# Interconnection System Impact Study
# Final Report – March 7, 2018

## Generator Interconnection Request No. TI-17-0706
## 40 MW Solar Energy Generating Facility
## Baca County, Colorado


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## 1.0 EXECUTIVE SUMMARY

This System Impact Study (SIS) is for Generator Interconnection Request No. TI-17-0706, a proposed 40 MW solar energy Generating Facility (GF) located in Baca County, Colorado. The SIS was prepared in accordance with Tri-State Generation and Transmission Association, Inc. (Tri-State) Generator Interconnection Procedures, and includes steady-state power flow, cost and schedule analyses for interconnection of the project as both a Network Resource and Non-Network Resource.

The proposed Project consists of sixteen (16) TMEIC, PVH-1.2700GR 2.5 MW solar inverters. Three Project point of interconnections (POI) were studied, which include:

1. One (1) 34.5-115 kV transformer and a 200 ft. 115kV generator tie line routed from the Project collector substation to a new 115kV station that intercepts the Lamar – Vilas 115 kV line approximately 19 miles from the Vilas Substation.

2. One (1) 34.5-115 kV transformer and a 19 mile 115kV generator tie line routed from the Project collector substation to the existing Vilas 115kV substation.

3. One (1) 34.5-69 kV transformer and a 19 mile 69kV generator tie line routed from the Project collector substation to the existing Vilas 69kV substation.

Steady-state power flow results:

For the 2018 Heavy Summer case, the addition of the Project caused the Vilas-Walsh 69kV distribution line to exceed its thermal limit following the loss of the Lamar-Willow Creek 115kV line resulting in required distribution system upgrades. A maximum of 28 MW can be interconnected without any required distribution system upgrades.

Additionally, Tri-State will need to ensure that terminal equipment for the Lamar - Willow Creek 115 kV line is upgraded prior to the Project. Presently, the meters and CT's limit this transmission line to 107 MVA.

<u>Sensitivity Analysis</u> modeled the Burlington - Lamar 230kV line, which has a planned in-service date of 2022.

For 2018 Heavy Summer and Light Autumn system conditions, no elements exceeded their emergency thermal limits with addition of the Project.

However, Tri-State will need to ensure that terminal equipment for the Lamar - Willow Creek 115 kV line is upgraded prior to the Project. Presently, the meters and CT's limit this transmission line to 107 MVA.

Reactive power / voltage regulation:

At full 40 MW output, the VAR capability required at the POI ranges from 13.1 MVAR produced (0.95 p.f. lag) to 13.1 MVAR absorbed (0.95 p.f. lead). This is the net MVAR to be produced or absorbed by the GF, depending upon the applicable range of voltage conditions at the POI.

Unit data provided by the Customer shows a reactive capability of 0.926 p.f. lag and 0.926 p.f. lead. The system model provided by the Interconnecting Customer shows that this GF can meet Tri-State's 0.95 p.f. lag to lead criteria at the POI. The Interconnecting Customer is responsible for installing equipment to ensure that the GF can achieve the net 0.95 p.f. lag and lead capability across the 0 to 40 MW net generation output rating as measured at the POI. Tri-State requires a portion of the new MVAR to be supplied by dynamic reactive power equipment.

Transient stability results:

The transient stability analysis only focused on interconnecting the Project to the Lamar – Vilas 115kV line.

Transient stability results identified that the project does not require additional mitigation and is compliant with the NERC/WECC criteria.

Simulation results for heavy summer and light autumn system conditions show that:

1. With the TMEIC solar inverters, the Project had acceptable voltage levels.
2. The solar inverters tripped during a few contingency events, which may be due to numerical anomalies of the models; since the Project tripped shortly after the fault. In order to keep the Project connected for all contingencies, the IC provided settings were revised – see Table 10 and 11.

   Note, the Project is required to remain in service during faults, three-phase or single line-to-ground (SLG) whichever is worse, with normal clearing times of approximately 4 to 9 cycles.
3. Acceptable damping and voltage recovery was observed.

Short circuit results:

The short circuit analysis only focused on interconnecting the Project to the Lamar – Vilas 115kV line. The GF increases the L-G fault by approximately 800 Amps at the 115 kV POI bus. The Main Substation Transformer is a significant source of ground current. The existing Lamar - Vilas 115 kV ground distance and directional ground overcurrent protection (line and remote bus protection) will be ineffective due to the zero sequence infeed at the POI. To mitigate this, a 115 kV ring bus is required at the project POI and the protection scheme will need to be updated accordingly.

The estimated costs for interconnecting the proposed Project for each point of interconnection is as follows (refer to Figures 7 through 9 in Section 5). Cost estimates do not include costs associated with Network Upgrades identified as mitigations to accommodate the Project size:

POI 1: Interconnect to Lamar – Vilas 115kV Line

| | |
|---|---|
| • Interconnection Facilities Costs (Non-Reimbursable): | $ 1.09 M |
| • Network Upgrade Costs (Reimbursable)[1]: | $ 6.77 M |
| TOTAL Cost (2018 dollars) for Interconnection: | $ 7.86 M |

POI 2: Interconnect to Vilas 115kV Substation

| | |
|---|---|
| • Interconnection Facilities Costs (Non-Reimbursable): | $ 1.09 M |
| • Network Upgrade Costs (Reimbursable)[1]: | $ 2.74 M |
| TOTAL Cost (2018 dollars) for Interconnection: | $ 3.83 M |

POI 3: Interconnect to Vilas 69kV Substation

| | |
|---|---|
| • Interconnection Facilities Costs (Non-Reimbursable): | $ 0.98 M |
| • Network Upgrade Costs (Reimbursable)[1]: | $ 2.09 M |
| TOTAL Cost (2018 dollars) for Interconnection: | $ 3.07 M |

Note that the above cost estimates do not include costs associated with distribution system upgrades required to accommodate the Project size. To interconnect the full Project size (40MW), an additional $2.94 M of distribution system upgrades are required for all POIs. Since the affected distribution system is not owned by Tri-State, these costs are not reimbursable. Additionally, the distribution system owner, Southeast Colorado Power Association (SECPA), will have final authority on the appropriate mitigations and associated costs.

The in-service date for this GF will depend on construction of the Interconnection Facilities, Network Upgrades, any distribution system upgrades, and will be a minimum of 18 to 24 months after the execution of a Generator Interconnection Agreement or Engineering and Procurement contract.

The Lamar area is a weaker part of the transmission system and includes several fast-acting VAR control devices. Previous generator interconnections have demonstrated the need for PSCAD/EMTP studies to ensure reliable integration with the existing system. TI-17-0706 will also require PSCAD/EMTP analysis during the facility study phase.

[1] *Note: Network upgrade costs are reimbursed only when payments are made to the Transmission Provider under its Tariff for transmission services with respect to the Generating Facility. Network upgrade costs are not reimbursed if transmission services are not secured from the Transmission Provider.*

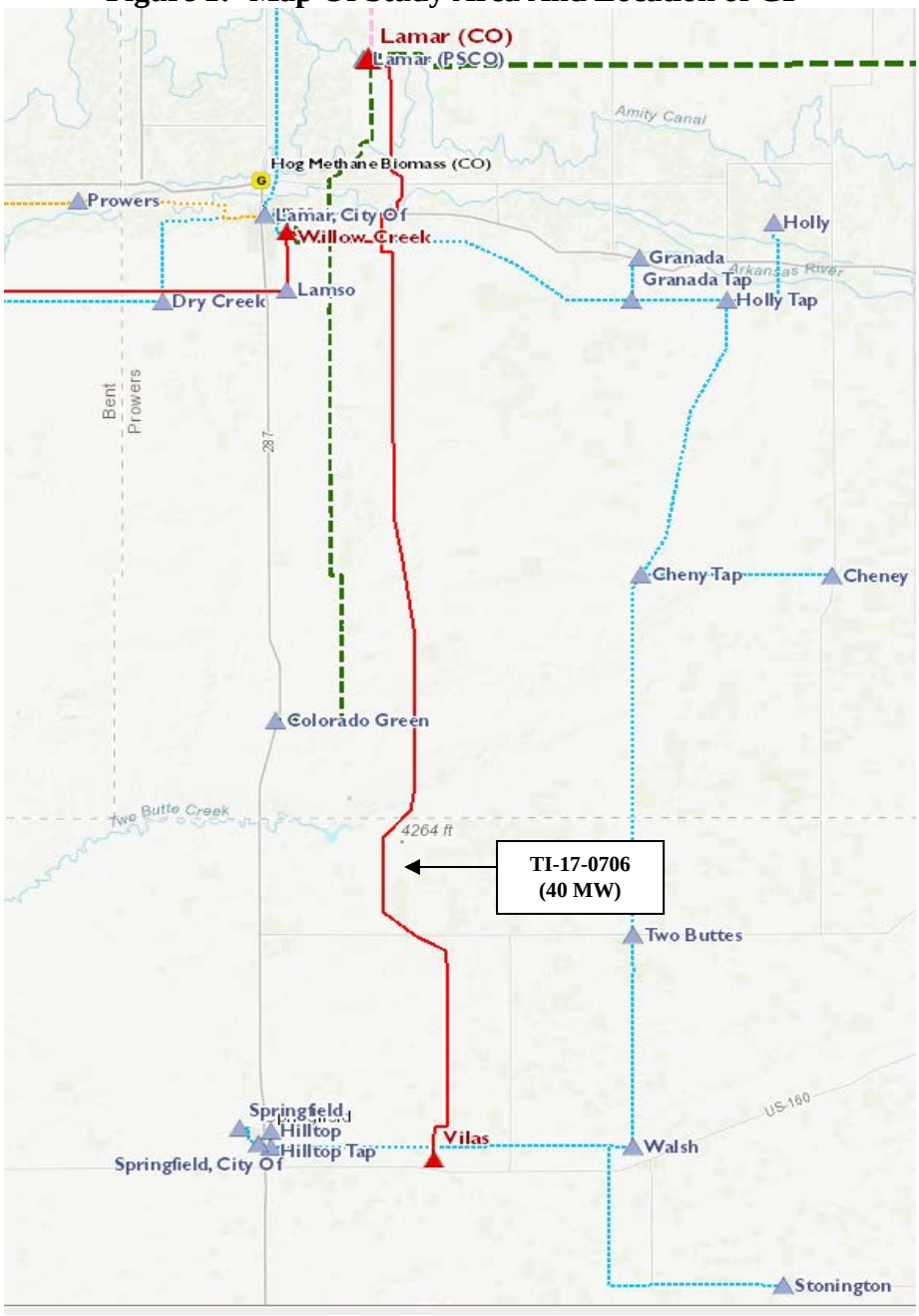
**NOTE:** Pursuant to Section 3.2.2.4 of Tri-State's Generation Interconnection Procedures, "Interconnection Service does not convey the right to deliver electricity to any customer or point of delivery. In order for an Interconnection Customer to obtain the right to deliver or inject energy beyond the Generating Facility Point of Interconnection or to improve its ability to do so, transmission service must be obtained pursuant to the provisions of the Transmission Provider's Tariff by either Interconnection Customer or the purchaser(s) of the output of the Generating facility." See Tri-State's Open Access Same Time Information System (OASIS) web site for information regarding requests for transmission service, related requirements and contact information.

## 2.0 BACKGROUND AND SCOPE

On May 3, 2017, the Interconnecting Customer submitted a Generator Interconnection Request for a 40 MW solar GF to be located approximately 19 miles from the Vilas Substation on the Lamar – Vilas 115 kV line. An Interconnection System Impact Study Agreement was executed on August 28, 2017. The solar inverter model data used in this study is that which was provided by the Customer in its Generator Interconnection Request.

This System Impact Study was prepared in accordance with Tri-State's Generator Interconnection Procedures and relevant FERC, NERC, WECC and Tri-State guidelines. The objectives are: 1) to evaluate the steady state performance of the system with the proposed project, 2) identify Interconnection Facilities and Network Upgrades, 3) check the GF's ability to meet Tri-State's voltage regulation and reactive power criteria, 4) assess the dynamic performance of the transmission system under specified stability contingencies, 5) perform a basic short circuit analysis to provide the estimated maximum (N-0) and minimum (N-1) short circuit currents, and 6) provide a preliminary estimate of the costs and schedule for all necessary Interconnection Facilities and Network Upgrades, subject to refinement in a Facilities Study.

**Figure 1: Map Of Study Area And Location of GF**




## 3.0 GF MODELING DATA

The project consists of one (1) 40 MW equivalent solar generator with one (1) 34.5-115 kV transformer; which interconnects to 1) a new substation that intercepts the Lamar – Vilas 115 kV line approximately 19 miles from the Vilas Substation, 2) the Vilas 115kV substation via a 19 mile gen-tie line or 3) the Vilas 69kV substation via a 19 mile gen-tie line. See Figure 1 for further details. Model data was based on information provided by the Interconnection Customer. The Customer must provide actual data and confirm actual reactive power operating capabilities prior to interconnecting the project, and ultimately prior to being deemed by Tri-State as suitable for commercial operation.

**Generator Data:** The study modeled one (1) equivalent generator. The collector system was modeled as an equivalent generator with a Pmax of 40 MW and reactive capability of 0.926 lag and 0.926 lead, 16.31 and -16.31 MVAR respectively.

**Table 1: Generator Data for Steady-State Power Flow Analyses**

| Unit | Description | *Modeled* |
|---|---|---|
| Pmax | Name plate rating (lumped equivalent gen model) | 40 MW |
| Qmin, Qmax | Reactive capability | 0.926 lag to 0.926 lead |
| Et | Terminal voltage | 0.60 kV |
| RSORCE | Synchronous resistance | 0.0000 p.u. |
| XSORCE | Synchronous reactance | 1.0000 p.u. |

**Table 2: Power Flow Data for Individual Generating Units**

| Unit | Description | *Manufacturer* |
|---|---|---|
| MBase | Generator MVA base | 2.7 MVA |
| Prated | Generator active power rating | 2.5 MW |
| Pmin | Minimum generation | 0.2 MW |
| Qmin, Qmax | Reactive capability | 0.926 lag to 0.926 lead |
| Vrated | Terminal voltage | 0.60 kV |
| Srated | Unit transformer Rating | 2.75 MVA |
| Xt | Unit Transformer Reactance (on transformer base) | 5.75% |
| Xt/Rt | Unit Transformer X/R ratio | 8.0 |

**34.5 kV Collector System:** The medium voltage collector system was modeled with equivalent impedances provided by the Customer. The solar system was interconnected to POI 1 and 2 with a 34.5-115 kV transformer and POI 3 with a 34.5-69 kV transformer.

**Main GF Substation Transformers:** The substation transformers were modeled with ratings of 40/54/67 MVA and a voltage ratio of 34.5 kV (gnd-wye) - 115 kV (or 69 kV) (gnd-wye). The transformer impedance was assumed to be 7% on the 40 MVA base ONAN rating with X/R of 15.

**115 kV or 69 kV Generator Tie Lines:**

POI to New 115kV substation: The GF to POI line impedance was based on 200 feet of 1-133 kcmil ACSR. The continuous thermal rating is 54 MVA with an impedance of R = 1.950E-4, X = 6.820E-4, B = 2.00E-5. All values are in p.u.

POI to Vilas 115kV substation: The GF to POI line impedance was based on nineteen (19) miles of 1-795 kcmil ACSR. The continuous thermal rating is 107 MVA with an impedance of R = 1.689E-2, X = 1.0687E-1, B = 1.5097E-2. All values are in p.u.

POI to Vilas 69kV substation: The GF to POI line impedance was based on nineteen (19) miles of 1-795 kcmil ACSR. The continuous thermal rating is 107 MVA with an impedance of R = 6.081E-3, X = 3.8474E-2, B = 5.4330E-3. All values are in p.u.

# 4.0 STEADY-STATE POWER FLOW ANALYSIS

The Customer requested that the Project be studied as a Network Resource. Network Resource Interconnection integrates a Generating Facility with the Transmission Provider's Transmission System in a manner comparable to the way the Transmission Provider integrates its own generating facilities to serve its native load customers.

## 4.1 Criteria and Assumptions

General Electric PSLF version 21.0_02 software was used for performing the steady-state power flow analysis with the following study criteria:

1. Tri-State's GIP 2018 HS and LA (18hs4a.sav) base cases were developed from WECC approved seed cases with updates from the latest available loads and resources data, topology (line and transformer ratings, planned and budgeted projects, etc.), and updates received from regional utilities and Affected Systems. These GIP base cases were further updated by Tri-State to reflect appropriate generation dispatching. The following base cases were utilized:
    a. 2018 Heavy Summer cases with and without the Project
    b. 2018 Light Autumn cases with and without the Project
2. To stress the system in the area of the Project, local Tri-State and Xcel resource transmission ownership rights in the Boone – Lamar transmission line (196 MW) and Tri-State's Twin Buttes II resource (75 MW) were dispatched at maximum output. Following is a summary of the modeled local generation.

**Table 3: Local Network Resource Generation Dispatches**

| Case | Description | Twin Buttes I | Twin Buttes II | CO Green East | CO Green West | Lamar DC Tie |
|---|---|---|---|---|---|---|
| 1 | 2018 Heavy Summer | 75 | 75 | 81 | 40 | 0 |
| 2 | 2018 Light Autumn | 34 | 75 | 81 | 81 | 0 |

3. The request was studied as a stand-alone project and did not include other generation requests that may exist in Tri-State's GIP queue.
4. The proposed Project output was accommodated by displacing generation resources at Craig Units 1, 2 and/or 3 (applicable as if this GF were a Network Resource, but with results similar to a Non-Network Resource).
5. Terminal equipment for the Lamar - Willow Creek 115 kV line was assumed to be upgraded prior to the Project. Presently, the meters and CT's limit this transmission line to 107 MVA.

6. Power flow (N-0) solution parameters were as follows: Transformer LTC Taps – locked taps; Area Interchange Control – disabled; Phase Shifters and DC Taps – non-adjusting; and Switched Shunts - enabled.

7. Power flow contingencies (N-1) utilized the following solution settings: Transformer LTC Taps – locked taps; Area Interchange Control – disabled; Phase Shifters and DC Taps – non-adjusting; and Switched Shunts – locked all. (Not allowing these voltages regulating solution parameters to adjust provides worse case results.) However, the Walsh 69kV shunt capacitor (3 - 5.4 MVAr) has quick switching relay; therefore, this shunt was allowed to switch during contingency events.

8. All buses, lines and transformers with nominal voltages greater than or equal to 69 kV in the Tri-State and surrounding areas were monitored in all study cases for N-0 and N-1 system conditions.

9. All three of the nearby study areas (PNM, Tri-State, and Xcel/PSCo) were investigated using the same overload criteria. Any thermal loading greater than 98% of the branch rating with a thermal overload increase of 2% or more was tabulated.

10. Analysis assumes that the GF controls the high voltage bus at the POI and should not negatively impact any controlled voltage buses on the transmission system.

11. Post-contingency power transfer capability is subject to voltage constraints as well as equipment ratings. The Project was tested against NERC/WECC reliability criteria and additions/exceptions are as listed in the following Table 4:

**Table 4: Voltage Criteria**

| Tri-State Voltage Criteria for Steady State Power Flow Analysis | | |
|---|---|---|
| **Conditions** | **Operating Voltages** | **Delta-V** |
| Normal (P0 Event) | 0.95 - 1.05 | N/A |
| Contingency (P1 Event) | 0.90 - 1.10 | 8% |
| Contingency (P2-P7 Event) | 0.90 - 1.10 | None |

## 4.2 Voltage Regulation and Reactive Power Criteria

1. The generating facility (GF) must be capable of either producing or absorbing VAR as measured at the POI to achieve a 0.95 power factor (pf) across the range of near 0% to 100% of facility MW rating, as calculated on the basis of nominal generator high-side bus voltage (1.0 per unit voltage).
2. The GF may be required to either produce VAR or absorb VAR from .90 per unit to 1.10 per unit voltage at the POI, with typical target regulating voltage being 1.03 per unit voltage.

3. The GF is required to supply a portion of the VAR on a continuously adjustable or dynamic basis. The amount of continuously adjustable VAR shall be equivalent to a minimum of 0.95 pf produced or absorbed at the high side of the generator substation bus across the full range (0 to 100%) of rated MW output. The remaining VAR required to meet the 0.95 pf criteria may be achieved with switched reactive devices.
4. The GF may utilize switched capacitors or reactors as long as the individual step size results in less than 3% change at the POI operating bus voltage. This step change voltage magnitude shall be calculated based on the minimum system (N-1) short circuit POI bus MVA level as supplied by Tri-State.
5. When the GF is not producing any real power (near 0 MW), the VAR exchange at the POI shall be near 0 MVAR, i.e., VAR neutral.

### 4.3 Steady-State Power Flow Results

1. N-0 (System Intact, Category P0) Study Results:

   The proposed project generation 40 MW can be added without thermal or voltage violations with all lines in-service.

2. N-1 (Single Contingency, Category P1) Study Results:

   Results for N-1 contingencies using the 2018 Heavy Summer and 2018 Light Autumn cases are shown in Tables 5 and 6 below.

   i. With the 2018 Heavy Summer case, the addition of the Project caused the Vilas-Walsh 69kV distribution line to exceed its thermal limit following the loss of the Lamar-Willow Creek 115kV line. A maximum of 28 MW can be interconnected without any required distribution system upgrades.

      Additionally, Tri-State will need to ensure that terminal equipment for the Lamar - Willow Creek 115 kV line is upgraded prior to the Project. Presently, the meters and CT's limit this transmission line to 107 MVA.

   ii. With the 2020 Light Autumn case, no elements exceeded their emergency thermal limit with addition of the Project.

   iii. Sensitivity: Burlington – Lamar 230kV line In-Service, 2018 Heavy Summer

      With the 2018 Heavy Summer and Light Autumn cases, no elements exceeded their emergency thermal limit with addition of the Project.

      However, Tri-State will need to ensure that terminal equipment for the Lamar - Willow Creek 115 kV line is upgraded prior to the Project. Presently, the meters and CT's limit this transmission line to 107 MVA.

3. Steady-state voltage violations: With an operating voltage range between 0.90 p.u. to 1.10 p.u., under single contingency outage conditions there were no voltage violations with the GF at full output.

4. Steady-state contingency voltage deviation: Each Balancing Authority's ΔV requirement was applied as per Table 4. There were no ΔV violations at monitored buses.

5. Reactive power required at the POI:

   At full 40 MW output, the VAR capability required at the POI ranges from 13.1 MVAR produced (0.95 p.f. lag) to 13.1 MVAR absorbed (0.95 p.f. lead). This is the net MVAR to be produced or absorbed by the GF, depending upon the applicable range of voltage conditions at the POI.

   Unit data provided by the Customer shows a reactive capability of 0.926 p.f. lag and 0.926 p.f. lead. The system model provided by the Interconnecting Customer shows that this GF can meet Tri-State's 0.95 p.f. lag to lead criteria at the POI. See Table 9.

   The Customer is responsible for installing equipment that will ensure that the GF can achieve the net 0.95 p.f. lag and lead capability across the 0 to 40 MW net generation output as measured at the POI. Tri-State requires a portion of the new MVAR to be supplied by dynamic reactive power equipment.

**Table 5: 2018 Heavy Summer – Thermal Results**

| AFFECTED ELEMENT | CONTINGENCY | Emergency Rating (Amps) | Pre-Project Percent Loading | POI 1, Post-Project Percent Loading | POI 2, Post-Project Percent Loading | POI 3, Post-Project Percent Loading | Maximum Output w/out Upgrade (MW) | Owner | Notes - Limiting Elements |
|---|---|---|---|---|---|---|---|---|---|
| LAMAR_CO - WILOW_CK 115kV | VILAS 115/69kV Transformer | 537 | 96.2 | 103.4 | 103.9 | 68.5 | **22/20** | TSGT | Note 1. |
| LAMAR_CO - WILOW_CK 115kV | VILAS - PROJECT_POI 115kV† | 537 | 96.6 | 103.4 | 68.5 | 68.5 | **22** | TSGT | Note 1. |
| VILAS - WALSH 69kV | LAMAR_CO – WILLOW_CK 115kV | 324 | 91.6 | 109.5 | 113.2 | 117.2 | **28** | SECPA | Note 2. |
| WILOW_CK 115/69 kV Tran T1 | VILAS 115/69kV Transformer | 32.3 MVA | 101.9 | 101.8 | 102.4 | 40.1 | 40 | TSGT | Ok. |
| WILOW_CK 115/69 kV Tran T2 | VILAS 115/69kV Transformer | 31.6 MVA | 104.1 | 104.1 | 104.7 | 41.0 | 40 | TSGT | Ok. |
| WILOW_CK 115/69 kV Tran T1 | VILAS - PROJECT_POI 115kV† | 32.3 MVA | 102.2 | 101.9 | 39.6 | 40.0 | 40 | TSGT | Reduces flow |
| WILOW_CK 115/69 kV Tran T2 | VILAS - PROJECT_POI 115kV† | 31.6 MVA | 104.5 | 104.2 | 40.5 | 40.8 | 40 | TSGT | Reduces flow |
| BOONE - LAJUNTAT 115 kV | BOONE-LAMAR_CO 230kV, Trip CO Green and Twin Butte Wind | 597 | 108.9 | 57.4 | 57.7 | 57.8 | 40 | TSGT | Reduces flow |
| WILOW_CK 115/69 kV Tran T2 | WILOW_CK 115/69 kV Tran T1 | 31.6 MVA | 118.2 | 104.7 | 99.5 | 95.2 | 40 | TSGT | Reduces flow |
| WILOW_CK 115/69 kV Tran T1 | WILOW_CK 115/69 kV Tran T2 | 32.3 MVA | 115.6 | 102.5 | 97.3 | 93.1 | 40 | TSGT | Reduces flow |
| | | | | | | | | | |

† For POI 2 and 3 this contingency is loss of the Lamar - Vilas 115kV line.

Note 1. Terminal equipment for the Lamar - Willow Creek 115 kV line is to be upgraded prior to the Project. Presently, the meters and CT's limit this transmission line to 107 MVA.

Note 2. Vilas-Walsh 69kV exceeds the thermal limit of the conductor. This may require rebuilding the line to accommodate the full 40MW output. However, since the line is not owned by Tri-State, Southeast Colorado Power Association (SECPA) will have final authority on the appropriate mitigations and associated costs.

**Table 6: 2018 Light Autumn – Thermal Results**

| AFFECTED ELEMENT | CONTINGENCY | Emergency Rating (Amps) | Pre-Project Percent Loading | POI 1, Post-Project Percent Loading | POI 2, Post-Project Percent Loading | POI 3, Post-Project Percent Loading | Maximum Output w/out Upgrade (MW) | Owner | Notes - Limiting Elements |
|---|---|---|---|---|---|---|---|---|---|
| PORTLAND - SKALA 115 kV | MIDWAYBR - W CANON 230kV | 557 | 101.0 | 104.3 | 104.3 | 104.3 | 40 | BHEC | |

**Table 7: 2018 Heavy Summer – Thermal Results, Sensitivity: Burlington – Lamar 230kV Line**

| AFFECTED ELEMENT | CONTINGENCY | Emergency Rating (Amps) | Pre-Project Percent Loading | POI 1, Post-Project Percent Loading | POI 2, Post-Project Percent Loading | POI 3, Post-Project Percent Loading | Maximum Output w/out Upgrade (MW) | Owner | Notes - Limiting Elements |
|---|---|---|---|---|---|---|---|---|---|
| LAMAR_CO - WILOW_CK 115kV | BOONE - LAMAR_CO 230kV | 537 | 94.6 | 100.2 | 98.6 | 97.1 | 40 | TSGT | Note 1. |
| WILOW_CK 115/69 kV Tran T1 | VILAS - PROJECT_POI 115kV† | 32.3 MVA | 101.6 | 101.3 | 40.2 | 40.7 | 40 | TSGT | Ok. |
| WILOW_CK 115/69 kV Tran T2 | VILAS - PROJECT_POI 115kV† | 31.6 MVA | 103.8 | 103.5 | 41.1 | 41.6 | 40 | TSGT | Ok. |
| WILOW_CK 115/69 kV Tran T1 | VILAS 115/69kV Transformer | 32.3 MVA | 101.4 | 101.2 | 101.6 | 40.7 | 40 | TSGT | Ok. |
| WILOW_CK 115/69 kV Tran T2 | VILAS 115/69kV Transformer | 31.6 MVA | 103.7 | 103.4 | 103.8 | 41.6 | 40 | TSGT | Reduces flow |
| WILOW_CK 115/69 kV Tran T2 | WILOW_CK 115/69 kV Tran T1 | 31.6 MVA | 119.6 | 106.8 | 101.5 | 97.3 | 40 | TSGT | Reduces flow |
| WILOW_CK 115/69 kV Tran T1 | WILOW_CK 115/69 kV Tran T2 | 32.3 MVA | 117.0 | 104.5 | 99.3 | 95.2 | 40 | TSGT | Reduces flow |

† For POI 2 and 3 this contingency is loss of the Lamar - Vilas 115kV line.

Note 1. Terminal equipment for the Lamar - Willow Creek 115 kV line is to be upgraded prior to the Project. Presently, the meters and CT's limit this transmission line to 107 MVA.

**Table 8: 2018 Light Autumn – Thermal Results, Sensitivity: Burlington – Lamar 230kV Line**

| AFFECTED ELEMENT | CONTINGENCY | Emergency Rating (Amps) | Pre-Project Percent Loading | POI 1, Post-Project Percent Loading | POI 2, Post-Project Percent Loading | POI 3, Post-Project Percent Loading | Maximum Output w/out Upgrade (MW) | Owner | Notes - Limiting Elements |
|---|---|---|---|---|---|---|---|---|---|
| PORTLAND - SKALA 115 kV | MIDWAYBR - W CANON 230kV | 557 | 99.8 | 102.7 | 102.7 | 102.7 | 40 | BHEC | |

**Table 9: Reactive Power Delivered to the Collector Bus and at POI Bus**
**Full Project Size: 40.0 MW, TMEIC, PVH-1.2700GR 2.5 MW-16 Units**

| Base Case | Fixed P.F. at MV Gen Equiv Collector Bus | P, Q, V At Gen Equiv MV | | | Net P, Q, V, PF At HV POI Bus | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Pgen (MW) | Qgen (MVAR) | Voltage (p.u.) | P (MW) | Q (MVAR) | PF at POI | Voltage (p.u.) | MVAR to meet PF Reqd at POI of 0.95 | MVAR Short(+) or Excess(-) |
| HS Base Case – 0.926 p.f. lag (producing MVAR) | | | | | | | | | | |
| | 0.926 | 0 | 0.0 | 0.95 | 0 | 0.18 | 0 | 0.95 | 0 | -0.18 |
| | 0.926 | 10 | 4.1 | 0.96 | 9.96 | 4.1 | 0.925 | 0.95 | 3.3 | 0.8 |
| | 0.926 | 20 | 8.2 | 0.968 | 19.86 | 7.64 | 0.933 | 0.95 | 6.5 | 1.1 |
| | 0.926 | 30 | 12.2 | 0.977 | 29.68 | 10.73 | 0.940 | 0.95 | 9.8 | 1.0 |
| | 0.926 | 40 | 16.3 | 0.985 | 39.44 | 13.6 | 0.945 | 0.95 | 13.0 | 0.6 |
| LA Base Case – 0.926 p.f. lead (absorbing MVAR) | | | | | | | | | | |
| | -0.926 | 0 | 0 | 1.05 | 0 | 0.23 | 0 | 1.05 | 0 | -0.2 |
| | -0.926 | 10 | -4.1 | 1.047 | 9.99 | -3.94 | 0.930 | 1.05 | -3.3 | -0.7 |
| | -0.926 | 20 | -8.2 | 1.044 | 19.89 | -8.54 | 0.919 | 1.05 | -6.5 | -2.0 |
| | -0.926 | 30 | -12.2 | 1.04 | 29.74 | -13.36 | 0.912 | 1.05 | -9.8 | -3.6 |
| | -0.926 | 40 | -16.3 | 1.036 | 39.51 | -18.64 | 0.904 | 1.05 | -13.0 | -5.7 |

# 5.0 DYNAMIC STABILITY ANALYSIS

## 5.1 Criteria and Assumptions

### 5.1.1 NERC/WECC Dynamic Criteria

General Electric PSLF version 21.0_02 software was used for dynamic stability analysis. Dynamic stability analysis was performed in accordance with the dynamic performance criteria shown in Figures W-1 and W-2 from the NERC/WECC TPL-001-WECC-CRT-3 Transmission System Planning Performance Criteria.

**Figure W-1 Bus Voltage Normal Recovery 1**

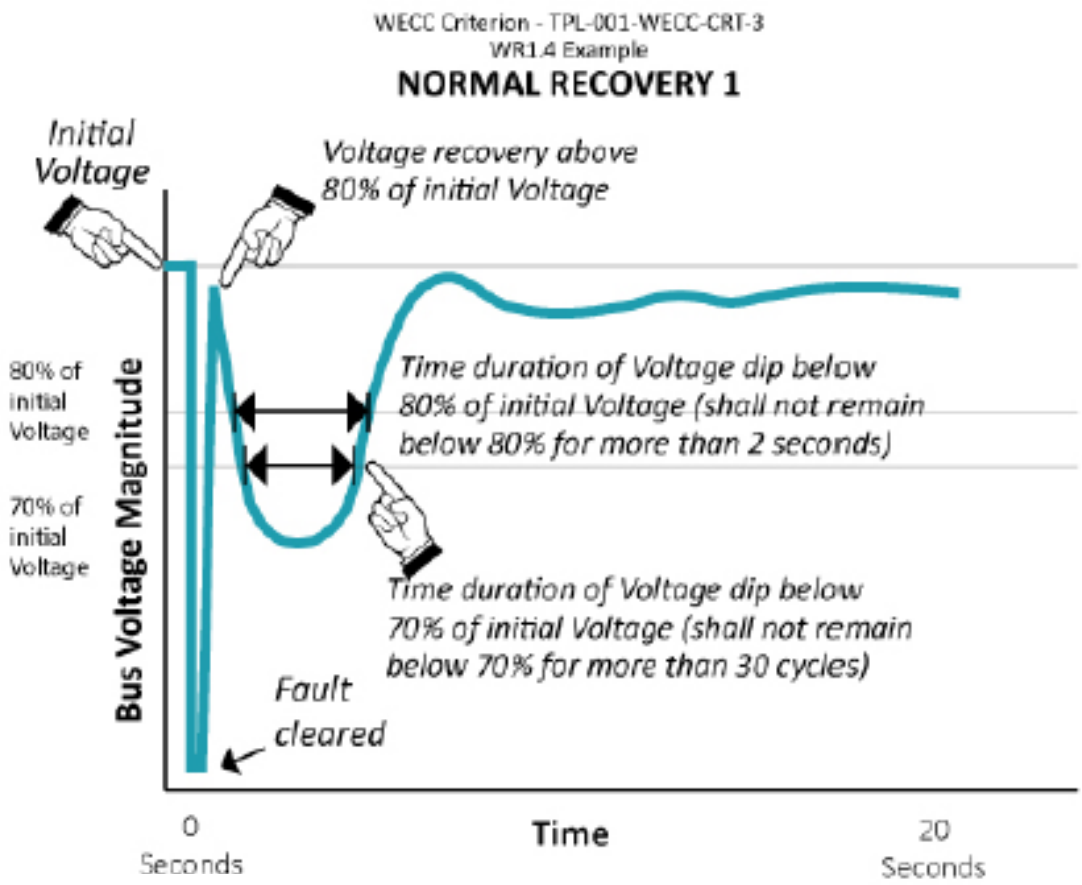
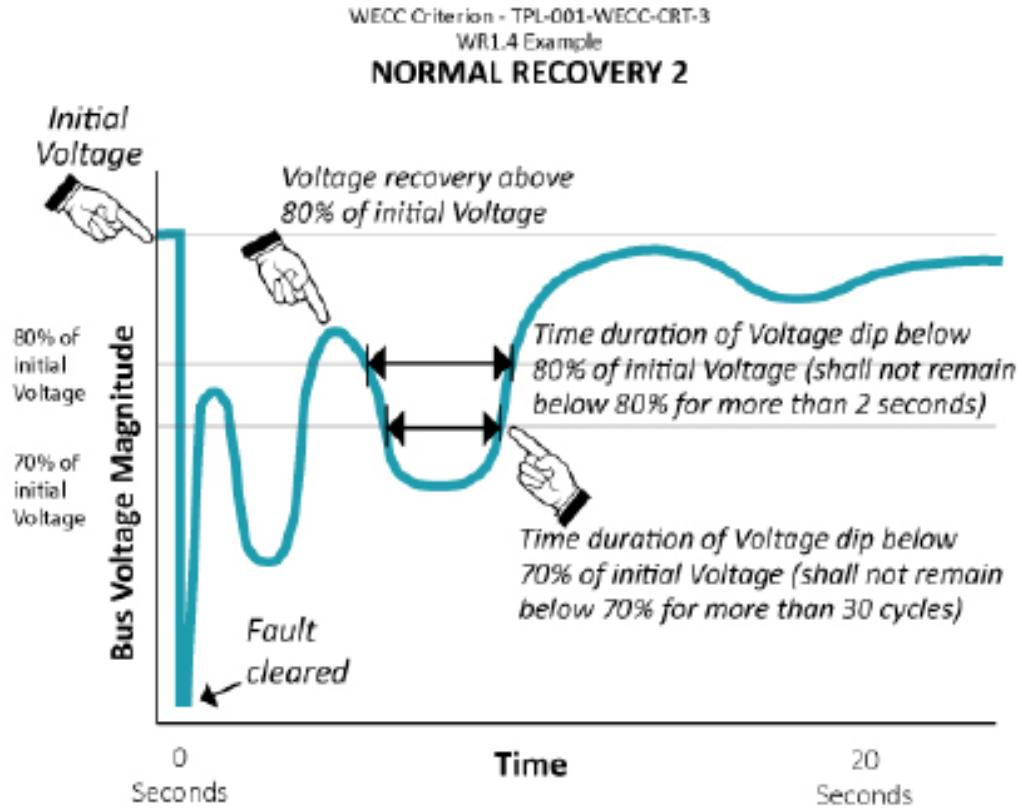



***Table W-1***

**Figure W-2 Bus Voltage Normal Recovery 2**




In addition, the NERC/WECC standard states that "[r]elay action, fault clearing time, and reclosing practice should be represented in simulations according to the planning and operation of the actual or planned systems. When simulating post transient conditions, actions are limited to automatic devices and no manual action is to be assumed."

### 5.1.2 Voltage Ride-Through Requirements

1. The GF shall be able to meet the dynamic response Low Voltage Ride Through (LVRT) requirements consistent with the latest proposed WECC / NERC criteria, in particular, as per the Tri-State GIP, Appendix G and FERC Order 661a for LVRT.

2. Generating plants are required to remain in service during faults, three-phase or single line-to-ground (SLG) whichever is worse, with normal clearing times of approximately 4 to 9 cycles, SLG faults with delayed clearing, and subsequent post-fault voltage recovery to pre-fault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the circuit breaker clearing times of the effected system to which the IC facilities are interconnecting. The

maximum clearing time the solar generating plant shall be required to withstand for a fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for faults, the solar generating plant may disconnect from the transmission system. A solar generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the POI. The IC may not disable low voltage ride through equipment while the plant is in-service.

3. This requirement does not apply to faults that may occur between the solar generator terminals and the POI.
4. Solar generating plants may meet the LVRT requirements by the performance of the generators or by installing additional equipment, e.g., Static VAR Compensator, or by a combination of generator performance and additional equipment.

## 5.2 Base Case Model Assumptions

1. The IC provided a dynamic stability model with TMEIC solar inverter parameters.
2. Three (3) point of interconnections were identified in the power flow portion of the analysis. However, the transient stability analysis only focused on interconnecting the Project to the Lamar – Vilas 115kV line.
3. The collector system was modeled with an equivalent collector system and one 115/34.5 kV substation transformer.
4. The Walsh 69kV substation has three (3) 5.4 MVAr shunt capacitors. In addition, the shunt capacitors have an overvoltage setting that sequentially switches the shunt capacitors off-line if the Walsh 69kV voltage is greater than 1.1 per unit. No under-voltage settings control the Walsh 69kV shunt capacitors – manual operation.
5. An under-voltage relay that monitors voltage at the Vilas 69kV substation will trip the Hilltop and Springfield load whenever the voltage is less than 0.9 per unit for four (4) seconds.
6. An under-voltage relay that monitors frequency at the Vilas 69kV substation will trip the Hilltop and Springfield load whenever the frequency is less than 59.1 Hz for 0.1 seconds (6 cycles).
7. Two (2) parameters were changed in the Power Plant controller model (repc_a) because the equivalent generator was not adjusting reactive power for changes in voltage. The “vfrz” (If Vreg < vfrz, then state s2 is frozen) was changed from 0.9 to 0.0 and the “dbd” (deadband) from -0.001 to 0.0.
8. Since, the provided model resulted in a voltage spike during faulted conditions, the under/over voltage generator trip relay (lhvrt) and under/over frequency generator trip relay (lhfrt) were modified in order to keep the Project connected during faulted conditions. A summary of voltage and frequency trip settings is provided in the following tables – original values are listed in parenthesis.

**Table 10 Voltage Ride Through Duration Settings**

| Voltage (pu) | Time (sec) | | Voltage (pu) | Time (sec) |
|---|---|---|---|---|
| 1.20 | **0.1** (0.0) | | 0.45 | 0.15 |
| 1.175 | 0.2 | | 0.65 | 0.30 |
| 1.15 | 0.5 | | 0.75 | 2.0 |
| 1.10 | 1.0 | | 0.90 | 3.0 |

**Table 11 Voltage Ride Through Duration Settings**

| Frequency (Hz) | Time (sec) | | Frequency (Hz) | Time (sec) |
|---|---|---|---|---|
| 61.7 | **0.3** (0.0) | | 57 | **0.3** (0.0) |
| 61.6 | 30 | | 57.3 | 0.75 |
| 60.6 | 180 | | 57.8 | 7.5 |
| | | | 58.4 | 30 |
| | | | 59.4 | 80 |

## 5.3 Methodology

Dynamic stability was evaluated as follows:

1. The 2018 HS and 2018 LA base cases were utilized with the GF in service.
2. System stability is observed by monitoring voltage and relative rotor angles of local machines and system damping.
3. Three-phase faults were simulated for all contingencies. Two contingencies were simulated for each line: a fault was applied at the near end and then applied at the far end of the transmission line. The corresponding stability contingencies to evaluate the solar farm's compliance with NERC/WECC criteria for dynamic stability are listed in the following table.

**Table 12 - List of Dynamic Stability Contingencies**

| Dynamic Stability Contingencies | | |
|---|---|---|
| No. | Description | Bus Numbers |
| 1 | 5-cycle 3-phase fault at POI 17-0706 115 kV, trip Project POI – HS_17-0706 115 kV line | 70905 - 70906 |
| 2 | 5-cycle 3-phase fault at POI 17-0706 115 kV, trip Project POI – Lamar 115 kV line | 70905 - 70253 |
| 3 | 5-cycle 3-phase fault at POI 17-0706 115 kV, trip Project POI – Vilas 115 kV line | 70905 - 70452 |
| 4 | 5-cycle 3-phase fault at Vilas 115 kV, trip Vilas 115-69 kV Transformer | 70452 - 70453 |
| 5 | 7-cycle 3-phase fault at Vilas 69 kV, trip Vilas – Walsh 69 kV line | 70453 - 70460 |
| 6 | 7-cycle 3-phase fault at Walsh 69 kV, trip Walsh – Willow Creek 69 kV line | 70460 - 70473 |
| 7 | 5-cycle 3-phase fault at Willow Creek 115 kV, trip Willow Creek – Lamar 115 kV line | 70472 - 70253 |
| 8 | 5-cycle 3-phase fault at Willow Creek 115 kV, trip Willow Creek – La Junta T 115 kV line | 70472 - 70247 |
| 9 | 4-cycle 3-phase fault at Lamar 230 kV, trip Lamar 230-115 kV No1 and No.2 Transformers | 70255 - 70253 |
| 10 | 5-cycle 3-phase fault at Lamar 230 kV, trip Lamar – Twin Butte 230 kV line | 70253 - 72006 |

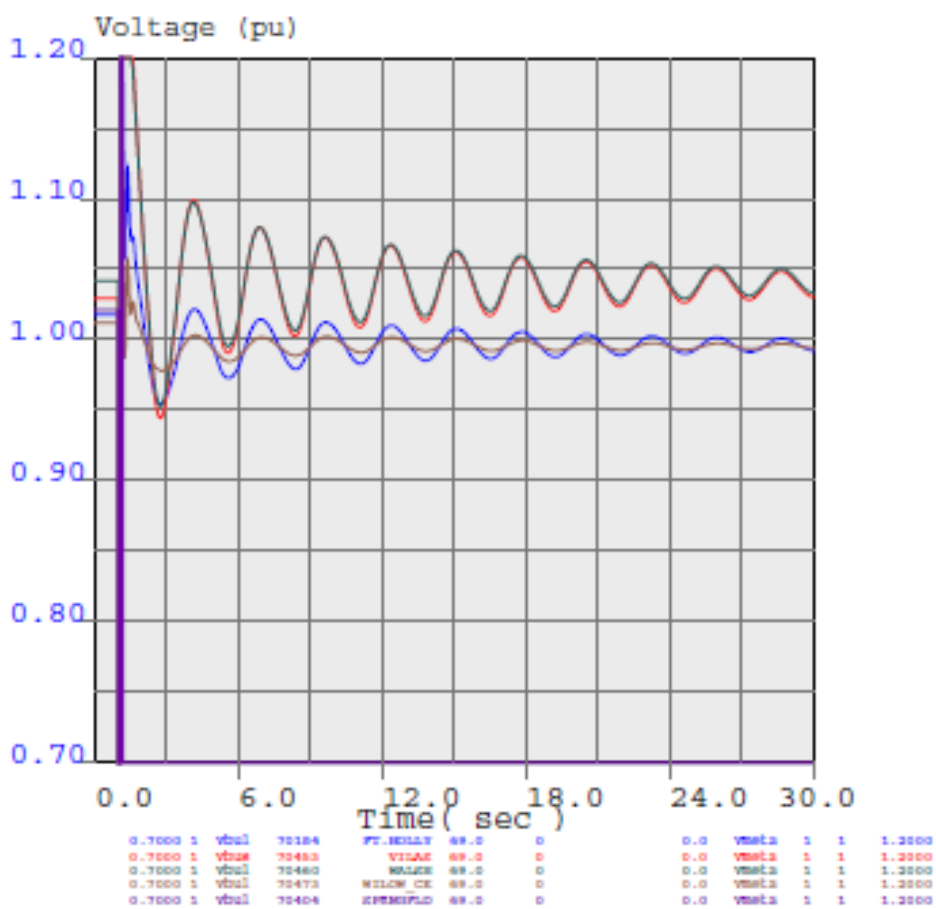
| Dynamic Stability Contingencies | | |
|---|---|---|
| No. | Description | Bus Numbers |
| 11 | 5-cycle 3-phase fault at Burlington 230 kV, trip Boone – Lamar 230 kV line | 70061 - 70254 |
| 12 | 5-cycle 3-phase fault at Boone 230 kV, trip Boone – Midway 230 kV line | 70061 - 70286 |
| 13 | 5-cycle 3-phase fault at Boone 230 kV, trip Boone – Comanche 230 kV line | 70061 - 70122 |
| 14 | 5-cycle 3-phase fault at Boone 230 kV, trip Boone 230-115 kV Transformer | 70061 -70060 |
| | Sensitivity: Burlington – Lamar 230kV line Modeled | |
| 15 | 5-cycle 3-phase fault at Burlington 230 kV, trip Burlington – Lamar 230 kV line | 73036 - 70255 |
| 16 | 5-cycle 3-phase fault at Burlington 230 kV, trip Burlington – Wray 230 kV line | 73036 - 73224 |

## 5.4 Results

Study results identified that the local area system damping is slow with three (3) Walsh shunt capacitors in-service (see Figure 3) for loss of the Project POI – Lamar 115kV line with the fault at the Lamar end of the line. However, the system damps out over time.

When the fault is at the Project POI for loss of the Project POI – Lamar 115kV line, the system damps out much quicker.

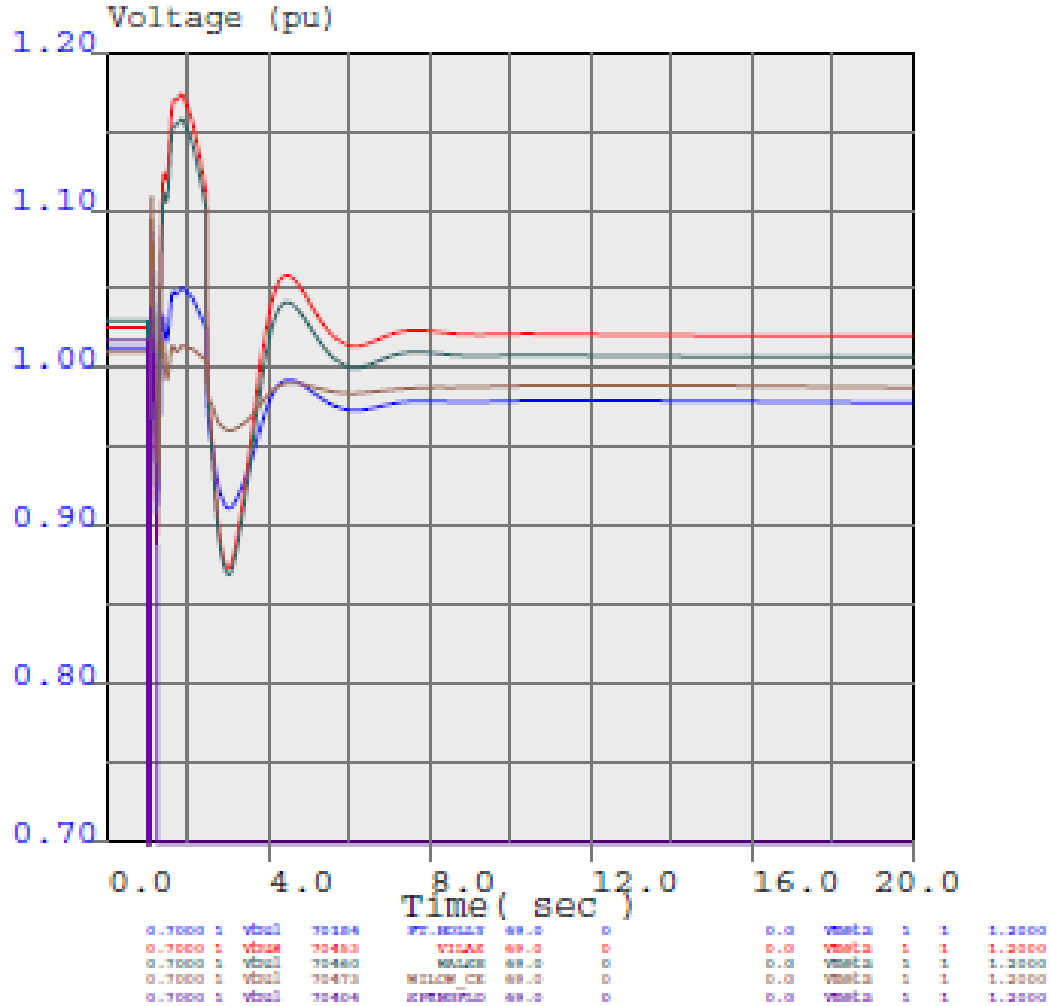
**Figure 3 Loss of Project POI-(Lamar) 230kV line: Three (3) Walsh Shunts In-Service**



With two (2) Walsh shunt capacitors in-service, the system damping is much quicker – see Figure 4. However, the Springfield and Hilltop generation trips by the Vilas 69kV under-frequency relay.

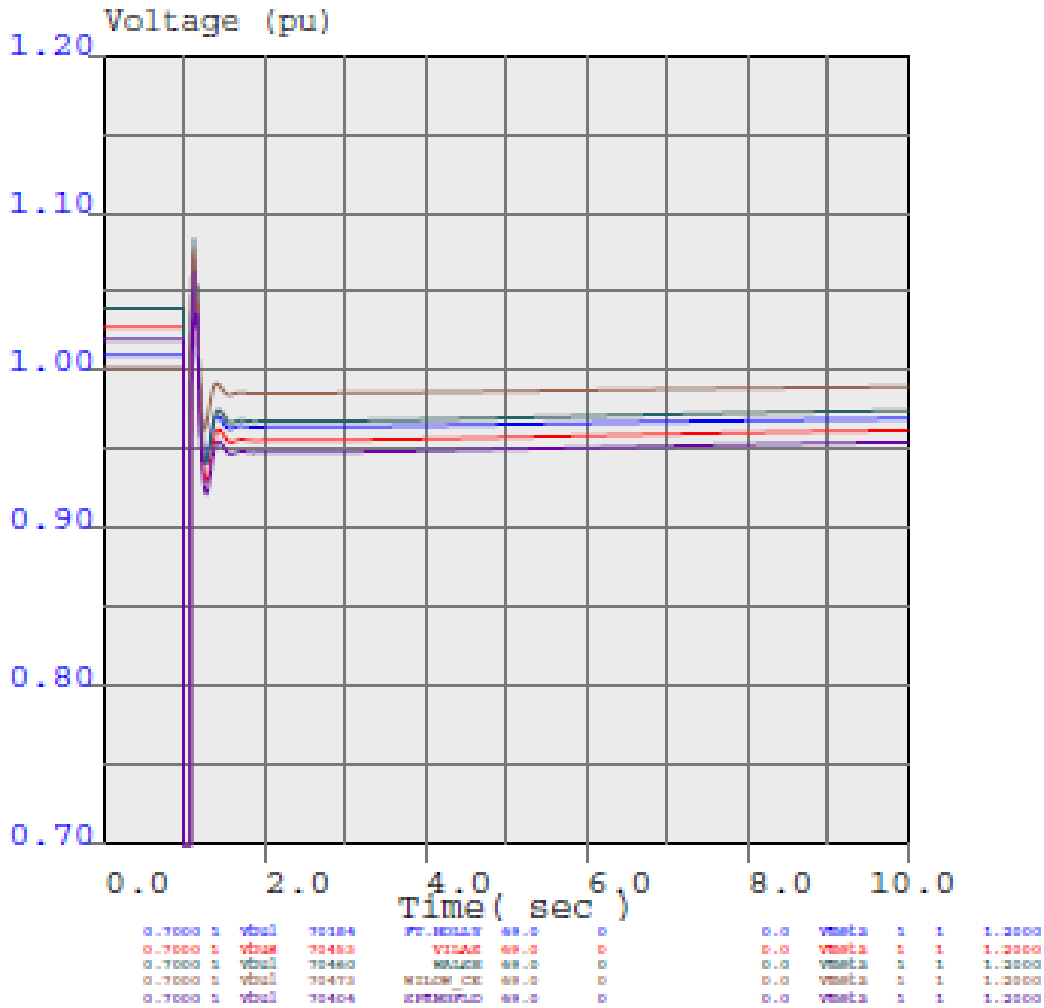
When the fault is at the Project POI for loss of the Project POI – Lamar 115kV line, the Vilas 69kV under-frequency relay does not operate.

**Figure 4 Loss of Project POI-(Lamar) 230kV line: Two (2) Walsh Shunts In-Service**




For comparison, Figure 5 plots loss of the Vilas – Lamar 230kV line with pre-project system conditions. It can be seen that no load is tripped from the under-frequency relay and system oscillations damp out quickly.

**Figure 5 Loss of Vilas-Lamar 230kV line: Three (3) Walsh Shunts In-Service, Pre-Project.**




Simulation results for summer and light autumn system conditions show that:

1. With the TMEIC solar inverters, the Project had acceptable voltage levels.
2. The solar inverters tripped during a few contingency events, which may be due to numerical anomalies of the models; since the Project tripped shortly after the fault. In order to keep the Project connected for all contingencies, the IC provided settings were revised – see Table 10 and 11.

   Note, the Project is required to remain in service during faults, three-phase or single line-to-ground (SLG) whichever is worse, with normal clearing times of approximately 4 to 9 cycles.
3. Acceptable damping and voltage recovery was observed.

# 6.0 SHORT-CIRCUIT ANALYSIS

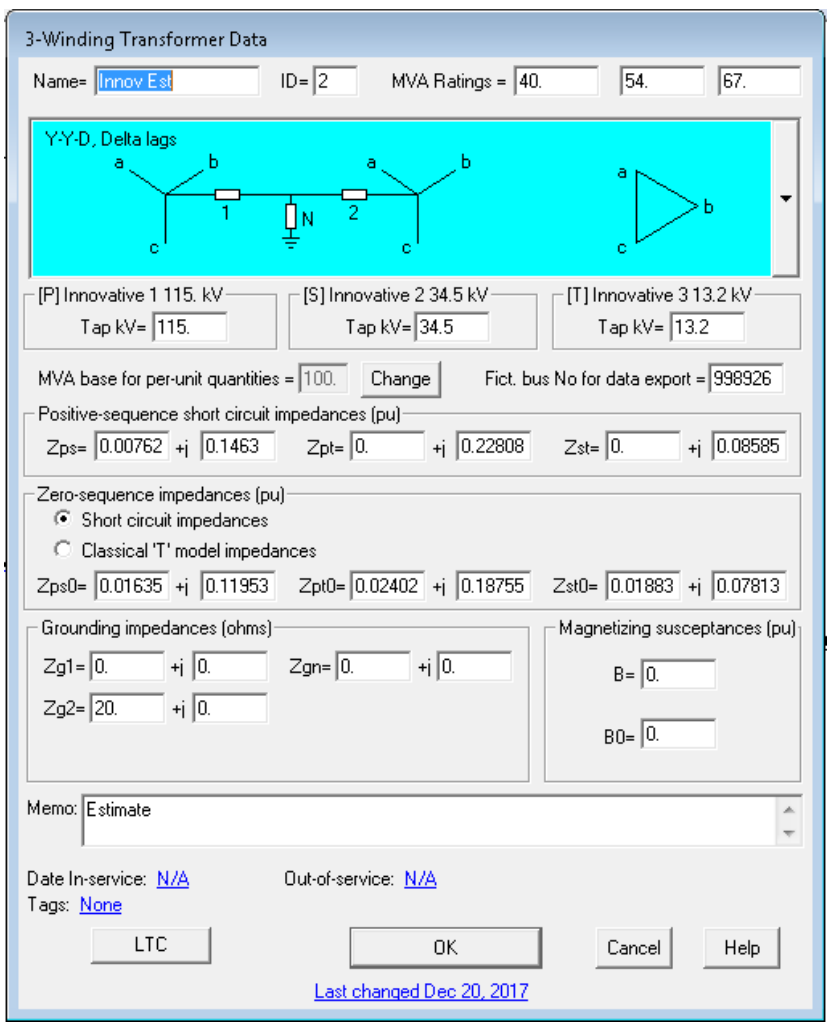
The GF has an acceptable impact on the Transmission System short-circuit magnitudes, which are shown in the tables below. The Line-Ground fault current increases approximately 800 amps at the POI bus. The three phase fault level increases about 300 amps for the duration of the 32 millisecond inverter contribution.

## 6.1 Assumptions and Methodology

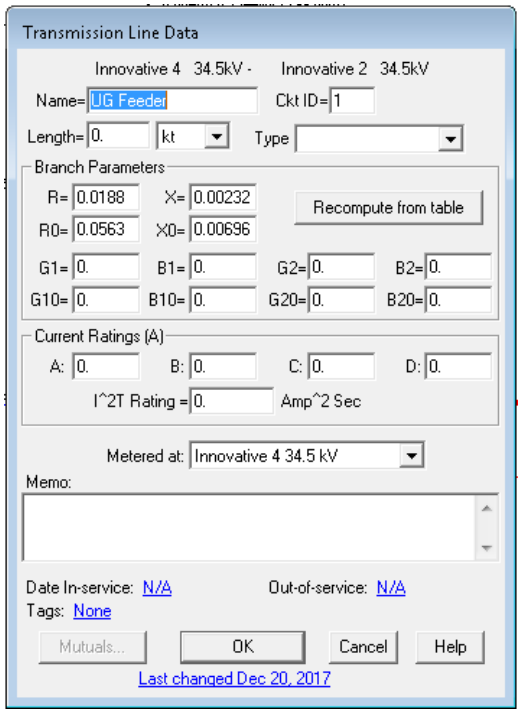
Short-circuit analysis was performed using Aspen OneLiner for 3-phase to ground and single line to ground faults at the Vilas 115 kV Substation POI bus, starting with the 2013 and 2016 case years' Aspen OneLiner model conditions. These faults were applied with and without the generation project in the existing system and with the addition of a future Burlington-Lamar 230 kV line. The GF main substation transformer model is an estimate based on an existing PV project transformer.

A. The one line diagram of the model used is shown in Figure 6 below.

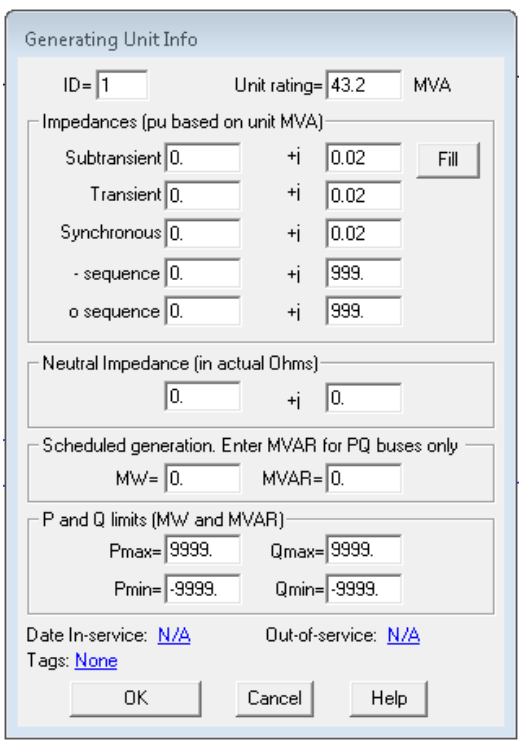
B. The GF's 115-34.5 transformer sequence impedance model data is as follows:



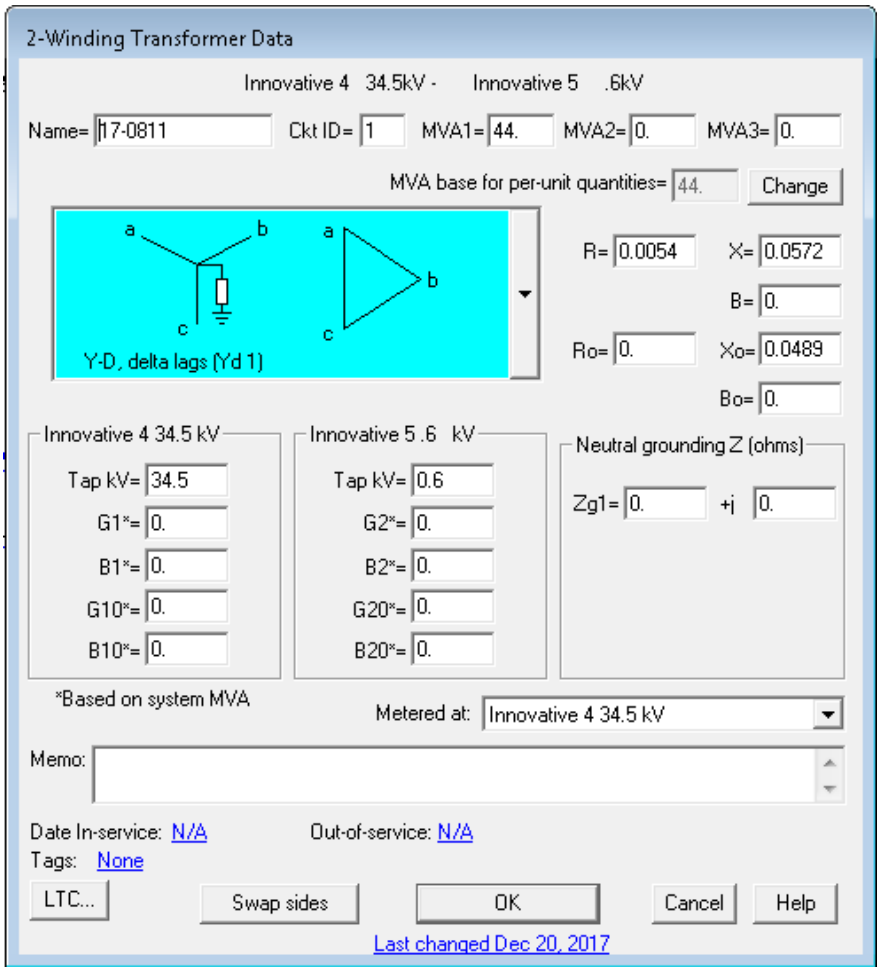
C. Positive Sequence impedance estimates used for all 34.5 kV GF collector system lumped equivalent feeder circuits are as provided by IC. Zero Sequence impedance for feeder assumed 3 times positive sequence impedance, as shown below:



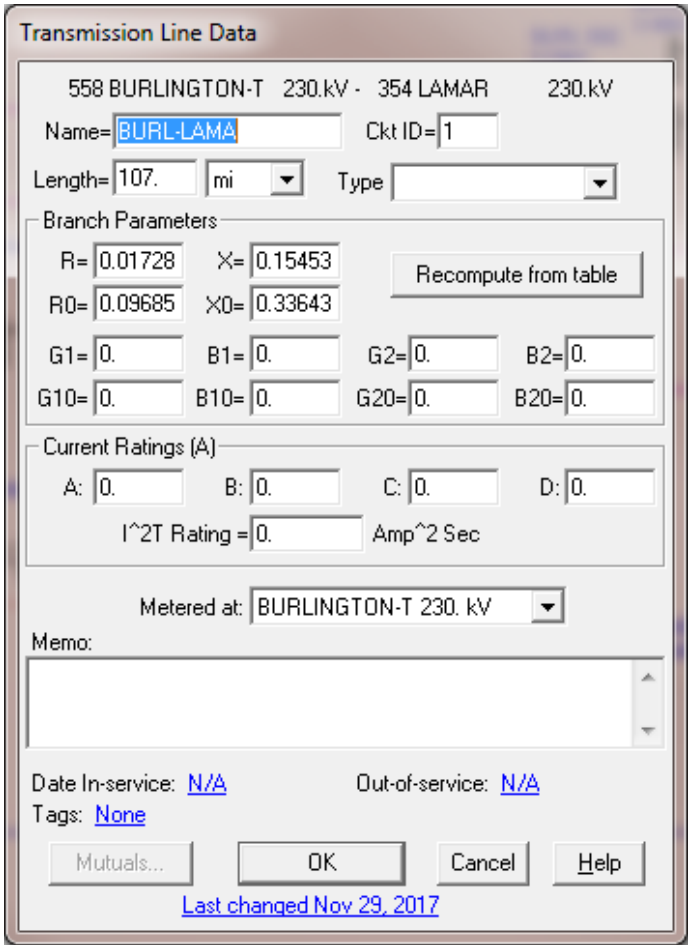

D. GF generators' short-circuit impedances were as follows:



E. GF generator step-up (GSU) transformers estimated as provided by IC as follows:



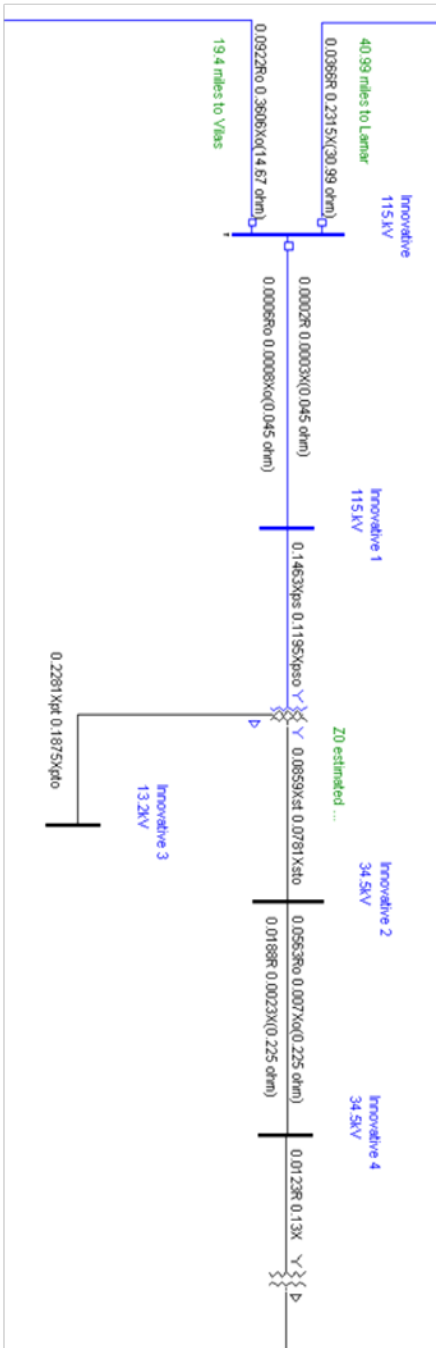
F. The future Burlington-Lamar 230 kV line was modeled using the following estimated parameters:
   1) Assumed 230kV Tangent H-Frame TH-230;
   2) Assumed Bittern Conductor;
   3) Assumed 1-DNO-7053 Optical Ground Wire;
   4) Assumed 1-3/8 EHS Ground Wire;
   5) Assumed 107 Miles;
   6) Line Parameters Calculated using assumptions above as:




## 6.2 Results

The tables below list results of the 115 kV bus faults, contributions from each of the 115 kV sources into the bus faults, and the network grid Thevenin equivalent impedances. The GF increases the L-G fault by approximately 800 Amps at the 115 kV POI bus. The Main Substation Transformer is a significant source of ground current. The existing Lamar - Vilas 115 kV ground distance and directional ground overcurrent protection (line and remote bus protection) will be ineffective due to the zero sequence infeed at the POI. To mitigate this, a 115 kV ring bus is required at the project POI and the protection scheme will need to be updated accordingly.

**Figure 6 Short-Circuit Model One-Line Diagram (pos. Z1 and neg. Z0 sequence impedances shown)**


Innovative
115 kV
40.99 miles to Lamar
0.0366R 0.2315X(30.99 ohm)
19.4 miles to Vilas
0.0922Ro 0.3606Xo(14.67 ohm)
0.0002R 0.0003X(0.045 ohm)
0.0006Ro 0.0008Xo(0.045 ohm)
Innovative 1
115 kV
0.1463Xps 0.1195Xpso
Z0 estimated ...
0.0659Xst 0.0781Xsto
Innovative 2
34.5kV
0.0563Ro 0.007Xo(0.225 ohm)
0.0188R 0.0023X(0.225 ohm)
Innovative 4
34.5kV
0.0123R 0.13X
0.2261Xpt 0.1875Xpto
Innovative 3
13.2kV

## Table 13 Short Circuit Results

| | POI 115 kV Bus (Total) 3-Ph Fault Level (Amps) | VILAS to POI 115 kV 3-Ph Fault Flow (Amps) | LAMAR to POI 115 kV 3-Ph Fault Flow (Amps) | Gen 115 kV to POI 115 kV 3-Ph Fault Flow (Amps) | POI 115 kV Bus (Total) SLG Fault Level (Amps) | VILAS to POI 115 kV SLG Fault Flow (Amps) | LAMAR to POI 115 kV SLG Fault Flow (Amps) | Gen 115 kV to POI 115 kV SLG Fault Flow (Amps) | Thevenin System Equivalent Impedance (R + jX p.u. on 100 MVA, 115 kV base) |
|---|---|---|---|---|---|---|---|---|---|
| **POI 115 kV Bus Fault (w/o generation; all lines in service)** | **1625** | 244 | 1388 | | **1375** | 682 | 695 | | Z1 =0.04431+j0.28306 Z2 = 0.04924+j0.30982 Z0 =0.07598+j0.40876 |
| POI 115 kV Bus Fault (w/o generation; VILAS to POI 115 kV out-of-service) | 1431 | | 1431 | | 933 | | 933 | | Z1 =0.0447+j0.32182 Z2 = 0.04832+j0.34605 Z0=0.19605+j0.79826 |
| POI 115 kV Bus Fault (w/o generation); LAMAR to POI 115 kV out-of-service) | 296 | 296 | | | 341 | 341 | | | Z1 =0.51074+j1.52845 Z2 = 0.60198+j1.65112 Z0 =0.10577+j0.83043 |
| Vilas 115 kV Bus Fault (w/o generation; all lines in service) | 1299 | 1031 | 1031 | | 1288 | 365 | 365 | | Z1 =0.06133+j0.35342 Z2 = 0.06739+j0.38266 Z0 =0.03012+j0.33774 |
| **POI 115 kV Bus Fault (with IC gen 40 MW); all lines in service)** | **1929** | 244 | 1388 | 325 | **2181** | 339 | 345 | 1498 | Z1 = 0.02109+j 0.1514 Z2 = 0.04925+j0.30984 Z0 = 0.01954+j0.12884 |

| | POI 115 kV Bus (Total) 3-Ph Fault Level (Amps) | VILAS to POI 115 kV 3-Ph Fault Flow (Amps) | LAMAR to POI 115 kV 3-Ph Fault Flow (Amps) | Gen 115 kV to POI 115 kV 3-Ph Fault Flow (Amps) | POI 115 kV Bus (Total) SLG Fault Level (Amps) | VILAS to POI 115 kV SLG Fault Flow (Amps) | LAMAR to POI 115 kV SLG Fault Flow (Amps) | Gen 115 kV to POI 115 kV SLG Fault Flow (Amps) | Thevenin System Equivalent Impedance (R + jX p.u. on 100 MVA, 115 kV base) |
|---|---|---|---|---|---|---|---|---|---|
| POI 115 kV Bus Fault (with IC gen 40 MW); VILAS to POI 115 kV out-of-service) | 1732 | | 1431 | 325 | 1946 | | 365 | 1588 | Z1 = 0.02091+j0.16178 Z2 = 0.04833+j0.34608 Z0 =0.02383+j0.15243 |
| POI 115 kV Bus Fault (with IC gen 40 MW); LAMAR to POI 115 kV out-of-service) | 618 | 296 | | 325 | 686 | 127 | | 559 | Z1 =0.04169+j0.26983 Z2 = 0.60247+j 1.6517 Z0 =0.02062+j 0.1533 |
| Vilas 115 kV Bus Fault (with IC gen 40 MW; all lines in service) | 1517 | 1242 | 961 | 325 | 1556 | 738 | 138 | 600 | Z1 =0.03857+j0.23645 Z2 = 0.06739+j0.38268 Z0 =0.02986+j0.24762 |

**Table 14 Short-Circuit Results – (Burlington – Lamar 230kV Line In Service)**

| | POI 115 V Bus (Total) 3-Ph Fault Level (Amps) | VILAS to POI 115 kV 3-Ph Fault Flow (Amps) | LAMAR to POI 115 kV 3-Ph Fault Flow (Amps) | Gen 115 kV to POI 115 kV 3-Ph Fault Flow (Amps) | POI 115 kV Bus (Total) SLG Fault Level (Amps) | VILAS to POI 115 kV SLG Fault Flow (Amps) | LAMAR to POI 115 kV SLG Fault Flow (Amps) | Gen 115 kV to POI 115 kV SLG Fault Flow (Amps) | Thevenin System Equivalent Impedance (R + jX p.u. on 100 MVA, 115 kV base) |
|---|---|---|---|---|---|---|---|---|---|
| **POI 115 kV Bus Fault (w/o generation ; all lines in service)** | **1704** | 251 | 1459 | | **1428** | 708 | 722 | | Z1 = 0.04261+j0.26945<br>Z2 = 0.04565+j0.28503<br>Z0 = 0.0761+j0.40838 |
| POI 115 kV Bus Fault (w/o generation; VILAS to POI 115 kV out-of-service) | 1497 | | 1497 | | 959 | | 959 | | Z1 = 0.04291+j0.30675<br>Z2 = 0.04475+j0.31938<br>Z0 = 0.19629+j0.79676 |
| POI 115 kV Bus Fault (w/o generation) ; LAMAR to POI 115 kV out-of-service) | 296 | 296 | | | 342 | 342 | | | Z1 = 0.51054+j1.5218<br>Z2 = 0.60042+j1.6366<br>Z0 = 0.10577+j0.83043 |
| Vilas 115 kV Bus Fault (w/o generation; all lines in service) | 1347 | 1071 | 1071 | | 1332 | 378 | 378 | | Z1 = 0.05966+j0.34039<br>Z2 = 0.0638+j0.35865<br>Z0 = 0.03018+j0.33762 |
| **POI 115 kV Bus Fault (with IC gen 40MW); all lines in service)** | **2013** | 251 | 1459 | 325 | **2306** | 359 | 366 | 1584 | Z1 = 0.02072+j0.14742<br>Z2 = 0.04566+j0.28505<br>Z0 = 0.01955+j0.1288 |

| | POI 115 V Bus (Total) 3-Ph Fault Level (Amps) | VILAS to POI 115 kV 3-Ph Fault Flow (Amps) | LAMAR to POI 115 kV 3-Ph Fault Flow (Amps) | Gen 115 kV to POI 115 kV 3-Ph Fault Flow (Amps) | POI 115 kV Bus (Total) SLG Fault Level (Amps) | VILAS to POI 115 kV SLG Fault Flow (Amps) | LAMAR to POI 115 kV SLG Fault Flow (Amps) | Gen 115 kV to POI 115 kV SLG Fault Flow (Amps) | Thevenin System Equivalent Impedance (R + jX p.u. on 100 MVA, 115 kV base) |
|---|---|---|---|---|---|---|---|---|---|
| POI 115 kV Bus Fault (with IC gen 40 MW); VILAS to POI 115 kV out-of-service) | 1804 | | 1497 | 325 | 2054 | | 386 | 1670 | Z1 = 0.02053+j0.15789<br>Z2 = 0.04476+j0.3194<br>Z0 = 0.02385+j0.15238 |
| POI 115 kV Bus Fault (with IC gen 40 MW); LAMAR to POI 115 kV out-of-service) | 620 | 296 | | 325 | 691 | 128 | | 563 | Z1 = 0.04175+j0.26965<br>Z2 = 0.6009+j1.63717<br>Z0 = 0.02062+j0.1533 |
| Vilas 115 kV Bus Fault (with IC gen 40 MW); all lines in service | 1567 | 1285 | 996 | 325 | 1622 | 769 | 144 | 626 | Z1 = 0.03823+j0.2324<br>Z2 = 0.0638+j0.35867<br>Z0 = 0.02987+j0.24761 |

## 7.0 SCOPE, COST AND SCHEDULE

The estimated total cost to interconnect the Project is broken out for each point of interconnection. The estimate further assumes that the Customer will construct 1) the 115-kV radial line from the Customer's main project substation to the new Station that intercepts the Lamar – Vilas 115kV line, or 2) the 115-kV radial line from the Customer's main project substation to the existing Vilas 115kV substation or 3) the 69-kV radial line from the Customer's main project substation to the Vilas 69-kV substation.

The cost estimate is broken out into two categories: 1) Interconnection Facilities which include all equipment installed between the POI at the main 115 kV bus (or 69 kV bus) and the Point of Change of Ownership (PCO) at the line dead-end structure just inside the Station fence, and 2) Network Upgrades consisting of the rest of the facilities installed in the Station to accommodate the interconnection. See Figures 7 through 9. The estimate includes all site work such as grounding and conduit installation inside the substation.

Note that the Customer will be responsible for constructing the radial 115 kV transmission line to the GF site and for providing the primary protection (relaying and interrupting device) for the Customer's step-up transformer located in its 115-34.5 kV or 69-34.5 kV substation yard. Equipment at the new Station will only provide backup protection for the Customer's 115-34.5 kV (or 69-34.5 kV) main transformer in the event of equipment failure or malfunction at the Customer's facility. To facilitate protective relaying and data acquisition, the Customer will need to include fiber optic cables (OPGW) on its radial 115 or 69 kV transmission line to provide communication channels for SCADA, metering (real time), and protective relaying.

The Customer is responsible for all engineering, procurement and construction of all GF facilities, including any STATCOM type voltage regulation / reactive compensation devices.

All costs are good faith estimates based on assumptions as stated in this SIS report. All estimates are in 2018 dollars (refer to Figures 7 through 9). However, cost estimates do not include costs associated with Network Upgrades identified as mitigations to accommodate the Project size:

POI 1: Interconnect to Lamar – Vilas 115kV Line

- Interconnection Facilities Costs (Non-Reimbursable): $ 1.09 M
- Network Upgrade Costs (Reimbursable)[2]: $ 6.77 M

TOTAL Cost (2018 dollars) for Interconnection: $ 7.86 M

POI 2: Interconnect to Vilas 115kV Substation

- Interconnection Facilities Costs (Non-Reimbursable): $ 1.09 M
- Network Upgrade Costs (Reimbursable)[2]: $ 2.74 M

TOTAL Cost (2018 dollars) for Interconnection: $ 3.83 M

POI 3: Interconnect to Vilas 69kV Substation

- Interconnection Facilities Costs (Non-Reimbursable): $ 0.98 M
- Network Upgrade Costs (Reimbursable)[2]: $ 2.09 M

TOTAL Cost (2018 dollars) for Interconnection: $ 3.07 M

Note that the above cost estimates do not include costs associated with distribution system upgrades required to accommodate the Project size. To interconnect the full Project size (40MW), an additional $2.94 M of distribution system upgrades are required for all POIs. Since the affected distribution system is not owned by Tri-State, these costs are not reimbursable. Additionally, the distribution system owner, Southeast Colorado Power Association (SECPA), will have final authority on the appropriate mitigations and associated costs.

[2] *Note: Network upgrade costs are reimbursed only when payments are made to the Transmission Provider under its Tariff for transmission services with respect to the Generating Facility. Network upgrade costs are not reimbursed if transmission services are not secured from the Transmission Provider.*

It is estimated that it will be a minimum of 18 to 24 months after receiving authorization to proceed for Tri-State to complete the engineering, design, procurement, construction, and testing activities identified in the scope of work for this Project. The schedule may be significantly affected should a Certificate of Public Convenience and Necessity be required by the Colorado Public Utilities Commission.

The Lamar area is a weaker part of the transmission system and includes several fast-acting VAR control devices. Previous generator interconnections have demonstrated the need for PSCAD/EMTP studies to ensure reliable integration with the existing system. TI-17-0706 will also require PSCAD/EMTP analysis during the facility study phase.

**NOTE:** Pursuant to Section 3.2.2.4 of Tri-State's Generation Interconnection Procedures, "Interconnection Service does not convey the right to deliver electricity to any customer or point of delivery. In order for an Interconnection Customer to obtain the right to deliver or inject energy beyond the Generating Facility Point of Interconnection or to improve its ability to do so, transmission service must be obtained pursuant to the provisions of the Transmission Provider's Tariff by either Interconnection Customer or the purchaser(s) of the output of the Generating facility." See Tri-State's Open Access Same Time Information System (OASIS) web site for information regarding requests for transmission service, related requirements and contact information.

**Figure 7 POI 1: New 115kV Station One-Line Diagram**

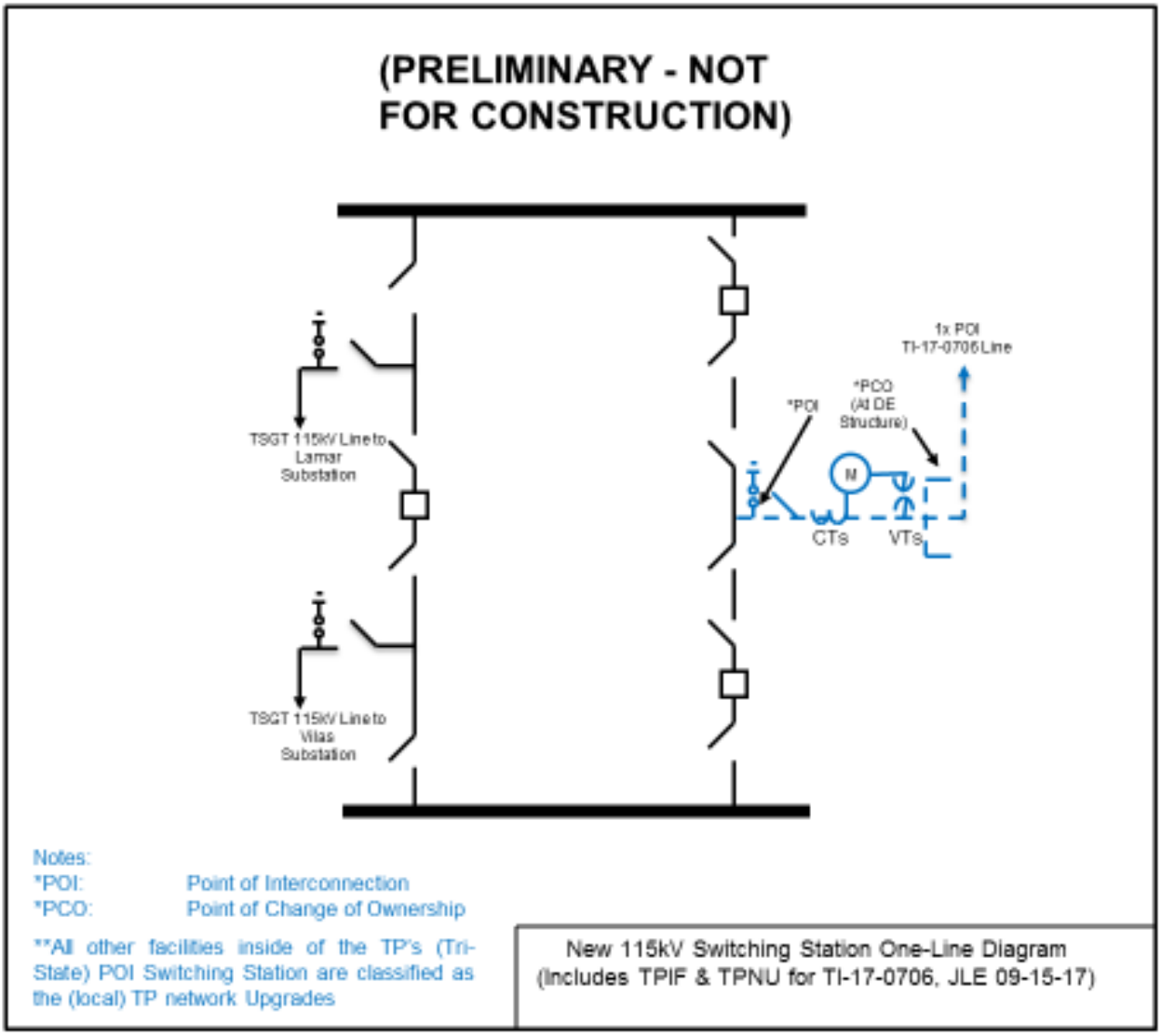


**Figure 8 POI 2: Vilas 115kV Station One-Line Diagram**

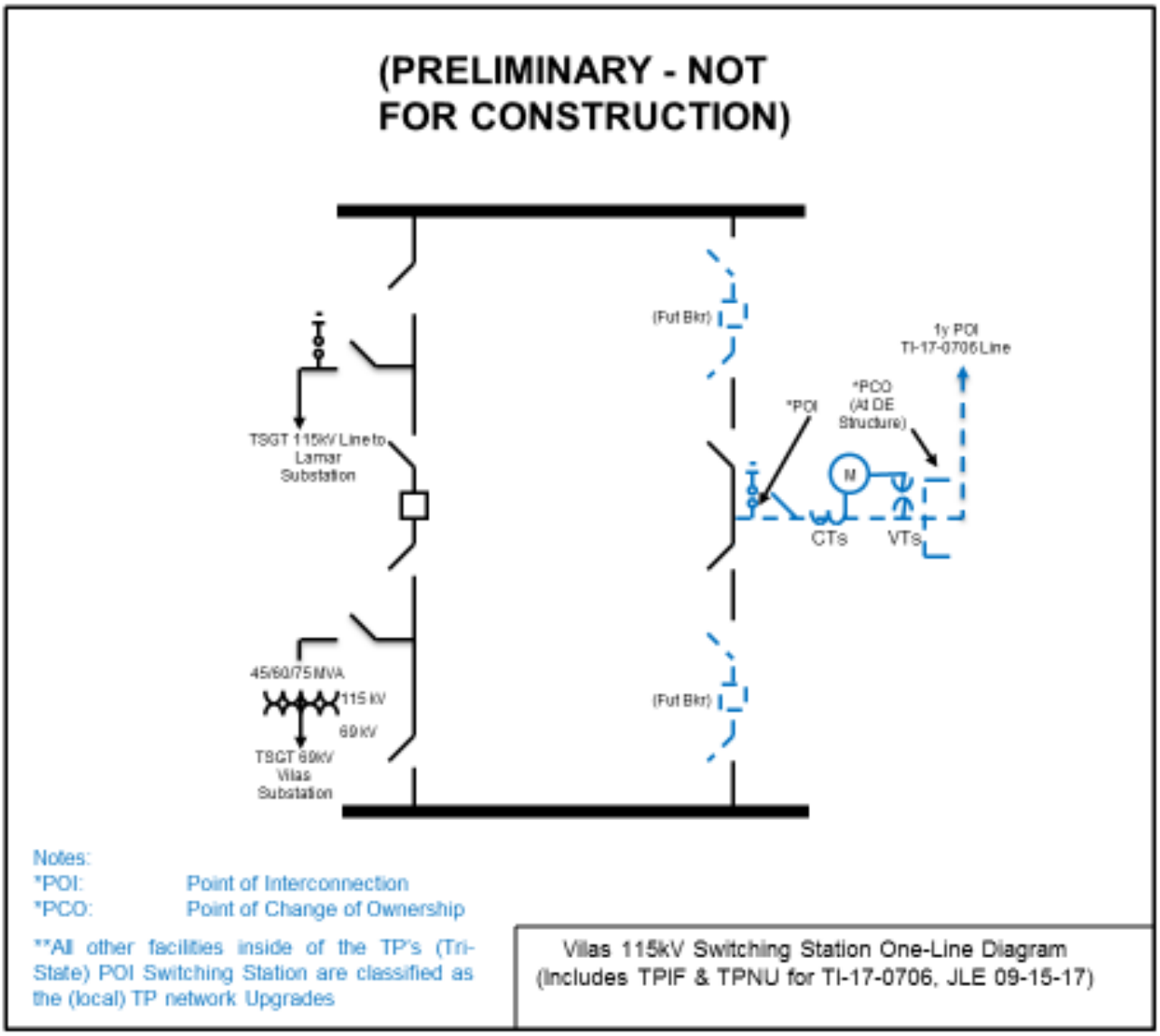


**Figure 9 POI 3: Vilas 69kV Station One-Line Diagram**

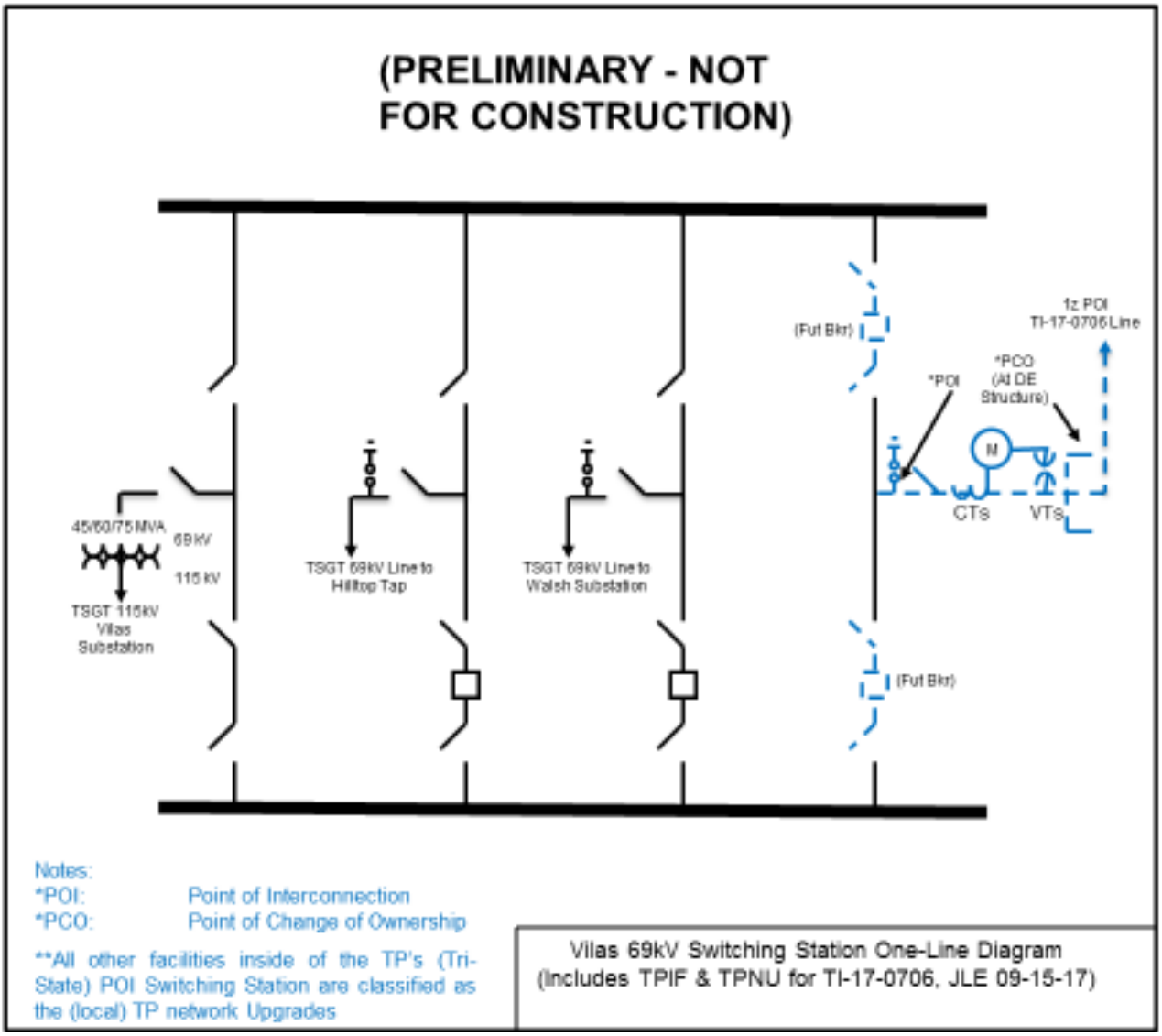


**Table 15: Summary Cost Estimate Details – Interconnection Facilities (Non-Reimbursable)**

| Element | Description | Cost Est. Millions |
|---|---|---|
| **New Station**<br><br>**115 kV line termination equipment** | Design, purchase, construct / install and test all equipment installed inside the New Station that is located between the PCO (line dead-end) and the POI (main bus tap point), consisting primarily of the following equipment:<br><br>• One (1) 115 kV monopole dead-end structure<br>• One (1) 115 kV slack span from monopole to existing structure at New Station.<br>• One (1) 115 kV 3-ph gang line end disconnect switch and associated structure.<br>• *Three (3) 115 kV metering current transformers (CTs), high accuracy class, extended range.<br>• *Three (3) 115 kV metering voltage transformers (VTs, high accuracy class). *Or alternative CT/VT combination metering units.<br>• PQ metering panel including SEL-735 Rev/PQ meter (typical) and line meters.<br>• Relaying for radial 115 kV line protection; primary, secondary, and breaker-failure.<br>• Three (3) 115 kV surge arresters (140 kV MCOV or as required).<br>• Line termination SCADA and telecommunication additions to RTU.<br>• Other associated substation equipment including, but not limited to, grounding, conduit, cable, foundations, support steel, bus and insulators. | **$1.09 M** |

**Table 16: Summary Cost Estimate Details – Network Upgrades POI1 (Reimbursable)**[3]

| Element | Description | Cost Est. Millions |
|---|---|---|
| **New Station** | Install necessary equipment in the 115 kV bus to terminate an additional circuit (see Figure 2, One-Line Diagram). Scope includes typical testing, checkout, and commissioning.<br><br>• Three (3) 115 kV power circuit breaker.<br>• Six (6) 115 kV 3-ph gang disconnect switches and associated structures.<br>• Circuit breaker station control panel<br>• SCADA and telemetry RTU communication equipment modifications.<br>• Other associated substation equipment including, but not limited to, grounding, conduit, cable, foundations, support steel, bus and insulators. | **$6.77 M** |
| **Lamar Substation – Relaying Mods** | • Relay settings changes (labor) for new POI line termination protection. | **(Minimal)** |
| **Vilas Substation – Relaying Mods** | • Relay settings changes (labor) for new POI line termination protection. | **(Minimal)** |

[3] *Note: Network upgrade costs are reimbursed only when payments are made to the Transmission Provider under its Tariff for transmission services with respect to the Generating Facility. Network upgrade costs are not reimbursed if transmission services are not secured from the Transmission Provider.*

**Table 17: Summary Cost Estimate Details – Network Upgrades POI2 (Reimbursable)[4]**

| Element | Description | Cost Est. Millions |
|---|---|---|
| **New Bay at Vilas 115kV** | Install necessary equipment in the 115 kV bus to terminate an additional circuit (see Figure 3, One-Line Diagram). Scope includes typical testing, checkout, and commissioning.<br><br>• Two (2) 115 kV power circuit breaker.<br>• Six (6) 115 kV 3-ph gang disconnect switches and associated structures.<br>• Circuit breaker station control panel<br>• SCADA and telemetry RTU communication equipment modifications.<br>• Other associated substation equipment including, but not limited to, grounding, conduit, cable, foundations, support steel, bus and insulators. | **$2.74 M** |
| **Lamar Substation – Relaying Mods** | • Relay settings changes (labor) for new POI line termination protection. | **(Minimal)** |
| **Vilas Substation – Relaying Mods** | • Relay settings changes (labor) for new POI line termination protection. | **(Minimal)** |

[4] *Note: Network upgrade costs are reimbursed only when payments are made to the Transmission Provider under its Tariff for transmission services with respect to the Generating Facility. Network upgrade costs are not reimbursed if transmission services are not secured from the Transmission Provider.*

**Table 18: Summary Cost Estimate Details – Interconnection Facilities (Non-Reimbursable)**

| Element | Description | Cost Est. Millions |
|---|---|---|
| **New Station**<br><br>**69 kV line termination equipment** | Design, purchase, construct / install and test all equipment installed inside the New Station that is located between the PCO (line dead-end) and the POI (main bus tap point), consisting primarily of the following equipment:<br><br>• One (1) 69 kV monopole dead-end structure<br>• One (1) 69 kV slack span from monopole to existing structure at New Station.<br>• One (1) 69 kV 3-ph gang line end disconnect switch and associated structure.<br>• *Three (3) 69 kV metering current transformers (CTs), high accuracy class, extended range.<br>• *Three (3) 69 kV metering voltage transformers (VTs, high accuracy class). *Or alternative CT/VT combination metering units.<br>• PQ metering panel including SEL-735 Rev/PQ meter (typical) and line meters.<br>• Relaying for radial 69 kV line protection; primary, secondary, and breaker-failure.<br>• Three (3) 69 kV surge arresters (140 kV MCOV or as required).<br>• Line termination SCADA and telecommunication additions to RTU.<br>• Other associated substation equipment including, but not limited to, grounding, conduit, cable, foundations, support steel, bus and insulators. | **$0.98 M** |

**Table 19: Summary Cost Estimate Details – Network Upgrades POI3 (Reimbursable)**[5]

| Element | Description | Cost Est. Millions |
|---|---|---|
| **New Bay at Vilas 69kV** | Install necessary equipment in the 115 kV bus to terminate an additional circuit (see Figure 4, One-Line Diagram). Scope includes typical testing, checkout, and commissioning.<br><br>• Two (2) 69 kV power circuit breaker.<br>• Six (6) 69 kV 3-ph gang disconnect switches and associated structures.<br>• Circuit breaker station control panel<br>• SCADA and telemetry RTU communication equipment modifications.<br>• Other associated substation equipment including, but not limited to, grounding, conduit, cable, foundations, support steel, bus and insulators. | **$2.09 M** |
| **Lamar Substation – Relaying Mods** | • Relay settings changes (labor) for new POI line termination protection. | **(Minimal)** |
| **Vilas Substation – Relaying Mods** | • Relay settings changes (labor) for new POI line termination protection. | **(Minimal)** |

**Table 20: Summary Cost Estimate Details – Distribution System Upgrades (Non-Reimbursable)**

| Element | Description | Cost Est. Millions |
|---|---|---|
| **Vilas – Walsh 69 kV Rebuild** | • Rebuild approximately 10 miles of 69 kV line to increase the thermal conductor limit.<br>• Note that since Vilas – Walsh 69 kV is not owned by Tri-State, SECPA will have final authority on the appropriate mitigations and associated costs. | **$2.94 M** |

[5] *Note: Network upgrade costs are reimbursed only when payments are made to the Transmission Provider under its Tariff for transmission services with respect to the Generating Facility. Network upgrade costs are not reimbursed if transmission services are not secured from the Transmission Provider.*

## 8.0 LIST OF APPENDICES

***NOTE: Appendices are Tri-State Confidential, are available only to the IC and Affected Systems upon request, and are not for posting on OASIS***

**Appendix A: Steady State Power Flow Study – List of N-1 Contingencies**

**Appendix B: Steady State Power Flow Study – Plots**

**Appendix C: Dynamic Stability Study – Switching Sequences**

**Appendix D: Dynamic Stability Study – Waveform Plots**

**Appendix E: Generation Dispatch Summary Listing (BAs 10, 70, 73)**