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December 26, 2011

Wyatt Pierce, P.E.
Project Manager
NID Support and Special Projects
Pacific Power

Subject: Revision 3 Washington Distribution Efficiency Study
Contract Release No. 3000071987

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Wyatt,

Attached to this letter is Commonwealth's Revision 3 report on the distribution efficiency opportunities for 19 distribution circuits in PacifiCorp's service area in Washington State. The attached report is in electronic Adobe pdf form. If you wish, Commonwealth will assemble one full hard copy report and will send it by regular mail. Please let me know if you would find this helpful.

This revision was necessary to address a PacifiCorp request to update the financial factors used in the calculations within the study and to correct the financial results from earlier Nob Hill revisions. As part of this effort you and I agreed to significantly revise the organization of the body of the report. Additionally, Appendices 7 and 12 were updated.

In addition to the full report, a Summary Report is also provided. The Summary Report is Section 1 of the full report.

Please let me know if you have any questions about the revised report. The Commonwealth team looks forward to the opportunity to serve you and PacifiCorp in the future.

Sincerely,

John P. White

John P. White, P.E.
Vice President
Commonwealth Associates, Inc.

# Distribution System Efficiency and Voltage Optimization Study

**Prepared for:**

PACIFIC POWER
A DIVISION OF PACIFICORP

**Prepared By:**

**COMMONWEALTH ASSOCIATES, INC.**

**with**

**UTILITY PLANNING SOLUTIONS, PLLC**

**Original: May 27, 2011**
**Revision 3: December 26, 2011**

Commonwealth
associates, inc.

# Distribution System Efficiency and Voltage Optimization Study

## Prepared for:

PACIFIC POWER
A DIVISION OF PACIFICORP

**Prepared by:**

John P. White, P.E.
Rick Cook, P.E.
Robert Fletcher, PhD, P.E. – Utility Planning Solutions, PLLC

**Approved by:**

John P. White, P.E.
Vice President and Regional Manager
Commonwealth Associates, Inc.

**Date:**
May 27, 2011
Revision 3: December 26, 2011

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# Table of Contents

# Appendices



# Table of Figures

# Table of Tables

# DEFINITIONS OF TERMS

| Term | Definition |
|---|---|
| aMW | Average Megawatt – a measure of electric capacity produced continuously for a period of one year. 6 aMW = 6 MW x 8760 hours/year = 52,560 MWh/year. |
| BCR | Benefit Cost Ratio – the ratio of benefits to cost. For this study<br>$$BCR = \frac{\text{(Present Value of the Energy Savings)}}{\text{(Present Value of the Costs of System Improvements)}}$$<br>This calculation is based on the anticipated 20 year life of the project. The costs include O&M costs and a capital update of the improvement assumed to be ten percent of the initial capital investment at year 15. |
| CVR | Conservation Voltage Reduction – is a means of reducing energy consumption as a result of reducing the primary voltage on an electric distribution system. Energy saved from CVR include no-load loss savings, distribution line loss savings, and end-use (service entrance) energy savings. See Appendix 1 for more detail. |
| CVR factor | Conservation Voltage Reduction factor ($CVR_f$) – is the percent change in energy consumption on a distribution system resulting from a one percent reduction in voltage. A positive CVR factor indicates that as the voltage goes down there are resultant energy savings. A CVR factor of 0.6 indicates there is a 0.6% energy savings for a 1% voltage reduction. |
| IVVO | Integrated Volt VAR Optimization – is the real time optimization of system voltage and reactive power (VAR). It requires a relatively sophisticated metering, communication and control system. Utilities are considering it as part of Smart Grid roll outs. IVVO is not studied in this report, although a Stage 3 implementation would include infrastructure useful for a future IVVO program. |

| | |
|---|---|
| LCLC | Life Cycle Levelized Costs – calculates the present value of an alternative expressed as an equal annual payment divided by the expected annual energy the alternative provides. If a project's present value is $500k, it has a 20 year life and it produces 400 MWh of energy per year then its LCLC equals:<br><br>(($500,000/20) / 400 MWh) = $62.5/MWh = $0.0625/kWh<br><br>For this study, LCLC's are calculated based on the anticipated 20 year life of the project. |
| LDC | Line Drop Compensation – is a means of setting voltage controls on the LTC for power transformers and voltage regulators so that the voltage regulated point on the circuit is farther out on the circuit than the location of the LTC or regulator. Using LDC is an important aspect of voltage optimization programs. |
| LTC | Load Tap Changer – is a voltage regulating device attached physically and electrically to a power transformer in a substation. It has the capability and controls to change load side voltage settings to maintain appropriate voltage levels in varying load situations. |
| M&V | Measurement and verification – Utilities implementing energy conservation programs in compliance with RCW 19.285 must report on expected and actual energy savings. Additional metering may be required to measure and verify actual energy savings. See Appendix 8 for more detail. |
| No-load loss | No-load loss – Energy losses from electrical devices, commonly transformers, which are energized but without load. It is advantageous to keep these losses as low as economically reasonable because they occur whenever the device is energized. |
| NPV | Net Present Value – is a means of expressing a time sequence of cash flows, both positive and negative, as a present day value. The NPV is the sum of annual cash flows which have each been discounted by a factor which accounts for the value of money in the future as compared to today. |
| SI | System Improvements – the changes made to the distribution system in a voltage optimization program in order to gain energy savings. These usually include phase balancing, installing capacitors to correct power factor, site specific reconductoring, and installation of line voltage regulators. |

| | |
|---|---|
| VO | Voltage Optimization – is a combination of CVR and system improvements that together provide more energy savings than CVR alone. |
| VO factor | Voltage Optimization factor ($VO_f$) – is expressed as the percent change in energy for a one percent change in voltage supplied at the end-use service entrance. VO factors are influenced by the percent of customers with non-electric heat, air-conditioning and the specific climate zone in which a distribution circuit is located. End-use energy savings associated with the VO factor can represent the majority (more than seventy-five percent in some systems) of the total energy saved in a voltage optimization program. The balance of the energy saved is derived from line loss savings and no-load loss savings. See Appendix 1 |

# STUDY OVERVIEW, FINDINGS AND RECOMMENDATIONS

## SECTION 1A – STUDY OVERVIEW

### Purpose

The purpose of this Distribution System Efficiency Study was to identify the potential energy and monetary savings associated with implementing a distribution system loss reduction and conservation voltage regulation application. Commonwealth Associates, Inc., with Utility Planning Solutions, PLLC, was contracted by PacifiCorp to provide a Distribution System Efficiency Study on 19 distribution feeders. Energy savings are determined for PacifiCorp's distribution system based on the Simplified Voltage Optimization (VO) Measurement and Verification (M&V) Protocol approved on May 4, 2010, by the Northwest Power and Conservation Council Regional Technical Forum committee. This report summarizes the assessment findings on the feeders, which are located in PacifiCorp's Walla Walla, Yakima and Sunnyside service areas.

The Simplified VO M&V Protocol provides a simple means to estimate end-use energy savings as a result of system improvements that allow the electric distribution system to operate more efficiently and within the lower band of the ANSI Standard voltage level. The protocol covers utility electric distribution systems serving mostly residential and light commercial loads. System loads do not need to be uniformly distributed throughout the distribution system. This protocol identifies the procedure to determine the average annual voltage for a distribution primary system with source voltage regulation. Minimum system stability thresholds, system data requirements, and measurement and verification formulations are included as part of this protocol.

The study addresses the level of effort and system improvement (SI) necessary to comply with minimum VO thresholds and estimates the potential for SI and VO efficiency energy savings. For this report, 19 PacifiCorp circuits served from 12 substations were studied. They included circuits in the Yakima, Walla Walla and Sunnyside areas. Ideally, all distribution feeders that are common to one substation power transformer voltage control zone should be evaluated. This was not the case for all of these selected circuits.

The study is a starting point and potential guide for PacifiCorp as it considers implementing distribution efficiency programs for all of its Washington distribution circuits.

The study provides information for use in developing recommendations for PacifiCorp's Integrated Resource Plan (IRP).

## Data

Data provided by PacifiCorp is assumed to be accurate and up to date. Modeling and data fielding verification was performed by Commonwealth. The following data was provided via on-site visits, phone conversation and e-mail. Data gathered included:

- GIS detailed AutoDesk Map files
- ABB FeederAll software, including PacifiCorp's Washington distribution circuit model
- Substation hourly peak kW and kVAR load history for 2009
- Summer and winter peak kW and kVAR loading for circuits in the study and for the adjacent circuits, those served by the same LTC or voltage regulator
- Locations and size of customers with large electrical demands
- Connected distribution transformer phase kVA for each feeder line section
- Line conductor sizes and phase configurations for each feeder
- Customer load characteristics used to determine VO factor
- Substation voltage control settings
- Financial and economic factors and marginal purchase power costs
- System planning criteria, system expansion guidelines and voltage standards
- Completed utility overview and scoping questionnaire
- Fully loaded hourly labor costs for crew labor, including transportation
- Block Cost Estimating Spreadsheet for system improvements

## Assumptions

The GIS data received was assumed to be preliminary and may need further investigation if additional study is required. The data reported in the Commonwealth Data Request Questionnaire, as well as additional data provided, was used in this analysis. In some cases, requested data was unavailable at the time or was unknown. Feeder load factors are based on PacifiCorp's measured data. Feeder maps used to prepare the system electric connectivity model using ABB FeederAll software were revised based on the information gained by Commonwealth's fielding efforts.

Heavy loads for the study are peak summer MW with a MVAR load level representative of the 95th percentile on the MVAR Histogram based on the annual transformer hourly data. This can be seen in Appendix 3. These loads were used in the study because they represent reasonably high loads and, together, they result in a greater voltage drop than what would happen at the recorded winter peak when the MVAR loading is less.

The light loads are at the 5th percentile, from the MW and MVAR Histograms. These loading levels were chosen because they represent reasonably low-load levels without considering lighter loads on the Histogram, which occur with near zero probability.

The PacifiCorp system information was assessed for compliance with the entire set of VO minimum system thresholds identified by the NWPCC RTF Simplified VO Protocol. Substation power transformer load losses were not considered in this study. In the third stage, the 3-step staged approach results in a VO design with a minimum primary voltage of 119 volts on 120 volt basis.

The cost of system improvements, including engineering, material and labor, were based on information provided by PacifiCorp and supplemented by Commonwealth's knowledge and understanding of industry costs.

The Simplified VO Protocol methodology is an accepted approach to estimating the savings available from voltage optimization. Its approach to estimating the energy savings is accurate for the purpose of this planning study. This document provides the study results of implementing possible VO improvements on the 19 PacifiCorp feeders identified. This study is not a detailed plan of action; further studies will be required before implementing voltage optimization and system improvements.

All model development and engineering assessments were performed using the ABB FeederAll engineering analysis tool. It is assumed this model accurately models voltage drops, losses, etc.

The LTC and voltage regulator "R" set points were changed in 0.5 volt increments.

## Study Basis

This study is based on information provided by PacifiCorp and circuit fielding by Commonwealth. PacifiCorp has an ABB FeederAll application that includes spatial location of feeder conductor sizes, phases and installed transformer kVA that is routinely maintained. Substation metering is installed on power transformers with feeder MW and MVAR demand. The PacifiCorp FeederAll application model has been updated to include up-to-date fielding information (i.e., wire sizes, transformer kVA sizes, phase connections, etc.) from Commonwealth fielding.

## Fielding

As the system data and other information was being assembled and reviewed, the first major step of the project was to field the 19 circuits and note differences between field observations and the maps. This was necessary to make the starting model as accurate as possible for the analysis. Commonwealth staff went into the field to record existing conditions and worked with PacifiCorp staff as needed. Marked-up maps were sent back to Commonwealth's office, where they were scanned and electronically stored and made available to the modeling staff.

## Staged Approach Used to Evaluate the Circuits

The study used a staged approach to evaluate the circuits. It started with an "As-is" base case and then moved through three evaluation stages for each circuit. For the As-is case, Commonwealth made corrections to the system model based on the changes found during fielding. From this model of the existing system, Commonwealth used FeederAll to examine the voltage and losses during heavily loaded conditions and lightly loaded conditions. Heavy loads for all stages are the peak summer MW with a MVAR load level equal to the 95th percentile of the transformer histogram. The light loads are at the 5th percentile of the transformer histogram for both MW and MVAR. For the As-is voltage profile analysis, Commonwealth modeled the primary system on a 120 volt basis in an effort to keep the voltage from dropping below 121 volts (band center) on any spot on each of the modeled circuits. This was not always attainable, but it was the goal.

From the As-is case, Commonwealth stepped through the three stages of changes. In Stage 1, the LTC control in FeederAll was set to hold the end of the line (EOL) voltage at, or near, 120 volts; the phase loadings were balanced; and existing capacitors were optimized. Included in the Stage 1 costs are funds for metering improvements in the substations and at the end of the line necessary to verify the circuit is operating consistently with the VO protocol.

In Stage 2, the modeling included new capacitors, mostly switched, reconductoring and voltage regulators. If voltage regulators are added, then funds are included to provide the necessary metering for the newly created voltage control zone downstream of the regulator. In Stage 2, the EOL voltage was left at 120 volts.

In Stage 3, the EOL voltage was set to 119 volts. Also in Stage 3, communication between the EOL metering to the substation was included, as was communication between line voltage regulators and substations. The results would have been significantly improved for Stage 3 Benefit-Cost Ratios (BCRs) and Life Cycle Levelized Costs (LCLCs) without the costs of the communication infrastructure. This communication is both for monitoring and voltage control for energy efficiency gains and power quality.

## Economic Analysis per Voltage Optimization Protocol

The costs and results from the system analysis were then used to complete the economic analysis consistent with the VO protocol and PacifiCorp's economic factors. This included analyzing the results from a Benefit-Cost Ratio (BCR) and Life Cycle Levelized Cost (LCLC) approach.

The financial and economic factors used in this study are shown in Table 1-1, below. It is important to note the assumed economic life of the energy savings is 20 years. Commonwealth has included funding capital, at year 15, equal to 10% of the initial capital investment to provide for modifications of the improvements near the end of the economic life. The economic analysis was performed using principles described in D.G. Newnan, T.G. Eschenbach, J.P. Lavelle, *Engineering Economic Analysis*, *Ninth Edition*, Oxford University Press, Inc., New York, 2004.

### Table 1–1: Financial Factors Used in the Study

| | |
|---|---|
| Retail Energy Rate Weighted Annual ($/kWh) | $0.08 |
| Minimum Permissible Benefit-Cost-Ratio BCR (p.u.) | 1.0 |
| Capital Equipment Life Expectancy (yr) | 48 |
| Planned life of Energy Savings (yr) | 20 |
| Capitalized Annual Fixed Charged Rate (p.u.) | 11.21% |
| Annual Inflation Rate for kW Demand (%/yr) | 1.80% |
| Annual Inflation Rate for kWh Energy (%/yr) | 1.80% |
| Annual Inflation Rate for Investment (%/yr) | 1.80% |
| Annual Inflation Rate for O&M (%/yr) | 1.80% |
| Maximum Permissible LCLC ($/kWh) | $0.10591 |
| Marginal Purchase Demand Rate ($/kW/yr) | $0.00 |
| Marginal Purchase Energy Rate ($/kWh) | $0.10591 |
| Annual Operation & Maintenance Expense (%/yr) | 2.00% |
| Present Worth Rate for Cost of Energy & Losses (%/yr) | 7.17% |
| Present Worth Rate for Cost of Investment (%/yr) | 7.20% |
| Maintenance Lump Sum Amount in Future Year (%) | 10.00% |
| Maintenance Lump Sum in Future Year (yr) | 15 |

## Implementation Considerations

The team then developed implementation considerations, risks and mitigation alternatives. These were developed using the results from the system analysis, the economic analysis, conversations and input from PacifiCorp staff and the utility operating experience of the Commonwealth team members.

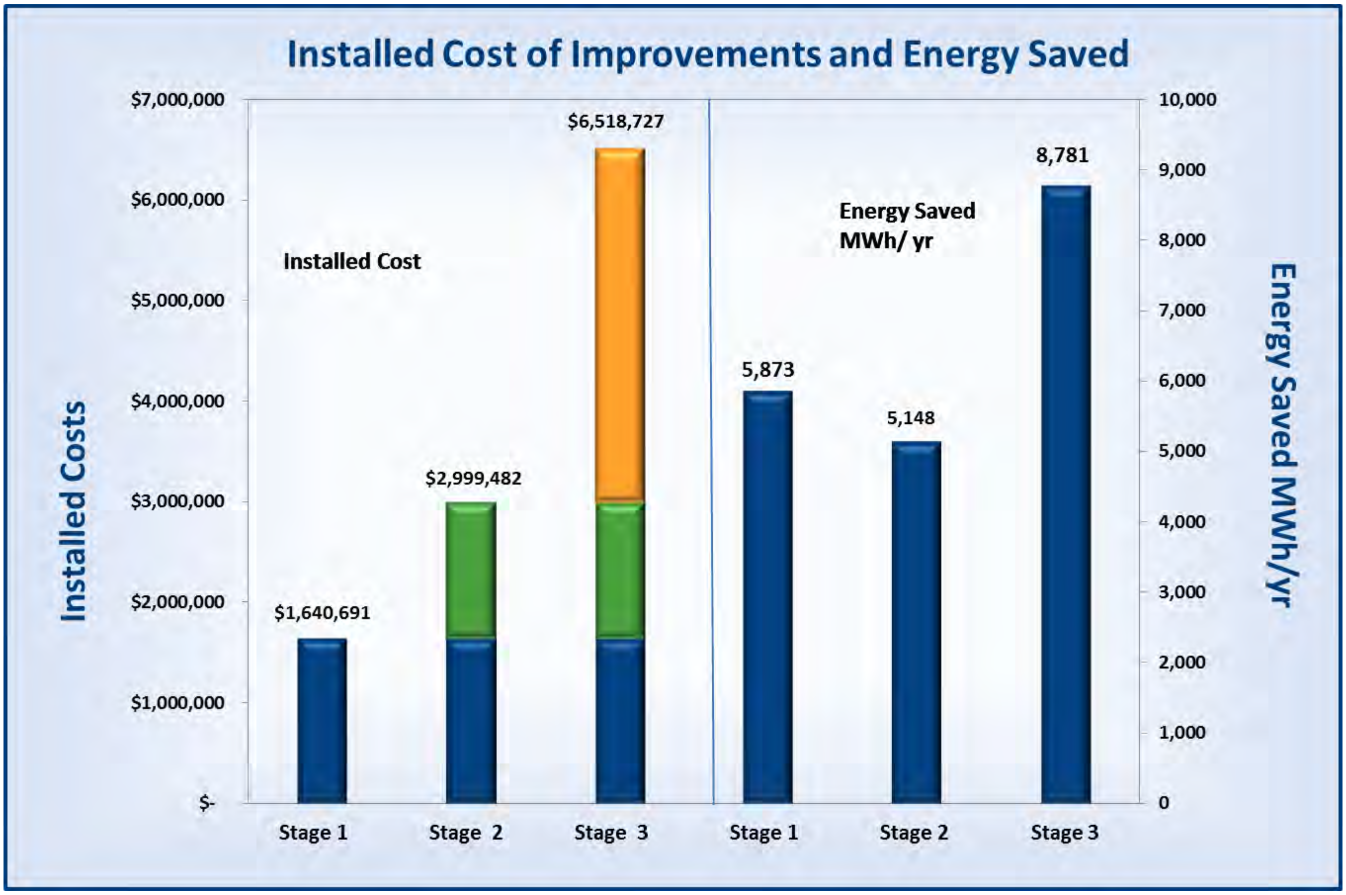
## Findings and Recommendations

Considering all of the above, Commonwealth then developed the conclusions, findings and recommendations included in this report. These follow next in the report.

## SECTION 1B – SUMMARY OF RESULTS

Figure 1-1 shows the costs and energy savings for each stage for all circuits regardless if a particular stage or circuit met the BCR and LCLC thresholds: 1.0 and $105.91/MWhr, respectively.

### Figure 1-1 Costs and Energy Savings by Stage:




The overall energy saved drops in stage two because the system improvements tend to raise and flatten voltage. The flattening tends to raise the voltage at the end of the impacted circuits. This is preparing the circuits for the voltage reduction which takes place in the third stage.

Table 1-2, below, provides an overview of the results for the studies associated with these 19 circuits.

**Table 1-2 Summary Results by Stage with all Circuits Considered**

| General Information | Stage 1 | Stage 2 | Stage 3 |
|---|---|---|---|
| Total Customers Served (#) | 30,747 | 30,747 | 30,747 |
| Feeder Annual Peak MW | 138.33 | 138.33 | 138.33 |
| Total Annual Energy Consumed (MWh/yr) | 627,608 | 627,608 | 627,608 |
| Average Customer Voltage Change (%) | 1.35% | 1.09% | 2.01% |
| Average Reduction in Annual Energy Delivered from Sub (%) | 0.94% | 0.82% | 1.40% |
| Total SI&VO Installed Cost | $1,640,691 | $2,999,482 | $6,518,722 |
| Utility Energy Savings Potential | | | |
| Line Loss Reduction (MWh/y) | 282.7 | 712.7 | 678.8 |
| No-load Loss Reduction (MWh/y) | 252.5 | 199.8 | 357.1 |
| VO Energy Savings (MWh/y) | 5,337.9 | 4,235.4 | 7,744.8 |
| Total Energy Savings (MWh/y) | 5,873.1 | 5,147.8 | 8,781 |
| Total Energy Savings (MWa) | 0.6704 | 0.5877 | 1.0024 |
| Total Coincidental Demand Reduction (kW) | 1142.6 | 1,093.2 | 1,766.9 |
| Average Customer Energy Reduction (kWh/yr) | 174 | 138 | 252 |
| Benefit Cost Projections | | | |
| Overall Utility Levelized Cost per kWh Saved | $0.0434 | $0.0906 | $0.1155 |
| Overall Utility Benefit Cost Ratio | 2.52 | 1.21 | 0.95 |
| Overall Net Utility PV Savings ($) | $4,734,832 | $1,194,119 | ($618,263) |

Stage 1 has the lowest LCLC, which is to be expected given the limitation of actions (reducing voltage, phase balancing and redeploying capacitors) for the energy saved. Stage 2 provides slightly less energy than Stage 1; however, it is at more than double the cost. This is the impact of the system improvements, which become fully beneficial when the voltage is lowered in Stage 3. Stage 3 offers the greatest energy savings as a result of the system modifications made and the reduction of the EOL voltage to 119 volts (on a 120 volt basis). A large part of the Stage 3 cost, approximately $2.7M, is due to the communication infrastructure required to provide real-time monitoring of voltage and energy at the substation and regulators, and EOL volt meters. At a total summary level the Stage 3 results do not meet the LCLC and BCR thresholds of $105.91/MWh and 1.0 respectively. However, the total results are close to the limits indicating that some of the individual results likely do meet the thresholds.

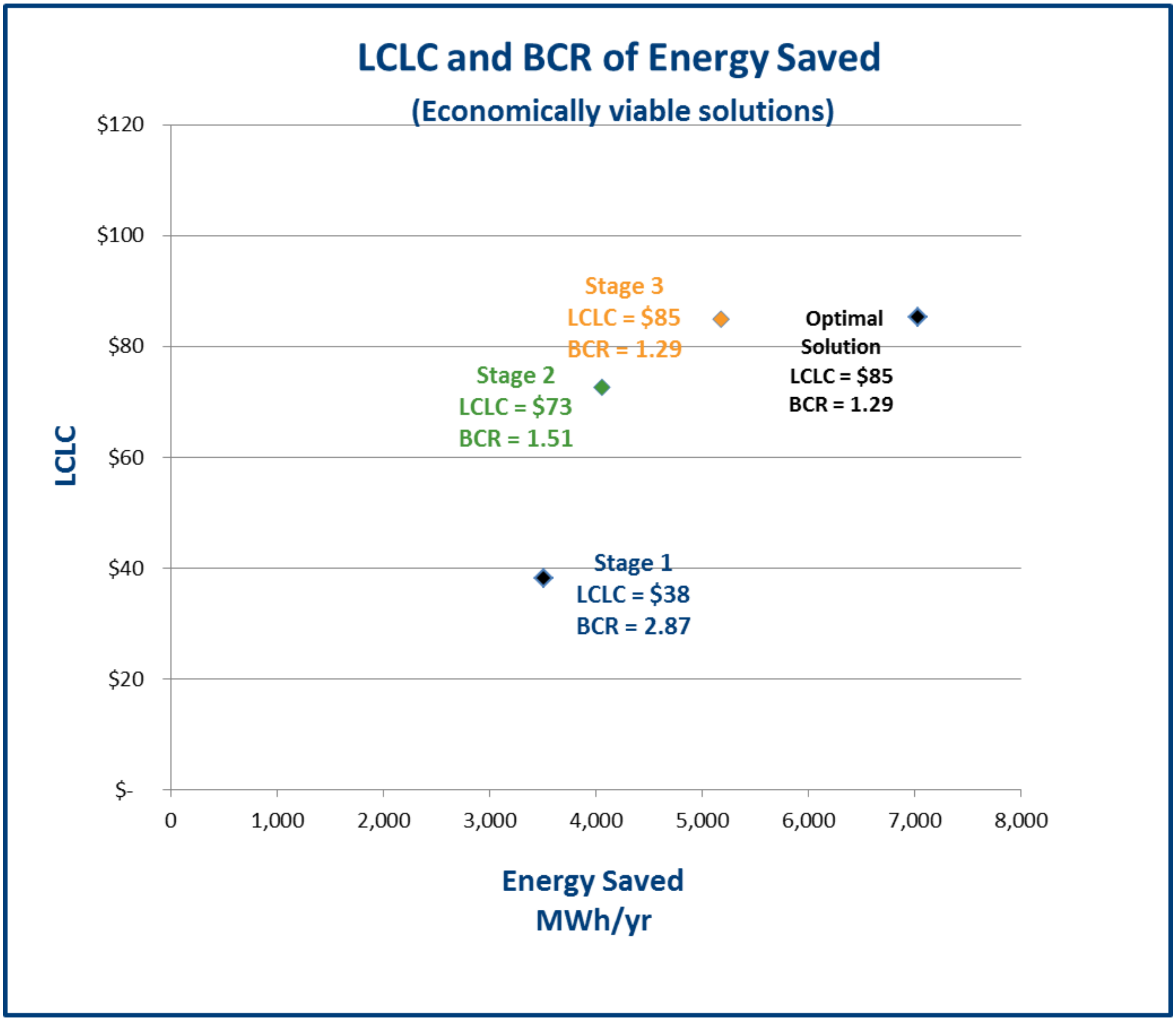
After analyzing all the circuits and stages, two things became clear. One, the individual circuit results in each stage should be considered from an economic perspective; and second, a valuable point of view could be gained if the results were considered from a total energy savings view while ensuring the circuits and stages selected also met the 1.0 BCR and the $105.91 LCLC thresholds. The goal of this second review was to get the most energy savings while staying within the economic thresholds. The results from this review are shown below by stage and from an optimal solution perspective.

**Table 1-3 Summary of Economically Viable Solutions by Stage and Over-All Optimal Solution**

| General Information | Stage 1 | Stage 2 | Stage 3 | Optimal Solution |
|---|---|---|---|---|
| Total Customers Served (#) | 22,225 | 22,958 | 18,665 | 27,909 |
| Feeder Annual Peak MW | 95.08 | 103.58 | 76.01 | 125.50 |
| Total Annual Energy Consumed (MWh/yr) | 438,826 | 476,160 | 357,575 | 574,046 |
| Average Customer Voltage Change (%) | 1.12% | 1.11% | 2.07% | 1.73% |
| Average Reduction in Annual Energy Delivered from Sub (%) | 0.80% | 0.85% | 1.45% | 1.23% |
| Total SI&VO Installed Cost | $863,209 | $1,893,973 | $2,826,294 | $3,854,835 |
| <u>Utility Energy Savings Potential</u> | | | | |
| Line Loss Reduction (MWh/y) | 198.0 | 565.0 | 371.5 | 643.1 |
| No-load Loss Reduction (MWh/y) | 129.5 | 146.4 | 187.1 | 267.5 |
| VO Energy Savings (MWh/y) | 3,185.9 | 3,347.2 | 4,621.5 | 6,127.4 |
| Total Energy Savings (MWh/y) | 3,513.4 | 4,058.5 | 5,180.1 | 7,038.0 |
| Total Energy Savings (MWa) | 0.4011 | 0.4633 | 0.5913 | 0.8034 |
| Total Coincidental Demand Reduction (kW) | 685.2 | 856.4 | 1,027.0 | 1,423.9 |
| Average Customer Energy Reduction (kWh/yr) | 143 | 146 | 248 | 220 |
| <u>Benefit Cost Projections</u> | | | | |
| Overall Utility Levelized Cost per kWh Saved | $0.0382 | $0.0726 | $0.0849 | $0.0852 |
| Overall Utility Benefit Cost Ratio | 2.87 | 1.51 | 1.29 | 1.29 |
| Overall Net Utility PV Savings ($) | $3,056,420 | $1,832,787 | $1,565,127 | $2,098,324 |

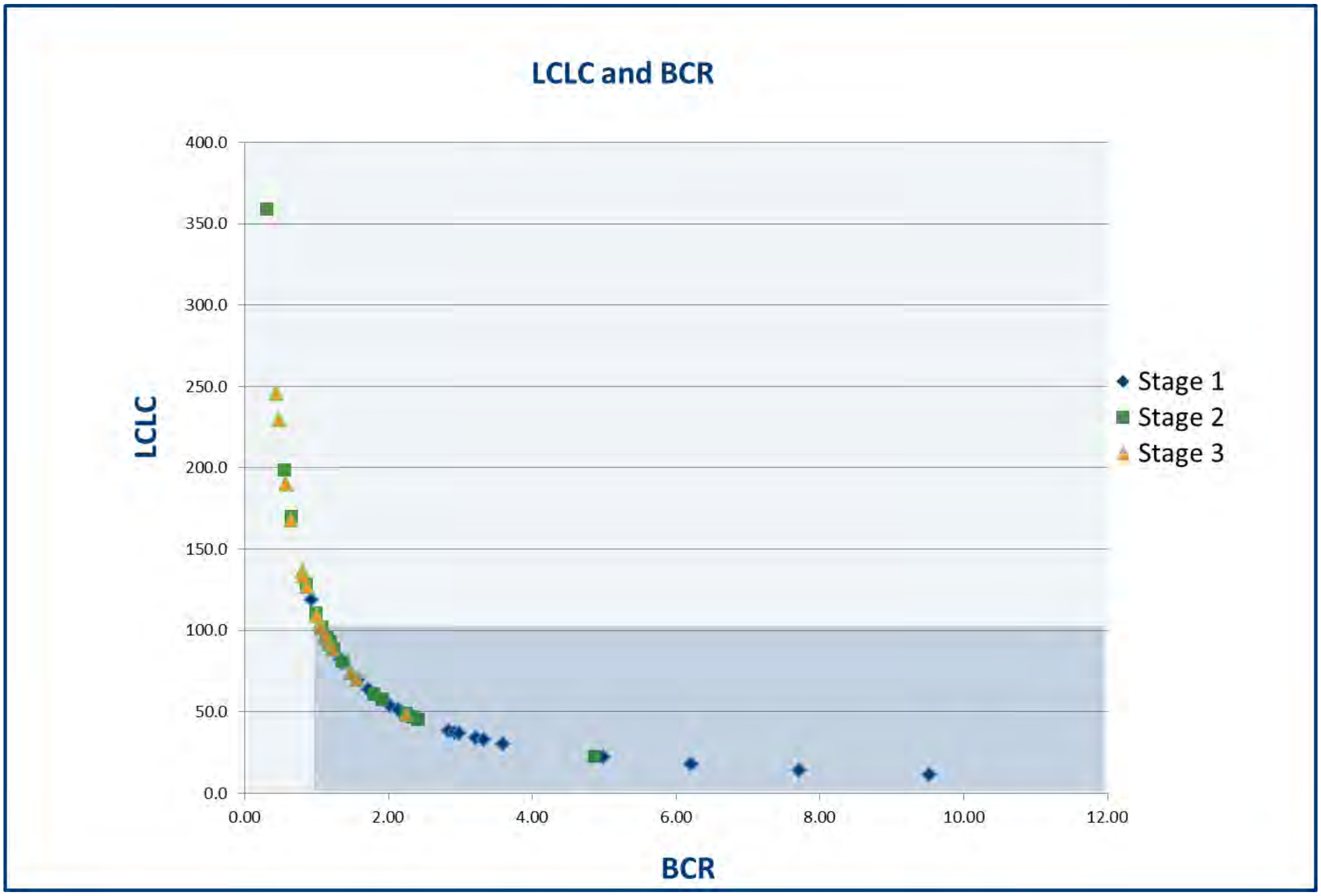
The numbers in the table above can be distilled down to the figure below. Figure 1-2 shows the annual energy saved, LCLC and BCR for by each stage when individual stage solutions that don't meet the BCR and LCLC thresholds are excluded from a given stage solution. The Optimal Solution includes the stage solution of each circuit which provides the most energy while meeting the economic thresholds. For each stage and for the Optimal Solution there are circuits which do not meet the economic considerations. For example, in the Optimal Solution the two circuits excluded are Pomeroy 5W342 and North Park 5Y356.

**Figure 1-2 Annual Energy Savings, LCLC & BCR by Stage and Optimal Solution:**
(Circuit solutions that do not meet the economic thresholds are excluded from that Stage.)



In addition to the roll up results described above Commonwealth reviewed the study results to determine the savings associated with each circuit for all three stages for all 19 circuits. In Figure 1-3, below, the LCLC and BCR results of each of the 19 circuits in all three stages are shown. The shaded area represents the area of the graph with an LCLC of less than $105.91 and a BCR ≥ 1.

**Figure 1 – 3 LCLC and BCR**




The figure clearly shows there a number of individual solutions within the shaded economic zone. Included are most Stage 1 results, and a good number Stage 2 and Stage 3 results. This is consistent with Table 1-3 above which shows the Optimal Solution as having the greatest number of customers served and largest peak load.

The results, as summarized, above indicate there is an opportunity for PacifiCorp to implement a Voltage Optimization and System Improvement program that provides energy savings within its economic thresholds.

## SECTION 1C – RECOMMENDATIONS

The results of this distribution system study for 19 Tier 1 circuits on PacifiCorp's Washington system are favorable and demonstrate that sustainable and potentially viable VO savings can be obtained. Commonwealth recommends that PacifiCorp consider the Optimal Solution scenario. This scenario provides the greatest amount of energy, as compared to the stage scenarios considered, within the utility's economic thresholds. The next step may be to analyze the results of the Optimal Scenario in the utility's Production Cost Model to further consider its cost effectiveness.

Commonwealth recommends such Voltage Optimization improvement efforts should be consistent with PacifiCorp's implementation strategy outlined in its Smart Grid Technology Report. This report was filed with the Washington Utilities and Transportation Commission in September 2010, in compliance with WAC 480-100-505. If, in the future, other Smart Grid initiatives are pursued by the company on these Tier 1 circuits, the Stage 3 implementation costs could reasonably be expected to be shared among additional Smart Grid programs. Sharing the communication infrastructure costs would have a direct impact on the Stage 3 BCR and LCLC values derived in this report.

### Viable Energy Savings Projects Are Feasible

The study indicates viable energy savings projects are feasible by implementing system improvements and voltage optimization. Based on the study results, Commonwealth's recommendation is:

- PacifiCorp should analyze the Integrated Resource Plan (IRP) data provided by Commonwealth for the Optimal Scenarios in PacifiCorp's Production Cost Model.

Should the results of the Production Cost Model be favorable, Commonwealth further recommends:

- Complete the voltage optimization studies on all circuits originating on a substation/power transformer that is included in the selected group.
- Select the final implementation group based on the findings of this study and the results of the study described in the preceding bullet.
- Develop an implementation and budget schedule such as is shown in Table 1-4.
- Field verify:
    - Loading on taps to be changed for phase balancing; select other taps if necessary
    - Locations selected for voltage regulators, capacitors, metering, etc., having usable pole, space, etc., for equipment to be installed. If necessary, find suitable alternative locations.
- Engineer system improvements – capacitor installations, regulators, line reconductoring, etc.
- Brief/train Field Engineers, Estimators and other appropriate field staff on voltage optimization and potential issues.

- Complete construction of needed system improvements.
- Closely follow operational implications, if any, of implementing voltage optimization.
- Install some recording volt meters on a temporary basis to respond to low-voltage reports and monitor end of control zone line voltages.
- Consider installing the Stage 3 communication infrastructure consistent with any Smart Grid effort undertaken by the utility. This approach will demonstrate if the metering is necessary to operate a voltage optimized system and to determine if there are other benefits that could help offset this investment if implemented for future Stage 3 VO circuits.
- If PacifiCorp decides to reduce the primary voltage on one or more of the circuits to 119 volts (on a 120 volt basis):
    - Follow a process similar to what is described in Section 1D in the bullets following the paragraph starting with: "*What if additional work is needed to address potential low voltage issues*"
    - Develop a service standard for the 119 volt voltage optimization zones
    - Complete communication infrastructure engineering and installation
- Follow the energy savings verification steps described in the Simplified Voltage Optimization Measurement and Verification Protocol, to measure and record savings.
- As PacifiCorp considers implementing a voltage optimization program, Commonwealth suggests, its staff stay current with this developing field. Studies continue which may guide PacifiCorp's implementation decisions and approaches.

During this study, Commonwealth's team noted that PacifiCorp's general operating approach on these 19 circuits – for example, setting the EOL voltage to 121 volts, using line drop compensation appropriately and utilizing both fixed and switched line capacitors – results in a relatively efficient system as a starting point. This reduces the amount of energy that might otherwise be available from a voltage optimization program on distribution circuits without this operating approach.

## SECTION 1D – IMPLEMENTATION CONSIDERATIONS

Commonwealth considered potential operational risks and other considerations for implementation. The most significant concern is the potential of customers having service entrance voltages below the ANSI C84.1 Range A acceptable level of 114 volts; 117 volts for primary metered customers.

In reviewing the work in this report, Commonwealth thinks the cost and response impacts of secondary voltage problems as noted in the report are a maximum probable amount. We also believe the likely level of impacts over the projected life cycle of these improvements are 25% to 50% less than what is calculated. We believe this because the actual number of customers reporting low-voltage issues is extremely low even though the As-is base case modeling shows that, on the end of some primary distribution circuits, the voltages are as low as 119 volts. This seems to indicate the secondary system voltage drops are not going to result in as many potential customer issues as estimated in the report. However, the value was not reduced because, as a PacifiCorp staff member indicated, it is hard to know where the system is compared to the knee of the curve. So, Commonwealth has left the estimate as is and recognizes it as a likely worst case impact from the two perspectives: cost impacts and customer issues.

Commonwealth has considered the "*What if additional work is needed to address potential low voltage issues?*" question and recommends the following as an approach to address the potential issue of customers experiencing low service entrance voltage due to a voltage optimization program that moves the end of the line primary voltage to 119 volts:

- Determine voltage zones on each distribution circuit where the voltage may drop below 120 volts. Use FeederAll to model each circuit in light load and heavy load conditions to determine where on each circuit the primary voltage will drop below 120 volts. Commonwealth completed this for the Tier 1 circuits.
- Determine customer kW loading. For some customers, PacifiCorp likely has kW demand information. For residential and small commercial, it is likely that PacifiCorp does not have this information. Commonwealth understands that PacifiCorp has customer kwh usage data by month or billing cycle. This information can be used to calculate average kW loads and, from this, it is possible to estimate the customer's normal peak demand.
- Determine transformer kW loading. Commonwealth understands PacifiCorp's GIS or similar system can determine which customers are connected to each transformer. If this is so, it should be possible to estimate the kW demand on each distribution transformer. Then, the ratio for each transformer's 'peak demand to name plate rating' can be determined. This ratio would need to be estimated for both heavy and light load conditions.
- Screen the customer loading and transformer loading. It should be possible to set up a spreadsheet or data base that considers the customer loading and transformer loading and provides a report when the transformer loading <u>and</u> customer loading are both at or above some threshold. The threshold for the transformer loading is probably a relatively high per-

centage (perhaps 90%) and the customer loading threshold will be in kW. Commonwealth recommends considering 10 kW as a starting point. This amount of load will cause approximately a 1% voltage drop in 100 feet of #2 Al Triplex (overhead or underground). It is also probably a good idea to screen at higher thresholds without the "and" requirement described above. This would flag excessive loading on transformers and services for the fielding described in the next bullet.

- Field-visit the transformers and services that do not pass the screening described above. In this step, a knowledgeable field person (engineer, field technician, service line worker, etc.) would check the transformer to ensure the loads are actually connected to the transformer as the records indicate. The same person would visually verify the conductor size and length of the service conductor for the customer(s) that have triggered the "large load" level.
- Consider the field visit data. In this step, the field findings are considered to determine if the customer(s) may have the potential for having a secondary system voltage drop of 5 or more volts. From this analysis, a judgment will be necessary to decide the next steps. It could range from doing nothing to installing temporary recording volt meters, changing taps on the distribution transformer, replacing services or installing a new distribution transformer.
- The field engineering and operational effort described above is included in the system improvement cost estimate.
- Consider installing some recording volt meters, even if they are not thought to be necessary, on the early fielding situations to confirm what has been modeled and calculated.
- Continue to respond appropriately to customers who call and ask about suspected low voltage.

The Commonwealth team working on this project has found the PacifiCorp team members to be highly knowledgeable and qualified to address distribution system issues as a result of training of PacifiCorp staff, such as estimators, line workers and other field staff, to help resolve issues that may arise due to implementing a voltage optimization program.

## Standards

If PacifiCorp selects a solution set with Stage 3 voltage optimization, Commonwealth recommends that PacifiCorp consider developing a Stage 3 VO Service Standard. This standard would include guidelines for selection of transformers, use of secondary taps and sizing of service conductors for the Stage 3 VO circuits.

## Operating Impacts

Commonwealth has considered the impacts of voltage optimization on a number of operational aspects of an electrical distribution system. There is nothing noted below that appears to be significant enough to cause PacifiCorp to stop considering the implementation of VO on the Tier 1 circuits studied.

- Safety: The introduction of voltage optimization into a distribution system does not materially change the operation of the distribution system, its equipment or complexity. As such, there is no reason to think it will impact the safe operation of PacifiCorp's system.

- Power Quality: With the exception of potential low voltage, the VO protocol as designed and as considered in this study will have a neutral or positive impact on the power quality of the circuits on which it is implemented. In regard to potential low voltage, Commonwealth recommends that PacifiCorp implement the steps described above in this section, or similar steps, to address this issue. Also, the end of the line voltage metering will provide PacifiCorp with additional voltage information for use with planning, engineering and operational responses.

- System Complexity: For Stage 1 circuits, there are no significant changes to the equipment on the circuits. The phase balancing and redeployment of capacitors does not materially alter the distribution system's complexity. The installation of switched capacitors and regulators, for stages 2 and 3, will require the field staff to be made aware of these devices. These are each well-proven distribution components that PacifiCorp currently has standard on its system. Their addition provides more to the overall quality of service than it contributes to operational or engineering complexity. Devices such as switched capacitors and voltage regulators as "active" devices do inherently increase the possibility of failures and related outages. However, they are well-proven devices that PacifiCorp has on its system and their use is not expected to negatively impact a circuit's reliability.

- Impacts to Substation Capacitors: Substation capacitors are used to improve power factor, losses and voltages on the bulk power system servicing the distribution substation transformers. To a lesser extent, they also help the distribution LTC regulators stay within their ±10 percent limits, but mostly the LTC regulators are responsible for maintaining the proper feeder voltages (so long as they are operating within their control range).
    - The application of switched capacitors in stages 2 and 3 will, in general, act to reduce the net reactive flow seen by the both the LTC and at the transformer high-side where the substation capacitors act. The additional reactive support added to each circuit is small compared to the substation capacitors in service at Bowman (3600 kVAR), Dodd Road (3000 kVAR), Mill Creek (3060 kVAR), and Nob Hill (4950 kVAR) and should not significantly impact their operation. The most likely outcome is that there will be a small decrease in the quantity of substation MVAR that is needed.

However, existing capacitors and settings should still fulfill their functions for the bulk power system and need not be changed. Future substation capacitor designs for circuits using voltage optimization may require slightly smaller sizes.

- Overall, Commonwealth does not see a need to change or adjust the existing substation capacitors or control settings. There may be a small reduction in the cost of future designs for substation capacitors where the tighter reactive control from the more extensive use of switched distribution capacitors reduces the reactive demand on the bulk electric system. It is possible that detailed analysis of the changed reactive requirements on the bulk electric system may call for reducing or eliminating some substation capacitors, but we would recommend that such changes be delayed until the intention to apply voltage optimization on all of the feeders emanating from the substation have been determined so that a complete picture of the impacts can be reviewed.

- Impacts to Substation LTC: The operation of the load tap changer (LTC) is impacted by the addition of switched distribution capacitors. The LTC may see a small increase in the frequency of operation caused by the added operation of switched capacitors. These impacts should be less significant than those seen for the switching of the larger and closer substation capacitor banks. The increased frequency of LTC operation should be minimal and cause negligible problems since the application of switched distribution capacitors is a common utility practice for which LTC transformers are designed.

## Circuits to Consider for Voltage Optimization

As PacifiCorp considers primary circuits to determine if they are good candidates for voltage optimization, Commonwealth recommends that PacifiCorp look for circuits with the following characteristics:

1. A good power factor. The feeder-source minimum power-factor must be greater than 0.96.

2. Balanced loads at the start of a voltage control zone – the feeder exit and at line voltage regulators. Phase-load-unbalance should be less than 0.15 per unit on 3φ lines. Also feeder-source neutral-current must be less than 40 amps on 3φ lines.

3. Circuits with relatively flat voltage profiles. This applies to both voltage control zones originating at substations and at line voltage regulators.

4. Consistency of voltage drop between feeders. Maximum voltage drop variance between multiple feeders served within a substation VO voltage control zone must be less than 2 volts (on a 120 volt base).

5. Circuits with significant residential and light commercial loads, in comparison to industrial loads, and which are relatively highly loaded.

As Commonwealth found in this study, some circuits fit these guidelines “naturally” and some required remedial action to make them VO compliant. This is a normal situation for electric utilities.

## 7-Year Capital Plan

PacifiCorp requested a capital spending plan be prepared as part of this study. Based on the Optimal Solution alternative, the capital spending plan in Table 1-4 was developed. These circuits are, based on this study, the most viable for consideration for voltage optimization. The circuits in the Optimal Solution were arranged by Stage, from Stage 1 to Stage 3. Then they were grouped by substation. This ordering seems logical because it allows PacifiCorp to implement the Voltage Optimization on a Stage by Stage approach and substation by substation sequence. It provides time for the additional engineering that will be needed for Stage 2 and Stage 3 work as compared to Stage 1. The resultant spending plan is shown below in Table 1-4.

Commonwealth acknowledges there are other ways of prioritizing the work. For example it could be prioritized by energy saved or greatest BCR. PacifiCorp may want to examine these alternative priorities before starting the implementation process.

## Table 1-4 Circuits for Capital Plan

### Based on Optimal Solutions having BCR ≥ 1.0 & LCLC ≤$105.91

| Service Area | Substation | Circuit | Implementation Stage | Estimated Cost | Annual Estimated Cost | |
|---|---|---|---|---|---|---|
| Walla Walla | Bowman | 5W154 | Stage 1 | $29,526 | | |
| Yakima | Wiley | 5Y434 | Stage 1 | $100,248 | | |
| Walla Walla | Dodd Rd | 4W22 | Stage 2 | $288,415 | | |
| Yakima | Orchard | 5Y456 | Stage 2 | $124,802 | $542,991 | Year 1 |
| Yakima | River Road | 5Y444 | Stage 2 | $264,201 | | |
| Lower Valley | Grandview | 5Y351 | Stage 2 | $221,349 | $485,550 | Year 2 |
| Walla Walla | Bowman | 5W150 | Stage 3 | $345,514 | Part of Year 6 total | |
| Walla Walla | Mill Creek | 5W116 | Stage 3 | $318,157 | | |
| Walla Walla | Mill Creek | 5W127 | Stage 3 | $256,139 | $574,296 | Year 3 |
| Yakima | Clinton | 5Y608 | Stage 3 | $281,975 | | |
| Yakima | Clinton | 5Y610 | Stage 3 | $260,606 | $542,581 | Year 4 |
| Yakima | Nob Hill | 5Y194 | Stage 3 | $297,023 | | |
| Yakima | Nob Hill | 5Y197 | Stage 3 | $154,291 | | |
| Yakima | Nob Hill | 5Y273 | Stage 3 | $241,604 | $692,918 | Year 5 |
| Yakima | Orchard | 5Y498 | Stage 3 | $230,336 | $575,850 | Year 6 |
| Lower Valley | Sunnyside | 5Y313 | Stage 3 | $240,890 | | |
| Lower Valley | Sunnyside | 5Y317 | Stage 3 | $203,759 | $444,649 | Year 7 |

# SECTION 2 – APPROACH TO ANALYSIS

## Circuit Fielding

To start the study, using printouts of the GIS detailed AutoDesk Maps, Commonwealth staff field verified each circuit. This included starting at the substation, noting the phasing leaving the station and following the circuit to the end of each lateral. The phasing for all transformers, corners and laterals was noted. The circuit conductor sizes and the location of line voltage regulators and capacitors were recorded. This information was captured on paper copies of the maps and then scanned and saved on CDs or DVDs and on Commonwealth's internal electronic network.

## Model Verification and Correction

Using the information gathered during the circuit fielding, Commonwealth corrected and verified the modeling in the ABB FeederAll system. After the models were corrected and verified, Commonwealth used FeederAll to analyze the circuits. This work included the 3-stage approach described below.

### *"As is" Base Case Voltage Profiling*

Commonwealth made corrections to the system model based on the changes found during fielding and from follow-up conversations with PacifiCorp staff. From this work, Commonwealth used the FeederAll model of the updated existing system to examine the voltage during heavy load conditions and light load conditions. Heavy loads for all stages are the peak summer MW with a MVAR load level representative of the 95th percentile. The light loads are at the 5th percentile for both MW and MVAR. These load levels were chosen because they represent reasonably possible high- and low-load levels without the "peak" loads or loads at near zero probability, both of which happen infrequently.

For the As-is voltage profile analysis, Commonwealth's modeling found that 12 of 19 circuits had primary low voltages at the end of the line in the range of 119 to 120 volts, on a 120 volt basis. The remainder of the circuits had As-is low voltages that were 120 volts or higher at the end of the line.

Commonwealth reviewed PacifiCorp-provided customer data for the 19 circuits regarding low voltage for the years 2001 to 2011. The small number of low-voltage complaints (eight) is consistent with the findings of this stage of the study. Approximately half of these issues appear to be the result of load increases made without the customer notifying PacifiCorp. See Appendix 11 for the reported customer voltage issues. This small number also provides some confidence to the assumptions associated with the expected low number of transformers and customers who may experience low voltage due to secondary system loading after implementing voltage optimization.

Commonwealth also found the Grandview circuit 5Y351 may have had substation settings contributing to the potential of customers having high-voltage conditions. PacifiCorp field engineers have taken steps to investigate and address this situation. As a result, the settings for the substation transformer were modified. This situation required revising the analysis for Grandview.

### *Pre-VO Compliant:*

The voltage optimization protocol requires that voltage control zones meet or exceed certain performance thresholds during normal operating conditions. In some situations, it may be necessary to perform system improvements to bring the system to within the thresholds. This was the case for some PacifiCorp circuits that had distribution system voltage drops greater than the 3.3% provided for in the protocol guidelines. The distribution system voltage drop is the reduction in voltage on the primary system from the regulated point to the lowest voltage point at the end of the line. In most cases, the circuits were compliant with all performance thresholds by Stage 2. Please see Appendix 8, Section 2.3, for more about the minimum operating performance thresholds.

### *Stage 1 Analysis:*

For the Stage 1 analysis, Commonwealth used the system model corrected from the fielding results. The work for this stage included balancing phasing and redeployment of in-place fixed capacitor banks on the circuit to achieve an improved power factor profile. The redeployment of capacitors was considered on a circuit-by-circuit basis. Commonwealth did not consider it in its analysis, but it understands that PacifiCorp would normally do this within a given service district. There could be a small reduction in the cost estimates for this effort if the capacitors were redeployed on this approach.

The circuit-specific changes are outlined in more detail in Section 4, below, and are shown on circuit maps in Appendix 6. Once these "O&M" type changes were made to the model, the end of the line voltage was reduced to no less than approximately 120 volts. For some circuits, the primary voltage did dip slightly below 120 volts. Keeping the voltage at or very near to 120 volts provides for the potential of a 6 volt drop on the secondary system. The analysis included primary voltages during both heavy and light load conditions.

Commonwealth also:

- Used the established VO protocol to calculate the energy savings associated with lowering the end of the line primary voltage to 120 volts for each circuit between the base case and the studied stage case.
- Developed cost estimates to complete the work to get the circuit into a Stage 1 configuration, including: metering, planning, engineering and construction; efforts to address potential increased low-voltage customer issues; and any ongoing maintenance and costs associated with the improvements. The estimated funding should be sufficient to research and develop an approach, complete fielding and develop solutions for specific transformers and services.
- Determined the additional O&M costs for Stage 1 should be low, due to the minimal additional investment. The annual O&M costs were increased by 2% of the capital investment

and the funding for Stage 1 should be adequate for meter data acquisition, which will be the major additional O&M work effort over the life of implementation for this stage.
- Performed an economic benefit-cost analysis for Stage 1 improvements, including the secondary system improvements described below.

### *Stage 2 Analysis:*

For the Stage 2 analysis, using the modifications from Stage 1 as a starting point, Commonwealth made system model modifications to include: new capacitors (switched and fixed), reconductoring, voltage regulators, etc. The circuit changes are outlined in more detail in Section 4, below, and are shown on circuit maps in Appendix 6. Using this model of the system, Commonwealth used FeederAll to analyze the circuit for heavy and light load conditions.

Commonwealth also:

- Used the established VO protocol to calculate the energy savings associated with operating the end of the line voltage at or near 120 volts for each circuit's respective Stage 2 configuration.
- Developed cost estimates to complete the work to get the circuit into a Stage 2 configuration. This included planning, engineering and construction; efforts to address potential increased low voltage customer issues; and any ongoing maintenance and costs associated with the improvements. For Stage 2, it is possible that the number of distribution transformers with primary voltages of 121 volts or less could be fewer than what would be expected for Stage 1. If this was the situation, the estimated costs for Stage 2 work were reduced, or negative, as the costs from stage to stage are cumulative. This situation would be created from the system improvements included in Stage 2.
- Considered the likely O&M costs in comparison to the 2% included in the financial analysis. The O&M funding for Stage 2 appears sufficient.
- Performed an economic benefit-cost analysis for Stage 2 improvements, including the secondary system improvements described below.

### *Stage 3 Analysis:*

For Stage 3 analysis, Commonwealth started with the circuit improvements from the Stage 2 work and modeled the system with an end of the line primary voltage of 119 volts.

Commonwealth then:

- Used the established VO protocol to calculate the change in average voltage for each circuit between the Pre-VO Compliant base case and the studied stage case.
- Used the established protocol to estimate the energy savings from this system configuration as compared to the base case.

- Developed cost estimates to complete the work to get the circuit into a Stage 3 configuration, including: metering, planning, engineering and construction and efforts to address potential increased low-voltage customer issues.
- Included 250 hours of PacifiCorp staff time in the cost estimates to develop new service standards for VO zones operating with end of the line voltages set to 119 volts
- Considered the likely O&M costs in comparison to the 2% included in the financial analysis. The O&M funding for Stage 3 appears sufficient.
- Performed an economic benefit-cost analysis for Stage 3 improvements, including the secondary system improvements described below.
- Using the stage-appropriate system, used FeederAll output as an input to ArcGIS to prepare circuit maps showing the voltage along each circuit. This included the circuits in heavy load and light load conditions.

## Secondary System Considerations

Commonwealth has considered the potential likelihood of customers having secondary system voltage drops of a large enough value to cause the service entrance voltage to drop below 114 volts. PacifiCorp's standards provide for secondary voltage drops of up to 5% (6 volts on a 120 volt basis). As the system's primary distribution voltage drops below 121 volts (leaving one volt for the downside bandwidth of the voltage regulator), it is possible that customers may have low-voltage scenarios develop. The probability of this happening is small. From the circuit information provided by PacifiCorp (see Appendix 11), it is clear there are infrequent customer inquiries about low voltage, even though the modeling indicates the primary voltage for a number of these 19 circuits drops below 120 volts (on a 120 volt basis) during normal operations. The data provided by PacifiCorp indicates that only 8 customers, over the last 10 years, have asked to have low-voltage issues investigated. There are a number of reasons that PacifiCorp may have such a small number of customers inquiring about low voltage, but the most likely reason is the load diversity at the distribution transformer level. The loading on the distribution transformers is approximately 39% of installed nameplate capacity during peak loads. This indicates the voltage drop of most transformers is not a major issue. For the vast majority of the transformers, the loading and voltage drop is going to be less during lightly loaded periods.

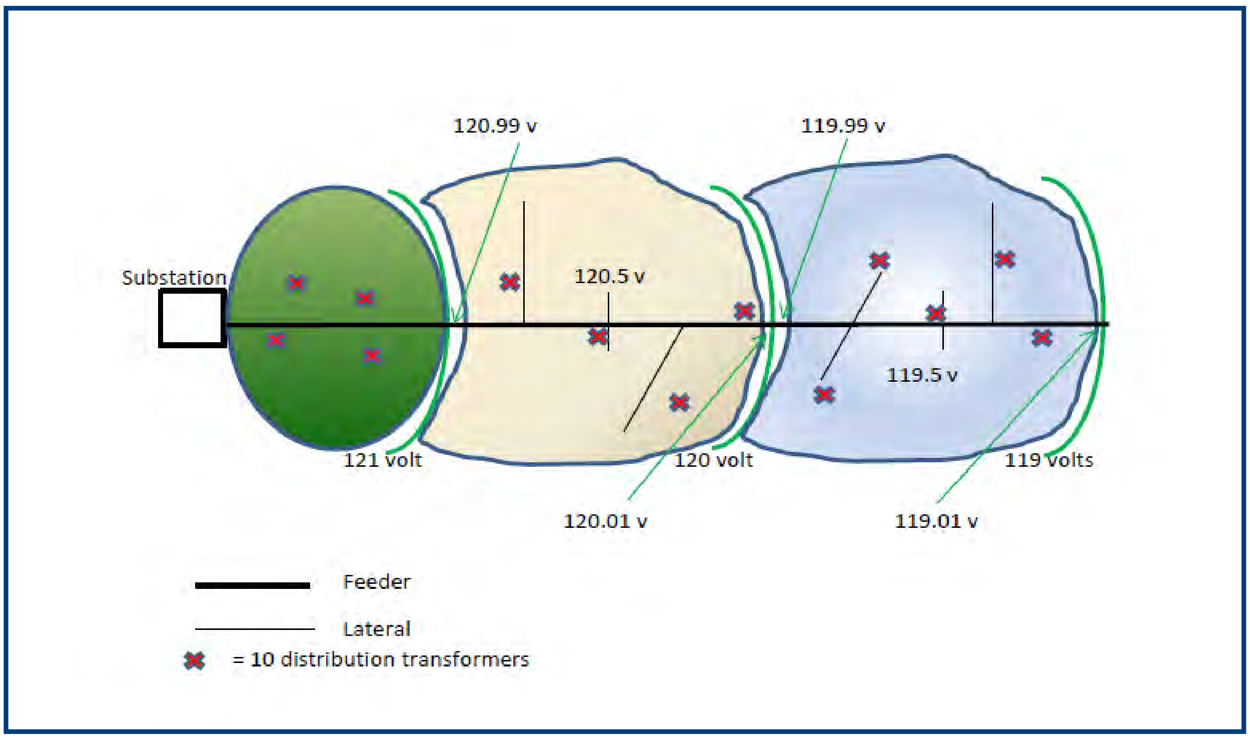
It is still possible that customers could experience low voltage, less than 114 volts, at the service entrance when the primary voltage (on 120 volt scale) is less than 120 volts or even between 120 and 121 volts. It is possible to determine, for a large group of distribution transformers and associated customers, the maximum probable number of transformers that may have a secondary voltage drop of more than a given value.

The secondary system voltage drop will have a Gaussian (normal) distribution. Based on this, it is possible to estimate the number of customers in the population that have secondary voltage drops of a particular amount or more. Commonwealth's approach to making these estimations is described in Appendix 2. From this approach, for heavy load, approximately 10.6% of the customers may have secondary voltage drop of more than 5 volts. Commonwealth used the same approach to determine there is a probability of 26.8% for transformers to have a secondary voltage drop greater than 4 volts during heavy load periods.

Figure 2-1, below, shows three voltage zones: greater than 121 volts, 120 to 121 volts and 119 to 120 volts. These are primary voltages on a 120 volt basis.

For the voltage zone of 119 to 120 volts, transformers at the 119.01 point of the zone with a secondary voltage of 4.02 volts will, allowing one volt for the downside bandwidth of the regulator, have a potential of causing service voltages to drop to below 114 volts. This same secondary voltage drop on a transformer with a primary voltage of 119.99 (or 119.03) would not have low voltage. To determine the potential number of impacted transformers, one must use the statistics found in Appendix 2 of this report. From Appendix 2, you will see that it is assumed there are 3% of the customers that have a secondary system voltage drop of 6 volts (5% on a 120 volt basis). Appendix 2 also shows that the number of customers expected to have a 5 volt or greater secondary system voltage drop is calculated to be 10.6%. Using the same methodology, the percentage of customers with a secondary system voltage drop of 4 or greater volts is 26.8%.

**Figure 2-1 Example Voltage Zone**




To determine the number of transformers that may have low voltage, it is necessary to know the voltage zone of interest: either the 119 to 120 or the 120 to 121 volt zone and the number of transformers in the zone of interest. For example, if there are 50 transformers in the 119 to 120 volt zone, then the number of transformers that may have low voltage = (50) x (.03 + .106)/2 = 3.4 transformers. For this study, the number of transformers was always rounded up. In this example, then, the number of transformers with potential low voltage would be 4.

To resolve the issues associated with these situations, Commonwealth suggests the following options:

1. Adjust distribution transformer taps
2. Replace distribution transformers
3. Replace service conductors

The costs for this work are included in the estimates.

To estimate the number of customers and transformers that may have secondary system voltage concerns in light load conditions, an additional step is taken. For this estimate, the result from above is multiplied by the ratio of each circuit's light load to heavy load. For this example, if the heavy load is 7500 kW and the light load is 3000 kW, then the ratio is 0.4 (3000/7500) multiplied by 3.4, or 1.4; again rounding up, the maximum expected number of transformers with secondary system voltage drops resulting in potential low voltage is 2. This approach recognizes that the distribution transformer and individual service loads would have a reduced probability of experiencing coincident voltage drops sufficient to cause a secondary system to have a low-voltage condition during a light load period.

Table 2-1, below, (from FeederAll results) shows the number of transformers on each circuit by stage that could, due to the primary voltage dropping below 120 volts, have low voltage at their service entrance. This number includes customers who may, at times, have secondary voltage drops in excess of 5% (6 volts) but who, due to the primary voltage being above 120 volts, are not currently experiencing voltages below 114 volts. These customers are included in the total number of customers whose secondary system (transformer and service) may require work to maintain the customer's service entrance voltage at 115 volts or greater.

Note: The numbers of transformers shown in the table are the maximum expected number if the voltage optimization would be implemented to that particular stage. This means the total number of transformers shown is not additive, stage to stage. In fact, it is common for the number to go down between Stage 1 and Stage 2.

## Table 2-1 Estimated Number of Customers with Potential Low Voltage and Associated Transformers

| Circuit | Controlling Case | Number of Trans-formers at or below 120 volts | Number of Trans-formers from 120 to 121 volts | Estimated total number of transformers that may have customers with low voltage at Service Entrance** |
|---|---|---|---|---|
| **Bowman 5W150** | | | | |
| Stage 1 | Heavy | 184 | 99 | 42 |
| Stage 2 | Heavy | 184 | 99 | 42 |
| Stage 3 | Heavy | 35 | 143 | 17 |
| **Bowman 5W154** | | | | |
| Stage 1 | Heavy | 0 | 6 | 1 |
| Stage 2 | Light | 0 | 350 | 8 |
| Stage 3 | Light | 350 | 22 | 21 |
| **Dodd Road 4W22** | | | | |
| Stage 1 | Heavy | 229 | 78 | 49 |
| Stage 2 | Light | 35 | 189 | 14 |
| Stage 3 | Light | 189 | 147 | 33 |
| **Mill Creek 5W116** | | | | |
| Stage 1 | Light | 91 | 294 | 10 |
| Stage 2 | Light | 0 | 319 | 6 |
| Stage 3 | Heavy | 63 | 98 | 19 |
| **Mill Creek 5W127** | | | | |
| Stage 1 | Light | 32 | 300 | 8 |
| Stage 2 | Light | 32 | 300 | 8 |
| Stage 3 | Light | 321 | 0 | 18 |
| **Pomeroy 5W342** | | | | |
| Stage 1 | Heavy | 83 | 27 | 16 |
| Stage 2 | Light | 0 | 398 | 8 |
| Stage 3 | Heavy | 64 | 197 | 26 |
| **Clinton 5Y608** | | | | |
| Stage 1 | Light | 38 | 341 | 12 |
| Stage 2 | Light | 0 | 161 | 5 |
| Stage 3 | Light | 161 | 218 | 17 |
| **Clinton 5Y610** | | | | |
| Stage 1 | Light | 16 | 277 | 7 |
| Stage 2 | Light | 0 | 95 | 2 |
| Stage 3 | Light | 95 | 198 | 10 |

| Circuit | Controlling Case | Number of Trans-formers at or below 120 volts | Number of Trans-formers from 120 to 121 volts | Estimated total number of transformers that may have customers with low voltage at Service Entrance** |
|---|---|---|---|---|
| **Orchard 5Y456** | | | | |
| Stage 1 | Light | 0 | 215 | 4 |
| Stage 2 | Light | 0 | 215 | 4 |
| Stage 3 | Heavy | 46 | 34 | 11 |
| **Orchard 5Y498** | | | | |
| Stage 1 | Light | 0 | 322 | 6 |
| Stage 2 | Light | 0 | 322 | 6 |
| Stage 3 | Heavy | 63 | 96 | 19 |
| **Wiley 5Y434** | | | | |
| Stage 1 | Heavy | 53 | 69 | 15 |
| Stage 2 | Heavy | 53 | 69 | 15 |
| Stage 3 | Heavy | 150 | 17 | 30 |
| **Nob Hill 5Y197** | | | | |
| Stage 1 | Heavy | 0 | 0 | 0 |
| Stage 2 | Heavy | 0 | 0 | 0 |
| Stage 3 | Heavy | 0 | 96 | 7 |
| **Nob Hill 5Y194** | | | | |
| Stage 1 | Light | 164 | 65 | 12 |
| Stage 2 | Light | 164 | 65 | 12 |
| Stage 3 | Light | 355 | 65 | 24 |
| **Nob Hill 5Y273** | | | | |
| Stage 1 | Light | 463 | 0 | 25 |
| Stage 2 | Light | 0 | 420 | 9 |
| Stage 3 | Light | 420 | 43 | 24 |
| **North Park 5Y356** | | | | |
| Stage 1 | Heavy | 158 | 73 | 35 |
| Stage 2 | Light | 0 | 232 | 6 |
| Stage 3 | Light | 232 | 244 | 23 |
| **River Road 5Y444** | | | | |
| Stage 1 | Light | 43 | 406 | 12 |
| Stage 2 | Light | 43 | 406 | 12 |
| Stage 3 | Heavy | 57 | 251 | 28 |
| **Sunnyside 5Y313** | | | | |
| Stage 1 | Light | 21 | 198 | 7 |
| Stage 2 | Light | 21 | 198 | 7 |
| Stage 3 | Light | 209 | 18 | 15 |

| Circuit | Controlling Case | Number of Trans-formers at or below 120 volts | Number of Trans-formers from 120 to 121 volts | Estimated total number of transformers that may have customers with low voltage at Service Entrance** |
|---|---|---|---|---|
| **Sunnyside 5Y317** | | | | |
| Stage 1 | | | | 0 |
| Stage 2 | | | | 0 |
| Stage 3 | Light | 135 | 19 | 9 |
| **Grandview 5Y351** | | | | |
| Stage 1 | Heavy | 19 | 20 | 5 |
| Stage 2 | Light | 155 | 174 | 12 |
| Stage 3 | Heavy | 63 | 111 | 20 |

**The numbers shown is the maximum expected number if the Voltage Optimization would be implemented to that particular stage. This means the total shown is not additive stage to stage. In fact, it is common for the number to go down between Stage 1 and Stage 2.

The output of the system study was then analyzed from an economic perspective using the financial factors in Section 1b.

## More on Light Load / Heavy Load Scaling

For this work, Commonwealth considered how the probability of a particular distribution transformer and the services off of it may have a low-voltage situation during light load after voltage optimization is implemented. This question is important because, during lightly loaded conditions, the voltage profile of the distribution circuit is "flatter" (has less voltage drop from the substation to the end of the line). The result is the potential for more transformers to have a lower primary source voltage during light loads than during heavy loads. The greater number of transformers is considered in the calculations for light load situations. The question to consider is: During light load periods, what is the change to the heavy load probability of having a secondary system with a specific, or greater, voltage drop? In this case, the voltage drops of concern are 4 volts or greater and 5 volts or greater. These are secondary system voltage drops that could, if the primary distribution system voltage were low enough, cause one or more customers being served from a particular transformer to have a service voltage of 115 volts or less.

Consider the components of the secondary system voltage drop. The voltage drop in the distribution transformer + the voltage drop in a shared secondary + the voltage drop in the service equals the secondary system voltage drop. In an equation:

$$V_{d\text{-}sec\ sys} = V_{d\ trans} + V_{d\ sec} + V_{d\ svc}$$

where:

$$V_{d\ trans} = (I_{trans})(Z_{trans});\ V_{d\ sec} = (I_{sec})(R_{sec\ cond});\ \text{and}\ V_{d\ svc} = (I_{svc})(R_{svc\ cond})$$

In this example, the impedances do not change appreciably as the current changes, so the voltage drop change is proportional to the change in the current. The sum of the transformer loadings on the distribution system is equal to the system load; therefore, as the system load drops, on average, so does the loading on an average transformer. As the loading on the transformer is the sum of the individual loads, the voltage drop would be expected to diminish as the current from the loads diminishes. The change in the voltage drop is proportional to the change in the load current, and on average, the system load changes with the transformer loadings. So, the likelihood of excessive voltage drop in an average transformer's secondary system at a given load level can be estimated by multiplying the ratio of the load at a given level to the peak load by the probability of the voltage drop at the peak level. This indicates that, for an average distribution transformer system, the probability, at light load, of the secondary voltage drop being equal to or more than a given amount is equal to the probability of that voltage drop scenario at peak load times the ratio of light load to heavy load. In equation form:

$$\text{Prob}\ (V_{d\ sec\ sys\ LL}) = \text{Prob}\ (V_{d\ sec\ syst\ HL}) \text{x}((\text{Light Load})/(\text{Heavy Load}))$$

The estimated probability of the voltage drops for four or more volts is 26.8%, and for five or more volts it is 10.6%, as calculated via the methodology in Appendix 2. If the heavy load is known, for any given light load the probability of these voltage drops occurring on a distribution transformer's secondary system can be also be estimated with the equation above. This is the approach used in this study.

# SECTION 3 – EXISTING SYSTEM ASSESSMENT

## Area Overview

The 19 PacifiCorp feeders evaluated in this study serve approximately 30,747 customers. The total system peak demand for the 19 feeders is 138 MW, delivering approximately 627,612 MWh annually. The average PacifiCorp customer on the 19 feeders has an annual consumption of approximately 20,412 kWh. There is 354,360 kVA of connected distribution transformer nameplate capacity. The average distribution transformer is loaded to approximately 39% of its nameplate when comparing the peak load for all circuits and the connected distribution transformer nameplate capacity. Table 3-1 summarizes the substations and circuits analyzed for this study.

### Table 3-1 Overview of Substations and Circuits Analyzed

| Station | Circuits in Study | Total Customers | Annual Peak (MW) | Comments |
|---|---|---|---|---|
| Bowman | 2 | 3,619 | 14.92 | One of the circuits has three capacitors installed and the other four. These circuits serve 68% residential load, 29% commercial load and small amounts of industrial and irrigation. |
| Dodd Rd | 1 | 1,181 | 8.7 | No capacitors are on this circuit. This circuit serves 45% residential load, 31% commercial, 13% industrial and 11% irrigation. |
| Mill Creek | 2 | 4,021 | 14.32 | One of the circuits has two capacitors installed and the other none. These circuits serve 76% residential load and 23% commercial. |
| Pomeroy | 1 | 1,204 | 6.04 | One capacitor is installed on this circuit. This circuit serves 70% residential and 29% commercial load with a very small amount of industrial load. |
| Clinton | 2 | 3,438 | 17.45 | One circuit has one capacitor installed and the other two. These circuits serve 62% residential and 38% commercial load. |
| Nob Hill | 3 | 5,661 | 22.07 | One circuit has two capacitors installed, one circuit has one capacitor installed and one circuit has no capacitors installed. These circuits serve 71% residential and 29% commercial load. |
| North Park | 1 | 1,634 | 6.79 | Two capacitors are installed on this circuit. This circuit serves 85% residential and 15% commercial load with a very small amount of irrigation. |
| Orchard | 2 | 3,172 | 13.58 | One of the circuits has one capacitor in- |

| Station | Circuits in Study | Total Customers | Annual Peak (MW) | Comments |
|---|---|---|---|---|
| | | | | stalled and the other none. These circuits serve 81% residential with the balance essentially commercial. |
| Wiley | 1 | 1,332 | 6.99 | No capacitors are on this circuit. This circuit serves 87% residential load, 11% commercial and the balance industrial. |
| River Road | 1 | 2,201 | 10.6 | One capacitor is installed on this circuit. This circuit serves 60% residential load and 39% commercial. |
| Grandview | 1 | 1,286 | 7.7 | There is one capacitor installed on this circuit. This circuit serves 62% residential load, 28% commercial, 5% irrigation and the balance industrial. |
| Sunnyside | 2 | 1,998 | 9.0 | One capacitor is installed on each circuit. These circuits serve 54% residential load and 45% commercial load. |

The Simplified Voltage Optimization (VO) Measurement and Verification (M&V) Protocol provides a basic approach to determine end-use energy savings when operating the electric distribution system more efficiently and within the lower band of the ANSI Standard voltage level. The protocol covers utility electric distribution systems serving mostly residential and light commercial load as defined by the utility. System loads do not need to be uniformly distributed throughout the distribution system.

Appendix 12 includes the summary information for each circuit. The appendix shows the following:

- 70% to 95% of the customers on each circuit have air conditioning.
- There is a large penetration of natural gas in the area, which results in non-electric heat providing the majority of consumer heating needs on most circuits.
- The heating and cooling zones for this area are classified as 1.
- The expected VO factor for end use savings ranges from 0.51 to 0.65.

The 19 primary distribution circuits use a variety of primary conductor types. The overhead primary conductors were found to range from #6Cu and #2ACSR up to 795 kcm AAC. Underground conductor sizes ranged from #2CU to 1000 kcm AL cable.

## Metering

***Substation:*** To meet the VO protocol verification requirements, it is necessary to have interval data for the MW, MVAR, phase amps and bus voltage for each circuit operated with voltage optimization. Most of the metering infrastructure is available to meet the protocol requirements. Metering is present in each substation for each power transformer. Potential transformers are available to be used for the feeder metering. The substation feeders are being protected with circuit breakers. The circuit breakers have current transformers that can be used for feeder metering. A control enclosure is available in which to mount a new meter. Additionally, PacifiCorp Tech Ops managers indicate most remote terminal units (RTU) and analog lines are available to get feeder ampere readings into RANGER.

***Line Voltage Regulator Metering*:** Because a line voltage regulator is the start of a separate voltage control zone, it is required that the same information be monitored and recorded at or near a voltage regulator as at a substation. It is likely that metering will need to be added to existing regulators.

***End of the Line (Voltage Zone) Metering*:** There is currently no end of the line voltage monitoring in place on these 19 PacifiCorp circuits. This will require only the equipment necessary to measure the end of the line voltage on one phase.

The necessary metering is outlined in Section 4, with details of the equipment and the expected installation costs for the required metering described in Appendix 13.

## Voltage Control

PacifiCorp's standards for voltage control are consistent with ANSI/IEEE C84.1. For this study, it was assumed PacifiCorp's customers will most generally have a secondary system voltage drop of less than or equal to 5% (6 volts on 120 volt base). This provides for the primary voltage to drop to 120 volts (1 per unit, on a 120 volt base) and still ensure a service entrance voltage of 114 volts.

In general, the substations have power transformer load tap changers (LTC) used for voltage regulation. For all stations the As-is, or base case, voltage controls apply line drop compensation settings with a base voltage setting, for most circuits, of 121 volts with a 2 volt bandwidth (plus or minus 1 volt). This approach to voltage regulation is consistent with the Simplified VO protocol.

## VO Minimum Threshold Assessment

The system was assessed to determine compliance with VO M&V Protocol minimum threshold limits for primary voltage, amperage unbalance, primary voltage drop and power factor. A number of the circuits required remedial action to come into the protocol criteria. At the end of Stage 1, a number of the circuits were not compliant with the protocol requirements to start voltage optimization. However, by Stage 2 all circuits were compliant with the protocol. It is not uncommon for a utility to need to make some adjustments to its system to bring some of its circuits into the acceptable range for the VO protocol. Refer to Appendix 8, Simplified VO M&V Protocols, Section 2.3, for the definition of minimum threshold limits.

# SECTION 4 – SYSTEM IMPROVEMENTS

## Primary System

System improvements (SI) are necessary to ensure compliance with minimum VO thresholds, improve distribution system efficiency, achieve lower end-user average voltages and reduce the risk of abnormal voltage. For the most part, the improvements considered were consistent with PacifiCorp's standard materials and approaches and are meant to be consistent with the work as described in PacifiCorp's Block Cost Estimating Spreadsheet.

The system improvements include:

- Phase changes to balance load and reduce neutral current.
- Installation of switched or fixed capacitors to improve power factor. From Commonwealth's examination of the current PacifiCorp application of capacitors, it is noted that switched distribution capacitors are used sparingly (only one was found on the19 Tier 1 feeders). Using only fixed banks, the existing capacitors on the distribution primary, for the most part, appear designed to seek to balance reactive needs between heavy and light load conditions. In redesigning the banks to include both fixed and switched capacitors, the fixed capacitor banks were used to satisfy light load reactive needs within 300 to 600 kVAR. Then, switched banks were used to serve the added reactive needs during heavy load, also generally within the range of 300 to 600 kVAR. This resulted in a tighter control of net feeder power factor, holding it close to unity power factor. A tighter power factor reduces feeder losses and it also results in flattening the voltage profile on the feeder, providing improved opportunity for voltage optimization. The results of installing these capacitors are shown in Appendix 14 and Appendix 15. The VAR profiles are noted in Appendix 14, and the power factor profiles are shown in Appendix 15. Both appendices show base case and system improvement modeling results.
- Reconductoring some sections of conductor where the existing wire is reaching the limit of its current carrying capacity.
- Installing line voltage regulators to reduce the voltage drop on the circuit.

With system improvements, the voltage profile along each feeder is flattened. With a smaller voltage drop along the feeder, the average feeder voltage can be reduced, which reduces system no-load loss and provides end-use energy savings.

## Metering Improvements

***Substation:*** To meet the VO protocol verification requirements, it is necessary to have the MW, MVAR, phase amperage and bus voltage for each circuit operated with voltage optimization. Most of the metering infrastructure is available to meet the protocol requirements. Metering is present in each substation for each power transformer. Potential transformers are available to be used for the feeder metering. The substation feeders are being protected with circuit breakers. The circuit breakers have current transformers that can be used for feeder metering. A control enclosure is available in which to mount a new meter. Additionally, PacifiCorp Tech Ops managers indicate most remote terminal units (RTU) and analog lines are available to get feeder ampere readings into RANGER.

In most cases, the installation of the meters in the substation should be relatively straightforward. The process for the substation installation will be to remove the existing demand meter and replace it with an SEL 751A relay, mounted on the panel in place of the existing meter. The overcurrent and reclosing relays will be maintained as backups. A test switch will be mounted adjacent to (below) the relay. The appropriate voltage quantities will be routed from the existing metering voltage transformer circuits, probably already in the control enclosure. The voltages will be wired to the test switch and relay. Current quantities will be wired to the test switch and relay from the feeder breaker current transformers. The relaying and metering settings will be installed in the relay, and a functional check of the relay will be performed. While it is likely the potential and current transformers will not be revenue accuracy metering, relay level accuracy is considered acceptable by the Simplified Voltage Optimization Protocol. PacifiCorp typically specifies an accuracy rating of 0.6% for relay and monitoring devices and 0.3% for revenue devices.

An accuracy class of 0.3 (or 0.6) indicates the device is certified by the manufacturer to be accurate to within 0.3% (or 0.6%) when operating at its rated value. When the current (for a current transformer) or voltage (for a potential transformer) drops significantly below the rated value, the error is allowed to increase without violating the accuracy standard. IEEE C57.13 allows that current transformers may have greater errors at lower currents. The standard permits twice the error at 10% current than is permitted at 100% current. So, a current transformer with an accuracy rating of 0.3% may have errors of 0.6% when the load is 10% of the rated amount. This means a current transformer in the 0.6 accuracy class may have permissible errors of 1.2% at the 10% load level. This greater error at such low current does not usually represent significant error in total registration of kilowatt hours.

For potential transformers, IEEE C57.13 requires the accuracy also be met at 90% voltage; this drop in voltage is greater than the voltage swing on PacifiCorp's distribution system. The 0.6% to 1.2% error range is not significant in determining the effects of voltage optimization and is why relay accuracy metering provides sufficient accuracy to determine if the implemented voltage optimization is acquiring the energy anticipated. It also provides the necessary data and information to appropriately control a distribution system being operated in a voltage optimization mode. For these reasons, Commonwealth does not recommend that PacifiCorp replace its relay accuracy current and potential transformers for voltage optimization.

***Line Voltage Regulator Metering:*** Because a line voltage regulator is the start of a separate voltage control zone, it is required that the same information be monitored and recorded at or near a line voltage regulator as is monitored and recorded at a substation. It is likely that metering will be needed to be added to existing regulators. What is described here provides for this. It is possible to order regulators with the metering necessary for voltage optimization, but to keep the costs consistent, this approach is what was included in the cost estimates for this work. The metering set for use at a 3-phase line regulator will be installed on a pole, as close to the load side of the regulators as practical. Three current transformers and three voltage transformers will be mounted on an instrument transformer cluster rack near the top of the pole. The voltage transformers will be connected to the line conductors through cutouts and hot clamps. The current transformers will be connected to the line across insulators added to the line, or at a deadend structure. The meter will be mounted to the pole near the base and connected to the voltage transformers using control cable. Since the meter will be exposed to public access, the control cable will be installed in conduit, up the pole, until the cable reaches 10 feet above the ground. After the wiring is complete, the meter will be installed in the meter base and the installation will be energized and verified.

***End of the Line (Voltage Zone) Metering:*** There is currently no end of the line voltage monitoring in place on these 19 PacifiCorp circuits. Equipment will be required to measure only the voltages. The installation at the end of the line will be different than the substation installation. One voltage transformer will be provided and mounted on a convenient pole. The transformer will be mounted on a cluster rack at the top of the pole and connected to the line using a fused cutout and hot clamps. The meter will be mounted to the pole near the base and connected to the voltage transformers using control cable. Since the meter will be exposed to public access, the control cable will be installed in conduit, up the pole, until the cable reaches a minimum of 10 feet above the ground. After the wiring is complete, the meter will be installed in the meter base and the installation energized and verified. This installation will require a line crew to install the instrument transformers at the top of the pole and a meter worker to install and verify the meter.

The details of the equipment and the expected installation costs for the above metering are described in Appendix 13. Commonwealth has increased the estimated costs for the substation and end of the line metering by 20% to provide a contingency for this work effort.

The VO protocol would consider the metering described above sufficient for implementation of the voltage optimization plan included in this report. However, PacifiCorp is concerned that implementing to Stage 3 could result in operational issues, such as low voltage. In an effort to more closely monitor and manage the system in a Stage 3 level of voltage optimization, PacifiCorp has requested that Commonwealth include real-time communication and monitoring with the metering equipment. The metering for stages 1 and 2 should be compatible with the communication and metering infrastructure, so there will be no lost investment if implementation for Stage 3 lags stages 1 and 2.

***Stage 3 Metering Communications:*** PacifiCorp is concerned that a Stage 3 implementation could result in customers having low voltage and asked that equipment and the associated costs for real-time monitoring and control be included in Stage 3 options. To do this, communications will be necessary between:

- Substations and the end of the line metering locations
- Substations and line voltage regulators
- Line voltage regulators and end of the line metering
- Substations to a central location for monitoring and data storage

The substation to the central monitoring and data storage location is communications gear, links, central equipment and software to support voltage optimization, IVVO, FDIR, AMI, DR and other Smart Grid services. It would be secure, real-time and always on communication. This is an accepted approach in the Voltage Optimization protocol. See Appendix 8, Simplified Voltage Optimization (VO) Measurement and Verification Protocol, for more information.

The communication between the stations and line metering equipment for both regulators and end of the line voltage metering would be wireless radio links.

The costs to provide this level of communication, which may be needed for full Smart Grid applications but may be more than is required for voltage optimization, will add approximately $2.7M to the project, or about 40% of all costs, if every circuit in the study is developed to a Stage 3 level. If voltage optimization is implemented, Commonwealth believes that experience may demonstrate that there is less need for and fewer benefits to the communication than PacifiCorp expects. If this turns out to be true, it may mitigate the need for this level of metering and communication, at least until there are other uses for the system, such as Smart Grid applications, that could also share the cost burden.

## Secondary System Considerations

For most circuits, it is possible that, as a result of voltage optimization, some number of distribution transformers, and hence customers, may have secondary voltage drops of sufficient magnitude to cause service entrance voltages to drop below 115 volts. Commonwealth's approach to addressing this is described in Section 2. Each of the circuits was analyzed based on this approach for each stage and for heavy and light load; the summary findings are included in Table 4-1, below.

## Location of System Improvements

The installation of capacitors, regulators and reconductoring are shown on the circuits map in Appendix 6. Additionally, the locations for the primary system improvements for each circuit are noted in Appendix 9, Summary of Analysis.

## Cost Estimating

The estimated costs by circuit and stage are shown in total in Table 4-1. In Table 4-2, the work is described in summary fashion with the respective cost for the work noted. Additional details showing the cost estimates are in Appendix 10. The costs are based on PacifiCorp's Block Cost Estimating Sheet and PacifiCorp's loaded hourly labor rates. Both of these are shown in Appendix 4. Where needed, Commonwealth has supplemented the PacifiCorp cost information with its knowledge of industry equipment and installation costs.

In addition to the system improvements described and included in the costs, Commonwealth has included costs for the following project related tasks:

- Engineering and analysis for phase swapping
- Planning, engineering and analysis to prepare for and respond to potential low-voltage problems.

The actions of implementing Stage 2 and Stage 3 voltage optimization are generally dependent on the previous stage or stages. For example, a Stage 3 model relies on the phase balancing completed in the Stage 1 model and the capacitors installed in the Stage 2 model. This approached allowed Commonwealth to add the estimated costs from Stage 1 to Stage 2 and the Stage 1 + Stage 2 total to the Stage 3 cost estimate. Following this approach did, at times, result in an anomaly when working with the solutions associated with addressing the potential low-voltage problems. It was possible that, after the system improvements for Stage 2 were completed, there would be fewer transformers potentially at risk of low voltage than would be at risk in the Stage 1 solution. Since the Stage 1 cost estimate included more transformers at risk than were at risk in the Stage 2 configuration, this required giving Stage 2 a cost credit for this component of the estimate.

The Financial Model assumes the increased operating and maintenance (O&M) cost for the voltage optimization effort will be 2% of the installed (capital) cost for each year of the life of the VO effort. For the BCR optimal solution with installed costs of approximately $520k, PacifiCorp should expect to have related O&M costs of $10,400 each year for the 20-year life of these VO projects. Assuming the 2% per year, the LCLC optimal solution with installed costs of approximately $1.25M, the O&M funding would be $25,000/year. These costs are included in the economic modeling for both the LCLC and BCR solutions. These funding levels seem appropriate, given the differences between the two solutions.

This amount of funding seems appropriate to support the work load for this level of VO programming. The work expected includes:

- Staff time to check and record voltage levels, either in field or via SCADA or similar system data transmission
- Incremental engineering time to review circuit parameters and make adjustments such as:
    - Phase balancing
    - Voltage control settings due to system modifications
    - Address post implementation questions regarding service voltages
- Engineering review to check and document system savings

- Incremental crew resource time to support engineering with field work associated with the above review of circuit parameters and related adjustments

Additional funding is included in the cost estimate for the development of a new standard for the selection of service conductors and distribution transformers on circuits implementing voltage optimization with end of the line primary voltages set to 119 volts. This is necessary if implementation includes any of the circuits to the Stage 3 level. The funding for the standard is included in the Optimal LCLC estimate for the effort to remedy potential low voltages.

### Table 4-1 System Improvement Cost Summary

| Service Area | Substation | Circuit | Stage1 | Stage 1 and Stage 2 | Stage 1, Stage 2, and Stage 3 |
|---|---|---|---|---|---|
| Walla Walla | Bowman | 5W150 | $180,378 | $329,870 | $341,514 |
| Walla Walla | Bowman | 5W154 | $29,526 | $102,929 | $272,600 |
| Walla Walla | Dodd Road | 4W22 | $219,622 | $288,415 | $583,960 |
| Walla Walla | Mill Creek | 5W116 | $58,178 | $150,565 | $318,157 |
| Walla Walla | Mill Creek | 5W127 | $83,645 | $106,799 | $256,139 |
| Walla Walla | Pomeroy | 5W342 | $107,846 | $317,873 | $622,153 |
| Yakima | Clinton | 5Y608 | $73,614 | $123,639 | $281,975 |
| Yakima | Clinton | 5Y610 | $53,438 | $118,025 | $260,606 |
| Yakima | Orchard | 5Y456 | $49,098 | $124,802 | $267,123 |
| Yakima | Orchard | 5Y498 | $44,502 | $65,499 | $230,336 |
| Yakima | Wiley | 5Y434 | $100,248 | $123,402 | $402,516 |
| Yakima | Nob Hill | 5Y197 | $23,910 | $47,064 | $154,291 |
| Yakima | Nob Hill | 5Y194 | $95,448 | $128,436 | $297,023 |
| Yakima | Nob Hill | 5Y273 | $128,058 | $107,026 | $241,604 |
| Yakima | North Park | 5Y356 | $166,286 | $231,435 | $522,300 |
| Yakima | River Road | 5Y444 | $85,444 | $264,201 | $552,570 |
| Sunnyside | Sunnyside | 5Y313 | $60,508 | $98,309 | $240,890 |
| Sunnyside | Sunnyside | 5Y317 | $26,690 | $49,844 | $203,759 |
| Sunnyside | Grandview | 5Y351 | $54,252 | $221,349 | $469,211 |
| | | Total | $1,640,691 | $2,999,482 | $6,518,727 |

## Table 4-2 System Improvement Costs by Circuit and Stage

| Circuit | | Action | Cost | Total Stage Cost |
|---|---|---|---|---|
| **Bowman 5W150** | | | | |
| | Stage 1 | Metering | $ 17,670 | |
| | | Transformer change out, tap changes and service change outs | $ 162,708 | |
| | | | | $ 180,378 |
| | Stage 2 | 900 kVAR switched capacitor addition | $ 20,997 | |
| | | Rotate phases | $ 4,820 | |
| | | Regulator addition | $ 72,594 | |
| | | Metering | $ 51,080 | |
| | | | | $ 149,492 |
| | Stage 3 | Install feeder metering package | $ 108,833 | |
| | | Credit for fewer transformer change out, tap changes and service change outs | $ (97,188) | |
| | | | | $ 11,645 |
| **Bowman 5W154** | | | | |
| | Stage 1 | Remove existing capacitors | $ 5,200 | |
| | | Metering | $ 17,670 | |
| | | Transformer change out, tap changes and service change outs | $ 6,656 | |
| | | | | $ 29,526 |
| | Stage 2 | Two 900 kVAR switched capacitor addition | $ 41,995 | |
| | | Transformer change out, tap changes and service change outs | $ 31,408 | |
| | | | | $ 73,403 |
| | Stage 3 | Install metering package | $ 115,748 | |
| | | Transformer change out, tap changes and service change outs | $ 53,924 | |
| | | | | $ 169,672 |
| **Dodd Road 4W22** | | | | |
| | Stage 1 | 900 kVAR fixed capacitor addition | $ 5,912 | |
| | | Metering | $ 17,670 | |
| | | Transformer change out, tap changes and service change outs | $ 196,040 | |
| | | | | $ 219,622 |
| | Stage 2 | 1,800 kVAR switched capacitor addition | $ 18,667 | |
| | | Two 300 kVAR switched capacitor additions | $ 24,802 | |
| | | 447 feet reconductoring | $ 59,133 | |
| | | Regulator addition | $ 74,187 | |
| | | Metering | $ 25,540 | |
| | | Credit for fewer transformer change out, tap changes and service change outs | $ (133,536) | |
| | | | | $ 68,793 |
| | Stage 3 | Install metering package | $ 221,029 | |
| | | Transformer change out, tap changes and service change outs | $ 74,516 | |
| | | | | $ 295,545 |

| Circuit | Action | Cost | Total Stage Cost |
|---|---|---|---|
| **Mill Creek 5W116** | | | |
| Stage 1 | Metering | $ 17,670 | |
| | Transformer change out, tap changes and service change outs | $ 40,508 | |
| | | | $ 58,178 |
| Stage 2 | 900 kVAR switched capacitor addition | $ 20,997 | |
| | Regulator addition | $ 63,842 | |
| | Metering | $ 25,540 | |
| | Credit for fewer transformer change out, tap changes and service change outs | $ (17,992) | |
| | | | $ 92,387 |
| Stage 3 | Install metering package | $ 115,748 | |
| | Transformer change out, tap changes and service change outs | $ 51,844 | |
| | | | $ 167,592 |
| **Mill Creek 5W127** | | | |
| Stage 1 | Phasing change | $ 8,400 | |
| | Phasing swaps | $ 14,460 | |
| | Metering | $ 17,670 | |
| | Transformer change out, tap changes and service change outs | $ 35,828 | |
| | 600 kVAR fixed capacitor addition | $ 7,287 | $ 83,645 |
| Stage 2 | 600 kVAR switched capacitor addition | $ 23,154 | |
| | | | $ 23,154 |
| Stage 3 | Install metering package | $ 108,833 | |
| | Transformer change out, tap changes and service change outs | $ 40,508 | |
| | | | $ 149,341 |
| **Pomeroy 5W342** | | | |
| Stage 1 | Phasing change | $ 4,200 | |
| | Phasing swaps | $ 9,640 | |
| | Metering | $ 17,670 | |
| | Transformer change out, tap changes and service change outs | $ 76,336 | |
| | | | $ 107,846 |
| Stage 2 | 300 kVAR switched capacitor addition | $ 17,333 | |
| | 355 feet reconductoring | $ 39,349 | |
| | 71 feet reconductoring | $ 10,930 | |
| | Regulator additions | $ 127,683 | |
| | Metering | $ 51,080 | |
| | Credit for fewer transformer change out, tap changes and service change outs | $ (36,348) | |
| | | | $ 210,027 |
| Stage 3 | Install metering package | $ 227,944 | |
| | Transformer change out, tap changes and service change outs | $ 76,336 | |
| | | | $ 304,280 |

| Circuit | Action | Cost | Total Stage Cost |
|---|---|---|---|
| **Clinton 5Y608** | | | |
| Stage 1 | Phasing change | $ 2,280 | |
| | Metering | $ 17,670 | |
| | Transformer change out, tap changes and service change outs | $ 53,664 | |
| | | | $ 73,614 |
| Stage 2 | 900 kVAR switched capacitor addition | $ 20,997 | |
| | 564 feet reconductoring | $ 62,515 | |
| | Credit for fewer transformer change out, tap changes and service change outs | $ (33,488) | |
| | | | $ 50,025 |
| Stage 3 | Install feeder metering package | $ 108,833 | |
| | Transformer change out, tap changes and service change outs | $ 49,504 | $ 158,337 |
| **Clinton 5Y610** | | | |
| Stage 1 | Phasing change | $ 2,280 | |
| | Metering | $ 17,670 | |
| | Transformer change out, tap changes and service change outs | $ 33,488 | |
| | | | $ 53,438 |
| Stage 2 | 600 kVAR switched capacitor addition | $ 23,154 | |
| | 576 feet reconductoring | $ 63,845 | |
| | Credit for fewer transformer change out, tap changes and service change outs | $ (22,412) | |
| | | | $ 64,587 |
| Stage 3 | Install feeder metering package | $ 108,833 | |
| | Transformer change out, tap changes and service change outs | $ 33,748 | |
| | | | $ 142,581 |
| **Orchard 5Y456** | | | |
| Stage 1 | Phasing change | $ 4,456 | |
| | Phasing swap | $ 4,820 | |
| | Metering | $ 17,670 | |
| | Transformer change out, tap changes and service change outs | $ 22,152 | |
| | | | $ 49,098 |
| Stage 2 | 600 kVAR switched capacitor addition | $ 23,154 | |
| | 1,023 feet reconductoring | $ 52,550 | |
| | | | $ 75,704 |
| Stage 3 | Install metering package | $ 108,833 | |
| | Transformer change out, tap changes and service change outs | $ 33,488 | |
| | | | $ 142,321 |

| Circuit | Action | Cost | Total Stage Cost |
|---|---|---|---|
| **Orchard 5Y498** | | | |
| Stage 1 | Transformer change out, tap changes and service change outs | $ 26,832 | |
| | Metering | $ 17,670 | |
| | | | $ 44,502 |
| Stage 2 | 900 kVAR switched capacitor addition | $ 20,997 | |
| | | | $ 20,997 |
| Stage 3 | Install metering package | $ 108,833 | |
| | Transformer change out, tap changes and service change outs | $ 56,004 | |
| | | | $ 164,837 |
| **Wiley 5Y434** | | | |
| Stage 1 | 600 kVAR fixed capacitor addition | $ 7,287 | |
| | 300 kVAR fixed capacitor addition | $ 10,292 | |
| | Metering | $ 17,670 | |
| | Transformer change out, tap changes and service change outs | $ 65,000 | |
| | | | $ 100,248 |
| Stage 2 | 600 kVAR switched capacitor addition | $ 23,154 | |
| | | | $ 23,154 |
| Stage 3 | Install metering package | $ 214,114 | |
| | Transformer change out, tap changes and service change outs | $ 65,000 | |
| | | | $ 279,114 |
| **Nob Hill 5Y197** | | | |
| Stage 1 | Transformer change out, tap changes and service change outs | $ 6,240 | |
| | Metering | $ 17,670 | |
| | | | $ 23,910 |
| Stage 2 | 900 kVAR switched capacitor addition | $ 23,154 | |
| | | | $ 23,154 |
| Stage 3 | Install metering package | $ 73,739 | |
| | Transformer change out, tap changes and service change outs | $ 33,488 | |
| | | | $ 107,227 |
| **Nob Hill 5Y194** | | | |
| Stage 1 | Metering | $ 17,670 | |
| | Install 3 fixed capacitor banks (300, 600 & 1200 kVAR) | $ 26,194 | |
| | Transformer change out, tap changes and service change outs | $ 51,584 | |
| | | | $ 95,448 |
| Stage 2 | Install 3 switched Capacitor banks (300, 600 & 1200 kVAR) | $ 70,706 | |
| | Credit for fixed capacitors from Stage 1 | $ (26,194) | |
| | 313 feet reconductoring | $ 24,790 | |
| | 119 feet reconductoring | $ 13,190 | |
| | Credit for fewer transformer change out, tap changes and service change outs | $ (49,504) | |
| | | | $ 32,988 |
| Stage 3 | Install metering package | $ 73,739 | |
| | Transformer change out, tap changes and service change outs | $ 94,848 | |
| | | | $ 168,587 |

| Circuit | Action | Cost | Total Stage Cost |
|---|---|---|---|
| **Nob Hill 5Y273** | | | |
| Stage 1 | Phasing swaps | $ 2,280 | |
| | 600 kVAR capacitor removal | $ 2,600 | |
| | Metering | $ 17,670 | |
| | Transformer change out, tap changes and service change outs | $ 105,508 | |
| | | | $ 128,058 |
| Stage 2 | 600 kVAR switched capacitor addition | $ 46,308 | |
| | Credit for fewer transformer change out, tap changes and service change outs | $ (67,340) | |
| | | | $ (21,032) |
| Stage 3 | Install metering package | $ 73,739 | |
| | Transformer change out, tap changes and service change outs | $ 60,840 | |
| | | | $ 134,579 |
| **North Park 5Y356** | | | |
| Stage 1 | Remove 900 kVAR capacitor | $ 2,600 | |
| | Metering | $ 17,670 | |
| | Transformer change out, tap changes and service change outs | $ 146,016 | |
| | | | $ 166,286 |
| Stage 2 | 900 kVAR switched capacitor addition | $ 20,997 | |
| | 607 feet reconductoring | $ 67,282 | |
| | Voltage regulator addition | $ 72,594 | |
| | Metering | $ 25,540 | |
| | Credit for fewer transformer change out, tap changes and service change outs | $ (121,264) | |
| | | | $ 65,149 |
| Stage 3 | Install metering package | $ 221,029 | |
| | Transformer change out, tap changes and service change outs | $ 69,836 | |
| | | | $ 290,865 |
| **River Road 5Y444** | | | |
| Stage 1 | Swap phasing | $ 6,840 | |
| | Reduce capacitor size 1200 kVAR to 600 kVAR | $ 9,350 | |
| | Metering | $ 17,670 | |
| | Transformer change out, tap changes and service change outs | $ 51,584 | |
| | | | $ 85,444 |
| Stage 2 | Addition of two 600 kVAR switched capacitors | $ 46,308 | |
| | 668 feet of reconductoring | $ 34,314 | |
| | Voltage regulator addition | $ 72,594 | |
| | Metering | $ 25,540 | |
| | | | $ 178,757 |
| Stage 3 | Install metering package | $ 221,029 | |
| | Transformer change out, tap changes and service change outs | $ 67,340 | |
| | | | $ 288,369 |

| Circuit | | Action | Cost | Total Stage Cost |
|---|---|---|---|---|
| **Sunnyside 5Y313** | | | | |
| | Stage 1 | Reduce capacitors from 1200 KVAR to 900 kVAR | $ 9,350 | |
| | | Metering | $ 17,670 | |
| | | Transformer change out, tap changes and service change outs | $ 33,488 | |
| | | | | $ 60,508 |
| | Stage 2 | 600 kVAR switched capacitor addition | $ 23,154 | |
| | | 300 kVAR switched capacitor addition | $ 14,647 | |
| | | | | $ 37,801 |
| | Stage 3 | Install metering package | $ 108,833 | |
| | | Transformer change out, tap changes and service change outs | $ 33,748 | |
| | | | | $ 142,581 |
| **Sunnyside 5Y317** | | | | |
| | Stage 1 | Phase swapping | $ 4,200 | |
| | | Three phase swap | $ 4,820 | |
| | | Metering | $ 17,670 | |
| | | | | $ 26,690 |
| | Stage 2 | 600 kVAR switched capacitor installation | $ 23,154 | |
| | | | | $ 23,154 |
| | Stage 3 | Install metering package | $ 115,748 | |
| | | Transformer change out, tap changes and service change outs | $ 38,168 | |
| | | | | $ 153,916 |
| **Grandview 5Y351** | | | | |
| | Stage 1 | Phase swapping | $ 4,820 | |
| | | Change 600 kVAR capacitor to 300 kVAR | $ 9,350 | |
| | | Metering | $ 17,670 | |
| | | Transformer change out, tap changes and service change outs | $ 22,412 | |
| | | | | $ 54,252 |
| | Stage 2 | Add two 600 kVAR switched capacitors | $ 46,308 | |
| | | Voltage Regulator addition | $ 63,842 | |
| | | Metering | $ 25,540 | |
| | | Transformer change out, tap changes and service change outs | $ 31,408 | |
| | | | | $ 167,097 |
| | Stage 3 | Install metering package | $ 214,114 | |
| | | Transformer change out, tap changes and service change outs | $ 33,748 | |
| | | | | $ 247,862 |
| | | **Total** | | **$ 6,518,727** |

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# Appendix 1: Washington State Rules and Regulations and Utility Distribution System Efficiency Measures

Washington State Rules and Regulations
And
Utility Distribution System Efficiency Measures

Prepared by R. H. Fletcher, PhD, P.E.
Utility Planning Solutions, PLLC
January 20, 2011

Washington State voters passed Initiative 937 on Nov. 7, 2006. This initiative imposes targets for energy conservation and use of eligible renewable resources on the state's electric utilities that serve more than 25,000 customers. Specifically, these utilities, both public and investor owned, must secure 15 percent of their power supply from renewable resources by 2020. Initiative 937, also called the Washington Energy Independence Act (WEIA) was codified at RCW Title 19 Chapter 285.

Beginning Jan. 1, 2010, the WEIA requires utilities with 25,000 customers or more to acquire all conservation that is cost-effective, reliable and feasible as stated in the Energy Financing Voter Approval Act, RCW 80.52.030. Each utility is required to set an annual target which may be based on their integrated resource plan or a proportion of their regional share of achievable cost-effective conservation potential. Conservation can include increases in the efficiency of energy use, production, or distribution. Each utility must pursue all available cost-effective, reliable, and feasible conservation consistent with methodologies used by the Pacific Northwest Electric Power and Conservation Planning Council in its most recently published regional power plan.

Investor Owned Electric companies in Washington State are regulated in accordance with Washington Administrative Code, WAC, Title 480 Chapter 109 regarding acquisition of minimum quantities of conservation and renewable energy and describes implementation requirements to comply with RCW 19.285. There is no mention of "distribution system efficiency" conservation measures, however, RCW 480.109.007 does provide definitions for the "Conservation Council" which is defined as the Northwest Electric Power and Conservation Council which implies Council approved measures are acceptable. The WAC Title 194 Chapter 37 was created for Public Owned electric utilities and describes implementation requirements for energy independence and can be used as a guide for Investor Owned Electric companies as well.

WAC 194.37.090 provides additional documentation of efficiency from distribution system loss reduction improvements, including peak demand management and voltage regulation not specific address in RCW 480.109. For example, WAC 194.37.060-090 defines acceptable conservation measures or programs if they meet NWPCC (Council) measures or programs in its power plan which is based on methodologies and protocols established by the Regional Technical Forum. In Section 194.37.090 (2)(a)(i…iv) documentation requirements for distribution system improvements are as follows

(i) For distribution system upgrades, the utility will prepare a distribution flow analysis to compare the annual energy losses of the system being replaced or upgraded to the final system as installed.

(ii) For conservation voltage regulation, the utility will prepare a distribution flow analysis to compare the annual energy losses of the system before and after the implementation of a voltage regulation program. The difference in annual kilowatt-hour requirement at the utility point(s) of receipt (for distribution utilities) or net energy for load for generating utilities may be counted as conservation savings.

(iii) For peak demand management, the utility will prepare a distribution flow analysis to compare the annual energy losses of the system before and after implementation of the peak demand management program. The change in net energy losses may be counted as conservation savings. Any net reduction in energy sales (economic curtailment) shall not be included in conservation savings.

(iv) The distribution flow analysis conducted for (b)(i), (ii), or (iii) of this subsection shall be prepared under the direction of, and carry the stamp of a registered professional electrical engineer licensed by the Washington department of licensing.

The Pacific Northwest Electric Power Planning and Conservation Act, P.L. 96-501, 16 U.S.C. 839 et seq. in Section 4 authorizes the Pacific Northwest Electric Power and Conservation Planning Council to ". . . establish such other voluntary advisory committees as it determines are necessary or appropriate to assist it in carrying out its functions and responsibilities . . .". The Regional Technical Forum committee (RTF) was created in 1999 in this regard.

The four goals adopted by the Council for the Regional Technical Forum committee (RTF) corresponding to its original charge from Congress and the Comprehensive Review are to:

1. Develop standardized protocols for verification and evaluation of energy savings and the performance of renewable resources.
2. Track regional progress toward the achievement of the region's conservation and renewable resource goals.
3. Provide feedback and suggestions for improving the effectiveness of the conservation and renewable resource development programs and activities in the region.
4. Conduct periodic reviews of the region's progress toward meeting its conservation and renewable resource goals at least every 5 years, acknowledging changes in the market for energy services and the potential availability of cost-effective conservation opportunities.

The distribution system conservation savings assessment used in the NWPCC 6$^{th}$ Power Plan was based on the estimates from measured data on 33 utility feeders, and analytical methods developed in a NEEA Distribution Efficiency Initiative study initiated in 2001 and completed in December 2007. The study was prepared by R.W. Beck, Inc. in association with five subcontractors and guided by the NEEA Technical Advisory Committee made up of NW electric utilities. The Council's 6$^{th}$ Power Plan estimate potential of distribution efficiency savings is 400 MWa by 2029 (7% of the total regional sector savings) as reported in Table E-1 "Estimated Cost-Effective Conservation Potential in Average Megawatts 2010-2014 and 2010 – 2029" of NWPCC 6$^{th}$ Power Plan Appendix E.

Costs and savings for four major distribution system measures in the 6$^{th}$ Power Plan were identified and applied to a descriptive data set of the region's distribution system. The measures are: Reduced System Voltage (LDC, Light System Improvements (capacitors and load balancing), Major System Improvements (reconductor, rephrasing, and regulators), and Enhanced Voltage Control (end-of-line feedback). The dataset contains system loads by customer class and load patterns, substation counts, feeder counts, customer counts, and climate zones for 137 regional utilities used to generate the units estimates.

To simplify the determination of distribution efficiency savings from voltage reduction and to encourage acceptance and adoption of distribution system efficiency, BPA worked with a newly form Energy Smart Utility Efficiency Technical Workgroup in 2009 and 2010 to develop a simplified measurement and verification protocol. The NWPCC and RTF adopted this new voltage reduction and distribution system efficiency methodology titled "Simplified Voltage Optimization (VO) Measurement and Verification Protocol" approved on May 4th, 2010. http://www.nwcouncil.org/energy/rtf/measures/protocols/ut/VoltageOptimization_Protocol_v1.pdf

The Simplified Voltage Optimization (VO) Measurement and Verification (M&V) Protocol provides a basic approach to determine end-use energy savings when operating the electric distribution system more efficiently and within the lower band of the ANSI Standard voltage level and is consistent with WAC 194.37.090 reporting requirements. The protocol covers utility electric distribution systems serving mostly residential and light commercial load as defined by the utility. System loads do not need to be uniformly distributed throughout the distribution system.

The VO Protocol identifies the procedure to determine the average annual voltage for a distribution primary system with source voltage regulation. Minimum system stability thresholds (e.g., max voltage drops, min power factors, max phase unbalance, etc.), system data requirements, and measurement and verification formulations are included as part of this Protocol. To meet the minimum thresholds, utilities generally achieve distribution efficiency and the ability to lower the customer's average voltage. The Protocol defines a VO factor that is used to estimate the end-use energy savings from reduced voltage and is based on the NEEA DEI Study. BPA has successfully applied this protocol to many NW electric utilities.

The CVR factor was used for the past 30 years to define the relationship between either annual demand or energy at the source of a distribution feeder and the average change in voltage at the source. The CVR factor includes the savings from system no load loss savings and end use savings and was derived via length field tests. Based on the NEEA DEI Study work and the "Simplified Voltage Optimization (VO) Measurement and Verification Protocol" approved on May 4th, 2010 by the RTF, a new industry voltage and energy savings factor has been developed to better represent the change in energy use at the end-use customer. The end-use VO Factor is a ratio of expected % change in energy delivered for each 1% change in average voltage supplied at the end-use service entrance.

The end-use VO Factor is given as a p.u. ratio for a given system and is determined from VO Factor Tables in Appendix A of the Protocol. The VO factor does not include savings from line or no-load loss savings. The no-load loss savings can be easily determined knowing the distribution transformer total connected kVA. The line loss savings can be determined using accurate distribution load flow models to simulate line losses before and after system improvements. The CVR factor has been replaced with the VO factor.

To determine the VO factor, you must enter the table identified for the Heating and cooling climate zone associated for each substation and select the appropriate VO Factor using the percent customers with Non-Electric Heating (and Heat Pumps) and percent of customers with Air-conditioning. The protocol further discusses the formulation to calculate the average voltage change on the feeder and is used with the VO factor to yield the total change in energy at the end-use customer. The line loss savings and no-load (core) distribution transformer loss savings are calculated separately from the VO savings.

Background Information Regarding the NWPCC 6th Power Plan

The Council uses its portfolio model to determine how much conservation is cost-effective to develop. The Pacific Northwest Electric Power Planning and Conservation Act defines regional cost-effectiveness as follows: "Cost-effective", when applied to any measure or resource referred to in this chapter, means that such measure or resource must be forecast to be reliable and available within the time it is needed, and to meet or reduce the electric power demand, as determined by the Council or the Administrator, as appropriate, of the consumers of the customers at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource, or any combination thereof.

Under the Act the term "system cost" means an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, the cost of distribution and transmission to the consumer and such quantifiable environmental costs and benefits as are directly attributable to such measure or resource. The Council has interpreted the Act's provisions to mean that in order for a conservation measure to be cost-effective the discounted present value of all of the measure's benefits should be compared to the present value of all of its costs. The NWPCC 6th Power Plan describes the conservation supply curves development in Appendix E of the 6th Power Plan. The NW annual distribution efficiency savings load factor is 0.558.
http://www.nwcouncil.org/energy/powerplan/6/final/SixthPowerPlan_Appendices.pdf

The estimated savings potential for distribution system efficiency in the northwest is given in Table E-1 "Estimated Cost-Effective Conservation Potential in Average Megawatts 2010-2014 and 2010 – 2029" of NWPCC 6th Power Plan Appendix E as follows:

| Distribution Sector | MWa by 2014 | MWa by 2029 | |
|---|---|---|---|
| Reduced system voltage | 47 | 160 | Reduce system voltage w/LDC voltage control method |
| Light system improvements | 8 | 80 | VAR management, phase load balancing, and feeder load balancing |
| Major system improvements | 9 | 90 | Voltage regulators on 1 of 4 substations |
| Voltage control | 4 | 40 | End of Line (EOL) voltage control method |
| Unique system improvements | 5 | 30 | Seattle City Light system implements EOL w/ major system improvements |
| All Distribution Efficiency Measures | 72 | 400 | |
| | | | |
| **Total for All Sectors** | **1308** | **5740** | |
| | 5.5% | 7.0% | |

# Appendix 2: Secondary System Voltage Drop Considerations

# Secondary System Voltage Drop Considerations

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April 22, 2011 (v8)

Generally, most secondary systems are radial-designed except for specific service areas (downtown areas, business districts, and some military and hospital installations) where reliability considerations are far more important than cost and economic considerations. The secondary radial systems include distribution transformers, secondary main conductors, and service conductors. The secondary facilities can be overhead or underground. The secondary design (size of transformer, secondary conductor, and services) objective is to minimize costs while still meeting the Utility's standard guidelines.

The goal for each secondary design is to provide satisfactory performance for voltage-drop (i.e., less than 5%) at minimum costs. There is a variety of system designs for one distribution transformer; some serve only one customer having only one span of conductor, while others serve six to 10 customers with multiple secondary connections. In the practice some voltage-drops maximums exceed design objectives (i.e. greater than 5%). The following provides a methodology describing how to estimate the number of potential secondary connections that many have voltage drops greater than any design guideline (i.e., greater than 4%). This information will help determine the impact of lowering the distribution voltage.

The ANSI C84.1 defines the maximum and minimum voltage favorable zone for service entrance voltage. In addition, the voltage level for a tolerable zone is provided. The favorable zone includes the majority of the existing operating voltages, and the voltages within this zone (i.e. Range A) provide satisfactory operation of the customer's equipment. PacifiCorp, in Section 3.3.1.1 Service Voltage of its Planning Standards for Voltage, states: "PacifiCorp's supply systems are to be designed and operated so that most service voltage levels are within the limits specified for Range A. The occurrence of service voltage outside of these limits is to be infrequent." This is consistent with how most electric utilities plan and operate their electric systems.

*Customer Coincident Loading - Considerations*

The utility voltage guidelines are applied to a large range of customer connection possibilities. As more customers are served by one transformer, the individual customer maximum loading coincident with the system load becomes less. Utilities periodically evaluate customer coincident loading patterns by conducting sample Load Surveys. Customer loading patterns can vary greatly between utilities depending on the climate zone, saturation electric heat and air-conditioning, and number of customers connected to a secondary system. For an example, see the load data example below.

| | | 30 min annual maximum diversified demands kVA per customer | | |
|---|---|---|---|---|
| No of customers being served from one transformer | *CF* | Class 1 | Class 2 | Class 3 |
| 1 | 1.0000 | 18.0 | 10 | 2.5 |
| 2 | 0.7500 | 13.5 | 7.5 | 1.9 |
| 4 | 0.6250 | 11.3 | 6.3 | 1.6 |
| 12 | 0.5416 | 9.7 | 5.4 | 1.4 |

Reference Turan Gönen, "Electric Power Distribution System Engineering" Dec 2007

As the number of customers served by a transformer or secondary conductor increases, the effective load impact on capacity requirement is decreased. The duration of sustained peak can also vary among utilities. The coincident factor (CF) is determined at each level of the distribution system and is a function of the total system coincidence and the number of similar loads. The average maximum diversified demand (AMDD) for any level is determined by multiplying the average maximum demand (AMD) for customers or components by *CF*. The coincident factor formulation used to determine the impact of customer or component loads on the next higher level in the distribution system where *N* is the number of parallel components given below. A typical formulation assumes that the total system coincidence is $CF_{\mathrm{TOTAL}} = 0.50$ "IEEE Standard 141(TM)-1993, *IEEE Recommended Practice for Electric Power Distribution for Industrial Plants*, Red Book."

$$CF_N = CF_{TOTAL} \cdot \left[1 + \frac{1}{N}\right] \qquad \text{Eq 1}$$

The typical distribution secondary system design voltage drop across the secondary system is highest during customer peak loading periods. If distribution system modeling includes secondary modeling, the voltage drop is the absolute difference between the voltage magnitude on the high side of the distribution transformer minus the voltage at the lowest voltage customer. It is not the arithmetic sum of the transformer voltage drop and the secondary conductor voltage drop. The voltage drop determination requires the use of coincident factors applied at each level of system equipment to determine the maximum diversified voltage drop.

It is very unlikely that the transformer's customer coincident peak load will be sustained for 30 minutes or longer and occur at the same time as the system peak primary voltage. Customers have peak demand at different times, and this is why capacity and voltage drops are calculated by taking coincidence factors into account. Coincident factors and typical customer load patterns are typically obtained from residential load surveys.

*Secondary Voltage Drop Normal Distribution - Example*

As shown, the determination of expected voltage drops for the secondary systems involves a variety of random variables (i.e., number of customer connected to one transformer, common service connections, maximum non diversified customer loads, coincidence probabilities, and physical design attributes.) These variables suggest a random distribution of coincidental secondary voltage drops. For example, given maximum voltage drop constraint of 5% or 6 Volts, the diversified average voltage drop across a large number of transformer populations may be only 2.5% while the maximum voltage drop observed may be greater than 5%.

The following is a real world example of secondary voltage drops on one feeder for a distribution Blackman Hurst feeder in Jackson, MI. Coincidental hourly peak load data for the secondary systems was collected from customer AMR data an assigned to end-use nodes on a distribution feeder model. The peak hourly voltage drops for customers on the secondary system across the feeder illustrates the random nature of the secondary system peak voltage drops during peak load conditions. Load Flow simulations were performed and included the modeling of distribution transformers, secondary conductors, service conductors, and spot coincident customer loads. There are 727 customers served by 418 distribution transformers/secondary systems. The peak hourly load flow analysis included determination of the secondary system voltage drop. Figure 1 shows the probability distribution for transformer/secondary voltage drops during peak conditions as determined from the load flow simulations. The mean secondary voltage drop at peak hourly conditions is 1.9% (2.3V) with a Std. Dev. of 2.2%. There are 33 (7.9%) transformer/secondary systems that have voltage drops greater than 5.0% (6.0V). There are 42 (10.0%) transformers with voltage drops greater than 4.2% (5.0V) needed to maintain 114V service voltage if the primary voltage is 119V. The maximum voltage drop is 15.0% or 18.0V.

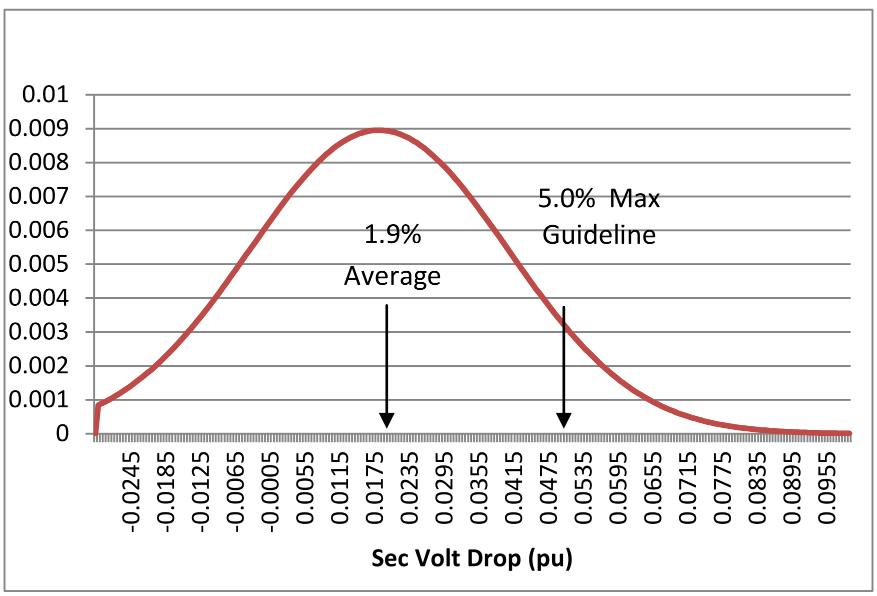



**Figure 1 - Distribution transformer/secondary max voltage drops**

The secondary systems seen in this example are heavily loaded with an average distribution transformer utilization of 220% of rated kVA at peak load conditions. This example illustrates poorly managed and designed secondary systems. The secondary voltage drop probability distribution will vary among utilities depending on their secondary design practices.

In addition to evaluating maximum secondary voltage drops for the example feeder, the load flow assessment also determined the secondary low voltages during peak load conditions. The minimum primary voltage is 119.8 Volts. There are 24 transformer/secondary installations that have customer service voltages less than 114V at peak loading conditions. Figure 2 shows a scatter diagram that illustrates the number of transformer/secondary systems that are below 114V. The average is service voltage is 118.8V. The minimum voltage is 103.0V during peak conditions. These customer low voltages are included as part of the 33 secondary systems having greater than 5% voltage drop at peak conditions.

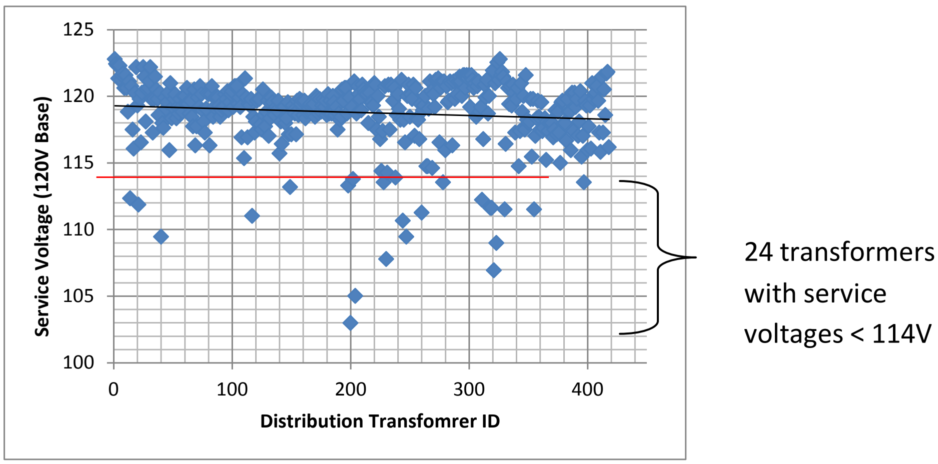



**Figure 2 - Lowest service voltage for each distribution transformer/secondary**

The example feeder illustrates the random nature of secondary system voltage performance during peak load conditions and that it closely resembles a Normal Distribution.

*Normal Distribution Probability Function – Basics*

The Normal Distribution function is defined as

$$f(X) = \frac{1}{\sigma \cdot \sqrt{2\pi}} \cdot e^{-\frac{1}{2}\left(\frac{x-\sigma}{\sigma}\right)^2}$$

Where,

σ = Std Dev and x = variable.

Given σ, the plot of f(X) is a bell shaped curve similar to the curve shown in Figure 1. The total area under the curve represents 100% probability. The probability of an event occurring between

$X_1$ and $X_2$ is the area under the Normal Distribution curve from $X_1$ and $X_2$ given σ. The values of $X$ can be converted to a Z Score which is the number of σ separation from the Mean $\overline{X}$. The Normal Distribution function is symmetrical allowing the calculation of probability by using the $Z$ Score Table 1. The probability for the positive half of the distribution function where the $\overline{X}$ is zero is 0.50 or 50%. The probability of having a value of $X < 1.88\ \sigma$ is 0.5000 + 0.4699 = 0.9699 or 97.0%. The probability of having $X > 1.88\ \sigma$ is 3.0%.

*Secondary Voltage Drop Normal Distribution –Feeder Example*

Consider a feeder with 1000 customers served from 150 transformers (6.7 customers per transformer) with 120 Volts on the high-side of each distribution transformer. The distribution system is better designed, monitored, and maintained than the example given above. This feeder example shows the probability of the number of customers (or transformers) that are likely to have voltage drops greater than 5Volt (4.167%) when the primary voltage is lowered by 1 Volt from 121V to 120V. It is assumed for secondary systems that there are few customers with maximum secondary voltages drops greater than the 5% or 6 Volts limit. Customers who exceed 5% are assumed to have lower than 114 Volts at their service.

Although it is unlikely that there are any customers with greater than 5% voltage drop, it is assumed here that **3%** or 30 customers (4.5 transformers) have maximum voltages greater than 5% limit. The average maximum voltage drop is assumed to be **2.5%** based on the field experience example give above. The value of $Z$ that yields 97% probability or 0.5000 + 0.4700 is $Z$=1.88. If $\overline{X}$ =2.5% and upper limit is $X_1$=5.0%, then $\sigma = (X_1 - \overline{X}) / Z$ = **1.335%**.

Given the assumptions above, if the design limit is reduced to 4.167% or 5 Volts, the probability of customers having maximum voltage drops greater than the 4.167% limit is determined with σ =1.335%, $\overline{X}$ =2.5%, and upper limit $X_2$=4.167%, then $Z = [(X_2 - \overline{X}) / \sigma] = 1.25$. Entering this value into the $Z$ Score Table yields a probability of 0.5000+0.3944 or 89.44% of customer with less than 4.167% voltage drop. The number of customers having greater than 4.167% voltage drop is 100% – 89.4% or 10.6%. Therefore, the number of customers having greater than 4.167% voltage drop is 106 (or 15.9 transformers).

The true impact is much less than 15.9 transformer secondary systems having service voltages less than 114V because not all of the high-side transformer voltages are at 119 Volts. The number of transformers impacted can therefore be assumed to be 50% or 8 transformers.

Given the assumptions above, if the design limit is reduced to 119.0V, the maximum secondary voltage drop 3.33% or 4 Volts. The probability of customers having maximum voltage drops greater than the 3.33% limit is determined with σ =1.335%, $\overline{X}$ =2.5%, and upper limit $X_2$=3.333%, then $Z = [(X_2 - \overline{X}) / \sigma] = 0.62$. Entering this value into the $Z$ Score Table yields a probability of 0.5000+0.2324 or 73.24% of customer with less than 3.33% voltage drop. The number of customers having greater than 3.33% voltage drop is 100% – 73.24% or 26.8%.

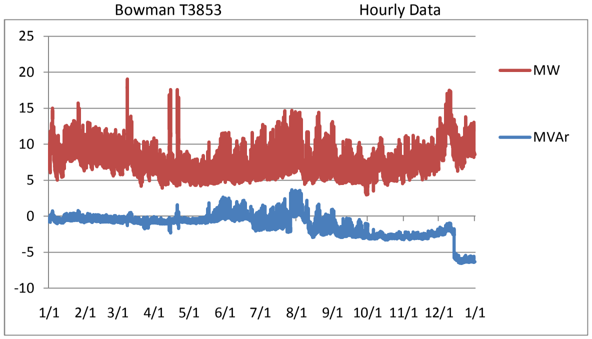
## Table 1 - Normal Distribution Z Score

| Probability Area from central to Z Score (Z = # of Std. Dev. mean) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Z** | **0.00** | **0.01** | **0.02** | **0.03** | **0.04** | **0.05** | **0.06** | **0.07** | **0.08** | **0.09** |
| **0.0** | 0.0000 | 0.0040 | 0.0080 | 0.0120 | 0.0160 | 0.0199 | 0.0239 | 0.0279 | 0.0319 | 0.0359 |
| **0.1** | 0.0398 | 0.0438 | 0.0478 | 0.0517 | 0.0557 | 0.0596 | 0.0636 | 0.0675 | 0.0714 | 0.0753 |
| **0.2** | 0.0793 | 0.0832 | 0.0871 | 0.0910 | 0.0948 | 0.0987 | 0.1026 | 0.1064 | 0.1103 | 0.1141 |
| **0.3** | 0.1179 | 0.1217 | 0.1255 | 0.1293 | 0.1331 | 0.1368 | 0.1406 | 0.1443 | 0.1480 | 0.1517 |
| **0.4** | 0.1554 | 0.1591 | 0.1628 | 0.1664 | 0.1700 | 0.1736 | 0.1772 | 0.1808 | 0.1844 | 0.1879 |
| **0.5** | 0.1915 | 0.1950 | 0.1985 | 0.2019 | 0.2054 | 0.2088 | 0.2123 | 0.2157 | 0.2190 | 0.2224 |
| **0.6** | 0.2257 | 0.2291 | 0.2324 | 0.2357 | 0.2389 | 0.2422 | 0.2454 | 0.2486 | 0.2517 | 0.2549 |
| **0.7** | 0.2580 | 0.2611 | 0.2642 | 0.2673 | 0.2704 | 0.2734 | 0.2764 | 0.2794 | 0.2823 | 0.2852 |
| **0.8** | 0.2881 | 0.2910 | 0.2939 | 0.2967 | 0.2995 | 0.3023 | 0.3051 | 0.3078 | 0.3106 | 0.3133 |
| **0.9** | 0.3159 | 0.3186 | 0.3212 | 0.3238 | 0.3264 | 0.3289 | 0.3315 | 0.3340 | 0.3365 | 0.3389 |
| **1.0** | 0.3413 | 0.3438 | 0.3461 | 0.3485 | 0.3508 | 0.3531 | 0.3554 | 0.3577 | 0.3599 | 0.3621 |
| **1.1** | 0.3643 | 0.3665 | 0.3686 | 0.3708 | 0.3729 | 0.3749 | 0.3770 | 0.3790 | 0.3810 | 0.3830 |
| **1.2** | 0.3849 | 0.3869 | 0.3888 | 0.3907 | 0.3925 | 0.3944 | 0.3962 | 0.3980 | 0.3997 | 0.4015 |
| **1.3** | 0.4032 | 0.4049 | 0.4066 | 0.4082 | 0.4099 | 0.4115 | 0.4131 | 0.4147 | 0.4162 | 0.4177 |
| **1.4** | 0.4192 | 0.4207 | 0.4222 | 0.4236 | 0.4251 | 0.4265 | 0.4279 | 0.4292 | 0.4306 | 0.4319 |
| **1.5** | 0.4332 | 0.4345 | 0.4357 | 0.4370 | 0.4382 | 0.4394 | 0.4406 | 0.4418 | 0.4429 | 0.4441 |
| **1.6** | 0.4452 | 0.4463 | 0.4474 | 0.4484 | 0.4495 | 0.4505 | 0.4515 | 0.4525 | 0.4535 | 0.4545 |
| **1.7** | 0.4554 | 0.4564 | 0.4573 | 0.4582 | 0.4591 | 0.4599 | 0.4608 | 0.4616 | 0.4625 | 0.4633 |
| **1.8** | 0.4641 | 0.4649 | 0.4656 | 0.4664 | 0.4671 | 0.4678 | 0.4686 | 0.4693 | 0.4699 | 0.4706 |
| **1.9** | 0.4713 | 0.4719 | 0.4726 | 0.4732 | 0.4738 | 0.4744 | 0.4750 | 0.4756 | 0.4761 | 0.4767 |
| **2.0** | 0.4772 | 0.4778 | 0.4783 | 0.4788 | 0.4793 | 0.4798 | 0.4803 | 0.4808 | 0.4812 | 0.4817 |
| **2.1** | 0.4821 | 0.4826 | 0.4830 | 0.4834 | 0.4838 | 0.4842 | 0.4846 | 0.4850 | 0.4854 | 0.4857 |
| **2.2** | 0.4861 | 0.4864 | 0.4868 | 0.4871 | 0.4875 | 0.4878 | 0.4881 | 0.4884 | 0.4887 | 0.4890 |
| **2.3** | 0.4893 | 0.4896 | 0.4898 | 0.4901 | 0.4904 | 0.4906 | 0.4909 | 0.4911 | 0.4913 | 0.4916 |
| **2.4** | 0.4918 | 0.4920 | 0.4922 | 0.4925 | 0.4927 | 0.4929 | 0.4931 | 0.4932 | 0.4934 | 0.4936 |
| **2.5** | 0.4938 | 0.4940 | 0.4941 | 0.4943 | 0.4945 | 0.4946 | 0.4948 | 0.4949 | 0.4951 | 0.4952 |
| **2.6** | 0.4953 | 0.4955 | 0.4956 | 0.4957 | 0.4959 | 0.4960 | 0.4961 | 0.4962 | 0.4963 | 0.4964 |
| **2.7** | 0.4965 | 0.4966 | 0.4967 | 0.4968 | 0.4969 | 0.4970 | 0.4971 | 0.4972 | 0.4973 | 0.4974 |
| **2.8** | 0.4974 | 0.4975 | 0.4976 | 0.4977 | 0.4977 | 0.4978 | 0.4979 | 0.4979 | 0.4980 | 0.4981 |
| **2.9** | 0.4981 | 0.4982 | 0.4982 | 0.4983 | 0.4984 | 0.4984 | 0.4985 | 0.4985 | 0.4986 | 0.4986 |
| **3.0** | 0.4987 | 0.4987 | 0.4987 | 0.4988 | 0.4988 | 0.4989 | 0.4989 | 0.4989 | 0.4990 | 0.4990 |

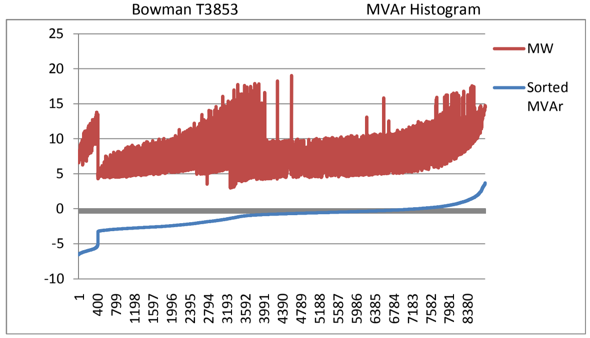
# Appendix 3:  Histograms

**Bowman Area Load Models Based On**
**Transformer Hourly Data and Annual Histograms for 2009**

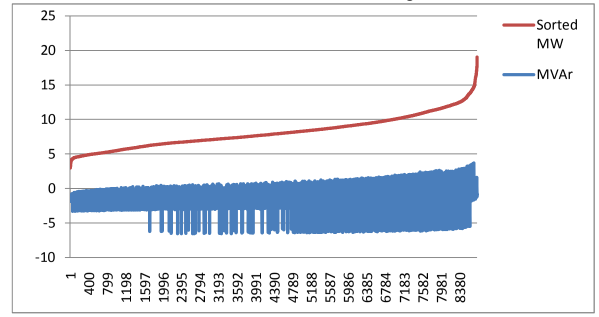
Bowman T3853 Hourly Data




Bowman T3853 MVAr Histogram




Bowman T3853 MW Histogram



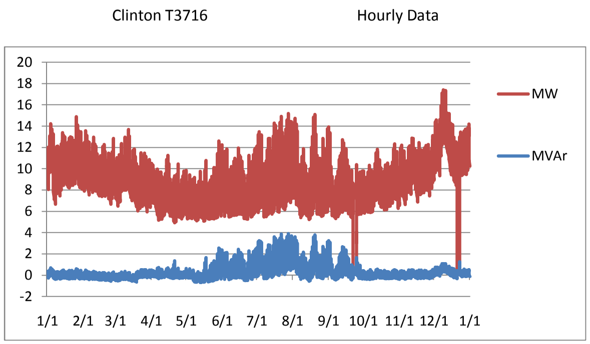

| | Connected kVA | |
|---|---|---|
| 5W150 | 23831.0 | 49.23% |
| 5W154 | 24580.5 | 50.77% |
| | 48411.5 | |

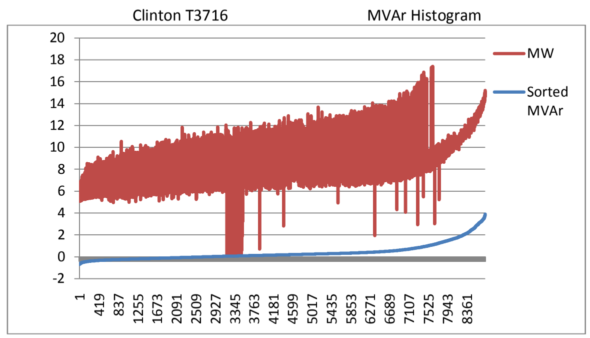
| | | Adj |
|---|---|---|
| | Q05 | Q05 |
| 5W150 | (1,575) | (856) |
| 5W154 | (1,625) | (2,027) |
| | (3,200) | (2,883) |
| | | 4800 |
| | | 1,917 |

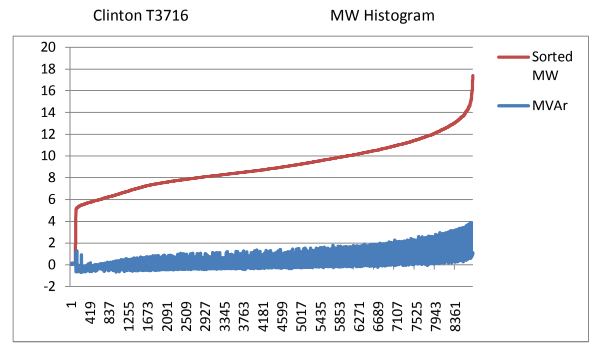
| Heavy Load Model | |
|---|---|
| Summer Peak Model | Q95 |
| 6,760 | 1,080 |
| 8,200 | (30) |
| | 1,050 |
| | 4800 |
| | 5,850 |

| | Light Load Model | | | |
|---|---|---|---|---|
| | P05 | Q05 | P95 | Winter Peak |
| 5W150 | 2,433 | (856) | 6,058 | 8,720 |
| 5W154 | 2,510 | (2,027) | 6,248 | 9,280 |
| | 4,943 | | 12,306 | |

**Clinton Area Load Models Based On**
**Transformer Hourly Data and Annual Histograms for 2009**




| | Connected kVA | |
|---|---|---|
| 5Y608 | 22603.5 | 52.97% |
| 5Y610 | 20066.0 | 47.03% |
| | 42669.5 | |

**Heavy Load Model**

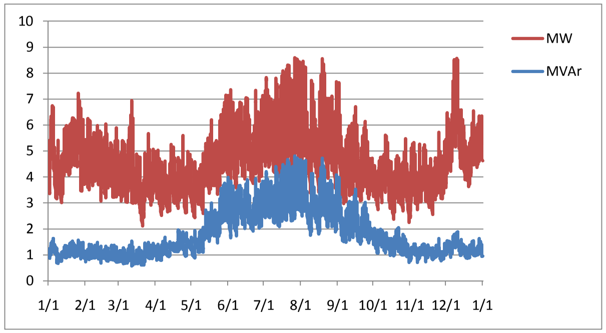
| | Q05 | Summer Peak Model | Q95 |
|---|---|---|---|
| 5Y608 | (68) | 8,200 | 1,200 |
| 5Y610 | (262) | 9,250 | 863 |
| | (330) | | 2,063 |
| | 3600 | | 3600 |
| | 3,270 | | 5,663 |

**Light Load Model**

| | P05 | Q05 | P95 | Winter Peak |
|---|---|---|---|---|
| 5Y608 | 3,050 | (68) | 6,839 | 10,400 |
| 5Y610 | 2,707 | (262) | 6,072 | 8,400 |
| | 5,757 | | 12,911 | |

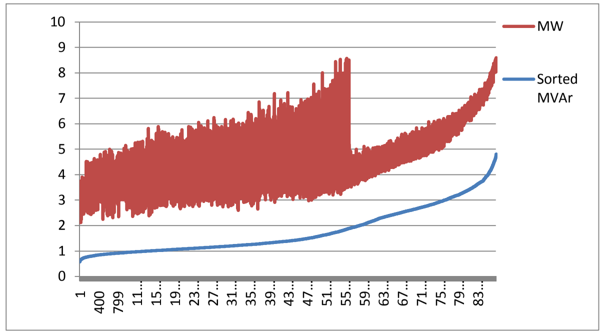
**Dodd Road Area Load Models Based On**
**Transformer Hourly Data and Annual Histograms for 2009**

Dodd Road T1202 Hourly Data



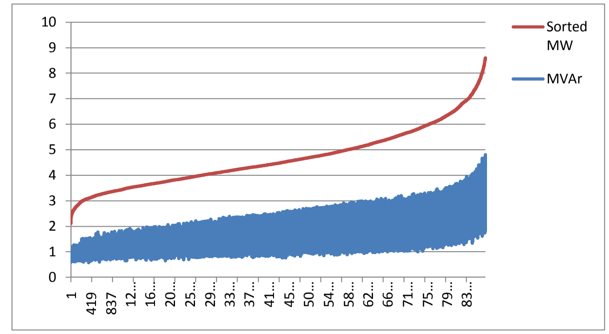

| | Connected kVA | |
|---|---|---|
| 4W22 | 29034.5 | 100.00% |

Dodd Road T1202 MVAr Histogram




| | Q05 | Heavy Load Model Summer Peak Model | Heavy Load Model Q95 |
|---|---|---|---|
| 4W22 | 855 | 8,700 | 3,552 |

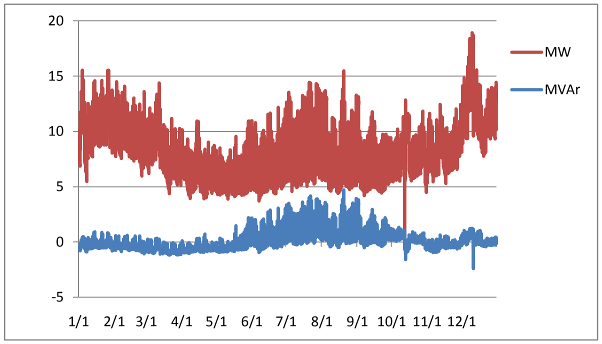
Dodd Road T1202 MW Histogram




| | Light Load Model P05 | Light Load Model Q05 | P95 | Winter Peak |
|---|---|---|---|---|
| 4W22 | 6,236 | 855 | 16,907 | 9,000 |

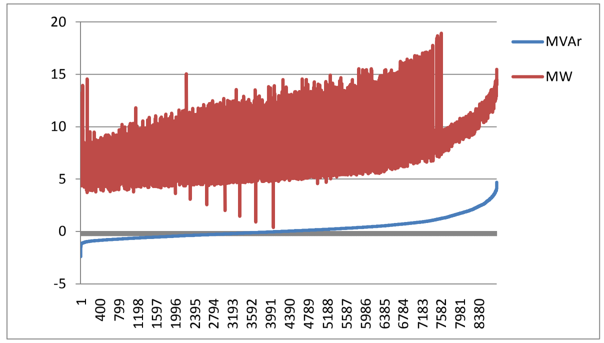
**Grandview Area Load Models Based On**
**Transformer Hourly Data and Annual Histograms for 2009**

Grandview T859 — Hourly Data



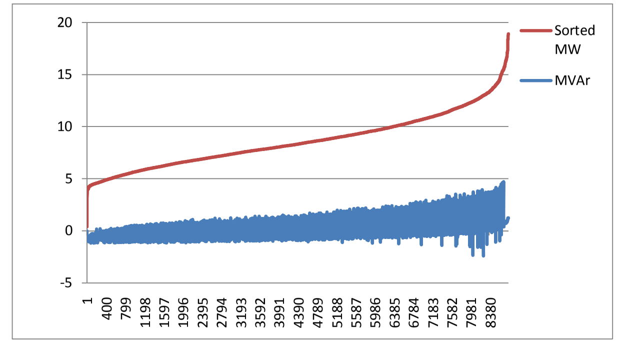

| | Connected kVA | |
|---|---|---|
| 5Y351 | 19929.8 | 43.94% |
| 5Y302 | 25422.5 | 56.06% |
| | 45352.3 | |

Grandview T859 — MVAr Histogram




| | Q05 | Summer Peak Model | Q95 |
|---|---|---|---|
| 5Y351 | (367) | 7700 | 996 |
| 5Y302 | (468) | 7440 | 1,271 |
| | (834) | | 2,267 |

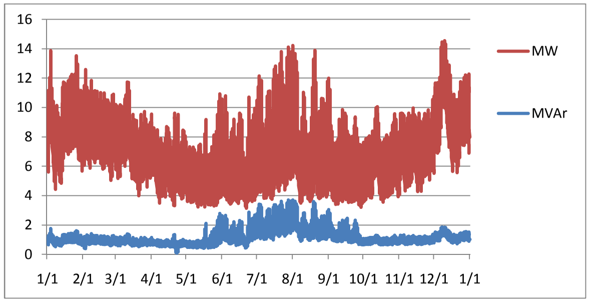
Grandview T859 — MW Histogram




| | P05 | Light Load Model | P95 | Winter Peak |
|---|---|---|---|---|
| 5Y351 | 2,171 | (367) | 5,806 | 8,900 |
| 5Y302 | 2,770 | (468) | 7,406 | 10,640 |
| | 4,941 | | 13,211 | |

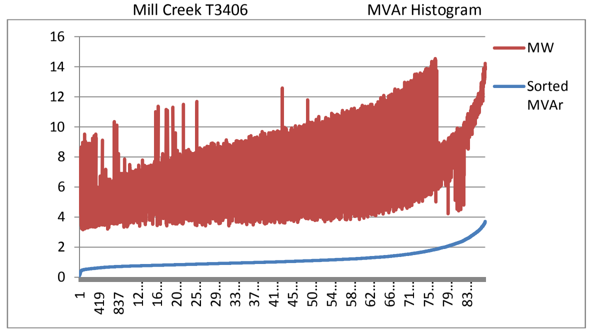
**Mill Creek Area Load Models Based On**
**Transformer Hourly Data and Annual Histograms for 2009**

Mill Creek T3406 Hourly Data



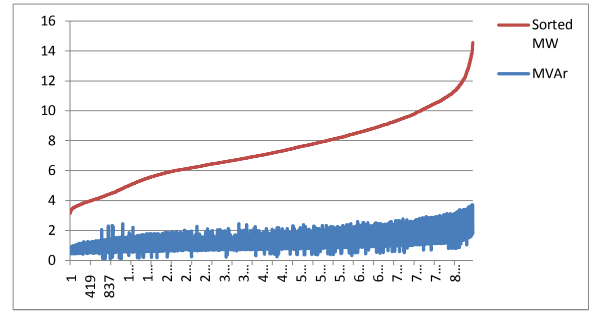

| | Connected kVA | |
|---|---|---|
| 5W116 | 17726.0 | 53.99% |
| 5W127 | 15105.0 | 46.01% |
| | 32831.0 | |

Mill Creek T3406 MVAr Histogram



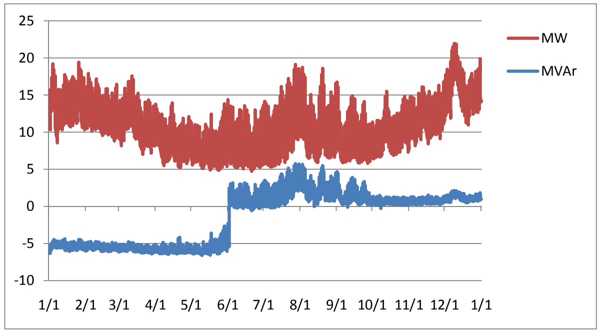

| | Q05 | Heavy Load Model Summer Peak Model | Q95 |
|---|---|---|---|
| 5W116 | 60 | 8,100 | 1,068 |
| 5W127 | 562 | 6,220 | 1,421 |
| | 622 | | 2,489 |
| | 600 | | 600 |
| | 1,222 | | 3,089 |

Mill Creek T3406 MW Histogram



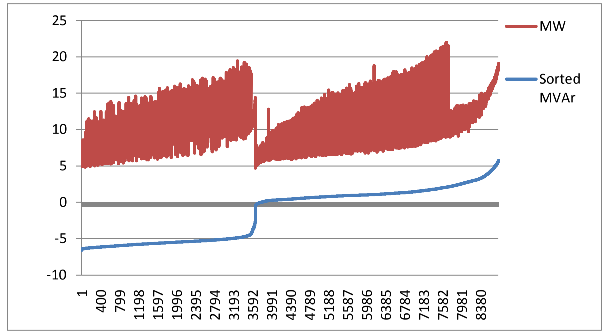

| | Light Load Model P05 | Q05 | P95 | Winter Peak |
|---|---|---|---|---|
| 5W116 | 2,148 | 60 | 6,049 | 7,750 |
| 5W127 | 1,830 | 562 | 5,154 | 7,120 |
| | 3,978 | | 11,203 | |

Nob Hill T2430 Hourly Data



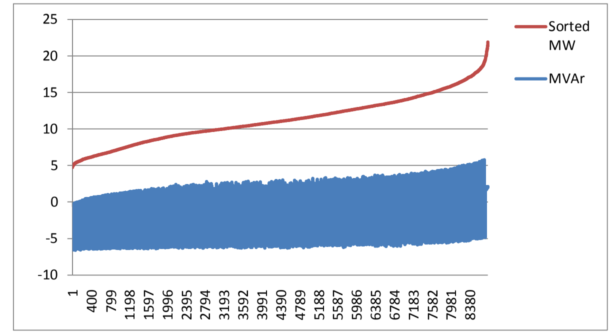

| | Connected kVA | |
|---|---|---|
| 5Y197 | 12613.5 | 26.07% |
| 5Y272 | 14398.0 | 29.75% |
| 5Y338 | 21380.5 | 44.18% |
| | 48392.0 | |

Nob Hill T2430 MVAr Histogram



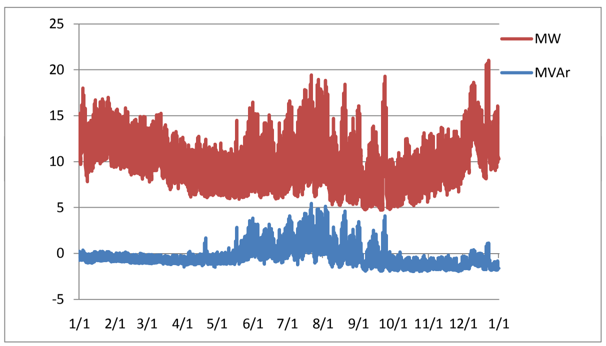

| | Q05 | Adj. Q05 | Heavy Load Model Sum Pk | Heavy Load Model Q95 |
|---|---|---|---|---|
| 5Y197 | (1,599) | 397 | 5,900 | 1,130 |
| 5Y272 | (1,826) | (147) | 5,500 | 690 |
| 5Y338 | (2,711) | 73 | 7,750 | 1,315 |
| | (6,136) | 323 | | 3,135 |
| | | 1200 | | 1200 |
| | | 1,523 | | 4,335 |

Nob Hill T2430 MW Histogram



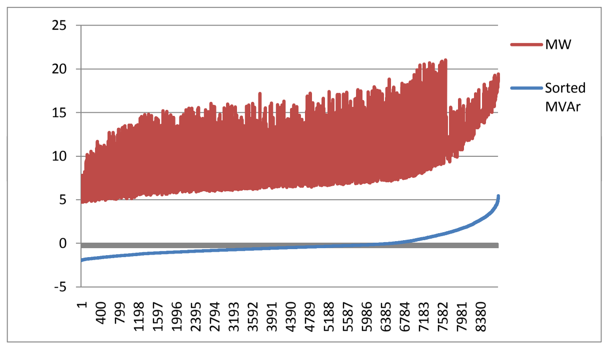

| | Light Load Model P05 | Light Load Model Q05 | P95 | Winter Peak |
|---|---|---|---|---|
| 5Y197 | 1,625 | 397 | 4,407 | 7,000 |
| 5Y272 | 1,855 | (147) | 5,030 | 8,400 |
| 5Y338 | 2,755 | 73 | 7,470 | 8,700 |
| | 6,236 | | 16,907 | |

Nob Hill T2402 Hourly Data



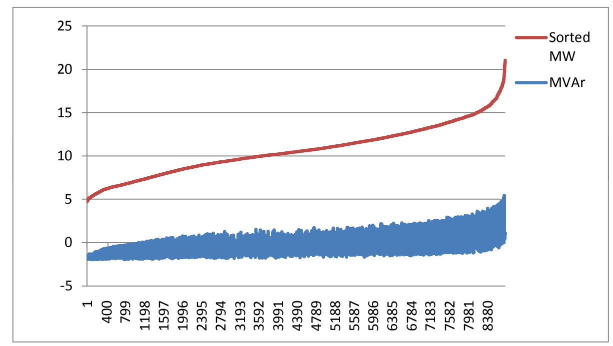

| | Connected kVA | |
|---|---|---|
| 5Y194 | 19095.5 | 43.46% |
| 5Y195 | 8463.0 | 19.26% |
| 5Y273 | 16377.52 | 37.28% |
| | 43936.0 | |

Nob Hill T2402 MVAr Histogram




| | Q05 | Heavy Load Model Summer Peak Model | Heavy Load Model Q95 |
|---|---|---|---|
| 5Y194 | (263) | 8200 | 1,529 |
| 5Y195 | (451) | 3,920 | 343 |
| 5Y273 | (911) | 8080 | 626 |
| | (1,624) | | 2,497 |
| | 2400 | | 2400 |
| | 776 | | 4,897 |

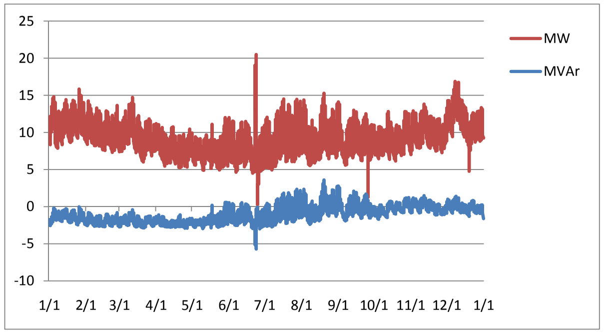
Nob Hill T2402 MW Histogram



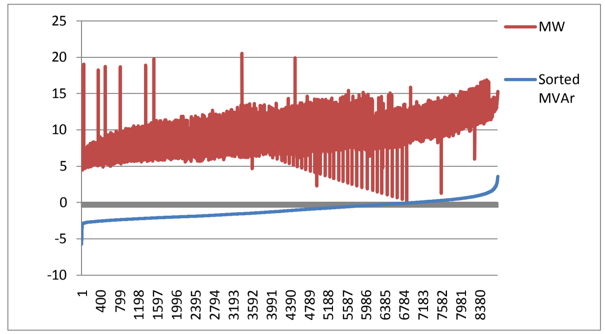

| | Light Load Model P05 | Light Load Model Q05 | P95 | Winter Peak |
|---|---|---|---|---|
| 5Y194 | 2,710 | (263) | 7,348 | 7,400 |
| 5Y195 | 1,201 | (451) | 3,257 | 3,560 |
| 5Y273 | 2,324 | (911) | 6,302 | 8,120 |
| | 6,237 | | 15,436 | |

**North Park Area Load Models Based On**
**Transformer Hourly Data and Annual Histograms for 2009**

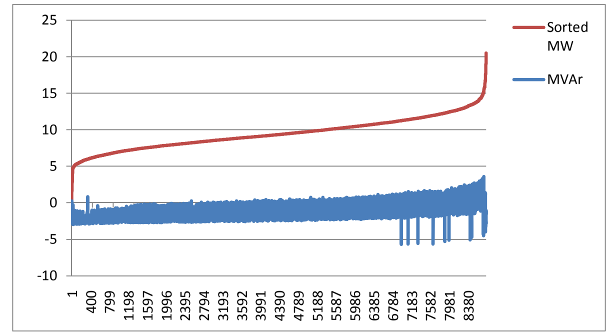
North Park T3536 Hourly Data




North Park T3536 MVAr Histogram




North Park T3536 MW Histogram



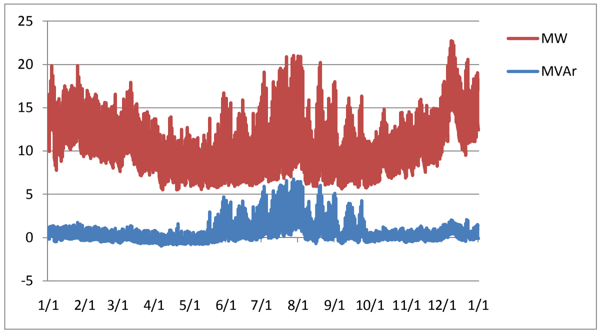

| | Connected kVA | |
|---|---|---|
| 5Y356 | 20180.0 | 40.46% |
| 5Y398 | 29702.51 | 59.54% |
| | 49882.5 | |

| | Q05 | Heavy Load Model: Summer Peak Model | Heavy Load Model: Q95 |
|---|---|---|---|
| 5Y356 | (1,433) | 6,800 | (43) |
| 5Y398 | (1,101) | 9,400 | 945 |
| | (2,533) | | 903 |
| | 2700 | | 2700 |
| | 167 | | 3,603 |

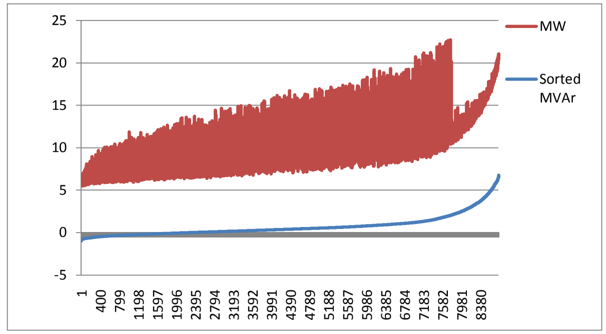
| | Light Load Model: P05 | Light Load Model: Q05 | P95 | Winter Peak |
|---|---|---|---|---|
| 5Y356 | 2,496 | (1,433) | 5,284 | 8,900 |
| 5Y398 | 3,674 | (1,101) | 7,777 | 10,200 |
| | 6,170 | | 13,061 | |

**Orchard Area Load Models Based On**
**Transformer Hourly Data and Annual Histograms for 2009**

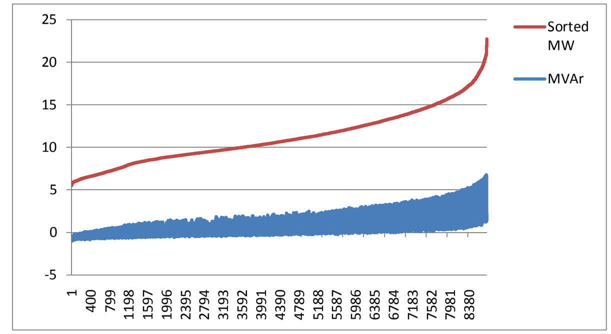
Orchard T5035 Hourly Data




Orchard T5035 MVAr Histogram




Orchard T5035 MW Histogram

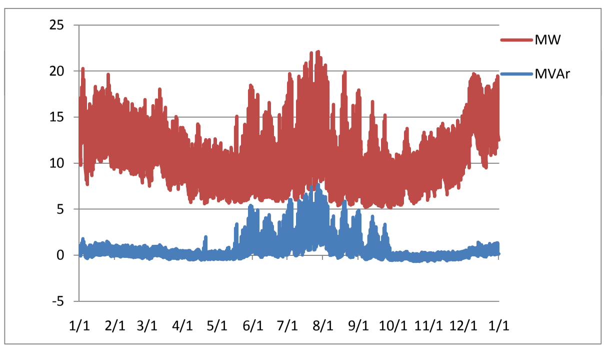



| | Connected kVA | |
|---|---|---|
| 5Y456 | 16682.0 | 27.75% |
| 5Y458 | 22817.5 | 37.96% |
| 5Y637 | 20613.0 | 34.29% |
| | 60112.5 | |

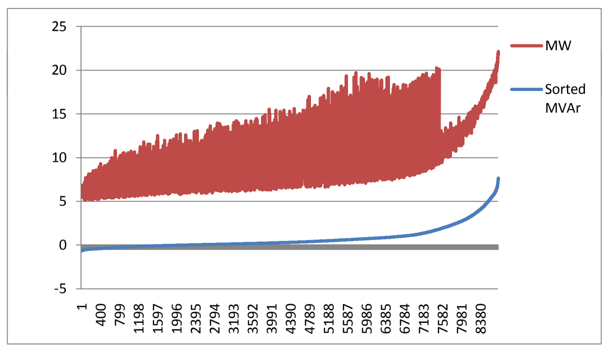
| | Q05 | Heavy Load Model: Summer Peak Model | Heavy Load Model: Q95 |
|---|---|---|---|
| 5Y456 | (327) | 7,300 | 772 |
| 5Y458 | (6) | 7,200 | 1,497 |
| 5Y637 | (121) | 7,600 | 1,236 |
| | (453) | | 3,504 |
| | 3,600 | | 3,600 |
| | 3,147 | | 7,104 |

| | Light Load Model: P05 | Light Load Model: Q05 | P95 | Winter Peak |
|---|---|---|---|---|
| 5Y456 | 1,837 | (327) | 4,711 | 6,700 |
| 5Y458 | 2,512 | (6) | 6,443 | 8,800 |
| 5Y637 | 2,270 | (121) | 5,821 | 8,440 |
| | 6,619 | | 16,975 | |

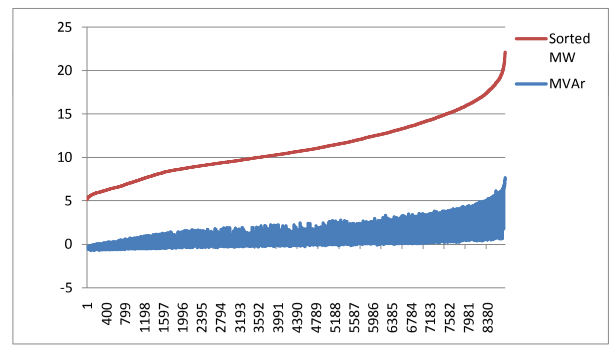
Orchard T3797 Hourly Data




Orchard T3797 MVAr Histogram




Orchard T3797 MW Histogram



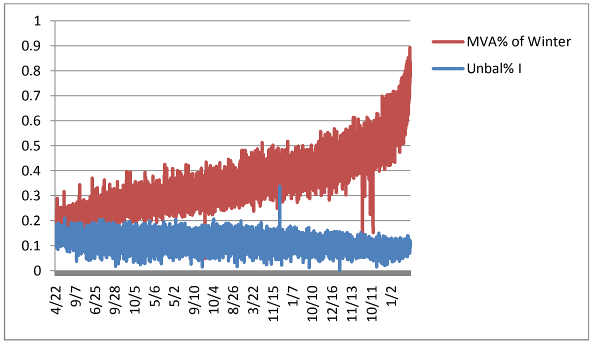

| | Connected kVA | |
|---|---|---|
| 5Y498 | 12638.0 | 22.98% |
| 5Y454 | 24210.0 | 44.02% |
| 5Y639 | 18148.5 | 33.00% |
| | 54996.6 | |

| | Q05 | Heavy Load Model: Summer Peak Model | Heavy Load Model: Q95 |
|---|---|---|---|
| 5Y498 | 188 | 6,280 | 1,150 |
| 5Y454 | (841) | 9,800 | 1,003 |
| 5Y639 | 269 | 7,720 | 1,651 |
| | (384) | | 3,803 |
| | 1200 | | 1200 |
| | 816 | | 5,003 |

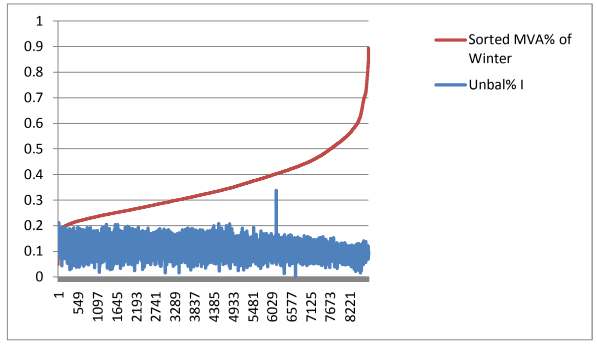
| | Light Load Model: P05 | Light Load Model: Q05 | P95 | Winter Peak |
|---|---|---|---|---|
| 5Y498 | 1,446 | 188 | 3,944 | 6,480 |
| 5Y454 | 2,769 | (841) | 7,555 | 10,000 |
| 5Y639 | 2,076 | 269 | 5,663 | 7,480 |
| | 6,291 | | 17,162 | |

**Pomeroy Area Load Models Based On**
**Transformer Hourly Data and Annual Histograms for 2009**

Pomeroy T944 Hourly Data




Pomeroy T944 MVA% of Winter Histogram




| | Connected kVA | |
|---|---|---|
| 5W342 | 16801.0 | 100.00% |

| | MVA05 | Heavy Load Model Winter Peak Model | | MVA05 |
|---|---|---|---|---|
| 5W342 | 1596 | 6,045 | (435) | 4330 |

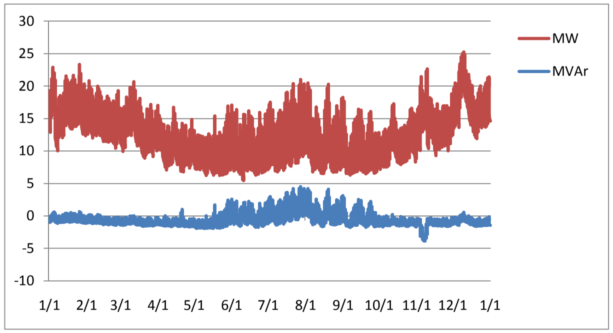
| | |
|---|---|
| Caps = | 600 |
| Load kVAr HL = | 165 |
| 1596 / 7498 = | 0.2640 |
| Load kVAr LL = | 44 |
| Caps = | (600) |
| | (556) |

| | Light Load Model kW * | KVAr * | Summer Peak kW | KVAr |
|---|---|---|---|---|
| 5W342 | 1596 | (556) | 3,538 | 254 |

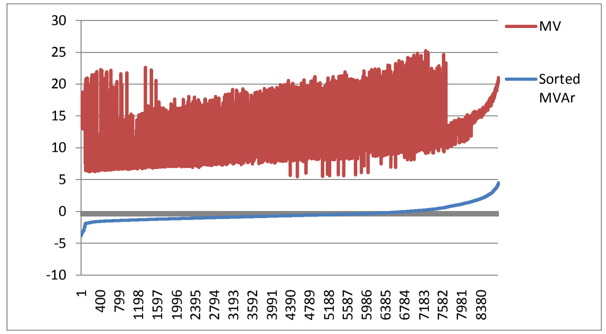
* Light Load kW=Winter Load x MVA05
and KVAr * at same power factor as Winter Load

**River Road Area Load Models Based On**
**Transformer Hourly Data and Annual Histograms for 2009**

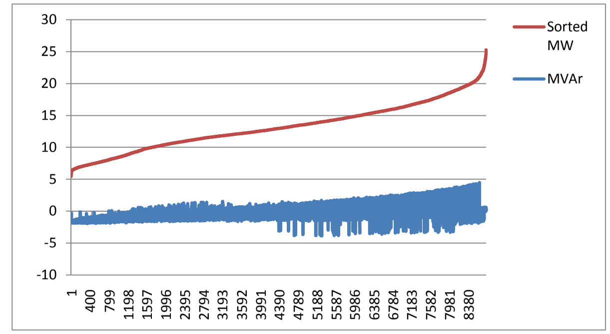
River Road T3453 Hourly Data




River Road T3453 MVAr Histogram




River Road T3453 MW Histogram



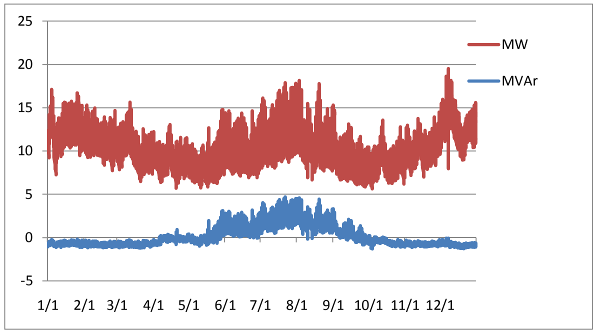

| | Connected kVA | |
|---|---|---|
| 5Y444 | 25987.0 | 44.91% |
| 5Y446 | 11730.5 | 20.27% |
| 5Y448 | 20141.0 | 34.81% |
| | 57858.5 | |

| | Q05 | Heavy Load Model Sum Pk | Heavy Load Model Q95 |
|---|---|---|---|
| 5Y444 | (786) | 10,600 | 727 |
| 5Y446 | (249) | 6,600 | 434 |
| 5Y448 | (512) | 4,360 | 661 |
| | (1,547) | | 1,822 |
| | 1800 | | 1800 |
| | 253 | | 3,622 |

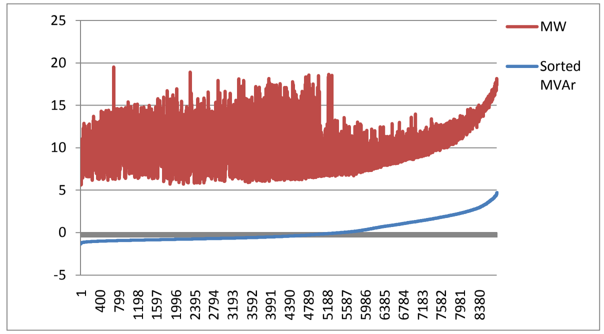
| | Light Load Model P05 | Light Load Model Q05 | P95 | Winter Peak |
|---|---|---|---|---|
| 5Y444 | 3,314 | (786) | 8,797 | 11,800 |
| 5Y446 | 1,496 | (249) | 3,971 | 9,900 |
| 5Y448 | 2,568 | (512) | 6,818 | 8,720 |
| | 7,378 | | 19,586 | |

**Sunnyside Area Load Models Based On**
**Transformer Hourly Data and Annual Histograms for 2009**

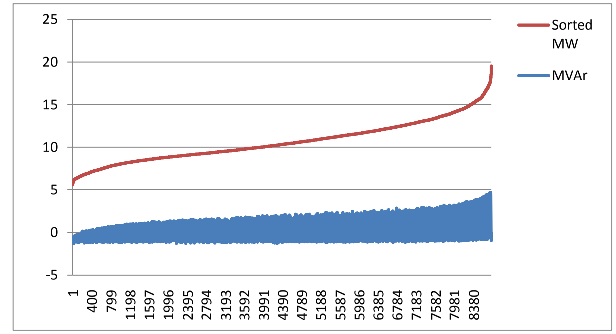
Sunnyside T3570 Hourly Data




Sunnyside T3570 MVAr Histogram




Sunnyside T3570 MW Histogram



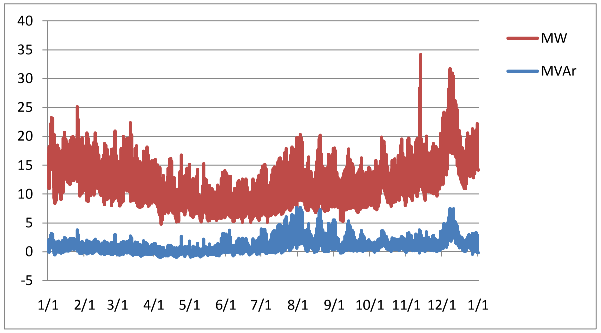

| | Connected kVA | |
|---|---|---|
| 5Y313 | 11258.9 | 22.01% |
| 5Y317 | 9096.5 | 17.79% |
| 5Y314 | 30786.7 | 60.20% |
| | 51142.1 | |

| | Q05 | Heavy Load Model Summer Peak | Heavy Load Model Q95 |
|---|---|---|---|
| 5Y313 | (220) | 4500 | 619 |
| 5Y317 | (178) | 4000 | 500 |
| 5Y314 | (601) | 9400 | 1,694 |
| | (998) | | 2,814 |

| | Light Load Model P05 | Light Load Model Q05 | P95 | Winter Peak |
|---|---|---|---|---|
| 5Y313 | 1,583 | (220) | 3,298 | 5,500 |
| 5Y317 | 1,279 | (178) | 2,664 | 4,600 |
| 5Y314 | 4,328 | (601) | 9,017 | 11,000 |
| | 7,190 | | 14,979 | |

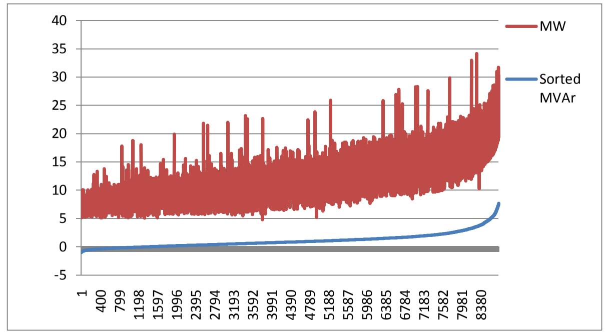
**Wiley Area Load Models Based On**
**Transformer Hourly Data and Annual Histograms for 2009**

Wiley T3676 Hourly Data



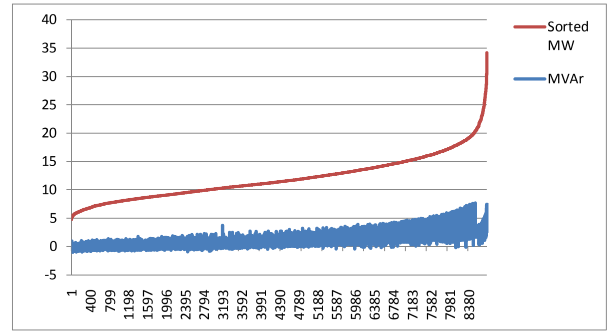

| | Connected kVA | |
|---|---|---|
| 5Y434 | 18624 | 23.55% |
| 5Y164 | 25936 | 32.80% |
| 5Y380 | 34519.49 | 43.65% |
| | 79079.5 | |

Wiley T3676 MVAr Histogram




| | Q05 | Heavy Load Model Sum Pk | Heavy Load Model Q95 |
|---|---|---|---|
| 5Y434 | 1,044 | 7,000 | 1,984 |
| 5Y164 | (646) | 5,900 | 663 |
| 5Y380 | (764) | 8,500 | 978 |
| | (365) | | 3,625 |
| | 4800 | | 4800 |
| | 4,435 | | 8,425 |

Wiley T3676 MW Histogram




| | Light Load Model P05 | Light Load Model Q05 | P95 | Winter Peak |
|---|---|---|---|---|
| 5Y434 | 1,642 | 1,044 | 4,421 | 7,800 |
| 5Y164 | 2,286 | (646) | 6,157 | 12,600 |
| 5Y380 | 3,043 | (764) | 8,194 | 9,600 |
| | 6,971 | | 18,772 | |

# Appendix 4: PacifiCorp Cost Estimating Spreadsheet and Crew Cost Information

| Description | UOM | Labor | Material | AFUDC |
|---|---|---|---|---|
| Primary Re-Conductor Urban 4/0 AAC Medium | feet | $ 41.09 | $ 41.84 | $ 10.37 |
| Primary Re-Conductor Urban 4/0 AAC Easy | feet | $ 27.22 | $ 25.65 | $ 6.61 |
| Primary Re-Conductor Urban 4/0 AAC Difficult | feet | $ 75.27 | $ 81.76 | $ 19.63 |
| Primary Re-Conductor Rural 4/0 AAC Medium | feet | $ 35.09 | $ 40.80 | $ 9.49 |
| Primary Re-Conductor Rural 4/0 AAC Easy | feet | $ 20.78 | $ 20.73 | $ 5.19 |
| Primary Re-Conductor Rural 4/0 AAC Difficult | feet | $ 64.59 | $ 78.31 | $ 17.86 |
| Primary Re-Conductor Urban 477 AAC Medium | feet | $ 44.24 | $ 45.33 | $ 11.20 |
| Primary Re-Conductor Urban 477 AAC Easy | feet | $ 28.73 | $ 28.89 | $ 7.20 |
| Primary Re-Conductor Urban 477 AAC Difficult | feet | $ 79.60 | $ 86.54 | $ 20.77 |
| Primary Re-Conductor Rural 477 AAC Medium | feet | $ 38.08 | $ 44.06 | $ 10.27 |
| Primary Re-Conductor Rural 477 AAC Easy | feet | $ 22.19 | $ 23.32 | $ 5.69 |
| Primary Re-Conductor Rural 477 AAC Difficult | feet | $ 68.89 | $ 82.81 | $ 18.96 |
| Primary Re-Conductor Urban 795 AAC Medium | feet | $ 54.93 | $ 51.97 | $ 13.36 |
| Primary Re-Conductor Urban 795 AAC Easy | feet | $ 38.40 | $ 34.29 | $ 9.09 |
| Primary Re-Conductor Urban 795 AAC Difficult | feet | $ 92.44 | $ 95.82 | $ 23.53 |
| Primary Re-Conductor Rural 795 AAC Medium | feet | $ 48.70 | $ 50.46 | $ 12.40 |
| Primary Re-Conductor Rural 795 AAC Easy | feet | $ 31.79 | $ 28.47 | $ 7.53 |
| Primary Re-Conductor Rural 795 AAC Difficult | feet | $ 81.67 | $ 91.77 | $ 21.68 |
| Primary Cable #2 Al 15 kV 1 Ph Medium In Conduit | feet | $ 23.67 | $ 36.70 | $ 7.55 |
| Primary Cable #2 Al 15 kV 1 Ph Easy In Conduit | feet | $ 18.55 | $ 36.70 | $ 6.91 |
| Primary Cable #2 Al 15 kV 1 Ph Difficult In Conduit | feet | $ 28.79 | $ 36.70 | $ 8.19 |
| Primary Cable 1/0 25 kV Medium In Conduit | feet | $ 19.88 | $ 33.07 | $ 6.62 |
| Primary Cable 1/0 25 kV Easy In Conduit | feet | $ 11.68 | $ 23.72 | $ 4.43 |
| Primary Cable 1/0 25 kV Difficult In Conduit | feet | $ 30.20 | $ 49.09 | $ 9.91 |
| Primary Cable 1000 Medium In Conduit | feet | $ 22.13 | $ 41.87 | $ 8.00 |
| Primary Cable 1000 Easy In Conduit | feet | $ 13.93 | $ 32.53 | $ 5.81 |
| Primary Cable 1000 Difficult In Conduit | feet | $ 32.45 | $ 57.90 | $ 11.29 |
| Primary Cable 4/0 Medium In Conduit | feet | $ 21.16 | $ 32.58 | $ 6.72 |
| Primary Cable 4/0 Easy In Conduit | feet | $ 12.97 | $ 23.23 | $ 4.53 |
| Primary Cable 4/0 Difficult In Conduit | feet | $ 31.49 | $ 48.60 | $ 10.01 |
| OH Switch-Unitized-Hookstick Operated 25 kV 600 A | each | $ 2,225.30 | $ 3,904.59 | $ 766.24 |
| Capacitor - Fixed 12000 V 600 kVar | each | $ 3,070.58 | $ 2,817.85 | $ 736.05 |
| Capacitor - Fixed 19920 V 600 kVar | each | $ 2,011.92 | $ 2,361.48 | $ 546.68 |
| Capacitor - Fixed 14400 V 900 kVar | each | $ 2,011.92 | $ 2,451.55 | $ 557.93 |
| Capacitor - Fixed 14400 V 600 kVar | each | $ 2,011.92 | $ 2,158.51 | $ 521.30 |
| Capacitor - Fixed 12000 V 1200 kVar | each | $ 3,070.58 | $ 3,610.71 | $ 835.16 |
| Capacitor - Fixed 12000 V 900 kVar | each | $ 3,070.58 | $ 2,687.98 | $ 719.82 |
| Capacitor - Fixed 7200 V 1200 kVar | each | $ 3,070.58 | $ 4,684.04 | $ 969.33 |
| Capacitor - Fixed 7200 V 600 kVar | each | $ 3,070.58 | $ 2,748.50 | $ 727.39 |
| Capacitor - Fixed 19920 V 900 kVar | each | $ 2,011.92 | $ 2,765.52 | $ 597.18 |
| Capacitor - Fixed 7200 V 900 kVar | each | $ 3,070.58 | $ 2,845.52 | $ 739.51 |
| Capacitor - Fixed 2400 V 150 kVar | each | $ 2,011.92 | $ 1,897.76 | $ 488.71 |
| Capacitor - Fixed 19920 V 1200 kVar | each | $ 2,011.92 | $ 2,765.52 | $ 597.18 |
| Capacitor - Fixed 14400 V 1200 kVar | each | $ 2,011.92 | $ 2,673.55 | $ 585.68 |
| Capacitor - Switched 19920 V 1200 kVar | each | $ 4,772.71 | $ 10,311.79 | $ 1,885.56 |
| Capacitor - Switched 12000 V 900 kVar | each | $ 6,574.70 | $ 10,392.83 | $ 2,120.94 |
| Capacitor - Switched 19920 V 900 kVar | each | $ 4,772.71 | $ 9,544.78 | $ 1,789.69 |
| Capacitor - Switched 12000 V 600 kVar | each | $ 6,574.70 | $ 12,135.53 | $ 2,338.78 |
| Capacitor - Switched 19920 V 600 kVar | each | $ 4,772.71 | $ 9,233.98 | $ 1,750.84 |
| Capacitor - Switched 12000 V 1200 kVar | each | $ 6,574.70 | $ 10,769.21 | $ 2,167.99 |

| | | | | |
|---|---|---|---|---|
| Capacitor - Switched 2400 V 150 kVar | each | $ 4,772.71 | $ 8,395.13 | $ 1,645.98 |
| Capacitor - Switched 7200 V 900 kVar | each | $ 6,574.70 | $ 10,796.58 | $ 2,171.41 |
| Capacitor - Switched 7200 V 600 kVar | each | $ 6,574.70 | $ 10,219.74 | $ 2,099.31 |
| Capacitor - Switched 7200 V 1200 kVar | each | $ 6,574.70 | $ 8,313.73 | $ 1,861.05 |
| Capacitor - Switched 14400 V 1200 kVar | each | $ 4,772.71 | $ 11,230.88 | $ 2,000.45 |
| Capacitor - Switched 14400 V 600 kVar | each | $ 4,772.71 | $ 9,189.59 | $ 1,745.29 |
| Capacitor - Switched 14400 V 900 kVar | each | $ 4,772.71 | $ 9,502.61 | $ 1,784.42 |
| Regulator - 3 Ph 19920 V 200 A | each | $ 11,202.63 | $ 39,521.26 | $ 6,340.49 |
| Regulator - 3 Ph 7620 V 219 A | each | $ 11,109.54 | $ 40,479.69 | $ 6,448.65 |
| Regulator - 3 Ph 7620 V 328 A | each | $ 11,109.54 | $ 47,552.68 | $ 7,332.78 |
| Regulator - 3 Ph 14400 V 100 A | each | $ 11,160.58 | $ 42,561.56 | $ 6,715.27 |
| Regulator - 3 Ph 14400 V 200 A | each | $ 11,160.58 | $ 47,859.89 | $ 7,377.56 |
| Regulator - 3 Ph 19920 V 100 A | each | $ 11,202.63 | $ 35,858.26 | $ 5,882.61 |
| Regulator - 3 Ph 7620 V 100 A | each | $ 11,109.54 | $ 36,053.62 | $ 5,895.40 |
| Regulator - 1 Ph 19920 V 50 A | each | $ 2,775.05 | $ - | $ 346.88 |
| Regulator - 1 Ph 14400 V 100 A | each | $ 2,775.05 | $ 13,209.42 | $ 1,998.06 |
| Regulator - 1 Ph 14400 V 50 A | each | $ 2,775.05 | $ - | $ 346.88 |
| Regulator - 1 Ph 7620 V 50 A | each | $ 2,775.05 | $ - | $ 346.88 |
| Regulator - 1 Ph 7620 V 100 A | each | $ 2,775.05 | $ 11,039.64 | $ 1,726.84 |
| OH Switch-Unitized-Handle Operated 35 kV 1200 A | each | $ 2,176.19 | $ 5,748.14 | $ 990.54 |
| OH Switch-Unitized-Handle Operated 25 kV 600 A | each | $ 2,225.30 | $ 5,841.36 | $ 1,008.33 |
| OH Switch-Unitized-Handle Operated 35 kV 600 A | each | $ 2,225.30 | $ 5,841.36 | $ 1,008.33 |
| Riser Pole | each | $ 3,070.33 | $ 2,275.25 | $ 668.20 |

**From:** Pierce, Wyatt
**To:** John P. White
**Subject:** FW: Crew costs
**Date:** Friday, January 14, 2011 3:09:51 PM

John,

I had pulled some numbers out of the efficiency calculator spreadsheet, and received the following information from our Operations department when I asked about it.

Wyatt W. Pierce, PE
**Desk:** 541•633•2481
**Cell:** 541•848•7970

**From:** Ooten, Chad
**Sent:** Friday, January 14, 2011 2:22 PM
**To:** Pierce, Wyatt
**Subject:** RE: Crew costs

The way we figure labor and equipment for a job is a little different than what you have in your spreadsheet. We have a set price per hour per man and that gives you a tooled up journeyman. All are the same from journeyman lineman to foremen as far as job costs. The per hour price will fluctuate from time to time, but right now today it is $129.05 per hour for one man tooled up with whatever tools and trucks needed on the job. The only time equipment would be an adder is if we have to rent something like a crane or taller highline bucket or something along the specialty equipment lines that we don't have already. We don't get into equipment per hour as extra charges like contractors do. With them you pay the per hour for each man along with a per hour charge for all the equipment they have also. We don't do that. Our cost is a tooled up man with a truck.

The cost per different crews below is just 129.05 per hour times the number of people and hours. These costs include whatever equipment and tools they need.

Journeyman $129.05 per hr.

2 man crew per hr $258.10
3 man crew per hour $ 387.15
4 man crew per hr $ 516.20

Journeyman per 8 hr day $1032.40
2 man crew per 8 hr day $ 2064.80
3 man crew per 8 hr day $ 3097.20
4 man crew per 8 hr day $ 4129.60

Let me know if you have any questions.

Thanks - Chad

---

**From:** Pierce, Wyatt
**Sent:** Friday, January 14, 2011 12:02 PM
**To:** Ooten, Chad
**Subject:** Crew costs

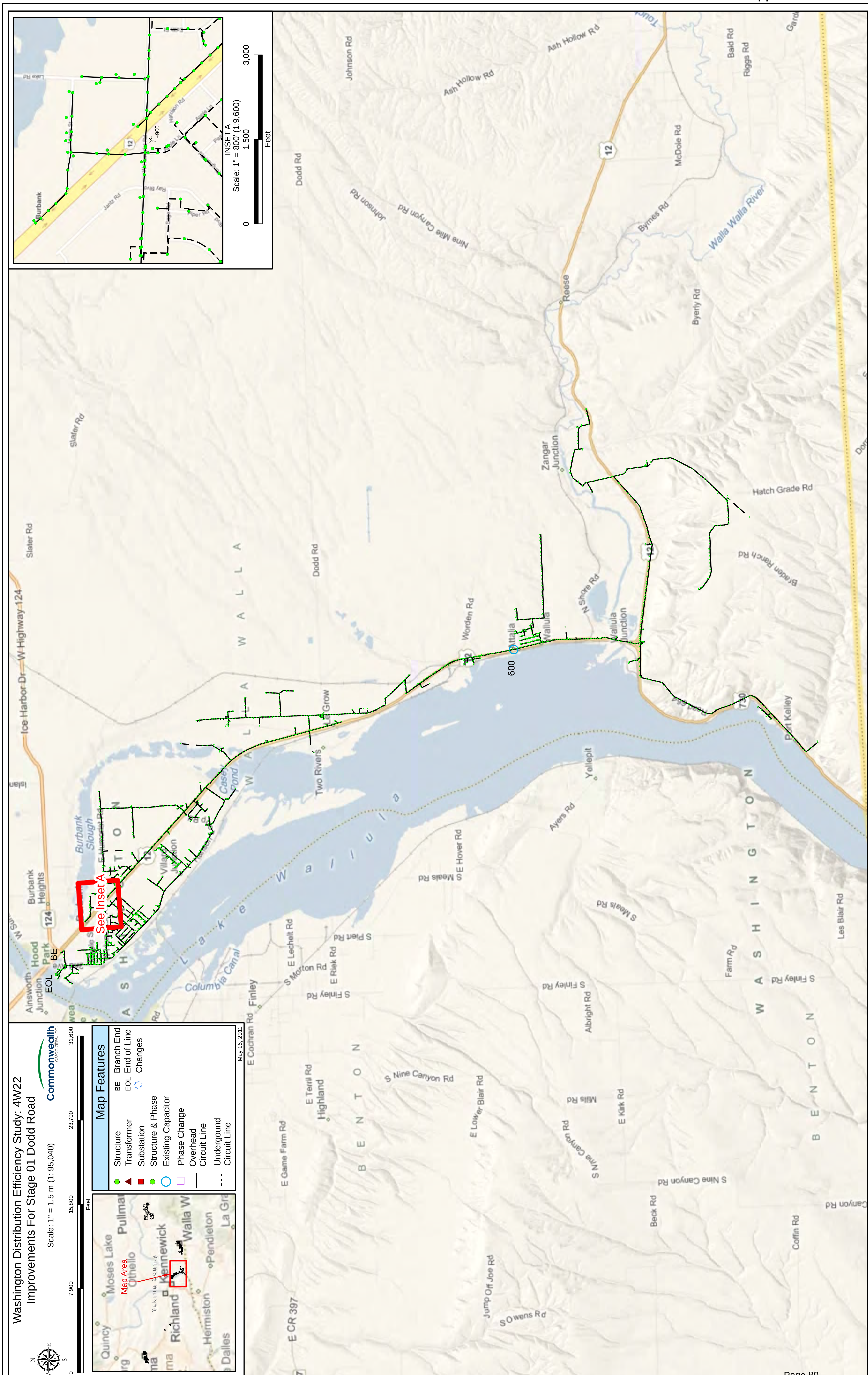
Chad,

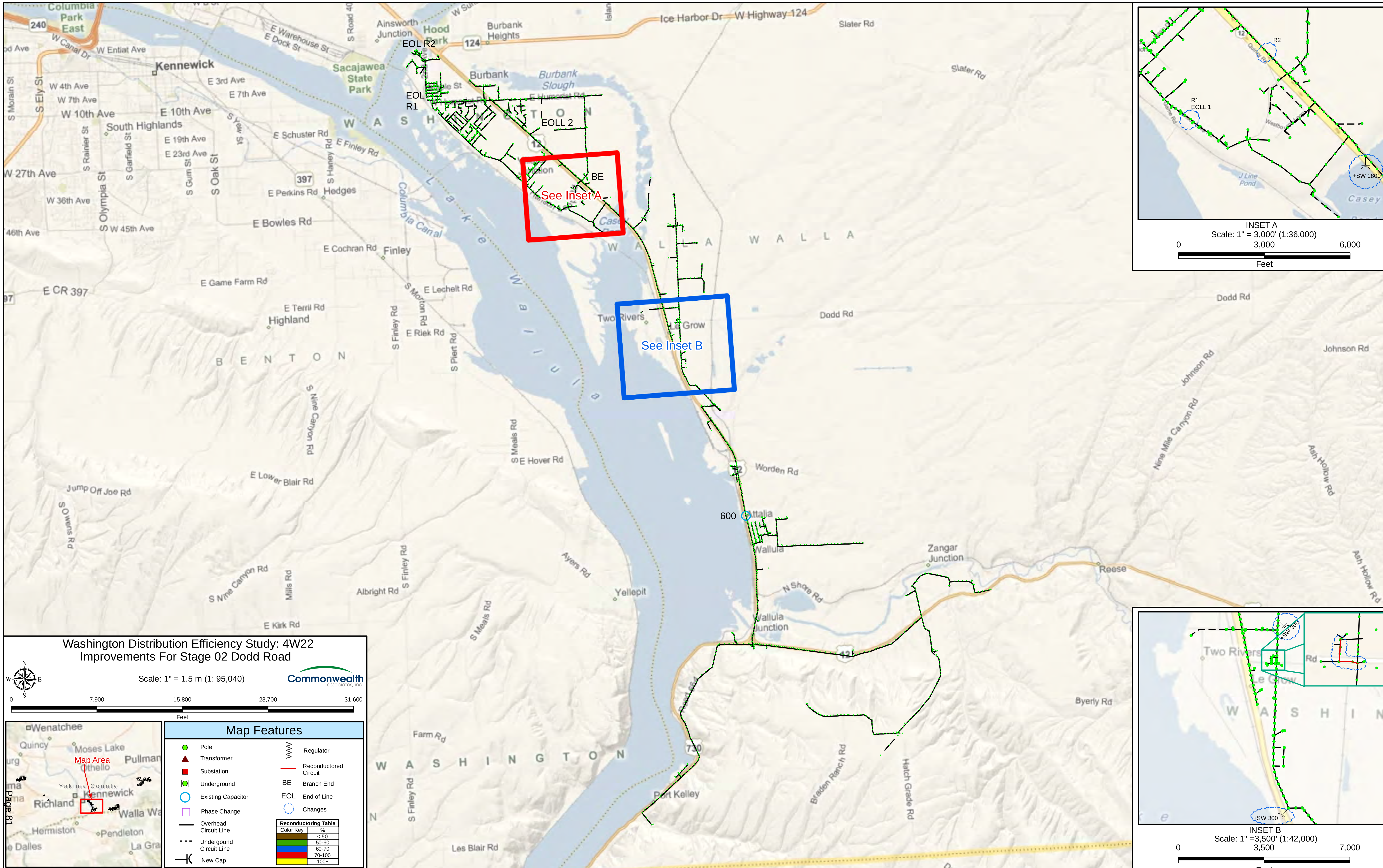
Could you please take a look at the attached spreadsheet. This is part of what our CVR contractors are using to determine feasibility of capital improvements. I feel like the values for crew and equipment costs may be listed lower than our company's reality. I would appreciate it if you could update any numbers you have at your disposal and return this to me.

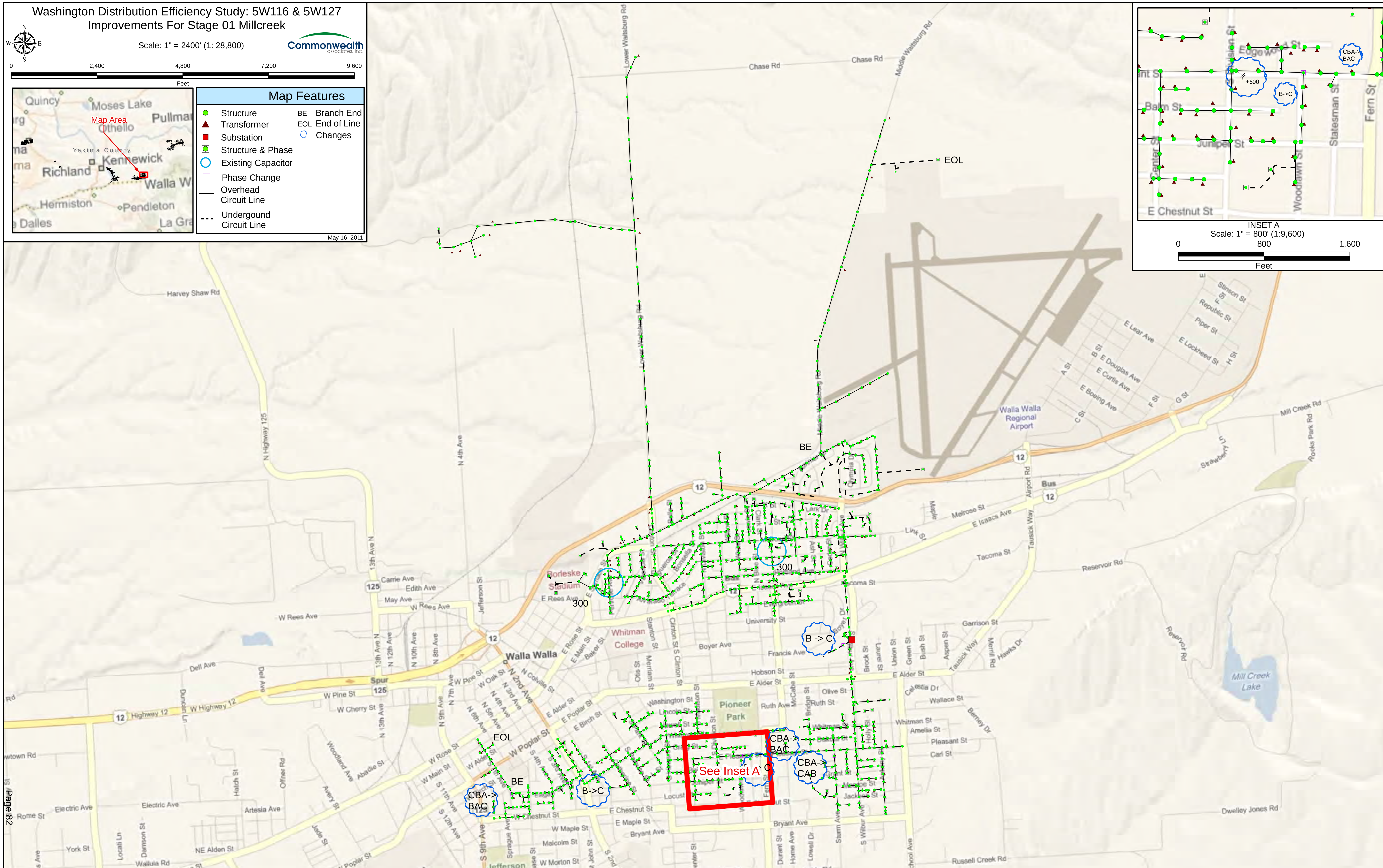
Thank you,

Wyatt W. Pierce, PE
**Pacific Power**
**NID Support & Special Projects**
**Desk:** 541•633•2481
**Cell:** 541•848•7970

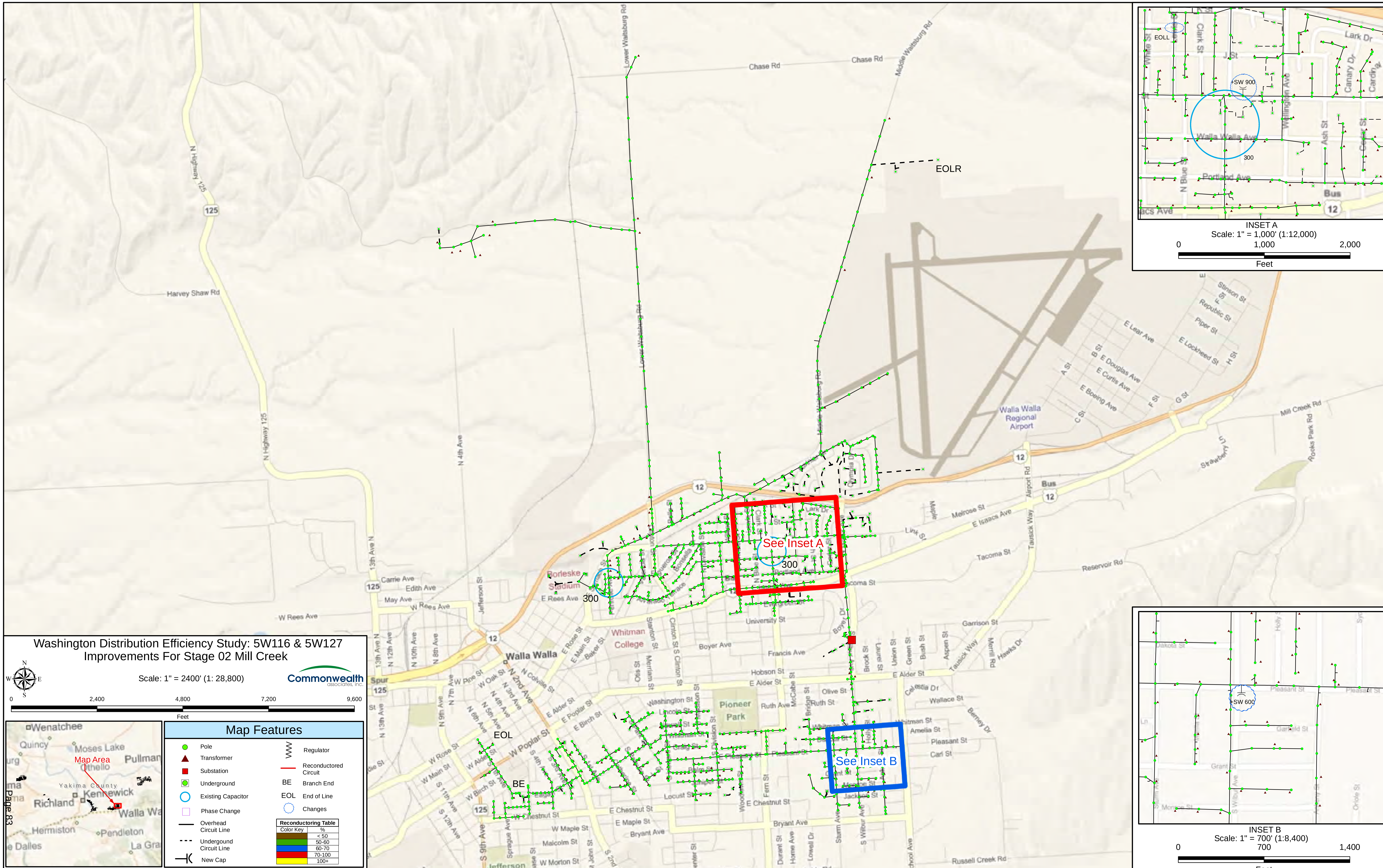
# Appendix 5:  Circuit Changes


Washington Distribution Efficiency Study: 4W22
Improvements For Stage 01 Dodd Road
Scale: 1" = 1.5 m (1: 95,040)
0 7,900 15,800 23,700 31,600
Feet
Commonwealth
Map Area
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
BE Branch End
EOL End of Line
Changes
May 16, 2011
INSET A
Scale: 1" = 800' (1:9,600)
0 1,500 3,000
Feet
See Inset A
EOL
BE
600
Lake Wallula
Walla Walla River
Hatch Grade Rd
Ash Hollow Rd
Nine Mile Canyon Rd
Dodd Rd
Johnson Rd
Byerly Rd
McDole Rd
Byrnes Rd
Zangar Junction
Wallula
Wallula Junction
Reese
Two Rivers
Finley
Burbank Heights
Ice Harbor Dr
W Highway 124
Slater Rd
Worden Rd
S Nine Canyon Rd
S Finley Rd
Yellepit
Ayers Rd
Les Blair Rd
Port Kelley
BENTON
WASHINGTON
WALLA WALLA

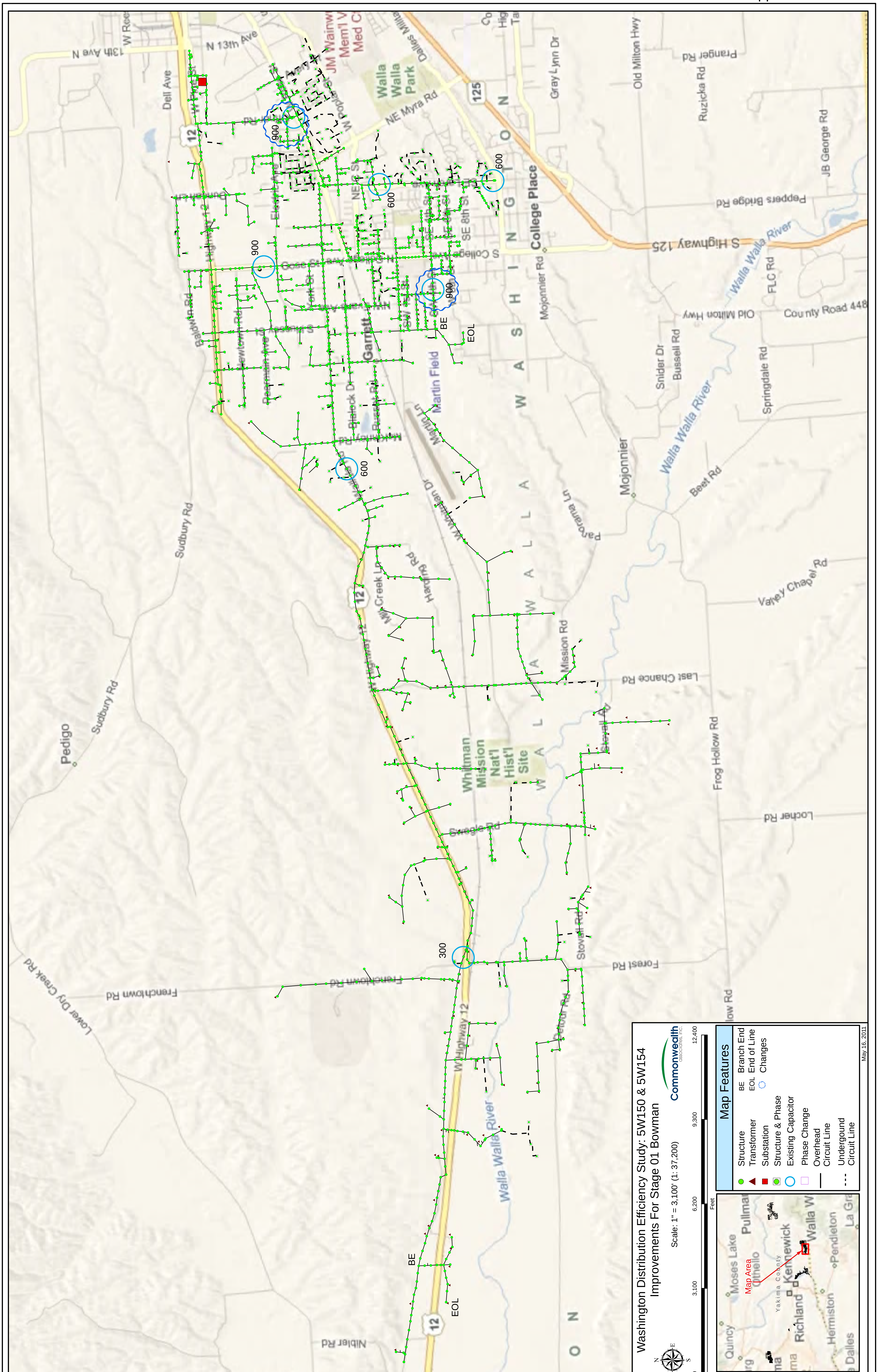

Washington Distribution Efficiency Study: 4W22
Improvements For Stage 02 Dodd Road
Scale: 1" = 1.5 m (1: 95,040)
Commonwealth
associates, inc.
0
7,900
15,800
23,700
31,600
Feet
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
New Cap
Regulator
Reconductored Circuit
BE Branch End
EOL End of Line
Changes
Reconductoring Table
Color Key
%
< 50
50-60
60-70
70-100
100+
May 12, 2011
Map Area
See Inset A
See Inset B
EOL R2
EOL R1
EOLL 2
BE
600
INSET A
Scale: 1" = 3,000' (1:36,000)
0
3,000
6,000
Feet
R2
R1
EOLL 1
SW 1800
INSET B
Scale: 1" =3,500' (1:42,000)
0
3,500
7,000
Feet
SW 300
Kennewick
Burbank
Finley
Two Rivers
Attalia
Wallula
Wallula Junction
Zangar Junction
Port Kelley
Lake Wallula
W A L L A W A L L A
B E N T O N
W A S H I N G T O N

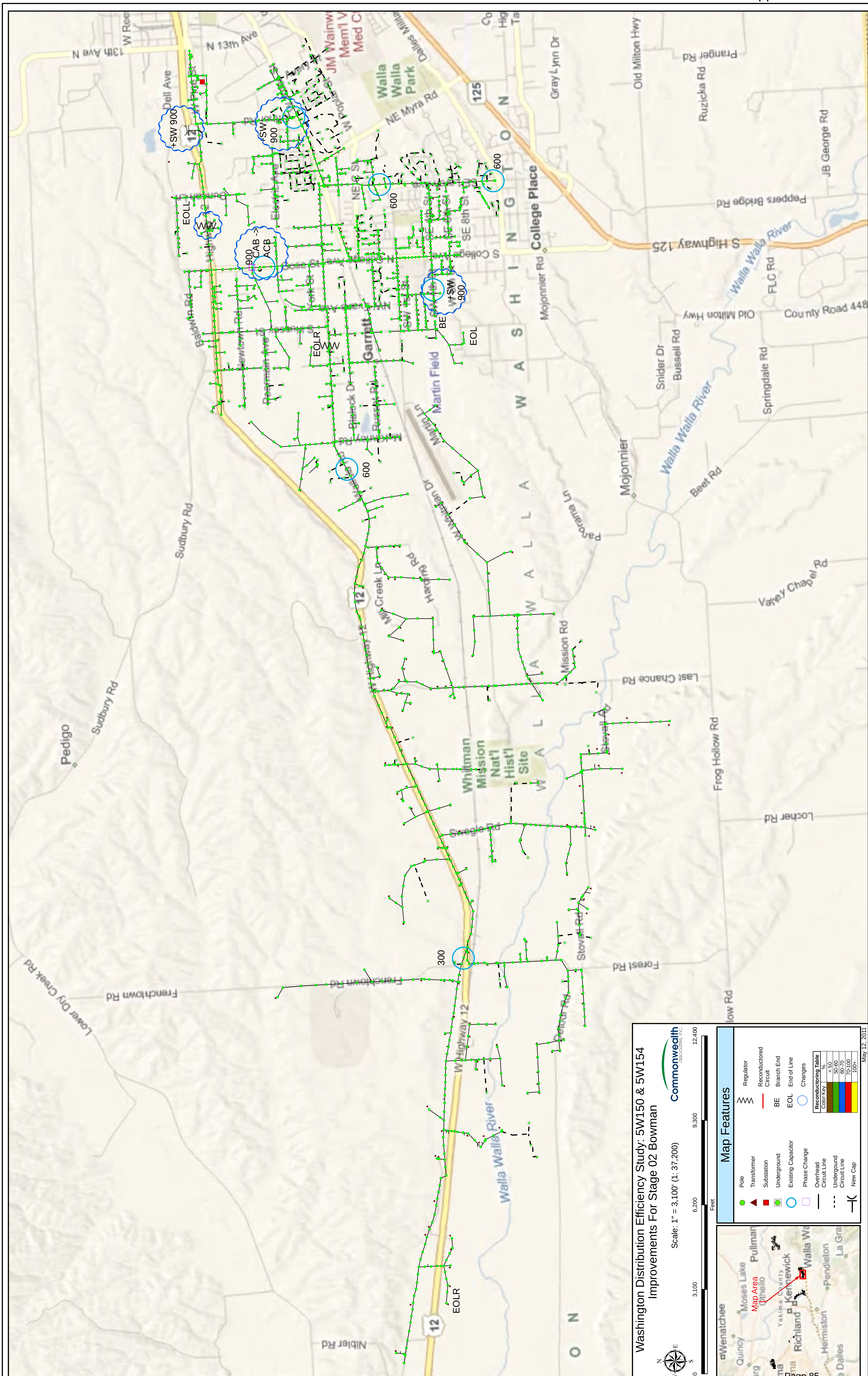


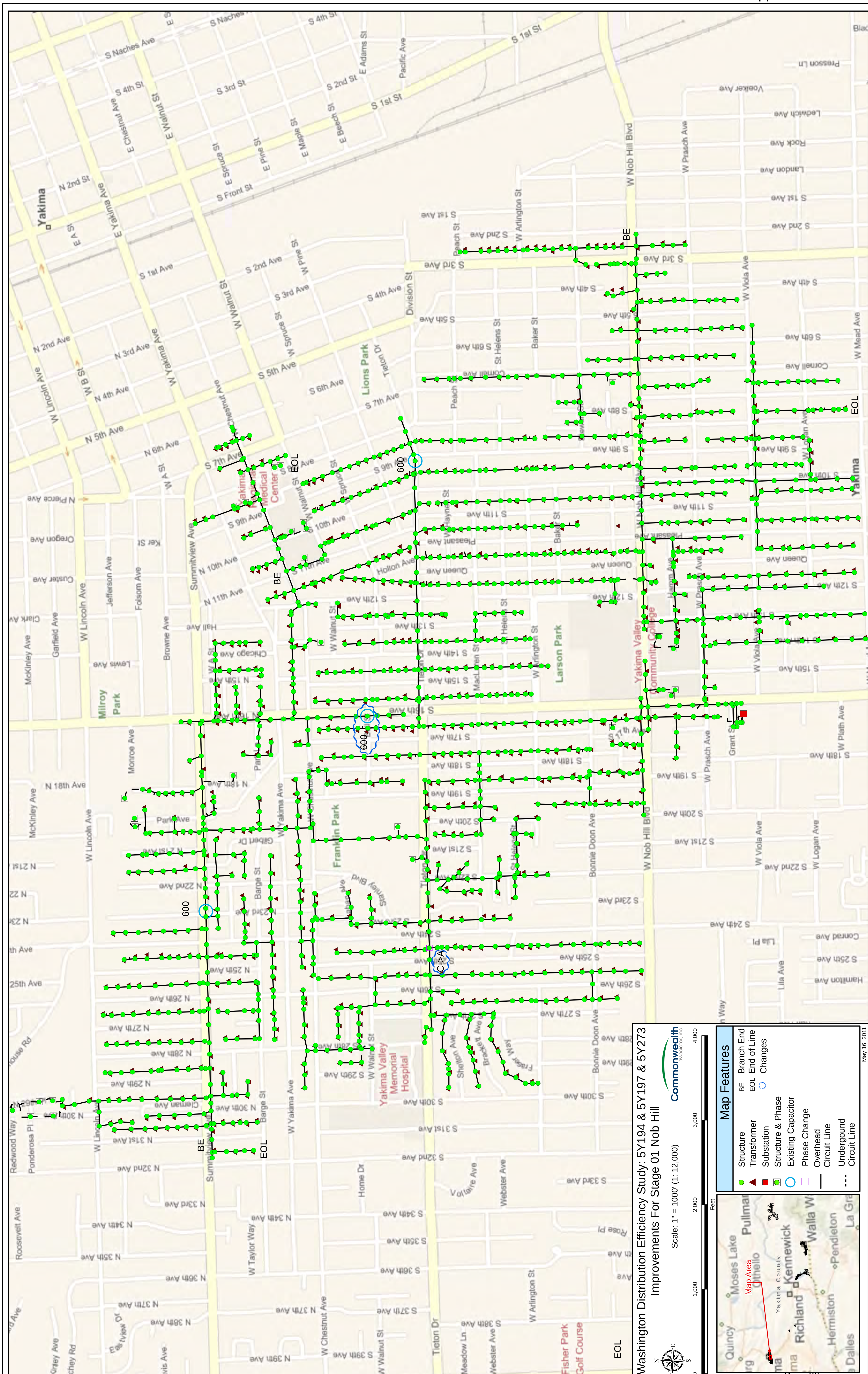
Washington Distribution Efficiency Study: 5W116 & 5W127
Improvements For Stage 01 Millcreek
Scale: 1" = 2400' (1: 28,800)
0
2,400
4,800
7,200
9,600
Feet
Commonwealth
Map Area
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
BE Branch End
EOL End of Line
Changes
May 16, 2011
INSET A
Scale: 1" = 800' (1:9,600)
0
800
1,600
Feet
CBA-> BAC
B->C
+600
EOL
BE
300
B -> C
CBA-> CAB
See Inset A
Walla Walla Regional Airport
Whitman College
Pioneer Park
Walla Walla

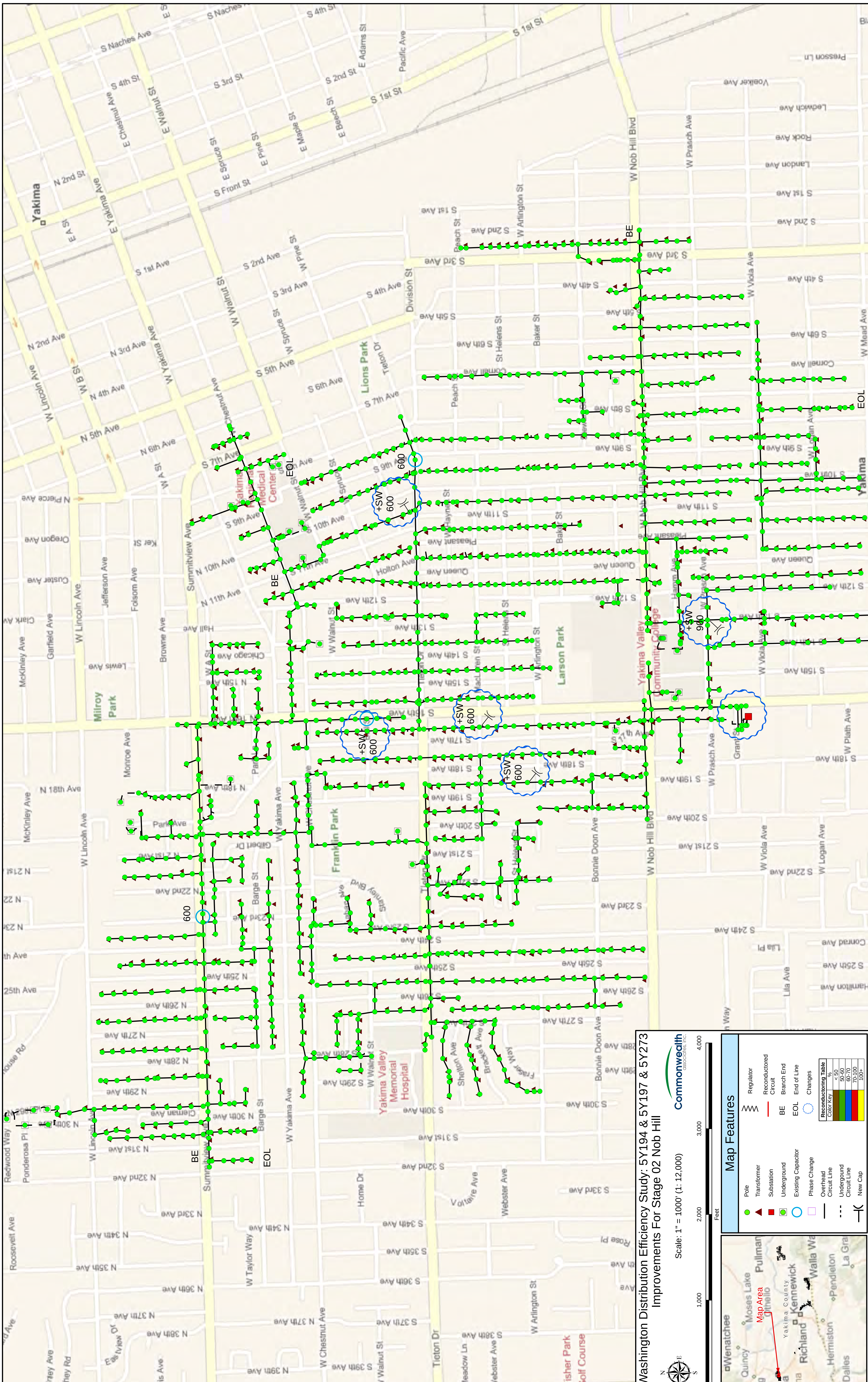


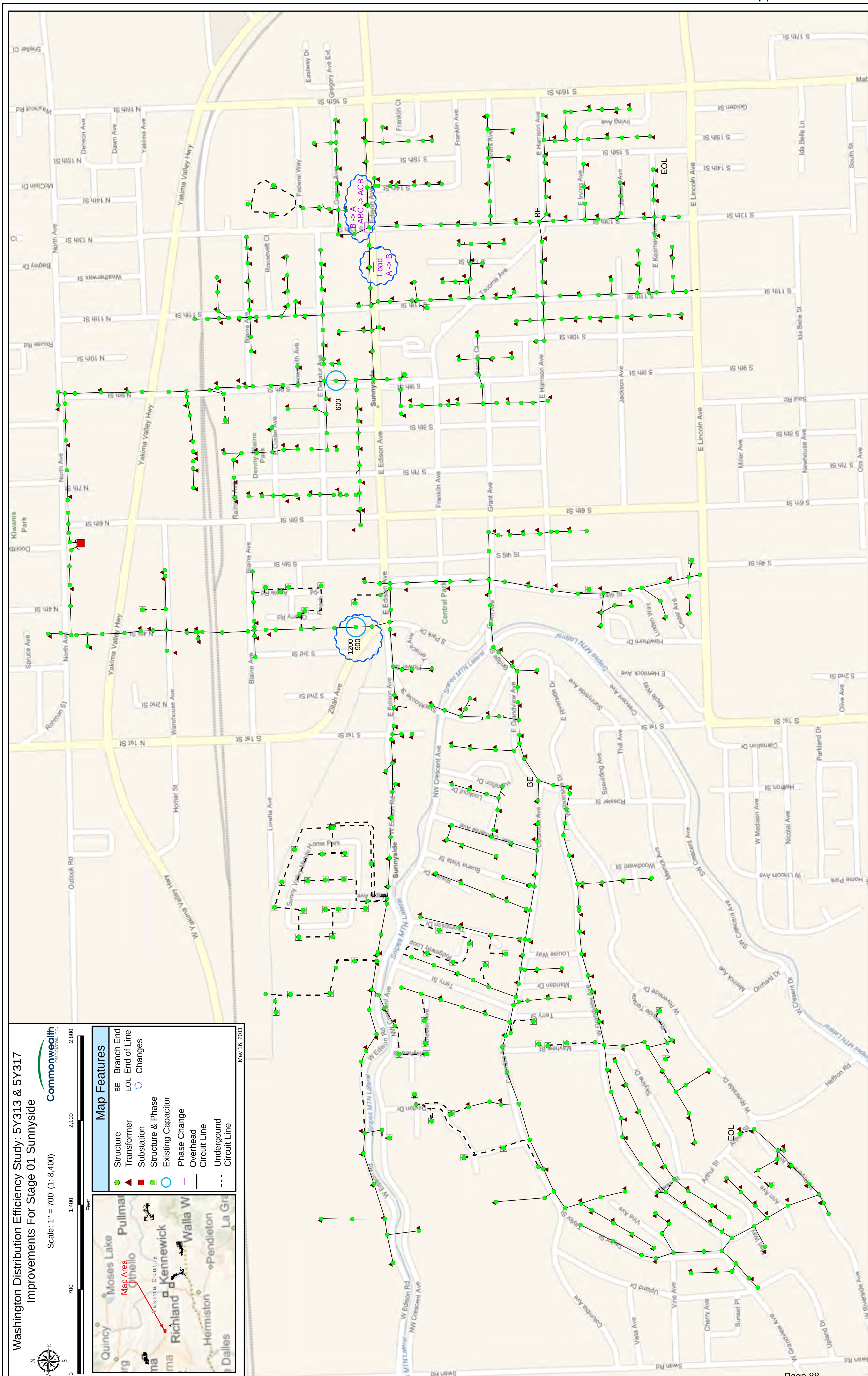
Washington Distribution Efficiency Study: 5W116 & 5W127
Improvements For Stage 02 Mill Creek
Scale: 1" = 2400' (1: 28,800)
0 2,400 4,800 7,200 9,600
Feet
Commonwealth associates, inc.
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Underground Circuit Line
New Cap
Regulator
Reconductored Circuit
BE Branch End
EOL End of Line
Changes
Reconductoring Table
Color Key %
< 50
50-60
60-70
70-100
100+
May 12, 2011
Map Area
INSET A
Scale: 1" = 1,000' (1:12,000)
0 1,000 2,000
Feet
INSET B
Scale: 1" = 700' (1:8,400)
0 700 1,400
Feet
See Inset A
See Inset B
EOLR
EOL
BE
EOLL
SW 900
SW 600
300
Walla Walla
Walla Walla Regional Airport
Whitman College
Pioneer Park
Borleske Stadium

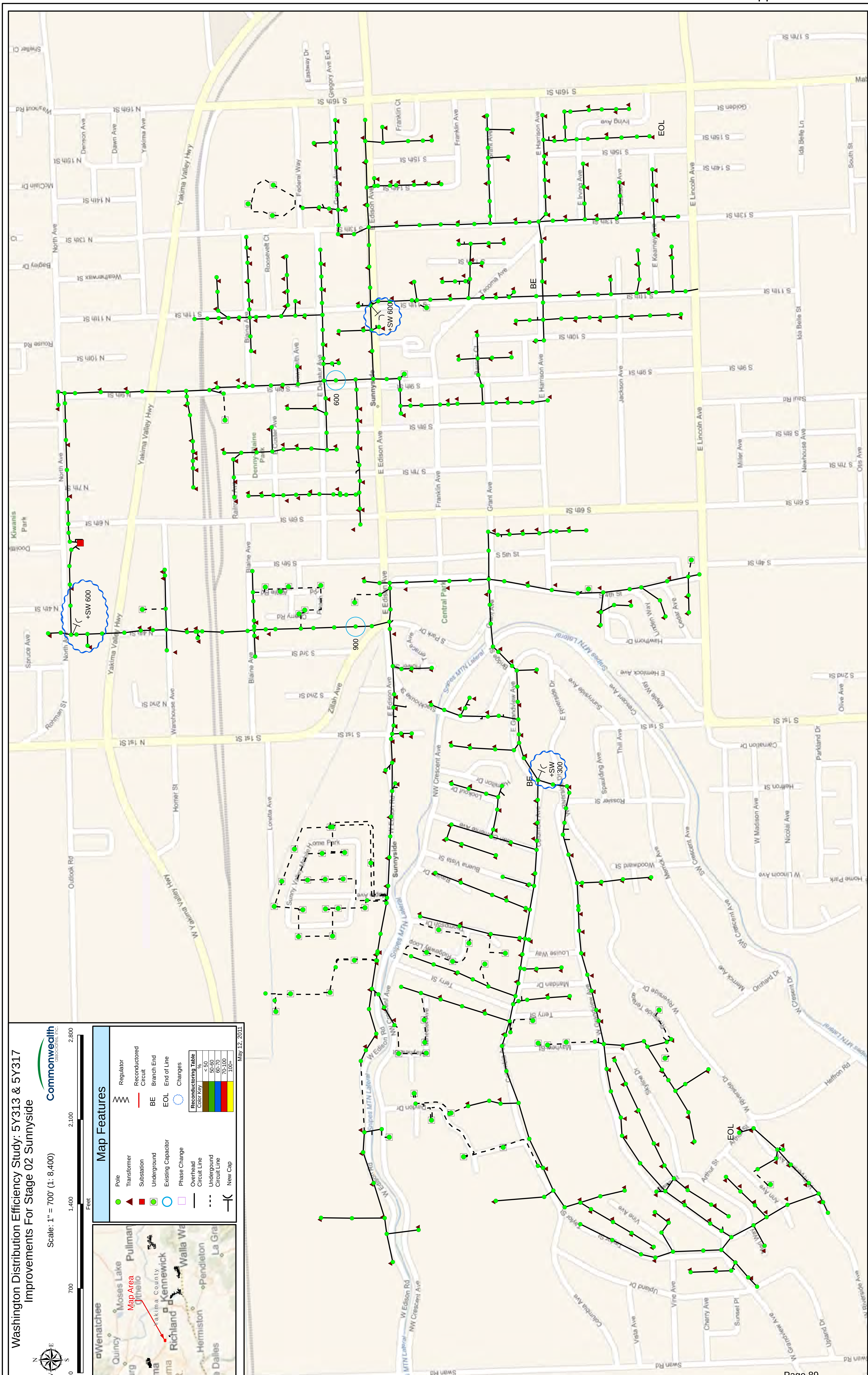

Washington Distribution Efficiency Study: 5W150 & 5W154
Improvements For Stage 01 Bowman
Scale: 1" = 3,100' (1: 37,200)
0
3,100
6,200
9,300
12,400
Feet
Commonwealth
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
BE Branch End
EOL End of Line
Changes
Map Area
May 16, 2011

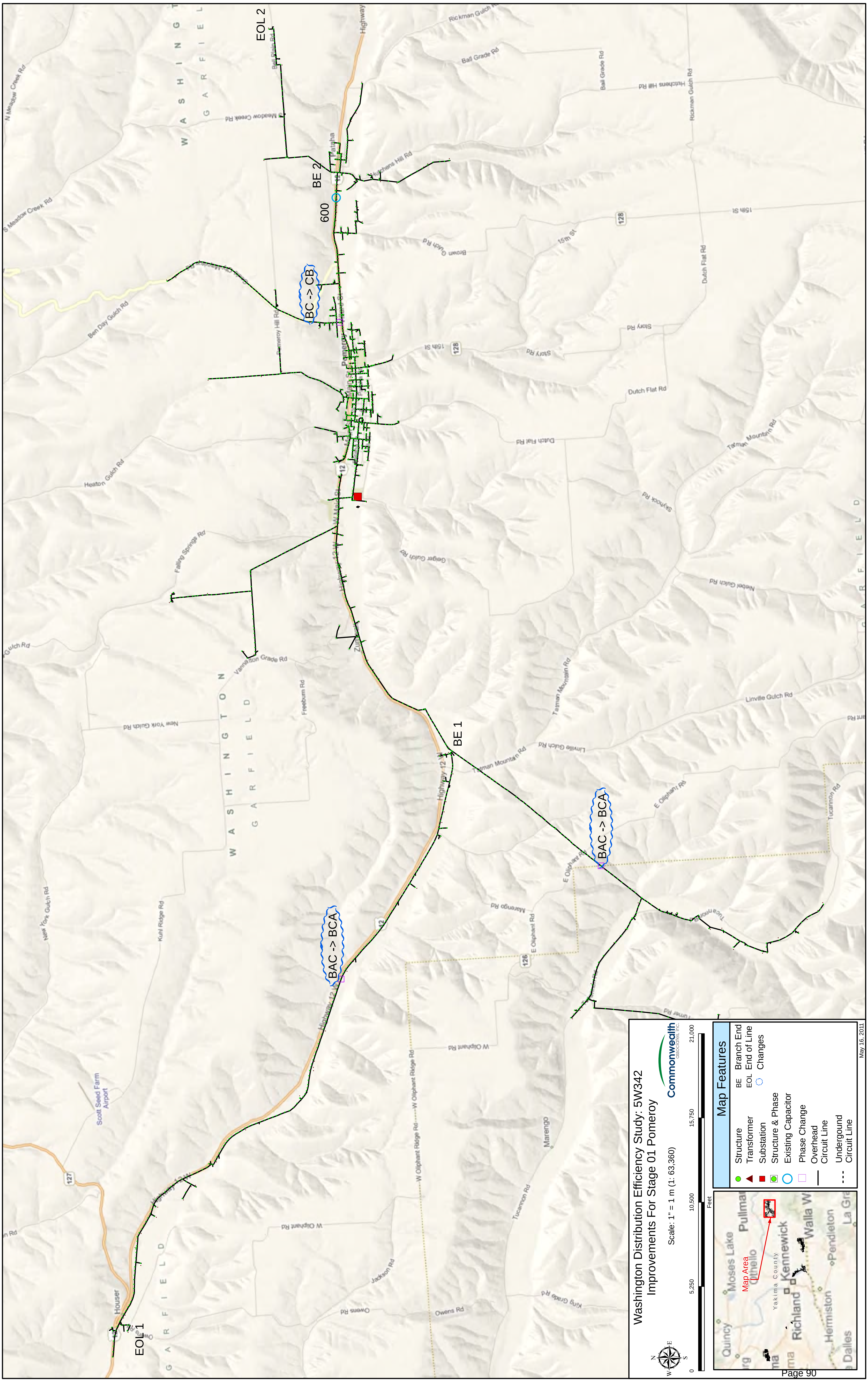

Washington Distribution Efficiency Study: 5W150 & 5W154
Improvements For Stage 02 Bowman
Scale: 1" = 3,100' (1: 37,200)
0
3,100
6,200
9,300
12,400
Feet
Commonwealth
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
New Cap
Regulator
Reconductored Circuit
BE Branch End
EOL End of Line
Changes
Reconductoring Table
May 12, 2011
+SW 900
600
300
EOLR
EOL
BE
CAB -> ACB


Washington Distribution Efficiency Study: 5Y194 & 5Y197 & 5Y273
Improvements For Stage 01 Nob Hill
Scale: 1" = 1000' (1:12,000)
0
1,000
2,000
3,000
4,000
Feet
Commonwealth
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
BE Branch End
EOL End of Line
Changes
Map Area
Yakima County
May 16, 2011

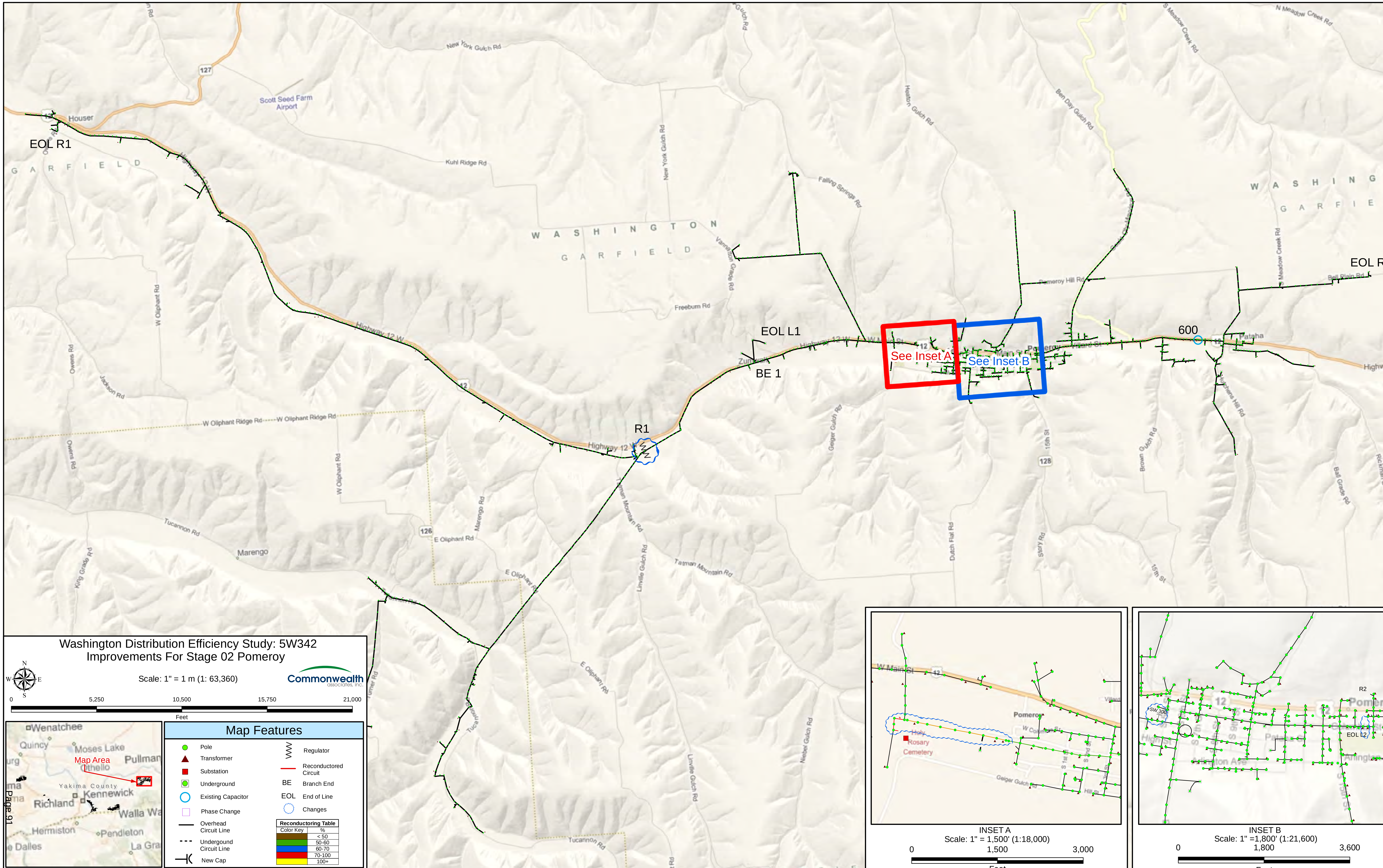

Washington Distribution Efficiency Study: 5Y194 & 5Y197 & 5Y273
Improvements For Stage 02 Nob Hill
Scale: 1" = 1000' (1: 12,000)
0
1,000
2,000
3,000
4,000
Feet
Commonwealth
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Underground Circuit Line
New Cap
Regulator
Reconductored Circuit
BE Branch End
EOL End of Line
Changes
Reconductoring Table
Color Key
%
< 50
50-60
60-70
70-100
100+
May 12, 2011
Map Area
Yakima County
Yakima
Nob Hill Blvd
Yakima Valley Community College
Yakima Valley Memorial Hospital
Franklin Park
Larson Park
Lions Park
Milroy Park
Fisher Park Golf Course
+SW 600
+SW 900
BE
EOL


Washington Distribution Efficiency Study: 5Y313 & 5Y317
Improvements For Stage 01 Sunnyside
Scale: 1" = 700' (1: 8,400)
0
700
1,400
2,100
2,800
Feet
Commonwealth
Map Area
Yakima County
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
BE Branch End
EOL End of Line
Changes
May 16, 2011
B -> A
ABC -> ACB
Load A -> B
600
1200
900
BE
EOL

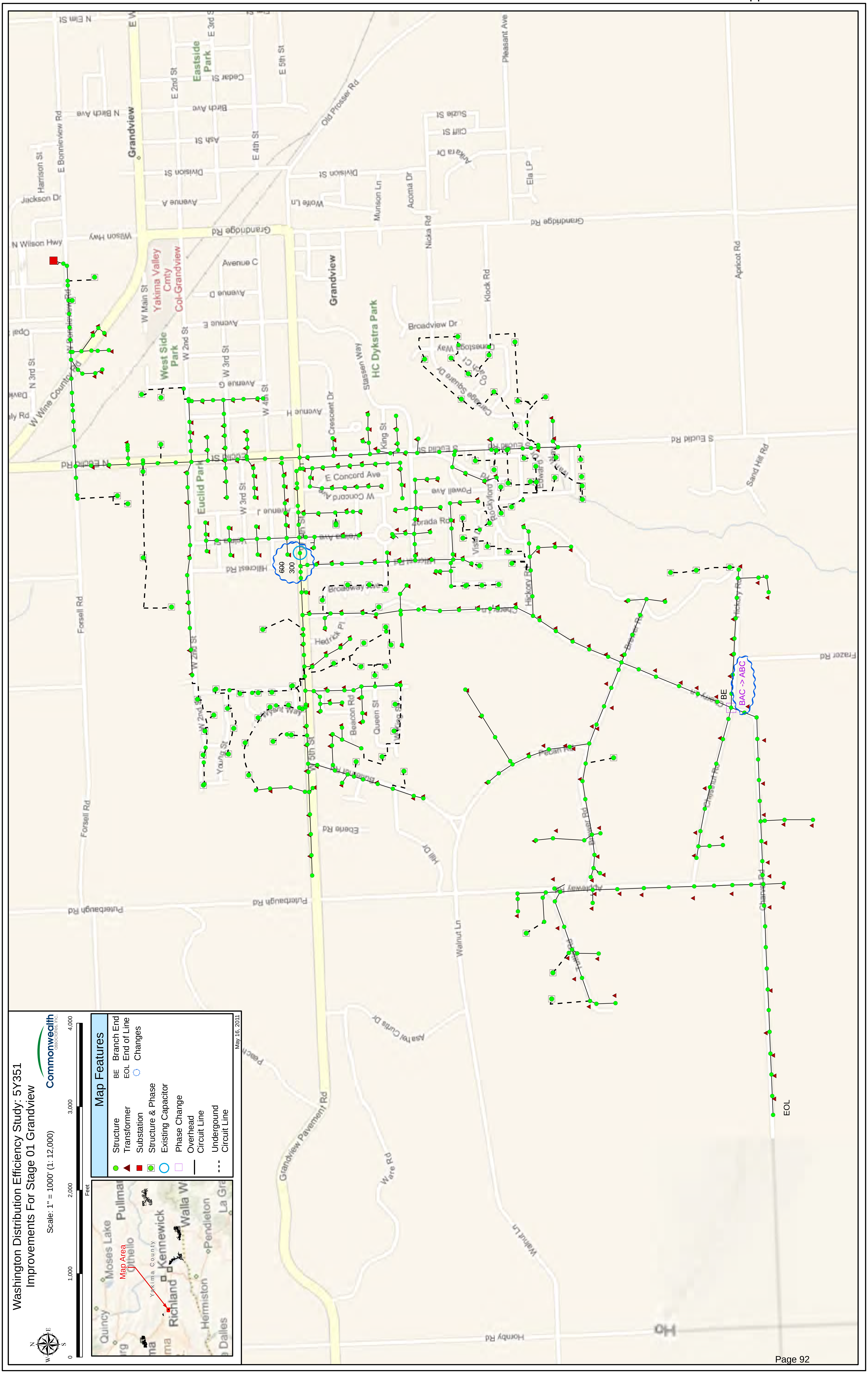

Washington Distribution Efficiency Study: 5Y313 & 5Y317
Improvements For Stage 02 Sunnyside
Scale: 1" = 700' (1: 8,400)
0
700
1,400
2,100
2,800
Feet
Commonwealth
Map Area
Yakima County
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Underground Circuit Line
New Cap
Regulator
Reconductored Circuit
BE Branch End
EOL End of Line
Changes
Reconductoring Table
Color Key
%
< 50
50-60
60-70
70-100
100+
May 12, 2011

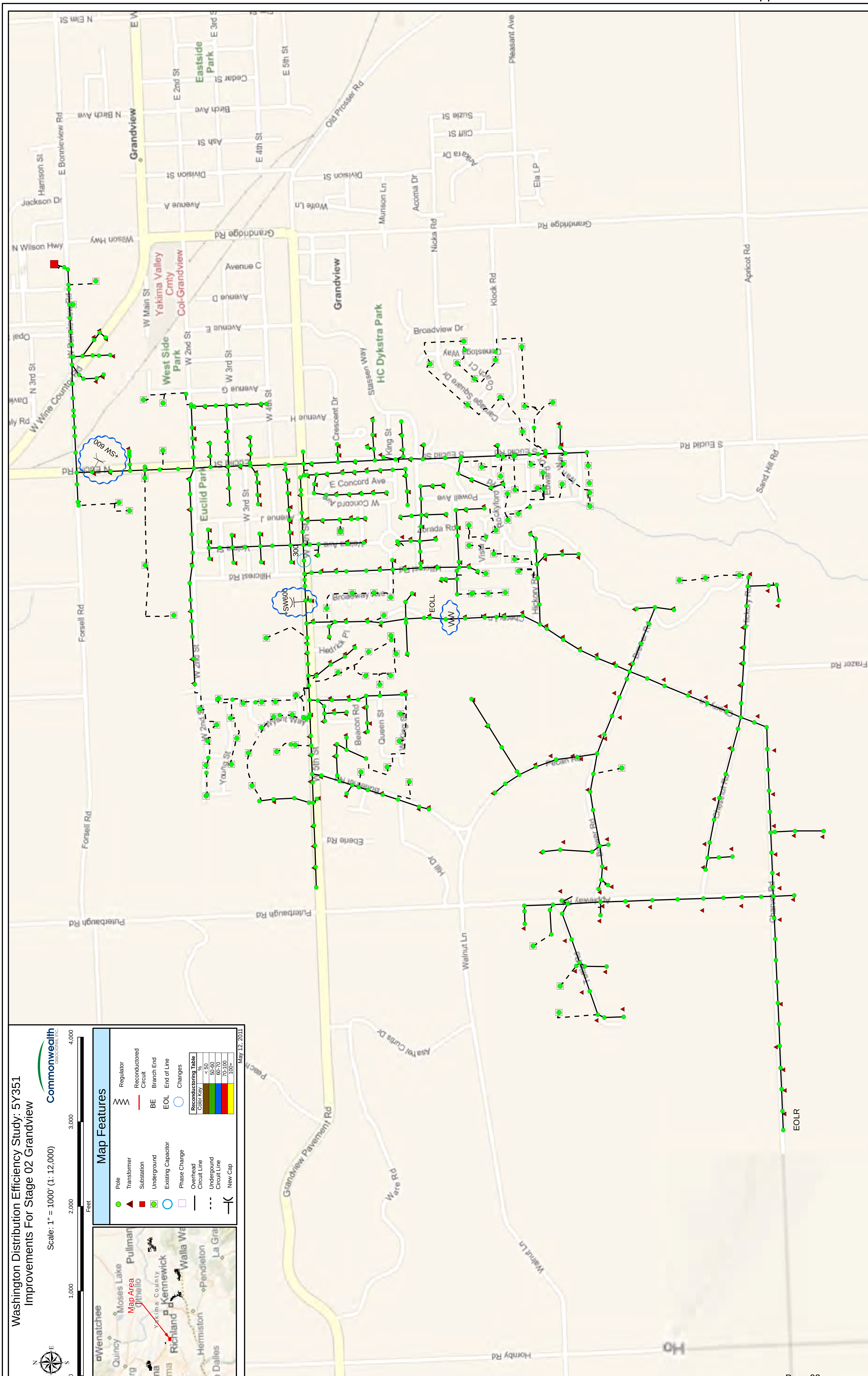


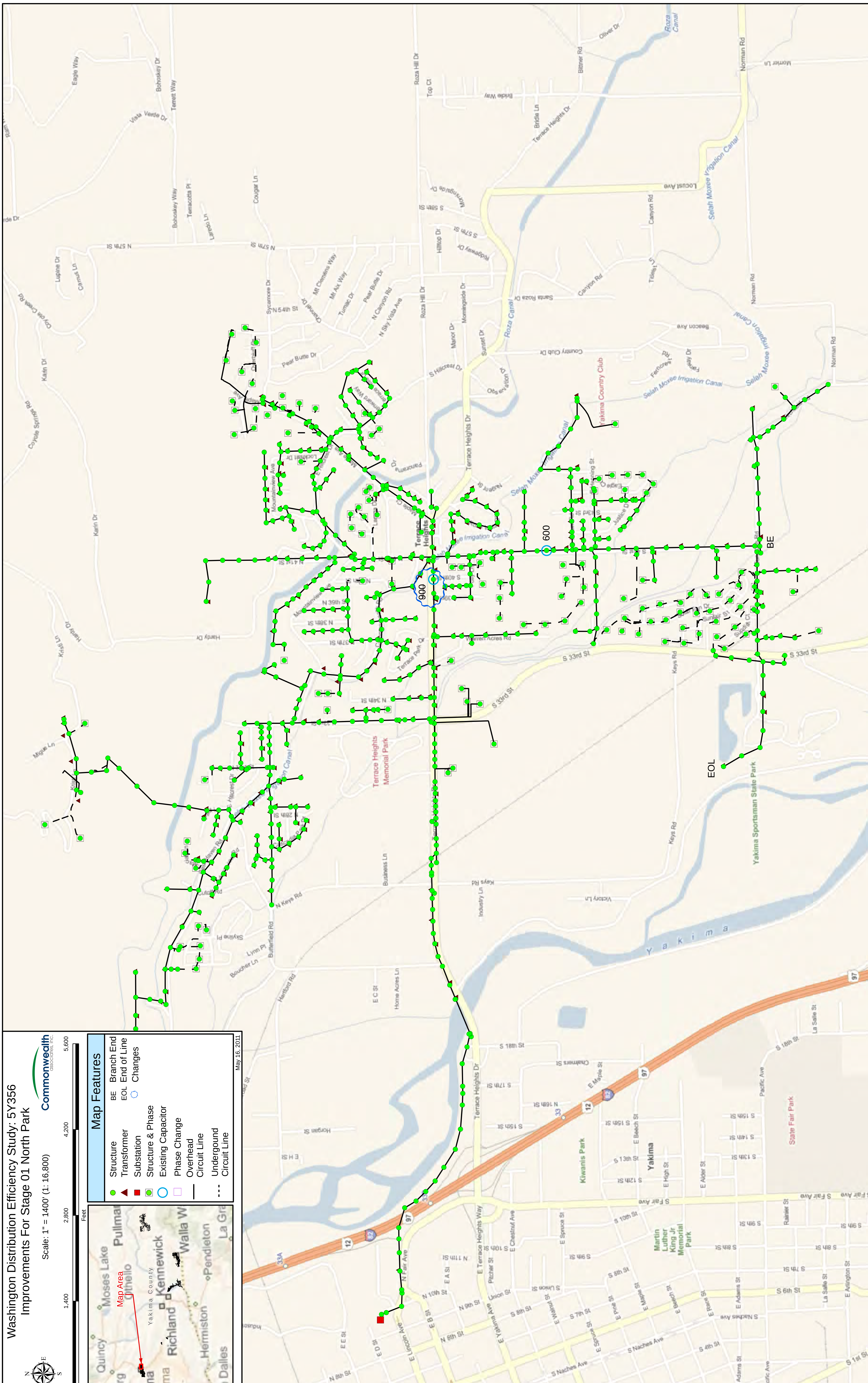
Washington Distribution Efficiency Study: 5W342
Improvements For Stage 01 Pomeroy
Scale: 1" = 1 m (1: 63,360)
0
5,250
10,500
15,750
21,000
Feet
Commonwealth Associates, Inc.
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
BE Branch End
EOL End of Line
Changes
May 16, 2011
Map Area
EOL 2
BE 2
600
BC -> CB
BE 1
BAC -> BCA
BAC -> BCA
EOL 1

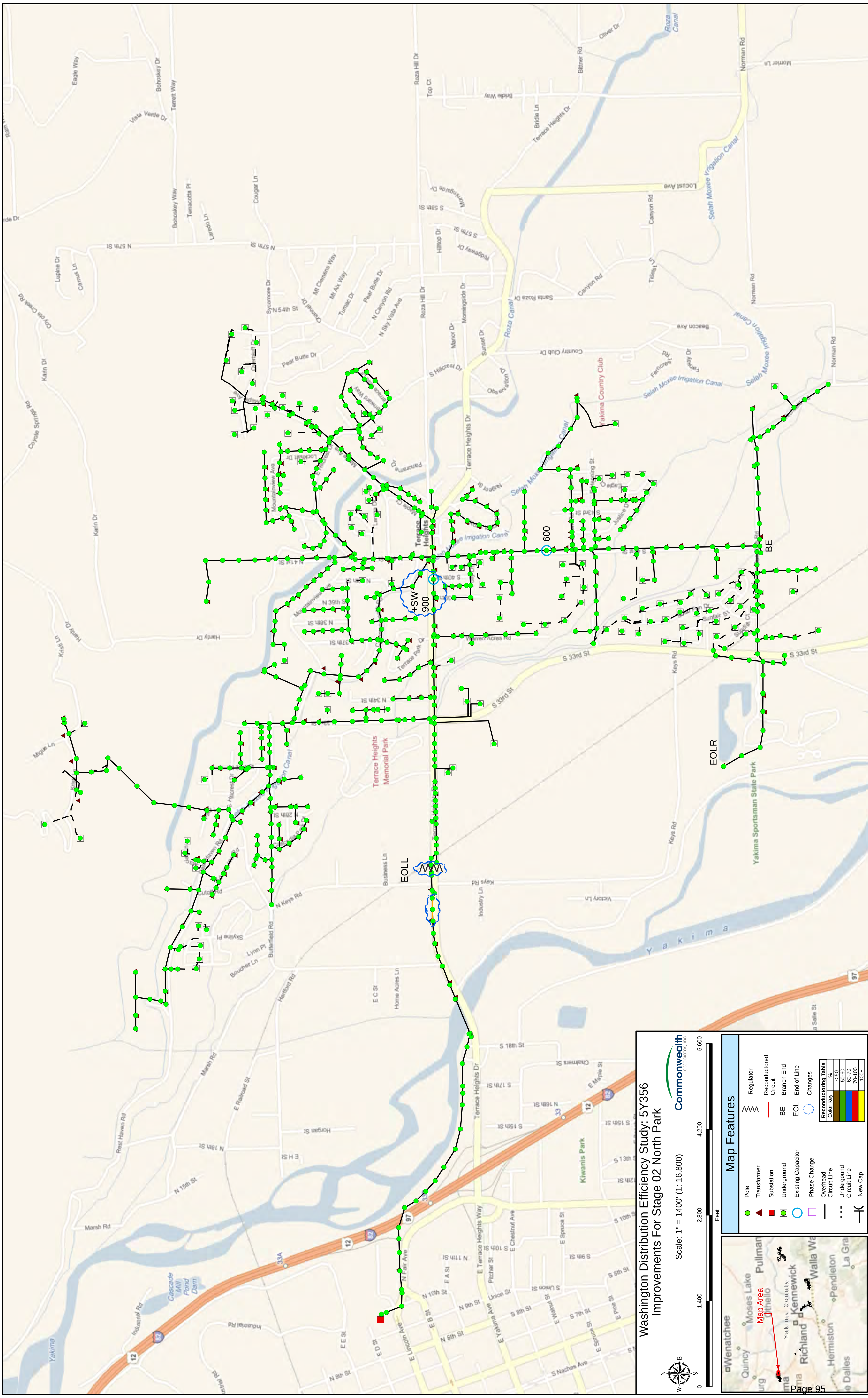


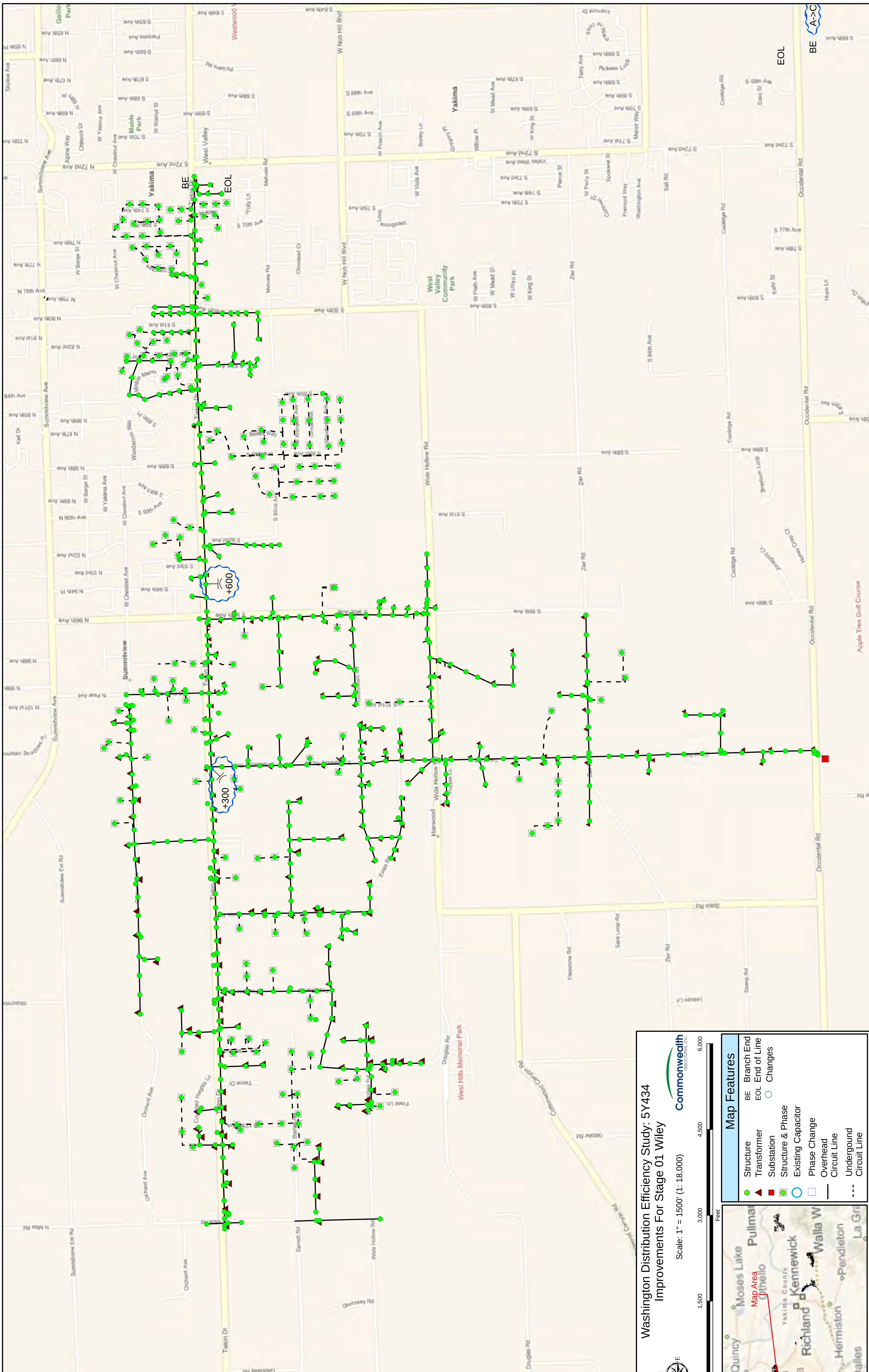
Washington Distribution Efficiency Study: 5W342
Improvements For Stage 02 Pomeroy
Scale: 1" = 1 m (1: 63,360)
0
5,250
10,500
15,750
21,000
Feet
Commonwealth
associates, inc.
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Underground Circuit Line
New Cap
Regulator
Reconductored Circuit
BE Branch End
EOL End of Line
Changes
Reconductoring Table
Color Key
%
< 50
50-60
60-70
70-100
100+
May 12, 2011
Map Area
Wenatchee
Quincy
Moses Lake
Othello
Pullman
Yakima County
Kennewick
Richland
Walla Wa
Hermiston
Pendleton
La Gra
Dalles
EOL R1
Houser
EOL L1
BE 1
R1
EOL R2
600
See Inset A
See Inset B
WASHINGTON
GARFIELD
Highway 12 W
Scott Seed Farm Airport
Kuhl Ridge Rd
New York Gulch Rd
W Oliphant Ridge Rd
Tucannon Rd
Marengo
Tatman Mountain Rd
Linville Gulch Rd
Pataha
INSET A
Scale: 1" = 1,500' (1:18,000)
0
1,500
3,000
Feet
W Main St
Pomeroy
Holy Rosary Cemetery
INSET B
Scale: 1" = 1,800' (1:21,600)
0
1,800
3,600
Feet
R2
EOL L2
SW 300

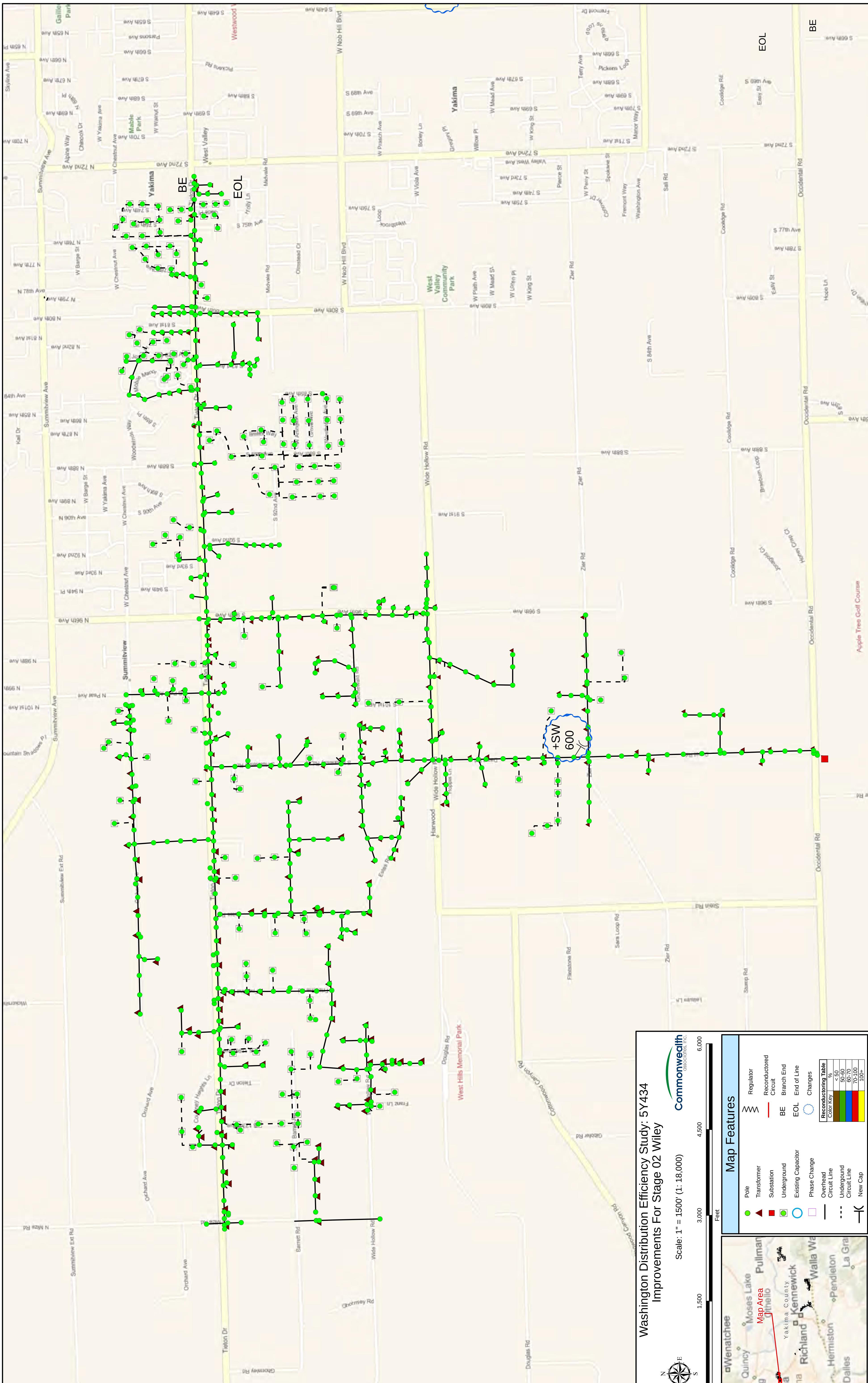

Washington Distribution Efficiency Study: 5Y351
Improvements For Stage 01 Grandview
Scale: 1" = 1000' (1: 12,000)
0
1,000
2,000
3,000
4,000
Feet
Commonwealth
Map Area
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
BE Branch End
EOL End of Line
Changes
May 16, 2011
BAC -> ABC
BE
EOL
600
300

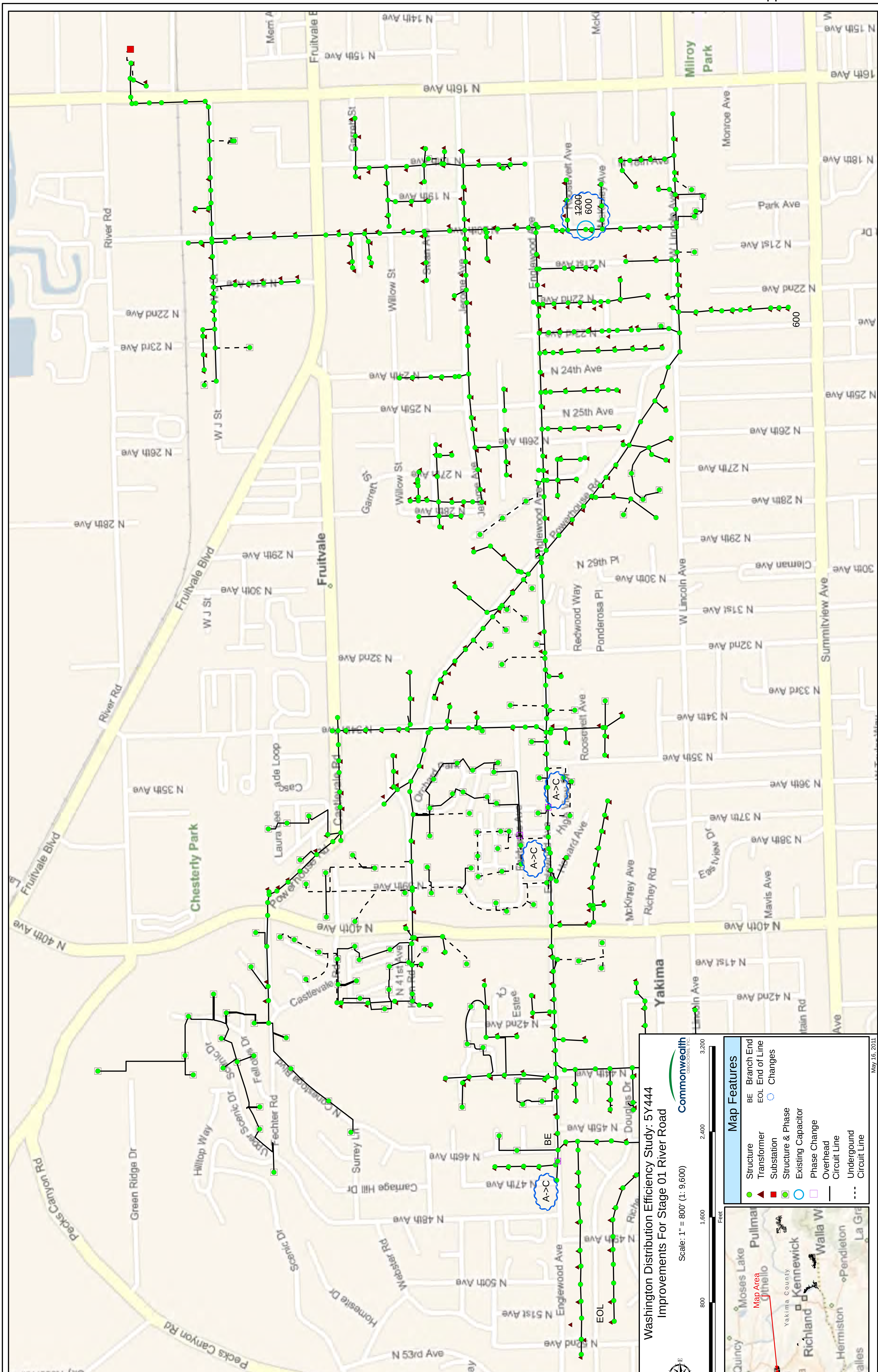

Washington Distribution Efficiency Study: 5Y351
Improvements For Stage 02 Grandview
Scale: 1" = 1000' (1: 12,000)
Commonwealth
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Underground Circuit Line
New Cap
Regulator
Reconductored Circuit
Branch End
End of Line
Changes
Reconductoring Table
Color Key
%
< 50
50-60
60-70
70-100
100+
May 12, 2011
Map Area
Yakima County
Grandview

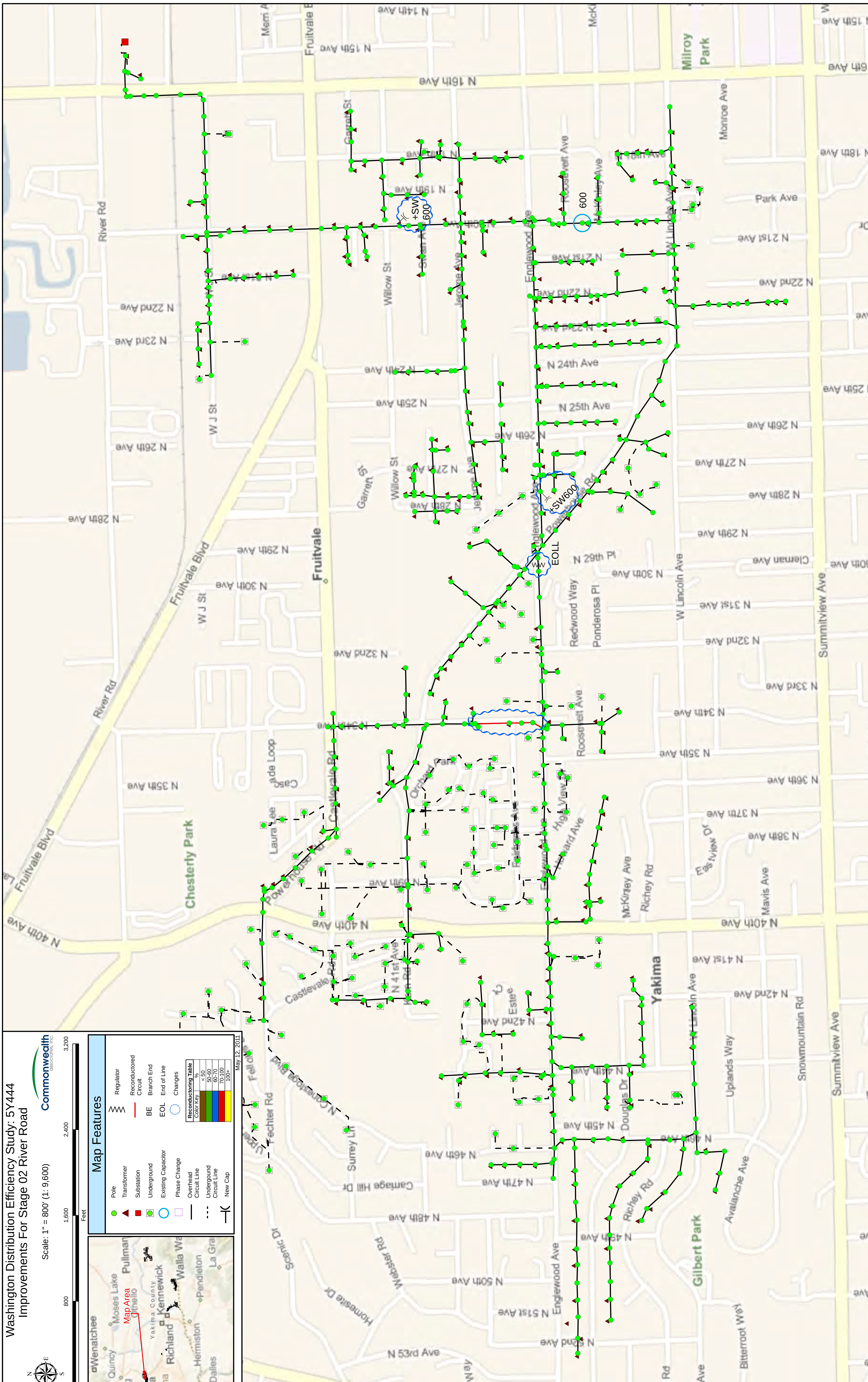

Washington Distribution Efficiency Study: 5Y356
Improvements For Stage 01 North Park
Scale: 1" = 1400' (1: 16,800)
Commonwealth Associates, Inc.
0
1,400
2,800
4,200
5,600
Feet
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Underground Circuit Line
BE Branch End
EOL End of Line
Changes
May 16, 2011
Map Area
Yakima County
600
900
BE
EOL


Washington Distribution Efficiency Study: 5Y356
Improvements For Stage 02 North Park
Scale: 1" = 1400' (1: 16,800)
0
1,400
2,800
4,200
5,600
Feet
Commonwealth
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Underground Circuit Line
New Cap
Regulator
Reconductored Circuit
BE Branch End
EOL End of Line
Changes
Reconductoring Table
Color Key
%
< 50
50-60
60-70
70-100
100+
May 12, 2011
Map Area
Yakima County
600
900
+SW
BE
EOLR
EOLL
Terrace Heights
Yakima Country Club
Terrace Heights Memorial Park
Yakima Sportsman State Park
Kiwanis Park
Roza Canal
Selah Moxee Irrigation Canal
Yakima

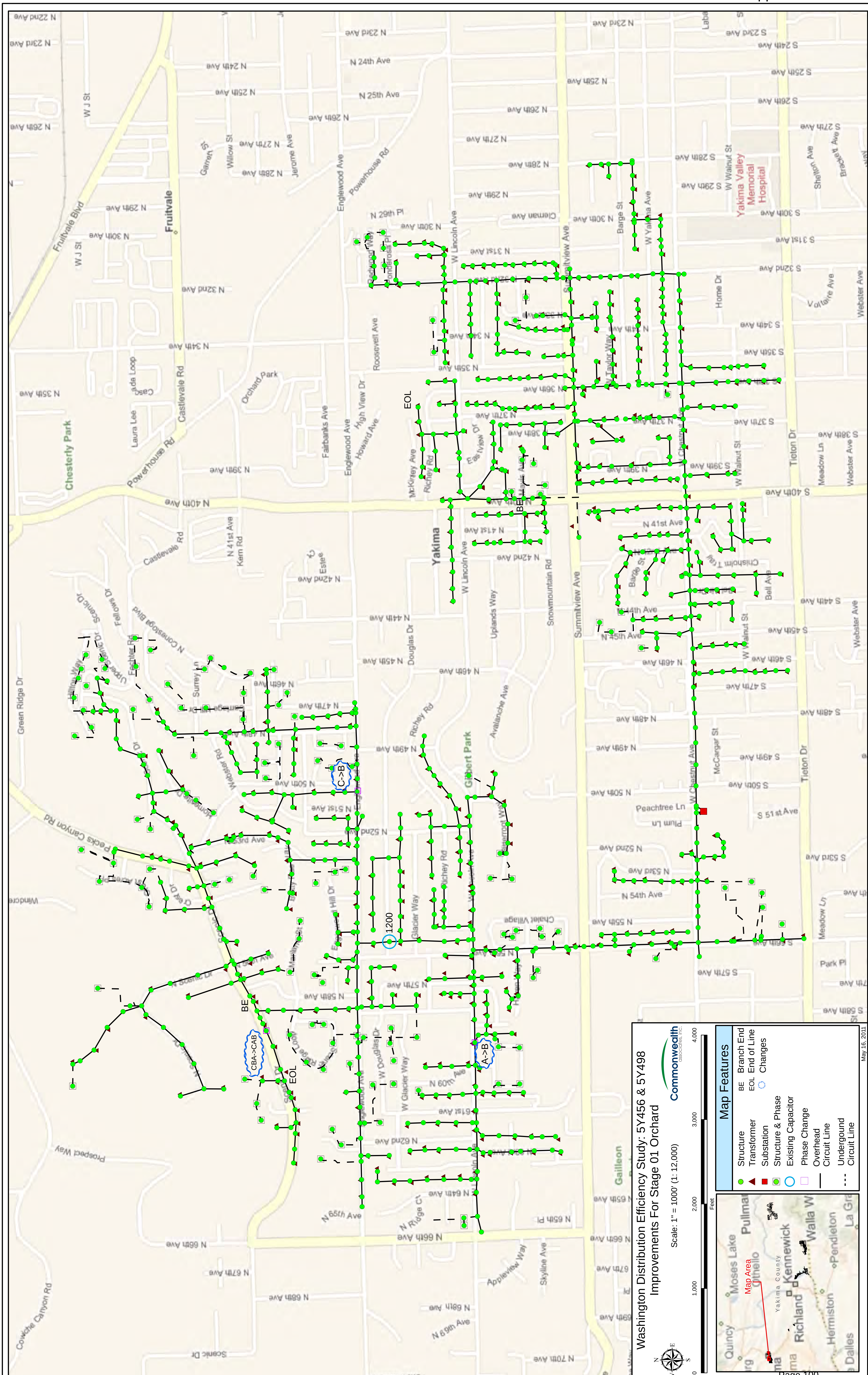

Washington Distribution Efficiency Study: 5Y434
Improvements For Stage 01 Wiley
Scale: 1" = 1500' (1: 18,000)
0
1,500
3,000
4,500
6,000
Feet
Commonwealth
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
BE Branch End
EOL End of Line
Changes
May 16, 2011
Map Area
Yakima County
+600
+300
BE
EOL


Washington Distribution Efficiency Study: 5Y434
Improvements For Stage 02 Wiley
Scale: 1" = 1500' (1: 18,000)
0 1,500 3,000 4,500 6,000
Feet
Commonwealth
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Underground Circuit Line
New Cap
Regulator
Reconductored Circuit
BE Branch End
EOL End of Line
Changes
Reconductoring Table
Color Key %
< 50
50-60
60-70
70-100
100+
May 12, 2011
Map Area
Yakima County
BE
EOL
+SW 600

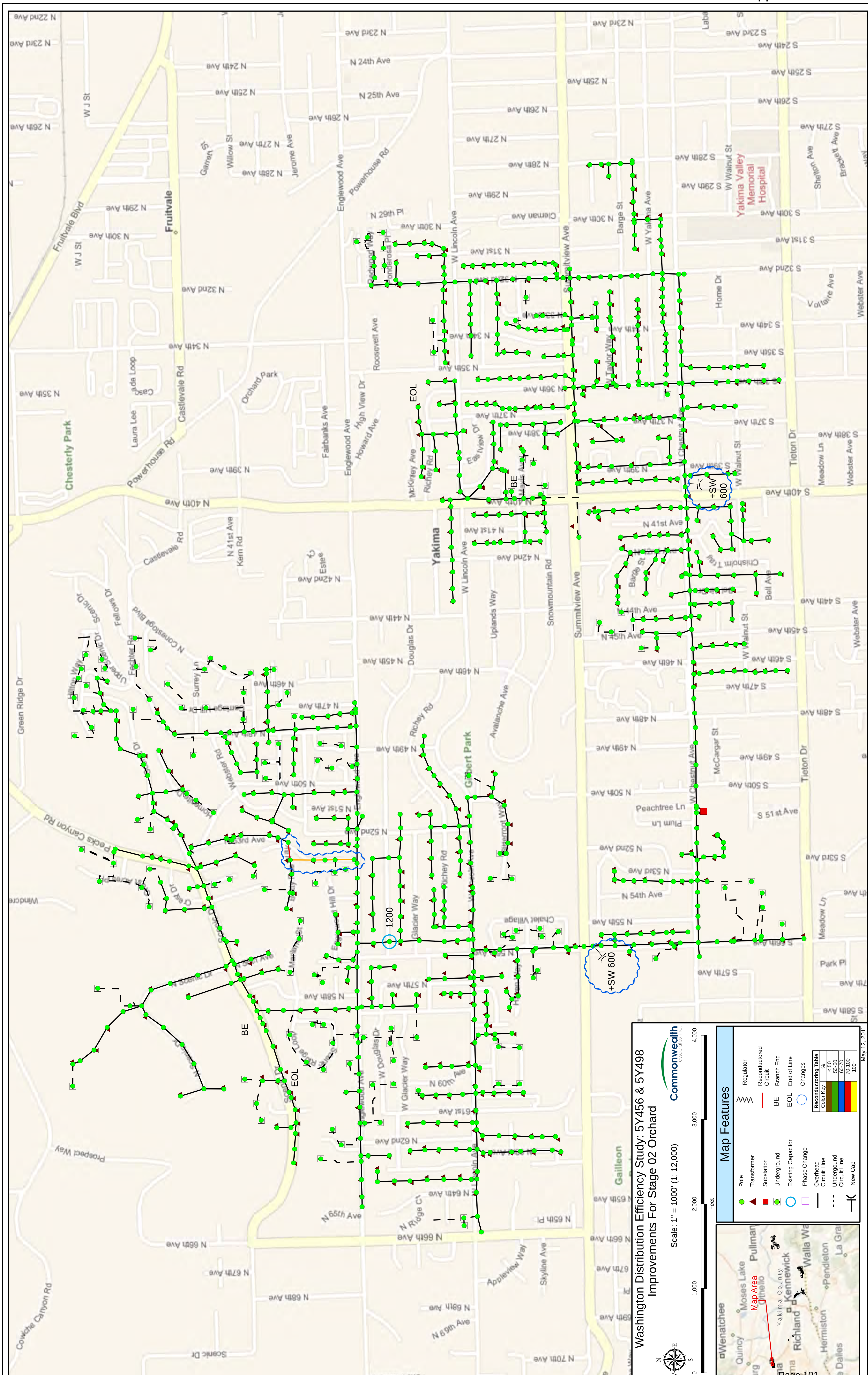

Washington Distribution Efficiency Study: 5Y444
Improvements For Stage 01 River Road
Scale: 1" = 800' (1: 9,600)
0
800
1,600
2,400
3,200
Feet
Commonwealth
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
BE Branch End
EOL End of Line
Changes
Map Area
Yakima County
May 16, 2011

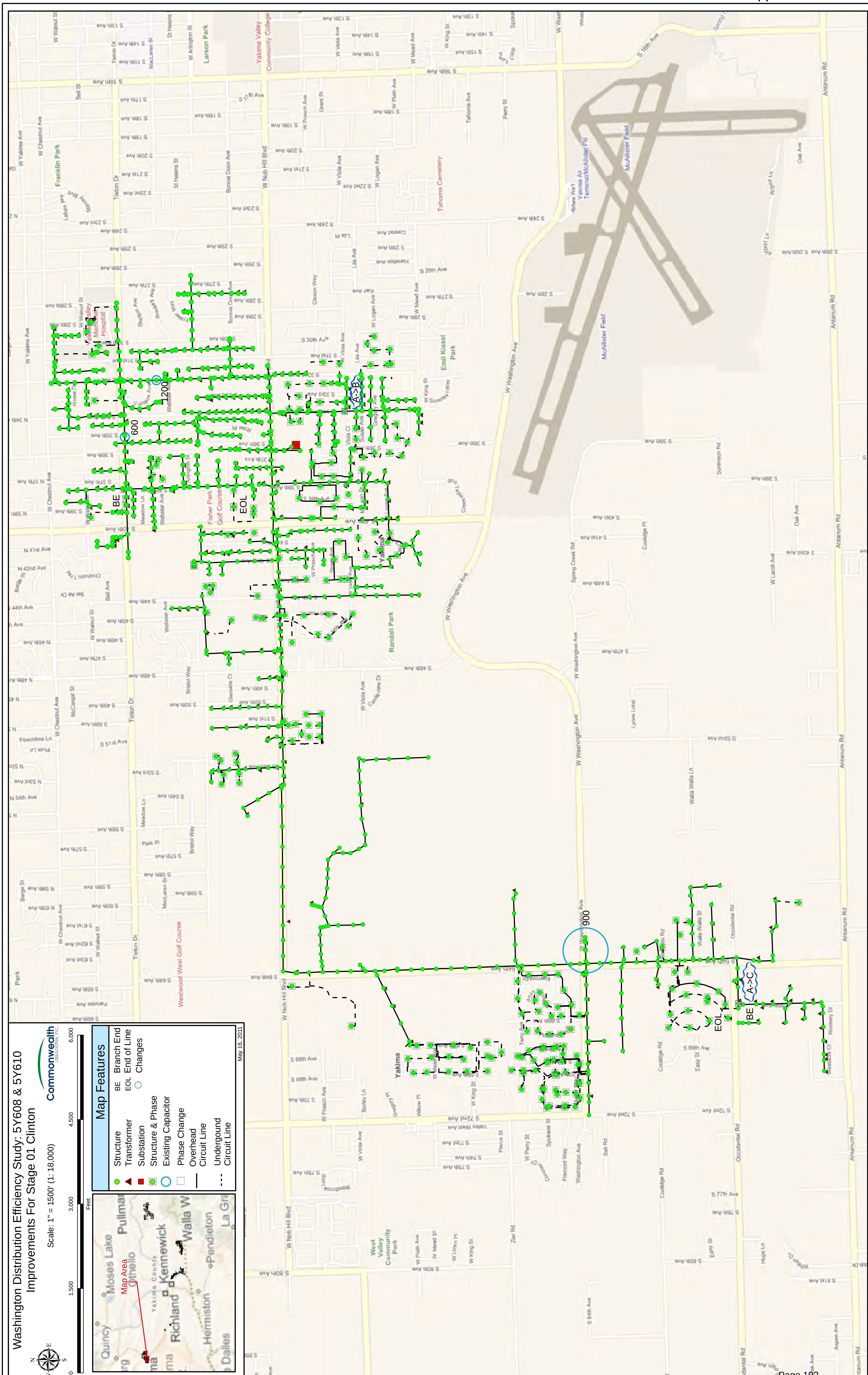


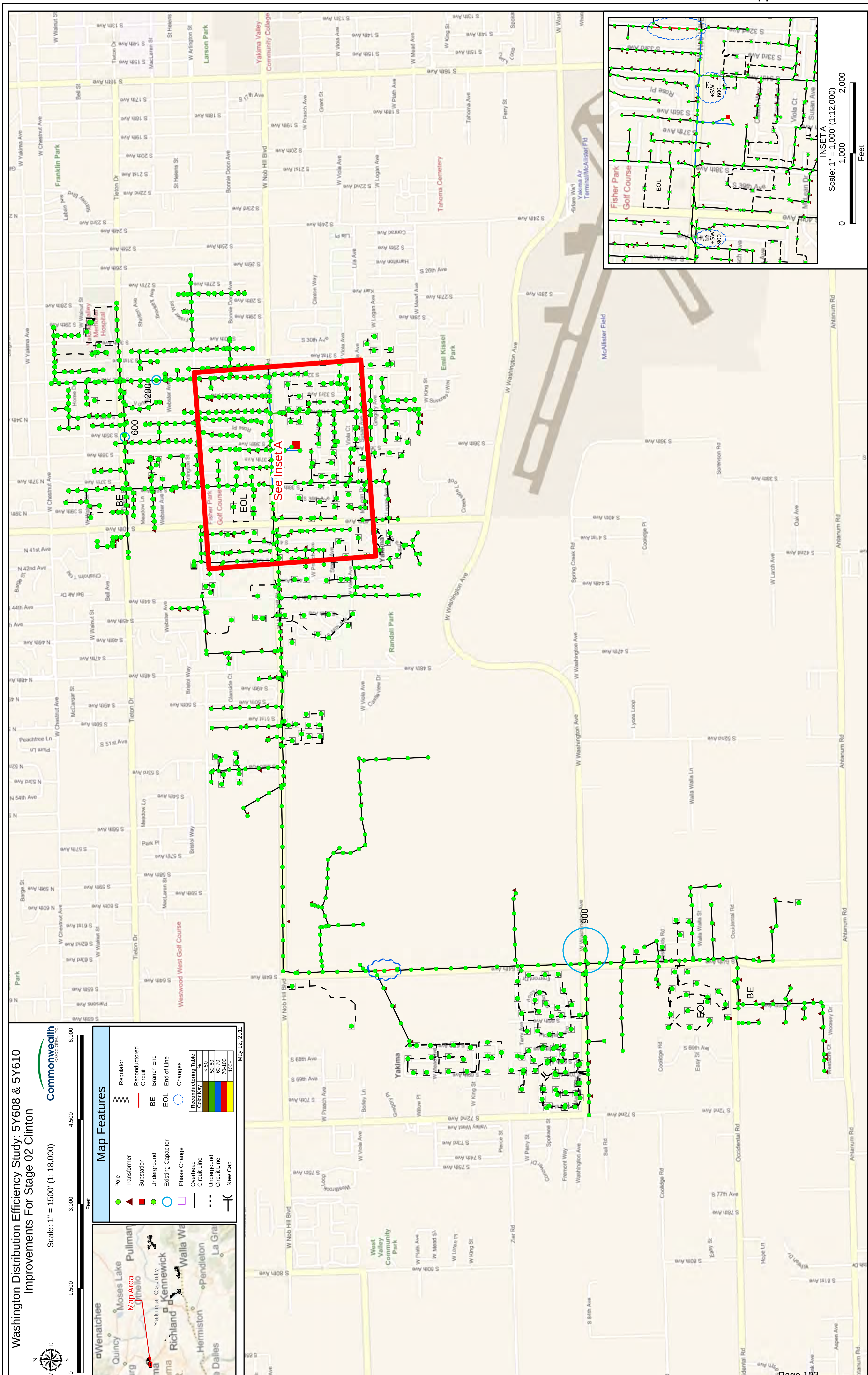
Washington Distribution Efficiency Study: 5Y444
Improvements For Stage 02 River Road
Scale: 1" = 800' (1: 9,600)
0
800
1,600
2,400
3,200
Feet
Commonwealth
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Underground Circuit Line
New Cap
Regulator
Reconductored Circuit
BE Branch End
EOL End of Line
Changes
Reconductoring Table
Color Key
%
< 50
50-60
60-70
70-100
100+
May 12, 2011
Map Area
Yakima County
Wenatchee
Moses Lake
Othello
Pullman
Kennewick
Richland
Walla Walla
Pendleton
Hermiston
Fruitvale Blvd
N 16th Ave
N 40th Ave
Summitview Ave
Yakima
Chesterly Park
Milroy Park
Gilbert Park
Fruitvale
+SW 600
SW600
EOLL
600



Washington Distribution Efficiency Study: 5Y456 & 5Y498
Improvements For Stage 01 Orchard
Scale: 1" = 1000' (1: 12,000)
Commonwealth
0
1,000
2,000
3,000
4,000
Feet
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
BE Branch End
EOL End of Line
Changes
May 16, 2011
Map Area
Yakima County
C->B
A->B
CBA->CAB
1200
EOL
BE

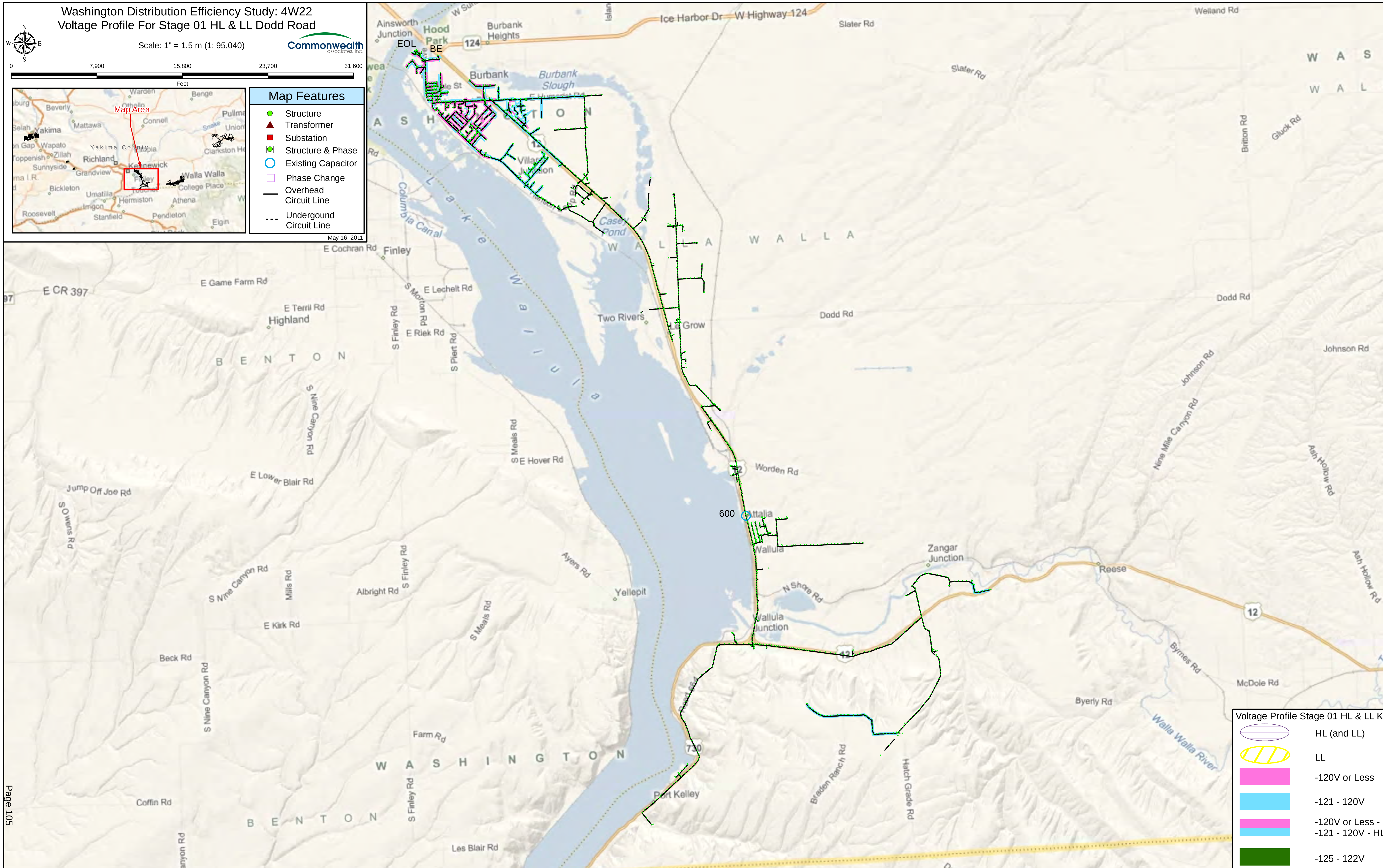

Washington Distribution Efficiency Study: 5Y456 & 5Y498
Improvements For Stage 02 Orchard
Scale: 1" = 1000' (1: 12,000)
0 1,000 2,000 3,000 4,000
Feet
Commonwealth Associates Inc.
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
New Cap
Regulator
Reconductored Circuit
BE Branch End
EOL End of Line
Changes
Reconductoring Table
Color Key %
< 50
50-60
60-70
70-100
100+
May 12, 2011
+SW 600
+SW 600
1200
EOL
BE
Yakima
Yakima Valley Memorial Hospital

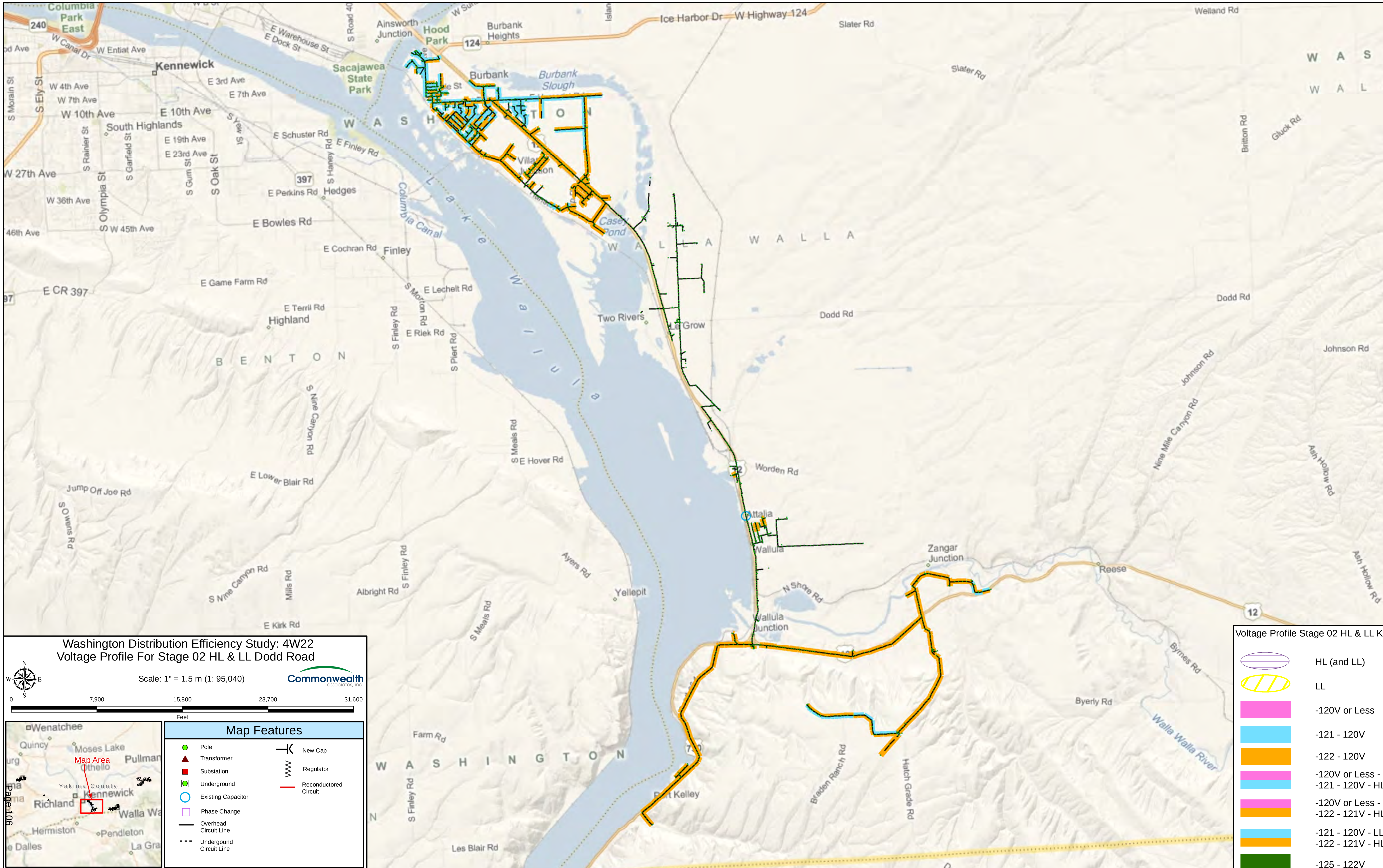

Washington Distribution Efficiency Study: 5Y608 & 5Y610
Improvements For Stage 01 Clinton
Scale: 1" = 1500' (1: 18,000)
0
1,500
3,000
4,500
6,000
Feet
Commonwealth
Map Area
Yakima County
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
BE Branch End
EOL End of Line
Changes
May 16, 2011



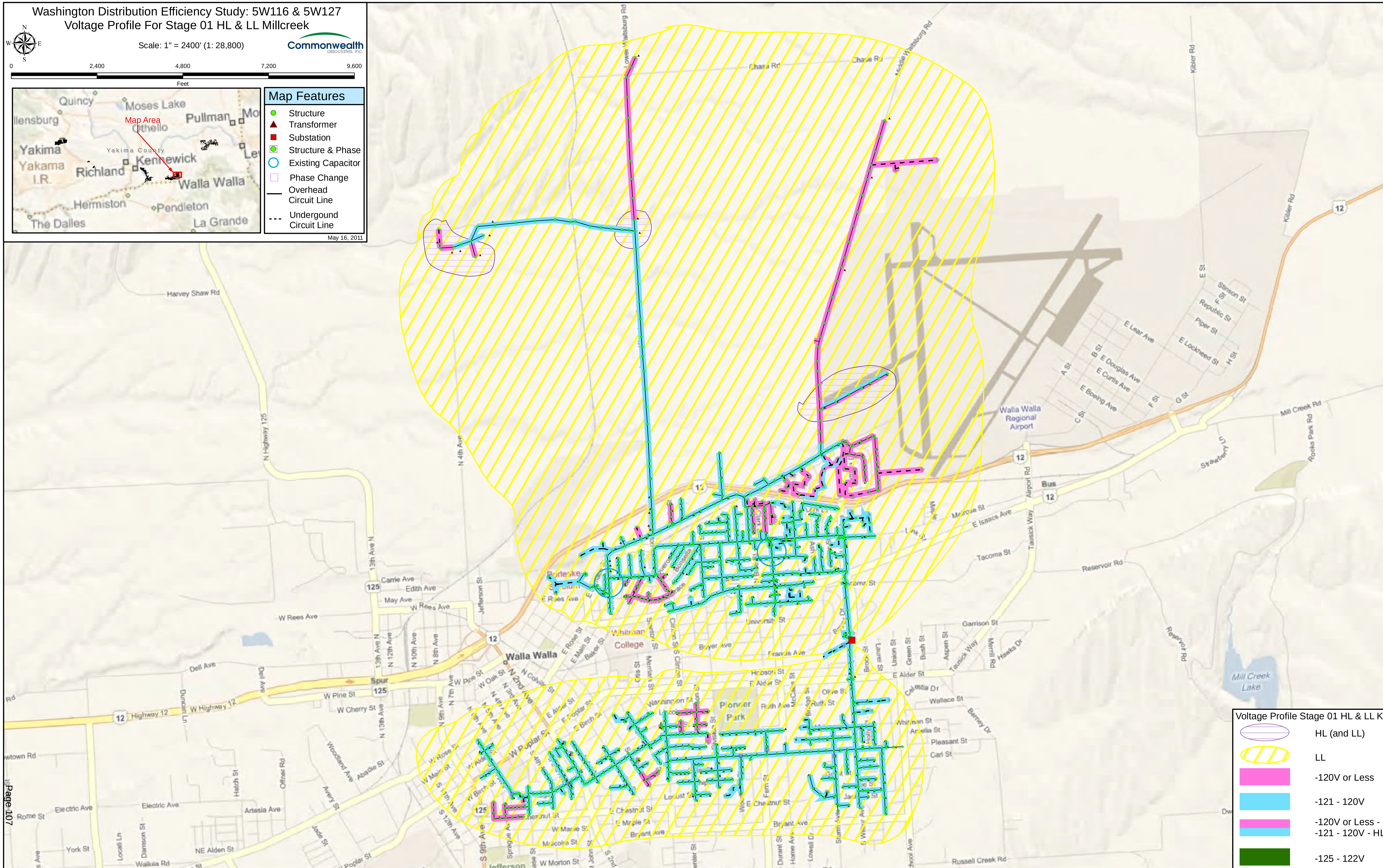
Washington Distribution Efficiency Study: 5Y608 & 5Y610
Improvements For Stage 02 Clinton
Scale: 1" = 1500' (1: 18,000)
0
1,500
3,000
4,500
6,000
Feet
Commonwealth
Map Area
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Underground Circuit Line
New Cap
Regulator
Reconductored Circuit
BE Branch End
EOL End of Line
Changes
Reconductoring Table
Color Key
%
< 50
50-60
60-70
70-100
100+
May 12, 2011
See Inset A
INSET A
Scale: 1" = 1,000' (1:12,000)
0
1,000
2,000
Feet
600
1200
900
BE
EOL

## Appendix 6:  Circuit Voltages

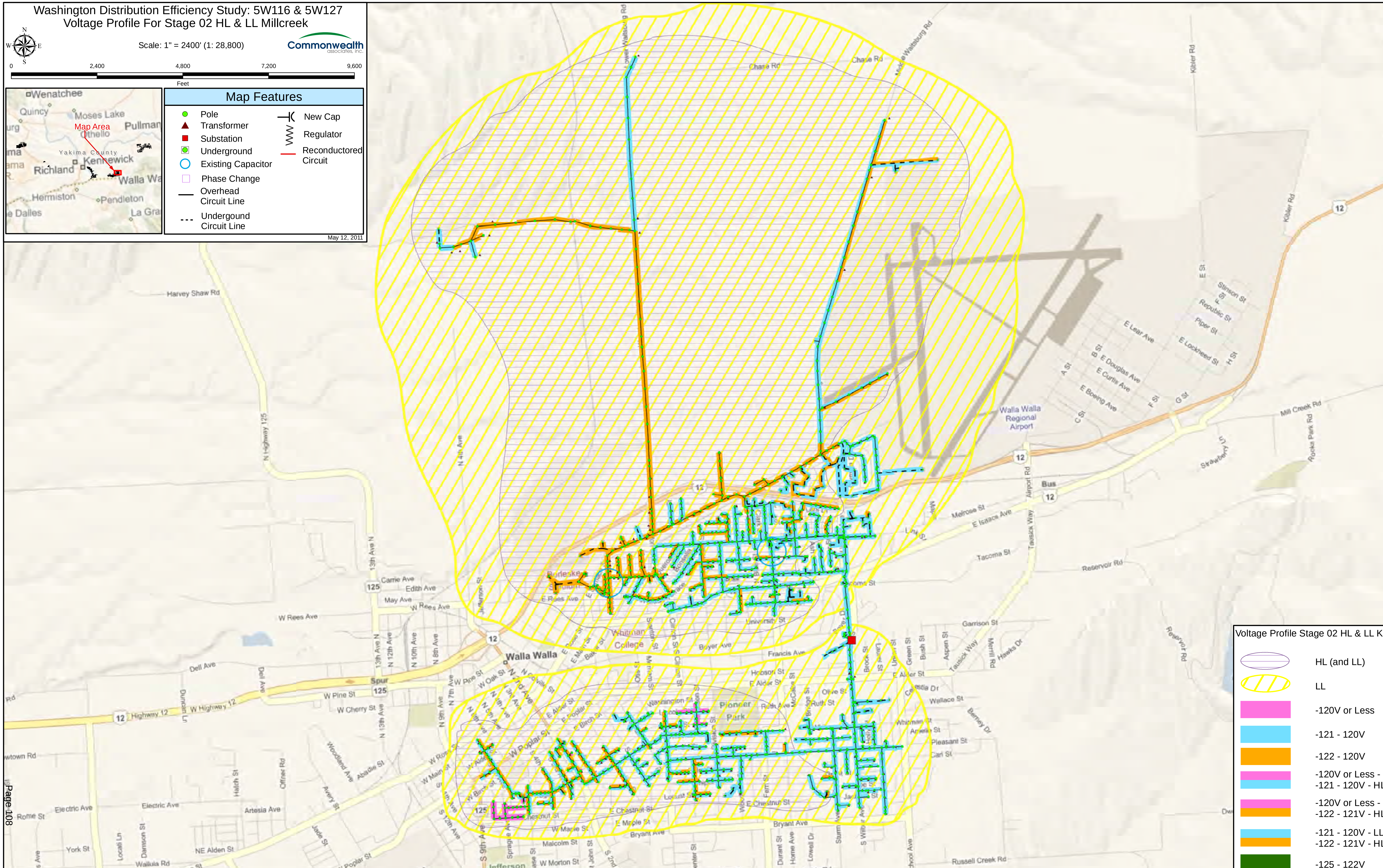

Washington Distribution Efficiency Study: 4W22
Voltage Profile For Stage 01 HL & LL Dodd Road
Scale: 1" = 1.5 m (1: 95,040)
Commonwealth
0
7,900
15,800
23,700
31,600
Feet
Map Area
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
May 16, 2011
EOL
BE
600
Voltage Profile Stage 01 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-120V or Less - LL
-121 - 120V - HL
-125 - 122V

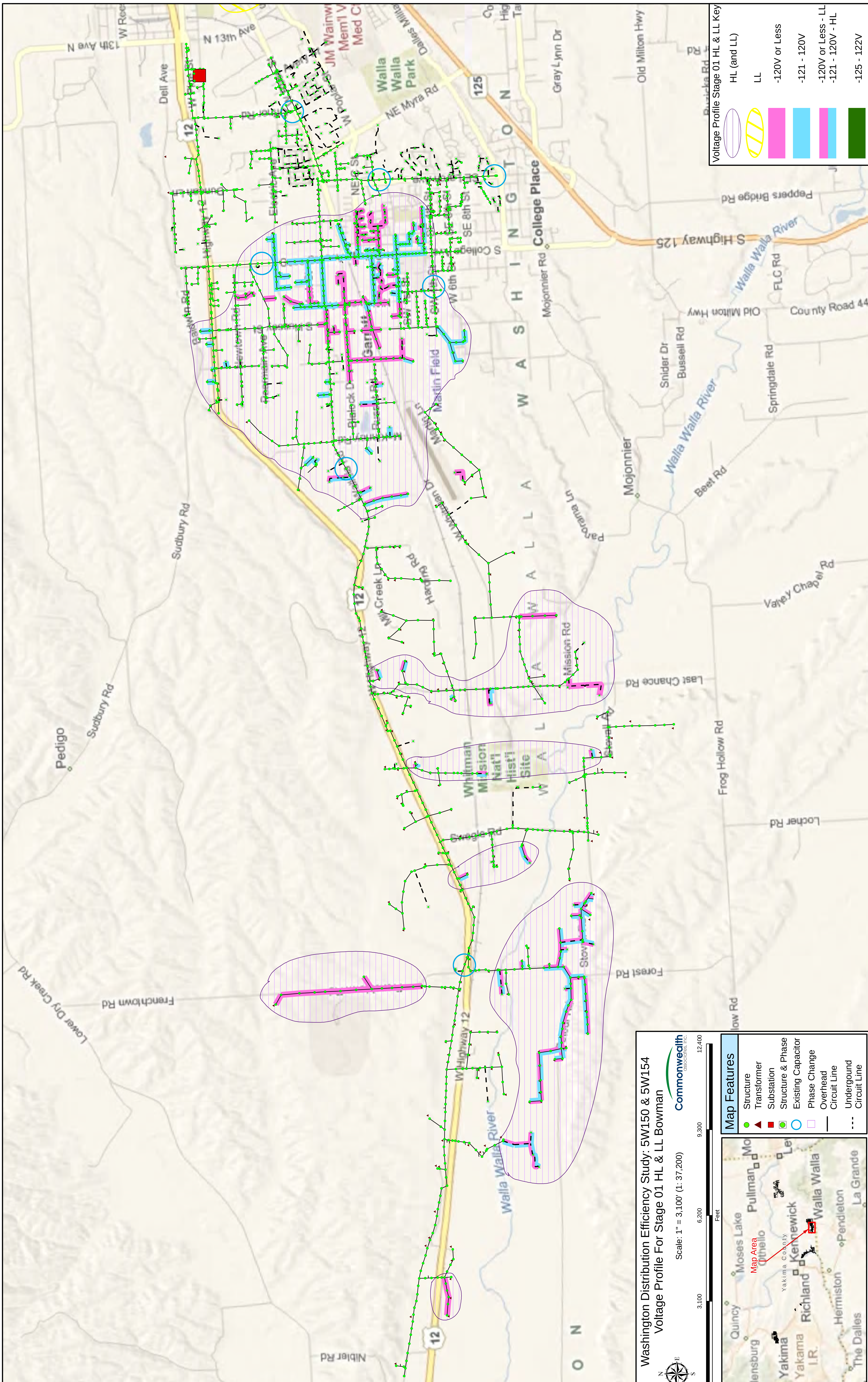


Washington Distribution Efficiency Study: 4W22
Voltage Profile For Stage 02 HL & LL Dodd Road
Scale: 1" = 1.5 m (1: 95,040)
Commonwealth Associates, Inc.
0 7,900 15,800 23,700 31,600 Feet
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
New Cap
Regulator
Reconductored Circuit
May 12, 2011
Map Area
Voltage Profile Stage 02 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-122 - 120V
-120V or Less - LL
-121 - 120V - HL
-120V or Less - LL
-122 - 121V - HL
-121 - 120V - LL
-122 - 121V - HL
-125 - 122V
Kennewick
Burbank
Finley
Two Rivers
Wallula
Wallula Junction
Zangar Junction
Reese
Lake Wallula
Walla Walla River
W A S H I N G T O N
B E N T O N
W A L L A W A L L A

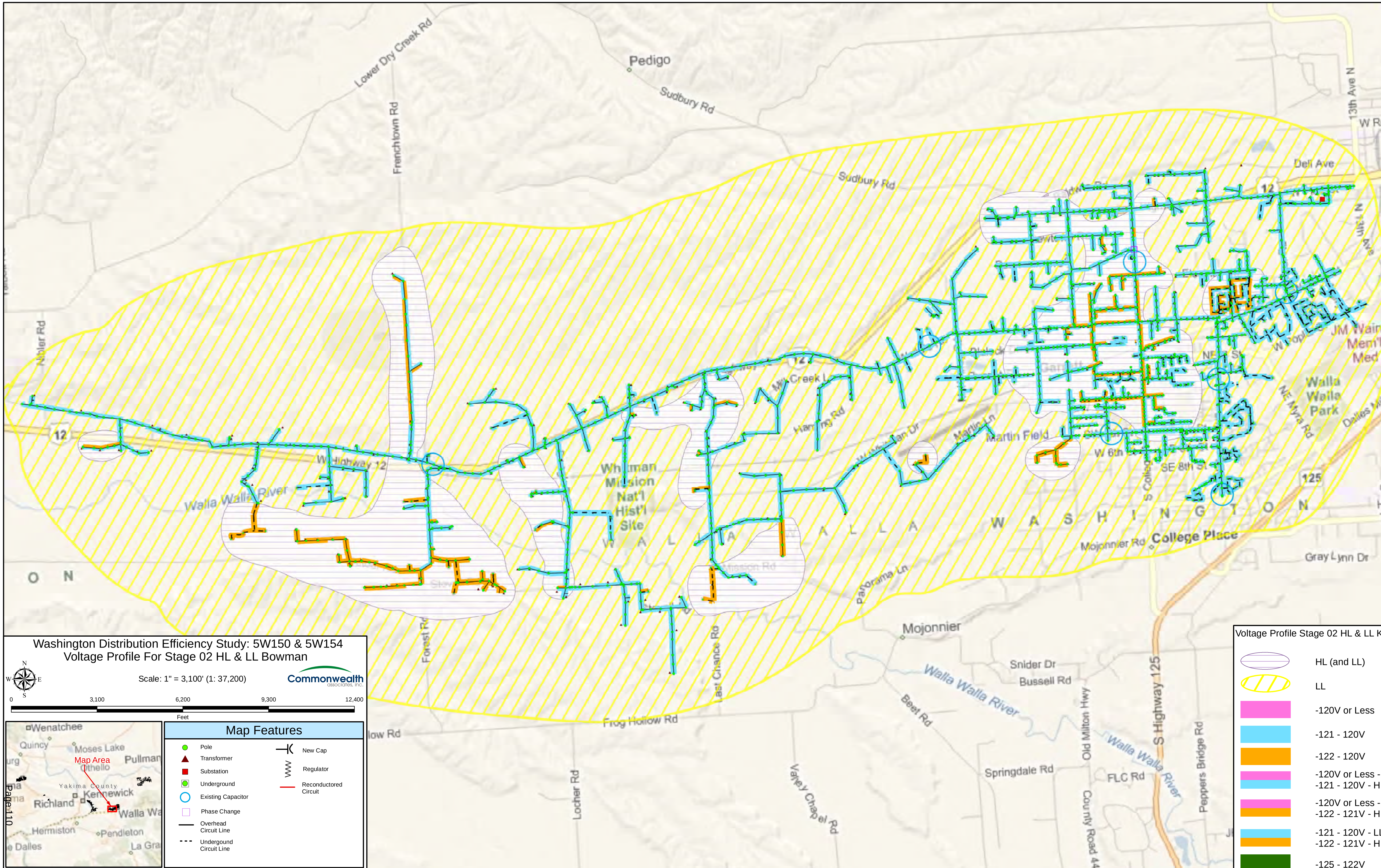

Washington Distribution Efficiency Study: 5W116 & 5W127
Voltage Profile For Stage 01 HL & LL Millcreek
Scale: 1" = 2400' (1: 28,800)
Commonwealth associates, inc.
0
2,400
4,800
7,200
9,600
Feet
Map Area
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
May 16, 2011
Voltage Profile Stage 01 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-120V or Less - LL
-121 - 120V - HL
-125 - 122V
Walla Walla Regional Airport
Walla Walla
Whitman College
Pioneer Park
Mill Creek Lake

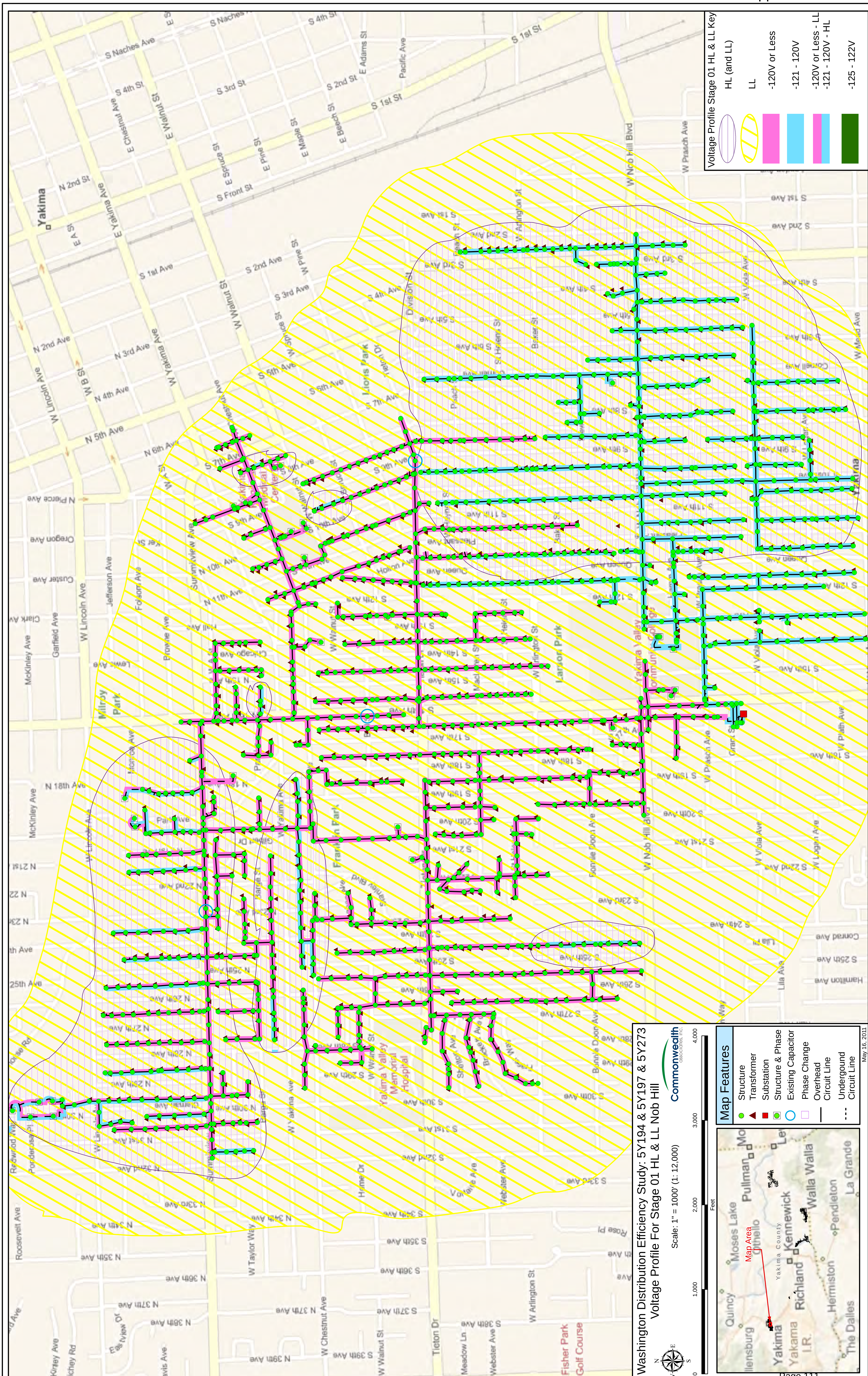
# Washington Distribution Efficiency Study: 5W116 & 5W127
## Voltage Profile For Stage 02 HL & LL Millcreek

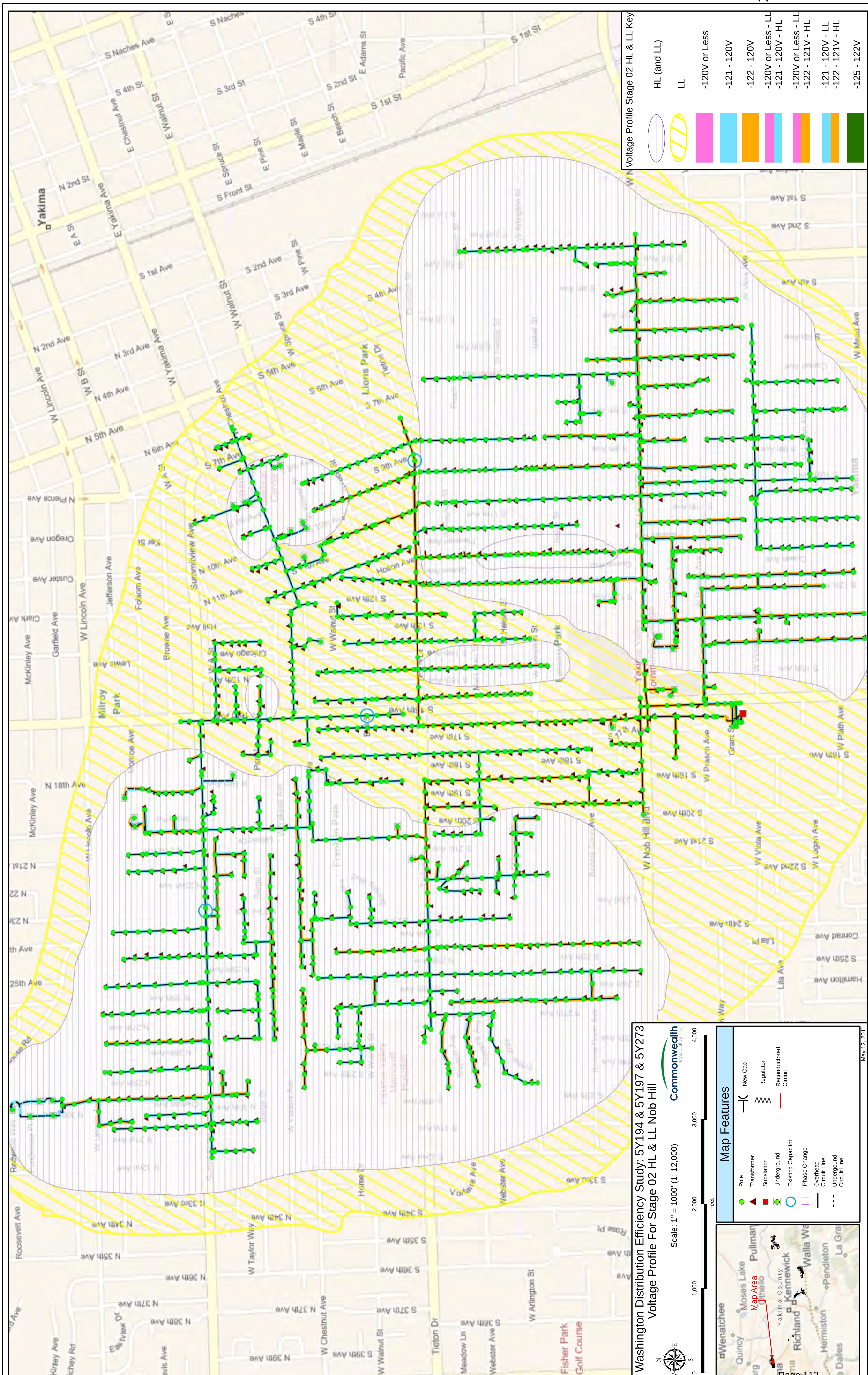


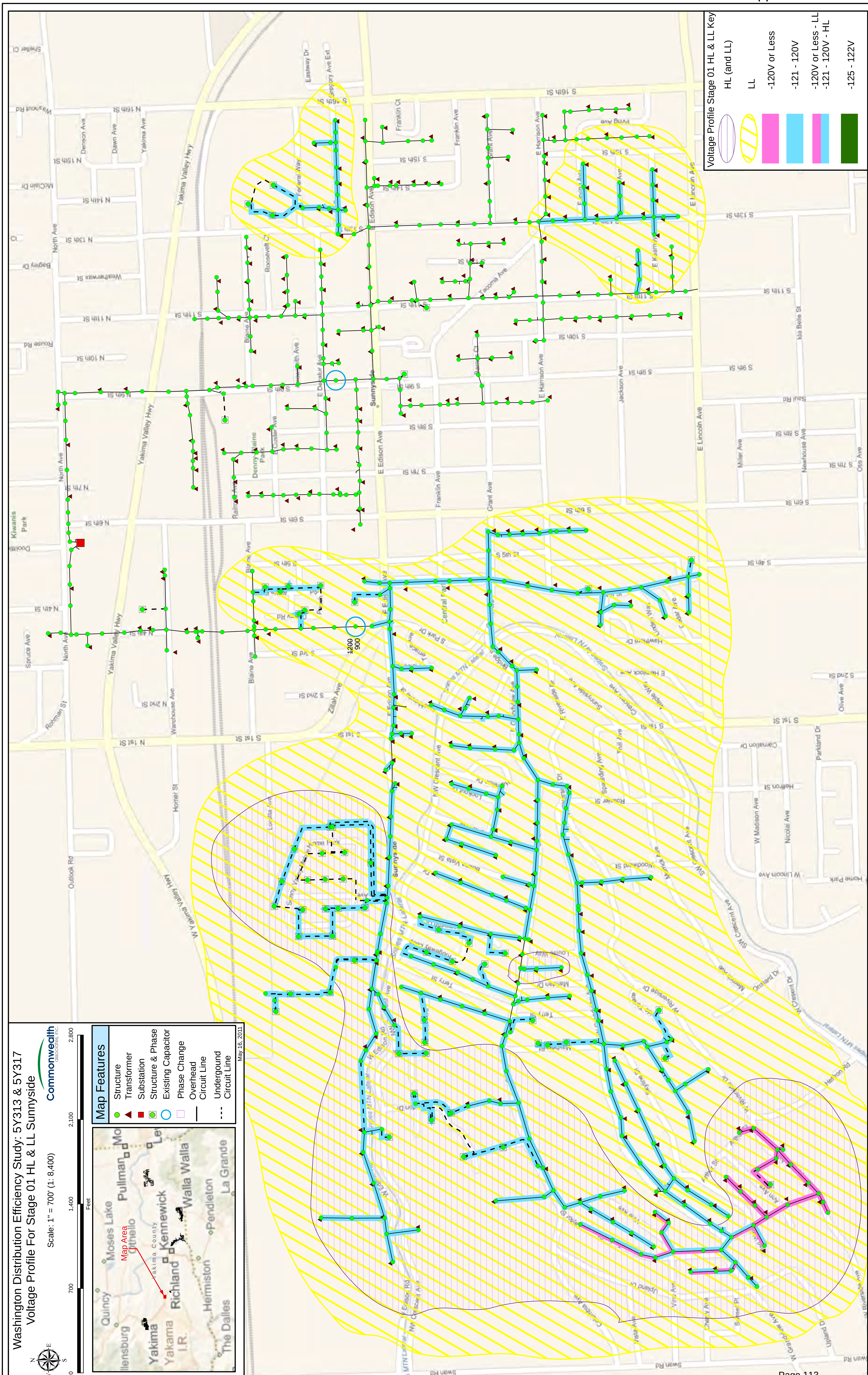


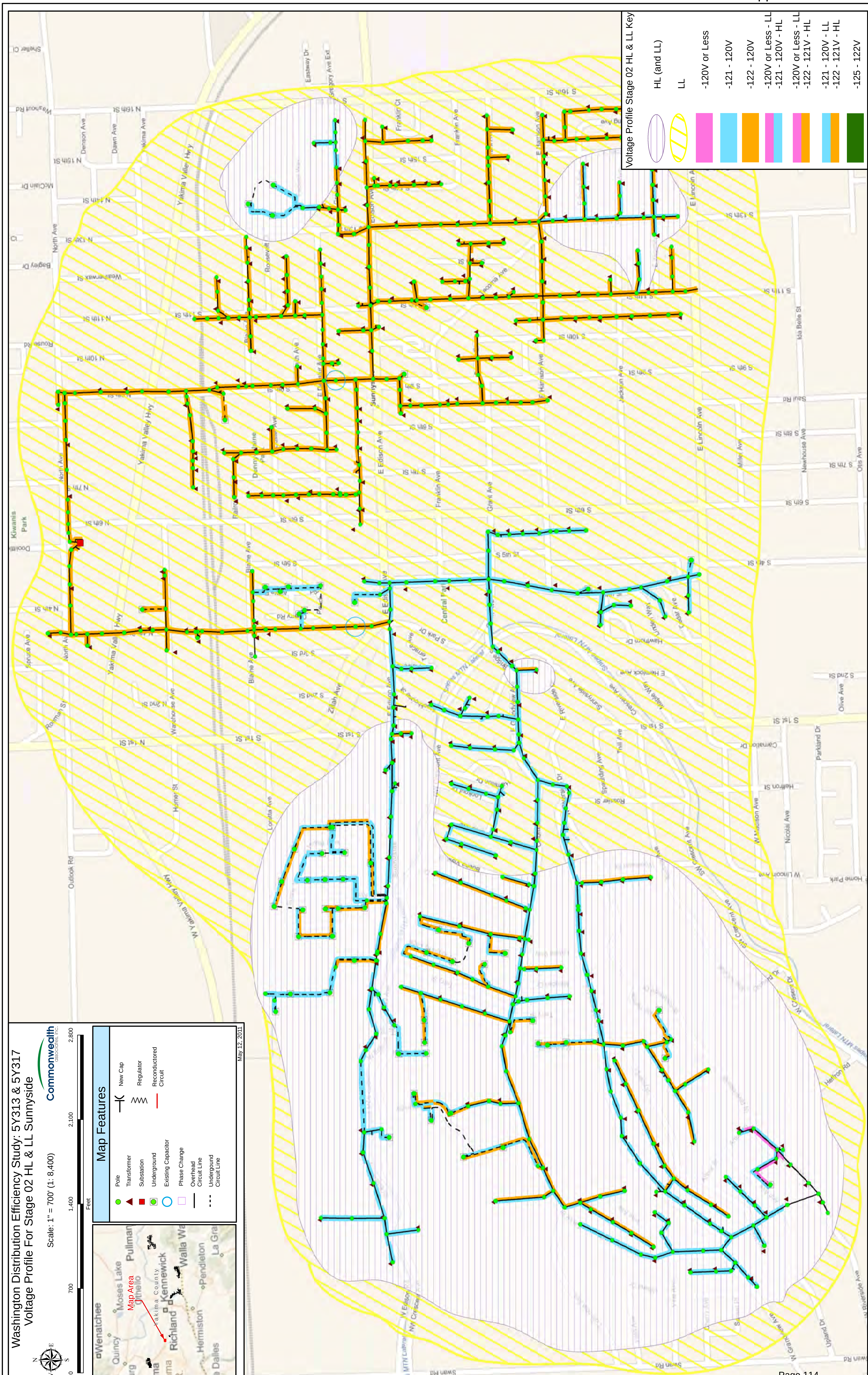
Washington Distribution Efficiency Study: 5W150 & 5W154
Voltage Profile For Stage 01 HL & LL Bowman
Scale: 1" = 3,100' (1: 37,200)
0 3,100 6,200 9,300 12,400
Feet
Commonwealth
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
May 16, 2011
Voltage Profile Stage 01 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-120V or Less - LL
-121 - 120V - HL
-125 - 122V
Map Area
College Place
Walla Walla River
Mojonnier
Pedigo
Martin Field
Whitman Mission Nat'l Hist'l Site
Frenchtown Rd
Sudbury Rd
Last Chance Rd
Forest Rd
Swegle Rd
Mission Rd
Old Milton Hwy
S Highway 125
Peppers Bridge Rd
Valley Chapel Rd
Lower Dry Creek Rd

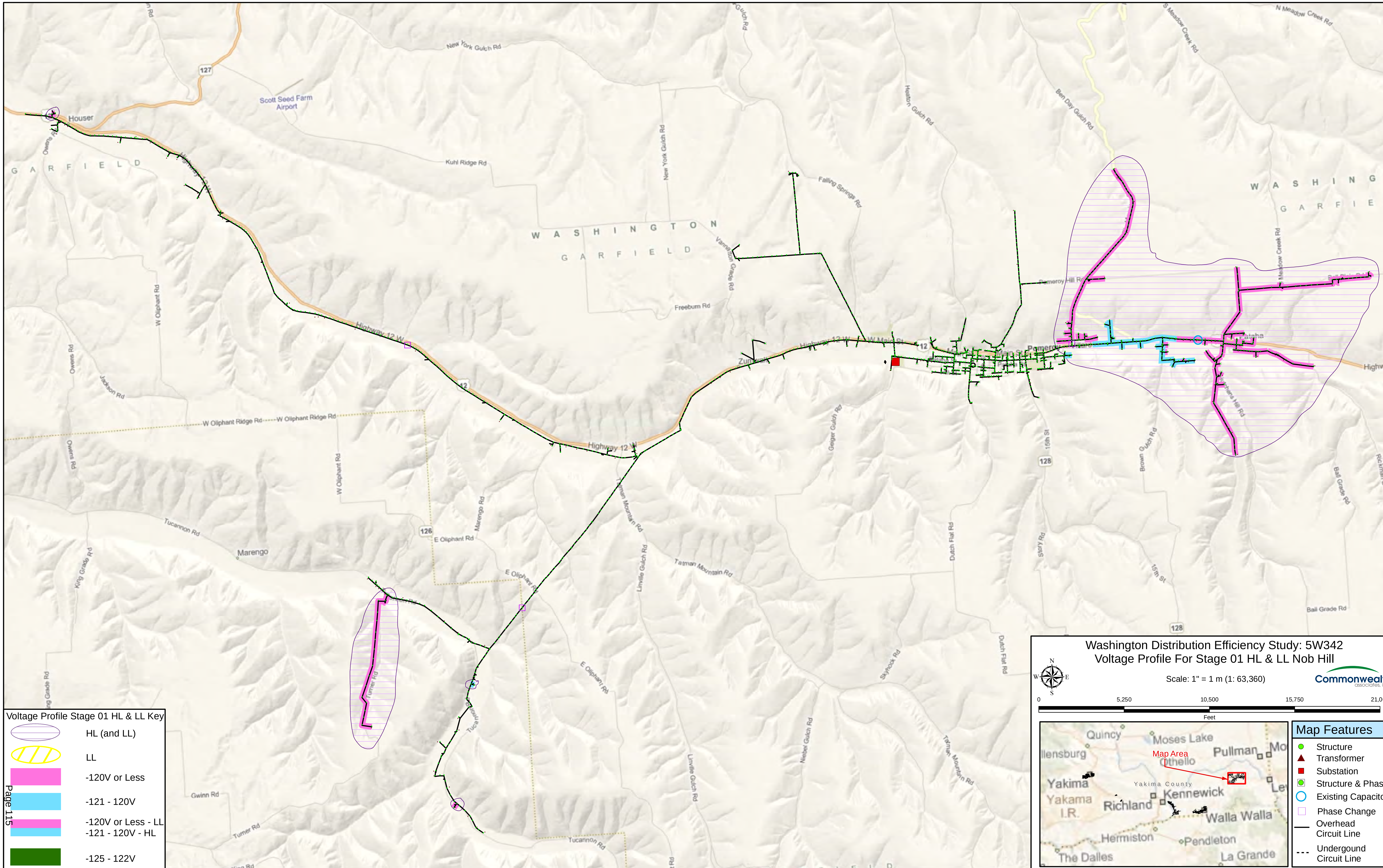

Washington Distribution Efficiency Study: 5W150 & 5W154
Voltage Profile For Stage 02 HL & LL Bowman
Scale: 1" = 3,100' (1: 37,200)
0
3,100
6,200
9,300
12,400
Feet
Commonwealth
associates, inc.
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
New Cap
Regulator
Reconductored Circuit
May 12, 2011
Voltage Profile Stage 02 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-122 - 120V
-120V or Less - LL
-121 - 120V - HL
-120V or Less - LL
-122 - 121V - HL
-121 - 120V - LL
-122 - 121V - HL
-125 - 122V
Wenatchee
Quincy
Moses Lake
Othello
Pullman
Map Area
Yakima County
Kennewick
Richland
Hermiston
Pendleton
Walla Wa
Pedigo
Sudbury Rd
Lower Dry Creek Rd
Frenchtown Rd
Nibler Rd
W Highway 12
Walla Walla River
Whitman Mission Nat'l Hist'l Site
Forest Rd
Last Chance Rd
Frog Hollow Rd
Locher Rd
Valley Chapel Rd
Mojonnier
Mojonnier Rd
College Place
Panorama Ln
Snider Dr
Bussell Rd
Beet Rd
Springdale Rd
Old Milton Hwy
County Road 448
FLC Rd
S Highway 125
Peppers Bridge Rd
Gray Lynn Dr
Martin Field
W 6th
SE 8th St
Mill Creek
Deli Ave
13th Ave N
N 13th Ave
Walla Walla Park
NE Myra Rd
JM Wainwright Mem'l VA Med Ctr
W A L L A   W A L L A
W A S H I N G T O N

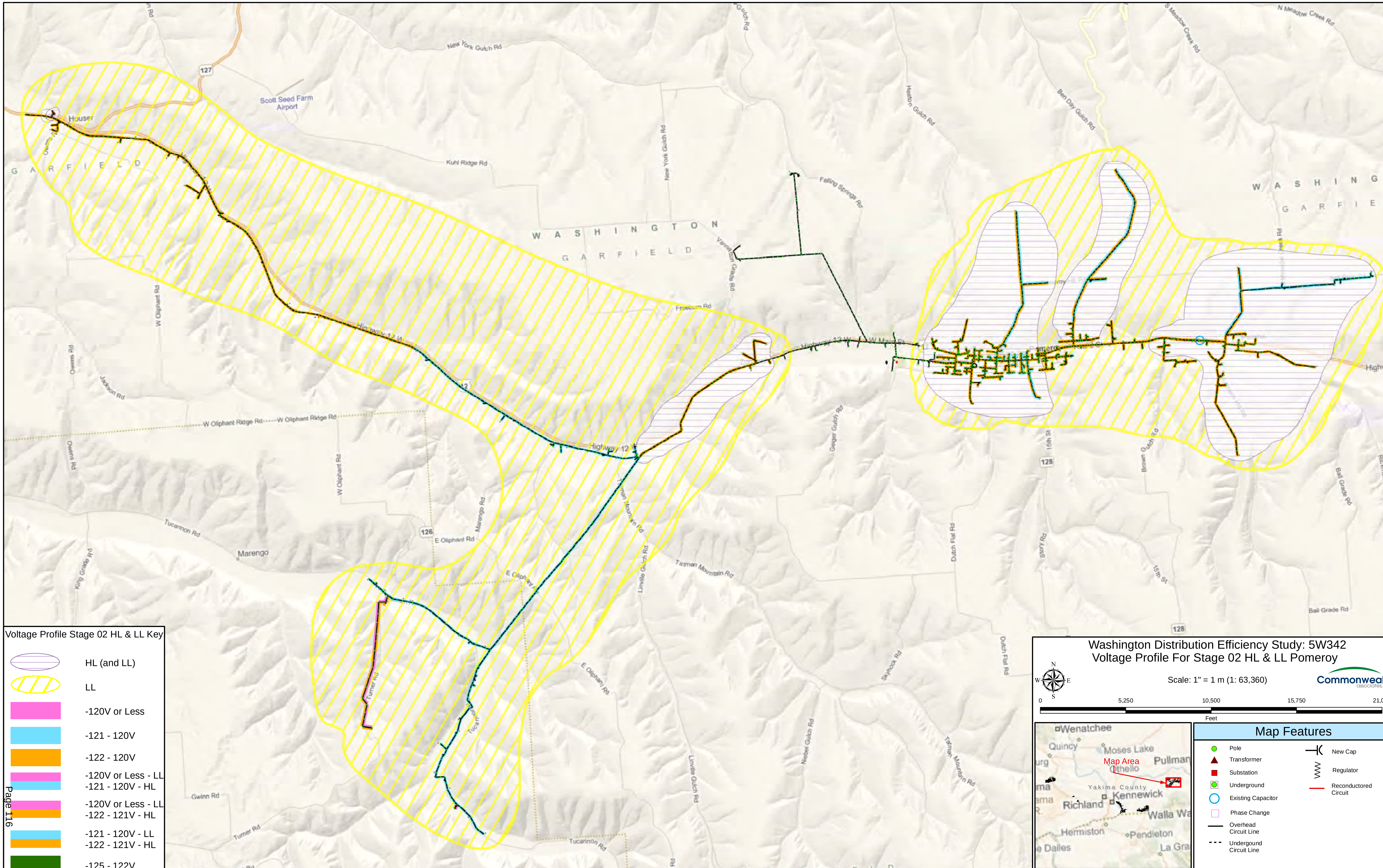

Washington Distribution Efficiency Study: 5Y194 & 5Y197 & 5Y273
Voltage Profile For Stage 01 HL & LL Nob Hill
Scale: 1" = 1000' (1:12,000)
Commonwealth associates inc.
0
1,000
2,000
3,000
4,000
Feet
May 16, 2011
Voltage Profile Stage 01 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-120V or Less - LL
-121 - 120V - HL
-125 - 122V
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
Map Area
Yakima County
Yakima
Kennewick
Richland
Walla Walla
Pullman
Moses Lake
Othello
Quincy
Pendleton
Hermiston
La Grande
The Dalles
Yakama I.R.
Yakima Valley Community College
Yakima Valley Memorial Hospital
Larson Park
Franklin Park
Lions Park
Milroy Park
Fisher Park Golf Course


Washington Distribution Efficiency Study: 5Y194 & 5Y197 & 5Y273
Voltage Profile For Stage 02 HL & LL Nob Hill
Scale: 1" = 1000' (1: 12,000)
0
1,000
2,000
3,000
4,000
Feet
Commonwealth
May 12, 2011
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Underground Circuit Line
New Cap
Regulator
Reconductored Circuit
Voltage Profile Stage 02 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-122 - 120V
-120V or Less - LL
-121 - 120V - HL
-120V or Less - LL
-122 - 121V - HL
-121 - 120V - LL
-122 - 121V - HL
-125 - 122V
Map Area
Yakima County


Washington Distribution Efficiency Study: 5Y313 & 5Y317
Voltage Profile For Stage 01 HL & LL Sunnyside
Scale: 1" = 700' (1: 8,400)
Commonwealth
0
700
1,400
2,100
2,800
Feet
Map Area
Yakima County
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
May 16, 2011
Voltage Profile Stage 01 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-120V or Less - LL
-121 - 120V - HL
-125 - 122V
1200
900

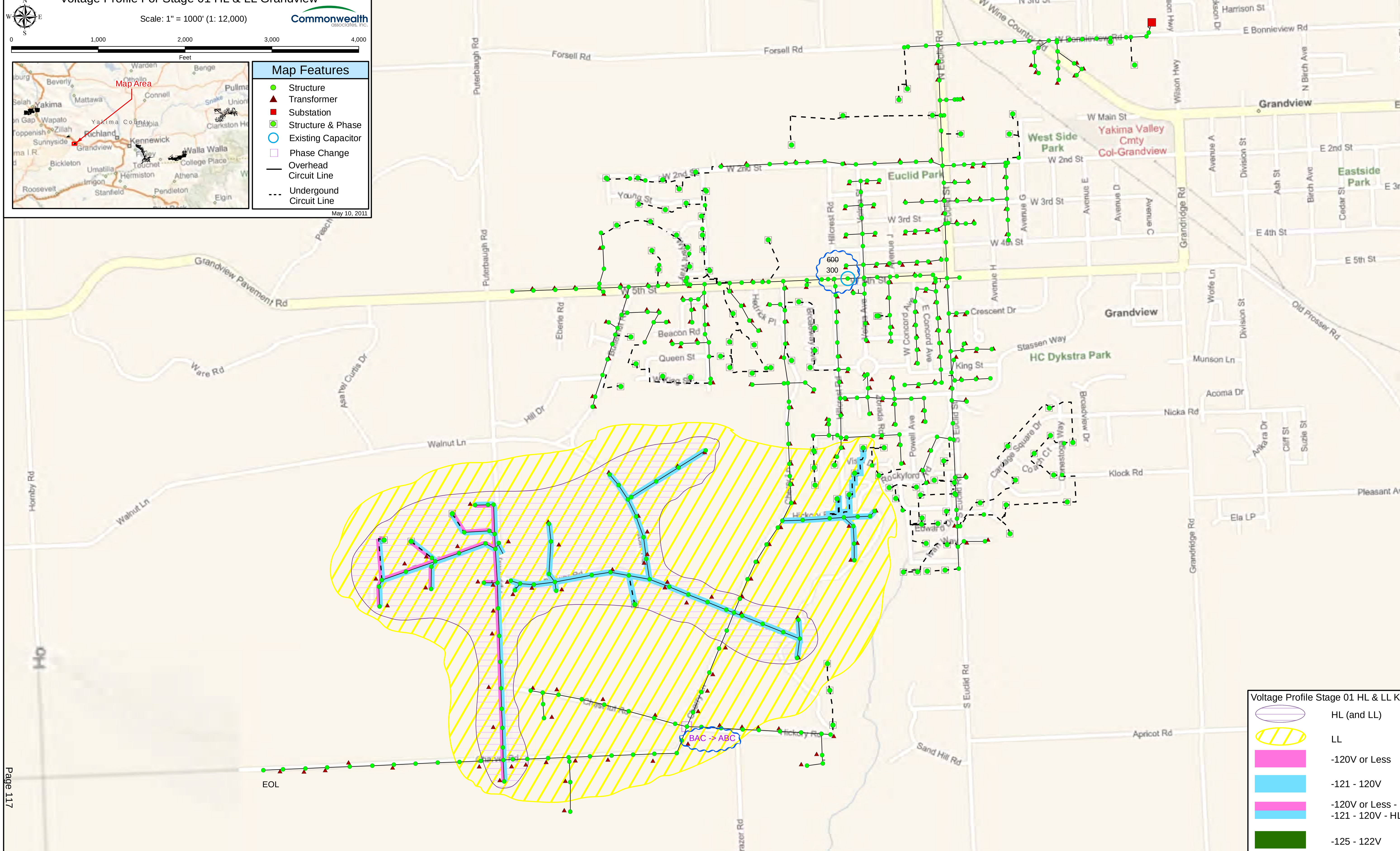

Washington Distribution Efficiency Study: 5Y313 & 5Y317
Voltage Profile For Stage 02 HL & LL Sunnyside
Scale: 1" = 700' (1: 8,400)
Commonwealth Associates, Inc.
0
700
1,400
2,100
2,800
Feet
Map Area
Yakima County
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Underground Circuit Line
New Cap
Regulator
Reconductored Circuit
May 12, 2011
Voltage Profile Stage 02 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-122 - 120V
-120V or Less - LL
-121 - 120V - HL
-120V or Less - LL
-122 - 121V - HL
-121 - 120V - LL
-122 - 121V - HL
-125 - 122V

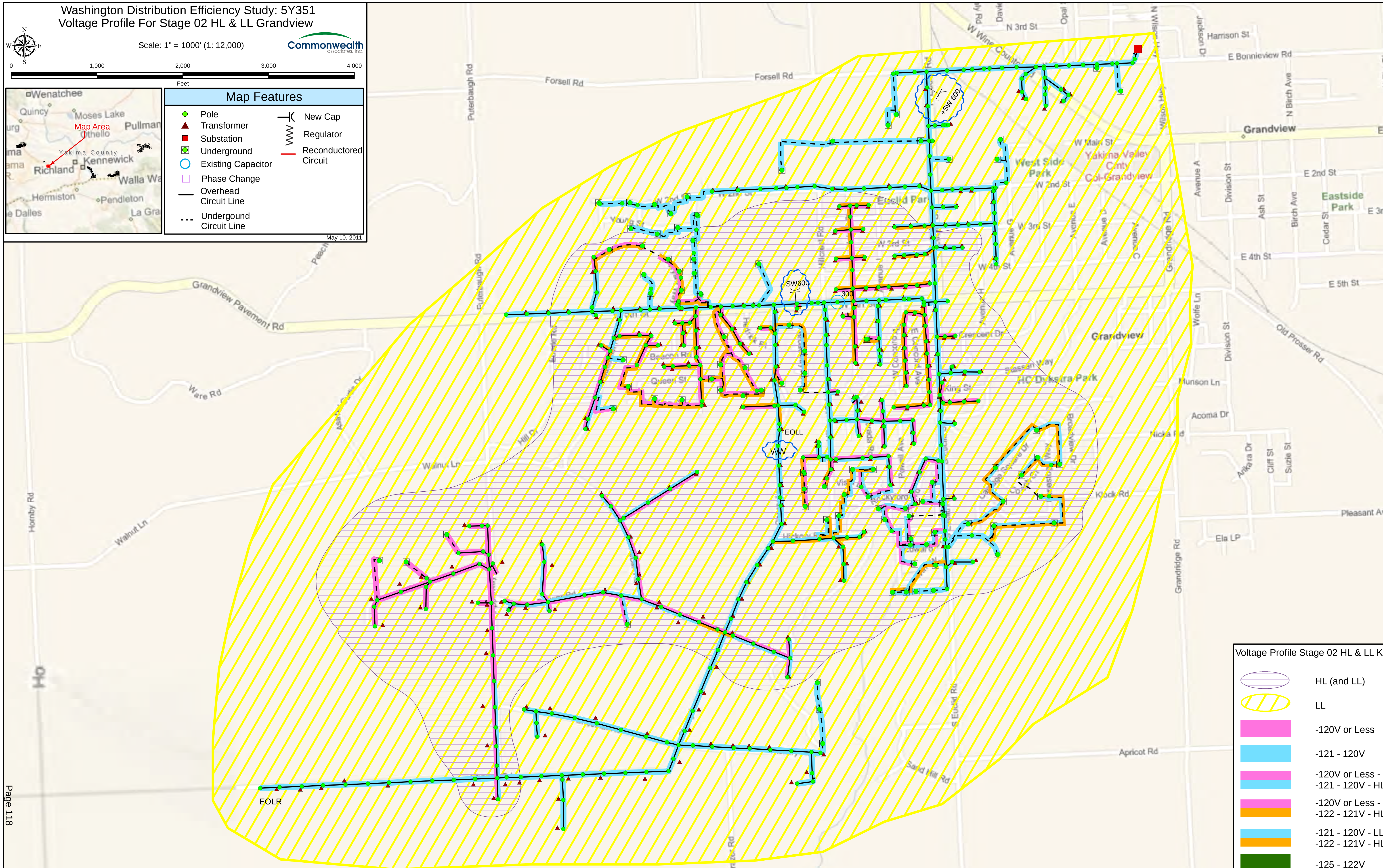

Washington Distribution Efficiency Study: 5W342
Voltage Profile For Stage 01 HL & LL Nob Hill
Scale: 1" = 1 m (1: 63,360)
Commonwealth associates, inc.
0
5,250
10,500
15,750
21,000
Feet
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
Map Area
May 16, 2011
Voltage Profile Stage 01 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-120V or Less - LL
-121 - 120V - HL
-125 - 122V

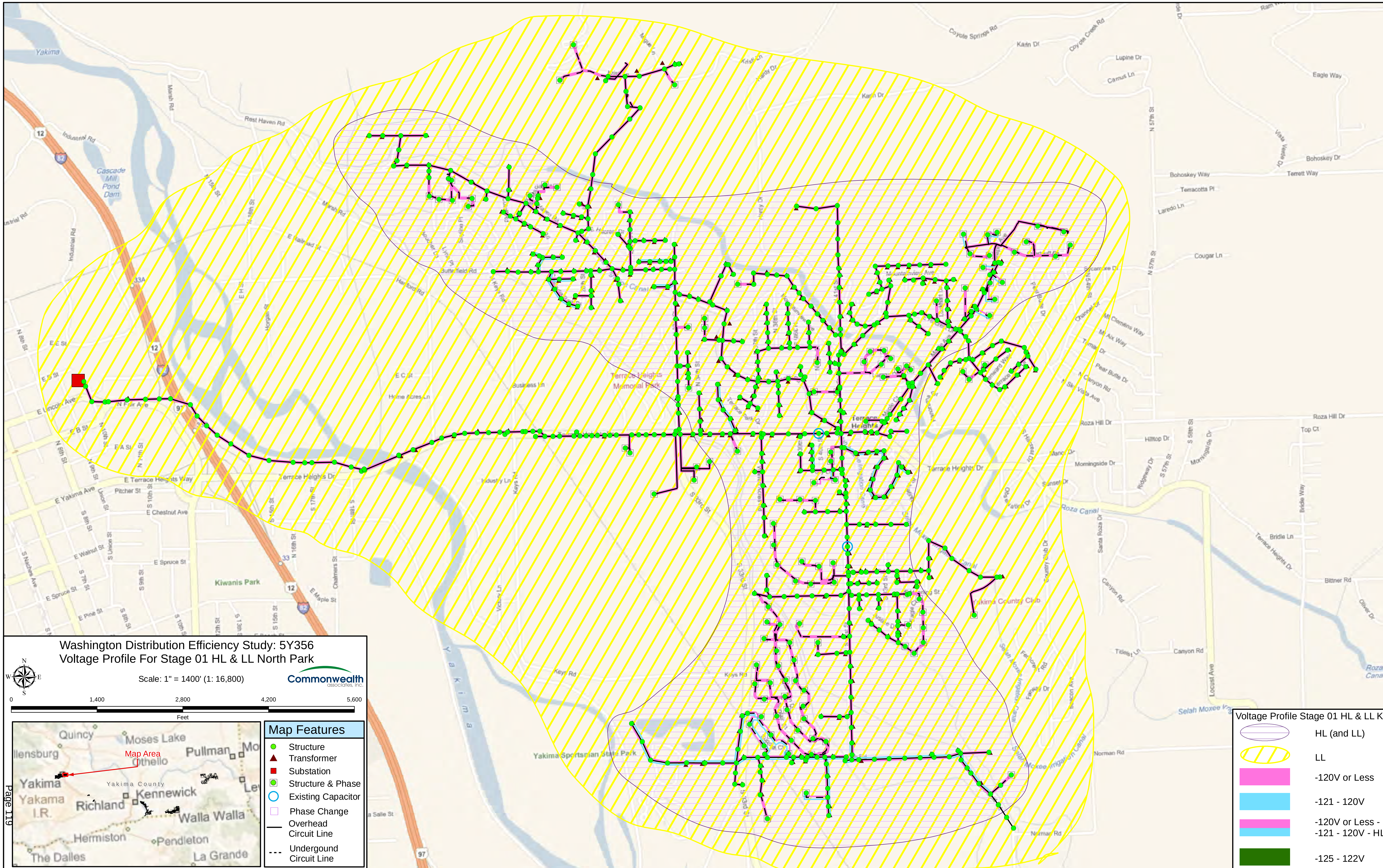

Washington Distribution Efficiency Study: 5W342
Voltage Profile For Stage 02 HL & LL Pomeroy
Scale: 1" = 1 m (1: 63,360)
0 5,250 10,500 15,750 21,000
Feet
Commonwealth
associates, inc.
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
New Cap
Regulator
Reconductored Circuit
Map Area
May 12, 2011
Voltage Profile Stage 02 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-122 - 120V
-120V or Less - LL
-121 - 120V - HL
-120V or Less - LL
-122 - 121V - HL
-121 - 120V - LL
-122 - 121V - HL
-125 - 122V

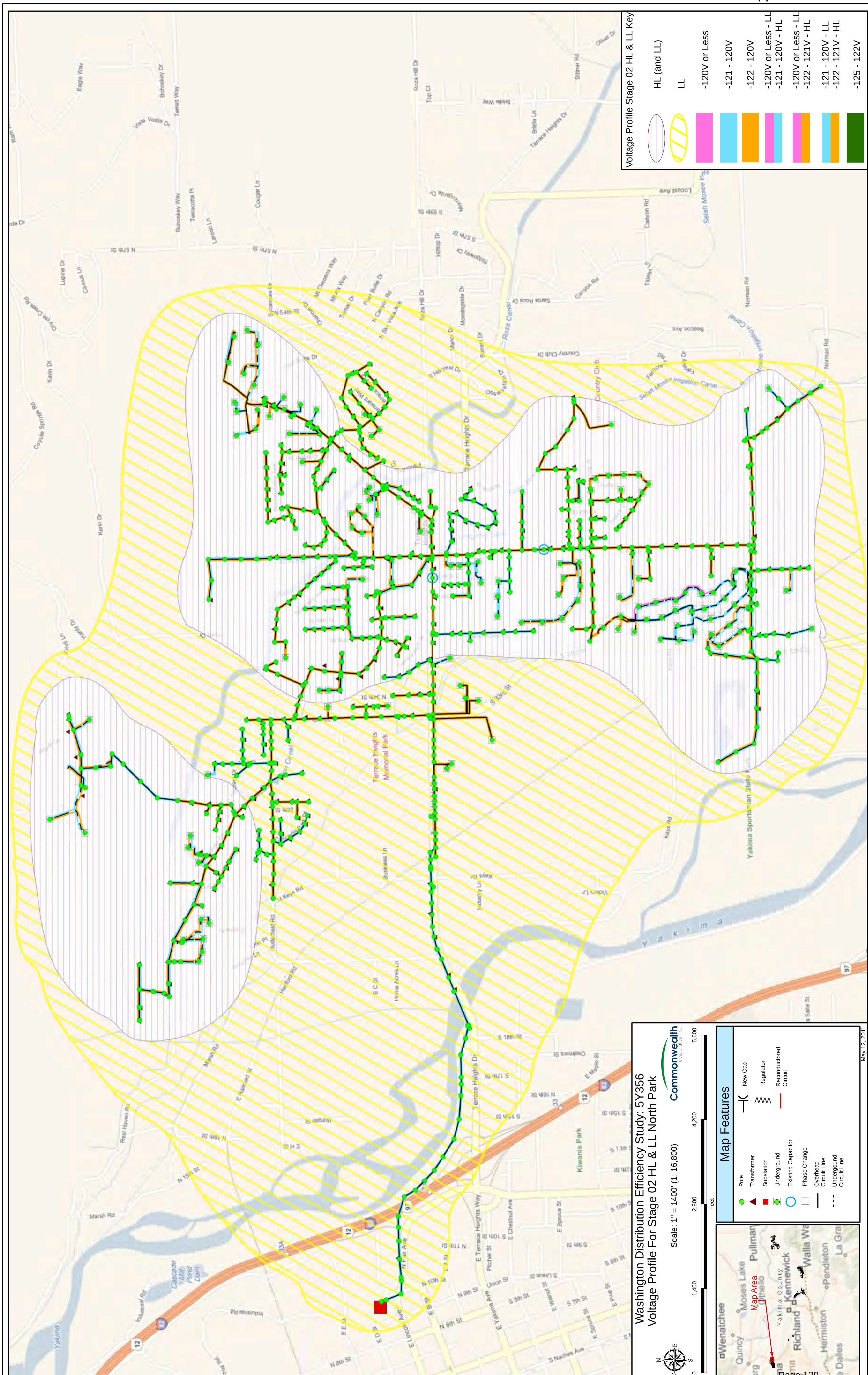
## Washington Distribution Efficiency Study: 5Y351
## Voltage Profile For Stage 01 HL & LL Grandview

Scale: 1" = 1000' (1: 12,000)

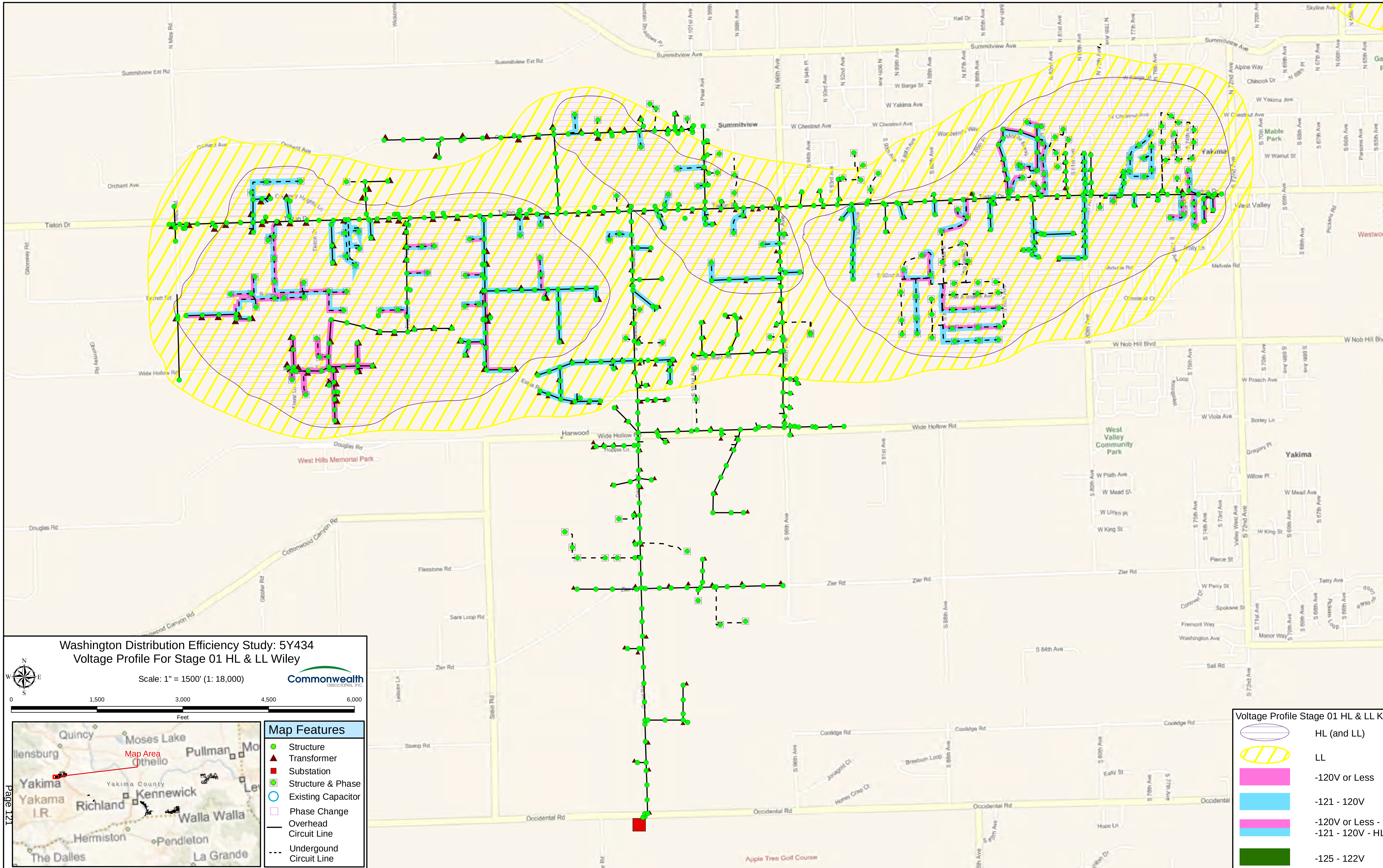


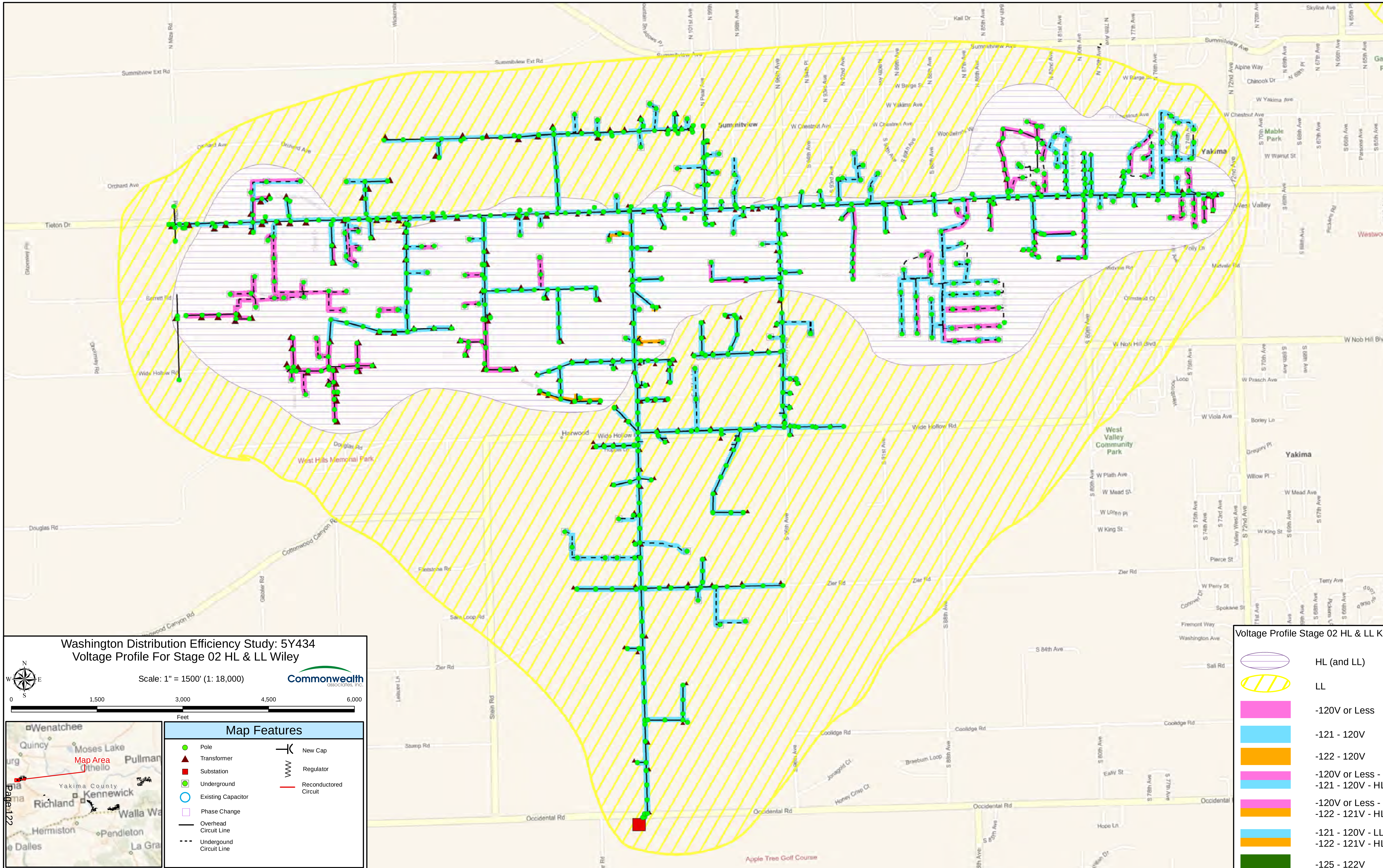

Washington Distribution Efficiency Study: 5Y351
Voltage Profile For Stage 02 HL & LL Grandview
Scale: 1" = 1000' (1: 12,000)
0
1,000
2,000
3,000
4,000
Feet
Commonwealth
Map Area
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
New Cap
Regulator
Reconductored Circuit
May 10, 2011
Voltage Profile Stage 02 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-120V or Less - LL
-121 - 120V - HL
-120V or Less - LL
-122 - 121V - HL
-121 - 120V - LL
-122 - 121V - HL
-125 - 122V
SW 600
SW600
300
EOLL
EOLR

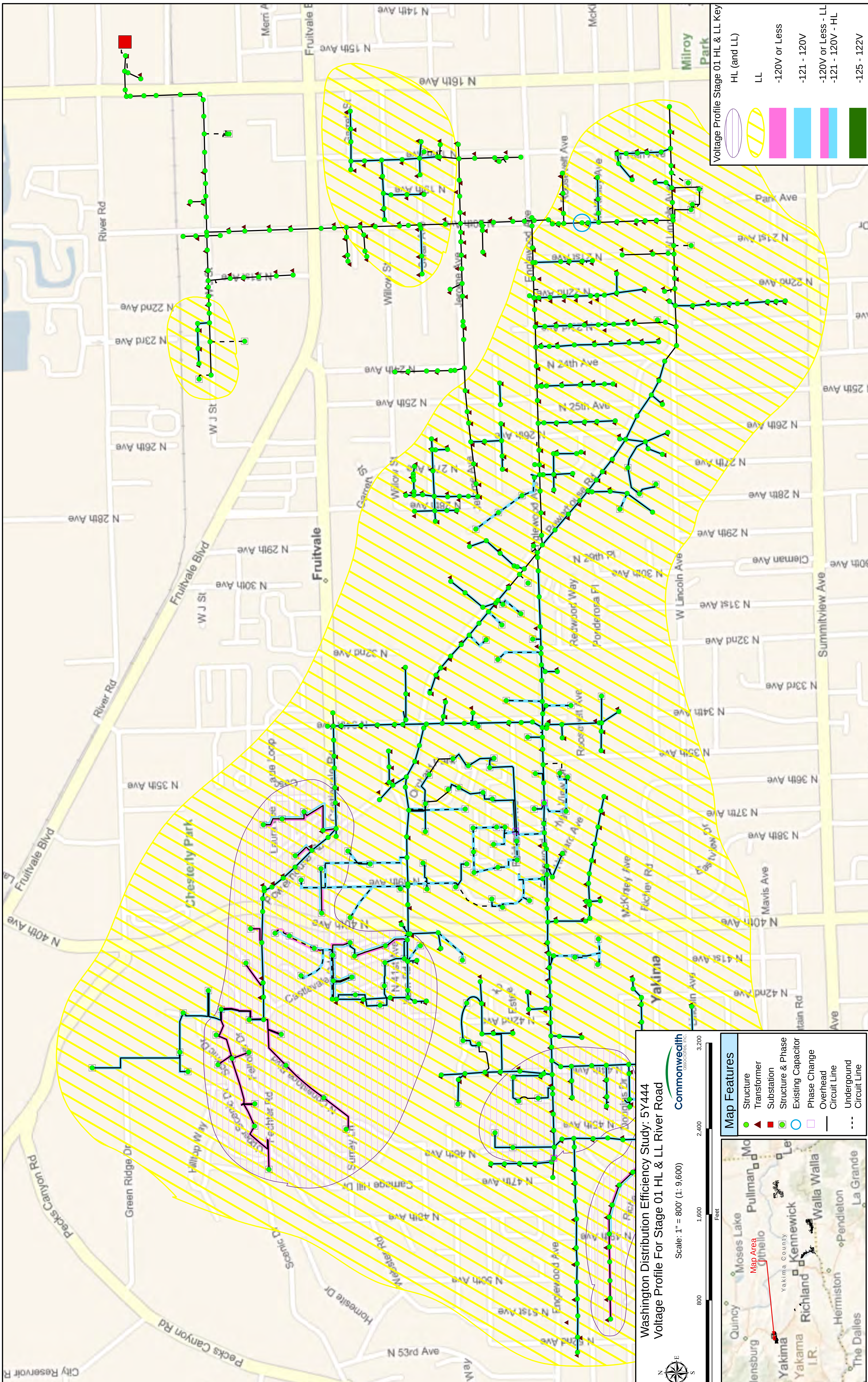

Washington Distribution Efficiency Study: 5Y356
Voltage Profile For Stage 01 HL & LL North Park
Scale: 1" = 1400' (1: 16,800)
Commonwealth
associates, inc.
0
1,400
2,800
4,200
5,600
Feet
Map Area
Yakima County
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
May 16, 2011
Voltage Profile Stage 01 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-120V or Less - LL
-121 - 120V - HL
-125 - 122V
Terrace Heights
Terrace Heights Memorial Park
Yakima Country Club
Yakima Sportsman State Park
Kiwanis Park
Cascade Mill Pond Dam
Roza Canal
Selah Moxee Irrigation Canal
Yakima



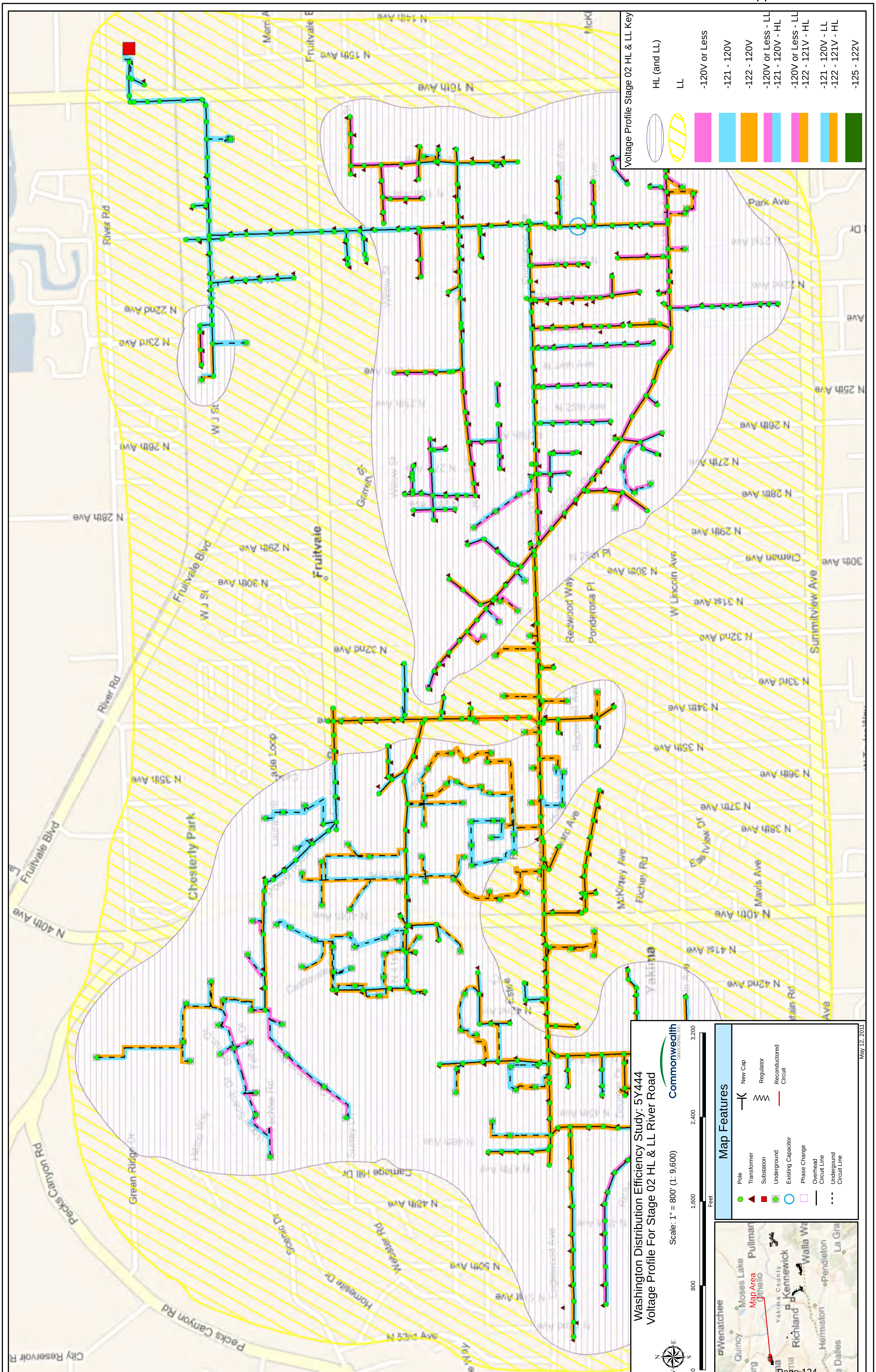
Voltage Profile Stage 02 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-122 - 120V
-120V or Less - LL
-121 - 120V - HL
-120V or Less - LL
-122 - 121V - HL
-121 - 120V - LL
-122 - 121V - HL
-125 - 122V
Washington Distribution Efficiency Study: 5Y356
Voltage Profile For Stage 02 HL & LL North Park
Scale: 1" = 1400' (1: 16,800)
Commonwealth associates, inc.
0
1,400
2,800
4,200
5,600
Feet
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Underground Circuit Line
New Cap
Regulator
Reconductored Circuit
May 12, 2011
Map Area
Yakima County
Wenatchee
Moses Lake
Othello
Quincy
Pullman
Kennewick
Richland
Walla Walla
Pendleton
Hermiston
La Grande
Terrace Heights Memorial Park
Yakima Sportsman State Park
Kiwanis Park
Roza Canal
Selah Moxee Irrigation Canal
Terrace Heights Dr
Yakima

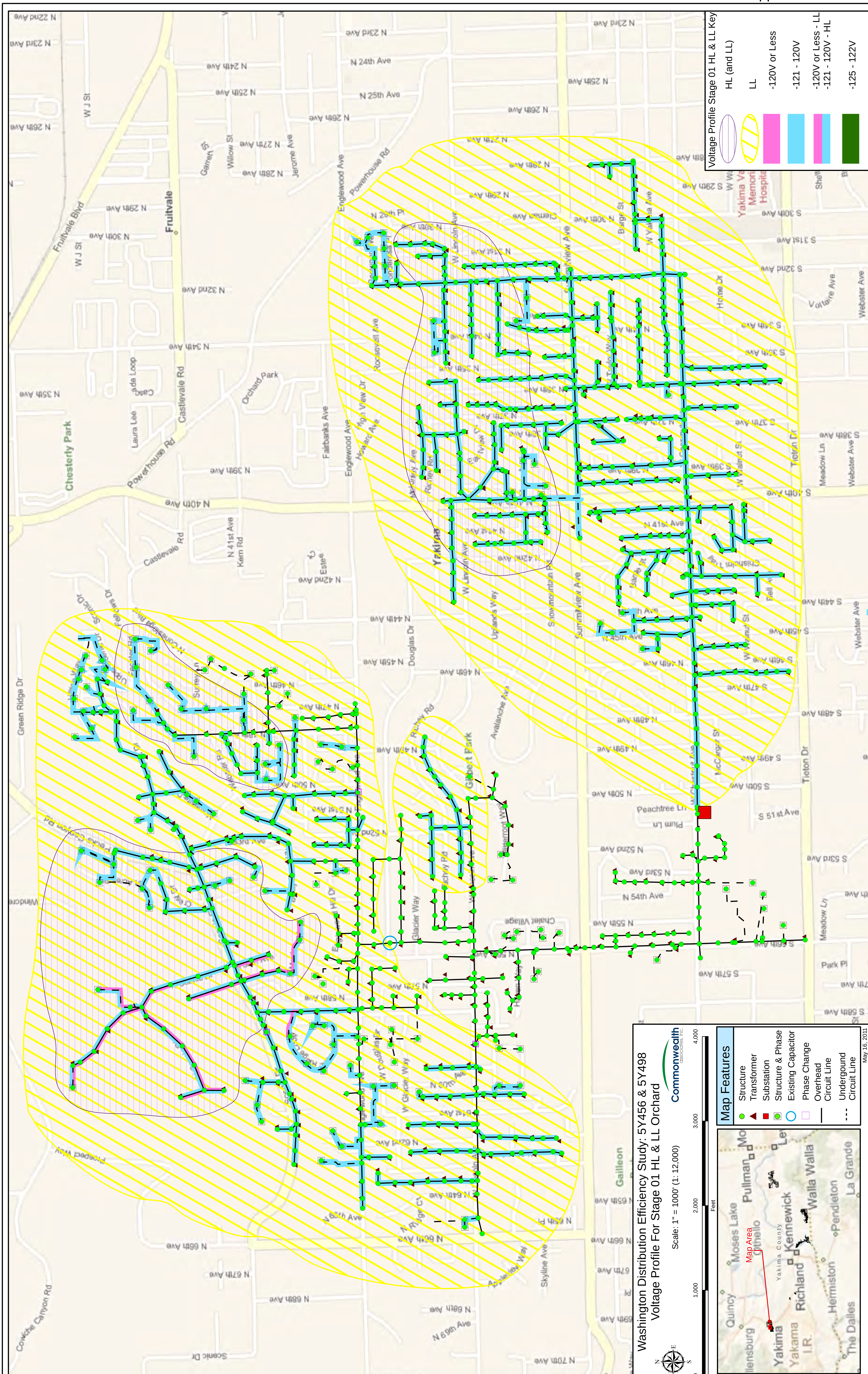

Washington Distribution Efficiency Study: 5Y434
Voltage Profile For Stage 01 HL & LL Wiley
Scale: 1" = 1500' (1: 18,000)
0
1,500
3,000
4,500
6,000
Feet
Commonwealth
associates, inc.
Map Area
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
May 16, 2011
Voltage Profile Stage 01 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-120V or Less - LL
-121 - 120V - HL
-125 - 122V

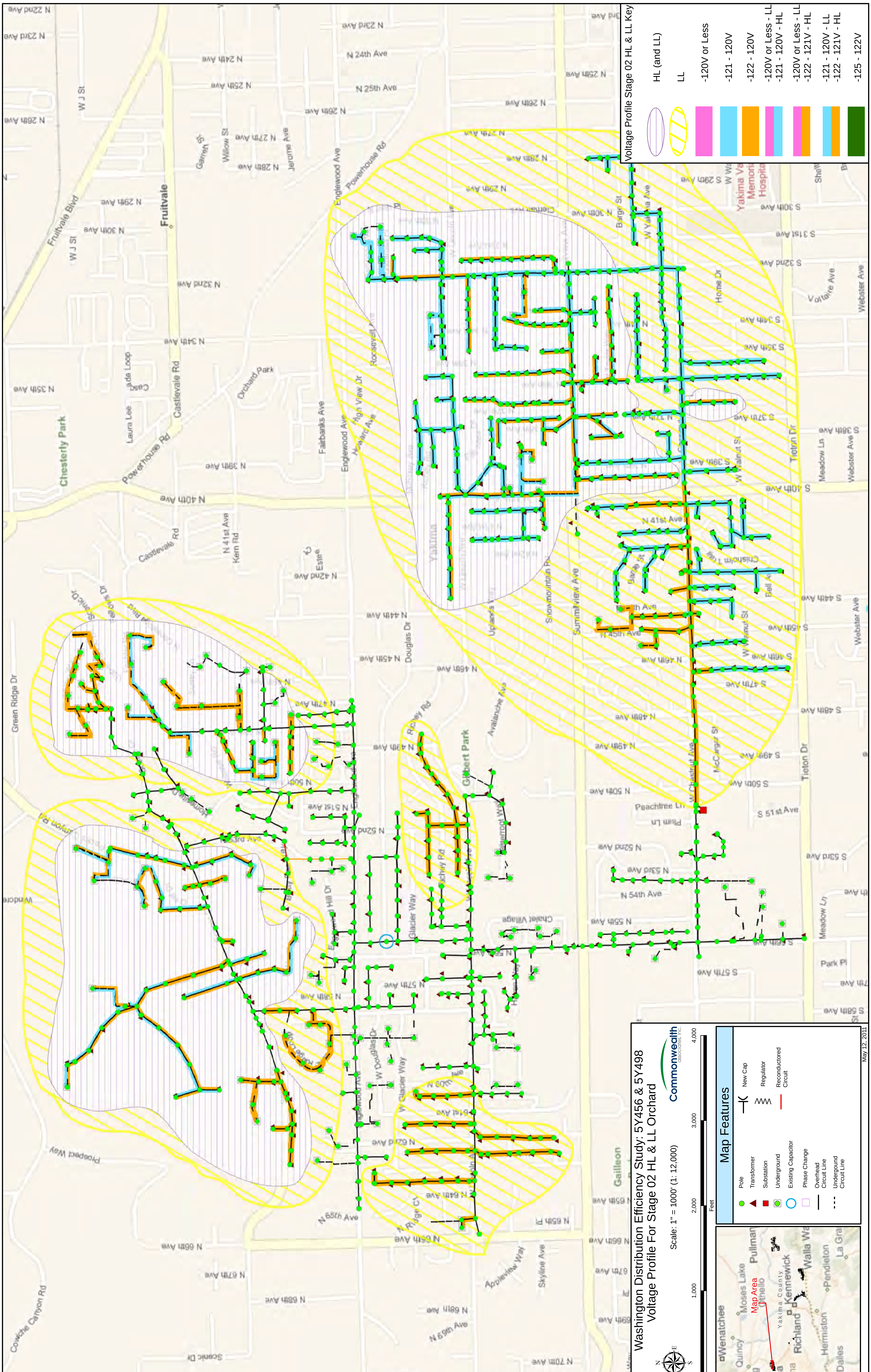

Washington Distribution Efficiency Study: 5Y434
Voltage Profile For Stage 02 HL & LL Wiley
Scale: 1" = 1500' (1: 18,000)
Commonwealth associates, inc.
0
1,500
3,000
4,500
6,000
Feet
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
New Cap
Regulator
Reconductored Circuit
May 12, 2011
Map Area
Yakima County
Voltage Profile Stage 02 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-122 - 120V
-120V or Less - LL
-121 - 120V - HL
-120V or Less - LL
-122 - 121V - HL
-121 - 120V - LL
-122 - 121V - HL
-125 - 122V

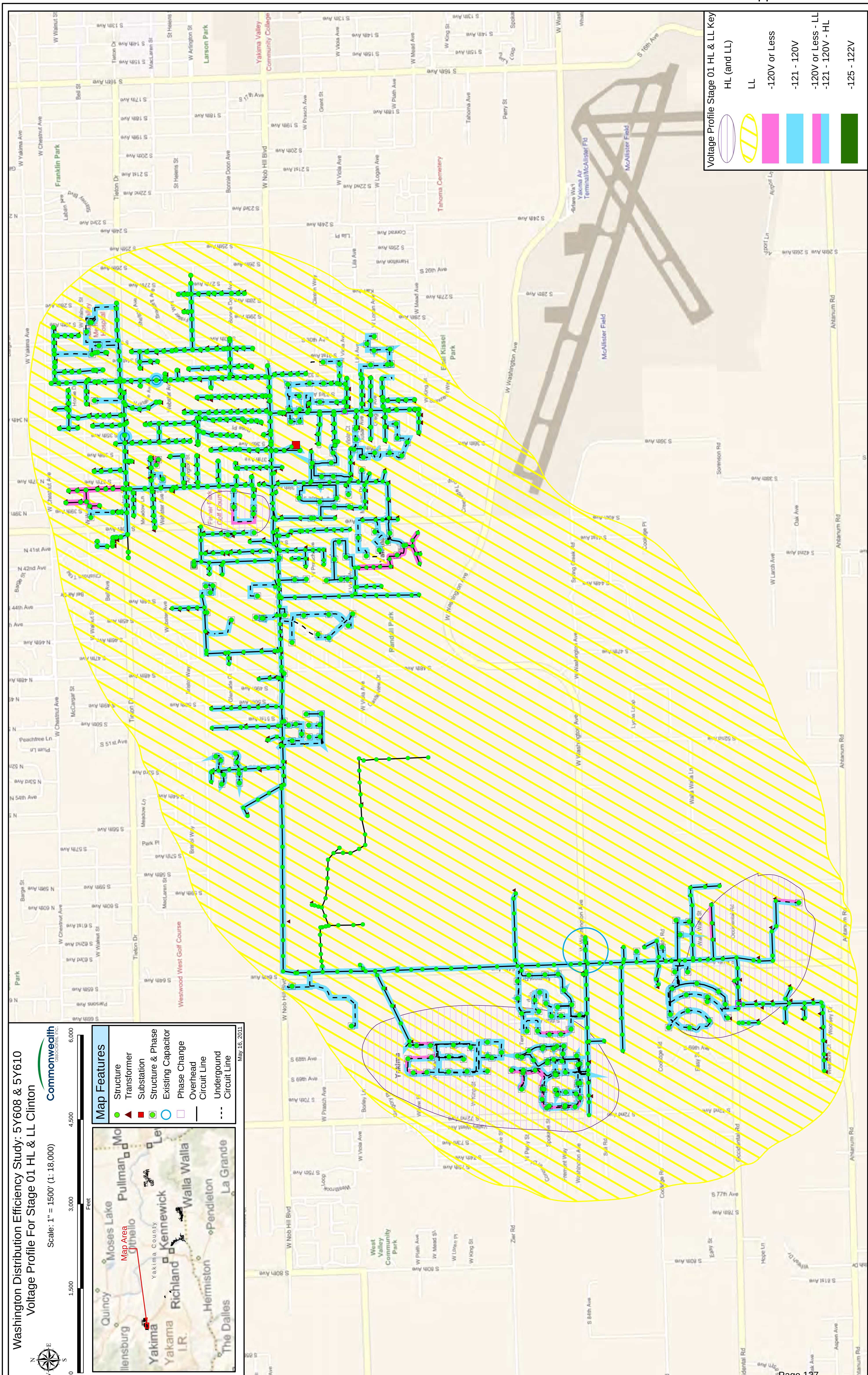


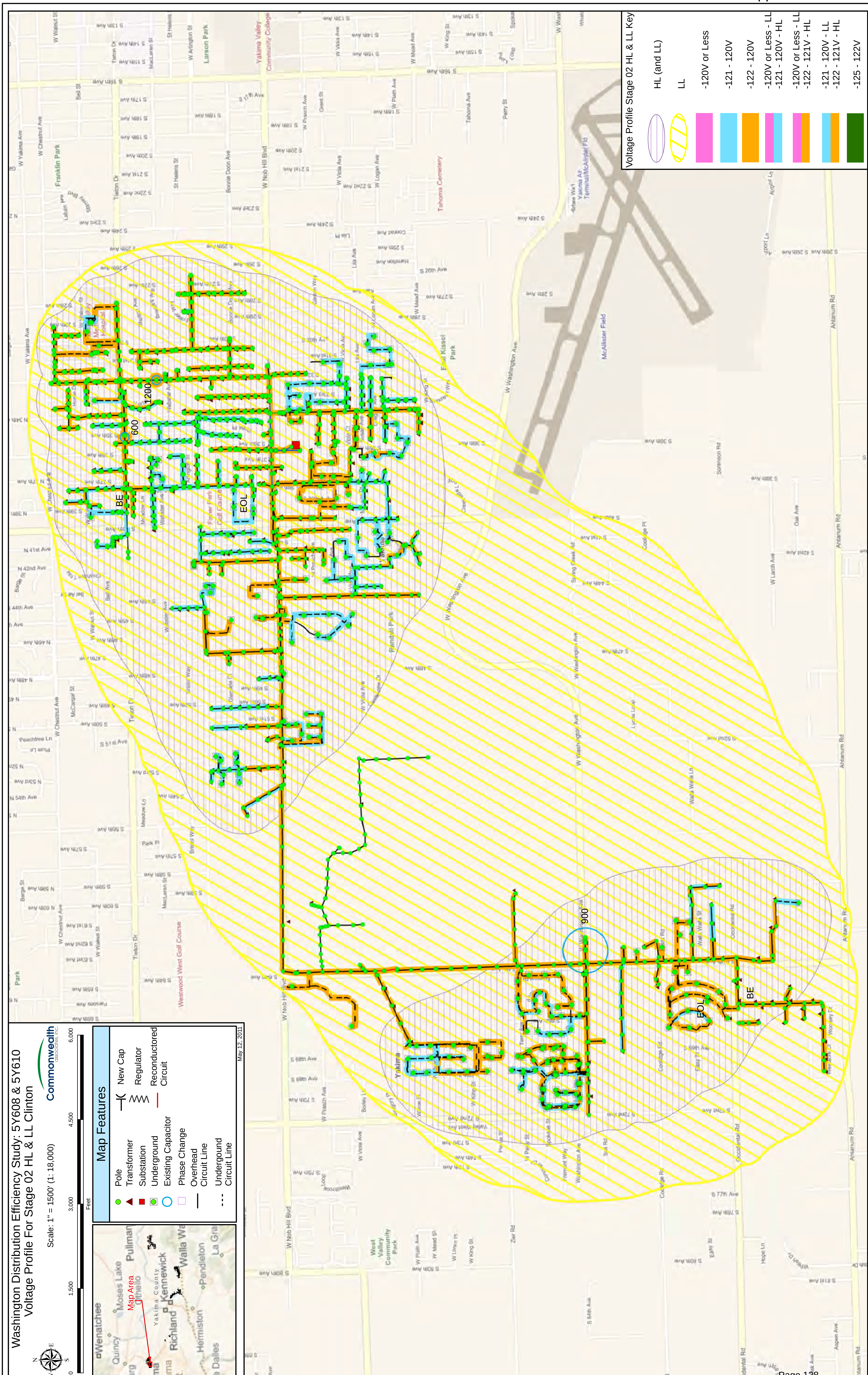
Washington Distribution Efficiency Study: 5Y444
Voltage Profile For Stage 01 HL & LL River Road
Scale: 1" = 800' (1: 9,600)
0 800 1,600 2,400 3,200
Feet
Commonwealth Associates, Inc.
Voltage Profile Stage 01 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-120V or Less - LL
-121 - 120V - HL
-125 - 122V
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
May 18, 2011
Map Area
Yakima County


Voltage Profile Stage 02 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-122 - 120V
-120V or Less - LL
-121 - 120V - HL
-120V or Less - LL
-122 - 121V - HL
-121 - 120V - LL
-122 - 121V - HL
-125 - 122V
Washington Distribution Efficiency Study: 5Y444
Voltage Profile For Stage 02 HL & LL River Road
Scale: 1" = 800' (1: 9,600)
0
800
1,600
2,400
3,200
Feet
Commonwealth
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Underground Circuit Line
New Cap
Regulator
Reconductored Circuit
May 12, 2011
Map Area
Wenatchee
Moses Lake
Othello
Pullman
Yakima County
Kennewick
Richland
Walla Walla
Pendleton
Hermiston
Quincy
N 16th Ave
N 15th Ave
N 14th Ave
River Rd
N 22nd Ave
N 23rd Ave
N 26th Ave
N 28th Ave
N 29th Ave
N 30th Ave
N 32nd Ave
Fruitvale Blvd
Fruitvale
Chesterly Park
N 35th Ave
N 40th Ave
Peck Canyon Rd
Pecks Canyon Rd
N 48th Ave
N 50th Ave
N 53rd Ave
Carriage Hill Dr
Green Ridge Dr
Homesite Dr
Webster Rd
Park Ave
Summitview Ave
W Lincoln Ave
Redwood Way
Ponderosa Pl
Clemen Ave
McKinley Ave
Richey Rd
Mavis Ave
Yakima
N 34th Ave
N 36th Ave
N 37th Ave
N 38th Ave
N 41st Ave
N 42nd Ave
N 31st Ave
N 33rd Ave
N 25th Ave
N 27th Ave
W J St


Washington Distribution Efficiency Study: 5Y456 & 5Y498
Voltage Profile For Stage 01 HL & LL Orchard
Scale: 1" = 1000' (1:12,000)
0
1,000
2,000
3,000
4,000
Feet
Commonwealth
May 16, 2011
Voltage Profile Stage 01 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-120V or Less - LL
-121 - 120V - HL
-125 - 122V
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
Map Area
Yakima County


Voltage Profile Stage 02 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-122 - 120V
-120V or Less - LL
-121 - 120V - HL
-120V or Less - LL
-122 - 121V - HL
-121 - 120V - LL
-122 - 121V - HL
-125 - 122V
Washington Distribution Efficiency Study: 5Y456 & 5Y498
Voltage Profile For Stage 02 HL & LL Orchard
Scale: 1" = 1000' (1: 12,000)
Commonwealth
0
1,000
2,000
3,000
4,000
Feet
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
New Cap
Regulator
Reconductored Circuit
May 12, 2011
Map Area
Yakima County
Wenatchee
Moses Lake
Kennewick
Richland
Pullman
Walla Walla
Pendleton
Hermiston
Quincy
Othello
N 40th Ave
Tieton Dr
Summitview Ave
Chesterly Park
Gilbert Park
Fruitvale
W Chestnut Ave
Englewood Ave
Powerhouse Rd
Castlevale Rd
N 56th Ave
S 56th Ave
N 65th Ave
Cowiche Canyon Rd


Washington Distribution Efficiency Study: 5Y608 & 5Y610
Voltage Profile For Stage 01 HL & LL Clinton
Scale: 1" = 1500' (1: 18,000)
0
1,500
3,000
4,500
6,000
Feet
Commonwealth
Map Area
Map Features
Structure
Transformer
Substation
Structure & Phase
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
May 16, 2011
Voltage Profile Stage 01 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-120V or Less - LL
-121 - 120V - HL
-125 - 122V



Washington Distribution Efficiency Study: 5Y608 & 5Y610
Voltage Profile For Stage 02 HL & LL Clinton
Scale: 1" = 1500' (1: 18,000)
0 1,500 3,000 4,500 6,000
Feet
Commonwealth
Map Features
Pole
Transformer
Substation
Underground
Existing Capacitor
Phase Change
Overhead Circuit Line
Undergound Circuit Line
New Cap
Regulator
Reconductored Circuit
May 12, 2011
Map Area
Voltage Profile Stage 02 HL & LL Key
HL (and LL)
LL
-120V or Less
-121 - 120V
-122 - 120V
-120V or Less - LL
-121 - 120V - HL
-120V or Less - LL
-122 - 121V - HL
-121 - 120V - LL
-122 - 121V - HL
-125 - 122V
600
1200
900
BE
EOL

## Appendix 7:  Detailed Results by Stage and Circuit

Appendix 7-1 Summary of Results by Stage with all Circuits Included

| General Information | Stage 1 | Stage 2 | Stage 3 |
|---|---|---|---|
| Total Customers Served (#) | 30,747 | 30,747 | 30,747 |
| Feeder Annual Peak MW | 138 | 138 | 138 |
| Total Annual Energy Consumed (MWh/yr) | 627,608 | 627,608 | 627,608 |
| Average Customer Voltage Change (%) | 1.35% | 1.09% | 2.01% |
| Average Reduction in Annual Energy Delivered from Sub | 0.94% | 0.82% | 1.40% |
| Total SI&VO Installed Cost | $1,640,691 | $2,999,482 | $6,518,727 |
| | | | |
| <u>Utility Energy Savings Potential</u> | | | |
| Line Loss Reduction (MWh/y) | 282.7 | 712.7 | 678.8 |
| No-load Loss Saved (MWh/y) | 252.5 | 199.8 | 357.1 |
| VO Energy Savings (MWh/y) | 5337.9 | 4235.4 | 7744.8 |
| Total Energy Savings (MWh/y) | 5873.1 | 5147.8 | 8780.7 |
| Total Energy Savings (MWa) | 0.6704 | 0.5877 | 1.0024 |
| Total Coincidental Demand Reduction (kW) | 1142.6 | 1093.2 | 1766.9 |
| Average Customer Energy Reduction (kWh/yr) | 174 | 138 | 252 |
| | | | |
| <u>Benefit Cost Projections</u> | | | |
| Overall Utility Levelized Cost per kWh saved | $0.0434 | $0.0906 | $0.1154 |
| Overall Utility Benefit Cost Ratio | 2.52 | 1.21 | 0.95 |
| Overall Net Utility PV Savings ($) | $4,734,832 | $1,194,119 | ($618,263) |

Appendix 7-2 Summary of Economically Viable Solutions by Stage and Overall Optimal Solution

| General Information | Stage 1 | Stage 2 | Stage 3 | Optimal Solution |
|---|---|---|---|---|
| Total Customers Served (#) | 22,225 | 22,958 | 18,665 | 27,909 |
| Feeder Annual Peak MW | 95.08 | 103.58 | 76.01 | 125.50 |
| Total Annual Energy Consumed (MWh/yr) | 438,826 | 476,160 | 357,575 | 574,046 |
| Average Customer Voltage Change (%) | 1.12% | 1.11% | 2.07% | 1.73% |
| Average Reduction in Annual Energy Delivered from Sub | 0.80% | 0.85% | 1.45% | 1.23% |
| Total SI&VO Installed Cost | $863,209 | $1,893,973 | $2,826,294 | $3,854,835 |
| | | | | |
| <u>Utility Energy Savings Potential</u> | | | | |
| Line Loss Reduction (MWh/y) | 198.0 | 565.0 | 371.5 | 643.1 |
| No-load Loss Saved (MWh/y) | 129.5 | 146.4 | 187.1 | 267.5 |
| VO Energy Savings (MWh/y) | 3185.9 | 3347.2 | 4621.5 | 6127.4 |
| Total Energy Savings (MWh/y) | 3513.4 | 4058.5 | 5180.1 | 7038.0 |
| Total Energy Savings (MWa) | 0.4011 | 0.4633 | 0.5913 | 0.8034 |
| Total Coincidental Demand Reduction (kW) | 685.2 | 856.4 | 1027.0 | 1423.9 |
| Average Customer Energy Reduction (kWh/yr) | 143 | 146 | 248 | 220 |
| | | | | |
| <u>Benefit Cost Projections</u> | | | | |
| Overall Utility Levelized Cost per kWh saved | $0.0382 | $0.0726 | $0.0848 | $0.0852 |
| Overall Utility Benefit Cost Ratio | 2.87 | 1.51 | 1.29 | 1.29 |
| Overall Net Utility PV Savings ($) | $3,056,420 | $1,832,787 | $1,565,127 | $2,098,324 |

Appendix 7-3 Stage 1 Results - Individual Circuits, Total and Total Viable Circuits

| Stage 1 - Results | NC<br>Walla Walla<br>**Bowman**<br>5W150 | Walla Walla<br>**Bowman**<br>5W154 | NC<br>Walla Walla<br>**Dodd Rd**<br>4W22 | Walla Walla<br>**Mill Creek**<br>5W116 | Walla Walla<br>**Mill Creek**<br>5W127 | NC<br>Walla Walla<br>**Pomeroy**<br>5W342 | Yakima<br>**Clinton**<br>5Y608 | Yakima<br>**Clinton**<br>5Y610 | Yakima<br>**Nob Hill**<br>5Y194 | Yakima<br>**Nob Hill**<br>5Y197 | Yakima<br>**Nob Hill**<br>5Y273 | NC<br>Yakima<br>**North Park**<br>5Y356 | NC<br>Yakima<br>**Orchard**<br>5Y456 | Yakima<br>**Orchard**<br>5Y498 | Yakima<br>**Wiley**<br>5Y434 | Yakima<br>**River Road**<br>5Y444 | NC<br>Lower Valley<br>**Grandview**<br>5Y351 | Lower Valley<br>**Sunnyside**<br>5Y313 | Lower Valley<br>**Sunnyside**<br>5Y317 | **Summary All Circuits** | **Summary Viable Solutions** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| General Information | NC | | NC | | | NC | | | | | | NC | NC | | | | NC | | | | |
| Total Customers Served (#) | 1,796 | 1,823 | 1,181 | 2,053 | 1,968 | 1,204 | 2,037 | 1,401 | 1,572 | 1,873 | 2,216 | 1,634 | 1,421 | 1,751 | 1,332 | 2,201 | 1,286 | 1,020 | 978 | 30,747 | 22,225 |
| Feeder Annual Peak MW | 6.72 | 8.20 | 8.70 | 8.10 | 6.22 | 6.04 | 8.20 | 9.25 | 8.37 | 5.90 | 7.98 | 6.79 | 7.30 | 6.28 | 6.99 | 10.60 | 7.70 | 5.00 | 4.00 | 138.33 | 95.08 |
| Total Annual Energy Consumed (MWh/yr) | 33,096 | 37,064 | 39,920 | 34,127 | 29,178 | 22,784 | 41,300 | 43,296 | 42,555 | 30,679 | 35,323 | 30,778 | 28,933 | 27,290 | 27,726 | 49,558 | 33,272 | 20,865 | 19,868 | 627,608 | 438,826 |
| Average Customer Voltage Change (%) | 1.51% | 0.83% | 2.27% | 2.78% | 0.83% | 1.02% | 0.83% | 0.83% | 1.30% | 1.58% | 1.57% | 3.42% | 0.98% | 1.21% | 0.83% | 0.76% | 1.81% | 0.60% | 0.65% | 1.35% | 1.12% |
| Reduction in Annual Energy Delivered from Sub (%) | 0.93% | 0.56% | 1.34% | 1.87% | 0.64% | 0.62% | 0.61% | 0.56% | 0.90% | 1.05% | 1.04% | 2.24% | 0.72% | 0.77% | 0.68% | 0.52% | 1.44% | 0.56% | 0.69% | 0.94% | 0.80% |
| Utility Energy Savings Potential | | | | | | | | | | | | | | | | | | | | | |
| Line Loss Reduction (MWh/y) | -31.060 | 0.299 | 32.428 | 4.831 | 25.019 | 14.065 | 20.530 | 4.103 | 31.600 | 1.861 | -4.047 | -17.109 | 18.585 | -8.442 | 33.510 | 6.618 | 67.763 | 33.317 | 48.810 | 282.678 | 198.007 |
| VO Energy Savings (MWh/y) | 318.9 | 197.7 | 470.2 | 607.1 | 155.6 | 118.4 | 220.3 | 230.9 | 340.4 | 310.9 | 357.9 | 672.9 | 180.8 | 210.5 | 147.9 | 241.7 | 390.7 | 80.8 | 84.2 | 5337.9 | 3185.9 |
| Total Energy Savings (MWh/y) | 306.3 | 208.6 | 536.1 | 636.7 | 187.2 | 141.3 | 250.6 | 243.7 | 384.4 | 323.0 | 367.2 | 690.3 | 207.9 | 210.0 | 189.4 | 258.6 | 477.8 | 117.8 | 136.3 | 5873.1 | 3513.4 |
| Total Energy Savings (MWa) | 0.0350 | 0.0238 | 0.0612 | 0.0727 | 0.0214 | 0.0161 | 0.0286 | 0.0278 | 0.0439 | 0.0369 | 0.0419 | 0.0788 | 0.0237 | 0.0240 | 0.0216 | 0.0295 | 0.0545 | 0.0134 | 0.0156 | 0.6704 | 0.4011 |
| Total Coincidental Demand Reduction (kW) | 53.7 | 38.9 | 103.9 | 120.1 | 38.3 | 29.7 | 48.8 | 46.2 | 75.0 | 60.8 | 68.2 | 126.3 | 43.0 | 38.0 | 42.8 | 49.3 | 100.8 | 28.4 | 30.5 | 1142.6 | 685.2 |
| Customer Average Energy Reduction (kWh/yr) | 178 | 108 | 398 | 296 | 79 | 98 | 108 | 165 | 217 | 166 | 162 | 412 | 127 | 120 | 111 | 110 | 304 | 79 | 86 | 174 | 143 |
| Distribution Line Losses | | | | | | | | | | | | | | | | | | | | | |
| Existing Base System Line Loss (kW) | 325.2 | 98.8 | 288.9 | 122.6 | 65.7 | 194.1 | 113.0 | 128.8 | 165.1 | 44.7 | 150.2 | 231.7 | 124.3 | 91.7 | 144.8 | 186.1 | 106.0 | 86.8 | 49.6 | 2718.1 | 1447.9 |
| Baseline Pre-VO System Line Loss (kW) | 334.3 | 98.7 | 278.3 | 120.8 | 57.8 | 187.9 | 107.2 | 127.5 | 156.3 | 44.2 | 151.6 | 237.4 | 116.7 | 94.7 | 131.1 | 184.0 | 81.7 | 74.2 | 35.5 | 2619.9 | 1383.6 |
| Line Loss Reduction (kW) | -9.1 | 0.1 | 10.6 | 1.8 | 7.9 | 6.2 | 5.8 | 1.3 | 8.8 | 0.5 | -1.4 | -5.7 | 7.6 | -3.0 | 13.7 | 2.1 | 24.3 | 12.6 | 14.1 | 98.2 | 64.3 |
| Line Loss Reduction (MWa) | -0.0035 | 0.0000341 | 0.0037 | 0.0006 | 0.0029 | 0.0016 | 0.0023 | 0.0005 | 0.0036 | 0.0002 | -0.0005 | -0.0020 | 0.0021 | -0.0010 | 0.0038 | 0.0008 | 0.0077 | 0.0038 | 0.0056 | 0.0323 | 0.0226 |
| End-Use Energy Consumption | | | | | | | | | | | | | | | | | | | | | |
| Average Volts Pre-VO (V) | 122.7 | 121.6 | 123.3 | 123.9 | 122.3 | 123.4 | 121.8 | 121.8 | 122.4 | 123.3 | 122.1 | 122.7 | 122.4 | 122.6 | 122.0 | 122.4 | 122.9 | 122.2 | 122.9 | 122.6 | 122.4 |
| Average Volts Post-VO (V) | 120.9 | 120.6 | 120.5 | 120.6 | 121.3 | 122.2 | 120.8 | 120.8 | 120.9 | 121.4 | 120.2 | 118.6 | 121.2 | 121.2 | 121.0 | 121.5 | 120.7 | 121.5 | 122.1 | 120.9 | 121.1 |
| VO Factor (for End-Use) from VO Protocol | 0.640 | 0.640 | 0.520 | 0.640 | 0.640 | 0.510 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.650 | 0.650 | 0.650 | 0.628 | 0.642 |
| Total End-Use Demand Reduction (kW) | 60.7 | 37.6 | 89.5 | 115.5 | 29.6 | 22.5 | 41.9 | 43.9 | 64.8 | 59.1 | 68.1 | 128.0 | 34.4 | 40.1 | 28.1 | 46.0 | 74.3 | 15.4 | 16.0 | 1015.6 | 606.1 |
| VO Energy Savings (MWa) | 0.0364 | 0.0226 | 0.0537 | 0.0693 | 0.0178 | 0.0135 | 0.0251 | 0.0264 | 0.0404 | 0.0354 | 0.0405 | 0.0768 | 0.0206 | 0.0240 | 0.0169 | 0.0276 | 0.0446 | 0.0092 | 0.0096 | 0.6105 | 0.3648 |
| Change in Voltage (pu) | 0.0151 | 0.0083 | 0.0227 | 0.0278 | 0.0083 | 0.0102 | 0.0083 | 0.0083 | 0.0125 | 0.0158 | 0.0158 | 0.0342 | 0.0098 | 0.0121 | 0.0083 | 0.0076 | 0.0181 | 0.0060 | 0.0065 | 0.0135 | 0.0112 |
| Distribution Transformer No-Load Losses | | | | | | | | | | | | | | | | | | | | | |
| Distribution Transformer Connected kVA | 23,831 | 24,581 | 29,035 | 17,726 | 15,105 | 16,801 | 22,604 | 20,066 | 19,096 | 12,614 | 16,378 | 20,180 | 16,682 | 12,638 | 18,624 | 25,987 | 20,980 | 11,852 | 9,580 | 354,357 | 226,848 |
| Total No-Load Loss (kW) | 71.5 | 73.7 | 87.1 | 53.2 | 45.3 | 50.4 | 67.8 | 60.2 | 57.3 | 37.8 | 49.1 | 60.5 | 50.0 | 37.9 | 55.9 | 78.0 | 62.9 | 35.6 | 28.7 | 1063.1 | 680.5 |
| Change in No-Load Loss (%) | 2.94% | 1.65% | 4.38% | 5.34% | 1.65% | 2.01% | 1.65% | 1.65% | 2.45% | 3.09% | 3.09% | 6.50% | 1.93% | 2.37% | 1.65% | 1.51% | 3.52% | 1.18% | 1.29% | 2.64% | 2.21% |
| Total No-Load Loss Reduction (kW) | 2.1 | 1.2 | 3.8 | 2.8 | 0.7 | 1.0 | 1.1 | 1.0 | 1.4 | 1.2 | 1.5 | 3.9 | 1.0 | 0.9 | 0.9 | 1.2 | 2.2 | 0.4 | 0.4 | 28.8 | 14.8 |
| No-Load Loss Saved (MWh/yr) | 18.4 | 10.6 | 33.4 | 24.9 | 6.5 | 8.9 | 9.8 | 8.7 | 12.3 | 10.3 | 13.3 | 34.5 | 8.4 | 7.9 | 8.1 | 10.3 | 19.4 | 3.7 | 3.3 | 252.5 | 129.5 |
| No_Load Loss Reduction (MWa) | 0.0021 | 0.0012 | 0.0038 | 0.0028 | 0.0007 | 0.0010 | 0.0011 | 0.0010 | 0.0014 | 0.0012 | 0.0015 | 0.0039 | 0.0010 | 0.0009 | 0.0009 | 0.0012 | 0.0022 | 0.0004 | 0.0004 | 0.0288 | 0.0148 |
| Utility Energy Efficiency Costs and Benefits | | | | | | | | | | | | | | | | | | | | | |
| VO Improvement Installation Cost | $180,378 | $29,526 | $219,622 | $58,178 | $83,645 | $107,846 | $73,614 | $53,438 | $95,448 | $23,910 | $128,058 | $166,286 | $49,098 | $44,502 | $100,248 | $85,444 | $54,252 | $60,508 | $26,690 | $1,640,691 | $863,209 |
| Energy Efficiency Incentives | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| VO Improvement First Year Cost | $180,378 | $29,526 | $219,622 | $58,178 | $83,645 | $107,846 | $73,614 | $53,438 | $95,448 | $23,910 | $128,058 | $166,286 | $49,098 | $44,502 | $100,248 | $85,444 | $54,252 | $60,508 | $26,690 | $1,640,691 | $863,209 |
| PV Annual Fixed Capital Charges | $270,859 | $44,337 | $329,789 | $87,361 | $125,603 | $161,944 | $110,540 | $80,244 | $143,327 | $35,904 | $192,294 | $249,698 | $73,726 | $66,825 | $150,534 | $128,304 | $81,466 | $90,860 | $40,078 | $2,463,693 | $1,296,211 |
| PV Annual Remaining Salvage Value | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| PV Operations & Maintenance Expense | $70,627 | $11,561 | $85,993 | $22,780 | $32,751 | $42,227 | $28,824 | $20,924 | $37,373 | $9,362 | $50,141 | $65,109 | $19,224 | $17,425 | $39,252 | $33,456 | $21,242 | $23,692 | $10,450 | $642,411 | $337,989 |
| Total Utility PV Costs | $341,486 | $55,898 | $415,781 | $110,141 | $158,354 | $204,171 | $139,364 | $101,167 | $180,699 | $45,266 | $242,435 | $314,807 | $92,951 | $84,250 | $189,786 | $161,760 | $102,708 | $114,552 | $50,529 | $3,106,104 | $1,634,200 |
| **Utility Annual Levelized Cost per kWh Saved** | $0.0916 | $0.0220 | $0.0637 | $0.0142 | $0.0695 | $0.1186 | $0.0457 | $0.0341 | $0.0386 | $0.0115 | $0.0542 | $0.0375 | $0.0367 | $0.0330 | $0.0823 | $0.0514 | $0.0177 | $0.0799 | $0.0305 | $0.0434 | $0.0382 |
| Utility Levelized Annual Cost per kW Reduction | $522 | $118 | $329 | $75 | $340 | $564 | $234 | $180 | $198 | $61 | $292 | $205 | $178 | $182 | $365 | $270 | $84 | $331 | $136 | $223 | $196 |
| **Utility Benefit / Cost Ratio** | 1.20 | 4.98 | 1.72 | 7.72 | 1.58 | 0.92 | 2.40 | 3.22 | 2.84 | 9.53 | 2.02 | 2.93 | 2.99 | 3.33 | 1.33 | 2.13 | 6.21 | 1.37 | 3.60 | 2.52 | 2.87 |
| Utility Revenue Requirements | | | | | | | | | | | | | | | | | | | | | |
| Avoided PV of Purchase Power Costs | $408,906 | $278,500 | $715,675 | $850,093 | $249,879 | $188,704 | $334,532 | $325,344 | $513,135 | $431,212 | $490,243 | $921,588 | $277,517 | $280,321 | $252,909 | $345,298 | $637,925 | $157,224 | $181,929 | $7,840,936 | $4,690,620 |
| Net Utility PV Savings | $67,420 | $222,603 | $299,894 | $739,952 | $91,525 | ($15,467) | $195,169 | $224,177 | $332,436 | $385,946 | $247,808 | $606,781 | $184,567 | $196,071 | $63,123 | $183,538 | $535,217 | $42,672 | $131,401 | $4,734,832 | $3,056,420 |
| Customer Impact / Substation | | | | | | | | | | | | | | | | | | | | | |
| Customer kWh/yr (before SI & VO) | 18,428 | 20,331 | 33,802 | 16,623 | 14,826 | 18,924 | 20,275 | 30,903 | 27,071 | 16,379 | 15,940 | 18,836 | 20,361 | 15,585 | 20,815 | 22,516 | 25,872 | 20,456 | 20,315 | 20,412 | 19,745 |
| Customer kWh/yr (after SI & VO) | 18,250 | 20,223 | 33,404 | 16,327 | 14,747 | 18,825 | 20,167 | 30,738 | 26,854 | 16,213 | 15,779 | 18,424 | 20,233 | 15,465 | 20,704 | 22,406 | 25,568 | 20,376 | 20,228 | 20,238 | 19,601 |

NC = Circuit is electrically non-compliant in first stage

| **Stage 2 - Results** | Walla Walla | Walla Walla | Walla Walla | Walla Walla | Walla Walla | Walla Walla | Yakima | Yakima | Yakima | Yakima | Yakima | Yakima | Yakima | Yakima | Yakima | Yakima | Lower Valley | Lower Valley | Lower Valley | **Summary** | **Summary** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Bowman** | **Bowman** | **Dodd Rd** | **Mill Creek** | **Mill Creek** | **Pomeroy** | **Clinton** | **Clinton** | **Nob Hill** | **Nob Hill** | **Nob Hill** | **North Park** | **Orchard** | **Orchard** | **Wiley** | **River Road** | **Grandview** | **Sunnyside** | **Sunnyside** | **All** | **Viable** |
| | 5W150 | 5W154 | 4W22 | 5W116 | 5W127 | 5W342 | 5Y608 | 5Y610 | 5Y194 | 5Y197 | 5Y273 | 5Y356 | 5Y456 | 5Y498 | 5Y434 | 5Y444 | 5Y351 | 5Y313 | 5Y317 | **Circuits** | **Solutions** |
| General Information | | | | | | | | | | | | | | | | | | | | | |
| Total Customers Served (#) | 1,796 | 1,823 | 1,181 | 2,053 | 1,968 | 1,204 | 2,037 | 1,401 | 1,572 | 1,873 | 2,216 | 1,634 | 1,421 | 1,751 | 1,332 | 2,201 | 1,286 | 1,020 | 978 | 30,747 | 22,958 |
| Feeder Annual Peak MW | 6.72 | 8.20 | 8.70 | 8.10 | 6.22 | 6.04 | 8.20 | 9.25 | 8.37 | 5.90 | 7.98 | 6.79 | 7.30 | 6.28 | 6.99 | 10.60 | 7.70 | 5.00 | 4.00 | 138.33 | 103.58 |
| Total Annual Energy Consumed (MWh/yr) | 33,096 | 37,064 | 39,920 | 34,127 | 29,178 | 22,784 | 41,300 | 43,296 | 42,555 | 30,679 | 35,323 | 30,778 | 28,933 | 27,290 | 27,726 | 49,558 | 33,272 | 20,865 | 19,868 | 627,608 | 476,160 |
| Average Customer Voltage Change (%) | 1.43% | 0.27% | 1.59% | 2.01% | 1.31% | 1.88% | 0.53% | 0.54% | 1.27% | 1.58% | 0.72% | 0.85% | 0.83% | 1.26% | 0.77% | 1.22% | 1.33% | 0.60% | 0.71% | 1.09% | 1.11% |
| Reduction in Annual Energy Delivered from Sub (%) | 1.21% | 0.12% | 1.21% | 1.40% | 0.93% | 1.28% | 0.46% | 0.46% | 0.99% | 1.06% | 0.58% | 0.59% | 0.76% | 0.82% | 0.63% | 0.81% | 1.07% | 0.72% | 0.68% | 0.82% | 0.85% |
| | | | | | | | | | | | | | | | | | | | | $0 | $0 |
| Utility Energy Savings Potential | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| Line Loss Reduction (MWh/y) | 78.163 | -21.821 | 126.960 | 21.470 | 16.457 | 55.922 | 43.637 | 41.508 | 70.630 | 3.457 | 29.863 | 4.888 | 57.439 | -5.093 | 30.517 | -2.250 | 55.648 | 65.827 | 39.429 | 712.651 | 564.982 |
| VO Energy Savings (MWh/y) | 303.5 | 63.0 | 330.4 | 438.1 | 245.1 | 218.5 | 139.3 | 150.6 | 340.4 | 310.9 | 169.6 | 167.3 | 154.3 | 220.7 | 135.8 | 388.2 | 287.4 | 80.8 | 91.5 | 4235.4 | 3347.2 |
| Total Energy Savings (MWh/y) | 399.3 | 44.6 | 481.1 | 477.7 | 271.7 | 290.5 | 189.2 | 197.8 | 423.4 | 324.6 | 205.8 | 181.1 | 219.0 | 223.8 | 173.7 | 402.4 | 357.4 | 150.3 | 134.5 | 5147.8 | 4058.5 |
| Total Energy Savings (MWa) | 0.0456 | 0.0051 | 0.0549 | 0.0545 | 0.0310 | 0.0332 | 0.0216 | 0.0226 | 0.0483 | 0.0371 | 0.0235 | 0.0207 | 0.0250 | 0.0255 | 0.0198 | 0.0459 | 0.0408 | 0.0172 | 0.0154 | 0.5877 | 0.4633 |
| Total Coincidental Demand Reduction (kW) | 82.7 | 5.1 | 107.1 | 93.4 | 54.2 | 72.6 | 45.0 | 41.9 | 84.5 | 61.5 | 43.6 | 35.0 | 53.7 | 41.0 | 41.4 | 74.9 | 79.5 | 44.2 | 31.9 | 1093.2 | 856.4 |
| Customer Average Energy Reduction (kWh/yr) | 169 | 35 | 280 | 213 | 125 | 181 | 68 | 107 | 217 | 166 | 77 | 102 | 109 | 126 | 102 | 176 | 223 | 79 | 94 | 138 | 146 |
| | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| Distribution Line Losses | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| Existing Base System Line Loss (kW) | 325.2 | 98.8 | 288.9 | 122.6 | 65.7 | 194.1 | 113.0 | 128.8 | 165.1 | 44.7 | 150.2 | 231.7 | 124.3 | 91.7 | 144.8 | 186.1 | 106.0 | 86.8 | 49.6 | 2718.1 | 1723.5 |
| Baseline Pre-VO System Line Loss (kW) | 302.3 | 106.1 | 247.4 | 114.6 | 59.3 | 164.9 | 95.2 | 116.2 | 146.8 | 43.5 | 139.6 | 229.5 | 100.8 | 93.6 | 130.1 | 186.9 | 82.8 | 58.4 | 35.5 | 2453.5 | 1520.6 |
| Line Loss Reduction (kW) | 22.9 | -7.3 | 41.5 | 8.0 | 6.4 | 29.2 | 17.8 | 12.6 | 18.3 | 1.2 | 10.6 | 2.2 | 23.5 | -1.9 | 14.7 | -0.8 | 23.2 | 28.4 | 14.1 | 264.6 | 202.9 |
| Line Loss Reduction (MWa) | 0.0089 | -0.0024910 | 0.0145 | 0.0025 | 0.0019 | 0.0064 | 0.0050 | 0.0047 | 0.0081 | 0.0004 | 0.0034 | 0.0006 | 0.0066 | -0.0006 | 0.0035 | -0.0003 | 0.0064 | 0.0075 | 0.0045 | 0.0814 | 0.0645 |
| | | | | | | | | | | | | | | | | | | | | 0.0 | 0.0 |
| End-Use Energy Consumption | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| Average Volts Pre-VO (V) | 122.3 | 121.6 | 122.1 | 123.2 | 122.3 | 122.9 | 121.8 | 121.8 | 122.4 | 123.3 | 122.1 | 121.9 | 122.1 | 122.6 | 122.0 | 122.2 | 122.3 | 122.2 | 122.9 | 122.3 | 122.4 |
| Average Volts Post-VO (V) | 120.6 | 121.2 | 120.2 | 120.8 | 120.7 | 120.6 | 121.2 | 121.2 | 120.9 | 121.4 | 121.2 | 120.9 | 121.1 | 121.1 | 121.1 | 120.8 | 120.7 | 121.5 | 122.0 | 121.0 | 121.1 |
| VO Factor (for End-Use) from VO Protocol | 0.640 | 0.640 | 0.520 | 0.640 | 0.640 | 0.510 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.650 | 0.650 | 0.650 | 0.628 | 0.634 |
| Total End-Use Demand Reduction (kW) | 57.7 | 12.0 | 62.9 | 83.3 | 46.6 | 41.6 | 26.5 | 28.6 | 64.8 | 59.1 | 32.3 | 31.8 | 29.4 | 42.0 | 25.8 | 73.9 | 54.7 | 15.4 | 17.4 | 805.8 | 636.8 |
| VO Energy Savings (MWa) | 0.0346 | 0.0072 | 0.0377 | 0.0500 | 0.0280 | 0.0249 | 0.0159 | 0.0172 | 0.0395 | 0.0354 | 0.0186 | 0.0191 | 0.0176 | 0.0252 | 0.0155 | 0.0443 | 0.0328 | 0.0092 | 0.0104 | 0.4833 | 0.3819 |
| Change in Voltage (pu) | 0.0143 | 0.0027 | 0.0159 | 0.0201 | 0.0131 | 0.0188 | 0.0053 | 0.0054 | 0.0125 | 0.0158 | 0.0075 | 0.0085 | 0.0083 | 0.0126 | 0.0077 | 0.0122 | 0.0133 | 0.0060 | 0.0071 | 0.0109 | 0.0111 |
| | | | | | | | | | | | | | | | | | | | | 0.0000 | 0.0000 |
| Distribution Transformer No-Load Losses | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| Distribution Transformer Connected kVA | 23,831 | 24,581 | 29,035 | 17,726 | 15,105 | 16,801 | 22,604 | 20,066 | 19,096 | 12,614 | 16,378 | 20,180 | 16,682 | 12,638 | 18,624 | 25,987 | 20,980 | 11,852 | 9,580 | 354,357 | 250,340 |
| Total No-Load Loss (kW) | 71.5 | 73.7 | 87.1 | 53.2 | 45.3 | 50.4 | 67.8 | 60.2 | 57.3 | 37.8 | 49.1 | 60.5 | 50.0 | 37.9 | 55.9 | 78.0 | 62.9 | 35.6 | 28.7 | 1063.1 | 751.0 |
| Change in No-Load Loss (%) | 2.81% | 0.53% | 3.11% | 3.89% | 2.57% | 3.66% | 1.05% | 1.08% | 2.45% | 3.09% | 1.48% | 1.68% | 1.65% | 2.48% | 1.51% | 2.40% | 2.61% | 1.18% | 1.40% | 2.14% | 2.18% |
| Total No-Load Loss Reduction (kW) | 2.0 | 0.4 | 2.7 | 2.1 | 1.2 | 1.8 | 0.7 | 0.6 | 1.4 | 1.2 | 0.7 | 1.0 | 0.8 | 0.9 | 0.8 | 1.9 | 1.6 | 0.4 | 0.4 | 22.8 | 16.7 |
| No-Load Loss Saved (MWh/yr) | 17.6 | 3.4 | 23.7 | 18.1 | 10.2 | 16.1 | 6.2 | 5.7 | 12.3 | 10.3 | 6.4 | 8.9 | 7.2 | 8.2 | 7.4 | 16.4 | 14.4 | 3.7 | 3.5 | 199.8 | 146.4 |
| No_Load Loss Reduction (MWa) | 0.0020 | 0.0004 | 0.0027 | 0.0021 | 0.0012 | 0.0018 | 0.0007 | 0.0006 | 0.0014 | 0.0012 | 0.0007 | 0.0010 | 0.0008 | 0.0009 | 0.0008 | 0.0019 | 0.0016 | 0.0004 | 0.0004 | 0.0228 | 0.0167 |
| | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| Utility Energy Efficiency Costs and Benefits | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| VO Improvement Installation Cost | $329,870 | $102,929 | $288,415 | $150,565 | $106,799 | $317,873 | $123,639 | $118,025 | $128,436 | $47,064 | $107,026 | $231,435 | $124,802 | $65,499 | $123,402 | $264,201 | $221,349 | $98,309 | $49,844 | $2,999,482 | $1,893,973 |
| Energy Efficiency Incentives | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| VO Improvement First Year Cost | $329,870 | $102,929 | $288,415 | $150,565 | $106,799 | $317,873 | $123,639 | $118,025 | $128,436 | $47,064 | $107,026 | $231,435 | $124,802 | $65,499 | $123,402 | $264,201 | $221,349 | $98,309 | $49,844 | $2,999,482 | $1,893,973 |
| PV Annual Fixed Capital Charges | $495,339 | $154,560 | $433,089 | $226,091 | $160,371 | $477,324 | $185,659 | $177,229 | $192,862 | $70,672 | $160,712 | $347,527 | $187,405 | $98,355 | $185,303 | $396,729 | $332,382 | $147,623 | $74,847 | $4,504,080 | $2,844,026 |
| PV Annual Remaining Salvage Value | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| PV Operations & Maintenance Expense | $129,160 | $40,302 | $112,929 | $58,954 | $41,817 | $124,463 | $48,411 | $46,213 | $50,289 | $18,428 | $41,906 | $90,618 | $48,866 | $25,646 | $48,318 | $103,448 | $86,669 | $38,493 | $19,516 | $1,174,445 | $741,584 |
| Total Utility PV Costs | $624,499 | $194,862 | $546,018 | $285,045 | $202,188 | $601,787 | $234,069 | $223,441 | $243,151 | $89,100 | $202,618 | $438,145 | $236,271 | $124,001 | $233,621 | $500,177 | $419,051 | $186,115 | $94,363 | $5,678,524 | $3,585,610 |
| **Utility Annual Levelized Cost per kWh Saved** | $0.1285 | $0.3587 | $0.0932 | $0.0490 | $0.0611 | $0.1701 | $0.1016 | $0.0928 | $0.0472 | $0.0225 | $0.0809 | $0.1987 | $0.0886 | $0.0455 | $0.1104 | $0.1021 | $0.0963 | $0.1017 | $0.0576 | $0.0906 | $0.0726 |
| Utility Levelized Annual Cost per kW Reduction | $620 | $3,150 | $419 | $251 | $306 | $681 | $427 | $438 | $236 | $119 | $382 | $1,027 | $361 | $248 | $464 | $548 | $433 | $346 | $243 | $427 | $344 |
| **Utility Benefit / Cost Ratio** | 0.85 | 0.31 | 1.18 | 2.24 | 1.79 | 0.64 | 1.08 | 1.18 | 2.32 | 4.86 | 1.36 | 0.55 | 1.24 | 2.41 | 0.99 | 1.07 | 1.14 | 1.08 | 1.90 | 1.21 | 1.51 |
| | | | | | | | | | | | | | | | | | | | | 0.0 | 0.0 |
| Utility Revenue Requirements | | | | | | | | | | | | | | | | | | | | 0.00 | 0.00 |
| Avoided PV of Purchase Power Costs | $533,043 | $59,567 | $642,293 | $637,725 | $362,773 | $387,888 | $252,591 | $264,012 | $565,243 | $433,343 | $274,753 | $241,787 | $292,328 | $298,787 | $231,962 | $537,218 | $477,151 | $200,627 | $179,554 | $6,872,644 | $5,418,397 |
| Net Utility PV Savings | ($91,457) | ($135,295) | $96,274 | $352,680 | $160,584 | ($213,899) | $18,521 | $40,570 | $322,092 | $344,243 | $72,134 | ($196,358) | $56,057 | $174,786 | ($1,659) | $37,041 | $58,100 | $14,512 | $85,191 | $1,194,119 | $1,832,787 |
| | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| Customer Impact / Substation | | | | | | | | | | | | | | | | | | | | $0.00 | $0.00 |
| Customer kWh/yr (before SI & VO) | 18,428 | 20,331 | 33,802 | 16,623 | 14,826 | 18,924 | 20,275 | 30,903 | 27,071 | 16,379 | 15,940 | 18,836 | 20,361 | 15,585 | 20,815 | 22,516 | 25,872 | 20,456 | 20,315 | 20,412 | 20,740 |
| Customer kWh/yr (after SI & VO) | 18,259 | 20,297 | 33,522 | 16,409 | 14,701 | 18,742 | 20,207 | 30,796 | 26,854 | 16,213 | 15,864 | 18,733 | 20,252 | 15,459 | 20,713 | 22,340 | 25,649 | 20,376 | 20,221 | 20,274 | 20,595 |

| Stage 3 - Results | Walla Walla Bowman 5W150 | Walla Walla Bowman 5W154 | Walla Walla Dodd Rd 4W22 | Walla Walla Mill Creek 5W116 | Walla Walla Mill Creek 5W127 | Walla Walla Pomeroy 5W342 | Yakima Clinton 5Y608 | Yakima Clinton 5Y610 | Yakima Nob Hill 5Y194 | Yakima Nob Hill 5Y197 | Yakima Nob Hill 5Y273 | Yakima North Park 5Y356 | Yakima Orchard 5Y456 | Yakima Orchard 5Y498 | Yakima Wiley 5Y434 | Yakima River Road 5Y444 | Lower Valley Grandview 5Y351 | Lower Valley Sunnyside 5Y313 | Lower Valley Sunnyside 5Y317 | Summary All Circuits | Summary Viable Solutions |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| General Information | | | | | | | | | | | | | | | | | | | | | |
| Total Customers Served (#) | 1,796 | 1,823 | 1,181 | 2,053 | 1,968 | 1,204 | 2,037 | 1,401 | 1,572 | 1,873 | 2,216 | 1,634 | 1,421 | 1,751 | 1,332 | 2,201 | 1,286 | 1,020 | 978 | 30,747 | 18,665 |
| Feeder Annual Peak MW | 6.72 | 8.20 | 8.70 | 8.10 | 6.22 | 6.04 | 8.20 | 9.25 | 8.37 | 5.90 | 7.98 | 6.79 | 7.30 | 6.28 | 6.99 | 10.60 | 7.70 | 5.00 | 4.00 | 138.33 | 76.01 |
| Total Annual Energy Consumed (MWh/yr) | 33,096 | 37,064 | 39,920 | 34,127 | 29,178 | 22,784 | 41,300 | 43,296 | 42,555 | 30,679 | 35,323 | 30,778 | 28,933 | 27,290 | 27,726 | 49,558 | 33,272 | 20,865 | 19,868 | 627,608 | 357,575 |
| Average Customer Voltage Change (%) | 2.27% | 1.10% | 2.43% | 2.84% | 2.15% | 2.71% | 1.36% | 1.38% | 2.10% | 2.41% | 1.55% | 1.68% | 1.67% | 2.10% | 1.60% | 2.06% | 2.16% | 2.26% | 2.38% | 2.01% | 2.07% |
| Reduction in Annual Energy Delivered from Sub (%) | 1.77% | 0.68% | 1.67% | 1.95% | 1.49% | 1.73% | 1.01% | 1.01% | 1.55% | 1.61% | 1.04% | 1.15% | 1.31% | 1.37% | 1.19% | 1.37% | 1.64% | 1.85% | 1.80% | 1.40% | 1.45% |
| | | | | | | | | | | | | | | | | | | | | $0 | $0 |
| Utility Energy Savings Potential | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| Line Loss Reduction (MWh/y) | 78.163 | -21.821 | 126.960 | 21.470 | 16.457 | 55.922 | 43.637 | 41.508 | 70.630 | 3.457 | -3.944 | 4.888 | 57.439 | -5.093 | 30.517 | -2.250 | 55.648 | 65.827 | 39.429 | 678.845 | 371.540 |
| VO Energy Savings (MWh/y) | 480.0 | 260.7 | 503.4 | 620.1 | 400.7 | 315.3 | 359.6 | 381.5 | 567.4 | 474.5 | 357.9 | 331.5 | 308.6 | 366.2 | 283.7 | 652.5 | 467.6 | 306.8 | 306.8 | 7744.8 | 4621.5 |
| Total Energy Savings (MWh/y) | 585.7 | 252.8 | 666.1 | 666.9 | 433.6 | 394.2 | 419.1 | 437.2 | 658.3 | 493.4 | 367.3 | 353.8 | 380.3 | 374.6 | 329.5 | 677.5 | 546.3 | 386.3 | 357.7 | 8780.7 | 5180.1 |
| Total Energy Savings (MWa) | 0.0669 | 0.0289 | 0.0760 | 0.0761 | 0.0495 | 0.0450 | 0.0478 | 0.0499 | 0.0751 | 0.0563 | 0.0419 | 0.0404 | 0.0434 | 0.0428 | 0.0376 | 0.0773 | 0.0624 | 0.0441 | 0.0408 | 1.0024 | 0.5913 |
| Total Coincidental Demand Reduction (kW) | 117.4 | 43.9 | 141.4 | 128.9 | 84.5 | 91.8 | 88.0 | 86.8 | 128.6 | 93.2 | 68.2 | 67.3 | 83.8 | 69.3 | 70.4 | 126.5 | 114.8 | 88.3 | 73.8 | 1766.9 | 1027.0 |
| Customer Average Energy Reduction (kWh/yr) | 267 | 143 | 426 | 302 | 204 | 262 | 177 | 272 | 361 | 253 | 162 | 203 | 217 | 209 | 213 | 296 | 364 | 301 | 314 | 252 | 248 |
| | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| Distribution Line Losses | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| Existing Base System Line Loss (kW) | 325.2 | 98.8 | 288.9 | 122.6 | 65.7 | 194.1 | 113.0 | 128.8 | 165.1 | 44.7 | 150.2 | 231.7 | 124.3 | 91.7 | 144.8 | 186.1 | 106.0 | 86.8 | 49.6 | 2718.1 | 1343.4 |
| Baseline Pre-VO System Line Loss (kW) | 302.3 | 106.1 | 247.4 | 114.6 | 59.3 | 164.9 | 95.2 | 116.2 | 146.8 | 43.5 | 151.6 | 229.5 | 100.8 | 93.6 | 130.1 | 186.9 | 82.8 | 58.4 | 35.5 | 2465.5 | 1217.0 |
| Line Loss Reduction (kW) | 22.9 | -7.3 | 41.5 | 8.0 | 6.4 | 29.2 | 17.8 | 12.6 | 18.3 | 1.2 | -1.4 | 2.2 | 23.5 | -1.9 | 14.7 | -0.8 | 23.2 | 28.4 | 14.1 | 252.6 | 126.4 |
| Line Loss Reduction (MWa) | 0.0089 | -0.0024910 | 0.0145 | 0.0025 | 0.0019 | 0.0064 | 0.0050 | 0.0047 | 0.0081 | 0.0004 | -0.0005 | 0.0006 | 0.0066 | -0.0006 | 0.0035 | -0.0003 | 0.0064 | 0.0075 | 0.0045 | 0.0775 | 0.0424 |
| | | | | | | | | | | | | | | | | | | | | 0.0 | 0.0 |
| End-Use Energy Consumption | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| Average Volts Pre-VO (V) | 122.3 | 121.6 | 122.1 | 123.2 | 122.3 | 122.9 | 121.8 | 121.8 | 122.4 | 123.3 | 122.1 | 121.9 | 122.1 | 122.6 | 122.0 | 122.2 | 122.3 | 122.2 | 122.9 | 122.3 | 122.5 |
| Average Volts Post-VO (V) | 119.6 | 120.2 | 119.2 | 119.8 | 119.7 | 119.6 | 120.2 | 120.2 | 119.9 | 120.4 | 120.2 | 119.9 | 120.1 | 120.1 | 120.1 | 119.8 | 119.7 | 119.5 | 120.0 | 119.9 | 120.0 |
| VO Factor (for End-Use) from VO Protocol | 0.640 | 0.640 | 0.520 | 0.640 | 0.640 | 0.510 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | 0.650 | 0.650 | 0.650 | 0.628 | 0.642 |
| Total End-Use Demand Reduction (kW) | 91.3 | 49.6 | 95.8 | 118.0 | 76.2 | 60.0 | 68.4 | 72.6 | 108.0 | 90.3 | 68.1 | 63.1 | 58.7 | 69.7 | 54.0 | 124.2 | 89.0 | 58.4 | 58.4 | 1473.5 | 879.3 |
| VO Energy Savings (MWa) | 0.0548 | 0.0298 | 0.0575 | 0.0708 | 0.0457 | 0.0360 | 0.0411 | 0.0435 | 0.0653 | 0.0540 | 0.0400 | 0.0378 | 0.0352 | 0.0418 | 0.0324 | 0.0745 | 0.0534 | 0.0350 | 0.0350 | 0.8836 | 0.5271 |
| Change in Voltage (pu) | 0.0227 | 0.0110 | 0.0243 | 0.0284 | 0.0215 | 0.0271 | 0.0136 | 0.0138 | 0.0208 | 0.0242 | 0.0158 | 0.0168 | 0.0167 | 0.0210 | 0.0160 | 0.0206 | 0.0216 | 0.0226 | 0.0238 | 0.0201 | 0.0207 |
| | | | | | | | | | | | | | | | | | | | | 0.0000 | 0.0000 |
| Distribution Transformer No-Load Losses | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| Distribution Transformer Connected kVA | 23,831 | 24,581 | 29,035 | 17,726 | 15,105 | 16,801 | 22,604 | 20,066 | 19,096 | 12,614 | 16,378 | 20,180 | 16,682 | 12,638 | 18,624 | 25,987 | 20,980 | 11,852 | 9,580 | 354,357 | 181,487 |
| Total No-Load Loss (kW) | 71.5 | 73.7 | 87.1 | 53.2 | 45.3 | 50.4 | 67.8 | 60.2 | 57.3 | 37.8 | 49.1 | 60.5 | 50.0 | 37.9 | 55.9 | 78.0 | 62.9 | 35.6 | 28.7 | 1063.1 | 544.5 |
| Change in No-Load Loss (%) | 4.38% | 2.16% | 4.68% | 5.45% | 4.16% | 5.21% | 2.67% | 2.70% | 4.04% | 4.66% | 3.09% | 3.28% | 3.25% | 4.07% | 3.12% | 3.99% | 4.19% | 4.38% | 4.59% | 3.90% | 4.02% |
| Total No-Load Loss Reduction (kW) | 3.1 | 1.6 | 4.1 | 2.9 | 1.9 | 2.6 | 1.8 | 1.6 | 2.3 | 1.8 | 1.5 | 2.0 | 1.6 | 1.5 | 1.7 | 3.1 | 2.6 | 1.6 | 1.3 | 40.8 | 21.4 |
| No-Load Loss Saved (MWh/yr) | 27.5 | 14.0 | 35.7 | 25.4 | 16.5 | 23.0 | 15.8 | 14.2 | 20.3 | 15.5 | 13.3 | 17.4 | 14.3 | 13.5 | 15.3 | 27.3 | 23.1 | 13.6 | 11.5 | 357.1 | 187.1 |
| No_Load Loss Reduction (MWa) | 0.0031 | 0.0016 | 0.0041 | 0.0029 | 0.0019 | 0.0026 | 0.0018 | 0.0016 | 0.0023 | 0.0018 | 0.0015 | 0.0020 | 0.0016 | 0.0015 | 0.0017 | 0.0031 | 0.0026 | 0.0016 | 0.0013 | 0.0408 | 0.0214 |
| | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| Utility Energy Efficiency Costs and Benefits | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| VO Improvement Installation Cost | $341,514 | $272,600 | $583,960 | $318,157 | $256,139 | $622,153 | $281,975 | $260,606 | $297,023 | $154,291 | $241,604 | $522,300 | $267,123 | $230,336 | $402,516 | $552,570 | $469,211 | $240,890 | $203,759 | $6,518,727 | $2,826,294 |
| Energy Efficiency Incentives | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| VO Improvement First Year Cost | $341,514 | $272,600 | $583,960 | $318,157 | $256,139 | $622,153 | $281,975 | $260,606 | $297,023 | $154,291 | $241,604 | $522,300 | $267,123 | $230,336 | $402,516 | $552,570 | $469,211 | $240,890 | $203,759 | $6,518,727 | $2,826,294 |
| PV Annual Fixed Capital Charges | $512,824 | $409,341 | $876,886 | $477,751 | $384,623 | $934,237 | $423,419 | $391,331 | $446,015 | $231,686 | $362,797 | $784,296 | $401,117 | $345,877 | $604,426 | $829,750 | $704,576 | $361,725 | $305,968 | $9,788,646 | $4,244,017 |
| PV Annual Remaining Salvage Value | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| PV Operations & Maintenance Expense | $133,720 | $106,736 | $228,649 | $124,574 | $100,291 | $243,603 | $110,407 | $102,040 | $116,299 | $60,413 | $94,600 | $204,506 | $104,592 | $90,188 | $157,605 | $216,358 | $183,719 | $94,320 | $79,782 | $2,552,402 | $1,106,633 |
| Total Utility PV Costs | $646,543 | $516,078 | $1,105,535 | $602,325 | $484,914 | $1,177,840 | $533,826 | $493,371 | $562,315 | $292,099 | $457,397 | $988,802 | $505,709 | $436,065 | $762,031 | $1,046,108 | $888,295 | $456,045 | $385,750 | $12,341,048 | $5,350,650 |
| **Utility Annual Levelized Cost per kWh Saved** | $0.0907 | $0.1676 | $0.1363 | $0.0742 | $0.0918 | $0.2454 | $0.1046 | $0.0927 | $0.0701 | $0.0486 | $0.1023 | $0.2295 | $0.1092 | $0.0956 | $0.1899 | $0.1268 | $0.1335 | $0.0970 | $0.0886 | $0.1154 | $0.0848 |
| Utility Levelized Annual Cost per kW Reduction | $452 | $966 | $642 | $384 | $471 | $1,054 | $498 | $467 | $359 | $257 | $551 | $1,207 | $495 | $517 | $889 | $679 | $635 | $424 | $429 | $574 | $428 |
| **Utility Benefit / Cost Ratio** | 1.21 | 0.65 | 0.80 | 1.48 | 1.19 | 0.45 | 1.05 | 1.18 | 1.56 | 2.26 | 1.07 | 0.48 | 1.00 | 1.15 | 0.58 | 0.86 | 0.82 | 1.13 | 1.24 | 0.95 | 1.29 |
| | | | | | | | | | | | | | | | | | | | | 0.0 | 0.0 |
| Utility Revenue Requirements | | | | | | | | | | | | | | | | | | | | 0.00 | 0.00 |
| Avoided PV of Purchase Power Costs | $781,889 | $337,556 | $889,222 | $890,364 | $578,917 | $526,343 | $559,511 | $583,692 | $878,875 | $658,736 | $490,381 | $472,297 | $507,735 | $500,127 | $439,891 | $904,559 | $729,405 | $515,681 | $477,604 | $11,722,785 | $6,915,777 |
| Net Utility PV Savings | $135,346 | ($178,521) | ($216,313) | $288,040 | $94,003 | ($651,497) | $25,685 | $90,321 | $316,560 | $366,637 | $32,984 | ($516,505) | $2,026 | $64,062 | ($322,140) | ($141,549) | ($158,891) | $59,636 | $91,854 | ($618,263) | $1,565,127 |
| | | | | | | | | | | | | | | | | | | | | 0 | 0 |
| Customer Impact / Substation | | | | | | | | | | | | | | | | | | | | $0.00 | $0.00 |
| Customer kWh/yr (before SI & VO) | 18,428 | 20,331 | 33,802 | 16,623 | 14,826 | 18,924 | 20,275 | 30,903 | 27,071 | 16,379 | 15,940 | 18,836 | 20,361 | 15,585 | 20,815 | 22,516 | 25,872 | 20,456 | 20,315 | 20,412 | 19,157 |
| Customer kWh/yr (after SI & VO) | 18,160 | 20,188 | 33,375 | 16,321 | 14,622 | 18,662 | 20,098 | 30,631 | 26,710 | 16,126 | 15,779 | 18,633 | 20,143 | 15,376 | 20,602 | 22,220 | 25,509 | 20,155 | 20,001 | 20,160 | 18,910 |

Appendix 7-6 Optimal Solutions by Circuit and Total Viable

| **Optimal Solution** | Walla Walla | Walla Walla | Walla Walla | Walla Walla | Walla Walla | Walla Walla | Yakima | Yakima | Yakima | Yakima | Yakima | Yakima | Yakima | Yakima | Yakima | Yakima | Lower Valley | Lower Valley | Lower Valley | **Optimal Summary** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (Greatest Savings and BCR >= 1 and LCLC <= $105.91) | **Bowman** | **Bowman** | **Dodd Rd** | **Mill Creek** | **Mill Creek** | **Pomeroy** | **Clinton** | **Clinton** | **Nob Hill** | **Nob Hill** | **Nob Hill** | **North Park** | **Orchard** | **Orchard** | **Wiley** | **River Road** | **Grandview** | **Sunnyside** | **Sunnyside** | |
| | 5W150 | 5W154 | 4W22 | 5W116 | 5W127 | 5W342 | 5Y608 | 5Y610 | 5Y194 | 5Y197 | 5Y273 | 5Y356 | 5Y456 | 5Y498 | 5Y434 | 5Y444 | 5Y351 | 5Y313 | 5Y317 | |
| General Information | | | | | | | | | | | | | | | | | | | | |
| Total Customers Served (#) | 1,796 | 1,823 | 1,181 | 2,053 | 1,968 | NC | 2,037 | 1,401 | 1,572 | 1,873 | 2,216 | NC | 1,421 | 1,751 | 1,332 | 2,201 | 1,286 | 1,020 | 978 | 27,909 |
| Feeder Annual Peak MW | 6.72 | 8.20 | 8.70 | 8.10 | 6.22 | NC | 8.20 | 9.25 | 8.37 | 5.90 | 7.98 | NC | 7.30 | 6.28 | 6.99 | 10.60 | 7.70 | 5.00 | 4.00 | 125.50 |
| Total Annual Energy Consumed (MWh/yr) | 33,096 | 37,064 | 39,920 | 34,127 | 29,178 | NC | 41,300 | 43,296 | 42,555 | 30,679 | 35,323 | NC | 28,933 | 27,290 | 27,726 | 49,558 | 33,272 | 20,865 | 19,868 | 574,046 |
| Average Customer Voltage Change (%) | 2.27% | 0.83% | 1.59% | 2.84% | 2.15% | NC | 1.36% | 1.38% | 2.10% | 2.41% | 1.55% | NC | 0.83% | 2.10% | 0.83% | 1.22% | 1.33% | 2.26% | 2.38% | 1.73% |
| Reduction in Annual Energy Delivered from Sub (%) | 1.77% | 0.56% | 1.21% | 1.95% | 1.49% | NC | 1.01% | 1.01% | 1.55% | 1.61% | 1.04% | NC | 0.76% | 1.37% | 0.68% | 0.81% | 1.07% | 1.85% | 1.80% | 1.23% |
| Utility Energy Savings Potential | | | | | | | | | | | | | | | | | | | | |
| Line Loss Reduction (MWh/y) | 78.163 | 0.299 | 126.960 | 21.470 | 16.457 | NC | 43.637 | 41.508 | 70.630 | 3.457 | -3.944 | NC | 57.439 | -5.093 | 33.510 | -2.250 | 55.648 | 65.827 | 39.429 | 643.147 |
| VO Energy Savings (MWh/y) | 480.0 | 197.7 | 330.4 | 620.1 | 400.7 | NC | 359.6 | 381.5 | 567.4 | 474.5 | 357.9 | NC | 154.3 | 366.2 | 147.9 | 388.2 | 287.4 | 306.8 | 306.8 | 6127.4 |
| Total Energy Savings (MWh/y) | 585.7 | 208.6 | 481.1 | 666.9 | 433.6 | NC | 419.1 | 437.2 | 658.3 | 493.4 | 367.3 | NC | 219.0 | 374.6 | 189.4 | 402.4 | 357.4 | 386.3 | 357.7 | 7038.0 |
| Total Energy Savings (MWa) | 0.0669 | 0.0238 | 0.0549 | 0.0761 | 0.0495 | NC | 0.0478 | 0.0499 | 0.0751 | 0.0563 | 0.0419 | NC | 0.0250 | 0.0428 | 0.0216 | 0.0459 | 0.0408 | 0.0441 | 0.0408 | 0.8034 |
| Total Coincidental Demand Reduction (kW) | 117.4 | 38.9 | 107.1 | 128.9 | 84.5 | NC | 88.0 | 86.8 | 128.6 | 93.2 | 68.2 | NC | 53.7 | 69.3 | 42.8 | 74.9 | 79.5 | 88.3 | 73.8 | 1423.9 |
| Customer Average Energy Reduction (kWh/yr) | 267 | 108 | 280 | 302 | 204 | NC | 177 | 272 | 361 | 253 | 162 | NC | 109 | 209 | 111 | 176 | 223 | 301 | 314 | 220 |
| Distribution Line Losses | | | | | | | | | | | | | | | | | | | | |
| Existing Base System Line Loss (kW) | 325.2 | 98.8 | 288.9 | 122.6 | 65.7 | NC | 113.0 | 128.8 | 165.1 | 44.7 | 150.2 | NC | 124.3 | 91.7 | 144.8 | 186.1 | 106.0 | 86.8 | 49.6 | 2292.3 |
| Baseline Pre-VO System Line Loss (kW) | 302.3 | 98.7 | 247.4 | 114.6 | 59.3 | NC | 95.2 | 116.2 | 146.8 | 43.5 | 151.6 | NC | 100.8 | 93.6 | 131.1 | 186.9 | 82.8 | 58.4 | 35.5 | 2064.7 |
| Line Loss Reduction (kW) | 22.9 | 0.1 | 41.5 | 8.0 | 6.4 | NC | 17.8 | 12.6 | 18.3 | 1.2 | -1.4 | NC | 23.5 | -1.9 | 13.7 | -0.8 | 23.2 | 28.4 | 14.1 | 227.6 |
| Line Loss Reduction (MWa) | 0.0089 | 0.0000 | 0.0145 | 0.0025 | 0.0019 | NC | 0.0050 | 0.0047 | 0.0081 | 0.0004 | -0.0005 | NC | 0.0066 | -0.0006 | 0.0038 | -0.0003 | 0.0064 | 0.0075 | 0.0045 | 0.0734 |
| End-Use Energy Consumption | | | | | | | | | | | | | | | | | | | | |
| Average Volts Pre-VO (V) | 122.3 | 121.6 | 122.1 | 123.2 | 122.3 | NC | 121.8 | 121.8 | 122.4 | 123.3 | 122.1 | NC | 122.1 | 122.6 | 122.0 | 122.2 | 122.3 | 122.2 | 122.9 | 122.3 |
| Average Volts Post-VO (V) | 119.6 | 120.6 | 120.2 | 119.8 | 119.7 | NC | 120.2 | 120.2 | 119.9 | 120.4 | 120.2 | NC | 121.1 | 120.1 | 121.0 | 120.8 | 120.7 | 119.5 | 120.0 | 120.2 |
| VO Factor (for End-Use) from VO Protocol | 0.640 | 0.640 | 0.520 | 0.640 | 0.640 | NC | 0.640 | 0.640 | 0.640 | 0.640 | 0.640 | NC | 0.640 | 0.640 | 0.640 | 0.640 | 0.650 | 0.650 | 0.650 | 0.635 |
| Total End-Use Demand Reduction (kW) | 91.3 | 37.6 | 62.9 | 118.0 | 76.2 | NC | 68.4 | 72.6 | 108.0 | 90.3 | 68.1 | NC | 29.4 | 69.7 | 28.1 | 73.9 | 54.7 | 58.4 | 58.4 | 1165.8 |
| VO Energy Savings (MWa) | 0.0548 | 0.0226 | 0.0377 | 0.0708 | 0.0457 | NC | 0.0411 | 0.0435 | 0.0653 | 0.0540 | 0.0400 | NC | 0.0176 | 0.0418 | 0.0169 | 0.0443 | 0.0328 | 0.0350 | 0.0350 | 0.6990 |
| Change in Voltage (pu) | 0.0227 | 0.0083 | 0.0159 | 0.0284 | 0.0215 | NC | 0.0136 | 0.0138 | 0.0208 | 0.0242 | 0.0158 | NC | 0.0083 | 0.0210 | 0.0083 | 0.0122 | 0.0133 | 0.0226 | 0.0238 | 0.0173 |
| Distribution Transformer No-Load Losses | | | | | | | | | | | | | | | | | | | | |
| Distribution Transformer Connected kVA | 23,831 | 24,581 | 29,035 | 17,726 | 15,105 | NC | 22,604 | 20,066 | 19,096 | 12,614 | 16,378 | NC | 16,682 | 12,638 | 18,624 | 25,987 | 20,980 | 11,852 | 9,580 | 317,376 |
| Total No-Load Loss (kW) | 71.5 | 73.7 | 87.1 | 53.2 | 45.3 | NC | 67.8 | 60.2 | 57.3 | 37.8 | 49.1 | NC | 50.0 | 37.9 | 55.9 | 78.0 | 62.9 | 35.6 | 28.7 | 952.1 |
| Change in No-Load Loss (%) | 4.38% | 1.65% | 3.11% | 5.45% | 4.16% | NC | 2.67% | 2.70% | 4.04% | 4.66% | 3.09% | NC | 1.65% | 4.07% | 1.65% | 2.40% | 2.61% | 4.38% | 4.59% | 3.38% |
| Total No-Load Loss Reduction (kW) | 3.1 | 1.2 | 2.7 | 2.9 | 1.9 | NC | 1.8 | 1.6 | 2.3 | 1.8 | 1.5 | NC | 0.8 | 1.5 | 0.9 | 1.9 | 1.6 | 1.6 | 1.3 | 30.5 |
| No-Load Loss Saved (MWh/yr) | 27.5 | 10.6 | 23.7 | 25.4 | 16.5 | NC | 15.8 | 14.2 | 20.3 | 15.5 | 13.3 | NC | 7.2 | 13.5 | 8.1 | 16.4 | 14.4 | 13.6 | 11.5 | 267.5 |
| No_Load Loss Reduction (MWa) | 0.0031 | 0.0012 | 0.0027 | 0.0029 | 0.0019 | NC | 0.0018 | 0.0016 | 0.0023 | 0.0018 | 0.0015 | NC | 0.0008 | 0.0015 | 0.0009 | 0.0019 | 0.0016 | 0.0016 | 0.0013 | 0.0305 |
| Utility Energy Efficiency Costs and Benefits | | | | | | | | | | | | | | | | | | | | |
| VO Improvement Installation Cost<br>Energy Efficiency Incentives | $341,514 | $29,526 | $288,415 | $318,157 | $256,139 | NC | $281,975 | $260,606 | $297,023 | $154,291 | $241,604 | NC | $124,802 | $230,336 | $100,248 | $264,201 | $221,349 | $240,890 | $203,759 | $3,854,835 |
| VO Improvement First Year Cost | $341,514 | $29,526 | $288,415 | $318,157 | $256,139 | NC | $281,975 | $260,606 | $297,023 | $154,291 | $241,604 | NC | $124,802 | $230,336 | $100,248 | $264,201 | $221,349 | $240,890 | $203,759 | $3,854,835 |
| PV Annual Fixed Capital Charges | $512,824 | $44,337 | $433,089 | $477,751 | $384,623 | NC | $423,419 | $391,331 | $446,015 | $231,686 | $362,797 | NC | $187,405 | $345,877 | $150,534 | $396,729 | $332,382 | $361,725 | $305,968 | $5,788,494 |
| PV Annual Remaining Salvage Value | $0 | $0 | $0 | $0 | $0 | NC | $0 | $0 | $0 | $0 | $0 | NC | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| PV Operations & Maintenance Expense | $133,720 | $11,561 | $112,929 | $124,574 | $100,291 | NC | $110,407 | $102,040 | $116,299 | $60,413 | $94,600 | NC | $48,866 | $90,188 | $39,252 | $103,448 | $86,669 | $94,320 | $79,782 | $1,509,357 |
| Total Utility PV Costs | $646,543 | $55,898 | $546,018 | $602,325 | $484,914 | NC | $533,826 | $493,371 | $562,315 | $292,099 | $457,397 | NC | $236,271 | $436,065 | $189,786 | $500,177 | $419,051 | $456,045 | $385,750 | $7,297,852 |
| **Utility Annual Levelized Cost per kWh Saved** | $0.0907 | $0.0220 | $0.0932 | $0.0742 | $0.0918 | NC | $0.1046 | $0.0927 | $0.0701 | $0.0486 | $0.1023 | NC | $0.0886 | $0.0956 | $0.0823 | $0.1021 | $0.0963 | $0.0970 | $0.0886 | $0.0852 |
| Utility Levelized Annual Cost per kW Reduction | $452 | $118 | $419 | $384 | $471 | NC | $498 | $467 | $359 | $257 | $551 | NC | $361 | $517 | $365 | $548 | $433 | $424 | $429 | $421 |
| **Utility Benefit / Cost Ratio** | 1.21 | 4.98 | 1.18 | 1.48 | 1.19 | NC | 1.05 | 1.18 | 1.56 | 2.26 | 1.07 | NC | 1.24 | 1.15 | 1.33 | 1.07 | 1.14 | 1.13 | 1.24 | 1.29 |
| Utility Revenue Requirements | | | | | | | | | | | | | | | | | | | | |
| Avoided PV of Purchase Power Costs | $781,889 | $278,500 | $642,293 | $890,364 | $578,917 | NC | $559,511 | $583,692 | $878,875 | $658,736 | $490,381 | NC | $292,328 | $500,127 | $252,909 | $537,218 | $477,151 | $515,681 | $477,604 | $9,396,175 |
| Net Utility PV Savings | $135,346 | $222,603 | $96,274 | $288,040 | $94,003 | NC | $25,685 | $90,321 | $316,560 | $366,637 | $32,984 | NC | $56,057 | $64,062 | $63,123 | $37,041 | $58,100 | $59,636 | $91,854 | $2,098,324 |
| Customer Impact / Substation | | | | | | | | | | | | | | | | | | | | |
| Customer kWh/yr (before SI & VO) | 18,428 | 20,331 | 33,802 | 16,623 | 14,826 | NC | 20,275 | 30,903 | 27,071 | 16,379 | 15,940 | NC | 20,361 | 15,585 | 20,815 | 22,516 | 25,872 | 20,456 | 20,315 | 20,568 |
| Customer kWh/yr (after SI & VO) | 18,160 | 20,223 | 33,522 | 16,321 | 14,622 | NC | 20,098 | 30,631 | 26,710 | 16,126 | 15,779 | NC | 20,252 | 15,376 | 20,704 | 22,340 | 25,649 | 20,155 | 20,001 | 20,349 |
| Optimal Recommended Solution | Stage 3 | Stage 1 | Stage 2 | Stage 3 | Stage 3 | NC | Stage 3 | Stage 3 | Stage 3 | Stage 3 | Stage 3 | NC | Stage 2 | Stage 3 | Stage 1 | Stage 2 | Stage 2 | Stage 3 | Stage 3 | |

NC = No stage solution is economically compliant

# Appendix 8:  Simplified Voltage Optimization (VO) Measurement and Verification Protocol

# Simplified Voltage Optimization (VO)

# Measurement and Verification Protocol

## 1.0 Introduction

### *1.1 Purpose*

The Simplified Voltage Optimization (VO) Measurement and Verification (M&V) Protocol provides a basic approach to determine end-use energy savings when operating the electric distribution system more efficiently and within the lower band of the ANSI Standard voltage level. The protocol covers utility electric distribution systems serving mostly residential and light commercial load as defined by the utility. System loads do not need to be uniformly distributed throughout the distribution system. This Protocol identifies the procedure to determine the average annual voltage for a distribution primary system with source voltage regulation. Minimum system stability thresholds, system data requirements, and measurement and verification formulations are included as part of this Protocol.

1.1.1 Attachments

- End-use VO Factors are identified in tables for use with this Protocol in Appendix A.
- Examples of data collected are included with this document to provide an understanding of the level of effort and detail to perform VO Assessments. See Examples: Data Collection Templates.

1.1.2 Clarification of issues throughout this document.

The items in **bold** will appear frequently throughout the document.

- When **adjusted annual kW peak demand** is mentioned, ‘adjusted’ refers to common efforts by the utility to adjust for temperature, abnormal switching, or unusual loading conditions that would cause artificial peak demand information. Unusual loading conditions could, for example, be due to outage or maintenance.
- When **system modeling** is mentioned, it refers to using industry accepted distribution system power flow simulation tools for analysis of distribution system electric characteristics.
- When **end-use VO Factor** is mentioned, it refers to the tables in Appendix A that are derived from the 2007 NEEA Distribution Efficiency Initiative Study for end-use consumption (Load Research Project) and included 395 randomly selected residential homes throughout the Northwest using 12 plus months of day VO-On/ day VO-Off recordings. This information was presented to the NWPCC Regional Technical Forum (RTF) in 2008.
- When **voltage control zone** is mentioned, it consists of all distribution lines that are controlled by a tap changing source voltage regulator. Several voltage-control-zones may exist within one substation area

- When **minimum operating performance thresholds** are mentioned, they refer to a set of specifications to achieve higher efficiency. These specifications, called performance thresholds, are described in the NEEA Distribution Efficiency Guidebook, January 2008, which provides guidelines for industry best practices for distribution system efficiency based on the research performed during the NEEA Distribution Efficiency Initiative Study.
- **Annual estimated or historical annual peak kW demand data** may be used for estimation of end use VO savings during study/assessment periods; however, actual metered annual kW peak demand data is used during the verification process.
- Calculations of all system improvements (reduction of line losses and no-load losses) will be made using industry accepted engineering methodologies. This Protocol does not propose new methods of calculating reduction of losses due to system improvements nor are Appendix A Tables used for non end-use VO calculations.
- Metering periods must not occur during a holiday or unusual circumstance that would lead to abnormal patterns in residential use.

### *1.2 Simplified Voltage Optimization Overview*

The Simplified VO Protocol encompasses three basic source voltage regulation techniques described below:

**Voltage Fixed Reduction (VFR)**: The Voltage Fixed Reduction methods require that the distribution substation source voltage regulator and line regulators voltages be lowered by a fixed amount. It is assumed that the pre-installation voltage is fixed at a known value. No remote automated voltage feedback controls are applied.

**Line Drop Compensation (LDC):** The Line Drop Compensation methods require that the distribution substation source voltage regulator and line regulators apply automatic voltage controls to control voltage up and down based on line load levels. When the feeder or substation load is changing, the voltage regulator simulates (calculates) an EOL voltage level and adjusts the regulator voltage to hold the EOL voltage constant. The voltage is locally sensed at the substation and line voltage regulator locations.

**Automated Voltage Feedback Control (AVFC):** The Automated Voltage Feedback Control methods require that the distribution substation source voltage regulator and line regulators voltages apply automatic voltage controls to control voltage up and down based on remote EOL voltage sensing. When the EOL voltage rises or falls below the pre-determine set point, the substation and line voltage regulators raise or lower their voltages as necessary to hold the remote EOL voltage constant. The voltage is locally and remotely sensed at the substation and line voltage regulator locations. Continuous voltage monitoring is required at EOL to feedback voltage.

All methods require voltage monitoring by the utility to periodically check that the end-of-line (EOL) voltages do not fall below a pre-determined set point.

All methods must be maintained annually in order to meet performance thresholds and VO guidelines.

## 2.0 Simplified VO M&V Approach

### *2.1 FEMP Measurement and Verification*

The Simplified VO M&V Protocol follow Option D as described in "Measurement & Verification for Federal Energy Projects, Version 2.2
www.eere.energy.gov/femp/financing/superespcs_mvresources.html
and "International Performance Measurement & Verification Protocol (IPMVP)", Volume I, March 2002 (www.ipmvp.org).

Option D is utilized because the VO M&V Protocol is applied to a single whole facility (substation or feeder) with many subparts requiring a collective approach and where the energy savings will be less than 10 percent. Option D allows for a minimum of pre and post metered data points, and includes some simulation modeling and/or calculations to arrive at the energy saved for each chosen facility or system.

### *2.2 Simplified VO M&V; Four Stages*

The Simplified VO M&V Protocol approach has four stages. The general steps of each stage are identified below. Processes that will be used throughout the stages are explained in 2.3 through 4.0.

1. Stage One - *Existing Performance Assessment and VO Implementation Plan*
    a. Gather actual or estimated distribution system historical data that is readily available including voltage settings and voltage operational standards.
    b. Perform preliminary assessment of distribution system's existing level of performance using system modeling.
    c. Develop a preliminary improvement plan describing the system improvements needed to meet minimum operating performance thresholds for VO.
    d. Develop preliminary plan for implementation of VO.
    e. Estimate costs and propose preliminary schedules.
    f. Calculate VO Factor from the VO Factor Tables.
    g. Estimate potential savings of VO application.
    h. Document all activities and results.

2. Stage Two - *System Improvements and Baseline Pre-VO measurements*
    a. Implement cost effective system improvements necessary to meet performance thresholds.
    b. Install source voltage regulating equipment necessary for operation of VO with controls set to mimic pre-VO average voltage conditions (non-VO operation). Pre-VO control settings are determined using system modeling. Perform pre-VO baseline measurements for 7-day period (168 hours). The detailed measurements are averaged over each hour.

c. Each voltage control zone must meet performance thresholds during this Pre-VO measurement period.
d. Determine baseline pre-VO overall average voltage for all VO voltage control zones included as part of the VO plan.
e. Identify final installation cost of system improvements including VO equipment.
f. Document all activities and results.

3. Stage Three - *VO Implementation and Post-VO Measurements and Verification*
   a. Prepare an initial estimate of end-use energy savings resulting from VO using results of pre-VO baseline measurements, planned post-VO conditions, and distribution system known or estimated customer load characteristics.
   b. Initiate post-VO operational voltage controls.
   c. Perform post-VO measurements for 7-day period (168 hours). The detailed measurements are averaged over each hour.
   d. Each voltage control zone must meet performance thresholds during this Post-VO measurement period.
   e. Determine post-VO overall average voltage for the voltage control zone. Prepare a final post-VO verified estimate of energy savings resulting from change in average annual voltage for baseline pre-VO and post-VO.
   f. Document all activities and results

4. Stage Four – Persistence of Energy Savings
   a. Complete annual self-certification checklist to ensure;
      i. Voltage settings are still in operation as prescribed within all VO voltage control zones.
      ii. Voltage control zones continue to meet performance thresholds. The annual VO performance self-certification is measured over a 12-month period.

### *2.3 About Minimum Operating Performance Thresholds*

The voltage control zones must meet or exceed performance thresholds during normal system switching configurations for the measurement periods; 7 days and/or 168 hours in Stage 2, 7 days and/or 168 hours in Stage 3, and there after during the Persistence period in Stage 4. All measurements during the measurement period are averaged over a one hour period.

In some cases it may be needed to perform system improvements to comply with performance thresholds (i.e. addition of line regulators, shunt capacitors, phase upgrades, line reconfigurations, and line reconductoring). If multiple VO voltage control zones are included as part of a substation system, the performance thresholds apply to each VO voltage control zone. System performance is determined from measurements at each VO voltage control zone source. Performance thresholds do not apply for non-VO voltage control zones.

For calculation purposes, load adjustment for temperature, abnormal switching configuration, or seasonal load anomalies may be performed to reflect normal annual loading operations.

1. The feeder-source <u>minimum power-factor</u> must be greater than 0.96. Power-factor

is total 3φ kW divided by total 3φ kVA.

2. The average of feeder-source power-factor must be greater than 0.98. Power-factor is defined in item 1 above.

3. Feeder-source phase-load-unbalance per unit (p.u.) must be less than 0.15 on 3φ lines. The p.u. unbalance is the average of (1-[Average 3φ peak hourly demand Amps] / [maximum 1φ hourly demand Amps]) over the measurement-period. Phase-load-unbalance is determined for each VO voltage-control-zone. Maximum 1φ hourly demand Amps is measured for each line phase (e.g. line phases A, B, or C). Feeder-source neutral-current must be less than 40 amps on 3φ lines.

4. Substation VO voltage-control-zone maximum adjusted voltage-drop must be less than 3.3%. The calculation uses voltage measurements over the period and adjusts them for peak load periods. For pre-VO and post-VO assessments, the maximum adjusted voltage-drop is the average of all voltage-drops over the measurement period multiplied by the ratio [annual 3φ peak kW hourly demand / average 3φ kW demand for measurement period]. Primary voltage-drop is difference between regulator bus and EOL (lowest voltage location).

   *Note: Voltage-drop is the reduction in voltage on primary line between regulator source and lowest voltage points. The voltage-drop % is the reduction in volts divided by source volts times 100. Substation VO regulator or VO line regulator annual 3φ peak kW hourly demand for a 12 month historical data period may be used with power flow simulations to determine the annual maximum voltage-drop for use with system assessment (Stage One) and self-certification monitoring (Stage Four). The peak kW demand is allocated across the VO voltage-control-zone feeder system.*

5. Line Regulator voltage-control-zone maximum adjusted voltage-drop must be less than 3.3%. The calculation uses voltage measurements over the period and adjusts them for the peak load periods. For pre-VO and post-VO assessments, the maximum adjusted voltage-drop is the average of voltage-drops over the measurement-period multiplied by the ratio [annual 3φ peak kW hourly demand / average 3φ kW demand for measurement period]. Primary voltage-drop is difference between regulator bus and EOL (lowest voltage location).

6. Secondary maximum allowed voltage-drop must be less than 4.0% for all VO voltage control zones. This value is difficult to obtain, and therefore, it may be established from utility standards and design guidelines. Any time the secondary voltage-drop exceeds 4.0%, the solution should be to fix the problem and not to increase the source voltage. Secondary systems include the distribution transformer, secondary conductors, and service wires.

7. Maximum voltage-drop variance between multiple feeders served within a substation VO voltage-control-zone must be less than 2 volts (on a 120V base). The voltage-drop p.u. variance is determined by comparing the maximum voltage-drops of each feeder measured over the measurement-period.

8. The VO primary line minimum hourly voltage must be greater than [114 Volts + ½ the voltage regulation bandwidth + secondary maximum allowed voltage-drop]. Acceptable voltage regulation bandwidth is in the range of 2V to 3V (on 120V base.) Primary line minimum-voltage must be measured near the expected lowest voltage location on the primary line at EOL.

9. The VO primary line maximum hourly voltage must be less than [126 Volts - ½ the voltage regulation bandwidth]. Acceptable voltage regulation bandwidth is in the range of 2V to 3V on 120V base. Primary line maximum voltage must be measured near the expected highest voltage location on the primary line at or near the voltage-control-zone regulator measured over the measurement-period averaged over each hour.

   *Note: The Customer Service Voltage must be between 126 Volts to 114 Volts for normal system switching configuration measured line to ground on a 120 Volt base over the measurement period integrated over the interval period of one hour. For infrequent abnormal operating conditions, the customer service voltage range is 127 Volts to 110 Volts.*

### *2.4 About Distribution System Load and Operating Data Collection*

Additional system data is collected for all VO voltage control zones from annual historical data, during the pre-VO and post-VO measurement periods, and through annual certification measurement periods. The system data is needed to determine the average voltage reduction and resultant energy savings for each VO voltage control zone.

Annual load peak demand or annual energy adjustments for temperature, abnormal switching configuration, or seasonal load anomalies may be performed to reflect normal annual loading operations.

This data is determined for each VO voltage control zone and includes:

1. Annual 3φ peak kW hourly demand and annual energy kWh. The VO assessment must also include an actual or adjusted annual kW peak demand and energy delivered by substation and assigned to each VO feeder and voltage control zone. This data is used to calculate annual load factor [annual 3φ kWh energy delivered / [maximum annual 3φ peak kW hourly demand * 8760 h]]
2. Hourly demand phase Amps for each VO voltage control zone source over the measurement period averaged over each hour.
3. Hourly demand kW over the measurement period for each VO voltage control zone, adjusted for normal conditions as required.
4. Hourly demand kvar over the measurement period for each VO voltage control zone, adjusted for normal conditions as required.
5. Maximum primary voltage-drop at the time of the 3φ peak kW demand (on 120V base). The voltage-drop is the average value measured over the peak hour. Distribution system modeling may be performed to determine system maximum primary voltage-drop. Source substation and line regulator Set-Point-Voltage settings on 120V base (in Volts)
6. Source substation and line regulator Current Transformer (CT) Primary Rating (in Amps)
7. Source substation and line regulator Potential Transformer (PT) Ratio (line-to-ground)
8. Source substation and line regulator real volts 'R' and reactive volts 'X' control setting on 120V base (in Volts)

9. Calculated regulator maximum voltage-rise at maximum 3φ peak kW hourly demand on 120V base (in Volts). Distribution system modeling and simulation may be performed to determine system maximum voltage-rise at maximum peak demand.

   *Note: The VO regulator voltage-rise is based on the peak load, control zone power factor and regulator control settings. For example, for most common conditions with average power factor greater than 0.98 and a 'X' setting equal to zero, the regulator maximum voltage-rise is ['R' setting (Volts) * average annual power factor (p.u.) * maximum annual 3φ peak hourly demand (Amps) / Current Transformer Primary Rating (Amps)]. All measurements are averaged over each hour.*

### *2.5 About Distribution System Equipment Data*

In addition to the measured or determined system parameters, additional information must be available to ensure correct system modeling, power flow simulations, and determine maximum voltage-drops and maximum voltage rises for all VO voltage control zones. The electric utility distribution system data is collected for system preliminary assessments, baseline pre-VO, post-VO, and annual self-certification M&V assessments for each VO application. The modeling data set includes:

1. Primary kV line-to-line voltage class (typically identified as the Distribution Transformer primary line-to-ground kV voltage rating.)
2. Distribution system maps and/or models depicting conductor sizes, phase configuration, and connected kVA size and location of distribution transformers.
3. Location, size, and type of all station regulators and line regulators including control settings for each (e.g., set-point-voltage, R & X settings, time delay, CT Rating and PT ratio, regulator bandwidth, and regulator first house protection settings.)
4. Location and size of Shunt Capacitor banks and control settings (if applicable). For simplified VO application, switch capacitor control must be 'var' control only.
5. Overall utility characteristics, design guidelines, construction standards, historical system studies, customer information, and equipment data.

### *2.6 About Metering Requirements*

Metering equipment is required to provide the measurement and verification of data for all VO voltage control zones for pre-VO, post-VO, and annual self-certification monitoring. Meters must collect kW demand, kvar demand, ampere demand, and volts measured over the measurement-period with measurements averaged over each hour. Metering locations include:

- Substation power transformer (on regulated voltage side).
- Substation feeder breakers.
- Line Regulator equipment (on regulated voltage side).
- Remote primary line EOL low voltage point locations (voltage recording meters only) for each VO voltage control zone.

Metering installations and calibration must be performed by qualified personnel. If feasible, it is desirable that all metering instrumentation complies with ANSI Standard C57.13

metering accuracy specifications. Substation and regulator metering data can be collected from energy/demand meters, electronic relays, or controllers provided they provide data on all phases present. Utility field self-verification and inspections are required to verify correct meter installation and correct register readings.

For VFR and LDC systems, one remote primary line EOL voltage-recording meter must be installed at the lowest voltage point locations on each of the primary feeders for each voltage-control-zone. For AVFC systems, there must be three-volt recording meters and volt remote feedback-sensing devices installed on each primary feeder at independent locations. The meters should measure voltage on all phases present for VRF, LDC, and AVFC systems.

## 3.0 About VO Factor and Energy Savings Calculations

### *3.1 Customer Data*

Customer load information is required for each distribution substation where VO may be applied. This customer information is used to determine the end-use VO Factor from Appendix A Tables, which are used in energy savings calculations. Based on known customer information available for the electric utility (e.g. customer information systems, utility mapping records, and customer billing system) the customer load characteristics are determined. It may be necessary to provide an estimate of customer load characteristics using typical load research data or other similar analysis. The required customer load characteristics are as follows:

1. Heating and cooling climate zone classification for each substation area.
2. Percentage of substation area total annual load (kWh) that is classified as residential class load.
3. Percentage of existing residential class consumers that have electric heat (hot water, space heating, and/or heat pump). Non electric heat is typically provided by gas, oil, or wood.
4. Percentage of existing residential class consumers that have any type of electric air conditioning.

### *3.2 About End Use VO Factor*

The end-use VO Factor is a ratio of expected % change in energy delivered for each 1% change in average voltage supplied at the end-use service entrance. The end use VO Factor is given as a p.u. ratio for a given system and is determined from VO Factor Tables in Appendix A of this Protocol. Enter the table identified for the Heating and cooling climate zone associated for each substation and select the appropriate VO Factor using the percent customers with Non-Electric Heating (and Heat Pumps) and percent of customers with Air-conditioning.

### *3.3 About Determination of Average Voltage Reduction*

For each VO voltage control zone (pre-VO and post-VO conditions), the average voltage formulation depends upon the voltage control method chosen (e.g., VFR, LDC, or AVFC.) The normalized average annual voltages are determined at the baseline pre-VO measurements (Stage 2) and post-VO measurements (Stage 3) from 168 metered-hours emulating a 7-day period as follows:

A = Calculated Feeder Maximum Annual Volt-Drop

= Average_of_all_Volt-Drop(hourly) * [maximum_annual_3φ_peak_kW_demand(hourly) / average_kW_demand(hourly)]

B = Calculated Regulator Maximum Annual Volt-Rise

= [Average_of_all_Regulator_Output_Voltages(hourly) – (Regulator_Set_Point_Voltage_Setting)] * [maximum_annual_3φ_peak_kW_demand(hourly) / average_kW_demand(hourly)]

*Note: The Volt-Drop (hourly) is the metered Regulator_Output_Voltage minus the lowest EOL voltage averaged over each hour. All values are calculated over the measurement-period. Variables A and B may be determined via system modeling simulations for initial VO average voltage estimates and annual self-certification assessments.*

The final post-VO verified average annual voltage reduction is the difference between the adjusted pre-VO and post-VO average annual voltages weighted by VO voltage control zone kW load and depends on the pre-VO and the post-VO voltage control techniques applied.

The annual 3φ peak kW hourly demand and Annual Load Factor are known from the measured historical data.

The baseline pre-VO overall average voltage for all VO voltage control zones is determined by applying the existing non-VO control settings and applying control setting adjustments to mimic pre-VO average voltage conditions (non-VO operation). Pre-VO control settings are determined using system modeling.

The adjusted average voltage calculation formulation for pre-VO and post-VO measurements for each voltage-control-zone is described as follows:

**** *VFR Methods****

For VFR applications, the regulator R and X control settings are zero.

Adjusted Average Voltage for VFR =
[Regulator_Set_Point_Voltage_Setting – ½ * A * Annual_Load_Factor]

**** *LDC and AVFC Methods****

For LDC applications, the regulator R and X control settings should be set so that the maximum voltage rise B is equal to or greater than the maximum annual voltage-drop A.

Adjusted Average Voltage for LDC or AVFC =
[Regulator_Set_Point_Voltage_Setting + Annual_Load_Factor *[B - 1/2 *A]]

### *3.4 About Determination of Average Annual Energy Reduction*

For each voltage-control-zone, the average voltage is calculated as shown in Section 3.3 above for the baseline pre-VO and post-VO conditions. If there are multiple voltage-control-zones within each VO application area, the overall system average annual voltage is the average of the control zone voltages weighted by control zone loads. All average annual voltages are on a 120V base.

Variables A and B can be determined via system modeling for initial VO average voltage estimates and annual self-certification assessments. The VO energy savings used for determining the initial VO estimate, final post-VO verification, or annual assessment is calculated as follows:

> Overall Average Voltage Reduction (in volts) =
> [Weighted Average Voltage (pre-VO) - Weighted Average Voltage (post-VO)]
>
> Overall Average Voltage Reduction (p.u.) =
> [Overall Average Voltage Reduction (in volts) / 120]
>
> Energy Change (p.u.) = Overall Average Voltage Reduction (p.u.) * VO Factor
>
> VO Energy Change (MWh) = Annual 3φ kWh energy load * Energy Change (p.u.)

The VO design should not yield voltages for customers outside the nominal ANSI C84.1 Standard Voltage Range of 126-114 Volts (on 120V base). In practice it is desired to achieve an overall average voltage for primary lines in the range of 122-118 Volts and depends on the secondary maximum allowed voltage-drop. At the residential and light commercial customer service meter, the goal is to have an average voltage between 120-114 Volts.

### *4.0 Recommendations for Ensuring Persistence of Energy Savings*

System improvements typically have a useful life exceeding 35 years. However, control settings are easily altered over time unless they are integrated into utility operating and design standards. For new operating design standards to become entrenched, a three-year monitoring and documentation period is recommended. Standards that become entrenched tend to extend the life of VO perpetually.

This 3-year period includes the following:

1. On a monthly basis, a utility must document that voltage control settings within each the VO voltage control zone are maintained as necessary to be consistent with those determined during the original VO project.
2. On an annual basis, provide total kWh usage on the voltage control zone and provide average voltage at Substation and EOL.
3. A utility must maintain this documentation (or provide it to the appropriate organization) annually for a 3-year period.
4. During this three year period, if the voltage control settings have been off-line, either intentionally or unintentionally for a period of 30 days or longer, the utility must continue to maintain the voltage control setting documentation for a period equal to 30 days or longer beyond the original 3 year documentation period.
5. Verify performance thresholds for each voltage-control-zone and corrective actions taken if any. Thresholds include:
    a. Feeder power factor – Average hourly > 0.98 from ***metered*** data

b. Feeder power factor – Maximum hourly > 0.96 from *metered* data
c. EOL primary voltage must be > [114 Volts + ½ the voltage regulation bandwidth + secondary maximum allowed voltage-drop] from *metered* data
d. Regulator primary voltage must be < [126 Volts - ½ the voltage regulation bandwidth + secondary maximum allowed voltage-drop] from *metered* data
e. Feeder load unbalance must be < 0.15 from system modeling
f. Feeder Source 3φ feeder neutral current < 40 Amps from *metered* data
g. Feeder maximum adjusted primary voltage-drops <3.3% from system modeling
h. Feeder maximum voltage-drop variance < 2.0 V on a 120V base.

# APPENDIX A
# VO FACTOR TABLES
# FOR USE WITH SIMPLIFIED VO M&V PROTOCOL

Source of VO Factors is 2007 NEEA DEI Project Load Research Survey Reported Results

*Instructions:* These End-Use VO Factors are for use with the Simplified VO M&V Protocol. The End-Use VO Factor Tables are for use with distribution system customers classified as residential and small commercial as defined by the utility. To identify the appropriate VO Factor, locate the VO Factor Table for the known heating and cooling zone. The end-use VO Factor is derived by selecting the percent of customers with non-electric heat (and heat pumps) and percent of customers with air-conditioning. VO Factors are shown as percent of change in energy to percent change in average annual voltage. The tables are obtained from the NEEA Distribution Efficiency Initiative project 2003-2007, which performed VO load research evaluation on end-use loads throughout the Northwest for different climate zone.

Table 1 – End-Use VO Factors for Climate Zone Heating 1 and Cooling 1

| | % of Customers with Non Electric Heat and Heat Pumps (e.g. gas, oil, or wood heat) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| %AC | 0% | 10% | 20% | 30% | 40% | 50% | 60% | 70% | 80% | 90% | 100% |
| 0 | 0.27 | 0.29 | 0.32 | 0.35 | 0.38 | 0.42 | 0.46 | 0.51 | 0.56 | 0.63 | 0.70 |
| 10 | 0.27 | 0.30 | 0.33 | 0.36 | 0.39 | 0.43 | 0.47 | 0.51 | 0.57 | 0.63 | 0.70 |
| 20 | 0.27 | 0.31 | 0.33 | 0.36 | 0.40 | 0.43 | 0.47 | 0.52 | 0.57 | 0.63 | 0.70 |
| 30 | 0.29 | 0.31 | 0.34 | 0.37 | 0.40 | 0.44 | 0.48 | 0.52 | 0.57 | 0.63 | 0.69 |
| 40 | 0.29 | 0.32 | 0.35 | 0.38 | 0.41 | 0.45 | 0.49 | 0.53 | 0.58 | 0.63 | 0.69 |
| 50 | 0.30 | 0.33 | 0.36 | 0.39 | 0.42 | 0.45 | 0.49 | 0.54 | 0.58 | 0.63 | 0.69 |
| 60 | 0.31 | 0.34 | 0.36 | 0.39 | 0.43 | 0.46 | 0.50 | 0.54 | 0.59 | 0.63 | 0.69 |
| 70 | 0.32 | 0.35 | 0.37 | 0.40 | 0.44 | 0.47 | 0.51 | 0.55 | 0.59 | 0.64 | 0.69 |
| 80 | 0.33 | 0.36 | 0.38 | 0.41 | 0.44 | 0.48 | 0.51 | 0.55 | 0.59 | 0.64 | 0.68 |
| 90 | 0.34 | 0.37 | 0.39 | 0.42 | 0.45 | 0.49 | 0.52 | 0.56 | 0.60 | 0.64 | 0.68 |
| 100 | 0.35 | 0.38 | 0.40 | 0.43 | 0.46 | 0.49 | 0.53 | 0.56 | 0.60 | 0.64 | 0.68 |

Table 2 – End-Use VO Factors for Climate Zone Heating 1 and Cooling 2

| | % of Customers with Non Electric Heat and Heat Pumps (e.g. gas, oil, or wood heat) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| %AC | 0% | 10% | 20% | 30% | 40% | 50% | 60% | 70% | 80% | 90% | 100% |
| 0 | 0.27 | 0.29 | 0.32 | 0.35 | 0.38 | 0.42 | 0.46 | 0.51 | 0.56 | 0.63 | 0.70 |
| 10 | 0.27 | 0.30 | 0.33 | 0.36 | 0.39 | 0.43 | 0.47 | 0.51 | 0.57 | 0.63 | 0.70 |
| 20 | 0.28 | 0.31 | 0.33 | 0.36 | 0.40 | 0.43 | 0.47 | 0.52 | 0.57 | 0.63 | 0.69 |
| 30 | 0.29 | 0.31 | 0.34 | 0.37 | 0.40 | 0.44 | 0.48 | 0.52 | 0.57 | 0.63 | 0.69 |
| 40 | 0.29 | 0.32 | 0.35 | 0.38 | 0.41 | 0.45 | 0.49 | 0.53 | 0.58 | 0.63 | 0.69 |
| 50 | 0.30 | 0.33 | 0.36 | 0.39 | 0.42 | 0.45 | 0.49 | 0.53 | 0.58 | 0.63 | 0.69 |
| 60 | 0.31 | 0.34 | 0.37 | 0.40 | 0.43 | 0.46 | 0.50 | 0.54 | 0.58 | 0.63 | 0.69 |
| 70 | 0.32 | 0.35 | 0.37 | 0.40 | 0.44 | 0.47 | 0.51 | 0.55 | 0.59 | 0.63 | 0.68 |
| 80 | 0.33 | 0.36 | 0.38 | 0.41 | 0.44 | 0.48 | 0.51 | 0.55 | 0.59 | 0.64 | 0.68 |
| 90 | 0.34 | 0.37 | 0.39 | 0.42 | 0.45 | 0.49 | 0.52 | 0.56 | 0.60 | 0.64 | 0.68 |
| 100 | 0.35 | 0.38 | 0.40 | 0.43 | 0.46 | 0.49 | 0.53 | 0.56 | 0.60 | 0.64 | 0.68 |

Table 3 – End-Use VO Factors for Climate Zone Heating 1 and Cooling 3

| %AC | % of Customers with Non Electric Heat and Heat Pumps (e.g. gas, oil, or wood heat) 0% | 10% | 20% | 30% | 40% | 50% | 60% | 70% | 80% | 90% | 100% |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0.27 | 0.29 | 0.32 | 0.35 | 0.39 | 0.42 | 0.46 | 0.51 | 0.55 | 0.61 | 0.66 |
| 10 | 0.27 | 0.30 | 0.33 | 0.36 | 0.39 | 0.43 | 0.47 | 0.51 | 0.56 | 0.61 | 0.66 |
| 20 | 0.28 | 0.31 | 0.34 | 0.37 | 0.40 | 0.44 | 0.47 | 0.52 | 0.56 | 0.61 | 0.66 |
| 30 | 0.29 | 0.31 | 0.34 | 0.37 | 0.41 | 0.44 | 0.48 | 0.52 | 0.56 | 0.61 | 0.66 |
| 40 | 0.29 | 0.32 | 0.35 | 0.38 | 0.41 | 0.45 | 0.49 | 0.53 | 0.57 | 0.61 | 0.66 |
| 50 | 0.30 | 0.33 | 0.36 | 0.39 | 0.42 | 0.46 | 0.49 | 0.53 | 0.57 | 0.61 | 0.66 |
| 60 | 0.31 | 0.34 | 0.37 | 0.40 | 0.43 | 0.46 | 0.50 | 0.54 | 0.57 | 0.62 | 0.66 |
| 70 | 0.32 | 0.35 | 0.38 | 0.41 | 0.44 | 0.47 | 0.50 | 0.54 | 0.58 | 0.62 | 0.66 |
| 80 | 0.33 | 0.36 | 0.39 | 0.42 | 0.45 | 0.48 | 0.51 | 0.55 | 0.58 | 0.62 | 0.66 |
| 90 | 0.34 | 0.37 | 0.40 | 0.42 | 0.45 | 0.49 | 0.52 | 0.55 | 0.59 | 0.62 | 0.66 |
| 100 | 0.35 | 0.38 | 0.41 | 0.43 | 0.46 | 0.49 | 0.52 | 0.56 | 0.59 | 0.62 | 0.66 |

Table 4 – End-Use VO Factors for Climate Zone Heating 2 and Cooling 1

| %AC | % of Customers with Non Electric Heat and Heat Pumps (e.g. gas, oil, or wood heat) 0% | 10% | 20% | 30% | 40% | 50% | 60% | 70% | 80% | 90% | 100% |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0.27 | 0.29 | 0.32 | 0.34 | 0.38 | 0.42 | 0.46 | 0.51 | 0.58 | 0.66 | 0.75 |
| 10 | 0.27 | 0.30 | 0.32 | 0.35 | 0.38 | 0.42 | 0.47 | 0.52 | 0.58 | 0.66 | 0.75 |
| 20 | 0.28 | 0.30 | 0.33 | 0.36 | 0.39 | 0.43 | 0.47 | 0.52 | 0.58 | 0.66 | 0.74 |
| 30 | 0.29 | 0.31 | 0.34 | 0.37 | 0.40 | 0.44 | 0.48 | 0.53 | 0.59 | 0.66 | 0.74 |
| 40 | 0.29 | 0.32 | 0.35 | 0.37 | 0.41 | 0.44 | 0.49 | 0.54 | 0.59 | 0.66 | 0.73 |
| 50 | 0.30 | 0.33 | 0.35 | 0.38 | 0.42 | 0.45 | 0.49 | 0.54 | 0.59 | 0.66 | 0.73 |
| 60 | 0.31 | 0.34 | 0.36 | 0.39 | 0.42 | 0.46 | 0.50 | 0.55 | 0.60 | 0.66 | 0.73 |
| 70 | 0.32 | 0.34 | 0.37 | 0.40 | 0.43 | 0.47 | 0.51 | 0.55 | 0.60 | 0.66 | 0.72 |
| 80 | 0.33 | 0.35 | 0.38 | 0.41 | 0.44 | 0.48 | 0.52 | 0.56 | 0.61 | 0.66 | 0.72 |
| 90 | 0.34 | 0.36 | 0.39 | 0.42 | 0.45 | 0.49 | 0.52 | 0.56 | 0.61 | 0.66 | 0.71 |
| 100 | 0.35 | 0.37 | 0.40 | 0.43 | 0.46 | 0.49 | 0.53 | 0.57 | 0.61 | 0.66 | 0.71 |

Table 5 – End-Use VO Factors for Climate Zone Heating 2 and Cooling 2

| %AC | % of Customers with Non Electric Heat and Heat Pumps (e.g. gas, oil, or wood heat) 0% | 10% | 20% | 30% | 40% | 50% | 60% | 70% | 80% | 90% | 100% |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0.27 | 0.29 | 0.32 | 0.34 | 0.38 | 0.42 | 0.46 | 0.51 | 0.58 | 0.66 | 0.75 |
| 10 | 0.27 | 0.30 | 0.32 | 0.35 | 0.38 | 0.42 | 0.47 | 0.52 | 0.58 | 0.66 | 0.75 |
| 20 | 0.28 | 0.30 | 0.33 | 0.36 | 0.39 | 0.43 | 0.47 | 0.52 | 0.58 | 0.66 | 0.74 |
| 30 | 0.29 | 0.31 | 0.34 | 0.37 | 0.40 | 0.44 | 0.48 | 0.53 | 0.59 | 0.66 | 0.74 |
| 40 | 0.29 | 0.32 | 0.32 | 0.37 | 0.41 | 0.44 | 0.49 | 0.54 | 0.59 | 0.66 | 0.73 |
| 50 | 0.30 | 0.33 | 0.35 | 0.38 | 0.42 | 0.45 | 0.49 | 0.54 | 0.59 | 0.66 | 0.73 |
| 60 | 0.31 | 0.34 | 0.36 | 0.39 | 0.42 | 0.46 | 0.50 | 0.55 | 0.60 | 0.66 | 0.73 |
| 70 | 0.32 | 0.34 | 0.37 | 0.40 | 0.43 | 0.47 | 0.51 | 0.56 | 0.60 | 0.66 | 0.72 |
| 80 | 0.33 | 0.35 | 0.38 | 0.41 | 0.44 | 0.48 | 0.52 | 0.56 | 0.61 | 0.66 | 0.72 |
| 90 | 0.34 | 0.36 | 0.39 | 0.42 | 0.45 | 0.49 | 0.52 | 0.56 | 0.61 | 0.66 | 0.71 |
| 100 | 0.35 | 0.37 | 0.40 | 0.43 | 0.46 | 0.49 | 0.53 | 0.57 | 0.61 | 0.66 | 0.71 |

Table 6 – End-Use VO Factors for Climate Zone Heating 2 and Cooling 3

| | % of Customers with Non Electric Heat and Heat Pumps (e.g. gas, oil, or wood heat) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| %AC | 0% | 10% | 20% | 30% | 40% | 50% | 60% | 70% | 80% | 90% | 100% |
| 0 | 0.27 | 0.29 | 0.32 | 0.34 | 0.38 | 0.42 | 0.46 | 0.51 | 0.58 | 0.65 | 0.75 |
| 10 | 0.27 | 0.30 | 0.32 | 0.35 | 0.39 | 0.42 | 0.47 | 0.52 | 0.58 | 0.65 | 0.75 |
| 20 | 0.28 | 0.30 | 0.33 | 0.36 | 0.39 | 0.43 | 0.47 | 0.52 | 0.58 | 0.65 | 0.74 |
| 30 | 0.29 | 0.31 | 0.34 | 0.37 | 0.40 | 0.44 | 0.48 | 0.53 | 0.59 | 0.66 | 0.74 |
| 40 | 0.29 | 0.32 | 0.35 | 0.37 | 0.41 | 0.45 | 0.49 | 0.54 | 0.59 | 0.66 | 0.73 |
| 50 | 0.30 | 0.33 | 0.35 | 0.38 | 0.42 | 0.45 | 0.49 | 0.54 | 0.59 | 0.66 | 0.73 |
| 60 | 0.31 | 0.34 | 0.36 | 0.39 | 0.42 | 0.46 | 0.50 | 0.55 | 0.60 | 0.66 | 0.72 |
| 70 | 0.32 | 0.34 | 0.37 | 0.40 | 0.43 | 0.47 | 0.51 | 0.55 | 0.60 | 0.66 | 0.72 |
| 80 | 0.33 | 0.35 | 0.38 | 0.41 | 0.44 | 0.48 | 0.52 | 0.56 | 0.60 | 0.66 | 0.72 |
| 90 | 0.34 | 0.36 | 0.39 | 0.42 | 0.45 | 0.49 | 0.52 | 0.56 | 0.61 | 0.66 | 0.71 |
| 100 | 0.35 | 0.37 | 0.40 | 0.43 | 0.46 | 0.49 | 0.53 | 0.57 | 0.61 | 0.66 | 0.71 |

Table 7 – End-Use VO Factors for Climate Zone Heating 3 and Cooling 1

| | % of Customers with Non Electric Heat and Heat Pumps (e.g. gas, oil, or wood heat) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| %AC | 0% | 10% | 20% | 30% | 40% | 50% | 60% | 70% | 80% | 90% | 100% |
| 0 | 0.27 | 0.29 | 0.32 | 0.35 | 0.38 | 0.42 | 0.46 | 0.51 | 0.57 | 0.64 | 0.73 |
| 10 | 0.27 | 0.30 | 0.32 | 0.35 | 0.39 | 0.42 | 0.47 | 0.52 | 0.58 | 0.64 | 0.73 |
| 20 | 0.28 | 0.30 | 0.33 | 0.36 | 0.39 | 0.43 | 0.47 | 0.52 | 0.58 | 0.65 | 0.72 |
| 30 | 0.29 | 0.31 | 0.34 | 0.37 | 0.40 | 0.44 | 0.48 | 0.53 | 0.58 | 0.65 | 0.72 |
| 40 | 0.29 | 0.32 | 0.35 | 0.38 | 0.41 | 0.45 | 0.49 | 0.53 | 0.59 | 0.65 | 0.72 |
| 50 | 0.30 | 0.33 | 0.35 | 0.38 | 0.42 | 0.45 | 0.49 | 0.54 | 0.59 | 0.65 | 0.71 |
| 60 | 0.31 | 0.34 | 0.36 | 0.39 | 0.43 | 0.46 | 0.50 | 0.54 | 0.59 | 0.65 | 0.71 |
| 70 | 0.32 | 0.35 | 0.37 | 0.40 | 0.43 | 0.47 | 0.54 | 0.55 | 0.60 | 0.65 | 0.71 |
| 80 | 0.33 | 0.35 | 0.38 | 0.41 | 0.44 | 0.48 | 0.51 | 0.56 | 0.60 | 0.65 | 0.70 |
| 90 | 0.34 | 0.36 | 0.39 | 0.42 | 0.45 | 0.49 | 0.52 | 0.56 | 0.60 | 0.65 | 0.70 |
| 100 | 0.35 | 0.38 | 0.40 | 0.43 | 0.46 | 0.49 | 0.53 | 0.57 | 0.61 | 0.65 | 0.70 |

Table 8 – End-Use VO Factors for Climate Zone Heating 3 and Cooling 2

| | % of Customers with Non Electric Heat and Heat Pumps (e.g. gas, oil, or wood heat) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| %AC | 0% | 10% | 20% | 30% | 40% | 50% | 60% | 70% | 80% | 90% | 100% |
| 0 | 0.27 | 0.29 | 0.32 | 0.35 | 0.38 | 0.42 | 0.46 | 0.51 | 0.57 | 0.64 | 0.73 |
| 10 | 0.27 | 0.30 | 0.32 | 0.35 | 0.39 | 0.42 | 0.47 | 0.52 | 0.58 | 0.64 | 0.73 |
| 20 | 0.28 | 0.30 | 0.33 | 0.36 | 0.39 | 0.43 | 0.47 | 0.52 | 0.58 | 0.65 | 0.72 |
| 30 | 0.29 | 0.31 | 0.34 | 0.37 | 0.40 | 0.44 | 0.48 | 0.53 | 0.58 | 0.65 | 0.72 |
| 40 | 0.29 | 0.32 | 0.35 | 0.38 | 0.41 | 0.45 | 0.49 | 0.53 | 0.59 | 0.65 | 0.72 |
| 50 | 0.30 | 0.33 | 0.35 | 0.38 | 0.42 | 0.45 | 0.49 | 0.54 | 0.59 | 0.65 | 0.71 |
| 60 | 0.31 | 0.34 | 0.36 | 0.39 | 0.43 | 0.46 | 0.50 | 0.54 | 0.59 | 0.65 | 0.71 |
| 70 | 0.32 | 0.35 | 0.37 | 0.40 | 0.43 | 0.47 | 0.51 | 0.55 | 0.60 | 0.65 | 0.71 |
| 80 | 0.33 | 0.35 | 0.38 | 0.41 | 0.44 | 0.48 | 0.51 | 0.56 | 0.60 | 0.65 | 0.70 |
| 90 | 0.34 | 0.36 | 0.39 | 0.42 | 0.45 | 0.49 | 0.52 | 0.56 | 0.60 | 0.65 | 0.70 |
| 100 | 0.35 | 0.38 | 0.40 | 0.43 | 0.46 | 0.49 | 0.53 | 0.57 | 0.61 | 0.65 | 0.70 |

Table 9 – End-Use VO Factors for Climate Zone Heating 3 and Cooling 3

| | % of Customers with Non Electric Heat and Heat Pumps (e.g. gas, oil, or wood heat) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| %AC | 0% | 10% | 20% | 30% | 40% | 50% | 60% | 70% | 80% | 90% | 100% |
| 0 | 0.27 | 0.29 | 0.32 | 0.35 | 0.38 | 0.42 | 0.46 | 0.51 | 0.57 | 0.64 | 0.73 |
| 10 | 0.27 | 0.30 | 0.32 | 0.35 | 0.39 | 0.42 | 0.47 | 0.52 | 0.58 | 0.64 | 0.73 |
| 20 | 0.28 | 0.30 | 0.33 | 0.36 | 0.39 | 0.43 | 0.47 | 0.52 | 0.58 | 0.65 | 0.72 |
| 30 | 0.29 | 0.31 | 0.34 | 0.37 | 0.40 | 0.44 | 0.48 | 0.53 | 0.58 | 0.65 | 0.72 |
| 40 | 0.29 | 0.32 | 0.35 | 0.38 | 0.41 | 0.45 | 0.49 | 0.53 | 0.59 | 0.65 | 0.72 |
| 50 | 0.30 | 0.33 | 0.35 | 0.38 | 0.42 | 0.45 | 0.49 | 0.54 | 0.59 | 0.65 | 0.71 |
| 60 | 0.31 | 0.34 | 0.36 | 0.39 | 0.43 | 0.46 | 0.50 | 0.54 | 0.59 | 0.65 | 0.71 |
| 70 | 0.32 | 0.35 | 0.37 | 0.40 | 0.43 | 0.47 | 0.51 | 0.55 | 0.60 | 0.65 | 0.71 |
| 80 | 0.33 | 0.35 | 0.38 | 0.41 | 0.44 | 0.48 | 0.51 | 0.56 | 0.60 | 0.65 | 0.70 |
| 90 | 0.34 | 0.36 | 0.39 | 0.42 | 0.45 | 0.49 | 0.52 | 0.56 | 0.60 | 0.65 | 0.70 |
| 100 | 0.35 | 038 | 0.40 | 0.43 | 0.46 | 0.49 | 0.53 | 0.57 | 0.61 | 0.65 | 0.70 |

####

## Appendix 9: Summary of Circuit Analysis by Stage

# Bowman 5W150 & 154

**Bowman Substation T3853**
**Summary of Distribution Power Flow Results**

| Bowman | | T3853 | Base Case (w/ Fielding) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | **Annual Energy kWhr** | **Feeder kW** | **Feeder kVAr** | **Unbalance %** | **Cap Banks kVAr** | **Power Factor %** | **Connected kVA** | **Losses kW** | **Losses kVAr** | **Rise at LTC %** | **Feeder Voltage Balance** | **BE: Branch Voltage Balance** | **LE: Control Zone Min Voltage** |
| 5W150 | A | | 2065.6 | 193.4 | | | | | | R = | 4.0 | 123.3 | 118.0 | 118.0 |
| | B | | 2278.6 | 283.1 | | | Cust/Load | 3.59 | | X = | 0.0 | 123.3 | 117.4 | 117.4 |
| | C | | 2370.8 | 388.1 | | | kVA/Cust | 10.20 | | CT = | 1200.0 | 123.3 | 114.7 | 114.7 |
| | | | | Ineut = | 37.6 | | Cust = | 2334 | | Vset = | 121.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | 33,096,331 | 6715.0 | 864.6 | 5.9% | 1800.0 | 99.2% | 23831.0 | 325.2 | 381.6 | 1.0276 | 0 V | Δ = 3.3 V | Δ = 8.6 V |
| | LL | | 2431.6 | -855.5 | | | | | | | 1.0147 | 121.8 | 120.3 | 120.3 |
| 5W154 | A | | 2728.8 | -4.8 | | | | | | R = | | 123.3 | 120.9 | 120.9 |
| | B | | 2841.6 | 39.0 | | | Cust/Load | | | X = | | 123.3 | 121.5 | |
| | C | | 2629.1 | -46.2 | | | kVA/Cust | | | CT = | | 123.3 | 122.4 | |
| | | | | Ineut = | 27.0 | | Cust = | 2074 | | Vset = | | | | |
| | | | | | | | | | | PT = | | | | |
| | T | 37,063,709 | 8199.5 | -12.0 | 4.0% | 3000.0 | 100.0% | 24580.5 | 98.8 | 247.7 | | 0 V | Δ = 1.5 V | Δ = 2.4 V |
| | LL | | 2507.5 | -2018.1 | | | | | | | | 121.8 | 123.1 | 123.1 |

| Existing Regulator | Settings | Regulator Flow HL | Regulator Flow LL |
|---|---|---|---|
| R = | 3.5 | 2683.2 | 988 |
| X = | 0.0 | 124.2 A | |
| CT = | 250.0 | | |
| Vset = | 120.0 | HL V = | 1.0145 |
| PT = | 60.0 | LL V = | 1.0053 |

| | | Regulator Voltage Pri | Regulator Voltage Sec | Control Zone Min Voltage |
|---|---|---|---|---|
| HL | A | 125.5 | 123.2 | |
| | B | 124.7 | 120.3 | 120.3 |
| | C | 121.7 | 117.1 | 117.1 |
| LL | | 120.5 | 119.5 | 119.5 |
| | | | | Δ = 4.6 V |

| **Changes for Stage-1** | | | **Node** | **Line** | **Load** | **Losses** | **Swap Phases** |
|---|---|---|---|---|---|---|---|
| **5W150** | **S01a** | | | | | | None |
| | **Spot Load Changes** | | TR_230303_593050171 | | 291, 0.961 | | |
| | | | TR_245000_1540700183 | | 0, 1 | | |
| | | | TR_249380_593050811 | | 153, 0.985 | | |
| | | | TR_361980_456710504 | | 13, 0.997 | | |
| **5W154** | **S01a** | | | | | | None |
| **5W150** | **S01b** | ~~Remove Caps~~ | FP269902_302080200 | | ~~- 900 kVAr~~ | To avoid further dropping the 8.6 V drop to EOL to 9.3 V we did not remove 900 kVAr | |
| **5W154** | **S01b** | Remove Caps | FP357704_369970265 | | - 900 kVAr | | |
| | | Remove Caps | FP300602_1540121947 | | - 900 kVAr | | |

| Bowman | | T3853 | Stage-01 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | | **Feeder kW** | **Feeder kVAr** | **Unbalance %** | **Cap Banks kVAr** | **Power Factor %** | **Connected kVA** | **Losses kW** | **Losses kVAr** | **Rise at LTC %** | **Feeder Voltage Balance** | **BE: Branch Voltage Balance** | **LE: Control Zone Min Voltage** |
| 5W150 | A | | 2042.2 | 171.9 | | | | | | R = | 7.0 | 125.0 | 119.9 | 119.9 |
| | B | | 2288.4 | 279.5 | | | | | | X = | 0.0 | 125.0 | 119.1 | 119.1 |
| | C | | 2379.0 | 385.1 | | | | | | CT = | 1200.0 | 125.0 | 116.5 | 116.5 |
| | | | | Ineut = | 41.5 | | | | | Vset = | 121.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 6709.6 | 836.5 | 6.4% | 1800.0 | 99.2% | 23831.0 | 334.3 | 394.8 | 1.0420 | 0 V | Δ = 3.4 V | Δ = 8.5 V |
| | LL | | 2431.4 | -874.8 | | | | | | | 1.0195 | 122.3 | 120.9 | 120.9 |
| 5W154 | A | | 2728.6 | 610.0 | | | | | | R = | | 125.0 | 120.8 | 120.8 |
| | B | | 2839.9 | 659.4 | | | | | | X = | | 125.0 | 121.5 | |
| | C | | 2628.7 | 579.0 | | | | | | CT = | | 125.0 | 122.2 | |
| | | | | Ineut = | 25.2 | | | | | Vset = | | | | |
| | | | | | | | | | | PT = | | | | |
| | T | | 8197.2 | 1848.4 | 3.9% | 3000.0 | 97.6% | 24580.5 | 98.7 | 256.1 | | 0 V | Δ = 1.3 V | Δ = 4.1 V |
| | LL | | 2496.4 | -138.3 | | | | | | | | 122.3 | 121.8 | 121.8 |

| Existing Regulator | Settings | Regulator Flow HL | Regulator Flow LL |
|---|---|---|---|
| R = | 3.5 | 2683.2 | 988 |
| X = | 0.0 | 124.2 A | |
| CT = | 250.0 | | |
| Vset = | 120.0 | HL V = | 1.0145 |
| PT = | 60.0 | LL V = | 1.0053 |

| | | Regulator Voltage Pri | Regulator Voltage Sec | Control Zone Min Voltage |
|---|---|---|---|---|
| HL | A | 125.2 | 122.8 | |
| | B | 124.3 | 119.7 | 119.7 |
| | C | 121.4 | 116.6 | 116.6 |
| LL | | 121.1 | 119.9 | 119.9 |
| | | | | Δ = 4.8 V |

| Changes for Stage-2 | | | Node | Line | Load | Losses | Swap Phases |
|---|---|---|---|---|---|---|---|
| 5W150 | S02a | | FP269903_302080452 | 5W150_302080024 | | | CAB->ABC |
| | S02b | Add Sw Cap | FP249363_593050816 | | + 900 kVAr | | |

| | Node | Line | Load | Conductor | Length (ft) |
|---|---|---|---|---|---|
| S02c | No reconductoring needed | | | | |

| Changes for Stage-2 | | | Node | Load |
|---|---|---|---|---|
| 5W154 | S02b | Add Sw Cap | FP357704_369970265 | + 900 kVAr |
| | | Add Sw Cap | FP300602_1540121947 | + 900 kVAr |

| | Node | Line | Load | Conductor | Length (ft) |
|---|---|---|---|---|---|
| S02c | No reconductoring needed | | | | |

5W150 S02e FP239002 5W150_593050032-SP1 [Id = 602] 328 A 3Ph 16 step 3x180 kVA

| Add Regulator | Settings | Regulator Flow HL | Regulator Flow LL | |
|---|---|---|---|---|
| R = | 4.5 | 5202.3 | 2225 | |
| X = | 0.0 | 240.9 A | | |
| CT = | 400.0 | | | |
| Vset = | 120.0 | HL V = | 1.0226 | 122.7 |
| PT = | 60.0 | LL V = | 1.0097 | 121.2 |

| | | Regulator Voltage Pri | Regulator Voltage Sec | Control Zone Min Voltage |
|---|---|---|---|---|
| HL | A | 120.0 | 123.1 | 119.9 |
| | B | 122.0 | 122.8 | 120.9 |
| | C | 120.3 | 122.6 | 120.2 |
| LL | | 120.0 | 120.8 | 120.1 |
| | | | | Δ = 3.1 V |

| Bowman | | T3853 | Stage-02 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Volt pu Balance | Regulator Voltage Pri | Min Volt pu |
| 5W150 | A | | 2292.1 | -7.5 | | | | | | R = | 9.0 | 124.1 | 120.0 | 120.0 |
| | B | | 2211.2 | -78.9 | | | | | | X = | 0.0 | 124.2 | 122.0 | 122.0 |
| | C | | 2188.9 | -84.5 | | | | | | CT = | 1200.0 | 124.2 | 120.3 | 120.3 |
| | | | | Ineut = | 17.3 | | | | | Vset = | 119.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 6692.2 | -170.9 | 2.8% | 1800.0 | 100.0% | 23831.0 | 302.3 | 359.7 | 1.0350 | 0 V | Δ = 2 V | Δ = 4.1 V |
| | LL | | 2429.6 | -839.9 | | | | | | | 1.0060 | 120.7 | 120.0 | 120.0 |
| 5W154 | A | | 2728.2 | -22.7 | | | | | | R = | | 124.1 | 121.9 | 121.9 |
| | B | | 2841.2 | 20.3 | | | | | | X = | | 124.2 | 122.5 | |
| | C | | 2628.8 | -64.5 | | | | | | CT = | | 124.2 | 123.3 | |
| | | | | Ineut = | 26.9 | | | | | Vset = | | | | |
| | | | | | | | | | | PT = | | | | |
| | T | | 8198.2 | -66.9 | 4.0% | 3000.0 | 100.0% | 24580.5 | 97.6 | 241.9 | | 0 V | Δ = 1.5 V | Δ = 2.3 V |
| | LL | | 2496.6 | -100.6 | | | | | | | | 120.7 | 120.1 | 120.1 |

| Existing Regulator | Settings | Regulator Flow HL | Regulator Flow LL |
|---|---|---|---|
| R = | 14.0 | 2683.2 | 988 |
| X = | 0.0 | 124.2 A | |
| CT = | 250.0 | | |
| Vset = | 118.0 | HL V = | 1.0413 |
| PT = | 60.0 | LL V = | 1.0047 |

| | | Regulator Voltage Pri | Regulator Voltage Sec | Control Zone Min Voltage |
|---|---|---|---|---|
| HL | A | 119.9 | 124.3 | 119.7 |
| | B | 120.9 | 125.5 | |
| | C | 120.2 | 124.7 | 120.1 |
| LL | | 120.1 | 120.4 | 119.4 |
| | | | | Δ = 4.6 V |

**Dodd Road Substation T1202**
**Summary of Distribution Power Flow Results**

# Dodd Road 4W22

| Dodd Road | | T1202 | Base Case (w/ Fielding) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | Annual Energy kWhr | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 4W22 | A | | 2729.8 | 1077.0 | | | | | | R = | 6.0 | 128.2 | 121.2 | 121.2 |
| | B | | 3052.6 | 1262.0 | | | Cust/Load | 3.02 | | X = | 0.0 | 128.2 | 119.5 | 119.5 |
| | C | | 2917.0 | 1193.0 | | | kVA/Cust | 20.00 | | CT = | 400.0 | 128.2 | 119.7 | 119.6 |
| | | | | Ineut = | 24.7 | | Cust = | 1451 | | Vset = | 121.0 | | | |
| | | | | | | | | | | PT = | 100.0 | | | |
| | T | 39,919,839 | 8699.4 | 3532.0 | 5.3% | 600.0 | 92.7% | 29034.5 | 288.9 | -13.5 | 1.0587 | 0 V | Δ = 1.7 V | Δ = 8.7 V |
| | LL | | 6235.6 | 845.0 | | | | | | | 1.0444 | 126.2 | 121.0 | 121.0 |

| Changes for Stage-1 | | | Node | Line | Load | Losses | Swap Phases |
|---|---|---|---|---|---|---|---|
| 4W22 | S01a | | | | | | none |
| | S01b | Add Cap | FP017006_682660347 | | + 900 kVAr | | |

| Dodd Road | | T1202 | Stage-01 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 4W22 | A | | 2726.1 | 793.2 | | | | | | R = | 5.0 | 125.0 | 118.8 | 118.8 |
| | B | | 3049.2 | 984.6 | | | | | | X = | 0.0 | 125.0 | 117.1 | 117.1 |
| | C | | 2913.4 | 916.1 | | | | | | CT = | 400.0 | 125.0 | 117.2 | 117.2 |
| | | | | Ineut = | 25.4 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 100.0 | | | |
| | T | | 8688.7 | 2693.9 | 5.3% | 600.0 | 95.5% | 29034.5 | 278.3 | -12.0 | 1.0420 | 0 V | Δ = 1.7 V | Δ = 7.9 V |
| | LL | | 6235.8 | -41.5 | | | | | | | 1.0301 | 123.6 | 119.3 | 119.3 |

| Changes for Stage-2 | | | Node | | |
|---|---|---|---|---|---|
| 4W22 | S02b | Add Sw Cap | FP179040_776390396 | | + 1800 kVAr |
| | | Add Sw Cap | FP289361_423450417 | | + 300 kVAr |
| | | Add Sw Cap | FP340061_1540847160 | | + 300 kVAr |

| | | Node | Line | Load | Conductor | Length (ft) |
|---|---|---|---|---|---|---|
| S02c | 1 from | FP289003_1540261624 | | | 1780 [20.8 #6 CU 3F | 447.0 |
| | to | FP339960_423450423 | | | 1690 [20.8 795AAC3PLn 8xa] | |

S02e1 FP187200 4W22_776390096-SP2 [Id = 1033] [20.8 3-ph 347A]

| Regulator | Settings | Regulator Flow HL | Regulator Flow LL |
|---|---|---|---|
| R = | 4.5 | 2006.7 | 1342 |
| X = | 0.0 | 92.9 A | |
| CT = | 120.0 | | |
| Vset = | 120.0 | HL V = | 1.0290 |
| PT = | 60.0 | LL V = | 1.0194 |

| | | Regulator Voltage Pri | Regulator Voltage Sec | Control Zone Min Voltage |
|---|---|---|---|---|
| HL | A | 120.8 | 123.8 | 120.6 |
| | B | 121.4 | 123.6 | 122.1 |
| | C | 121.0 | 123.3 | 121.1 |
| LL | | 120.4 | 122.0 | 119.9 |

S02e2 FP172640 4W22_776390081-SP1 [Id = 1033] [20.8 3-ph 347A]

| Regulator | Settings | Regulator Flow HL | Regulator Flow LL |
|---|---|---|---|
| R = | 6.0 | 2814.2 | 2047 |
| X = | 0.0 | 130.3 A | |
| CT = | 150.0 | | |
| Vset = | 118.0 | HL V = | 1.0268 |
| PT = | 60.0 | LL V = | 1.0149 |

| | | Regulator Voltage Pri | Regulator Voltage Sec | Control Zone Min Voltage |
|---|---|---|---|---|
| HL | A | 121.6 | 123.1 | 120.5 |
| | B | 120.9 | 123.2 | 119.8 |
| | C | 120.8 | 123.0 | 119.9 |
| LL | | 120.4 | 121.6 | 119.9 |

| Dodd Road | | T1202 | Stage-02 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 4W22 | A | | 2716.5 | -65.1 | | | | | | R = | 4.0 | 124.0 | 121.9 | |
| | B | | 3038.2 | 119.1 | | | | | | X = | 0.0 | 124.0 | 121.3 | |
| | C | | 2903.2 | 55.4 | | | | | | CT = | 400.0 | 124.0 | 121.2 | 119.8 |
| | | | | Ineut = | 25.1 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 100.0 | | | |
| | T | | 8657.9 | 109.4 | 5.3% | 600.0 | 100.0% | 29034.5 | 247.4 | -33.0 | 1.0336 | 0 V | Δ = 0.7 V | Δ = 4.2 V |
| | LL | | 6236.4 | -9.2 | | | | | | | 1.0241 | 122.9 | 120.8 | 119.9 |

Mill Creek Substation   T3406
Summary of Distribution Power Flow Results

# Mill Creek 5W116 & 127

| Mill Creek | | T3406 | Base Case (w/ Fielding) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | Annual Energy kWhr | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5W116 | A | | 2618.1 | 326.9 | | | | | | R = | 0.0 | 123.9 | 121.3 | 120.0 |
| | B | | 2704.0 | 345.6 | | | Cust/Load | 6.24 | | X = | 0.0 | 123.9 | 120.0 | 118.5 |
| | C | | 2775.2 | 387.3 | | | kVA/Cust | 7.40 | | CT = | 900.0 | 124.0 | 120.6 | 118.9 |
| | | | | Ineut = | 17.8 | | Cust = | 2402 | | Vset = | 124.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | 34,126,578 | 8097.3 | 1059.7 | 2.8% | 600.0 | 99.2% | 17726.0 | 122.6 | 193.9 | 1.0333 | 0 V | Δ = 1.3 V | Δ = 5.4 V |
| | LL | | 2147.5 | 59.4 | | | | | | | 1.0333 | 124.0 | 123.1 | 122.7 |
| | | | | | | | | | | | | | | |
| 5W127 | A | | 2103.5 | 479.1 | | | | | | | | 123.9 | 118.8 | 118.8 |
| | B | | 2734.4 | 649.5 | | | Cust/Load | 6.53 | | | | 123.9 | 121.2 | 121.2 |
| | C | | 1380.5 | 287.7 | | | kVA/Cust | 7.00 | | | | 124.0 | 123.9 | 123.9 |
| | | | | Ineut = | 163.1 | | Cust = | 2169 | | | | | | |
| | | | | | | | | | | | | | | |
| | T | 29,177,609 | 6218.4 | 1416.2 | 31.9% | 0.0 | 97.5% | 15105.0 | 65.7 | 190.4 | | 0.1 V | Δ = 5.1 V | Δ = 5.1 V |
| | LL | | 1830.5 | 562.2 | | | | | | | | 124.0 | 122.4 | 122.3 |
| | | | | | | | | | | | | | | |

| | | | Node | Line | Load | Losses | Swap Phases |
|---|---|---|---|---|---|---|---|
| **Changes for Stage-1** | | | **Node** | **Line** | **Load** | **Losses** | **Swap Phases** |
| **5W116** | **S01a** | | | | | | None |
| **5W127** | **S01a** | | FP288803_544871716 | 5W127_544870102 | | | CBA->CAB |
| | | | FP219405_242020779 | 5W127_242020295 | | | B->C |
| | | | FP283816_544870486 | 5W127_544870085 | | | B->C |
| | | | FP291702_717550718 | 5W127_717550132 | | | CBA->BAC |
| | | | FP294700_717550725 | 5W127_1540944656 | | | B->C |
| | | | FP285903_544870459 | 5W127_544870096 | | | CBA->BAC |
| **5W116** | **S01b** | | | | | | |
| **5W127** | **S01b** | New Cap | FP282811_544870470 | | + 600 kVAr | | |

| Mill Creek | | T3406 | Stage-01 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5W116 | A | | 2617.4 | 314.0 | | | | | | R = | 8.0 | 124.8 | 122.3 | 121.0 |
| | B | | 2703.1 | 336.8 | | | | | | X = | 0.0 | 124.9 | 121.0 | 119.5 |
| | C | | 2775.0 | 381.0 | | | | | | CT = | 900.0 | 124.9 | 121.5 | 119.8 |
| | | | | Ineut = | 18.0 | | | | | Vset = | 119.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 8095.5 | 1031.8 | 2.8% | 600.0 | 99.2% | 17726.0 | 120.8 | 189.2 | 1.0408 | 0 V | Δ = 1.4 V | Δ = 5.3 V |
| | LL | | 2148.0 | 98.5 | | | | | | | 1.0053 | 120.6 | 119.7 | 119.3 |
| | | | | | | | | | | | | | | |
| 5W127 | A | | 2101.1 | 268.7 | | | | | | | | 124.8 | 121.5 | 121.4 |
| | B | | 2158.7 | 273.9 | | | | | | | | 124.9 | 122.9 | 122.9 |
| | C | | 1950.5 | 209.4 | | | | | | | | 124.9 | 123.5 | 123.5 |
| | | | | Ineut = | 27.9 | | | | | | | | | |
| | | | | | | | | | | | | | | |
| | T | | 6210.3 | 752.0 | 4.3% | 0.0 | 99.3% | 15105.0 | 57.8 | 163.0 | | 0 V | Δ = 2.1 V | Δ = 3.4 V |
| | LL | | 1830.0 | -42.6 | | | | | | | | 120.6 | 119.7 | 119.7 |
| | | | | | | | | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Changes for Stage-2** | | | **Node** | | **Load** | | |
| **5W116** | **S02b** | Add Sw Cap | FP166061_755430427 | | + 900 kVAr | | |
| | | | **Node** | **Line** | **Load** | **Conductor** | **Length (ft)** |
| | **S02c** | No reconductoring needed | | | | | |
| | | | **Node** | | **Load** | | |

| | | | | |
|---|---|---|---|---|
| **5W127** | **S02b** | Add Sw Cap | FP289805_544870439 | +600 kVAr |

| | **Node** | **Line** | **Load** | **Conductor** | **Length (ft)** |
|---|---|---|---|---|---|
| **S02c** | No reconductoring needed | | | | |
| **S02e** | FP165101 | 5W116_755430072-SP1 | [Id = 63] 219 A 3Ph 16 step 3x180 kVA | | |

| **Add Regulator** | **Settings** | **Regulator Flow HL** | **Regulator Flow LL** | | | | **Regulator Voltage Pri** | **Regulator Voltage Sec** | **Reg. Min Voltage** |
|---|---|---|---|---|---|---|---|---|---|
| R = | 7.0 | 3316 | 878 | | HL | A | 122.0 | 124.1 | 121.6 |
| X = | 0.0 | 153.5 A | | | | B | 120.5 | 122.5 | 120.0 |
| CT = | 400.0 | | | | | C | 121.2 | 123.3 | 120.2 |
| Vset = | 120.0 | HL V = | 1.0224 | 122.7 | LL | | 120.2 | 120.9 | 120.3 |
| PT = | 60.0 | LL V = | 1.0059 | 120.7 | | | | | |

| **Mill Creek** | | **T3406** | **Stage-02** | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | | **Feeder kW** | **Feeder kVAr** | **Unbalance %** | **Cap Banks kVAr** | **Power Factor %** | **Connected kVA** | **Losses kW** | **Losses kVAr** | **Rise at LTC %** | **Feeder Voltage Balance** | **BE: Branch Voltage Balance** | **LE: Control Zone Min Voltage** |
| 5W116 | A | | 2615.3 | 123.4 | | | | | | R = | 4.0 | 122.9 | 122.0 | 122.0 |
| | B | | 2701.1 | 155.5 | | | | | | X = | 0.0 | 122.9 | 120.5 | 120.5 |
| | C | | 2772.9 | 198.3 | | | | | | CT = | 900.0 | 122.9 | 121.2 | 121.2 |
| | | | | Ineut = | 19.4 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 8089.3 | 477.2 | 2.8% | 600.0 | 99.8% | 17726.0 | 114.6 | 192.2 | 1.0246 | 0 V | Δ = 1.5 V | Δ = 2.4 V |
| | LL | | 2147.9 | 95.4 | | | | | | | 1.0068 | 120.8 | 120.2 | 120.2 |
| 5W127 | A | | 2102.0 | 70.5 | | | | | | | | 122.9 | 119.6 | 119.6 |
| | B | | 2159.4 | 73.3 | | | | | | | | 122.9 | 121.1 | 121.1 |
| | C | | 1950.4 | 6.8 | | | | | | | | 122.9 | 121.8 | 121.7 |
| | | | | Ineut = | 28.7 | | | | | | | | | |
| | T | | 6211.8 | 150.6 | 4.3% | 0.0 | 100.0% | 15105.0 | 59.3 | 167.8 | | 0 V | Δ = 2.1 V | Δ = 3.3 V |
| | LL | | 1830.0 | -44.6 | | | | | | | | 120.8 | 119.9 | 119.9 |

**Pomeroy Substation T944**
**Summary of Distribution Power Flow Results**

# Pomeroy 5W342

| Pomeroy | | T944 | Base Case (w/ Fielding) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | Annual Energy kWhr | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE1: Branch Voltage Balance | LE1: Control Zone Min Voltage |
| 5W342 | A | | 1821.1 | -165.4 | | | | | | R = | 2.0 | 124.7 | 123.3 | 122.3 |
| | B | | 1926.8 | -171.6 | | | Cust/Load | 3.40 | | X = | 0.0 | 124.7 | 121.5 | 119.0 |
| | C | | 2292.4 | -108.3 | | | kVA/Cust | 11.0 | | CT = | 400.0 | 124.7 | 121.2 | 122.3 |
| | | | | Ineut = | 55.4 | | Cust = | 1528 | | Vset = | 123.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | 22,784,281 | 6040.3 | -445.3 | 13.9% | 600.0 | 99.7% | 16801.0 | 194.1 | 135.5 | 1.0367 | 0 V | Δ = 2.1 V | Δ = 5.6 V |
| | LL | | 1595.6 | -558.6 | | | | | | | 1.0281 | 123.5 | 122.6 | 121.4 |
| | | | | | | | | | | | | | 122.3 | 122.2 |

| BE2: Branch Voltage Balance | LE2: Control Zone Min Voltage |
|---|---|
| 119.7 | 118.5 |
| 120.4 | |
| 116.6 | |
| Δ = 3.7 V | Δ = 6.3 V |
| | |
| | Δreg = 3.1 V |

| Changes for Stage-1 | | Node | Line | Load | Losses | Swap Phases |
|---|---|---|---|---|---|---|
| 5W342 | S01a | FP171860_420450094 | 5W342_420450011 | | | BAC->BCA |
| | | FP310600_463490170 | 5W342_1540118006 | | | BAC->BCA |
| | | FP325202_761212279 | 5W342_761210085 | | | BC->CB |
| | Spot Load Changes | TR_314380_761210523 | | 281, 0.997 | | |
| | | TR_315100_1540376750 | | 184, .997 | | |
| | | TR_317080_761210594 | | 216, .936 | | |
| | | TR_317180_761210375 | | 459, .997 | | |
| | | TR_329402_761210710 | | 0, 1 | | |
| | S01b | | | None | | |

| Pomeroy | | T944 | Stage-01 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE1: Branch Voltage Balance | LE1: Control Zone Min Voltage |
| 5W342 | A | | 1918.6 | -170.8 | | | | | | R = | 2.5 | 124.7 | 121.7 | 117.6 |
| | B | | 2150.5 | -139.9 | | | | | | X = | 0.0 | 124.7 | 122.5 | 121.2 |
| | C | | 1965.1 | -153.8 | | | | | | CT = | 400.0 | 124.8 | 122.6 | 120.8 |
| | | | | Ineut = | 27.2 | | | | | Vset = | 123.0 | | Trial 1 R = | 3.0 |
| | | | | | | | | | | PT = | 60.0 | | Trial 2 R = | 4.0 |
| | T | | 6034.2 | -464.5 | 6.9% | 600.0 | 99.7% | 16801.0 | 187.9 | 129.6 | 1.0396 | 0 V | Δ = 0.8 V | Δ = 7.2 V |
| | LL | | 1595.3 | -558.9 | | | | | | | 1.0288 | 123.5 | 122.6 | 121.4 |
| | | | | | | | | | | | | | 122.8 | 122.8 |

6.1

| BE2: Branch Voltage Balance | LE2: Control Zone Min Voltage |
|---|---|
| 119.2 | 118.1 |
| 119.8 | |
| 119.5 | |
| Δ = 0.6 V | Δ = 6.6 V |
| | Δreg = 3.3 V |

**Changes for Stage-2** **Node**

| | | | | | |
|---|---|---|---|---|---|
| **5W342** | **S02b** | Add Sw Cap | FP312104_761212376 | Switched | 300 kVAr |

| | | | Node | Line | Load | Conductor | Length (ft) |
|---|---|---|---|---|---|---|---|
| **S02c** | 1 | from | MP_463490150 | Reconductor | existing | 1/0 CU | 355.0 |
| | | to | FP365261_463490189 | | new | 477 AAC | |
| | 2 | from | FP311103_761210762 | Reconductor | existing | #6 CU | 71.0 |
| | | to | FP311104_761210780 | | new | 1/0 CU | |

FP044303A 5W342_1540871261-SP2 [Id = 63] 219 A 3Ph 16 step 3x180 kVA

| | Regulator | Settings | Regulator Flow HL | Regulator Flow LL |
|---|---|---|---|---|
| **S02e1** | R = | 10.5 | 439 | 131 |
| | X = | 0.0 | 20.3 | |
| | CT = | 50.0 | | |
| | Vset = | 120.0 | HL V = | 1.0356 |
| | PT = | 60.0 | LL V = | 1.0106 |

| | | Regulator Voltage Pri | Regulator Voltage Sec | Control Zone Min Voltage |
|---|---|---|---|---|
| HL | A | 120.3 | 124.0 | 119.9 |
| | B | 121.1 | 124.9 | 123.6 |
| | C | 121.1 | 124.9 | 123.1 |
| LL | | 120.0 | 121.5 | 120.3 |

FP321102A 5W342_761210113 [Id = 63] 219 A 3Ph 16 step 3x180 kVA

| | Regulator | Settings | Regulator Flow HL | Regulator Flow LL |
|---|---|---|---|---|
| **S02e2** | R = | 7.0 | 1708 | 793 |
| | X = | 0.0 | | |
| | CT = | 100.0 | | |
| | Vset = | 118.0 | HL V = | 1.0294 |
| | PT = | 60.0 | LL V = | 1.0048 |

| | | Regulator Voltage Pri | Regulator Voltage Sec | Control Zone Min Voltage |
|---|---|---|---|---|
| HL | A | 120.5 | 123.9 | 121.2 |
| | B | 120.0 | 123.4 | |
| | C | 120.7 | 124.1 | |
| LL | | 120.4 | 120.7 | 120.2 |

| Pomeroy | | T944 | Stage-02 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE1: Branch Voltage Balance | LEL: Control Zone Min Voltage |
| 5W342 | A | | 1923.9 | -172.7 | | | | | | R = | 4.5 | 123.1 | 121.6 | |
| | B | | 2129.5 | -146.6 | | | | | | X = | 0.0 | 123.1 | 121.9 | 121.9 |
| | C | | 1957.6 | -155.2 | | | | | | CT = | 400.0 | 123.1 | 122.0 | |
| | | | | Ineut = | 24.3 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | Δreg = 0 V |
| | T | | 6011.0 | -474.5 | 6.3% | 600.0 | 99.7% | 16801.0 | 164.9 | 126.0 | 1.0262 | 0 V | Δ = 0.4 V | Δ = 1.3 V |
| | LL | | 1594.1 | -531.1 | | | | | | | 1.0069 | 120.8 | 120.4 | 120.5 |
| | | | | | | | | | | | | 0.0 | 120.4 | 120.4 |

23.0

| BE2: Branch Voltage Balance | LE2: Control Zone Min Voltage |
|---|---|
| 120.5 | 120.5 |
| 120.0 | 120.0 |
| 120.7 | 120.7 |
| Δ = 0.7 V | Δ = 3.1 V |
| | Δreg = 0 V |

## Clinton 5Y608 & 610

**Clinton Substation T3716**
**Summary of Distribution Power Flow Results**

| Clinton | | T3716 | Base Case (w/ Fielding) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | Annual Energy kWhr | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5Y608 | A | | 2995.4 | 482.3 | | | | | | R = | 2.0 | 122.1 | 116.2 | 116.0 |
| | B | | 2711.8 | 404.5 | | | Cust/Load | 5.51 | | X = | 4.0 | 122.2 | 119.5 | |
| | C | | 2490.5 | 303.3 | | | kVA/Cust | 10.80 | | CT = | 2000.0 | 122.2 | 120.7 | |
| | | | | Ineut = | 60.6 | | Cust = | 2088 | | Vset = | 121.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | 41,300,182 | 8197.7 | 1190.1 | 9.6% | 900.0 | 99.0% | 22603.5 | 113.0 | 241.6 | 1.0167 | 0 V | Δ = 4.5 V | Δ = 6.2 V |
| | LL | | 3049.0 | -67.8 | | | | | | | 1.0103 | 121.3 | 119.8 | 119.8 |
| | | | | | | | | | | | | | | |
| 5Y610 | A | | 3376.8 | 387.3 | | | | | | | | 122.1 | 119.0 | 118.1 |
| | B | | 2848.0 | 197.5 | | | Cust/Load | 5.07 | | | | 122.2 | 120.6 | |
| | C | | 3022.7 | 270.5 | | | kVA/Cust | 13.50 | | | | 122.2 | 119.6 | |
| | | | | Ineut = | 69.0 | | Cust = | 1485 | | | | | | |
| | | | | | | | | | | | | | | |
| | T | 43,295,527 | 9247.5 | 855.2 | 9.5% | 1800.0 | 99.6% | 20066.0 | 128.8 | 213.7 | | 0 V | Δ = 1.7 V | Δ = 4 V |
| | LL | | 2707.4 | -262.4 | | | | | | | | 121.3 | 120.5 | 120.2 |
| | | | | | | | | | | | | | | |

| Changes for Stage-1 | | Node | Line | Load | Losses | Swap Phases |
|---|---|---|---|---|---|---|
| **5Y608** | **S01a** | FP055861_389072157 | 5Y608_389070384 | | | A->C |
| **5Y610** | **S01b** | FP278203_479410700 | 5Y610_479410265 | | | A->B |

| Clinton | | T3716 | Stage-01 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5Y608 | A | | 2870.7 | 417.6 | | | | | | R = | 13.0 | 124.4 | 120.0 | 120.0 |
| | B | | 2718.2 | 388.4 | | | | | | X = | 4.0 | 124.4 | 121.0 | |
| | C | | 2602.5 | 330.3 | | | | | | CT = | 2000.0 | 124.4 | 122.2 | |
| | | | | Ineut = | 30.3 | | | | | Vset = | 119.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 8191.4 | 1136.3 | 5.1% | 900.0 | 99.1% | 22603.5 | 107.2 | 225.7 | 1.0370 | 0 V | Δ = 2.2 V | Δ = 4.4 V |
| | LL | | 3049.3 | -28.2 | | | | | | | 1.0058 | 119.0 | 118.0 | 118.0 |
| | | | | | | | | | | | | | | |
| 5Y610 | A | | 3068.3 | 271.0 | | | | | | R = | | 124.4 | 121.4 | 120.5 |
| | B | | 3158.1 | 261.0 | | | | | | X = | | 124.4 | 122.7 | |
| | C | | 3018.2 | 243.6 | | | | | | CT = | | 124.4 | 122.1 | |
| | | | | Ineut = | 19.3 | | | | | Vset = | | | | |
| | | | | | | | | | | PT = | | | | |
| | T | | 9244.6 | 775.7 | 2.5% | 1800.0 | 99.6% | 20066.0 | 127.5 | 207.5 | | 0 V | Δ = 1.4 V | Δ = 3.9 V |
| | LL | | 2708.0 | -189.9 | | | | | | | | 119.0 | 118.2 | 117.9 |
| | | | | | | | | | | | | | | |

| Changes for Stage-2 | | | Node | Load |
|---|---|---|---|---|
| **5Y608** | **S02b** | Add Sw Cap | FP274441 | + 900 kVAr |

| | | | Node | Conductor | Length (ft) |
|---|---|---|---|---|---|
| **S02c** | 1 | from | FP280201_984800474 | 943 [12.5 #4 ACS3PSn 8xa] | 564.0 |
| | | to | FP280103_984800473 | 1055 [12.5 477AAC3PLn 8xa] | |

| Changes for Stage-2 | | | Node | |
|---|---|---|---|---|
| **5Y610** | **S02b** | Add Sw Cap | FP278510_460481740 | + 600 kVAr |

| | | | Node | Conductor | Length (ft) |
|---|---|---|---|---|---|
| **S02c** | 1 | from | FP279560_460480611 | 1083 [12.5 4/0AAC3PMn 8xa] | 576.0 |
| | | to | FP279609_460480657 | 1055 [12.5 477AAC3PLn 8xa] | |

| Clinton | | T3716 | Stage-02 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5Y608 | A | | 2867.0 | 93.9 | | | | | | R = | 13.0 | 124.4 | 120.7 | 120.6 |
| | B | | 2714 | 62.8 | | | | | | X = | 4.0 | 124.4 | 121.8 | |
| | C | | 2598.7 | 3.9 | | | | | | CT = | 2000.0 | 124.4 | 122.9 | |
| | | | | Ineut = | 30.4 | | | | | Vset = | 119.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 8179.7 | 160.6 | 5.2% | 900.0 | 100.0% | 22603.5 | 95.2 | 220.8 | 1.0370 | 0 V | Δ = 2.2 V | Δ = 3.8 V |
| | LL | | 3048.9 | -58.2 | | | | | | | 1.0058 | 120.7 | 119.8 | 119.8 |
| 5Y610 | A | | 3064.4 | 53.6 | | | | | | R = | | 124.4 | 121.6 | 120.8 |
| | B | | 3155.9 | 44.1 | | | | | | X = | | 124.4 | 122.9 | |
| | C | | 3014.6 | 25.6 | | | | | | CT = | | 124.4 | 122.3 | |
| | | | | Ineut = | 19.5 | | | | | Vset = | | | | |
| | | | | | | | | | | PT = | | | | |
| | T | | 9234.9 | 123.3 | 2.5% | 1800.0 | 100.0% | 20066.0 | 116.2 | 201.2 | | 0 V | Δ = 1.3 V | Δ = 3.6 V |
| | LL | | 2707.7 | -243.8 | | | | | | | | 120.7 | 120.0 | 119.7 |

# Nob Hill 5Y194 & 5Y197

**Nob Hill Substation T2430**
**Summary of Distribution Power Flow Results**

| Nob Hill | | T2430 | Base Case (w/ Fielding) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | Annual Energy kWhr | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | Branch Voltage Balance | Control Zone Min Voltage |
| 5Y197 | A | | 1809.5 | 347.6 | | | | | | R = | 4.0 | 123.2 | 121.8 | |
| | B | | 1982.4 | 372.5 | | | Cust/Load | 6.59 | | X = | 2.0 | 123.3 | 122.2 | 121.0 |
| | C | | 2107.5 | 408.1 | | | kVA/Cust | 6.40 | | CT = | 2000.0 | 123.3 | 121.5 | |
| | | | | Ineut = | 33.9 | | Cust = | 1970 | | Vset = | 121.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | 30,678,758 | 5899.4 | 1128.3 | 7.2% | 0.0 | 98.2% | 12613.5 | 44.7 | 91.9 | 2.47% | 0 V | Δ = 0.7 V | Δ = 2.2 V |
| | LL | | 1625.6 | 396.9 | | | | | | | 1.32% | 121.7 | 121.2 | 121.1 |
| | | | | | | | | | | | | | | |
| 5Y194 | A | | 2894.9 | 668.4 | | | | | | | | 122.9 | 118.3 | 117.9 |
| | B | | 2819.0 | 635.7 | | | Cust/Load | 8.76 | | | | 122.9 | 119.6 | |
| | C | | 2652.4 | 562.3 | | | kVA/Cust | 9.50 | | | | 122.9 | 120.3 | |
| | | | | Ineut = | 31.8 | | Cust = | 2005 | | | | | | |
| | | | | | | | | | | | | | | |
| | T | 42,555,015 | 8366.3 | 1866.3 | 3.8% | 1200.0 | 97.6% | 19095.5 | 165.1 | 329.2 | 1.0247 | 0 V | Δ = 2 V | Δ = 5 V |
| | LL | | 2727.4 | 8.0 | | | | | | | 1.0132 | 121.6 | 120.5 | 120.3 |
| | | | | | | | | | | | | | | |
| 5Y272 | ** | | 5500 | 690 | | 600.0 | | 14398.0 | | | | | | |
| | | | | | | | | | | | | | | |
| | LL | | 1855 | -147 | | | | | | | | | | |

| Changes for Stage-1 | | | Node | Line | Load | Losses | Swap Phases |
|---|---|---|---|---|---|---|---|
| 5Y197 | S01a | | | | | | None |
| | S01b | | | | | | |
| 5Y194 | S01a | | | | | | None |
| | S01b | Add Fixed Cap | FP243305_991160290 | | 600 -> 1200 kVAr | | |
| | | Add Fixed Cap | FP242209_991162198 | | + 300 kVAr | | |
| | | Add Fixed Cap | FP239013_556790634 | | + 600 kVAr | | |

| Nob Hill | | T2430 | Stage-01 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | Branch Voltage Balance | Control Zone Min Voltage |
| 5Y197 | A | | 1809.5 | 347.4 | | | | | | R = | 7.5 | 123.5 | 122.0 | |
| | B | | 1982.3 | 372.4 | | | | | | X = | 2.0 | 123.5 | 122.5 | 121.3 |
| | C | | 2107.4 | 408.0 | | | | | | CT = | 2000.0 | 123.5 | 121.8 | |
| | | | | Ineut = | 34.3 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 5899.2 | 1127.8 | 7.2% | 0.0 | 98.2% | 12613.5 | 44.2 | 91.0 | 2.96% | 0 V | Δ = 0.7 V | Δ = 2.2 V |
| | LL | | 1628.8 | 397.5 | | | | | | | 0.91% | 121.1 | 120.6 | 120.4 |
| | | | | | | | | | | | | | | |
| 5Y194 | A | | 2891.0 | 146.5 | | | | | | | | 123.5 | 119.9 | 119.5 |
| | B | | 2817.1 | 107.6 | | | | | | | | 123.5 | 121.2 | |
| | C | | 2649.3 | 29.3 | | | | | | | | 123.5 | 121.9 | |
| | | | | Ineut = | 32.6 | | | | | | | | | |
| | | | | | | | | | | | | | | |
| | T | | 8357.4 | 283.4 | 3.8% | 1200.0 | 99.9% | 19095.5 | 156.3 | 311.1 | | 0 V | Δ = 2 V | Δ = 4 V |
| | LL | | 2732.9 | -1520.1 | | | | | | | | 121.1 | 120.9 | 120.8 |
| | | | | | | | | | | | | | | |
| 5Y272 | ** | | 5500 | 690 | | | | 14398.0 | | | | | | |
| | | | | | | | | | | | | | | |
| | LL | | 1855 | -147 | | | | | | | | | | |

| **Changes for Stage-2** | | | **Node** | **Load** |
|---|---|---|---|---|
| **5Y197** | **S02b** | Add Sw Cap | FP251304 | + 900 kVAr |

| | | **Node** | **Line** | **Load** | **Conductor** | **Length (ft)** |
|---|---|---|---|---|---|---|
| **S02c** | No changes | | | | | |

| **Changes for Stage-2** | | | **Node** | **Load** |
|---|---|---|---|---|
| **5Y194** | **S02b** | Add Sw Cap | FP243305_991160290 | 600 kVAr fixed, 600 kVAr switched * |
| | | Add Sw Cap | FP242209_991162198 | + 300 kVAr * |
| | | Add Sw Cap | FP239013_556790634 | + 600 kVAr * |
| | | | | * Add switching mechanism for fixed capacitors added in Stage 01. |

| | | | **Node** | **Line** | **Load** | **Conductor** | **Length (ft)** |
|---|---|---|---|---|---|---|---|
| **S02c** | 1 | from | MP_931350832 | | | 1050 [12.5 500 AL3 | 313.0 |
| | | to | FP999999_931350864 | | | 1049 [12.5 1000AL3PUGCond] | |
| | 2 | from | FP999999_931350864 | | | 1097 [12.5 2/0ACS | 119.0 |
| | | to | FP269312_931350900 | | | 1055 [12.5 477AAC3PLn 8xa] | |

| **Nob Hill** | | **T2430** | **Stage-02** | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | | **kW** | **kVAr** | **%** | **kVAr** | **Factor** | **kVA** | **kW** | **kVAr** | **%** | **Balance** | **Voltage** | **Zone Min** |
| 5Y197 | A | | 1809.1 | 31.0 | | | | | | R = | 7.5 | 123.5 | 122.2 | |
| | B | | 1982 | 56.0 | | | | | | X = | 2.0 | 123.5 | 122.6 | 121.4 |
| | C | | 2107.3 | 91.6 | | | | | | CT = | 2000.0 | 123.5 | 122.0 | |
| | | | | Ineut = | 34.3 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 5898.4 | 178.6 | 7.2% | 0.0 | 100.0% | 12613.5 | 43.5 | 89.2 | 2.96% | 0 V | Δ = 0.7 V | Δ = 2.1 V |
| | LL | | 1628.8 | 397.5 | | | | | | | 0.91% | 121.1 | 120.6 | 120.4 |
| | | | | | | | | | | | | | | |
| 5Y194 | A | | 2887.6 | 143.3 | | | | | | | | 123.5 | 120.0 | 119.7 |
| | B | | 2813.9 | 104.5 | | | | | | | | 123.5 | 121.3 | |
| | C | | 2646.5 | 26.5 | | | | | | | | 123.5 | 122.0 | |
| | | | | Ineut = | 32.5 | | | | | | | | | |
| | | | | | | | | | | | | | | |
| | T | | 8348.0 | 274.3 | 3.8% | 1200.0 | 99.9% | 19095.5 | 146.8 | 308.5 | | 0 V | Δ = 2 V | Δ = 3.8 V |
| | LL | | 2727.6 | 18.4 | | | | | | | | 121.1 | 120.0 | 119.8 |
| | | | | | | | | | | | | | | |
| 5Y272 | ** | | 5500 | 690 | | | | 14398.0 | | | | | | |
| | | | | | | | | | | | | | | |
| | LL | | 1855 | -147 | | | | | | | | | | |
| | | | | | | | | | | | | | | |

# Nob Hill 5Y273

**Nob Hill Substation T2402**
**Summary of Distribution Power Flow Results**

| Nob Hill | | T2402 | Base Case (w/ Fielding) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | Annual Energy kWhr | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5Y273 | A | | 2450.5 | 126.1 | | | | | | R = | 4.0 | 123.9 | 120.9 | |
| | B | | 2650.1 | 174.4 | | | Cust/Load | 4.95 | | X = | 0.0 | 123.9 | 120.3 | 119.7 |
| | C | | 2884.2 | 260.7 | | | kVA/Cust | 7.10 | | CT = | 1200.0 | 123.9 | 121.3 | |
| | | | | Ineut = | 51.1 | | Cust = | 2292 | | Vset = | 121.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 7984.8 | 561.1 | 8.4% | 1200.0 | 99.8% | 16377.5 | 150.2 | 324.5 | 1.0337 | | | Δ = 0 V |
| | LL | | 2324.6 | -911.4 | | | | | | | 1.0164 | 121.8 | 121.3 | 121.1 |
| 5Y195 | ** | | 3920 | 343 | | 600.0 | | 8463.0 | | | | | | |
| | LL | | 1201 | -451 | | | | | | | | | | |
| 5Y338 | ** | | 7750 | 1315 | | 600.0 | | 21380.5 | | | | | | |
| | LL | | 2755 | 73 | | | | | | | | | | |

| Changes for Stage-1 | | | Node | Line | Load | Losses | Swap Phases |
|---|---|---|---|---|---|---|---|
| **5Y273** | **S01a** | | FP264901_656800698 | 5Y273_656800259 | | | C->A |
| | **S01b** | Remove Cap | FP239106_556790602 | | | - 600 kVar | |

| Nob Hill | | T2402 | Stage-01 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5Y273 | A | | 2833.4 | 539.6 | | | | | | R = | 8.5 | 124.6 | 120.3 | 120.0 |
| | B | | 2761.0 | 509.8 | | | | | | X = | 0.0 | 124.6 | 121.7 | |
| | C | | 2598.2 | 444.1 | | | | | | CT = | 1200.0 | 124.6 | 122.2 | |
| | | | | Ineut = | 30.3 | | | | | Vset = | 118.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 8192.6 | 1493.4 | 3.8% | 1200.0 | 98.4% | 16377.5 | 151.6 | 301.4 | 1.0373 | 0 V | Δ = 1.9 V | Δ = 4.6 V |
| | LL | | 2710.7 | -222.3 | | | | | | | 1.0005 | 119.9 | 118.9 | 118.8 |
| 5Y195 | ** | | 3920 | 343 | | | | 8463.0 | | | | | | |
| | LL | | 1201 | -451 | | | | | | | | | | |
| 5Y338 | ** | | 7750 | 1315 | | | | 21380.5 | | | | | | |
| | LL | | 2755 | 73 | | | | | | | | | | |

| Changes for Stage-2 | | | Node | Load |
|---|---|---|---|---|
| **5Y273** | **S02b** | Add Sw Cap | FP239106_556790602 | + 600 kVAr |
| | | Add Sw Cap | FP268700 | + 600 kVAr |

| | | Node | Line | Load | Conductor | Length (ft) |
|---|---|---|---|---|---|---|
| **S02c** | None | | | | | |

# APPENDIX 9

| Nob Hill | | T2402 | Stage-02 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5Y273 | A | | 2828.8 | 119.7 | | | | | | R = | 5.5 | 124.2 | 120.7 | 120.4 |
| | B | | 2757.5 | 85.7 | | | | | | X = | 0.0 | 124.3 | 122.0 | |
| | C | | 2594.2 | 17.2 | | | | | | CT = | 1200.0 | 124.3 | 122.7 | |
| | | | | Ineut = | 30.9 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 8180.5 | 222.6 | 3.7% | 1200.0 | 100.0% | 16377.5 | 139.6 | 293.0 | 1.0349 | 0 V | Δ = 1.9 V | Δ = 3.9 V |
| | LL | | 2709.3 | -252.4 | | | | | | | 1.0111 | 121.2 | 120.3 | 120.2 |
| | | | | | | | | | | | | | | |
| 5Y195 | ** | | 3920 | 343 | | | | 8463.0 | | | | | | |
| | | | | | | | | | | | | | | |
| | LL | | 1201 | -451 | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| 5Y338 | ** | | 7750 | 1315 | | | | 21380.5 | | | | | | |
| | | | | | | | | | | | | | | |
| | LL | | 2755 | 73 | | | | | | | | | | |
| | | | | | | | | | | | | | | |

# North Park 5Y356

**North Park Substation T3536**
**Summary of Distribution Power Flow Results**

| North Park | | T3536 | Base Case (w/ Fielding) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | **Annual Energy kWhr** | **Feeder kW** | **Feeder kVAr** | **Unbalance %** | **Cap Banks kVAr** | **Power Factor %** | **Connected kVA** | **Losses kW** | **Losses kVAr** | **Rise at LTC %** | **Feeder Voltage Balance** | **BE: Branch Voltage Balance** | **EOL: Cntl Zone Min Voltage** |
| 5Y356 | A | | 2330.4 | -9.9 | | | | | | R = | 5.0 | 125.5 | 120.5 | |
| | B | | 2109.2 | -96.0 | | | Cust/Load | 3.81 | | X = | 0.0 | 125.5 | 122.7 | 122.5 |
| | C | | 2350.4 | 25.9 | | | kVA/Cust | 11.10 | | CT = | 1000.0 | 125.5 | 119.1 | 118.9 |
| | | | | Ineut = | 36.7 | | Cust = | 1814 | | Vset = | 121.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | 30,777,644 | 6790.0 | -80.0 | 3.8% | 1500.0 | 100.0% | 20180.0 | 231.7 | 394.2 | 1.0396 | 0 V | Δ = 3.6 V | Δ = 6.6 V |
| | LL | | 2494.6 | -1436.3 | | | | | | | 1.0202 | 122.7 | 122.0 | 122.0 |
| 5Y398 | ** | | 9400.0 | 945.2 | | 1200.0 | | 29702.5 | | | | | | |
| | LL | | 3673.8 | -1100.7 | | | | | | | | | | |

| Changes for Stage-1 | | | Node | Line | Load | Losses | Swap Phases |
|---|---|---|---|---|---|---|---|
| 5Y356 | S01a | | | | | | None |
| | S01b | Remove Cap | FP219900_826650557 | | -900 kVar | | |

| North Park | | T3536 | Stage-01 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | | **Feeder kW** | **Feeder kVAr** | **Unbalance %** | **Cap Banks kVAr** | **Power Factor %** | **Connected kVA** | **Losses kW** | **Losses kVAr** | **Rise at LTC %** | **Feeder Voltage Balance** | **BE: Branch Voltage Balance** | **EOL: Cntl Zone Min Voltage** |
| 5Y356 | A | | 2330.8 | 309.3 | | | | | | R = | 12.0 | 125.0 | 118.8 | |
| | B | | 2111.8 | 232.1 | | | | | | X = | 0.0 | 125.0 | 120.9 | 120.7 |
| | C | | 2353.2 | 342.5 | | | | | | CT = | 1000.0 | 125.0 | 117.3 | 117.1 |
| | | | | Ineut = | 36.0 | | | | | Vset = | 116.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 6795.8 | 883.9 | 3.9% | 1500.0 | 99.2% | 20180.0 | 237.4 | 405.1 | 1.0417 | 0 V | Δ = 3.6 V | Δ = 7.9 V |
| | LL | | 2487.2 | -452.0 | | | | | | | 0.9952 | 119.4 | 117.4 | 117.3 |
| 5Y398 | ** | | 9400.0 | 945.2 | | | | | | | | | | |
| | LL | | 3673.8 | -1100.7 | | | | | | | | | | |

**Changes for Stage-2** **Node**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **5Y356** | **S02b** | Add Sw Cap | FP219900_826650557 | | +900 kVar | | |
| | | | **Node** | **Line** | **Load** | **Conductor** | **Length (ft)** |
| | **S02c** | 1 from | FP178002_640300540 | | | 1083 [12.5 4/0AAC3 | 607.0 |
| | | to | FPUNK_640300538 | | | 1055 [12.5 477AAC3PLn 8xa] | |
| | **S02e** | | FP160001_274180881 | 5Y356_274180328-SP1 | [Id = 602] 328 A 3Ph 16 step 3x180 kVA | | |

| **Regulator** | **Settings** | **Reg Flow kVA HL** | **Reg Flow kVA LL** | | | | **Regulator Voltage Sec** | **Branch Volt pu Balance** | **Reg. Min Voltage** |
|---|---|---|---|---|---|---|---|---|---|
| R = | 5.5 | 6650.6 | 2508.7 | | HL | A | 123.6 | 120.9 | |
| X = | 0.0 | | | | | B | 123.1 | 121.5 | 121.3 |
| CT = | 500.0 | | | | | C | 123.4 | 120.4 | 120.2 |
| Vset = | 120.0 | HL V = | 1.0282 | 123.3869 | LL | | 121.1 | 120.4 | 120.3 |
| PT = | 60.0 | LL V = | 1.0106 | | | | | | |

| North Park | | T3536 | Stage-02 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | | **Feeder kW** | **Feeder kVAr** | **Unbalance %** | **Cap Banks kVAr** | **Power Factor %** | **Connected kVA** | **Losses kW** | **Losses kVAr** | **Rise at LTC %** | **Feeder Volt pu Balance** | **Regulator Voltage Pri** | **Min Volt pu** |
| 5Y356 | A | | 2328.8 | -7.7 | | | | | | R = | 6.0 | 123.5 | 121.2 | 121.2 |
| | B | | 2108.8 | -77.5 | | | | | | X = | 0.0 | 123.5 | 122.3 | 122.3 |
| | C | | 2347.5 | 21.3 | | | | | | CT = | 1000.0 | 123.5 | 120.3 | 120.3 |
| | | | | Ineut = | 35.6 | | | | | Vset = | 119.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 6785.1 | -63.9 | 3.8% | 1500.0 | 100.0% | 20180.0 | 229.5 | 389.2 | 1.0292 | 0 V | Δ = 2 V | Δ = 3.1 V |
| | LL | | 2485.0 | -479.2 | | | | | | | 1.0059 | 120.7 | 119.8 | 119.8 |
| 5Y398 | ** | | 9400.0 | 945.2 | | | | | | | | | | |
| | LL | | 3673.8 | -1100.7 | | | | | | | | | | |

# Orchard 5Y456

**Orchard Substation T5035**
**Summary of Distribution Power Flow Results**

| Orchard | | T5035 | Base Case (w/ Fielding) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | **Annual Energy kWhr** | **Feeder kW** | **Feeder kVAr** | **Unbalance %** | **Cap Banks kVAr** | **Power Factor %** | **Connected kVA** | **Losses kW** | **Losses kVAr** | **Rise at LTC %** | **Feeder Voltage Balance** | **BE: Branch Voltage Balance** | **LE: Control Zone Min Voltage** |
| 5Y456 | A | | 2747.4 | 371.1 | | | | | | R = | 5.0 | 126.0 | 120.0 | 119.7 |
| | B | | 1943.0 | 88.2 | | | Cust/Load | 4.07 | | X = | 2.0 | 126.1 | 125.2 | |
| | C | | 2607.3 | 306.2 | | | kVA/Cust | 10.50 | | CT = | 1300.0 | 126.0 | 121.9 | |
| | | | | Ineut = | 102.4 | | Cust = | 1582 | | Vset = | 121.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | 28,932,545 | 7297.7 | 765.5 | 12.9% | 1200.0 | 99.5% | 16682.0 | 124.3 | 172.5 | 1.0432 | 0 V | Δ = 5.2 V | Δ = 6.3 V |
| | LL | | 1837.2 | -324.2 | | | | | | | 1.0179 | 122.4 | 121.0 | 120.9 |
| 5Y458 | ** | | 7200 | 1497 | | 1200.0 | | 22817.5 | | | | | | |
| | LL | | 2512 | -6 | | | | | | | | | | |
| 5Y637 | ** | | 7600 | 1236 | | 1200.0 | | 20613.0 | | | | | | |
| | LL | | 2270 | -121 | | | | | | | | | | |

| **Changes for Stage-1** | | **Node** | **Line** | **Load** | **Losses** | **Swap Phases** |
|---|---|---|---|---|---|---|
| **5Y456** | **S01a** | FP168004_306160613 | 5Y456_306160060 | | | C->B |
| | | FP213700_738390496 | 5Y456_738390191 | | | A->B |
| | | FP163200_306160581 | 5Y456_306160113 | | | CBA->CAB |
| | **S01b** | | | | | |

*At EOL A & C phases end, B phase continues.

| Orchard | | T5035 | Stage-01 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | | **Feeder kW** | **Feeder kVAr** | **Unbalance %** | **Cap Banks kVAr** | **Power Factor %** | **Connected kVA** | **Losses kW** | **Losses kVAr** | **Rise at LTC %** | **Feeder Voltage Balance** | **BE: Branch Voltage Balance** | **LE: Control Zone Min Voltage** |
| 5Y456 | A | | 2417.4 | 258.9 | | | | | | R = | 6.0 | 124.9 | 120.6 | 120.6 |
| | B | | 2401.2 | 248.0 | | | | | | X = | 2.0 | 124.9 | 122.4 | 122.3 |
| | C | | 2471.5 | 271.1 | | | | | | CT = | 1300.0 | 124.9 | 122.8 | 122.8 |
| | | | | Ineut = | 8.2 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 7290.1 | 777.9 | 1.7% | 1200.0 | 99.4% | 16682.0 | 116.7 | 161.3 | 1.0414 | 0 V | Δ = 2.2 V | Δ = 4.3 V |
| | LL | | 1836.6 | -303.6 | | | | | | | 1.0115 | 121.4 | 120.3 | 120.3 |
| 5Y458 | ** | | 7200 | 1497 | | | | | | | | | | |
| | LL | | 2512 | -6 | | | | | | | | | | |
| 5Y637 | ** | | 7600 | 1236 | | | | | | | | | | |
| | LL | | 2270 | -121 | | | | | | | | | | |

| **Changes for Stage-2** | | | **Node** | **Load** |
|---|---|---|---|---|
| **5Y456** | **S02b** | Add Sw Cap | FP215411 | +600 kVAr |

| | | | **Node** | **Line** | **Load** | **Conductor** | **Length (ft)** |
|---|---|---|---|---|---|---|---|
| **S02c** | 1 | from | FP167000_306160615 | | | 1256 [12.5 #6 CU 3F | 812.0 |
| | | to | FP167101_306161294 | | | 1243 [12.5 #2AAC3PSn 8xa] | |
| | 2 | from | FP167101_306161294 | | | 943 [12.5 #4ACS | 211.0 |
| | | to | FP167102_306160572 | | | 1243 [12.5 #2AAC3PSn 8xa] | |

| Orchard | | T5035 | Stage-02 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | | **Feeder kW** | **Feeder kVAr** | **Unbalance %** | **Cap Banks kVAr** | **Power Factor %** | **Connected kVA** | **Losses kW** | **Losses kVAr** | **Rise at LTC %** | **Feeder Voltage Balance** | **BE: Branch Voltage Balance** | **LE: Control Zone Min Voltage** |
| 5Y456 | A | | 2423.0 | 50.1 | | | | | | R = | 5.5 | 124.5 | 120.2 | 120.2 |
| | B | | 2384.7 | 30.2 | | | | | | X = | 2.0 | 124.6 | 122.0 | 121.9 |
| | C | | 2466.5 | 56.7 | | | | | | CT = | 1300.0 | 124.6 | 122.4 | 122.4 |
| | | | | Ineut = | 9.0 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 7274.2 | 137.0 | 1.7% | 1200.0 | 100.0% | 16682.0 | 100.8 | 160.7 | 1.0382 | 0 V | Δ = 2.2 V | Δ = 4.3 V |
| | LL | | 1836.6 | -301.1 | | | | | | | 1.0105 | 121.2 | 120.2 | 120.2 |
| 5Y458 | ** | | 7200 | 1497 | | | | | | | | | | |
| | LL | | 2512 | -6 | | | | | | | | | | |
| 5Y637 | ** | | 7600 | 1236 | | | | | | | | | | |
| | LL | | 2270 | -121 | | | | | | | | | | |

# Orchard 5Y498

**Orchard Substation T3797**
**Summary of Distribution Power Flow Results**

| Orchard | | T3797 | Base Case (w/ Fielding) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | **Annual Energy kWhr** | **Feeder kW** | **Feeder kVAr** | **Unbalance %** | **Cap Banks kVAr** | **Power Factor %** | **Connected kVA** | **Losses kW** | **Losses kVAr** | **Rise at LTC %** | **Feeder Voltage Balance** | **BE: Branch Voltage Balance** | **LE: Control Zone Min Voltage** |
| 5Y498 | A | | 2299.0 | 424.6 | | | | | | R = | 4.0 | 126.1 | 123.2 | |
| | B | | 2076.0 | 363.4 | | | Cust/Load | 6.49 | | X = | 2.0 | 126.2 | 123.5 | |
| | C | | 1902.7 | 356.9 | | | kVA/Cust | 6.00 | | CT = | 1100.0 | 126.2 | 122.7 | 122.3 |
| | | | | Ineut = | 49.3 | | Cust = | 2091 | | Vset = | 121.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | 27,289,488 | 6277.7 | 1144.9 | 9.9% | 0.0 | 98.4% | 12638.0 | 91.7 | 177.6 | 1.0444 | 0 V | Δ = 0.8 V | Δ = 3.9 V |
| | LL | | 1445.2 | 187.2 | | | | | | | 1.0169 | 122.2 | 121.5 | 121.4 |
| 5Y454 | ** | | 9800 | 1003 | | 1200.0 | | 24210.0 | | | | | | |
| | LL | | 2769 | -841 | | | | | | | | | | |
| 5Y639 | ** | | 7720 | 1651 | | 0.0 | | 18148.5 | | | | | | |
| | LL | | 2076 | 269 | | | | | | | | | | |

| **Changes for Stage-1** | | **Node** | **Line** | **Load** | **Losses** | **Swap Phases** |
|---|---|---|---|---|---|---|
| **5Y498** | **S01a** | | | | | None |
| | **S01b** | | | | | |

| Orchard | | T3797 | Stage-01 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | | **Feeder kW** | **Feeder kVAr** | **Unbalance %** | **Cap Banks kVAr** | **Power Factor %** | **Connected kVA** | **Losses kW** | **Losses kVAr** | **Rise at LTC %** | **Feeder Voltage Balance** | **BE: Branch Voltage Balance** | **LE: Control Zone Min Voltage** |
| 5Y498 | A | | 2300.2 | 427.2 | | | | | | R = | 4.0 | 124.2 | 121.2 | |
| | B | | 2076.8 | 365.1 | | | | | | X = | 2.0 | 124.3 | 121.6 | |
| | C | | 1903.9 | 359.4 | | | | | | CT = | 1100.0 | 124.3 | 120.7 | 120.3 |
| | | | | Ineut = | 50.1 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 6280.9 | 1151.7 | 9.9% | 0.0 | 98.4% | 12638.0 | 94.7 | 184.1 | 1.0361 | 0 V | Δ = 0.9 V | Δ = 3.9 V |
| | LL | | 1445.3 | 187.7 | | | | | | | 1.0086 | 121.0 | 120.3 | 120.2 |
| 5Y454 | ** | | 9800 | 1003 | | | | | | | | | | |
| | LL | | 2769 | -841 | | | | | | | | | | |
| 5Y639 | ** | | 7720 | 1651 | | | | | | | | | | |
| | LL | | 2076 | 269 | | | | | | | | | | |

| **Changes for Stage-2** | | | **Node** | **Load** |
|---|---|---|---|---|
| **5Y498** | **S02b** | Add Sw Cap | FP225240 | + 900 kVAr |

| | | **Node** | **Line** | **Load** | **Conductor** | **Length (ft)** |
|---|---|---|---|---|---|---|
| **S02c** | No Conductor Changes | | | | | |

| Orchard | | T3797 | Stage-02 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5Y498 | A | | 2299.7 | 111.3 | | | | | | R = | 3.5 | 123.7 | 121.1 | |
| | B | | 2076.3 | 47.1 | | | | | | X = | 2.0 | 123.8 | 121.4 | |
| | C | | 1902.9 | 39.7 | | | | | | CT = | 1100.0 | 123.8 | 120.6 | 120.2 |
| | | | | Ineut = | 50.3 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 6278.9 | 198.0 | 9.9% | 0.0 | 100.0% | 12638.0 | 93.6 | 181.7 | 1.0319 | 0 V | Δ = 0.8 V | Δ = 3.2 V |
| | LL | | 1445.3 | 187.9 | | | | | | | 1.0075 | 120.9 | 120.1 | 120.0 |
| | | | | | | | | | | | | | | |
| 5Y454 | ** | | 9800 | 1003 | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| | LL | | 2769 | -841 | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| 5Y639 | ** | | 7720 | 1651 | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| | LL | | 2076 | 269 | | | | | | | | | | |
| | | | | | | | | | | | | | | |

## River Road 5Y444

**River Road Substation T3453**
**Summary of Distribution Power Flow Results**

| River Road | | T3453 | Base Case (w/ Fielding) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | Annual Energy kWhr | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5Y444 | A | | 3986.7 | 362.2 | | | | | | R = | 3.0 | 125.3 | 120.3 | 120.1 |
| | B | | 3556.9 | 284.7 | | | Cust/Load | 5.57 | | X = | 7.0 | 125.3 | 121.4 | |
| | C | | 3051.2 | 51.0 | | | kVA/Cust | 10.40 | | CT = | 1000.0 | 125.3 | 123.4 | |
| | | | | Ineut = | 105.8 | | Cust = | 2502 | | Vset = | 121.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | 49,558,070 | 10594.8 | 697.8 | 12.9% | 1200.0 | 99.8% | 25987.0 | 186.1 | 519.3 | 1.0382 | 0 V | Δ = 3.1 V | Δ = 5.2 V |
| | LL | | 3313.5 | -787.3 | | | | | | | 1.0127 | 121.6 | 120.7 | 120.7 |
| 5Y446 | ** | | 6600 | 434 | | 300.0 | | 11730.5 | | | | | | |
| | LL | | 1496 | -249 | | | | | | | | | | |
| 5Y448 | ** | | 4360 | 661 | | 600.0 | | 20141.0 | | | | | | |
| | LL | | 2568 | -512 | | | | | | | | | | |

| Changes for Stage-1 | | | Node | Line | Load | Losses | Swap Phases |
|---|---|---|---|---|---|---|---|
| 5Y444 | S01a | | FP150014_154241218 | 5Y444_154240243 | | | A -> C |
| | | | FP157000_154241204 | 5Y444_154240477 | | | A -> C |
| | | | FP156080_154241134 | 5Y444_154240377 | | | A -> C |
| | S01b | Reduce Cap | FP237905_419030342 | | 1200 kVAr -> 600 kVAr | | |

| River Road | | T3453 | Stage-01 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5Y444 | A | | 3661.1 | 453.6 | | | | | | R = | 5.0 | 125.5 | 121.9 | |
| | B | | 3580.4 | 501.1 | | | | | | X = | 7.0 | 125.6 | 120.3 | 120.0 |
| | C | | 3351.1 | 378.7 | | | | | | CT = | 1000.0 | 125.6 | 122.8 | |
| | | | | Ineut = | 30.7 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 10592.6 | 1333.4 | 3.7% | 1200.0 | 99.2% | 25987.0 | 184.0 | 512.4 | 1.0465 | 0 V | Δ = 2.5 V | Δ = 5.6 V |
| | LL | | 3311.4 | -157.4 | | | | | | | 1.0101 | 121.2 | 120.0 | 119.9 |
| 5Y446 | ** | | 6600 | 434 | | | | | | | | | | |
| | LL | | 1496 | -249 | | | | | | | | | | |
| 5Y448 | ** | | 4360 | 661 | | | | | | | | | | |
| | LL | | 2568 | -512 | | | | | | | | | | |

| Changes for Stage-2 | | | Node | Line | Load | Conductor | Length (ft) |
|---|---|---|---|---|---|---|---|
| 5Y444 | S02b | Add Sw Cap | FP232945 | | + 600 kVAr | | |
| | | Add Sw Cap | FP147243 | | + 600 kVAr | | |
| | S02c | 1 from | FP158001_80630559 | | | 1256 [12.5 #6 CU 3F | 106.0 |
| | | to | FP158002_154241123 | | | 17 [12.5 1/0ACS3PSn 8xa] | |
| | | 2 from | FP158002_154241123 | | | 938 [12.5 #2 ACS 3P | 562.0 |
| | | to | FP158104_154241172 | | | 17 [12.5 1/0ACS3PSn 8xa] | |
| | S02e | Add Regulator | FP141001_33500763 | 5Y444_1031038802-SP1 | [Id = 602] 328 A 3Ph 16 step 3x180 kVA | | |

| Regulator | Settings | Reg Flow kVA HL | Reg Flow kVA LL |
|---|---|---|---|
| R = | 5.5 | 6189.1 | 1944.5 |
| X = | 0.0 | 286.5 A | |
| CT = | 500.0 | | |
| Vset = | 120.0 | HL V = | 1.0263 |
| PT = | 60.0 | LL V = | 1.0083 |

123.1519

HL

LL

| | | Regulator Voltage Pri | Regulator Voltage Sec | Reg. Min Voltage |
|---|---|---|---|---|
| HL | A | 120.7 | 123.0 | |
| | B | 120.5 | 122.8 | 119.9 |
| | C | 121.5 | 123.1 | |
| LL | | 120.0 | 120.7 | 120.4 |

| River Road | | T3453 | Stage-02 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Volt pu Balance | Regulator Voltage Pri | Min Volt pu |
| 5Y444 | A | | 3662.1 | 61.6 | | | | | | R = | 2.0 | 122.5 | 120.7 | 120.7 |
| | B | | 3582 | 113.7 | | | | | | X = | 7.0 | 122.6 | 120.5 | 120.5 |
| | C | | 3351.5 | -12.2 | | | | | | CT = | 1000.0 | 122.6 | 121.5 | 121.5 |
| | | | | Ineut = | 31.1 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 10595.6 | 163.1 | 3.7% | 1200.0 | 100.0% | 25987.0 | 186.9 | 526.8 | 1.0216 | 0 V | Δ = 1 V | Δ = 2.1 V |
| | LL | | 3311.0 | -147.4 | | | | | | | 1.0015 | 120.2 | 120.0 | 120.0 |
| 5Y446 | ** | | 6600 | 434 | | | | | | | | | | |
| | LL | | 1496 | -249 | | | | | | | | | | |
| 5Y448 | ** | | 4360 | 661 | | | | | | | | | | |
| | LL | | 2568 | -512 | | | | | | | | | | |

Wiley 5Y434

**Wiley Substation T3676**
**Summary of Distribution Power Flow Results**

| Wiley | | T3676 | Base Case (w/ Fielding) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | Annual Energy kWhr | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5Y434 | A | | 2253.7 | 626.0 | | | | | | R = | 4.0 | 122.3 | 116.1 | 116.1 |
| | B | | 2493.4 | 716.0 | | | Cust/Load | 3.8 | | X = | 1.0 | 122.4 | 117.0 | |
| | C | | 2245.0 | 619.5 | | | kVA/Cust | 11.7 | | CT = | 2000.0 | 122.4 | 118.8 | |
| | | | | Ineut = | 35.9 | | Cust = | 1588 | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | 27,725,682 | 6992.1 | 1961.5 | 7.0% | 0.0 | 96.3% | 18624.0 | 144.8 | 345.9 | 1.0172 | 0 V | Δ = 2.8 V | Δ = 6.2 V |
| | LL | | 1641.9 | 1045.2 | | | | | | | 1.0053 | 120.7 | 118.5 | 118.5 |
| 5Y164 | ** | | 5900 | 663 | | 2100.0 | | 25936.0 | | | | | | |
| | LL | | 2286 | -646 | | | | | | | | | | |
| 5Y380 | ** | | 8500 | 978 | | 2700.0 | | 34519.5 | | | | | | |
| | LL | | 3043 | -764 | | | | | | | | | | |

| **Changes for Stage-1** | | | **Node** | **Line** | **Load** | **Losses** | **Swap Phases** |
|---|---|---|---|---|---|---|---|
| **5Y434** | **S01a** | | | | | | None |
| | **S01b** | Add Cap | FP301903_506870503 | | 600 kVar | | |
| | | Add Cap | FP254905_47582199 | | 300 kVAr | | |

| Wiley | | T3676 | Stage-01 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5Y434 | A | | 2246.8 | 307.4 | | | | | | R = | 9.5 | 124.6 | 119.7 | 119.7 |
| | B | | 2488.8 | 395.5 | | | | | | X = | 1.0 | 124.7 | 120.5 | |
| | C | | 2242.1 | 291.9 | | | | | | CT = | 2000.0 | 124.7 | 122.4 | |
| | | | | Ineut = | 36.5 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 6977.7 | 994.8 | 7.0% | 0.0 | 99.0% | 18624.0 | 131.1 | 308.1 | 1.0399 | 0 V | Δ = 2.7 V | Δ = 4.9 V |
| | LL | | 1639.1 | 119.9 | | | | | | | 1.0127 | 121.5 | 120.5 | 120.5 |
| 5Y164 | ** | | 5900 | 663 | | | | | | | | | | |
| | LL | | 2286 | -646 | | | | | | | | | | |
| 5Y380 | ** | | 8500 | 978 | | | | | | | | | | |
| | LL | | 3043 | -764 | | | | | | | | | | |

| **Changes for Stage-2** | | | **Node** | **Load** |
|---|---|---|---|---|
| **5Y434** | **S02b** | Add Sw Cap | FP365800 | + 600 kVAr |

| | | **Node** | **Line** | **Load** | **Conductor** | **Length (ft)** |
|---|---|---|---|---|---|---|
| **S02c** | No Conductor Changes | | | | | |

| Wiley | | T3676 | Stage-02 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | | **Feeder kW** | **Feeder kVAr** | **Unbalance %** | **Cap Banks kVAr** | **Power Factor %** | **Connected kVA** | **Losses kW** | **Losses kVAr** | **Rise at LTC %** | **Feeder Voltage Balance** | **BE: Branch Voltage Balance** | **LE: Control Zone Min Voltage** |
| 5Y434 | A | | 2246.0 | 92.3 | | | | | | R = | 9.5 | 124.6 | 120.0 | 120.0 |
| | B | | 2488.7 | 179.8 | | | | | | X = | 1.0 | 124.7 | 120.7 | |
| | C | | 2241.8 | 74.0 | | | | | | CT = | 2000.0 | 124.7 | 122.7 | |
| | | | | Ineut = | 36.9 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 60.0 | | | |
| | T | | 6976.5 | 346.1 | 7.0% | 0.0 | 99.9% | 18624.0 | 130.1 | 304.5 | 1.0399 | 0 V | Δ = 2.7 V | Δ = 4.6 V |
| | LL | | 1639.2 | 133.2 | | | | | | | 1.0127 | 120.7 | 119.7 | 119.7 |
| | | | | | | | | | | | | | | |
| 5Y164 | ** | | 5900 | 663 | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| | LL | | 2286 | -646 | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| 5Y380 | ** | | 8500 | 978 | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| | LL | | 3043 | -764 | | | | | | | | | | |
| | | | | | | | | | | | | | | |

# Grandview 5Y351

**Grandview Substation T859**
**Summary Of Distribution Power Flow Results**

| Grandview | | T859 | Base Case (w/ Fielding) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | **Annual Energy kWhr** | **Feeder kW** | **Feeder kVAr** | **Unbalance** | **Cap Banks kVAr** | **Power Factor %** | **Connected kVA** | **Losses kW** | **Losses kVAr** | **Rise at LTC %** | **Feeder Voltage Balance** | **BE: Branch Voltage Balance** | **LE: Control Zone Min Voltage** |
| 5Y351 | A | | 2230.7 | 241.2 | | | | | | R = | 6.5 | 134.2 | 131.3 | |
| | B | | 2964.0 | 443.6 | | | Cust/Load | 4.19 | | X = | 0.0 | 134.3 | 130.2 | 129.2 |
| | C | | 2504.7 | 308.1 | | | kVA/Cust | 14.10 | | CT = | 500.0 | 134.3 | 132.5 | |
| | | | | Ineut = | 83.6 | | Cust = | 1377 | | Vset = | 121.0 | | | |
| | | | | | | | | | | PT = | 104.0 | | | |
| | T | 33,271,598 | 7699.4 | 993.0 | 15.5% | 600.0 | 99.2% | 20980.4 | 106.0 | 199.0 | 1.0843 | 0 V | | Δ = 5.1 V |
| | LL | | 2170.9 | -367.2 | | | | | | | 1.0331 | 124.6 | 123.8 | 123.5 |
| 5Y302 | ** | | 7440 | 1271 | | | | 26760.5 | | | | | | |
| | LL | | 2770 | -468 | | | | | | | | | | |

| **Changes for Stage-1** | | | **Node** | **Line** | | **Load** | **Losses** | **Swap Phases** |
|---|---|---|---|---|---|---|---|---|
| **5Y351** | **S01a** | | FP274501_564110792 | 5Y351_564110009 | | | | BAC --> ABC |
| **5Y351** | **S01b** | Reduce Cap | FP227502_728880503 | | Fixed | 600 kVAr --> 300 kVAr | | |

| Grandview | | T859 | Stage-01 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | | **Feeder kW** | **Feeder kVAr** | **Unbalance %** | **Cap Banks kVAr** | **Power Factor %** | **Connected kVA** | **Losses kW** | **Losses kVAr** | **Rise at LTC %** | **Feeder Voltage Balance** | **BE: Branch Voltage Balance** | **LE: Control Zone Min Voltage** |
| 5Y351 | A | | 2462.0 | 454.5 | | | | | | R = | 4.0 | 125.4 | 120.5 | 119.4 |
| | B | | 2737.1 | 526.9 | | | | | | X = | 0.0 | 125.5 | 123.5 | |
| | C | | 2513.5 | 458.5 | | | | | | CT = | 500.0 | 125.5 | 122.4 | |
| | | | | Ineut = | 35.9 | | | | | Vset = | 120.0 | | | |
| | | | | | | | | | | PT = | 104.0 | | | |
| | T | | 7712.6 | 1439.8 | 6.5% | 300.0 | 98.3% | 20980.4 | 75.2 | 128.9 | 1.0467 | 0 V | | Δ = 6 V |
| | LL | | 2170.9 | -26.8 | | | | | | | 1.0152 | 121.8 | 120.6 | 120.4 |
| 5Y302 | ** | | 7440 | 1271 | | | | | | | | | | |
| | LL | | 2770 | -468 | | | | | | | | | | |

**Grandview Substation T859**
**Summary Of Distribution Power Flow Results**

| **Changes for Stage-2** | | | **Node** | | |
|---|---|---|---|---|---|
| **5Y351** | **S02b** | Add Sw Cap | FP229907_1040375491 | Switched | 600 kVAr |
| | | Add Sw Cap | FP226502_728882270 | Switched | 600 kVAr |

| | | **Node** | **Line** | **Load** | **Conductor** | **Length (ft)** |
|---|---|---|---|---|---|---|
| **S02c** | No Reconductoring needed | | | | | |

**S02e** Add Regulator FP226205_728880766 5Y351_728880260-SP1
[Id = 63] 219 A 3Ph 16 step 3x180 kVA Flow (kVA) = 855.1

| **Regulator** | **Settings** | **Regulator Flow HL** | | **Regulator Flow LL** |
|---|---|---|---|---|
| R = | 2.5 | 855.05 | | 237 |
| X = | 0.0 | | | |
| CT = | 50.0 | | | |
| Vset = | 120.0 | HL | V = | 1.0165 |
| PT = | 60.0 | LL | V = | 1.0046 |

| | | **Regulator Voltage Pri** | **Regulator Voltage Sec** | **Control Zone Min Voltage** |
|---|---|---|---|---|
| HL | A | 120.0 | 122.1 | 119.7 |
| | B | 121.5 | 123.8 | |
| | C | 121.8 | 124.1 | |
| LL | | 119.6 | 120.3 | 119.6 |
| | | | | Δ = 2.4 V |

| Grandview | | T859 | Stage-02 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5Y351 | A | | 2461.8 | 50.1 | | | | | | R = | 3.0 | 123.1 | 120.0 | 120.0 |
| | B | | 2738.4 | 118.0 | | | | | | X = | 0.0 | 123.1 | 121.5 | 121.5 |
| | C | | 2513.3 | 45.7 | | | | | | CT = | 500.0 | 123.1 | 121.8 | 121.8 |
| | | | | Ineut = | 37.6 | | | | | Vset = | 119.0 | | | |
| | | | | | | | | | | PT = | 104.0 | | | |
| | T | | 7713.5 | 213.8 | 6.5% | 1500.0 | 100.0% | 20980.4 | 83.0 | 147.6 | 1.0267 | 0 V | | Δ = 3.1 V |
| | LL | | 2171.0 | -17.4 | | | | | | | 1.0031 | 120.4 | 119.6 | 119.6 |
| 5Y302 | ** | | 7440 | 1271 | | | | | | | | | | |
| | LL | | 2770 | -468 | | | | | | | | | | |

# Sunnyside 5Y313 & 317

**Sunnyside Substation T3570**
**Summary Of Distribution Power Flow Results**

| Sunnyside | | T3570 | Base Case (w/ Fielding) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | Annual Energy kWhr | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5Y313 | A | | 1385.6 | 159.1 | | | | | | R = | 4.0 | 125.7 | 123.3 | |
| | B | | 1593.8 | 243.2 | | | Cust/Load | 4.97 | | X = | 2.0 | 125.7 | 123.6 | |
| | C | | 1519.6 | 213.7 | | | kVA/Cust | 10.20 | | CT = | 1000.0 | 125.7 | 123.0 | 121.5 |
| | | | | Ineut = | 26.0 | | Cust = | 1172 | | Vset = | 121.0 | | | |
| | | | | | | | | | | PT = | 104.0 | | | |
| | T | 20,864,708 | 4499.0 | 616.0 | 6.3% | 1200.0 | 99.1% | 11851.5 | 86.8 | 94.1 | 1.0381 | 0 V | | Δ = 4.2 V |
| | LL | | 1584.4 | -205.1 | | | | | | | 1.0172 | 122.5 | 121.6 | 121.0 |
| | | | | | | | | | | | | | | |
| 5Y314 | T | | 9400 | 1694 | | 3000.0 | | 32407.1 | | | | | | |
| | LL | | 4328 | -601 | | | | | | | | | | |
| | | | | | | | Cust/Load | 8.29 | | | | | | |
| 5Y317 | A | | 1148.1 | 106.0 | | | kVA/Cust | 7.60 | | | | 125.6 | 123.7 | |
| | B | | 1782.0 | 306.0 | Ineut = 93.4 | | Cust = | 1277 | | | | 125.6 | 123.0 | 122.8 |
| | C | | 1069.7 | 86.9 | | | | | | | | 125.7 | 125.3 | |
| | T | 19,867,620 | 3999.8 | 498.9 | 33.7% | 600.0 | 99.2% | 9579.6 | 49.6 | 60.4 | | 0 V | | Δ = 2.8 V |
| | LL | | 1279.3 | -129.0 | | | | | | | | 122.5 | 121.7 | 121.6 |
| | | | | | | | | | | | | | | |

| Changes for Stage-1 | | | Node | Line | Load | Swap Phases |
|---|---|---|---|---|---|---|
| **5Y317** | **S01a** | | FP257504_823200895 | 5Y317_823200406 | | B-->A |
| | | | | 5Y317_823200313 | | ABC-->ACB |
| | | | | | TR_257501_823200453 | A-->B |
| **5Y313** | **S01b** | 1. Reduce Cap | FP251510_823200918 | | 1200 kVAr --> 900 kVAr | |

*** Losses prior to redistribution of fixed caps

| Sunnyside | | T3570 | Stage-01 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Circuit ID | Ph | | Feeder kW | Feeder kVAr | Unbalance % | Cap Banks kVAr | Power Factor % | Connected kVA | Losses kW | Losses kVAr | Rise at LTC % | Feeder Voltage Balance | BE: Branch Voltage Balance | LE: Control Zone Min Voltage |
| 5Y313 | A | | 1386.6 | 275.1 | | | | | | R = | 4.0 | 124.2 | 121.7 | |
| | B | | 1594.9 | 358.9 | | | | | | X = | 2.0 | 124.2 | 122.0 | |
| | C | | 1520.7 | 329.7 | | | | | | CT = | 1000.0 | 124.2 | 121.4 | 119.9 |
| | | | | Ineut = | 26.3 | | | | | Vset = | 121.0 | | | |
| | | | | | | | | *** | 74.2 | PT = | 104.0 | | | |
| | T | | 4502.2 | 963.7 | 6.3% | 900.0 | 97.8% | 11851.5 | 77.0 | 64.7 | 1.0357 | 0 V | | Δ = 4.3 V |
| | LL | | 1584.3 | 121.9 | | | | | | | 1.0128 | 121.5 | 120.5 | 119.9 |
| | | | | | | | | | | | | | | |
| 5Y314 | ** | | 9400 | 1694 | | | | | | | | | | |
| | LL | | 4328 | -601 | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| 5Y317 | A | | 1409.6 | 192.9 | | | | | | | | 124.2 | 121.9 | 121.7 |
| | B | | 1378.5 | 182.9 | 26.3 | | | | | | | 124.2 | 122.5 | |
| | C | | 1209.2 | 133.5 | | | | *** | 35.3 | | | 124.2 | 123.0 | |
| | T | | 3997.3 | 509.2 | 5.8% | 600.0 | 99.2% | 9579.6 | 35.5 | 42.6 | | 0 V | | Δ = 2.5 V |
| | LL | | 1279.0 | -162.9 | | | | | | | | 121.5 | 120.9 | 120.8 |
| | | | | | | | | | | | | | | |

**Sunnyside Substation T3570**
**Summary Of Distribution Power Flow Results**

| **Changes for Stage-2** | | | **Node** | **Line** | **Load** | **Conductor** | **Length (ft)** |
|---|---|---|---|---|---|---|---|
| **5Y313** | **S02b** | 1 New Switched | FP251902_823200877 | | +SW 600 kVAr | | |
| | | 2 New Switched | FP269202_42390692 | | +SW 300 kVAr | | |
| | **S02c** | No reconductoring | | | | | |
| **5Y317** | **S02b** | New Switched | FP256511_937580500 | | +SW 600 kVAr | | |
| | **S02c** | No reconductoring | | | | | |

| **Sunnyside** | | **T3570** | **Stage-02** | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit ID** | **Ph** | | **Feeder kW** | **Feeder kVAr** | **Unbalance %** | **Cap Banks kVAr** | **Power Factor %** | **Connected kVA** | **Losses kW** | | **Rise at LTC %** | **Feeder Voltage Balance** | **BE: Branch Voltage Balance** | **LE: Control Zone Min Voltage** |
| 5Y313 | A | | 1381.5 | -43.2 | | | | | | R = | 3.5 | 123.9 | 122.1 | |
| | B | | 1587.6 | 39.4 | | | | | | X = | 2.0 | 123.9 | 122.5 | |
| | C | | 1514.5 | 10.9 | | | | | | CT = | 1000.0 | 123.9 | 121.8 | 120.4 |
| | | | | Ineut = | 26.1 | | | | | Vset = | 121.0 | | | |
| | | | | | | | | | | PT = | 104.0 | | | |
| | T | | 4483.6 | 7.0 | 6.2% | 900.0 | 100.0% | 11851.5 | 58.4 | 61.0 | 1.0331 | 0 V | | Δ = 3.6 V |
| | LL | | 1584.3 | 121.4 | | | | | | | 1.0131 | 121.6 | 120.6 | 120.0 |
| | | | | | | | | | | | | | | |
| 5Y314 | ** | | 9400 | 1694 | | | | | | | | | | |
| | LL | | 4328 | -601 | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| 5Y317 | A | | 1409.5 | -15.6 | | | | | | | | 123.9 | 123.9 | 121.7 |
| | B | | 1378.6 | -27.2 | Ineut = 26.6 | | | | | | | 123.9 | 122.5 | |
| | C | | 1208.9 | -77.4 | | | | | | | | 123.9 | 123.0 | |
| | T | | 3997.0 | -120.2 | 5.8% | 600.0 | 100.0% | 9579.6 | 35.3 | 42.3 | | 0 V | | Δ = 2.2 V |
| | LL | | 1279.0 | -163.3 | | | | | | | | 121.6 | 120.9 | 120.8 |
| | | | | | | | | | | | | | | |

# Appendix 10: Cost Estimates

**Bowman 5W150**

## Changes for Stage 1

| | Node | Line | Load | Losses | Swap Phases |
|---|---|---|---|---|---|
| | No phase changes were necessary | | | | |

| **Metering** | |
|---|---|
| Substation | $8,130 |
| **End of Line** | $9,540 |
| | $17,670 |

**Stage 1 Costs to address Potential Low Voltages**
Heavy Load is the Controlling Case

| | |
|---|---|
| **Number of Transformers at or below 120 volts** | 184 |
| *Estimated percent with secondary Vd > 4 volts* | 26.8% |
| Number of Transformers from 120 to 121 volts | 99 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |

Estimated total number of transformers that
may have customers with low voltage at Service Entrance = 42

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 13 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $59,488 |
| 29 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $45,240 |
| 4 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $6,240 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $51,740 |
| | | Total estimated cost to resolve low voltage concerns: | $162,708 |

**Total Stage 1 = $180,378**

## Changes for Stage 2

| | Node | Line | Load | Losses | Swap Phases | | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Add Sw Cap | FP249363_593050816 | | + 900 kVAr | | | | | | | | |
| | | | | | | | $6,575 | $10,393 | $2,121 | $19,088 | |
| | | | | | | | | | | $1,909 | Engineering = 10% of Total |
| | | | | | | | | | | $20,997 | |
| | | | | | | **Three Phase swap** | | | | | |
| | FP269903_302080452 | 5W150_302080024 | | Rotate phases | CAB->ACB | Engineer | | 4 | $130 | $520 | Engineering and Analysis |
| | | | | | | Svc Line Worker | | 0 | $130 | $0 | Install /Remove metering |
| | | | | | | Notifier | | 4 | $100 | $400 | Notify customers of outage |
| | | | | | | SVC Crew (4 person + 2 flaggers) | | 6 | $650 | $3,900 | Make phase changes |
| | | | | | | Total | | 14 | | $4,820 | |
| | FP243261 | 5W150_593050046-SP2 | 328 A 3Ph 16 step 3x180 kVA | | | | $11,110 | $47,553 | $7,333 | $65,995 | Per Block Estimate |
| | | | | | | | | | | $6,599 | Engineering = 10% of total |
| | | | | | | | | | | $72,594 | |

| **Metering** | | |
|---|---|---|
| Regulator | $32,000 | x 2 for new and existing |
| End of Line | $19,080 | x 2 for new and existing |
| | $51,080 | |

**Stage 2 Costs to address Potential Low Voltages**
The number of impacted transformers is slightly less in stage 2 than in stage 1. No additional costs

Stage 2 Modification Total = $149,492

**Stage 1 + Stage 2 Modification Total = $329,870**

**Changes for Stage 3**
All changes in Stage three are to address potential low voltage.

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 1 | $3,551 | $3,551 | |
| Line regulator: wireless 'radio' link to the substation | 0 | $3,364 | $0 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 0.5 | $210,563 | $105,282 | Shared cost with 5W154 |
| | | Subtotal: | $108,833 | |

**Stage 3 Costs to address Potential Low Voltages**
Heavy Load is the Controlling Case
25 less transformers will be impacted.

| | |
|---|---|
| **Number of Transformers at or below 120 volts** | 35 |
| *Estimated percent with secondary Vd > 4 volts* | 26.8% |
| Number of Transformers from 120 to 121 volts | 143 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |

Estimated total number of transformers that
may have customers with low voltage at Service Entrance = 17

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| -8 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | ($36,608) |
| -17 | transformer tap changes | (4 hrs x 3 person crew) per tap change | ($26,520) |
| -2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | ($3,120) |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | ($30,940) |
| | | Total estimated cost to resolve low voltage concerns: | ($97,188) |

Stage 3 Modification Total = $11,645

**Stage 1 + Stage 2 + Stage 3 Modification Total = $341,514**

## Bowman 5W154

| | | | |
|---|---|---|---|
| Remove Caps | FP357704_369970265 | - 900 kVAr | |
| Remove Caps | FP300602_1540121947 | - 900 kVAr | |

**Estimate to remove both capacitors**

| | | | | |
|---|---|---|---|---|
| Engineer | 8 | 130 | 1040 | Engineering & Admin |
| SVC Crew (3 person + 2 flaggers) | 8 | 520 | 4160 | Remove Cap Bank |
| | | | 5200 | |

No phase adjusments required for balancing

**Metering**

| | |
|---|---|
| Substation | $8,130 |
| End of Line | $9,540 |
| | $17,670 |

**Stage 1 Costs to address Potential Low Voltages**
Heavy Load is the Controlling Case

| | |
|---|---|
| **Number of Transformers at or below 120 volts** | 0 |
| *Estimated percent with secondary Vd > 4 volts* | 26.8% |
| Number of Transformers from 120 to 121 volts | 6 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |

Estimated total number of transformers that may have customers with low voltage at Service Entrance = 1

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 1 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $4,576 |
| 0 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $0 |
| 0 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $0 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $2,080 |
| | | Total estimated cost to resolve low voltage concerns: | $6,656 |

**Total Stage 1 = $29,526**

| **Changes for Stage 2** | **Node** | **Load** |
|---|---|---|
| Add Sw Cap | FP357704_369970265 | + 900 kVAr |
| Add Sw Cap | FP300602_1540121947 | + 900 kVAr |

**Cost to install both Capacitors**

| Labor | Material | AFUDC | Total | |
|---|---|---|---|---|
| $13,149 | $20,786 | $4,242 | $38,177 | |
| | | | $3,818 | Engineering = 10% of Total |
| | | | $41,995 | |

| **Node** | **Line** | **Load** | **Conductor** | **Length (ft)** |
|---|---|---|---|---|
| No reconductoring needed | | | | |

**Stage 2 Costs to address Potential Low Voltages**
Light Load is Controlling Case.
7 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 0 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 350 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 2510 |
| Heavy Load = | 8200 |
| Light Load / Heavy Load = | 0.31 |

Estimated total number of transformers that may have customers with low voltage at Service Entrance = 8

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 3 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $13,728 |
| 4 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $6,240 |
| 1 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $1,560 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $9,880 |
| | | Total estimated cost to resolve low voltage concerns: | $31,408 |

Stage 2 Modification Total = $73,403

**Stage 1 + Stage 2 Modification Total = $102,929**

**Changes for Stage 3**

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 2 | $3,551 | $7,102 | |
| Line regulator: wireless 'radio' link to the substation | 1 | $3,364 | $3,364 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 0.5 | $210,563 | $105,282 | Shared cost with 5W150 |
| | | Subtotal: | $115,748 | |

**Stage 3 Costs to address Potential Low Voltages**

Light Load is Controlling Case.

13 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 350 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 22 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 2510 |
| Heavy Load = | 8200 |
| Light Load / Heavy Load = | 0.31 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 21 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 4 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $18,304 |
| 9 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $14,040 |
| 3 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $4,680 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $16,900 |
| | | Total estimated cost to resolve low voltage concerns: | $53,924 |

Stage 3 Modification Total = $169,672

**Stage 1 + Stage 2 + Stage 3 Modification Total = $272,600**

## Dodd Road 4W22

| Changes for Stage 1 | | Node | Line | Load | Losses | Swap Phases | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | none | | | | | |
| | Add Cap | FP017006_682660347 | | + 900 kVAr | | | $2,012 | $2,766 | $597 | $5,375 | |
| | | | | | | | | | | $537 | Engineering = 10% of Total |
| | | | | | | | | | | $5,912 | |

| Metering | |
|---|---|
| Substation | $8,130 |
| End of Line | $9,540 |
| | $17,670 |

**Stage 1 Costs to address Potential Low Voltages**
Heavy Load is the Controlling Case

| | |
|---|---|
| **Number of Transformers at or below 120 volts** | 229 |
| *Estimated percent with secondary Vd > 4 volts* | 26.8% |
| **Number of Transformers from 120 to 121 volts** | 78 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |

Estimated total number of transformers that
may have customers with low voltage at Service Entrance = 49

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 15 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $68,640 |
| 34 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $53,040 |
| 8 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $12,480 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $61,880 |
| | | Total estimated cost to resolve low voltage concerns: | $196,040 |

**Total Stage 1 = $219,622**

| Changes for Stage 2 | | Node | Load | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|
| | Add Sw Cap | FP179040_776390396 | + 1800 kVAr | $4,773 | $10,312 | $1,886 | $16,970 | |
| | | | *used 1200kVAR for pricing | | | | $1,697 | Engineering = 10% of Total |
| | | | | | | | $18,667 | |

| | Node | Load | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|
| Add Sw Cap | FP289361_423450417 | + 300 kVAr | | | | | |
| Add Sw Cap | FP340061_1540847160 | + 300 kVAr | $9,545 | $10,408 | $2,594 | $22,547 | |
| | | | | | | $2,255 | Engineering = 10% of Total |
| | | | | | | $24,802 | |

Per-foot costs:

| | | Node | Conductor | Length (ft) | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | $55 | $52 | $13 | $120 | |
| 1 | from | FP289003_1540261624 | 1780 [20.8 #6 CU 3PSn 8xa] | 447.0 | | | | $53,757 | |
| | to | FP339960_423450423 | 1690 [20.8 795AAC3PLn 8xa] | | | | | $5,376 | Engineering = 10% of Total |
| | | | | | | | | $59,133 | |

*used pricing for 3 ph 7620 V 328 A

| | | | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|
| FP187200 | 4W22_776390096-SP2 | [Id = 1033] [20.8 3-ph 347A] | $11,110 | $49,000 | $7,333 | $67,442 | $49k Per email from Wyatt |
| | | | | | | $6,744 | Engineering = 10% of total |
| | | | | | | $74,187 | |

| Metering | |
|---|---|
| Regulator | $16,000 |
| End of Line | $9,540 |
| | $25,540 |

**Stage 2 Costs to address Potential Low Voltages**

Light Load is Stage 2 Controlling Case.

35 less transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 35 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 189 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 6236 |
| Heavy Load = | 8700 |
| Light Load / Heavy Load = | 0.72 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 14 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| -11 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | ($50,336) |
| -24 | transformer tap changes | (4 hrs x 3 person crew) per tap change | ($37,440) |
| -2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | ($3,120) |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | ($42,640) |
| | | Total estimated cost to resolve low voltage concerns: | ($133,536) |

Stage 2 Modification Total= $68,793

**Stage 1 + Stage 2 Modification Total = $288,415**

**Changes for Stage 3**

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 2 | $3,551 | $7,102 | |
| Line regulator: wireless 'radio' link to the substation | 1 | $3,364 | $3,364 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 1 | $210,563 | $210,563 | |
| | | Subtotal: | $221,029 | |

**Stage 3 Costs to address Potential Low Voltages**

Light Load is Stage 3 Controlling Case.

19 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 189 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 147 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 6236 |
| Heavy Load = | 8700 |
| Light Load / Heavy Load = | 0.72 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 33 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 6 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $27,456 |
| 13 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $20,280 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $23,660 |
| | | Total estimated cost to resolve low voltage concerns: | $74,516 |

Stage 3 Modification Total = $295,545

**Stage 1 + Stage 2 + Stage 3 Modification Total = $583,960**

## Mill Creek 5W116

| Changes for Stage 1 | Node | Line | Load | Losses | Swap Phases |
|---|---|---|---|---|---|
| | | | | | None |

| Metering | |
|---|---|
| Substation | $8,130 |
| End of Line | $9,540 |
| | $17,670 |

**Stage 1 Costs to address Potential Low Voltages**
Light Load is Controlling Case

| | |
|---|---|
| Number of Transformers at or below 120 volts | 91 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 294 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 2148 |
| Heavy Load = | 8100 |
| Light Load / Heavy Load = | 0.27 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 10 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 3 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $13,728 |
| 7 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $10,920 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $12,740 |
| | | Total estimated cost to resolve low voltage concerns: | $40,508 |

**Total Stage 1 = $58,178**

| Stage 2 Improvements | | Node | | Load | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|---|
| | Add Sw Cap | FP166061_755430427 | | + 900 kVAr | $6,575 | $10,393 | $2,121 | $19,088 | |
| | | | | | | | | $1,909 | Engineering = 10% of Total |
| | | | | | | | | $20,997 | |
| **S02e** | | FP165101 | 5W116_755430072-SP1 | [Id = 63] 219 A 3Ph 16 step 3x180 kVA | $11,110 | $40,480 | $6,449 | $58,038 | |
| | | | | | | | | $5,804 | Engineering = 10% of Total |
| | | | | | | | | $63,842 | |

| Metering | |
|---|---|
| Regulator | $16,000 |
| End of Line | $9,540 |
| | $25,540 |

**Stage 2 Costs to address Potential Low Voltages**
Light Load is Stage 2 Controlling Case.
4 less transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 0 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 319 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 2148 |
| Heavy Load = | 8100 |
| Light Load / Heavy Load = | 0.27 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 6 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| -2 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | ($9,152) |
| -2 | transformer tap changes | (4 hrs x 3 person crew) per tap change | ($3,120) |
| 0 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $0 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | ($5,720) |
| | | Total estimated cost to resolve low voltage concerns: | ($17,992) |

Stage 2 Modification Total= $92,387

**Stage 1 + Stage 2 Modification Total = $150,565**

**Changes for Stage 3**

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 2 | $3,551 | $7,102 | |
| Line regulator: wireless 'radio' link to the substation | 1 | $3,364 | $3,364 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 0.5 | $210,563 | $105,282 | Share cost with 5W127 |
| | | Subtotal: | $115,748 | |

**Stage 3 Costs to address Potential Low Voltages**

Heavy Load is the Controlling Case.

13 more transformers will be impacted.

| | |
|---|---|
| **Number of Transformers at or below 120 volts** | 63 |
| *Estimated percent with secondary Vd > 4 volts* | 26.8% |
| **Number of Transformers from 120 to 121 volts** | 98 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |

Estimated total number of transformers that may have customers with low voltage at Service Entrance = 19

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 4 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $18,304 |
| 9 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $14,040 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $16,380 |
| | | Total estimated cost to resolve low voltage concerns: | $51,844 |

Stage 3 Modification Total = $167,592

**Stage 1 + Stage 2 + Stage 3 Modification Total = $318,156**

## Mill Creek 5W127

**Changes for Stage 1**

| | | |
|---|---|---|
| FP288803_544871716 | 5W127_544870102 | CBA->CAB |
| FP219405_242020779 | 5W127_242020295 | B->C |
| FP283816_544870486 | 5W127_544870085 | B->C |
| FP291702_717550718 | 5W127_717550132 | CBA->BAC |
| FP294700_717550725 | 5W127_1540944656 | B->C |
| FP285903_544870459 | 5W127_544870096 | CBA->BAC |

Three (3) Single Phase changes

| Staff | hours | rate | total | Work Description |
|---|---|---|---|---|
| Engineer | 12 | $130 | $1,560 | Engineering and Analysis |
| Svc Line Worker | 0 | $130 | $0 | Install /Remove metering |
| Notifier | 6 | $100 | $600 | Notify customers of outage |
| SVC Crew (3 person + 2 flaggers) | 12 | $520 | $6,240 | Make phase changes |
| Total | 30 | | $8,400 | |

**Three (3) x Three Phase swaps**

| | | | | |
|---|---|---|---|---|
| Engineer | 12 | $130 | $1,560 | Engineering and Analysis |
| Svc Line Worker | 0 | $130 | $0 | Install /Remove metering |
| Notifier | 12 | $100 | $1,200 | Notify customers of outage |
| SVC Crew (4 person + 2 flaggers) | 18 | $650 | $11,700 | Make phase changes |
| Total | 42 | | $14,460 | |

**Metering**

| | |
|---|---|
| Substation | $8,130 |
| End of Line | $9,540 |
| | $17,670 |

| | | | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|
| Add Cap | FP282811_544870470 | 600 kVar | $3,071 | $2,818 | $736 | $6,624 | |
| | | | | | | $662 | Engineering = 10% of Total |
| | | | | | | $7,287 | |

**Stage 1 Costs to address Potential Low Voltages**
Light Load is Controlling Case

| | |
|---|---|
| Number of Transformers at or below 120 volts | 32 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 300 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 1830 |
| Heavy Load = | 6220 |
| Light Load / Heavy Load = | 0.29 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 8 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 3 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $13,728 |
| 5 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $7,800 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $11,180 |
| | | Total estimated cost to resolve low voltage concerns: | $35,828 |

**Total Stage 1 = $83,645**

| Changes for Stage 2 | | Node | Load | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|
| | | | | $6,575 | $12,136 | $2,339 | $21,049 | |
| **S02b** | Add Sw Cap | FP289805_544870439 | +600 kVAr | | | | $2,105 | Engineering = 10% of Total |
| | | | | | | | $23,154 | |

**Stage 2 Costs to address Potential Low Voltages**
The number of impacted transformers is less in stage 2 than in stage 1. No additional costs

Stage 2 Modification Total= $23,154

**Stage 1 + Stage 2 Modification Total = $106,799**

**Changes for Stage 3**

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 1 | $3,551 | $3,551 | |
| Line regulator: wireless 'radio' link to the substation | 0 | $3,364 | $0 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 0.5 | $210,563 | $105,282 | Share cost with 5W116 |
| | | Subtotal: | $108,833 | |

**Stage 3 Costs to address Potential Low Voltages**

Light Load is Controlling Case.

10 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 321 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 0 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 1830 |
| Heavy Load = | 6220 |
| Light Load / Heavy Load = | 0.29 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 18 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 3 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $13,728 |
| 7 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $10,920 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $12,740 |
| | | Total estimated cost to resolve low voltage concerns: | $40,508 |

Stage 3 Modification Total = $149,341

**Stage 1 + Stage 2 + Stage 3 Modification Total = $256,139**

## Pomeroy 5W342

**Changes for Stage 1**

| | Node | | Swap Phases |
|---|---|---|---|
| **S01a** | FP171860_420450094 | 5W342_420450011 | BAC->BCA |
| | FP310600_463490170 | 5W342_1540118006 | BAC->BCA |
| | FP325202_761212279 | 5W342_761210085 | BC->CB |

One (1) Two Phase changes

| Staff | hours | rate | total | Work Description |
|---|---|---|---|---|
| Engineer | 6 | $130 | $780 | Engineering and Analysis |
| Svc Line Worker | 0 | $130 | $0 | Install /Remove metering |
| Notifier | 3 | $100 | $300 | Notify customers of outage |
| SVC Crew (3 person + 2 flaggers) | 6 | $520 | $3,120 | Make phase changes |
| Total | 15 | | $4,200 | |

**Two (2) x Three Phase swaps**

| | | | | |
|---|---|---|---|---|
| Engineer | 8 | $130 | $1,040 | Engineering and Analysis |
| Svc Line Worker | 0 | $130 | $0 | Install /Remove metering |
| Notifier | 8 | $100 | $800 | Notify customers of outage |
| SVC Crew (4 person + 2 flaggers) | 12 | $650 | $7,800 | Make phase changes |
| Total | 28 | | $9,640 | |

**Metering**

| | |
|---|---|
| Substation | $8,130 |
| End of Line | $9,540 |
| | $17,670 |

**Stage 1 Costs to address Potential Low Voltages**
Heavy Load is the Controlling Case

| | |
|---|---|
| Number of Transformers at or below 120 volts | 83 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 27 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |

Estimated total number of transformers that may have customers with low voltage at Service Entrance = 18

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 6 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $27,456 |
| 12 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $18,720 |
| 4 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $6,240 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $23,920 |
| | | Total estimated cost to resolve low voltage concerns: | $76,336 |

**Total Stage 1 = $107,846**

**Changes for Stage 2**

| | | Node | | |
|---|---|---|---|---|
| **S02b** | Add Sw Cap | FP312104_761212376 | Switched | 300 kVAr |

Cost for 300 kVAR Installations (based on 600 kVAR cost in block estimate)

| Labor | Material | AFUDC | Total | |
|---|---|---|---|---|
| $4,773 | $9,234 | $1,751 | $15,758 | |
| | | | $1,576 | Engineering = 10% of Total |
| | | | $17,333 | |

| | | | Node | Line | | Conductor | Length (ft) |
|---|---|---|---|---|---|---|---|
| **S02c** | 1 | from | MP_463490150 | Reconductor | existing | 1/0 CU | 355.0 |
| | | to | FP365261_463490189 | | new | 477 AAC | |
| | 2 | from | FP311103_761210762 | Reconductor | existing | #6 CU | 71.0 |
| | | to | FP311104_761210780 | | new | 1/0 CU | |
| | | | | | | 4/0 AAC for pricing | |

Per-foot costs:

| | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|
| 1 | $44 | $45 | $11 | $101 | |
| | | | | $35,772 | |
| | | | | $3,577 | Engineering = 10% of Total |
| | | | | $39,349 | |
| 2 | $41 | $42 | $10 | $93 | |
| | | | | $6,624 | |
| | | | | $662 | Engineering = 10% of Total |
| | | | | $7,286 | |
| | | | | $3,643 | 50% Small Job mark up |
| | | | | $10,930 | Total Estimate |

| | | |
|---|---|---|
| FP044303A | 5W342_1540871261-SP2 | 219 A 3Ph 16 step 3x180 kVA |
| FP321102A | 5W342_761210113 | 219 A 3Ph 16 step 3x180 kVA |

Costs are for both units installed

| Labor | Material | AFUDC | Total | |
|---|---|---|---|---|
| $22,219 | $80,959 | $12,897 | $116,076 | |
| | | | $11,608 | Engineering = 10% of Total |
| | | | $127,683 | |

Costs are for metering at both Regulators and end of line metering

| Metering | |
|---|---|
| Regulator | $32,000 |
| End of Line | $19,080 |
| | $51,080 |

**Stage 2 Costs to address Potential Low Voltages**

Light Load is Stage 2 Controlling Case.

10 less transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 0 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 398 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 1596 |
| Heavy Load = | 6045 |
| Light Load / Heavy Load = | 0.26 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 8 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| -3 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | ($13,728) |
| -7 | transformer tap changes | (4 hrs x 3 person crew) per tap change | ($10,920) |
| 0 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $0 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | ($11,700) |
| | | Total estimated cost to resolve low voltage concerns: | ($36,348) |

Stage 2 Modification Total= $210,027

**Stage 1 + Stage 2 Modification Total = $317,873**

**Changes for Stage 3**

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 3 | $3,551 | $10,653 | |
| Line regulator: wireless 'radio' link to the substation | 2 | $3,364 | $6,728 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 1 | $210,563 | $210,563 | |
| | | Subtotal: | $227,944 | |

**Stage 3 Costs to address Potential Low Voltages**

Heavy Load is the Controlling Case.

18 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 64 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 197 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 26 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 6 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $27,456 |
| 12 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $18,720 |
| 4 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $6,240 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $23,920 |
| | | Total estimated cost to resolve low voltage concerns: | $76,336 |

Stage 3 Modification Total = $304,280

**Stage 1 + Stage 2 + Stage 3 Modification Total = $622,153**

## Clinton 5Y608

| Changes for Stage 1 | | Node | Line | Load | Losses | Swap Phases | Staff | hours | rate | total | Work Description |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | Engineer | 4 | $130 | $520 | Engineering and Analysis |
| | | | | | | | Svc Line Worker | 0 | $130 | $0 | Install /Remove metering |
| **5Y608** | **S01a** | FP055861_389072157 | 5Y608_389070384 | | | A->C | Notifier | 2 | $100 | $200 | Notify customers of outage |
| | | | | | | | SVC Crew (3 person + 2 flaggers) | 3 | $520 | $1,560 | Make phase changes |
| | | | | | | | Total | 9 | | $2,280 | |

| **Metering** | |
|---|---|
| Substation | $8,130 |
| End of Line | $9,540 |
| | $17,670 |

**Stage 1 Costs to address Potential Low Voltages**
Light Load is Controlling Case

| | |
|---|---|
| Number of Transformers at or below 120 volts | 38 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 341 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 3050 |
| Heavy Load = | 8200 |
| Light Load / Heavy Load = | 0.37 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 12 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 4 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $18,304 |
| 8 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $12,480 |
| 4 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $6,240 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $16,640 |
| | | Total estimated cost to resolve low voltage concerns: | $53,664 |

**Total Stage 1 = $73,614**

**Changes for Stage 2**

| | | Node | Load | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|
| **S02b** | Add Sw Cap | FP274441 | + 900 kVAr | $6,575 | $10,393 | $2,121 | $19,088 | |
| | | | | | | | $1,909 | Engineering = 10% of Total |
| | | | | | | | $20,997 | |

| | | Node | Conductor | Length (ft) | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **S02c** | 1 from | FP280201_984800474 | 943 [12.5 #4 ACS3PSn 8xa] | 564.0 | $44.24 | $45.33 | $11.20 | $101 | Per foot cost - Urban Average |
| | to | FP280103_984800473 | 1055 [12.5 477AAC3PLn 8xa] | | | | | $56,832 | Labor, Material, AFUDC, Total |
| | | | | | | | | $5,683 | Engineering = 10% of total |
| | | | | | | | | $62,515 | Total |

**Stage 2 Costs to address Potential Low Voltages**
Light Load is Controlling Case.
7 less transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 0 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 161 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 3050 |
| Heavy Load = | 8200 |
| Light Load / Heavy Load = | 0.37 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 5 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| -3 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | ($13,728) |
| -4 | transformer tap changes | (4 hrs x 3 person crew) per tap change | ($6,240) |
| -2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | ($3,120) |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | ($10,400) |
| | | Total estimated cost to resolve low voltage concerns: | ($33,488) |

The number of impacted transformers is less in stage 2 than in stage 1. No additional costs

**Stage 2 Modification Total =** $50,025

**Stage 1 + Stage 2 Modification Total = $123,639**

**Changes for Stage 3**
All changes in Stage three are to address potential low voltage.

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 1 | $3,551 | $3,551 | |
| Line regulator: wireless 'radio' link to the substation | 0 | $3,364 | $0 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 0.5 | $210,563 | $105,282 | Shared cost with 5Y610 |
| | | Subtotal: | $108,833 | |

**Stage 3 Costs to address Potential Low Voltages**
Light Load is Controlling Case
12 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 161 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 218 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 3050 |
| Heavy Load = | 8200 |
| Light Load / Heavy Load = | 0.37 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 17 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 4 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $18,304 |
| 8 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $12,480 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $15,600 |
| | | Total estimated cost to resolve low voltage concerns: | $49,504 |

**Stage 3 Modification Total =** $158,337

**Stage 1 + Stage 2 + Stage 3 Modification Total = $281,975**

## Clinton 5Y610

| Changes for Stage 1 | Node | Line | Load | Losses | Swap Phases | Staff | hours | rate | total | Work Description |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Engineer | 4 | $130 | $520 | Engineering and Analysis |
| | | | | | | Svc Line Worker | 0 | $130 | $0 | Install /Remove metering |
| **S01b** | FP278203_479410700 | 5Y610_479410265 | | | A->B | Notifier | 2 | $100 | $200 | Notify customers of outage |
| | | | | | | SVC Crew (3 person + 2 flaggers) | 3 | $520 | $1,560 | Make phase changes |
| | | | | | | Total | 9 | | $2,280 | |

| Metering | |
|---|---|
| Substation | $8,130 |
| End of Line | $9,540 |
| | $17,670 |

**Stage 1 Costs to address Potential Low Voltages**

*Light Load is Controlling Case*

| | | |
|---|---|---|
| Number of Transformers at or below 120 volts | | 16 |
| Estimated percent with secondary Vd > 4 volts | | 26.8% |
| Number of Transformers from 120 to 121 volts | | 277 |
| Estimated percent with secondary Vd > 5 volts | | 10.6% |
| Light Load = | 2707 | |
| Heavy Load = | 9250 | |
| Light Load / Heavy Load = | 0.29 | |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | | 7 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 3 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $13,728 |
| 4 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $6,240 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $10,400 |
| | | Total estimated cost to resolve low voltage concerns: | $33,488 |

**Total Stage 1 = $53,438**

| Changes for Stage 2 | | Node | Load | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|
| | | | | $6,575 | $12,136 | $2,339 | $21,049 | |
| **S02b** | Add Sw Cap | FP278510_460481740 | + 600 kVAr | | | | $2,105 | Engineering = 10% of Total |
| | | | | | | | $23,154 | |

| | | Node | Conductor | Length (ft) | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | $ 44.24 | $ 45.33 | $ 11.20 | $101 | Per foot cost - Urban Average |
| **S02c** | 1 from | FP279560_460480611 | 1083 [12.5 4/0AAC3PMn 8xa] | 576.0 | | | | $58,041 | Labor, Material, AFUDC, Total |
| | to | FP279609_460480657 | 1055 [12.5 477AAC3PLn 8xa] | | | | | $5,804 | Engineering = 10% of total |
| | | | | | | | | $63,845 | Total |

**Stage 2 Costs to address Potential Low Voltages**

*Light Load is Controlling Case.*

5 less transformers will be impacted.

| | | |
|---|---|---|
| Number of Transformers at or below 120 volts | | 0 |
| Estimated percent with secondary Vd > 4 volts | | 26.8% |
| Number of Transformers from 120 to 121 volts | | 95 |
| Estimated percent with secondary Vd > 5 volts | | 10.6% |
| Light Load = | 2707 | |
| Heavy Load = | 9250 | |
| Light Load / Heavy Load = | 0.29 | |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | | 2 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| -2 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | ($9,152) |
| -3 | transformer tap changes | (4 hrs x 3 person crew) per tap change | ($4,680) |
| -1 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | ($1,560) |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | ($7,020) |
| | | Total estimated cost to resolve low voltage concerns: | ($22,412) |

**Stage 2 Modification Total =** $64,587

**Stage 1 + Stage 2 Modification Total = $118,025**

**Changes for Stage 3**

All changes in Stage three are to address potential low voltage.

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 1 | $3,551 | $3,551 | |
| Line regulator: wireless 'radio' link to the substation | 0 | $3,364 | $0 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 0.5 | $210,563 | $105,282 | Shared cost with 5Y608 |
| | | Subtotal: | $108,833 | |

**Stage 3 Costs to address Potential Low Voltages**

Light Load is Controlling Case.

8 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 95 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 198 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 2707 |
| Heavy Load = | 9250 |
| Light Load / Heavy Load = | 0.29 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 10 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 3 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $13,728 |
| 5 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $7,800 |
| 1 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $1,560 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $10,660 |
| | | Total estimated cost to resolve low voltage concerns: | $33,748 |

**Stage 3 Modification Total =** $142,581

**Stage 1 + Stage 2 + Stage 3 Modification Total = $260,606**

## Orchard 5Y456

| Changes for Stage 1 | Node | Line | Load | Losses | Swap Phases | Staff | hours | rate | total | Work Description |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | **2 - Single Phase moves** | | | | |
| | | | | | | Engineer | 7.2 | $130 | $936 | Engineering and Analysis |
| S01a | FP168004_306160613 | 5Y456_306160060 | | | C->B | Svc Line Worker | 0 | $130 | $0 | Install /Remove metering |
| | FP213700_738390496 | 5Y456_738390191 | | | A->B | Notifier | 4 | $100 | $400 | Notify customers of outage |
| | FP163200_306160581 | 5Y456_306160113 | | | CBA->CAB | SVC Crew (3 person + 2 flaggers) | 6 | $520 | $3,120 | Make phase changes |
| | | | | | | Total | 17.2 | | $4,456 | |
| | | | | | | **Three Phase swap** | | | | |
| | | | | | | Engineer | 4 | $130 | $520 | Engineering and Analysis |
| | | | | | | Svc Line Worker | 0 | $130 | $0 | Install /Remove metering |
| | | | | | | Notifier | 4 | $100 | $400 | Notify customers of outage |
| | | | | | | SVC Crew (4 person + 2 flaggers) | 6 | $650 | $3,900 | Make phase changes |
| | | | | | | Total | 14 | | $4,820 | |
| | | | | | | | **Metering** | | | |
| | | | | | | | Substation | | $8,130 | |
| | | | | | | | End of Line | | $9,540 | |
| | | | | | | | | | $17,670 | |

**Stage 1 Costs to address Potential Low Voltages**

*HL Case is subset of LL Case w/ same number of potential transformers*

| | |
|---|---|
| Number of Transformers at or below 120 volts | 0 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 215 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 1837 |
| Heavy Load = | 7300 |
| Light Load / Heavy Load = | 0.25 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 4 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 2 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $9,152 |
| 2 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $3,120 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $6,760 |
| | | Total estimated cost to resolve low voltage concerns: | $22,152 |

**Total Stage 1 = $49,098**

| Changes for Stage 2 | | Node | Load | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|
| | | | | $6,575 | $12,136 | $2,339 | $21,049 | |
| S02b | Add Sw Cap | FP215411 | + 600 kVAr | | | | $2,105 | Engineering = 10% of Total |
| | | | | | | | $23,154 | |

| | | | Node | Conductor | Length (ft) | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| S02c | 1 | from | 7000_306160615 | 1256 [12.5 #6 CU 3 | 812.0 | $21 | $21 | $5 | $47 | Per foot cost - Urban Average |
| | | to | 7101_306161294 | 1243 [12.5 #2AAC3PSn 8xa] | | Used 4/0 Easy cost | | | $47,773 | Labor, Material, AFUDC, Total |
| | | | | | | | | | $4,777 | Engineering = 10% of total |
| | 2 | from | 7101_306161294 | 943 [12.5 #4ACS 3I | 211.0 | | | | $52,550 | Total |
| | | to | 7102_306160572 | 1243 [12.5 #2AAC3PSn 8xa] | | | | | | |
| | | | | Total reconductor= | 1023.0 | | | | | |

**Stage 2 Costs to address Potential Low Voltages**

The number of impacted transformers is less in stage 2 than in stage 1. No additional costs

**Stage 2 Modification Total =** $75,704

**Stage 1 + Stage 2 Modification Total = $124,802**

**Changes for Stage 3**

All changes in Stage three are to address potential low voltage.

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 1 | $3,551 | $3,551 | |
| Line regulator: wireless 'radio' link to the substation | 0 | $3,364 | $0 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 0.5 | $210,563 | $105,282 | |
| | | Subtotal: | $108,833 | |

**Stage 3 Costs to address Potential Low Voltages**

Heavy Load is controlling case.

7 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 46 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 34 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 11 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 3 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $13,728 |
| 4 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $6,240 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $10,400 |
| | | Total estimated cost to resolve low voltage concerns: | $33,488 |

**Stage 3 Modification Total =** $142,321

**Stage 1 + Stage 2 + Stage 3 Modification Total = $267,123**

## Orchard 5Y498

| Changes for Stage 1 | | Node | Line | Load | Losses | Swap Phases | Staff | hours | rate | total | Work Description |
|---|---|---|---|---|---|---|---|---|---|---|---|

No System Improvements necessay for Stage 1

**Stage 1 Costs to address Potential Low Voltages**
HL Case is subset of LL Case

| | |
|---|---|
| Number of Transformers at or below 120 volts | 0 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 322 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 1446 |
| Heavy Load = | 6280 |
| Light Load / Heavy Load = | 0.23 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 6 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 2 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $9,152 |
| 4 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $6,240 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $8,320 |
| | | Total estimated cost to resolve low voltage concerns: | $26,832 |

| **Metering** | |
|---|---|
| Substation | $8,130 |
| End of Line | $9,540 |
| | $17,670 |

**Total Stage 1 =** $44,502

| Changes for Stage 2 | | Node | Load | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|
| | | | | $6,575 | $10,393 | $2,121 | $19,088 | |
| **S02b** | Add Sw Cap | FP225240 | + 900 kVAr | | | | $1,909 | Engineering = 10% of Total |
| | | | | | | | $20,997 | |

**Stage 2 Costs to address Potential Low Voltages**
The number of impacted transformers is the same as in stage 1. No additional costs

**Stage 2 Modification Total =** $20,997

**Stage 1 + Stage 2 Modification Total =** $65,499

**Changes for Stage 3**

All changes in Stage three are to address potential low voltage.

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 1 | $3,551 | $3,551 | |
| Line regulator: wireless 'radio' link to the substation | 0 | $3,364 | $0 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 0.5 | $210,563 | $105,282 | |
| | | Subtotal: | $108,833 | |

**Stage 3 Costs to address Potential Low Voltages**

Heavy Load is controlling case

13 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 63 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 96 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 19 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 4 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $18,304 |
| 9 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $14,040 |
| 4 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $6,240 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $17,420 |
| | | Total estimated cost to resolve low voltage concerns: | $56,004 |

**Stage 3 Modification Total =** $164,837

**Stage 1 + Stage 2 + Stage 3 Modification Total = $230,336**

## Wiley 5Y434

| Changes for Stage 1 | Node | Line | Load | Losses | Swap Phases | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **No phase changes** | | | | | None | | | | | |
| | | | | | | **Labor** | **Material** | **AFUDC** | **Total** | |
| Add Cap | FP301903_506870503 | | 600 kVar | | | $3,071 | $2,818 | $736 | $6,624 | |
| | | | | | | | | | $662 | Engineering = 10% of Total |
| | | | | | | | | | $7,287 | |
| Add Cap | FP254905_47582199 | | 300 kVar | | | $3,071 | $5,209 | $1,076 | $9,356 | |
| | | | | | | | | | $936 | Engineering = 10% of Total |
| | | | | | | | | | $10,292 | |

| Metering | |
|---|---|
| Substation | $8,130 |
| End of Line | $9,540 |
| | $17,670 |

**Stage 1 Costs to address Potential Low Voltages**
Heavy Load is controlling case

| | |
|---|---|
| Number of Transformers at or below 120 volts | 53 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 69 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 15 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 5 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $22,880 |
| 10 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $15,600 |
| 4 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $6,240 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $20,280 |
| | | Total estimated cost to resolve low voltage concerns: | $65,000 |

**Total Stage 1 = $100,248**

| Changes for Stage 2 | | Node | Load | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | **Labor** | **Material** | **AFUDC** | **Total** | |
| **S02b** | Add Sw Cap | FP365800 | + 600 kVAr | $6,575 | $12,136 | $2,339 | $21,049 | |
| | | | | | | | $2,105 | Engineering = 10% of Total |
| | | | | | | | $23,154 | Total |

**Stage 2 Costs to address Potential Low Voltages**
The number of impacted transformers is only slightly less than in stage 1. No additional costs

**Stage 2 Modification Total=** $23,154

**Stage 1 + Stage 2 Modification Total = $123,402**

**Changes for Stage 3**
All changes in Stage three are to address potential low voltage.

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 1 | $3,551 | $3,551 | |
| Line regulator: wireless 'radio' link to the substation | 0 | $3,364 | $0 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 1 | $210,563 | $210,563 | |
| | | Subtotal: | $214,114 | |

**Stage 3 Costs to address Potential Low Voltages**
Heavy Load is controlling case.
15 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 150 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 17 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 30 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 5 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $22,880 |
| 10 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $15,600 |
| 4 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $6,240 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $20,280 |
| | | Total estimated cost to resolve low voltage concerns: | $65,000 |

**Stage 3 Modification Total =** $279,114

**Stage 1 + Stage 2 + Stage 3 Modification Total = $402,516**

## Nob Hill 5Y197

| Changes for Stage 1 | Node | Line | Load | Losses | Swap Phases |
|---|---|---|---|---|---|
| **S01a** | No Phase changes for Stage 1 | | | | |

**Stage 1 Costs to address Potential Low Voltages**
Heavy Load is controlling case

| | |
|---|---|
| Number of Transformers at or below 120 volts | 0 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 0 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 0 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 0 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $0 |
| 0 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $0 |
| 3 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $4,680 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $1,560 |
| | | Total estimated cost to resolve low voltage concerns: | $6,240 |

| **Metering** | |
|---|---|
| Substation | $8,130 |
| End of Line | $9,540 |
| | $17,670 |

**Total Stage 1 = $23,910**

| Changes for Stage 2 | | Node | Load | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|
| **S02b** | Add Sw Cap | FP365800 | + 900 kVAr | $6,575 | $12,136 | $2,339 | $21,049 | |
| | | | | | | | $2,105 | Engineering = 10% of Total |
| | | | | | | | $23,154 | Total |

**Stage 2 Costs to address Potential Low Voltages**
The number of impacted transformers is less than in stage 1. No additional costs

**Stage 2 Modification Total= $23,154**

**Stage 1 + Stage 2 Modification Total = $47,064**

**Changes for Stage 3**

All changes in Stage three are to address potential low voltage.

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 1 | $3,551 | $3,551 | |
| Line regulator: wireless 'radio' link to the substation | 0 | $3,364 | $0 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 0.33 | $210,563 | $70,188 | Shared cost with 5Y194 & 5Y273 |
| | | Subtotal: | $73,739 | |

**Stage 3 Costs to address Potential Low Voltages**

Heavy Load is controlling case

7 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 0 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 96 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 7 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 3 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $13,728 |
| 4 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $6,240 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $10,400 |
| | | Total estimated cost to resolve low voltage concerns: | $33,488 |

**Stage 3 Modification Total =** $107,227

**Stage 1 + Stage 2 + Stage 3 Modification Total = $154,291**

## Nob Hill 5Y194

| Changes for Stage 1 | | Node | Line | Load | Losses | Swap Phases | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **S01b** | Add Fixed Cap | FP2433005_991160290 | | +1200 kVAr | | | $3,071 | $3,611 | $835 | $7,517 | |
| | | | | | | | | | | $752 | Engineering = 10% of Total |
| | | | | | | | | | | $8,269 | Total |
| | Add Fixed Cap | FP242209_991162198 | | +300 kVAr | | | $3,071 | $5,209 | $1,076 | $9,356 | |
| | | | | | | | | | | $936 | Engineering = 10% of Total |
| | | | | | | | | | | $10,292 | |
| Relocate Fixed Cap | | FP242209_991162198 | | 600 kVAR | | | $6,141 | | $798 | $6,940 | |
| | | | | | | | | | | $694 | Engineering = 10% of Total |
| | | | | | | | | | | $7,633 | |

No Phase changes for Stage 1

| **Metering** | |
|---|---|
| Substation | $8,130 |
| End of Line | $9,540 |
| | $17,670 |

**Stage 1 Costs to address Potential Low Voltages**

LL Case is controlling case with HL as subset

| | |
|---|---|
| Number of Transformers at or below 120 volts | 164 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 65 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 2710 |
| Heavy Load = | 8200 |
| Light Load / Heavy Load = | 0.33 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 12 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 4 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $18,304 |
| 8 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $12,480 |
| 3 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $4,680 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $16,120 |
| | | Total estimated cost to resolve low voltage concerns: | $51,584 |

**Total Stage 1 = $95,448**

**Changes for Stage 2**

| | | Node | Load | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|
| **S02b** | Add Sw Cap | FP2433005_991160290 | + 1200 kVAr | $19,725 | $36,406 | $4,678 | $60,809 | Cost for all 3 units installed |
| | Add Sw Cap | FP242209_991162198 | + 600 kVAr | | | | $6,081 | Engineering = 10% of Total |
| | Add Sw Cap | FP242209_991162198 | +600 kVAr (only 300 kVAR needed) | | | | $66,889 | Total |
| | Remove 600 kVAr fixed bank | | | $3,071 | | $399 | $3,470 | |
| | | | | | | | $347 | Engineering = 10% of Total |
| | | | | | | | $3,817 | |
| | Credit for Stage one fixed Capacitors at the same locations | | | | | | ($26,194) | |

| | | | Node | Conductor | Length (ft) | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| **S02c** | 1 | from | MP_931350832 | 1050 [12.5 500 AL3PUGCond] | 313.0 | $6,927 | $13,105 | $2,504 | $22,536 | Urban Average Cost |
| | | to | FP999999_931350864 | 1049 [12.5 1000AL3PUGCond] | | | | | $2,254 | Engineering = 10% of Total |
| | | | | | | | | | $24,790 | Total |
| | 2 | from | FP999999_931350864 | 1097 [12.5 2/0ACS 3PSn 8xa] | 119.0 | $5,265 | $5,394 | $1,332 | $11,991 | Urban Medium Cost |
| | | to | FP269312_931350900 | 1055 [12.5 477AAC3PLn 8xa] | | | | | $1,199 | Engineering = 10% of Total |
| | | | | | | | | | $13,190 | Total |

**Stage 2 Costs to address Potential Low Voltages**

LL Case is controlling case with HL as subset.

12 less transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 0 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 0 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 2710 |
| Heavy Load = | 8200 |
| Light Load / Heavy Load = | 0.33 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 0 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| -4 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | ($18,304) |
| -8 | transformer tap changes | (4 hrs x 3 person crew) per tap change | ($12,480) |
| -2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | ($3,120) |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | ($15,600) |
| | | Total estimated cost to resolve low voltage concerns: | ($49,504) |

**Stage 2 Modification Total=** $32,988

**Stage 1 + Stage 2 Modification Total =** $128,436

**Changes for Stage 3**

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 1 | $3,551 | $3,551 | |
| Line regulator: wireless 'radio' link to the substation | 0 | $3,364 | $0 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 0.33 | $210,563 | $70,188 | Shared cost with 5Y197 and 5Y273 |
| | | Subtotal: | $73,739 | |

**Stage 3 Costs to address Potential Low Voltages**

LL Case is controlling case with HL as subset.

24 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 355 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 65 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 2710 |
| Heavy Load = | 8200 |
| Light Load / Heavy Load = | 0.33 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 24 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 8 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $36,608 |
| 16 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $24,960 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $30,160 |
| | | Total estimated cost to resolve low voltage concerns: | $94,848 |

**Stage 3 Modification Total =** $168,587

**Stage 1 + Stage 2 + Stage 3 Modification Total =** $297,023

## Nob Hill 5Y273

| | Changes for Stage 1 | Node | Line | Load | Losses | Swap Phases | Staff | hours | rate | total | Work Description |
|---|---|---|---|---|---|---|---|---|---|---|---|
| S01a | FP264901_656800698 | 5Y273_656800259 | | | | C->A | Engineer | 4 | 130 | 520 | Engineering and Analysis |
| | | | | | | | Svc Line Worker | 0 | 130 | 0 | Install /Remove metering |
| | | | | | | | Notifier | 2 | 100 | 200 | Notify customers of outage |
| | | | | | | | SVC Crew (3 person + 2 flaggers) | 3 | 520 | 1560 | Make phase changes |
| | | | | | | | Total | 9 | | $2,280 | |
| S01b | Remove Cap | FP239106_556790602 | | | | - 600 kVar | Engineer | 4 | 130 | 520 | Engineering & Admin |
| | | | | | | | SVC Crew (3 person + 2 flaggers) | 4 | 520 | 2080 | Remove Cap Bank |
| | | | | | | | | | | 2600 | |

**Metering**

| | |
|---|---|
| Substation | $8,130 |
| End of Line | $9,540 |
| | $17,670 |

**Stage 1 Costs to address Potential Low Voltages**

LL Case is controlling case with HL as subset

| | |
|---|---|
| Number of Transformers at or below 120 volts | 463 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 0 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 2324 |
| Heavy Load = | 8080 |
| Light Load / Heavy Load = | 0.29 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 25 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 8 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $36,608 |
| 17 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $26,520 |
| 6 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $9,360 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $33,020 |
| | | Total estimated cost to resolve low voltage concerns: | $105,508 |

**Total Stage 1 = $128,058**

**Changes for Stage-2** | **Node** | **Load**

| | | | | | **Labor** | **Material** | **AFUDC** | **Total** | |
|---|---|---|---|---|---|---|---|---|---|
| **S02b** | Add Sw Cap | FP239106_556790602 | + 600 kVAr | | $13,149 | $24,271 | $4,678 | $42,098 | Cost are for both units installed |
| | Add Sw Cap | FP268700 | + 600 kVAr | | | | | $4,210 | Engineering = 10% of Total |
| | | | | | | | | $46,308 | Total |

**Stage 2 Costs to address Potential Low Voltages**
LL Case is controlling case with HL as subset.
16 less transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 0 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 420 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 2324 |
| Heavy Load = | 8080 |
| Light Load / Heavy Load = | 0.29 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 9 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| -5 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | ($22,880) |
| -11 | transformer tap changes | (4 hrs x 3 person crew) per tap change | ($17,160) |
| -4 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | ($6,240) |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | ($21,060) |
| | | Total estimated cost to resolve low voltage concerns: | ($67,340) |

**Stage 2 Modification Total =** ($21,032)

**Stage 1 + Stage 2 Modification Total =** $107,026

**Changes for Stage 3**

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 1 | $3,551 | $3,551 | |
| Line regulator: wireless 'radio' link to the substation | 0 | $3,364 | $0 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 0.33 | $210,563 | $70,188 | Shared cost w/ 5Y194 and 5Y197 |
| | | Subtotal: | $73,739 | |

**Stage 3 Costs to address Potential Low Voltages**
LL Case is controlling case with HL as subset.
15 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 420 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 43 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 2324 |
| Heavy Load = | 8080 |
| Light Load / Heavy Load = | 0.29 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 24 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 5 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $22,880 |
| 10 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $15,600 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $19,240 |
| | | Total estimated cost to resolve low voltage concerns: | $60,840 |

**Stage 3 Modification Total =** $134,579

**Stage 1 + Stage 2 + Stage 3 Modification Total = $241,604**

## North Park 5Y356

| Changes for Stage 1 | | Node | Line | Load | Losses | Swap Phases |
|---|---|---|---|---|---|---|
| S01a | | No Line/Phase swaping needed | | | | |
| S01b | Remove Cap | FP219900_826650557 | | -900 kVar | | |

| | Qty | Rate | Amount | |
|---|---|---|---|---|
| Engineer | 4 | 130 | 520 | Engineering & Admin |
| SVC Crew (3 person + 2 flaggers) | 4 | 520 | 2080 | Remove Cap Bank |
| | | | 2600 | |

**Metering**

| | |
|---|---|
| Substation | $8,130 |
| End of Line | $9,540 |
| | $17,670 |

**Stage 1 Costs to address Potential Low Voltages**
Heavy Load is controlling case

| | |
|---|---|
| Number of Transformers at or below 120 volts | 158 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 73 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 35 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 11 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $50,336 |
| 24 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $37,440 |
| 8 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $12,480 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $45,760 |
| | | Total estimated cost to resolve low voltage concerns: | $146,016 |

**Total Stage 1 = $166,286**

| Changes for Stage 2 | | Node | | Load | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | $6,575 | $10,393 | $2,121 | $19,088 | |
| S02b | Add Sw Cap | FP219900_826650557 | | +900 kVar | | | | $1,909 | Engineering = 10% of Total |
| | | | | | | | | $20,997 | |

| | | Node | Conductor | Length (ft) | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|---|
| S02c | 1 from | FP178002_640300540 | 1083 [12.5 4/0AAC3PMn 8xa] | 607.0 | $26,854 | $27,515 | $6,796 | $61,165 | Urban Average Cost |
| | to | FPUNK_640300538 | 1055 [12.5 477AAC3PLn 8xa] | | | | | $6,117 | Engineering = 10% of Total |
| | | | | | | | | $67,282 | Total |

| | | | | | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|---|
| S02e | Line Regulator | FP160001_274180881 | 5Y356_274180328-SP1 | [Id = 602] 328 A 3Ph 16 step 3x180 kVA | $11,110 | $47,553 | $7,333 | $65,995 | Per Block Estimate |
| | | | | | | | | $6,599 | Engineering = 10% of total |
| | | | | | | | | $72,594 | |

**Metering**

| | |
|---|---|
| Regulator | $16,000 |
| End of Line | $9,540 |
| | 25540 |

**Stage 2 Costs to address Potential Low Voltages**

LL Case is controlling case with HL as subset.

29 less transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 0 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 232 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 2496 |
| Heavy Load = | 6800 |
| Light Load / Heavy Load = | 0.37 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 6 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| -9 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | ($41,184) |
| -20 | transformer tap changes | (4 hrs x 3 person crew) per tap change | ($31,200) |
| -7 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | ($10,920) |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | ($37,960) |
| | | Total estimated cost to resolve low voltage concerns: | ($121,264) |

**Stage 2 Costs to address Potential Low Voltages**

The number of impacted transformers is approximately the same as stage 1. No additional costs

**Stage 2 Modification Total =** $65,149

**Stage 1 + Stage 2 Modification Total =** $231,435

**Changes for Stage 3**

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 2 | $3,551 | $7,102 | |
| Line regulator: wireless 'radio' link to the substation | 1 | $3,364 | $3,364 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 1 | $210,563 | $210,563 | |
| | | Subtotal: | $221,029 | |

**Stage 3 Costs to address Potential Low Voltages**

LL Case is controlling case with HL as subset.

17 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 232 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 244 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 2496 |
| Heavy Load = | 6800 |
| Light Load / Heavy Load = | 0.37 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 23 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 6 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $27,456 |
| 11 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $17,160 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $22,100 |
| | | Total estimated cost to resolve low voltage concerns: | $69,836 |

**Stage 3 Modification Total =** $290,865

**Stage 1 + Stage 2 + Stage 3 Modification Total = $522,300**

## River Road 5Y444

| Changes for Stage 1 | | Node | Line | Load | Losses | Swap Phases |
|---|---|---|---|---|---|---|
| S01a | | FP150014_154241218 | 5Y444_154240243 | | | A -> C |
| | | FP157000_154241204 | 5Y444_154240477 | | | A -> C |
| | | FP156080_154241134 | 5Y444_154240377 | | | A -> C |
| S01b | Reduce Cap | FP237905_419030342 | | 1200 kVAr -> 600 kVAr | | |

**Three - 1 Phase swap**

| | | | | |
|---|---|---|---|---|
| Engineer | 12 | $130 | $1,560 | Engineering and Analysis |
| Svc Line Worker | 0 | $130 | $0 | Install /Remove metering |
| Notifier | 6 | $100 | $600 | Notify customers of outage |
| SVC Crew (4 person + 2 flaggers) | 9 | $520 | $4,680 | Make phase changes |
| Total | 27 | | $6,840 | |

| Labor | Material | AFUDC | Total | |
|---|---|---|---|---|
| $8,000 | $500 | $0 | $8,500 | |
| | | | $850 | Engineering = 10% of Total |
| | | | $9,350 | |

**Metering**

| | |
|---|---|
| Substation | $8,130 |
| End of Line | $9,540 |
| | $17,670 |

**Stage 1 Costs to address Potential Low Voltages**

For Stage 1 LL Case is controlling case with HL as subset

| | |
|---|---|
| Number of Transformers at or below 120 volts | 43 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 406 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 3314 |
| Heavy Load = | 10600 |
| Light Load / Heavy Load = | 0.31 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 12 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 4 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $18,304 |
| 8 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $12,480 |
| 3 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $4,680 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $16,120 |
| | | Total estimated cost to resolve low voltage concerns: | $51,584 |

**Total Stage 1 = $85,444**

**Changes for Stage 2** | **Node** | **Load**

| | | | | | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|---|
| **S02b** | Add Sw Cap | FP232945 | + 600 kVAr | | | | | | |
| | Add Sw Cap | FP147243 | + 600 kVAr | | $13,149 | $24,271 | $4,678 | $42,098 | Cost are for both units installed |
| | | | | | | | | $4,210 | Engineering = 10% of Total |
| | | | | | | | | $46,308 | Total |

| | | Node | Conductor | Length (ft) | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **S02c** | 1 from | FP158001_80630559 | 1256 [12.5 #6 CU 3PSn 8xa] | 106.0 | $21 | $21 | $5 | $47 | Per foot cost - Urban Average |
| | to | FP158002_154241123 | 17 [12.5 1/0ACS3PSn 8xa] | | Used 4/0 Easy cost | | | $31,195 | Labor, Material, AFUDC, Total |
| | | | | | | | | $3,119 | Engineering = 10% of total |
| | 2 from | FP158002_154241123 | 938 [12.5 #2 ACS 3PSn 8xa] | 562.0 | | | | $34,314 | Total |
| | to | FP158104_154241172 | 17 [12.5 1/0ACS3PSn 8xa] | | | | | | |
| | | | Total Reconductor = | 668.0 | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **S02e** | Add Regulator | FP141001_33500763 | 5Y444_1031038802-SP1 | [Id = 602] 328 A 3Ph 16 step 3x180 kVA | $11,110 | $47,553 | $7,333 | $65,995 | Per Block Estimate |
| | | | | | | | | $6,599 | Engineering = 10% of total |
| | | | | | | | | $72,594 | |

| **Metering** | |
|---|---|
| Regulator | $16,000 |
| End of Line | $9,540 |
| | $25,540 |

**Stage 2 Costs to address Potential Low Voltages**

The number of impacted transformers is the same as stage 1. No additional costs

**Stage 2 Modification Total=** $178,757

**Stage 1 + Stage 2 Modification Total =** $264,201

**Changes for Stage 3**

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 2 | $3,551 | $7,102 | |
| Line regulator: wireless 'radio' link to the substation | 1 | $3,364 | $3,364 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 1 | $210,563 | $210,563 | |
| | | Subtotal: | $221,029 | |

**Stage 3 Costs to address Potential Low Voltages**

Heavy Load is controlling case for Stage 3.

16 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 57 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 251 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 28 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 5 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $22,880 |
| 11 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $17,160 |
| 4 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $6,240 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $21,060 |
| | | Total estimated cost to resolve low voltage concerns: | $67,340 |

**Stage 3 Modification Total =** $288,369

**Stage 1 + Stage 2 + Stage 3 Modification Total = $552,570**

## Sunnyside 5Y313

### Changes for Stage 1

| | | | Node | Line | Load | Labor | Material | AFUDC | Total | Work Description |
|---|---|---|---|---|---|---|---|---|---|---|
| **5Y313** | **S01b** | 1. Reduce Cap | FP251510_823200918 | | 1200 kVAr --> 900 kVAr | $8,000 | $500 | $0 | $8,500 | |
| | | | | | | | | | $850 | Engineering = 10% of Total |
| | | | | | | | | | $9,350 | |

| Metering | Total |
|---|---|
| Substation | $8,130 |
| **End of Line** | $9,540 |
| | $17,670 |

**Stage 1 Costs to address Potential Low Voltages**
Light Load is Controlling Case.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 21 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 198 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 1583 |
| Heavy Load = | 4500 |
| Light Load / Heavy Load = | 0.35 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 7 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 3 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $13,728 |
| 4 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $6,240 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $10,400 |
| | | Total estimated cost to resolve low voltage concerns: | $33,488 |

**Total Stage 1 = $60,508**

### Changes for Stage 2

| | | | Node | Line | Load | Labor | Material | AFUDC | Total | Work Description |
|---|---|---|---|---|---|---|---|---|---|---|
| **5Y313** | **S02b** | 1 New Switche | FP251902_823200877 | | +SW 600 kVAr | $6,575 | $12,136 | $2,339 | $21,049 | |
| | | | | | | | | | $2,105 | Engineering = 10% of Total |
| | | | | | | **$0.13** | | | $23,154 | |
| | | 2 New Switche | FP269202_42390692 | | +SW 300 kVAr | $6,575 | $5,209 | $1,532 | $13,316 | |
| | | | | | | | | | $1,332 | Engineering = 10% of Total |
| | | | | | | | | | $14,647 | |

**Stage 2 Costs to address Potential Low Voltages**
The number of transformers is basically the same as Stage 1 - no additional costs

Stage 2 Modification Total= $37,801

**Stage 1 + Stage 2 Modification Total = $98,309**

**Changes for Stage 3**

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 1 | $3,551 | $3,551 | |
| Line regulator: wireless 'radio' link to the substation | 0 | $3,364 | $0 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 0.5 | $210,563 | $105,282 | Shared cost with 5Y317 |
| | | Subtotal: | $108,833 | |

**Stage 3 Costs to address Potential Low Voltages**

Light Load is Controlling Case.

8 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 209 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 18 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 1583 |
| Heavy Load = | 4500 |
| Light Load / Heavy Load = | 0.35 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 15 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 3 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $13,728 |
| 5 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $7,800 |
| 1 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $1,560 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $10,660 |
| | | Total estimated cost to resolve low voltage concerns: | $33,748 |

Stage 3 Modification Total= $142,581

**Stage 1 + Stage 2 + Stage 3 Modification Total = $240,890**

## Sunnyside 5Y317

| Changes for Stage 1 | | Node | Line | Load | Swap Phases |
|---|---|---|---|---|---|
| **5Y317** | **S01a** | FP257504_823200895 | 5Y317_823200406 | | B-->A |
| | | | 5Y317_823200313 | | ABC-->ACB |
| | | | | TR_257501_823200453 | A-->B |

Two 1-phase changes (tap and transformer)

| Staff | hours | rate | total | Work Description |
|---|---|---|---|---|
| Engineer | 6 | $130 | $780 | Engineering and Analysis |
| Svc Line Worker | 0 | $130 | $0 | Install /Remove metering |
| Notifier | 3 | $100 | $300 | Notify customers of outage |
| SVC Crew (3 person + 2 flaggers) | 6 | $520 | $3,120 | Make phase changes |
| Total | 15 | | $4,200 | |

**One - Three Phase swap**

| | | | | |
|---|---|---|---|---|
| Engineer | 4 | $130 | $520 | Engineering and Analysis |
| Svc Line Worker | 0 | $130 | $0 | Install /Remove metering |
| Notifier | 4 | $100 | $400 | Notify customers of outage |
| SVC Crew (4 person + 2 flaggers) | 6 | $650 | $3,900 | Make phase changes |
| Total | 14 | | $4,820 | |

| **Metering** | | |
|---|---|---|
| Substation | $8,130 | |
| **End of Line** | $9,540 | |
| | $17,670 | total metering |

**Stage 1 Costs to address Potential Low Voltages**

The number of transformers with potentially low secondary voltage = 0

**Total Stage 1 =** $26,690

| Changes for Stage 2 | | Node | Line | Load | Labor | Material | AFUDC | Total | |
|---|---|---|---|---|---|---|---|---|---|
| **S02b** | New Switched | FP256511_937580500 | | +SW 600 kVAr | $6,575 | $12,136 | $2,339 | $21,049 | |
| | | | | | | | | $2,105 | Engineering = 10% of Total |
| | | | | | | | | $23,154 | |

**Stage 2 Costs to address Potential Low Voltages**

The number of transformers with potentially low secondary voltage = 0

Stage 2 Modification Total= $23,154

**Stage 1 + Stage 2 Modification Total =** $49,844

**Changes for Stage 3**

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 2 | $3,551 | $7,102 | |
| Line regulator: wireless 'radio' link to the substation | 1 | $3,364 | $3,364 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 0.5 | $210,563 | $105,282 | Shared cost with 5Y313 |
| | | Subtotal: | $115,748 | |

**Stage 3 Costs to address Potential Low Voltages**

Light Load is Controlling Case.

9 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 135 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 19 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 1279 |
| Heavy Load = | 4000 |
| Light Load / Heavy Load = | 0.32 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 9 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 3 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $13,728 |
| 6 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $9,360 |
| 2 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $3,120 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $11,960 |
| | | Total estimated cost to resolve low voltage concerns: | $38,168 |

Stage 3 Modification Total= $153,916

**Stage 1 + Stage 2 + Stage 3 Modification Total = $203,759**

## Grandview 5Y351

| Changes for Stage 1 | | | Node | Line | | Load | Losses | Swap Phases |
|---|---|---|---|---|---|---|---|---|
| **5Y351** | **S01a** | | FP274501_564110792 | 5Y351_564110009 | | | | BAC --> ABC |
| **5Y351** | **S01b** | Reduce Cap | FP227502_728880503 | | Fixed | 600 kVAr --> 300 kVAr | | |

**One - Three Phase swap**

| | | | | |
|---|---|---|---|---|
| Engineer | 4 | $130 | $520 | Engineering and Analysis |
| Svc Line Worker | 0 | $130 | $0 | Install /Remove metering |
| Notifier | 4 | $100 | $400 | Notify customers of outage |
| SVC Crew (4 person + 2 flaggers) | 6 | $650 | $3,900 | Make phase changes |
| Total | 14 | | $4,820 | |

| Labor | Material | AFUDC | Total | |
|---|---|---|---|---|
| $8,000 | $500 | $0 | $8,500 | |
| | | | $850 | Engineering = 10% of Total |
| | | | $9,350 | |

| Metering | | |
|---|---|---|
| Substation | $8,130 | |
| **End of Line** | $9,540 | |
| | $17,670 | total metering |

**Stage 1 Costs to address Potential Low Voltages**
Heavy Load is Controlling Case.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 19 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 20 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 5 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 2 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $9,152 |
| 3 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $4,680 |
| 1 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $1,560 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $7,020 |
| | | Total estimated cost to resolve low voltage concerns: | $22,412 |

**Total Stage 1 = $54,252**

---

| Changes for Stage 2 | | | Node | Line | | |
|---|---|---|---|---|---|---|
| **5Y351** | **S02b** | Add Sw Cap | FP229907_1040375491 | | Switched | 600 kVAr |
| | | Add Sw Cap | FP226502_728882270 | | Switched | 600 kVAr |
| | | Add Regulator | FP226205_728880766 | 5Y351_728880260-SP1 | | |
| | | [Id = 63] | 219 A 3Ph 16 step 3x180 kVA | Flow (kVA) = | 855.1 | |

Costs to install both capacitor banks

| Labor | Material | AFUDC | Total | |
|---|---|---|---|---|
| $13,149 | $24,271 | $4,678 | $42,098 | |
| | | | $4,210 | Engineering = 10% of Total |
| **$0.13** | | | $46,308 | |
| $11,110 | $40,480 | $6,449 | $58,038 | |
| | | | $5,804 | Engineering = 10% of Total |
| | | | $63,842 | |

| Metering | |
|---|---|
| Regulator | $16,000 |
| End of Line | $9,540 |
| | $25,540 |

**Stage 2 Costs to address Potential Low Voltages**

Light Load is Controlling Case.

7 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 155 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 174 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Light Load = | 2171 |
| Heavy Load = | 7700 |
| Light Load / Heavy Load = | 0.28 |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 12 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 3 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $13,728 |
| 4 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $6,240 |
| 1 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $1,560 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $9,880 |
| | | Total estimated cost to resolve low voltage concerns: | $31,408 |

Stage 2 Modification Total= $167,097

**Stage 1 + Stage 2 Modification Total = $221,349**

**Changes for Stage 3**

| Work Description | No. of locations | Cost per location | Total | Notes |
|---|---|---|---|---|
| End of 1ph voltage control zone: wireless 'radio' link to substation | 1 | $3,551 | $3,551 | |
| Line regulator: wireless 'radio' link to the substation | 0 | $3,364 | $0 | |
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | 1 | $210,563 | $210,563 | |
| | | Subtotal: | $214,114 | |

**Stage 3 Costs to address Potential Low Voltages**

Heavy Load is Controlling Case.

8 more transformers will be impacted.

| | |
|---|---|
| Number of Transformers at or below 120 volts | 63 |
| Estimated percent with secondary Vd > 4 volts | 26.8% |
| Number of Transformers from 120 to 121 volts | 111 |
| Estimated percent with secondary Vd > 5 volts | 10.6% |
| Estimated total number of transformers that may have customers with low voltage at Service Entrance = | 20 |

Assumed Solution:

| Qty. (ea) | Work Description | Assumptions | Total |
|---|---|---|---|
| 3 | transformer change out | (8 hrs x 4 person crew) + 10% of labor for material - per unit | $13,728 |
| 5 | transformer tap changes | (4 hrs x 3 person crew) per tap change | $7,800 |
| 1 | service change out | (4 hrs x 2 person crew) + 50% of labor for material - per unit | $1,560 |
| | Planning and Engineering | (Estimated to be 50% of Crew Labor) | $10,660 |
| | | Total estimated cost to resolve low voltage concerns: | $33,748 |

Stage 3 Modification Total = $247,862

**Stage 1 + Stage 2 + Stage 3 Modification Total = $469,211**

# Appendix 11: High and Low Voltage Reports

**John P. White**

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**From:** Pierce, Wyatt [Wyatt.Pierce@PacifiCorp.com]
**Sent:** Wednesday, April 06, 2011 3:16 PM
**To:** John P. White
**Subject:** Revised OPQ list
**Attachments:** Voltage OPQ List for Tier 1 Circuits version 2.xlsx

John,

As promised, here is a new version of the OPQ sheet, which I think looks better. It's the same data except for one row. Doug informed me that the third OPQ on the old list was not an issue, so I removed it.

Thanks,

Wyatt W. Pierce, PE
**Pacific Power**
**NID Support & Special Projects**
**Desk:** 541•633•2481
**Cell:** 541•848•7970

| Feeder | Request Date | OPQ Number | Voltage | Request Description | Xfmr ID | Comments |
|---|---|---|---|---|---|---|
| 4W22 | 10/20/2005 | **2737162** | Maybe | PLEASE INVESTIGATE, CUST IS EXPERIENCING LOW VOLTAGE DUE TOSOME UPGRADES IN HIS AREA BECAUSE OF CONSTRUCTION AROUND HIM, HE FEELS HIS SERVICE HAS BEE | TR_126582_726180197 | CONCLUSION UNKNOWN. |
| 4W22 | 11/16/2005 | **2751051** | Yes | PLEASE INVESTIGATE, CUST IS EXPERIENCING LOW VOLTAGE DUE TOSOME UPGRADES IN HIS AREA BECAUSE OF CONSTRUCTION. SINCE UPGRADE, HAS HAD LOW VOLTAGE. NOT | TR_126582_726180197 | A SECTIONALIZER WAS ADDED TO REDUCE THE SECONDARY LENGTH. |
| 5W116 | 2/25/2009 | **5288343** | Yes | PLEASE INVESTIGATE. LIGHT BULBS HAVE BEEN BURNING OUT TOO FAST. THEIR ELECTRICIAN THINKS TOO MUCH VOLTAGE IS COMING IN AND 312 N DIVISION AND 314 N DI | TR_212704_122450256 | POSSIBLY LIGHTLY LOADED PHASE, CLOSE TO SUB. |
| 5W116 | 6/21/2010 | **5444889** | Yes | FLICKERING LIGHTS - CUSTOMER HAS INSTALLED A HEAT PUMP WITHOUT INFORMING US. SET RVM PER REQUEST OF DOUG G/ENGINEER. | TR_161001_755430222 | CUSTOMER INTRODUCED NEW 9% FLICKER. |
| 5W127 | 11/22/2010 | **5496672** | Yes | PLEASE INVESTIGATE CUST GETTING DIMMING LIGHTS WHEN RUNNINGA SAW IN THE GARRAGE. AN ELECTRICTION STATED THAT SHE THOUGHT THAT OUR LINE FROM THE POLE T | TR_281801_544870376 | STEADY STATE 113V UNDER LOAD, 7% FLICKER. |
| 5W154 | 8/17/2004 | **2508998** | Maybe | PLEASE INVESTIGATE. CUSTOMER IS EXPERIENCING POWER FLUCTUATIONS. SOMETIMES JUST MINUTES APART, SOMETIMES HOURS APART. THE VOLTAGE SEEMS TO DECREASE | TR_358607_369970338 | FAR FROM SUB; CONCLUSION UNKNOWN. |
| 5W342 | 2/26/2007 | **2984768** | Yes | CUSTOMER'S LIGHTS DIM WHEN HEAT PUMP STARTS UP. PLEASESET MR-4 | TR_355402_463490102 | NEW HEAT PUMP, NEW 5.4% DIP. |
| 5Y317 | 12/10/2008 | **5266498** | Yes | PLEASE INVESTIGATE. STATES THAT THEY HAVE A LOT OF LIGHT BULBS BURN OUT. NO ISSUES WITH BREAKERS GOING OFF A LOT THOUGH. LAND LORD TOLD THEM THAT 130V | TR_255603_823200514 | POSSIBLY LIGHTLY LOADED PHASE, CLOSE TO SUB. |
| 5Y351 | 1/3/2011 | **5507484** | Yes | FROM DMS# 674204: CUST STATES VOLTAGE AT SITE IS 515, SVCMANWAS ALREADY AT THIS SITE, ASKED US TO CREATE A REQUEST | TR_230801_858280420 | WE MEASURED 515V ON 480V SYSTEM. WE LOWERED THE VOLTAGE. |
| 5Y356 | 7/22/2003 | **2303616** | Maybe | DMS ORDER HAS BEEN SENT. PLEASE INVESTIGATE VOLT ISSUES THAT ARE CAUSING CUSTOMER TO LOSE POWER AND, IN SEVERAL CASES, LOSE APPLIANCES. CUSTOMER HAS | TR_157583_1031037258 | FAR FROM SUB; CONCLUSION UNKNOWN. |
| 5Y456 | 7/30/2010 | **5458766** | Yes | KEN MARTIN EXPERIENCES BROWN OUTS EVERYTIME TURNS ON AC. LIGHTING DIMS CANNOT RECEIVE ANY POWER. HAS HAD ELECTRICIAN TOSITE STATES NOT INTERNAL. HAPPE | TR_164180_306160252 | CUST ADDED A/C. |
| 5Y498 | 1/30/2009 | **5280544** | Yes | PLEASE INVESTIGATE WHEN FURNACE COMES ON ELECTRICIAN TOLD HIM THERE IS NOT ENOUGH VOLTAGE COMING TO THE HOME PLS CHECK THIS HAPPENS DAILY THANKS CUSTO | TR_229202_185300510 | CUSTOMER WAS ALREADY NEAR LIMIT AND THEN ADDED LOAD. |

# Appendix 12: Summary of Study Data

| Circuit No. | 5W150 | 5W154 | 5W22 | 5W116 | 5W127 | 5W342 | 5Y608 | 5Y610 | 5Y194 | 5Y197 | 5Y273 | 5Y356 | 5Y456 | 5Y498 | 5Y434 | 5Y444 | 5Y351 | 5Y313 | 5Y317 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Substation | BOWMAN | BOWMAN | DODD RD | MILL CREEK | MILL CREEK | POMEROY | CLINTON | CLINTON | NOB HILL | NOB HILL | NOB HILL | NORTH PARK | ORCHARD | ORCHARD | WILEY | RIVER ROAD | GRANDVIEW | SUNNYSIDE | SUNNYSIDE |
| Circuit Name | PINE STREET | GARDEN | WINDWARD | GREEN PARK | WILBUR | POMEROY | IKE | BOULEVARD | 16TH AVE | TWELFTH AVE. | 18TH AVE | FREEWAY | COWICHE | PEACH | DAZET | WRIGHT | EUCLID | CARNATION | EDISON |
| **Base Case** | T3853 | T3853 | T1202 | T3406 | T3406 | T3303 | T3716 | T3716 | T2430 | T2430 | T2402 | T3536 | T5035 | T3797 | T3676 | T3453 | T859 | T3570 | T3570 |
| **Feeder VCZ (lowest voltage)** | 114.7V | 120.9 | 119.5V | 118.5V | 118.8V | 119.0V | 116.0V | 118.1V | 118.3 | 121.1V | 119.7 | 118.9V | 119.7V | 122.3V | 116.1V | 120.1 | 122.1 | 121.5 | 122.8 |
| Existing VD% (peak Load) | 7.2 | 2.0 | 7.3 | 4.5 | 4.2 | 4.6 | 5.2 | 3.3 | 4.2 | 1.8 | 3.5 | 5.5 | 5.3 | 3.3 | 5.2 | 4.3 | 4.5 | 3.5 | 2.3 |
| Existing V-Rise (Peak Load) | 2.3 | 2.3 | 7.2 | 0.0 | 0.0 | 1.7 | 1.2 | 1.2 | 2.3 | 2.3 | 2.9 | 4.5 | 5.0 | 5.2 | 2.4 | 4.3 | 6.5 | 4.7 | 4.7 |
| Existing V-Set (No Load) | 121.0 | 121.0 | 121.0 | 124.0 | 124.0 | 123.0 | 121.0 | 121.0 | **121.0** | **121.0** | 121.0 | 121.0 | 121.0 | 121.0 | 120.0 | 121.0 | 121.0 | 121.0 | 121.0 |
| Existing kW Demand (Fdr) | 6,715.0 | 8,198.8 | 8,699.4 | 8,097.3 | 6,218.4 | 6,040.3 | 8,197.7 | 9,247.6 | 8,366.3 | 5,899.4 | 7,984.8 | 6,790.0 | 7,297.7 | 6,277.7 | 6,992.1 | 10,595.0 | 7,699.4 | 4,999.0 | 3,999.8 |
| Existing kW Demand (Reg 1) | 2,683.2 | | | | | | | | | | | | | | | | | | |
| **Regulator 1 VCZ** | | | | | | | | | | | | | | | | | | | |
| Existing VD% (peak Load) | 3.8 | | | | | | | | | | | | | | | | | | |
| Existing V-Rise (Peak Load) | 4.7 | | | | | | | | | | | | | | | | | | |
| Existing V-Set (No Load) | 120.0 | | | | | | | | | | | | | | | | | | |
| Existing kW Demand (Reg 1) | 2,683.2 | | | | | | | | | | | | | | | | | | |
| Existing kW Demand (Reg 2) | 0.0 | | | | | | | | | | | | | | | | | | |
| **Customers** | 1,796 | 1,823 | 1,181 | 2,053 | 1,968 | 1,204 | 2,037 | 1,401 | 1,572 | 1,873 | 2,216 | 1,634 | 1,421 | 1,751 | 1,332 | 2,201 | 1,286 | 1,020 | 978 |
| **Annual MWh** | 33,096.3 | 37,063.7 | 39,919.8 | 34,126.5 | 29,177.6 | 22,784.2 | 41,300.1 | 43,295.5 | 42,555.0 | 30,678.7 | 35,323.2 | 30,777.6 | 28,932.5 | 27,289.5 | 27,725.6 | 49,558.0 | 33,271.6 | 20,864.7 | 19,867.6 |
| **kW Line Loss** | 325.2 | 98.8 | 288.9 | 122.6 | 65.7 | 194.1 | 113.0 | 128.8 | 165.1 | 44.7 | 150.2 | 231.7 | 124.3 | 91.7 | 144.8 | 186.1 | 76.9 | 86.8 | 49.6 |
| **Connected Ttransfomers kVA** | 23,831.0 | 24,580.5 | 29,034.5 | 17,726.0 | 15,105.0 | 16,801.0 | 22,603.5 | 20,066.0 | 19,095.5 | 12,613.5 | 16,377.5 | 20,180.0 | 16,682.0 | 12,638.0 | 18,624.0 | 25,987.0 | 20,980.4 | 11,851.5 | 9,579.6 |
| **Heat Zone** | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **Cool Zone** | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **% w/ A/C** | 95% | 95% | 95% | 95% | 95% | 85% | 90% | 85% | 85% | 85% | 85% | 85% | 95% | 85% | 90% | 80% | 80% | 75% | 70% |
| **% w/ non-e heat** | 90% | 90% | 60% | 90% | 90% | 60% | 50% | 100% | 100% | 100% | 100% | 80% | 98% | 100% | 80% | 97% | 95% | 95% | 99% |
| **VO factor** | 0.64 | 0.64 | 0.52 | 0.64 | 0.64 | 0.51 | 0.64 | 0.64 | 0.64 | 0.64 | 0.64 | 0.64 | 0.64 | 0.64 | 0.64 | 0.64 | 0.65 | 0.65 | 0.65 |
| **Stage 1 Case** | NC | | NC | | | NC | | | | | | NC | NC | | | | NC | | |
| **Feeder VCZ** | | | | | | | | | | | | | | | | | | | |
| C Max VD% (peak Load) | 7.2 | 2.0 | 7.3 | 4.5 | 2.8 | 4.6 | 3.7 | 3.3 | 4.2 | 1.8 | 3.5 | 5.5 | 5.3 | 3.3 | 4.1 | 4.3 | 4.5 | 3.5 | 2.3 |
| C V-Rise (Peak Load) | 8.6 | 2.3 | 8.7 | 2.5 | 5.9 | 3.7 | 5.4 | 5.4 | 2.3+2.7 | 2.3+1.7 | 2.9+1.3 | 6.6 | 6.3 | 5.2 | 4.7 | 5.2 | 6.5 | 4.7 | 4.7 |
| C V-Set (No Load) | 121 | 121 | 121 | 124 | 120 | 123 | 120 | 120 | **121** | **121** | 121 | 121 | 121 | 121 | 121 | 121 | 121 | 121.0 | 121.0 |
| C kW Demand (Fdr) | 6715.0 | 8198.8 | 8699.4 | 8097.3 | 6218.4 | 6040.3 | 8197.7 | 9247.6 | 8366.3 | 5899.4 | 7984.8 | 6790.0 | 7297.7 | 6277.7 | 6992.1 | 10595.0 | 7699.4 | 4,999.0 | 3,999.8 |
| C kW Demand (Reg 1) | 2683.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Post-VO Max VD% (peak Load) | 7.1 | 2.0 | 6.6 | 4.4 | 2.8 | 6.0 | 3.7 | 3.3 | 3.3 | 1.8 | 3.8 | 6.6 | 3.6 | 3.3 | 4.1 | 4.7 | 4.9 | 3.5 | 2.1 |
| Post-VO V-Rise (Peak Load) | 4.0 | 2.3 | 5.0 | 5.9 | 5.9 | 1.7 | 5.4 | 5.4 | 3.5 | 3.5 | 6.6 | 9.0 | 4.9 | 4.3 | 4.7 | 5.6 | 6.4 | 3.2 | 3.2 |
| Post-VO V-Set (No Load) | 121.0 | 120.0 | 120.0 | 119.0 | 119.0 | 123.0 | 119.0 | 119.0 | 120.0 | 120.0 | 118.0 | 116.0 | 120.0 | 120.0 | 120.0 | 120.0 | 119.0 | 121.0 | 121.0 |
| **Regulator 1 VCZ** | | | | | | | | | | | | | | | | | | | |
| C Max VD% (peak Load) | 3.8 | | | | | | | | | | | | | | | | | | |
| C V-Rise (Peak Load) | 5.4 | | | | | | | | | | | | | | | | | | |
| C V-Set (No Load) | 120.0 | | | | | | | | | | | | | | | | | | |
| C kW Demand (Reg 1) | 2,683.2 | | | | | | | | | | | | | | | | | | |
| C kW Demand (Reg 2) | 0.0 | | | | | | | | | | | | | | | | | | |
| Post-VO Max VD% (peak Load) | 4.0 | | | | | | | | | | | | | | | | | | |
| Post-VO V-Rise (Peak Load) | 4.3 | | | | | | | | | | | | | | | | | | |
| Post-VO V-Set (No Load) | 120.0 | | | | | | | | | | | | | | | | | | |
| **kW Line Loss** | 334.3 | 98.7 | 278.3 | 120.8 | 57.8 | 187.9 | 107.2 | 127.5 | 156.3 | 44.2 | 151.6 | 237.4 | 116.7 | 94.7 | 131.1 | 184.0 | 81.7 | 74.2 | 35.5 |
| **Improvement Costs $** | $180,378 | $29,526 | $219,622 | $58,178 | $83,645 | $107,846 | $73,614 | $53,438 | $95,448 | $23,910 | $128,058 | $166,286 | $49,098 | $44,502 | $100,248 | $85,444 | $54,252 | $60,508 | $26,690 |
| **Stage 2 Case** | One Exist Reg | | | | | | | | | | | | | | | | | | |
| **Feeder VCZ** | Add 1 Reg | | Add 2 Reg | Add 1 Reg | | Add 2 Reg | | | | | | Add 1 Reg | | | | Add 1 Reg | Add 1 Reg | | |
| C Max VD% (peak Load) | | 2.0 | | 2.4 | 2.8 | | 3.7 | 3.3 | 4.2 | 1.8 | 3.5 | 2.8 | 3.6 | 3.3 | 4.1 | 2.7 | 2.8 | 3.5 | 2.3 |
| C V-Rise (Peak Load) | Add one | 2.3 | Add two | 0.0 | 5.9 | Add two | 5.4 | 5.4 | 2.3+2.7 | 2.3+2.7 | 2.9+1.3 | 4.5 | 4.6 | 5.2 | 4.7 | 4.3 | 4.5 | 4.7 | 4.7 |
| C V-Set (No Load) | series | 121 | paralell | 124 | 120 | paralell | 120 | 120 | 121 | 121 | 121 | 121 | 121 | 121 | 121 | 121 | 121 | 121.0 | 121.0 |
| C kW Demand (Fdr) | reg | 8198.8 | regs | 8097.3 | 6218.4 | regs | 8197.7 | 9247.6 | 8366.3 | 5899.4 | 7984.8 | 6790.0 | 7297.7 | 6277.7 | 6992.1 | 10595.0 | 7699.4 | 4,999.0 | 3,999.8 |
| C kW Demand (Reg 1) | | 0.0 | | 3304.0 | 0.0 | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 6650.0 | 0.0 | 0.0 | 0.0 | 6189.0 | 851.7 | 0.0 | 0.0 |
| Post-VO Max VD% (peak Load) | | 0.8 | | 2.0 | 2.7 | | 3.2 | 3.0 | 3.2 | 1.8 | 3.2 | 2.6 | 3.6 | 2.7 | 3.8 | 1.7 | 2.5 | 3.0 | 1.8 |
| Post-VO V-Rise (Peak Load) | | 2.9 | | 2.9 | 2.9 | | 4.0 | 4.0 | 3.5 | 3.5 | 4.3 | 4.5 | 4.6 | 3.8 | 4.7 | 2.6 | 2.9 | 2.9 | 2.9 |
| Post-VO V-Set (No Load) | | 120.0 | 120.0 | 120.0 | 120.0 | 120.0 | 120.0 | 120.0 | 120.0 | 120.0 | 120.0 | 119.0 | 120.0 | 120.0 | 120.0 | 120.0 | 120.0 | 121.0 | 121.0 |
| **Regulator 1 VCZ** | | | | | | | | | | | | | | | | | | | |
| C Max VD% (peak Load) | | | | 2.1 | | | | | | | | 2.7 | | | | 1.7 | 1.7 | | |
| C V-Rise (Peak Load) | | | | -0.5 | | | | | | | | 3.4 | | | | 3.1 | 2.0 | | |
| C V-Set (No Load) | | | | 124.0 | | | | | | | | 121.0 | | | | 121.0 | 121.0 | | |
| C kW Demand (Reg 1) | | | | 3,304.0 | | | | | | | | 6,650.0 | | | | 6,189.0 | 851.7 | | |
| C kW Demand (Reg 2) | | | | 0.0 | | | | | | | | 0.0 | | | | 0.0 | 0.0 | | |
| Post-VO Max VD% (peak Load) | | | | 2.5 | | | | | | | | 2.7 | | | | 2.4 | 2.0 | | |
| Post-VO V-Rise (Peak Load) | | | | 3.3 | | | | | | | | 3.4 | | | | 2.8 | 2.7 | | |
| Post-VO V-Set (No Load) | | | | 120.0 | | | | | | | | 120.0 | | | | 120.0 | 120.0 | | |
| **kW Line Loss** | 302.3 | 106.1 | 247.4 | 114.6 | 59.3 | 164.9 | 95.2 | 116.2 | 146.8 | 43.5 | 139.6 | 229.5 | 100.8 | 93.6 | 130.1 | 186.9 | 82.8 | 58.4 | 35.3 |
| **Improvement Costs $** | $329,870 | $102,929 | $288,415 | $150,565 | $106,799 | $317,873 | $123,639 | $118,025 | $128,436 | $47,064 | $107,026 | $231,435 | $124,802 | $65,499 | $123,402 | $264,201 | $221,349 | $98,309 | $49,844 |

| Circuit No. | 5W150 | 5W154 | 5W22 | 5W116 | 5W127 | 5W342 | 5Y608 | 5Y610 | 5Y194 | 5Y197 | 5Y273 | 5Y356 | 5Y456 | 5Y498 | 5Y434 | 5Y444 | 5Y351 | 5Y313 | 5Y317 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Substation | BOWMAN | BOWMAN | DODD RD | MILL CREEK | MILL CREEK | POMEROY | CLINTON | CLINTON | NOB HILL | NOB HILL | NOB HILL | NORTH PARK | ORCHARD | ORCHARD | WILEY | RIVER ROAD | GRANDVIEW | SUNNYSIDE | SUNNYSIDE |
| Circuit Name | PINE STREET | GARDEN | WINDWARD | GREEN PARK | WILBUR | POMEROY | IKE | BOULEVARD | 16TH AVE | TWELFTH AVE. | 18TH AVE | FREEWAY | COWICHE | PEACH | DAZET | WRIGHT | EUCLID | CARNATION | EDISON |

| Stage 3 Case | One Exist Reg | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Feeder VCZ | Add 1 Reg | | Add 2 Reg | Add 1 Reg | | Add 2 Reg | | | | | | Add 1 Reg | | | | Add 1 Reg | Add 1 Reg | | |
| C Max VD% (peak Load) | | 2.0 | | 2.4 | 2.8 | | 3.7 | 3.3 | 4.2 | 1.8 | 3.5 | 2.8 | 3.6 | 3.3 | 4.1 | 2.7 | 2.8 | 3.5 | 2.3 |
| C V-Rise (Peak Load) | Add one | 2.3 | Add two | 0.0 | 5.9 | Add two | 5.4 | 5.4 | 2.3+2.7 | 2.3+2.7 | 2.9+1.3 | 4.5 | 4.6 | 5.2 | 4.7 | 4.3 | 4.5 | 4.7 | 4.7 |
| C V-Set (No Load) | series | 121 | paralell | 124 | 120 | paralell | 120 | 120 | 121 | 121 | 121 | 121 | 121 | 121 | 121 | 121 | 121 | 121 | 121.0 |
| C kW Demand (Fdr) | reg | 8198.8 | regs | 8097.3 | 6218.4 | regs | 8197.7 | 9247.6 | 8366.3 | 5899.4 | 7984.8 | 6790.0 | 7297.7 | 6277.7 | 6992.1 | 10595.0 | 7699.4 | 4999.0 | 3,999.8 |
| C kW Demand (Reg 1) | | 0.0 | | 3304.0 | 0.0 | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 6650.0 | 0.0 | 0.0 | 0.0 | 6189.0 | 851.7 | 0.0 | 0.0 |
| Post-VO Max VD% (peak Load) | | 0.8 | | 2.0 | 2.7 | | 3.2 | 3.0 | 3.2 | 1.8 | 3.2 | 2.6 | 3.6 | 2.7 | 3.8 | 1.7 | 2.5 | 3.0 | 1.8 |
| Post-VO V-Rise (Peak Load) | | 2.9 | | 2.9 | 2.9 | | 4.0 | 4.0 | 3.5 | 3.5 | 4.3 | 4.5 | 4.6 | 3.8 | 4.7 | 2.6 | 2.9 | 2.9 | 2.9 |
| Post-VO V-Set (No Load) | | 119.0 | | 119.0 | 119.0 | | 119.0 | 119.0 | 119.0 | 119.0 | 119.0 | 118.0 | 119.0 | 119.0 | 119.0 | 119.0 | 119.0 | 119.0 | 119.0 |
| Regulator VCZ | | | | | | | | | | | | | | | | | | | |
| C Max VD% (peak Load) | | | | 2.1 | | | | | | | | 2.7 | | | | 1.7 | 1.7 | | |
| C V-Rise (Peak Load) | | | | -0.5 | | | | | | | | 3.4 | | | | 3.1 | 2.0 | | |
| C V-Set (No Load) | | | | 124.0 | | | | | | | | 121.0 | | | | 121.0 | 121.0 | | |
| C kW Demand (Reg 1) | | | | 3,304.0 | | | | | | | | 6,650.0 | | | | 6,189.0 | 851.7 | | |
| C kW Demand (Reg 2) | | | | 0.0 | | | | | | | | 0.0 | | | | 0.0 | 0.0 | | |
| Post-VO Max VD% (peak Load) | | | | 2.5 | | | | | | | | 2.7 | | | | 2.4 | 2.0 | | |
| Post-VO V-Rise (Peak Load) | | | | 3.3 | | | | | | | | 3.4 | | | | 2.8 | 2.7 | | |
| Post-VO V-Set (No Load) | | | | 119.0 | | | | | | | | 119.0 | | | | 119.0 | 119.0 | | |
| kW Line Loss | 302.3 | 106.1 | 247.4 | 114.6 | 59.3 | 164.9 | 95.2 | 116.2 | 146.8 | 43.5 | 151.6 | 229.5 | 100.8 | 93.6 | 130.1 | 186.9 | 82.9 | 58.4 | 35.3 |
| Improvement Costs $ | $345,514 | $272,600 | $583,960 | $318,157 | $256,139 | $622,153 | $281,975 | $260,606 | $297,023 | $154,291 | $241,604 | $522,300 | $267,123 | $230,336 | $402,516 | $552,570 | $469,211 | $240,890 | $203,759 |

# Appendix 13:  Metering and Communication Costs

# Commonwealth Developed
# Metering – Cost Estimate

Each feeder in each substation will need to be individually monitored and metered. Similarly, the end of the line will need to be metered. However, only voltage quantity will be monitored. The load side of a three-phase line regulator will need to be metered with a full complement of quantities monitored.

Several choices for multi-function meters are available that could be used to meter the distribution circuits. For this estimate, an SEL 751A Feeder Protection Relay was selected for use in the substation. A single phase GE kV2 Multifunction Electricity Meter was chosen for the end of the line application. And, a three phase GE kV2 Multifunction Electricity Meter was selected to be used at a line regulator

## Metering Within the Substation

Metering is present in each substation for each power transformer load. That means that there are voltage transformers available to be used for the feeder metering. The substation feeders are being protected with circuit breakers. The circuit breakers have current transformers which can be used for feeder metering. A control enclosure is available in which to mount the meter.

The installation of the meters in the substation should be straightforward. The process for the substation installation will be to remove the existing overcurrent and reclosing relays and replace them with the SEL 751A relay. The relay will be mounted on the panel in place of the existing relays. A test switch will be mounted adjacent (below) the relay. The appropriate voltage quantities will be routed from the existing metering voltage transformer circuits, probably already in the control enclosure. The voltages will be wired to the test switch and relay. Current quantities will be wired to the test switch and relay from the feeder breaker current transformers. The relaying and metering settings will be installed in the relay and a functional check of the relay will be performed.

The estimated cost per circuit to install the metering in a substation is itemized as follows:

| | ITEM | QTY | EA | Total |
|---|---|---|---|---|
| | | | | |
| 1 | SEL 751A Feeder Protection Relay | 1 | 2,500.00 | 2,500.00 |
| 2 | Modifications to the relay panel | 1 | 300.00 | 300.00 |
| | Labor (assume 2 relay/metermen 8 hours per instl.) | 8 | 258.10 | 2,064.80 |
| 3 | Test Switch | 1 | 175.00 | 175.00 |
| 4 | 4 conductor control cable (ft) | 150 | 1.25 | 187.50 |
| 5 | Labor (assume 6 hours per installation) | 6 | 258.10 | 1,548.60 |
| | ( 2 man crew = $258.10 per hour) | | | |
| | | | TOTAL | 6,775.90 |

Metering at the End of the Line

At the end of the line, there will only be a need to measure the voltage quantities. The installation at the end of the line will be different than the substation installation. One voltage transformers will be provided and mounted on a convenient pole. The transformer will be mounted on a cluster rack at the top of the pole and connected to the line using a fuse cutout and hot clamps. The meter will be mounted to the pole near the base and connected to the voltage transformers using control cable. Since the meter will be exposed to public access, the control cable will be installed in conduit, up the pole, until the cable reaches 10 feet above the ground. After the wiring is complete, the meter will be installed in the meter base and the installation energized and verified. This installation will require a line crew to install the instrument transformers at the top of the pole and a meter man (men) to install and verify the meter.

The estimated cost per circuit to install the metering at the end of the circuit is itemized as follows:

| | ITEM | QTY | EA | TOTAL |
|---|---|---|---|---|
| | | | | |
| 1 | GE kV2 1-Ph. Multifunction Meter | 1 | $1,200.00 | $1,200.00 |
| 2 | Meter base with space for test switch. | 1 | $200.00 | $200.00 |
| 3 | Test Switch | 1 | $125.00 | $125.00 |
| 4 | Fuse cutouts and hot clamps | 1 | $550.00 | $550.00 |
| 5 | Instrument transformer rack | 1 | $250.00 | $250.00 |
| 6 | Voltage transformer | 1 | $1,200.00 | $1,200.00 |
| 7 | 4 conductor control cable (ft) | 75 | $1.25 | $93.75 |
| 8 | Ground rods and ground wire (lot) | 1 | $200.00 | $200.00 |
| 9 | Labor (assume 8 hours per installation) | 8 | $516.20 | $4,129.60 |
| | (4 man crew, linemen and metermen = $516.2 per hour) | | | |
| | | | TOTAL | $7,948.35 |
| | | | | |

Metering at a Three Phase Line Regulator

The metering set for use at a three-phase line regulator will be installed on a pole, as close to the load side of the regulators as practical. Three current transformers and three voltage transformers will be mounted on an instrument transformer cluster rack near the top of the pole. The voltage transformers will be connected to the line conductors through cutouts and hot clamps. The current transformers will be connected to the line across insulators added to the line, or at a deadend structure. The meter will be mounted to the pole near the base and connected to the voltage transformers using control cable. Since the meter will be exposed to public access, the control cable will be installed in conduit, up the pole, until the cable reaches 10 feet above the ground. After the wiring is complete, the meter will be installed in the meter base and the installation energized and verified. This installation will require a line crew to install the instrument transformers at the top of the pole and a meter man (men) to install and verify the meter.

The estimated cost per circuit to install the metering at a three phase voltage regulator is itemized as follows:

| | ITEM | QTY | EA | TOTAL |
|---|---|---|---|---|
| | | | | |
| 1 | GE kV2 3-Ph. Multifunction Meter | 1 | $1,750.00 | $1,750.00 |
| 2 | Meter base with space for test switch. | 1 | $275.00 | $275.00 |
| 3 | Test Switch | 1 | $175.00 | $175.00 |
| 4 | Fuse cutouts and hot clamps | 3 | $550.00 | $1,650.00 |
| 5 | Instrument transformer rack | 1 | $500.00 | $500.00 |
| 6 | Voltage transformer | 3 | $1,200.00 | $3,600.00 |
| 7 | Current transformers | 3 | $1,200.00 | $3,600.00 |
| 8 | 12 conductor control cable (ft) | 75 | $1.55 | $116.25 |
| 9 | Ground rods and ground wire (lot) | 1 | $200.00 | $200.00 |
| 10 | Labor (assume 8 hours per installation) | 8 | $516.20 | $4,129.60 |
| | (4 man crew, linemen and metermen = $516.2 per hour) | | | |
| | | | TOTAL | $15,995.85 |

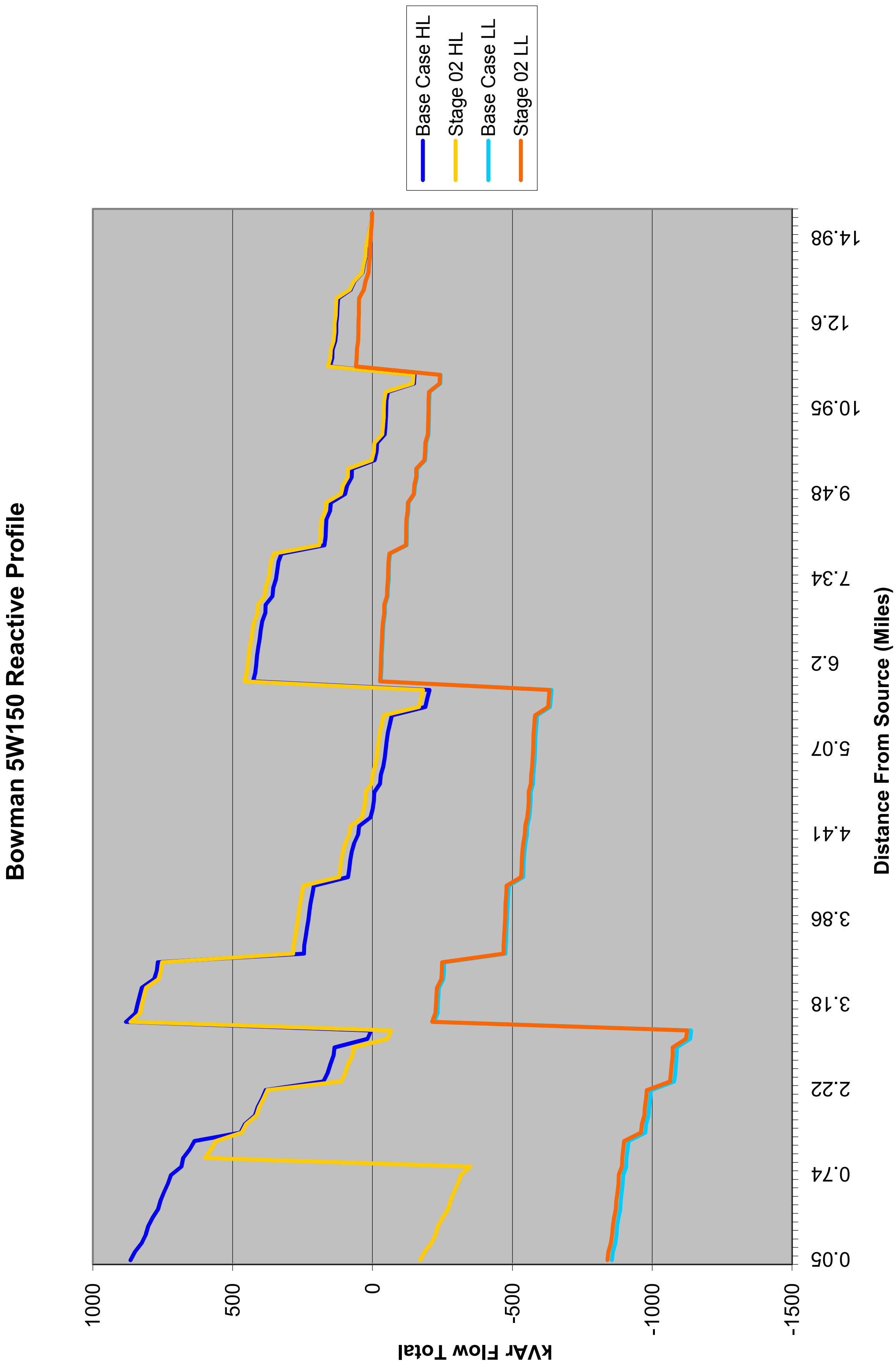
# Metering and Communications Cost Estimate for Stage 3 Implementation

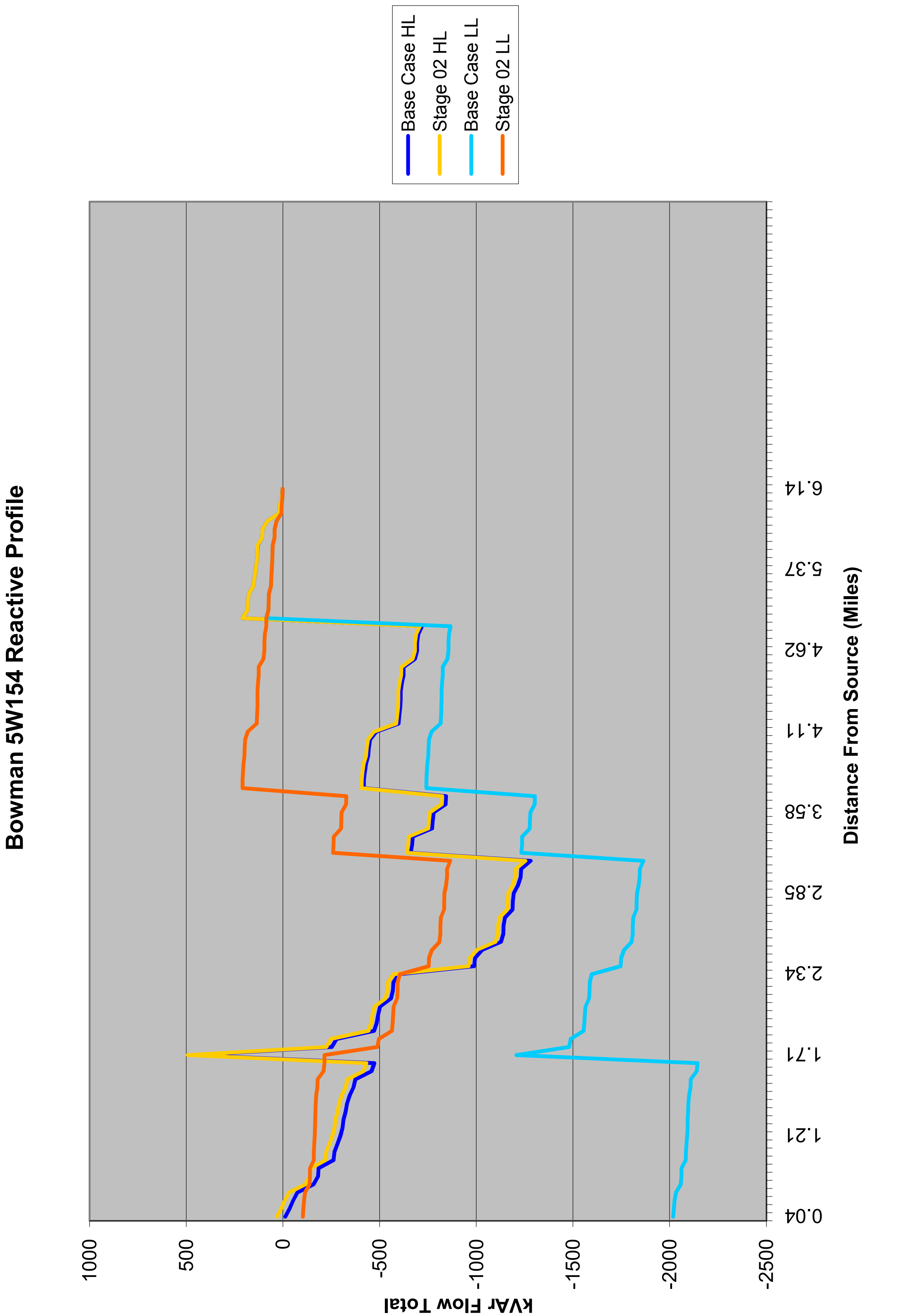
| Work Description (Feeder Improvements) | Cost Per Location | Walla Walla 5W150 | Walla Walla 5W154 | Walla Walla 4W22 | Walla Walla 5W116 | Walla Walla 5W127 | Walla Walla 5W342 | Yakima 5Y608 | Yakima 5Y610 | Yakima 5Y194 | Yakima 5Y197 | Yakima 5Y273 | Yakima 5Y356 | Yakima 5Y456 | Yakima 5Y498 | Yakima 5Y434 | Yakima 5Y444 | Sunnyside 5Y351 | Sunnyside 5Y313 | Sunnyside 5Y317 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Three phase voltage control points** | | | 1 | 1 | | 1 | 2 | | | | | | | | | | | 1 | | |
| **Single phase voltage control points** | | 1 | 2 | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| End of voltage control zone: **3ph** primary metering on new pole | $ 11,500 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| End of voltage control zone: **1ph** primary metering on new pole | $ 6,700 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| End of **any** voltage control zone: revenue meter, socket, test switch, miscellaneous wiring | $ 8,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| End of **1ph** voltage control zone: wireless 'radio' link to substation | $ 3,551 | 1 | 2 | 2 | 1 | 2 | 3 | 1 | 1 | 1 | 1 | 1 | 2 | 1 | 1 | 1 | 2 | 1 | 1 | 2 |
| Line regulator: wireless 'radio' link to substation | $ 3,364 | 0 | 1 | 1 | 0 | 1 | 2 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 1 |
| | **Total Circuit Cost** | **$3,551** | **$10,466** | **$10,466** | **$3,551** | **$10,466** | **$17,381** | **$3,551** | **$3,551** | **$3,551** | **$3,551** | **$3,551** | **$10,466** | **$3,551** | **$3,551** | **$3,551** | **$10,466** | **$3,551** | **$3,551** | **$10,466** |
| | **Total, Tier 1 Circuits** | $ 122,789 | | | | | | | | | | | | | | | | | | |
| | **Average Circuit Cost** | **$ 6,463** | | | | | | | | | | | | | | | | | | |

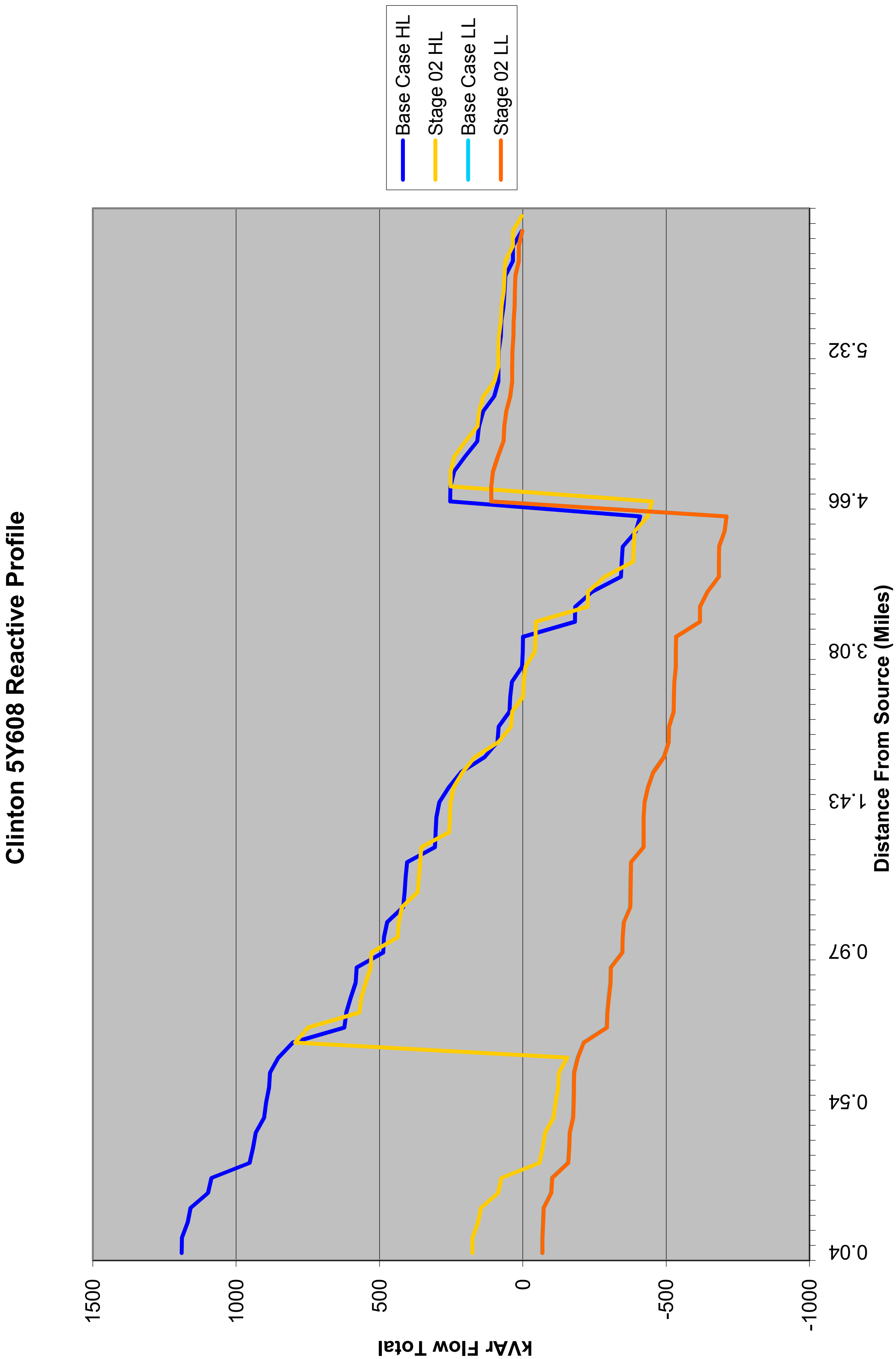
| Work Description (Substation Improvements) | Cost Per Substation | All Districts | | Walla Walla Substations | Yakima Substations | Sunnyside Substations |
|---|---|---|---|---|---|---|
| Substation: communications gear, links, central equipment, software to support CVR, IVVO, FDIR, AMI, DR, other smart grid services. Secure, real-time, always on. | $ 210,563 | | | 4 | 6 | 2 |
| | **Total, Tier 1 Subs** | **$ 2,526,756** | | $ 842,252 | $ 1,263,378 | $ 421,126 |

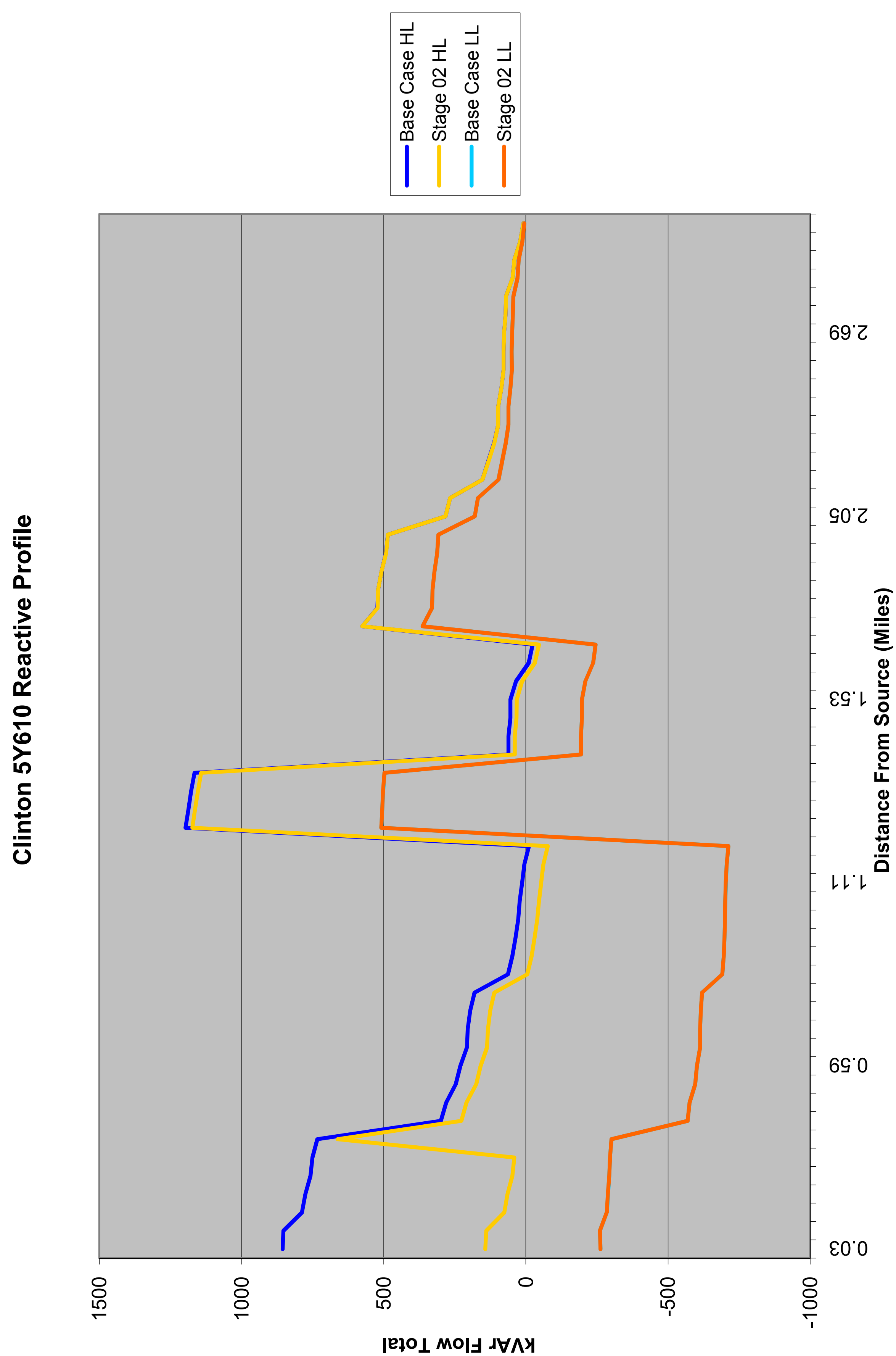
| Work Description (All Improvements) | | All Districts | | Walla Walla Substations | Yakima Substations | Sunnyside Substations |
|---|---|---|---|---|---|---|
| | **Total All Circuits and Subs** | **$ 2,649,545** | | $ 898,133 | $ 1,312,718 | $ 438,694 |
| | **Average Circuit Cost** | **$ 139,450** | | $ 149,689 | $ 131,272 | $ 146,231 |

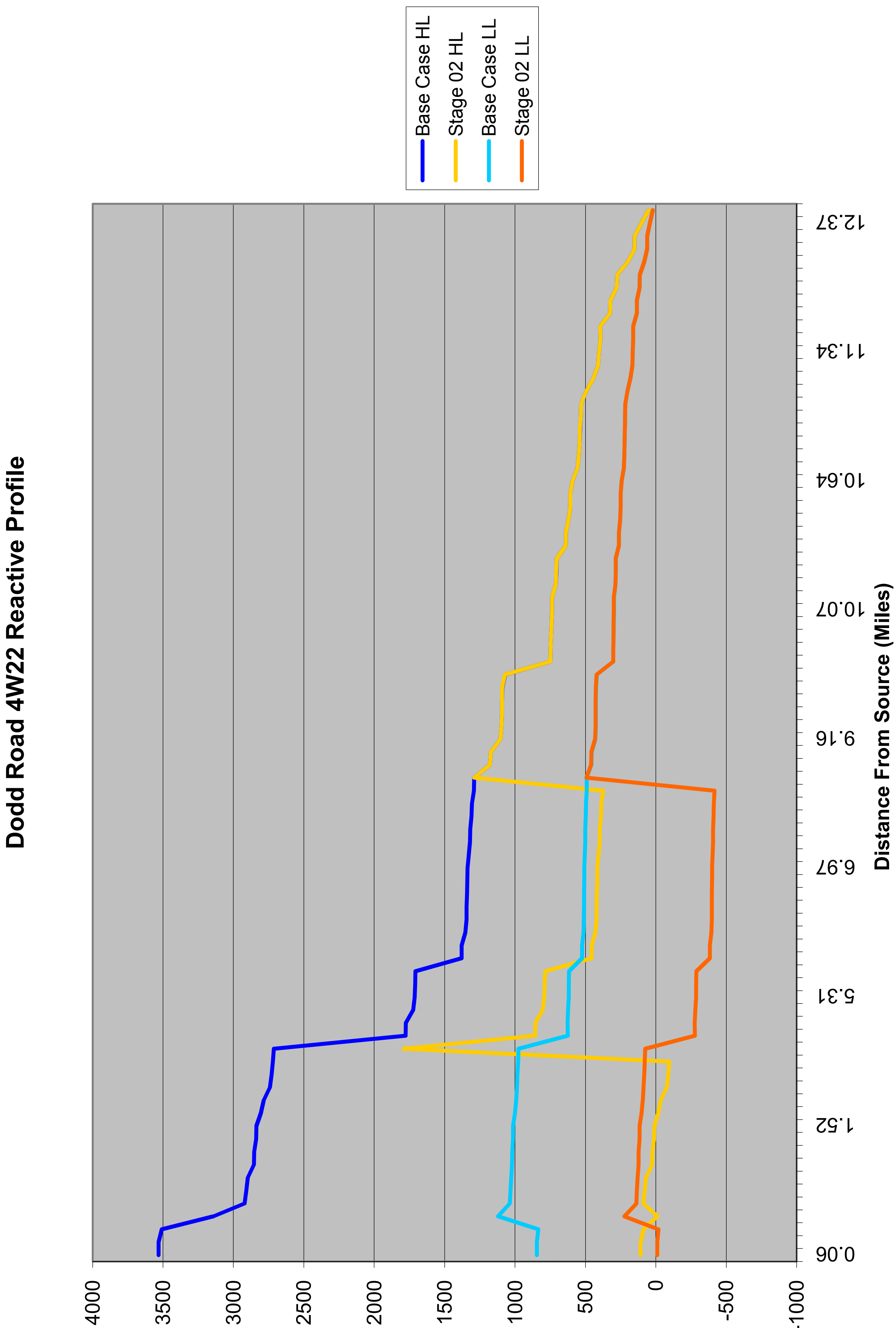
## Appendix 14: VAR Profiles

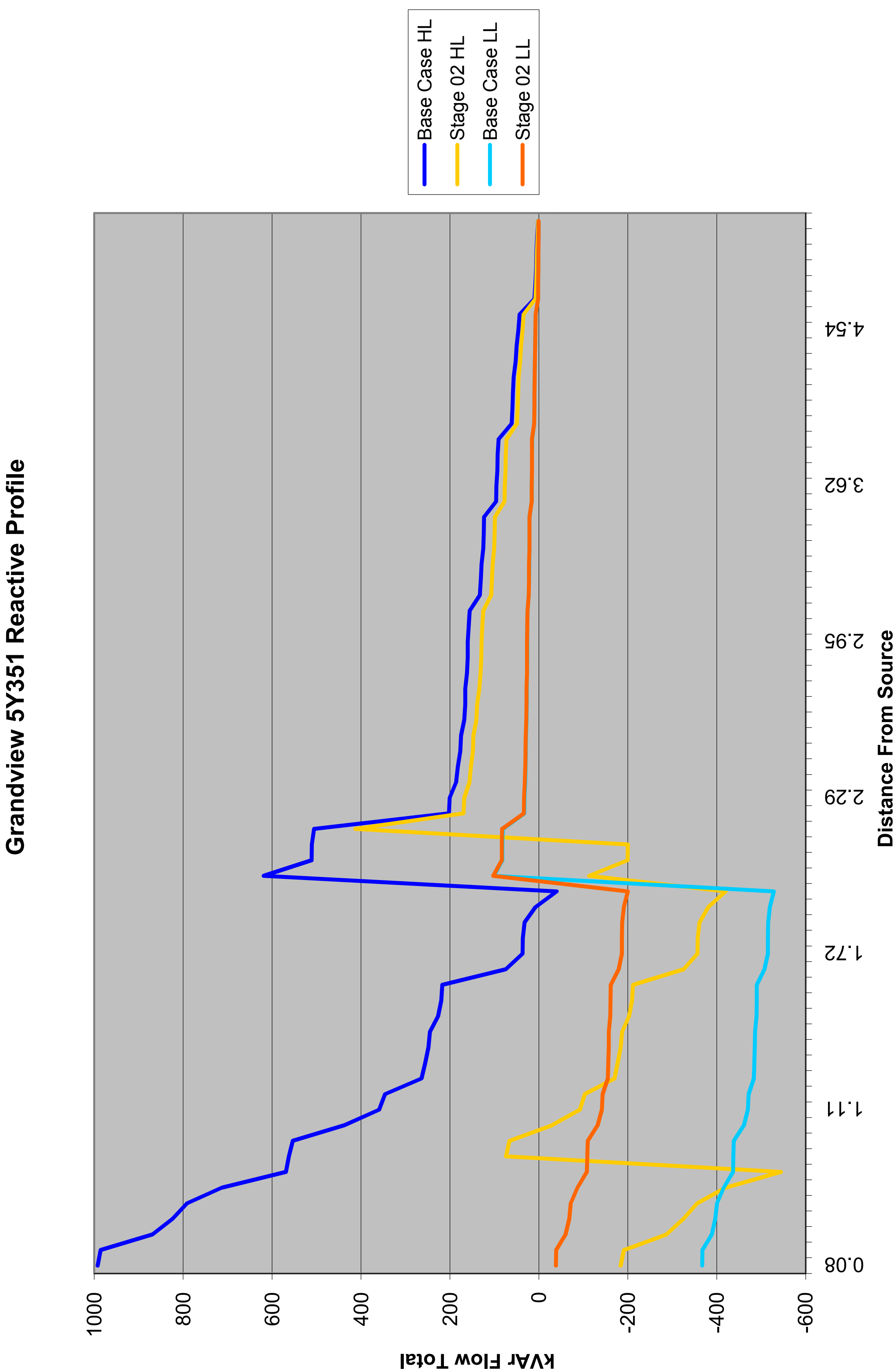

Bowman 5W150 Reactive Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
kVAr Flow Total
1000
500
0
-500
-1000
-1500
0.05
0.74
2.22
3.18
3.86
4.41
5.07
6.2
7.34
9.48
10.95
12.6
14.98
Distance From Source (Miles)

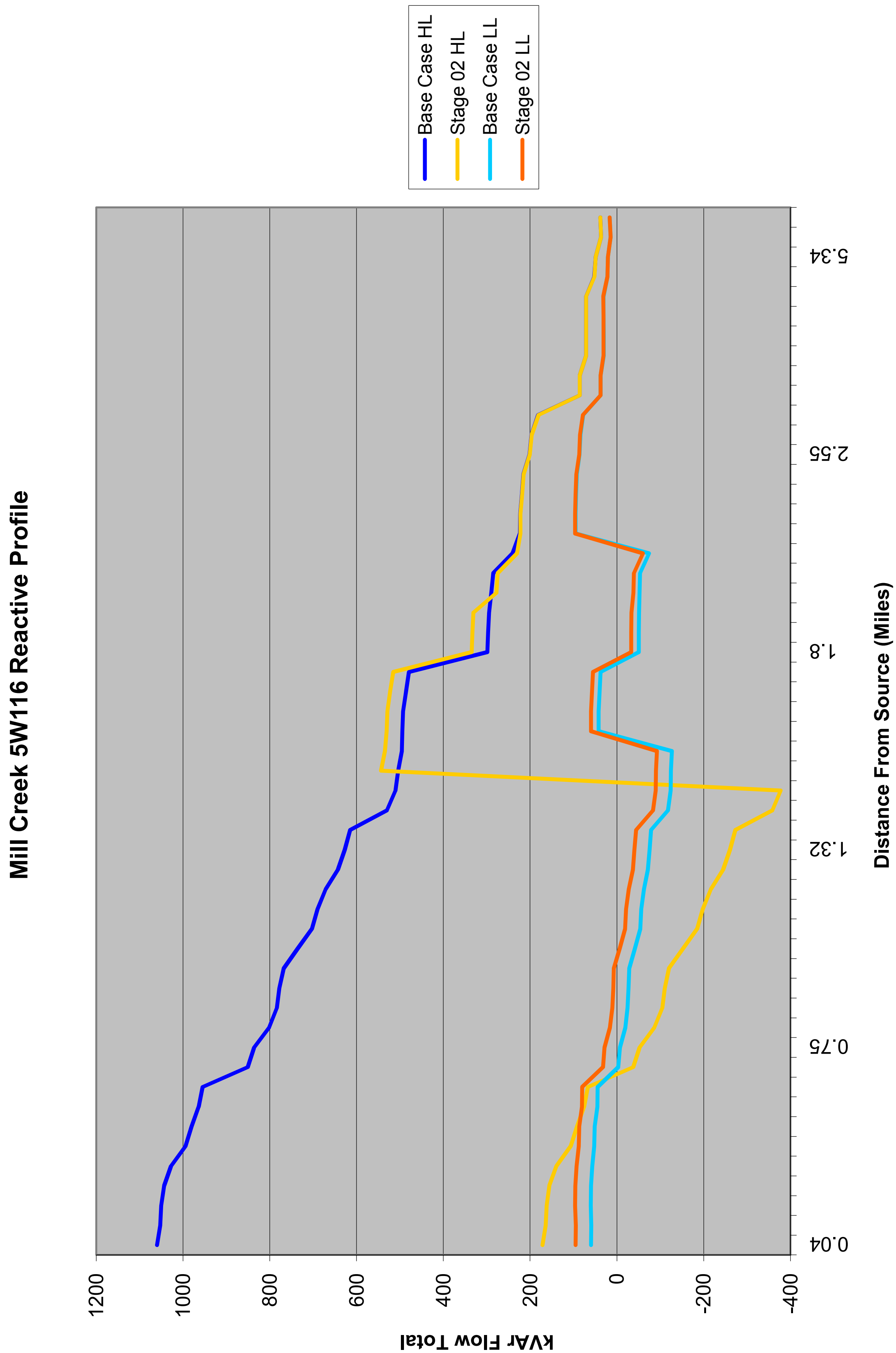

Bowman 5W154 Reactive Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
kVAr Flow Total
1000
500
0
-500
-1000
-1500
-2000
-2500
Distance From Source (Miles)
0.04
1.21
1.71
2.34
2.85
3.58
4.11
4.62
5.37
6.14

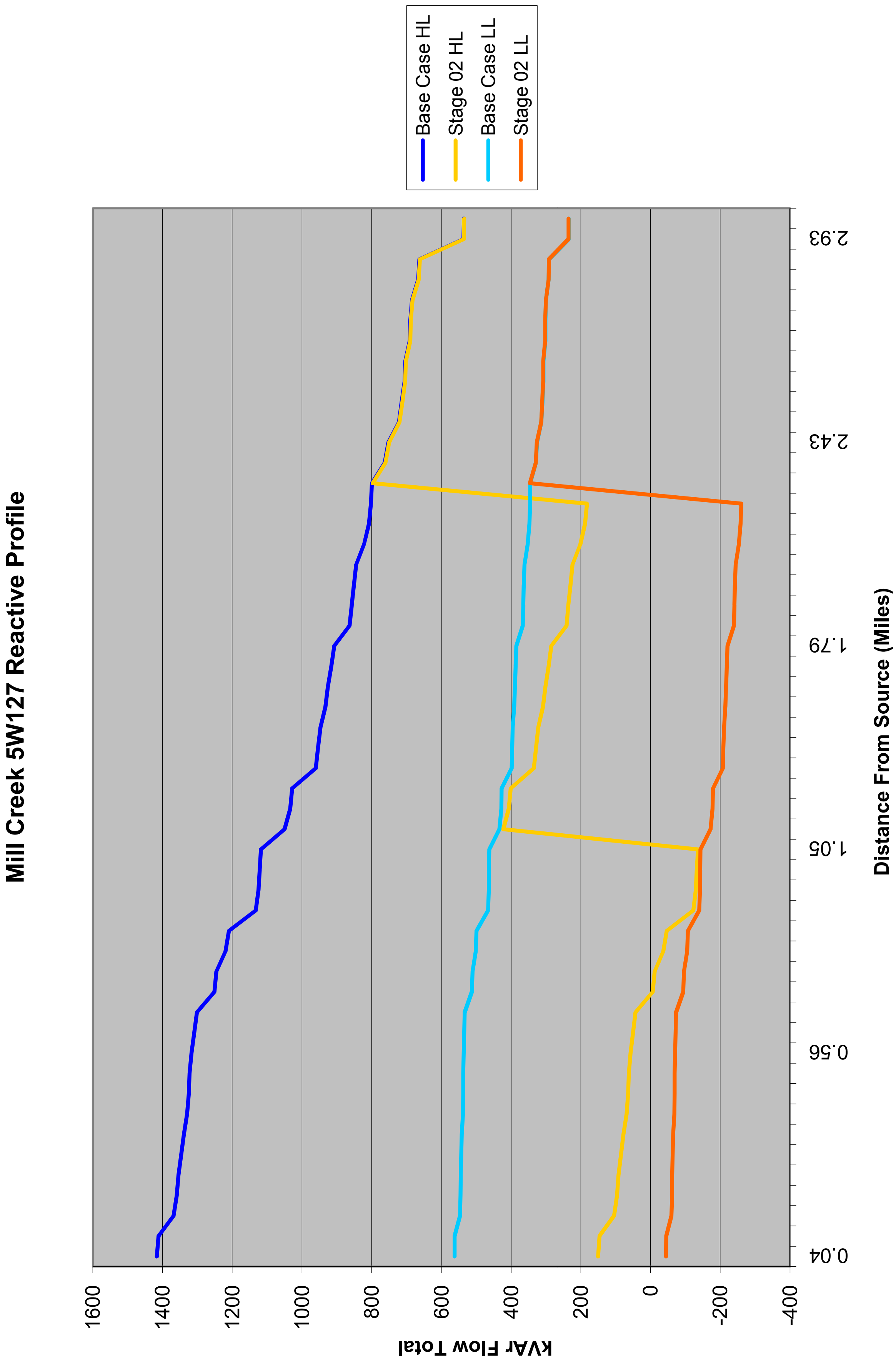

Clinton 5Y608 Reactive Profile
kVAr Flow Total
1500
1000
500
0
-500
-1000
Distance From Source (Miles)
0.04
0.54
0.97
1.43
3.08
4.66
5.32
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL

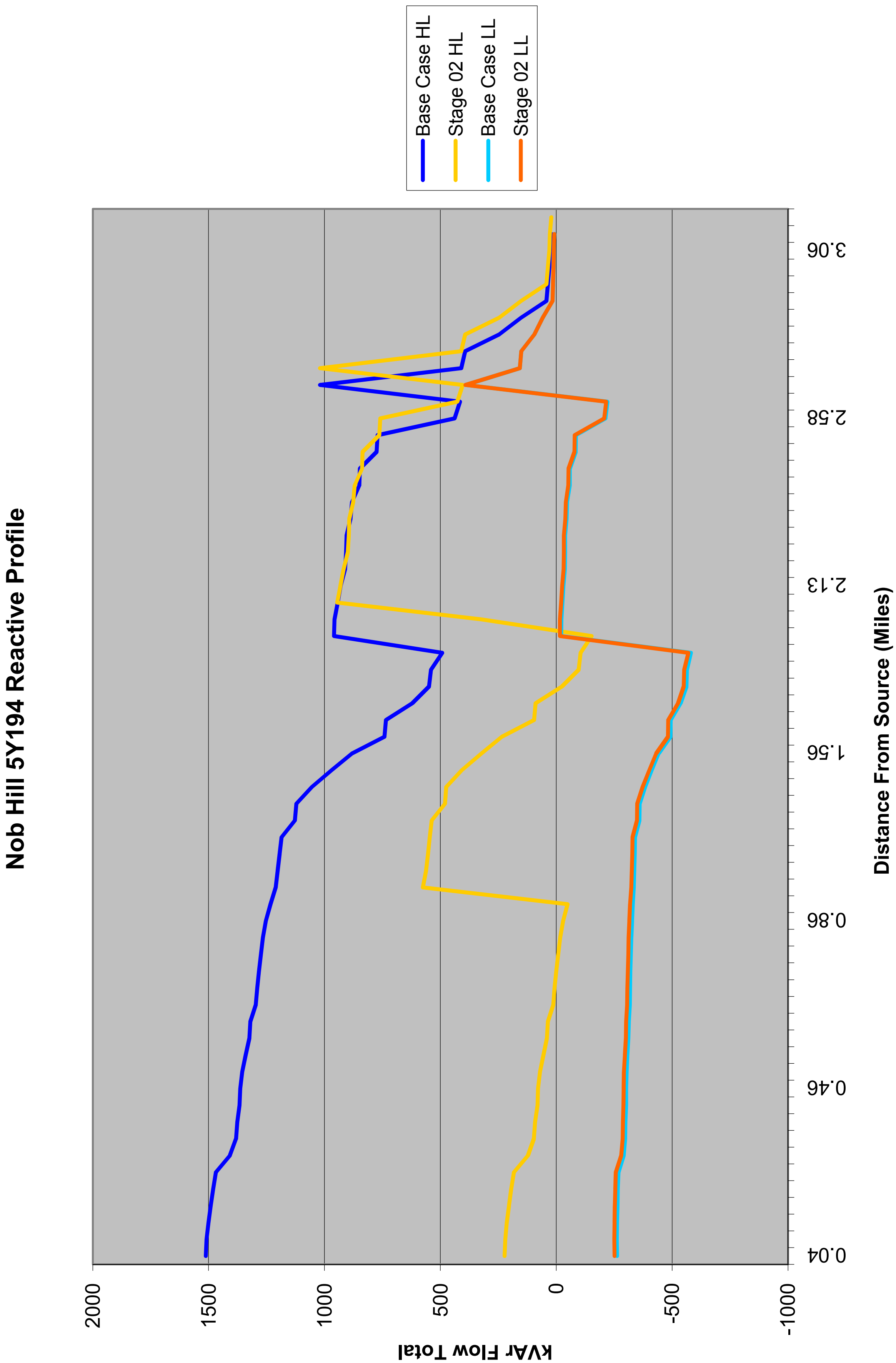

Clinton 5Y610 Reactive Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
kVAr Flow Total
1500
1000
500
0
-500
-1000
Distance From Source (Miles)
0.03
0.59
1.11
1.53
2.05
2.69

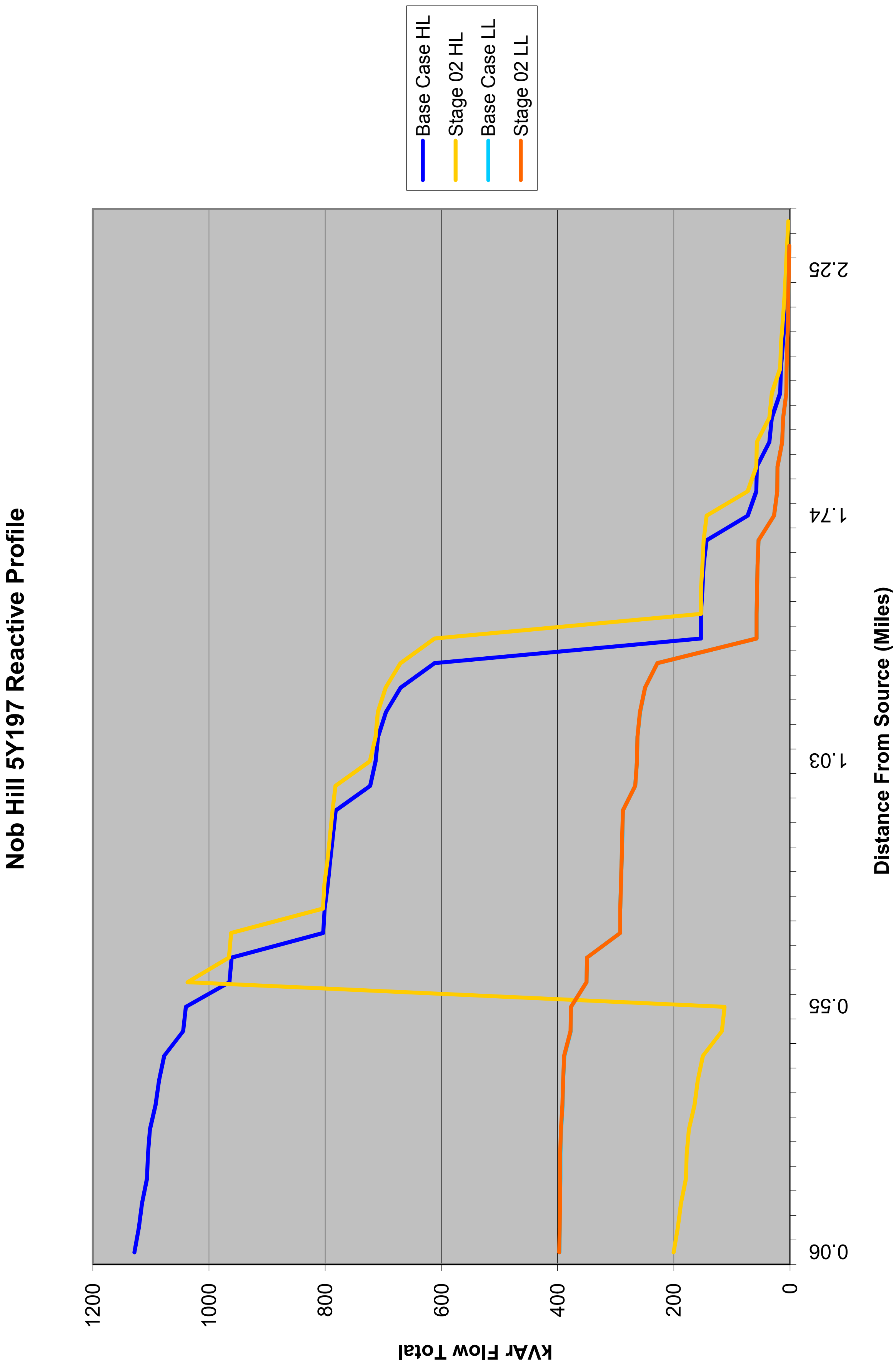

Dodd Road 4W22 Reactive Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
kVAr Flow Total
4000
3500
3000
2500
2000
1500
1000
500
0
-500
-1000
0.06
1.52
5.31
6.97
9.16
10.07
10.64
11.34
12.37
Distance From Source (Miles)

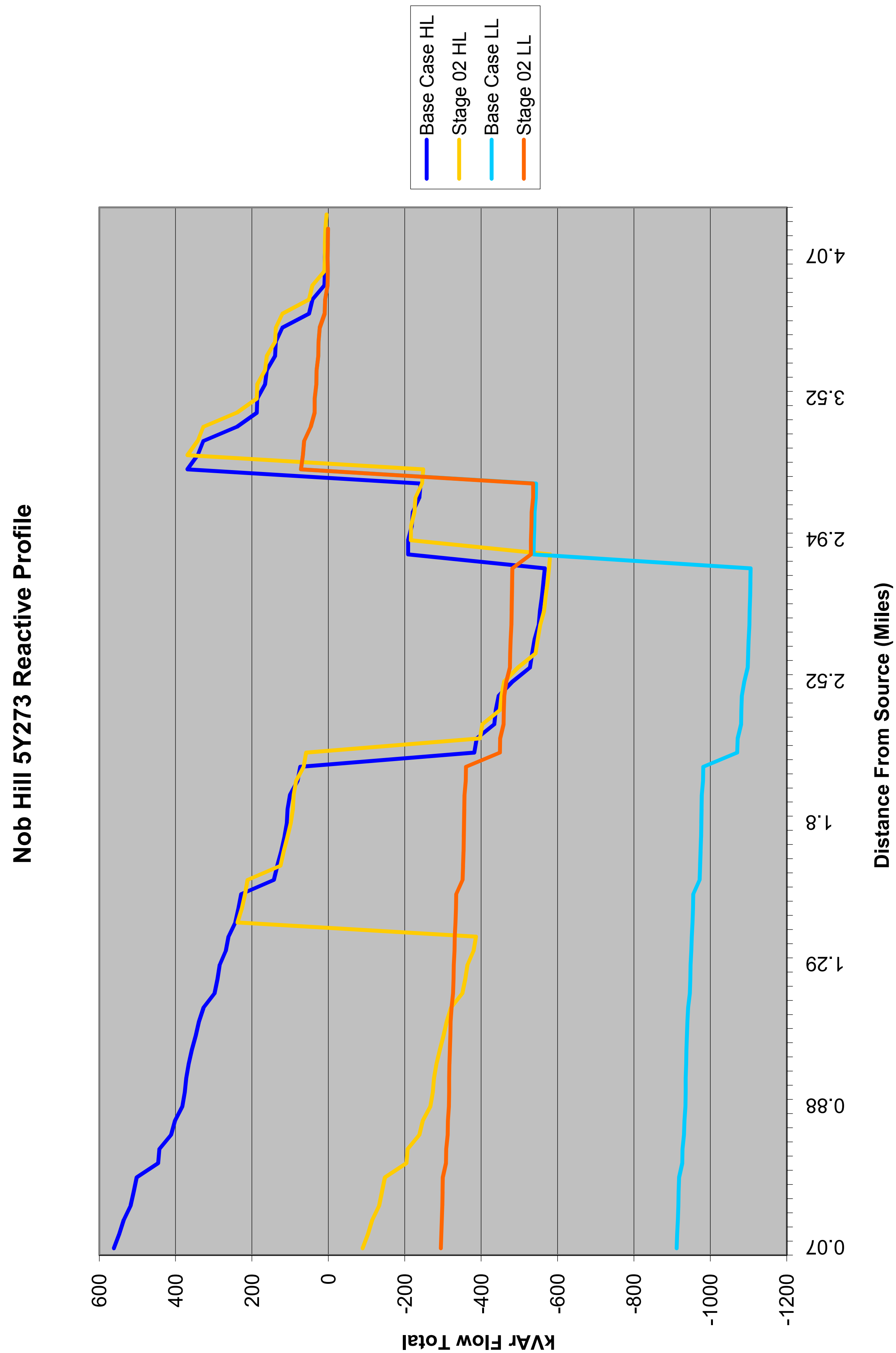

Grandview 5Y351 Reactive Profile
kVAr Flow Total
Distance From Source
1000
800
600
400
200
0
-200
-400
-600
0.08
1.11
1.72
2.29
2.95
3.62
4.54
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL


Mill Creek 5W116 Reactive Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
kVAr Flow Total
1200
1000
800
600
400
200
0
-200
-400
Distance From Source (Miles)
0.04
0.75
1.32
1.8
2.55
5.34

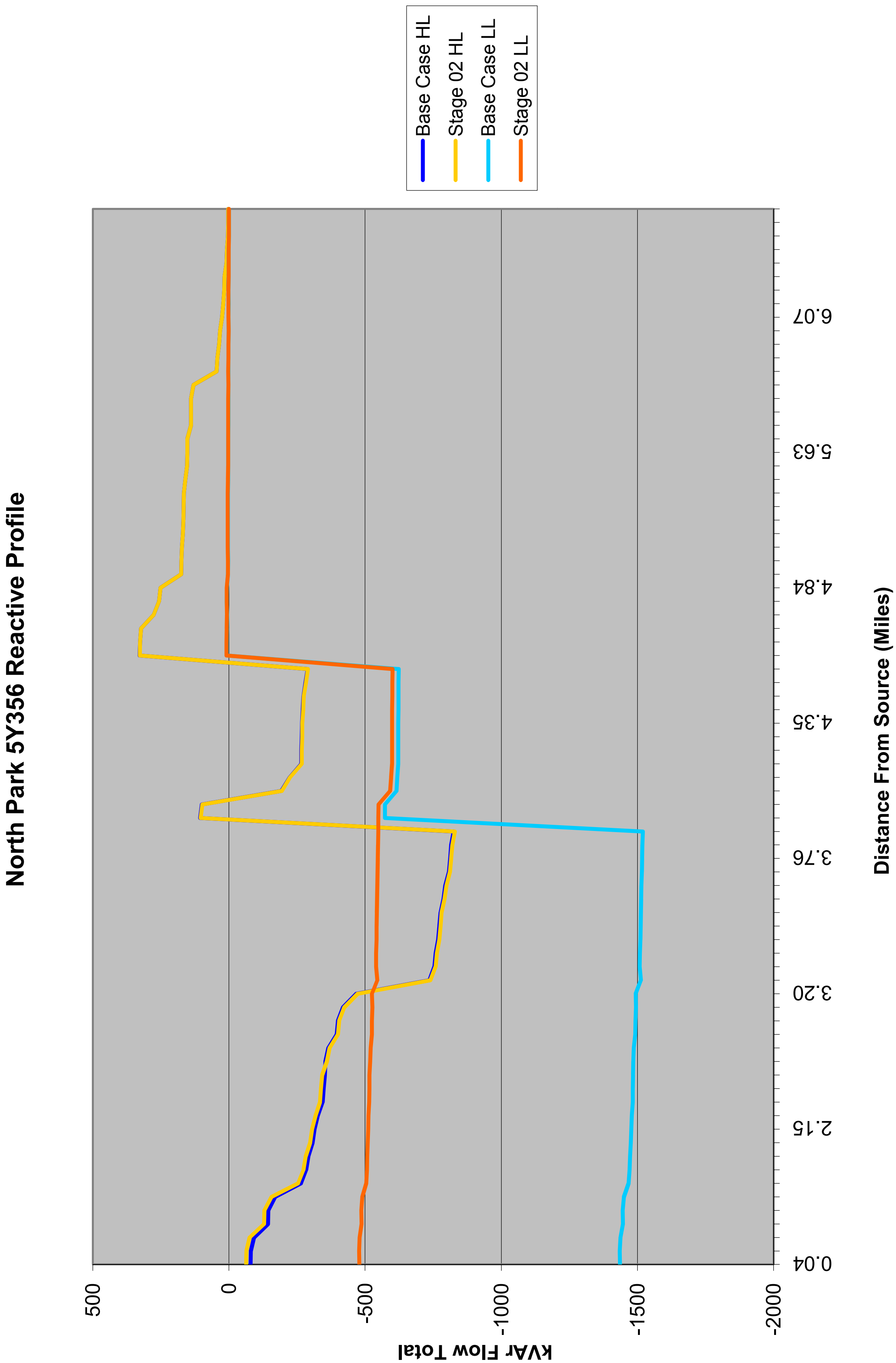

Mill Creek 5W127 Reactive Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
kVAr Flow Total
1600
1400
1200
1000
800
600
400
200
0
-200
-400
Distance From Source (Miles)
0.04
0.56
1.05
1.79
2.43
2.93

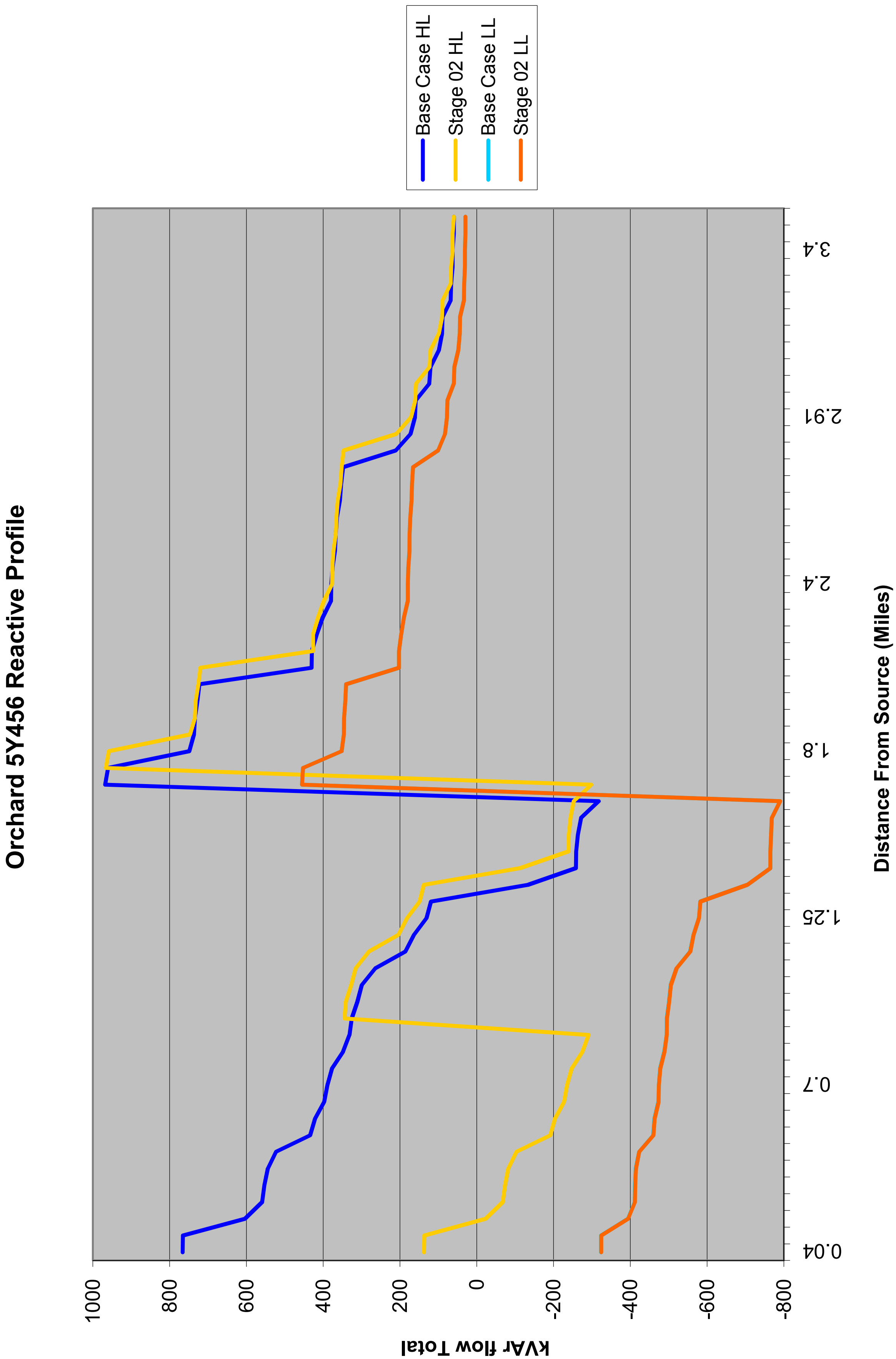

Nob Hill 5Y194 Reactive Profile
kVAr Flow Total
Distance From Source (Miles)
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
2000
1500
1000
500
0
-500
-1000
0.04
0.46
0.86
1.56
2.13
2.58
3.06

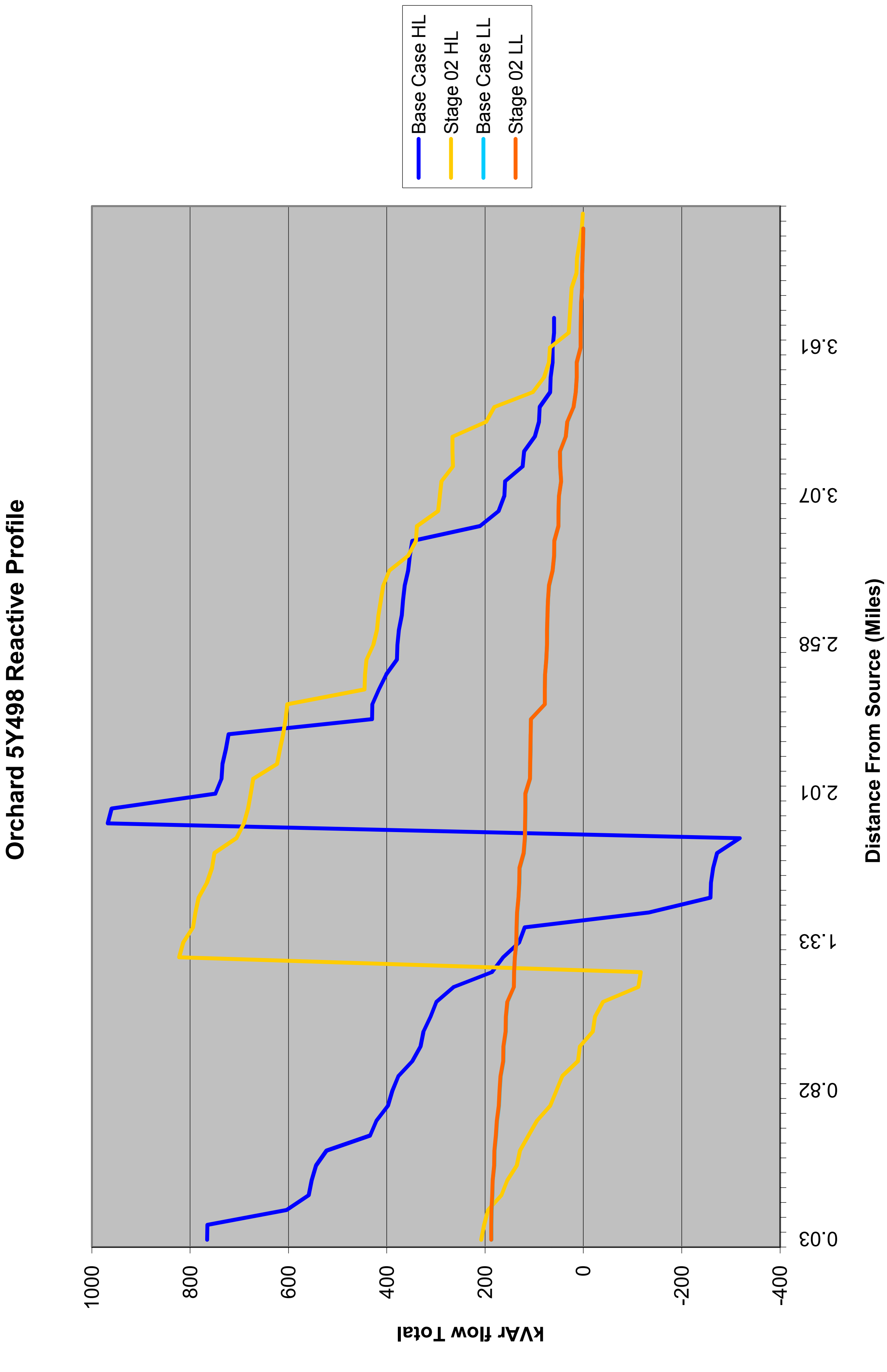

Nob Hill 5Y197 Reactive Profile
kVAr Flow Total
0
200
400
600
800
1000
1200
Distance From Source (Miles)
0.06
0.55
1.03
1.74
2.25
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL

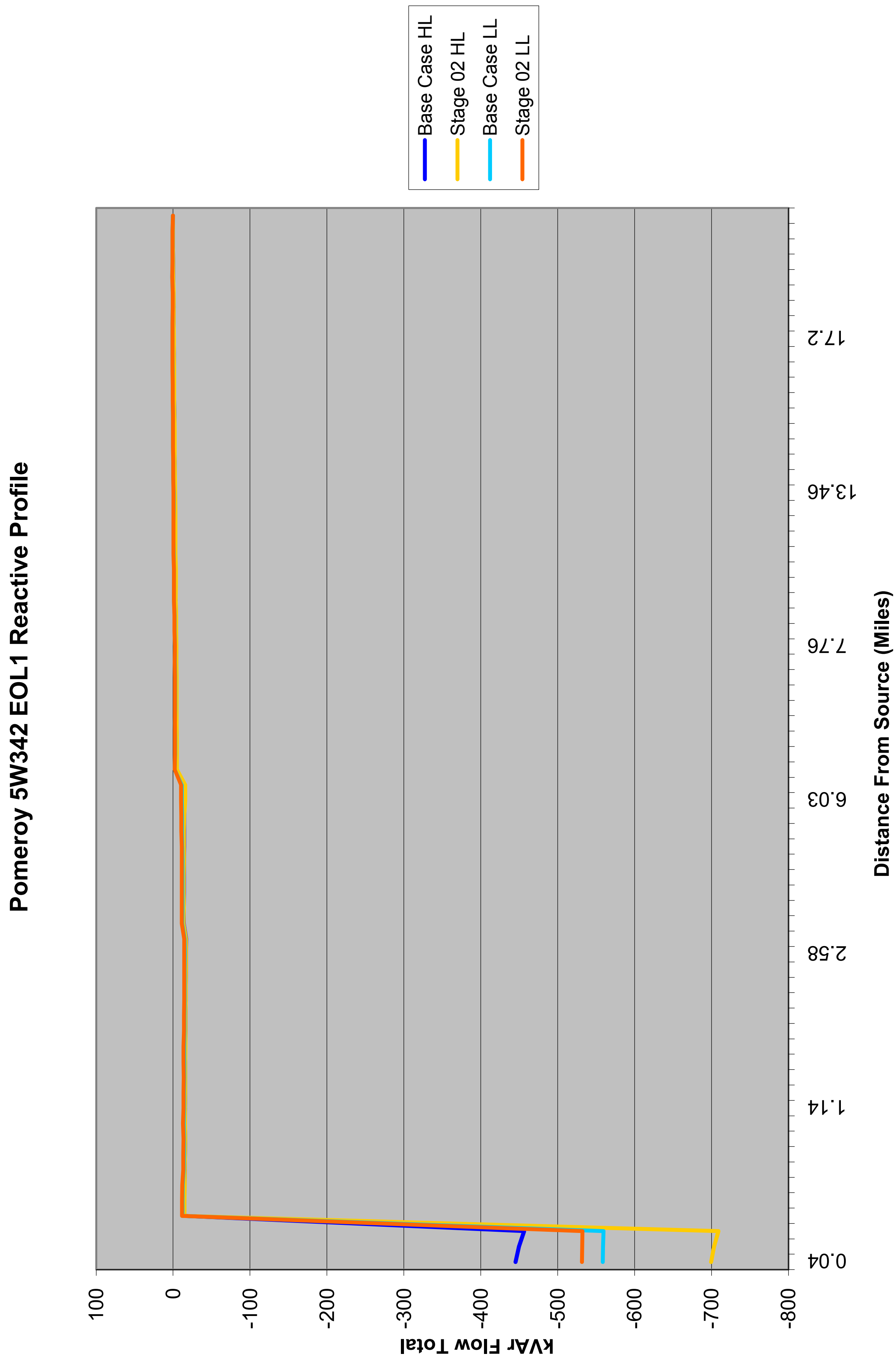


Nob Hill 5Y273 Reactive Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
kVAr Flow Total
600
400
200
0
-200
-400
-600
-800
-1000
-1200
Distance From Source (Miles)
0.07
0.88
1.29
1.8
2.52
2.94
3.52
4.07

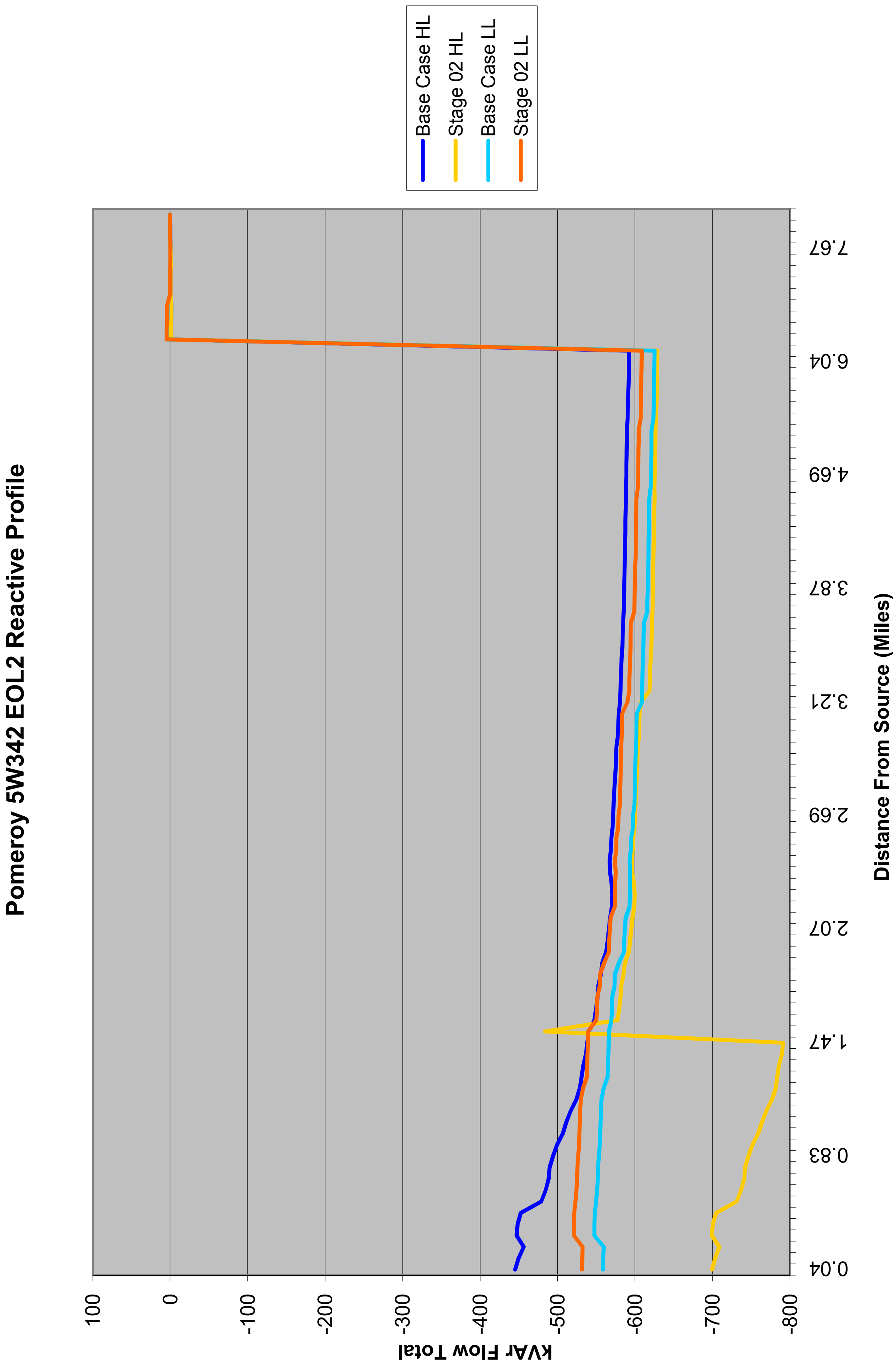

North Park 5Y356 Reactive Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
kVAr Flow Total
500
0
-500
-1000
-1500
-2000
Distance From Source (Miles)
0.04
2.15
3.20
3.76
4.35
4.84
5.63
6.07


Orchard 5Y456 Reactive Profile
kVAr flow Total
Distance From Source (Miles)
1000
800
600
400
200
0
-200
-400
-600
-800
0.04
0.7
1.25
1.8
2.4
2.91
3.4
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL

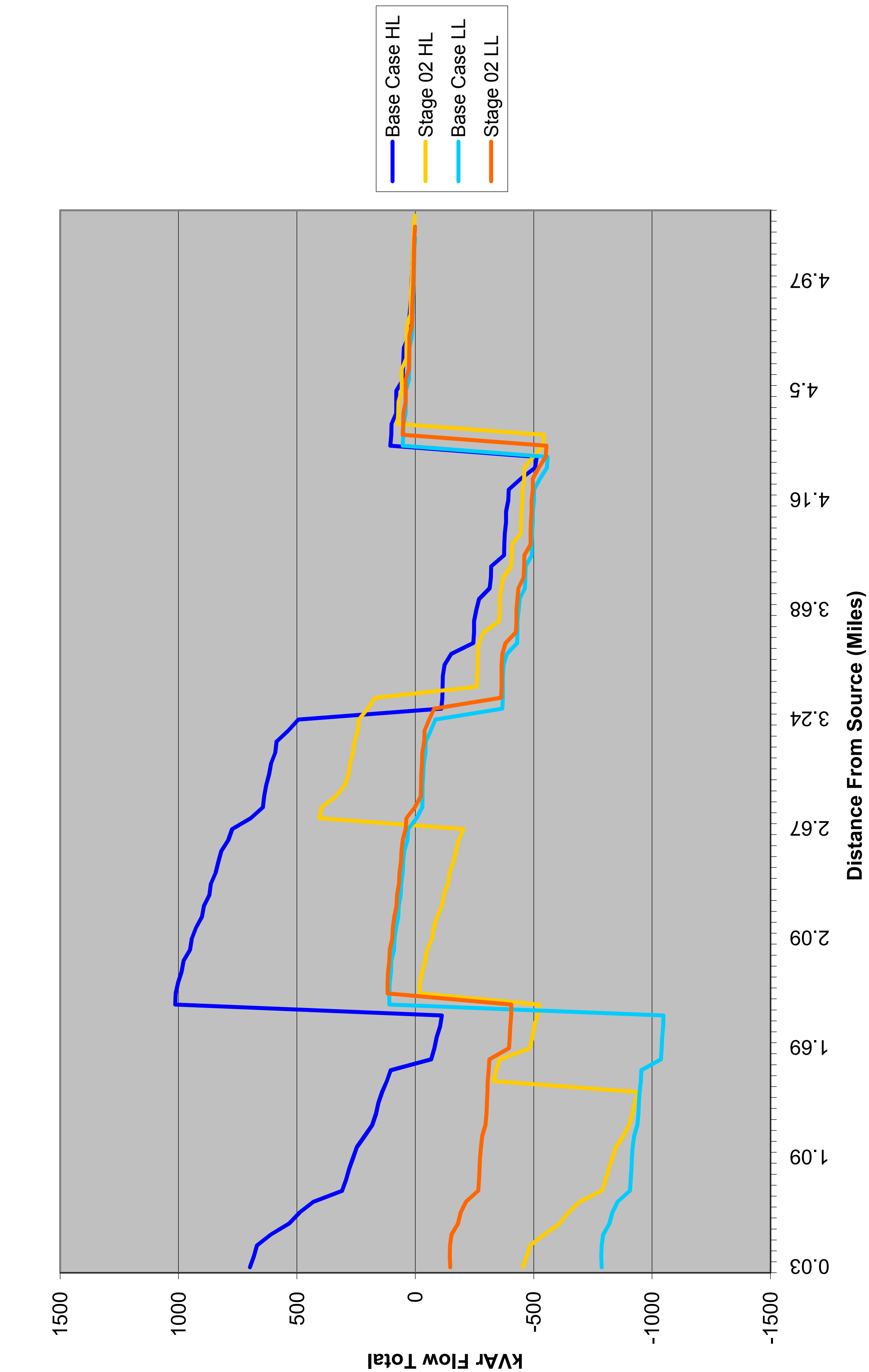

Orchard 5Y498 Reactive Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
kVAr flow Total
1000
800
600
400
200
0
-200
-400
Distance From Source (Miles)
0.03
0.82
1.33
2.01
2.58
3.07
3.61

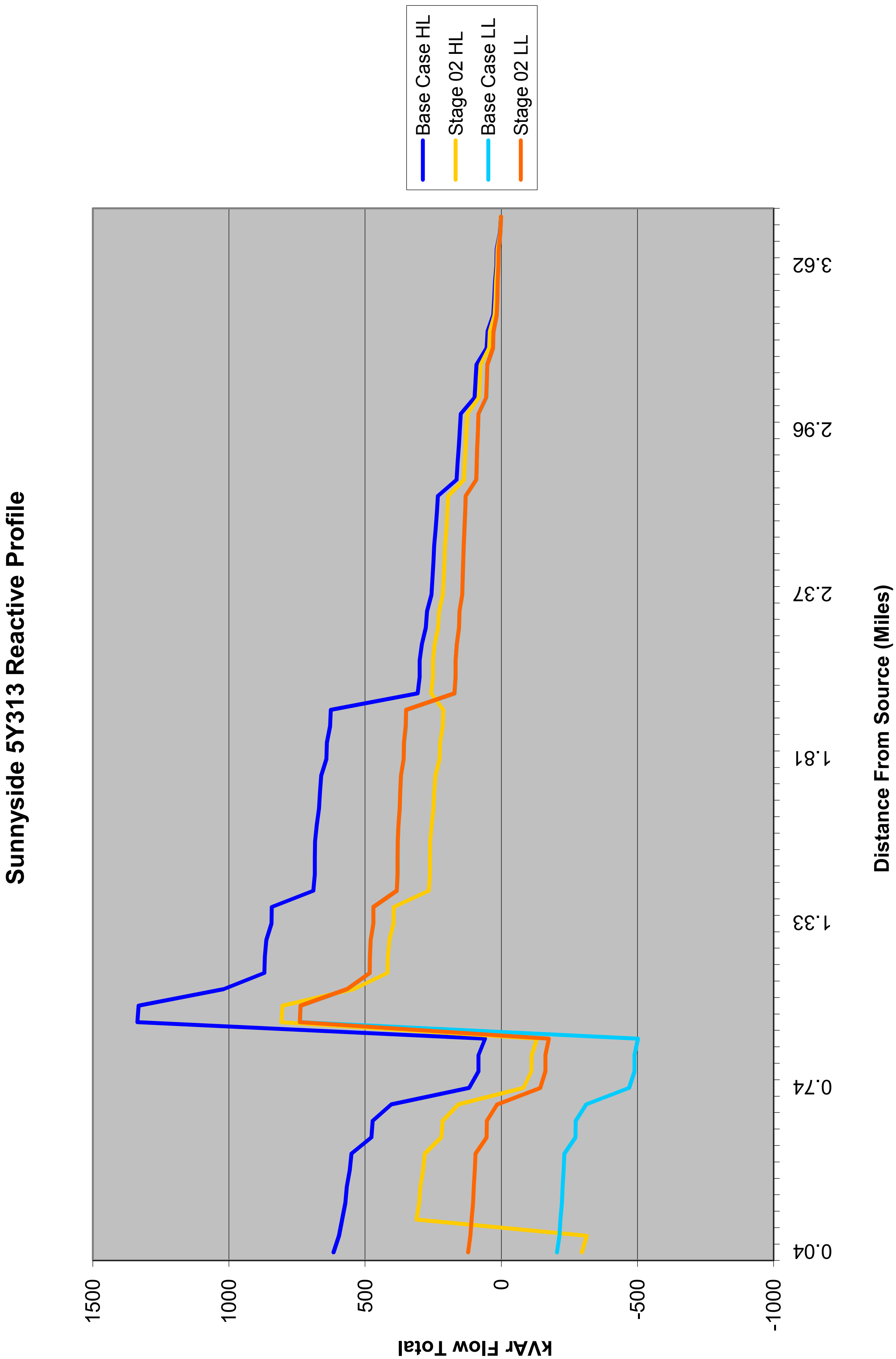


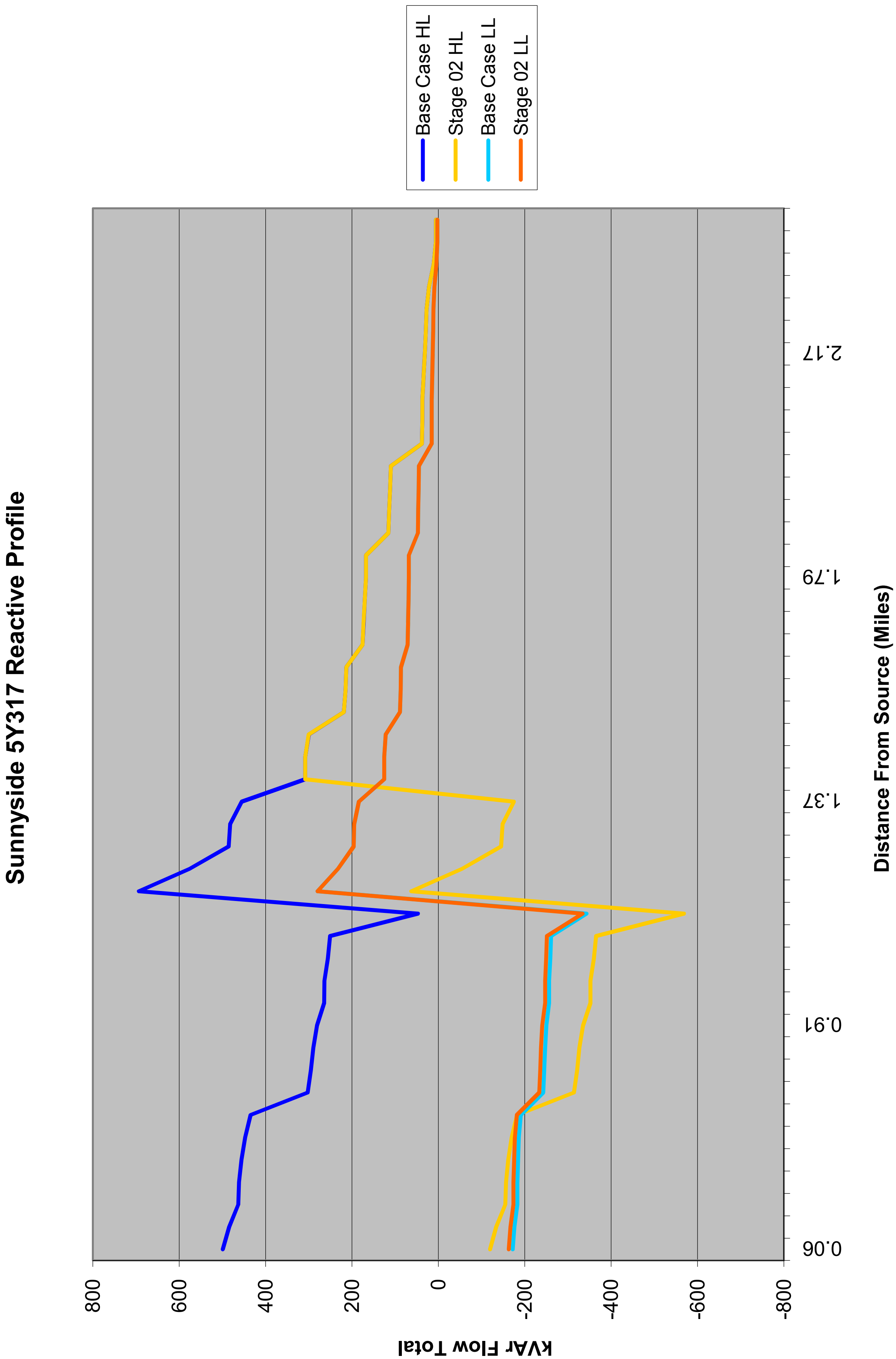
Pomeroy 5W342 EOL1 Reactive Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
kVAr Flow Total
100
0
-100
-200
-300
-400
-500
-600
-700
-800
Distance From Source (Miles)
0.04
1.14
2.58
6.03
7.76
13.46
17.2

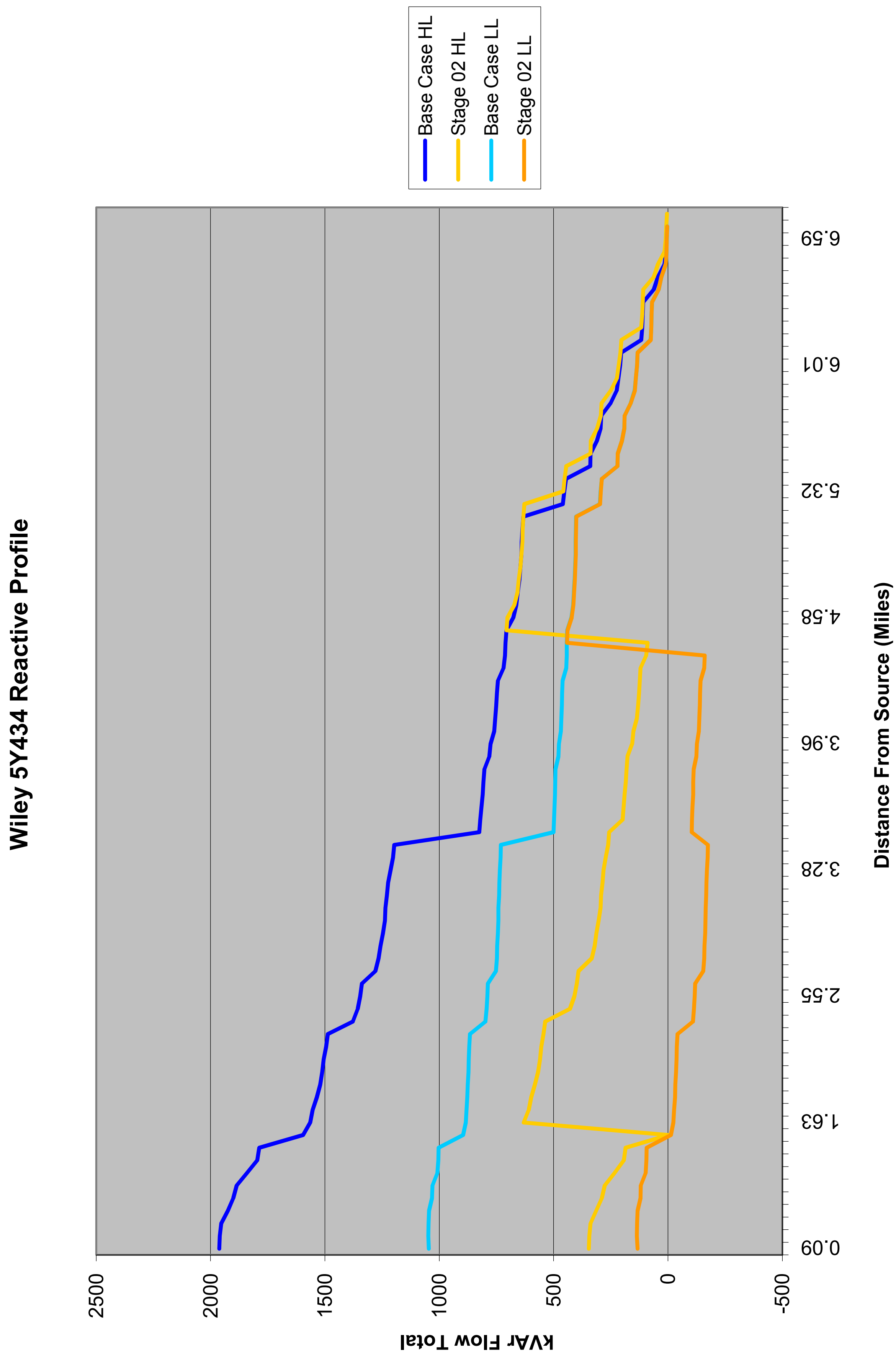

Pomeroy 5W342 EOL2 Reactive Profile
kVAr Flow Total
Distance From Source (Miles)
100
0
-100
-200
-300
-400
-500
-600
-700
-800
0.04
0.83
1.47
2.07
2.69
3.21
3.87
4.69
6.04
7.67
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL

## River Road 5Y444 Reactive Profile



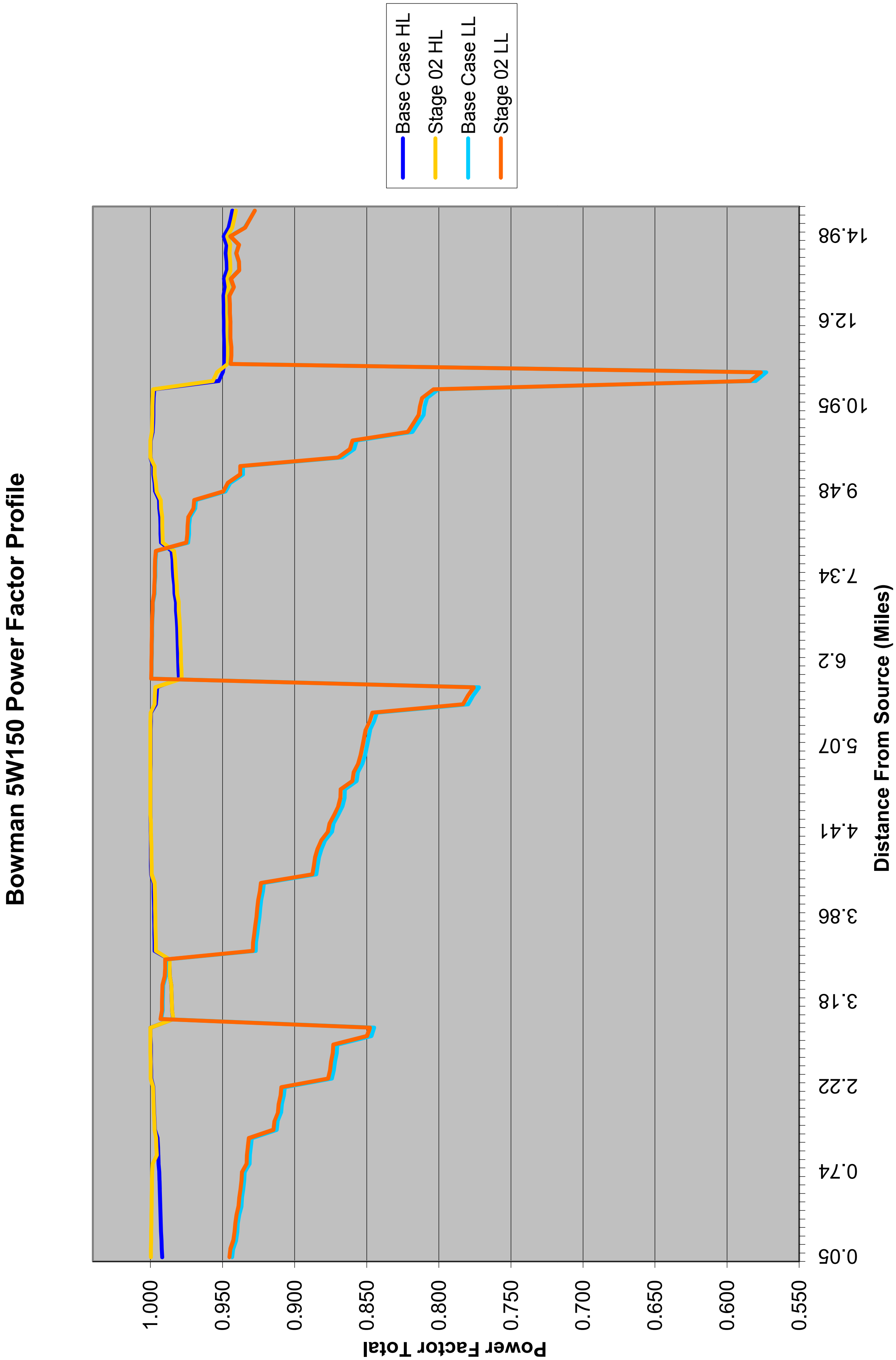

Sunnyside 5Y313 Reactive Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
kVAr Flow Total
1500
1000
500
0
-500
-1000
Distance From Source (Miles)
0.04
0.74
1.33
1.81
2.37
2.96
3.62

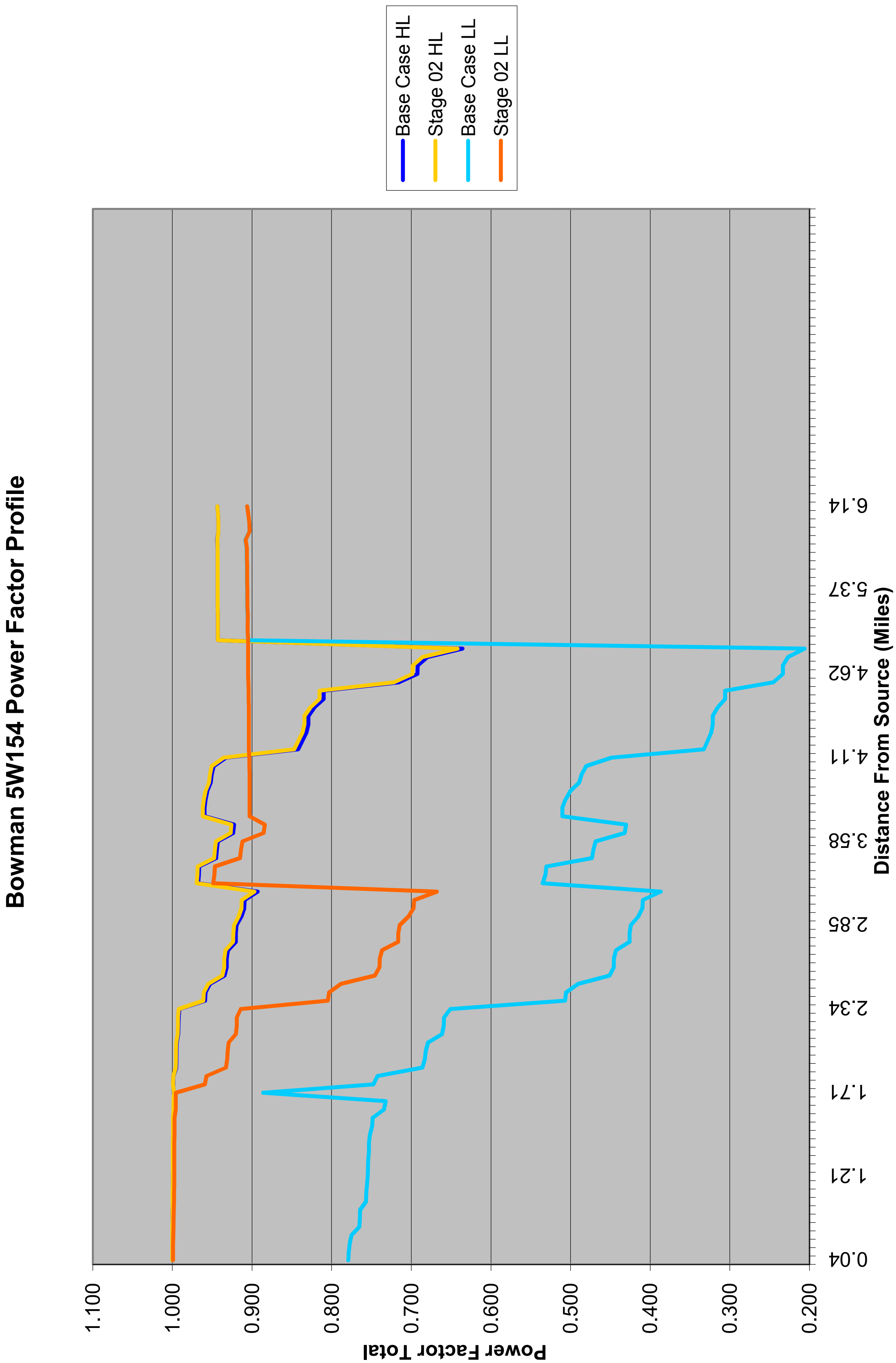

Sunnyside 5Y317 Reactive Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
kVAr Flow Total
800
600
400
200
0
-200
-400
-600
-800
Distance From Source (Miles)
0.06
0.91
1.37
1.79
2.17

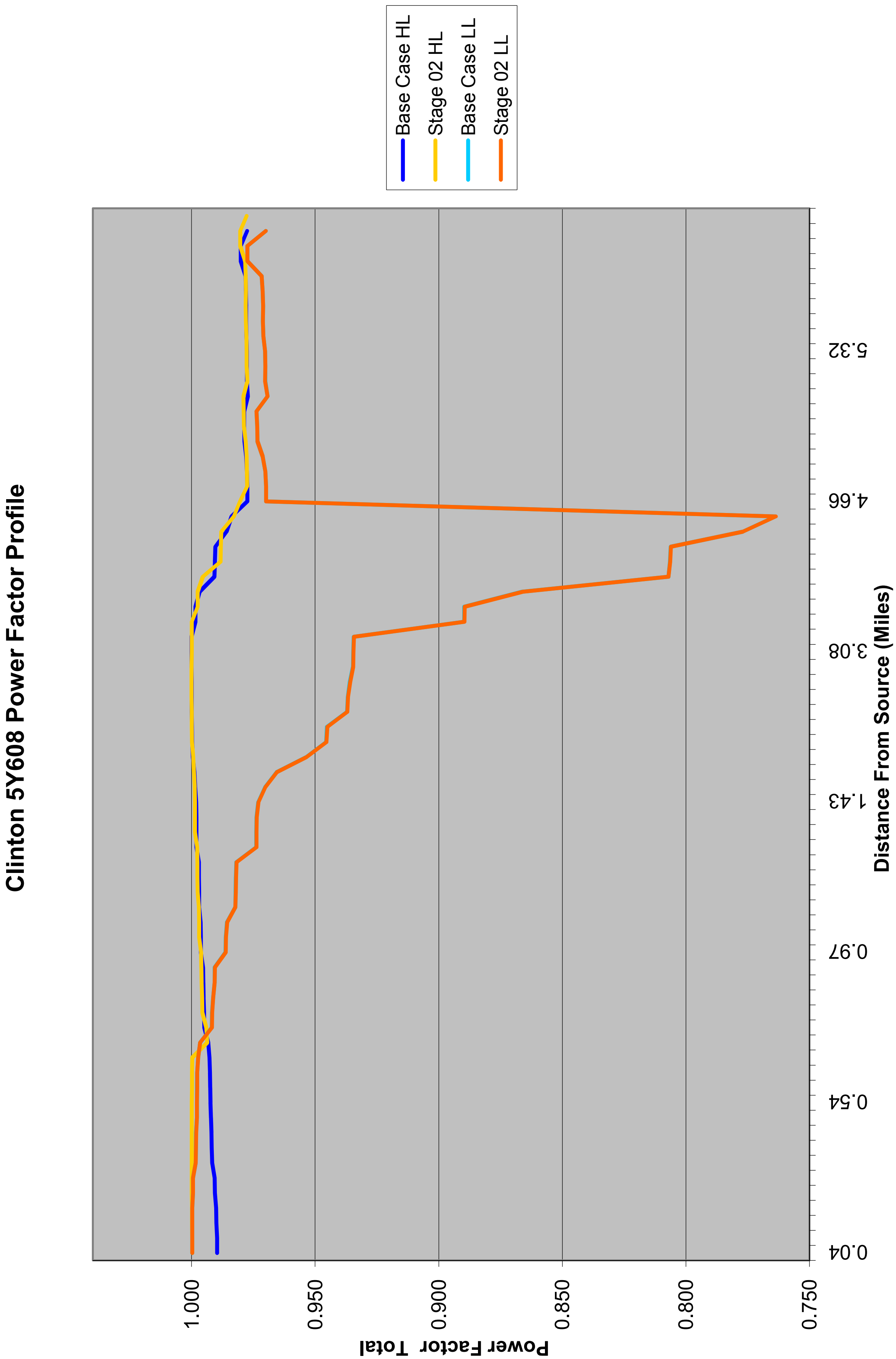


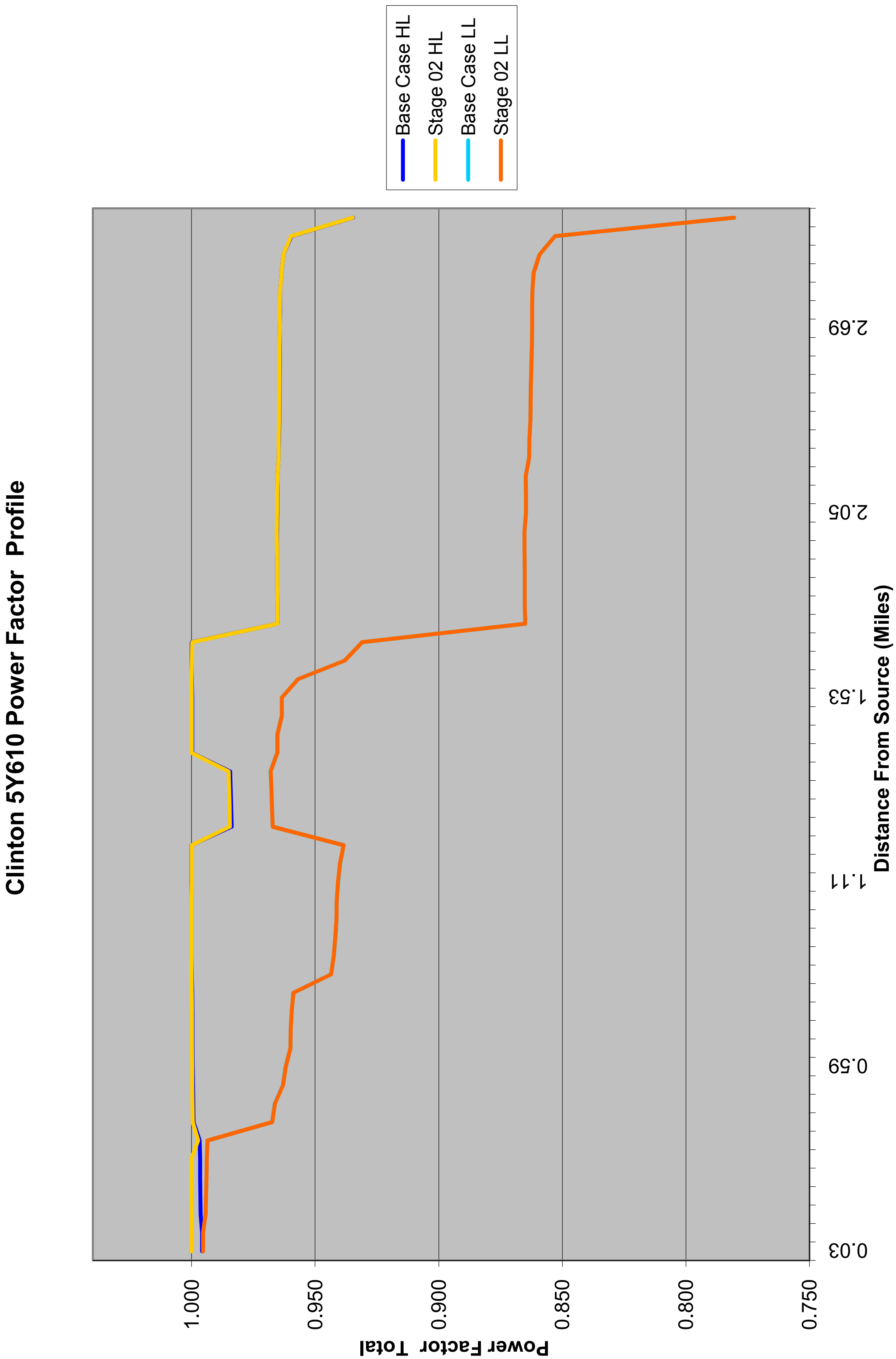
Wiley 5Y434 Reactive Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
kVAr Flow Total
2500
2000
1500
1000
500
0
-500
0.09
1.63
2.55
3.28
3.96
4.58
5.32
6.01
6.59
Distance From Source (Miles)

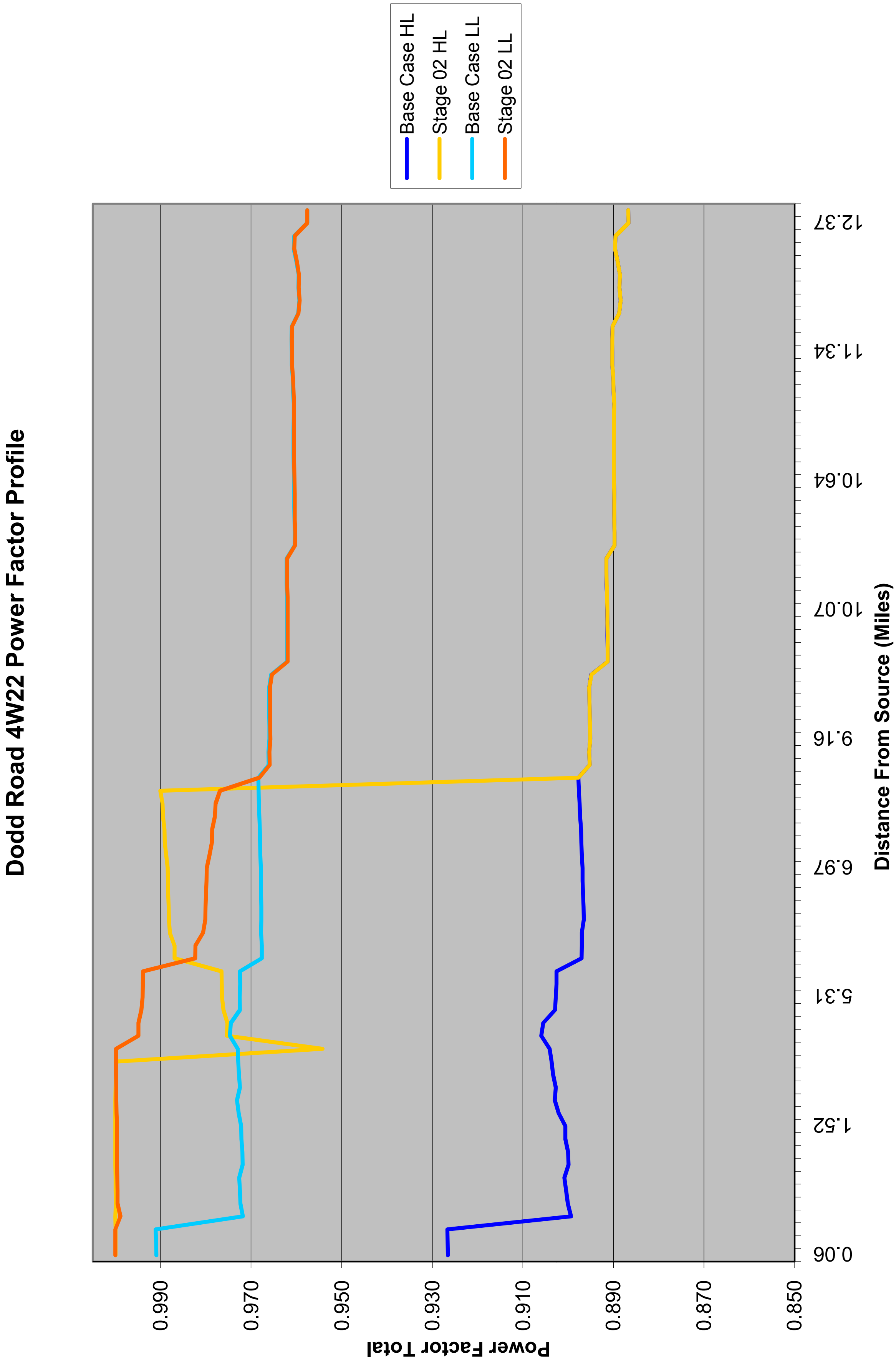
## Appendix 15: Power Factor Profiles

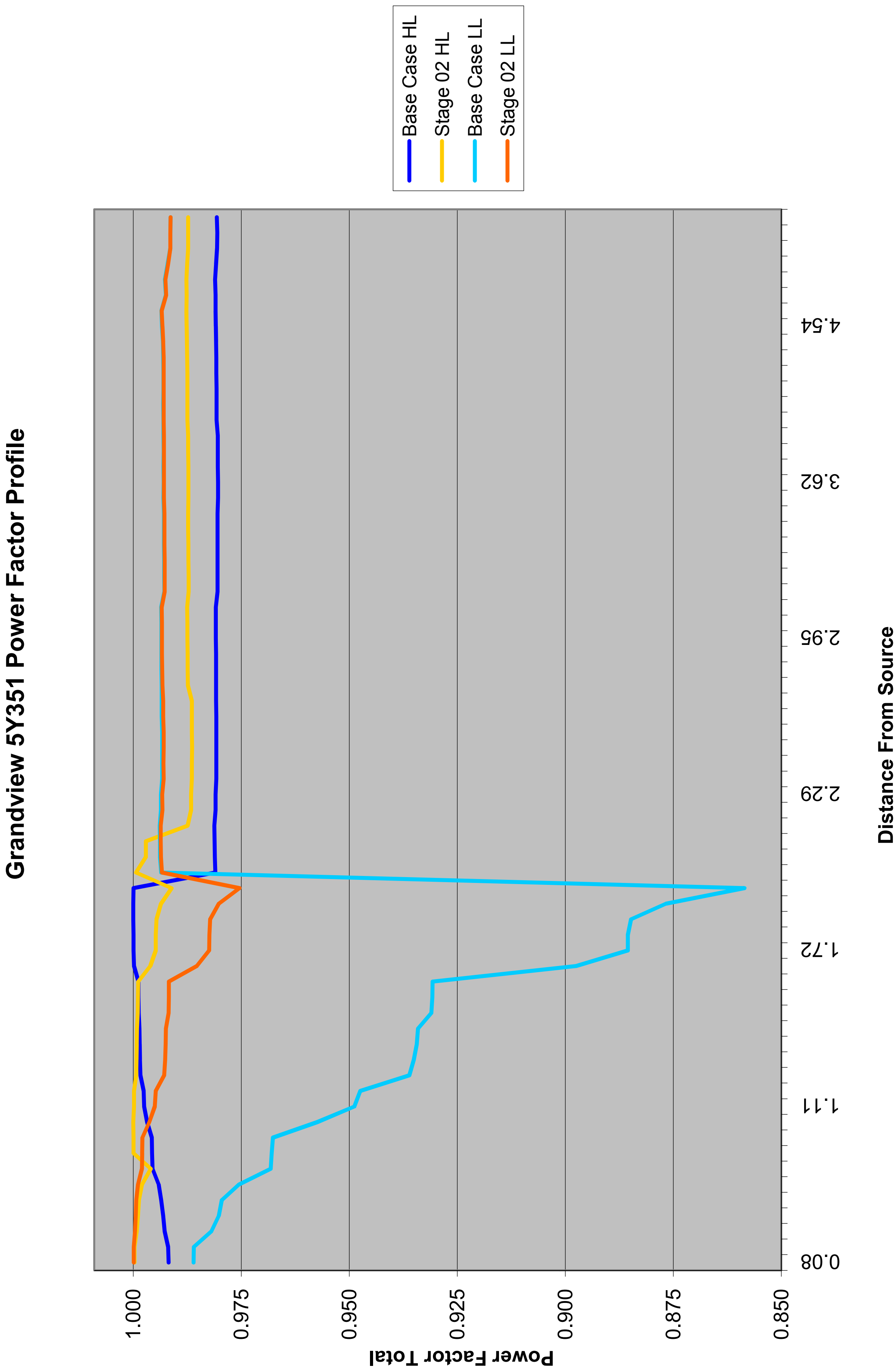

Bowman 5W150 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
Power Factor Total
1.000
0.950
0.900
0.850
0.800
0.750
0.700
0.650
0.600
0.550
0.05
0.74
2.22
3.18
3.86
4.41
5.07
6.2
7.34
9.48
10.95
12.6
14.98
Distance From Source (Miles)

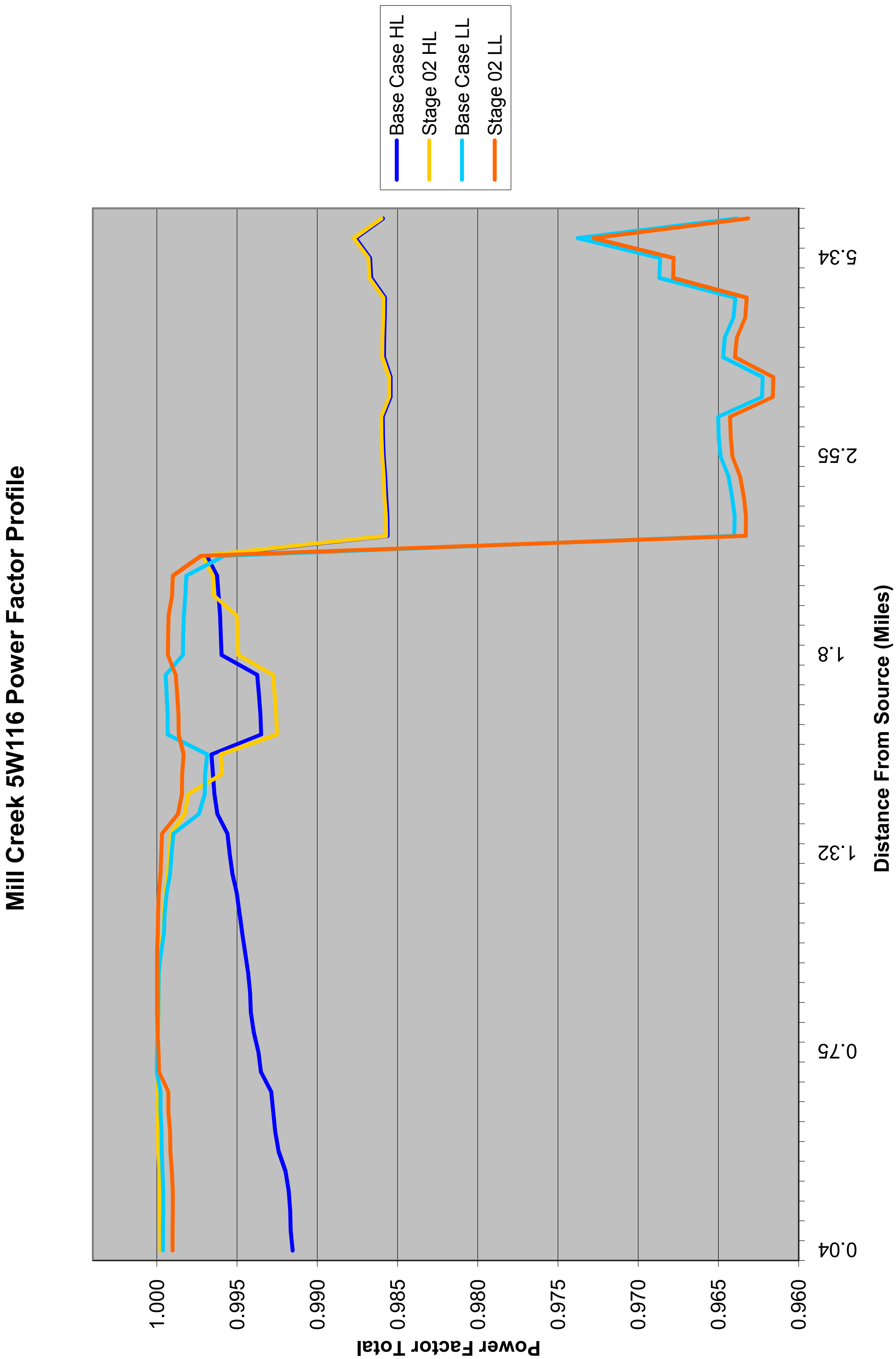

Bowman 5W154 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
Power Factor Total
1.100
1.000
0.900
0.800
0.700
0.600
0.500
0.400
0.300
0.200
0.04
1.21
1.71
2.34
2.85
3.58
4.11
4.62
5.37
6.14
Distance From Source (Miles)

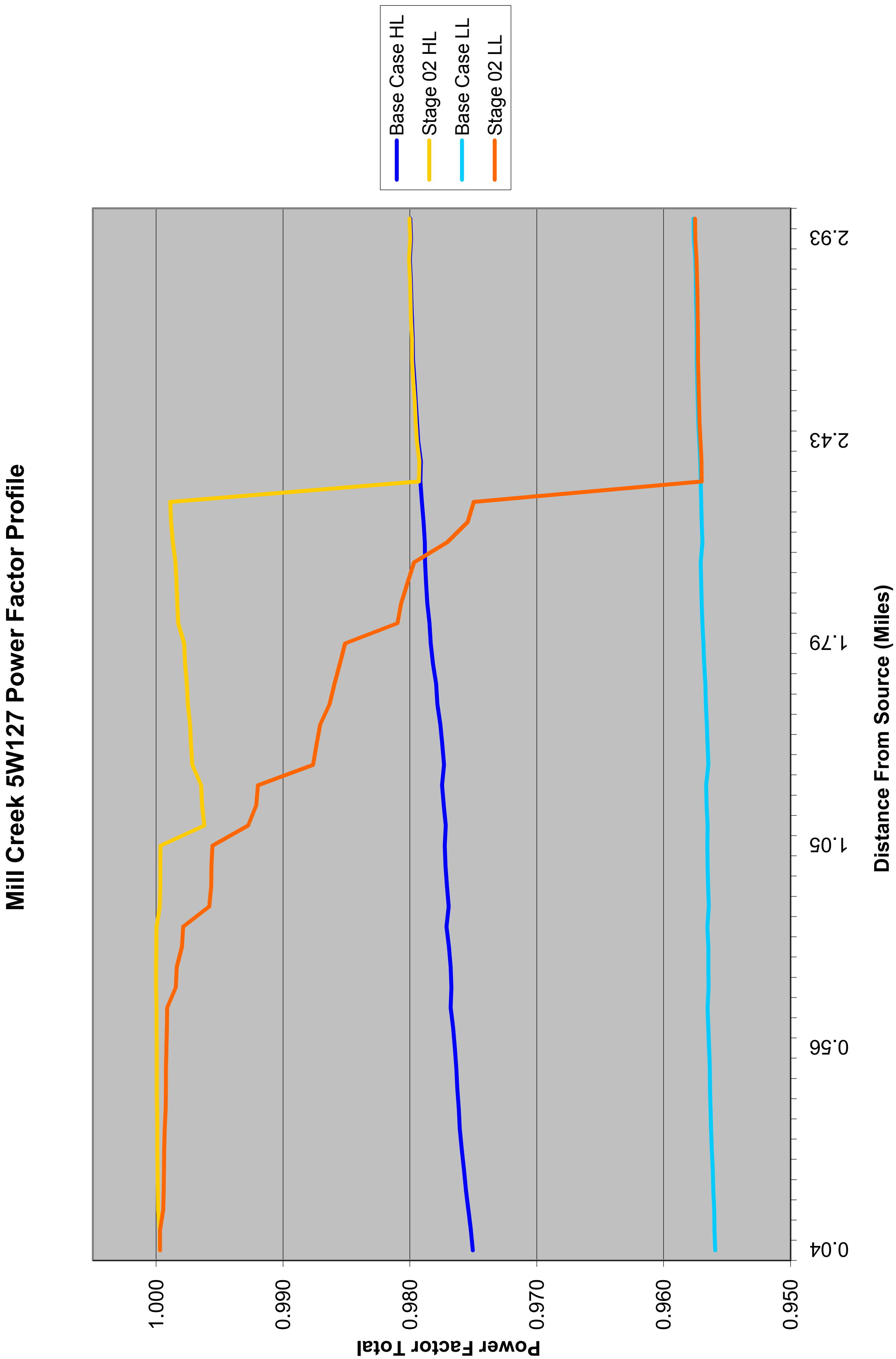

Clinton 5Y608 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
1.000
0.950
0.900
0.850
0.800
0.750
Power Factor Total
0.04
0.54
0.97
1.43
3.08
4.66
5.32
Distance From Source (Miles)


Clinton 5Y610 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
Power Factor Total
1.000
0.950
0.900
0.850
0.800
0.750
Distance From Source (Miles)
0.03
0.59
1.11
1.53
2.05
2.69

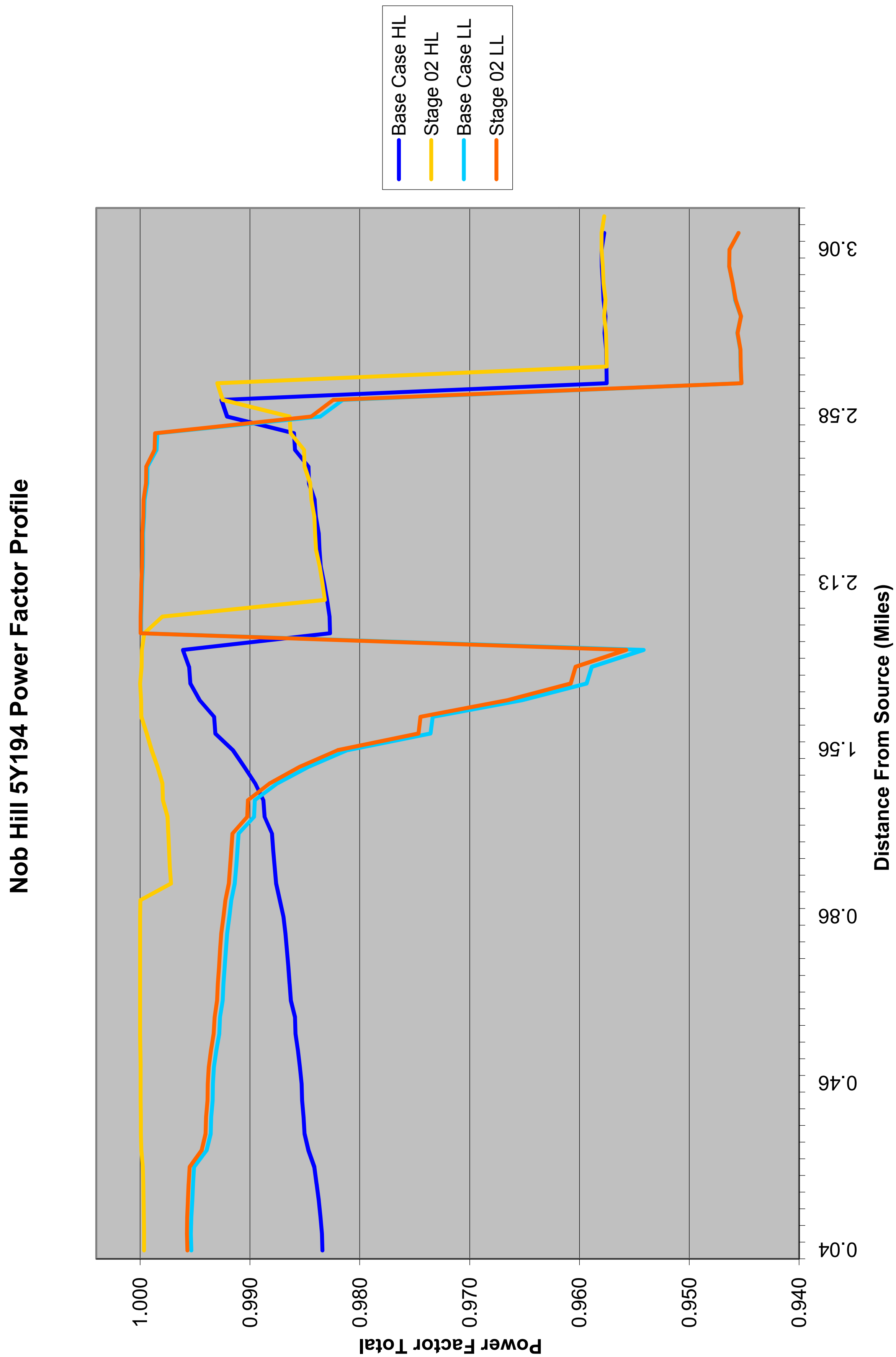

Dodd Road 4W22 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
Power Factor Total
0.990
0.970
0.950
0.930
0.910
0.890
0.870
0.850
Distance From Source (Miles)
0.06
1.52
5.31
6.97
9.16
10.07
10.64
11.34
12.37

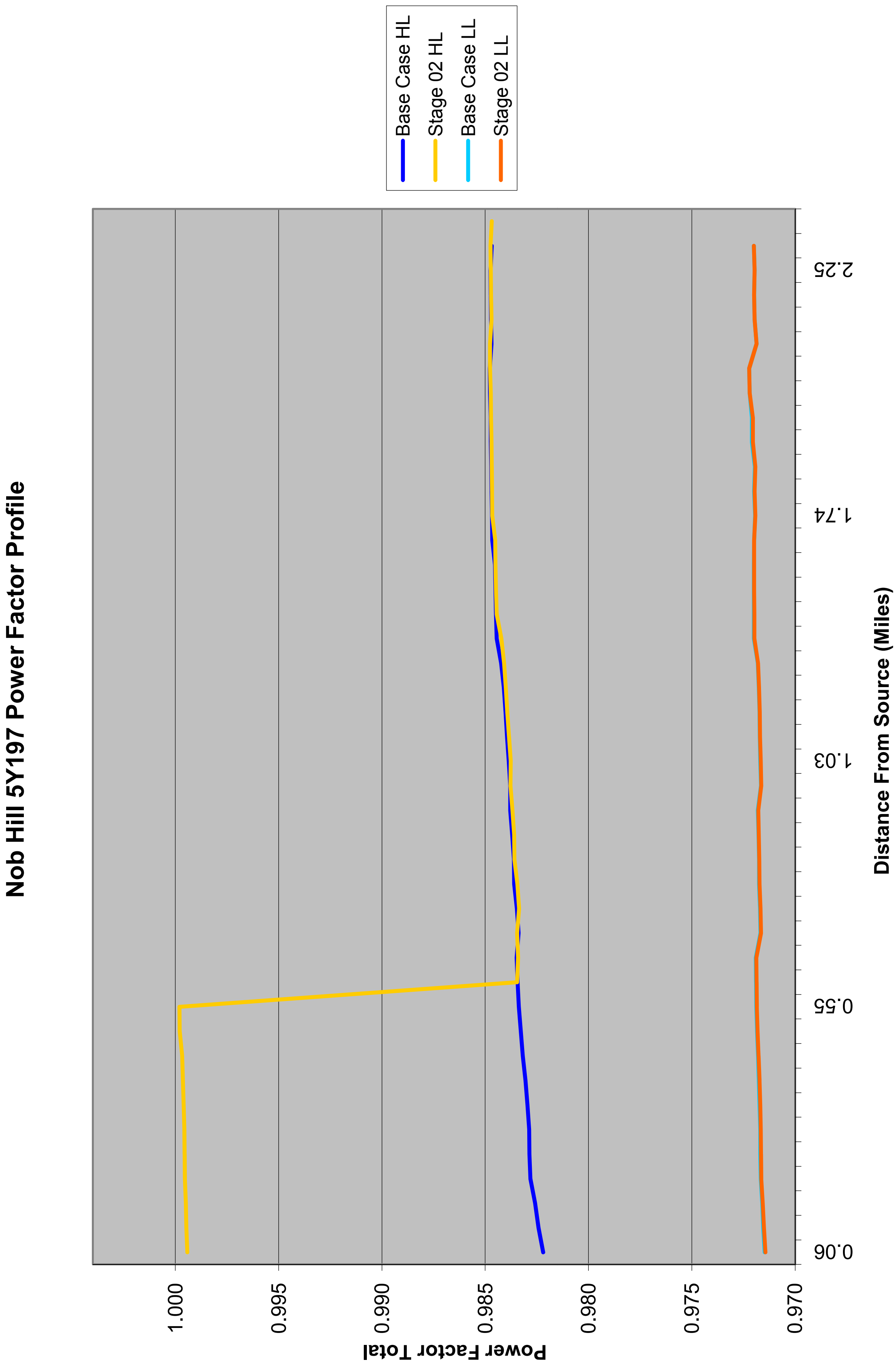

Grandview 5Y351 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
Power Factor Total
1.000
0.975
0.950
0.925
0.900
0.875
0.850
Distance From Source
0.08
1.11
1.72
2.29
2.95
3.62
4.54

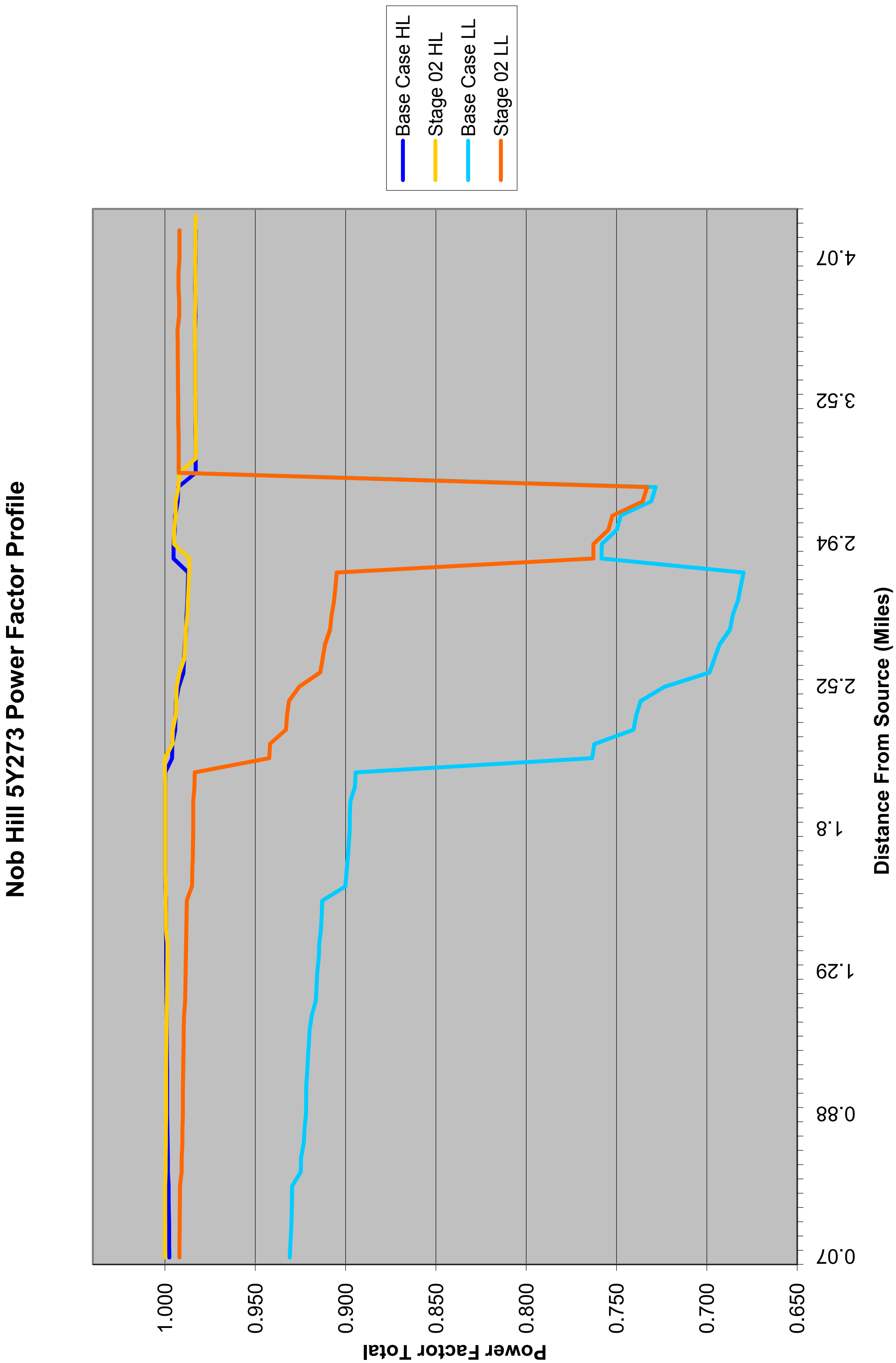

Mill Creek 5W116 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
Power Factor Total
1.000
0.995
0.990
0.985
0.980
0.975
0.970
0.965
0.960
Distance From Source (Miles)
0.04
0.75
1.32
1.8
2.55
5.34

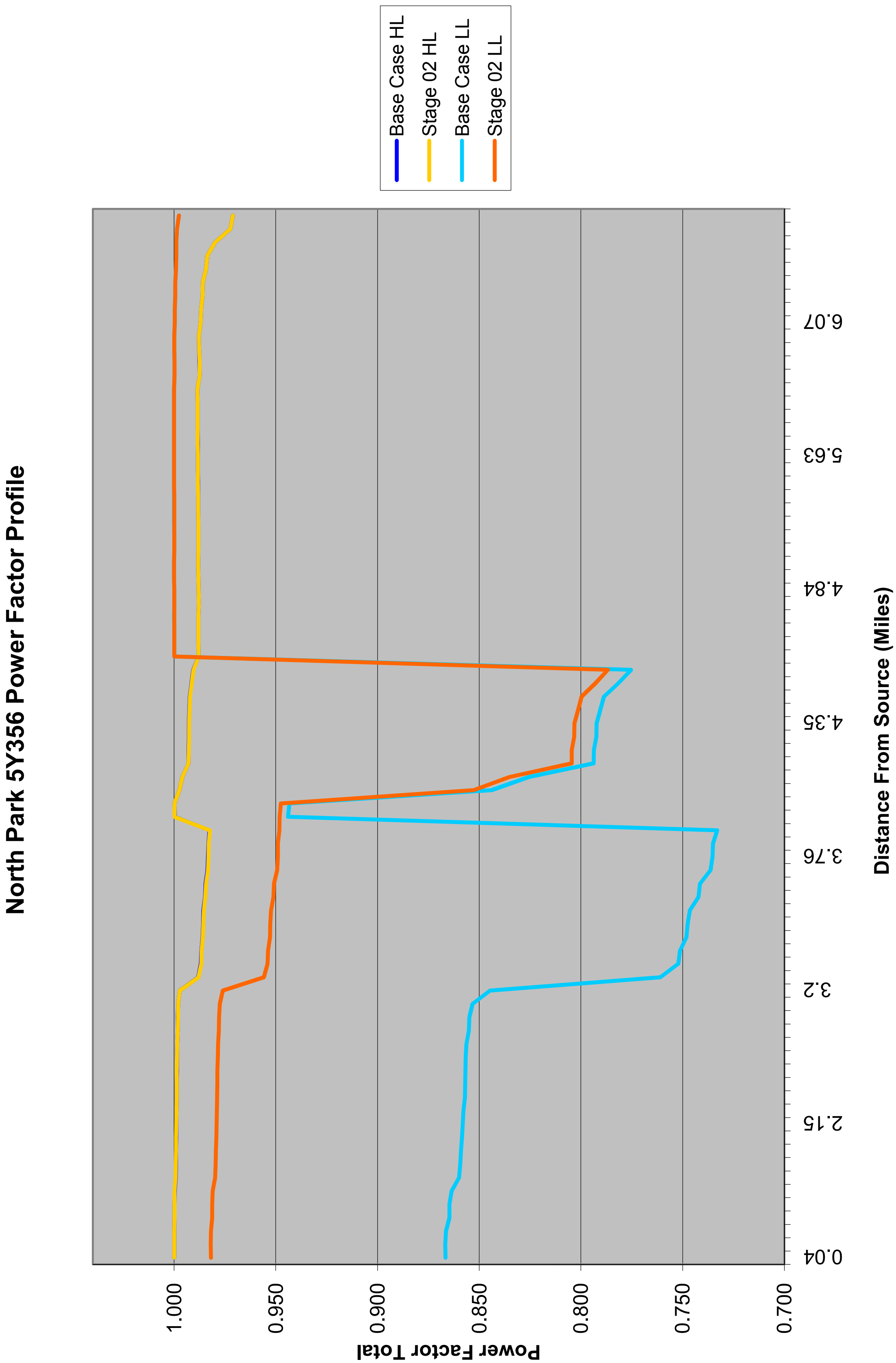


Mill Creek 5W127 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
Power Factor Total
1.000
0.990
0.980
0.970
0.960
0.950
Distance From Source (Miles)
0.04
0.56
1.05
1.79
2.43
2.93

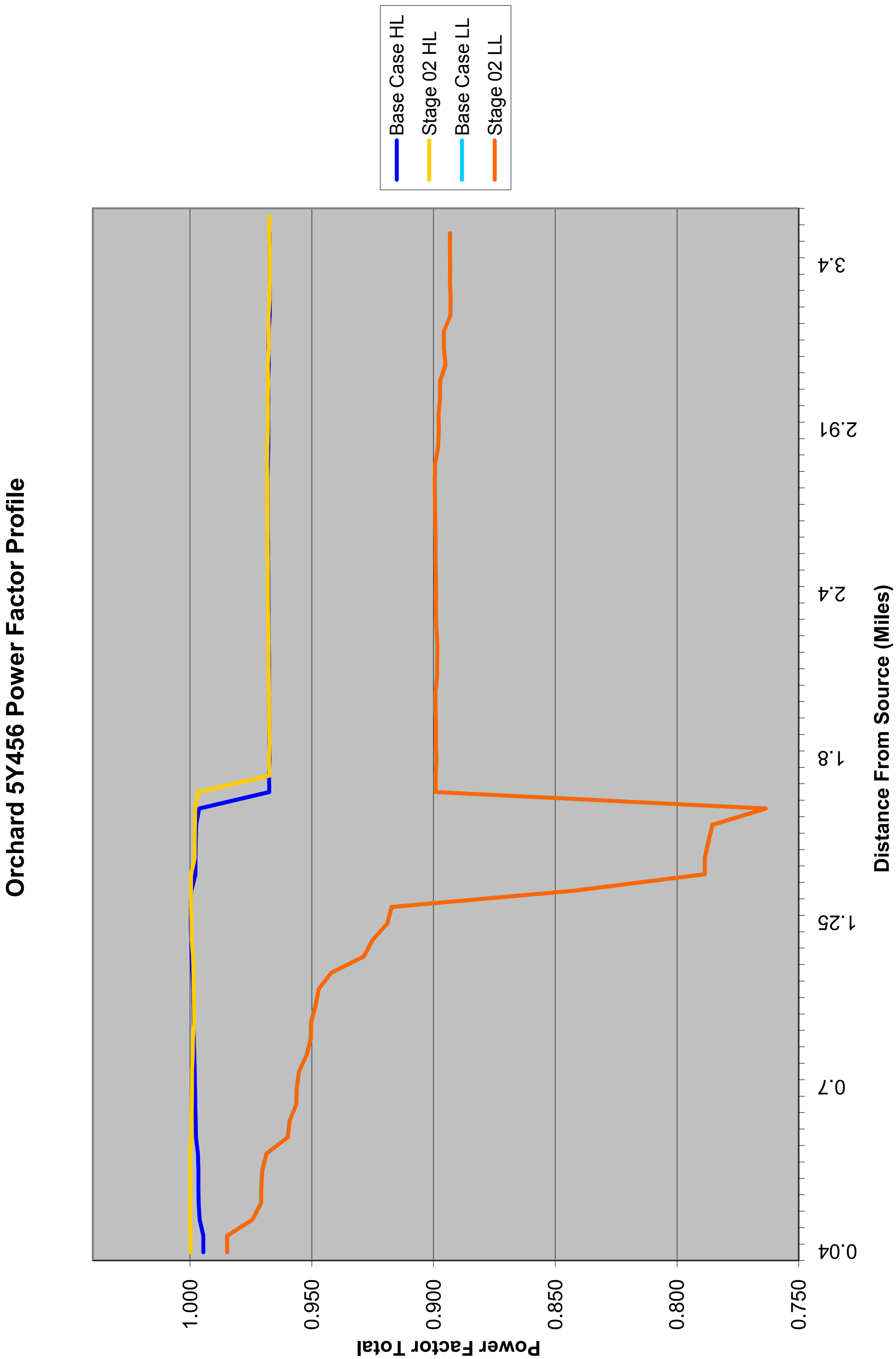

Nob Hill 5Y194 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
Power Factor Total
1.000
0.990
0.980
0.970
0.960
0.950
0.940
Distance From Source (Miles)
0.04
0.46
0.86
1.56
2.13
2.58
3.06

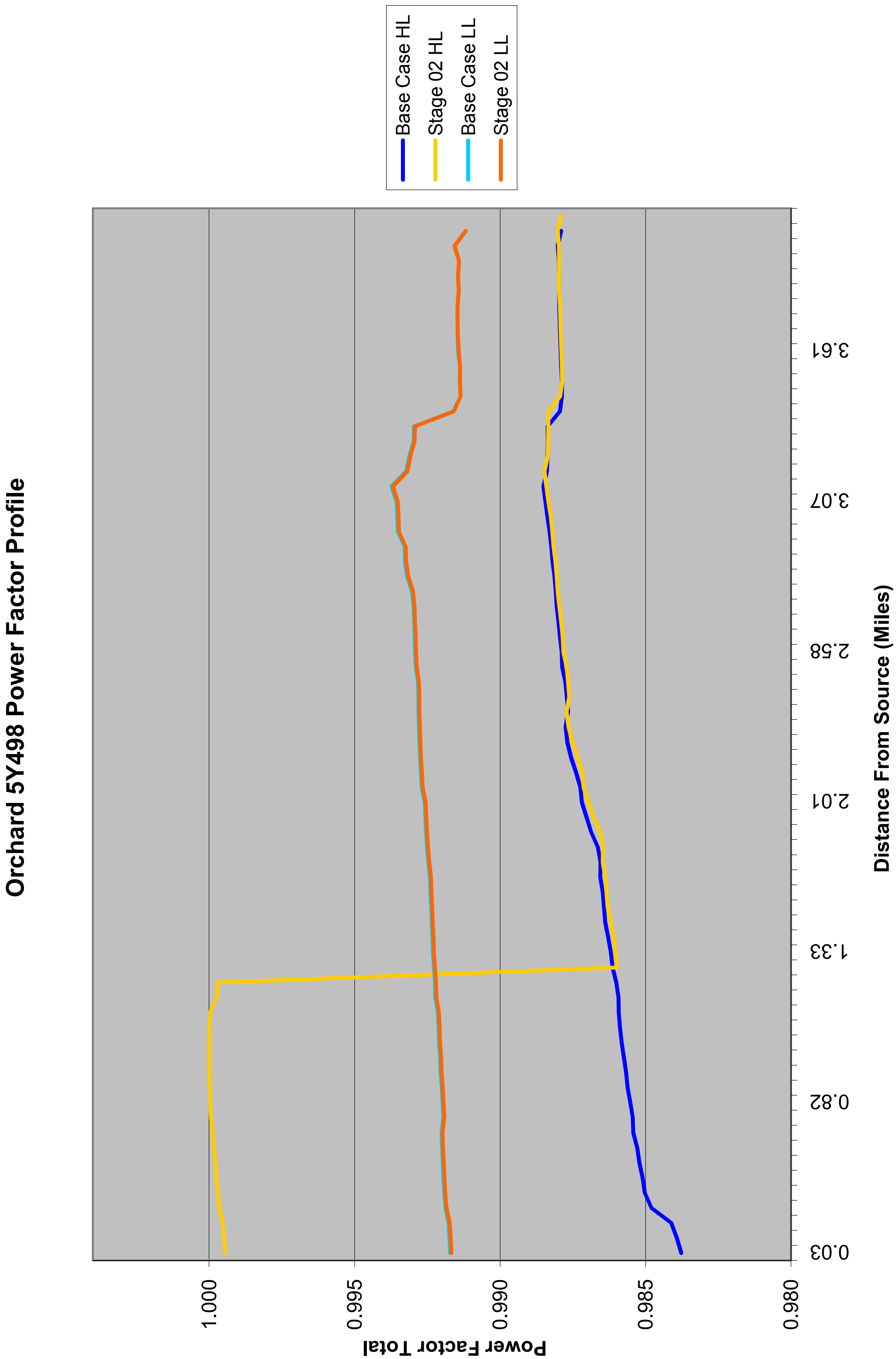

Nob Hill 5Y197 Power Factor Profile
Power Factor Total
1.000
0.995
0.990
0.985
0.980
0.975
0.970
0.06
0.55
1.03
1.74
2.25
Distance From Source (Miles)
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL

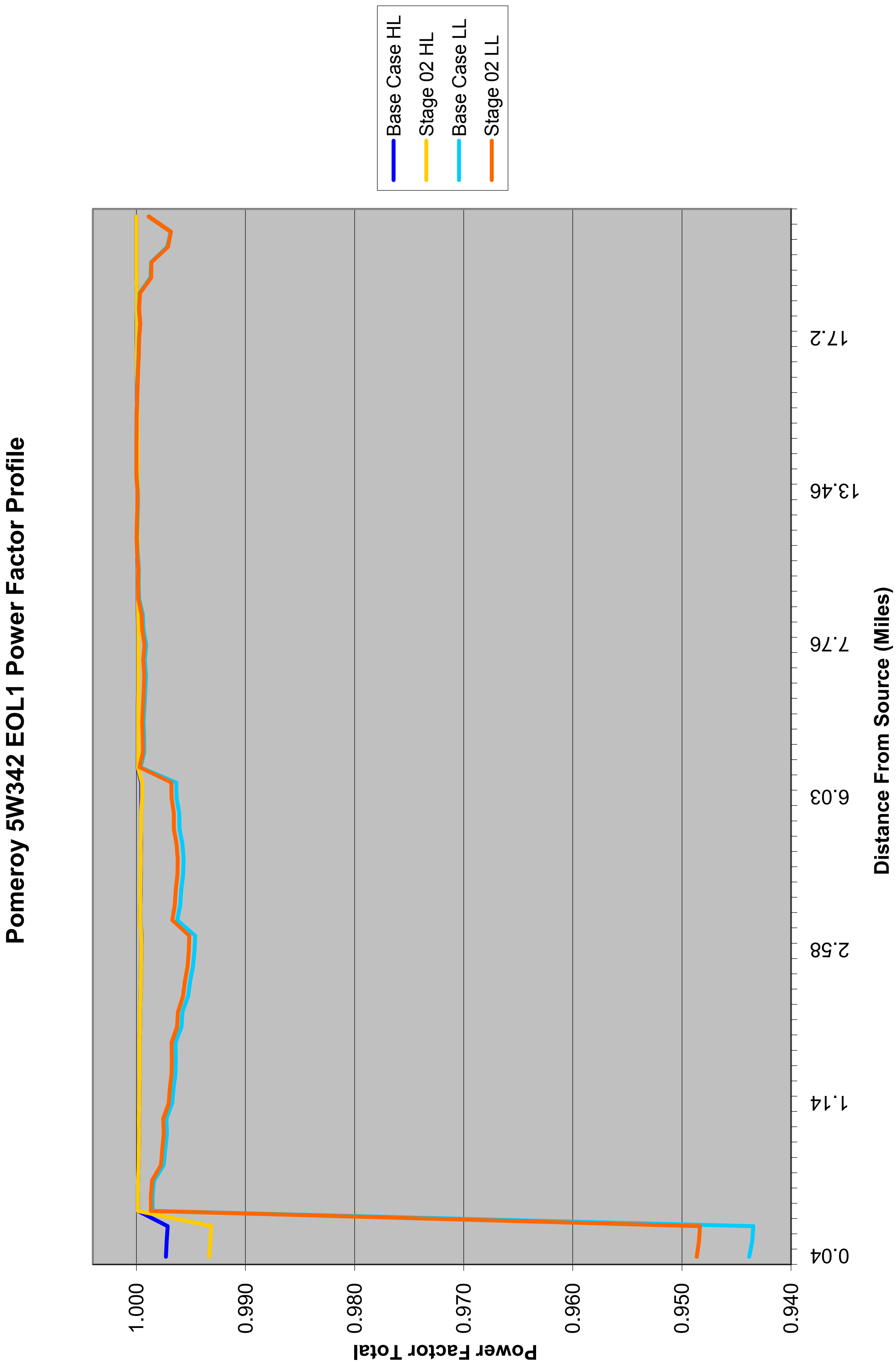

Nob Hill 5Y273 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
Power Factor Total
1.000
0.950
0.900
0.850
0.800
0.750
0.700
0.650
0.07
0.88
1.29
1.8
2.52
2.94
3.52
4.07
Distance From Source (Miles)

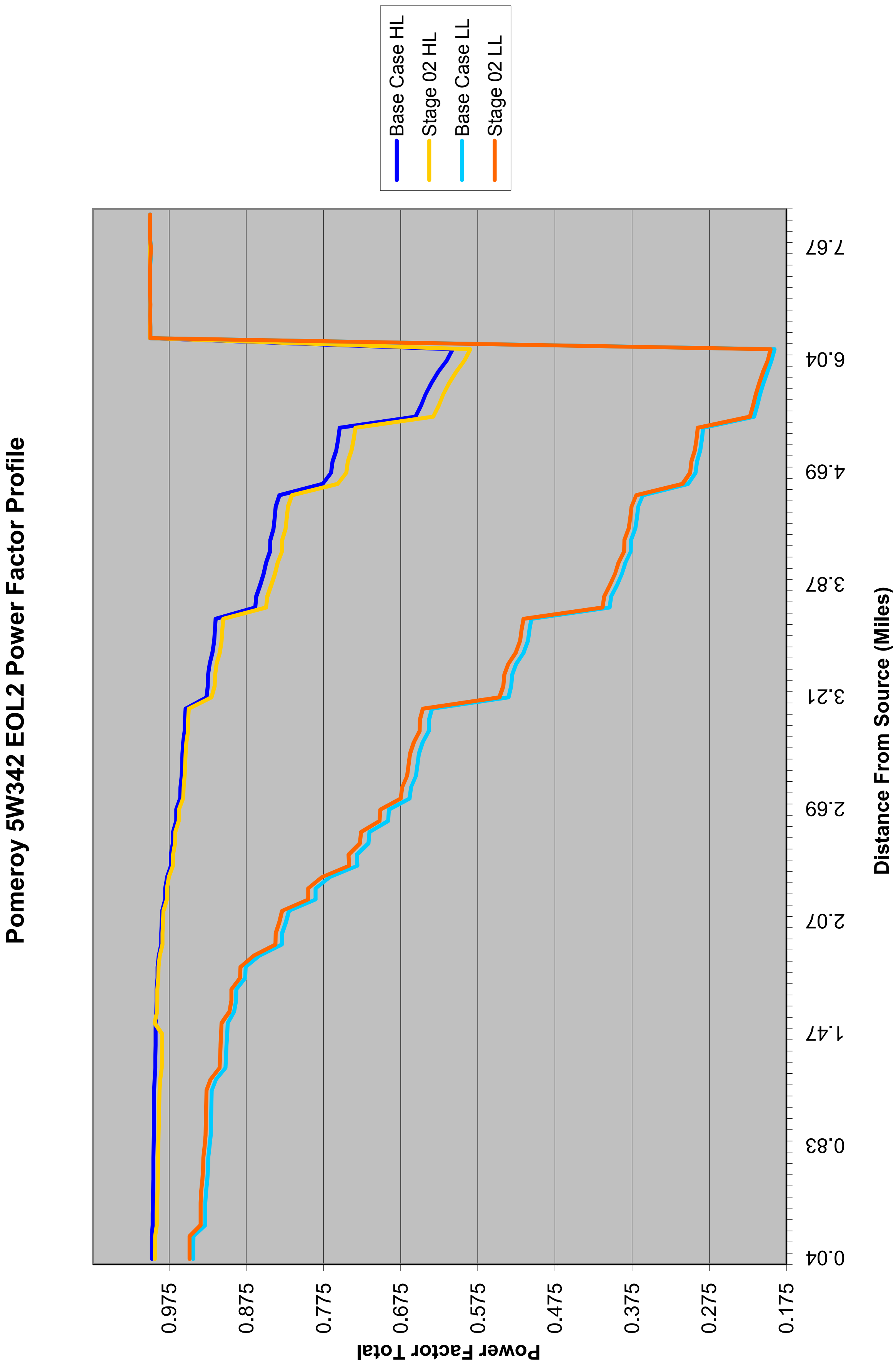


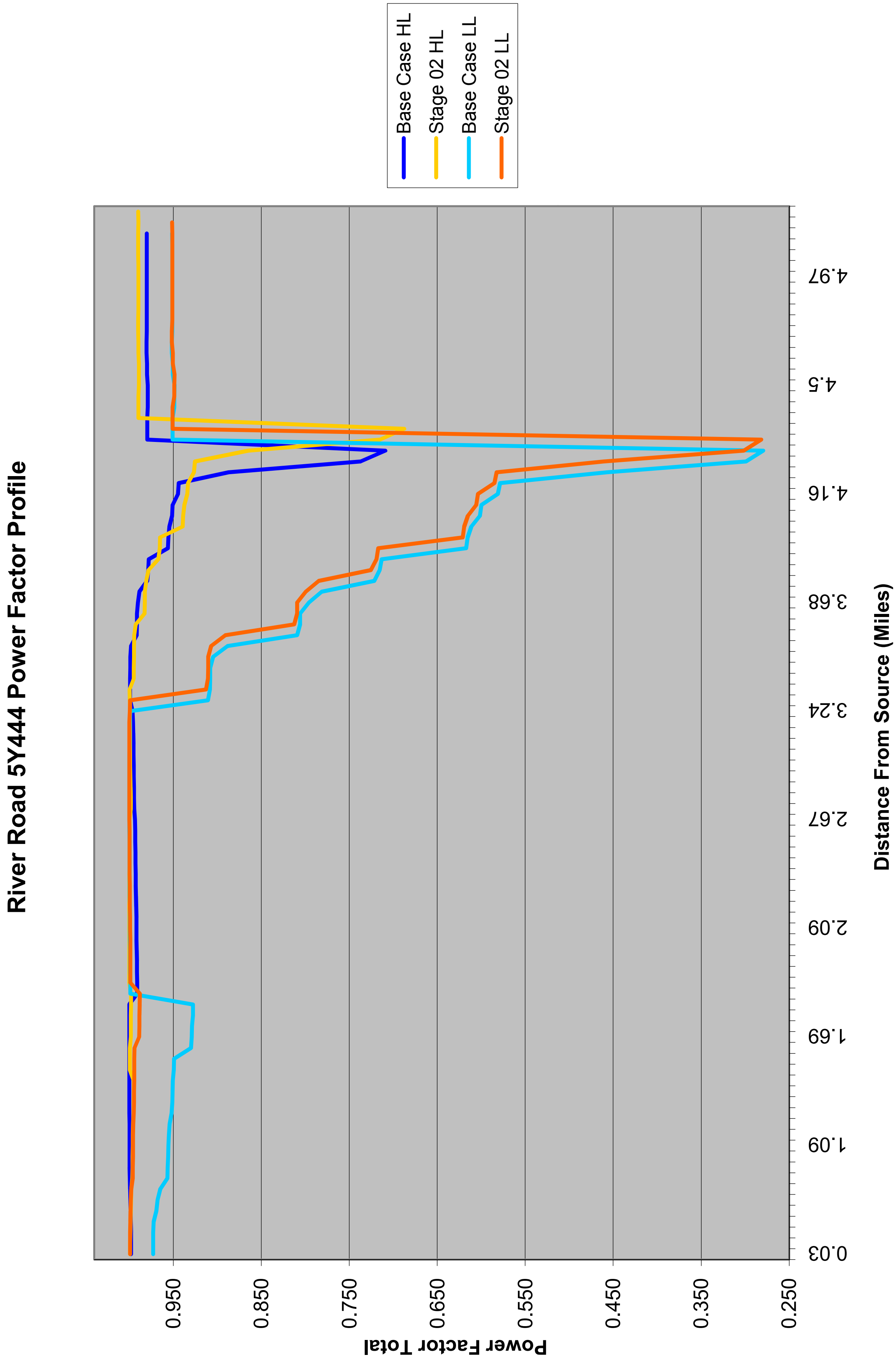
North Park 5Y356 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
Power Factor Total
1.000
0.950
0.900
0.850
0.800
0.750
0.700
Distance From Source (Miles)
0.04
2.15
3.2
3.76
4.35
4.84
5.63
6.07

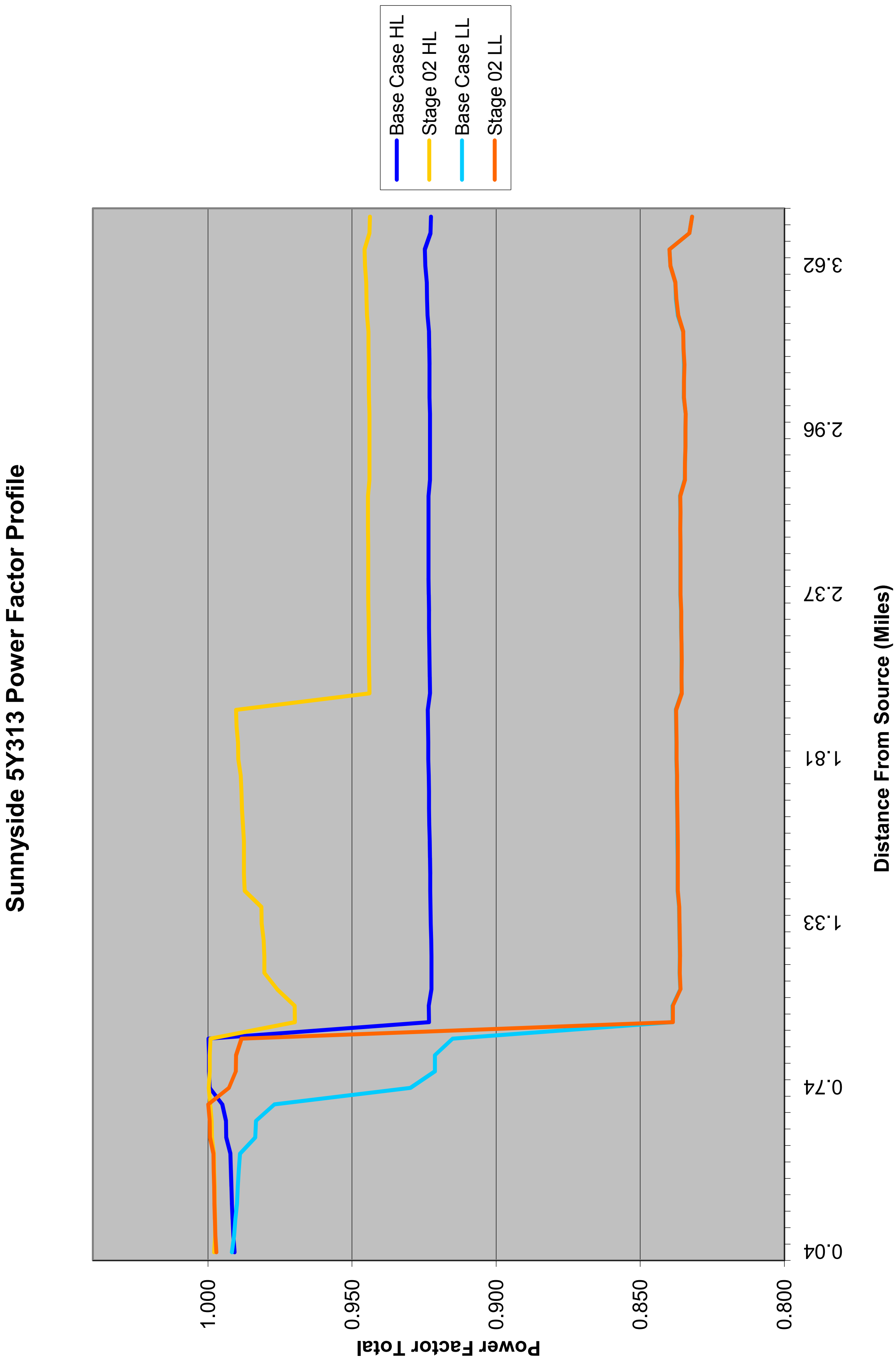

Orchard 5Y456 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
Power Factor Total
1.000
0.950
0.900
0.850
0.800
0.750
Distance From Source (Miles)
0.04
0.7
1.25
1.8
2.4
2.91
3.4

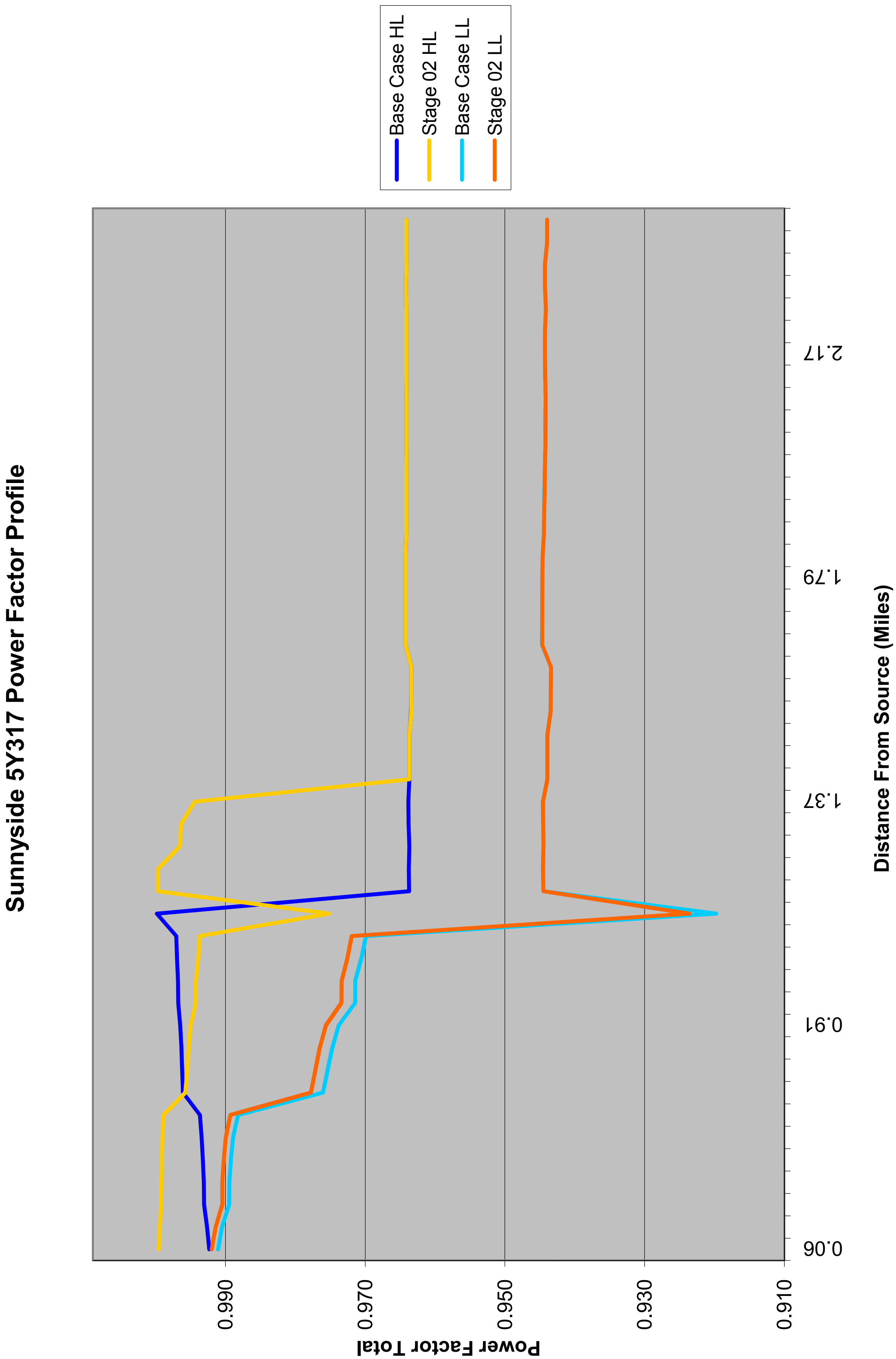

Orchard 5Y498 Power Factor Profile
Power Factor Total
1.000
0.995
0.990
0.985
0.980
Distance From Source (Miles)
0.03
0.82
1.33
2.01
2.58
3.07
3.61
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL

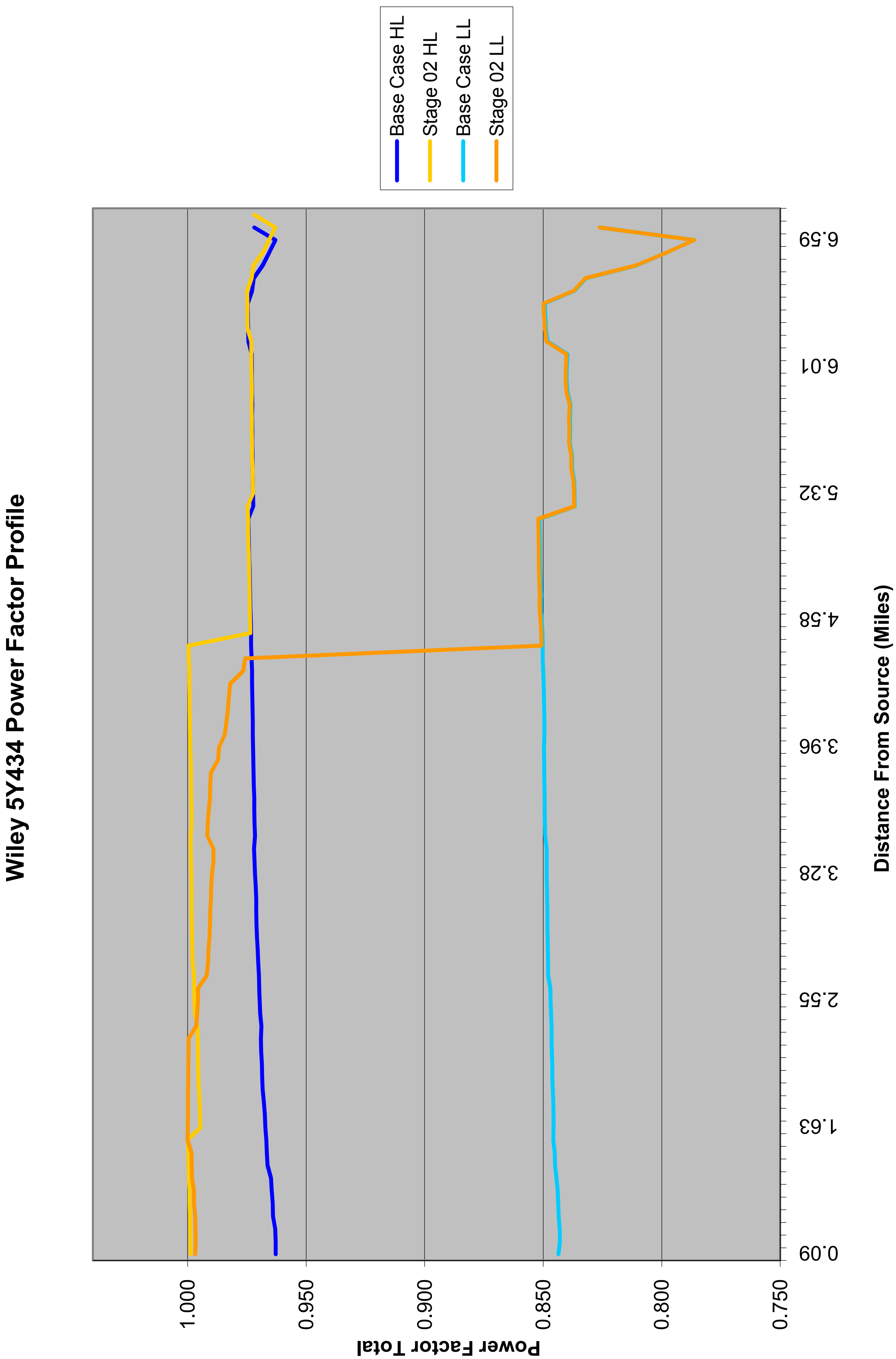

Pomeroy 5W342 EOL1 Power Factor Profile
Power Factor Total
1.000
0.990
0.980
0.970
0.960
0.950
0.940
Distance From Source (Miles)
0.04
1.14
2.58
6.03
7.76
13.46
17.2
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL


Pomeroy 5W342 EOL2 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
Power Factor Total
0.975
0.875
0.775
0.675
0.575
0.475
0.375
0.275
0.175
Distance From Source (Miles)
0.04
0.83
1.47
2.07
2.69
3.21
3.87
4.69
6.04
7.67


River Road 5Y444 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
Power Factor Total
0.950
0.850
0.750
0.650
0.550
0.450
0.350
0.250
0.03
1.09
1.69
2.09
2.67
3.24
3.68
4.16
4.5
4.97
Distance From Source (Miles)


Sunnyside 5Y313 Power Factor Profile
Power Factor Total
1.000
0.950
0.900
0.850
0.800
Distance From Source (Miles)
0.04
0.74
1.33
1.81
2.37
2.96
3.62
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL


Sunnyside 5Y317 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
Power Factor Total
0.990
0.970
0.950
0.930
0.910
Distance From Source (Miles)
0.06
0.91
1.37
1.79
2.17


Wiley 5Y434 Power Factor Profile
Base Case HL
Stage 02 HL
Base Case LL
Stage 02 LL
Power Factor Total
1.000
0.950
0.900
0.850
0.800
0.750
Distance From Source (Miles)
0.09
1.63
2.55
3.28
3.96
4.58
5.32
6.01
6.59

# Appendix 16:  Comparison of Distribution System Efficiency Potential

# Comparison of Distribution System Efficiency Potential

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April 22, 2011 (v1)

Electric utilities vary in distribution system design and operation practices. However, Northwest utilities have primary and secondary systems that are radial-designed except for specific service areas (downtown areas, business districts, and some military and hospital installations) where reliability considerations are far more important than cost and economic considerations. The primary voltage class among utilities varies from 4kV to 34.5 kV. Most are either 12.5kV or 24.9 kV systems. Allowable maximum conductor loading, percent phase unbalance, maximum voltage drops, and minimum power factor practices also differ among utilities.

The following table provides a comparison of utility practices and potential energy savings that is available based on typical financial constraints. Typical NW utility and High Performance utility attributes are based on experience performing distribution system feasibility studies in the Northwest.

| | PacifiCorp 19 feeder Attributes | Typical NW Utility Attributes | High Performance Utility Attributes |
|---|---|---|---|
| Feeder Metering | kW, kvar and Amp demand Manual Data Collection | kW, kvar and Amp demand Manual Data Collection | Hourly kW, kvar, and Amp Manual Data Collection |
| Maximum conductor loading % of emergency | 60% | 80% | <50% |
| Maximum allowed phase unbalance | 20% | 30% | <15% |
| Minimum hourly *PF* | 95% | 93% | >96% |
| Average Annual hourly *PF* | 97% | 96% | >98% |
| Maximum Allowed Primary voltage drop(V) | 5 | 5 | <3 |
| Maximum allowed Secondary voltage drop(V) | 6 | 3.5 | <3 |
| Source REG Voltage Control Method | LDC | Fixed | LDC |
| Source REG Voltage Settings | 121 | 124 | 119 |
| Exist Pri Volts | 122.0 | 123.0 | 119.6 |
| Potential for Avg Pri Volts | 120.6 | 119.6 | 119.6 |
| Potential average voltage change | 1.17 % | 2.83% | 0% |
| Potential VO Energy Savings(%) | 0.61% | 1.48% | 0% |

Notes

1. Potential for energy savings assumes an end-use VO factor of 0.6 and system loss savings 15% of total savings.
2. The Potential Average Primary voltage is determined by the utility's financial constraints. For PacifiCorp, the average voltage potential is higher than other utilities due to PacifiCorp requirement to have continuous voltage monitoring because of high secondary voltage drops and the potential for voltages below 114V at the end-use service entrance.

The Pacific energy savings potential from its distribution systems is lower than other northwest utilities primarily due to its existing operating practices with line drop compensation (LDC) and having a relatively low source regulator voltage setting of 121V. However, PacifiCorp does have the potential to increase its energy saving by removing the costly continuous voltage monitor requirement as part of the lowering of voltage initiative to 119V. Other PacifiCorp design and operation attributes are similar to those of the typical northwest utility and exhibit potential for distribution efficiency loss reduction.

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