AGENDA
UTILITY ADVISORY COMMITTEE
March 20, 2025

Hybrid Meeting In-person and via Zoom

https://us02web.zoom.us/j/88484122683

AMERICANS WITH DISABILITIES ACT

The City of Ellensburg strives to make our services, programs, and activities readily accessible and usable by individuals with disabilities. Reasonable accommodations will be made upon request. Please furnish the ADA Coordinator with your request in sufficient time for the City to provide a reasonable accommodation by calling the City of Ellensburg ADA Coordinator at (509) 962-7222 or email ADAcoordinator@ellensburgwa.gov.

CITY OF ELLENSBURG
UTILITY ADVISORY COMMITTEE AGENDA
Council Chambers
501 North Anderson Street
Ellensburg, WA 98926
And remotely via Zoom
Thursday, March 20, 2025
3:30 PM - Regular Meeting

1. **Call to Order and Roll Call of Members**
   - 1.A Grant Craig resignation from Committee.
2. **Approval of Agenda** (No Public Comment)
3. **Approval of Minutes**
   - 3.A Feb 20 UAC regular meeting minutes
4. **Approval of Consent Agenda**
5. **Correspondence and Citizen Comments on Non-Agenda Items**
6. **Telecommunications Utility Discussion Items**
7. **Electric, Natural Gas, Water, Wastewater, Stormwater Utility Discussion Items**
   - 7.A Appoint Selection Committee Members
   - 7.B 2023 Electrical System Plan
8. **Staff Informational Items**
   - 8.A Public Works and Utilities Updates
9. **Commission Representative Update**
10. **Adjournment**

For more information on the Ellensburg Utility Advisory Committee, contact Operations Analyst, Kim Bowie, at 509-962-7124.
The Contents of this agenda have been photocopied on recycled paper.

Kim Bowie

From: Grant Craig <grantc@TCFI.com>
Sent: Thursday, March 6, 2025 12:13 PM
To: Kim Bowie
Subject: [Ext] resigning from Utility commision

CAUTION - EXTERNAL EMAIL: The email below is from an external source. Please exercise caution before opening attachments, clicking links, fulfilling requests, or following guidance.

Hello Kim,

I am retiring this week and will be resigning from the Utility commission early.

Thanks for the opportunity and please let me know by tomorrow if you need anything further. My email address will cease tomorrow afternoon.

Thanks,

Grant Craig

TWIN CITY FOODS

Grant Craig
Senior Division Manager

P: 509.962.9806 ext.3225
M: 509.607.1492
twincityfoods.com

For over 80 years, Twin City Foods, Inc. has been committed to growing, harvesting, processing, freezing, packaging, and distributing the highest quality quick frozen vegetable products.

CITY OF ELLENSBURG **Minutes of Utility Advisory Committee, Regular Meeting**

Date of Meeting **February 20, 2025**
Time of Meeting **3:30 PM**
Place of Meeting **Council Chambers**
501 North Anderson Street
Ellensburg, WA 98926
And remotely via Zoom

1. Call to Order and Roll Call of Members

Chair Bousson called the meeting to order at 3:30 pm.

Members present: Nancy Lillquist, City Council; Delano Palmer, City Council; Jeff Bousson, CWU; Audrey Huerta, Utility Customer; Grant Craig, Utility Customer (Zoom); Bryan Clark, KITTCOM (Zoom).

Also present: Darin Yusi, Gas Engineer (Zoom); Kim Bowie, Operations Analyst; Buddy Stanavich, Energy Resource Manager; Nicole Baker, Sustainability & Energy Coordinator (Zoom); John Mooers, Rate Analyst (Zoom); Ryan Lyyski, Public Works & Utilities Director; Heidi Behrends- Cerniwey, City Manager; Derek Mayo, Engineering Services Manager; Ben Fabion, Telecom; Jim Goeben, IT Director; Brian Cortese. Engineering Tech; Terry Weiner, City Attorney.

2. Approval of Agenda

Committee member Lillquist moved to discuss item 7.A after 8.B. **Agenda approved as amended 6-0**.

3. Approval of Minutes

3.A Jan 16 UAC regular meeting minutes

Committee member Palmer moved to approve the regular meeting minutes. **Motion approved. 6-0**

4. Approval of Consent Agenda

No consent items.

5. Correspondence and Citizen Comments on Non-Agenda Items

5.A Meghan Anderson - Public Comment
Chair Bousson acknowledged the public comment letter received.

6. Telecommunications Utility Discussion Items

Ben Fabion gave telecom project updates.

7. Electric, Natural Gas, Water, Wastewater, Stormwater Utility Discussion Items

8. Staff Informational Items

8.A Future Committee Role Discussion and Reorganization
The City Manager shared the re-organization of departments and what the future of the Utility Advisory could look like.

8.B City of Ellensburg Decarbonization Planning Grant
Buddy Stanavich presented options to utilize grant funds by June 30, 2025.

7.A Update of Public Works Permitting Fees in the Public Works Development Standards

Committee member Palmer moved to forward a favorable recommendation Council and Staff to proceed with an Administrative Hearing to update the Permitting Chapter of the Public Works Development Standards and to update Ellensburg City Code Section 9.92.300 and 9.92.400. **Motion Approved 5-0**

8.C Public Works and Utilities Updates
Staff shared Public Works updates.

9. Commission Representative Update

Chair Bousson would like to discuss, at the next meeting (or subsequent meeting when more information is available), BPA cuts and how it will impact our community.

10. Adjournment

Meeting adjourned at 5:10 pm

Meeting Date: March 20, 2025
City of Ellensburg
Utility Advisory Committee Agenda Report

Agenda Subject:	Appoint Selection Committee Members
Submitted by:	Buddy Stanavich , Energy Resources Manager
Department:	Public Works & Utilities

Suggested Motion/Action:
Appoint a Selection Committee that will interview applicants that meet the qualifications for appointment.

Background/Summary:
This panel should consist of the Committee Chair, a Council member, and one member of the committee. The panel may not equal or exceed a quorum, which is four (4) members in this case.

Previous Council Action:

Analysis:

Financial Impact:

Budget Adjustment: No

Attachments:
1. Board Commission Appointment Process - Revised 3-8-2022

TO: **Board & Commission Staff & Directors**
FROM: **Heidi Behrends Cerniwey, City Manager**
Laurie Gigstead, Executive Assistant
DATE: **March 8, 2022**
RE: **Revised Appointment Process for City Boards & Commissions, 2/22/2022**

Background: At the meeting on February 22, 2022, the Ellensburg City Council provided direction for a new administrative process to appoint and re-appoint members of the City's Boards and Commissions. The revision was preceded by a goal to encourage informed and engaged representatives of the community and to offer opportunities for new voices to serve in these advisory roles.

1. **Application:** An application for appointment or re-appointment will be available on the City website or by contacting the City Manager's Office. Applications may be submitted at any time, but applications will only be considered when an opening on a board and commission exists.
    a. New applicants and those interested in re-appointment will submit the designated application form.
    b. The application will include a notification for the requirement to attend a board or commission meeting prior to being interviewed and considered for appointment to a position on that board or commission.
    c. Application closing dates will be published for each position opening.
    d. Applicants wishing to be re-appointed when their current term ends will need to re-apply for consideration.
    e. Applications are kept on file for six (6) months.
2. **Requirement to Attend Meeting:** New applicants will be invited to attend the board or commission's next meeting. Applicants should notify staff or the chair of their intention to attend the meeting and will be encouraged by the chair to introduce themselves, when appropriate. Note: All City meetings will continue to offer remote attendance options.
    a. Applicants must attend at least one board or commission meeting prior to being interviewed and considered for appointment to a position on that board or commission.
3. **Interview:** A panel that consists of the board or commission staff or chair and the Council liaison or member, in addition to one or more members of the board or commission (may not equal or exceed a quorum), will interview the applicants that meet the qualifications for appointment.
    a. Sample interview questions will be provided to board and commission staff
    b. Each applicant will be asked the same general questions, limited in scope to their qualifications and ability to serve on the commission.
    c. The panel will select an applicant to recommend to City Council for appointment from those interviewed. Staff role is to provide guidance and support to the interview panel and do not participate as decision-makers in the selection process.
    d. If no applicants are qualified or applicant(s) withdraw, the panel may request additional public notice to post the position to attract applicants for consideration.

Any additional posting actions will be reported to Council at the next regular or special meeting.

4. **Recommendation & Council Appointment:** The board/commission designated interview team will make a formal recommendation for appointment to the City Council at the next regular or special meeting.
    a. Staff will submit a brief memo addressed to the full City Council (template link) outlining their recommendation for appointment to the vacant seat. This will include applications for the recommended appointee and all applicants interviewed for the position. Personal information and addresses of applicants will be redacted (per RCW 42.56.230(3)).
    b. City Manager's Office staff will create the agenda item for the agenda and invite the recommended applicant to the meeting to introduce themselves to the Council. Staff may be requested to attend the meeting to answer questions about the appointment process.
    c. City Council has full authority to confirm, modify, or reject the recommended appointment at the open meeting.
    d. City Manager's Office staff will notify the Board and Commission staff of the official appointment decision.

Board and Commission staff will receive training on interview skills, implicit bias, and onboarding new members.

Recruitment Actions and Principles for City Board and Commission Members:

- **Actively recruit community members for service:**
    - Be proactive in announcing and recruiting for openings (i.e. in October for December expirations and in March for May expirations)
    - Executive team staff (PIO and Manager's Office) will advertise upcoming terms that will expire and potential vacancies – noting accepting new applications until ____.)
    - Tell our story – people need to understand the role, purpose, and opportunity available for service
    - Be inclusive with language of materials with service opportunities, especially Spanish translation for materials and translator services available for meeting participation
    - Students are an important part of our community and policy changes should consider impacts on their ability to serve on boards and commissions

Meeting Date: March 20, 2025
City of Ellensburg
Utility Advisory Committee Agenda Report

Agenda Subject: 2023 Electrical System Plan
Submitted by: Paul Meyer, Electrical Engineer
Department: Public Works & Utilities

Suggested Motion/Action:
Recommend City Council to accept the 2023 Electrical System Plan as complete.

Background/Summary:
Every six years, the City of Ellensburg hires a consultant to perform an electric system study to analyze our distribution system and infrastructure needs based on load requirements. The last study was completed in 2017. This study includes reviewing and updating our current distribution system's model, determining the City's load growth requirements based on population increases and development of a six-year capital facilities plan. AT the end of 2023 the city contracted with Powers Engineers, Inc. to provide a new Electrical System Plan.

Previous Council Action:
11/16/2023 Approved the Agreement for Professional Services for the 2023 Electrical System Plan with the consultant Powers Engineers, Inc.

Analysis:
The consultant has completed the final draft of the Electrical System Plan and will present their findings to the UAC for review and discussion. Any required revisions to the report will be made prior to the presentation to the City Council at the April 7th meeting.

Financial Impact:
The fee from the consultant for this project is $244,329.26 including tax, with a balance of $30,329.26 remaining on the contract. The 2025 Light Fund has an adequate ending fund balance to cover the costs.

Budget Adjustment: No

Attachments:
1. City of Ellensburg LRPCWP Report Draft14MAR

March 14, 2025

THE CITY OF ELLENSBURG

Capital Facilities Plan
20 Year System Plan

Revision E Draft

PROJECT NUMBER:
0248168.0000

PROJECT CONTACT:
KYLE BENNETT, P.E.
EMAIL:
KYLE.BENNETT@POWERENG.COM
PHONE:
(208) 788-0431

POWER ENGINEERS

Capital Facilities Plan
20 Year System Plan

PREPARED FOR:
THE CITY OF ELLENSBURG

PREPARED BY:
EVAN POWERS – 720-881-4919 – EVAN.POWERS@POWERENG.COM
JEFFREY SHUPE – 720-823-2610 – JEFFREY.SHUPE@POWERENG.COM
JEFF MANN – 720-881-4904 – JEFF.MANN@POWERENG.COM

REVISION HISTORY						
REV.	ISSUE DATE	ISSUED FOR	PREP BY	CHKD BY	APPD BY	NOTES
A	2024-08-12	Prelim	EJP	JAS	JAS	Issued for preliminary review
B	2024-08-26	Prelim	EJP	JAS	JAS	Revisions and additional sections, additional appendix
C	2024-10-11	Prelim	EJP	JAS	JAS	Revisions and additional appendix
D	2025-01-09	Appvl	JAS	KDB	JAS	Added DER, BPA Coordination sections, DER Appendix, corrections
E	2025-03-14	Draft	EJP	JAS	JAS	Revised DER, BPA, EV, AMI sections

“Issued For” Definitions:
- “Prelim” means this document is issued for preliminary review, not for implementation
- “Appvl” means this document is issued for review and approval, not for implementation
- “Impl” means this document is issued for implementation
- “Record” means this document is issued after project completion for project file

TABLE OF CONTENTS

ACRONYMS AND DEFINITIONS **7**

1.0 EXECUTIVE SUMMARY **8**

2.0 DATA **9**

3.0 LOAD FORECASTS AND PLANNING CRITERIA **9**

3.1 LOAD FORECASTS 9
Projected Loads – 2030 10
Projected Loads – 2044 11
3.2 PLANNING CRITERIA 12

4.0 EXISTING SYSTEM ANALYSIS **15**

4.1 DISTRIBUTION SUBSTATIONS 15
4.2 DISTRIBUTION SYSTEM 15
4.3 SYSTEM IMPROVEMENT RECOMMENDATIONS 15
4.4 RESULTS OF SYSTEM IMPROVEMENTS 18
4.5 COSTS OF EXISTING SYSTEM IMPROVEMENT RECOMMENDATIONS 18
4.6 CAPACITOR REVIEW 19

5.0 CAPITAL FACILITIES PLAN **23**

5.1 CAPITAL FACILITIES PLAN – 6 YEAR OVERVIEW 23
5.2 DISTRIBUTION SYSTEM 23
5.3 SYSTEM IMPROVEMENT RECOMMENDATIONS 23
5.4 RESULTS OF SYSTEM IMPROVEMENTS 24
5.5 COST OF SYSTEM IMPROVEMENT RECOMMENDATIONS 24

6.0 20 – YEAR SYSTEM PLAN **25**

6.1 20 YEAR OVERVIEW 25
6.2 DISTRIBUTION SYSTEM 25
6.3 SYSTEM IMPROVEMENT RECOMMENDATIONS 25
6.4 RESULTS OF SYSTEM IMPROVEMENTS 30
6.5 COST OF SYSTEM RECOMMENDED IMPROVEMENTS 30

7.0 DISTRIBUTION SYSTEM MITIGATION **32**

7.1 DISTRIBUTION SYSTEM CONTINGENCY MITIGATION OVERVIEW 32
7.2 DOLARWAY #1 SUBSTATION OUT OF SERVICE 32
2025: 32
2030: 33
2044: 35
7.3 DOLARWAY #2 SUBSTATION OUT OF SERVICE 37
7.4 EAST ELLENSBURG SUBSTATION OUT OF SERVICE 37
2025: 37
2030: 39
2044: 40
7.5 HELENA SUBSTATION OUT OF SERVICE 42
2025: 42
2030: 43

2044: 44
7.6 EAST ELLENSBURG #2 SUBSTATION OUT OF SERVICE 45
2044: 45
7.7 SOUTH ELLENSBURG SUBSTATION OUT OF SERVICE 47
2044: 47

8.0 RESIDENTIAL NATURAL GAS CONVERSION – 2030 LOADS 50

8.1 OVERVIEW 50
RCW 70A.45.020 50
RCW 70A.65.00 50
Initiative Measure No. 2117 50
Design Standards 50
8.2 RESIDENTIAL GAS CONVERSION - 2030 LOADS ON DISTRIBUTION SYSTEM 51

9.0 RESIDENTIAL NATURAL GAS CONVERSION – 2044 LOADS 52

9.1 OVERVIEW 52
9.2 RESIDENTIAL GAS CONVERSION DISTRIBUTION SYSTEM – 2044 LOADS 52
9.3 RESIDENTIAL GAS CONVERSION SYSTEM IMPROVEMENT RECOMMENDATIONS – 2044 LOADS 52
9.4 RESULTS OF SYSTEM IMPROVEMENTS 52

10.0 ELECTRICAL VEHICLE CHARGING STATIONS 54

10.1 OVERVIEW 54
RCW 19.27.540 Electric vehicle Infrastructure Requirements – Rules 54
RCW 43.31.970 Electric Vehicle Infrastructure. 54
RCW 64.38.062 54
WAC 51-50-0429 54
RCW 47.80.090 54
10.2 RESIDENTIAL ELECTRIC VEHICLE CHARGING DISTRIBUTION SYSTEM LOADING 54
10.3 RESIDENTIAL ELECTRIC VEHICLE CHARGING SYSTEM IMPROVEMENT RECOMMENDATIONS 55
10.4 CHARGING SYSTEM CONSIDERATIONS 55
EV Charging System Installations 55
EV to Grid 56
Design Standards 56
10.5 EV CHARGING RATES AND INCENTIVES 56
Installation Incentives 56
Rates 56
Charging Management 57

11.0 BENEFITS OF AMI IMPLEMENTATION 58

12.0 DEMAND RESPONSE PROGRAM 61

12.1 OVERVIEW 61
WAC 480-100-620 – Integrated Resource Plan – Demand Response 61
RCWs 19.280.030 and 19.285.040 – Resource Planning 61
12.2 PARTICIPATION IMPACTS 62
12.2 TECHNOLOGY 65
12.3 DEMAND MANAGEMENT PROGRAM 67
Customer Engagement 67
Analysis 67

Design/Implementation 67
Contracts 68
12.4 EXAMPLE WEB LAYOUT 68
General Demand Response Title Page 69
Specific Program Option Pages 69
Forms, Terms, and Conditions 71
12.5 PAIRING WITH RESIDENTIAL GAS CONVERSION 72
12.6 ANTICIPATED BPA REGIONAL DEMAND MANAGEMENT 72

13.0 VOLT & VAR INVESTIGATION 73

13.1 OVERVIEW 73
13.2 CONSERVATION VOLTAGE REGULATION 73
13.3 CONSERVATION SYSTEM LOSS REDUCTION 73

14.0 PLANNING CONSULTATION WITH BPA 75

14.1 OVERVIEW 75
14.2 JOINT PLANNING WITH BPA AREA ENGINEER 75
Planning and Forecasting 75
New Load Growth Constraints 75
City Engagement with BPA 76
Joint Planning 76
BPA Transmission Limitations 77
14.3 FORECAST OF 6 YEAR AND 20 YEAR SYSTEM DEMAND 79
14.4 COORDINATION WITH ENERGY FORECASTS, NEW BPA CONTRACTS AND REGIONAL GENERATION RESOURCES 80

15.0 SYSTEM MODEL SOFTWARE MIGRATION INVESTIGATION 81

SYNERGI 81
CYME 81
EDD (ELECTRICAL DISTRIBUTION DESIGN) – AN NISC ENGINEERING MODULE 82
MILSOFT 82

APPENDIX – A 84

LOAD GROWTH AREAS AND SPECIFIC SPOT LOADS APPLIED TO THE SYSTEM 84

APPENDIX – B 98

FULL LIST OF SYSTEM IMPROVEMENT RECOMMENDATIONS 98

APPENDIX – C 106

DECARBONIZATION OF CENTRAL WASHINGTON UNIVERSITY 106
Overview 107
Phase 1 – 2025 107
Phase 2 – 2027 107
Phase 3 – 2030 107
Phase 4 – 2033 107
Phase 5 – 2036 108
Phase 6 – 2039 108
Phase 7 – 2044 108
Contingency Overview 109

Sub 1 109
Sub 2 111
Sub 3 112
Sub 1 and 2 113
Sub 2 and 3 116
Sub 1 and 3 116

APPENDIX – D 118

WINCO FOODS 118
Overview 119

APPENDIX – E 127

EXAMPLE FORMS FOR DEMAND RESPONSE 127
Direct Participation Customer Notification Letter 128
PSE Demand Response Terms and Conditions 136
DRP Performance Bond Letter 151
DRP Registration Form 154
Third Party DRP Form 159
DRP Agreement 164
PSE Business Demand Response Quick Reference Guide (QRG) 179
Voltus Case Study – City District 182

LIST OF TABLES

Table 1: Acronyms and Definitions 7
Table 2: Peak Feeder Demands 10
Table 3: System Spot Loads – 2030 11
Table 4: System Spot Loads – 2044 12
Table 5: Recommended System Improvements – 2025 17
Table 6: Existing System Recommended Improvement Costs 18
Table 7: Existing System Feeder kVAR and Power Factor Values 19
Table 8: Existing System Capacitors 20
Table 9: Existing System Feeder kVAR and Power Factor Values, Capacitor Configuration 1 20
Table 10: Existing System Feeder kVAR and Power Factor Values, Capacitor Configuration 2 21
Table 11: Existing System Feeder kVAR and Power Factor Values, Capacitor Configuration 3a 21
Table 12: Existing System Feeder kVAR and Power Factor Values, Feeder 9 express serving CWU, Capacitor Configuration 3b 22
Table 13: Recommended System Improvements – 2030 24
Table 14: 2030 System Recommended Improvement Costs 24
Table 15: Recommended System Improvements – 2044 29
Table 16: 2044 System Recommended Improvement Costs 31
Table 17: Alternative System Improvements For Accelerated Residential Gas Conversion – 2030 51
Table 18: Recommended System Improvements Residential Gas Conversion – 2044 52
Table 19: AMI Technologies 60
Table 20: NADR Model Results 64
Table 21: South Ellensburg Area 115 kV Line Capacity 77
Table 22: North Ellensburg Area 115 kV Line Capacity 77
Table 23: Summary of Forecast Large Load Additions and Total System Demand 80
Table 24: Winco Projected Diversified Loading 119
Table 25: 2030, Winco On Feeder 7, Non-Exclusive 119
Table 26: 2044, Winco On Feeder 7, Non-Exclusive 120
Table 27: 2030, Winco On Feeder 7, Non-Exclusive, N-1 121
Table 28: 2030, Winco On South Ellensburg, N-1 121
Table 29: 2044, Winco On Feeder 7, Non-Exclusive, N-1 122
Table 30: 2044, Winco On South Ellensburg, N-1 122
Table 31: 2030, Winco On Feeder 7, Exclusive 123
Table 32: 2044, Winco On Feeder 7, Exclusive 124
Table 33: 2030, Winco On Feeder 7, Exclusive, N-1 124
Table 34: 2044, Winco On Feeder 7, Exclusive, N-1 125
Table 35: Winco Recommended Improvements 126

LIST OF FIGURES

Figure 1: Table 3 of IEEE Standard C57.91-2011 Loading on Basis of Temperatures 14
Figure 2: Dolarway #1 Substation Out of Service Recommended Configuration for 2025 33
Figure 3: Dolarway #1 Substation Out of Service Recommended Configuration for 2030 35
Figure 4: Dolarway #1 Substation Out of Service Recommended Configuration for 2044 37
Figure 5: East Ellensburg Substation Out of Service Recommended Configuration for 2025 39
Figure 6: East Ellensburg Substation Out of Service Recommended Configuration for 2030 40
Figure 7: East Ellensburg Substation Out of Service Recommended Configuration for 2044 41
Figure 8: Helena Substation Out of Service Recommended Configuration for 2025 43

Figure 9: Helena Substation Out of Service Recommended Configuration for 2030 44
Figure 10: Helena Substation Out of Service Recommended Configuration for 2044 45
Figure 11: East Ellensburg #2 Substation Out of Service Recommended Configuration for 2044 47
Figure 12: South Ellensburg Substation Out of Service Recommended Configuration for 2044 49
Figure 13: Example Commercial or Industrial Demand Response Hardware Configuration 66
Figure 14: Example Intro Webpage 69
Figure 15: Example Program Summary Webpage 70
Figure 16: Example FAQ Webpage 71
Figure 17: Flow chart of BPA Coordination Process 78
Figure 18: Black Horse Housing Development Site 84
Figure 19: CWU's Substation 1 85
Figure 20: CWU's Substation 2 86
Figure 21: CWU's Substation 3 87
Figure 22: Field House Recreational Facility Site 87
Figure 23: EV Charging Station, South I-90 Interchange Site 88
Figure 24: New Transfer Station Site 89
Figure 25: EV Charging Station, WEST I-90 Interchange Site 90
Figure 26: WINCO Foods Site 91
Figure 27: East Gregory Place Housing Development Site 92
Figure 28: East Bull Road Housing Development Site 93
Figure 29: South Teal Road Housing Development Site 94
Figure 30: West Bull Road Housing Development Site 95
Figure 31: Wigeon Avenue Housing Development Site 96
Figure 32: The City of Ellensburg Urban Growth Area Border 97
Figure 33: Direct Participation Customer Notification Letter Example 135
Figure 34: PSE Demand Response Terms and Conditions 150
Figure 35: DRP Performance Bond Letter 153
Figure 36: DRP Registration Form 158
Figure 37: Third Party DRP Form 163
Figure 38: DRP Agreement 178
Figure 39: PSE Business Demand Response QRG 180
Figure 40: Voltus Case Study – City District 183

ACRONYMS AND DEFINITIONS

ACRONYMS AND DEFINITIONS	
RCW	Revised Code of Washington
WAC	Washington Administrative Code
EV	Electric Vehicle
BPA	Bonneville Power Administration
PSE	Puget Sound Energy
DRP	Demand Response Program
QRG	Quick Reference Guide
CWU	Central Washington University
N-1	System operation under the loss of a source
AMI	Advanced Metering Infrastructure
DER	Distributed Energy Resources
kW	Kilo Watt
MVA	Mega Volt Amperes
kWH	Kilo Watt Hours
kVAR	Kilo Volt Amperes Reactive
IEEE	Institute of Electrical and Electronics Engineers
WNϕ	Will Not Phase
PF	Power Factor
CCA	Climate Commitment Act
UL	Underwriters Laboratories
SEL	Schweitzer Engineering Laboratories
RTAC	Real Time Automation Controller
LEED	Leadership in Energy and Environmental Design
EEI	Energy Efficiency Incentive
CVR	Conservation Voltage Reduction
SCADA	Supervisory Control and Data Acquisition
WECC	Western Electricity Coordinating Council
NERC	North American Electric Reliability Corporation
FERC	Federal Energy Regulatory Commission
LLFS	Line Load Feasibility Study
PUD	Public Utility District
GIS	Geographic Information System
MDMS	Meter Data Management System
CIS	Customer Information System
N.O.	Normally Open
N.C.	Normally Closed
LTC	Load Tap Changer
DCFC	EV Direct Current Fast Charger
L2 or LII	EV level 2 charger

TABLE 1: ACRONYMS AND DEFINITIONS

1.0 EXECUTIVE SUMMARY

This Capital Facilities Plan and 20 Year System Plan is for The City of Ellensburg's (The City) existing distribution system, located in Ellensburg, Washington. This existing system consists of four substations, totaling 14 feeders.

POWER Engineers, Inc. (POWER) was tasked with analyzing the performance of The City's electrical distribution system against population and load growth for the years 2024-2044 with a detailed focus on the six-year period for 2024-2030.

The existing system does not show any overloading conditions. Feeders 11, 13, 17, and 18 show sections of unbalanced loads. It is recommended to balance these existing loads by moving tap placements and implementing the improvements and load shifts identified in Table 5 for the existing system.

The 2030 system and the 2044 systems both require substantial improvements to maintain the system service within the system planning requirements and to maintain reliability. Residential subdivision load growth plus potential large loads require the planned Dolarway #1 Substation transformer upgrade to be completed, a new substation added in the south area of The City, new feeders and existing feeder upgrades.

Central Washington University (CWU) has approached The City with a planned decarbonization natural gas to electric conversion over the next 20 years. These added CWU electric system loads and CWU facility changes will require expansion of the East Ellensburg Substation and the addition of two express feeders to serve the increased load at CWU central plant substations. A detailed phase by phase analysis of the CWU load impacts is provided in Appendix C of this report.

The City's residential gas service decarbonization impacts were analyzed for conversion to electric space heating and water heating. This conversion has the potential to double the peak day loads on the electric system. An additional substation with new feeders northwest of The City and feeder expansions at the Helena and new South City substation are recommended along with substation load transfers to meet the increased peak demand on the system.

Impacts of electrical vehicle charging on the system were also analyzed. Other system improvements including Advanced Meter Infrastructure (AMI), Demand Response (DER) and Voltage Management were explored.

The impact of contingencies such as a substation out of service at peak load times where analyzed in detail. Recommended feeder transfers and improvements are provided to maintain service under those contingency conditions.

A full list of recommended improvements to the system can be found in Appendix B.
This distribution system study was performed using the DNV Synergi Electric version 6.21.0 modeling software package.

2.0 DATA

The following data was used for the analysis and was gathered from The City's sources. Any changes to this data will have an impact on the results of the analysis.

The City provided peak kW demands for each substation and feeder in the existing system. The decision was made to use the data from November 2023 and January 2024 due to extreme cold weather peak load conditions and record electrical demand consumption per system transformer. These conditions produce the maximum stress on the electrical system and although those weather conditions may not occur every year the system must have sufficient capacity to meet the demand when they do occur. The electrical usage peaks have load growth based on potential large loads and residential expansion into The City's urban growth area over the next twenty years.

3.0 LOAD FORECASTS AND PLANNING CRITERIA

3.1 Load Forecasts

The City provided peak kW demands for each substation and feeder in the existing system. The decision was made to use the data from November 2023 and January 2024 due to extreme cold weather conditions, and record MW demand consumption per system transformer. Allocated peak kW demand projections for each of The City's substation and feeder were based on forecasts and growth rates provided by The City. Load growth was based on a population increase of 11,757 customers during the next 20 years. 6-year peak kW demand projections for each feeder were based on non-coincident peak loading. The load projections were tabulated by spreadsheet by year. Known and newly proposed large loads were included in the forecast. The forecast also included EV residential charging and natural gas conversion fuel switching loads. The peak demands for each transformer are as follows:

- Dolarway #1 Substation: 14 MVA – 11/14/2023
- Dolarway #2 Substation: 18 MVA – 11/14/2023
- East Ellensburg Substation: 15 MVA – 1/16/2024
- Helena Substation: 12.2 MVA – 1/16/2024

The peak demands for each feeder by phase are as follows:

PEAK FEEDER DEMANDS					
Feeder	**Date**	**Aϕ**	**Bϕ**	**Cϕ**	**N**
1	11/14/2023	298 A	309 A	334 A	45 A
2	11/14/2023	135 A	115 A	125 A	40 A
3	11/14/2023	211 A	221 A	211 A	42 A
4	11/14/2023	117 A	100 A	140 A	47 A
5	11/14/2023	135 A	144 A	134 A	31 A
6	11/14/2023	150 A	144 A	134 A	22 A
9	11/14/2023	263 A	251 A	259 A	22 A
10	11/14/2023	169 A	162 A	192 A	40 A
11	1/16/2024	136 A	68 A	103 A	70 A
12	1/16/2024	303 A	289 A	296 A	36 A
13	1/16/2024	281 A	225 A	241 A	69 A
14	1/16/2024	54 A	67 A	86 A	35 A
17	1/16/2024	339 A	383 A	343 A	75 A
18	1/16/2024	176 A	228 A	171 A	71 A

TABLE 2: PEAK FEEDER DEMANDS

The peak demands will have load growth based on known residential expansion and expansion into urban growth areas along with potential large loads applied over the next twenty years.

For the existing system loads, kWH usage per customer was provided by The City and placed into the Synergi model. From there the model was able to use the feeder demands and kWH loads to assign kW and kVAR values throughout each line section of the model.

Projected Loads – 2030

The six year peak kW demand projection for each feeder is based on non-coincident peak loading and newly proposed spot loads as shown in Table 3 below:

SYSTEM SPOT LOADS – 2030		
Spot Load	**MW**	**Figure**
Black Horse housing development	0.24 MW	13
CWU decarbonization	10.3 MVA	14, 15, 16
CWU EV infrastructure	0.23 MVA	14, 15, 16
CWU new construction	0.26 MVA	14, 15, 16
Ellensburg Community Fieldhouse	0.20 MW	17
EV charging station at the south I-90 interchange	3.00 MW	18
New Ellensburg transfer station	0.63 MW	19
EV charging station at the west I-90 interchange	3.00 MW	20

SYSTEM SPOT LOADS – 2030		
Winco Foods	7.70 MW	21
East Gregory Place housing development	0.15 MW	22
East Bull Road housing development	0.05 MW	23
South Teal Road housing development	0.10 MW	24
West Bull Road housing development	0.35 MW	25
Wigeon housing development	0.08 MW	26

TABLE 3: SYSTEM SPOT LOADS – 2030

Projected Loads – 2044

The 20-year peak kW demand projection for each feeder is based on non-coincident peak loading and newly proposed spot loads as shown in Table 4 below:

SYSTEM SPOT LOADS – 2044		
Spot Load	**MW**	**Figure**
Black Horse housing development	0.24 MW	13
CWU decarbonization	14.5 MVA	14, 15, 16
CWU EV infrastructure	0.86 MVA	14, 15, 16
CWU new construction	6.90 MVA	14, 15, 16
Ellensburg Community Fieldhouse	0.20 MW	17
EV charging station at the south I-90 Interchange	7.00 MW	18
New Ellensburg transfer station	0.63 MW	19
EV charging station at the west I-90 Interchange	7.00 MW	20
Winco Foods	9.20 MW	21
East Gregory Place housing development	0.15 MW	22
East Bull Road housing development	0.05 MW	23
South Teal Road housing development	0.10 MW	24
West Bull Road housing development	0.35 MW	25
Wigeon housing development	0.08 MW	26

SYSTEM SPOT LOADS – 2044		
Urban growth area north	1.84 MW	27
Urban growth area west	5.32 MW	27
Urban growth area east	4.01 MW	27
Urban growth area southeast	0.15 MW	27

TABLE 4: SYSTEM SPOT LOADS – 2044

3.2 Planning Criteria

The following design criteria was developed by The City and POWER as an aid in determining the improvements required. They included acceptable voltage levels, loading of facilities and age/reliability standards. The planning criteria was based on The City and Industry standard practices. All service areas were evaluated with respect to the criteria to maintain adequate and dependable service to each consumer.

1. The maximum substation bus voltage will be 124V for all seasons. The maximum planning voltage for normal operations will be 118V. The maximum voltage for contingency will be 114V. The maximum system voltage is 126V.

2. The following equipment will be evaluated for replacement if thermally loaded by more than the percentage shown of it's nameplate rating:

    a. 80% - Power Transformer (Top Rating)
    b. 80% - Substation/Line Voltage Regulators
    c. 80% - Circuit Level Reclosers

3. Primary conductors will be evaluated for replacement if loaded 80% or more of their thermal rating.

4. Single-phase lines will be evaluated for replacement if loaded more than 50 amperes at peak.

5. Primary conductors will be marked for replacement if loaded at 80% of their thermal rating.

6. New lines and line conversions to be built according to the standards of the ultimate primary voltage levels as recommended in the system plan.

7. New primary conductor sizes to be:

    a. #1/0 AAC
    b. #4/0 AAC
    c. 336 Kcmil AAC
    d. 795 Kcmil AAC
    e. #1/0 AL URD 220 mil
    f. #4/0 AL URD 220 mil
    g. 350 MCM AL URD 220 mil

h. 750 MCM AL 220 mil
i. 1000 MCM AL 220 mil

8. All new distribution lines will be designed and constructed according to The City's standard construction specifications and guidelines.

9. Reverse power flow will be considered in areas for load transfer.

10. There will be no more than one regulator per feeder, exceptions will be made on a case-by-case basis.

11. Substation transformer unbalance should not exceed 25%, or 75 amperes, whichever is less.

12. Feeder unbalance at substations should not exceed 40% or 50 amperes for feeders where the highest loaded phase is 149 amperes or less. For feeders with phase load being more than 150 amperes, unbalance shouldn't exceed 25% or 75 amperes, whichever is less.

13. On downstream feeders, where the highest loaded phase is 149 amperes or less, unbalance should not exceed 40% or 50 amperes, whichever is less. Where the highest loaded phase is above 150 amperes, unbalance should not exceed 25% or 100 amperes, whichever is less.

14. Where large motors exist, voltage balance may be of concern. The maximum allowable voltage unbalance is 2% according to IEEE 141-1993.

15. Winter peaks were used to determine the system peak for The City. Customer billing data from November 2023 was used for system load allocation by feeder by phase.

16. Normal system loading will be a maximum of 80% conductor loading, and 50% conductor loading for feeder ties to allow load transfer.

17. Transformers will be allowed to be continuously loaded to 130% of ONAN rating during winter conditions.

18. Transformers will be allowed to be continuously loaded to 108% of ONAN rating during normal conditions.

Table 3 of IEEE Standard C57.91-2011 Loading on Basis of Temperatures (Ambient other than 30°C and Average Winding Rise Less than Limiting Values) (For Quick Approximation) (Ambient Temperature Range 0°C to 50°C)		
	% of Rating	
Type of Cooling	Decrease Load for Each °C Higher Temperature	Increase Load for Each °C Lower Temperature
Self-cooled – ONAN	1.5	1.0
Water-cooled – ONWF	1.5	1.0
Forced-air-cooled – ONAN/ONAF, ONAN/ONAF/ONAF	1.0	0.75
Forced-air-cooled – OFAF, OFWF, ODWF, and ONAN/OFAF/OFAF	1.0	0.75

-average ambient other than 30 ° C and average winding rise less than limiting values, for quick approximation, ambient temperature range – 30 ° C to 50 ° C

FIGURE 1: TABLE 3 OF IEEE STANDARD C57.91-2011 LOADING ON BASIS OF TEMPERATURES

19. Hydraulic circuit reclosers should not be loaded more than 80%.

20. Electronically controlled reclosers and relay-controlled breakers should not be loaded more than 100%.

21. Poles and/or crossarms to be replaced if found to be physically deteriorated by visual inspection and/or tests.

22. Primary distribution lines to be rebuilt and/ or relocated if found to be unsafe or in violation of safety codes/guidelines including the National Electric Safety Code, Vernon's Annotated Civil Statutes Washington Administrative Code, and relevant RUS Bulletins.

23. Power factor will be corrected to 97% lead or lag or better. Improvements to power factor usually result in some demand reductions, energy conservation, and lower reactive costs.

24. Conductors shall be considered for replacement if found to contain an average of over two splices per phase per span in any 1-mile increment, or if conductor is old in poor condition or has been annealed.

25. WAC 480-100-373 states that electric utilities must maintain the voltage on their distribution system reasonably constant and any allowed variation must be a gradual change in voltage as a result of normal changes in load. The voltage variations may not be more than 5% above or below the standard voltage adopted and the total voltage variation from minimum to maximum value may not exceed 8% of the standard voltage. A utility may allow greater voltage variation than that specified in this rule in case of emergency service or when service is supplied directly from a transmission line. A utility may also permit greater voltage variations in an area where the revenues received do not justify close voltage regulation. In such cases, electric utilities must provide the best voltage regulation that is economically and technically practicable under the circumstances.

4.0 EXISTING SYSTEM ANALYSIS

4.1 Distribution Substations

The existing configuration for the Dolarway #1 Substation shows that the 20 MVA transformer is at a loading of approximately 44%, serves 8.8 MVA of load, and operates at an average of 123 V.

The existing configuration for the Dolarway #2 Substation shows that the 33 MVA transformer is at a loading of approximately 50%, serves 16.8 MVA of load, and operates at an average of 123 V.

The existing configuration for the East Ellensburg Substation shows that the 22 MVA transformer is at a loading of approximately 76%, serves 16.0 MVA of load, and operates at an average of 123 V.

The existing configuration for the Helena Substation shows that the 33 MVA transformer is at a loading of approximately 40%, serves 12.2 MVA of load, and operates at an average of 124 V.

It is recommended to shift load or upgrade capacity by adding more transformers, or replacing existing transformers when loading is at or exceeds 80% to provide longevity to equipment life, and to give more options to shift load throughout the system.

It is also recommended that The City proceed with its plan to replace and upgrade the transformer bank for Dolarway #1 Substation with a 33 MVA transformer and lineup.

4.2 Distribution System

The existing system is within the voltage range and loading limits defined in the planning criteria. East Ellensburg Substation’s Feeder 11, Feeder 13, Helena Substation’s Feeder 17 and Feeder 18 all experience load imbalance in certain sections. It is suggested that loads be balanced where possible.

4.3 System Improvement Recommendations

Below are system improvement options, suggested for capacity and load balancing for the 2025 system:

2025 SYSTEM RECOMMENDED IMPROVEMENTS				
Improvement Number	**Substation - Feeder**	**Description**	**From - To**	**Reason For Improvement**
1	Dolarway #1 -	New 33 MVA Transformer	Dolarway #1 Substation	This change is already in progress and is to improve system capacity
2	Dolarway #1 – 1	Add WNϕ[1] N.O., add #1/0 AL URD 220 mil UG cable, move section from C → B phase	Add WNϕ[1] N.O. switch in between HRD61 and HRD63, add 1/0 UG conductor to connect HRD64 to HRT16 to move the C phase section east of the new WNϕ[1] switch to B phase	Load imbalance of 52% downstream of distribution pole HRM02
3	East Ellensburg - 11	Move Tap Placement A→C	Distribution Poles JPD06 to JPD04	Load imbalance of 45%
4	East Ellensburg - 13	Move Tap Placement C→B	Fuse F127 at Distribution pole IQD69	Load imbalance of 65% at JQM02
5	Helena – 17	Convert single phase to three phase overhead line, in the Cascade Village area. Cost dependent on work order design	From HPV16 to Pole HPD58, convert underground to three phase From Pole HPD58 to Pole HOD23 and HOD11 to HOD06, convert overhead to three phase conduit to move existing C phase taps to A and B, leaving C phase underground connection at HOD23 to Lexus Lane N.O. HOT12. Install N.O. switch at HOD06 and install 750 MCM AL 220 mil Cable through spare empty 4” and tap to the 750 MCM AL 220 mil Cable north south run.	Load imbalance of 79% due to C phase load at Fuse F267 on Helena Ave. BPA Pole
6	Helena - 17	Move Tap Placement B → C	F255 to GNV05	Load imbalance of 58%
7	Helena - 17	Move Tap Placement A → C	Vault HNV22 to HNS13	Load imbalance of 43%
8	Helena - 17	Move Tap Placement A → C	Vault GNV07 to GNT43	Load imbalance of 43%

2025 SYSTEM RECOMMENDED IMPROVEMENTS				
9	Helena – 18	Split Campus Village Apartments, Glacier Apartments, and Greenpointe Townhomes load	Opening B phase 1998b conductor at IOV26 Open 3 Phase conductors 2109a, 2092c, 2091b at IOV08 Make P012 N.C. Make cable 2036b at IOV23 N.C.	Load imbalance of 43% on Feeder 18 at F292
10		Shift Load Feeder 12→Feeder 9	Open Switch S123, Close Switch S124	East Ellensburg Substation Transformer Overloading to 82%. Overloading may happen prior to 2030 depending on the decarbonization progress of CWU. See Appendix C of this report for a further breakdown of decarbonization phases

TABLE 5: RECOMMENDED SYSTEM IMPROVEMENTS – 2025

[1] Designates Will Not Phase

4.4 Results of System Improvements

Following the tap changes, the upgrade to the Dolarway #1 transformer, and the start of decarbonization loads from CWU are shown in Appendix C, all transformer loading is under 100% for the 2025 system:

- Dolarway #1 Substation – 56%
- Dolarway #2 Substation – 32%
- East Ellensburg Substation – 63%
- Helena Substation – 38%

4.5 Costs of Existing System Improvement Recommendations

Below are the costs of system improvement options for the 2025 system:

2025 SYSTEM RECOMMENDED IMPROVEMENT COSTS					
Improv. Number	**Substation - Feeder**	**Description**	**Units(qty or miles)**	**Unit Cost**	**Total**
1	Dolarway #1	New 33 MVA Transformer (in progress)	1	$0	$0
2	Dolarway #1 – 1	Move Tap Placement C→B	1	$6,250	$6,250
		New #1/0 AL URD 220 mil UG cable	0.05	$150,000	$7,500
3	East Ellensburg – 11	Move Tap Placement A→C	1	$6,250	$6,250
4	East Ellensburg – 13	Move Tap Placement C→B	1	$6,250	$6,250
5	Helena – 17	Single phase to three phase conversion	0.39	$58,500	$61,500
5	Helena – 17	Move Tap Placement C→B	1	$6,250	$6,250
5	Helena – 17	Move Tap Placement C→B	1	$6,250	$6,250
5	Helena – 17	Move Tap Placement C→A	1	$6,250	$6,250
5	Helena – 17	New 750 MCM AL 220 mil cable	0.03	$400,000	$12,000
6	Helena – 17	Move Tap Placement B→C	1	$6,250	$6,250
7	Helena - 17	Move Tap Placement A→C	1	$6,250	$6,250
8	Helena - 17	Move Tap Placement A→C	1	$6,250	$6,250
9	Helena - 18	Move Tap Placement B→PARK	1	$6,250	$6,250
9	Helena - 18	Move tap placement 3 phase→PARK	1	$6,250	$6,250
					Total: $149,750

TABLE 6: EXISTING SYSTEM RECOMMENDED IMPROVEMENT COSTS

4.6 Capacitor Review

The City's existing distribution system was reviewed for its placement of capacitors on feeders and the power factor of each feeder. Below is the existing feeder kVAR, and power factor values by feeder at peak times:

EXISTING SYSTEM FEEDER KVAR AND POWER FACTOR VALUES		
Substation – Feeder	**kVAR**	**Power Factor**
Dolarway #1 – 4	346	99
Dolarway #1 – 5	366	99
Dolarway #1 – 6	418	99
Dolarway #1 – 9	-3	100
Dolarway #2 – 1	1742	97
Dolarway #2 – 2	-41	-100
Dolarway #2 – 3	-3028	-76
Dolarway #2 – 10	-1519	-92
East Ellensburg – 11	98	100
East Ellensburg – 12	421	100
East Ellensburg – 13	539	99
East Ellensburg – 14	0	100
Helena – 17	783	100
Helena – 18	424	100

TABLE 7: EXISTING SYSTEM FEEDER KVAR AND POWER FACTOR VALUES

The planning criteria outlined in Section 3.2 of this report state: 'Power factor will be corrected to 97% lead or lag or better. Improvements to power factor usually result in some demand reductions, energy conservation, and lower reactive costs.'

Dolarway #2 Feeders 3 and 10 will be evaluated to correct the power factors to meet the planning criteria. All other feeders will be evaluated for the removal, replacement, or shifting of system capacitors. Below is a list of all capacitors in the current system:

EXISTING SYSTEM CAPACITORS		
Capacitor	**Substation – Feeder**	**kVAR**
C001	Dolarway #2 – 3	600
C002	Dolarway #2 – 10	300
C003	Dolarway #2 – 10	150
C004	Dolarway #2 – 1	600
C005	Dolarway #2 – 3	600
C006	Dolarway #2 – 2	300
C008	Dolarway #2 – 1	300
C009	Dolarway #2 – 2	300
C010	Dolarway #1 – 5	300
C011	Dolarway #2 – 10	300
C012	Dolarway #1 – 5	300
C013	Dolarway #1 – 5	300
C014	Dolarway #2 – 10	300
C015	Dolarway #1 – 6	300
C016	East Ellensburg – 11	300

TABLE 8: EXISTING SYSTEM CAPACITORS

If all capacitors in the system are turned off, the feeder values at peak times will be as follows:

EXISTING SYSTEM FEEDER KVAR AND POWER FACTOR VALUES, CAPACITOR CONFIGURATION 1			
Substation – Feeder	**kVAR**	**Power Factor**	**Capacitor On/Off**
Dolarway #1 – 4	345	99	
Dolarway #1 – 5	1310	91	C010 & C012 & C013 Off
Dolarway #1 – 6	734	97	C015 Off
Dolarway #1 – 9	-3	100	
Dolarway #2 – 1	2362	95	C004 & C008 Off
Dolarway #2 – 2	590	98	C006 & C009 Off
Dolarway #2 – 3	-1763	-89	C001 & C005 Off
Dolarway #2 – 10	-423	-99	C002 & C003 & C011 &C014 Off
East Ellensburg – 11	417	98	C016 Off
East Ellensburg – 12	423	100	
East Ellensburg – 13	542	99	
East Ellensburg – 14	0	100	
Helena – 17	783	100	
Helena – 18	424	100	

TABLE 9: EXISTING SYSTEM FEEDER KVAR AND POWER FACTOR VALUES, CAPACITOR CONFIGURATION 1

After all the capacitors in the system are turned off, Dolarway #1 Feeder 5, Dolarway #2 Feeder 1 and Dolarway #2 Feeder 3 exceed the power factor requirements in the planning criteria.

If C002, C003, C006, C009, C011, C014, C015, and C016 remained off and C001, C004, C005, C008, C010, C012, C013, are turned on, the feeder values will be as follows:

EXISTING SYSTEM FEEDER KVAR AND POWER FACTOR VALUES, CAPACITOR CONFIGURATION 2			
Substation – Feeder	**kVAR**	**Power Factor**	**Capacitor On/Off**
Dolarway #1 – 4	344	99	
Dolarway #1 – 5	359	99	C010 & C012 & C013 On
Dolarway #1 – 6	733	97	C015 Off
Dolarway #1 – 9	-3	100	
Dolarway #2 – 1	1436	98	C004 & C008 On
Dolarway #2 – 2	589	98	C006 & C009 Off
Dolarway #2 – 3	-3032	-76	C001 & C005 On
Dolarway #2 – 10	-425	-99	C002 & C003 & C011 &C014 Off
East Ellensburg – 11	416	98	C016 Off
East Ellensburg – 12	420	100	
East Ellensburg – 13	540	99	
East Ellensburg – 14	0	100	
Helena – 17	783	100	
Helena – 18	424	100	

TABLE 10: EXISTING SYSTEM FEEDER KVAR AND POWER FACTOR VALUES, CAPACITOR CONFIGURATION 2

If C001, C002, C003, C005, C006, C008, C009, C011, C013, C014, C015, and C016 remained off and C004, C010, C012, are turned on, the feeder values will be as follows:

EXISTING SYSTEM FEEDER KVAR AND POWER FACTOR VALUES, CAPACITOR CONFIGURATION 3a			
Substation – Feeder	**kVAR**	**Power Factor**	**Capacitor On/Off**
Dolarway #1 – 4	345	99	
Dolarway #1 – 5	679	97	C010 & C012 On & C013 Off
Dolarway #1 – 6	733	97	C015 Off
Dolarway #1 – 9	-3	100	
Dolarway #2 – 1	1745	97	C004 On & C008 Off
Dolarway #2 – 2	589	98	C006 & C009 Off
Dolarway #2 – 3	-1764	-89	C001 & C005 Off
Dolarway #2 – 10	-425	-99	C002 & C003 & C011 &C014 Off
East Ellensburg – 11	416	98	C016 Off
East Ellensburg – 12	420	100	
East Ellensburg – 13	540	99	
East Ellensburg – 14	0	100	
Helena – 17	783	100	
Helena – 18	424	100	

TABLE 11: EXISTING SYSTEM FEEDER KVAR AND POWER FACTOR VALUES, CAPACITOR CONFIGURATION 3A

Feeder 9 is an express feeder to give the system the ability to serve CWU from the Dolarway #1 Substation. If the load from CWU is shifted from East Ellensburg Feeder 12 to Dolarway #1 Feeder 1, if C001, C002, C003, C005, C006, C008, C009, C011, C013, C014, C015, and C016 were turned off and C004, C010, C012, were turned on, the feeder values at peak times will be as follows:

EXISTING SYSTEM FEEDER KVAR AND POWER FACTOR VALUES, FEEDER 9 EXPRESS SERVING CWU, CAPACITOR CONFIGURATION 3b			
Substation – Feeder	**kVAR**	**Power Factor**	**Capacitor On/Off**
Dolarway #1 – 4	345	99	
Dolarway #1 – 5	679	97	C010 & C012 On & C013 Off
Dolarway #1 – 6	733	97	C015 Off
Dolarway #1 – 9	490	100	
Dolarway #2 – 1	1745	97	C004 On & C008 Off
Dolarway #2 – 2	589	98	C006 & C009 Off
Dolarway #2 – 3	-1764	-89	C001 & C005 Off
Dolarway #2 – 10	-425	-99	C002 & C003 & C011 &C014 Off
East Ellensburg – 11	415	98	C016 Off
East Ellensburg – 12	-3	0	
East Ellensburg – 13	538	100	
East Ellensburg – 14	0	100	
Helena – 17	783	100	
Helena – 18	424	100	

TABLE 12: EXISTING SYSTEM FEEDER KVAR AND POWER FACTOR VALUES, FEEDER 9 EXPRESS SERVING CWU, CAPACITOR CONFIGURATION 3B

It appears that when these capacitors: C001, C002, C003, C005, C006, C008, C009, C011, C013, C014, C015, and C016 are disconnected, we remain within planning criteria power factor on all feeders except Feeder 3. Feeder 3 is leading outside of the planning criteria, however adding inductors to the line would be expensive and would not provide any economic benefits. The system that was analyzed was winter peaking. Feeder 3 primarily serves Twin City Foods which is not demanding peak loads during the winter season. To resolve the leading power factor during winter months it is recommended to add more load to Feeder 3 from Feeder 10 through switching. Capacitor C005 is automatic switching, this capacitor should stay connected in the system to serve Twin City Foods. It is recommended to disconnect these capacitors C001, C002, C003, C006, C008, C009, C011, C013, C014, C015, and C016 and monitor and measure the system for at least one year to include a peak loading season. This way if the feeder meter power factor is still at or above 97% lead or lagging power factor, the disconnected capacitors could be removed.

5.0 CAPITAL FACILITIES PLAN

5.1 Capital Facilities Plan – 6 Year Overview

In 2030, assuming the system configuration is the same from 2025, all loads forecasted in Table 3 were applied.

The South EV infrastructure was modeled initially on Dolarway #1 Feeder 1 to show the effects of the new load on the existing local equipment and conductors. It is planned to build out an exclusive feeder to the new load in section 5.3 of this report.

The Dolarway #1 Substation shows that the peak demand on the 33 MVA transformer is at a loading of approximately 78%, serving 26.5 MVA of load, and operates at an average of 124 V.

Dolarway #2 Substation shows that the 33 MVA transformer is at a loading of approximately 60%, serves 20.0 MVA of load, and operates at an average of 123 V.

East Ellensburg Substation shows that the 22 MVA transformer is at a loading of approximately 78%, serves 16.4 MVA of load, and operates at an average of 123 V.

The existing configuration for the Helena Substation shows that the 33 MVA transformer is at a loading of approximately 38%, serves 12.2 MVA of load, and operates at an average of 124 V.

It is recommended to shift load or upgrade capacity by adding more transformers or replace existing substation transformers when loading is at or exceeds 80% to provide longevity to equipment life, and to provide options to shift load throughout the system.

5.2 Distribution System

The 2030 system is not compliant with the planning criteria. Dolarway #1 Feeder 1 experiences conductor loading of over 80%.

5.3 System Improvement Recommendations

Below are system improvement options, suggested for capacity for the 2030 system:

2030 SYSTEM RECOMMENDED IMPROVEMENTS				
Improvement Number	**Substation - Feeder**	**Description**	**Location, From - To**	**Reason For Improvement**
11	Dolarway #2 - 7	New 1000 MCM AL 220 mil Cable Installation	Dolarway #2 Substation – South to FQD01 – South to Winco site.	To serve Winco Foods
12	Dolarway #2 - 8	New 750 MCM AL 220 mil Cable Installation	Dolarway #2 Substation – east to FQM22 – GQM10 – GQM28 – GRM15 – Switch S030 – Run east to proposed charging station	To remove EV infrastructure off of Dolarway #1 Feeder 1, to the newly constructed Dolarway #2, Feeder 8.

TABLE 13: RECOMMENDED SYSTEM IMPROVEMENTS – 2030

5.4 Results of System Improvements

Following the upgrading of conductor, and load shifting at peak times, all transformer loading for the 2030 system is:

- Dolarway #1 Substation – 68%
- Dolarway #2 Substation – 70%
- East Ellensburg Substation – 78%
- Helena Substation – 38%

It is recommended to monitor loading to ensure that further load shifts to Helena Substation are not required since it's possible to utilize available transformer capacity.

5.5 Cost of System Improvement Recommendations

Below are the costs of system improvement options for the 2030 system:

2030 SYSTEM RECOMMENDED IMPROVEMENT COSTS					
Improvement Number	**Substation – Feeder**	**Description**	**Units(qty or miles)**	**Unit Cost**	**Total**
11	Dolarway #2 – 7	New 1000 MCM AL 220 mil Cable Installation	0.83	$450,000	$373,500
12	Dolarway #2 – 8	New 750 MCM AL 220 mil Cable Installation	1.9	$400,000	$760,000
					Total: $1,133,500

TABLE 14: 2030 SYSTEM RECOMMENDED IMPROVEMENT COSTS

6.0 20 – YEAR SYSTEM PLAN

6.1 20 Year Overview

In 2044, assuming the system configuration is the same from 2030, all loads forecasted from Table 4 were applied.

The Dolarway #1 Substation shows that the 33 MVA transformer is at a loading of approximately 104%, serves 35.0 MVA of load, and operates at an average of 123 V at peak.

The Dolarway #2 Substation shows that the 33 MVA transformer is at a loading of approximately 106%, serves 35.7 MVA of load, and operates at an average of 123 V at peak.

The East Ellensburg Substation shows that the 22 MVA transformer is at a loading of approximately 121%, serves 26.0 MVA of load, and operates at an average of 123 V.

The Helena Substation shows that the 33 MVA transformer is at a loading of approximately 49%, serves 15.8 MVA of load, and operates at an average of 124 V.

It is recommended that The City improve available capacity by adding a new 33 MVA transformer bank and line up to the East Ellensburg Substation and the addition of a new two bank substation with one transformer installed in the South Ellensburg Substation southeast of Berry and Canyon roads.

6.2 Distribution System

The 2044 system is not compliant with the planning criteria. Below are system discrepancies listed by feeder:

- Feeder 1
  - Conductor overloading
- Feeder 4
  - Conductor overloading
  - Voltage imbalance
  - Undervoltage
- Feeder 7
  - Conductor approaching overloading
- Feeder 9
  - Conductor approaching overloading
- Feeder 12
  - Conductor approaching overloading
- Feeder 17
  - Conductor approaching overloading

6.3 System Improvement Recommendations

Below are system improvement options, recommended for capacity and load balancing for the 2044 system:

2044 SYSTEM RECOMMENDED IMPROVEMENTS				
Improvement Number	**Substation – Feeder**	**Description**	**Location, To - From**	**Reason For Improvement**
13	Dolarway #1 – 4	Cable Replacement 336 AAC → 795 kCM AAC	Dolarway #1 Substation – Switch S116	Conductor loaded to 139% due to EV charging infrastructure, after the load shift of improvement number 27, the conductor is still loaded to 97%
14	Dolarway #1 – 4	Cable Replacement 750 MCM→1000 MCM AL 220 mil	Switch S116 – Switch S115, Switch S114 – Switch S045	Conductor loading to 133% due to EV charging infrastructure, after the load shift of improvement number 27, the conductor is still loaded to 94%
15	East Ellensburg #2	New 33 MVA Transformer Bank	East Ellensburg Substation	To improve capacity to serve CWU decarbonization, existing East Ellensburg Substation transformer overloaded to 106%, Dolarway #1 Substation overloaded to 104%. Overloading may happen prior to 2044 depending on the decarbonization progress of CWU. See Appendix C of this report for a further breakdown of decarbonization phases

2044 SYSTEM RECOMMENDED IMPROVEMENTS				
16	East Ellensburg #2 – 19	New 750 MCM AL 220 mil Cable Installation	East Ellensburg Substation – Distribution pole IPM25 – Distribution pole IPM24 – Distribution pole IPM23 – Distribution pole IPM22 – Distribution pole IPM21 – Vault IPV05 – Vault IPV05 – CWU CHESTNUT ST SWITCHYARD – Vault IPV04 – Vault IPV01 – Vault HPV19 – Vault HPV09 – Vault HPV05 – Vault HPV07 – Switch cabinet HPC03 – Vault HPV07 – Vault HPV23 – Vault HPV22 – Vault HPV21	To serve part of CWU's total load
17	East Ellensburg #2 – 20	New 750 MCM AL 220 mil Cable Installation	East Ellensburg Substation – Distribution pole IPM25 – Distribution pole IPM24 – Distribution pole IPM23 – Distribution pole IPM22 – Distribution pole IPM21 – Vault IPV05 – Vault IPV07 – CWU CHESTNUT ST SWITCHYARD	To serve part of CWU's total load
18	South Ellensburg -	New South Ellensburg Substation	SE of Berry Rd & Canyon Rd crossing	Improve system capacity, Dolarway #2 Substation loaded to 132% due to new EV infrastructure and new large customer loads

2044 SYSTEM RECOMMENDED IMPROVEMENTS				
19	South Ellensburg -	New 115kV Transmission	BPA Ellensburg-Moxee #1 Transmission tap between 3/7 & 3/9 then SW of Mattoon Lake – Run SE – Run east in parallel with Berry Rd to South Ellensburg Substation site	To provide service to the new South Ellensburg Substation
20	South Ellensburg – 24	New Line Construction 795 kCM AAC	South Ellensburg Substation site – North to Berry Rd – West to connect to Distribution pole ITM02	To connect new Feeder 24 to system
21	South Ellensburg – 24	Cable Replacement 350 CU→750 MCM AL 220 mil	Vault HTV11 – Vault HTV07	Conductor loading to 103% due to EV infrastructure
22	South Ellensburg – 25	New Line Construction 336 kCM AAC	South Ellensburg Substation site – North to Berry Rd – Vault ITV03	To connect new Feeder 25 to system
23	South Ellensburg – 25	New #1/0 AL URD 220 mil Cable Installation	ITV03 – East to Bull Rd – N to connect into system at Vault JTV10	To connect new Feeder 25 to system
24		Shift EV Load Feeder 8→South Ellensburg Substation	Dependent on new Feeder design	Dolarway #2 Transformer Overloading due to second phase loading of EV infrastructure
25		Shift Load Feeder 13→Feeder 25	Dependent on new Feeder design	To evenly distribute load to new South Ellensburg Substation, from East Ellensburg
26		Shift Load Feeder 9→Feeder 19	Dependent on new Feeder design	Dolarway #2 Substation transformer Overloading due to part of the CWU decarbonization load

2044 SYSTEM RECOMMENDED IMPROVEMENTS				
27		Shift Load Feeder 4→Feeder 6	Open switch S055, Close switch S139	Dolarway #1 Transformer overloading due to second phase loading of EV infrastructure
28		Shift Load Feeder 1→Feeder 24	Dependent on new Feeder design	Dolarway #2 Substation Transformer Overloading due to second phase EV infrastructure. Since Feeder 24 is fed into the existing overhead infrastructure of Feeder 1, the design of Feeder 8 will need to be able to support switching to Feeder 1 near the new south EV infrastructure.
29		Shift Load Feeder 12→Feeder 20	Open Switch S063 and shift college load to newly constructed Feeders	East Ellensburg Substation Transformer Overloading due to the CWU decarbonization load

TABLE 15: RECOMMENDED SYSTEM IMPROVEMENTS – 2044

6.4 Results of System Improvements

Following the addition of two new transformers, conductor upgrades, and load shifting at peak times, all transformer loading is under 80% for the 2044 system:

- Dolarway #1 Substation – 79%
- Dolarway #2 Substation – 65%
- East Ellensburg Substation – 73%
- East Ellensburg #2 Substation – 55%
- Helena Substation – 49%
- South Ellensburg Substation – 35%

The two feeders serving CWU from East Ellensburg #2 Substation could become overloaded if the total load is not distributed properly, it is recommended that loading be balanced and monitored for CWU to ensure load is properly distributed between each feeder.

Improvement Number 14: Cable Replacement 750 MCM AL→1000 MCM AL may see loading of over 80% at peak depending on actual 2044 loads. It's recommended to monitor the progression of loads and potentially shift some of the load to Helena Substation through switching or potentially through a new feeder.

Improvement Number 21: Cable Replacement of 350 MCM AL→750 MCM AL will see loading of over 80% at peak depending on actual 2044 loads. It's recommended to monitor the progression of loads and potentially shift some of the loading through switching or potentially through a new feeder out of the South Ellensburg Substation.

6.5 Cost of System Recommended Improvements

Below are the costs of system improvement options for the 2044 system:

2044 SYSTEM RECOMMENDED IMPROVEMENT COSTS					
Improvement Number	**Substation - Feeder**	**Description**	**Units(qty or miles)**	**Unit Cost**	**Total**
13	Dolarway #1 – 4	Cable Replacement 336 AAC→795 kCM AAC	1.03	$465,000	$478,950
14	Dolarway #1 – 4	Cable Replacement 750 MCM→1000 MCM AL 220 mil	0.48	$450,000	$216,000
15	East Ellensburg #2	New 33 MVA Transformer Bank	1	$3,500,000	$3,500,000
16	East Ellensburg #2 – 19	New 750 MCM AL 220 mil Cable Installation	1.29	$400,000	$516,000

2044 SYSTEM RECOMMENDED IMPROVEMENT COSTS					
17	East Ellensburg #2 – 20	New 750 MCM AL 220 mil Cable Installation	0.85	$400,000	$340,000
18	South Ellensburg -	New South Ellensburg Substation	1	$5,000,000	$5,000,000
19	South Ellensburg -	New 115kV Transmission	1.14	$1,000,000	$2,550,127
		BPA line switches at the tap		$1,410,127	
20	South Ellensburg – 24	New Line Construction 795 kCM AAC	0.06	$310,000	$18,600
21	South Ellensburg – 24	Cable Replacement 350 CU→750 MCM AL 220 mil	0.19	$450,000	$85,500
22	South Ellensburg – 25	New Line Construction 336 kCM AAC	0.13	$208,000	$27,040
23	South Ellensburg – 25	New #1/0 AL URD 220 mil Cable Installation	0.67	$150,000	$100,500
					Total: $12,832,717

TABLE 16: 2044 SYSTEM RECOMMENDED IMPROVEMENT COSTS

7.0 DISTRIBUTION SYSTEM MITIGATION

7.1 Distribution System Contingency Mitigation Overview

The system was studied for the contingency of one substation transformer out of service at peak load time (system N-1 condition) for the existing system, the 2030 and 2044 recommended systems.

7.2 Dolarway #1 Substation Out of Service

2025:

If the Dolarway #1 Substation is taken out of service, the existing system can operate by:

- Shifting Dolarway #1's load to the Dolarway #2 Transformer by:
    - Opening the new distribution interrupter switch between Dolarway #1 and it's getaway
    - Closing the new bus tie switch between the two transformer runs

After the shifting of loads in the existing system the transformers will be loaded to approximately:

- Dolarway #2 Substation – 88%
- East Ellensburg Substation – 63%
- Helena Substation – 38%

This arrangement of steps will keep all remaining transformers in the system underloaded.

Figure 2 shows the recommended configuration.

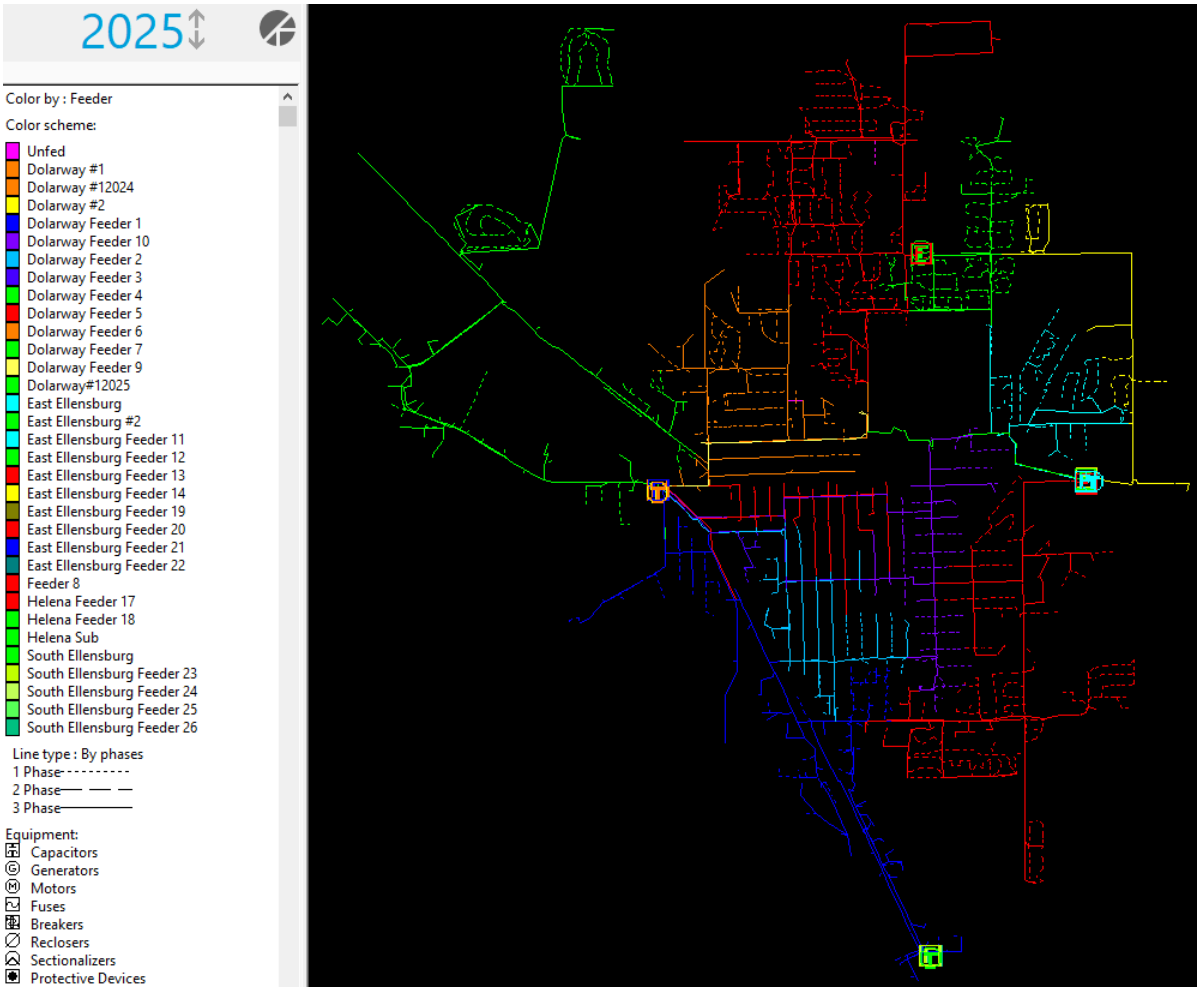


FIGURE 2: DOLARWAY #1 SUBSTATION OUT OF SERVICE RECOMMENDED CONFIGURATION FOR 2025

2030:

In 2030 Feeder 7 and Feeder 8 will be added to Dolarway #2 Substation, in the event of the Dolarway #1 Substation transformer going out of service, with the 2030 configuration and all other new system loads, the system will be overloaded at peak times. After this load shift the transformers will be peak loaded to approximately:

- Dolarway #2 Substation – 143%
- East Ellensburg Substation – 78%
- Helena Substation – 38%

Dolarway #2 Substation's loading can be relieved by:

- Shifting Feeder 6's load to Feeder 17 by:
  - Opening Feeder 6 at the Dolarway Substation
  - Closing switch S096
- Shifting Feeder 9's load to Feeder 17 by:

- Opening Feeder 9 at the Dolarway Substation
- Closing switch S029

After this load shift the transformers will be peak loaded to approximately:

- Dolarway #2 Substation – 117%
- East Ellensburg Substation – 78%
- Helena Substation – 61%

This arrangement in 2030 will cause significant overloading of conductors, low voltage and service loss to customers. It is recommended that capacity of the system be upgraded for the Dolarway #1 Substation contingency at peak load times to be able to operate at 100% in the event that Dolarway #1 Substation were to be taken out of service.

To accomplish this by 2030 one or more of the following are recommended:

- South Ellensburg Substation project is accelerated complete and in service.
- East Ellensburg Substation expansion is accelerated complete and in service.
  - Construction of Feeders 19, 20 to serve the growing decarbonization efforts at CWU.
- Addition of new tie feeders of appropriate conductor size be constructed out of the Helena Substation to transfer load from East Ellensburg Substation, Dolarway #2 Substation, and potentially to serve CWU's Wildcat Way Substation. These new feeders would alleviate the need for the accelerated substation construction noted above.

Figure 3 shows the recommended configuration without any improvements to system capacity.

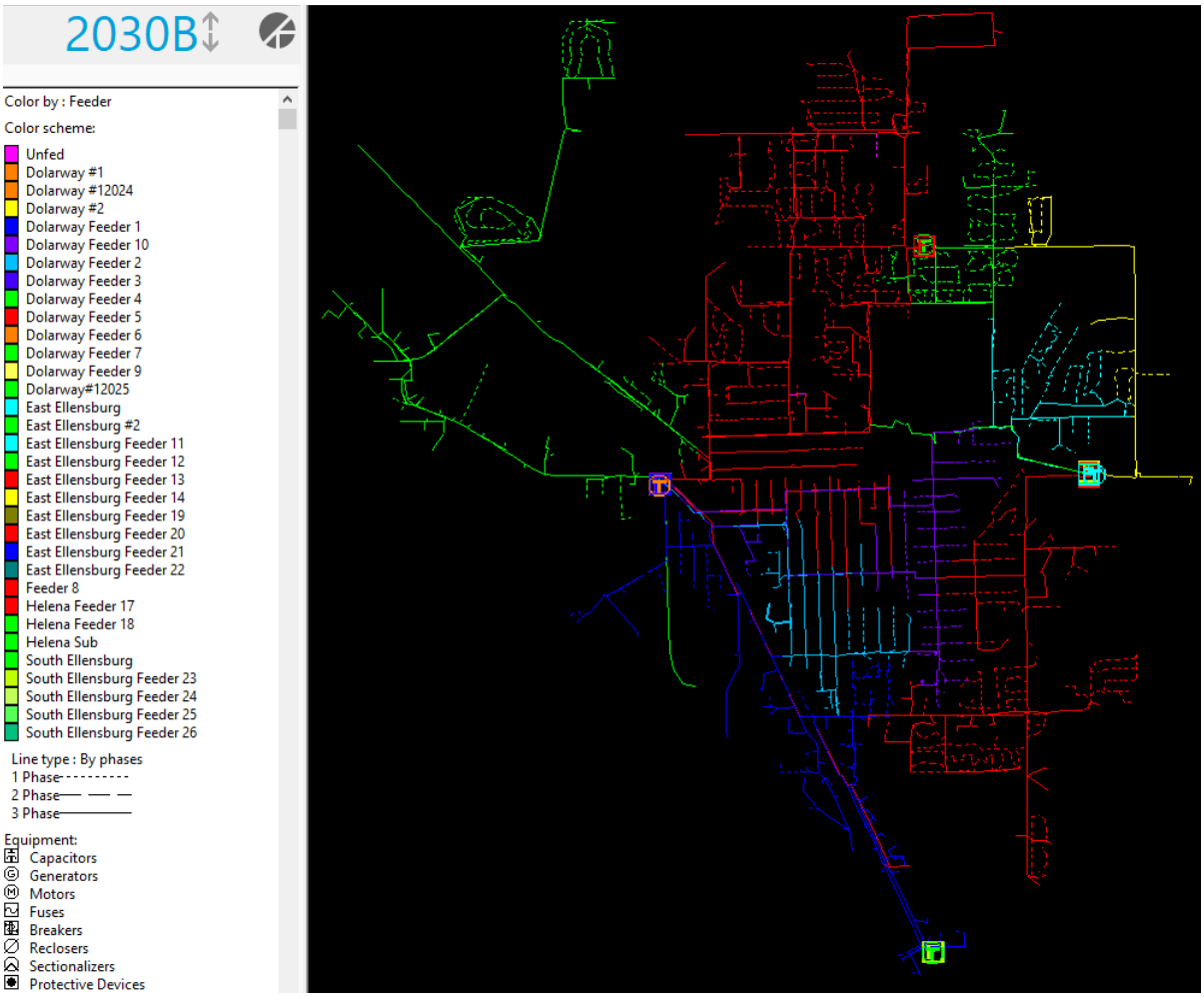


FIGURE 3: DOLARWAY #1 SUBSTATION OUT OF SERVICE RECOMMENDED CONFIGURATION FOR 2030

2044:

In 2044 all expected loads and projects are assumed to be in service. From the 2030 system, loads will need to be shifted by:

- Shifting Feeder 1's load to the newly constructed South Ellensburg Feeder 24 by:
  - Opening Feeder 1 at the Dolarway #1 Substation
  - Closing switch S030

- Move South Interchange Charging station load to Feeder 24:
  - Due to the location of the new EV charging station, it is recommended to design the circuit to be fed from the Dolarway #1 Substation, or the new South Ellensburg Substation

This arrangement in 2044 will prevent transformers from being overloaded at peak, however there will be under voltage to some customers, voltage imbalance and overloading on certain lines. Mitigation will depend on the actual development and placement of loads on the 20-year system. It is

recommended that subsequent planning studies, knowing more accurately actual load growth placement evaluate this contingency and feeder impacts.

In lieu of these transfers and improvements a new West Helena Substation along the existing transmission line route could be constructed with additional new feeders constructed to relieve the Dolarway #1 Substation capacity deficit. The West Helena Substation alternative is further developed in the residential gas conversion section of this report.

These load transfers and additional feeder improvements are needed to operate at 100% of projected load at peak times in 2044 if Dolarway #1 Substation were to be taken out of service. After this load shift the transformers will be loaded too approximately (at peak usage time):

- Dolarway #2 Substation – 102%
- East Ellensburg Substation – 73%
- Helena Substation – 70%
- East Ellensburg #2 Substation – 55%
- South Ellensburg Substation – 56%

Figure 4 shows the recommended configuration.

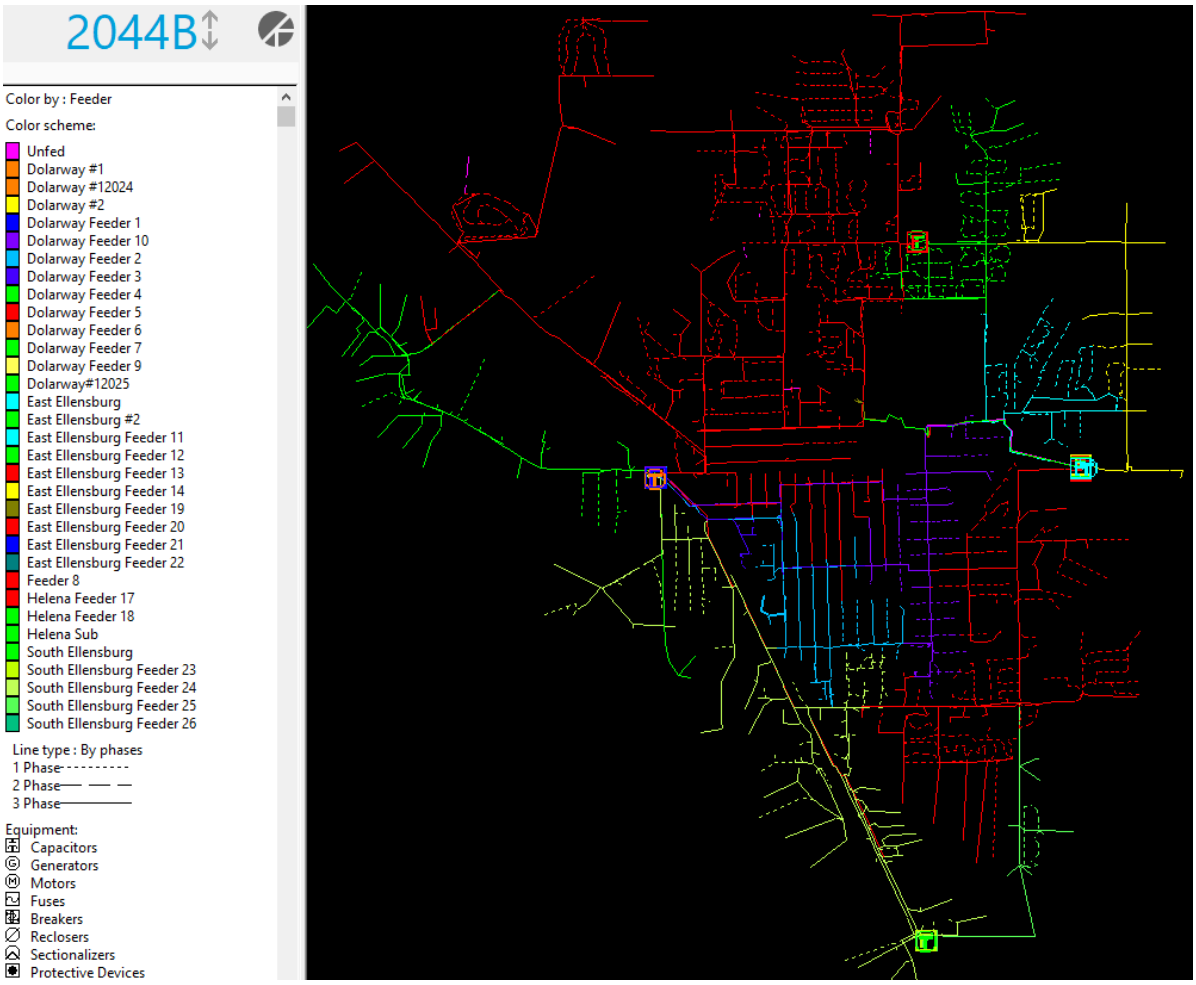


FIGURE 4: DOLARWAY #1 SUBSTATION OUT OF SERVICE RECOMMENDED CONFIGURATION FOR 2044

7.3 Dolarway #2 Substation Out of Service

It is recommended that the same procedures outlined in section 7.2 of this report be followed due to the similarities of the Dolarway #1 and Dolarway #2 Substations and the bus tie switch that connects the two.

7.4 East Ellensburg Substation Out of Service

2025:

If East Ellensburg is taken out of service, the existing system can operate by:

- Shifting load from Feeder 11 to Feeder 18 by:
  - Opening Feeder 11 at the East Ellensburg Substation switchgear
  - Closing switch S112
- Shifting load from Feeder 12 to Feeder 9 by:

    - Opening Feeder 12 at the East Ellensburg Substation switchgear
    - Closing switch S123
- Shifting load from Feeder 13 to Feeder 1 by:
    - Opening Feeder 13 at the East Ellensburg Substation switchgear
    - Closing switch S080
- Shifting load from Feeder 14 to Feeder 18 by:
    - Opening Feeder 14 at the East Ellensburg Substation switchgear
    - Closing switch S023

These load transfers will ensure that all other transformers on the system do not become overloaded. Some parts of the system will have voltage and current imbalance. Dolarway #1 Substation's 1000 MCM AL getaway, and the 336 AAC following in series will be loaded to over 100%. It is recommended that this configuration not be ran at peak times and that loads be balanced to ensure system service standards are attained. After the shifting of loads in the existing system the transformers will be loaded too approximately:

- Dolarway #1 Substation – 74%
- Dolarway #2 Substation – 44%
- Helena Substation – 48%

Figure 5 shows the recommended configuration.

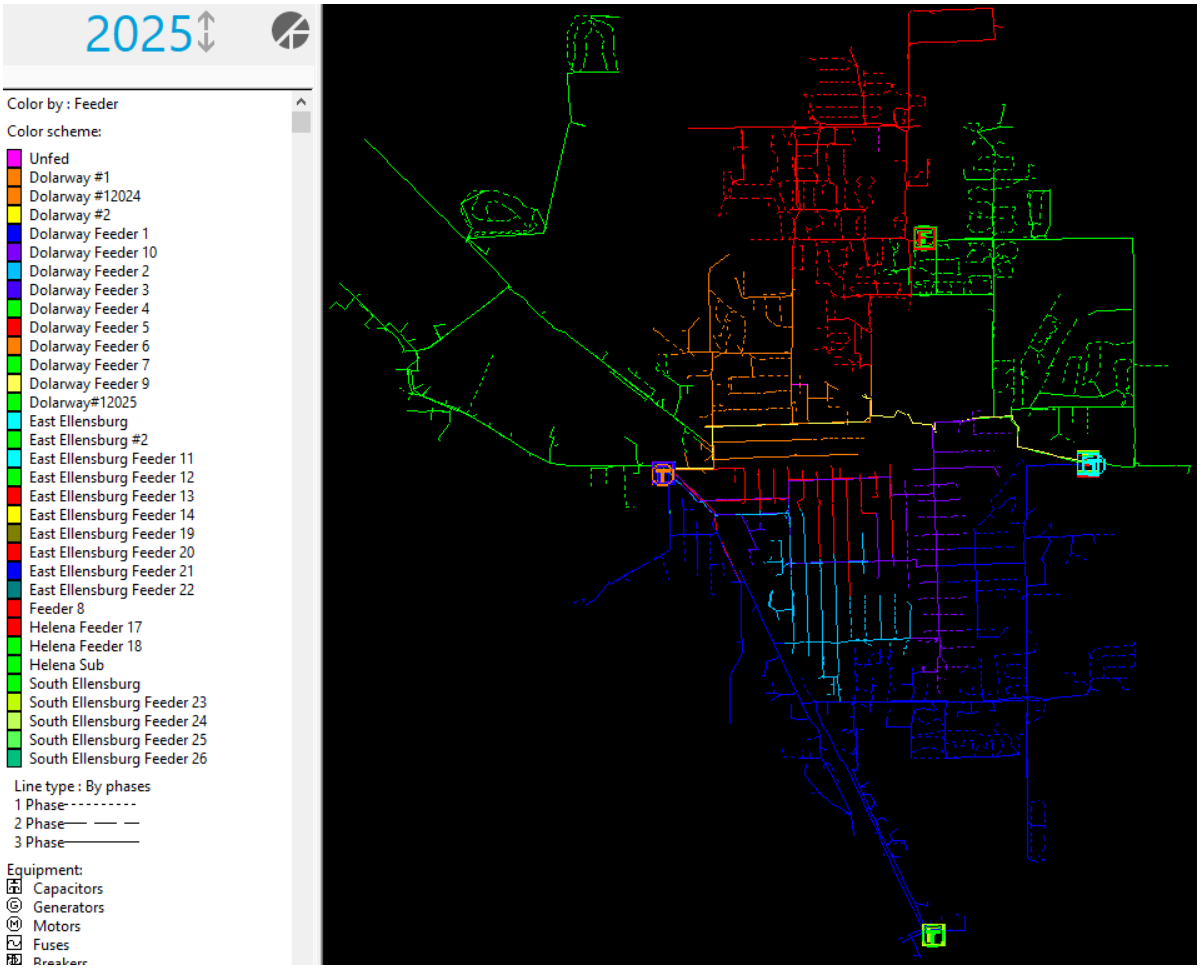


FIGURE 5: EAST ELLENSBURG SUBSTATION OUT OF SERVICE RECOMMENDED CONFIGURATION FOR 2025

2030:

In 2030 Feeder 7 and 8 will be added to Dolarway #2 Substation, and additional loads are also expected to be added to the system. In the event of the East Ellensburg Substation transformer going out of service, with the existing configuration, the system will be overloaded at peak times. Loads will need to be shifted by:

- Offloading Feeder 6 to Feeder 17 by:
  - Opening Feeder 6 at the Dolarway #2 Substation switchgear
  - Closing switch S096

After this load shift the transformers will be peak loaded too approximately:

- Dolarway #1 Substation – 90%
- Dolarway #2 Substation – 73%
- Helena Substation – 65%

This arrangement in 2030 will prevent the remaining transformers in the system from being overloaded, however the lines and cable get-aways for Feeder 1 will be overloaded at peak times. The feeder conductor will either need to be upgraded, or this arrangement will need to occur at non-peak times. Other parts of the system will have some voltage imbalance, it's recommended to monitor loads and voltages on the system to identify any trouble areas and maintain service standards under this contingency.

Figure 6 shows the recommended configuration.

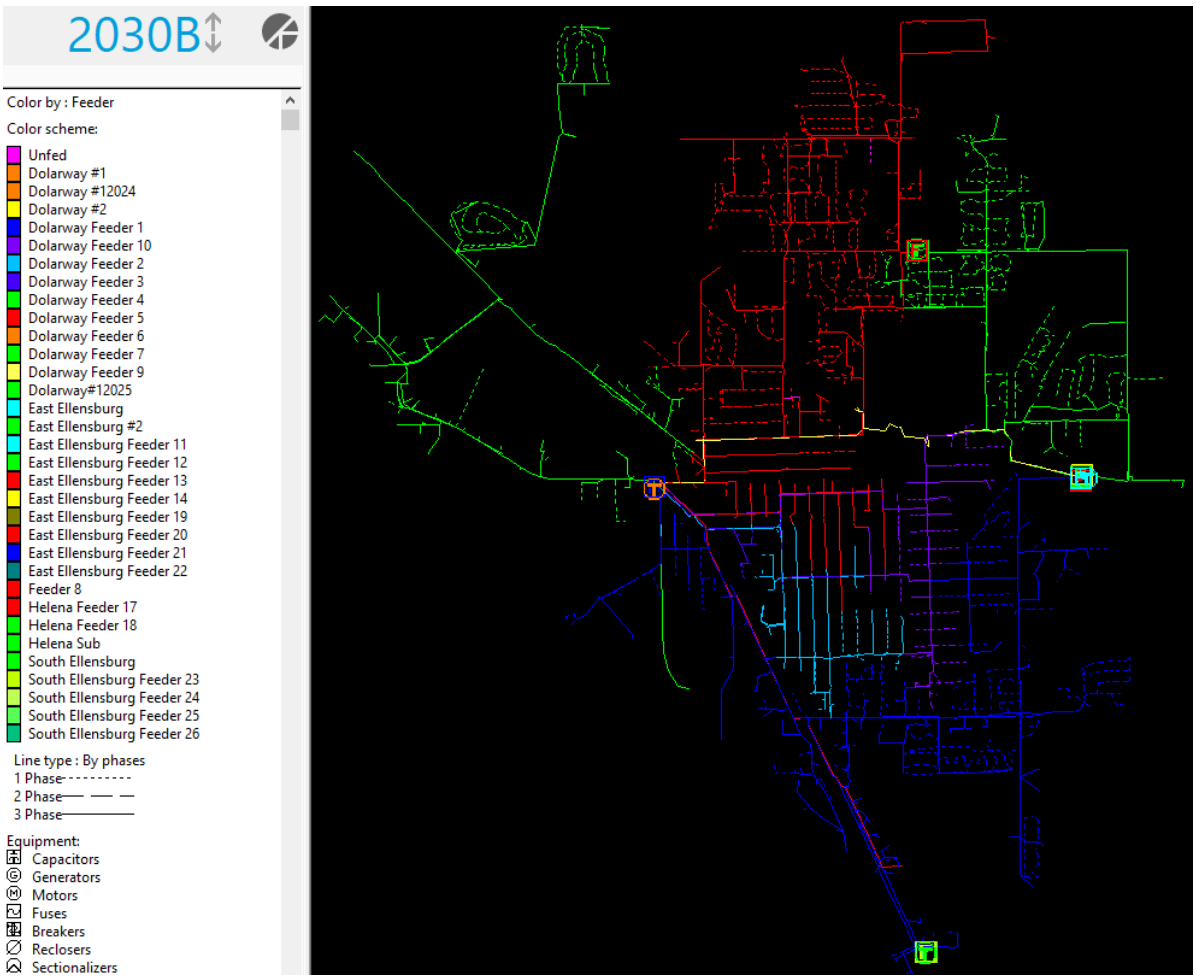


FIGURE 6: EAST ELLENSBURG SUBSTATION OUT OF SERVICE RECOMMENDED CONFIGURATION FOR 2030

2044:

In 2044 all expected loads and projects are assumed to be in service.

This arrangement in 2044 will prevent transformers from being overloaded at peak, however there will be under voltage to customers, voltage imbalances and overloading on certain lines. Mitigation will depend on the actual development and placement of loads on the 20-year system. It's recommended that subsequent planning studies, to know the actual load growth placement in order to evaluate this contingency and its feeder impacts.

Additional transfers will be needed for this configuration to be able to operate under 100% capacity of the system if East Ellensburg Substation were to be taken out of service. After this load shift the transformers will be peak loaded too approximately:

- Dolarway #1 Substation – 100%
- Dolarway #2 Substation – 42%
- Helena Substation – 99%
- East Ellensburg #2 Substation – 53%
- South Ellensburg Substation – 35%

Dolarway #1 Feeder 1 will still have loading issues in this configuration, to alleviate this issue it is recommended to build out additional tie feeders from South Ellensburg Substation to shift load off Feeder 1.

Figure 7 shows the recommended configuration.

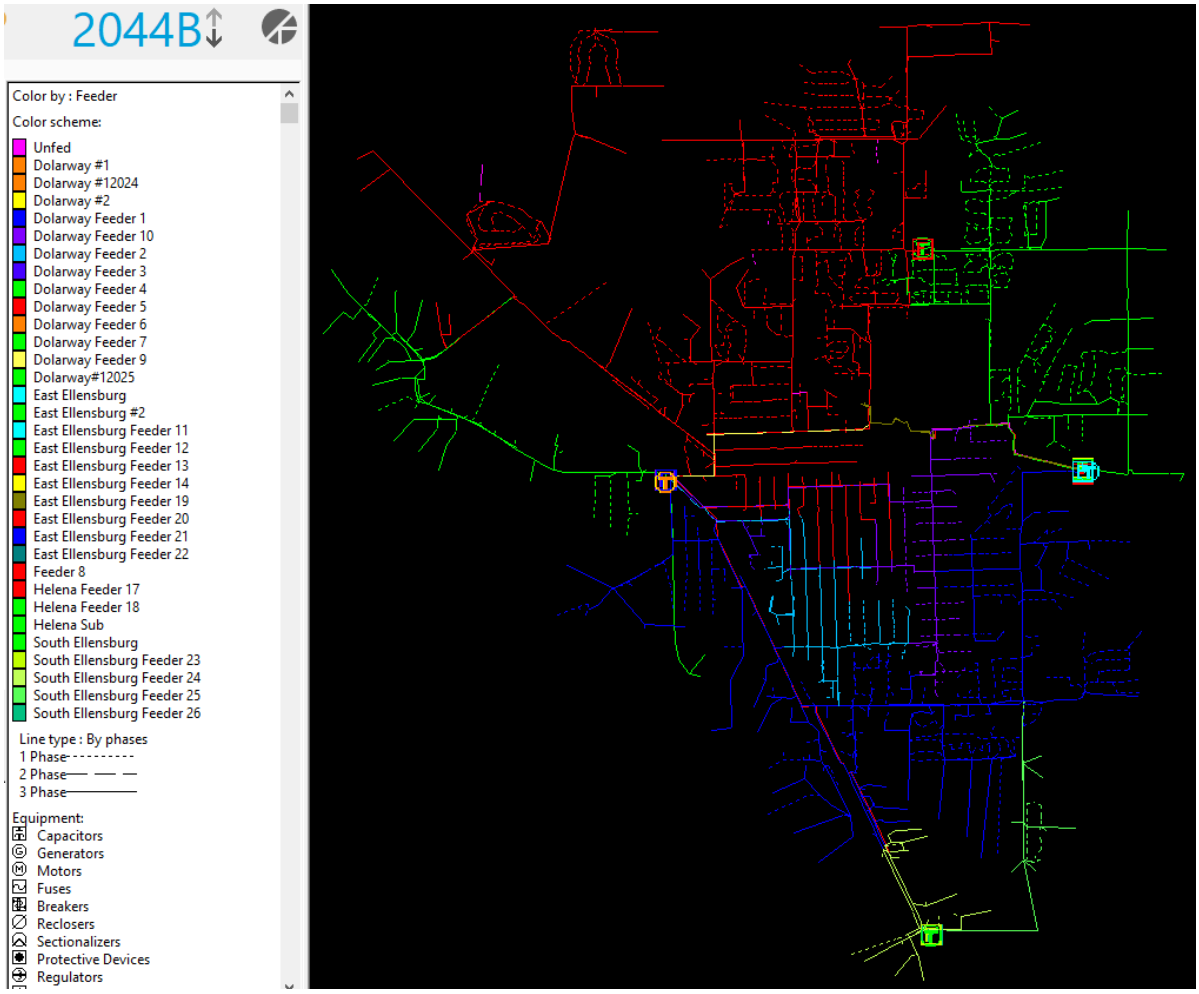


FIGURE 7: EAST ELLENSBURG SUBSTATION OUT OF SERVICE RECOMMENDED CONFIGURATION FOR 2044

7.5 Helena Substation Out of Service

2025:

If Helena Substation is taken out of service, the existing system can operate by:

- Shifting load from Feeder 17 to Feeder 6 by:
  - Opening Feeder 17 at the Helena Substation switchgear
  - Closing switch S096
- Shifting load from Feeder 18 to Feeder 14 by:
  - Opening Feeder 18 at the Helena Substation switchgear
  - Closing switch S023

This arrangement of steps will keep all remaining transformers in the system underloaded. Some parts of the system will have voltage imbalance. It is recommended that loads be balanced to ensure system service standards are attained. It is also recommended to monitor loads and voltages on the system to identify any trouble areas and maintain service standards under this contingency.

After the shifting of loads in the existing system the transformers will be loaded too approximately:

- Dolarway #1 Substation – 56%
- Dolarway #2 Substation – 57%
- East Ellensburg Substation – 81%

Figure 8 shows the recommended configuration.

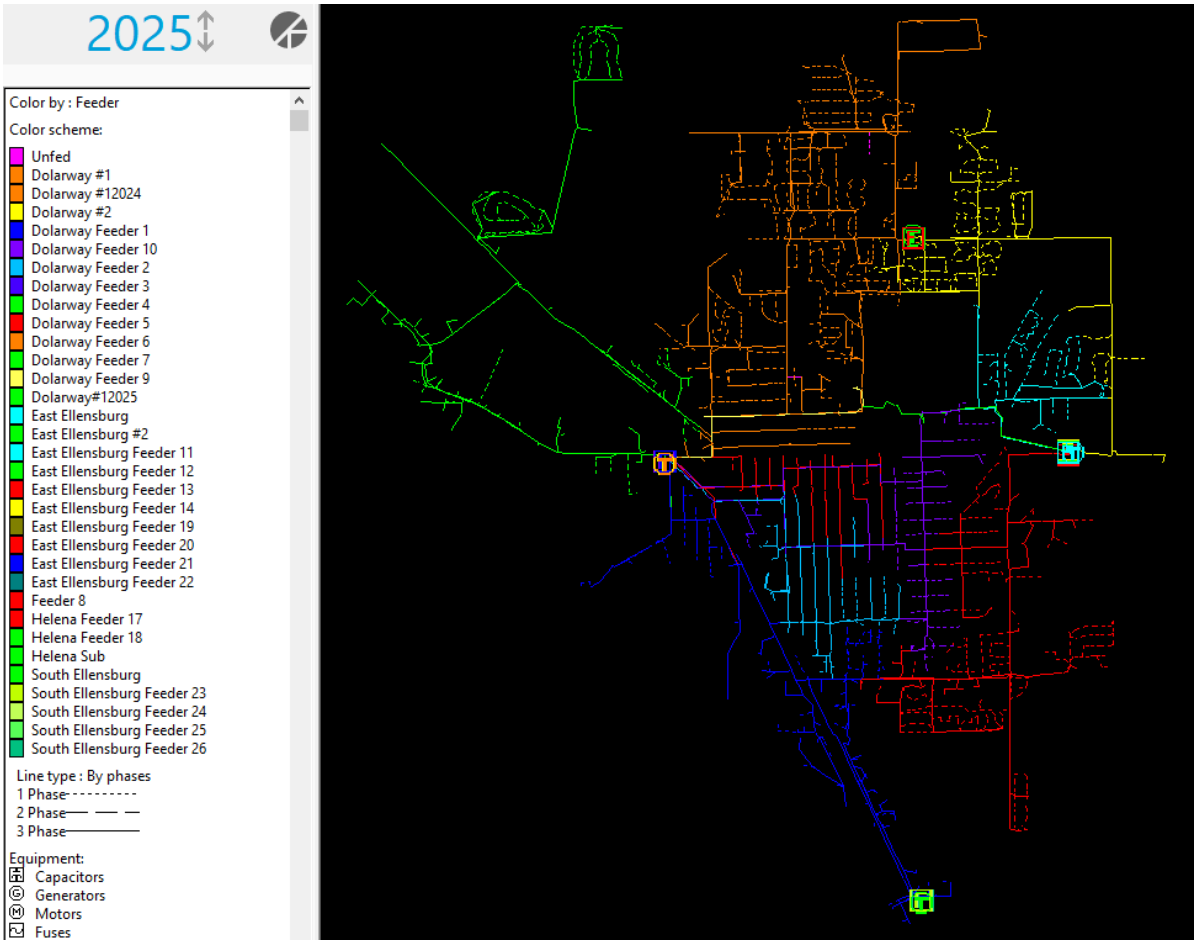


FIGURE 8: HELENA SUBSTATION OUT OF SERVICE RECOMMENDED CONFIGURATION FOR 2025

2030:

In 2030 Feeder 7 and Feeder 8 will be added to Dolarway #2 Substation, along with new spot loads. In the event Helena Substation is out of service, with the existing configuration, the system will be underloaded if the previous steps for 2025 performed. With the additional 2030 loads and improvements, the peak loading of the system will be:

- Dolarway #1 Substation – 68%
- Dolarway #2 Substation – 96%
- East Ellensburg Substation – 97%

This arrangement in 2030 will keep all remaining transformers in the system from being overloaded, however the lines and cables coming out of Feeder 6 will be overloaded at peak times. The feeder conductor will either need to be upgraded, or this arrangement will have to occur at non-peak times. Other parts of the system will have voltage imbalances, it's recommended to monitor loads and voltages on the system to identify any trouble areas and maintain service standards under this contingency.

Figure 9 shows the recommended configuration.

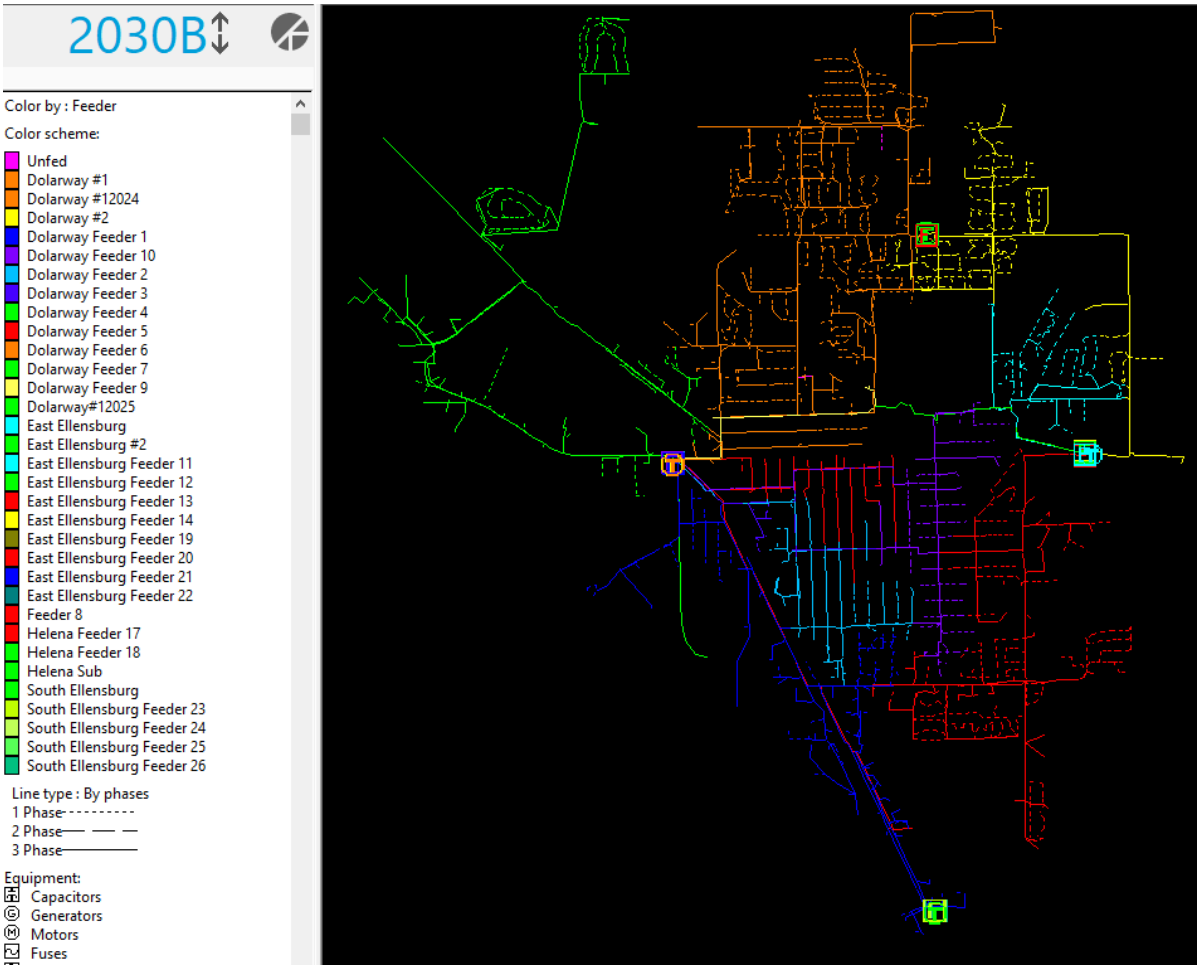


FIGURE 9: HELENA SUBSTATION OUT OF SERVICE RECOMMENDED CONFIGURATION FOR 2030

2044:

In 2044 all expected loads and project are assumed to be in service. In the event Helena Substation is out of service, with the existing configuration this arrangement in 2044 will prevent transformers from being overloaded at peak, however there will be under voltage to some customers, voltage imbalance and overloading on certain lines. Mitigation will depend on the actual development and placement of loads on the 20-year system. It is recommended that subsequent planning studies are performed to know the actual load growth placement to evaluate this contingency and feeder impacts.

In lieu of these transfers and improvements a new West Helena Substation along the existing transmission line route could be constructed with additional new feeders constructed to relieve the Helena Substation capacity deficit and relieve the loading on the Dolarway #2 Substation transformer. The West Helena Substation alternative is further developed in the residential gas conversion section of this report.

After this load shift the transformers will be peak loaded too approximately:

- Dolarway #1 Substation – 79%
- Dolarway #2 Substation – 102%
- East Ellensburg Substation – 96%
- East Ellensburg #2 Substation – 55%
- South Ellensburg Substation – 35%

Figure 10 shows the recommended configuration.

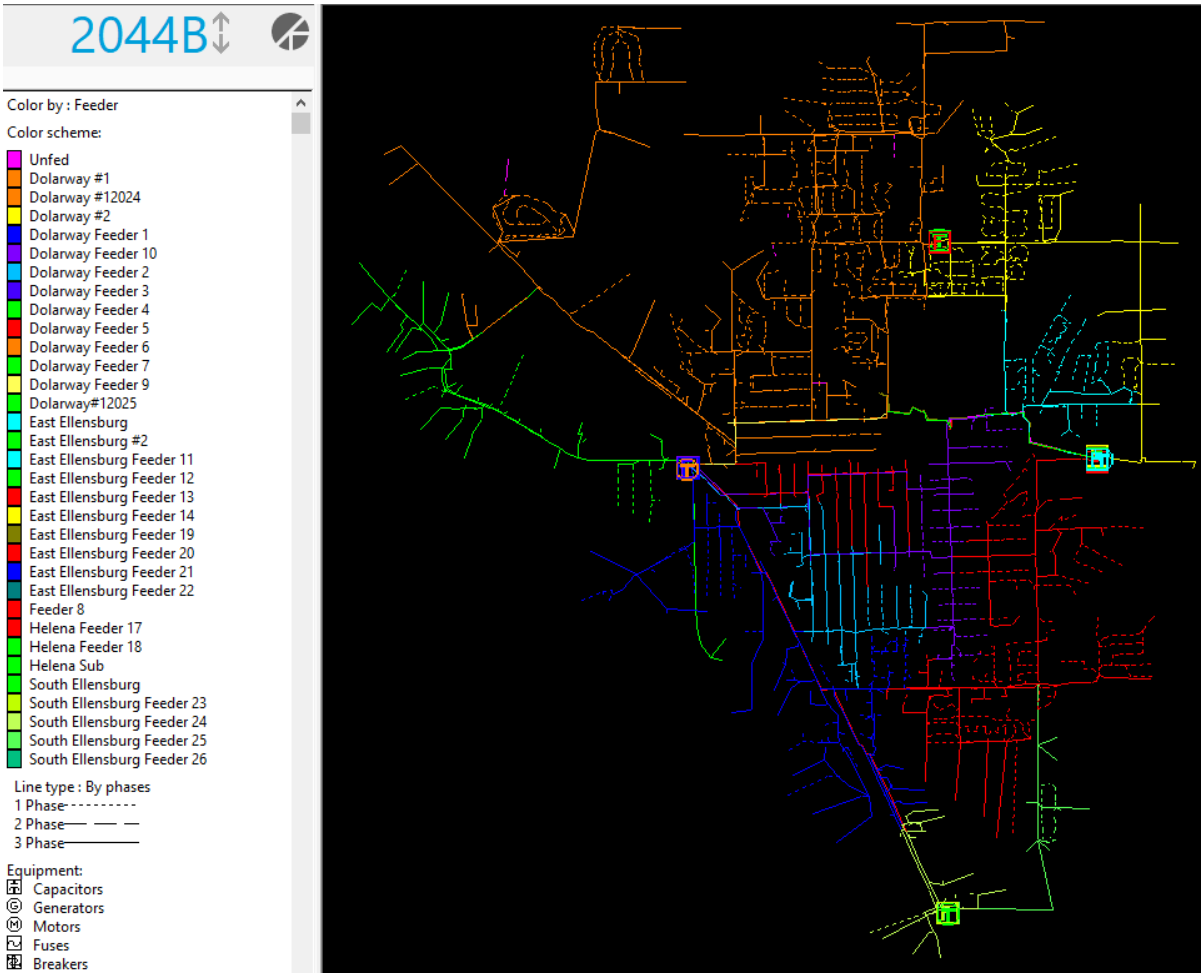


FIGURE 10: HELENA SUBSTATION OUT OF SERVICE RECOMMENDED CONFIGURATION FOR 2044

7.6 East Ellensburg #2 Substation Out of Service

2044:

If East Ellensburg #2 Substation is taken out of service, the 2044 system can operate by:

- Shifting load from Feeder 19 to Feeder 9 by:

    - Opening Feeder 19 at the new East Ellensburg #2 Substation switchgear
    - Dependent on the design of East Ellensburg #2's Feeder 19 design, however it is suggested to allow Feeder 9 to energize the line by closing switch S123 and S124
- Shifting load from Feeder 20 to Feeder 12 by:
    - Opening Feeder 20 at the new East Ellensburg #2 Substation switchgear
    - Dependent on the design of East Ellensburg #2's Feeder 20 design, however it is suggested to allow Feeder 12 to energize the line through the Chestnut Street switchyard and opening S051
- Shifting load from Feeder 14 to Feeder 18 by:
    - Opening Feeder 14 at the East Ellensburg Substation switchgear
    - Close switch S023

This arrangement in 2044 will prevent transformers from being overloaded at peak, however there will be loading levels that exceed the planning criteria on certain conductors. Mitigation will depend on the actual development and placement of loads on the 20-year system. It is recommended that subsequent planning studies are performed to know the actual load growth placement, CWU decarbonization loads and timing in order to evaluate this contingency and feeder impacts.

In lieu of these transfers and improvements a new West Helena Substation along the existing transmission line route could be constructed with additional new feeders constructed to relieve the East Ellensburg #2 Substation capacity deficit and relieve the loading on the Dolarway transformers and East Ellensburg #1 Substation. The West Helena Substation alternative is further developed in the residential gas conversion section of this report.

If the East Ellensburg #2 Substation were to be taken out of service and with the load shifts above the transformers will be peak loaded too approximately:

- Dolarway #1 Substation – 79%
- Dolarway #2 Substation – 95%
- East Ellensburg Substation – 107%
- Helena Substation – 55%
- South Ellensburg Substation – 35%

Figure 11 shows the recommended configuration.

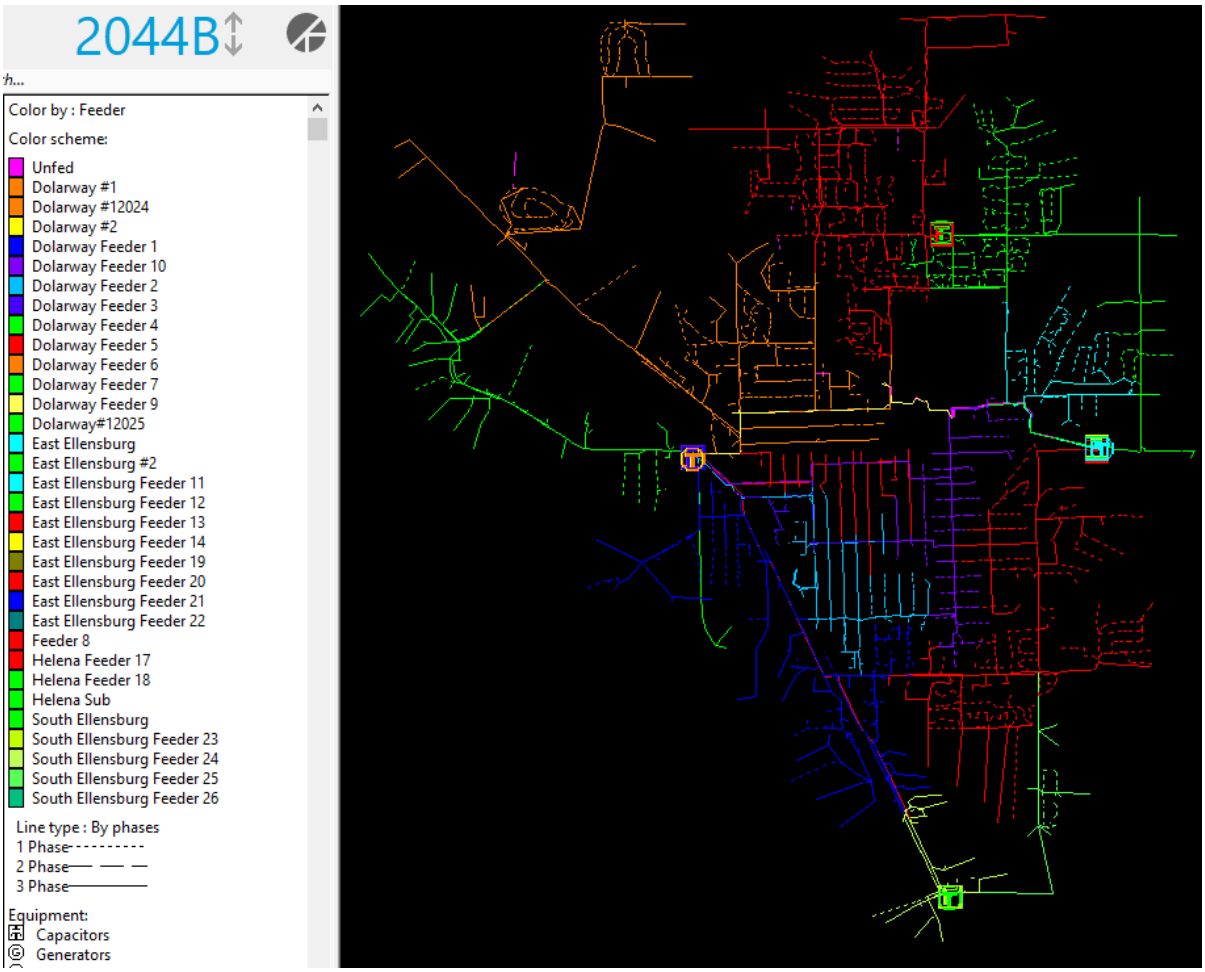


FIGURE 11: EAST ELLENSBURG #2 SUBSTATION OUT OF SERVICE RECOMMENDED CONFIGURATION FOR 2044

7.7 South Ellensburg Substation Out of Service

2044:

If South Ellensburg Substation is taken out of service, the 2044 system can operate by:

- Shifting load from Feeder 24 to Feeder 1 by:
  - Opening Feeder 24 at the new South Ellensburg Substation switchgear
  - Closing switch S030
  - Reconnect Feeder 8 to the South EV charging station

- Shifting load from Feeder 25 to Feeder 13 by:
  - Opening Feeder 25 at the new South Ellensburg Substation switchgear
  - Opening switch S033

This arrangement in 2044 will prevent the substation transformers from being overloaded at peak load times. However, there will conductors exceeding the thermal loading defined in planning criteria at

certain sections. Mitigation will depend on the actual development and placement of loads on the 20-year system. It's recommended that subsequent planning studies, knowing more accurately actual load growth placement and the CWU decarbonization loads and timing, evaluate this contingency and feeder impacts.

Adding a second bank to the South Ellensburg Substation is an option to relieve the remaining high loading on the other substations and contingency feeder impacts. It would not help for a transmission outage to the South Ellensburg Substation or a high side bus contingency affecting both transformers. A second bank would allow service to be maintained for scheduled off peak maintenance on either transformer bank. This option is also discussed in the residential natural gas conversion section.

After this load shift the transformers will be peak loaded to approximately:

- Dolarway #1 Substation – 89%
- Dolarway #2 Substation – 89%
- East Ellensburg Substation – 77%
- East Ellensburg #2 Substation – 55%
- Helena Substation – 49%

Figure 12 shows the recommended configuration.

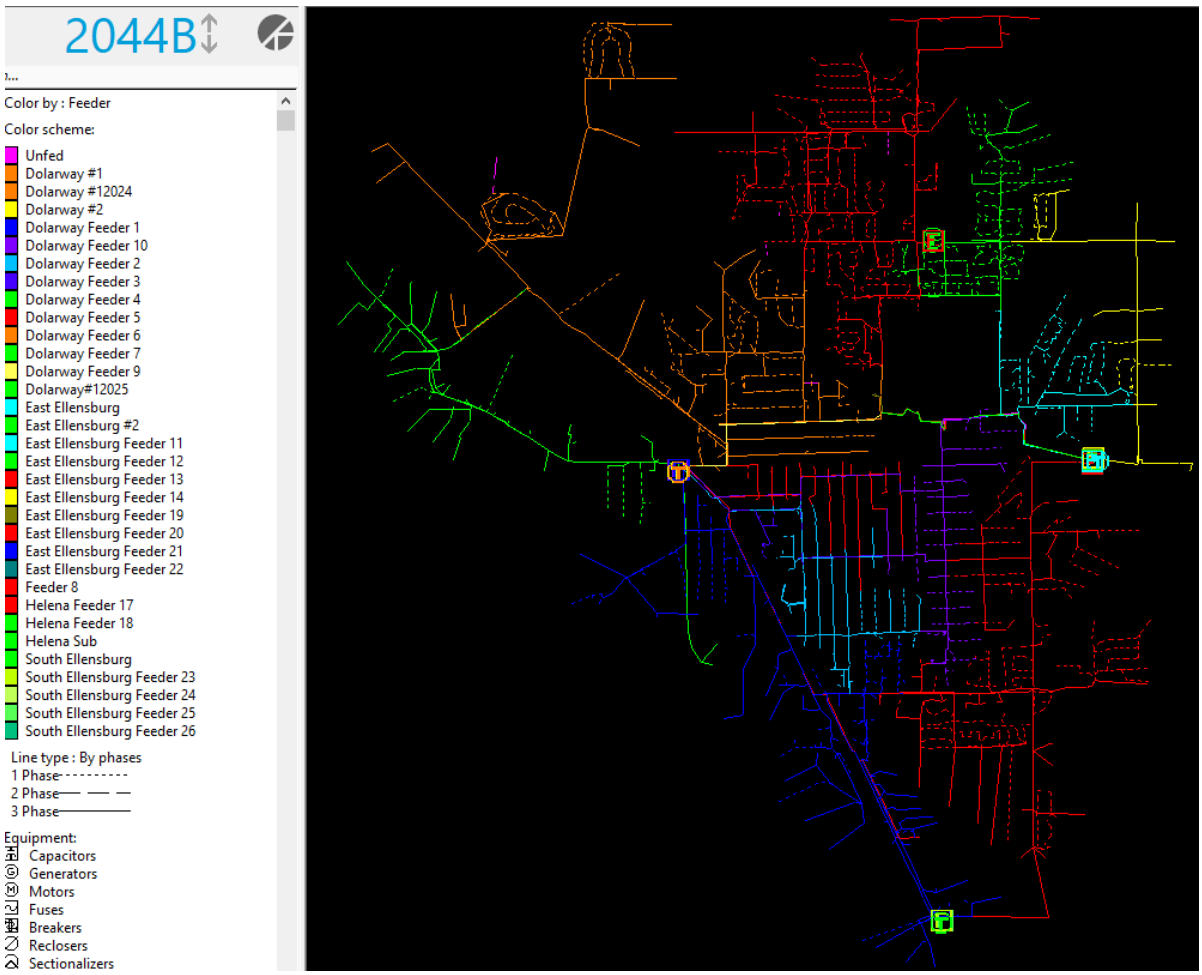


FIGURE 12: SOUTH ELLENSBURG SUBSTATION OUT OF SERVICE RECOMMENDED CONFIGURATION FOR 2044

8.0 RESIDENTIAL NATURAL GAS CONVERSION – 2030 LOADS

8.1 Overview

RCW 70A.45.020

- Greenhouse gas emissions reduction

RCW 70A.65.00

- Greenhouse gas cap and investment program

Initiative Measure No. 2117

- Revises RCW 70A.65.00 Climate Commitment Act

The State of Washington passed the Climate Commitment Act (CCA) with requirements to reduce the use of natural gas (gas) in the State. The City had a report produced by Lighthouse Energy Consulting in August 2023 on the expected impact of the CCA requirements on The City's gas utility. Electrical loads are expected to increase as gas customers convert to electric heat pumps for space heating and electric water heat pumps for water heating needs over time. Critical to The City's electrical system operation is the expected increase in electrical peak loads from the conversion. The report forecasts that peak day winter electrical loads for residential and commercial customers will increase by 30% in 2030 and double by 2041 over the unconverted system. For the gas conversion analysis, we increased the forecast 2030 loads by a multiplier of 1.3 (130%) and the 2044 loads by 2.0 (200%) to reflect the potential peak demand increase of the residential and commercial gas conversion. Although newer neighborhoods may already have some heat pump penetration, we assumed a worst-case scenario and applied the peak demand increase to all customers. As gas usage and gas to electric conversion proceeds adjustments to the peak factor can be made.

We applied those loads to 2030 and 2044 electrical system model and assessed the potential impacts. For scale reference the 2044 unconverted system doubles the number of electrical customers from the present system and the new gas conversion loads double that projected peak residential.

Central Washington University (CWU) presented The City with a potential plan to convert the CWU gas use to electric. Those conversion loads were included in the 2030 and 2044 general system analysis since they have a large potential impact to the system and are isolated to three main CWU central plant connection points. An additional breakdown of each of the CWU planned conversion phases is included in Appendix C of this report.

The electrical system was evaluated for customer service voltage, wire and conductor capacities and substation transformer loading. Improvements to correct feeder overloading and substation capacities are outlined below.

Design Standards

We recommend that The City update subdivision, Platt and secondary service load assumptions and design standards for new installations to prepare for potential Heat Pump load additions. This could include factors such as how many customers are connected to shared transformers, increasing the assumed customer load for secondary conductor sizing and voltage drop calculations, increasing the size subdivision loop underground primary conductors and limiting how many transformers are

connected to primary loop sections. Load assumptions will be different for new areas that have natural gas heating VS those that will have electric heat pump service. Transformer and secondary conductor sizing are the primary concerns for areas served from overhead lines.

8.2 Residential Gas conversion - 2030 Loads on Distribution System

After applying the load multiplier of 1.3, the transformer loading for the 2030 system is:

- Dolarway #1 Substation – 77%
- Dolarway #2 Substation – 74%
- East Ellensburg Substation – 92%
- Helena Substation – 50%

Decarbonization progress will need to be closely monitored, if decarbonization progresses faster than expected a need for a new "West Helena Substation" may be necessary to accommodate for growth. Below are additional system improvements for a new West Helena Substation.

ALTERNATIVE SYSTEM IMPROVEMENTS FOR ACCELERATIED RESIDENTIAL GAS CONVERSION - 2030		
Substation	**Description**	**Reason For Improvement**
West Helena	33 MVA Transformer	Improve System Capacity
West Helena	Commission new spare feeder	For future system improvements
West Helena	Commission new feeder	Tie into East Ellensburg Substation Feeder 14
West Helena	Commission new feeder	Tie into East Ellensburg Substation Feeder 11
West Helena	Commission new spare feeder	For future system improvements

TABLE 17: ALTERNATIVE SYSTEM IMPROVEMENTS FOR ACCELERATED RESIDENTIAL GAS CONVERSION – 2030

9.0 RESIDENTIAL NATURAL GAS CONVERSION – 2044 LOADS

9.1 Overview

Based on a study done by Lighthouse Energy Consulting for The City in August 2023 a load multiplier of 2.0 was applied to residential spot and distributed loads for the 2044 system.

9.2 Residential Gas Conversion Distribution System – 2044 Loads

After applying a residential gas conversion peak load addition, additional substation capacity is needed to support the system. With the additional gas conversion loads transformer loading for the 2044 system is:

- Dolarway #1 Substation – 112%
- Dolarway #2 Substation – 96%
- East Ellensburg Substation – 126%
- East Ellensburg #2 Substation – 55%
- Helena Substation – 100%
- South Ellensburg Substation – 43%

9.3 Residential Gas Conversion System Improvement Recommendations – 2044 Loads

Below are system improvement options, recommended for capacity and load balancing, for the 2044 system:

RECOMMENDED SYSTEM IMPROVEMENTS RESIDENTIAL GAS CONVERSION - 2044		
Substation	**Description**	**Reason For Improvement**
West Helena	Construct new West Helena Substation along existing transmission route and build out at least two new feeders to tie in and transfer load. One feeder to tie in at vault EOC02, another into IOC02, another east of switch S023	Shift load from East Ellensburg Substation and Dolarway #1 Substation to West Helena Substation

TABLE 18: RECOMMENDED SYSTEM IMPROVEMENTS RESIDENTIAL GAS CONVERSION – 2044

9.4 Results of System Improvements

Following the addition of two new feeders out of West Helena Substation and the 2030 new feeders from Helena Substation the 2044 system transformers will be loaded to:

- Dolarway #1 Substation – 71%
- Dolarway #2 Substation – 96%
- East Ellensburg Substation – 86%

- East Ellensburg #2 Substation – 55%
- Helena Substation – 100%
- West Helena Substation – 72%
- South Ellensburg Substation – 43%

Decarbonization progress will need to be closely monitored, if decarbonization progresses faster than expected a need for a new transformer bank at the South Ellensburg Substation may be necessary to accommodate for growth.

10.0 ELECTRICAL VEHICLE CHARGING STATIONS

10.1 Overview

RCW 19.27.540 Electric vehicle Infrastructure Requirements – Rules

Electrification infrastructure requirements:

- Building code: The building code council shall adopt rules for electric vehicle infrastructure requirements.
  - The rules adopted under this section must require electric vehicle charging capability at all new buildings that provide on-site parking.
  - Where parking is provided, the greater of one parking space or ten percent of parking spaces, rounded to the next whole number, must be provided with wiring or raceway sized to accommodate 208/240 V 40-amp or equivalent electric vehicle charging.

RCW 43.31.970 Electric Vehicle Infrastructure.

Local governments, ordinance and regulation

- States: The department of commerce must distribute to local governments model ordinances, model development regulations, and guidance for local governments for siting and installing electric vehicle infrastructure, and in particular battery charging stations, and appropriate handling, recycling, and storage of electric vehicle batteries and equipment, when available.

RCW 64.38.062

- Requires homeowners' associations to approve the installation of EV charging stations in designated parking spaces or on a lot owner's property

WAC 51-50-0429

- Specifies the number of EV-ready parking spaces required for different types of occupancies

RCW 47.80.090

- Addresses electric vehicle infrastructure as part of regional transportation planning

For the 2044 system a load multiplier of 1.02 was applied to residential spot and distributed loads. This multiplier was based on the amount of kWH per month that is needed for Level 2 residential chargers, 60 kWH midsize or SUV electric vehicles and 6 to 8 hours of charging time. The assumption was made that every electric customer would charge their vehicle at home for 50% of the battery capacity every day. The remaining 50% charging capacity is assumed to be at central charging stations or commercial charging locations or not needing full charging all the time.

10.2 Residential Electric Vehicle Charging Distribution System Loading

After applying the load multiplier, the substation transformer loading for the 2044 system is:

- Dolarway #1 Substation – 81%
- Dolarway #2 Substation – 66%
- East Ellensburg Substation – 75%
- East Ellensburg #2 Substation – 56%
- Helena Substation – 50%

- South Ellensburg Substation – 35%

10.3 Residential Electric Vehicle Charging System Improvement Recommendations

The growth from EV conversion to the 2044 system had minimal peak load impacts to the already recommended system improvements. EV conversion should be closely monitored to ensure that loading expectations stay the same. It is recommended to further shift loads from Dolarway #2 Substation to East Ellensburg Substation, or Helena Substation where possible to balance transformer loading. It may also be possible to shift loads to newly constructed feeders from the South Ellensburg Substation, or West Helena Substation if those substations are installed for other system reasons.

Residential gas conversion has much larger load impact to the system. If residential gas conversion improvements are made, they should cover the residential EV charging on the system. EV charging will likely impact residential distribution transformer loading the most. Individual distribution transformers are traditionally not load monitored based on historic use and loading. However, the diversity of existing customers sharing a transformer will decrease depending on the penetration of EV charging and potentially increase the transformer peak load or even overload a transformer. For low ambient temperatures (cold snaps) distribution transformers can be loaded up to 2 times the name plate capacity without significant loss of life. This allows for significant flexibility of loading on peak system days and cold weather conditions. However, combined with gas conversion heat pump loads. Loading will increase on distribution transformers with heat pump cooling loads occurring at high summer ambient temperatures when transformers are susceptible to overheating.

AMI metering systems allow for aggregation of individual residential meter demands and loading to be tracked on distribution transformers. POWER recommends consideration of an AMI system that would allow for transformer load tracking and monitoring of service voltage for both EV charging and new residential heat pump loads. This would allow for proactive trending over several years to see the actual load capacity impacts before they cause quality of service impacts and the actual load impact trend on system feeders and transformers and serve as a planning and budgeting tool if impacts are occurring. In addition, voltage monitoring at the meter may track transient voltage dips from sudden peak EV loading and or from heat pump motor starting. Large starting loads could cause transient service voltage drops (flicker) due to service conductor voltage drop and cause equipment (chargers) to shut down or go into protection mode and be an inconvenience to those customers. This can be a problem for small wire size services or long service wire lengths. As gas to electric conversion and EV charging penetration begin to occur, voltage trends will allow for proactive monitoring and corrections for these issues before customer or system damages occur and complaints happen.

10.4 Charging System Considerations

EV Charging System Installations

Charger installations to the home or business only need to meet State Electrical Code (RCW) requirements the same as any other electrical load or appliance installation. Since these are behind the meter The City does not have direct authority over these installations. The City's general conditions for electrical service ask the customer to inform The City of significant changes or load additions

made by the customer but customers routinely neglect to inform the utility of these changes. The AMI monitoring discussed above helps to mitigate and identify if a customer is potentially overloading a service or neighborhood transformer.

EV to Grid

Level 2 chargers for residential use are one-way devices, that is for charging load only. They do not provide for EV to grid service. If in the future devices that provide for energy back to The City become common, The City should require the same UL listing and IEEE inverter protections as residential solar does now. Similar to solar, separate metering and disconnecting means are required for anti-islanding, back feed and safety. The Washington State Electrical code requires an accessible disconnecting means for generation resources.

Design Standards

We recommend that The City update subdivision, Platt and secondary service load assumptions and design standards for new installations to prepare for potential EV load additions. This could include factors such as how many customers are connected to shared transformers, increasing the assumed customer load for secondary conductor sizing and voltage drop calculations, increasing the size subdivision loop underground primary conductors and limiting how many transformers are connected to primary loop sections. Load assumptions will be different for new areas that have natural gas heating VS those that will have electric heat pump service. Transformer and secondary conductor sizing are the primary concerns for areas served from overhead lines.

10.5 EV Charging Rates and Incentives

Northwest utilities have implemented a variety of EV rates, installation incentives and charge management options. Programs are offered that reflect the utilities goals such as encouraging EV use to minimize carbon emissions or steer usage to periods of lower power cost.

Installation Incentives

Some northwest utilities have opted to encourage EV adoption with charger installation incentives. Residential installation rebates for qualified Level II chargers are common. PSE offers $300 with additional rebates for low- or qualified-income customers. Clark PUD offers A $500 rebate for internet connected Level II chargers and $100 for not connected chargers. Tacoma Public Utilities do not offer residential installation incentives. Seattle City Light has focused on providing curbside charger installations for both Level II and for DC Fast chargers.

Rates

Most of the Northwest Utilities are charging standard energy and demand rates for residential and commercial EV charging with no general discounts. Seattle City Light charges $0.21/kwh for curb side level II charging using utility supplied equipment. Curbside Direct Current Fast Chargers (DCFC) have a daytime time of use rate of $0.3175/kwh and all other hours at $0.1737. Similarly, Tacoma Public Utilities has a public charging station energy and demand discount from regular general service rates for installations with at least on DCFC and less than 1MWA of capacity with an additional 20% discount if the customer takes primary voltage service. Utility provided charging equipment installations charge $0.25/kwh for Level II and DCFC at $0.40/kwh.

Charging Management

Depending on the utilities power cost structure there may be opportunities to optimize power costs with time of use rates for general service and EV charging. Time of use options generally require an AMI type meter and a rate structure with lower cost for off peak charging (and general use) if supported by a reduced wholesale power cost structure. Clark PUD offers a $50 annual discount for Level II residential chargers with internet connected chargers that can be enrolled in a charge management program such as “Optiwatt” that manages the time and intensity of charging within utility requirements without an advanced utility meter. Demand Energy Response programs can also manage EV charging to mitigate potential capacity issues at service transformers and on feeders.

11.0 BENEFITS OF AMI IMPLEMENTATION

Advanced Metering Infrastructure or AMI is primarily a customer usage metering system that features two-way communication between every customer end point or service and a collection and monitoring head end to collect and store customer kWH usage and other information such as service voltage. The type of communication system can vary widely from power line carrier type systems that use the electrical primary wire to carry a data signal, optical fiber communication networks, mesh radio systems that talk meter to meter communication with some collector sites, to broadcast type communications with central towers communicating with many meters at a time. The critical characteristic is two-way communication and data flow up from the meter and commands and directions down from the central system.

Generally, the cost benefits of an AMI system are reduction in meter reading costs, improved staff safety by reducing time in the field, near real time data collection for customer billing, remote connects and disconnects, pre-pay systems that allow for the customer to be in control of their utility costs rather than after the fact as traditional systems operate. Many utilities find the largest cost benefit is from reduced overtime and increased operations efficiency for highly skilled line and operating staff on call outs for connects and disconnects and spot meter reads.

For the purposes of this study, we will concentrate on the some of the system benefits that an AMI system provides:

Real time outage notifications. These can be fed into an Outage Management System that spotlights the likely failed equipment location or simply provides an aid to a dispatcher or system operation monitor to send a crew directly to the problem location. An AMI system can allow for the identification of protective devices that may have operated allowing for faster crew response and reduced outage time.

Service point system voltage monitoring. Service quality can be tracked and trended to allow for the proactive identification and correction of issues before an outage occurs, improving customer reliability.

Metering interval data will show customer peak service loading and the collection of transformer loading data that has not been available in the past. Trends on potential transformer overloading can prevent unscheduled outages and reduce call outs and overtime costs. This capability will be critical for residential natural gas conversion and other new customer loads and their impact on distribution transformers. Also, the AMI system can help track and trend expected growth in residential EV charging to allow for planning and trending and identification of impacts before they occur.

The customer metering interval loading data also allows for actual feeder, breaker and line loading to be calculated. That along with service voltage readings can validate if a system improvement such as a conductor or feeder upgrade is truly needed by removing uncertainty and assumptions inherent in all system simulations and modeling programs that have been traditionally used. This likely may allow for reduced capital expenditures for system improvements and or deferrals until they are truly needed with improved certainty of need.

Customer service quality and reliability improvements are improved by finding and fixing problems before they have a customer impact. This allows for proactive work by the utility rather than waiting

for a customer to call about a problem. This builds customer's good will and assurance that the utility is on top of the system.

Two-way meter communication also establishes a system and network for a demand management system. Many AMI meter systems can control customer loads such as water heating or air conditioning and heating systems. These in turn can reduce the system electrical peak or allow for the peak to be shifted in time. Soon the NW electrical system is expected to develop past regional capacity limits due to electrical loads increasing and the changing of generation from base load plants to distributed and renewable sources. It is anticipated that suppliers like BPA will present cost signals to a utility that encourage demand reductions and peak shifting. AMI systems can be specified to be the ready infrastructure to enable creation of demand management programs and help optimize utility power costs.

Many AMI systems allow for communication with field devices such as regulators, reclosers, breakers and switches. This communication can enable automatic switching to isolate a faulted section and quickly restore service to customers not affected by fault. These types of systems can dramatically lower outage times and improve customer reliability and customer satisfaction. The AMI system can be an enabling technology to allow for the implementation of these type of systems.

Lastly AMI systems allow for the collection of extensive engineering data on the system, improving engineering efficiency and minimizing potential capital expenditures through improved knowledge of the system.

The first step to implementing an AMI system is to have a cost benefit study completed. The study should identify the features of an AMI system that will provide the best value and savings to The City and capture the main use cases and requirements needed to develop a request for proposal to be issued to the AMI industry. Also, a study will typically identify how the program should be developed and then presented to the community to help customers see the value and benefits they can expect from an AMI system. We recommend that The City begins a cost benefit analysis, due to the diversity of various AMI technologies, we cannot explicitly recommend an AMI product at this time. Below is a table showing capabilities of common AMI products.

When integrating AMI, it is crucial to ask detailed questions about the full cost to avoid unexpected expenses. Lead times may be longer if working with a proprietary system, so planning ahead is essential. Avoid rushing the process, as thorough vetting ensures smooth data integration and collection. All systems that connect the infrastructure should be fully operational and tested before deployment. Secure a written guarantee for technical support to prevent service gaps. Engaging various utility groups for input can help identify potential challenges early. A phased deployment approach helps mitigate risks and drafting a comprehensive labor plan ensures an efficient AMI replacement and installation process.

Features/Product	Gas/water meter compatibility	Comm Type	Meter Flexibility[1]	Real Time Usage	Prepay	Remote Disconnect	Theft Prevention	Load Control	Outage Management
Itron	X	X[4]	X[2]	X	X	X[3]	X	X	X
Landis+Gyr	X	RF/Cellular		X	X	X[3]	X	X	X
Sensus	X	RF		X		X	X		X
Trilliant Inc.	X	Cellular	X	X	X	X	X	X	X
Aclara	X	X[4]		X	X	X	X	X	X
Tantalus	X	X[4]	X	X				X	X

1: Some meters will only communicate exclusively with one proprietary system

2: Some Itron products can communicate with other ERT systems, but not all have this capability

3: Both 200A and 320A remote disconnect

4: Multiple communication option (RF, Cellular, Fiber)

TABLE 19: AMI TECHNOLOGIES

12.0 DEMAND RESPONSE PROGRAM

12.1 Overview

WAC 480-100-620 – Integrated Resource Plan – Demand Response

RCWs 19.280.030 and 19.285.040 – Resource Planning

Demand Response is a general term used in the electric utility industry for several customer load management, utility peak management and utility voltage optimization programs. We discuss utility voltage optimization programs below in Section 13.0.

Direct customer demand response refers to programs that manage customer energy use at critical utility system peak times. Systems can operate via broadband or directly through a utility communication system. For instance, a city AMI program operating through the utility meter could provide a signal to customer heating or air conditioning equipment to turnoff or adjust a heat pump or water heater for a period of time. Cumulatively such reductions across many customers can lower the expected utility peak demand.

RCWs 19.280.030 and 19.285.040 refer to the requirement for qualifying electric utilities to develop a resource plan to meet clean energy requirements in The State of Washington, and to meet energy conservation and renewable energy targets. These plans are required for utilities with more than 25,000 customers and that are not full requirements customers. At this time, The City is a full requirements customer and is not required to participate but should the RCWs requirements change or should The City no longer be a full requirements customer of BPA and increase above 25,000 meters, The City would need to develop a resource plan meeting the requirements set forth by these sections in the RCWs.

In general, Demand Response programs provide the utility with the ability to control demand peaks and thus control demand charges. As power supply concerns grow, limiting the strain on The City's distribution system and BPA's transmission system, may also pose a benefit to The City in the form of deferring system improvements through the implementation of Demand Response. The benefits to The City will include the possibility to defer system improvement costs to support increased demands, improved grid stability, and the possibility of seeing an increase in renewable penetration at the customer level. It should be noted that too much renewable penetration could have negative consequences to the distribution system and should be monitored.

Customers obviously would not want to limit their demand for energy during peak conditions without incentives. At this time, customers are not enrolled in time of use fee schedules, so the incentives to limit demand would be altruistic behavior or financial incentive. These financial incentives could be offered by The City in the form of one time or reoccurring rebates associated with enrollment, re-enrollment, or cumulative energy use saved during events or requests by The City to respond. The incentives value will need to be analyzed and set by The City based on the proportional benefit each customer's enrollment provides to The City. An example is that a large customer (commercial, university, or otherwise) who represents more of the overall system demand, could provide a greater benefit or impact to The City's system during an event, and should be incentivized in a greater amount than a small residential customer.

The City could offer to the less consequential customers the opportunity to enroll for more altruistic reasons or a smaller negligible financial incentive. An attractive approach that could generate interest is identifying how enrolling in a Demand Response program would benefit neighbors or the general community by keeping power available to those at risk or emergency services. Many community members would find personal value in "helping," while others could find a benefit to their marketing campaigns. The City could provide marketing material or labels signifying to the general public where customers or businesses are enrolled in Demand Response for the betterment of the overall community.

The benefits to customers will need to outweigh or balance with the negative consequences. Customers will rightfully identify that they will be placed into a category of accounts that could be limited in power. It will be critical to identify that the consequence will not be a full outage of power, but rather a limit to use of specific equipment or capped power demand during an event. The obvious negative consequence to enrolling in Demand Response is the introduction of a new party that can control power usage. Being clear about what The City can and cannot do with these accounts will be critical in mitigating concerns regarding utility control over the meter or equipment served by the meter.

The City may also find that implementing a Demand Response program is technically complex or expensive or that consumers will be reluctant to enroll in a program that has been established. The high cost of establishing the program could be followed by no real return in the investment.

In summary, the utility will see a more stable system, may be able to defer capital costs for system improvements (which benefits the customers), customers could see a financial gain depending on their participation, the ability to market themselves as a champion of Demand Response, and the overall community could benefit from lower emissions (due to a reduction in load), and the possibility to improve energy market efficiencies.

The disadvantages are the reduction in control over demand at the customer level (customer inconvenience), negative impact to critical customers where any supply disruption is not acceptable (ex. hospitals, police, fire stations), technical implementation challenges, and uncertainty in enrollment levels.

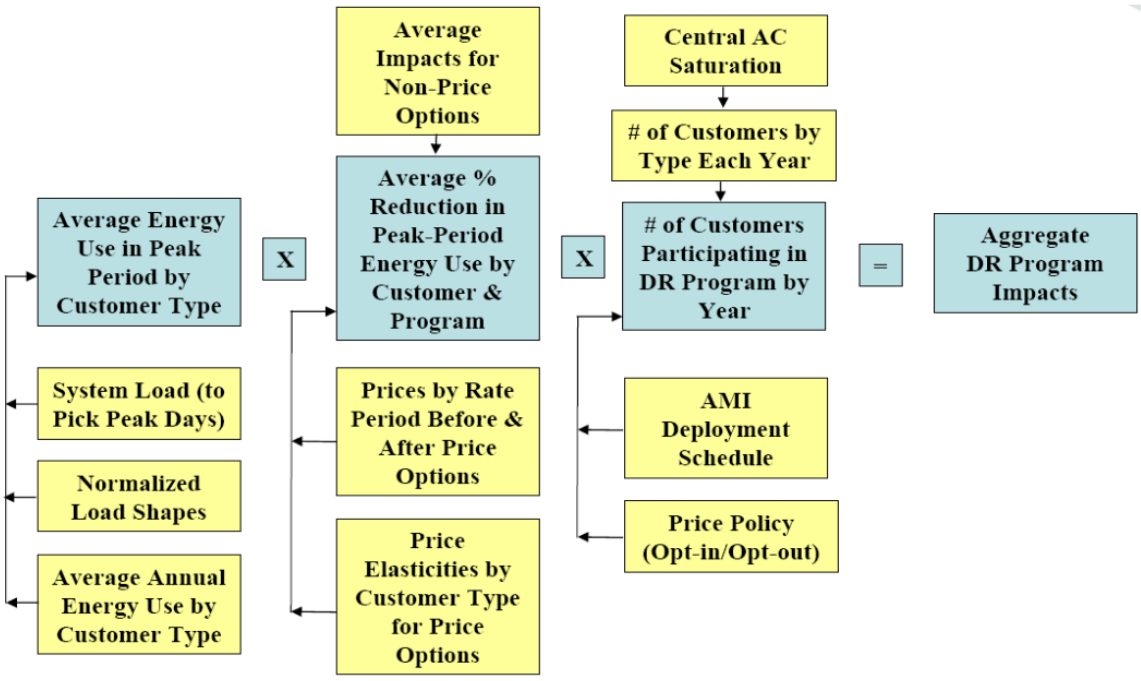
12.2 Participation Impacts

Demand Response participation is a significant driver of direct benefits to the utility. With too low of a participation rate among certain demographics (ex. Residential customers), an incentive program's costs could exceed the benefits gained. Recent reports (see Energy Systems Integration Group) from industry working groups and power providers indicate that total participation in Demand Response as a percentage of total accounts is still fairly low. It should be noted that while participation rates typical range from 2% to 8% of total accounts, some states are seeing adoption between 14% and 27%. Washington State has an average of 14% participation in demand response programs which is an improvement.

Setting expectations or goals for the participation rate of customers in a utility's footprint allow the providers to determine if the costs of implementation are worth the benefits. Additional reports (see FERC Demand Response and Advanced Metering) show that potential peak savings due to demand

response range between 1% and 10% with an average of 6.5%. By considering the expected peak savings and the participation rates providers can evaluate the total cost savings against implementation costs to determine if a demand response program is valuable.

The key inputs for determining the potential of a demand response can be seen below. With these inputs the costs and benefits can be evaluated for multiple cases and used to set goals and objectives.



Included as an attachment to this report is a native copy of the NADR model Excel file. The following information describes the estimated impacts for a few scenarios as a point of reference. Inputs have been selected by City of Ellensburg employees and POWER Engineers.

DEMAND RESPONSE POTENTIAL IMPACTS [1]					
YEAR	CUSTOMER TYPE	% OF PEAK REDUCTION POTENTIAL	% CUSTOMER PARTICIPATION	DR PROGRAM KW SAVINGS [2]	DEMAND CHARGE SAVINGS [3]
2025	Residential	23%	14%	3,122	$50,031
	Commercial	1%	14%	256	$4,097
	Industrial	2%	100%	110	$12,637
	Total			**3,488**	**$66,766**
2026	Residential	23%	5%	3,797	$21,735
	Commercial	1%	5%	310	$1,777
	Industrial	2%	100%	134	$15,393
	Total			**4,242**	**$38,905**

DEMAND RESPONSE POTENTIAL IMPACTS [1]					
YEAR	CUSTOMER TYPE	% OF PEAK REDUCTION POTENTIAL	% CUSTOMER PARTICIPATION	DR PROGRAM KW SAVINGS [2]	DEMAND CHARGE SAVINGS [3]
2027	Residential	23%	8%	3,831	$35,088
	Commercial	1%	8%	314	$2,873
	Industrial	2%	100%	136	$15,583
	Total			**4,281**	**$53,545**
2028	Residential	23%	10%	3,741	$42,825
	Commercial	1%	10%	306	$3,506
	Industrial	2%	100%	133	$15,203
	Total			**4,180**	**$61,534**
2029	Residential	23%	10%	3,851	$44,089
	Commercial	1%	10%	315	$3,611
	Industrial	2%	100%	137	$15,678
	Total			**4,304**	**$63,377**
2030	Residential	23%	14%	4,152	$66,553
	Commercial	1%	14%	340	$5,454
	Industrial	2%	100%	148	$16,913
	Total			**4,641**	**$88,920**
2031	Residential	23%	14%	4,333	$69,439
	Commercial	1%	14%	354	$5,680
	Industrial	2%	100%	154	$17,578
	Total			**4,841**	**$92,698**
2032	Residential	23%	14%	4,484	$71,861
	Commercial	1%	14%	367	$5,880
	Industrial	2%	100%	159	$18,244
	Total			**5,010**	**$95,984**
2033	Residential	23%	14%	4,563	$73,124
	Commercial	1%	14%	374	$5,986
	Industrial	2%	100%	162	$18,529
	Total			**5,098**	**$97,639**
2034	Residential	23%	14%	4,565	$73,164
	Commercial	1%	14%	374	$5,986
	Industrial	2%	100%	162	$18,529
	Total			**5,100**	**$97,679**

1. Total program savings will require further discussion/analysis. Incentives and implementation costs are NOT included at this time.
2. Average yearly kw savings based on yearly peak kw normalized using the avg/peak demand ratio 0f 83%.
3. Based solely on demand reduction charges at a yearly average of $9.54/KW

TABLE 20: NADR MODEL RESULTS

12.2 Technology

Demand Response requires sufficient hardware and software to identify and respond during demand events. Accurate metering and control devices will need to be installed in the distribution system to implement the program.

New Advanced Metering Infrastructure (AMI) devices provide much of what is needed. AMI is being integrated into aging distribution systems, not because of the Demand Response benefits, but rather the data collection benefits provided to utility operations and maintenance. With AMI becoming more and more deployed, the opportunity to roll out Demand Response is improved at a lower entry cost. Further, past the higher cost AMI equipment, more affordable technology is available to be installed in the home past the meter. Industrial and large commercial programs would likely be different than for residential customers. Examples of the technology and system design that may be required to implement these programs. These examples are conceptual and the actual hardware selections and final design may be different. Specific manufacturers may not be necessary as AMI meters are improving every day and The City may find their AMI provider has an option to replace some of the equipment below.

Commercial demand response applications could be implemented at various levels of complexity. At its most basic, a localized meter could be provided with a signal to enter into demand response mode and issue commands to the customer to curtail power usage or to disconnect loads to meet the demand response requirements. A microprocessor-based meter, such as an SEL-735 could be enabled to perform some of these functions. Communications would be required via fiber, radio, or cellular service to issue the commands to the meter for execution. Meters with the options required to implement this type of scheme cost around $5,000.

A step up from a single device would be a more integrated solution using similar devices linked to a centralized unit. The revenue meters at the customer end would be installed and configured to transmit loading data back to a central processing unit, such as an SEL RTAC, where multiple metering devices also send back their data. Rules and commands would be programmed to initiate requests automatically or manually for demand response inside the data processor. The SEL-735 meters could be positioned at each point of delivery for select customers and then routed back to a centrally located SEL RTAC. An RTAC starts at around $1,000 but can become more expensive as different options are added. On the high end, $8,000 may be expected. The following diagram shows a generalized layout of the type of equipment needed to build a modest demand response system.

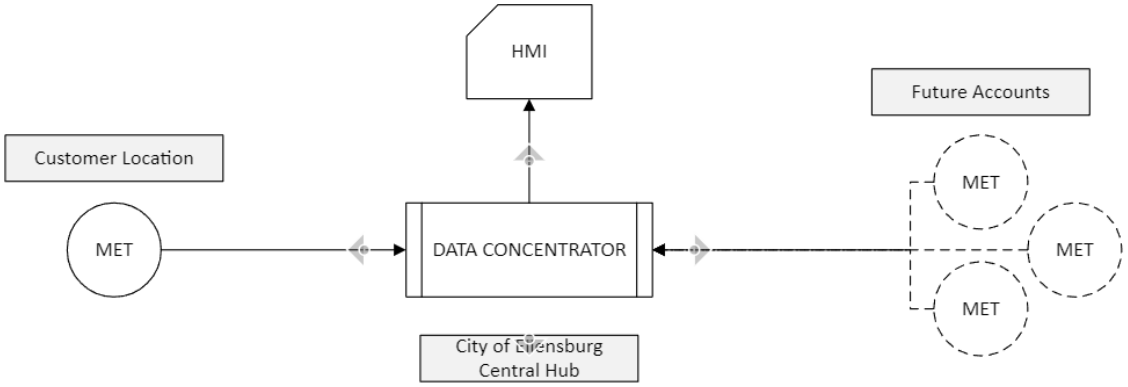


FIGURE 13: EXAMPLE COMMERCIAL OR INDUSTRIAL DEMAND RESPONSE HARDWARE CONFIGURATION

An alternative to some of the hardware shown in the figure above could include implementing the data processing in a cloud-based application. The power data will still need to be collected at the point of delivery by meters, but then could be transmitted over the internet to a cloud-based application for processing. Make sure to consider user interface, programming, and security requirements to protect your customers' privacy in any case. Costs for cloud-based applications will depend on the provider and the options required.

For individual residential or small commercial customer installations, Residential Thermostat Demand Response programs take advantage of smart (communicating) thermostats to reduce the heating setpoint, running the customers system less, saving customers energy and lowering the demand on utility feeders, substations and reducing the utility overall system peak.

Google has been offering such a program via their Nest thermostat for some time now. The thermostat communicates via a customer's WIFI and the internet with a management portal which directs adjustments of the setpoint. Utilities provide a signal to the portal to control when and how long identified thermostats in their area are adjusted. Since The City is a winter peaking system, thermostat setpoints would be lowered during the peak time. Anticipating the peak demand time, the program will pre-heat the home (raising the setpoint) before the critical period then allows the home to run cooler through the peak and then return to normal settings. Similar control could also be applied to water heaters or to cooling systems if summer demand response is needed.

Recently Google has opened the portal to work with other smart thermostats. The most common thermostats include Nest, EcoBee Premium, Honeywell Home Smart, Amazon Smart, EcoBee 3 Lite and Wyze. Additional models and manufacturers are rapidly entering the market. The Google portal interfaces with an energy management company that the utility selects to provide timing for demand management events.

This is simply one example of how a readily available device could make a Demand Response program more attainable. In any event, the technology must be able to communicate back to a main control center where data is received, processed, stored, and actions are taken based on system performance. The system must be able to submit requests to be received and acted upon by the customers' device in the end to fully implement the program.

12.3 Demand Management Program

A city sponsored Demand Management program could include the following:

Customer Engagement

Install a panel or commission to evaluate how best to reach customers in a way that incentivizes them to enroll. Develop marketing material to describe the program, options and incentives, the pros and cons to enrollment, and present forms and materials needed to enroll. Further identify the products and technologies that The City would provide or others that would be supplied by the customer. Below are key items the panel may want to focus on to implement the program.

- A utility customer communication program to inform and recruit customers to the program.
- Identify technology requirements and who will provide them.
    - Smart devices (ex. AMI meters, smart thermostat, or other) for the customer. Equipment after the meter could be provided at a general cost of around $280 per device.
- Emphasize billing credits (dependent on the account) available within the program.
    - Enrollment credit
    - Re-enrollment credit
    - Credit based on energy savings (kWh)
- Develop marketing materials to customers for their personal or business use declaring they are enrolled in the program.
- Identify to businesses interested in LEED certification that they are awarded 1 point for Demand Response Program participation.
- Leverage community member goals and values by encouraging voluntary participation to improve quality of life (reduced emissions, improved system reliability, public acknowledgment, etc).

Analysis

The City should study and focus primarily on specific accounts (large accounts) where a reduction in demand will be most impactful. Larger accounts such as commercial customers, large office or rental buildings, or industry accounts can offer the most opportunity to reduce demand at a lower equipment cost to The City. This would be offset somewhat by the higher level of incentive to provide back to the customer. In any event, the impacts of a specific size of account (commercial, residential, industrial, large, small, or other) should be studied to choose the accounts that The City would like to encourage to join the program.

Design/Implementation

Once the target audience is identified, the design and implementation of the program would be the next step. Evaluate the existing hardware and software available in The City's toolbox and classify it as Demand Response enabled, capable, or disabled. Identify the equipment, material cost, installation cost, and implementation cost with new products needed to incorporate the targeted accounts into The City's Demand Response control system.

The overall system design can be many things but would have a general requirement of having data collection devices (localized at The City's substations, or dispersed throughout the distribution system), data processing equipment to identify when to initiate requests, a master control device to

send commands, and user end devices to receive commands and respond with curtailment or equipment shut off to activate the demand response. These devices will likely perform more than one of the general functions.

Contracts

Interested customers would need to enter into a legal agreement with The City to set the terms and conditions of the program. These documents would define responsibilities, requirements, limits, schedules, incentives, and other items that require legal documentation and processing.

All of the above steps will require development and examples of these items are included in Appendix E for reference. The City will likely find that the Analysis, Design/Implementation and Contracts steps are the most straightforward as they are based on technical requirements and limitations, or clearly stated in terms understood generally by the public.

The first step, Customer Engagement, will be the biggest challenge simply due to each customer or subset of customers having different personal or business goals that may or may not stay the same in time. The City may find it beneficial to start the Demand Response program by targeting only accounts that present the greatest system improvement impacts and gauge their general interest. By focusing on key accounts, a pilot Demand Response could be implemented with a lower level of complexity and cost, allowing The City and customers to evaluate the long term benefit of a Demand Response program.

12.4 Example Web Layout

To assist The City with describing the program to the community, the following, general pages could be provided on The City's webpage as assistance to customers in understanding both Demand Response programs in general, and for specifics regarding programs and options that may be available to them.

General Demand Response Title Page

Flexible and efficient solutions to meet growing demand

Demand response is a strategy designed to decrease load on the grid during times of peak use. It involves modifying the way customers use energy – particularly when they use it– to prevent spikes in energy usage and ensure reliability. In response to our region's growing energy needs, we now operate demand response programs across our service territory. Encouraging simple, energy-saving behavior changes and utilizing technologies like smart thermostats, these programs help ensure reliable electricity for all.

FIGURE 14: EXAMPLE INTRO WEBPAGE

Further expand this page to emphasize how the program will work. Be clear that the program is 100% voluntary and if enrollees will be notified in advance of any requirement to lower or shift demand (if that is an option). If the program will automatically curtail demand, be clear on that point as well. Identify what incentivization will be available to participants.

After the general "how it works" section of the page, continue on and describe how The City will deploy the program or it's options. Include or link descriptions of pilot programs and any lessons learned.

Specific Program Option Pages

If multiple options of the program will be available to different users (ex. commercial accounts vs. residential), develop a page for each option. A starting page showing all options with general key points should make it easy for readers to choose options that may be right for them.

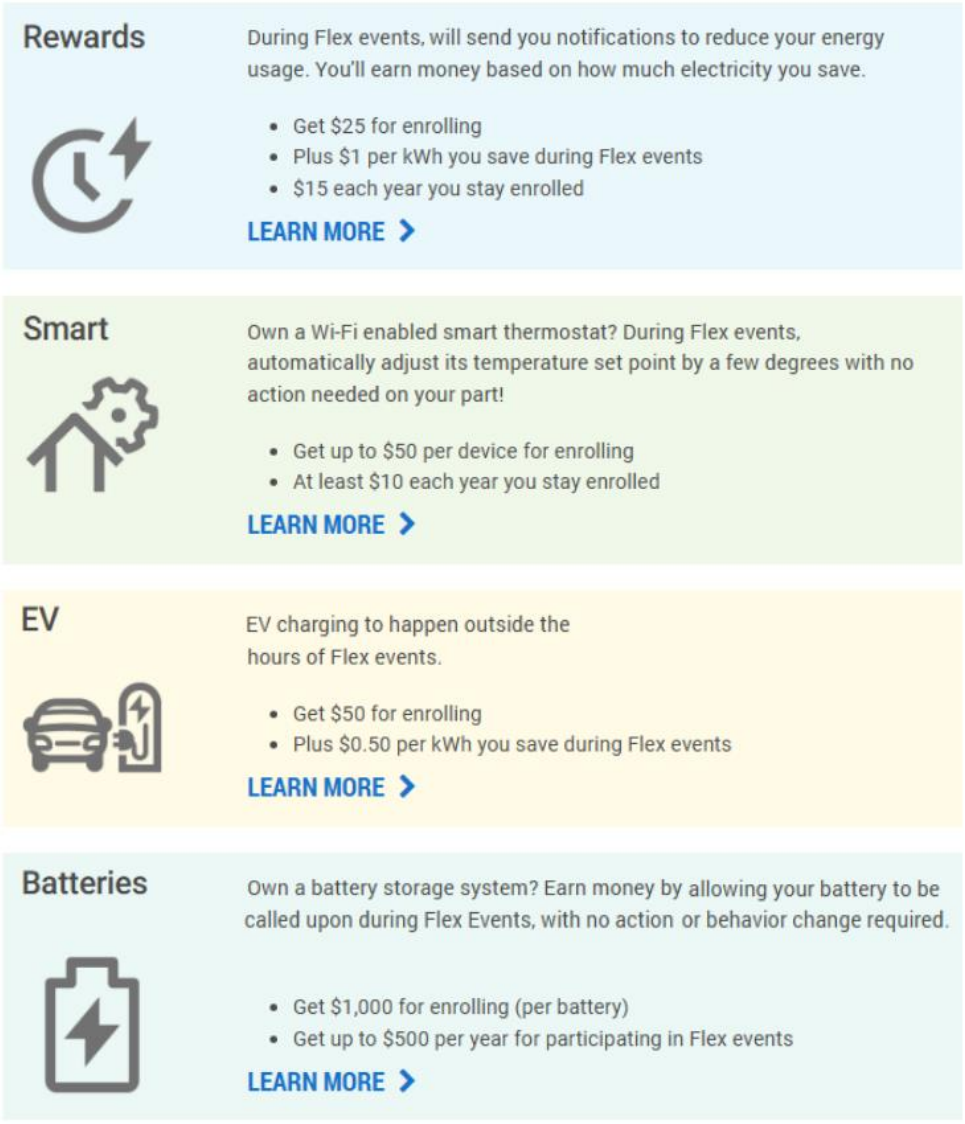


FIGURE 15: EXAMPLE PROGRAM SUMMARY WEBPAGE

After mentioning key items such as automatic response to system conditions or commands, or event notification, further describe how each will be applied. For event notifications how will they be received, how much prior notification will be provided (if any), and if specific hardware or equipment requirements will be necessary.

Tables can also be used to show readers a comparison of the program options and a general frequently asked questions section can be added (focused on Demand Response programs).

Specific pages for each program option should be established to describe the programs in further detail calling out eligibility, requirements, how to enroll, further steps following enrollment, and frequently asked questions specific to the program.

Laying out the information in an easy to read and understand format will be important. Allowing the reader to expose and hide answers to the FAQ can help them navigate to questions that are important to them without being lost within a large set of questions.

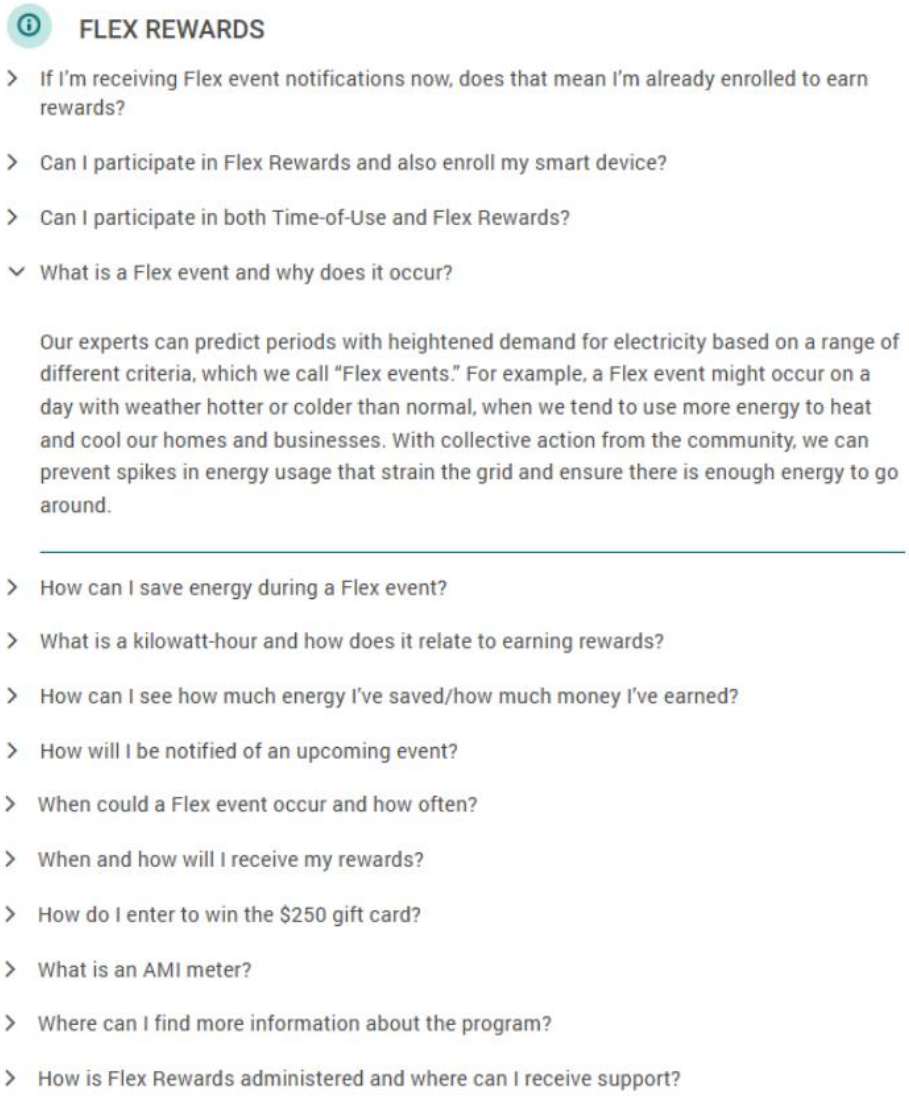


FIGURE 16: EXAMPLE FAQ WEBPAGE

Forms, Terms, and Conditions

Include a section of the website that is the home of all program related applications and agreements. These forms should be kept up to date so the public are able to fill out and submit their documents to The City. Example Terms and Conditions are included in Appendix E for reference based on forms presently in use by Puget Sound Energy.

12.5 Pairing with Residential Gas Conversion

The City has a unique opportunity to help control long term electrical system peak demands associated with the residential gas conversion program. A demand response program paired with gas conversion program incentives could reduce the potential system improvements needed in the Residential Gas Conversion sections above. If the anticipated two times increase in peak load with gas conversion is reduced with a Demand Response requirement to enroll new heat pumps and water heaters installed, a significant portion of the conversion capital investment and subsequent rate pressure on the electrical system may be reduced.

In the future as The City considers supporting their customers in converting from gas to electric, with incentives, it may be desirable to attach conditions and requirements to participate in a Demand Response program voluntarily to receive the incentives.

12.6 Anticipated BPA Regional Demand Management

The NW region and BPA are projecting generation shortfalls as the region converts to renewable electrical sources and regional gas conversions have encouraged growing electrical loads. BPA is exploring load management programs to help limit the increased regional electrical demand. A demand response pilot program was recently opened to allow BPA to gather load response results to help inform what a regional demand response program might achieve. It is anticipated that BPA may implement a regional demand response program to control both generation and transmission system demand. Such a program would likely feature peak signaling for energy reductions (generation) and for transmission system demand reductions. If such a signal was available, it would become the trigger for any The City's demand response programs. That could include thermostat programs for both general electrical customers, gas converted customers and any direct customer demand response via an AMI metering system. The pilot program provided standard conservation EEI incentives to the pilot participants. If a regional demand response program was created, it is anticipated that BPA would provide financial incentives to utilities that help BPA meet load control goals. If The City had already built the demand response infrastructure for residential peak reduction it would also be available for BPA program incentives and improve the return on investment in a Demand Response program.

13.0 VOLT & VAR INVESTIGATION

13.1 Overview

The City's electrical system is relatively compact and does not have to serve a large geographical area. This has resulted in an electrical system with short feeders from substations to customer load areas. Because of this, The City's feeders are generally capacity limited (ampacity) and don't experience large voltage drops delivering energy to customers. The system analysis shows that when capacity constraints are removed, The City's feeders have significant voltage margin above the minimum voltage planning criteria at service transformers. This makes The City system a prime candidate for energy savings and demand reduction through Conservation Voltage Regulation (CVR).

13.2 Conservation Voltage Regulation

CVR allows the system voltage regulators to reduce the supply voltage on the system at peak or critical system times. Reduced voltage lowers system electrical demand and results in energy savings for resistive customers loads and energy shifting and peak demand reduction for motor (inductive) loads.

CVR requires a control system to change the regulator setpoints to alternate levels during peak times achieving system peak demand reduction savings and customer energy savings. The key is to monitor feeder end point voltage levels to ensure that adequate service voltage is maintained for quality service. Typically, a utility SCADA system is used to control regulators and transformer load tap changer settings and monitor system performance however The City does not yet have a SCADA system. CVR can be implemented without a full SCADA system by using a central electronic controller such as an SEL RTAC unit at an operations or engineering location, broadband communication to the substation regulators and network communication to select system end point meters. An AMI system would provide robust voltage monitoring at all customer meters and may also be available for substation communications depending on the AMI system selected. It appears that broadband communications may also be installed in The City by third parties in the near future and would be available for direct communication to substations and meters. Cellular data communication is also suitable for the substation link and select end point meters if AMI or broadband is not available. An SEL RTAC, programmed by The City or a consultant, including communication interface cards, input output (IO) cards and cellular modems for end point meters can be installed with a $40,000 budget. BPA includes CVR conservation payments and incentives under the conservation EEI program covering up to 80% of a system cost.

The amount of potential energy savings from CVR is highly variable and depends on the mix of equipment types and loads at each customer. A conservation study in conjunction with BPA EEI typical program savings data will be able to identify the potential range of energy savings available from CVR based on surveys of customer equipment types and if the savings meet cost benefit criteria. Any CVR system peak demand reductions will complement any DER program direct customer demand savings.

13.3 Conservation System Loss Reduction

BPA has a standard conservation EEI program available for electric system improvements that provide energy savings and system loss reductions. Generally, the program pays an incentive to

install larger cable or wire sizes on feeders than the standard size. The larger wire and cable results in energy kWH savings through loss reduction. There is a standard BPA EEI program methodology to calculate the potential savings, measure costs and incentives on a case-by-case basis. An example would be for the utility to install an oversized conductor, say 795 AAC instead of 336 ACSR, when planning a line rebuild and the additional cost is paid for with an incentive. Depending on the feeder loading the resulting savings may be sufficient to justify the extra cost. AMI meter data to show the actual feeder customer energy usage takes some of the assumptions and guess work out of the savings calculations and may allow The City to capture the potential savings. POWER recommends that as system improvements are planned, and additional system data becomes available, that the report suggested mitigations and improvements be evaluated for EEI loss reduction and incentives in the design and engineering process. Loss reductions can be in the range of 2% to 10%. Reduction of existing system losses depends on customer usage, feeder loading and capacity limits of existing conductors.

14.0 PLANNING CONSULTATION WITH BPA

14.1 Overview

The City is engaged with BPA under the existing service contract to plan for capacity and energy needs in the future. This section outlines the capacity planning process with BPA and summarizes forecast demand (capacity) for the 6-year (2030) period and for the 20-year (2044) period. Recommendations are made for engaging with the BPA area engineer to plan for the projected loads and system needs identified in the study. The forecast includes potential large customers, electric vehicle charging loads, impacts of residential natural gas conversion and load changes at Central Washington University.

14.2 Joint Planning with BPA Area Engineer

Planning and Forecasting

Planning and load forecasting is divided into two separate areas within BPA, Transmission and Energy. Transmission is focused on the peak demands on the entire BPA Northwest regional system. Energy is focused on generation resource production over time including the Northwest Hydroelectric system. The Area Engineer for The City at BPA is the critical contact for planning and anticipating BPA system capacity needs for The City in coordination with neighboring utilities. BPA transmission planning engineers complete short-term and long-term load flow studies annually with contingencies to validate the reliability of the system and meet regional (WECC) and Federal (NERC/FERC) requirements.

New Load Growth Constraints

Under the existing BPA service contract, BPA meets the general load growth needs of The City. The exception is for “New Large Loads” of 10MW or more. Loads at that level require special study to determine any impacts to the transmission system with the cost of improvements or mitigations born by the utility. Typically, those costs are passed on to the large load customer. The impacts of general organic load growth occurring year over year are the responsibility of BPA Transmission along with the cost for any improvements. The forecasted large loads included in this planning study are under 10MW of demand and do not meet the “New Large Load” trigger criteria of 10aMW (87,600 MWh) in a rolling 12 month period. We recommend that The City engage with the BPA Area Engineer to incorporate the potential system growth and forecasted demands detailed in this report to be included into the BPA planning and modeling process. Typically, this is an ongoing process.

Improvements and mitigations are identified for forecasted needs annually but not budgeted and built until actual system loads and conditions are likely and firm. A consistent and ongoing dialog with BPA is critical to show when new customers or The City’s system load growth is firm to secure priority improvement funding in BPA’s capital budget. Securing The City’s large customer commitments, agreements and initial funding is essential to establish the priority in the BPA capital budget. We recommend presenting these agreements to your Area Engineer when preliminary and when final to keep them engaged. Studies of the impacts of State legislative mandates, such as residential gas conversion, that The City has already completed and that were incorporated into this plan also help demonstrate the priority of needed growth improvements. We recommend discussing these sections of the plan with your Area Engineer to demonstrate the upcoming needs for electric energy to offset the reduction of natural gas energy.

City Engagement with BPA

City staff has been engaged with BPA planning for the proposed South Ellensburg Substation. A line load feasibility study (LLFS) was completed by BPA for the proposed South Ellensburg Substation in August 2024. That substation would require a new connection to the BPA Ellensburg- Moxee #1 115kV line. Because it would be a new interconnection, The City will be responsible for the costs of the interconnection namely three switches at the interconnect point. The cost of the interconnect with BPA overhead and 50% contingency was estimated at $1,410,127.

The study was conducted as if the interconnection was a new 28MW load triggering New Large Load requirements. At the time of the interconnection study request, the study loads were not yet available from this plan. If there was an actual 28MW of new load, voltage at area substation buses would not be sustained adequately under fault contingencies and new capacitors would be required to be installed to support voltage in the area. 25MVAr of capacitor would be adequate to correct the system impact. However, BPA identified 40MVAr would be the minimal size to support future load growth in the Ellensburg region. The cost of the capacitance was estimated at $6,494,290 with overhead and 50% contingency for the 40 MVAr capacitors. In any scenario The City should not be responsible for costs associated with other area utility load growth and costs for capacitors greater than 25MVAr.

Note that the costs mentioned above are very preliminary and would likely be reduced as plans become more specific. The City staff are already discussing and refining those with BPA.

Joint Planning

The City should demonstrate with the load projections summarized below that there will not be 28MW of new load at the interconnection. The load on the new South Ellensburg Substation is the result of load transfers from The City's existing interconnections with BPA at Dolarway and East Ellensburg substations and no new large customer projected load meets the 10MW trigger for a new large load.

It is recommended to clarify this information with BPA and identify that The City should not be responsible for the proposed capacitor costs. We recommend that The City engage with BPA along with POWER to clarify the actual loads that are forecast and revise the interconnection plan. If BPA insists that the new interconnection is a new large load, a revised plan without the South Ellensburg Substation could be developed with service from the existing Dolarway and East Ellensburg substations at substantially less cost than the proposed BPA capacitor alternative.

This system study also proposes a new West Helena Substation to meet natural gas conversion loads if they occur. That substation will require a new interconnection with BPA since that substation would tap the existing BPA transmission line to East Ellensburg. The natural gas conversion load will be a general system load increase to all BPA points of delivery and will occur with or without a new substation interconnection.

BPA Transmission Limitations

The BPA 115kV system in the area is supported from two sources to the East of Ellensburg, Columbia 35 miles away and Midway 64 miles away. Loss of the closer source results in the worst impacts to the system resulting in nearly out of compliance low voltage at all substation buses in the area. Any area load growth from The City, Kittitas PUD and Puget Sound Energy pushes the contingency bus voltages below the compliance limits in both winter and summer. Area load growth may also result in summer line overload to the Moxee- Ellensburg #1 115kV line. BPA has a planned improvement to the Moxee – Ellensburg #1 115kV line that is scheduled for 2025 that will eliminate the line overloads for up to 28MW of load growth. The Columbia – Ellensburg 115kV line showed no contingency overloads in any scenario. **Low post contingency bus voltage will still need mitigation with the load growth applied.** The Columbia Smithson Ellensburg line has ratings of 1070A and 1250A respectively. BPA projects summer loading of 42% and 33% in 2032 with winter loading less than that. The Columbia – Ellensburg line has capacity available for 450A or 89.6MW of new load. However, post fault low voltage on the Ellensburg Substation bus will likely occur before the full capacity is reached.

MOXEE - ELLENSBURG #1 115KV LINE (AMPS)			
	WINTER	**SUMMER**	**SUMMER 2034 CONTINGENT LOADING %**
EXISTING LINE 2024	726	443	119
IMPROVED LINE 2025 (ACSR/TW PARAKEET)	NA	830	64

TABLE 21: SOUTH ELLENSBURG AREA 115 KV LINE CAPACITY

COLUMBIA SMITHSON & SMITHSON ELLENSBURG 115KV LINE (AMPS)			
	WINTER	**SUMMER**	**SUMMER 2032 LOADING %**
COLUMBIA - SMITHSON	NA	1070	42
SMITHSON - ELLENSBURG	NA	1250	33

TABLE 22: NORTH ELLENSBURG AREA 115 KV LINE CAPACITY

Included below is a flow chart of the stages of the planning process with BPA Transmission for general load growth.

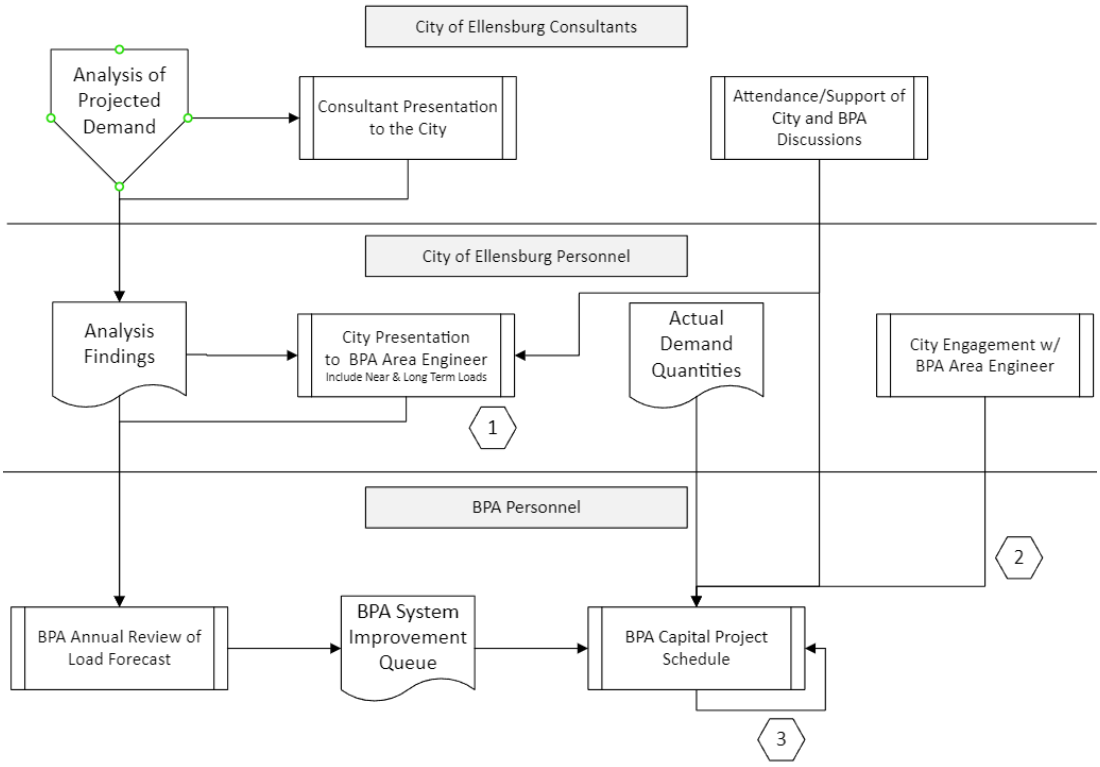


FIGURE 17: FLOW CHART OF BPA COORDINATION PROCESS

Numbered callouts are related to the following summary list of recommendations and strategies associated with the points of interaction with BPA's Area Engineer.

1. City Presentation to BPA Area Engineer:
    a. Share near and long term load requirements from this study with attention to Table 23 below.
    b. Identify forecasted large loads are each under 10MW and do not meet the "New Large Load" trigger criteria.
    c. Clarify the South Ellensburg Substation project is not new load and The City should not be responsible for the proposed capacitor costs.
    d. Identify the new Helena Substation, to meet natural gas conversion load, would tap an existing The City's transmission line and point of delivery. In this case, no new interconnection with BPA would be needed.
2. City Engagement with BPA Area Engineer:
    a. Establish consistent and ongoing dialog with BPA to show load growth is firm and secure.
    b. Present load agreements to your Area Engineer when preliminary and when final.
    c. Provide studies showing impacts of State legislative mandates incorporated into this plan to demonstrate priority of needed growth improvements.
3. BPA Capital Project Schedule
    a. Maintain consistent and ongoing dialog with BPA.
    b. Identify competing projects and continue to use the strategies above in a similar manner.

14.3 Forecast of 6 Year and 20 Year System Demand

The system study incorporated a forecast of general load growth (including electric vehicle and natural gas conversion), growth inside The City's urban growth boundary and specific large load growth and changes. Table 23 below details the large load additions by year that are included in the 6-year (2030) and 20-year (2044) system. Central Washington University provided a load forecast that includes heating plant conversions from natural gas to electric, additions and changes to buildings and distributed electric vehicle charging points on campus. Public Electric Vehicle charging stations near the East and West I90 interchanges are anticipated to occur and expand within each of the 6-year and 20-year periods. This information will be central to the planning discussions with BPA and will help establish timing for any area transmission improvements.

CITY OF ELLENSBURG SUMMARY OF FORECAST LARGE LOAD ADDITIONS NON-COINCIDENT MVA							
Year	**Central Washington University**	**Public Electric Vehicle Charging**	**Winco (forecast diversified demand)**	**System Total**	**MWh Historic 0.48 Annual LDF**	**MWh Range Minimum 0.38 Annual LDF*2**	**MWh Range Maximum 0.57 Annual LDF*2**
2025	1.287			53.8	225,326 *1		
2026	2.540		9.1				
2027	0.629						
2028	-1.562						
2029	1.902						
2030	-0.800	6.0		75.1	314,535	251,628	377,442
2031	1.295		1.8				
2032	2.612						
2033	1.355						
2034	0.046						
2035	3.449						
2036	0.046						
2037	0.046						
2038	0.252						
2039	0.046						
2040	2.112						
2041	0.046						
2042	0.046						
2043	0.046						
2044	0.046	8.0		112.5	471,174	376,939	565,409

CITY OF ELLENSBURG SUMMARY OF FORECAST LARGE LOAD ADDITIONS NON-COINCIDENT MVA							
Year	**Central Washington University**	**Public Electric Vehicle Charging**	**Winco (forecast diversified demand)**	**System Total**	**MWh Historic 0.48 Annual LDF**	**MWh Range Minimum 0.38 Annual LDF*2**	**MWh Range Maximum 0.57 Annual LDF*2**
Total Non-Coinc. MVA	**15.439**	**14.0**	**10.9**				

TABLE 23: SUMMARY OF FORECAST LARGE LOAD ADDITIONS AND TOTAL SYSTEM DEMAND

*1 Actual system MWh Oct 22 to Sept 23 achieving a 0.48 Annual Load Factor

*2 +/- 20% from estimate

*The system was modeled with the large loads in this table along with the general customer load growth as discussed in Section 3.1.

14.4 Coordination with Energy Forecasts, New BPA Contracts and Regional Generation Resources

The other half of planning with BPA is on the resource (BPA Power) side. The projected system growth identified in this study will increase The City's energy requirements with BPA. Those projections are captured in an annual load forecasting(energy) process with BPA Power separate from the Transmission Area Engineer. The existing BPA contracts have a lower cost block of energy available based on the Federal Hydro Power System called TIER I. Additional energy needs above the TIER I allocation is billed at a higher TIER II rate and includes additional resources beyond the Hydro Power System. Increased energy needs will change what The City pays under the existing contract between Tier I and Tier II rates when the existing energy allocation for Tier I is exceeded. The City presently has a forecast net requirement of 25.697 aMW and 23.982 aMW available under TIER I in the BPA Fiscal Year 2025 rate period. This leaves a projected 1.715 aMW in TIER II. We recommend that The City investigate the energy impacts of the projected system growth under the existing and potential new contract alternatives. Focus the investigation on how much energy would fall in different rate tiers and the associated costs and the impact to the Cost of Service. Substantially added usage in more expensive tiers could require The City to change their retail rate energy blocks and the kWh rate in the blocks. The biggest impact to The City will be from large customer usage, so adjustments to the large commercial rates would have the most impact. Estimates of the potential MWh energy usage on the forecasted system are include in Table 23 above.

BPA is presently engaged in developing new service contracts with public power utilities in the region. The new contracts may have limits to how much load growth BPA will serve going forward and if utilities will need to acquire additional resources beyond BPA. There may be options for BPA to serve the growth or for The City to acquire its own resource to serve load growth. We recommend that the long-term plan loads forecasted in this report be assessed against the Public Power proposed BPA contract alternatives to help judge the impacts of those alternatives on The City power costs. New distributed energy resources, small community scale solar, energy storage facilities, or other alternative generation sources may be acceptable to BPA as part of the solution to upcoming service challenges.

15.0 SYSTEM MODEL SOFTWARE MIGRATION INVESTIGATION

The City is contemplating migrating to a new distribution analysis software package. POWER has been in contact with three vendors that could replace the existing Synergi package that The City currently has a single license for. Contacts on integration with other software (GIS, AMI, etc.) have been completed via telephone with the below providers. A summary of the findings includes:

Synergi

Upfront Costs:

- None other than work required to integrate with the revised GIS system for facilities and mapping and a potential upgrade or change to The City's Customer Service and Billing system. If an AMI system is adopted in the future, integration with metering and customer usage data may come from the AMI system or a meter data management system (MDMS) paired with an AMI system. Synergi indicated that the existing licensing and maintenance fees include integration support.

Annual Costs:

- $2,250 (current costs for existing single license)

Advantages:

- The City is already familiar with software.
- Training on use is less than a new package.
- Synergi has the capabilities to meet The City's current and future requirements.

Disadvantages:

- The City has expressed frustration on the difficulty in use of the existing software. Integration with The City's other applications has been difficult despite the integration support.
- Not used as much by other public utilities as other available software in the Pacific Northwest.

Cyme

Upfront Costs:

- Load Flow & Short Circuit - $19,300
- Protective Device Analysis - $5,400
- Mapping Compatibility - $2,000
- Integrate with new AMI functions - Yes

Annual Costs

- 15% annually ($2,250)

Advantages:

- Similar to Synergi.
- Can import existing Synergi model.
- Background overlays including DWG, DXF, KMZ and GIS Shape files available
- Perhaps more powerful and useful if The City desires to do more advanced studies.

- Quite respected in the distribution industry. CYME offers many other modules such as cable ampacity modeling which is POWER's "go-to" package.
- Can be customized for AMI mapping (using EXCEL interface) for downstream visualize of low voltages or outages.
- Can be leased on a 6 month basis.

Disadvantages:

- More expensive.
- Training on new software

EDD (Electrical Distribution Design) – an NISC Engineering Module

Upfront Costs:

- Load Flow & Short Circuit – requires the full NISC Enterprise Resource Program in addition to the engineering software.
- Protective Device Analysis - requires the full NISC Enterprise Resource Program in addition to the engineering software.
- Integrate with new AMI functions - Yes

Annual Costs – Depends on total NISC ERP package implemented.

Advantages:

- Similar to Synergi.
- Compatible with The City's existing GIS system
- Advanced distribution analysis functions when paired with an AMI system. Captures real-time losses by feeder section. Loop feed analysis available.

Disadvantages:

- Requires NISC Customer Information System (CIS), Accounting, and other ERP modules.
- Not available as stand alone.
- Training on new software.
- Without AMI data, analysis capabilities similar to other modeling programs.

Milsoft

Upfront Costs:

- Load Flow, Short Circuit and Protective Device analysis - $19,300
- The above with LandBase (GIS), Contingency and Reliability modules - $21,000
- Integrate with new AMI functions - Yes.

Annual Costs - No cost for 5 year contract (15% or ~ $3,150 per license)

Advantages:

- Similar to Synergi.
- Widely used industry wide and specifically Pacific Northwest and near-by utilities. POWER uses this program as our "go-to" distribution analysis software package.

- Ease of use over Synergi.
- Customer distribution transformer loading function included.
- System changes and proposed system improvements are tracked in detail and are easier to manage than in Synergi.

Disadvantages:

- Training on new software
- Integration costs for the transfer of existing data ($10,000 expected).

APPENDIX – A

Load Growth Areas and Specific Spot Loads Applied to The System

FIGURE 18: BLACK HORSE HOUSING DEVELOPMENT SITE

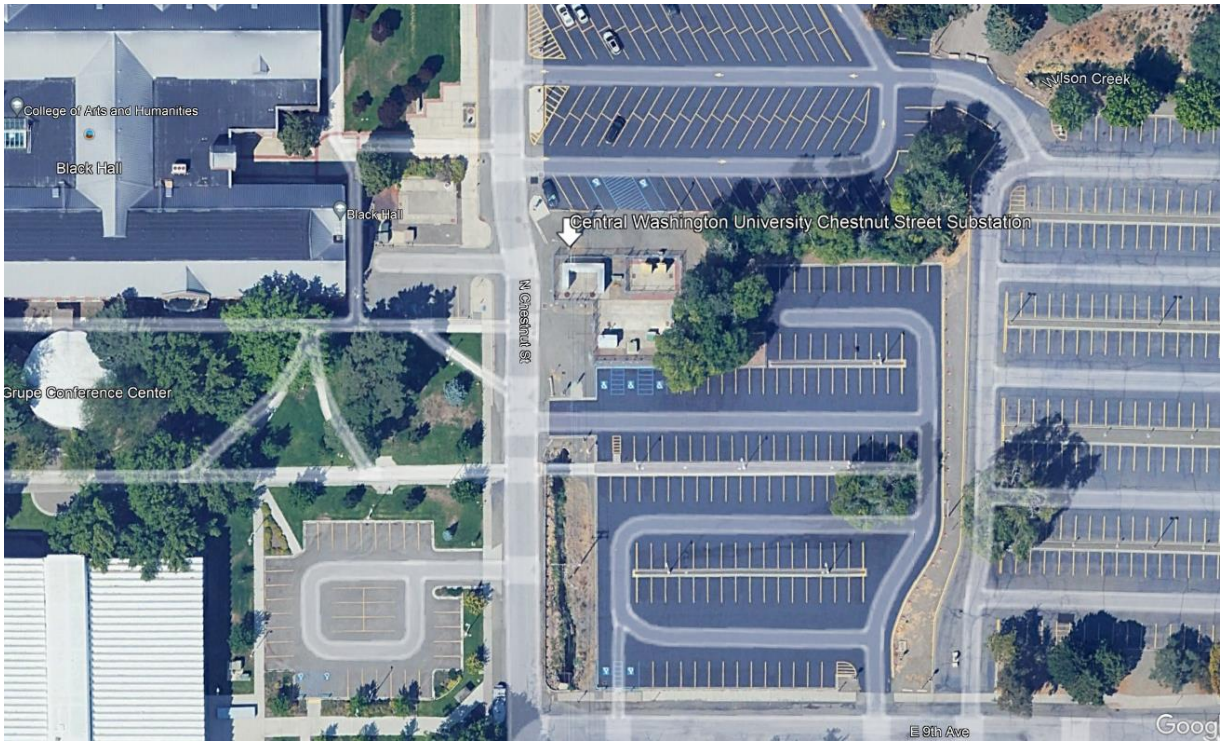


FIGURE 19: CWU'S SUBSTATION 1

FIGURE 20: CWU'S SUBSTATION 2

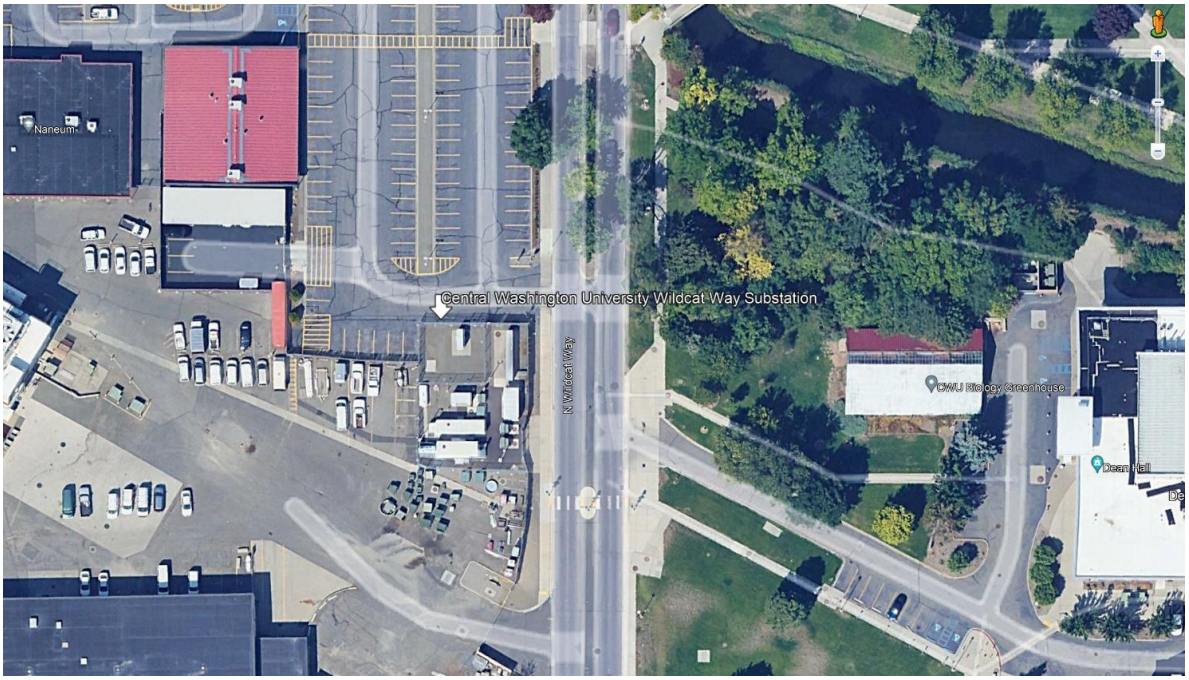


FIGURE 21: CWU'S SUBSTATION 3

FIGURE 22: FIELD HOUSE RECREATIONAL FACILITY SITE

FIGURE 23: EV CHARGING STATION, SOUTH I-90 INTERCHANGE SITE

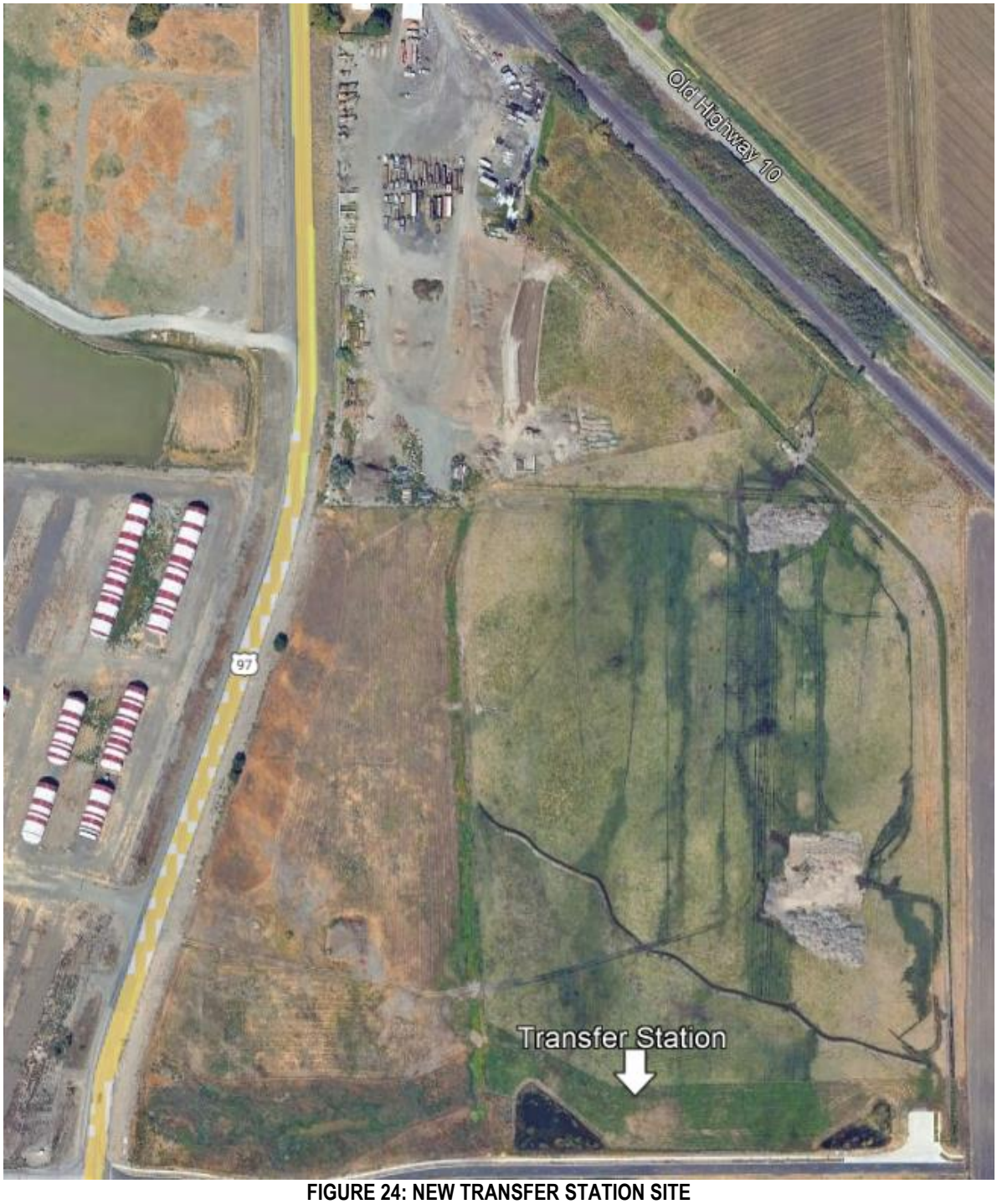


FIGURE 24: NEW TRANSFER STATION SITE

FIGURE 25: EV CHARGING STATION, WEST I-90 INTERCHANGE SITE

FIGURE 26: WINCO FOODS SITE

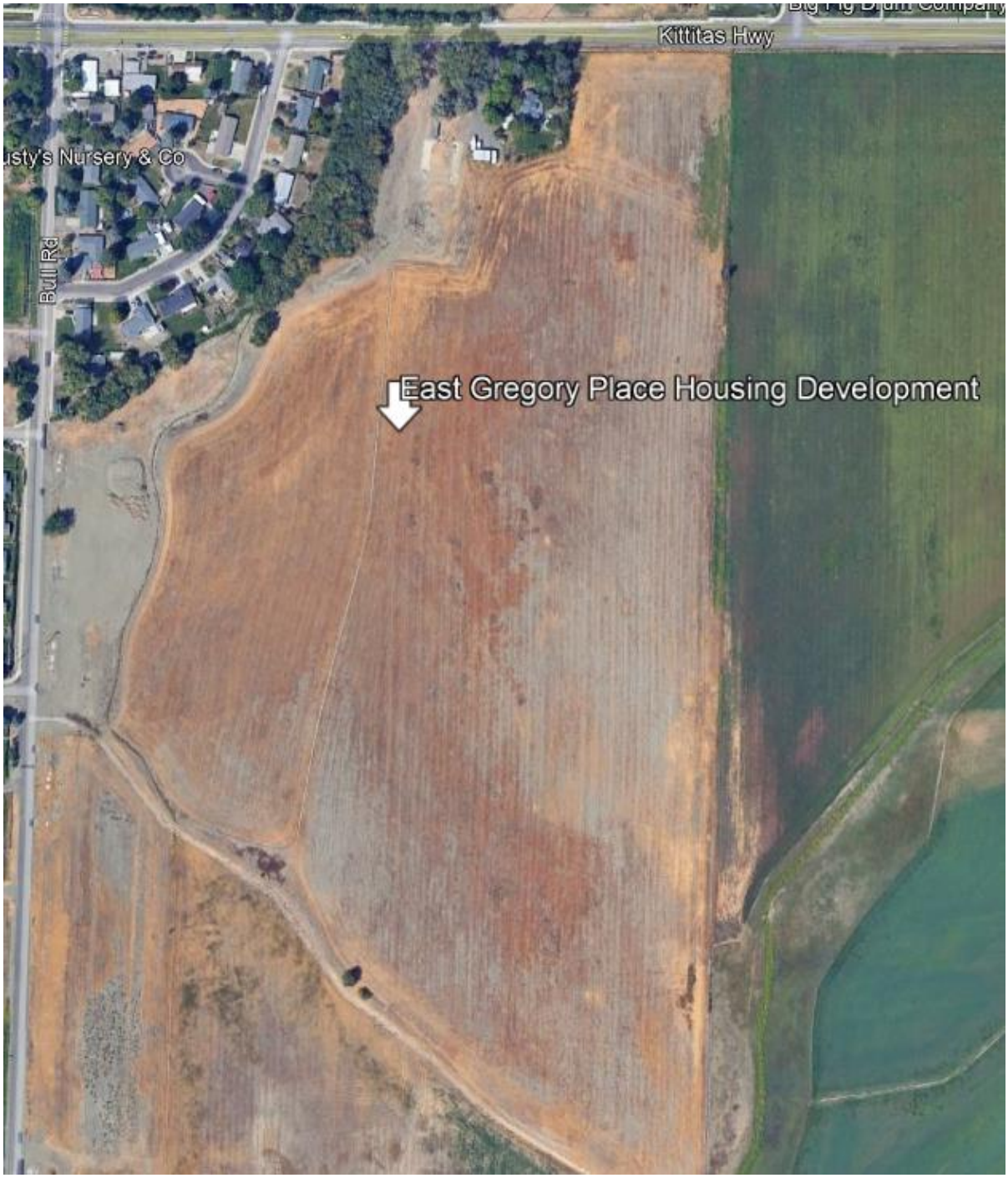


FIGURE 27: EAST GREGORY PLACE HOUSING DEVELOPMENT SITE

FIGURE 28: EAST BULL ROAD HOUSING DEVELOPMENT SITE

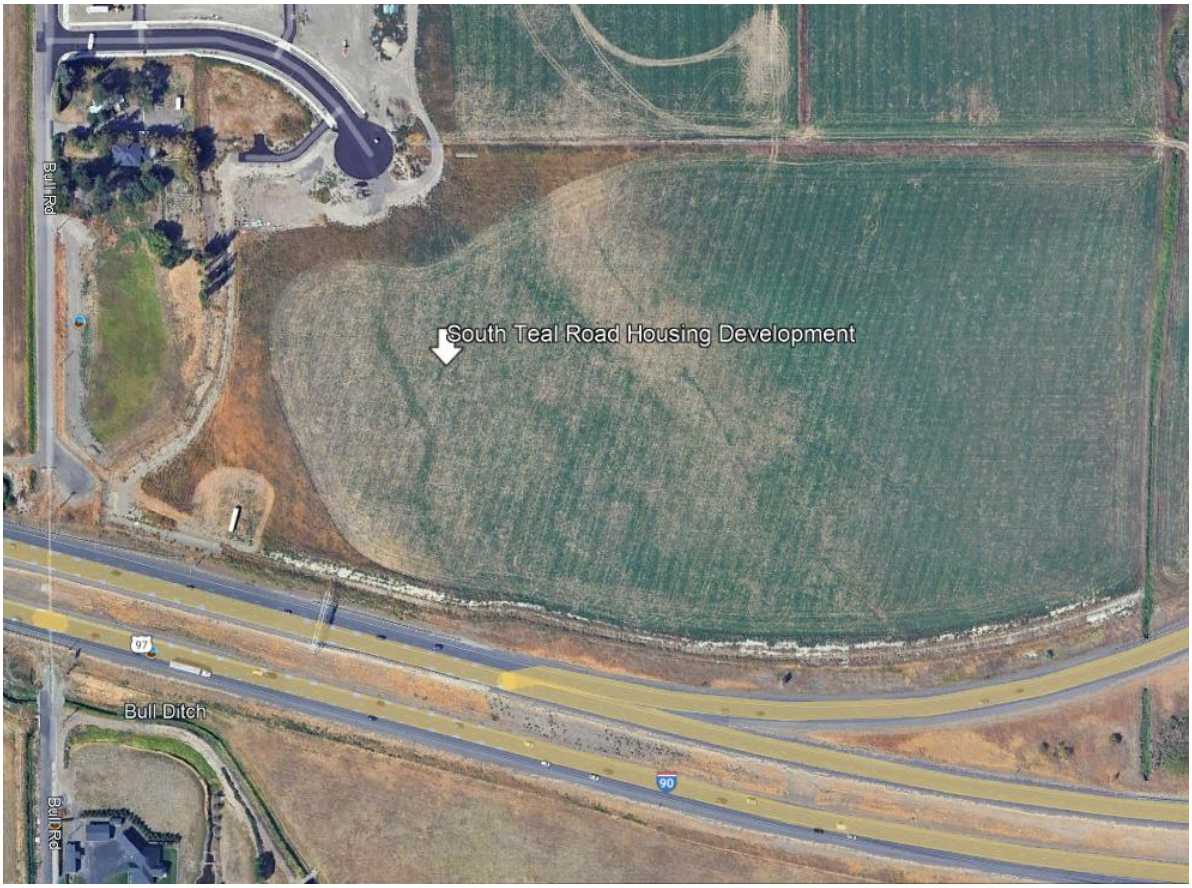


FIGURE 29: SOUTH TEAL ROAD HOUSING DEVELOPMENT SITE

FIGURE 30: WEST BULL ROAD HOUSING DEVELOPMENT SITE

FIGURE 31: WIGEON AVENUE HOUSING DEVELOPMENT SITE

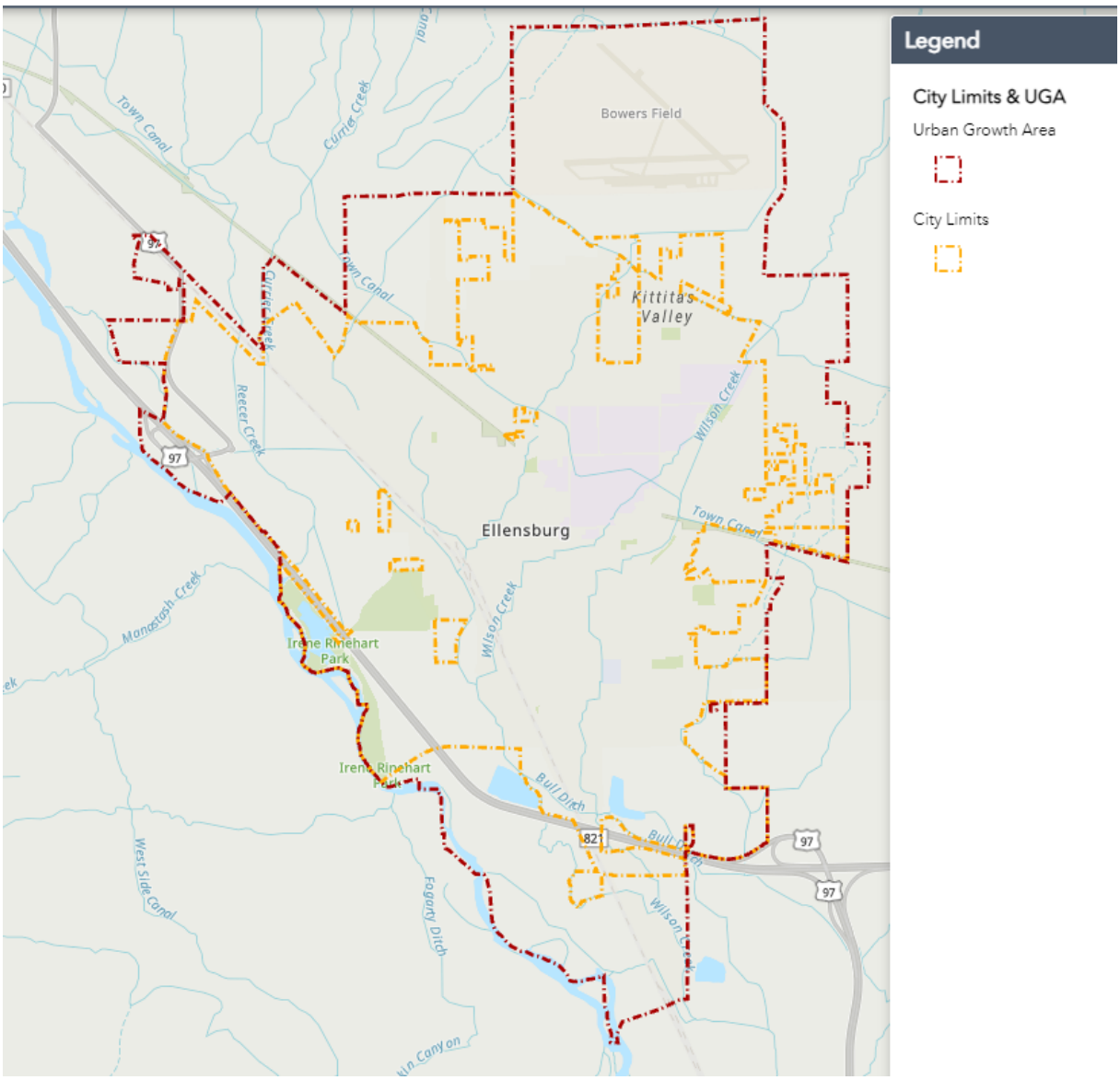


FIGURE 32: THE CITY OF ELLENSBURG URBAN GROWTH AREA BORDER

APPENDIX – B

Full List of System Improvement Recommendations

2025 SYSTEM RECOMMENDED IMPROVEMENTS				
Improvement Number	**Substation - Feeder**	**Description**	**From - To**	**Reason For Improvement**
1	Dolarway #1 -	New 33 MVA Transformer	Dolarway #1 Substation	This change is already in progress and is to improve system capacity
2	Dolarway #1 – 1	Add WNϕ[1] N.O, add 1/0 UG conductor, move section from C → B phase	Add WNϕ[1] N.O switch in between HRD61 and HRD63, add 1/0 UG conductor to connect HRD64 to HRT16 to move the C phase section east of the new WNϕ[1] switch to B phase	Load imbalance of 52% downstream of distribution pole HRM02
3	East Ellensburg - 11	Move Tap Placement A→C	Distribution Poles JPD06 to JPD04	Load imbalance of 45%
4	East Ellensburg - 13	Move Tap Placement C→B	Fuse F127 at Distribution pole IQD69	Load imbalance of 65% at JQM02
5	Helena – 17	Convert single phase to three phase overhead line, in the Cascade Village area. Cost dependent on work order design	From HPV16 to Pole HPD58, convert underground to three phase From Pole HPD58 to Pole HOD23 and HOD11 to HOD06, convert overhead to three phase conduit to move existing C phase taps to A and B, leaving C phase underground connection at HOD23 to Lexus Lane N.O. HOT12. Install N.O. switch at HOD06 and install 750 MCM AL 220 mil Cable through spare empty 4” and tap to the 750 MCM AL 220 mil Cable at pull vault and intercept cables 1358C, 1357b, and 1359a on the north south run.	Load imbalance of 79% due to C phase load at Fuse F267 on Helena Ave. BPA Pole
6	Helena - 17	Move Tap Placement B → C	F255 to GNV05	Load imbalance of 58%
7	Helena - 17	Move Tap Placement A → C	Vault HNV22 to HNS13	Load imbalance of 43%
8	Helena - 17	Move Tap Placement A → C	Vault GNV07 to GNT43	Load imbalance of 43%

9	Helena – 18	Split Campus Village Apartments, Glacier Apartments, and Greenpointe Townhomes load	opening B phase 1998b conductor at IOV26 Open 3 Phase conductors 2109a, 2092c, 2091b at IOV08 Make P012 N.C. Make cable 2036b at IOV23 N.C.	Load imbalance of 43% on Feeder 18 at F292
10		Shift Load Feeder 12→Feeder 9	Open Switch S123, Close Switch S124	East Ellensburg Substation Transformer Overloading to 82%. Overloading may happen prior to 2030 depending on the decarbonization progress of CWU. See Appendix C of this report for a further breakdown of decarbonization phases
2030 SYSTEM RECOMMENDED IMPROVEMENTS				
Improvement Number	**Substation - Feeder**	**Description**	**Location, From - To**	**Reason For Improvement**
11	Dolarway #2 - 7	New 1000 MCM AL 220 mil Cable Installation	Dolarway #2 Substation – South to FQD01 – South to Winco site.	To serve Winco Foods

12	Dolarway #2 - 8	New 750 MCM AL 220 mil Cable Installation	Dolarway #2 Substation – east to FQM22 – GQM10 – GQM28 – GRM15 – Switch S030 – Run east to proposed charging station	To serve EV charging infrastructure on Dolarway #2
2044 SYSTEM RECOMMENDED IMPROVEMENTS				
Improvement Number	**Substation – Feeder**	**Description**	**Location, To - From**	**Reason For Improvement**
13	Dolarway #1 – 4	Cable Replacement 336 AAC → 795 kCM AAC	Dolarway #1 Substation – Switch S116	Conductor loaded to 139% due to EV charging infrastructure, after the load shift of improvement number 27, the conductor is still loaded to 97%

14	Dolarway #1 – 4	Cable Replacement 750 MCM→1000 MCM AL 220 mil	Switch S116 – Switch S115, Switch S114 – Switch S045	Conductor loading to 133% due to EV charging infrastructure, after the load shift of improvement number 27, the conductor is still loaded to 94%
15	East Ellensburg #2	New 33 MVA Transformer Bank	East Ellensburg Substation	To improve capacity to serve CWU decarbonization, existing East Ellensburg Substation transformer overloaded to 106%, Dolarway #1 Substation overloaded to 104%. Overloading may happen prior to 2044 depending on the decarbonization progress of CWU. See Appendix C of this report for a further breakdown of decarbonization phases

16	East Ellensburg #2 – 19	New 750 MCM AL 220 mil Cable Installation	East Ellensburg Substation – Distribution pole IPM25 – Distribution pole IPM24 – Distribution pole IPM23 – Distribution pole IPM22 – Distribution pole IPM21 – Vault IPV05 – Vault IPV05 – CWU CHESTNUT ST SWITCHYARD – Vault IPV04 – Vault IPV01 – Vault HPV19 – Vault HPV09 – Vault HPV05 – Vault HPV07 – Switch cabinet HPC03 – Vault HPV07 – Vault HPV23 – Vault HPV22 – Vault HPV21	To serve 1/4 of CWU's total load
17	East Ellensburg #2 – 20	New 750 MCM AL 220 mil Cable Installation	East Ellensburg Substation – Distribution pole IPM25 – Distribution pole IPM24 – Distribution pole IPM23 – Distribution pole IPM22 – Distribution pole IPM21 – Vault IPV05 – Vault IPV07 – CWU CHESTNUT ST SWITCHYARD	To serve 1/4 of CWU's total load
18	South Ellensburg -	New South Ellensburg Substation	SE of Berry Rd & Canyon Rd crossing	Improve system capacity, Dolarway #2 Substation loaded to 132% due to new EV infrastructure and new large customer loads
19	South Ellensburg -	New 115kV Transmission	BPA Ellensburg-Moxee #1 Transmission tap between 3/7 & 3/9 then SW of Mattoon Lake – Run SE – Run east in parallel with Berry Rd to South Ellensburg Substation site	To provide service to the new South Ellensburg Substation

20	South Ellensburg – 24	New Line Construction 795 kCM AAC	South Ellensburg Substation site – North to Berry Rd – West to connect to Distribution pole ITM02	To connect new Feeder 24 to system
21	South Ellensburg – 24	Cable Replacement 350 CU→750 MCM AL 220 mil	Vault HTV11 – Vault HTV07	Conductor loading to 103% due to EV infrastructure
22	South Ellensburg – 25	New Line Construction 336 kCM AAC	South Ellensburg Substation site – North to Berry Rd – Vault ITV03	To connect new Feeder 25 to system
23	South Ellensburg – 25	New #1/0 AL URD 220 mil Cable Installation	ITV03 - East to Bull Rd – N to connect into system at Vault JTV10	To connect new Feeder 25 to system
24		Shift EV Load Feeder 8→South Ellensburg Substation	Dependent on new Feeder design	Dolarway #2 Transformer Overloading due to second phase loading of EV infrastructure
25		Shift Load Feeder 13→Feeder 25	Dependent on new Feeder design	To evenly distribute load to new South Ellensburg Substation, from East Ellensburg
26		Shift Load Feeder 9→Feeder 19 and Feeder 22	Dependent on new Feeder design	Dolarway #2 Substation transformer Overloading due to part of the CWU decarbonization load
27		Shift Load Feeder 4→Feeder 6	Open switch S055, Close switch S139	Dolarway #1 Transformer overloading due to second phase loading of EV infrastructure

28		Shift Load Feeder 1→Feeder 24	Dependent on new Feeder design	Dolarway #2 Substation Transformer Overloading due to second phase EV infrastructure. Since Feeder 24 is fed into the existing overhead infrastructure of Feeder 1, the design of Feeder 8 will need to be able to support switching to Feeder 1 near the new south EV infrastructure.
29		Shift Load Feeder 12→Feeder 20 and Feeder 21	Open Switch S063 and shift college load to newly constructed Feeders	East Ellensburg Substation Transformer Overloading due to the CWU decarbonization load

[1] Designates Will Not Phase

APPENDIX – C

Decarbonization of Central Washington University

Overview

The decarbonization of CWU was outlined by a separate contractor, Mckinstry. Each phase was modeled in Synergi electric against existing, 2025, 2030, and 2044 models without residential gas or EV conversion load growth multipliers. Total load growth by 2044 was calculated to be 15,751 kVA.

Phase 1 – 2025

In 2025 1,287 kVA was added to Central Washington University's Load. This loading was already included in the 2025 system in Section 4.4. Substation Transformer loading for this year is as follows:

- Dolarway #1 Substation – 56%
- Dolarway #2 Substation – 21%
- East Ellensburg Substation – 82%
- Helena Substation – 38%

Since East Ellensburg Substation is exceeding 80%, it is suggested that improvement number 10 is initiated. After this improvement, Substation transformer loading is as follows:

- Dolarway #1 Substation – 56%
- Dolarway #2 Substation – 32%
- East Ellensburg Substation – 63%
- Helena Substation – 38%

Phase 2 – 2027

In 2027 3,169 kVA was added to Central Washington Universities Load. Applying this additional load to the 2025 system in section 4.4. Substation Transformer loading for this year is as follows:

- Dolarway #1 Substation – 56%
- Dolarway #2 Substation – 33%
- East Ellensburg Substation – 76%
- Helena Substation – 38%

Phase 3 – 2030

In 2030 there will be a decline growth of -461 kVA to Central Washington University's Load. This is due to the predicted decommissioning of electrical load. This loading was already included in the 2030 system in section 5.4. Substation Transformer loading for this year is as follows:

- Dolarway #1 Substation – 68%
- Dolarway #2 Substation – 70%
- East Ellensburg Substation – 78%
- Helena Substation – 38%

Phase 4 – 2033

In 2033 5,262 kVA was added to Central Washington University's Load. Applying this additional load to the 2030 system in section 5.4. Substation Transformer loading for this year is as follows:

- Dolarway #1 Substation – 68%
- Dolarway #2 Substation – 77%

- East Ellensburg Substation – 93%
- Helena Substation – 38%

Since East Ellensburg Substation is exceeding 80%, it is suggested that improvement numbers 16 and 17 are initiated. After this improvement, Substation transformer loading is as follows:

- Dolarway #1 Substation – 68%
- Dolarway #2 Substation – 56%
- East Ellensburg Substation – 63%
- East Ellensburg #2 Substation – 40%
- Helena Substation – 38%

Phase 5 – 2036

In 2036 3,542 kVA was added to Central Washington University's Load. Applying this additional load to the 2030 system in section 5.4. substation transformer loading for this year is as follows:

- Dolarway #1 Substation – 68%
- Dolarway #2 Substation – 56%
- East Ellensburg Substation – 67%
- East Ellensburg #2 Substation – 49%
- Helena Substation – 38%

Phase 6 – 2039

In 2039 344 kVA was added to Central Washington University's Load. Applying this additional load to the 2030 system in section 5.4. Substation Transformer loading for this year is as follows:

- Dolarway #1 Substation – 68%
- Dolarway #2 Substation – 56%
- East Ellensburg Substation – 67%
- East Ellensburg #2 – 49%
- Helena Substation – 38%

Phase 7 – 2044

In 2044 2,296 kVA was added to Central Washington University's Load. Applying this additional load to the 2044 system in section 6.4. Substation Transformer loading for this year is as follows:

- Dolarway #1 Substation – 79%
- Dolarway #2 Substation – 65%
- East Ellensburg Substation – 73%
- East Ellensburg #2 Substation – 55%
- Helena Substation – 49%
- South Ellensburg – 35%

Contingency Overview

This section will outline different loading allocation possibilities to different distribution points throughout CWU's system.

Sub 1

If all of the college load was fed through Sub 1 of CWU's system The City's substation loading levels would be:

- Phase 1 2025 if Substation 1 is fed through the East Ellensburg Substation:
  - Dolarway #1 Substation – 56%
  - Dolarway #2 Substation – 21%
  - East Ellensburg Substation – 82%
  - Helena Substation – 38%

Although the planning criteria allows transformers to be loaded to 108%, it is suggested to shift load from East Ellensburg to other substations to preserve equipment life.

- Phase 1 2025 if Substation 1 is fed through the Dolarway #2 Substation:
  - Dolarway #1 Substation – 56%
  - Dolarway #2 Substation – 44%
  - East Ellensburg Substation – 46%
  - Helena Substation – 38%

- Phase 2 2027 if Substation 1 is fed through the East Ellensburg Substation:
  - Dolarway #1 Substation – 56%
  - Dolarway #2 Substation – 21%
  - East Ellensburg Substation – 98%
  - Helena Substation – 38%

In this case the 336 AAC line and the 750 MCM cable along East Ellensburg Feeder 12 will be loaded to over 100% it is suggested that in this configuration that the line be upgraded to 795 ACSR and 1000 MCM. This will bring both conductor types to under 100%, however the 1000MCM cable will still be loaded to over 80%. It is recommended to monitor CWU decarbonization progress and loading if this configuration is put in place. Although the planning criteria allows transformers to be loaded to 108%, it is suggested to shift load from East Ellensburg to other substations to preserve equipment life.

- Phase 2 2027 if Substation 1 is fed through the Dolarway #2 Substation:
  - Dolarway #1 Substation – 56%
  - Dolarway #2 Substation – 53%
  - East Ellensburg Substation – 46%
  - Helena Substation – 38%

In this case the 336 AAC line and the 1000 MCM cable along Dolarway #2 Feeder 9 will be loaded to over 80% it is suggested that in this configuration that the line be upgraded to 795 ACSR. It is recommended to monitor CWU decarbonization progress and loading if this configuration is put in place.

- Phase 3 2030 if Substation 1 is fed through the East Ellensburg Substation:
    - Dolarway #1 Substation – 68%
    - Dolarway #2 Substation – 56%
    - East Ellensburg Substation – 100%
    - Helena Substation – 38%

In this case, along East Ellensburg Feeder 12, the 750 MCM cable will be overloaded and the 336 AAC conductor will be loaded to over 80%. It is still recommended to upgrade both to prevent the overloading of equipment. It is recommended to monitor CWU decarbonization progress and loading if this configuration is put in place. Although the planning criteria allows transformers to be loaded to 108%, it is suggested to shift load from East Ellensburg to other substations to preserve equipment life.

- Phase 3 2030 if Substation 1 is fed through the Dolarway #2 Substation:
    - Dolarway #1 Substation – 68%
    - Dolarway #2 Substation – 90%
    - East Ellensburg Substation – 49%
    - Helena Substation – 38%

In this case, along Dolarway #2 Feeder 9, the 750 MCM cable will be overloaded and the 336 AAC conductor will be loaded to over 80%. It is still recommended to upgrade both to prevent the overloading of equipment. It is recommended to monitor CWU decarbonization progress and loading if this configuration is put in place. Although the planning criteria allows transformers to be loaded to 108%, it is suggested to shift load from Dolarway #2 to other substations to preserve equipment life.

- Phase 4 2033:
    - Dolarway #1 Substation – 68%
    - Dolarway #2 Substation – 56%
    - East Ellensburg Substation – 49%
    - East Ellensburg #2 – 54%
    - Helena Substation – 38%

In this case it shows that if the college is fed through Sub 1 exclusively through a single feeder the entire route would experience about 791A of current. The proposed cable for East Ellensburg #2 Feeder 20 is 750 MCM, this configuration would load the cable to 154%. If the cable was 1000 MCM it would be loaded to 141%. This should be taken into consideration with the design of East Ellensburg #2 substation. It is recommended that if this configuration is put into place that it is done at non-peak times to preserve equipment or to design the new system to feed the college through multiple feeders at Sub 1.

- Phase 5 2036:
    - Dolarway #1 Substation – 68%
    - Dolarway #2 Substation – 56%
    - East Ellensburg Substation – 49%
    - East Ellensburg #2 – 65%
    - Helena Substation – 38%

In this case it shows that if the college is fed through Sub 1 exclusively through a single feeder the entire route would experience about 999A of current. The proposed cable for East Ellensburg #2 Feeder 20 is 750 MCM, this configuration would load the cable to 192%. If the cable was 1000 MCM it would be loaded to 175%. This should be taken into consideration with the design of East Ellensburg #2 substation. It is recommended that if this configuration is put into place that it is done at non-peak times to preserve equipment or to design the new system to feed the college through multiple feeders at Sub 1.

- Phase 6 2039:
    - Dolarway #1 Substation – 68%
    - Dolarway #2 Substation – 56%
    - East Ellensburg Substation – 49%
    - East Ellensburg #2 – 70%
    - Helena Substation – 38%

- Phase 7 2044:
    - Dolarway #1 Substation – 79%
    - Dolarway #2 Substation – 65%
    - East Ellensburg Substation – 53%
    - East Ellensburg #2 – 71%
    - Helena Substation – 49%
    - South Ellensburg Substation – 35%

Sub 2

If all of the college load was fed through Sub 2 of CWU's system The City's substation loading levels would be:

- Phase 1 2025:
    - Dolarway #1 Substation – 56%
    - Dolarway #2 Substation – 21%
    - East Ellensburg Substation – 82%
    - Helena Substation – 38%

If the entire college load is fed through Sub 2, the 350 MCM that runs from IOC02 to IOC04 will be overloaded to 114%. The 336 AAC for East Ellensburg Feeder 11 will be loaded to 95%. It is recommended that this conductor be upgraded, or that this configuration is not ran at peak times to prevent conductor over loading.

- Phase 2 2027:
    - Dolarway #1 Substation – 56%
    - Dolarway #2 Substation – 21%
    - East Ellensburg Substation – 98%
    - Helena Substation – 38%

At this phase, if the entire college load is fed through Sub 2, the 336AAC for East Ellensburg Feeder 11 will be loaded to 102%, the 750 MCM AL will be loaded to 104%. The 1000 MCM AL getaway for East Ellensburg Feeder 11 will be loaded to 117%. It is recommended that this conductor be upgraded, or that this configuration is not ran at peak times to prevent conductor overloading.

- Phase 3 2030:
    - Dolarway #1 Substation – 68%
    - Dolarway #2 Substation – 56%
    - East Ellensburg Substation – 100%
    - Helena Substation – 38%

At this phase, if the entire college load is fed through Sub 2, the East Ellensburg Substation will be loaded to 100%. Although the planning criteria permits transformer loading to 108%, it is recommended to shift load elsewhere, or that this configuration is not ran at peak times.

- Phase 4 2033:
    - Dolarway #1 Substation – 68%
    - Dolarway #2 Substation – 56%
    - East Ellensburg Substation – 126%
    - East Ellensburg #2 Substation – 0%
    - Helena Substation – 38%

- Phase 5 2036:
    - Dolarway #1 Substation – 68%
    - Dolarway #2 Substation – 56%
    - East Ellensburg Substation – 145%
    - East Ellensburg #2 Substation – 0%
    - Helena Substation – 38%

- Phase 6 2039:
    - Dolarway #1 Substation – 68%
    - Dolarway #2 Substation – 56%
    - East Ellensburg Substation – 147%
    - East Ellensburg #2 Substation – 0%
    - Helena Substation – 38%

- Phase 7 2044:
    - Dolarway #1 Substation – 79%
    - Dolarway #2 Substation – 65%
    - East Ellensburg Substation – 165%
    - East Ellensburg #2 Substation – 0%
    - Helena Substation – 49%
    - South Ellensburg Substation – 35%

For this configuration it is recommended that a spare Feeder be built out of East Ellensburg #2 to serve Sub 2 and take load from the East Ellensburg Substation transformer.

Sub 3

If all of the college load was fed through Sub 3 the results would be the same as Sub 1 above due to the fact that both Substation 1 and Substation 3 share the same path.

Sub 1 and 2

If the college load was fed equally between Sub 1 and Sub 2 of CWU's system, The City's substation loading levels would be:

- Phase 1 2025 if Substation 1 is fed through the East Ellensburg Substation:
  - Dolarway #1 Substation – 56%
  - Dolarway #2 Substation – 21%
  - East Ellensburg Substation – 82%
  - Helena Substation – 38%

- Phase 1 2025 if Substation 1 is fed through the Dolarway #2 Substation:
  - Dolarway #1 Substation – 56%
  - Dolarway #2 Substation – 32%
  - East Ellensburg Substation – 64%
  - Helena Substation – 38%

- Phase 2 2027 if Substation 1 is fed through the East Ellensburg Substation:
  - Dolarway #1 Substation – 56%
  - Dolarway #2 Substation – 21%
  - East Ellensburg Substation – 97%
  - Helena Substation – 38%

- Phase 2 2027 if Substation 1 is fed through the Dolarway #2 Substation:
  - Dolarway #1 Substation – 56%
  - Dolarway #2 Substation – 36%
  - East Ellensburg Substation – 72%
  - Helena Substation – 38%

- Phase 3 2030 if Substation 1 is fed through the East Ellensburg Substation:
  - Dolarway #1 Substation – 68%
  - Dolarway #2 Substation – 56%
  - East Ellensburg Substation – 99%
  - Helena Substation – 38%

- Phase 3 2030 if Substation 1 is fed through the Dolarway #2 Substation:
  - Dolarway #1 Substation – 68%
  - Dolarway #2 Substation – 71%
  - East Ellensburg Substation – 75%
  - Helena Substation – 38%

- Phase 4 2033 if Substation 1 is fed through the East Ellensburg Substation:
  - Dolarway #1 Substation – 68%
  - Dolarway #2 Substation – 56%
  - East Ellensburg Substation – 86%
  - East Ellensburg #2 Substation – 26%
  - Helena Substation – 38%

In this configuration the 350 MCM that runs from IOC02 to IOC04 will be overloaded to 113%. The 1000 MCM AL getaway for East Ellensburg's Feeder 11 will be loaded to 90%. The 336 AAC conductor for Feeder 11 will be loaded to 95%. It is recommended to shift load off of Feeder 11, upgrade conductors, or not run this configuration at peak loading times.

- Phase 4 2033 if Substation 1 is fed through the Dolarway #2 Substation:
    - Dolarway #1 Substation – 68%
    - Dolarway #2 Substation – 56%
    - East Ellensburg Substation – 88%
    - East Ellensburg #2 Substation – 21%
    - Helena Substation – 38%

In this configuration the 350 MCM that runs from IOC02 to IOC04 will be overloaded to 113%. The 1000 MCM AL getaway for East Ellensburg's Feeder 11 will be loaded to 90%. The 336 AAC conductor for Feeder 11 will be loaded to 95%. It is recommended to shift load off of Feeder 11, upgrade conductors, or not run this configuration at peak loading times.

- Phase 5 2036 if Substation 1 is fed through the East Ellensburg Substation:
    - Dolarway #1 Substation – 68%
    - Dolarway #2 Substation – 56%
    - East Ellensburg Substation – 95%
    - East Ellensburg #2 Substation – 31%
    - Helena Substation – 38%

In this configuration the 1000 MCM AL getaway for East Ellensburg's Feeder 11 will be loaded to 105%. The 336 AAC conductor for Feeder 11 will be loaded to 111%. The 750 MCM AL cable that runs from IOM15 to S111 will be loaded to 91%. East Ellensburg's Feeder 11 1000 MCM AL that runs from IPM20 to IPM19 is loaded to 87%. East Ellensburg #2 Feeder 20 has a recommended getaway of 1000 MCM AL, in this configuration it is loaded to 84%. It is recommended to shift load off of Feeder 11, upgrade conductors, or not run this configuration at peak loading times.

- Phase 5 2036 if Substation 1 is fed through the Dolarway #2 Substation:
    - Dolarway #1 Substation – 68%
    - Dolarway #2 Substation – 56%
    - East Ellensburg Substation – 97%
    - East Ellensburg #2 Substation – 29%
    - Helena Substation – 38%

In this configuration the 1000 MCM AL getaway for East Ellensburg's Feeder 11 will be loaded to 105%. The 336 AAC conductor for Feeder 11 will be loaded to 111%. The 750 MCM AL cable that runs from IOM15 to S111 will be loaded to 91%. East Ellensburg's Feeder 11 1000 MCM AL that runs from IPM20 to IPM19 is loaded to 87%. East Ellensburg #2 Feeder 20 has a recommended getaway of 1000 MCM AL, in this configuration it is loaded to 84%. It is recommended to shift load off of Feeder 11, upgrade conductors, or not run this configuration at peak loading times.

- Phase 6 2039 if Substation 1 is fed through the East Ellensburg Substation:
    - Dolarway #1 Substation – 68%
    - Dolarway #2 Substation – 56%

  - East Ellensburg Substation – 95%
  - East Ellensburg #2 Substation – 30%
  - Helena Substation – 38%

In this configuration East Ellensburg's Feeder 11 1000 MCM AL that runs from IPM20 to IPM19 is loaded to 87%. The 750 MCM AL cable that runs from IOM15 to S111 will be loaded to 93%. East Ellensburg #2 Feeder 20 has a recommended getaway of 1000 MCM AL, in this configuration it is loaded to 85%. It is recommended to shift load off of Feeder 11, upgrade conductors, or not run this configuration at peak loading times.

- Phase 6 2039 if Substation 1 is fed through the Dolarway #2 Substation:
  - Dolarway #1 Substation – 68%
  - Dolarway #2 Substation – 56%
  - East Ellensburg Substation – 98%
  - East Ellensburg #2 Substation – 29%
  - Helena Substation – 38%

In this configuration East Ellensburg's Feeder 11 1000 MCM AL that runs from IPM20 to IPM19 is loaded to 87%. The 750 MCM AL cable that runs from IOM15 to S111 will be loaded to 93%. East Ellensburg #2 Feeder 20 has a recommended getaway of 1000 MCM AL, in this configuration it is loaded to 85%. It is recommended to shift load off of Feeder 11, upgrade conductors, or not run this configuration at peak loading times.

- Phase 7 2044 if Substation 1 is fed through the East Ellensburg Substation:
  - Dolarway #1 Substation – 79%
  - Dolarway #2 Substation – 65%
  - East Ellensburg Substation – 105%
  - East Ellensburg #2 Substation – 34%
  - Helena Substation – 49%
  - South Ellensburg Substation – 35%

In this configuration East Ellensburg's Feeder 11 1000 MCM AL that runs from IPM20 to IPM19 is loaded to 95%. The 750 MCM AL cable that runs from IOM15 to S111 will be loaded to 103%. East Ellensburg #2 Feeder 20 has a recommended getaway of 1000 MCM AL, in this configuration it is loaded to 93%.

- Phase 7 2044 if Substation 1 is fed through the Dolarway #2 Substation:
  - Dolarway #1 Substation – 79%
  - Dolarway #2 Substation – 65%
  - East Ellensburg Substation – 105%
  - East Ellensburg #2 Substation – 34%
  - Helena Substation – 49%
  - South Ellensburg Substation – 35%

In this configuration East Ellensburg's Feeder 11 1000 MCM AL that runs from IPM20 to IPM19 is loaded to 95%. The 750 MCM AL cable that runs from IOM15 to S111 will be loaded to 103%. East Ellensburg #2 Feeder 20 has a recommended getaway of 1000 MCM AL, in this configuration it is loaded to 93%.

Sub 2 and 3

If the college load was fed equally between Sub 2 and Sub 3 of CWU's system The City's substation loading levels would directly reflect the case above *Sub 1 and 2* due to Sub 1 and Sub 3 being along the same series path.

Sub 1 and 3

If the college load was fed equally between Sub 1 by East Ellensburg Substation Feeder 12 and Sub 3 of CWU's system by Dolarway #2 Substation Feeder 9. The City's substation loading levels would be:

- Phase 1 2025 if Substation 1 is fed through the East Ellensburg Substation:
  - Dolarway #1 Substation – 56%
  - Dolarway #2 Substation – 32%
  - East Ellensburg Substation – 63%
  - Helena Substation – 38%

- Phase 2 2027 if Substation 1 is fed through the East Ellensburg Substation:
  - Dolarway #1 Substation – 56%
  - Dolarway #2 Substation – 37%
  - East Ellensburg Substation – 70%
  - Helena Substation – 38%

- Phase 3 2030 if Substation 1 is fed through the East Ellensburg Substation:
  - Dolarway #1 Substation – 68%
  - Dolarway #2 Substation – 73%
  - East Ellensburg Substation – 73%
  - Helena Substation – 38%

- Phase 4 2033 if Substation 1 is fed through the East Ellensburg Substation:
  - Dolarway #1 Substation – 68%
  - Dolarway #2 Substation – 56%
  - East Ellensburg Substation – 49%
  - East Ellensburg #2 Substation – 47%
  - Helena Substation – 38%

- Phase 5 2036 if Substation 1 is fed through the East Ellensburg Substation:
  - Dolarway #1 Substation – 68%
  - Dolarway #2 Substation – 56%
  - East Ellensburg Substation – 49%
  - East Ellensburg #2 Substation – 62%
  - Helena Substation – 38%

In this configuration East Ellensburg #2 Feeder 19 and Feeder 20's 1000 MCM AL getaways will reach 84% loading.

- Phase 6 2039 if Substation 1 is fed through the East Ellensburg Substation:
  - Dolarway #1 Substation – 68%

- Dolarway #2 Substation – 56%
- East Ellensburg Substation – 49%
- East Ellensburg #2 Substation – 62%
- Helena Substation – 38%

In this configuration East Ellensburg #2 Feeder 19 and Feeder 20's 1000 MCM AL getaways will reach 85% loading.

- Phase 7 2044 if Substation 1 is fed through the East Ellensburg Substation:
  - Dolarway #1 Substation – 79%
  - Dolarway #2 Substation – 65%
  - East Ellensburg Substation – 53%
  - East Ellensburg #2 Substation – 69%
  - Helena Substation – 49%
  - South Ellensburg Substation – 35%

In this configuration East Ellensburg #2 Feeder 19 and Feeder 20's 1000 MCM AL getaways will reach 94% loading.

APPENDIX – D

Winco Foods

Overview

Winco foods approached The City with a request to serve a spot load that will be added to the system west of 509 Storage in two phases. The first phase load is 9.1 MVA for refrigeration, automation, reefer trucks, dry, ripening, MHE battery charging, truck return center, EV chargers, and ambient load, this was modeled in 2030 of the Synergi model. The second phase load is 10.9 MVA for future ambient and cooler expansions, this was modeled in 2044 of the Synergi model. In September 2024, a consultant for WinCo presented a report, "Projected Primary Service Loading at Ellensburg Winco Facility." Below is a breakdown of the assumed loads taken from this report and applied to the Synergi Model:

WINCO PROJECTED DIVERSIFIED LOADING		
	Phase 1	**Phase 2**
MVA	9.1	10.9
MW	7.7	9.2
PF	0.85	0.85

TABLE 24: WINCO PROJECTED DIVERSIFIED LOADING

The City planned to build out a Feeder 7 out of the Dolarway #2 Substation to serve the new loads including Winco Foods and to tie into the existing system. Below is the loading data for Dolarway Substations in 2030 after Dolarway #2 Feeder 7 is in service and serving WinCo and other loads:

2030, WINCO ON FEEDER 7, NON-EXCLUSIVE		
	Winco Out of Service	**Winco In Service**
Dolarway #1 % Loading	68%	68%
Dolarway #1 MVA	23.1	23.1
Dolarway #1 Bus Voltage	123.8	123.8
Dolarway #2 % Loading	42%	70%
Dolarway #2 MVA	14.1	23.5
Dolarway #2 Bus Voltage	123.9	123.3
Feeder 1 Voltage Average	123.8	123.8
Feeder 2 Voltage Average	123.8	123.8
Feeder 3 Voltage Average	123.8	123.8
Feeder 4 Voltage Average	123.8	123.8
Feeder 5 Voltage Average	123.8	123.8
Feeder 6 Voltage Average	123.9	123.3
Feeder 7 Voltage Average	123.9	123.2
Feeder 8 Voltage Average	123.9	123.3
Feeder 9 Voltage Average	123.9	123.3
Feeder 10 Voltage Average	123.9	123.3
Feeder 7 MVA	3.2	12.4
Feeder 7 Getaway Loading	26%	102%
Feeder 8 MVA	0	0
Dolarway #1 LTC TAP	2	2
Dolarway #2 LTC TAP	3	7

TABLE 25: 2030, WINCO ON FEEDER 7, NON-EXCLUSIVE

In 2030 with Feeder 7 serving WinCo and other loads the Dolarway #1 and Dolarway #2 substations are within the planning criteria capacity and voltages. However, the 1000 MCM AL getaway for Feeder 7 will be loaded to 102%. It is recommended that if this configuration is used that Feeder 7 be upgraded to a double 1000 MCM AL circuit, or Feeder 7 will need to be built out to exclusively serve WinCo.

Below is the loading data for Dolarway Substations in 2044 after Dolarway #2 Feeder 7 is in service and serving WinCo and other loads:

2044, WINCO ON FEEDER 7, NON-EXCLUSIVE		
	Winco Out of Service	**Winco In Service**
Dolarway #1 % Loading	79%	79%
Dolarway #1 MVA	26.7	26.7
Dolarway #1 Bus Voltage	123.2	123.2
Dolarway #2 % Loading	55%	89%
Dolarway #2 MVA	18.3	30.0
Dolarway #2 Bus Voltage	123.8	123.7
Feeder 1 Voltage Average	123.1	123.1
Feeder 2 Voltage Average	123.2	123.2
Feeder 3 Voltage Average	123.2	123.2
Feeder 4 Voltage Average	123.1	123.1
Feeder 5 Voltage Average	123.2	123.2
Feeder 6 Voltage Average	123.8	123.6
Feeder 7 Voltage Average	123.7	123.5
Feeder 8 Voltage Average	123.8	123.7
Feeder 9 Voltage Average	123.8	123.7
Feeder 10 Voltage Average	123.8	123.7
Feeder 7 MVA	7.6	18.5
Feeder 7 Getaway Loading	62%	153%
Feeder 8 MVA	0	0
Dolarway #1 LTC TAP	3	3
Dolarway #2 LTC TAP	4	10

TABLE 26: 2044, WINCO ON FEEDER 7, NON-EXCLUSIVE

In 2044 with Feeder 7 serving WinCo and other loads the Dolarway #1 and Dolarway #2 substations are within the planning criteria voltages. However, the 1000 MCM AL getaway for Feeder 7 will be loaded to 153%. It is recommended that if this configuration is used that Feeder 7 be upgraded to a double 1000 MCM AL circuit, or Feeder 7 will need to be built out to exclusively serve WinCo. The Dolarway #2 Substation will be loaded to 83%, it is recommended to shift load off of this Substation to remain within the limits of the planning criteria.

In the event that Dolarway #1 Substation was taken out of service, and Feeder 7 served WinCo and other loads in 2030 the data would be as follows:

2030, WINCO ON FEEDER 7, NON-EXCLUSIVE, N-1		
	Winco Out of Service	**Winco In Service**
Dolarway #2 % Loading	113%	143%
Dolarway #2 MVA	37.9	48.2
Dolarway #2 Bus Voltage	123.4	124.1
Feeder 1 Voltage Average	123.3	124.1
Feeder 2 Voltage Average	123.4	124.1
Feeder 3 Voltage Average	123.4	124.1
Feeder 4 Voltage Average	123.4	124.1
Feeder 5 Voltage Average	123.4	124.1
Feeder 6 Voltage Average	123.4	124.1
Feeder 7 Voltage Average	123.4	124.0
Feeder 8 Voltage Average	123.4	124.1
Feeder 9 Voltage Average	123.4	124.1
Feeder 10 Voltage Average	123.4	124.1
Feeder 7 MVA	3.2	12.4
Feeder 7 Getaway Loading	26%	102%
Feeder 8 MVA	0	0
Dolarway #2 LTC TAP	6	13

TABLE 27: 2030, WINCO ON FEEDER 7, NON-EXCLUSIVE, N-1

Capacity for the Dolarway #2 Substation would be exceeded and Feeder 7's getaway will be still overloaded. In the event that Dolarway #1 Substation would be out of service at peak times in 2030, load would need to be shifted off of the Dolarway #2 Substation. Therefore, it is recommended that the WinCo load be shifted off of the Dolarway Substation #2 Substation. This can be accomplished by building a new single bank substation to serve WinCo, or by building the proposed South Ellensburg Substation early by 2030 and building out an additional spare feeder from it.

In the event that Dolarway #1 Substation was taken out of service, and the South Ellensburg Substation served WinCo in 2030 the data would be as follows:

2030, WINCO ON SOUTH ELLENSBURG, N-1	
Dolarway #2 % Loading	112%
Dolarway #2 MVA	37.9
Dolarway #2 Bus Voltage	123.4
Dolarway #2 LTC TAP	6
South Ellensburg % Loading	28%
South Ellensburg MVA	9.6

TABLE 28: 2030, WINCO ON SOUTH ELLENSBURG, N-1

Capacity for the Dolarway #2 Substation would be exceeded in an N-1 condition, however more load can be shifted off of this Substation to keep it below max loading during peak times. In an N-1 condition with one of the Dolarway Substations out of service it is highly recommended to shift the WinCo load to different substation.

In the event that Dolarway #1 Substation was taken out of service, and the South Ellensburg was built by 2030 and served WinCo in 2030 the data would be as follows:

2044, WINCO ON FEEDER 7, NON-EXCLUSIVE, N-1		
	Winco Out of Service	**Winco In Service**
Dolarway #2 % Loading	137%	176%
Dolarway #2 MVA	46.5	59.7
Dolarway #2 Bus Voltage	123.4	121.8
Feeder 1 Voltage Average	123.4	121.7
Feeder 2 Voltage Average	123.4	121.7
Feeder 3 Voltage Average	123.4	122.8
Feeder 4 Voltage Average	123.4	121.7
Feeder 5 Voltage Average	123.4	121.7
Feeder 6 Voltage Average	123.4	121.8
Feeder 7 Voltage Average	123.4	121.6
Feeder 8 Voltage Average	123.4	121.8
Feeder 9 Voltage Average	123.4	121.8
Feeder 10 Voltage Average	123.4	121.8
Feeder 7 MVA	7.5	18.3
Feeder 7 Getaway Loading	62%	153%
Feeder 8 MVA	0	0
Dolarway #2 LTC TAP	10	16

TABLE 29: 2044, WINCO ON FEEDER 7, NON-EXCLUSIVE, N-1

Capacity for the Dolarway #2 Substation will still be exceeded and Feeder 7's getaway will be still overloaded. In the event that Dolarway #1 Substation would be out of service at peak times in 2044, load would need to be shifted off of the Dolarway #2 Substation. Therefore, it is recommended that the WinCo load be shifted off of the Dolarway Substation #2 Substation. This can be accomplished by building a new single bank substation to serve WinCo, or by building out an additional spare feeder from the proposed South Ellensburg Substation.

In the event that Dolarway #1 Substation was taken out of service, and the South Ellensburg Substation had a feeder built out to serve WinCo:

2044, WINCO ON SOUTH ELLENSBURG, N-1	
Dolarway #2 % Loading	112%
Dolarway #2 MVA	37.9
Dolarway #2 Bus Voltage	123.7
Dolarway #2 LTC TAP	7
South Ellensburg % Loading	69%
South Ellensburg MVA	23.4

TABLE 30: 2044, WINCO ON SOUTH ELLENSBURG, N-1

Capacity for the Dolarway #2 Substation would be exceeded in an N-1 condition, however more load can be shifted off of this Substation to keep it below max loading during peak times. In an N-1

condition with one of the Dolarway Substations out of service it is highly recommended to shift the WinCo load to different substation.

Below is the loading data for Dolarway Substations in 2030 after Dolarway #2 Feeder 7 is in service and serving only WinCo:

2030, WINCO ON FEEDER 7, EXCLUSIVE		
	Winco Out of Service	**Winco In Service**
Dolarway #1 % Loading	68%	68%
Dolarway #1 MVA	23.1	23.1
Dolarway #1 Bus Voltage	123.8	123.8
Dolarway #2 % Loading	42%	70%
Dolarway #2 MVA	14.1	23.5
Dolarway #2 Bus Voltage	123.9	123.3
Feeder 1 Voltage Average	123.8	123.8
Feeder 2 Voltage Average	123.8	123.8
Feeder 3 Voltage Average	123.8	123.8
Feeder 4 Voltage Average	123.8	123.8
Feeder 5 Voltage Average	123.8	123.8
Feeder 6 Voltage Average	123.9	123.3
Feeder 7 Voltage Average	123.9	123.2
Feeder 8 Voltage Average	123.8	123.3
Feeder 9 Voltage Average	123.9	123.3
Feeder 10 Voltage Average	123.9	123.3
Feeder 7 MVA	0.1	9.3
Feeder 7 Getaway Loading	1%	76%
Feeder 8 MVA	3.3	3.3
Dolarway #1 LTC TAP	2	2
Dolarway #2 LTC TAP	3	7

TABLE 31: 2030, WINCO ON FEEDER 7, EXCLUSIVE

In 2030 with Feeder 7 serving only WinCo the Dolarway #1 and Dolarway #2 substations and Feeder getaways are within the planning criteria voltages and capacity loading.

Below is the loading data for Dolarway Substations in 2044 after Dolarway #2 Feeder 7 is in service and serving only WinCo:

2044, WINCO ON FEEDER 7, EXCLUSIVE		
	Winco Out of Service	**Winco In Service**
Dolarway #1 % Loading	79%	79%
Dolarway #1 MVA	26.7	26.7
Dolarway #1 Bus Voltage	123.2	123.2
Dolarway #2 % Loading	33%	65%
Dolarway #2 MVA	10.6	21.6
Dolarway #2 Bus Voltage	123.3	123.6
Feeder 1 Voltage Average	123.1	123.1
Feeder 2 Voltage Average	123.2	123.2

2044, WINCO ON FEEDER 7, EXCLUSIVE		
Feeder 3 Voltage Average	123.2	123.2
Feeder 4 Voltage Average	123.1	123.1
Feeder 5 Voltage Average	123.2	123.2
Feeder 6 Voltage Average	123.3	123.6
Feeder 7 Voltage Average	123.3	123.5
Feeder 8 Voltage Average	123.3	123.6
Feeder 9 Voltage Average	123.3	123.6
Feeder 10 Voltage Average	123.3	123.6
Feeder 7 MVA	0.1	11.1
Feeder 7 Getaway Loading	1%	92%
Feeder 8 MVA	0	0
Dolarway #1 LTC TAP	3	3
Dolarway #2 LTC TAP	1	6

TABLE 32: 2044, WINCO ON FEEDER 7, EXCLUSIVE

In 2044 with Feeder 7 serving only WinCo the Dolarway #1 and Dolarway #2 substations are within the planning criteria voltages and capacity loading. However, the 1000 MCM AL getaway for Feeder 7 will be loaded to 92%. It is recommended that if this configuration is used that Feeder 7 be upgraded to a double 1000 MCM AL circuit to serve WinCo.

In the event that Dolarway #1 Substation was taken out of service, and Feeder 7 served exclusively WinCo in 2030 the data would be as follows:

2030, WINCO ON FEEDER 7, EXCLUSIVE, N-1		
	Winco Out of Service	**Winco In Service**
Dolarway #2 % Loading	113%	143%
Dolarway #2 MVA	37.9	48.2
Dolarway #2 Bus Voltage	123.4	124.1
Feeder 1 Voltage Average	123.3	124.1
Feeder 2 Voltage Average	123.4	124.1
Feeder 3 Voltage Average	123.4	124.1
Feeder 4 Voltage Average	123.4	124.1
Feeder 5 Voltage Average	123.4	124.1
Feeder 6 Voltage Average	123.4	124.1
Feeder 7 Voltage Average	123.4	124.0
Feeder 8 Voltage Average	123.4	124.1
Feeder 9 Voltage Average	123.4	124.1
Feeder 10 Voltage Average	123.4	124.1
Feeder 7 MVA	0.1	9.3
Feeder 7 Getaway Loading	1%	77%
Feeder 8 MVA	3.3	3.3
Dolarway #2 LTC TAP	6	13

TABLE 33: 2030, WINCO ON FEEDER 7, EXCLUSIVE, N-1

In 2030 with the Dolarway #1 Substation out of service and Feeder 7 serving only WinCo the Dolarway #2 substation is loaded to 143% and is not within the planning criteria. It is recommended

that if this configuration is used that Feeder 7 be upgraded to a double 1000 MCM AL circuit to serve WinCo.

In the event that Dolarway #1 Substation was taken out of service, and Feeder 7 served exclusively WinCo in 2044 the data would be as follows:

2044, WINCO ON FEEDER 7, EXCLUSIVE, N-1		
	Winco Out of Service	**Winco In Service**
Dolarway #2 % Loading	112%	149%
Dolarway #2 MVA	37.9	50.4
Dolarway #2 Bus Voltage	123.7	123.4
Feeder 1 Voltage Average	123.7	123.4
Feeder 2 Voltage Average	123.7	123.4
Feeder 3 Voltage Average	123.7	123.4
Feeder 4 Voltage Average	123.7	123.4
Feeder 5 Voltage Average	123.7	123.4
Feeder 6 Voltage Average	123.7	123.4
Feeder 7 Voltage Average	123.7	123.3
Feeder 8 Voltage Average	123.7	123.4
Feeder 9 Voltage Average	123.7	123.4
Feeder 10 Voltage Average	123.7	123.4
Feeder 7 MVA	0.1	11.1
Feeder 7 Getaway Loading	1%	92%
Feeder 8 MVA	0	0
Dolarway #2 LTC TAP	7	14

TABLE 34: 2044, WINCO ON FEEDER 7, EXCLUSIVE, N-1

In 2044 with the Dolarway #1 Substation out of service and Feeder 7 serving only WinCo the Dolarway #2 substation is loaded to 149% and Feeder 7's getaway is loaded to 92%, both are not within the planning criteria. It is recommended that if this configuration is used that Feeder 7 be upgraded to a double 1000 MCM AL circuit to serve WinCo, load be shifted off of Dolarway#2 Substation, or a spare feeder be built out of the South Ellensburg substation to serve WinCo when the Dolarway #1 Substation is out of service.

Another recommendation would be a new substation to serve new and existing infrastructure loads in the southwest area of The City. This new substation could provide capacity and load shifting options to The City's current system.

Below is a cost estimate of the recommended improvements to serve WinCo:

WINCO RECOMMENDED IMPROVEMENTS A				
Substation - Feeder	**Description**	**Units(qty. or miles)**	**Unit Cost**	**Total**
Dolarway #2 – Feeder 7	1000 MCM AL Double Circuit	0.83	$900,000	$747,000
South Ellensburg – Feeder Spare	1000 MCM AL Double Circuit	1.8	$900,000	$1,620,000
WINCO RECOMMENDED IMPROVEMENTS B				
WinCo Substation	New Substation to serve WinCo	1	$5,000,000	$5,000,000
WinCo Substation	115 kV Transmission	0.20	$1,000,000	$200,000
WinCo Substation	1000 MCM AL Double Circuit	0.02	$900,000	$18,000

TABLE 35: WINCO RECOMMENDED IMPROVEMENTS

APPENDIX – E

Example Forms for Demand Response

Direct Participation Customer Notification Letter

Below is an example notification letter that The City can provide to it's customers for direct participation.

ELECTRIC RULE NO. 24/32
DIRECT PARTICIPATION DEMAND RESPONSE

CUSTOMER NOTIFICATION FORM LETTER

FOR NON-UTILITY DEMAND RESPONSE PROVIDERS SERVING
RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS

[***Date***]

Dear Customer,

[***DRP Name***] sends this letter by the order of the California Public Utilities Commission ("Commission" or "CPUC") to all residential and small commercial customers[1] who have expressed interest in enrolling in Demand Response ("DR") Services with a non-utility DR Provider (DRP). You have the right to choose to enroll in DR Service(s) with a non-utility DRP. This letter is only a summary and may not fully convey the terms and conditions of your contract.

SUMMARY OF YOUR DR SERVICE CONTRACT

Terms and Conditions

Incentive payment(s)	*Insert whether the payment is fixed, e.g., $/customer/yr. or mo. or $/kW/yr. or mo., and/or variable, e.g., energy payments, etc.*
Response to a DR Event	*Insert what is required of the customer; indicate whether the response is mandatory or voluntary; indicate the minimum duration of the event if applicable.*
Event Notification	*Insert the time in advance for customer to be notified about an event, e.g., real time, 5, or 30 min. etc.*
Event Criteria	*Insert the list of criteria for which an event will be triggered.*
Event Period	*Insert the season and monthly/weekly/daily hours that an event will be triggered.*
Number of Events	*Insert the limit or estimated number of events/month/week/day if applicable including 'unlimited.'*
Term(s) of DR Service	*Insert the start and end dates of the enrollment.*
Installed Equipment	*Insert what equipment is needed at the customer's site and the costs to the customer if any.*
Meter Data Access	*Insert what and how the DRP will access customer usage and other account data.*
Penalties for non-performance	*Insert if there are any penalties for non-performance and describe how the penalties will be calculated.*
Your right to cancel	*Insert the grace period in which the customer can cancel the enrollment without any charges or penalties.*

[1] D.12-11-025, Ordering Paragraph 17.

ELECTRIC RULE NO. 24/32
DIRECT PARTICIPATION DEMAND RESPONSE

Estimated Incentive Payments	*Provide the estimated incentive payments based on the customers' load and the terms and conditions on an annual basis or the total if the enrollment is less than a year.*
Additional Information	*Insert additional details describing the terms and conditions.*

[For customers enrolled in utility's event-based demand response program(s):]

We would like to inform you that upon the enrollment in our [*DR Service*] as of [*date*], utility will automatically disenroll your service account from [*Peak Day Pricing or Critical Peak Pricing*] and place it under an Otherwise Applicable Tariff (OAT). You should be aware that you may lose your bill protection under [*Peak Day Pricing or Critical Peak Pricing*]. Please contact [*Utility*] for more details on [*Peak Day Pricing or Critical Peak Pricing*] obligations and OAT provisions.

Attached please find additional customer information and a summary of CPUC rules on DR Services.

Sincerely yours,

[*DRP Signature block*]
/s/_____

ELECTRIC RULE NO. 24/32
DIRECT PARTICIPATION DEMAND RESPONSE

STATE OF CALIFORNIA Edmund G. Brown Jr., Governor

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE

SAN FRANCISCO, CA 94102-3298

ELECTRIC RULE NO. 24/32
DIRECT PARTICIPATION DEMAND RESPONSE

IMPORTANT CUSTOMER INFORMATION

The DR Provider's (DRP's) letter provides only a summary of the terms and conditions. If you want more detail about the costs, terms, and conditions of your DR Service, read the complete terms and conditions in your contract with the non-utility DRP or by calling your DRP representative. Please read the DRP letter and the following information carefully prior to the commencement of DR service.

SUMMARY OF CPUC RULES ON DR SERVICES

The California Public Utilities Commission ("CPUC" or "Commission") adopted a set of rules, called Electric Rule 24/32, applicable to all DRPs providing DR Services to utilities' Bundled Service customers, which can be found on your utility's website[2]. The following are some important highlights of Rule 24/32, and other applicable CPUC regulations:

DRP Registration

All non-utility DRPs must have a valid registration with the Commission and the California Independent System Operator (CAISO) prior to providing DR Service(s). Customers should confirm non-utility DRPs are properly registered and listed on the CPUC website, when considering the DR Services[3].

Enrollment with Multiple DRPs or Utility DR Programs

The CPUC prohibits customer account registration with multiple DRPs at the CAISO for the same period or in DR Service with a non-utility DRP while simultaneously participating in a utility demand response program. You need to notify your DRP to disenroll you from your current DR Service or program prior to enrolling with another DRP for the same period.

By enrolling in a DR Service with a non-utility DRP, you understand that you must disenroll from your utility's demand response program(s). Disenrollment from the DR Services or utility's

[2] PG&E's Rule 24: http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_24.pdf
SCE's Rule 24: https://www.sce.com/NR/sc3/tm2/pdf/Rule_24.pdf
SDG&E's Rule 32: http://www.sdge.com/tm2/pdf/ELEC_ELEC-RULES_ERULE32.pdf
[3] You may find registered non-utility DRPs on the CPUC website at: http://www.cpuc.ca.gov/General.aspx?id=6306

program(s) will be subject to any contractual or program obligations currently in effect with your current DR Service or your utility's demand response program(s)[4].

If you are currently in the [*Peak Day Pricing or Critical Peak Pricing*] program, you will be automatically disenrolled from the program upon the enrollment of DR Service and the DRP successfully registering your service account in the CAISO's system. Your utility will place your service account under a new applicable rate schedule, e.g., Time of Use rate. You may lose bill protection under the [*Peak Day Pricing or Critical Peak Pricing*] program, which may affect your utility bills.

Meter Data Access

All non-utility DRPs must obtain customer approval in order to access your electric usage data and other personal information regarding your service account. Consent is provided through your utility's Customer Information Service Request (CISR-DRP) form, or other electronic means, if available. You may obtain the CISR-DRP form from your utility or non-utility DRP. The CISR-DRP form also allows you to revoke, at any time, any previously granted authorization, subject to any early termination provisions specified in your contract.

The CISR-DRP form provides you with options to authorize your DRP to access your data, including for a specified period of time or indefinitely, until revoked by you. If you make no election, your utility will assume that your authorization is for an indefinite period of time (per CPUC Resolution E-4599). With your permission, your DRP may also act as your agent to *automatically* revoke data transmittal on your behalf upon disenrollment from DR Service.

When discontinuing DR Service with your DRP, it will be YOUR responsibility to REVOKE authorization to STOP the transmittal of your energy usage data and other previously authorized personal information from your utility to the DRP.

Customer Privacy

Once you authorize disclosure of your energy usage data and other personal information to a non-utility DRP, the non-utility DRP is required to maintain the privacy and security of that data, subject to the Commission's privacy policies, your utility is not. The Commission's privacy policies can be found in Decisions (D.) 12-08-045 and 11-07-056-or by contacting your DRP.

Complaint Procedures

You have the option to file a complaint or action at the appropriate business court or agency. You may also file a formal complaint, informal complaint, or seek alternative dispute resolution (ADR) at the Commission regarding your DR Services.

Informal Complaint:

Before filing a formal complaint, a consumer may wish to resolve the matter informally by contacting the CPUC's Consumer Affairs Branch (CAB). CAB can assist consumers in

[4] Please check with your utility or its website for a complete list of utility DR programs. http://www.cpuc.ca.gov/General.aspx?id=5926

resolving a matter with a DR Provider or a Utility by providing neutral evaluation of issues. CAB can also help consumers file an informal complaint.

Contact the Consumer Affairs Branch:
Before calling the Consumer Affairs Branch, review the information provided on "How To Prepare For Your Contact With CAB": http://consumers.cpuc.ca.gov/howtoprepare/

Call 800-649-7570 (toll free) or 415-703-4973
TDD for speech and hearing impaired call 800-229-6846 (statewide).
Public telephone hours are between 8:30 a.m. and 4:30 p.m.

Submit an informal complaint online at: http://consumers.cpuc.ca.gov/CAB

Mail an informal complaint to:
Consumer Affairs Branch
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Formal Complaint:

Through the Formal Complaint procedure, the Commission can order the DRP to take corrective action, including reimbursements for non-payment for performance. It is important to note, however, that the Commission is not allowed to award damages for such things as personal injury, property damage, emotional distress, or loss of wages or profits. To request compensation for damages, the customer must file a claim in a civil court.

Privacy Notice

Whether or not your Formal Complaint is filed in paper form or electronically, Formal Complaints filed with the Commission become a public record and may be posted on the CPUC's website. Therefore, any information you provide in the Formal Complaint, including, but not limited to, your name, address, city, state, zip code, telephone number, email address and the facts of your case may be available on-line for later public viewing.

A formal complaint must be filed at the Commission. **If you need help with or have any questions about filing your formal complaint, contact the CPUC's Public Advisor's Office.**

CPUC Public Advisor's Office
505 Van Ness Avenue
San Francisco, CA 94102
Call 866-849-8390 (toll free) or 415-703-2074
public.advisor@cpuc.ca.gov
http://consumers.cpuc.ca.gov/pao/

Instructions for filing a formal complaint:
http://consumers.cpuc.ca.gov/formalcomplaintinfo/

ELECTRIC RULE NO. 24/32
DIRECT PARTICIPATION DEMAND RESPONSE

Alternative Dispute Resolution Program (ADR)

ADR commonly describes processes, such as facilitation, negotiation, mediation, and early neutral evaluation to help disputants resolve a conflict without a formal decision by a court or agency. When successful, ADR may achieve results that a court or agency could not order, give the parties more ownership in the result, and reduce litigation and agency costs.

The Administrative Law Judge (ALJ) Division administers the ADR program and trained, experienced ALJs serve as neutrals in the program.

ADR can occur at any time during a formal proceeding. The early use of ADR saves parties time and money and avoids unnecessary escalation of a dispute. On occasion, ADR may be available to help resolve disputes that are still informal and have yet to be filed as formal complaints. Most ADR sessions are completed in ½ to 2 days. Some ADR sessions continue over several weeks, with the parties meeting for a day or two at a time.

For additional information visit: http://www.cpuc.ca.gov/alternative_dispute_resolution/

USEFUL WEBSITES & CONTACT INFORMATION

California Public Utilities Commission
Consumer Affairs Branch
505 Van Ness Avenue
San Francisco, CA 94102
Call 800-649-7570 (toll free) or 415-703-4973
www.cpuc.ca.gov

Energy Division - DRP Registration Desk
FAQ on Demand Response Providers: http://www.cpuc.ca.gov/General.aspx?id=6306
DRP_Registration@cpuc.ca.gov

[Delete utility information that doesn't apply below]

Pacific Gas and Electric Company (PG&E)
PG&E Electric Rule 24 Program: 415-973-6500, or Rule24Program@pge.com
PG&E Rule 24: http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_24.pdf

Southern California Edison Company (SCE)
SCE Customer Support: 800-655-4555, or SCE3rdPartyDRP@sce.com
SCE Rule 24: https://www.sce.com/NR/sc3/tm2/pdf/Rule_24.pdf

San Diego Gas & Electric Company (SDG&E)
SDG&E Energy Savings Center: 800-644-6133, or esc@semprautilities.com
SDG&E Rule 32: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-RULES_ERULE32.pdf

[*DRP*]

ELECTRIC RULE NO. 24/32
DIRECT PARTICIPATION DEMAND RESPONSE

[*Insert DRP contact information for customer service or representative*]

5

FIGURE 33: DIRECT PARTICIPATION CUSTOMER NOTIFICATION LETTER EXAMPLE

PSE Demand Response Terms and Conditions

Below is an example from Pudget Sound Energy of the terms and conditions that The City can provide to it's customers.

Puget Sound Energy – Flex Smart, Flex Rewards, Flex EV, Flex Batteries – Residential & Small Commercial Customer Terms and Conditions

Last Updated: November 5, 2024

Thank you for your interest in participating in Puget Sound Energy's Flex Smart, Flex EV, Flex Batteries and Flex Rewards program (individually "Flex Smart," "Flex EV," "Flex Batteries," and collectively, the "Program"). The Program is offered by Puget Sound Energy ("PSE"), and its subcontractors, AutoGrid, Inc, and Energy 350, Inc. (collectively, "Contractors"). These Terms of Use (these "Terms") are a legal agreement between the undersigned customer ("You" or "Participant"), PSE and its Contractors governing Your participation in the Program.

BY COMPLETING YOUR ENROLLMENT IN THE PROGRAM OR BY OTHERWISE PARTICIPATING IN THE PROGRAM, YOU AGREE TO BE BOUND BY THESE TERMS. IF YOU DO NOT AGREE TO THESE TERMS YOU MAY NOT PARTICIPATE IN THE PROGRAM.

You certify that all information provided for enrollment into the Program is accurate and complete.

1. **Program Eligibility:**

This program is available to select PSE customers only. In order to enroll for the Program, You agree to provide PSE information to verify Your eligibility for the Program.

"Eligibility" is defined as a PSE customer who heats and cools , charges their electric vehicle, and/or heats their water with PSE electricity as a primary fuel source. PSE reserves the right to update or change the requirements for Eligibility at its sole discretion. You agree that the information You provide to PSE in connection with the Program ("User Data") will be true, accurate, current and complete. Eligibility requirements are listed at Your Manufacturer's enrollment page, and made available by request from AutoGrid and Energy 350. You understand that the Program is available until termination and that Incentive amounts (as detailed below) are subject to change without notice.

- You must meet the following eligibility requirements to participate in the Program: You must be an electricity account holder of PSE on a residential or commercial rate 24 or 25 for the duration of the Program. Flex Batteries participants may only be on a residential rate.
- You must be at least eighteen (18) years old.
- Your utility service account must be metered by PSE's Advanced Metered Infrastructure AMI technology (a "Smart Meter") that provides 15-minute interval data. If Your electricity meter has been replaced with a digital meter, it is likely a Smart Meter.

- If You are enrolled in another third-party Demand Response ("DR") program, or any other similar PSE program, PSE will inform You and ask You to withdraw from the other program or withdraw Your registration from the Program.
- If You have a permanently-installed backup generator that uses diesel, natural gas, gasoline, or propane You must inform AutoGrid in writing of its make and model.
- PSE will ask You to share Your meter and in some cases EV data with AutoGrid which will be used as detailed in AutoGrid's privacy policy available

  here: https://www.auto-grid.com/privacy-policy/, and PSE's privacy policy here: https://www.pse.com/en/pages/privacy. In this case, PSE will provide You an online process for making that approval.
- You must comply with the Terms for the duration of the Program.
- Unless otherwise authorized as eligible to, customers who use natural gas or any other non-electric form of primary heating are not eligible to participate in Flex Smart.
- Customers participating in PSE's Time Varying Rates: Peak Time Rebates are not eligible.

PSE will make a final determination of Your eligibility to participate in the Program at its sole discretion. PSE reserves the right to update or change the requirements for Eligibility at its sole discretion.

2. Methods of Participation

You may use Your existing smart device ("Device"), which is connected to Your WiFi or purchase one in any marketplace, which is then installed and connected to Your WiFi, or participate without the use of a Device as described below. The following types of Device are currently supported in this Program:

- Smart thermostats
- Line voltage connected thermostats
- Electric vehicle chargers
- Electric vehicles
- Electric resistance or heat pump water heaters
- Battery energy storage systems

Please visit pse.com/flex for the most up-to-date list of brands that are currently

supported.

If You are participating in the Program without any Device, AutoGrid will contact You to manually reduce Your electricity usage by participating in a program known as Flex Rewards, a Behavioral Demand Response ("BDR") program.

3. **The Program.**

3.1. Program Term. The Program is available at PSE's discretion, and Your participation in the Program will continue without further notice to You until You terminate Your participation from the Program, as provided herein, or Your participation is terminated in accordance with Section 14 below. If the Program is terminated by PSE, Your participation in the Program will terminate without notice to You.

3.2. Changes. PSE reserves the right, in its sole discretion, to modify or to discontinue the Program at any time.

3.3. Devices. By participating in the Program, You hereby grant to PSE the right to remotely access and control one or more eligible thermostats, electric vehicle, electric vehicle charger, battery energy storage system or water heater (if applicable) at the address You are enrolling (each, Your "Device"). When You authorize a Device, You may be presented with additional terms from the Device manufacturer (the "Manufacturer"). These Terms are in addition to, and are not replaced by, those terms. By authorizing a Device, You understand and agree that You are enabling PSE to control that Device in connection with the Program. You further authorize PSE and its Contractors to obtain and share information about Devices used to participate in the Program with Manufacturers in order to facilitate Your participation in the Program and validate Your compliance with Program requirements. List of eligible Device types are detailed in Sections 3.7, 3.9, and 3.10 below.

3.4. Control. As part of this Program, PSE will call events to make changes to Your participating Device without any manual intervention by You. At any time that You desire, You may override this change simply by turning Your Device to a different temperature or using the other methods enabled by the Device Manufacturer. Flex Batteries participants' ability to opt out of an event depends on the battery manufacturer's ability to support an opt out. Overriding changes made to Your Device will not result in Your disqualification for Incentives offered to Program participants as described below. Continued overriding of Your Device, or consistent lack of participation in called events may result in Your termination of Your enrollment status of the Program, as further detailed in Section 14.

3.5. Communications. As part of this Program, You may receive important notifications including but not limited to topics such as Program changes, Your Program enrollment status, Incentive payments, and event notifications via email

or text messages (together, "Communications"). These are not marketing Communications, and only serve to provide important information specific to the Program. You may opt-out of these Communications at any time upon receipt. Opting-out of Program Communications may prevent You from receiving notifications about program changes, Your Program enrollment status, and incentive payments. In the scenario that You opt-out of Communications, You are agreeing to not receive such information, including Program updates, enrollment status, incentive information, and event notifications, and will not hold PSE responsible for providing updates in regard to the Program, Your enrollment status, Incentive payment updates, or event notifications. For the Flex Rewards Program specifically, where you must manually take action when an event is scheduled, receiving Communications, including notifications for Events is required and opting out of all Event notifications will lead to unenrollment in the Flex Rewards Program.

3.6. Communication with Your Device. When there is a potential for a stress on PSE's electricity grid, AutoGrid will communicate with Your Device in order to temporarily reduce the associated electricity use (hereby referred to as "Event" or "Flex Events"). After the Event is over, AutoGrid will return Your Device to its normal setting. Exact details, including Rewards and our schedule of notifications depend on Your Device, are detailed below.

3.6.1. Manual Reduction of Electricity Usage. If You are a Flex Rewards participant, not using any smart Devices, AutoGrid will contact You via email and/or SMS to manually reduce Your electricity usage. Example of ways to manually reduce Your electricity usage are listed here: www.pse.com/flextips. Exact details including Rewards and our schedule of notifications are detailed in the Program website, located at pse.com/Flex.

3.7. Flex Smart – Devices.

3.7.1. Using Smart Thermostats to Join this Program – A list of eligible smart thermostats that qualify as a Device can be found at the Program's PSE.com web page

3.7.2. Incentive – Upon successful enrollment in the Program with an eligible Device, You will receive a one-time enrollment incentive ("Enrollment Reward"). The current Enrollment Reward value for smart thermostats totals fifty dollars ($50) per Device, and twenty dollars ($20) per line-voltage connected thermostat. Please allow 4 to 6 weeks for processing Your Enrollment Reward. If You remain enrolled in the Program, You will be eligible for an additional Incentive (as defined below) on an annual basis, and the current value of such an additional Incentive totals twenty dollars per season of enrollment ($20) for smart thermostats, and ten dollars ($10) per line-voltage connected thermostat per season of enrollment. Customers enrolled in the program with a commercial rate schedule (24 & 25), will receive a check for their energy reduction performance 30 days after the

conclusion of each season. The amount will be calculated as $35/kW x average kW reduced across all events of the season. The amount and frequency of any Incentive under the Program may be subject to change with notice. See Sections 4, 6 and 7 below for more details. If Customer has opted-out from PSE communications they may not receive notifications related to Program updates and changes

3.7.3.Program Parameters – Your Device will be remotely accessed no more than 15 times between November 1 and March 31, and 15 times between May 1 and September 30, only on non-holiday days, between the hours of 6 AM and 10 PM. The duration of each Event is 4 hours or less. Your temperature setting may be adjusted 2 to 4 degrees Fahrenheit outside of normal settings unless You have selected different Device parameters or otherwise specified by You, and will return to normal after each Event

3.7.4.Notifications – You will be notified between 10 minutes to 60 minutes before the start of each Event except in cases of a grid emergency as declared by PSE. In some circumstances you may be notified of an Event up to 24 hours in advance of the Event. The notification will be via the Device's smart phone app and/or via the Device's display

3.7.5.Opting Out – You have the option to not participate in one or all of the Events

3.8. Flex Rewards

3.8.1.Participating without Devices - enrollees receive notifications when Events are scheduled and adjust behavior to earn incentives.

3.8.2.Notifications - Receiving notifications for Events is required and opting out of all Event notifications will lead to unenrollment. If You ask to unsubscribe from emails, the Program may opt to send You SMS notifications, or if You STOP SMS messages, the Program may send You email notifications. PSE may send emails in lieu of SMS notifications or SMS in lieu of emails when necessary. Notification frequency and timing varies by Event type and season. Participants will receive at least one notification within 24 hours ahead of an Event unless PSE declares a grid emergency.

3.8.3.Incentive - Upon successful enrollment in the program, You will receive a one-time Enrollment Reward, which is currently twenty-five dollars ($25). Allow 4-6 weeks for processing Your Enrollment Reward. You also earn $1 per kWh reduced during an Event and Your earnings will be tallied and payment frequency will be per season at minimum. The energy reduction for an Event is based on an industry standard calculation and may be updated or changed by PSE at any time without notice. You will be eligible for an additional incentive on an annual basis, and the current value is fifteen dollars ($15) per household. You must be actively enrolled during the month of payout.

3.8.4. *Program Parameters* - You will be notified no more than 15 times between November-1 and March-31, and no more than 15 times between May-1 and September-30, only on non-holiday days, between the hours of 6 AM and 10 PM. The duration of each Event is 4 hours or less.

3.9. Flex EV – Devices

3.9.1. *Using an electric vehicle enrolled in the Optiwatt app or electric vehicle charger to Join this Program* – A list of eligible electric vehicles and electric vehicle chargers that qualify as a Device can be found at the Program's web page https://www.pse.com/en/rebates/PSE-flex/flex-ev

3.9.2. *Incentive* - Upon successful enrollment in the program, You will receive a one-time Enrollment Reward, which is currently fifty ($50). Allow 4-6 weeks for processing Your Enrollment Reward. You also earn $0.50 per kWh reduced during an Event. Your earnings will be tallied and payment frequency will be per season at minimum. The energy reduction for an Event is based on an industry standard calculation and may be updated or changed by PSE at any time without notice.

3.9.3. *Program Parameters* - Your device will be remotely accessed no more than 15 times between November-1 and March-31, and 15 times between May-1 and September-30, Monday through Sunday, between the hours of 6 AM and 10 PM. The duration of each Event is 4 hours or less. In addition, AutoGrid will collect information such as charging status, charging rate, charging duration, total energy used, plug status (plugged in or not plugged in), and, specifically for EV's, location during each charging session each day during the Term. All such data is subject to AutoGrid's privacy policy, located here: https://www.auto-grid.com/privacy-policy/. You have the right to request removal of such data, including EV location data, if requested within 90 days of termination of program participation. If You do not request deletion of Your EV data, AutoGrid will remove the EV data from its systems within an applicable period of the contract expiration automatically.

3.9.4. *Opting Out* – You have the option to not participate in one or all of the Events and can opt out through your device specific app, disabling participation in the Event directly through your equipment, or, overriding the event for your Wallbox charger by unplugging it for 30 seconds and plugging it back in.

3.9.5. *Account Creation* – Note that when you enroll an electric vehicle (EV) via the AutoGrid FlexSaver portal, an account automatically will be created for you at Optiwatt, a subcontractor. Your name, email address, service address and PSE account number will be shared with Optiwatt, in order to manage your EV enrollment. Optiwatt may send you transactional emails from time to time, and marketing emails, from which you may opt-out. You may cancel your Optiwatt account within the Optiwatt app or via Optiwatt.com – this will disable your participation in the PSE Flex EV

program.

3.10.Flex Batteries – *Devices*

3.10.1.Using a battery energy storage system (BESS) to join this Program – A list of eligible equipment that qualify as a BESS Device can be found at the Program's PSE.com web page.

3.10.2.Incentives – per battery. The enrollment incentive is applicable only for the original purchase, installation, and enrollment of the Device, except when certain conditions in section 3.10.5 are met. Please allow 4 to 6 weeks for processing Your Enrollment Reward, which will be sent in the form of a check to the participant. If You remain enrolled in the Program and meet the performance requirements (section 3.10.4.), You will be eligible for an additional, annual Incentive of $500, which will come in the form of a digital reward (detailed in Section 4 Incentives") sent to the participant's email and sent in October of each qualifying year for active enrollments. The annual reward will not be prorated for partial participation or enrollment unless certain conditions in Section 3.10.5 are met. The amount and frequency of any Incentive under the Program may be subject to change with notice. See Sections 4, 6 and 7 below for more details. If Customer has opted-out from PSE communications they may not receive notifications related to Program updates and changes.

3.10.2.1.Participants who qualified for additional incentives during the interconnection application process are subject to the same terms and conditions herein. The final incentive payment for completing installation will be processed when the device is fully enrolled in the program and paid directly to the installer unless otherwise noted.

3.10.3.Program Parameters – Your Device will be remotely accessed no more than 30 times between November-1 and March-31 (the winter season), and 30 times between May-1 and September-30 (the summer season), Monday through Sunday, between the hours of 6 AM and 10 PM. The duration of each Event is 4 hours or less. Your Device will receive a signal to discharge for the scheduled event and discharge for the defined duration. Within 24 hours of a scheduled Event start, a command will be sent in preparation of the event to charge the battery as needed either from the grid or solar, if applicable.

3.10.4.Performance requirements – To qualify for participation in the program and be eligible to receive the program's enrollment and annual incentives, Your Device must have a minimum state of charge ("SoC" or "backup reserve" during an event) set at no greater than 20%. If the device is found to have a minimum SoC set greater than 20% the program will notify the Participant to reset SoC. If the minimum SoC setting is found to be higher than 20% consistently, Participant and Device may be removed from the program and

may result in a forfeiture of annual incentives. To qualify for the annual incentive, Participant must (1) remain in the program for at least two full years (24 months); and (2) must discharge at least 10 kWh each winter and summer season. Participants who enroll after the winter season in a given year will qualify for the annual incentive if they meet the 10 kWh requirement for the summer season.

3.10.5. Other requirements. Other requirements, include, but are not limited to:

3.10.5.1. Participant is responsible for maintaining the safe operation and functionality of the Device while participating in the program.

3.10.5.2. If the Device is consistently unavailable, participant and Device may be removed from the program and may result in a forfeiture of annual incentives.

3.10.5.3. Exceptional circumstances such as move-outs triggering account closures are exempt from the 24-month participation requirement.

3.10.5.4. If the Device changes ownership, re-enrollment in the program will only qualify the participant for the annual incentive.

3.10.5.5. If the Device is replaced, the participant may be eligible for a subsequent enrollment incentive only if the Device undergoes a complete replacement, pending incentive availability and eligibility defined at the time of the new interconnection application.

3.10.5.6. The program participant, Device owner, and PSE account holder must be the same. Device owners who are not also the enrolled PSE account holder are not eligible for the program (e.g., landlord whose tenants are PSE account holders). PSE account holders may enroll if prior agreement from Device owner is received. If found that enrollment of a device with an owner different from the PSE account holder is not meeting the terms of the program, enrollment may be terminated.

3.11. Opting Out – You have the option to not participate in Events. A Participant may opt out of events at their sole discretion as supported by the device manufacturer. See section 3.10.4 regarding Performance requirements for the annual incentive.

4. Incentives.

In connection with the Program, PSE may offer certain rebates, offers, or other incentives (together, including the Enrollment Reward, "Incentives") contingent on Your enrollment and continued participation in the Program. PSE reserves the right to determine qualifications for Incentives in its sole discretion. All enrollment Incentive payments will be made in the form of a customer-selected gift card except for Flex

Batteries. Flex Batteries participants will receive a check for enrolling. Subsequent Flex Batteries annual incentives will be issued as a check or customer-selected gift card. The amount, timing, and frequency of payment depends on the participating Device as detailed in Section 3 above. Please allow 4 to 6 weeks for processing Your registration and payment. PSE reserves the right to alter or change the form of Incentive payments and/or method of payment delivery. Third-party incentive processor willreceive your name, email, mailing address and PSE account number in order to process your incentives.

5. Eligibility for Incentives.

If You suspend or terminate your participation in the Program for any reason during the Term, including by disconnecting Your Devices, You will be ineligible to receive any accrued or subsequent Incentives.

PSE reserves the right to make changes to Incentives from time to time. In such cases, You will be notified via email at the address on file with PSE and will have the option to terminate Your participation.

6. **Additional Incentives.**

6.1. Referral – PSE currently offers ten dollars ($10) for each enrollee referred to the program by You. To track referrals, You must use the unique referral link from Your own FlexSaver account.

6.2. Giveaway – PSE may offer a monthly giveaway, called Flex and Win! ("Giveaway"), on a monthly, seasonal basis while promotion is available during the Program, starting November 2023 and ending December 31, 2029, for active residential PSE customers. Winners may be drawn monthly for summer season months: May 1 through September 30; and winter season months: November 1 through March 31 ("Giveaway Monthly Periods"). In total, there will be 10 monthly drawings in a calendar year. In 2023, the first drawing will be for August 2023.

6.2.1. Automatic Entry – Each eligible participant in the Program will be automatically entered in each monthly giveaway to win a $250 electronic gift card as long as they are a participant in the Program in good standing during that entire Giveaway Monthly Period. Two (2) winners each month for each Giveaway Monthly Period will be selected from all eligible entries. Odds of winning are subject to number of entries (by way of example, if 1,000 entries are received by calendar month end, then the odds will be 1:1,000). A maximum of two (2) prizes will be awarded per monthly period.

NO PURCHASE OR PAYMENT NECESSARY. VOID WHERE PROHIBITED. PSE customers who do not formally enroll in Flex Smart or Flex Rewards Program may still enter in the monthly giveaway by sending a handwritten postcard or letter to AutoGrid's office with the following information:

- Name
- PSE account address
- Email address
- State: "I intend to enter the monthly giveaway for PSE's Flex Smart Program."

Mail to 255 Shoreline Dr #350, Redwood City, CA 94065. Cost of postcard and postage is customer's responsibility. Only one mail-in entry per individual entrant for each Giveaway Monthly Period. Only mail-in entries received during the Giveaway Monthly Period will be eligible for the drawing for that Giveaway Monthly Period. A separate mail-in entry is required to be eligible for each Giveaway Monthly Period throughout the Giveaway. The Program will not accept bulk-mailed, commercial mailing, mass mailing postcards or letters or any mail-in entries that are late or incomplete. If you are entered automatically as a participant in the Program you cannot enter the Giveaway through a mail-in entry.

The Giveaway is limited to residents of Washington State. By automatically entering into the Giveaway either through participation in the Program or submitting a mail entry, the PSE customer consents to be contacted by email at the address provided.

Giveaway winners will be randomly selected for each Giveaway Monthly Period and notified by email. The $250 electronic gift card then will be processed and sent within a month of notification. If a winner does not confirm acceptance of the prize within ten calendar (10) days of email notification, that winner will be disqualified and an alternative winner selected. If the alternative winner does not respond within ten calendar (10) days of email notification, then there is no monthly winner for that month. Winners are responsible for all taxes incurred in connection with the prize awarded. PSE reserves the right to modify, cancel or terminate this Giveaway at any time.

There are no substitutions or cash redemptions for any prices, except in the Program's sole discretion. Prizes are not transferable and lost or misplaced prizes will not be replaced. Prizes are subject to any terms and conditions on the electronic gift card.

Directors, officers, contractors and employees of PSE and Contractors and any of their respective parent companies, affiliate companies, subsidiaries, agents, professional advisors, advertising and promotional agencies, and immediate families of each are not eligible to win any prizes.

8. Your Information.

You authorize PSE to share information about Your account including, but not limited to,

10

Your name, street address, account number, electrical usage, Device and billing information with their approved Contractors hired to implement and measure the performance of the Program. Customer data will be kept confidential by the Contractors and will not be used for any purpose other than implementation of the Program. By submitting User Data and any other data, materials, or information in connection with the Program, You are licensing such information to PSE and its Contractors for the purpose of providing the Program. In addition, You hereby authorize PSE and its Contractors to access Your information maintained by PSE and/or the Device Manufacturer solely in order for PSE and its Contractors to provide the Program and confirm Your eligibility. For example, You authorize PSE and its Contractors to obtain and share information about Devices used to participate in the Program with Device Manufacturers in order to facilitate Your participation in the Program and validate Your compliance with Program requirements. You understand and agree that by authorizing PSE to control Your Device in connection with the Program, PSE may receive access to data from Your Device directly, including data collected from its sensors. For the avoidance of doubt, notwithstanding anything to the contrary in these Terms, PSE retains its right to access and utilize Your Customer Data to provide You with utility service and manage its electrical system, independently from this Program.

9. Personal Non-Commercial Use.

The Program is offered for Your own personal, non- commercial use. Any commercial utilization of the Program is expressly prohibited unless otherwise authorized by PSE. In the instance of PSE authorizing commercial use of the Program, the full Program Terms are applicable.

10. Costs.

PSE is not responsible for costs associated with providing the systems necessary for You to participate in the Program, such as Devices or internet access. You are responsible for all taxes incurred with the issuance of any Incentives under the Program. AutoGrid will report incentives greater than $600 received in a calendar year as income on IRS Form 1099 unless “Corporation” or “Exempt” tax status is marked on Your W-9. AutoGrid will collect as part of the enrollment process for certain Program(s) or if AutoGrid anticipates succeeding payments to You will total or exceed $600. AutoGrid can and will withhold any payments until such a W-9, if requested by AutoGrid for certain Program(s), is completed and received.

11. No Warranty; Disclaimer.

YOUR PARTICIPATION IN THE PROGRAM IS AT YOUR SOLE DISCRETION AND RISK. THE PROGRAM IS OFFERED “AS IS” AND “AS AVAILABLE” WITHOUT WARRANTIES OF ANY KIND. PSE EXPRESSLY DISCLAIMS ALL WARRANTIES OF ANY KIND RELATING TO THE PROGRAM, WHETHER EXPRESS, IMPLIED OR STATUTORY (INCLUDING, WITHOUT LIMITATION, ANY IMPLIED WARRANTIES FOR CONDITIONS OF MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE, TITLE, NON- INFRINGEMENT OR NON-MISAPPROPRIATION OR

INTELLECTUAL PROPERTY RIGHTS OF A THIRD PARTY) AND ANY WARRANTIES OR CONDITIONS ARISING UNDER ANY OTHER LEGAL REQUIREMENT. PSE MAKES NO WARRANTIES THAT THE OPERATION OF THE PROGRAM WILL BE UNINTERRUPTED OR ERROR-FREE. PSE MAKES NO GUARANTEE OF AN UNINTERRUPTED SUPPLY OF POWER.

12. Indemnification.

To the fullest extent permitted by applicable law, You agree to indemnify, and hold PSE, its officers, directors, employees, and agents (each, an "Indemnified Party"), harmless from and against any claims, liabilities, damages, losses, and expenses, including without limitation reasonable attorney's fees and costs, arising out of or in any way connected with Your participation in the Program. You have no obligation to indemnify an Indemnified Party to the extent of the sole negligence, or willful misconduct of such Indemnified Party.

13. Limitation of Liability.

13.1. Limitation of Liability. YOU AGREE THAT, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, UNDER NO CIRCUMSTANCES SHALL PSE, ITS CONTRACTORS OR THE DEVICE MANUFACTURERS BE LIABLE TO YOU FOR ANY INDIRECT, INCIDENTAL, SPECIAL OR CONSEQUENTIAL DAMAGES, ARISING OUT OF YOUR PARTICIPATION IN THE PROGRAM, EVEN IF PSE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES. IF YOU ARE DISSATISFIED WITH THE PROGRAM OR WITH ANY OF THESE TERMS, OR FEEL PSE HAS BREACHED THESE TERMS, YOUR SOLE AND EXCLUSIVE REMEDY IS TO DISCONTINUE PARTICIPATION IN THE PROGRAM.

13.2. Exclusions. NOTHING IN THESE TERMS AND IN PARTICULAR WITHIN THIS "LIMITATION OF LIABILITY" CLAUSE SHALL ATTEMPT TO EXCLUDE LIABILITY THAT CANNOT BE EXCLUDED UNDER APPLICABLE LAW, INCLUDING LIABILITY FOR A PARTY'S FRAUD, WILLFUL INJURY TO THE PERSON OR PROPERTY OF ANOTHER, OR VIOLATION OF LAW, WHETHER WILFUL OR NEGLIGENT.

14. Termination.

14.1. Termination By PSE. PSE may terminate the Program, or Your participation in the Program, at any time, with or without cause, by providing You with written notice of such termination, which will be via the email You have on record for this Program.

14.2. Termination by You. You may terminate Your participation in the Program at any time and for any reason by unenrolling in the Program via Your Device's unenrollment process, sending an email to Flex@pse.com, or calling AutoGrid at 888-292-0502. To terminate your water heater's participation in the Program, contact Energy 350 at 833- 203-1947.

14.3. Rights at Termination. Upon termination, all rights granted to You by these Terms will immediately cease.

14.4. Survival. Any suspension, termination or cancellation of the Program will not affect Your obligations under these Terms which are intended to survive such suspension, termination or cancellation.

15. General.

15.1. Applicable Law and Dispute Resolution. These Terms shall be governed by the laws of the State of Washington, without giving effect to any conflict of laws or principles that may require the application of the law of another jurisdiction

15.2. Consent and Capacity. You represent that You are over 18 years of age and have the necessary legal capacity to execute this agreement and that You are an authorized representative with authority to legally bind the account holder designated below. You represent that You have received the necessary consents and approvals from the owner(s) or occupant(s) of any premises that is participating in the Program. You are solely responsible for any failure to receive necessary consents and approvals for the installation of qualifying equipment, including Devices, within Your premise or qualifying property and participation in the Program. Your participation is completely voluntary, and You can decide to withdraw at any point in the Program.

15.3. Entire Agreement. These Terms are the entire and exclusive agreement between PSE, Contractor, and You regarding the Program, and supersede and replace any prior agreements regarding the same. This is not a contract for utility service. Utility service provided to You by PSE remains subject to all PSE terms, conditions, rates, regulations, municipal codes, and policies.

15.4. No Assignment. You will not assign these Terms or assign any rights or delegate any obligations hereunder, in whole or in part, whether voluntarily or by operation of law, without the prior written consent of PSE. Any purported assignment or delegation by You without the appropriate prior written consent of PSE will be null and void.

15.5. Severability and Waiver. In the event that any provision in these Terms is held to be invalid or unenforceable, the remaining provisions will remain in full force and effect. The failure of PSE to enforce any right or provision of these Terms will not be deemed a waiver of such right or provision.

15.6. Questions. If You have questions about these Terms or the Program, please contact the Program team at Flex@pse.com. We will communicate with You regarding this Program at the email address provided in the enrollment form.

15.7. Communications. By participating in this Program, You agree to receive Communications regarding the Program from PSE or its Contractors at the email

address and phone number provided for this Program. These Communications may be sent by PSE or its Contractors. You understand that You may opt out of these Communications at any time.

15.8. Consent. You agree to allow AutoGrid to coordinate with You and, as applicable, the manufacturers of your Device(s), to access personally identifiable information to remotely control Your Device(s) from the date You join the Program until the Program ends or PSE terminates Your enrollment. You agree to keep your Device(s) operational and connected to the wireless network of Your premise during the Term at Your sole cost and expense.

ChargePoint is a trademark of ChargePoint Inc.

Wallbox is a trademark of Wallbox USA Inc.

EvoCharge is a trademark of EvoCharge Inc.

Juicebox is a trademark of Enel X Way USA LLC.

SolarEdge is a trademark of SolarEdge Technologies Inc.

Google Nest is a trademark of Google LLC

Neviweb® is a registered trademark of Sinopé Technologies Inc ecobee is a registered trademark of ecobee Inc. Ltd

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14

FIGURE 34: PSE DEMAND RESPONSE TERMS AND CONDITIONS

DRP Performance Bond Letter

Below is an example Performance Bond Letter that The City can provide to it's customers if a third party were to manage the DRP program.

ELECTRIC RULE NO. 24/32
DIRECT PARTICIPATION DEMAND RESPONSE

STATE OF CALIFORNIA — Edmund G. Brown Jr., Governor

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE

SAN FRANCISCO, CA 94102-3298

Demand Response Provider Performance Bond Letter Sample

FOR NON-UTILITY DEMAND RESPONSE PROVIDERS SERVING
RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS

This language is provided to assist Demand Response Providers and bond issuers. Other forms may be acceptable provided they include the substantive language from this sample, subject to Energy Division staff approval.

All bonds must meet the following three criteria at a minimum:

1. The bond must be issued in a sufficiently high dollar amount to reimburse ratepayers for any amount of losses ratepayers may incur due to the Demand Response Provider's (DRP) negligence or misconduct.
2. The bond must guarantee the DRP's performance and provide that if there is a failure to perform the California Public Utilities Commission may receive reimbursement for the dollar value of that failure.
3. The bond must require payment to the State of California and the California Public Utilities Commission any amounts payable in the bond upon any default by the DRP.

Sample Language:

KNOW ALL BY THESE PRESENTS that we [INSERT NAME OF DRP], as Principal, and [INSERT NAME OF SURETY], a corporation organized and existing under the laws of the State of _____ and authorized to transact business in the State of California, as surety, are held and firmly bound unto the California Public Utilities Commission, as Obligee, in the penal sum of $_____ [INSERT AMOUNT AS SET IN RULE 24/32, SECTION E.1.D], good and lawful money of the United States of America, for the payment of which well and truly to be made we bind ourselves, our heirs, administrators, executors, successors and assigns, jointly and severally, firmly by these presents.

Updated 9.19.16

ELECTRIC RULE NO. 24/32
DIRECT PARTICIPATION DEMAND RESPONSE

WHEREAS the Principal has made application to the Obligee for Registration as a Demand Response Provider under the provisions of the California Public Utilities Code, applicable California Public Utilities Commission decisions and the Pacific Gas and Electric Company's (PG&E's) and Southern California Edison Company's (SCE's) Electric Rule No. 24, and San Diego Gas and Electric Company's Electric Rule No. 32, Direct Participation Demand Response Rules ; and

WHEREAS the principal is required to post a performance bond in accordance with the provisions of the California Public Utilities Code and applicable California Public Utilities Commission decisions, including without limitation Decisions 13-05-012 and 12-11-025, for claims/damages resulting from the principal's nonperformance, fraud, or other violations of the laws, decisions and orders applicable to Demand Response Providers.

NOW, THEREFORE, if the Principal shall faithfully conform to, abide by, and/or perform all obligations under any applicable laws, decisions, and orders administered or issued by said Obligee, or any other applicable laws, decisions, and orders, including, without limitation, paying to the Obligee, or to any other person(s) or entity(s) as required by law, all monies due, or which shall become due, pursuant to such laws, decisions, and orders referenced herein, and receiving only funds to which Principal is legally due under Obligee's Direct Participation Demand Response Rules (Electric Rules 24/32), then the above obligation shall be void, otherwise to be and remain in full force and effect. If Principal shall fail in any of the foregoing ways, the above obligation shall be due and payable to Obligee up to the full amount of the bond.

The bond issuer reserves the right to cancel this bond by giving ninety (90) days written notice to the Obligee, and on the effective date of such ninety-day cancellation notice, the bond issuer is discharged and relieved of any liability, except the bond issuer shall remain liable for amounts not paid to customers by the DRP where the DRP's obligation to pay arises out of an involuntary cancellation of the DRP's customers from the DRP's contracts and where the involuntary cancelation occurs, or was noticed to the utility, before the termination of the bond. It is understood and agreed that the bond issuer will in no event be liable for an amount in excess of the stated coverage amount of this bond. Any termination notice must be sent to California Public Utilities Commission - 505 Van Ness Avenue, San Francisco, CA 94102, Attention: Energy Division - - Demand Response Provider Registration, by certified/return receipt mail.

Updated 9.19.16

FIGURE 35: DRP PERFORMANCE BOND LETTER

DRP Registration Form

Below is an example Registration Form that The City can provide to it's customers if a third party were to manage the DRP program.

DEMAND RESPONSE SERVICE PROVIDER REGISTRATION APPLICATION FORM

Pursuant to Electric Rule 24/32, this form must be completed by all Demand Response Providers (DRPs) utilizing bundled service customers in a California System Operator (CAISO) Demand Response Service. DRPs serving Residential customers and/or Small commercial customers with peak demand less than 20 kW ("Small Customers") must complete this entire form and post bond in accordance with the instructions found in this form.

DRP No. _____

(Filled by CPUC)

*****PLEASE PRINT OR TYPE*****

1. **Exact Legal Name of Registrant:**

_____

If registrant is conducting business in California under a fictitious business name, list all the names under which the registrant is doing business as (DBA) in California, and the date and county in which the fictitious business name statement was filed (Attach additional page if necessary). For each DBA, provide a copy of the proof of publication of the fictitious business name, or a copy of the certified fictitious business name statement. (See Business & Professions Code Sections 17910, 17917, 17926)

_____	_____	_____
DBA	Date	County
_____	_____	_____
DBA	Date	County
_____	_____	_____
DBA	Date	County

2. **Current Address:**

_____
Address

_____
City State Zip Code

3. **Current Telephone Number:** _____

4. **Type of Ownership:**

❒ Individual ❒ Partnership ❒ Corporation ❒ Limited Liability Company

❒ Government Entity ❒ Other

Complete and mail this application along with $100.00 certified check to:
State of California
Public Utilities Commission
Energy Division - DRP Registration
505 Van Ness Avenue
San Francisco, CA 94102

INCOMPLETE APPLICATIONS CANNOT BE PROCESSED

FOR CPUC USE ONLY

Application Processed

By: _____

Date: _____

Rev. 1/5/2016

5. **If a non-California corporation, limited liability company, or limited partnership, attach a copy of the certificate from the California Secretary of State permitting the entity to transact business in California. (See Corporations Code Sections 2105, 15692, 17451)**

6. **a. If registrant is a corporation, the state in which the registrant is incorporated and**

Date of Incorporation:_____ State of Incorporation: _____
(Date) (State)

b. List names and titles of corporate officers. (Attach additional page if necessary)

_____

_____

_____

_____

7. **If registrant has listed type of ownership as "government entity" provide a brief description of the government entity, and list the names and titles of the personnel responsible for providing DRP DR Services to residential and small commercial customers. (Attach additional page if necessary)**

_____

_____

_____

_____

8. **The street address and telephone number of the registrant's principal place of business, if *DIFFERENT* from current address and telephone number listed in line numbers 2 and 3:**

_____
Street Address

_____
City **State** **Zip Code**

_____
Telephone Number

9. Estimated number of Residential and Small Commercial Customers that you plan to provide DRP DR services to, if any.

10. **Before you can apply to register as a demand response provider (DRP), you are required to execute a service agreement with each utility distribution company (UDC) in whose service territory you plan to do business. State the name of each Utility for which you have a signed a DRP Service Agreement. Attach to this form an executed copy of each DRP Service Agreement.**

Name of Utility(ies):

_____

_____

11. The name, title, address and telephone number of the person to whom correspondence or communication regarding customer complaints or inquiries are to be addressed.

_____
Name **Title**

_____
Address

_____
City **State** **Zip Code**

_____ _____ _____
Telephone Number **FAX Number (If available)** **E-Mail Address (If available)**

12. Name and Address of Agent for Service of Process:
(Must Be Located In California - See Corporations Code Sections 1505, 15800, 17057, 17060)

Name:_____

Street Address:_____

City and State:_____ **Zip Code:**_____

13. Disclosures

a. Has the registrant, or any of the general partners, or corporate officers or directors, or limited liability company members, managers, and officers, ever been convicted of any felony?

❒ **No** ❒ **Yes** **If yes, please explain on additional page.**

b. Within the last ten years, have any of these persons had any civil, criminal, or regulatory sanctions imposed against them pursuant to any state or federal consumer protection law or regulation?

❒ **No** ❒ **Yes** **If yes, please explain on additional page.**

NOTICE

Each DRP registered with the California Public Utilities Commission (CPUC) should be familiar with all the laws and decisions pertaining to the offering of demand response services to customers in California. This notice mentions some of the provisions that the DRP must abide by.

For DRPs (which, pursuant to Rule 24/32 include "an entity that is responsible for performing any or all the functions associated with either a CAISO-DRP and/or an Aggregator") providing DRP DR Services to Small Customers, to be issued a DRP Registration number, they are required to provide the CPUC with a performance bond in favor of the CPUC in the minimum amount specified by the CPUC's DRP Bond Formula contained in Pacific Gas and Electric Company's and Southern California Edison Company's Electric Rule 24 and San Diego Gas and Electric Company's Electric Rule 32, respectively. The performance bond must be received by the CPUC before the DRP registration will be considered complete. The performance bond shall be delivered to the Energy Division address listed on the first page of this form. This deposit requirement is subject to change. If a bond is to be or has been posted by a partnering DRP for this same group of customers, you attest that bond remittance by the partnering DRP is accommodated through a commercial agreement between the two DRPs. Such accommodation should consist of evidence satisfactory to the Energy Division that the bond protects customers served by both DRPs. This requirement may be satisfied if 1) bond is issued in the name of both DRPs, 2) each DRP

has its own bond, or 3) by other arrangement that makes clear that action of either DRP will cause payment on the bond. The following information must also be provided.

Name of Partnering DRP_____
Number of Small Customers _____
If you are posting bond on behalf of partnering DRP for this same group of customers, the following information must also be provided.

Name of Partnering DRP _____
Number of Small Customers covered by Bond _____

Prior to registering the customer in CAISO, a DRP providing DRP DR Services to any Small Customer is required to provide the potential customer with a written notice that describes the price, terms, and conditions of service. The notice shall include all of the elements set forth in the CPUC's direct participation consumer protection decisions, D.12-11-025 and D.13-12-029.

Any material change in the information required by this form shall be provided to the CPUC within 60 days, except for any change in the DRP's telephone number or address, which shall be reported within five days of such a change.

Mail the original signed form and a hard copy together with all required documents ($100 certified check, DRP Service Agreement with utility(ies), performance bond (if applicable) and Customer Notification Form Letter (if applicable) to the Energy Division address listed on the first page of this form and send an electronic copy of the package to drp_registration@cpuc.ca.gov.

DECLARATION

If this registration form is verified outside of California, the verification must be made by an affidavit sworn or affirmed before a notary public.)

I, (print name and title) _____ hereby certify that I am empowered to act on behalf of _____ (registrant's name) and to make this application on its behalf. I declare under the penalty of perjury under the laws of the State of California that I have read the above notice, that the above statements and information submitted in connection with this application are true and correct, and that any documents furnished in connection with this application are true and correct copies.

Dated this _____, at _____
(Date) (Place of Execution)

Signature:_____

Page 4 of 4
Rev. 1/5/2016

FIGURE 36: DRP REGISTRATION FORM

Third Party DRP Form

Below is an example DRP Form that The City can provide to it's customers if a third party were to manage the DRP program.

San Diego Gas & Electric Company
San Diego, California

Revised Cal. P.U.C. Sheet No. 61663-E
Canceling Revised Cal. P.U.C. Sheet No. 30366-E

Sheet 1

SAMPLE FORMS

FORM 144-0820

Customer Information Service Request for Demand Response Providers (CISR-DRP)

1/2024 T

(See Attached)

1C9
Advice Ltr. No. 4370-E
Decision No. D.23-09-006

Issued by
Dan Skopec
Senior Vice President
Regulatory Affairs

Submitted Jan 26, 2024
Effective Jan 26, 2024
Resolution No.

SDGE™

CUSTOMER INFORMATION SERVICE REQUEST FOR DEMAND RESPONSE PROVIDERS (CISR-DRP)

IMPORTANT INFORMATION FOR CUSTOMERS
THIS IS A LEGALLY BINDING CONTRACT - READ IT CAREFULLY

San Diego Gas & Electric Company's (SDG&E's) Electric Rule 33 and its corresponding privacy policies, which can be found at http://www.sdge.com/customer-privacy, limit the disclosure of your personal information, such as your name, address, phone number, or electric account and billing information, to third parties unless you expressly authorize us to do so. This form facilitates the disclosure of your personal energy-related data to non-utility Demand Response Providers (DRPs) so that you may obtain Demand Response services offered by such DRPs in accordance with SDG&E's Electric Rule 32, which can be accessed at http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-RULES_ERULE32.pdf. This form may be used to authorize the release of Bundled, Community Choice Aggregation (CCA), and Direct Access (DA) customer information. In some cases, two DRPs may collaborate to provide customers with Rule 32 Demand Response services. Accordingly, this form allows for disclosure of your information to both a Primary DRP and an optional Secondary DRP. Once you authorize the DRPs to access your personal energy-related data, you are responsible for ensuring that the DRPs safeguard this information from further disclosure without your consent. This authorization is separate from any other agreements between you and any DRP for Demand Response services. This form also permits your Primary and Secondary DRP the ability to request SDG&E make limited changes to the SDG&E electric meter(s) serving the service account(s) being enrolled in Demand Response services, as specified in Section C below.

I, (Customer),

Customer Name According To SDG&E Records					
Contact Name *(if different from above)*	First		Last		
E-Mail			Phone		

(Either an e-mail address or phone number is required.)

do hereby (*check only one*): ☐ AUTHORIZE (*sign Section D*) ☐ REVOKE (*sign Section H*)

access to my personal energy-related data for the following DRP(s):

Name of Primary DRP		SDG&E Rule 32 ID	
E-Mail		Phone	

(Complete the following table only if you are authorizing data to be released to a Secondary DRP)

Name of Secondary DRP		SDG&E Rule 32 ID	
E-Mail		Phone	

Concerning the following service accounts:

SERVICE ADDRESS (NUMBER AND STREET)	SERVICE CITY	SERVICE ACCOUNT #

(You can include additional service agreements by attaching a list to this form.)

SDGE™

CUSTOMER INFORMATION SERVICE REQUEST FOR DRP (CISR-DRP)

FOR AUTHORIZATION USE ONLY

A. TIMEFRAME OF AUTHORIZATION (check only one option)

☐ Begin today and continue until_____(mm/dd/yyyy) or until revoked by customer or DRP.

☐ Begin today and continue indefinitely or until revoked by Customer or DRP.

B. SUMMARY OF INFORMATION AUTHORIZED TO BE RELEASED

I, (Customer), authorize SDG&E to disclose to the above DRP(s) for the service accounts listed above and/or attached to this form:) customer information (e.g., service account number, service address, rate schedule), 2) up to 36 months of historical and ongoing electric and gas meter data and/or monthly usage data, 3) current SDG&E demand response programs in which I am known to participate, 4) historical energy efficiency program(s) in which I qualified and was paid, 5) the last 12 months of electric ans gas rates for the current meter and notification of rate change, and 6) the information identified in Section D of Electric Rule 32.

C. CHANGES YOU AUTHORIZE THE DRP TO MAKE ON YOUR BEHALF

I, (Customer), grant the above-referenced DRP(s) permission to request that SDG&E shorten the interval length of my electric meter(s), if available, for the service accounts listed above and/or attached to this form, when the DRP has successfully registered such service accounts with the CAISO's Relevant Systems, if SDG&E is the Meter Service Provider.

I, (Customer), also grant the above-referenced DRP(s) permission to revoke this authorization on my behalf. I understand that a revocation submitted by any party to this authorization shall revoke this authorization for all parties.

D. CUSTOMER AGREEMENT

I, (Customer), authorize the actions and changes to be made (or undertaken) by SDG&E as specified in this authorization. I understand that my information may be transmitted to the DRP(s) even after the authorization has ended to update to the data for the period during which this authorization was valid. In all cases, this authorization will be automatically revoked for a service account when such service account is closed. I understand SDG&E reserves the right to verify any authorization request submitted before releasing information or taking any action on my behalf.

I, (Customer), understand and agree that if any of my service accounts listed herein are on Critical Peak Pricing (CPP), those service accounts will be scheduled to be unenrolled from CPP when those service account(s) are successfully registered in the CAISO's Relevant Systems by one of the above DRPs. I agree to bear any resulting financial consequences, including without limitation, loss of bill protection, loss of existing reservations of capacity, or loss of incentives related to my participation in CPP.

If I am not the Customer or Record, I declare that I am authorized to execute this authorization on behalf of the Customer of Record listed at the top of this form and I have authority to financially bind the Customer of Record.

I hereby release, hold harmless, and indemnify SDG&E from any liability, claims, demands, and causes of action, damages, or expenses resulting from: ( ) any release of information to the DRP(s) pursuant to this authorization; (2) the unauthorized use of this information by the DRP(s) or any other third party; and (3) any actions taken by a DRP pursuant to this authorization. I understand that I may revoke this authorization at any time by submitting a revocation request using this same form or authorized electronic process accepted by SDG&E. If submitted electronically, I hereby indicate my consent to the use of electronic authorization.

Authorized Signature of Customer	Date Signed (mm/dd/yyyy)

SDGE™

CUSTOMER INFORMATION SERVICE REQUEST FOR DRP (CISR-DRP)

E. PRIMARY DRP'S AGREEMENT REGARDING CUSTOMER RELEASE AUTHORIZATION

I, (Primary DRP), hereby agree to comply with this agreement, and to release, hold harmless, and indemnify SDG&E from any liability, claims, demand, causes of action, damages, or expenses resulting from the use of customer information obtained pursuant to this authorization. If submitted electronically, I hereby indicate my consent to the use of electronic authorization.

Authorized Signature of First DRP | Date Signed (mm/dd/yyyy)

F. SECONDARY DRP'S AGREEMENT REGARDING CUSTOMER RELEASE AUTHORIZATION

I, (Secondary DRP), hereby agree to comply with this agreement, and to release, hold harmless, and indemnify SDG&E from any liability, claims, demand, causes of action, damages, or expenses resulting from the use of customer information obtained pursuant to this Authorization. If submitted electronically, I hereby indicate my consent to the use of electronic authorization.

Authorized Signature of Second DRP | Date Signed (mm/dd/yyyy)

G. JURISDICTION OF CPUC

This authorization is subject to such modifications as the California Public Utilities Commission may direct from time to time in the exercise of its jurisdiction.

FOR REVOCATION USE ONLY

H. CUSTOMER REVOCATION OF AUTHORIZATION

I, (Customer), hereby revoke the authorization to release information to the DRP(s) listed above. I hereby release, hold harmless, and indemnify SDG&E from any liability, claims, demands, causes of action, damages, or expenses resulting from: ( ) this revocation; (2) any refusal to release information to the DRP(s) pursuant to this revocation; and (3) any conduct by the DRP(s) in connection with this revocation. If submitted electronically, I hereby indicate my consent to the use of electronic authorization.

Authorized Signature of Customer or Its Agent | Date Signed (mm/dd/yyyy)

I. DRP REVOCATION OF AUTHORIZATION/DISCONTINUANCE FROM DEMAND RESPONSE SERVICE

I, (DRP), hereby revoke the authorization to release the Customer's information to the above designated DRP(s). Further, I hereby notify SDG&E that the date of the Customer's actual or anticipated revocation or discontinuance from my Demand Response services is_____(mm/dd/yyyy). I hereby release, hold harmless, and indemnify SDG&E and its agents from any liability, claims, demands, causes of action, damages, or expenses resulting from: ( ) this revocation, (2) any refusal by SDG&E to release information to the DRP(s) pursuant to this revocation, (3) any conduct by my DRP(s) in connection with this revocation, and ( ) my DRP(s)' failure to timely notify SDG&E of the Customer's revocation or discontinuance from my Demand Response services. If submitted electronically, I hereby indicate my consent to the use of electronic authorization.

Authorized Signature of DRP | Date Signed (mm/dd/yyyy)

Page 3 of 3

Form 144-0820
01/2024

FIGURE 37: THIRD PARTY DRP FORM

DRP Agreement

Below is an example DRP Agreement that The City can provide to it's customers if a third party were to manage the DRP program.

San Diego Gas & Electric Company
San Diego, California

Revised Cal. P.U.C. Sheet No. 27107-E
Canceling Original Cal. P.U.C. Sheet No. 24735-E

SAMPLE FORMS Sheet 1

FORM 144-0821

Demand Response Provider (DRP) Service Agreement

01/2016 T

(See Attached)

1C5
Advice Ltr. No. 2821-E-C
Decision No.

Issued by
Dan Skopec
Vice President
Regulatory Affairs

Date Filed Jan 28, 2016
Effective Jan 1, 2016
Resolution No.

SDGE
A Sempra Energy utility®

DEMAND RESPONSE PROVIDER (DRP) SERVICE AGREEMENT

This Demand Response Provider ("DRP") Service Agreement ("Agreement") is made and entered into as of this ___day of____, by and between "_____" ("DRP"), a _____organized and existing under the laws of the state of_____, and the Utility, "San Diego Gas and Electric Company" ("SDG&E"), wherein SDG&E is a corporation organized and existing under the laws of the state of California. From time to time, DRP and SDG&E shall be individually referred to herein as a "Party" and collectively as the "Parties."

Section 1: General Description of Agreement

1.1 This Agreement is a legally binding contract. The Parties named in this Agreement are bound by the terms set forth herein and otherwise incorporated herein by reference, and the Parties are also bound by the requirements of Electric Rule 32, which this Agreement is intended, in part, to effectuate. This Agreement and Electric Rule 32 shall govern the business relationship between the Parties hereto by which DRP shall offer Demand Response Provider Demand Response Service (DRP DR Service) in the California Independent System Operator's (CAISO's) wholesale electricity markets through transactions with bundled service customers in SDG&E's service territory. Each Party, by agreeing to undertake specific activities and responsibilities for or on behalf of customers, acknowledges that each Party shall relieve and discharge the other Party of the responsibility for said activities and responsibilities with respect to those customers, consistent with Rule 32, Section C. Except where explicitly defined herein, the definitions controlling this Agreement are contained in SDG&E's Rule 1, Definitions, and/or Rule 32, Direct Participation Demand Response.

1.2 The form of this Agreement has been developed as part of the California Public Utility Commission's (CPUC's or Commission's) regulatory process, was intended to conform to CPUC directives, was filed with and approved by the CPUC for use between a SDG&E and a DRP participating in the wholesale market with SDG&E's bundled service customers, and may not be waived, altered, amended or modified, except as provided a) herein or in Rule 32 or b) as may otherwise be authorized by the CPUC. Each party shall be responsible for keeping up-to-date on Commission-authorized changes.

Section 2: Representations

2.1 Each Party agrees to remain in compliance with the terms of this Agreement, Rule 32, as amended from time to time upon CPUC approval, and other applicable Commission rules and requirements regarding use of the SDG&E's bundled load to provide demand response in the wholesale electricity market.

2.2 Each person executing this Agreement for the respective Parties expressly represents and warrants he or she has authority to bind the entity on whose behalf this Agreement is executed.

Form 144-0821
01/2016

2.3 Each Party represents that (a) it has the full power and authority to execute and deliver this Agreement and to perform its terms and conditions; (b) the execution, delivery and performance of this Agreement have been duly authorized by all necessary corporate or other action by such Party; and (c) this Agreement constitutes such Party's legal, valid and binding obligation, enforceable against such Party in accordance with its terms.

2.4 Each Party shall (a) exercise all reasonable care, diligence, and good faith in the performance of its duties pursuant to this Agreement; and (b) carry out its duties in accordance with applicable recognized professional standards in accordance with the requirements of this Agreement.

2.5 As two (2) DRPs may be involved with providing DR Services for a single customer into the wholesale electricity market, the DRP represents that, in so far as it is partnering with another DRP to provide these services, the division of total responsibilities as contained in Rule 32 and its associated contracts has been parsed out between the parties such that all responsibilities have been met through one or more commercial agreements. Each partnering DRP is required to sign this Service Agreement and register DRP status with the Commission.

Section 3: Term of Service

The term of this Agreement shall commence on the last date of execution by both Parties hereto (the "Effective Date") and shall terminate on the earlier of (a) the date the DRP informs the SDG&E it is no longer operating as a DRP for the SDG&E's customers; (b) upon termination pursuant to Section 5 hereof; (c) the effective date of a new DRP Service Agreement between the Parties hereto, or (d) upon relevant modification of Rule 32 that materially affects this Agreement. Notwithstanding the Effective Date of this Agreement, the DRP acknowledges it may only offer Demand Response Service to customers effective on or after the CPUC-approved date for commencement of such services by DRPs, and only after it has fulfilled the provisions of Rule 32, Section E.1 and E.3 (CPUC requirements for DRPs enrolling Bundled Service customers).

Section 4: Billing, Metering, Payment, Other Duties

4.1 Metering services that are available to the DRP shall be as described in SDG&E's Electric Rule 32, Section F.

4.2 SDG&E will bill and the DRP agrees to pay for all services and products provided by SDG&E, and approved by the CPUC, related to direct participation demand response services in accordance with the terms and conditions set forth in Electric Rule 32 and any fee schedule to be adopted in cost recovery application, hereinafter Schedule E-DRP. Any services provided by the DRP to Utility shall be by separate agreement between the Parties and are not a subject of this Agreement.

4.3 SDG&E, to the extent it is acting as the Meter Data Management Agent (MDMA), agrees to provide meter data to the DRP, in accordance with Sections D and F of Electric Rule 32.

Form 144-0821
01/2016

MDMA services, requested by the DRP or its customers, may be provided by SDG&E subject to a separate agreement or an otherwise applicable tariff.

4.4 DRP may request access from the SDG&E to customer-specific electric energy usage data subject to obtaining customer authorization and consistent with Commission precedents and orders governing customer data access, as described in SDG&E's Electric Rule 32, Section D. Customer data may also be obtained through Data Pulse Equipment installed by the SDG&E provided the DRP has obtained customer consent for such utilization and provided that acquisition of data and such utilization does not interfere with SDG&E's metering equipment. DRP will be responsible for installation costs. Upon mutual agreement of the parties, customers may authorize DRP access to data using electronic means. As soon as reasonably practical, electronic authorization of third-party data access should supersede paper forms.

4.5. To the extent a customer indicates on the Customer Information Request Form for Demand Response Providers (CISR-DRP) that it authorizes its DRP to notify SDG&E of the customer's disenrollment from Demand Response Service pursuant to the relevant checkbox on the Form CISR-DRP, the DRP must effectuate the customer's wishes by notifying the SDGE immediately so that SDG&E can terminate transmission of the specified data to the DRP. The DRP releases, holds harmless and indemnifies SDG&E from any liability, claims, demands, causes of action, damages or expenses resulting from any failure to timely notify SDG&E of the customer's disenrollment. In the event that the customer, not the DRP on the customer's behalf, revokes access to customer meter data, SDG&E shall provide the DRP with immediate notice of the revocation.

4.6. In accordance with Rule 32, Section H, the DRP must establish a security deposit limited to twice the estimated maximum monthly bill for SDG&E charges under this Agreement.

Section 5: Events of Default and Remedy for Default

5.1 An Event of Default under this Agreement shall occur if either Party breaches a material term of this Agreement or SDG&E's Electric Rule 32 and does not cure such breach within thirty (30) calendar days of receipt of written notice from the non-defaulting Party, or within such time as may be provided by this Agreement or Rule 32.

5.2 In the Event of Default, the non-defaulting Party shall be entitled (a) to exercise any and all remedies available under SDG&E's Electric Rule 32; (b) to the extent not inconsistent with SDG&E's Electric Rule 32, to exercise any and all remedies provided for by law or in equity; and (c) to terminate this Agreement upon written notice to the other Party which shall be effective upon the receipt thereof.

5.3 Breach by any Party hereto of any provision of Rule 32 shall be governed by applicable provisions therein and each Party will retain all rights granted thereunder.

Form 144-0821
01/2016

Section 6: Nondisclosure

6.1 Neither Party may disclose any Confidential Information obtained pursuant to this Agreement to any third party, including affiliates of such Party, without the express prior written consent of the other Party. As used herein, the term "Confidential Information" shall include, but not be limited to, all business, financial, and commercial information pertaining to the Parties, customers of either or both Parties, suppliers for either Party, personnel of either Party, any trade secrets, and other information of a similar nature, whether written or in intangible form that is marked proprietary or confidential with the appropriate owner's name. Without limiting the foregoing, Confidential Information shall also include customer-specific information transmitted by SDG&E to the DRP regarding location of customer service accounts on the CAISO grid (Sub-Lap and pNode), service voltage, meter numbers and types, the identity of customers' MDMA, Meter Service Provider and Load Serving Entity, and any Unique Customer Identifier(s) assigned by SDG&E and entered into CAISO's Demand Response System by a DRP. Confidential Information shall not include information known to either Party prior to obtaining the same from the other Party, information in the public domain, or information obtained by a Party from a third party who did not, directly or indirectly, receive the same from the other Party to this Agreement or from a party who was under an obligation of confidentiality to the other Party to this Agreement, or information developed by either Party independent of any Confidential Information. The receiving Party shall use the higher of the standard of care that the receiving Party uses to preserve its own confidential information or a reasonable standard of care to prevent unauthorized use or disclosure of such Confidential Information. These obligations with respect to treatment of Confidential Information shall survive this Agreement pursuant to Section 22.8 below. Customers' interval usage data, disclosed by SDG&E subject to customer authorization via Form CISR-DRP, shall not be considered Confidential Information as defined in this Agreement. However, the DRP is subject to Rule 33 as a Covered Entity to the extent that the DRP receives interval usage data for more than ten customers.

6.2 Notwithstanding the foregoing, Confidential Information may be disclosed to any governmental, judicial or regulatory authority requiring such Confidential Information pursuant to any applicable law, regulation, ruling, or order, provided that: (a) such Confidential Information is submitted under any applicable provision, if any, for confidential treatment by such governmental, judicial or regulatory authority; and (b) prior to such disclosure, the other Party is given prompt notice of the disclosure requirement so it may take whatever action it deems appropriate, including intervention in any proceeding and the seeking of any injunction to prohibit such disclosure.

Section 7: Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorneys' fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the total amount paid or payable to SDG&E under this Agreement or Schedule E-DRP during the six-month period immediately preceding the event giving rise to the claim(s). In no event shall either Party be liable to the other Party for

any indirect, special, consequential, or punitive damages of any kind whatsoever, whether in contract, tort or strict liability.

Section 8: Indemnification

8.1 To the fullest extent permitted by law, and subject to the limitations set forth in Section 7 of this Agreement, each Party (the "Indemnifying Party") shall indemnify, defend and hold harmless the other Party, and its current and future direct and indirect parent companies, affiliates, subsidiaries and their shareholders, officers, directors, employees, contractors agents, servants, successors and assigns (collectively, the "Indemnified Party") from and against any and all third-party claims and/or liabilities for losses, expenses, damage to property, injury to or death of any person, including reasonable expenses, legal and otherwise, which shall include reasonable attorneys' fees ("Claims"), to the extent arising from negligent or willful act or omission by the Indemnifying Party in the performance of this Agreement, except to the extent arising from any negligent or willful act or omission of the Indemnified Party. This Section 8 represents the Indemnifying Parties' entire obligation and the Indemnified Party's exclusive remedy regarding any third party claims.

8.2 If any claim covered by Section 8.1 is brought against the Indemnified Party, then the Indemnifying Party shall be entitled to assume the defense of such claim. If a conflict precludes the Indemnifying Party from assuming the defense, then the Indemnifying Party shall reimburse the Indemnified Party on a monthly basis for the Indemnified Party's defense through separate counsel of the Indemnified Party's choice. Even if the Indemnifying Party assumes the defense of the Indemnified Party, the Indemnified Party, at its sole option, may participate in the defense, at its own expense, with counsel of its own choice without relieving the Indemnifying Party of any of its obligations hereunder. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages of any kind whatsoever, whether in contract, tort or strict liability.

8.3 The Indemnifying Party's obligation to indemnify under this Section 8 shall survive termination or assignment (from the period of time prior to the assignment) of this Agreement, and shall not be limited in any way by any limitation on the amount or type of damages, compensation or benefits payable by or for the Indemnifying Party under any statutory scheme, including, without limitation, under any Worker's Compensation Acts, Disability Benefit Acts or other Employee Benefit Acts.

Section 9: Assignment and Delegation

9.1 Neither Party to this Agreement shall assign any of its rights or obligations under this Agreement, except with the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed. No assignment of this Agreement shall relieve the assigning Party of any of its obligations under this Agreement until such obligations have been assumed by the assignee. When duly assigned in accordance with the foregoing, this Agreement shall be binding upon and shall inure to the benefit of the assignee and the assignor shall be relieved of its rights and obligations. Any assignment in violation of this Section 9 shall be void *ab initio*.

Form 144-0821
01/2016

9.2 Notwithstanding the provisions of this Section 9, either Party may subcontract its duties under this Agreement to a subcontractor, provided that the subcontracting Party shall remain fully responsible as a principal and not as a guarantor for performance of any subcontracted duties, shall serve as the point of contact between its subcontractor and the other Party, and shall provide the other Party at least thirty (30) calendar days' prior written notice of any such subcontracting, which notice shall include such information about the subcontractor as the other Party shall reasonably require, and provided further that each Party may subcontract its obligation to provide Metering or Meter Reading Services under this Agreement only to subcontractors who have complied with all certification or registration requirements described in applicable law, CPUC rules and SDG&E's Electric Rule 32. If either Party subcontracts any of its duties hereunder, it shall cause its subcontractors to perform in a manner which is in conformity with that Party's obligations under this Agreement.

Section 10: Independent Contractors

Each Party shall perform its obligations under this Agreement (including any obligations performed by a Party's designees as permitted under Section 9 of this Agreement) as an independent contractor.

Section 11: Entire Agreement

This Agreement consists of, in its entirety, this Demand Response Provider Service Agreement and all attachments hereto, and all Demand Response Service Requests submitted pursuant to this Agreement and SDG&E's Electric Rule 32. This Agreement supersedes all other service agreements or understandings, written or oral, between the Parties related to the subject matter hereof with the exception of Rule 32, the terms of which are incorporated herein, and Schedule E-DRP, which shall be read in conjunction with this Agreement.

Section 12: Enforceability

If any provision of this Agreement or the application thereof, is to any extent held invalid or unenforceable, the remainder of this Agreement and the application thereof, other than those provisions which have been held invalid or unenforceable, shall not be affected and shall continue in full force and effect and shall be enforceable to the fullest extent permitted by law or in equity.

Section 13: Notices

13.1 Except as otherwise provided in this Agreement, any notices under this Agreement shall be in writing and shall be effective upon delivery if delivered by (a) hand; (b) email; (c) U.S. Mail, first class postage pre-paid, or (d) facsimile, with confirmation of receipt to the Parties as follows:

If the notice is to the DRP:
Company Name Contact Name:
Business Address:
E-mail address:
Facsimile:

If the notice is to the LSE:
Contact Name:
Business Address:
E-mail address
Facsimile:

13.2 Each Party shall be entitled to specify as its proper address any other address in the United States upon written notice to the other Party.

13.3 Each Party shall designate in Attachment A the person(s) to be contacted with respect to specific operational matters relating to Demand Response Service. Each Party shall be entitled to specify any change to such person(s) upon written notice to the other Party.

Section 14: Time of Essence

The Parties expressly agree that time is of the essence for all portions of this Agreement.

Section 15: Dispute Resolution

15.1 Should SDG&E and DRP have an unresolved dispute under this Agreement, the dispute shall initially be referred to a Vice President of SDG&E, or his/her designee, and an officer of DRP, or designee, for resolution. Should the dispute remain unresolved after good faith informal dispute resolution, the Parties shall proceed under the Dispute Resolution outlined in Section I of SDG&E's Electric Rule 32.

15.2 If the dispute involves a request for damages, Parties are notified that the Commission has no authority to award damages. To resolve such issues, the Parties may mutually agree to pursue mediation or arbitration to resolve such issues, or, if no agreement is reached, to pursue other legal remedies that may be available to the Parties with the understanding that nothing in this section vitiates the effect of Sections 7 and 8 *supra*.

Section 16: Applicable Law and Venue

This Agreement shall be interpreted, governed by and construed in accordance with the laws of the State of California, and shall exclude any choice of law rules that direct the application of the laws of another jurisdiction, irrespective of the place of execution or of the order in which the signatures of the parties are affixed or of the place or places of performance. Except for matters and disputes with respect to which the CPUC is the initial proper venue for dispute resolution pursuant to applicable law or this Agreement, the federal and state courts located in San Diego

County, California shall constitute the sole proper venue for resolution of any matter or dispute hereunder, and the Parties submit to the exclusive jurisdiction of such courts with respect to such matters and disputes.

Section 17: Force Majeure

Neither Party shall be liable for any delay or failure in the performance of any part of this Agreement (other than obligations to pay money) due to any event of force majeure or other cause beyond its reasonable control, including but not limited to, unusually severe weather, flood, fire, lightning, epidemic, quarantine restriction, war, sabotage, act of a public enemy, earthquake, insurrection, riot, civil disturbance, strike, work stoppage caused by jurisdictional and similar disputes, restraint by court order or public authority, or action or non-action by or inability to obtain authorization or approval from any governmental authority, or any combination of these causes ("Force Majeure Event"), which by the exercise of due diligence and foresight such Party could not reasonably have been expected to avoid and which by the exercise of due diligence is unable to overcome. It is agreed that upon receipt of notice from the affected Party about such Force Majeure Event to the other Party within a reasonable time after the cause relied on, then the obligations of the Party, so far as they are affected by the event of force majeure, shall be suspended during the continuation of such inability and circumstance and shall, so far as possible, be remedied with all reasonable dispatch. Both Parties shall take all reasonable steps to comply with this Agreement and SDG&E's Electric Rule 32 despite occurrence of a Force Majeure Event.

Section 18: Not a Joint Venture

Unless specifically stated in this Agreement to be otherwise, the duties, obligations, and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation, or liability on or with regard to either Party. Each Party shall be liable individually and severally for its own obligations under this Agreement.

Section 19: Conflicts Between this Agreement and SDG&E's Electric Rule 32

Should a conflict exist or develop between the provisions of this Agreement and SDG&E's Electric Rule 32, Rule 32 shall prevail.

Section 20: Amendments or Modifications

20.1 Except as provided in Section 1.2, no amendments or modifications shall be made to this Agreement, in whole or in part, except by an instrument in writing executed by authorized representatives of the Parties to the extent they are consistent with Commission approval, and no amendment or modification shall be made by course of performance, course of dealing or usage of trade. Substantive changes to the terms of this Agreement shall be first approved by the Commission.

Form 144-0821
01/2016

20.2 This Agreement may be subject to such changes or modifications as the CPUC may from time to time direct or necessitate in the exercise of its jurisdiction, and the Parties may amend the Agreement to conform to changes directed or necessitated by the CPUC. In the event the Parties are unable to agree on the required changes or modifications to this Agreement, their dispute shall be resolved in accordance with the provisions of Section 15 hereof or, in the alternative, DRP may elect to terminate this Agreement upon written notice to SDG&E, which shall be effective upon the receipt thereof. SDG&E retains the right to unilaterally file with the CPUC, pursuant to the CPUC's rules and regulations, an application for a change in SDG&E's rates, charges, classification, service, or rules, or any agreement relating thereto.

Section 21: Audits

21.1 When the DRP reasonably believes that errors related to billing and metering activity may have occurred and SDG&E is the MDMA for the customer(s), the DRP may request the production of such documents as may be required to verify the accuracy of such billing and metering, provided that requisite customer consent has been obtained by the DRP. Such documents shall be provided within ten (10) business days of such request. In the event the requesting Party, upon review of such documents, discovers actual errors related to metering activity, the requesting Party may direct that an audit be conducted. SDG&E and the DRP shall designate their own employee representative or their contracted representative to audit the other party's records subject to confidentiality requirements.

21.2 Any such audit shall be undertaken by the SDG&E, the DRP, or their contracted representative at reasonable times without interference with the audited Party's business operations, and in compliance with the audited Party's security procedures. SDG&E and the DRP agree to cooperate fully with any such audit.

21.3 Specific records to support the accuracy of meter data provided in the settlement process may require examination of metering support documentation maintained by subcontractors. Each of the SDG&E and the DRP shall include a similar clause in their agreements with their subcontractors reserving the right to designate their own employee representative, or their contracted representative to audit records related to the settlement process for Demand Response Service.

21.4 The auditing Party will notify the audited Party in writing of any exception taken as a result of an audit. The audited Party shall refund the amount of any undisputed exception to the auditing Party within thirty (30) days. If the audited Party fails to make such payment, the audited Party agrees to pay interest, accruing monthly, at a rate equal to the prime rate plus two percent (2%) of Bank of America NT&SA, San Francisco, or any successor institution, in effect from time to time, but not to exceed the maximum contract rate permitted by the applicable usury laws of the State of California. Interest will be computed from the date of written notification of exceptions to the date the audited Party reimburses the auditing Party for any exception. The cost of such audit shall be paid by the auditing Party; provided, however, that in the event an audit verifies overcharges of five percent (5%) or more, then the audited Party shall reimburse the auditing Party for the cost of the audit.

21.5 This right to audit shall extend for a period of three (3) years following the date of final payment under this Agreement. Each party and each subcontractor shall retain all necessary records and documentation for the entire length of this audit period.

Section 22: Miscellaneous

22.1 Unless otherwise stated in this Agreement: (a) any reference in this Agreement to a section, subsection, attachment or similar term refers to the provisions of this Agreement; (b) a reference to a section includes that section and all its subsections; and (c) the words "include," "includes," and "including" when used in this Agreement shall be deemed in each case to be followed by the words "without limitation." The Parties agree that the normal rule of construction to the effect that any ambiguities are to be resolved against the drafting Party shall not be employed in the interpretation of this Agreement.

22.2 The provisions of this Agreement are for the benefit of the Parties and not for any other person or third party beneficiary. The provisions of this Agreement shall not impart rights enforceable by any person, firm, or organization other than a Party or a successor or assignee of a Party to this Agreement.

22.3 The descriptive headings of the various sections of this Agreement have been inserted for convenience of reference only and shall in no way define, modify or restrict any of the terms and provisions thereof.

22.4 Any waiver at any time by either Party of its rights with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not be deemed a waiver with respect to any other or subsequent default or matter and no waiver shall be considered effective unless in writing signed by the waiving Party.

22.5 Each Party shall be responsible for paying its own attorneys' fees and other costs associated with this Agreement, except as provided in Sections 7 and 8 hereof.

22.6 To the extent that the CPUC has a right under then-current law to audit either Party's compliance with this Agreement or other legal or regulatory requirements pertaining to Demand Response Service that Party shall cooperate with such audits. Nothing in this Section shall be construed as an admission by either Party with respect to the right of the CPUC to conduct such audits or the scope thereof.

22.7 Except as may be provided or limited by this Agreement, the obligations which by their nature are intended to survive termination of this Agreement, including representations, warranties, covenants and rights and obligations with respect to indemnification, payment, settlement, and confidentiality, shall so survive.

22.8 Except as otherwise provided in this Agreement, all rights of termination, cancellation or other remedies in this Agreement are cumulative. Use of any remedy shall not preclude any other remedy in this Agreement.

Form 144-0821
01/2016

The Parties have executed this Agreement on the dates indicated below, to be effective upon the later date.

The signatories hereto represent that they have been appropriately authorized to enter into this Contract on behalf of the party for whom they sign.

DEMAND RESPONSE PROVIDER:

NAME OF AUTHORIZED INDIVIDUAL:_____

SIGNATURE:_____

TITLE:_____

MAILING ADDRESS:_____

TELEPHONE:_____

SAN DIEGO GAS AND ELECTRIC COMPANY

NAME OF AUTHORIZED INDIVIDUAL:_____

SIGNATURE:_____

TITLE:_____

DATE EXECUTED: _____

Form 144-0821
01/2016

ATTACHMENT A

Metering and Meter Reading Services

A. **Contact Persons (Section 13.3)**:

1. Metering and Meter Reading Services

LSE Contact:

Email Address: _____

DRP Contact:

Email Address: _____

MDMA Contact:

Email Address: _____

B. **Parties' Representatives (Section 15.1)**:

LSE Representative: _____

Contact Name: _____

Business Address: _____

Phone Number: _____

_____

Email Address: _____

DRP Representative: _____

Contact Name: _____

Business Address: _____

Phone Number: _____

_____

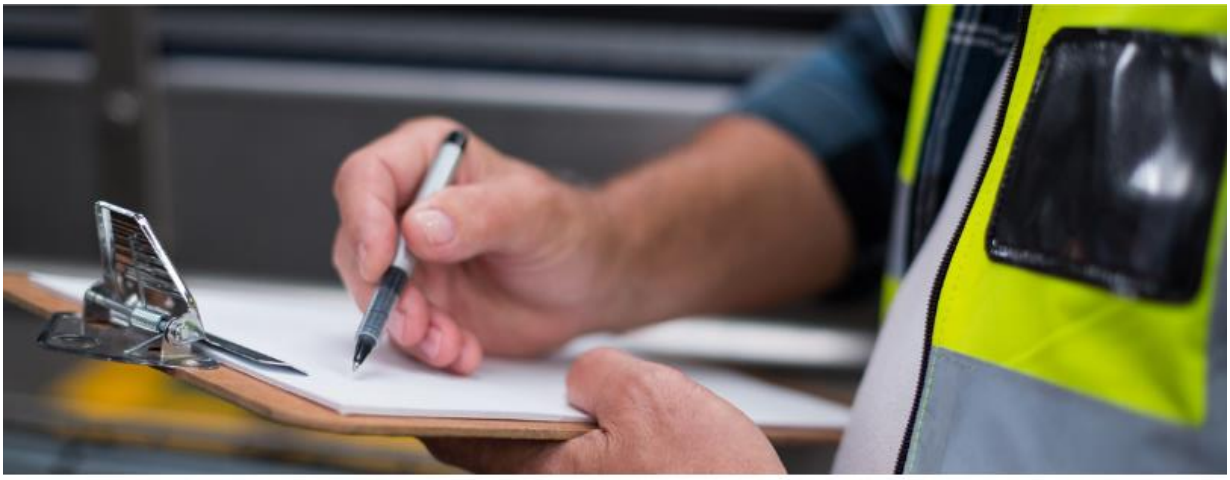
Email Address: _____

A-1

FIGURE 38: DRP AGREEMENT

PSE Business Demand Response Quick Reference Guide (QRG)

Below is an example brochure with QR code that The City can provide to it's business customers to sign up for demand response.



Business Demand Response

Earn incentives for curtailing energy use

Our business demand response program provides an opportunity for small, medium, large and industrial businesses to earn incentive payments while helping maintain reliable electricity. Whether it's our hot summer months or cold winter season, you can earn incentives simply by limiting electric use for short periods of time. When the demand for electricity approaches critical peak levels, utilities and grid operators dispatch our demand response network, which is made up of local organizations and residents that have agreed to reduce energy use during times of high demand.

How it works

We've teamed up with AutoGrid and Enel to develop a custom curtailment plan that includes actions like adjusting HVAC set points, reducing lighting and modifying production lines to name a few.

The team:

- Reviews your business' historical electrical use data and provides an assessment on where and how you can effectively shed load during demand response events.
- Helps you understand the actions taken during a demand response event (automated or behavioral), while also providing you with an estimate of the incentive amount you can earn by participating.
- Breaks down the calculations for you. Your earnings will be a combination of your business' committed load reduction capacity and the average of your participation across all events within a given season, multiplied by a fixed kilowatt (kW) amount.

How you qualify and apply

To be eligible for this program, you must be a current PSE business electric customer and your business site must be within PSE's electric service area and use electricity from PSE. Use the QR code on this flyer to apply. If you have questions, get in touch with us at **businessdemandresponse@pse.com**.

Energy-efficiency programs like Business Demand Response support your clean-energy goals and align with PSE's aspirational goal to lower carbon emissions to net zero by 2045. Learn how at **pse.com/TOGETHER**.

pse.com/bdrp

PSE PUGET SOUND ENERGY

FIGURE 39: PSE BUSINESS DEMAND RESPONSE QRG

Frequently asked questions

How do I participate?

We'll work with you to identify your energy-reduction potential and create a strategy that delivers maximum value with minimum impact to your operations. These measures will be outlined in a detailed energy-reduction plan.

In some cases, our team will install necessary metering devices at your facility to establish communication with their network operations center so they can monitor your energy consumption levels in real time. Throughout the process, our team will fully manage enrollment, measurement, verification and payments all on your behalf.

How do I get notified when it's time to reduce?

The notification you'll receive is called a "dispatch," and you'll be alerted by text message, email and/or phone call. Once you receive the notification, you'll respond by reducing energy use in accordance with your energy-reduction plan. At the conclusion of the event (the dispatch period), you'll receive a post-event follow-up from our team.

What can I expect during a dispatch?

Notification: When PSE anticipates high demand on the grid, we will dispatch our demand response network into action. Our team will notify you via text message, email and/or phone call, depending on your preferences, to inform you of when the dispatch will begin.

Response: At the start of the dispatch, your facility will reduce its electricity use according to your predetermined energy-reduction plan, either manually or, if requested, through our automated tool measures.

Support: Before, during and after a dispatch, our team remain in communication with your facility. Our team is available 24/7/365, supporting you to ensure that you achieve the highest possible levels of performance and payments.

What types of reductions can I make?

Our team has extensive experience creating energy-reduction strategies that work within the operational limitations of a wide variety of facilities, including cold storage, manufacturing, food processing, universities, malls, office buildings and more. Our team can also help implement full control systems that allow your electric load to be toggled remotely.

Common reduction examples include:

- Reducing nonessential lighting
- Modifying manufacturing processes
- Adjusting HVAC equipment
- Dialing back pumps
- Changing settings in industrial freezers

Customers often facilitate dispatch participation by simply shifting many of their energy-intensive processes by a few hours.

Can I sign up for Business Demand Response if I have an existing PSE grant?

Yes. Participation in this program is a layer on top of other PSE grant programs offered. For example, if you have an existing Business Lighting Incentive retrofit grant, you may also participate in our Business Demand Response program.

pse.com/bdrp

PSE PUGET SOUND ENERGY

8063 10/23

Voltus Case Study – City District

Below is a summary of a city district case study performed by Voltus.

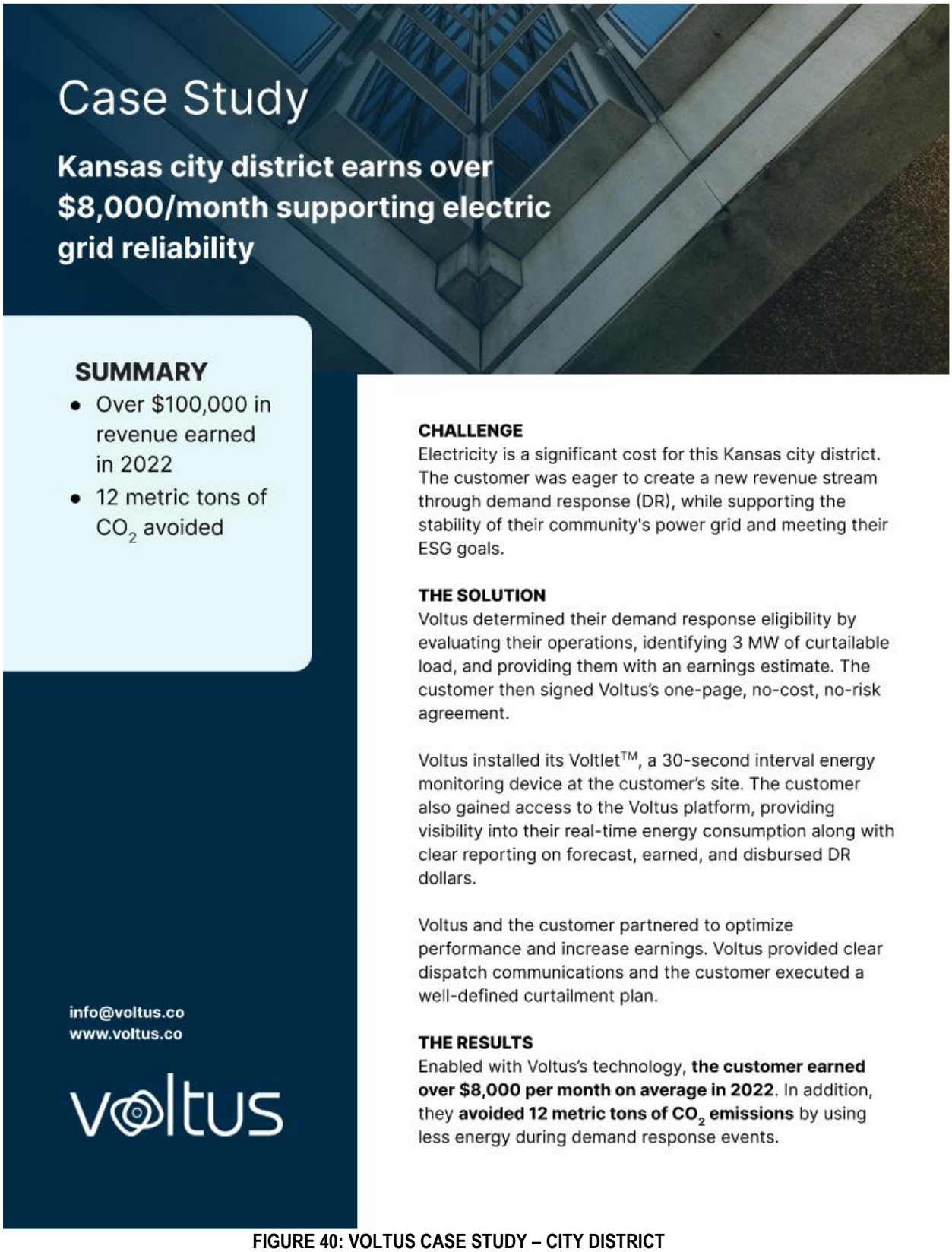


FIGURE 40: VOLTUS CASE STUDY – CITY DISTRICT

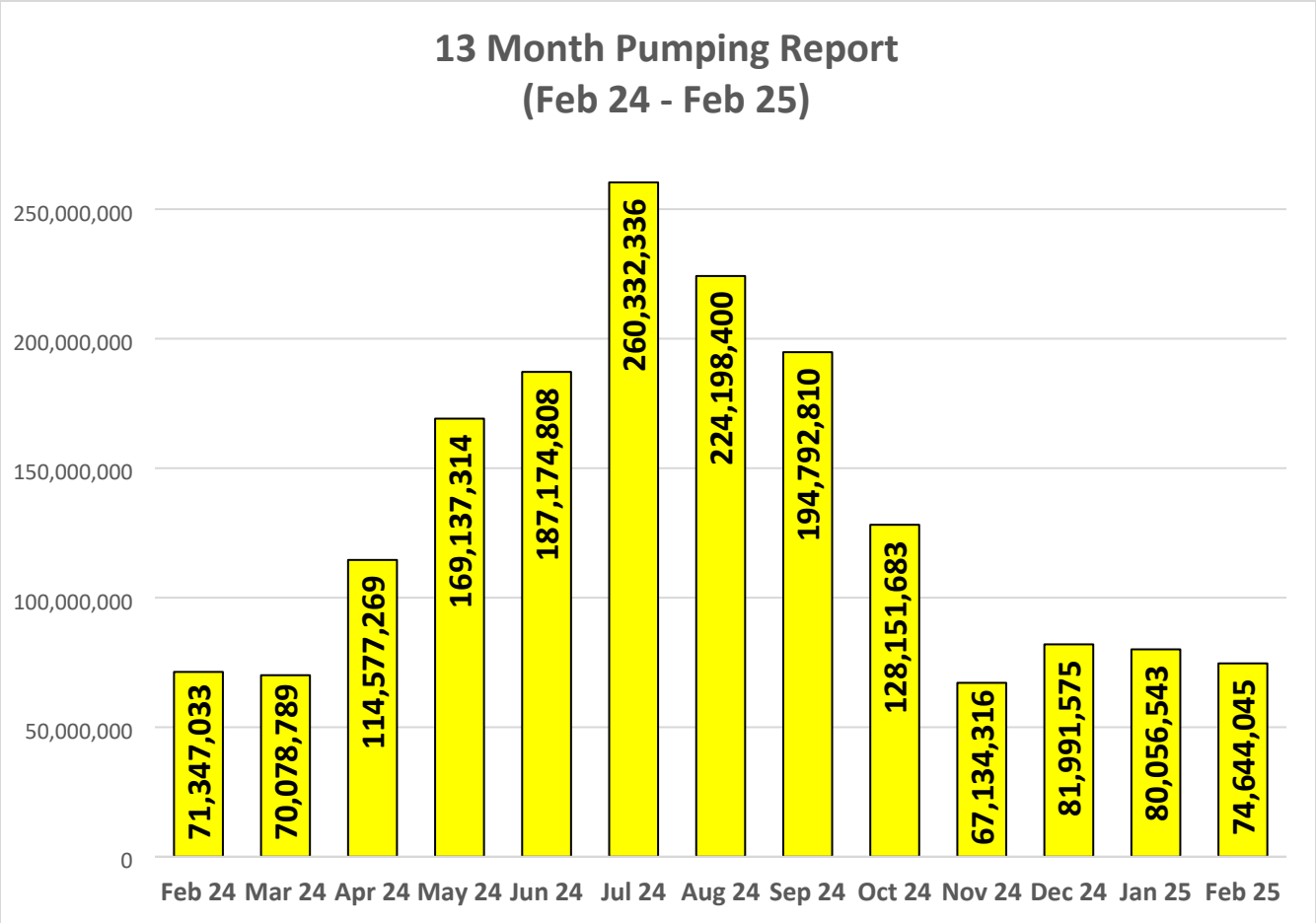
Public Works & Utilities Monthly Report
March 2025

Sewer:

- Collections staff assisted two local government agencies, Kittitas County Public Works and the City of Cle Elum, by providing vac truck excavation and jetting operations during emergency situations.
- Crews have been working with contractors on the Anderson Road sewer main extension project.
- Staff continue to work with consultants and provide data for collections system modeling. This modeling is a key component of the ongoing project to update the General Sewer Plan.
- Staff has completed the biosolids permit renewal application and have submitted it to the DOE. The 2024 annual biosolids reports have also been completed and sent off to the DOE and the EPA. Both agencies require submittal of these reports.
- Several operations staff members will be attending training in March to earn continuing education credits (CEUs) that are required to maintain their various certifications.

Water:

- Water Division crews worked closely with consultants and contractors on the Craig's Hill Booster Station start-up. The station is currently in operation and staff continue to work on fine tuning its performance.
- Crews continue to install water services and meters in new developments. 29 new meters have already been installed in 2025 at the time this report.
- Two Water Division employees are attending training in March to earn continuing education credits (CEUs) that are required to maintain their various certifications.
- The Washington State Department of Health released the Water Quality Monitoring Schedule for 2025. Staff have reviewed the schedule and the City will be required to take and submit 65 samples this year for various different tests. These sampling requirements are in addition to the standard 20 bacteriological samples that are taken and submitted monthly. This is a considerably greater number of required samples then in previous years. Most of the increased sampling is due to additional PFAS sampling that is mandated by the DOH.
- Water pumped during February of 2025 was 74,644,045 gallons. The amount of water pumped in February of 2024 was 71,347,033 gallons.



Stormwater and Street Trees:

- Staff is actively working on the annual report to Ecology, and it is due March 31, 2025.
- Staff finished the annual management plan and will take it to the Environmental commission for acceptance TBD.
- Staff prepared a 48-slide power point presentation outlining the new permit for the city manager and directors February 15th and 16th in the Council Chambers. Staff will be giving the same presentation to all staff in Public Works and Utilities on March 6th. Staff will be giving the same presentation to contractors at the Dial 811 seminar on March 14th at Hal Holmes.
- Staff will be giving a presentation to City Council on March 17th, to update the Council on the status of the levee project.
- The fish screen for Gateway 2, is actively being permitted and built for installation before April 15th on East Branch Creek. Once this happens and the updated 60% design report to Ecology is approved, then maybe Ecology will grant an extension for the grant.
- Staff is preparing for the annual Arbor Day Tree Giveaway. This year the program will run from April 7th – 25th and will be open residents wanting to plant a tree in the right-of-way or on private property in a residential zone.
- The Stormwater and Parks Departments are partnering with CWU's SLICE volunteers on a tree and vegetation planting event at Irene Rinehart Park. Our focus will be on restoring areas affected by last year's park fires, and if time permits, we will also do a trash clean-up. This effort is similar to the project we completed last year.

Electric:

- Appears that the Light Department is in the home stretch for receiving funding for the Rotary Park Solar Project. We expect award by April 1.
- Staff is continuing to meet with representatives of Winco Foods to discuss the electrical load requirements of their new distribution facility. A bi-weekly meeting has been scheduled with the City and Winco to review and discuss construction schedules, electrical loads and electrical rates.
- The Presentations 2024 Electrical System Plan to the UAC is scheduled for the March 20th meeting and the April 7th City Council meeting.
- Crews have been busy performing customer driven work.
- Norm Hedden our temporary lineman has returned to work for the city beginning February 18th .
- Cole Sullivan, Journeyman Lineworker, will start March 17, 2025.
- Staff is working with PSE to complete the PSE cutovers on Vantage Hwy. The completion of this work is pending PSE completion of their system removal plan.
- Riverline has been on-site performing maintenance work in March.
- Staff is working with Zipley Fiber and also Lightwave to install fiber throughout the city.
- IBEW Contract Negotiations are ongoing.
- The selection of the new energy serviced director has been completed, and Buddy Stanavich has been selected. His first day as the director will be April 1st.
- Staff met with BPA to discuss the Interconnection System Impact Study L0604 for the South Ellensburg Substation. Staff has directed BPA to proceed with the Facility Assessment Study, anticipated completion date is 3/10/2026.
- Staff participated in the Public Works and Utilities annual retreat.
- Jordan attended the week and a half Lineman School at Camp Rilea.

Gas:

- The Natural Gas Division safety survey to measure the effectiveness of its Public Awareness Program ran from May 1 until October 5, 2024. Results will be presented at a future UAC meeting.
- Norton Corrosion Limited was selected to provide our Natural Gas System Corrosion Control Evaluation & Survey. A kick-off meeting will be held with Norton Corrosion in March.
- Crews are performing commercial meter maintenance, residential meter change outs, and customer driven service work. Crews performed monthly pipeline patrol duties.
- Staff completed and submitted internal end-of-year reports as well as required annual reports to PHMSA and the UTC.
- Granite Service Line and System Loop project is still under design review and permitting.
- A L&I Compliance Review of our Gas Mainfitter Apprenticeship Program took place on February 24th. No compliance issues were found.
- Our annual atmospheric corrosion survey will be starting soon. One-third of the gas system will be surveyed.
- Staff participated in the recent Climate Commitment Act (CCA) Auction #9 on March 5th, 2025, and successfully obtained allowances at the settlement price of $50.00/allowance.