Subregional RTEP Committee – Western FirstEnergy Supplemental Projects

July 22, 2022

Needs

Stakeholders must submit any comments within 10 days of this meeting in order to provide time necessary to consider these comments prior to the next phase of the M-3 process

FirstEnergy

Need Number: ATSI-2022-Mutiple (See next slide)

Process Stage: Need Meeting – 07/22/2022

Project Driver:

Equipment Material Condition, Performance and Risk

Specific Assumption References:

Global Factors

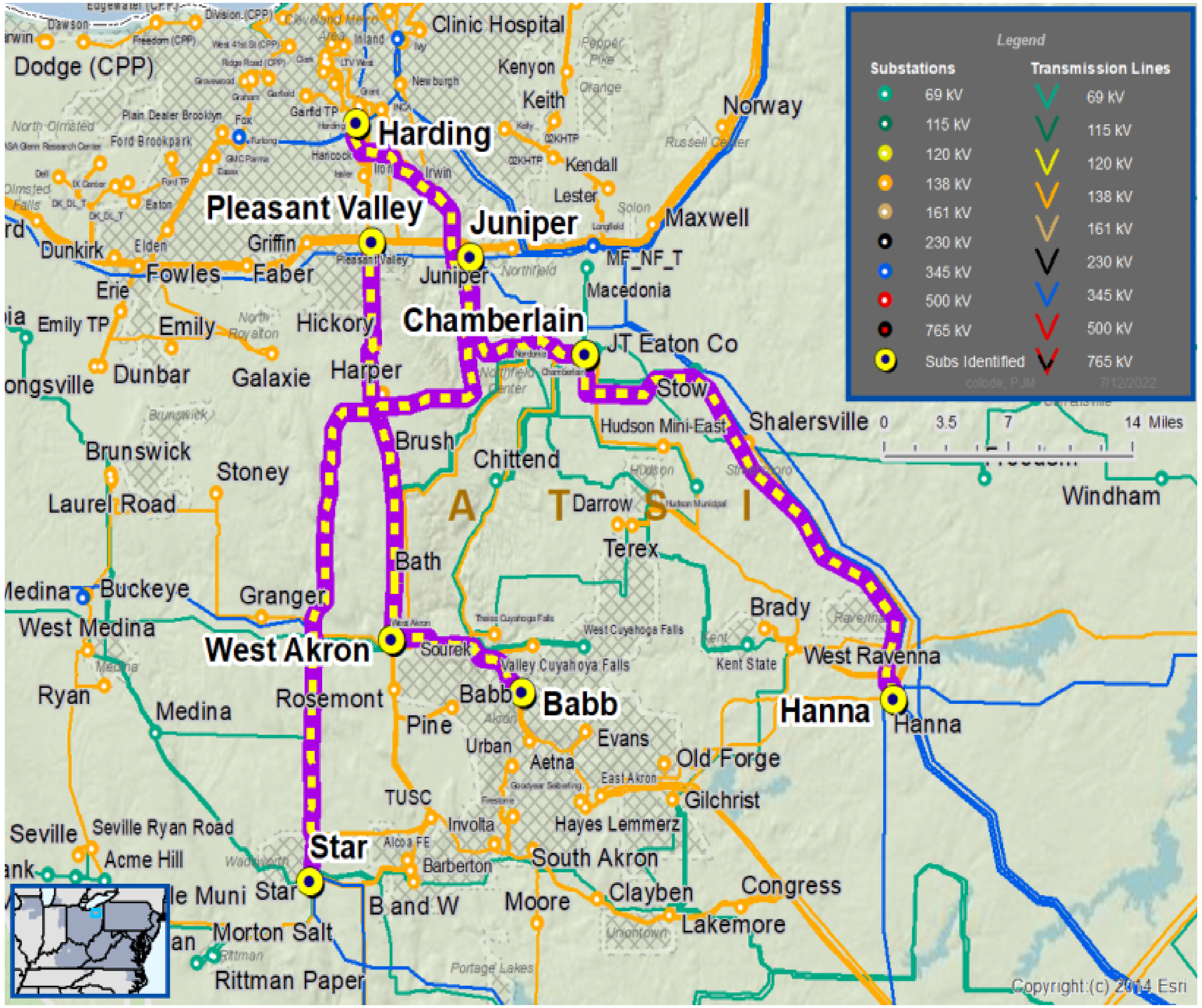
- System reliability and performance
- Substation / line equipment limits

Upgrade Relay Schemes

- Relay schemes that have a history of misoperation
- Obsolete and difficult to repair communication equipment (DTT, Blocking, etc.)
- Communication technology upgrades

Problem Statement:

- Since 2018 there have been seven (7) reportable misoperations in ATSI as a result of a power line carrier communication (PLC) issues and several other PLC systems have concerning health issues based on alarm and maintenance records.
- Per NATF reporting, DCB schemes are by far the most common protection scheme to misoperate accounting for over 31% of all reported misoperations.
- During the period of 2014-Q1 2018, 2.4% of misoperations in FE were due to the DCB protection scheme. Another 12% of misoperations were due to communication failures, relay failures and unknowns in a DCB-PLC configuration.
- Transmission line ratings are limited by terminal equipment.



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ATSI-2022	Transmission Line / Substation Locations	Existing Line/Terminal Equipment MVA Rating (SN / SE)	Existing Conductor/Transformer MVA Rating (SN / SE)	Limiting Terminal Equipment
-016	Pleasant Valley-West Akron 138 kV Line	153 / 199 217 (WN) / 229 (WE)	237 / 287 267 (WN) / 339 (WE)	Wave trap, substation conductor
-017	Chamberlin-Harding 345 kV Line	1245 / 1394 1394 (WN) / 1394 (WE)	1560 / 1900 1766 (WN) / 2251 (WE)	Circuit breaker, disconnect switch, substation conductor, and relay
-018	Chamberlin-Hanna 345 kV Line	1230 / 1394 1394 (WN) / 1394 (WE)	1542 / 1878 1746 (WN) / 2225 (WE)	Circuit breaker, disconnect switch, substation conductor, and relay
-019	Juniper -Star 345 kV Line	1289 / 1289 1289 (WN) / 1289 (WE)	1518 / 1849 1719 (WN) / 2192 (WE)	Relay, disconnect switch, substation conductor
-021	Babb-West Akron 138 kV Line	190 / 209 217 (WN) / 223 (WE)	200 / 242 226 (WN) / 286 (WE)	Relay, substation conductor, wave trap

Solutions

Stakeholders must submit any comments within 10 days of this meeting in order to provide time necessary to consider these comments prior to the next phase of the M-3 process

Carbon Limestone (Lowellville) 69 kV New Customer

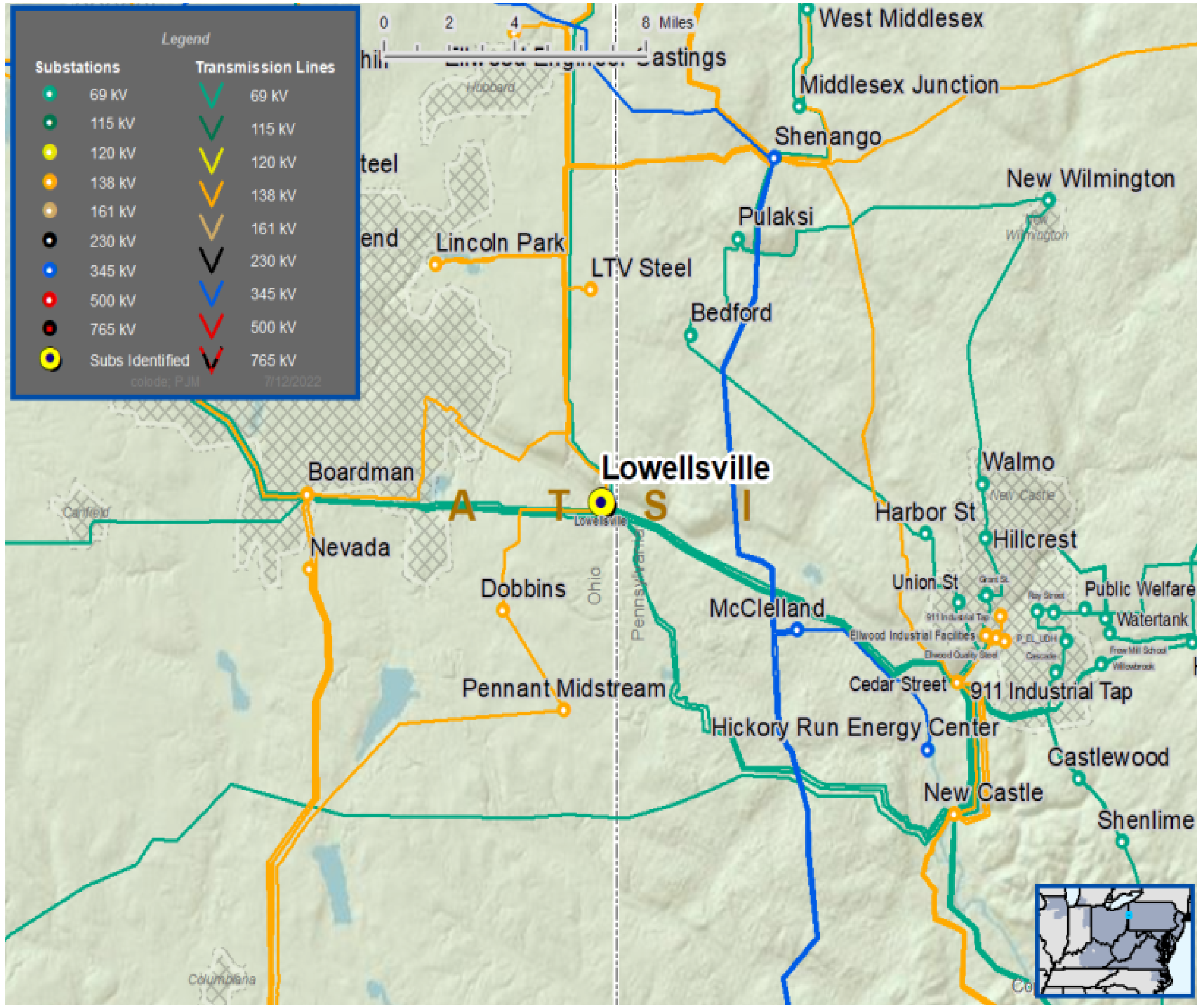
Need Number: ATSI-2022-002
Process Stage: Solution Meeting –07/22/2022
Previously Presented: Need Meeting – 03/18/2022

Supplemental Project Driver(s):
Customer Service

Specific Assumption Reference(s)
Customer connection request evaluated per FirstEnergy's "Requirements for Transmission Connected Facilities" document and "Transmission Planning Criteria" document.

Problem Statement
New Customer Connection – A customer requested 69 kV transmission service for approximately 15 MVA of total load near the Carbon Limestone (Lowellville) 69 kV line.

Requested In-Service Date: December 30, 2022



ATSI Transmission Zone M-3 Process
Carbon Limestone (Lowellville) 69 kV New Customer

Need Number: ATSI-2022-002
Process Stage: Solution Meeting – 07/22/2022
Previously Presented: Need Meeting – 03/18/2022

Proposed Solution:

69 kV Transmission Line Tap

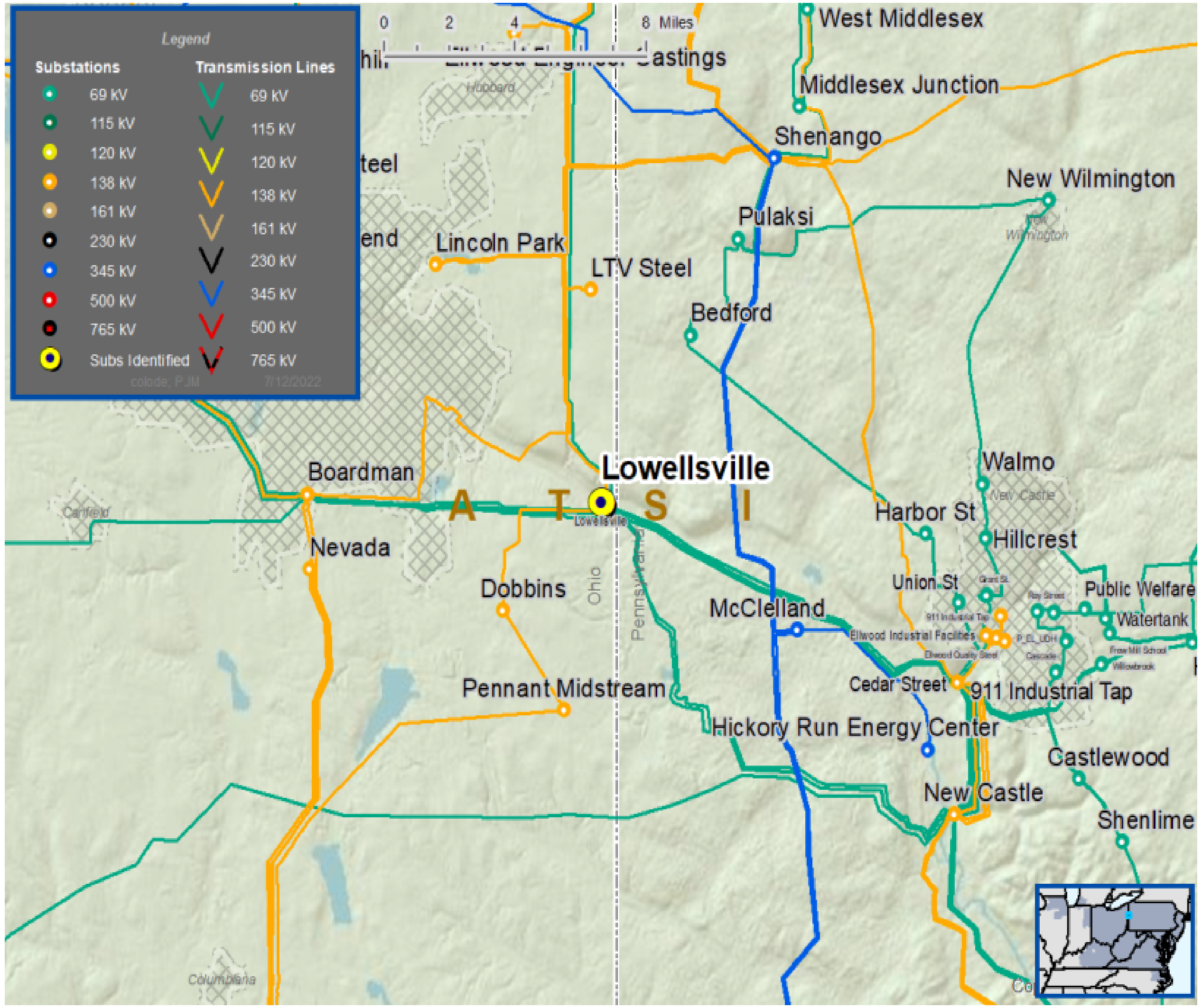
- Install one SCADA controlled transmission line switch
- Adjust relay settings at Lowellville substation

Alternatives Considered:

- Tap Lowellville-New Castle 69 kV Line, and construct 1.3 miles of 69 kV Line to customer substation

Estimated Project Cost: $0.1M

Projected In-Service: 09/02/2022
Status: Engineering



FirstEnergy

Need Number: ATSI-2021-003

Process Stage: Solution Meeting – 07/22/2022

Previously Presented: Need Meeting – 01/15/2021

Supplemental Project Driver(s):

Customer Service

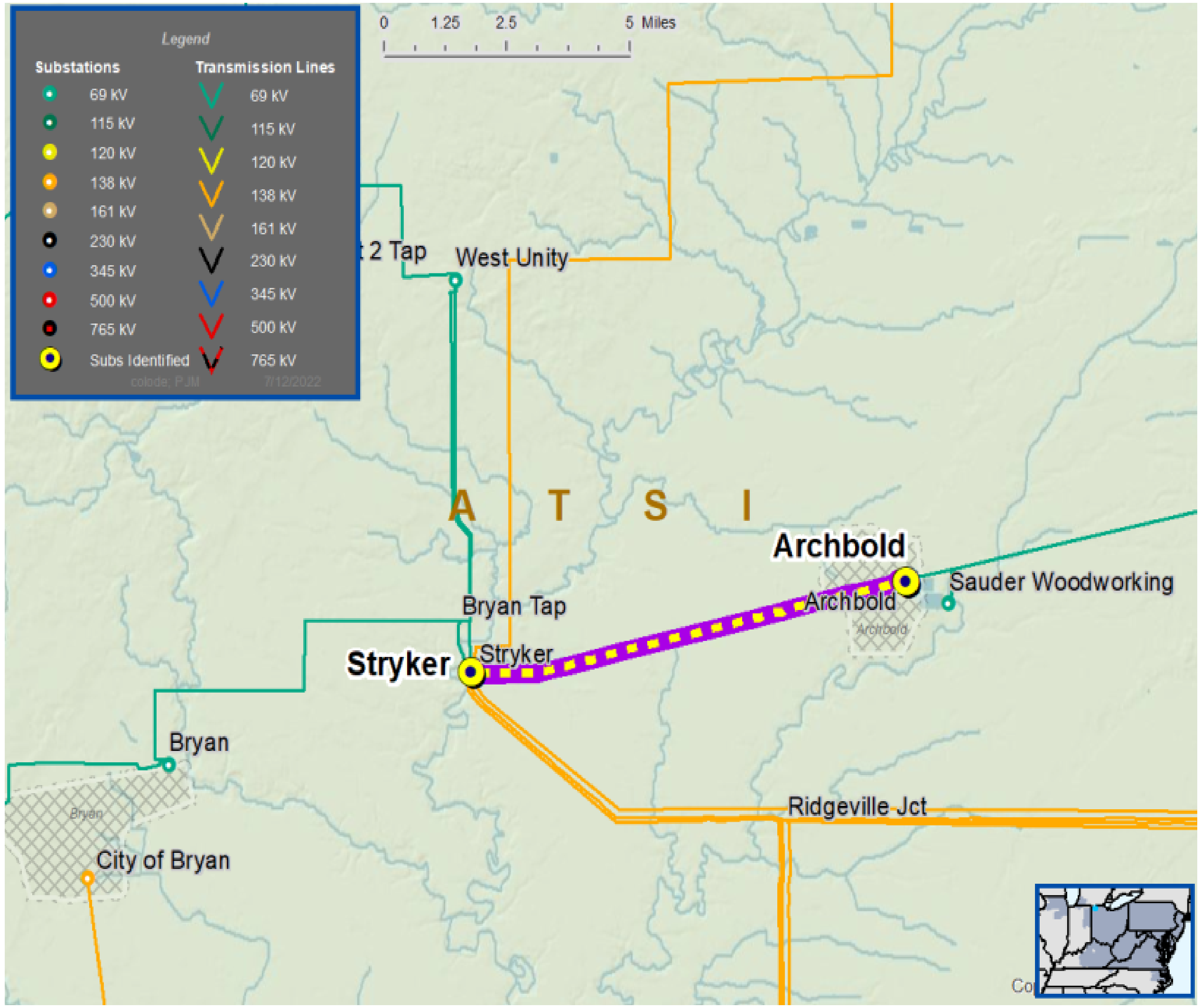
Specific Assumption Reference(s)

Customer connection requests will be evaluated per FirstEnergy's "Requirements for Transmission Connected Facilities" document and "Transmission Planning Criteria" document.

Problem Statement

New Customer Connection – A customer requested 69 kV transmission service for approximately 5.6 MVA of total load near the East Archbold – Stryker 69 kV line.

Requested In-Service Date: May 1, 2021



Need Number: ATSI-2021-003
Process Stage: Solution Meeting – 07/22/2022
Previously Presented: Need Meeting – 01/15/2021

Proposed Solution:

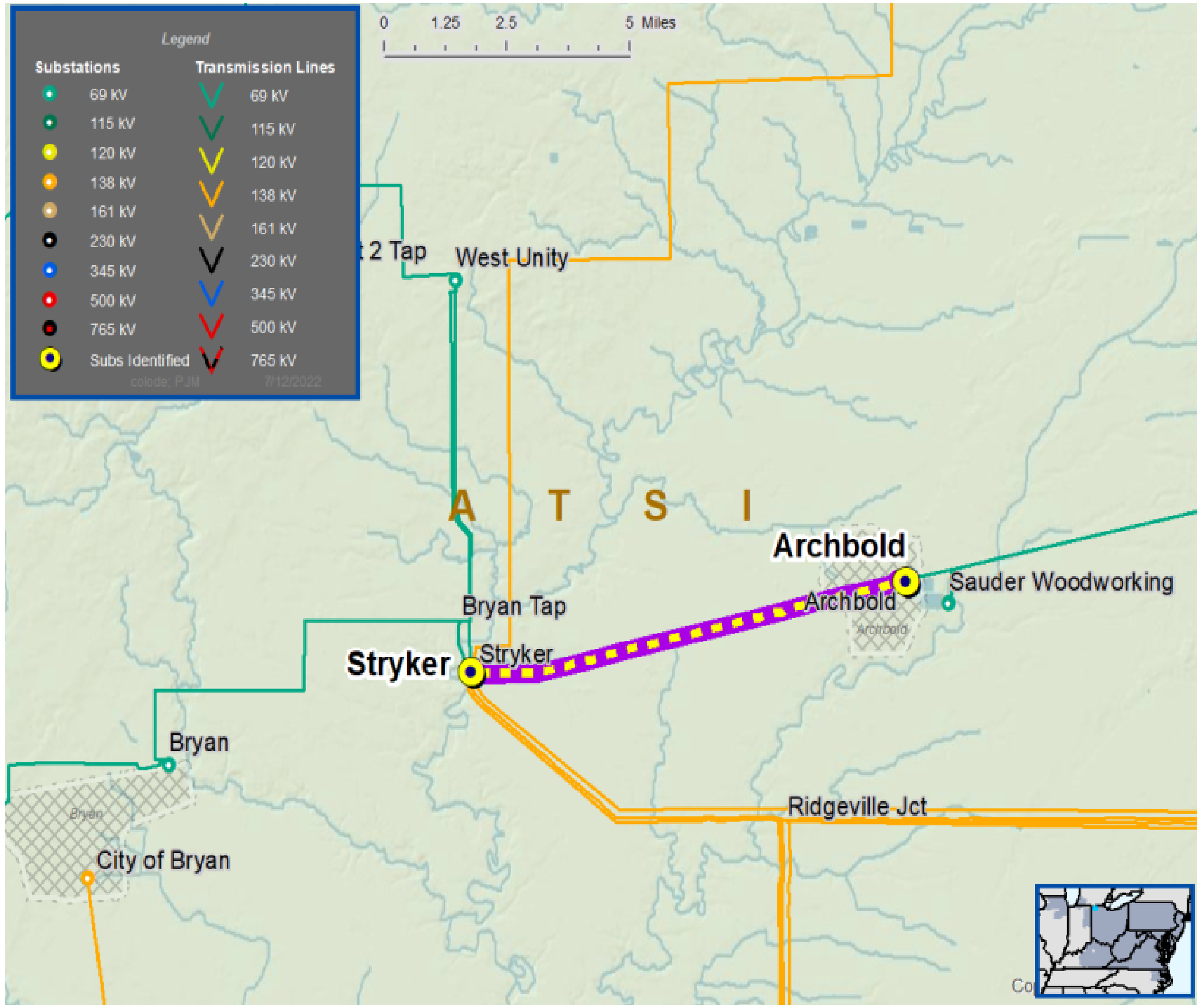
New 69 kV Customer

- Construct a 69 kV tap (approximately 0.1 miles) off the East Archbold – Stryker 69 kV line to the customer substation. The customer substation tap location is approximately 6 miles from Stryker substation.
- Add two SCADA control switches at transmission line tap location and one tap switch
- Revise relay settings at East Archbold and Stryker Substations

Alternatives Considered:

- No alternatives considered for this project

Estimated Project Cost: $1.7M
Projected In-Service: 12/01/2022
Status: Engineering
Model: 2019 Series 2024 Summer RTEP 50/50



FirstEnergy

ATSI Transmission Zone M-3 Process
Leroy Center - Mayfield Q2 138 kV

Need Number: ATSI-2021-015
Process Stage: Solution Meeting – 07/22/2022
Previously Presented: Need Meeting – 08/16/2021

Supplemental Project Driver(s):
Equipment Material Condition, Performance, and Risk
Infrastructure Resilience

Specific Assumption Reference(s):
Global Factors

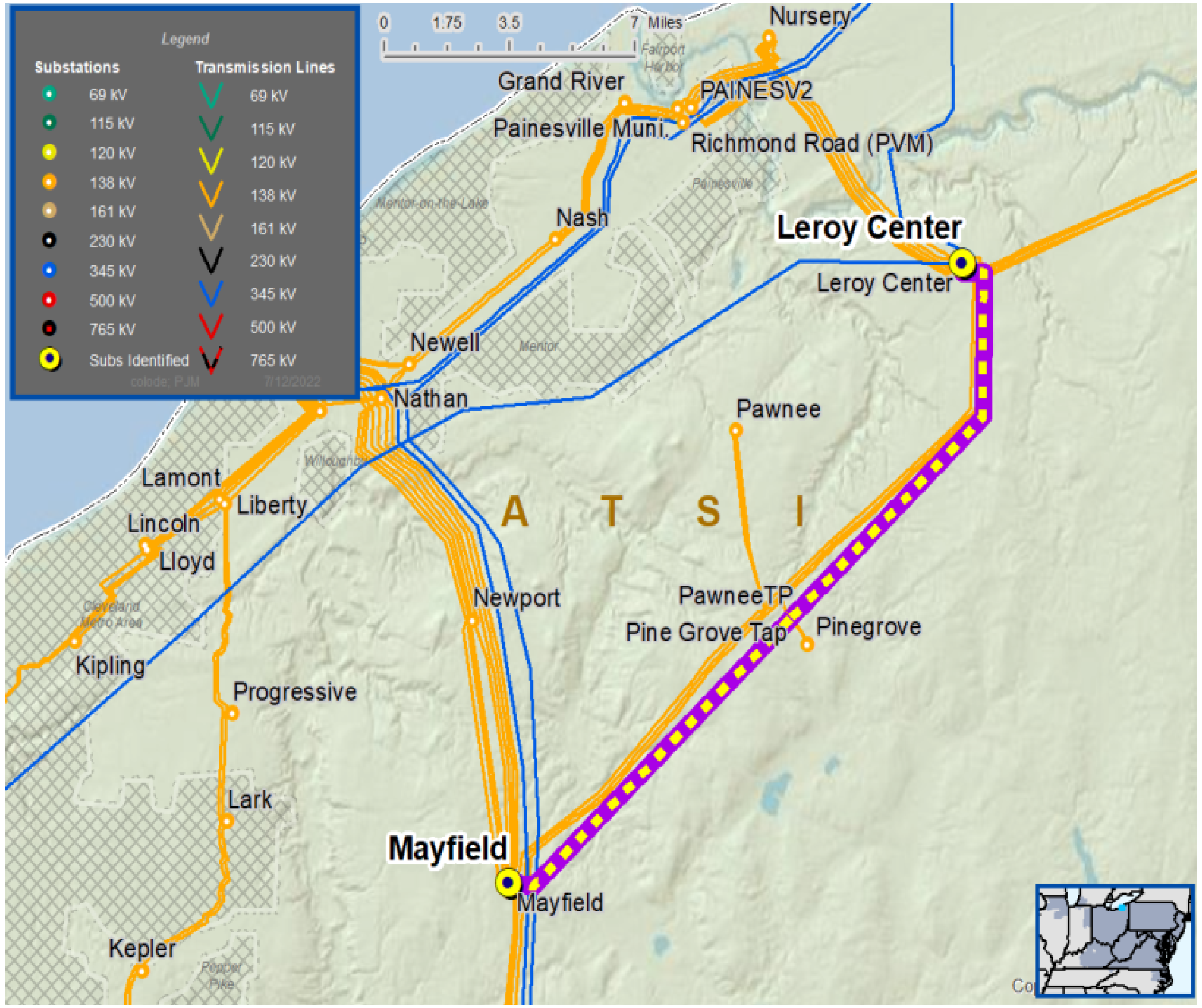
- System Reliability and Performance
- Load at risk in planning and operational scenarios
- Increase line loading limits
- Age/condition of transmission line conductors

Line Condition Rebuild/Replacement

- Transmission lines with loading at 80% or greater
- End of Life Methodology

Problem Statement

- The Leroy Center – Mayfield Q2 138 kV line loads to 95% under contingency conditions in the 2020 RTEP Case.
- The Leroy Center – Mayfield Q2 138 kV line has the potential to feed 7,017 customers and 20 MW at the Pawnee Substation, back up feed to LC-MF Q1 138 kV line.
- The existing conductor is 4/0 CU and can cause protection issues due to not being able to handle the short circuit current for faults.



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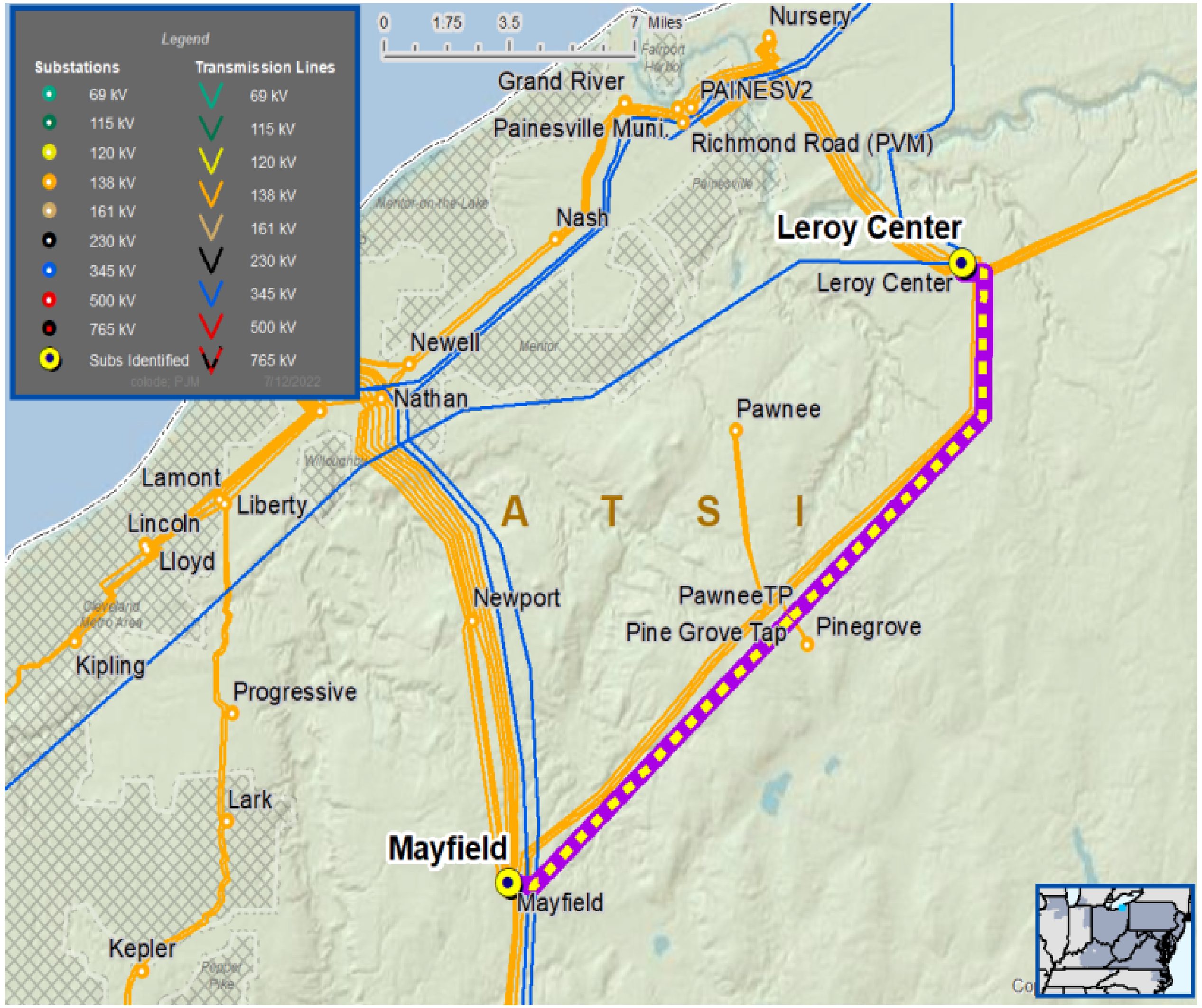
Need Number: ATSI-2021-015

Process Stage: Solution Meeting – 07/22/2022

Presently Presented: Need Meeting – 08/16/2021

Problem Statement Continued…

- Age/condition of transmission line conductors and hardware (mid 1940s).
- The Leroy Center – Mayfield Q2 138 kV line has experienced one (1) sustained outage in the past five years.



Need Number: ATSI-2021-015
Process Stage: Solution Meeting – 07/22/2022
Presently Presented: Need Meeting – 08/16/2021

Proposed Solution:

- Reconductor the Leroy Center-Mayfield Q2 138 kV Line (~16 miles) from Leroy Center - Pawnee Tap and Pawnee Tap - Mayfield with 336 ACSS. Replace tower structures, insulators and hardware as needed to address condition items and support new conductor.

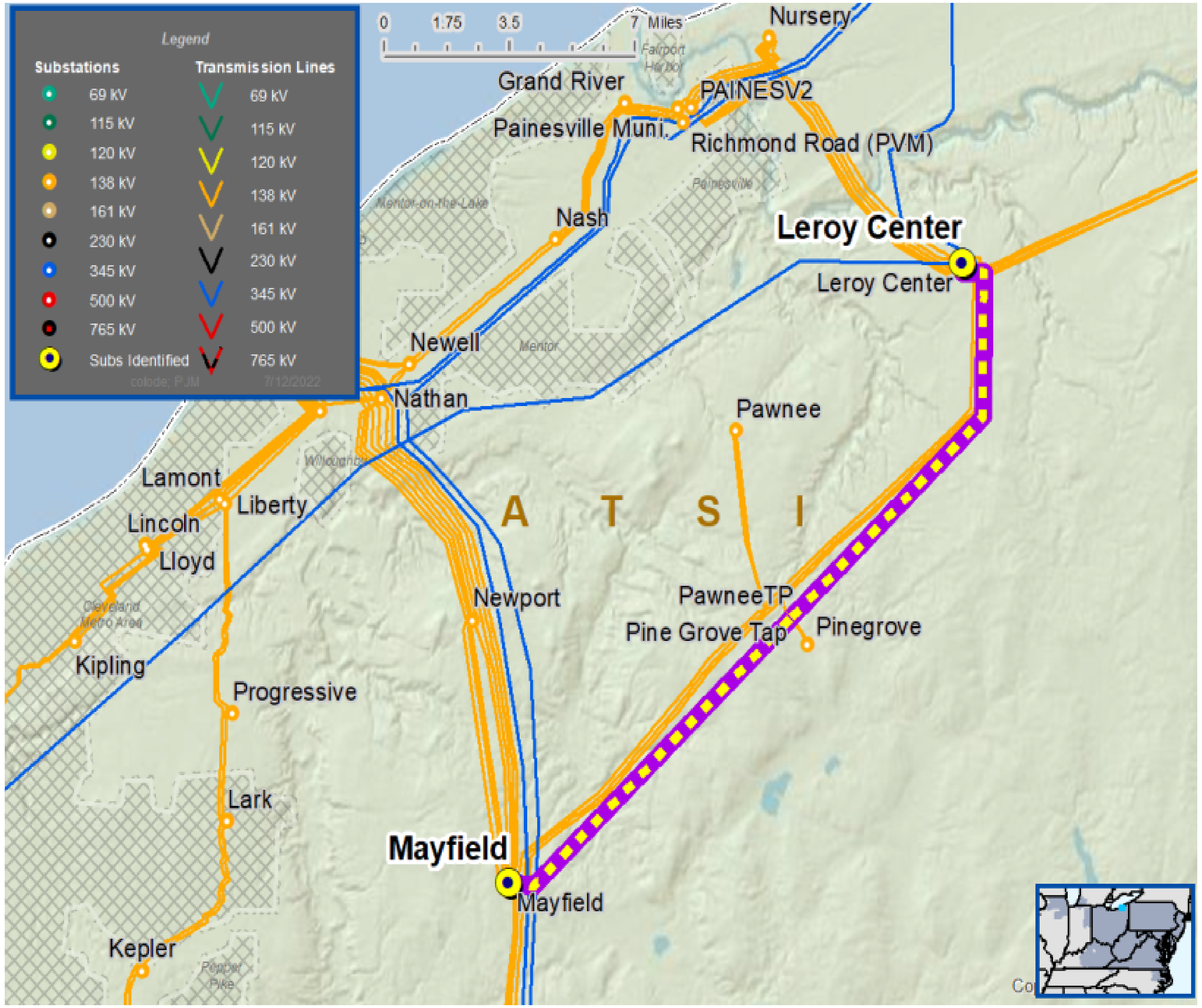
Transmission Line Ratings:

- Leroy Center - Mayfield Q2 138 kV Line
  - Before Proposed Solution: 115 MVA SN/ 115 MVA SE
  - After Proposed Solution: 252 MVA SN / 291 MVA SE

Alternatives Considered:

- Maintain existing condition. No alternatives considered for this project

Estimated Project Cost: $14.9M
Projected In-Service: 06/01/2026
Status: Engineering
Model: 2020 Series 2025 Summer RTEP 50/50



Re-Present Solutions

Stakeholders must submit any comments within 10 days of this meeting in order to provide time necessary to consider these comments prior to the next phase of the M-3 process

FirstEnergy

Need Number: ATSI-2019-011 (s1954)

Process Stage: Re-Present Solutions Meeting – 07/22/2022

Previously Presented: Needs Meeting 01/14/2019
Solutions Meeting 03/25/2019

Project Driver(s):

Equipment Material, Condition, Performance and Risk

Operational Flexibility and Efficiency

Infrastructure Resilience

Specific Assumption Reference(s)

Global Considerations

- System reliability and performance
- Substation / Line equipment limits

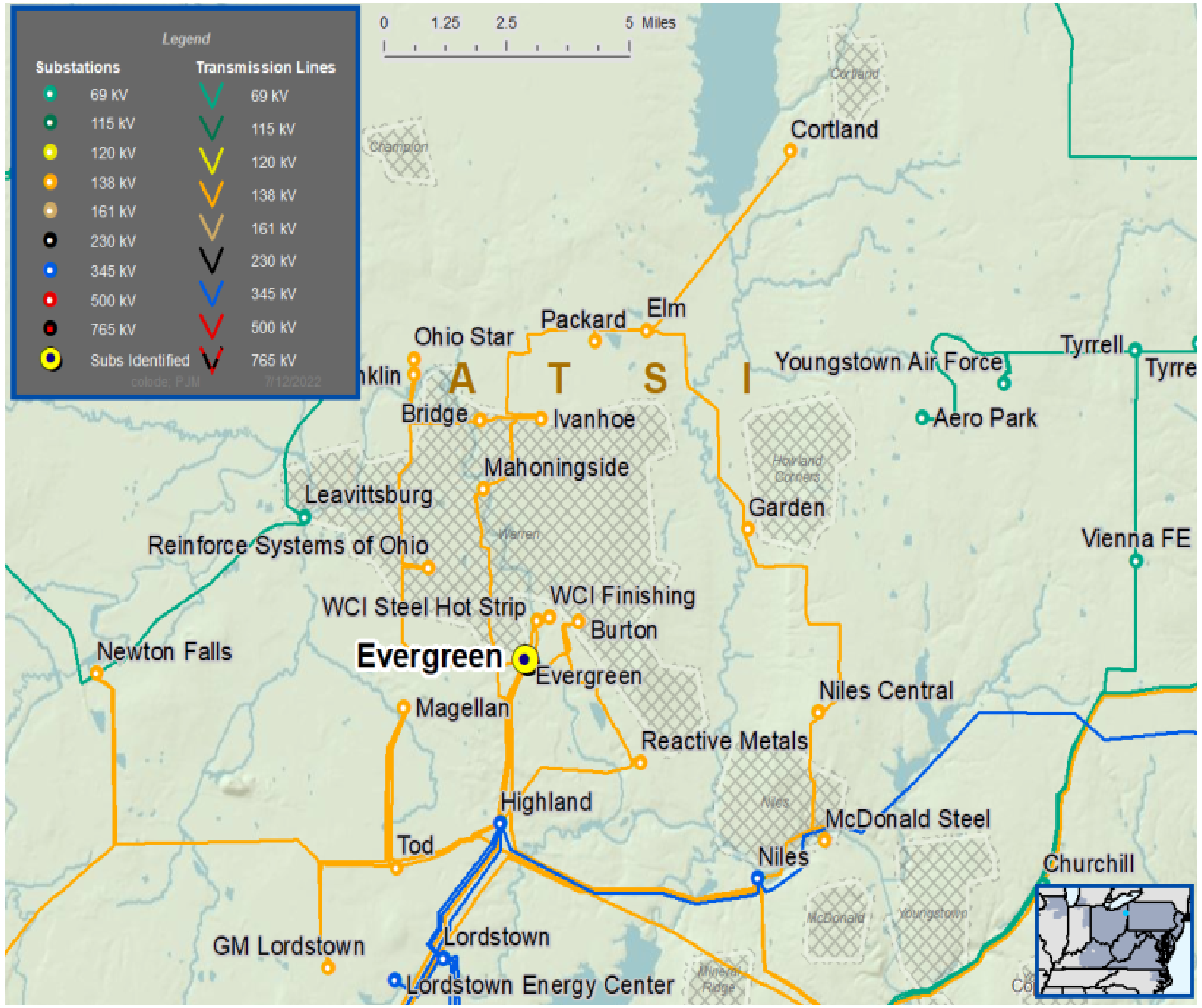
Upgrade Relay Schemes

- Bus protection schemes
- Relay schemes that have a history of mis-operation

Problem Statement

Evergreen Substation 138 kV Equipment and Protection

- BES bus protection is presently performed by a complex scheme that has a history of causing mis-operations at other substations. The scheme uses distributed electromechanical relays to exclude a bus fault rather than detecting the bus fault directly.



ATSI Transmission Zone M-3 Process
Evergreen Substation

Need Number: ATSI-2019-011 (s1954)

Process Stage: Re-Present Solutions Meeting – 07/22/2022

Previously Presented: Needs Meeting 01/14/2019
Solutions Meeting 03/25/2019

Proposed Solution:

Evergreen 138 kV Relay Upgrades

- Replace bus protection scheme with dual differential protection.
- Replace bus PTs due to condition
- Replace 3 breakers (B23, B24, and B27 bus transfer) due to condition and insufficient lack of sufficient CTs for proper system to support standard, redundant bus protection
- Add a new 138 kV bus tie breaker, disconnect switches, and relaying to eliminate exposure of the transmission system related to customer-owned equipment failures/faults in the substation

Transmission Line Ratings:

- Evergreen-Ivanhoe 138 kV Line
    - Before Proposed Solution: 226 MVA WN / 249 MVA WE
    - After Proposed Solution: 226 MVA WN / 286 MVA WE
- Evergreen-Niles 138 kV Line
    - Before Proposed Solution: 224 MVA SN / 293 MVA SE
    - After Proposed Solution: 278 MVA SN / 339 MVA SE

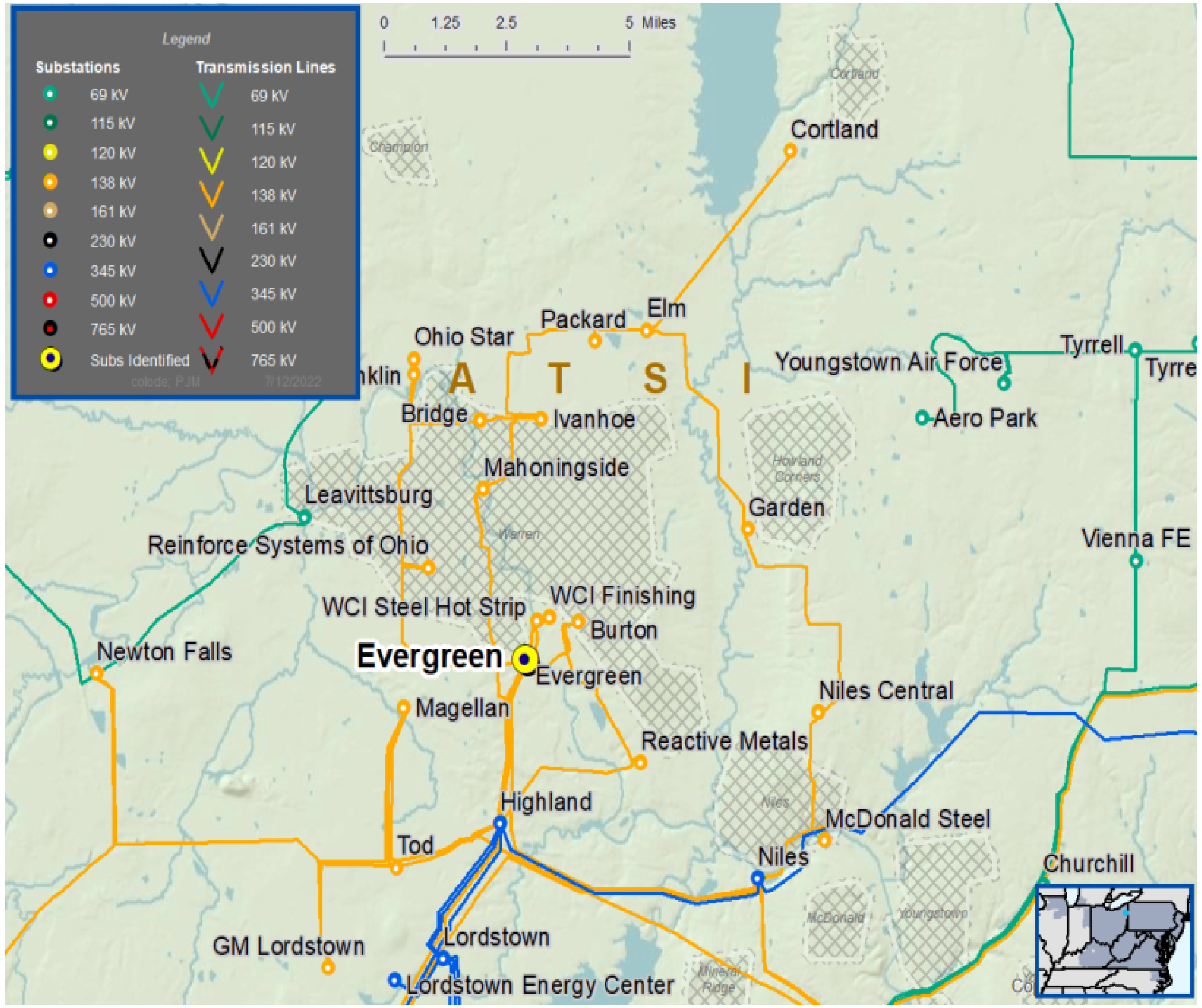
Alternatives Considered:

- Maintain existing protection scheme with high risk for mis-operation.

Estimated Project Cost: $~~1.3M~~ 4.2M

Projected IS Date: ~~3/1/2021~~12/08/2023

Status: ~~Conceptual~~ Engineering



Assumptions

Activity	Timing
Posting of TO Assumptions Meeting information	20 days before Assumptions Meeting
Stakeholder comments	10 days after Assumptions Meeting

Needs

Activity	Timing
TOs and Stakeholders Post Needs Meeting slides	10 days before Needs Meeting
Stakeholder comments	10 days after Needs Meeting

Solutions

Activity	Timing
TOs and Stakeholders Post Solutions Meeting slides	10 days before Solutions Meeting
Stakeholder comments	10 days after Solutions Meeting

Submission of Supplemental Projects & Local Plan

Activity	Timing
Do No Harm (DNH) analysis for selected solution	Prior to posting selected solution
Post selected solution(s)	Following completion of DNH analysis
Stakeholder comments	10 days prior to Local Plan Submission for integration into RTEP
Local Plan submitted to PJM for integration into RTEP	Following review and consideration of comments received after posting of selected solutions

Revision History

7/12/2022 – V1 – Original version posted to pjm.com