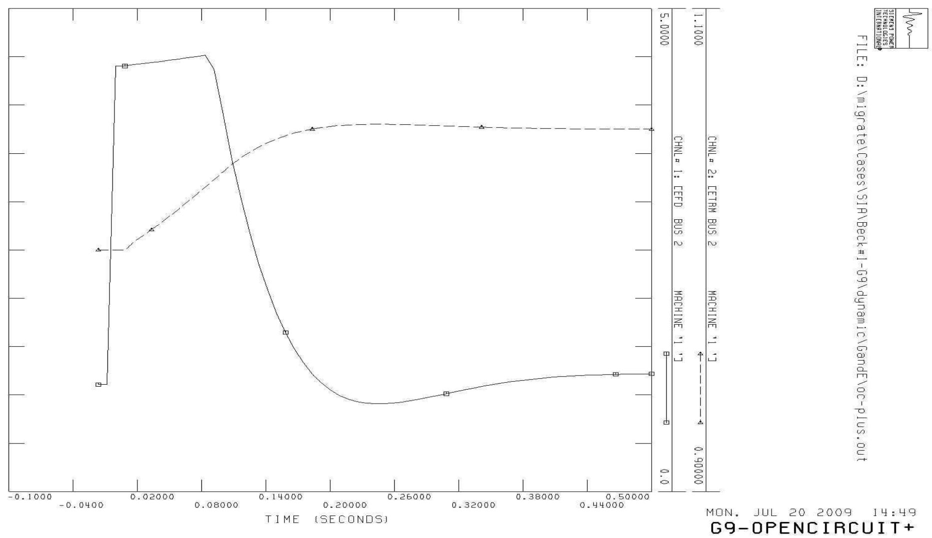


Figure 5: Open-circuit test (positive) results for Beck#1 G9

This test shows a positive ceiling voltage of 4.516 pu, higher than the 3.616 pu required.

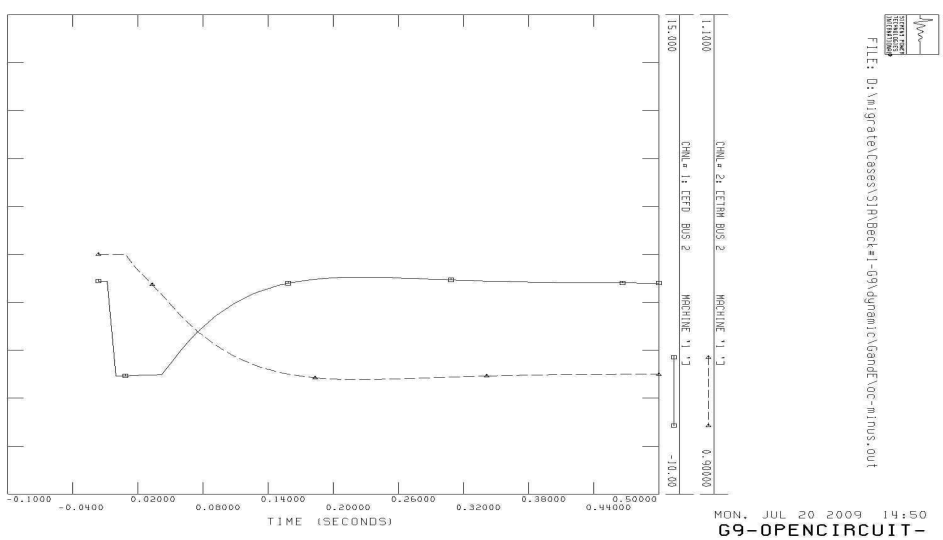


Figure 6: Open-circuit test (negative) results for Beck#1 G9

This test shows a negative ceiling voltage of – 3.813 pu, which is more (on the negative side) than the - 2.531 pu required.

The response time of the exciter in both directions is obviously (from the graphs above) less than 50 ms.

7.5.2 Speed governor test results

Transient simulation determined that the speed governor droop of G9 is within the required range:

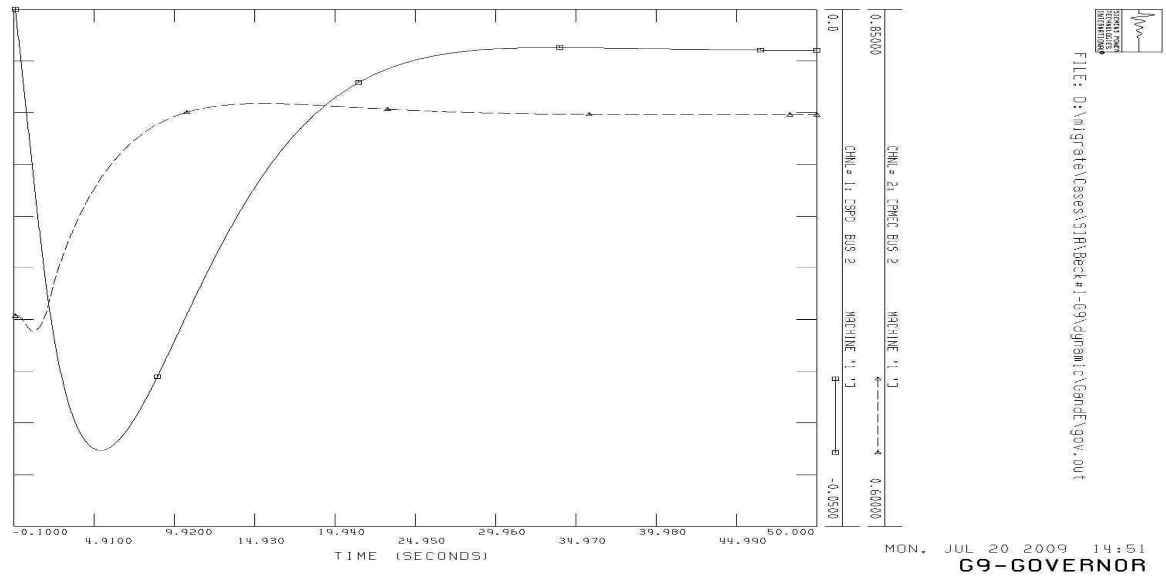


Figure 7: Governor test results for Beck#1 G9

The hydraulic governor droop of the model used in this study is 4.13 % which is within the required range.

7.5.3 Dynamic stability test results

Using the data provided by the applicant, transient stability studies were performed to determine the dynamic performance of the rehabilitated unit and its control systems on the transient stability behaviour of the system for most critical single element contingencies in the area. Machine rotor angles and transient voltages were monitored to assess the impact of the new facilities on the speed and magnitude of the transient response of the system.

The following scenarios were simulated:

- Summer extreme weather, loss of Q4N due to a fault close to Beck#1 GS
- Summer extreme weather, loss of Q12S due to a fault close to Beck#1 GS.

It was determined that post rehabilitation, G9 does not deteriorate the transient response of the local system.

Calculation of fault clearing time for both scenarios is provided in Appendix C.

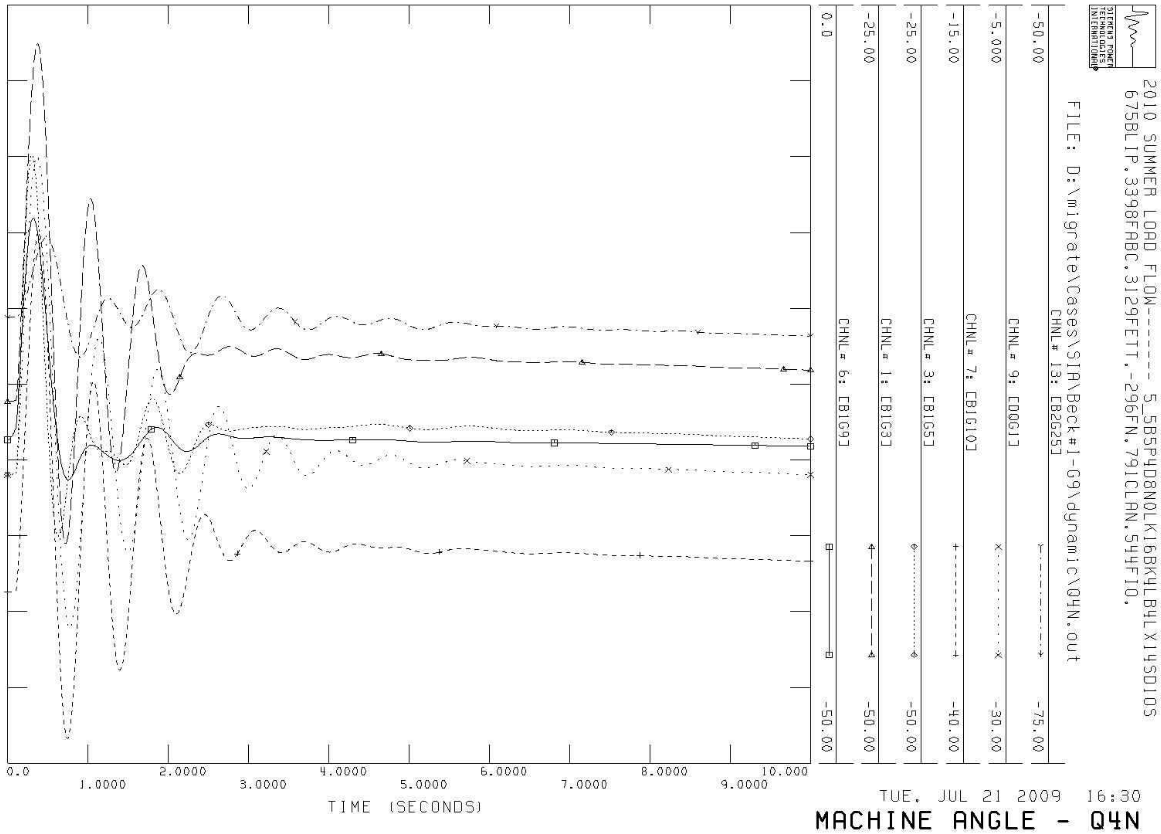


Figure 8: Machine rotor angles at Beck#1 and DeCew for Q4N fault close to Beck#1 GS

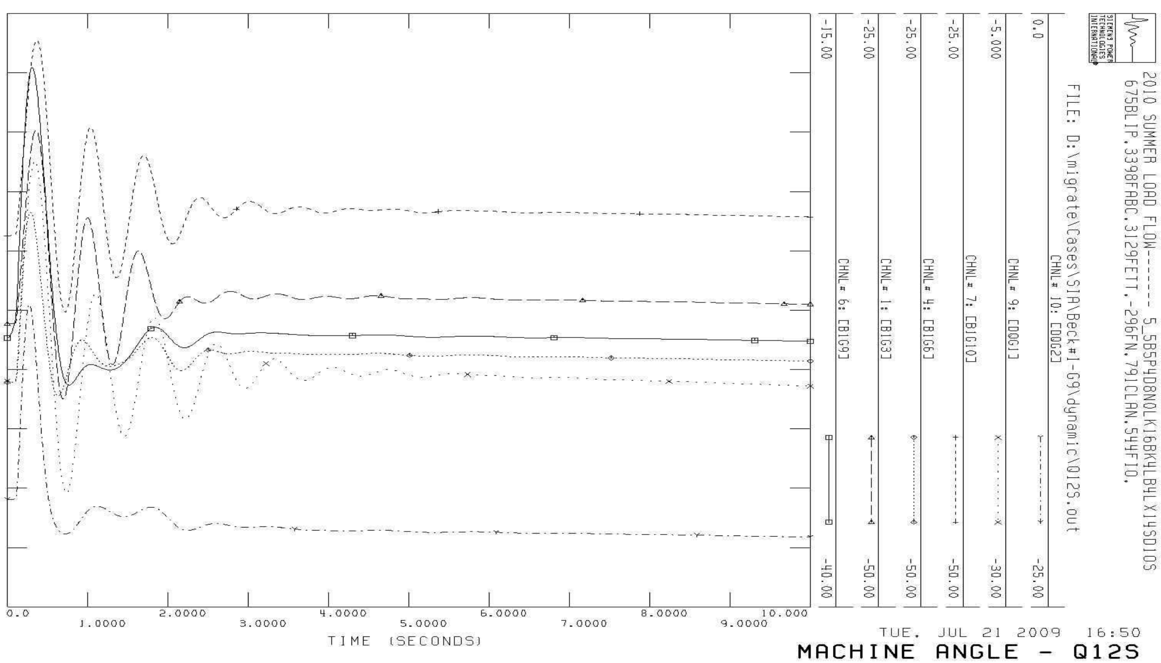


Figure 9: Machine rotor angles at Beck#1 and DeCew for Q12S fault close to Beck#1 GS

The results show that, for both contingencies studied, the new Beck#1 G9 hydraulic generating unit displayed stable performance and the system oscillations were well damped.

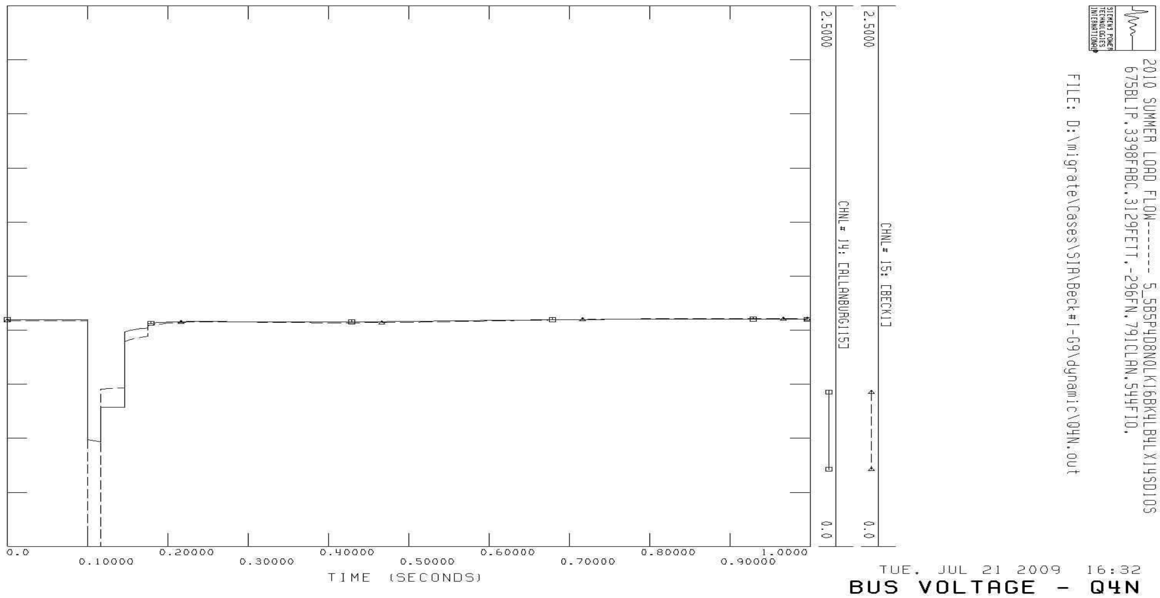


Figure 10: Allanburg and Beck #1 115 kV voltages for Q4N fault close to Beck#1 GS

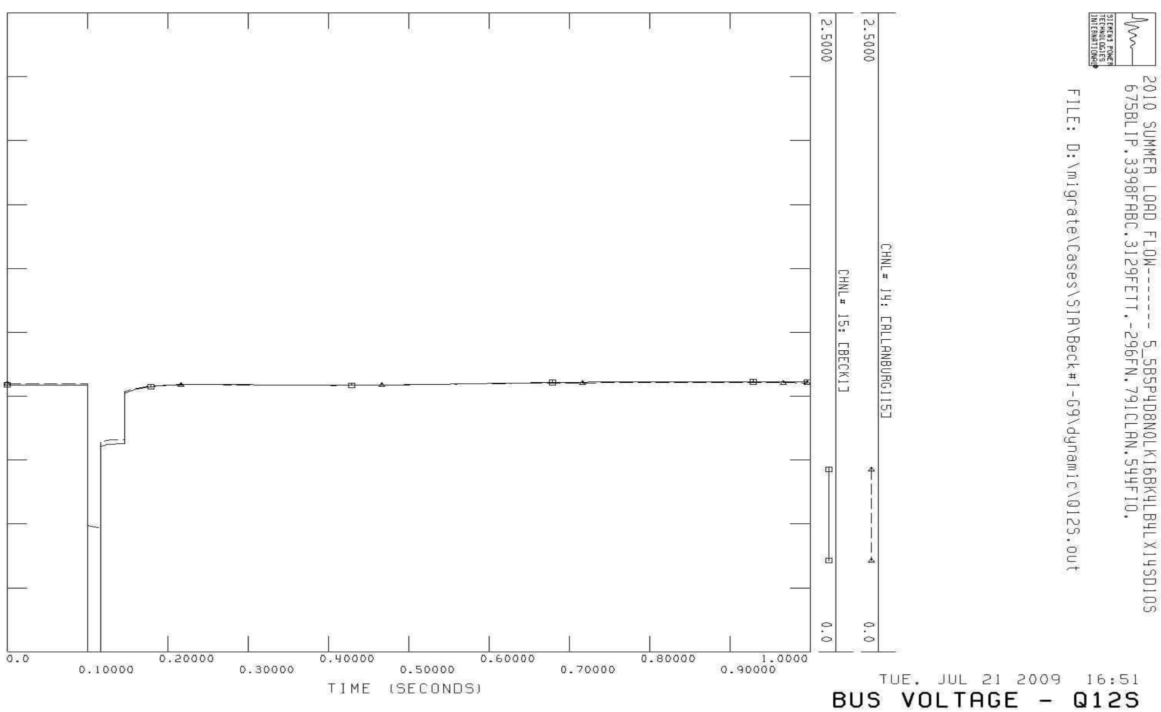


Figure 11: Allanburg and Beck #1 115 kV voltages for Q12S fault close to Beck#1 GS

The minimum post-contingency voltage sag remains above 70% of the nominal voltage and doesn't go below 80% of the nominal voltage for more than 250 ms within 10 seconds following the fault.

OPG stated that in-service modeling parameters of Sir Adam Beck #1 – G9 exciter and governor, submitted on the SIA Application form, will be identical with the recently upgraded G7.

The proponent is responsible for ensuring that the performance of the equipment that is eventually supplied and installed in this generation facility is similar to the predicted performance or exceeds the predicted performance observed in the simulation results obtained using provided equipment models and data.

– End of Section –

Appendix A: Generator Capability Curves

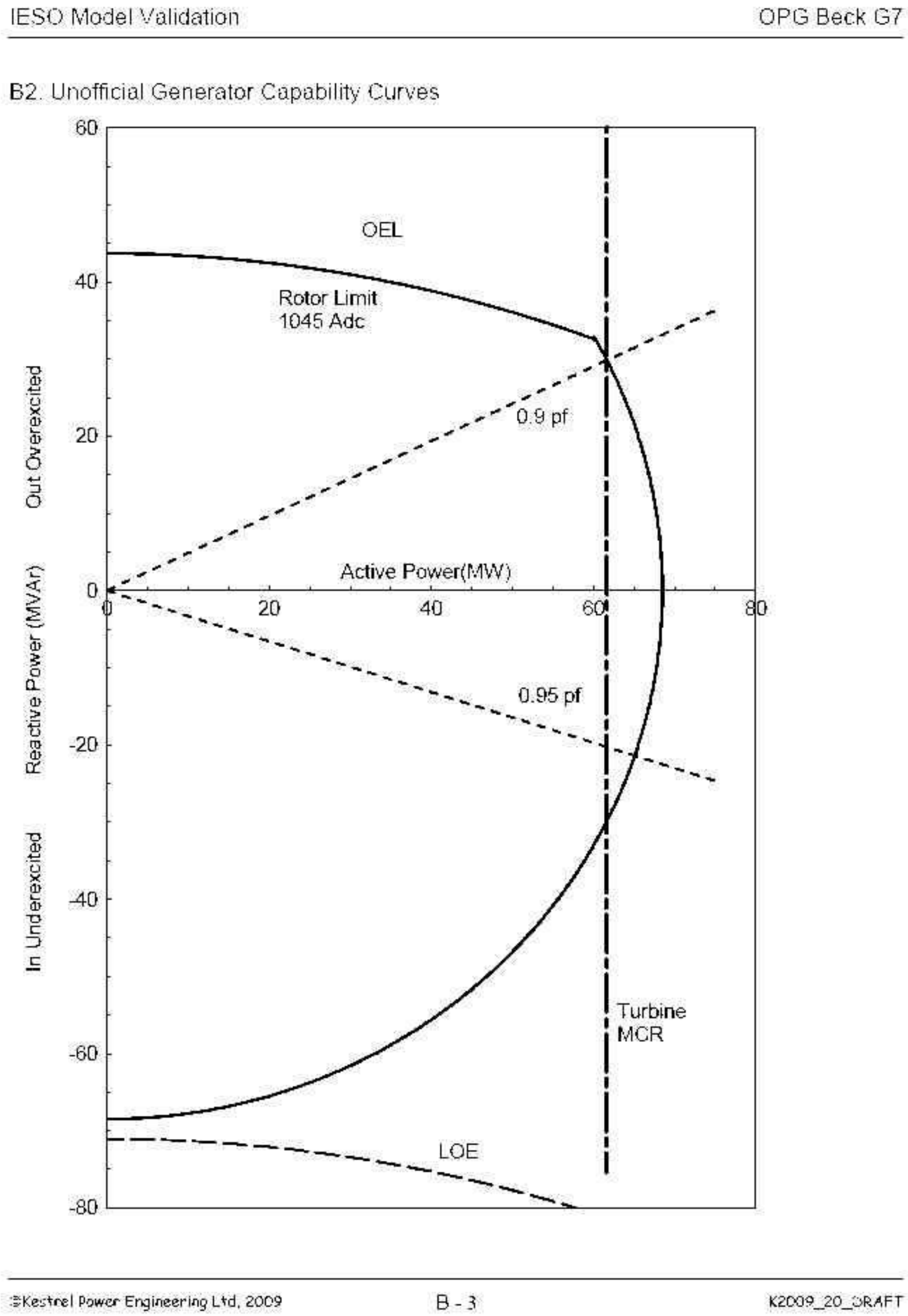


Figure 12: Beck G7 capability curves submitted for G9

– End of Section –

Appendix B: Post-contingency voltage at monitored buses

Table 6: Post contingency voltage deviation - High demand, pre tap action

	Contingency						
Monitored bus	Q12S	Q11S	Q4N	Q2AH	G9	T4H	L4L36
MIDDLEPT8086500.00	0.002%	0.004%	0.012%	-0.020%	0.003%	-0.046%	0.018%
MIDDLEPT8185500.00	0.002%	0.003%	0.011%	-0.019%	0.003%	-0.040%	0.017%
BECK_#2_TS 220.00	0.010%	0.018%	0.054%	-0.088%	0.011%	-0.137%	0.081%
MIDDLEPT_DK1220.00	0.013%	0.014%	0.030%	-0.029%	-0.008%	-0.100%	0.045%
MIDDLEPT_DK2220.00	0.008%	0.010%	0.022%	-0.024%	-0.004%	-0.065%	0.033%
BECK_#1_SS60118.05	-0.430%	-0.301%	-0.066%	-0.254%	0.205%	0.130%	0.004%
DECEW_FLS_SS118.05	0.587%	0.635%	0.192%	-0.346%	0.085%	0.223%	0.303%
ALLANBURG_TS118.05	0.070%	0.118%	0.354%	-0.563%	0.050%	0.325%	0.530%
MMFX_STL_T3 118.05	0.070%	0.118%	0.354%	-0.563%	0.050%	0.325%	0.530%
MMFX_STL_T2 118.05	0.070%	0.118%	0.354%	-0.563%	0.050%	0.325%	0.530%
MMFX_STL_L1 27.600	0.070%	0.118%	0.354%	-0.563%	0.050%	0.326%	0.530%
MMFX_STL_L2 27.600	0.070%	0.118%	0.354%	-0.563%	0.050%	0.326%	0.530%
THOROLD_D1A 118.05	0.290%	0.339%	0.278%	-0.480%	0.069%	0.279%	0.428%
THOROLD_D3A 118.05	0.254%	0.301%	0.304%	-0.482%	0.061%	0.293%	0.457%
THOROLD_BY 13.800	0.273%	0.322%	0.292%	-0.482%	0.065%	0.286%	0.443%
THOROLD_EQ 13.800	0.280%	0.331%	0.300%	-0.495%	0.067%	0.294%	0.455%
AB_CONS_NF49118.05	0.210%	0.260%	0.297%	-0.518%	0.065%	0.291%	0.457%
AB_CONS_NF4913.800	0.211%	0.261%	0.298%	-0.520%	0.065%	0.292%	0.459%
GEORGIA_PAC 118.05	0.252%	0.302%	0.287%	-0.498%	0.067%	0.284%	0.441%
GEORGIA_PAC 4.1600	0.265%	0.317%	0.301%	-0.523%	0.070%	0.298%	0.463%
VANSICKLE_D9118.05	0.739%	0.678%	0.175%	-0.341%	0.096%	0.219%	0.284%
VANSICKLE_10118.05	0.632%	0.793%	0.175%	-0.341%	0.095%	0.219%	0.284%
VANSICKLE_BY13.800	0.760%	0.817%	0.195%	-0.378%	0.106%	0.243%	0.315%
CARLTON_D10S118.05	0.670%	0.874%	0.168%	-0.341%	0.102%	0.219%	0.277%
CARLTON_D9HS118.05	0.817%	0.717%	0.168%	-0.341%	0.102%	0.219%	0.277%
CARLTON_BY 13.800	0.839%	0.894%	0.189%	-0.383%	0.115%	0.246%	0.311%
CARLTON_HK 13.800	0.820%	0.871%	0.185%	-0.374%	0.112%	0.241%	0.304%
CARLTON_R1 13.800	0.746%	0.795%	0.168%	-0.341%	0.102%	0.219%	0.277%
CARLTON_EQ 13.800	0.741%	0.804%	0.169%	-0.342%	0.102%	0.220%	0.278%
GLENDALE_D10118.05	0.776%	1.438%	0.103%	-0.310%	0.135%	0.197%	0.200%
GLENDALE_D9H118.05	1.355%	0.812%	0.103%	-0.311%	0.136%	0.198%	0.201%

GLENDALE_EY 13.800	1.156%	1.222%	0.112%	-0.336%	0.147%	0.214%	0.217%
GLENDALE_BJ 13.800	1.149%	1.189%	0.110%	-0.331%	0.144%	0.211%	0.214%
GLENDALE_DQ 13.800	1.138%	1.196%	0.110%	-0.330%	0.144%	0.210%	0.213%
BUNTING_Q12S118.05	0.000%	1.150%	0.103%	-0.313%	0.137%	0.199%	0.201%
BUNTING_Q11S118.05	1.147%	0.000%	0.103%	-0.311%	0.136%	0.198%	0.200%
BUNTING_J1J213.800	6.132%	4.752%	0.111%	-0.335%	0.147%	0.213%	0.216%
BUNTING_Q1Q213.800	6.347%	5.324%	0.112%	-0.337%	0.147%	0.214%	0.217%
NOTL_MTS_#2 118.05	0.287%	0.000%	0.041%	-0.284%	0.164%	0.175%	0.127%
NOTL_MTS#2B127.600	0.296%	0.000%	0.042%	-0.293%	0.169%	0.180%	0.131%
NOTL_MTS#2B227.600	0.302%	0.000%	0.043%	-0.299%	0.172%	0.184%	0.134%
NOTL_MTS_#1 118.05	0.000%	0.440%	0.053%	-0.289%	0.159%	0.179%	0.141%
NOTL_MTS_#1 27.600	0.000%	0.505%	0.060%	-0.331%	0.182%	0.206%	0.162%
STANLEY_Q3L 118.05	-0.424%	-0.295%	0.379%	-0.256%	0.203%	0.137%	0.450%
STANLEY_Q4N 118.05	-0.260%	-0.157%	0.000%	-0.364%	0.155%	0.205%	0.000%
STANLEY_BY 13.800	-0.361%	-0.238%	4.359%	-0.324%	0.188%	0.186%	4.438%
STANLEY_JQ 13.800	-0.376%	-0.248%	6.192%	-0.337%	0.196%	0.193%	6.279%
MURRAY_TS 118.05	-0.065%	0.009%	0.632%	-0.444%	0.082%	0.309%	2.897%
MURRAY_QZ 13.800	-0.070%	0.010%	0.681%	-0.478%	0.089%	0.333%	3.125%
MURRAY_TSY1213.800	-0.071%	0.010%	0.695%	-0.487%	0.090%	0.340%	3.188%
MURRAY_TS_J 13.800	-0.068%	0.010%	0.668%	-0.469%	0.087%	0.326%	3.063%
MURRAY_TS_K 13.800	-0.070%	0.010%	0.683%	-0.479%	0.089%	0.334%	3.132%
CNP_#18_CTS 118.05	-0.070%	0.010%	0.683%	-0.479%	0.089%	0.334%	3.133%
CNP_#18_CTS 34.500	-0.078%	0.011%	0.765%	-0.536%	0.100%	0.374%	3.520%
STEVENSVILLE118.05	-0.068%	0.010%	0.667%	-0.468%	0.087%	0.326%	3.058%
STEVENSVILLE34.500	-0.071%	0.010%	0.691%	-0.485%	0.090%	0.338%	3.172%
RANKINE_A37N118.05	-0.065%	0.009%	0.638%	-0.448%	0.083%	0.312%	2.924%
RANKINE_CTS 44.000	-0.070%	0.010%	0.688%	-0.482%	0.090%	0.336%	3.155%
KALAR_MTSA36118.05	-0.002%	0.060%	0.509%	-0.501%	0.068%	0.316%	0.000%
KALAR_MTSA37118.05	-0.002%	0.060%	0.507%	-0.502%	0.068%	0.316%	1.900%
KALAR_MTSB1213.800	-0.002%	0.065%	0.554%	-0.546%	0.074%	0.345%	7.383%
DUNNVILLE_TS118.05	-0.038%	0.035%	0.311%	0.000%	0.089%	0.000%	0.479%
DUNNVILLE_TS27.600	-0.040%	0.037%	0.332%	0.000%	0.094%	0.000%	0.511%
VINELAND_DS 118.05	-0.038%	0.034%	0.309%	0.000%	0.088%	0.000%	0.476%
VINELAND_B1 27.600	-0.038%	0.035%	0.315%	0.000%	0.090%	0.000%	0.485%
VINELAND_B2 27.600	-0.038%	0.035%	0.315%	0.000%	0.090%	0.000%	0.485%
BEAMSVIL_Q2A118.05	-0.038%	0.035%	0.313%	0.000%	0.089%	0.000%	0.482%
BEAMSVIL_BY 27.600	-0.040%	0.037%	0.332%	0.000%	0.095%	0.000%	0.511%

Table 7: Post contingency voltage deviation - High demand, post tap action

	Contingency						
Monitored bus	Q12S	Q11S	Q4N	Q2AH	G9	T4H	L4L36
MIDDLEPT8086500.00	0.001%	0.148%	0.187%	-0.022%	0.179%	-0.048%	0.192%
MIDDLEPT8185500.00	0.001%	0.009%	0.046%	-0.020%	0.040%	-0.042%	0.052%
BECK_#2_TS 220.00	0.006%	-0.016%	0.218%	-0.094%	0.183%	-0.143%	0.243%
MIDDLEPT_DK1220.00	0.004%	-0.215%	-0.119%	-0.054%	-0.142%	-0.125%	-0.108%
MIDDLEPT_DK2220.00	0.002%	-0.061%	0.016%	-0.042%	0.006%	-0.084%	0.030%
BECK_#1_SS60118.05	-0.435%	-0.320%	-0.024%	-0.258%	0.267%	0.127%	0.041%
DECEW_FLS_SS118.05	0.579%	0.608%	0.258%	-0.353%	0.160%	0.218%	0.361%
ALLANBURG_TS118.05	0.063%	0.081%	0.459%	-0.573%	0.159%	0.318%	0.622%
MMFX_STL_T3 118.05	0.063%	0.081%	0.460%	-0.573%	0.159%	0.318%	0.622%
MMFX_STL_T2 118.05	0.063%	0.081%	0.460%	-0.573%	0.159%	0.318%	0.622%
MMFX_STL_L1 27.600	0.063%	0.081%	0.460%	-0.573%	0.159%	0.318%	0.623%
MMFX_STL_L2 27.600	0.063%	0.081%	0.460%	-0.573%	0.159%	0.318%	0.623%
THOROLD_D1A 118.05	0.283%	0.307%	0.368%	-0.488%	0.164%	0.272%	0.506%
THOROLD_D3A 118.05	0.246%	0.268%	0.395%	-0.491%	0.158%	0.286%	0.537%
THOROLD_BY 13.800	0.266%	0.289%	0.383%	0.864%	0.161%	0.280%	0.523%
THOROLD_EQ 13.800	0.273%	0.297%	0.393%	0.867%	0.166%	0.287%	0.537%
AB_CONS_NF49118.05	0.203%	0.225%	0.393%	-0.527%	0.166%	0.284%	0.540%
AB_CONS_NF4913.800	0.204%	0.226%	0.395%	-0.529%	0.166%	0.285%	0.543%
GEORGIA_PAC 118.05	0.245%	0.269%	0.379%	-0.507%	0.165%	0.277%	0.522%
GEORGIA_PAC 4.1600	0.257%	0.282%	0.398%	-0.532%	0.173%	0.291%	0.548%
VANSICKLE_D9118.05	0.731%	0.652%	0.241%	-0.347%	0.170%	0.214%	0.341%
VANSICKLE_10118.05	0.623%	0.766%	0.241%	-0.347%	0.170%	0.214%	0.341%
VANSICKLE_BY13.800	0.751%	0.788%	0.267%	-0.385%	0.189%	0.238%	0.378%
CARLTON_D10S118.05	0.661%	0.847%	0.233%	-0.347%	0.177%	0.214%	0.333%
CARLTON_D9HS118.05	0.809%	0.691%	0.233%	-0.347%	0.177%	0.214%	0.334%
CARLTON_BY 13.800	0.829%	0.865%	0.263%	-0.390%	0.199%	0.241%	0.375%
CARLTON_HK 13.800	0.811%	0.842%	0.256%	-0.381%	0.194%	0.235%	0.366%
CARLTON_R1 13.800	0.737%	0.769%	0.234%	-0.347%	0.177%	0.214%	0.334%
CARLTON_EQ 13.800	0.732%	0.778%	0.234%	-0.348%	0.178%	0.215%	0.335%
GLENDALE_D10118.05	0.764%	1.411%	0.161%	-0.315%	0.206%	0.193%	0.251%
GLENDALE_D9H118.05	1.346%	0.787%	0.162%	-0.317%	0.207%	0.194%	0.252%
GLENDALE_EY 13.800	1.145%	1.194%	0.175%	-0.342%	0.224%	0.209%	0.272%
GLENDALE_BJ 13.800	1.138%	1.162%	0.172%	-0.337%	0.221%	0.206%	0.268%
GLENDALE_DQ 13.800	1.127%	1.169%	0.172%	-0.336%	0.220%	0.205%	0.267%
BUNTING_Q12S118.05	0.000%	1.125%	0.162%	-0.318%	0.209%	0.195%	0.252%
BUNTING_Q11S118.05	1.130%	0.000%	0.162%	-0.317%	0.208%	0.194%	0.251%
BUNTING_J1J213.800	4.681%	4.724%	0.174%	-0.341%	0.224%	0.208%	0.271%
BUNTING_Q1Q213.800	4.855%	5.296%	0.175%	-0.343%	0.225%	0.210%	0.272%

NOTL_MTS_#2 118.05	0.278%	0.000%	0.093%	-0.289%	0.231%	0.171%	0.172%
NOTL_MTS#2B127.600	0.287%	0.000%	0.096%	-0.299%	0.239%	0.176%	0.178%
NOTL_MTS#2B227.600	0.292%	0.000%	0.097%	-0.304%	0.243%	0.179%	0.181%
NOTL_MTS_#1 118.05	0.000%	0.417%	0.106%	-0.294%	0.227%	0.175%	0.187%
NOTL_MTS_#1 27.600	0.000%	0.478%	0.121%	-0.337%	0.261%	0.201%	0.215%
STANLEY_Q3L 118.05	-0.430%	-0.315%	0.422%	-0.261%	0.266%	0.134%	0.488%
STANLEY_Q4N 118.05	-0.266%	-0.183%	0.000%	-0.371%	0.235%	0.200%	0.000%
STANLEY_BY 13.800	-0.367%	-0.262%	4.406%	-0.329%	0.263%	0.182%	4.480%
STANLEY_JQ 13.800	-0.382%	-0.273%	6.244%	-0.343%	0.274%	0.189%	6.325%
MURRAY_TS 118.05	-0.071%	-0.024%	0.743%	-0.452%	0.180%	0.303%	2.981%
MURRAY_QZ 13.800	-0.077%	-0.025%	0.800%	-0.487%	0.194%	0.326%	3.216%
MURRAY_TSY1213.800	-0.078%	-0.026%	0.816%	-0.496%	0.197%	0.332%	3.280%
MURRAY_TS_J 13.800	-0.075%	-0.025%	0.785%	0.906%	0.190%	0.320%	3.152%
MURRAY_TS_K 13.800	-0.077%	-0.025%	0.802%	-0.488%	0.194%	0.327%	3.223%
CNP_#18_CTS 118.05	-0.077%	-0.025%	0.802%	-0.488%	0.194%	0.327%	3.224%
CNP_#18_CTS 34.500	-0.086%	-0.028%	0.899%	-0.546%	0.217%	0.366%	0.958%
STEVENSVILLE118.05	-0.075%	-0.025%	0.783%	-0.476%	0.190%	0.319%	3.147%
STEVENSVILLE34.500	-0.078%	-0.026%	0.812%	-0.494%	0.196%	0.331%	1.413%
RANKINE_A37N118.05	-0.072%	-0.024%	0.750%	-0.456%	0.181%	0.305%	3.009%
RANKINE_CTS 44.000	-0.077%	-0.026%	0.808%	-0.491%	0.195%	0.329%	3.247%
KALAR_MTSA36118.05	-0.009%	0.025%	0.617%	-0.510%	0.171%	0.309%	0.000%
KALAR_MTSA37118.05	-0.008%	0.025%	0.615%	-0.511%	0.171%	0.309%	1.981%
KALAR_MTSB1213.800	-0.009%	0.027%	0.672%	-0.556%	0.186%	0.337%	0.165%
DUNNVILLE_TS118.05	-0.045%	-0.002%	0.412%	0.000%	0.197%	0.000%	0.567%
DUNNVILLE_TS27.600	-0.048%	-0.002%	0.439%	0.000%	0.210%	0.000%	0.604%
VINELAND_DS 118.05	-0.045%	-0.002%	0.409%	0.000%	0.196%	0.000%	0.563%
VINELAND_B1 27.600	-0.045%	-0.002%	0.417%	0.000%	0.200%	0.000%	0.574%
VINELAND_B2 27.600	-0.045%	-0.002%	0.417%	0.000%	0.200%	0.000%	0.574%
BEAMSVIL_Q2A118.05	-0.045%	-0.002%	0.414%	0.000%	0.198%	0.000%	0.570%
BEAMSVIL_BY 27.600	-0.048%	-0.002%	0.440%	0.000%	0.211%	0.000%	0.605%

Table 8: Post contingency voltage deviation - Low demand, pre tap action

	Contingency						
Monitored bus	Q12S	Q11S	Q4N	Q2AH	G9	T4H	L4L36
MIDDLEPT8086500.00	0.006%	0.005%	0.006%	-0.006%	-0.008%	-0.020%	0.008%
MIDDLEPT8185500.00	0.005%	0.005%	0.006%	-0.005%	-0.007%	-0.017%	0.007%
BECK_#2_TS 220.00	0.022%	0.021%	0.027%	-0.032%	-0.024%	-0.060%	0.034%
MIDDLEPT_DK1220.00	0.019%	0.016%	0.015%	-0.002%	-0.035%	-0.042%	0.019%
MIDDLEPT_DK2220.00	0.014%	0.012%	0.011%	-0.002%	-0.025%	-0.024%	0.014%
BECK_#1_SS60118.05	-0.172%	-0.109%	0.075%	0.012%	0.008%	0.180%	0.091%

DECEW_FLS_SS118.05	0.483%	0.450%	0.200%	-0.093%	-0.069%	0.233%	0.233%
ALLANBURG_TS118.05	0.123%	0.124%	0.173%	-0.254%	-0.100%	0.219%	0.221%
MMFX_STL_T3 118.05	0.123%	0.124%	0.173%	-0.254%	-0.100%	0.219%	0.221%
MMFX_STL_T2 118.05	0.123%	0.124%	0.173%	-0.254%	-0.100%	0.219%	0.221%
MMFX_STL_L1 27.600	0.123%	0.124%	0.173%	-0.254%	-0.100%	0.219%	0.221%
MMFX_STL_L2 27.600	0.123%	0.124%	0.173%	-0.254%	-0.100%	0.219%	0.221%
THOROLD_D1A 118.05	0.275%	0.263%	0.181%	-0.190%	-0.085%	0.222%	0.223%
THOROLD_D3A 118.05	0.248%	0.237%	0.200%	-0.186%	-0.092%	0.234%	0.242%
THOROLD_BY 13.800	0.263%	0.250%	0.191%	-0.188%	-0.089%	0.229%	0.233%
THOROLD_EQ 13.800	0.267%	0.254%	0.194%	-0.191%	-0.090%	0.233%	0.237%
AB_CONS_NF49118.05	0.221%	0.214%	0.166%	-0.222%	-0.088%	0.214%	0.211%
AB_CONS_NF4913.800	0.221%	0.215%	0.167%	-0.222%	-0.088%	0.214%	0.211%
GEORGIA_PAC 118.05	0.250%	0.240%	0.174%	-0.205%	-0.086%	0.218%	0.217%
GEORGIA_PAC 4.1600	0.257%	0.246%	0.179%	-0.211%	-0.088%	0.224%	0.223%
VANSICKLE_D9118.05	0.589%	0.469%	0.197%	-0.082%	-0.064%	0.233%	0.228%
VANSICKLE_10118.05	0.497%	0.543%	0.196%	-0.082%	-0.064%	0.232%	0.227%
VANSICKLE_BY13.800	0.573%	0.534%	0.208%	-0.087%	-0.067%	0.245%	0.240%
CARLTON_D10S118.05	0.513%	0.588%	0.195%	-0.077%	-0.061%	0.233%	0.225%
CARLTON_D9HS118.05	0.641%	0.486%	0.195%	-0.076%	-0.061%	0.234%	0.226%
CARLTON_BY 13.800	0.617%	0.572%	0.208%	-0.082%	-0.065%	0.249%	0.241%
CARLTON_HK 13.800	0.610%	0.563%	0.205%	-0.081%	-0.064%	0.246%	0.237%
CARLTON_R1 13.800	0.577%	0.538%	0.195%	-0.077%	-0.061%	0.234%	0.226%
CARLTON_EQ 13.800	0.572%	0.543%	0.195%	-0.077%	-0.061%	0.234%	0.226%
GLENDALE_D10118.05	0.526%	0.930%	0.172%	-0.039%	-0.041%	0.226%	0.197%
GLENDALE_D9H118.05	1.033%	0.516%	0.172%	-0.039%	-0.041%	0.226%	0.198%
GLENDALE_EY 13.800	0.814%	0.756%	0.179%	-0.041%	-0.043%	0.236%	0.206%
GLENDALE_BJ 13.800	0.820%	0.743%	0.178%	-0.041%	-0.043%	0.234%	0.205%
GLENDALE_DQ 13.800	0.811%	0.748%	0.178%	-0.040%	-0.043%	0.234%	0.205%
BUNTING_Q12S118.05	0.000%	0.683%	0.172%	-0.039%	-0.041%	0.227%	0.198%
BUNTING_Q11S118.05	0.696%	0.000%	0.172%	-0.039%	-0.041%	0.226%	0.198%
BUNTING_J1J213.800	3.186%	2.681%	0.179%	-0.040%	-0.043%	0.236%	0.206%
BUNTING_Q1Q213.800	3.301%	2.900%	0.180%	-0.040%	-0.043%	0.237%	0.207%
NOTL_MTS_#2 118.05	0.244%	0.000%	0.141%	-0.012%	-0.022%	0.213%	0.163%
NOTL_MTS#2B127.600	0.248%	0.000%	0.144%	-0.012%	-0.023%	0.217%	0.166%
NOTL_MTS#2B227.600	0.251%	0.000%	0.145%	-0.012%	-0.023%	0.219%	0.167%
NOTL_MTS_#1 118.05	0.000%	0.308%	0.148%	-0.016%	-0.026%	0.216%	0.170%
NOTL_MTS_#1 27.600	0.000%	0.330%	0.158%	-0.017%	-0.028%	0.231%	0.182%
STANLEY_Q3L 118.05	-0.167%	-0.105%	0.295%	0.014%	0.005%	0.187%	0.311%
STANLEY_Q4N 118.05	-0.066%	-0.025%	0.000%	-0.064%	-0.032%	0.212%	0.000%
STANLEY_BY 13.800	-0.118%	-0.065%	2.696%	-0.017%	-0.017%	0.214%	2.712%
STANLEY_JQ 13.800	-0.121%	-0.067%	3.248%	-0.018%	-0.017%	0.218%	3.265%

MURRAY_TS 118.05	0.054%	0.073%	0.079%	-0.105%	-0.091%	0.278%	1.102%
MURRAY_QZ 13.800	0.057%	0.076%	0.083%	-0.110%	-0.094%	0.290%	1.150%
MURRAY_TSY1213.800	0.057%	0.077%	0.084%	-0.111%	-0.095%	0.293%	1.163%
MURRAY_TS_J 13.800	0.055%	0.074%	0.081%	-0.107%	-0.092%	0.282%	1.120%
MURRAY_TS_K 13.800	0.057%	0.076%	0.083%	-0.110%	-0.094%	0.290%	1.151%
CNP_#18_CTS 118.05	0.056%	0.076%	0.082%	-0.109%	-0.094%	0.288%	1.143%
CNP_#18_CTS 34.500	0.059%	0.080%	0.087%	-0.115%	-0.099%	0.304%	1.208%
STEVENSVILLE118.05	0.056%	0.075%	0.081%	-0.108%	-0.093%	0.285%	1.131%
STEVENSVILLE34.500	0.057%	0.076%	0.083%	-0.110%	-0.095%	0.290%	1.152%
RANKINE_A37N118.05	0.055%	0.073%	0.080%	-0.106%	-0.091%	0.279%	1.107%
RANKINE_CTS 44.000	0.057%	0.076%	0.083%	-0.110%	-0.094%	0.290%	1.151%
KALAR_MTSA36118.05	0.087%	0.097%	0.125%	-0.173%	-0.095%	0.252%	0.000%
KALAR_MTSA37118.05	0.087%	0.098%	0.126%	-0.174%	-0.095%	0.252%	0.738%
KALAR_MTSB1213.800	0.091%	0.102%	0.132%	-0.182%	-0.100%	0.264%	3.432%
DUNNVILLE_TS118.05	0.069%	0.084%	0.204%	0.000%	-0.087%	0.000%	0.247%
DUNNVILLE_TS27.600	0.071%	0.086%	0.211%	0.000%	-0.090%	0.000%	0.255%
VINELAND_DS 118.05	0.069%	0.083%	0.203%	0.000%	-0.087%	0.000%	0.246%
VINELAND_B1 27.600	0.069%	0.084%	0.205%	0.000%	-0.088%	0.000%	0.249%
VINELAND_B2 27.600	0.069%	0.084%	0.205%	0.000%	-0.088%	0.000%	0.249%
BEAMSVIL_Q2A118.05	0.069%	0.084%	0.204%	0.000%	-0.087%	0.000%	0.248%
BEAMSVIL_BY 27.600	0.071%	0.086%	0.211%	0.000%	-0.090%	0.000%	0.255%

Table 9: Post contingency voltage deviation - Low demand, post tap action

	Contingency						
Monitored bus	Q12S	Q11S	Q4N	Q2AH	G9	T4H	L4L36
MIDDLEPT8086500.00	0.004%	0.004%	0.007%	-0.011%	-0.001%	-0.026%	0.008%
MIDDLEPT8185500.00	0.004%	0.004%	0.006%	-0.010%	0.000%	-0.022%	0.008%
BECK_#2_TS 220.00	0.017%	0.018%	0.028%	-0.047%	-0.002%	-0.075%	0.035%
MIDDLEPT_DK1220.00	0.010%	0.011%	0.016%	-0.026%	-0.004%	-0.067%	0.020%
MIDDLEPT_DK2220.00	0.007%	0.008%	0.012%	-0.022%	0.000%	-0.043%	0.016%
BECK_#1_SS60118.05	-0.174%	-0.110%	0.076%	0.006%	0.018%	0.176%	0.091%
DECEW_FLS_SS118.05	0.479%	0.448%	0.201%	-0.105%	-0.052%	0.225%	0.232%
ALLANBURG_TS118.05	0.118%	0.121%	0.174%	-0.269%	-0.079%	0.207%	0.221%
MMFX_STL_T3 118.05	0.118%	0.121%	0.174%	-0.269%	-0.079%	0.207%	0.221%
MMFX_STL_T2 118.05	0.118%	0.121%	0.174%	-0.269%	-0.079%	0.207%	0.221%
MMFX_STL_L1 27.600	0.118%	0.121%	0.174%	-0.269%	-0.079%	0.207%	0.221%
MMFX_STL_L2 27.600	0.118%	0.121%	0.174%	-0.269%	-0.079%	0.207%	0.221%
THOROLD_D1A 118.05	0.271%	0.260%	0.182%	-0.204%	-0.066%	0.212%	0.222%
THOROLD_D3A 118.05	0.244%	0.234%	0.201%	-0.200%	-0.073%	0.224%	0.242%
THOROLD_BY 13.800	0.258%	0.247%	0.192%	-0.202%	-0.069%	0.218%	0.233%

THOROLD_EQ 13.800	0.262%	0.251%	0.195%	-0.205%	-0.070%	0.222%	0.236%
AB_CONS_NF49118.05	0.216%	0.211%	0.167%	-0.236%	-0.068%	0.203%	0.210%
AB_CONS_NF4913.800	0.217%	0.212%	0.168%	-0.237%	-0.068%	0.203%	0.211%
GEORGIA_PAC 118.05	0.245%	0.237%	0.175%	-0.220%	-0.067%	0.207%	0.216%
GEORGIA_PAC 4.1600	0.252%	0.243%	0.179%	-0.225%	-0.068%	0.213%	0.222%
VANSICKLE_D9118.05	0.585%	0.466%	0.197%	-0.094%	-0.047%	0.225%	0.228%
VANSICKLE_10118.05	0.493%	0.540%	0.197%	-0.094%	-0.047%	0.225%	0.227%
VANSICKLE_BY13.800	0.569%	0.532%	0.208%	-0.099%	-0.050%	0.237%	0.240%
CARLTON_D10S118.05	0.510%	0.585%	0.196%	-0.088%	-0.045%	0.226%	0.225%
CARLTON_D9HS118.05	0.637%	0.484%	0.196%	-0.088%	-0.045%	0.226%	0.226%
CARLTON_BY 13.800	0.613%	0.570%	0.209%	-0.094%	-0.048%	0.241%	0.241%
CARLTON_HK 13.800	0.606%	0.561%	0.206%	-0.093%	-0.047%	0.238%	0.237%
CARLTON_R1 13.800	0.574%	0.535%	0.196%	-0.088%	-0.045%	0.226%	0.226%
CARLTON_EQ 13.800	0.568%	0.541%	0.196%	-0.088%	-0.045%	0.226%	0.226%
GLENDALE_D10118.05	0.522%	0.928%	0.172%	-0.049%	-0.027%	0.219%	0.197%
GLENDALE_D9H118.05	1.029%	0.514%	0.172%	-0.049%	-0.027%	0.220%	0.197%
GLENDALE_EY 13.800	0.810%	0.754%	0.180%	-0.051%	-0.028%	0.229%	0.206%
GLENDALE_BJ 13.800	0.816%	0.740%	0.179%	-0.051%	-0.028%	0.228%	0.205%
GLENDALE_DQ 13.800	0.808%	0.746%	0.179%	-0.050%	-0.027%	0.227%	0.204%
BUNTING_Q12S118.05	0.000%	0.680%	0.173%	-0.049%	-0.027%	0.220%	0.198%
BUNTING_Q11S118.05	0.693%	0.000%	0.172%	-0.048%	-0.027%	0.220%	0.197%
BUNTING_J1J213.800	3.182%	2.679%	0.180%	-0.050%	-0.028%	0.229%	0.206%
BUNTING_Q1Q213.800	3.298%	2.897%	0.180%	-0.051%	-0.028%	0.230%	0.206%
NOTL_MTS_#2 118.05	0.242%	0.000%	0.142%	-0.020%	-0.010%	0.208%	0.163%
NOTL_MTS#2B127.600	0.246%	0.000%	0.144%	-0.021%	-0.010%	0.211%	0.166%
NOTL_MTS#2B227.600	0.248%	0.000%	0.146%	-0.021%	-0.010%	0.213%	0.167%
NOTL_MTS_#1 118.05	0.000%	0.306%	0.148%	-0.024%	-0.013%	0.210%	0.170%
NOTL_MTS_#1 27.600	0.000%	0.328%	0.158%	-0.026%	-0.014%	0.225%	0.182%
STANLEY_Q3L 118.05	-0.169%	-0.106%	0.295%	0.008%	0.015%	0.182%	0.311%
STANLEY_Q4N 118.05	-0.069%	-0.027%	0.000%	-0.073%	-0.018%	0.205%	0.000%
STANLEY_BY 13.800	-0.121%	-0.067%	2.696%	-0.025%	-0.004%	0.209%	2.712%
STANLEY_JQ 13.800	-0.124%	-0.069%	3.248%	-0.026%	-0.004%	0.212%	3.265%
MURRAY_TS 118.05	0.050%	0.070%	0.080%	-0.118%	-0.073%	0.268%	1.100%
MURRAY_QZ 13.800	0.052%	0.073%	0.084%	-0.123%	-0.076%	0.280%	1.148%
MURRAY_TSY1213.800	0.053%	0.074%	0.085%	-0.124%	-0.077%	0.283%	1.161%
MURRAY_TS_J 13.800	0.051%	0.072%	0.082%	-0.120%	-0.074%	0.272%	1.118%
MURRAY_TS_K 13.800	0.052%	0.073%	0.084%	-0.123%	-0.076%	0.280%	1.148%
CNP_#18_CTS 118.05	0.052%	0.073%	0.083%	-0.122%	-0.075%	0.278%	1.141%
CNP_#18_CTS 34.500	0.055%	0.077%	0.088%	-0.129%	-0.080%	0.294%	1.206%
STEVENSVILLE118.05	0.051%	0.072%	0.082%	-0.121%	-0.075%	0.275%	1.128%
STEVENSVILLE34.500	0.052%	0.074%	0.084%	-0.123%	-0.076%	0.280%	1.150%

RANKINE_A37N118.05	0.050%	0.071%	0.081%	-0.118%	-0.073%	0.269%	1.105%
RANKINE_CTS 44.000	0.052%	0.073%	0.084%	-0.123%	-0.076%	0.280%	1.149%
KALAR_MTSA36118.05	0.082%	0.094%	0.126%	-0.187%	-0.076%	0.241%	0.000%
KALAR_MTSA37118.05	0.083%	0.095%	0.127%	-0.188%	-0.076%	0.241%	0.736%
KALAR_MTSB1213.800	0.086%	0.099%	0.133%	-0.197%	-0.080%	0.253%	0.703%
DUNNVILLE_TS118.05	0.064%	0.081%	0.205%	0.000%	-0.068%	0.000%	0.247%
DUNNVILLE_TS27.600	0.067%	0.083%	0.212%	0.000%	-0.070%	0.000%	0.255%
VINELAND_DS 118.05	0.064%	0.080%	0.204%	0.000%	-0.067%	0.000%	0.246%
VINELAND_B1 27.600	0.065%	0.081%	0.206%	0.000%	-0.068%	0.000%	0.248%
VINELAND_B2 27.600	0.065%	0.081%	0.206%	0.000%	-0.068%	0.000%	0.248%
BEAMSVIL_Q2A118.05	0.064%	0.081%	0.205%	0.000%	-0.068%	0.000%	0.247%
BEAMSVIL_BY 27.600	0.067%	0.083%	0.212%	0.000%	-0.070%	0.000%	0.255%

– End of Section –

Appendix C: Calculation of Fault Clearing Time

The following tables shows the Fault Clearing Time calculation for Q4N and Q12S faults close to Beck#1 GS.

Table 10: Fault clearing time for a Q4N fault close to Beck#1 GS

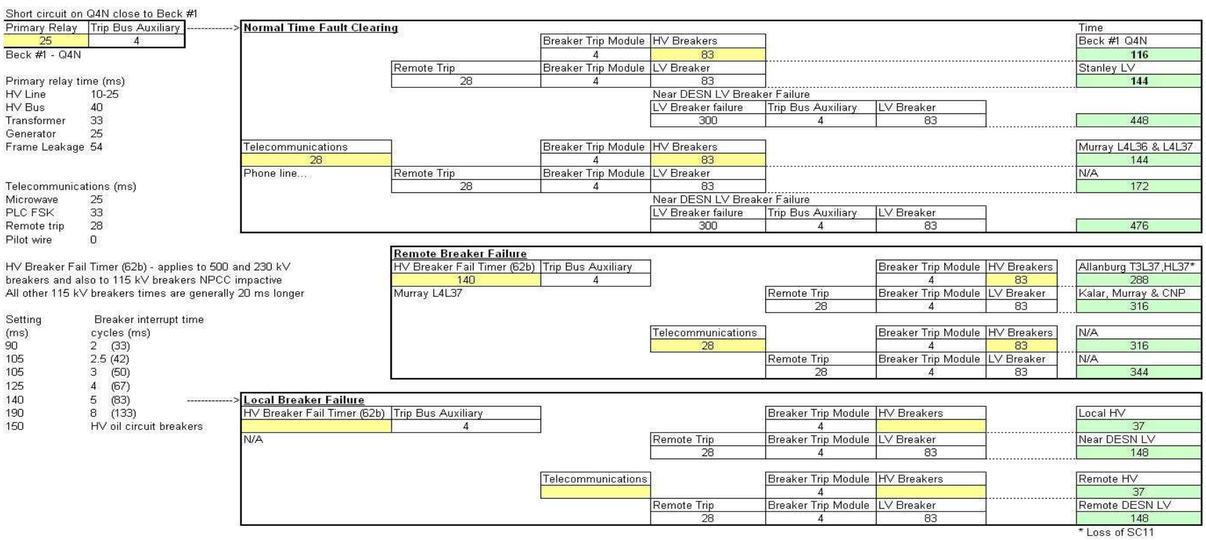
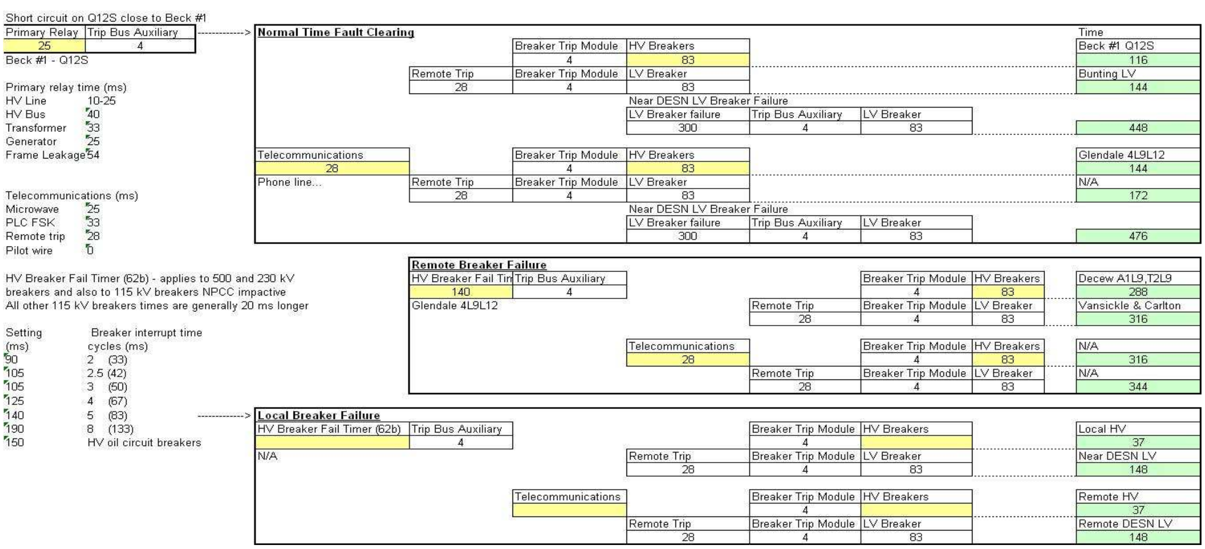


Table 11: Fault clearing time for a Q12S fault close to Beck#1 GS



– End of Section –

References

Document Name	Document ID
Q4N 115 kV conductor relocation	CAA ID# 2008-EX406
Beck#1 G7 conversion	CAA ID# 2006-252
Beck#1 units: G3, G4, G5, G6, G8, G9 and G10 Governor Replacement	CAA ID# 2008-EX413

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