Siemens PTI Report Number: R022-13

Dynamic Stability Assessment of Grain Belt Express Clean Line HVDC Project

Prepared for

Clean Line Energy Partners LLC

Submitted by:

Satish Natti, Ph D
Carlos Grande-Moran, Ph D
Yuri Kazachkov
Nelson J. Bacalao, Ph D

March 2013

P/21-113728

Siemens Industry, Inc.
Siemens Power Technologies International
400 State Street • P.O. Box 1058
Schenectady, New York 12301-1058 USA
Tel: +1 (518) 395-5000 • Fax: +1 (518) 346-2777
www.siemens.com/power-technologies

Revision History

Date	Rev.	Description
March 2013	1	Initial draft
March 14, 2013	2	Clean Line team's comments incorporated

Contents

Legal Notice

This document was prepared by Siemens Industry, Inc., Siemens Power Technologies International (Siemens PTI), solely for the benefit of Clean Line Energy Partners LLC. Neither Siemens PTI, nor parent corporation or its or their affiliates, nor Clean Line Energy Partners LLC, nor any person acting in their behalf (a) makes any warranty, expressed or implied, with respect to the use of any information or methods disclosed in this document; or (b) assumes any liability with respect to the use of any information or methods disclosed in this document.

Any recipient of this document, by their acceptance or use of this document, releases Siemens PTI, its parent corporation and its and their affiliates, and Clean Line Energy Partners LLC from any liability for direct, indirect, consequential or special loss or damage whether arising in contract, warranty, express or implied, tort or otherwise, and irrespective of fault, negligence, and strict liability.

This page intentionally left blank.

Executive Summary

Clean Line Energy Partners LLC is currently developing the Grain Belt Express Clean Line (GBX) Project. The project is planned to be a multi-terminal ±600 kV HVDC bi-pole line which will transport large amounts of new, renewable energy, primarily sourced from wind turbine generators (WTG). The wind turbine generation will be independently developed within the Southwest Power Pool's (SPP) geographic footprint in and around the northwestern portion of Oklahoma and in the southwestern portion of Kansas. The power will then be transmitted via the GBX Project approximately 500-550 miles to a location at or near the Palmyra Tap 345kV bus in the Ameren Missouri (AMMO in the MISO) and then a further 200 miles to the Sullivan 765kV substation in the American Electric Power (AEP in the PJM) power systems. The Project will have a planned delivery capability of 3,500 MW as measured at the receiving ends of the HVDC line (500 MW at Palmyra Tap and 3,000 MW at Sullivan). The Sullivan terminal will be designed to receive up to 3,500 MW.

Siemens Industry, Power Technologies International (Siemens PTI) was engaged to evaluate the impacts of the GBX Project from a steady state and dynamic performance point of view. This report presents the stability analysis results to determine the dynamic performance of the study area due to the addition of the GBX Project.

The wind turbine generation is modeled as Type 3 (doubly fed induction generators) and Type 4 (full converter) located within a possible collector system. The collector system design considered in this study is a best engineering estimate based on available wind potential resources in the vicinity of the northwestern portion of Oklahoma and in the southwestern portion of Kansas. It is expected that the wind generation is collected using a 138 kV transmission network connecting the wind parks to main 345 kV stations and then ultimately transferred to the HVDC rectifier station via a 345 kV transmission network. For this analysis, the wind generation was directly connected to the HVDC rectifier station via a 345 kV network without modeling of the 138 kV collection system. Future design studies will include design of the 138 kV system to collect the wind generation and deliver it to the 345 kV transmission network. The collector system losses and reactive power needs of the GBX Project will be covered by the project wind generation and interconnected reactive power sources such that minimal exchange of real and reactive power with SPP at the Point of Interconnection (POI) is maintained under normal operating conditions. However, following the loss of a pole in the GBX project, some of the power flowing through the project will temporarily flow into the SPP system.

As part of the study, several disturbances within the vicinity of the GBX Project were selected to evaluate the dynamic performance of the system. Study methodology and assumptions were discussed with SPP and other affected parties. Affected parties were determined in the January 7, 2013 issued report entitled *Steady State Assessment of the Grain Belt Express Clean Line HVDC Project*.

During the analysis of the Clean Line Plains and Eastern (P&E) project, dynamic reactive support from synchronous condensers was proposed as a solution to handle the low Short Circuit Ratio (SCR[1] of less than 2) at the point of interconnection. Taking advantage of the

[1] Ratio of 3-phase short circuit MVA without the WTG in place to the total wind turbine generation capacity

P&E project stability study evaluation, and given that the interconnection points for both the P&E and the GBX projects have similar short circuit levels (in the order of 5,000 MVA), dynamic reactive support of 900 MVAr from synchronous condensers was modeled at the rectifier station. The addition of 900 MVAr from synchronous condensers increased the SCR to slightly higher than 2 under system intact conditions. Note that this was modeled as a single synchronous condenser as part of the reactive compensation at the rectifier station and its size and division into smaller units was not optimized in this study as this will be undertaken during the detailed design of the GBX project and its controls.

Three scenarios, 2017 Summer Peak, 2017 Light Load and 2022 Summer Peak, with different dispatch and loading conditions are considered in the study. These scenarios were identified by SPP staff and the affected parties as relevant scenarios considering the project's expected in-service dates.

The following are the main conclusions of the overall system stability analysis:

- As proprietary HVDC models from the yet to be selected HVDC vendor are not available, HVDC models from the PSS/E library are used. These HVDC models do not fully capture the control capability of the HVDC converter stations thus, up to 900 MVAr from a synchronous condenser are required, from a modeling perspective, for the PSS/E stability models to solve by improving the short circuit levels (i.e. system strength) at the Clark County 345 kV substation. This condenser was considered in all cases. Once proprietary HVDC models are provided by the HVDC vendor, the control capability of the HVDC converter can be properly modeled and thus reduce the required amount of synchronous condensers. Furthermore, for reliability and practical reasons, smaller parallel synchronous condensers would be used to make up the required total. This synchronous condenser is to be optimized at the time of the GBX project design

- Faults at Rockport that involve tripping the 765 kV line to Jefferson require the GBX Project generation injection at Sullivan to be reduced, while keeping the full reactive capability of the inverter station available. The associated WTG is assumed to flow in the underlying AC system during the stability runs

- For an N-1-1 outage at Clark County substation, it is necessary to trip approximately 877 MW of the project WTG

The main results of the study that drove these conclusions are summarized below:

- Taking advantage of the P&E Stability Study, and given that the Hitchland and Clark County substations have similar short circuit levels (around 5,000 MVA); up to 900 MVAr from synchronous condensers were proposed for all simulations

- The 2017 Summer Peak case showed stable study area dynamic performance for all selected faults except for 3ph fault at Rockport substation (Fault # 34)

  – For this particular fault, all on-line generating units at the Rockport plant have stepped out of synchronism with the rest of the system. Tripping of these units does not have an adverse impact on the rotor angle stability of rest of the study area

  - By reducing the GBX project injection at Sullivan by 1,500 MW (achieved by blocking one pole), the Rockport generating units remain on-line and in synchronism with the system. Note that full reactive compensation (switched shunts) is required at the converter stations to meet the voltage performance criteria

- The 2017 Light Load case showed stable study area dynamic performance for all selected faults except for Fault # 34. For this fault, the voltages around the Sullivan substation area did not meet the voltage performance criteria

  - By reducing the GBX project injection at Sullivan by 1,500 MW (achieved by blocking one pole), the voltages around the Sullivan substation met the voltage performance criteria

- The 2022 Summer Peak case showed stable study area dynamic performance for all selected faults except for a 3ph fault at Rockport substation (Fault # 34)

  - For this particular fault, all on-line generating units at Rockport plant have stepped out of synchronism with the rest of the system. Tripping of these units does not have adverse impact on the rotor angle stability of the rest of the study area

  - By reducing the GBX project injection at Sullivan 1,500 MW (achieved by blocking one pole), the Rockport generating units remain on-line and in synchronism with the system. Note that full reactive compensation (switched shunts) is required at the converter stations to meet the voltage performance criteria.

Again, it should be noted that it may be possible to reduce the size of the recommended 900 MVAr from synchronous condensers by HVDC control schemes at the converter stations. However, this combination was not tested in this study and it will be part of the reactive optimization of the Project design as well as the selection of the required number of parallel synchronous condensers once proprietary HVDC models become available.

Introduction

Clean Line Energy Partners LLC (Clean Line) is currently developing the Grain Belt Express Clean Line Project (GBX Project) which will use a multi-terminal HVDC technology to deliver primarily wind generated electricity from southwestern Kansas and northwestern Oklahoma to serve load centers in the AMMO and AEP control areas. The GBX Project is being developed as a ±600-kV HVDC overhead line and is expected to interconnect the Clark County 345 kV substation (SPP) to the Palmyra 345 kV Tap (AMMO) and the Sullivan 765 kV substation (AEP) through a new 345 kV substation and three 765/345 kV transformers. The connection of wind turbine generation resources to Sullivan via Palmyra Tap is proposed as an approximately 700-750 mile[2] multi-terminal HVDC transmission line at or near the Palmyra Tap (AMMO in the MISO) substation and Sullivan (AEP in the PJM).

Siemens Industry, Power Technologies International (Siemens PTI) has provided consulting services to Clean Line to estimate the steady state impacts of the GBX Project. In continuation to this effort, Siemens PTI has also conducted the system stability study to determine the impact of the GBX Project on dynamic performance of the power system within the study area.

Figure 1-1: Approximate Geographic Location of the GBX Project

[2] Actual mileage will be dependent upon final routing.

This report presents the study methodology, summary of the stability analysis results, and proposed solutions to the identified issues. The report is organized as follows:

Section 2 of this report presents the stability case development process which includes generation and transmission topology changes within the study area, modeling of the proposed HVDC line, and modeling of the GBX Project's expected Wind Turbine Generation (WTG).

Section 3 presents methodology and assumptions used in the study. The selected list of disturbances for evaluating the dynamic performance of the system along with performance evaluation criteria are presented in this section.

Section 4 presents analysis of study results and major findings of the study.

Section 5 presents the analysis of three phase (3ph) faults at Spearville and Clark County substations with prior line outages. This analysis was done to evaluate the impact of pre-existing outages on the lines that, as will be observed, had the most significant impact on stability.

Section 6 presents the summary of swing current analysis on key underlying SPP 345 kV lines for 3ph faults at both converter stations that involves double pole outage.

Section 7 presents the sensitivity case of reduced GBX Project generation of 1,750 MW (250 MW injection at Palmyra and 1,500 MW inject at Sullivan) in 2017 Light Load scenario. This case was assessed without the proposed synchronous condenser.

Section 8 presents the sensitivity case of connecting the GBX Project to 345 kV network at Sullivan. Selected 3ph faults are studied for dynamic performance of the study area.

Section 9 presents the study conclusions and recommendations.

Finally, the Appendices section presents dynamic model parameters and stability plots for all three scenarios.

Section

2

Stability Case Development

The stability analysis is performed using the "2011 Build 1 Stability Package"[3] (called here after "Stability Package") provided by SPP. Since the steady state analysis was performed using the "2011 Build 2 scenario"[4] (called here after "Build 2") cases, we compared the load flow cases from the Stability Package and the Build 2 scenario for any generation and transmission topology changes that needed to be incorporated in the Stability Package.

This section presents generation and transmission changes and provides details of the GBX Project addition along with collector system description.

2.1 Generation Changes

Table 2-1 shows the generation comparison of the 2017 Summer Peak case[5]. The table also shows the wind generation dispatched in both cases. Both cases have substantially similar dispatch (a maximum of 4% difference was noted in relevant areas). No additional generation was added with the exception of the wind turbine generation associated with the GBX project.

Similarly, Table 2-2 shows the generation comparison between the Build 2 case and Stability Package case for the 2017 Light Load case and Table 2-3 shows the generation comparison between the Build 2 case and Stability Package case for the 2022 Summer Peak case. No additional generation was added except for the GBX project wind generation as the dispatches were practically identical.

The branch loadings of the Stability Package load flow cases (2017 Summer Peak, 2017 Light Load and 2022 Summer Peak) were compared against the normal line rating (Rate A) within the SPP footprint[6], and no thermal overloads were observed.

Further, the Stability Package load flow cases were compared against the Build 2 scenario load flow cases for any significant changes in branch loadings. The comparison criteria include changes greater than 3% in branch loadings (MW) for branches operating at 230 kV and above voltage levels within the SPP footprint. The branch loading tables are listed in Appendix A, by each balancing area. It can be observed from these tables that most of the branch loadings in the Stability Package load flow cases differ from those of the Build 2 scenario load flow cases by less than +/- 50 MW except for very few lines with a difference between 50 MW and 100 MW.

Based on generation and branch loading comparisons, it is assumed that both the Stability Package load flow cases and Build 2 scenario load flow cases are stressed identically for the

[3] 2011 Build 1 package was the latest available stability package at the time of the study
[4] These are the original cases received from SPP
[5] The delta change in Pgen (%) = (Pgen in Stability Case/Pgen in Build 2 – 1)X100
[6] SPP footprint is defined as areas 500 – 599, 640, 645 and 650

purpose of this study and no additional generation was added other than the expected project's WTG generation. The next section presents the transmission topology changes.

Table 2-1: Generation Comparison – 2017 Summer Peak

		2017 Summer Peak Build 2				2017 Summer Peak Stability				Change in Total Pgen
		Total		Wind		Total		Wind		
Area		Pgen	Pmax	Pgen	Pmax	Pgen	Pmax	Pgen	Pmax	
534	SUNC	1,118	2,029	89	759	1,111	2,161	47	313	-1%
531	MIDW	135	408	33	261	130	249	36	102	-4%
536	WERE	6,489	7,740	46	150	6,587	7,740	46	150	2%
526	SPS	6,615	8,589	63	994	6,601	8,358	57	879	0%
525	WFEC	1,305	2,673	22	539	1,305	2,597	22	255	0%
524	OKGE	6,961	9,306	99	1,141	6,975	9,199	105	882	0%
520	AEPW	10,117	16,799	23	388	10,107	16,670	15	214	0%
541	KCPL	4,495	5,336	240	308	4,493	5,336	240	308	0%
540	GMO	1,184	2,028	0	170	1,178	2,028	0	170	0%
545	INDN	202	288	0	0	202	288	0	0	0%
515	SWPA	1,996	2,564	0	122	1,996	2,564	0	122	0%
502	CLEC	3,663	4,617	0	0	3,663	4,617	0	0	0%
351	EES	29,083	42,202	0	0	29,084	42,202	0	0	0%
503	LAFA	168	465	0	0	168	465	0	0	0%
504	LEPA	123	211	0	0	123	211	0	0	0%
523	GRDA	1,217	1,532	0	0	1,265	1,532	0	0	4%
527	OMPA	196	197	0	0	193	197	0	0	-2%
542	KACY	580	961	0	0	580	961	0	0	0%
544	EMDE	1,106	1,460	0	0	1,107	1,460	0	0	0%
546	SPRM	879	1,060	0	0	879	1,060	0	0	0%
330	AECI	4,538	5,622	0	0	4,522	5,622	0	0	0%
640	NPPD	2,907	4,687	22	345	2,907	4,687	22	345	0%
645	OPPD	3,249	3,781	12	60	3,249	3,766	12	45	0%
	Total	**88,326**	**124,555**	**650**	**5,237**	**88,425**	**123,969**	**603**	**3,785**	0%

Table 2-2: Generation Comparison – 2017 Light Load

Area		2017 Light Load Build 2 Total Pgen	2017 Light Load Build 2 Total Pmax	2017 Light Load Build 2 Wind Pgen	2017 Light Load Build 2 Wind Pmax	2017 Light Load Stability Total Pgen	2017 Light Load Stability Total Pmax	2017 Light Load Stability Wind Pgen	2017 Light Load Stability Wind Pmax	Change in Total Pgen
534	SUNC	652	2,029	102	439	643	2,481	139	566	-1%
531	MIDW	85	408	75	261	86	304	75	158	0%
536	WERE	5,070	7,740	0	0	5,121	7,740	80	150	1%
526	SPS	3,330	8,578	123	834	3,328	8,501	165	993	0%
525	WFEC	1,264	2,673	37	200	1,267	2,682	97	340	0%
524	OKGE	2,419	9,306	123	1,141	2,412	9,194	129	882	0%
520	AEPW	2,858	16,799	23	388	2,855	16,670	15	214	0%
541	KCPL	2,375	5,336	0	308	2,376	5,336	0	308	0%
540	GMO	285	2,028	0	170	284	2,028	0	170	0%
545	INDN	0	288	0	0	0	288	0	0	0%
515	SWPA	999	2,564	0	122	999	2,564	0	122	0%
502	CLEC	1,800	4,617	0	0	1,800	4,617	0	0	0%
351	EES	19,334	42,202	0	0	19,335	42,202	0	0	0%
503	LAFA	54	465	0	0	54	465	0	0	0%
504	LEPA	85	211	0	0	85	211	0	0	0%
523	GRDA	727	1,532	0	0	750	1,532	0	0	3%
527	OMPA	107	197	0	0	107	197	0	0	-1%
542	KACY	236	961	0	0	236	961	0	0	0%
544	EMDE	98	1,460	0	0	98	1,460	0	0	0%
546	SPRM	257	1,060	0	0	257	1,060	0	0	0%
330	AECI	1,181	5,622	0	0	1,174	5,622	0	0	-1%
640	NPPD	1,484	4,687	77	345	1,484	4,687	77	345	0%
645	OPPD	1,154	3,813	21	60	1,154	3,813	21	60	0%
	Total	**45,856**	**124,576**	**582**	**4,268**	**45,903**	**124,614**	**798**	**4,308**	0%

Table 2-3: Generation Comparison – 2022 Summer Peak

Area		2022 Summer Peak Build 2 Total Pgen	2022 Summer Peak Build 2 Total Pmax	2022 Summer Peak Build 2 Wind Pgen	2022 Summer Peak Build 2 Wind Pmax	2022 Summer Peak Stability Total Pgen	2022 Summer Peak Stability Total Pmax	2022 Summer Peak Stability Wind Pgen	2022 Summer Peak Stability Wind Pmax	Change in Total Pgen
534	SUNC	1,304	2,029	78	439	1,306	2,283	91	434	0%
531	MIDW	136	408	33	261	136	249	36	102	0%
536	WERE	6,744	7,740	0	0	6,894	7,740	46	150	2%
526	SPS	7,424	8,605	47	834	7,411	8,374	57	879	0%
525	WFEC	1,536	2,673	8	200	1,538	2,616	50	274	0%
524	OKGE	7,389	9,306	99	1,141	7,405	9,194	105	882	0%
520	AEPW	10,706	16,799	73	388	10,695	16,670	65	214	0%
541	KCPL	4,788	5,342	240	308	4,786	5,342	240	308	0%
540	GMO	1,343	2,028	60	170	1,337	2,028	60	170	0%
545	INDN	216	288	0	0	216	288	0	0	0%
515	SWPA	2,031	2,564	52	122	2,031	2,564	52	122	0%
502	CLEC	3,609	4,617	0	0	3,610	4,617	0	0	0%
351	EES	30,260	42,202	0	0	30,262	42,202	0	0	0%
503	LAFA	310	465	0	0	310	465	0	0	0%
504	LEPA	128	211	0	0	128	211	0	0	0%
523	GRDA	1,315	1,532	0	0	1,349	1,532	0	0	3%
527	OMPA	248	197	0	0	214	197	0	0	-14%
542	KACY	594	961	0	0	594	961	0	0	0%
544	EMDE	1,203	1,460	0	0	1,204	1,460	0	0	0%
546	SPRM	998	1,160	0	0	998	1,160	0	0	0%
330	AECI	4,930	5,622	0	0	4,917	5,622	0	0	0%
640	NPPD	3,123	4,687	22	345	3,123	4,687	22	345	0%
645	OPPD	3,506	3,990	12	60	3,506	3,975	12	45	0%
	Total	**93,843**	**124,886**	**724**	**4,268**	**93,971**	**124,436**	**836**	**3,925**	0%

2.2 Transmission Topology Changes

The Stability Package load flow cases were compared with those of Build 2 scenario cases for transmission topology changes in the 230 kV and above voltage level networks within the SPP area.

In all comparisons, no major changes were observed except that in a Build 2 case the Longwood (508809) – El Dorado (337562) 345 kV line is tapped at Sarpet (337376) substation and is connected to the 230 kV network through a step down transformer. In the Stability Package load flow cases, this line is not tapped at Sarpet. It is assumed that this change in configuration will not affect the case since this line is located far from the GBX Project, and hence it was not modeled in the Stability Package cases.

Furthermore, in the 2022 Summer Peak stability load flow case, a Spearville – Jaybird 345 kV line connected to the Moore county 138 kV substation as shown in Figure 2-1 was found. This line was not found in any of the Build 2 or ITP cases. Therefore, to make the stability case consistent with the load flow cases used for the steady state analysis a conservative approach was taken. The line and the three winding transformer from the 2022 Summer Peak Stability were removed from the model.

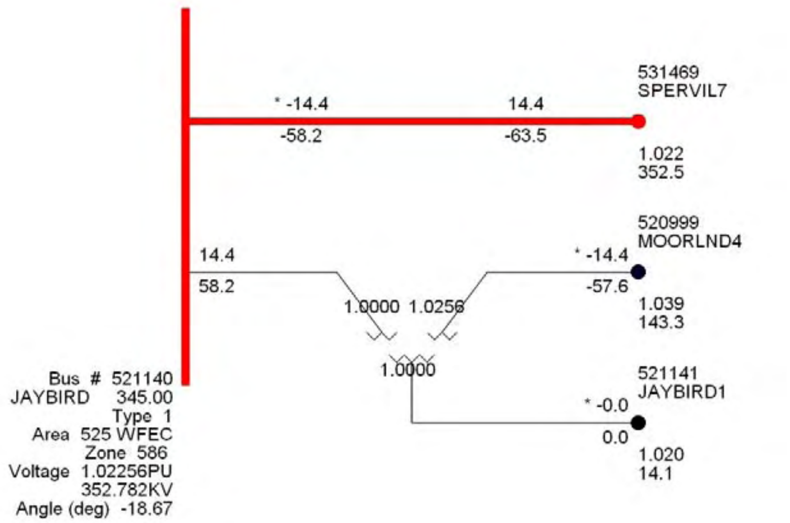

Figure 2-1: Spearville – Jaybird 345 kV Line (2022 Summer Peak)

Figure 2-2 shows the transmission topology around the Hitchland and Spearville area in the 2017 Summer Peak Stability Package case. Note that the northern part of the Group 2 Priority Projects (called the V-plan) is not modeled according to the latest configuration. For example, the Thistle substation is still named as Flat Ridge. This load flow case was modified to represent the latest expected configuration by adding the following projects:

- The Group 2 Priority Projects were updated to represent the latest information provided by ITC to SPP[7]

[7] This configuration was found to be updated in SPP's ITP cases

- The Hitchland 345 kV substation is expanded to represent the latest information provided by SPS (i.e. a Hitchland 2 substation was added to the system.)
- Additional corrections included:
  - Transformer at Thistle connected to Medicine Lodge is kept out of service
  - Line reactors along the lines from Hitchland – Woodward were initially wrongly placed on the line section of Hitchland 1 to Hitchland 2 substations. These reactors were moved on to the Hitchland – Woodward line section

Figure 2-3 shows the transmission topology around the Hitchland and Spearville area in the modified 2017 Summer Peak Stability Package. Similarly, these changes are also applied to 2017 Light Load and 2022 Summer Peak cases.

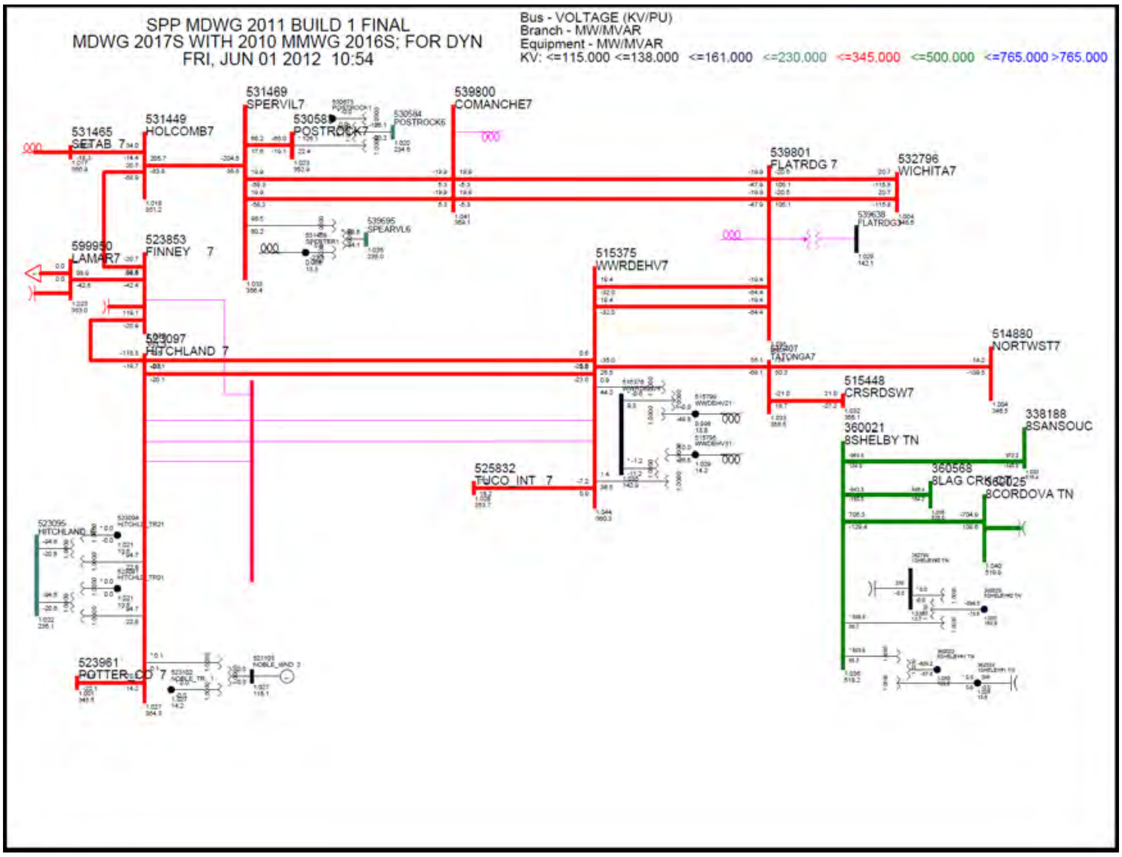

Figure 2-2: Transmission Topology around Hitchland and Spearville – 2017 Summer Peak Stability Case

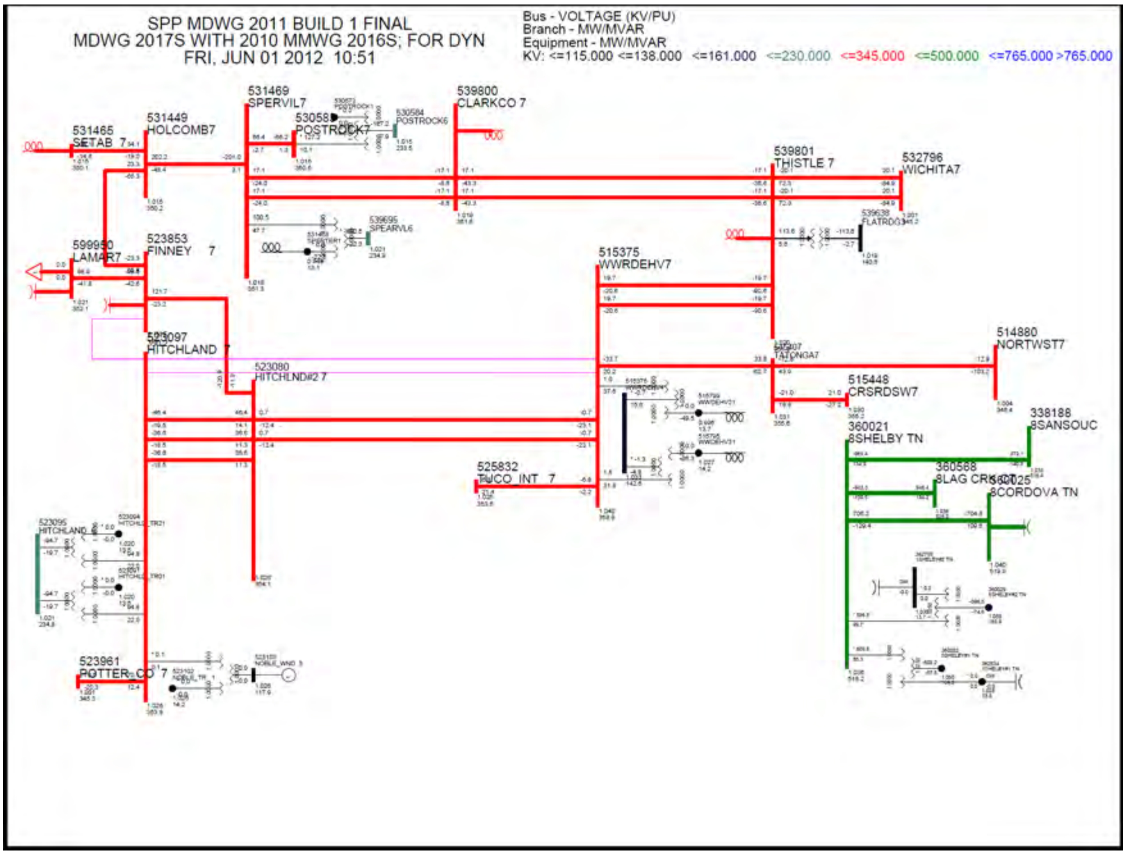

Figure 2-3: Transmission Topology around Hitchland and Spearville – 2017 Summer Peak Modified Stability Case

2.2.1 MISO Multi Value Projects

The following projects have been added to the system to reflect MISO's Multi Value Projects (MVP) near the project injection locations as shown in Figure 2-4 and Figure 2-5.

- Ottumwa – MO wind zone – Adair 345 kV lines
- Adair 345 kV/161 kV transformer
- Palmyra Tap – Palmyra 345 kV line
- Quincy – Meredosia – WZ IL – Pawnee – Pana – Mt Zion – Kansas – Sugar Creek 345 kV lines
- 345 kV/138 kV transformers at Quincy (1), Pawnee (2), Pana (1) and Mt Zion (1)
- Greentown – Brook Stone 765 kV line
- Brook Stone 765 kV/345 kV transformer
- Brook Stone – Reynolds – Burr Oak – Hiple 345 kV lines
- Robinson Park – Weeds Lake 345 kV line is tied to Hiple

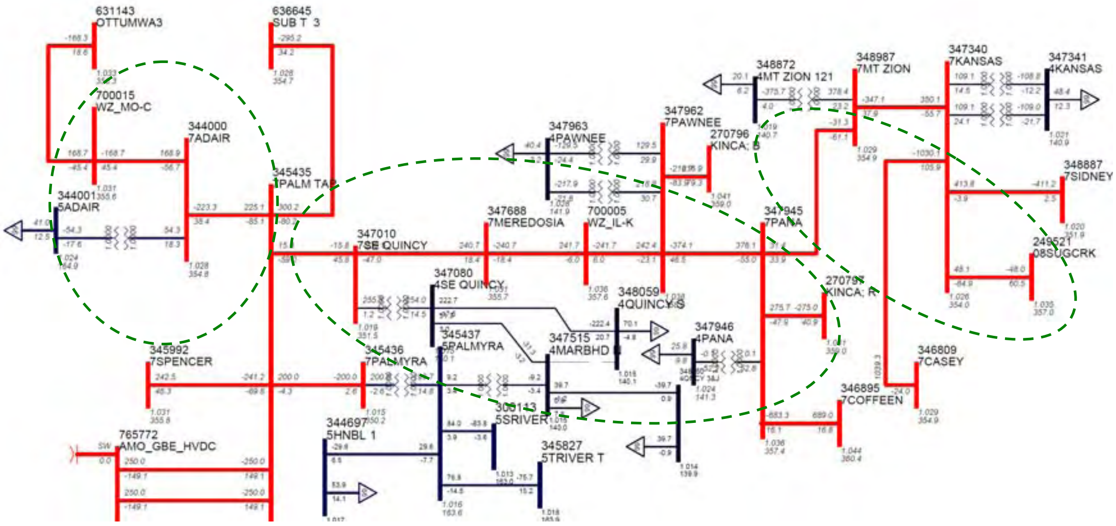

Figure 2-4: MISO Multi Value Projects (MVP) – 1

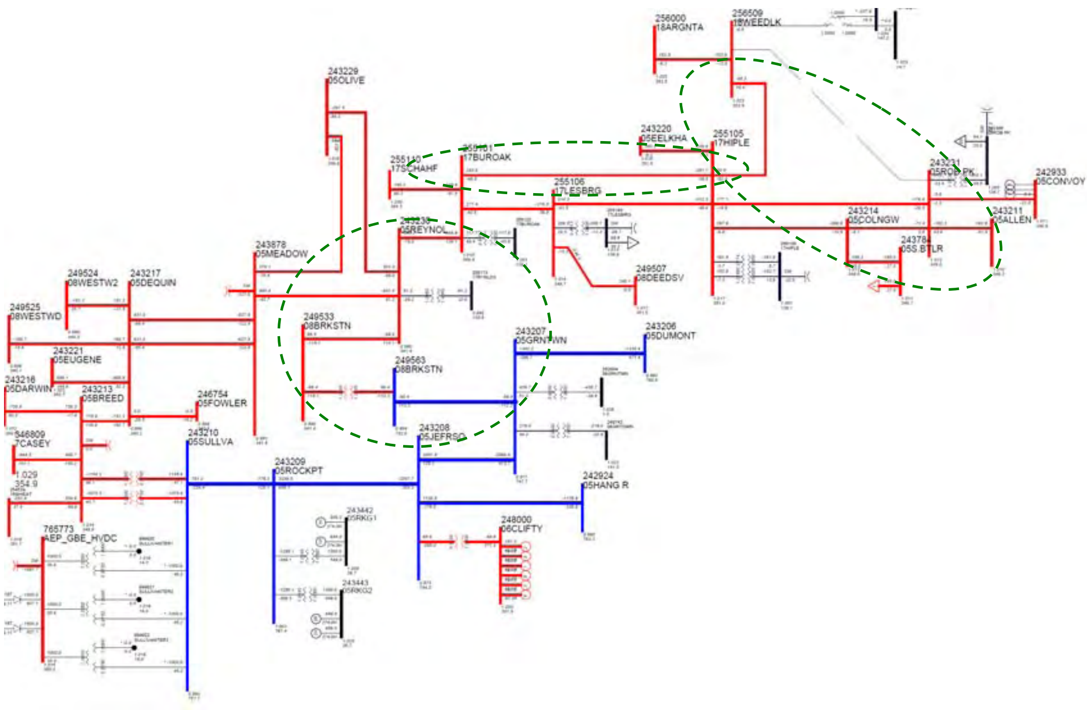

Figure 2-5: MISO Multi Value Projects (MVP) – 2

These projects are not the entirety of the MISO MVP, but a selection of the projects that are located in the area of influence of the GBX.

The next section presents the details of the GBX Project addition on top of these modified Stability Package load flow cases.

2.3 Grain Belt Express Project Addition

The Grain Belt Express project addition was done in two steps: (1) HVDC line addition and, (2) Wind Turbine Generation (WTG) addition. The modeling of the GBX project is similar to that done in the Steady State models except that the project's required reactive compensation at the converter stations and the collector system representation were modified as described in this section.

2.3.1 HVDC Line Addition

The GBX HVDC project was modeled as a three-terminal HVDC bi-pole originating at Clark County 345 kV substation (SPP) and delivering 500 MW at Palmyra Tap 345 kV substation (AMMO) and remaining 3,000 MW at Sullivan 345 kV substation (AEP). The inverter at Sullivan substation is connected to a new 345 kV substation and then to 765 kV network through three 765/345 kV transformers. The static reactive compensation at the converter stations is modeled in several steps of 275 MVAr units as described below. Note that the reactive compensation[8] at the rectifier station is slightly higher due to a higher rated windward converter station requirement in order to account for converter station and DC line losses.

Table 2-4 shows the available fault levels and the short circuit ratio (SCR)[9] calculated with 4,000 MW of additional wind generation. An SCR of 1.29 indicates an extremely weak interconnection point[10] at Clark County.

Table 2-4: Short Circuit Ratio at Clark County

	Without SC		With SC	
ClarkCo - 539800	Fault MVA	SCR[1]	Fault MVA	SCR[1]
2017 LL	4844.48	1.21	8406.06	2.10
2017 SP	5471.96	1.37	9034.25	2.26
2022 SP	5950.93	1.49	9514.52	2.38

1. SCR calculated for a wind capacity of 4,000 MW

During Clean Line Plains and Eastern (P&E) project studies, dynamic reactive support from synchronous condensers was proposed as one possible solution to handle the low short circuit levels (SCR of less than 2) at the point of interconnection. Taking advantage of the P&E project stability study evaluation, and given that the interconnection points for both P&E and GBX projects have similar short circuit levels (around 5,000 MVA); a dynamic reactive support of 900 MVAr synchronous condenser is proposed at the rectifier station. As shown in the table, the addition of a 900 MVAr synchronous condenser increased the SCR slightly higher than 2 under system intact conditions.

The following combination of reactive compensation at the converter stations is modeled as part of the addition of HVDC multi-terminal line:

- Reactive compensation at the Clark County rectifier station is modeled as 275x5 resulting in 1,375 MVAr of static switched shunt reactive compensation, and a

[8] The total reactive compensation is sized as approximately 60% of the MW flow along the HVDC line and this flow is higher at the rectifier station compared to the inverter station due to line losses.
[9] Short circuit ratio is a measure of strength of the interconnection point and is defined as the ratio of available fault MVA level to the capacity of the wind generation addition.
[10] In several studies, for example the CREZ reactive study, it was observed that SCR less than 2 is an indication of a weak interconnection point.

synchronous condenser of 900 MVAr resulting in a combined total of 2,275 MVAr. The dynamic parameters of this SC are provided in Appendix B

- Reactive compensation at the Sullivan inverter station is modeled as 275x7 MVAr resulting in a total of 1,925 MVAr of static switched shunts
- Reactive compensation at the Palmyra inverter station is modeled as 300x1 MVAr of static switched shunts

As will be discussed in later sections, withproper control schemes at the HVDC converter stations, it should be possible to reduce the size of the proposed 900 MVAr synchronous condenser. At this time it is anticipated that required dynamic support would be somewhere between 450 MVAr and 900 MVAr. Its final size will be dependent, among other things, on the converter station voltage control design.

Figure 2-6 shows the configuration of the three-terminal HVDC line and Table 2-5 through Table 2-9 show the multi-terminal bi-pole HVDC line parameters used in the load flow case. The tables show the modeling information for Pole 1, and are similar for Pole 2.

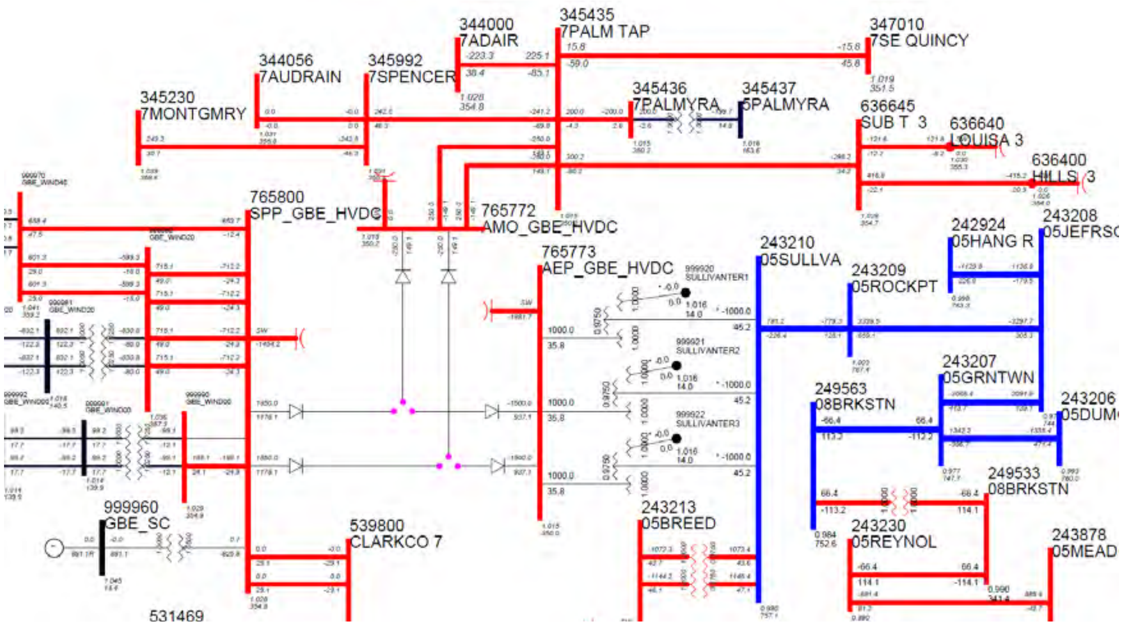

Figure 2-6: GBX HVDC Multi-Terminal Line

Table 2-5: HVDC Line Modeling in Load Flow Case – Showing Two Poles/Lines

Line Name	Control mode	Number of Converters	Number of DC buses	Number of DC links	Vcmode kV	(+ pole) inverter ac bus	(- pole) inverter ac bus
1	Power	3	6	5	300	765773	0
2	Power	3	6	5	300	765773	0

Table 2-6 Converter Parameters – Showing for Pole 1

Converter Number	Bus Number	Bus Name	Pole (Pos./Neg.)	Min (deg)	Max (deg)	Setval (kV/amps/MW)	Nb	Ebase (kV)
1	765800	SPP_GBE_HVDC345.00	1	5	24	1850	1	345
2	765772	AMO_GBE_HVDC345.00	1	15	25	-250	1	345
3	765773	AEP_GBE_HVDC345.00	1	15	25	600	1	345

Table 2-7 Converter Parameters (Contd.) – Showing for Pole 1

Converter Number	Bus Number	Rc (ohms)	Xc (ohms)	Transformer Ratio (p.v.)	Tap (pu)	Tap Min (pu)	Tap Max (pu)	Tap Step (pu)	Margin (pu)	Particip. factor
1	765800	0	26.42	1.5819	1	0.85	1.15	0.00625	0	1
2	765772	0	185.3	1.5572	1.03125	0.85	1.15	0.00625	0	1
3	765773	0	29.93	1.5342	1.01875	0.85	1.15	0.00625	0	1

Table 2-8 DC Bus Numbers – Showing for Pole 1

DC Bus	DC bus Name	Converter Bus	Area Number	Zone Number	Owner Number	RG (ohms)	2nd DC Bus
1	DC_RECT	765800	534	1529	1	9999	0
2	DC_RECT_P	None	534	1529	1	9999	0
3	DC_INV2_P	None	534	1529	1	9999	0
4	DC_INV1	765772	356	1330	1	9999	0
5	DC_INV2	765773	205	1252	1	9999	0
6	DC_INV1_P	None	534	1529	1	9999	0

Table 2-9 DC Link Parameters – Showing for Pole 1

DC Link	From DC Bus	From DC Name	To DC Bus	To DC Name	Id	Metered (From/To)	RDC (ohms)	LDC-Mh
1	1	DC_RECT	2	DC_RECT_P	1	1	0.02	500
2	2	DC_RECT_P	6	DC_INV1_P	1	1	9.134	0
3	6	DC_INV1_P	3	DC_INV2_P	1	1	3.619	0
4	3	DC_INV2_P	5	DC_INV2	1	1	0.02	500
5	6	DC_INV1_P	4	DC_INV1	1	1	0.02	500

2.3.2 Wind Turbine Generation Addition

2.3.2.1 Collector System Representation

At the time of the stability study, updated information was available regarding the possible wind generating plant locations. This section describes the updated collector system representation used for stability studies.

The collector system layout is preliminary and is based on analytical work performed by Clean Line to determine high-potential wind sites dictated by resource potential and environmental factors. Figure 2-7 shows the geographic locations where WTG could be developed that could access the GBX Project along with their corresponding sizes. It should be highlighted that this figure is neither final nor an exhaustive analysis of viable wind sites and was provided by Clean Line in order to simulate a potential collector system model.

Around 1,278 MW of potential generation are available within approximately 10 miles of the rectifier station. The other circles show other viable wind resource areas at farther distances from the rectifier station along with the associated potential megawatts within each area.

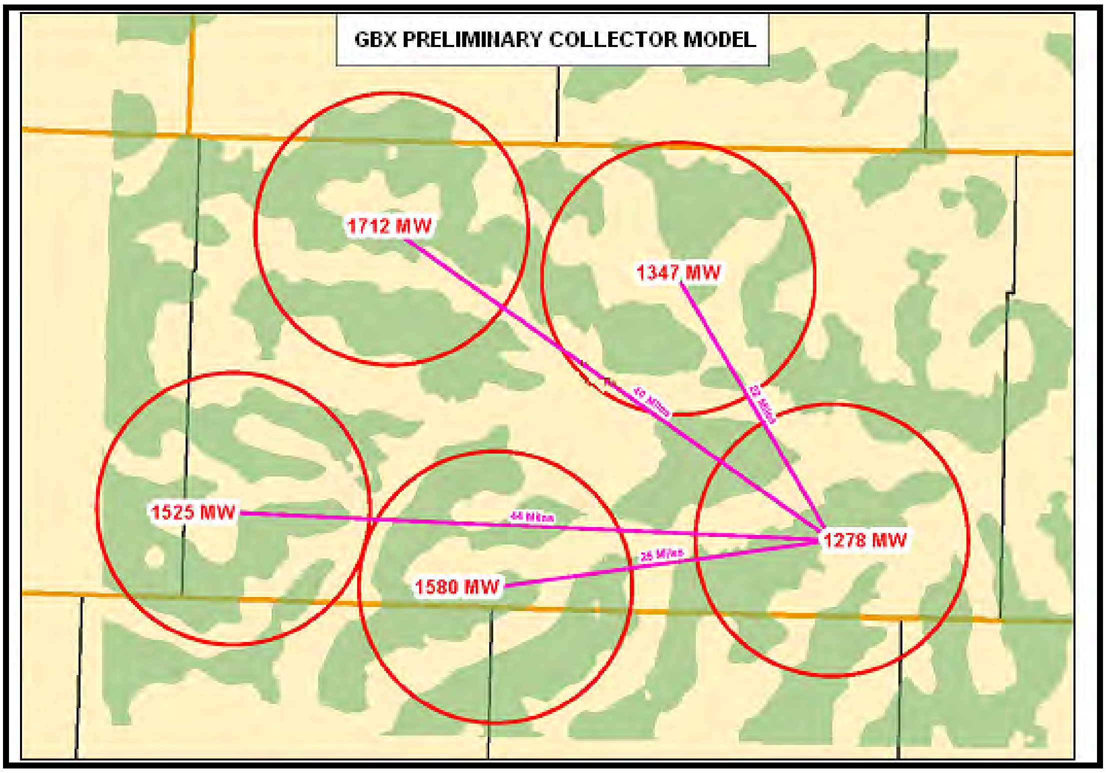

Figure 2-7: GBX Preliminary Draft Collector System – Potential Wind Locations

For the purposes of stability studies, Siemens PTI recommended modeling only Type 3 (doubly fed induction generators) and Type 4 (full converter) WTG's in each of the renewable resource areas. The developed model involves a 345 kV transmission network as a backbone to move power from the wind areas to the rectifier station. The transmission is gradually stepped down near the WTG to match its voltage level. Conceptually, Figure 2-8 shows the wind circles with a transmission system overlay comprised of 345 kV, 138 kV, 34.5 kV lines. The voltage levels of the Type 3 and Type 4 WTG's are also shown. The 345 kV transmission facilities from the rectifier station are assumed to have lengths of 1-mile, 20-miles and 40-miles depending on the location of the resources. The number and sizing of the transmission elements are chosen to provide a viable path for the WTG's under N-1 conditions to transfer maximum possible generation to the rectifier station.

Enough WTG was modeled in order to ensure that collector system and HVDC line and converter losses are accounted for with a resultant delivery of 3,000 MW to AEP and remaining 500 MW to AMMO, while maintaining close to zero flows across the interconnection between SPP and the GBX rectifier station.

Figure 2-9 shows the proposed collector system representation modeled in the 2017 Summer Peak case with the dispatched generation levels at three sites (1-mile, 20-mile, and 40-mile) for a total dispatched level of 3,756 MW.

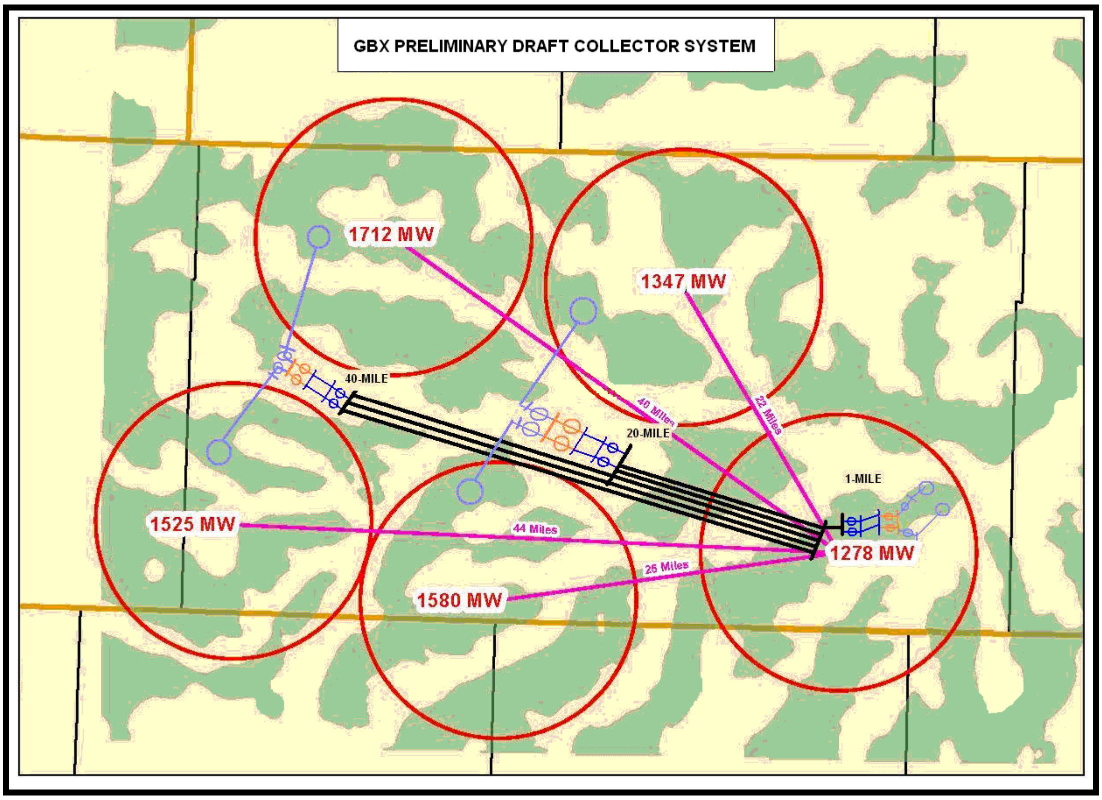

Figure 2-8: Proposed Collector System Representation for the Study

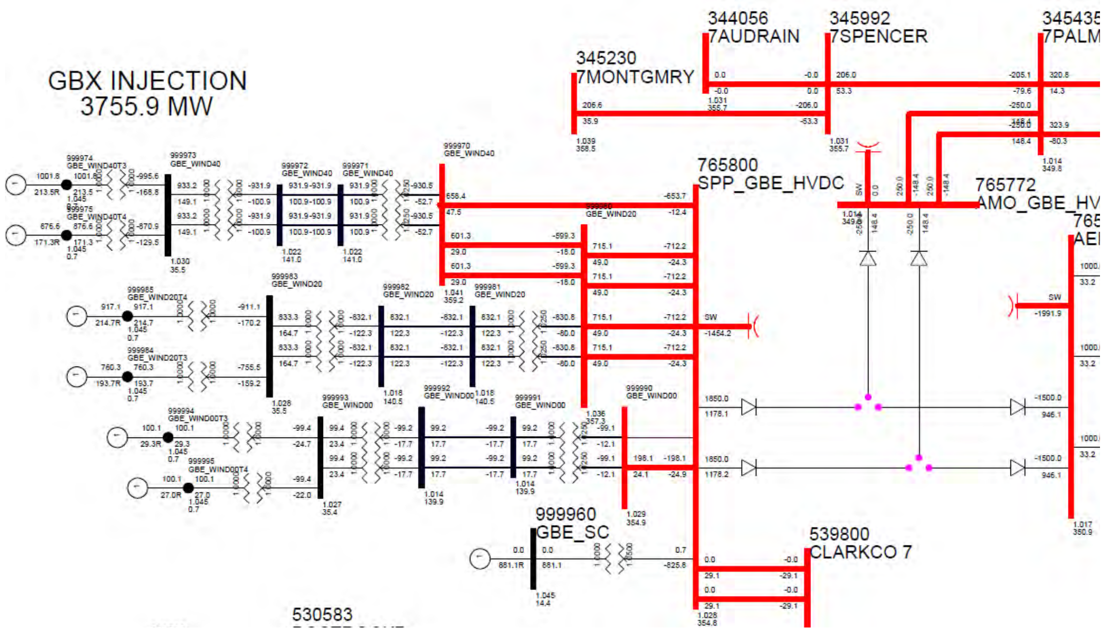

Figure 2-9: Proposed Collector System Modeled in 2017 Summer Peak Case

Table 2-10 shows the 345 kV line parameters used for the study. The 138 kV network is currently modeled using zero impedance lines, as it is typically the case in these studies where the actual location of the wind generation plants is unknown. Future interconnection studies for the individual wind plants, once they are identified, will incorporate detailed modeling of the 138 kV lines and equivalent 34.5 kV collector system, and will identify any additional requirements to ensure stable operation of the plants.

Table 2-11 shows the assumed ratings of collector system transformers used in the study.

Table 2-10: 345 kV Line Parameters

	R (pu)	X (pu)	B (pu)	MVA	Amp
1 mile	0.00003	0.00046	0.00940	1631	2729
20 mile	0.00059	0.00927	0.18584	1631	2729
40 mile	0.00118	0.01853	0.37168	1631	2729

Table 2-11: Assumed Ratings of Collector System Transformers

Site	T/F	MVA	Z (pu)	X/R
Site 1	345/138 kV	140	8%	35
1-mile	138/34.5 kV	140	8%	35
Site 2	345/138 kV	1288	8%	35
20-mile	138/34.5 kV	1288	8%	35
Site 3	345/138 kV	1396	8%	35
40-mile	138/34.5 kV	1396	8%	35

Table 2-12 shows the dispatched generation and the mix of WTG type at each site for the 2017 Summer Peak case. Similarly, Table 2-13 and Table 2-14 show totals for the 2017 Light Load and the 2022 Summer Peak cases, respectively. Two key points to be noted:

- Around 5% of the total generation is dispatched at Site 1, 45% of total generation is dispatched at Site 2 and 50% of total generation is dispatched at Site 3, thus there is a bias towards remote generation

- Though the mix of generation varies between individual sites, the total generation is split approximately 50% between Type 3 and Type 4 WTG's

Table 2-12: WTG at Each Site of the Proposed Collector System – 2017 Summer Peak

Pgen	Site 1	Site 2	Site 3	Total
MW	200	1677	1878	3756
% of Total	5%	45%	50%	100%
Distance	1 mile	20 miles	40 miles	

	Pgen	Site 1	Site 2	Site 3	Total
Type3	MW	100	760	1002	1862
Type4	MW	100	917	877	1894
Type3	%	50%	45%	53%	50%
Type4	%	50%	55%	47%	50%

Table 2-13: WTG at Each Site of the Proposed Collector System – 2017 Light Load

Pgen	Site 1	Site 2	Site 3	Total
MW	200	1677	1878	3756
% of Total	5%	45%	50%	100%
Distance	1 mile	20 miles	40 miles	

	Pgen	Site 1	Site 2	Site 3	Total
Type3	MW	100	760	1002	1862
Type4	MW	100	917	877	1894
Type3	%	50%	45%	53%	50%
Type4	%	50%	55%	47%	50%

Table 2-14: WTG at Each Site of the Proposed Collector System – 2022 Summer Peak

Pgen	Site 1	Site 2	Site 3	Total
MW	200	1677	1878	3756
% of Total	5%	45%	50%	100%
Distance	1 mile	20 miles	40 miles	

	Pgen	Site 1	Site 2	Site 3	Total
Type3	MW	100	760	1002	1862
Type4	MW	100	917	877	1894
Type3	%	50%	45%	53%	50%
Type4	%	50%	55%	47%	50%

2.3.2.2 Generation Type

The Type 3 doubly-fed induction generators (DFIG) and the Type 4 full-scale converter connected asynchronous generators are considered to represent the GBX Project wind turbine generation. The Type 3 generators are represented by an equivalent 1.5 MW GE wind turbine driven generator and the Type 4 generators are represented by an equivalent 2.5 MW GE wind turbine driven generator. The dynamic model parameters of these generators are shown in Appendix B.

The equivalent Type 3 and Type 4 WTG's were modeled at each site resulting in a total of 6 generators in load flow models as shown in Table 2-15, Table 2-16, and Table 2-17. The dispatched generation varies slightly among the three cases. It is assumed that around 95% of installed capacity (Pmax) is being dispatched. Table 2-18 shows the generator transformer data for Type 3 and Type 4 WTG.

Table 2-15: WTG Dispatch – 2017 Summer Peak Case

Bus	Type	# Units	Pgen	Pmax	Qmin	Qmax	Mbase	Pgen/Pmax
999974	3	701	1001.8	1052	-509	509	1171	95%
999975	4	368	876.6	920	-442	442	1104	95%
999984	3	532	760.3	798	-386	386	888	95%
999985	4	385	917.1	963	-462	462	1155	95%
999994	3	70	100.1	105	-51	51	117	95%
999995	4	42	100.1	105	-50	50	126	95%
			3755.9	**3942**			**4561**	

Table 2-16: WTG Dispatch – 2017 Light Load Case

Bus	Type	# Units	Pgen	Pmax	Qmin	Qmax	Mbase	Pgen/Pmax
999974	3	701	1001.8	1052	-509	509	1171	95%
999975	4	368	876.5	920	-442	442	1104	95%
999984	3	532	760.3	798	-386	386	888	95%
999985	4	385	917.1	963	-462	462	1155	95%
999994	3	70	100.1	105	-51	51	117	95%
999995	4	42	100.1	105	-50	50	126	95%
			3755.8	**3942**			**4561**	

Table 2-17: WTG Dispatch – 2022 Summer Peak Case

Bus	Type	# Units	Pgen	Pmax	Qmin	Qmax	Mbase	Pgen/Pmax
999974	3	701	1001.8	1052	-509	509	1171	95%
999975	4	368	876.6	920	-442	442	1104	95%
999984	3	532	760.3	798	-386	386	888	95%
999985	4	385	917.1	963	-462	462	1155	95%
999994	3	70	100.1	105	-51	51	117	95%
999995	4	42	100.1	105	-50	50	126	95%
			3755.9	**3942**			**4561**	

Table 2-18: Generator Transformer Data for each WTG type

	Unit MVA	Z (pu)	X/R
Type 3	1.75	5.75%	7.5
Type 4	2.8	6%	7.5

The project wind generation is injected into the GBX Project AC substation with a scheduled transfer of 3,500 MW through the three-terminal HVDC bi-pole link. The injected wind generation (approximately 3,756 MW) accounts for losses in the collector system, DC line losses, and losses in the converter stations such that exactly 3,000 MW (measured at inverter station) is being injected into the AEP balancing area and 500 MW (measured at inverter station) into AMMO balancing area. In order to balance the injected project generation, six balancing areas within PJM are considered for scaling down of generation such that 3,000 MW of project generation is being injected. Similarly, two balancing areas within MISO are considered for scaling down of generation in order to inject 500 MW of project generation.

Table 2-19 shows the generation scaling for 2017 Light Load condition. The PJM areas are scaled down by around 8.7% while the MISO areas are scaled down by around 5.9%, against their combined generation dispatch (Pgen). Table 2-20 and Table 2-21 show the generation scaling for 2017 Summer Peak and 2022 Summer Peak conditions, respectively.

Table 2-19 Selected Balancing Areas for Generation Scale Down – 2017 Light Load

		Pre-project	Post-project
Area	Name	Total Pgen	Total Pgen
201	AP	5378.9	4854.8
202	FE	5461.7	5093.1
205	AEP	9787.6	8960
209	DAY	1996.4	1956.9
215	DLCO	2228	2001.2
222	CE	9550.2	8583.9
		34402.8	31449.9
	3000	**8.7%**	

		Pre-project	Post-project
Area	Name	Total Pgen	Total Pgen
356	AMMO	3152.7	2968.7
357	AMIL	5384.9	5092.3
		8537.6	8061
	500	**5.9%**	

Table 2-20 Selected Balancing Areas for Generation Scale Down – 2017 Summer Peak

		Pre-project	Post-project
Area	Name	Total Pgen	Total Pgen
201	AP	9973	9601.5
202	FE	13675.2	13156.5
205	AEP	24159.7	23358
209	DAY	3761.3	3628.8
215	DLCO	3296.7	3173.5
222	CE	26083.8	25141.3
		80949.7	78059.6
	3000	**3.7%**	

		Pre-project	Post-project
Area	Name	Total Pgen	Total Pgen
356	AMMO	9136.2	8926
357	AMIL	11703.3	11455.8
		20839.5	20381.8
	500	**2.4%**	

Table 2-21 Selected Balancing Areas for Generation Scale Down – 2022 Summer Peak

		Pre-project	Post-project
Area	Name	Total Pgen	Total Pgen
201	AP	10345.1	9977.3
202	FE	13557.7	13065.7
205	AEP	25117.7	24326.7
209	DAY	4067.8	3930.6
215	DLCO	3322.8	3204.3
222	CE	28123.4	27149.7
		84534.5	81654.3
	3000	**3.5%**	

		Pre-project	Post-project
Area	Name	Total Pgen	Total Pgen
356	AMMO	9574.3	9363.2
357	AMIL	12044.2	11798.5
		21618.5	21161.7
	500	**2.3%**	

Figure 2-10 shows the final topology with the GBX project modeled in the 2017 Sumer Peak Case.

Figure 2-11 and Figure 2-12 show the similar representation for 2017 Light Load and 2022 Summer Peak cases, respectively. This final configuration includes a 900 MVAr synchronous condenser that displaces an equal amount of static reactive compensation at the Clark County 345 kV substation, as discussed in this report.

The dynamic model parameters of the HVDC line and WTG are presented in Appendix B.

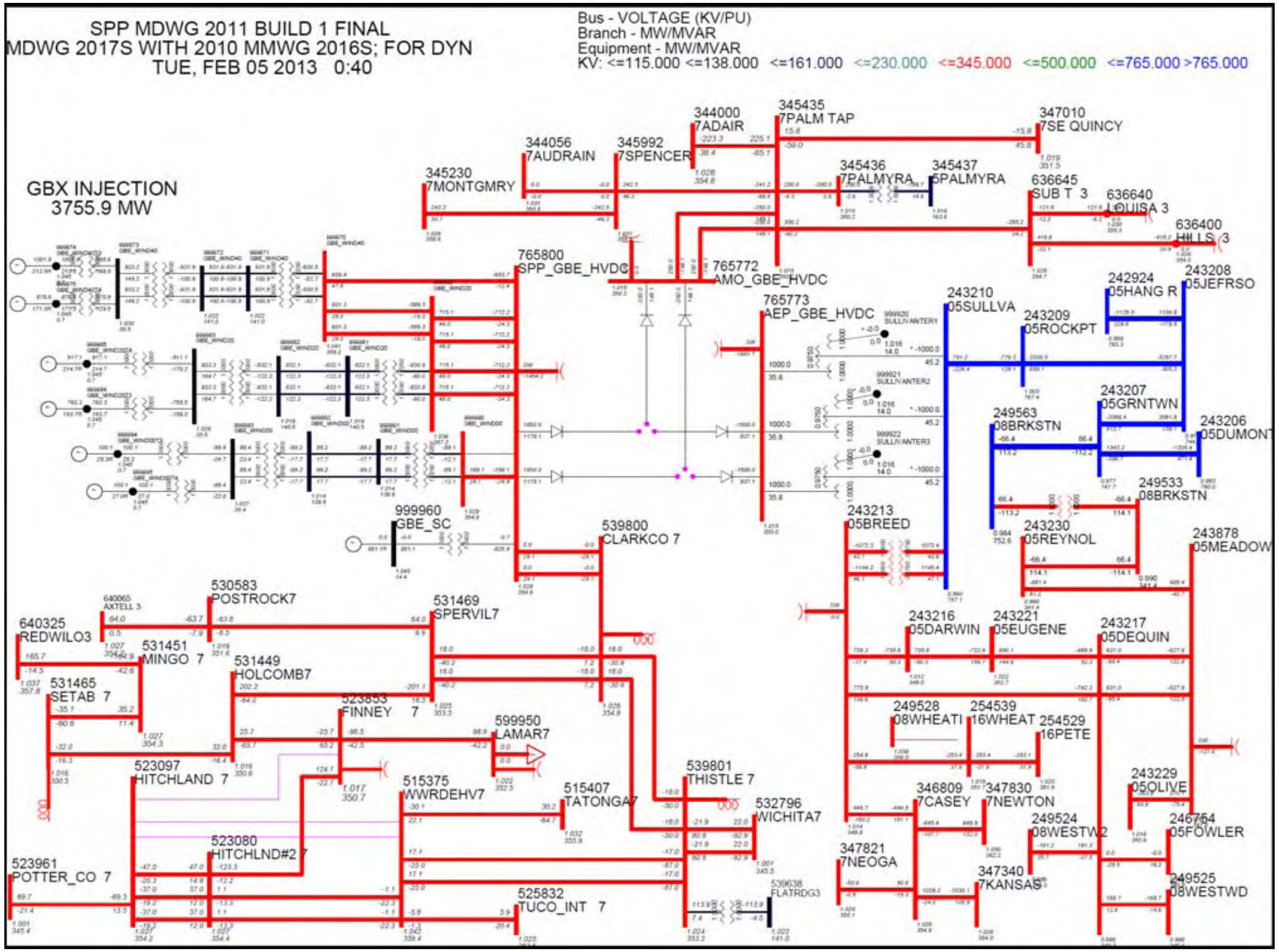

Figure 2-10: 2017 Summer Peak – Topology with GBX Project

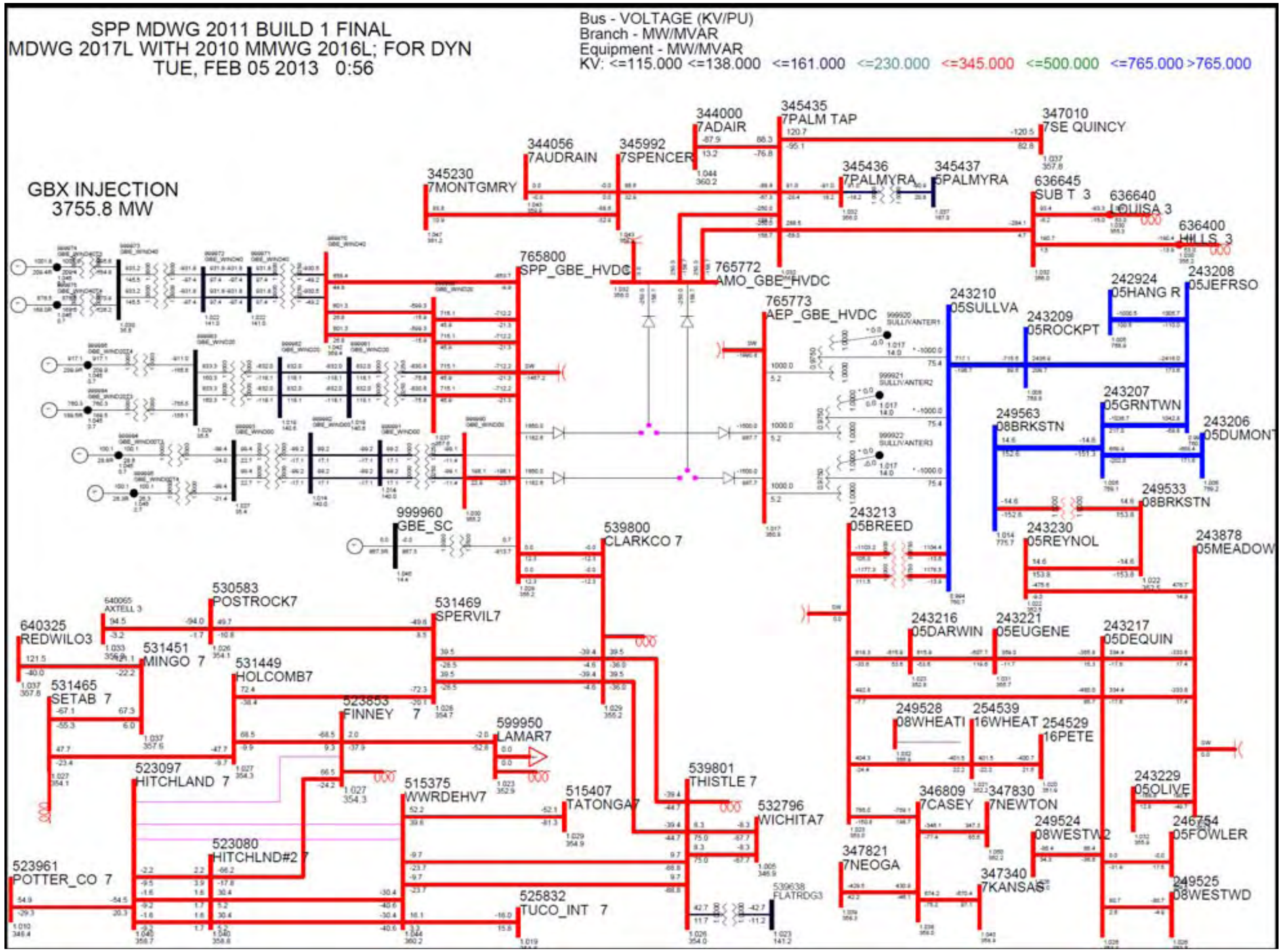

Figure 2-11: 2017 Light Load – Topology with GBX Project

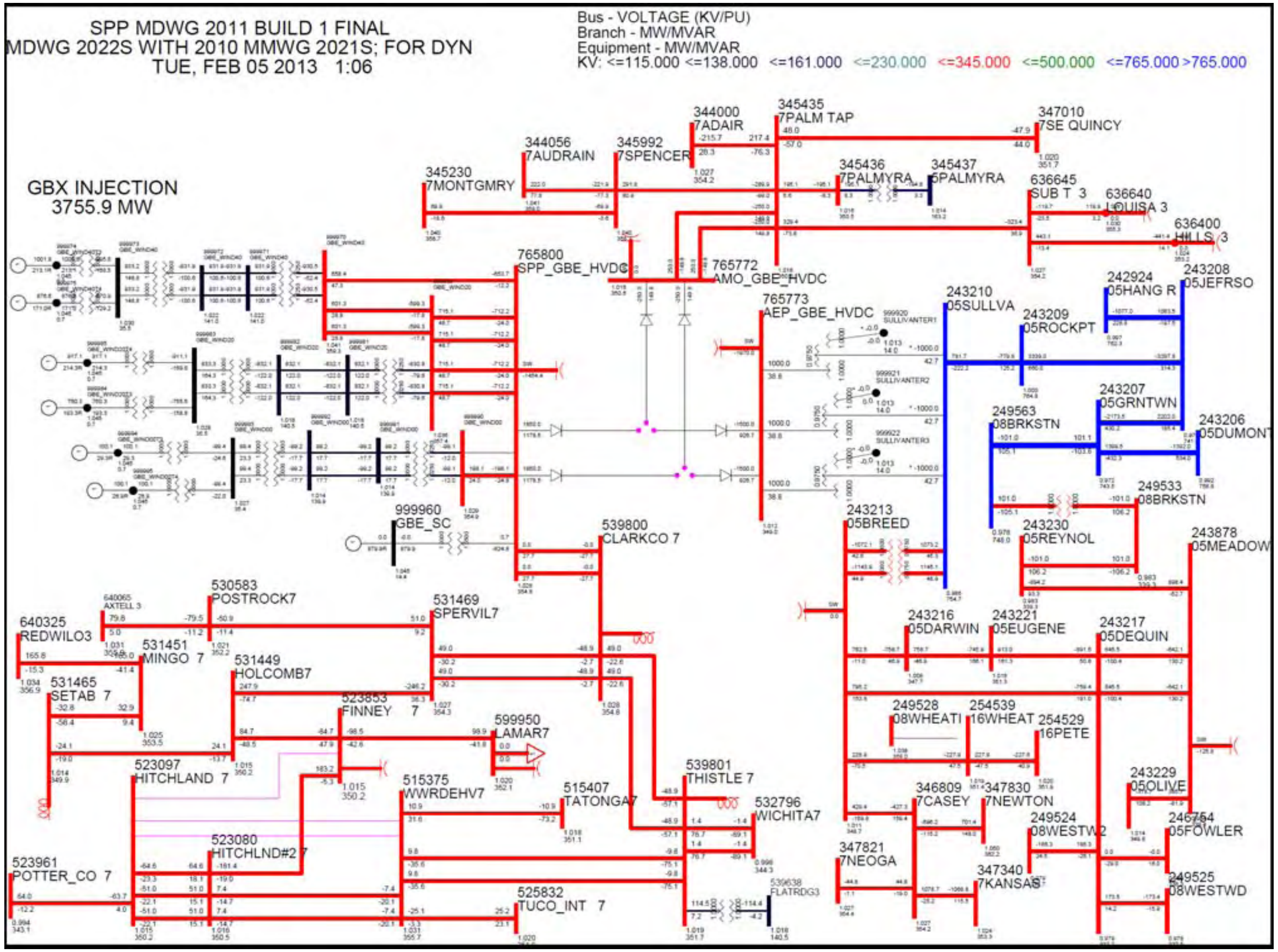

Figure 2-12: 2022 Summer Peak – Topology with GBX Project

Section
3

Study Methodology

This section presents the methodology and assumptions used for the stability study followed by the performance criteria used in the assessment of the dynamic behavior of the GBX Project for selected disturbances in its vicinity.

3.1 Assumptions

The following assumptions were used for this study:

- The dynamic simulations were performed using PSS®E Revision 30
- The 2011 Build 1 Stability Package provided by SPP was used for all simulations
- One quarter of a system cycle (0.004167 sec) was used as the time step in all simulations
- All simulations were run for 10 seconds
- Major generating units electrically close to the location where disturbances were applied (approximately up to 10 buses) were monitored for dynamic performance of the study area[11]. In particular,
  - Terminal voltages and rotor angles were monitored for all synchronous generating units in areas listed in Table 3-1
  - For other areas not shown in the table (e.g. AEP, AMMO), selected generating units listed in Table 3-2 and Table 3-3 were added for monitoring their terminal voltages and rotor angles

Table 3-1: Areas including all Synchronous Units for Monitoring

AREA	NAME	AREA	NAME
523	GRDA	540	GMO
524	OKGE	541	KCPL
526	SPS	542	KACY
531	MIDW	640	NPPD
534	SUNC	330	AECI
536	WERE	351	EES

[11] Assumption is that if none of the units at this electrical distance from the selected disturbance location loses synchronism with SPP system then no other generating units located beyond this point will lose synchronism

Table 3-2: Other Units included for Monitoring – Around Palmyra

Location	Units included for monitroing	Area
Audrain	Units at 344061, 344062, 344063	356 AMMO
Callaway	Unit at 344225	356 AMMO
Kinmundy	Unit at 344876	356 AMMO
Labody	Units at 344894, 344895	356 AMMO
Meramad	Units at 345132, 345156	356 AMMO
Osage	Unit at 345400	356 AMMO
Peno Creek	Units at 345441	356 AMMO
Rush Island	Unit at 345670	356 AMMO
Sioux	Units at 345756, 345765	356 AMMO
Venice	Unit at 345882	356 AMMO
Raccoon Ck	Unit at 345994	356 AMMO
Goose Creek	Unit at 345998	356 AMMO
Keokuk	Unit at 344863	356 AMMO
Alsey	Unit at 346516	357 AMIL
Avena	Unit at 346573	357 AMIL
Coffeen	Unit at 346897	357 AMIL
Gibson City	Unit at 347112	357 AMIL
Grand Tower	Unit at 347170	357 AMIL
Holland Energy	Unit at 347231	357 AMIL
Hutsonville	Unit at 347271	357 AMIL
RELU	Unit at 347819	357 AMIL
Newton	Units at 347832	357 AMIL
Clinton	Unit at 349101	357 AMIL
Vermilion	Unit at 349109	357 AMIL
WoodRiver	Unit at 349115	357 AMIL
Havana	Unit at 349121	357 AMIL
Tilton	Unit at 349122	357 AMIL
Baldwin	Unit at 349126	357 AMIL
Prairie State	Unit at 349129	357 AMIL
Edwards	Unit at 349632	357 AMIL
Duck Ck	Unit at 349633	357 AMIL
Railsplitter	Unit at 349724	357 AMIL

Table 3-3 Other Units included for Monitoring – Around Sullivan

Location	Units included for monitroing	Area
Rockport	Units at 243442, 243443	205 AEP
Petersburg	Units at 254811-254814	216 IPL
Gibson	Units at 251861-251865	208 DEM
Wheatland	Units at 251897-251900	208 DEM
Merom	Units at 248773	207 HE
Clifty Ck	Units at 248000	206 OVEC
Trimble Co	Units at 324034 - 324041	363 LGEE
Cayuga	Units at 251849, 251850	208 DEM
Amos	Units at 242891 - 242893	205 AEP
Mountaineer	Units at 242894	205 AEP
Mitchel	Units at 243188, 243189	205 AEP
Muskingum	Unit at 242940	205 AEP
Lawrenceburg	Units at 243226	205 AEP
Tanner	Unit at 243233	205 AEP
Cook	Units at 243440, 243441	205 AEP
Conesville	Unit at 243622	205 AEP
Bigsandy	Units at 243763, 243764	205 AEP
Killen	Unit at 253038	209 DAY
Stuart	Unit at 253077	209 DAY

3.2 Fault Definitions

In general, the following faults were tested to assess the dynamic performance of generating units in the study area:

- Three-phase (3ph) bolted faults with normal clearing time and outage of faulted line
- Primary protection failure – Single Line to Ground (SLG) faults with delayed clearing time and outage of the faulted line
- Stuck breaker – Single Line to Ground (SLG) faults with delayed clearing time and outage of faulted line along with other lines as required

In particular, faults tested at the HVDC converter stations include:

- Three-phase bolted fault at 345 kV rectifier and inverter stations
  - Cleared in normal time (manual unblocking of both poles during simulation)
  - Cleared in normal time followed by single pole unblocking (manual unblocking during simulation)
  - Cleared in normal time followed by both poles blocked
- SLG fault with delayed clearing time (stuck breaker)

The fault clearing times for different types of faults and voltage levels are shown in Table 3-4. Note that the line reclosing sequence was not considered in fault definitions. The MTDC1T HVDC model was used to represent the GBX three-terminal HVDC line in all dynamic simulations. This model is a well-tested PSS®E table driven model. The model provides the flexibility of manual unblocking of the pole by changing the model ICONs. Please refer to PSS®E manual for additional details of the model.

Table 3-4: Fault Clearing Times

Type	Description	500 kV and above (Cycles)	345 kV and below (Cycles)
3PH	3ph, Normal clearing	4	5
SLG	SLG, delayed due to protection failure	13	16
SLG	SLG, delayed due to breaker failure	13	16

The fault sequence for 3ph faults cleared in normal time is carried out as:

- Three-phase bolted fault applied at bus terminal
- Fault is cleared in 4 or 5 cycles depending on voltage (refer to Table 3-4) and followed by tripping of the faulted line

The fault sequence for SLG faults cleared in delayed time due to primary system protection failure is carried out as:

- SLG fault applied at bus terminal
- Fault is cleared after 13 or 16 cycles depending on voltage (refer to Table 3-4) followed by tripping of the faulted line

The fault sequence for SLG faults cleared in delayed time due to a stuck breaker is carried out as:

- SLG fault applied at bus terminal
- Fault is cleared after 13 or 16 cycles depending on voltage (Table 3-4) followed by tripping the faulted line and any other lines as required

Table 3-5 shows a list of all studied three-phase faults with normal clearing. Table 3-6 shows all SLG faults (protection failure) considered in the study.

Table 3-5: List of Three-phase Faults – Normal Clearing

3 Phase Faults, Normal Clearing			
No	Type	Description	kV
1	3ph, both poles blocked	At Clark Co 765800, both poles are blocked	345
2	3ph, single pole recovery	At Clark Co 765800, one pole is recovered	345
3	3ph, both poles recovery	At Clark Co 765800, both poles are recovered	345
4	3ph, both poles blocked	At Sullivan 765773, both poles are blocked	345
5	3ph, single pole recovery	At Sullivan 765773, one pole is recovered	345
6	3ph, both poles recovery	At Sullivan 765773, both poles are recovered	345
7	3ph, both poles blocked	At Palmyra 765772, both poles are blocked	345
8	3ph, single pole recovery	At Palmyra 765772, one pole is recovered	345
9	3ph, both poles recovery	At Palmyra 765772, both poles are recovered	345
10	3ph, single pole recovery	the Palmyra inverter of the recovered pole is still	345
11	3ph, normal clearing	Clarck Co 539800 - Thistle 539801	345
12	3ph, normal clearing	Clark Co 539800 - Spearville 531469	345
13	3ph, normal clearing	Thistle 539801 - Witchita 532796	345
14	3ph, normal clearing	Thistle 539801 - Woodward 515375	345
15	3ph, normal clearing	Woodward 515375 - Tatonga 515407	345
16	3ph, normal clearing	Spearville 531469 - Holcomb 531449	345
17	3ph, normal clearing	Spearville 531469 - Postrock 530583	345
18	3ph, normal clearing	Spearville 345/230 kV TF (531469 - 539695)	345/230
19	3ph, normal clearing	Spearville 539695 - Mulgreen 539679	230
20	3ph, normal clearing	Postrock 530583 - Axtell 640065	345
21	3ph, normal clearing	Holcomb 531449 - Finney 523853	345
22	3ph, normal clearing	Holcomb 531449 - Setab 531465	345
23	3ph, normal clearing	Finney 523853 - Hitchland 523080	345
24	3ph, normal clearing	Finney 523853 - Lamar 599950	345
25	3ph, normal clearing	Setab 531465 - Mingo 531451	345
26	3ph, normal clearing	Mingo 531451 - Redwillow 640325	345
27	3ph, normal clearing	Sullivan 3wnd TF (243210-765773-999920)	765/345
28	3ph, normal clearing	Sullivan 765/345 kV TF (243210 - 243213)	765/345
29	3ph, normal clearing	Sullivan 243210 - Rockport 243209	765
30	3ph, normal clearing	Breed 243213 - Casey 346809	345
31	3ph, normal clearing	Breed 243213 - Darwin 243216	345
32	3ph, normal clearing	Breed 243213 - Dequine 243217	345
33	3ph, normal clearing	Breed 243213 - Wheat 254539	345
34	3ph, normal clearing	Rockport 243209 - Jefferson 243208	765
35	3ph, normal clearing	Palmyra 765772 - Palmyra tap 345435	345
36	3ph, normal clearing	Palmyra Tap 345435 - Sub T 636645	345
37	3ph, normal clearing	Palmyra Tap 345435 - Plamyra 345436	345
38	3ph, normal clearing	Palmyra Tap 345435 - Adair 344000	345
39	3ph, normal clearing	Palmyra Tap 345435 - Spencer 345992	345
40	3ph, normal clearing	Palmyra Tap 345435 - Se Quincy 347010	345

Table 3-6: List of SLG Faults – Protection Failure

SLG Faults Delayed Clearing (Protection Failure)			
No	Type	Description	kV
41	SLG, delayed clearing	Clarck Co 539800 - Thistle 539801	345
42	SLG, delayed clearing	Clark Co 539800 - Spearville 531469	345
43	SLG, delayed clearing	Thistle 539801 - Witchita 532796	345
44	SLG, delayed clearing	Thistle 539801 - Woodward 515375	345
45	SLG, delayed clearing	Woodward 515375 - Tatonga 515407	345
46	SLG, delayed clearing	Spearville 531469 - Holcomb 531449	345
47	SLG, delayed clearing	Spearville 531469 - Postrock 530583	345
48	SLG, delayed clearing	Spearville 345/230 kV TF (531469 - 539695)	345/230
49	SLG, delayed clearing	Spearville 539695 - Mulgreen 539679	230
50	SLG, delayed clearing	Postrock 530583 - Axtell 640065	345
51	SLG, delayed clearing	Holcomb 531449 - Finney 523853	345
52	SLG, delayed clearing	Holcomb 531449 - Setab 531465	345
53	SLG, delayed clearing	Finney 523853 - Hitchland 523080	345
54	SLG, delayed clearing	Finney 523853 - Lamar 599950	345
55	SLG, delayed clearing	Setab 531465 - Mingo 531451	345
56	SLG, delayed clearing	Mingo 531451 - Redwillow 640325	345
57	SLG, delayed clearing	Sullivan 3wnd TF (243210-765773-999920)	765/345
58	SLG, delayed clearing	Sullivan 765/345 kV TF (243210 - 243213)	765/345
59	SLG, delayed clearing	Sullivan 243210 - Rockport 243209	765
60	SLG, delayed clearing	Breed 243213 - Casey 346809	345
61	SLG, delayed clearing	Breed 243213 - Darwin 243216	345
62	SLG, delayed clearing	Breed 243213 - Dequine 243217	345
63	SLG, delayed clearing	Breed 243213 - Wheat 254539	345
64	SLG, delayed clearing	Rockport 243209 - Jefferson 243208	765
65	SLG, delayed clearing	Palmyra 765772 - Palmyra tap 345435	345
66	SLG, delayed clearing	Palmyra Tap 345435 - Sub T 636645	345
67	SLG, delayed clearing	Palmyra Tap 345435 - Plamyra 345436	345
68	SLG, delayed clearing	Palmyra Tap 345435 - Adair 344000	345
69	SLG, delayed clearing	Palmyra Tap 345435 - Spencer 345992	345
70	SLG, delayed clearing	Palmyra Tap 345435 - Se Quincy 347010	345

The stuck breaker faults are considered only at three substations as listed in Table 3-7. The breaker arrangements at the converter stations were not yet defined at the time of the study therefore, Siemens PTI defined these stuck breaker faults based on technical judgment as described below.

Table 3-7: List of SLG Faults – Stuck Breaker

SLG Fault, Delayed Clearing (Stuck Breaker)			
No	Type	Description	kV
71	SLG, delayed clearing	Fault at Rectifier, block the pole and trip line to collector system	345
72	SLG, delayed clearing	Fault at Sullivan, trip 3wnd and 2wnd transformers	765/345
73	SLG, delayed clearing	Fault at Palmyra Tap, trip lines to inverter station and to Palmyra	345

At Rectifier 345 kV substation

Figure 3-1 shows the assumed breaker and half representation shared by the HVDC line and the WTG projects. For a SLG fault on the line very close to the substation, the bus breaker (B3) operates in 5 cycles to try to clear the fault and the HVDC protection blocks the pole. The middle breaker (B2) is stuck thus the backup protection operates in 11 cycles to isolate the fault by tripping the line to the collector system of WTG. The total fault duration is 16 cycles. Note that this arrangement prevents a single stuck breaker from tripping both poles.

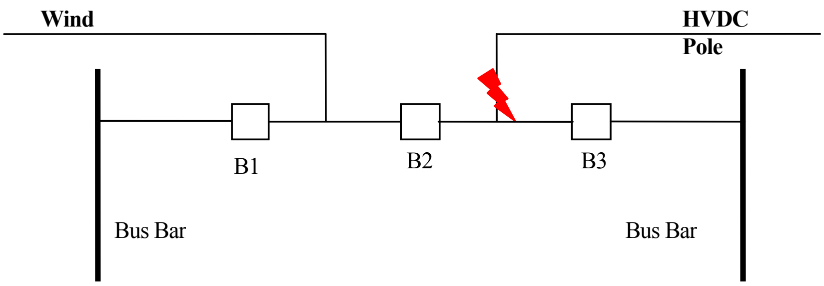

Figure 3-1: Assumed Breaker Arrangement at Rectifier Station

At Sullivan 765 kV substation:

Figure 3-2 shows the assumed breaker and half representation shared by the 3-winding transformer connected to the inverter station and 2-winding transformer connected to Breed 345 kV station. For a SLG fault near the 3-winding transformer, the bus breaker (B1) operates in 4 cycles to try to clear the fault. The middle breaker (B2) is stuck thus the backup protection operates in 9 cycles to isolate the fault by tripping the 2-winding transformer connected to Breed. The total fault duration is 13 cycles.

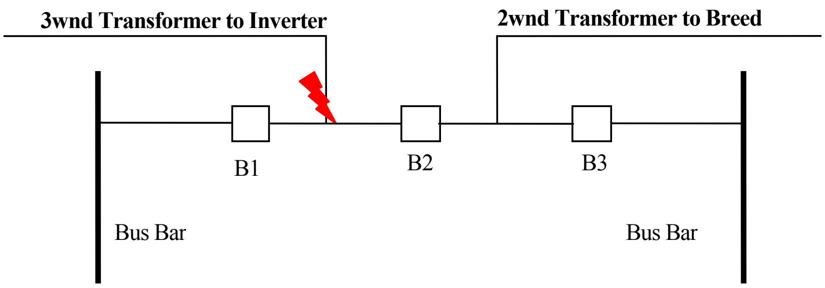

Figure 3-2: Assumed Breaker Arrangement at Sullivan 765 kV Station

At Palmyra Tap 345 kV substation:

Figure 3-3 shows the assumed breaker and half representation shared by the line connected to the HVDC inverter station and the line to Palmyra substation. For a SLG fault on the line very close to the substation as shown in the figure, the bus breaker (B1) operates in 5 cycles to try to clear the fault. The middle breaker (B2) is stuck thus the backup protection operates in 11 cycles to isolate the fault by tripping the line connected to Palmyra. The total fault duration is 16 cycles.

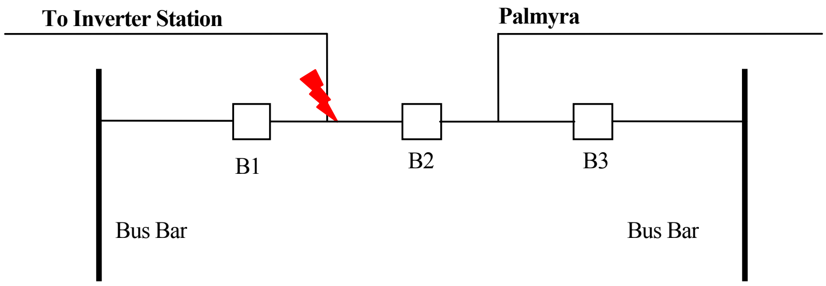

Figure 3-3: Assumed Breaker Arrangement at Palmyra Tap 345 KV Station

3.2.1 Quick Reactor Switching (QRS) at Rockport

The existing Quick Reactor Switching (QRS) scheme was modeled for faults at Rockport that involves tripping of Rockport – Jefferson 765 kV line (FLT#34 and FLT#64). As per the actual language from PJM's Transmission Operations Manual 3, the QRS is described as below:

"*Quick Reactor Switching (QRS) – The 765 kV Rockport–Sullivan 150 MVAR shunt reactor bank at Rockport automatically opens within 5 cycles and recloses in 1 minute for contingencies on the Rockport – Jefferson 765 kV line. This works in conjunction with the Fast Valving scheme to improve voltage and stability after select contingencies.*"

In this study, the Rockport reactors and the Rockport – Jefferson 765 kV line were disconnected at the same time, i.e. in 4 cycles for 3ph faults and 13 cycles for SLG faults measured from the fault inception time.

3.2.2 Fast Valve Control Action at Rockport Plant

Siemens PTI was aware of the fast valve control action at Rockport plant, but it was not utilized in this study. The intention is to evaluate the GBX Project performance in the absence of the fast valve control at Rockport plant. The dynamic model of the Rockport units does not simulate the fast valve control action of the speed governor associated with these units. It is our anticipation that simulating the fast valve control action at Rockport units would help rotor angle stability and voltage recovery further.

3.3 Equivalent Fault Admittance Values for SLG Faults

In order to simulate SLG faults, equivalent fault admittances representing the negative and zero sequence networks as seen from the fault location ($1/[Z_0+Z_2]$) are required. These fault admittance values were provided by SPP, MISO and PJM, and are shown in Table 3-8, Table 3-9 and Table 3-10, respectively.

Table 3-8: Fault Admittance Values on SPP Side[12]

Bus	Substation	Fault Admt (MVA)
765800	Rectifier 345 kV	129.64-j3057
539800	Clark Co 345 kV	129.64-j3057
523853	Finney 345 kV	229.27-j3013.33
531449	Holcomb 345 kV	212.32-j3113.02
531451	Mingo 345 kV	130.09-j1151.86
530583	Postrock 345 kV	213.89-j2100.5
531465	Setab 345 kV	156.14-j1530.21
531469	Spearville 345 kV	266.24-j3244.89
539695	Spearville 230 kV	168.83-j2594.27
539801	Thistle 345 kV	447.72-j2322.42
515375	Woodward 345 kV	425.64-j2792.85

Table 3-9: Fault Admittance Values on MISO Side

Bus	Substation	Fault Admt (MVA)
344056	Montegomery 345 kV	1013.78 -j 5071.61
345992	Spencer Ck 345 kV	396.96 j 3724.16
345230	Audrain 345 kV	396.96 j 3724.16
345435	Palmyra Tap 345 kV	554.76 -j 3067.22
765772	Palmyra 345 kV	499.53 -j 2771.19

Table 3-10 Fault Admittance Values on PJM Side

Bus	Substation	Fault Admt (MVA)
243210	Sullivan 765 kV	560.85 -j 7054.15
243209	Rockport 765 kV	400.917 -j11751.02
243213	Breed 345 kV	744.02 -j 7838.9

3.4 Dynamic Stability Performance Criteria

The following criteria were used in evaluating the study area dynamic performance for the selected disturbances:

- Voltage dip should not exceed more than 25% of nominal voltage or not below 0.75 pu. SPP currently does not have a criteria in this respect but we understand that one is under study and the assumptions above are normally accepted (e.g. WECC.)
- Post disturbance voltages should stay within acceptable operating limits (within +5% and -10% of nominal voltage)
- Generating units within the study area should remain in synchronous operation following clearing of the fault
  - This is ensured by well damped rotor angle and electric power dynamic responses

[12] Admittances are expressed in MVA calculated as the per unit value x 100 MVA.

- System frequency deviation immediately following the inception of a fault is within under frequency load-shedding protection and prime mover limits

Whenever a particular disturbance results in loss of synchronism of a generating unit and/or post-disturbance transmission system voltages are below acceptable limits in the study area, one of the following techniques (or a combination) is studied as a potential solution to resolve the issue:

- Reduction of the fault clearing time
- Provide additional dynamic reactive support, as required
- Additional measures such as special protection schemes (SPS), with the assistance of affected parties, as necessary

Section
4

Stability Analysis Results

The GBX project was modeled in all three scenarios provided by SPP. The stability packages were updated for each case that was used in the dynamic simulations. Response files were created for the selected disturbances to automate the simulation process.

Initialization of all three cases provided the following dynamic model initialization issues:

- Vestas machines at buses 639579, 639698 and 693722 showed warnings related to a mismatch between Pmax and Mbase. For these units, the Mbase was replaced with Pmax to remove these warnings
- A CBEST model at bus 401080 showed a warning related to a mismatch between Xsource in the load flow case and the dynamic data. The value in the load flow case was changed to match its counterpart in the dynamic data file

After modifying the load flow cases with the above changes, a no-fault (flat run) was performed to ensure numerical stability in the integration process used in the dynamic simulation. A successful run was obtained for all three scenarios. Following these flat runs, dynamic simulations for all selected faults were tested to assess the dynamic performance of the GBX Project and all generating units in the study area. The next section presents the stability analysis results for each scenario.

4.1 2017 Summer Peak Case Results

4.1.1 Three Phase Faults

The 3ph stability analysis results identified the following key faults that pose significant stress on the system:

- Fault # 29 – 3ph fault at Sullivan and cleared by tripping the 765 kV line to Rockport
- Fault # 34 – 3ph fault at Rockport and cleared by tripping the 765 kV line to Jefferson

Fault # 29

During the steady state analysis of the GBX Project, we identified that Fault # 29 was a severe fault and requires additional reactive support. However, this fault showed stable performance during the dynamic analysis as the HVDC controls adjust their angles to minimum values to provide the required reactive support. It is important to note that this additional support obtained through the HVDC controls is just enough to maintain the system voltages to meet the performance criteria as shown in Figure 4-1. We consider this fault as severe, but the corresponding dynamic performance of the study area is acceptable. Later in this report, it is shown that the GBX Project 345 kV connection at Sullivan provides better voltage performance for the same fault.

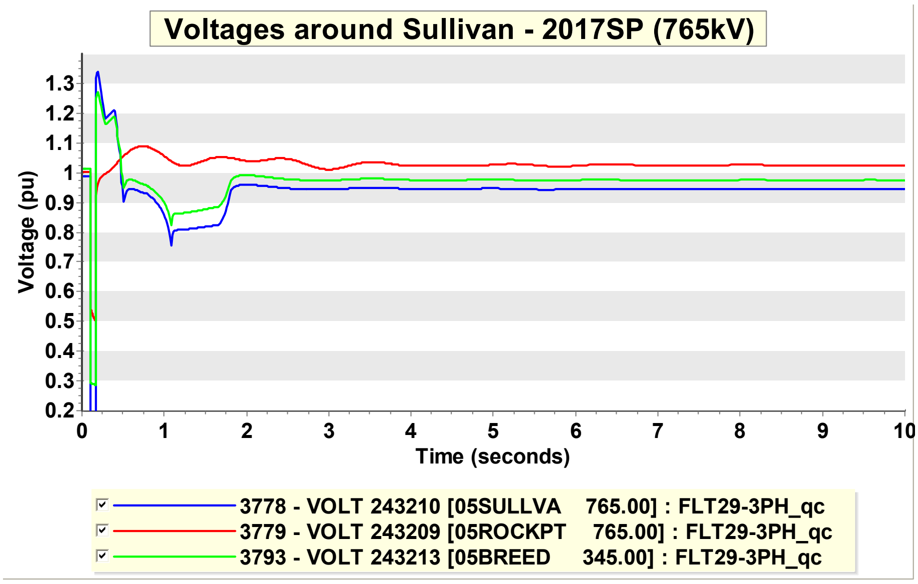

Figure 4-1: Voltages around Sullivan – Fault # 29

Fault # 34

For this particular fault, all on-line generating units at the Rockport plant were tripped by the out-of-step protection associated with these units as they have stepped out of synchronism with the system. In addition to the GBX Project generation of 3,000 MW, around 2,600 MW of generation at the Rockport plant is now pushed back in to the Sullivan 765 kV substation and onto the underlying 345 kV network at Breed substation. Due to this severe stress on the system, bus voltages within the vicinity of Sullivan substation are not able to recover immediately after clearing the fault. The Rockport units are tripped at around 1.25 seconds time and following this the system voltages recover as shown in Figure 4-2. Note that the tripping of Rockport units does not have an adverse impact on rotor angle stability of the system and the balance of the monitored units within the study area remained in synchronism.

As a mitigation scheme, one pole of the multi-terminal HVDC line is blocked immediately after clearing the fault thus limiting the GBX Project injection into Sullivan substation to 1,500 MW. Note that the remaining 1,500 MW of GBX Project generation will flow into the SPP system at the rectifier station. While blocking the pole, two options are explored as described below:

1. The capacitor banks at Sullivan inverter station are reduced by half in size. In this case, it is observed that the Rockport units tripped at 2 seconds which is not a desired performance. Figure 4-3 shows the corresponding voltage performance around Sullivan area

2. The capacitor banks at Sullivan Inverter station are allowed to operate at their full capacity[13]. It is noted that Rockport units did not trip in this case and the corresponding voltage performance is shown in Figure 4-4. The voltage dip is about 17.8% (measured voltage of 0.822 pu) and meets the voltage performance criteria

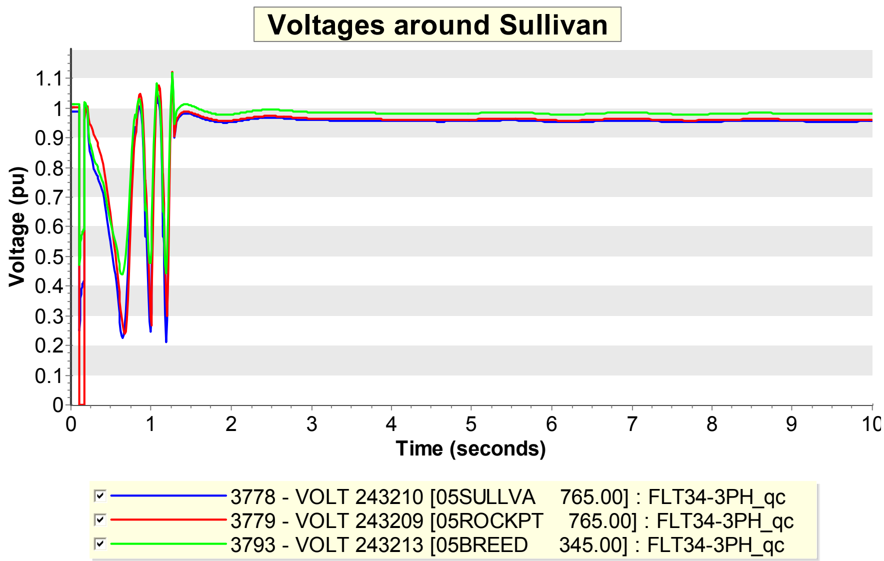

Figure 4-2: Voltages around Sullivan – Fault # 34

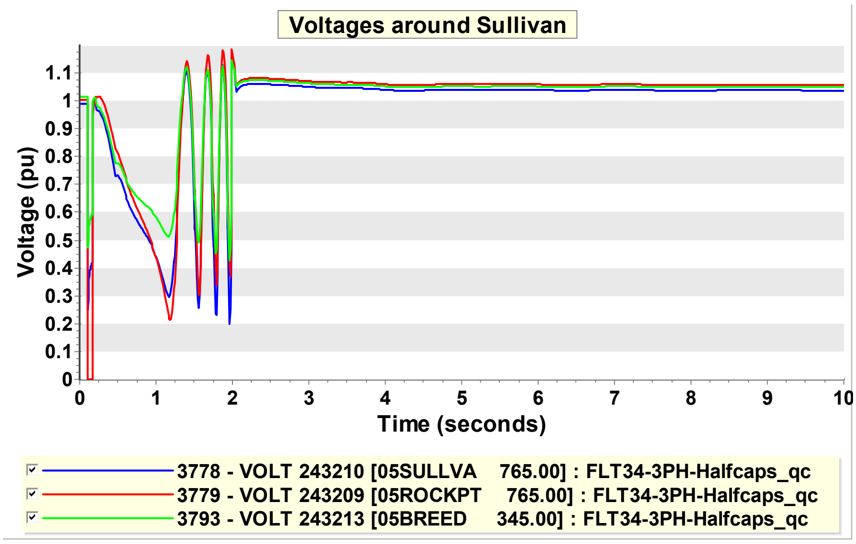

Figure 4-3: Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 34

[13] The idea of not following the pole outage with tripping of shunt capacitors is a practical approach unless over voltages are observed, which is not the case for the fault under consideration. Hence leaving the full compensation is justifiable.

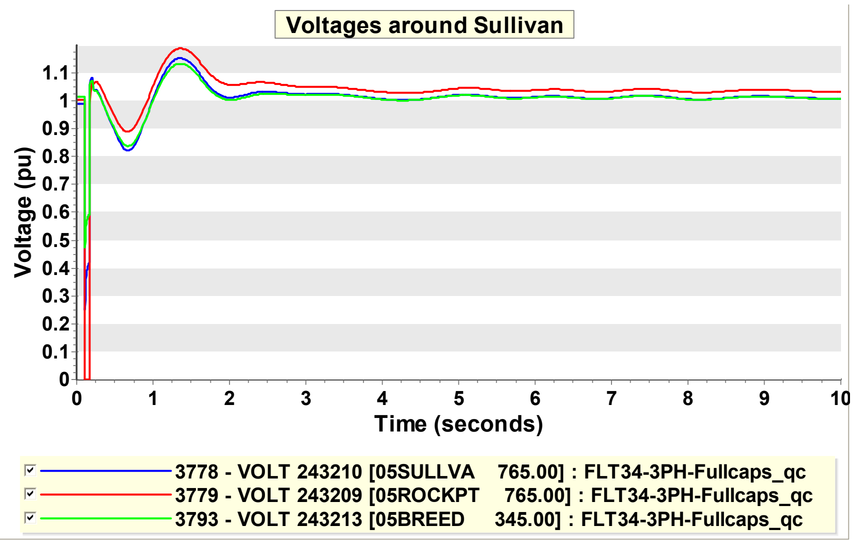

Figure 4-4: Voltages around Sullivan with One pole Blocked (Full Cap Banks) – Fault # 34

4.1.2 SLG Faults – Protection Failure

All SLG faults (protection failure) showed stable dynamic performance of the study area, except for Fault # 64 which is a SLG fault at Rockport 765 kV substation and is cleared by tripping the 765 kV line to Jefferson substation. Similar to the 3ph fault (Fault # 34), all on-line generating units at Rockport plant were tripped by the out-of-step protection associated with these units as they have stepped out of synchronism with the system. The bus voltages within the vicinity of Sullivan substation are not able to recover immediately after clearing the fault, but as shown in Figure 4-5, the voltages started recovering after the Rockport units are tripped at around 1.45 seconds.

As a mitigation scheme, one pole of the multi-terminal HVDC line is blocked immediately after clearing the fault; thus, the GBX injection into Sullivan is limited to 1,500 MW. The remaining 1,500 MW of GBX Project generation will flow into the SPP system.

Figure 4-6 shows the voltage performance while the pole is blocked and capacitor banks at Sullivan inverter are reduced by half in size. The Rockport units did not trip and the system voltages recovered. However, the observed voltage dip is about 27.9% (measured voltage of 0.721 pu) which is not acceptable as per the proposed performance criteria of 25%.

Figure 4-7 shows the voltage performance while one pole is blocked with the capacitor banks at Sullivan inverter operating at their full capacity. The Rockport units did not trip and the voltages around Sullivan are smoothly recovered after clearing the fault. The observed voltage dip is about 8% (observed voltage of 0.92 pu).

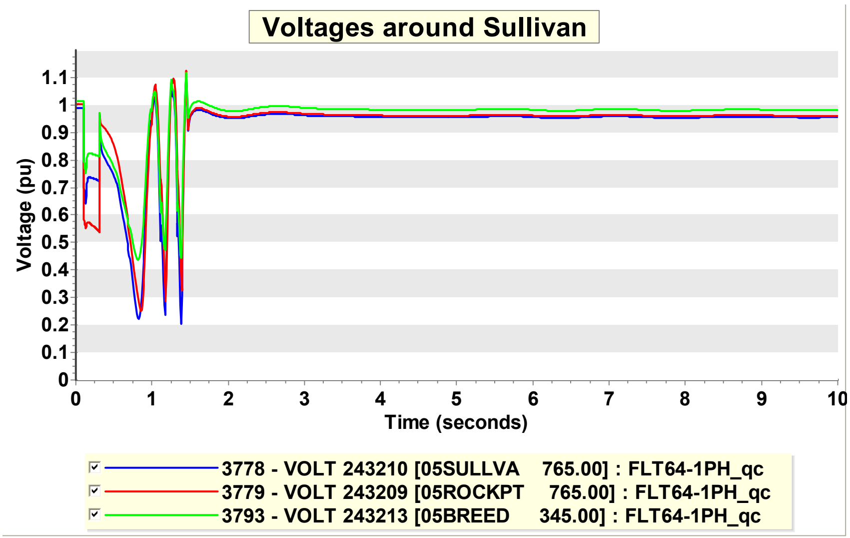

Figure 4-5: Voltages around Sullivan – Fault # 64

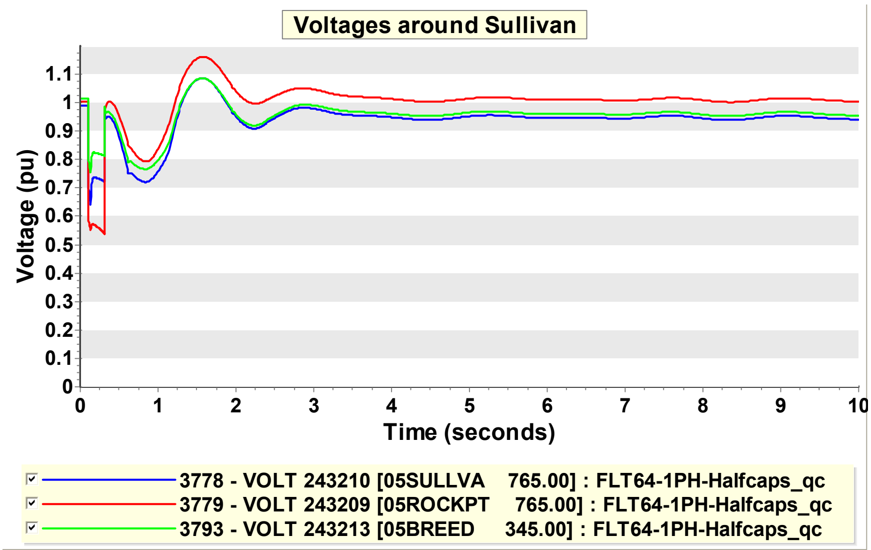

Figure 4-6: Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 64

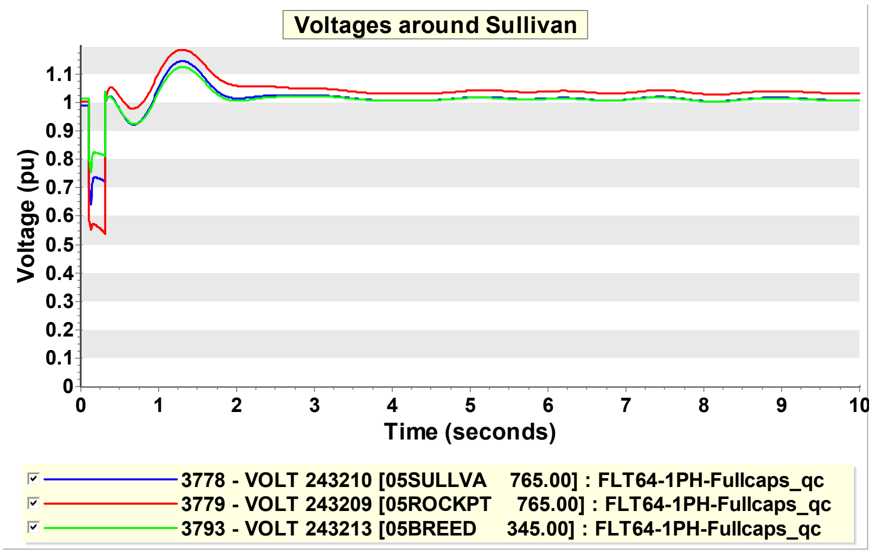

Figure 4-7: Voltages around Sullivan with One Pole Blocked (Full Cap Banks) – Fault # 64

4.1.3 SLG Faults – Stuck Breaker

The study area showed stable performance for the selected SLG faults (stuck breaker).

4.1.4 Observations

Appendix C shows the 2017 Summer Peak stability analysis plots for both 3ph and SLG faults. The following are the key observations of the stability analysis:

- The 3ph fault at Sullivan that involves tripping of Sullivan–Rockport 765 kV lines appears to be severe but the study area is stable
- Faults at Rockport that involve tripping of the Rockport–Jefferson 765 kV line are considered as critical faults. These faults require the GBX Project injection into Sullivan to be reduced while maintaining full shunt reactive compensation capability at converter stations
  - In this study, we reduced the GBX injection into Sullivan to 1,500 MW by blocking one pole of the HVDC line. The remaining GBX Project generation is allowed to sink into the SPP system
  - Though it was not tested in this study, we believe that the actual GBX injection into Sullivan could be higher than 1,500 MW

Further, Table 4-1 shows the list of units tripped due to under-frequency relay action for almost all tested faults. Testing these faults on the pre-project case revealed that these same units were also tripping due to the same under-frequency relay action and thus the GBX project is not the cause of tripping. Similar behavior was observed during the stability study of the Plains and Eastern project and at that time we raised this issue with SPP and, per their suggestion, we ignored these messages while analyzing the results.

Table 4-1 Units Tripped for all Faults

Contingency	Dynamic Performance of Units
All Faults	Machine 3 at bus 253627 Tripped for under frequency at 2.5833s
	Machine 1 at bus 253625 Tripped for under frequency at 2.7208s
	Machine 2 at bus 253626 Tripped for under frequency at 2.7208s

4.2 2017 Light Load Case Results

4.2.1 Three Phase Faults

All 3ph faults showed stable dynamic performance of the study area. Unlike the Peak Load conditions, it was observed that Rockport units did not trip for the critical fault at Rockport substation (Fault # 34) due to less dispatched generation of 1,760 MW at the Rockport plant (as opposed to 2,600 MW dispatched in Peak Load conditions), but the Sullivan area voltages did not meet the voltage performance criteria. Figure 4-8 shows the corresponding voltage performance at Sullivan substation. The first dip immediately after clearing the fault is about 37.3% (observed voltage of 0.627 pu) and the voltage recovery is poor.

As a mitigation scheme, one pole of the multi-terminal HVDC line is blocked immediately after clearing the fault thus limiting the GBX Project injection into Sullivan substation to 1,500 MW. Figure 4-9 shows the corresponding voltage performance with the capacitor banks at the inverter station reduced to half in size. The bus voltages around Sullivan substation area have recovered smoothly, meeting the voltage performance criteria.

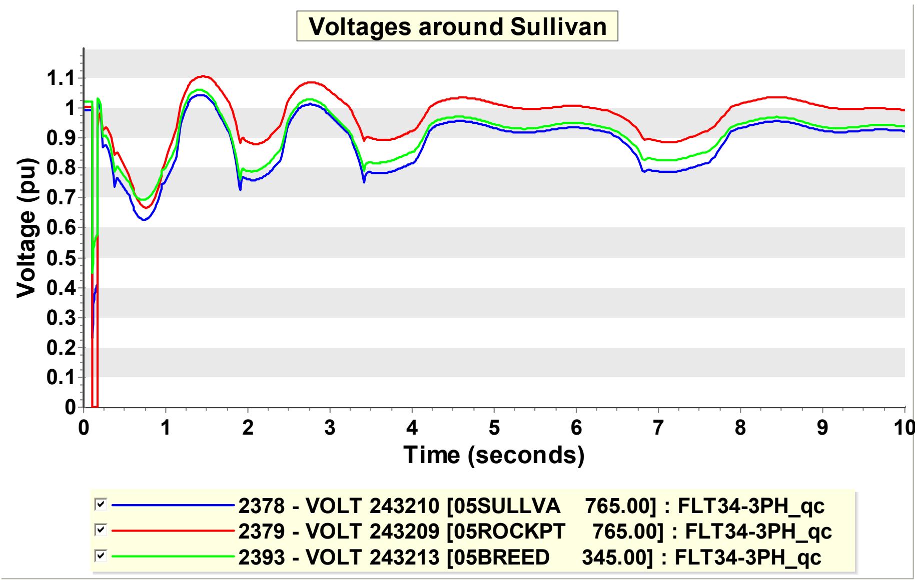

Figure 4-8: Voltage around Sullivan – Fault # 34

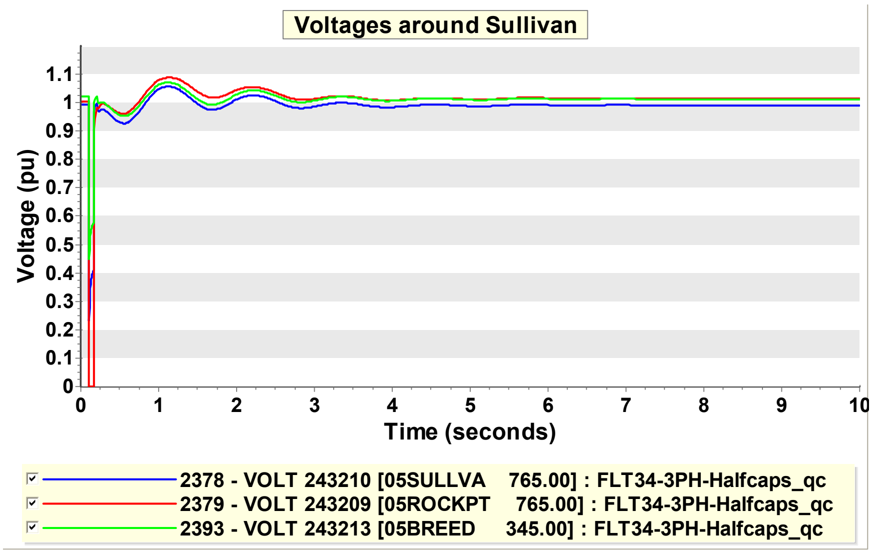

Figure 4-9: Voltage around Sullivan with One Pole is Blocked (Half Cap Banks) – Fault # 34

4.2.2 SLG Faults (Protection Failure)

The SLG faults analysis results showed similar performance as that of 3ph faults analysis. All SLG faults (protection failure) showed stable dynamic performance of the study area, except for Fault # 64. The Rockport units remained on-line for this fault, but the voltages around Sullivan are not completely recovered as shown in Figure 4-10. The observed voltage dip is about 31.2% (measured voltage of 0.688 pu).

As a mitigation scheme, one pole of the multi-terminal HVDC line is blocked immediately after clearing the fault thus limiting the GBX Project injection into Sullivan substation to 1,500 MW. Figure 4-11 shows the corresponding voltage performance with the capacitor banks at the inverter station reduced to half in size. The bus voltages around Sullivan substation area have recovered smoothly, meeting the voltage performance criteria.

4.2.3 SLG Faults (Stuck Breaker)

The study area showed stable performance for the selected SLG faults (stuck breaker).

4.2.4 Observations

Appendix D shows the 2017 Light Load stability analysis plots for both 3ph and SLG faults. The following are the key observations of the stability analysis:

- Faults at Rockport that involves tripping of Rockport–Jefferson 765 kV line are considered as critical faults.

- Though the Rockport units did not trip for these critical faults, the voltage performance around Sullivan substation is not acceptable. These faults require the GBX Project injection into Sullivan to be reduced to maintain desired voltage performance. It is not required to maintain the full shunt reactive compensation capability at converter stations

– In this study, we reduced the GBX injection into Sullivan to 1,500 MW by blocking one pole of the HVDC line. The remaining GBX Project generation is allowed to sink into the SPP system

– Though it was not tested in this study, we believe that the actual GBX injection into Sullivan could be higher than 1,500 MW

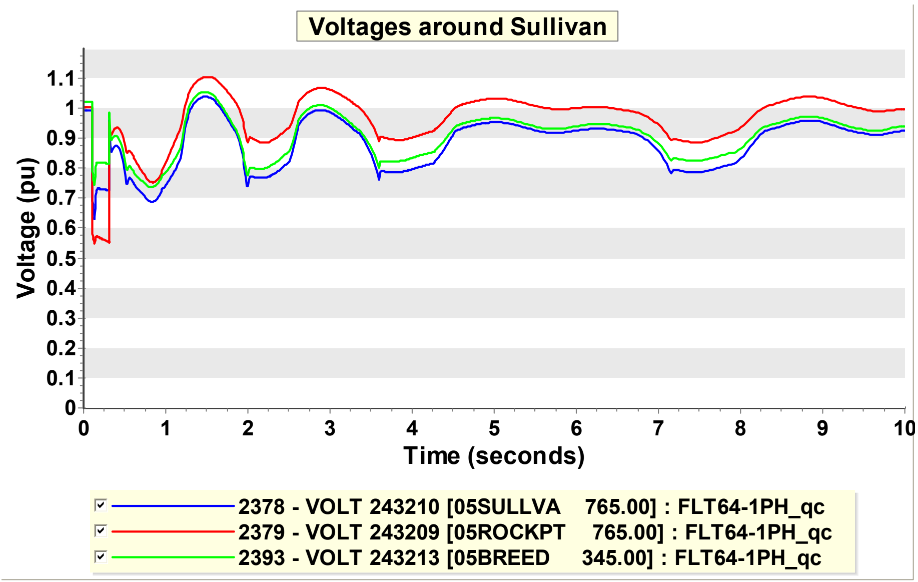

Figure 4-10: Voltages around Sullivan – Fault # 64

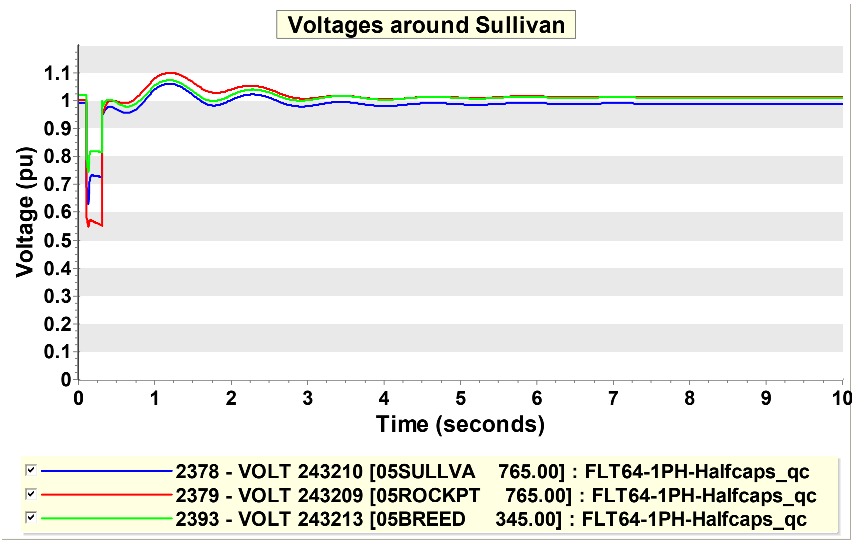

Figure 4-11: Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 64

4.3 2022 Summer Peak Case Results

The 2022 Summer Peak stability analysis results are in general similar to that of 2017 Summer Peak stability analysis results. They both have similar observations as described in following subsections.

4.3.1 Three Phase Faults

The 3ph stability analysis results identified the following key faults that pose significant stress on the system:

- Fault # 29 – 3ph fault at Sullivan and cleared by tripping the 765 kV line to Rockport
- Fault # 34 – 3ph fault at Rockport and cleared by tripping the 765 kV line to Jefferson

Fault # 29

During the steady state analysis of the GBX Project, we identified that Fault # 29 was a severe fault and requires additional reactive support. However, this fault showed stable study area performance during the stability analysis as the HVDC controls adjust their angles to minimum values to provide the required reactive support. It is important to note that this additional support obtained through the HVDC controls is just enough to maintain the system voltages to meet the performance criteria as shown in Figure 4-12. The observed voltage dip is about 25% (measured voltage of 0.75 pu).

We consider this fault as severe; but the corresponding dynamic performance of the study area is acceptable. Later in this report, it is shown that the GBX Project 345 kV connection at Sullivan provides better voltage performance for the same fault.

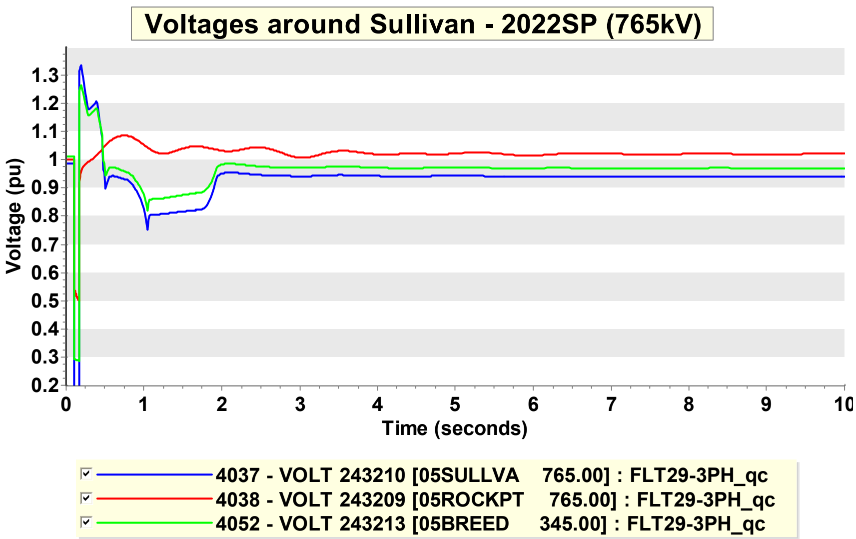

Figure 4-12: Voltages around Sullivan – Fault # 29

Fault # 34

Similar to the 2017 Summer Peak scenario, voltages around Sullivan substation did not recover immediately after the fault is cleared as shown in Figure 4-13. The Rockport generating units are tripped at about 1.27 seconds time and then the system voltages started to recover. However, the rest of the monitored units in the study area remained in synchronism with the system, thus tripping of Rockport units does not have an adverse effect on rotor angle stability of the study area.

Figure 4-14 shows the voltage performance at Sullivan with one of the HVDC lines blocked and with corresponding reduction of reactive compensation at the converter stations to half in size. This mitigation scheme did not help as the Rockport units still tripped at around 1.9 seconds time.

With full reactive compensation (switched shunts) available at the Sullivan inverter followed by pole blocking (as opposed to reducing to half in size), it was observed that the Rockport units remain on-line and the Sullivan side voltages recovered as shown in Figure 4-15. The voltage dip is about 20.2% (measured voltage of 0.798 pu) meeting the voltage performance criteria.

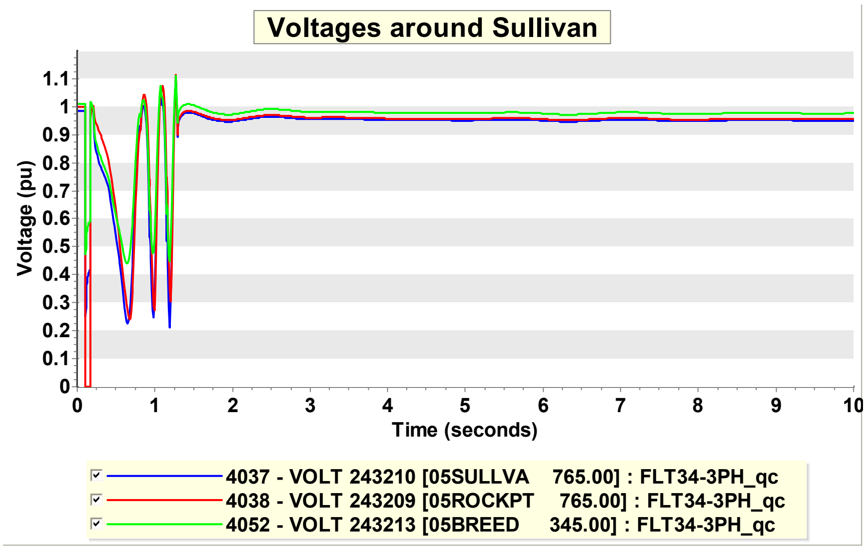

Figure 4-13 Voltages around Sullivan – Fault # 34

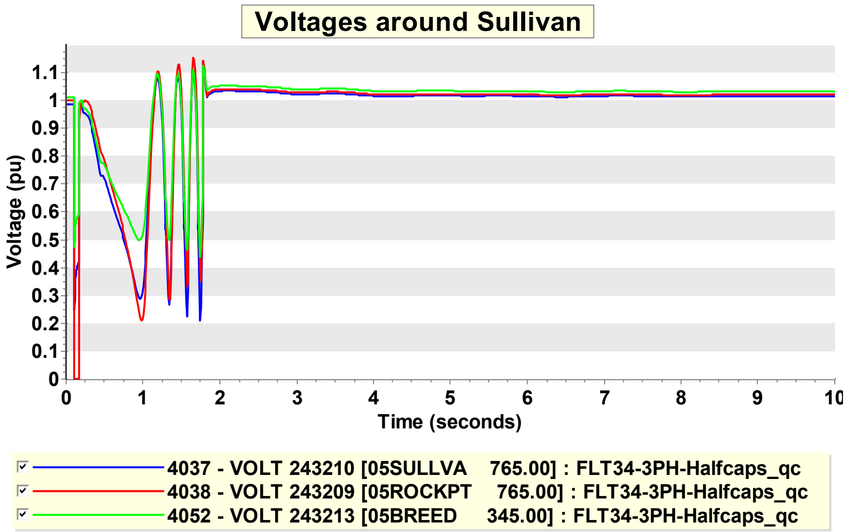

Figure 4-14 Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 34

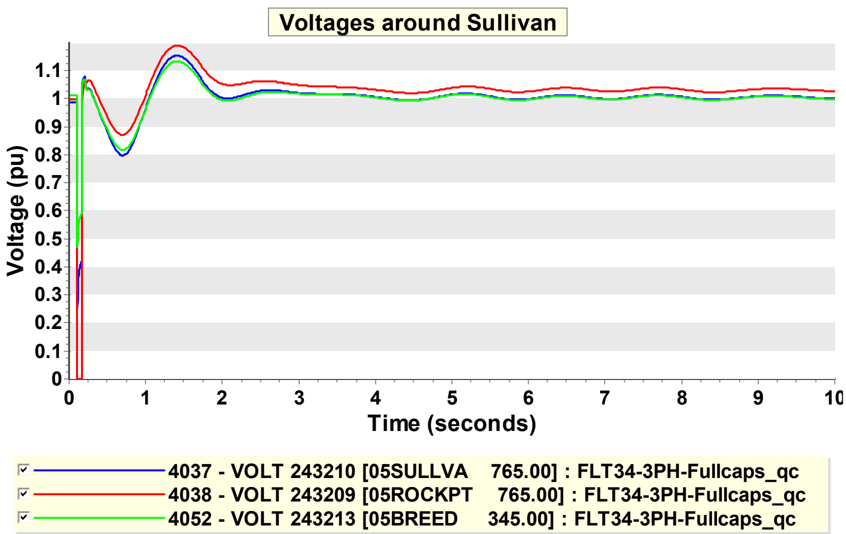

Figure 4-15 Voltages around Sullivan with One Pole Blocked (Full Cap Banks) – Fault # 34

4.3.2 SLG Faults (Protection Failure)

All SLG faults (protection failure) showed stable dynamic performance of the study area, except for Fault # 64. Again, similar to the 3ph fault (Fault # 34) all on-line generating units at Rockport plant were tripped by the out-of-step protection associated with these units as they have stepped out of synchronism with the system. The bus voltages within the vicinity of Sullivan substation are not able to recover immediately after clearing the fault, but as shown in Figure 4-16, the voltages started recovering after the Rockport units are tripped at around 1.45 seconds.

Figure 4-17 shows the voltage performance when one pole is blocked and the capacitor banks at the Sullivan inverter are reduced by half in size. The Rockport units did not trip and the system voltages are recovered. However, the observed voltage dip is about 28.9% (measured voltage of 0.711 pu) which is not acceptable as per the proposed performance criteria of 25%.

Figure 4-18 shows the voltage performance when one pole is blocked and with the capacitor banks at the Sullivan inverter operating at their full capacity. The Rockport units did not trip and the voltages around Sullivan recovered smoothly after clearing the fault. The observed voltage dip is about 8.3% (measured voltage of 0.917 pu).

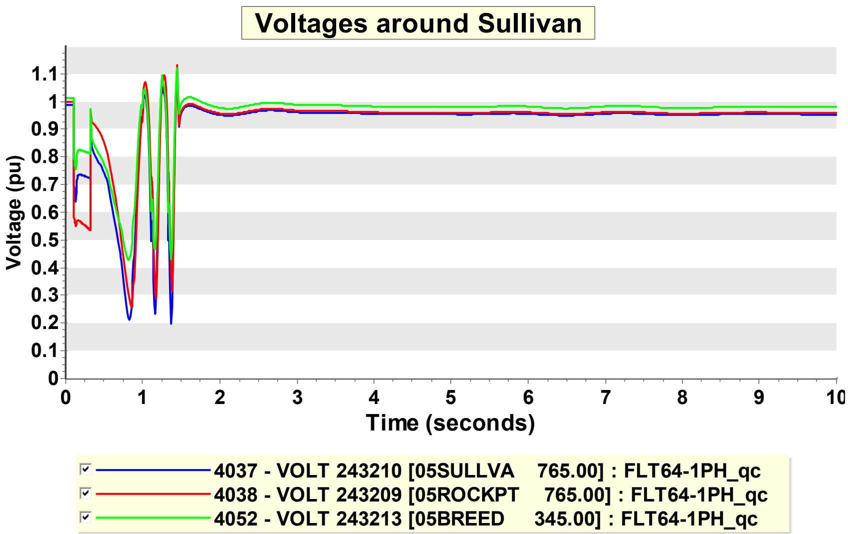

Figure 4-16: Voltages around Sullivan – Fault # 64

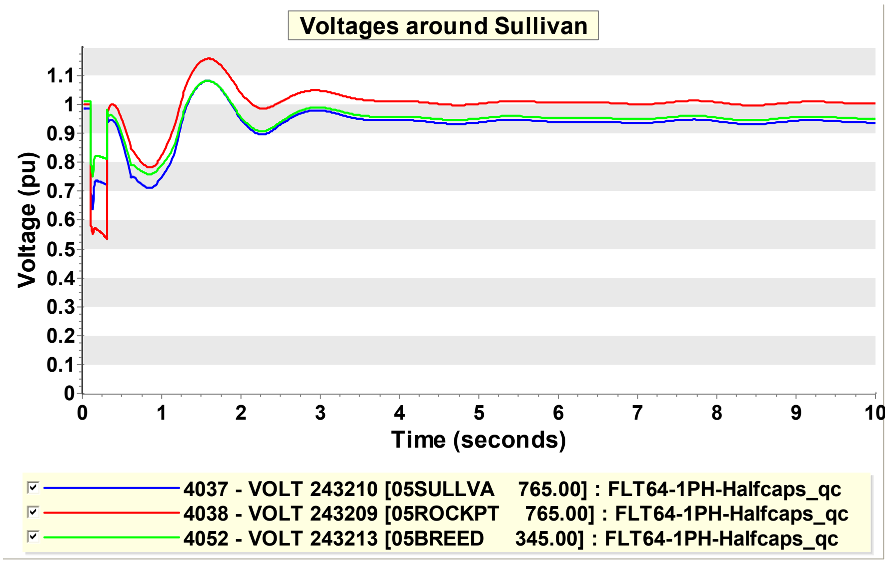

Figure 4-17: Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 64

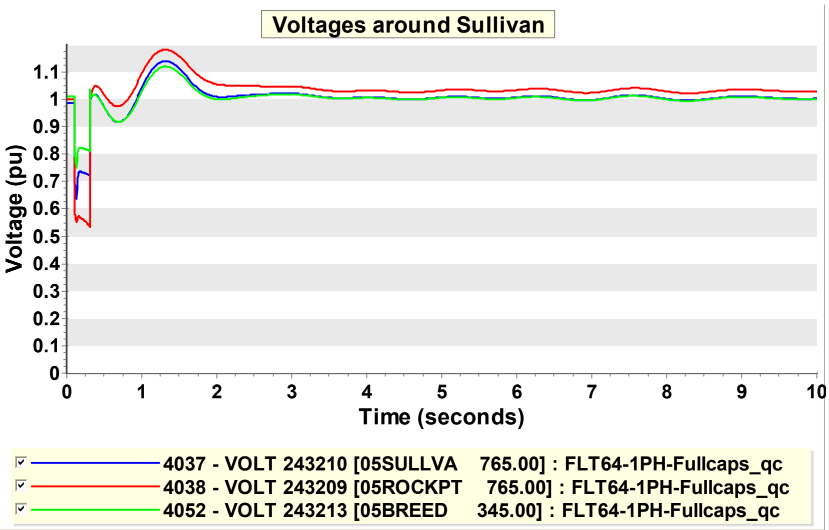

Figure 4-18: Voltages around Sullivan with One Pole Blocked (Full Cap Banks) – Fault # 64

4.3.3 SLG Faults (Stuck Breaker)

The study area showed stable performance for the selected SLG faults (stuck breaker).

4.3.4 Observations

Appendix E shows the 2017 Summer Peak stability analysis plots for both 3ph and SLG faults. The following are the key observations of the stability analysis:

- The 3ph fault at Sullivan that involves tripping of Sullivan – Rockport 765 kV lines appears to be severe but the study area is stable

- Faults at Rockport that involves tripping of Rockport to Jefferson 765 kV line are considered as critical faults. These faults require the GBX Project injection into Sullivan to be reduced while maintaining full shunt reactive compensation capability at the converter stations

  – In this study, we reduced the GBX injection into Sullivan to 1,500 MW by blocking one pole of the HVDC line. The remaining GBX Project generation is allowed to sink into the SPP system

  – Though it was not tested in this study, we believe that the actual GBX injection into Sullivan could be higher than 1,500 MW

Furthermore, it is noted that Unit # 1 at bus 200020 (225 PJM) was tripped by over speed relay action between 5 and 10 seconds into dynamic simulation, for almost all faults. This unit was tripped in the Plains & Eastern project as well and tests on the pre-project case revealed that the unit tripped due to bad modeling data and not due to the GBX project.

Section

5

N-1-1 Outages at Clark County and Spearville Substations

This section presents the stability assessment of the GBX Project for 3ph faults at Spearville and Clark County substations with a prior outage of a line, for example for maintenance purposes. This situation is treated as N-1-1 outage since the first line was taken out of service and allowed for manual adjustments in the system, and then a fault occurs at or near the substation that trips the second line. We consider such N-1-1 outages nearby the GBX Project that may impact the dynamic performance of the study area and need to be addressed.

This analysis was conducted for faults at Spearville and Clark County substations as they are close to the GBX Project rectifier station and the associated impacts will be more severe compared to faults at substations far from the project location. The selected faults are tested on 2017 Light Load, 2017 Summer Peak and 2022 Summer Peak scenarios. The following subsections will provide the analysis results.

5.1 Spearville Substation

Table 5-1 shows the list of faults considered at Spearville substation. The description of the events is presented below.

Table 5-1 3Ph Faults at Spearville Substation

No	Description	kV
12A	1. Prior Outage of Clark Co - Spearville Ckt 1 2. 3ph fault at Spearville substation 3. Clear the fault, trip Clark Co - Spearville Ckt 2	345
17A	1. Prior Outage of Spearville - Holcomb 345kV line 2. 3ph fault at Spearville substation 3. Clear the fault, trip Spearville - Postrock 345kV line	345

Fault 12A: A separate load flow case was created with Clark County–Spearville 345 kV circuit 1 taken out of service. The load flow case was solved with taps and switched shunts allowed to move. This accounts for the first line outage and manual adjustments. Then a 3ph fault was applied at Spearville substation that was cleared in 5 cycles of normal clearing time by tripping the Clark County–Spearville 345 kV circuit 2.

Fault 17A: A separate load flow case was created with the Spearville–Holcomb 345 kV line taken out of service. The load flow case was solved with taps and switched shunts allowed to move. This accounts for the first line outage and manual adjustments. Then a 3ph fault was applied at Spearville substation that was cleared in 5 cycles of normal clearing time by tripping the Spearville–Post Rock 345 kV line.

Analysis Results: The stability results indicate that the study area is stable for the selected faults in all three scenarios. The corresponding stability plots are shown in Appendix F.

5.2 Clark County Substation

Table 5-2 shows the list of faults at Clark County substation. The description of the events is presented below.

Table 5-2: 3Ph Faults at Clark County Substation

No	Description	kV
11A	1. Prior Outage of Clark Co - Thistle Ckt 1 2. 3ph fault at Clark Co substation 3. Clear the fault, trip Clark Co - Thistle Ckt 2	345
12B	1. Prior Outage of Clark Co - Spearville Ckt 1 2. 3ph fault at Clark Co substation 3. Clear the fault, trip Clark Co - Spearville Ckt 2	345

Fault 11A: A separate load flow case was created with Clark County–Thistle 345 kV circuit 1 taken out of service. The load flow case was solved with taps and switched shunts allowed to move. This accounts for the first line out and manual adjustments. Then a 3ph fault was applied at Clark County substation that was cleared in 5 cycles of normal clearing time by tripping the Clark County–Thistle 345 kV circuit 2.

Fault 12B: This fault is similar to Fault 12A described above, except that the fault was applied at Clark County substation.

Analysis Results: Faults 11A and 12B are tested on 2017 Light Load, 2017 Summer Peak and 2022 Summer Peak scenarios. We observed that the GBX Project wind units have tripped for both faults in all three scenarios which is not a desired performance.

When the fault is applied at Clark County substation, the HVDC poles are blocked right away which results in ramping up of GBX Project wind units as there is no path for the wind generation to flow in to the SPP system because of the fault at Clark County. After the fault is cleared, the HVDC poles attempt to unblock but before they are completely unblocked, the wind generation attempts to sink into the SPP system momentarily. However, because of the outage of the double circuit line, there is not sufficient system strength to support this sudden flow. In the meantime, the wind units continue to accelerate to unacceptable speeds and eventually get tripped before the HVDC poles are completely recovered.

Another way to understand this situation is through the available short circuit levels at Clark County substation under different transmission topology conditions. Table 5-3 shows the fault MVA levels without the new WTG at Clark County when all transmission circuits are in-service (SC Test 1), and how the fault MVA levels decrease in the event of double circuit outage to Spearville (SC Test 2) and Thistle (SC Test 3). These values are computed with the 900 MVAr from synchronous condensers connected. The table also shows the short circuit ratio (SCR) calculated with 4,000 MW of additional wind generation.

Note that there is a significant reduction in short circuit level even with the synchronous condenser taking the values from 8,406 MVA (SCR of 2.10) to 6,141 MVA (SCR of 1.54) for the outage of double circuit line to Spearville in 2017 Light Load scenario. This value further goes down to 6,126 MVA (SCR of 1.53) for the outage of double circuit line to Thistle. Similar values can be observed for 2017 and 2022 Sumer Peak scenarios.

Table 5-3 Fault MVA and Short Circuit Ratio at Clark County

		SC Test 1		SC Test 2		SC Test 3	
Scenario	Bus #	Fault MVA	SCR	Fault MVA	SCR	Fault MVA	SCR
2017 LL	539800	8406	2.10	6141	1.54	6126	1.53
2017 SP	539800	9034	2.26	6275	1.57	6494	1.62
2022 SP	539800	9076	2.27	6278	1.57	6528	1.63

SC Test 1 = All Transmission in-service

SC Test 2 = Clark Co - Spearville Double Ckt Out

SC Test 3 = Clark Co - Thistle Double Ckt Out

SCR calculated for a wind capacity of 4,000 MW

As a mitigation scheme, we tripped some of the GBX Project generation and observed that the HVDC poles and system voltages recovered smoothly thus the study area is stable. Table 5-4 shows the amount of generation that needs to be tripped for Fault 11A and 12B in all three scenarios. The wind unit modeled at bus 999984 was tripped to achieve 760 MW of generation reduction, and the wind unit at bus 999975 was tripped to achieve 877 MW of generation reduction. Note that the scheduled flow along the HVDC poles was also reduced simultaneously. The corresponding stability plots are shown in Appendix F.

Table 5-4 Curtailed GBX Project WTG

	2017LL (MW)	2017SP (MW)	2022SP (MW)
Fault 11A	877	760	760
Fault 12B	877	877	877

5.3 Summary

The key points that summarize the N-1-1 outage analysis:

- The study area is stable for faults at Spearville substation with a prior line outage
- The GBX Project generation needs to be reduced up to 877 MW for faults at Clark County substation with a prior line outage
- For faults at Clark County, the loss of double circuit line to Spearville is more severe compared to losing the double circuit line to Thistle as per the system conditions

5.4 Additional Considerations

As mentioned at several instances in this report, the short circuit strength at Clark County is important for close-in faults under different operating conditions. Recall that for the same reason, a synchronous condenser (up to 900 MVAr) was modeled at the rectifier station to improve the system strength. Currently, it was modeled as a single unit in load flow models but in reality it will be installed as several units of smaller capacity for reliability reasons. Furthermore, the actual size of the synchronous condenser depends on the capability of

HVDC controls, and will be determined later during the detailed design study phase of the Project.

The results above can also be used to infer what could happen for the loss of partial capability of the synchronous condenser assuming it was modeled in several smaller units. In such a case, unless spare capacity is installed, the short circuit capability at Clark County (close to the rectifier station) would be decreased, in a way similar to losing the double circuit lines as discussed in previous subsections. We did not perform the test, but by taking advantage of the N-1-1 outage analysis results, we anticipate that the GBX Project generation may need to be partially curtailed in the event of losing some capability of the synchronous condenser. The value of the generation reduction will be a function of the lost MVA support and the system configuration.

Section

6

Transient Current Flow Analysis

This section presents the evaluation of the transient current increase on key underlying SPP 345 kV lines following the sudden loss of both poles with the objective of evaluating the possibility of the protection tripping of these lines.

In extreme conditions such as double pole outage, all the project wind generation of 3,576 MW (as modeled) flows in to the SPP system resulting in increased currents along the lines near by the project. This sudden increase in currents might be of interest from a protection point of view and this section presents the analysis of such transient current flows along the nearby lines for selected faults.

Table 6-1 shows the selected faults that create significant increase in currents along the lines close to the project. These faults involve blocking of both poles thus all GBX Project generation will flow in to the SPP system.

We observed that measured peak currents are high for 2017 Light Load scenario, and these are shown in Table 6-2. It can be observed that the maximum transient currents are below the lines' nominal currents for all monitored lines, except for the 345 kV line from Clark County to the rectifier station. For faults which block both poles, the transient current can be up to 144% of the nominal current in the lines connecting the Project to Clark County, but this peak happens for a few tenths of a second and should not result in operation of the protection.

Figure 6-1 to Figure 6-3 show the transient current flows along the 345 kV lines at the Clark County substation close to the GBX Project for the faults listed in above table.

Table 6-1 Faults Simulated for the Current Flow Analysis

3 Phase Faults, Normal Clearing			
No	Type	Description	kV
1	3ph, both poles blocked	At Clark Co 765800, both poles are blocked	345
4	3ph, both poles blocked	At Sullivan 765773, both poles are blocked	345
7	3ph, both poles blocked	At Palmyra 765772, both poles are blocked	345

Table 6-2 Measured Current Peaks

					Maximum Transient Current (post fault opening)					
Monitored 345 kV Lines			Normal Rating		Fault # 1		Fault # 4		Fault # 7	
From	To	Id	MVA	I nominal (A)	Amps	% I nominal (A)	Amps	% I nominal (A)	Amps	% I nominal (A)
765800 SPP_GBE_HVDC	539800 CLARKCO 7	1	1793	3001	4314	144%	4296	143%	4291	143%
539800 CLARKCO 7	539801 THISTLE 7	1	1793	3001	2365	79%	2379	79%	2375	79%
539800 CLARKCO 7	531469 SPERVIL7	1	1793	3001	1929	64%	1901	63%	1899	63%

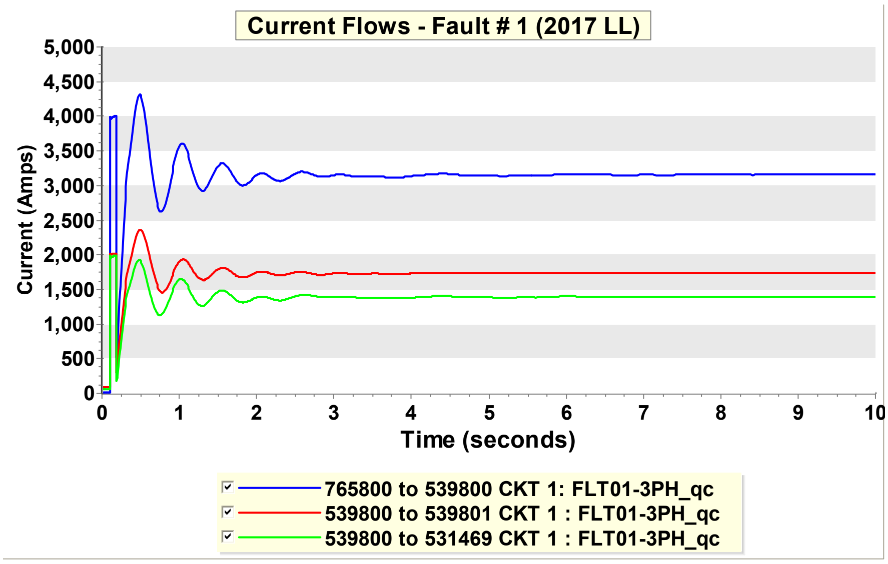

Figure 6-1 Fault # 1 – 2017 Light Load

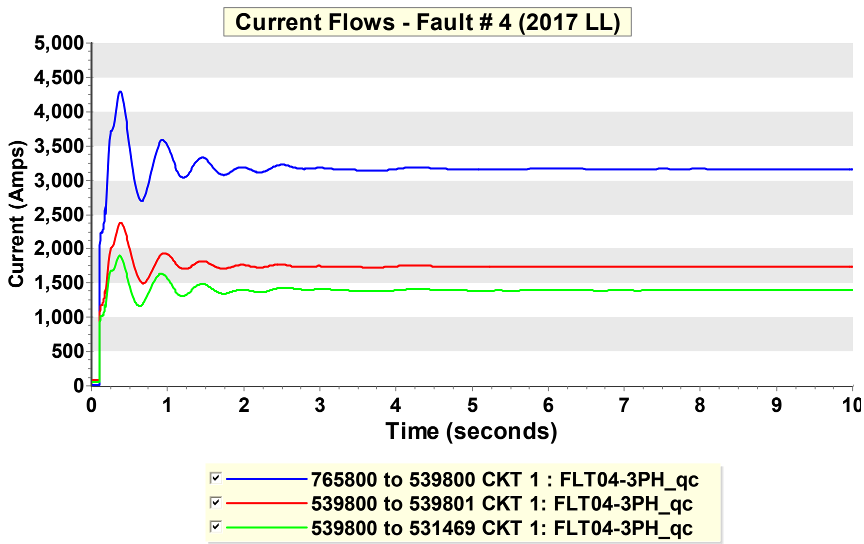

Figure 6-2 Fault # 4 – 2017 Light Load

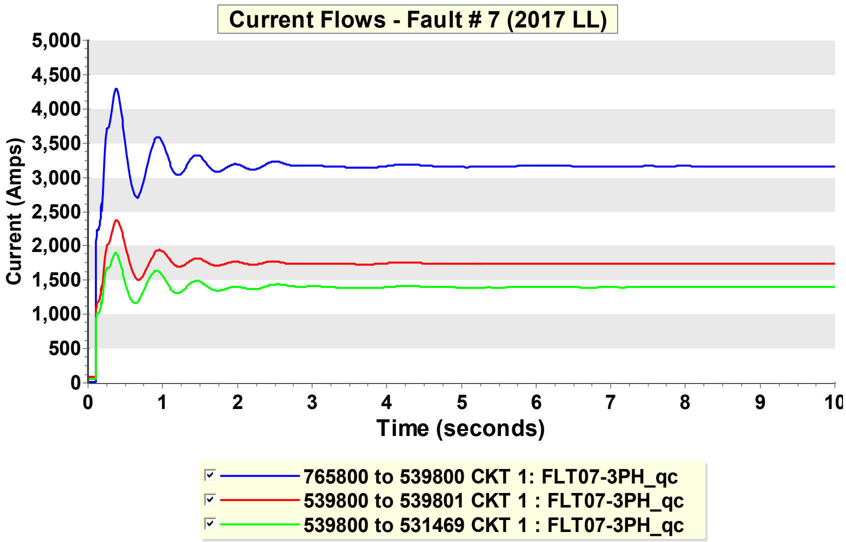

Figure 6-3 Fault # 7 – 2017 Light Load

Section
7

Sensitivity Case of 1750 MW Project Generation

A sensitivity case of reduced project wind generation of 1,750 MW (half of the originally studied 3,500 MW of wind generation) and injections in to Sullivan substation (1,500 MW) and Palmyra substation (250 MW) was developed to study the project impacts with reduced wind generation.

The load flow case with 3,756 MW of GBX Project generation was modified by turning-off approximately half of the generation as opposed to reducing the dispatched generation while keeping the same installed capacity. Table 7-1 shows the dispatched generation after modifying the load flow case with reduced installed capacity.

Figure 7-1 shows the updated project generation where the units connected by dotted lines indicate turned-off units. Also note that the synchronous condenser is turned off since the installed capacity of wind is reduced almost by half, resulting in a short circuit ratio of higher than 2. The reactive compensation at both converter stations is 1,100 MVAr (4x275).

This sensitivity was implemented on a 2017 Light Load case and tested for a 3ph fault in the lines connecting the GBX Project's HVDC converter to the Clark County 345 kV substation as shown in the Table 7-2. The list also includes critical faults at the Sullivan end of the project.

Appendix G shows the corresponding stability plots, where it can be observed that the system is stable; all units remain online, rotor oscillations are well damped and system voltages remain within acceptable ranges.

Table 7-1 Project WTG with Reduced Installed Capacity and Reactive Limits

Bus	Type	# Units	Pgen	Pmax	Qmin	Qmax	Mbase	Pgen/Pmax
999984	3	532	737.1	798	-386	386	888	92.4%
999985	4	385	889.1	963	-462	462	1155	92.4%
999994	3	70	97.0	105	-51	51	117	92.4%
999995	4	42	97.0	105	-50	50	126	92.4%
			1820.3	**1971**			**2286**	

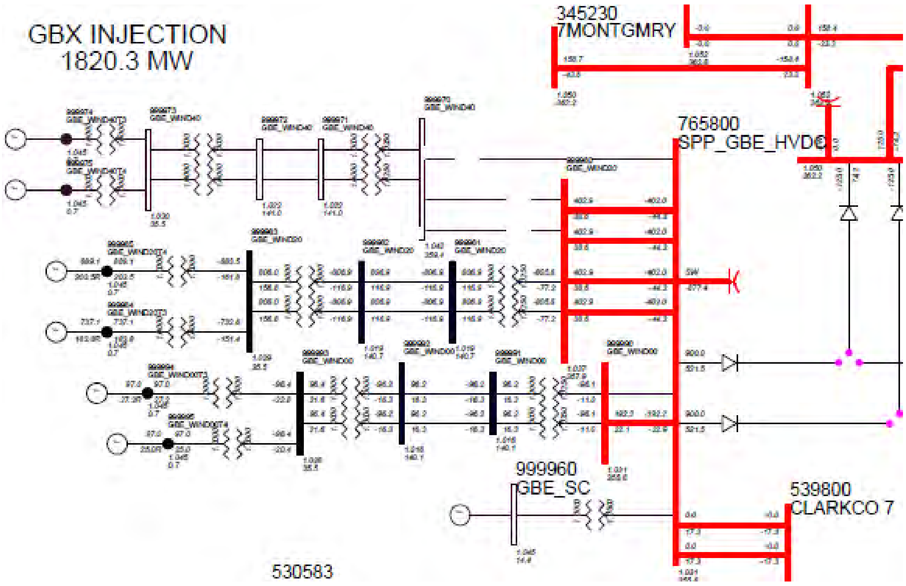

Figure 7-1 Reduced Project Wind Generation – Dotted lines shows turned-off elements

Table 7-2: List of Fault for 1750 MW Sensitivity Case

No	Description	kV
1	At Clark Co 765800, both poles are blocked	345
2	At Clark Co 765800, one pole is recovered	345
3	At Clark Co 765800, both poles are recovered	345
11	Clarck Co 539800 - Thistle 539801 ckt 1	345
12	Clark Co 539800 - Spearville 531469 ckt 1	345
29	Sullivan 243210 - Rockport 243209	765
34	Rockport 243209 - Jefferson 243208	765

Section

8

345 kV Connection Option at Sullivan

The HVDC inverter at Sullivan is rated at 345 kV and is connected to the 765 kV bus at Sullivan through three transformers. It was observed that most of the GBX Project generation flows back into the underlying 345 kV network through existing 765/345 kV transformers at Breed making them overload during certain contingencies. Since the HVDC converters are rated at 345 kV, a sensitivity case of connecting the GBX Project directly to the 345 kV network at Sullivan substation (as opposed to the 765 kV Sullivan bus via three transformers) was studied.

Figure 8-1 shows the 345 kV connection of the GBX Project at Sullivan substation. The inverters are connected to Breed via a 345 kV double circuit line of approximately 10 miles long. Though these lines are modeled as double circuit, the final configuration may have more than two circuits for N-1 capability depending on the conductor ratings.

We anticipate that this connection change would impact the GBX Project performance more for faults at Sullivan than at Clark County. For this reason, the stability analysis was performed for selected contingencies (only 3ph faults) at converter stations and at receiving end points as shown in the Table 8-1. This list includes all faults at the receiving end that were tested during the stability analysis with GBX Project connected to 765 kV bus at Sullivan. The Quick Reactor Switching (QRS) was simulated for the Fault # 34, but not the fast valve control action at Rockport plant.

The stability analysis was conducted on 2017 Light Load, 2017 Summer Peak and 2022 Summer Peak scenarios. The following subsections will present the study results.

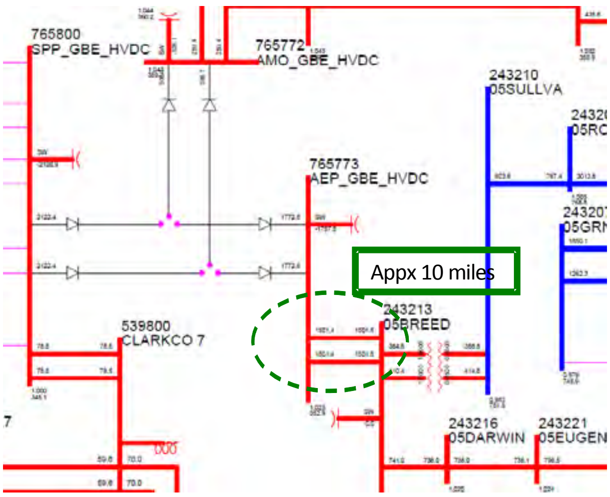

Figure 8-1: 345 kV Connection of the GBX Project at Sullivan

Table 8-1 Selected Contingencies

3 Phase Faults, Normal Clearing			
No	Type	Description	kV
1	3ph, both poles blocked	At Clark Co 765800, both poles are blocked	345
2	3ph, single pole recovery	At Clark Co 765800, one pole is recovered	345
3	3ph, both poles recovery	At Clark Co 765800, both poles are recovered	345
4	3ph, both poles blocked	At Sullivan 765773, both poles are blocked	345
5	3ph, single pole recovery	At Sullivan 765773, one pole is recovered	345
6	3ph, both poles recovery	At Sullivan 765773, both poles are recovered	345
7	3ph, both poles blocked	At Palmyra 765772, both poles are blocked	345
8	3ph, single pole recovery	At Palmyra 765772, one pole is recovered	345
9	3ph, both poles recovery	At Palmyra 765772, both poles are recovered	345
27	3ph, normal clearing	Sullivan 765773 - Breed 243213	345
28	3ph, normal clearing	Sullivan 765/345 kV TF (243210 - 243213)	765/345
29	3ph, normal clearing	Sullivan 243210 - Rockport 243209	765
30	3ph, normal clearing	Breed 243213 - Casey 346809	345
31	3ph, normal clearing	Breed 243213 - Darwin 243216	345
32	3ph, normal clearing	Breed 243213 - Dequine 243217	345
33	3ph, normal clearing	Breed 243213 - Wheat 254539	345
34	3ph, normal clearing	Rockport 243209 - Jefferson 243208	765
35	3ph, normal clearing	Palmyra 765772 - Palmyra tap 345435	345
36	3ph, normal clearing	Palmyra Tap 345435 - Sub T 636645	345
37	3ph, normal clearing	Palmyra Tap 345435 - Plamyra 345436	345
38	3ph, normal clearing	Palmyra Tap 345435 - Adair 344000	345
39	3ph, normal clearing	Palmyra Tap 345435 - Spencer 345992	345
40	3ph, normal clearing	Palmyra Tap 345435 - Se Quincy 347010	345

8.1 2017 Summer Peak Case Results

All 3ph faults showed stable dynamic performance of the study area except for the critical fault at Rockport (Fault # 34). As shown in Figure 8-2, the Rockport generating units are tripped at about 1.51 seconds time and then the system voltages started to recover. However, the rest of the monitored units in the study area remained in synchronism with the system thus tripping of the Rockport units does not have further adverse effects on rotor angle stability of the study area.

Figure 8-3 shows the voltage performance at Sullivan with one of the HVDC lines blocked with corresponding reduction of reactive compensation at the converter stations by half in size. The Rockport units did not trip and the voltages are well recovered. However, the observed voltage dip is about 39.1% (measured voltage of 0.609 pu) not meeting the desired voltage performance criteria. Note that for a similar situation when GBX Project is connected to the 765 kV bus at Sullivan, the Rockport units have tripped as the reactive requirement is higher in this case to supply the losses across the Project transformers at Sullivan.

With full reactive compensation (switched shunts) available at the Sullivan inverter followed by one pole blocking (as opposed to reducing by half in size), it was observed that the Rockport units remain on-line and the Sullivan side voltages recovered as shown in Figure 8-4.

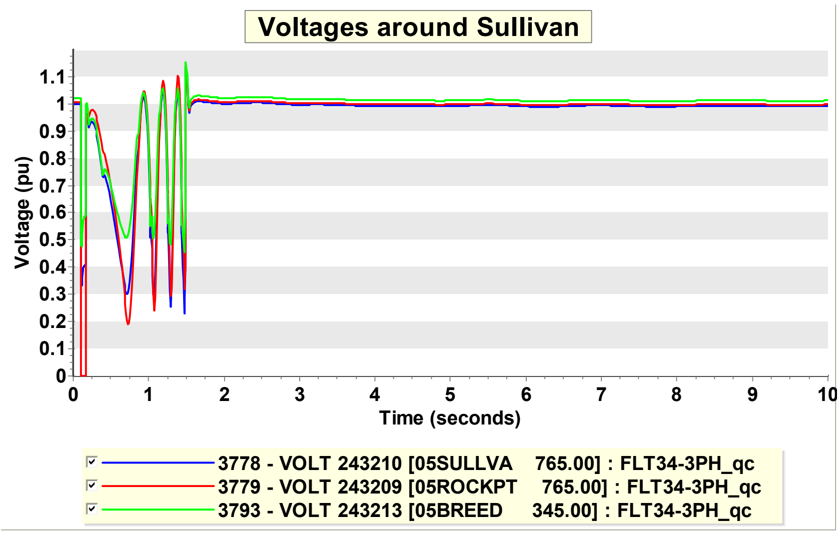

Figure 8-2: Voltages around Sullivan – Fault # 34

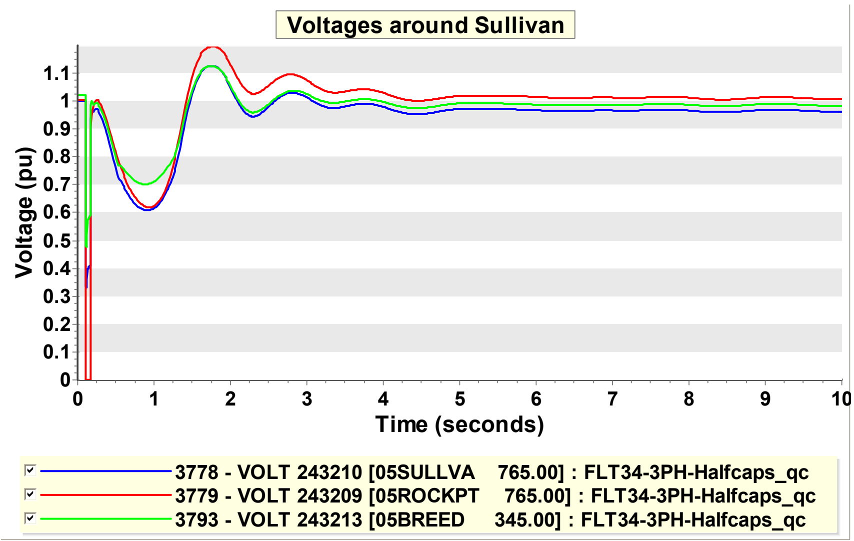

Figure 8-3: Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 34

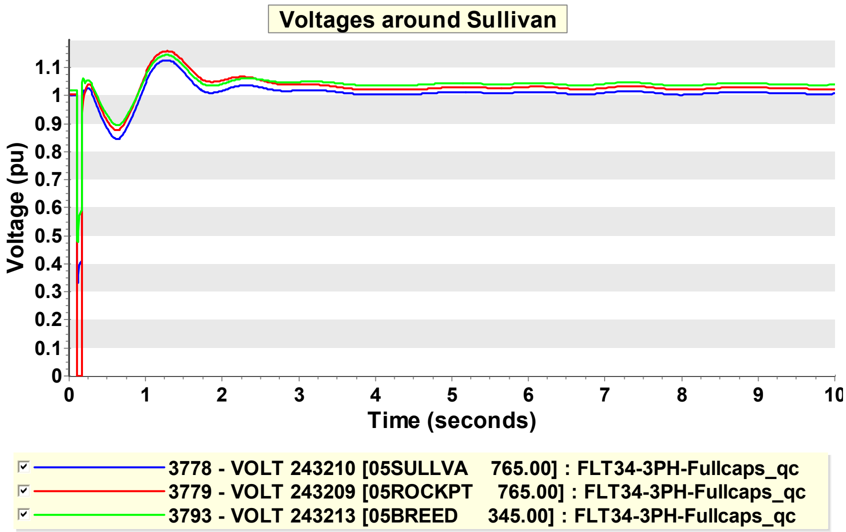

Figure 8-4: Voltages around Sullivan with One Pole Blocked (Full Cap Banks) – Fault # 34

8.2 2017 Light Load Case Results

All 3ph faults showed stable dynamic performance of the study area. Unlike the Peak Load conditions, it was observed that Rockport units did not trip for the critical fault at the Rockport substation (Fault # 34) due to less dispatched generation of 1,760 MW at the Rockport plant (as opposed to 2,600 MW dispatched in Peak Load conditions). As shown in Figure 8-5, a voltage dip of 25.5% (measured voltage of 0.745 pu) was observed around the Sullivan area.

While this voltage dip is marginal against the performance criteria of 25% dip, Figure 8-6 shows the improved voltage performance when one pole is blocked.

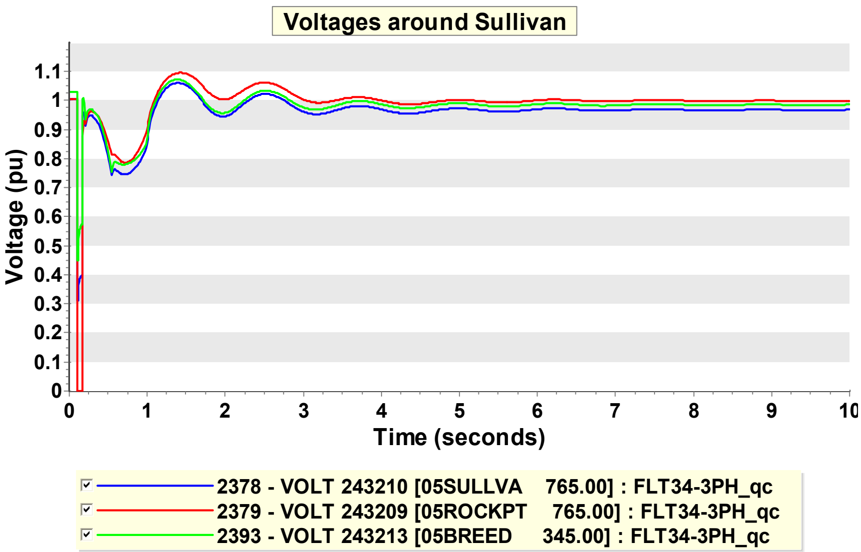

Figure 8-5: Voltages around Sullivan – Fault # 34

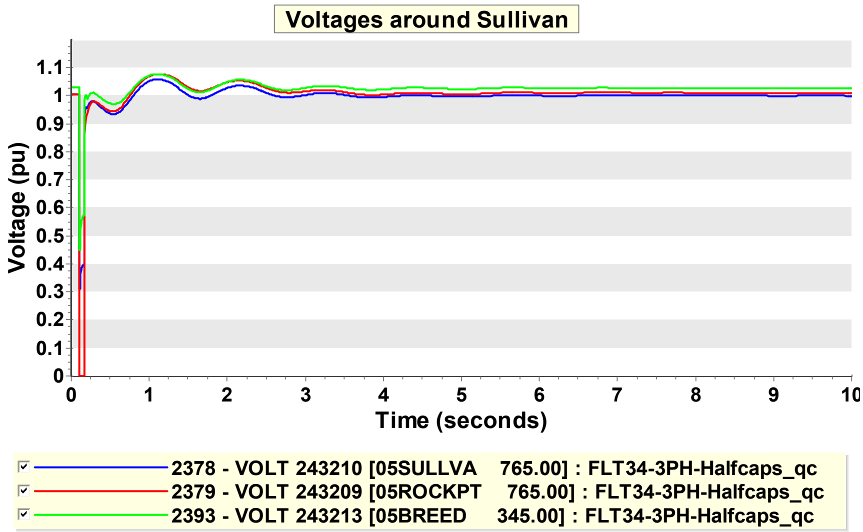

Figure 8-6: Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 34

8.3 2022 Summer Peak Case Results

All 3ph faults showed stable dynamic performance of the study area except for the critical fault at Rockport (Fault # 34). As shown in Figure 8-7, the Rockport generating units are tripped at about 1.51 seconds time and then the system voltages started to recover. However, the rest of the monitored units in the study area remained in synchronism with the system thus tripping of Rockport units does not have further adverse effects on rotor angle stability of the study area.

Figure 8-8 shows the voltage performance at Sullivan with one of the HVDC lines blocked and with corresponding reduction of reactive compensation at the converter stations by half in size. The Rockport units did not trip and the voltages are well recovered. However, the observed voltage dip is about 38.2% (measured voltage of 0.618 pu) not meeting the desired voltage performance criteria. Note that the Rockport units have tripped for the similar situation when the GBX Project is connected to the 765 kV bus at Sullivan.

With full reactive compensation (switched shunts) available at the Sullivan inverter followed by one pole blocking (as opposed to reducing by half in size), it was observed that the Rockport units remained on-line and the Sullivan side voltages recovered as shown in Figure 8-9.

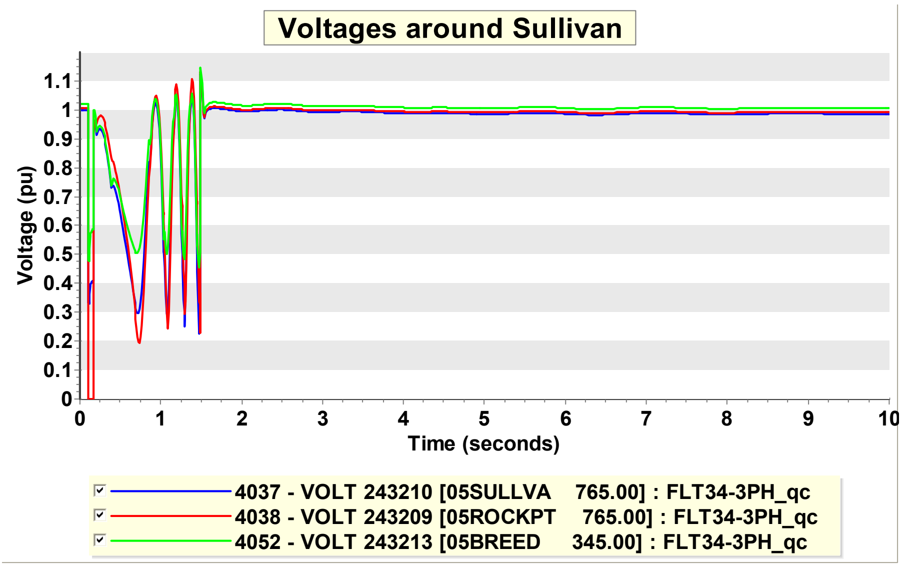

Figure 8-7: Voltages around Sullivan – Fault # 34

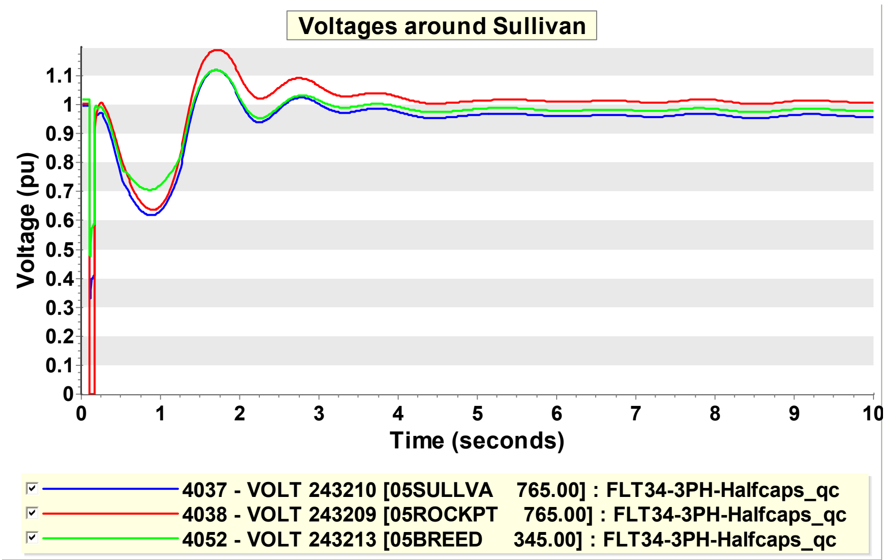

Figure 8-8: Voltages around Sullivan with One Pole Blocked (Half Cap Banks) – Fault # 34

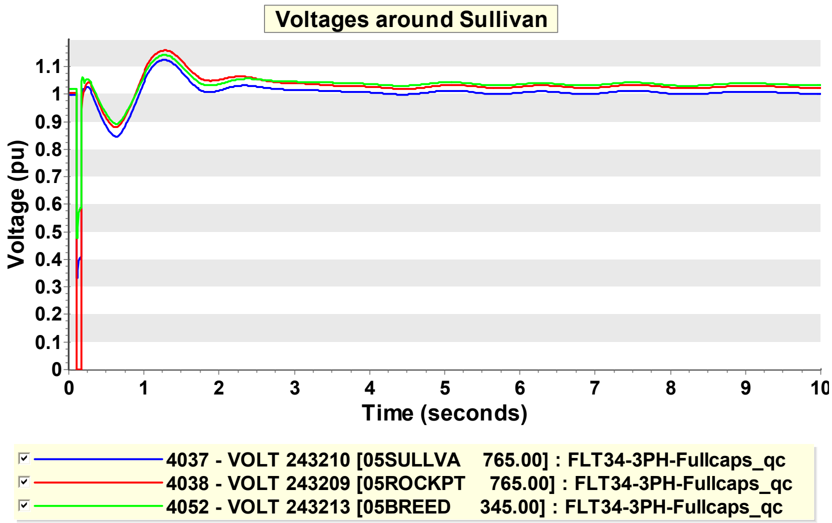

Figure 8-9: Voltages around Sullivan with One Pole Blocked (Full Cap Banks) – Fault # 34

8.4 Comparison of 765 kV and 345 kV Connections

We observed that the reactive requirement at Sullivan substation is higher for the 765 kV connection option mainly because of the losses across the GBX Project transformers and the increased flow on the 765/345 kV transformer to Breed. This reduction in reactive power consumption for the direct 345 kV connection option (as no transformation is required in this case) is contributing to the better voltage performance for faults at Sullivan and Rockport.

Figure 8-10 shows the voltage performance for a 3ph fault at Sullivan (Fault # 29) with the 765 kV connection option. The voltage performance for the same fault with 345 kV connection option can be seen in Figure 8-11. It is evident from these figures that the 345 kV connection offers better voltage performance for faults at Sullivan.

Also for faults at Rockport (Fault # 34), the 2017 Light Load scenario with 345 kV connection option showed much better voltage recovery (refer to Figure 8-5) compared to that of 765 kV connection option (refer to Figure 4-8).

In peak loading conditions with 765kV connection option, the Rockport units tripped for the same fault (Fault # 34) when one pole was blocked with the reduced capacitor banks at the Sullivan inverter station as shown in Figure 4-3 and Figure 4-14. For the similar condition with 345 kV connection option, it was observed that the Rockport units did not trip as shown in Figure 8-3 and Figure 8-8.

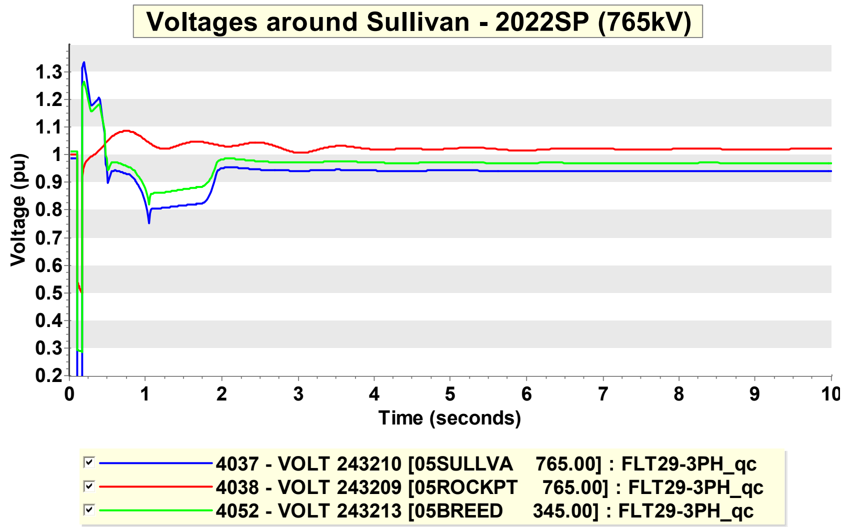

Figure 8-10: Voltage Performance for Fault # 29 – 2022SP 765 kV Connection Option

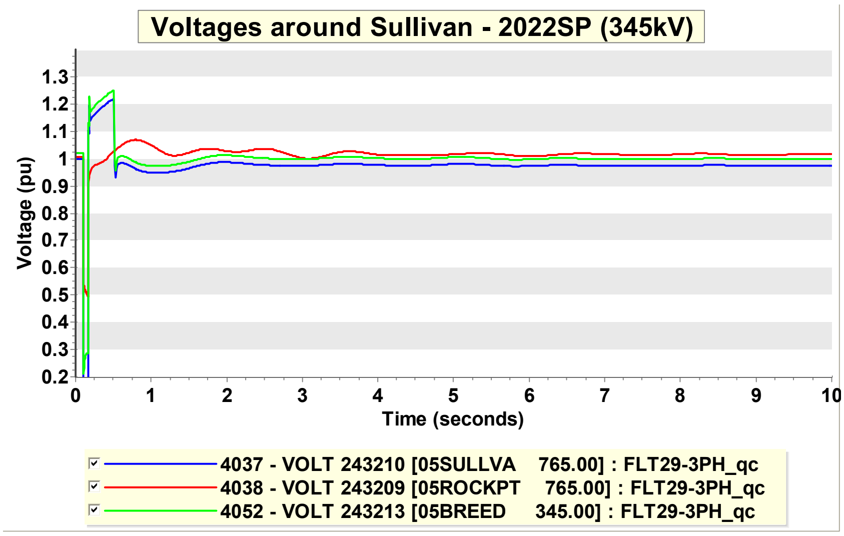

Figure 8-11: Voltage Performance for Fault # 29 – 2022SP 345 kV Connection Option

8.5 Observations

In general, similar results were observed for both 765 kV and 345 kV connection options at Sullivan. However, better voltage performance can be observed with 345 kV connection option.

Section

9

Conclusions

The following are the main conclusions of the system stability analysis.

- As proprietary HVDC models from the yet to be selected HVDC vendor are not available, HVDC models from the PSS/E library are used. These HVDC models do not fully capture the control capability of the HVDC converter stations and therefore up to a 900 MVAr synchronous condenser is required, from a modeling perspective, for the PSS/E stability models to solve by to improving the short circuit levels (i.e. system strength) at the Clark County 345 kV substation. This condenser was considered in all cases. Note, once proprietary HVDC models are provided by the HVDC vendor, the control capability of the HVDC converter can be properly modeled and the required amount of synchronous condensers could be reduced. Furthermore, for reliability and practical reasons, smaller parallel synchronous condensers would be used to make up the required improvement in short circuit levels. This synchronous condenser is to be optimized at the time of the GBX project design

- The 2017 Summer Peak case showed stable study area dynamic performance for all selected faults except for the 3ph fault at Rockport substation (Fault # 34)

  – For this particular fault, all on-line generating units at the Rockport plant have stepped out of synchronism with the rest of the system. Tripping of these units does not have adverse impact on the rotor angle stability of rest of the study area

  – By reducing the GBX project generation by 1,500 MW (achieved by blocking one pole), the Rockport generating units remain on-line and in synchronism with the system. Note that it is required to have full reactive compensation (switched shunts) at all converter stations to meet the voltage performance criteria

- The 2017 Light Load case showed stable study area dynamic performance for all selected faults except for Fault # 34. For this fault, the voltages around Sullivan substation area did not meet the voltage performance criteria

  – By reducing the GBX project generation by 1,500 MW (achieved by blocking one pole) the voltages around Sullivan substation did meet the voltage performance criteria

- The 2022 Summer Peak case showed stable study area dynamic performance for all selected faults except for the 3ph fault at Rockport substation (Fault # 34)

  – For this particular fault, all on-line generating units at Rockport plant have stepped out of synchronism with the rest of the system. Tripping of these units does not have adverse impacts on rotor angle stability of rest of the study area

  - By reducing the GBX project generation by 1,500 MW (achieved by blocking one pole), the Rockport generating units remain on-line and in synchronism with the system. Note that it is required to have full reactive compensation (switched shunts) at all converter stations to meet the voltage performance criteria

- The 3ph fault at Sullivan followed by the trip of the line to Rockport (Fault # 34) appears to be severe for peak load conditions from a voltage perspective but showed stable study area performance and met the voltage performance criteria

- With a prior outage of a line at Clark County, a 3ph fault that trips the second line (N-1-1 outage) requires up to approximately 877 MW disconnection of GBX Project wind generation

- During the double pole outage condition, transient currents with a peak of 148% (2017 Light Load) were observed along the 345 kV lines connected from Project rectifier station to Clark County. However, this peak exists for only few tenths of a second

- The stability analysis of the GBX Project with the 345 kV connection option showed similar results as that of the 765 kV connection. However, better voltage performance can be observed with the 345 kV connection option

Overall, the interconnection of the GBX project showed a stable study area dynamic performance for the selected disturbances, with few exceptions especially in the Peak Loading conditions. The recommended solution to the unstable cases is reduction of GBX project generation by 1,500 MW (tested by blocking one pole) while maintaining full reactive compensation (switched shunts) at all converter stations for the critical faults at the PJM side and approximately 900 MW (877 MW) reduction of GBX project generation (tested by disconnecting project wind generation) for critical N-1-1 conditions at the SPP side.

A 900 MVAr synchronous condenser is proposed to improve the short circuit capability in the Clark County area to increase the SCR at the POI of the expected wind generation. It may be possible to reduce the size of the synchronous condenser by HVDC controls at converter stations, as well as the required number of smaller parallel units; however, this was not considered in this study and should be considered during the project reactive power requirement optimization stage.