REPORT

Power to Ontario.
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System Impact Assessment Report

CONNECTION ASSESSMENT & APPROVAL PROCESS

Issue 1.0

Final Report

Project: **Fort Chicago London District Energy Cogeneration Plant**

Applicant: London Hydro

Proponent: Fort Chicago District Energy Ltd.

CAA ID 2007-261

Transmission Assessments & Performance Department

June 27, 2008

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Disclaimers

Acknowledgement

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

<u>Disclaimers</u>

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 System Impact 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 System Impact 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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Executive Summary

Description

Fort Chicago District Energy Ltd. (the Proponent) is proposing to develop a cogeneration plant in London, Ontario, under a power purchase contract with the OPA. This System Impact Assessment (SIA) examined the impact of the proposed connection on the reliability of the IESO-controlled grid (ICG).

Fort Chicago London District Energy Cogeneration Plant (the Plant) will be a 22.97 MVA embedded generation facility, connected to the London Hydro (the Applicant) distribution system. The Plant will connect to the 27.6 kV feeder 26M53 out of Talbot TS, at approximately 3.1 km from the transformer station. The feeder is normally connected to the 27.6 kV bus Q1at Talbot TS.

The Plant will consist of a gas turbine synchronous generator with a maximum output of 15.7 MW, and three steam turbine induction generators for a total of 3.3 MW. The plant will have a maximum output of 19.0 MW.

The simplified connection arrangement is shown in Figure 1 of this report.

At this time, the Proponent will not participate in the Ontario Electricity Markets. The generators will operate independent of dispatch instructions from the IESO.

The SIA provides the Proponent and the Applicant with a list of specific requirements to ensure that the new facility, when connected, will not have a material adverse effect on the reliability of the ICG. Although the SIA report points out significant Market Rules requirements for generation stations, it does not reiterate all of them. However, the Plant has to meet all the applicable Market Rules requirements.

As the SIA looks at the impact of the new facility only on the transmission system, a Customer Impact Assessment (CIA) has to be performed by the Transmitter, Hydro One, to assess the impact the new generation plant has on transmission customers. If the CIA or other affected customers identify additional connection requirements that merit significant changes to the final SIA Report, these requirements would be addressed in an Addendum to the SIA Report.

London Hydro, the host distributor, has commissioned a Connection Impact Assessment (CxIA), as required by the Distribution System Code (DSC) and a final copy was provided to the IESO. Major findings from the CxIA are also included in this report.

The initial in service date for the proposed generating plant was May 2008, but the project schedule has been delayed.

Findings

This System Impact Assessment has examined the effect of the Plant on the reliability of the IESO-Controlled Grid. The studies found the following:

1. The Plant will increase the short-circuit at Talbot 27.6 kV bus above the maximum accepted level by the Transmission System Code, as mentioned in the London Hydro's CxIA. The Proponent is working to solve this issue by installing a grounding reactor in the neutral connection of the main step-up

transformer at the Plant. A CIA will be conducted by Hydro One (transmission) to evaluate the impact on its facilities at Talbot TS and surrounding transmission customers.

2. The proposed synchronous generator will have a range of reactive power capability between 1.938 Mvar at leading power factor, and 7.83 Mvar in lagging power factor at rated active power. The synchronous generator does not meet the minimum reactive power capability requirement of 5.16 Mvar in leading power factor at rated active power, at its terminals, as per existing Market Rules Appendix 4.2, Reference 1. However, when the synchronous generator operates at maximum leading power factor of 1.94 Mvar, the effect on the reactive power as measured at the 27.6 kV side of Talbot TS exceeds the required 5.16 Mvar. This effect exceeds that of a synchronous generator connected to the ICG and operating in 0.95 leading power factor.
3. The Plant has the capability to reduce its reactive power flow to zero, as measured at the facility's connection point. It also has the capability not to cause any increase in reactive power requirements at the transmission system transformer station, as required by the DSC.
4. The Plant will increase the short circuit current in the area, but will not result in short circuit levels in excess of the interrupting capability of the transmission (high voltage) breakers.
5. The Plant will displace part of the Talbot TS load, but will not result in a net injection of power into the IESO-controlled grid during peak or light load conditions.
6. The connection of the Plant will not result in thermal overloading of any existing transmission facilities in the area, under pre or post-contingency conditions.
7. With no reverse power flow anticipated at Talbot TS, the Plant will not impact on the proper operation of protection systems of transmission elements, or on the voltage regulation facilities at Talbot TS or Buchanan TS.
8. The post-contingency voltages and voltage changes in area of study will be within the acceptable limits under the entire reactive power output range of the synchronous generator GT1.
9. Over the entire range of reactive power output capability of GT1 generator, the voltage changes on the 230 kV and 27.6 kV levels at Talbot TS are up to 0.5 kV, under the locked Under-Load-Tap-Changer (ULTC) conditions.
10. The excitation system of the synchronous generator meets the Market Rules lower performance requirements for synchronous generators.
11. The performance of the generator governor system meets the Market Rules requirements.
12. The proposed synchronous generator is stable during transient periods for faults close to the 27.8 kV bus at Talbot, as well as faults on the transmission system.

Notification of Approval for Connection Proposal

From the information provided, our review concludes that the proposed connection of the Plant will not have material adverse effect on the reliability of the IESO-controlled grid, subject to meeting the requirements specified in this report

It is recommended that a *Notification of Conditional Approval for Connection* be issued for the Plant subject to the IESO receiving from Proponent and Applicant written acknowledgements that the requirements described below under the heading "IESO Requirements for Connection" will be implemented.

If the Plant either does not meet the performance standards when installed or is subsequently determined not to meet those performance standards, the IESO connection approval may be withdrawn until the performance standards or their equivalent can be demonstrated.

IESO's Requirements for Connection

The Plant has to comply with all applicable Market Rules and Distribution System Code requirements. In particular, the IESO has the following requirements:

1. The host distributor must respect the requirements from the Distribution System Code, as specified in Section 6.2 and Appendix F. The host distributor has the obligation to revise protection settings at the Plant interconnection point to ensure that they are coordinated with the distribution system protections. The existing distribution protection settings must be revised, as required.
2. At this time, the IESO does not designate the Plant as being required to provide real time monitoring data. However, at any time after the connection assessment is complete, if the IESO determines that real time monitoring data is required to maintain the reliability of the ICG, the Proponent will be required to provide the IESO with aggregate MW and Mvar real time data for the Plant as measured at the point of connection to the distribution system, and the status of the main facility breakers. Should the provision of real time data be required in the future, the IESO will provide reasonable notice to the Proponent to make the necessary arrangements to comply.
3. Protection systems must be designed to meet all the requirements of the DSC and any additional requirements identified by London Hydro and Hydro One. The units must be equipped with protection systems able to detect the out-of-step conditions which must instantaneously trip the generators if these conditions occur.
4. The synchronous generator should be capable of operating at full active power for a limited period of time for grid frequencies as low as 58.8 Hz. The synchronous generator should not trip for under-frequency system conditions that are below 60 Hz but above 57.0 Hz and above the curve shown in Figure 3 of this report.
5. If the Talbot M53 feeder is connected to the Under Frequency Load Shedding (UFLS) relays, London Hydro and Hydro One have to either increase the demand connected to UFLS relays to compensate for the loss by configuration of generation from the Plant, or to substitute M53 with a different feeder with at least the same amount of load for connection to the UFLS relays.
6. If the Plant has the automatic reconnection capability, the embedded generators shall be able to disable the automatic reconnection when directed by IESO or by the distributor. When the automatic reconnection is enabled, it shall be only active when frequency is below 60.1Hz. The frequency supervisory relay shall allow for settings to be changed, and changes shall be made only at the IESO request.
7. The synchronous generator does not meet the minimum reactive power capability requirement in leading power factor at rated active power. However, when the synchronous generator operates at its maximum leading power factor at rated active power, the effect on the reactive power as measured at Talbot TS exceeds that of a compliant synchronous generator of the same size connected to the ICG and operating in 0.95 leading power factor. At the present time, the synchronous generator's reactive capability is deemed to be adequate for maintaining the reliability of the ICG. At any time after the connection assessment is complete, if the IESO determines that a higher requirement is necessary to maintain reliable operation of the ICG, additional reactive power capability requirements may be imposed, up to the range of 0.9 lagging power factor to 0.95 leading power factor at rated active power, at the synchronous generator terminal. Should a higher reactive capability for the synchronous

generator be required in the future, the IESO will provide reasonable notice to the Proponent to make the necessary arrangements to comply.

8. The synchronous generator GT1 should be capable to operate in both voltage control and power factor control, and will operate as directed by the distributor.
9. The power factor regulator shall be capable of maintaining a power factor within ± 1% between 90% lagging and 95% leading. The var regulator shall be capable of maintaining reactive power within ± 2.5% of rated MVA. The power factor or var regulator shall have an adjustable effective response time between 10 to 60 seconds.
10. The Plant shall not trip for grid design criteria contingencies on the transmission system unless the contingency would disconnect the generating unit by configuration. All embedded generators shall have sufficient low-voltage-ride-through capability to avoid generation loss for faults in the transmission system, as indicated in section 5.3 of this report.
11. The Proponent is required to complete the facilities registration process in a timely manner before IESO final approval for connection is granted. Finalized models and data, including any controls that would be operational, must be provided to the IESO.
12. During commissioning, the Proponent must provide evidence to the IESO confirming that the equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in the finalized models and data. This evidence shall be either type tests conducted 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, the Proponent must accept any restrictions the IESO may impose upon their connection to the power grid.
13. The operation performance of the equipment must meet or exceed the predicted performance observed in simulations done by the IESO for the SIA. The IESO and the host distributor may be required to take corrective actions up to Plant disconnection if the performance of the facility would result in adverse impact on the ICG, e.g. sustained oscillations or excessive voltage decline.
14. Final connection of this project may also be subject to additional requirements specified in the CIA performed by the transmitter (Hydro One). The CIA will evaluate the impact of this proposed connection on the transmission customers, including the impact on the short-circuit adequacy of the 27.6 kV breakers at Talbot TS. If required, the CIA will address also the proper operation of protections, voltage regulating facilities and metering devices at Talbot TS, and proper operation of protections at Buchanan TS on 230 kV circuits W36 and W37. Any additional requirements resulting from the CIA will be included in the final SIA report or in an Addendum to the Final SIA report.
15. During the IESO facilities registration process, connection Proponents will be required to demonstrate to the IESO that all requirements identified in the System Impact Assessment (SIA) report have been satisfied.

– End of Section –

1. Project Description

Fort Chicago District Energy Ltd. (the Proponent) is proposing to develop a cogeneration plant consisting of three steam turbine induction generators, and one gas turbine synchronous generator in London, Ontario, under a power purchase contract with the OPA.

Fort Chicago London District Energy Cogeneration Plant (the Plant) will be a 22.972 MVA embedded generation facility, connected to the London Hydro distribution system. The generation facility will connect to the 27.6 kV feeder 26M53 out of Talbot TS, at approximately 3.1 km from the transformer station. The feeder is normally connected to the 27.6 kV Q1 bus at Talbot TS.

This System Impact Assessment (SIA) examined the impact on the reliability of the IESO-controlled grid (ICG) of the proposed Plant, including the adequacy of the short circuit and thermal capability of the transmission system, assessed the voltage performance and transient stability of the power system with the Plant connected, and evaluated the performance characteristics of the generators and associated equipment against the Market Rules standard requirements.

The SIA provides the Proponent and London Hydro (the Applicant) with a list of specific requirements to ensure that the Plant, when connected, will not have a material adverse effect on the reliability of the ICG. Although the SIA report points out significant Market Rules requirements for generation stations, it does not reiterate all of them. However, the new facility has to meet all the applicable Market Rules requirements.

For embedded generation, the Distribution System Code obligates the distributors to perform an impact assessment that "*shall set out the impact of the proposed generation facility on the distributor's distribution system and any customers of the distributor including:*

(a) any voltage impacts, impacts on current loading settings and impacts on fault currents;

(b) the connection feasibility;

(c) the need for any line or equipment upgrades;

(d) the need for transmission system protection modifications; and

(e) any metering requirements."

The IESO has received a copy of the Connection Impact Assessment (CxIA) on the distribution system commissioned by London Hydro. The main negative impact identified in the assessment was that the line-to-ground short-circuit level on the distribution system exceeds the allowable limits. The Proponent is working to solve this issue by installing a grounding reactor in the neutral connection of the main step-up transformer at the generation plant.

The initial in service date for the proposed generating plant was May 2008, but the schedule has been delayed.

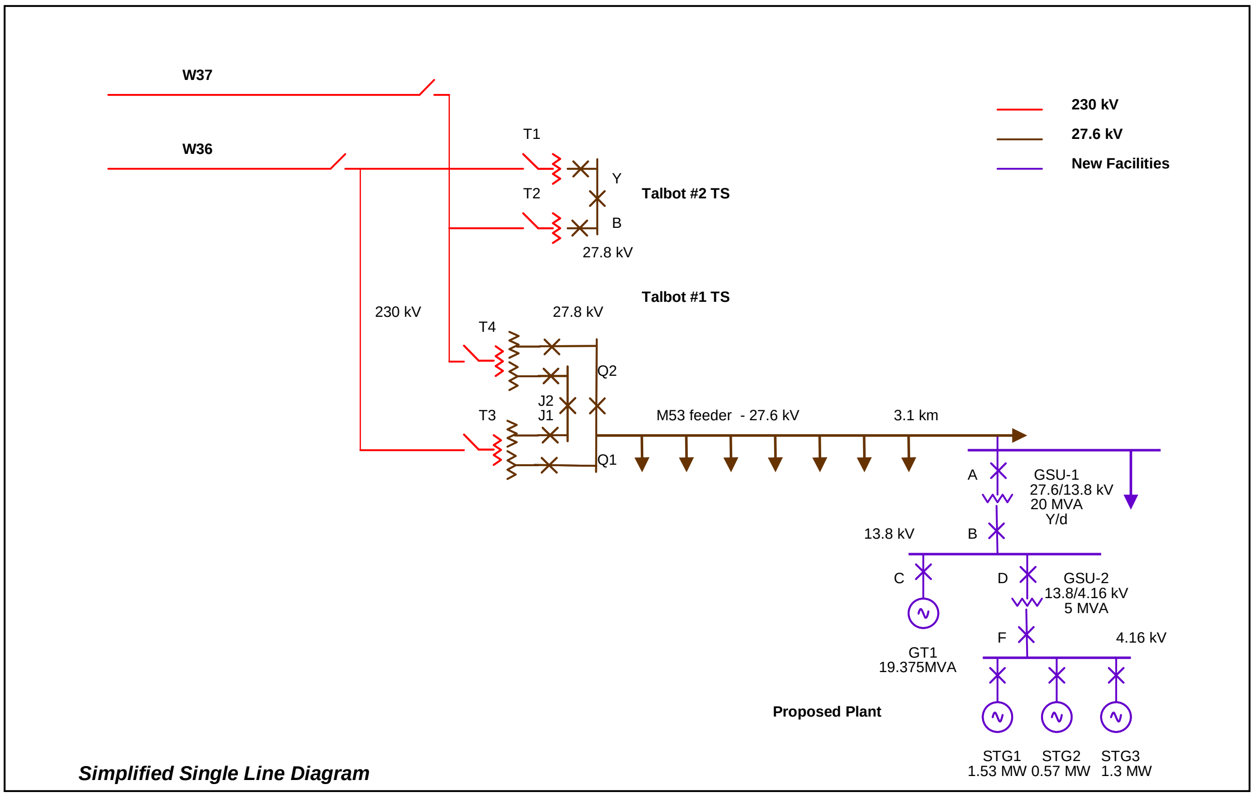
– End of Section –

2. Review of Connection Proposal

2.1 Connection Arrangement

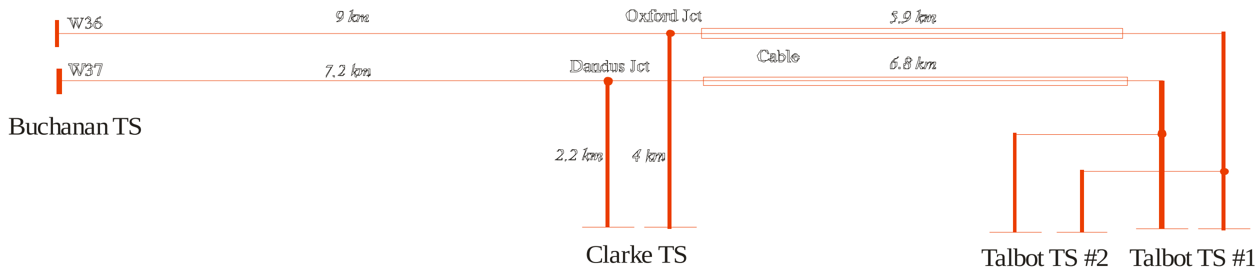
The simplified proposed Plant connection and the distribution system single line diagram are shown in Figure 1 of this report. Since the Plant connects to the distribution system, the IESO has no comments on the Plant connection arrangement.

Figure 1 – Simplified Single Line Diagram



A schematic diagram of the 230 kV W36/W37 transmission lines in the London area supplying Talbot TS is shown in Figure 2. On the diagrams, Talbot #1 is the old Talbot station, and Talbot #2 is the new station recently built at the same location. The M53 feeder is supplied from the old Talbot #1 transformers.

Figure 2: W36 / W37 Transmission Lines



2.2 On-line Monitoring

Market Rules Chapter 4 section 7.3 requires that each embedded generator that is not a market participant or whose embedded generation facility is not a registered facility; whose embedded generation facility includes a generation unit rated at greater than 20 MVA or that comprises generation units the ratings of which in the aggregate exceeds 20 MVA; and that is designated by the IESO as being required to provide such data in order to enable the IESO to maintain the reliability of the ICG, shall provide the IESO with real time data on a continual basis. The Plant is greater than 20 MVA.

At this time, the IESO does not designate the proposed Plant as being required to provide real time monitoring data. However, at any time after the connection assessment is complete, if the IESO determines that real time monitoring data is required to maintain the reliability of the ICG, the Proponent will be required to provide the IESO with aggregate MW and Mvar real time data for the generation plant as measured at the point of connection to the distribution system, and the status of the main facility breakers. Should the provision of real time data be required in the future, the IESO will provide reasonable notice to the Proponent to make the necessary arrangements to comply.

2.3 Protection Systems

The host distributor has the obligation to revise protection settings at the Plant interconnection point to ensure that they are coordinated with the distribution system protections. The existing distribution protection settings must be revised, as required.

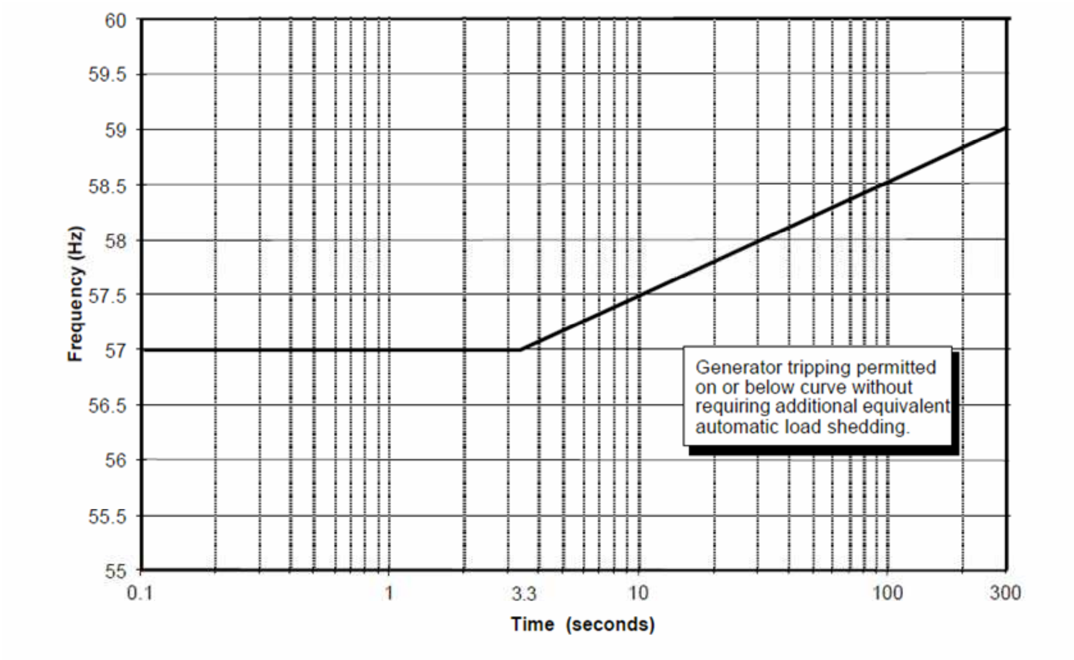
Reverse active power flow into the transmission system is not anticipated to occur with the addition of the Plant. However, under any other circumstances, if the reverse power flow occurs, issues such as proper operation of protections, voltage regulating facilities and metering devices must be reinvestigated.

Protection systems must be designed to meet all the requirements of the *DSC* and any additional requirements identified by London Hydro and Hydro One. The units must be equipped with protection systems able to detect the out-of-step conditions which must instantaneously trip the generators if these conditions occur.

2.4 Under-Frequency Tripping

Reference #3 of Appendix 4.2 of the *Market Rul*es requires generating facilities to be capable of operating continuously at full power for a system frequency range between 59.4 to 60.6 Hz. For under-frequency system conditions, generators shall not trip for frequency variations that are above the curve shown in Figure 3.

Figure 3: Standard for Setting Under-Frequency Trip Protection for New Generators



The Proponent confirmed that the plant will satisfy the standard from Figure 3.

2.5 Under Frequency Load Shedding (UFLS)

Each distributor and connected wholesale customer, in conjunction with the relevant transmitter, shall make arrangements to enable the automatic under-frequency disconnection of at least 30% of its total demand based on the distribution of demand during peak conditions. In all automatic UFLS areas, there must be at least 30% of area demand connected to under-frequency relays, after accounting for relay outages, the impact of generators that may trip prematurely on under-frequency and generators connected to the feeders on UFLS relays.

As mentioned above, the Proponent confirmed that the Plant will not trip prematurely on under-frequency.

If the Talbot M53 feeder is connected to the UFLS relays, London Hydro and Hydro One have to either increase the demand connected to UFLS relays to compensate for the loss by configuration of the Plant generation, or to substitute M53 with a different feeder with at least the same amount of load for connection to the UFLS relays.

2.6 Over Frequency Tripping and Automatic Reconnection

If the Plant has the automatic reconnection capability, the embedded generators shall be able to disable the automatic reconnection when directed by IESO or by the distributor. When the automatic reconnection is enabled, it shall be only active when frequency is below 60.1Hz. The frequency supervisory relay shall allow for settings to be changed, and changes shall be made only at the IESO request.

– End of Section –

3. Data Verification

The Proponent is advised that if the actual parameters will significantly differ from those used in this assessment, the results of this SIA would have to be revised.

3.1 Generator and Transformer Data

All generators larger than 10 MVA must satisfy applicable *Generation Facility Requirements* in Appendix 4.2, references 1 to 16 of the *Market Rules*.

In particular, references 1 and 2 require that a synchronous generator unit must comply with the following requirements:

- the generator shall be capable to supply at its terminal reactive power within the range 90% lagging (overexcited) to 95% leading (underexcited) power factor based on rated active power at rated voltage. Rated active power shall be the lesser of registered maximum continuous real power and 90% of the unit nameplate MVA.
- the generator shall be capable to operate continuously at full active power continuously while operating at a generator terminal voltage ranging from 0.95 pu to 1.05 pu of the generator rated terminal voltage.

Table 1 – GT1 Generator Data

Station	***Unit***	***Type***	***MVA***	***Rated PF***	***Maximum MW***	***kV***	***Xd''***
The Plant	GT1	CTG	19.375	0.80	15.7	13.8	0.204

Table 2 –GT1 Generator – Reactive Power at Rated MW

Station	***Unit***	***Rated MW***	***Q required at rated MW and 0.95 lead PF***	***Q required at rated MW and 0.9 lag PF***	***Q minimum capability curve***	***Q maximum capability curve***
The Plant	GT1	15.7	5.16	7.6	**-1.93**	11.43

The proposed synchronous generator does not meet the minimum reactive power capability requirement of 5.16 Mvar in leading power factor at rated active power, as per existing Market Rules Appendix 4.2, Reference 1. It can also be observed from Table 3 below that, even by taking into account the reactive power used by the induction generators, the Plant cannot achieve the minimum reactive power requirement of 5.16 Mvar in leading power factor.

However, as presented later in section 5.5 of this report, when the synchronous generator operates at maximum leading power factor of 1.94 Mvar, the effect on the reactive power as measured at Talbot TS exceeds the required 5.16 Mvar in leading power factor.

Table 3 – Plant Capability

	GT1	***STG1***	***STG2***	***STG3***	***Total Facility***
Rated MVA	19.375	3.358	0.622	1.415	**24.771**
Maximum MW	15.700	1.430	0.570	1.300	**19.000**
Rated MW	15.700				
Minimum Mvar at rated MW (from capability curve)	-1.938	-0.620	-0.250	-0.560	**-3.368**
Maximum Mvar at rated MW (from capability curve)	11.431	-0.620	-0.250	-0.560	**10.001**
Required min Mvar at rated MW	-5.160				
Required max Mvar at rated MW	7.604				

The IESO is in the process of reviewing the Market Rules requirements for embedded generators. Under the proposed technical requirements, the embedded generators shall have, as a minimum, the capability to reduce their reactive power flow to zero, as measured at the facility's connection point.

The synchronous generator does not meet the minimum reactive power capability requirement in leading power factor at rated active power. However, when the synchronous generator operates at its maximum leading power factor at rated active power, the effect on the reactive power as measured at the 27.6 kV side of Talbot TS exceeds this minimum reactive power requirement. At the present time, the synchronous generator's reactive capability is deemed to be adequate for maintaining the reliability of the ICG. At any time after the connection assessment is complete, if the IESO determines that a higher requirement is necessary to maintain reliable operation of the ICG, additional reactive power capability requirements may be imposed, up to the range of 0.9 lagging power factor to 0.95 leading power factor at rated active power, at the synchronous generator terminal. Should this be required in the future, the IESO will provide reasonable notice to the Proponent to make the necessary arrangements to comply.

Table 4 – Induction Generator Data

Identifier	***STG1***	***STG2***	***STG3***
Generation (MW)	1.43	0.57	1.30
Terminal voltage (kV)	4.16	4.16	4.16
Power factor	0.918	0.918	0.918
Reactive power at full output (Mvar)	0.62	0.25	0.56
Reactive power at no output (Mvar)	0	0	0
Power factor correction installed	none	none	none
Rated speed (RPM)	3621	3621	3621
Rated slip (%)	0.583	0.583	0.583
Starting inrush current (multiple of full load)	5.3	5.3	5.3

Table 5 - Transformers

Station	***Name***	***MVA***	***Connectivity***	***kV***	***R %***	***X %***	***MVA base***	***Taps***
The Plant	GSU1	15/20	Y - d	27.6-13.8	0.48	6.75	15	+/-2x2.5%
	GSU2	3.75/5	Yo - d	13.8-4.16	0.4	5.8	3.75	-

3.2 Connection Equipment (buses, circuit breakers, disconnects, feeders)

Table 6 - Breakers

Station	Breaker	Rated kV	Interrupting Time	Rated Continuous A	Interrupting Media	Rated Symmetrical Interrupting Capability kA
The Plant	B	13.8	51 ms	2000 A	SF6	37 / 41 kA
	A	27.6	51 ms	1250 A	SF6	37 / 41 kA

Feeder impedance in ohms per 1000 m was provided by the distributor, as follows.

Table 7 – M53 Feeder

Section	Cable	Length km	R1= R2	X1=X2	Ro	Xo
Section 1	1000 kcmil	0.385	0.14	0.1599	0.28	0.07
Section 2	556 kcmil	2.74	0.102099	0.403699	0.276499	1.094599

3.3 Dynamic Models

(a) Generators

Table 8 – CTG1 Generator Dynamic Data - Model GENROU

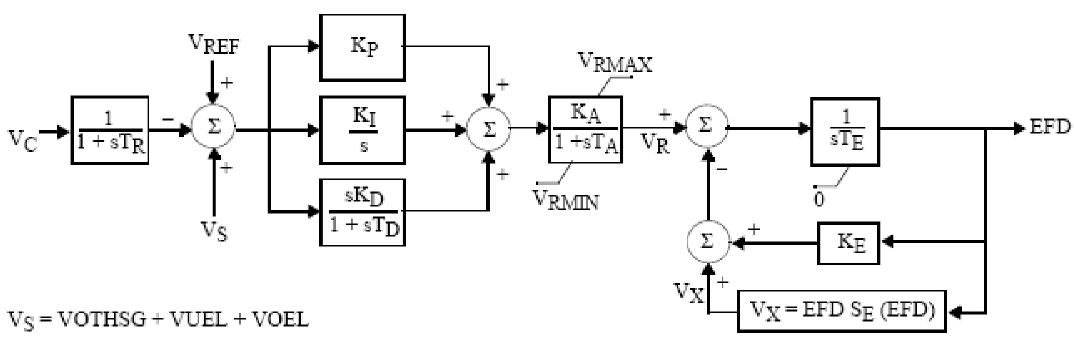
CONs	CTG - G1
T'_{do}	7.63 s
T''_{do}	0.037 s
T''_{qo}	0.10 s
H	3.228 kW-s / kVA
D	2.1 kN m s / rad
X_d	1.8 pu
X_q	0.785 pu
X'_d	0.294 pu
X'_q	0.306
$X''_d = X''_q$	0.204 pu
X_l	0.134 pu
S(1.0)	0.102
S(1.2)	0.304
M_{base}	19.375 MVA

(b) Automatic Excitation Systems

As per London Hydro's CxIA, the synchronous generator is requested to have the capability to operate in both power factor control and voltage control.

Table 9 – GT1 – Excitation System - Model AC8B

CONs	*GT1*
T_R	0.005 s
K_P	200
K_I	100
K_D	75
T_D	0.01
K_A	0.144
T_A	0 s
V_{RMAX}	13.4
V_{RMIN}	0
T_E	0.32 s
K_E	1
E_1	2
$S1(E_1)$	0
E_2	4
$S2(E_2)$	0



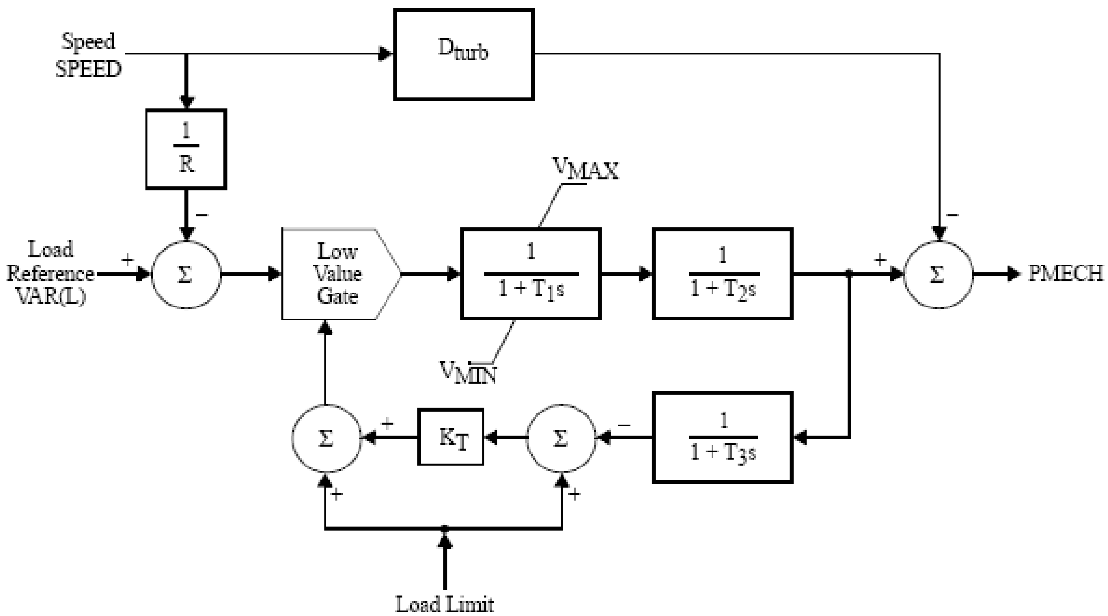
(c) Power System Stabilizer (PSS)

The proposed synchronous generator does not have a PSS. Based on the results from the exciter testing, a PSS is not required.

d) Speed Governor Systems

Table 10 – GT1 – Gas Turbine Governor – Model GAST

CONs	*G1*
R Speed Droop	0.05
T_1(sec)	0.3
T_2 (sec)	0.1
T_3 (sec)	0.5
Ambient temperature load limit, AT	1.05
K_T	2
V_{MAX}	1.4
V_{MIN}	-0.2
D_{turb}	0



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4. Short Circuit Assessment

The impact of the Plant on the distribution system has been conducted by London Hydro as part of the Connection Impact Assessment (CxIA). The analysis included the short-circuit adequacy of the 27.6 kV distribution equipment. London Hydro's study identified that the new line-to-ground short-circuit exceeds the acceptable level. The Proponent confirmed that it is working towards solving this issue by installing a grounding reactor in the neutral connection of the main step up transformer at the proposed Plant.

The fault contribution from the new plant at Talbot TS Q bus, as calculated in the CxIA is presented below.

Table 11 – Plant Contribution at Talbot TS

Bus	***Symmetrical***		***Asymmetrical***	
	3-phase (kA)	***L-G (kA)***	***3-phase (kA)***	***L-G (kA)***
Talbot Q bus	1.437	2.246	1.646	2.764

Obviously, the fault contribution from the Plant into the 230 kV system is significantly lower, due to the impedance and transformation ratio of the transformers. Less than 0.35 kA fault contribution is expected into the high voltage system.

As part of the SIA, the IESO investigates the impact of the new connections on the IESO-controlled grid fault levels and the adequacy of the high voltage breakers to interrupt the faults.

The high voltage breakers to be impacted the most are at Buchanan TS. The minimum short circuit interrupting capability of the 230 kV and 115 kV breakers at Buchanan TS and the short circuit levels as calculated by Hydro One in 2007 are provided in Table 12 below. The fault levels include the contribution from the future Greenfield Energy Centre generating station.

Table 12 - Buchanan Short-circuit Analysis

Station	***Minimum Breaker Rating (kA)***		***Fault Levels (kA)***			
	Symmetrical	***Asymmetrical***	***Symmetrical***		***Asymmetrical***	
			3-Phase	***L-G***	***3-Phase***	***L-G***
Buchanan 115 kV	39.3	45.5	24.2	28.2	28.8	35.4
Buchanan 230 kV	35.7	46.2	30.0	25.5	35.3	32.5

It can be observed that the existing margins between breaker interrupting capabilities and the short-circuit levels are adequate to accommodate the fault increase resulting from the new plant.

Therefore, no detailed fault level studies were required for the SIA.

In addition to this short circuit assessment, Hydro One conducts the *Connection Impact Assessment* (CIA) short circuit assessment to verify that the fault interrupting devices at the connection point of its customers and on the low voltage side of its transformer stations are adequate to interrupt the increased short circuit levels attributable to the connection of a new facility.

The CIA will evaluate the impact of this proposed connection on the transmission customers, including the short-circuit adequacy of the 27.6 kV breakers at Talbot TS. Any additional requirements resulting from the CIA will be included in the final SIA report or in an Addendum to the Final SIA report.

End of Section –

5. System Impact Studies

5.1 Description

The technical studies focused on identifying the impact of the new generation station on the reliability of the IESO-controlled grid. It includes thermal loading assessment of 230 kV transmission lines W36 and W37 and system voltage performance in the Buchanan – Talbot area. It also evaluates dynamic control systems proposed for the Plant and the power system transient stability.

The studies were performed for the 2008 summer peak load and 2008 spring light load conditions.

5.2 Area Loads and Load Growth

The loads at the existing Talbot TS and Clarke TS are supplied via the 230 kV double circuit line W36 - W37 emanating from Buchanan 230 kV switchyard.

Due to the load increase in the area and the existing station approaching their capacities, a new DESN station was commissioned on March 3, 2008 at Talbot TS, called in this assessment Talbot TS #2, which consists of two step-down transformers T1 and T2.

Hydro One provided load forecast at Clarke TS, Talbot TS #1 and Talbot TS #2 for the SIA evaluating the impact of Talbot TS #2, as shown in Table 13 below.

Table 13 - Station Load Forecast (MVA)

	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Clarke TS	102	103	105	112	115	118	120	123	125
Talbot TS #1 (T3+T4)	210	157	156	158	160	162	164	166	167
Talbot TS #2 (T1+T2)		58	101	111	113	115	118	120	121
Total	312	318	362	381	388	395	402	409	413

The maximum load recorded in 2007 at Talbot TS was 187 MW (203 MVA) on Sept 6 at 17:00. The maximum load recorded on Q1Q2 buses at the same time was 85 MW.

In 2007, the minimum load of 65 MW at Talbot TS was recorded on July 2nd, when the Q1Q2 bus load was 31.3 MW. A minimum of 27.3 MW load on Q1Q2 buses was recorded on Sept 30th.

Talbot TS loading and Q1Q2 bus loading for 2007 are presented in Figure 6 and Figure 7, respectively.

Figure 6 – Talbot TS Load – January 1st to December 31st, 2007

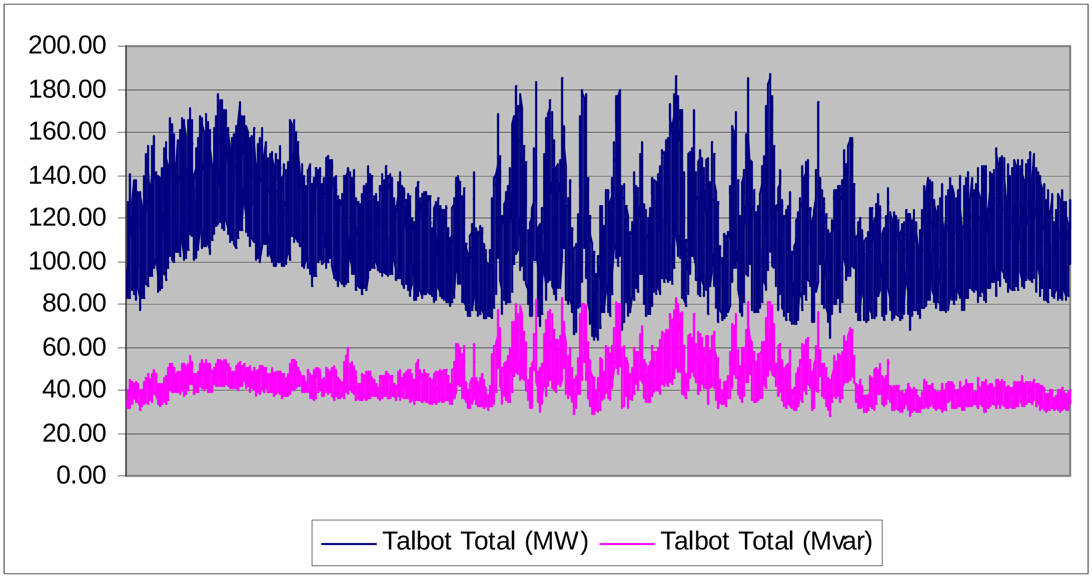
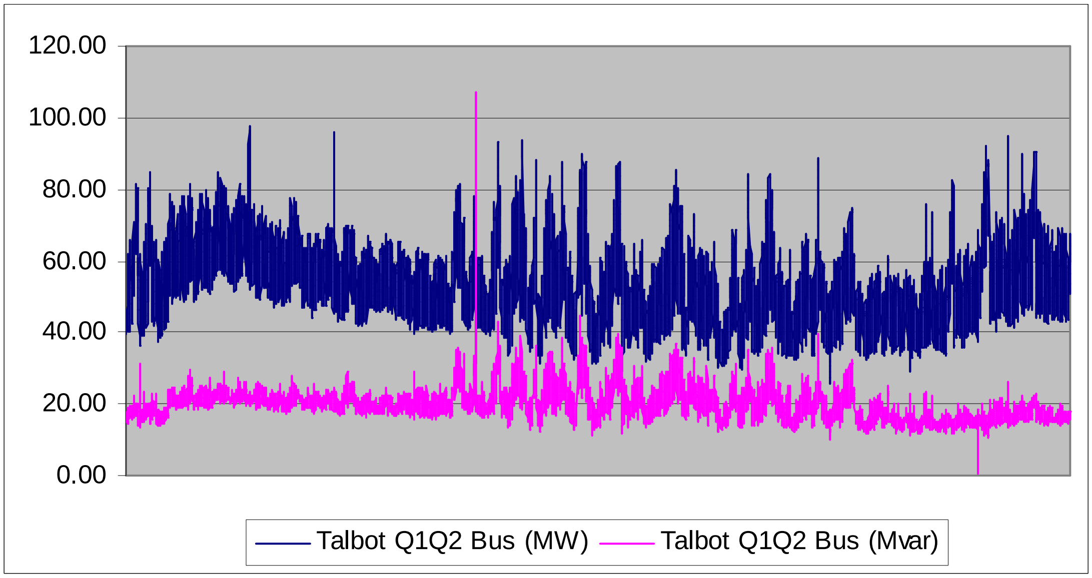


Figure 7 – Talbot Q1Q2 Bus – January 1st to December 31st, 2007



The new Talbot TS loadings and Q1Q2 bus loading during the first part of 2008 are presented below in Figure 8 and Figure 9, respectively.

It can be observed that since the new DESN was commissioned on March 3rd, the loadings on the old T3 and T4 Talbot transformers, as well as on the Q1Q2 buses have decreased. From the telemetry before March 25th, the minimum Q1Q2 bus load of 21.62 MW was recorded on March 15th at 4:00, when the total T3+T4 load was 63.8 MW.

Figure 8 – Talbot TS Load – January 1st to March 25th 2008

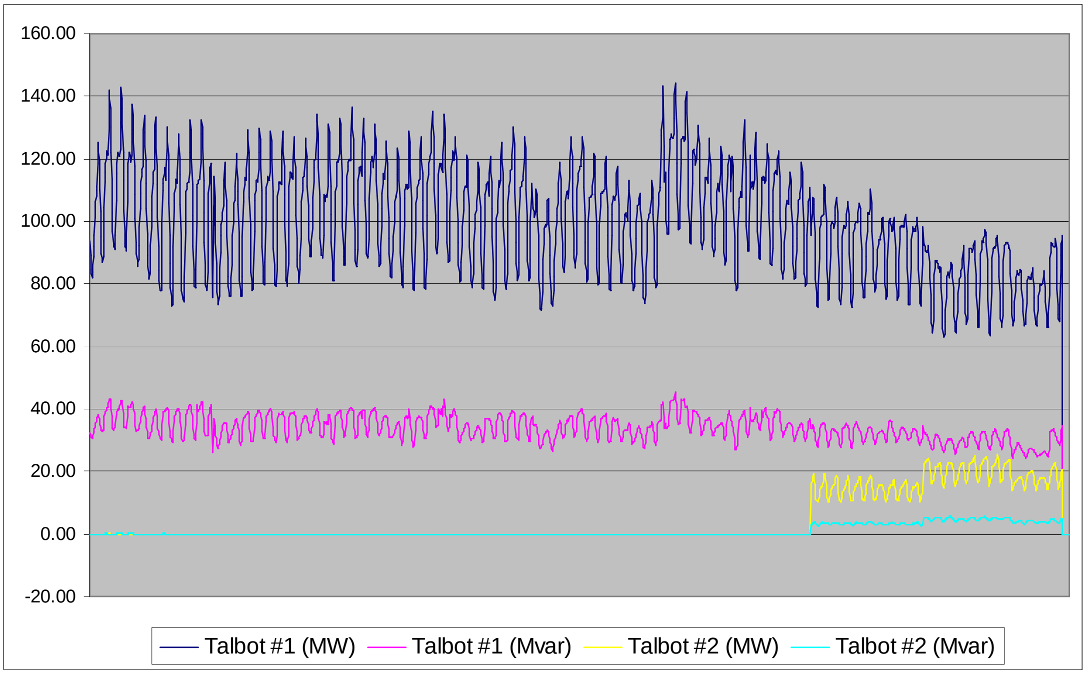


Figure 9 – Talbot Q1Q2 Bus – January 1st to March 25th 2008

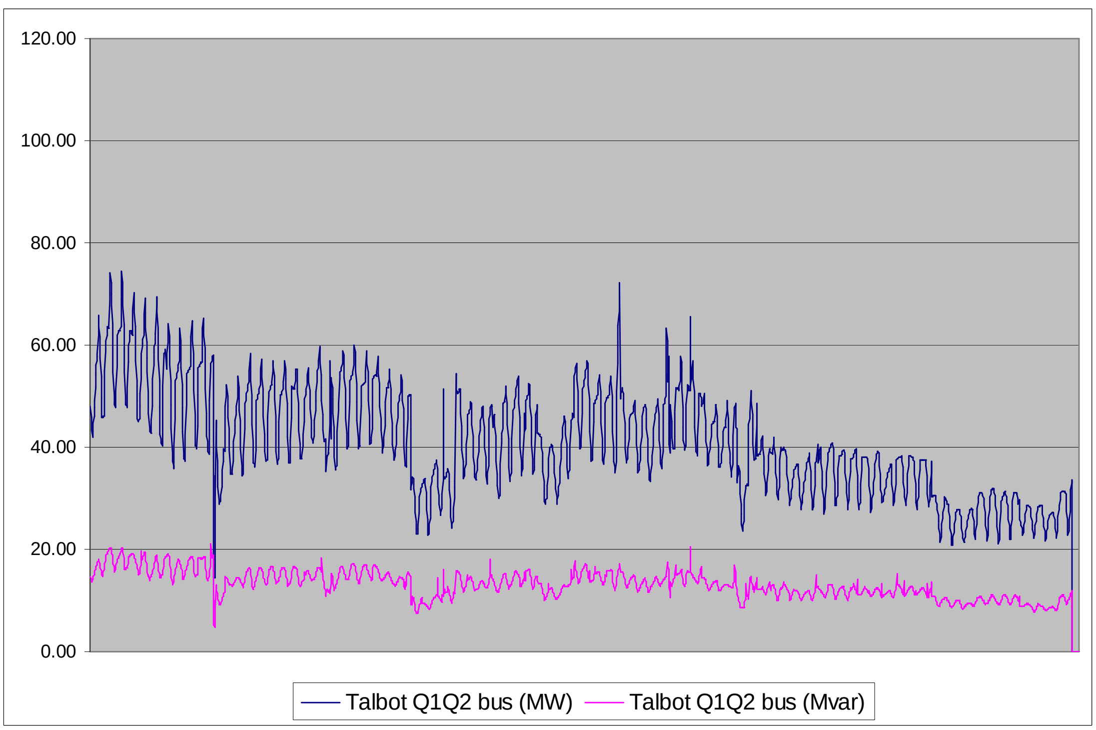
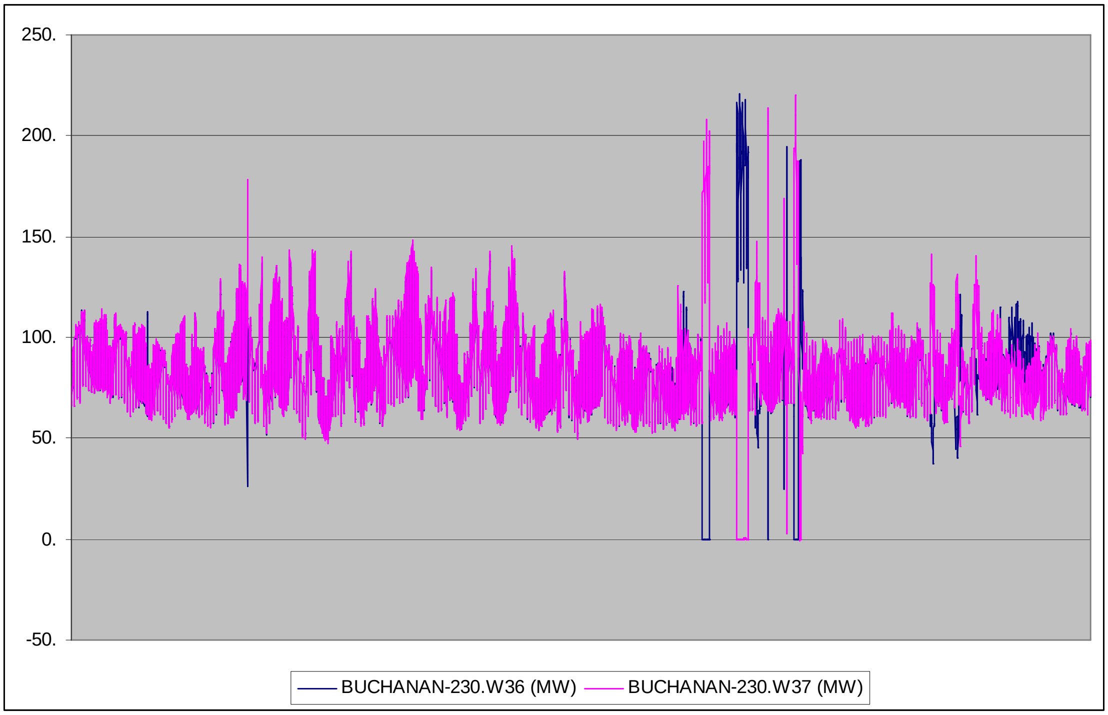


Figure 10 below presents the loading for one year on the 230 kV circuits W36 and W37 at Buchanan. The minimum load was recorded on February 7, 2007, when each circuit was loaded at 48 MW, for a total of 96 MW.

Figure 10 – 230 kV circuits W36 and W37 loading – April 1st 2007 to April 1sr 2008



5.3 Study Assumptions

Modeling Assumptions

Based on the information provided by London Hydro and the Proponent, the Plant has been added to the IESO base case model. The parameters used for simulation are listed in section 3 of this report. Since no dynamic data was provided for the inductions generators, they were modeled using the induction generator model CIMTR3 with typical parameters for dynamic simulations.

The IESO base case model does not include London Hydro distribution system. However, the 27.6 kV feeder M53, where the plant will connect to, was modeled in detail, with the distribution loads and feeder impedances as provided by the London Hydro.

The remaining load connected to the distribution system at Talbot TS was modeled as connected directly to the LV bus.

The load power factor was assumed to be 0.9 at all stations in the area.

Based on the load distribution forecast presented in Table 13 above, Talbot #1 will be loaded at 75% of its previous load after Talbot #2 is in service.

Using the 2007 minimums, this results in a minimum load forecast of 0.75 x 65 MW = 48.7 MW on T3+T4 transformers, and a minimum load of 0.75 x 27.3 MW = 20.4 MW on the Q1Q2 bus. The same 75% ratio was used to derive the peak load for the LV buses.

The M53 feeder peak load was assumed as per London Hydro load information, with a power factor of 0.9.

The light load conditions for the M53 feeder, Talbot #2 TS and Clarke TS were calculated by applying a 35% factor to the peak forecast, factor in line with the actual minimum / maximum load ratio in the area.

For the light load scenario, the Western Zone of the Ontario system was reduced to 50% of its peak load.

Table 14 below summarizes the loading assumptions used for the technical studies.

Table 14 - Load Assumptions

Station	***Load Assumptions (MW)*** ***2008 Peak***	***2008 Light***
Talbot #1 TS	141.3	48.7
Q1Q2 bus (includes M53)	63.8	20.4
J1J2 bus	77.5	28.3
M53 feeder	10.7	3.7
Talbot #2 TS	52.2	18.3
Clarke TS	92.7	32.4
Ontario Western Area	3100	1550

Table 15 – Generation Assumptions

	GT1	***STG1***	***STG2***	***STG3***	***Total Facility***
Maximum MW	15.700	1.430	0.570	1.300	19.00
Maximum Mvar at leading PF	-1.938	-0.620	-0.250	-0.560	-3.368
Maximum Mvar at lagging PF	7.604	-0.620	-0.250	-0.560	6.174

The generation output was assumed to be as per the Proponent's data. The gas turbine generator GT1 and the steam turbine generators were assumed to produce a total of **19.00 MW**.

The transformation ratio at the Plant was assumed to be 1.05:1 pu for the 27.6-13.8 kV transformer, and 1:1 pu for the 13.8 - 4.16 kV transformer.

Thermal ratings

The thermal ratings for the transmission elements used in SIA assessments are normally confirmed or provided by the equipment owner.

The continuous ampacity ratings for the overhead conductors were calculated at the lowest of the sag temperature or 93^{o}C operating temperature, with a 35^{o}C ambient temperature and 4 km/h wind speed. The long term emergency ratings (LTE) for the overhead conductors were calculated at the lowest of the sag temperature or 127^{o}C operating temperature, with a 35^{o}C ambient temperature and 4 km/h wind speed. The 15 minute-LTR or short term emergency ratings (STE) were calculated for a pre-load equal with the continuous ratings of the overhead lines.

The continuous and emergency MVA ratings for lines were calculated assuming 240 kV at the 230 kV level.

Load Modeling

Load was modeled as a *constant MVA* for the thermal assessment.

For steady-state voltage studies, the load in the studied area was modeled as voltage dependant prior to the tap changer response (P modeled as 50% constant current and 50% constant impedance; Q modeled as 100% constant impedance), and as constant MVA after the transformer tap changers responded.

For transient studies, the load in Ontario was modeled as voltage dependant load: P modeled as 50% constant current and 50% constant impedance, and Q modeled as 100% constant impedance.

5.4 Thermal Loading Assessment

The *Ontario Resource and Transmission Assessment Criteria (ORTAC)* requires that all line and equipment loadings to be within their continuous ratings with all elements in service, and within their long-term emergency ratings with one element out of service. It is acceptable to be loaded up to their short-term emergency ratings immediately following contingencies, where control actions are available to reduce the loadings below the long-term emergency ratings.

No detailed thermal assessment was required to be conducted for the SIA, since the Plant does not result in increased power flow over the transmission elements.

During the peak load conditions, the addition of the Plant will relieve loading on the 230 kV circuits W36 and W37, on the T3 and T4 step down transformers at Talbot TS, as well as on the 27.6 kV Q1Q2 bus. No reverse power flow will occur on the above system elements.

Even under minimum load conditions, with a maximum Plant output of 19.0 MW and Q1Q2 minimum forecast bus load of 20.4 MW, no reverse power flow is expected to occur into the Q1Q2 bus or into transmission elements.

Regardless of the system loading conditions, there will be higher load flows on most of the sections of the 27.6 kV feeder M53, in reverse direction, after the Plant comes into service. However, the scope of the SIA does not cover the feeder assessment. It is expected that the CxIA conducted by London Hydro has investigated these conditions.

Therefore, it can be concluded without any detailed technical power flow simulations that the addition of the Plant will not negatively impact the thermal capability of the ICG pre or post-contingency.

5.5 Voltage Assessment

The IESO requires all the generation units connected to the ICG to be operated in voltage control mode. However, embedded generators have to comply with the voltage operating requirements as established by the host distributor in order to minimize the impact of the new connections on the distribution system. London Hydro's CxIA required the Plant to be capable to operate in both voltage control and power factor control.

The *Ontario Resource and Transmission Assessment Criteria* states that with all facilities in service pre-contingency, system voltage declines after a contingency are to be limited to 10% in the transmission system, both before and after transformer tap changer action, and the voltage on the 230 kV system is to be minimum 207 kV.

The post-contingency voltage declines at the transformer station LV buses are to be limited to 10% before tap changer action and 5% after tap changer action.

Voltage performance simulations were conducted with load modeled as voltage dependant prior to the Under-Load-Tap-Changer (ULTC) response (P modeled as 50 % constant current and 50 % constant impedance; Q modeled as 100% constant impedance), and as constant MVA after the transformer tap changers responded (post-ULTC).

The Proponent advised us that the induction generators will trip automatically if the synchronous generator trips. Therefore, the only contingency simulated was the loss of the entire Plant, under both peak and light load conditions.

To cover the entire range of reactive power from the synchronous generator, several cases were set up. The steady-state voltage results are presented in Tables 16 and Table 17 below, for the peak load and light load conditions, respectively. For the purpose of this report, the voltages of interest are only the transmission voltages and the 27.6 kV buses at the transformer stations. Voltages at the end of the feeder and on the 13.8 and 4.16 kV buses inside the Plant are presented for information purposes only.

As it can be observed, the post-contingency voltages and voltage changes were within the acceptable limits under both load level conditions and the entire range of reactive power output.

An additional assessment was conducted to assess the effect of the reactive power injection at the Plant on the system voltages and station flows, under the fixed ULTC conditions, therefore removing the influence of the voltage regulating devices. The voltage changes were up to 0.5 kV on both 230 kV and 27.6 kV levels at Talbot TS under the entire range of reactive power output capability of GT1 generator. If the GT1 generator were to achieve the required reactive output at 0.95 leading PF of 5.16 Mvar, the voltage changes on the 230 kV and 27.6 kV buses were 0.6 kV and 0.8 kV, respectively. The results are presented in Tables 18 and Table 19 below, for the peak load and light load conditions, respectively.

The DSC requires that the reactive power requirements at the transmission system transformer station should not materially increase because of the connection of the embedded generator. Based on the results presented in Table 18 for peak load conditions, this requirement would be met if the synchronous generator produces at least 1.5 Mvar.

Table16: Voltage Decline – Peak Load Conditions

Bus		***Plant at 1 PF (GT1 at 3.00 Mvar)***				***Plant at no Mvar impact at TS (GT1 at 4.50 Mvar)***				***GT1 at 0.9 PF - Lagging (GT1 at 7.60 Mvar)***				***GT1 at Maximum Leading PF (GT1 at -1.94 Mvar)***			
		Pre Cont.	***Post-Contingency***			***Pre Cont.***	***Post-Contingency***			***Pre Cont.***	***Post-Contingency***			***Pre Cont.***	***Post-Contingency***		
		(kV)	***Pre-ULTC (kV)***	***Post-ULTC (kV)***	***Largest Decline (%)***	***(kV)***	***Pre-ULTC (kV)***	***Post-ULTC (kV)***	***Largest Decline (%)***	***(kV)***	***Pre-ULTC (kV)***	***Post-ULTC (kV)***	***Largest Decline (%)***	***(kV)***	***Pre-ULTC (kV)***	***Post-ULTC (kV)***	***Largest Decline (%)***
Buchanan TS	230 kV	246.2	246.0	246.0	0.08	246.2	246.0	246.0	0.08	246.3	246.0	246.0	0.12	246	246.0	246.0	0.00
Clarke TS	230 kV W36	245.8	245.6	245.6	0.08	245.8	245.6	245.6	0.08	246	245.6	245.6	0.16	245.5	245.6	245.6	-0.04
	230 kV W37	245.6	245.5	245.4	0.08	245.7	245.4	245.4	0.12	245.8	245.5	245.5	0.12	245.4	245.4	245.4	0.00
	27.6 kV	28.9	28.9	28.9	0.00	28.9	28.9	28.9	0.00	28.9	28.9	28.9	0.00	28.9	28.9	28.9	0.00
Talbot TS	230 kV W36	245.8	245.6	245.6	0.08	245.8	245.6	245.6	0.08	245.9	245.6	245.6	0.12	245.5	245.5	245.5	0.00
	230 kV W37	245.6	245.4	245.4	0.08	245.7	245.4	245.4	0.12	245.8	245.4	245.4	0.16	245.4	245.4	245.4	0.00
	Q1Q2 27.6 kV	***28.5***	***28.4***	***28.4***	***0.35***	***28.5***	***28.4***	***28.4***	***0.35***	***28.7***	***28.4***	***28.4***	***1.05***	***28.2***	***28.4***	***28.4***	***-0.71***
	J1J2 27.6 kV	28.1	28.1	28.1	0.00	28.1	28.1	28.1	0.00	28.1	28.1	28.1	0.00	28	28.1	28.1	-0.36
	BY 27.6 kV	28.9	28.9	28.9	0.00	28.9	28.9	28.9	0.00	28.9	28.9	28.9	0.00	28.9	28.9	28.9	0.00
Plant	27.6 kV	28.7	28.1	28.1	2.09	29.1	28.1	28.1	3.44	29.7	28.1	28.1	**5.39**	27.5	28.1	28.1	-2.18
	13.8 kV	13.8	0.0	0.0	100.00	14	0.0	0.0	100.00	14.5	0.0	0.0	100.00	12.9	0.0	0.0	100.00
	4.16 kV	4.1	0.0	0.0	100.00	4.2	0.0	0.0	100.00	4.3	0.0	0.0	100.00	3.8	0.0	0.0	100.00

Table 17: Voltage Decline – Light Load Conditions

Bus		***Plant at 1 PF (GT1 at 3.00 Mvar)***				***Plant at no Mvar impact at TS (GT1 at 4.50 Mvar)***				***GT1 at 0.9 PF - Lagging (GT1 at 7.60 Mvar)***				***GT1 at Maximum Leading PF (GT1 at -1.94 Mvar)***			
		Pre Cont.	***Post-Contingency***			***Pre Cont.***	***Post-Contingency***			***Pre Cont.***	***Post-Contingency***			***Pre Cont.***	***Post-Contingency***		
		(kV)	***Pre-ULTC (kV)***	***Post-ULTC (kV)***	***Largest Decline (%)***	***(kV)***	***Pre-ULTC (kV)***	***Post-ULTC (kV)***	***Largest Decline (%)***	***(kV)***	***Pre-ULTC (kV)***	***Post-ULTC (kV)***	***Largest Decline (%)***	***(kV)***	***Pre-ULTC (kV)***	***Post-ULTC (kV)***	***Largest Decline (%)***
Buchanan TS	230 kV	246.6	246.6	246.6	0.00	246.6	246.6	246.6	0.00	246.7	246.6	246.6	0.04	246.5	246.6	246.6	-0.04
Clarke TS	230 kV W36	247.3	247.3	247.3	0.00	247.4	247.3	247.3	0.04	247.5	247.4	247.4	0.04	247.2	247.3	247.3	-0.04
	230 kV W37	247	247.0	247.0	0.00	247.1	247.0	247.0	0.04	247.1	246.9	246.9	0.08	246.8	247.0	247.0	-0.08
	27.6 kV	28.9	28.9	28.9	0.00	28.9	28.9	28.9	0.00	28.9	28.9	28.9	0.00	28.9	28.9	28.9	0.00
Talbot TS	230 kV W36	247.4	247.4	247.4	0.00	247.5	247.4	247.4	0.04	247.7	247.5	247.5	0.08	247.3	247.4	247.4	-0.04
	230 kV W37	247.1	247.1	247.1	0.00	247.2	247.1	247.1	0.04	247.2	247.0	247.0	0.08	246.9	247.1	247.1	-0.08
	Q1Q2 27.6 kV	***28.7***	***28.7***	***28.7***	***0.00***	***28.8***	***28.7***	***28.7***	***0.35***	***28.8***	***28.6***	***28.6***	***0.69***	***28.4***	***28.7***	***28.7***	***-1.06***
	J1J2 27.6 kV	28.6	28.6	28.6	0.00	28.6	28.6	28.6	0.00	28.5	28.4	28.4	0.35	28.5	28.6	28.6	-0.35
	BY 27.6 kV	28.9	28.9	28.9	0.00	28.9	28.9	28.9	0.00	28.9	28.9	28.9	0.00	28.9	28.9	28.9	0.00
Plant	27.6 kV	29.2	28.6	28.6	2.05	29.5	28.6	28.6	3.05	30	28.4	28.4	**5.33**	28	28.6	28.6	-2.14
	13.8 kV	14	0.0	0.0	100.00	14.3	0.0	0.0	100.00	14.7	0.0	0.0	100.00	13.1	0.0	0.0	100.00
	4.16 kV	4.1	0.0	0.0	100.00	4.2	0.0	0.0	100.00	4.3	0.0	0.0	100.00	3.9	0.0	0.0	100.00

Table 18: Plant Impact on Voltages and Flows – Peak Load Conditions

ULTC's locked at 3 Mvar

Bus		***Plant O/S (kV)***	***GT1 at 15.7 MW and -5.16 Mvar (kV)***	***-1.94 Mvar (kV)***	***0.00 Mvar (kV)***	***1.50 Mvar (kV)***	***3.00 Mvar (kV)***	***4.50 Mvar (kV)***	***7.60 Mvar (kV)***
Buchanan TS	230 kV	246	245.9	246.0	246.0	246.1	246.2	246.2	246.3
Clarke TS	230 kV W36	245.6	245.4	245.6	245.6	245.7	245.8	245.8	246.0
	230 kV W37	245.4	245.3	245.4	245.5	245.6	245.6	245.7	245.8
	27.6 kV	28.9	28.9	28.9	28.9	28.9	28.9	28.9	28.9
Talbot TS	230 kV W36	245.5	245.4	245.5	245.6	245.7	245.8	245.8	246.0
	230 kV W37	245.4	245.2	245.4	245.5	245.6	245.6	245.7	245.8
	Q1Q2 27.6 kV	***28.4***	***27.9***	***28.2***	***28.3***	***28.4***	***28.5***	***28.5***	***28.7***
	J1J2 27.6 kV	28.1	28.0	28.0	28.1	28.1	28.1	28.1	28.1
	BY 27.6 kV	28.9	28.9	28.9	28.9	28.9	28.9	28.9	29.0
Plant	27.6 kV	28.1	26.7	27.6	28.0	28.4	28.7	29.1	29.7
	13.8 kV	0	12.3	12.9	13.3	13.5	13.8	14	14.5
	4.16 kV	0	3.6	3.8	3.9	4.0	4.1	4.2	4.3
M53 flow	(MW)	10.9	-7.1	-7.6	-7.9	-7.7	-7.8	-7.9	-7.8
	(Mvar)	5.3	16.7	12.6	10.4	8.6	7	5.4	2.3
T3+T4 Flow	(MW)	141.6	123.7	123.6	123.6	123.4	123.4	123.4	123.5
	(Mvar)	**90.3**	99.9	95.1	92.4	**90.3**	88.5	86.8	83.2
Change in Feeder Losses (MW)			1	0.5	0.2	0.4	0.3	0.2	0.3
Change in Transformer Losses (MW)			1.1	1	1	0.8	0.8	0.8	0.9

Table 19: Plant Impact on Voltages and Flows – Light Load Conditions

ULTC's locked at 3 Mvar

Bus		***Plant O/S (kV)***	***GT1 at 15.7 MW and -5.16 Mvar (kV)***	***-1.94 Mvar (kV)***	***3.00 Mvar (kV)***	***4.50 Mvar (kV)***	***7.60 Mvar (kV)***
Buchanan TS	230 kV	246.6	246.4	246.5	246.6	246.6	246.6
Clarke TS	230 kV W36	247.3	247.0	247.2	247.3	247.4	247.4
	230 kV W37	247	246.7	246.8	247	247.1	247.1
	27.6 kV	28.9	28.9	28.9	28.9	28.9	28.9
Talbot TS	230 kV W36	247.4	247.1	247.3	247.4	247.5	247.5
	230 kV W37	247.1	246.8	246.9	247.1	247.2	247.2
	Q1Q2 27.6 kV	***28.7***	***28.2***	***28.4***	***28.7***	***28.8***	***28.8***
	J1J2 27.6 kV	28.6	28.5	28.5	28.6	28.6	28.6
	BY 27.6 kV	28.9	28.9	28.9	28.9	28.9	28.9
Plant	27.6 kV	28.6	27.2	28.0	29.2	29.5	29.5
	13.8 kV	0	12.5	13.1	14	14.3	14.3
	4.16 kV	0	3.7	3.9	4.1	4.2	4.2
M53 flow	(MW)	4.2	-13.9	-14.4	-14.5	-14.5	-14.5
	(Mvar)	1.9	13.4	9.4	3.8	2.2	-0.9
Change in Feeder Losses (MW)			0.9	0.4	0.3	0.3	0.3

It also can be observed from Tables 18 and 19 above that when the synchronous generator operates at maximum reactive power of 1.94 Mvar in leading power factor, the impact on the reactive power as measured at the 27.6 kV side of Talbot TS exceeds the minimum requirement of 5.16 Mvar in leading power factor. The M53 reactive power flow changes from 5.3 Mvar to 12.6 Mvar for an effect of 7.3 Mvar during peak load conditions, and from 1.9 Mvar to 9.4 Mvar for an effect of 7.5 Mvar during light load conditions.

5.6 Assessment of Dynamic Control Systems

The dynamic models for the proposed generators and their control systems were presented in section 3 of this report.

Exciter Performance Testing

The GT1 generator will be equipped with a rotating rectifier unit capable to operate as a voltage controller or as a var / power factor controller. The var / pf controller is a summing point type controller and makes up the outside loop of a two-loop system. This controller is implemented as a slow PI type controller. The voltage regulator forms the inner loop and is implemented as a fast PID controller.

The power factor regulator shall be capable of maintaining a power factor within ± 1% between 90% lagging and 95% leading. The var regulator shall be capable of maintaining reactive power within ± 2.5% of rated MVA. The power factor or var regulator shall have an adjustable effective response time between 10 to 60 seconds.

Due to the slow response of the outer loop, the input from the VAR/ PF regulator was neglected in the testing of the excitation system and during the transient simulations.

As per Market Rules, 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%. The voltage response time is defined as the time in seconds for the excitation voltage to attain 95% of the difference between the ceiling voltage and rated load field voltage;

- 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.

Where the IESO determines that a lower requirement would not adversely impact the reliable operation of the IESO-controlled grid, the synchronous generation unit shall be equipped with an excitation system with:

- an excitation system nominal response of at least 0.50 and

- a positive ceiling voltage at least 150% of rated field voltage.

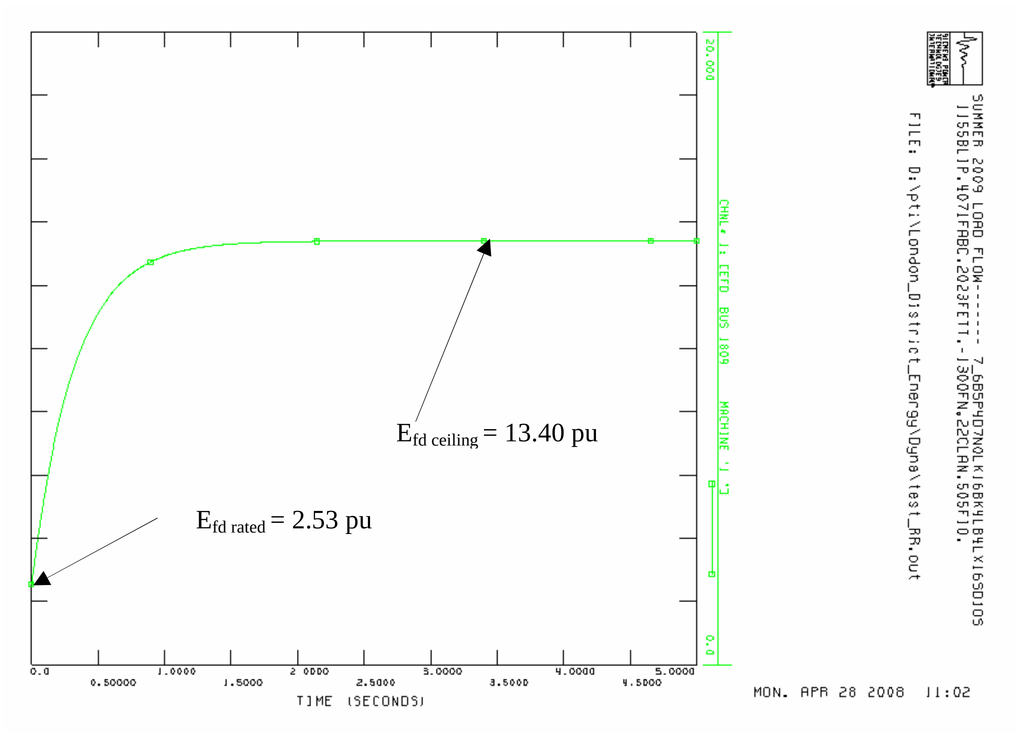
Two tests were performed to analyze exciter performance: Response Ratio Test and Open Circuit Step Response Test.

a) Excitation System Response Ratio Test

In this test, the generator is initialized to its rated output with a 0.9 power factor. At time equal to zero, the voltage regulator reference setting is changed by a large amount and the behavior of the field voltage is observed. The excitation system is being driven to its ceiling as rapidly as possible. The graphic in Figure 11 illustrates the response ratio test for GT1 exciter.

It can be observed that the GT1 field voltage increased from the rated value of 2.53 pu to a ceiling of 13.40 pu, exceeding the positive ceiling voltage requirement.

Figure 11: GT1 Exciter Response Ratio Test



b) Excitation System Open Circuit Step Response Test

Under this test, the generator is initialized with its terminal voltage set to 1.0 pu, under open circuit conditions. A step change of 5% is then applied to the voltage regulator reference, and responses of field voltage and generator terminal voltage are monitored. The graphic in Figure 12 illustrates the open circuit test for GT1 exciter.

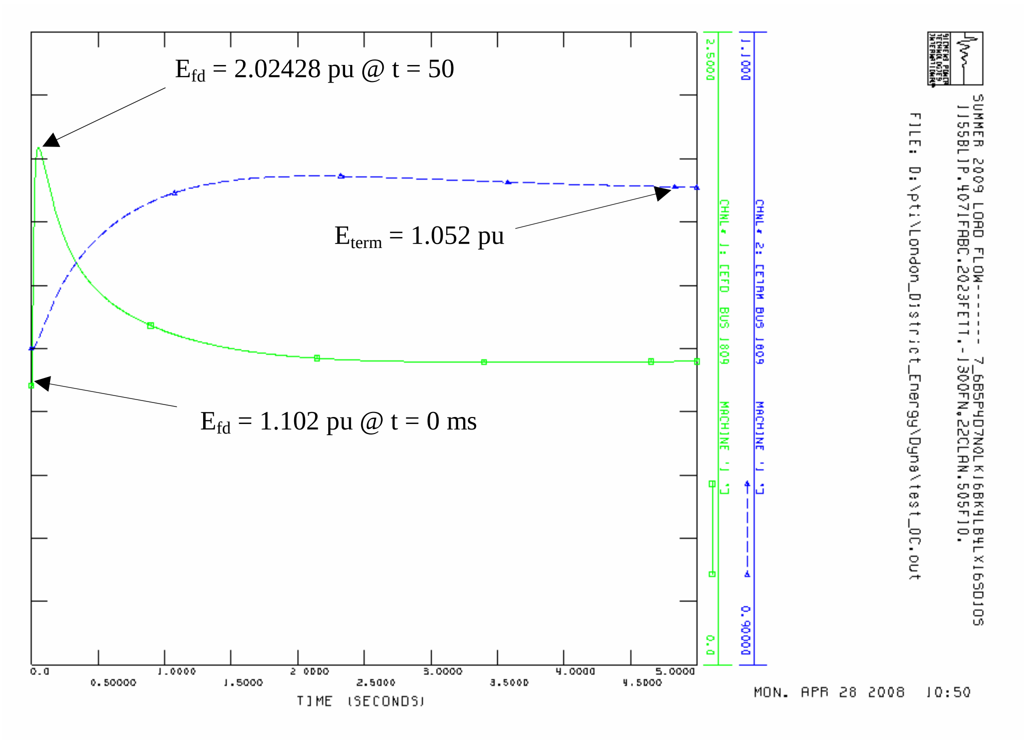
To avoid penalizing exciters with higher field voltage ceiling than the minimum requirement, the required ceiling field voltage rather than actual ceiling is used to assess the voltage response time.

The numerical results from the open circuit test are presented in Table 20 below. It can be observed that the exciter does not meet the field voltage response time requirement, as per higher standard requirements from Appendix 4.2 of the Market Rules.

Table 20 – Excitation Voltage Response Time

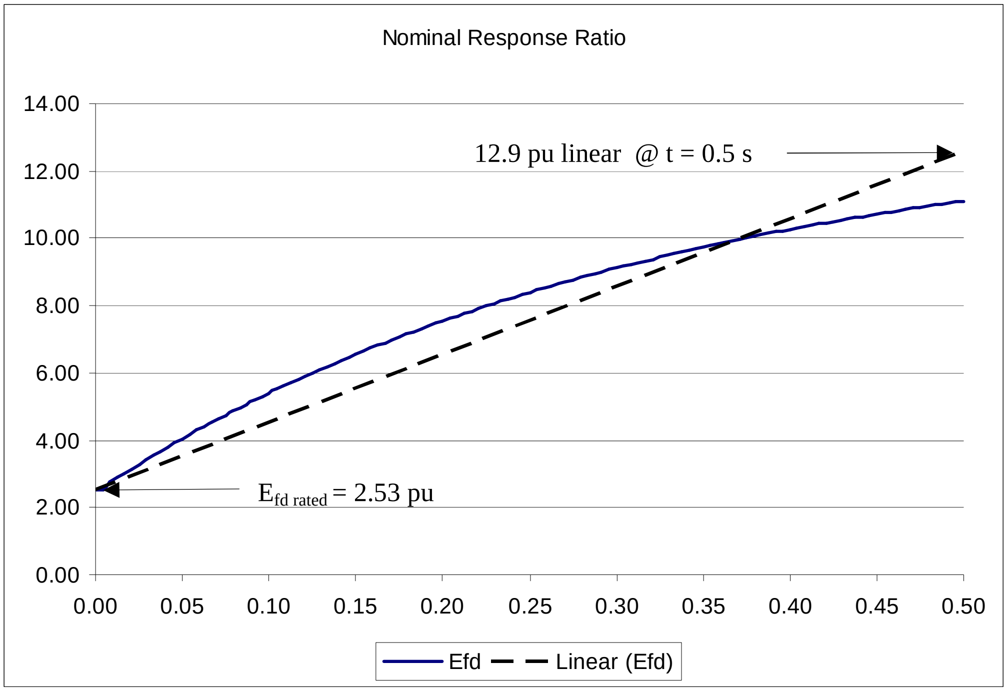
	GT1
Efd rated (pu)	2.5324
Efd initial (t=o) (pu)	1.1020
Efd to be attained in 50 ms: 0.95 x (2 x Efd rated – Efd rated) (pu)	2.4058
Efd required in 50 ms (pu)	3.5078
Efd max after 50 ms (pu) (also the max Efd)	**2.0428**

Figure 12: GT1 Exciter Open Circuit Test



To assess the excitation system compliance with the lower performance requirements, the nominal response was calculated using the Response Ratio test for 0.5 seconds, as per Figure 13. The calculated nominal response was 8.20, exceeding the minimum nominal response requirement of 0.5.

Figure 13: GT1 Exciter– Nominal Response Calculation



Nominal Response = (12.9 - 2.53) / (0.5 x 2.53) = 8.20

It can be concluded that the GT1 excitation system meets the Market Rules lower performance requirements for synchronous generators.

Speed Governor Testing

As per *Market Rules*, Chapter 4, Appendix 4.2 each synchronous generation unit with a nameplate rating of greater than 10 MVA shall be operated with a speed governor meeting the following requirements:

- shall have a permanent speed droop that can be set in the range between 3% and 7% and the intentional deadband shall not be wider than ± 36 mHz;

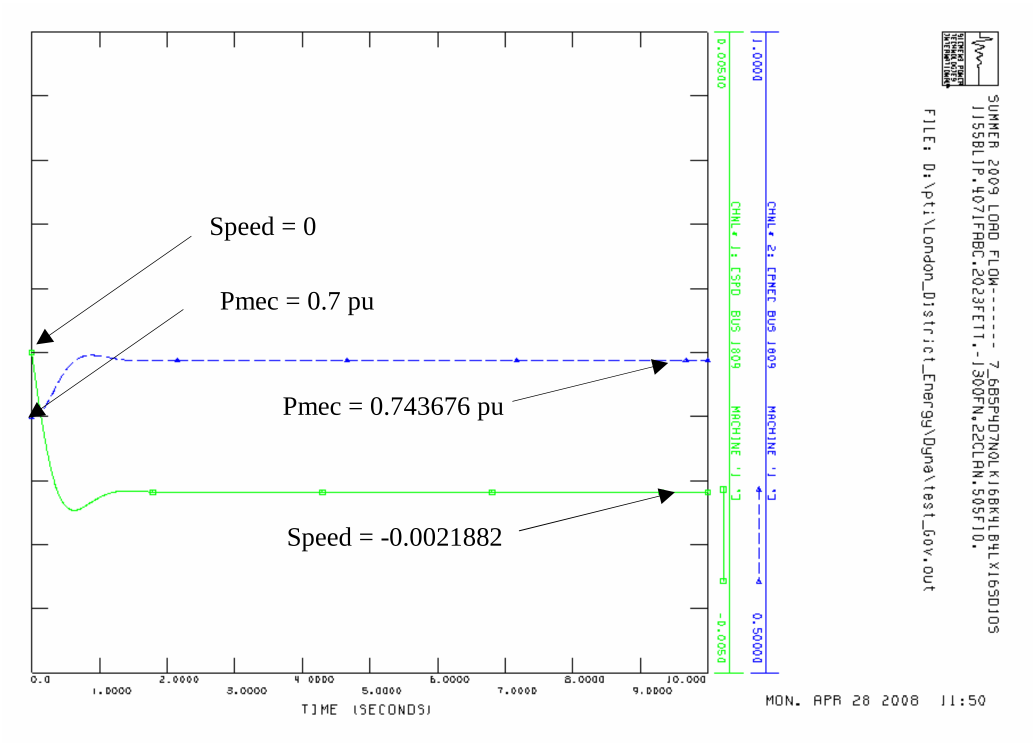
- shall be able to arrest the unit's speed, following full load rejection to prevent a trip due to overspeed, and shall demonstrate stable performance with adequate damping under all operating conditions;

- shall control speed in a stable fashion during both island and interconnected operation;

- to the extent practical governors shall provide immediate, appropriate and sustained response to abnormal frequency excursions;

- control systems that inhibit governor response shall be automatically disabled by frequency deviations not larger than ± 100 mHz.

Figure 14: GT1 Governor Test



dP = 0.04376; df = 0.21882E-2; droop= 5.00 %

To check the governor performance, a 5% step change in unit load in isolation was performed. This simulation reveals the transient variation of turbine power and machine speed, indicating the damping due to the turbine and governor loop only. The test results for synchronous generator GT1 are presented in Figure 14.

As can be observed, the governing unit presented a well damped response. The calculated resulting droop was approximately 5%. No intentional frequency dead band is added to the proposed governor model.

Power System Stabilizer (PSS) Testing

As per Appendix 4.2 Reference 15 from Market Rules, each synchronous generating unit that is equipped with an excitation system that meets the higher performance requirements specified in sub-section 1 of section 12 in Appendix 4.2 of the Market Rules, shall also be equipped with a power system stabilizer.

The GT1 excitation system is a slower exciter meeting the lower performance requirements from the Market Rules and does not require PSS.

5.7 Transient Stability Analysis

Excitation systems regulating generator output reactive power (var) or power factor (pf) to a user-specified set point have a pf / var Regulator or Controller. In the case of a Controller, the Automatic Voltage Regulator (AVR) is equipped with a slow outer-loop control, which uses the error between the desired and measured pf, var, or reactive current signal to change the AVR's set-point, to maintain the desired unit reactive output. A pf / var Regulator eliminates the AVR terminal voltage feedback loop, and instead directly controls the unit's field voltage to regulate pf or var to the user's reference set point.

Based on the information received from the Proponent, the GT1 synchronous generator will be equipped with an excitation system with a PF / var controller. As mentioned before, the effective response time for the controller is between 10 to 60 seconds. Therefore, due to the short period of the transient time, it was assumed that the excitation system will respond to terminal voltage changes and the PF/ var controller has no impact.

To assess the transient stability of the Plant and its impact on the ICG, two major disturbances were simulated:

- three-phase fault on a LV feeder close to the Talbot Q1Q2 bus and
- three-phase fault on the 230 kV circuit W37 close to Talbot TS

Three diagrams were included in this report for each simulation. First diagram presents rotor angles for the GT1 generator at the Plant, and one generator at TA Sarnia, Brighton Beach, Nanticoke and Bruce generating stations. The second and third diagrams plot voltages at Talbot TS and the Plant on the LV buses for duration of 15 seconds and 2 seconds, respectively.

Simulations were conducted for peak load conditions as well as for light load conditions. Since the results were similar for both scenarios, only the results for the peak load simulations are presented in this report.

Three-phase fault on a LV feeder close to the Talbot Q1Q2 bus

This simulates a 3-phase fault on a feeder close to Talbot TS, detected by the feeder protection in 40 ms, with a 4 ms auxiliary trip relay (ATR), 4 ms for the breaker trip module (BTM), and 133 ms (8 cycle) breaker opening time. The fault was cleared after 180 ms.

The results of the simulations presented in the Figures 15 to 17 below conclude that the proposed generator is stable for faults close to the 27.6 kV bus at Talbot TS.

Figure 15: Rotor Angles – LV Fault – Peak Load

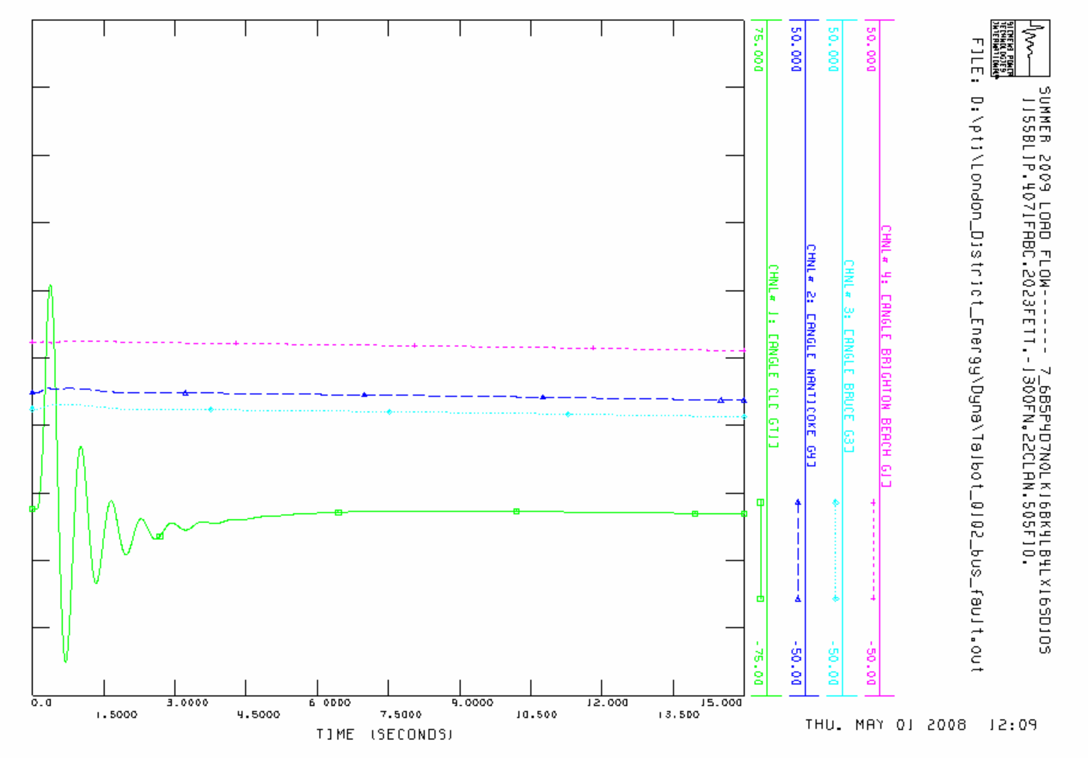


Figure 16: Voltages – LV Fault – Peak Load (15 sec)

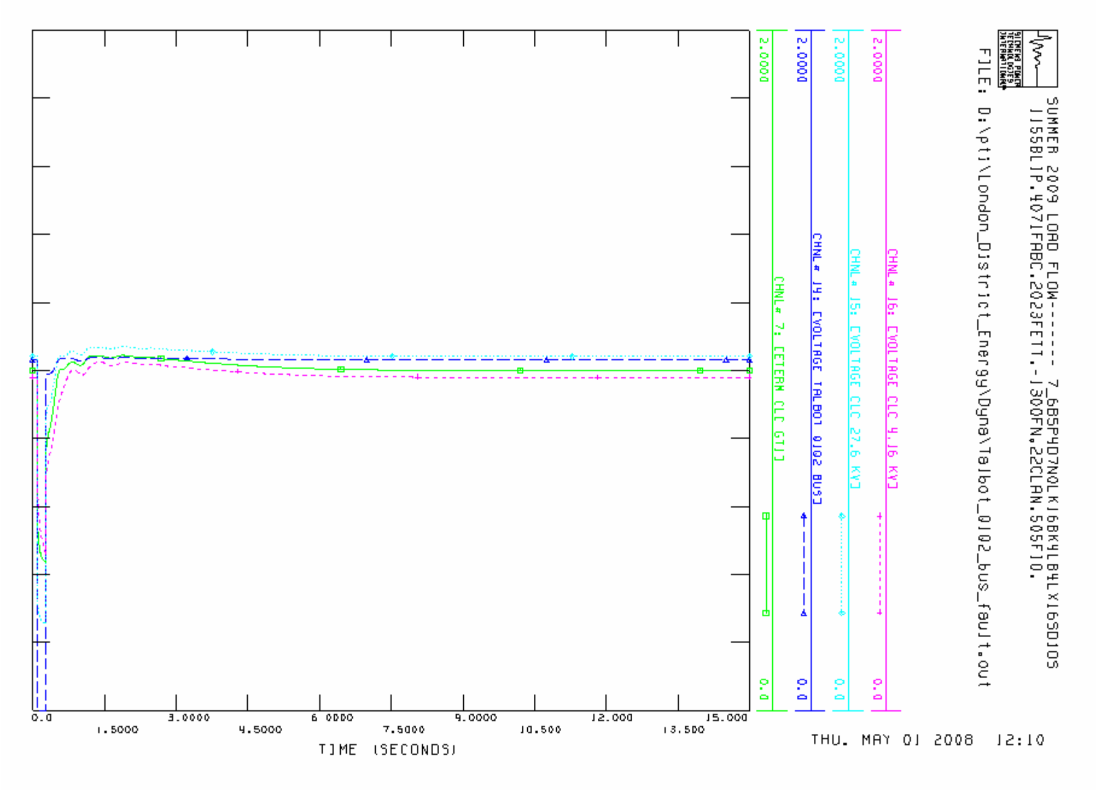
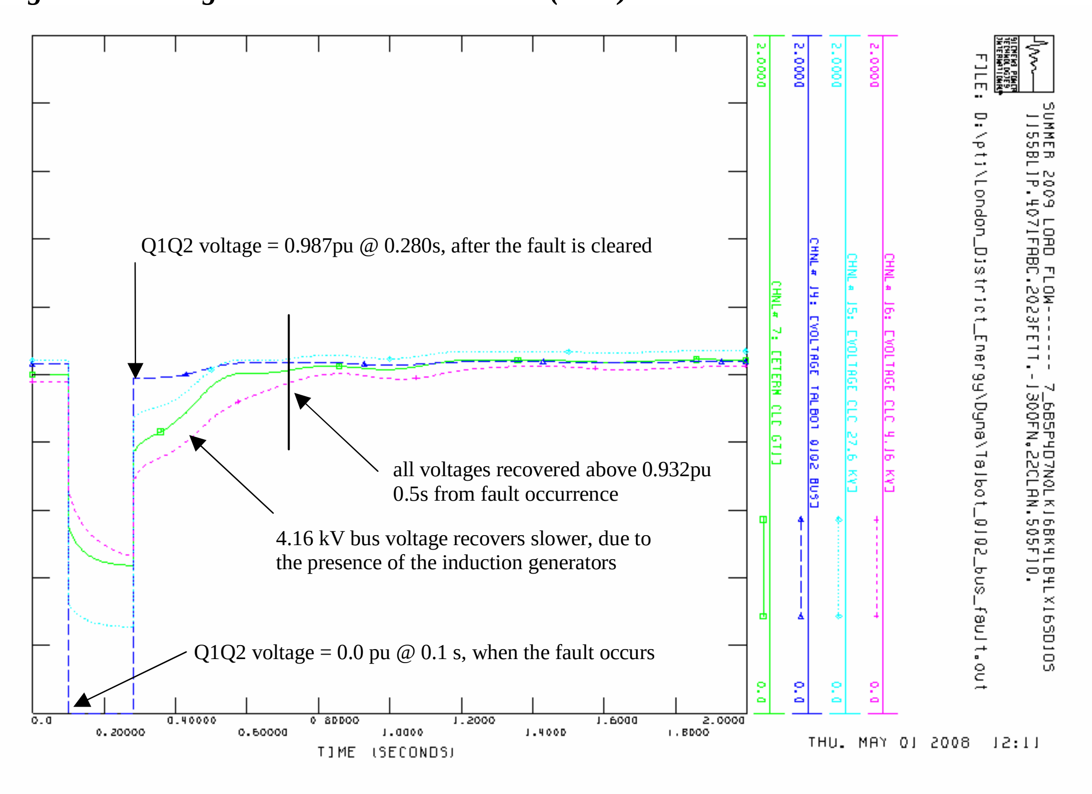


Figure 17: Voltages – LV Fault – Peak Load (2 sec)



<u>Three-phase fault on the 230 kV circuit W36 close to Talbot TS</u>

This simulates a three phase fault on W37 circuit close to Talbot TS. The fault was cleared in 83 ms at Buchanan (25 ms protection time + 4 ms ATR + 4 ms BTM + 50 ms/3cycle breaker time on 230 kV and 115 kV yards) and in 144 ms at Talbot T4 and T2, and Clarke T4 on the low voltage side (25 ms protection time + 4 ms ATR + 28 ms transfer trip + 4 ms BTM + 83 ms/5cycle LV breaker time). The loss of W37 is more significant than the loss of W36, since the first contingency removes also the autotransformer T4 at Buchanan.

The results of the simulations presented in the Figures 18 to 20 below conclude that the proposed GT1 generator is stable for faults on the 230 kV system.

Figure 18: Rotor Angles – W37 fault – Peak Load

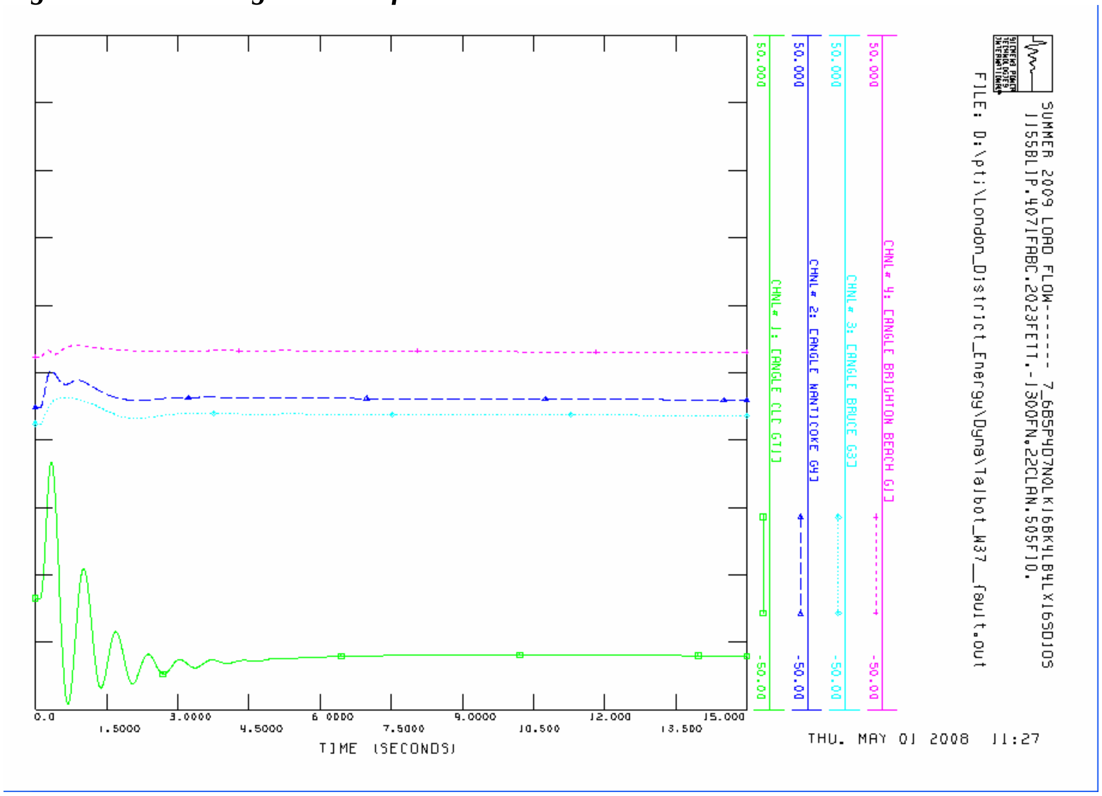


Figure 19: Voltages – W37 fault – Peak Load (15 sec)

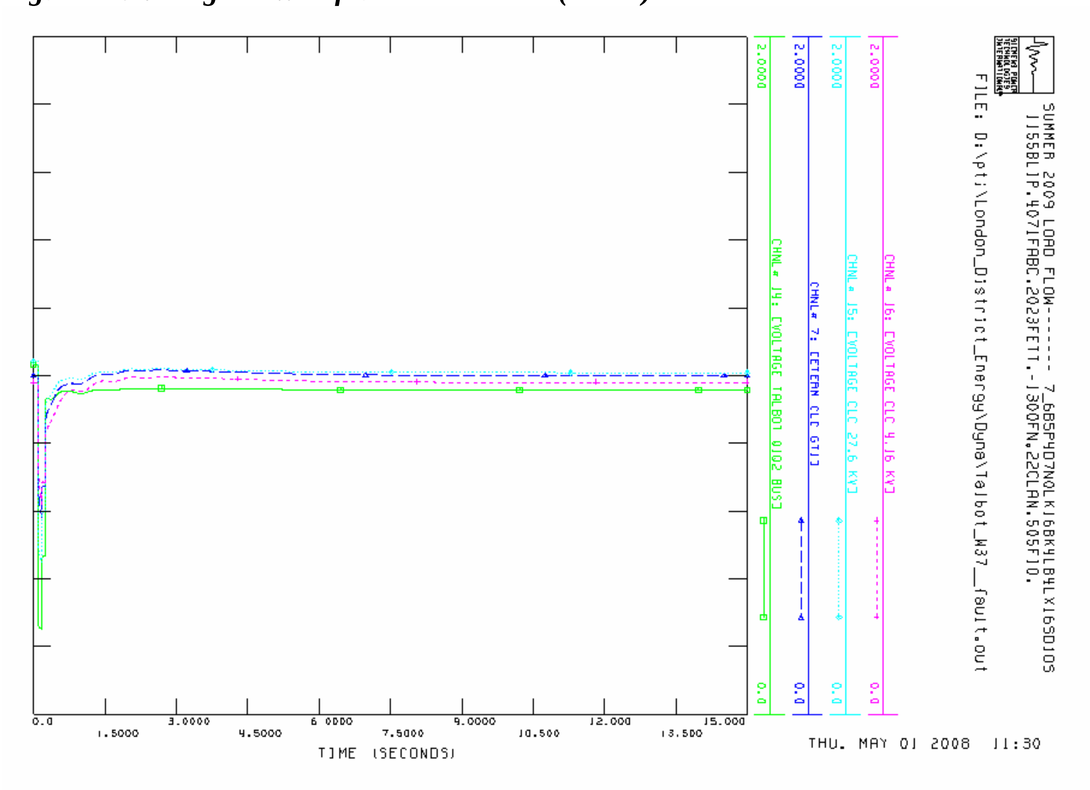
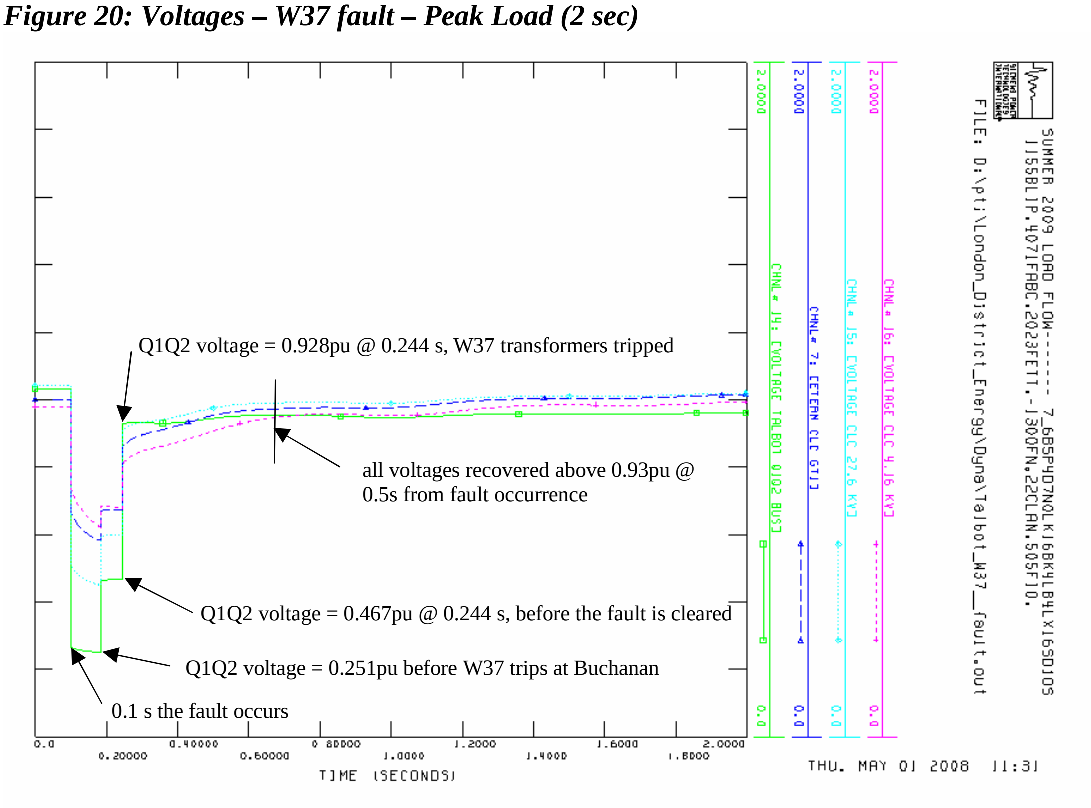


Figure 20: Voltages – W37 fault – Peak Load (2 sec)



From Figure 20 above, it can be seen that during the fault on the circuit W37, the voltage on the LV bus Q1Q2 went as low as 0.251 pu for 83 ms, but recovered after 144 ms to 0.928 pu when the fault was cleared. The voltage performance at the Plant connection point is presented for information purposes only. It is the Proponent's responsibility to ensure that the Plant meets the low voltage ride through requirement.

The Plant shall not trip for recognized contingencies on the transmission system unless the contingency would disconnect the generating unit by configuration. All embedded generators shall have sufficient low-voltage-ride-through capability to avoid generation loss for faults in the transmission system.

– **End of Section –**

– **End of Report –**