Reliability Analysis Update

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Sub Regional RTEP Committee - PJM West

October 14, 2022

Changes to Existing Projects

Baseline Reliability Projects

AEP Transmission Zone: Baseline B3104 Cost Increase

B3104: Previously presented on 03/07/2019 TEAC

Problem Statement: Polaris - Westerville 138 kV line is overloaded for multiple N-1-1 contingency pairs with the Conesville unit 4 deactivation.

B3104 scope: Perform a sag study (~ 3.6 miles) to increase the Summer Emergency rating to 310 MVA

- Current rating: SN 223 MVA / SE 226 MVA
- New rating: SN 223 MVA / SE 310 MVA

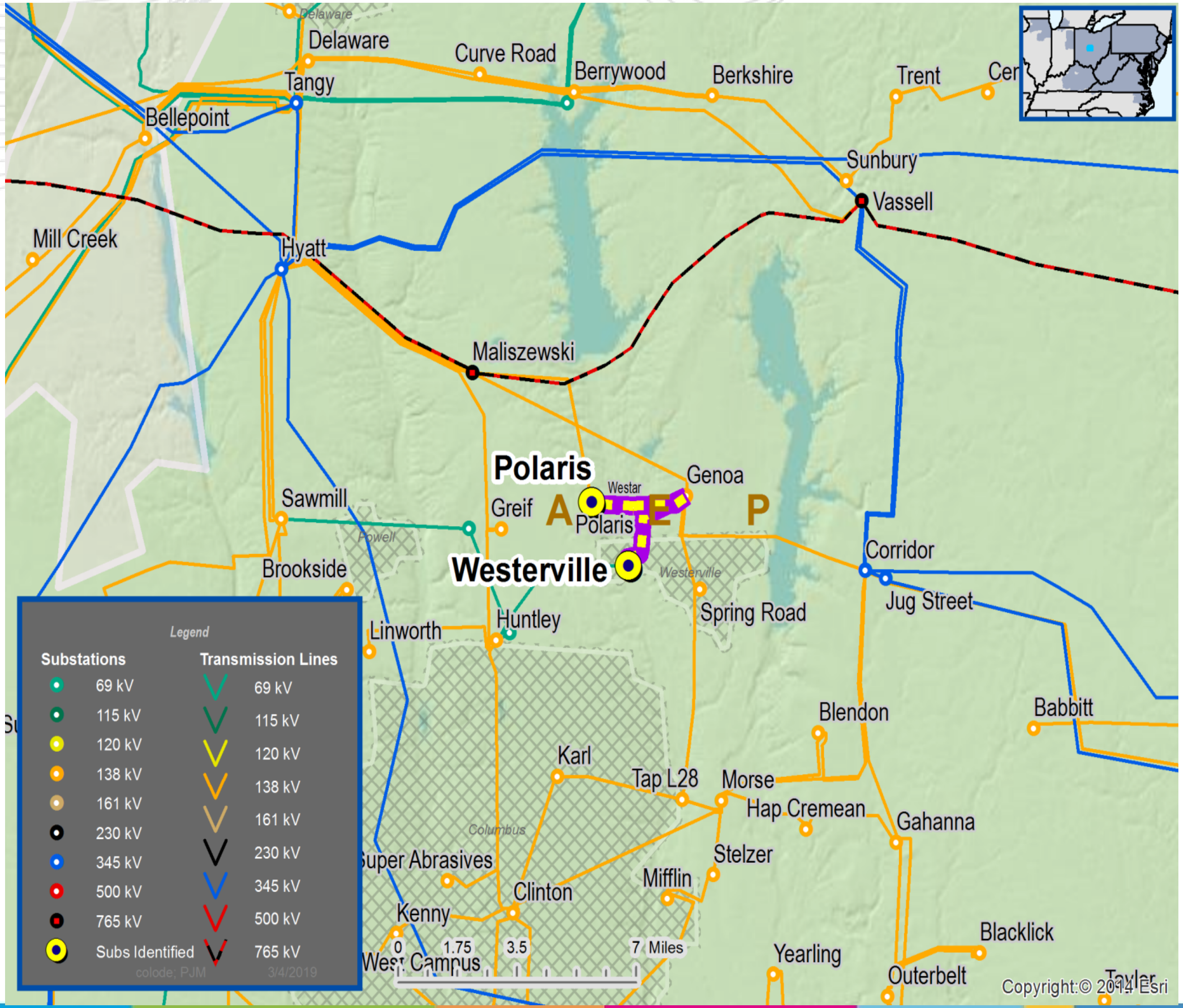
Original Estimated Cost: $0.5M -> **New Estimated Cost:** $3.82M

Required IS Date: 6/1/2020

Original Projected IS Date: 6/1/2020 -> **New Projected IS Date:** 1/24/2023

Reason for the Cost and IS Date Change: After LIDAR was completed it was determined that the full scope of work is required in order to meet the desired ratings noted above. The scope includes: Ten structure replacements, three distribution poles modifications, re-sag two spans of existing conductor, and one existing street light relocation.

The scope of work combined with material procurement issues led to delays in the project's initial timeline. The projected timeline of the project has continued to be updated in the PJM construction tracker as changes have occurred.
In order to alleviate the possible overload condition until such time the permanent solution can be implemented, a potential operating procedure was identified to open the 138 kV line between Genoa and Spring Road SW to offload the Polaris – Westar line if the loading rises above the emergency rating in real time operations.



Recommended Solution

Baseline Reliability Projects

AEP Transmission Zone: Baseline Darrah – Barnett 69 kV Line Rebuild

Process Stage: Recommended Solution

Criteria: AEP 715 Criteria

Assumption Reference: 2027 RTEP assumption

Model Used for Analysis: 2027 Winter RTEP case

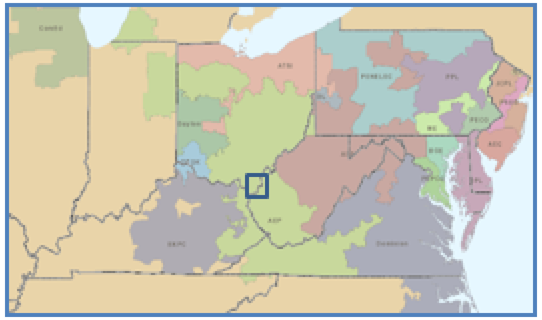
Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-AEP-T1, 2022W1-AEP-T2

In 2027 RTEP winter case, the Darrah – Barnett 69 kV line is overloaded under a N-1-1 contingency scenario

Existing Facility Rating:

Branch	SN/SE/WN/WE (MVA)
Darrah – Barnett 69 kV	50/50/63/63



Existing
Proposed
Related

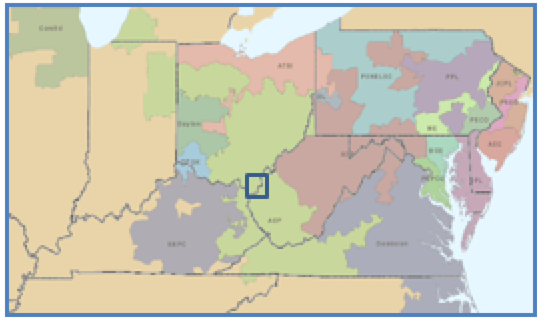
AEP Transmission Zone: Baseline Darrah – Barnett 69 kV Line Rebuild

Recommened Solution:

- Rebuild the existing Darrah - Barnett 69 kV line, approximately 2.8 miles and replace a riser at Darrah Station. (**B3722**)

Transmission Estimated Cost: $6.98M

Ancillary Benefits: Supplemental needs on the Darrah – Barnett 69 kV line section: Darrah - Owens Illinois Circuit originally installed in 1954, currently has 213 conditions on 86 structures



Preliminary Facility Rating:

Branch	SN/SE/WN/WE (MVA)
Darrah – Barnett 69 kV	93/114/118/134

Required IS Date: 12/1/2027

Projected IS Date: 12/1/2027

Previously Presented: 9/16/2022

AEP Transmission Zone: Baseline
George Washington-Kammer 138kV Line Rebuild

Process Stage: Recommended Solution

Criteria: Summer Generation Deliverability

Assumption Reference: 2027 RTEP assumption

Model Used for Analysis: 2027 Summer RTEP case

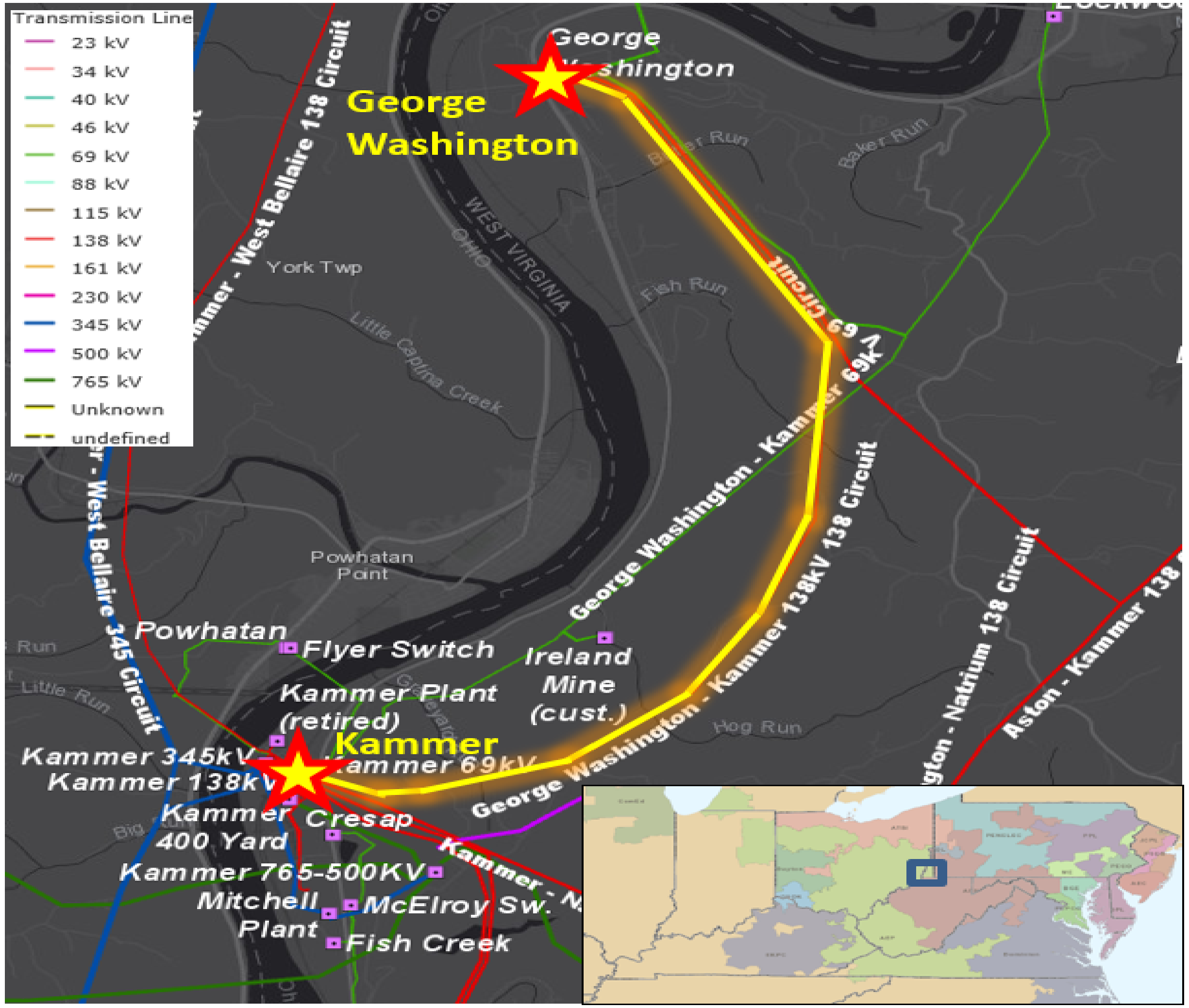
Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-GD-S1032

In 2027 RTEP Summer case, the George Washington-Kammer 138 kV line is overloaded under a contingency scenario in generation deliverability test.

Existing Facility Rating:

Branch	SN/SE/WN/WE (MVA)
George Washington – Kammer 138kV	446/621/563/698



George Washington-Kammer 138kV Line Rebuild

Recommended Solution:

- Rebuild the George Washington – Kammer 138kV circuit, except for 0.1-mile of previously-upgraded T-line outside each terminal station (6.7 miles of total upgrade scope). Remove the existing 6-wired steel lattice towers and supplement the right-of-way as needed. (**B3723**)

Transmission Estimated Cost: $18.3M

Ancillary Benefits: Addresses M-3 facility condition needs (AEP-2021-OH013), as presented in 3/19/2021 and 5/19/2022 W-SRREP

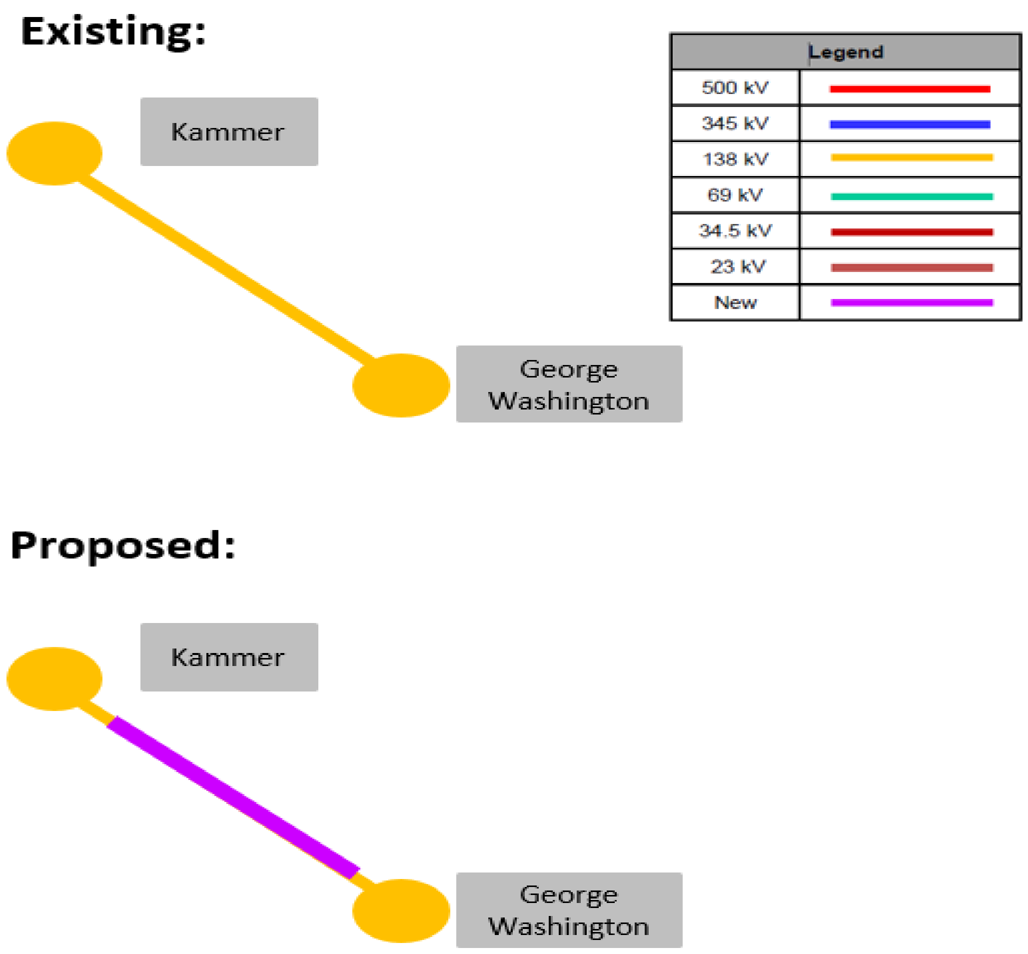
Preliminary Facility Rating:

Branch	SN/SE/WN/WE (MVA)
George Washington – Kammer 138kV	730/747/791/791

Required IS Date: 6/1/2027

Projected IS Date: 6/1/2024

Previously Presented: 9/16/2022



AEP Transmission Zone: Baseline Roanoke Station Circuit Switcher

Process Stage: Recommended Solution

Criteria: AEP 715 Criteria

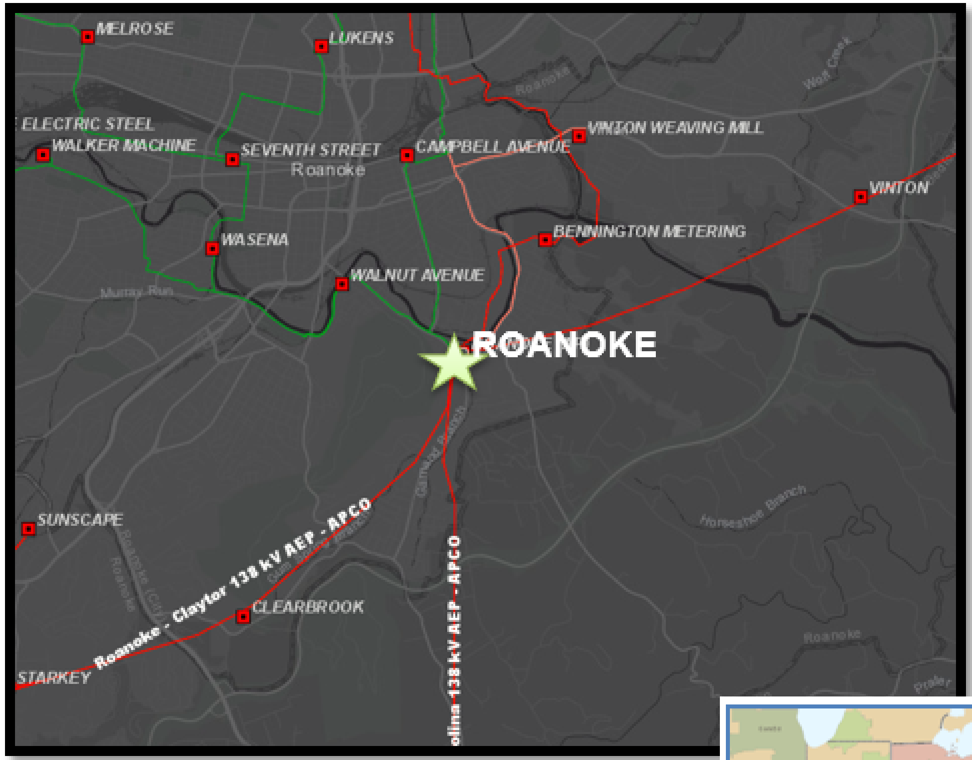
Assumption Reference: 2027 RTEP assumption

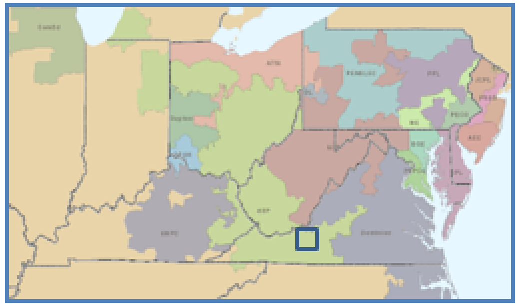
Model Used for Analysis: 2027 Summer RTEP case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-AEP-T5 through T9

In 2027 RTEP summer case, the Cloverdale-Ingersoll Rand-Monterey Avenue 69 kV line sections are overloaded under multiple N-1-1 contingency scenarios.





AEP Transmission Zone: Baseline Roanoke Station Circuit Switcher

Recommended Solution:

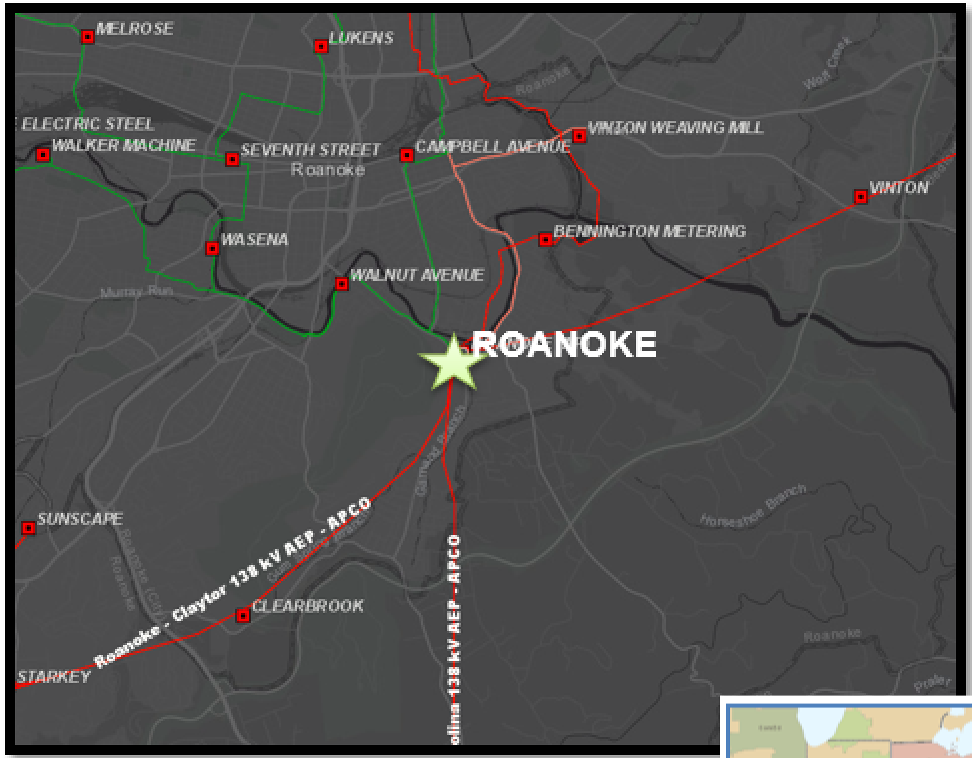
- Install 138 kV circuit switcher on the high-side of Transformer #2 at Roanoke Station (previously proposed as a portion of s2469.7, posted in 2021 AEP local plan) . (**B3724**)

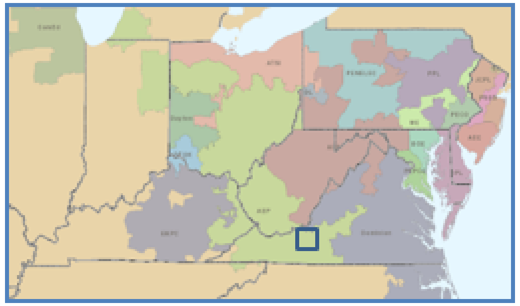
Transmission Estimated Cost: $0.1M

Ancillary Benefits: Separates the transformer and bus zones of protection. Included as part of s2469.7 previously, now converted to baseline

Required IS Date: 6/1/2027

Projected IS Date: 6/1/2027
Previously Presented: 9/16/2022





Avery – Hayes 138 kV line

Process Stage: Recommended Solution

Criteria: Generation Deliverability

Assumption Reference: 2027 RTEP assumption

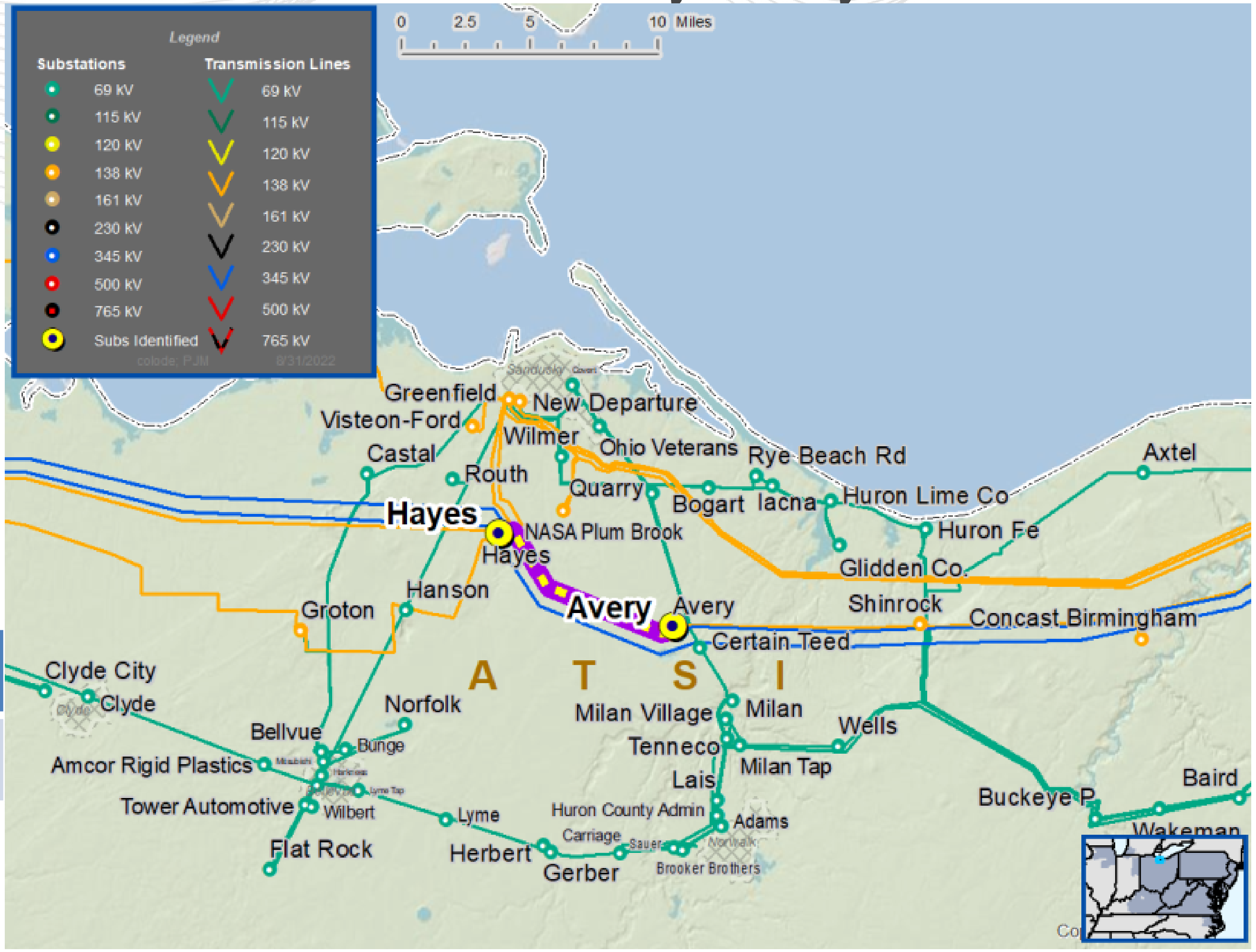
Model Used for Analysis: 2027 Summer RTEP case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-GD-S1030

In 2027 RTEP Summer case, Hayes to Avery 138 kV line is overloaded due to a tower contingency

Branch	SN/SE/WN/WE (MVA)
Hayes to Avery 138 kV	233/282/263/333



ATSI Transmission Zone: Baseline Avery – Hayes 138 kV line

Recommended Solution:

Rebuild and reconductor the Avery-Hayes 138 kV line (approx. 6.5 miles) with 795 KCMIL 26/7 ACSR (b3721)

Transmission Estimated Cost: $10.4M

Ancillary Benefits: Capacity increase for future growth

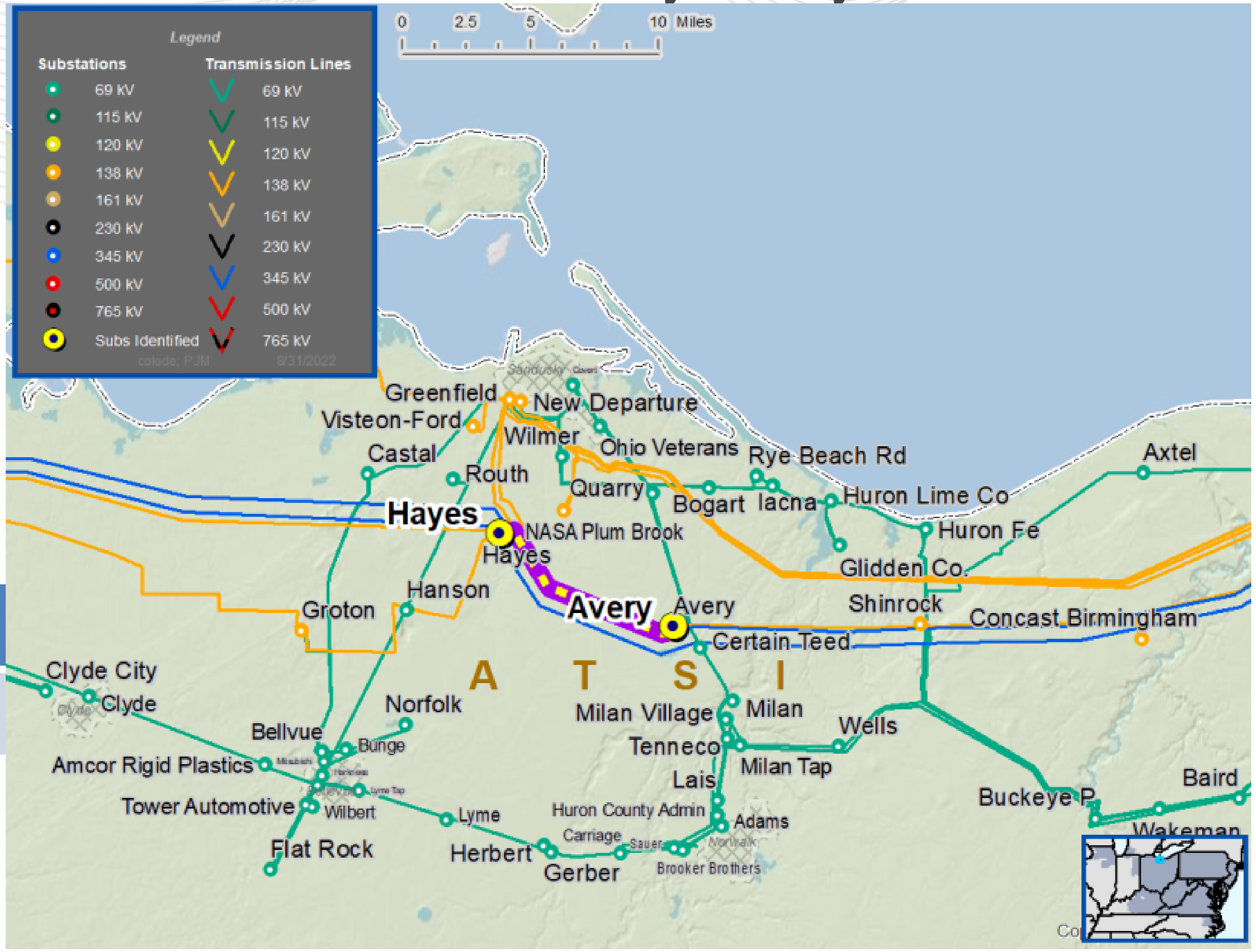
Alternatives: None

Preliminary Facility Rating:

Branch	SN/SE/WN/WE (MVA)
Hayes to Avery 138 kV	278/339/315/401

Required in-service date: 6/1/2027

Projected in-service date: 6/1/2027



ATSI Transmission Zone: Baseline Abbe – Johnson 69 kV line

Process Stage: Recommended Solution

Criteria: First Energy 715 Criteria

Assumption Reference: 2027 RTEP assumption

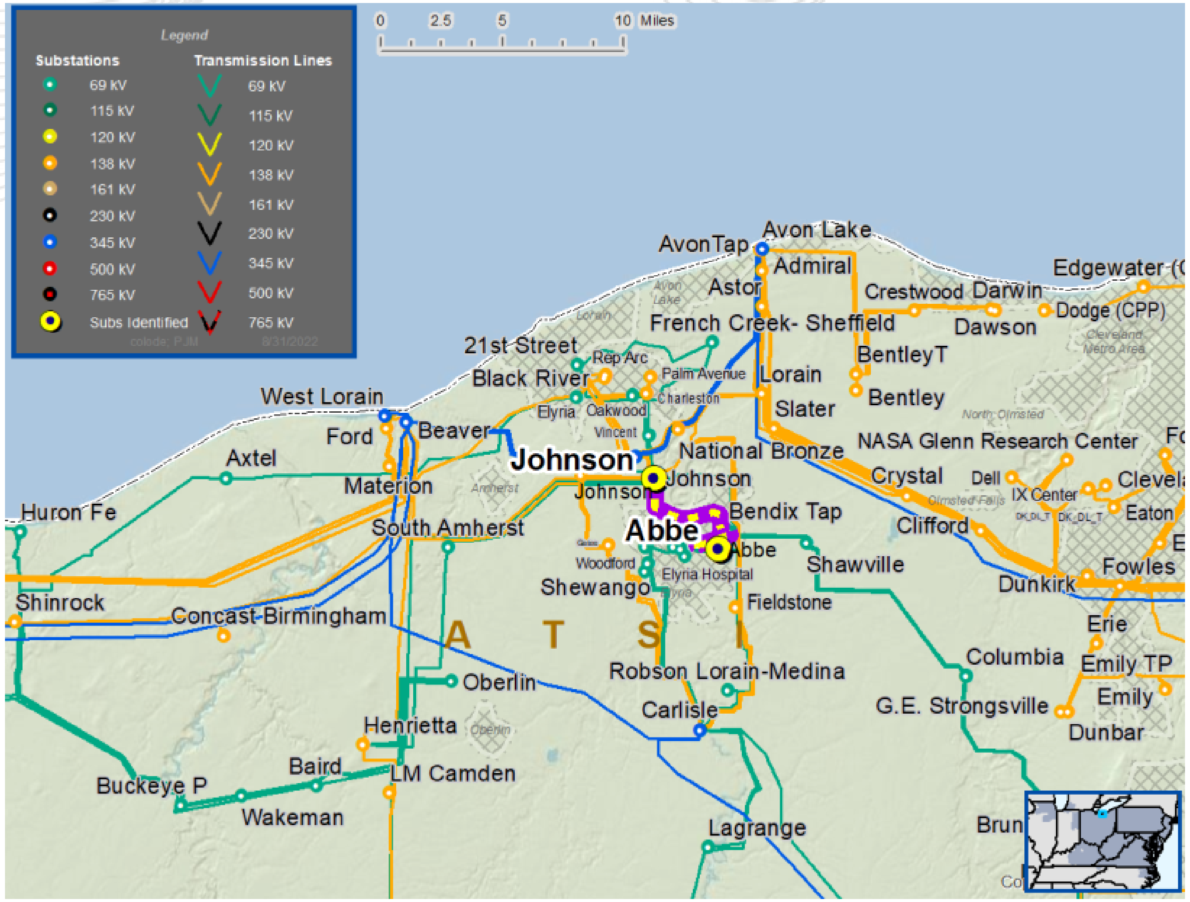
Model Used for Analysis: 2027 Summer RTEP case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-ATSI-T1

In 2027 RTEP Summer case, Johnson to Redman 138 kV line is overloaded due to a P2-1 contingency

Branch	SN/SE/WN/WE (MVA)
Abbe to Johnson 138 kV	76/92/87/111



ATSI Transmission Zone: Baseline Abbe – Johnson 69 kV line

Recommended Solution:

- Rebuild the Abbe-Johnson #2 69 kV Line (approx. 4.9 miles) with 556 kcmil ACSR conductor
- Replace (3) disconnect switches (A17, D15 & D16) and line drops and revise relay settings at Abbe.
- Replace (1) disconnect switch (A159) and line drops and revise relay settings at Johnson.
- Replace (2) MOAB disconnect switches (A4 & A5), (1) disconnect switch (D9), and line drops at Redman. (b3720)

Transmission Estimated Cost: $10.9M

Ancillary Benefits: Capacity increase for future growth

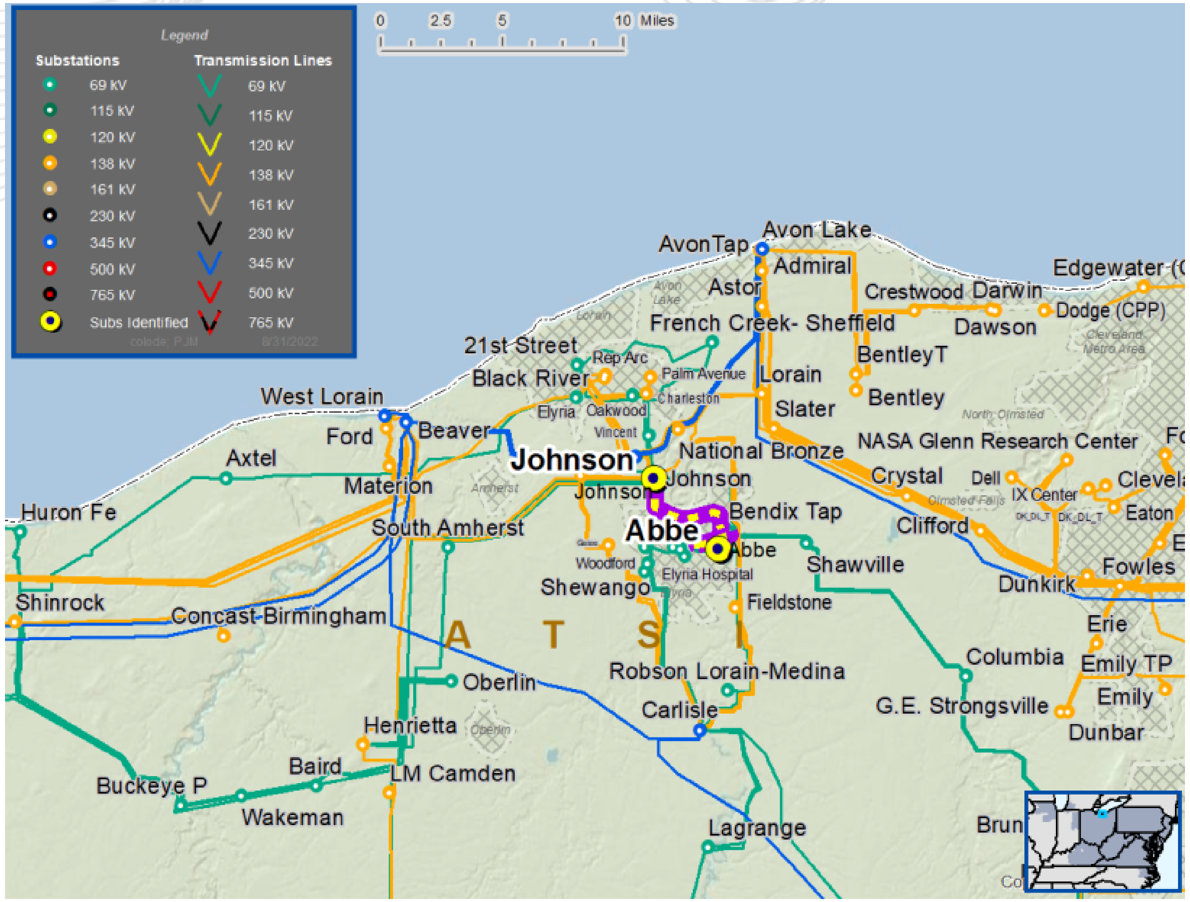
Alternatives: None

Preliminary Facility Rating:

Branch	SN/SE/WN/WE (MVA)
Abbe to Johnson 138 kV	111/134/125/159

Required in-service date: 6/1/2027

Projected in-service date: 6/1/2026



First Review

Baseline Reliability Projects

AEP Transmission Zone: Baseline McComb 40kV Breaker J Replacement

Process Stage: First Review Solution

Criteria: AEP 715 Criteria

Assumption Reference: 2027 RTEP assumption

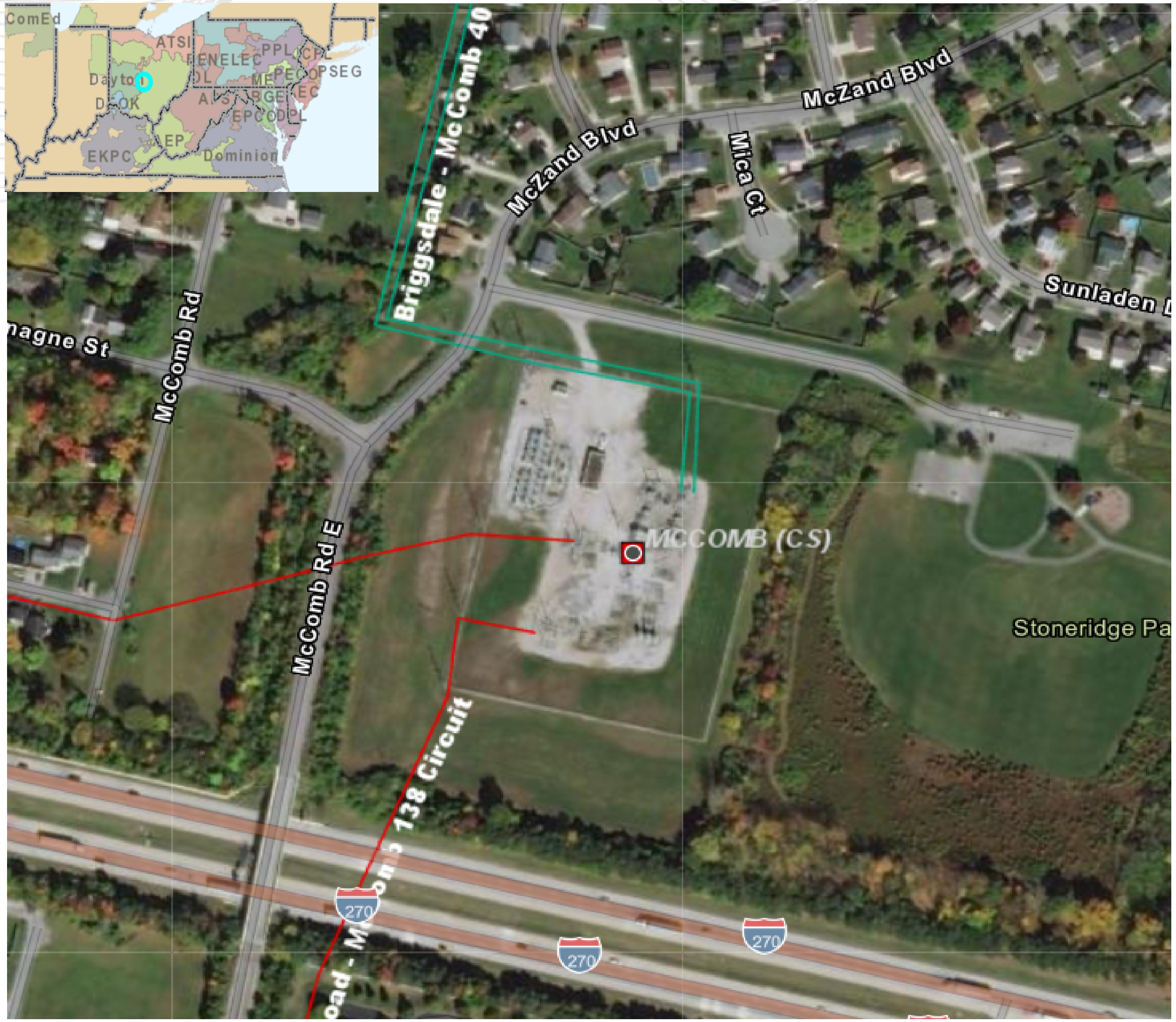
Model Used for Analysis: 2027 RTEP short circuit case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-AEP-SC1

In 2027 RTEP short circuit case, 40 kV circuit breaker 'J' at McComb station was identified as being overdutied.

Existing Facility Rating: 18kA



AEP Transmission Zone: Baseline McComb 40kV Breaker J Replacement

Proposed Solution:

Replace 40kV breaker J at McComb station with a new 3000A 40kA breaker

Transmission Estimated Cost: $0.5M

Alternatives: None

Ancillary Benefits: Breaker J was identified as part of the need under AEP-2019-OH020.

Preliminary Facility Rating: 40kA

Required in-service date: 6/1/2027

Projected in-service date: 6/1/2025

Existing:

Legend	
500 kV	
345 kV	
138 kV	
69 kV	
34.5 kV	
23 kV	
New	

Proposed:

AEP Transmission Zone: Baseline Morgan Run 34.5kV Cap Bank

Process Stage: First Review Solution

Criteria: AEP 715 Criteria

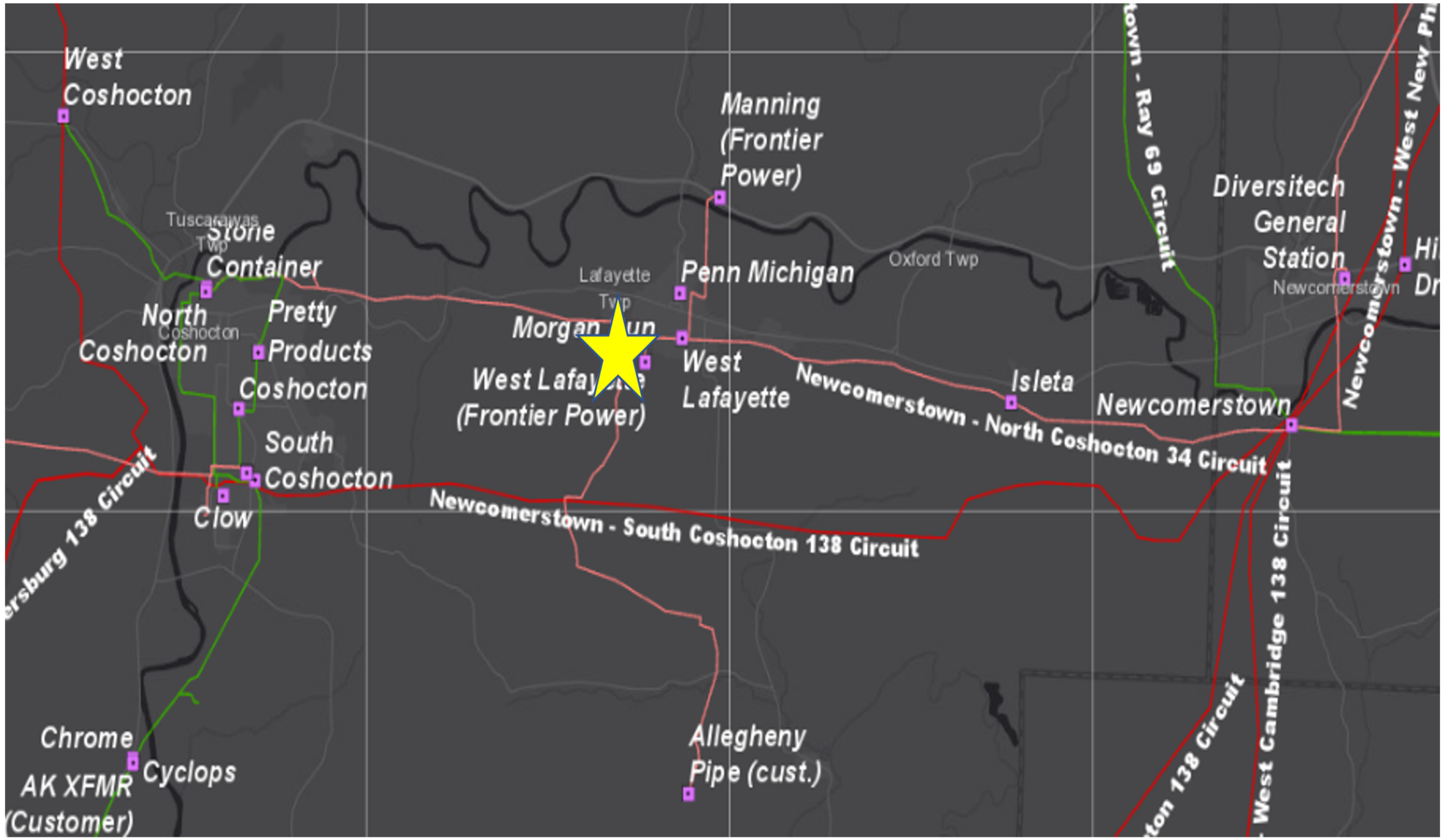
Assumption Reference: 2027 RTEP assumption

Model Used for Analysis: 2027 RTEP summer case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-AEP-VM22 through 2022W1-AEP-VM39. 2022W1-AEP-VD25 through 2022W1-AEP-VD33; 2022W1-AEP-VD38 through 2022W1-AEP-VD47.

In 2027 RTEP summer case, low voltage and voltage-drop violations on the 34.5kV system between North Coshocton, Newcomerstown, and West New Philly stations, including Allegheny Pipe, East Coshocton, Gen Tire, Isleta, Morgan Run, North Coshocton, Newcomerstown, W Lafayette, Copper head 34.5kV buses, under multiple N-1-1 contingency scenarios.



Proposed Solution:

Install a 6 MVAR, 34.5kV cap bank at Morgan Run station.

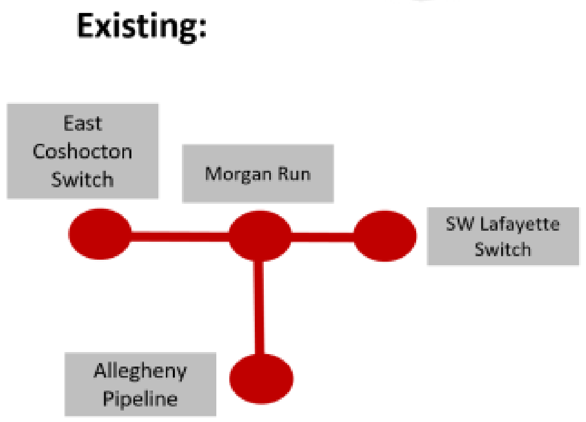
Transmission Estimated Cost: $0.37M

Alternatives: An alternative solution would be adding another source to the 34.5kV system bounded by North Coshocton, Newcomerstown and West New Philly. In order to resolve the specific N-1-1 contingencies of concern, the source would need to be near North Coshocton or Newcomerstown. A 2nd 69-34.5kV transformer could be installed at either station, however, this would be more costly than a 34.5kV cap bank, as high-side 69kV breaker(s) would be needed, along with relays, etc. In addition, AEP's long-term plan is to convert 34.5kV areas to 69kV or 138kV, so it is not recommended to add a new source to this 34.5kV area at this time, given the relatively small amount of customer load served from the system. Estimated cost: $10M

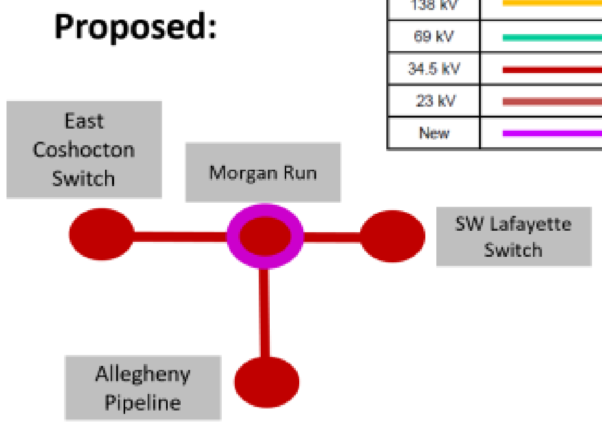
Ancillary Benefits: Improved year-round operating voltages on the 34.5kV system; increased SCADA voltage data for AEP Operations personnel, increasing the accuracy of state-estimation, etc.

Required in-service date: 6/1/2027

Projected in-service date: 6/1/2027



Legend	
500 kV	
345 kV	
138 kV	
69 kV	
34.5 kV	
23 kV	
New	



AEP Transmission Zone: Baseline Summerhill-Willow Grove 69kV Line Rebuild

Process Stage: First Review Solution

Criteria: AEP 715 Criteria

Assumption Reference: 2027 RTEP assumption

Model Used for Analysis: 2027 RTEP summer case

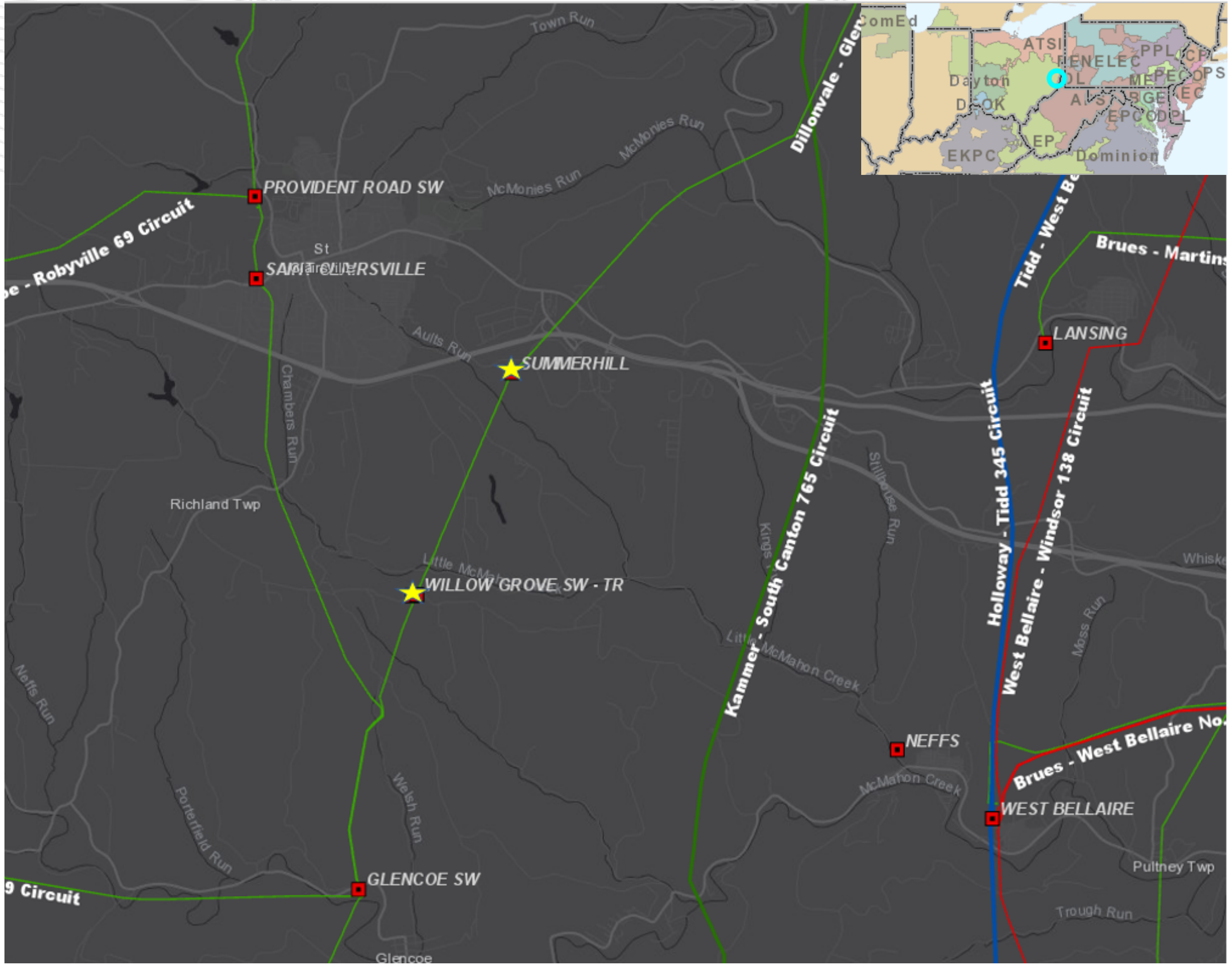
Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-AEP-T10

In 2027 RTEP summer case, The Summerhill-Willow Grove Switch 69kV line segment is overloaded for an N-1-1 contingency pair.

Existing Facility Rating:

Branch	SN/SE/WN/WE (MVA)
05SUMMERHI -05WILLGRSS 69kV	50/50/63/63



AEP Transmission Zone: Baseline Summerhill-Willow Grove 69kV Line Rebuild

Proposed Solution:

Rebuild the 1.8 mile 69kV T-line between Summerhill and Willow Grove Switch. Replace 4/0 ACSR conductor with 556 ACSR.

Transmission Estimated Cost: $5.1M

Preliminary Facility Rating:

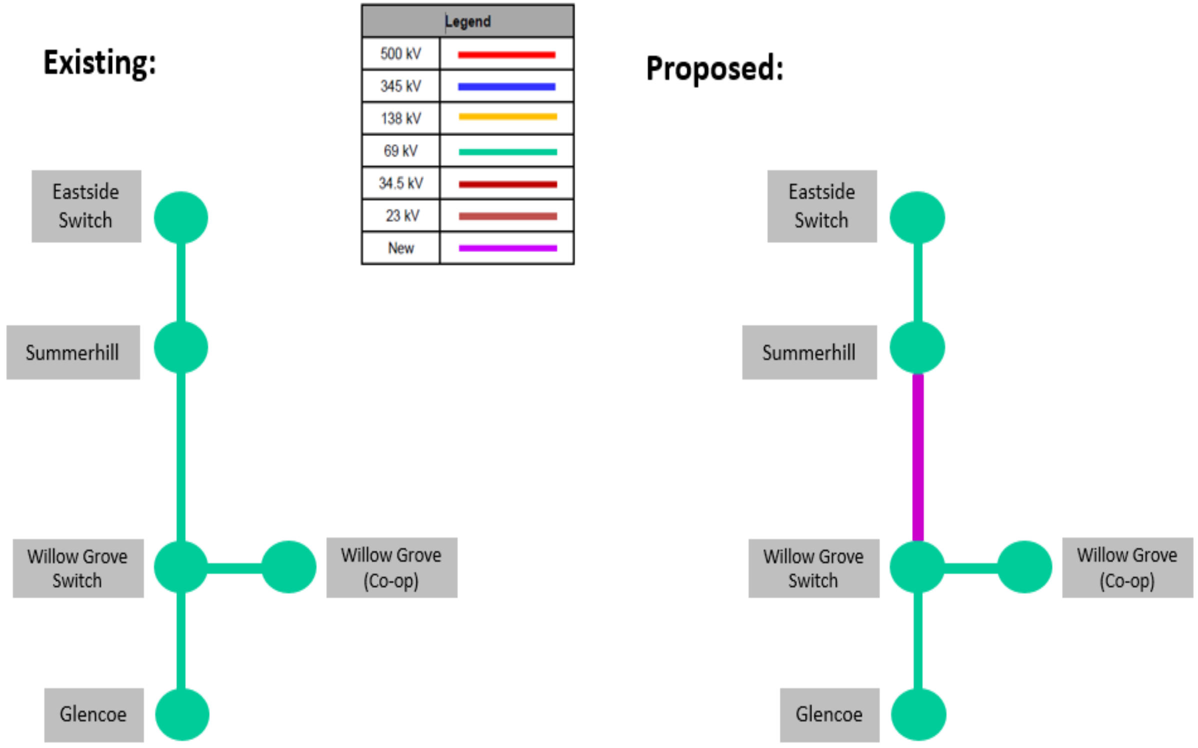
Branch	SN/SE/WN/WE (MVA)
05SUMMERHI -05WILLGRSS 69kV	82/90/107/113

Alternatives: Reconductor the 69kV T-Line with the existing wood poles, instead of doing a full rebuild. However, due to the age/condition of the facilities, a full rebuild is recommended.

Ancillary Benefits: Addresses potential M-3 facility condition needs, as documented by field personnel and AEP Asset Renewal groups. Existing structure conditions include broken down leads, broken molding, and cracked cross-bracing. This portion of line was originally constructed in 1946, primarily with wooden H-frame structures. The line has experienced over 680k CMI between 2015-2021 with 8 momentary and 2 permanent outages. There are 37 structures (46% of the line) with at least one open condition. There are 67 open conditions along the line.

Required in-service date: 6/1/2027

Projected in-service date: 6/1/2027



AEP Transmission Zone: Baseline Rarden-Rosemount Cap Banks

Process Stage: First Review Solution

Criteria: AEP 715 Criteria

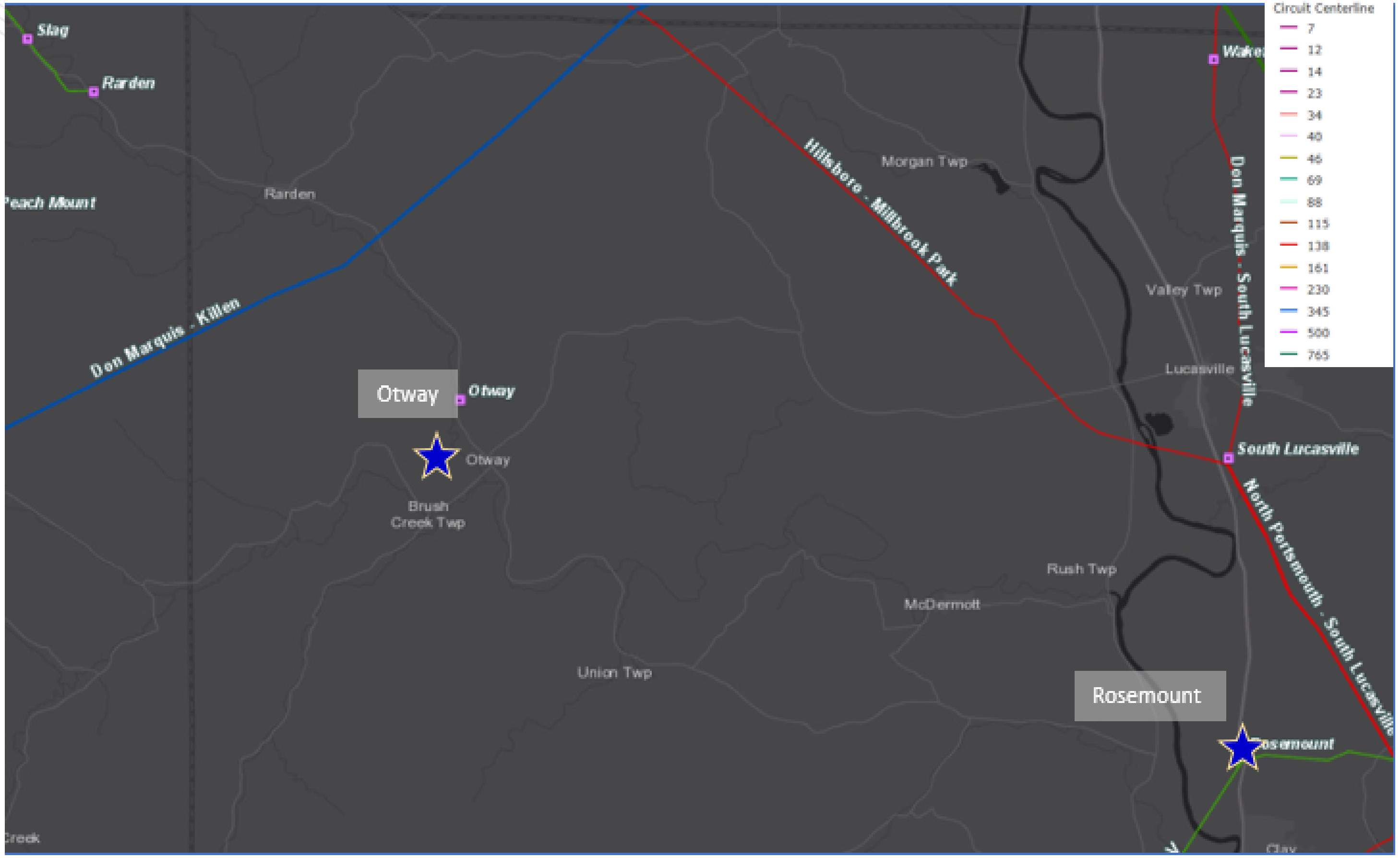
Assumption Reference: 2027 RTEP assumption

Model Used for Analysis: 2027 RTEP summer case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-AEP-VD34 through 2022W1-AEP-VD37

In 2027 RTEP summer case, voltage-drop violations at Rarden switch, Otway station, Tick Ridge station, and Rarden station 69kV buses under a N-1-1 contingency scenario.



AEP Transmission Zone: Baseline Rarden-Rosemount Cap Banks

Proposed Solution:

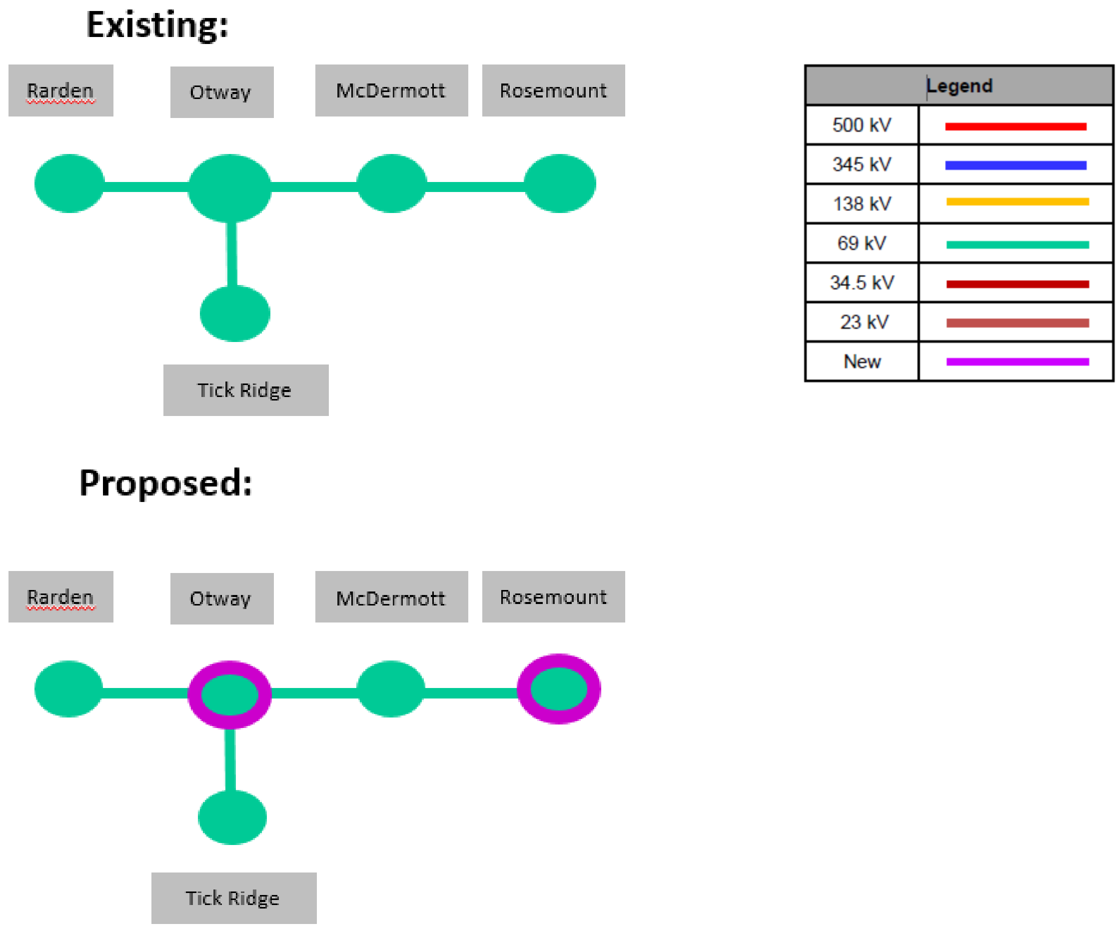
Install a 7.7 MVAR, 69kV cap bank at both Otway station and Rosemount station to resolve N-1-1 voltage-drop violations

Transmission Estimated Cost: $1.73M

Alternatives: None

Required in-service date: 6/1/2027

Projected in-service date: 6/15/2026



AEP Transmission Zone: Baseline Abingdon Station Upgrades

Process Stage: First Review Solution

Criteria: AEP 715 Criteria

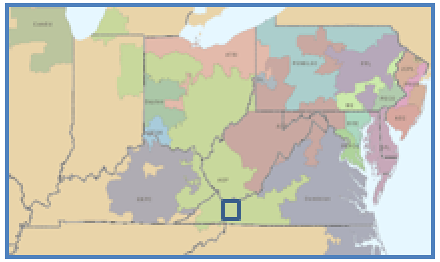
Assumption Reference: 2027 RTEP assumption

Model Used for Analysis: 2027 RTEP summer/winter cases

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-AEP-T3, 2022W1-AEP-T4, 2022W1-AEP-VM1 through 2022W1-AEP-VM3, 2022W1-AEP-VD1 through 2022W1-AEP-VD4

In 2027 RTEP summer/winter case, Thermal overload on the Arrowhead - Hillman Highway 69 kV line under multiple N-1-1 contingency pairs. In 2027 RTEP winter case, Voltage Mag. and Voltage Drop Violations at Arrowhead, Damascus, Hillman and South Abington 69kV buses under a N-1-1 contingency pair.



AEP Transmission Zone: Baseline Abingdon Station Upgrades

Proposed Solution:

- Terminate the existing Broadford – Wolf Hills #1 138 kV line into Abingdon 138 kV Station. This line currently bypasses the existing Abingdon 138 kV Station.
- Install two new 138 kV circuit breakers on each new line exit towards Broadford and towards Wolf Hills #1
- Install one new 138 kV circuit breaker on line exit towards South Abingdon for standard bus sectionalizing

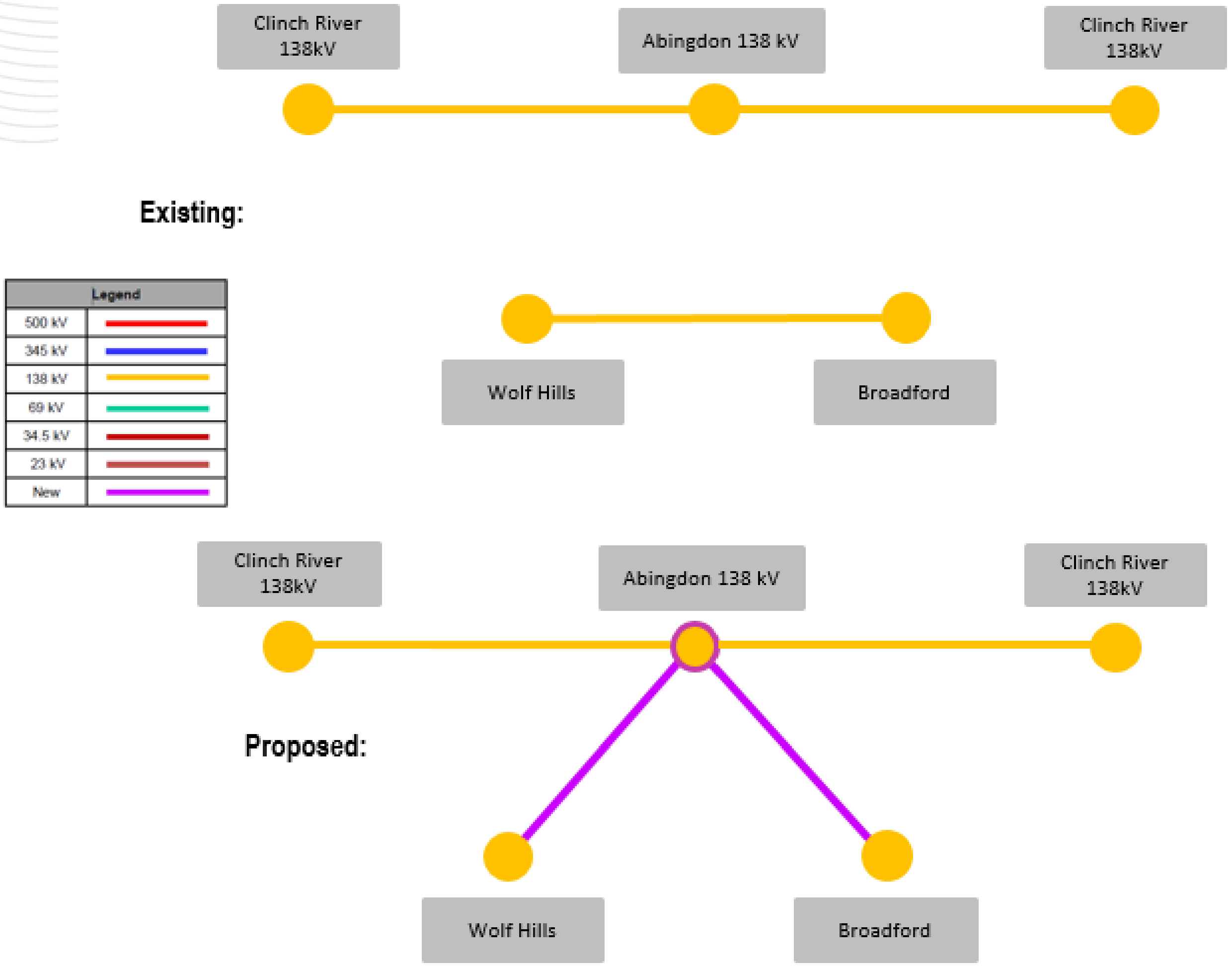
Transmission Estimated Cost: $8.48M

Ancillary Benefits: Operational flexibility is improved with the additional sources into Abingdon

Alternatives: Rebuild the existing Arrowhead - Hillman Highway 69 kV line and install a new 34.6 MVAR Capacitor at South Abingdon 138 kV Station. Estimated cost: $15M

Required in-service date: 6/1/2027

Projected in-service date: 6/1/2027



AEP Transmission Zone: Baseline Breaks - Dorton 69kV Conversion

Process Stage: First Review Solution

Criteria: AEP 715 Criteria

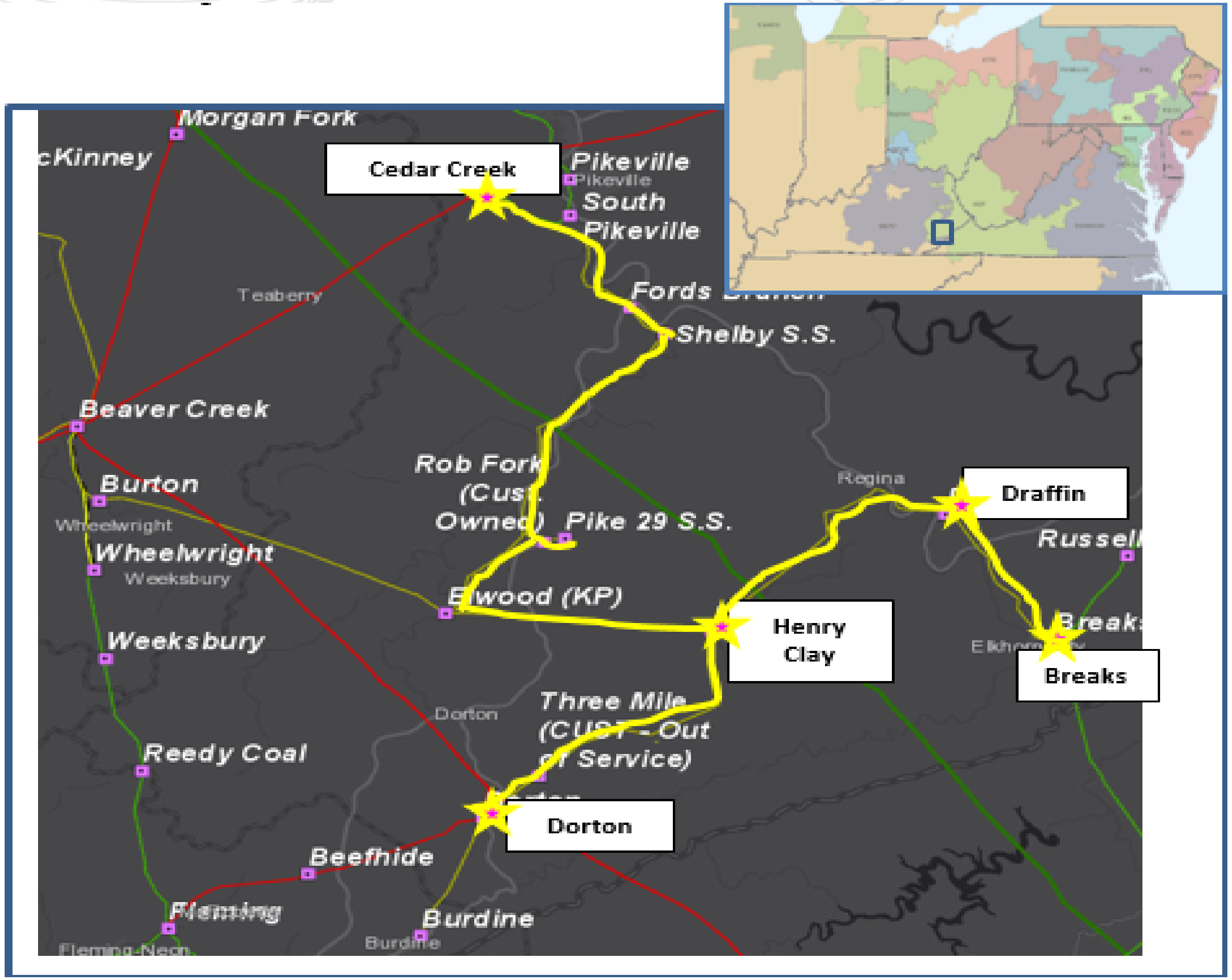
Assumption Reference: 2027 RTEP assumption

Model Used for Analysis: 2027 RTEP Winter case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-AEP-VM4 through 2022W1-AEP-VM21, 2022W1-AEP-VD5 through 2022W1-AEP-VD24

In 2027 Winter RTEP case, Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations under multiple N-1-1 contingency scenarios.



AEP Transmission Zone: Baseline Breaks - Dorton 69kV Conversion

Proposed Solution:

Transmission Components:

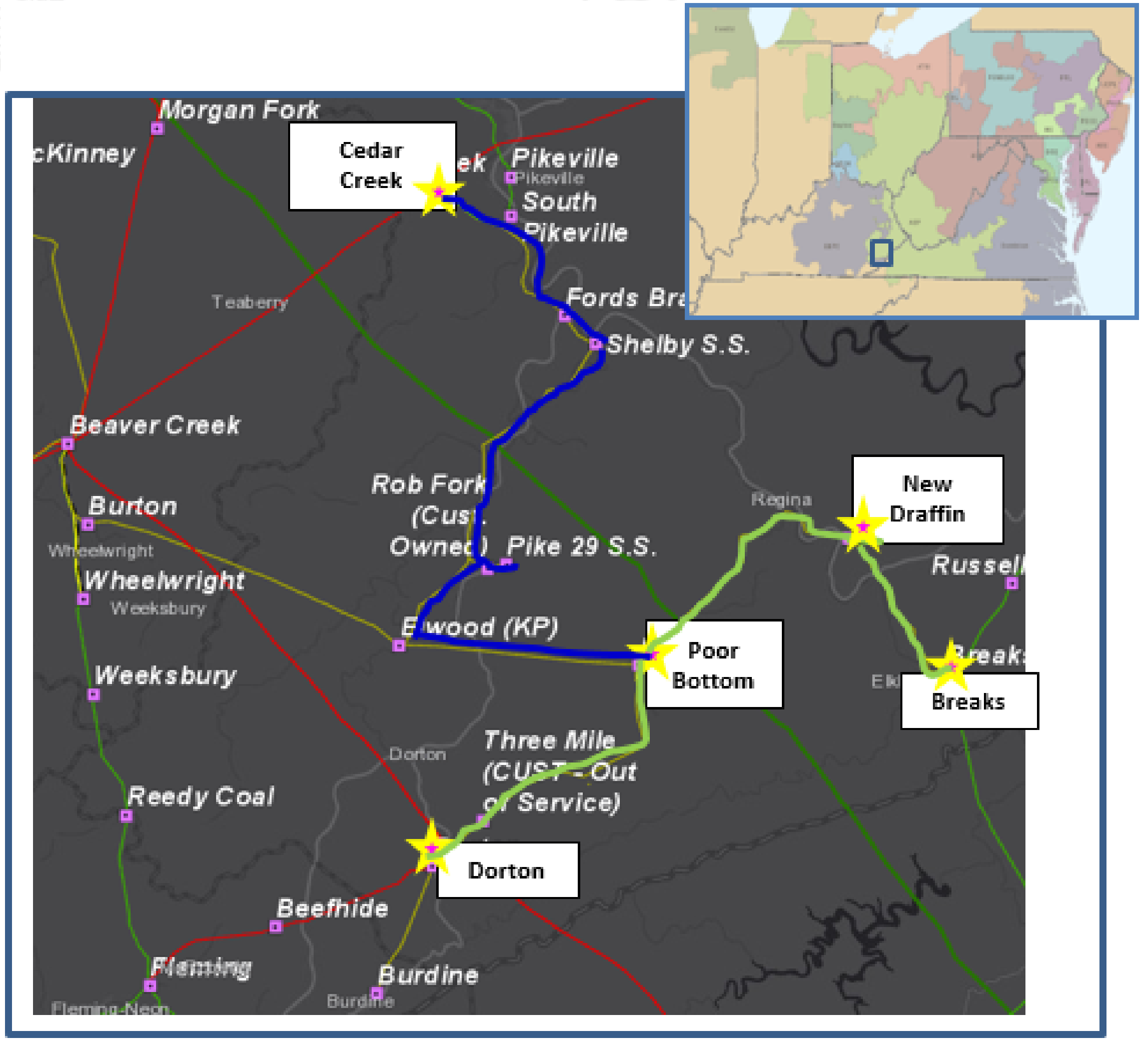
- Establish 69kV bus and new 69 kV line CB at Dorton substation. $1.13 M
- At Breaks substation, reuse 72kV breaker A as the new 69kV line breaker. $0.71 M
- Rebuild ~16.7 mi Dorton – Breaks 46kV line to 69kV. $58.52
- Retire ~17.2 mi Cedar Creek – Elwood 46kV circuit. $11.15 M
- Retire ~ 6.2 mi Henry Clay – Elwood 46kV line section. $4.3 M
- Retire Henry Clay 46 kV substation and replace with Poor Bottom 69 kV station. Install a new 0.7 mi double circuit extension to Poor Bottom 69kV. $3.42 M
- Retire Draffin substation and replace with a new substation. Install a new 0.25 mi double circuit extension to New Draffin substation. $2.01M
- Remote End work at Jenkins substation. $0.03 M
- Provide Transition fiber to Dorton, Breaks, Poor Bottom, Jenkins and New Draffin substations. $0.41M
- Henry Clay S.S Retirement: $ 0.3 M
- Cedar Creek substation work: $0.44 M
- Breaks substation retire 46kV equipment: $0.25 M
- Retire Pike 29 SS and Rob Fork SS: $0.42 M

Total Transmission Estimated Cost: $83M

Distribution Components:

- Serve Pike 29 and Rob Fork customers from nearby 34kV Distribution sources. $ 2.23 M (D cost)
- Poor Bottom substation install: $8.46 M (D cost)
- Henry Clay 46kV substation retirement: $0.82 M (D cost)
- New Draffin 69kV substation install: $6.66 M (D cost)
- Draffin 46kV substation retirement: $0.68 M (D cost)

Total Distribution Estimated Cost: $18.9M



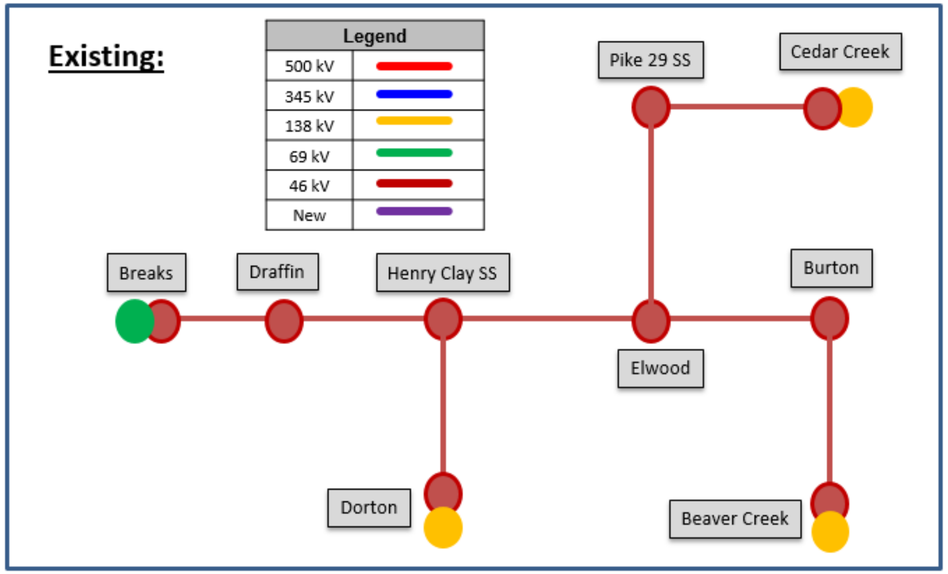
AEP Transmission Zone: Baseline Breaks - Dorton 69kV Conversion

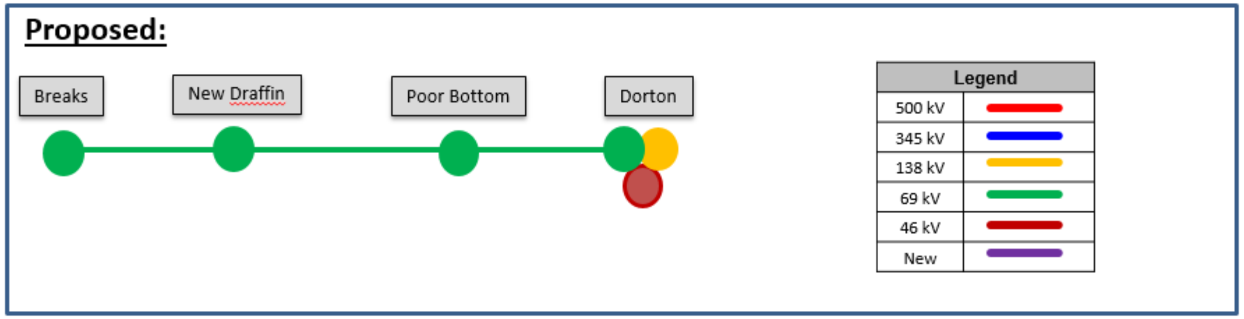
Alternatives: Install 9.6 MVAR 46kV Cap Bank at Dorton substation. This cap bank must be served off the 46kV Bus. Also, install 12.9 MVAR Cap Bank at Cedar Creek substation 46kV Bus. While this fixes the baseline issues identified, it does not address the supplemental needs as identified and mitigated with the proposed solution. (Estimated Cost: $2.58 M)

Ancillary Benefits: This proposal completely addresses identified supplemental needs on Cedar Creek – Elwood 46kV under Need AEP-2019-AP032 (presented 8/29/2019 W-SRRTEP), and Identified supplemental needs on Breaks – Dorton – Elwood 46kV circuit under AEP-2020-AP012 (presented 2/21/2020 W-SRRTEP). The proposal proposes retirement of roughly 23.4 mi of obsolete 46kV line.

Required in-service date: 12/1/2027

Projected in-service date: 7/31/2027





APS Transmission Zone: Baseline Charleroi - Dry Run 138 kV

Process Stage: First Review Solution

Criteria: Generation Deliverability

Assumption Reference: 2027 RTEP assumption

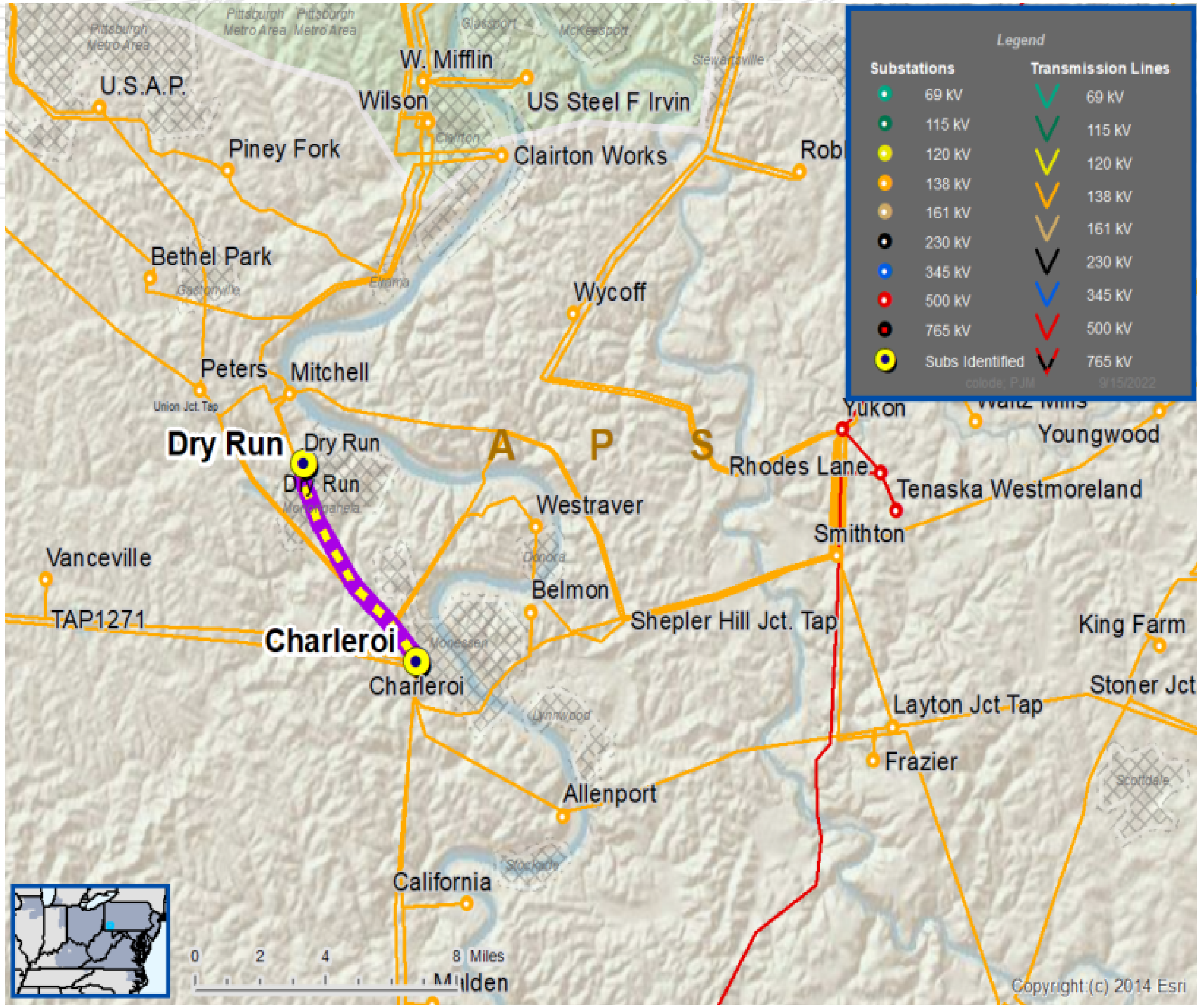
Model Used for Analysis: 2027 Summer RTEP case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-GD-S601 and 2022W1-GD-S943

In 2027 RTEP Summer case, Charleroi to Dry Run 138 kV line is overloaded due to a breaker and bus contingency.

Branch	SN/SE/WN/WE (MVA)
Charleroi – Dry Run 138 kV	292/314/325/343



APS Transmission Zone: Baseline
Charleroi - Dry Run 138 kV

Proposed Solution:

Replace limiting terminal equipment.

Transmission Estimated Cost: $0.38M

Ancillary Benefits: Upgrading the limiting terminal equipment will increase the ratings of the line.

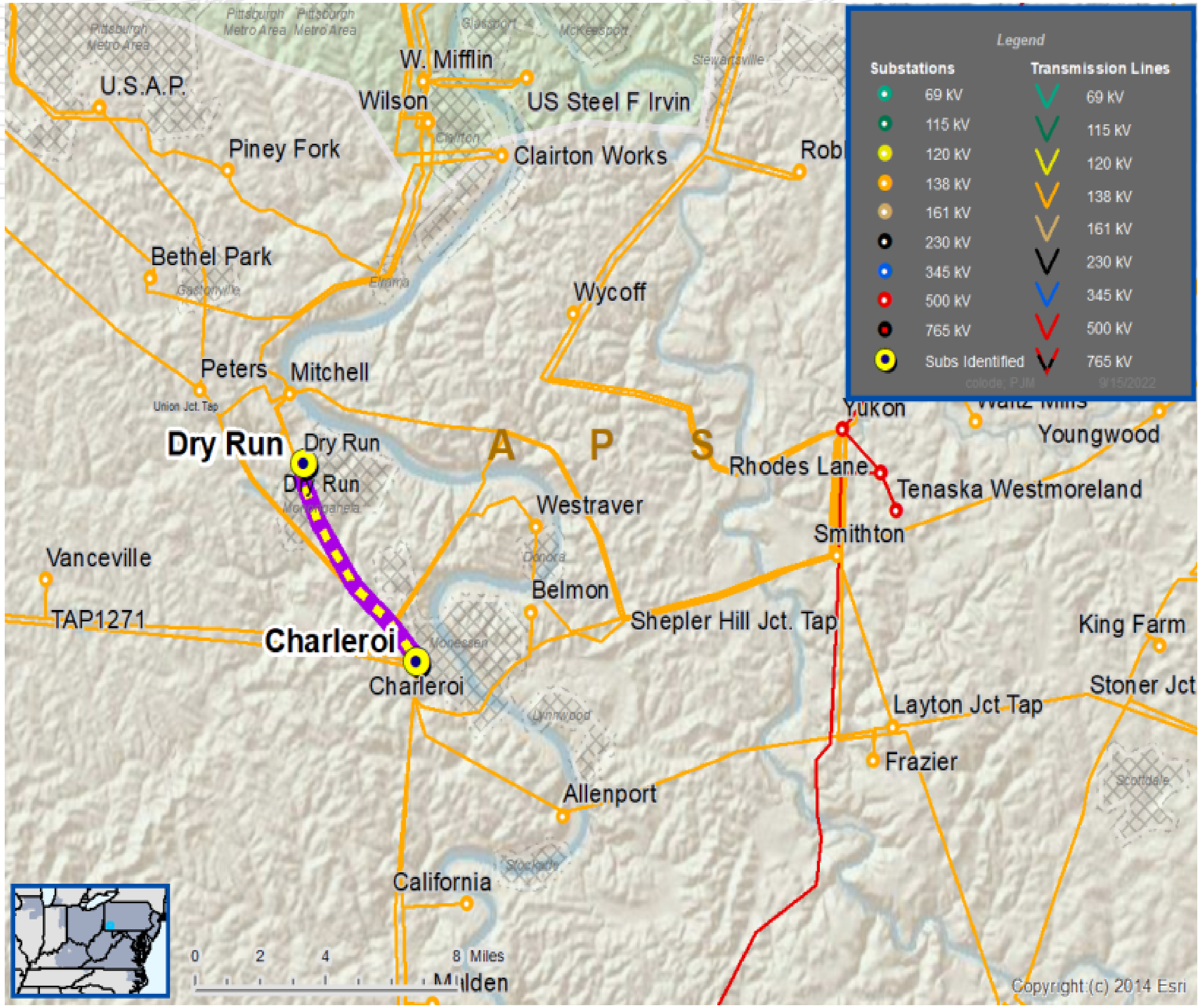
Alternatives: None

Preliminary Facility Rating:

Branch	SN/SE/WN/WE (MVA)
Charleroi – Dry Run 138 kV	308/376/349/445

Required in-service date: 6/1/2027

Projected in-service date: 6/1/2027



APS Transmission Zone: Baseline Dry Run – Mitchell 138 kV

Process Stage: First Review Solution

Criteria: Generation Deliverability

Assumption Reference: 2027 RTEP assumption

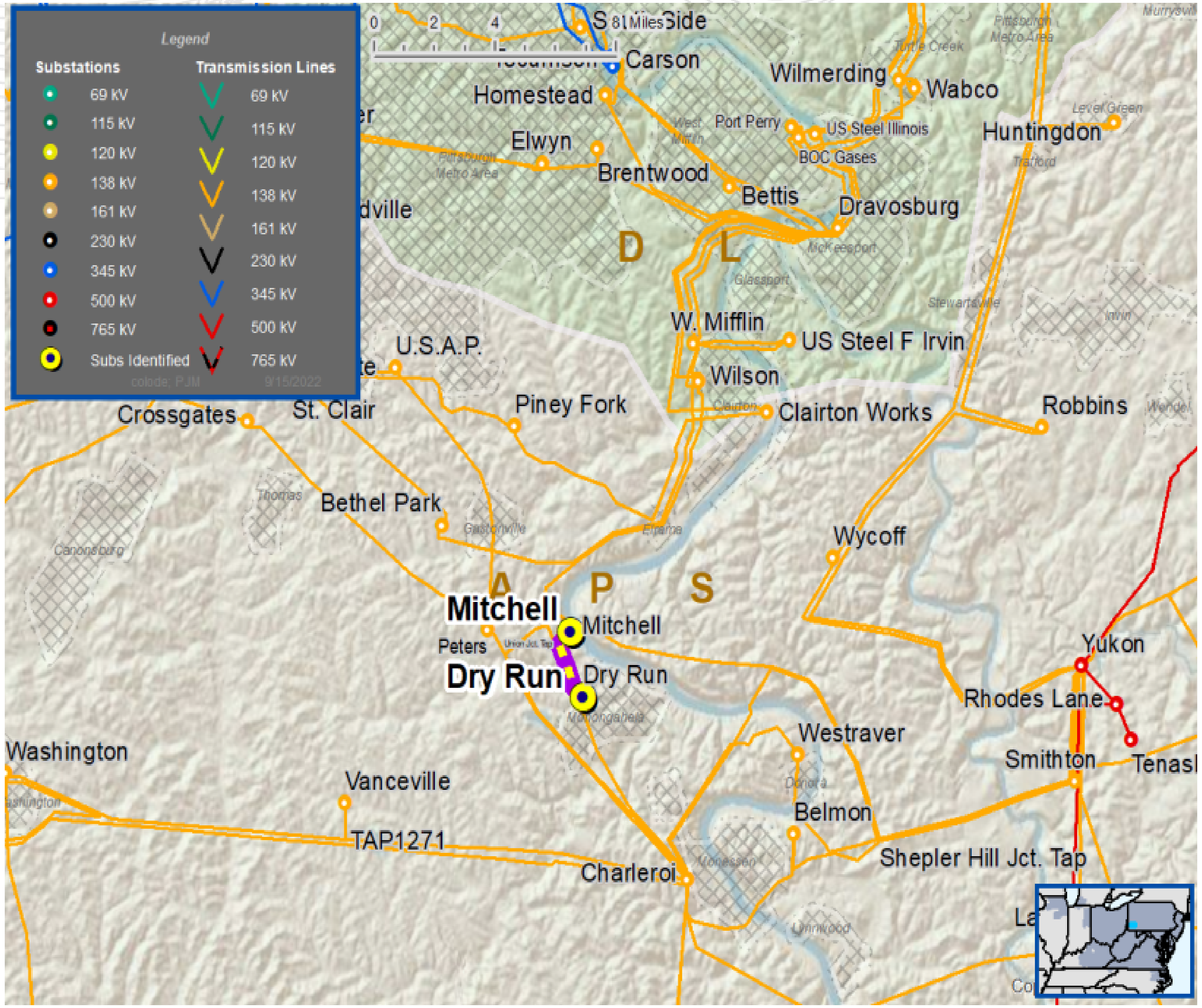
Model Used for Analysis: 2027 Summer RTEP case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-GD-S633 and 2022W1-GD-S949

In 2027 RTEP Summer case, Dry Run to Mitchell 138 kV line is overloaded due to a breaker and bus contingency.

Branch	SN/SE/WN/WE (MVA)
Dry Run - Mitchell 138 kV	292/314/325/343



APS Transmission Zone: Baseline
Dry Run – Mitchell 138 kV

Proposed Solution:

Replace limiting terminal equipment.

Transmission Estimated Cost: $0.40M

Ancillary Benefits: Upgrading the limiting terminal equipment will increase the ratings of the line.

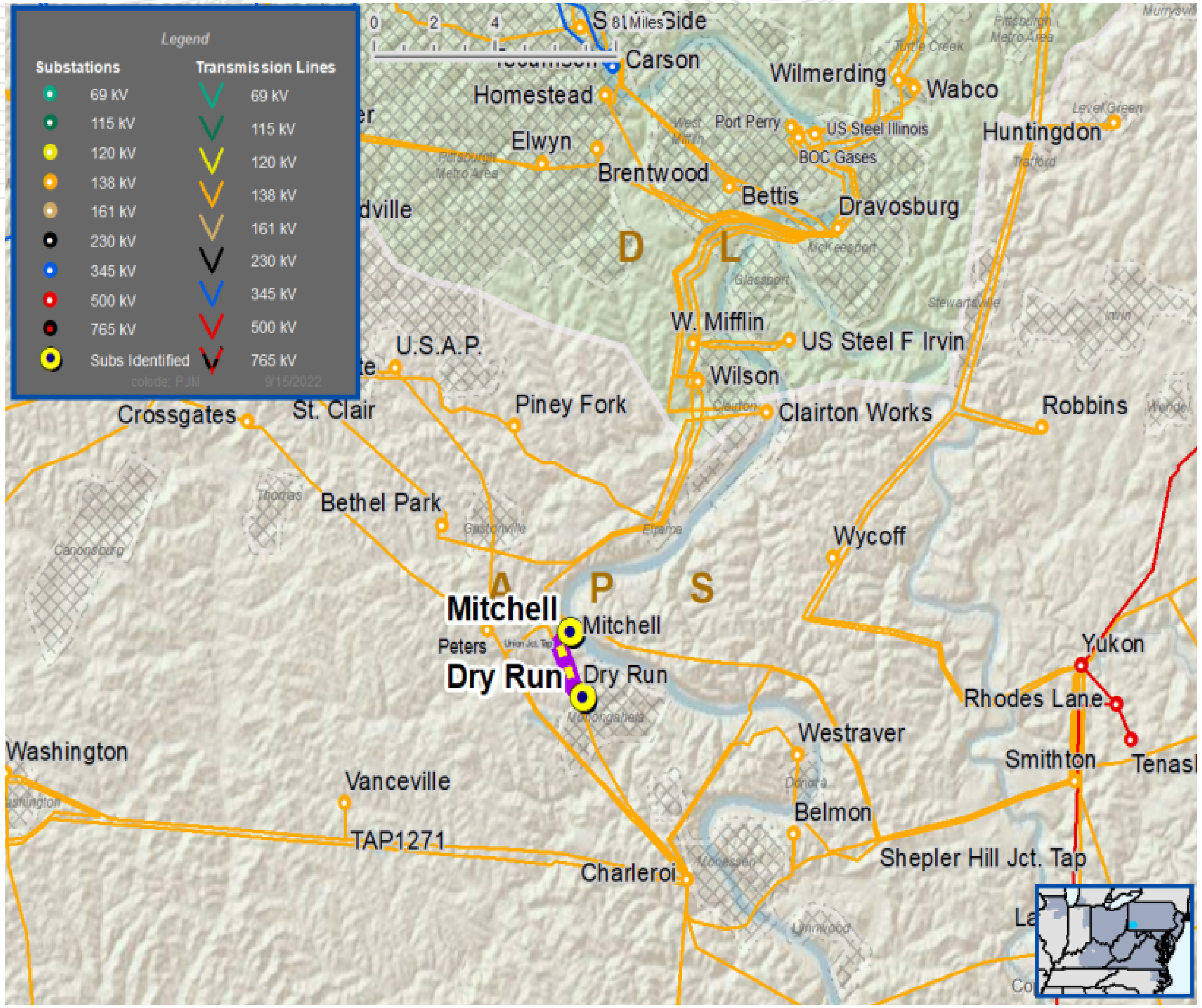
Alternatives: None

Preliminary Facility Rating:

Branch	SN/SE/WN/WE (MVA)
Dry Run – Mitchell 138 kV	308/376/349/445

Required in-service date: 6/1/2027

Projected in-service date: 6/1/2027



APS Transmission Zone: Baseline Glen Falls – Bridgeport Hill 138 kV

Process Stage: First Review Solution

Criteria: Generation Deliverability

Assumption Reference: 2027 RTEP assumption

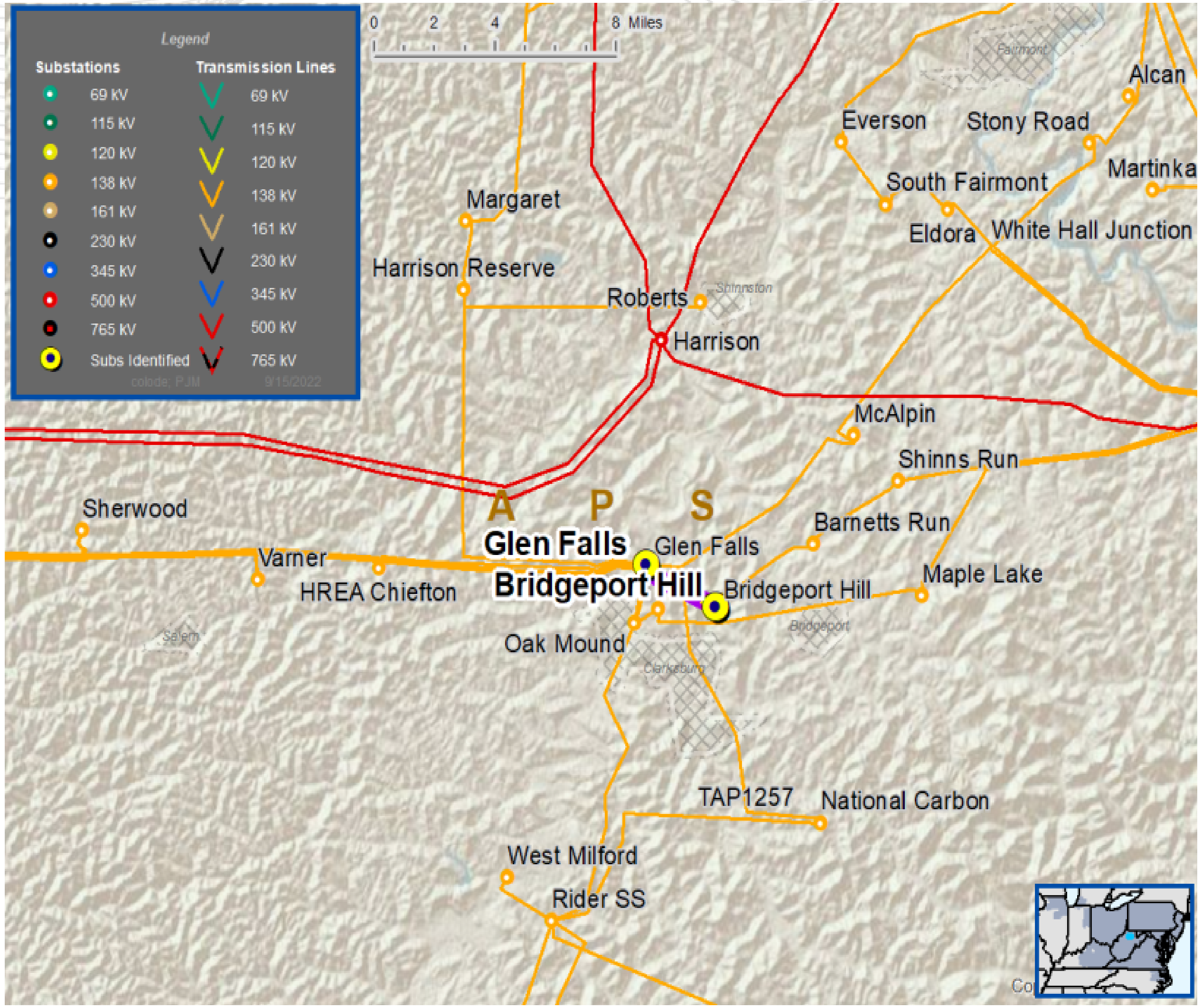
Model Used for Analysis: 2027 Summer RTEP case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-GD-S608, 2022W1-GD-S945, 2022W1-GD-S615 and 2022W1-GD-S616.

In 2027 RTEP Summer case, Charleroi to Dry Run 138 kV line is overloaded due to three breaker and one bus contingency.

Branch	SN/SE/WN/WE (MVA)
Glen Falls – Bridgeport Hill 138 kV	176/209/217/229



APS Transmission Zone: Baseline Glen Falls – Bridgeport Hill 138 kV

Proposed Solution:

Replace limiting terminal equipment.

Transmission Estimated Cost: $1.88M

Ancillary Benefits: Upgrading the limiting terminal equipment will increase the ratings of the line.

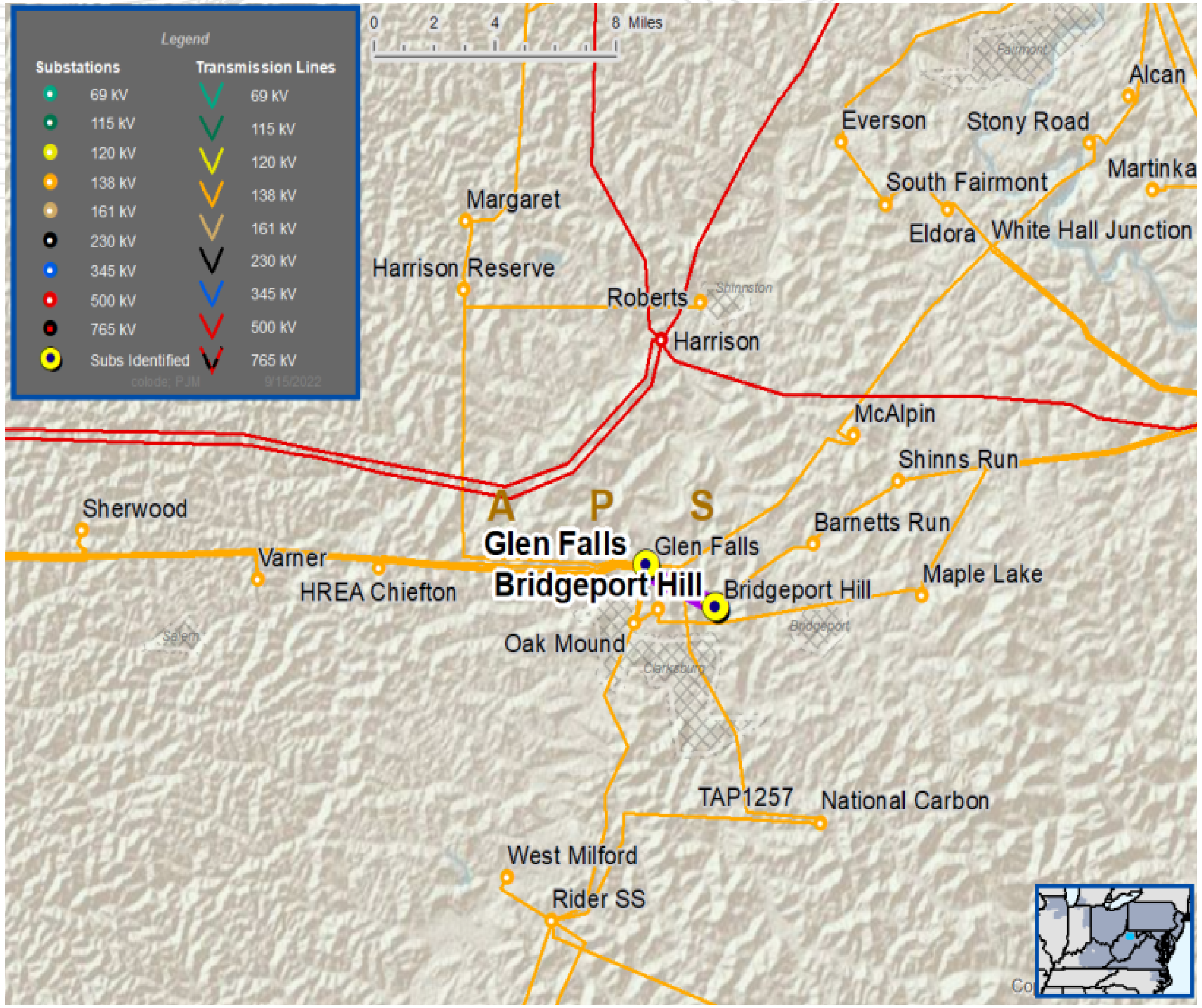
Alternatives: None

Preliminary Facility Rating:

Branch	SN/SE/WN/WE (MVA)
Glen Falls – Bridgeport Hill 138 kV	221/268/250/317

Required in-service date: 6/1/2027

Projected in-service date: 6/1/2027



APS Transmission Zone: Baseline Yukon - Charleroi No.1 138 kV

Process Stage: First Review Solution

Criteria: Generation Deliverability

Assumption Reference: 2027 RTEP assumption

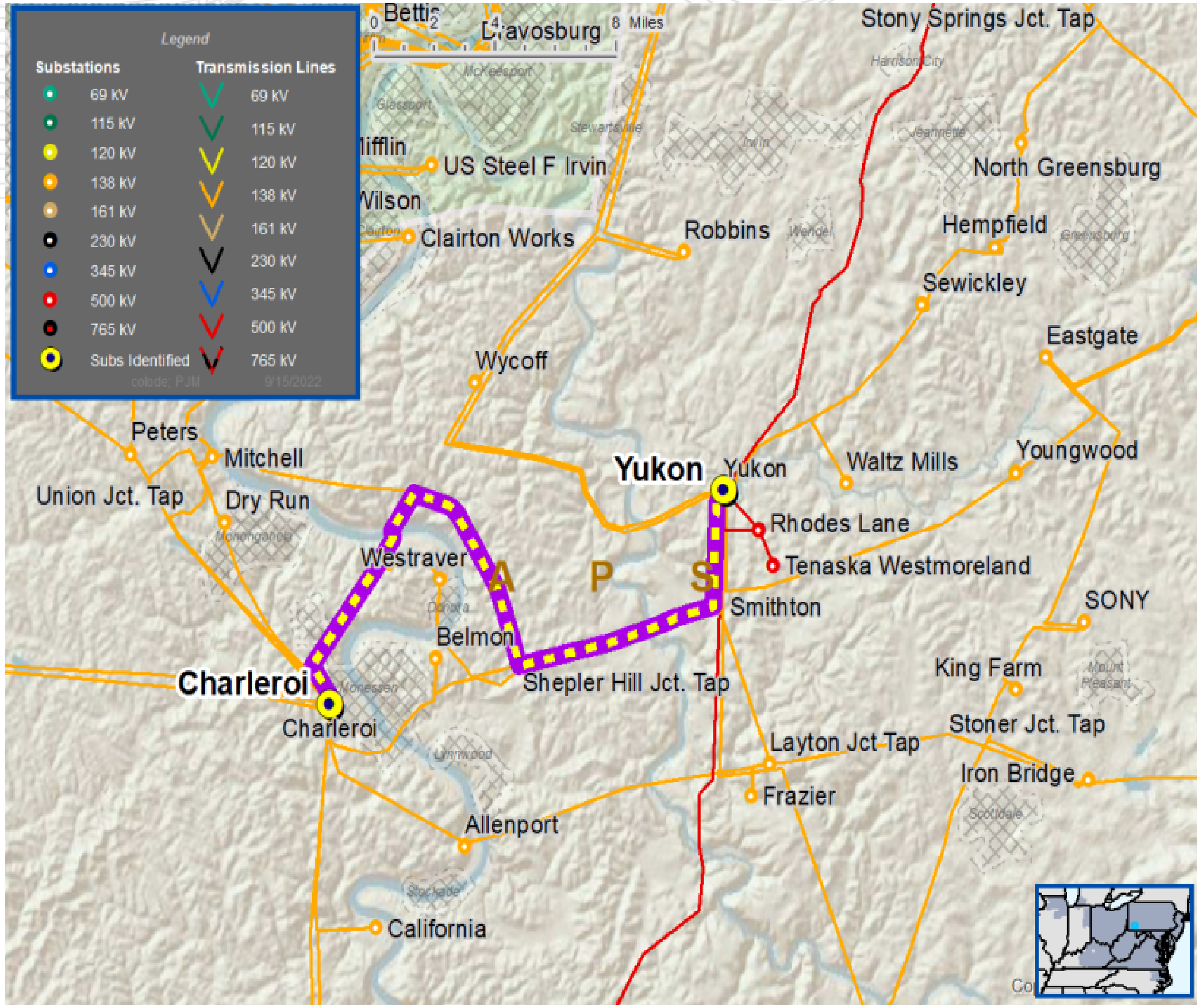
Model Used for Analysis: 2027 Summer RTEP case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-GD-S1033

In 2027 RTEP Summer case, Yukon to Charleroi # 1 138 kV line is overloaded due to a tower contingency.

Branch	SN/SE/WN/WE (MVA)
Yukon - Charleroi No.1 138 kV	292/314/325/343



APS Transmission Zone: Baseline Yukon - Charleroi No.1 138 kV

Proposed Solution:

Replace limiting terminal equipment.

Transmission Estimated Cost: $0.7M

Ancillary Benefits: Upgrading the limiting terminal equipment will increase the ratings of the line.

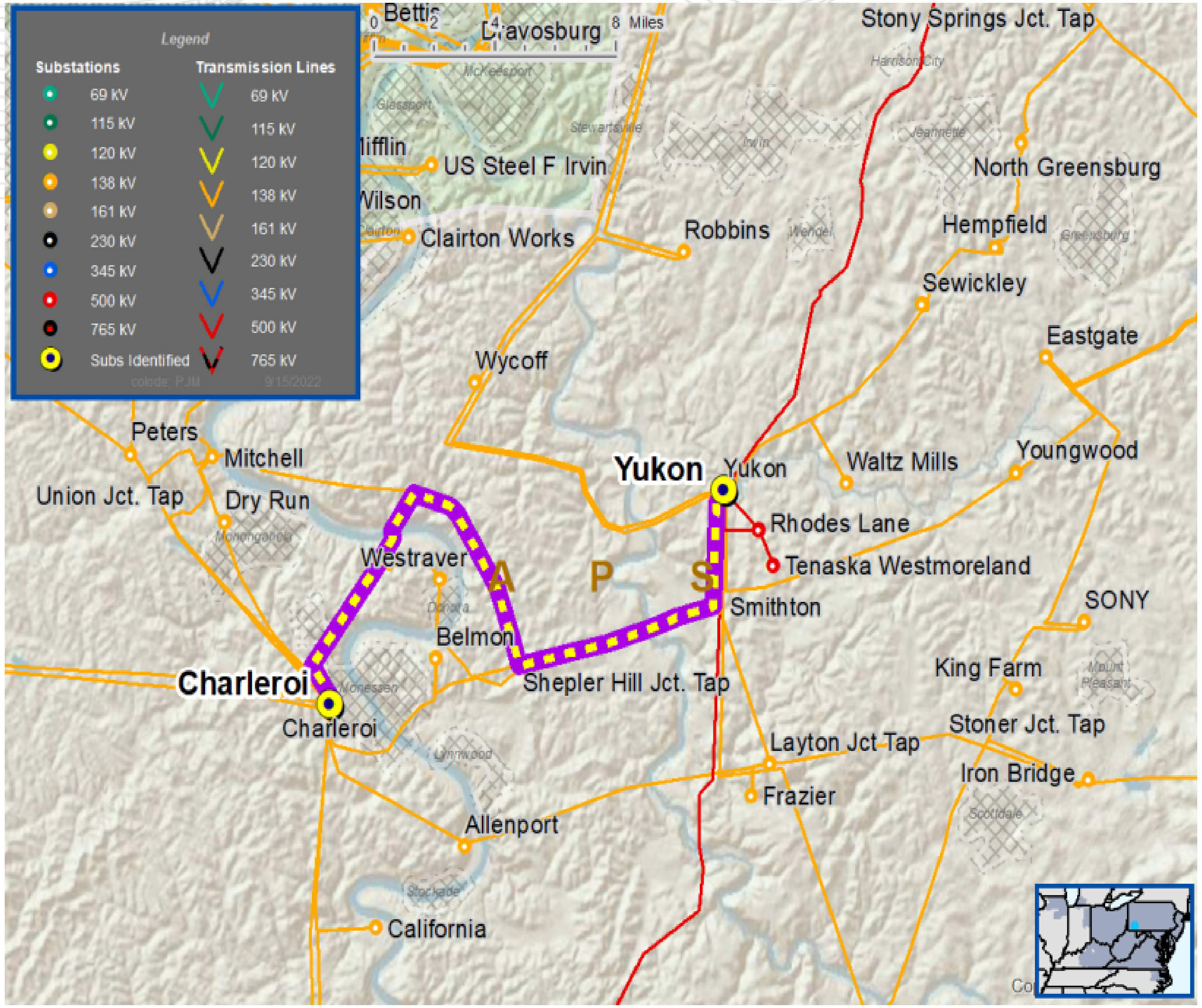
Alternatives: None

Preliminary Facility Rating:

Branch	SN/SE/WN/WE (MVA)
Yukon - Charleroi No.1 138 kV	308/376/349/445

Required in-service date: 6/1/2027

Projected in-service date: 6/1/2027



APS Transmission Zone: Baseline Yukon - Charleroi No.2 138 kV

Process Stage: First Review Solution

Criteria: Generation Deliverability

Assumption Reference: 2027 RTEP assumption

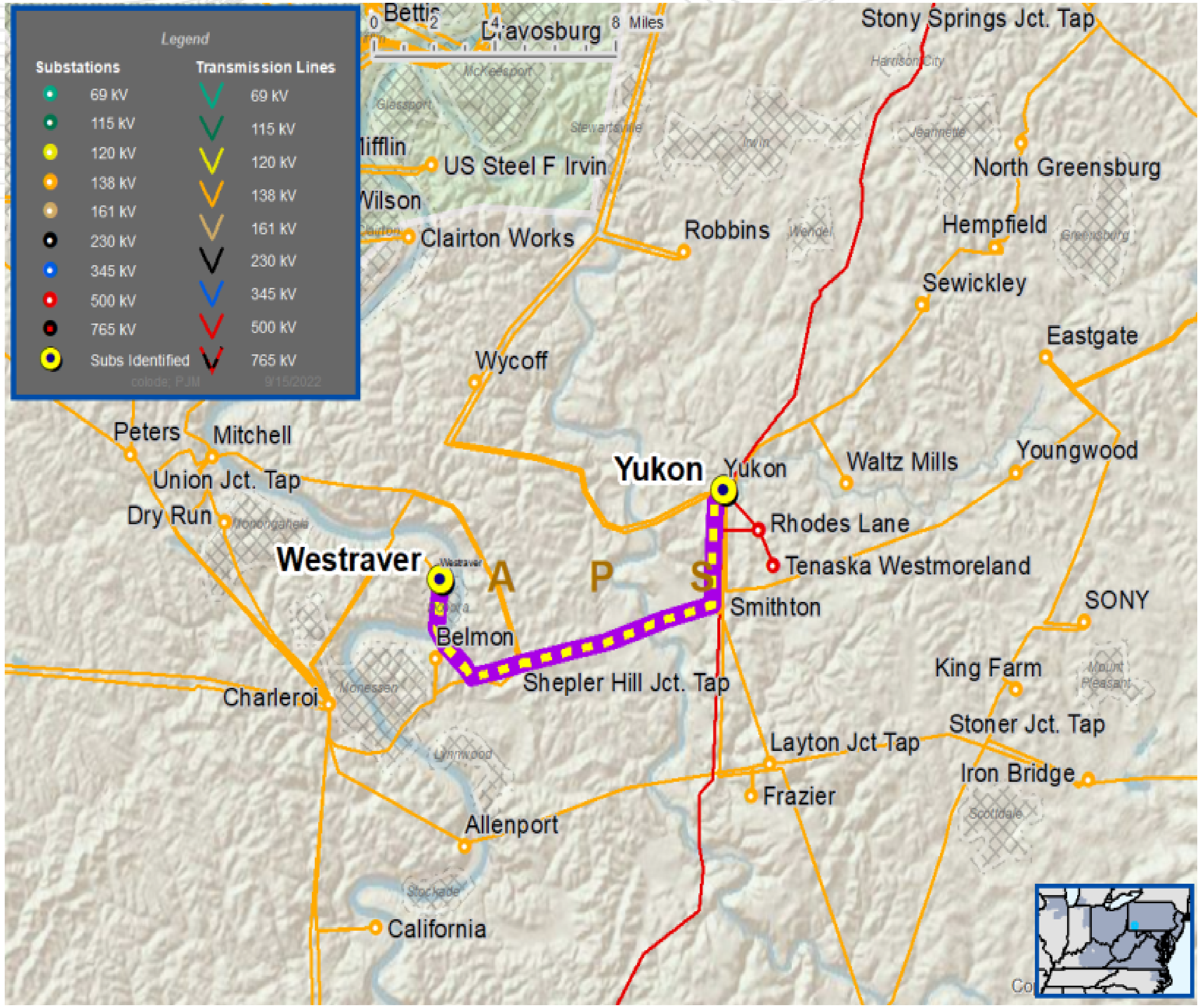
Model Used for Analysis: 2027 Summer RTEP case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-GD-S1029

In 2027 RTEP Summer case, Yukon to Westraver 138 kV line is overloaded due to a tower contingency.

Branch	SN/SE/WN/WE (MVA)
Yukon - Westraver 138 kV	292/314/325/343
Westraver – Charleroi 138 kV	274/314/325/343



APS Transmission Zone: Baseline Yukon - Charleroi No.2 138 kV

Proposed Solution:

Replace limiting terminal equipment.

Transmission Estimated Cost: $0.45M

Ancillary Benefits: Upgrading the limiting terminal equipment will increase the ratings of the line.

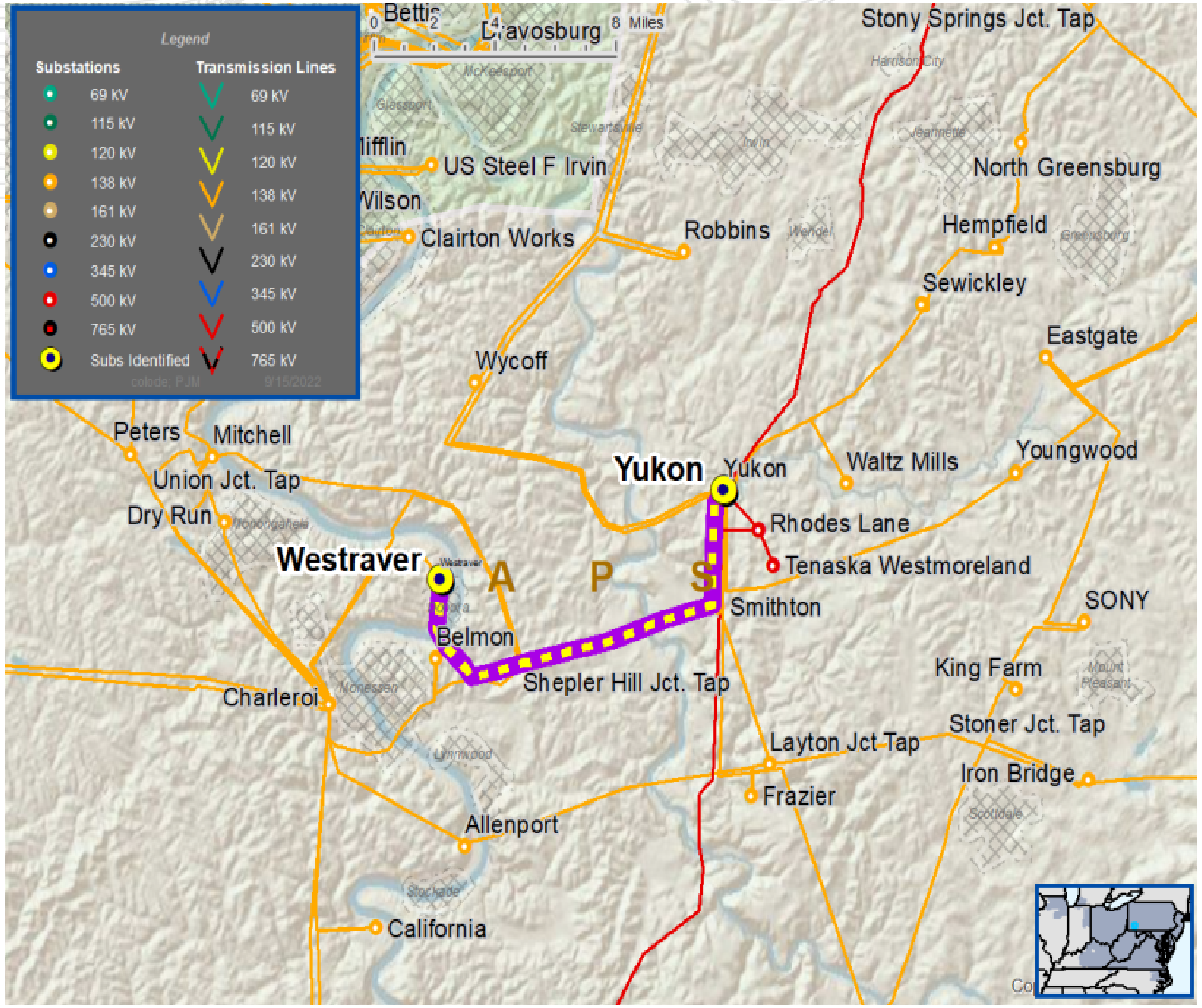
Alternatives: None

Preliminary Facility Rating:

Branch	SN/SE/WN/WE (MVA)
Yukon - Westraver138 kV	308/376/349/445
Westraver – Charleroi 138 kV	297/365/345/441

Required in-service date: 6/1/2027

Projected in-service date: 6/1/2027



APS Transmission Zone: Baseline Cherry Run - Harmony Jct tap 138 kV

Process Stage: First Review Solution

Criteria: Generation Deliverability

Assumption Reference: 2027 RTEP assumption

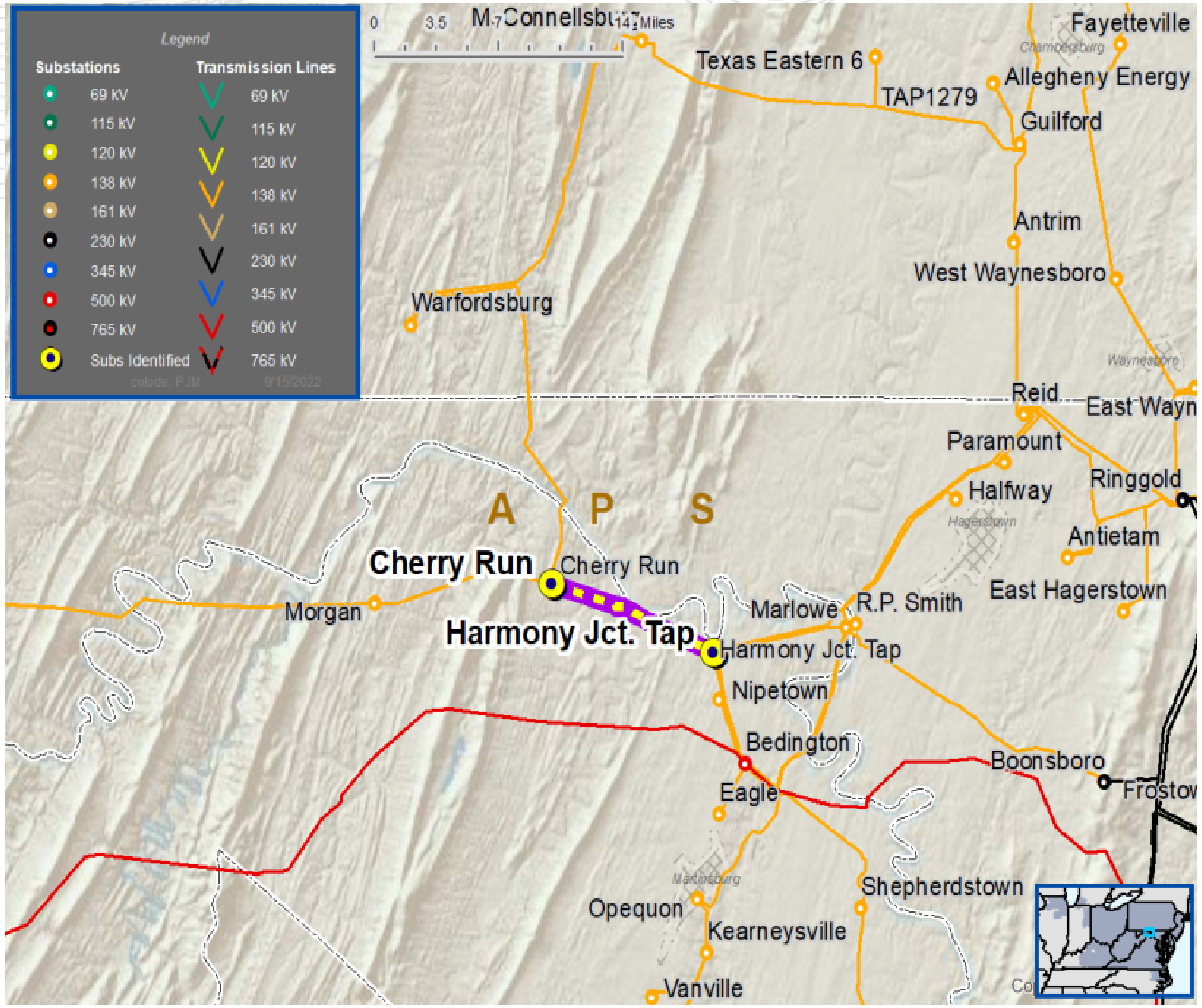
Model Used for Analysis: 2027 Summer and Winter RTEP case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-GD-S565 and 2022W1-GD-S940

In 2027 RTEP Summer case, Cherry Run to Harmony Junction tap 138 kV line is overloaded due to one breaker and one bus contingency.

Branch	SN/SE/WN/WE (MVA)
Cherry Run - Harmony Jct tap 138 kV	210/229/229/229
Marlowe – Harmony Jct tap 138 kV	225/295/325/343
Bedington – Harmony Jct tap 138 kV	294/350/349/401



APS Transmission Zone: Baseline Cherry Run - Harmony Jct tap 138 kV

Proposed Solution:

- At Bedington Substation: Replace substation conductor, wavetrap, CT's and upgrade relaying
- At Cherry Run Substation: Replace substation conductor, wavetrap, CT's, disconnect switches, circuit breaker and upgrade relaying
- At Marlowe: Replace substation conductor, wavetrap, CT's and upgrade relaying

Transmission Estimated Cost: $4.66M

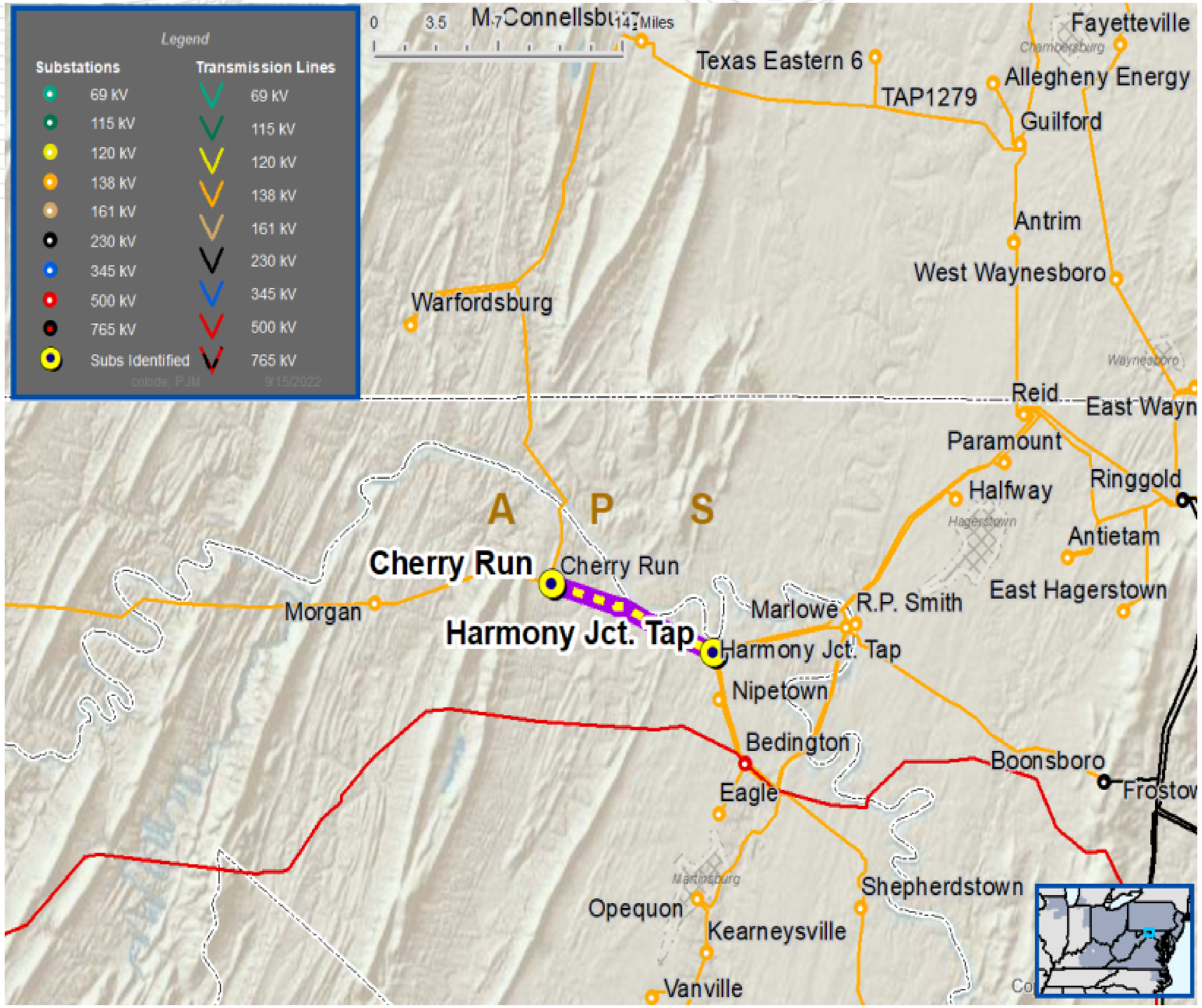
Ancillary Benefits: Upgrading the limiting terminal equipment will increase the ratings of the line.

Alternatives: None

Branch	SN/SE/WN/WE (MVA)
Cherry Run - Harmony Jct tap 138 Kv	221/268/250/317
Marlowe – Harmony Jct tap 138 kV	308/376/349/445
Bedington – Harmony Jct tap 138 kV	308/376/349/445

Required in-service date: 6/1/2027

Projected in-service date: 6/1/2027



APS Transmission Zone: Baseline Shanor – Krendale 138 kV

Process Stage: First Review Solution

Criteria: Generation Deliverability

Assumption Reference: 2027 RTEP assumption

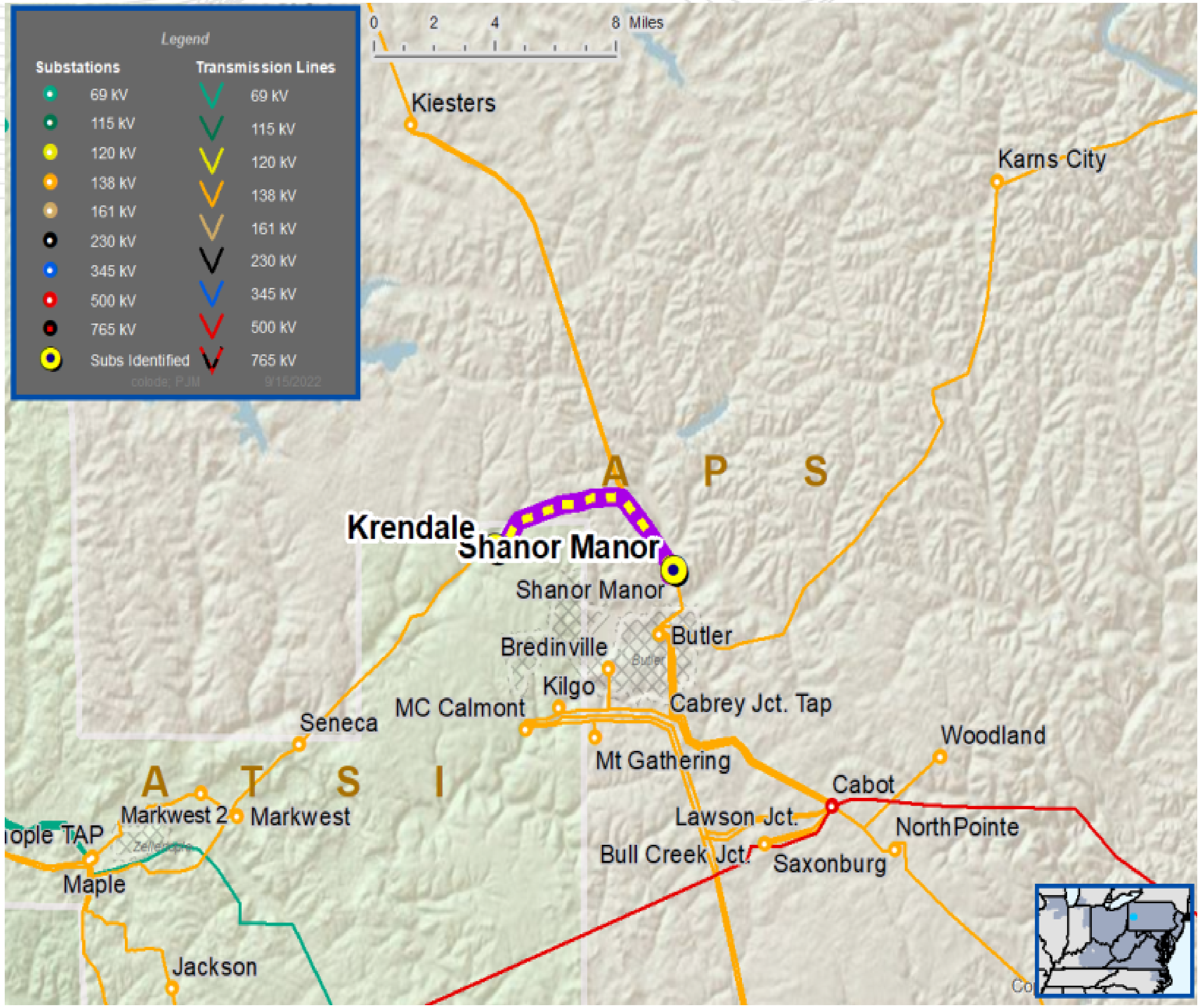
Model Used for Analysis: 2027 Summer RTEP case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-GD-S28

In 2027 RTEP Summer case, Shanor to Krendale 138 kV line is overloaded due to single contingency.

Branch	SN/SE/WN/WE (MVA)
Shanor – Krendale 138 kV line	353/422/419/459



APS Transmission Zone: Baseline Shanor – Krendale 138 kV

Proposed Solution:

- Replace one span of 1272 ACSR from Krendale substation to structure 35 (~630 ft)
- Replace one span of 1272 ACSR from Shanor Manor to structure 21 (~148 ft)
- Replace 1272 ACSR risers at Krendale & Shanor Manor Substations
- Replace 1272 ACSR Substation Conductor at Krendale Substation
- Replace relaying at Krendale Substation
- Revise Relay Settings at Butler & Shanor Manor Substations.

Transmission Estimated Cost: $1.75M

Ancillary Benefits: Upgrading the limiting terminal equipment will increase the ratings of the line.

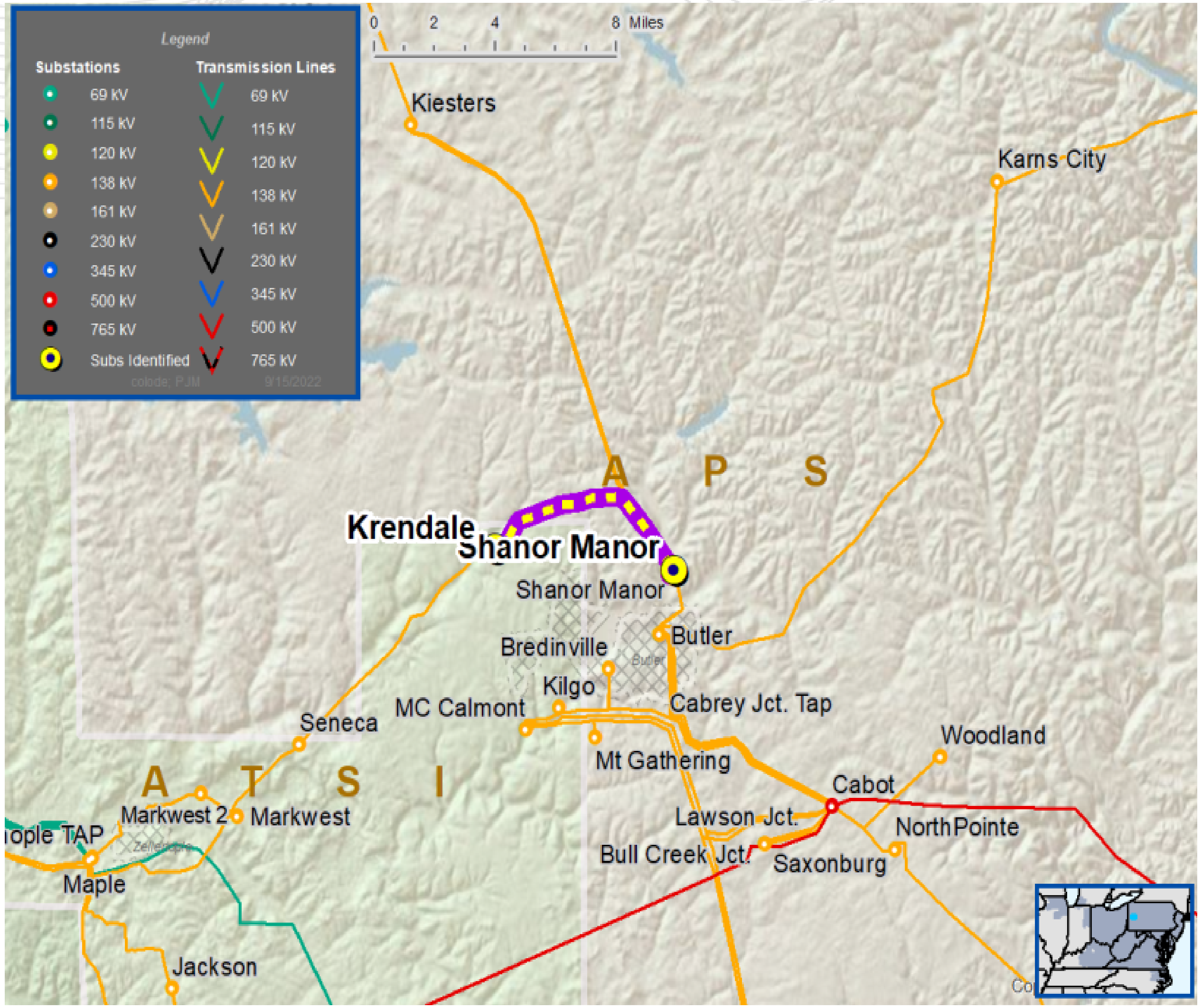
Alternatives: None

Preliminary Facility Rating:

Branch	SN/SE/WN/WE (MVA)
Shanor – Krendale 138 kV line	443/535/500/607

Required in-service date: 6/1/2027

Projected in-service date: 12/1/2023



APS Transmission Zone: Baseline Carbon Center 230 kV Substation

Process Stage: First Review Solution

Criteria: Baseline Analysis

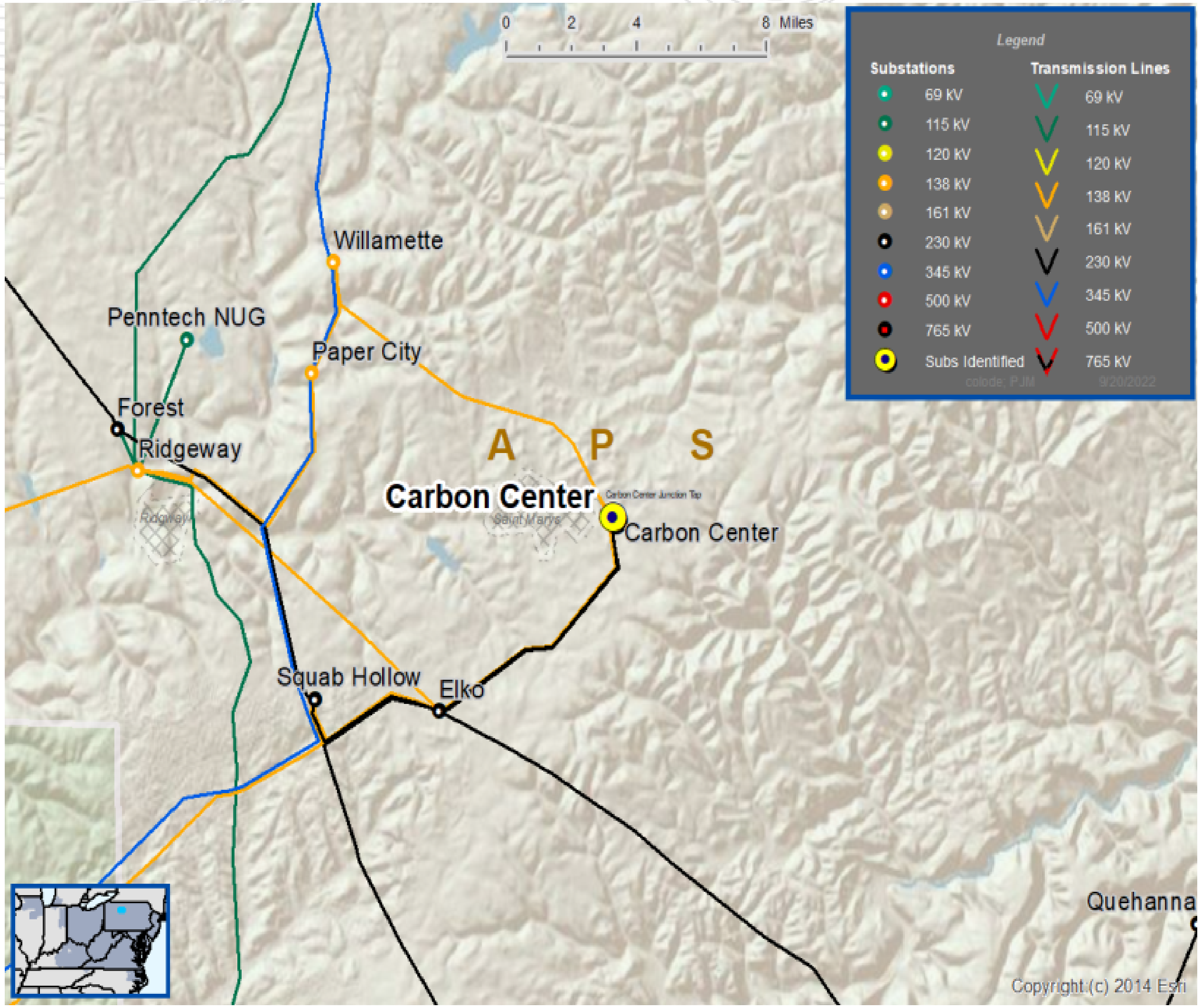
Assumption Reference: 2027 RTEP assumption

Model Used for Analysis: 2027 Summer and Winter RTEP case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-N1-WT83 & 2022W1-N1-ST5

In 2027 RTEP Summer and winter case, Elko to Ridgeway 138 kV line is overloaded to P5 contingency.



APS Transmission Zone: Baseline Carbon Center 230 kV Substation

Proposed Solution:

- At Carbon Center Substation: Replace and add relaying to ensure there is redundancy for 230 kV and 138 kV bus & stuck breaker faults to avoid remote-end clearing. The new redundant relaying shall meet the TPL-001-4 non-redundant relays standard.

Transmission Estimated Cost: $0.57M

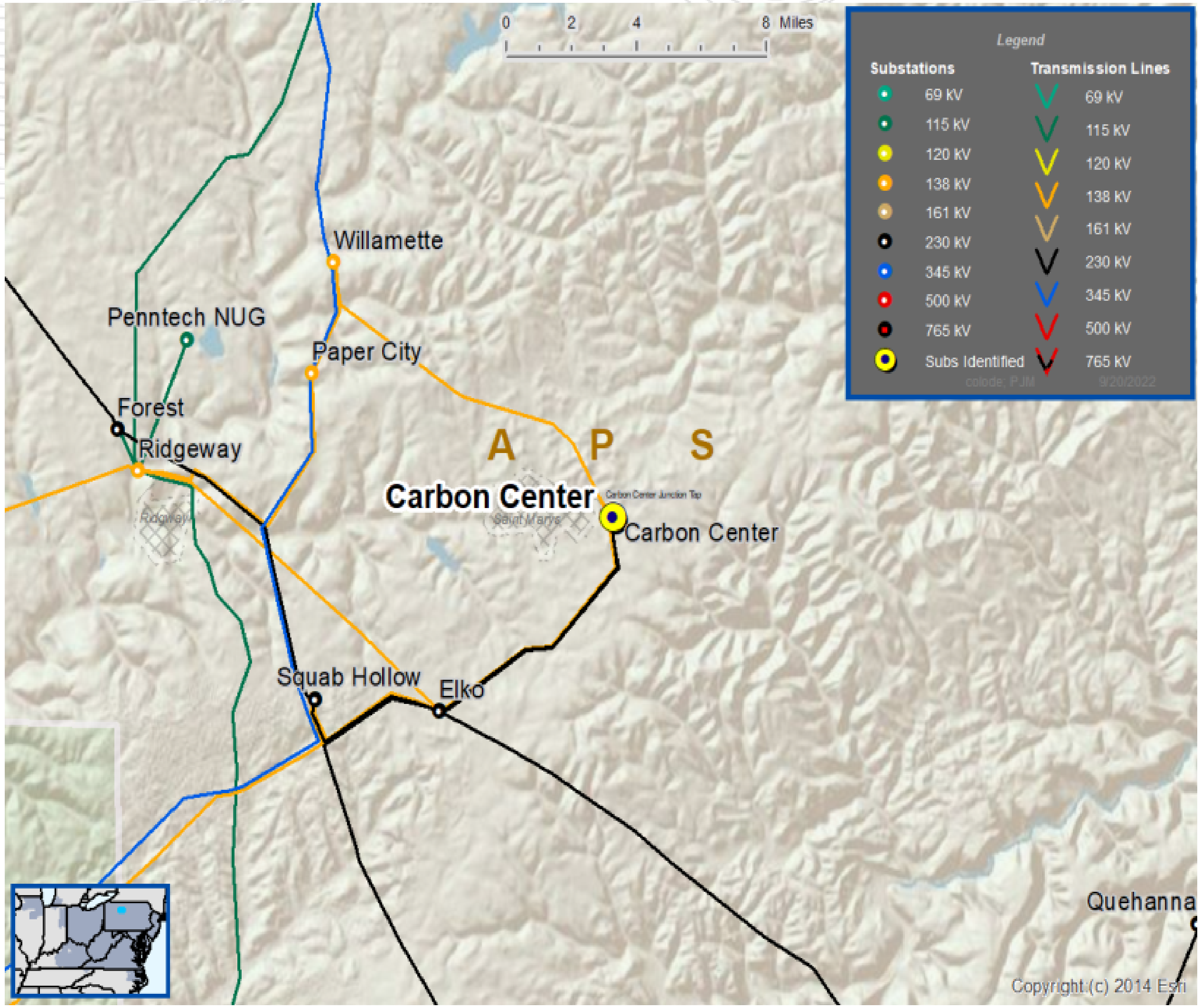
Ancillary Benefits: Installation of redundant relaying will prevent outage scenarios and improve reliability of the transmission system.

Alternatives: None

Preliminary Facility Rating: N/A

Required in-service date: 6/1/2027

Projected in-service date: 6/1/2027



APS Transmission Zone: Baseline Meadow Brook 500 kV Substation

Process Stage: First Review Solution

Criteria: Baseline Analysis

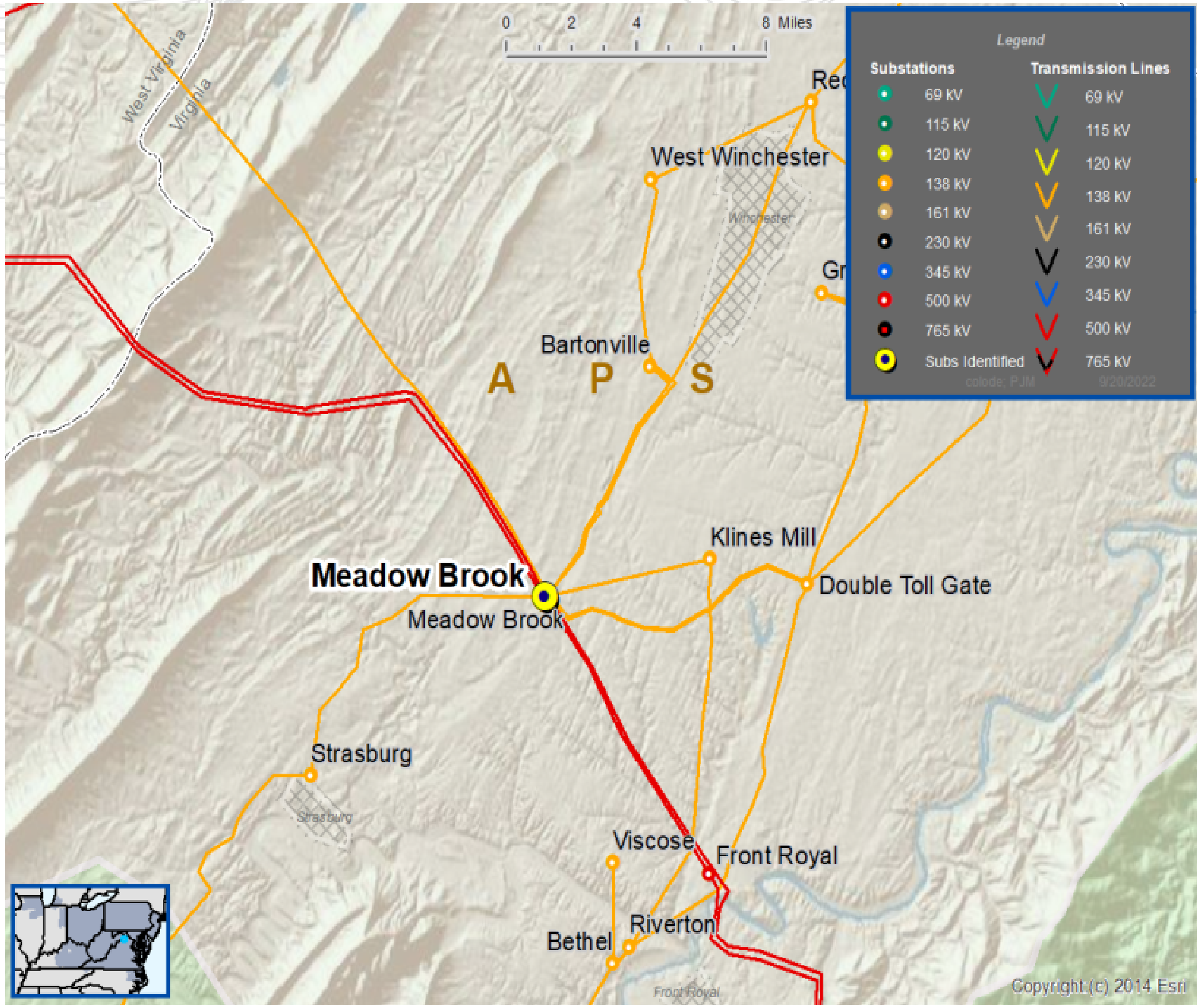
Assumption Reference: 2027 RTEP assumption

Model Used for Analysis: 2027 Summer and Winter RTEP case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-N1-ST3, 2022W1-N1-ST4, 2022W1-N1-ST14, 2022W1-N1-ST15, 2022W1-N1-SVM1, 2022W1-N1-SVM2, 2022W1-N1-SVM5 through 2022W1-N1-SVM10, 2022W1-N1-SVM13 through 2022W1-N1-SVM16, 2022W1-N1-SVD3, 2022W1-N1-SVD4, 2022W1-N1-SVD7 through 2022W1-N1-SV12, 2022W1-N1-SV15, 2022W1-N1-SV16, 2022W1-N1-SV19, 2022W1-N1-SV20, 2022W1-N1-WT20, 2022W1-N1-WT21, 2022W1-N1-WT67, 2022W1-N1-WT68, 2022W1-N1-WVM3, 2022W1-N1-WV4, 2022W1-N1-WV11, 2022W1-N1-WV12, 2022W1-N1-WV15 to 2022W1-N1-WV18. 2022W1-N1-WV21, 2022W1-N1-WV22, 2022W1-N1-WV29, 2022W1-N1-WV30, 2022W1-N1-WV33, 2022W1-N1-WV34, 2022W1-N1-WV39, 2022W1-N1-WV40, 2022W1-N1-WVD3, 2022W1-N1-WVD4, 2022W1-N1-WVD15, 2022W1-N1-WVD16, 2022W1-N1-WVD19, 2022W1-N1-WVD20, 2022W1-N1-WVD21, 2022W1-N1-WVD22, 2022W1-N1-WVD25, 2022W1-N1-WVD26, 2022W1-N1-WVD37, 2022W1-N1-WVD38, 2022W1-N1-WVD43 & 2022W1-N1-WVD44

In 2027 RTEP Summer and winter case, Thermal overloads voltage drop violations and voltage magnitude violations at multiple 138 kV buses due to two P5 contingencies.



APS Transmission Zone: Baseline Meadow Brook 500 kV Substation

Proposed Solution:

- At Meadow Brook Substation: Replace and add relaying to ensure there is redundancy for 500 kV and 138 kV bus & stuck breaker faults to avoid remote-end clearing. The new redundant relaying shall meet the TPL-001-4 non-redundant relays standard

Transmission Estimated Cost: $0.21M

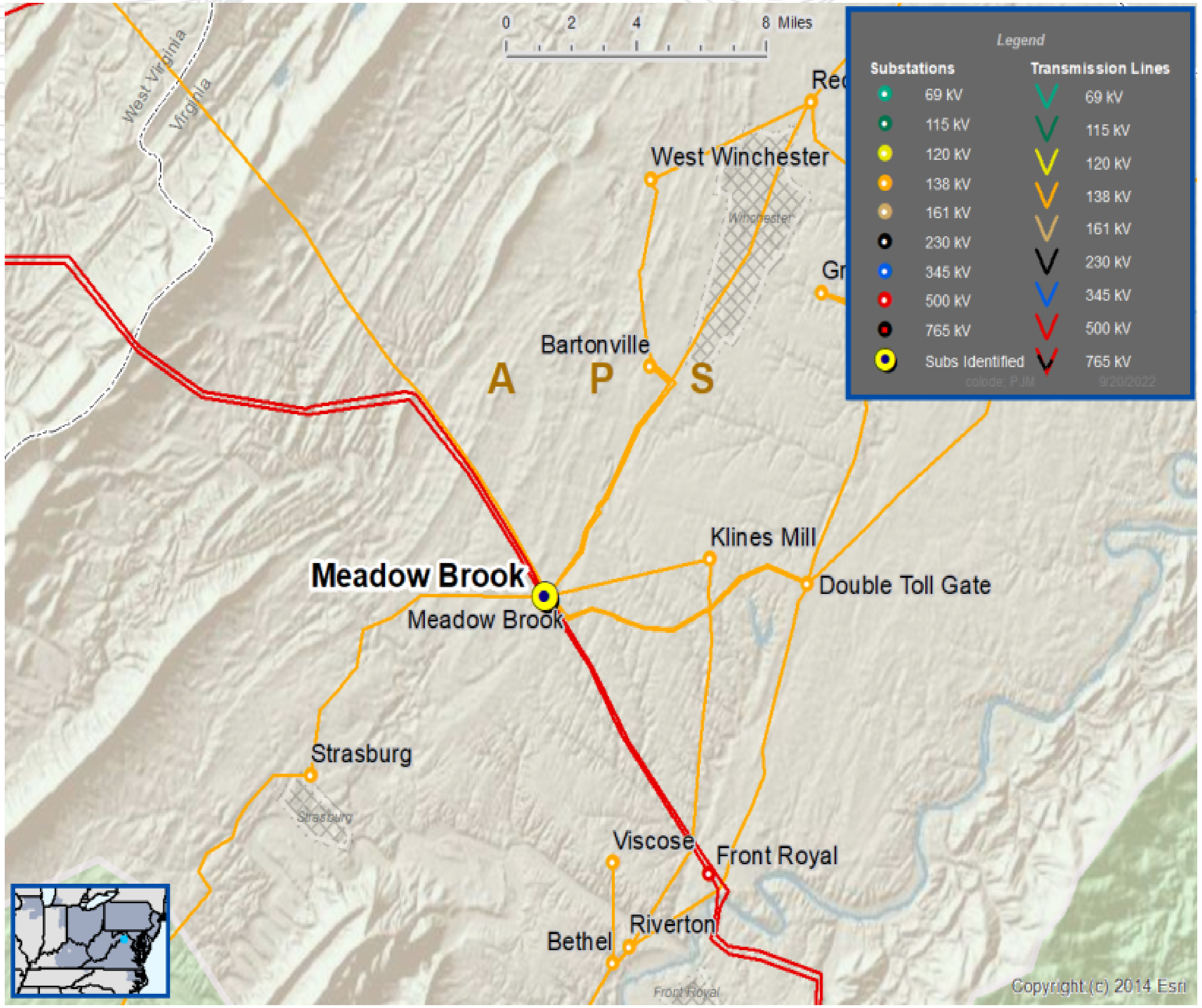
Ancillary Benefits: Installation of redundant relaying will prevent outage scenarios and improve reliability of the transmission system.

Alternatives: None

Preliminary Facility Rating: N/A

Required in-service date: 6/1/2027

Projected in-service date: 6/1/2027



APS Transmission Zone: Baseline Bedington 500 kV Substation

Process Stage: First Review Solution

Criteria: Baseline Analysis

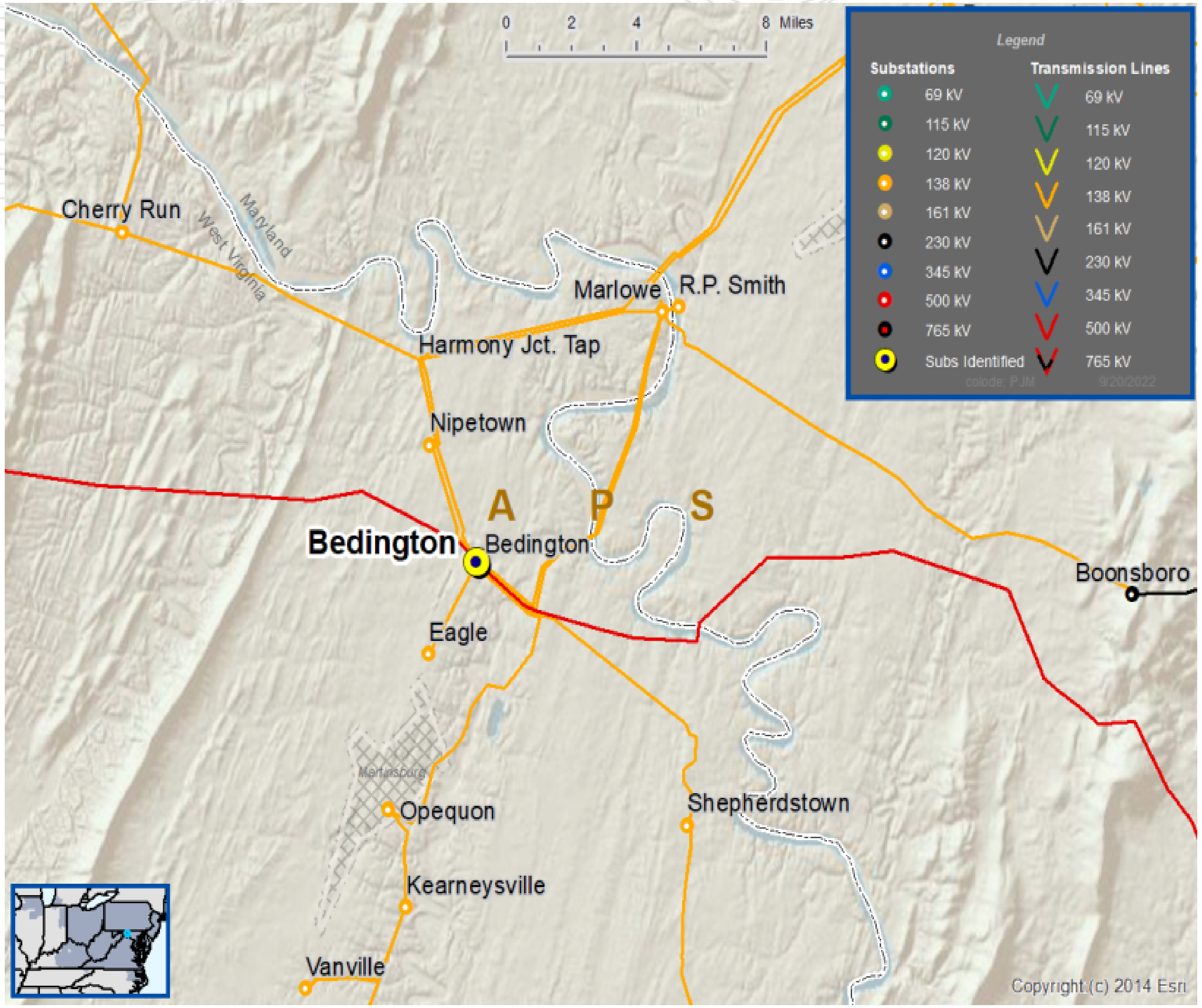
Assumption Reference: 2027 RTEP assumption

Model Used for Analysis: 2027 Summer and Winter RTEP case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement:. 2022W1-N1-SVM3, 2022W1-N1-SVM4, 2022W1-N1-SVM11, 2022W1-N1-SVM12, 2022W1-N1-SVD1, 2022W1-N1-SVD2, 2022W1-N1-SVD5, 2022W1-N1-SVD6, 2022W1-N1-SVD13, 2022W1-N1-SVD14, 2022W1-N1-SVD17, 2022W1-N1-SVD18, 2022W1-N1-WT88, 2022W1-N1-WT89, 2022W1-N1-WVM1, 2022W1-N1-WVM2, 2022W1-N1-WVM5 through 2022W1-N1-WVM10, 2022W1-N1-WVM13, 2022W1-N1-WVM14, 2022W1-N1-WVM19, 2022W1-N1-WVM20, 2022W1-N1-WVM23 through 2022W1-N1-WVM28, 2022W1-N1-WVM31, 2022W1-N1-WVM32, 2022W1-N1-WVM35 thorugh 2022W1-N1-WVM38, 2022W1-N1-WVD1, 2022W1-N1-WVD2, 2022W1-N1-WVD5 through 2022W1-N1-WVD14, 2022W1-N1-WVD17, 2022W1-N1-WVD18, 2022W1-N1-WVD23, 2022W1-N1-WVD24, 2022W1-N1-WVD27 through 2022W1-N1-WVD36, 2022W1-N1-WVD39 through 2022W1-N1-WVD42, 2022W1-N1-WVD45 & 2022W1-N1-WVD46

In 2027 RTEP Summer and winter case, Thermal overloads voltage drop violations and voltage magnitude violations at multiple 138 kV buses due to two P5 contingencies.



APS Transmission Zone: Baseline Bedington 500 kV Substation

Proposed Solution:

- At Bedington Substation: Replace and add relaying to ensure there is redundancy for 500 kV and 138 kV bus & stuck breaker faults to avoid remote-end clearing. The new redundant relaying shall meet the TPL-001-4 non-redundant relays standard.

Transmission Estimated Cost: $0.28M

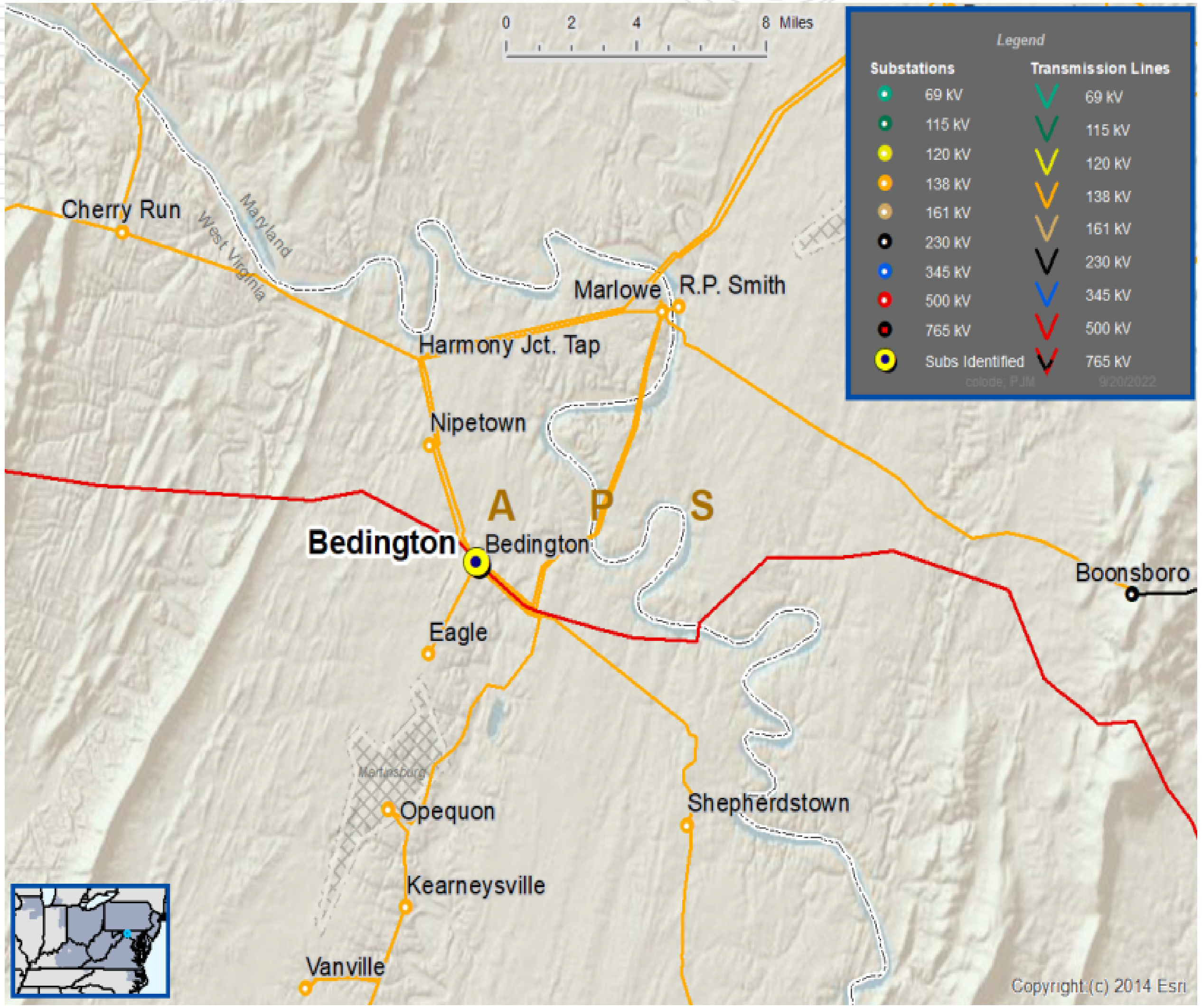
Ancillary Benefits: Installation of redundant relaying will prevent outage scenarios and improve reliability of the transmission system.

Alternatives: None

Preliminary Facility Rating: N/A

Required in-service date: 6/1/2027

Projected in-service date: 6/1/2027



EKPC Transmission Zone: Baseline Fawkes-Duncannon Lane Tap 69 kV Rebuild

Process Stage: First Review

Criteria: EKPC 715 Criteria

Assumption Reference: EKPC Assumptions Presentation slides 3-10

Model Used for Analysis: EKPC's internal models representing 2026/27 winter peak conditions that were used for EKPC's annual system screening analysis for 2022 planning cycle. Includes Cooper Units 1 and 2 off with replacement generation imported from the north of EKPC system.

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement:

The Fawkes-Duncannon Lane Tap 69 kV line (LGEE-EKPC tie line) is overloaded for an N-1 outage.

Violation was posted as part of the 2022 Window 1: FG# 2022W1-EKPC-T1

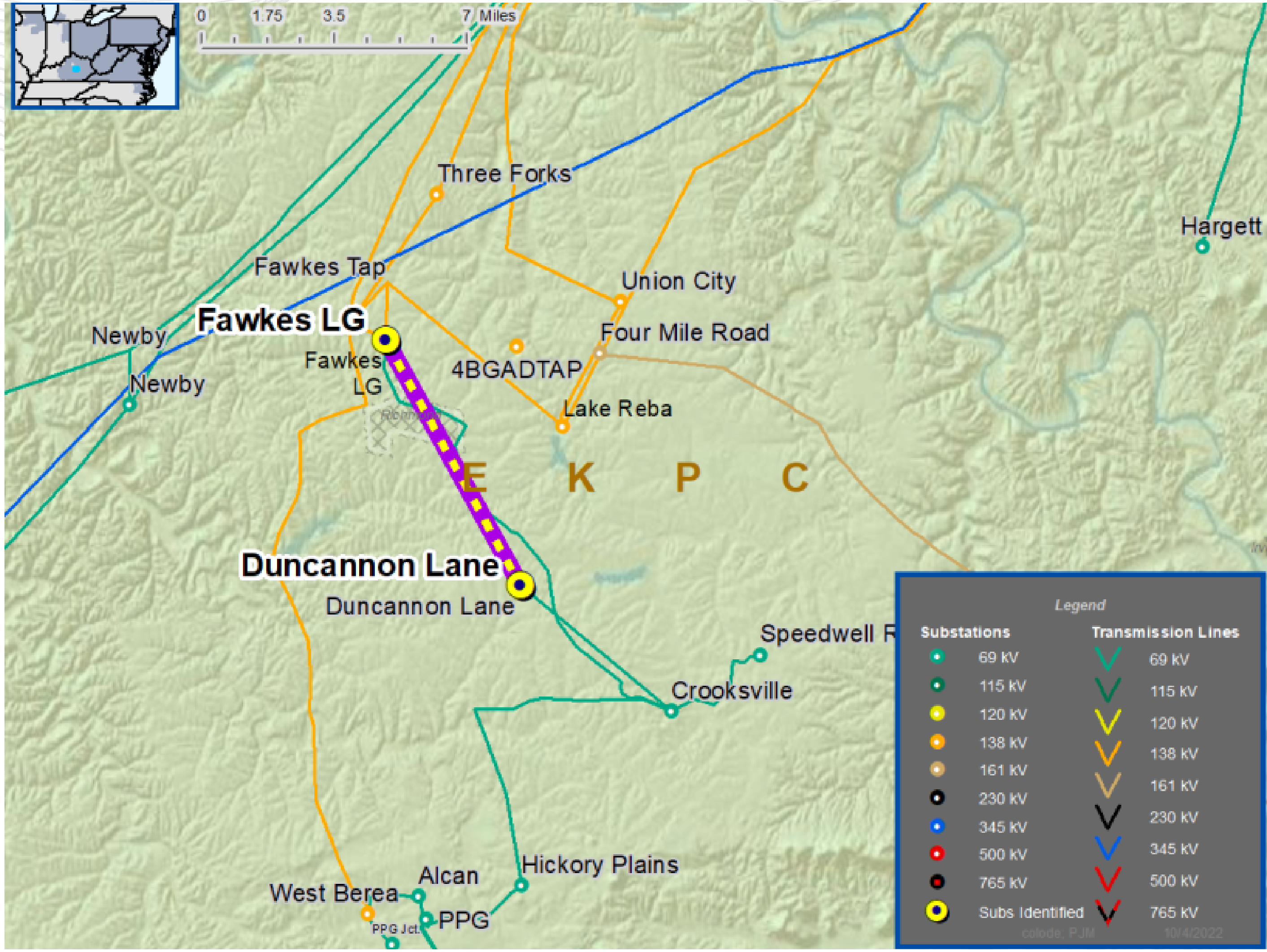
Existing Facility Rating: 89SN/98SE, 128WN/134WE MVA

Proposed Facility Rating: 114SN/127SE, 166WN/174WE MVA

Proposed Solution:

Rebuild EKPC's Fawkes-Duncannon Lane Tap 556.5 ACSR 69 kV line section (7.2 miles) using 795 ACSR.

Estimated Cost: $8.5 M



EKPC Transmission Zone: Baseline Fawkes-Duncannon Lane Tap 69 kV Rebuild

Alternatives:

1. Increase the maximum operating temperature of the existing 556.5 MCM ACSR conductor in the KU Fawkes-Duncannon Lane Tap 69 KV line section from 212 degrees Fahrenheit to 302 degrees Fahrenheit.

   Estimated cost: $1.5M

2. Establish a new normally-open interconnection with LGE/KU south of the Crooksville Junction tap point.

   Estimated cost: $10.5 M

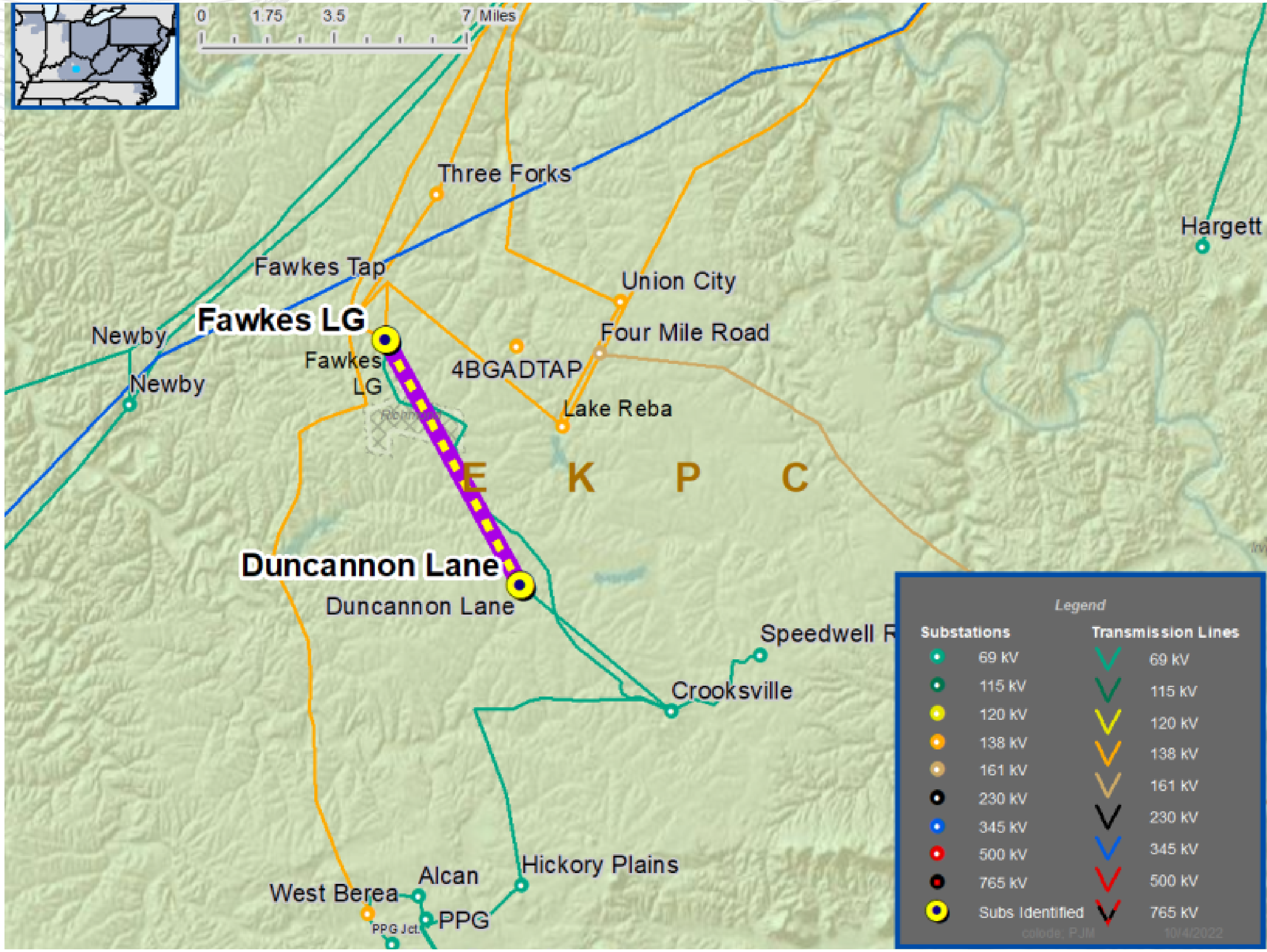
3. Construct a new 138 kV line from the EKPC Fawkes substation to the Crooksville Junction tap point and construct a new 138/69 KV substation near this location for connection to the existing KU Fawkes-West Berea 69 KV circuit.

   Estimated cost: $24.8 M

Ancillary Benefits: Replacement of aging infrastructure associated with line section.

Required In-Service: 12/1/2026

Projected In-Service: 12/31/2024



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SRRTEP-W Reliability Analysis Update

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Revision History

- V1 – 10/10/2022 – Original slides posted
- V2 – 10/13/2022 – Slide #25, correct the estimated cost from \$8.23M to \$8.48M


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