CITY OF ASHLAND
ELECTRICAL SYSTEM MASTER PLAN
September 2024

Prepared For:

CITY OF ASHLAND
90 N. Mountain Avenue
Ashland, OR 97520

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Chapter 1 INTRODUCTION

1.1 PURPOSE

The purpose of this study is to perform an electrical system evaluation and develop an orderly, economic improvement plan for the City of Ashland Electric Department. The evaluation and improvement plan is intended to help ensure that Ashland’s electrical system has the operational capacity, reliability, and flexibility to meet long-term planning criteria. The study identifies and recommends system improvements that allow Ashland to supply adequate and quality power to customers for the intermediate future (10 years) and practical improvements to support long-term operations.

The study provides recommendations for modifications to existing facilities as well as new construction to economically meet projected system load changes and growth so that no facilities become obsolete or underrated early in their service lives. In addition, the study considers impacts on the City’s distribution system caused by known and planned Bonneville Power Administration (BPA) and PacifiCorp facility modifications.

The recommendations presented in this report should be used as a guide by City of Ashland management and staff in planning and implementing electrical system improvements. Suggested improvements are based on projected system load growth and changing electrical industry conditions with the aim of improving service quality and reliability while complying with construction, operation, and safety standards.

This study was conducted based on the best available information at the time. Some assumptions were necessary and are noted in the report. Any changes in equipment or system configuration from the data used in this report may result in a change in recommendations. Except where noted, this study evaluated the system as it was configured at the time the study was performed.

Over time, conditions generally change, and these changes can affect the feasibility or practicality of certain system improvements. This report should be reviewed and updated periodically since changing system conditions, supply chains, and available technologies may affect the economic viability or integrity of the recommended plans. By following an approach of periodically reviewing and updating the plan, Ashland will maintain a valuable, up-to-date tool to aid management and staff in the process of system operation, maintenance, and planning.

1.2 PROJECT AUTHORIZATION

In August 2023, City of Ashland Electric Department (Ashland) authorized Stoddard Power Systems (SPS) to conduct a study of the City of Ashland Electric Department’s Electric System Master Plan. The study consists of various tasks as described in the Technical Proposal from June 2023 and some detailed areas of concentration as identified during the project. This report contains the results of the City of Ashland Electric System Master Plan.

1.3 SCOPE OF WORK

The following is a summary of the scope of services performed in this study.

Load Forecast: Evaluation of the Ashland system-wide growth patterns based on historical, recent (prior 10-year period) and expected future growth, from data provided by the Ashland's Electric Department and population projections from the City of Ashland, Jackson County, BPA, PacifiCorp and Regional Planners. This data is used to estimate future feeder and substation peak loading throughout the system analysis period and to determine recommended system improvements.

System Planning Criteria: Establishment of realistic planning criteria and objectives upon which short-term and long-term planning are based. These planning standards were used to determine loading guidelines, the appropriate level of backup support under outage conditions, practical conductor sizes, acceptable voltage drop levels, and improvement timing.

Transmission and Substation Evaluation: Evaluation of the existing transmission system facilities serving Ashland for interconnection and switching flexibility, looping capabilities, isolated segments, and overall operation and performance for power supply and delivery to the Electrical Department facilities. Also, evaluation of the existing substations' points-of-delivery for equipment ratings, capacities, and configurations. This effort includes consideration of reliability, protection components, protection philosophy, interruption frequency and duration, power availability and the ability to serve growth, and operation and maintenance programs.

Analysis of the Existing System: Evaluation of the ability of the existing electric system to provide economical, high-quality service in terms of component loading, voltage levels, line losses, power factor, and reliability in the short-term and intermediate future. This effort includes a review of the existing system performance based on the following criteria:

- System reliability
- System capacity
- System flexibility
- System and feeder peak loads
- System construction practices
- Operation and maintenance policies
- Environmental sensitivity
- System equipment aging
- Identification of trouble spots and poorly performing equipment
- Review adequacy of system record keeping

Power Flow Analysis: Analysis of the City's electric system circuits using computer modeling software. The system was modeled on a system-wide single-phase and three-phase basis using Milsoft software package. The power flow analysis modeled the system for the following conditions:

- Case 1A Base Case Peak Load
- Case 1B Base Case Light Load

- Case 2A Ten-Year Growth Case
- Case 2B Twenty-Year Growth Case
- Case 3A Ashland Substation Transformer Out-Of-Service
- Case 3B Mountain Avenue Substation Transformer Out-Of-Service
- Case 3C Oak Knoll Substation Transformer K1 Out-Of-Service
- Case 3D Oak Knoll Substation Transformer K2 Out-Of-Service
- Case 4A AS/A2000 Business Feeder Out-Of-Service
- Case 4B AS/A2001 North Main Feeder Out-Of-Service
- Case 4C AS/A2002 Railroad Feeder Out-Of-Service
- Case 4D MAS/M3006 N. Mountain Feeder Out-Of-Service
- Case 4E MAS/M3009 Morton Feeder Out-Of-Service
- Case 4F MAS/M3012 S. Mountain Feeder Out-Of-Service
- Case 4G MAS/M3015 Wightman Feeder Out-Of-Service
- Case 4H OKS/K4056 HWY 99 Feeder Out-Of-Service
- Case 4I OKS/K4070 HWY 66 Feeder Out-Of-Service

The Power Flow analyses performed for the conditions noted above identified the system configuration voltage drops, load balance, real and reactive power flows, and system losses at system buses as labeled. The results presented in the Power Flow Chapter detail the analysis output reports.

Short Circuit Analysis: A short circuit analysis was performed under the Base Case configuration to update the maximum fault availability throughout the system. The results are presented in the Short Circuit Chapter with detailed fault data examples and analysis output reports. The short circuit ratings for all equipment were evaluated for adequacy based on the expected maximum short circuit currents.

Protective Device Coordination: The system coordination and protection were evaluated using the system model developed for the power flow and short circuit calculations. A time-current curve coordination chart showing the devices listed below is presented for each distribution feeder:

- Transformer damage curve
- Conductor or insulation damage curve
- Maximum available short circuit symmetrical and asymmetrical fault current
- Time-current curves of primary protection devices
- Time-current curves of secondary protection devices
- Time-current curves of major backbone protection devices

The results are presented in detailed tabulation with recommended settings for existing protective devices. In addition, analyses of coordination charts and recommended protective device changes that will improve system reliability are provided. The development of a fusing application guide for the sizing of downstream fuses is also provided.

Renewable Energy: The City of Ashland has a Climate and Energy Action Plan (CEAP) implemented. Transition to clean energy by adopting electric appliances and electric vehicles is a major part of the CEAP. The study discusses the existing situations of the City's policy, program, load profiles, and challenges, and provides an overview of potential actions that can be taken to prepare the electrical infrastructure for future increased distributed renewable energy programs and steps to align system planning with the City's CEAP to a practical extent.

Prepare Electric System Master Plan Report: A report summarizing the results of the study is provided that includes:

- Documentation of references, planning criteria, related calculations, computer reports, and techniques used in the analysis.
- Analysis and evaluation of the existing electric system, identification of alternative improvement options and suggested areas that need focused attention.
- A list of conclusions, recommendations, and proposed system improvements with projected construction timing and estimated costs.
- System maps and analysis plots showing the configurations and results of the various study cases, including recommended system improvements.

Chapter 2 EXECUTIVE SUMMARY

2.1 GENERAL

The City of Ashland's is presently serving approximately 12,817 customer meters. The City's electric service area is surrounded by the Pacific Power (PacifiCorp) Medford service region.

All electric power sold by the City of Ashland is provided by Bonneville Power Administration (BPA) and transmitted through PacifiCorp's 115 kV transmission system. The City owns and operates its distribution facilities (12.47/7.2 kV) and takes service from three substations:

- Mountain Avenue Substation, which is now City-owned and was purchased from BPA in March 2023. Mountain Avenue serves four (4) City distribution feeder circuits and has two (2) spare positions.
- Ashland Substation, which is owned and operated by PacifiCorp, feeds a City-owned distribution facility serving four City feeder circuits.
- Oak Knoll Substation, which is owned and operated by PacifiCorp, feeds three (3) City-owned distribution feeder circuits.

Over the last 10 years, PacifiCorp has made improvements to the transmission system serving the City of Ashland. The City's electric system is now served by a looped 115 kV transmission system with multiple backup sources. The transmission source to these substations is fed from a ring bus at PacifiCorp's Baldy Switching Station located in the Medford region. Line 19 originates at the Baldy Switching Station and is then tapped becoming Line 82, providing service to PacifiCorp's Oak Knoll Substation and continuing onto PacifiCorp's Ashland Substation. Between Oak Knoll and Ashland Substations, the line is again tapped to serve the BPA short transmission circuit feeding the City-owned Mountain Avenue Substation. Alternate transmission sources are available to the Ashland area from PacifiCorp's Copco 2 and Sage Road facilities. In addition to the two substations, PacifiCorp owns and maintains a few distribution poles in and adjacent to the City's service territory and city limits.

The City's distribution system (12.47/7.2 kV) consists of 52.7 miles of overhead three-phase and single-phase primary circuitry; and 79.5 miles of three-phase and single-phase underground primary circuitry. A high-level view of the City's electric distribution feeder system and service territory is shown in Figure 2-1 and Figure 2-2, respectively.

In 2023 the City eliminated a substantial portion of the BPA Transfer Service Delivery Charge per-kW-per-month for power delivered at 12.47/7.2 kV by taking ownership of the Mountain Avenue Substation. This change established a 115 kV point-of-delivery transmission tap with BPA's transmission line along Mountain Avenue that extends to the PacifiCorp circuit at the Nevada Street intersection.

The City continues to have an exclusive power purchase agreement with BPA based on energy and peak demand, and BPA has a General Transfer Agreement (GTA) with PacifiCorp for the use of their transmission and substation facilities. The City pays $1.12 per kW per month for delivery at 12.47 kV at Ashland and Oak Knoll Substations. Delivery charges, substation ownership, and transmission improvements are further discussed in Chapter 5.

There is a strong correlation between ambient temperature (high and low) and peak loading on the City's electric system. Evaluation of the electric system's load data indicates that its most recent peak was 45.9 MW, which occurred in June 2021. In the evaluation period from 2004 to 2013, the highest system peak was 43.5 MW, and occurred in December 2013. Recent demand records show that the City now has more of a summer peak pattern. We recommend the City continue to monitor summer peak demands as equipment ratings under summer conditions should not be overloaded and equipment (e.g., cables) full-load ratings are lower than under winter conditions due to the inherently higher ambient temperature in the summer. Historical data, weather trends, and future system growth are further discussed in Chapter 3.

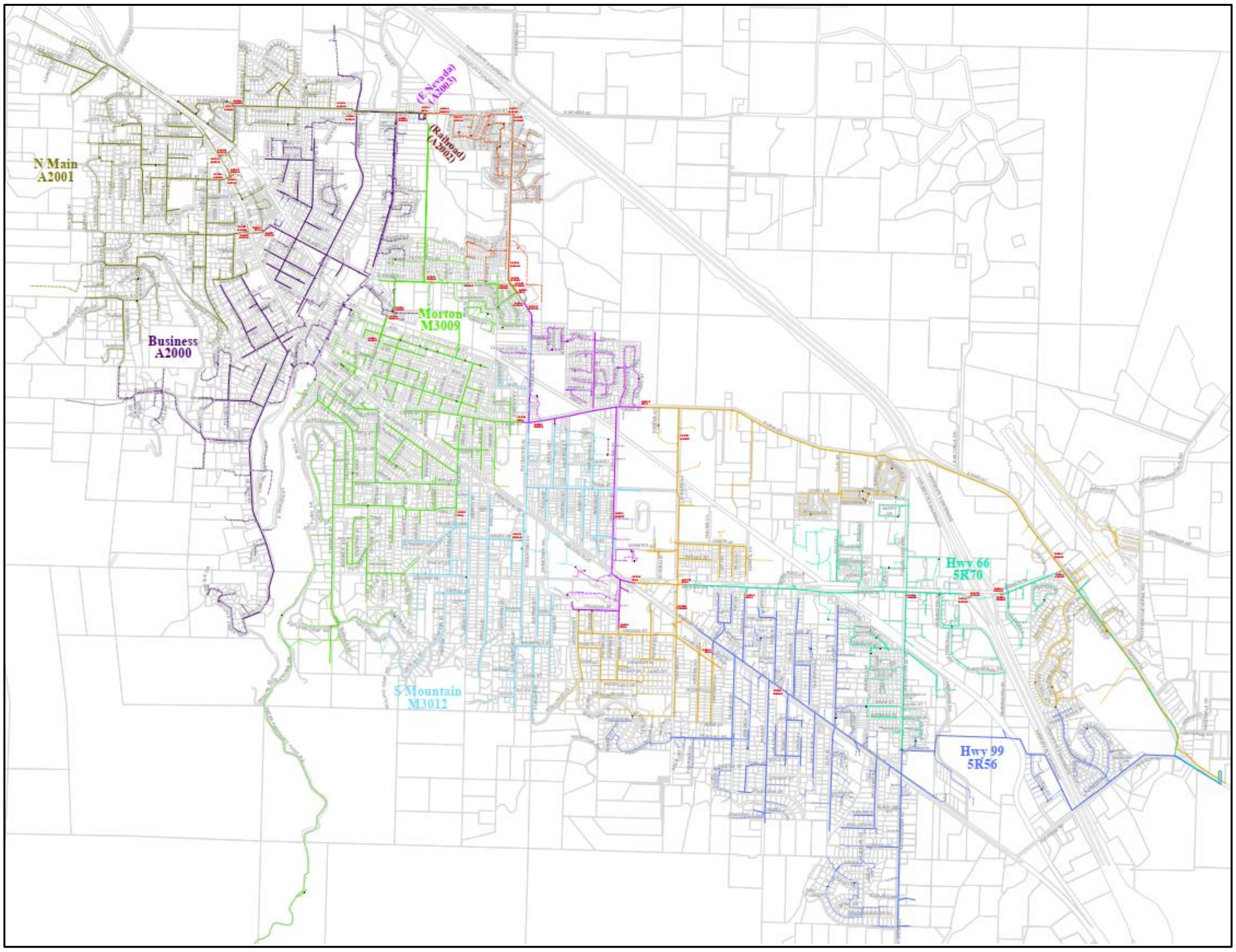


Figure 2-1: City of Ashland Electric Distribution Feeder System Map

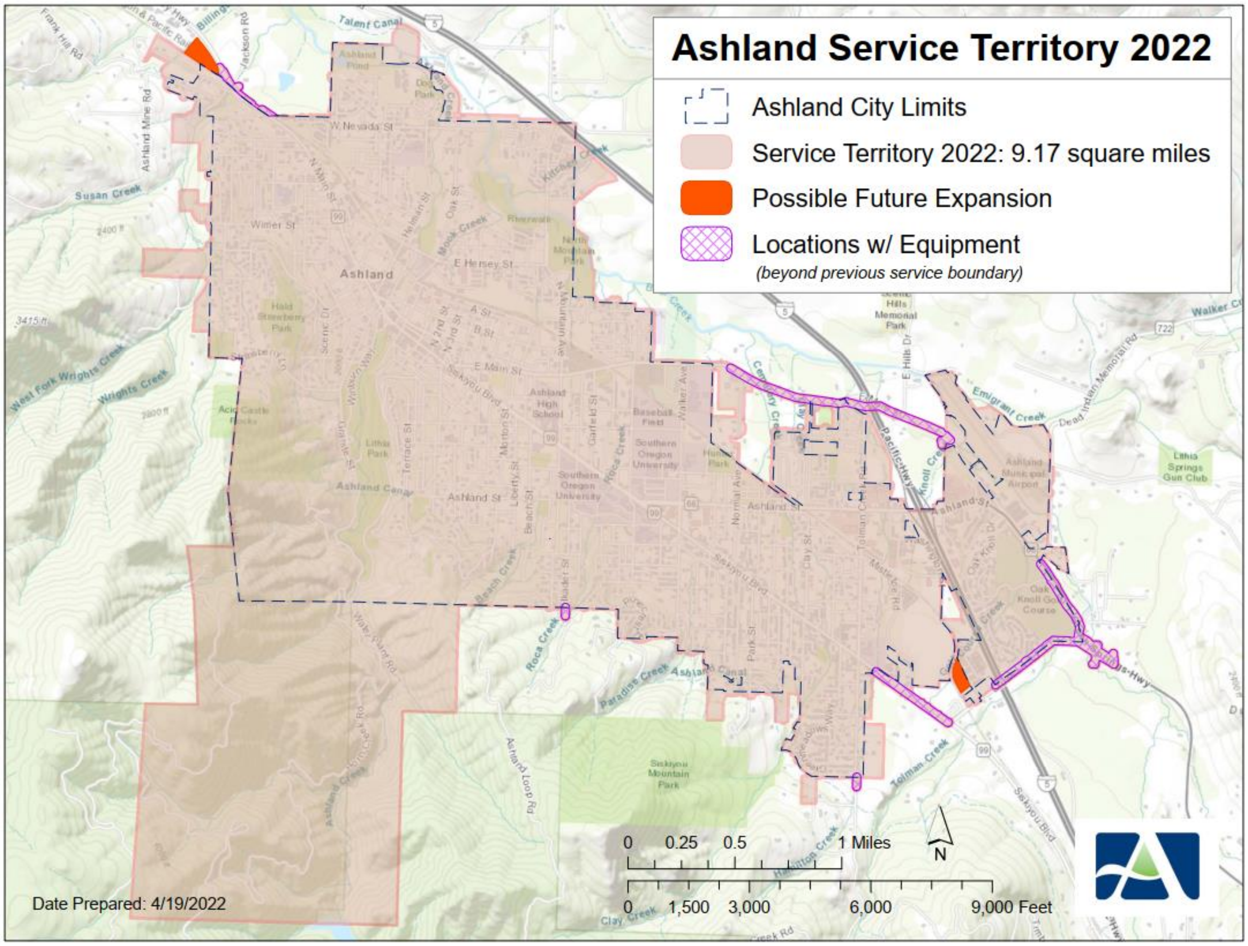


Figure 2-2: City of Ashland Electric System Service Territory

Ashland's annual energy usage from 2003 to 2023 was around 175,000 MWh with an approximate 5,300 MWh (or 3%) standard deviation. A slight decreasing energy useage trend appeared in the last two years, partly because only 2/3 of the Mountain Avenue Substation load was captured due to a blown PT fuse from June 2022 through September 2023. Additionally, there has been an increase in PV installations around the City that may be contributing to the decrease. Overall, the relatively consistent annual energy use indicates that there is an unlikely potential for a new summer or winter energy consumption peak until an extreme cold or hot weather event is experienced. Presently the City's electric system infrastructure is sized adequately to serve expected peak system loads.

Based on available system load data and the assumptions used for this study, there is sufficient substation transformer and distribution system circuit capacity to serve the City's expected peak demand load through 2033, under normal operating conditions. However, the loss of any single major system component ('single-contingency' failure condition) could result in a reduction of the overall system capacity to below the capability to serve potential historic peak demand. Single-contingency limitations and concerns are described in greater detail in Chapter 5 and Chapter 7.

The conclusions and recommendations throughout the remainder of this section are based on the overall goal of maintaining adequate substation capacity, and a flexible distribution system available to reliably serve existing and future projected loads.

2.2 MAJOR IMPROVEMENTS SINCE THE 2013 SYSTEM STUDY

In the 11 years since the previous study, some significant electric system changes have taken place that improved service and reliability to the City's electrical department customers. Major improvements are listed below.

2.2.1 Transmission

PacifiCorp's upgrade from the 69-kV source at Ashland Substation to 115-kV significantly increased the capacity from that source. Additionally, other PacifiCorp Medford regional area transmission system upgrades and reconfigurations enabled other strong backup sources to the Ashland transmission loop.

2.2.2 Substations

Mountain Avenue Substation

The City's purchase of the Mountain Avenue Substation from BPA is a significant adjustment in power transformation charges for the City. It will now allow the electric system to expand, monitor, and improve facilities at this substation as deemed necessary. Although the City had previously owned the 12.47/7.2 kV distribution facilities at this substation, they now own the property, all high-voltage components, and the control building. Suggestions for operation and maintenance improvements at this site include:

a) One-day training session by a capable engineering group for City staff and crews that will operate and maintain this facility. Training should include:
   - Explanation of the existing facility's purpose and function (control building to yard)
   - Review of all substation design drawings
   - Major equipment monitoring and routine service
   - Functional operation of all components

b) Preparation of a complete inspection and maintenance schedule for both City staff and services to be performed by contractors.

c) A proposed timeline schedule for equipment retirement and replacement.

d) Recommendation for adding a second transformer bank with primary protection, regulation, and completion of the remaining two distribution feeders. This improvement along with distribution system circuit configuration modifications will allow the City to transfer considerable load from PacifiCorp substation(s) to the City-owned Mountain Avenue Substation, giving the City more control over their facilities and saving power purchase costs by eliminating wheeling some power through PacifiCorp substation facilities.

e) The City should be aware that the existing transformer was manufactured in 1976 and was installed used. The estimated remaining service life is approximately 20 years. However, obtaining a new transformer will require development of a purchase document and technical specification, time for suppliers to propose, bid reviews, evaluation and award recommendation, manufacture, and delivery. In today's market conditions, this process could take up to 5 years to obtain a new transformer.

Ashland Substation

The PacifiCorp-owned Ashland Substation (also known as Nevada Street Substation) contains a City-owned distribution rack originally constructed in the 1950/60s which has undergone several modifications during its existence. Although functional, by today's standards the rack could be considered outdated and somewhat of a liability.

In 2012 the City converted an existing City-owned building near this substation to a control facility and installed new microprocessor multifunctional circuit controllers for all 4 feeders. This improvement gave the City control and monitoring capability of these feeders from the off-site control building, and remote monitoring capability via its SCADA system.

In 2015 consideration was given to replacing the aged City-owned distribution facilities inside the PacifiCorp Ashland Substation with a City-owned substation directly across Nevada Street on City-owned vacant property. This location seemed ideal since two looped transmission sources exist directly outside the lot and the new facility could easily tie into the existing four City distribution feeders.

Preliminary layout and rendition drawings were created for both open-rack and metalclad-style substations. Although this improvement would give the City control over the substation and distribution facilities and save power purchase costs by eliminating wheeling through PacifiCorp's Ashland Substation facilities the concept was not pursued further.

As the City's existing distribution rack in the PacifiCorp Ashland Substation yard continues to deteriorate the City may want to reconsider building a new substation as described above at this existing City-owned site.

Oak Knoll Substation

In 2014 the City installed pole-mounted recloser controllers adjacent to the PacifiCorp Oak Knoll Substation giving the City control of its three distribution feeders served from this substation, and it also provided the City with monitoring and control capabilities of these feeders from outside the substation via its SCADA system.

2.2.3 Distribution

- In 2018 the electric department revised and updated both the commercial and residential New Service Application forms.
- In 2018 the electric department's Supervisory Control and Data Acquisition (SCADA) System situated in the dispatch center was upgraded to a new Ignition software platform to improve the monitor and control capability of distribution feeder circuits, field reclosers and capacitors, including the Reeder Gulch Hydro facility. This improvement offers the City the ability to monitor and document system performance in real-time, identify and prevent potential problems, and assist with troubleshooting when necessary. The City should further expand the SCADA system to include monitoring of the newly acquired Mountain Avenue Substation 115 kV protection devices.
- In 2019 the City installed underground construction consisting of multiple conduits and vault system from the Mountain Avenue Substation along Hersey Street to N. Main Street for future installation of major backbone circuits and lateral taps.
- The electric department is currently implementing several fire mitigation activities, such as potential fuel clearing, installation of composite poles in lieu of wood poles, fuse spark

inhibitor products, and many other devices in accordance with the recommendations in the recent (2022) Wildfire Mitigation Plan.

- In 2023 the Electric Service Requirements (ESR) manual was upgraded to conform with City and neighboring PacifiCorp policies on system interconnection and service construction standards for internal, developer and contractor use.
- The City installed self-supporting steel poles for the East Main I-5 feeder crossing east and west of the interstate highway.
- The City installed self-supporting steel poles with recloser protection, monitor and control capability of the three distribution feeders directly outside the PacifiCorp Oak Knoll Substation.
- The City installed a new underground circuitry interconnection with various solar projects on the SOU campus and major PV developments within the City's service territory.
- The City completed several underground conversions and cable replacements, strengthened circuit intertie connections, and looped circuits to serve critical customers.

2.3 COMMENTS & RECOMMENDATIONS

In general, we recommend the City's electrical department adopt the planning criteria and implement the system improvements as presented in this report and specifically noted in Table 2-1. Improvements should be made as necessary to economically serve the actual load, while at the same time meeting prudent service quality and reliability standards.

We recommend that the electrical department review and update this report approximately every five years to confirm that decisions regarding improvements are based on current system conditions. All new facilities should be constructed in accordance with the latest expansion plan to ensure that no facilities become obsolete early in their service lives.

Specific recommendations resulting from this study are intended to meet normal load growth requirements and resolve specific operating deficiencies. All cost estimates shown are in 2024 dollars and are based on work performed by a contractor after competitive bidding unless otherwise stated.

It should be noted that some of the recommended improvements are already in progress and other recommendations do not have a fixed timeline or cost associated with them. In some instances, the work associated with the improvement is expected to be performed by the City's electrical department staff and line crew as part of their ongoing maintenance activities. In other instances, costs cannot be accurately estimated until the scope of the improvement to be undertaken is refined.

Transmission

With PacifiCorp's facility improvements made over the last several years, the transmission sources and system are now capable of serving the entire City's electric load for the foreseeable future. The existing multiple source configuration and available backup transmission paths will provide the City with adequate service integrity and reliability into the long-term future.

Substations

As discussed in Chapter 3 and Chapter 7, sufficient substation capacity is currently available to serve the City's expected peak loads for the next 10 years under normal operating conditions.

However, the loss of any single major system component under high load conditions can create the potential for overloading portions of the system and creating extended outages for electric customers.

The failure of a transformer at either the Mountain Avenue Substation or PacifiCorp's Ashland Substation during a peak load condition could create severe transformer overload conditions on the remaining in-service substation transformers.

A prioritized list of recommended substation-related improvements and budgetary cost estimates are presented in Table 2-1 of this Chapter. Major recommendations related to the substations serving the City include:

- Purchase and install one 115 -12.47/7.2 kV, 15/20/25 MVA power transformer as the second transformer bank at Mountain Avenue Substation to increase the capacity to serve load and reduce reliability on PacifiCorp's facilities, while at the same time reducing power purchase costs.
- Perform staff training for operation and maintenance of all facilities at the Mountain Avenue Substation as outlined in this report.
- Prepare a comprehensive inspection and maintenance schedule for the Mountain Avenue Substation for services to be performed by City Electric Department staff and contracted service providers.
- Consider retiring the existing City-owned distribution rack at PacifiCorp's Ashland Substation and constructing a new City-owned Nevada Street Substation at the City-owned property as described above.

Distribution

Based on the projected peak for 2033, all City-owned distribution system components have sufficient capacity at this time. The electrical department has strengthened some feeder backbone conductors and feeder tie circuits over the last several years. However, as load is added and growth occurs feeder and conductor loading should be monitored to ensure spare capacity remains and is available when load transfers become necessary.

Transferring certain feeders at peak load will become problematic in the next ten years, particularly during summer peak loading because equipment's summer ratings are lower than their winter ratings.

Recommended distribution system improvements are also listed in Table 2-1. Major recommendations related to the distribution system include:

- Monitor and balance existing feeder loading to minimize phase imbalance.
- To enhance the City's wildfire mitigation activities the electric department might want to consider implementing the following practices:
    - Replacement of fuses and installation of S&C TripSaver devices on circuit taps in wooded areas of the distribution system.
    - Installation of S&C VacuFuse devices to cover fuses and prevent sparks and hot debris from potential fire-causing blown fusses, particularly on transformer protection fuses on circuit taps in wooded areas of the distribution system.
- The electric department may want to consider updating its existing customer metering technology by implementing an Automated Metering Infrastructure (AMI) system that can

telemeter customer usage data directly to the electric and water departments plus billing department collector system, consistent with industry-standard smart metering trends.

- Automatic Meter Reading (AMR) is an automated technology used to collect consumption, diagnostic and status data from electric, gas and water metering devices. The AMR system transfers this data to a central database for billing, troubleshooting and analysis. Over the past several decades, most utilities have integrated advanced metering technologies throughout their service areas. The implementation of this technology has improved customer service and helped utilities function more efficiently.
- Around the year 2000 Ashland installed the Itron automatic meter reading (AMR) technology, including Itron drive-by or hand-held encoder receiver transmitter (ERT®) devices to gather metered data used for customer billing. While this technology has been effective for that purpose, utilities are increasingly finding that one-way communication networks limit their ability to support advanced customer and operational applications, and that benefits of two-way communications capability is preferred.
- One option to upgrade the existing City metering is to adopt the Tantalus TRUConnect multi-purpose utility platform, which will enable Smart Grid applications for monitoring and control of electric, water and gas utilities. This two-way AMI communications platform supports a variety of high-value utility applications which can include:
  - Advanced Metering Infrastructure (AMI)
  - Closed Loop Voltage Reduction (CLVR®)
  - Outage management
  - Remote connect/disconnect
  - Prepay of electric power
  - Power quality analysis
  - Load management
  - Revenue assurance
  - Reliability analysis
  - Asset management
  - Streetlight control
  - Net metering
- For the City of Ashland, which has a large investment in ERT technology in its existing metering system, there is a process to enable advanced applications while continuing to leverage the ERT assets. The TRUConnect ability will allow the City to build on its existing AMR groundwork to take advantage of operationally efficient advanced applications at a fraction of time and cost of a full system replacement. The system is designed to be strategically deployed as determined by the utility, since Tantalus and Itron have developed solutions to help mitigate full system replacement costs.
- The solution developed by Tantalus and Itron would deploy TUNet network infrastructure over Ashland's complete service area or a specific strategic

geographic area by replacing a percentage of electric meters. Typical full ERT overlay deployments involve a replacement of 15% to 20% of the existing electric meters without the need to replace any ERTs on the water meters. Further information on this matter should be requested from the Itron/Tantalus NW representative.

Table 2-1: Recommendations

Item	Description	Estimated Cost (2024)
General System		
G-1	The City should consider the future of Electric Vehicle (EV) impact on the distribution facilities by increasing transformer capacity in new developments. An estimated 5 kW per resident should be allocated when sizing new transformers. The EV charger minimal use time will impact transformer energy losses which must be paid for by the serving utility (City of Ashland) and will likely impact future electric rates.	NA
G-2	Self-healing distribution systems may be desirable in the near future, especially in highly congested downtown areas. Although such sectionalizing systems are currently available they may not be cost-effective. To minimize downtime due to faults, many utilities now utilize automated fault interrupting and sectionalizing switches with SCADA system interconnection at critical distribution locations. The City may want to evaluate the use of these devices for 'self-healing' (automated restoration) of the distribution system at key locations. The cost estimates provided include all equipment and installation costs per switch. This will require SCADA communication interconnection which should be easily implemented.	$75,000 Overhead Mount $150,000 Pad Mount
G-3	Consider an update to the previous Arc-Flash Study (2010) to bring it into compliance with present standards.	$7,500
G-4	Consider an update to the previous Spill Prevention Control and Countermeasures Plan (SPCC) to bring it into compliance with present standards.	$4,200
G-5	The City may want to consider modifications to the Distributed Generation Interconnection Control Ordinance. These changes could regulate how low-voltage generators are connected to the City's distribution system. The language should require that interconnection control must be in accordance with IEEE and NEC standards. New technology has advanced distributed generation devices to the point where their installation is common, however because of the potential for these devices to cause system disturbances that can affect sensitive customer loads and the overall system performance, the adoption of this change will allow the City to take the appropriate action should policy violations occur. The inclusion of this type of interconnection control and net metering language may require modifications to the existing Electric Ordinance.	NA
G-6	The potential upgrade of the City's customer revenue metering could be considerably enhanced by implementing new AMI devices that can interact with the existing meters and then transmit metered data onto the City's billing department collective system. In addition to monitoring usage, the system revisions would include the capability to provide outage notifications, and have remote disconnect and reconnect capabilities.	TBD
G-7	<u>System Development Charges</u> We recommend that the City evaluate its policies and procedures concerning the review and assessed fee schedule for system development construction. It is important that City develop service and construction standards to cover typical system developments and apply these standards consistently. The city's fee schedule of charges to developers should include all City-related costs as well as necessary engineering services required for design, review, and services during construction. The fee structure should be periodically reviewed to maintain comparable charges with similarly sized municipalities.	NA

Item	Description	Estimated Cost (2024)
G-8	The City has an electric system map with most of the data up to date. However, there is missing information on conductors and protective devices including fuses (size and type) and pad-mount switchgear settings. We recommend the City continue the practice of updating information into its distribution mapping system so all the information reflects the field's as-built conditions and can be readily available for line assessment, system troubleshooting, future planning studies, as well as component inventory database.	Normal Maintenance Activity
Transmission System		
T-1	The City's crew should be trained regarding service and maintenance on the high-voltage primary switching sequence to de-energize and re-energize the substation equipment at Mountain Avenue Substation.	(see S-1)
Substations [MAS = Mountain Avenue Substation, AS = Ashland Substation, OKS = Oak Knoll Substation]		
S-1 (MAS)	The City should conduct a staff training session for the operation and maintenance of all facilities at the Mountain Avenue Substation as outlined in this report as soon as possible. This training should be provided by a qualified engineering service provider who has experience in such activities.	$7,500
S-2 (MAS)	The City should have a comprehensive inspection and maintenance schedule created for the Mountain Avenue Substation describing services to be performed by City staff and contracted service providers. This schedule should be prepared by a qualified engineering service provider that has experience in such activities.	$7,500
S-3 (MAS)	Now that the City owns Mountain Avenue Substation it should consider installing an online gas-monitoring system on the existing power transformer to continuously monitor transformer health. Sensor capabilities vary widely but could allow the City to monitor up to eight critical fault gases in addition to moisture. It can be installed while the unit remains in service and is field-based, requiring no manual oil sampling or lab testing.	$7,500 Base Unit $25,000 Unit With Pump
S-5 (MAS)	The City should have a Bid Procurement Document and Technical Specification prepared for the purchase of a second bank transformer at the Mountain Avenue Substation. The transformer should be rated 12/16/20 MVA or 15/20/25 MVA suited to complement the intermediate replacement of the existing transformer. It is estimated this process could take 5 years from onset until a transformer is placed on the foundation pad. The preparation of this document, advertisement, bid activities, evaluation and award should be performed by a qualified engineering service provider that has experience in such activities.	$1,350,000 Transformer $750,000 Construction
S-6 (MAS)	To coincide with the addition of a second transformer bank at Mountain Avenue Substation as described in improvement S-5, the City should have the necessary design prepared to implement the new transformer. This will require a Construction Document consisting of Bid Documents, Technical Specifications and Drawings, and should be performed by a qualified engineering service provider that has experience in such activities. It will entail procurement of all necessary equipment and contractor services for construction and installation activities.	$150,000

Item	Description	Estimated Cost (2024)
S-7 (MAS)	With improvements S-5/6, to shift load onto the City owned Mountain Avenue Substation, the City should construct the two remaining available feeder circuits out of the Mountain Avenue Substation. The circuits should be installed, and existing Mountain Avenue Substation feeders adjusted to shift load off the Ashland/Oak Knoll circuits and place greater load on the Mountain Avenue Substation. The cost estimates assume underground conductors installed by City crews in existing ducts and vaults. Each underground feeder cable construction is estimated to be 6,000-feet at $30/ft for all material and labor including any line extensions and sectionalizing switchgear.	$200,000 (each feeder)
S-7 (MAS)	The existing transformer protection at Mountain Avenue Substation only has one level of phase and neutral overcurrent protection. We recommended that the City consider adding a transformer differential protection relay for improved transformer protection. At the same time the City should consider including monitor and control of the substation high-voltage circuit switcher and protective relay devices into the SCADA system.	$15,000 Engineering $25,000 Material and labor
S-8 (AS)	The City should consider the retirement of the City-owned distribution rack located in the PacifiCorp Ashland Substation. An ideal replacement would be construction of a new substation located on the City-owned property directly across from this facility on Nevada Street. This location has looped transmission circuits adjacent to the property and could easily interconnect with the existing distribution feeder circuits. Substation concept renditions have been previously prepared and could be pursued or modified as needed, Followed by planning department approval, necessary design, equipment procurement, and contractor construction. Again, it is estimated this process could take 5 years from onset until a transformer is placed on the foundation pad	$3,000,000 Engineering, Transformer, Construction
S-9	At all substations, implement a periodic (5-year) microprocessor relay testing, calibrating, and maintenance program.	Normal Maintenance
S-10 (MAS)	The existing bank 1 power transformer was fabricated in 1976 and installed ‘used’ at Mountain Avenue Substation. Because of the age and expected service life of this transformer the City should plan for its replacement at some point.	$20,000 Engineering $1,350,000 Transformer
Distribution System		
D-1	The City should continue to implement activities and materials as noted in the Wildfire Mitigation Plan, especially in the heavily wooded areas of the City’s western service territory.	Normal Maintenance Activity
D-2	As load increases, rebalance existing loads as necessary to maintain equal distribution of loading to the extent possible, under normal operating conditions. Balance phase loading on each phase as practical and ensure sufficient feeder capacity is available under system tie configurations.	Normal Maintenance Activity

Item	Description	Estimated Cost (2024)
	We recommend that phase imbalance on all feeders be monitored under peak load conditions. If imbalance on the listed feeders exceeds 15%, action should be taken to shift load and reduce imbalance to below 10%.	
D-3	To standardize construction practices the City should confirm the use of existing overhead conductor sag and tension construction stringing charts for multiple conductors and conditions based on NESC Zone 2 Loading District. These charts are based on calculations and specific weather criteria to ensure consistent installation standards for the mid-valley region.	Existing Sag-Ten Tables
D-4	The City should target 500-1000 feet of aging bare concentric neutral cable per year for replacement in addition to replacing segments as they fail. These bare neutral cables are known to corrode leading to potential public safety issues as well as voltage problems due to loss of neutral return.	\$100/ft \$50,000-\$100,000
D-5	The City should consider and continue the practice of adding overhead and underground fault indicators on feeder main backbones to assist in location of faults.	\$150 each
D-6	For underground facilities, where applicable, fused elbow connectors in vaults or at equipment can help isolate circuit taps and minimize the number of customers experiencing interruptions or outages. The City may want to consider installation of fused load-break elbows at specific backbone circuit taps or major tap locations presently not sectionalized. See Section 9 for further discussion of pad mount distribution equipment	\$350 per Elbow \$250 per Fuse
D-7	The City should ensure that all crew members have sufficient knowledge and training regarding pad-mounting sectionalizing equipment operation and tap interruption restoration.	NA
D-8	Depending on the load distribution, some of the backbone fuses, 140K and 100K, along the Ashland/Business feeder are recommended to be monitored, as they will likely exceed their rated capacity. The City should monitor the through load and make necessary adjustments if needed.	Normal Maintenance Activity
D-9 (MAS)	Verify Feeder M3009 recloser settings and change them to be identical with other Mountain Avenue Substation feeder settings if inappropriate implementation is confirmed.	Normal Maintenance Activity
D-10	The City should consider conforming to pole testing requirements by having poles tested every 10-12 years, or test approximately 10% each year. For poles that have not been inspected for some time, it is suggested primary circuit poles receive a full intrusive inspection, which includes excavation around the pole to a depth of 18", and inspection of the pole exterior for decay and treatment with a boron/copper-based product to prolong pole life. Testing should include sound and bore to determine if the pole has any voids. If voids are present the pole should be treated with a copper-based product to slow decay. Poles with extensive decay and not serviceable should be rejected. The poles should also receive a periodic visual inspection for obvious signs of damage or decay.	\$100/Pole Est.

Item	Description	Estimated Cost (2024)
D-11	The City should consider having an infrared thermal imaging investigation performed on all substation and switching station equipment and on all primary circuit overhead pole assemblies. This service should be performed after the pole inspection, treatment and/or replacement is complete, so that the infrared inspection is performed on pole top assemblies that will remain in service.	$25/Pole Est $500/Sub Bay Est.
Renewable Energy		
R-1	The City has existing programs and policies to encourage if not require non-fossil fuel sources for house appliances and vehicles. Any reduction in non-renewable energy consumption will put the City closer to achieving the 100% goal. However, this will shift the burden of non-renewable reduction to the electric system in terms of load growth. Another approach is developing programs to incentivize energy efficiency improvements and energy use reductions, which have the highest effectiveness in reducing non-renewable energy consumption.	NA
R-2	Adding renewable generation to the City's system. This can be achieved by continuing to support community projects to add distributed generation resources. The City does not own transmission resources and has limited siting available for large-scale PV generation. As discussed in Item S-8, we recommend the Ashland Substation be expanded to a new City-owned substation to increase capacity and reliability. If a suitable site near Oak Street can be identified, adding a large PV system to the new substation development would be an option for adding the needed capacity.	NA
R-3	The City purchases all electric energy from BPA, the majority of which comes from the hydroelectric facilities in the BPA territory. As such, BPA's energy fuel mix is generally 78% to 85% renewable and an additional 11% non-greenhouse gas-producing nuclear. Therefore, only 5% to 10% of the energy purchased by Ashland is potentially greenhouse gas producing. One approach the City might consider taking to achieve 100% greenhouse gas-free energy use is simply to identify enough renewable energy such that it offsets 5% to 10% of what would have been required to be purchased from BPA.	NA
R-4	The EV increase rate is hard to predict as it depends on many factors such as various levels of incentives from the Federal, State, and City, economic, and supply chain situations. We recommend the City continue monitoring the EV registrations and charger installations in town and consider an evaluation period of every two to three years. If the growth is rapid, the City may want to consider implementing a dynamic rate structure or smart charging policy to avoid significant peak demand increase in the evening.	NA

Chapter 3 LOAD FORECAST

3.1 GENERAL

This chapter describes a load forecast developed for the City of Ashland Electric Department based on the system peak demand expected for a 1 in 10 year cold or hot weather event. Included are five-year, ten-year, and twenty-year projections covering the period from 2024 to 2043, based on BPA and Electrical Department metered data as well as information and projections provided by the following sources:

- The City of Ashland Urban Growth Boundary
- The City of Ashland Buildable Lands Inventory
- The Jackson County Comprehensive Plan
- The Oregon Office of Economic Analysis (OEA)
- Portland State University Population Research Center
- Bonneville Power Administration Customer Portal
- PacifiCorp
- United States Census Data
- The Public Utility Commission of Oregon
- National Oceanic and Atmospheric Administration (NOAA) Climate Data Online Search

The load forecast projections and assumptions are the result of population growth and weather experienced during the period from 2013 through 2022. The analysis shows a strong correlation between temperature and system power demand for both cold and hot temperatures.

3.2 HISTORICAL OPERATING SYSTEMS

The City of Ashland's customer base has grown approximately 2.3% from 2003 to 2023 but has slowed in the last 10 years. Now the City serves approximately 12,817 customers.

- From 2003 to 2013, customer growth was from 10,100 to 12,705, ~2.3% annual growth rate.
- From 2014 to 2023, customer growth was from 12,705 to 12,817, ~0.09% annual growth rate.

In the 2003 study, it was noted that the City of Ashland's historical maximum system peak, 44.6 MW, occurred in December 1990. In the evaluation period from 2004 to 2013, the highest system peak was 43.49 MW, and occurred in December 2013. Per the metered data available for the last 10 years, the electric system's maximum peak was 45.92 MW, which occurred in June 2021. This peak load was divided between the City-owned Mountain Avenue Substation, PacifiCorp's Ashland Substation (AS) and Oak Knoll Substation (OKS). The concurrent demand at each substation during the peak was 14.4 MW (MAS), 14.3 MW (AS), and 17.4 MW (OKS).

Table 3-1, Figure 3-1, and Figure 3-2 demonstrate comparisons between energy, peak demand, and population from 2003 through 2023. The population growth from 2010 to 2022 shows a slow but steady increasing pattern (~0.7% annually). There was a 0.8% decrease in 2023, however, population growth is expected to continue at a rate of around 0.63% for the next decade according to Portland State University's Population Report.

Based on the curves shown in Figure 3-1, Ashland's annual energy usage from 2003 to 2023 was around 176,000 MWh with an approximate 4,500 MWh (or 3%) standard deviation. The energy consumption has been stable over the last several years. This relatively consistent annual energy use indicates that there is an unlikely potential for a new summer or winter energy consumption peak until an extremely cold or hot weather event is experienced. Ashland's annual peak demand profile in Figure 3-2 indicates that the correlation between peak demand and population isn't strong in most of the last 20 years. The peak trends appear to be more closely linked to weather than population.

Average energy consumption typically correlates with population. Even though the population growth is expected to slow, with the City's carbon neutrality goal and Climate & Energy Action plans, the City's average energy consumption is likely going to increase due to the gradual change from fossil fuel to electric-powered appliances and electrical vehicle (EV) chargers. Therefore, energy and demand are expected to increase with fluctuations more influenced by weather in the near future (~5 years). More EV chargers are expected to be installed in the City, which will likely affect some of the feeder peak demands. However, the EV increase rate is hard to predict as it depends on many factors such as various levels of incentives from the Federal, State, and City, economic, and supply chain situations. The City should continue monitoring the EV registrations and charger installations in town and should consider an evaluation period of every two to three years due to the rapidly changing EV market.

More discussion about the load forecast can be found in Section 3.4.

Table 3-1: Population Growth, Energy Use, and Peak Demand

Year	Peak (kW)	Energy (kWh)	Population
2003	37,970	171,920,100	20,430
2004	38,330	175,293,480	20,590
2005	38,690	178,064,595	20,880
2006	39,070	180,419,455	20,974
2007	39,430	182,696,625	21,062
2008	39,800	184,296,170	20,782
2009	40,160	177,741,226	20,996
2010	40,530	168,980,735	20,078
2011	40,880	176,722,735	20,255
2012	41,260	179,815,430	20,325
2013	43,490	185,231,385	20,295
2014	38,885	173,668,763	20,340
2015	38,940	174,410,074	20,405
2016	39,940	171,240,240	20,620
2017	38,505	178,273,030	20,700
2018	38,700	173,236,580	20,815
2019	37,605	172,884,771	20,960
2020	38,195	170,324,005	21,105
2021	45,920	175,664,178	21,554
2022	40,670	173,338,189 (a)	21,642
2023	42,914	173,389,804 (a)	21,457

Notes

a) A fuse blow on the BPA metering station in Mountain Avenue Substation resulted in incorrect metering from June 2022 through September 2023. The values above include the unmetered amount estimated by BPA.

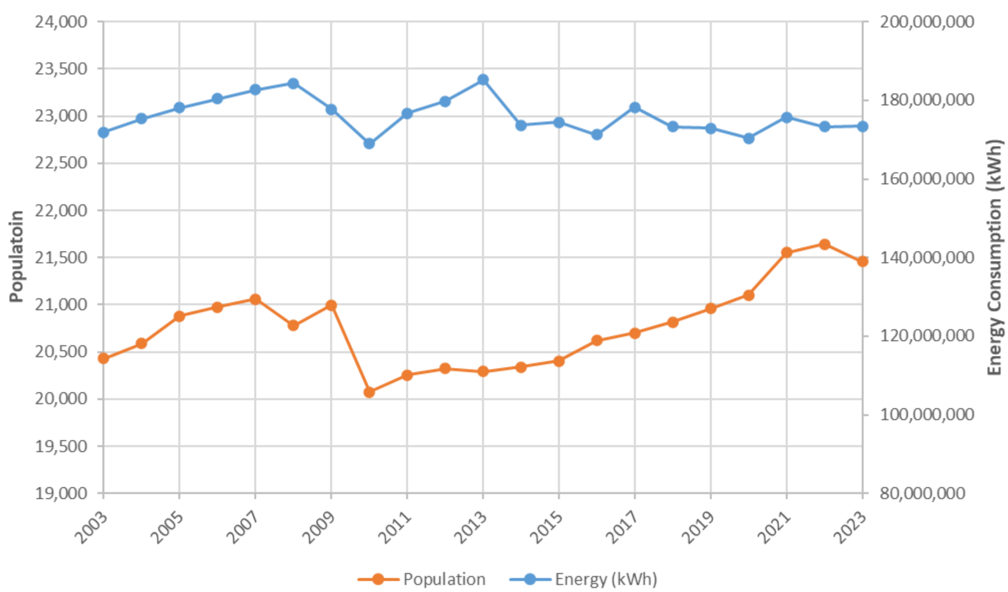


Figure 3-1: System Annual Energy Use vs. Population

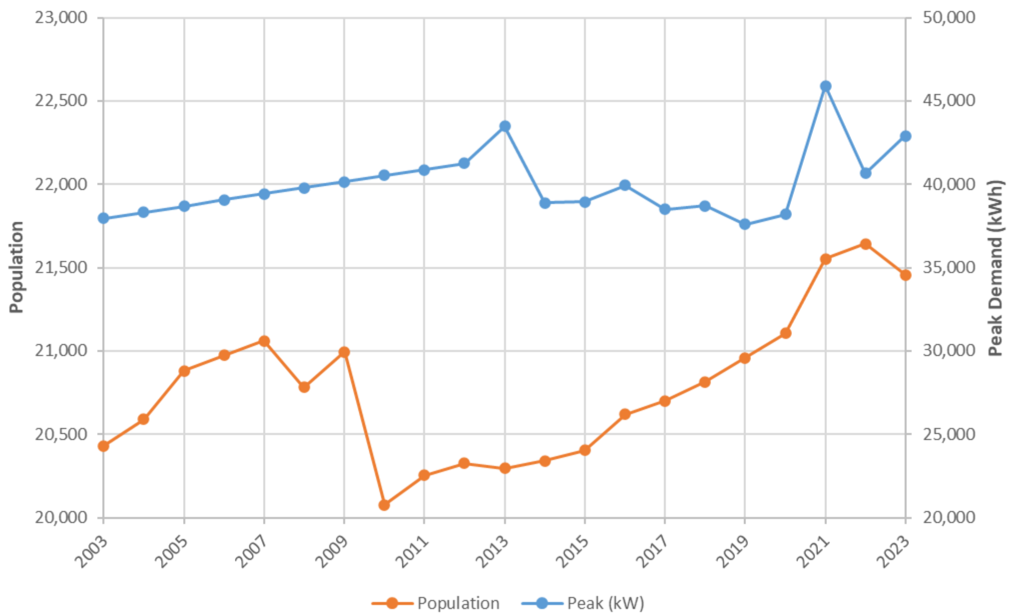


Figure 3-2: System Annual Peak Demand vs. Population

The electric systems' coincidental monthly peak demands and some statistics for the period of 2014-2023 are shown in Table 3-2 and plotted in Figure 3-3 (BPA data for 2013 is not complete). Over the last 10 years, the average peak demand had an overall growing trend with variations possibly due to a combination of changes in weather patterns and business operating profiles. The difference in energy and demand trends may also be due to the increase in PV development in the City's system which has a cumulative effect on energy but a lesser effect on demand due to the time period of demand peak being non-coincident with the PV production peak (specifically, demand peaks are generally in the morning and early evening while PV product peak is in the early afternoon).

Historically, the City's peak demands are more characterized by winter and summer peaks. Specifically, the annual peak demands in the last 10 years occurred in the summer except for 2017, in which its winter peak and summer peak were about the same (38,505 kW vs. 37,890 kW, with only a 615-kW difference). We assumed that summer peaks will continue to be the dominant yearly peak in the future with the possible exception of years with an extreme winter storm condition.

Table 3-2: Monthly Peak Demand (kW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
January	36,655	32,720	32,335	38,505	30,400	31,800	32,600	35,210	30,635	22,980
February	33,500	30,815	32,030	32,395	34,595	35,525	34,175	34,060	36,025	35,169
March	29,455	29,585	29,065	31,085	32,120	31,265	29,670	31,400	29,770	32,401
April	25,485	27,265	24,995	25,455	28,130	24,965	23,840	24,345	29,160	31,161
May	25,565	25,315	26,175	30,140	24,520	22,920	31,350	27,790	26,780	27,532
June	27,820	38,940	38,165	36,585	31,290	34,695	34,300	45,920	35,355	34,379
July	38,885	38,900	39,250	37,515	38,700	33,045	38,195	37,930	40,670	37,164
August	33,105	35,065	39,940	37,890	36,850	37,605	37,815	37,420	33,165	42,914
September	28,140	30,480	27,585	31,145	29,035	34,775	36,320	27,730	33,205	27,477
October	23,485	24,070	25,105	25,400	24,020	28,210	26,115	26,730	23,420	26,338
November	31,220	32,155	28,225	30,660	29,705	33,200	32,785	30,515	27,495	31,064
December	35,045	33,130	34,270	32,860	32,040	32,825	33,510	34,010	31,090	30,291
Average	30,697	31,537	31,428	32,470	30,950	31,736	32,556	32,755	31,398	31,572
Sum Avg.	33,270	37,635	39,118	37,330	35,613	35,115	36,770	40,423	36,397	38,152
Winter Avg.	32,860	32,498	35,057	32,618	33,122	33,200	34,260	33,557	29,746	30,773
Max	38,885	38,940	39,940	38,505	38,700	37,605	38,195	45,920	40,670	42,914

Notes:

a) Summer average includes consecutive months of June, July, and August.
b) Winter average includes consecutive months of December, the following January and February.
c) **Highlighted cells** indicate the peak demand for the associated year.

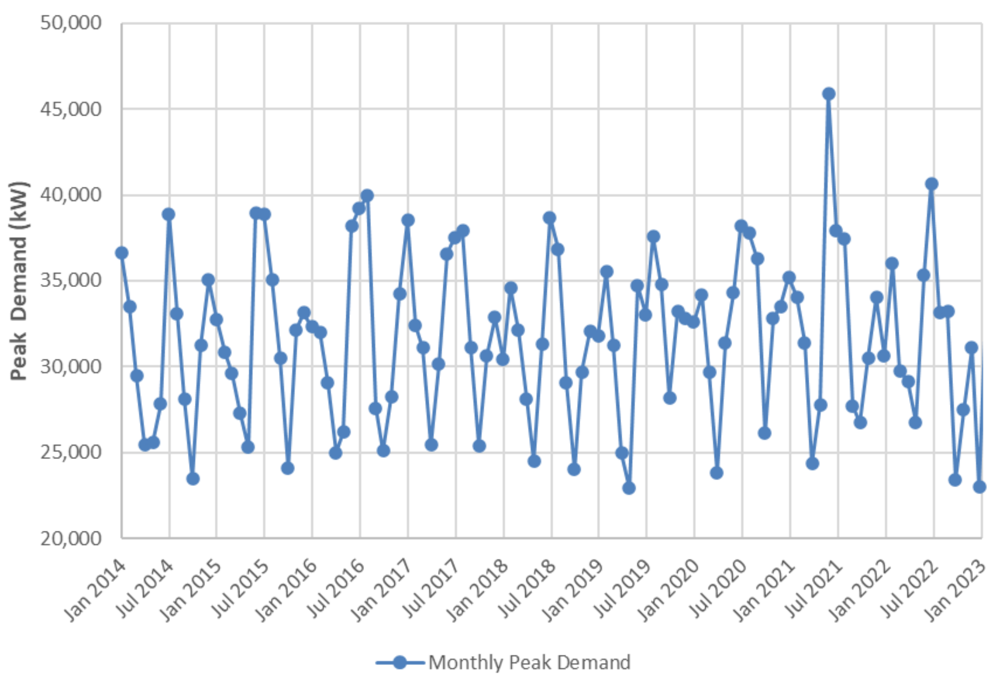


Figure 3-3: System Monthly Peak Demand

PacifiCorp Load

Table 3-3 lists the peak demands for the three transformers in PacifiCorp's Ashland Substation and Oak Knoll Substation as well as the peak demands for the Ashland loads only. PacifiCorp's loads served by these transformers are shown as a percentage and must be considered in the transformer capacity evaluation. The estimated average demand for PacifiCorp's load through Ashland Substation is approximately 4.2 MW with a peak of 5.5 MW in the past 10 years, and the estimated average demand for PacifiCorp's load in Oak Knoll Substation is approximately 6.5 MW with a peak of 9.0 MW.

Table 3-3: PacifiCorp Facility Load Data and Comparison with BPA Data

Year	Ashland Sub Total Peak Demand, PCorp Record (a) (d)	Oak Knoll Sub Toal Peak Demand, PCorp Record (a) (c) (e)	Ashland Sub, Peak Demand, Ashland Load Only (b)	Oak Knoll Sub, Peak Demand, Ashland Load Only (b)
2014	15,653	19,346	12,490	13,560
2015	17,383	25,313	14,820	15,890
2016	16,412	20,482	13,200	13,890
2017	17,463	22,528	13,830	14,890
2018	15,902	20,429	12,450	13,350
2019	15,352	19,959	17,805	15,120
2020	16,488	20,976	12,010	14,520
2021	18,602	22,979	20,775	17,260
2022	18,777	22,727	14,470	16,870
2023	17,446	21,898	12,800	14,600

Notes:

a) Based on data provided by PacifiCorp. This load includes PacifiCorp's feeder loads and Ashland's loads.
b) Based on BPA's meter data for the City of Ashland.
c) Summation of the peak demands for the two transformers (non-coincident).
d) Approximately 30% of the Ashland Substation transformer load is for PacifiCorp's load.
e) Approximately 33% of the Oak Knoll Substation transformer load is for PacifiCorp's load.

3.3 WEATHER-RELATED CONSIDERATIONS

To examine the effect of weather on system peak demand and energy use, we obtained Oregon Climate Service data from the Ashland weather station for 2013-2023. Analysis of the data for this period yields statistical 1 in 10-year cold and hot weather events of approximately 19° F and 112° F. The all-time records for this region are -20° F and 115° F respectively.

Figure 3-4 shows the heating degree days (HDD) during the winter months vs. the City of Ashland's winter energy consumption for the period of 2014-2023. The average HDD for this period is also included in the graph. Figure 3-5 shows the number of cooling degree days (CDD) and average during the summer months vs. the City of Ashland's summer energy consumption for the same period. HDD and CDD are measurements, based on outside air temperature, that are designed to reflect the demand for energy needed to provide heat or cooling for a building or home for every degree above or below 65° F.

Figure 3-4 shows that Ashland's winter energy consumption has a strong correlation with the number of HDDs in a given year for the last 10 years. The correlation coefficient between energy consumption and HDD is about 0.71 for the period from 2014 to 2023 (Note: A coefficient of 1 indicates a perfect positive relationship while -1 indicates a perfect negative relationship.). Similarly, the City's summer energy consumption and the number of CDD's in this period show a strong correlation but slightly lower correlation (Figure 3-5), with an overall correlation coefficient of 0.77.

Figure 3-6 shows the monthly mean demand plotted with the monthly mean temperature for 2014-2023. It is important to note that there are two peaks each year, one in summer and one in winter. The overall correlation between them isn't strong, however, if breaking a year into two evaluation periods, the mean demand is negatively correlated with mean temperature in winter months, and positively correlated in summer months. Also, Ashland's summer demands are relatively higher than the City's winter demand, indicating the City's customers may use air conditioning and irrigation during the summer more than they use heating in the winter. This seems to be a trend in many western Oregon regions as CDD's (or high temperatures days) are increasing in frequency and the installed AC capacity is also increasing.

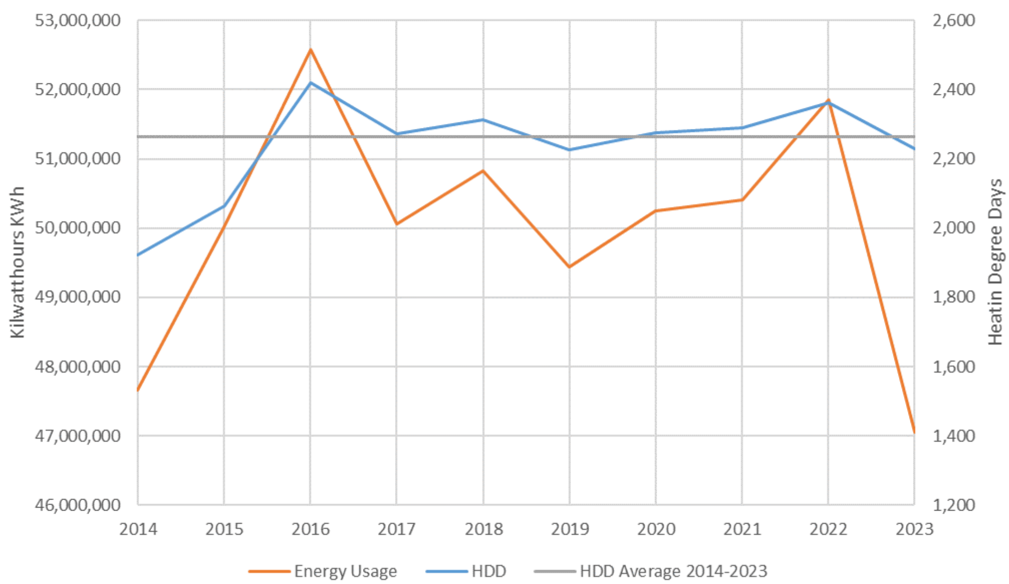


Figure 3-4: Heating Degree Days Recorded by Ashland Weather Station vs. The City's Energy Consumption

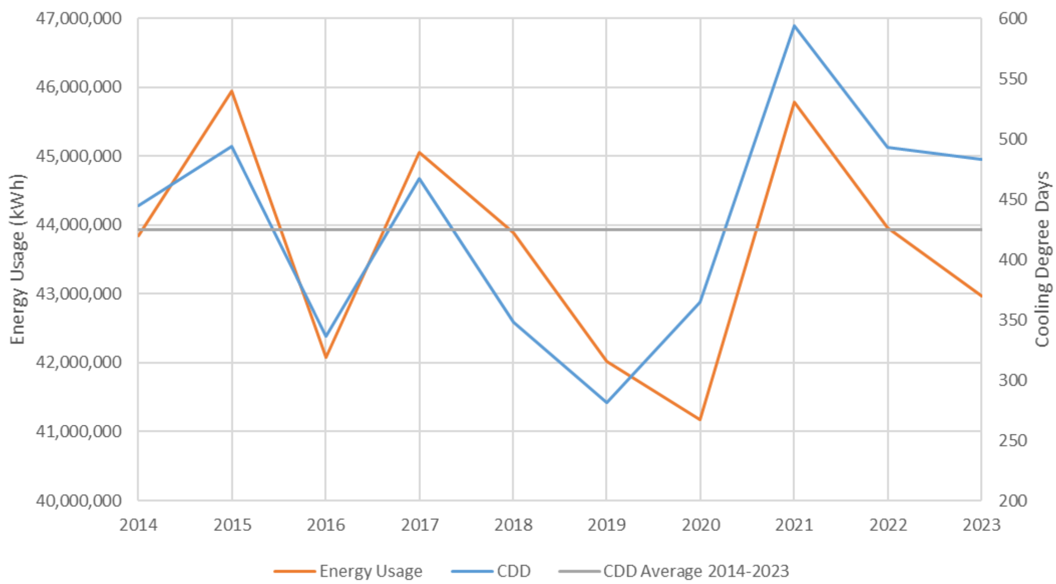


Figure 3-5: Cooling Degree Days Recorded by Ashland Weather Station vs. The City's Energy Consumption

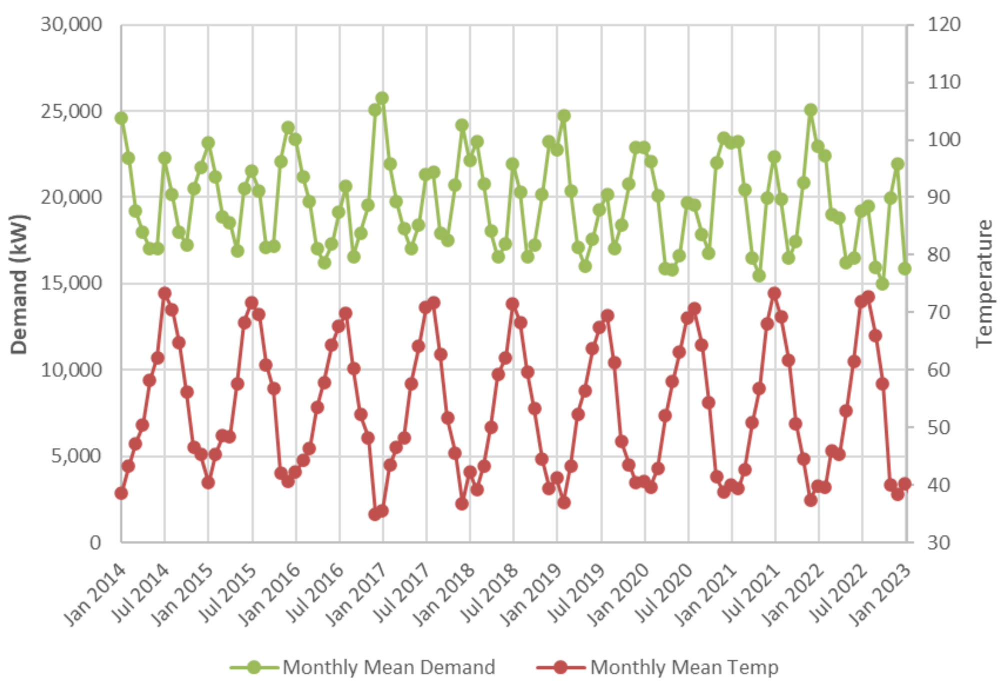


Figure 3-6: Monthly Mean Temperature and Monthly Mean Demand (kW)

Table 3-4 and Table 3-5 show the two highest winter and summer peaks for 2014-2023 with correlated minimum and maximum temperatures for the respective peak days. The June 28, 2021 peak is used as the base case for the 10- and 20-year peak load growth projections. It is assumed, but unknown, that the demand and temperature are coincidental. However, the time of day for each peak is consistent with the expected proximity to the minimum or maximum temperature.

Table 3-4: Highest Winter Peaks and Correlated Minimum Temperatures

Date	Peak (MW)	Temperature (F)
12/9/2013, 9:00:00 AM	43.5	8°
1/16/2014, 9:00:00 AM	36.7	24°
1/6/2017, 9:00:00 AM	38.5	9°

Table 3-5: Highest Summer Peaks and Correlated Maximum Temperatures

Date	Peak (MW)	Temperature (F)
6/28/2021, 5:00:00 PM	45.9	112°
7/29/2022, 5:00:00 PM	40.7 [(a)]	113°
8/14/2023, 6:00:00 PM	42.9 [(a)]	110°

Notes:

a) A fuse blow on the BPA metering station in Mountain Avenue Substation resulted in incorrect metering from June 2022 through September 2023.

3.4 GROWTH FORECASTS

Since the City must be able to serve all customers reliably under peak load, system planning, and design requirements should incorporate the Peak Demand Forecast.

The BPA annual peak forecast for the Ashland area is presented in Table 3-6 alongside the Peak Demand Forecast estimated in this study.

The BPA forecast is based on a growth rate of 0% for the next ten years. This growth rate may be reasonable, but it must be noted that the BPA forecast typically uses a 1 in 2-year weather event as its planning criteria. By design, this BPA method results in peak demand estimates that do not account for the possibility of extreme cold or hot weather events. The City’s actual system peak each of the past 10 years was higher than the BPA forecast peak for each of the next 10 years.

PacifiCorp also provided a growth forecast for its Ashland Substation and Oak Knoll Substation for the 2024-2033 period which assumes an average annual growth rate of approximately 1.0% for Ashland Substation and 0.5% for Oak Knoll Substation. According to PacifiCorp staff, this forecast is based on historical data and calculated annual growth rate using linear regression.

The City of Ashland has implemented a series of Climate & Energy Action plans to reach the carbon neutrality goal, including fuel switching, more clean energy, EVs, energy-efficient equipment/appliances, etc. Some of these initiatives are likely to reduce the peak demand and energy usage, while some will contribute to an increase. We recommend that the City base its system planning on a minimum of at least a 1 in 10-year weather criteria and assume a consistent correction between energy/demand and population. The City’s Peak Demand Forecast in Table 3-6 is based on this criterion and an annual growth rate of 0.72%. This growth rate is slightly higher than the projected growth rate in Portland State’s 2023 Population Forecast (0.6% average annual growth rate). This rate is reasonable for long-term forecasting purposes based on the City’s energy, peak demand, and population profile in the last 10 years.

Figure 3-7 shows the yearly peak demand during the past 10 years along with growth forecasts and available transformation capacity. PacifiCorp’s coincident peak data was estimated based on the data provided. Total transformation capacity is shown under various transformer cooling conditions. Transformation capacity margin of the system decreases slowly from the present to 2033 due to load growth at the forecast rate. The City's overall available transformation capacity exceeds the current and projected peak demands with a margin of about 42% capacity over the worst-case projected peak. This available margin is only available if all three substations are fully in service.

If either Ashland Substation or Mountain Avenue Substation is offline, about 24% of the overall capacity would be unavailable. The rest of the transformer capacity appears to be sufficient to support the historical and forecast peak demand with proper switching and load transfer. However, if Oak Knoll Substation is offline or any two transformers are out of service, the City's margin is greatly reduced, particularly when considering the 65° C rating of the transformers.

The individual substation peak load and forecast load profiles are illustrated in Figure 3-8, Figure 3-9, and Figure 3-10 for Ashland Substation, Mountain Avenue Substation and Oak Knoll Substation respectively.

For Ashland Substation, the combined peak loads (Ashland's and PacifiCorp's) are mostly above the transformer's Forced Air Level 1 rating (Figure 3-8). However, both PacifiCorp's forecast and this planning study's forecast for the next 10 years show the combined load could exceed the existing transformer Forced Air Level 2 rating. Even though the 65° C MVA rating provides an additional 12% capacity, we recommend the City initiate a dialogue with PacifiCorp proactively about replacing the existing transformer with a larger unit. Or consider building a new City-owned substation on the City-owned property next to the existing site. The latter option is preferred as the existing equipment at PacifiCorp's substation was built in 1960's and the new substation would provide the City with improved reliability and flexibility.

The existing transformer at Mountain Avenue Substation appears to be sufficient for the historical and forecast peak demands for the next 10 years (Figure 3-9). Similarly, the combined transformer ratings at Oak Knoll Substations are sufficient for the forecast peak demands (including both Ashland's and PacifiCorp's loads). Individual transformer capacity was not evaluated due to limited data, however, we do not expect it will be a problem.

Table 3-6: BPA and Estimated Load Forecasts

Year	BPA Forecast, Ashland Sub	BPA Forecast, Mountain Ave Sub	BPA Forecast, Oak Knoll Sub	BPA Forecast, Overall (Non-Coincident / Coincident) [c]	Estimated Load Forecast
2021	N/A	N/A	N/A	N/A	**45,920**
2024	12,800	12,100	14,600	39,500 / 37,700	46,251
2025	12,800	12,100	14,600	39,500 / 37,700	46,584
2026	12,800	12,100	14,600	39,500 / 37,700	46,919
2027	12,800	12,100	14,600	39,500 / 37,700	47,257
2028	12,800	12,100	14,600	39,500 / 37,700	47,597
2029	12,800	12,100	14,600	39,500 / 37,700	47,940
2030	12,800	12,100	14,600	39,500 / 37,700	48,285
2031	12,800	12,100	14,600	39,500 / 37,700	48,633
2032	12,800	12,100	14,600	39,500 / 37,700	48,983
2033	12,800	12,100	14,600	39,500 / 37,700	**49,335**
2034	N/A	N/A	N/A	N/A	49,691
2035	N/A	N/A	N/A	N/A	50,048
2036	N/A	N/A	N/A	N/A	50,409
2037	N/A	N/A	N/A	N/A	50,772
2038	N/A	N/A	N/A	N/A	51,137
2039	N/A	N/A	N/A	N/A	51,505
2040	N/A	N/A	N/A	N/A	51,876
2041	N/A	N/A	N/A	N/A	52,250
2042	N/A	N/A	N/A	N/A	52,626
2043	N/A	N/A	N/A	N/A	**53,005**

Notes:

a) The study was performed in 2023. The historical peak in the past 10 years was used as the base case for the forecast.
b) BPA forecast is for 10 years and only goes to 2033.
c) Non-coincident peak is the direct summation of peak demands for the three substations.

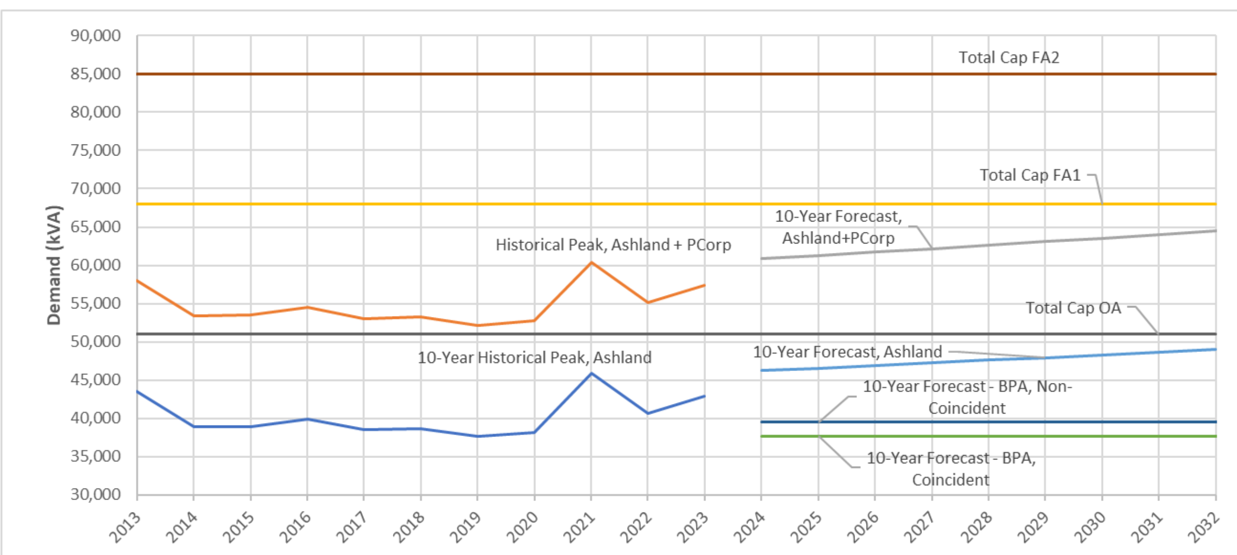


Figure 3-7: Projected Growth of Potential Peak Demand vs. Transformation Capacities (MVA ratings at 55° C are used.)

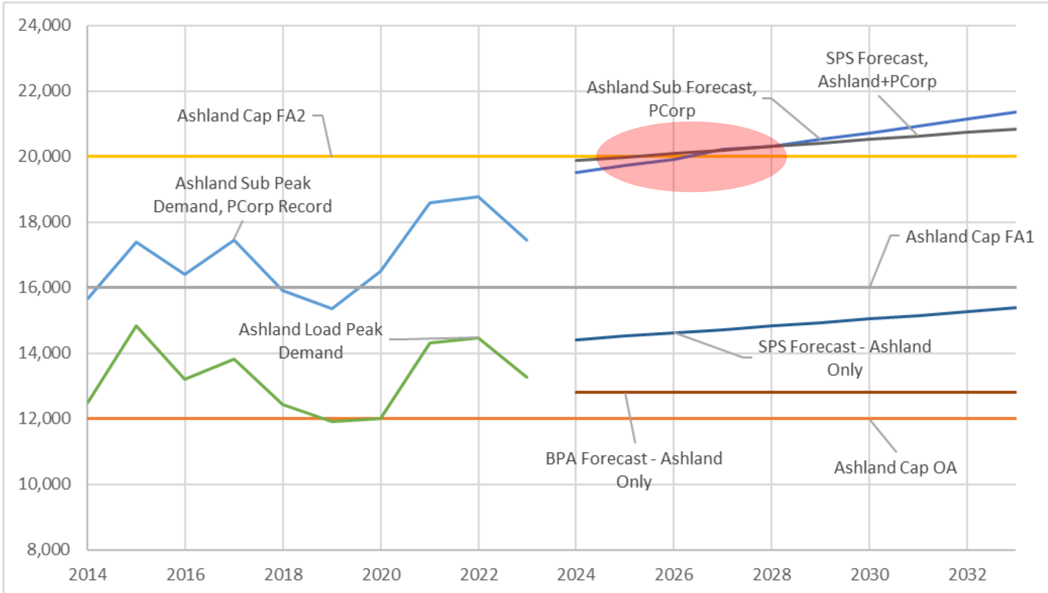


Figure 3-8: Projected Growth of Potential Peak Demand vs. Transformation Capacities, Ashland Substation (MVA ratings at 55ºC are used.)

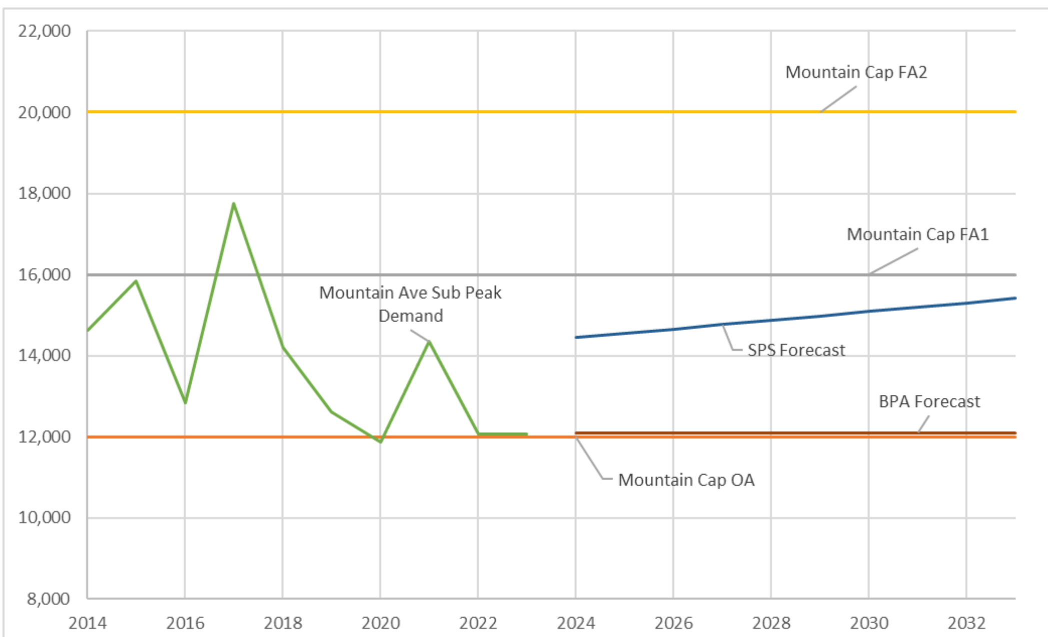


*Figure 3-9: Projected Growth of Potential Peak Demand vs. Transformation Capacities, Mountain Avenue Substation (MVA ratings at 55° C are used.) [**Note**: The peak demands in 2015 and 2017 are way higher than the typical peak demands seen at this substation. These two peaks were likely from abnormal system conditions or switching configurations and are not used for the forecast base.]*

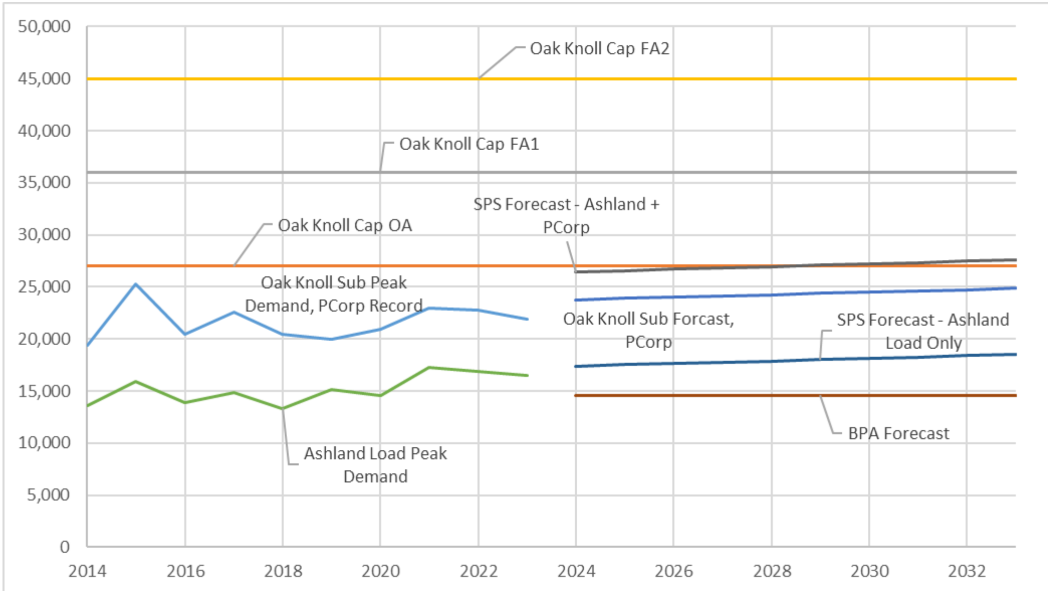


Figure 3-10: Projected Growth of Potential Peak Demand vs. Transformation Capacities, Oak Knoll Substation (MVA ratings at 55° C are used.)

3.5 CONCLUSIONS

The recommended improvements and improvement schedule used in this study are based on the system peak demand calculations summarized in Table 3-7. These demands were determined using a conservative system peak growth rate of 0.72% similar to, but slightly greater than the population trending information from Portland State University's report, Coordinated Population Forecast in conjunction with the recent 2021,10-year system peak of 45.92 MW as a base value.

The schedule of improvements should be evaluated annually and modified as needed to correspond with actual growth and peak demand as the load develops. As the system currently stands, there is sufficient total transformation capacity to handle 10-year and 20-year peak demand events during normal operating conditions. However, the transformer capacity at Ashland Substation may not be sufficient for the forecasted future growth, and adjustments and upgrades should be considered at this facility.

Table 3-7: Study Load Forecast Summary

	Base Case: 2021 Peak	10-Year Forecast	20-Year Forecast
System Load	45.92 MW	49.34 MW	53.0 MW

Notes:

a) This forecast is the system coincident peak.

Chapter 4 SYSTEM PLANNING CRITERIA

4.1 GENERAL

As part of the planning study, specific guidelines and planning criteria were developed and tailored to the City of Ashland's electric system and service objectives. Many of the criteria discussed below were established in the previous electric system planning study and are based on factors that affect system operations and maintenance, these include:

- Providing dependable and economical electric service to ratepayers while giving strong attention to public and personal safety.
- The planning, construction, and operating practices of comparable electric utilities.
- The risk taken by following less stringent planning practices.
- The development of transmission and substation criteria so that in the future the City may take ownership, operate, and maintain such facilities.

4.2 SYSTEM LOADING

The City of Ashland experienced steady growth from the mid-1990s through approximately 2008 when both population and energy consumption increased, as seen in Table 3-1. Local and regional planning entities project the population of the City of Ashland to increase throughout the planning period at an average annual rate of less than 1%. A discussion of population and load growth is presented in Chapter 3 and specific areas of growth are presented in Chapter 7.

Prudent utility practices require that system improvements be implemented prior to load growth to allow the utility to meet customer service demand. On the other hand, existing facilities should be utilized to the maximum practical extent to avoid costly premature construction of new facilities. Therefore, the recommended improvements in this report should be made as needed based on the best available growth data. The time frame of improvement implementation should be adjusted if the actual load growth varies significantly from the load forecasts but with sufficient time allowed for necessary engineering, permitting, material procurement and construction.

4.3 SYSTEM RELIABILITY

A primary consideration in system planning is reliability. As of the last study, the City adopted a “single-contingency reliability criterion” and this reliability criterion approach should be continued. Single-contingency reliability is achieved when an outage of any single major component of the electrical system (transmission or distribution line, substation transformer, protective device, cable segment, switching component, etc.) results in only minor service interruption to as few customers as possible.

To meet these objectives, and assure acceptable service continuity to the extent practical, the following criteria are recommended for use in planning and operating the electric system:

- Substations should have at least one alternate transmission line source (looped).
- Transmission line sections should be capable of being removed from service for

maintenance without causing customer service interruptions.

- Single substation transformer outages should not cause prolonged customer service interruptions. This requires the ability to transfer all feeders to an alternate source under all potential loading conditions.
- The electric utility should have documented distribution circuit switching schemes ready at all times. These schemes should allow for the transfer of load in case of the loss of any individual feeder or substation.
- The electric utility should have a documented emergency load curtailment plan that identifies probable load-shedding schemes, critical loads, and establishes load restoration plans.
- Arrangements for substation emergency backup during failure or planned maintenance through use of mobile transformers should be negotiated.
- Distribution feeders should be designed to be loaded to a maximum of approximately 7.5 MW (~340 A) during normal operation and temporary loading up to 11 MW (~490 A) during planned maintenance or emergency system outages with load transfers.
- Each distribution feeder should be capable of being supplied by one or more alternate distribution sources through group-operated, load-break switching devices installed at appropriate system locations. This will allow circuit breakers or reclosers and other feeder components to be taken out of service while maintenance is performed without causing lengthy customer service interruptions.
- When feeder circuits are connected to two separate substation transformers (parallel operation or hot transfer), load sharing between the two transformers will generally not be equal due to variations in the transformer impedance and line characteristic impedances. When opening feeder tie switches, considerable current and voltage can exist across the switch. We recommend, to the extent possible, all tie switching involving connection and disconnection of two energized transformers be done via three-pole group-operated switches, preferably with load-break capability.
- During situations when the electric utility has substations served by different transmission systems, parallel operation or hot transfer of feeders from the two substations served under this configuration should be avoided to prevent a condition of extreme fault current available at the tie point of the two sources. If the utility determines it is necessary to parallel operation from two transmission systems, it should first be confirmed that the two transmission systems are synchronized and the transmission operator should be notified.
- The coordination of protective devices should be reviewed and updated as needed to ensure proper protection of system components and to minimize the impact of faults and disturbances on adjacent portions of the system.
- Specific inspection and maintenance procedures with reporting documentation should be developed and adopted to ensure that all facilities are maintained in proper condition and that all safety and reliability criteria are met.
- Transmission line sections should be capable of being removed from service for maintenance without causing customer service interruptions.
- Single substation transformer outages should not cause prolonged customer service interruptions.
- The City should continue the practice of updating distribution circuit sectionalizing

schemes. These schemes should allow for the transfer of load in case of the loss of any individual feeder or substation.

4.4 SYSTEM DESIGN

The design of new facilities should be based on the following criteria:

- The City should continue using the standard distribution conductor sizes as selected in the previous study and recent electric development construction projects. The conductor selections and characteristics are shown in Table 4-1 through Table 4-6 below. The ampacities listed in these tables show that the distribution backbone conductors are capable of supporting greater loading than the design criteria, allowing for some reserve capacity.
- Where practical each backbone feeder circuit should be interconnected with two adjacent backbone circuits to accommodate load transfer.
- The design criteria philosophy is to allow any feeder to carry approximately two-thirds (2/3) of an adjacent feeder's load in case of the loss of the adjacent feeder.
- The application of standard distribution conductor sizes should be continued and follow the outline shown below:

Table 4-1: Overhead Conductors

Voltage	Conductor	Circuit Application
12.47/7.2-kV	556.5-kcmil AAC	Distribution Main Backbones
12.47/7.2-kV	336.4-kcmil AAC and #4/0-AAC	Distribution Large Taps
12.47/7.2-kV	#1/0 AAC and #2 AAC	Distribution Small Taps

Table 4-2: Underground Conductors

Voltage	Conductor	Circuit Application
12.47/7.2-kV	750-kcmil AL	Distribution Main Backbone
12.47/7.2-kV	500-kcmil AL and #4/0-AL	Distribution Large Taps
12.47/7.2-kV	#1/0-AL and #2-AL	Distribution Small Taps

- The maximum ampacity rating and relative MW capacity for winter and summer loading for typical overhead and underground conductors and the City's standard conductor sizes are shown in Tables 4-3 through 4-6 below:

Table 4-3: Capacity of Overhead Conductors

Conductor			Winter (b)		Summer (b)	
Copper	ACSR	AAC	Ampacity	MW (c)	Ampacity	MW (c)
#6			165	3.46	115	2.41
#4			225	4.71	155	3.25
	#4		170	3.56	118	2.47
		#4	164	3.44	113	2.37
#2			290	6.08	200	4.19
	#2		225	4.71	155	3.25
		#2	220	4.61	152	3.18
	#1/0		295	6.18	204	4.27
		#1/0	297	6.22	205	4.29
	#2/0		348	7.29	240	5.03
		#2/0	345	7.23	238	4.99
	#4/0		450	9.43	310	6.49
		#4/0	465	9.74	320	6.70
	336.4		670	14.04	464	9.72
		336.4	628	13.16	435	9.11
	397		746	15.63	517	10.83
	556.5		925	19.38	642	13.45
		556.5	868	18.18	602	12.61
	795		1174	24.60	815	17.07

Notes:

a) Based on 75 Celsius (degrees) conductor temperature, 0 Celsius (degrees) Winter Ambient, 40 Celsius (degrees) Summer Ambient.

b) Electric Transmission and Distributions Reference Book, Westinghouse Electric Corporation, Pg. 48, Figures 25 and 26.

c) All MW ratings assume a three-phase system with 97% power factor.

*Table 4-4: Underground Cable Capacity 7.2 kV, EPR 133%, **Full Concentric** (a)*

Conductor	In Duct Bank (b)	
	One Circuit (Amps)	MW (c) (1-Phase)
#2 AL	135	0.94
#1/0 AL	175	1.22
#2/0 AL	205	1.43
#4/0 AL	260	1.82

Notes:

a) Based on Okonite URO-J literature for **ONE single-phase circuit**, one conductor in one conduit, with 105 deg C, 220 mil, 133% EPR insulation level with full concentric neutral.

b) 105 C conductor temperature, RHO = 90, 20 Celsius (degrees) ambient earth temperature, 100% load factor (applicable both summer and winter loading).

c) All MW ratings assume a single-phase system with 97% power factor.

*Table 4-5: Underground Cable Capacity 15 kV, EPR 133%, **1/3 Concentric** (a)*

Conductor	In Duct Bank (b)	
	One Circuit (Amps)	MW (c) (3-Phase)
#1/0 AL	170	3.56
#4/0 AL	255	5.34
500 kcmil AL	405	8.48
750 kcmil AL	505	10.58

Notes:

a) Based on AIEE-ICEA Power Cable Ampacity Ratings, Volume I and II and Okonite URO-J literature for ONE three-phase circuit, three conductors in one conduit, with 105 deg C, 220 mil, 133% EPR insulation level with 1/3 concentric neutral. Derating is required for multiple circuits in a single duct bank.

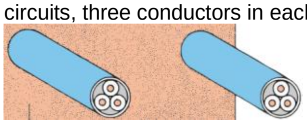
b) 105 C conductor temperature, RHO = 90, 20 Celsius (degrees) ambient earth temperature, 100% load factor (applicable both summer and winter loading).
c) All MW ratings assume a three-phase system with 97% power factor.

Table 4-6: Underground Cable Capacity – TWO Circuit Duct Bank [(a)]

Conductor	In Duct Bank [(b)]	
	Two Circuit (Amps)	**MW [(c)] (3-Phase)**
#4/0 AL	222	4.65
500 kcmil AL	357	7.48
750 kcmil AL	438	9.18

Notes:

a) Based on AIEE-ICEA Power Cable Ampacity Ratings, Volume I and II and Okonite URO-J literature for TWO three-phase circuits, three conductors in each conduit, with 105 deg C, 220 mil, 133% EPR insulation level with 1/3 concentric neutral.



b) 105 C conductor temperature, RHO = 90, 20 Celsius (degrees) ambient earth temperature, 100% load factor (applicable both summer and winter loading).
c) All MW ratings assume a three-phase system with 97% power factor.

Other recommendations include:

- Phase load imbalance on distribution feeders should be minimized to avoid overloading individual phases and reduce the need to oversize feeder backbone and tap conductors. If the imbalance on any feeder exceeds 15% during high load conditions, loads should be shifted between phases to reduce imbalance to 10% or below. This practice will help minimize neutral current and reduce neutral-to-ground potential.
- Substation main regulated bus voltage should be maintained in a range of 122-volt to 126-volt on a 120-volt base. Acceptable voltage standards and ranges are presented in Table 6-9 appearing in Chapter 6, Distribution System Evaluation.
- Voltage regulator settings should include first-house protection limiting the voltage to 126-volt maximum, and line drop compensation settings established to take into account line characteristic parameters.
- During high load conditions, the capacity of voltage regulators can be increased by programming the regulator controller to limit the maximum voltage adjustment range from the normal +/-10% to a lesser range. This allows the regulator to carry greater load (current), known as the so-called “load bonus” capability of most regulator controls. The capabilities for “load bonus” operation are dependent on the specific regulators and associated regulator controllers.
- Future substations should standardize on 15/20/25-MVA or 20/26/33-MVA, 115-12.47/7.2-kV, power transformer ratings, serving four to six feeder bay capacity. Substation improvement planning should begin when peak loading reaches the existing substation facilities’ self-cooled (OA) transformer ratings, and if continued growth is expected to occur.
- The implementation of self-healing load-transfer smart switches at key locations within the distribution system could be considered as a long-term goal to increase system reliability and uninterrupted service.

- The Electric Department should continue the practice of updating information in its distribution mapping system so it can be readily available for line assessment, system troubleshooting, future planning studies, as well as component inventory database.

4.5 CAPACITOR BANKS

The installation of capacitor banks should be considered to maintain power factors between 97 to 99 percent lagging at peak load and on feeders that experience low end of line voltage. Improving peak power factor will reduce demand charges and improve system efficiency.

- For large commercial or industrial customers, the preferred location of capacitor banks is the customer's site.
- A General Rule of Thumb for locating connected (fixed) capacitor banks on residential feeders is to locate the capacitor bank at a distance of about 1/2 to 2/3 of the total line length from the substation.
- If needed or desired, computer modeling simulation can provide optimal capacitor location placement and necessary settings.
- Total installed fixed capacitor bank installations should be limited to avoid an excessive leading power factor during low load conditions.
- Feeders with large, variable reactive power demands are often most effectively served with a combination of fixed and automatically switched capacitor banks. Fixed capacitor banks should be sized to the maximum that does not result in excessive leading power factor under low load and switched capacitor banks should be sized to make up the difference between fixed and the required kVAR under peak conditions at the target minimum power factor (typically 0.97).
- When installing or replacing capacitors the following guidelines should be observed:
    - Larger capacitor banks are typically more economical per kVAR than smaller banks, and it is generally best to avoid the use of capacitor banks less than 300 kVAR whenever possible.
    - Care should be exercised in sizing and locating switched capacitors so that the maximum primary voltage flicker does not exceed 3 volts (120-volt base) during normal capacitor switching.
    - Capacitors should not be installed on the load side of single-phase sectionalizing devices, as distorted or resonant voltage conditions may result from single-phasing.
    - Fixed capacitor banks should be manually switched seasonally as necessary to avoid excessive leading power factors during lowest demand periods.

Chapter 5 TRANSMISSION & SUBSTATION PLANNING

5.1 TRANSMISSION SYSTEM

5.1.1 Existing System

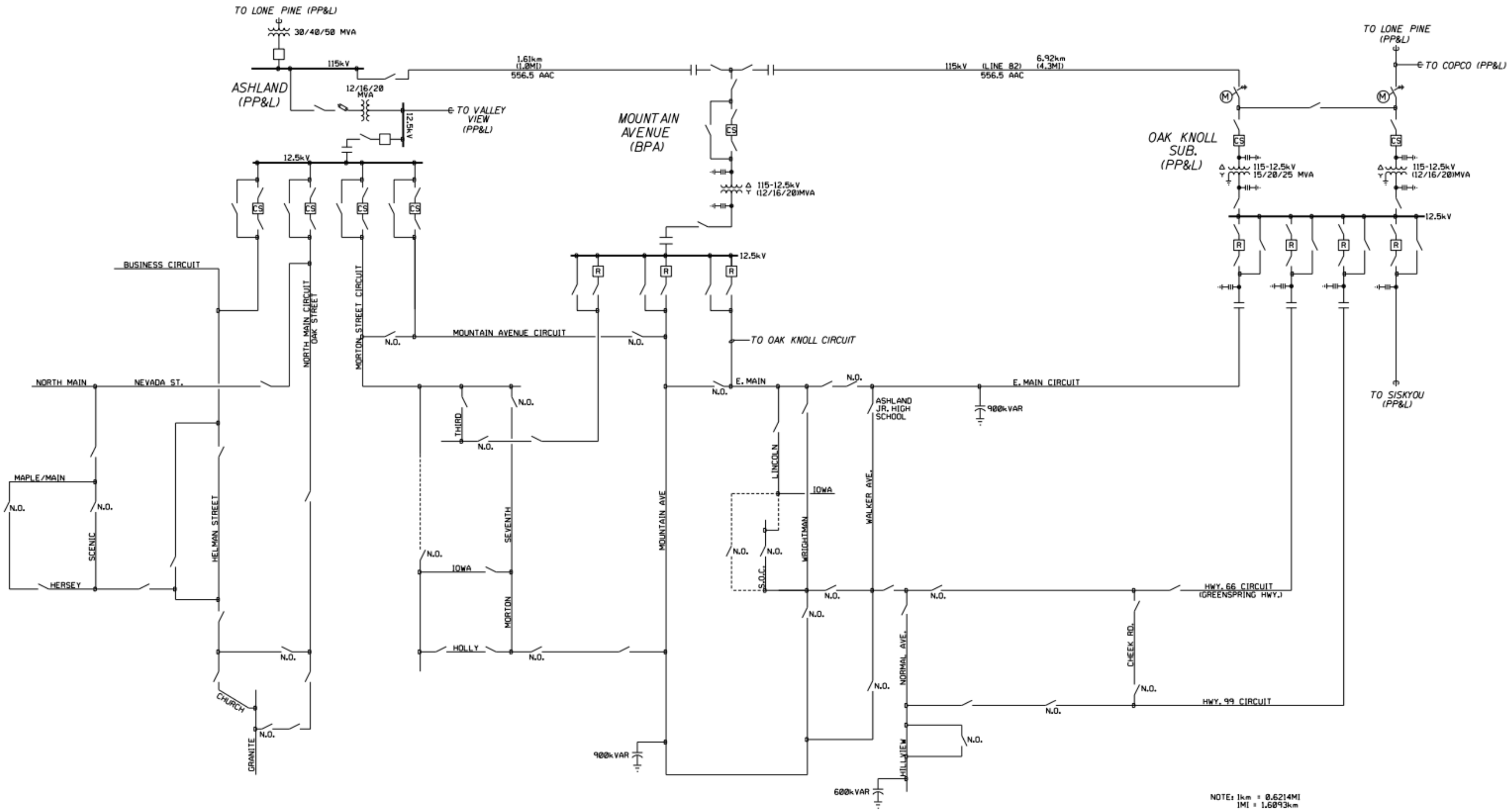
The City of Ashland's distribution service area is located within PacifiCorp's Medford service territory with power delivered to the City over the PacifiCorp transmission system, and a short 0.8-mile BPA-owned transmission line tap into the Mountain Avenue Substation. A simplified one-line diagram of substations and other descriptive diagrams of PacifiCorp's system related to the service to Ashland's electric facilities appear in Figure 5-1. Relevant drawings or references are provided in Appendix B.

Since the last study in 2013, PacifiCorp has completed the following upgrades to the Medford region transmission facilities (refer to Appendix B1 and B4 in Appendix B for a transmission map of the region)

- Added 115 kV circuit breaker at Oak Knoll Substation on 115 kV transmission supply from Line 19 via Oak Knoll Tap in 2014.
- Replaced ABB relays with SEL-751 on Oak Knoll 5R55, 5R56, 5R70, 5R93 and 5R94 in 2014.
- Replaced Lone Pine 115 kV circuit breaker 2R1 on 115 kV transmission supply to Line 19 in 2020.
- Replaced Oak Knoll 12.5 kV circuit breakers 5R55 and 5R56, added HIFD to SEL-751, and added RTAC in 2022.
- Installed new recloser on Oak Knoll 5R56 at Facility Point 01439001.0233601, July 2023.

Since mid-2013, the normal transmission supply to the City of Ashland has been 115 kV from Lone Pine Substation via Baldy Switching Station. The 115 kV loops through Ashland from Oak Knoll Substation to Mountain Avenue Substation and then to Ashland Substation. The Ashland Substation 115 kV loop connects back to Lone Pine via a 115 kV to 69 kV transformer at Belknap and a 69 kV line back to Lone Pine. If a transmission element along this path fails, automated switching procedures will be implemented by PacifiCorp grid operations remotely to isolate the affected line section and reconfigure the system to provide an alternate transmission path to Ashland, Mountain Avenue, and Oak Knoll substations. The Copco 2 Substation provides an alternate source via the Oak Knoll Tap.

Listed in Table 5-1 are PacifiCorp's normal and alternate transmission source circuits with summer and winter rated capacity based on the limiting conductor size, type, and loading criteria. According to PacifiCorp, the Sage Road Backup Source may have limited capability to supply Ashland-Oak Knoll at summer peak due to other system loads. All other sources have sufficient capacity to serve current and future peak winter and summer loads into the long-term future.



CITY OF ASHLAND

Figure 5-1: One Line Diagram – Transmission and Distribution System for Ashland
*(**Note**: Mountain Avenue Substation has been owned by the City of Ashland since 2023.)*

Table 5-1: Transmission Source Continuous Ratings

Source Name	Description	Summer Rating (MVA)	Winter Rating (MVA)
Normal Source to Ashland Substation	Line 19 South → Baldy Switching → Line 74 → Voorhies Crossing → Line 3 → Talent Substation → Ashland Substation	116	?
Normal Source to Oak Knoll Substation	Line 19 South → Baldy Switching → Line 19 → Line 82 → Oak Knoll Substation	97	?
Copco2 Backup Source	Copco2 → Baldy Switching → Ashland transmission loop	110	?
Sage Road Backup Source	Sage Road → Jacksonville → Griffin Creek → Voorhies Crossing → Ashland transmission loop	101	?

5.1.2 PacifiCorp and BPA Future Plan

BPA has no major modifications currently planned that would involve the transmission system serving the Ashland area. PacifiCorp planned improvements include:

- Replace 115 kV transmission switches 2R104 and 2R105 at Oak Knoll Tap with upgraded switching capability in 2023-2024.
- Replace line protective fuses on Oak Knoll 5R56 and Ashland 5R241 distribution feeders as part of wildfire mitigation upgrades. Project is planned to be completed in two phases with work beginning in 2023.
- Meridian Remedial Action Scheme (RAS) Expansion in 2024. Addition of 115 kV transmission circuit supplying several substations including Ashland, Mountain Avenue and Oak Knoll to be armed for load shedding in an event that two 500 kV transmission sources into the Medford region are lost during heavy load conditions.
- Replace relays on Ashland Substation 5R241 with SEL-751 w/HIFD in 2025.
- Replace Lone Pine – Whetstone 230 kV line in 2025.
- Expansion of Copco No. 2 Substation 115 kV yard to a breaker-and-a-half configuration in 2025-2026 (provides alternate transmission supply to Oak Knoll, Mountain Avenue and Ashland substations).
- Lone Pine – Sage Road 115 kV Line #2 (includes conversion of 69 kV Line 49-1 to 115 kV and new line extension) in 2026.
- Rebuild and conversion of Lone Pine to Belknap 69 kV transmission line to 115 kV (long-range project proposed for 2032).

5.1.3 Discussion

With the facility improvements made over the last 10 years, all normal transmission sources are now capable of serving the entire Ashland regional load (48.98 MW in 2032) into the long-term future. The present looped configuration and available backup transmission paths provide the City of Ashland with additional service integrity.

Reliability criteria established for most major utilities dictates that any transmission lines supplying 50 MW or more, and serving two or more substations, should be provided with an adequate alternate looped source if such capability can be provided at a reasonable cost. The Copco2 and Sage Road backup sources transmission system satisfies this reliability criterion for the foreseen future.

The transmission configuration for this area has not changed. As discussed in the previous study, a permanent fault on the 5.4-mile 115 kV Line 82 between the Ashland 115 kV breaker (2R266) and the Oak Knoll 115 kV breaker (2R262) would interrupt supply to the entire City of Ashland for some period of time. Restoration of power would be the responsibility of PacifiCorp. If this does happen, PacifiCorp has stated that they will first remotely open the isolation switches at Oak Knoll and Ashland Substations and remotely close the 115 kV breakers to restore power to Ashland and Oak Knoll. Local PacifiCorp crews would then need to be dispatched to find the faulted segment and isolate it via manually operated line switches before restoring power to Mountain Avenue Substation. If possible, all customers would be restored before line crews would begin repair work on the faulted line segment.

To reduce the impact of a 115 kV fault to the City, it would be necessary for PacifiCorp to install additional 115 kV circuit breakers and protective relaying to help automatically restrict the outage to a smaller portion of their transmission system. Alternatively, more remotely operated isolation switches could be installed. However, the present level of sectionalizing provided by PacifiCorp is typical for the number of substations and total number of customers involved. Improvements to the 115 kV system sectionalizing capability should be a point of future discussions between the City and PacifiCorp.

The weak link in the transmission system is the 0.81-mile 115 kV radial BPA segment tapped from Line 82 that serves Mountain Avenue Substation. An outage on this line would de-energize and take out Mountain Avenue Substation until repairs are completed. This line is owned by BPA. As discussed above, an outage along Line 82 between Oak Knoll and Ashland Substations would require manual switching to restore service to Mountain Avenue. Although it would be desirable to have this tap looped and the switching automated, it is unlikely either will happen and this situation is not unusual given the short length of this tap.

PacifiCorp has provided a summary of transmission outages affecting service to the City of Ashland. Since 2013, there have been 30 outages of greater than 15 minutes with an average outage time of approximately 140 minutes and a most common outage duration of 30 minutes. BPA also provided an incomplete outage report for Mountain Avenue Substation which listed four unique events in addition to some of the transmission outages provided by PacifiCorp. There was a total of 3 BPA Planned Outages during this period with durations lasting anywhere from 409 minutes to 2 days. It should be noted that planned outages have loads transferred beforehand to ensure continuity of service to BPA customers. Detailed outage lists can be found in Chapter 6.

5.2 SUBSTATION SYSTEMS

5.2.1 Existing Systems

Three substations provide distribution services to the City of Ashland. PacifiCorp owns both the Ashland and Oak Knoll Substations providing service to the City of Ashland 12.47 kV distribution rack facility (POD) and four distribution feeders within the PacifiCorp Ashland Substation, and to the three 12.47 kV distribution points-of-delivery (POD) outside the PacifiCorp Oak Knoll Substation. The City has owned the Mountain Avenue Substation since 2023 providing service to the City of Ashland distribution feeders. The POD is at 115 kV while the BPA’s meters are situated on the 12.47 kV bus.

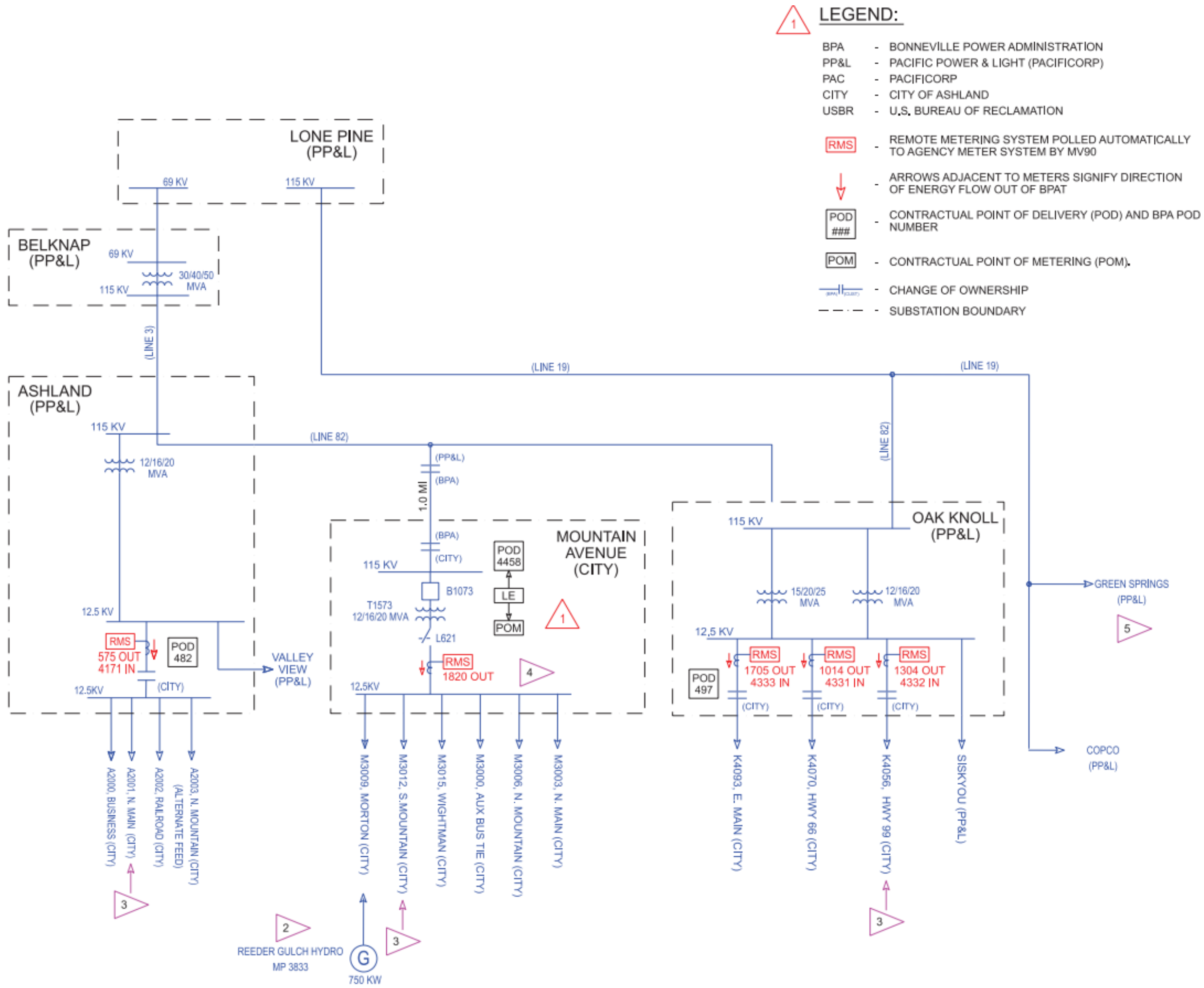


Figure 5-2: BPA Metering Diagram (V2023)

Since the previous study, the City has:

- Extended the distribution rack at Mountain Avenue Substation to add more feeder positions;
- Upgraded the recloser protective devices at Ashland Substation and installed the controllers in a City-owned control building;
- Installed City-owned pole mounted protective recloser controllers outside the PacifiCorp Oak Knoll Substation;
- Installed a Supervisory Control and Data Acquisition (SCADA) system that now includes all City-owned feeder circuit controllers at the Mountain Avenue, Ashland, and Oak Knoll Substations;
- The electric department's SCADA system allows real-time monitoring and control of connected system devices, such as substation reclosers and voltage regulators from a computer terminal in the Electric Department's main office;
- Installed pad-mounted sectionalizing VFI switchgear for various new developments.

The City purchases power from BPA with power delivered through a General Transfer Agreement via the PacifiCorp transmission system and facilities as described below. Under its contract with the City, PacifiCorp is responsible for providing service consistent with prudent utility practices. BPA meters these independent points of delivery as identified in Table 5-2.

Table 5-2: BPA Metering Designations

Substation	Point-of Delivery Name	Meter Number
Ashland	Business/North Main/Railroad/North Mountain	575
Oak Knoll	East Main	1705
	Highway 66	1014
	Highway 99	1304
Mountain Avenue	Morton/South Mountain/Wightman	1820

The existing substation transformer nameplate capacity, manufacture date, winter ratings, and the transformation capacity available to serve City loads are shown in Table 5-3.

Table 5-3: Transformer Capacity Available

Substation Transformer Mfgr. Date	Peak Load (kW)	Annual Energy (kWh)	Ave. Monthly Load Factor (%)	Transformer Voltage (kV)	Transformer Nameplate Rating (MVA) at Specified Temp Rise	Winter Planning Rating [(a)(d)] (MW) at Specified Ambient Temp	Note	Secondary Regulation
Ashland Substation T-3499 1974s	19,520	~56,500,000	62.6% [(e)]	115-12.47/7.2	12/16/20 @ 55 ºC 13.4/18/22.4 @ 65 ºC	25.7 @ 5 ºC	b, c	3-1Ø 667/889 kVA 7.2 kV Nom. +/- 10%
Mountain Ave Substation T-1573 1978	17,750	~60,000,000	60.2% [(e)]	115-12.47/7.2	12/16/20 @ 55 ºC 13.4/17.9/22.4 @ 65 ºC	25.7 @ 5 ºC	b, c	1-3Ø 2000kVA 7.2 kV Nom. +/- 10%
Oak Knoll Substation T3234 1967	12,720	~59,600,000	56.6% [(e)]	115-12.47/7.2	12/16/20 @ 55 ºC 13.4/17.9/22.4 @ 65 ºC	25.7 @ 5 ºC	b, c	LTC
Oak Knoll Substation T3856 1992	11,050			115-12.47/7.2	15/20/25 @ 55 ºC	28.8 @ 5 ºC	b, c	1-3Ø 2000/2667 kVA 7.2 kV Nom. +/- 10%

Notes:

a) Typical planning MW ratings are at 0.97 power factor, 5 degrees C ambient, and 100% load factor based on ANSI standard C57.91 – 2011.
b) Peak Load, Annual Energy, and Ave. Monthly Load Factor figures are maximum values from the period of December 2023 through December 2032. All values displayed are downloaded from BPA raw metered data.
c) If voltage regulator maximum nameplate rating is exceeded the City should implement the equipment Load Bonus, Add-Amp or similar feature to adjust the current range upward to match the load but limit the voltage regulation.
d) Winter planning ratings based on Table 3 in IEEE C57.91 – 2011.
e) Both Ashland Substation and Oak Knoll Substation feed one PacifiCorp circuit, which has a peak demand of about 5.5 MW and 9.0 MW respectively.

One-line diagrams of each substation are presented in Appendix B as B2, B3, and B5/B6. A brief description of each substation and its facilities that serve the City follows below:

5.2.2 ASHLAND SUBSTATION

At Ashland Substation, the City takes delivery from the regulated 12.47/7.2 kV bus through one PacifiCorp secondary 1200 A breaker (5R241). This PacifiCorp breaker feeds a City-owned distribution rack and four distribution reclosers serving four City feeder circuits. Both the substation and the City-owned distribution rack were constructed in the 1950/60s era.

The City of Ashland's four reclosers serving the feeders from the Ashland Substation City's distribution rack includes a fused bypass arrangement for each feeder, should a recloser be out-of-service or require maintenance. The feeder reclosers are rated 560 A with 400 A bypass fuses.

In 2013 the City replaced and upgraded the recloser controllers, placing them in an existing City owned and refurbished building across Nevada Street from the Ashland Substation. The City has implemented SCADA capability for these four feeders and in 2014 considered replacement of the distribution rack with a new City-owned substation due to age, reliability, and safety concerns, but no further action was taken.

Also in 2013, PacifiCorp upgraded the 69 kV terminal of the Ashland Substation to 115 kV and removed the 69/115 kV auto-transformer. The substation is now looped at 115 kV. Distribution facilities are served through a 116 kV x 12.47/7.2 kV, 12/16/20 MVA transformer (T-3499) with a manufacture date of 1974, three single-phase voltage regulators, and a 12.47 kV distribution rack with main and auxiliary buses. The 115 kV transmission source from Talent Substation and Voorhies Crossing is protected with a primary circuit switcher. The 115 kV source on Line 82 from Oak Knoll Substation has a disconnect switch which can be remotely operated.

In addition to breaker 5R241, a 15.5 kV, 1200 A secondary breaker (5R245) serves the PacifiCorp Valley View distribution circuit. Should breaker 5R241 serving the City fail or need to be removed from service, City loads would be protected by the City-owned reclosers, the 400A City owned recloser by-pass fuses, or transferred via the auxiliary bus to PacifiCorp breaker 5R245. Breaker 5R245 was replaced with a 1200 A rated breaker in 2015. It will have the capacity to serve all Ashland Substation load in addition to the normal PacifiCorp loads should the need arise.

5.2.3 OAK KNOLL SUBSTATION

At Oak Knoll Substation, PacifiCorp provides 12.47 kV service to the City from three distribution breaker positions serving three separate PODs and City feeder circuits. City ownership of the Oak Knoll feeders begins just outside the substation.

The PacifiCorp Oak Knoll Substation, constructed in 1965, has two 115 kV incoming terminals serving two power transformers with both transformers normally in service. Transformer T- 3234 (Bank #1) rated 116 kV x 12.47/7.2 kV, 12/16/20 MVA with a manufacture date of 1967, has load-tap changer regulation and normally feeds the substation bypass bus serving the PacifiCorp Siskiyou distribution feeder and the City of Ashland Highway 99 feeder.

Transformer T-3856 (Bank #2) rated 116 kV x 12.47/7.2 kV, 15/20/25 MVA with a manufacture date of 1992, has secondary voltage regulation and normally feeds the substation main bus serving the City of Ashland Highway 66 and East Main feeders.

Feeder breakers 5R56 and 5R93 are rated for 600 A, and 5R70 is rated for 1200 A. The substation also has a normally open 1200 A tie breaker that can connect the main and bypass buses. The substation configuration offers flexible switching should any one device fail or need to be out-of-service for maintenance. The City of Ashland owns no equipment within the Oak Knoll Substation.

The City has installed three separate pole-mounted reclosers just outside the PacifiCorp Oak Knoll Substation. This improvement allows the City to directly control these feeders without involving PacifiCorp staff. The installation included equipment with SCADA capability allowing the City to remotely monitor and control these feeders.

5.2.4 MOUNTAIN AVENUE SUBSTATION

At Mountain Avenue Substation the site, high voltage equipment, control building and ancillary components previously owned by BPA were purchased by the City in 2023. The City now takes delivery of power at 115 kV and owns all high-voltage equipment plus the previously City-owned three-phase voltage regulator, two distribution racks plus sectionalizing equipment, the six distribution reclosers and feeder getaway facilities presently serving four feeder circuits. The City now owns the Control Building and all ancillary devices plus the previously City-owned panel-mounted feeder recloser controllers and SCADA system equipment.

The Mountain Avenue Substation, constructed in 1994, has one 115 kV incoming source. Distribution facilities are served through a 115 kV x 12.47/7.2 kV, 12/16/20 MVA rated transformer (T-1573), with a 1976 manufacture date, and secondary voltage regulation feeding a 12.47 kV distribution rack with main and auxiliary buses. A 115 kV circuit switcher provides transformer protection.

The original distribution facilities, consisting of a rack serving three City feeders through 560 A reclosers, were expanded by the City in 2010 to include the addition of a second distribution rack capable of serving three additional City feeders. The distribution racks are configured with main and auxiliary buses allowing flexible switching arrangements so that load can be transferred to another source or circuit should a recloser need to be taken out-of-service. The racks are tied together via gang-operated load break tie switches and the second (newer) distribution rack also contains a transformer bay to be served from a future second power transformer.

5.3 SUBSTATION HISTORY AND OWNERSHIP

In 1996, Bonneville Power Administration (BPA) began to offer the sale of BPA-owned Distribution Substations to its customers, and early on BPA approached City of Ashland offering the sale of Mountain Avenue Substation. The City considered purchase of the substation and had its present worth evaluated in 2003 and again in 2013, however BPA's asking price was considerably above its assessed value and the City concluded this option was not in its best interest at that time.

Because of the great value in cost savings for eliminating BPA's low voltage transformation 'delivery charge' by taking ownership of the substation and power delivery at transmission voltage, the City successfully negotiated purchase of the substation from BPA in October 2023.

Prior to the Mountain Avenue Substation purchase the City took delivery of all power at the substation at the 12.47/7.2 kV secondary voltage and was required to pay a Utility Delivery Charge (UDC) for all energy purchased through the BPA-owned substation. BPA put the UDC charge in place in 1996 to recover the costs of owning, operating, and maintaining low-voltage facilities. Since then, BPA has increased these rates significantly to fully recover costs from utilities that continue to take low-voltage delivery.

The BPA Delivery Charge rate increased from $0.75/kW in 1996, to $1.399/kW in October 2013, to $1.27/kW in 2022, to $1.12/kW in 2024. Approximately 10 years ago BPA stated it was likely to continue to increase every two years in 5 to 15 percent increments. However, since then BPA has renamed Delivery Charge to Transfer Service and dispersed these charges into other account areas. Nonetheless, the monthly and annual savings from the City's reduction in Utility Delivery Charges because of the purchase of Mountain Avenue Substation is a significant source for continuing support for the electrical department's objective of gaining control of its own power delivery, system configuration, switching schemes, and facility maintenance.

Presently, based on the average substation monthly peak of 11,058 kW in 2021 (Table 5-4) and the current Transfer Service rate of $1.12/kW, the City saves approximately $12,385 monthly and $148,620 annually by owning the Mountain Avenue Substation.

The City could further reduce the transfer service cost with construction of a City-owned substation on Nevada Street across from PacifiCorp's Ashland Substation site. By doing this the City could save approximately $11,409 monthly and $136,913 annually based on an average substation monthly peak of 10,187 kW (Table 5-5).

Substation ownership allows the City to independently determine substation facility needs and reduce the total cost of providing service in the long-term. However, the City would also assume the risk associated with owning substation facilities as well as operations and maintenance costs.

Table 5-4: Energy and Demand Data – Meter 1820, Mountain Avenue Substation, 2021

Month	Energy (kWh)	Demand (kW)	Peak Hour & Date
January	5,718,375	11,950	1/26/21 19:00
February	5,159,100	11,300	2/4/21 9:00
March	4,984,900	10,600	3/16/21 9:00
April	3,782,475	8,125	4/26/21 9:00
May	3,682,250	13,475	5/13/21 19:00
June	4,376,688	14,350	6/28/21 17:00
July	5,076,375	11,700	7/6/21 18:00
August	4,586,300	12,000	8/11/21 18:00
September	3,701,650	8,750	9/8/21 18:00
October	4,216,725	8,900	10/12/21 9:00
November	4,939,000	10,150	11/22/21 9:00
December	6,146,975	11,400	12/27/21 18:00

Table 5-5: Energy and Demand Data – Meter 575, Ashland Substation, 2021

Month	Energy (kWh)	Demand (kW)	Peak Hour & Date
January	5,270,920	10,680	1/26/21 19:00
February	4,740,140	10,700	2/7/21 13:00
March	4,626,900	9,280	3/15/21 10:00
April	3,633,860	7,320	4/6/21 8:00
May	3,485,960	8,840	5/31/21 19:00
June	4,576,080	14,310	6/28/21 17:00
July	5,352,110	12,360	7/3/21 19:00
August	4,663,520	11,780	8/11/21 18:00
September	3,734,660	8,830	9/8/21 18:00
October	4,000,820	8,060	10/12/21 8:00
November	4,659,090	9,510	11/22/21 8:00
December	5,809,360	10,570	12/31/21 18:00

5.4 IMPROVEMENT DISCUSSION

5.4.1 Substation Expansion

The power flow analysis indicates that the loss of either the Ashland or Mountain Avenue Substation transformer under current peak load conditions could lead to the inability to serve customers without significant transformer overload and accelerated transformer aging.

The PacifiCorp Ashland Substation located close to the City's load center contains a City-owned 12.47 kV distribution rack that is old and in deteriorating condition. In the past the City had considered a new distribution rack that would enhance flexibility and maintenance, however, the new distribution rack would still be served from a single PacifiCorp breaker. In 2011 the City considered construction of a City-owned substation across Nevada Street from PacifiCorp's Ashland Substation on City-owned property. This concept should now be reconsidered. The City has easy access to this site with looped transmission source readily available and a control building is already in place. By constructing a City-owned substation at this location and taking delivery at 115 kV the City would reduce the power purchase transformation charges similar to Mountain Avenue Substation.

The Oak Knoll Substation, located in the southeast region of the City's service area, is well situated for load growth in its general vicinity. However, due to its location it has limited ability for extension that could efficiently reach the City's core load center. The previously installed City-owned sectionalizing reclosers on the three Oak Knoll feeders outside the substation, which have SCADA monitor and control, is about the extent of improvements the City can make to enhance service from these feeders.

The most practical substation facility for improvement and future expansion is the Mountain Avenue Substation. This substation recently purchased by the City is centrally located to the core load and consists of a developed site suitable for expansion. In 2008 the City expanded its distribution facilities by adding a second distribution rack with three new feeder bays and a transformer bay. The Mountain Avenue Substation has been constructed so that capacity can be increased with the addition of a second power transformer.

It is expected the City will need additional substation transformation capacity within the intermediate (10-year) future to comply with the single-contingency planning criteria, and as noted previously in this study it is suggested that the City plan to add this second transformer bank. This is because of the age of the existing transformer and time involved to procure, fabricate, and deliver a second transform to the site.

Once a second transformer is available it will:

- relive the concern of having the ability to meet expected peak loads,
- provide single contingency outage flexibility at peak load, and
- reduce the exposure to lengthy outages while a mobile transformer is placed in service.

5.5 IMPLICATIONS OF NERC BULK ELECTRIC SYSTEM CLASSIFICATION (BES)

FERC has recently issued its Final Ruling regarding the NERC definition of the Bulk Electric System (BES). In its ruling it accepted the NERC definition of the BES. Portions of the electric power grid falling under the BES definition are required to maintain a specified level of reliability and security. This imposes additional record-keeping and documentation requirements on the owning utility and can result in the imposition of fines if the NERC requirements are not met. The basic rule is that transmission facilities operating at 100 kV or higher are considered part of the BES. However, this voltage limit is not an absolute dividing line. There are several "Exclusions" and "Inclusions" that are applied that depend on system criteria other than voltage.

Because the City takes power delivery at 115 kV but does not own the transmission system, only serves load, and is not operated as a contiguous loop its facilities are <u>not</u> considered part of the BES designation. This is because of Exclusion E-1 in the NERC BES definition as described in the FERC ruling:

> *<u>Exclusion E1 provides as follows:</u>*
> *Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:*
>
> *a) Only serves Load. Or,*
>
> *b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,*
>
> *c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I2, I3, or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).*
>
> *Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.*
>
> *Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.*

5.6 CONCLUSION

Over the last 10 years, PacifiCorp has made major improvements to the transmission facilities serving the City of Ashland. The current looped configuration and available backup transmission paths provide the City with satisfactory service reliability and capacity into the long-term future. The substation facilities serving the City of Ashland provide adequate capacity to serve the City's winter and summer peak load under normal conditions. However, with additional load growth and in contingency situations, the City's electric system may not be able to meet the single contingency outage criteria.

As the City considers options for additional transformation capacity, it should

- Consider adding a second transformer bank at Mountain Avenue Substation, and
- Revisit the option of a new City-owned substation on Nevada Street with removal of its distribution facilities from the PacifiCorp Ashland Substation.

5.7 RECOMMENDATION

The major improvement recommendations presented below are in order of priority, selected from the options identified in this chapter and relate to substation facilities serving the City's electric facilities. Summary descriptions and associated costs for these and miscellaneous improvements appear in Table 2-1. These estimates assume the City will incur costs directly for the improvements with construction performed by contractors. The estimates do not include any site acquisition, establishment of rights-of-way and easements, or environmental and impact permitting studies, since none are believed to be necessary. It is suggested the City thoroughly explore each recommended improvement and determine complete costs prior to moving forward with any improvement option.

Major Improvement 1 – Mountain Avenue Substation

Expansion of the substation facilities by adding a second transformer bank. This will require the necessary primary dead-end structure and protection device, the secondary voltage regulation, required bus support structures and buswork, plus required relaying and control ancillary components and construction installation.

Cost Estimate	Power Transformer	$1,350,000
	Substation Components and Construction	$ 750,000
Total Cost		$2,100,000

Major Improvement 2 – New Nevada Street Substation

Construct a new City-owned Nevada Street Substation on existing City-owned property. This will require the necessary site development, power transformer, primary dead-end in-out structures and protective device, voltage regulation, required bus support structures and buswork, plus relaying and control ancillary components and construction installation. The City may decide to use the existing control building or replace it new.

Cost Estimate	Power Transformer	$1,350,000
	Substation Components and Construction	$1,650,000
Total Cost Estimate		$3,000.000

Major Improvement 3 – Replace Mountain Avenue Substation - Bank 1 Transformer

As mentioned elsewhere in this study the existing bank 1 power transformer was fabricated in 1976 and installed 'used' at Mountain Avenue Substation. Because of the age and expected service life of this transformer the City should plan for its replacement which could take up to five years from creation of a procurement document to transformer installation.

Cost Estimate	Power Transformer	$1,350,000
	Engineering/Contractor Services	$ 200,000
Total Cost		$1,550,000

Chapter 6 DISTRIBUTION SYSTEM EVALUATION

6.1 BACKGROUND

The City of Ashland's electric distribution system was evaluated for capacity under high and low load conditions. The high load case is based on historic metering data. To produce 10-year and 20-year load estimates for analysis and planning, the base-case system peak demand was adjusted to increase proportional to the population growth as outlined in Chapter 3. Specific areas of system growth are modeled and discussed in detail in Chapter 7. Table 6-1 below, indicates loading conditions examined in this study.

Table 6-1: Study Loading Conditions

	Base Case (Light)	Base Case (Historical Peak, 2021)	10-Year (2033) [c]	20-Year (2043) [c]
System Coincident Peak [a]	31.8 MW	45.9 MW	49.3 MW	53.0 MW
Ashland Substation Modeled Load [b]	9.4 MW	14.3 MW	15.5 MW	15.9 MW
Mountain Avenue Substation Modeled load [b]	11.3 MW	14.2 MW	15.2 MW	16.2 MW
Oak Knoll Substation Modeled load [b]	11.2 MW	17.6 MW	19.0 MW	20.4 MW

Notes:

a) Coincident system peak demand based on BPA's hourly data.
b) Coincident system peak demand for individual substations with normal switching configurations. Load allocation in the model considers large clients using their actual peak and small customers by linear distribution. This load allocation process may result in a small difference between the total substation feeder loads and the system loads listed above, but it is acceptable to this study.
c) Detailed forecast growth rate is discussed in Chapter 3.

The preparation of this study is based on detailed distribution system information gathered from the City of Ashland staff and the distribution system GIS maps. The GIS maps include data on location, name, connectivity, size, and rating for system components such as conductors, transformers, capacitor banks, switches, protective devices, poles, and vaults. The analysis model used, which indicates node and segment electrical data, is included in Appendix C.

6.2 DISTRIBUTION SYSTEM CAPACITY

Results of the model analysis show the City's distribution system presently provides reliable service at acceptable voltage levels for all loading conditions including the historical peak when operating in the normal system configuration.

Substation meter data was obtained through the BPA customer portal website for each point of delivery. Table 6-2 to Table 6-6 indicates energy use and peak demand data for all substation feeders for the 10-year historical peak in 2021. Individual feeder data at Ashland Substation and Mountain Avenue Substation is not available from BPA, however, the City's SCADA system has an archive of individual feeder data.

*Table 6-2: **Ashland Substation** Loading Summary 2021, **BPA Meter #575***

Month	Energy (kWh)	Reactive (kVARh)	Demand (kW)	Peak Hour & Date	Power Factor	Load Factor
January	5,270,920	2,150	10,680	1/26/21 19:00	100	66.33
February	4,740,140	1,050	10,700	2/7/21 13:00	100	65.92
March	4,626,900	180	9,280	3/15/21 10:00	100	67.1
April	3,633,860	450	7,320	4/6/21 8:00	100	68.95
May	3,485,960	25,550	8,840	5/31/21 19:00	100	53
June	4,576,080	389,700	14,310	6/28/21 17:00	99.64	44.41
July	5,352,110	624,220	12,360	7/3/21 19:00	99.33	58.2
August	4,663,520	387,460	11,780	8/11/21 18:00	99.66	53.21
September	3,734,660	97,860	8,830	9/8/21 18:00	99.97	58.74
October	4,000,820	200	8,060	10/12/21 8:00	100	66.72
November	4,659,090	710	9,510	11/22/21 8:00	100	67.95
December	5,809,360	6,910	10,570	12/31/21 18:00	100	73.87

Notes:

a) The reactive power consumption in summer is higher, resulting in relatively lower power factors, but is still close to unity.

*Table 6-3: **Mountain Avenue Substation** Loading Summary 2021, **BPA Meter #1820***

Month	Energy (kWh)	Reactive (kVARh)	Demand (kW)	Peak Hour & Date	Power Factor	Load Factor
January	5,718,375	0	11,950	1/26/21 19:00	100.00	64.32
February	5,159,100	0	11,300	2/4/21 9:00	100.00	67.94
March	4,984,900	0	10,600	3/16/21 9:00	100.00	63.29
April	3,782,475	0	8,125	4/26/21 9:00	100.00	64.66
May	3,682,250	9,200	13,475	5/13/21 19:00	100.00	36.73
June	4,376,688	231,325	14,350	6/28/21 17:00	99.86	42.36
July	5,076,375	429,125	11,700	7/6/21 18:00	99.64	58.32
August	4,586,300	351,550	12,000	8/11/21 18:00	99.71	51.37
September	3,701,650	231,450	8,750	9/8/21 18:00	99.81	58.76
October	4,216,725	80,450	8,900	10/12/21 9:00	99.98	63.68
November	4,939,000	129,750	10,150	11/22/21 9:00	99.97	67.49
December	6,146,975	151,200	11,400	12/27/21 18:00	99.97	72.47

Notes:

a) The reactive power consumption in summer is higher, resulting in relatively lower power factors, but is still close to unity.

*Table 6-4: **Oak Knoll Substation** Loading Summary 2021, Feeder E. Main, **BPA Meter #1705***

Month	Energy (kWh)	Reactive (kVARh)	Demand (kW)	Peak Hour & Date	Power Factor	Load Factor
January	1,950,530	122,090	3,990	1/26/21 9:00	99.8	65.71
February	1,784,970	92,470	3,990	2/4/21 9:00	99.87	66.57
March	1,758,780	166,670	3,650	3/16/21 9:00	99.55	64.85

Month	Energy (kWh)	Reactive (kVARh)	Demand (kW)	Peak Hour & Date	Power Factor	Load Factor
April	1,429,190	191,430	2,970	4/6/21 9:00	99.11	66.83
May	1,401,210	180,840	3,140	5/31/21 16:00	99.18	59.98
June	1,787,970	186,900	6,160	6/28/21 16:00	99.46	40.31
July	2,055,120	147,900	5,070	7/29/21 16:00	99.74	54.48
August	1,845,910	119,120	4,960	8/13/21 16:00	99.79	50.02
September	1,481,050	145,290	3,880	9/7/21 17:00	99.52	53.02
October	1,524,330	217,490	3,110	10/12/21 9:00	99	65.88
November	1,730,920	171,490	3,510	11/22/21 9:00	99.51	68.4
December	2,100,070	97,070	3,870	12/15/21 11:00	99.89	72.94

Notes:

a) The reactive power consumption in summer is higher, resulting in relatively lower power factors, but is still close to unity.

Table 6-5: Oak Knoll Substation Loading Summary 2021, HWY 66, ***BPA Meter #1014***

Month	Energy (kWh)	Reactive (kVARh)	Demand (kW)	Peak Hour & Date	Power Factor	Load Factor
January	1,790,430	15,250	3,620	1/26/21 11:00	100	66.48
February	1,652,060	9,950	3,340	2/4/21 11:00	100	73.61
March	1,715,400	15,950	3,270	3/15/21 11:00	100	70.6
April	1,443,580	22,060	2,670	4/6/21 9:00	99.99	75.09
May	1,438,780	55,870	3,110	5/31/21 18:00	99.92	62.18
June	1,725,730	188,600	4,690	6/28/21 17:00	99.41	51.11
July	1,945,660	246,510	4,160	7/6/21 17:00	99.21	62.86
August	1,754,510	174,980	4,080	8/11/21 17:00	99.51	57.8
September	1,446,660	68,670	3,230	9/7/21 17:00	99.89	62.21
October	1,523,940	19,400	3,320	10/26/21 15:00	99.99	61.7
November	1,614,380	2,610	3,060	11/8/21 9:00	100	73.17
December	1,901,970	500	3,440	12/15/21 18:00	100	74.31

Notes:

a) The reactive power consumption in summer is higher, resulting in relatively lower power factors, but is still close to unity.

Table 6-6: Oak Knoll Substation Loading Summary 2021, HWY 99, ***BPA Meter #1304***

Month	Energy (kWh)	Reactive (kVARh)	Demand (kW)	Peak Hour & Date	Power Factor	Load Factor
January	2,496,400	20	5,610	1/26/21 19:00	100	59.81
February	2,265,700	50	5,200	2/4/21 9:00	100	64.84
March	2,129,760	19,270	4,750	3/16/21 9:00	100	60.35
April	1,565,060	143,910	3,500	4/12/21 8:00	99.58	62.11
May	1,482,860	153,490	4,130	5/31/21 19:00	99.47	48.26
June	1,901,330	185,640	6,640	6/28/21 18:00	99.53	39.77
July	2,205,370	174,690	5,560	7/3/21 19:00	99.69	53.31

Month	Energy (kWh)	Reactive (kVARh)	Demand (kW)	Peak Hour & Date	Power Factor	Load Factor
August	1,927,680	114,440	5,370	8/11/21 19:00	99.82	48.25
September	1,501,360	88,960	3,840	9/6/21 19:00	99.82	54.3
October	1,713,090	82,050	4,910	10/26/21 15:00	99.89	46.89
November	2,053,910	25,770	4,490	11/8/21 8:00	99.99	63.45
December	2,710,880	9,680	5,200	12/27/21 19:00	100	70.07

Notes:

a) The reactive power consumption in summer is higher, resulting in relatively lower power factors, but is still close to unity.

A useful aid to help visualize system load characteristics are the winter and summer daily load profiles as seen in Figure 6-1 and 6-2, respectively. Peak loads are represented for each hour of the day, averaged separately for weekdays and weekends.

The winter load profile, Figure 6-1, created from recorded data during the study period shows a trend with daily winter peaks in the morning and early evening hours as expected for a predominantly residential load system. The power consumption during weekend days is slightly lower than on weekdays. The summer load profile, Figure 6-2, created from recorded data during the study period shows a different trend with single afternoon peak characteristics likely attributed to air conditioning or industrial/commercial load. Additionally, the power consumption during weekend days is slightly lower in the daytime.

The general patterns seen in these daily load profiles may give the City a better idea of how to achieve system load balance if desired. Loading could be shifted to different times of the day, such as the operation of motors to fill reservoirs or operate lift stations.

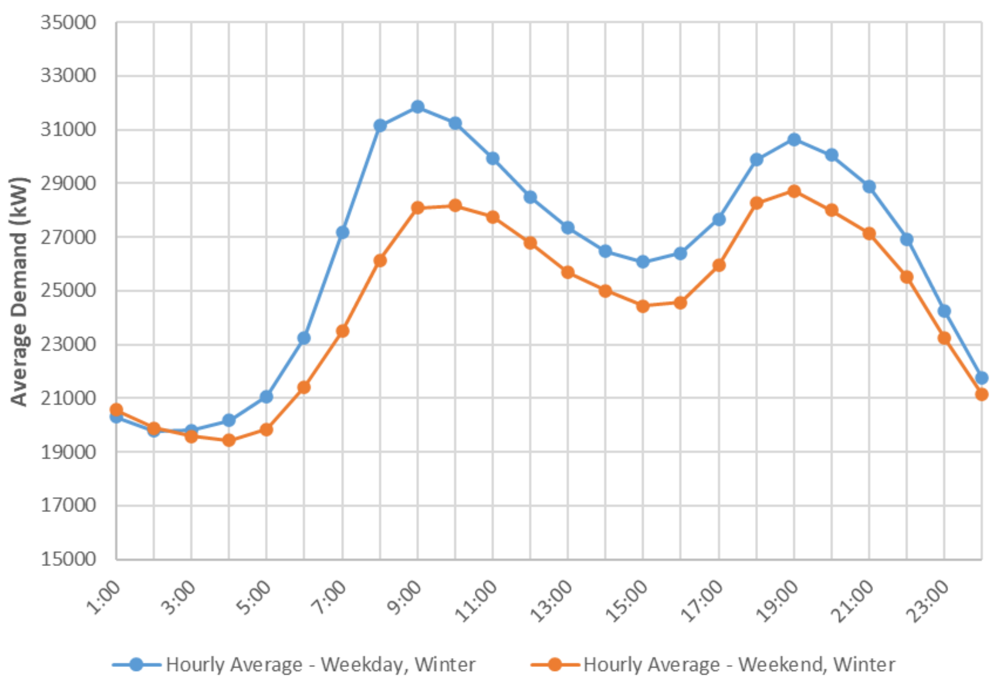


Figure 6-1: Average Hourly Peak Load for January 2017

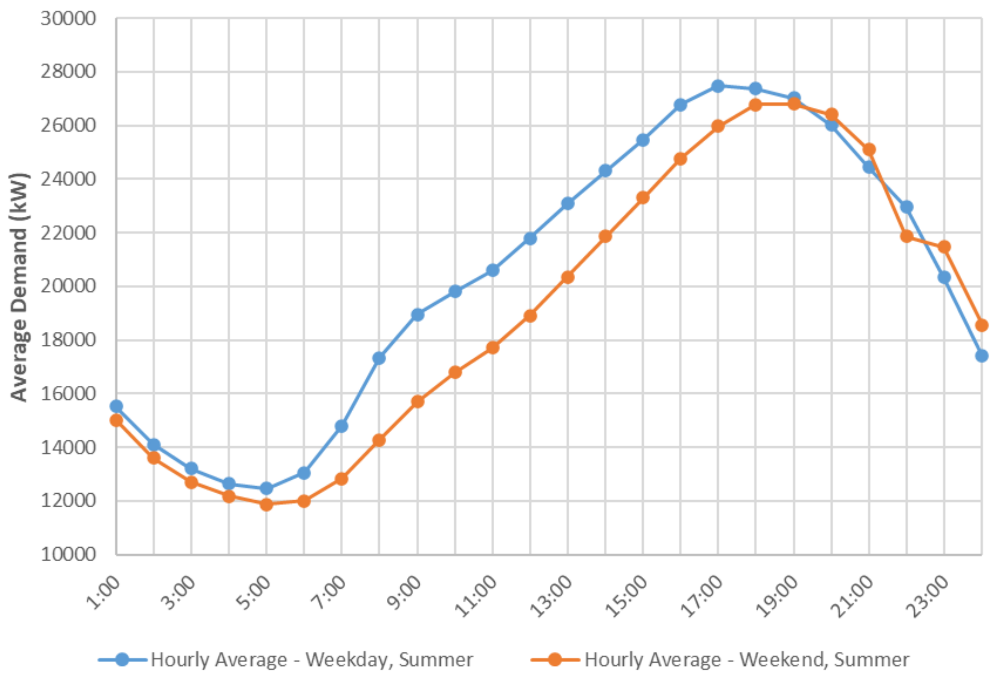


Figure 6-2: Average Hourly Peak Load for June 2021

Ashland is currently providing quality electric service and has made continual system improvements since the last study in 2013. Based on the most recent system peak (June 2021), with any feeder out-of-service, the City can serve loads from adjacent circuits under normal conditions. However, loss of some feeder circuits during peak conditions could cause other parts of the system to exceed capacity. Additionally, the loss of a substation transformer at peak load could result in severe transformer overload conditions at another substation. These conditions will become more severe as load growth occurs and could lead to the City not being able to meet single contingency outage criteria in the future without an increase in system capacity.

6.2.1 Distribution System

The City's electric system serves customers from 10 distribution feeders, having a total of 12 substation feeder positions available. Table 6-7 and Table 6-8 summarize the summer and winter existing feeder voltage ratings, backbone conductor characteristics, capacities, kW ratings, recommended loading, and actual (non-coincidental) loading from 2014 through 2023. From data in these two tables, it appears that:

- All the feeders currently have adequate capacity to serve peak loads under normal conditions and under the emergency sectionalized conditions evaluated.
- However, some feeders are more loaded than others, and this plus load imbalance reduces operational flexibility during emergency operating conditions. As future load growth occurs, the City should add load strategically, where feasible, to balance loading between existing feeders to minimize feeder and conductor overloading especially under sectionalized conditions.

*Table 6-7: Existing Feeder Loading—Normal Conditions (**SUMMER**)*

Substation/ Feeder	Voltage (kV)	Feeder Main Conductors			Summer Peak Load		Peak Load % of Conductor	
		Size/Material[c]	Rating[b] [d] Amps	Rating[b] [d] kW	Present (kW) [a]	Recom'd (kW) [e]	Rating	Recom'd Loading
Ashland Substation								
A2000 – Business	12.47/7.2	556 AAC	642	13,450	6,076	7,500	45%	56%
A2001 – North Main	12.47/7.2	750 kcmil, URD	505	10,580	6,110	7,500	58%	71%
	12.47/7.2	556 AAC	642	13,450	6,110	7,500	45%	56%
A2002 – Railroad	12.47/7.2	750 kcmil, URD	505	10,580	2,226	7,500	21%	71%
	12.47/7.2	556 AAC	642	13,450	2,226	7,500	17%	56%
	12.47/7.2	336 AAC	464	9,721	2,226	7,500	23%	77%
A2003 – N. Mountain Alt	12.47/7.2	See information for Feeder M3006						
Mountain Avenue Substation								
M3006 – N. Mountain	12.47/7.2	750 kcmil, URD	505	10,580	1,677	7,500	23%	71%
	12.47/7.2	556 AAC	642	13,450	1,677	7,500	16%	56%
M3009 – Morton	12.47/7.2	750 kcmil, URD	505	10,580	5,803	7,500	12%	71%
	12.47/7.2	336 AAC	464	9,721	5,803	7,500	55%	77%
M3012 – S. Mountain	12.47/7.2	750 kcmil, URD	505	10,580	4,603	7,500	60%	71%
	12.47/7.2	566 AAC	642	13,450	4,603	7,500	44%	56%
	12.47/7.2	336 AAC	464	9,721	4,603	7,500	34%	77%
M3015 – Wightman	12.47/7.2	750 kcmil, URD	505	10,580	2,268	7,500	47%	71%
	12.47/7.2	566 AAC	642	13,450	2,268	7,500	21%	56%
	12.47/7.2	336 AAC	464	9,721	2,268	7,500	17%	77%
Oak Knoll Substation								
K4056 (5R56) – HWY 99	12.47/7.2	336 AAC	464	9,721	6,357	7,500	65%	77%
K4070 (5R70) – HWY 66	12.47/7.2	336 AAC	464	9,721	4,632	7,500	48%	77%
K4093 (5R93) – E. Main	12.47/7.2	336 AAC	464	9,721	5,808	7,500	60%	77%

a) Individual winter feeder peaks are from City's SCADA system data for 2022.
b) All kW ratings assume a three-phase system with 97% power factor.
c) Conductor size/material data obtained from City staff and system maps.
d) Overhead conductors shown with summer ampacity ratings.
e) Recommended loading is for normal conditions, non-sectionalized. More discussion can be found in Chapter 4.

*Table 6-8: Existing Feeder Loading—Normal Conditions (**WINTER**)*

Substation/ Feeder	Voltage (kV)	Feeder Main Conductors			Winter Peak Load		Peak Load % of Conductor	
		Size/Material[c]	Rating[b] [d]		Present (kW) [a]	Recom'd (kW) [e]	Rating	Recom'd Loading
			Amps	kW				
Ashland Substation								
A2000 – Business	12.47/7.2	556 AAC	925	19,379	4,820	7,500	25%	39%
A2001 – North Main	12.47/7.2	750 kcmil, URD	505	10,580	4,613	7,500	44%	71%
	12.47/7.2	556 AAC	925	19,379	4,613	7,500	24%	39%
A2002 – Railroad	12.47/7.2	750 kcmil, URD	505	10,580	1,472	7,500	14%	71%
	12.47/7.2	556 AAC	925	19,379	1,472	7,500	8%	39%
	12.47/7.2	336 AAC	670	14,037	1,472	7,500	10%	53%
A2003 – N. Mountain Alt	12.47/7.2	See information for Feeder M3006						
Mountain Avenue Substation								
M3006 – N. Mountain	12.47/7.2	750 kcmil, URD	505	10,580	924	7,500	9%	71%
	12.47/7.2	556 AAC	925	19,379	924	7,500	5%	39%
M3009 – Morton	12.47/7.2	750 kcmil, URD	505	10,580	4,858	7,500	46%	71%
	12.47/7.2	336 AAC	670	14,037	4,858	7,500	35%	53%
M3012 – S. Mountain	12.47/7.2	750 kcmil, URD	505	10,580	4,145	7,500	39%	71%
	12.47/7.2	566 AAC	925	19,379	4,145	7,500	21%	39%
	12.47/7.2	336 AAC	670	14,037	4,145	7,500	30%	53%
M3015 – Wightman	12.47/7.2	750 kcmil, URD	505	10,580	2,067	7,500	20%	71%
	12.47/7.2	566 AAC	925	19,379	2,067	7,500	11%	39%
	12.47/7.2	336 AAC	670	14,037	2,067	7,500	15%	53%
Oak Knoll Substation								
K4056 (5R56) – HWY 99	12.47/7.2	336 AAC	670	14,037	5,613	7,500	40%	53%
K4070 (5R70) – HWY 66	12.47/7.2	336 AAC	670	14,037	3,360	7,500	24%	53%
K4093 (5R93) – E. Main	12.47/7.2	336 AAC	670	14,037	3,952	7,500	28%	53%

a) Individual summer feeder peaks are from City's SCADA system data for 2022.
b) All kW ratings assume a three-phase system with 97% power factor.
c) Conductor size/material data obtained from City staff and system maps.
d) Overhead conductors shown with winter ampacity ratings.
e) Recommended loading is for normal conditions, non-sectionalized. More discussion can be found in Chapter 4.

6.2.2 Capacitor Banks

The City's electric distribution system presently has eight (8) 12.47/7.2 kV capacitor banks installed at various locations throughout the system. Capacitors are generally used to maintain adequate voltage and power factor, as well as reduce line losses. Table 6-9 shows the electric system's existing capacitor banks, their feeder, location, size and type of control.

Based on the analysis results of the present system configuration, no additional capacitor installations are required within this intermediate planning period for overall system correction. For general recommendations regarding capacitor placement and configuration, see Chapter 4

Table 6-9: Electric System Capacitor Banks

Feeder	Location	Rating	Type and Status
A2000 - Business	Helman & Tracks	600 kVAR	Fixed "ON" At 12.47 kV
A2001 - N. Main	Maple Street	600 kVAR	Fixed "ON" At 12.47 kV
M3009 - Morton	Morton & East Main	600 kVAR	Fixed "ON" At 12.47 kV
M3012 - S. Mountain	S. Mountain & Iowa	900 kVAR	Automatic, At 12.47 kV
M3015 - Wightman	N. Mountain & Clear Creek	600 kVAR	Automatic, At 12.47 kV
5R56 - Hwy 99	35 Crowson Rd	600 kVAR	Automatic, At 12.47 kV
5R70 - Hwy 66	Hwy 66 & Crowson Rd	600 kVAR	Automatic, At 12.47 kV
5R93 - E. Main	3018 Green Springs Hwy 66	900 kVAR	Automatic, At 12.47 kV

6.3 DISTRIBUTION EQUIPMENT INVENTORY REVIEW

6.3.1 Transformer

Based on the inventory provided by the City (Table 6-10), there are about 2140 distribution transformers within the Ashland electric system. Distribution transformer life is affected by several factors, such as loading, environmental temperature, maintenance (e.g., oil, bushing), testing, etc. According to reference documents (‘*The Feasibility Of Replacing Or Upgrading Utility Distribution Transformers During Routine Maintenance*’) by the Department of Energy, present distribution transformers are designed to operate for 20 years at designed load and specified hot-spot temperature. Underloaded transformers are less stressed thermally and may have lives extending well beyond 30 years, but transformers loaded to greater than nameplate rating for extended times may have significantly shortened lifetimes. The national average age for utility distribution transformer life is about 31.95 years with a standard deviation of 6.4 years. According to a utility company survey in the DOE document, the retirement age ranged from 14 to 35 years and the average age was nearly 25 years, with a standard deviation of about 5 years.

Besides abnormal transformer failures, Ashland might consider the replacement of older distribution transformers by adopting a retirement age such as 24 years based on the national perspective, an earlier age such as 20 years, or adjusted based on the electric department's field experience.

Table 6-10: City of Ashland, Transformer Inventory

Year	Qty.	Year	Qty.
2000	13	2013	14
2001	11	2014	14
2002	17	2015	16
2003	54	2016	25
2004	17	2017	25
2005	2	2018	38

Year	Qty.	Year	Qty.
2006	1	2019	37
2007	4	2020	30
2008	4	2021	42
2009	2	2022	18
2011	19	2023	15
2012	28	Unknown	1692

a) Most of the manufacture dates were not recorded.

6.3.2 Poles

The City's inventory list shows a total of 2,517 poles in the system with construction additions tabulated starting in 1950 (Table 6-11). We recommend the City conform with standard pole testing requirements by having poles tested every 10-12 years or testing approximately 10% (250 poles) each year. For any poles that have not been inspected for some time, it is suggested primary circuit poles receive a full intrusive inspection, which includes excavation around the pole to a depth of 18", and inspection of the pole exterior for decay and treatment with a boron/copper-based product to prolong pole life. Testing should include sound and bore to determine if the pole has any voids. If voids are present the pole should be treated with a copper-based product to slow decay. Poles with extensive decay and that are not serviceable should be rejected and replaced. The poles should also be visually inspected for obvious signs of damage or decay.

Table 6-11: City of Ashland, Pole Inventory

Year	Qty.	Year	Qty.	Year	Qty.
1950	6	1976	3	2004	14
1951	1	1977	2	2005	13
1954	6	1978	4	2006	1
1955	4	1979	2	2007	9
1957	2	1980	2	2008	2
1958	1	1983	3	2009	39
1959	4	1987	1	2010	18
1960	2	1988	3	2011	29
1961	15	1989	2	2012	16
1962	4	1990	3	2013	39
1963	14	1991	7	2014	9
1964	14	1993	19	2015	18
1965	2	1994	15	2016	6
1966	6	1995	2	2017	7
1967	3	1996	2	2018	24
1968	1	1997	1	2019	15
1969	5	1998	4	2020	14
1970	1	2000	4	2021	8
1971	8	2001	7	2022	4
1972	5	2002	7	2023	11
1973	4	2003	21	Unknown	1999

a) Most of the manufacture/installation dates were not recorded.

6.3.3 Conductors

The City has a total of 2,736 conductor segments in the system with new construction additions tabulated starting in 2012 (Table 6-12). The City has a program established to periodically perform infrared thermal imaging investigations of all City-owned distribution infrastructure, including primary circuit overhead pole assemblies and circuit conductors. This service should be performed after pole inspection, treatment, and/or replacement is complete so that the infrared inspection is performed on pole top assemblies that will remain in service. Conductors should also receive a periodic visual inspection for obvious signs of damage. In 2023, the City found several hot spots on switches using drones with infrared cameras and cleared a few bird nests on poles.

Table 6-12: City of Ashland, Conductor Inventory

Year	Qty. (segment)
2012	39
2013	20
2014	13
2015	23
2016	69
2017	39
2018	26
2019	46
2020	60
2021	47
2022	24
2023	27
Unknown	2,303

a) Most of the manufacture/installation dates were not recorded.

6.3.4 Meters

There are approximately 12,172 meters in the City's distribution system with new meter additions tabulated starting in 2011. Many of them might have been installed earlier but not recorded by the City.

Table 6-13: City of Ashland, Meter Inventory

Year	Qty.
2011	58
2012	12
2013	32
2014	58
2015	86
2016	76
2017	106
2018	90
2019	85

2020	96
2021	79
2022	86
2023	21
Unknown	11,287

a) Most of the manufacture/installation dates were not recorded.

6.4 SYSTEM PERFORMANCE

6.4.1 Service Reliability

As discussed in Chapter 5, reliability of electric service is a primary consideration in system planning. The City's electric system should use a single contingency reliability criterion, which means the outage of any single major component of the electric system cannot result in a prolonged outage to any customer.

The IEEE has developed specific guidelines through Standard 1366, Guide for Power Distribution Reliability Indices, to evaluate distribution reliability consisting of measures for monitoring outage duration and frequency. These reliability indices have received industry-wide acceptance and are divided into two categories, customer-based indices and load-based indices.

Customer-based indices record the frequency and duration of outages from individual customers and are used mainly for residential areas. Load-based indices record the frequency and duration of outages of circuits that are relevant to serving industrial and commercial loads. The IEEE sustained interruption indices are defined below for convenience.

SAIFI: System Average Interruption Frequency Index

$$\frac{\text{Total Number of Customers Interrupted}}{\text{Total Number of Customers}}$$

SAIDI: System Average Interruption Duration Index

$$\frac{\text{Sum of Customer Interruption Durations}}{\text{Total Number of Customers}}$$

CAIFI: Customer Average Interruption Frequency Index

$$\frac{\text{Total Number of Customers Interrupted}}{\text{Number of Distinct Customers Affected within Reporting Period}}$$

CAIDI: Customer Average Interruption Duration Index

$$\frac{\text{Sum of Customer Interruption Durations (SAIDI)}}{\text{Total Number of Customers Interrupted (SAIFI)}}$$

ASAI: Average Service Availability Index

$$\frac{\text{Customer Hours Service Availability}}{\text{Customer Hours Service Demand}}$$

ATPII: Average Time per Interruption Index

$$\frac{\text{Sum of Interruption Duration}}{\text{Number of Interruptions}}$$

CMPII: Customer Minutes per Interruption Index

$$\frac{\text{Sum of Customer Interruption Duration}}{\text{Number of Interruptions}}$$

SAIFI is expressed with a unit of outages per year for the average customer. Both the SAIDI and CAIDI are expressed in minutes, and ASAI is a percentage. The national averages for SAIFI, SAIDI, CAIDI, and ASAI from example years between 2005-2020 are shown in Table 6-14 below.

The City has established a program and collects necessary data for calculating some of these indices listed above annually or every few years. The City recorded a total of 230 outages from 2014 through 2023, and a summary of the number of affected customers and total duration is shown in Table 6-11.

The available data shows that SAIFI is ~0.12 interruptions per customer on average for the last 10 years. The City's average interruption frequency is less than the 2020 National average of 0.86. SAIDI and CAIDI are about 20.8 and 171.4 minutes respectively. Compared to the National Outage Data for 2020, system average outage duration is shorter, 20.8 vs. 139.2; however, the outage duration for the affected customers is about 28 minutes (~20%) longer, 171.4 vs. 143.5. CAIDI reflects the average time required to restore service to the affected customers and can change significantly every year. Many different factors contribute to outages (Table 6-16) and the required time for service restoration. Outages due to extreme weather and fire are typically challenging to recover from, especially for clients in rural and wooded areas. Overall, the City has good service reliability.

Table 6-14: National Average Outage Data (APPA Reliability and Operations Report)

Survey Year	SAIFI (Interruptions)	SAIDI (Minutes)	CAIDI (Minutes)	ASAI (%)
2005	1.6	54.03	65.91	99.79
2007	4.18	69.8	90.06	99.97
2009	0.88	68.98	86.75	99.9
2011	0.81	46.36	73.86	99.86
2013	1.11	58.49	96.47	99.87
2015	0.91	62.53	78.8	99.91
2018	0.99	60.02	82.4	99.95
2020	0.86	139.16	143.52	99.97

Table 6-15: City of Ashland Outage Data – Last 10 Years

Circuit Name	Substation Name	Number of System Interruptions
A2000 - Business	Nevada Street	41
A2001 - North Main	Nevada Street	31
A2002 - Railroad	Nevada Street	11
M3006 - North Mountain	Mountain Ave	4
M3009 - Morton	Mountain Ave	39
M3012 - South Mountain	Mountain Ave	33
M3015 - Wightman	Mountain Ave	8
K4056 - Hwy 99	Oak Knoll	31
K4070 - Hwy 66	Oak Knoll	14
K4093 - East Main	Oak Knoll	18
Circuit Name	**Substation Name**	**Customer Interruptions**
A2000 - Business	Nevada Street	1583
A2001 - North Main	Nevada Street	944
A2002 - Railroad	Nevada Street	672
M3006 - North Mountain	Mountain Ave	4
M3012 - South Mountain	Mountain Ave	3609
M3009 - Morton	Mountain Ave	2394
M3015 - Wightman	Mountain Ave	1953
K4056 - Hwy 99	Oak Knoll	1529
K4070 - Hwy 66	Oak Knoll	359
K4093 - East Main	Oak Knoll	2526
Circuit Name	**Substation Name**	**Customer Outage Duration (min.)**
A2000 - Business	Nevada Street	199222
A2001 - North Main	Nevada Street	184910
A2002 - Railroad	Nevada Street	72514
M3006 - North Mountain	Mountain Ave	536
M3009 - Morton	Mountain Ave	532471
M3012 - South Mountain	Mountain Ave	547367
M3015 - Wightman	Mountain Ave	353301
K4056 - Hwy 99	Oak Knoll	318852
K4070 - Hwy 66	Oak Knoll	65071
K4093 - East Main	Oak Knoll	395544

Table 6-16: City of Ashland Outage Cause Profile, Last 10 Years

Cause	Total Outages	Percentage
Squirrel	53	22.7%
Equipment Worn Out	35	15.0%
Tree	29	12.4%
Electrical Failure	26	11.2%
Vehicle Accident	13	5.6%
Lightning	13	5.6%
Unknown	12	5.2%
Equipment Damage	7	3.0%
Bird	7	3.0%
Overhead	7	3.0%
Underground	6	2.6%
Wind	5	2.1%
Fire Department	3	1.3%
Non-Utility Excavation	3	1.3%
Storm	3	1.3%
Other - Lightning	2	0.9%
Repairs	2	0.9%
Human Accident	2	0.9%
Failure of Greater Transmission	1	0.4%
Contractor-Dig-In	1	0.4%
Equipment Replacement	1	0.4%
Contact with Foreign Object	1	0.4%
Ice	1	0.4%

BPA and PacifiCorp provided their recorded 10-year outages for the circuits serving the City's electrical system, these are presented in Table 6-17 and Table 6-18. Of these events, about 50% have a duration of more than 2 hours.

Table 6-17: BPA 10-Year Outage Record

Outage Start Date/Time	Outage End Date/Time	Duration (min.)	kV	Auto/Planed	Cause	Responsible System	Component
6/15/2015 3:00	6/15/2015 18:50	950	12.5	Auto	Bird or Animal	BPA	Transformer, Power
10/5/2015 13:18	10/7/2015 15:10	2992	12.5	Plan	Maintenance	BPA	
5/16/2017 7:34	5/16/2017 14:23	409	12.5	Plan	Maintenance	BPA	
6/25/2017 17:27	6/25/2017 18:08	41	12.5	Auto	Unknown	Customer	Not Applicable
9/19/2017 7:47	9/20/2017 13:48	1801	12.5	Plan	Maintenance	BPA	

Table 6-18: PacifiCorp 10-Year Outage Record

Year	Outage Class	Duration (mins)	Substation
2013			
1/26/13 9:47 AM	Distribution	75 to 90 minutes	Ashland (Mtn.Ave, PUD)
2/13/13 11:53 AM	Distribution	45 to 60 minutes	Ashland (Mtn.Ave, PUD)
6/12/13 1:29 PM	Distribution	30 to 45 minutes	Ashland (Mtn.Ave, PUD)
10/31/13 1:43 PM	Distribution	15 to 30 minutes	Oak Knoll
2014			
4/14/14 5:25 PM	Transmission	0 to 15 minutes	Lone Pine
12/15/14 7:30 AM	Distribution	45 to 60 minutes	Ashland (Mtn.Ave, PUD)
2016			
3/12/16 4:42 PM	Distribution	225 to 240 minutes	Oak Knoll
2017			
1/7/17 8:48 AM	Distribution	495 to 510 minutes	Oak Knoll
1/7/17 8:48 AM	Distribution	495 to 510 minutes	Ashland (Mtn.Ave, PUD)
1/22/17 3:13 AM	Distribution	135 to 150 minutes	Oak Knoll
5/20/17 2:46 PM	Distribution	345 to 360 minutes	Ashland (Mtn.Ave, PUD)
5/20/17 2:46 PM	Distribution	330 to 345 minutes	Ashland (Mtn.Ave, PUD)
6/25/17 5:27 PM	Distribution	30 to 45 minutes	Oak Knoll
6/25/17 5:27 PM	Distribution	30 to 45 minutes	Ashland (Mtn.Ave, PUD)
6/25/17 5:27 PM	Distribution	30 to 45 minutes	Oak Knoll
2018			
1/24/18 9:25 PM	Transmission	0 to 15 minutes	Lone Pine
6/24/18 10:51 PM	Distribution	240 to 255 minutes	Oak Knoll
7/21/18 8:27 PM	Distribution	390 to 405 minutes	Ashland (Mtn.Ave, PUD)
7/21/18 9:12 PM	Distribution	345 to 360 minutes	Ashland (Mtn.Ave, PUD)
12/14/18 8:24 AM	Distribution	195 to 210 minutes	Oak Knoll
12/14/18 8:24 AM	Distribution	195 to 210 minutes	Ashland (Mtn.Ave, PUD)
2019			
2/13/19 11:47 AM	Distribution	0 to 15 minutes	Ashland (Mtn.Ave, PUD)
7/24/19 4:30 PM	Distribution	45 to 60 minutes	Ashland (Mtn.Ave, PUD)
7/24/19 4:30 PM	Distribution	45 to 60 minutes	Oak Knoll
2021			
6/27/21 9:06 PM	Distribution	15 to 30 minutes	Oak Knoll
6/27/21 9:06 PM	Distribution	15 to 30 minutes	Ashland (Mtn.Ave, PUD)
6/27/21 9:06 PM	Distribution	15 to 30 minutes	Oak Knoll
10/26/21 9:09 AM	Distribution	300 to 315 minutes	Oak Knoll
2022			
3/5/22 7:32 AM	Distribution	105 to 120 minutes	Ashland (Mtn.Ave, PUD)
3/5/22 1:15 PM	Distribution	75 to 90 minutes	Ashland (Mtn.Ave, PUD)
4/11/22 8:06 AM	Distribution	240 to 255 minutes	Oak Knoll
5/31/22 12:04 PM	Distribution	135 to 150 minutes	Oak Knoll
5/31/22 12:04 PM	Distribution	105 to 120 minutes	Oak Knoll

6.4.2 System Voltage Levels

In accordance with standards established by the American National Standard Institute (ANSI C84.1, Range A), the voltage ranges in Table 6-19, shown as acceptable voltage or allowable voltage drop, should be maintained throughout the City's electric system. The voltages shown are presented on a 120 volt base, however the percentages indicated apply to any voltage base, for example 12.47/7.2 kV, 480/277 V, etc., as applicable to the location.

Table 6-19: Acceptable Voltage Levels

Facility	Acceptable Voltage or Allowable Voltage Drop (120V Base Volts)	Acceptable Percentage
Bus voltage range at substation	122 - 126	102% - 105%
Maximum voltage drop along a distribution feeder	8	6.7%
Voltage range at primary terminals of distribution transformers	118 - 126	98% - 105%
Maximum voltage drop across distribution transformer and service conductors	4	3.3%
Voltage range at customer's meter	114 - 126	95% - 105%
Voltage range at customer's utilization equipment	110 - 126	92% - 105%

The Base Case Power Flow results indicate that present system voltages under peak conditions are at acceptable levels, with the maximum voltage drop on any feeder between substation and last customer at approximately 1.1%. However, substation voltages should be monitored to ensure proper distribution voltage levels are being maintained. In addition, during substation outages or feeder transfers, feeder voltage levels should also be monitored to ensure proper voltage levels are maintained.

The City should keep in mind the fact that minor voltage regulation can have noticeable effects on customer equipment. For example, a situation where typical household equipment experiences an under-voltage of 10 percent can result in reduced lighting output of 30 percent and can cut heating and range output by up to 20 percent. Over-voltage of 10 percent in household equipment can result in a reduction of lamp life up to 70 percent and cause overheating of heaters and ranges.

At present, customers expect an extremely high quality of service and reliable power supply. Momentary interruptions, voltage disturbances, and sine wave distortions that would have gone unnoticed a few years ago are not as well tolerated with modern day loads. Among these sensitive loads are business and home computers, cash registers, security alarms, digital devices, home business center and entertainment equipment, and other sensitive equipment.

6.4.3 Phase Current Imbalance

The primary concern of imbalanced loading between phases of a circuit is the resulting unbalanced phase voltages. Unbalanced voltages can cause additional negative sequence currents to circulate in three-phase motors. This negative sequence current can lead to motors overheating. Load imbalance also causes excessive neutral currents, which can cause increased system losses and can affect ground relaying.

Because system loads are continually changing, and since single-phase loads are present on each feeder, it is nearly impossible to achieve perfect phase balance. During high load conditions we recommend a policy of monitoring phase imbalance on each feeder. If the imbalance on any feeder exceeds 15%, loading should be transferred between phases to reduce imbalance to 10% or below. System balance may fluctuate seasonally or with system peaks, but these fluctuations should not be excessive if the policy above is followed.

Based on the field system reading on January 26, 2024, the imbalance percentages for the three substations are given in Table 6-20. For all three substations, although some feeders have an imbalance range greater than 10% but less than or equal to 15%, the overall substation imbalance rates are between 5% and 7%.

Table 6-20: Phase Imbalance of Connected Load, January 26, 2024

Feeder Number	Phase A (amp)	Phase B (amp)	Phase C (amp)	Max Imbalance (amp)	Imbalance (%)
A2000 - Business	166	154	118	20	14%
A2001 - North Main	115	145	161	21	15%
A2002 - Railroad	35	46	48	5	12%
Substation Total	316	345	327	16	5%
M3006 - North Mountain	25	32	29	3	12%
M3009 - Morton	167	134	142	19	13%
M3012 - South Mountain	131	139	121	9	7%
M3015 - Wightman	67	63	57	5	7%
Substation Total	390	368	349	21	6%
K4056 - Hwy 99	155	155	162	5	3%
K4070 - Hwy 66	110	129	102	15	13%
K4093 - East Main	123	145	122	15	12%
Substation Total	388	429	386	28	7%

We recommend that the City monitor the imbalance on all feeders during various load conditions and adjust phasing where feasible to improve overall load balance, with the goal of maintaining imbalance to below 10%. A period of monitoring is necessary following field changes of any feeder to identify the effect of the change on feeder balance. Additionally, phase balance should be considered prior to adding or reconfiguring feeder loads.

Although the phase loading and ampacity imbalance deviations shown above in themselves are not ANSI/IEEE standards violations, these conditions can result in end-of-feeder voltage imbalance that may be in violation of ANSI C84.1 standards. We suggest the City occasionally monitor voltages at the end of lengthy feeders to ensure the electric supply is operating to limit the maximum voltage imbalance to 3 percent when measured at the electric utility revenue meter under no-load conditions.

Chapter 7 POWER FLOW ANALYSIS

7.1 METHOD

The City of Ashland electric distribution system was modeled based on the following data:

- The City's distribution system maps and data compiled during the study process including updated records of conductor type, size, and phasing; transformer locations, kVA ratings and phase connections; fuse locations and ratings; switching and sectionalizing schemes; capacitor devices with ratings and connection type; and switch location and status.
- BPA point-of-delivery meter data and Ashland SCADA data for the system, substations, feeders, and large industrial/commercial/irrigation loads.
- All distribution transformers (connected loads) and their kVA ratings, entered as the corresponding load type in the analysis database. These connected loads were scaled to match the total feeder load in the model to the historical peak feeder demands.
- The most recent coincidental feeder and system peak demand of 45.9 MW from June 2021 was used as the Base Case Peak Load criteria, Case 1A.
- Case 1B is the Base Case Light Load. Data from recent years was examined, and a system load of 31.8 MW was modeled to create the conditions from January 2019.
- In the ten-year growth case, Case 2A, a system peak demand of 49.3 MW was modeled based on the load forecast projections in Chapter 3. Allocations of additional kVA are detailed in Section 7.1.2 of this chapter.
- In the twenty-year growth case, Case 2B, a system peak demand of 53 MW was modeled based on the load forecast projections from Chapter 3.
- To assess the loss of a substation transformer, the system was modeled under Base Case (1A) conditions with each substation power transformer individually removed from service and its load transferred to adjacent substation feeders. These transformer out-of-service models are evaluated and identified as Case 3A, Case 3B, Case 3C and Case 3D analyses.
- To assess the loss of a feeder, the system was modeled under Base Case (1A) conditions with each feeder circuit removed individually from service and its load transferred to adjacent feeder circuit(s). These feeder out-of-service models are evaluated and identified as Case 4 analyses (Case 4A to Case 4G).
- The observed feeder power factor varies from 0.98 to 0.997. A conservative load power factor, 0.98, was used in the model for all cases.
- BPA's voltage schedules for this area and surrounding regions are typically 117 kV to 119 kV with a 2 kV band. This system has been modeled with BPA voltage at LOW or 117 kV and all voltage regulators and LTC at a voltage set point of 123V (+2.5%) on a 120V base, as most of the cases consider historical or forecasted peak demands.

Power flow analysis was conducted based on the above data. A printout of the Milsoft model can be found in Appendix D. Analysis was performed with major load peak data and the spot feeder loads scaled as necessary to simulate historic peak demand conditions unless otherwise stated. Some loads were distributed across the various system sections proportionally to simulate peak conditions. Table 7-1 lists the City's major energy users (peak demand >= 50 kW) with their peak consumptions from 2022 to 2023. These loads and all smaller transformers were linearly scaled accordingly in the model to establish different cases described in this Chapter.

Table 7-1: Largest Industrial/Commercial Accounts, Peak Demand >= 50 kW, 2022 to 2023

Client	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug
Bards Inn	43.2	34.8	48	61.2	51.6	55.2	58.8	60	60	60	60	39.6
City Of Ashland	41.12	47.68	40.44	50.24	50.4	51.68	58.76	54.08	52.48	39.6	39.68	39.68
City Of Ashland	34.8	90.7	90.7	37.6	31.2	34.8	31.6	34	32.4	32	33.2	34.4
City Of Ashland	86.7	27.2	31.2	32.4	23.2	25.2	25.2	8	6.84	6.72	6.52	6.4
City Of Ashland, Sewage Disposal Plant	512.7	512.7	569.1	524.7	524.7	524.1	544.5	544.5	525.3	520.8	514.2	497.1
Darex Llc	115.8	104.6	73.6	57.2	57.8	57.4	60.8	59.2	63.2	78.6	93.6	90
Historic Ashland Armory	76.08	67.2	50.64	46.8	32.52	43.68	46.32	42.72	28.56	54.6	54.24	70.92
Mix	65.44	65.2	64	65.52	57.08	57.8	57.92	59.56	60.28	58.44	60.04	60.8
New Horizons Woodworks	64.4	64.4	67.2	67.2	68.6	68.6	67.4	67.7	68.2	64.1	64.4	60.7
OSFA	100.36	100.72	88.56	80.16	67	82.8	81.52	86.52	90.44	98.12	102.64	100.76
OSFA	64.4	64.4	66.8	66.8	170	164	35.6	56.8	50.8	55.6	55.6	65.6
OSFA	162	174	156	164	22	43.2	43.2	40	52	134	120.64	122.88
Pacific Rental Properties	57.24	56.16	43.36	52.96	63.36	57.12	50.72	55.64	50.56	38.68	33.92	38.56
Parks Dept Ice Rink	0.8	0.8	0.8	103.2	48	47.2	43.2	0.8	0.8	0.8	0.8	0.8
Plaza Inn & Suites	110	104	82	104	112	102	102	102	82	102	98	124
Standing Stone Brewing Co.	28.88	24.88	15.12	11.76	13.04	11.12	11.6	12.88	13.68	15.76	21.52	26.32
Standing Stone Brewing Co.	28.88	24.88	15.12	11.76	13.04	11.12	11.6	12.88	13.68	15.76	21.52	26.32
Ashland Public Schools	159.2	159.2	170.4	183.2	241.6	202.4	240	233.6	132.8	132.8	132.8	132.8
Deja Vu	26.3	11.1	3.2	4.3	4.1	4	4.9	4.1	10.8	38.5	28.1	49.7
Hillside Inn	22	22.8	42	42	48	51.2	51.2	51.2	51.2	51.2	51.2	51.2
Market Of Choice #11	166	161.6	157	143.8	148.4	144.6	138.4	144.2	147.6	160.6	158.4	163.6
National Fish & Wildlife	352.4	301.6	245	248.6	225.8	215.6	201	230.8	267.6	278.6	324.6	366.8
Science Works	50.72	49.76	50.72	50.08	55.68	52	53.76	55.36	56.8	78.24	78.72	88
Oak St. Tank & Steel	38.08	43.52	50.4	49.6	46.08	45.6	44	43.68	45.6	45.76	43.52	29.6
Ashco Inc	52.8	52.8	53.4	35.4	31.2	35.4	2.94	41.4	47.4	47.4	47.4	113.4
Ashland Ymca	142.4	112	80	80	80	76.8	76.8	80	96	110.4	136	147.2
Ashland Ymca	60	53.6	38.4	38.4	39.2	39.2	40	37.6	48	51.2	63.2	68
Ashland Automotive, Inc	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2
Holiday Inn Express	80	80	80	80	84	84	84	84	56	54	68	72
Taco Bell #1683	53.64	46.2	41.4	32.34	32.16	32.58	31.26	35.58	40.26	40.62	46.38	47.28
Caldera Brewing Co	151	161.5	135	112.5	123	119	115.5	123.5	120.5	130	153.5	137.5
Ashland Shop N Kart	101	94.9	100.3	66.8	53	53.4	57.4	53	84.3	97.7	98.9	104.7
Ashland Shop N Kart	98.4	99.2	96.48	99.2	103.68	98.88	98.08	107.36	99.36	99.52	100.16	99.68
Bi Mart	100.4	90.4	62	46.4	61.6	62.8	62.8	72.8	100	92	98	114.8
Albertsons Inc #573	258.4	227	213.8	203.8	201.4	202.2	207.4	207.4	236.4	236	243.6	249.2
OHRA	40.16	36.48	36.16	47.68	53.44	50.4	51.04	49.28	40.64	30.56	36	40.64
Yerba Prima	59.2	51.6	55.2	52	52	63.2	63.2	61.2	61.2	61.2	66.8	60.8
Windsor Inn	64.48	57.76	51.2	95.2	89.76	84.32	84.64	87.36	69.6	45.44	62.4	62.24
Scottish Inns	34.04	28	22.08	37.92	39.8	36.76	51.2	39.48	25.6	23.8	30.08	29.4
Wen Oregon, Llc	57.04	54.96	48.88	40.16	39.76	40.32	37.36	40.16	53.6	47.68	49.28	52.48
Tpi/Rite Aid, Store # 5385 1408	110.16	88.32	54.72	53.6	54.08	55.36	54.72	53.6	91.44	91.44	100.4	106.72
Donald E Lewis Retirement Center	7.6	7.6	8	13.2	116	11.6	11.6	15.6	10	116	11.6	7.6
El Paraiso Mexican Cuisine	60.8	60.8	60.8	60.8	31.2	31.2	26.4	34.8	52.4	52	54.8	56.8
Adroit Construction	36.8	33.6	50.4	60.8	61.6	62.4	62.4	62.4	62.4	62.4	62.4	39.2
Ashland Public Schools	179.8	151.8	132.8	126.2	95.8	104	96.6	94.8	170	147	187.6	155.2
Blackstone Audio, Inc	47.6	44	38	35.2	35.2	32.8	34.4	40.8	45.6	45.6	49.2	50.4
Blackstone Audio, Inc	54.92	53.52	50.28	50.2	52.72	43.72	48.96	49.44	48.6	52	54.24	54.04
City Of Ashland	26.32	50.4	48	48	51.2	48	48	48	19.84	21.12	48	51.2
Sbd Opco Company, Llc	51.6	51.6	52.8	52.8	62	66.4	54	54	54	60.4	60.4	48
Sbd Opco Company, Llc	63.6	54.6	58.2	67.2	82.8	75.6	60.6	60	56.4	69	58.2	77.4
Alexis Packer	52.96	41.96	42	43.36	41.6	43.28	41.64	45.28	45.4	48.12	52.84	52.84
Ashland Food Cooperative	150.64	129.04	108.96	102.72	104.96	101.68	104.88	103.12	136	124.56	132.08	144.24
Ashland Public Schools	193.2	183.96	193.08	205.08	198.36	201	199.56	193.68	190.56	191.76	147.24	156.24
Ashland Public Schools	105.2	96	81.76	78.32	76.16	76.4	74.96	75.36	80.88	85.84	86.16	89.36
Ashland Public Schools	122	132	132	132	110	120	138	140	158	190	156	190
Ashland Public Schools	128.9	103.7	70.1	0.9	0.9	0.9	0.9	65.4	77.4	74.5	80.7	118.6
Ashland Public Schools	44.4	18	18	18	20.4	24	24	48	36	36	36	54
Ashland Public Schools	122	132	132	132	110	120	138	140	158	190	156	190
Centurylink, Inc.	148	136	134	130	130	128	128	146	174	236	236	236
City Of Ashland	37.6	37.6	37.6	136.7	136.4	134	129.5	133.7	133.7	112.7	86.7	86.7
Cropper Medical	50.9	52.066	56.374	48.621	58.069	56.268	54.669	46.007	48.65	44.291	40.917	43.989
Ilene Rubinstein	42.4	42	48	59.6	59.2	60	53.6	53.2	53.2	53.2	53.2	43.2

Client	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug
Safeway Stores Inc. #4292	200.7	177	157.5	161.7	156.6	145.8	157.5	188.4	174	198.6	231.6	205.5
Stratford Inn	60.72	60.72	68.04	70.2	70.2	67.2	68.04	68.04	65.16	80.04	80.04	68.4
Asante	82.2	102.1	96.5	88.4	77.7	86.5	75.8	88.1	75.7	81.3	94.5	83.4
Linda Vista-Prestige Care	108	84	84	66	72	72	72	72	96	96	96	108
Maple Ridge Senior Living	140	138	144	180	188	186	190	174	180	180	180	180
Southern Oregon Chiropractic	96.4	96.4	96.4	96.4	96.4	96.4	96	96.4	96.4	96.4	96.4	96.4
William Epstein	62	51.48	50.76	47.08	47.32	44.04	49.04	48.8	46.28	56.44	53.44	57.08
Ashland Assisted Living Llc	154.4	140.8	117.6	139.8	141	151.2	143.8	143.6	121.2	117	130.4	136.8
Cpm Real Estate Services Inc.	41.77	44.98	45.6	50.29	51.28	51.97	53.03	53.03	52.64	47.56	41.5	46.15
Cpm Real Estate Services Inc.	49.6	30.4	24	25.6	27.2	25.6	25.6	25.6	24	33.6	60.8	52.8
Mountain Meadows Homeowners Assoc	84	72	66	76	84	84	72	64	72	72	86	76
Parks Dept	58.4	58.4	58.8	58.8	0.4	0.4	58.4	58.4	58.4	58.4	58.4	0.4
OSFA	53.4	53.4	53.4	53.4	53.4	53.4	31.56	31.32	33.48	37.92	53.76	53.4
Varsity Theatre	48	48	44	28	30	30	30	48	52	54	56	60
OSFA	108.64	114.08	105.12	108.48	98.6	68.96	87.2	98	105.6	107.6	140	140
Ashland Springs Hotel	196.8	191.6	164.4	175.6	170	166.4	160	174.8	181.8	190.8	196	208.6
Ashland Springs Hotel	202.8	173.6	224.4	277.6	277.6	267.2	250.8	240	188.8	214.8	240.4	244
Ashland Springs Hotel	20.2	20.2	16.2	16.8	16.6	15.6	15.4	15	18.8	191.8	212.2	203
OSFA	71.2	76	76	76	47.2	30.4	110	104	134	60	68	32
Domestic Solutions Llc.	20.4	20	20	22	16	16	10	11	14	19	16.8	140
Jackson County Library District	72.8	72.8	72.8	72.8	64.8	64.8	64.8	64.8	64.8	59.2	61.6	61.92
Ev Charging Solutions, Inc	7.12	7.16	7	3.68	7.12	6.96	7.12	57.36	49.72	7.16	54.36	58.84
Ashland Elks Lodge #944	50.16	39.92	30.48	33.28	28.88	33.52	31.88	42.68	48.56	46.04	52.68	46.88
SOU	65.28	65.28	66.24	76.48	74.24	75.52	84.4	84.4	60.16	76	76.48	76.48
SOU/Physical Plant Department	902.4	828	861.6	880.8	849.6	873.6	900		892.8	871.2	878.4	844.8
Vishal Patel	48	38.4	58.8	57.6	57.6	61.2	67.2	67.2	67.2	50.4	54	54
City Of Ashland, Electric Dept-Tracking	200.4	193.5	155.7	156.3	171	167.1	160.5	155.1	149.7	160.8	176.7	183.9
City Of Ashland, Service Ctr	32.76	96.72	123.72	123.72	123.72	123.72	147.6	147.6	147.6	147.6	147.6	36
City Of Ashland	52	24.6	20.36	18.36	19.96	19.72	19.2	19.08	32	32	19.44	23.48
Hull Properties	116.8	109.76	114.88	151.68	177.44	172.8	173.76	184.48	167.2	102.08	100.8	108.48
Lachlan Scotland	73.2	73.2	73.2	73.2	50	37.2	46.8	59.6	64	70.8	86	61.2
Lachlan Scotland	123.4	110	102.6	123.2	108.6	78.8	119.4	139.2	145	144	145.8	137
OSFA	128.4	138	114.8	96.2	68.16	77.8	51.2	55.52	54.72	54.24	115	117.4
Sou/Physical Plant Department	1322.4	1216.8	1075.2	496.8	504	463.2	482.4	484.8	928.8	1046.4	1111.2	1012.8
Sou/Physical Plant Department	861.6	837.6	828	756	758.4	756	712.8	679.2	708	727.2	744	744

7.1.1 Evaluation Criteria

The following electrical criteria were used in power flow analysis.

- Overvoltage: >105%
- Undervoltage: <95%
- Overload: >100% equipment capacity
- Overload warning: >=90% and <=100%

Service voltages should be maintained in the acceptable range per ANSI C84.1 as discussed in Section 6.3.2. Equipment running above its rated capacity is considered an overload and is recommended to be upsized. Equipment identified as an overload warning is recommended to be monitored and considered in the future improvement plan.

7.1.2 Power Flow Result Understanding

In general, caution should be practiced when interpreting system problems indicated by the power flow analyses. Power flow results typically identify system problems such as heavily loaded or overloaded conductors and undervoltage conditions. The modeled conditions are the result of analysis under peak or other ‘worst case’ conditions that may be considered extreme. The goal is to evaluate system operation under realistic worst-case conditions. We recommend that where problems are noted, the City should verify that the actual system components and conditions support the analysis conclusions.

Also, as with any model, the results will only be as accurate as the data used. For example, conductor sizes and materials, system component phasing, and interconnectivity are modeled using information from the City's distribution system detail maps and correspondence with City staff. If there is inaccuracy in the map compilation or any parameter of the data characteristics, there could be inaccuracy in the results.

7.2 Power Flow Case, Load Allocation and Results

NORMAL CONFIGURATION

To evaluate the electric system's capacity and operating concerns in the existing (or normal) system configuration, the following scenarios were analyzed:

7.2.1 Case 1A: Base Case Peak Load

The Base Case Peak Load power flow analysis was performed under the most recent peak load conditions. Based on load data from BPA metering system, a coincident demand of 45.9 MW occurred on June 28, 2021. The modeled loads for Ashland Substation, Mountain Avenue Substation, and Oak Knoll Substation are approximately 14.3 MW, 14.2 MW, and 17.6 MW consecutively, based on the distribution system loading. The PacifiCorp-owned Ashland Substation and Oak Knoll Substation have separate feeders for PacifiCorp's customers. At the same time during the historical peak in 2021, the estimated PacifiCorp loads in Ashland Substation and Oak Knoll Substation are approximately 4.3 MW and 5.5 MW, which was modeled to evaluate the substation transformers. This power flow model evaluates the system in its normal configuration with each substation serving its own feeders.

The feeder loading (kW) and power factor from the power flow results of Case 1A are summarized in Table 7-2. The results of this analysis indicate that there are no conductor and transformer overload problems or bus voltage problems for the majority of the City's electric system.

Table 7-2: Case 1A Power Flow Details

Feeder Load	kW	PF (%)	Amps
A2000 – Business	6,321	98.0	291.4
A2001 – North Main	6,192	97.7	286.1
A2002 – Railroad	1,819	98.0	98.0
M3006 – N. Mountain	985.6	98.9	45.0
M3009 – Morton	5,683	97.9	262.1
M3012 – S. Mountain	5,131	97.5	237.8
M3015 – Wightman	2,403	98.1	110.7
K4056 (5R56) – HWY 99	6,699	97.3	311.1
K4070 (5R70) – HWY 66	4,748	97.8	219.3
K4093 (5R93) – E. Main	6,168	97.0	287.3
Ashland System Load	**kW**		
	46,150[(a)]		
Substation Load	**kW**		
AS Transformer	18,795[(b, c)]		
MAS Transformer	14,267		
OKS Transformer T1	12,265[(b, c)]		
OKS Transformer T2	10,955		

a) System noncoincident peak load is slightly different from the peak load as discussed previously due to scaling factors and system losses.
b) Ashland Substation load includes ~4.3 MW for PacifiCorp.
c) Oak Knoll Substation load includes ~5.5 MW for PacifiCorp.

Feeder backbone voltage profiles based on the power flow analysis for Case 1A are shown in Figure 7-1 to Figure 7-10. The feeder voltages appear to be in acceptable ranges for utility services and reasonably balanced. Depending on the load distribution, some of the backbone fuses, 140K and 100K, along the Ashland/Business feeder are recommended to be monitored, as they may reach their rated capacity.

The estimated peak load in Ashland Substation in this case is only 6% away from the transformer overload rating of 20 MVA. PacifiCorp typically uses 120% of the nameplate rating as their guide for Winter capacity rating, however, the City of Ashland has a Summer peak load pattern. The available summer capacity at Ashland Substation is near capacity and could become underrated with future load growth or extreme weather events.

The transformers at the other two substations appear to have sufficient capacity for the historical peak loads and there is room for future load growth for normal feeder switching configuration.

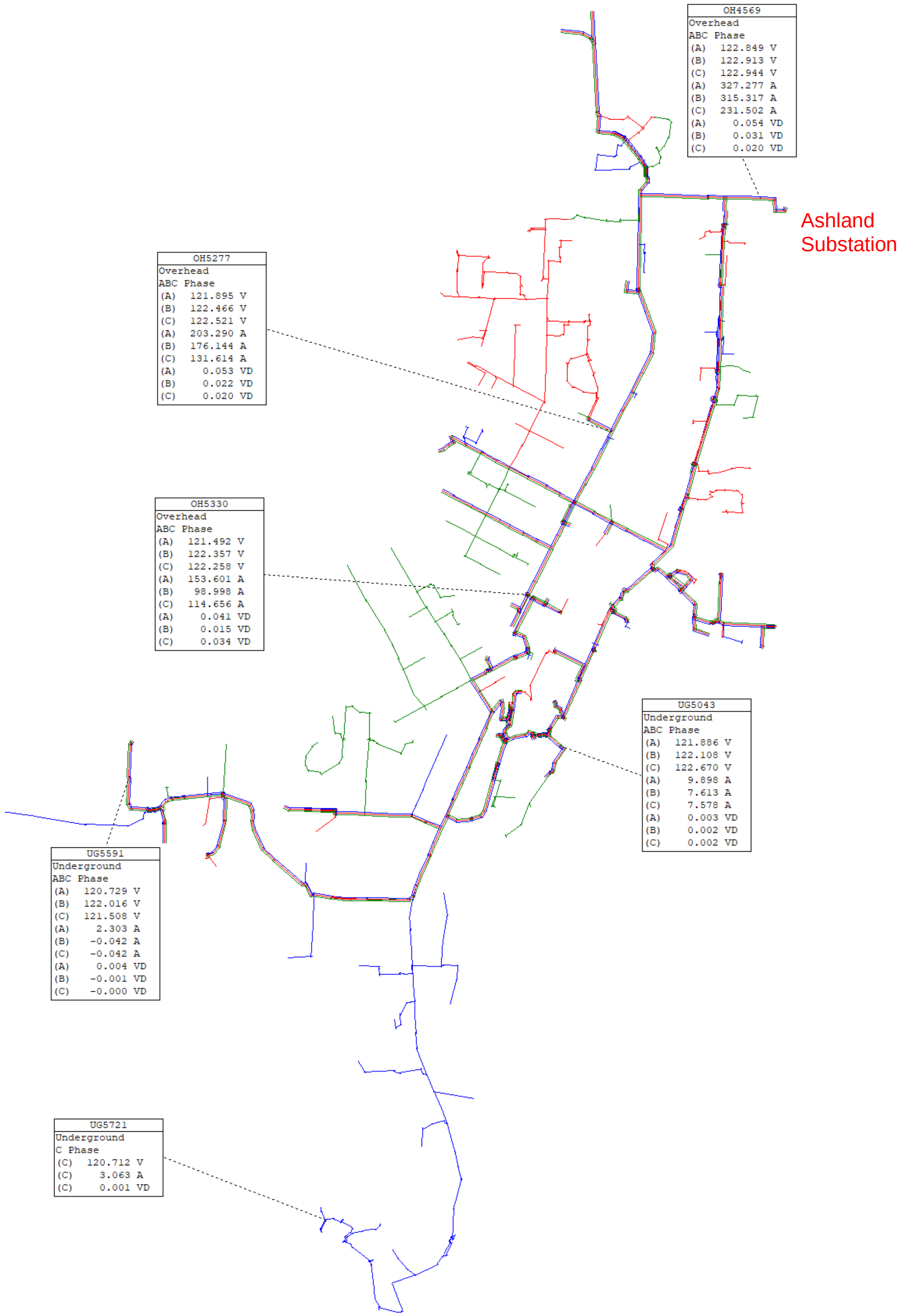


Figure 7-1: Case 1A Voltage Profiles – Ashland Substation / Business Feeder

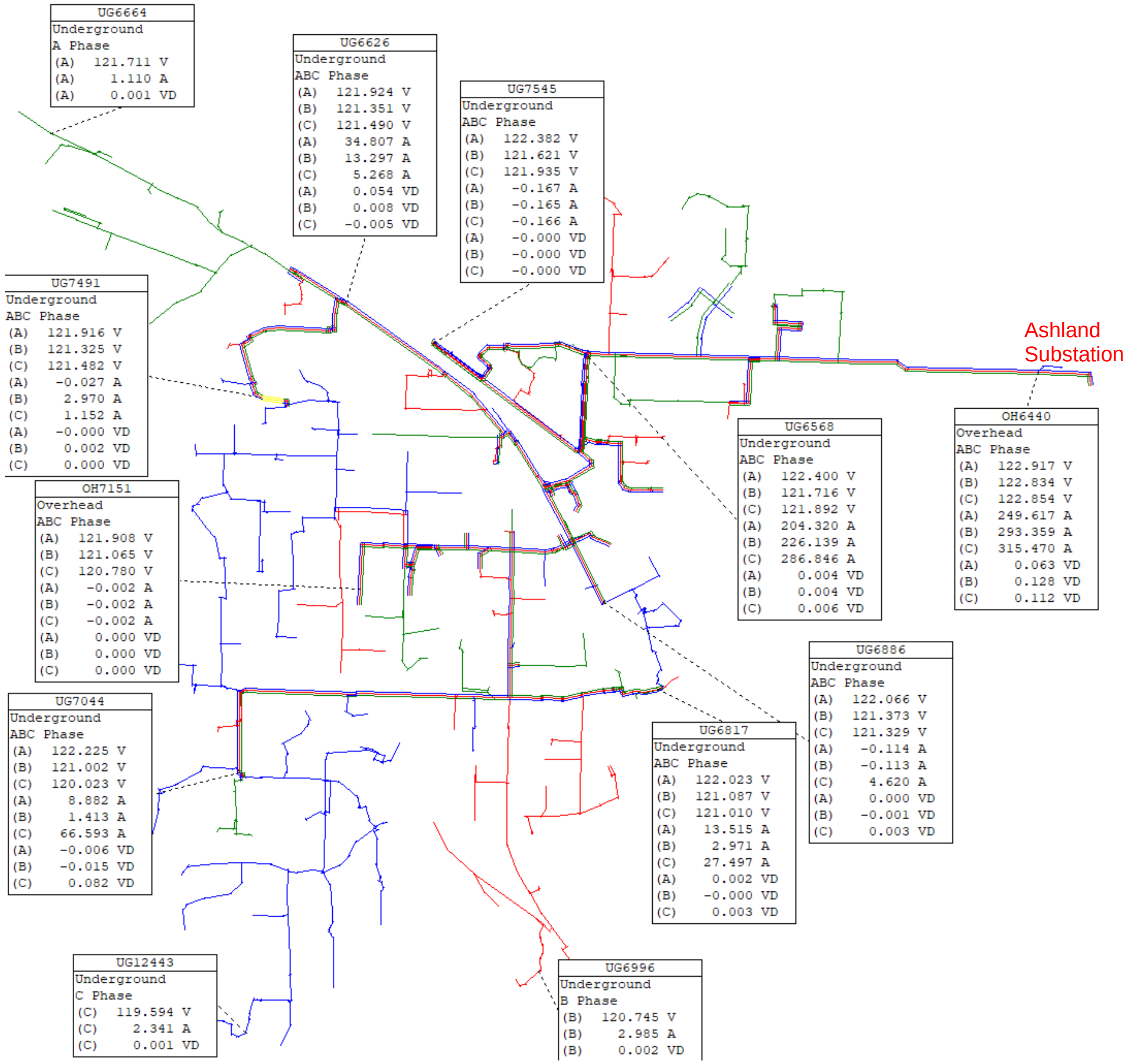


Figure 7-2: Case 1A Voltage Profiles – Ashland Substation / North Main Feeder

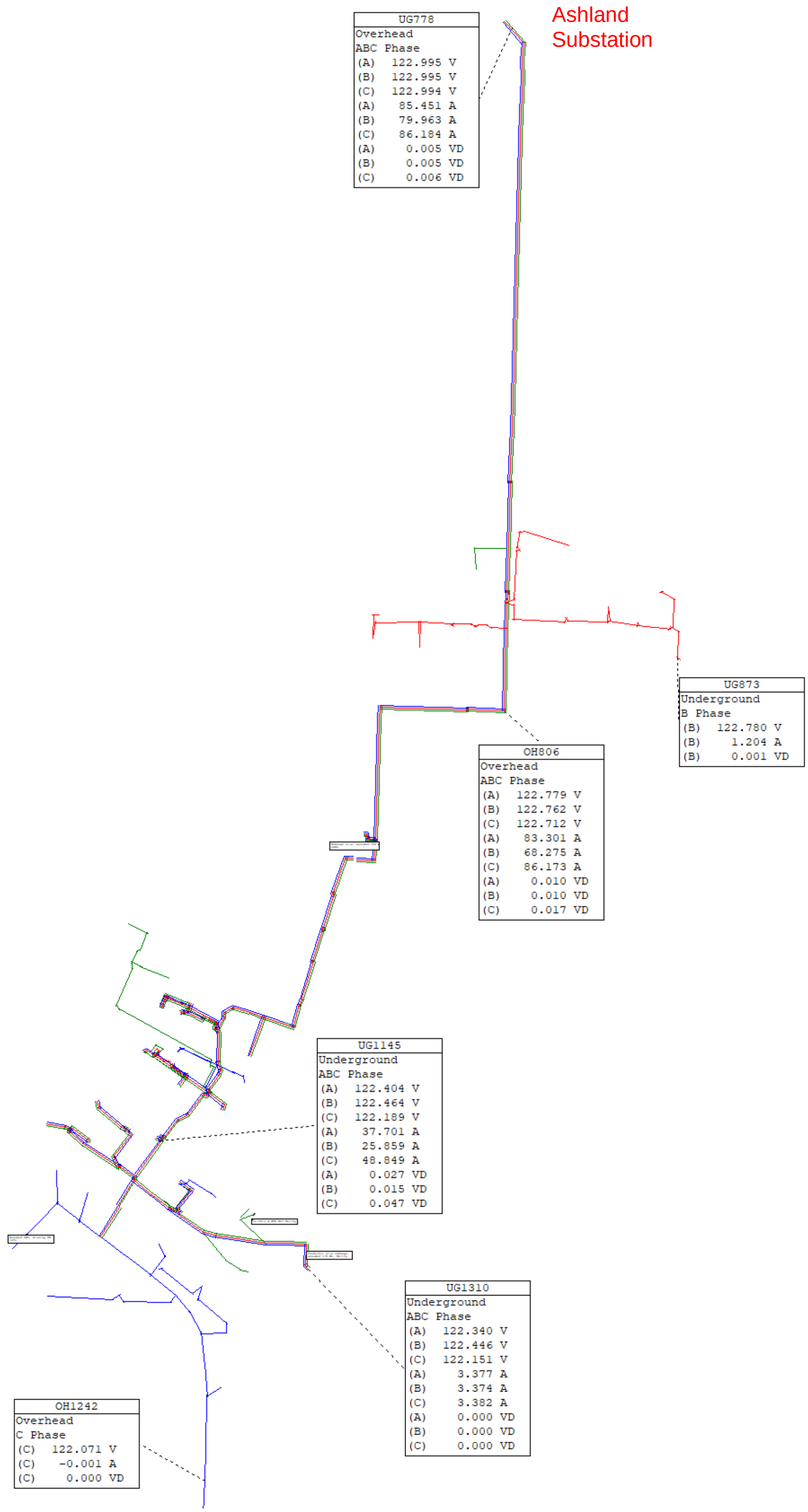


Figure 7-3: Case 1A Voltage Profiles – Ashland Substation / Rail Road Feeder

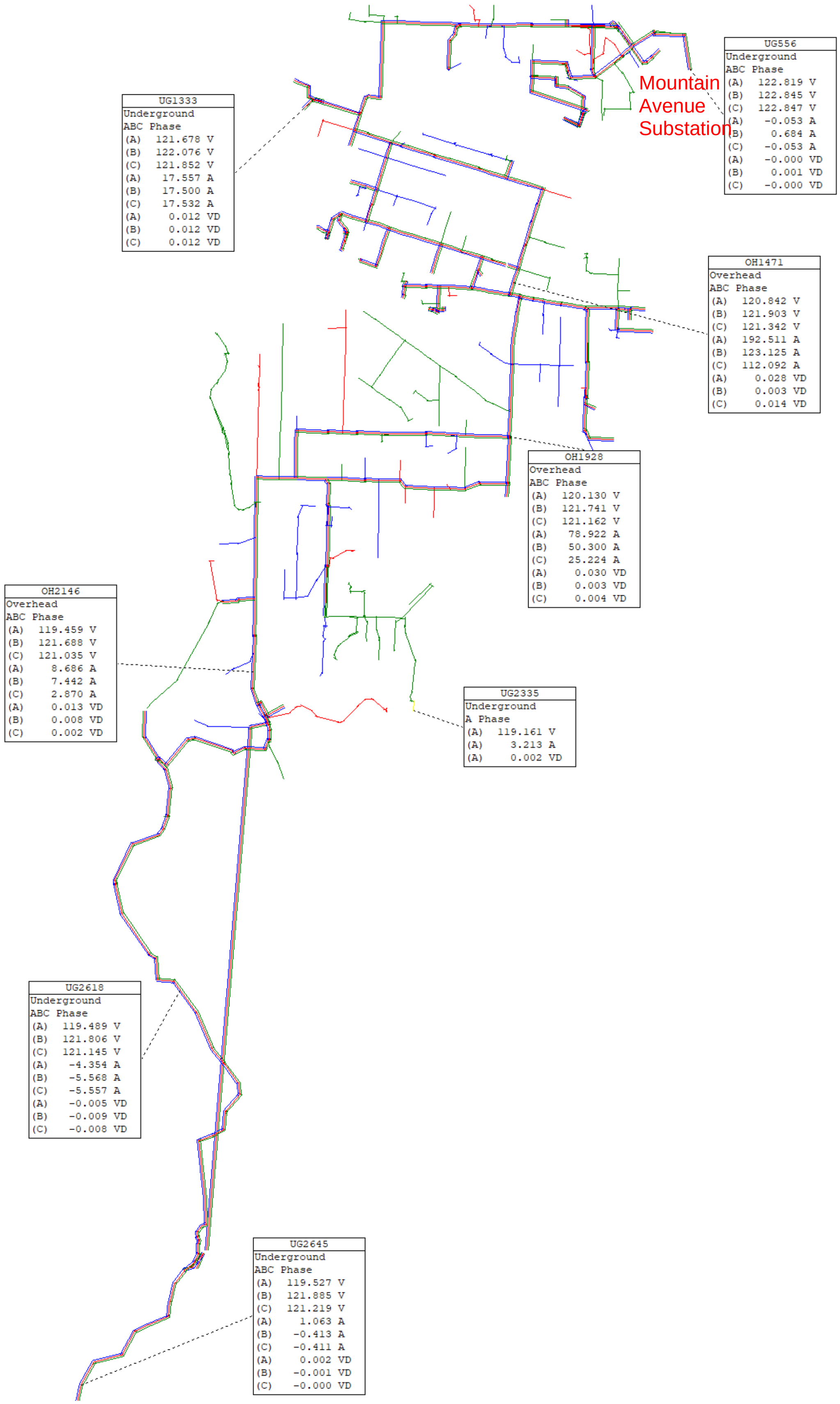


Figure 7-4: Case 1A Voltage Profiles – Mountain Avenue Substation / Morton Feeder

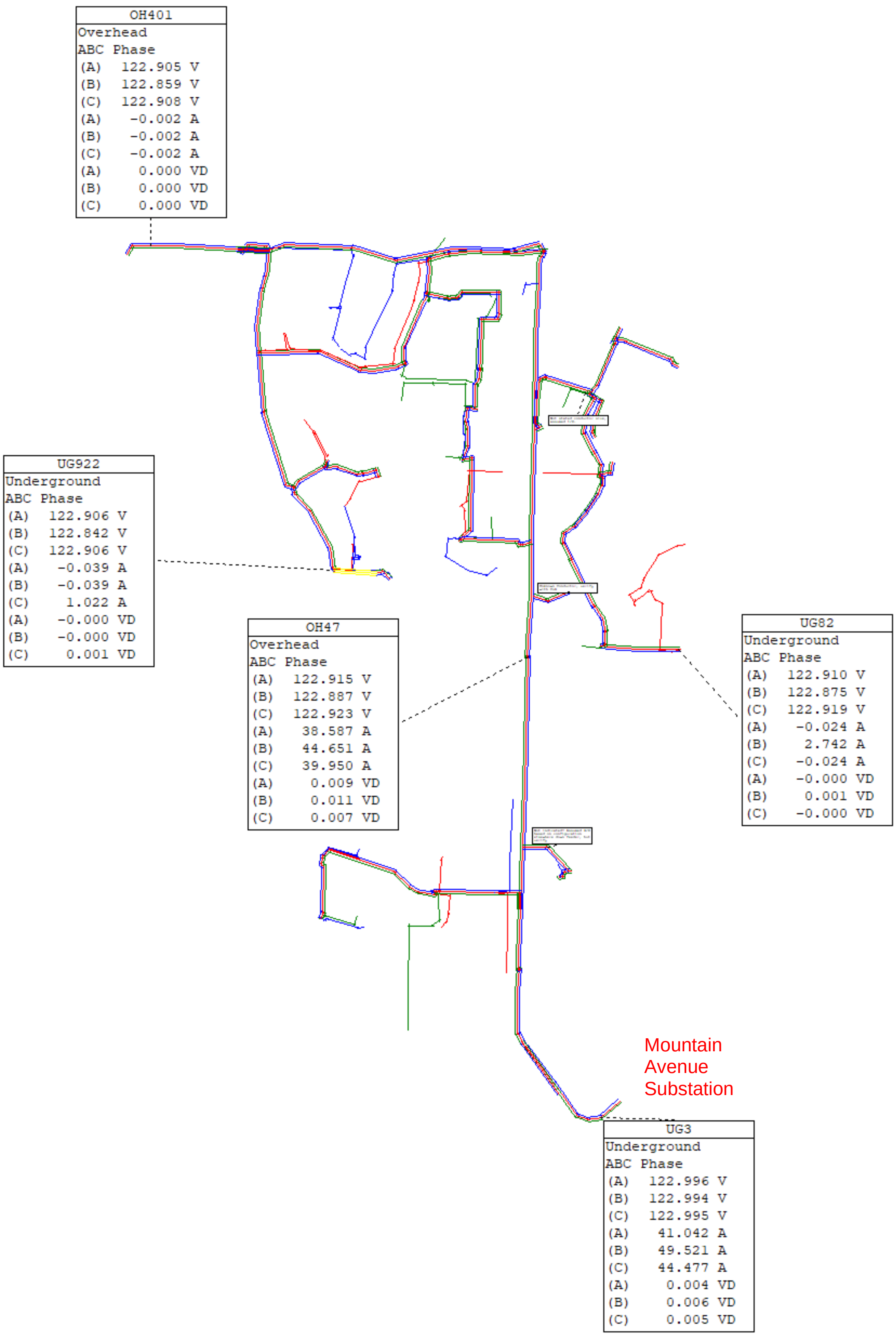


Figure 7-5: Case 1A Voltage Profiles – Mountain Avenue Substation / North Mountain Feeder

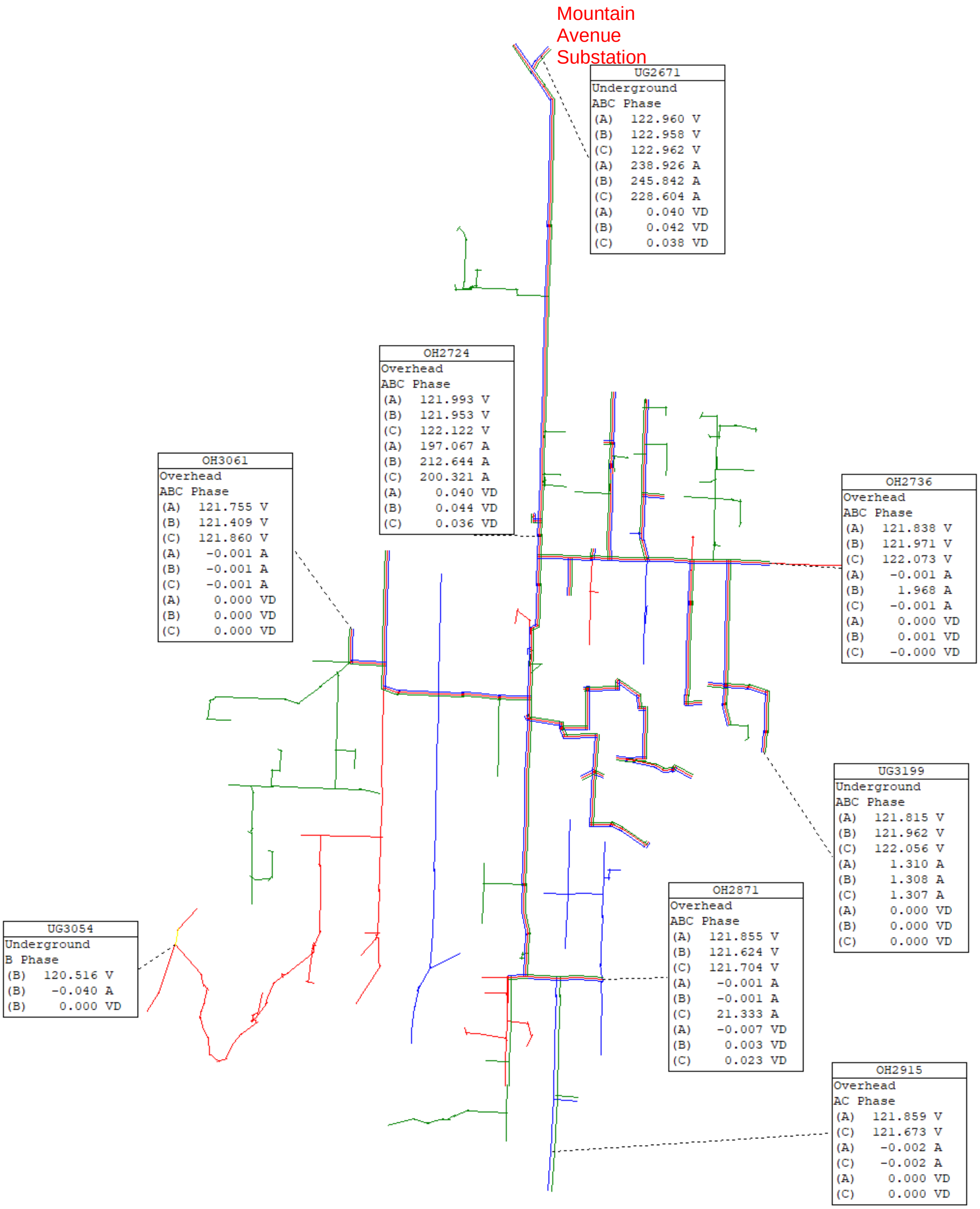


Figure 7-6: Case 1A Voltage Profiles – Mountain Avenue Substation / South Mountain Feeder

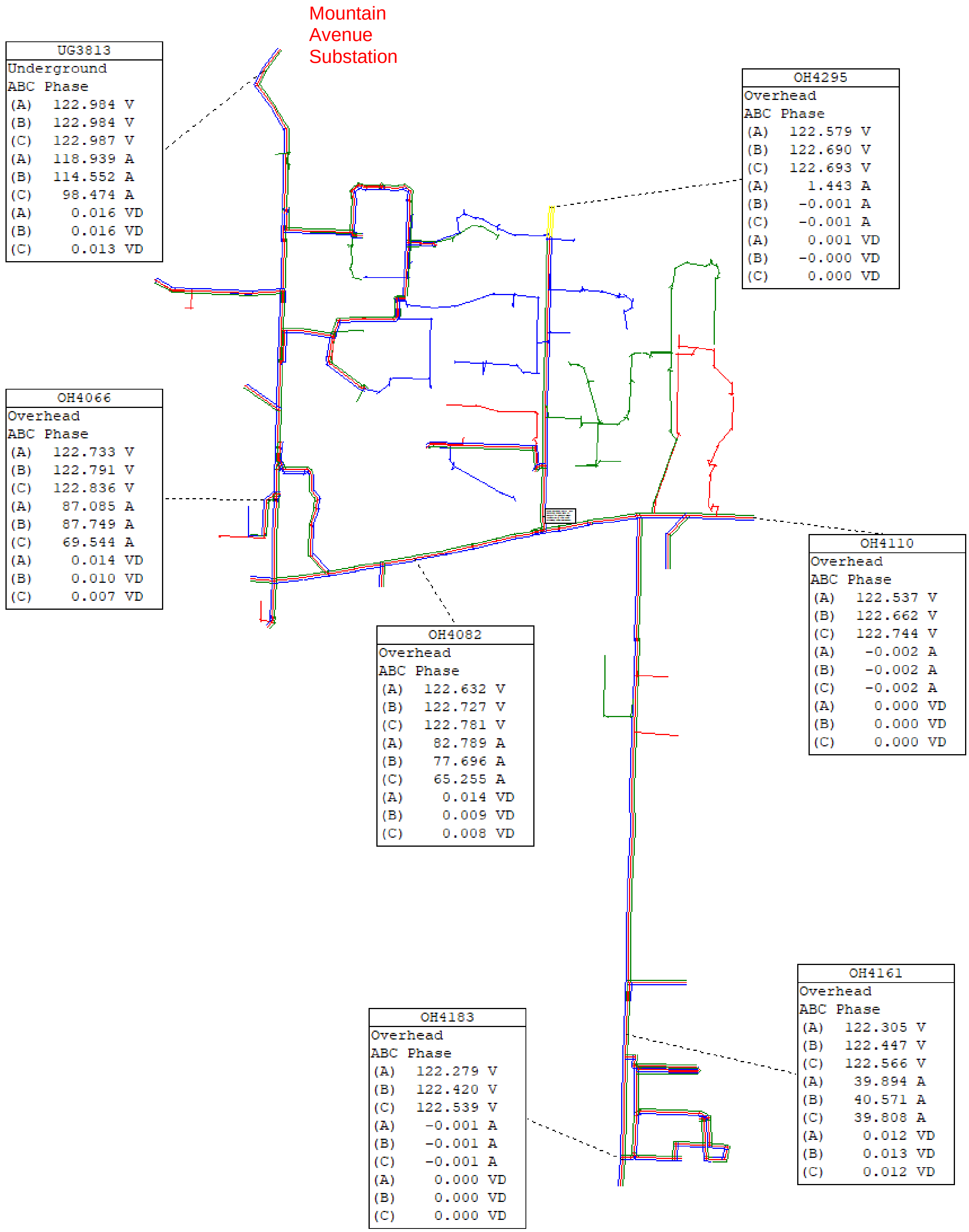


Figure 7-7: Case 1A Voltage Profiles – Mountain Avenue Substation / Wightman Feeder

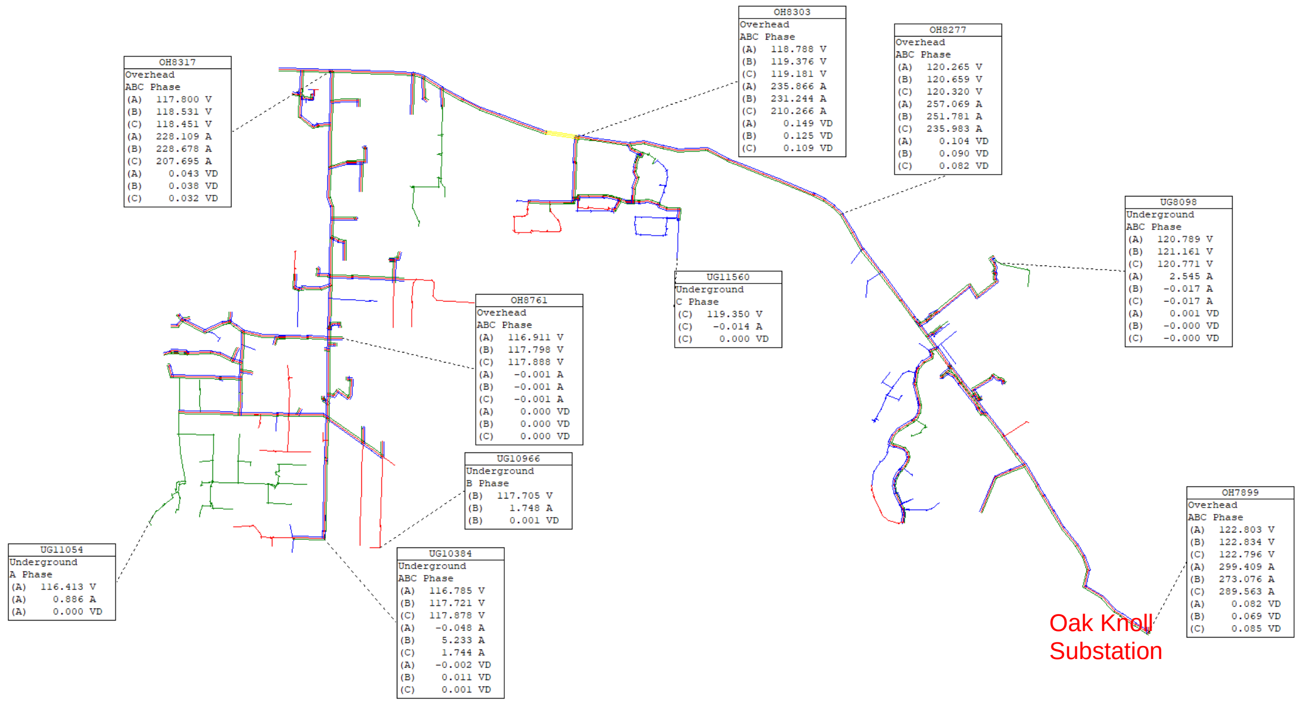


Figure 7-8: Case 1A Voltage Profiles – Oak Knoll Substation / East Main Feeder

At the end of the East Main feeder, Phase A voltage is close to 0.97 pu, which is still acceptable for utility delivery voltages.

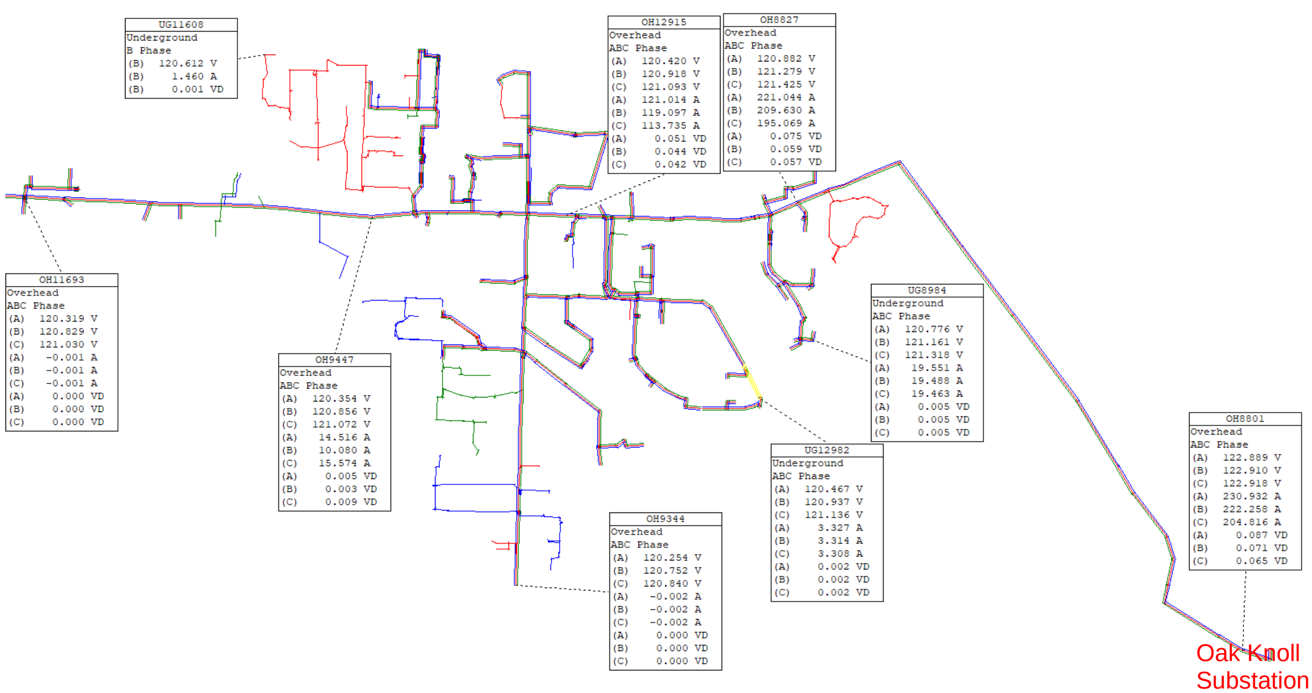


Figure 7-9: Case 1A Voltage Profiles – Oak Knoll Substation / HWY 66 Feeder

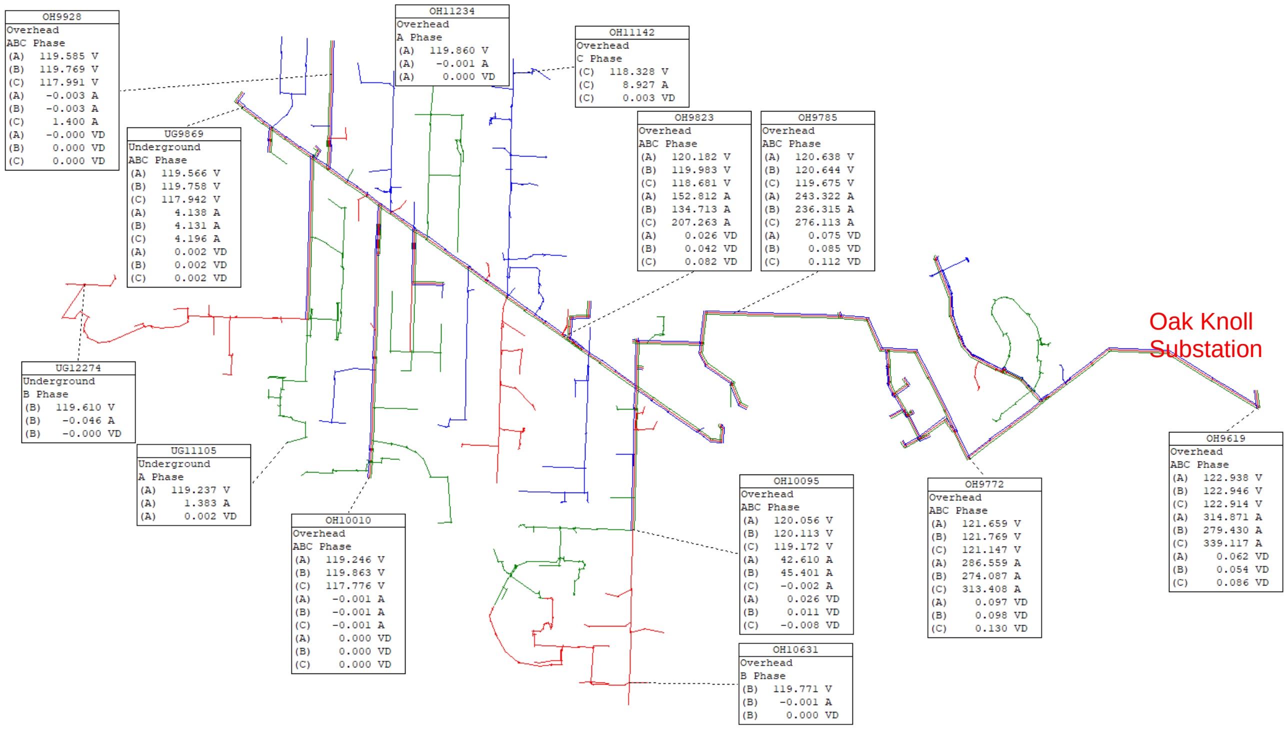


Figure 7-10: Case 1A Voltage Profiles – Oak Knoll Substation / HWY 99 Feeder

7.2.2 Case 1B: Base Case Light Load

To determine representative light load conditions for modeling, we examined the BPA metered demand data from recent years. A system demand of 31.8 MW was modeled based on data from January 2019. Similarly, load was distributed to each feeder using historical observations of BPA load data and the City's records on large customers. Small loads were linearly scaled down to achieve the base case light load level.

The results indicate that there are no conductor and transformer overload problems, or bus over/undervoltage violations. The feeder loading (kW) and power factor from the power flow results of Case 1B are shown in Table 7-3.

Table 7-3: Case 1B Power Flow Details

Feeder Load	kW	PF (%)	Amps
A2000 – Business	4,199	98.2	193.1
A2001 – North Main	4,036	98.1	185.8
A2002 – Railroad	1,192	98.1	54.9
M3006 – N. Mountain	773	99.1	35.2
M3009 – Morton	4,461	98.1	205.4
M3012 – S. Mountain	4,068	97.5	188.4
M3015 – Wightman	1,968	98.2	90.5
K4056 (5R56) – HWY 99	4,246	97.7	196.2
K4070 (5R70) – HWY 66	3,017	98.2	138.8
K4093 (5R93) – E. Main	3,897	97.7	180.2
Ashland System Load	**kW**		
	31,857 [(a)]		
Substation Load	**kW**		
AS Transformer	13,812[(b, c)]		
MAS Transformer	11,310		
OKS Transformer T1	9,787 [(b, c)]		
OKS Transformer T2	6,929		

a) System noncoincident peak load is slightly different from the peak load as discussed previously due to scaling factors and system losses.
b) Ashland Substation load includes ~4.3 MW for PacifiCorp.
c) Oak Knoll Substation load includes ~5.5 MW for PacifiCorp.

7.2.3 Case 2A: Ten-Year Growth Case

The load forecast presented in Chapter 3 calls for an additional 3.4 MW of peak demand growth considering a 0.72% annual growth rate. The modeled allotment of the growth was implemented by linearly scaling up the load profile in the base Case 1A. Adding these loads results in a combined peak load of 49.3 MW distributed as shown in Table 7-4.

No undervoltage or overvoltage violations were observed in the ten-year growth case based on normal regulator bank operation. The substation transformers have sufficient capacity except for the transformer in the Ashland Substation. PacifiCorp customer loading of 4.3 MW and 5.5 MW were considered in Ashland Substation and Oak Knoll Substation respectively, along with their historical last 10 year peaks of approximately 5.5 MW and 9 MW. Considering the assumed load growth and PacifiCorp's loads, the total substation load in Ashland Substation will likely exceed the transformer overload rating of 20 MVA by 5% to 10%. PacifiCorp typically adds 20% to the nameplate rating as their guide for Winter capacity rating, however, it does not compensate for the City of Ashland Summer peak loading pattern.

If PacifiCorp does not upgrade Ashland Substation with a larger transformer or add a second transformer in parallel in the next decade, we recommend the City consider building a new Nevada Substation with a 15/20/25 MVA transformer with the benefits of zero wheeling cost or transformation cost, full control of the substation, improved service reliability and backup capability. With the new substation, the distribution circuits could be reconfigured to extend and pick up portions of Oak Knoll feeders to reduce PacifiCorp dependence and transformation charges at Oak Knoll Substation.

Depending on the load distribution, some of the backbone fuses, 140K and 100K, along the Ashland/Business feeder are recommended to be monitored, as they will likely exceed their rated capacity.

Table 7-4: Case 2A Power Flow Details

Feeder Load	kW	PF (%)	Amps
A2000 – Business	6,904	97.9	318.5
A2001 – North Main	6,638	97.5	306.9
A2002 – Railroad	1,954	97.9	90.1
M3006 – N. Mountain	985.6	98.9	45.0
M3009 – Morton	6,126	97.8	282.8
M3012 – S. Mountain	5,511	97.4	255.4
M3015 – Wightman	2,580	98.2	118.8
K4056 (5R56) – HWY 99	7,212	97.1	335.3
K4070 (5R70) – HWY 66	5,112	97.7	236.3
K4093 (5R93) – E. Main	6,640	96.8	309.8
Ashland System Load	**kW**		
	49,663 [a]		
Substation Load	**kW**		
AS Transformer	19,982[b, c]		
MAS Transformer	15,276		
OKS Transformer T1	12,784 [b, c]		
OKS Transformer T2	11,796		

a) System noncoincident peak load is slightly different from the peak load as discussed previously due to scaling factors and system losses.
b) Ashland Substation load includes ~4,3 MW for PacifiCorp.
c) Oak Knoll Substation load includes ~5.5 MW for PacifiCorp.

7.2.4 Case 2B: Twenty-Year Growth Case

Combined with the load additions for the previous growth case and the same growth rate, the Load Forecast presented in Chapter 3 calls for an additional 3.7 MW of peak demand growth for the twenty-year analysis. Similarly, the modeled allotment of the growth was implemented by linearly scaling up the load profile in Case 2A. Adding these loads results in a combined peak load of 53 MW distributed as shown in Table 7-5.

No undervoltage or overvoltage violations were observed in the twenty-year growth case based on normal regulator bank and operation. As expected, the 20-year growth case results show that the observed concerns noted for Case 2A will be further worsened. Some smaller-sized transformers could likely reach their rated capacity (between 90% and 100%) if not overloaded.

Table 7-5: Case 2B Power Flow Details

Feeder Load	kW	PF (%)	Amps
A2000 – Business	7,429	97.9	342.9
A2001 – North Main	6,380	97.7	295.0
A2002 – Railroad	2,099	97.9	96.9
M3006 – N. Mountain	1,147	98.8	52.5
M3009 – Morton	6,255	97.8	288.8
M3012 – S. Mountain	5,925	97.4	274.8
M3015 – Wightman	2,836	98.0	130.7
K4056 (5R56) – HWY 99	7,752	97	360.8
K4070 (5R70) – HWY 66	5,494	97.7	254.1
K4093 (5R93) – E. Main	7,148	96.6	334.0
Ashland System Load	**kW**		
	52,500 [(a)]		
Substation Load	**kW**		
AS Transformer	20,404[(b, c)]		
MAS Transformer	16,247		
OKS Transformer T1	13,31 [(b, c)]		
OKS Transformer T2	12,694		

a) System noncoincident peak load is slightly different from the peak load as discussed previously due to scaling factors and system losses.
b) Ashland Substation load includes ~4,3 MW for PacifiCorp.
c) Oak Knoll Substation load includes ~5.5 MW for PacifiCorp.

SECTIONALIZED CONFIGURATIONS

To evaluate the electric system's switching flexibility during outage conditions, sectionalized power flow cases were performed under the Base Case (Case 1A) loading, 45.9 MW. The following scenarios were analyzed:

- Individual substation transformer outages and substation outages
- Individual distribution feeder outages

7.2.5 Loss-of-Transformer Cases

Cases 3A to 3D modeled the base case as a sectionalized system under peak load with each substation power transformer source out-of-service, and its load transferred accordingly. For each loss-of-substation transformer scenario, the system is configured as identified in Table 7-6.

Case 3A Ashland Substation Transformer Out-Of-Service

The following system switching was modeled to simulate the necessary switching and transfer of Ashland substation load to other substation transformers.

- Close SW-1073 to tie A2001 to A2000, close SW-1064 to serve both A2000 and A2001 from M3006.
- Close SW-1068 to serve A2002 from M3009.

With the switching detailed above, all Ashland Substation load is transferred to Mountain Avenue Substation feeders. The Mountain Avenue Substation transformer is heavily overloaded to ~160% of the nameplate fan-cooled overload capacity. Configuring the system as described will significantly reduce the transformer's service life. In addition, the existing protection settings (typically 150%) would likely trip the transformer off-line. Similarly, the 3-phase voltage regulator will be overloaded. The North Mountain feeder would be required to serve approximately 13.8 MW of load, and segments of conductor along the North Mountain feeder would be at capacity or overloaded as described below:

- The main 750 kcmil UG getaway will be loaded to 130% of capacity, 13.82 MW vs. 10.58 MW rating.
- The main 556 kcmil AAC overhead cables will be loaded to 109% of capacity, 13.69 MW vs. 12.61 MW summer rating.
- The section of 750 kcmil UG cable between E6603 and E8601 is overloaded to 121% of capacity, 12.77 MW vs. 10.58 MW rating.
- The section of 336.4 kcmil AAC overhead cable connecting M3006 to the Ashland Substation circuits is loaded to 138% of capacity, 12.61 MW vs. 9.11 MW summer rating.

Based on the above, Mountain Avenue Substation does not seem to have sufficient capacity to back up the City's peak loads supplied by Ashland Substation. The backbone circuit capacity for North Mountain feeder is not rated for a total of 13.8 MW of loads. The City will have to make significant upgrades (i.e., installing a second transformer in parallel) at the Mountain Avenue Substation and its feeder to make the 100% backup feasible for peak conditions.

Table 7-6: System Sectionalizing Analysis - Single Transformer Bank Outage

Case	Substation & Feeder	Peak Load (kW)	Sectionalized Peak (kW)	Sectionalized Peak (kW)	Sectionalized Peak (kW)	Sectionalized Peak (kW)
Case 3A	**Ashland Substation**	18,795	**AS XFMR Out of Service** [a]	31,008	18,795	18,795
	A2000 - Business	6,321	To M3006	12,490	6,321	6,321
	A2001 - North Main	6,192	To M3006	6,192	6,192	6,192
	A2002 - Railroad	1,819	To M3009	7,531	1,819	1,819
Case 3B	**Mountain Avenue Substation**	14,267	28,908	**MAS XFMR Out of Service**	14,267	14,267
	M3006 - N. Mtn	985.6	13,844	To A2000	985.6	985.6
	M3009 – Morton	5,683	7,530	To A2002	5,683	5,683
	M3012 – S. Mtn	5,131	5,131	To A2000	5,131	5,131
	M3015 – Wightman	2,403	2,403	To K4093	2,403	2,403
Case 3C	**Oak Knoll Substation**	23,226	23,226	25,819	**OKS XFMR K1 Out of Service**	
	K4056 – HWY 99	6,699	6,699	6,699	To XFMR K2	
	K4070 – HWY 66	4,748	4,748	4,748	---	
	K4093 – E. Main	6,168	6,168	8,745	---	
Case 3D	**Oak Knoll Substation**	23,226	23,226	25,819	23,295	**OKS XFMR K2 Out of Service**
	K4056 – HWY 99	6,699	6,699	6,699	6,699	---
	K4070 – HWY 66	4,748	4,748	4,748	4,748	To XFMR K1
	K4093 – E. Main	6,168	6,168	8,745	6,168	To XFMR K1

a) PacifiCorp load is not included in the load transfer analysis.

Case 3B Mountain Avenue Substation Transformer Out-Of-Service

The following system sectionalizing was modeled to simulate the necessary switching and transfer of Mountain Avenue substation load to other substation transformers.

- Close SW-1062 to tie M3006 and M3012, and close SW-1064 to feed M3006 and M3012 from A2000.
- Close SW-1068 to feed M3009 from A2002.
- Close SW-1051 to feed M3015 from 5R93.

With the sectionalizing described above, the Ashland Substation transformer and regulators are severely overloaded to 173% and 130%, respectively, of nameplate fan-cooled capacity under peak loading with Mountain Avenue Substation out-of-service. The transformer at Oak Knoll Substation seems to be sufficient. No additional overload or low voltage conditions are encountered with normal regulator operations.

If the City desires to pursue a 100% backup, significant upgrades will be required at Ashland Substation, or the development of a new City-owned Nevada Substation as discussed under Section 7.2.3.

Case 3C Oak Knoll Substation Transformer K1 Out-Of-Service

When Transformer K1 (12/16/20 MVA) is out of service, Transformer K2 (15/20/25 MVA) needs to support 23.3 MW (or 24.8 MVA) of load, which is just below the nameplate overload rating. No additional overload or low voltage conditions are encountered with normal regulator operations.

Case 3D Oak Knoll Substation Transformer K2 Out-Of-Service

When Transformer K2 is out of service, Transformer K1 needs to support 23.4 MW (or 25.4 MVA) of load, which is about 27% above its nameplate overload rating. The LTC within this transformer can maintain all the service voltage to acceptable ranges.

7.2.6 Loss-of-Substation Cases

Case 3A and Case 3B are essentially the cases for loss of Ashland substation and loss of Mountain Avenue Substation. As discussed above, loss of either substation at peak load will result in severe transformer overload conditions at other substations, which would risk accelerating the loss-of-life on transformers and cables. The level of overload may not be allowed by typically thermal overload protection, which indicates the City might not have a sufficient backup during peak load conditions as discussed.

When Oak Knoll Substation is out (or loss of the two transformers), the Oak Knoll feeders will have to be supported by Mountain Avenue Substation based on the substation and feeder locations. However, the transformer at Mountain Avenue Substation (12/16/20 MVA) is expected to be loaded close to 75%, resulting in 5 MW of reserved capacity. It might be enough to support one of the three Oak Knoll Substation feeders, but will not have adequate capacity to be considered a full backup source. Under this condition without a second transformer at Mountain Avenue Substation (as discussed under Case 3B), it is assumed PacifiCorp would utilize their portable transformer(s) to keep the Oak Knoll Substation feeders energized.

7.2.7 Loss-of-Feeder Cases

Cases 4A to 4K modeled the base case as a sectionalized system under peak load with each distribution feeder circuit's source out-of-service, and its load transferred to the adjacent feeder(s) accordingly. For each feeder out-of-service condition, the system is configured as identified in Table 7-7.

Case 4A AS/A2000 Business Feeder Out-Of-Service

Close SW-1073 to feed AS/A2000 from AS/A2001.

A distribution feeder is typically designed with a maximum of approximately 7.5 MW (~340 A) normal operation capacity and 11 MW (~490 A) temporary or emergency rating. After switching, no voltage concerns were observed; Feeder A2001 likely needs to carry 12.7 MW of load, which is 15% above the emergency rating. Additionally, the 750 kcmil AL underground conductors along Vansant Street are expected to have a through load of 11.58 MW during the analyzed peak condition, which exceeds its in-duct rating 9.18 MW (as shown in Chapter 4) by 26%. This won't work for the in-duct cables, and the City will have to feeder a portion of A2000 from another feeder other than A2001 to avoid that.

Case 4B AS/A2001 North Main Feeder Out-Of-Service

Close SW-1073 to feed AS/A2001 from AS/A2000.

After switching, Feeder A2000 is expected to be loaded to 12.6 MW, which is 15% above the emergency rating. No voltage concerns and overloaded conductors were observed in this case.

Case 4C AS/A2002 Railroad Feeder Out-Of-Service

Close SW-1068 to feed AS/A2002 from MAS/M3009.

After switching, Feeder M3009 is expected to be loaded to 7.5 MW. No voltage concerns and overloaded conductors were observed in this case.

Case 4D MAS/M3006 N. Mountain Feeder Out-Of-Service

Close SW-1062 to feed MAS/M3006 from MAS/M3012.

After switching, Feeder M3012 is expected to be loaded to 6.1 MW. No voltage concerns and overloaded conductors were observed in this case.

Case 4E MAS/M3009 Morton Feeder Out-Of-Service

Close SW-1020 to feed MAS/M3009 from MAS/M3015.

After switching, Feeder M3015 is expected to be loaded to 8.1 MW. No voltage concerns and overloaded conductors were observed in this case.

Case 4F MAS/M3012 S. Mountain Feeder Out-Of-Service

Close SW-1062 to feed MAS/M3012 from MAS/M3006.

After switching, Feeder M3006 is expected to be loaded to 6.1 MW. No voltage concerns and overloaded conductors were observed in this case.

Case 4G MAS/M3015 Wightman Feeder Out-Of-Service

Close SW-1051 to feed MAS/M3015 from OKS/K4093.

After switching, Feeder OKS/K4093 is expected to be loaded to 8.745 MW, which is about 17% above the 7.5 MW typical maximum normal operation rating but less than the emergency rating. No voltage concerns and overloaded conductors were observed in this case with voltage regulators at 105% boosting.

Case 4H OKS/K4056 HWY 99 Feeder Out-Of-Service

Close SW-1039 to feed OKS/K4056 from OKS/K4070.

After switching, no voltage concerns were observed with voltage regulators at 105% boosting; Feeder K4070 likely needs to carry 11.8 MW of load, which is 7% above the emergency rating. Additionally, the backbone 336.4 AAC overhead conductors along HWY 66 are expected to be overloaded by 21% (9.72 MW summer rating vs. 11.8 MW). During peak conditions like this, the City may want to consider feeding a portion of K4056 from another feeder other than K4070 to avoid that.

Case 4I OKS/K4070 HWY 66 Feeder Out-Of-Service

Close SW-1039 to feed OKS/K4070 from OKS/K4056.

After switching, no voltage concerns were observed with voltage regulators at 105% boosting; Feeder K4056 likely needs to carry 11.8 MW of load, which is 7% above the emergency rating. Similarly to Case 4H, the backbone 336.4 AAC overhead conductors along Crowson Road and HWY 99 are expected to be overloaded by 21% (9.72 MW summer rating vs. 11.8 MW). During peak conditions like this, the City may want to consider feeding a portion of K4070 from another feeder other than K4056 to avoid that.

Case 4J OKS/K4093 E. Main Feeder Out-Of-Service

Close SW-1051 to feed OKS/K4093 from MAS/M3015.

After switching, Feeder M3015 is expected to be loaded to 8.5 MW, which is about 13% above the 7.5 MW typical maximum normal operation rating but less than the emergency rating. No voltage concerns and overloaded conductors were observed in this case.

Table 7-7: System Sectionalizing Analysis - Loss-of Feeder Outage

Case	Feeder	Peak Load (kVA)	Sectionalized Peak (kVA)	Sectionalized Peak (kVA)	Sectionalized Peak (kVA)	Sectionalized Peak (kVA)	Sectionalized Peak (kVA)	Sectionalized Peak (kVA)	Sectionalized Peak (kVA)	Sectionalized Peak (kVA)	Sectionalized Peak (kVA)	Sectionalized Peak (kVA)
Ashland Substation [a)]		18,630	18,630	18,630	16,810	18,630	18,630	18,630	18,630	18,630	18,630	18,630
Case 4A	A2000 - Business	6,321	A2000 Out of Serv. To A2001 Close SW1073	12,579	6,321	6,321	6,321	6,321	6,321	6,321	6,321	6,321
Case 4B	A2001 - North Main	6,192	12,723	A2001 Out of Serv. To A2000 Close SW1073	6,192	6,192	6,192	6,192	6,192	6,192	6,192	6,192
Case 4C	A2002 - Railroad	1,819	1,819	1,819	A2002 Out of Serv. To M3009 Close SW1068	1,819	1,819	1,819	1,819	1,819	1,819	1,819
Mountain Ave Substation		14,203	14,203	14,203	16,050	14,203	14,203	14,203	11,843	14,203	14,203	20,432
Case 4D	M3006 - N. Mtn	985.6	985.6	985.6	985.6	M3006 Out of Serv. To M3012 Close SW1062	985.6	6,124	985.6	985.6	985.6	985.6
Case 4E	M3009 – Morton	5,683	5,683	5,683	7,530	5,683	M3009 Out of Serv. To M3015 Close SW1020	5,683	5,683	5,683	5,683	5,683
Case 4F	M3012 – S. Mtn	5,131	5,131	5,131	5,131	6,117	5,131	M3012 Out of Serv. To M3006 Close SW1062	5,131	5,131	5,131	5,131
Case 4G	M3015 – Wightman	2,403	2,403	2,403	2,403	2,403	8,079	2,403	M3015 Out of Serv. To K4093 Close SW1051	2,403	2,403	8,497
Oak Knoll Substation [a)]		23,220	23,220	23,220	23,220	23,220	23,220	23,220	25,819	23,220	23,220	17,020
Case 4H	K4056 – HWY 99	6,699	6,699	6,699	6,699	6,699	6,699	6,699	6,699	K4056 Out of Serv. To K4070 Close SW1039	11,796	6,699
Case 4I	K4070 – HWY 66	4,748	4,748	4,748	4,748	4,748	4,748	4,748	4,748	11,801	K4070 Out of Serv. To K4056 Close SW1039	4,748
Case 4J	K4093 – E. Main	6,168	6,168	6,168	6,168	6,168	6,168	6,168	8,745	6,168	6,168	K4093 Out of Serv. To M3015 Close SW1051

a) PacifiCorp load included in substation peak.

Chapter 8 SHORT CIRCUIT ANALYSIS

8.1 METHOD

A short circuit analysis of the Ashland electric system was performed based on the following data:

- Data for the circuit configurations and conductor segment sizes, material types, and lengths as created for the power flow analysis.
- Short circuit fault-current data provided by PacifiCorp and BPA under the configuration conditions noted herein:

  Ashland Substation Data from PacifiCorp:

  Three-phase Fault MVA at 115 kV = 1106.1 MVA
  Single-phase Fault MVA at 115 kV = 829.5 MVA
  Impedance X1/R1 = 7.84
  X0/R0 = 8.43

  Oak Knoll Substation Data from PacifiCorp:

  Three-phase Fault MVA at 115 kV = 1119.3 MVA
  Single-phase Fault MVA at 115 kV = 906.6 MVA
  Impedance X1/R1 = 8.75
  X0/R0 = 8.72

  Mountain Avenue Substation Data from BPA:

  Three-phase Fault MVA at 115 kV = 975 MVA
  Single-phase Fault MVA at 115 kV = 722.9 MVA
  Impedance X1/R1 = 6.8
  X0/R0 = 7.1

- For analysis purposes, the delivery voltage is set at nominal 12.78 kV or 1.025 per unit, equivalent to ~123 volts on a 120-volt base.
- Ground fault impedance is assumed to be 40 ohms as a guideline for minimum fault current calculations as recommended by RUS Bulletin 1724E-102. The actual ground fault impedance could be higher depending on the contacted surface characteristics. Case-by-case fault analysis can be done upon request. Solidly grounded faults are used to calculate the maximum fault currents.

8.2 ANALYSIS RESULTS

Table 8-1 shows the maximum fault current values available at the substation 12.47 kV regulated buses with the system in normal configuration and all substations fed from BPA normal source transmission systems. Figure 8-1 to Figure 8-3 show the color contour of the fault currents. Some of the fault levels at the end of feeders are less than 2,000 A due to increased feeder length and size of the circuit conductors, which is expected.

As time allows during routine service the City should check all nameplate ratings to verify that distribution system protective devices are adequately rated in comparison to the short circuit fault-current available at various system locations. If any equipment is found to be of insufficient interrupting capacity, the device should be replaced.

Table 8-1: Normal Configuration Fault Currents (Symmetrical Amps)

SUBSTATION SECONDARY BUS	L-G	L-L	L-L-G	3-PH
Ashland Substation	5,541	4,624	5,459	5,339
Mountain Avenue Substation	7,593	6,228	7,444	7,191
Oak Knoll Substation, Bank 1	5,584	4,661	5,500	5,382
Oak Knoll Substation, Bank 2	6,928	5,726	6,796	6,611

a) The short circuit information is based on single-ended faults at the 12.47 kV bus.

Included in Appendix E is the complete short circuit analysis report as configured for the Base Case. The short circuit analysis report printouts are presented for each feeder by substation. The analysis model is developed based on various system junctions and conductors, and the short circuit fault current data is organized in the same manner. For the majority of the analysis 'buses', these are pole, vault, and distribution system component numbers as taken from the City's electric system maps. The City can determine the available fault current at any system component or nearby component by referring to the substation-feeder short circuit report printout and the associated system component number as they appear on the system maps.

The short circuit information provided is based on single-ended faults with one transformer source feeding each fault location. During switching operations in which transformers are paralleled the fault current will be considerably higher and may momentarily exceed equipment ratings.

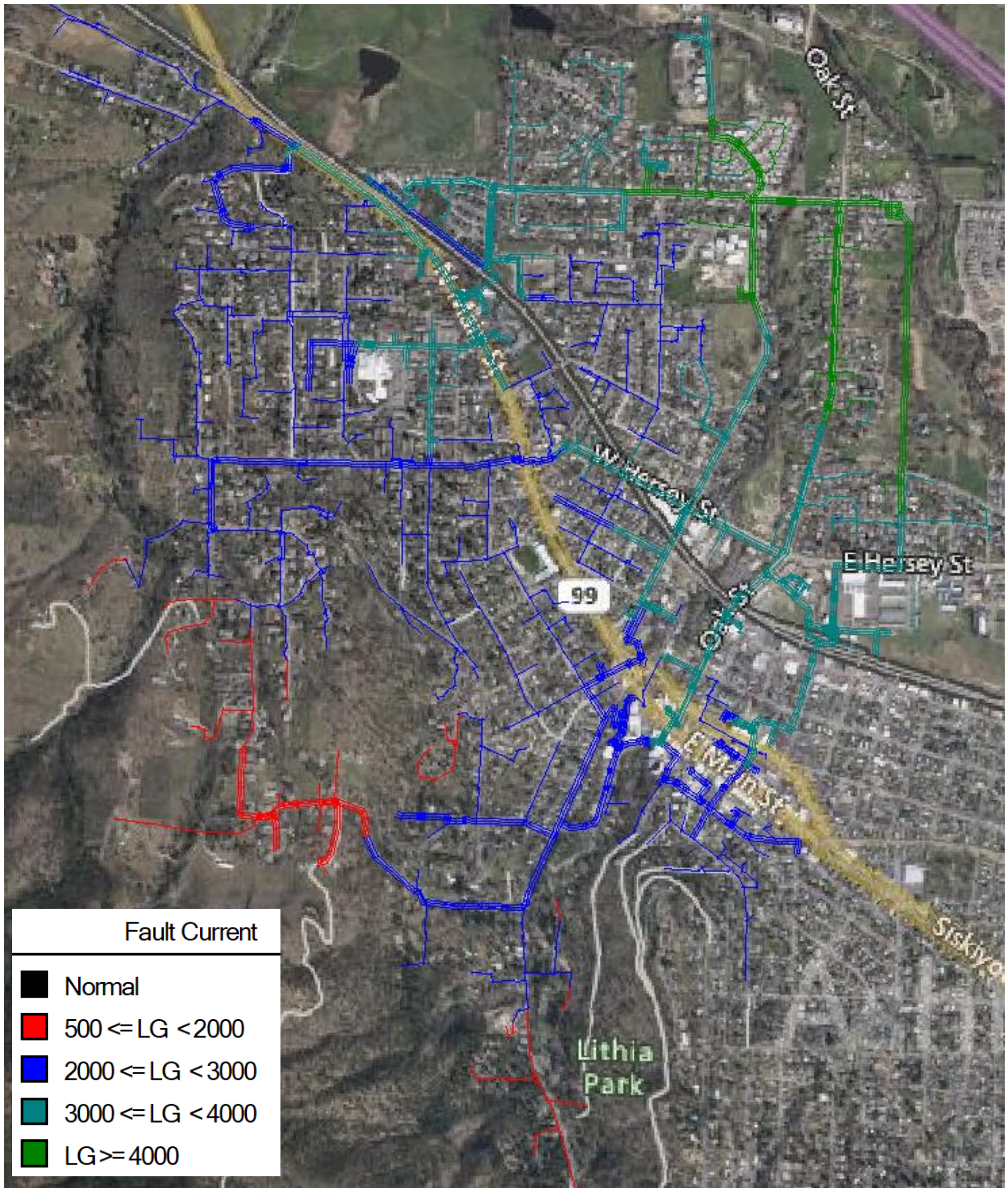


Figure 8-1: Fault Current Profile or Contour, Base Case with Normal Configuration, Ashland Substation

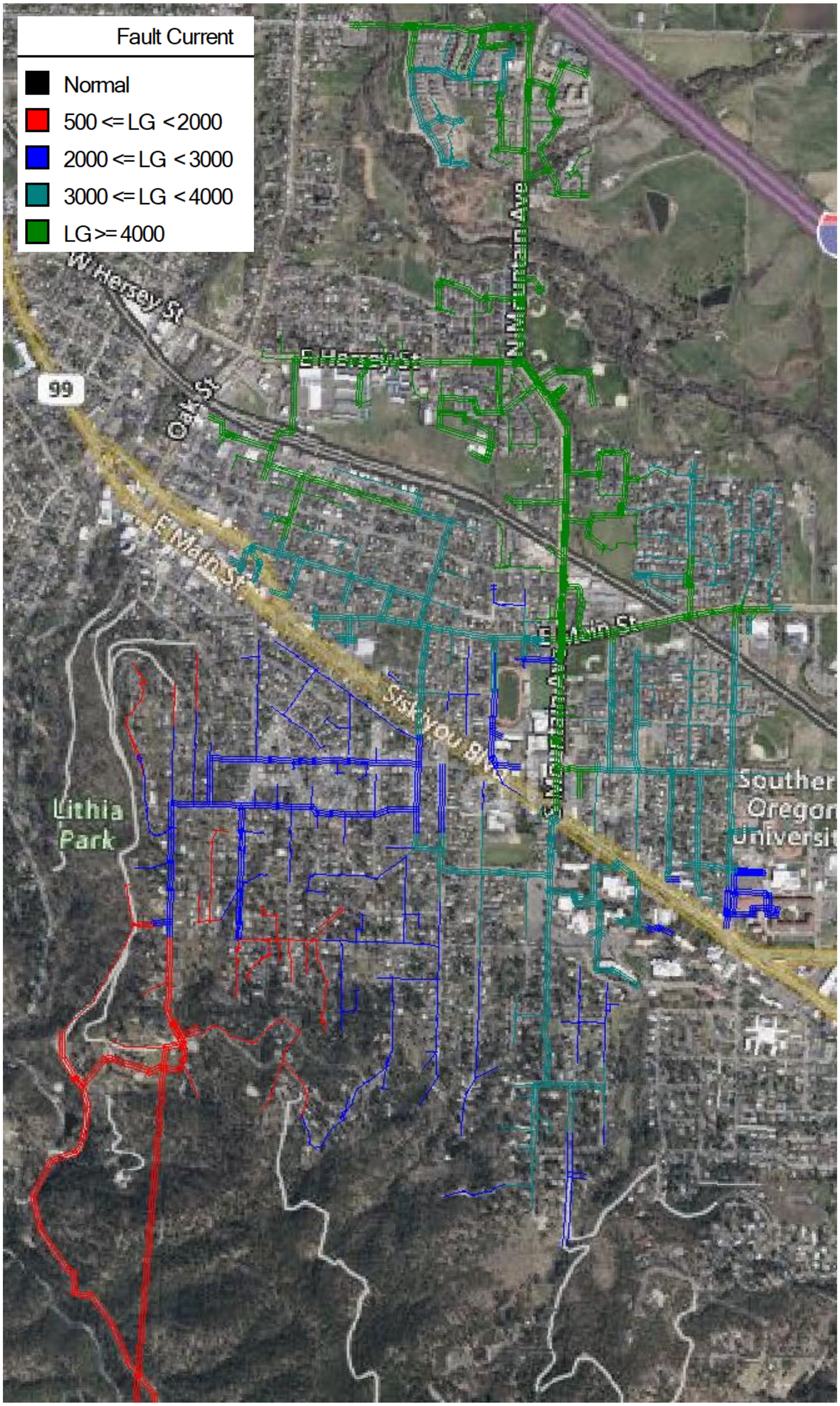


Figure 8-2: Fault Current Profile or Contour, Base Case with Normal Configuration, Mountain Avenue Substation

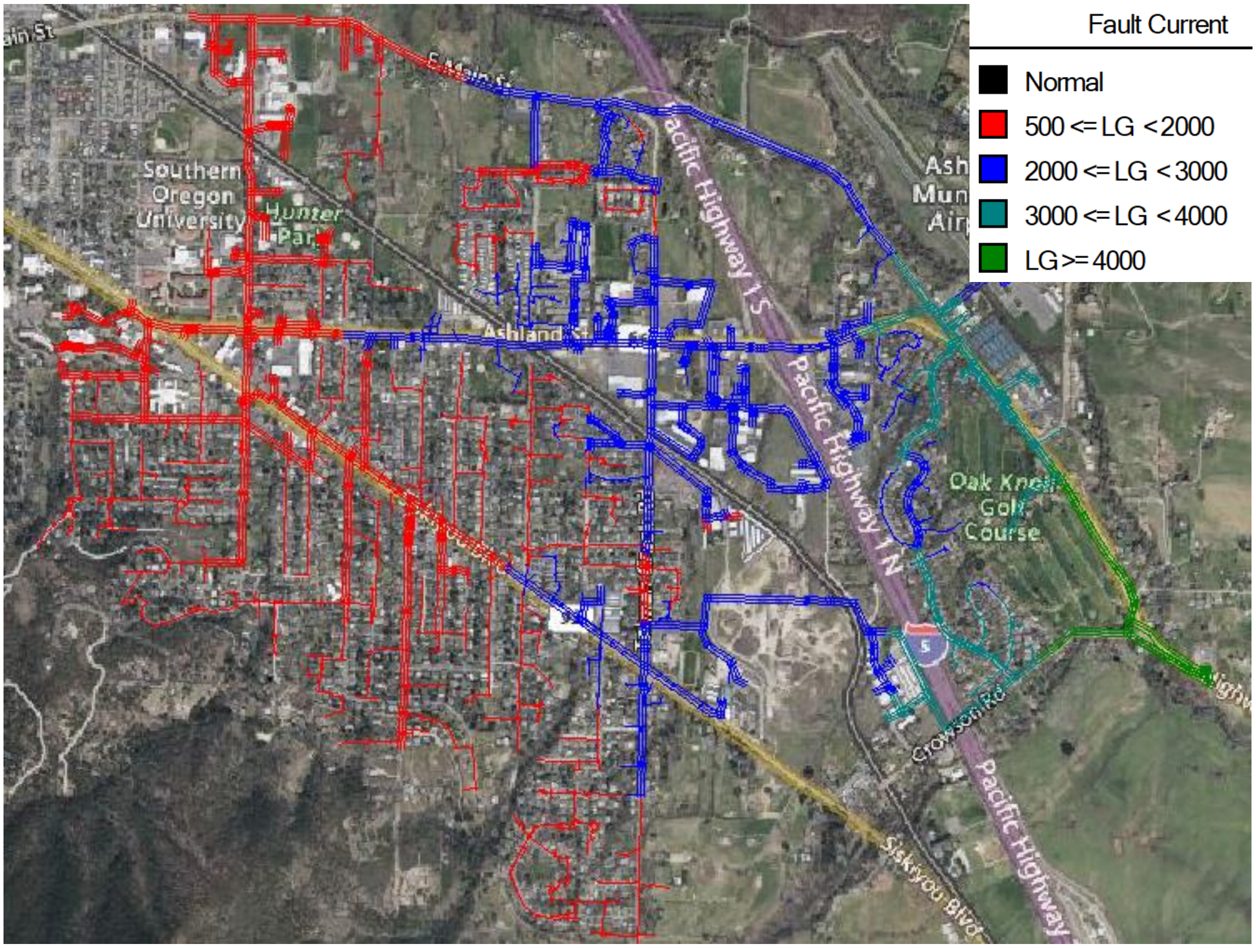


Figure 8-3: Fault Current Profile or Contour, Base Case with Normal Configuration, Oak Knoll Substation

Chapter 9 PROTECTIVE DEVICE COORDINATION

9.1 METHOD

A coordination analysis was performed to determine proper protective device settings that will quickly isolate the source of a fault or system interruption to minimize the number of customers with interrupted service, system damage, and outage duration. In determining protective device settings some compromise is generally required between system protection and continuous electric service.

Major substation and feeder protective device coordination are analyzed in this study with protective time-current curves provided for each feeder. The Ashland electric distribution system was analyzed using the existing normal circuit configuration. The evaluation is based on protective device settings at the substation and fuse ratings as displayed on the Ashland mapping system. Fuse sizes should be verified by Ashland to ensure proper system coordination. This fuse verification task is usually performed on a feeder-by-feeder basis as time allows or when mis-coordination occurs.

The protection recommendations provided by the Institute of Electrical and Electronic Engineers (*IEEE*), the American National Standards Institute (*ANSI*) and the National Electrical Safety Code (*NESC*) establish the basis for this system coordination study. They provide the boundaries that protective devices should operate within to ensure equipment reliability and safety of the system.

The selection and coordination of the system's protective devices are determined by plotting the time- versus-current operating characteristic curves for substation protection components and for the individual protective devices on each feeder. Each device is compared with its respective upstream device to ensure proper selectivity and protection. If lack of selectivity or protection is found, methods of changing the device's current, time setting, or the device itself are identified where possible.

In determining if sufficient protection exists all protective device characteristic-curves should fall within the boundaries established by *IEEE*, *ANSI* and the *NESC*. All device curves must be adequately separated to make certain that undesirable operations will not occur. The criteria for adequate separation depends on the type of device used and the safety factor desired. The settings recommended in this report are based on the following guidelines:

- For coordination between digital relays, separation between curves should be a minimum of 0.2 seconds at the maximum expected short circuit current.
- For coordination between digital relays and downstream fuses, the separation should be a minimum of 0.2 seconds.
- For coordination between fuses, a clear separation of curves is required. Pre-loading and safety factors should be considered.

The following general guidelines were used in determining the system protection plan.

- Restrict outages due to permanent faults to the smallest system section for the shortest time.

- Provide special consideration for critical loads.
- The device nearest the fault should clear a permanent or temporary fault before the backup fuse interrupts the circuit or the breaker/recloser operates to lockout.
- Coordinate devices for the best balance of protection and continuity of service.
- Assume 70 percent of overhead system faults are temporary.
- Assume 70 percent of overhead system faults are ground faults.
- Presently, the City has EEI-NEMA Types ‘T’ and ‘K’ fuse links installed in the system. The ‘T’ links are somewhat slower operating fuses and provide a better range of coordination with breakers and recloser protection.
- Ideally, attempt to use no more than three fuses in series beyond a breaker, recloser, or sectionalizer.
- Where possible, select a minimum trip on breaker and recloser protection that is at least two times the peak load current. This facilitates cold load pickup.
- The load current should be less than 70 percent of the continuous current rating of the device to allow for load growth.
- For overhead systems, ensure that all parts of the feeder are within the zone of a reclosing device. This allows the breaker or the recloser to sense and operate for minimum faults at the extreme ends of the feeder circuit.

9.2 PROTECTION CRITERIA

This section presents definitions and methodology specific to the applications of fuses and other protective devices on the Ashland distribution system. A summary of substation protective device settings is included in this section for use in verifying, tabulating, and making field settings. Specific problems are addressed in the following discussion.

9.2.1 Fuse Application

The Ashland distribution system protection philosophy consists of applying fusing protection to all tap points away from the main feeder backbone conductor. The application of distribution class fuses on the Ashland electric system feeders includes the protection of main feeder tap lines, radial line taps, underground taps, and distribution transformer fusing.

Due to the potential for heavy load currents and to minimize the number of customers interrupted, the installation of fuses in the main feeder circuit backbone is not recommended. In the future, even though loads are expected to grow, the addition of new feeders and the balancing of loads should help reduce the load current on most feeders, resulting in easier coordination capability.

Presently, Ashland has line electronic sectionalizing devices near major underground circuits and taps. Should nuisance outages or misoperation between protective devices occur because of improper coordination, the protective settings should be reevaluated and the installation of line sectionalizing or recloser devices only be considered if necessary. For now, the systems feeder downstream coordination design will continue to rely primarily on existing sectionalizing devices and fusing.

As a general rule, tap lines should be fused to protect the main distribution feeder backbone lines. This includes long tap lines, taps that are known to have unusual or vulnerable exposure, taps to underground risers/dips, and taps with a history of being subjected to an unusually high number of faults.

Line tap fuses should normally have as small a rating as load current will allow, and yet provide optimum coordination with the substation relays. Both the speed at which faults are cleared and the sensitivity of the ground fault protection increase as the ratings of the line tap fuses decrease. However, when coordinating with multiple-shot reclosing, the fuses must be large enough to avoid damage during the reclosing "fast" operation. For this study, line tap fusing was evaluated for adequate coordination with upstream protective devices but were not evaluated for sizing based on tap load.

It appears that the electric department has not identified all distribution fuse sizes on the system feeder maps. We recommend, as time allows, the electric department verify/install and indicate all fuse sizes as necessary based on the criteria set forth in this study. The following suggestions and data should assist the electric department in evaluating its existing fuse practices and the selection of fuses in the future.

When describing two or more fuse links, or other system protective devices, conventional definitions identify the nearest device to the fault on the load side as the “protecting” device and the next device toward the source side as the backup or “protected” device. This convention is used in the recommendations listed below.

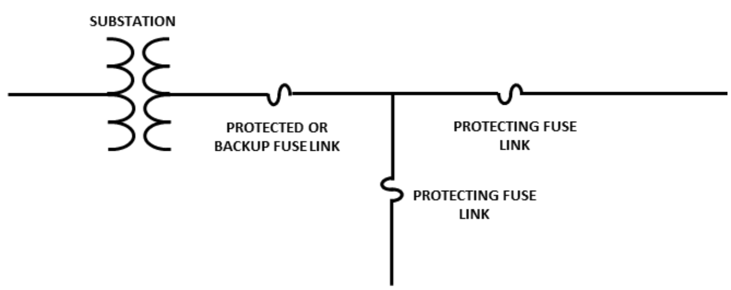


Figure 9-1: Conventional Definition of Protective Devices Based on Location

Fuse Selection

Fuse and cutout selection depends on the load current, system voltage, system type, and available fault current, which determine the current rating, voltage rating, and duty type of the cutout, respectively.

- Fuse Current Rating - The rated continuous current of the fuse should be equal to or greater than the maximum continuous load current that it will be required to carry.
- Fuse Duty - The symmetrical interrupting rating should be equal to or greater than the maximum calculated fault current possible on the load side of the fuse.
- Voltage Rating - The proper voltage rating is determined by the following system characteristics:
    - Maximum system phase-to-phase or phase-to-ground voltage
    - System grounding

- Single-phase or three-phase circuits

Selecting the proper voltage rating will ensure the basic insulation level (BIL) of the cutout will match that of the system.

Fuse Types and Characteristics

Fuses can be applied to a variety of applications requiring overcurrent protection of distribution systems and equipment. When properly coordinated with other overcurrent devices, sectionalizing to isolate faulted feeder branches and equipment is accomplished.

Fuse links are designed to meet ANSI C37.42 and NEMA SG2.1 standards. Fuses are divided into two categories, expulsion fuses classified as “zero-awaiting devices” which await the zero point to extinguish an arc, and current-limiting fuses classified as “zero-forcing devices” which introduce a high resistance into the circuit forcing the current to a relatively low value.

The ANSI standards define two classifications of fuses, Power Fuses and Distribution Fuses, which apply to both expulsion and current-limiting fuse categories as follows.

- Power Fuses are typically applied in a substation or close to a substation, and, according to ANSI C37.46 standards, have higher voltage ratings (2.8 to 169 kV) and higher X/R ratio ratings (15 to 25).
- Distribution Fuses are typically applied away from substations, and, according to ANSI C37.47 standards, have lower voltage ratings (5.2 to 38 kV) and lower X/R ratio ratings (8 to 15).

Some fuses have specific electrical characteristics in accordance with rating systems defined by industry standards. Understanding this rating system is important when applying fuses to establish which manufacturer fuses are interchangeable. Fuses are electrically interchangeable when they have:

- The same characteristics throughout the entire time range of standard time-current curves. They are typically plotted from 0.01 seconds to a minimum of 300 seconds for expulsion fuses and to 1000 seconds for current-limiting fuses.
- The same long-time continuous current ratings.

If fuses are not electrically and mechanically interchangeable, then a time-current characteristic study should be completed to ensure coordination is maintained.

Electrical equipment such as transformers, switches, relays, and conductors are exposed to various levels of current during normal operation. Generally, electrical devices can withstand high electrical currents for a short period of time and low current for prolonged periods of time without thermal failure or mechanical damage. The ability to withstand various levels of current for varying periods of time is referred to as the ‘time-current characteristic.’

The coordination of power systems involves the selection of fuse links to protect equipment with various time-current characteristics while coordinating with other system devices, reclosers, sectionalizers, breakers, relays, and other fuses. Some types of fuse links, described below, have a wide range of time-current characteristics as summarized in Table 9-1.

The speed ratio of fuse links 100 amps and below is the ratio between the current that melts the fuse in 0.1 seconds to the current that melts the fuse in 300 seconds. The higher the ratio, the slower the melting speed. The speed ratio for fuses rated above 100 amps is the ratio between the melting currents at 0.1 seconds and 600 seconds.

The following information is provided to present some background on specific fuse criteria and assist with fuse selection.

- **Type K** fuse link is a ‘fast’ fuse with a nominal speed ratio of 7 and is well suited for fast time-current characteristic applications such as capacitor protection.
- **Type 200 (N)** fuse link is classified as a ‘medium’ speed fuse with a nominal speed ratio of 9. It provides more surge withstand capability than type K fuse links and good coordination with reclosers and relays.
- **Type QA** fuse link is also classified as a ‘medium’ speed fuse with a nominal speed ratio of 9. It carries 100% of rated current without damage, providing good coordination characteristics with reclosers and relays.
- **Type T** fuse link meets requirements for ‘slow’ speed fuses, with a nominal speed ratio of 12, providing slower time-current characteristics than K 200, and QA fuse links, and coordinates well with reclosers and relays.
- **Type KS** fuse link employs dual element construction that gives high surge withstand capability. With a nominal speed ratio of 20 it is classified as a ‘very slow’ fuse link and is a good choice for line fusing and transformer protection.
- **Type X** fuse link employs dual element construction specially designed for transformer protection, has an ‘extra slow’ nominal speed ratio of 32, and provides excellent surge withstand to avoid nuisance blowing from lightning and switching surges.

Table 9-1: Fuse Speed Ratio Chart

	SINGLE ELEMENT			DUAL ELEMENT	
Designation	**Fast**	**Medium**	**Slow**	**Very Slow**	**Extra Slow**
Type	K	200 (N), QA	T	KS	X
Speed Ratio	6-8	7-11	10-13	20	32

Table 9-2 and Table 9-3 present the standard requirements of the expulsion and current-limiting fuse rating system, respectively. Note that for some fuse types (e.g., N, QA, or X) the rating system does not have a point-of-coordination requirement, as noted in Table 9-2. This means that such fuses of different manufacturers will not be fabricated identically, and duplicate coordination may not be maintained between different manufacturer devices.

Table 9-2: Expulsion Fuse Rating System

Fuse Series	Size	Coordination Point	Melting Current	ANSI Std.
E	0-100E	300 sec	200 – 240%	C37.46
	125-200E	600 sec	220 – 264%	C37.46
K	0-100K	0.1, 10, 300 sec, Speed Ratio Fast[a]	Table 6 ANSI Std	C37.42
	140-200K	0.1, 10, 600 sec, Speed Ratio Fast[a]	Table 6 ANSI Std	C37.42
T	0-100T	0.1, 10, 300 sec, Speed Ratio Slow[a]	Table 7 ANSI Std	C37.42

Fuse Series	Size	Coordination Point	Melting Current	ANSI Std.
	140-200T	0.1, 10, 600 sec, Speed Ratio Slow[a]	Table 7 ANSI Std	C37.42
D, H, N, QA, S, X, Bay-O-Net, etc.	ALL	NONE	N/A	N/A

a) Speed ratio is the ratio of minimum melting current at 0.1 second to the minimum melting current at 300 or 600 seconds, depending on fuse size.
b) There are no standards requiring electrical interchangeability.

Table 9-3: Current-Limiting Fuse Rating System

Fuse Series	Size	Coordination Point	Melting Current	ANSI Std.
C	ALL	1000 sec	170 – 240%	C37.47
E	0-100E	300 sec	200 – 240%	C37.46
	125-200E	600 sec	220 – 264%	C37.46

As stated previously, ANSI and IEEE standards divide fuses into classifications between extra fast to extra slow type links. The choice of classification, fast-to-slow, depends on the desired protection to be established for the distribution system. Fast links remove faults from the system in less time, whereas slow links have a greater withstand capability to transient and inrush currents, coordinate well with inverse relays and better with each other over a wide range of currents.

Further, the continuous current rating of types T and K (tin) links is 150 percent of nameplate and the continuous current rating of type K (silver) and type H and N (tin) links are 100 percent of nameplate rating. Table 9-4 shows the continuous current rating that tin links will carry without overheating when installed in properly sized cutouts.

Table 9-4: Fuse Continuous Current Ratings, Continuous Current-Carrying Capacity of Tin Fuse Links

High Surge Link Rating	Continuous Current (amperes)	N Rating	Continuous Current (amperes)	EEI-NEMA K or T Rating	Continuous Current (amperes)	EEI-NEMA K or T Rating	Continuous Current (amperes)
1H	1	25	25	6	9	40	60*
2H	2	30	30	8	12	50	75*
3H	3	40	40	10	15	65	95
5H	5	50	50	12	18	80	120†
8H	8	60	60	15	23	100	150†
		75	75	20	30	140	190
N Rating		85	85	25	38	200	200
5	5	100	100	30	45		
8	8	125	125				
10	10	150	150				
15	15	200	200				
20	20						

***** Only when used in a 100- or 200-ampere cutout.
† Only when used in a 200-ampere cutout. Limited by continuous current rating of cutout.

Specific Fusing Recommendations

The basic interruption device for the majority of Ashland's electric distribution system is the 'T' tin link expulsion fuse or type 'K' for both overhead and underground applications, with some use of current-limiting fuses for three-phase pad-mount transformer applications. We recommend that Ashland continue to use type ‘T’ fuse links and replace the existing type ‘K’ fuses when possible. However, in areas of high fire danger, current limiting fuses should be utilized instead of expulsion fuses as described in the City’s Fire Mitigation Plan. This is discussed further below.

There may be portions of the Ashland underground network system configured with no fusing other than at the origin of the radial tap. This is not unusual for radial taps. Under faulted conditions, this protection will isolate a fault from the main feeder backbone, but the lack of downstream protection can result in interruption to a greater number of customers than is necessary. Some UG sectionalizing devices have tap circuit electronic selectable protection settings, whereas underground cabinets with only tap (junction) capabilities may have fused elbows or no protection.

Should frequent outages occur in underground service areas, we suggest that Ashland consider the use of current-limiting fuses, type NX, ELS, ELSP, ELST, or equivalent (depending on the application) or the use of padmount sectionalizing devices with adjustable interrupting ratings. Reference to Cooper Power System (Eaton) fuses is only for convenience and equivalent manufacturer fuses are acceptable.

Ashland may want to consider the use of current-limiting type fuses at strategic underground locations within the distribution system. Current-limiting type fuses provide superior overload protection for underground cable distribution systems. These fuses are noiseless and expel no hot gases or burning particles while interrupting currents. Their current-limiting capability greatly reduces the momentary fault duty on protected equipment, extending life and saving expenditures. The ability of current-limiting type fuses to interrupt low-current faults eliminates the need for auxiliary devices to handle these troublesome current levels. These fuses extend the system coordination because of their fast clearing and current-limiting ability, assisting in the elimination of conductor and equipment damage caused by high fault currents. This operating advantage to limit fault current, known as let-through current, reduces the burning and damage at the point of fault.

Where flexible source sectionalizing is necessary and fast tap restoration is desired at critical underground tap locations, the use of pad-mounted switchgear with load break isolation source switches and quick operating, adjustable setting, single or three-phase interruption should be considered. Although this type of equipment is considerably more expensive than fused tap points, the superior sectionalizing, flexible interrupting protection, and quick service restoration make it practical at strategic locations. At locations where three-phase loads are served, these devices can also prevent troublesome single-phasing conditions.

The guidelines below identify the criteria used when evaluating and selecting fusing for the Ashland electric system. It is recommended that Ashland adopt the practices suggested below when applying fusing to the system in the future.

- Fuses should normally not be loaded more than 90 percent of continuous current rating to avoid excessive fuse pre-loading which reduces fuse melting time. Where practical the fuse size chosen should allow for load growth.
- Maximum clearing time of the protecting (load side) link should not exceed 75 percent of the minimum melting time of the protected (source side) link. This assures the protecting

link will interrupt and clear the fault before the protected link is damaged in any way by compensating for pre-loading, ambient temperature, and heat of fusion.

- EEI-NEMA type T links are generally preferred over K links for both tap line fusing and transformer protection. Type T links provide better coordination with substation relays and have better overload and inrush characteristics than K links.
- EEI-NEMA type T (tin) and type K (tin) links are divided into two rated category series:
  - **Preferred sizes**: **6, 10, 15, 25, 40, 65, 100, 140, and 200 amperes.**
  - Non-Preferred sizes: 8, 12, 20, 30, 50, and 80 amperes.
- We recommend Ashland install preferred category fuse sizes. Mixing fuses with adjacent ratings from preferred and non-preferred categories reduces the coordination available when applying fuses in series.
- Ashland may have installations of mixed preferred and non-preferred fuses. To save expense where installations have mixed category fuses with adjacent ratings that will clearly not coordinate well, Ashland may desire to change fuse size by utilizing both categories but restrict use so that each radial tap uses only one fuse category. This approach will, however, require more warehousing and good recordkeeping.
- Coordination of series combinations of fuses depends on the fuse types, their continuous ratings, and the available fault current. Table 9-12 and Table 9-13 will assist Ashland staff with coordinating Type K and T fuses in series, respectively.
- Coordinate line tap fuses with the substation breaker relay and feeder recloser control settings. Avoid attempting to coordinate a line tap fuse with a downstream distribution transformer fuse, which can result in the line tap fuse mis-coordinating with the substation protective devices.
- Line tap fuses in series should always be coordinated with each other, the substation breaker relays, and feeder protective devices. Attempt to minimize the number of fuses in series. Normally, no more than three fuses in series can be completely coordinated.
- Avoid the use of 200-amp line tap fuses, as they provide limited coordination with the substation breaker relays and feeder protective devices. When capacity of 200 amps is required, consider installing an electronically controlled automatic line sectionalizer or recloser with phase and ground sensing.
- Cutouts used for manual sectionalizing of the main feeder line should be equipped with either solid links or oversized fuses. Multiple shot reclosing (with "Fuse Saving") will coordinate with only a narrow range of fuse sizes and these should be used for line taps. It is generally difficult to coordinate with both main line fuses and line tap fuses.
- If outages indicate that a protective device needs to be installed on a feeder 'main line' to reduce the number of customers affected by faults, consider using an electronic line recloser with phase and ground tripping and adjustable reclosing. These devices will allow better coordination with upstream substation breakers or reclosers.
- Table 9-12 and Table 9-13, in conjunction with short circuit (fault) data provided in this report should be helpful in applying line tap fuses. For effective ground fault coordination, fuse ratings as low as feasible are preferred. Generally, it is desirable to install fuse links rated to or less than 100 amps.

- The basic goal in coordinating downstream overhead fuses with substation relays is to fit the fuse curve in between the relay fast and slow curves where "*fuse saving*" is being applied. The fuse sizes selected will accomplish this over the fault current range indicated. Fuses smaller than those suggested can be used with some sacrifice in coordination. For these smaller fuses, a fault downstream of the fuse may cause both the fuse and the relay to operate, but the reclosing relay should then reclose successfully restoring the main line to service.
- Fuse link applications for primary distribution transformer protection are guided by fusing ratios. Link selection is always a compromise because primary links cannot distinguish between short-time overloads, long-duration overloads, and high-impedance secondary faults. These external fuse links are usually selected to blow when load current exceeds a predetermined multiple of full load current for 300 seconds. This multiple is known as the fusing ratio. As the transformer fusing ratio increases, overload protection decreases but load-pickup ability increases.
- A fusing ratio of 3 is most popular and allows an overload of 300 percent, with adequate margin for inrush current. A schedule based on a fusing ratio of 2 to 3 is shown in Table 9-14. Type T and K links provide the best overload protection and rapidly remove damaged transformers from the system, but at a sacrifice of the short-time overload capability of the transformer. High-surge H fuse links, designed for primary fusing of small-sized transformers, are also included in Table 9-14. The H fuse links provide overload protection and withstand short-time current surges.

To assist in the selection of current limiting fuses, Table App F-1 and Table App F-2 are provided in Appendix X. These tables describe transformer applications for single and three-phase pad-mounted transformers, respectively.

Table App F-3 can be used for the selection of type NX fuses for coordination with standard expulsion type fuses, if desired. For best coordination when applying current-limiting type fuses, the expulsion (type T or K) link fuses should always be used as the source protection, and the current-limiting fuse as the load protection. The NX type fuse provides good overload protection for underground cable distribution systems by greatly reducing the momentary duty on protected equipment and extends system coordination because of its fast clearing capability.

To assist with the selection of types ELS and ELST current-limiting fuses, Table App F-4, Table App F-5, and Table App F-6 are provided which display ELS fuse type continuous current ratings, and single-phase and three-phase transformer current rating recommendations, respectively; Table App F-7 and Table App F-8 are provided which display ELST fuse type continuous current ratings, and three-phase transformer current rating recommendations, respectively.

The ELS type full range current-limiting fuse is designed for use in series with Bay-O-Net fuses (two-fuses scheme) for oil-filled padmount transformers and sectionalizing equipment devices offering quiet and safe operating characteristics. The ELST type fuse consists of full range current-limiting tandem fuses. The current-limiting section efficiently reduces the effects of high fault current on upstream and downstream devices, while the expulsion section protects the current-limiting fuse from system voltage.

The electric department should be aware that modern Bay-O-Net fusing that is not applied in series with a current-limiting fuse requires an isolation link. Ashland may currently be obtaining pad-mount transformers with this type of fusing. Isolation links are not fuses and do not have an interrupting rating. During a transformer failure, the isolation link will melt so that the opened primary circuit of a faulted transformer cannot be re-energized by the line crew, providing extra protection during re-fusing operations.

Wildfire Mitigation Considerations

Type T expulsion-style fuses are common for tap line protection and transformer protection and they are fire-safe per the manufacturers' catalog. However, their primary characteristic is that they are vented devices in which after their fuse element melts and arcs, the expulsion effect of the gases produced by the interaction of the arc with other parts of the fuse results in the current interruption in the circuit. The molten metal combined with ventilated gas could be a source of ignition for fire. These fuses are not a good choice in areas that have high fire risks. Non-expulsion fuses or current-limiting fuses (CLF) are recommended in the high-risk area. For large and rural electrical systems, the current-limiting feature of the CLF may not be triggered due to low fault currents, but the nonexpulsion feature is what provides the most benefit with regard to wildfire mitigation.

The Cooper ELF current-limiting dropout fuse has a self-contained design that operates silently and eliminates expulsive showers that are from typical expulsion fuse operation. These fuses have a full-range current-limiting rating that ensures reliable operation of both overloads and fault currents. These features make it suitable for areas where a high fire hazard exists. This type of fuse has sizes up to 100A at 8.3 kV as shown in Table 9-15.

Cooper also has ELF-LR liquid fuse replacements that are noiseless and expel no hot gases or burning particles while performing fault current interruptions. They are recommended in heavily wooded areas and when tree trimming falls behind. This type of fuse has sizes up to 20A at 8.3 kV (Table 9-16), and is suitable for smaller circuits.

Both ELF and ELF-LR fuses are designed to protect pole-type transformers, single-phase and three-phase laterals, and underground taps. They coordinate with Type T and Type K fuse links as shown in Table 9-17 and Table 9-18 specifically.

9.3 FUSE SELECTION EXAMPLES

Three examples of distribution fuse sizing selection are provided below to assist in determining the appropriate fuse sizes for Ashland's electric distribution system.

9.3.1 EXAMPLE 1. Fused Tap Protection

Given: Assume a tap is presently protected with three 25T fuse links and has upstream protection consisting of 100T fuses. Further, assume the total connected load at this tap is as follows; A-phase = 200 kVA, B-phase = 487.5 kVA, and C-phase = 150 kVA, and the tap has an available short circuit fault current of 2,860 amps.

Find: Evaluate the tap to determine if adequate protection is provided.

Solution: In the heaviest loaded phase, the maximum full load current is 487.5-kVA/7.2 kV = 68 amps. To account for future growth and connected transformer inrush current a typical multiplier of 1.5 is taken times the current value, resulting in 102 amps. A fuse with a continuous current rating near this value is sought. Table 9-4 indicates that a 65T fuse link is the proper size fuse for this application.

However, notice that the connected kVA loading at the location identified above is badly unbalanced and should be adjusted. If loads are reconnected to provide good phase balance, near 280 kVA per phase, a 40T fuse link can be selected as the preferred fuse for this tap location, (i.e., 280 kVA/7.2 kV x 1.5 = 58 amps, and the use of Table 9-4 suggests a 40T fuse).

Also, it must be determined if the selected fuse for the tap will coordinate with the three upstream 100T fuse links of the main feeder tap. As noted above the short circuit report indicates the maximum fault current available at bus x is 2,860 amps.

To determine if the downstream (protecting) fuse will coordinate with the upstream (protected) fuse Table 9-13 must be examined. Table 9-13 indicates that the maximum fault current at which the 65T protecting fuse link will coordinate with for the protected 100T fuse link is 2,200 amps. Since the available fault current (2,860 amps) exceeds this value the next smaller preferred fuse size should be selected, this is a 40T fuse link. The chart in Table 9-13 shows that these fuses will coordinate nicely to a fault value of 6,100 amps.

As shown in the above example, with properly balanced loads the 40T fuse link will provide adequate continuous current and protection at this tap. It would therefore be recommended that: a) the loads are reconnected to allow evenly distributed phase balance, and b) the existing 25T fuses be removed and replaced with 40T fuse links.

9.3.2 EXAMPLE 2. Fused Three-Phase Transformer Tap Protection

Given: Assume an overhead line is to be tapped and that the tap is overhead connected to serve an underground dip and a new 300 kVA, 12.47 GrdY/7.2 kV x 208Y/120 V, 2 percent impedance pad mount transformer, and that the fuse must coordinate with upstream 65A K or T link fuse protection. The short circuit analysis indicates the maximum fault current available at this tap as 2100 amps.

Find: Determine the proper size fuse to protect the tap and transformer and yet adequately allow for cold load pickup and inrush currents to avoid fuse damage.

Solution: Although it is strongly suggested to compare time-current-curves to ensure adequate continuous coordination and protection of all devices and associated conductors, the general procedure required to size fusing for this application is as follows:

- Transformer full-load current = 300 kVA/(12.47 kV x 1.7321) = 13.9 amps.
- To avoid nuisance fuse operation, cold-load pickup should be evaluated. Fuse protection will be sufficient if the fuse has a continuous current rating equal to approximately 2 x full-load current. In this case 2 x 13.9 = 28 amps. In looking at Table 9-4, we see that a 20 amp K or T link fuse has a continuous current rating of 30 amps, and this fuse's continuous current rating shown on the minimum-melt time-current curve falls to the right of the 28 amp value on the curve.
- The fuse's minimum-melt time-current curve should also be compared with other multiples of transformer rated load current. These other points on the curve include 6 x full-load current for 1 second, and 3 x full-load current for 10 seconds. In this case, 84 amps for 1 second and 42 amps for 10 seconds, respectively.

- To account for transformer inrush, the combined magnetizing and load-inrush current, referred to as hot-load pickup, the fuse must be able to withstand this momentary current equivalent to 10 to 12 time full-load current for 0.1 seconds. In this case, that point is at 140 amps and 0.1 seconds. Here again, the selected fuse minimum-melt curve should be to the right of this point on the time-current curve.

The EEI-NEMA Type K or T tin fuse minimum-melt curve is provided at the end of this chapter and the points noted in the above example are highlighted to demonstrate that the chosen 20-amp fuse satisfies all necessary selection criteria. It should also be observed that the 20K link curve clearly coordinates with the 65K fuse, and by inspection of Table 9-12, the protecting 20K fuse will coordinate with the protected 65K fuse up to 2200 amps, above the maximum available fault current. If Ashland is adhering to the fuse selection criteria of using only preferred fuse sizes, a 25K link will also coordinate nicely at this location.

9.3.3 EXAMPLE 3. Single-Phase Transformer Tap Protection

Given: Assume a fuse size selection is needed to provide protection for an overhead line tap that is to serve one pole-mounted distribution transformer rated 100 kVA, 7.2 kV x 240/120 V.

Find: Determine the transformer full-load amps (FLA) and select the proper fuse size. Typically, a suitable fuse will have a continuous current cap approximately 2 times FLA to accommodate overload and inrush. Table 9-14 can be used to make this fuse selection by choosing the connection type, in this case Wye-Connected Primary ‘Figure D’ and then searching in the ‘7200/12470Y’ Column for the proper fuse. A more thorough evaluation can be accomplished by using the method below but requires a comparison with the fuse time-current curve characteristics.

Solution: Calculate the transformer magnetizing in-rush currents at 12 times FLA for 0.1 second and 25 times FLA for 0.01 second. Also, to avoid nuisance fuse operation include the potential contributions of cold load pickup at the following multiples of FLA; 6 x FLA for 1 second, 3 x FLA for 10 seconds, and 2 x FLA for 15 minutes. These current and time values are then to be compared with the selected fuse time-current curve characteristics to assure the fuse is not damaged and does not operate under these conditions. Calculations for both fuse selection methods follow:

- Calculate FLA = 100 kVA/7.2 kV = 13.9 amps. Therefore, 1.5 x = 20.8 and 2 x = 27.8 amps. So, a fuse with a continuous current rating in this range will be satisfactory, and, since Ashland uses ‘T’ link fuses, we see from Table 9-4 that a 15 amp or 20 amp fuse will be suitable. Table 9-14 agrees with this finding.
- Calculating the various currents for time-current curve comparison at specific times results in the following values:
    - 25 x FLA = 347 amps @ 0.001 second.
    - 12 x FLA = 167 amps @ 0.1 second.
    - 6 x FLA = 83.3 amps @ 1.0 second.
    - 3 x FLA = 41.7 amps @ 10 seconds.
    - 2 x FLA = 27.8 amps @ 15 minutes.

- A comparison of the currents and times calculated above with the 15K link minimum-melt curve indicates the 15 amp fuse will satisfy the above criteria and is a suitable installation.

9.3.4 Other Protective Devices

Sectionalizer Protection for Overhead Construction

Three-phase electronic sectionalizers should be considered in the future and are recommended for locations that require overcurrent protection where a 140T fuse cannot carry the full load current of the connected transformers (full load current x 1.5 multiplier), except in specific areas where a vacuum fault interrupting device will provide better protection of large critical overhead and underground taps. It should be noted that for most distribution applications Electronic Sectionalizers have a maximum continuous rating of 200 amp, and that the minimum pickup current is selectable. An example of such a switch is Eatons/Cooper, *Distributed Automated Switch (DAS*) a switch with electronic control.

The possible use of sectionalizers is introduced in this study to present a method to secure proper coordination due to potential load increase on particular taps. Sectionalizers have not been required in the past because fuses could be sized to obtain adequate coordination. The use of fuses larger than 140T is not recommended because they will not coordinate properly with the upstream overcurrent protection. Although three-phase electronic reclosers are preferable, consideration for the use of sectionalizers is suggested because of the cost savings associated with their use.

The main disadvantage of using sectionalizers instead of reclosers is that sectionalizers cannot reclose. A fault downstream of a sectionalizer will cause the next upstream reclosing device to operate, temporarily interrupting service to a larger portion of the distribution system; this allows the sectionalizer to then interrupt. A sectionalizer can sense fault current and then isolate the downstream circuit while the line is de-energized by the upstream device (substation breaker/recloser). Isolation can occur at a selectable number (count) of operations by the upstream device (normally one or two counts).

The Ashland distribution system consists of substation reclosers with reclosing relays. A fault downstream of a sectionalizer would cause the overcurrent and reclosing relays at the substation to operate, interrupting service to the entire feeder, rather than isolating the fault and interrupting service to a small portion of the distribution system, which would occur if a line recloser were applied instead of a sectionalizer. Sectionalizers, where applied, can provide a significant advantage over the use of fuses because sectionalizers are much easier to coordinate due to a selectable range of settings. No specific installations of these devices are recommended at this time, but consideration of their use is suggested on major taps off feeder backbone circuits as loads grow and at important underground taps which should not be subjected to reclose operations. We recommend that prior to the installation of such devices that actual tap current measurements be performed to ensure system loading has developed to justify the use of sectionalizers for protection.

Pad Mounted Switchgear Protection for Underground Construction

Vacuum fault-interrupting pad-mounted load-break switchgear is presently in use on the Ashland electric system. These devices are placed at important switching and sectionalizing locations within the distribution system to allow service from alternate sources, and to allow fast interruption of faulted 200-amp major tap segments to minimize affected customers.

These devices typically accept one or two sources (600 amp) and offer two or more interruptible tap services (200 amp), although other configurations are available.

These devices lend themselves well to placement within existing underground systems and can easily be programmed to coordinate with upstream fusing and substation protective devices. They offer the following advantages:

- Alternate source service
- Source load-break switching
- Tap vacuum fault interruption – no need for fuses
- Immediate service restoration – no fuse replacement
- Electronic control settings consisting of the following features:

  a. adjustable coordination trip settings

  b. three-phase or single-phase trip selection

  c. instantaneous trip availability

  d. ground trip availability

  e. completely dead-front construction

  f. compliance with all Standards requirements

9.4 SUBSTATION PROTECTIVE DEVICE SETTINGS

The various protective equipment at the three substation facilities are described in this section. This includes the protective devices serving as transformer protection equipment and distribution protection equipment. The substation and switch station arrangements are shown on one-line diagrams presented in Appendix D.

9.4.1 Substations

PacifiCorp Ashland Substation

The PacifiCorp Ashland Substation transformer is protected by a 115 kV Circuit Switcher 2R154 with two electronic multifunction relays (TPU2000R and Basler BE1-51). The TPU2000R provides transformer differential protection, while the BE1-51 relay provides overcurrent protection for the transformers. On the 12.47 kV side, PacifiCorp has two CO-9 relays for phase and neutral overcurrent protection for the City circuit. The City of Ashland-owned switch rack within the PacifiCorp Ashland Substation has four reclosers with Cooper Form 6 controllers. These reclosers are programmed with 3 shots at intervals of 0.6-sec/2-sec/lockout. These device settings are summarized below in Table 9-5 and Table 9-6.

Table 9-5: Ashland Substation PacifiCorp Relay Settings, Existing

Device	Element	Pickup	Time Dial	Instantaneous	Delay	Curve
BE1-51	Backup Phase OC	3 (180 A at 115 kV)	15	15 (2700 A)	-	B6
TPU2000	Primary Phase OC	2.5 (150 A at 115 kV)	3.0	-	-	VI
	Primary Phase OC	5.8 (1392 A at 12.47 kV)	3.0	-	-	VI
	Primary Ground OC	5.0 (1200 A at 12.47 kV)	3.5	-	-	VI
WEST. CO-9	Phase OC	6 (1200 A at 12.47 kV)	2.0	-	-	CO-9
	Ground OC	6 (1200 A at 12.47 kV)	2.0	-	-	CO-9

Table 9-6: Ashland Substation City Feeder Relay Settings, Existing

A2000, A2001, A2002, A2003						
Device	**Element**	**Pickup (Primary)**	**Time Dial**	**Time Adder**	**Min. Resp. Time**	**Curve**
Cooper F6	Phase Slow	560 A	1	0	---	117
	Phase Fast	560 A	1	0	---	104
	Phase HCT[1]	Disabled	---	---	---	---
	Ground Slow	240 A	1	0	---	135
	Ground Fast	240 A	1	0	---	106
	Ground HCT	Disabled	---	---	---	---
	Reclose	0.6-sec/5-sec/lockout (3-shot)				
	Phase CLPU	560 A	**2**	**0**	**---**	**117**
	Ground CLPU	240 A	**2**	**0**	**---**	**135**
	Reclose CLPU	5-sec/lockout, Active time: 15 seconds				

a) CLPU indicates Cold Load Pickup, which is used to prevent inadvertent trips from occurring during restoration after a sustained outage

City Owned Mountain Avenue Substation

Mountain Avenue Substation originally owned by BPA, was purchased by the City of Ashland in April, 2023. The City has not made any substation upgrades to date. The transformer protection is adopted from BPA. Currently, the substation transformer is protected by a Circuit Breaker with phase and neutral overcurrent relays, both of which are BE1-51. Each feeder recloser has a Cooper Form 6 controller for monitoring and control. These reclosers are programmed with 3 shots at intervals of 0.6-sec/2-sec/lockout. Their settings are summarized in Table 9-7 and Table 9-8.

There is no transformer differential relay for this substation transformer. We recommended the City consider a protection relay upgrade at this substation. Additionally, the feeder controller settings for feeder M3009 (Morton) appear to have the same fast, slow, and CLPU curves for phase and ground protections, which are not consistent with the settings for other feeders. It does not look like Morton feeder needs a unique protection scheme like this, so the existing settings are questionable and may not have been programmed correctly when installed. If there is no particular reason, we recommend the City update the settings for feeder M3009 to maintain consistency.

Table 9-7: Mountain Avenue Substation Relay Settings, Existing

Device	Element	Pickup	Time Dial	Instantaneous	Delay	Curve
BE1-51	Phase OC	2.0 (240 A at 115 kV)	7	15 (3600 A)	-	B6
BE1-51	Neutral OC	2.0 (240 A at 115 kV)	52	-	-	B6

Table 9-8: Mountain Avenue Substation Feeder Relay Settings, Existing

M3006, M3012, M3015						
Device	**Element**	**Pickup (Primary)**	**Time Dial**	**Time Adder**	**Min. Resp. Time**	**Curve**
Cooper F6	Phase Slow	560 A	1	0	0.1	165
	Phase Fast	560 A	1	0	---	103
	Phase HCT	Disabled	---	---	---	---
	Ground Slow	240 A	1	0	---	135
	Ground Fast	240 A	1	0	---	106
	Ground HCT	Disabled	---	---	---	---
	Reclose	0.6-sec/2-sec/lockout (3-shot)				
	Phase CLPU	560 A	2	0	0.3	165
	Ground CLPU	240 A	2	0	0.3	135
	Reclose CLPU	5-sec/lockout, Active time: 30 seconds				
M3009						
Device	**Element**	**Pickup (Primary)**	**Time Dial**	**Time Adder**	**Min. Resp. Time**	**Curve**
Cooper F6	Phase Slow	560 A	1	0	---	133
	Phase Fast	560 A	1	0	---	133
	Phase HCT	Disabled	---	---	---	---
	Ground Slow	240 A	1	0	---	133
	Ground Fast	240 A	1	0	---	133
	Ground HCT	Disabled	---	---	---	---
	Reclose	0.6-sec/2-sec/lockout (3-shot)				
	Phase CLPU	560 A	2	0	0.3	133
	Ground CLPU	240 A	2	0	0.3	133
	Reclose CLPU	5-sec/lockout, Active time: 30 seconds				

PacifiCorp Oak Knoll Substation

The PacifiCorp Oak Knoll Substation transformer has two transformer banks with main and auxiliary buses implemented. During normal configuration, breakers 5R55 and 5R56 (Feeder K4056) are served from transformer bank #1, and breakers 5R70 and 5R93 (Feeders K4070 and K4090) are served from bank #2. Each transformer has a primary breaker controlled by a primary SEL 387E relay and a backup BE1-51 relay. Each 12.47 kV feeder breaker is controlled by a SEL 751 feeder protection relay. The City of Ashland-owned switch rack within the PacifiCorp Oak Knoll Substation has three reclosers with Cooper Form 6 controllers. These reclosers are programmed with 3 shots at intervals of 0.6-sec/2-sec/lockout.

These device settings are summarized below in Table 9-9 and Table 9-10.

Table 9-9: Oak Knoll Substation PacifiCorp Relay Settings, Existing

Device	Element	Pickup	Time Dial	Instantaneous	Delay	Curve
BE1-51, Bank 1	Backup Phase OC	2.25 (180 A at 115 kV)	17	11.2 (2016 A)	-	B6
SEL 387E, Bank 1	Primary Phase OC	2.0 (160 A at 115 kV)	3.3	-	-	U3
	Primary Phase OC	5.8 (1392 A at 12.47 kV)	3.6	-	-	U3
	Primary Ground OC	2.0 (480 A at 12.47 kV)	13.4	-	-	U3
SEL751, 5R56	Phase OC	7 (560 A at 12.47 kV)	5.5	-	-	U4
	Ground OC	3 (240 A at 12.47 kV)	8.3	-	-	U3
BE1-51, Bank 2	Backup Phase OC	2.25 (203 A at 115 kV)	16	12 (2430 A)	-	B6
SEL 387E, Bank 2	Primary Phase OC	2.2 (198 A at 115 kV)	3.1	-	-	U3
	Primary Phase OC	4.4 (1760 A at 12.47 kV)	6.8	-	-	U3
	Primary Ground OC	1.2 (480 A at 12.47 kV)	14.8	-	-	U3
SEL751, 5R70	Phase OC	7 (560 A at 12.47 kV)	5.5	-	-	U4
	Ground OC	3 (240 A at 12.47 kV)	8.3	-	-	U3
SEL751, 5R93	Phase OC	7 (560 A at 12.47 kV)	5.5	-	-	U4
	Ground OC	3 (240 A at 12.47 kV)	8.3	-	-	U3

Table 9-10: Oak Knoll Substation Feeder Relay Settings, Existing

K4056, K4070, K4093						
Device	**Element**	**Pickup (Primary)**	**Time Dial**	**Time Adder**	**Min. Resp. Time**	**Curve**
Cooper F6	Phase Slow	560 A	1	0	---	117
	Phase Fast	560 A	1	0	---	104
	Phase HCT	Disabled	---	---	---	---
	Ground Slow	240 A	1	0	---	135
	Ground Fast	240 A	1	0	---	106
	Ground HCT	Disabled	---	---	---	---
	Reclose	0.6-sec/5-sec/lockout (3-shot)				
	Phase CLPU	560 A	2	0	---	117
	Ground CLPU	240 A	2	0	---	135
	Reclose CLPU	5-sec/lockout, Active time: 15 seconds				

9.5 Field Recloser and VFI Switchgear Settings

Ashland has ten (10) CPS/Eaton VFI switchgear sectionalizing devices, and three (3) CPS/NOVA field reclosers with Cooper Form 6 controls. The ten VFIs are listed below and most of the protected ways are set at 200 A as a feeder tap using the Cooper EF curve, while a few others serve smaller taps with lower settings.

Address	Map Location ID	Settings
• 811 Briggs Ln	E5043630	Tap 1 60A, Tap 2 60A
• 1299 Hagen Way	E5101731	Tap 1 20A, Tap 2 40A
• 396 Randy St.	E5057535	Tap 1 40A, Tap 2 40A
• 842 Kestrel PW	E5046550	Tap 1 100A, Tap 2 100A

- 2202 Abbott Ave	E5112300	Tap 1 vacant, Tap 2 200A
- 2200 Ashland St.	E5142827	Tap 1 vacant, Tap 2 200A
- 310 Kestrel PW	E5046603	Tap 1 200A, Tap 2 200A
- 955 E Nevada St.	E5048601	Tap 1 200A, Tap 2 20A
- 489 Russell St.	E5097835	Tap 1 200A, Tap 2
- 449 Rogue Pl	E5046183	Tap 1 200A, Tap 2

Their field NOVA controller settings for the three filed reclosers are summarized in Table 9-11.

Table 9-11: Field Recloser Controller Settings, Existing

2nd and B Street, Feeder A2002						
Device	**Element**	**Pickup (Primary)**	**Time Dial**	**Time Adder**	**Min. Resp. Time**	**Curve**
Cooper F6	Phase Slow	200 A	1	0	---	165
	Phase HCT	Disabled	---	---	---	---
	Ground Slow	150 A	1	0	---	133
	Ground HCT	Disabled	---	---	---	---
	Reclose	lockout (1-shot)				
	Phase CLPU	450 A	1	0	---	165
	Ground CLPU	210 A	1	0	---	133
	Reclose CLPU	lockout (1-shot), Active time: 30 seconds				
Iowa and Morton Street, Feeder M3009						
Device	**Element**	**Pickup (Primary)**	**Time Dial**	**Time Adder**	**Min. Resp. Time**	**Curve**
Cooper F6	Phase Slow	200 A	1	0	---	165
	Phase HCT	Disabled	---	---	---	---
	Ground Slow	150 A	1	0	---	133
	Ground HCT	Disabled	---	---	---	---
	Reclose	lockout (1-shot)				
	Phase CLPU	450 A	1	0	---	165
	Ground CLPU	210 A	1	0	---	133
	Reclose CLPU	lockout (1-shot), Active time: 30 seconds				
Southern Oregon University, Feeder K4070						
Device	**Element**	**Pickup (Primary)**	**Time Dial**	**Time Adder**	**Min. Resp. Time**	**Curve**
Cooper F6	Phase Fast	300 A	1	0	---	117
	Phase HCT	Disabled	---	---	---	---
	Ground Fast	150 A	1	0	---	138
	Ground HCT	Disabled	---	---	---	---
	Reclose	lockout (1-shot)				
	Phase CLPU	450 A	1	0	---	117
	Ground CLPU	225 A	1	0	---	138
	Reclose CLPU	lockout (1-shot), Active time: 30 seconds				

9.6 PROTECTIVE DEVICE COORDINATION CURVES

Explanation of Time-Current Curves

Coordination analysis was performed using EasyPower software due to the extensive library of devices. EasyPower plots the time-current curve characteristics of the various system protective devices (relays/recloser controllers/fuses) corresponding to their particular rating or setting and identifies each device curve with a label. Other useful information is plotted on the diagrams to assist in interpreting the results, such as:

Transformer Full Load Current: Full-load current is calculated based on the power transformer nominal self-cooled or “OA” rating. This value of current is plotted on the time-current curve’s upper horizontal axis as a short, vertical line, labeled “XFMR X FLA”.

Transformer Inrush Current: Inrush current usually ranges from 8 to 12 times the power transformer full-load current, at 0.10 seconds. This value is plotted as a bullet and labeled “XFMR X INRUSH.” Protective devices upstream of the transformer must be set to allow transformer inrush current to flow without the device tripping.

Transformer Damage Curves: ANSI Standard C57.109 specifies damage curves for transformers. For delta-wye transformers, EasyPower plots a two-part curve based on this ANSI standard. The upper part of the curve is the 100 percent damage curve for 3-phase faults. The lower part of the curve, starting with the vertical-line portion and going downward, is the 58 percent damage curve for phase-to-ground faults. The lower part of the 58 percent curve shows the mechanical damage curve.

Conductor Damage Curves: Conductor damage curves are included to indicate conductor annealing characteristics and are labeled with the size and material of the conductor. Usually only the smallest conductors (lowest ampacity rating) in the portion of the system selected for evaluation are shown, with larger conductors inherently having much greater capacity.

Maximum Fault Current: For devices having interrupting ratings, such as fuses and circuit reclosers and circuit breakers, the plot cuts off at the value for maximum total fault at that bus location. This total fault current may in fact be higher than the actual maximum current the device must interrupt if there is motor contribution to fault current from the load side of the protective device. These values are plotted as a short vertical line, ‘tick’ marks, along the TCC lower horizontal axis, labeled “DEVICE ID”, and also identify the available asymmetrical fault current, the current used to determine trip time.

Protective Device Pickup Current: All protective devices have a current pickup setting. This value of current is identified on the time-current curve upper horizontal axis by plotting a short, vertical line, labeled “DEVICE ID”.

Time-Current Curve Plots

In an attempt to condense the quantity of coordination time-current curves, where possible, multiple downstream components have been placed on the same time-current curve plot. To eliminate redundancy, most often the largest downstream tap or transformer has been chosen to evaluate system coordination, assuming less rated devices will inherently coordinate.

A ‘phase’ and ‘ground’ time-current curve plot has been prepared for each feeder, displaying the existing device settings and ratings. Curves for each feeder are presented in Appendix A.

9.7 ANALYSIS OF EXISTING SETTINGS

The protective device coordination evaluation for the City’s distribution system indicated that all Ashland Substation feeder recloser control settings are identical, all the Oak Knoll Substation feeder recloser control settings are identical, and three of the four Mountain Avenue Substation feeder recloser controls have the same settings except for Feeder M3009. Most of the feeder reclosers have a scheme of 1-fast and two-slow operations until the recloser locks out, while Feeder M3009 has slow operations only based on the record settings. All feeder reclosers have Cold Load Pickup (CLPU) enabled as well.

The multiple shot reclosing allows for different coordination curves to be applied with each reclose attempt. In this case with a ‘1-fast and two-slow‘ scheme, it allows for fast downstream “fuse-saving” operation to be applied before slower operation and longer open intervals are applied (“fuse-clearing”) to allow downstream fuses to clear permanent faults. This feature is illustrated in almost all the TCCs for feeder protection.

CLPU is used to prevent inadvertent trips from occurring during restoration after a sustained outage. Cold load is the ‘phenomenon where excessive currents are drawn by distribution loads when restored after extended outages’. Sometimes it may be extremely difficult to reenergize the circuits without causing protective devices to operate due to high inrush currents caused by magnetizing currents to transformers, motor starting, capacitor charging currents, currents to raise heating device temperatures, loss of load diversity, etc., at different time durations varying from cycles to seconds. The inrush current can be more than 200% of the normal operating current for approximately 2 seconds, with the magnitude of the inrush current mostly related to load diversity. Typically, a 200% to 400% of full load for CLPU is considered reasonable but could be low and cause relay mis-operation during service restoration. It can also be achieved by manipulating the time multipliers for the protection curves.

Upon reviewing the TCCs in Appendix A, it appears that:

- The protection between substation relays and feeder recloser controllers coordinate. Fast operation by reclosers can save major tap fuses during momentary faults.
- Field VFIs and field reclosers coordinate well with substation feeder reclosers.
- The large downstream fuses may not coordinate with the recloser control in the long-time region, especially for ground protection, but the coordination in the short-time and instantaneous regions is acceptable.
- Along Feeder K4093, the underground tap to Clay St. is protected by 140A fuses based on the City’s electrical map, while the downstream VFI at E2300 (Abbott Avenue) appears to be set at 200 A. The coordination around the short-time and instantaneous region between these devices appears to be reasonable, however, we recommend the City consider adjusting these tap pickups from 200 A to 140 A or less.

9.8 Conclusions

This report evaluates Ashland’s major protective device components and feeder main tap coordination during normal configurations. No specific protective changes are recommended, except feeder M3009 recloser settings as noted. However, other minor suggested recommendations presented in this report should be reviewed and evaluated by Ashland on an as-needed basis or as time allows such verification and subsequent modification.

- The City’s electrical map system is missing fuse data in many locations. We recommend the City verify installed fuses and complete the map data.

- Verify Feeder M3009 recloser settings and adjust them to be identical with other Mountain Avenue Substation feeder settings if inappropriate implementation is confirmed.
- Due to the age of equipment, test all feeder recloser and switchgear devices on a 5-year basis to verify working condition. All sectionalizing devices should be exercised to ensure proper operation.
- As stated above, this review addresses major substation protection and backbone feeder coordination during normal configurations. Most of the small feeder tap fuses were not modeled as they are note expected to have coordination problems with substation reclosers. If the City has any concerns about any taps off the backbone feeder, a specific review can be done upon request.

Table 9-12: Type K Fuse Link Coordination Between EEI-NEMA Type K Fuse Links

Protecting Fuse Link Rating (amperes)	Protected Link Rating													
	8K	**10K**	**12K**	**15K**	**20K**	**25K**	**30K**	**40K**	**50K**	**65K**	**80K**	**100K**	**140K**	**200K**
	Maximum Fault Current At Which B Will Protect A (amperes)													
6K		190	350	510	650	840	1060	1340	1700	2200	2800	3900	5800	9200
8K			210	440	650	840	1060	1340	1700	2200	2800	3900	5800	9200
10K				300	540	840	1060	1340	1700	2200	2800	3900	5800	9200
12K					320	710	1060	1340	1700	2200	2800	3900	5800	9200
15K						430	870	1340	1700	2200	2800	3900	5800	9200
20K							500	1100	1700	2200	2800	3900	5800	9200
25K								660	1350	2200	2800	3900	5800	9200
30K									850	1700	2800	3900	5800	9200
40K										1100	2200	3900	5800	9200
50K											1450	3500	5800	9200
65K												2400	5800	9200
80K													4500	9200
100K													2400	9100
140K														4000

This table shows maximum values of fault currents at which EEI-NEMA Type K fuse links will coordinate with each other. The table is based on maximum-clearing time curves for protecting links and 75 percent of minimum-melting time curves for protected links.

Cooper Power Systems Reference

Table 9-13:Type T Fuse Link Coordination Between EEI-NEMA Type T Fuse Links

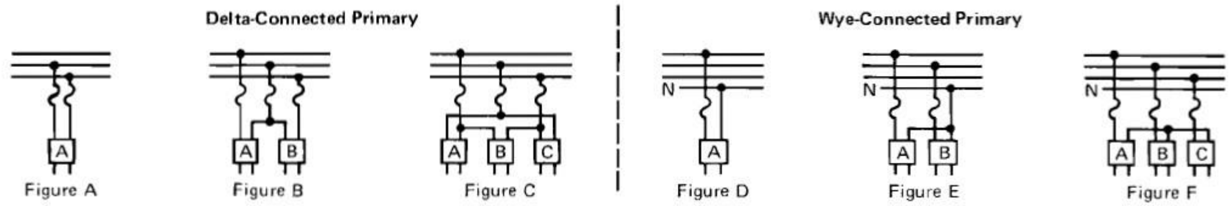
Protecting Fuse Link Rating (amperes)	**Protected Link Rating**													
	8T	**10T**	**12T**	**15T**	**20T**	**25T**	**30T**	**40T**	**50T**	**65T**	**80T**	**100T**	**140T**	**200T**
	Maximum Fault Current At Which B Will Protect A (amperes)													
6T		350	680	920	1200	1500	2000	2540	3200	4100	5000	6100	9700	15200
8T			375	800	1200	1500	2000	2540	3200	4100	5000	6100	9700	15200
10T				530	1100	1500	2000	2540	3200	4100	5000	6100	9700	15200
12T					680	1280	2000	2540	3200	4100	5000	6100	9700	15200
15T						730	1700	2540	3200	4100	5000	6100	9700	15200
20T							990	2100	3200	4100	5000	6100	9700	15200
25T								1400	2600	4100	5000	6100	9700	15200
30T									1500	3100	5000	6100	9700	15200
40T										1700	3800	6100	9700	15200
50T											1750	4400	9700	15200
65T												2200	9700	15200
80T													7200	15200
100T													4000	13800
140T														7500

This table shows maximum values of fault currents at which EEI-NEMA Type T fuse links will coordinate with each other. The table is based on maximum-clearing time curves for protecting links and 75 percent of minimum-melting time curves for protected links.

Cooper Power Systems Reference

Table 9-14: Distribution Transformer Fuse Protection

Suggested Primary Fusing for Distribution Transformers
Fuse Ratings Based on Use of EEI-NEMA Type "K" or "T" Fuse Links and High-Surge Type "H" Links
(Protection Between 200% and 300% of Rated Load)



Transformer Size (kVA)	7200 Delta				7200/12470Y		7620/13200Y		12000 Delta			
	Figures A and B		Figure C		Figures D, E and F		Figures D, E and F		Figures A and B		Figure C	
	Rated Amps	Link Rating	Rated Amps	Link Rating	Rated Amps	Link Rating	Rated Amps	Link Rating	Rated Amps	Link Rating	Rated Amps	Link Rating
3	.416	1H	.722	1H	.416	1H	.394	1H	.250	1H	.432	1H
5	.694	1H	1.201	1H	.694	1H	.656	1H	.417	1H	.722	1H
10	1.389	2H	2.4	5H	1.389	2H	1.312	2H	.833	1H	1.44	2H
15	2.083	3H	3.61	5H	2.083	3H	1.97	3H	1.25	1H	2.16	3H
25	3.47	5H	5.94	8	3.47	5H	3.28	5H	2.083	3H	3.61	5H
37.5	5.21	6	9.01	12	5.21	6	4.92	6	3.125	5H	5.42	6
50	6.94	8	12.01	15	6.94	8	6.56	8	4.17	6	7.22	10
75	10.42	12	18.05	25	10.42	12	9.84	12	6.25	8	10.8	12
100	13.89	15	24.0	30	13.89	15	13.12	15	8.33	10	14.44	15
167	23.2	30	40.1	50	23.2	25	21.8	25	13.87	15	23.8	30
250	34.73	40	59.4	80	34.73	40	32.8	40	20.83	25	36.1	50
333	46.3	50	80.2	100	46.3	50	43.7	50	27.75	30	47.5	65
500	69.4	80	120.1	140	69.4	80	65.6	80	41.67	60	72.2	80

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Suggested Primary Fusing for Distribution Transformers
Fuse Ratings Based on Use of Type "N" Fuse Links and High-Surge Type "H" Links
(Protection Between 200% and 300% of Rated Load)

Transformer Size (kVA)	7200 Delta				7200/12470Y		7620/13200Y		12000 Delta			
	Figures A and B		Figure C		Figures D, E and F		Figures D, E and F		Figures A and B		Figure C	
	Rated Amps	Link Rating	Rated Amps	Link Rating	Rated Amps	Link Rating	Rated Amps	Link Rating	Rated Amps	Link Rating	Rated Amps	Link Rating
3	.416	1H	.722	1H	.416	1H	.394	1H	.250	1H	.432	1H
5	.694	1H	1.201	1H	.694	1H	.656	1H	.417	1H	.722	1H
10	1.389	2H	2.4	5H	1.389	2H	1.312	2H	.833	1H	1.44	2H
15	2.083	3H	3.61	5H	2.083	3H	1.97	3H	1.25	1H	2.16	3H
25	3.47	5H	5.94	10	3.47	5H	3.28	5H	2.083	3H	3.61	5H
37.5	5.21	8	9.01	20	5.21	8	4.92	8	3.125	5H	5.42	8
50	6.94	10	12.01	20	6.94	10	6.56	10	4.17	8	7.22	15
75	10.42	20	18.05	30	10.42	20	9.84	20	6.25	10	10.8	20
100	13.89	20	24.0	40	13.89	20	13.12	20	8.33	15	14.44	20
167	23.2	40	40.1	60	23.2	40	21.8	30	13.87	20	23.8	40
250	34.73	50	59.4	100	34.73	50	32.8	50	20.83	30	36.1	60
333	46.3	60	80.2	150	46.3	60	43.7	60	27.75	40	47.5	85
500	69.4	100	120.1	150	69.4	100	65.6	100	41.67	60	72.2	100

Cooper Power Systems Reference

Table 9-15: ELF Fuse Electrical Ratings and Characteristics

Fuse Ratings		Cutout Rating		Continuous Current Ratings (A)[a]					
Voltage (kV)	Current (A)	Voltage (kV)	BIL (kV)	25°C	40°C	55°C	Minimum Melt I^2t ($A^2 \cdot s$)	Maximum Clear I^2t ($A^2 \cdot s$)	Maximum Interrupting Current (A rms symmetrical)
8.3	6	15	110	8	7	6	520	4550	31000
	8			12	11	11	1150	6500	
	12			18	17	16	1150	7000	
	18			25	24	23	1350	8600	
	20			27	26	25	2000	11700	
	25			34	33	31	2900	17000	
	30			43	41	39	4000	20000	
	40			50	48	46	8000	39000	
	50*			68	65	62	16000	65000	
	65*			78	75	71	20000	100000	
	80*			95	91	87	32000	150000	
	100*			120	114	109	46000	215000	

a. For temperatures other than listed, a deration factor of 0.26% per °C can be applied.
* Multi-barrel design
** 15 kV, 125 kV BIL, 6 through 25 A (single barrel part numbers FAK44W6 through FAK44W25) and 30 through 50 A (double barrel part numbers FAK44W30P, AK44W40, and FAK44W50) have been tested and approved for 17.2 kV application.

Table 9-16: ELF-LR Fuse Electrical Ratings and Characteristics

Fuse Ratings	Mount Rating		Continuous Current Ratings (A)*					
Voltage (kV)	Current (A)	Voltage (kV)	25°C	40°C	55°C	Minimum Melt I^2t ($A^2 \cdot s$)	Maximum Clear I2t ($A^2 \cdot s$)	Maximum Current Interrupting (A rms symmetrical)
8.3/13.2	6	7.2	8	7	6	520	4000	50,000
	8	7.2	12	11	11	1150	5000	50,000
	12	7.2	18	17	16	1150	5000	50,000
	18	7.2	25	24	23	1350	8000	50,000
	20	7.2	27	26	25	2000	10000	50,000

a. For temperatures other than listed, a deration factor of 0.26% per °C can be applied.

Cooper Power Systems Reference

Table 9-17: ELF Fuse Coordination Between EEI-NEMA Type K Fuse Links

Protecting ELF fuse current rating (A)	Protected K-Link current rating (A)										
	15	20	25	30	40	50	65	80	100	140	200
6	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*
8	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*
12	55	90	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*
18	–	–	90	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*
20	–	–	70	130	31000*	31000*	31000*	31000*	31000*	31000*	31000*
25	–	–	–	90	170	31000*	31000*	31000*	31000*	31000*	31000*
30	–	–	–	–	130	385	31000*	31000*	31000*	31000*	31000*
40	–	–	–	–	–	170	230	350	31000*	31000*	31000*

* 31,000 A at 8.3 kV. 20,000 A at 15 kV

Table 9-18: ELF Fuse Coordination Between EEI-NEMA Type T Fuse Links

Protecting ELF fuse current rating (A)	Protected T-link current rating (A)										
	15	20	25	30	40	50	65	80	100	140	200
6	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*
8	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*
12	–	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*
18	–	–	.	31000*	31000*	31000*	31000*	31000*	31000*	31000*	31000*
20	–	–	–	–	31000*	31000*	31000*	31000*	31000*	31000*	31000*
25	–	–	–	–	31000*	31000*	31000*	31000*	31000*	31000*	31000*
30	–	–	–	–	–	31000*	31000*	31000*	31000*	31000*	31000*
40	–	–	–	–	–	–	31000*	31000*	31000*	31000*	31000*

* 31,000 A at 8.3 kV. 20,000 A at 15 kV

Cooper Power Systems Reference

Chapter 10 RENEWABLE ENERGY

10.1 GENERAL

In 2011, the City of Ashland initiated a Climate & Energy Action Plan (CEAP) with a vision to reduce greenhouse gas emissions and improve the resilience of the environment, infrastructure, and people from future impacts of climate change. The Goals of the plan are to:

- Reduce overall Ashland community greenhouse gas emissions by 8% on average every year to 2050
- Attain carbon neutrality in City operations by 2030, and reduce fossil fuel consumption by 50% by 2030 and 100% by 2050
- Be ready for projected climate changes

The focus of the electric department planning study is to attempt to prepare the electrical infrastructure for future demands and includes a review of the impacts of growth, weather, and climate concerns. To align system planning with the City's CEAP this section will address the following considerations:

- Recommendations for integration of the City's Climate and Energy Action Plan (CEAP) and potential impacts on electrical infrastructure.
- Opportunities and barriers for adding renewable energy resources such as solar, wind, and/or hydro power, etc.
- An assessment of the City's readiness to accommodate high adoption of Electric Vehicles (EVs) and fuel-switching (natural gas reduction)

This chapter discusses the existing situations of the City's policy, program, load profiles, barriers and challenges, and provides recommendations attempting to prepare the electrical infrastructure for future demands and align system planning with the City's CEAP to the extent possible.

10.2 CLIMATE & ENERGY ACTION PLAN (CEAP)

Initiated in 2011 and approved in 2017, the City's CEAP outlines a vision of collaboration in a long-term effort to achieve the CEAP goals by following several different paths, including:

- Transition to clean energy
- Maximize water and energy efficiency and reuse
- Support climate-friendly land use and management
- Reduce consumption of carbon-intensive goods and services
- Inform and work with residents, organizations, and government
- Lead by example

10.3 TRANSITION TO CLEAN ENERGY

Using clean energy is one of the major paths in the City's CEAP, and the City plans to do the following to increase the clean energy resources gradually.

10.3.1 Natural Gas Ban Or Fuel-Switching Policy

In 2023, the City of Ashland voted and decided to develop an ordinary ban on natural gas for new residential development. Ashland became the third Oregon city to commit to developing a policy to transition new homes off fossil fuels. Once passed, appliances for heating or cooking would have to be all electric for new home construction. This is intended to reduce fossil fuel consumption and greenhouse gas emissions. However, the increased use of electric appliances will increase the electric load and is likely to have an impact on the City's electric systems.

For example, based on the discussion in Chapters 3, 5, and 7 the peak demand (including PacifiCorp's load) in Ashland Substation during the 10-year historical peak in 2021 was about 94% of the transformer overload rating of 20 MVA. PacifiCorp typically uses 120% of the nameplate rating as their guide for Winter capacity rating. However, the City of Ashland has a Summer peak load pattern. The Ashland substation is very near capacity and may be under capacity if extreme summer weather conditions occur. Load growth that affects peak conditions can be expected to further stress the system. The increase in use of electrical appliances, as well as the shift from traditional vehicles to EVs, is likely to further exacerbate the stress on Ashland Substation.

PacifiCorp also has a feeder served out of its Ashland Substation with considerable load. We recommend the City work with PacifiCorp to monitor this substation peak, especially during peaking hours in summer and winter.

To address the potential overloading condition on Ashland Substation and allow for load growth the achieve the CEAP goals, relocating feeder sections to Mountain Avenue Substation can provide temporary relief but, for long-term planning, we recommend the City consider building a City-owned substation next to the existing Ashland Substation with more capacity, control, and reliability for both normal feeder switching configurations and emergency configurations with feeder interconnections to other substations feeders. This will greatly improve the resilience of the City's electric system.

10.3.2 Increase Renewable Energy Portfolio

According to the US Energy Information Administration, utility-scale electricity generation in the United States is mainly from three fuel categories: fossil fuels, nuclear energy, and renewable energy. Other utility-scale sources include non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Fossil fuels involve coal, natural gas, petroleum, and other gases, while renewable energy sources include wind, hydro, solar (photovoltaic and solar thermal), biomass (wood, landfill gas, solid waste, and other biomass waste), and geothermal.

Figure 10-1 shows the recent electricity fuel mix profiles for the nation and Oregon in general. Figure 10-2 shows the electricity fuel mix profile for the Bonneville Power Administration (BPA). Using the 2021 data as an example for a horizontal comparison in Figure 10-3, BPA's electricity fuel mix profile shows much more renewable sources than the percentage at the national and

State levels, specifically ~85% for BPA vs. 50% for Oregon in average and 22.5% for the nation in 2021.

Figure 10-1: National (on the right) and Oregon (on the left) Electricity Fuel Mix, 2021 [Source: https://www.oregon.gov/energy/energy-oregon/pages/electricity-mix-in-oregon.aspx. The available data on this website is only up to 2021]

BPA Fuel Mix Percent Summary. Calendar Year 2023.

Type	CY 2021	CY 2022	CY 2023	Percent Change
Biomass and Waste	0.000%	0.0%	0.0%	0%
Geothermal	0.000%	0.0%	0.0%	0%
Small Hydroelectric	0.853%	0.7%	0.8%	0%
Solar	0.000%	0.0%	0.0%	0%
Wind with RECs	0.000%	0.0%	0.0%	0%
Coal	0.000%	0.0%	0.0%	0%
Large Hydroelectric	83.652%	84.2%	77.2%	-7.1%
Natural Gas	0.000%	0.0%	0.0%	0%
Nuclear	10.894%	11.0%	11.3%	0%
Non Specified purchases [1]	3.982%	3.4%	10.1%	6.7%
EIM purchases [2]	0.000%	0.3%	0.2%	0%
Wind without RECs [3]	0.619%	0.4%	0.4%	0%
Total		100%	100%	

1) Non Specified purchases are purchases made from another system without knowledge of specific fuel type. Reporting agencies in Washington assign their generic fuel mix to the BPA purchase amount based on their determination of the Northwest power pool region resources. This figure does not include amounts of power available to BPA through participation in the EIM.
2) BPA joined the Western Energy Imbalance Market (EIM) in May 2022.
3) BPA conveys its RECs to other parties and does not retire them.

Figure 10-2: BPA Fule Mix Summary in 2021, 2022, and 2023 [Source: https://www.bpa.gov/-/media/Aep/power/fuel-mix/2022-bpa-fuel-mix.pdf, https://www.bpa.gov/-/media/Aep/power/fuel-mix/2023-bpa-fuel-mix.pdf]

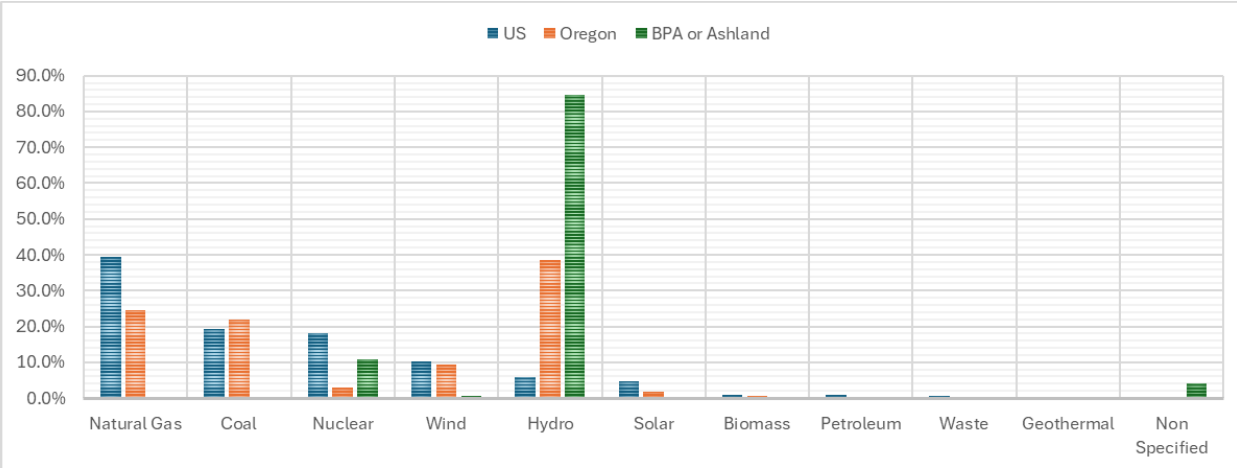

Figure 10-3: Electricity Resource Profile Comparison Between The Nation, Oregon, and BPA/Ashland, 2021

At the time of this study, the City of Ashland is a full-requirements customer of BPA and BPA provides all of the electricity purchased by the City. Therefore, the City's fuel mix is mainly determined by BPA's energy fuel mix. As a result, the City of Ashland's renewable energy portfolio was approximately 85% in 2021 and 78% in 2023 for energy imported from BPA. The actual percentage for the City will be slightly higher due to the small hydro and accumulated small commercial and residential PV generation in the City's electric system. Also note that 11% of BPA portfolio is from nuclear power generation. Therefore, only 5% to 10% of the energy purchased by the City is from potential greenhouse gas emitting production.

The annual percentage of renewable energy resources changes depending on weather, reservoir storage, and other factors. For example, hydro generation dropped 7.1% in 2023 compared to 2022, which affects Ashland's electricity fuel mix. If the BPA energy fuel mix profile is not completely renewable, Ashland's fuel mix will be similar due to the BPA power import dependency.

The City of Ashland can buy additional renewable resources from the open market and have that energy wheeled through BPA's transmission network. That energy could be used to offset the non-renewable energy in the BPA profile. The actual energy delivered by BPA would of course still have the same energy mix but, by offsetting the amount of non-renewable energy that would have been delivered, the City would effectively be 100% greenhouse gas free.

Adding residential, commercial, and community-level renewable energy resources such as solar energy, small hydro, and other types has a similar impact in terms of the renewable energy portfolio. Even though they are mostly small-scale, they are within or near the City's network and do not need transmission wheeling services, which might be more cost-effective.

Solar Energy (Photovoltaic)

The City of Ashland started community and commercial solar projects in 2000. Figure 10-4 shows the annual installation capacity profile between 2000 and 2017. Based on the latest information available the total installed commercial solar is about 1.28 MW, and the total installed residential solar is about 3.82 MW. That is overall 5.1 MW of nameplate capacity. The expected summer peak output is about 3.5 to 4 MW assuming fixed axis stands, modern PV panel ratings, and Ashland's solar irradiance profile.

For solar energy (or other renewables) less than or equal to 25 kW, there are generally no barriers or issues with installation as long as they meet NEC and the City's metering and installation requirements. For solar energy (or other renewables) greater than 25 kW and less than 200 kW, depending on the location and total installed capacity versus available capacity, prior consultation and approval by the City are required and generally engineering studies are required to ensure voltage stability, service reliability, and no transmission export. The City, State, and Federal Government have various incentive programs for these levels of solar projects.

A system definition of 'Large' is relative to where the generation is connected. For distribution level connections, large is greater than 200 kW. BPA's standard classifies as a small generation resource when a single or combined generating capacity is greater than 0.2 MW and equal to or less than 20 MW. This is primarily a function of transmission connection. Post-2028 BPA contracts under discussion with the City would allow the City to develop a single combined generation capacity of up to 5 MW. However, the City has no transmission resources as the City's electric infrastructure is distribution only. Interconnection of large PV generation requires Feasibility, Impact, and Facility studies on the feeder level, substation level, and transmission level by both the City and transmission provider (BPA or PacifiCorp in this case).

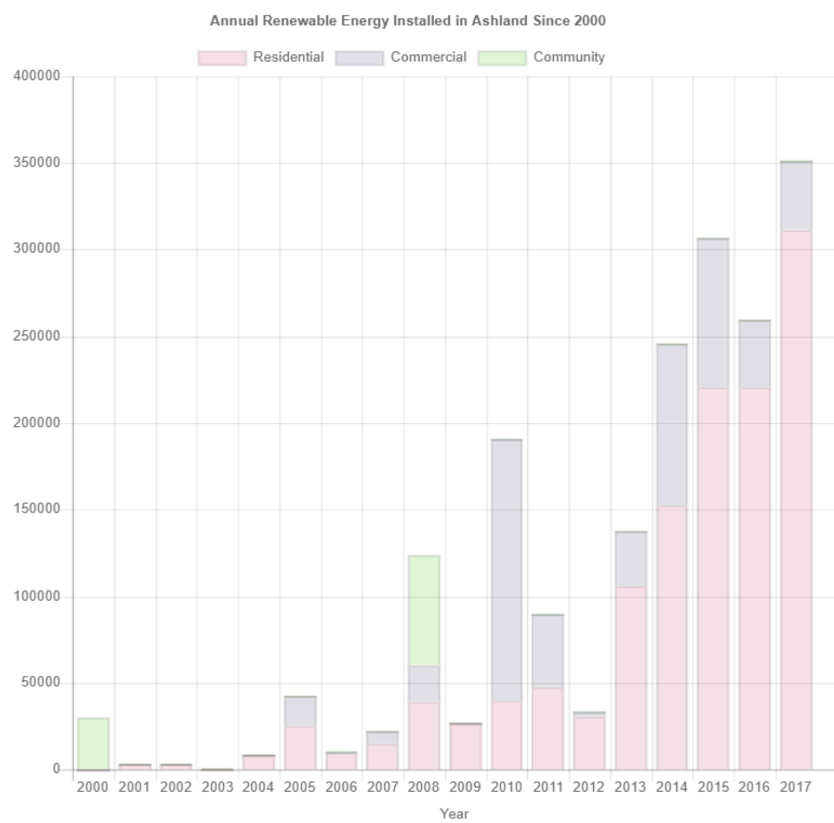

Figure 10-4: Installed Solar Energy Capacity (Watts) In Ashland Since 2000

Hydro Power

The City of Ashland has an existing small hydro generation, Reeder Gulch Hydroelectric (RGH) at Hosler Dam, which has an 845 kVA generator with its power output limited by penstock and water demand. According to the City's SCADA system, this unit is outputting ~250 kW of power continuously during normal conditions.

Adding additional generators is not feasible but the existing unit is capable of higher output. Upgrades to the turbine and/or needle valves would allow for an increase in output closer to the generator nameplate. Additional capacity improvements can be achieved by modifying the penstock but would likely be at a much higher cost. In any case, the Reeder Gulch Hydro is a significant renewable energy resource that is already owned and operated by the City and should be utilized at maximum capacity. We also note that the capacity factor of the Reeder Gulch Hydro is significantly higher than PV systems are capable of due to the ability to run 24 hours a day, dependent only on water resources. Therefore, to achieve the same energy output a much larger PV system would be required.

Other Resources

Other potential renewable resources include biomass, biogas, geothermal, and wind. These do not necessarily need to be within the City's electric service territory and can be in the nearby region. For example:

- Potential biomass plant expansion in the Rogue Valley and potential biomass cogen plant project at Southern Oregon University.
- Methane gas from food waste, yard waste, and manure that can be used to generate electricity or as a vehicle fuel.
- Geothermal for power generation (e.g., geothermal plant in Oregon Institute of Technology OIT campus, about 2 MW) or direct use for heating
- County-level collaborative efforts in wind energy

When these potential resources are considered, similar interconnection studies are required to evaluate the feasibility, impact, required system upgrades, and associated budget for construction and future maintenance.

10.3.3 Electric Vehicle (EV)

The use of EVs has increased steadily over the past 10 years as the technology matures and more charging stations are available. EVs have the potential to meet transportation needs and be part of the clean energy future. According to Oregon.gov, the total number of registered electric vehicles in Oregon as of July 2023 was 74,427. The City of Ashland (Zip Code: 97520) had approximately 900 in July 2023. EV growth over the past three years has averaged about 150 vehicles a year and is likely to continue near that rate or faster, depending on available vehicles, charging infrastructure, and government incentives. As such, the City can expect to at least double EV use in the next 5 to 6 years in Ashland depending on regulating & incentive policies and supply chain considerations.

EVs are an important part of the City of Ashland's CEAP. The City has various incentive programs for EVs, E-Bikes, chargers, etc. The City currently has approximately 4,590 households with an average car ownership of two per household. For planning purposes, if the City is able to sufficiently incentivize EV use such that there is an average of one EV per household along with the 0.63% growth rate discussed in Section 3, the City could see as many as 5000 EVs in use in 10 years.

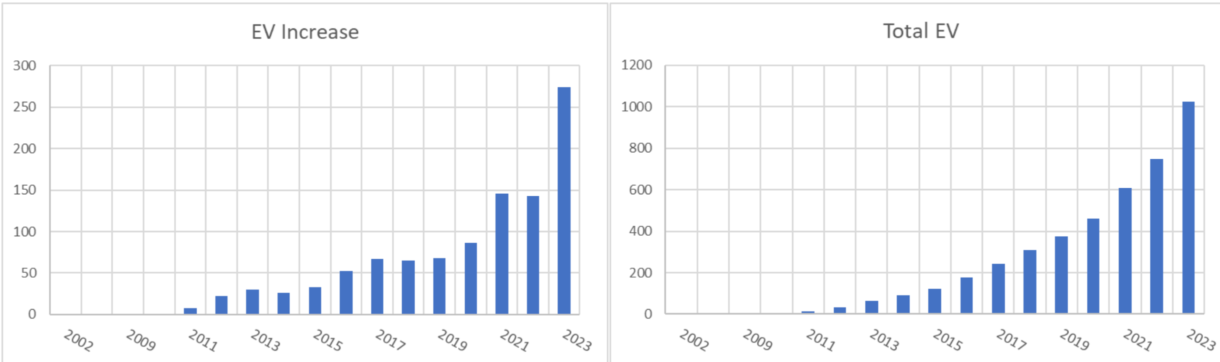

Figure 10-5: Annual EV Increase and Accumulated Total From 2000 to 2023 [Source: https://www.oregon.gov/energy/Data-and-Reports/Pages/Oregon-Electric-Vehicle-Dashboard.aspx. The above statistic data stops in December 2023]

Currently, the City has and/or plans to install the following charging stations:

- 16 City-owned, Level 2 chargers [Public access]
- 24 Tesla superchargers [Public access]
- 11 City-owned Level 2 chargers at the service center;
- Plan to add six more Level 2 and two Level 3 chargers at the service center
- Plan to add 20 more City-owned Level 2 public chargers in 2024 [Public access]
- Southern Oregon University has14 level 2 EV chargers on campus [Public access]

Table 10-1: Typical EV Charger Profile

Charger Type	***Typical Output Power***	***Estimated Charging Time (40 kWh)***	***Estimated Range per Hour***	***User Case***
Level 1	1 – 1.8 kW	22 – 40 hours	3 – 7 miles/hour	Home / Backup
Level 2	3 – 22 kW	2 – 13 hours	10 – 75 miles/hour	Work / Hotel / Public chargers
Level 3	30 – 360 kW	15 mins – 1.5 hours	120 – 1400 miles/hour	Fleets / Dealer / Hwy service / Supercharger

Different chargers have various performance and power requirements as outlined in

Table 10-1. Besides the clean energy feature of EVs, increased EV brings the following challenges:

- **Increase power demand**. EV charging requires a significant amount of electricity, especially during peak charging periods. This increased demand can strain the existing electric system infrastructure, leading to potential issues such as voltage fluctuations and load imbalances.
    - Uncontrolled charging increases the system peak demand. For about 1000 EVs (Figure 10-5), assuming each has a charger. 70% of the chargers are Level 1, ~1.5 kW, 30% are Level 2, ~15 kW, uncontrolled charging, and a diversity factor of 2.5 (40% are in use concurrently), The estimated total kW increase during the charging hours is about 2.2 MW. Without diversifying the total estimated peak is about 5.5 MW.

   - Smart charging technology or algorithms including delayed charging, controlled charging, demand response, or using a dynamic rate structure to reshape the load curve (aka. peak shift or shaving). These technologies or algorithms are common in some of the public utilities in California. As EV counts increase, we recommend the City monitor the daily feeder load pattern/shape and implement associate alerts or flags. A smart charging policy/program may be needed and should be discussed before the EV load profile becomes a concern.

- **Potential equipment overload**. Simultaneous charging during peak times can overload local transformers and distribution circuits, which can result in power outages or require expensive infrastructure upgrades to meet the growing demand.
- **Capital Cost from infrastructure upgrades**.

  Distribution transformers have to be sized with future EV additions. We recommend the City consider the future of Electric Vehicle (EV) impact on the distribution facilities by increasing transformer capacity in new developments. An estimated 5 kW per resident should be allocated when sizing new transformers. The EV charger minimal use time will impact transformer energy losses which must be paid for by the serving utility (City of Ashland) and will likely impact future electric rates.

  Other costs can be technology upgrades for smart charging based on demand response.

The impact of increased EV use in the City over the next 10 years will affect the City peak demand and total energy consumption. However, the impact on peak demand is difficult to predict as the charger technologies mature and the City may be able to take steps, such as regulating smart charging, to help reduce coincident charging load. Based on information from the Department of Transportation, Energy consumption can be estimated to be ~11.81 kW-hrs per day per EV. With an increase in vehicle count of 4000 EVs over the next 10 years, the total energy consumption increase can be estimated to be about 17,242 MWh per year. That is an increase of ~10% in energy consumption based on the average yearly totals over the past 10 years.

As a rough estimate of peak demand impact, we can assume ~70% Level 1 charging and ~30% Level 2 charging with power requirements of 1.5 kW and 15 kW respectively. With a diversity factor (ratio of sum of non-coincident maximum load to coincident peak) of 2.5 the estimated peak demand for EV charging can be estimated to be ~8.9 MW. If that peak occurs coincident with the existing summer peak, and with the estimated peak demand increase from growth outlined in Section 5, the City could see peak demand in excess of 58 MW within a 10-year period without using any smart charging technology or algorithms to shave or shift the peak.

10.4 Discussion and Recommendations

The City's goal of developing an electric energy usage that is 100% from non-fossil fuel resources can be achieved using several approaches. The primary methods for eliminating non-renewable energy from the City's use can be summarized as follows:

1. **Reduce energy consumption**. This approach can be used to reduce non-renewable consumption but cannot fully eliminate it. The City can expect an increase in consumption as EV numbers increase and the City's initiatives to electrify appliances that could alternatively utilize natural gas or other non-renewable resources will shift the

burden of non-renewable reduction to the electric system. However, any reduction in non-renewable energy consumption will put the City closer to achieving the 100% goal.

2. **Add additional renewable generation to the City's system**. This can be achieved by continuing to support community projects to add distributed generation resources. The City's current community 1 MW project will certainly support this approach. However, the City does not own transmission resources and has limited siting available for large-scale PV generation.
3. **Purchase renewable energy from an outside provider and have it wheeled to the City**. This option would typically involve identifying a renewable generation provider that would establish a power purchase agreement with the City and establishing a wheeling agreement with BPA and/or PacifiCorp. This requires the least amount of infrastructure changes to the City but would ultimately result in higher rates to consumers.

The first option can be achieved by developing programs to incentivize energy efficiency improvements and energy use reductions. A community program focused on energy efficiency and consumption reduction could include:

- Building audits and retrofits to HVAC equipment, lighting equipment, insulation systems, and appliances.
- Community awareness programs advocating good use habits including
    - Fully disconnecting charging devices and switching off standby equipment.
    - Draught-proofing windows and doors.
    - Turning off or reducing lights.
    - Reducing and/or consolidating washing.
    - Avoiding tumble drying.
    - Shorter shower durations and showers in lieu of baths.
    - Adjusting heating and cooling setpoints to reduce cycling
- Community program to provide rebates for energy efficiency improvements

The improvements from the energy efficiency program have the highest effectiveness in reducing non-renewable energy consumption.

The City and community-owned renewable generation resources directly create energy that offsets non-renewable resources. As stated above, large-scale generation projects are not likely to be feasible in the area without connecting directly to transmission. However, the City purchases all electric energy from BPA, the majority of which comes from the hydroelectric facilities in the BPA territory. As such, BPA's energy fuel mix is generally 78% to 85% renewable and an additional 11% non-greenhouse gas producing nuclear. Therefore, only 5% to 10% of the energy purchased by Ashland is potentially greenhouse gas producing. Ashland's energy consumption is typically on the order of 180,000 MWh per year. One approach the City might consider taking to achieve 100% greenhouse gas-free energy use is simply to identify enough renewable energy such that it offsets 5% to 10% of what would have been required to be purchased from BPA. Therefore, a reasonable target for directly procuring or generating renewable energy would be between 9,000 MWh and 18,000 MWh per year.

Currently, the installed commercial and residential PV capacity in the City is about 4 MW. The planned community 1 MW PV development would increase that capacity to 5 MW. In estimated effective capacity factor for PV in Southern Oregon is between 20% and 25%. At 20% the current and planned PV systems can be expected to produce ~9,000 MWh per year. The hydro output averages ~250 kW resulting in a total yearly production of about ~2,200 MWh. As stated above, we recommend the City work to increase hydro production which could improve the energy contribution.

The City's total renewable energy production, with the planned 1 MW PV system, is about 11,200 MWh per year. To fully offset the ~18,000 MWh of energy from greenhouse gas emitting processes the City will need to produce and/or procure an additional ~8,000 MWh of clean energy. Assuming a 20% capacity factor, the City would need an additional 4.6 MW of installed PV capacity or some other suitable clean energy source. The current growth trend in residential and commercial installed facilities will help reach the needed capacity. As discussed earlier in this report, we are recommending the Ashland Substation be expanded to a new City-owned substation to increase capacity and reliability. If a suitable site near Oak Street can be identified, adding a large PV system to the new substation development would be an option for adding the needed capacity.

The third option is a viable option for adding additional renewable energy to the City's profile but the cost of energy would be considerably higher than the rates the City currently pays. Unlike renewable development programs, we are not aware of any grant or incentive programs to offset the cost increases from wheeling energy directly from renewable power produce.