Transmission Planning Standards for the Baltimore Gas & Electric Company Transmission System

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Record of Revision

Revision	Description of Change	Approval	Date
0	Issued prior to development of a TAMU formal tracking and approval process	Not formally signed	March 1, 2004
1	Add Section II to Clarify Methods and Objectives Incorporate Substation Expansion Criteria	See Original	March 12, 2007
2	Made changes to update document to reflect the change from MAAC compliance to RF and NERC standards compliance	See Original	March 19, 2009
3	Clarify RAS requirements	See Original	March 22, 2010
4	Revised criteria for cables, transformer protection and substation design and also added requirements for dedicated facilities,	See Original	August 27, 2012
5	Revised section labeling, Revised Radial load criteria to address PJM criteria and number of allowable customers (Sections 4.2.3.6, 6.1)	See Original	March 24, 2014
6	Revised section 7 to reflect NERC standard compliance, Revised schematic diagrams to complement Transmission one line, Add definition for Interconnection Customers/ Developers Administrative changes	Eric Yeh Transmission Planning	February 29, 2016

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1. Introduction

The Baltimore Gas and Electric Company (BGE), a regulated energy delivery company in Central Maryland, is a subsidiary of the Exelon Corporation (EXC).

BGE is an electric and gas public transmission and distribution utility company with a 2,300-square-mile service territory that covers the City of Baltimore and all or part of ten counties in Central Maryland.

BGE’s transmission facilities are connected to those of neighboring utility systems as part of the PJM Interconnection. BGE is a member of the Regional Transmission Organization (RTO), PJM, in the Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia areas. Membership provides opportunities for bulk power sales and allows the use of larger, more efficient generating units, resulting in lower costs to customers and increased service reliability.

Under the PJM Tariff and various agreements, BGE and other market participants can use regional transmission facilities for energy, capacity and ancillary services.

BGE is committed to providing safe and reliable service to our customers through the operation, maintenance, modification and expansion of the electric system to meet the existing and future needs of our customers.

This will be done by responsibly planning and constructing interconnection facilities, transmission systems, distribution systems, substations, and land for future substations and right-of-ways.

The BGE planning standards and principles discussed in this document are intended to provide for the development of an economical and reliable transmission system. At the very minimum, BGE’s transmission planning standards for the bulk electric system are consistent with Reliability*First* Regional Reliability Council Standards and the North American Electric Reliability Corporation (NERC) Planning Standards. As the regional RTO, PJM is responsible for planning the bulk transmission system, including BGE’s facilities, under the PJM Open Access Transmission Tariff and Schedule 6 of the PJM Operating Agreement.

The application of prudent engineering and business judgment must concurrently be exercised along with the employment of these standards. Circumstances may dictate that these standards and philosophies as discussed herein require modification in the future. Therefore, the employment of these standards should not be used to preclude the consideration of other sound designs or proposals.

2. Planning Objectives and Methods

2.1. Planning Objectives

The BGE system has been planned and constructed over the last 100 years. During that time the needs and methods have been in a state of continuous evolution. Because it is not feasible to continuously redesign the entire system, much of the existing infrastructure was built in a manner that are not ideal for today's needs. The objective of this standard is to define the methods and practices that BGE feels are appropriate to provide the characteristics that are desirable in today's environment. These are some of the characteristics considered when planning the expansion of the BGE Transmission system:

- Reliability
- Security
- Public Safety
- Personnel Safety
- Operability
- Environmental Impact
- Economics
- Flexibility and future expandability
- Adequacy

2.2. Planning Methods

The BGE Transmission System consists of assets at three voltage levels. The 500kV system functions to import power from other parts of the PJM system. This power is fed to the BGE 230kV system at our 500/230kV stations. The 230kV system transmits power to a number of 230/115kV stations around the BGE system. In addition to the power taken from the 500kV system, the 230kV system serves to connect local generation. There are also a few 230kV lines that interconnect with neighboring utilities.

Power is supplied to the 115kV system at our 230/115kV substation as well as from a number of local generating stations. The 115kV system connects to the 230kV system at a number of places. In some cases, substations are supplied directly from a network connected 115kV station; but in many instances, two 115kV radial circuit taps extend from the network system to supply one or more distribution substations.

In general, load on the BGE system is served from the 115kV system. In some instances, BGE connects load directly to the 230kV system. This is general only done if 115kV circuits are not available or when security or expected loads dictate the necessity to do so. BGE does not allow load to be connected directly to the 500kV system.

3. Glossary

ASPEN (Advanced Systems for Power Engineering, Inc.) – The software company that makes ASPEN Oneliner and the ASPEN Breaker Rating Module used by BGE for circuit breaker short circuit analysis.

Bulk Electric System – BGE equipment and facilities 100kV and above that meet the ReliabilityFirst definition of the Bulk Electric System. These facilities are provided by the official BGE BES facilities list.

BGE Transmission System – The system of Extra High Voltage (EHV) and High Voltage (HV) facilities within the BGE Transmission Zone of the PJM Transmission System, including equipment and facilities 100kV and above. These facilities include BES facilities as well as radial circuits and substations that do not meet the ReliabilityFirst BES facility definition.

Bus – When referring to the term “bus” in these standards, all devices that would be initially interrupted, or the devices within a zone of protection including a bus should be considered part of the bus. Bus outages are significant when evaluating the transmission system for voltage drop or emergency thermal rating violations.

Bus Section – “Bus section” refers to any section of a bus or section of another element that can be isolated via any switching device and operated by a bus. Bus section outages are significant when evaluating the transmission system for voltage magnitude or normal thermal rating violations.

Cascading System Disturbance – A system disturbance where the interruption of a facility within a single zone of protection causes a second adjacent zone of protection to operate interrupting subsequent facilities and then causing a third adjacent zone of protection to operate. This in turn could possibly cause other system equipment to be interrupted leading to a system collapse or blackout.

Dedicated Facility - A facility that is constructed for the use of a single customer.

Element - Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.

Extra High Voltage (EHV) – Those transmission facilities operating at a voltage of 345 kV or higher.

High Voltage (HV) – Those transmission facilities operating at a voltage of 115 kV or higher but less than 345 kV.

Interconnection Customers/Developer – A company or group seeking to interconnect with the BGE Transmission System. The interconnection customer/developer may be seeking to connect Generation, Transmission, or End-User (load serving) facilities

LAS (Load Analysis Subcommittee) – PJM Planning Subcommittee that is responsible for the long-term forecast of PJM peaks, energy and load management by zone.

MMWG (Multiregional Modeling Working Group) – The NERC working group that develops the transmission loadflow models used throughout the industry for planning and reliability analysis.

NERC (North American Electric Reliability Council) – The regulatory entity whose mission is to ensure the reliability of the Bulk-Power System in North America. NERC develops and enforces reliability standards and is subject to oversight by the Federal Energy Regulatory Commission.

Network Transmission Facility – A transmission facility whose main purpose is to transmit power over distances rather than supply power directly to load.

Over-duty Circuit Breaker – A circuit breaker with available fault current in excess of its interrupting capability.

Radial Transmission Facility – A non-networked circuit on which power tends to flow in one direction to serve load. Radial transmission facilities on the BGE System are operated at 230 kV and 115 kV.

RF (ReliabilityFirst) – The NERC regional reliability council that BGE is a member of or any successor organization.

PSS/E (Power System Simulator for Engineering) – The software product produced by Siemen's Power Technologies, Inc. (PTI) used by BGE for loadflow, short circuit, and stability analysis.

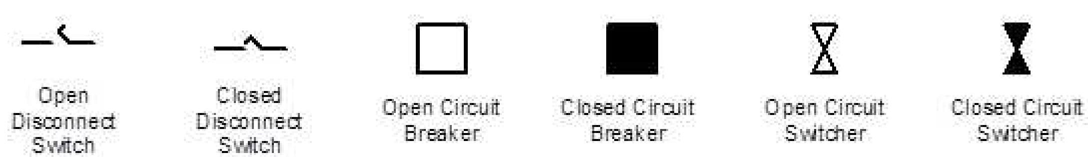
RTEP – (Regional Transmission Expansion Plan) – The transmission system plan that is developed by PJM, which encompasses the entire PJM footprint and covers a five-year future timeframe.

RTEPP – (Regional Transmission Expansion Planning Process) – The process through which PJM develops the RTEP.

RAS – (Remedial Action Scheme) – A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, curtailing or tripping generation or other sources, curtailing or tripping load, or reconfiguring a System(s).

Zone of Protection - A section of the transmission system, separated or bounded by breakers, which is automatically isolated from the balance of the system when a fault occurs within its boundary.

Symbols:



4. Reliability Criteria & Testing Methodology

4.1. Transmission System Model Creation

4.1.1. Introduction

In order to perform thermal steady state analysis, voltage and reactive power analysis, short circuit analysis, dynamic analysis, and emergency import capability analysis with any degree of confidence, all of the major elements of the electrical system must be included in the model along with their appropriate electrical characteristics and power capabilities. These include but are not limited to transmission lines, transformers, capacitors, reactors, circuit breakers, generators, and loads. The model is developed on a per unit basis on a 100 MVA base.

4.1.2. Overhead Transmission Lines

Transmission lines within BGE's service territory should be modeled with all appropriate electrical parameters and capabilities. For overhead lines, the electrical parameters are calculated using the physical parameters of each transmission circuit.

All of the appropriate physical characteristics of the conductor and the structures supporting those conductors are entered into an impedance calculation program which then provides the total positive sequence impedance, zero sequence impedance, charging, and mutual coupling inductance of each line. This data is then used in the load flow, stability, and short circuit models.

For proposed lines, the values are calculated using typical values for similar transmission lines. Once the lines are constructed, the actual electrical parameters are calculated from the as-built physical characteristics. For existing lines that have been modified, the new electrical parameters are to be calculated if the physical change is determined by BGE to be electrically significant.

The thermal ratings of overhead lines are calculated using the PJM Transmission and Substation Design Subcommittee's Bare Overhead Conductor Rating report as a guide. Normal and emergency thermal ratings are input into the transmission system models. All ratings changes are reflected in the electrical models, regardless of the degree of change.

4.1.3. Underground Transmission Lines

All of the appropriate physical characteristics of both new and existing underground cables are entered into an impedance calculation program which then provides the total positive sequence impedance, zero sequence impedance, and charging. This data is then used in the load flow, stability, and short circuit models. For new underground circuits, following a cable (fluid filled or solid dielectric) fault, reclosing should not be used to test the circuit.

Underground lines associated with overhead should have cable fault detection when terminated. The fault detection will prevent reclose into the faulted cable.

4.1.4. Interconnection to Transmission Owners

As part of the PJM RTO, BGE has interconnections to other transmission owners at the 500 kV, 230 kV, and the 115 kV levels.

The impedance calculations for these lines are the joint responsibility of PJM and the transmission owners. Each transmission owner verifies the impedance value of the line up to the service territory boundary.

It is also the responsibility of the transmission owner to produce and maintain the electrical ratings of the interconnection lines up to the point of interconnection, including any substation limitations. The lowest ratings of each circuit are used by PJM in the planning models.

4.1.5. Interconnection Customers

The data associated with all interconnection customers, including generation and merchant transmission, are provided to PJM by the interconnection customer. This data is entered into system models by PJM.

Any changes to existing generators that impact the short-circuit, load flow or stability models are provided by the interconnection customer to PJM. PJM then includes these values in the models. Changes to existing interconnection customer facilities are also provided by the interconnection customer to PJM.

For new interconnection customers, the data and modeling of all the interconnection facilities are provided by PJM, using data from the interconnection customer and the transmission owner. The transmission owner provides the parameters for any facilities that the transmission owner constructs for an interconnection customer.

4.1.6.Transformers

The Bulk power transformers are rated in accordance with the BES methodology maintained by the BGE Substation Engineering organization.

4.1.7. Loads

All of the loads are input at each load-serving transformer low side bus that is represented in the electric system model. Several load levels are modeled as required by the MMWG Schedule for each study year. The typical loads represented are:

- Summer Peak Load – defined as summer peak demand expected to be served, reflecting load reductions for peak shaving.
- Winter Peak Load - defined as winter peak demand expected to be served, reflecting load reductions for peak shaving.
- Light Load – defined as a typical early morning load level in April, modeling at or near minimum load conditions.
- Spring Peak Load – defined as typical April peak load conditions.
- Fall Peak Load – defined as typical October peak load conditions.

The most current area load forecast is applied at each transformer bus in the load flow model. The total system load in BGE's service territory is then scaled to match the forecasted seasonal load for BGE's Service Territory as provided by PJM's Load Analysis Subcommittee (LAS). This same methodology is applied to load data modeling within models that are provided to the MMWG as well as the PJM RTEP and other NERC Planning models provided by BGE.

4.1.8. Capacitors

In the models, distribution capacitors are represented as separate and distinct pieces of equipment and not netted with the reactive load.

For each transmission supplied substation, capacitors are modeled on the low-side of the substation assuming unity power factor on the high side, approximating the sum of all of the 13kV line capacitors, distribution supplied substation capacitors, and 34.5kV line capacitors, and transmission supplied substation capacitors expected to be available for the time frame being studied.The capacitors are modeled with continuous operation, showing the small increments of capacitance that can be brought on during actual system operation.

Bulk Power capacitors are modeled to reflect the blocks of capacitance that are switched on with the capacitor's operation. Values are input into the models that best represent the control scheme of the capacitors on the distribution system.

Actual operating voltage schedules are set by distribution planners and followed as best as possible when modeling the transmission system. Section 4.2.5 better clarifies system voltage scheduling.

4.1.9. Reactors

Most reactors in BGE's system are located on distribution feeders and therefore are not represented in the transmission models. For those reactors located on the transmission system or on the low-side buses supplying distribution feeders, impedance values are calculated and included in the transmission system model.

4.1.10. Circuit Breakers

BGE maintains a circuit breaker database for all breakers on the system. Data for short circuit interrupting capabilities, contact parting times, and nameplate interrupting times are obtained from this database and these values are entered into the ASPEN transmission system short circuit model. All of these parameters are based on ANSI Standard C37.010-1979. In addition to each breaker's physical characteristics, the ASPEN short circuit models additionally include system configuration information.

4.1.11. Transmission Model Completion

All of the components discussed in sections 4.1.2 to 4.1.10 are joined together to create BGE's Transmission System model. The model represents all available facilities and creates the normal system configuration of the transmission system. BGE supplies modeling data to PJM to combine with information from all of the transmission owners, generation providers, and load serving entities, as well as transfers between adjacent control areas to develop the PJM RTEP models. The PJM RTEP models are used to perform analysis and assist in the development of future expansion plans by PJM members.

PJM provides the same data to Reliability*First* to combine with information from all of the transmission owners, generation providers, and load serving entities, as well as transfers between adjacent control areas within the *ReliabilityFirst* footprint to develop MMWG models used to perform reliability assessments.

The PJM RTEP and MMWGRF models are then used by BGE along with load data from our internal distribution areas to develop power flow models for internal analysis. The system is evaluated based on normal system configuration and abnormal or emergency system configurations as set forth within this document.

4.2. Steady State Analysis

4.2.1. Introduction

To ensure that BGE's transmission system is planned and operated safely, economically, and reliably, steady state analysis must be performed. This analysis is performed to ensure that the system meets all NERC, RF, PJM and BGE standards under normal operations and given a variety of outages or contingencies and other operating conditions, where applicable.

4.2.2. Creating Contingency Files

The BGE Bulk Electric System is tested based on the NERC, PJM, RF, and BGE standards. These standards define the tests for system operation with no contingencies, single element contingencies and multiple element contingencies. The contingency definitions used by BGE are the same as applicable NERC TPL contingency definitions. The remaining BGE high voltage transmission system is tested based on these contingencies and the BGE criteria laid out within this document.

These tests are used to evaluate how the system responds to each of the contingencies, which determines whether or not there are reliability criteria violations.

Actual operation of the system, including relay operation, automatic changeovers, and outage sequencing are modeled as accurately as possible using input from transmission operations and system protection engineers. These two organizations are the most familiar with the actual operation and maintenance practices that determine the system configuration during normal and abnormal operation.

Normal, abnormal, and emergency configurations are evaluated against the NERC, RF, PJM or BGE reliability requirements as appropriate.

4.2.2.1. Line Outages

Many of the contingencies that are evaluated are outages of transmission circuits. For the purpose of analysis, transmission circuits, in general, are defined as the path or facilities between circuit breakers that are within one zone of protection. In practice, transmission circuits can supply more than one distribution substation between breakers resulting in the loss of more than one transformer for a single line outage. In this case, it must be determined whether the stations supplied are equipped with high-side or low-side automatic changeover schemes that are designed to transfer load to other transmission-supplied substations following such contingencies. For these scenarios, distribution planners are consulted to verify the modeling of distribution transfers resulting from the transmission outages. The worst-case outages must be determined and accurately simulated.

4.2.2.2. Transformer Outages

Transformer Outages follow the same rules as circuit or line outages as discussed above; i.e. each contingency should be simulated by interrupting facilities within one zone of protection. The simulation must also recognize that some transformer outages result in the loss of circuits or other transformers. Each outage and the particular cause of the outage will determine how the system is reconfigured. As with line outages, it must be determined where load transfers occur and how the other transformers are impacted.

4.2.2.3. Shunt Device Outages

Shunt device outages follow the same rules as circuit or line outages as discussed above; i.e. each contingency should be simulated by interrupting facilities within one zone of protection.

4.2.2.4. Bus Outages

Some bus outages will result in the loss of transformers or transmission circuits. As such, the guidelines for transformer and line outages should be followed when simulating bus outages. Bus outages on the BGE system will interrupt all facilities within the zone of protection that are solely dependent on the bus for system connectivity.

As with the previous contingencies, the impacts to the rest of the transmission and distribution system must be reviewed to see how the system automatically responds.

4.2.2.5. Generator Outages

Most generators are supplied through a synchronizing breaker, and thus, the loss of a generator is isolated from the rest of the system. Each switching station that generation is connected into should be reviewed carefully to verify that the disturbance is isolated, i.e. no other equipment is lost.

To more realistically simulate the network response to the sudden loss of one or more generators, an inertial power flow solution is normally utilized when determining the steady state effects of generator contingencies.

4.2.2.6. Double Circuit Tower Line (DCTL) Outages

The simultaneous loss of any two transmission circuits contained on the same overhead tower line is considered a DCTL contingency excluding circuits that share a common structure for less than 1 mile When simulating DCTL contingencies, each circuit loss is simulated as described earlier and proper load transfers are reflected.

4.2.2.7. Stuck Breaker Operation

A stuck or failed circuit breaker event will usually result in the loss of adjacent lines, transformers, buses and/or generators. As such, a combination of all of the above activities discussed in sections 4.2.2.1 to 4.2.2.5 is used when creating contingency files for stuck breaker operation. Note: Breaker failure contingencies are limited to a single failed breaker

4.2.2.8. Extreme Events

Most events are a result of one or more of the scenarios described above. As such, the contingency files for modeling extreme events are set up using one or a combination of the contingencies described previously.

Extreme events are those events beyond which any NERC, RF, PJM, or BGE standards require a corrective action plan to resolve. Extreme events are analyzed to determine the risk of cascading outages, voltage collapse, or other widespread system problems.
These initiating events include but are not be limited to:

- Loss of a tower line with three or more circuits
- Loss of all Transmission lines on a common Right-of-Way
- Loss of a switching station or substation (loss of one voltage level plus transformers).
- Loss of all generating units at a station
- Loss of a large Load or major Load center

4.2.3. Thermal Analysis

4.2.3.1. Introduction

The BGE *Bulk Electric System* must meet the requirements of all NERC, RF, PJM, and BGE Reliability Principles and Standards. *All BGE BES facilities* must be able to withstand the occurrence of any single, DCTL, stuck breaker, or two element contingency (N-1-1) on any BGE Transmission System facility.

The remainder of BGE's transmission system is comprised of radial facilities. These facilities are evaluated using load forecasts as provided by BGE Distribution Planning. Solutions will be considered for violations of BGE radial criteria but implementation will be decided based on other factors that include feasibility, cost, and customer sensitivity.

4.2.3.2. Single Element

The loss of any single transmission line, generating unit, transformer, or bus, in addition to normal scheduled outages of transmission system facilities, should not result in any facility exceeding its applicable emergency thermal rating or in any violation of applicable voltage criteria (see Section 4.2.4). After the outage, the system must be capable of readjustment so that all equipment (on the BGE and neighboring systems) will be loaded within normal ratings and operating at appropriate voltage levels. When readjusting the system to keep loading within normal ratings, bus outages may be adjusted to bus section outages where proper switching is available. In addition, substations with straight bus and double bus bar configurations will be excluded from this analysis. These outages will be considered as Abnormal and Extreme Outages as noted in Section 4.2.3.5.

4.2.3.3. Two Elements (N-1-1)

All BGE BES facilities should be tested to ensure they comply with the following criteria:

- After occurrence of an outage specified in the single element criteria and readjustment of the system, the subsequent outage of any remaining generator, transformer or line must not cause the short time emergency rating of any facility to be exceeded or any applicable voltage criteria to be violated.

- After the second outage, the loading on the remaining equipment must be within applicable emergency ratings and voltage criteria must not be violated for the probable duration of the outage.

4.2.3.4. Multiple Facility Outages (DCTL and Stuck Breaker)

All BGE BES facilities should be tested to ensure they comply with the following criteria:

- The loss of any double circuit tower line, failed circuit breaker, or the combination of facilities resulting from a line fault coupled with a stuck breaker in addition to normal scheduled generator outages should not exceed the short-term emergency rating of any facility or violate applicable voltage criteria.

- After the outage, the system must be capable of readjustment so that all equipment will be loaded within applicable emergency ratings and voltage criteria will not be violated for the probable duration of the outage.

4.2.3.5. Extreme Events

All extreme events, those beyond our defined planning criteria cannot always be analyzed. A good effort shall be put forward to examine as many conceivable extreme events as deemed necessary by transmission planners or system operations.

Although the system may be tested for these extremely unlikely events, mitigation of any problems caused by these types of disturbances shall only be implemented when a thorough cost benefit analysis indicates the mitigation is prudent.

4.2.3.6. Loss of Load

The BGE transmission system shall be planned so that, for the loss of any single element (generator, line, transformer, or bus section), there should be no loss of the supply to a distribution substation. For the loss of any two elements, the loss of load should not exceed 300 MW.

4.2.4. Voltage & Reactive Power Analysis

4.2.4.1. Introduction

The BGE transmission system nominal voltages are: 34.5 kV, 115 kV, 230 kV, and 500 kV. The cross town 34.5 kV system dates back to the early 1930's and still functions as a part of the transmission system. The operating ranges for these voltage levels during normal system conditions can be found in Table1 below.

Table 1 Range of Operating Voltages Under Normal Conditions

Nominal Voltage	Range in PU.
34.5 kV	0.95 - 1.04
115 kV	0.95 - 1.04
230 kV	0.95 - 1.05
500 kV	1.00 - 1.10

When performing steady state voltage analysis, an AC solution must be utilized. For normal system conditions (base case), system voltages must fall within the ranges above. For any single element, DCTL, stuck breaker, or two element, contingency, the two steady state voltage criteria stated below must be met.

4.2.4.2. Voltage Drop Analysis

First, system voltages directly after any event must not drop greater than the percentages listed in Table 2. This test is performed using a base case solved within acceptable tolerances and then adjusting the system to simulate each contingency. Base case voltages should be noted for later comparisons. When simulating each contingency, the case is solved in two steps. First, all equipment is locked, i.e. transformer taps, switched shunts, phase shifting transformers, and DC taps. Then, when feasible, generation voltage control is switched from the high side of each step up transformer to the generator bus and is regulated to the pre-contingency generator bus voltage. At this point the case is solved and voltages are noted and compared to base case voltages.

Table 2 Range of Allowable Voltage Drop Following Contingency Events

Nominal Voltage	Allowable Voltage Drop
34.5 kV	<5-10%
115 kV	<5%
230 kV	<5%
500 kV	<5-8%

4.2.4.3. Voltage Magnitude Analysis

Next, the case is resolved allowing generation voltage control to be placed back at the high voltage of the step up transformers and also allowing the proper equipment to adjust, *i.e.* transformer taps and switched shunts. Voltages should then be checked in order to verify that no voltages deviate from the ranges listed in Table 3 below.

Table 3 Range of Allowable Post Contingency Voltages Following System Readjustment

Nominal Voltage	Range in PU.
34.5 kV	0.95 - 1.05
115 kV	0.95 - 1.05
230 kV	0.95 - 1.05
500 kV	0.95 - 1.10

Sufficient megavar capacity with adequate controls shall be provided to supply the reactive system requirements within the BGE territory in order to maintain acceptable emergency transmission voltage profiles during all of the contingencies described in the Creating Contingency Files and Thermal Criteria sections 4.2.2 and 4.2.3 above.
The voltage criteria tests described above should be used as a screening tool to determine when and where reactive sources are needed. A detailed voltage collapse analysis should be performed when voltage deficient areas are identified.

4.2.5. Voltage Control Philosophy

4.2.5.1. Introduction

There are various strategies that can be employed to control voltage on an electric power system. The use of regulating transformers, load tap changing transformers, capacitors, generators, FACTS devices and synchronous condensers can all be used independently or in concert for voltage control.

BGE uses a combination of load tap changing transformers and capacitors with capacitors as its primary method of voltage control.

The information below generalizes our voltage control philosophy and may not be practical at all of our substations.

Note: The BGE transmission model described earlier does not completely model the operation of the voltage control system used by BGE. A fundamental key to BGE's voltage control lies with the load-biased response of line and substation capacitors on the distribution system, none of which are explicitly modeled in the transmission system models.

4.2.5.2. 500kV Loop

The 500 kV Loop is operated by PJM. BGE is provided power via 500 kV injection points at the Calvert Cliffs Switchyard, Waugh Chapel and Conastone. The 500kV voltage is operated normally between 500 kV and 550 kV per PJM's voltage criteria, at levels, which provides required support to the lower voltage systems within PJM.

4.2.5.3. 230kV Ring

PJM is also responsible for operating the 230 kV network system owned by BGE. BGE's 230 kV ring envelops the highest load density areas of BGE. It receives power from the 500 kV system via single-phase 500 kV-230 kV transformers at Conastone and Waugh Chapel.

There are several interconnections to the 230 kV ring. There are two with PEPCO; High Ridge to Burtonsville and Waugh Chapel to Bowie, two with PP&L; Conastone to Otter Creek and Graceton to Manor, and one 230 kV interconnection with PECO; Graceton to Cooper. The 230 kV voltage is not scheduled per se and varies as the 115 kV underlying system is maintained at targeted levels. The exception to this statement is the 230 kV bus voltage at Brandon Shores, which is the regulated point for the Brandon Shores generation.

The 230 kV system also supplies load directly via several 230/34 kV and 230/13 kV transformations. At these substations, all of the transformers are equipped with LTCs and are scheduled to maintain unity voltage on the low-side of the transformer at peak and 0.956 per unit at light load conditions. This is done by load biased voltage control using the LTCs. Load biased capacitors are utilized to manage VAR flows to achieve unity power factor to the transformer high-sides

4.2.5.4. 115kV Ring

The 115 kV ring is operated by BGE using 230/115 kV LTC's to meet the 115kV voltage schedule. The voltage schedule is defined to maximize the use of distribution capacitors and to allow a surplus of tap positions on the LTCs for peak load conditions.

The 115kV system is operated during light load conditions with 115kV voltage schedules set as low as 0.977 PU. This low 115kV voltage schedule coupled with a lower distribution voltage schedule minimizes the number of distribution capacitors operating to support voltage. As system loads rise to intermediate and peak levels, the 115 kV voltage schedule is adjusted within a range of 0.98 – 0.99 PU while the distribution system's voltage schedule rises with load, forcing distribution capacitors to operate & increasing distribution voltages. The 230/115 kV transformer taps are then driven into more bucking mode increasing VAR flow to the transmission system. When load levels approach90% of the forecasted system peak load, 115 kV voltage schedules are raised gradually within a range of 0.996 - 1.017 PU.

There are many 115 kV transformers that supply load directly to the 4.4 kV, 13.8 kV and 34.5 kV voltage levels. Most of these substations have fixed-tap transformers whose taps have been selected such that at peak, the low-side voltage of the transformer will be at 1 PU and achieve unity power factor to the transformer high-side when coupled with the line capacitor support.

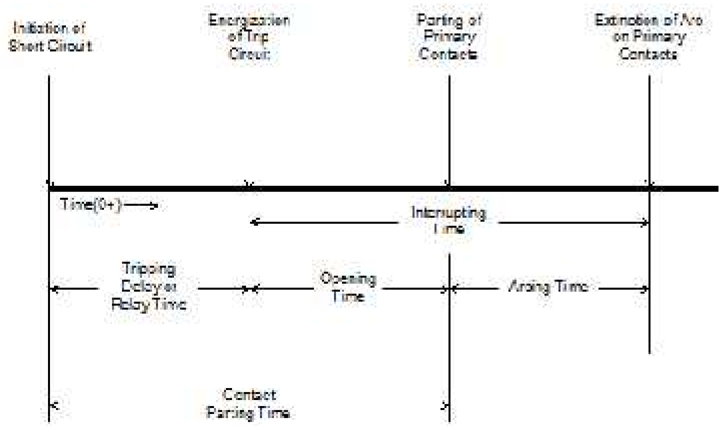
On the feeders supplied by these transformers, line capacitors are installed as close as possible to the load to also control voltages. Central controller at the substation or on an IT computer server (Yukon) supplying the feeders controls most of these capacitors. These control schemes are similar to the LTC control scheme in that they are either load biased voltage control or load biased VAR controlled.

4.3. Short Circuit Analysis

4.3.1.Introduction

Short circuit analysis is performed to ensure that available fault current levels do not exceed the interrupting capability on all BGE transmission system circuit breakers. This analysis is performed by Transmission Planning for all 115 kV, 230 kV, 500 kV circuit breakers along with the 34.5 kV breakers at the Westport, Gould Street, and Riverside 34.5 kV stations. BGE short circuit analysis is based on the ANSI/IEEE C37 Standards. There are three necessary components to consider when determining a breaker's fault duty:

1. Each circuit breaker's asymmetrical interrupting capability
2. The available fault current for each breaker depending upon the station configuration
3. The quickest times each breaker will begin to interrupt the fault (contact parting time-see Figure 1)



4.3.2. Circuit Breaker Database

Each circuit breaker interrupting capability and contact parting time is kept in the BGE circuit breaker database. Each circuit breaker's interrupting capability in kA, is determined from the asymmetrical interrupting capability at the operating kV and is adjusted for re-close if re-close is applicable.

The sequencing of a circuit breaker's reaction to a fault is shown in Figure 1. The initiation of the short circuit would occur at the initial occurrence of a fault (t=0). The time of concern when determining a circuit breakers fault duty is the time of contact parting. This is the time it takes a breaker's trip circuit to energize along with the time it takes the breaker's contacts to open. The contact parting time for each breaker is generated in the breaker database by the equation:

Contact Parting Time = Relay Time + Breaker Contact Start Time

The Breaker Contact Start time is determined by the nameplate cycles of the breaker and can be determined from the following logic statements:

Breaker Nameplate Cycles	Breaker Contact Parting Time Cycles
2	1
3	1.5
5	2.5
8	3.5

Table 4

If Cycles = 2 Then Breaker Contact Start = 1
If Cycles = 3 Then Breaker Contact Start = 1.5
If Cycles = 5 Then Breaker Contact Start = 2.5
If Cycles = 8 Then Breaker Contact Start = 3.5

Figure 1 Contact Parting Time

4.3.3. Performing the Analysis

BGE utilizes the ASPEN Short Circuit software to perform short circuit analysis. The PSS/e software may be used to verify the results obtained via the ASPEN program; however justification for over-duty breakers will be determined using the ASPEN Breaker Rating Module.

Each year, PJM and the PJM Transmission Owners develop a short circuit system model (positive and zero sequence) reflecting the system two years ahead. The model for the BGE system is developed following the methodologies described in section 4.1 of this document. This model contains all system enhancements planned for the study year along with all transmission and generation in service (connections operated as normally open are taken into consideration on an individual basis). BGE breaker information is entered into the ASPEN Breaker Rating Module per the above required information and a short circuit duty scan is performed annually and on an as needed basis.

For any circuit breakers identified as over-duty beyond 95% of their interrupting capability, a detailed analysis is required. This includes verification of all data entered into the ASPEN program. In addition, it may be critical that actual relay time will be modeled to develop more accurate contact parting time. The detailed analysis also includes verification of the equipment that each of the breakers are protecting. The following figures illustrate the various designs and protected equipment for each design.

4.3.3.1. Line Breakers

Each line breaker must be able to interrupt the greater of the available fault current from the group of protected equipment on each side of the circuit breaker. In the figures below, this would be either the total current for circuit 1 or the total current for circuit 2. The available fault current for each group of protected equipment needs to be checked with the circuit breaker(s) at the opposite end of the faulted line, both open and closed.

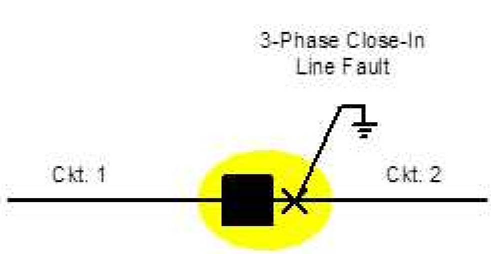


Figure 2 Line Breaker

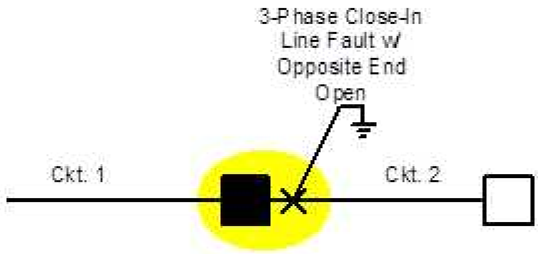


Figure 3 Line Breaker

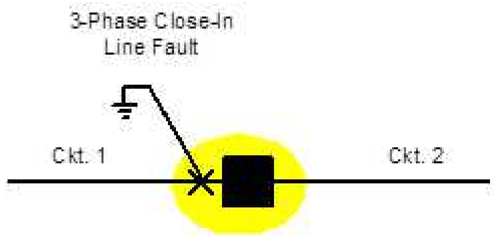


Figure 4 Line Breaker

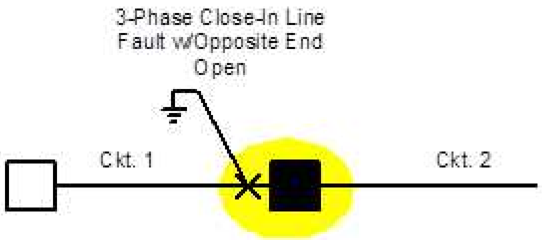


Figure 5 Line Breaker

4.3.3.2. Ring Bus

For a ring bus design, each breaker must be able to interrupt the greater of the total available fault current at the bus less the contribution from the equipment between the breaker under study and the adjacent breaker on either side (assuming the breaker under study is the last to open). For breaker B1 in the figures below, this would be the total fault current at the bus less the current from either circuit 1 or circuit 2. Again, for the ring bus design, the available fault current needs to be checked with the circuit breaker(s) at the opposite end of the faulted line, both open and closed.

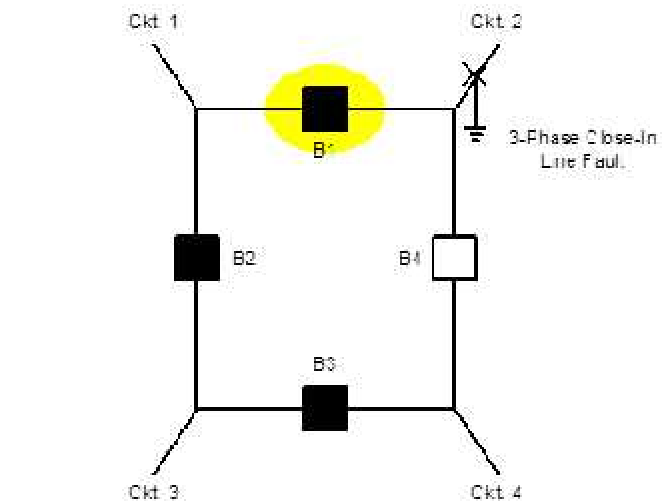


Figure 6 Ring Bus

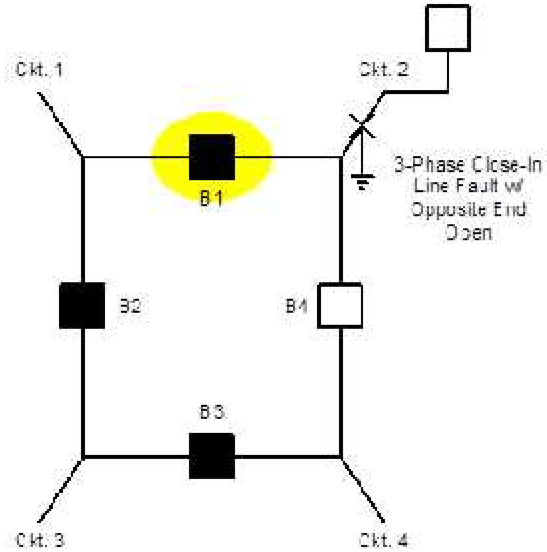


Figure 7 Ring Bus

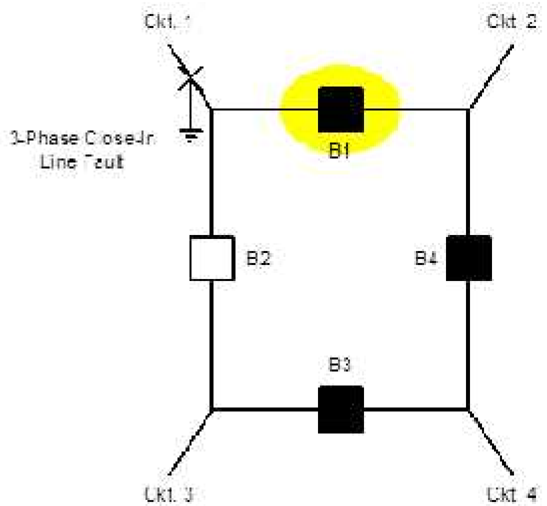


Figure 8 Ring Bus

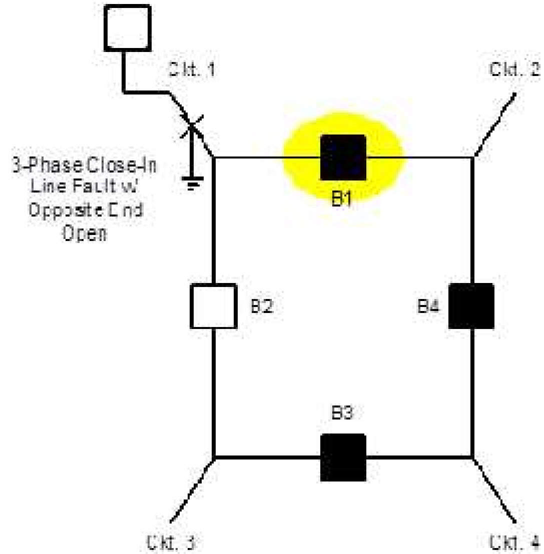


Figure 9 Ring Bus

4.3.3.3. Breaker & a Half

For a breaker & a half design, each breaker must be able to interrupt the total available fault current at the bus. For this analysis, the breaker under study is assumed to be the last to open. Each tie-breaker must be able to interrupt the greater of the total available fault current at the bus less the contribution from the equipment in either bay.

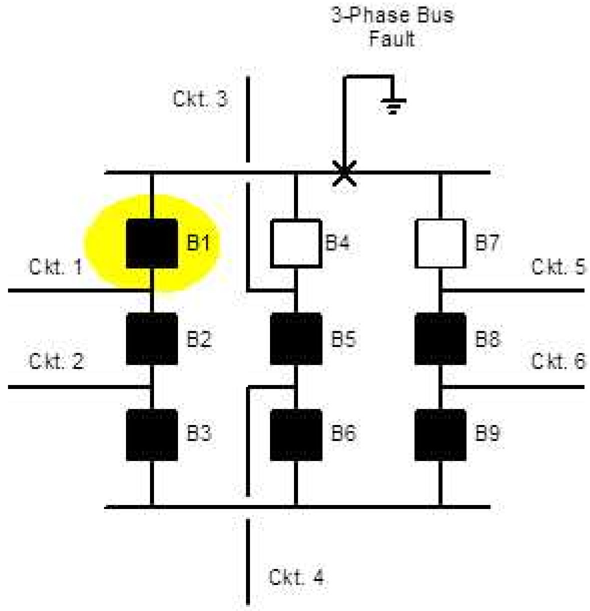


Figure 10 True Breaker & a Half

4.3.3.4. Breaker & a Half with Connections on Bus

For a breaker & a half station with connections on either bus, each bus breaker must be able to interrupt the greater of (1) the total available fault current at the bus less the contribution from the equipment connected to the bus or (2) the total available fault current at the bus less the contribution from the equipment contained within the bay of the breaker under study. Each tie breaker must be able to interrupt the greater of the total available fault current at the bus less the contribution from the equipment in either bay.

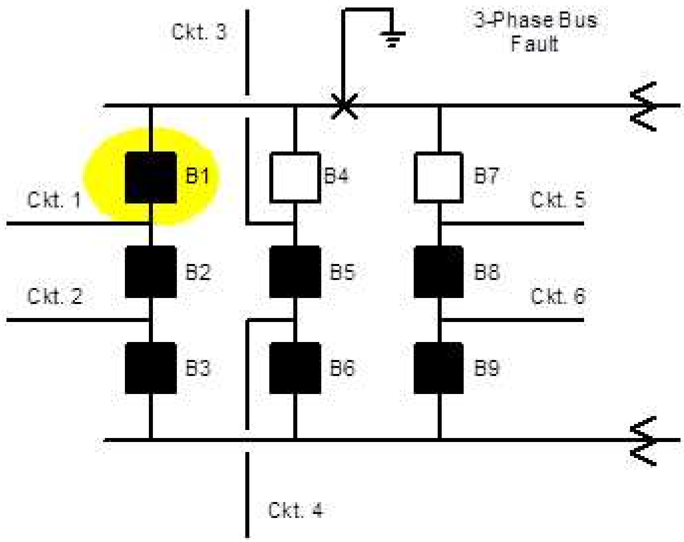


Figure 11 Breaker & a half w/ transformers or other connections on bus

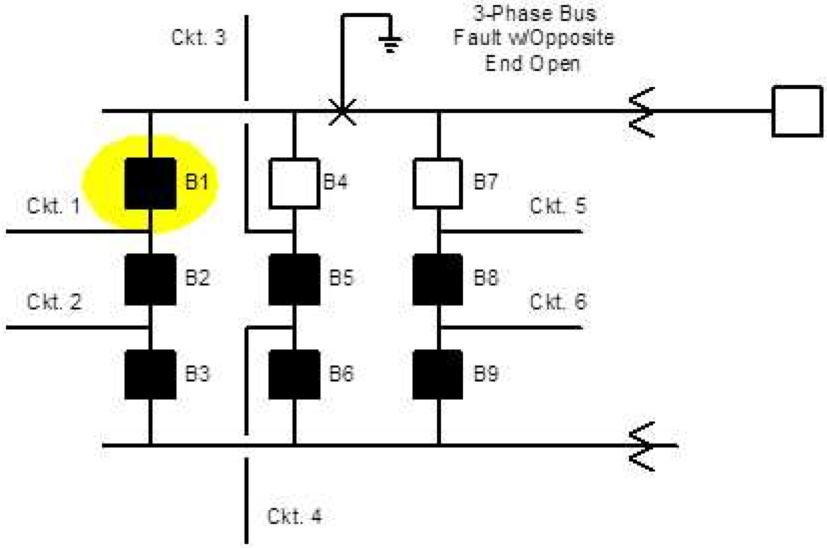


Figure 12 Breaker & a half w/ transformers or other connections on bus

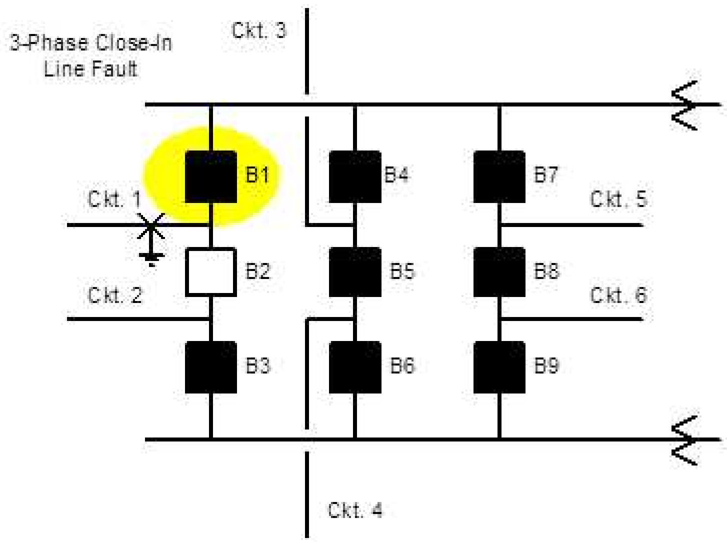


Figure 13 Breaker & a half w/ transformers or other connections on bus

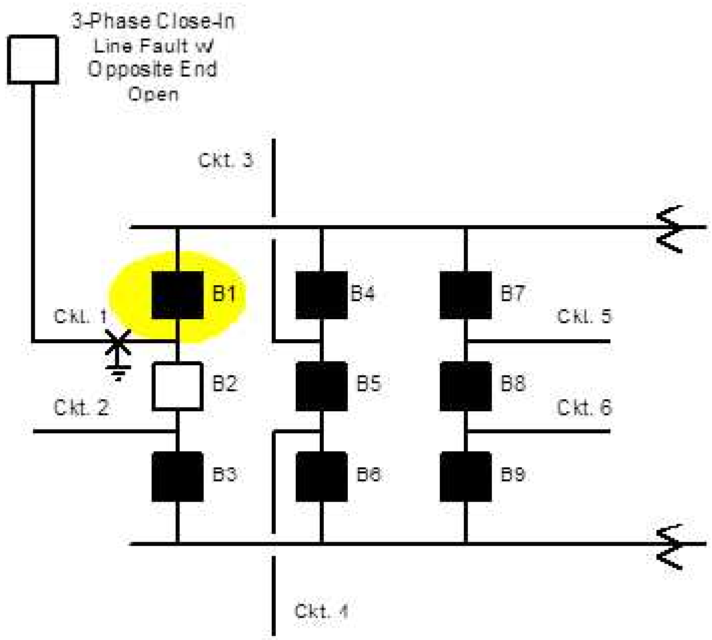


Figure 14 Breaker & a half w/ transformers or other connections on bus

4.3.4.Possible Solutions

Any over-duty circuit breakers should be mitigated as soon as possible. Some temporary solutions that can help to relieve the stress on circuit breakers are listed below.

- Delay contact parting times via delaying relay trip times
- Transfer trip schemes that bypass the over-duty breaker(s) when interrupting faults
- Blocking automatic reclose functionality
- Temporary system reconfiguration

The solutions listed above are considered temporary solutions to be used only to relieve the possible stress on circuit breakers until a permanent solution can be implemented. Permanent solutions would include, but not be limited to the following.

- Installation of a fault current limiting device
- Installation of capacitors within a specified distance of the circuit breaker (only feasible if the installation will increase the interrupting capability of the breaker)
- Replacement of the breaker(s)
- Permanent system reconfiguration

4.4. Dynamic Analysis

4.4.1.Introduction

Dynamic stability describes the ability of the power system to remain synchronized following a disturbance. Dynamic stability analysis includes transient or first swing stability analysis and up to 10 minutes after any disturbance. Analyzing the system for dynamic stability is crucial to the security of the system, as certain contingencies on the system could cause the system to become unstable.

Because the growth in system loads tend to make the system more stable by adding additional damping, dynamic stability analysis is performed when system changes occur that could affect dynamic performance. The need for this analysis is initiated via various sources including but not limited to the following:

- Primary and backup relay scheme changes that are outside the clearing time published under the PJM Relay Subcommittee Share Point.
- The addition, removal, or re-rating of generation on the system
- Generation control system changes
- Large network impedance changes
- Abnormal system configuration

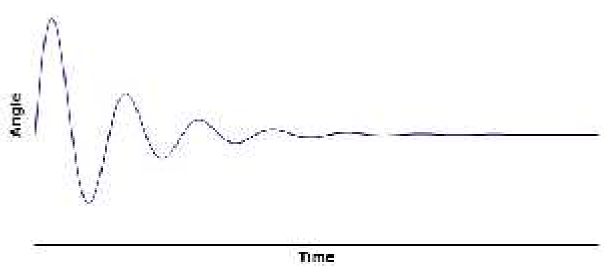
The base case for stability analysis is created in a similar manner to that of the load flow and short circuit base cases. Additional information is necessary in order to simulate the combined dynamic responses of various equipment across the transmission system. Included in this additional information are models for generators, excitation systems, power system stabilizers, governors, and other various equipment. A dynamic simulation links the system model or load flow information with the dynamic data or models to determine if the system or generators within the system will remain stable for various disturbances.

Loads are modeled as constant power in loadflow analysis; however, during stability analysis, loads should be modeled as constant current for the real portion (MW) and constant impedance for the reactive portion (MVAR) unless a representation is known that more specifically applies to the system studied.

All base cases are developed by RF and PJM with information provided by generation owners. Case are made available to PJM and RF members. The worst case load level (light, intermediate, or peak) are utilized to study each scenario except when studies are initiated by bulk power operations with specific system conditions that need to be modeled.

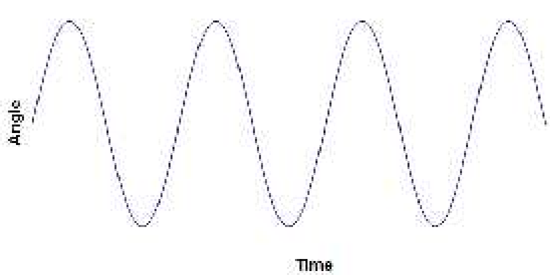
The power system's response to a disturbance is simulated to determine whether or not the system remains stable. In most cases, the output of the simulation is analyzed in graphical form, either creating a power vs. angle curve or plotting system variables (angle, voltage, power, frequency, etc.) with respect to time.

The plot below illustrates a system disturbance that remains stable. In this simulation, a fault occurred at time 0+ and the magnitude of the oscillations reduced in magnitude as time increased.

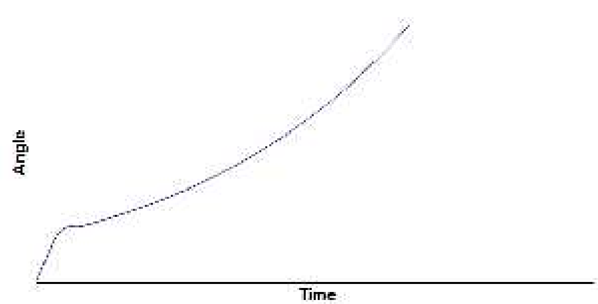


Plot 1 System Remaining Stable After Disturbance

Two examples of unstable systems can be found below. Plot 2 illustrates a system disturbance that causes sustained oscillations and Plot 3 illustrates a system disturbance that causes dynamic instability.



Plot 2 System Experiencing Sustained Oscillations



Plot 3 System Experiencing Dynamic Instability

4.4.2. Disturbances

Per NERC criteria, the stability of BGE's and neighboring transmission systems must be sustained without loss of load for all contingencies as described in section 4.4.1 including:

- Three-phase fault with normal clearing
- Single phase-to-ground fault with a stuck breaker or any other cause for delayed clearing
- The loss of any single facility with no fault

For BGE, the system should also remain stable given the following disturbances:

- Three-phase fault at a point 80% of the circuit impedance away from the station under study with zone two clearing
- Failure of a generator
- Failure or all generation from one station
- Opening or closing of a transmission facility
- Loss of a large block of load
- Faulted circuit breaker

For all of the disturbances above, the system must maintain angle stability. In cases where the system is unstable, the system should be enhanced to improve stability as set forth in section 4.4.4.

4.4.3.Performing the Analysis

BGE performs dynamic stability analysis utilizing the PSS/e Power System Simulation software. Base case load flows and dynamics data are obtained from PJM or RFRF and will include the BGE system in as much detail as possible with the neighboring systems as modeled by PJM and RFRF. When performing the analysis the most up-to-date information should be used. This would include any recent enhancements to system models, generation models, or operating times.

For all contingencies involving faults, the fault clearing times are of the utmost importance. The amount of time it takes for a fault to clear has a direct impact on the stability of the system.

When performing dynamic stability analysis actual operating times should be obtained whenever possible. These times include zone one and zone two clearing times, backup clearing times, reclosing times, and auto-transfer times. The clearing times include the total relay trip times plus the longest probable breaker interrupting times. Whereas in short circuit analysis we use the quickest possible total interrupting times to simulate worst case scenarios, for stability analysis, we assume the longest possible total interrupting times to simulate worst case scenarios.

Often, transmission operations may request a stability analysis be performed for any contingency given the system in an abnormal configuration. When these requests are made, care should be taken to modify the base case so that it is as similar as possible to the system configuration under study. The load level, generation dispatch, and voltage control mechanisms should be reviewed to create a study case as close as possible to what the system is experiencing.

4.4.4.Possible Solutions

There are several ways to enhance system stability in the event that unstable conditions are identified. Some are listed below.

- Independent pole breakers
- The addition of power system stabilizers
- Shorten fault clearing times (primary or backup) – faster breaker
- Generation runback or trip schemes
- Limitation of generation output
- Addition of transmission lines
- Addition of transmission series capacitors
- Addition of transmission shunt capacitors
- Addition of dynamic reactive devices
- Schemes for the removal or transfer of load

An analysis of the system's response to a disturbance that causes instability will provide an indication as to what system enhancements can be employed to attain stability. An economic analysis must be performed to determine the best solution.

As a delivery company, BGE does not own generators to which it can make enhancements. BGE can only change the characteristics of the transmission system to make the system stable. PJM may direct those that control the generating stations to make changes to their units for stability problems and BGE may provide input to that process if the generating unit impacts BGE's facilities.

4.5. Emergency Import Capability

NERC provides guidelines for defining terms and simulation techniques for use in the determination of transfer capability in its report *Transmission Transfer Capability*. (North American Electric Reliability Council. *Transmission Transfer Capability*, May, 1995). As established in the NERC document, the First Contingency Total Transfer Capability (FCTTC) is the sum of normal base transfers and the First Contingency Incremental Transfer Capability (FCITC). Normal base power transfers are those power transfers that are considered to be part of normal base system loading for the condition being analyzed. FCITC is defined as the amount of power, incremental above normal base power transfers that can be transferred over the transmission network in a reliable manner. The BGE transmission system's Emergency Import Capability is determined according to the NERC FCTTC criteria and definition.

If any two (or more) companies are geographically proximate and tightly interconnected, it is often more appropriate to examine Emergency Import Capability on a geographic rather than a strictly company basis. As neighboring companies regularly share the same transmission tie lines in bringing power into their respective systems, import analysis for the combined systems must be examined. BGE and the Potomac Electric Power Company (PEPCO) form such an identifiable subarea within PJM. Because of this, emergency import capability should be determined for the BGE and PEPCO combined area as well as the BGE area alone.

Annually, the ability of the PJM transmission network to deliver power to load is assessed. As part of that analysis, an assessment is conducted to demonstrate the deliverability of the aggregate of PJM capacity resources to the load for each predefined electric sub-area within the PJM control area. This analysis ensures that there is an adequate balance of generation resources within the sub-area and import capability into the sub-area to maintain the sub-area's defined reliability criteria. Conversely, the deliverability of generation within each sub-area to the aggregate PJM load is also assessed. This test is designed to ensure that there is sufficient export capability out of each sub-area such that generation is available to serve load throughout the PJM control area.

BGE, in coordination with the PJM Office of the Interconnection, will plan its transmission system such that there will be sufficient import capability into the BGE and combined BGE and PEPCO sub-region so that the probability of occurrence of load exceeding the available capacity resources shall not be greater, on the average, than one day in ten years.

PJM plans its capacity reserve requirements for the entire pool to meet the same one day in ten year reliability level. Each year, a stochastic analysis of the system is performed using the GEBGE (or a program approved and accepted by the PJM Planning Committee) Generation Reliability Program to determine the capacity reserves required for PJM to attain its design reliability level. This program does not, however, consider transmission constraints within the PJM system. A further analysis determines the Capacity Emergency Transfer Objective (CETO) for each member company and all applicable subsystems. This analysis establishes the actual level of transfer capability required for each transmission subsystem.

Both analyses performed assume planned capacity resources based on the latest published in-service dates. They consider the quantity and location (external or native to the subsystem) of the capacity resources, expected availability of resources, forecast load levels and annual load shapes, the availability of active load management programs, and load-forecast uncertainties. Forced outage rates are based on five-year historical rates used for reliability planning.

CETO analysis uses the GEBGE reliability program (or a program approved and accepted by the PJM Planning Committee) to establish the relationship between Sub-regional Transfer Capability and risk of Sub-regional loss-of-load solely due to insufficient transfer capability. This risk assessment is independent of the risk analysis of PJM loss-of-load due to insufficient capacity reserves. This risk is usually expressed in a reliability index (R.I.) of years of experience per day of interruption. The PJM accepted level is one day in 25 years (or 0.04 days per year). This actually means that, on the average, one interruption will occur for every 25 years of operating experience within the sub-region due to insufficient transfer capability between the sub-region and the remainder of PJM.

The second part of the emergency import capability analysis involves the use of load flow analysis to calculate the level of Emergency Import Capability available, without interrupting or curtailing existing and planned firm transmission services, to deliver external capacity resources and emergency capacity assistance into the system. The results of this analysis give the Capacity Emergency Transfer Limits (CETL).

In order to meet the import capability criteria, the CETL value must be greater than or equal to the corresponding CETO value for both the BGE and combined BGE and PEPCO subareas over the transaction period.

The load flow base case used for CETL determination is constructed the same way as the load flow used in CETO analysis, except for the following changes which are required in order to create a capacity emergency in the sub-area and thus a resulting capacity transfer from the interconnected system into the sub-area.

CETL testing has all sub-area loads set to the LAS diversified accounting peak loads. Generation is forced out across the PJM System in proportion to forced outage rates. Sub area loads are set to 105% of the non-diversified expected peak load with the amount above the accounting peak at an 80% power factor. The most critical, usually the largest, unit in each sub area is forced out for each study area's CETL analysis. The need for emergency power imports is simulated by outaging additional capacity resources in the sub area. The capacity shortfall is supplied by the remainder of the pool or, if necessary, by other control areas without regard for economics.

Emergency imports are increased until limited by system voltage or thermal capability. The sub-area's power import at this transfer level is the sub area's CETL. The tests performed to evaluate the CETL are those set in PJM Manual M14-B

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The PJM Interconnection is responsible for performing the CETO/CETL tests as part of routine analysis of resource deliverability and PJM transmission adequacy assessments. BGE performs the CETL tests for study purposes.

5. Planning Design Guidelines for System Expansion

5.1. Substation Expansion Philosophy

To ensure consistency of substation design, BGE has developed expansion guidelines. These guidelines are intended to enhance BGE and PJM operations and support a dependable operating environment. BGE will use these guidelines in the design and construction of new substations and they will also serve as a guide for the expansion or modification of existing substations. While it is neither practical nor cost-justifiable to immediately rebuild all existing substations to these new standards, whenever modifications are made to existing substations, BGE will move the substation configurations toward these new standards. Although several station configurations are allowed, the station configuration may initially be required to be built for breaker and half based on load flow and technical analysis. Consideration for transition to the ultimate configuration will be factored into the initial build configuration decision.

Situations may arise where physical space limitations or other considerations may require a variation from these standards in the design of a station. To preserve the physical space needed for the expansion of the transmission substation, distribution facilities should not be placed in areas allocated for transmission. Transmission equipment such as transformers, capacitors, towers should not be placed in space dedicated for future expansion of substation breaker bays.

Circuit breakers can be utilized in place of circuit switchers when deemed necessary and where circuit switchers are normally required. When a circuit breaker is required or deemed necessary, a single pole breaker can be utilized when greater reliability is needed.

5.2. Extra High Voltage (EHV) 500kV Reliability Criteria and Practice

The BGE substation expansion philosophy for the Extra High Voltage (EHV) system is intended to provide the EHV system with the highest level of reliability of all voltage classes. This is because a disturbance on the 500 kV system can affect the greatest number of customers since this system has the highest load delivery capability. Additionally, such disturbances have the greatest potential for propagating to adjacent transmission systems. In the event of a blackout, the EHV system must be able to support system restoration efforts in the shortest possible time.

The following design criterion applies to all BGE 500 kV substation installations:

- Each element (Line or Transformer) must be separated by a circuit breaker to ensure system disturbances are minimized
- A faulted element must not result in the loss of an additional element
- A failed bus breaker or a bus fault does not result in the loss of an additional element
- During maintenance, no additional transmission elements will be taken out of service except for the element being maintained
- When constructing a two breaker bay, all six of the associated disconnect switches are required to minimize outage duration during the installation of the remaining tie breaker.
- A ring configuration is acceptable with three element designs interconnecting any combination of lines and transformers. A four element ring is acceptable only if two of the elements are transformers (Figure 9)
- No elements may connect to a bus without a circuit breaker
- Relay protection must comply with applicable BGE standards and PJM standards and requirements as published by the Relay Subcommittee
- Transmission lines with more than two relay terminals are not permitted. For application of this requirement a terminal is considered to be any location where relays and inter-station

communications must be installed in order to achieve coordinated protection that meets the requirements of BGE standard EPB-13006

- Line disconnect switches are required on all transmission line, transformer and generator connections to the substation
- All new 500 kV equipment shall be rated for a minimum of 4000A continuous current and 63kA interrupting capability

In practice, BGE substation expansion of the EHV system is based on breaker and a half configurations with all elements terminating between breakers with no elements connected directly to the bus as shown in Figures 15, 16 and 17. These substation designs are standard designs used throughout the utility industry because of its high reliability and improved operability. This high level of reliability is necessary since planning reliability criteria includes model simulations of double contingency outages, tower outages and breaker failure.

Although the designs shown in figures 15, 16 and 17 are generally required for EHV installations, ring bus configurations are acceptable for three or four element EHV substations (Figures 18 and 19). This is permitted when no more than four elements are connected at a substation, and multiple outages will not result in a “split” station. When more than four elements interconnect at a station, the station design must evolve to a breaker and a half configuration to avoid such station “splits.”

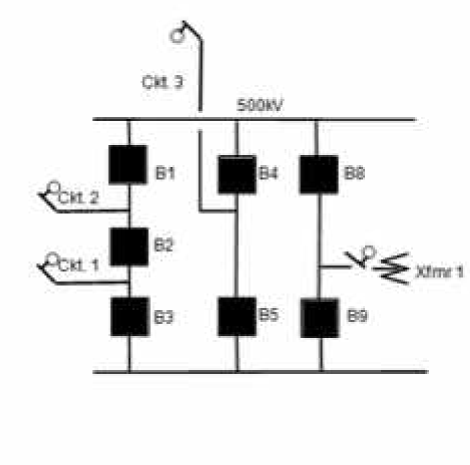
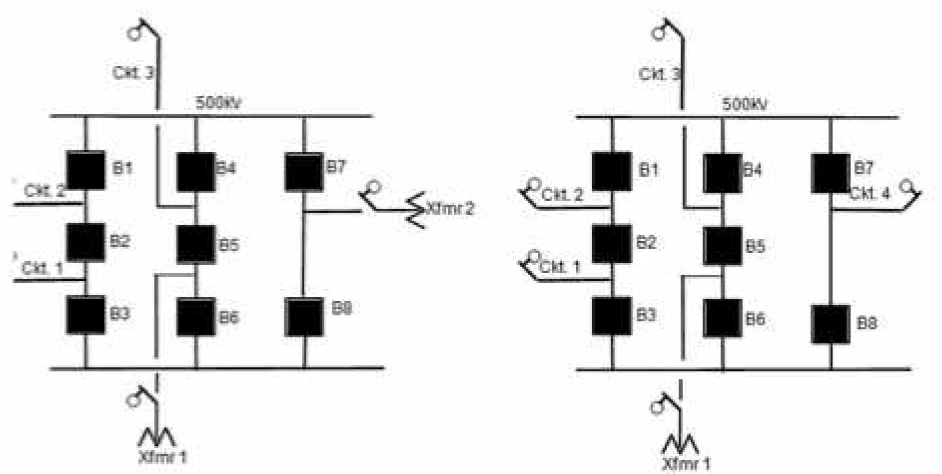


Figure 15
Typical 500 kV four-element breaker and a half switching station design



Typical 500 kV five-element breaker and a half switching station designs

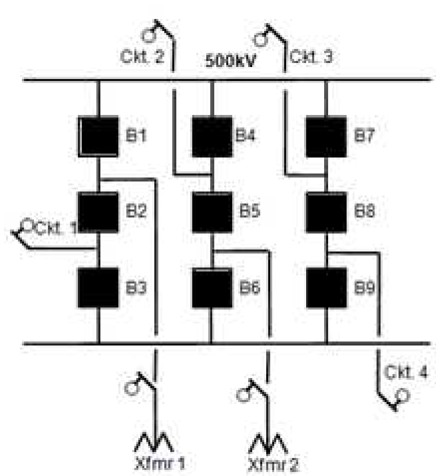


Figure 17
Typical larger 500 kV breaker and a half switching station design

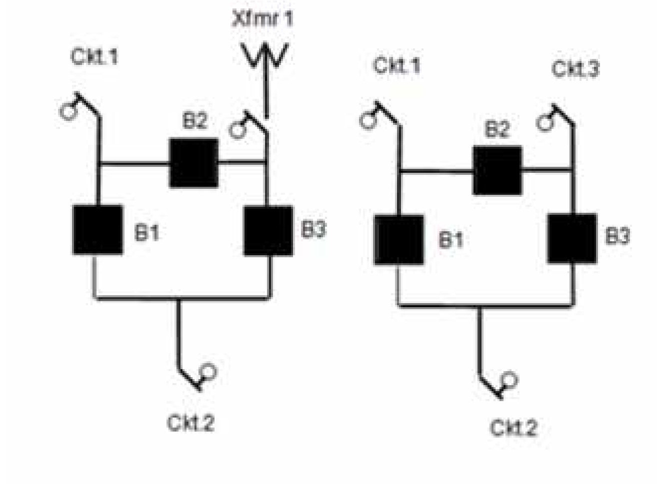


Figure 18
Typical 500 kV three-element ring designs

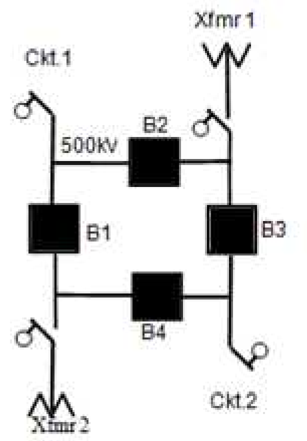


Figure 19
Typical 500 kV four-element ring designs

5.3. High Voltage (230 kV) Reliability Criteria and Practice

BGE's High Voltage (HV) system includes all 230 kV and 115 kV facilities. The BGE 230 kV transmission system is designed to provide a secure and reliable supply of power to the BGE 115 kV system connections to facilitate the transport of power to load areas. HV relay protection must be redundant and in compliance with PJM Relay Subcommittee requirements.

5.3.1. 500/230 kV Substations and 230 kV Switching Stations

The following design criterion applies to all BGE 500/230 kV substations and 230 kV switching station installations:

- Each element (Line or Transformer) must be separated by a circuit breaker to insure system disturbances are minimized
- A faulted element must not result in the loss of an additional element
- A failed bus breaker or bus fault does not result in the loss of an additional element
- During maintenance, no additional transmission element will need to be taken out of service except for the element under repair
- When constructing a two breaker bay, six disconnect switches and wire connections should be installed to minimize the outage duration during the installation of the remaining breaker
- A ring configuration may be acceptable if the station has only three or four elements
- All elements that connects to a ring shall have associated disconnect switches
- Relay protection must comply with applicable BGE standards and PJM standards and requirements as published by the Relay Subcommittee
- Transmission lines with more than two relay terminals are not permitted. For application of this requirement a terminal is considered to be any location where relays and inter-station communications must be installed in order to achieve coordinated protection that meets the requirements of BGE standard EPB-13006
- For a transformer connected directly to a bus, there will be a separate zone of protection to indicate an internal transformer fault

- Low side of a 500-230 kV transformer can connect to the 230 kV bus (Figures 22 and 23)
- Line disconnect switches are required for terminations at substations for underground circuits and transformers
- The ring configuration and a two bay breaker and a half configuration must have line disconnects
- There should not be more than four elements for a two bay breaker and a half or a ring configuration

Expansion of BGE 230 kV-switching stations and substations is based on a breaker and a half configurations as shown in figures 20-23. Similar to the 500 kV switching stations, ring configurations as shown in Figures 24 and 25 are allowed for three and four element installations.

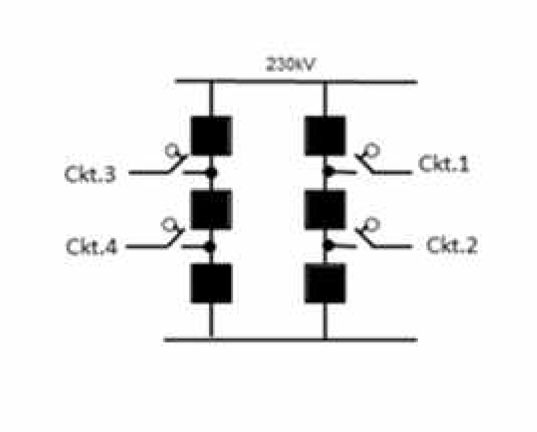


Figure 20
Typical 230 kV four-element breaker and half switching station design

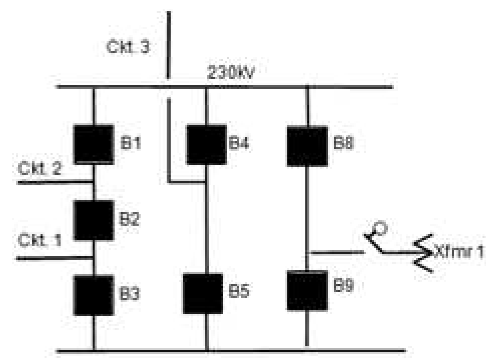


Figure 21
Typical 230 kV four-element breaker and half substation design

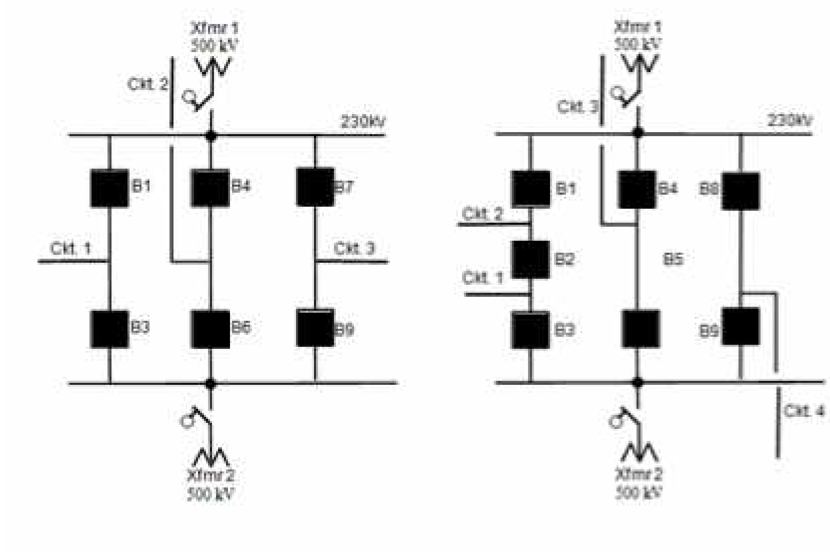


Figure 22
Typical 500/230 kV four and five element substation design

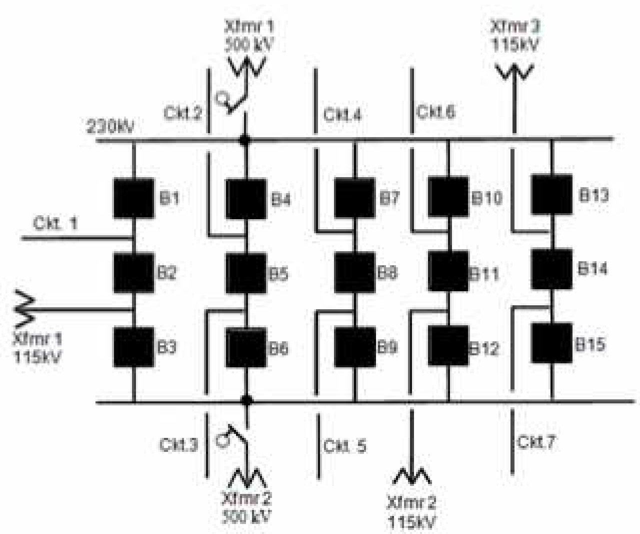


Figure 23
Expanded 500/230 kV switching station to full breaker and half station

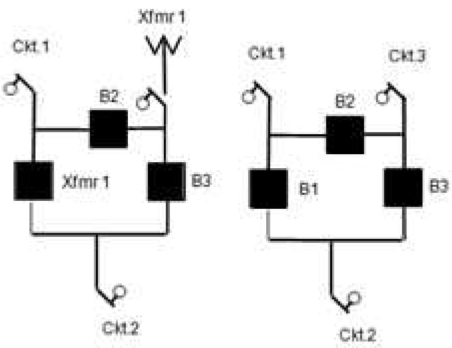


Figure 24
Typical 230 kV three-element ring designs

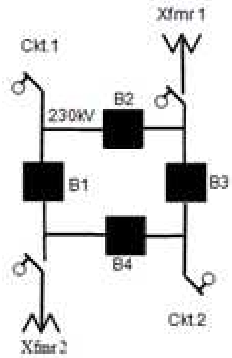


Figure 25
Typical 230 kV four-element ring design

5.3.2. 230/115 kV Substations

All 230/115 kV substations must be designed to provide sufficient reliability to the 115 kV system while not appreciably decreasing 230 kV network reliability. The configuration in Figure 26 is designed to minimize 230kV substation fault levels while maintaining a reliable transmission system. Refer to Figures 21, 24, 25 and 27 to see other configurations for 230/115 kV substations.

The following design criterion applies to all BGE 230/115 kV substation installations:

- Each element (Line or Transformer) must be separated by a circuit breaker to ensure system disturbances are minimized
- A 230 kV line outage must not drop any 230/115 kV transformers
- During maintenance , no additional transmission element will be need to be taken out of service except for the element under repair
- When constructing a two breaker bay, six disconnect switches and wire connections should be installed to minimize the outage duration during the installation of the remaining breaker.
- All elements that connect to a ring should have associated disconnect switches when feasible
- Transmission lines with more than three relay terminals are not permitted. For application of this requirement a terminal is considered to be any location where relays and inter-station communications must be installed in order to achieve coordinated protection that meets the requirements of BGE standard EPB-13006
- Relay protection must be redundant and in compliance with BGE and PJM Relay Subcommittee requirements
- Line disconnect switches are required for terminations at substations for underground circuits and transformers
- 230 kV line breakers should open to isolate the fault on the transformer. Upon the opening of the circuit switchers, the line breakers should automatically close restoring the line. The preferred configuration is to have a three breaker ring station.

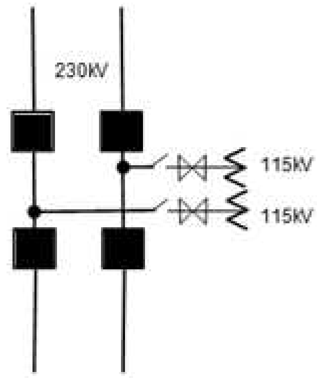


Figure 26
Typical 230/115 kV substation design

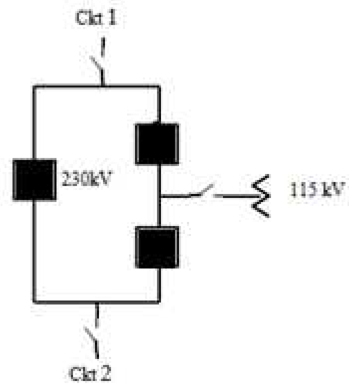


Figure 27
Three breaker ring station

5.3.3. 230/34.5 kV and 230/13.8 kV Substations

On the BGE system, 230/34.5 kV and 230/13.8 kV substations primarily feed radial distribution load. The design objective of these substations is to reliably serve distribution load while isolating the disturbances on the distribution system and preventing them from propagating to the 230 kV system.

The following design criterion applies to all 230/34.5 kV and 230/13.8 kV substations:

- A 230 kV breaker must be installed when connecting a distribution substation to the 230kV system
- A transformer lead fault resulting in a momentary interruption of the thru transmission path is acceptable when automatic restoration of thru transmission is applied
- During maintenance, no additional transmission will be taken out of service except the element being maintained
- Relay protection must be redundant and in compliance with BGE and PJM Relay Subcommittee requirements
- Line disconnect switches are required for terminations at substations for underground circuits
- Every transformer shall have a dedicated transformer isolation circuit switcher

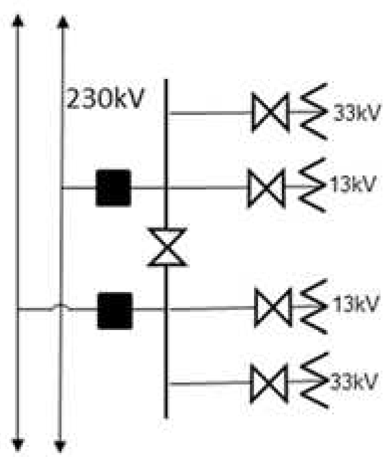


Figure 28
Typical 230/34.5 kV and 230/13.8 kV substation design

5.4. High Voltage (115 kV) Reliability Criteria and Practice

Expansion of 115 kV switching substations is based on a breaker and a half configuration with some variations allowed similar to the 230 kV switching station configurations. The concept is to provide a secure and reliable 115 kV switching substation that will facilitate the transport of power within the local BGE region and provide backup to the local load areas.

The 115 kV transmission system plays the major role of supplying power to distribution stations. Often 115 kV stations may function as both a switching station and a supply of power to the distribution system. For these stations, the connection of a high voltage transformer directly to the 115 kV bus is required. Due to the relatively high system fault levels on the BGE system, the number of substations with a solid 115 kV bus is carefully considered.

in support of reliability and system security, the transmission protection system consists of relays and circuit breakers that are designed to have zones of redundant protection. During brief times of protection upgrades or testing, the 115 kV system may be configured with multiple elements unavailable.

5.4.1.115 kV switching Substations

Expansion of BGE 115 kV switching substations is based on a breaker and a half configuration as shown in Figure 29; however, variations similar to the 230 kV switching station configurations are allowed for three and four element installations.

The following design criterion applies to a 115 kV breaker and a half substation:

- Each element (Line or Transformer) must be separated by a circuit breaker to ensure system disturbances are minimized
- A faulted element must not result in the loss of an additional element
- A failed bus breaker or bus fault does not result in the loss of an additional element
- During maintenance, no additional element will be taken out of service except for the element under repair
- The low side of a 230-115 kV transformer can connect to the 115 kV bus
- Transmission lines with more than three relay terminals are not permitted

  For application of this requirement a terminal is considered to be any location where relays and inter-station communications must be installed in order to achieve coordinated protection that meets the requirements of BGE standard EPB-13006
- Relay protection must be redundant and in compliance with BGE and PJM Relay Subcommittee requirements
- Line disconnect switches are required for terminations at substations for underground circuits and transformers
- Two Transformers can share a position in the bay but each transformer should be separated by a circuit switcher

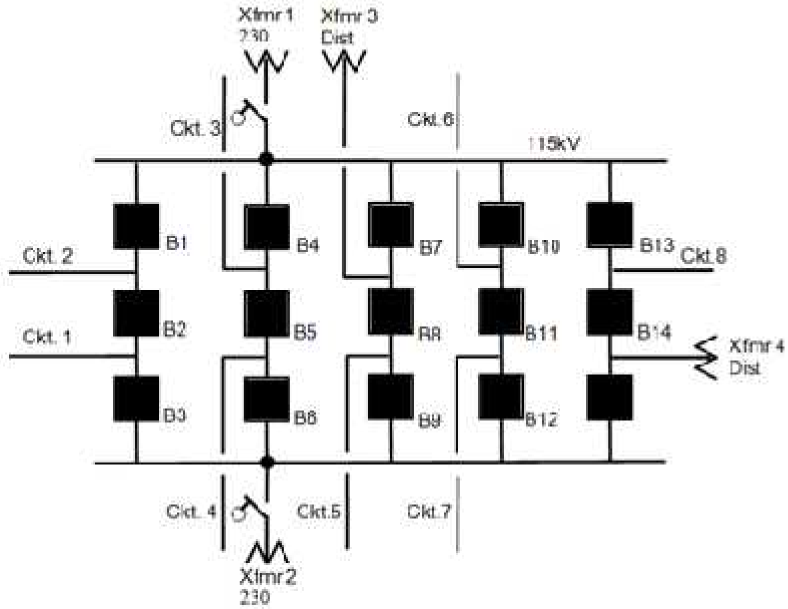


Figure 29
Typical 115 kV switching station expanded to full breaker and half design

5.4.2. Downtown Baltimore 115 kV Substations

For 115 kV distribution substations that serve downtown Baltimore distribution transformers, the disturbances on the distribution system should have minimum adverse effect on the 115 system (and in turn other distribution transformers). This is accomplished by the addition of a bus sectionalizing breaker. In general, these stations carry high load levels of approximately 240 MW by four 80 MVA 115/13.8 kV trans-formers as shown in Figure 30.

5.4.2.1. Two Breaker distribution station

The following design criterion applies to 115 kV stations feeding downtown Baltimore distribution transformers with two 115 kV connections at each bus:

- The loss of a 115 kV line or transformer should not propagate line outages beyond the next station
- A bus or line fault should not result in more than one transformer out at a station
- Circuit switchers should be placed on the high side of a 115/13.8kV transformer to provide isolation if the transformer from a line or other transformers
- Maintenance performed by opening a bus breaker and a subsequent line outage shall not drop more than one 115 kV transmission line
- During maintenance no additional element should be taken out of service except for the element under repair
- Relay protection should be redundant and in compliance with BGE and PJM Relay Subcommittee requirements
- A 115kV breaker should be added if two transformers connect to the same line at a substation
- Line disconnect switches are required for terminations at substations for underground circuits and transformers

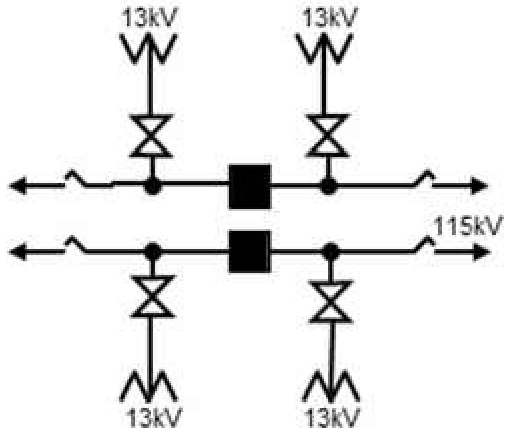


Figure 30
Typical 115 kV Downtown Baltimore Switching Station Serving Distribution Transformers

5.4.2.2. Three Breaker distribution station

Expansion of the urban Baltimore 115 kV distribution substation to accommodate additional 115 kV lines is in Figure 31. This design shows a 115 kV station configured to act as two separate 115 kV ring stations. Similar to other BGE ring designs, these rings should be limited to no more than three lines.

The following design criterion applies to 115 kV stations feeding downtown Baltimore distribution transformers with more than two 115 kV connections at each bus:

- The loss of a 115 kV line or transformer should not propagate line outages beyond the next station
- A bus or line fault should not result in more than one transformer out at a station
- Maintenance performed by opening a bus breaker and a subsequent line outage will not drop an additional 115 kV transmission line of another substation
- During circuit breaker maintenance there should be no interruption of any 115 kV transmission path
- Circuit switchers should be placed on the high side of a 115/13.8kV transformer to provide isolation if the transformer from a line or other transformers.
- For maintenance, no additional element will be out except for the element under repair
- Relay protection must be redundant and in compliance with BGE and PJM Relay Subcommittee requirements
- All elements that connect to a ring should have associated disconnect switches

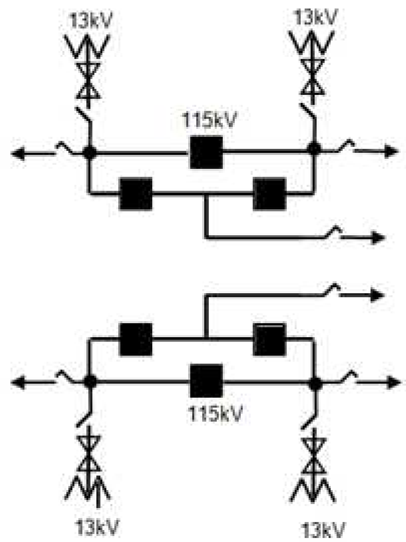


Figure 31
Typical 115 kV Downtown Baltimore Switching Station with Three-Element Ring Buses

5.4.2.3. Four-element ring bus station

Expansion of the downtown Baltimore 115 kV transmission system may include the connection of all four 115 kV lines to a station. The configuration used is a four-element ring shown in Figure 32. This ring is limited to four lines to avoid the potential of splitting a station into two disconnected sections resulting in complex operation that may occur during maintenance and outages.

The following design criterion applies to 115 kV stations feeding downtown Baltimore distribution transformers with a solid four-element ring bus:

- The loss of a 115 kV line or transformer should not split the 115 kV station
- The loss of a 115 kV line or transformer should not propagate outages beyond the next station
- A bus fault should result in the outage of no more than one 13.8 kV distribution transformer at any station
- Maintenance performed by opening a bus breaker and a subsequent line outage should not drop an additional 115 kV transmission line of another station.
- No more than four lines can terminate at this type of station
- Circuit switchers should be placed on the high side of a 115/13.8kV transformer to provide isolation from a line or other transformers
- During circuit breaker maintenance there should be no interruption of any 115 kV transmission path
- During maintenance no additional element should be out except for the element under repair
- Relay protection must be redundant and in compliance with BGE and PJM Relay Subcommittee requirements

- Line disconnect switches are required for terminations at substations for underground circuits and transformers
- All elements connected to a ring should have associated disconnect switches

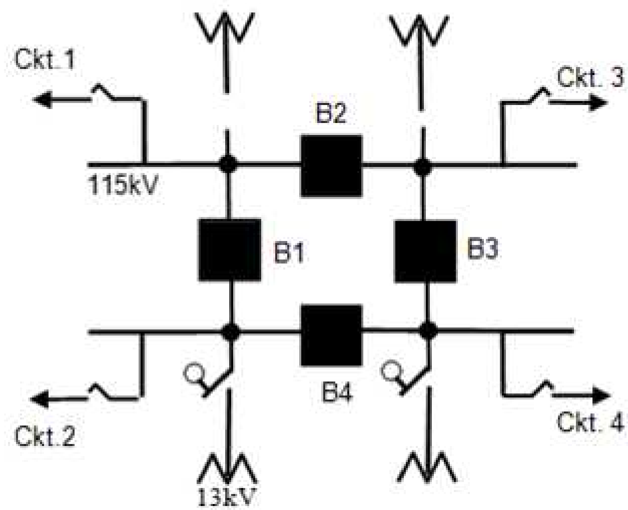


Figure 32
Typical 115kV Downtown Baltimore Switching Station with a Four-Element Ring Bus

5.4.3.Requirements for Substation Separation

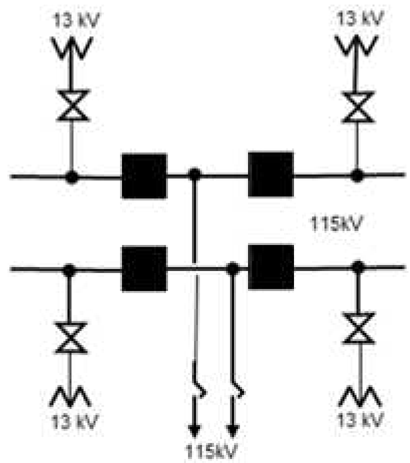
When expansion of the 115 kV transmission system adds additional exposure to a transmission line due to the addition of a line tap or multiple transformer taps, additional protection to the substation is required where exposure has increased. The need for additional line protection may also be required to improve transmission reliability to customers or the overall 115 kV system.

Generally, the additional line protection is provided by the installation of line circuit breakers on both sides of the tapped line. These breakers reduce the added 115 kV transmission exposure introduced by the line tap. Figure 33 shows an example of the addition of breakers to the basic BGE substation design of a non-downtown Baltimore 115 kV substation.

The preferred configuration is shown in Figure 34, by connecting the transmission lines in a ring configuration.

The following guidelines will be used to determine the situations where additional line protection is required:

- Tap extensions for overhead lines over one mile and for underground lines over two miles
- The total number of tapped substations on a 115 kV line exceeds three
- The total load lost for a double circuit tower outage exceeds 300 MW
- Special cases identified by a critical transmission line path or critical customer load
- BGE operations has a need based for improvement on operation or reliability issues
- There is an underground transmission line connected to overhead sections to improve the ability to isolate overhead lines from underground cables



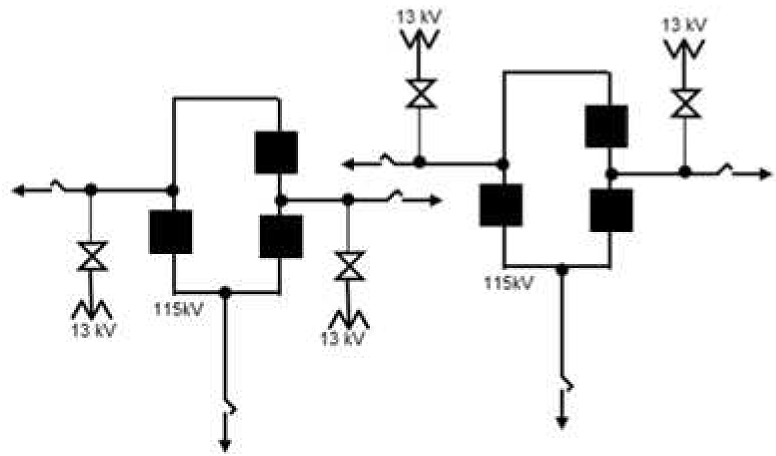


Figure 33
Example Substation Design Requiring Additional Breakers

Figure 34
Example Substation Design Requiring Additional Breakers

5.5. Additional Requirements for Interconnection Facilities

When a company seeks to interconnect with the BGE Transmission System, care must be taken so that disturbances initiated on one system do not propagate onto the other system. Therefore, BGE stations should be designed so that the interconnection is maintained for element outages occurring within BGE. Similarly, the connection of transmission, load or generation customers must ensure that disturbances on customer facilities will not result in outages in the BGE system.

Because of the heightened need for the security of interconnection facilities and the need to protect the BGE system from events on customer facilities, the following additional guidelines apply to such facilities:

- Isolation between BGE and the other company should be accomplished at a minimum with a circuit breaker
- BGE reliability and operability should not be comprised in any way due to non-BGE standard equipment. BGE will also review the configurations based on reliability and operational issues and modify the design for approval as needed.
- All equipment must meet BGE equipment standards if it is within a BGE substation or it is operated by BGE
- Interconnection substations should be designed such that a bus outage or element outage should not split a station or disconnect an interconnection facility
- Line disconnect switches are required for underground circuit terminations at substations and when connected to the overhead sections
- New generators shall have a method of synchronizing so that BGE will not have to operate the station breakers for generation operation

The following designs are acceptable for interconnection facilities:

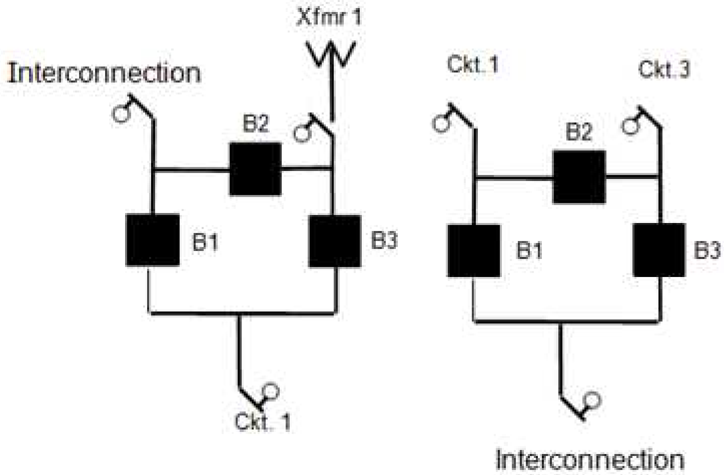


Figure 35
230kV Substation with Ring Interconnection

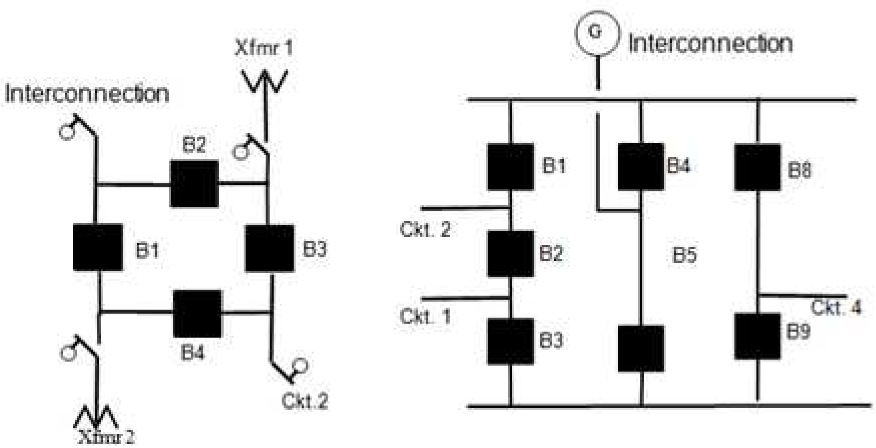


Figure 36
230kV Substation Interconnections

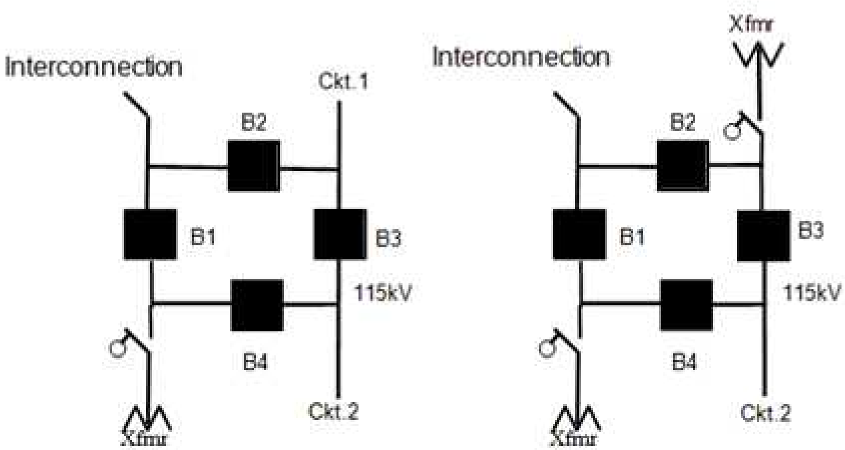


Figure 37
115kV Substation with Ring and Interconnection

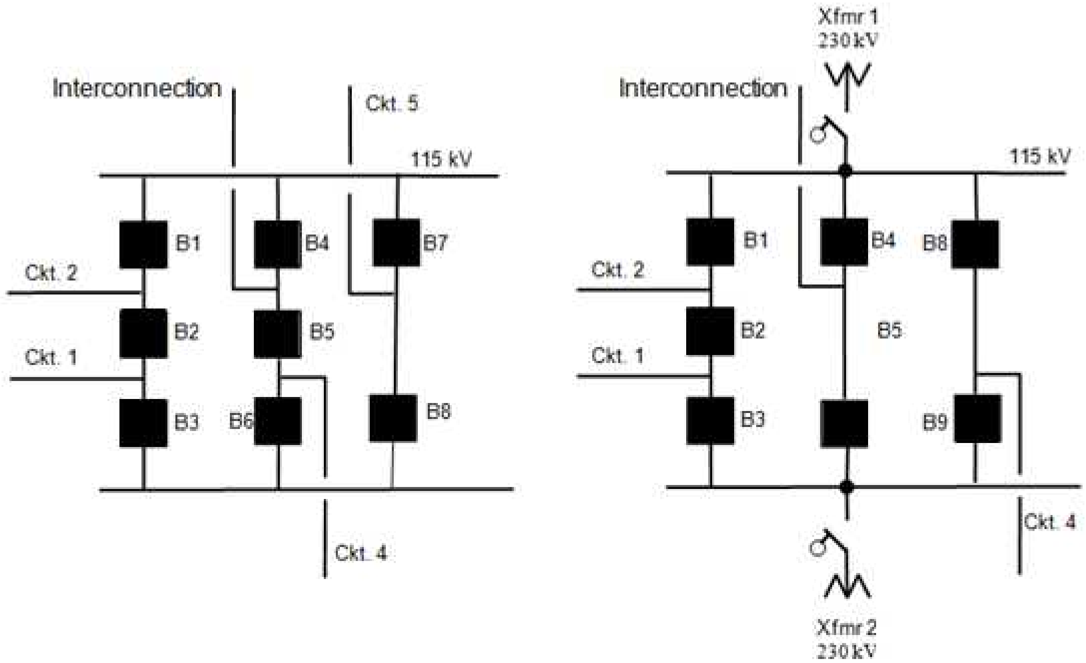


Figure 38
115kV Substation Interconnection

5.6. Additional Requirements for 500 kV interconnection Facilities

The following criteria apply to all 500 kV substation installations:

- In all arrangements each line or transformer, by itself, must occupy a single zone of protection that is bounded by circuit breakers.
- In breaker-and-a-half arrangements, each bus, by itself, must occupy a single zone of protection bounded by circuit breakers.
- Substation designs must ensure that a failed breaker will result in the loss of no more than two elements and will not electrically separate the remaining elements from each other
- All elements that connect to the ring shall have associated disconnect switches
- Three-breaker ring bus arrangements are permitted when the connected elements are limited to three lines, or to two lines and a transformer
- Four-breaker ring bus arrangements are permitted when the connected elements are limited to two lines and two transformers
- Ring bus designs should be physically and electrically constructed to permit the eventual evolution of the station to a breaker-and-a-half arrangement when the station is expanded
- In ring bus designs, the station should be physically and electrically designed so that lines are not terminated in positions that will ultimately evolve into busses. It is permissible to terminate transformers in these positions

The following designs are acceptable for 500 kV interconnection facilities:

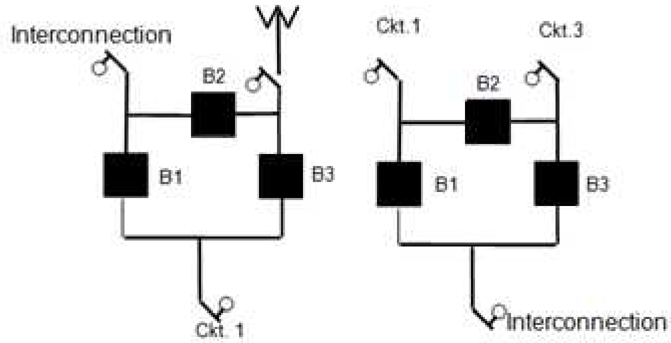


Figure 39
500kV Substation with Ring Interconnection

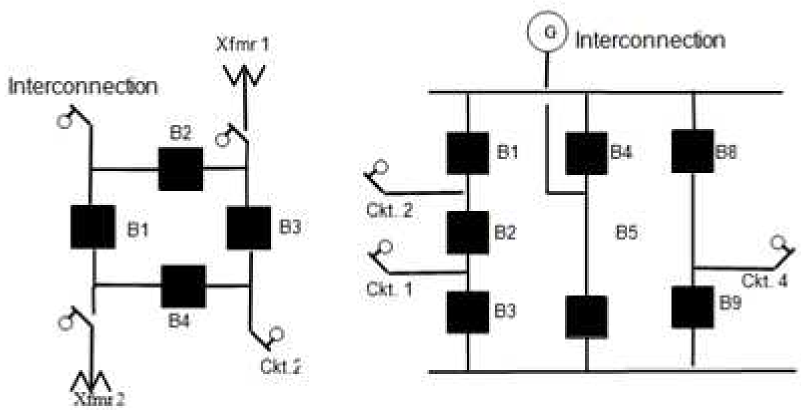


Figure 40
500kV Substation with Ring Interconnection

5.7. Restrictions of Sole Use or Dedicated Facilities

- A dedicated facility is one whose sole purpose is to supply a single customer. This facility is designed in such a manner that all existing and planned equipment, open equipment positions and open areas are solely designated for the single customer use. Since this facility is designated for single use, no other entities can connect to this facility, as filed and approved by FERC as a dedicated facility
- The equipment is paid by the sole use customer
- The design is approved by BGE
- There are no open positions available for other use aside from this single customer
- The connections are only to BGE and to the sole customer

5.8. Substation Expansion from Ring Bus to Breaker and Half Design

The following diagrams illustrate how ring bus configurations should be physically designed to allow for eventual expansion to break and half design.

It is also recommended that when constructing a two breaker bay, six disconnect switches and wire connections should be installed to minimize the outage duration during the installation of the remaining breaker

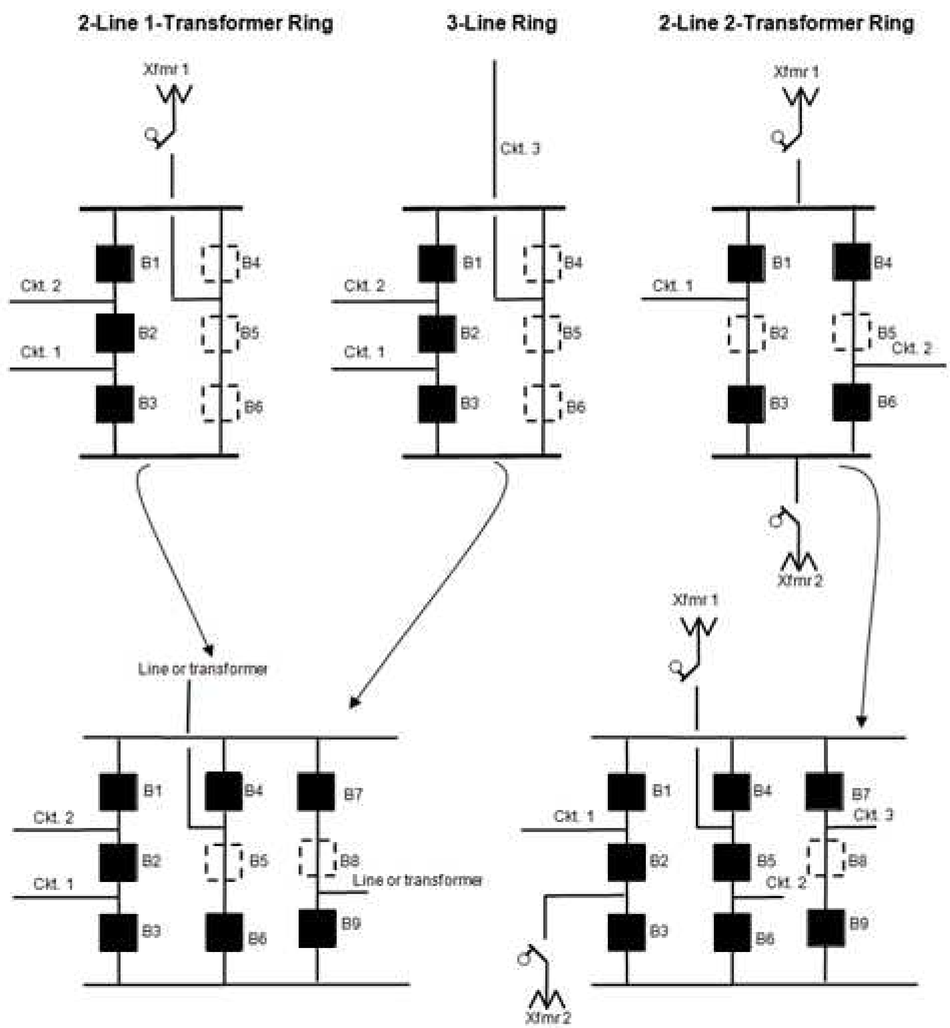


Figure 41
Substation Expansion

6. Radial Criteria

6.1. Introduction

No area supplied by two radial circuits should supply an excess of 300 MW of load during peak operating conditions. The geographical footprint served by the substations supplied by the radial circuits defines an area. Exceptions are allowable when distribution load transfers allow the total load to be brought below the 300 MW level in emergency situations, however, this must not cause overloads on other transmission circuits or distribution feeders.

No radial transmission system should supply more load than the MVA level of the emergency rating of the lowest rated radial circuit supplying the specific load. Given abnormal operation and contingencies, this allows the load to be supplied with a reasonable amount of reliability.

6.2. Expansion

It is preferable to supply load via networked transmission, however, in certain situations, radial supplies may be required. New overhead radial supplies must be justified by a joint study performed by transmission and distribution planners. A cost benefit analysis may be used to justify a new radial supply.

In addition to the criteria applied to the current system, new radial supplies exposed to a common mode failure should serve no more than 30,000 customers where restoration would require greater than four hours.

6.3. Other BGE Radial Transmission System Criteria

Please refer to BGE’s System Planning Procedures and Guidelines Manual. This document presents BGE’s philosophy pertaining to the expansion of radial transmission systems.

7. Remedial Action SchemeRASThis section was perviously referred to as ”Special Protection System (SPS)”

7.1. Introduction

Normal protective relaying systems typically sense faults on a given element and isolate the faulted element. In general, a Remedial Action Scheme (RAS) is a protective relaying system or remedial action scheme that is designed to detect abnormal system conditions (not necessarily limited to faults) and take automatic corrective action by controlling other facilities. The RAS action can be remote to the problem sensed and can include tripping of system elements, generation rejection, generator runback, load shedding, or other control actions.

Because RAS actions are not limited to the facility on which a disturbance is sensed, there is an inherent risk that misoperation will result in a failure to initiate the action required to realize the desired outcome. These unanticipated conditions may pose a significant risk to the reliability of the transmission system. For this reason BGE is very judicious about the application of Remedial Action Schemes. A thorough technical analysis should be conducted as part of the approval process before any RAS may be integrated into the BGE Transmission System. This process will help determine the potential for any negative impact to the transmission system reliability.

7.2. Allowable Uses for RAS

An RAS shall not be installed as a substitute for good system design or operating practices. RAS implementation shall be generally limited to providing protection for temporary conditions that may exist due to construction delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. The decision to employ an RAS should take into account the complexity of the scheme, the consequences of misoperation, and the potential to interact with other RASs on the system.

7.3. Temporary RAS Installation

Mitigation of thermal problems for single element contingencies, two element contingencies, and multiple facility contingencies will be allowed for temporary relief only. Allowable uses for temporary RAS installation would include:

- Providing protection during construction lags, i.e. to mitigate potential overloads on facilities that will be permanently mitigated by system enhancements in the current transmission plan.
- Providing protection during maintenance outages.

Installation of a permanent solution should be completed as soon as possible after the installation of a temporary RAS.

7.3.1. Restrictions on the Use of Temporary RAS Installations

The following restrictions on RAS installation and use are applicable to all applications within the BGE Transmission Zone:

- Temporary RAS installations may be initiated through detection of overloaded equipment only if an evaluation is performed to assure that the RAS would not interact with other RAS application such that it could pose a risk of cascading outages.
- An RAS installed to address a voltage criteria violation may only be used as a temporary installation. Any RAS used for voltage drop criteria violation shall be designed with sufficient

redundancy such that the RAS is capable of performing its intended function while itself experiencing a single component failure.

- No equipment overload, instability, or voltage problems beyond the facility the RAS was intended to protect may be caused by the operation of the RAS.
- Care should be taken to prevent unintended interaction between different RASs. Unless specifically designed or evaluated to work together no more than one RAS may employ the same monitored condition or mitigating action except for functional redundancy of a separate RAS.
- An RAS time delay (if any) shall coordinate with all other short-time limitations within applicable loadings.

7.4. Permanent RAS Installation

An RAS may be installed permanently on BGE's transmission system only for the mitigation of extreme disturbances. Allowable uses for permanent RAS installations would include providing protection against:

- The loss of all lines of a certain voltage emanating from a single substation.
- The loss of all circuits in a single right-of-way.
- The loss of all generation at any one station.
- The loss of a large load center.

7.4.1.Restrictions on Permanent RAS Use

The following restrictions on RAS installation and use are applicable to all permanent application within the BGE Transmission Zone:

- An RAS may not include the shedding of load as part of the remedial scheme unless for the mitigation of an extreme disturbance.
- All permanent RASs shall be initiated by the loss of a physical facility and may not be initiated through detection of overloaded equipment.
- An RAS may not be used as a permanent solution to mitigate a voltage criteria violation since failure of the RAS to operate would not permit other timely action to be taken to protect against the voltage criteria violation.
- Permanent relief of stability problems through the installation of an RAS is not allowed for any contingencies.
- No equipment overload, instability, or voltage problems beyond the facility the RAS was intended to protect may be caused by the operation of the RAS.
- No equipment overload, instability, or voltage problems beyond the facility the RAS was intended to protect may be caused by the misoperation or failure of the RAS to operate when desired.
- Care should be taken to prevent unintended interaction between different RASs. Unless specifically designed or evaluated to work together no more than one RAS may employ the same monitored condition or mitigating action except for functional redundancy of a separate RAS.
- An RAS time delay (if any) shall coordinate with all other short-time limitations within applicable loadings.

7.5. RAS Design & Planning

The design and planning for the installation of any RAS should ensure reliable system performance and operation. This requires close coordination between system protection and transmission planning engineers.

In all RAS installations, the RAS must be physically located at the same site as the facility being altered. If the facility being monitored is at a remote location, redundant communication paths must be supplied between the monitored facility and the RAS.

7.5.1. Design

The design of any RAS should ensure that the system will be both dependable and secure. Dependability ensures that the RAS will operate as intended, and when needed. Security ensures that the RAS will not operate when not intended.

7.5.1.1. Dependability

Each RAS shall be designed with redundancy so that any single element failure will not prevent the RAS from operating when required. Redundancy may be obtained through physical or functional duplication.

7.5.1.2. Security

Each RAS shall be designed so that any failure of an internal device of the RAS will not cause the RAS to operate when not required.

7.6. Planning

The system shall be planned so that misoperation will not cause cascading outages. Misoperation includes: operation without an initiating incident, partial operation, slow operation or non-operation during an initiating event. Each RAS shall be coordinated with other protection and control systems including those of neighboring transmission systems.

RASs shall be analyzed every five years to ensure misoperation will not cause adverse effects such as cascading outages. Identification of such effects will require replacement of the RAS with system enhancements.