# DISTRIBUTION SYSTEM ELECTRIFICATION STUDY

LOS ALAMOS COUNTY

CHAPTERS 1-4 INTERMEDIATE DRAFT RELEASE

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REVISION A

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| Revision A | 6/17/2025 | The intermediate release of chapters 1-4 for BPU review. |
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# CONTENTS


1.0 Inputs and Assumptions ........ 1-1
1.1 LACDPU Provided Documents and Data ........ 1-1
1.2 Substation Transformers ........ 1-2
1.3 Distribution Feeder Peak Load ........ 1-2
1.3.1 Los Alamos Townsite Substation ........ 1-3
1.3.2 Additional Loads Considered for the LASS Substation ........ 1-4
1.3.3 White Rock Community ........ 1-5
1.4 Distribution Feeder Minimum Daylight Load ........ 1-5
1.5 Solar PV ........ 1-6
1.6 Residential Customers ........ 1-8
1.7 Commercial Customers ........ 1-8
1.8 Distribution System Equipment ........ 1-8
1.9 Load Allocation Process ........ 1-8
1.10 New Los Alamos Switching Station ........ 1-9
1.11 Distribution Planning Criteria ........ 1-12
1.12 Eastgate Substation Representative Cost ........ 1-12
1.13 White Rock Substation Upgrade Representative Cost ........ 1-12
1.14 Representative Distribution System Equipment Costs ........ 1-13

2.0 Existing System Review ........ 2-1
2.1 Distribution Asset Health and Reliability Review ........ 2-1
2.1.1 Service Transformers ........ 2-1
2.1.2 Mainline Switches ........ 2-2
2.1.3 Overhead Conductor and Underground Cable ........ 2-2
2.2 Substation Assessment ........ 2-3
2.2.1 White Rock Substation ........ 2-3
2.3 Current and Future Supply Markets Assessment ........ 2-5
2.4 Existing Distribution System Model and Power Flow Assessment - Peak Load ........ 2-6
2.4.1 WindMil Power Flow Model Fidelity ........ 2-6
2.4.2 Normal Configuration Review ........ 2-7
2.4.3 Contingency Configuration Review ........ 2-11
2.4.4 System Reliability Observations ........ 2-12
2.5 Hosting Capacity Assessment - Minimum Daylight Load ........ 2-12
2.5.1 Planning Criteria - Hosting Capacity Limitations ........ 2-12
2.5.2 Minimum Daylight Load Models ........ 2-12
2.5.3 Hosting Capacity Visuals ........ 2-13
2.5.4 Summary of Results ........ 2-14
2.6 Grid Modernization Strategies ........ 2-16

3.0 Adoption Modeling and Forecasting .... 3-1
3.1 Electrification Scenarios .... 3-1
3.2 Forecasting Methodology .... 3-2
3.3 Transportation Electrification .... 3-4
3.3.1 Vehicle Population Estimate .... 3-5
3.3.2 Charging Behavior and Infrastructure .... 3-6
3.3.3 Zero Emission Vehicle Public Policy .... 3-8
3.3.4 Los Alamos County Fleet .... 3-9
3.3.5 Atomic City Transit .... 3-10
3.3.6 Los Alamos Public Schools .... 3-10
3.3.7 Commercial Fleets .... 3-11
3.3.8 Residential Vehicles .... 3-12
3.3.9 Public charging .... 3-13
3.4 Home Electrification .... 3-14
3.4.1 Space heating .... 3-14
3.4.2 Water heating .... 3-17
3.4.3 Clothes drying .... 3-18
3.4.4 Cooking .... 3-18
3.5 Commercial Electrification .... 3-19
3.5.1 Space heating .... 3-20
3.5.2 Water heating .... 3-20
3.6 Solar PV & Batteries .... 3-21
3.7 Electrification Forecast Results .... 3-23
3.7.1 Scenario 1 .... 3-24
3.7.2 Scenario 2 .... 3-25
3.7.3 Scenario 3 .... 3-27
4.0 Electric Distribution System Impact Analysis .... 4-1
4.1 Electrification Impact Analysis Methodology .... 4-1
4.2 2055 Scenario 1 Electrification Impact .... 4-2
4.2.1 Study Area Configuration .... 4-2
4.2.2 Conductor and Equipment Buildout .... 4-4
4.2.3 Normal Configuration Power Flow Analysis .... 4-7
4.2.4 Contingency Configuration Review .... 4-8
4.2.5 Asset Replacement Estimate .... 4-10
4.3 2040 Scenario 1 Electrification Impact .... 4-10
4.3.1 Study Area Configuration .... 4-11
4.3.2 Conductor and Equipment Buildout .... 4-13
4.3.3 Normal Configuration Power Flow Analysis .... 4-16
4.3.4 Contingency Configuration Analysis .... 4-17
4.3.5 Asset Replacement Estimate .... 4-19
4.4 2055 Scenario 2 Electrification Impact .... 4-19
4.4.1 Study Area Configuration .... 4-20

4.4.2 Conductor and Equipment Buildout ........ 4-22
4.4.3 Normal Configuration Power Flow Analysis ........ 4-25
4.4.4 Contingency Configuration Analysis ........ 4-26
4.4.5 Asset Replacement Estimate ........ 4-28
**4.5 2040 Scenario 2 Electrification Impact ........ 4-28**
4.5.1 Study Area Configuration ........ 4-29
4.5.2 Conductor and Equipment Buildout ........ 4-31
4.5.3 Normal Configuration Power Flow Analysis ........ 4-34
4.5.4 Contingency Configuration Analysis ........ 4-35
4.5.5 Asset Replacement Estimate ........ 4-37
**4.6 2055 Scenario 3 Electrification Impact ........ 4-37**
4.6.1 Conductor and Equipment Buildout ........ 4-40
4.6.2 Normal Configuration Power Flow Analysis ........ 4-43
4.6.3 Contingency Configuration Review ........ 4-44
4.6.4 Asset Replacement Estimate ........ 4-45
**4.7 2040 Scenario 3 Electrification Impact ........ 4-46**
4.7.1 Conductor and Equipment Buildout ........ 4-48
4.7.2 Normal Configuration Power Flow Analysis ........ 4-51
4.7.3 Contingency Configuration Review ........ 4-52
4.7.4 Asset Replacement Estimate ........ 4-53
**4.8 BESS within the Electric System ........ 1**
4.8.1 Transmission Scale BESS ........ 1
4.8.2 Distribution Level BESS ........ 2
4.8.3 Residential Level BESS ........ 2
4.8.4 Mobile BESS ........ 3
4.8.5 Ownership and Operation of BESS ........ 4
**4.9 Fault Location, Isolation, and Service Restoration (FLISR) ........ 5**
**4.10 Distribution System Microgrid ........ 6**
**4.11 Modular Substations ........ 7**
**4.12 Volt-VAR Optimization ........ 9**
**4.13 Demand Response Programs ........ 10**

## APPENDICES

**Appendix A – Hosting Capacity Analysis Results**
**Appendix B – Grid Modernization Strategies**

# FIGURES


Figure 1-1: Los Alamos Townsite Substation 2024 Load Readings ........................ 1-3
Figure 1-2: Connected Solar PV Capacity ................................................ 1-7
Figure 1-3: Residential Solar PV System Size ........................................... 1-7
Figure 1-4: Previous Configuration of the Los Alamos Town Site System...............1-10
Figure 1-5: Current Configuration of the Los Alamos Townsite System
with LASS Substation Energized ................................................1-11
Figure 2-1: LACDPU System Service Transformer Installations............................ 2-1
Figure 2-2: LACDPU System Switch Installations ......................................... 2-2
Figure 2-3: LACDPU System Primary Overhead Conductor and Primary
Underground Cable Line Miles ................................................. 2-3
Figure 2-4: Los Alamos Townsite System Colored By Substation.......................... 2-8
Figure 2-5: White Rock System Colored by Distribution Feeder .........................2-10
Figure 2-6: Hosting Capacity Analysis Feeder Visual Example ...........................2-14
Figure 3-1: Diffusion of Innovation...................................................... 3-3
Figure 3-2: Daily Climate Normal (1991 - 2020) - Los Alamos, NM ......................3-15
Figure 3-3: Connected PV Generation ...................................................3-21
Figure 3-4: Scenario 1, 2040 ............................................................3-24
Figure 3-5: Scenario 1, 2055 ............................................................3-25
Figure 3-6: Scenario 2, 2040 ............................................................3-26
Figure 3-7: Scenario 2, 2055 ............................................................3-26
Figure 3-8: Scenario 3, 2040 ............................................................3-27
Figure 3-9: Scenario 3, 2055 ............................................................3-28
Figure 4-1: 2055 Scenario 1 Los Alamos Townsite System Configuration................ 4-3
Figure 4-2: 2055 Scenario 1 White Rock System Configuration .......................... 4-4
Figure 4-3: 2055 Scenario 1 Los Alamos Townsite System Conductor and
Equipment Buildout ........................................................... 4-5
Figure 4-4: 2055 Scenario 1 White Rock System Conductor and
Equipment Buildout ........................................................... 4-6
Figure 4-5: 2040 Scenario 1 Los Alamos Townsite System Configuration...............4-12
Figure 4-6: 2040 Scenario 1 White Rock System Configuration .........................4-13
Figure 4-7: 2040 Scenario 1 Los Alamos Townsite System Configuration...............4-14
Figure 4-8: 2040 Scenario 1 White Rock System Conductor and
Equipment Buildout ...........................................................4-15
Figure 4-9: 2055 Scenario 2 Los Alamos Townsite System Configuration...............4-21
Figure 4-10: 2055 Scenario 2 White Rock System Configuration........................4-22
Figure 4-11: 2055 Scenario 2 Los Alamos Townsite System Conductor and
Equipment Buildout ...........................................................4-23
Figure 4-12: 2055 Scenario 2 White Rock System Conductor and
Equipment .....................................................................4-24
Figure 4-13: 2040 Scenario 2 Los Alamos Townsite System Configuration .............4-30
Figure 4-14: 2040 Scenario 2 White Rock System Configuration........................4-31
Figure 4-15: 2040 Scenario 2 Los Alamos Townsite System Conductor and
Equipment Buildout ...........................................................4-32
Figure 4-16: 2040 Scenario 2 White Rock System Conductor and
Equipment .....................................................................4-33
Figure 4-17: 2055 Scenario 3 Los Alamos Townsite System Configuration .............4-39
Figure 4-18: 2055 Scenario 3 White Rock System Configuration........................4-40

Figure 4-19: 2055 Scenario 3 Los Alamos Townsite System Conductor and Equipment Buildout ........ 4-41
Figure 4-20: 2055 Scenario 3 White Rock System Conductor and Equipment Buildout ........ 4-42
Figure 4-21: 2040 Scenario 3 Los Alamos Townsite System Configuration ........ 4-47
Figure 4-22: 2040 Scenario 3 White Rock System Configuration ........ 4-48
Figure 4-23: 2040 Scenario 3 Los Alamos Townsite System Conductor and Equipment Buildout ........ 4-49
Figure 4-24: 2040 Scenario 3 White Rock System Conductor and Equipment Buildout ........ 4-50
Figure 4-25: Distribution Line Recloser ........ 5
Figure 4-26: White Rock Substation ........ 7
Figure 4-27: Modular Substation Example from Manitoba Hydro ........ 8
Figure 4-28: Electric Vehicle Supply Equipment ........ 10

## TABLES

Table 1-1: Substation Transformer Ratings ........ 1-2
Table 1-2: Los Alamos Townsite Substation Peak Load ........ 1-3
Table 1-3: Los Alamos Townsite Feeder Amperage Readings ........ 1-4
Table 1-4: Los Alamos Town Site Substation Feeder Amperage Scaled to Peak Load ........ 1-4
Table 1-5: Additional Loads Considered in Los Alamos ........ 1-5
Table 1-6: White Rock Feeder Amperage Readings ........ 1-5
Table 1-7: Los Alamos System Feeder Minimum Daylight Load Readings ........ 1-6
Table 1-8: Minimum Daylight Load for Additional Feeders ........ 1-6
Table 1-9: Distribution Feeder Load Allocation Method ........ 1-9
Table 1-10: Eastgate Substation Representative Cost ........ 1-12
Table 1-11: White Rock Substation Upgrade Representative Cost ........ 1-13
Table 1-12: Common Equipment Representative Costs ........ 1-13
Table 2-1: Los Alamos Townsite System Normal Configuration Power Flow Results ........ 2-9
Table 2-2: White Rock System Normal Configuration Power Flow Results ........ 2-10
Table 2-3: Los Alamos Townsite System Contingency Configuration Summary ........ 2-11
Table 2-4: White Rock System Contingency Configuration Summary ........ 2-11
Table 2-5: Feeder Minimum Daylight Load ........ 2-13
Table 2-6: Summary of Hosting Capacity Analysis Results ........ 2-15
Table 2-7: Grid Modernization Strategies Summary ........ 2-16
Table 3-1: Vehicle Count Per Household ........ 3-5
Table 3-2: Vehicles by Weight Class & Location ........ 3-6
Table 3-3: Los Alamos County Fleet, 2040 ........ 3-9
Table 3-4: Los Alamos County Fleet, 2055 ........ 3-9
Table 3-5: Atomic City Transit, 2040 ........ 3-10
Table 3-6: Atomic City Transit, 2055 ........ 3-10
Table 3-7: Los Alamos Public Schools, 2040 ........ 3-11
Table 3-8: Los Alamos Public Schools, 2055 ........ 3-11
Table 3-9: Commercial Fleets, 2040 ........ 3-11
Table 3-10: Commercial Fleets, 2055 ........ 3-11
Table 3-11: Residential EVs, 2040 ........ 3-13

Table 3-12: Residential EVs, 2055 ....... 3-13
Table 3-13: Public Chargers, 2040 ....... 3-13
Table 3-14: Public Chargers, 2055 ....... 3-13
Table 3-15: Space Heating, 2040 ....... 3-16
Table 3-16: Space Heating, 2055 ....... 3-16
Table 3-17: Water Heating, 2040 ....... 3-17
Table 3-18: Water Heating, 2055 ....... 3-18
Table 3-19: Clothes Dryers, 2040 ....... 3-18
Table 3-20: Clothes Dryers, 2055 ....... 3-18
Table 3-21: Cooking, 2040 ....... 3-19
Table 3-22: Cooking, 2055 ....... 3-19
Table 3-23: Commercial Space Heating, 2040 ....... 3-20
Table 3-24: Commercial Space Heating, 2055 ....... 3-20
Table 3-25: Commercial Water Heating, 2040 ....... 3-20
Table 3-26: Commercial Water Heating, 2055 ....... 3-21
Table 3-27: Residential Solar & Battery, 2040 ....... 3-22
Table 3-28: Residential Solar & Battery, 2055 ....... 3-22
Table 3-29: Commercial Solar & Battery, 2040 ....... 3-23
Table 3-30: Commercial Solar & Battery, 2055 ....... 3-23
Table 3-31: Total Additional Electrification Peak Load ....... 3-23
Table 4-1: Electrification Scenarios Forecasted System Load ....... 4-1
Table 4-2: 2055 Scenario 1 Modeled Load ....... 4-2
Table 4-3: 2055 Scenario 1 Los Alamos Townsite System Conductor and Equipment Quantities ....... 4-6
Table 4-4: 2055 Scenario 1 White Rock System Conductor and Equipment Quantities ....... 4-7
Table 4-5: 2055 Scenario 1 Los Alamos System Power Flow Results ....... 4-7
Table 4-6: 2055 Scenario 1 White Rock System Power Flow Results ....... 4-8
Table 4-7: 2055 Scenario 1 Los Alamos Townsite System Contingency Review ....... 4-9
Table 4-8: 2055 Scenario 1 White Rock System Contingency Review ....... 4-9
Table 4-9: 2055 Scenario 1 Los Alamos Townsite System Asset Replacement Estimate ....... 4-10
Table 4-10: 2055 Scenario 1 White Rock System Asset Replacement Estimate ....... 4-10
Table 4-11: 2040 Scenario 1 Modeled Load ....... 4-11
Table 4-12: 2040 Scenario 1 Los Alamos Townsite System Conductor and Equipment Quantities ....... 4-15
Table 4-13: 2040 Scenario 1 White Rock System Conductor and Equipment Quantities ....... 4-16
Table 4-14: 2040 Scenario 1 Los Alamos System Power Flow Results ....... 4-16
Table 4-15: 2040 Scenario 1 White Rock System Power Flow Results ....... 4-17
Table 4-16: 2040 Scenario 1 Los Alamos Townsite System Contingency Review ....... 4-18
Table 4-17: 2040 Scenario 1 White Rock System Contingency Review ....... 4-18
Table 4-18: 2040 Scenario 1 Los Alamos Townsite System Asset Replacement Estimate ....... 4-19
Table 4-19: 2040 Scenario 1 White Rock System Asset Replacement Estimate ....... 4-19
Table 4-20: 2055 Scenario 2 Modeled Load ....... 4-20

Table 4-21: 2055 Scenario 2 Los Alamos Townsite System Conductor and Equipment Quantities....4-24
Table 4-22: 2055 Scenario 2 White Rock System Conductor and Equipment Quantities....4-25
Table 4-23: 2055 Scenario 2 Los Alamos System Power Flow Results....4-25
Table 4-24: 2055 Scenario 2 White Rock System Power Flow Results....4-26
Table 4-25: 2055 Scenario 2 Los Alamos Townsite System Contingency Review....4-27
Table 4-26: 2055 Scenario 2 White Rock System Contingency Review....4-27
Table 4-27: 2055 Scenario 2 Los Alamos Townsite System Asset Replacement Estimate....4-28
Table 4-28: 2055 Scenario 2 White Rock System Asset Replacement Estimate....4-28
Table 4-29: 2040 Scenario 2 Modeled Load....4-29
Table 4-30: 2040 Scenario 2 Los Alamos Townsite System Conductor and Equipment Quantities....4-33
Table 4-31: 2040 Scenario 2 White Rock System Conductor and Equipment Quantities....4-34
Table 4-32: 2040 Scenario 2 Los Alamos System Power Flow Results....4-34
Table 4-33: 2040 Scenario 2 White Rock System Power Flow Results....4-35
Table 4-34: 2040 Scenario 2 Los Alamos Townsite System Contingency Review....4-36
Table 4-35: 2040 Scenario 2 White Rock System Contingency Review....4-37
Table 4-36: 2040 Scenario 2 Los Alamos Townsite System Asset Replacement Estimate....4-37
Table 4-37: 2040 Scenario 2 White Rock System Asset Replacement Estimate....4-37
Table 4-38: 2055 Scenario 3 Modeled Load....4-38
Table 4-39: 2055 Scenario 3 Los Alamos Townsite System Conductor and Equipment Quantities....4-42
Table 4-40: 2055 Scenario 3 White Rock System Conductor and Equipment Quantities....4-43
Table 4-41: 2055 Scenario 3 Los Alamos System Power Flow Results....4-43
Table 4-42: 2055 Scenario 3 White Rock System Power Flow Results....4-44
Table 4-43: 2055 Scenario 3 Los Alamos Townsite System Contingency Review....4-44
Table 4-44: 2055 Scenario 3 White Rock System Contingency Review....4-45
Table 4-45: 2055 Scenario 3 Los Alamos Townsite System Asset Replacement Estimate....4-45
Table 4-46: 2055 Scenario 3 White Rock System Asset Replacement Estimate....4-46
Table 4-47: 2040 Scenario 3 Modeled Load....4-46
Table 4-48: 2040 Scenario 3 Los Alamos Townsite System Conductor and Equipment Quantities....4-50
Table 4-49: 2040 Scenario 3 White Rock System Conductor and Equipment Quantities....4-51
Table 4-50: 2040 Scenario 3 Los Alamos System Power Flow Results....4-51
Table 4-51: 2040 Scenario 3 White Rock System Power Flow Results....4-52
Table 4-52: 2040 Scenario 3 Los Alamos Townsite System Contingency Review....4-52
Table 4-53: 2040 Scenario 3 White Rock System Contingency Review....4-53

Table 4-54: 2040 Scenario 3 Los Alamos Townsite System Asset Replacement Estimate ........ 4-53
Table 4-55: 2055 Scenario 3 White Rock System Asset Replacement Estimate ........ 4-53
Table 4-56: Transmission Scale BESS ........ 1
Table 4-57: Distribution Scale BESS ........ 2
Table 4-58: Residential Scale BESS ........ 3
Table 4-59: Residential Scale BESS ........ 4
Table 4-60: BESS Ownership and Operation Considerations ........ 4
Table 4-61: Modular Vs Traditional Substation Considerations ........ 8

# 1.0 Inputs and Assumptions

The Los Alamos County Department of Public Utilities (LACDPU) provided many data sources to the 1898 & Co. project team assist with the assessment of the distribution system. Several workshops and discussions were held to identify system planning criteria, objectives for system improvements, and concerns for the safe and reliable operation of the system as electrification continues. The following sections document many of the data sources, planning criteria, and key decisions made for this study.

## 1.1 LACDPU Provided Documents and Data

During the initial stages of this study, LACDPU provided several documents and resources to 1898 & Co. These documents were beneficial for understanding the status of the existing system, the growth of solar PV adoption, asset health, and other various insights to the utility. The following list provides a summary of the documentation reviewed by 1898 & Co.

- **2024 Electrical Condition Assessment** – This document provided an overview of the health of various assets within the LACDPU system. It also discussed historical reliability, operational considerations, and a narrative overview of the system.
- **Electric Resilience Presentation to BPU** – This presentation provided an overview of the LACDPU system and objectives for performing future studies.
- **Los Alamos Integrated Resource Plan** - This document provided an overview of the Los Alamos 2022 IRP, including its preferred portfolio and near-term action plan on resource procurement.
- **Experience and Operations** – This document summarizes the Electric Distribution Department staff, education levels, responsibilities, and job functions.
- **Los Alamos Climate Action Plan (CAP)** – A plan compiled by Los Alamos County to identify carbon emission sources and develop focus areas/strategies for reducing carbon emissions.
- **Reliability Plan 2024** - This document outlines the upcoming projects that LACDPU is constructing to improve the system's reliability and resiliency. It also provides additional discussions on growing PV on the LACDPU system, operational challenges, and aging infrastructure.
- **Town Site Loads** – This Excel file contained the manual meter readings of the distribution feeders at the Townsite Substation, at different times, for the previous year. Amperage per phase was provided along with the reactive power demand.
- **White Rock Sub Loads** - This Excel file contained the manual meter readings of the distribution feeders at the White Rock Substation, at different times, for the previous year. Amperage per phase was provided along with the reactive power demand.
- **Electrification Usage Data** – Total energy usage for all customers in the months of March 2025 and December 2024 was provided, organized by customer meter number.
- **Electrification Customer Data** – Monthly energy and peak demand data were provided for commercial customers for the 12-month period from November 2023 to November 2024.
- **EA4 Feeder Monthly Peaks** - Monthly energy and peak demand readings for the EA4 feeder.
- **LA3_S** - Monthly energy and peak demand for the Los Alamos Research Park facility.
- **TC1-TC2 2024 kW Calculated** – Hourly demand data during 2024 for the TC1 and TC2 primary feeders that serve the Los Alamos Townsite Substation.
- **Los Alamos Power Pool Maximum Demand** – Monthly peak demand data for the Los Alamos Power Pool.

- **Consumption Gas Report** - Monthly natural gas consumption data by customer was provided for the 12-month period from February 2024 to February 2025.
- **PV Meter List** - LACDPU tracks solar PV applications and installations within the county. This list provided insights into the rate of PV adoption over time.
- **Utility Rules and Regulations** - Municipal codes, policies, and procedures are documented on the county's website[1].
- **DPU Construction Standards** - Standard drawings pertaining to the construction of various common components of the electric utility system[2].
- **WindMil Power Flow Model** - This is a model of the LACDPU system that contains pertinent information for conducting power flow analysis, such as power lines, transformers, switches, protective device equipment, and customer loads.
- **Jemez Fire Protection Electric Estimates** - An estimate prepared for a recent large project was shared to provide representative costs for common equipment purchased by LACDPU.
- **White Rock Phasing Maps** - These maps were provided to assist in the WindMil model cleanup effort and validate line phasing for the White Rock system.
- **LACDPU Asset Transfer Project Overview Presentation** - This presentation was shared to understand the assets being transferred from LANL ownership to LACDPU ownership and how the system will be reconfigured with the LASS Substation.

## 1.2 Substation Transformers

The LACDPU system is served by two substations. Table 1-1 shows the substation transformers used in both the Los Alamos Townsite and White Rock systems. At each substation, there are multiple transformers to maintain service in case of equipment failure.

**Table 1-1: Substation Transformer Ratings**

| Substation | Normal Rating | Comments |
|---|---|---|
| Los Alamos Townsite 1 | 20,000 kVA | Shared with LANL |
| Los Alamos Townsite 2 | 20,000 kVA | Shared with LANL |
| White Rock XFMR 1 | 5,000 kVA | Backup transformer |
| White Rock XFMR 2 | 7,500 kVA | Primary transformer |

## 1.3 Distribution Feeder Peak Load

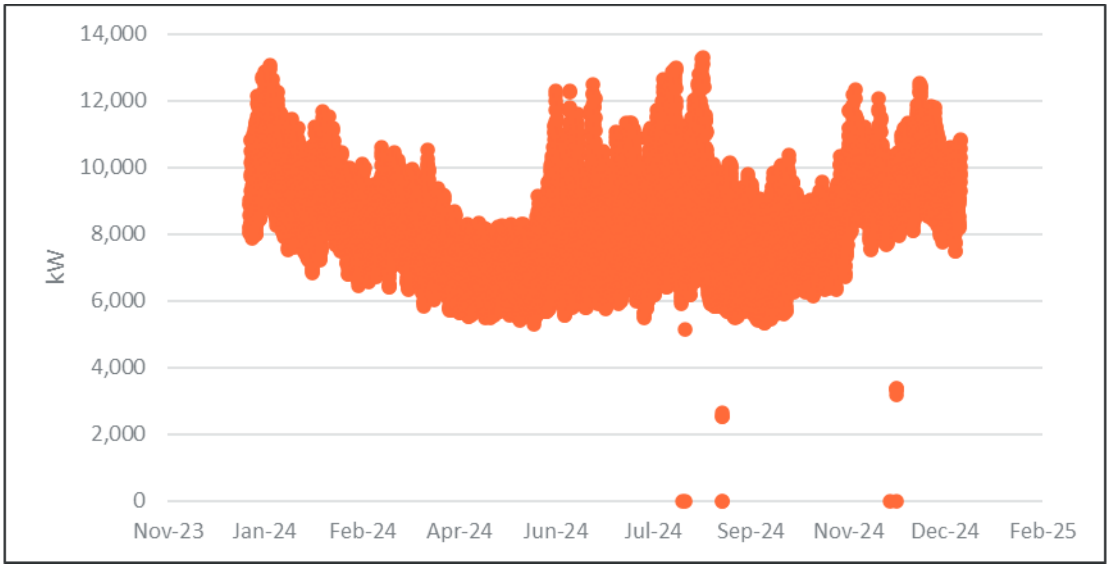
The LACDPU project team identified system load data to allocate the peak planning model. Data availability was a challenge for both the Los Alamos Townsite and White Rock systems, as LACDPU does not have historical distribution feeder SCADA data. Slightly different approaches were taken for the Los Alamos Townsite and White Rock systems.

[1] Los Alamos County Rules and Regulations
https://library.municode.com/nm/los_alamos_county/codes/code_of_ordinances?nodeId=PTIICOOR_CH40UT
[2] DPU Construction Standards
https://losalamosnm.egnyte.com/fl/nViBAuIAID#folder-link/DPU%20Construction%20Standards

### 1.3.1 Los Alamos Townsite Substation

Two primary feeders from the Los Alamos National Laboratory (LANL) TA-3 Substation serve the Los Alamos Town Site. Real power readings for these two primary feeders were the foundation for allocating the planning model for the Los Alamos Townsite system. Hourly real power readings for the year 2024 were reviewed for these two primary feeders. Figure 1-1 shows the yearly profile for the aggregated Los Alamos Townsite Substation. The Los Alamos Townsite Substation appears to peak at a similar magnitude in both the summer and winter seasons.

Figure 1-1: Los Alamos Townsite Substation 2024 Load Readings




1898 & Co. selected the winter peak to model for this study because the complete LACDPU system historically has peaked in the winter, and other data provided by LACDPU centers around this winter season. Table 1-2 shows the peak primary feeder readings for the community of Los Alamos in the winter season. No reactive power readings were available for these two primary feeders. A 95% power factor was assumed for the Los Alamos Townsite system.

Table 1-2: Los Alamos Townsite Substation Peak Load

| Primary Feeder | Distribution Feeders Served | Peak Load | Date |
|---|---|---|---|
| TC 1 | 13, 14, 15 | 9,009 kW | 1/11/2024 7:00 PM |
| TC 2 | 16, 17, 18 | 4,050 kW | 1/11/2024 7:00 PM |
| Total | - | 13,059 kW | 1/11/2024 7:00 PM |

LACDPU does not have historical SCADA readings for the distribution feeders serving the Los Alamos Townsite system. However, amperage readings are periodically recorded for each feeder. Table 1-3 shows the amperage readings for each feeder recorded during similar date and weather conditions to the peak load shown in Table 1-2 above. These readings show that each distribution feeder on the system is balanced. The total of these readings shows 11,401 kVA of total load on the Los Alamos Townsite system. These readings were scaled to estimate the feeder amperage during the recorded peak on 1/11/2024.

Table 1-3: Los Alamos Townsite Feeder Amperage Readings

| Feeder | Amps A | Amps B | Amps C | kVA | Date |
|---|---|---|---|---|---|
| 13 | 129 | 130 | 131 | 2,972 | 1/9/2025 4:00 PM |
| 14 | 95 | 70 | 97 | 1,997 | 1/9/2025 4:00 PM |
| 15 | 77 | 92 | 111 | 2,134 | 1/9/2025 4:00 PM |
| 16 | 84 | 114 | 82 | 2,134 | 1/9/2025 4:00 PM |
| 17 | 65 | 70 | 67 | 1,539 | 1/9/2025 4:00 PM |
| 18 | 27 | 28 | 27 | 625 | 1/9/2025 4:00 PM |
| **Total** | **477** | **504** | **515** | **11,401** | **1/9/2025 4:00 PM** |

The scaled distribution feeder amperage to match the Los Alamos Townsite Substation peak on 1/11/2024 is shown in Table 1-4. These phase currents were used during the WindMil model load allocation process.

Table 1-4: Los Alamos Town Site Substation Feeder Amperage Scaled to Peak Load

| Feeder | Amps A | Amps B | Amps C | kVA |
|---|---|---|---|---|
| 13 | 156 | 157 | 158 | 3,583 |
| 14 | 115 | 84 | 117 | 2,407 |
| 15 | 93 | 111 | 134 | 2,572 |
| 16 | 101 | 137 | 99 | 2,572 |
| 17 | 78 | 84 | 81 | 1,856 |
| 18 | 33 | 34 | 33 | 753 |
| **Total** | **576** | **607** | **622** | **13,743** |

### 1.3.2 Additional Loads Considered for the LASS Substation

LACDPU historically has served some loads using distribution feeders from LANL. These loads were not included in the data shown above for the primary feeders TC1 and TC2, but must be considered within the WindMil power flow model. Once the LASS Substation is energized, these loads will be served directly through the LACDPU infrastructure. Table 1-5 shows the peak load used for this study. Some additional assumptions were necessary to estimate peak load on these distribution feeders.

Table 1-5: Additional Loads Considered in Los Alamos

| Feeder | Amps A | Amps B | Amps C | kVA | Comments |
|---|---|---|---|---|---|
| EA4 | 72 | 72 | 72 | 1,686 | This feeder primarily serves water wells on the east side of the Los Alamos Townsite system. The maximum demand recorded for this feeder in January 2024 was utilized for this study |
| NS3 | 26 | 26 | 26 | 628 | This feeder primarily serves the Los Alamos Research Park. Peak month metered demand for these customers was utilized for this study. |
| NS6 | 54 | 54 | 54 | 1,294 | This feeder primarily serves the Los Alamos Medical Center. To estimate peak demand for this feeder, a combination of peak month billing demand and transformer sizes was used. |
| S-18 | 5 | 10 | 14 | 242 | Phase current readings were utilized for this feeder. |

### 1.3.3 White Rock Community

No historical SCADA readings are available for the White Rock system. Like Los Alamos Townsite, amp readings are taken periodically and recorded. These periodical amp readings were the best data available for modeling the White Rock system peak load. The peak readings in Table 1-6 were used for allocating the White Rock system planning model. A 95% power factor was also assumed for the White Rock system.

Table 1-6: White Rock Feeder Amperage Readings

| Feeder | Amps A | Amps B | Amps C | kVA | Date |
|---|---|---|---|---|---|
| WR1 | 101 | 110 | 79 | 2,087 | 1/21/2025 4:10 PM |
| WR2 | 81 | 58 | 64 | 1,461 | 1/21/2025 4:10 PM |
| WR3 | 9 | 4 | 10 | 165 | 1/21/2025 4:10 PM |
| **Total** | **191** | **172** | **153** | **3,713** | **1/21/2025 4:10 PM** |

## 1.4 Distribution Feeder Minimum Daylight Load

System load data to allocate the minimum daylight load planning model was necessary to perform the hosting capacity analysis. Periodical feeder amperage readings were used to determine the minimum daylight load for all distribution feeders in the LACDPU system. Table 1-7 shows the readings used for allocating the planning model. Because historical SCADA readings are not available, the minimum daylight load for these feeders could potentially be lower. When LACDPU has more frequent meter readings, the minimum daylight load for each distribution feeder can be tracked more accurately.

Table 1-7: Los Alamos System Feeder Minimum Daylight Load Readings

| Station | Feeder | Amps A | Amps B | Amps C | kVA | Date |
|---|---|---|---|---|---|---|
| Town Site | 13 | 67 | 66 | 70 | 1,547 | 4/7/2025 4:18 PM |
| | 14 | 42 | 47 | 48 | 1,044 | 4/7/2025 4:18 PM |
| | 15 | 42 | 53 | 60 | 1,181 | 4/7/2025 4:18 PM |
| | 16 | 53 | 47 | 53 | 1,166 | 4/7/2025 4:18 PM |
| | 17 | 60 | 65 | 62 | 1,425 | 4/7/2025 4:18 PM |
| | 18 | 24 | 27 | 25 | 579 | 4/7/2025 4:18 PM |
| | **Total** | **288** | **305** | **318** | **6,942** | **4/7/2025 4:18 PM** |
| White Rock | WR1 | 56 | 61 | 43 | 1,151 | 4/7/2025 1:34 PM |
| | WR2 | 36 | 18 | 22 | 547 | 4/7/2025 1:34 PM |
| | WR3 | 0 | 0 | 5 | 36 | 4/7/2025 1:34 PM |
| | **Total** | **92** | **79** | **70** | **1,734** | **4/7/2025 1:34 PM** |

As discussed in the distribution feeder peak load section, there are some LACDPU loads served through the LANL infrastructure. Feeder amperage readings during a minimum daylight time were not available for these feeders. Some additional data sources were reviewed, and assumptions were made to estimate the minimum daylight load as shown in Table 1-8.

Table 1-8: Minimum Daylight Load for Additional Feeders

| Feeder | Amps A | Amps B | Amps C | kVA | Comments |
|---|---|---|---|---|---|
| EA4 | 8 | 8 | 8 | 197 | This feeder primarily serves water wells on the east side of the Los Alamos Townsite system. Only monthly peak demand readings are available. In November 2024, a monthly peak of 197 kW was recorded. This reading was utilized for the feeder daytime minimum load, as it is approximately 15% of the peak load. |
| NS3 | 8 | 8 | 8 | 190 | No daytime minimum feeder readings were available. 30% of the peak load was utilized for this daytime minimum load. |
| NS6 | 16 | 16 | 16 | 382 | No daytime minimum feeder readings were available. 30% of the peak load was utilized for this daytime minimum load. |
| S-18 | 1 | 3 | 4 | 62 | No daytime minimum feeder amperage readings were available during this study. 50% of the peak feeder amperage readings were utilized to represent the daytime minimum load. |

## 1.5 Solar PV

The LACDPU system has many customer-owned solar PV systems in operation. 1898 & Co. reviewed historical records to understand the number of solar PV generators in the system today and the rate of adoption over time. Figure  shows the growth in solar PV installations over time.

Figure 1-2: Connected Solar PV Capacity

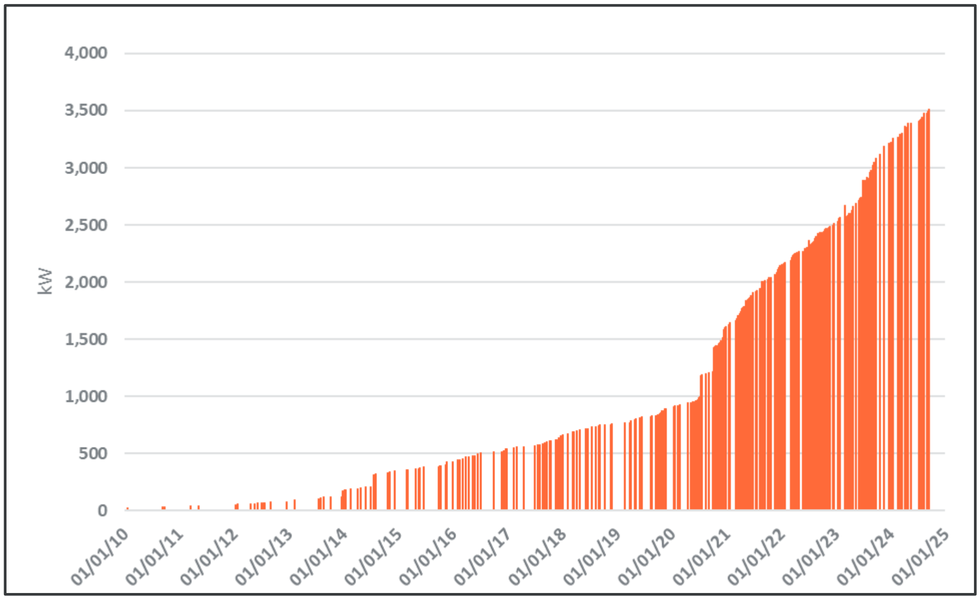
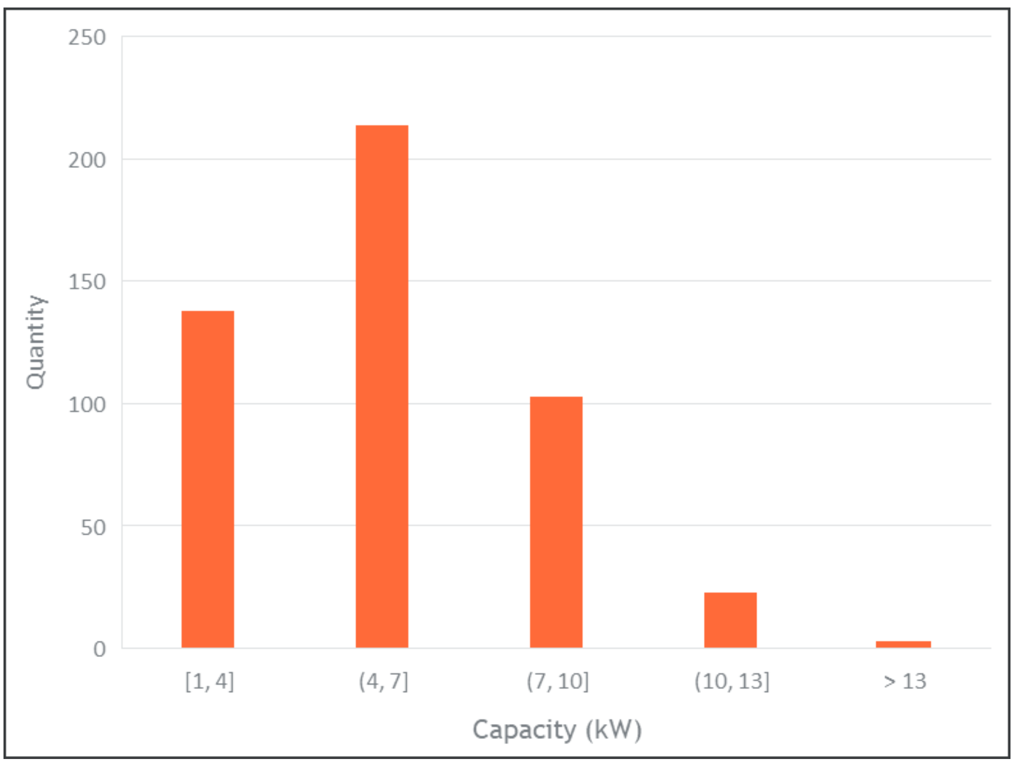



Figure  shows the sizes of solar PV installations within the County. Most customer-owned systems are below 10 kW, which is typical of residential-sized generators. However, there are some systems greater than 10 kW connected in the County.

Figure 1-3: Residential Solar PV System Size



## 1.6 Residential Customers

Residential customers within the LACDPU system are billed based on energy usage each month. Billing information was incorporated into the WindMil power flow model during the load allocation process, and monthly kWh usage was used to allocate the baseline models.

## 1.7 Commercial Customers

Commercial customers within the LACDPU system have different billing structures from residential customers. Peak demand is recorded monthly for commercial customers and incorporated into their monthly bill. This peak demand recorded during the peak month was utilized by 1898 & Co. for validating the peak power flow model and representing the grid impact from commercial customers. Specific considerations were given if a customer's peak demand was greater than 25 kW. These peak demands are specific to each customer and do not necessarily coincide with the LACDPU system peak. There is natural diversity among customers, so it is not likely that all commercial customers will reach their individual peak demand at the same time. However, weather and other conditions can influence customers to be near their peak load around the same time. For the daytime minimum power flow model, monthly kWh energy use was considered instead of peak demand for commercial customers when allocating the model.

## 1.8 Distribution System Equipment

Many utilities typically utilize capacitor banks and voltage regulators to maintain customer service voltage and improve system performance. The LACDPU system is compact relative to other distribution systems. LACDPU uses a 125 V setpoint at both the White Rock and Los Alamos substations to maintain voltage on the distribution system.

## 1.9 Load Allocation Process

The primary objective for load allocation was to utilize customer billing data (kWh method) to more accurately model where energy is being consumed at higher rates within the LACDPU system within the WindMil power flow model. For most of the distribution feeders, this method worked successfully. However, for Los Alamos Townsite Substation Feeder 13, the kWh method would not converge. Nonconvergence can result from connectivity errors in the model, inaccurate load data, or inaccurate equipment data. For this distribution feeder, the transformer kVA method was utilized to allocate the model. This alternate method allocates load in the model based on the service transformer size and can simplify the convergence of the power flow simulation. EA4 is a distribution feeder that is sourced from LANL and serves water pumping facilities east of Los Alamos. This is a long feeder that also has nonconvergence issues. This distribution feeder was allocated using the "length" method, where the load is placed along the line sections of the feeder proportional to their length. This method is the least desirable but was necessary for the convergence of the power flow simulation. Table 1-9 identifies the method that was utilized for each distribution feeder.

**Table 1-9: Distribution Feeder Load Allocation Method**

| Station | Distribution Feeder | Allocation Method |
|---|---|---|
| Town Site | 13 | Transformer kVA Method |
| | 14 | kWH Method |
| | 15 | kWH Method |
| | 16 | kWH Method |
| | 17 | kWH Method |
| | 18 | kWH Method |
| LANL | EA4 | Length |
| White Rock | WR1 | kWH Method |
| | WR2 | kWH Method |
| | WR3 | kWH Method |

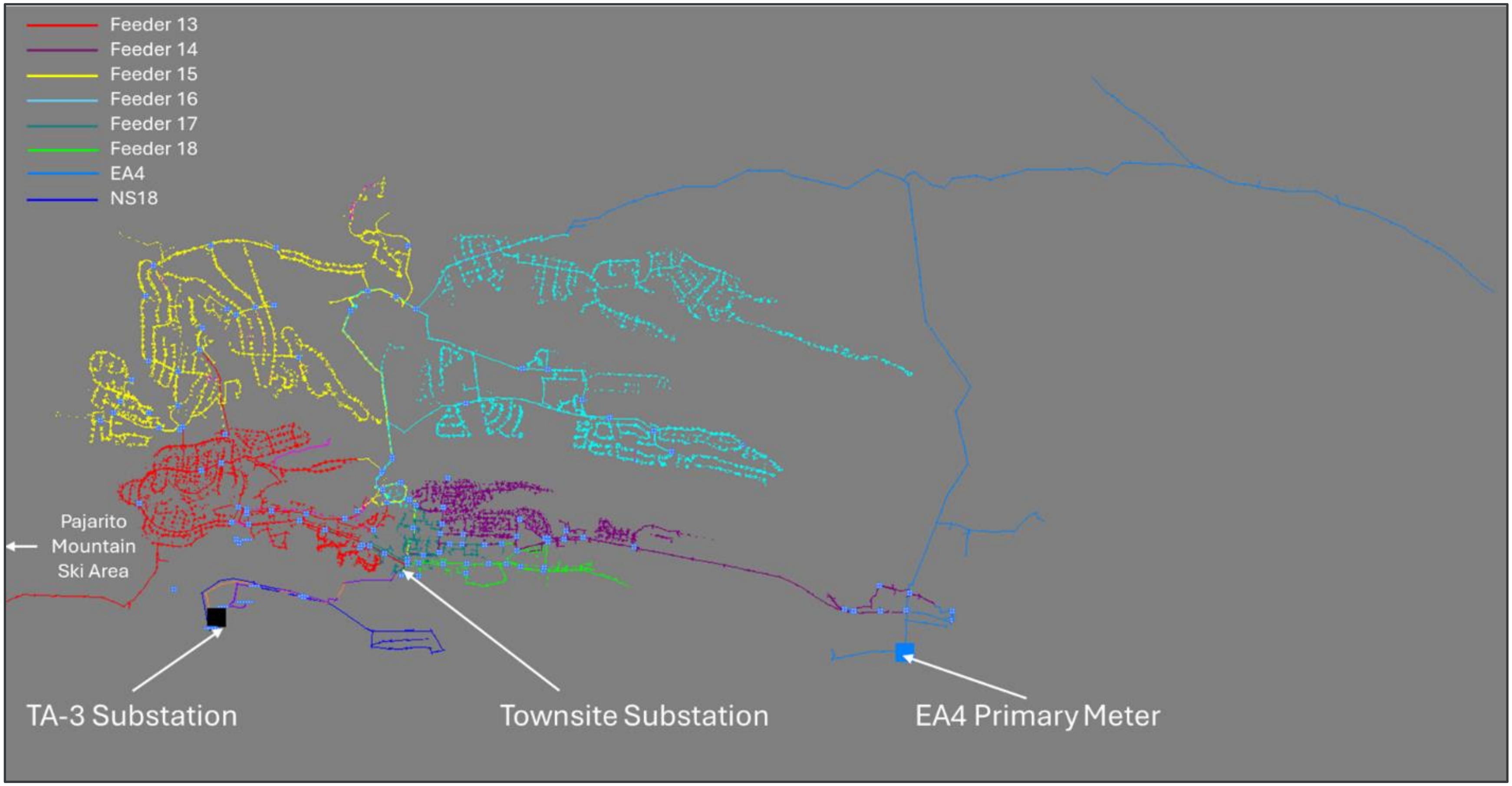
The distribution feeder amperage readings are shown in Table 1-4, Table 1-6, and Table 1-7 and were used to allocate each distribution feeder for the peak load and daytime minimum load models. The following assumptions were used when allocating the model.

- A 95% power factor was assumed for all customers within the LACDPU system.
- For the peak model, rooftop PV generators were set to 0% output due to the Los Alamos Townsite system's peak time in the evening. 35% was used in White Rock, as the recorded peak was at 4 PM.
- For the minimum model, rooftop PV generators were set to 70% output for the Los Alamos Townsite and White Rock systems.
- Commercial customers' load was set to their peak demand during January for the peak load model. Commercial customers were allocated similarly to residential customers for the daytime minimum load model.

## 1.10 New Los Alamos Switching Station

LACDPU recently energized the new LASS Substation to provide an additional source and new distribution feeders to the Los Alamos Townsite System. This new station will improve reliability by reducing customer counts per feeder and exposure per feeder, and improve the system's operational flexibility. Figure  shows the previous configuration of the Los Alamos Townsite system. The previous configuration utilized six county-owned distribution feeders, and several distribution feeders sourced from LANL.

**Figure 1-4: Previous Configuration of the Los Alamos Town Site System**



The previous configuration of the Los Alamos system was used to allocate the power flow model based on historical data. Next, the model was reconfigured to represent the current configuration of the Los Alamos system with the LASS Substation energized. Figure  shows the model updated with the new LASS Substation, which adds redundancy and additional distribution feeders to the area. This current configuration, with the LASS Substation energized, was the foundation for the power flow analysis in this study.

**Figure 1-5: Current Configuration of the Los Alamos Townsite System with LASS Substation Energized**

## 1.11 Distribution Planning Criteria

The following criteria were used to evaluate the distribution system's performance, both for the existing system assessment and for analyzing the future system. Distribution planning criteria are based on normal operating equipment ratings and standard system criteria to maintain safe and reliable customer service.

- No conductor or equipment should exceed 100% of the normal rating.
- The primary voltage should be between 118 V and 126 V, following ANSI C84.1 range A and assuming a 4 V drop through the service transformer.
- LACDPU system feeder relays and reclosers are not configured to detect reverse power flow. Reverse power flow through these devices was not permitted for hosting capacity analysis.

## 1.12 Eastgate Substation Representative Cost

LACDPU has previously proposed constructing a new substation on the east border of the Los Alamos Townsite system. This would be a traditional substation with power transformers connected to the area's 115 kV transmission system. This study confirmed that the Eastgate Substation was required to successfully serve customers in the Los Alamos Townsite system for all electrification scenarios. Table 1-10 shows the assumed capacity and equipment for the Eastgate Substation in each electrification forecast scenario. The range of magnitude estimates for each scenario was incorporated into the financial analysis. These costs are 2025 dollars.

**Table 1-10: Eastgate Substation Representative Cost**

| Scenario | Capacity and Equipment | Cost |
|---|---|---|
| High Electrification | Two 33.7 MVA transformers, each with a four-feeder switchgear and a tie breaker between the two switchgears. One mile 115 kV transmission line extension. | $17,700,000 |
| Medium Electrification | Two 22.4 MVA Transformers, each with a four-feeder switchgear and tie breaker between the two switchgears. One mile 115 kV transmission line extension. | $17,000,000 |
| Low Electrification | Two 14 MVA Transformers, each with a four-feeder switchgear and tie breaker between the two switchgears. One mile 115 kV transmission line extension. | $16,800,000 |

## 1.13 White Rock Substation Upgrade Representative Cost

Upgrades at the White Rock Substation are anticipated to be necessary for supporting forecasted electrification load growth in the White Rock system. Table 1-11 shows the assumed upgraded capacity and equipment for the White Rock Substation in each electrification forecast scenario. The range of magnitude estimates for each scenario was incorporated into the financial analysis. These costs are 2025 dollars.

Table 1-11: White Rock Substation Upgrade Representative Cost

| Scenario | Capacity and Equipment | Cost |
|---|---|---|
| High Electrification | Upgrade the complete White Rock Substation to two 22.4 MVA transformers, with four feeder switchgears and a tie-breaker between the two switchgears. | $12,700,000 |
| Medium Electrification | Upgrade the complete White Rock Substation to two 14 MVA transformers, four feeder switchgears and a tie-breaker between the two switchgears. | $12,700,000 |
| 2055 Low Electrification | Replace the existing transformers with two 10 MVA transformers and keep much of the equipment the same. | $5,200,000 |
| 2040 Low Electrification | Only replace Transformer 1 with a 10 MVA transformer and keep much of the equipment within the substation the same. | $2,600,000 |

## 1.14 Representative Distribution System Equipment Costs

LACDPU provided copies of recent job estimates that were reviewed, in addition to other construction estimate documentation in the State of New Mexico, to inform the following range of magnitude estimates for typical equipment identified in this study. Table 1-12 shows the common equipment utilized in the distribution system. This is not an exhaustive list of equipment utilized by the LACDPU. This range of magnitude costs was used to estimate the high-level financial impact of each electrification scenario evaluated. It is anticipated that with electrification, single-phase residential service transformers will be replaced with higher ratings, and/or multiple transformers will replace a single existing service transformer. A higher equipment cost of $10,000 was used for this study, which is approximately 1.25 times the average historical residential service transformer cost ($8,000). Secondary service lines can vary significantly for customers throughout the LACDPU system. This estimated average service line upgrade cost was applied in this study. These costs are 2025 dollars.

Table 1-12: Common Equipment Representative Costs

| Equipment/Project | Unit Cost |
|---|---|
| 1 Mile of Installed 500 MCM CU Cable | $2,300,000 |
| 1 Mile of Installed 4/0 CU Cable | $1,800,000 |
| 1 Mile of Installed 477 ACSR Conductor | $525,000 |
| 1 Mile of Installed 4/0 ACSR Conductor | $500,000 |
| PME Switch (Various Types) | $75,000 |
| Overhead Switch | $25,000 |
| 1,800 kVAR Capacitor Bank | $115,000 |
| 500 kVA Voltage Regulator | $90,000 |
| Residential Single-Phase Service Transformer (Various Sizes) | $10,000 |
| Commercial Three-Phase Service Transformer (Various Sizes) | $90,000 |
| Typical Secondary Service Line Upgrade (~500 ft.) | $6,000 |

# 2.0 Existing System Review

The 1898 & Co. team reviewed several data sources provided by LACDPU to understand the condition of the existing infrastructure. System models were also evaluated, and power flow analysis was performed to observe their performance.

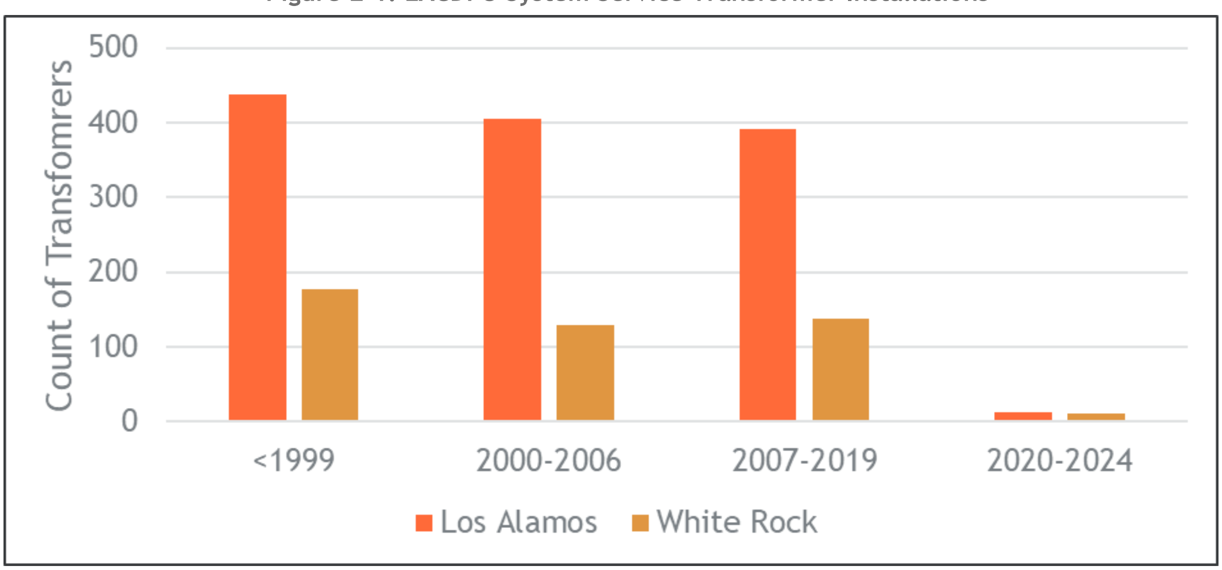
## 2.1 Distribution Asset Health and Reliability Review

Operating an electrical distribution system requires the procurement and maintenance of many different assets. Some of the major assets in the Los Alamos system are service transformers, main line switches, underground cable, and overhead conductor. These assets are vital to the delivery of power from the county-owned substations to customers. LACDPU performed a condition assessment of these major assets that 1898 & Co. reviewed for this study. A summary of this assessment and the 1898 & Co. review is discussed below.

### 2.1.1 Service Transformers

Service transformers convert the primary system medium voltage to the appropriate utilization voltage for customers. These transformers can be mounted on pole tops or pad mounted. For the LACDPU system, service transformers have an expected service life of 25-40 years. Figure  shows the ages of all service transformers within the LACDPU system. Approximately 600 service transformers were installed before 1999 and are nearing the end of their expected service life. LACDPU typically does not replace service transformers until failure, visible equipment damage, or if there are customer service increases that require an upgrade of the service transformer. This service transformer replacement practice is typical for the electric utility industry. LACDPU is replacing aged assets as operational budgets allow. When service transformers are replaced, LACDPU increases the size to provide additional capacity for future electrification. It is assumed in this study that the secondary service conductors are of the same age and condition as the associated service transformers. Secondary service conductors must also be replaced at similar rates to the service transformers. Given this study's 30-year horizon, it is anticipated that most existing service transformers and associated secondary service conductors will need to be replaced by 2055.

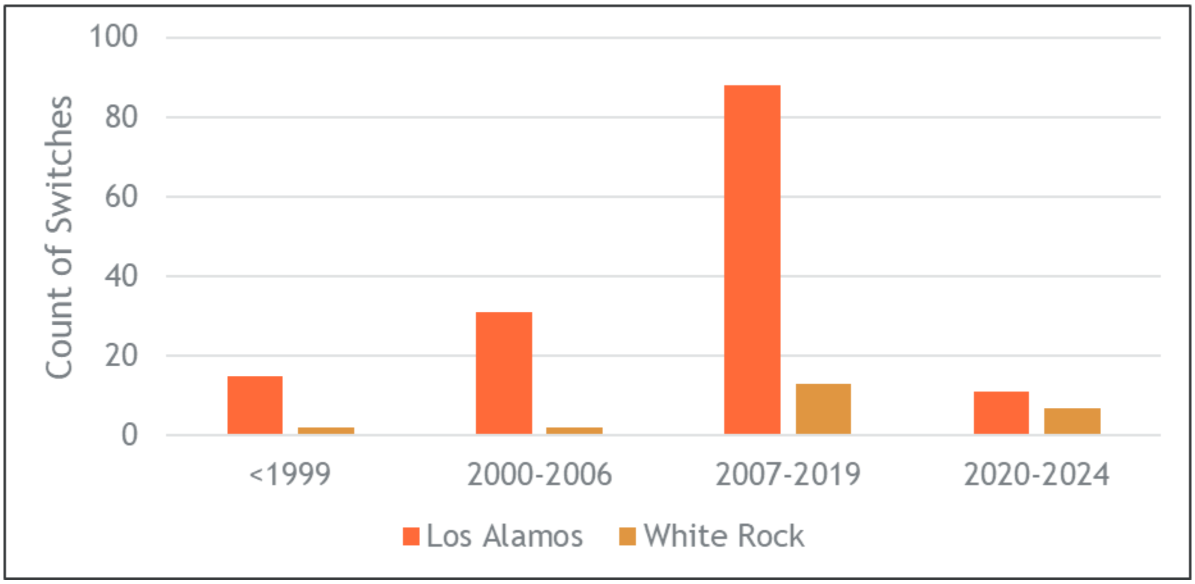
Figure 2-1: LACDPU System Service Transformer Installations



### 2.1.2 Mainline Switches

Mainline switches are used to sectionalize/isolate portions of the distribution feeder and provide termination points for conductor/cable. Mainline switches are primarily in the underground portion of the LACDPU system and are pad mounted. For the LACDPU system, mainline switches have an expected life of 20 years. Figure  shows the ages of all mainline switches within the LACDPU system. Since 2006, LACDPU has made a significant effort to replace failing switches. Most switches within the LACDPU system operate within the expected asset life. LACDPU inspects switches for damage/deterioration and replaces switches preemptively when issues are identified. However, some switches are beyond their life expectancy and must be replaced to avoid equipment failure and customer outages. Given this study’s 30-year timeline, it is anticipated that all existing mainline switches will need to be replaced by 2055.

Figure 2-2: LACDPU System Switch Installations

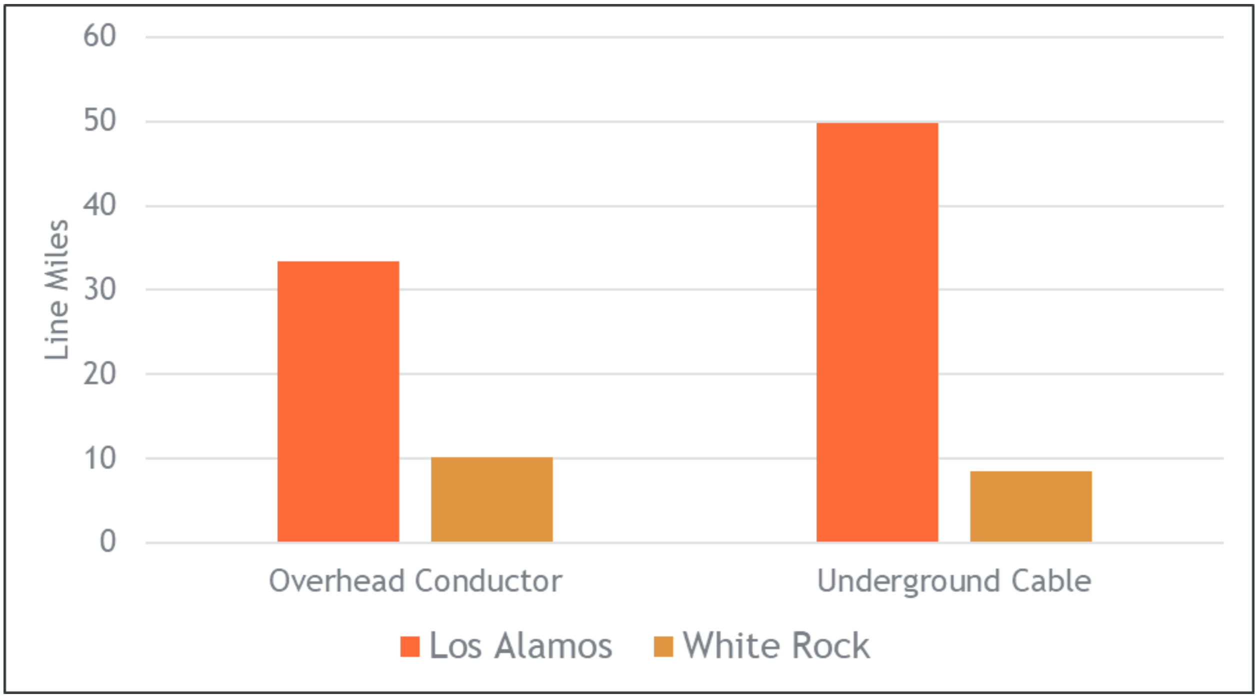



### 2.1.3 Overhead Conductor and Underground Cable

Overhead conductors are a cost-effective way to deliver power to customers. However, they are more susceptible to faults and typically have lower reliability than underground cable. Overhead conductors are also more aesthetically impactful. The life expectancy of overhead conductors used in the LACDPU system is 40 years. The WindMil power flow model shows that approximately 43 line-miles of primary overhead conductor exist within the LACDPU system.

Underground cable distributes power to customers with minimal aesthetic impact and typically better reliability than overhead conductors. The life expectancy of underground cables used in the LACDPU system is 30 years. However, if cable is installed in conduit, it can have an improved lifespan over direct buried cable. The WindMil power flow model shows that approximately 58 line-miles of primary underground cable exist within the LACDPU system. Figure  shows the approximate number of primary overhead conductors and primary underground cables within the LACDPU system. Given this study's 30-year timeline, most existing overhead conductors and underground cables are anticipated to need to be replaced by 2055.

Figure 2-3: LACDPU System Primary Overhead Conductor and Primary Underground Cable Line Miles




## 2.2 Substation Assessment

1898 & Co. performed a walk-down of LACDPU-owned substation yards to visually inspect the condition of equipment and to assess the overall condition and functionality of key components. This included a general review of transformers, circuit breakers, switchgear, busbars, grounding systems, and protective relays to identify signs of wear, malfunction, or potential safety risks. Additionally, the review evaluated the condition of site access, security, and the substation layout, alongside a review of control and SCADA systems. Environmental factors were considered, including a review of oil spill containment to ensure compliance with local and national regulations.

Below are recommendations regarding repairs, upgrades, or operational improvements to enhance the substation's efficiency and safety. This also includes a list of action items to address areas requiring attention to ensure long-term reliability.

### 2.2.1 White Rock Substation

This is a two (2) unit Substation with Unit 1 (115kV/12.47kV at 5/5.6/7 MVA) installed in the 1950s. In 2019, transformer arresters & bushings were replaced, and a new circuit switcher and switchgear enclosure were installed. Dead-End Disconnect Switch blades were replaced in 2020.

Findings and recommendations for Unit 1 of White Rock Substation are as follows:

- The existing Transformer is equipped with an automatic tap changer; however, it is not functioning properly, requiring maintenance crews to manually adjust tap settings in the field. We recommend replacing this with an automatic on-load tap changer to ensure proper voltage regulation.

Unit 2 (115kV/12.47kV at 7.5/11.5/15.5 MVA), first installed around the 1950s, underwent a full rebuild in 2006, which included a new circuit switcher, transformer and switchgear enclosure.

Findings and recommendations for Unit 2 of Whiterock Substation are as follows:

- The existing Transformer has multiple leaks; we recommend addressing these repairs as soon as possible to prevent further issues and maintain the integrity of the transformer. We also recommend performing annual Dissolved Gas Analysis (DGA) testing on the transformer as it supports early fault detection, enables condition-based maintenance, and contributes to extending the transformer's operational life.

The following recommendations are applicable to both Unit 1 & Unit 2 of White Rock Station:

- The existing GE relays are outdated, obsolete, no longer supported by GE as of January 2020 and have limited capabilities, such as no advanced protection schemes, no programmable logic, basic metering, run on legacy software, have only basic communication protocols, and don't support web-based HMI. We recommend replacing them with SEL relays, which offer enhanced protection and communication capabilities. SEL relays offer advanced features such as arc flash detection, event recording, diagnostic capabilities, support latest communication protocols, built-in programmable logic, and are equipped against cybersecurity threats.
- The existing GE meters provide basic energy and power calculations, but lack advanced power quality monitoring, supports legacy communication protocols, runs on legacy software, lacks encryption, have fixed I/O's and legacy support from GE. We recommend replacing them with SEL-735 meters to improve accuracy and resolution. SEL meters offer advanced power monitoring, built-in programmable logic for custom alarms, extensive event logs, modular I/O's, and support a wide range of modern communication protocols.
- We recommend replacing the existing RTU with the SEL-RTAC w/HMI capability which offers data acquisition & visualization, system integration, local/remote monitoring, control, integrated alarms, and annunciation.
- This station currently uses radio/modem setup for communication purposes. We recommend upgrading to fiber to improve data speed, reliability, and security.

### 2.2.2 Los Alamos Town Site Switching Station

This Station is a single switchgear enclosure in the town of Los Alamos without any type of security fencing.

Findings and recommendations for Town Site are as follows:

- We recommend installing a durable, weather-resistant security fence around the switchgear to safeguard personnel, prevent unauthorized access, reduce liability, and comply with safety regulations.
- Breakers at this station currently lack remote control capability. We recommend upgrading them to enable remote operation for improved safety, control, and response time.
- The existing GE relays are outdated, obsolete, no longer supported by GE as of January 2020 and have limited capabilities, such as no advanced protection schemes, no programmable logic, basic metering, run on legacy software, have only basic communication protocols, and don't support web-based HMI. We recommend replacing them with SEL relays, which offer enhanced protection and communication capabilities. SEL relays offer advanced features such as arc flash detection, event recording, diagnostic

capabilities, support latest communication protocols, built-in programmable logic, and are equipped against cybersecurity threats.

- The existing Bitronics meters are suitable for basic metering and monitoring but lack advanced power quality monitoring, supports legacy communication protocols, lacks encryption, and have fixed I/O's. We recommend replacing them with SEL-735 meters to improve accuracy and resolution. SEL meters offer advanced power monitoring, built-in programmable logic for custom alarms, extensive event logs, modular I/O's, and support a wide range of modern communication protocols.
- We recommend replacing the existing RTU with the SEL-RTAC w/HMI capability which offers data acquisition & visualization, system integration, local/remote monitoring, control, integrated alarms, and annunciation.
- This station currently uses radio/modem setup for communication purposes. We recommend upgrading to fiber to improve data speed, reliability, and security.

## 2.3 Current and Future Supply Markets Assessment

LACDPU and LANL make up the Los Alamos Power Pool (LAPP) and are currently in the implementation phase of their 2022 Integrated Resource Plan (IRP), completed in June of 2022, which determined what new resources to procure into the future to help cover their growing power supply needs. The 2022 IRP[3] included a preferred portfolio that included storage, solar, wind, and a small-modular nuclear reactor (SMR) by the end of the study period. However, the SMR project for which LACDPU was going to have a Power-Purchase Agreement (PPA) in 2030 was cancelled by the developer in November of 2023[4], so at minimum, resource procurement will have to account for covering the loss of this SMR PPA. 1898 & Co. recommends that LAPP complete an updated IRP that expands on the three cases that were evaluated in the 2022 IRP to account for all potential scenarios and determine what the optimal resource solution is. 1898 & Co. also recommends that after the 2022 IRP is updated, LAPP look at completing "IRP-lite" modeling in between the full IRP analysis to see what the optimal resource selection is based on actual market conditions and after resource procurement by LAPP.

For LAPP to determine what existing resources are available for procurement currently, they should consider releasing All-Source Request for Proposals (ASRFPs) for generating resources that are tied to what resources were considered as part of the 2022 IRP preferred portfolio. As some of the capacities for different resources LAPP is looking to acquire are under 100 MW in certain years, LAPP could consider working with Public Service Company of New Mexico (PNM) or another New Mexico entity in acquiring larger assets, whether through ownership or PPAs. 1898 & Co. cannot comment on any potential resources that could be under development in New Mexico that LAPP could investigate acquiring due to potential conflicts of interest.

[3] FTI Consulting (2022, June) Los Alamos County 2022 Integrated Resource Plan https://www.losalamosnm.us/files/sharedassets/public/v/1/departments/utilities/documents/integrated-resource-plan-irp-2022-final-report.pdf

[4] (2023, November 8). Utah Associated Municipal Power Systems (UAMPS) and NuScale Power agree to terminate the Carbon Free Power Project. https://www.nuscalepower.com/press-releases/2023/utah-associated-municipal-power-systems-and-nuscale-power-agree-to-terminate-the-carbon-free-power-project

As PNM has expressed its interest in joining the California Independent System Operator (CAISO) Extended Day-Ahead Market (EDAM), there is potential for more competitive bids from resources that LAPP can procure if they also follow PNM into participating in the CAISO EDAM. However, 1898 & Co. cannot comment with any certainty on the impacts of CAISO EDAM participation, as EDAM is not expected to become operational until May of 2026. PNM has expressed interest in becoming a participant, but has not given an explicit timeline of when they would join. Assuming PNM joins EDAM and LAPP follows PNM, LAPP would then be able to procure energy from members who are participants in the EDAM; however, they will have to verify how the power gets delivered to their footprint and would then need to be aware of potential transmission congestion and wheeling costs if they are looking to procure resources outside LAPP's footprint. These potential bottlenecks could be congestion that reduces the expected economic flow into the footprint or "pancaked" transmission/wheeling costs required to move the power as most major utilities in Arizona have announced their intentions to join SPP Markets + (a competitor to the CAISO EDAM) and the power must wheel through AZ to get into NM because of the current transmission topology.

As the CAISO EDAM Market participation rules have not been finalized, there are potential issues that could arise if LAPP were to join EDAM. Currently, load-serving entities who are members of CAISO are required to have a 15% Planning Reserve Margin (PRM) on top of their peak load to meet any potential shortfalls on their own. The 2022 preferred portfolio for LAPP did not feature a continuous 15% PRM across all years and would require additional resources to be procured to reach the 15% PRM, assuming this is still a requirement if/when LAPP joins the EDAM. LAPP should monitor these market participation rules and update its IRP modeling and resource procurement accordingly to understand the impacts of joining CAISO EDAM.

## 2.4 Existing Distribution System Model and Power Flow Assessment - Peak Load

Electric utilities typically use power flow software to study the distribution system. WindMil, a software developed by MilSoft, is utilized by LACDPU and is a standard software used among electric cooperatives and municipal utilities throughout the United States. The WindMil power flow model aggregates GIS data, equipment attributes, customer demand, and operational measurements to perform various analyses.

### 2.4.1 WindMil Power Flow Model Fidelity

After reviewing the GIS system for recent changes, the LACDPU staff developed the existing system's WindMil power flow model used for this study. LACDPU does not presently have a direct connection between the GIS system and its WindMil power flow model. As a result, manual efforts were necessary to clean up the power flow model in preparation for this study. New meters and equipment have been added for new customer loads connected in recent years. Solar PV customers are maintained in the GIS system, but these generators were not initially modeled in the WindMil power flow model. 1898 & Co. worked with the LACDPU staff to incorporate solar PV generators into the power flow model for further analysis. Another effort taken was to map billing information to modeled customers to perform a more accurate load allocation. This mapping was achieved, but must be manually maintained until a direct connection can be made between the GIS, billing information systems, and the WindMil power flow model.

1898 & Co. recommends that LACDPU further investigate the following opportunities to improve power flow modeling efforts.

- Work with MilSoft to maintain the ability to extract a current model from the GIS system. Doing so should reduce the manual efforts of maintaining a GIS system and a WindMil model separately. Below is a summary of manual efforts used to clean the model in preparation for power flow analysis.

- Meter numbers were not maintained in the WindMil power flow model. A scripting effort was required to identify the appropriate meter number for each customer in the power flow model.
- Solar PV customers were not contained in the WindMil power flow model. A scripting effort was required to add PV generators to the WindMil power flow model.
- Phasing within the power flow model was not accurate. LACDPU phasing maps were reviewed manually to correct phasing in the model. Assumptions for customer phasing were made if phasing maps were not available.
- Single-phase transformers within the overhead portions of the system were not modeled correctly. Single-phase transformers were distributed among the two-phase laterals. Manual corrections were performed.
- In several locations, conductor types were upgraded to reflect recent capital projects where three-phase lines were extended to new pad mount switchgear.
- Secondary conductors in many locations were not modeled correctly. A strenuous effort was necessary to correct parallel secondary conductors and unintended loops. This model cleanup can potentially influence the results of the power flow analysis. Field verification and improv GIS mapping would be the ideal approach to correct this in the future.

- Maintain a historical record of SCADA data for feeders and substations. Recording historical interval data for the distribution feeders and substation transformers will help future modeling efforts allocate loads to different system demands.
- Develop a process for incorporating customer billing information into the WindMil power flow model. This will streamline future load allocations and specific scenario analysis. Not all customers within the WindMil power flow model successfully incorporated billing information, which influenced the accuracy of the load allocation and required 1898 & Co. to utilize different load allocation methods in this study.

### 2.4.2 Normal Configuration Review

1898 & Co. evaluated the current Los Alamos Townsite system's power flow with the energized LASS Substation. Figure  shows an overview of the Los Alamos Townsite system. Red represents the feeders that originate from the LASS Substation. Blue represents the distribution feeders that originate from the Townsite Substation. Green represents the primary feeders that originate from the TA3 Substation.

**Figure 2-4: Los Alamos Townsite System Colored By Substation**

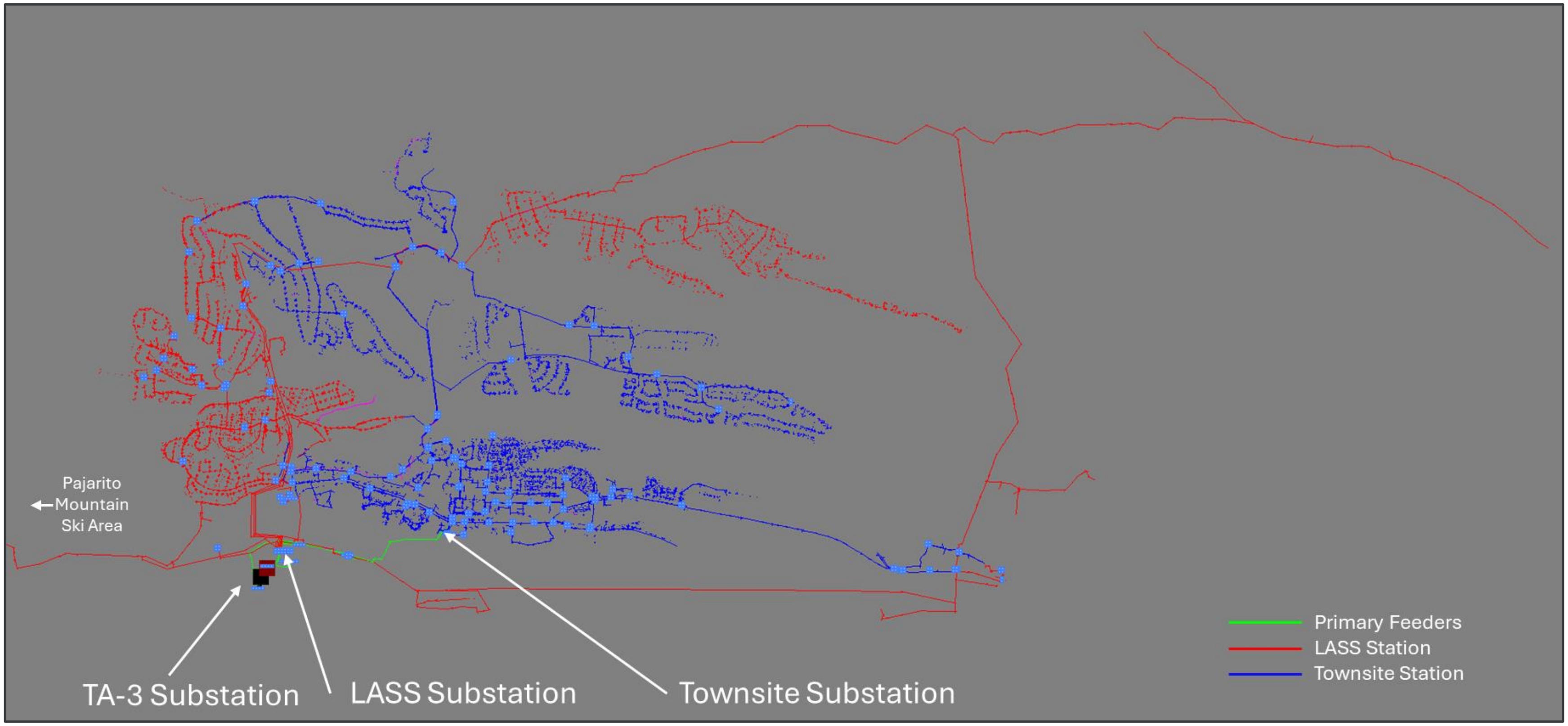


Table 2-1 shows the power flow results for each distribution feeder within the Los Alamos Townsite system. No voltage or equipment loading violations were observed. The LASS Substation results in many more distribution feeders within the Los Alamos Townsite system, which helps reduce the customer load per feeder. Reducing the load per distribution feeder helps to limit the number of customers impacted by potential outages. However, the LASS Substation does not increase the load serving capacity of the Los Alamos Townsite System. The substation transformers at the TA-3 Substation limit the load serving capacity.

**Table 2-1: Los Alamos Townsite System Normal Configuration Power Flow Results**

| Station | Distribution Feeder | kW | kVAR | kVA | Max Amps | Min Voltage |
|---|---|---|---|---|---|---|
| Town Site | 13 | 1,123 | -92 | 1,141 | 61 | 122.9 |
| | 14 | 2,304 | 761 | 2,427 | 110 | 122.5 |
| | 15 | 1,148 | 342 | 1,198 | 61 | 122.8 |
| | 16 | 1,244 | 352 | 1,294 | 69 | 121.8 |
| | 17 | 1,836 | 605 | 1,933 | 83 | 124.0 |
| | 18 | 710 | 236 | 749 | 33 | 123.6 |
| | **Substation** | **8,409** | **2,221** | **8,698** | **-** | **-** |
| LASS | 13T | 1,605 | 770 | 1,781 | 82 | 123.6 |
| | NS6 | 1,270 | 247 | 1,294 | 54 | 124.8 |
| | 15T | 1,246 | 372 | 1,300 | 77.1 | 123.1 |
| | NSM6* | - | - | - | - | - |
| | 16T | 1,280 | 397 | 1,340 | 69 | 122.2 |
| | NS3 | 621 | 89 | 628 | 99 | 124.8 |
| | NS18 | 1,864 | 636 | 1,970 | 87 | 120.0 |
| | 18T | 502 | 240 | 557 | 24 | 123.6 |
| | **Substation** | **8,468** | **2,918** | **8,958** | **-** | **-** |

*Feeder NSM6 is reserved for emergency restoration of NS6, which serves the Los Alamos County Medical Center.

Figure shows an overview of the White Rock system. Only one substation serves the White Rock system, and each distribution feeder is colored individually. Feeders WR1 and WR2 serve most of the White Rock load.

Figure 2-5: White Rock System Colored by Distribution Feeder

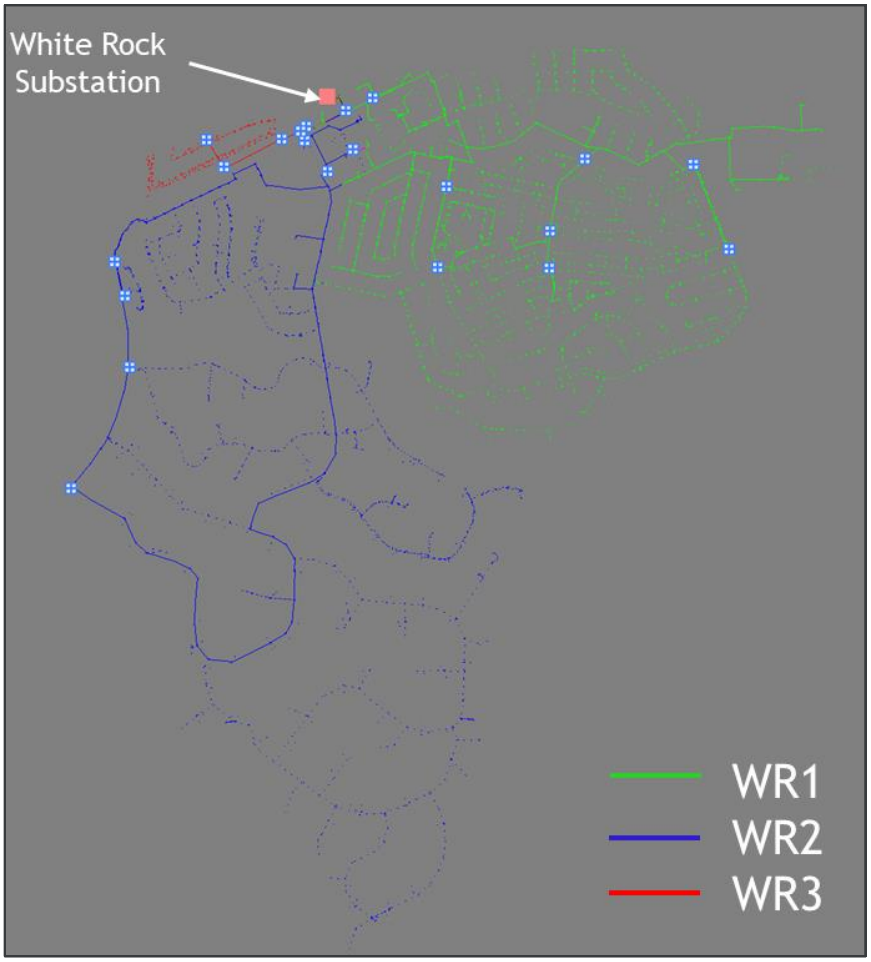



Table 2-2 shows the power flow results for each distribution feeder within the White Rock system. No voltage or equipment loading violations were observed. Transformer 1, which has a normal rating of 7,500 kVA, usually serves the White Rock system. This review shows some remaining load-serving capacity in the normal configuration.

Table 2-2: White Rock System Normal Configuration Power Flow Results

| Station | Distribution Feeder | kW | kVAR | kVA | Max Amps | Min Voltage |
|---|---|---|---|---|---|---|
| White Rock | WR1 | 2,075 | 710 | 2,193 | 112 | 120.6 |
| | WR2 | 1,455 | 505 | 1,540 | 82 | 121.2 |
| | WR3 | 163 | 54 | 171 | 10 | 124.3 |
| | Substation | 3,693 | 1,270 | 3,905 | - | - |

### 2.4.3 Contingency Configuration Review

After reviewing the normal configuration power flow results, various contingency configurations were evaluated to determine whether the LACDPU system has sufficient capacity. Using the power flow model, contingency restoration efforts were reviewed for each primary feeder and substation transformer in the Los Alamos Townsite system. Table 2-3 shows the summary of results for the Los Alamos Townsite system. All customers can be successfully restored with the LASS Substation constructed and in operation before the forecasted electrification load growth is applied.

Table 2-3: Los Alamos Townsite System Contingency Configuration Summary

| Scenario | Total Applicable Customer Load kVA | Customer Load to Restore kVA | Remaining Applicable Capacity kVA | Loading Violations? | Voltage Violations? | Comments |
|---|---|---|---|---|---|---|
| Loss of XFMR 1 | 9,038 | 17,811 | 20,000 | No | No | Primary feeders TC2 and LC2 are used to restore customer load. Transformer 2 is the most limiting element in this contingency. |
| Loss of XFMR 2 | 8,443 | 17,811 | 20,000 | No | No | Primary feeders TC1 and LC1 are used to restore customer load. Transformer 1 is the most limiting element in this contingency. |
| Loss of TC1 | 4,719 | 8,682 | 14,100 | No | No | Primary feeder TC2 is used to restore customer load through the Townsite switchgear. The TC2 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of TC2 | 3,963 | 8,682 | 16,000 | No | No | Primary feeder TC1 is used to restore customer load through the Townsite switchgear. The TC1 parallel 500 MCM CU cable is the most limiting element in this contingency. |
| Loss of LC1 | 4,483 | 8,831 | 14,100 | No | No | Primary feeder LC2 is used to restore customer load through the LASS switchgear. The LC2 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of LC2 | 4,348 | 8,831 | 14,100 | No | No | Primary feeder LC1 is used to restore customer load through the LASS switchgear. The LC1 1000 MCM CU cable is the most limiting element in this contingency. |

The loss of the main power transformer was reviewed in the White Rock system in Table 2-4. The backup transformer at the White Rock Substation can successfully restore all customers. However, the 5 MVA rating of the backup transformer at White Rock Substation does not leave much capacity for additional load growth. Substation transformer upgrades will be necessary for the White Rock system with anticipated electrification load increases.

Table 2-4: White Rock System Contingency Configuration Summary

| Scenario | Total Applicable Customer Load kVA | Customer Load to Restore kVA | Remaining Applicable Capacity kVA | Loading Violations? | Voltage Violations? | Comments |
|---|---|---|---|---|---|---|
| Loss of XFMR 1 | 3,905 | 3,905 | 5,000 | No | No | Transformer 1, which has a higher 7,500 kVA rating, usually serves the load. Transformer 2 has sufficient capacity to restore all the White Rock load. Feeder 16 and 17 restore all customers through distribution feeder ties. Transformer 2 is the most limiting element in this contingency. |

### 2.4.4 System Reliability Observations

The contingency review showed that the LACDPU system is configured to restore all customers for major outage events impacting the substations and primary feeders. However, extended outages can occur due to faults/equipment failure impacting radial portions of the distribution feeders in the LACDPU system. The White Rock system is constructed with many loops that can be used to restore power to customers while repairs are made on the system. The Los Alamos Townsite system has larger radial distribution feeders extending onto the mesas. These radially fed mesas can present challenges in maintaining customer power due to an outage. Opportunities to loop these radial areas will help to improve future restoration efforts and potential outages necessary for construction efforts.

## 2.5 Hosting Capacity Assessment – Minimum Daylight Load

Hosting capacity analysis is a study method that estimates how much Distributed Energy Resources (DERs) can be added to the electric distribution system without requiring system improvements. Typically, hosting capacity analysis is performed during the minimum daylight load time, where customer load is low and DER output can be high, resulting in greater potential for reverse power flow. WindMil can perform many steady-state analyses, but hosting capacity analysis is a method that WindMil does not support. 1898 & Co. utilized the export function from WindMil to convert the power flow model to another power flow software called Cyme, which is developed by Eaton. Cyme can perform hosting capacity analysis and was used to generate the results discussed in this section.

### 2.5.1 Planning Criteria – Hosting Capacity Limitations

Increasing DER penetration on the distribution system provides more renewable energy to the local grid and can offset the use of fossil fuels. However, increasing DER penetration can cause challenges in operating and maintaining the distribution system. DER has the potential to cause equipment loading violations if enough renewable energy is produced above equipment ratings. High voltage violations can occur if generation exceeds local load and voltage rises as a result. The protection system can also be negatively impacted as increasing reverse power flows can desensitize protection schemes and cause nuisance tripping of relays due to phase imbalance. To properly evaluate the hosting capacity of the LACDPU distribution feeders, 1898 & Co. and the LACDPU project team discussed the desired planning criteria to maintain safe and reliable operation of the system without requiring system improvements.

- **Equipment Loading** – no conductor or equipment should exceed 100% of the normal rating.
- **Voltage** – primary system voltage must remain between 118 V and 126 V.
- **Reverse Power Flow (Protection)** – No reverse power flow is allowed through reclosers or the feeder relay.

### 2.5.2 Minimum Daylight Load Models

The distribution system is most stressed by DER during the minimum daylight load, where generation output is most likely to exceed customer load in the distribution system. LACDPU gathered phase amperage readings for each feeder during a light load day in the spring. These amperage readings are contained in Section 1.4. The WindMil model was allocated with these minimum daylight load readings, and then the Los Alamos Townsite system model was reconfigured to represent the new configuration with the LASS Substation energized. Table 2-5 shows the minimum daylight load estimated for each of the distribution feeders in the new configuration.

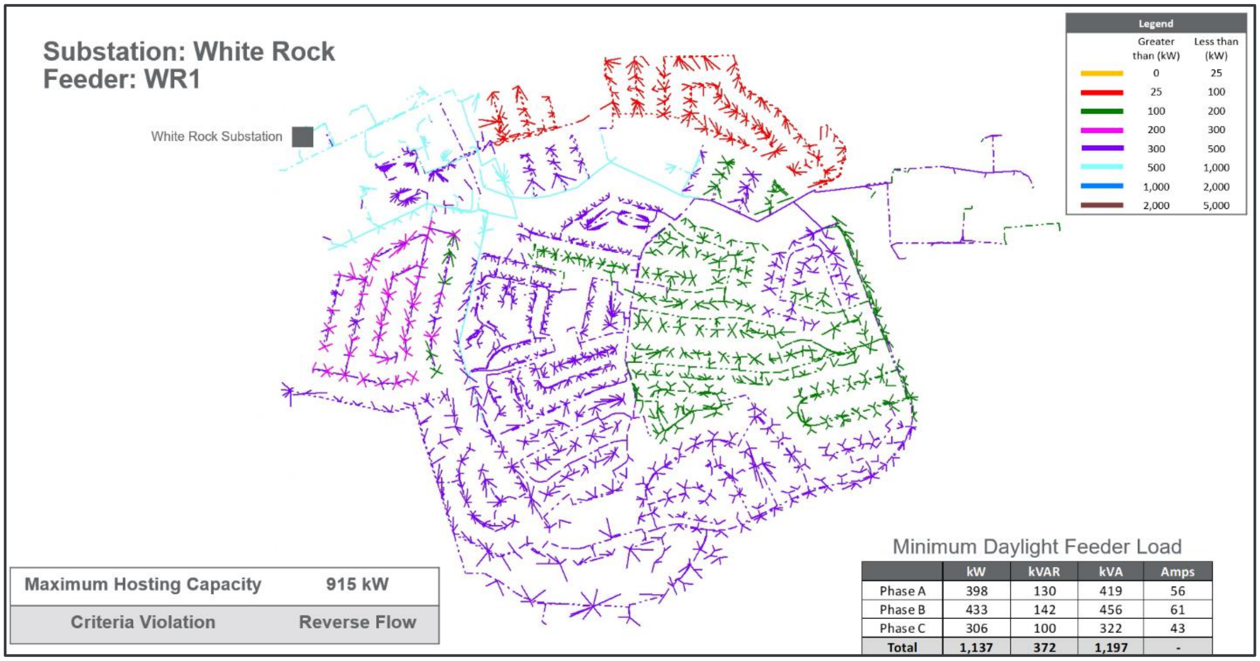
**Table 2-5: Feeder Minimum Daylight Load**

| Substation | Feeder | kW | kVAR | kVA |
|---|---|---|---|---|
| Town Site | 13 | 499 | -264 | 575 |
| Town Site | 14 | 981 | 286 | 1,022 |
| Town Site | 15 | 526 | 151 | 548 |
| Town Site | 16 | 560 | 128 | 575 |
| Town Site | 17 | 1,360 | 397 | 1,418 |
| Town Site | 18 | 557 | 168 | 582 |
| LASS | 13T | 679 | 512 | 852 |
| LASS | S6 | 375 | 74 | 382 |
| LASS | 15T | 594 | 159 | 616 |
| LASS | 16T | 560 | 238 | 609 |
| LASS | NS3 | 180 | 48 | 186 |
| LASS | NS18 | 243 | 69 | 253 |
| LASS | 18T | 303 | 172 | 349 |
| White Rock | WR1 | 1,113 | 324 | 1,160 |
| White Rock | WR2 | 531 | 168 | 556 |
| White Rock | WR3 | 35 | 11 | 38 |

### 2.5.3 Hosting Capacity Visuals

Figure  shows an example of the hosting capacity heat maps that were prepared while performing this analysis. The legend color shows the remaining capacity in each line section to host additional DER. Typically, the greatest hosting capacity is observed nearest to the substation where the conductor and equipment have the highest ratings. Proximity to the substation also reduces the potential for reverse power flow through protective devices and high voltage from excess generation. The maximum hosting capacity value identified for each feeder is most often found near the substation and represents the largest amount of generation that could be placed on the feeder at an optimal location. Minimum daylight feeder load power flow results are also shown in each visual as customer load impacts the hosting capacity. The hosting capacity generally decreases further from the substation where conductor sizes are smaller, and voltage rise is more likely. See Appendix A for visuals of each feeder analyzed.

Figure 2-6: Hosting Capacity Analysis Feeder Visual Example




### 2.5.4 Summary of Results

Hosting capacity analysis was performed individually for each of the distribution feeders within the LACDPU system. The summary of results is shown in Table 2-6. Reverse power flow through the feeder relay was the most limiting criterion from this analysis. To host additional DER beyond the hosting capacity presented in this analysis, LACDPU will need to evaluate system improvements for the feeder relays and other protective devices. System improvements are related to correctly sensing the direction of current flow to avoid desensitization and nuisance tripping. It is important to note that this analysis was based on feeder amperage readings provided by LACDPU during the spring of 2025. The hosting capacity represented in this study is intended to reflect only the current modeled primary system. If the daytime minimum load decreases, the hosting capacity is expected to decrease also. As new customer DER is added to the LACDPU system, the hosting capacity of the system will be reduced and these hosting capacity results will become outdated. Secondary conductors, service transformers, and panel upgrades may still be required for customer-owned new PV interconnections even if there is some hosting capacity represented on the primary system.

Table 2-6: Summary of Hosting Capacity Analysis Results

| Substation | Feeder | Existing DER Capacity kW | Maximum Remaining Hosting Capacity kW | Criteria Violation |
|---|---|---|---|---|
| Town Site | 13 | 137 | 461 | Reverse Flow |
| Town Site | 14 | 178 | 929 | Reverse Flow |
| Town Site | 15 | 140 | 435 | Reverse Flow |
| Town Site | 16 | 287 | 425 | Reverse Flow |
| Town Site | 17 | 0 | 1,309 | Reverse Flow |
| Town Site | 18 | 14 | 534 | Reverse Flow |
| LASS Station | 13T | 117 | 625 | Reverse Flow |
| LASS Station | S6 | 0 | 375 | Reverse Flow |
| LASS Station | 15T | 123 | 408 | Reverse Flow |
| LASS Station | 16T | 208 | 334 | Reverse Flow |
| LASS Station | NS3 | 0 | 180 | Reverse Flow |
| LASS Station | NS18 | 0 | 205 | Reverse Flow |
| LASS Station | 18T | 0 | 285 | Reverse Flow |
| White Rock | WR1 | 276 | 915 | Reverse Flow |
| White Rock | WR2 | 328 | 383 | Reverse Flow |
| White Rock | WR3 | 66 | 35 | Reverse Flow |

## 2.6 Grid Modernization Strategies

Modernizing the electric distribution system will require investment in new technologies and operational methods. Typically, the term Advanced Distribution Management System (ADMS) is used to describe the operation of the holistic distribution system through generation control, load management, protective equipment, data systems, and billing information. Table 2-7 shows each technology/strategy and the anticipated value to LACDPU based on the unique characteristics of their system. The next steps indicate recommended actions for the LACDPU project team to explore and implement these technologies and methods further. Appendix B contains the takeaways from each workshop discussion and further details.

**Table 2-7: Grid Modernization Strategies Summary**

| Technology/Strategy | Value to LACDPU | Next Steps |
| --- | --- | --- |
| Transmission Scale BESS | Low | There is no near-term action; this is an area where there may be value in the long term. It is dependent on cooperation with Pueblo and other parties. |
| Distribution Scale BESS | High | Near-term, LACDPU should consider a further detailed feasibility study. |
| Residential BESS | Low | No action, not an area to pursue for LACDPU. |
| Mobile BESS | High | In the near term, LACDPU should consider adding a mobile BESS to its portfolio. Several use cases are under consideration for this resource. |
| FLISR | Medium | LACDPU should look for opportunities to implement reclosers and smart switches into the system in the future. System reliability is good today, but it will need to be monitored as the system grows with electrification. |
| Distribution Microgrid | Medium | No near-term action. Consider microgrid compatibility when deploying new equipment on the system. As technology matures, there may be more opportunities in the long term. |
| Modular Substations | Low | This study has shown how traditional substation capacity can serve the forecasted electrification load. Modular substations are not necessary for LACDPU in the near term. |
| Volt-Var Optimization | Low | There is no near-term action. Voltage is well-regulated in the system today. Increasing DER penetration may require LACDPU to focus more on Volt-VAR optimization in the long term. |
| Demand Response Programs | High | Thermostat, water heater, or managed EV charging programs are areas to further investigate |

# 3.0 Adoption Modeling and Forecasting

In 2024, Los Alamos County adopted an ambitious Climate Action Plan (CAP) to protect the community's health and environment.[5] The CAP outlines a roadmap to achieve carbon neutrality by 2050, requiring the elimination of natural gas from buildings and the full adoption of electric vehicles. While reaching these goals demands significant Community efforts, the necessary technologies, such as electric vehicles, heat pumps, and induction stoves, are commercially available today. The primary challenge lies in deploying these technologies and establishing supportive public policies.

Meeting the CAP objectives necessitates grid expansion as the transportation and building sectors electrify. Concurrently, Los Alamos County customers may invest in solar panels and distributed energy resources (DERs). However, severe weather and aging infrastructure could increase service interruptions, increasing customer sensitivity to outages as they depend on the grid for heating, cooling, and transportation.

To address these challenges, Los Alamos County needs a 30-year master plan that integrates these climate goals and identifies necessary infrastructure enhancements to support anticipated electrification loads. To create this master plan, it is important to quantify the current market and forecast future grid demand.

1898 & Co. analyzed four major market segments: transportation electrification, home electrification, commercial electrification, and distributed solar PV and batteries. We developed three scenarios to create different bookends for the potential adoption of each electrification technology in a market segment. These scenarios informed different projections for grid demand over the next 30 years.

## 3.1 Electrification Scenarios

1898 & Co. developed three scenarios projecting grid demand growth over the next 30 years.

**Scenario 1** aligns with Los Alamos County's Climate Action Plan (CAP), targeting carbon neutrality by 2050. This requires 100% electric vehicle (EV) adoption for passenger cars and eliminating natural gas in all buildings. The CAP also calls for new building standards that improve energy efficiency. A 2022 NREL report indicates a correlation between EV ownership and increased homeowner adoption of rooftop solar and battery energy storage systems (BESS), so under this scenario, 1898 & Co. assumes that these two technologies will have a very high adoption rate.[6] Therefore, Scenario 1 projects the following by 2055:

- 100% EV adoption for all vehicles.
- 100% electrification of all homes and commercial properties, eliminating natural gas use.
- 20% improvement in energy efficiency for homes and commercial properties.
- 50% adoption of rooftop solar for homes and commercial properties.
- 20% adoption of BESS for homes and commercial properties.

[5] *Los Alamos Climate Action Plan*. (2024). Los Alamos County. https://www.losalamosnm.us/files/sharedassets/public/v/2/departments/county-manager/documents/losalamoscap_20241104-reduced.pdf

[6] Sharda, S., Garikapati, V. M., Goulias, K., Reyna, J. L., Sun, B., Spurlock, C. A., & Needell, Z. (2022, November 13). *Is the Adoption of Electric Vehicles (EVs) and Solar Photovoltaics (PVs) Interdependent or Independent?* Behavior, Energy, and Climate Change Conference, Washington DC. https://docs.nrel.gov/docs/fy23osti/84543.pdf

**Scenario 2** reflects New Mexico's current public policy landscape, including federal, state, and local grants, incentives, and tax credits. Where available, it also follows historical trends in Los Alamos County. Intended as a moderate projection based on January 2025 conditions, Scenario 2 assumes the following by 2055:

- Continuation of Los Alamos County's historical EV adoption rate.
- 50% electrification of homes and commercial properties, eliminating natural gas use.
- 10% improvement in energy efficiency for homes and commercial properties.
- 25% adoption of rooftop solar for homes and commercial properties.
- 10% adoption of BESS for homes and commercial properties.

**Scenario 3** assumes minimal influence from the CAP or government regulations on technology adoption, resulting in significantly lower rates of electrification. By 2055, Scenario 3 projects:

- EV adoption rates match the statewide average in Los Alamos County.
- 25% electrification of homes and commercial properties, eliminating natural gas use.
- No improvement in energy efficiency for homes and commercial properties.
- 10% adoption of rooftop solar for homes and commercial properties.
- 5% adoption of BESS for homes and commercial properties.

## 3.2 Forecasting Methodology

This analysis addresses the key question: What are the different potentials for Los Alamos County's residents adopting new technologies? To help frame this potential, 1898 & Co. used the Bass Diffusion Model to help show adoption trends over the 30-year forecast. The Bass Diffusion Model is shown below:

$$\frac{dN(t)}{dt} = \left[p + q * \frac{N(t)}{m}\right] * [m - N(t)]$$

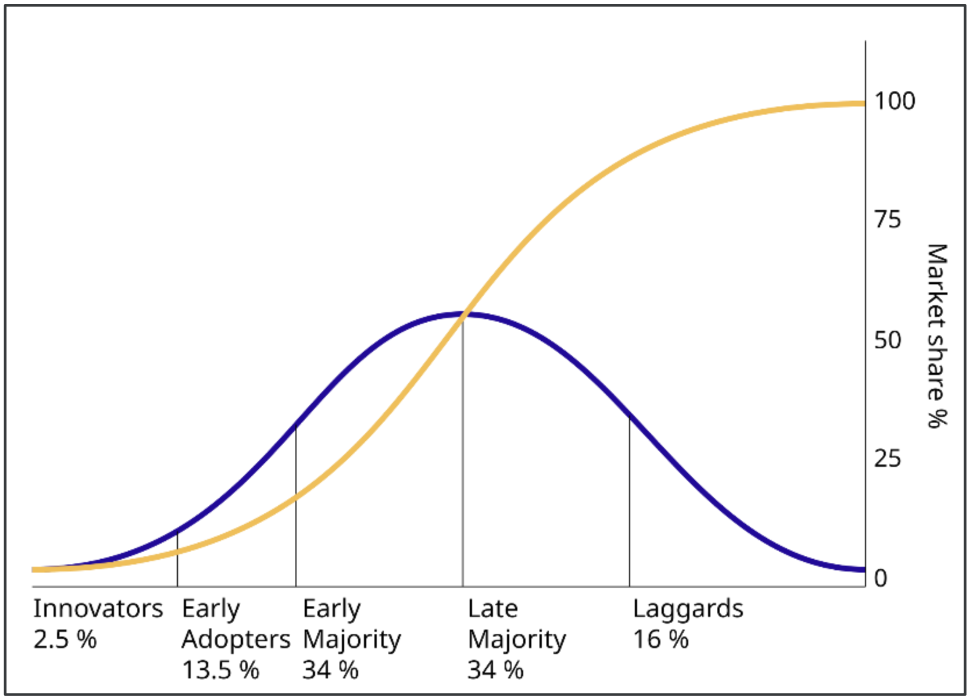
Where:

- **N(t):** Cumulative adopters at time $t$.
- **m:** Total potential market size (Los Alamos County population).
- **p:** Coefficient of innovation (external influence, e.g., advertising).
- **q:** Coefficient of imitation (internal influence, e.g., word-of-mouth).
- **dN(t)/dt:** Adoption rate at time $t$.

The Bass model is suitable because the key variables are well-defined. The market size (*m*) is relatively stable, based on the county's consistent population. While the adoption rate (*dN(t)/dt*) could be unrealistic (e.g., 25% of households replacing water heaters annually), 1898 & Co. adjusted this to reflect realistic technology lifecycles (i.e., only 1/15 of the population of water heaters are purchased each year, because water heaters have a 15-year lifespan). While *p* and *q* are less directly observable, they were calibrated to match the projected outcomes of each scenario. For example, in Scenario 1 (100% electric water heater adoption by 2055), *p* and *q* were adjusted to reach 100% market share by 2055; similarly, Scenarios 2 and 3 had adjusted *p* and *q* values reflecting 50% and 25% market share by the same date, respectively.

The Bass Diffusion model generates a characteristic "S-curve," illustrating the adoption phases: the innovator experimenting with the new technology, followed by early adopters, a rapid increase among the early majority, and a slower uptake by the late majority and laggards. The curve's shape remains consistent across scenarios; however, adjusting *p* and *q* alters how slow or fast the slope of adoption occurs. For example, repealing a tax credit (reducing *p*) would stretch the curve, while introducing a grant program (increasing *p*) would compress it.

**Figure 3-1: Diffusion of Innovation**



*P* and *q* are sensitive to many factors, such as government policies and incentives, the product's cost and lifespan, and the community's attitude towards it. Los Alamos County residents fit the profile of consumers most likely to buy or lease an electric vehicle: they are highly educated, high-income, and have multiple vehicles in the household.[7] 30% of New Mexico's population has a bachelor's degree or higher, but 68% of Los Alamos County residents have a college degree. The average New Mexican with a bachelor's degree earns $54,832 annually, but the same person earns, on average, $87,014 in Los Alamos County.[8] 65% of households in the Los Alamos townsite and 83% of White Rock residents own two or more vehicles.[9] Given these demographic characteristics, 1898 & Co. expects the community to view EVs positively and adopt the technology more quickly than the rest of the state. Other zero-emission technologies, such as heat pumps, induction stoves, and solar panels, are also expected to be adopted at a higher rate than in the surrounding region.

The Bass Diffusion Model provides yearly estimates of technology adoption within the community. This process is repeated for each scenario, resulting in three distinct market share projections for each technology over the next 30 years.

Subsequently, 1898 & Co. characterized each device's grid impact, considering its energy consumption profile, operational duration, and the likelihood of simultaneous operation across multiple households. The grid impact of each device is multiplied by the number of devices in the community for each scenario.

## 3.3 Transportation Electrification

Transportation and related land use account for 38% of Los Alamos County's greenhouse gas emissions, as identified in the county's climate action plan. While the plan advocates for increased public transit and bicycle use, most air quality agencies around the country prioritize zero-emission vehicles (ZEVs) as a mitigation strategy. ZEVs offer a direct replacement for existing vehicles, enabling straightforward tracking of vehicle registrations and quantifiable emission reductions. However, widespread ZEV adoption requires upgrades to electric utility infrastructure to meet the increased power demand.

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[7] (PDF) An Analysis of Attributes of Electric Vehicle Owners' Travel and Purchasing Behavior: The Case of Maryland. (n.d.). *ResearchGate*. Retrieved June 16, 2025, from https://www.researchgate.net/publication/335455046_An_Analysis_of_Attributes_of_Electric_Vehicle_Owners'_Travel_and_Purchasing_Behavior_The_Case_of_Maryland

[8] U.S. Census Bureau, U.S. Department of Commerce. (n.d.). Educational Attainment. *American Community Survey, ACS 5-Year Estimates Subject Tables, Table S1501*. Retrieved June 16, 2025, from https://data.census.gov/table/ACSST5Y2023.S1501?t=Education&g=040XX00US35_050XX00US35028_160XX00US3542320,3584740&moe=false.

[9] U.S. Census Bureau, U.S. Department of Commerce. "Selected Housing Characteristics." American Community Survey, ACS 5-Year Estimates Data Profiles, Table DP04, 2023, https://data.census.gov/table/ACSDP5Y2023.DP04?q=dp04&g=040XX00US35_050XX00US35028_160XX00US3542320,3584740&moe=false.

### 3.3.1 Vehicle Population Estimate

In 2020, Los Alamos County had a population of 19,419, with 13,179 residing in the Los Alamos census-designated place (CDP, hereafter called Los Alamos Townsite) and 5,852 in White Rock CDP.[10] The county comprises 8,754 households: 7,304 single-family homes, 1,291 multi-family dwellings, and 159 manufactured homes. 8,667 households are DPU customers.[11] Occupancy rates are approximately 95%, slightly higher in Los Alamos Townsite and lower in White Rock.[12]

There is no detailed survey of the county's vehicle population, but statewide and national estimates provide a basis for calculation. The 2021 VIUS survey reported 1,310,700 vehicles in New Mexico, with 95.2% light-duty passenger cars and pickup trucks, 3% medium-duty, and 1.9% heavy-duty vehicles.[13] Census Bureau data (Table 3-1) provides vehicle ownership estimates per household for Los Alamos County, Los Alamos Townsite, and White Rock.

**Table 3-1: Vehicle Count Per Household**

| Vehicle Count | LACDPU | Los Alamos Townsite | White Rock |
|---|---|---|---|
| Zero Vehicles | 1.60% | 2.30% | 0.00% |
| One Vehicle | 29.50% | 32.40% | 16.90% |
| Two Vehicles | 39.10% | 39.70% | 38.70% |
| Three+ Vehicles | 29.80% | 25.60% | 44.40% |

Based on Experian's North American Automotive Database, supplemented by data from VIUS, ACS, and household counts, 1898 & Co. estimates a total of 18,839 vehicles in Los Alamos County: 13,409 in Los Alamos townsite and 5,432 in White Rock. A detailed breakdown by vehicle weight class for the county, Los Alamos Townsite, and White Rock is provided in Table 3-2. These populations will be further broken down by their respective fleets in the following sections of this chapter.

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[10] *U.S. Census Bureau QuickFacts: White Rock CDP, New Mexico; Los Alamos CDP, New Mexico; Los Alamos County, New Mexico; New Mexico*. (n.d.). Retrieved June 2, 2025, from https://www.census.gov/quickfacts/fact/table/whiterockcdpnewmexico,losalamoscdpnewmexico,losalamoscountynewmexico,NM/EDU635223

[11] *Annual Report 2024*. (n.d.). Los Alamos Department of Public Utilities. Retrieved June 2, 2025, from https://indd.adobe.com/view/00a3a765-088f-41a2-96cc-cda75220b416

[12] *DP04: Selected Housing Characteristics—Census Bureau Table*. (n.d.). Retrieved June 2, 2025, from https://data.census.gov/table/ACSDP5Y2023.DP04?q=dp04&g=040XX00US35_050XX00US35028_160XX00US3542320,3584740&moe=false

[13] *VIUS213A: All Vehicles by ... - Census Bureau Table*. (n.d.). Retrieved June 2, 2025, from https://data.census.gov/table/VIUSA2021.VIUS213A?q=vius21&g=040XX00US35

**Table 3-2: Vehicles by Weight Class & Location**

| Vehicle Class | LACDPU | Los Alamos Townsite | White Rock |
|---|---|---|---|
| Light Duty (Class 1 & 2) | 17,927 | 12,884 | 5,333 |
| Medium Duty (Class 3, 4, 5, & 6) | 565 | 402 | 166 |
| Heavy Duty (Class 7 & 8) | 347 | 247 | 100 |
| **Total** | **18,839** | **13,409** | **5,542** |

As of January 2025, Experian's North American Automotive Database estimated approximately 497 EVs registered in the county (out of 11,471 statewide), with virtually all of them light-duty passenger cars owned by residents.

The VIUS survey estimates approximately 57,300 new vehicle registrations annually in New Mexico, encompassing new and used car sales and in-migration.[14] For Los Alamos County, this equates to approximately 824 vehicles per year. In the Forecasting Methodology section, this figure serves as the upper limit for annual EV adoption, representing 100% electric vehicle adoption among new registrations.

### 3.3.2 Charging Behavior and Infrastructure

Forecasting the grid impact of transportation electrification requires understanding how people will interact with their EVs. The preexisting grid can handle a handful of EVs in a neighborhood, but the grid impact of EVs will be significantly magnified if all 18,830 vehicles are plugged in simultaneously.

Fortunately, such an event is less likely to occur as people have different work and leisure schedules, varying miles driven, various driving behaviors, and different access to home EV charging. The coincident load, which is the load of all EVs charging at the same time, for residential charging is calculated in this study as follows:

$$Coincident\ Load = N * kW * HC * DF$$

Where:

- N is the number of EVs in the community
- kW is the average power rating of the charger (in kW)
- HC is the percentage of EV drivers who charge at home
- DF is the diversity factor, representing the percentage of EV drivers charging at any given time. The diversity factor can also be viewed as the probability of all vehicles charging at the same time.

[14] *2021 VIUS Table 2b*. (n.d.). Tableau Software. Retrieved June 2, 2025, from https://explore.dot.gov/views/2021VIUSTable2b/Dashboard1?%3Aembed=y&%3AshowVizHome=n&%3AapiID=host0#navType=0&na

The Bass Diffusion Model estimates how many EVs will be in Los Alamos County for each scenario for a given year. However, this population of EVs can be further split up based on their behaviors. Generally, 30% of drivers will plug in immediately upon coming home, most likely around 6 pm. 40% of drivers will schedule their car to charge at a preset time using either an app on their phone or a smart charging station. The driver plugs in their car at 6 pm but then instructs the app to charge the vehicle at a specific time (i.e., 5 am). The app will trigger the charging to begin at the appropriate time, such as 1:45 am, to ensure the charging session is finished at the pre-set time. Lastly, 30% of drivers may not use a Level 2 charger and opt for a Level 1 charger by plugging it into a household 120V outlet. This "slow charging" means drivers who plug in at 6 pm will likely still be charging by 5 am the next day and will probably only unplug once it's time to leave the house.[15]

To track these different charging behaviors, 1898 & Co. split the residential EV population into three groups with different charging behaviors. The Immediate and Scheduled charging groups use a level 2 charger with an assumed output of 7.7 kW. The Level 1 charging group uses a typical household 120V wall outlet with a maximum output of 1.44 kW.

Another factor that can reduce the grid impact of residential home charging is the assumption that some vehicles do not have access to a home charger. On average, 80% of EV drivers charge at home.[16] The other 20% may not have access to a charger and must rely on public charging stations, or they may have charged up elsewhere earlier in the day and don't need to charge at home.

In addition, most EVs may only need to charge every two or three days, depending on the miles driven. The average daily vehicle miles traveled in New Mexico is 38 miles, while most EVs have a range of 250 miles or more. For this analysis, 1898 & Co. chose a 30% diversity factor to represent the coincident probability of drivers charging at the same time. The diversity factor can also be viewed as drivers charging every two to three days.[17] 1898 & Co. adjusted to this 100% for all non-residential vehicles to represent daily charging.

The outcome of these assumptions is that 1898 & Co. repeated this calculation with minor adjustments for the following distinct groups within transportation electrification:

- Los Alamos County Fleet
- Atomic City Transit
- Los Alamos Public School Districts
- Commercial fleets
- Residential EVs - Immediate charging
- Residential EVs - Scheduled charging
- Residential EVs - Level 1 charging

[15] Smart, J. G., & Salisbury, S. D. (2015). *Plugged In: How Americans Charge Their Electric Vehicles* (No. INL/EXT-15-35584). Idaho National Laboratory. https://avt.inl.gov/sites/default/files/pdf/arra/PluggedInSummaryReport.pdf

[16] Blonsky, M., Munankarmi, P., & Balamurugan, S. P. (2021). Incorporating Residential Smart Electric Vehicle Charging in Home Energy Management Systems. *2021 IEEE Green Technologies Conference (GreenTech)*, 187–194. https://doi.org/10.1109/GreenTech48523.2021.00039

[17] Bollerslev, J., Andersen, P. B., Jensen, T. V., Marinelli, M., Thingvad, A., Calearo, L., & Weckesser, T. (2022). Coincidence Factors for Domestic EV Charging From Driving and Plug-In Behavior. *IEEE Transactions on Transportation Electrification*, *8*(1), 808–819. https://doi.org/10.1109/TTE.2021.3088275

### 3.3.3 Zero Emission Vehicle Public Policy

Governments can play a significant role in EV adoption, primarily by leveraging economic policy tools. Some policymakers advocate for new incentive programs or regulations, while others attempt to dismantle existing ones. Just as important, many policymakers do not advocate one way or the other, and their neutral stance allows the status quo to persist.

As of January 2025, the federal government had pulled two major levers. First, the Inflation Reduction Act reengineered the long-standing EV tax credit to allow taxpayers to claim up to $7,500 if the EV was made in America and used a battery with a high percentage of minerals sourced from America and allied countries.[18] Second, the EPA adopted tighter emission standards for light and medium-duty vehicles beginning in 2027, which would significantly reduce the air pollution that new cars can legally emit.[19] The simplest option for automakers would be to sell considerably more zero-emission vehicles to balance out the emissions of all the other cars they sell. Since January 2025, the new administration has signaled that it will change both policies, but it is unclear how much or what potential impact it could have on the EV market.

In 2022, the New Mexico state legislature adopted the New Motor Vehicle Emission Standards.[20] These rules require automakers to sell cars and trucks that produce fewer emissions compared to the federal emission standards and partially align with several air quality rules from California: Advanced Clean Cars II, Advanced Clean Trucks, and the Heavy-Duty Omnibus. Unlike the EPA emission standards for model year 2027 mentioned previously, the New Mexico rule requires at least 43% of all new cars sold in 2027 to be zero-emission, and that requirement will ramp up to 82% by 2032. Since January 2025, the new federal administration has signaled that it wants to challenge the three California air quality rules that New Mexico's New Motor Vehicle Emission Standards align with, so it is unclear whether the White House will also challenge this rule.

New Mexico also offers the EV Charging Station Make-Ready Building Renovation tax credit. This tax credit provides homeowners with $500 for purchasing and installing equipment that makes the house EV-ready, with additional plus-ups for qualified income-eligible residents or commercial properties.[21]

Lastly, no local county or LACDPU-specific public policy related to EVs exists. New Mexico anti-donation laws preclude LACDPU from offering rebates that PNM and other utilities in the state offer.

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[18] *Credits for new clean vehicles purchased in 2023 or after | Internal Revenue Service*. (n.d.). Retrieved June 2, 2025, from https://www.irs.gov/credits-deductions/credits-for-new-clean-vehicles-purchased-in-2023-or-after

[19] *Multi-Pollutant Emissions Standards for Model Years 2027 and Later LightDuty and Medium-Duty Vehicles: Final Rule* (No. EPA-420-F-24-016). (2024). United States Environmental Protection Agency. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1019VP5.pdf

[20] *New Motor Vehicle Emissions Standards (Advanced Clean Cars II/Advanced Clean Trucks)*. (n.d.). Retrieved June 2, 2025, from https://www.env.nm.gov/climate-change-bureau/transportation/

[21] Energy Conserving Products. (n.d.). *Energy Conservation and Management*. Retrieved June 2, 2025, from https://www.emnrd.nm.gov/ecmd/tax-incentives/energy-conserving-products/

### 3.3.4 Los Alamos County Fleet

The Los Alamos County government maintains a fleet to carry out the county's day-to-day operations. This fleet comprises 128 light-duty cars and trucks, 78 medium-duty vehicles, and 29 heavy-duty vehicles.[22]

Vehicles in municipalities and county government fleets typically drive 10,000 miles or less annually, and 1898 & Co. has assumed that Los Alamos falls within this range. For this reason, 1898 & Co. assumes that light-duty vehicles will charge once every 3 days on a level 2 charger with 7.7 kW output, medium-duty vehicles will charge daily with a 22.5 kW charger, and heavy-duty vehicles will charge daily with a 50 kW charger. 1898 & Co. expects that most vehicles will begin charging at 6 pm and finish at 2 am, with a small percentage continuing to charge into the morning hours depending on day-to-day variations.

Most county vehicles will dwell overnight at the Los Alamos County Warehouse, alongside buses from Atomic City Transit and the Los Alamos Public School District. Given the concentration of high-power charging for medium- and heavy-duty vehicles, the site is an excellent candidate for a charging management solution. This software system can assess the battery status for all vehicles plugged in and optimize based on their schedules, i.e., prioritize the transit buses to full charge before beginning their service at 5:30 am, while delaying school buses until after their morning service. Electrifying vehicles at this county-owned facility presents unique challenges, but opportunities exist to optimize and flatten the grid impacts of charging these vehicles.

1898 & Co. forecast the following outcomes for the three scenarios:

**Table 3-3: Los Alamos County Fleet, 2040**

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| Vehicle Quantity | 64 Light Duty Vehicles<br>39 Medium Duty Vehicles<br>15 Heavy Duty Vehicles | 32 Light Duty Vehicles<br>20 Medium Duty Vehicles<br>7 Heavy Duty Vehicles | 16 Light Duty Vehicles<br>10 Medium Duty Vehicles<br>4 Heavy Duty Vehicles |
| Daily kWh | 5,032 | 2,516 | 1,258 |
| Peak kW | 529 | 265 | 132 |

**Table 3-4: Los Alamos County Fleet, 2055**

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| Vehicle Quantity | 128 Light Duty Vehicles<br>78 Medium Duty Vehicles<br>29 Heavy Duty Vehicles | 64 Light Duty Vehicles<br>39 Medium Duty Vehicles<br>15 Heavy Duty Vehicles | 32 Light Duty Vehicles<br>20 Medium Duty Vehicles<br>7 Heavy Duty Vehicles |
| Daily kWh | 10,065 | 5,032 | 2,516 |
| Peak kW | 1,059 | 529 | 265 |

[22] FTI Consulting. (2022). *Los Alamos County 2022 Integrated Resource Plan*. https://www.losalamosnm.us/files/sharedassets/public/v/1/departments/utilities/documents/integrated-resource-plan-irp-2022-final-report.pdf

### 3.3.5 Atomic City Transit

Atomic City Transit offers Los Alamos townsite and White Rock public transportation services. 1898 & Co. does not have detailed information on the 14 transit buses' duty cycles, but the transit agency has already selected the Gillig 35' Battery Electric Low Floor Plus bus as their choice for zero-emission buses in the future. Transit service begins at 5:50 am and ends at 7:37 pm. 1898 & Co. assumes that the transit buses will have at least 10 hours to charge at night, which would mean that a 50 kW charger would be sufficient for most buses.

However, an on-route charging station may be required if Atomic City Transit were to operate a more challenging route. An on-route pantograph charging station is a high-power overhead system that connects to battery electric buses at transit stops to rapidly recharge their batteries without disrupting service. The Gillig bus is capable of charging via this method at 350 kW, but most transit agencies only let their buses "top off" for ten minutes before returning to service, which translates to an hourly load of 58 kW because this opportunity charger would only be active during the day, so it would not coincide with the heavy charging demands that occur in the evening.

As mentioned previously, a charging management system is an ideal solution for flattening the charging demands on the county's fleet.

1898 & Co. has forecast the following outcomes for the three scenarios:

Table 3-5: Atomic City Transit, 2040

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| Vehicle Quantity | 7 | 4 | 2 |
| Daily kWh | 3,500 | 2,000 | 1,000 |
| Peak kW | 350 | 200 | 100 |

Table 3-6: Atomic City Transit, 2055

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| Vehicle Quantity | 14 | 7 | 4 |
| Daily kWh | 7,000 | 3,500 | 2,000 |
| Peak kW | 700 | 350 | 200 |

### 3.3.6 Los Alamos Public Schools

The Los Alamos Public Schools has a fleet of 20 school buses. Like most school districts, the school buses operate on a morning and early afternoon shift, transporting students to and from the schools. The midday downtime of school buses offers a unique opportunity to shift the charging time to daytime hours, when demand on the grid is near its daily minimum load due to solar PV generation. The school district can minimize its grid impact by shifting most charging between 9 am and 2 pm and performing supplemental charging at night as needed. In this study, we have assumed 50 kW charger for each bus will be sufficient, but the school district can eliminate the nighttime charging if a higher-power charger is available.

As mentioned previously, a charging management system is an ideal solution for flattening the charging demands on the county's fleet.

1898 & Co. forecast the following outcomes for the three scenarios:

Table 3-7: Los Alamos Public Schools, 2040

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| Vehicle Quantity | 10 | 5 | 3 |
| Daily kWh | 2,400 | 1,200 | 720 |
| Peak kW | 325 | 163 | 98 |

Table 3-8: Los Alamos Public Schools, 2055

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| Vehicle Quantity | 20 | 10 | 5 |
| Daily kWh | 4,800 | 2,400 | 1,200 |
| Peak kW | 650 | 325 | 163 |

### 3.3.7 Commercial Fleets

After eliminating the county, transit, and school district fleets, 18,570 vehicles are owned by either residents or commercial fleets. 1898 & Co. assumes that all remaining medium and heavy-duty vehicles belong to commercial fleets and that the duty cycle of light-duty commercial vehicles is similar light duty vehicles in charging behavior.

1898 & Co. assumes that local businesses own 487 medium-duty and 284 heavy-duty vehicles. 1898 & Co. does not know these fleets' duty cycles, but data from the VIUS survey indicates that most of these vehicles drive 100 to 178 miles daily. For this reason, 1898 & Co. assumes that these vehicles will charge during the night.

1898 & Co. assumes that medium-duty vehicles will charge daily with a 22.5 kW charger and heavy-duty vehicles will charge daily with a 50 kW charger. 1898 & Co. expects that most vehicles will begin charging at 6 pm and finish by 4 am, with some vehicles charging in the middle of the day when employees take their lunch breaks.

1898 & Co. forecast the following outcomes for the three scenarios:

Table 3-9: Commercial Fleets, 2040

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| Vehicle Quantity | 302 Medium Duty Vehicles<br>176 Heavy Duty Vehicles | 197 Medium Duty Vehicles<br>115 Heavy Duty Vehicles | 136 Medium Duty Vehicles<br>79 Heavy Duty Vehicles |
| Daily kWh | 37,774 | 24,679 | 17,005 |
| Peak kW | 3,974 | 2,596 | 1,789 |

Table 3-10: Commercial Fleets, 2055

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| Vehicle Quantity | 487 Medium Duty Vehicles<br>284 Heavy Duty Vehicles | 465 Medium Duty Vehicles<br>271 Heavy Duty Vehicles | 331 Medium Duty Vehicles<br>193 Heavy Duty Vehicles |
| Daily kWh | 60,982 | 58,219 | 41,398 |
| Peak kW | 6,415 | 6,125 | 4,355 |

### 3.3.8 Residential Vehicles

This section outlines the three types of charging assumed for residential light-duty vehicles. We have assumed that on any given day, some vehicles will immediately charge, others will schedule a charge, and the last set of vehicles will only use Level 1 charging.

#### *3.3.8.1 Immediate Charging*

The remaining 17,799 light-duty vehicles are assumed to be owned by Los Alamos County residents. As outlined previously, approximately 80% of EV drivers charge at home, and 30% of drivers charge on any day. Based on charging behavior and the time of day, the EV population can be further split into three different groups.

The first group is EV drivers who plug their cars in immediately upon returning home, approximately 30% of the population or up to 5,340 vehicles daily. These cars charge on a 7.7 kW level 2 charger and will likely take up to 4 to 6 hours to fully charge. The peak demand for this group will likely occur around 6 pm on a typical workday and be completed by 11 pm.

#### *3.3.8.2 Scheduled Charging*

The second group is EV drivers who plug in their cars upon returning home but preset their EVs to charge at a specific time. This group will be the most responsive to a potential time-of-use rate with EV drivers programming their chargers or vehicles to take advantage of it. 1898 & Co. expects 40% of Los Alamos County's EV drivers to follow this behavior, with up to 7,120 vehicles daily. These cars will charge on a 7.7 kW charger and take about 4 to 6 hours to fully charge.

The timing of this group can vary depending on how a time-of-use rate is structured. 1898 & Co. assumed that this population would end charging by 5 am. This means that a small number of cars could start charging by midnight with more vehicles starting to charge as time progresses until 100% of this population is charging at 4 am. The percentage will drop sharply each hour after 5 am as people start their day.

#### *3.3.8.3 Level 1 Charging*

The last group is EV drivers who plug their cars in immediately upon returning home to a level 1 charger that is powered from a standard 120V wall outlet. The assumed power output of the level 1 charger is 1.4 kW, and over 11 hours from 6 pm to 5 am, the car will gain approximately 15.4 kWh. The advantage of this approach is that the driver does not need to purchase and install additional hardware, as most EVs come with a level 1 charger standard, nor hire an electrician to install a 240V outlet. For residents who do not make frequent trips to Santa Fe or Albuquerque, Level 1 charging is sufficient for traveling within the county.

1898 & Co. expects 30% of the population, or up to 5,339 vehicles per day, to charge using this method. Most EV drivers will charge immediately upon returning home around 6 pm until they leave the house the next day.

#### *3.3.8.4 Residential Charging Summary*

1898 & Co. forecast the following outcomes for the three scenarios for all three behaviors:

Table 3-11: Residential EVs, 2040

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| Vehicle Quantity | Immediate: 2,105<br>Scheduled: 3,469<br>Level 1: 2,602 | Immediate: 1,148<br>Scheduled: 2,193<br>Level 1: 1,645 | Immediate: 278<br>Scheduled: 1,033<br>Level 1: 775 |
| Daily kWh | 102,987 | 62,366 | 25,412 |
| Peak kW | 8,469 at 1 AM | 5,240 at 1 AM | 2,302 at 1 AM |

Table 3-12: Residential EVs, 2055

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| Vehicle Quantity | Immediate: 4,690<br>Scheduled: 6,916<br>Level 1: 5,187 | Immediate: 3,718<br>Scheduled: 5,619<br>Level 1: 4,215 | Immediate: 1,124<br>Scheduled: 2,161<br>Level 1: 1,621 |
| Daily kWh | 212,754 | 171,472 | 61,335 |
| Peak kW | 17,196 at 1 AM | 13,914 at 1 AM | 5,158 at 1 AM |

### 3.3.9 Public charging

The last significant load from transportation electrification comes from public charging stations. 1898 & Co. examined the impact of residents who may not have access to a home charger or need to charge while driving around town.

NREL offers a straightforward approach for estimating the number of public charging stations for a given population.[23] Following their method and using the forecasted EV population in 2040 and 2055, 1898 & Co. projects the following outcomes for the three scenarios:

Table 3-13: Public Chargers, 2040

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| Charger Quantity | Level 2: 217<br>DCFC: 18 | Level 2: 137<br>DCFC: 12 | Level 2: 65<br>DCFC: 6 |
| Daily kWh | 15,215 | 9,767 | 4,812 |
| Peak kW | 1,148 | 738 | 365 |

Table 3-14: Public Chargers, 2055

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| Charger Quantity | Level 2: 432<br>DCFC: 36 | Level 2: 351<br>DCFC: 28 | Level 2: 135<br>DCFC: 12 |
| Daily kWh | 29,940 | 24,003 | 9,630 |
| Peak kW | 2,258 | 1,809 | 728 |

[23] Wood, E., Borlaug, B., Moniot, M., Lee, D.-Y., Ge, Y., Yang, F., & Liu, Z. (n.d.). *The 2030 National Charging Network: Estimating U.S. Light-Duty Demand for Electric Vehicle Charging Infrastructure*.

## 3.4 Home Electrification

Per the 2020 census, Los Alamos County comprises 8,754 households, of which 7,581 utilize natural gas, averaging 743 therms annually per household.[24] These households primarily use natural gas for four appliances: space heating (furnaces or boilers), water heating, clothes drying, and cooking (ranges). While all-electric alternatives have long existed, recent advancements in heat pump technology and smart features offer significantly improved efficiency compared to both older electric and gas appliances.

Precise appliance usage data (gas vs. electric) for Los Alamos County was unavailable for this study. However, leveraging the U.S. Energy Information Administration (EIA)'s national household energy consumption surveys and applying their New Mexico-specific data to estimate current market share, 1898 & Co. developed various forecasts to meet each of the three scenarios. According to the 2020 EIA survey, New Mexico's natural gas end-use distribution is: 63% space heating, 30% water heating, 3% clothes drying, and 3.5% cooking.[25]

### 3.4.1 Space heating

The EIA estimates that 67% of homes in New Mexico utilize a natural gas furnace for central heating, with an additional 7% relying on steam or hot water boilers. In Los Alamos County, this translates to approximately 6,478 out of 8,754 households using natural gas as their primary heating source.

There are several options available for electrifying central heating systems. The simplest of these technologies is the resistive heater. It converts electrical energy into thermal energy by passing an electric current through a resistive material, such as a metal coil. However, resistive heaters are not very efficient; for each kilowatt (kW) of energy consumed, they provide only a kW-equivalent in heat. The HVAC industry uses the coefficient of performance (COP) to measure the efficiency of heating or cooling systems, defined as the ratio of useful heating or cooling output to energy input. A resistive heater typically has a COP of 1.0. However, a significant advantage is their cost: with small units available from big box stores for as low as $10, and many different shapes and sizes are available at moderately higher prices. These are best used to heat individual bedrooms rather than the whole house, so that the total potential market size could be one per bedroom, plus an extra one for a family room.

A more efficient alternative is the heat pump, which functions as an air conditioner that can reverse its operation. By using a reversible valve, the refrigerant within the unit can transfer heat from the outside to the inside of a house. Depending on outdoor temperatures, heat pumps can achieve a COP ranging from 2.0 to 4.0, making them significantly more efficient than resistive heaters.

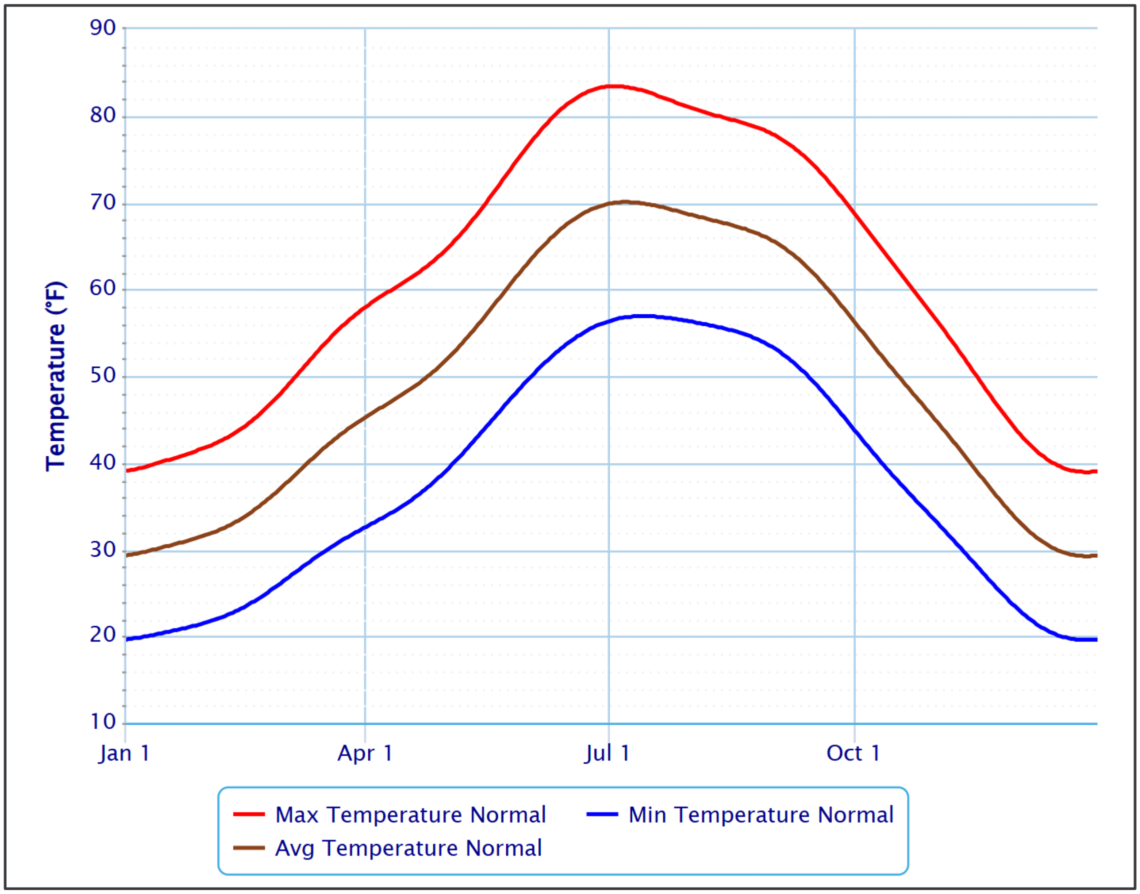
One drawback of heat pumps is their reduced effectiveness in extremely cold conditions. At temperatures around 5°F, the COP of many heat pumps may drop to 1.0. However, recent advancements in refrigerants have allowed some models to generate heat even at -20°F. Additionally, the industry has introduced a "cold climate" label for products, achieving a COP of 1.75 at 5°F.

[24] *FY2023 Annual Report*. (2024, February 22). Los Alamos Department of Public Utilities. https://indd.adobe.com/view/7a4f583d-abf0-437d-bf0d-bb170d516fce

[25] *Highlights for space heating in U.S. homes by state, 2020*. (2023, March). U.S. Energy Information Administration, Office of Energy Demand and Integrated Statistics. https://www.eia.gov/consumption/residential/data/2020/state/pdf/State%20Space%20Heating.pdf

While Los Alamos County might consider cold-climate heat pumps, they are likely unnecessary for most residents. Historical weather data from the Los Alamos airport over the past 25 years shows the coldest extended period was 20 hours below 10°F in January 2013. Typically, the daily minimum temperature is in the low 20s, making standard heat pumps sufficient for the area. Moreover, an off-the-shelf heat pump is significantly more efficient than a gas furnace, which generally has a COP of 0.80.

Figure 3-2: Daily Climate Normal (1991 - 2020) - Los Alamos, NM[26]




Some residents may be concerned about those 20 hours below 10°F and may also be worried that an intense winter storm could considerably lower temperatures for up to a week. Many heat pump manufacturers now offer optional resistant heaters for the heat pump itself, which would keep the unit warm enough to work more efficiently.

As of January 2025, New Mexicans can benefit from various incentive programs. The federal government offers a tax credit of up to $2,000 for purchasing and installing a heat pump, alongside an additional $8,000 rebate from the Home Electric and Appliance Rebate Program. Additionally, New Mexico provides a $1,000 Sustainable Building Tax Credit. However, LACDPU does not offer incentives due to an anti-donation law.

[26] US Department of Commerce, N. (n.d.). *Daily Climate Normals (1991-2020)—LOS ALAMOS, NM*. NOAA's National Weather Service. Retrieved June 16, 2025, from https://www.weather.gov/wrh/Climate?wfo=abq

Heat pumps are available in two styles: centralized and mini-split systems. A centralized heat pump resembles a central air conditioner and costs between $2,000 and $5,500, plus installation. A mini-split system, ideal for single rooms, uses a smaller outdoor unit and an air handler, costing around $1,500 plus installation. Both types have a lifespan of 10 to 20 years. A centralized heat pump is ideal for homes with existing ductwork and air conditioning, while mini-splits are suitable for supplemental heating in persistently cold rooms. Mini-splits are generally more efficient than centralized heat pumps.

Regardless of the technology chosen, space heating will significantly impact the LACDPU grid with forecasted peak load occurring at 5 a.m., typically the coldest time of day in January. Unlike electric vehicles, 80% of homes will likely be running space heating devices at the same time, with additional devices like resistant heaters activated to provide supplemental heating.

1898 & Co. projects the following outcomes for the three scenarios:

**Table 3-15: Space Heating, 2040**

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | Central Heat Pump: 2,003<br>Mini-split: 4,872<br>Resistant Heater: 1,601<br>Backup for heat pumps: 601 | Central Heat Pump: 261<br>Mini-split: 708<br>Resistant Heater: 968<br>Backup for heat pumps: 78 | Central Heat Pump: 151<br>Mini-split: 415<br>Resistant Heater: 597<br>Backup for heat pumps: 45 |
| Daily kWh | 95,610 | 16,878 | 11,021 |
| Peak kW | 8,012 | 1,651 | 1,088 |

**Table 3-16: Space Heating, 2055**

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | Central Heat Pump: 3,971<br>Mini-split: 10,883<br>Resistant Heater: 11,843<br>Backup for heat pumps: 1,191 | Central Heat Pump: 1,993<br>Mini-split: 5,403<br>Resistant Heater: 5,957<br>Backup for heat pumps: 598 | Central Heat Pump: 997<br>Mini-split: 2,735<br>Resistant Heater: 2,893<br>Backup for heat pumps: 299 |
| Daily kWh | 221,049 | 124,424 | 69,105 |
| Peak kW | 20,898 | 11,775 | 6,507 |

#### *3.4.1.1 Building Energy Efficiency*

The climate action plan highlights several reasons for enhancing building energy efficiency, but from a grid perspective, the most compelling reason is the ability to capture energy from previously generated heat. In cold conditions, heat escapes from a house through small gaps in windows and doorways, as well as through inadequate insulation in exterior walls and roofs. To maintain a stable interior temperature, the home's heating system must compensate for this net heat loss. By sealing air leaks and improving insulation, these losses can be significantly reduced, allowing the home to retain more heat from the heating system.

1898 & Co. incorporated a multiplier into space heating calculations to simulate the potential impacts of new building standards and incentive programs aimed at upgrading existing homes. The improvements modeled for each scenario are as follows:

- **Scenario 1:** 20% improvement
- **Scenario 2:** 10% improvement
- **Scenario 3:** 0% improvement

These multipliers are incorporated into the forecast presented in Table 3-15 and Table 3-16.

### 3.4.2 Water heating

EIA estimates that 70% of homes in New Mexico use natural gas water heaters, while 10% utilize propane. In Los Alamos County, this equates to approximately 6,128 out of 8,754 households relying on fossil fuels as their primary water heating source.

For those considering all-electric water heating options, there are two primary technologies available. The first is the conventional electric storage water tank, which employs resistive heating to warm water within a large tank. This system typically requires 4.5 kW to heat the water, taking approximately one hour to do so.

The second option is a heat pump water heater. While resembling a conventional electric storage tank, it is generally taller to accommodate the heat pump component. This system usually consumes 3 kW to heat water but may take an additional 20 minutes to complete the process. By transferring heat from the ambient air into the tank, it can also dehumidify the surrounding air, necessitating a drainage pipe for condensate removal. Both 120V and 240V models are commercially available.

A third alternative is an all-electric tankless water heater. This device uses substantial resistive heaters to instantly heat water, often drawing around 25 kW. Widespread adoption of this technology could significantly increase energy consumption, so they are generally not incentivized.

Incentives for water heaters often mirror those for heat pumps. Homeowners can receive a tax credit covering 30% (up to $2,000) of the purchase and installation costs of a heat pump water heater, with a total tax credit cap of $3,200 per year for all appliances receiving a tax credit. To maximize this benefit, homeowners might consider purchasing a heat pump one year and a qualified water heater the next, thereby leveraging the $2,000 tax credit for each year. Additionally, the Home Electric and Appliance Rebate Program offers a $1,750 tax credit for qualified water heaters. New Mexico also provides a $1,000 Sustainable Building Tax Credit. However, Los Alamos County does not offer incentives due to an anti-donation law.

Unlike space heating, water heating demands can occur at almost any time of day. 1898 & Co. anticipates that most households will experience peak usage during the morning and early evening hours, coinciding with residents starting or ending their day.

1898 & Co. projects the following outcomes for the three scenarios:

**Table 3-17: Water Heating, 2040**

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | Conventional: 2,268<br>Heat Pump: 1,683 | Conventional: 528<br>Heat Pump: 284 | Conventional: 51<br>Heat Pump: 166 |
| Daily kWh | 35,022 | 8,542 | 1,811 |
| Peak kW | 2,606 | 636 | 135 |

Table 3-18: Water Heating, 2055

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | Conventional: 2,606<br>Heat Pump: 4,359 | Conventional: 1,046<br>Heat Pump: 2,167 | Conventional: 102<br>Heat Pump: 1,097 |
| Daily kWh | 52,752 | 26,240 | 8,559 |
| Peak kW | 3,926 | 1,953 | 637 |

### 3.4.3 Clothes drying

EIA estimates that 80% of New Mexico homes already use an electric clothes dryer, 18% use natural gas, and 1% use propane. In Los Alamos County, this translates to approximately 1,721 homes using fossil fuels as their primary fuel for drying clothes.

Several alternative all-electric clothes drying technologies exist, but the most popular option is a heat pump clothes dryer. Like the heat pump water heater, this device is more energy efficient than traditional electric clothes dryers but can take an extra 30 minutes to dry a typical load of laundry.

The Home Electrification and Appliance Rebates program allows homeowners to receive up to $840 per household. There are no state incentive programs, and LACDPU does not offer incentives due to an anti-donation law.

Like water heaters, 1898 & Co. assumes that most homes will have heavy usage in the morning and early evening hours when residents start or end their day.

1898 & Co. projects the following outcomes for the three scenarios:

Table 3-19: Clothes Dryers, 2040

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | Conventional: 656<br>Heat Pump: 337 | Conventional: 270<br>Heat Pump: 57 | Conventional: 39<br>Heat Pump: 33 |
| Daily kWh | 4,538 | 1,642 | 304 |
| Peak kW | 712 | 258 | 48 |

Table 3-20: Clothes Dryers, 2055

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | Conventional: 806<br>Heat Pump: 872 | Conventional: 458<br>Heat Pump: 433 | Conventional: 76<br>Heat Pump: 219 |
| Daily kWh | 6,839 | 3,718 | 1,021 |
| Peak kW | 1,073 | 583 | 160 |

### 3.4.4 Cooking

The EIA estimates that 55% of homes in New Mexico use an electric range, cooktop, or oven, while 50% use a natural gas range, cooktop, or oven. This overlap is due to hybrid equipment that utilizes both electricity and natural gas. In Los Alamos County, this translates to approximately 4,377 households relying on fossil fuels as their primary cooking fuel.

Traditional electric cooktops operate similarly to resistive heaters: electricity flows through a resistive material, converting into thermal energy to heat anything in contact, including an unfortunately placed hand. Recently, induction cooktops have gained popularity for their efficiency and safety features. Induction technology uses magnetic fields to directly heat the pan, and the cooktop automatically turns off if the pan is removed. The “burner” does not conduct heat – only the pan is heated by the magnetic force. For a typical meal, a resistive coil cooktop consumes 3 kW, whereas an induction cooktop uses only 2.1 kW. The oven component remains the same in both types of devices.

The Home Electrification and Appliance Rebates program offers homeowners up to $840 per household. There are no state-level incentive programs, and Los Alamos County does not provide incentives due to an anti-donation law.

Like water heaters and clothes dryers, 1898 & Co. anticipates that most households will experience peak usage of cooking appliances during morning and early evening hours, aligning with residents' daily routines.

1898 & Co. projects the following outcomes for the three scenarios:

Table 3-21: Cooking, 2040

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | Conventional: 330<br>Induction: 1,347 | Conventional: 142<br>Induction: 227 | Conventional: 77<br>Induction: 133 |
| Daily kWh | 5,843 | 1,383 | 782 |
| Peak kW | 917 | 217 | 123 |

Table 3-22: Cooking, 2055

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | Conventional: 413<br>Induction: 3,487 | Conventional: 240<br>Induction: 1,734 | Conventional: 142<br>Induction: 878 |
| Daily kWh | 13,099 | 3,337 | 3,470 |
| Peak kW | 2,055 | 1,047 | 544 |

## 3.5 Commercial Electrification

Los Alamos County is home to 960 commercial properties serving a wide range of purposes from agriculture to aviation. These buildings vary significantly in size, with some as small as 500 square feet and others exceeding 50,000 square feet. Despite their diverse uses and sizes, all these buildings share a common requirement: the need for an HVAC system to regulate interior temperatures and ensure a consistent supply of hot water.

### 3.5.1 Space heating

1898 & Co. projects that all commercial properties will employ central heat pumps, with larger properties utilizing multiple units. For expansive buildings exceeding 5,000 square feet, specialized heat pump technologies designed for large facilities will be implemented. This emerging sector within the HVAC industry offers numerous promising solutions. 1898 & Co. anticipates that these central heat pumps will be most active during the morning, activating around 5 a.m. and reaching their peak by 9 a.m. This schedule ensures that buildings are comfortably warm when employees arrive, with energy use leveling off once the building is occupied and doors are closed. At the end of the workday, the heat pumps will transition to an idle mode, consuming energy at a reduced rate until the next workday begins.

1898 & Co. projects the following outcomes for the three scenarios:

**Table 3-23: Commercial Space Heating, 2040**

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | 388 | 63 | 37 |
| Daily kWh | 50,555 | 9,266 | 6,030 |
| Peak kW | 4,681 | 858 | 558 |

**Table 3-24: Commercial Space Heating, 2055**

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | 968 | 482 | 244 |
| Daily kWh | 126,223 | 70,687 | 39,762 |
| Peak kW | 11,687 | 6,545 | 3,682 |

### 3.5.2 Water heating

1898 & Co. assumes that all commercial properties will use a conventional electric storage water heater and that larger properties will use specialized technologies designed for large facilities.

1898 & Co. assumes that these water heaters will follow the same pattern as the commercial space heaters - activating around 5 am, peaking around 9 am, and then holding a steady state for the rest of the workday. At the end of the workday, the water heaters will enter an idle mode that draws a low amount of energy until the next workday.

1898 & Co. projects the following outcomes for the three scenarios:

**Table 3-25: Commercial Water Heating, 2040**

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | 694 | 318 | 219 |
| Daily kWh | 34,069 | 17,213 | 12,979 |
| Peak kW | 3,155 | 1,594 | 1,202 |

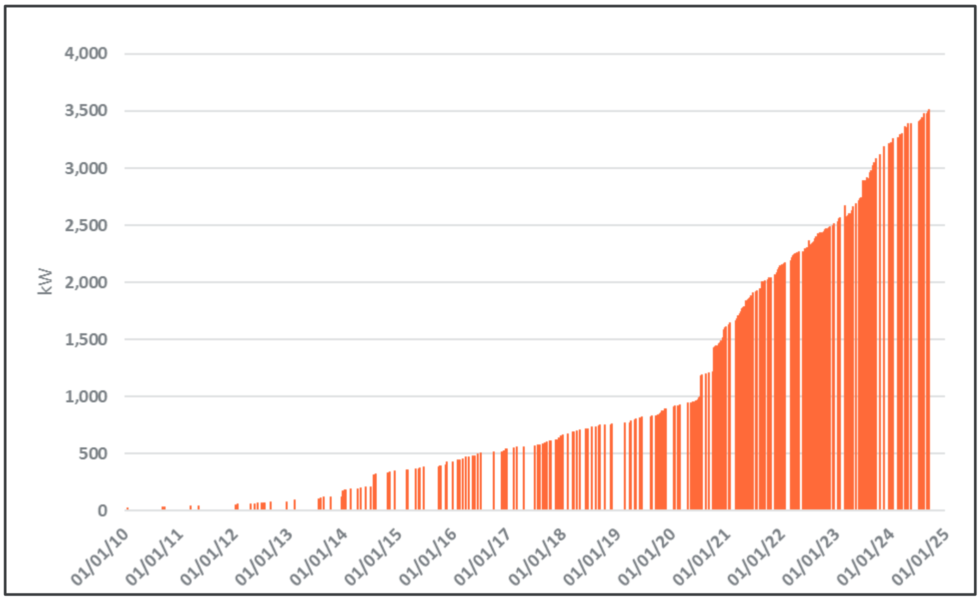
Table 3-26: Commercial Water Heating, 2055

| ` | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | 741 | 484 | 279 |
| Daily kWh | 36,417 | 26,561 | 16,731 |
| Peak kW | 3,372 | 2,459 | 1,549 |

## 3.6 Solar PV & Batteries

As of January 1, 2025, Los Alamos County has 516 solar-generation customers, including 481 residential and 35 commercial properties. Residential customers constitute 5.5% of all homes in the county, while commercial customers represent 3.6% of all commercial buildings. The most common solar PV system size ranges from 4 to 7 kW, with the LACDPU typically restricting residential installations to no more than 10 kW.

Figure 3-3: Connected PV Generation




70% of solar PV systems were installed since 2020, indicating that early adopters are currently driving the technology toward mainstream acceptance. However, peak solar production does not necessarily align with peak energy usage. As previously discussed, winter peak energy usage occurs around 5 to 6 am, depending on the severity of the cold, and decreases rapidly as residents unplug their vehicles, turn off heat pumps, and leave their homes. Meanwhile, as the sun rises, solar PV begins generating energy. 1898 & Co. found that this misalignment effectively mitigates much of the increased grid demand from electrification during daytime hours.

Battery energy storage systems could offer a solution, although most residential products are 15 kWh or smaller. When paired with solar panels, these systems reduce net grid exports during daylight hours until fully charged. At the end of the day, when residents return home, plug in electric vehicles, and resume evening activities, the batteries typically discharge completely within three to four hours. While batteries influence the rate at which grid demand increases, their impact is short-lived.

Batteries have gained popularity at other utilities with the introduction of time-of-use rates, though they generally lag solar installations.[27] Despite their relatively high cost, batteries become economical when used to store solar energy for consumption during peak hours. The federal government provides a residential clean energy tax credit, but neither New Mexico nor Los Alamos County offers additional incentives. LACDPU compensates PV solar customers with excess generation at the average wholesale cost, based on a rolling average over the previous 12 months.

1898 & Co. forecasts the following outcomes for the three scenarios in both residential and commercial applications on a clear day in January. Overcast weather conditions will reduce the potential output of the solar PV systems. Negative numbers are used to represent the direction of energy flow, specifically indicating the output of solar generation to the grid. It is assumed that batteries are recharged by solar systems, thereby offsetting the energy that would otherwise be back fed to the grid.

**Table 3-27: Residential Solar & Battery, 2040**

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | Solar: 1,023<br>Battery: 308 | Solar: 482<br>Battery: 192 | Solar: 234<br>Battery: 118 |
| Max Daily kWh | Solar: (31,757)<br>Battery: 2,413 | Solar: (15,227)<br>Battery: 1,508 | Solar: (7,332)<br>Battery: 927 |
| Peak kW | Solar: (4,890)<br>Battery: 302 | Solar: (2,345)<br>Battery: 189 | Solar: (1,129)<br>Battery: 116 |

**Table 3-28: Residential Solar & Battery, 2055**

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | Solar: 3,915<br>Battery: 1,810 | Solar: 1,691<br>Battery: 894 | Solar: 602<br>Battery: 439 |
| Max Daily kWh | Solar: (119,111)<br>Battery: 14,192 | Solar: (51,927)<br>Battery: 7,011 | Solar: (19,043)<br>Battery: 3,444 |
| Peak kW | Solar: (18,342)<br>Battery: 1,774 | Solar: (7,996)<br>Battery: 876 | Solar: (2,932)<br>Battery: 430 |

[27] Sharda, S., Garikapati, V. M., Goulias, K., Reyna, J. L., Sun, B., Spurlock, C. A., & Needell, Z. (n.d.). *Is the Adoption of Electric Vehicles (EVs) and Solar Photovoltaics (PVs) Interdependent or Independent?* https://docs.nrel.gov/docs/fy23osti/84543.pdf

Table 3-29: Commercial Solar & Battery, 2040

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | Solar: 201<br>Battery: 18 | Solar: 88<br>Battery: 8 | Solar: 42<br>Battery: 0 |
| Max Daily kWh | Solar: (16,154)<br>Battery: 308 | Solar: (6,947)<br>Battery: 146 | Solar: (3,417)<br>Battery: 0 |
| Peak kW | Solar: (2,488)<br>Battery: 38 | Solar: (1,070)<br>Battery: 18 | Solar: (526)<br>Battery: 0 |

Table 3-30: Commercial Solar & Battery, 2055

| | Scenario 1 | Scenario 2 | Scenario 3 |
|---|---|---|---|
| New Equipment Quantity | Solar: 445<br>Battery: 48 | Solar: 201<br>Battery: 18 | Solar: 88<br>Battery: 8 |
| Max Daily kWh | Solar: (36,224)<br>Battery: 935 | Solar: (16,154)<br>Battery: 308 | Solar: (6,947)<br>Battery: 146 |
| Peak kW | Solar: (5,578)<br>Battery: 117 | Solar: (2,488)<br>Battery: 38 | Solar: (1,070)<br>Battery: 18 |

## 3.7 Electrification Forecast Results

In all scenarios, LACDPU is expected to experience a substantial rise in electricity usage. In the most conservative projection, Scenario 3, the peak load is anticipated to increase by at least 4.4 MW by 2040 and 13.5 MW by 2055, representing a 60% increase over the current peak demand of the LAC electric system. Conversely, in the most aggressive projection, Scenario 1, the peak load is projected to rise by 20.9 MW in 2040 and 44.4 MW by 2055, equating to a 200% increase compared to the current peak demand of the LAC electric system.

Scenarios 1 and 3 are designed as boundary conditions and are unlikely to occur exactly as described. Scenario 1 would require federal, state, and local governments to significantly promote zero-emission technologies while discouraging fossil fuel use wherever feasible over the next thirty years. Conversely, Scenario 3 represents limited influence from government regulations and reflects new technologies' natural adoption rate over the next thirty years.

A more probable outcome lies somewhere between these two bookends, reflecting evolving policy goals from federal and state governments over the next thirty years. Scenario 2 forecasts an increase in peak load by 8.5 MW in 2040 and 28.0 MW in 2055, a 120% rise compared to the current peak demand of the LAC electric system. This scenario is not exactly equidistant between the boundary scenarios because residents of Los Alamos County display a strong interest in electric vehicles, heat pumps, and solar, making these technologies likely to be adopted even if political support fluctuates.

Table 3-31: Total Additional Electrification Peak Load

| Scenarios | 2040 Additional Peak Load (MW) | 2055 Additional Peak Load (MW) |
|---|---|---|
| Scenario 1 | 20.9 | 44.4 |
| Scenario 2 | 8.5 | 28.0 |
| Scenario 3 | 4.4 | 13.5 |

To help understand how each electrification technology contributes to grid impact, 1898 & Co. created daily profiles based on the peak kW for each scenario. The daily profiles shown help illustrate the difference in the use of each technology and how load can be shifted to help flatten the overall peak demand. A cold winter day was chosen as the peak time for evaluation, as electric heat contributes significantly to winter demand, and the COP of heat pumps decreases in cold weather. Additionally, EVs also consume more energy in cold weather and will need to charge more in the wintertime. Lastly, if demand response controls are in place for EV charging, in the summer, peak demand from EV charging can be shifted to be more coincident with solar PV generation or shifted into the late evening or early morning.

### 3.7.1 Scenario 1

The 24-hour profiles illustrating net increases due to electrification on a peak winter day in both 2040 and 2055 are shown below:

Figure 3-4: Scenario 1, 2040

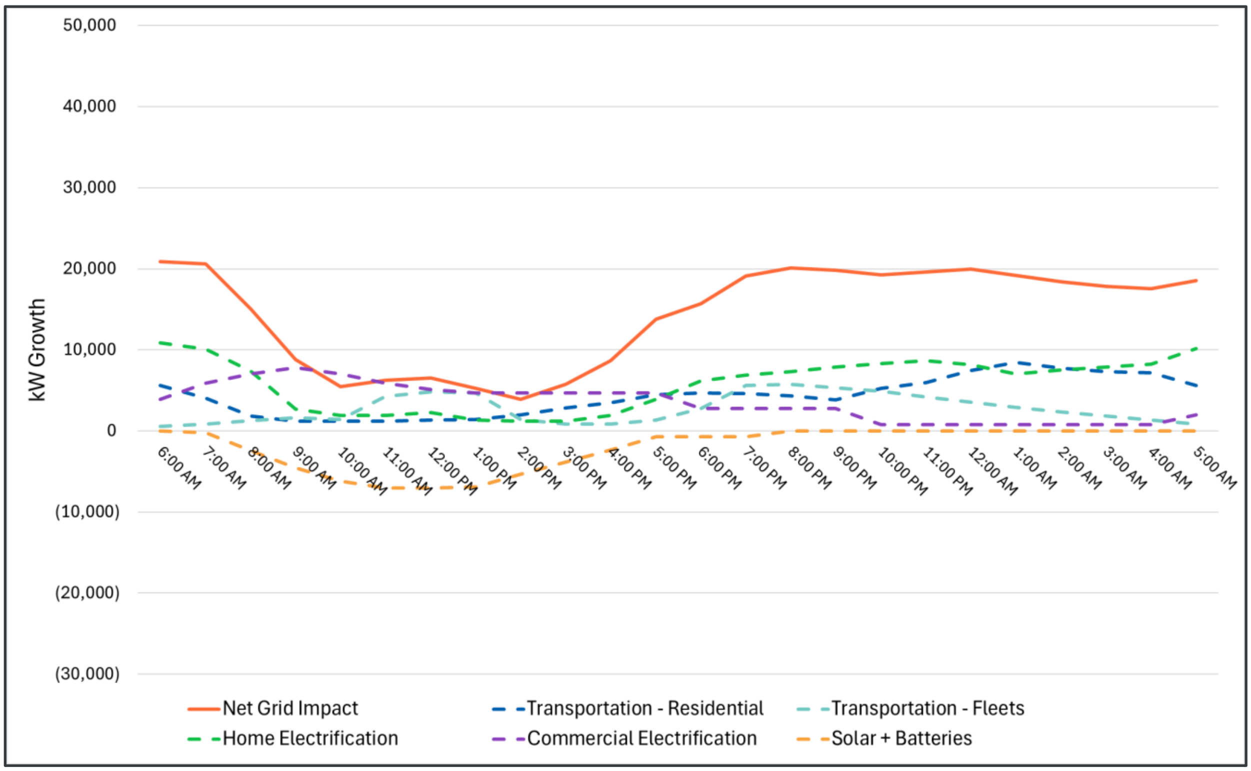
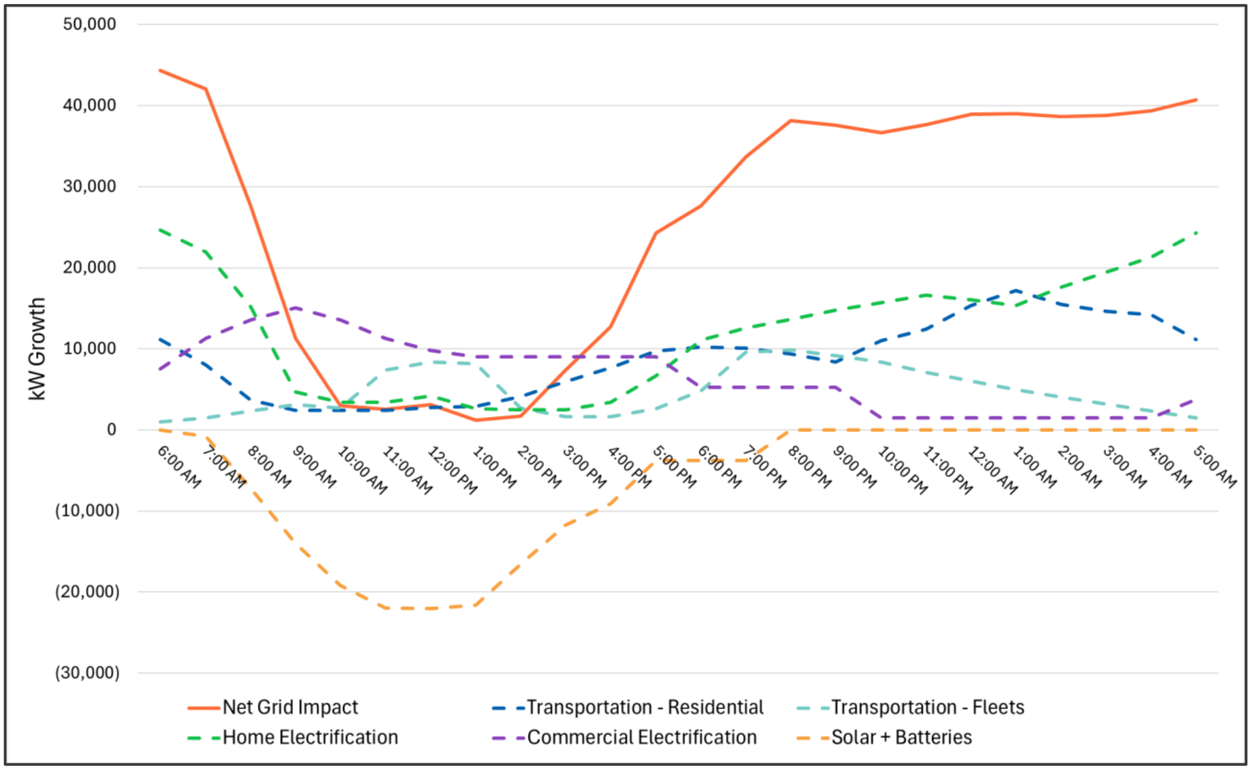


Figure 3-5: Scenario 1, 2055




In 2040, the daily peak demand (20.9 MW) occurs at 6 AM, driven primarily by home electrification needs, particularly space heating, alongside approximately equal demand from residential EV charging and commercial electrification. The grid demand decreases rapidly after 7 AM as both home electrification and residential EV charging reduce, coinciding with an increase in solar generation. The daily minimum demand (3.9 MW) is observed at 2 PM when the daytime charging of electric school buses subsides, although solar generation remains substantial. From 3 PM onwards, as solar generation diminishes, there is a noticeable increase in demand due to home electrification, residential EV charging, and commercial fleet EV charging.

By 2055, the pattern observed in 2040 is expected to persist but at nearly twice the magnitude (44 and 1.1 MW, respectively). The influence of 20% of homes equipped with battery energy storage systems is visible but brief, lasting approximately four hours between 4 PM and 8 PM.

### 3.7.2 Scenario 2

The 24-hour profiles illustrating net increases due to electrification on a peak winter day in both 2040 and 2055 are shown below:

Figure 3-6: Scenario 2, 2040

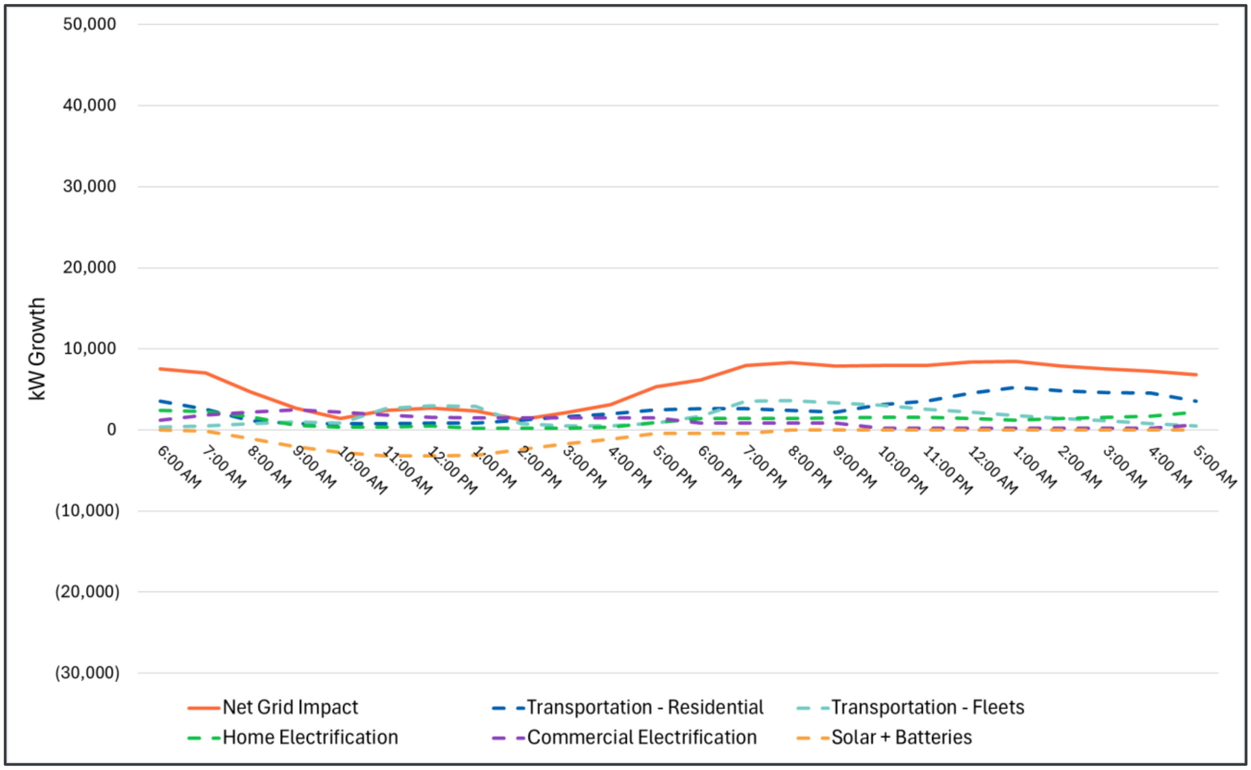
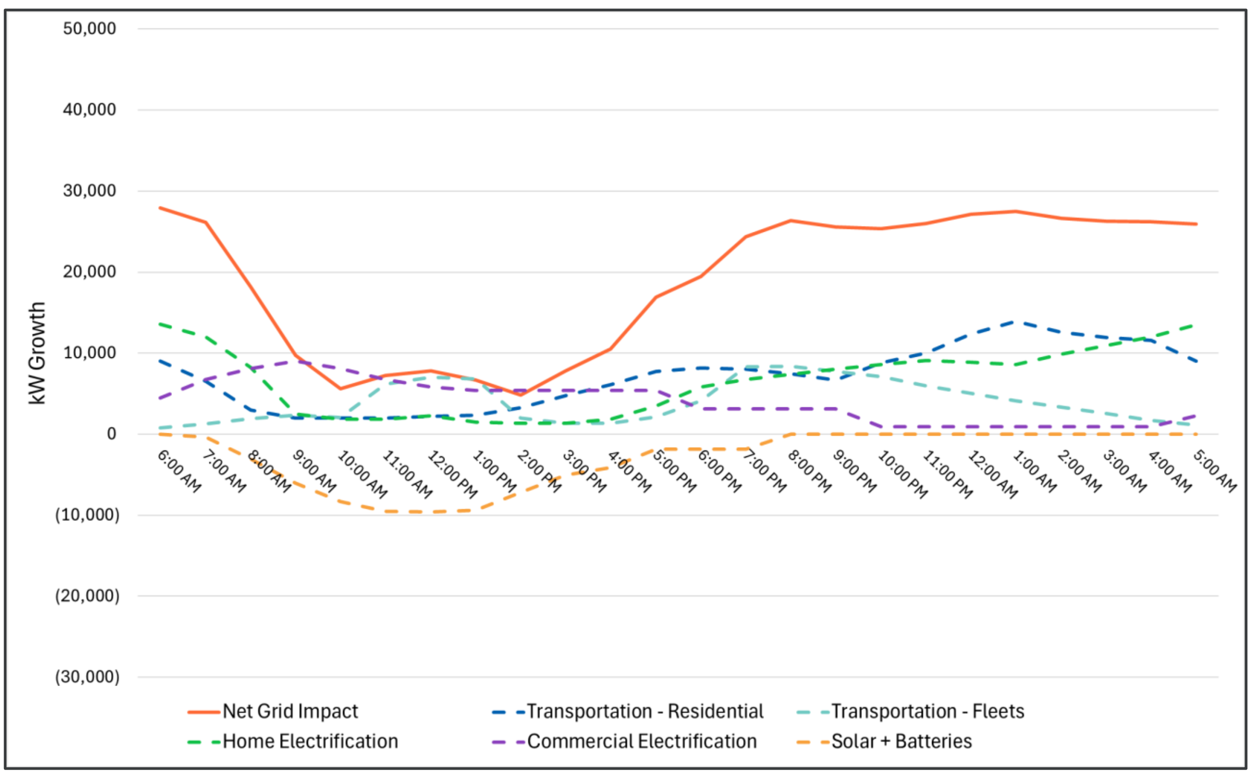



Figure 3-7: Scenario 2, 2055



In 2040, the daily peak demand of 8.5 MW occurs at 1 AM, primarily due to residential EV charging. Unlike Scenario 1, all-electric space heating is not as widely adopted, resulting in a less pronounced impact on the grid and not influencing the daily peak during high heating demand periods. Residential EV charging continues to dominate demand throughout the night until 7 AM, when commercial electrification and solar generation begin to rise. The daily minimum demand of 1.2 MW is recorded at 2 PM as the daytime charging of electric school buses decreases, despite substantial solar generation. After 3 PM, residential EV charging demand steadily increases as solar generation diminishes.

By 2055, the daily peak demand shifts to 27.9 MW at 6 AM, driven by home electrification, particularly space heating. While residential EV charging still peaks at 1 AM, the demand for space heating surpasses it in the early morning hours. The daily minimum demand (4.8 MW) still occurs at 2 PM. The pattern and magnitude of demand are like the 2040 forecast in Scenario 1.

### 3.7.3 Scenario 3

The 24-hour profiles illustrating net increases due to electrification on a peak winter day in both 2040 and 2055 are shown below:

**Figure 3-8: Scenario 3, 2040**

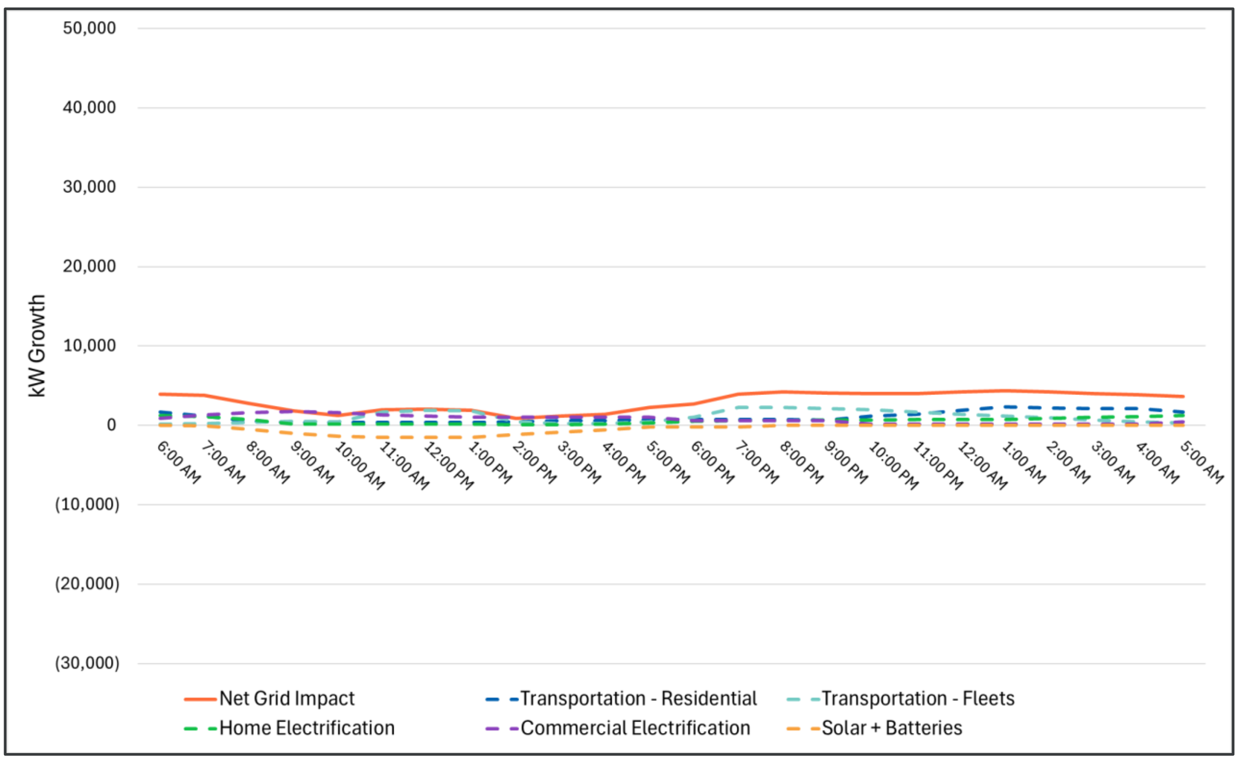
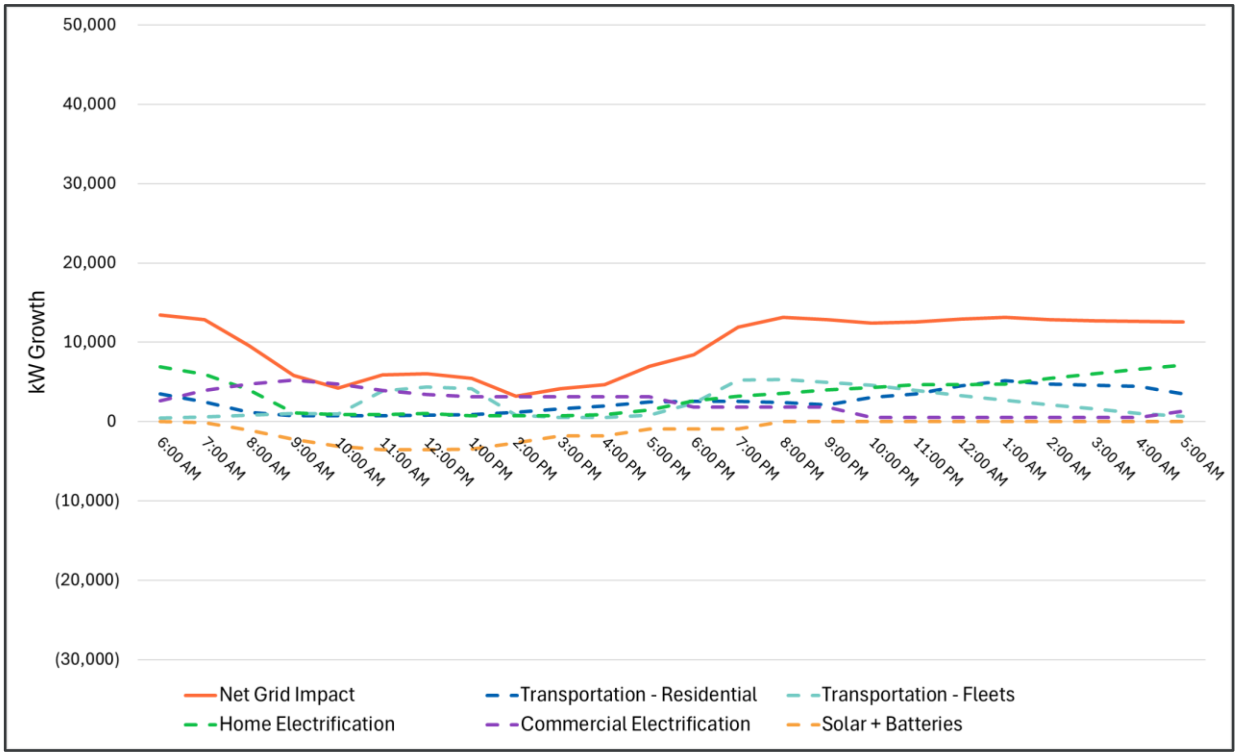


Figure 3-9: Scenario 3, 2055




In 2040, the daily peak demand (4.4 MW) occurs at 1 AM due to residential EV charging. Like in Scenario 2, all-electric space heating does not shape peak demand like in Scenario 1. Residential EV charging demands dominate most of the demand throughout the night until 7 AM, at which point commercial electrification and solar generation start to increase. The daily minimum demand (0.9 MW) is observed at 2 PM when the daytime charging of electric school buses subsides.

In 2055, the daily peak demand (13.5 MW) shifts to 6 AM due to home electrification, primarily space heating. Residential EV charging still peaks at 1 AM at 13.1 MW, but space heating overtakes that demand in the early morning hours. The daily minimum occurs at 2 PM at 3.1 MW.

# 4.0 Electric Distribution System Impact Analysis

The electrification forecasts shown in Section 3.0 were applied to the WindMil power flow model to understand the impact on the existing system. Table 4-1 shows the existing LACDPU modeled load and the increase in the electrification load modeled for three forecast scenarios. Six total power flow scenarios were evaluated to identify necessary capital projects, such as substation transformer upgrades, new substation transformers, new distribution feeders, and conductor upgrades. These upgrades were incorporated into the power flow model to mitigate planning criteria violations.

Table 4-1: Electrification Scenarios Forecasted System Load

| Scenario | LACDPU Existing System Load kVA | 2040 Total Forecasted LACDPU System Load kVA | 2055 Total Forecasted LACDPU System Load kVA |
|---|---|---|---|
| Scenario 1 | 21,716 | 44,899 | 69,586 |
| Scenario 2 | 21,716 | 30,769 | 52,283 |
| Scenario 3 | 21,716 | 27,032 | 37,040 |

## 4.1 Electrification Impact Analysis Methodology

The following steps were applied to the WindMil power flow model to perform the electrification impact analysis.

- The electrification forecast load was added to the existing system peak power flow model.
- All electrification forecast load was applied to the power flow model with a 95% power factor.
- The electrification forecast load was applied evenly throughout the power flow model. Existing loads were scaled until the total system demand matched the system demand forecast for each scenario.
- Existing solar PV generation was turned off. The system peak is anticipated to occur in the late evening/early morning hours for all forecast scenarios when customer generation will not be producing.
- Secondary service transformers were removed from the model to resolve nonconvergence issues with the power flow simulations. This enabled the study to focus on the primary system impacts of electrification.

Once the electrification forecast load was added to the power flow model, several analyses were performed to understand the impact of electrification and the system improvements that are necessary to maintain service to all customers in each scenario.

- **Normal Configuration Analysis** – After applying the electrification forecast load, planning criteria violations were identified. The system power flow model was reconfigured by adding new substation sources, distribution feeders, conductor upgrades, and new equipment to resolve planning criteria violations. Power flow results were recorded to confirm that all planning criteria were maintained with system improvements applied.
- **Contingency Configuration Review** - The most impactful substation and primary feeder contingency scenarios were evaluated to determine whether the system would be capable of maintaining service to all customers. Feeder outage considerations were also made to determine whether certain loops or mainline tie paths should be upgraded.

- **Asset Replacement Estimate** – LACDPU is anticipated to need to maintain a rate of asset replacement primarily due to age, deterioration, and increasing customer energy consumption through the 30-year study horizon. For each scenario, asset replacement estimates are provided to document the magnitude of assets that should be considered for future system operating budgets.
- **Financial Impact Summary** - The financial impact of each scenario was determined using the system improvement projects and asset replacement estimates, along with representative costs documented in Section 1.0.

## 4.2 2055 Scenario 1 Electrification Impact

2055 Scenario 1 added 46,727 kVA to the LACDPU system power flow model. Table 4-2 shows how this load was applied to the Los Alamos Townsite and the White Rock systems.

Table 4-2: 2055 Scenario 1 Modeled Load

| System | Existing System Load kVA | Forecasted Electrification Load kVA | Total Forecasted System Load kVA |
|---|---|---|---|
| Los Alamos Townsite | 17,811 | 33,721 | 52,469 |
| White Rock | 3,905 | 13,006 | 17,117 |
| Total | 21,716 | 46,727 | 69,586 |

### 4.2.1 Study Area Configuration

Figure  shows the proposed configuration for the Los Alamos Townsite system, colored by substation. To successfully serve the forecasted electrification growth in this scenario, the Eastgate Substation must be constructed. The Eastgate Substation must contain two 33.7 MVA transformers and two four-feeder switchgear with a main tie breaker between the two switchgears. Six new distribution feeders were constructed in the planning model to bring this new capacity west towards the load centers. A significant amount of the Los Alamos Townsite system load must be served from the Eastgate Substation to avoid overloading the existing LASS and Townsite substations. The LASS Substation was primarily used to serve commercial loads near the substation, along with the Pajarito Mountain ski area and some residential loads. Much of the Townsite Substation load was transferred to Eastgate Substation, but some feeders were routed back north to spread the load across the existing LASS and Townsite substation feeders.

**Figure 4-1: 2055 Scenario 1 Los Alamos Townsite System Configuration**

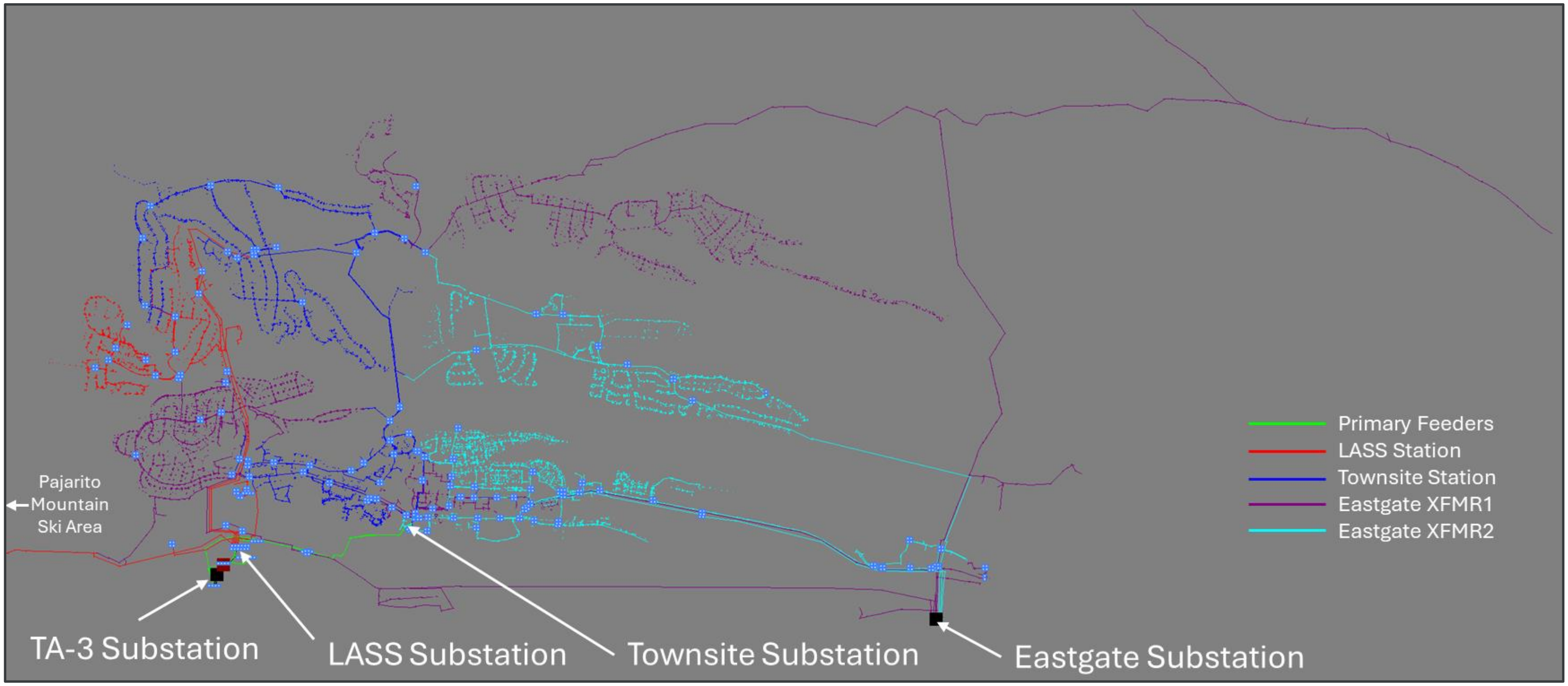
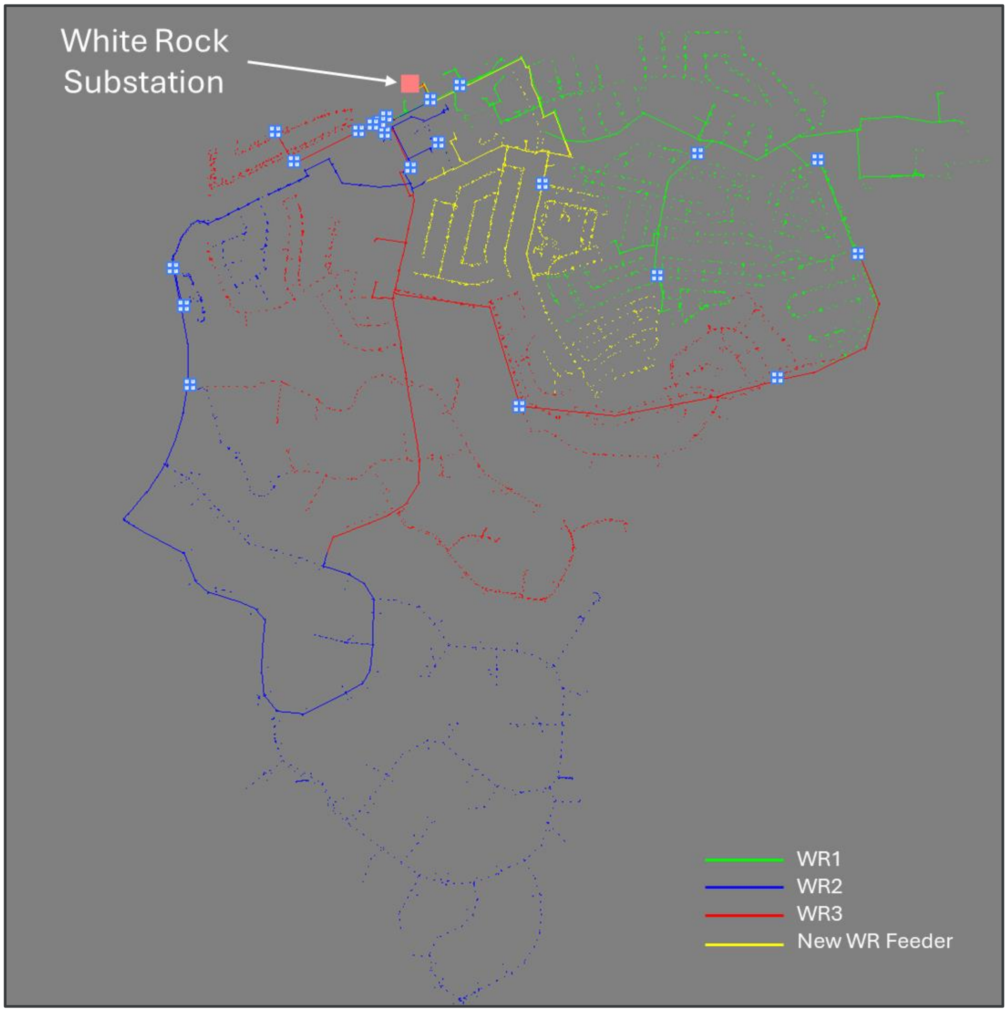


Figure  shows the proposed configuration for the White Rock system, colored by distribution feeder. To successfully serve the forecasted electrification growth in this scenario, both substation transformers must be upgraded to 22.4 MVA and accompanied by two four-feeder switchgear and a main tiebreaker between the two switchgears. One new distribution feeder was constructed from the White Rock Substation to evenly spread the load within the system.

Figure 4-2: 2055 Scenario 1 White Rock System Configuration




### 4.2.2 Conductor and Equipment Buildout

Figure  shows the conductor buildout and new equipment that was used to reconfigure the area and mitigate observed planning criteria violations for the Los Alamos Townsite system. Table 4-3 shows the quantities of conductor and equipment used in this scenario. Extending distribution feeders from the Eastgate Substation required the use of voltage regulators for two long overhead feeders. Voltage regulators were placed to raise voltage after confirming that voltage could not be maintained after upgrading the main line conductor and installing capacitor banks. Several new underground switches were utilized to create new tie points and connect the new distribution feeders into the existing underground portions of the system. Some conductor upgrades were proposed to strengthen mainline ties for contingency restoration efforts with the forecasted load. No upgrades were applied to the feeder serving the Pajarito Mountain ski area, except for one new capacitor bank.

**Figure 4-3: 2055 Scenario 1 Los Alamos Townsite System Conductor and Equipment Buildout**

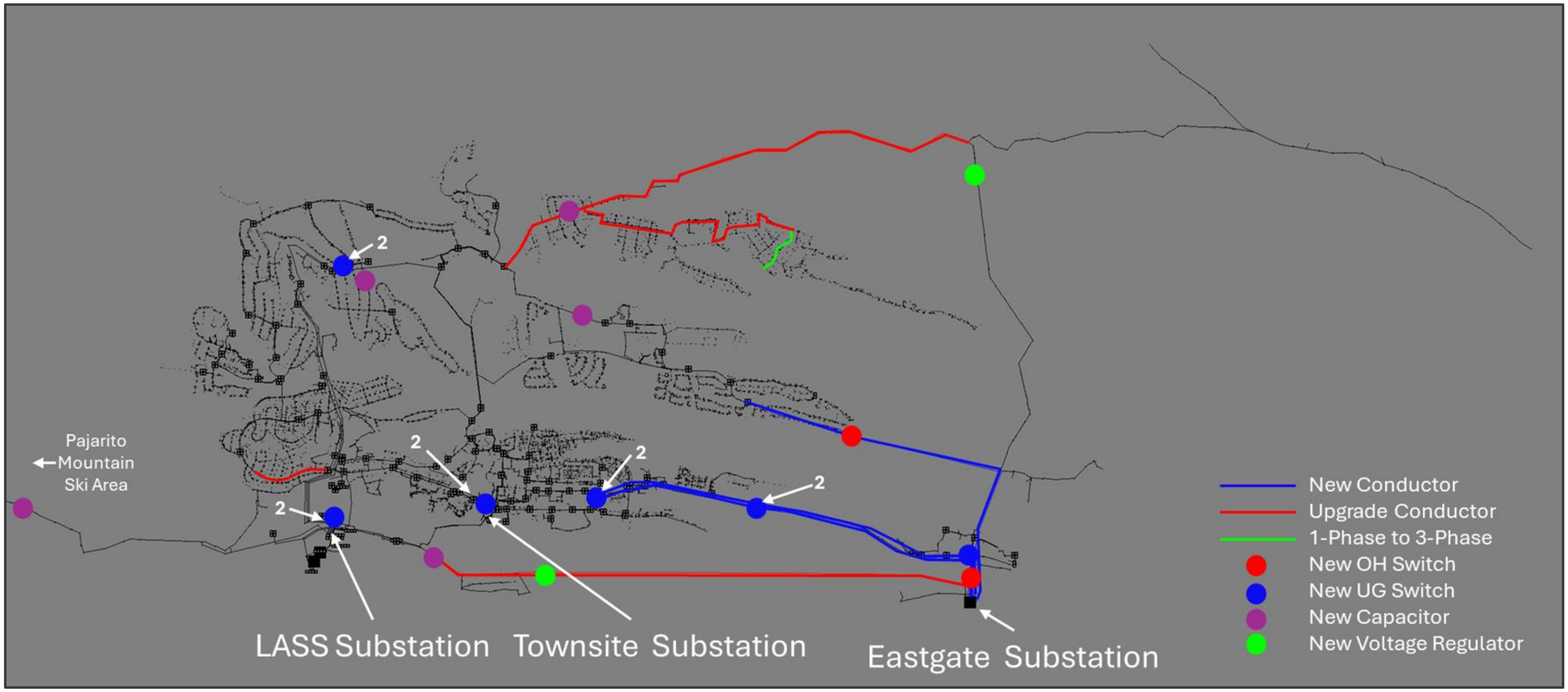


Table 4-3: 2055 Scenario 1 Los Alamos Townsite System Conductor and Equipment Quantities

| Conductor/ Equipment | Quantity |
|---|---|
| 500 MCM CU Cable (miles) | 7.9 |
| 4/0 CU Cable (miles) | 0 |
| 477 ACSR Conductor (miles) | 7.8 |
| 4/0 ACSR Conductor (miles) | 1.9 |
| UG Switch (PME) | 11 |
| OH Switch | 2 |
| Capacitor Bank | 5 |
| Voltage Regulator | 2 |

Figure  shows the conductor buildout and new equipment that were used to reconfigure the area and mitigate observed planning criteria violations for the White Rock system. Table 4-4 shows the quantities of conductors and equipment used in this scenario. The main loops through the White Rock system must be upgraded to maintain sufficient capacity for any contingency scenario involving the substation equipment or a failure on a distribution feeder. Each main line loop must be constructed to support the full load of the loop during peak loading conditions.

Figure 4-4: 2055 Scenario 1 White Rock System Conductor and Equipment Buildout

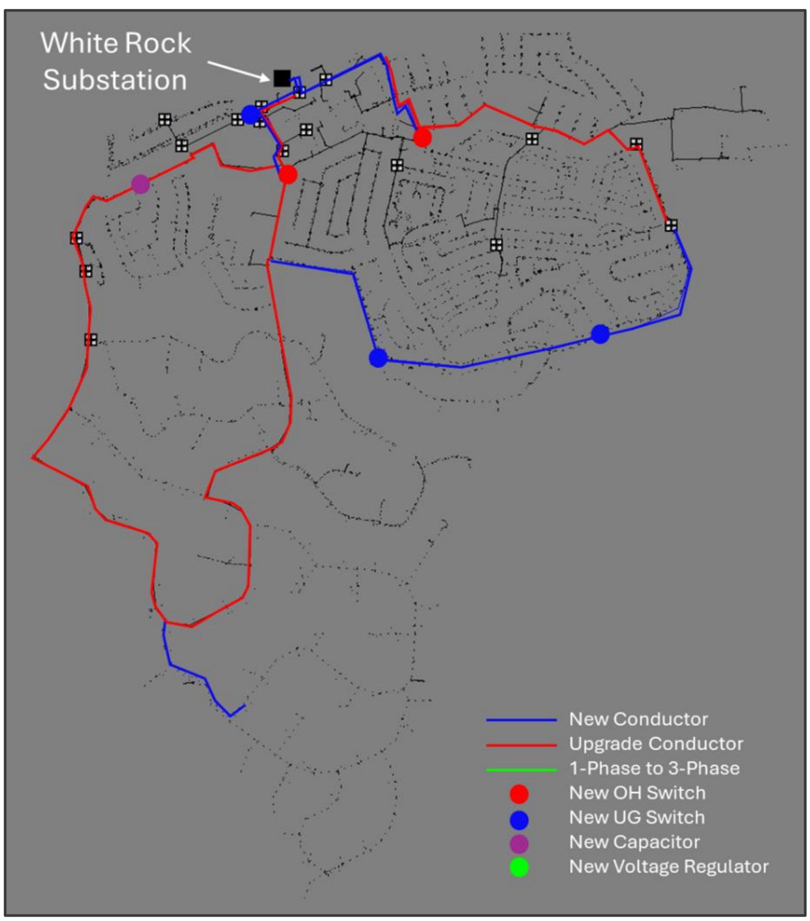


**Table 4-4: 2055 Scenario 1 White Rock System Conductor and Equipment Quantities**

| Conductor/ Equipment | Quantity |
|---|---|
| 500 MCM CU Cable (miles) | 4.4 |
| 4/0 CU Cable (miles) | 0 |
| Installed 477 ACSR Conductor (miles) | 3.7 |
| 4/0 ACSR Conductor (miles) | 0.1 |
| UG Switch (PME) | 3 |
| OH Switch | 2 |
| Capacitor Bank | 1 |
| Voltage Regulator | 0 |

### 4.2.3 Normal Configuration Power Flow Analysis

Table 4-5 shows the Los Alamos Townsite system power flow results. In this new configuration, all planning criteria were maintained.

**Table 4-5: 2055 Scenario 1 Los Alamos System Power Flow Results**

| Station | Distribution Feeder | kW | kVAR | kVA | Max Amps | Min Voltage |
|---|---|---|---|---|---|---|
| Town Site | 13 | 3,554 | 1,340 | 3,805 | 211 | 122.5 |
| | 14** | - | - | - | - | - |
| | 15 | 2,013 | 768 | 2,155 | 116 | 118.7 |
| | 16 | 2,158 | -449 | 2,227 | 123 | 121.5 |
| | 17** | - | - | - | - | - |
| | 18 | 212 | 59 | 220 | 9 | 124.5 |
| | **Substation** | **8,049** | **1,916** | **8,278** | **-** | **-** |
| LASS | 13T** | - | - | - | - | - |
| | NS6 | 4,010 | 820 | 4,093 | 172 | 124.3 |
| | 15T | 2,804 | 1,099 | 3,013 | 153 | 121.2 |
| | NSM6* | - | - | - | - | - |
| | 16T** | - | - | - | - | - |
| | NS3 | 1,956 | 292 | 1,978 | 83 | 124.7 |
| | NS18** | - | - | - | - | - |
| | 18 | 1,602 | -340 | 1,639 | 71 | 122.7 |
| | **Substation** | **10,460** | **2,071** | **10,672** | **-** | **-** |
| Eastgate | 11 | 5,441 | 438 | 5,461 | 240 | 122.6 |
| | 12 | 5,895 | 2,108 | 6,262 | 295 | 119.5 |
| | 13 | 5,960 | 1,427 | 6,140 | 290 | 119.6 |
| | **Transformer 1** | **17,299** | **3,974** | **17,754** | **-** | **-** |
| | 21 | 7,268 | 2,662 | 7,742 | 353 | 119.8 |
| | 21 | 3,875 | -570 | 3,920 | 179 | 124.2 |
| | 23 | 2,160 | 755 | 2,289 | 107 | 123.1 |
| | **Transformer 2** | **13,305** | **2,848** | **13,607** | **-** | **-** |

*Feeder NSM6 is reserved for emergency restoration of NS6, which serves the Los Alamos County Medical Center.

**These feeders do not normally serve load in this configuration, but are useful for contingency restoration efforts.

Table 4-6 shows the White Rock system power flow results. In this new configuration, all planning criteria were maintained.

Table 4-6: 2055 Scenario 1 White Rock System Power Flow Results

| Station | Distribution Feeder | kW | kVAR | kVA | Max Amps | Min Voltage |
|---|---|---|---|---|---|---|
| White Rock | WR1 | 5,193 | 1366 | 5,370 | 256 | 121.9 |
| | WR2 | 3,350 | -187 | 3,360 | 174 | 118.8 |
| | WR3 | 5,319 | 1,051 | 5,423 | 278 | 121.4 |
| | New WR Feeder | 2,602 | 836 | 2,733 | 135 | 121.9 |
| | Substation | 16,469 | 3,030 | 16,750 | - | - |

### 4.2.4 Contingency Configuration Review

Table 4-7 shows the substation transformer and primary feeder contingency scenarios evaluated for the Los Alamos Townsite system. There is sufficient capacity for all major substation transformers and primary feeder contingency scenarios. The system model was also evaluated to determine if all distribution feeders from the Eastgate Substation could be restored if one of the substation switchgear must be de-energized and the bus tie is unavailable. There are sufficient ties within the Los Alamos Townsite system to restore Eastgate Substation feeders. Conductor upgrades were performed to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 4-7: 2055 Scenario 1 Los Alamos Townsite System Contingency Review

| Scenario | Customer Load to Restore kVA | Total Applicable Customer Load kVA | Remaining Applicable Capacity kVA | Loading Violations? | Voltage Violations? | Comments |
|---|---|---|---|---|---|---|
| Loss of TA-3 XFMR 1 | 13,103 | 18,950 | 20,000 | No | No | Primary feeders TC2 and LC2 are used to restore customer load. TA-3 Transformer 2 is the most limiting element in this contingency. |
| Loss of TA-3 XFMR 2 | 5,997 | 18,950 | 20,000 | No | No | Primary feeders TC1 and LC1 are used to restore customer load. TA-3 Transformer 1 is the most limiting element in this contingency. |
| Loss of TC1 | 6,022 | 8,457 | 14,100 | No | No | Primary feeder TC2 is used to restore customer load through the Townsite switchgear. The TC2 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of TC2 | 2,435 | 8,457 | 16,000 | No | No | Primary feeder TC1 is used to restore customer load through the Townsite switchgear. The TC1 parallel 500 MCM CU cable is the most limiting element in this contingency. |
| Loss of LC1 | 7,081 | 10,643 | 14,100 | No | No | Primary feeder LC2 is used to restore customer load through the LASS switchgear. The LC2 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of LC2 | 3,562 | 10,643 | 14,100 | No | No | Primary feeder LC1 is used to restore customer load through the LASS switchgear. The LC1 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of Eastgate XFMR 1 | 17,754 | 31,345 | 33,700 | No | No | Operate the bus tie to restore the Eastgate 1 customer load using the Eastgate 2 transformer. |
| Loss of Eastgate XFMR 2 | 13,608 | 31,345 | 33,700 | No | No | Operate the bus tie to restore the Eastgate 2 customer load using the Eastgate 1 transformer. |

Table 4-8 shows the most impactful contingency scenario for the White Rock system if Transformer 2 becomes de-energized. All planning criteria can be maintained if the bus tie is operated and customers are restored through Transformer 1 at the White Rock Substation. The system model was also evaluated if a substation switchgear must be de-energized. The existing backup feeders (16 and 17) can successfully serve the entire White Rock system load if the Transformer 2 switchgear must be de-energized. Conductor upgrades are required to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 4-8: 2055 Scenario 1 White Rock System Contingency Review

| Scenario | Total Applicable Customer Load kVA | Customer Load to Restore kVA | Remaining Applicable Capacity kVA | Loading Violations? | Voltage Violations? | Comments |
|---|---|---|---|---|---|---|
| Loss of XFMR 2 | 16,750 | 16,750 | 22,400 | No | No | With both substation transformers rated at 22,400 kVA, there is sufficient capacity to restore all customers if Transformer 2 becomes de-energized by operating the bus tie. |

### 4.2.5 Asset Replacement Estimate

Power flow analysis identified system upgrades to increase capacity and improve voltage adherence within the system. Due to aging and deterioration, assets within the LACDPU system are anticipated to be replaced over time. In 2055 Scenario 1, based on the present age of existing assets (Section 2.1), considering a 30-year period, many of the LACDPU system assets may need to be replaced. Table 4-9 shows the estimated asset replacements over the 30-year period for the Los Alamos Townsite system. Conductors and cables that were identified for upgrade due to capacity needs in the power flow analysis were not included in this asset replacement estimate.

**Table 4-9: 2055 Scenario 1 Los Alamos Townsite System Asset Replacement Estimate**

| Conductor/ Equipment | % of Assets Replaced | Quantity |
|---|---|---|
| Overhead Conductor Replacements (miles) | 100% | 25 |
| Underground Cable Replacements (miles) | 95% | 46 |
| Mainline Switches | 100% | 137 |
| Three-Phase Service Transformers | 80% | 147 |
| Single-Phase Service Transformers | 90% | 842 |
| Secondary Services | 90% | 5,724 |

Table 4-10 shows the estimated asset replacements over the 30-year period for the White Rock system's 2055 Scenario 1. The power flow analysis upgraded a significant number of conductors and cables, thereby reducing the quantity required for asset replacement.

**Table 4-10: 2055 Scenario 1 White Rock System Asset Replacement Estimate**

| Conductor/ Equipment | % of Assets Replaced | Quantity |
|---|---|---|
| Overhead Conductor Replacements (miles) | 100% | 6 |
| Underground Cable Replacements (miles) | 90% | 6 |
| Mainline Switches | 100% | 23 |
| Three-Phase Service Transformers | 80% | 29 |
| Single-Phase Service Transformers | 90% | 372 |
| Secondary Services | 90% | 2,352 |

## 4.3 2040 Scenario 1 Electrification Impact

2040 Scenario 1 added 22,040 kVA to the LACDPU system power flow model. Table 4-11 shows how this load was applied to the Los Alamos Townsite and the White Rock systems.

**Table 4-11: 2040 Scenario 1 Modeled Load**

| System | Existing System Load kVA | Forecasted Electrification Load kVA | Total Forecasted System Load kVA |
|---|---|---|---|
| Los Alamos Townsite | 17,811 | 15,867 | 34,616 |
| White Rock | 3,905 | 6,173 | 10,283 |
| Total | 21,716 | 22,040 | 44,899 |

### 4.3.1 Study Area Configuration

Figure  shows the proposed configuration for the Los Alamos Townsite system, colored by substation. To successfully serve the forecasted electrification growth in this scenario, the Eastgate Substation must be constructed. The Eastgate Substation must contain two transformers and two four-feeder switchgear with a main tie breaker between the two switchgears. In 2055 Scenario 1, two 33.7 MVA transformers are required to serve the forecasted load. Although smaller transformers would work for the 2040 Scenario 1, two 33.7 MVA transformers were installed at the Eastgate Substation, knowing the potential load serving need of the future 2055 Scenario 1. However, only four new distribution feeders were constructed in the planning model to bring this new capacity west towards the load centers given the forecasted load in 2040. A significant amount of the Los Alamos Townsite system load must be served from the Eastgate Substation to avoid overloading the existing LASS and Townsite substations. The LASS Substation was primarily used to serve commercial loads near the substation, along with the Pajarito Mountain ski area and some residential loads. Much of the Townsite Substation load was transferred to Eastgate Substation, but some feeders were routed back north to spread the load across the existing LASS and Townsite substation feeders.

**Figure 4-5: 2040 Scenario 1 Los Alamos Townsite System Configuration**

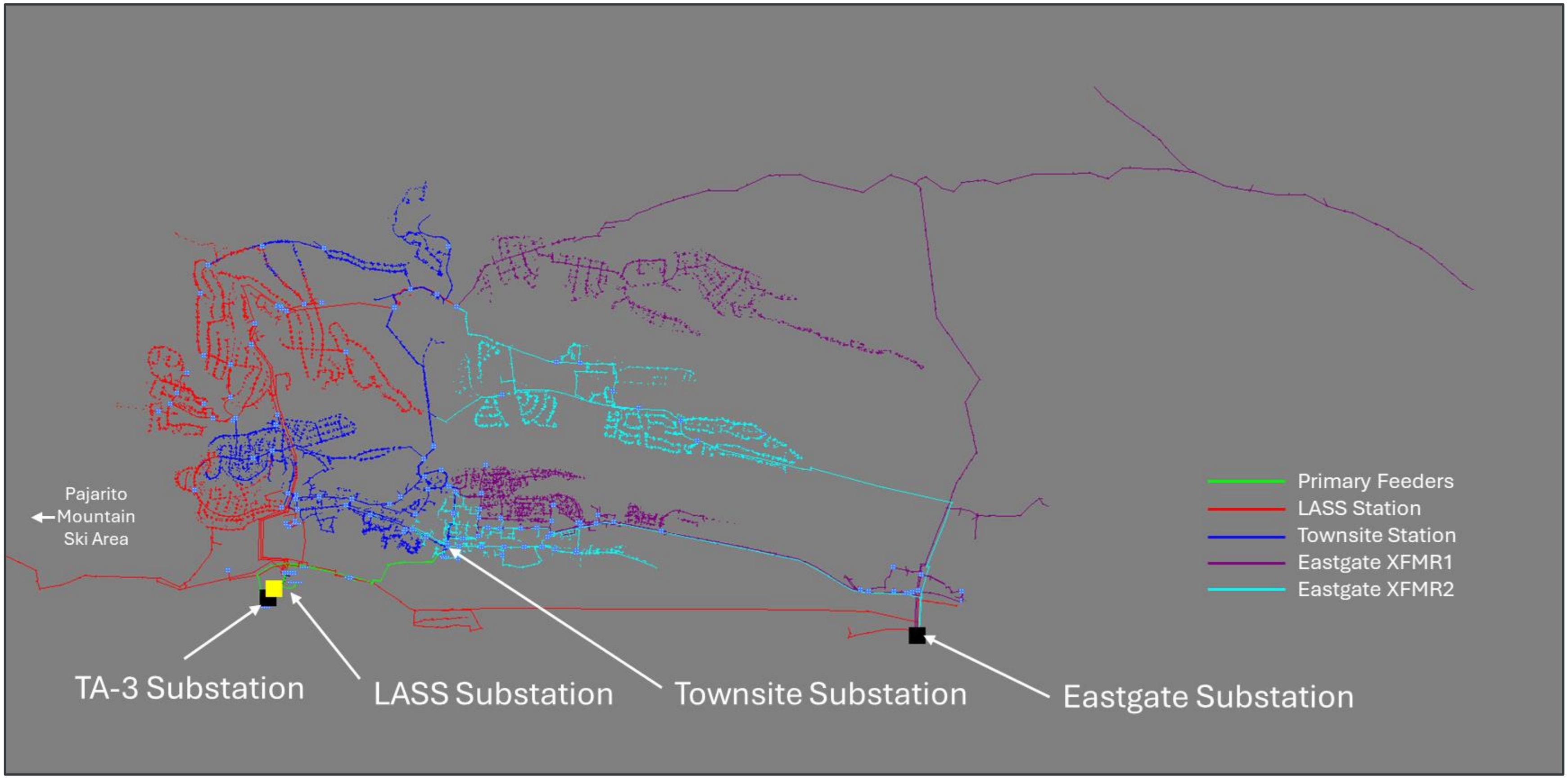
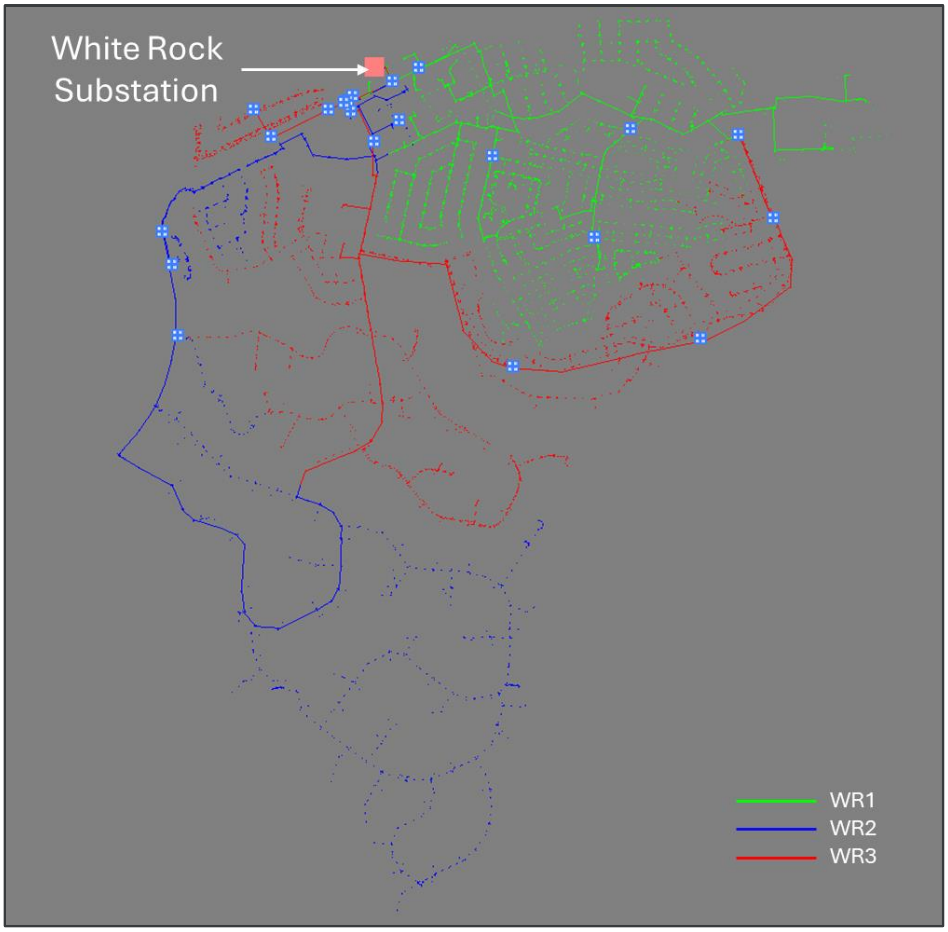


Figure  shows the proposed configuration for the White Rock system, colored by distribution feeder. To successfully serve the forecast electrification growth in this scenario, both substation transformers must be upgraded to 22.4 MVA and accompanied by two four-feeder switchgears and a main tie-breaker between the two switchgears. For 2040 Scenario 1, a smaller transformer size could be feasible, but it is assumed that LACDPU would construct the substation transformer sized for the full buildout in 2055. No new distribution feeders are required, given the load forecast in this scenario for 2040.

**Figure 4-6: 2040 Scenario 1 White Rock System Configuration**




### 4.3.2 Conductor and Equipment Buildout

Figure  shows the conductor buildout and new equipment that was used to reconfigure the area and mitigate observed planning criteria violations for the Los Alamos Townsite system. Table 4-12 shows the quantities of conductor and equipment used in this scenario. Extending distribution feeders from the Eastgate Substation required the use of voltage regulators for two long overhead feeders. Voltage regulators were not required in this scenario because the feeder load was lower than modeled in the 2055 scenario. Several new underground switches were utilized to create new tie points and connect the new distribution feeders into the existing underground portions of the system. Some conductor upgrades were proposed to strengthen mainline ties for contingency restoration efforts with the forecasted load. No upgrades were applied to the feeder serving the Pajarito Mountain ski area, except for one new capacitor bank.

Figure 4-7: 2040 Scenario 1 Los Alamos Townsite System Configuration

Table 4-12: 2040 Scenario 1 Los Alamos Townsite System Conductor and Equipment Quantities

| Conductor/ Equipment | Quantity |
|---|---|
| 500 MCM CU Cable (miles) | 4.4 |
| 4/0 CU Cable (miles) | 0 |
| 477 ACSR Conductor (miles) | 4.2 |
| 4/0 ACSR Conductor (miles) | 0 |
| UG Switch (PME) | 5 |
| OH Switch | 1 |
| Capacitor Bank | 2 |
| Voltage Regulator | 0 |

Figure  shows the conductor buildout and new equipment that was used to reconfigure the area and mitigate observed planning criteria violations for the White Rock system. Table 4-13 shows the quantities of conductor and equipment used in this scenario. The main loops through the White Rock system must be upgraded to maintain sufficient capacity for any contingency scenario involving the substation equipment or a failure on a distribution feeder. Each main line loop must be constructed to support the full load of the loop during peak loading conditions.

Figure 4-8: 2040 Scenario 1 White Rock System Conductor and Equipment Buildout

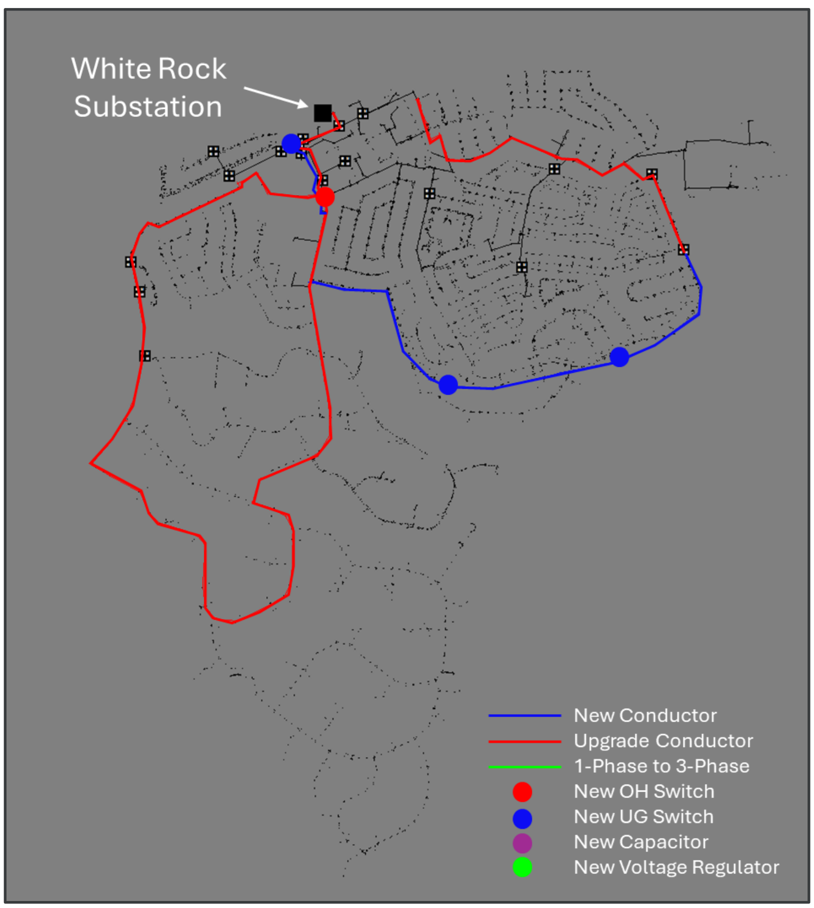


Table 4-13: 2040 Scenario 1 White Rock System Conductor and Equipment Quantities

| Conductor/ Equipment | Quantity |
|---|---|
| 500 MCM CU Cable (miles) | 3.5 |
| 4/0 CU Cable (miles) | 0 |
| Installed 477 ACSR Conductor (miles) | 3.7 |
| 4/0 ACSR Conductor (miles) | 0 |
| UG Switch (PME) | 3 |
| OH Switch | 1 |
| Capacitor Bank | 0 |
| Voltage Regulator | 0 |

### 4.3.3 Normal Configuration Power Flow Analysis

Table 4-14 shows the Los Alamos Townsite system power flow results. In this new configuration, all planning criteria were maintained.

Table 4-14: 2040 Scenario 1 Los Alamos System Power Flow Results

| Station | Distribution Feeder | kW | kVAR | kVA | Max Amps | Min Voltage |
|---|---|---|---|---|---|---|
| Town Site | 13 | 2,452 | 70 | 2,458 | 133 | 123.5 |
| | 14** | - | - | - | - | - |
| | 15 | 3,378 | 961 | 3,512 | 154 | 121.3 |
| | 16 | 33 | -22 | 54 | 4 | 124.9 |
| | 17** | - | - | - | - | - |
| | 18 | 147 | 37 | 151 | 6 | 124.9 |
| | **Substation** | **6,127** | **1,213** | **6,252** | - | - |
| LASS | 13T | 1,155 | 325 | 1,199 | 58 | 124.6 |
| | NS6 | 2,771 | 900 | 2,913 | 125 | 124.5 |
| | 15T | 1,058 | 170 | 1,073 | 64 | 123.5 |
| | NSM6* | - | - | - | - | - |
| | 16T | 1,455 | 336 | 1,495 | 87 | 122.7 |
| | NS3 | 1,353 | 433 | 1,420 | 60 | 124.7 |
| | NS18 | 786 | 244 | 823 | 44 | 123.9 |
| | 18 | 1,101 | 312 | 1,145 | 50 | 122.3 |
| | **Substation** | **9,766** | **2,940** | **10,206** | - | - |
| Eastgate | 11 | 4,014 | 201 | 4,020 | 177 | 120.5 |
| | 12 | 5,160 | 1,543 | 5,386 | 244 | 121.6 |
| | **Transformer 1** | **7,174** | **1,745** | **9,339** | - | - |
| | 21 | 5,575 | 1,752 | 5,845 | 253 | 121.4 |
| | 21 | 2,658 | 129 | 2,675 | 143 | 122.5 |
| | **Transformer 2** | **8,235** | **1,880** | **8,447** | - | - |

*Feeder NSM6 is reserved for emergency restoration of NS6, which serves the Los Alamos County Medical Center.

**These feeders do not normally serve load in this configuration, but are useful for contingency restoration efforts.

Table 4-15 shows the White Rock system power flow results. In this new configuration, all planning criteria were maintained.

Table 4-15: 2040 Scenario 1 White Rock System Power Flow Results

| Station | Distribution Feeder | kW | kVAR | kVA | Max Amps | Min Voltage |
|---|---|---|---|---|---|---|
| White Rock | WR1 | 4,215 | 995 | 4,331 | 205 | 122.5 |
| | WR2 | 1,998 | 617 | 2091 | 103 | 121.5 |
| | WR3 | 3,643 | 446 | 3,670 | 172 | 123.5 |
| | Substation | 9,857 | 2,044 | 10,067 | - | - |

### 4.3.4 Contingency Configuration Analysis

Table 4-16 shows the substation transformer and primary feeder contingency scenarios evaluated for the Los Alamos Townsite system. There is sufficient capacity for all major substation transformers and primary feeder contingency scenarios. The system model was also evaluated to determine if all distribution feeders from the Eastgate Substation could be restored if one of the substation switchgear must be de-energized and the bus tie is unavailable. There are sufficient ties within the Los Alamos Townsite system to restore Eastgate Substation feeders. Conductor upgrades were performed to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 4-16: 2040 Scenario 1 Los Alamos Townsite System Contingency Review

| Scenario | Customer Load to Restore kVA | Total Applicable Customer Load kVA | Remaining Applicable Capacity kVA | Loading Violations? | Voltage Violations? | Comments |
|---|---|---|---|---|---|---|
| Loss of TA-3 XFMR 1 | 11,144 | 16,211 | 20,000 | No | No | Primary feeders TC2 and LC2 are used to restore customer load. TA-3 Transformer 2 is the most limiting element in this contingency. |
| Loss of TA-3 XFMR 2 | 5,067 | 16,211 | 20,000 | No | No | Primary feeders TC1 and LC1 are used to restore customer load. TA-3 Transformer 1 is the most limiting element in this contingency. |
| Loss of TC1 | 5,968 | 6,153 | 14,100 | No | No | Primary feeder TC2 is used to restore customer load through the Townsite switchgear. The TC2 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of TC2 | 185 | 6,153 | 16,000 | No | No | Primary feeder TC1 is used to restore customer load through the Townsite switchgear. The TC1 parallel 500 MCM CU cable is the most limiting element in this contingency. |
| Loss of LC1 | 5,176 | 10,058 | 14,100 | No | No | Primary feeder LC2 is used to restore customer load through the LASS switchgear. The LC2 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of LC2 | 4,882 | 10,058 | 14,100 | No | No | Primary feeder LC1 is used to restore customer load through the LASS switchgear. The LC1 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of Eastgate XFMR 1 | 9,339 | 17,774 | 33,700 | No | No | Operate the bus tie to restore the Eastgate 1 customer load using the Eastgate 2 transformer. |
| Loss of Eastgate XFMR 2 | 8,447 | 17,774 | 33,700 | No | No | Operate the bus tie to restore the Eastgate 2 customer load using the Eastgate 1 transformer. |

Table 4-17 shows the most impactful contingency scenario for the White Rock system if Transformer 2 becomes de-energized. All planning criteria can be maintained if the bus tie is operated and customers are restored through Transformer 1 at the White Rock Substation. The system model was also evaluated to determine if a substation switchgear must be de-energized. The existing backup feeders (16 and 17) can successfully serve the entire White Rock system load if the Transformer 2 switchgear must be de-energized. Conductor upgrades are required to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 4-17: 2040 Scenario 1 White Rock System Contingency Review

| Scenario | Total Applicable Customer Load kVA | Customer Load to Restore kVA | Remaining Applicable Capacity kVA | Loading Violations? | Voltage Violations? | Comments |
|---|---|---|---|---|---|---|
| Loss of XFMR 2 | 10,067 | 10,067 | 22,400 | No | No | With both substation transformers rated at 22,400 kVA, there is sufficient capacity to restore all customers if Transformer 2 becomes de-energized by operating the bus tie. |

### 4.3.5 Asset Replacement Estimate

Power flow analysis identified system upgrades to increase capacity and improve voltage adherence within the system. Due to aging and deterioration, assets within the LACDPU system are anticipated to be replaced over time. In 2040 Scenario 1, based on the present age of existing assets (Section 2.1), considering a 15-year period, many of the LACDPU system assets may need to be replaced. Table 4-18 shows the estimated asset replacements over the 15-year period for the Los Alamos Townsite system. Conductors and cables that were identified for upgrade due to capacity needs in the power flow analysis were not included in this asset replacement estimate.

**Table 4-18: 2040 Scenario 1 Los Alamos Townsite System Asset Replacement Estimate**

| Conductor/ Equipment | % of Assets Replaced | Quantity |
|---|---|---|
| Overhead Conductor Replacements (miles) | 30% | 7 |
| Underground Cable Replacements (miles) | 65% | 32 |
| Mainline Switches | 90% | 123 |
| Three-Phase Service Transformers | 25% | 46 |
| Single-Phase Service Transformers | 35% | 327 |
| Secondary Services | 30% | 1,908 |

Table 4-19 shows the estimated asset replacements over the 15-year period for the White Rock system's 2040 Scenario 1. The power flow analysis upgraded a significant number of conductors and cables, thereby reducing the quantity required for asset replacement.

**Table 4-19: 2040 Scenario 1 White Rock System Asset Replacement Estimate**

| Conductor/ Equipment | % of Assets Replaced | Quantity |
|---|---|---|
| Overhead Conductor Replacements (miles) | 95% | 6 |
| Underground Cable Replacements (miles) | 50% | 3 |
| Mainline Switches | 70% | 16 |
| Three-Phase Service Transformers | 40% | 14 |
| Single-Phase Service Transformers | 50% | 207 |
| Secondary Services | 40% | 1,045 |

## 4.4 2055 Scenario 2 Electrification Impact

2055 Scenario 2 added 52,283 kVA to the LACDPU system power flow model. Table 4-20 shows how this load was applied to the Los Alamos Townsite and the White Rock systems.

Table 4-20: 2055 Scenario 2 Modeled Load

| System | Existing System Load kVA | Forecasted Electrification Load kVA | Total Forecasted System Load kVA |
|---|---|---|---|
| Los Alamos Townsite | 17,811 | 21,166 | 39,915 |
| White Rock | 3,905 | 8,258 | 12,368 |
| Total | 21,716 | 29,424 | 52,283 |

### 4.4.1 Study Area Configuration

Figure  shows the proposed configuration for the Los Alamos Townsite system, colored by substation. To successfully serve the forecasted electrification growth in this scenario, the Eastgate Substation must be constructed. The Eastgate Substation must contain two 22.4 MVA transformers and two four-feeder switchgears with a main tie breaker between the two switchgears. Four new distribution feeders were constructed in the planning model to bring this new capacity west towards the load centers. A significant amount of the Los Alamos Townsite system load must be served from the Eastgate Substation to avoid overloading the existing LASS and Townsite substations. The LASS Substation was primarily used to serve commercial loads near the substation, along with the Pajarito Mountain ski area and some residential loads. Much of the Townsite Substation load was transferred to Eastgate Substation, but some feeders were routed back north to spread the load across the existing LASS and Townsite substation feeders.

**Figure 4-9: 2055 Scenario 2 Los Alamos Townsite System Configuration**

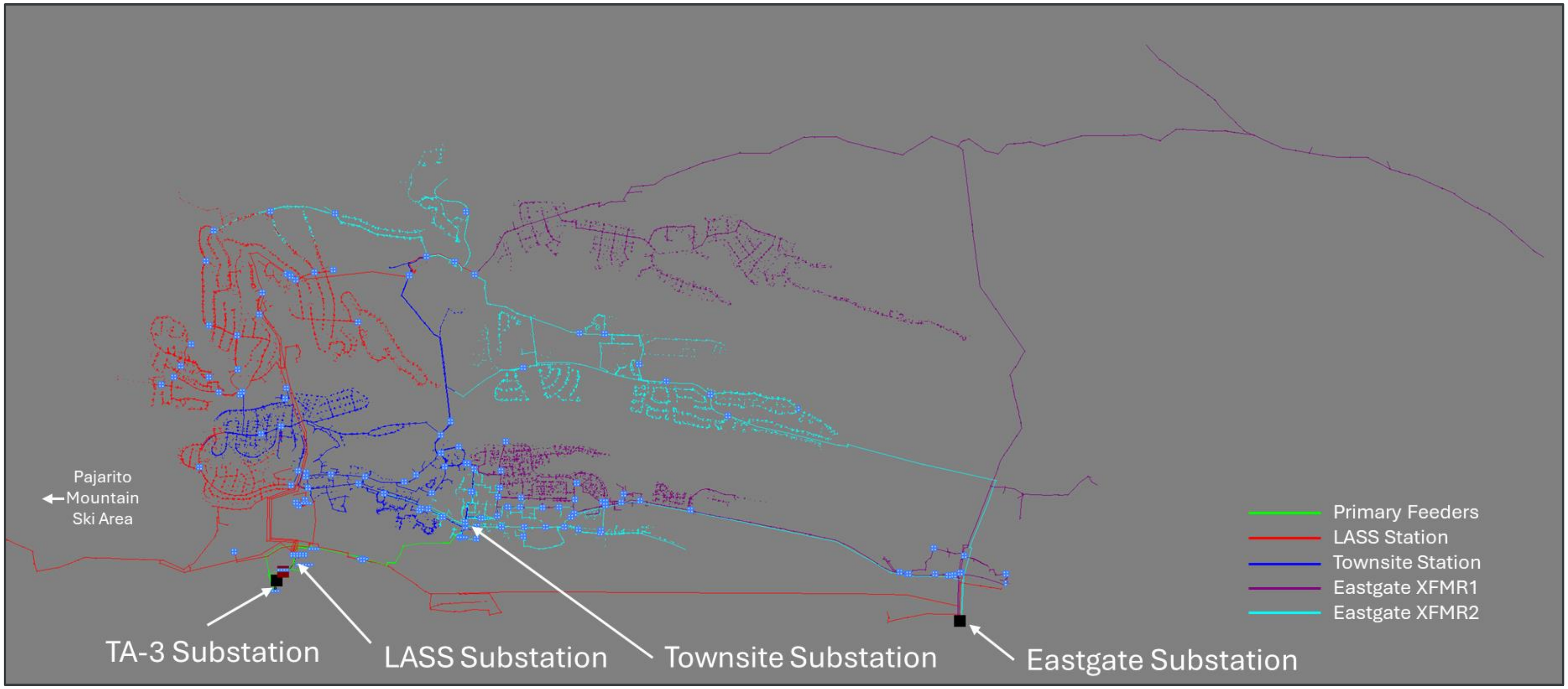
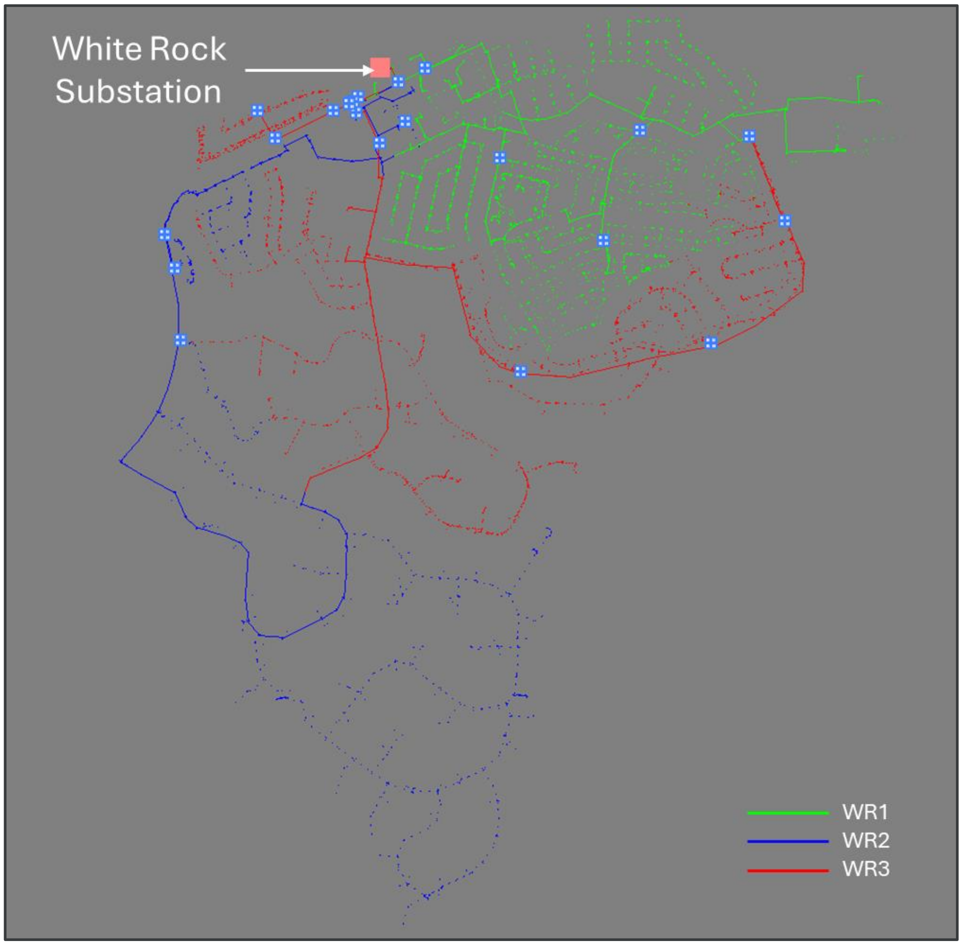


Figure shows the proposed configuration for the White Rock system, colored by distribution feeder. To successfully serve the forecasted electrification growth in this scenario, both substation transformers must be upgraded to 14 MVA and accompanied by two four-feeder switchgears and a main tie-breaker between the two switchgears. No new distribution feeders were constructed for this scenario, but WR3 was extended to serve more load in the center of the White Rock system.

**Figure 4-10: 2055 Scenario 2 White Rock System Configuration**




### 4.4.2 Conductor and Equipment Buildout

Figure shows the conductor buildout and new equipment that was used to reconfigure the area and mitigate observed planning criteria violations for the Los Alamos Townsite system. Table 4-21 shows the quantities of conductor and equipment used in this scenario. Extending distribution feeders from the Eastgate Substation required the use of voltage regulators for the one long overhead feeder that serves the northern portion of the area. This voltage regulator was placed to raise the voltage after confirming that the voltage could not be maintained after upgrading the main line conductor and installing capacitor banks. Several new underground switches were utilized to create new tie points and connect the new distribution feeders into the existing underground portions of the system. Some conductor upgrades were proposed to strengthen mainline ties for contingency restoration efforts with the forecasted load. No upgrades were applied to the feeder serving the Pajarito Mountain ski area.

**Figure 4-11: 2055 Scenario 2 Los Alamos Townsite System Conductor and Equipment Buildout**

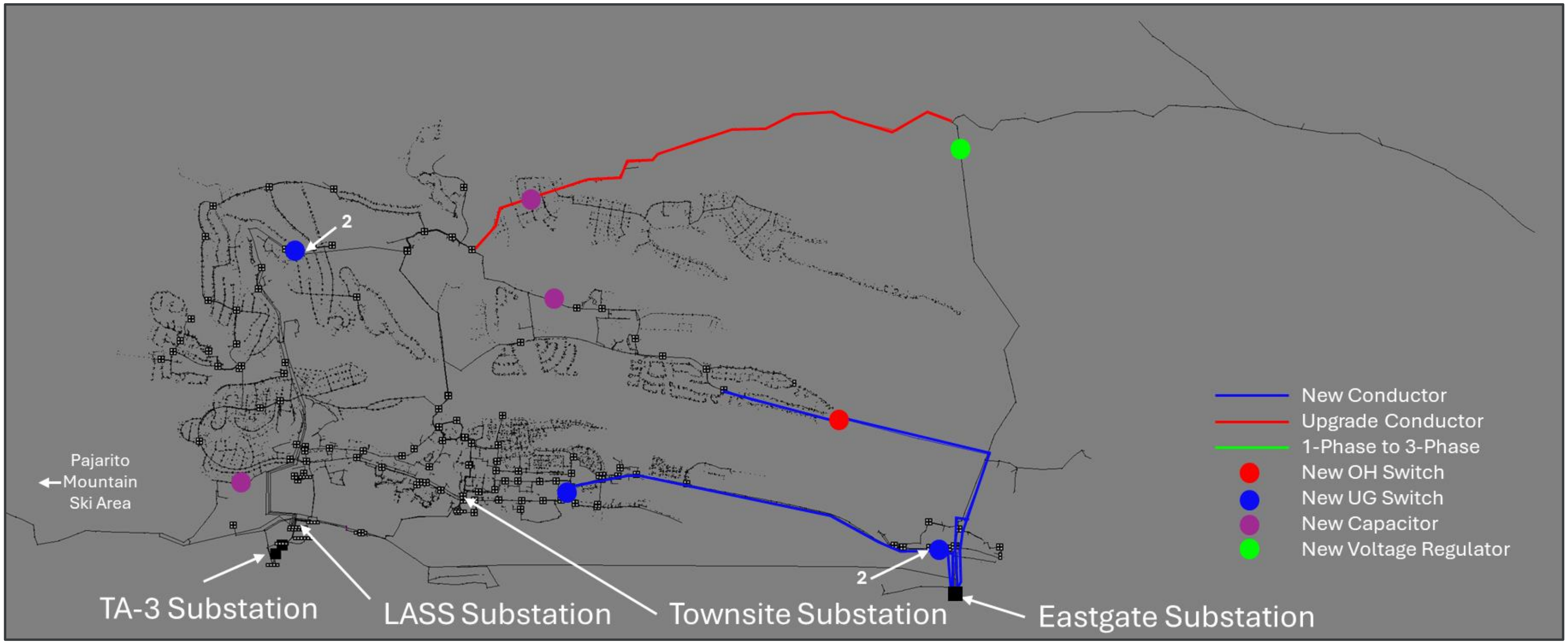


Table 4-21: 2055 Scenario 2 Los Alamos Townsite System Conductor and Equipment Quantities

| Conductor/ Equipment | Quantity |
|---|---|
| 500 MCM CU Cable (miles) | 4.4 |
| 4/0 CU Cable (miles) | 0 |
| Installed 477 ACSR Conductor (miles) | 4.2 |
| 4/0 ACSR Conductor (miles) | 0 |
| UG Switch (PME) | 5 |
| OH Switch | 1 |
| Capacitor Bank | 3 |
| Voltage Regulator | 1 |

Figure  shows the conductor buildout and new equipment that were used to reconfigure the area and mitigate observed planning criteria violations for the White Rock system. Table 4-22 shows the quantities of conductor and equipment used in this scenario. The main loops through the White Rock system must be upgraded to maintain sufficient capacity for any contingency scenario involving the substation equipment or a failure on a distribution feeder. Each main line loop must be constructed to support the full load of the loop during peak loading conditions.

Figure 4-12: 2055 Scenario 2 White Rock System Conductor and Equipment

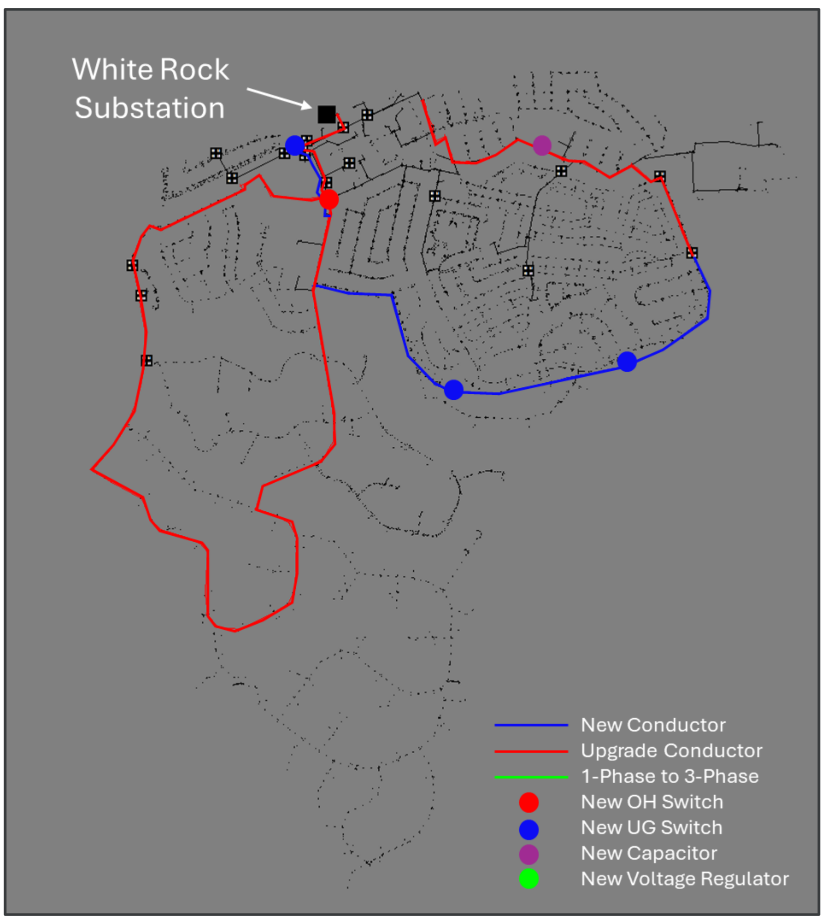


Table 4-22: 2055 Scenario 2 White Rock System Conductor and Equipment Quantities

| Conductor/ Equipment | Quantity |
|---|---|
| 500 MCM CU Cable (miles) | 3.5 |
| 4/0 CU Cable (miles) | 0 |
| Installed 477 ACSR Conductor (miles) | 3.7 |
| 4/0 ACSR Conductor (miles) | 0 |
| UG Switch (PME) | 3 |
| OH Switch | 1 |
| Capacitor Bank | 1 |
| Voltage Regulator | 0 |

### 4.4.3 Normal Configuration Power Flow Analysis

Table 4-23 shows the Los Alamos Townsite system power flow results. In this new configuration, all planning criteria were maintained.

Table 4-23: 2055 Scenario 2 Los Alamos System Power Flow Results

| Station | Distribution Feeder | kW | kVAR | kVA | Max Amps | Min Voltage |
|---|---|---|---|---|---|---|
| Town Site | 13 | 2,760 | 173 | 2,770 | 150 | 123.3 |
| | 14** | - | - | - | - | - |
| | 15 | 2,647 | 800 | 2,766 | 125 | 121.2 |
| | 16 | 37 | -20 | 59 | 5 | 124.8 |
| | 17** | - | - | - | - | - |
| | 18 | 165 | 43 | 170 | 7 | 124.9 |
| | **Substation** | **5,713** | **1,133** | **5,828** | - | - |
| LASS | 13T** | 1,301 | -925 | 1,605 | 73 | 124.6 |
| | NS6 | 3,118 | 1,015 | 3,279 | 138 | 124.5 |
| | 15T | 1,192 | 215 | 1,212 | 72 | 123.3 |
| | NSM6* | - | - | - | - | - |
| | 16T** | 1,640 | 399 | 1,688 | 98 | 122.4 |
| | NS3 | 1,522 | 489 | 1,599 | 67 | 124.6 |
| | NS18** | 884 | 278 | 927 | 49 | 123.8 |
| | 18 | 1,242 | 362 | 1,294 | 57 | 121.9 |
| | **Substation** | **10,997** | **2,106** | **11,207** | - | - |
| Eastgate | 11 | 4,349 | 318 | 4,362 | 192 | 122.0 |
| | 12 | 5,817 | 1,774 | 6,082 | 276 | 121.1 |
| | **Transformer 1** | **10,166** | **2,093** | **10,380** | - | - |
| | 21 | 6,293 | 2,016 | 6,609 | 286 | 120.7 |
| | 21 | 4,177 | -20 | 4,187 | 209 | 121.3 |
| | **Transformer 2** | **10,471** | **1,995** | **10,661** | - | - |

*Feeder NSM6 is reserved for emergency restoration of NS6, which serves the Los Alamos County Medical Center.

**These feeders do not normally serve load in this configuration, but are useful for contingency restoration efforts.

Table 4-24 shows the White Rock system power flow results. In this new configuration, all planning criteria were maintained.

**Table 4-24: 2055 Scenario 2 White Rock System Power Flow Results**

| Station | Distribution Feeder | kW | kVAR | kVA | Max Amps | Min Voltage |
|---|---|---|---|---|---|---|
| White Rock | WR1 | 4,959 | -59 | 4,961 | 234 | 122.4 |
| | WR2 | 2,352 | 742 | 2,467 | 122 | 120.9 |
| | WR3 | 4,286 | 669 | 4,338 | 203 | 123.3 |
| | Substation | 11,599 | 1,338 | 11,681 | - | - |

### 4.4.4 Contingency Configuration Analysis

Table 4-25 shows the substation transformer and primary feeder contingency scenarios evaluated for the Los Alamos Townsite system. There is sufficient capacity for all major substation transformers and primary feeder contingency scenarios. The system model was also evaluated to determine if all distribution feeders from the Eastgate Substation could be restored if one of the substation switchgear must be de-energized and the bus tie is unavailable. There are sufficient ties within the Los Alamos Townsite system to restore Eastgate Substation feeders. Conductor upgrades were performed to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 4-25: 2055 Scenario 2 Los Alamos Townsite System Contingency Review

| Scenario | Customer Load to Restore kVA | Total Applicable Customer Load kVA | Remaining Applicable Capacity kVA | Loading Violations? | Voltage Violations? | Comments |
|---|---|---|---|---|---|---|
| Loss of TA-3 XFMR 1 | 11,160 | 16,874 | 20,000 | No | No | Primary feeders TC2 and LC2 are used to restore customer load. TA-3 Transformer 2 is the most limiting element in this contingency. |
| Loss of TA-3 XFMR 2 | 5,714 | 16,874 | 20,000 | No | No | Primary feeders TC1 and LC1 are used to restore customer load. TA-3 Transformer 1 is the most limiting element in this contingency. |
| Loss of TC1 | 5,537 | 5,743 | 14,100 | No | No | Primary feeder TC2 is used to restore customer load through the Townsite switchgear. The TC2 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of TC2 | 206 | 5,743 | 16,000 | No | No | Primary feeder TC1 is used to restore customer load through the Townsite switchgear. The TC1 parallel 500 MCM CU cable is the most limiting element in this contingency. |
| Loss of LC1 | 5,623 | 11,131 | 14,100 | No | No | Primary feeder LC2 is used to restore customer load through the LASS switchgear. The LC2 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of LC2 | 5,508 | 11,131 | 14,100 | No | No | Primary feeder LC1 is used to restore customer load through the LASS switchgear. The LC1 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of Eastgate XFMR 1 | 10,380 | 21,031 | 22,400 | No | No | Operate the bus tie to restore the Eastgate 1 customer load using the Eastgate 2 transformer. |
| Loss of Eastgate XFMR 2 | 10,661 | 21,031 | 22,400 | No | No | Operate the bus tie to restore the Eastgate 2 customer load using the Eastgate 1 transformer. |

Table 4-26 shows the most impactful contingency scenario for the White Rock system if Transformer 2 becomes de-energized. All planning criteria can be maintained if the bus tie is operated and customers are restored through Transformer 1 at the White Rock Substation. The system model was also evaluated to determine if a substation switchgear must be de-energized. The existing backup feeders (16 and 17) can successfully serve the entire White Rock system load if the Transformer 2 switchgear must be de-energized. Conductor upgrades are required to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 4-26: 2055 Scenario 2 White Rock System Contingency Review

| Scenario | Total Applicable Customer Load kVA | Customer Load to Restore kVA | Remaining Applicable Capacity kVA | Loading Violations? | Voltage Violations? | Comments |
|---|---|---|---|---|---|---|
| Loss of XFMR 2 | 11,688 | 11,688 | 14,000 | No | No | With both substation transformers rated at 14,000 kVA, there is sufficient capacity to restore all customers if Transformer 2 becomes de-energized by operating the bus tie. |

### 4.4.5 Asset Replacement Estimate

Power flow analysis identified system upgrades to increase capacity and improve voltage adherence within the system. Due to aging and deterioration, assets within the LACDPU system are anticipated to be replaced over time. In 2055 Scenario 2, based on the present age of existing assets (Section 2.1), considering a 30-year period, many of the LACDPU system assets may need to be replaced. Table 4-27 shows the estimated asset replacements over the 30-year period for the Los Alamos Townsite system. Conductors and cables that were identified for upgrade due to capacity needs in the power flow analysis were not included in this asset replacement estimate.

Table 4-27: 2055 Scenario 2 Los Alamos Townsite System Asset Replacement Estimate

| Conductor/ Equipment | % of Assets Replaced | Quantity |
|---|---|---|
| Overhead Conductor Replacements (miles) | 100% | 30 |
| Underground Cable Replacements (miles) | 95% | 47 |
| Mainline Switches | 100% | 137 |
| Three-Phase Service Transformers | 70% | 129 |
| Single-Phase Service Transformers | 80% | 748 |
| Secondary Services | 80% | 5,088 |

Table 4-28 shows the estimated asset replacements over the 30-year period for the White Rock system's 2055 Scenario 2. The power flow analysis upgraded a significant number of conductors and cables, thereby reducing the quantity required for asset replacement.

Table 4-28: 2055 Scenario 2 White Rock System Asset Replacement Estimate

| Conductor/ Equipment | % of Assets Replaced | Quantity |
|---|---|---|
| Overhead Conductor Replacements (miles) | 100% | 6 |
| Underground Cable Replacements (miles) | 90% | 6 |
| Mainline Switches | 100% | 23 |
| Three-Phase Service Transformers | 70% | 25 |
| Single-Phase Service Transformers | 80% | 330 |
| Secondary Services | 80% | 2,090 |

## 4.5 2040 Scenario 2 Electrification Impact

2040 Scenario 2 added 7,911 kVA to the LACDPU system power flow model. Table 4-29 shows how this load was applied to the Los Alamos Townsite and the White Rock systems.

Table 4-29: 2040 Scenario 2 Modeled Load

| System | Existing System Load kVA | Forecasted Electrification Load kVA | Total Forecasted System Load kVA |
|---|---|---|---|
| Los Alamos Townsite | 17,811 | 5,686 | 24,435 |
| White Rock | 3,905 | 2,224 | 6,335 |
| Total | 21,716 | 7,911 | 30,769 |

### 4.5.1 Study Area Configuration

Figure  shows the proposed configuration for the Los Alamos Townsite system, colored by substation. To successfully serve the forecasted electrification growth in this scenario, the Eastgate Substation must be constructed. The Eastgate Substation must contain two transformers and two four-feeder switchgears with a main tie breaker between the two switchgears. In 2055 Scenario 2, two 22.4 MVA transformers are required to serve the forecasted load. Although smaller transformers would work for this 2040 scenario, two 22.4 MVA transformers were installed at the Eastgate Substation, knowing the potential load serving need of the future 2055 scenario. However, only two new distribution feeders were constructed in the planning model to bring this new capacity west towards the load centers, given the forecasted load in 2040. Some of the Los Alamos Townsite system load must be served from the Eastgate Substation to avoid overloading the existing LASS and Townsite substations. The LASS Substation was primarily used to serve commercial loads near the substation, along with the Pajarito Mountain ski area and some residential loads. Some of the Townsite Substation load was transferred to Eastgate Substation.

**Figure 4-13: 2040 Scenario 2 Los Alamos Townsite System Configuration**

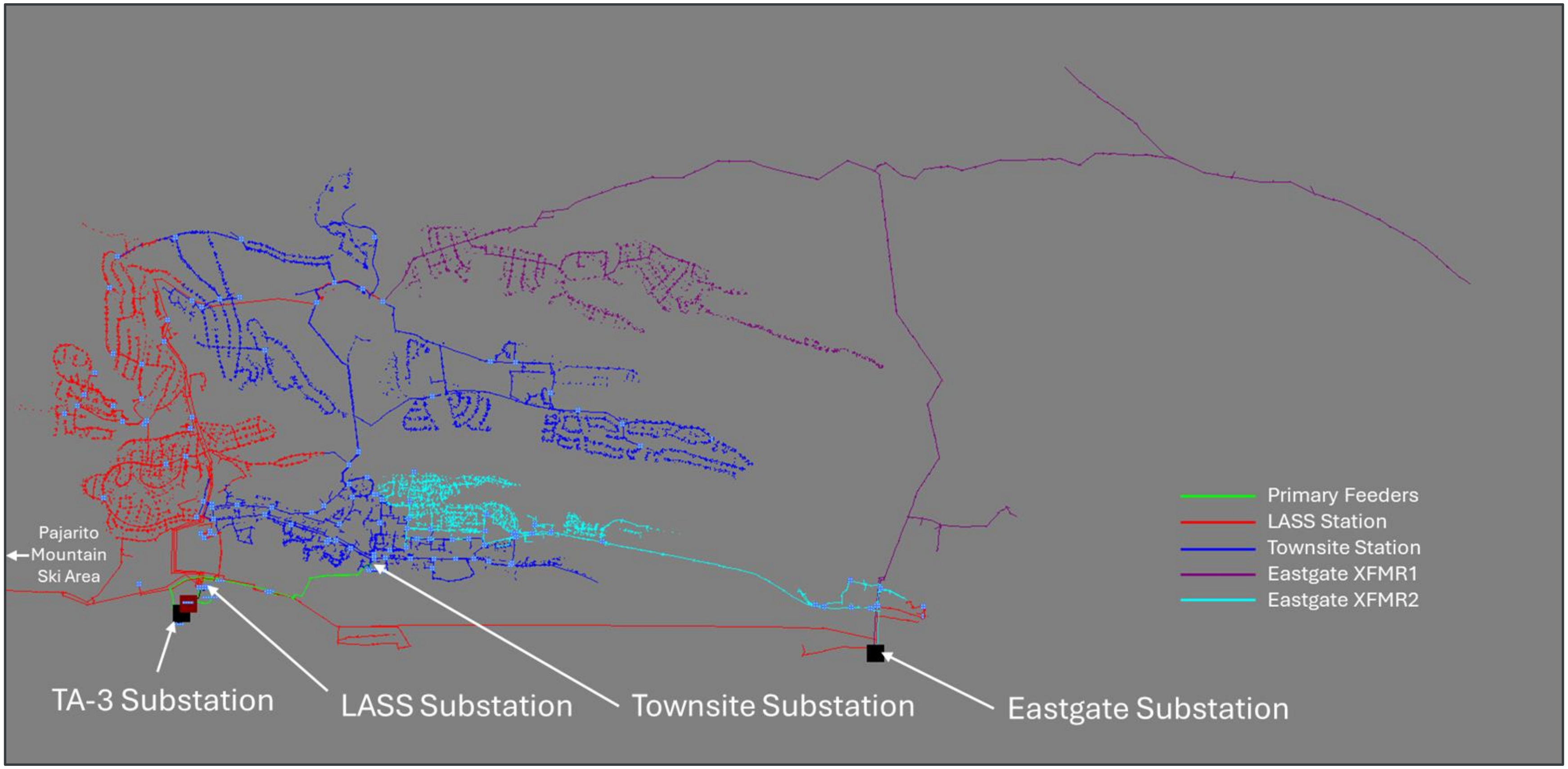
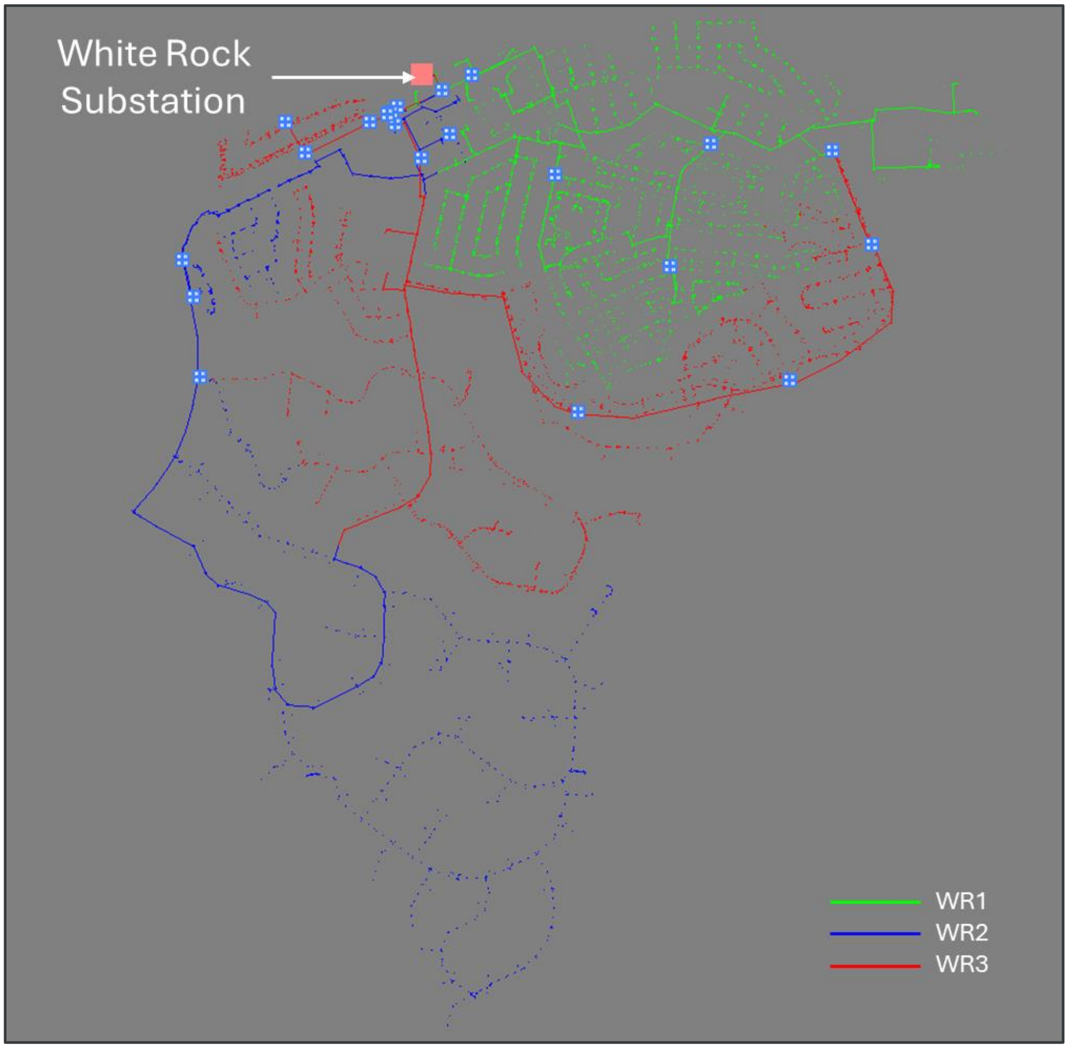


Figure  shows the proposed configuration for the White Rock system, colored by distribution feeder. To successfully serve the forecasted electrification growth in this scenario, White Rock Transformer 1 must be upgraded to 14 MVA to accommodate the 2040 and the 2055 forecasted loads. No new distribution feeders were constructed for this scenario, but WR3 was extended to serve more load in the center of the White Rock system.

Figure 4-14: 2040 Scenario 2 White Rock System Configuration




### 4.5.2 Conductor and Equipment Buildout

Figure  shows the conductor buildout and new equipment that were used to reconfigure the area and mitigate observed planning criteria violations for the Los Alamos Townsite system. Table 4-30 shows the quantities of conductors and equipment used in this scenario. One new underground switch was utilized to connect the new distribution feeders to the existing underground portions of the system. Some conductor upgrades were proposed to strengthen mainline ties for contingency restoration efforts with the forecasted load. No upgrades were applied to the feeder serving the Pajarito Mountain ski area.

Figure 4-15: 2040 Scenario 2 Los Alamos Townsite System Conductor and Equipment Buildout

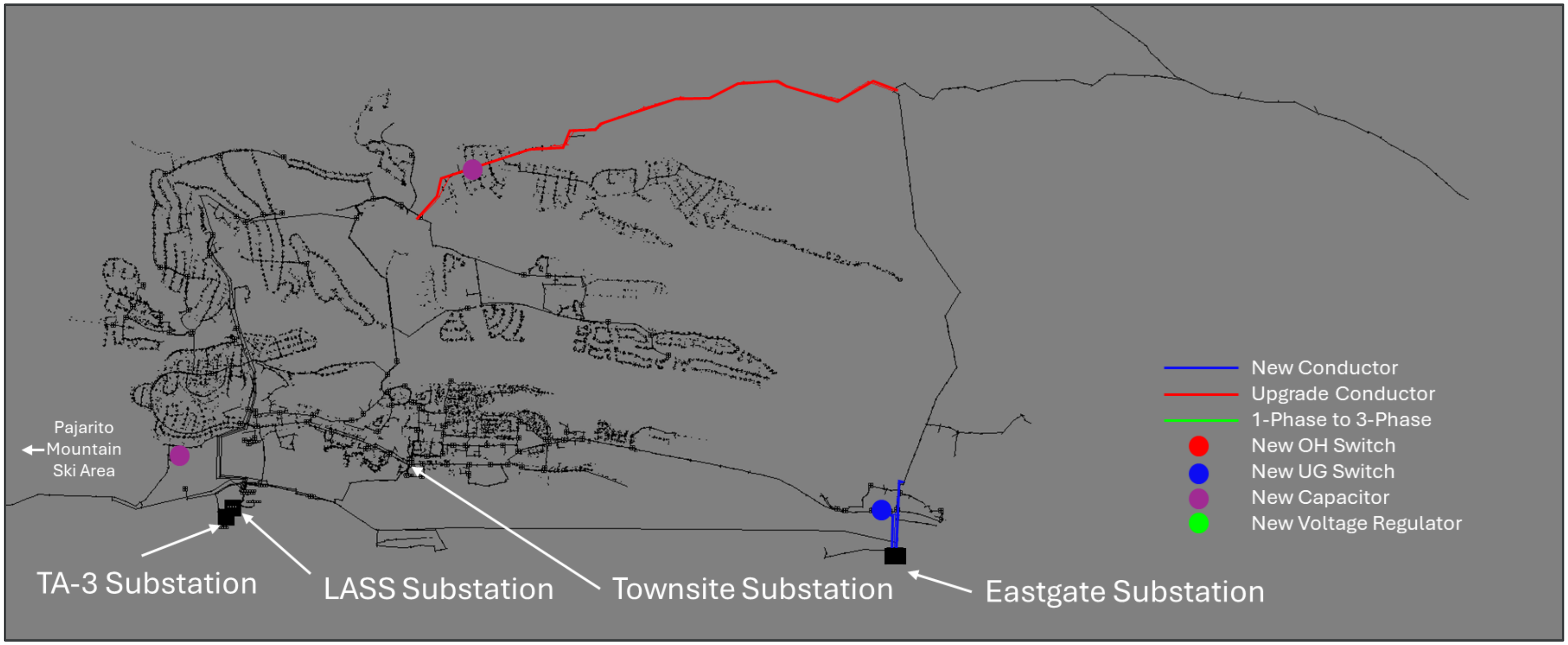


Table 4-30: 2040 Scenario 2 Los Alamos Townsite System Conductor and Equipment Quantities

| Conductor/ Equipment | Quantity |
|---|---|
| 500 MCM CU Cable (miles) | 0.8 |
| 4/0 CU Cable (miles) | 0 |
| Installed 477 ACSR Conductor (miles) | 3 |
| 4/0 ACSR Conductor (miles) | 0 |
| UG Switch (PME) | 1 |
| OH Switch | 0 |
| Capacitor Bank | 1 |
| Voltage Regulator | 0 |

Figure  shows the conductor buildout and new equipment that was used to reconfigure the area and mitigate observed planning criteria violations for the White Rock system. Table 4-31 shows the quantities of conductor and equipment used in this scenario.

Figure 4-16: 2040 Scenario 2 White Rock System Conductor and Equipment

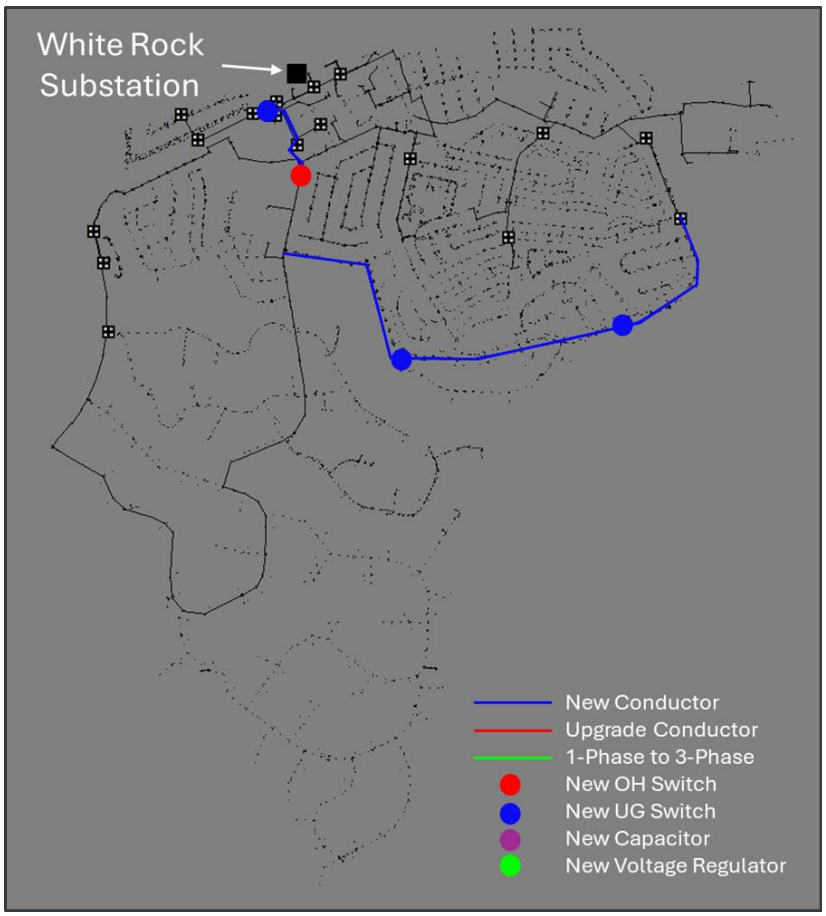


Table 4-31: 2040 Scenario 2 White Rock System Conductor and Equipment Quantities

| Conductor/ Equipment | Quantity |
|---|---|
| 500 MCM CU Cable (miles) | 1.9 |
| 4/0 CU Cable (miles) | 0 |
| Installed 477 ACSR Conductor (miles) | 0 |
| 4/0 ACSR Conductor (miles) | 0 |
| UG Switch (PME) | 3 |
| OH Switch | 1 |
| Capacitor Bank | 0 |
| Voltage Regulator | 0 |

### 4.5.3 Normal Configuration Power Flow Analysis

Table 4-40 shows the Los Alamos Townsite system power flow results. In this new configuration, all planning criteria were maintained.

Table 4-32: 2040 Scenario 2 Los Alamos System Power Flow Results

| Station | Distribution Feeder | kW | kVAR | kVA | Max Amps | Min Voltage |
|---|---|---|---|---|---|---|
| Town Site | 13 | 1,650 | -205 | 1,670 | 89 | 123.8 |
| | 14** | - | - | - | - | - |
| | 15 | 1,670 | 384 | 1,715 | 87 | 122.4 |
| | 16 | 1,819 | 467 | 1,879 | 101 | 120.4 |
| | 17 | 3,669 | 1,093 | 3,829 | 167 | 123.6 |
| | 18 | 99 | 21 | 101 | 4 | 123.8 |
| | **Substation** | **9,036** | **2,141** | **9,292** | **-** | **-** |
| LASS | 13T | 2,361 | 675 | 2,456 | 114 | 123.2 |
| | NS6 | 1,866 | 600 | 1,960 | 82 | 124.6 |
| | 15T | 1,810 | 427 | 1,861 | 111 | 122.4 |
| | NSM6* | - | - | - | - | - |
| | 16T** | - | - | - | - | - |
| | NS3 | 911 | 298 | 958 | 40 | 124.8 |
| | NS18 | 649 | 187 | 676 | 35 | 124.0 |
| | 18 | 739 | 184 | 761 | 33 | 123.2 |
| | **Substation** | **8,439** | **2,467** | **8,806** | **-** | **-** |
| Eastgate | 11 | 3,149 | -183 | 3,160 | 145 | 121.5 |
| | **Transformer 1** | **3,149** | **-183** | **3,160** | **-** | **-** |
| | 21 | 3,340 | 924 | 3,465 | 158 | 122.7 |
| | **Transformer 2** | **3,340** | **924** | **3,465** | **-** | **-** |

*Feeder NSM6 is reserved for emergency restoration of NS6, which serves the Los Alamos County Medical Center.

**These feeders do not normally serve load in this configuration, but are useful for contingency restoration efforts.

Table 4-33 shows the White Rock system power flow results. In this new configuration, all planning criteria were maintained. White Rock Transformer 2, rated at 7,500 kVA, can serve this forecasted load, but is near the rating.

Table 4-33: 2040 Scenario 2 White Rock System Power Flow Results

| Station | Distribution Feeder | kW | kVAR | kVA | Max Amps | Min Voltage |
|---|---|---|---|---|---|---|
| White Rock | WR1 | 2,596 | 447 | 2,634 | 122 | 123.5 |
| | WR2 | 1,235 | 361 | 1,286 | 64 | 121.5 |
| | WR3 | 2,243 | -31 | 2,246 | 112 | 124.1 |
| | Substation | 6,074 | 777 | 6,124 | - | - |

### 4.5.4 Contingency Configuration Analysis

Table 4-42 shows the substation transformer and primary feeder contingency scenarios evaluated for the Los Alamos Townsite system. There is sufficient capacity for all major substation transformers and primary feeder contingency scenarios. The system model was also evaluated to determine if all distribution feeders from the Eastgate Substation could be restored if one of the substation switchgear must be de-energized and the bus tie is unavailable. There are sufficient ties within the Los Alamos Townsite system to restore Eastgate Substation feeders. Conductor upgrades were performed to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 4-34: 2040 Scenario 2 Los Alamos Townsite System Contingency Review

| Scenario | Customer Load to Restore kVA | Total Applicable Customer Load kVA | Remaining Applicable Capacity kVA | Loading Violations? | Voltage Violations? | Comments |
|---|---|---|---|---|---|---|
| Loss of TA-3 XFMR 1 | 9,614 | 17,830 | 20,000 | No | No | Primary feeders TC2 and LC2 are used to restore customer load. TA-3 Transformer 2 is the most limiting element in this contingency. |
| Loss of TA-3 XFMR 2 | 8,216 | 17,830 | 20,000 | No | No | Primary feeders TC1 and LC1 are used to restore customer load. TA-3 Transformer 1 is the most limiting element in this contingency. |
| Loss of TC1 | 3,339 | 9,181 | 14,100 | No | No | Primary feeder TC2 is used to restore customer load through the Townsite switchgear. The TC2 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of TC2 | 5,842 | 9,181 | 16,000 | No | No | Primary feeder TC1 is used to restore customer load through the Townsite switchgear. The TC1 parallel 500 MCM CU cable is the most limiting element in this contingency. |
| Loss of LC1 | 6,275 | 8,649 | 14,100 | No | No | Primary feeder LC2 is used to restore customer load through the LASS switchgear. The LC2 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of LC2 | 2,374 | 8,649 | 14,100 | No | No | Primary feeder LC1 is used to restore customer load through the LASS switchgear. The LC1 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of Eastgate XFMR 1 | 3,160 | 6,625 | 22,400 | No | No | Operate the bus tie to restore the Eastgate 1 customer load using the Eastgate 2 transformer. |
| Loss of Eastgate XFMR 2 | 3,465 | 6,625 | 22,400 | No | No | Operate the bus tie to restore the Eastgate 2 customer load using the Eastgate 1 transformer. |

Table 4-35 shows the most impactful contingency scenario for the White Rock system if Transformer 2 becomes de-energized. All planning criteria can be maintained if the bus tie is operated and customers are restored through Transformer 1 at the White Rock Substation. The system model was also evaluated to determine if a substation switchgear must be de-energized. The existing backup feeders (16 and 17) can successfully serve the entire White Rock system load if the Transformer 2 switchgear must be de-energized. Conductor upgrades are required to strengthen the main line tie paths between the feeders in the system and were documented in the sections above.

Table 4-35: 2040 Scenario 2 White Rock System Contingency Review

| Scenario | Total Applicable Customer Load kVA | Customer Load to Restore kVA | Remaining Applicable Capacity kVA | Loading Violations? | Voltage Violations? | Comments |
|---|---|---|---|---|---|---|
| Loss of XFMR 2 | 6,124 | 6,124 | 14,000 | No | No | With Transformer 1 upgraded to 14,000 kVA, there is sufficient capacity to restore all customers if Transformer 2 becomes de-energized by operating the bus tie. |

### 4.5.5 Asset Replacement Estimate

Power flow analysis identified system upgrades to increase capacity and improve voltage adherence within the system. Due to aging and deterioration, assets within the LACDPU system are anticipated to be replaced over time. In 2040 Scenario 2, based on the present age of existing assets (Section 2.1), considering a 15-year period, many of the LACDPU system assets may need to be replaced. Table 4-36 shows the estimated asset replacements over the 15-year period for the Los Alamos Townsite system. Conductors and cables that were identified for upgrade due to capacity needs in the power flow analysis were not included in this asset replacement estimate.

Table 4-36: 2040 Scenario 2 Los Alamos Townsite System Asset Replacement Estimate

| Conductor/ Equipment | % of Assets Replaced | Quantity |
|---|---|---|
| Overhead Conductor Replacements (miles) | 30% | 7 |
| Underground Cable Replacements (miles) | 65% | 32 |
| Mainline Switches | 90% | 123 |
| Three-Phase Service Transformers | 25% | 46 |
| Single-Phase Service Transformers | 35% | 327 |
| Secondary Services | 30% | 1,908 |

Table 4-45 shows the estimated asset replacements over the 15-year period for the White Rock system's 2040 Scenario 2.

Table 4-37: 2040 Scenario 2 White Rock System Asset Replacement Estimate

| Conductor/ Equipment | % of Assets Replaced | Quantity |
|---|---|---|
| Overhead Conductor Replacements (miles) | 95% | 10 |
| Underground Cable Replacements (miles) | 50% | 4 |
| Mainline Switches | 70% | 16 |
| Three-Phase Service Transformers | 40% | 14 |
| Single-Phase Service Transformers | 50% | 207 |
| Secondary Services | 40% | 1,045 |

## 4.6 2055 Scenario 3 Electrification Impact

2055 Scenario 3 added 14,181 kVA to the LACDPU system power flow model. Table 4-38 shows how this load was applied to the Los Alamos Townsite and the White Rock systems.

Table 4-38: 2055 Scenario 3 Modeled Load

| System | Existing System Load kVA | Forecasted Electrification Load kVA | Total Forecasted System Load kVA |
|---|---|---|---|
| Los Alamos Townsite | 17,811 | 10,232 | 28,980 |
| White Rock | 3,905 | 3,949 | 8,060 |
| Total | 21,716 | 14,181 | 37,040 |

Figure  shows the proposed configuration for the Los Alamos Townsite system, colored by substation. To successfully serve the forecasted electrification growth in this scenario, the Eastgate Substation must be constructed. The Eastgate Substation must contain two 14 MVA transformers and two four-feeder switchgears with a main tie breaker between the two switchgears. Three new distribution feeders were constructed in the planning model to bring this new capacity west towards the load centers. Most of the electrification load growth must be served from the Eastgate Substation to avoid overloading the existing LASS and Townsite substations. The LASS Substation was primarily used to serve commercial loads near the substation, along with the Pajarito Mountain ski area and some residential loads. Much of the Townsite Substation load was transferred to Eastgate Substation, but some feeders were routed back north to spread the load across the existing LASS and Townsite substation feeders.

**Figure 4-17: 2055 Scenario 3 Los Alamos Townsite System Configuration**

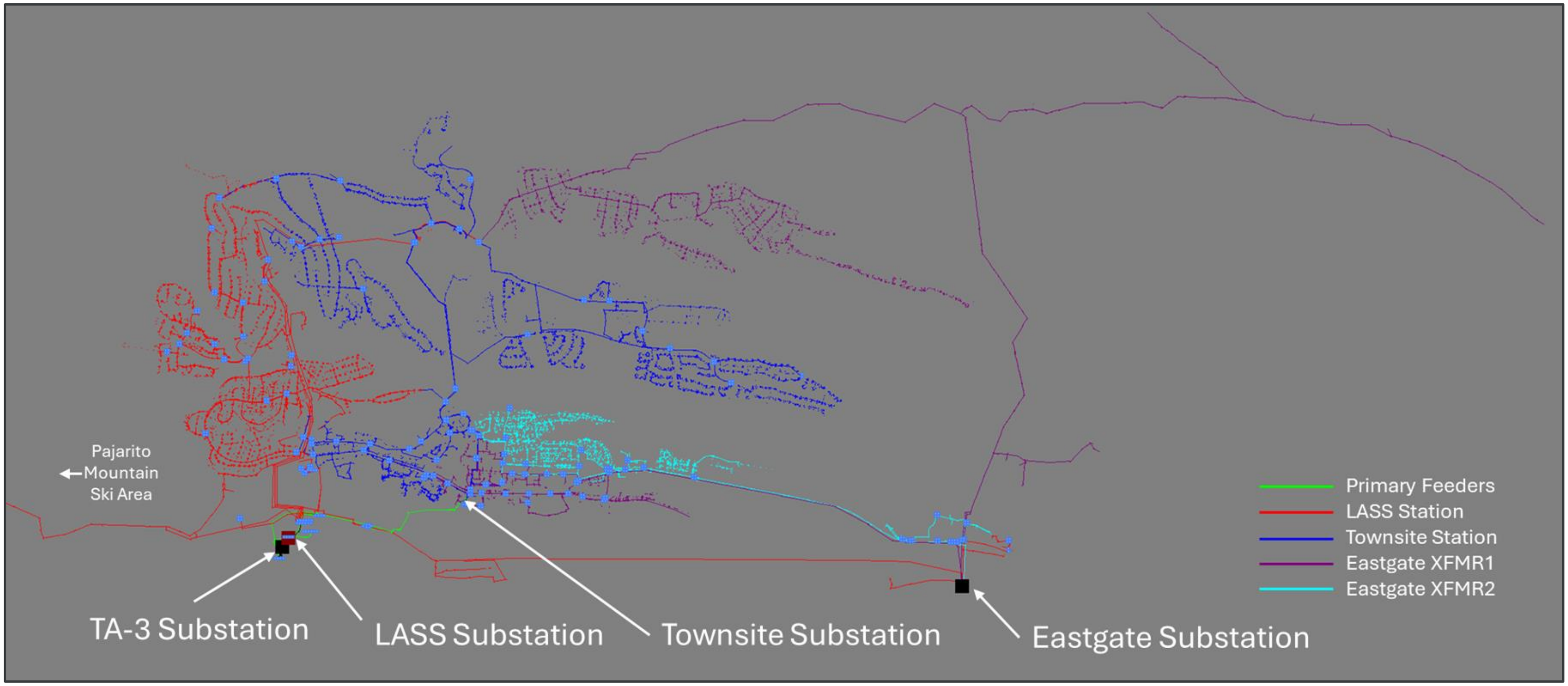
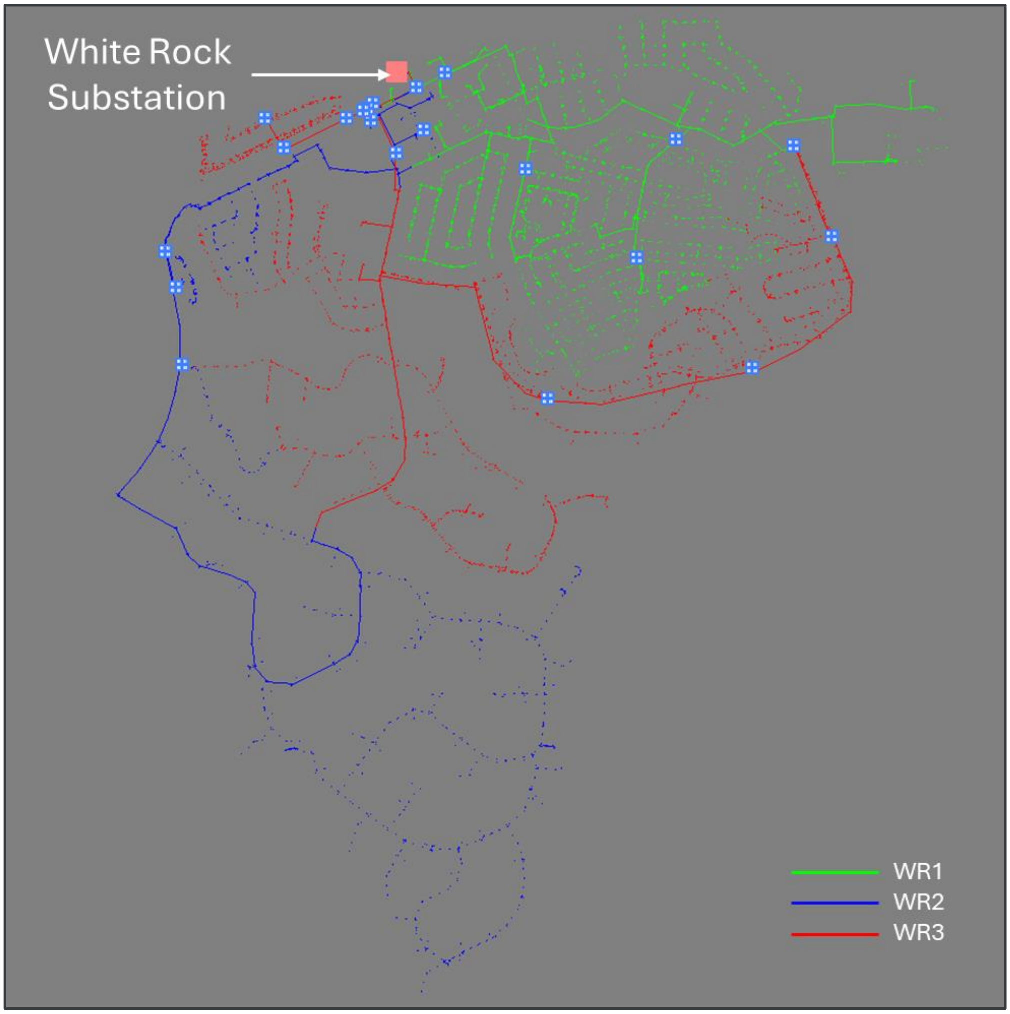


Figure shows the proposed configuration for the White Rock system, colored by distribution feeder. To successfully serve the forecasted electrification growth in this scenario, both substation transformers must be upgraded to 10 MVA and accompanied by two four-feeder switchgear and a main tiebreaker between the two switchgears.

Figure 4-18: 2055 Scenario 3 White Rock System Configuration




### 4.6.1 Conductor and Equipment Buildout

Figure shows the conductor buildout and new equipment that was used to reconfigure the area and mitigate observed planning criteria violations for the Los Alamos Townsite system. Table 4-39 shows the quantities of conductor and equipment used in this scenario. No voltage regulators were required in this scenario. Several new underground switches were utilized to create new tie points and connect the new distribution feeders into the existing underground portions of the system. Some conductor upgrades were proposed to strengthen mainline ties for contingency restoration efforts with the forecasted load. No upgrades were applied to the feeder serving the Pajarito Mountain ski area.

**Figure 4-19: 2055 Scenario 3 Los Alamos Townsite System Conductor and Equipment Buildout**

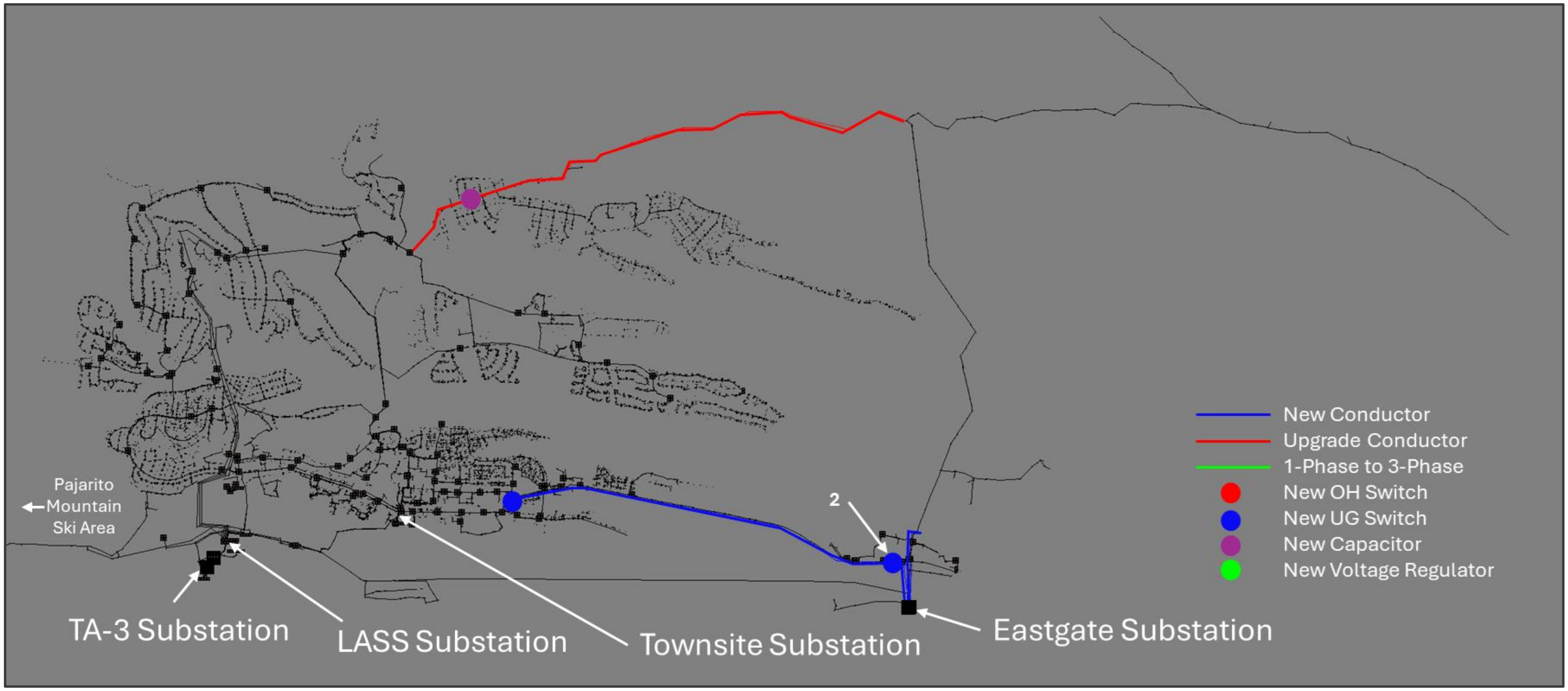


Table 4-39: 2055 Scenario 3 Los Alamos Townsite System Conductor and Equipment Quantities

| Conductor/ Equipment | Quantity |
|---|---|
| 500 MCM CU Cable (miles) | 3.2 |
| 4/0 CU Cable (miles) | 0 |
| 477 ACSR Conductor (miles) | 3 |
| 4/0 ACSR Conductor (miles) | 0 |
| UG Switch (PME) | 3 |
| OH Switch | 0 |
| Capacitor Bank | 1 |
| Voltage Regulator | 0 |

Figure  shows the conductor buildout and new equipment that were used to reconfigure the area and mitigate observed planning criteria violations for the White Rock system. Table 4-40 shows the quantities of conductor and equipment used in this scenario. The main loops through the White Rock system were not upgraded in this scenario. However, extending the underground mainline created a strong tie point for White Rock Feeder 1 and Feeder 3.

Figure 4-20: 2055 Scenario 3 White Rock System Conductor and Equipment Buildout

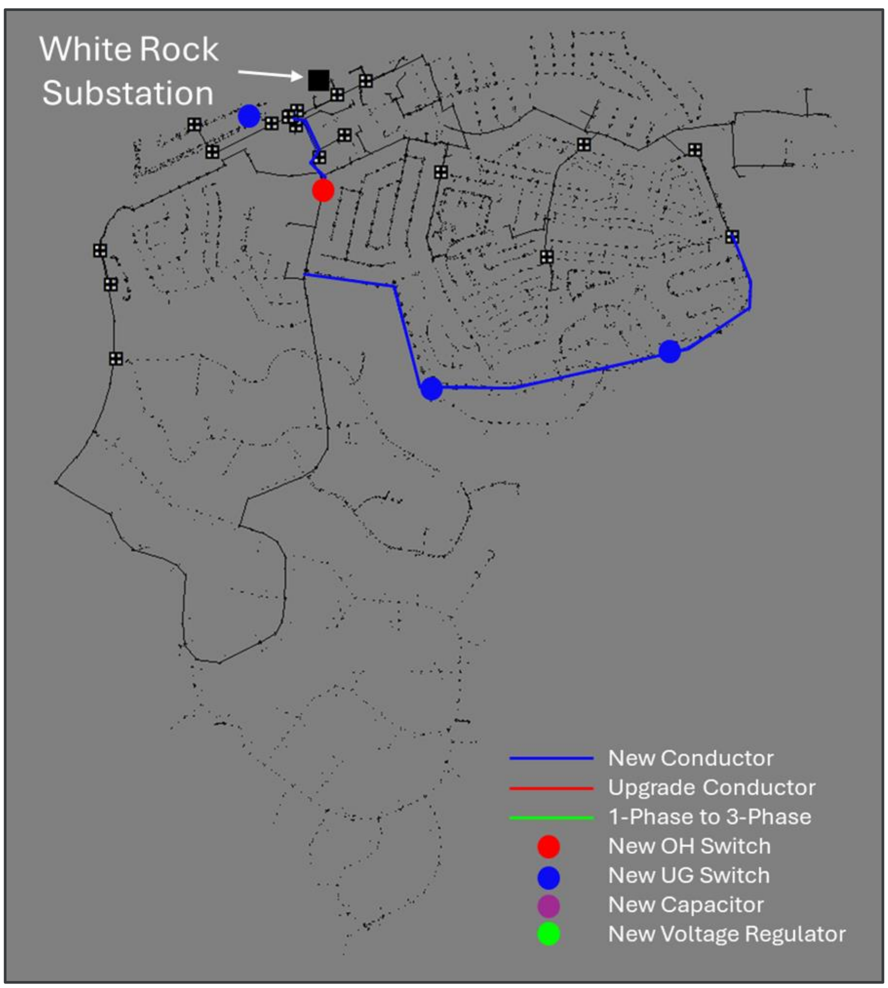


Table 4-40: 2055 Scenario 3 White Rock System Conductor and Equipment Quantities

| Conductor/ Equipment | Quantity |
|---|---|
| 500 MCM CU Cable (miles) | 1.9 |
| 4/0 CU Cable (miles) | 0 |
| Installed 477 ACSR Conductor (miles) | 0 |
| 4/0 ACSR Conductor (miles) | 0 |
| UG Switch (PME) | 3 |
| OH Switch | 1 |
| Capacitor Bank | 0 |
| Voltage Regulator | 0 |

### 4.6.2 Normal Configuration Power Flow Analysis

Table 4-41 shows the Los Alamos Townsite system power flow results. In this new configuration, all planning criteria were maintained.

Table 4-41: 2055 Scenario 3 Los Alamos System Power Flow Results

| Station | Distribution Feeder | kW | kVAR | kVA | Max Amps | Min Voltage |
|---|---|---|---|---|---|---|
| Town Site | 13 | 1,919 | -113 | 1,929 | 104 | 123.5 |
| | 14** | - | - | - | - | - |
| | 15 | 1,945 | 481 | 2,003 | 102 | 121.9 |
| | 16 | 2,120 | 570 | 2,197 | 118 | 120.4 |
| | 17** | - | - | - | - | - |
| | 18 | 115 | 27 | 118 | 5 | 124.5 |
| | **Substation** | **6,183** | **1,100** | **6,286** | **-** | **-** |
| LASS | 13T** | 2,749 | 807 | 2,865 | 133 | 123.1 |
| | NS6 | 2,170 | 701 | 2,280 | 96 | 124.5 |
| | 15T | 2,108 | 530 | 2,174 | 130 | 121.9 |
| | NSM6* | - | - | - | - | - |
| | 16T** | - | - | - | - | - |
| | NS3 | 1,060 | 337 | 1,112 | 47 | 124.8 |
| | NS18** | 755 | 223 | 788 | 41 | 123.8 |
| | 18 | 860 | 226 | 890 | 39 | 122.9 |
| | **Substation** | **9,828** | **3,013** | **10,299** | **-** | **-** |
| Eastgate | 11 | 3,440 | -55 | 3,447 | 160 | 120.6 |
| | 12 | 4,360 | 1,322 | 4,556 | 197 | 121.5 |
| | **Transformer 1** | **7,800** | **1,267** | **7,903** | **-** | **-** |
| | 21 | 3,889 | 1,113 | 4,046 | 184 | 122.3 |
| | **Transformer 2** | 3,889 | 1,113 | 4,046 | - | - |

*Feeder NSM6 is reserved for emergency restoration of NS6, which serves the Los Alamos County Medical Center.
**These feeders do not normally serve load in this configuration, but are useful for contingency restoration efforts.

Table 4-42 shows the White Rock system power flow results. In this new configuration, all planning criteria were maintained.

Table 4-42: 2055 Scenario 3 White Rock System Power Flow Results

| Station | Distribution Feeder | kW | kVAR | kVA | Max Amps | Min Voltage |
|---|---|---|---|---|---|---|
| White Rock | WR1 | 3,339 | 696 | 3,411 | 157 | 123.1 |
| | WR2 | 1,591 | 483 | 1,662 | 82 | 120.5 |
| | WR3 | 2,883 | 188 | 2,891 | 145 | 123.5 |
| | Substation | 7,815 | 1,376 | 7,939 | - | - |

### 4.6.3 Contingency Configuration Review

Table 4-43 shows the substation transformer and primary feeder contingency scenarios evaluated for the Los Alamos Townsite system. There is sufficient capacity for all major substation transformers and primary feeder contingency scenarios. The system model was also evaluated to determine if all distribution feeders from the Eastgate Substation could be restored if one of the substation switchgear must be de-energized and the bus tie is unavailable. There are sufficient ties within the Los Alamos Townsite system to restore Eastgate Substation feeders.

Table 4-43: 2055 Scenario 3 Los Alamos Townsite System Contingency Review

| Scenario | Customer Load to Restore kVA | Total Applicable Customer Load kVA | Remaining Applicable Capacity kVA | Loading Violations? | Voltage Violations? | Comments |
|---|---|---|---|---|---|---|
| Loss of TA-3 XFMR 1 | 11,219 | 16,299 | 20,000 | No | No | Primary feeders TC2 and LC2 are used to restore customer load. TA-3 Transformer 2 is the most limiting element in this contingency. |
| Loss of TA-3 XFMR 2 | 5,080 | 16,299 | 20,000 | No | No | Primary feeders TC1 and LC1 are used to restore customer load. TA-3 Transformer 1 is the most limiting element in this contingency. |
| Loss of TC1 | 3,899 | 6,209 | 14,100 | No | No | Primary feeder TC2 is used to restore customer load through the Townsite switchgear. The TC2 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of TC2 | 2,310 | 6,209 | 16,000 | No | No | Primary feeder TC1 is used to restore customer load through the Townsite switchgear. The TC1 parallel 500 MCM CU cable is the most limiting element in this contingency. |
| Loss of LC1 | 7,320 | 10,090 | 14,100 | No | No | Primary feeder LC2 is used to restore customer load through the LASS switchgear. The LC2 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of LC2 | 2,770 | 10,090 | 14,100 | No | No | Primary feeder LC1 is used to restore customer load through the LASS switchgear. The LC1 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of Eastgate XFMR 1 | 7,903 | 11,925 | 14,000 | No | No | Operate the bus tie to restore the Eastgate 1 customer load using the Eastgate 2 transformer. |
| Loss of Eastgate XFMR 2 | 4,0046 | 11,925 | 14,000 | No | No | Operate the bus tie to restore the Eastgate 2 customer load using the Eastgate 1 transformer. |

Table 4-44 shows the most impactful contingency scenario for the White Rock system if Transformer 2 becomes de-energized. All planning criteria can be maintained if the bus tie is operated and customers are restored through Transformer 1 at the White Rock Substation. The system model was also evaluated to determine if a substation switchgear must be de-energized. The existing backup feeders (16 and 17) can successfully serve the entire White Rock system load if the Transformer 2 switchgear must be de-energized.

Table 4-44: 2055 Scenario 3 White Rock System Contingency Review

| Scenario | Total Applicable Customer Load kVA | Customer Load to Restore kVA | Remaining Applicable Capacity kVA | Loading Violations? | Voltage Violations? | Comments |
|---|---|---|---|---|---|---|
| Loss of XFMR 2 | 7,940 | 7,940 | 10,000 | No | No | With both substation transformers rated at 10,000 kVA, there is sufficient capacity to restore all customers if Transformer 2 becomes de-energized by operating the bus tie. |

### 4.6.4 Asset Replacement Estimate

Power flow analysis identified system upgrades to increase capacity and improve voltage adherence within the system. Due to aging and deterioration, assets within the LACDPU system are anticipated to be replaced over time. In 2055 Scenario 3, based on the present age of existing assets (Section 2.1), considering a 30-year period, many of the LACDPU system assets may need to be replaced. Table 4-45 shows the estimated asset replacements over the 30-year period for the Los Alamos Townsite system. Conductors and cables that were identified for upgrade due to capacity needs in the power flow analysis were not included in this asset replacement estimate.

Table 4-45: 2055 Scenario 3 Los Alamos Townsite System Asset Replacement Estimate

| Conductor/ Equipment | % of Assets Replaced | Quantity |
|---|---|---|
| Overhead Conductor Replacements (miles) | 100% | 30 |
| Underground Cable Replacements (miles) | 95% | 47 |
| Mainline Switches | 100% | 137 |
| Three-Phase Service Transformers | 60% | 110 |
| Single-Phase Service Transformers | 70% | 655 |
| Secondary Services | 70% | 4,452 |

Table 4-46 shows the estimated asset replacements over the 30-year period for the White Rock system's 2055 Scenario 3. This scenario required fewer upgrades to improve distribution feeder capacity than the higher scenarios. The quantity of conductor and cable replacements is greater in this scenario as a result.

Table 4-46: 2055 Scenario 3 White Rock System Asset Replacement Estimate

| Conductor/ Equipment | % of Assets Replaced | Quantity |
|---|---|---|
| Overhead Conductor Replacements (miles) | 100% | 10 |
| Underground Cable Replacements (miles) | 90% | 8 |
| Mainline Switches | 100% | 23 |
| Three-Phase Service Transformers | 60% | 22 |
| Single-Phase Service Transformers | 70% | 289 |
| Secondary Services | 70% | 1,829 |

## 4.7 2040 Scenario 3 Electrification Impact

2040 Scenario 3 added 4,173 kVA to the LACDPU system power flow model. Table 4-47 shows how this load was applied to the Los Alamos Townsite and the White Rock systems.

Table 4-47: 2040 Scenario 3 Modeled Load

| System | Existing System Load kVA | Forecasted Electrification Load kVA | Total Forecasted System Load kVA |
|---|---|---|---|
| Los Alamos Townsite | 17,811 | 2,998 | 21,746 |
| White Rock | 3,905 | 1,175 | 5,285 |
| Total | 21,716 | 4,173 | 27,032 |

Figure  shows the proposed configuration for the Los Alamos Townsite system, colored by substation. To successfully serve the forecasted electrification growth in this scenario, the Eastgate Substation must be constructed. The Eastgate Substation must contain two transformers and two four-feeder switchgears with a main tie breaker between the two switchgears. In 2055 Scenario 3, two 14 MVA transformers are required to serve the forecasted load. Although smaller transformers would work for this 2040 scenario, two 14 MVA transformers were modeled at the Eastgate Substation, knowing the potential load serving need of the future 2055 scenario. However, only two new distribution feeders were constructed in the planning model to bring this new capacity west towards the load centers, given the forecasted load in 2040. Some of the Los Alamos Townsite system load must be served from the Eastgate Substation to avoid overloading the existing LASS and Townsite substations. The LASS Substation was primarily used to serve commercial loads near the substation, along with the Pajarito Mountain ski area and some residential loads. Some of the Townsite Substation load was transferred to Eastgate Substation.

**Figure 4-21: 2040 Scenario 3 Los Alamos Townsite System Configuration**

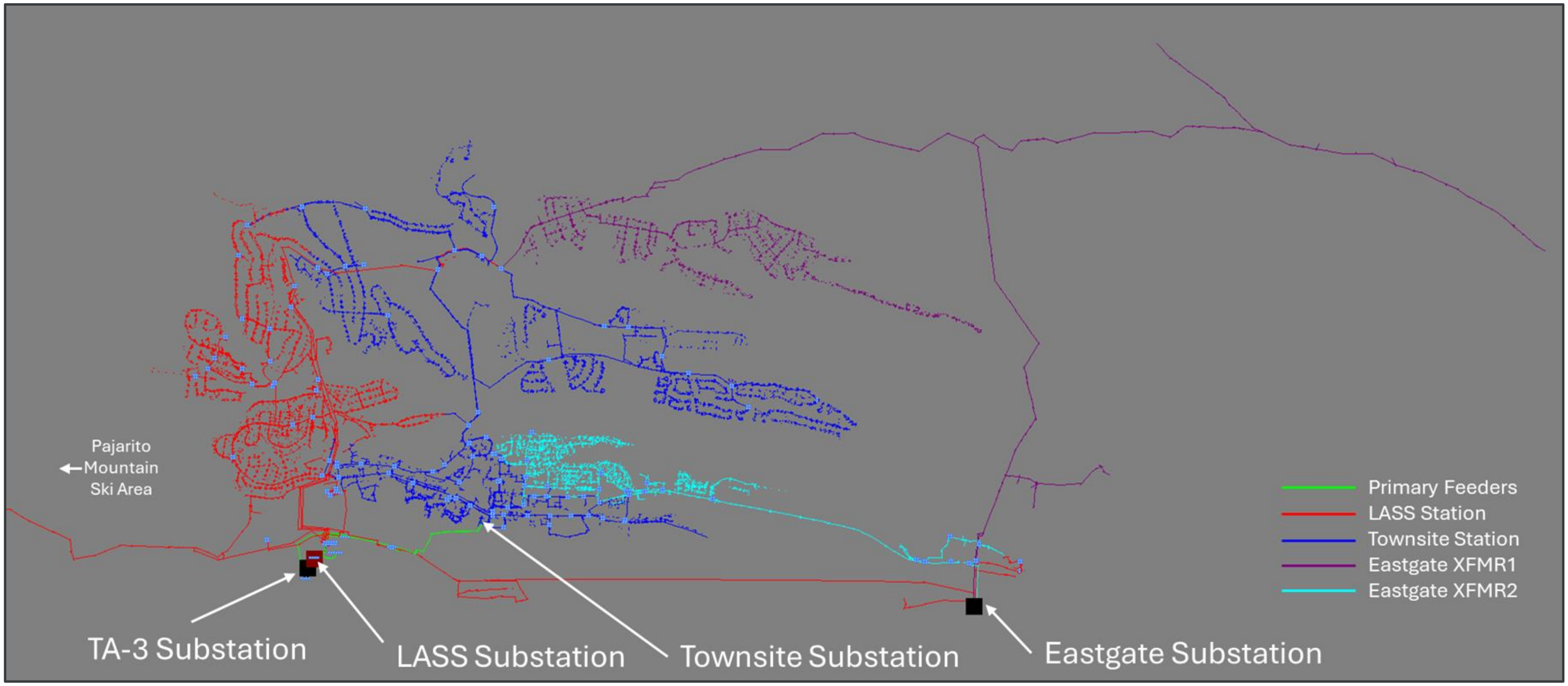
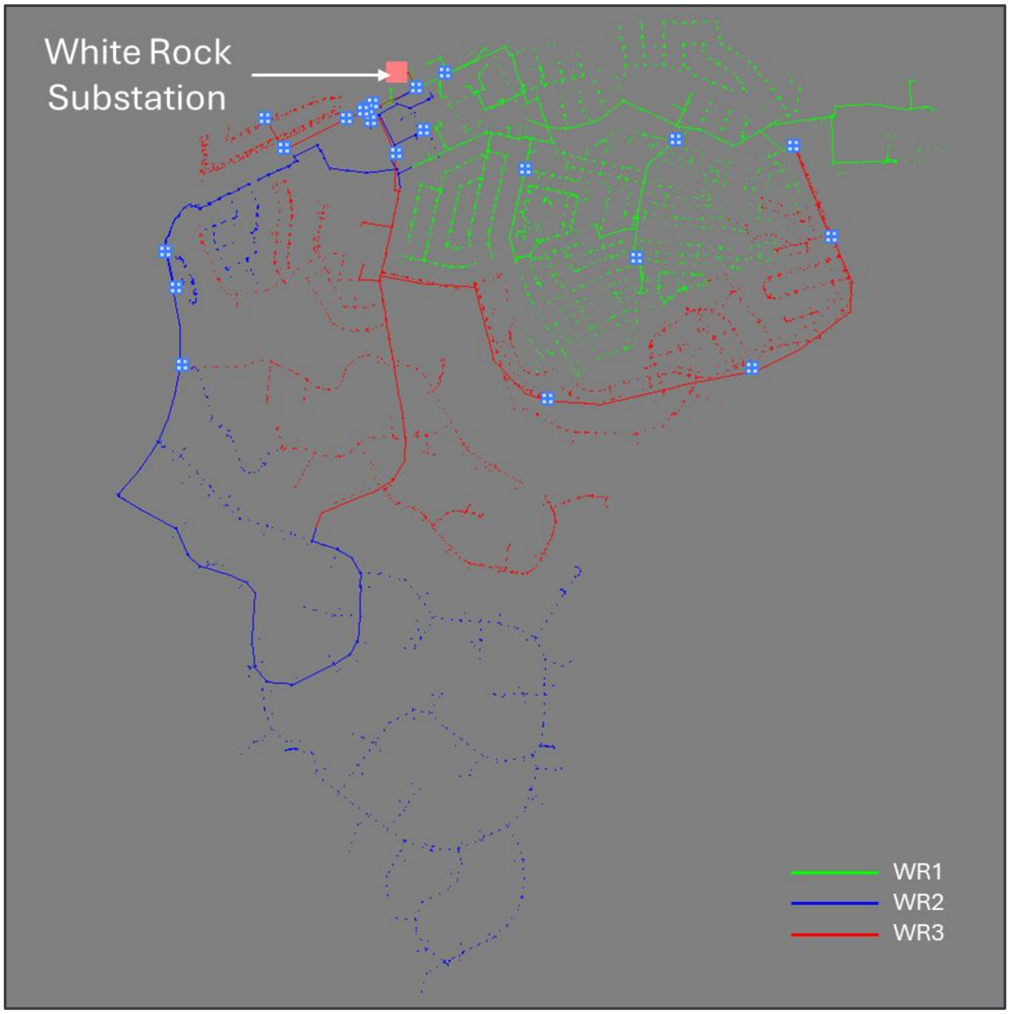


Figure  shows the proposed configuration for the White Rock system, colored by the distribution feeder. White Rock Transformer 2, with a rating of 7.5 MVA, is sized appropriately to serve the White Rock system load in the 2040 Scenario 3. However, for successful contingency support in this area, White Rock Transformer 1 must be upgraded to 10 MVA. 10 MVA is the appropriate size to serve forecasted load growth in the low scenario through 2055.

**Figure 4-22: 2040 Scenario 3 White Rock System Configuration**




### 4.7.1 Conductor and Equipment Buildout

Figure  shows the conductor buildout and new equipment that was used to reconfigure the area and mitigate observed planning criteria violations for the Los Alamos Townsite system. Table 4-48 shows the quantities of conductor and equipment used in this scenario. No voltage regulators were required in this scenario. One new underground switch was utilized to connect a new distribution feeder into the existing underground portion of the system. Some conductor upgrades were proposed to strengthen mainline ties for contingency restoration efforts with the forecasted load. No upgrades were applied to the feeder serving the Pajarito Mountain ski area.

**Figure 4-23: 2040 Scenario 3 Los Alamos Townsite System Conductor and Equipment Buildout**

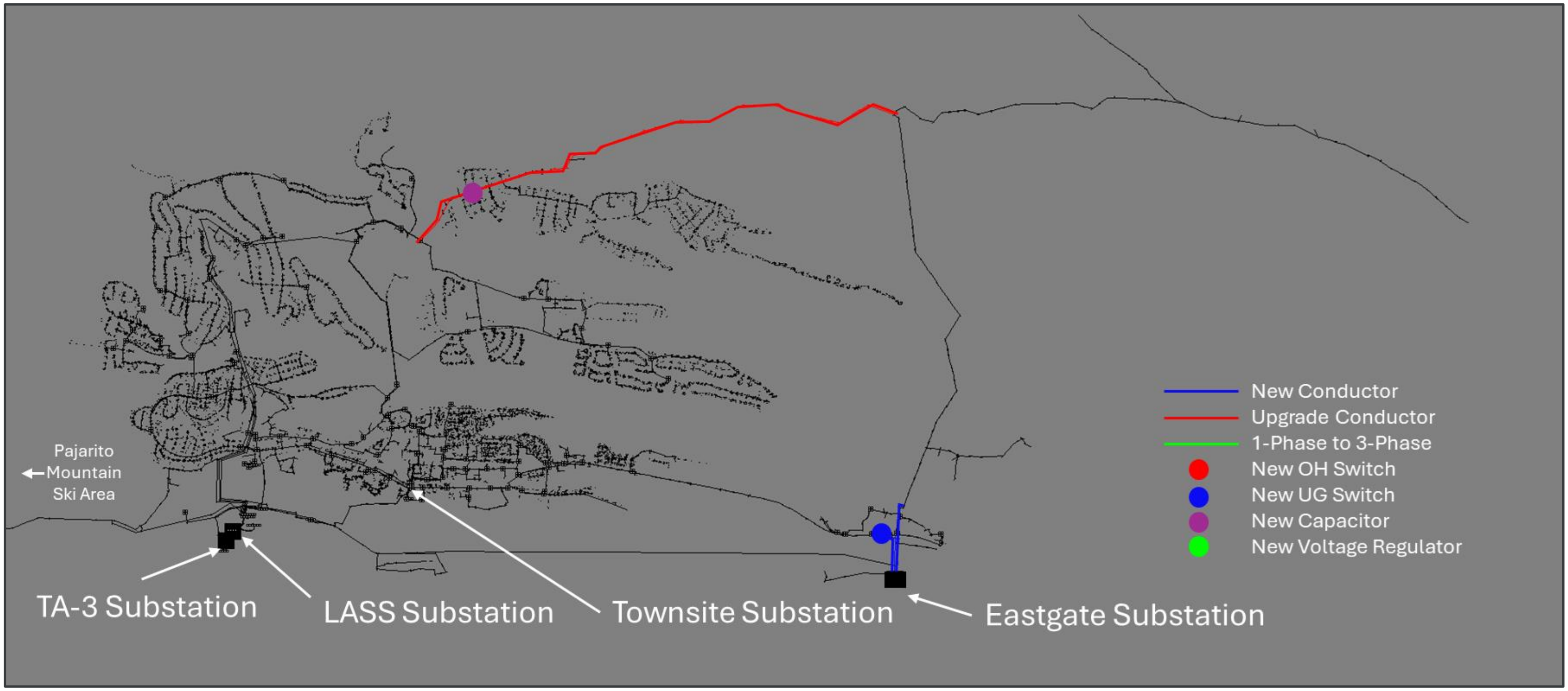


Table 4-48: 2040 Scenario 3 Los Alamos Townsite System Conductor and Equipment Quantities

| Conductor/ Equipment | Quantity |
|---|---|
| 500 MCM CU Cable (miles) | 0.8 |
| 4/0 CU Cable (miles) | 0 |
| 477 ACSR Conductor (miles) | 3 |
| 4/0 ACSR Conductor (miles) | 0 |
| UG Switch (PME) | 1 |
| OH Switch | 0 |
| Capacitor Bank | 1 |
| Voltage Regulator | 0 |

Figure  shows the conductor buildout and new equipment that was used to reconfigure the area and mitigate observed planning criteria violations for the White Rock system. Table 4-49 shows the quantities of conductor and equipment used in this scenario. The main loops through the White Rock system were not upgraded in this scenario. However, extending the underground mainline created a strong tie point for White Rock Feeder 1 and Feeder 3.

Figure 4-24: 2040 Scenario 3 White Rock System Conductor and Equipment Buildout

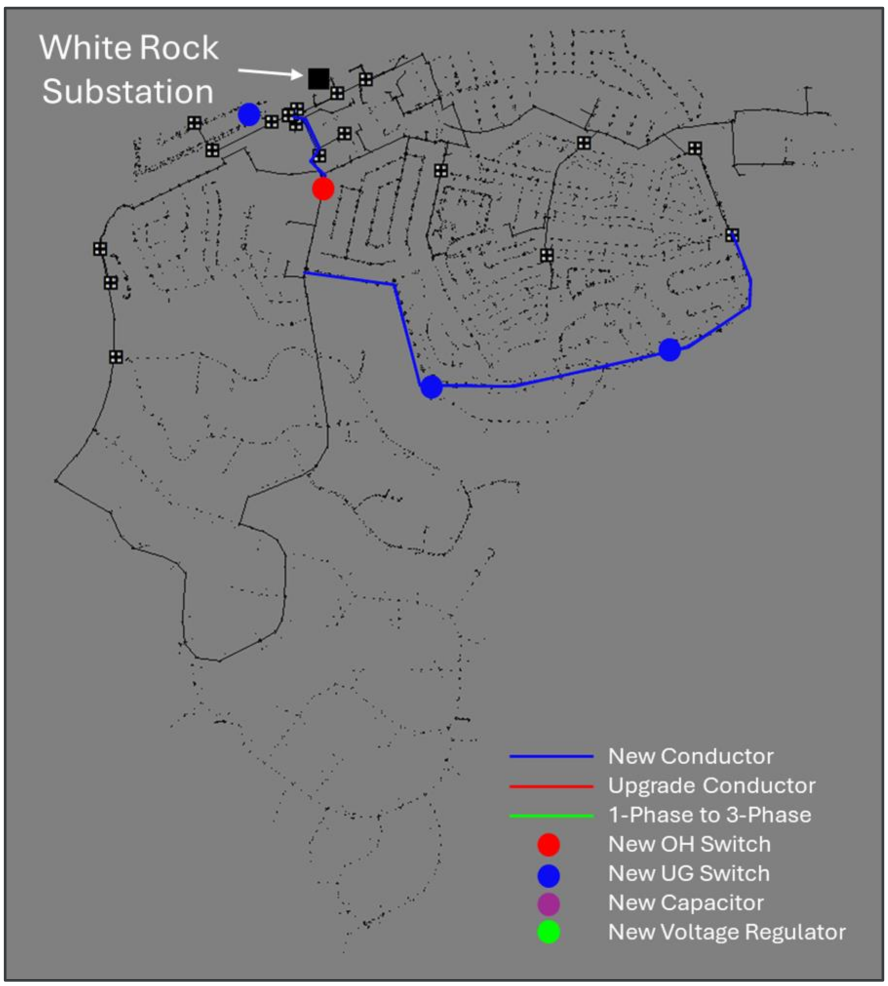


Table 4-49: 2040 Scenario 3 White Rock System Conductor and Equipment Quantities

| Conductor/ Equipment | Quantity |
|---|---|
| 500 MCM CU Cable (miles) | 1.9 |
| 4/0 CU Cable (miles) | 0 |
| Installed 477 ACSR Conductor (miles) | 0 |
| 4/0 ACSR Conductor (miles) | 0 |
| UG Switch (PME) | 3 |
| OH Switch | 1 |
| Capacitor Bank | 0 |
| Voltage Regulator | 0 |

### 4.7.2 Normal Configuration Power Flow Analysis

Table 4-50 shows the Los Alamos Townsite system power flow results. In this new configuration, all planning criteria were maintained.

Table 4-50: 2040 Scenario 3 Los Alamos System Power Flow Results

| Station | Distribution Feeder | kW | kVAR | kVA | Max Amps | Min Voltage |
|---|---|---|---|---|---|---|
| Town Site | 13 | 1,430 | -280 | 1,465 | 78 | 124.1 |
| | 14** | - | - | - | - | - |
| | 15 | 1,447 | 306 | 1,479 | 75 | 122.8 |
| | 16 | 1,574 | 381 | 1,620 | 87 | 121.0 |
| | 17 | 3,180 | 932 | 3,314 | 144 | 123.8 |
| | 18 | 86 | 17 | 87 | 4 | 124.0 |
| | **Substation** | **7,821** | **1,620** | **7,991** | **-** | **-** |
| LASS | 13T | 2,045 | 567 | 2,122 | 98 | 123.5 |
| | NS6 | 1,617 | 518 | 1,698 | 71 | 124.6 |
| | 15T | 1,567 | 343 | 1,605 | 96 | 122.7 |
| | NSM6* | - | - | - | - | - |
| | 16T** | - | - | - | - | - |
| | NS3 | 790 | 248 | 828 | 35 | 124.8 |
| | NS18 | 563 | 158 | 585 | 31 | 124.1 |
| | 18T | 640 | 149 | 657 | 29 | 123.5 |
| | **Substation** | **7,306** | **2,032** | **7,594** | **-** | **-** |
| Eastgate | 11 | 2,913 | -286 | 2,932 | 134 | 122.3 |
| | **Transformer 1** | 2,913 | -286 | 2,932 | - | - |
| | 21 | 2,891 | 770 | 2,992 | 136 | 123.0 |
| | **Transformer 2** | 2,891 | 770 | 2,992 | - | - |

*Feeder NSM6 is reserved for emergency restoration of NS6, which serves the Los Alamos County Medical Center.

**These feeders do not normally serve load in this configuration, but are useful for contingency restoration efforts.

Table 4-51 shows the White Rock system power flow results. In this new configuration, all planning criteria were maintained.

Table 4-51: 2040 Scenario 3 White Rock System Power Flow Results

| Station | Distribution Feeder | kW | kVAR | kVA | Max Amps | Min Voltage |
|---|---|---|---|---|---|---|
| White Rock | WR1 | 2,216 | 317 | 2,239 | 104 | 123.6 |
| | WR2 | 1,053 | 299 | 1,095 | 54 | 122.0 |
| | WR3 | 1,916 | -143 | 1,925 | 96 | 123.9 |
| | Substation | 5,186 | 473 | 5,208 | - | - |

### 4.7.3 Contingency Configuration Review

Table 4-52 shows the substation transformer and primary feeder contingency scenarios evaluated for the Los Alamos Townsite system. There is sufficient capacity for all major substation transformers and primary feeder contingency scenarios. The system model was also evaluated to determine if all distribution feeders from the Eastgate Substation could be restored if one of the substation switchgear must be de-energized and the bus tie is unavailable. There are sufficient ties within the Los Alamos Townsite system to restore Eastgate Substation feeders.

Table 4-52: 2040 Scenario 3 Los Alamos Townsite System Contingency Review

| Scenario | Customer Load to Restore kVA | Total Applicable Customer Load kVA | Remaining Applicable Capacity kVA | Loading Violations? | Voltage Violations? | Comments |
|---|---|---|---|---|---|---|
| Loss of TA-3 XFMR 1 | 8,307 | 15,399 | 20,000 | No | No | Primary feeders TC2 and LC2 are used to restore customer load. TA-3 Transformer 2 is the most limiting element in this contingency. |
| Loss of TA-3 XFMR 2 | 7,092 | 15,399 | 20,000 | No | No | Primary feeders TC1 and LC1 are used to restore customer load. TA-3 Transformer 1 is the most limiting element in this contingency. |
| Loss of TC1 | 2,886 | 7,928 | 14,100 | No | No | Primary feeder TC2 is used to restore customer load through the Townsite switchgear. The TC2 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of TC2 | 5,042 | 7,928 | 16,000 | No | No | Primary feeder TC1 is used to restore customer load through the Townsite switchgear. The TC1 parallel 500 MCM CU cable is the most limiting element in this contingency. |
| Loss of LC1 | 5,421 | 7,092 | 14,100 | No | No | Primary feeder LC2 is used to restore customer load through the LASS switchgear. The LC2 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of LC2 | 2,050 | 7,092 | 14,100 | No | No | Primary feeder LC1 is used to restore customer load through the LASS switchgear. The LC1 1000 MCM CU cable is the most limiting element in this contingency. |
| Loss of Eastgate XFMR 1 | 2,932 | 5,823 | 14,000 | No | No | Operate the bus tie to restore the Eastgate 1 customer load using the Eastgate 2 transformer. |
| Loss of Eastgate XFMR 2 | 2,991 | 5,823 | 14,000 | No | No | Operate the bus tie to restore the Eastgate 2 customer load using the Eastgate 1 transformer. |

Table 4-53 shows the most impactful contingency scenario for the White Rock system if Transformer 2 becomes de-energized. All planning criteria can be maintained by utilizing feeders 16 and 17 to restore customers through White Rock Transformer 1.

Table 4-53: 2040 Scenario 3 White Rock System Contingency Review

| Scenario | Total Applicable Customer Load kVA | Customer Load to Restore kVA | Remaining Applicable Capacity kVA | Loading Violations? | Voltage Violations? | Comments |
|---|---|---|---|---|---|---|
| Loss of XFMR 2 | 5,210 | 5,210 | 10,000 | No | No | With White Rock Transformer 1 upgraded to 10,000 kVA and White Rock Transformer 2 already rated at 7,500 kVA, there is sufficient capacity to restore all customers for loss of either transformer. |

### 4.7.4 Asset Replacement Estimate

Power flow analysis identified system upgrades to increase capacity and improve voltage adherence within the system. Due to aging and deterioration, assets within the LACDPU system are anticipated to be replaced over time. In 2040 Scenario 3, based on the present age of existing assets (Section 2.1), considering a 15-year period, many of the LACDPU system assets may need to be replaced. Table 4-54 shows the estimated asset replacements over the 15-year period for the Los Alamos Townsite system. Conductors and cables that were identified for upgrade due to capacity needs in the power flow analysis were not included in this asset replacement estimate.

Table 4-54: 2040 Scenario 3 Los Alamos Townsite System Asset Replacement Estimate

| Conductor/ Equipment | % of Assets Replaced | Quantity |
|---|---|---|
| Overhead Conductor Replacements (miles) | 30% | 7 |
| Underground Cable Replacements (miles) | 65% | 32 |
| Mainline Switches | 90% | 123 |
| Three-Phase Service Transformers | 25% | 46 |
| Single-Phase Service Transformers | 35% | 327 |
| Secondary Services | 30% | 1,908 |

Table 4-55 shows the estimated asset replacements over the 30-year period for the White Rock system's 2040 Scenario 3. This scenario required fewer upgrades to improve distribution feeder capacity than the higher scenarios. The quantity of conductor and cable replacements is greater in this scenario as a result.

Table 4-55: 2055 Scenario 3 White Rock System Asset Replacement Estimate

| Conductor/ Equipment | % of Assets Replaced | Quantity |
|---|---|---|
| Overhead Conductor Replacements (miles) | 95% | 10 |
| Underground Cable Replacements (miles) | 50% | 4 |
| Mainline Switches | 70% | 16 |
| Three-Phase Service Transformers | 40% | 14 |
| Single-Phase Service Transformers | 50% | 207 |
| Secondary Services | 40% | 1,045 |

# APPENDIX A – HOSTING CAPACITY ANALYSIS RESULTS

# Substation: White Rock
# Feeder: WR1


**Legend**

| | Greater than (kW) | Less than (kW) |
|---|---|---|
| Yellow | 0 | 25 |
| Red | 25 | 100 |
| Green | 100 | 200 |
| Magenta | 200 | 300 |
| Purple | 300 | 500 |
| Cyan | 500 | 1,000 |
| Blue | 1,000 | 2,000 |
| Brown | 2,000 | 5,000 |

| Maximum Hosting Capacity | 915 kW |
|---|---|
| Criteria Violation | Reverse Flow |

## Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 398 | 130 | 419 | 56 |
| Phase B | 433 | 142 | 456 | 61 |
| Phase C | 306 | 100 | 322 | 43 |
| **Total** | **1,137** | **372** | **1,197** | **-** |

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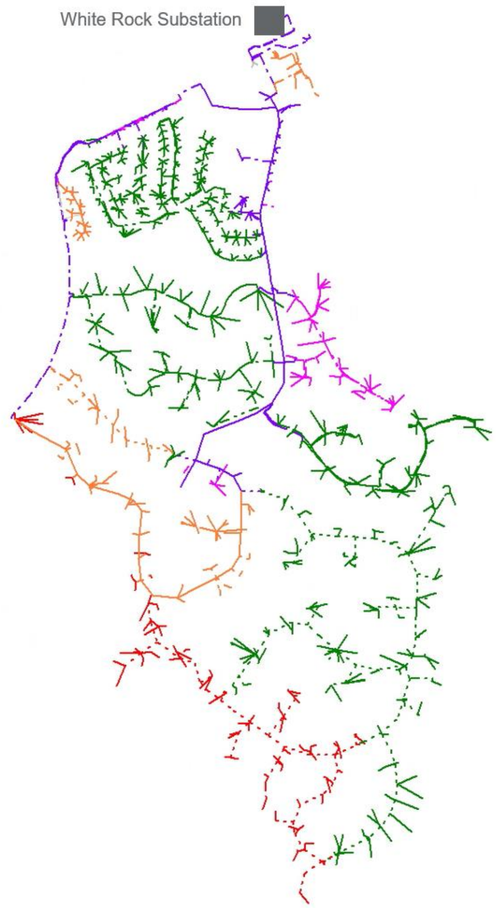
# Substation: White Rock
# Feeder: WR2




**Legend**

| | Greater than (kW) | Less than (kW) |
|---|---|---|
| Yellow | 0 | 25 |
| Red | 25 | 100 |
| Green | 100 | 200 |
| Magenta | 200 | 300 |
| Purple | 300 | 500 |
| Light blue | 500 | 1,000 |
| Blue | 1,000 | 2,000 |
| Brown | 2,000 | 5,000 |

| Maximum Hosting Capacity | 383 kW |
|---|---|
| Criteria Violation | Reverse Flow |

## Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 256 | 103 | 276 | 38 |
| Phase B | 128 | 61 | 142 | 20 |
| Phase C | 157 | 71 | 172 | 24 |
| **Total** | **541** | **235** | **590** | **-** |

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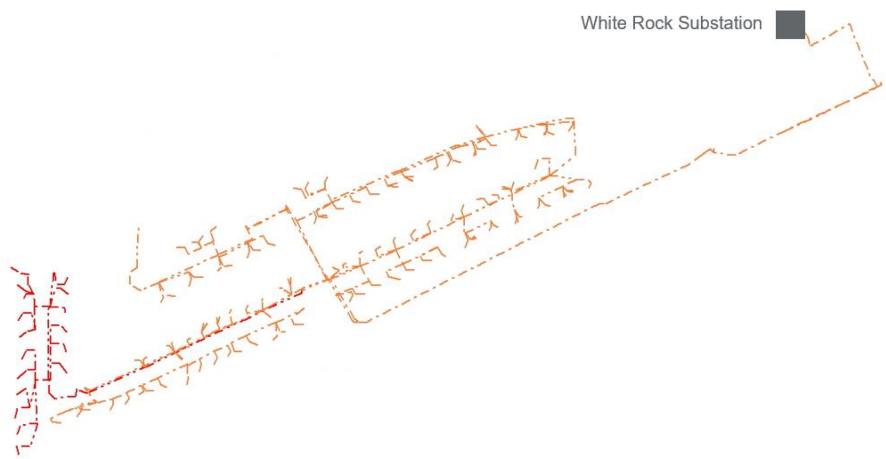
# Substation: White Rock
# Feeder: WR3




| Legend | | |
|---|---|---|
| | Greater than (kW) | Less than (kW) |
| Yellow | 0 | 25 |
| Red | 25 | 100 |
| Green | 100 | 200 |
| Magenta | 200 | 300 |
| Purple | 300 | 500 |
| Cyan | 500 | 1,000 |
| Blue | 1,000 | 2,000 |
| Brown | 2,000 | 5,000 |

| Maximum Hosting Capacity | 35 kW |
|---|---|
| Criteria Violation | Reverse Flow |

## Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 1 | 1 | 1 | 0 |
| Phase B | 1 | 11 | 1 | 0 |
| Phase C | 36 | 12 | 38 | 5 |
| **Total** | **38** | **24** | **40** | **-** |

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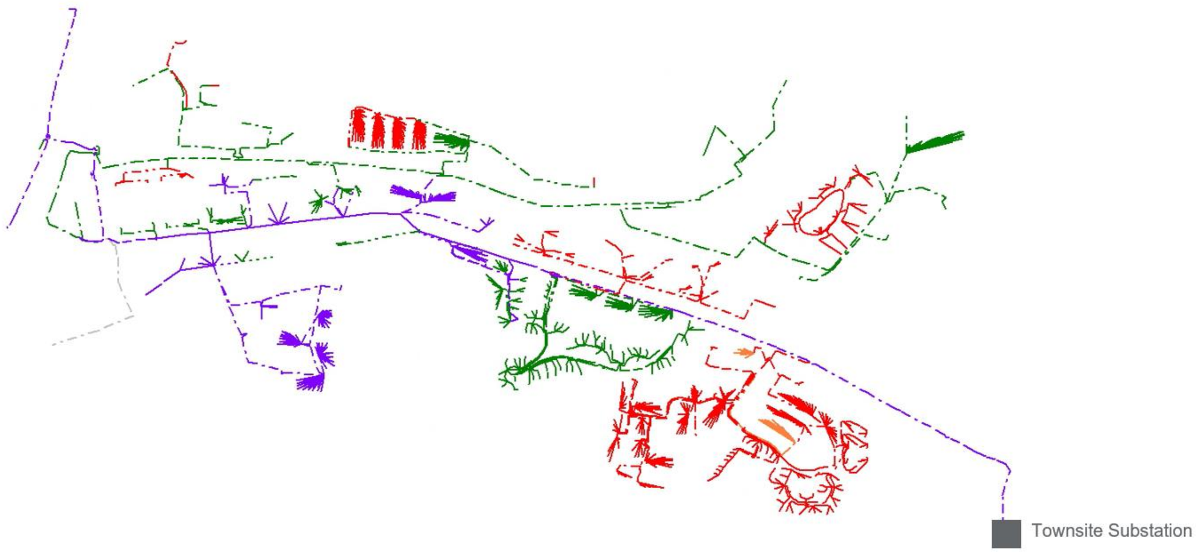
# Substation: Townsite
# Feeder: Feeder 13




| Legend | Greater than (kW) | Less than (kW) |
|---|---|---|
| | 0 | 25 |
| | 25 | 100 |
| | 100 | 200 |
| | 200 | 300 |
| | 300 | 500 |
| | 500 | 1,000 |
| | 1,000 | 2,000 |
| | 2,000 | 5,000 |

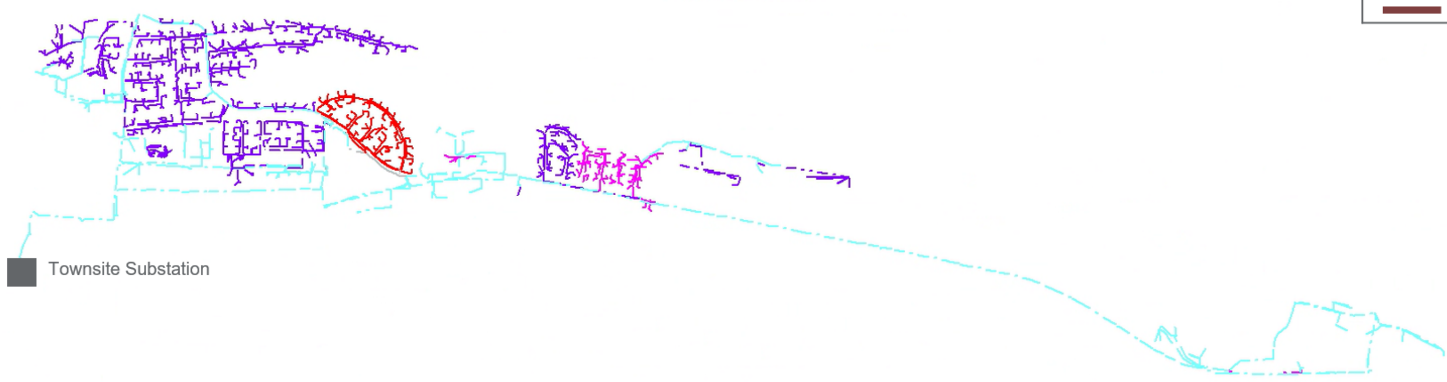
| | |
|---|---|
| **Maximum Hosting Capacity** | **461 kW** |
| **Criteria Violation** | **Reverse Flow** |

## Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 183 | -47 | 189 | 24 |
| Phase B | 154 | -126 | 199 | 25 |
| Phase C | 162 | -99 | 190 | 24 |
| **Total** | **499** | **-272** | **578** | **-** |

# Substation: Townsite
# Feeder: Feeder 14

| Legend | Greater than (kW) | Less than (kW) |
|---|---|---|
| (yellow) | 0 | 25 |
| (red) | 25 | 100 |
| (green) | 100 | 200 |
| (magenta) | 200 | 300 |
| (purple) | 300 | 500 |
| (cyan) | 500 | 1,000 |
| (blue) | 1,000 | 2,000 |
| (brown) | 2,000 | 5,000 |

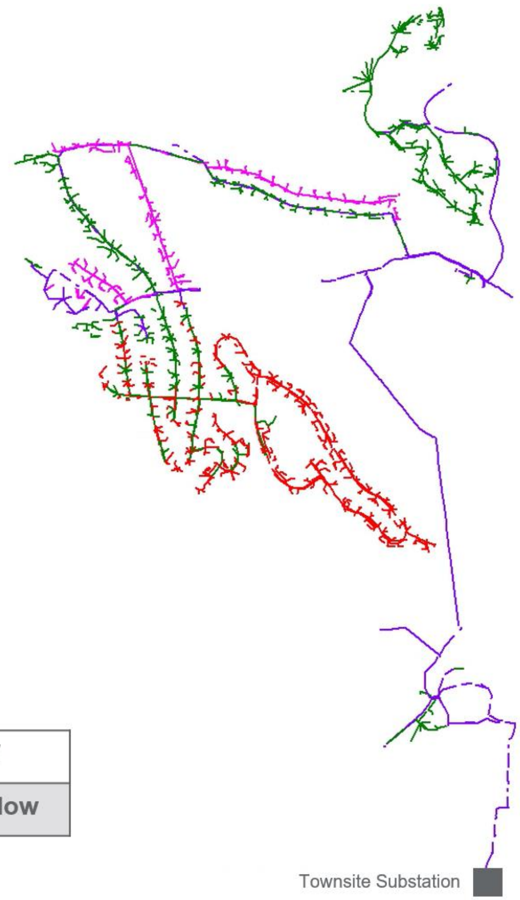



| Maximum Hosting Capacity | 929 kW |
|---|---|
| Criteria Violation | Reverse Flow |

## Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 310 | 90 | 323 | 41 |
| Phase B | 337 | 110 | 355 | 45 |
| Phase C | 333 | 97 | 347 | 44 |
| **Total** | **980** | **297** | **1,025** | **-** |

# Substation: Townsite
# Feeder: Feeder 15



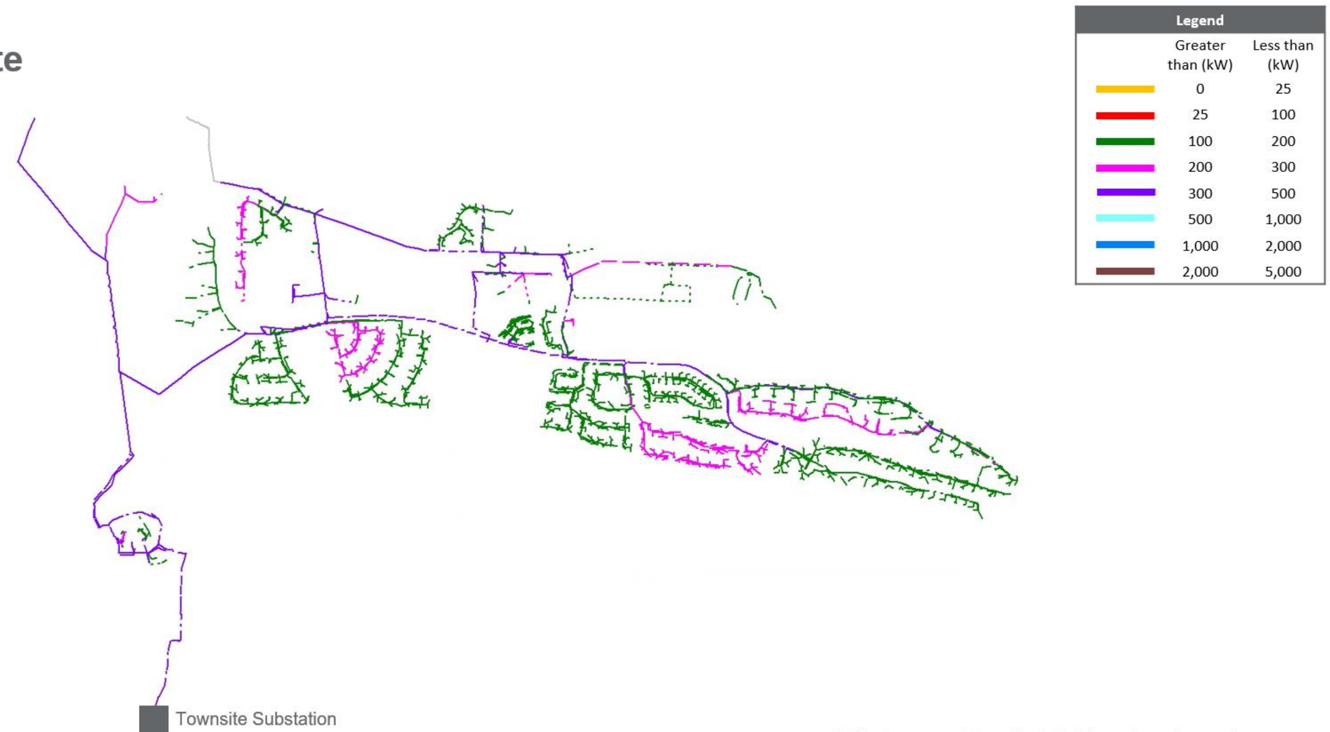

| Legend | | |
|---|---|---|
| | Greater than (kW) | Less than (kW) |
| Yellow | 0 | 25 |
| Red | 25 | 100 |
| Green | 100 | 200 |
| Magenta | 200 | 300 |
| Purple | 300 | 500 |
| Cyan | 500 | 1,000 |
| Blue | 1,000 | 2,000 |
| Brown | 2,000 | 5,000 |

| | |
|---|---|
| **Maximum Hosting Capacity** | **435 kW** |
| **Criteria Violation** | **Reverse Flow** |

## Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 164 | 51 | 171 | 22 |
| Phase B | 218 | 68 | 229 | 29 |
| Phase C | 145 | 33 | 148 | 19 |
| **Total** | **527** | **152** | **548** | **-** |

# Substation: Townsite
# Feeder: Feeder 16




| Maximum Hosting Capacity | 425 kW |
|---|---|
| Criteria Violation | Reverse Flow |

Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 141 | 21 | 143 | 18 |
| Phase B | 151 | 37 | 156 | 20 |
| Phase C | 270 | 71 | 280 | 35 |
| Total | 562 | 129 | 579 | - |

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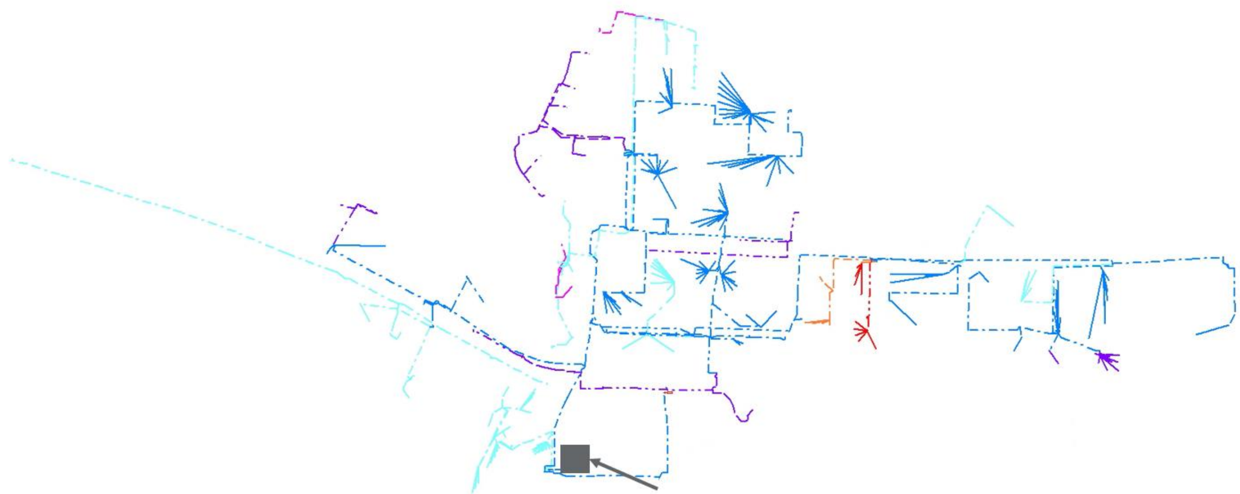
# Substation: Townsite
# Feeder: Feeder 17

| Legend | Greater than (kW) | Less than (kW) |
|---|---|---|
| (yellow) | 0 | 25 |
| (red) | 25 | 100 |
| (green) | 100 | 200 |
| (magenta) | 200 | 300 |
| (purple) | 300 | 500 |
| (cyan) | 500 | 1,000 |
| (blue) | 1,000 | 2,000 |
| (brown) | 2,000 | 5,000 |




| | |
|---|---|
| **Maximum Hosting Capacity** | **1,309 kW** |
| **Criteria Violation** | **Reverse Flow** |

## Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 436 | 95 | 436 | 56 |
| Phase B | 478 | 157 | 503 | 64 |
| Phase C | 449 | 146 | 472 | 60 |
| **Total** | **1,363** | **398** | **1,411** | **-** |

# Substation: Townsite
# Feeder: Feeder 18

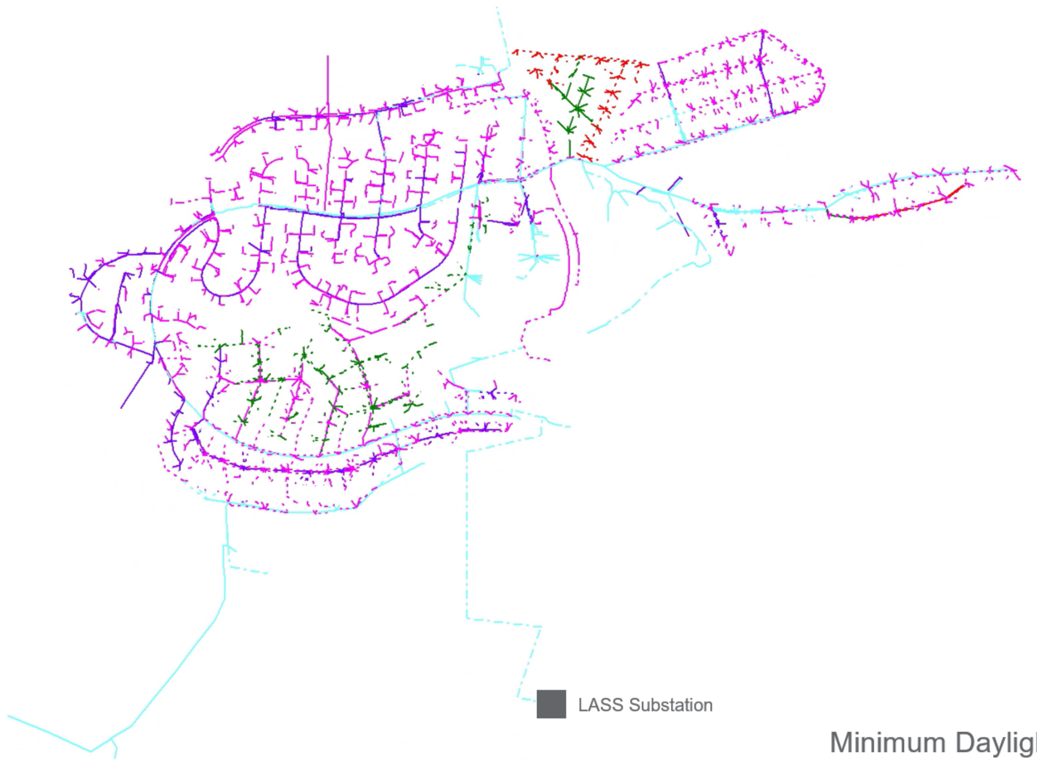

| Legend | Greater than (kW) | Less than (kW) |
|---|---|---|
| Yellow | 0 | 25 |
| Red | 25 | 100 |
| Green | 100 | 200 |
| Magenta | 200 | 300 |
| Purple | 300 | 500 |
| Cyan | 500 | 1,000 |
| Blue | 1,000 | 2,000 |
| Brown | 2,000 | 5,000 |

| Maximum Hosting Capacity | 534 kW |
|---|---|
| Criteria Violation | Reverse Flow |

Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 178 | 53 | 186 | 23 |
| Phase B | 199 | 59 | 207 | 26 |
| Phase C | 182 | 56 | 190 | 24 |
| **Total** | **559** | **168** | **583** | **-** |

## Substation: LASS
## Feeder: Feeder 13T




| Legend | | |
|---|---|---|
| | Greater than (kW) | Less than (kW) |
| Yellow | 0 | 25 |
| Red | 25 | 100 |
| Green | 100 | 200 |
| Magenta | 200 | 300 |
| Purple | 300 | 500 |
| Cyan | 500 | 1,000 |
| Blue | 1,000 | 2,000 |
| Brown | 2,000 | 5,000 |

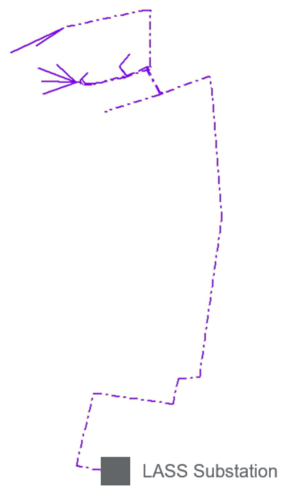
| | |
|---|---|
| **Maximum Hosting Capacity** | **625 kW** |
| **Criteria Violation** | **Reverse Flow** |

### Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 209 | 136 | 249 | 31 |
| Phase B | 236 | 202 | 311 | 39 |
| Phase C | 234 | 173 | 291 | 37 |
| **Total** | **679** | **511** | **851** | **-** |

## Substation: LASS
## Feeder: Feeder NS6

| Legend | | |
|---|---|---|
| | Greater than (kW) | Less than (kW) |
| Yellow | 0 | 25 |
| Red | 25 | 100 |
| Green | 100 | 200 |
| Magenta | 200 | 300 |
| Purple | 300 | 500 |
| Cyan | 500 | 1,000 |
| Blue | 1,000 | 2,000 |
| Brown | 2,000 | 5,000 |




| Maximum Hosting Capacity | 375 kW |
|---|---|
| Criteria Violation | Reverse Flow |

Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 125 | 26 | 128 | 16 |
| Phase B | 125 | 26 | 128 | 16 |
| Phase C | 125 | 26 | 128 | 16 |
| **Total** | **375** | **78** | **384** | **-** |

# Substation: LASS
# Feeder: Feeder 15T


| Legend | Greater than (kW) | Less than (kW) |
|---|---|---|
| Yellow | 0 | 25 |
| Red | 25 | 100 |
| Green | 100 | 200 |
| Magenta | 200 | 300 |
| Purple | 300 | 500 |
| Cyan | 500 | 1,000 |
| Blue | 1,000 | 2,000 |
| Brown | 2,000 | 5,000 |

| | |
|---|---|
| **Maximum Hosting Capacity** | **408 kW** |
| **Criteria Violation** | **Reverse Flow** |

## Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 136 | 29 | 139 | 19 |
| Phase B | 153 | 31 | 156 | 22 |
| Phase C | 250 | 84 | 264 | 37 |
| **Total** | **539** | **144** | **559** | **-** |

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# Substation: LASS
# Feeder: Feeder 16T


**Legend**

| | Greater than (kW) | Less than (kW) |
|---|---|---|
| Yellow | 0 | 25 |
| Red | 25 | 100 |
| Green | 100 | 200 |
| Magenta | 200 | 300 |
| Purple | 300 | 500 |
| Light blue | 500 | 1,000 |
| Blue | 1,000 | 2,000 |
| Brown | 2,000 | 5,000 |

| | |
|---|---|
| **Maximum Hosting Capacity** | **334 kW** |
| **Criteria Violation** | **Reverse Flow** |

## Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 255 | 109 | 277 | 35 |
| Phase B | 196 | 31 | 211 | 27 |
| Phase C | 112 | 2 | 124 | 16 |
| **Total** | **563** | **142** | **612** | **-** |

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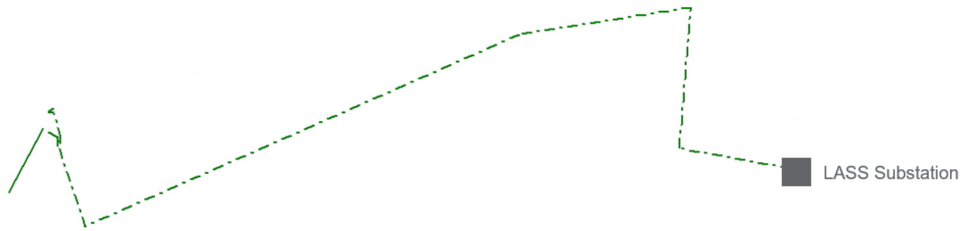
## Substation: LASS
## Feeder: Feeder NS3

| Legend | Greater than (kW) | Less than (kW) |
|---|---|---|
| Yellow | 0 | 25 |
| Red | 25 | 100 |
| Green | 100 | 200 |
| Magenta | 200 | 300 |
| Purple | 300 | 500 |
| Cyan | 500 | 1,000 |
| Blue | 1,000 | 2,000 |
| Brown | 2,000 | 5,000 |

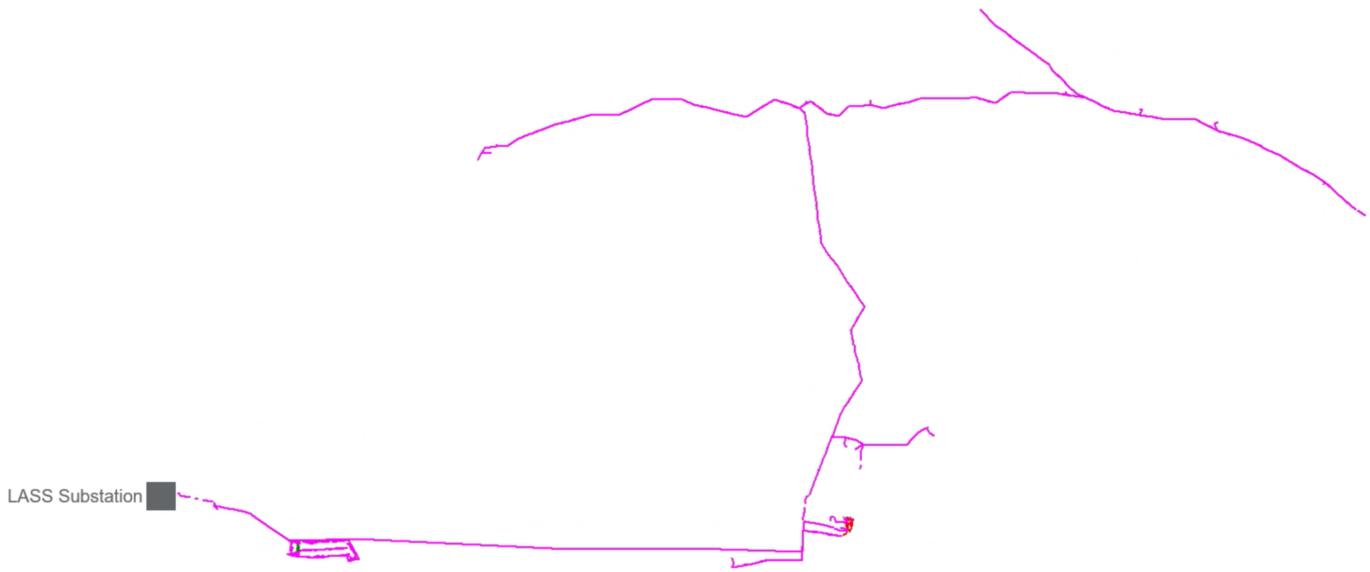



| | |
|---|---|
| **Maximum Hosting Capacity** | **180 kW** |
| **Criteria Violation** | **Reverse Flow** |

### Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 60 | 18 | 63 | 8 |
| Phase B | 60 | 18 | 63 | 8 |
| Phase C | 60 | 18 | 63 | 8 |
| **Total** | **180** | **54** | **189** | **-** |

# Substation: LASS
# Feeder: Feeder NS18




| Legend | Greater than (kW) | Less than (kW) |
|---|---|---|
| Yellow | 0 | 25 |
| Red | 25 | 100 |
| Green | 100 | 200 |
| Magenta | 200 | 300 |
| Purple | 300 | 500 |
| Cyan | 500 | 1,000 |
| Blue | 1,000 | 2,000 |
| Brown | 2,000 | 5,000 |

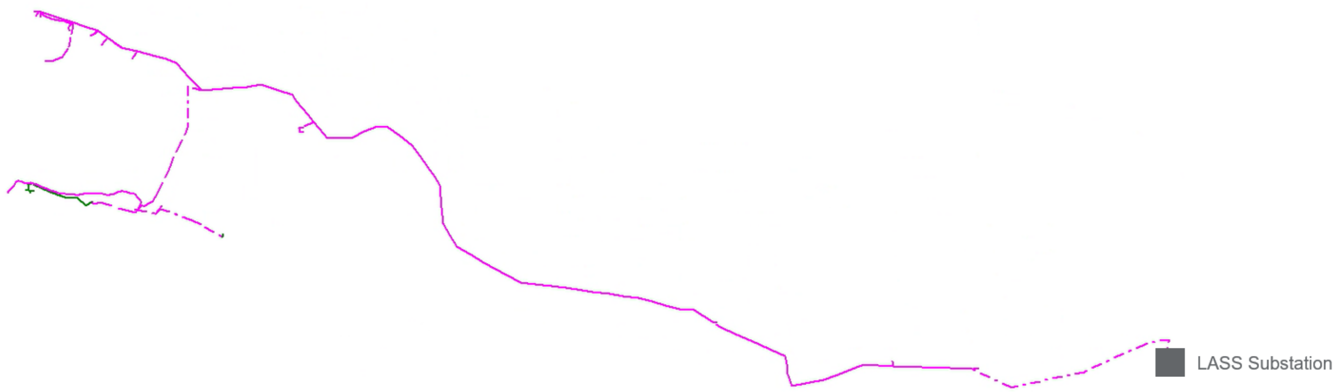
| | |
|---|---|
| **Maximum Hosting Capacity** | **205 kW** |
| **Criteria Violation** | **Reverse Flow** |

## Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 69 | 23 | 73 | 9 |
| Phase B | 83 | 29 | 88 | 11 |
| Phase C | 91 | 31 | 96 | 12 |
| **Total** | **243** | **83** | **257** | **-** |

# Substation: LASS
# Feeder: Feeder NS18

| Legend | Greater than (kW) | Less than (kW) |
|---|---|---|
| Yellow | 0 | 25 |
| Red | 25 | 100 |
| Green | 100 | 200 |
| Magenta | 200 | 300 |
| Purple | 300 | 500 |
| Cyan | 500 | 1,000 |
| Blue | 1,000 | 2,000 |
| Brown | 2,000 | 5,000 |




| | |
|---|---|
| **Maximum Hosting Capacity** | **285 kW** |
| **Criteria Violation** | **Reverse Flow** |

## Minimum Daylight Feeder Load

| | kW | kVAR | kVA | Amps |
|---|---|---|---|---|
| Phase A | 108 | 6 | 125 | 16 |
| Phase B | 100 | 68 | 121 | 15 |
| Phase C | 96 | 65 | 115 | 15 |
| **Total** | **304** | **139** | **361** | **-** |

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# APPENDIX B – GRID MODERNIZATION STRATEGIES

## 4.8 BESS within the Electric System

BESS resources are versatile and can provide many different services to the electric system. A single BESS cannot necessarily provide all services at once. The size, location, operating agreement, and other factors will limit the services that can be provided to the system. The common use cases for BESS on the utility system are shown below.

- **Energy Arbitrage:** Charge the battery during times of low customer demand and high renewable generation output, and discharge it during times of high customer demand and low renewable generation output.
- **Firm Capacity/Peaking Capacity:** Installed capacity that can reliably operate during high-risk hours.
- **Ancillary Services:** The battery can support the operation of the electric system through frequency and/or voltage support. A BESS resource's quick operating time can make it suitable for ancillary services over other types of generation sources.
- **Capital Project Deferral:** The battery can supply energy during peak demand and defer/repLACDPUe the need for traditional wire upgrades. It can also store excess renewable energy that otherwise might require traditional wire upgrades to mitigate equipment overloads.
- **Microgrid/Reliability Improvements**: The battery can be used to island the distribution system during outages or storm events.

### 4.8.1 Transmission Scale BESS

Transmission-scale BESS are becoming increasingly popular for utilities throughout North America. Typical sizes of these installations are 50+ MW and 2-4 hours of storage. Table 4-56 compares the positives and challenges of a transmission-scale BESS.

Table 4-56: Transmission Scale BESS

| Positives | Challenges |
|---|---|
| More Economical - large installations will be cheaper to construct on a unit cost basis | Limited Distribution System Improvement - reduced opportunity to defer distribution system investments or provide ancillary service to distribution feeders. |
| Simpler Control - a single resource to control and manage. Useful for managing system-level power flow and maintaining demand charges/upstream impacts. | Siting/Construction - Given Los Alamos's geography, it may be difficult to find adequate sites for installing a transmission-scale resource. |
| More Impactful Grid Services - a larger BESS could provide services beyond the LACDPU system and potentially become an additional revenue stream for the county. | |

A transmission scale resource would likely require cooperation with neighboring Pueblo communities and/or Los Alamos National Lab. A new transmission line serving Los Alamos is likely a necessity to enable the interconnection of a larger resource owned by LACDPU. LACDPU could pursue joint ownership of a larger transmission-scale resource or construct a site in conjunction with other parties. Land for a larger project like this will be a major challenge. If LACDPU can develop a larger-scale BESS project, there could be opportunities to generate revenue by providing grid services to the surrounding utilities.

### 4.8.2 Distribution Level BESS

Distribution-scale BESS is a newer development for utilities throughout North America. Typically, the size of the distribution BESS resources has made them cost-prohibitive solutions. However, the costs of materials and installations are coming down, resulting in more BESS being connected to the distribution system. Typical sizes of these installations are 2-10 MW with 2-4 hours of storage. Table 4-57 compares the positives and challenges of a distribution-scale BESS.

Table 4-57: Distribution Scale BESS

| Positives | Challenges |
|---|---|
| Siting/Construction - Given Los Alamos's geography, it should be easier to find suitable locations to construct a distribution-scale BESS. | Less Economical - smaller installations will be more expensive to construct on a unit cost basis. |
| System and Feeder Benefits - a BESS on the distribution system can provide system benefits (at a smaller scale) but can also be used to manage local power flow and provide ancillary services needed locally. | Limited Use Cases - where a distribution BESS is located may influence the types of services it can provide. A single distribution BESS will not be able to provide all services at the same time. |
| Microgrid Potential - locating BESS closer to load centers can simplify the design and operation of a microgrid. | Public Opposition - safety and environmental impacts could be a challenge with the distribution BESS located closer to homes and businesses. |

Distribution scale BESS is likely the right size for the LACDPU system, considering the amount of power served and the geography of the area. Further study will be required to identify a suitable location, size, storage capacity, onsite generation needs, system impacts and other factors. Initial discussions were focused on constructing a distribution-scale BESS on county-owned land that is in the canyons and near the distribution system. As the system evolves, LACDPU will need to consider what use cases are most desired for each BESS project, as that will influence the viable locations and system impacts from operating the BESS.

### 4.8.3 Residential Level BESS

Residential-scale BESS is growing in popularity among utility customers. New programs are being developed at various utilities to leverage the assets owned and maintained by their customers. Typical sizes of these installations are 3-10 kW with 2-6 hours of storage. Aggregating these resources across a distribution feeder/distribution system can result in large amounts of energy storage. This concept of aggregating customer resources is often referred to as “Virtual Power Plants”. Table 4-58 compares the positives and challenges of a distribution-scale BESS.

Table 4-58: Residential Scale BESS

| Positives | Challenges |
|---|---|
| Environmental Impact - no land will be required to construct a larger BESS site. Given Los Alamos's geography, this may be the most feasible option. | Complexity – aggregating the control of customer-owned BESS may be challenging. Customers may not be willing to give LACDPU control of their assets. |
| Local Improvement - The closer the resources are to the loads, the fewer losses will occur, and power quality can be managed more successfully. | Insufficient Energy Storage – not all customers will invest in a BESS. If adoption is low, the number and types of services these customer-owned BESS can provide to the distribution system will be reduced. |
| Microgrid Potential - if customers own enough BESS, there could be potential for dynamic microgrid operation. | Cost - LACDPU may need to offer higher compensation to customers participating in a residential BESS program. The structure of the LACDPU municipal utility may prohibit incentives/rebates for residential BESS. |

It will likely be some time before there is enough BESS deployed within the LACDPU system that a virtual power plant would be feasible. LACDPU could implement new rate structures/financial incentives for customers to use their own BESS resources to reduce the strain on the grid by shifting the load. During the discussion with the LACDPU project team, a virtual power plant program is something that could be considered in the future, but is likely not going to be a sought-after solution in the near term.

### 4.8.4 Mobile BESS

Mobile BESS is a recent development in the energy storage industry. Utilities are beginning to utilize mobile BESS to limit outages during planned capital work on the system. Other use cases are to provide capacity to a distribution feeder during storm restoration efforts or to support temporary loads. Typical sizes of these installations are 250-1,000 kW with 1-2 hours of storage. Recent quotes from mobile BESS vendors are in the range of $1M-$2M+ depending on the configuration desired. Table 4-59 compares the positives and challenges of mobile BESS.

Table 4-59: Residential Scale BESS

| Positives | Challenges |
|---|---|
| Versatile - ability to move into areas in need of the distribution system. This resource can be used for a variety of reasons over the life span of the asset. | High Cost - a mobile BESS will have the highest cost for energy storage compared to permanently installed solutions. |
| Temporary - being mobile in nature, this resource can be parked in areas that are not suitable for a permanent installation. | Logistics - LACDPU would need to have trained staff to transport this equipment or contract out this service. The geography of Los Alamos may make it difficult to find suitable locations for connecting a mobile BESS in the need areas. |
| Quiet Operation - Deploying mobile BESS in pLACDPUe of a diesel generator would be viewed much more positively by customers. | Return on Investment - The LACDPU system is not as dynamic as larger utilities, so the effort required to own and operate this equipment may not be necessary. |

Opportunities to use a mobile BESS in the LACDPU system were discussed around the water wells and fleet vehicle charging. Mobile BESS would allow LACDPU to deploy energy storage quickly to areas in need. It could also be used as a temporary solution to serve loads until a permanent BESS can be constructed.

### 4.8.5 Ownership and Operation of BESS

If LACDPU determines a desirable use case for BESS within their system, additional considerations must be made about the ownership model of this new resource. Table 4-60 shows the benefits of both models for BESS within the utility system.

Table 4-60: BESS Ownership and Operation Considerations

| Own and Operate | Contract with BESS Operators |
|---|---|
| Control - ownership will provide the most flexibility when controlling this resource. If LACDPU wants to change the use case of the BESS over time, it can. | Capital Cost - reduced capital investment in constructing these resources. |
| Knowledge/Experience - LACDPU engineers will gain more exposure to this resource and may identify new ways to dispatch when operating the system. | Liability - reduced concern of having staff on hand to operate this resource. A simpler forecast of the cost of using this resource. |

## 4.9 Fault Location, Isolation, and Service Restoration (FLISR)

FLISR is a term used in the electric utility industry to describe an automated method of isolating faults and restoring customers. When a fault occurs, protective relays will detect an abnormal condition in the distribution system and open a circuit breaker or recloser to isolate the faulted equipment. These actions can be automated through the investment of new reclosers and other protective devices on the distribution feeders that are capable of communication. With communication in pLACDPUe, system operators can manually control these devices, or more advanced systems can be developed that perform real-time calculations to identify optimal network configurations. Investing in new protective device technology can also provide opportunities for improved data/telemetry, load shed capability, improved reliability, and reduced operations and maintenance costs. Figure  shows an image of a distribution recloser that can be configured with remote control capability.

Figure 4-25: Distribution Line Recloser

During discussions with the LACDPU project team, fault restoration efforts were reviewed, and several determinations were made specific to the service territory. The LACDPU service territory is compact relative to many of the utilities that implement FLISR schemes. Utilities that experience the greatest benefit from FLISR schemes have high amounts of overhead exposure, inclement weather, and long response times when outages occur. The LACDPU system benefits from greater emphasis on underground construction and short response times when an outage does occur.

Installing new reclosers in areas of greater overhead exposure could benefit the LACDPU system by reducing outage impacts. However, implementing a complete FLISR scheme in the LACDPU system would require investment in new equipment and software to configure, which could be costly for such a small utility. Although the value of FLISR for LACDPU may be low today, as the distribution system grows due to electrification, this method may become more valuable to the county. If LACDPU chooses to install new reclosers and protective devices, they should verify the remote control and communications capabilities of the equipment, as FLISR might be implemented in the future.

## 4.10 Distribution System Microgrid

Distribution system microgrids are becoming an increasingly popular option among electric utilities. Microgrids are often constructed to improve reliability, but can also provide other benefits like improved efficiency and increased operability. Microgrids can be contained within a single building or as large as a college campus or city sector. The size of the microgrid and its use case will influence many of the design parameters.

The project team discussed several considerations when designing a microgrid related to the size, use case, customer participation, and factors unique to the LACDPU system. This discussion is summarized below.

- **Loads/Customers in the Microgrid:** Typically, there is a community focus to the customers that participate in a microgrid. The LACDPU project team identified that a downtown microgrid, inclusive of the police station, grocery stores, and community center, would be desirable. Additionally, a microgrid focused on the sewer plant/water well sites would be beneficial, as this is critical infrastructure that serves the community.
- **Duration of Microgrid Island:** The duration that a microgrid must sustain an island will significantly impact the required generation and energy storage. Often, pairing PV with battery storage is a way to sustain longer microgrid islands. However, it was discussed with the LACDPU project team that there is limited land available for large-scale PV systems within the LACDPU system. For LACDPU, a microgrid will likely need to be paired with natural gas generation to sustain an island for an extended length of time. A future detailed study will help to define the design parameters for the length of the sustained island and the generation requirements of the microgrid.
- **Customer Load Shed Potential:** Load shed is a technique employed in many microgrids to extend the operation of an island if the power or energy demands of customers cannot be met. Load shed strategies are typically more viable in industrial applications where parallel processes can be energized/de-energized. Upon discussion with the LACDPU project team, the LACDPU system primarily serves residential and commercial customers. If the microgrid is focused on community buildings and/or residential customers, there would be limited potential for load shedding. The microgrid must be designed to serve the total load of customers participating in the microgrid.
- **Size of Microgrid:** The physical size of the microgrid and the number of customers participating will impact several of the design parameters. When a microgrid is operated in an islanded mode, the fault current supplied by the utility system is significantly reduced, and this can impact existing protection schemes. LACDPU may need to upgrade existing protective devices or implement group settings so that the safety of the system is not compromised during islanded operation of the microgrid.
- **Cybersecurity Risks:** LACDPU does not presently have any remote operability of its system. A microgrid will inherently bring more telemetry and remote operation of utility equipment. As new equipment and technology are included in a microgrid, there is an increased risk of cybersecurity attacks. LACDPU should work with vendors to discuss their mitigations for cybersecurity risks as these new technologies are adopted onto the LACDPU system.

A fully functioning microgrid will likely be a long-term option for the LACDPU system, but these design considerations can help guide LACDPU towards developing a microgrid in the future. As new technologies are deployed on the system, LACDPU engineers should verify the compatibility of new equipment with microgrid controllers. Siting generation sources closer to the customer loads is another area of importance for a future microgrid, but it would also help to improve the LACDPU system's resilience and efficiency. LACDPU should investigate further the feasibility of generation within the service territory. Due to the geography and climate of Los Alamos, natural gas generation may be a solution, as land to develop PV systems is limited.

## 4.11 Modular Substations

Modular substations have been deployed by several utilities when traditional substation construction is cost-prohibitive or undesirable to customers. Traditional substations utilize large power transformers to convert transmission voltage to distribution voltage for delivering power to homes and businesses. Traditional substations can vary in size from 0.25 acres to 4+ acres. Energized components such as the power transformer, switchgear, and bus work are contained within a fence to protect the public and protect the substation equipment from damage. Typically, two or more distribution feeders are routed from a traditional substation to serve homes and businesses. Figure 4-26 shows an image of a traditional substation in the White Rock community.

**Figure 4-26: White Rock Substation**

Modular substations perform the same function as traditional substations but are constructed to be smaller, do not require a fence or large barriers, and are faster to construct. However, modular substations are not capable of delivering as much power as traditional substations. So, it could take multiple modular substations to provide the necessary capacity that a single traditional substation can. Figure  shows an image of a modular substation from Manitoba Hydro, an electric utility in Canada[28].

Figure 4-27: Modular Substation Example from Manitoba Hydro

Table 4-61 shows a summary of the discussion with the LACDPU project team regarding the potential use of modular substations within the county. If LACDPU desires to pursue modular substations, additional feasibility analysis must be performed and design considerations made.

Table 4-61: Modular Vs Traditional Substation Considerations

| Consideration | Modular Substation | Traditional Substation |
|---|---|---|
| Construction | Preassembled equipment, shorter construction times, and shorter lead times | On-site construction/assembly, longer construction times, longer lead times, and future expansion can be challenging |
| Operations and Maintenance | Quick replacement, hot stick operable, reduced copper theft potential, similar life expectancy to traditional substation assets, and more locations to maintain | More rigorous maintenance schedules, expensive components, fewer locations to maintain |
| Safety | No live front components, tamper resistant, grounding to IEEE 80 | Physical security equipment required (fencing, locks, etc.), exposed bus work, and more stringent safety training |
| Environmental | Less visual impact, low impact from oil spills, reduced EMF exposure | Large footprint, large transmission structures, more public visibility, perceived environmental impact |

[28] Manitoba Hydro modular substation example - https://www.mhi.ca/products/hvpt

## 4.12 Volt-VAR Optimization

Capacitor banks, shunt inductors, and voltage regulators are typically used by utilities to regulate voltage within the distribution system. As DER penetration increases on the distribution system, voltage compliance can become more challenging and require adjustments to typical operating procedures. The LACDPU system is primarily made up of residential and commercial customers. These customers typically have a very high power factor, which results in more efficient operation of the system. Because the LACDPU system serves minimal large motors/industrial customers, minimal capacitor banks are located on the LACDPU system. The geography of the LACDPU system also results in relatively short distribution feeders that can successfully maintain service voltage for customers. Historically, LACDPU has maintained compliance with voltage criteria without applying Volt-VAR optimization.

As DER penetration increases on the LACDPU system, there is potential for voltage rise when customer generation is high. This is further exacerbated when customer generation is high and local customer demand is low (spring/fall seasons). Utilities across the country are adjusting their interconnection agreements to require new PV customers to adopt Volt-VAR inverter control to assist in regulating voltage on the distribution feeder. PNM implemented such a requirement in 2024[29]. PV customers on the LACDPU system presently operate at unity power factor to maximize generator output and customer return on the investment. 1898 & Co. recommends that LACDPU update its interconnection agreement to incorporate dynamic voltage control, such as the Volt-VAR inverter control outlined in the PNM TIIR document. By pushing this control scheme to new PV customers' equipment, the LACDPU system will benefit from improved voltage regulation and help to mitigate potential high-voltage violations for customers.

Even with dynamic voltage control enabled for new PV customers, the LACDPU system may still require additional voltage regulating equipment to maintain compliance with ANSI C84.1. Static compensators are a technology that is gaining traction with distribution utilities. A static compensator uses power electronics to absorb/produce reactive power on a distribution feeder to regulate voltage. Static compensators can react very quickly and improve the efficiency of the system by producing/absorbing reactive power closer to the areas of need. There is no need for static compensators in the near term for the LACDPU system. However, if LACDPU is experiencing sustained high voltage within a focused area, a static compensator may be a solution in the future. Alternatively, if PV penetration is resulting in high voltage throughout the system, lowering the substation voltage setpoint is another solution. If the substation voltage setpoint is lowered, it must be confirmed that low voltage does not result during peak load times.

Conservation Voltage Reduction (CVR) is a method related to Volt-VAR optimization and energy efficiency. CVR is a strategy that LACDPU could pursue in the future to reduce its peak demand as better voltage regulation is implemented on the system. To successfully implement CVR, additional equipment like capacitor banks, voltage regulators, or even static compensators could be required on the LACDPU system. No near-term action for CVR is recommended for LACDPU, but this may be a future option for the county to make incremental improvements to the system's peak demand in the future.

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[29] PNM TIIR Requirements - https://www.pnm.com/documents/28767612/28777474/PNM+Technical+Interconnection+and+Interoperability+Requirements+%28Feb+1%2C+2024%29.pdf/bc34f992-67c7-43b5-eda5-3ff014d97c04?t=1704474064849

## 4.13 Demand Response Programs

Customer load varies throughout each day and season. Electric utilities across the country have implemented demand response programs to influence how customer load impacts the electric distribution system. During times of high customer demand, the utility can operate a demand response program to reduce customer load and improve the reliability of the electric system. Common demand response programs focus on the largest energy sources in a residential home, such as space heating/cooling and water heating. Typically, utilities will interface with smart thermostats or other controllers of these electric loads to influence the grid impact. Often, customers can be credited back for opting into a demand response program or provided other monetary incentives for participation.

Another method of reducing peak customer demand on the electric system is with various rate structures. Time of use rates can be implemented to encourage customers to shift their electricity usage outside the hours where peak demand typically occurs. Customers who can adjust their demand are then charged reduced rates for energy consumption outside the peak time. In addition to time-of-use rates, demand charges can also be implemented to encourage customers to limit their peak demand impact on the grid. A demand response program would charge customers based on the maximum power consumed each month. Customers who can minimize their maximum power consumption will reduce the demand charge component of their electric bill. Customers who reduce their maximum power consumption help to minimize the electric grid impacts from their energy consumption.

Electric vehicle adoption is growing and represents a new type of load for many customers who typically drive internal combustion engine vehicles. Electric vehicles can consume large amounts of energy from the grid, but these loads can be flexible. As EV adoption rates increase, there may be new opportunities for LACDPU to implement managed EV charging programs in addition to rate structures to spread out EV charging and limit the impact on the electric grid. These managed EV charging programs would require input from drivers, such as the typical daily drive distances and the time the vehicle must be charged. The program would be administered to spread EV charging load while meeting the needs of customers to have their vehicles charged and ready for use at the appropriate time each day. LACDPU should look for opportunities to implement a managed EV charging program when EV adoption rates increase and solutions from vendors become more mature. Figure  shows an image of electric vehicle supply equipment (EVSE).

**Figure 4-28: Electric Vehicle Supply Equipment**

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