Embedded Generation (SE-57)

Minutes of Meeting

Date held: February 10, 2009	**Time held:** 8:30 am	**Location held:** Toronto Congress Center
Invited/Attended:	**Company name:**	**Attendance Status:** (A)ttended; (R)egrets; (S)ubstitute
Adams, Tom	Unaffiliated	A
Britton, Terry	Veridian Connections Inc.	A
Chang, Selina	Rodan Energy & Metering Solutions Inc.	A
Cheng, Clarence	Ontario Ministry of Energy	A
Cumming, Hugh	Union Gas	A
Devitt, Kevin	Ontario Power Authority	A
Dubeski, Phil	Toronto Hydro Electric System Limited	A
Hunt, Bob	Hunt Management Services Ltd.	A
Kosnik, Tom	Optisolar Farms Canada	A
Kuriychuk, Michael	Pathchoice Energy Consulting Inc.	A
Loncar, John	Union Gas	A
Loughren, Chris	Bruce Power	A
Malinowski, Martin	Rodan Energy & Metering Solutions Inc.	A
Medley, Jill	SunEdison	A
Norris, Paul	Ontario Waterpower Association	Via teleconferencing
Pattani, Naren	Hydro One	A
Pelland, Sophie	Natural Resources Canada	Via teleconferencing
Peterson, Dave	Ontario Power Generation	A
Petrella, Tony	Ontario Power Generation	A
Remtulla, Faruq	Hydro One	A
Ronson, Peter	Markham District Energy	A
Russell, Stewart	AIM SOP Phase 1 LP	A
Sharma, Pankaj	Hydro One	A
Simmons, Sarah	Ontario Power Authority	A
Taylor, Kristopher	Essex Power Group	A
Whitehead, Kevin	Whitby Hydro	A
Adam, Gabriel	IESO	A
Constantinescu, Barb	IESO	A
Drake, Gordon	IESO	A
Falvo, Mike	IESO	A

SE-57 – Embedded Generation
Committee Chair: David Robitaille
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Finkbeiner, Darren	IESO	A
Greenberg, Jessica	IESO	A
Hastings, Martin	IESO	A
Khan, Khaqan	IESO	A
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All meeting material is available on the IESO web site at: SE-57

Agenda Item #1 - Administration

Darren Finkbeiner of the IESO welcomed the group and described why the meeting was called. He stated that the session would be in 2 phases. The first part would be addressing the leftover action items from the meeting that was held last year. The second part is to look to this group to deal with emerging issues associated with renewable generation (surplus baseload generation, forecasting, etc.). Darren went on to state that we are all aware of the future supply mix and that the new minister has an aggressive view from a "green" perspective. These issues are paramount and must be addressed. Looking at where we are today, the second week in February, we are seeing an overnight demand of 14,270 MW. With 14,000 MW of nuclear, a few thousand MW in wind and a couple thousand in must-run water, how are we going to deal with the surplus baseload generation (SBG)? Darren stated that we need to be prepared to manage this type of situation and this new supply mix. Darren then looked to the group to see who the IESO needs to reach out inside and outside of those engaged with SE-57 currently. He stated that it is not just market participants as all embedded generation will show up as reduced demand with the way things are today, with no visibility. Darren concluded by saying that this is manageable and the solutions are in this room. We need to start somewhere, which is the second part of the meeting today.

a. Review Agenda

Dave Robitaille of the IESO announced one agenda change (moving priority dispatch before renewable forecasting) and asked if there were any others. The agenda was approved with this one change.

b. Action Items

Dave Robitaille of the IESO reviewed the open action items from last meeting. The first and third action items were closed and Barb Constantinescu will speak to the action during her presentation. The second action item is open and will be on-going as market rule changes are required. Finally, the fourth action item remains open and will be addressed as SE-57 moves forward.

c. Minutes

The minutes posted are final.

Agenda Item #2 - CAA Process and Performance Standard Update

CAA Process

Barb Constantinescu of the IESO provided an update on the CAA process for embedded generators. The process will not require local distribution centers (LDC) to apply for a SIA but will require them to provide specific required data on their embedded generation to the IESO. The IESO will move forward with the appropriate rule changes required.

Member Questions, Comments and Discussions

The following questions were asked by members, along with the response from Barb:

- When will the report for the technical assessment finalized?
  - The report is still in draft form and is currently not public. The participant then asked if the draft report could be attached to the minutes. Barb agreed.
- Will the regional SIA design incorporates generation above 10 MW?
  - The rules were developed with the RESOP program in mind. Generation above 10 MW would still need to come to the IESO for a SIA.
- What is driving the need for additional reactive compensation devices?
  - The shortage of VARS is driving the change. The voltage recovery after a contingency would be too slow and the recovery is below the criteria.
- Are you assuming that distributed generation cannot provide VARS?
  - It is our understanding that distributors cannot use dynamic reactive capability due to certain rules (Hydro One) that protect the customer. Furthermore, even if they were capable, they are too far away. We are using a conservative approach by not accounting for these VARS.
- Will the embedded generation currently held up by the SIA process be released? And will the associated cost be released?
  - Yes, the held-up generation will be released.
  - Hydro One spoke to the cost: the issue of cost allocation has not been discussed and they are not sure who will pay. Right now they are in the planning phase in order to be ready for process commitment. The current rules have the cost paid by the distributed generator. A participant stressed the significance and importance of cost allocation. He stated that some projects may not become economic after taking into consideration the cost. Hydro One stated that they were working from the planning side and cannot make that decision, but they are in communication with those at Hydro One making the decision.
- Does the study look at characteristics of the system outside of distributed generation that may help with dynamic reactive power?
  - The study looks at only the existing system. The next steps will include future considerations.

Performance Standards

Mike Falvo of the IESO provided an update on the next steps of the performance standards for embedded generation. He stated that, at this time, that there would be no new performance requirements imposed on small distributed generation, and some clarification changes made to the existing performance requirements to further facilitate embedded generation connections. The existing IEEE 1547 standard regarding distribution-connected is consistent with the IESO objects, but it could be improved. At this time IESO would just be monitoring the progress as more embedded generation comes online. If changes to IEEE 1547 are warranted, then changes may be sought in the Distribution System Code, with appropriate load and other stakeholder input.

Member Questions, Comments and Discussions

There were a few clarification questions around the NERC/NPCC discussions and if loads were involved. Mike stated that we can get load comments to the discussions. There were also some clarification questions around the presentation. Mike indicated that there are some standards, such as the existing Under Frequency Load Shedding programs, that were designed without embedded generation in mind and these will have to be reviewed at the NPCC level, and may evolve to accommodate significant amounts of embedded generation.

Agenda Item # 3 - Proposed Revised Scope

Dave Robitaille of the IESO presented the proposed revised scope for SE-57. He outlined the three new areas of the stakeholder plan as well as a new name: Embedded and Renewable Generation. He stated that the draft revised stakeholder plan will be posted for comment.

Member Questions, Comments and Discussions

There were many comments and questions from members:

- Will the IESO reach out to those not in the room to comment on the plan, for example NUGS?
  - Yes
- Is the scope all renewables or just wind?
  - The scope branches across all generation types: self-scheduling intermittents, dispatchables, embedded market participants, embedded non-market participants, etc. We were using wind for ease of examples but it is not the focus.
- Is there any thought to creating a new stakeholder engagement plan for this issue, as it is much broader than just embedded.
  - Yes, it is broad however we have engaged a group of participants that we want engaged in the expanded scope discussions and we want to build on that relationship and ensuring continuous engagement.

- Are demand-side solutions within the scope?
  - Yes. The IESO has a control actions list when the province is under-generated and is looking to create something similar for times of over-generation. This includes loads. This is not just for global concerns but also local over-generation.
- There was not enough notice of the expanded scope of SE-57. This is an area of great concern and should have been given more time before the meeting.
- Is this going to be overlap with the wind power standing committee (WPSC)?
  - No, we are ensuring there is no overlap. The WPSC focuses on wind issues. This group will be looking at all renewable generation. We want to ensure that there is consistency with how each different type of renewable generation is treated and that needs to be done through one stakeholder plan. There will be close coordination between the SE-57 group and the WPSC.
- The physical aspects of SE-57 need to be a high priority and need to be completed as soon as possible, as they will have associated costs (the visibility, telemetry, assessment aspects).
  - These requirements would be through the SIA process. The telemetry and visibility aspects need to be discussed with the LDCs. It is important to understand that we are trying to maximize penetration of renewables and are working quickly on these physical aspects, but these other issues in the proposed expanded scope are also extremely important to the IESO.
- It is important that if the IESO needs an embedded generator, these requirements should be communicated to the generator themselves, not just through the LDCs.
  - We agree and currently contact the embedded generator. We are hoping that the existing requirements from the LDC are sufficient and that we will not need new requirements.
- What are the timelines for these changes?
  - Telemetry and visibility will be prior to the fall, hopefully the summer
  - Performance standards do not require changes at this time and the changes associated with dynamic VARS will go to the Technical Panel.

Agenda Item #4 - Priority Dispatch

Jessica Greenberg of the IESO presented and described the issue of priority dispatch and solicited feedback from the group. She stated that the draft paper will be posted for comment.

Member Questions, Comments and Discussions

A member asked what the presumption of hydro is going forward and will it be considered baseload or load following going forward? The IESO stated that there were assumptions made through the IESO's operability assessment of the OPA's IPSP. The IESO recognizes that hydro can be ponded or spilled, there is an understanding that there is a mix and are trying to be as flexible as possible when making these dispatch decisions.

Another member pointed out that an obvious choice is not having imports on during times of surplus baseload generation (SBG). The IESO stated that this was the case today. There are times when imports are on to support exports and if these exports fail, a SBG situation may be the result and it may seem that imports were already flowing. But, for the most part, imports are not on during SBG.

Darren Finkbeiner elaborated on what exactly the IESO is looking for. He stated that if the IESO runs into a SBG situation in the middle of the night and they have the choice of manoeuvring a nuclear generator, spilling water or spilling wind, the IESO needs to come up with a procedure for these times. He went on to state that the IESO and the group need to understand all the implications associated with moving all generation types. Finally Darren stated that the IESO currently does not compensate self-schedulers for dispatching off and stated that this may need to be revisited (with the OPA as well).

A member informed the group of the regulatory challenges associated with hydro. He stated that hydro facilities are required to manage within an operating band and if they are outside of this band, the result may be a non-compliance matter in terms of legislation. With hydro, it is all about the water levels and flows.

Another member elaborated on the issues that a nuclear generator faces with dispatches. He added to the presentation saying that nuclear units also have environmental limitations. He went on to further state that when a nuclear generator goes down for 3 days, they have to open their breakers and, according to the market rules, are not compensated either.

A member stated that no-one will argue about the implications of manoeuvring a nuclear generator, under OPA contracts, an embedded generator may get penalized for being dispatched down. He also asked about logistics. He stated that smaller embedded generators may not have someone at the station in the middle of the night to adhere to dispatch instructions. The IESO stated that those generators connected directly to the grid have an obligation to have someone manning the station 24 hours a day, 7 days a week. For those that are not directly connected to the grid, the IESO is not sure what the rules are or what the contracts say. This is why there is a need to talk to the LDCs/EDA. This way we can identify any logistic issues.

A member from the OPA asked if the IESO could elaborate on the scenarios so that they can manage their contracts to help. Darren Finkbeiner restated that this is manageable and that the group needs to determine a priority order. Darren went on to say that the IESO cannot define specific scenarios but he did say that SBG situations will get larger, not smaller. These conditions can be global or local but we cannot specify hours.

Another member asked if the Market Rules could be amended to allow for compensation for dispatch off instructions. The IESO stated that they didn't know what was appropriate – rule changes or an OPA contract – but the rule changes are an option if deemed the appropriate action.

A member suggested creating a new class of market participant for dispatch issues. This class would not be a market participant but would have rules in terms of dispatch issues. The IESO said this could be an option.

Agenda Item #5 - Centralized Renewable Forecasting

Jessica Greenberg of the IESO presented the merits of centralized renewable forecasting and solicited feedback from the group. She stated that the draft paper will be posted for comment.

Member Questions, Comments and Discussions

A member stated that there were comments at the last WPSC around incentives for supplying accurate forecasts and that the OPA come up with these incentives. The IESO stated that current rules only require forecast updates for the DACP run and after that, updates on a best-efforts basis. The IESO then stated that this meeting was meant just to introduce the topic and could not speak to incentives at this time. The point of today's meeting was to get feedback.

A member asked why the IESO was looking to centralized forecasting when the WPSC recommended against it. Jessica Greenberg stated that at the time of the recommendation (May 2008) there was very little wind penetration. She stated that in order to prepare for what is coming online, we need to start looking at this now. We need to complete study and assessments, and these things do not happen over night.

Another member stated that wind impacts both supply and demand. He suggested there may be some natural offsets.

Agenda Item#6 - Additional Business

Dave Robitaille of IESO asked the participants if there was any other business. One member asked if other participants should be involved in the discussions that the IESO is planning on having with the EDA because it will impact others. The IESO acknowledged the point. Another member asked if longer term demand side solutions was part of the new scope. The IESO stated that it is a legitimate issue, but probably not for discussion at this forum.

Dave then restated that the proposed stakeholder plan along with the two papers will be posted for comment for two weeks.

Action Item Summary				
#	Date	Action	Comments	Status
1	January 31, 2008	IESO to study the size of the impact of known generation applications. The IESO is planning such a study but will need to determine the parameters of the study.	Closed under Agenda Item 2.	Closed
2	January 31, 2008	The IESO will provide an overview of the potential injections to the Technical Panel in time for their deliberations on potential market rules.	This will be an on-going item as SE-57 progresses.	Open
3	January 31, 2008	The IESO to provide the reasons for the proposed connection assessment requirement triggers.	Closed under Agenda Item 2.	Closed
4	January 31, 2008	The IESO is to coordinate the threshold for providing telemetry with the LDC's requirements.		Open

Dynamic Reactive Compensation for High Penetration of Embedded Generation in the IESO-Controlled Grid

System Capability, Market Facilitation Department, IESO

1. Introduction

Embedded Generation (EG) is a small scale production of power, typically located close to electricity consumers. Technologies used for EG include combined head and power, solar, wind, biomass, and gas. In Ontario, as a result of the Standard Offer Program (SOP), a large amount of EG projects has been proposed to be directly connected to distribution systems in the IESO-Controlled Grid (ICG). These small projects, when integrated to distribution systems, will cause substation transformer power to be reversed under some operating conditions, thus may have some aggregate impacts on the reliability of the ICG. One of the impacts is on dynamic reactive capability.

Dynamic reactive capability, i.e. fast reactive power support, in the power system is very critical to maintain the system reliability. It helps the voltage recovery following a fault. The voltage recovery is usually delayed by load dynamics, such as dynamics of induction motors. At the same time, the slow voltage recovery may trigger protection relays to disconnect some electric loads and subsequent creation of over-voltages. Automatic restarting of motor loads also depresses system voltages and prevents voltage recovery. These phenomena are well known to utilities and ensuring sufficient dynamic reactive capability in the system is the solution. The phenomena of system voltage depression after fault activity have been observed in Northwest ICG (Bowater/Thunder Bay C1 situation) and other utilities [1, 2].

The least amount of dynamic reactive power in the system, required to maintain the system reliability, is difficult to obtain through system study. The Market Rules define dynamic reactive requirements for individual generation facility. This is actually a simple approach to guarantee sufficient dynamic reactive power to withstand a certain degree of disturbance in the system. The system is usually operated to maximize its dynamic reactive capability by running the generators in voltage control and at a power factor close to unity. Static reactive compensation is installed and utilized to facilitate the generators to operate at a close-to-unity power factor.

Currently, much of electrical energy in Ontario is produced by large centralized plants, consisting of synchronous generators directly connected to the transmission system. High penetration of EG will displace a large amount of generation in the existing system. Some generators, of the same capacity as the EG units, will be shut off. The existing generators to be displaced have the dynamic reactive capability defined in the Market Rules. However, most EG units are induction generators or Doubly Fed Induction Generators (DFIGs), and have different reactive capability from conventional synchronous generators. Furthermore, distributors prefer operate EG units in the power factor control, indicating small or no dynamic reactive capability for EG units. Thus, high penetration of EG may greatly impact the system dynamic reactive capability. The system dynamic reactive capability needs to be investigated and re-evaluated after the incorporation of a large amount of EG.

The objectives of this report are to investigate dynamic reactive capability of the system with high penetration of EG, identify any need for dynamic reactive compensation, and justify appropriate solutions of dynamic reactive compensation to eliminate possible adverse impact brought by EG on the reliability of the ICG.

2. Methodologies

Short-term voltage stability assessment is performed to study the system dynamic reactive capability. Short-term voltage stability is referred as system transient voltage stability maintained in a short time frame of several seconds. This time frame involves the time from the onset of a system disturbance to just prior to the activation of the automatic LTC. Both rotor angle instability and voltage instability may occur within this time frame. The following fast-acting, automatically controlled power system equipments are considered in assessing system performance within this time frame [2, 3]:

- Synchronous generators
- Automatic switched shunt capacitors
- Induction motor dynamics
- Static Var Compensators
- Flexible AC Transmission System (FACTS) devices
- Excitation system dynamics
- Voltage-dependent loads

Particularly, short-term voltage stability depends on load characteristics [4]. Motor loads, often shunt capacitor compensated, draw very high current when starting or when slowed due to system disturbances. Heavily loaded, constant torque type mechanical loads are the most onerous. These loads, i.e. air conditioner compressor motors, may comprise up to 50% of summer peak load. The potential for voltage stability problems is heightened because both shunt capacitor reactive power and induction motor electrical torque decrease with the square of the voltage. Thus, voltage recovery or collapse is greatly influenced by the percentage of the motor load. In this report, the following load distribution is assumed for each load in the ICG [2]:

- Small motor load: 45 %
- Large motor load: 15 %
- Discharge lightning 20%
- Constant power 5%
- Mix of constant current and constant impedance for real power and constant impedance for reactive power 15%

Determination of required dynamic reactive power within a system to maintain its reliability is a challenging issue due to insufficient and/or inaccurate system dynamic data. In this report, identification of the impact of high penetration of EG and justification of adequate dynamic reactive compensation is based on comparison of voltage dynamic response between the following systems:

- An original (existing) system without EG unit;
- A revised system formed by incorporating a large amount of EG units into the original system and displacing the same capacity of existing generation as these EG units, with or without dynamic reactive compensation.

The original system contains conventional synchronous generators and other generating facilities[1] that provide the same reactive capability as synchronous generators. As the reactive capability of a synchronous generator is defined by the Market Rules, we assume the dynamic reactive capability of the original system is necessary and adequate for the reliable operation of the ICG. The revised system is compared with the original system in terms of system dynamic performance (post-fault voltage response) to judge the adequacy of dynamic reactive power within the revised system.

PSS/E Vestas V-82 models are used to represent the EG units in this report[2]. These EG units are running in the power factor control.

3. High Penetration of EG in A Study System

A study system [3] has been adopted to investigate the general impact of high penetration of EG on system dynamic performance. The single line diagram of the study system is shown in Figure 1. The green part in the single line diagram is a 500-kV transmission system, which deliveries the electricity from the sending end (left side, generation area) to the receiving end (right side, load area). Two loads are fed from the 500-kV receiving bus: an industrial load is served directly via a LTC transformer and a residential and commercial load is served via two LTC transformers and an equivalent for sub-transmission impedance. Two remote generators deliver about 5000 MW to the load area through five 500-kV lines. The load area includes a 1094 MW equivalent generator. Figure 1 also shows the rated bus voltages, MW and max/min MVAr of the generators, and the impedance of lines and transformers. More details of the study system are provided in [3].

1000 MW EG units are considered to be integrated into the study system in either generation area or load area. These EG units displace the same amount of generation in either generation area or load area. Based on different locations of EG units and generation to be displaced, the following five scenarios are simulated and compared:

Scenario 1: Original system, no EG in the system;
Scenario 2: 1000 MW EG at the receiving end, displacing generation at the receiving end;
Scenario 3: 1000 MW EG at the receiving end, displacing generation at the sending end;
Scenario 4: 1000 MW EG at the sending end, displacing generation at the receiving end;
Scenario 5: 1000 MW EG at the sending end, displacing generation at the sending end;

[1] Other generating facilities referred to wind farms that are directly connected to the ICG. The Market Rules require a wind farm provide the same reactive capability as a synchronous generator.

[2] There are primarily three types of EG technology: (i) induction generator, (ii) doubly-fed induction generator (DFIG), and (iii) converter-interfaced unit. Vestas V82 is an induction generator with SVC at its terminal to compensate reactive power so that the unit operates at the desired power factor. The three types of EG have similar dynamic performance in terms of reactive capability when the EG units are running in the power factor control.

Figures 2-3 show the voltage response at the 500-kV receiving and sending busses for the defined scenarios. The system is subject to a 3-phase fault at the middle of one 500-kV transmission line. The transmission line is tripped 100 ms after the fault inception.

Simulation results show that the voltage performance is more affected at the 500-kV receiving end by penetration of EG than at the sending end. In the load area, Scenario 3 has almost the same dynamic voltage performance as the original system (Scenario 1) while voltage performance in Scenarios 2, 4, and 5 is much worse than Scenario 1.

When EG units are highly penetrated in a system, the optimal scenario is that the EG units are located at the receiving end, while the displaced generation is at the sending end (Scenario 3). All the capacity of EG units is utilized to alleviate the stress of the transmission system. Although the EG units operate in the power factor control, which reduces dynamic reactive power in the system, the dynamic performance is least affected and no dynamic reactive compensation is necessary.

The worst scenario is the EG unit are located in the generation area while the displaced generation is at the receiving end (Scenario 4). Incorporation of EG units not only reduces dynamic reactive power in the system, but also increases the system stress. A more stressed transmission system would demand more dynamic reactive power in the system to maintain its reliability.

The EG units in Scenarios 2 and 5 have no impact on the transmission system stress. The voltage response in these two scenarios shows that decrement of dynamic reactive power due to the power factor control of EG units, deteriorates system dynamic performance. The system voltage performance is more adversely affected when EG units are located at the receiving end (Scenario 2).

A practical transmission system does not have apparent receiving and sending ends. Generation to be displaced by EG units may be somewhere between receiving and sending ends. The EG units are mainly located in the distribution system viewed as a load area. As the penetration level is increasing, the substation transformer flow may be reversed and some power will be injected into the transmission system. This indicates that part of the EG capacity may be located at the sending end of the transmission system. Thus, practical situation of high penetration of EG in the ICG may be a mix of scenarios and practical voltage performance after incorporation of EG units will be between the optimal scenario (Scenario 3) and the worst scenario (Scenario 4).

Simulation results based on the study system conclude that high penetration of EG has adverse impact on system dynamic performance and the level of adverse impact relates to locations of EG and generation to be displaced. Dynamic reactive compensation is required to eliminate the adverse impact.

4. Proposed Dynamic Reactive Solutions

Dynamic reactive compensation has been identified as necessary for high penetration of EG in the study system. The next step is to determine an appropriate solution of dynamic reactive compensation that could successfully eliminate the adverse impact brought by EG. A complete solution of dynamic reactive compensation consists of the size of required dynamic reactive facilities and their locations.

4.1 Size of Dynamic Reactive Facilities

As mentioned above, the level of adverse impact on system dynamic performance by EG depends on the locations of EG units and displaced generation. If all the capacity of EG units is utilized to alleviate the transmission system stress by supplying just local load and displace remote generation, (Scenario 3), minimum or no dynamic reactive compensation is required. Practically, alleviation of transmission system stress is one of the benefits provided by EG. This indicates that dynamic reactive capability of EG units may be lower than that of conventional synchronous generators to maintain the same system dynamic performance.

The IESO acknowledges the benefit of EG on alleviating the transmission stress and proposes a new approach to define the requirement of dynamic reactive capability for EG. In this approach, the capacity of EG behind each substation is divided into the following two parts:

- Part I: the part of EG capacity equal to the local load within a distribution system (the system behind transformers of a substation).
- Part II: the part of EG capacity equal to the reverse power through substation transformers brought by EG units.

Approximately, we assume that Part I capacity is utilized to alleviate the stress of the transmission system and require no dynamic reactive compensation for this part of EG capacity. Part II capacity is equivalent to a generator directly connected to the transmission system and the dynamic reactive compensation for this part capacity should meet the dynamic reactive requirement in the Market Rules for a synchronous generator.

The relief of dynamic reactive requirement for Part I capacity follows the conclusions obtained in Section 3 (Scenario 3) and assumes that the generation to be displaced by EG is located at the system sending end. This assumption is only valid under a light load condition when the system is not stressed. If the transmission system is not stressed, the transmission system could be approximately reduced to one bus and all the generators directly connected to the transmission system approximately reduced to one generator at this bus which is the high-voltage side of the substation transformers.

When the system is stressed, the transmission impedance plays a critical role in consuming the system reactive power and the transmission system could not be reasonably reduced as aforementioned for the light load condition. The generation to be displaced can be no longer assumed at the sending end. Thus, even though there is no reverse power through substation transformers under the peak load condition, the system performance may be deteriorated by the penetration of EG depending on the location of generation to be displaced.

Therefore, dynamic reactive compensation for penetration of EG should be determined under the light load condition. The proposed approach needs to determine the amount of dynamic reactive compensation pursuant to the requirement in the Market Rules for the generating capacity equal to maximum reverse flow through substation transformers under the light load condition.

The Market Rules require that a synchronous generator unit connecting to the ICG must have the minimum capability to supply reactive power continuously at all active power outputs in the range of 0.9 lagging to 0.95 leading power factor based on rated active power at its generator terminal. Assuming total EG capacity behind one substation is P_{EG}, and total load behind this substation at the light load condition, including distribution losses and transformer losses, is $P_{L, Light}$, the maximum reverse power through substation transformers would be (P_{EG}-$P_{L, Light}$). Therefore, required capacity of dynamic reactive facilities could be deduced as
+0.484 (P_{EG}-$P_{L, Light}$)/-0.33 (P_{EG}-$P_{L, Light}$).

The proposed approach also assumes that, to accommodate a certain amount of EG, required dynamic reactive compensation to maintain dynamic performance of the system under the peak load condition is identical to the dynamic reactive requirement under the light load condition. This assumption will be verified through simulations. The dynamic reactive compensation determined by this approach is adequate to maintain the system dynamic performance under any operation condition.

4.2 Location of Dynamic Reactive Facilities

Dynamic reactive facilities of required size may be spread and located at various sites to provide the appropriate level of compensation and lowest cost option for the rate payer or proponents. Various location options include:

(1) LV bus of the substation
(2) Along the LV feeder lines
(3) At the EG sites
(4) HV side of a substation

In Options (1)–(3), dynamic reactive facilities are distributed at all the substations with EG units. The size of dynamic reactive devices for each substation is separately determined by the maximum reverse flow through substation transformers under the light load condition. We call these types of dynamic reactive compensation as **Distributed Solution**.

Option (4) addresses dynamic reactive compensation for EG projects at the transmission level on a regional basis. This option selects one or two substations and installs regional required dynamic reactive facility at the HV bus of the selected substations. The size of dynamic reactive facilities is equal to the aggregate size of dynamic reactive facilities in the distributed solution. This type of dynamic reactive compensation is called as **Aggregate Solution**.

In the next section, we will look into **Option-1 distributed solution** and **Option-4 aggregate solution**, and compare the effects of both solutions on system dynamic voltage performance.

5. High Penetration of EG in Southwest ICG

High penetration of EG into a practical system of southwest ICG is studied to justify the necessity and the adequacy of dynamic reactive compensation deduced by the proposed approach. The southwest ICG consists of all 230-kV and 500-kV transmission system south of Essa TS, west of Claireville TS, and east of Buchanan TS and Longwood TS.

Table 1 lists the EG projects that are practically most probable to be incorporated into the Southwest ICG. These EG projects are distributed in 14 substations. Column II in Table 1 shows the maximum allowed reverse flow through transformers at each substation. The maximum allowed reverse flow is imposed by transmitter Hydro One and equal to 60% of the full-cooling rating of transformers at each substation. Column III is the minimum load of each substation corresponding to the system light load condition. Columns II and III determine the maximum capacity of EG units behind each substation, shown in Column IV. The study adopts the PSS/E Vestas V82 model to represent the EG units. Number and capacity of EG units behind each substation are shown in Column V and VI, Table 1. Total capacity of EG units to be installed in the Southwest ICG is 1001.55 MW.

Table 1: List of EG projects in the Southwest ICG

Substation	Max Allowed Reverse Flow (MVA)	Min Load (MW)	Max EG (MW)	# of Vestas V82 Unit	Actual EG(MW)
Centralia	22.5	14.1	34.4	20	33
Elmira	20	14.9	32.9	19	31.35
Fergus	75	40.4	107.9	65	107.25
Goderich	22.5	0	20.3	12	19.8
Hanover	50	43.9	88.9	53	87.45
Jarvis	50	41.3	86.3	52	85.8
Meaford	25	13.2	35.7	21	34.65
Norfolk	50	19.5	64.5	39	64.35
Orangeville	50	41.1	86.1	52	85.8
	25	7.2	29.7	18	29.7
	50	10.2	55.2	33	54.45
Owen Sound	75	51.4	118.9	72	118.8
Palmerston	50	21.5	66.5	40	66
Seaforth	25	13.6	36.1	21	34.65
Stayner	50	38.3	83.3	50	82.5
Wingham	50	22.3	67.3	40	66
Total			1014	607	1001.55

Double-line-to-ground (LLG) fault on double 500-kV circuits B560V/B561M (Bruce by Claireville and Milton) at Willow Creek Junction is simulated to investigate system dynamic performance. This is the worst-case disturbance in the southwest ICG in terms of dynamic voltage performance.

The Option-1 distributed solution of dynamic reactive compensation is firstly chosen to study the impact of EG with or without proposed amount of dynamic reactive compensation. Dynamic reactive facilities are represented by STATCOM devices. Total capacity of STATCOM devices is about 295 MVAr based on the proposed approach. Under pre-fault conditions, STATCOM devices are running close to zero output to achieve a maximum effect of dynamic reactive support to the system. Static reactive facilities (shunt capacitors and/or reactors) are used as necessary at appropriate locations to achieve such an operating condition.

For each study case, we primarily examine the 230-kV voltage response at Orangeville, Buchanan, and Burlington TS, which is taken as the indication of system dynamic performance in the southwest ICG.

5.1 Impact of EG with/without Dynamic Reactive Compensation

5.1.1 Light Load Condition

2008 light load base case, with approximately 12406 MW demand and 12723 MW generation in the IESO-controlled grid, is used for simulation. Table 2 shows the study scenarios for light load condition. Before the incorporation of EG, there is 1000 MW generation (2 generating units) scheduled in one of three generation stations: Nanticoke, Lennox, and Lambton GS (Scenarios 1-3). The 1000 MW EG displaces this 1000 MW generation in Scenarios 4-5.

Table 2: Scenario Definitions for Light Load Condition

Scenario	Generation Scheduled				STATCOM
	Nanticoke	Lennox	Lambton	EG	
1	1000 MW	0	0	0	-
2	0	1000MW	0	0	-
3	0	0	1000MW	0	-
4	0	0	0	1000MW	0
5	0	0	0	1000MW	295 MVAr

Figures 4-6 show the voltage responses due to the LLG faults on circuits B560V/B561M at Willow Creek Junction under the light load condition. For the existing system, 1000-MW generation at Nanticoke GS (Scenario 1) provides the best system performance and 1000-MW generation at Lambton GS (Scenario 3) provides the least performance in the original system. Penetration of EG without STATCOM devices significantly slows the post-fault voltage recovery. After the installation of proposed STATCOM devices, the system dynamic performance is restored and better than the least performance (Scenario 3) of the original system at Orangeville and Burlington TS. The dynamic performance at Buchanan TS is still a bit worse than the least level of the original system. However, they are quite close to each other. Thus, the proposed dynamic reactive compensation successfully eliminates the adverse impact of EG units on system dynamic performance.

5.1.2 Peak Load Condition

2008 peak load base case, with approximately 27953 MW demand and 28812 MW generation in the IESO-controlled grid, is adopted for simulation. In the original system, most units in Nanticoke, Lennox, and Lambton GS are in-service. Penetration of EG would displace the 1000-MW generation by shutting off 2 generating units at one of the three plants: Nanticoke, Lennox, and Lambton GS. Table 3 shows the study scenarios for peak load condition.

Table 3: Scenario Definitions for Peak Load Condition

Scenario	Generation Displaced			EG Scheduled	STATCOMs
	Nanticoke	Lennox	Lambton		
1	0	0	0	0	-
2	1000MW	0	0	1000MW	-
3	0	1000MW	0	1000MW	-
4	0	0	1000MW	1000MW	0
5	1000MW	0	0	1000MW	295 MVAr
6	0	1000MW	0	1000MW	295 MVAr
7	0	0	1000MW	1000MW	295 MVAr

Figures 7-9 show the voltage responses due to the LLG fault on circuits B560V/B561M at Willow Creek Junction under the peak load condition. In Figures 7(A)-9(A), the voltage response after EG penetration without dynamic reactive compensation (Scenario 2, 3, and 4) is compared with the response in the original system (Scenario 1). The system voltage performance is deteriorated by the penetration of EG. The level of adverse impact depends on the location of the displaced generation. The system voltage would not recover if the EG displaces the generation at Nanticoke GS (Scenario 2). It takes much longer time for the voltage recovery when displacing the generation at Lennox GS (Scenario 3), as compared with the original system. Replacing the generation in Lambton GS (Scenario 4) has relatively less adverse impact. This is due to the alleviation of the transmission system stress brought by penetration of EG. Lambton GS is approximately at the sending end of the southwest ICG. However, the lowest post-fault voltage at Orangeville TS in Scenario 4 is decreased below 0.7 pu due to the incorporation of EG, which is not acceptable based on the Market Rules.

Figures 7(B)-9(B) compare the voltage response of EG penetration with dynamic reactive compensation (Scenarios 5, 6 and 7) with the original system (Scenario 1). The voltage response in Scenarios 5 and 6 is almost identical at Orangeville, Buchanan, and Burlington TS and Scenario 7 provides a better system dynamic performance than Scenarios 5 and 6. All the three scenarios with proposed dynamic reactive compensation provide better dynamic performance than the original system (Scenario 1). This indicates that the proposed dynamic reactive solution successfully eliminates the adverse impact brought by the penetration of EG and restores the dynamic system performance to or above the original level.

Figures 7-9 indicate that although there is no reverse flow through substation transformers under the peak load condition, the system dynamic performance is adversely impacted by penetration of EG without dynamic reactive capability. Dynamic reactive compensation is necessary to maintain the reliability of the ICG. Proposed distributed solution of dynamic reactive compensation is adequate to maintain the system dynamic performance.

5.2 Comparison of Dynamic Reactive Solutions

Simulations are performed to look into the aggregate solution (Option 4) and compare it with the distributed solution (Option 1). STATCOM devices distributed at all substations with EG in the Subsection 5.1 are replaced by one STATCOM device of 295 MVAr, which is equal to the aggregate capacity of distributed STATCOM devices, installed at the 230-kV bus of Orangeville TS.

Figures 10-12 show the voltage response under the light load condition for both distributed and aggregate solutions of dynamic reactive compensation, and the original system. The aggregate solution results in a better voltage performance at Orangeville TS, and a bit worse performance at Buchanan and Burlington TS, as compared with the distributed solution. The dynamic voltage performance at Buchanan and Burlington TS based on the aggregate solution is a bit worse than the least performance in the original system. However, the difference is quite small.

Figures 13-15 show the voltage response under the peak load condition for both distributed and aggregate solutions of dynamic reactive compensation, and the original system. The dynamic voltage performance based on the aggregate solution is worse than the distributed solution. However, the voltage performance based on the aggregate solution is no worse than that of the original system. The aggregate solution of dynamic reactive compensation is adequate to maintain the system reliability after the incorporation of a large amount of EG.

Simulation results indicate that the aggregate solution of dynamic reactive compensation, with the same capability as the distributed solution, is adequate to eliminate the adverse impact caused by high penetration of EG, although the distributed solution is more effective to improve the system dynamic voltage performance. It is suggested that more than one substation be selected for dynamic reactive facilities in the aggregate solution to improve its effectiveness.

6. Summary and Conclusions

This report investigated and identified the potential adverse impact of high penetration of EG on system dynamic performance. The IESO have proposed an approach to determine appropriate amount of dynamic reactive compensation for the EG to eliminate the adverse impact of high penetration of EG. Two dynamic reactive solutions: distributed and aggregate solutions have been proposed and studied.

Short-term voltage stability of a study system and the southwest ICG, with and without high penetration of EG, has been studied in the PSS/E time-domain simulation environment. The study results conclude that:

- High penetration of EG units may have adverse impact on system dynamic performance. Dynamic reactive compensation is required to maintain the system dynamic performance,
- Dynamic reactive compensation, obtained based on the requirement in the Market Rules for the generating capacity equal to maximum reverse power through substation transformers under the light load condition, is adequate to eliminate the possible adverse impact of EG units on system dynamic performance,
- Both distributed and aggregate solutions of dynamic reactive compensation for EG units are appropriate to maintain the system dynamic performance.

Appendix: Figures

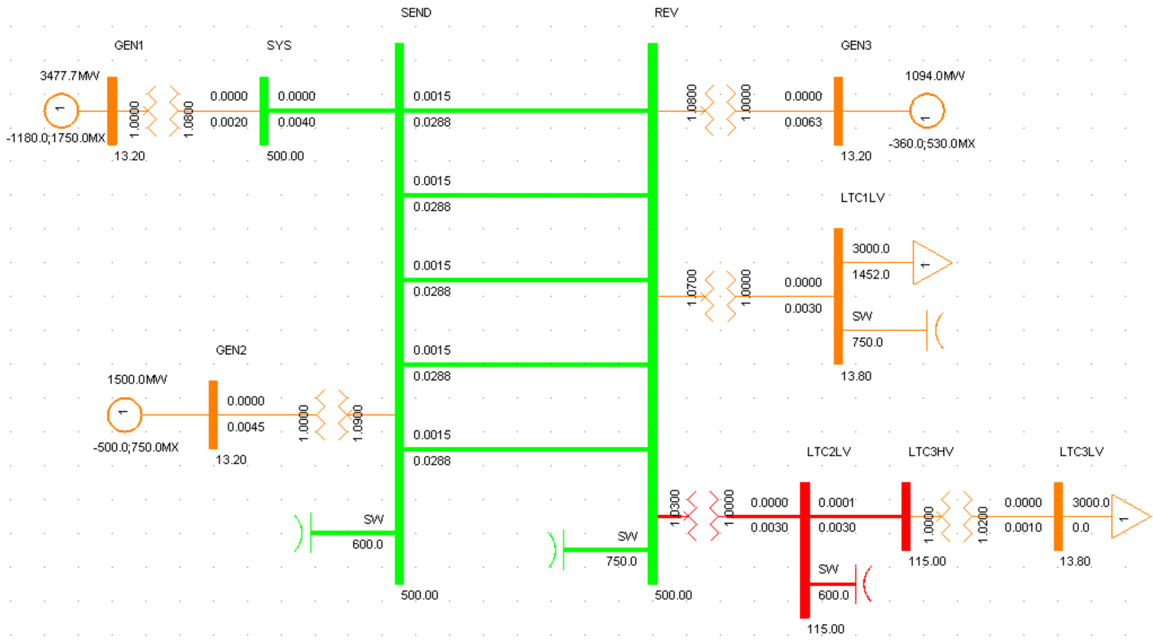


Figure 1: Single line diagram of the study system

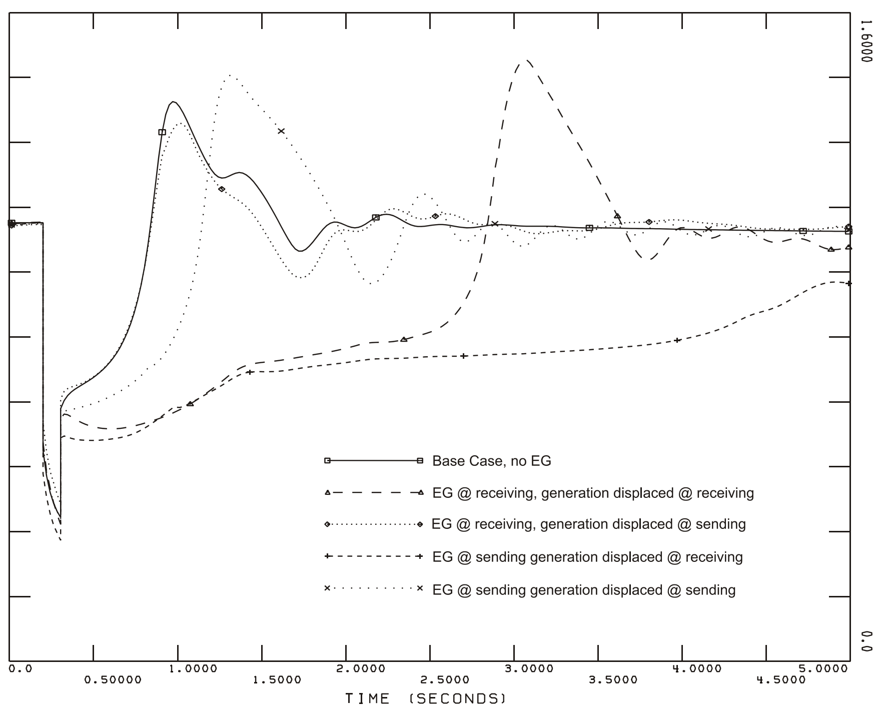


Figure 2: Voltage response at the 500-kV receiving bus due to a 3-phase fault at the middle of one 500-kV transmission line, tripped 100 ms after the fault inception

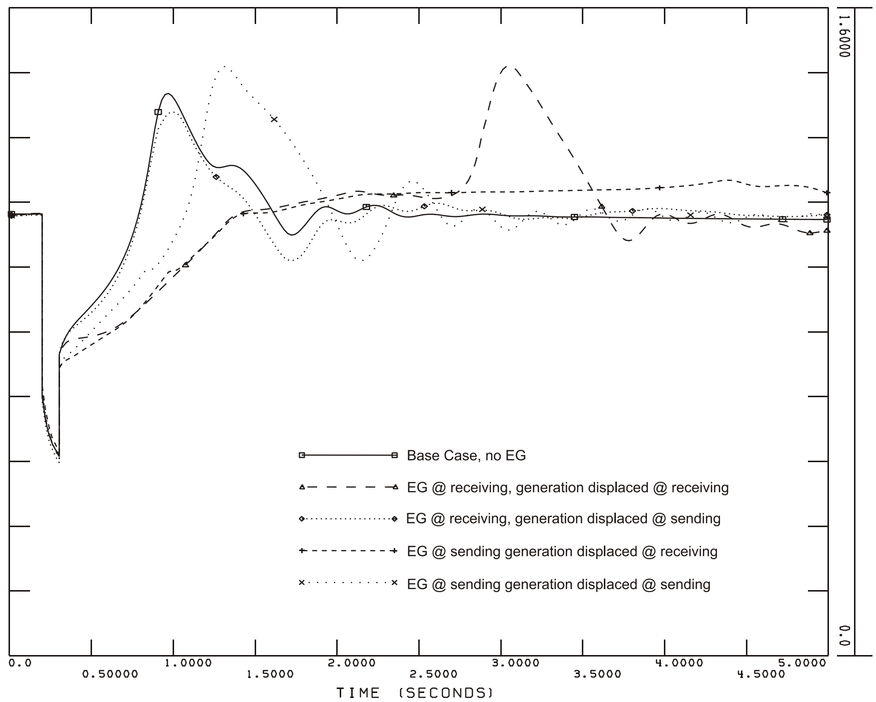


Figure 3: Voltage response at the 500-kV sending bus due to a 3-phase fault at the middle of one 500-kV transmission line, tripped 100 ms after the fault inception

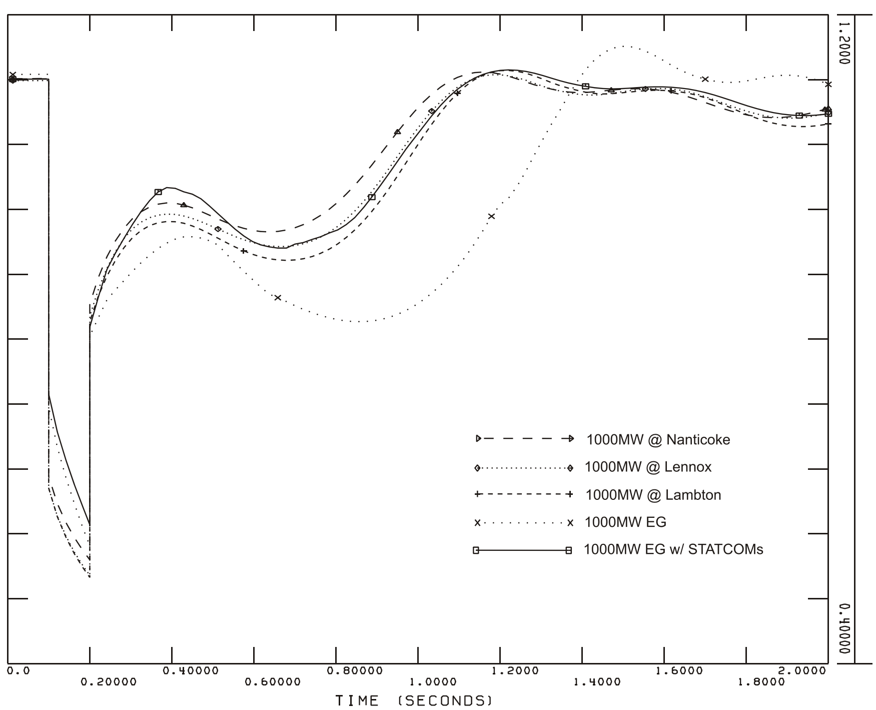


Figure 4: Voltage response of Orangeville 230-kV bus due to the LLG fault on circuits B560V/B561M at Willow Creek Junction under the light load condition

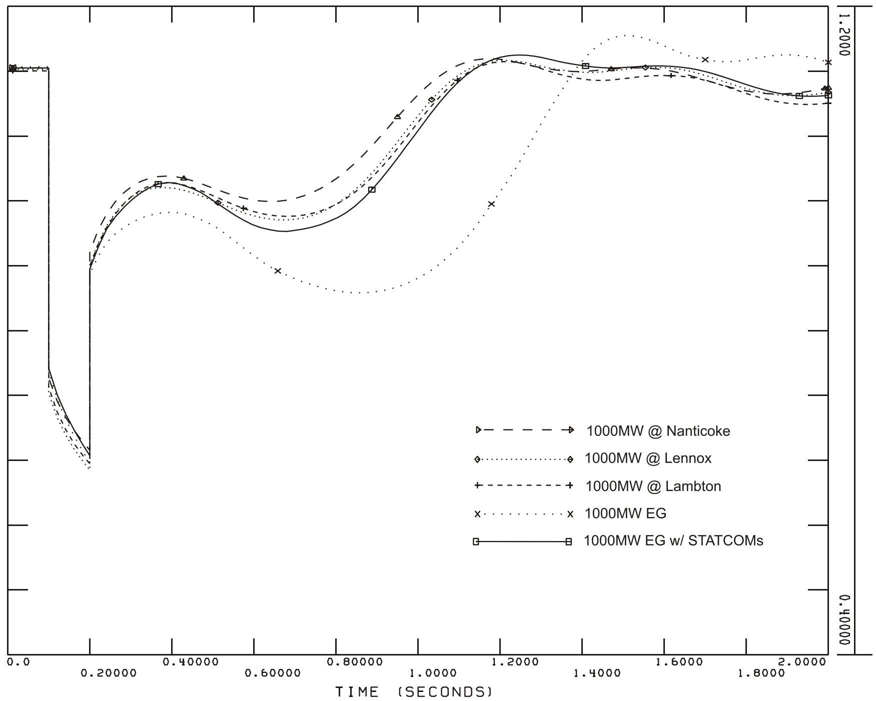


Figure 5: Voltage response of Buchanan 230-kV bus due to the LLG fault on circuits B560V/B561M at Willow Creek Junction under the light load condition

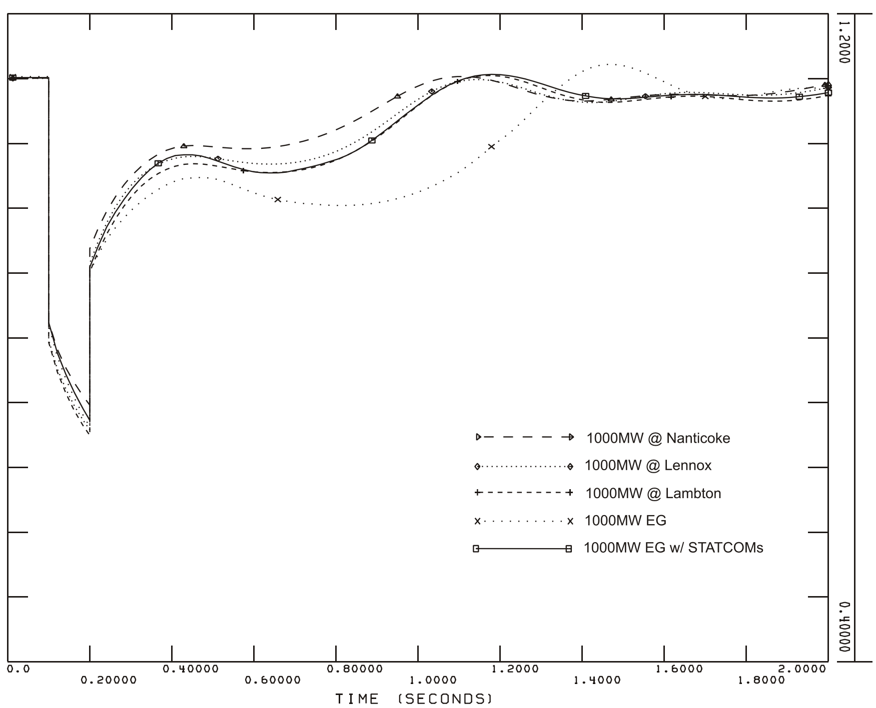
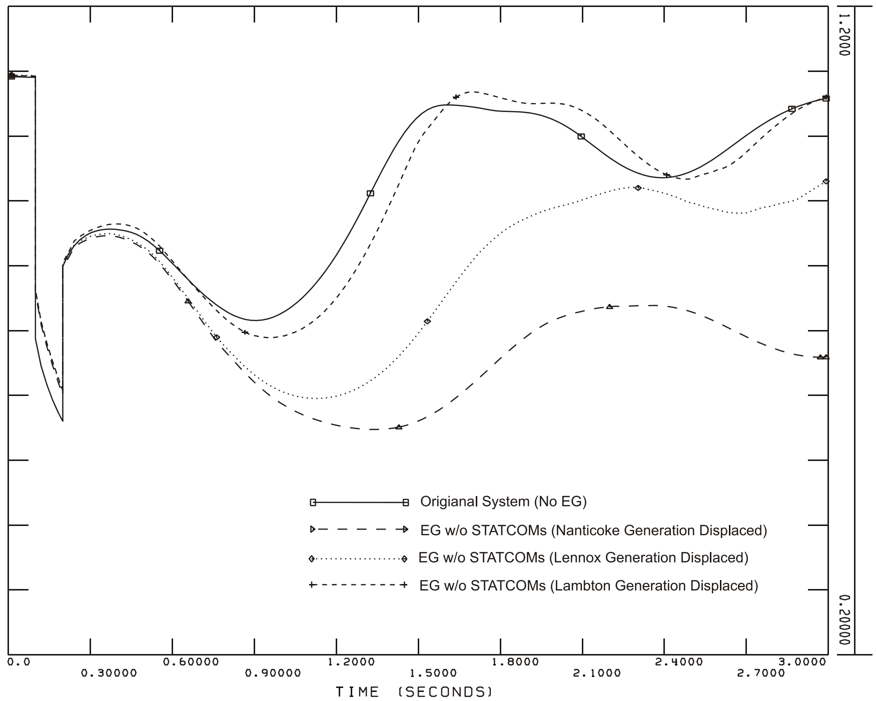
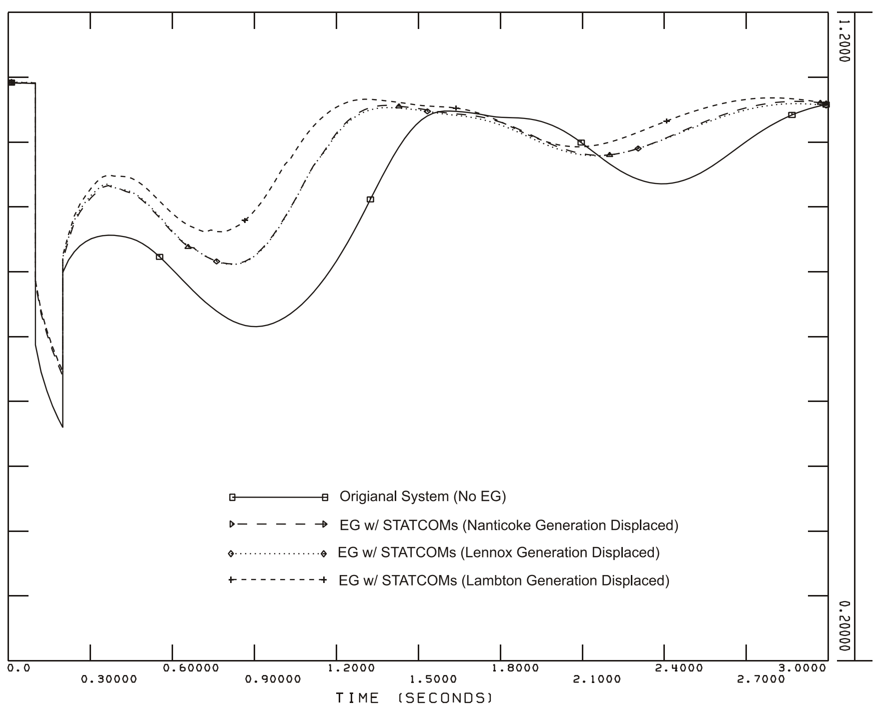


Figure 6: Voltage response of Burlington 230-kV bus due to the LLG fault on circuits B560V/B561M at Willow Creek Junction under the light load condition

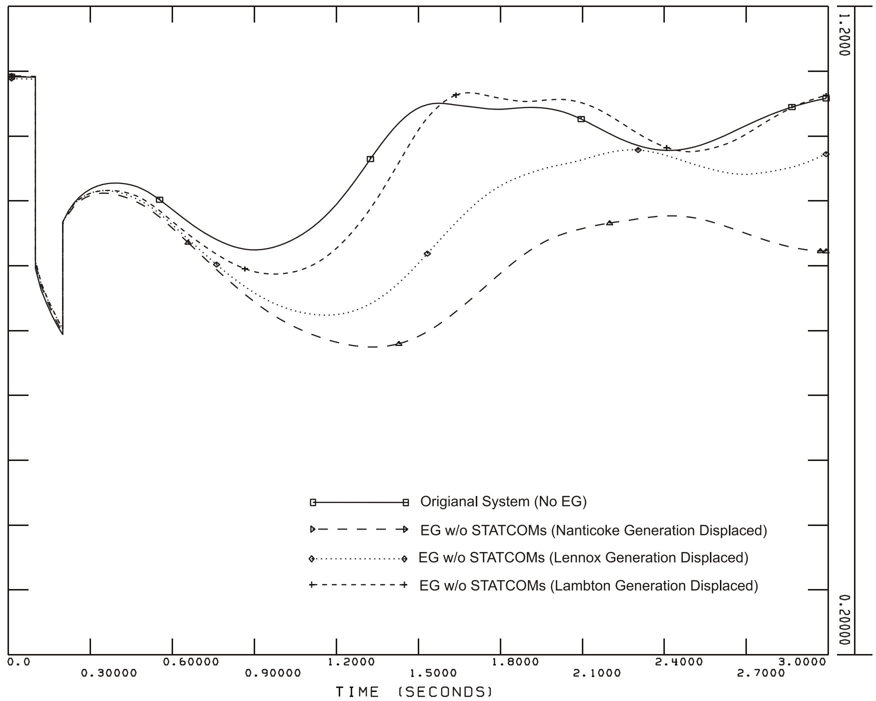


(A) EG Penetration without STATCOMs

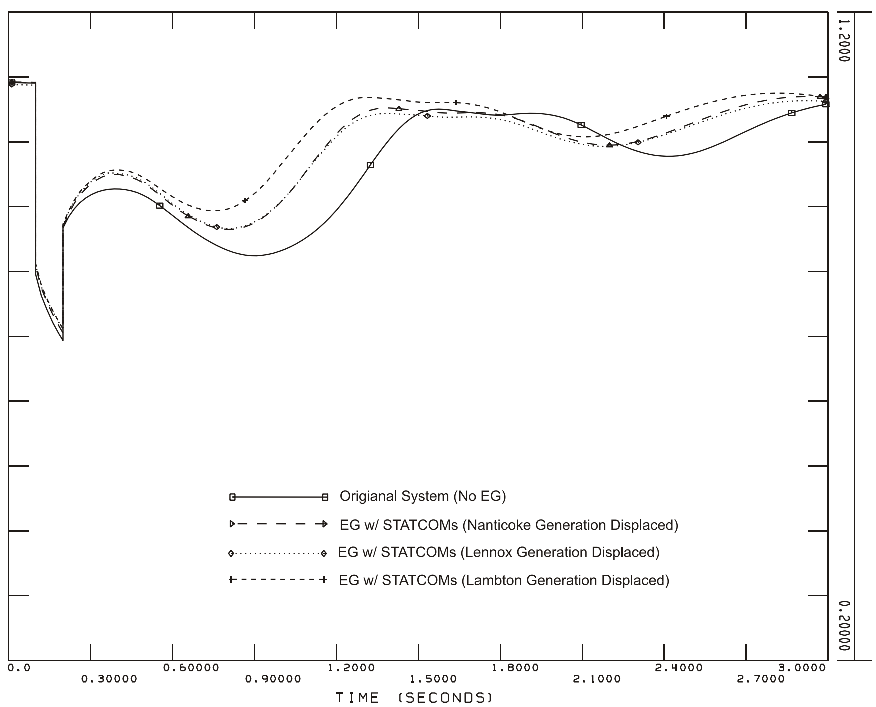


(B) EG Penetration with STATCOMs

Figure 7: Voltage response of Orangeville 230-kV bus due to the LLG fault on circuits B560V/B561M at Willow Creek Junction under the peak load condition

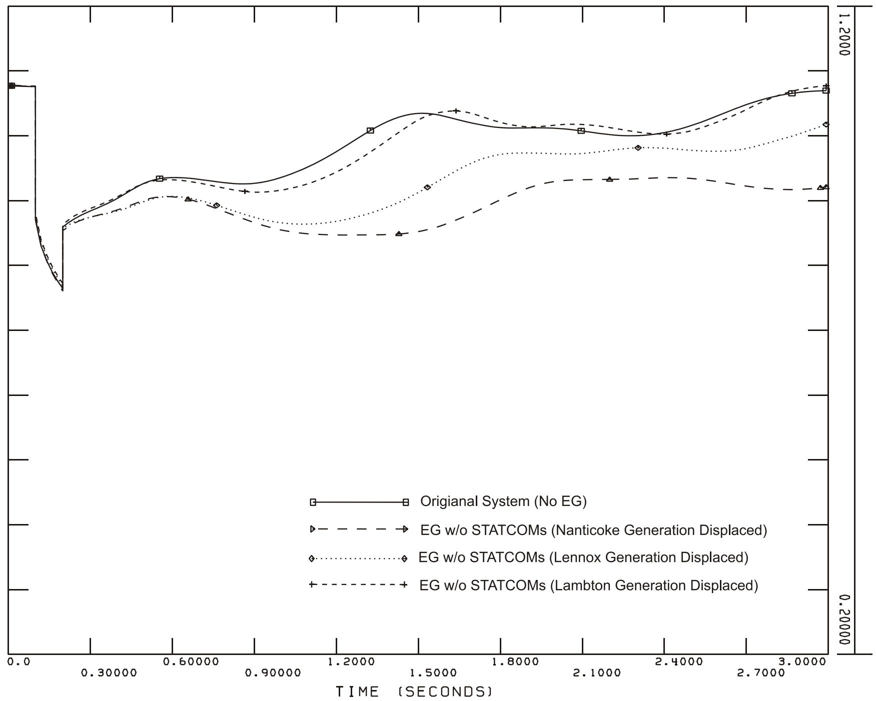


(A) EG Penetration without STATCOMs

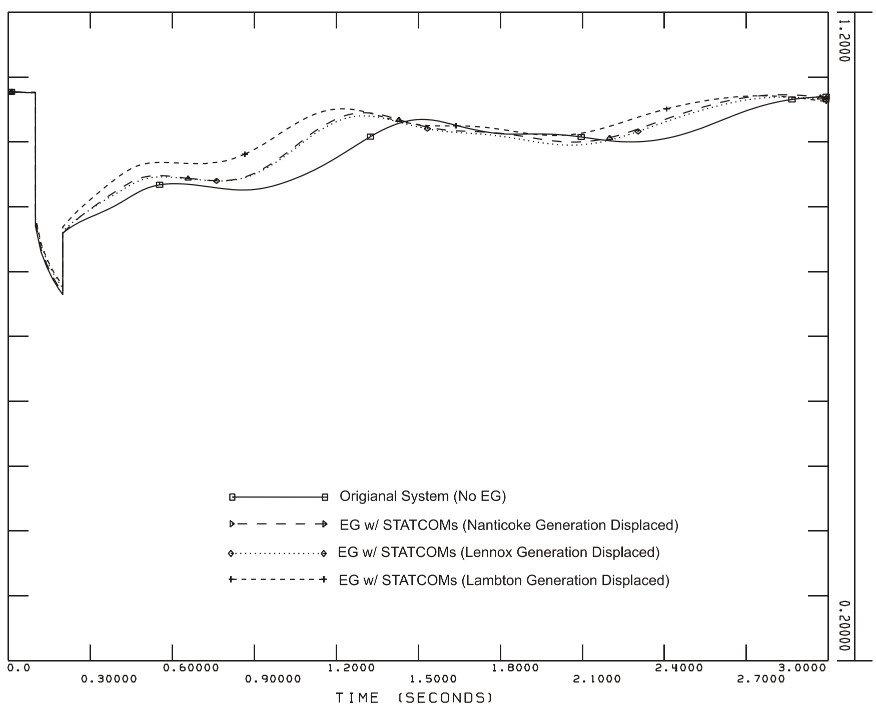


(B) EG Penetration with STATCOMs

Figure 8: Voltage response of Buchanan 230-kV bus due to the LLG fault on circuits B560V/B561M at Willow Creek Junction under the peak load condition



(A) EG Penetration without STATCOMs



(B) EG Penetration with STATCOMs

Figure 9: Voltage response of Burlington 230-kV bus due to the LLG fault on circuits B560V/B561M at Willow Creek Junction under the peak load condition

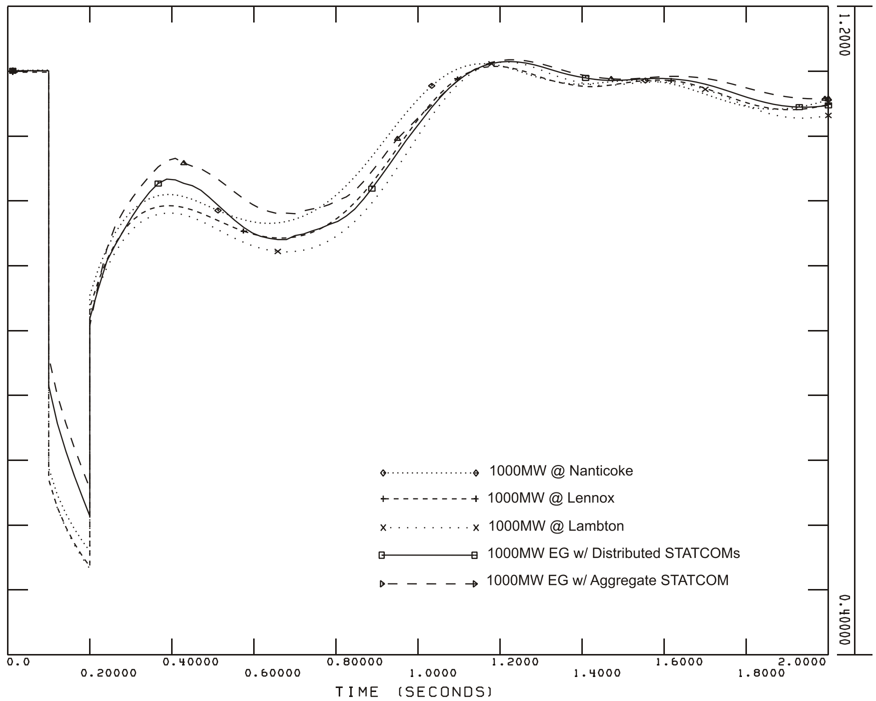


Figure 10: Voltage response of Orangeville 230-kV bus due to the LLG fault on circuits B560V/B561M at Willow Creek Junction under the light load condition

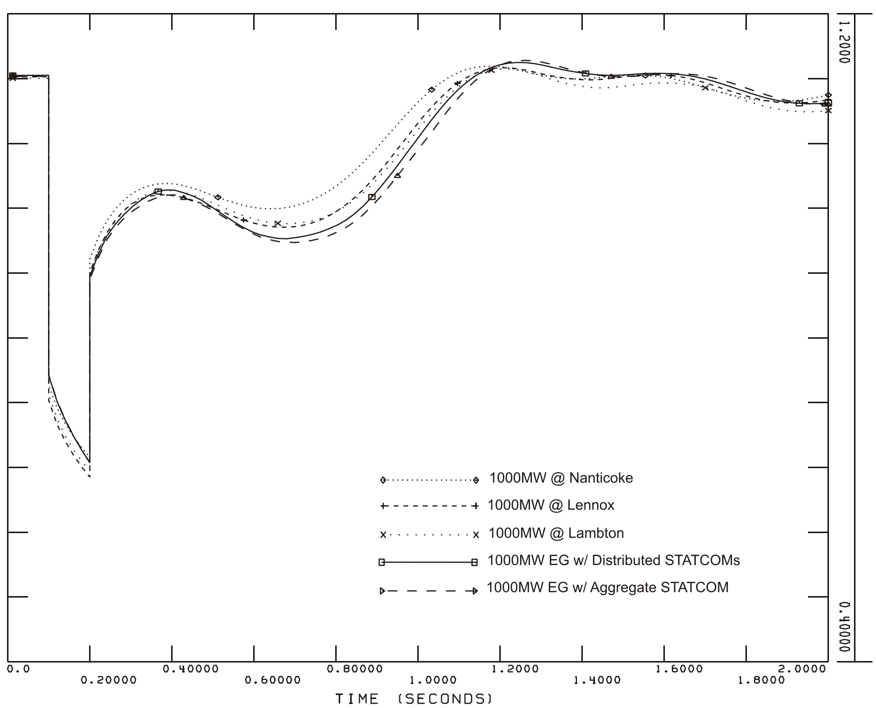


Figure 11: Voltage response of Buchanan 230-kV bus due to the LLG fault on circuits B560V/B561M at Willow Creek Junction under the light load condition

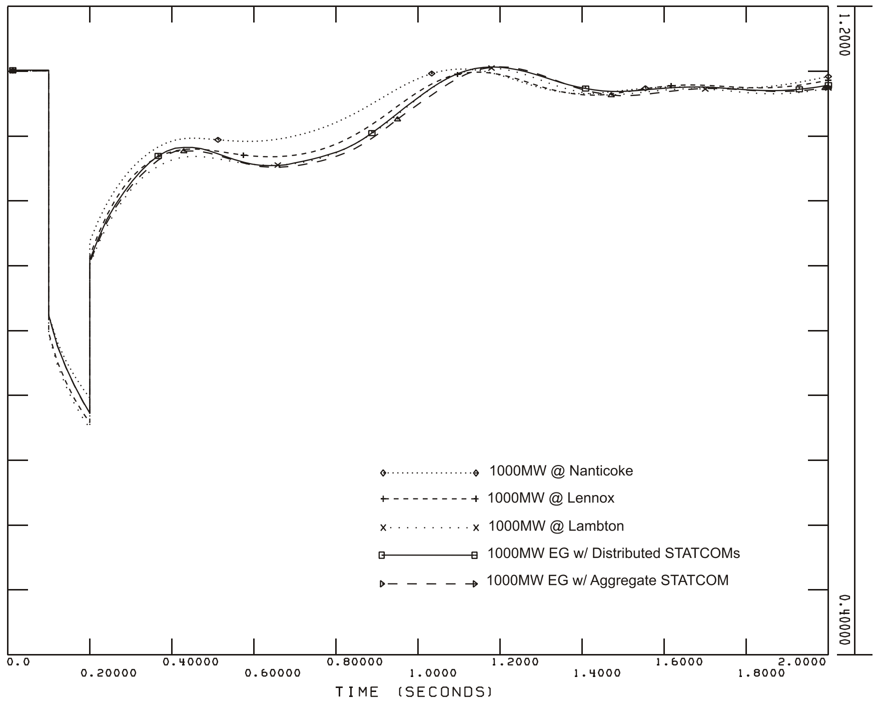


Figure 12: Voltage response of Burlington 230-kV bus due to the LLG fault on circuits B560V/B561M at Willow Creek Junction under the light load condition

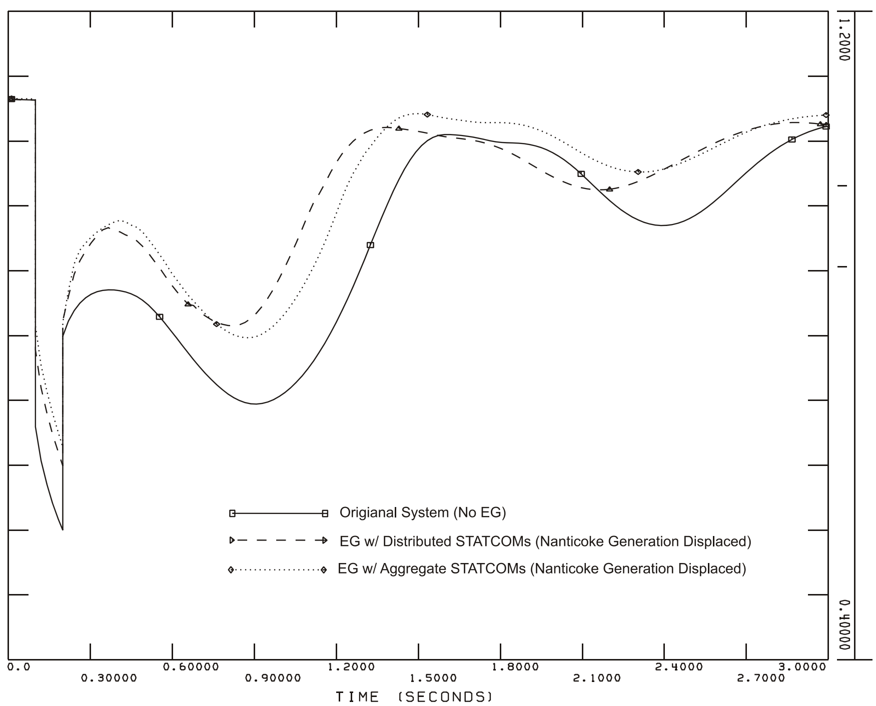


Figure 13: Voltage response of Orangeville 230-kV bus due to the LLG fault on circuits B560V/B561M at Willow Creek Junction under the peak load condition

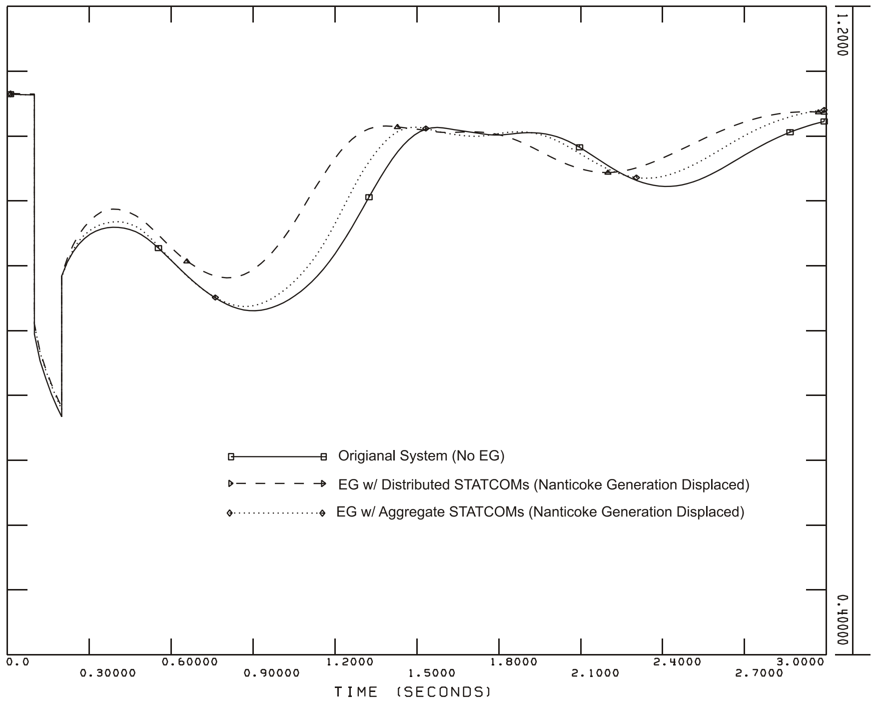


Figure 14: Voltage response of Buchanan 230-kV bus due to the LLG fault on circuits B560V/B561M at Willow Creek Junction under the peak load condition

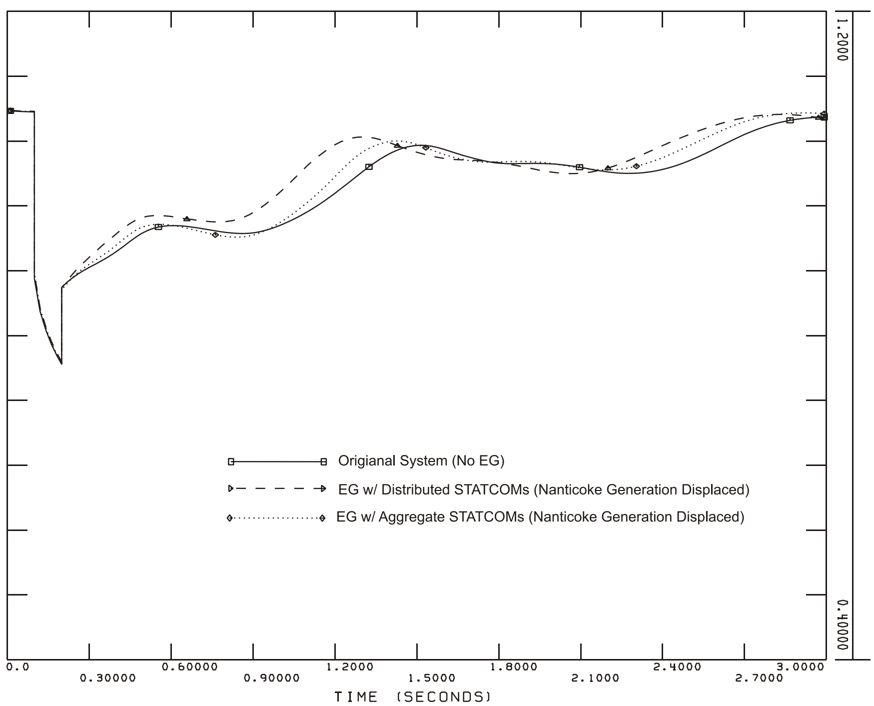


Figure 15: Voltage response of Burlington 230-kV bus due to the LLG fault on circuits B560V/B561M at Willow Creek Junction under the peak load condition

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[2] J. A. Diaz de Leon II and C. W. Taylor, “Understanding and Solving Short-Term Voltage Stability Problems”, in *Proc. 2002 IEEE Power Engineering Society Summer Meeting*, vol. 2, pp. 745-752.

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[4] IEEE Committee Report, “Standard Load Models for Power Flow and Dynamic Performance”, *IEEE Transactions on Power Systems*, vol. 10, no. 3, pp. 1302-1313, August 1995.