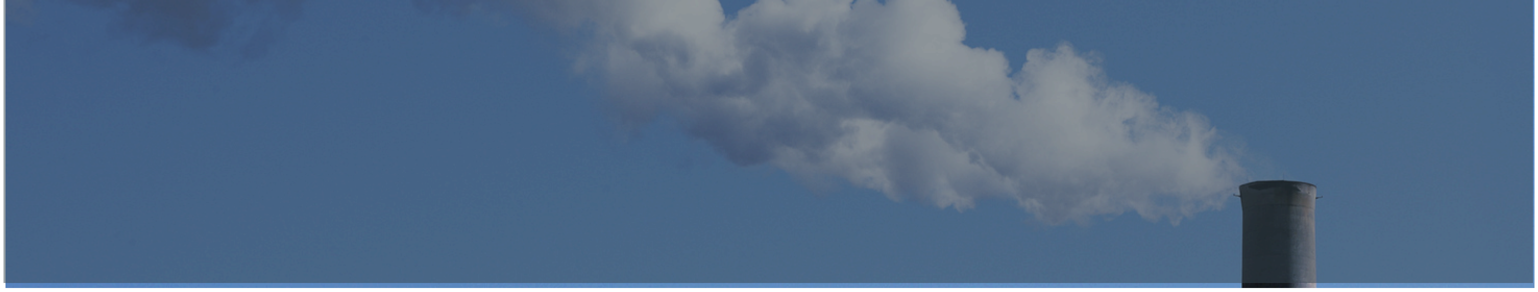
# AUGUST 2025 BALTIMORE LOAD SHED EVENT

RELIABILITY FIRST

## AFTER ACTION ANALYSIS

October 2025

# TABLE OF CONTENTS



# EXECUTIVE SUMMARY

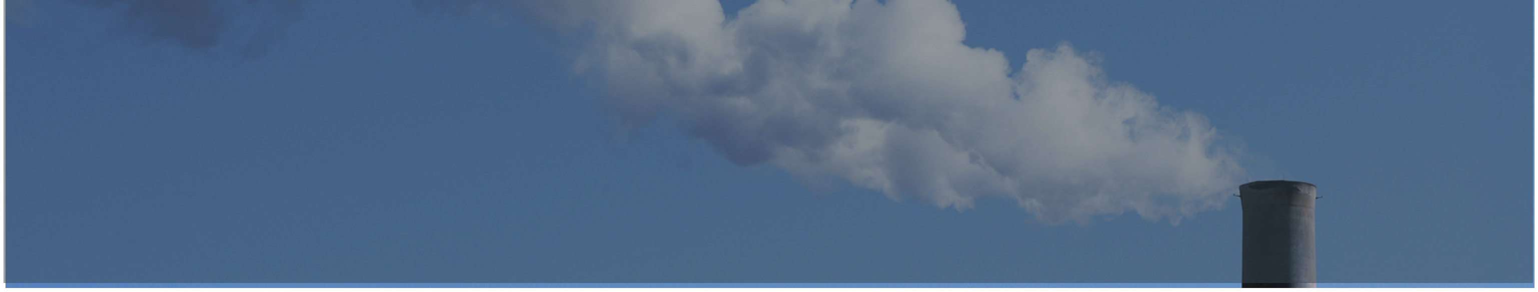
This report summarizes ReliabilityFirst's (RF) analysis of the bulk power system disturbance impacting approximately 4,000 customers in the Baltimore, Maryland, area on Monday, August 11, 2025. It incorporates critical data and a sequence of events provided by the impacted entities and includes RF's independent analysis, technical findings, and evaluation of the sequence of events.

On August 11, 2025, a substation outage occurred at Baltimore Gas and Electric Company (BGE)'s Brandon Shores substation. This outage resulted in approximately 20 megawatts (MW) of customer load shed, impacting approximately 4,000 customers for a duration of 28 minutes. The outage was triggered by multiple failed insulators as a result of flashover, which led to the loss of the entire substation[1] and required coordinated efforts between BGE and PJM Interconnection (PJM)[2] to manage the situation through escalating emergency procedures. BGE and PJM followed those emergency procedures to initiate demand response, public appeals, and voltage reduction actions.

As PJM continued to monitor the system, its operational analysis indicated pre-emptive load shedding was required to prevent a possible cascading outage. Once partial restoration of the substation was completed, analysis indicated that load could be safely restored as crews continued to work on the remaining repairs.

BGE identified the cause of the outage as contamination combined with moisture on the insulators, which had previously passed inspection earlier in the year. On the day of the event, BGE replaced five insulators to restore priority transmission lines, enabling BGE and PJM to terminate emergency procedures and restore the load that was shed. BGE replaced four additional visibly damaged insulators in the following days to return the entire substation back to service. In the following weeks, BGE replaced approximately 238 additional insulators in the substation to reinforce system reliability.

[1] The loss of the entire substation entails the opening of all the 230 kV breakers at Brandon Shores substation, interrupting the power flow across the network and taking offline the Brandon Shores generating units (owned by Talen Energy). A flashed insulator occurs when the electricity inadvertently travels over the insulator from the energized section to the non-energized section resulting in a fault. Circuit breakers open to interrupt the flow of current to protect substation equipment from further damage and for the safety of personnel at the substation.
[2] BGE is the electric utility and Transmission Owner (TO) that owns the Brandon Shores substation and its equipment. PJM is the Reliability Coordinator (RC) and Transmission Operator (TOP) responsible for maintaining the reliability of the electric grid in their footprint which includes the BGE footprint plus all or parts of 13 states. The transmission system operators at BGE coordinate at a local level with PJM system operators at the regional level to mitigate reliability risks to the electric grid in real-time operations.



A forensic and chemical analysis is underway to determine the nature and source of the contamination. Preliminary lab results indicate that most of the contamination was from sodium chloride (salt). Forensic testing is critical in identifying preventative measures, extent of condition, and ensuring long term operational resilience.

The Brandon Shores substation also serves as a host for 635 MW and 638 MW coal-fired generating units owned by Talen Energy. Adjacent to Brandon Shores substation there are two additional oil generating units at the Wagner Substation. All four units are currently under a Reliability Must Run (RMR) contract,[3] which maintains their availability until transmission reinforcements are completed in 2029.

*Brandon Shores Generating Station*

At the time of the substation outage, the two Brandon Shores units were operating, but tripped offline as a result of the substation outage. Although the event and customer outages were not a resource adequacy concern,[4] RF analysis indicated that additional generation and/or Demand Response in the impacted area could have helped to mitigate the emergency conditions that led to the load shed.

[3] An RMR contract indicates that PJM studies concluded transmission violations that would result from the retirement of these units. Transmission projects were initiated so that these units can be retired by an estimated date of May 31, 2029.
[4] Resource adequacy refers to ensuring there are enough generation resources to meet demand. The emergency conditions were due to potential line overloads from importing power from outside the area, not from a regional lack of generation resources in the PJM footprint.

# EVENT OVERVIEW

## PRE-EVENT SYSTEM CONDITIONS

The event began at approximately 3:38 a.m. on Monday, August 11, 2025. At the time, the Brandon Shores substation was enveloped in heavy, dense fog. The substation is located next to the Patapsco River in Anne Arundel County, Maryland, approximately 8 miles southeast of Baltimore. PJM's anticipated load for the day was 143,562 MW, including 5,238 MW in the BGE zone, with forecasted high temperatures in the mid-80s degrees Fahrenheit.

The transmission system in the affected area was fully in-service prior to the first operation at 3:38 a.m. Brandon Shores Units 1 and 2 were online, but the nearby Wagner units were not running.

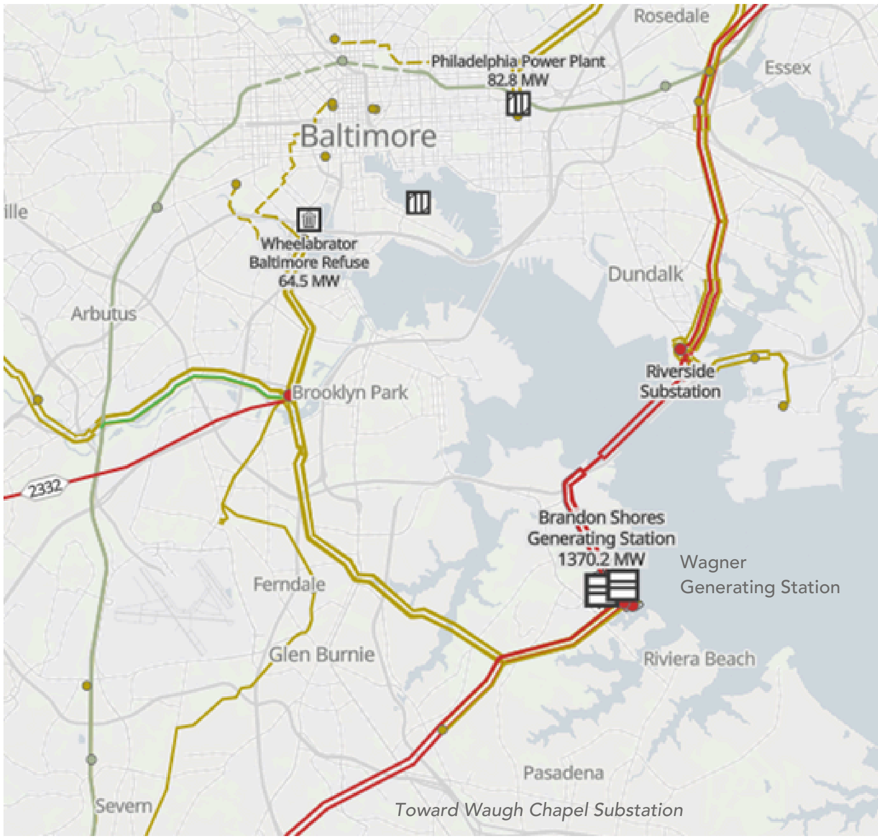



Figure 1: Transmission Map of the Brandon Shores area *(Source: Openinframap.org)*

## EVENT TIMELINE

Using the map in Figure 1, the red lines are 230 kV lines that are networked through the adjacent Brandon Shores and Wagner substations. Two 230 kV lines (Circuits 2344 and 2345) are connected from Brandon Shores to Riverside substation as shown on the map. Two 230 KV lines (Circuits 2342 and 2343) are connected from Brandon Shores to Waugh Chapel substation (southwest). The mustard lines are 115 kV lines that are networked through Wagner substation.

The sequence of events below details the outages that led to all the 230 kV circuit breakers opening at Brandon Shores substation, interrupting power flow to Riverside, Waugh Chapel, and Wagner substations. The event started at 3:38 a.m. with the opening and reclosing[5] of a single line coming from the Brandon Shores substation.

**3:38 AM** – Circuit 2345 (Brandon Shores – Riverside) opened and reclosed

**3:38 AM** – Brandon Shores unit 1 tripped[6]

**3:59 AM** – Circuit 2345 (Brandon Shores – Riverside) opened and reclosed again

**4:02 AM** – Circuit 2345 (Brandon Shores-Riverside) de-energized via SCADA[7] after personnel reported a flash in the substation

**5:18 AM** – 230 kV Bus #1-#3 tripped and locked out[8]

**5:55 AM** – 230 kV breaker fails

**5:56 AM** – 230 kV Bus #2-#4 Bus tripped and locked out

**6:26 AM** – Circuit 2347 (Brandon Shore-Wagner) tripped and locked out

**7:38 AM** – All remaining 230 kV breakers at Brandon Shores tripped, resulting in the loss of all power through the substation, including the loss of Brandon Shores generating unit 2

[5] Circuit breakers open, de-energizing (opening) a line due to a system fault, to protect electrical equipment and maintain safety. If the fault is temporary, the breakers reclose, restoring the line to service.
[6] Tripping refers to circuit breakers opening to clear a fault. In this case, this outage appears to be a misoperation, referred to as an overtrip where the relaying opened the circuit breakers unnecessarily due to a nearby fault on the system.
[7] SCADA is System Control and Data Acquisition. This refers to the system operator's ability to monitor and control the system remotely, in this case opening the breakers remotely and intentionally to investigate.
[8] A bus consists of a series of connected breakers at a substation used to network lines, transformers, and other electrical equipment. Bus outages are relatively rare due to their design; however, equipment failure (such as a failed insulator) can result in a bus outage, opening multiple circuit breakers at once. Locked out refers to the breakers remaining open to clear the fault and prevent equipment damage.

As of 7:38 a.m., the Brandon Shores substation was out of service, and both Brandon Shores Units 1 and 2 were offline. PJM dispatched all generation in the BGE zone that was available, and recalled generation that was on maintenance outage. Because startup times can vary, not all units were available immediately.

Beginning with the first event at 3:38 a.m., BGE began to assess the issues causing the outages as the fog started to burn off that morning. BGE determined that failed insulators[9] were the major cause of the outages and they would need to be replaced. BGE determined that the insulators failed due to contamination that caused a series of insulator failures resulting in bus outages.

As the event was unfolding throughout the morning, both PJM and BGE performed system studies[10] to identify future impacts to the BGE transmission zone. Looking at the load forecast for the day given the loss of Brandon Shores substation, studies showed possible transmission line rating exceedances on the surrounding 115 kV and 230 kV system as the load ramped up throughout the day. PJM and BGE performed studies to determine which 230 kV transmission lines were priority restoration to ensure system reliability. To restore the priority transmission circuits, BGE needed to replace three line insulators and two bus insulators, plus clean[11] insulators that did not need to be replaced. However, mitigation was needed until these repairs were completed.

Beginning around 8:30 a.m., PJM and BGE began to implement emergency procedures based on the forecasted loading and possible transmission line rating exceedances in the Baltimore area.

**8:45 AM** – PJM implemented their Pre-Emergency Load Management procedure in the BGE transmission zone and called for the 120-minute product(s).[12] The estimated time for implementation was 10:45 a.m. BGE also implemented internal load management procedures.

**9:00 AM** – PJM implemented their Pre-Emergency Load Management procedure in the BGE zone and called for the 30-minute and 60-minute product(s). The estimated time for implementation was 10 a.m. for both products.

[9] A substation insulator is a device in a substation that provides both electrical insulation and mechanical support for energized equipment. They are made of non-conductive material to separate the energized components from non-energized components. A failure consists of the energized component flashing over to the non-energized component (i.e., a fault).
[10] System studies are performed by system operators in the control room to assess contingencies on the system (i.e., will there be line overloads, voltage deviations, or other issues if the system loses another line, transformer, or generator). These studies are required by NERC standards and are used to maintain the reliability of the system. When problems are identified, system operators can mitigate these issues by redirecting power flows, dispatching generation, or a series of emergency procedures as detailed in this report.
[11] Insulators are naturally cleaned through rainfall to wash contaminants from the insulators to prevent tracking and flashovers. In the absence of rainfall, insulators can be manually cleaned.
[12] The 120 (and 30 and 60) minute products refer to load management where participants must curtail their load within the timeframe instructed. This is used to reduce stress (e.g., possible line overloads) on the system during pre-emergency conditions.

These preemptive steps were taken to mitigate the forecasted transmission exceedances on the 115 kV system across the peak loading period.

As repairs progressed throughout the day, continued system studies of the BGE zone identified the need for more emergency procedures to be implemented. PJM implemented the following emergency procedures to mitigate forecasted overloads on the 115 kV system.

**1:03 PM** – BGE made public appeals asking customers to conserve electricity to reduce the potential for widespread outages.

**2:15 PM** – Emergency Load Management in the BGE zone called for the 30-minute and 60-minute product(s). The estimated time of implementation was 2:45 p.m. for the 30-minute product and 3:15 p.m. for the 60-minute product. As of this time in the event, PJM and BGE realized approximately 230 MW of load relief.

**2:15 PM** – PJM issued an Energy Emergency Alert Level 2 (EEA2)[14] for the BGE zone.

**3:00 PM** – PJM implemented a 5% voltage reduction[14] for the BGE zone for the local transmission emergency. The voltage reduction action resulted in approximately 60 MW of load reduction in the BGE zone. Also, PJM and BGE asked for the curtailment of non-essential building load.

**3:52 PM** – PJM issued a load shed directive to mitigate an N-5 cascade analysis[15] impacting the Chestnut-Fredrick Rd 115 kV transmission line to reduce contingency loading that was over 115% of the load dump ratings[16] on lines and transformers.

BGE implemented approximately 20 MW of load shed to keep all flows below 115% of the load dump rating. This load shed impacted approximately 4,000 customers in Howard County. A later independent study and review by RF confirmed that this location was optimal for emergency load shed in this event.

Restoration efforts continued in the Brandon Shores substation. At this point, the three line insulators and two bus insulators were replaced, insulators were cleaned, and the line restoration began. Restoration occurred based on the prioritization that was identified earlier in the day.

[13] An EEA2 is the second level of NERC's Energy Emergency Alerts declaring that load management is required to maintain grid reliability. Energy Emergency Alerts are defined in NERC Reliability Standard EOP-011-4.
[14] A voltage reduction is an emergency procedure detailed in PJM Manual 13. Since Power = Voltage x Current, reducing the voltage reduces the total power consumption since the current remains the same.
[15] An N-5 cascade analysis is also detailed in PJM Manual 13 and further explained later in this report. This emergency action results in shedding load to prevent a possible cascading outage.
[16] As per PJM Manual 03, a load dump rating is the highest rating set for PJM facilities (e.g., lines, transformers) in the context of emergency operations. The rating is determined to aid the PJM and member operators in identifying the speed necessary to relieve overloads.

**4:05 PM** – BGE restored three 230 kV circuits out of Brandon Shores:

- 230 kV circuit Brandon Shores – Waugh Chapel (2342)
- 230 kV circuit Brandon Shores – Waugh Chapel (2343)
- 230 kV circuit Brandon Shores – Wagner (2346)

Once these lines were back in service, PJM and BGE were able to work on canceling all emergency procedures in the reverse order of their declaration.

**4:20 PM** – All load that was shed was directed to be restored.

**5:15 PM** – The 5% voltage reduction action and curtailment of non-essential building load ended.

**5:15 PM** – EEA0 was declared (i.e., cancelling the EEA2 issued earlier).

**5:15 PM** – Emergency Load Management (30-minute and 60-minute product(s)) restored.

**8:00 PM** – Pre-Emergency Load Management (30-minute and 60-minute product(s)) restored.

**8:00 PM** – Pre-Emergency Load Management (120-minute product(s)) restored.

The insulator repairs allowed PJM and BGE to restore three 230 kV lines back to service to alleviate reliability concerns. However, other repairs were needed to bring the rest of the Brandon Shores substation back into service, plus additional insulators needed to be cleaned. The following table is a recap of Emergency Procedures on August11 as posted on PJM's website:

| Priority (All) | Message Type | Effective Start Time | Regions (BGE) | Emergency Message | Effective End Time |
|---|---|---|---|---|---|
| Action | Load Shed Directive | 08.11.2025 15:52 | BGE | A Load Shed Directive has been issued to mitigate an N-5 cascade analysis at 115kv Chestnut -Fredrick Rd 110-528-A in BGE .<br>Additional Comments: Load shed directive to maintain post contingency flow below 115% of load dump rating. | 08.11.2025 16:20 |
| Action | Voltage Reduction Action | 08.11.2025 15:00 | BGE | A Voltage Reduction Action of 5 % and a NERC level EEA2 have been issued for BGE .<br>NOTE: Curtailment of Non-Essential Building Load should be issued prior to, but no later than the same time as a Voltage Reduction. | 08.11.2025 17:09 |
| Action | Emergency Load Mgmt Reduction Action | 08.11.2025 14:15 | BGE | An Emergency Load Mgmt Reduction Action and a NERC level EEA2 have been issued. Load reduction start times can be found by clicking on the hyperlink(s) in the Regions column. Load reductions should continue until released by PJM. Reductions are mandatory based on product requirements. CSPs should review DR Hub for specific registration details. Lead Time(s) dispatched: Short_60,Quick_30 . Product(s) dispatched: Capacity Performance DR | 08.11.2025 17:15 |
| Warning | Post Contingency Local Load Relief Warning | 08.11.2025 12:30 | BGE | A Post Contingency Local Load Relief Warning has been issued to maintain CHESTNUT-FRED 110528-A at 195.0 MVA in the BC for Transmission Contingency Control.<br>Additional Comments: Load -No Generation or Switching available | 08.11.2025 16:21 |
| Action | Pre-Emergency Load Mgmt Reduction Action | 08.11.2025 09:30 | BGE | A Pre-Emergency Load Mgmt Reduction Action has been issued. Load reduction start times can be found by clicking on the hyperlink(s) in the Regions column. Load reductions should continue until released by PJM. Reductions are mandatory based on product requirements. CSPs should review DR Hub for specific registration details. Lead Time(s) dispatched: Quick_30 . Product(s) dispatched: Capacity Performance DR | 08.11.2025 20:00 |
| Action | Pre-Emergency Load Mgmt Reduction Action | 08.11.2025 09:00 | BGE | A Pre-Emergency Load Mgmt Reduction Action has been issued. Load reduction start times can be found by clicking on the hyperlink(s) in the Regions column. Load reductions should continue until released by PJM. Reductions are mandatory based on product requirements. CSPs should review DR Hub for specific registration details. Lead Time(s) dispatched: Short_60 . Product(s) dispatched: Capacity Performance DR | 08.11.2025 20:00 |
| Action | Pre-Emergency Load Mgmt Reduction Action | 08.11.2025 08:45 | BGE | A Pre-Emergency Load Mgmt Reduction Action has been issued. Load reduction start times can be found by clicking on the hyperlink(s) in the Regions column. Load reductions should continue until released by PJM. Reductions are mandatory based on product requirements. CSPs should review DR Hub for specific registration details. Lead Time(s) dispatched: Long_120 . Product(s) dispatched: Capacity Performance DR | 08.11.2025 20:00 |

Figure 2: PJM Emergency Procedures in BGE region, August 11, 2025

## CAUSAL ANALYSIS SUMMARY

At this time, BGE has determined that the cause of the event appears to be the combination of moisture and contamination found on the insulators. Other factors that may have played a role in the event were the weather and possibly the age and conditions of the insulators, which will be reviewed during the forensic testing and analysis.

The failed and non-failed insulators had a heavy film contaminant on them. BGE sent the contaminant out to an external lab for analysis. The preliminary lab results indicate that the majority of the contamination was sodium chloride, however, analytical work is continuing regarding the investigation of the insulator failures. The Brandon Shores substation is located in an industrial area.

The weather in the area during the morning of the event was cooler with heavy fog that set in. The nearby Patapsco River and cooler temperatures resulted in the fog that ultimately affected the insulators that had contamination on them.[17]

The insulators associated with the event were porcelain station posts. These insulators are rated for 900 kV Basic Insulation Level (BIL) applied on the 230 kV system.[18] This model of porcelain insulator was fabricated/fired in the 1977 timeframe.

Figure 3: Brandon Shores 230 kV insulator with tracking

[17] Increased moisture in the air along with contamination on the insulators may have increased the likelihood of the flashovers that resulted in the failed insulators and subsequent equipment outages.
[18] 900 kV BIL means the equipment has been tested to withstand a 900 kV impulse voltage without failing. It is typical to have 900 kV BIL on 230 kV class equipment to protect against lightning or switching surges.

## PREVENTATIVE MEASURES

BGE reported that it completes corona scans[19] annually for the Brandon Shores substation, and that the last corona scan was completed on April 29, 2025, with no anomalies or concerns observed. Brandon Shores is one of four BGE substations that receives a corona scan, and all scans were completed in the spring of 2025. The corona scans will continue on an annual basis going forward.

Infrared scans are another tool that BGE uses to inspect substations. The Brandon Shores substation is currently inspected by infrared scan biannually, while the rest of the BGE substation fleet is inspected by infrared scan on an annual basis. The Brandon Shores substation was last inspected via infrared scan on July 14, 2025. During the July inspection BGE reported that there were no thermal anomalies or concerns noted.

During repairs, infrared scans were completed daily to help ensure the safety of the personnel working on repairs and to prioritize the work to maintain the reliability of the Bulk Electric System. BGE began performing these scans monthly starting in September 2025 at the Brandon Shores substation to monitor the insulator replacements and cleanings that occurred.

BGE reported that it performs monthly substation inspections on all facilities, and the last inspection of Brandon Shores substation (before the event) occurred on July 31. At that time there were no adverse findings or observations.

Monthly substation inspections will continue as they have for all BGE substations. The monthly inspection process follows a strict protocol documented in BGE's asset tracking tool and includes both visual and hands-on checks to assess equipment health, detect oil leaks, alarms, performance anomalies, and signs of unauthorized access or vandalism. Inspectors also look for unusual sights, sounds, or smells that could indicate issues.

BGE is conducting an extent-of-condition analysis of similar station configurations to determine if this risk exists elsewhere in the BGE system. BGE is also taking additional steps to partner with industry and vendor subject matter experts to introduce advanced monitoring tools to anticipate potential insulator failures. The monitoring periodicity utilizing this advanced tooling will be determined following the initial analysis.

[19] These scans are preventative measures to look for possible tracking across insulators.

## COMMUNICATIONS

PJM and BGE management established regular checkpoints throughout the day of the event to ensure situational awareness. PJM communicated system conditions via the Reliability Coordinator Information System (RCIS) throughout the day of the outage. This allowed neighboring transmission zones to understand the system conditions in the area.

PJM also directly reached out to the RF Operational Analysis and Awareness team (OAA) to provide real-time updates as the event unfolded. PJM also coordinated System Operation Subcommittee virtual calls to notify and inform additional PJM Transmission Owners of the event.

PJM and BGE reported the event as required by the NERC Reliability Standard EOP-004.[20] Those reports were received in the afternoon by RF OAA, NERC and the Department of Energy (DOE). Multiple iterations were received throughout the afternoon, with the final report arriving the next morning as required.

PJM and BGE were in continuous communication throughout the day. They coordinated substation repairs, insulator cleaning, and discussed system conditions as load increased and during all emergency procedures. The coordination that occurred ensured that the emergency procedures were implemented in a timely manner.

BGE issued call-for-conservation messages to customers via email and placed messaging on web banners,[21] social media,[22] and the main customer service phone line, and BGE shared these same messages with the media. The messaging noted that load shed was possible and provided customers with guidance on how to prepare. It is not certain how much relief was provided by the public appeals. In a separate case study from September 2022, California successfully used text notifications to help manage power supply demand during an emergency.[23]

[20] NERC Reliability Standard EOP-004-4 requires responsible entities (e.g., Reliability Coordinators, Transmission Owners, etc.) to report events per their Operating Plan. Examples of event type thresholds include public appeals for load reduction, voltage reductions, and firm load shedding > 100 MW.
[21] BGE press release
[22] BGE post on X
[23] While emails, social media notifications, website banners, and announcements on television, radio, and from prominent officials is common, California implemented public appeal text alerts that were estimated by CAISO to provide significant short term relief during a September 2022 energy alert.

# PJM N-5 CASCADING ANALYSIS

Day-ahead and real-time operational studies are paramount to maintaining the reliability of the electric grid. As required by the NERC Reliability Standards, at least once every 30 minutes the control room operators perform a Real-time Assessment to determine risks on the system such as thermal, voltage, and stability concerns. Most control rooms have technologies that perform these contingency studies continuously every few minutes to monitor system conditions. When the system operators identify a contingency (i.e., the loss of a transmission facility) that may result in adverse reliability conditions, they perform mitigating actions to redirect power, bring on (or curtail) generation, restore facilities to service, and/or perform emergency procedures as detailed in the sequence of events in this report.

PJM procedures state that a Post Contingency Local Load Relief Warning (PCLLRW) is issued after all other means of transmission constraint control have been exhausted or until sufficient generation is on-line to control the constraint within designated limits and timelines, as identified in PJM Manual 03. However, if post-contingency flows were to exceed 115% of the 15-minute load dump rating and the contingency were to occur, there is a concern that the facility may trip before actions could be implemented to reduce the flow within limits. To prepare for this potential N-2 (initial contingency plus the overloaded facility) and prevent a cascade, PJM will perform up to an N-5 analysis on facilities over 115% of their 15-minute load dump rating.

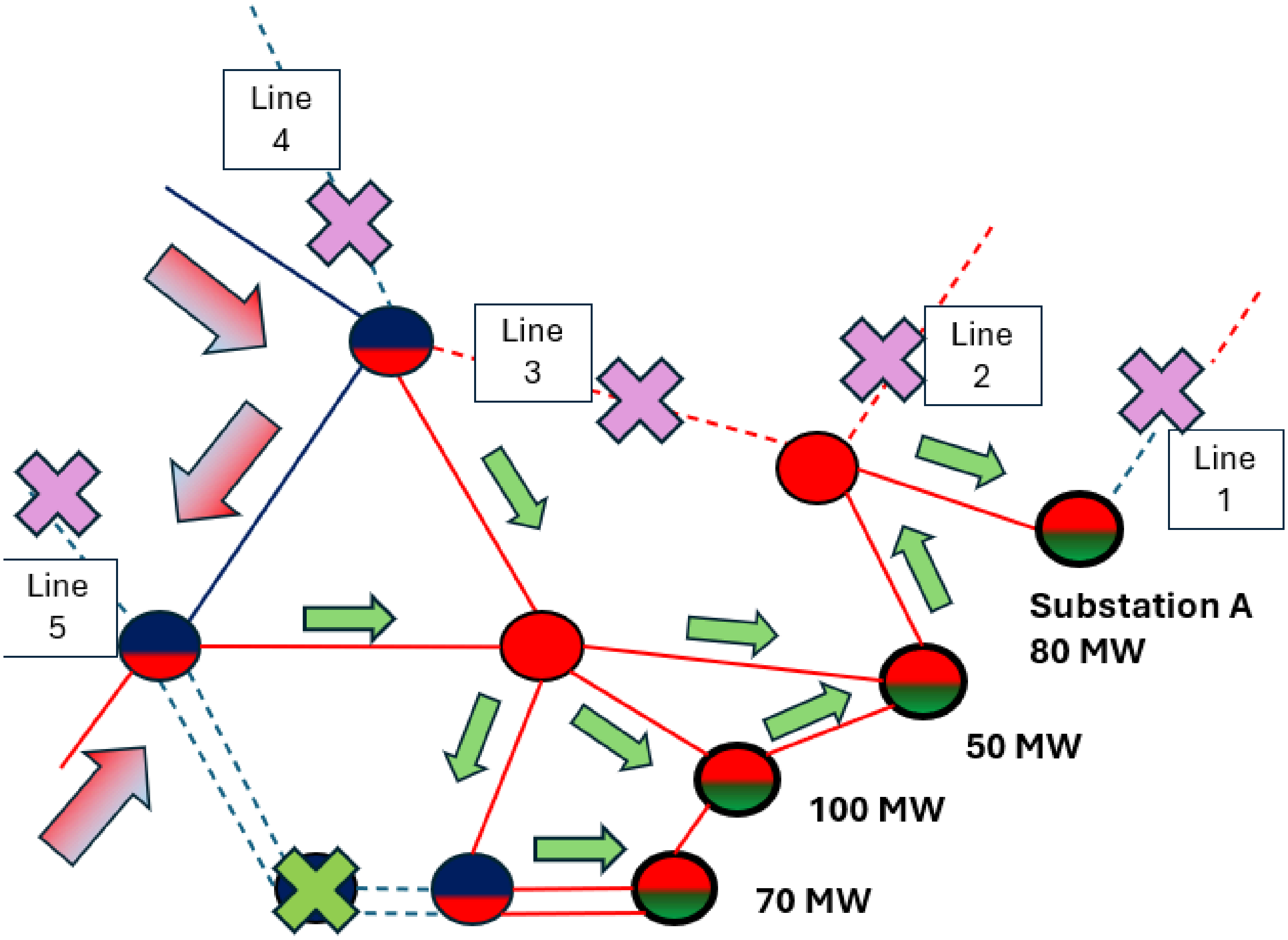
If a facility approaches 115% of its load dump limit post-contingency, the PJM operator will study the loss of the contingency element and the overloaded facility. If the study results indicate no additional facilities will overload over 115% of their load dump limit, this is determined to be a localized event, and no additional pre-contingency actions will be taken.

If the study results in an additional facility(s) with over 115% of its load dump rating, the operator will continue the analysis to also simulate tripping of the additional facilities. This analysis will be performed tripping a maximum of five facilities. If the study indicates either a non-converged case[24] or if the analysis continues to show facilities exceeding 115% of their load dump limits, this will be considered a potential cascade situation. The PJM operator will review the results with the Transmission Owner and direct pre-contingency load shed.[25]

[24] If both PJM and the impacted Transmission Operator(s) agree the non-convergence is the result of an unsupportable radial load pocket in the final state after taking out the initial contingency and overloaded elements (i.e. local voltage collapse), this will be considered a local event and pre-contingency load shed will not be instructed by PJM.
[25] Load shed will be directed in the amount needed to maintain the post contingency flow below 115% of the load dump limit on the original contingency within 30 minutes of verification of the potential cascade situation.

PJM did not direct a certain amount of load shed or in a particular area, but rather directed load shed to bring the facilities under the 115% load dump limit as required by the PJM procedures. The location where BGE shed load provided the greatest relief of the overloaded facilities. The total amount of load that was shed was approximately 20 MW for approximately 28 minutes (3:52-4:20 p.m.) prior to restoration of the transmission lines out of the Brandon Shores substation at 4:05 p.m.

An illustrative example of how the N-5 cascade analysis works is included below and shown in more detail **Appendix A** at the end of this report.




*In this N-5 example, shedding **50 MW** at Substation A possibly saves **300 MW** from being lost (80+50+100+70 MW) from the potential cascade if we were to lose **Line #1** and all the subsequent lines. There could even be more overloads and load loss outside of this area. Operators use load shed as a tool to preserve the reliability of the grid at large.*

# RF ANALYSIS & ASSESSMENT

The details of the event, including the equipment outages, were reported to RF by PJM and BGE. RF performed the independent analyses, outlined below, to review the substation outage impact, load shed mitigation, and circumstances surrounding the Brandon Shores substation.

RF studied the post-contingency overloads that were experienced on August 11 with the loss of the Brandon Shores 230 kV substation. Based on this study, RF agreed with PJM and BGE's conclusion that load shed was needed to prevent a cascading outage. A cascading outage could have led to an uncontrolled load loss event of more than 1,500 MW, comparable to the amount of load serving the entire population of Baltimore.[26]

*Baltimore, Maryland, is home to more than 560,00 people.*

RF also performed a study assessing the impact of the same event in the future following the planned retirement of the Brandon Shores and Wagner generation units, and the construction of transmission projects in place in the PJM RTEP,[27] including projects to facilitate retirement of the units and terminate the RMR contract.[28] The study showed BES reliability is maintained.

Additional RF studies were performed to assess the risk around local resource adequacy concerns (i.e., whether additional generation or Demand Response in the Baltimore County area could have helped to mitigate the contingency overloads and prevent load shed). First, RF analyzed the

[26] There are different approximations for how many customers per MW, ranging from 200-900 depending on the time of day, energy use per customer, and large customer loads in the area. Baltimore has an estimated population of more than 560,000 people.
[27] PJM's Regional Transmission Expansion Plan (RTEP) report details transmission projects to preserve and enhance reliability.
[28] More information is available in PJM's project database

generation retirements and replacements in and around Baltimore over the past 10 years. The following data comes directly from the EIA databases[29] of generation installed and retired. In the past 10 years, Baltimore and Anne Arundel County (where Brandon Shores is located) experienced more than 1,100 MW (nameplate) of generator retirements. Looking again at Baltimore plus its surrounding counties,[30] these generation retirements have been offset by approximately 250 MW of new (nameplate) capacity.

The *NERC Long Term Reliability Assessment* recommends managing the pace of generation retirements.[31] This does not mean that generators cannot or should not be retired due to markets, costs, end-of-life, or policy goals. What it suggests, however, is that replacement infrastructure (such as new generators, lines, grid-enhancing technologies, and/or load flexibility) should be developed and implemented to match the pace of change and maintain reliability. RF studies indicated that the retired generation would have helped to mitigate the transmission overloads and prevent the possible cascading outages. **Appendix B** at the end of the report details the retired and newly installed generating units over the past 10 years.

RF also reviewed how much Demand Response located in and around Baltimore could have helped to mitigate this event. Demand Response is a voluntary program that incentivizes customers to temporarily reduce consumption when the electric grid faces reliability-based issues.[32] The customers that participate are spread over a larger area and not designed to mitigate specific outages or events. Due to the uncertainty of specific locations and magnitudes of Demand Response across the transmission zone, analysis results used to determine how much is needed to mitigate a specific event can vary. A broad group of customer volunteers can address reliability issues affecting the area.

For the specific outage of Brandon Shores substation, RF used power flow analysis to determine the load reduction that would have the most significant impact on post-event loading on 115 kV facilities in the area. In this case, a minimum of 242 MW of load reduction, in the local area, was required to be shed to mitigate the identified reliability issues. RF also reviewed uniformly reducing all customers in the area (i.e., a widespread Demand Response approach across the BGE transmission zone) and determined that 1,729 MW of load reduction was required to mitigate the identified reliability issues. Therefore, a range of 242 – 1,729 MW of Demand Response, depending on the exact locations, would have been needed to mitigate the contingency overloads. During the event, PJM received approximately 230 MW of Demand Response. Currently the BGE transmission zone has approximately 233.4 MW of Demand Response spread

[29] EIA Preliminary Monthly Electric Generator Inventory
[30] Baltimore, Baltimore City, Harford, Carroll, Howard, Frederick, Montgomery, and Anne Arundel Counties
[31] NERC Long Term Reliability Assessment (page 10: Recommendations)
[32] For more information on Demand Response in the PJM footprint, a fact sheet is provided. Load Management Demand Response is a near-last measure tool used by operators to mitigate the need for further emergency procedures such as voltage reductions and non-voluntary manual load shed.


over 886 locations.[33] The RF analysis focused on the outage of Brandon Shores substation only, and the Demand Response megawatt values provided may not mitigate other events in the area.

RF also collects data from industry in the form of TADS[34] data to help assess reliability risks. Contamination (a major factor during this outage, as discussed above) is a risk that is tracked when assessing equipment failures. RF reviewed the TADS data and did not identify an increasing trend of contamination related outages. However, this is a risk RF will continue to monitor. The most recent NERC State of Reliability Report indicated one large transmission event occurred in 2023 caused by contamination outside of the RF region. Currently there are no NERC Reliability Standards that govern inspections for contamination or require washing of insulators, yet it is something that is addressed through outreach, NERC Lessons Learned, and the sharing of best practices.[35]

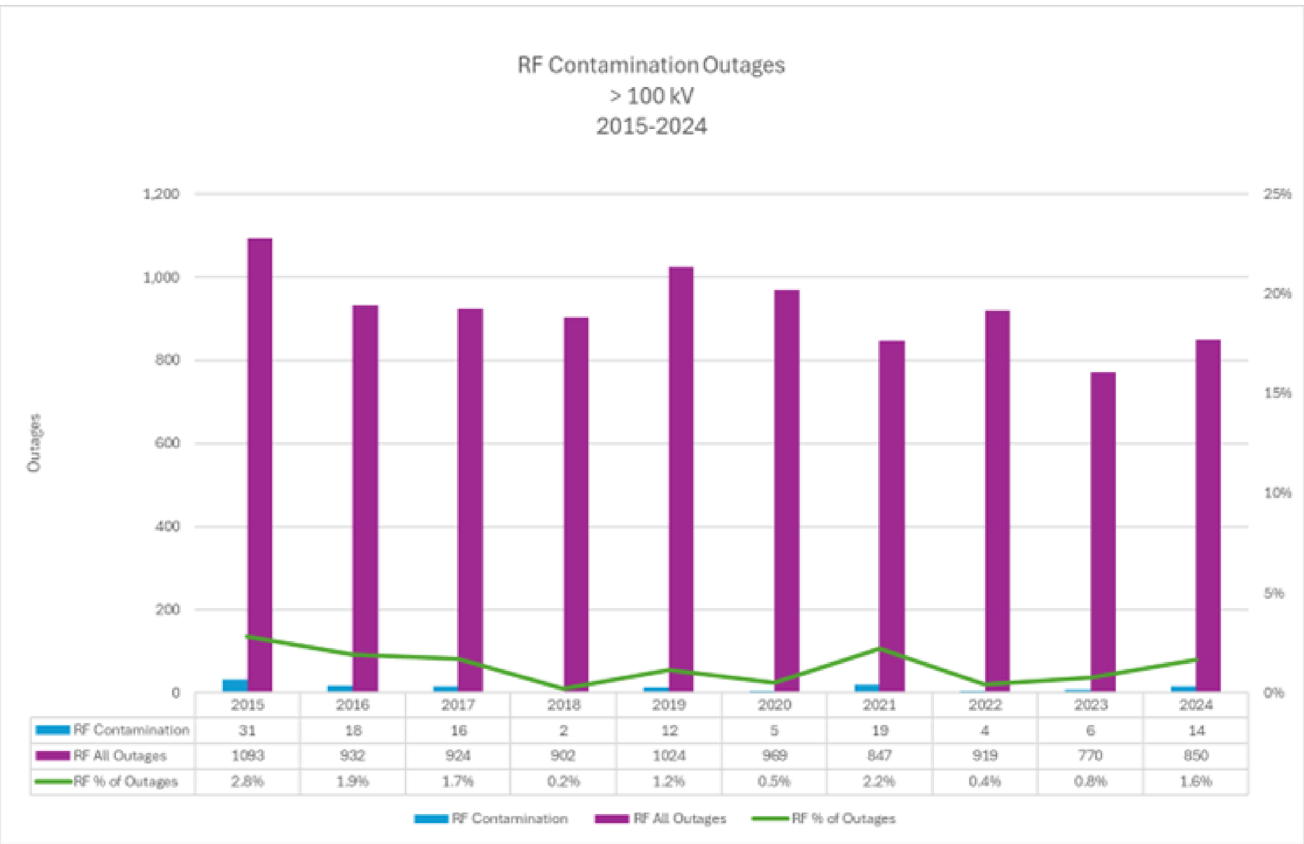



*Figure 4: TADS data, Contamination[36] as a percentage of outages*

[33] PJM Load Response Activity Report: September 2025
[34] TADS stands for the Transmission Availability Data System, used to develop metrics on grid reliability. Utilities submit quarterly outage data in a common format that is published as an aggregate in the annual NERC State of Reliability Report.
[35] See examples of NERC Lessons Learned documents on this topic here, here, and here.
[36] Contamination is defined in TADS as automatic outages caused by contamination such as bird droppings, dust, corrosion, salt spray, industrial pollution, smog, or ash. This encompasses more types of contamination than the contamination observed on the Brandon Shores insulators.

# CONCLUSIONS

On the morning of August 11, 2025, PJM and BGE were presented with an unplanned outage. Between 3:38 a.m. and 7:38 a.m., multiple trips occurred in the Brandon Shores substation, removing all the 230 kV lines from service plus generating units 1 and 2. PJM and BGE promptly began coordinating running system studies based on forecasted loading in the area for the day. While the studies were being performed, BGE assessed the damage at the substation and created a plan for restoration.

Based on the studies, PJM and BGE decided to start implementing emergency procedures to help mitigate the issues on the 115 kV system. Early in the morning, PJM and BGE used pre-emergency load management and requested approximately 230 MW. BGE had created a plan for restoration based on needs for transmission reliability.

PJM went into further emergency procedures as the need arose based on system conditions and the N-5 Cascading Analysis, up to and including directing load shed to mitigate the contingency overloading of line segments under the 115% load dump rating. The amount of load at risk from a potential cascade was approximately 1,200 MW according to PJM’s analysis.

Shortly after the load shed, BGE was able to restore three lines networked through the Brandon Shores substation. This provided the reliability relief that was needed to mitigate the contingency overloads. PJM and BGE backed out of all initiated emergency procedures and restored the load in 28 minutes.

While the Brandon Shores substation was not fully restored, BGE continued to coordinate with PJM to clean and repair the other impacted circuits. BGE took precautionary steps to keep all the field crews safe during the restoration efforts.

Overall, PJM and BGE followed emergency procedures, acting quickly to preserve the BGE Zones Transmission system and prevent a possible cascading outage. Approximately 20 MW of load was shed to ensure the transmission system stayed reliable and intact. If load had not been shed, cascading load at stake was approximately 1,200 MW. The actions that PJM and BGE took preserved the system’s integrity.

BGE's mitigating actions going forward include implementing new procedures to prevent a similar occurrence, such as conducting an extent of condition review to track insulators susceptible to corrosion and flashovers.

Studies completed by the RF Engineering and System Performance team mimicked the impact of the Brandon Shores 230 kV event on August 11. The analysis concluded that the manual load shed taken by PJM and BGE was at an optimal location to mitigate adverse system conditions and prevent cascading outages. The RF analysis indicated that the manual load shed mitigated a potential uncontrolled loss of more than 1,500 MW of load in the Baltimore area, which was slightly more than PJM's estimated value of 1,200 MW.

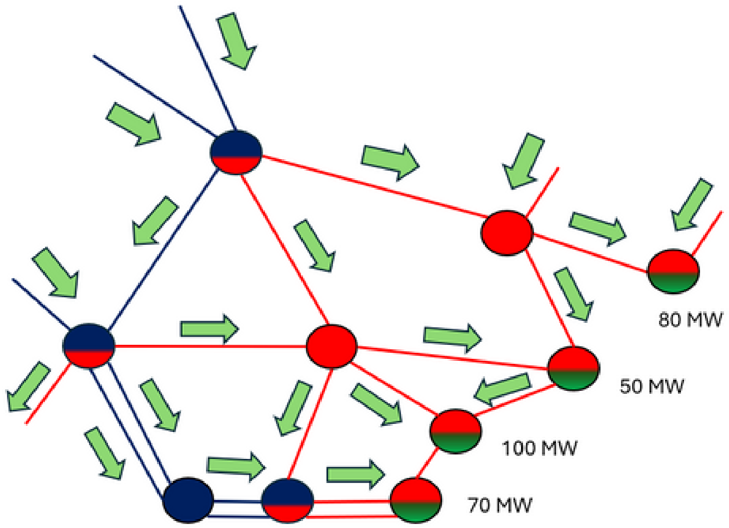
RF also looked at the impact of previous generation retirements in the area to determine what impact, if any, these retirements would have had during the event. Studies concluded that the availability of the retired generation in the area would have helped to reduce the likelihood of load shedding during the event.

More specifically, the availability of quick start generation, or additional Demand Response resources, in the local 115 kV system would have been impactful in mitigating the impacts of the loss of Brandon Shores substation. Additional transmission infrastructure or reinforcements including Grid-Enhancing Technologies[37] (GETS) may have helped to mitigate the impact as well, however transmission planning studies do not necessitate these types of projects for the loss of a substation scenario.

At the time of this report, initial forensic studies evaluating the failed insulators indicated sodium chloride contamination on the insulators, however tests are still ongoing to learn more about the contamination, insulators, and equipment failures that ultimately led to the loss of the entire substation. For any questions related to this report, please contact RF at communications@rfirst.org.

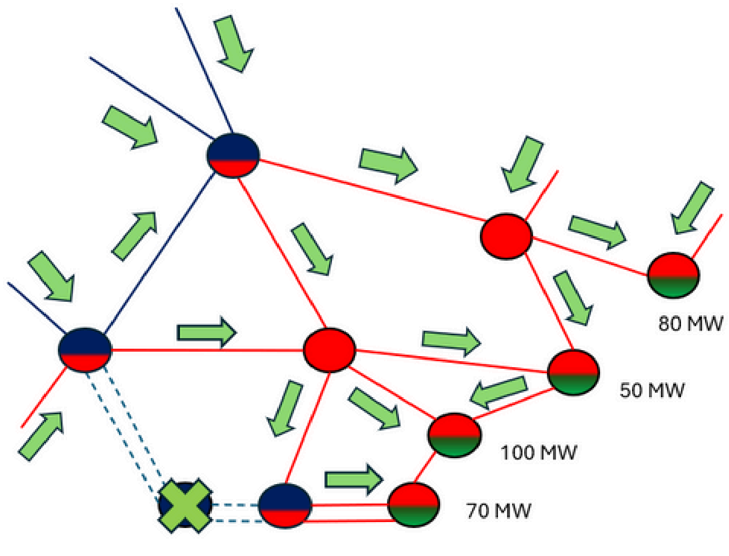
[37] Grid-Enhancing Technologies are explained in this NERC Reliability Insights article.

# APPENDIX A: N-5 CASCADE EXAMPLE



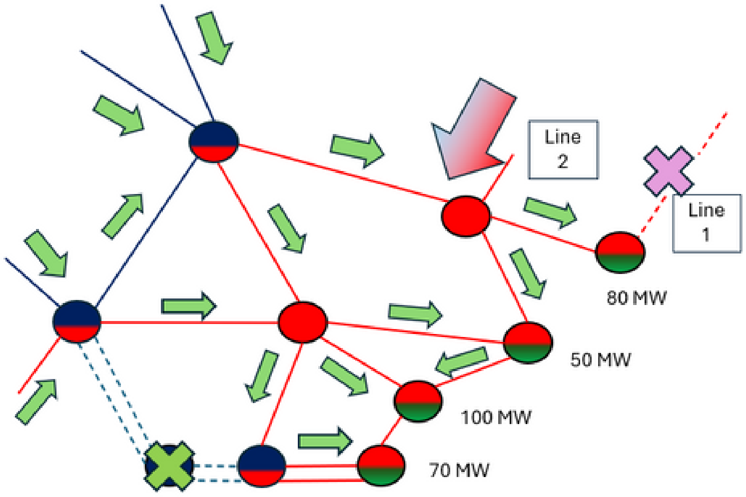

The high-voltage grid is a network of transmission lines and substations networked together to deliver power to the customer loads. In the example below, the **Blue** is the 230 kV network, the **Red** is the 115 kV network, and the **Green** represents a Distribution voltage and customer load.

Substations with two colors have a power transformer that steps down the voltage. The arrows represent the flow of current.

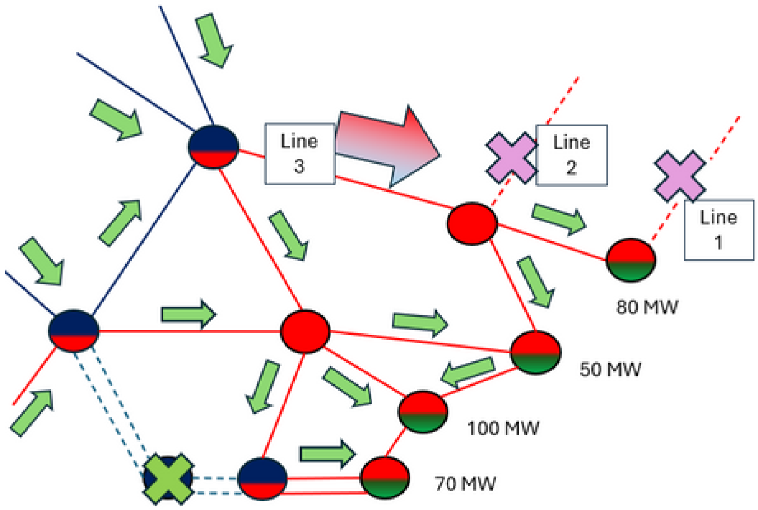



**SUBSTATION OUTAGE**

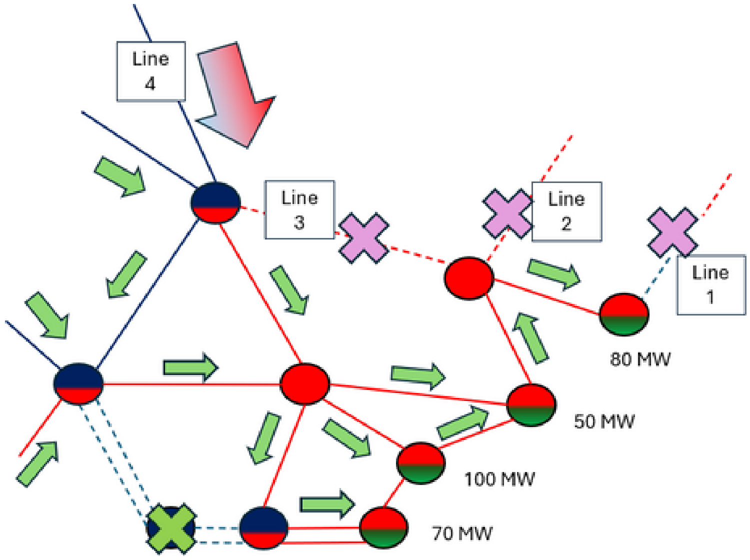
Starting off, we have a substation outage, de-energizing every line in-and-out of that substation. Power is re-routed around the outage to serve the customers. System operators are monitoring for transmission line and transformer overloads. At this point, all customers are being served and there are no overloads.



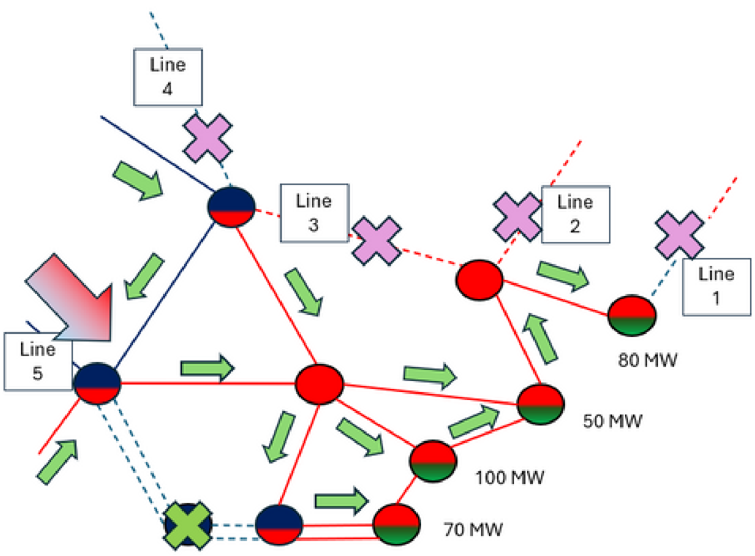

Contingency analysis determines that if there were an outage on **Line #1** for whatever reason (e.g., lightning, squirrel, equipment failure, etc.) we would overload **Line #2** at over 115% of its load dump rating. This is dangerous because that means we may lose **Line #2** instantly before operators could act.



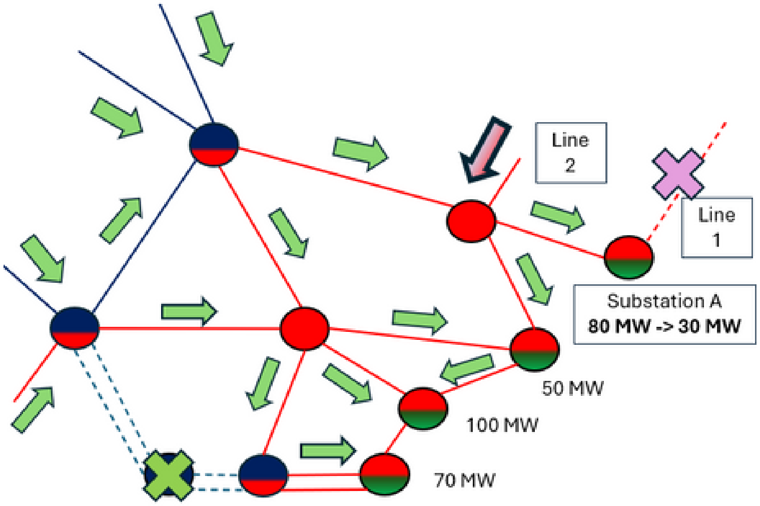

Let’s assume we lose **Line #1** and then **Line #2** trips (because it’s over 115% of its load dump rating). Then what? Studies show that **Line #3** would be over 115% of its load dump rating. Operators assume **Line #3** would trip instantly before operators could act.



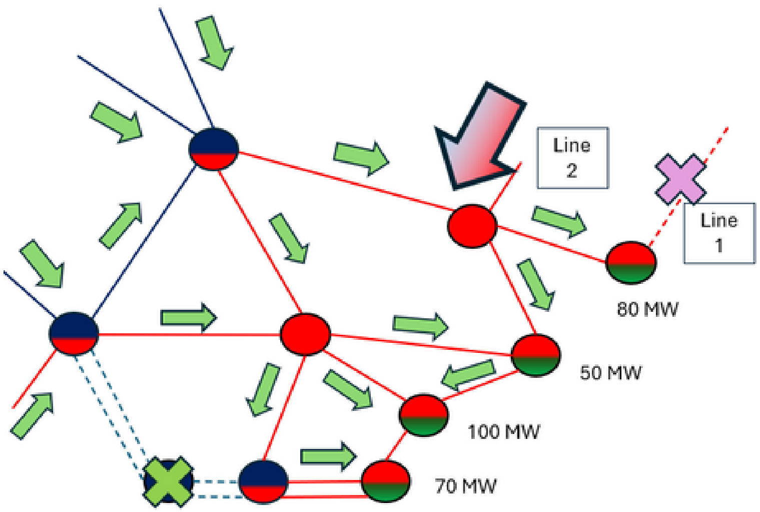

Assuming **Line #3** trips, then what? Studies show that **Line #4** would be over 115% of its load dump rating. Operators assume **Line #4** would trip instantly before operators could act.




Assuming **Line #4** trips, then what? Studies show that **Line #5** would be over 115% of its load dump rating. We have now reached our **N-5 threshold** and operators need to determine how much load to shed to prevent the contingency overload on **Line #2**.

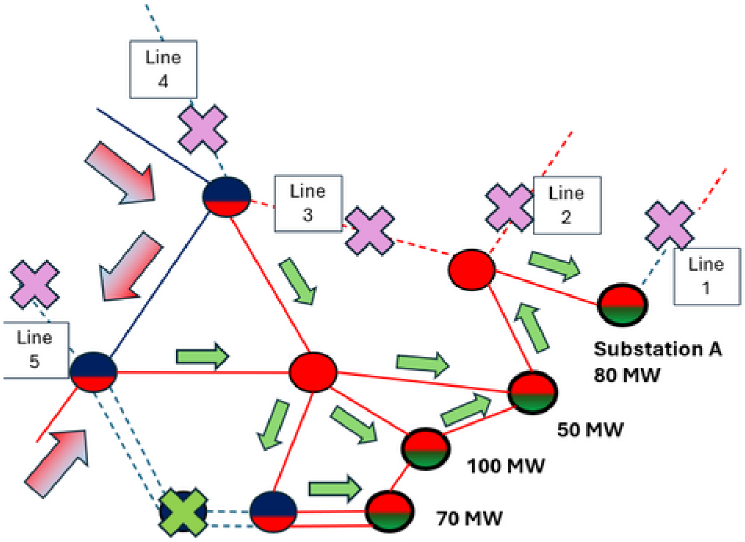



Going back to the beginning of the sequence, the loss of **Line #1** will result in an overload on **Line #2** and then a possible cascading outage. If we shed load (let's say 50 MW) at **Substation A**, the loss of **Line #1** will result in **Line #2** being loaded at 95% which is not over its limit. This prevents the possible cascade.




Other possible mitigations instead of load shed include:

- **Demand Response** (DR) at or around any of the four distribution substations
- **Generation** around the distribution substations, reducing the line imports
- **New transmission lines** into the area
- **Restoring** the 230 kV substation outage




In this N-5 example, shedding **50 MW** at **Substation A** possibly saves **300 MW** from being lost (80+50+100+70 MW) from the potential cascade if we were to lose **Line #1** and all the subsequent lines.

There could even be more overloads and load loss outside of this area. Operators use load shed as a tool to preserve the reliability of the grid at large.

# APPENDIX B: RETIRED AND NEW CAPACTIY IN THE BALTIMORE AREA 2016-2025

**Retired generating units[38] in Baltimore, Baltimore City, and Anne Arundel County, 2016-2025**

| Plant Name | County | Generator ID | Nameplate Capacity (MW) | Technology | Retirement Year |
|---|---|---|---|---|---|
| Riverside | Baltimore | 4 | 72.2 | Natural Gas Steam Turbine | 2016 |
| CP Crane Power, LLC | Baltimore | 1 | 190.4 | Conventional Steam Coal | 2018 |
| CP Crane Power, LLC | Baltimore | 2 | 209.4 | Conventional Steam Coal | 2018 |
| CP Crane Power, LLC | Baltimore | GT1 | 16 | Petroleum Liquids | 2018 |
| Riverside | Baltimore | GT8 | 25 | Petroleum Liquids | 2019 |
| Gould Street | Baltimore City | 3 | 103.5 | Natural Gas Steam Turbine | 2019 |
| Riverside | Baltimore | GT7 | 25 | Petroleum Liquids | 2019 |
| Herbert A Wagner | Anne Arundel | 2 | 136 | Conventional Steam Coal | 2020 |
| Notch Cliff | Baltimore | GT1 | 18 | Natural Gas Fired Combustion Turbine | 2020 |
| Notch Cliff | Baltimore | GT2 | 18 | Natural Gas Fired Combustion Turbine | 2020 |
| Notch Cliff | Baltimore | GT3 | 18 | Natural Gas Fired Combustion Turbine | 2020 |
| Notch Cliff | Baltimore | GT4 | 18 | Natural Gas Fired Combustion Turbine | 2020 |
| Westport | Baltimore City | GT5 | 121.5 | Natural Gas Fired Combustion Turbine | 2020 |
| Notch Cliff | Baltimore | GT5 | 18 | Natural Gas Fired Combustion Turbine | 2020 |
| Notch Cliff | Baltimore | GT6 | 18 | Natural Gas Fired Combustion Turbine | 2020 |
| Notch Cliff | Baltimore | GT7 | 18 | Natural Gas Fired Combustion Turbine | 2020 |
| Notch Cliff | Baltimore | GT8 | 18 | Natural Gas Fired Combustion Turbine | 2020 |
| Herbert A Wagner | Anne Arundel | 1 | 132.8 | Petroleum Liquids | 2025 |
| Herbert A Wagner | Anne Arundel | GT1 | 16 | Petroleum Liquids | 2025 |

[38] Data derived from Preliminary Monthly Electric Generator Inventory (form EIA-860m)

## New generating units installed around Baltimore, 2016-2025

| Plant Name | County | Generator ID | Nameplate Capacity (MW) | Technology | Operating Year |
|---|---|---|---|---|---|
| The Clorox Company | Harford | PV1 | 1.6 | Solar Photovoltaic | 2016 |
| Havre de Grace II - E at Perryman | Harford | PV1 | 1.4 | Solar Photovoltaic | 2016 |
| Pfeffers | Baltimore | SO147 | 1 | Solar Photovoltaic | 2016 |
| APG Combined Heat and Power Plant | Harford | GEN1 | 7.9 | Natural Gas Fired Combustion Turbine | 2016 |
| IGS Solar I - BWI5 | Baltimore | BWI5 | 1.1 | Solar Photovoltaic | 2016 |
| Baker Point | Frederick | GEN1 | 9 | Solar Photovoltaic | 2016 |
| Fort Detrick Solar PV | Frederick | FDSPV | 15.7 | Solar Photovoltaic | 2016 |
| Macy's MD Joppa Solar Project | Harford | MMDJ | 1.8 | Solar Photovoltaic | 2016 |
| Montgomery County Correctional | Montgomery | PV1 | 1.4 | Solar Photovoltaic | 2017 |
| IGS Solar I - BWI2 | Baltimore | BWI2 | 1.4 | Solar Photovoltaic | 2017 |
| Anne Arundel County Public | Anne Arundel | X0001 | 1 | Solar Photovoltaic | 2017 |
| NIH Cogeneration Facility | Montgomery | CGT | 28 | Natural Gas Fired Combustion Turbine | 2018 |
| Annapolis Solar Park, LLC | Anne Arundel | ASP12 | 12 | Solar Photovoltaic | 2018 |
| Montgomery County Solar | Montgomery | 1 | 1.9 | Solar Photovoltaic | 2018 |
| NIST Solar | Montgomery | PV1 | 4 | Solar Photovoltaic | 2018 |
| APG Old Bayside | Harford | 10115 | 1.7 | Solar Photovoltaic | 2018 |
| APG New Chesapeake | Harford | 10115 | 2.3 | Solar Photovoltaic | 2018 |
| MNCPPC Germantown Solar | Montgomery | X0008 | 1 | Solar Photovoltaic | 2018 |
| Francis Scott Key Mall | Frederick | FSK | 1.6 | Solar Photovoltaic | 2018 |
| Amazon Maryland DCA1 | Baltimore | DCA1 | 1.3 | Solar Photovoltaic | 2019 |

## New generating units installed around Baltimore, 2016-2025 (continued)

| Plant Name | County | Generator ID | Nameplate Capacity (MW) | Technology | Operating Year |
|---|---|---|---|---|---|
| BTC2 Solar (CSG) | Baltimore | 18 | 2 | Solar Photovoltaic | 2019 |
| Old Court Rd Solar | Howard | OLDCT | 2 | Solar Photovoltaic | 2019 |
| Frederick County - Landfill | Frederick | PV1 | 2 | Solar Photovoltaic | 2019 |
| White CSG | Baltimore | 15124 | 2 | Solar Photovoltaic | 2020 |
| Timonium Fairgrounds | Baltimore | FAIR1 | 1.9 | Solar Photovoltaic | 2020 |
| 6685 Santa Barbara Ct | Howard | SBAR | 1 | Solar Photovoltaic | 2020 |
| 7448 Candlewood Road | Anne Arundel | 1 | 1.5 | Solar Photovoltaic | 2020 |
| Burns Solar One LLC | Baltimore | 64606 | 2 | Solar Photovoltaic | 2020 |
| White Marsh Solar | Baltimore | WM | 1.5 | Solar Photovoltaic | 2020 |
| P52ES 1755 Henryton Rd Phase | Howard | HCSG | 1.9 | Solar Photovoltaic | 2021 |
| P52ES 1755 Henryton Rd Phase | Howard | HVNM | 1.9 | Solar Photovoltaic | 2021 |
| OER Checkerspot | Anne Arundel | CHECK | 1.5 | Solar Photovoltaic | 2021 |
| Bomber CSG | Carroll | BOMB | 6 | Solar Photovoltaic | 2021 |
| Hollins Ferry CSG | Baltimore City | HOLL | 1.5 | Solar Photovoltaic | 2021 |
| Shepherds Mill CSG | Carroll | SHEPM | 2 | Solar Photovoltaic | 2021 |
| Snowden River CSG | Howard | SNOWD | 1.9 | Solar Photovoltaic | 2021 |
| THD Baltimore DC - 5830 Project Tiger | Baltimore | P3685 | 1.6 | Solar Photovoltaic | 2021 |
| THD Baltimore DCs - 5829 Project Lion | Baltimore | P3887 | 3.8 | Solar Photovoltaic | 2021 |
| Eastern Landfill Gas LLC | Baltimore | 4 | 1 | Landfill Gas | 2022 |
| Maryland Bioenergy Center (Jessup) | Howard | CHP1 | 1.1 | Natural Gas Fired Combustion Turbine | 2022 |
| OER Patuxent CSG | Anne Arundel | PATUX | 2 | Solar Photovoltaic | 2022 |
| MO32 (CSG) | Montgomery | MO32 | 2 | Solar Photovoltaic | 2022 |
| MO33 CSG | Montgomery | MO33 | 2 | Solar Photovoltaic | 2022 |

## New generating units installed around Baltimore, 2016-2025 (continued)

| Plant Name | County | Generator ID | Nameplate Capacity (MW) | Technology | Operating Year |
|---|---|---|---|---|---|
| Brookville Smart Bus Depot Microgrid | Montgomery | BESS | 1.5 | Batteries | 2022 |
| Brookville Smart Bus Depot Microgrid | Montgomery | PV | 1.7 | Solar Photovoltaic | 2022 |
| KDC Solar TC Little Patuxent WWTP LLC | Howard | TCLP | 2 | Solar Photovoltaic | 2022 |
| KDC Solar TC George Howard LLC | Howard | TCGH | 2 | Solar Photovoltaic | 2022 |
| KDC Solar TC Blandair Park LLC | Howard | TCBP | 2 | Solar Photovoltaic | 2022 |
| CPG - Duke 5300A Holabird | Baltimore City | 5003A | 1.5 | Solar Photovoltaic | 2022 |
| CPG - Duke 5300B Holabird | Baltimore City | 5003B | 1.5 | Solar Photovoltaic | 2022 |
| CPG - Duke 5900 Holabird | Baltimore City | 5900 | 1.5 | Solar Photovoltaic | 2022 |
| CPG - Duke 6000 Holabird | Baltimore City | 6000 | 1.5 | Solar Photovoltaic | 2022 |
| Union Bridge Solar | Carroll | PV1 | 8.2 | Solar Photovoltaic | 2022 |
| Brookville Smart Bus Depot Microgrid | Montgomery | GENS | 0.6 | Natural Gas Internal Combustion Engine | 2023 |
| Friendship I | Howard | 569 | 2 | Solar Photovoltaic | 2023 |
| Friendship II | Howard | 570 | 2 | Solar Photovoltaic | 2023 |
| KDC Solar CV Ascend One LLC | Howard | CVAO | 2 | Solar Photovoltaic | 2023 |
| KDC Solar CV Cedar Lane Park LLC | Howard | CVCL | 2 | Solar Photovoltaic | 2023 |
| KDC Solar CV Central MD Regional Transit | Howard | CVRT | 2 | Solar Photovoltaic | 2023 |
| KDC Solar CV Animal Control LLC | Howard | CVAC | 2 | Solar Photovoltaic | 2023 |
| KDC Solar CV O'Donnell Property LLC | Howard | CVOD | 2 | Solar Photovoltaic | 2023 |
| FFP - MD Foxhall | Baltimore | P5658 | 2 | Solar Photovoltaic | 2023 |

## New generating units installed around Baltimore, 2016-2025 (continued)

| Plant Name | County | Generator ID | Nameplate Capacity (MW) | Technology | Operating Year |
|---|---|---|---|---|---|
| Boyd Soccerplex | Montgomery | LHAPV | 1 | Solar Photovoltaic | 2023 |
| Fort Detrick Solar PV | Frederick | FDSBS | 6 | Batteries | 2024 |
| Brookville Smart Bus Depot Microgrid | Montgomery | GEN2 | 0.6 | Natural Gas Internal Combustion Engine | 2024 |
| Brookville Smart Bus Depot Microgrid | Montgomery | GEN3 | 0.6 | Natural Gas Internal Combustion Engine | 2024 |
| Cannonball Solar (CSG) | Frederick | CBALL | 2 | Solar Photovoltaic | 2024 |
| Oaks Landfill - ANEM | Montgomery | 882 | 2 | Solar Photovoltaic | 2024 |
| Ten Oaks | Howard | SC | 2 | Solar Photovoltaic | 2024 |
| Lion One | Baltimore | SC | 2 | Solar Photovoltaic | 2024 |
| Oaks Landfill CS 1 | Montgomery | 883 | 2 | Solar Photovoltaic | 2024 |
| MD JESSUP 7950 OCEANO AVE | Howard | 22337 | 1.5 | Solar Photovoltaic | 2024 |
| Oaks Landfill CS 2 | Montgomery | 884 | 2 | Solar Photovoltaic | 2024 |
| Fairview Farms | Harford | FVFPV | 30 | Solar Photovoltaic | 2024 |
| Fairhaven | Anne Arundel | FAIRH | 2.5 | Batteries | 2024 |
| Chaberton Solar Catherine | Howard | CHAB | 2 | Solar Photovoltaic | 2024 |
| MD - CPG - Ten Oaks | Howard | 10OAK | 2 | Solar Photovoltaic | 2024 |
| MD BALTIMORE 4851 HOLABIRD AVE | Baltimore | 21376 | 1.8 | Solar Photovoltaic | 2025 |
| Chaberton Solar Lime Kiln | Howard | CHLI | 2 | Solar Photovoltaic | 2025 |
| Chaberton Solar Matterhorn | Baltimore | CHMA | 2 | Solar Photovoltaic | 2025 |
| TPE MD HO93 | Howard | TP93 | 2 | Solar Photovoltaic | 2025 |