Benton PUD
State of the System

October 11, 2022

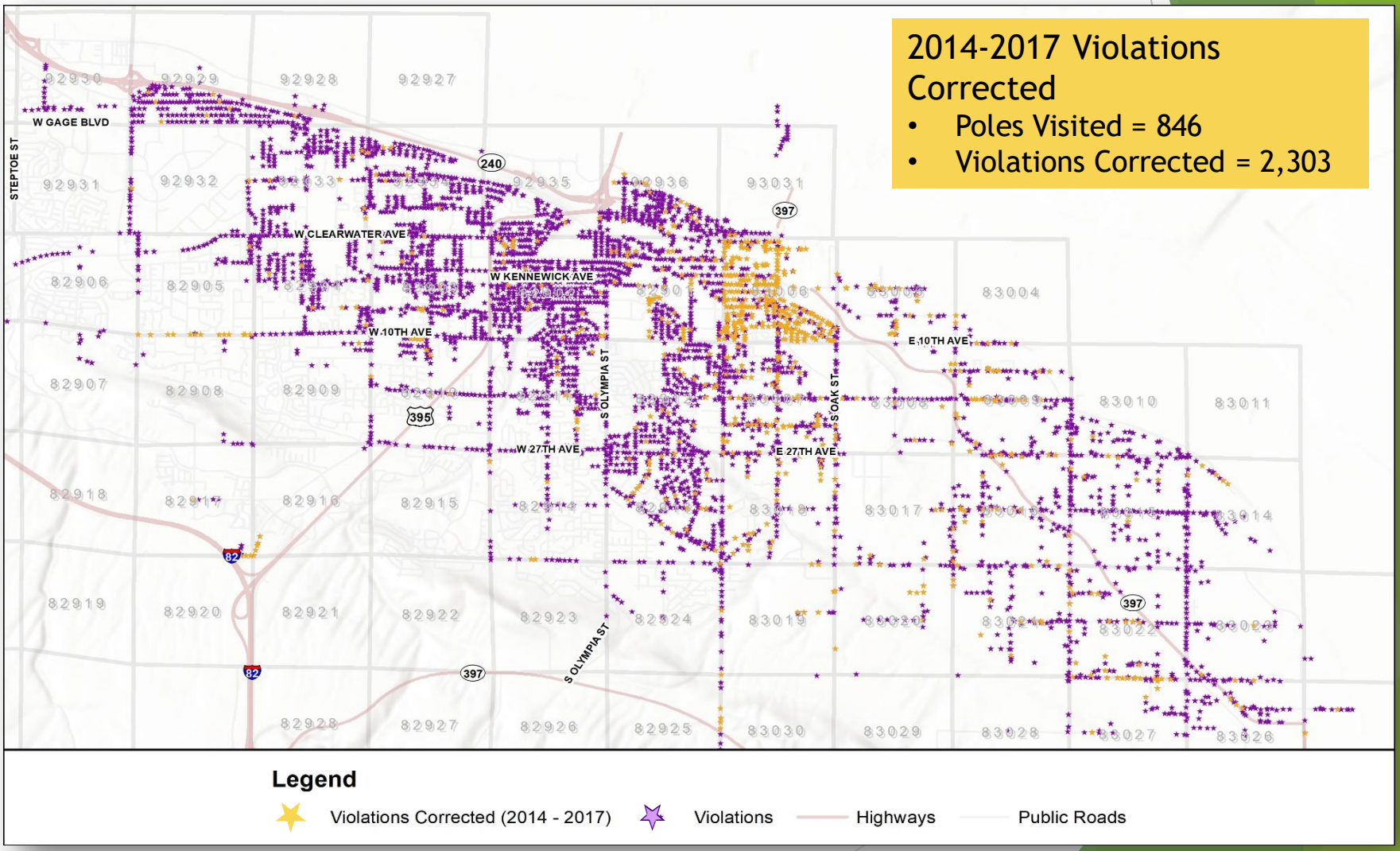
RP3 RELIABLE PUBLIC POWER PROVIDER
American Public Power Association

State of the System

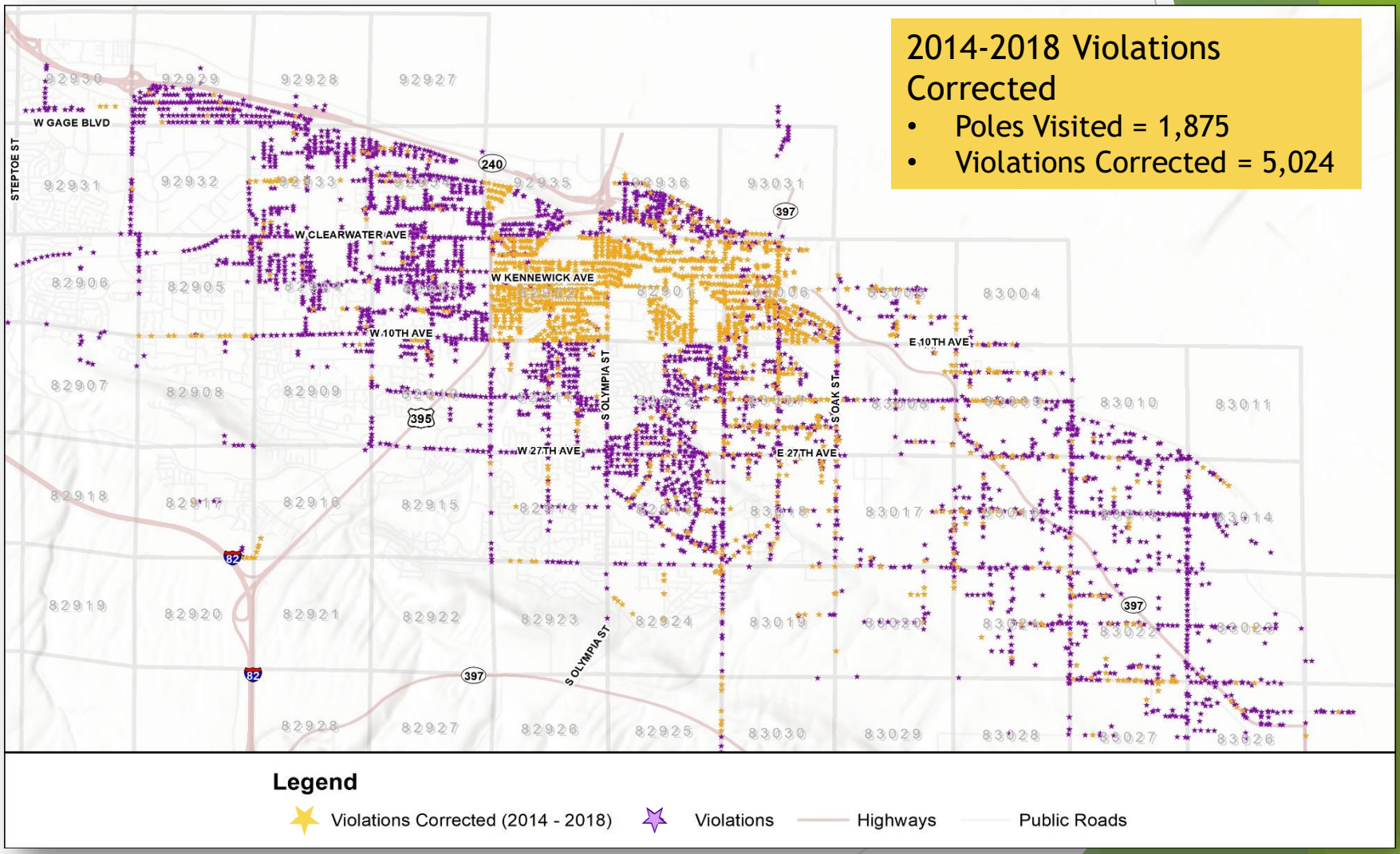
Objectives:

- Increased accountability for managing:
  - Joint Use NESC Compliance
  - Quality Assurance Program
- Focus on Reliability
  - Underground Cable Replacement
  - SCADA on Feeders
  - Wildfire Mitigation
  - Transmission Reliability Improvement Projects
- Equipment and facilities maintenance

Joint Use NESC Compliance Program



Joint Use NESC Compliance Program



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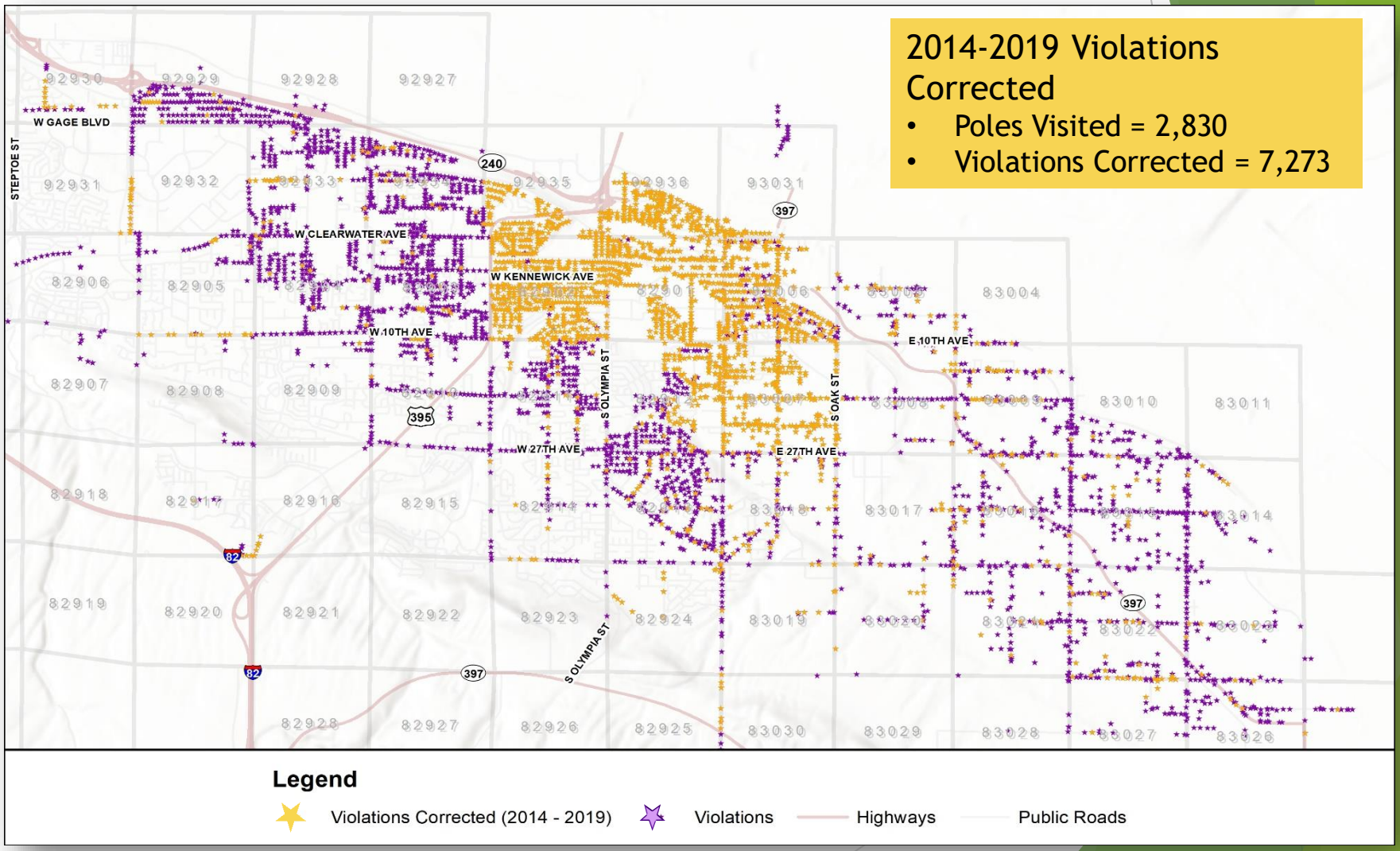
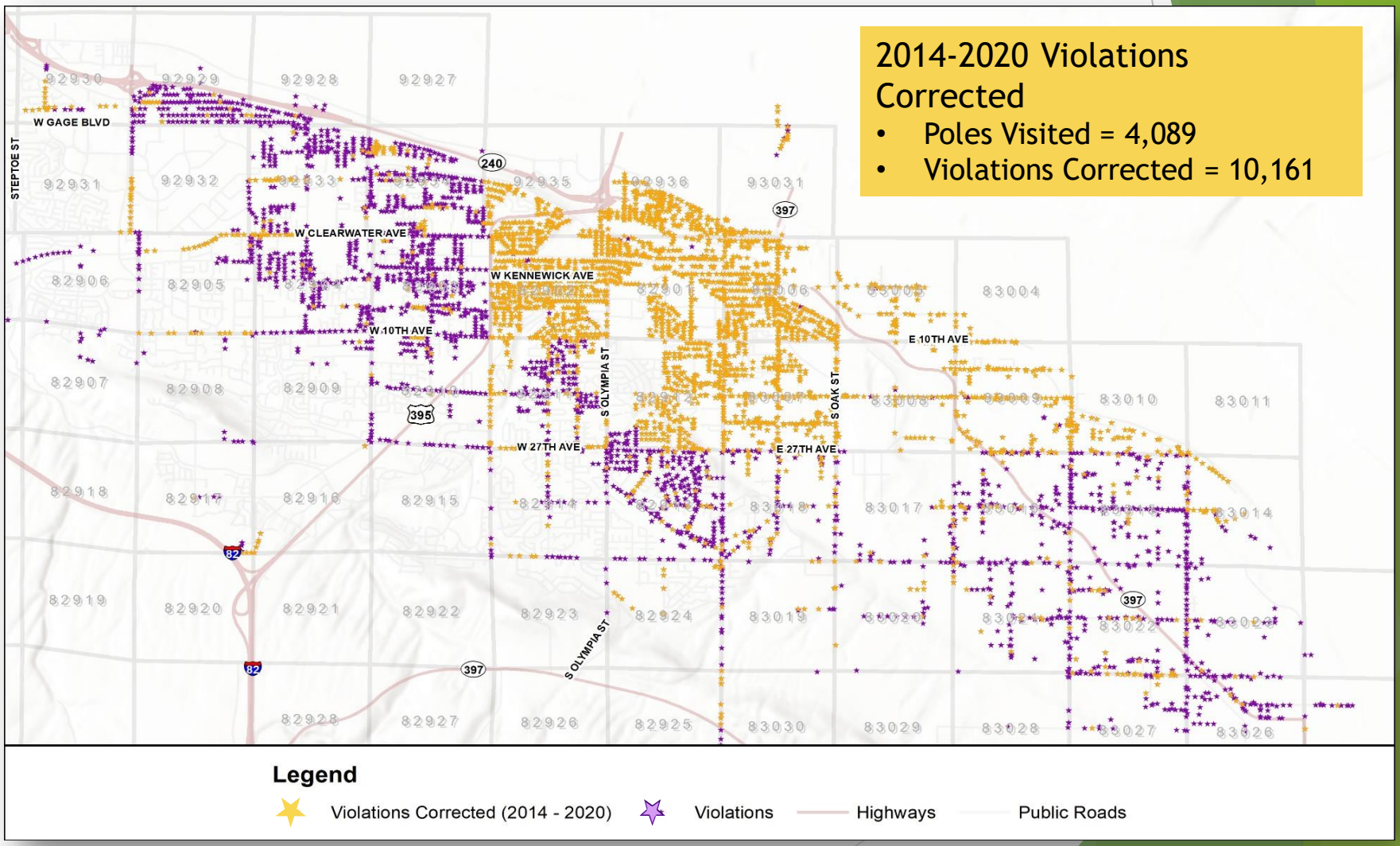
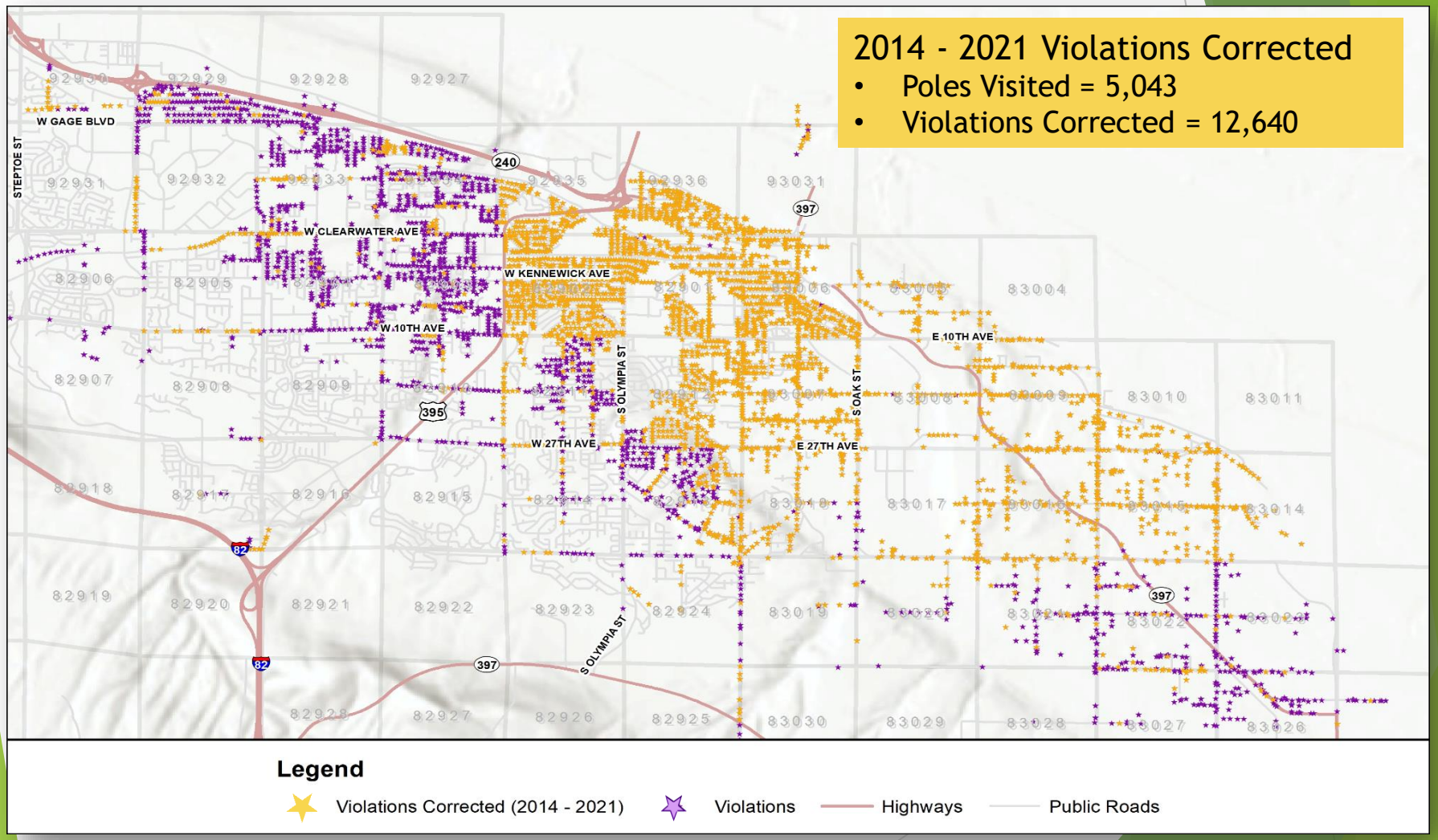


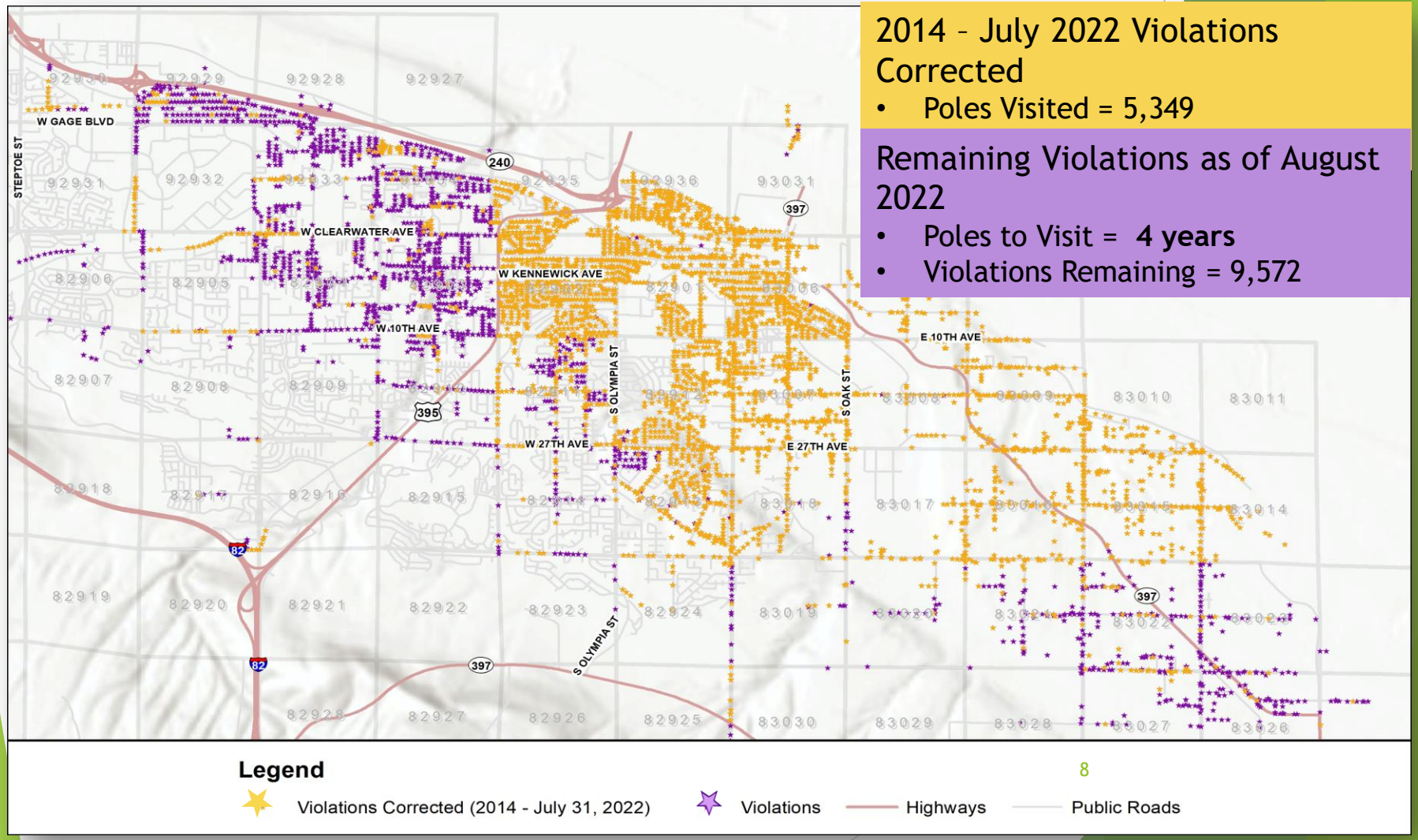
Joint Use NESC Compliance Program



Joint Use NESC Compliance Program



Joint Use NESC Compliance Program



2014 – July 2022 Violations Corrected

- Poles Visited = 5,349

Remaining Violations as of August 2022

- Poles to Visit = **4 years**
- Violations Remaining = 9,572

Joint Use NESC Compliance Program

Description	Poles Visited	Violations Corrected	New Violations Found
2022 YTD One Touch	305	996	498
2022 YTD Corrected by JU Partners	1	1	
2021 One Touch	917	2,426	1,403
2021 Corrected by JU Partners	37	53	
2020 One Touch	1,137	2,639	904
2020 Corrections by JU Partners	122	249	
2019 One Touch	955	2,249	1,456 (2015-19)
2018 One Touch	1,029	2,721	
2017 One Touch (Nov/Dec Only)	92	145	
Prior to One Touch corrections	754	2,158	
LIFETIME	5,349	13,637	4,261

Joint Use NESC Compliance Program

As of July 31st:

Additional 498 violations have been discovered by BPUD field personnel in 2022 and they are identified below.

Description	New Violations Found
Bonding	65%
<40” at Pole	14.5%
Incomplete Work	14%
Groundline Clearance	3%
Standoff Bracket	1%
Boxed Pole	1%
<30” Midspan	.5%
BPUDBB <40”	.5%
<12” Serv/Sec	.5%

Quality Assurance

2019 Work Order Inspections			
Work Orders	Trimester 1	Trimester 2	Trimester 3
Value	$1.62M	$6.30M	$3.97M
Number Planned	39 of 141	49 of 204	50 of 223
% to Inspect	28%	24%	22%
% to Inspect by $$	44%	49%	63%
% Inspected thru 10/7	100%	94%	96%

Inspections performed by Staff including Electrical Engineers.

Findings

- Equipment, cable and pole numbering errors and/or omissions
- Minor Workmanship Issues and Variations in “As-Built” versus Design

Quality Assurance

2020 Work Order Inspections			
Work Orders	Trimester 1	Trimester 2	Trimester 3
Value	$4.65M	$3.21M	$3.96M
Number Planned	44 of 177	45 of 179	48 of 185
% to Inspect	25%	25%	25%
% to Inspect by $$	65%	25%	72%
% Inspected thru 10/7	43%	51%	31%

Inspections performed by Staff including Electrical Engineers.

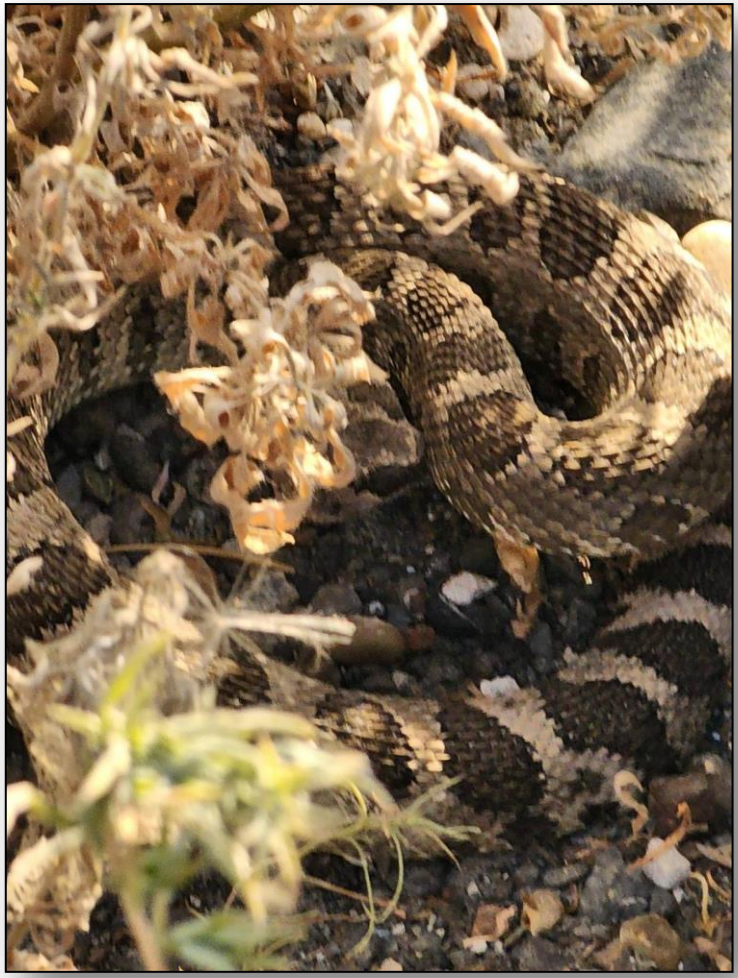
Findings

- Equipment, cable and pole numbering errors and/or omissions
- Minor Workmanship Issues and Variations in “As-Built” versus Design

Quality Assurance

2021 Work Order Inspections			
Work Orders	Trimester 1	Trimester 2	Trimester 3
Value	$5.49M	$1.64M	$3.29M
Number Planned	38 of 161	34 of 148	36 of 166
% to Inspect	24%	23%	22%
% to Inspect by $$	66%	37%	35%
% Inspected	0%	0%	0%

District staff in six groups of two will be performing work order inspections weekly until they are complete.



Underground Cable Replacement

Replaced to date
149,477 feet
$7.65M

2021 Results
16,500 feet
$1.20M

2022 Results
21,300 feet
$1.26M

Future Plans By Priority/Type

1. Direct Buried - 124,724' - 7 Yrs
2. Injected Cable - 156,273' - 8.5 Yrs
3. In Conduit - 62,502' - 1.75 Yrs

Substation Relay Upgrades

2021: Gum Street

2022: Mobile Sub

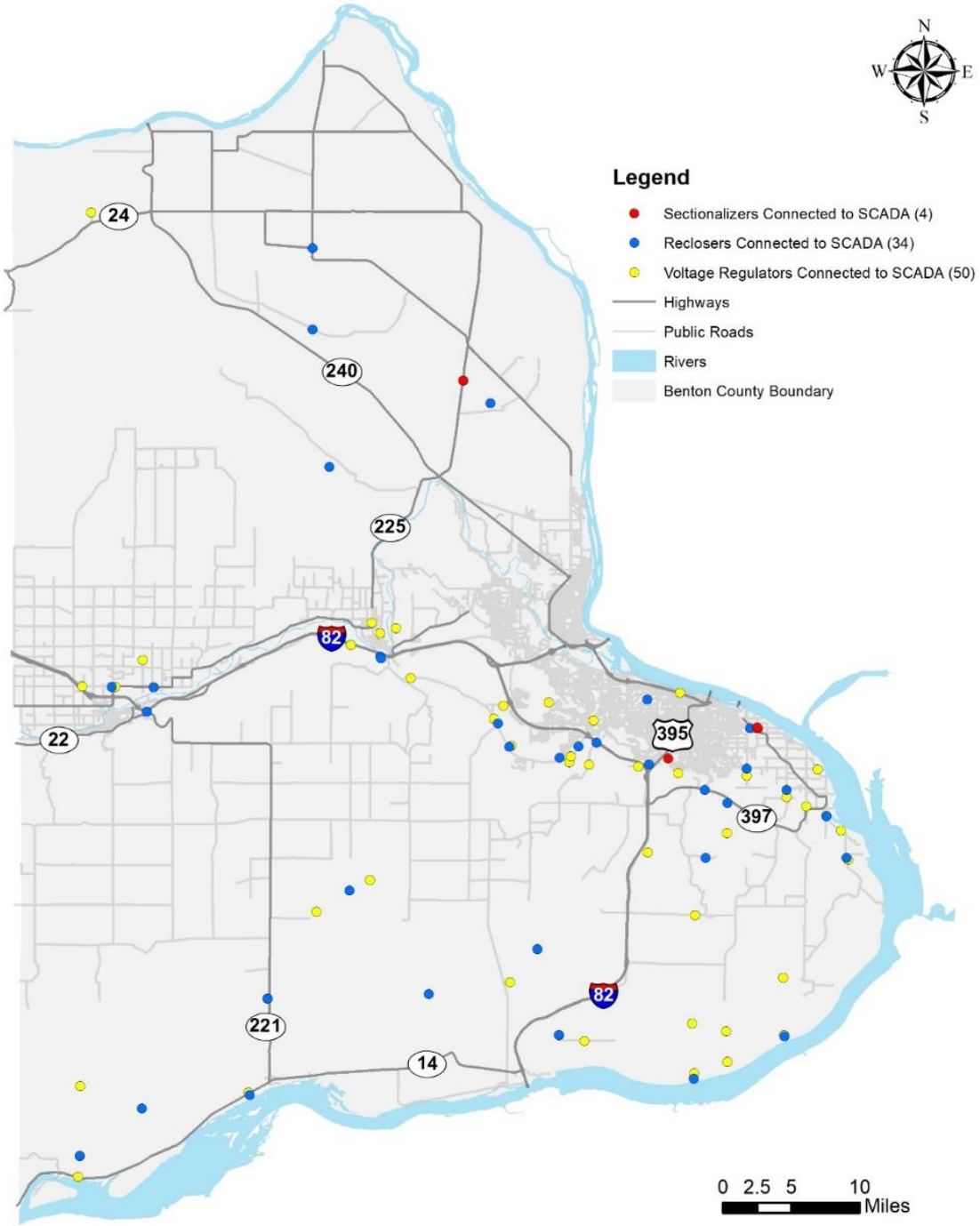
Ely Bay 1

2022: Angus Bay 1

Substation Relays

Capital Budget Planning:

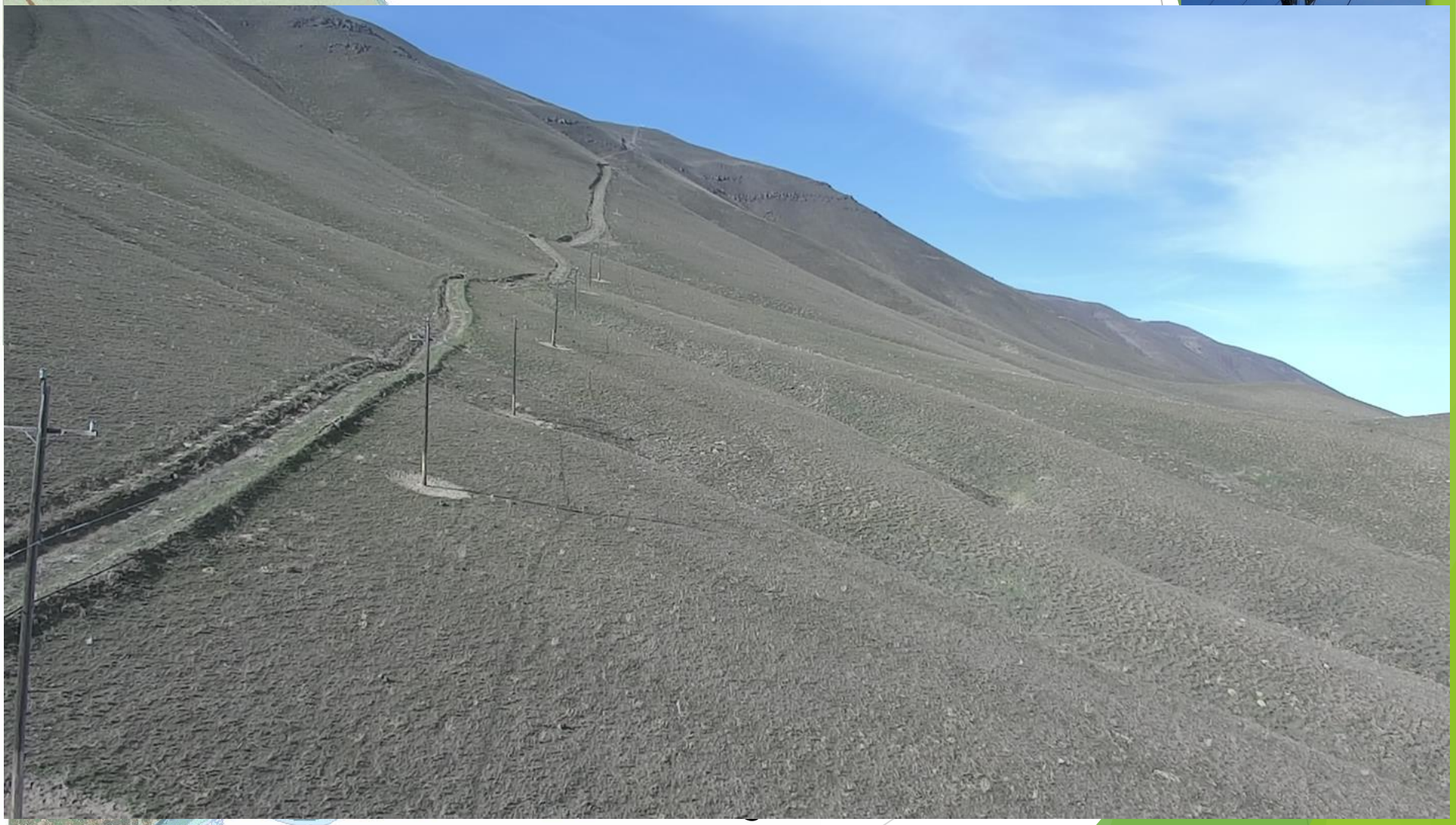
2023:	Hedges	$55K
	Vista Bay#1	
2024:	Angus Bay 2	$115K
2025:	Sunset Road	$150K
	Vista Bay #2	
2026:	Prosser Bay 1	$250K
	Prosser Bay 2	$250K
2027:	Riverfront	$300K



SCADA Line Device Communications

- ✓ **SCADA Connected:**
  - **Voltage Regulators - 50**
  - **Reclosers - 34**
  - **Sectionalizers - 4**

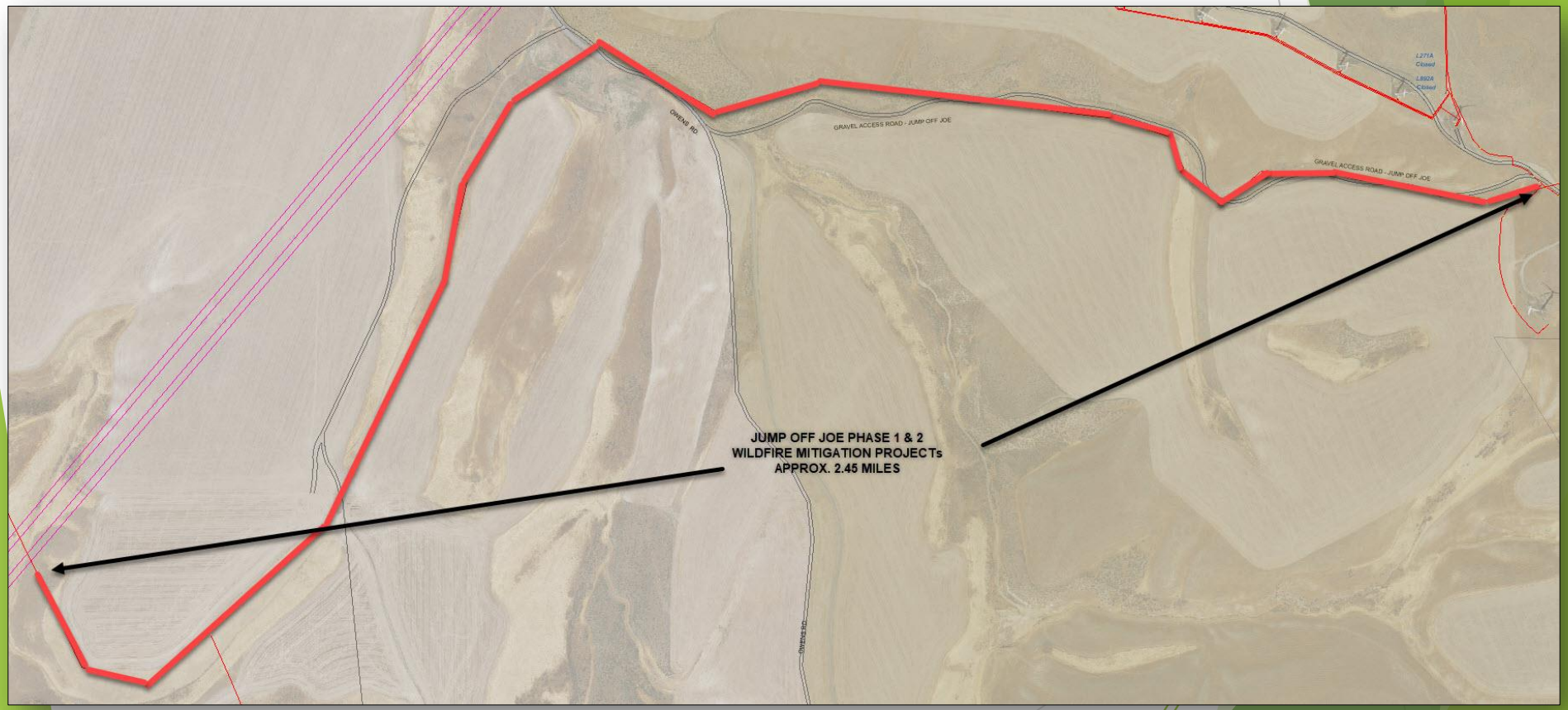
Wildfire Mitigation



Wildfire Mitigation

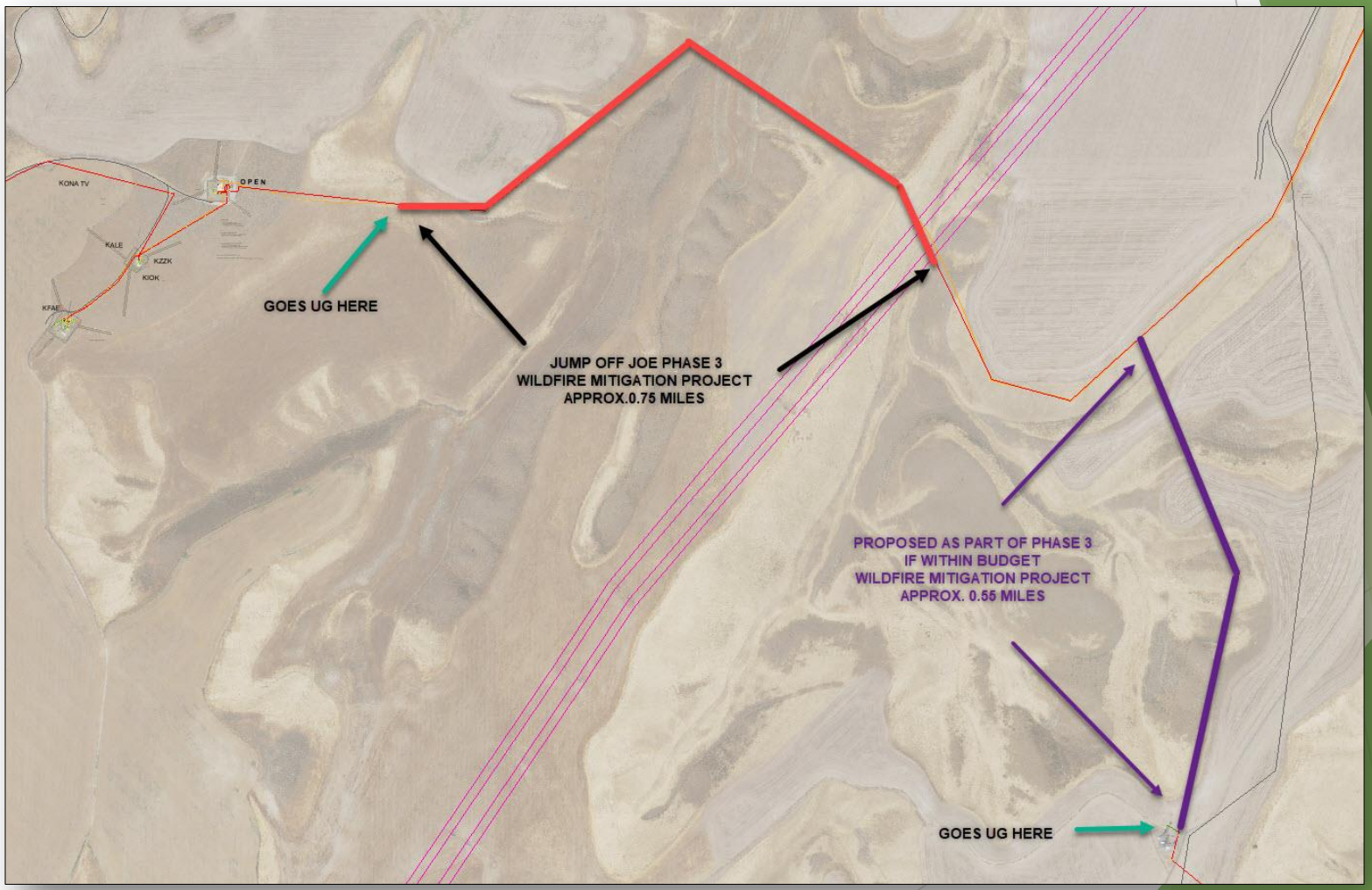
Wildfire Mitigation

Jump Off Joe – Phase One and Two



Wildfire Mitigation

Jump Off Joe – Phase 3



5 Year Safety Inspections
N
W
E
S
Legend
2022
2023
2024
2025
2026
Miles

late

Maintenance Update
5 Year Inspections

Overhead:

- 3 Tree Limbs rubbed on Services
- 3 Services needed tape on connectors
- 3
- 3 [illegible] Tops
- 1 Nest
- 1 Missing tag

Underground:

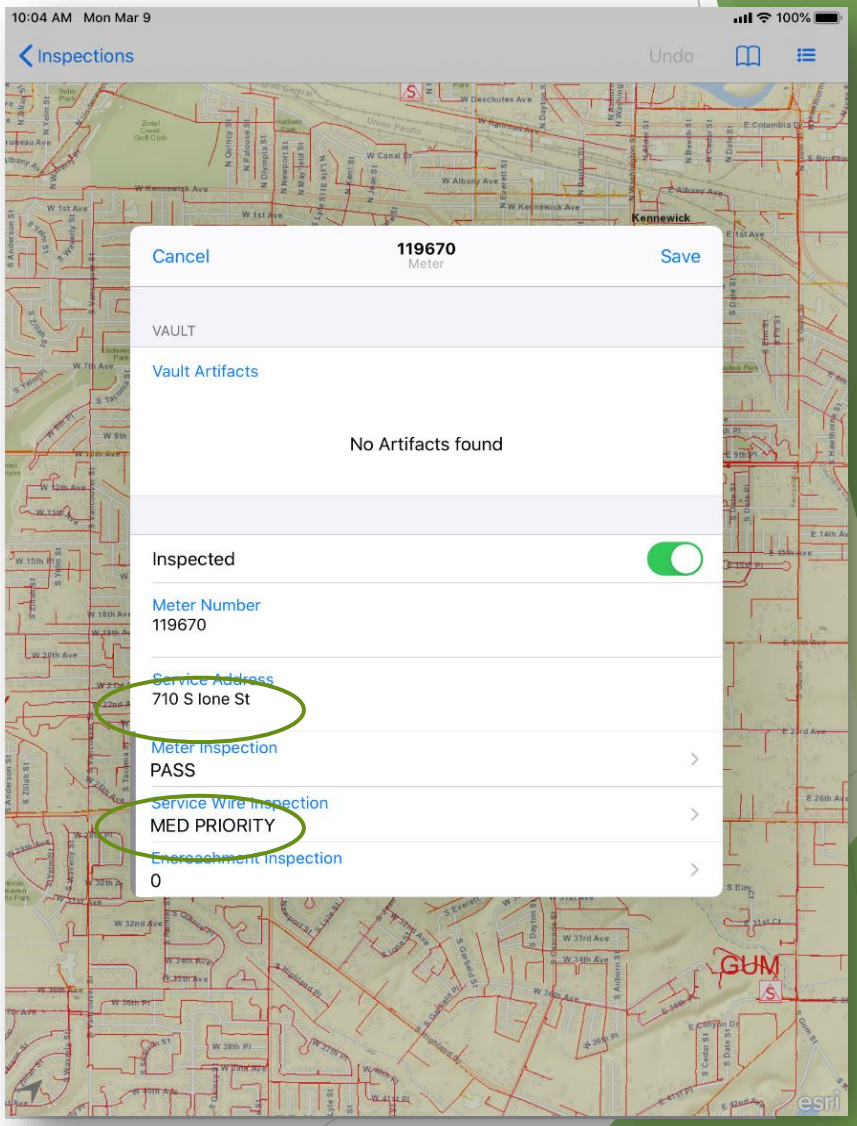
- 10 Vegetation blocki[illegible] access
- 1 Transformer off pad
- 1 Broken J-box latch
- 1 Fence build over a J-box

29 Items Found for 2022

Maintenance Update Inspections

Our inspection program prioritizes repair work:

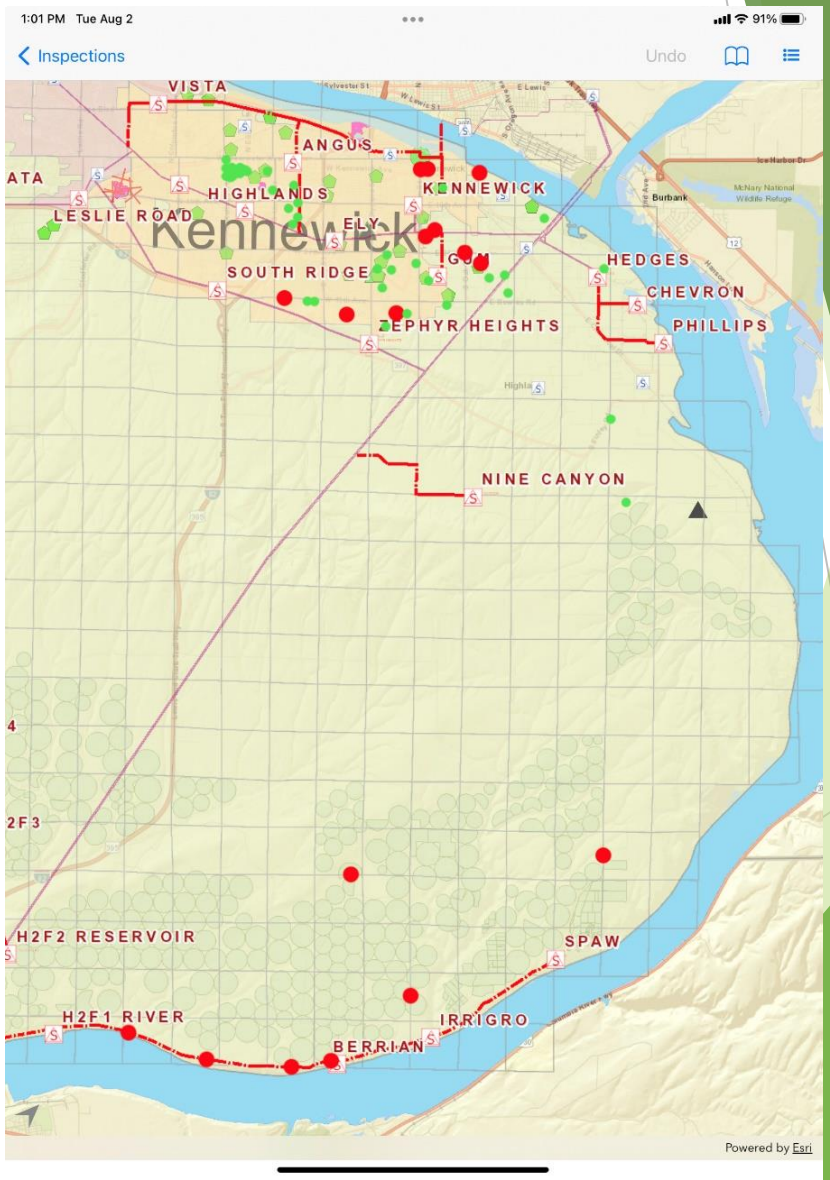
- *Low Priority*: Failure is not an immediate threat to public safety – repair within 3 months
- *Medium Priority*: Failure may lead to a threat to public safety – repair within 30 days
- *High Priority*: Failure is a probable threat – make emergency repairs as needed – full repairs within 48 hours



Maintenance Update Inspection Reports

The green dots represent everything that has been inspected.

A correction map is generated; now the green dots represent items corrected and red dots represent items that still need attention.



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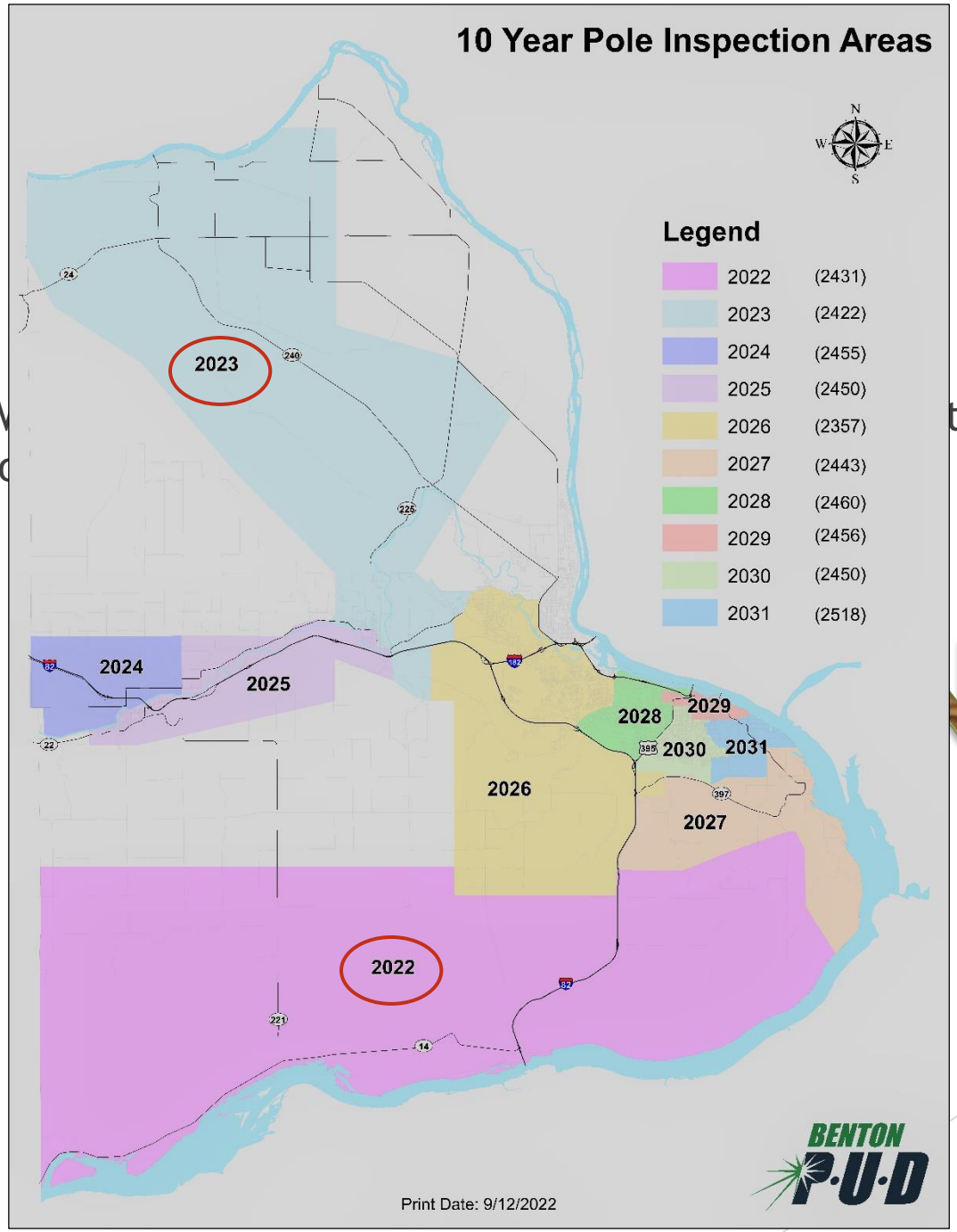
  to



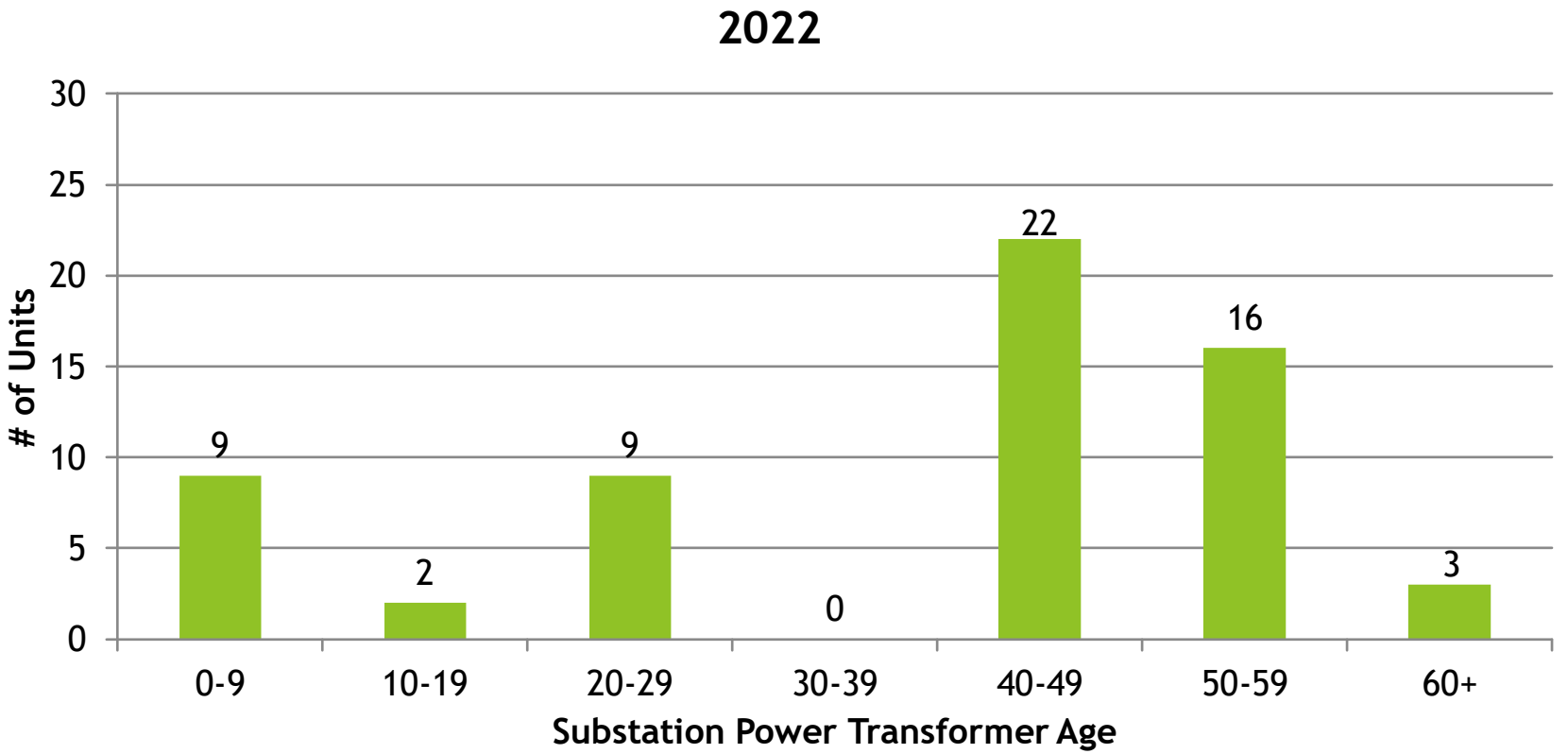
10 Year Pole Inspection Areas
N
W
E
S
Legend
2022 (2431)
2023 (2422)
2024 (2455)
2025 (2450)
2026 (2357)
2027 (2443)
2028 (2460)
2029 (2456)
2030 (2450)
2031 (2518)
2023
2024
2025
2026
2027
2028
2029
2030
2031
2022
Print Date: 9/12/2022
BENTON P·U·D

- 2021 Pole Testing Expense: $103,832
- Reject Poles: 4
  - 23% failure rate
- All were replaced
  - $5,632 average cost to replace

- 2022 Pole Testing Expenses: $208,145
- Reject Poles:
  - 74% failure rate
- 2022 Jobs are in the process of being scheduled; total cost is not available.

Transmission Distribution; 4 guy stub pole

Maintenance Update
Power Transformer Age



Maintenance Update
Power Transformer Wellness Chart

Location	DN	Last Test	Over	HVC1	LVC1	HVC2	LVC2	LVHC	HVSA	LVSA	Exc	Oil	TTR	LS	KF	DGA	FUR	ICP	LTC score	Total
Prior #4	13	2/3/2022	D	G	D	G	n/a	n/a	G	G	I	G	G	UN	QU	AC	AC		n/a	20
Inventory	57	11/24/2014	I	D	G	G	G	n/a	G	G	G	G	G	AC	QU	AC	AC		n/a	17
Inventory (Benton City Bay 2)	50	9/27/2016	I	G	G	G	G	n/a	G	G	G	G	G	AC	AC	AC	AC		n/a	12
Nine Canyon Bay 2	54	10/30/2018	G	D	D	D	D	n/a	G	G	G	G	G	AC	UN	AC	AC	AC	n/a	11
Prior #3	14	2/16/2016	G	G	G	G	G	I	G	G	I	G	G	AC	AC	AC	AC		n/a	9
Prosser Bay 2	48	10/24/2018	D	G	D	G	G	n/a	G	G	G	G	G	AC	QU	AC	AC		n/a	8
Angus Bay 1	40	4/19/2016	G	I	G	D	G	n/a	G	G	G	G	G	AC	AC	AC	AC		n/a	7
Ely Bay 2 (LTC)	31	5/10/2022	G	G	n/a	G	n/a	G	G	G	I	G	G	AC	AC	AC	AC		0	6
Orchard View Bay 1 (LTC)	32	5/4/2017	G	G	G	G	I	n/a	G	G	G	G	G	AC	AC	AC	AC		3	6
H2F #4	46	11/16/2017	G	G	G	G	G	n/a	G	G	I	G	G	AC	AC	AC	AC		n/a	6
Gum Street (LTC)	55	4/25/2018	G	G	G	G	G	n/a	I	I	G	G	G	AC	AC	AC	AC		0	6
Nine Canyon Bay 1	52	10/30/2018	G	G	I	G	G	n/a	G	G	G	G	G	AC	QU	AC	AC	AC	n/a	6
Phillips Bay 2	2	2/24/2021	G	D	n/a	G	n/a	n/a	G	n/a	G	G	G	AC	QU	AC	AC		n/a	5
Hedges	43	6/11/2018	G	D	n/a	G	n/a	G	I	G	G	G	G	AC	AC	AC	AC	AC	n/a	5
H2F #3	5	11/14/2017	G	D	n/a	G	n/a	G	G	G	G	G	G	QU	AC	AC	AC		n/a	5
Inventory (old Vista Bay 2)	20	5/11/2011	G	D	n/a	G	n/a	G	G	I	G	G	G	AC	AC	AC	AC		n/a	5
Kennewick Bay 3	35	10/28/2016	G	D	I	G	G	n/a	G	G	G	G	G	AC	AC	AC	AC		n/a	5
Angus Bay 3	39	6/7/2021	D	G	n/a	G	n/a	G	G	G	G	G	n/a	AC	AC	AC	AC		n/a	4
Irrigro	12	2/18/2016	D	G	n/a	G	n/a	G	G	G	G	G	G	AC	AC	AC	AC		n/a	4
Cold Creek	26	5/9/2018	D	G	n/a	G	n/a	G	G	G	G	G	G	AC	AC	AC	AC		n/a	4
Prior #2	45	1/30/2018	D	G	G	G	G	n/a	G	G	G	G	G	AC	AC	AC	AC		n/a	4
Phillips Bay 3	3	2/22/2021	G	D	n/a	D	n/a	n/a	G	n/a	G	G	G	AC	AC	AC	AC		n/a	3
Sandpiper	16	1/24/2019	G	G	n/a	G	n/a	G	G	G	G	G	G	AC	QU	AC	AC		n/a	3
Sunheaven #1	17	12/1/2016	G	G	n/a	G	n/a	G	G	G	G	G	G	AC	QU	AC	AC		n/a	3
Sunheaven #2	24	2/6/2017	G	G	n/a	G	n/a	G	G	n/a	G	G	n/a	AC	QU	AC	AC		n/a	3

Maintenance Update Testing

- Substation Transformers are tested every 6 years (previously this was every 3 years for units with load tap changer).
- In 2021, 12 transformers were scheduled, tested and maintained. This was out of 57 in-service total units.
- In 2022, 9 transformers, including the mobile sub, have been scheduled, tested, and maintained to date.
- An additional 10 are scheduled for the remainder of 2022 and winter 22/23.
- 9 transformers are scheduled for testing/maintenance in 2023.

Maintenance Update Testing

- Substation Breakers / Reclosers and Line Devices are inspected, tested, and maintained on a 2 – 6 year annual cycle.
- In 2021, 12 station breakers / reclosers were tested, inspected, and cleaned and 44 were inspected out of 121.
- In 2021, 22 of 229 line devices were scheduled, tested and inspected.

Aging Infrastructure Overview

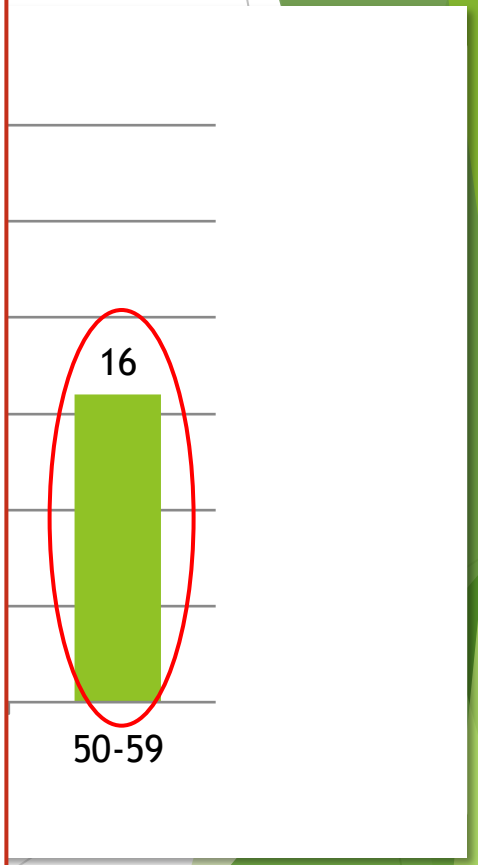
Power Transformer Age

Capital Budget Planning: 2025 – 2035

These 16 Transformers will need to be evaluated for replacement.

Cost: Approx $800K each
Cost Over 10 Years: Approx $12.8M

Cost Per Year (Avg): $1.3M



Power Transformer Age

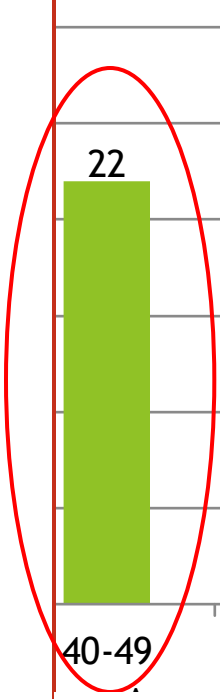
Capital Budget Planning: 2035 – 2045

These 22 Transformers will need to be evaluated for replacement.

Cost: Approx $800K each

Cost Over 10 Years: Approx $17.6M

Cost Per Year (Avg): $1.8M



Substation Metalclad Replacement

Substation Metalclad Replacement

Capital Budget Planning:

Ely Bay 1:	2022:	$500K
Vista Bay 1:	2023:	$1.03M
Vista Bay 2:	2025:	$770K

Substation Breaker/Recloser Replacement

Substation Breaker/Recloser Replacement

Capital Budget Planning:

Angus Bay 2	2022:	$187K
Angus Bay 1	2022:	$210K
Angus Bay 3	2023:	220K

2025 – 2035:

Kennewick:

All 9 Breakers: $560K

Prosser:

All 6 Breakers: $373K

Substation 3Ø Regulators

Capital Budget Planning:

Prosser Bay 1 2022: $572K

Prosser Bay 2 2023: $611K

Hedges 2023: $42K*

**Using Spare Regulator*

Major Projects Oak Street

Oak Street

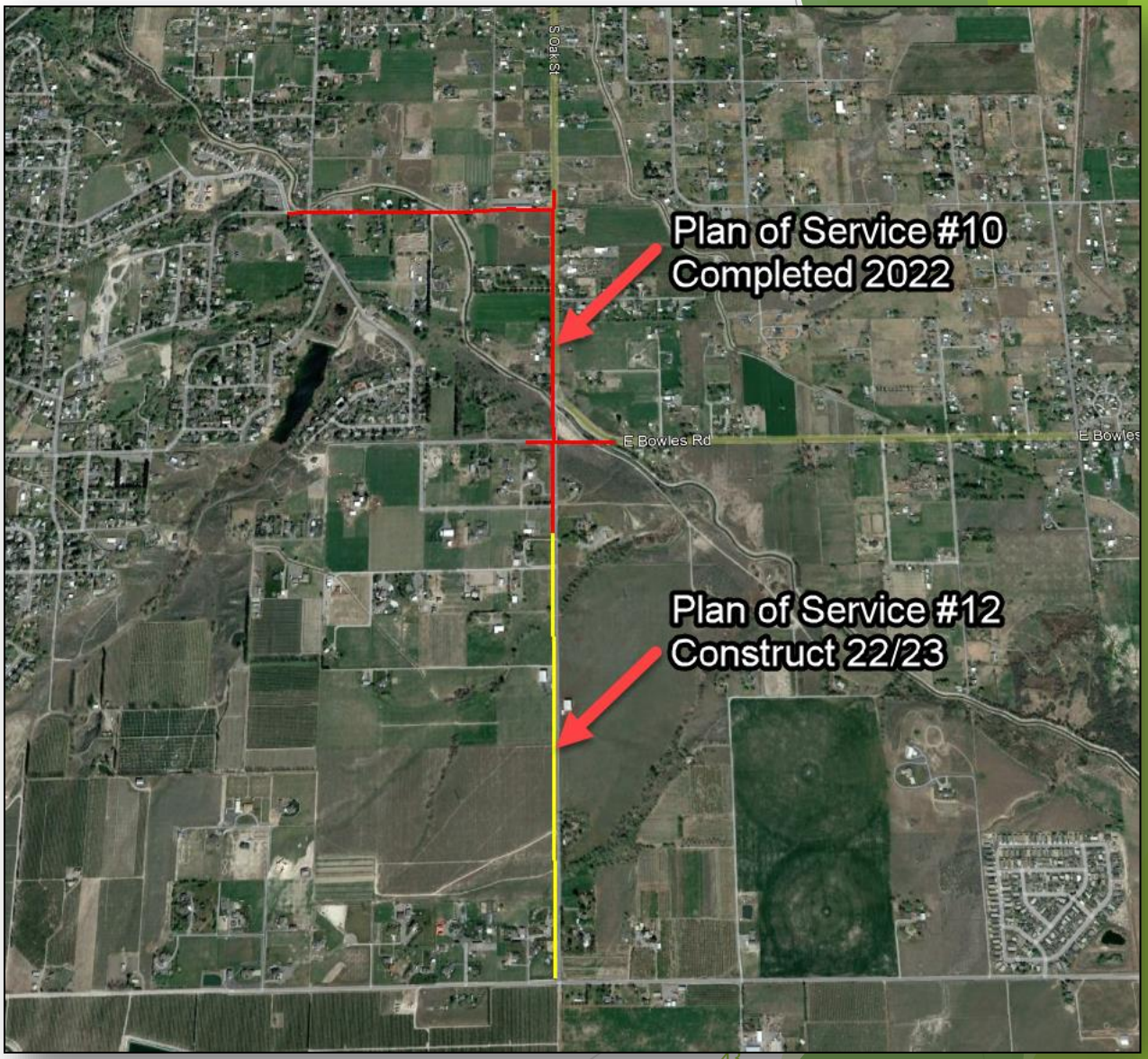
Capital Budget:

#10: Reconductor 3Ø and add second circuit:

$650K

#12: Reconductor:

$200K



Major Projects Clodfelter

Clodfelter

Capital Budget:

Reconductor: $523K

Major Projects Wallowa

Wallowa

Capital Budget:

#115: Cable installation and reconductor:

$330K

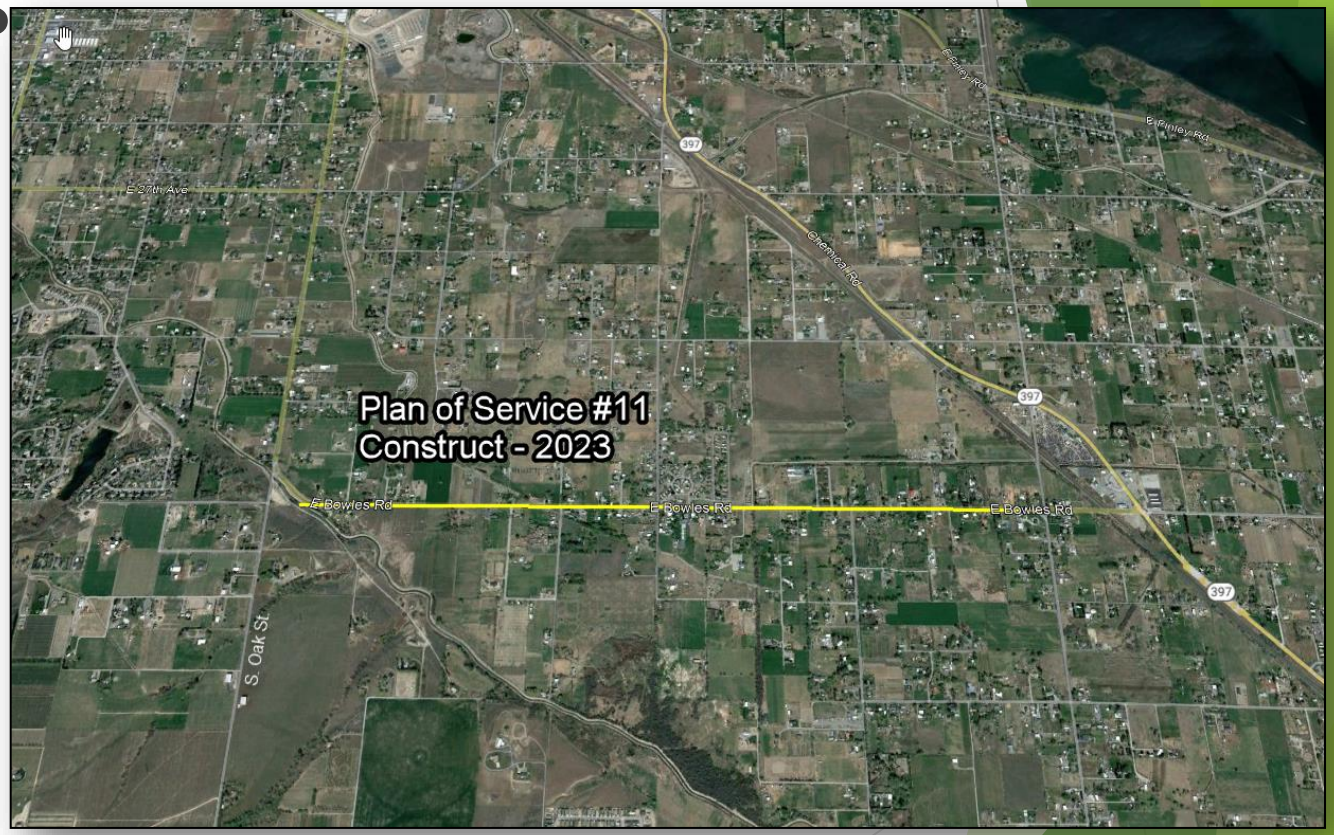
Major Projects - 2023

East Bowles Road

Capital Budget Planning:

Reconductor: $518K*

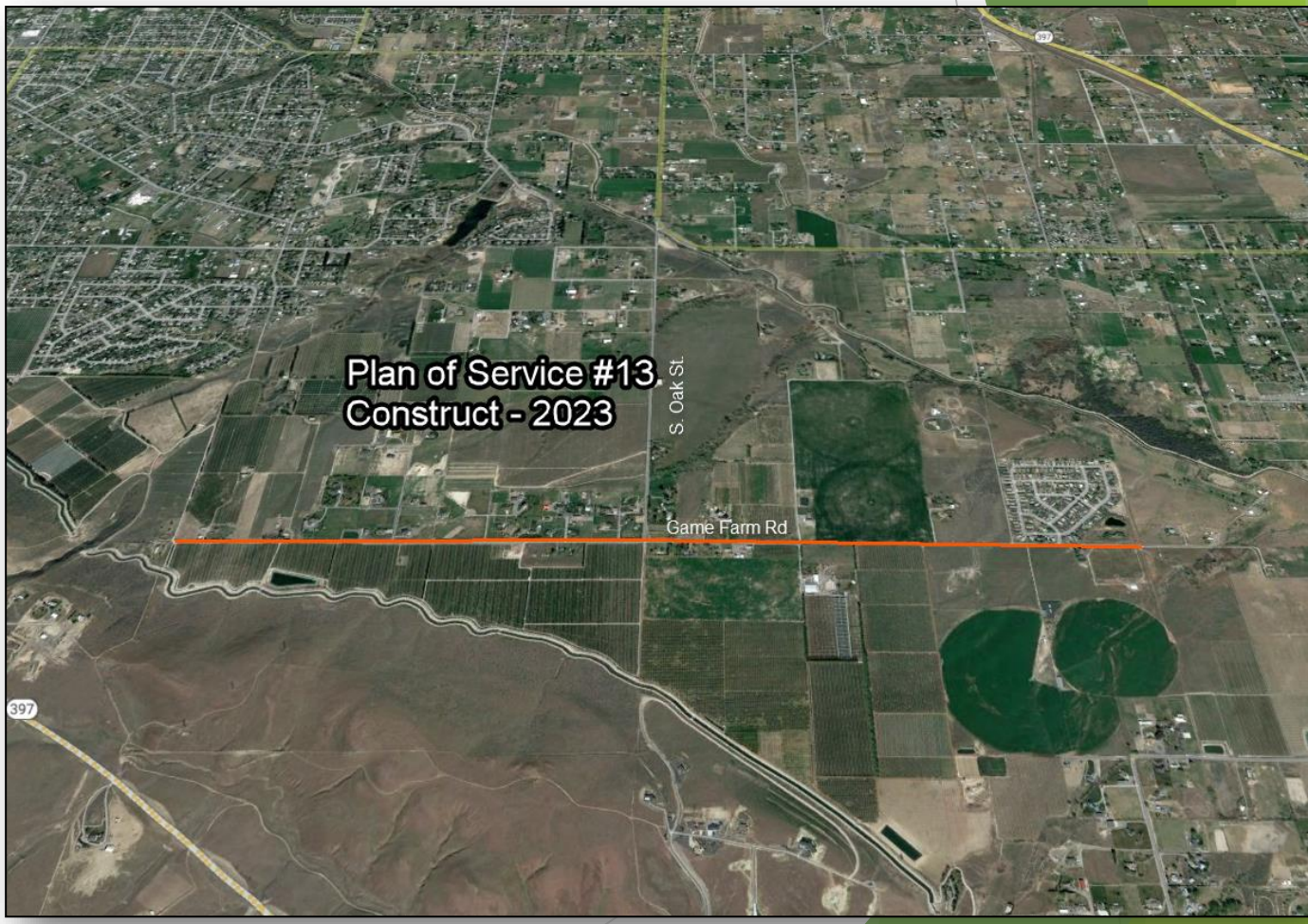
**All but one pole between S. Oak Street and Haney Road have some type of OH device on it*



East Game Farm Road

Capital Budget Planning:

Reconductor: $327K



Benton City Feeder to Sunset Road

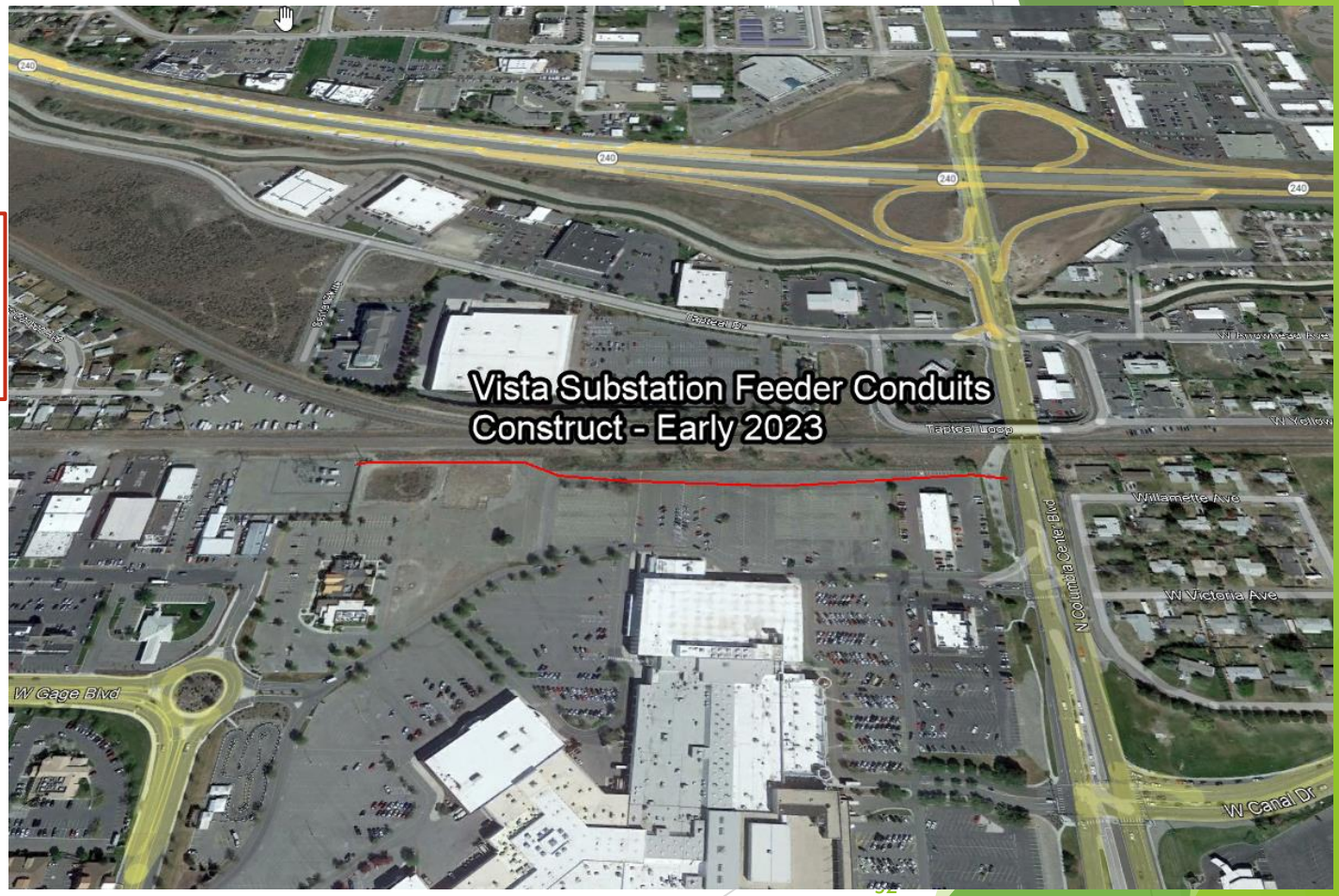
Capital Budget Planning:

Reconductor: $915K

Vista Substation Feeder Getaway

Capital Budget Planning:

Replacements: $564K



Questions?

DEMAND RESPONSE

Developing a *cost-effective*, *reliable* *and* *feasible* demand response program

DATE: 10/11/22

Agenda

#1
Status

#2
Northwest

#3
Drivers

#4
Potential

#5
Strategy

#6
Timeline

#1 - STATUS

Is the District planning for demand response?

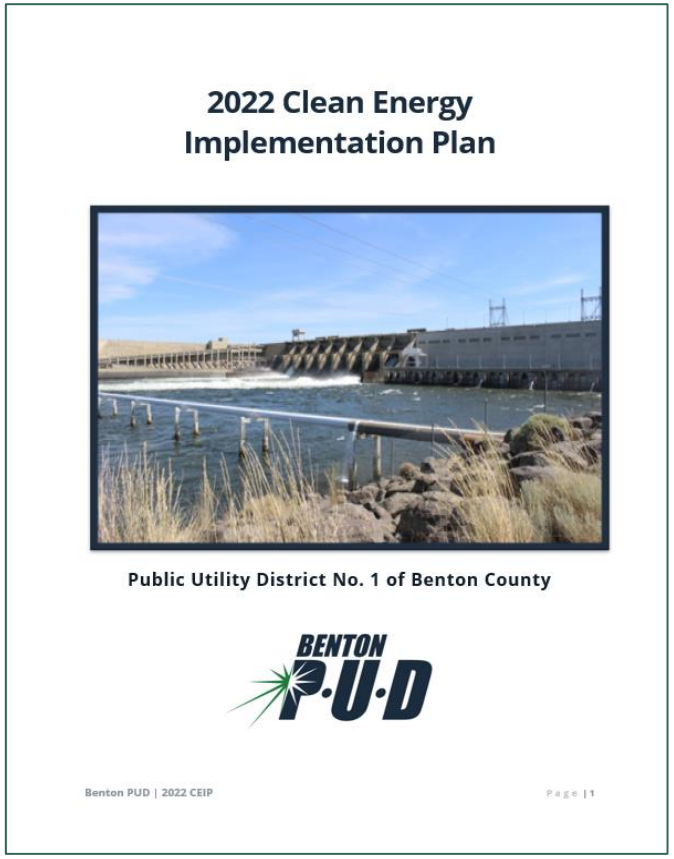
2019 Strategic Planning Session – Demand Response (DR)

- **Date:** October 8, 2019
- **Title:** *What about Demand Response? As a capacity resource*
- **Question:** Should the District consider demand response as a capacity resource?
- **Takeaways:**
  - **DR should be considered** as a potential capacity resource
  - DR program development is **complex**
  - District is **well positioned**, especially due to our **enabling technology**, to develop a program
- **Key recommendations:**
  1. **Proceed with evaluating DR programs, including rate-based options**, for **cost-effectiveness, reliability and feasibility**, consistent with the requirements of the Clean Energy Transformation Act (RCW 19.405).
  2. Move towards an IRP process that evaluates the economic potential of DR as a capacity resource.
  3. Presented a preliminary timeline of a path forward for DR program implementation planning.

See District website for the meeting presentation (pages 65-108),
https://www.bentonpud.org/getattachment/Board-Meetings/2019/2019-10-08/Commission-Handouts-2019-10-08-website.pdf.aspx?lang=en-US&ext=.pdf

DR in the Clean Energy Implementation Plan (CEIP)

DR Target was 0 MW for 2022-2025



Resolution No. 2585 - Nov 9, 2021

From the 2022-2026 CEIP:

1. "The District expects to complete its first ever **demand response potential assessment (DRPA)** in the Fall of 2021."
2. "The District plans to utilize the DRPA results and subsequent analysis as an **input to its next full IRP update in 2024**."
3. "After first determining the potential DR measures that are both cost-effective and achievable, the District would then **require time to plan for implementation and customer engagement**."
4. "**Final development** of any DR programs that are cost-effective, reliable, and feasible are unlikely to occur until the end of the interim period at the earliest."
5. "It is expected that DR resources will be **further assessed in the next interim performance period 2026-2029** as the District continues researching DR programs."

DR Target may stay at 0 MW for the 2026 CEIP

#2 - NORTHWEST

Is the Northwest Planning for Demand Response?

Northwest Power and Conservation Council (NWPCC)

2021 Power Plan

March 2022

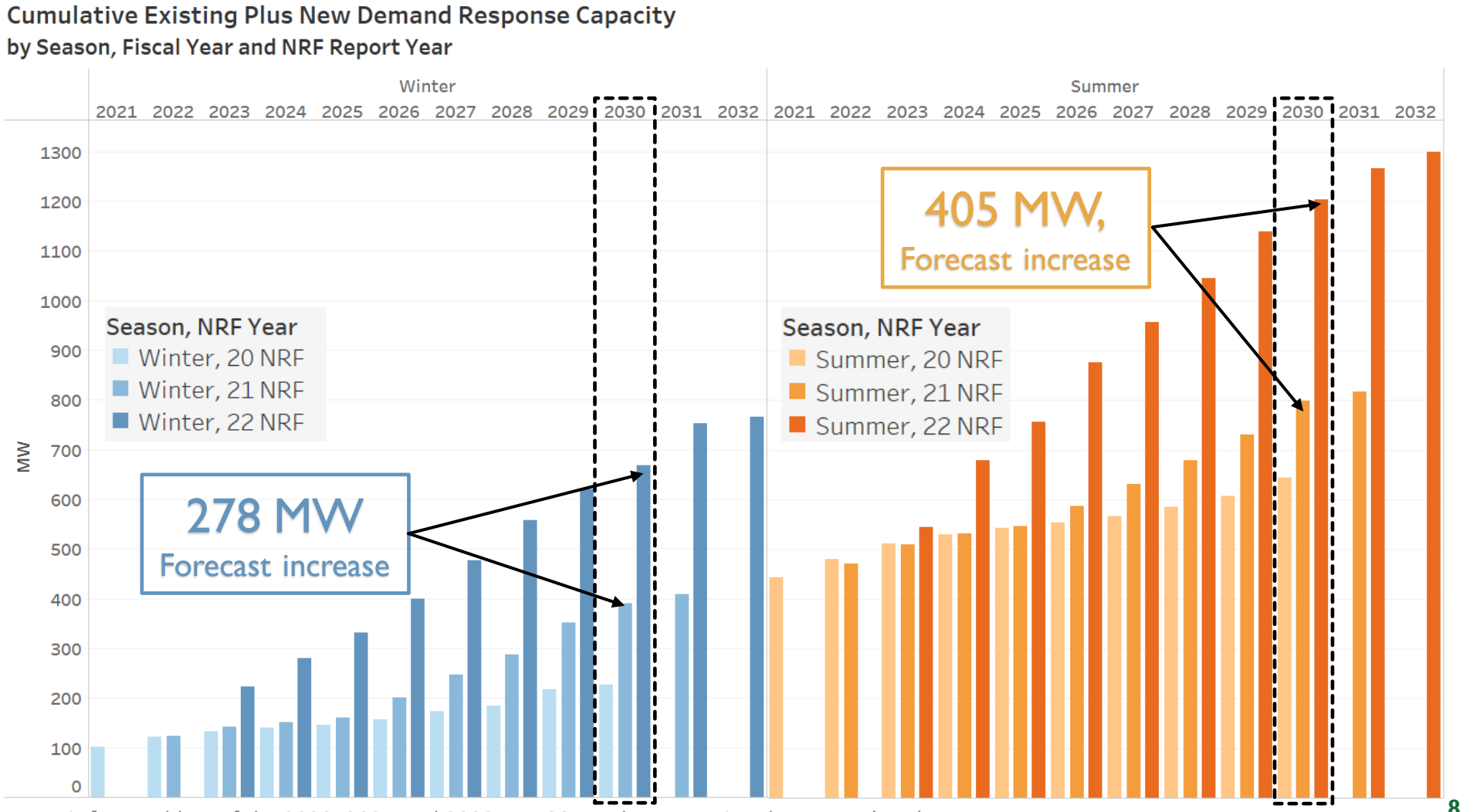
- Council recommends DR types that are **"frequently deployable, low cost, and with minimal customer impact"**
- Council recommends utilities examine two types of DR:
  - **1) Residential Time-of-Use (TOU) Rates**
    - *Plan target is 200 MW by 2027*
  - **2) Demand Voltage Regulation (DVR)**
    - *Plan target is 520 MW by 2027*

***"Bonneville should work to enable and encourage its customer utilities to pursue these** and other low-cost and high-value demand response measures in an equitable manner."*

Pacific Northwest Utility Conference Committee (PNUCC) – 1 of 2

2022 Northwest Regional Forecast
(Apr 2022)

"This year's report contains a ***notable increase in projected demand response*** *over time."*

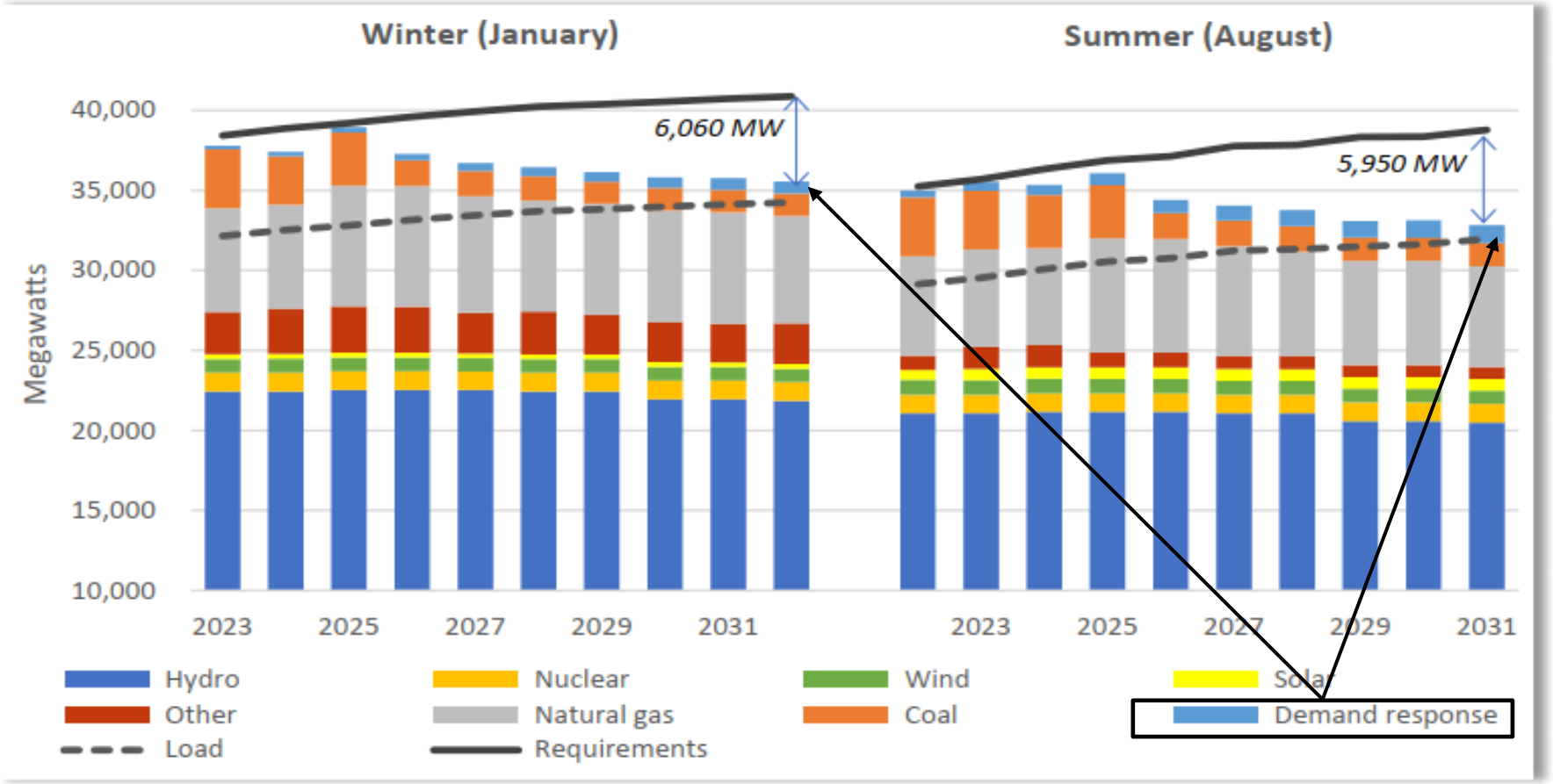


Data is from Table 7 of the 2020, 2021 and 2022 PNUCC Northwest Regional Forecast (NRF).

Pacific Northwest Utility Conference Committee (PNUCC) – 2 of 2

Although growing, DR remains a **very small portion (~2% - 4%) of the region's total** planned resources

Figure 5. **Peak Capacity Load/Resource Picture**



Data is from Figure 5 of the 2022 PNUCC Northwest Regional Forecast.

Bonneville Power Administration (BPA)

2022 Resource Program *(Preliminary)*

- DR is part of the **least-cost** resource strategy, **for the first time**
  - 436 MW Summer, 283 MW Winter **by 2027**
- DR **products selected**:
  - Critical Peak Pricing (CPP)
  - Demand Voltage Regulation (DVR)
- Based on BPA's **Dec. 2021 DRPA**

*"DR shows up as a **regularly deployed, low impact, low cost** energy related load management product" – 6/28/22 BPA Presentation*

*"**It will take some time** for BPA managers to internally discuss next steps related to the Demand Response selected in the Resource Program." – 8/18/22 BPA Staff*

BPA 20-Year (2022-2043) DR Potential - 1 of 2

Figure 4. 20-Year Summer Achievable Potential Supply Curve with Levelized Cost (2016$)

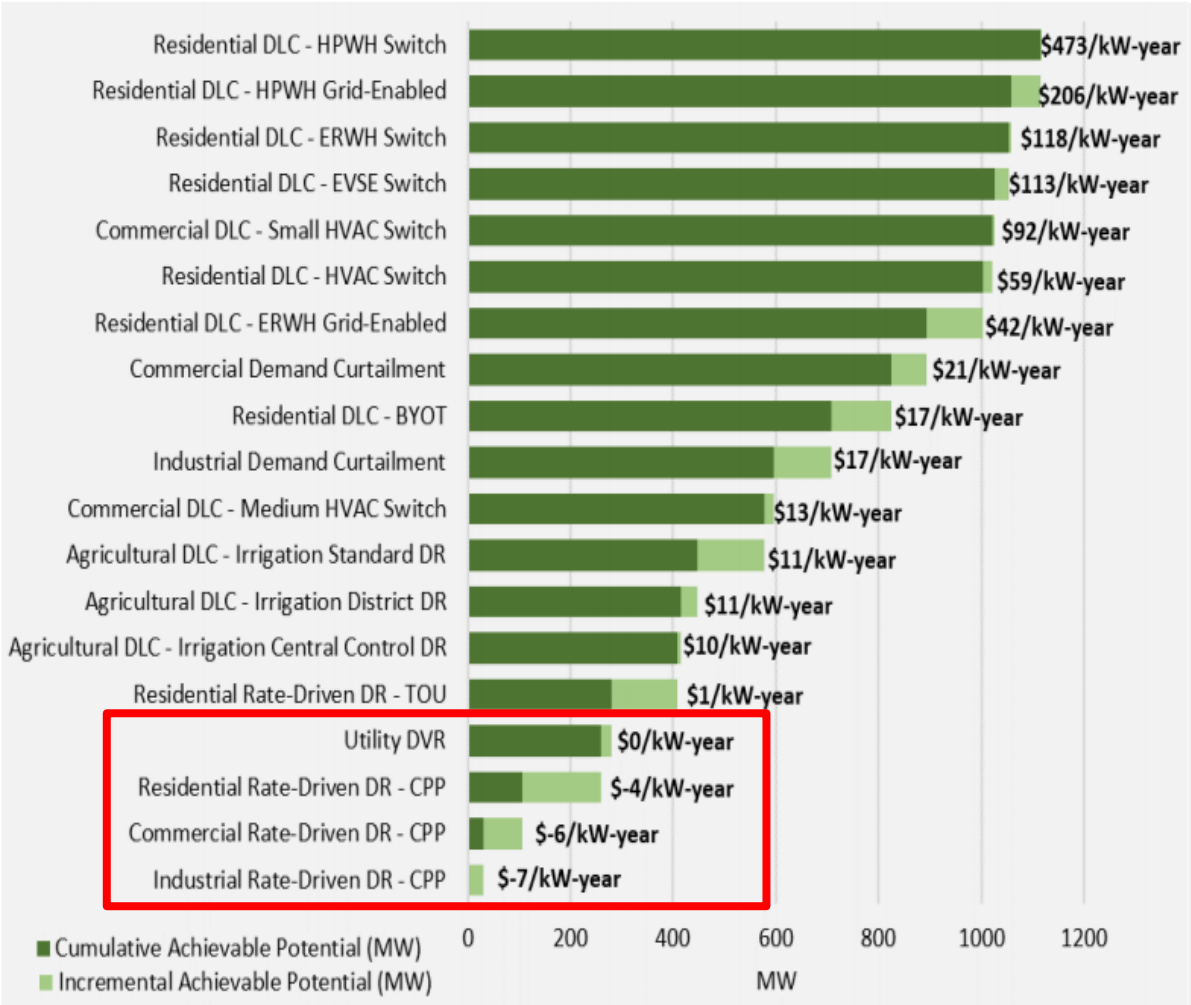
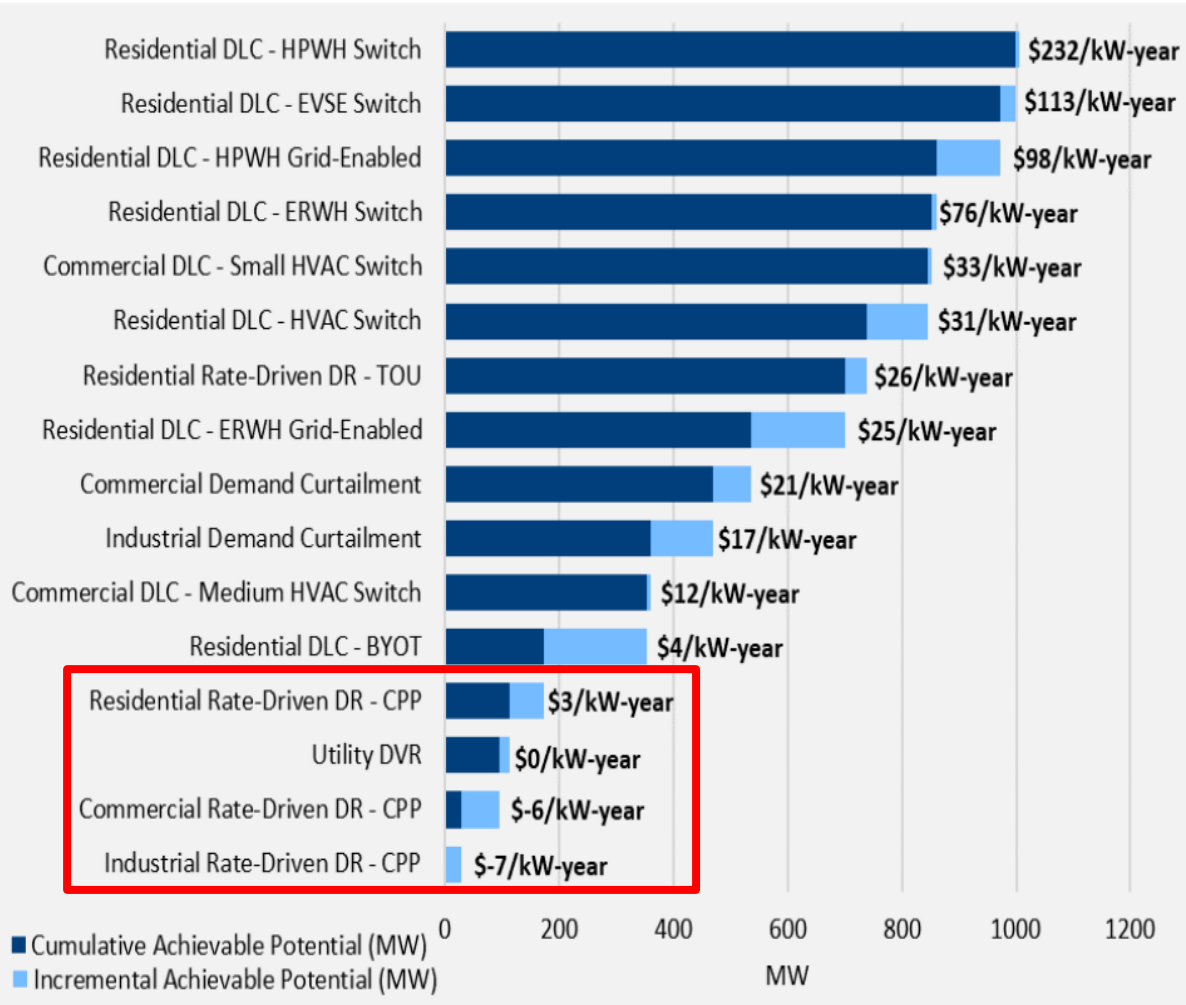


Figure 5. 20-Year Winter Achievable Potential Supply Curve with Levelized Cost (2016$)



Figures are from BPA's December 2021 Demand Response Potential Assessment.

BPA 20-Year (2022-2043) DR Potential - 2 of 2

Figure 12. Typical Operations Annual Summer Achievable Potential Forecast

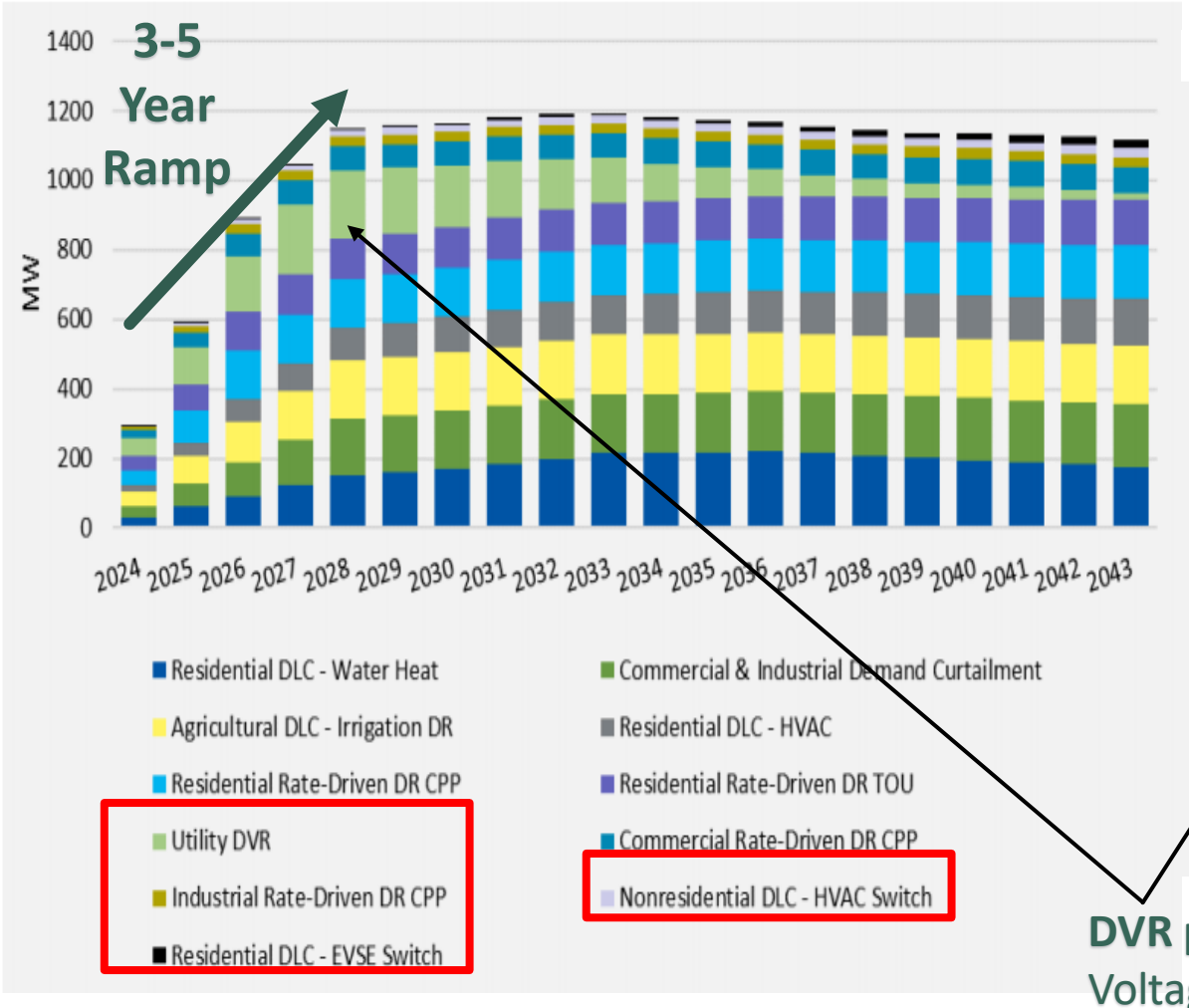
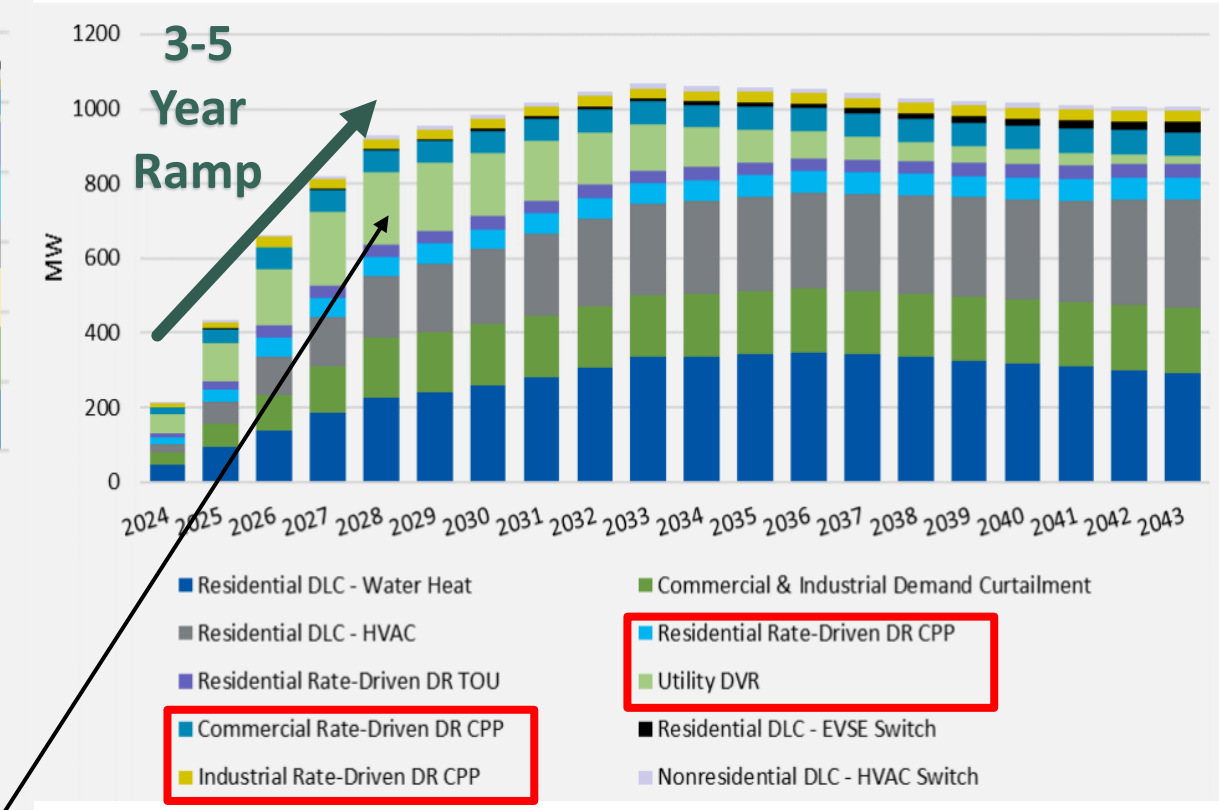


Figure 13. Typical Operations Annual Winter Achievable Potential Forecast



DVR potential decreases over time due to growth of Voltage Optimization/Conservation Voltage Reduction (CVR)

Figures are from BPA's December 2021 Demand Response Potential Assessment.

DR at Seattle City Light

- 2022-2025 CEIP, **DR Target = 0 MW**
- 2022 IRP includes new DR:

NEW RESOURCE ADDITIONS BY TIME PERIOD	2022–2031	2032–2041	TOTAL
Solar (MW)	175	0	175
Wind (MW)	225	50	275
Energy Efficiency (aMW)	85	31	116
Customer Solar Programs (MW)	24	28	52
Summer Demand Response (MW)	47	31	78
Winter Demand Response (MW)	79	43	122

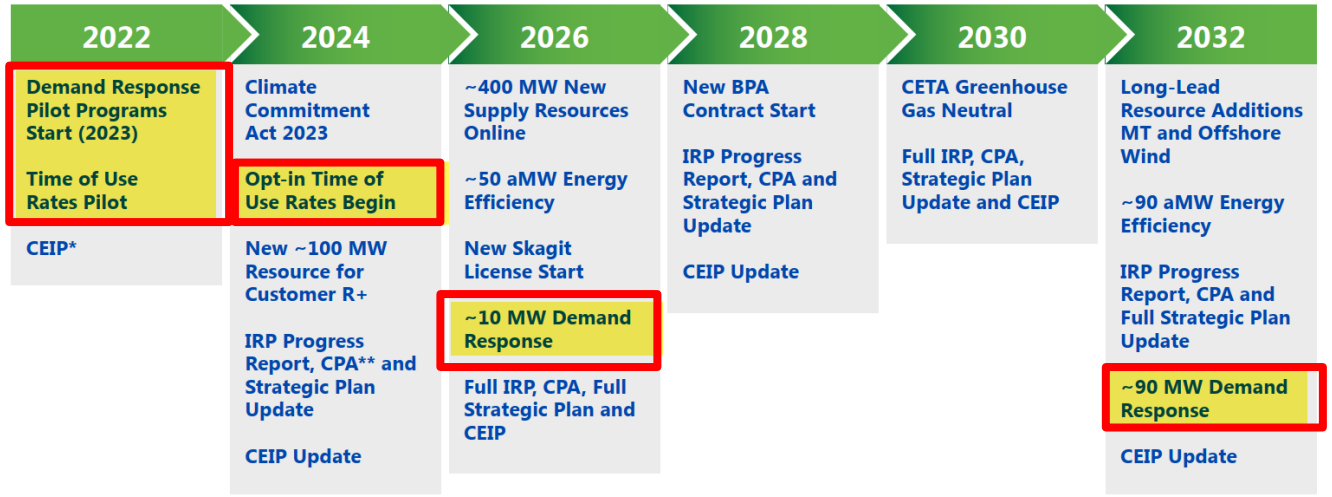
2022 IRP Recommended Top Portfolio Plan

Table 8 Demand Response Program Size Over Time

Program	Summer			Winter		
	2025	2030	2040	2025	2030	2040
Commercial/Industrial Curtail	2	11	11	2	8	9
Thermostat	1	7	12	3	36	51
Resistance Water Heating	6	40	65	7	43	70
Heat Pump Water Heating	0	2	3	1	5	7

*"The 2022 IRP is the **first to recommend a portfolio that endorses demand response programs**, as they not only manage climate- or electrification-related extremes, but also generally reduce customers' energy burden." – SCL 2022 IRP*

2022 IRP Ten Year Important Milestones



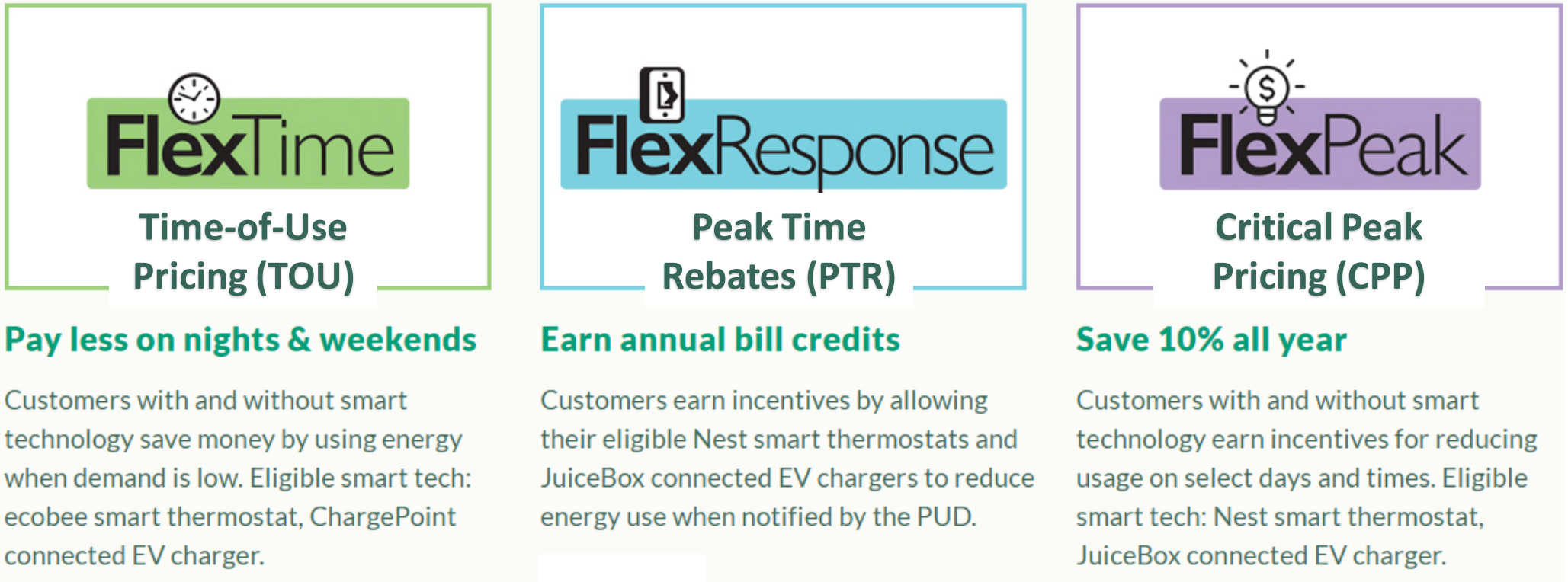
*CEIP – Clean Energy Implementation Plan a requirement of the Clean Energy Transformation Act.
**CPA – Conservation Potential Assessment.

Seattle City Light 2022 IRP: https://www.seattle.gov/documents/Departments/CityLight/2022IntegratedResourcePlan.pdf

DR at Snohomish PUD – 1 of 2

- 2022-2025 CEIP, **DR Target = 5.6 MW** by 2025
- Residential "FlexEnergy" Pilots (Oct 2021 – Mar 2023):

Also known as:



Graphic is from Snohomish PUD's FlexEnergy website: https://www.snopud.com/save-energy/residential/flexenergy/

DR at Snohomish PUD – 2 of 2

Avoided Costs

Avoided market power purchases

- During peak events, market power purchase prices were typically 54% higher ($62.32 per MWh) than in other hours (average $40.44 per MWh).
- On Dec. 20, the PUD called an event when prices were $126.26 per MWh or 312% higher than average.

Costs avoided thanks to shifting energy use off-peak

with a natural gas generator:*
$7,876

with utility battery storage:
$14,177

What would that mean scaled up?

If 10,000 customers had been part of FlexEnergy, it would have avoided costs of:

Natural gas generator: $144,514
Utility battery storage: $260,128

If 100,000 customers had been part of FlexEnergy, it would have avoided costs of:

Natural gas generator: $1,445,138
Utility battery storage: $2,601,284

Graphics are from Snohomish PUD's FlexEnergy Year 1 Winter Summary Report: https://www.snopud.com/wp-content/uploads/2022/07/FlexEnergyWinterSummary.pdf

#3 - DRIVERS (PART 1 OF 2)

Why is the District considering demand response?

Steve Wright's Perspective on DR

APRIL 1, 2022 - CLEARING UP QUESTION?

"Volumetric rates work in a system focused on energy costs, but they're increasingly out of step with a renewable resource-heavy system with a growing need for capacity. **Where do you see rate structures headed?**"

STEVE WRIGHT'S RESPONSE:

"**We're headed toward dynamic rates** for a bunch of really clear reasons that make a lot of sense. **We need consumers to be more involved** on their side of the meter to help balance the system.

I am not optimistic, I will admit, about the **reliability** components right now. I've been very concerned about **resource adequacy** going back to 2017, 2018 when we first started doing these studies showing what would happen if we went to 80 percent or higher clean energy standards in the Northwest.

The time frame that we're looking at with some legislation—particularly Washington's Clean Energy Transformation Act—and the time frame to develop resources don't seem to match up very well. **I think that means we're going to have a lot more demand response…"**

https://www.newsdata.com/clearing_up/opinion_and_perspectives/utilities-strive-to-keep-up-as-pace-of-change-accelerates/article_539cdd54-b215-11ec-b01a-a3d827585602.html

Example of a DR Event in California

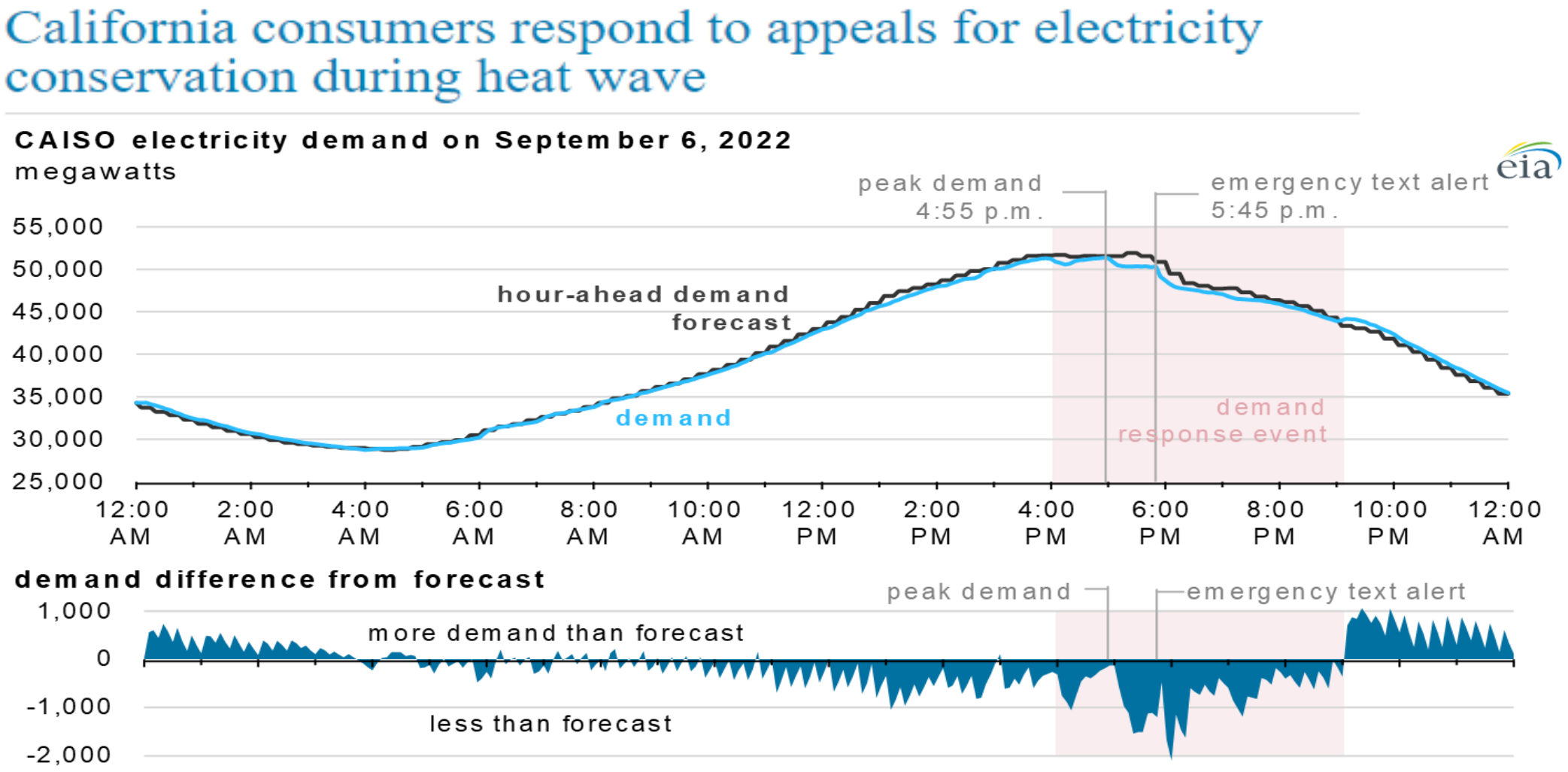
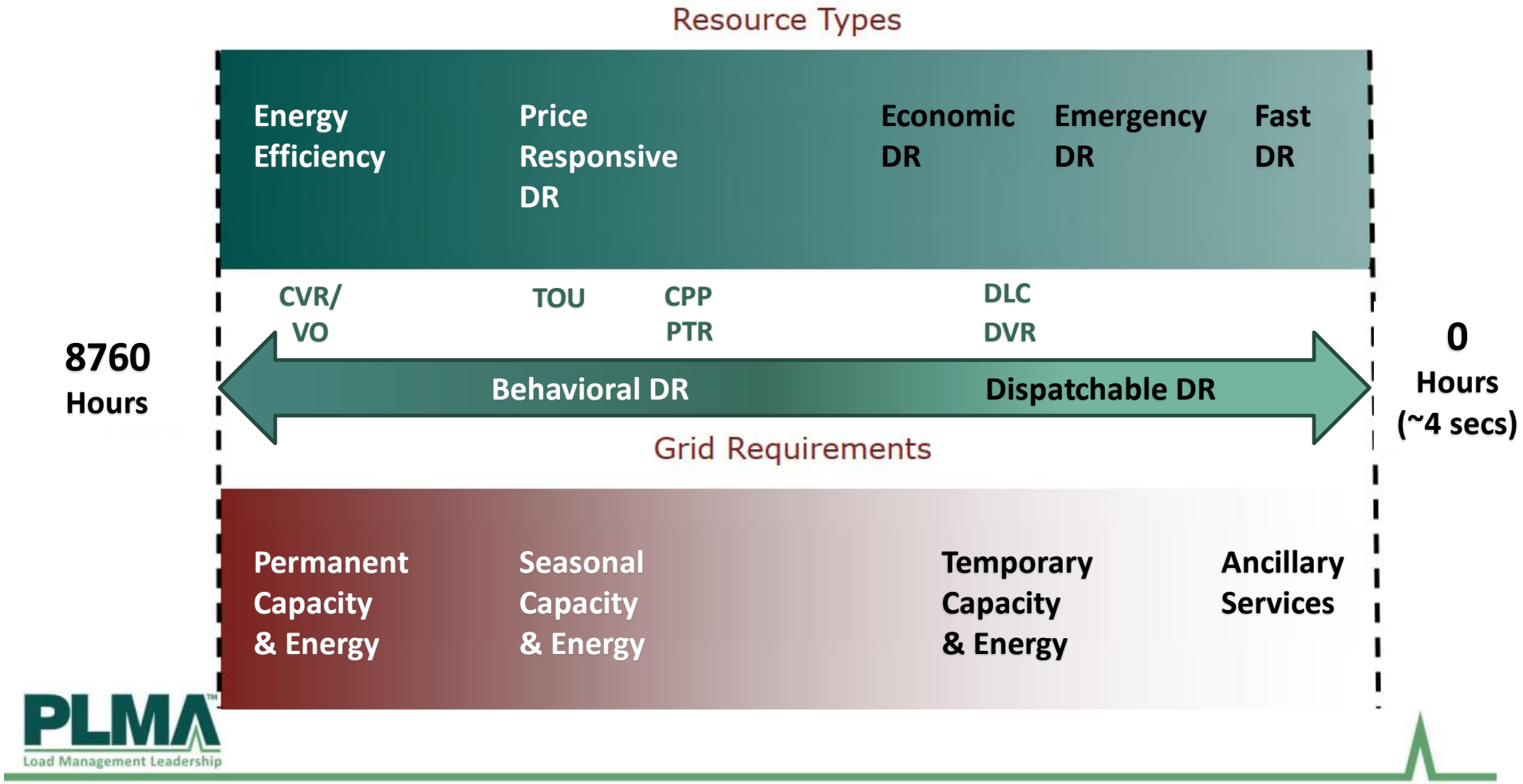


Image is from a 9/28/22 article by the U.S. Energy Information Administration (EIA): https://www.eia.gov/todayinenergy/detail.php?id=54039

Spectrum of Grid Needs and DR Types



DLC	Direct Load Control
DVR	Demand Voltage Reduction/Regulation
CVR	Conservation Voltage Reduction/Regulation
VO	Voltage Optimization
TOU	Time-of-Use
CPP	Critical Peak Pricing
PTR	Peak Time Rebate

Slide adapted from Peak Load Management Association's (PLMA) Demand Response Training Series - "Program Design & Implementation" (9/22/20).

The District's Primary Driver for DR

- **AS-IS** (Slice/Block BPA Contract)

  From the District's "DR Program Development" project agreement (6/12/20):

  Desired Results

  Consistent with the District's 2020-2021 Strategic Plan and 2020 Integrated Resource Plan action plan, this project agreement is to develop a comprehensive demand response program that addresses the District's seasonal power supply deficits, reduces market exposure as market volatility increases with the retirement of dispatchable resources, and supports the District's compliance with Washington State's Clean Energy Transformation Act (CETA). The demand response program developed and implemented must be beneficial to Benton PUD customers by reducing power supply cost increases and/or risk and must be consistent with the District's Rate Strategy and the associated cost-causation principles included in the District's cost of service analysis.

- **TO-BE** (Load Following BPA Contract) *Effective Oct 1, 2023*
  - BPA power bill **demand charges**
  - CETA compliance remains a driver of **DR evaluation**

Washington's Clean Energy Implementation Plan Rules

WAC 194.40.200(3)(b) – Demand response resources.

The CEIP must specify a target for the amount, expressed in megawatts, of demand response resources to be acquired during the period. The demand response target must comply with WAC 194-40-330(2).

Existing target 0 MW, specified in **2021**

Next target to be specified in **2025**

WAC 194.40.330(2) – Demand response resources.

(a) Assessment of potential. Each utility must assess the amount of demand response resource that is cost-effective, reliable, and feasible.

DRPA

(b) Target. The demand response target for any compliance period must be sufficient to meet the utility's obligation under RCW 19.405.040(6) and must be consistent with the utility's integrated resource plan or resource plan and any distributed energy resource plan adopted under RCW 19.280.100.

CETA Greenhouse gas neutral by 2030

District expects to meet CETA RCW **without DR**

(c) Measurement and verification. Each utility must maintain and apply measurement and verification protocols to determine the amount of capacity resulting from demand response resources and to verify the acquisition or installation of the demand response resources being recorded or claimed. The utility must document the methodologies, assumptions, and factual inputs used in its measurement and verification of demand response resources."

Targets **require** measurement & verification

Other Drivers for DR

- **Other BPA charges**
  - BPA coincident peak demand (Network transmission bill)
  - Load shaping (Load Following power bill)
  - Avoided Tier 2 power purchases
- **T&D Planning & Operations**
  - Deferring system upgrades
  - Accommodating electrification/decarbonization
  - Accommodating distributed energy resources
- **Emergency Load Reduction**
  - BPA energy or transmission emergency
  - District transmission or distribution emergency
- **Plus, one more CRITICAL driver of program design…**

THE 2021 NORTHWEST POWER PLAN

*"We identified that demand voltage regulation (DVR) and time-of-use (TOU) rates **can help substantially in ramping and peak periods**. Additional value may also be obtained to **relieve transmission constraints and defer transmission and distribution system upgrades**."*

Customer Needs – Trusted Energy Partner

- **How do I…**
  - save **money**?
  - help the **grid**?
  - use new **technology**?
  - support **clean energy**?
  - support the **community**?
  - use energy more **efficiently**?

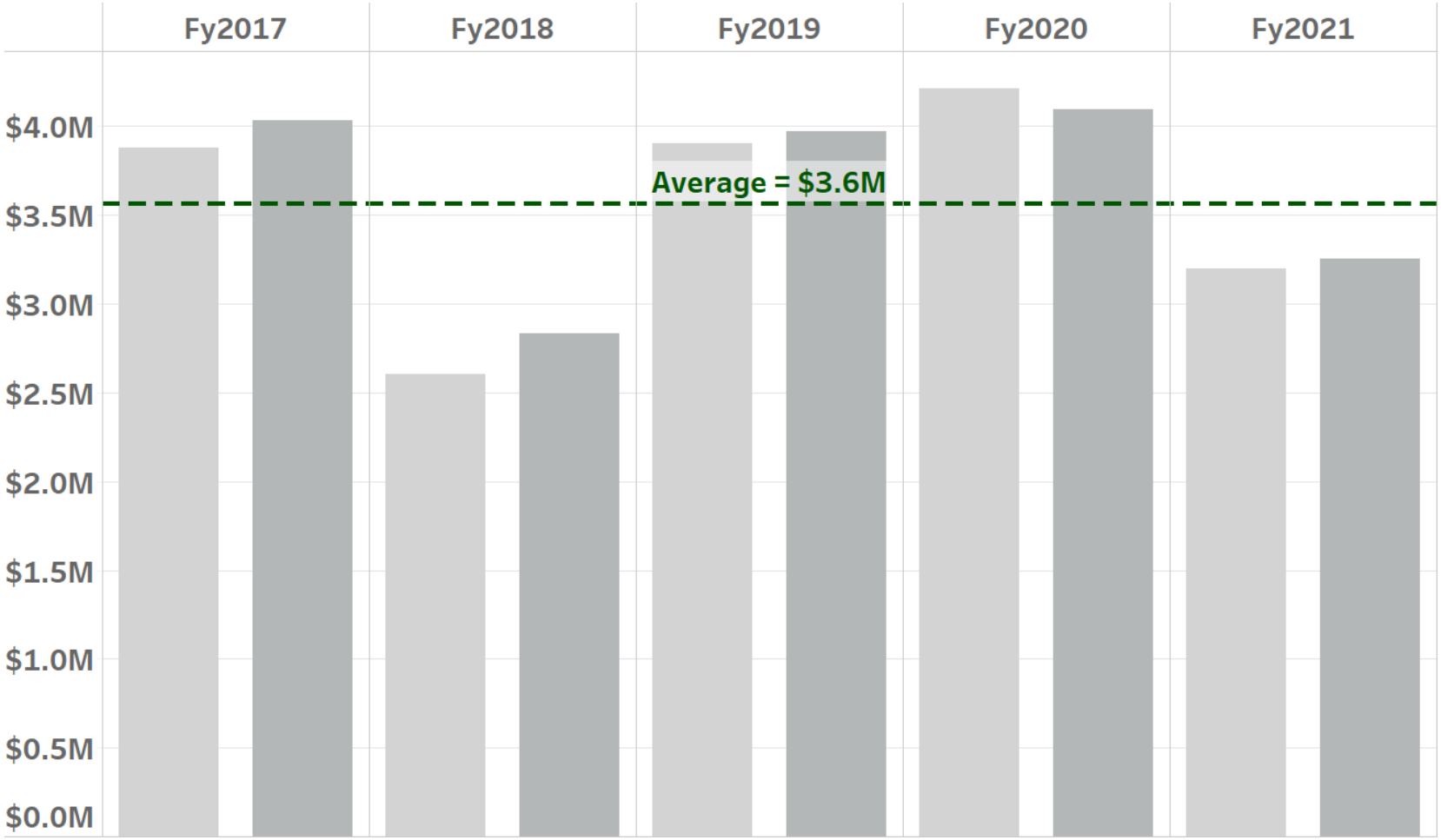
DR program design should identify opportunities for meeting customer needs.

$

#3 - DRIVERS (PART 2 OF 2)

What are BPA's Demand Charges?

Annual Cost of BPA Demand Charges



About
$3.6M per year,

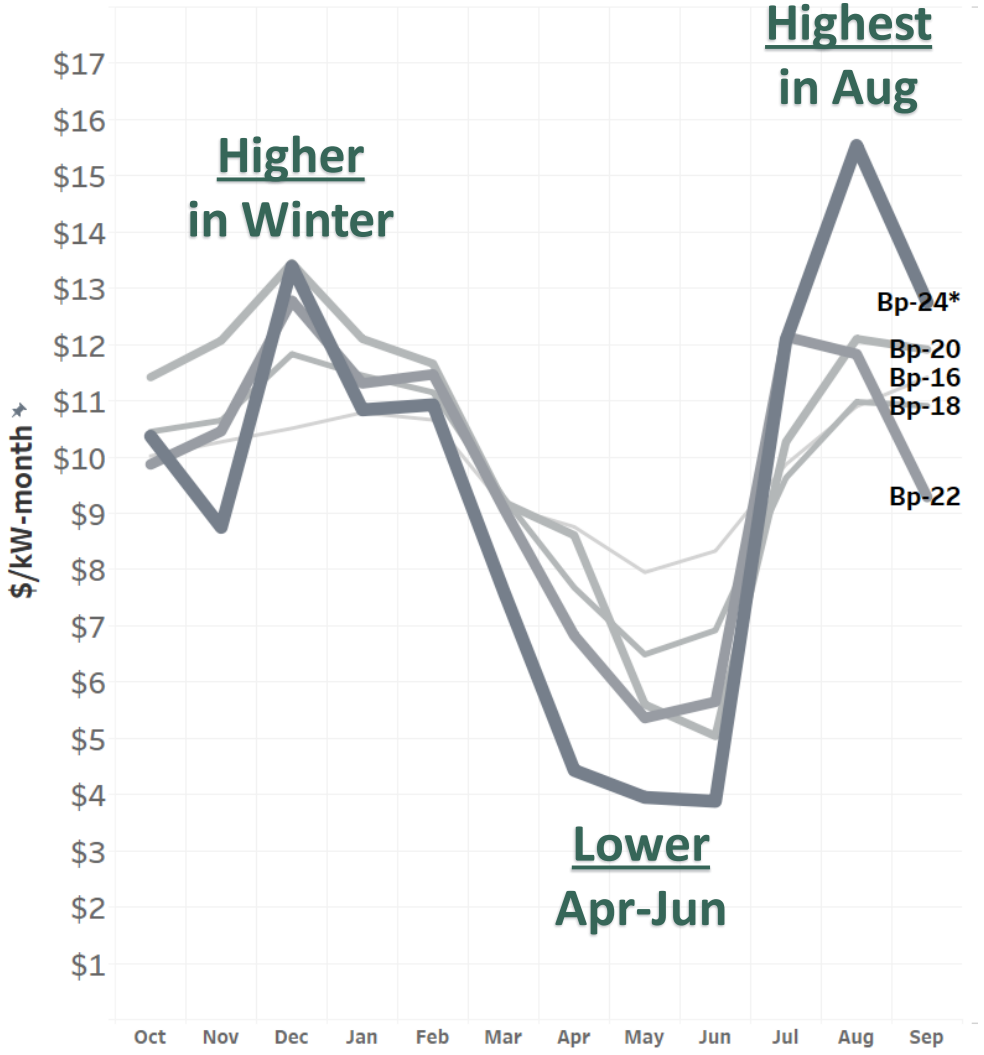
if the District had been Load Following

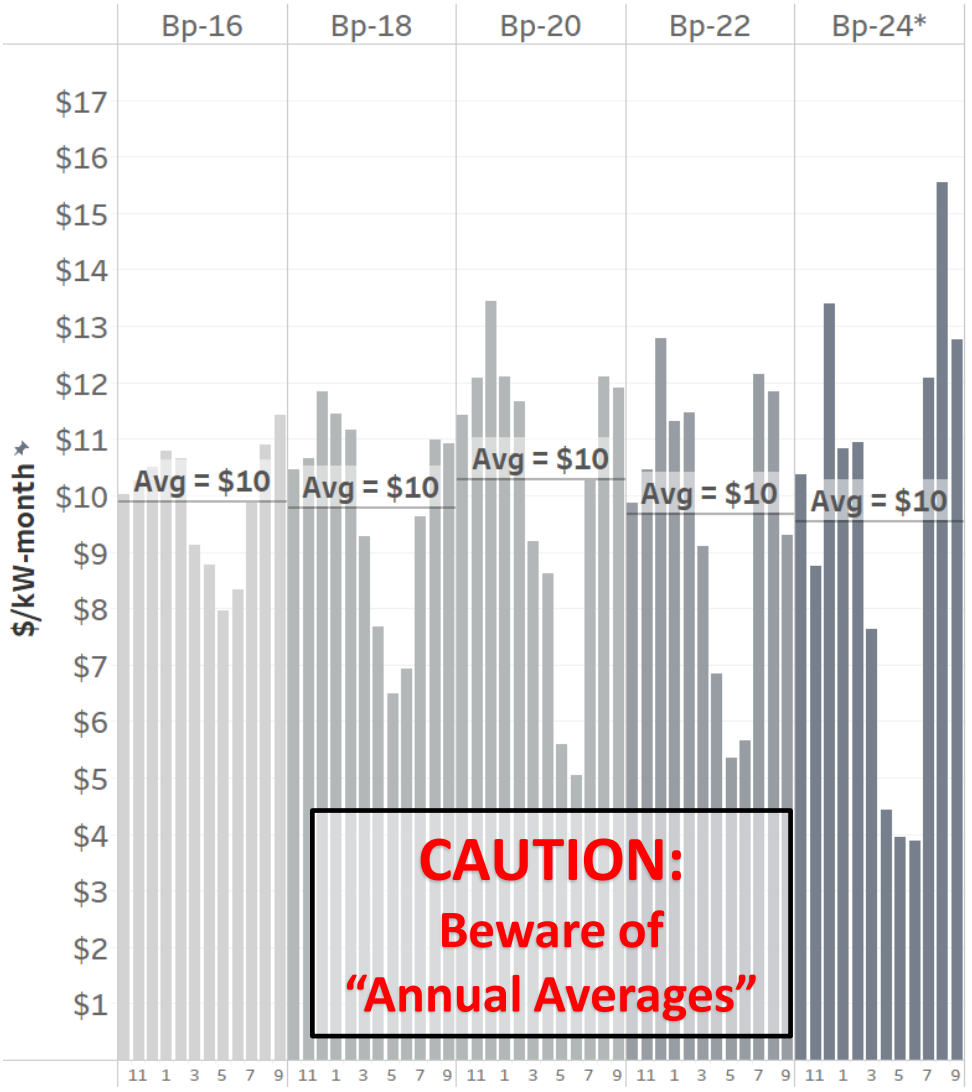
Scenario Description
- Historical Rates w/CDQ
- BP-24* Rates w/CDQ

CDQ to be explained later

Estimated fiscal year demand charges using BPA's Rate Impact Model (RIM), assuming historical actual load with historical demand rates and historical load with (*) BP-24 proposed demand rates .

BPA's Monthly Demand Rates



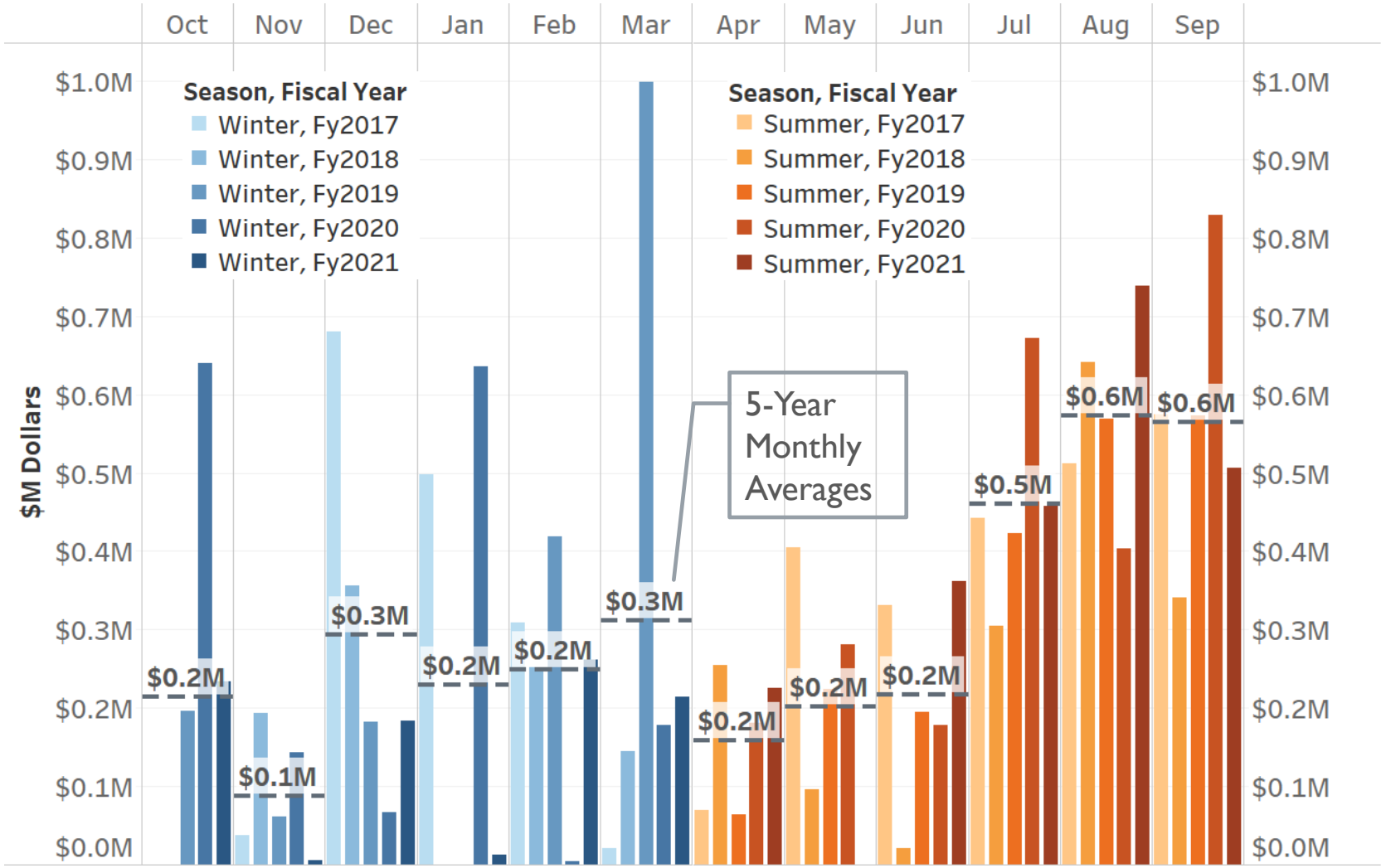


Demand Rates:

1. **Rates** represent marginal cost of new capacity
2. **Vary** by month
3. **Change** over time

* BP-24 proposed demand rates

Monthly Cost of Demand Charges

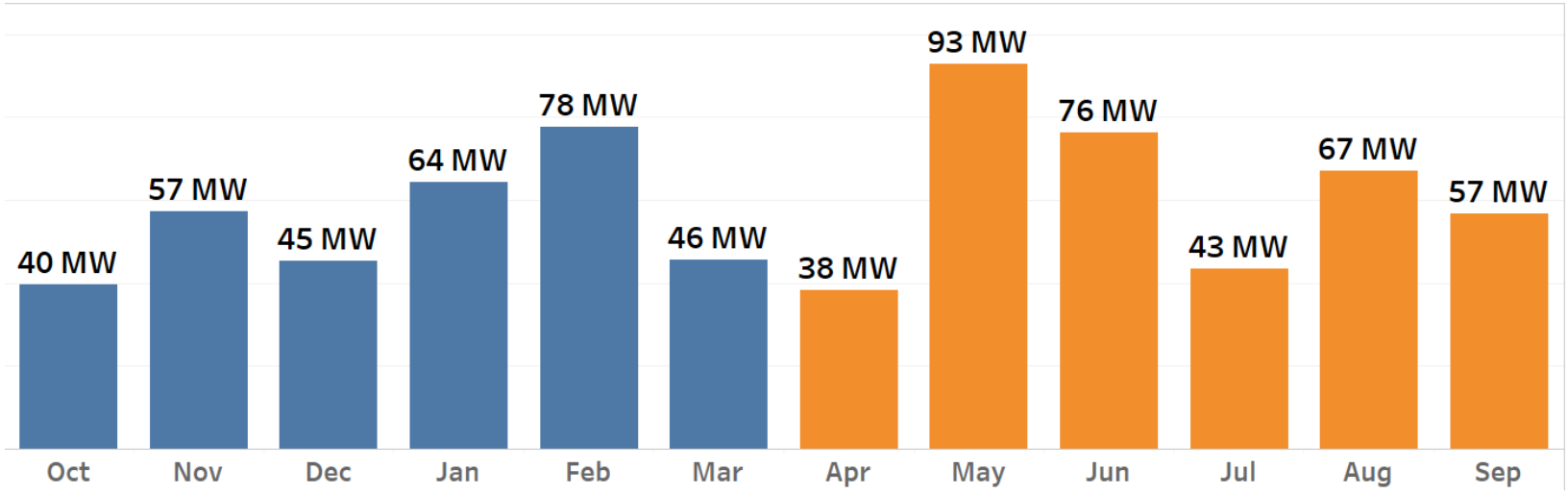


Demand Charges:

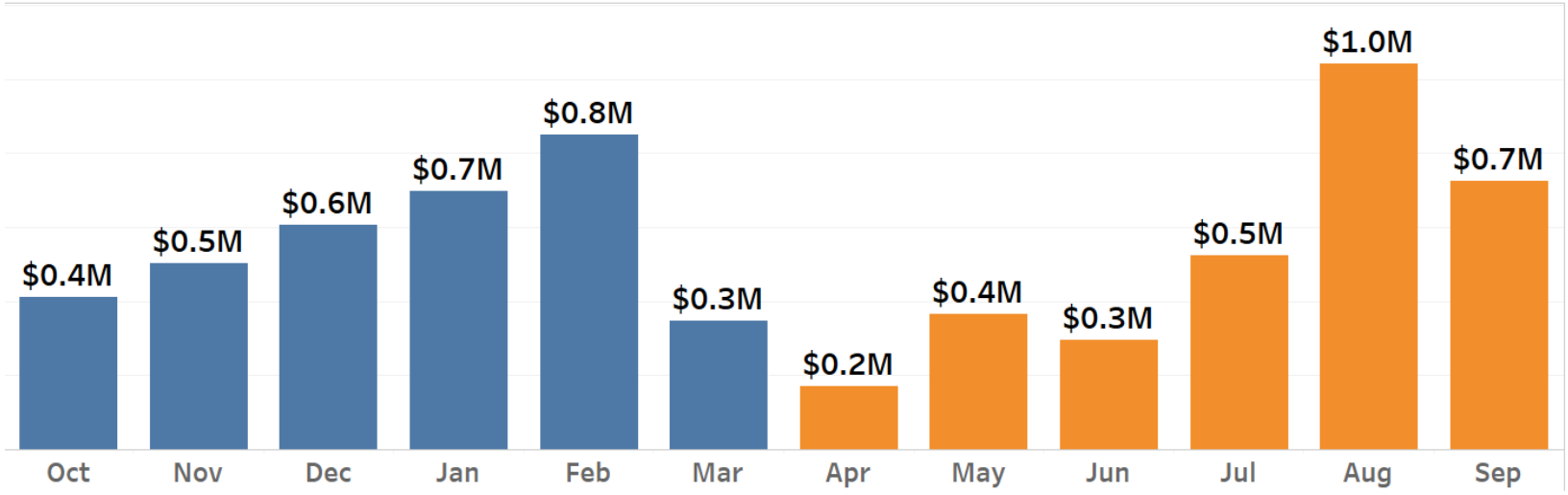
1. **Vary by month <u>from $0-$1M</u>**
2. Vary due to peak & average load
3. **Vary over time,** due to BPA rate changes
4. **Reduced** by Contract Demand Quantity (CDQ)

Estimated monthly demand charges using BPA's Rate Impact Model (RIM), assuming historical actual load with historical demand rates.

Contract Demand Quantity (CDQ)

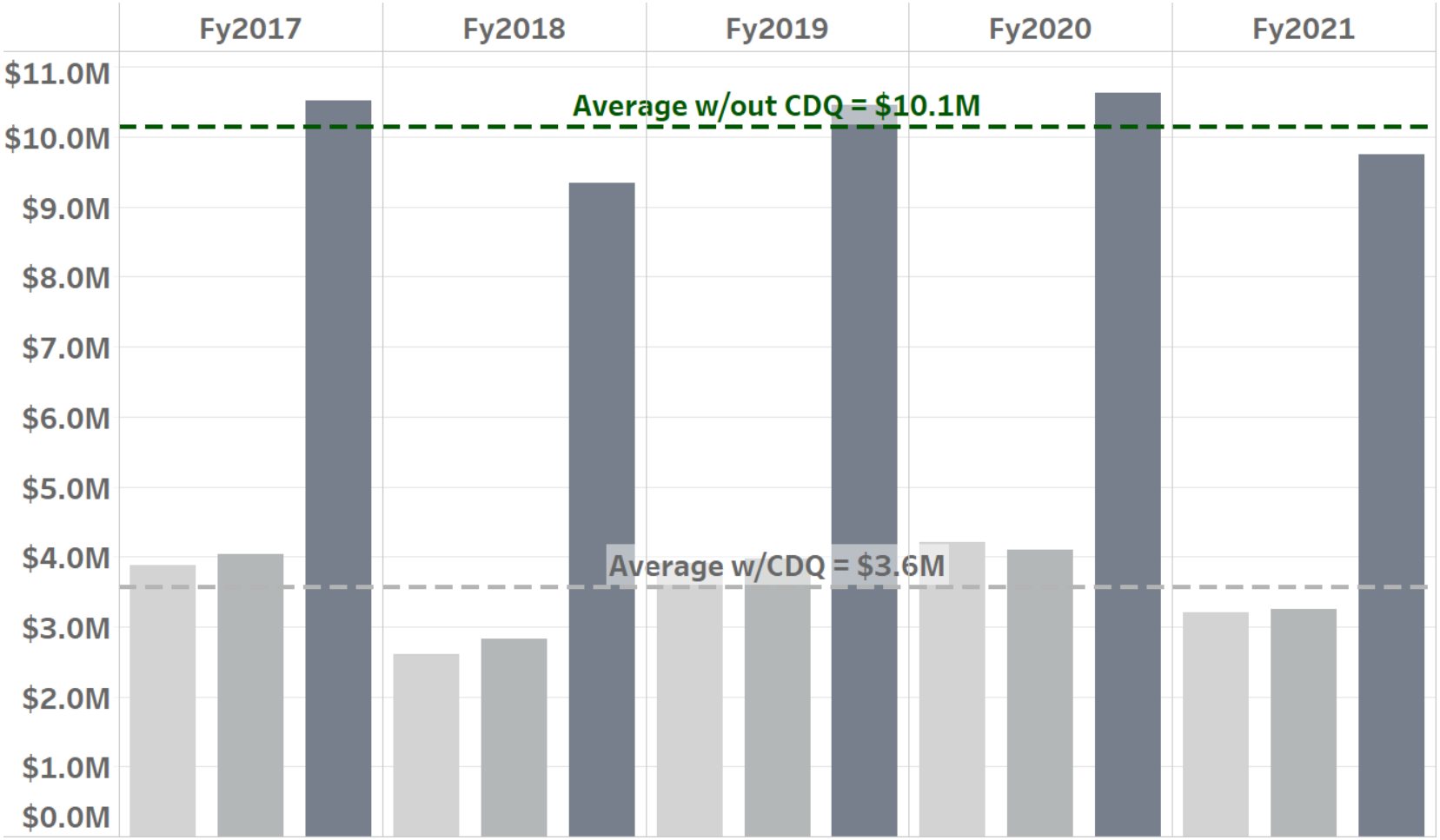


Monthly CDQ values in Megawatts (MW)



Monthly CDQ savings in Millions of dollars ($M), based on BP-24 Proposed Rates

Annual Cost of BPA Demand Charges without CDQ

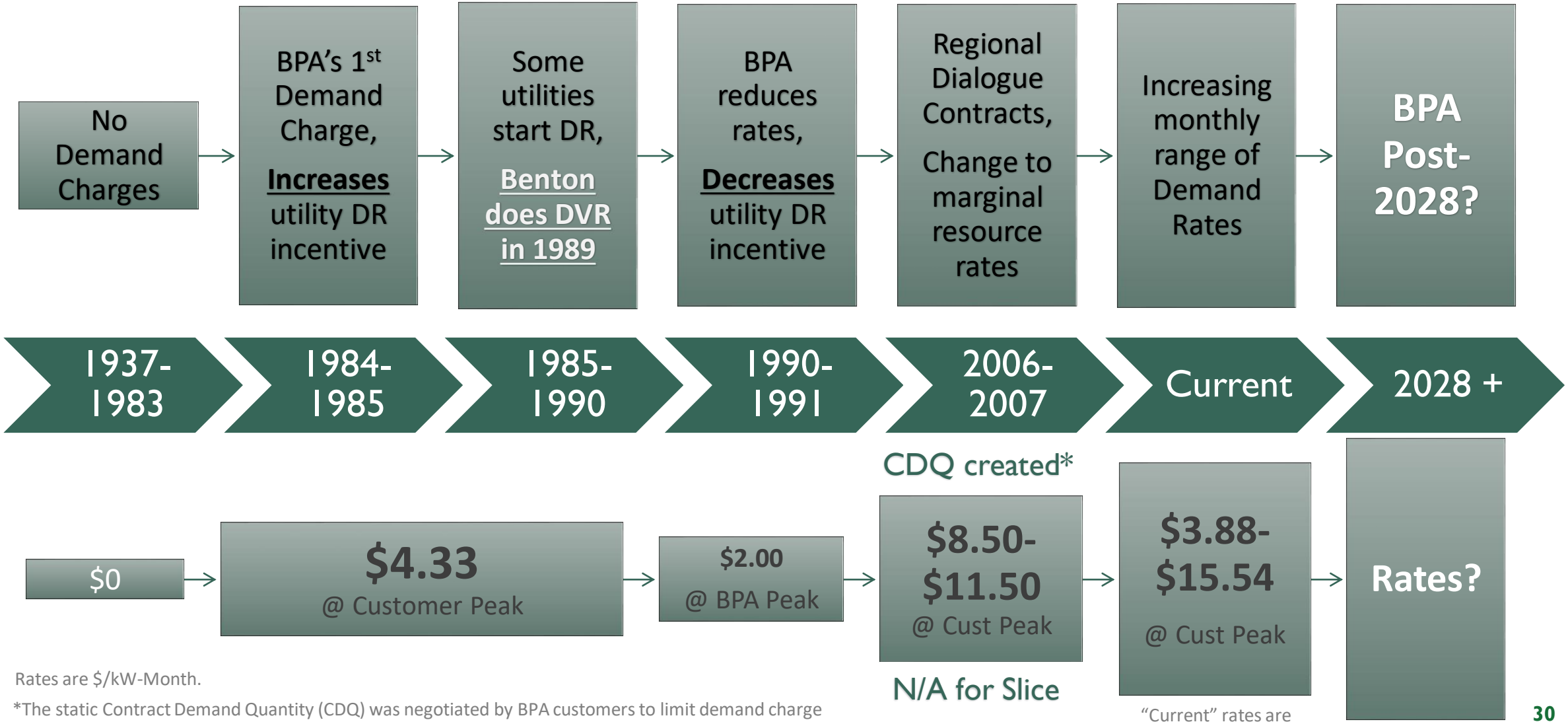


Annual cost **increases by $6.5M**

*"With regard to Contract Demand Quantity (CDQ), **Bonneville does not intend to use these values** in the rate design applicable during the Provider of Choice contract period." - **BPA Post-2028 Concept Paper***

Estimated fiscal year demand charges using BPA's Rate Impact Model (RIM), assuming historical actual load, (*) BP-24 proposed rates, and without the existing Contract Demand Quantity (CDQ).

History of BPA Demand Charges



Rates are $/kW-Month.

*The static Contract Demand Quantity (CDQ) was negotiated by BPA customers to limit demand charge cost increases by "grandfathering" a portion of the utility's 2006 peak demand, reducing their billed kW.

"Current" rates are BP-24 proposed.

#4 - POTENTIAL

What is the District's demand response potential?

Demand Response Potential Assessment (DRPA)

What is DR Potential?

- Estimates how many MWs of load reduction (or other load modification) are feasible over time
- Represents what could be achieved given certain conditions are met (e.g., customers accept the program, cost effectiveness, etc.)

Why is it Important?

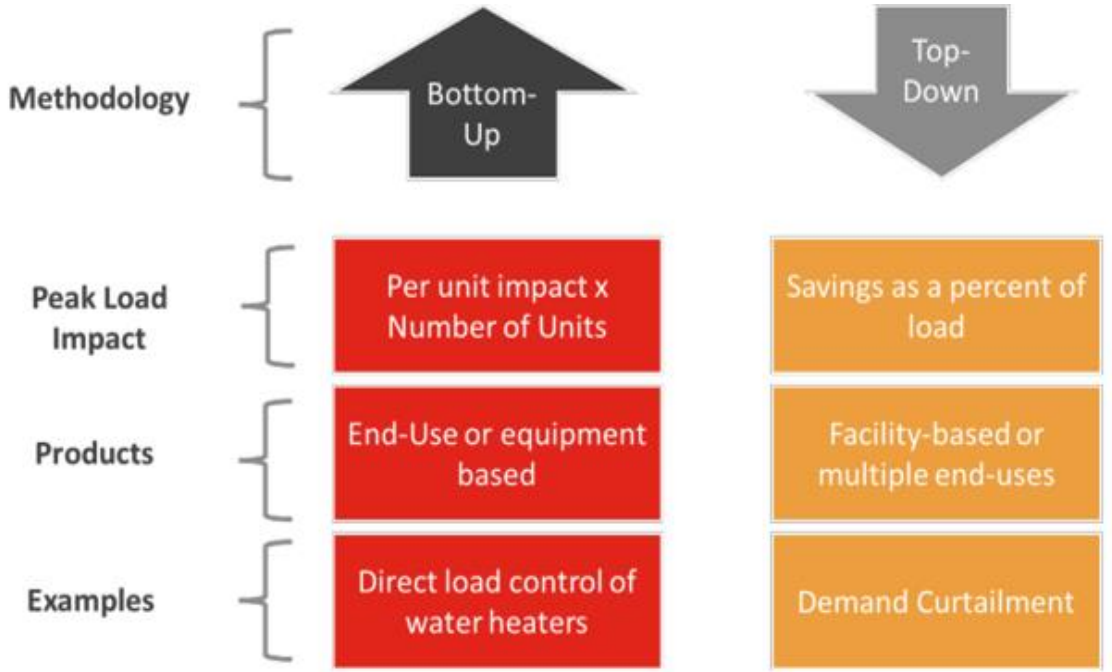
- Helps to prioritize program focus and design efforts
  - Important caveat – DR potential studies are not program designs
- Serves as regulatory and business due diligence tool
- A tool in the IRP process
- Can identify the "game changer" large customers

PLMA™
Load Management Leadership

DRPA Assumptions and Modeling

Key Variables	Description	
Participation Rates	• Percentage of eligible customers enrolled in DR programs • Participation and ramp	
Unit Impacts	• kW reduction per device • Percent of enrolled load	
Costs	• Program development (One-time fixed costs) • Marketing, installation, technology enablement (One-time variable costs) • Annual program admin. costs, customer incentives, O&M, etc.(Recurring fixed and variable costs)	
Global Parameters	• Avoided Costs • Inflation Rate • Line Losses	• Program Lifetime • Discount Rate

Modeling Methods:



Other Assumptions:

Profile = Calendar Year 2018
Seasons = Summer (Jun, Jul, Aug), Winter (Dec, Jan, Feb)
Events = 4-hour event duration, 20-hour season maximum (5 events)

DR Products Considered in the District's DRPA

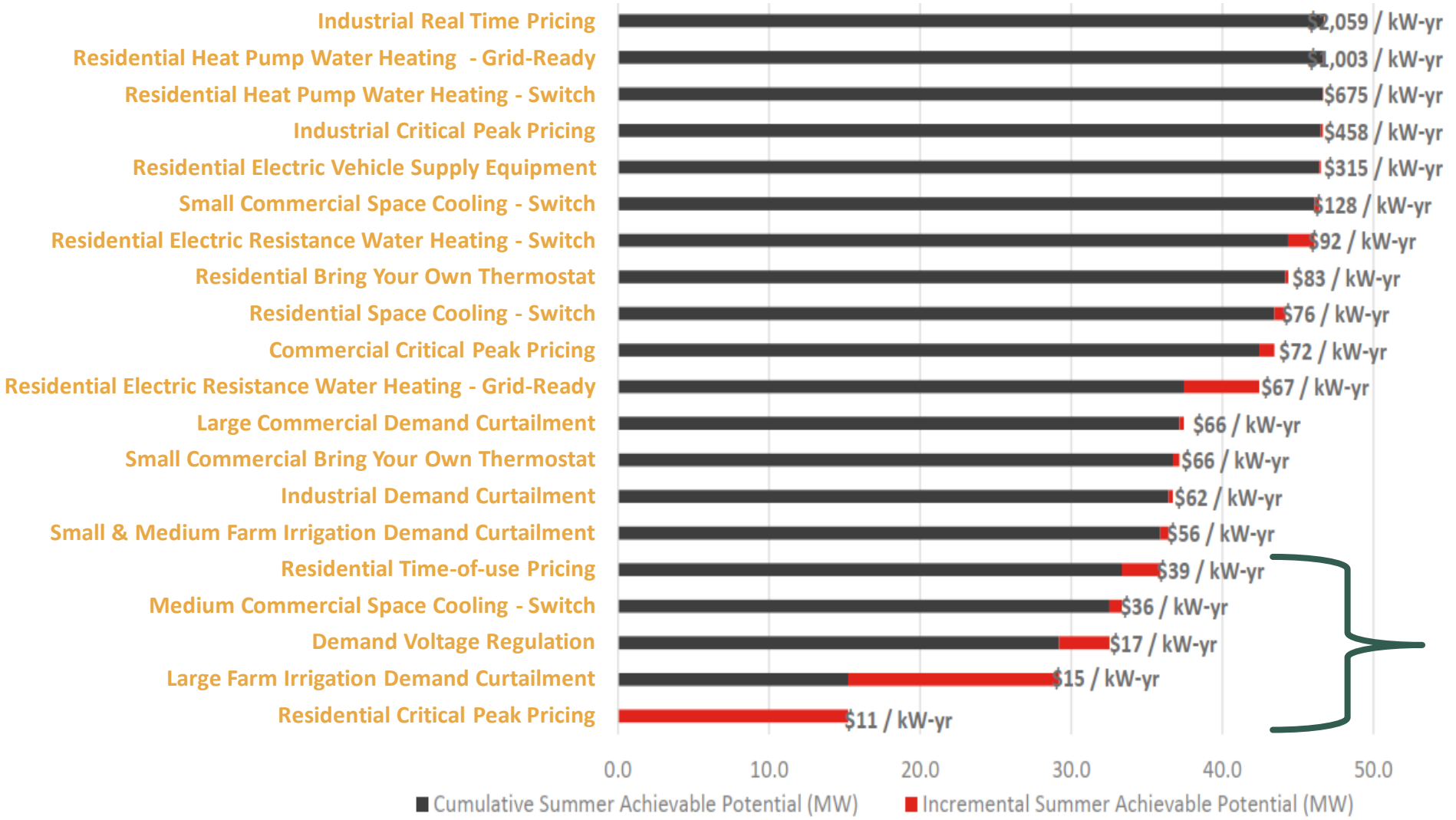
Type	Category	Product Description	Seasonality: Summer	Seasonality: Winter
Firm/ Controlled	Demand Curtailment	Large Farm Irrigation Demand Curtailment	↓	
		Small & Medium Farm Irrigation Demand Curtailment	↓	
		Industrial Demand Curtailment	↓	↓
		Large Commercial Demand Curtailment	↓	↓
	Space Cooling	Medium Commercial Space Cooling - Switch	↑	
		Small Commercial Space Cooling - Switch	↑	
		Residential Space Cooling - Switch	↑	
	Space Heating	Medium Commercial Space Heating - Switch		↑
		Small Commercial Space Heating - Switch		↑
		Residential Space Heating - Switch		↑
	Bring Your Own Thermostat	Small Commercial Bring Your Own Thermostat	↑	↑
		Residential Bring Your Own Thermostat	↑	↑
	Water Heating	Residential Electric Resistance Water Heating - Switch	↑	↑
		Residential Electric Resistance Water Heating - Grid-Ready	↑	↑
		Residential Heat Pump Water Heating - Switch	↑	↑
		Residential Heat Pump Water Heating - Grid-Ready	↑	↑
	Electric Vehicle	Residential Electric Vehicle Supply Equipment	↑	↑
	Utility System	Demand Voltage Regulation	↓	↓
Non-Firm/ Price Based	Rates	Industrial Critical Peak Pricing	↓	↓
		Industrial Real Time Pricing	↓	↓
		Commercial Critical Peak Pricing	↓	↓
		Residential Time-of-use Pricing	↓	↓
		Residential Critical Peak Pricing	↓	↓

Modeling	Seasonality: Summer	Seasonality: Winter
Top-Down	↓	↓
Bottom-Up	↑	↑

DR Products:

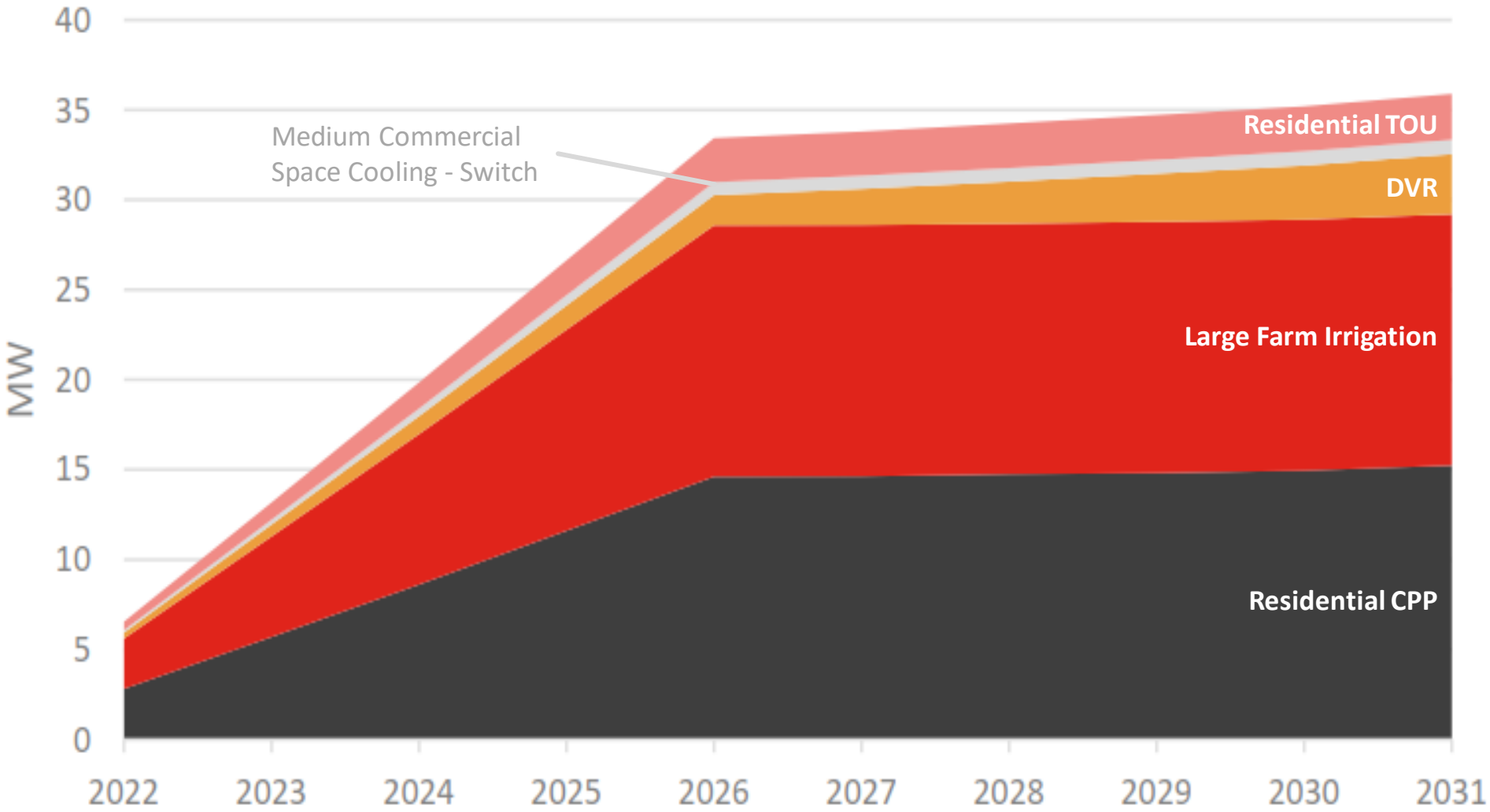
- Same products and assumptions as NWPCC's 2021 Power Plan
- 23 Products
  - 20 Summer
  - 18 Winter

10-Year Achievable Potential & Levelized Cost - Summer



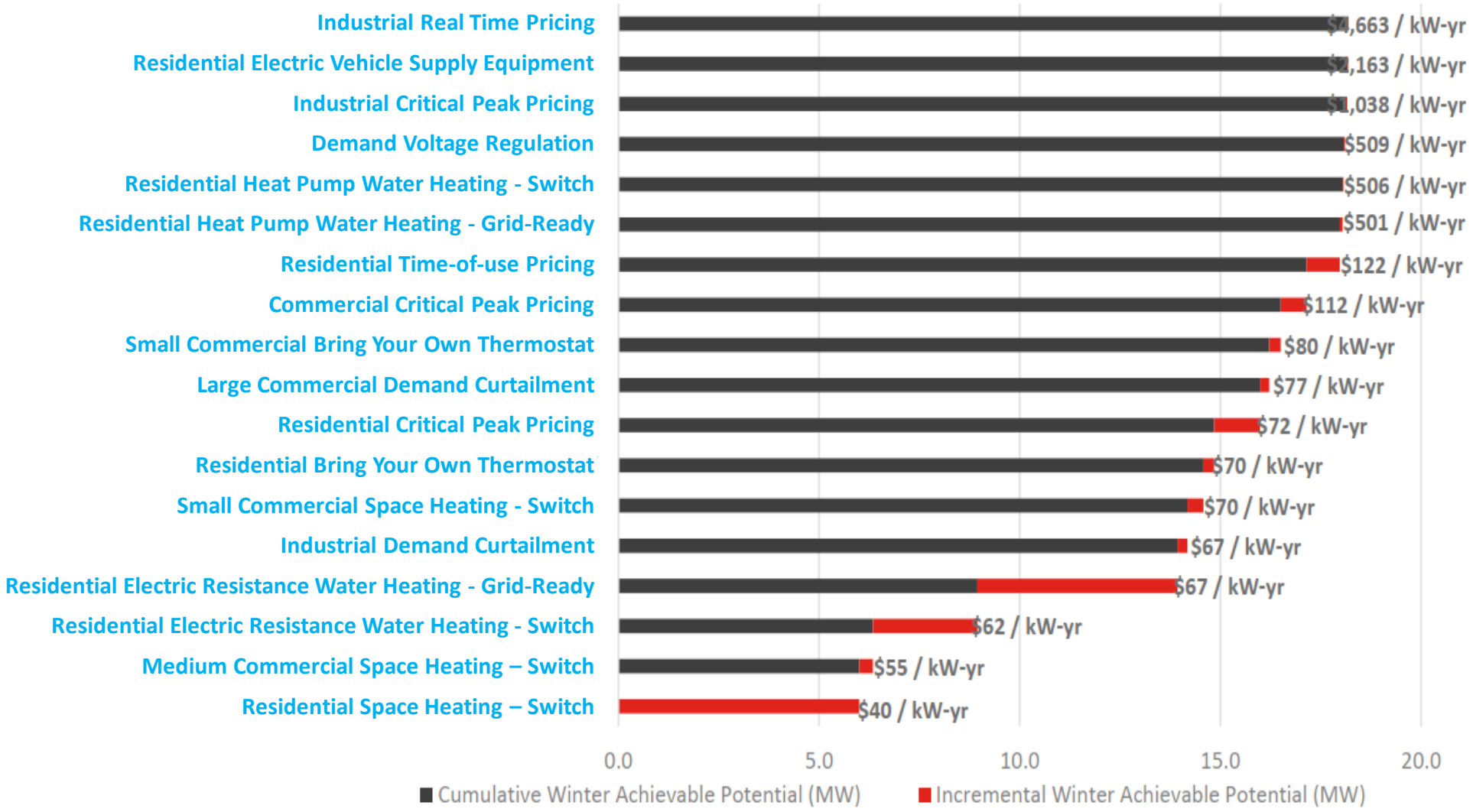
The most cost-effective products are less than $40/kW-Year

10-Year Cost-Effective Potential - Summer



- 10-Year potential is **36 MW**
- **5-Year ramp** is assumed
- Showing programs deployed in parallel

10-Year Achievable Potential & Levelized Cost - Winter



- Winter potential is less and more costly in this DRPA;
- However, the 2018 load shape was a very mild winter

DRPA Requires Continuous Refinement

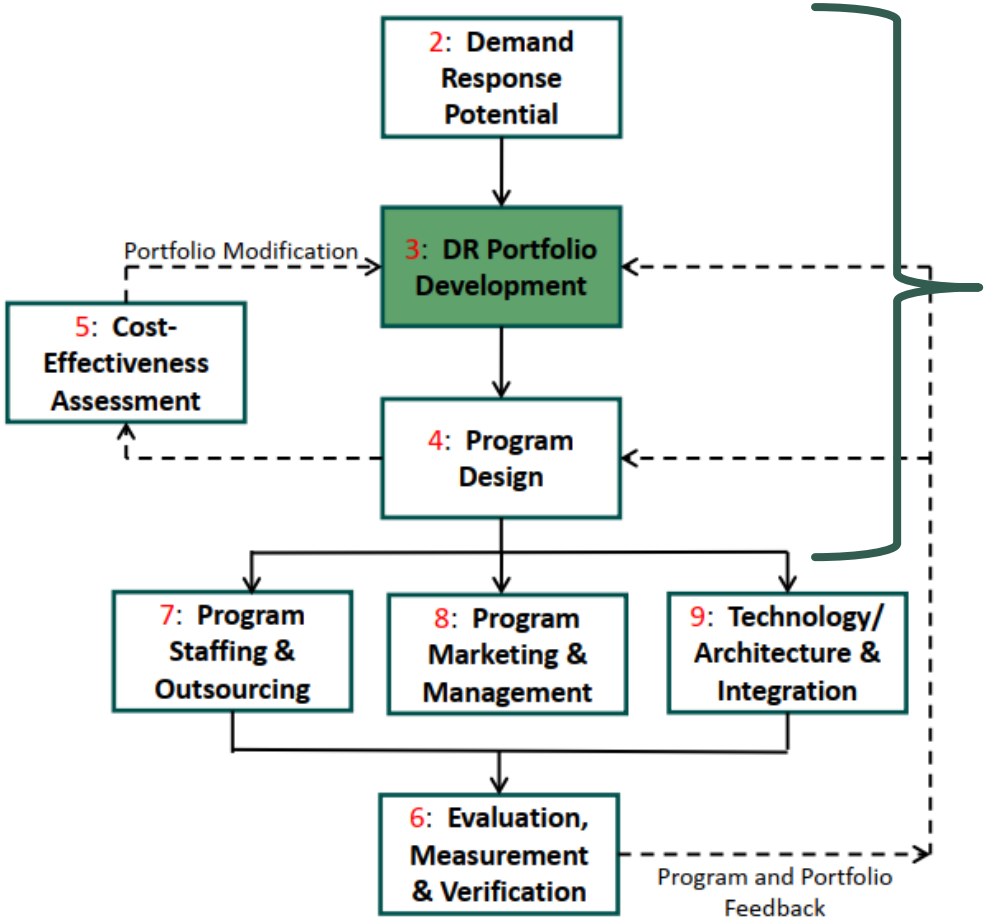
- **Improve** annual load shapes and seasons
- **Update** with BPA's 2021 DRPA Product Assumptions
- **Improve** the benefit-cost analysis
  - Refine the value of demand charges and other drivers
- **Complete** detailed review of segment applicability,
  - For example, need to ensure irrigation excluded from DVR results
- **Consider** more detailed analysis of DVR and irrigation
- **Consider** how to estimate time-of-day residential demand

#5 - STRATEGY

What should the District's strategy be for demand response?

The DR Program Development Process

- Understand DR drivers and needs
- Map needs to DR program attributes
- Develop program concepts and portfolios
- Understand diverse applications of DR with EE and DERs more broadly



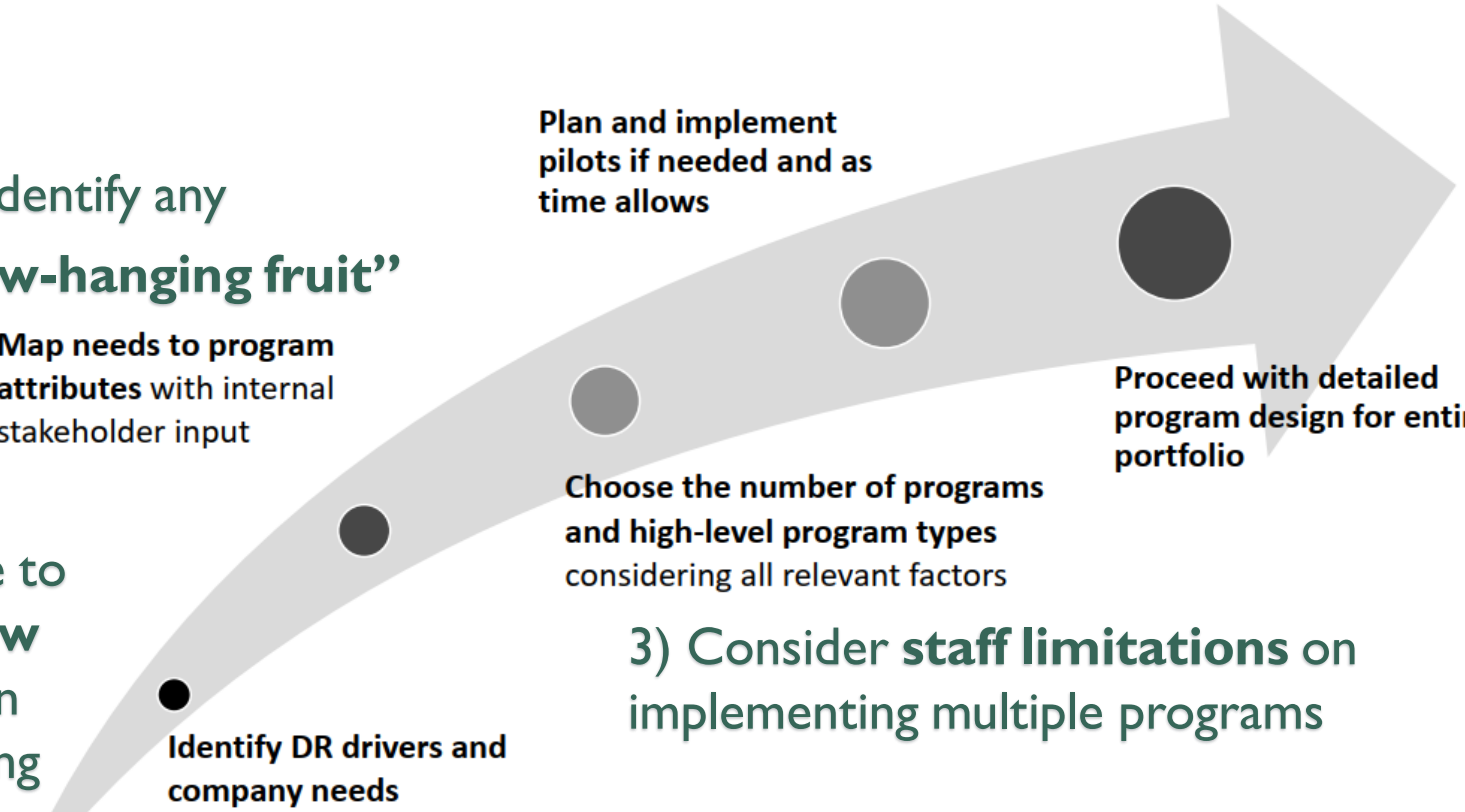
We are at the beginning.

Need time to iterate through this portion.

PLMA™ Load Management Leadership

Slide adapted from Peak Load Management Association's (PLMA) Demand Response Training Series - "Program Design & Implementation" (9/22/20).

Trajectory of a DR Portfolio Design



1) Need time to **evaluate new drivers,** given Load Following switch.

2) Identify any **"low-hanging fruit"**

3) Consider **staff limitations** on implementing multiple programs

When are programs needed?

Consider BPA Post-2028 Contract Timing

PLMA Load Management Leadership

Source: Guidehouse (formerly Navigant)

Slide adapted from Peak Load Management Association's (PLMA) Demand Response Training Series - "Program Design & Implementation" (9/22/20).

Demand Response Portfolio & Strategy

Residential	Commercial	Industrial	Irrigation	Utility
• Pursue time-of-day demand charges	• No programs identified at this time	• No programs identified at this time	• Consider developing a pilot program	• Pursue Voltage Optimization • Consider pursuing DVR

Energy Efficiency

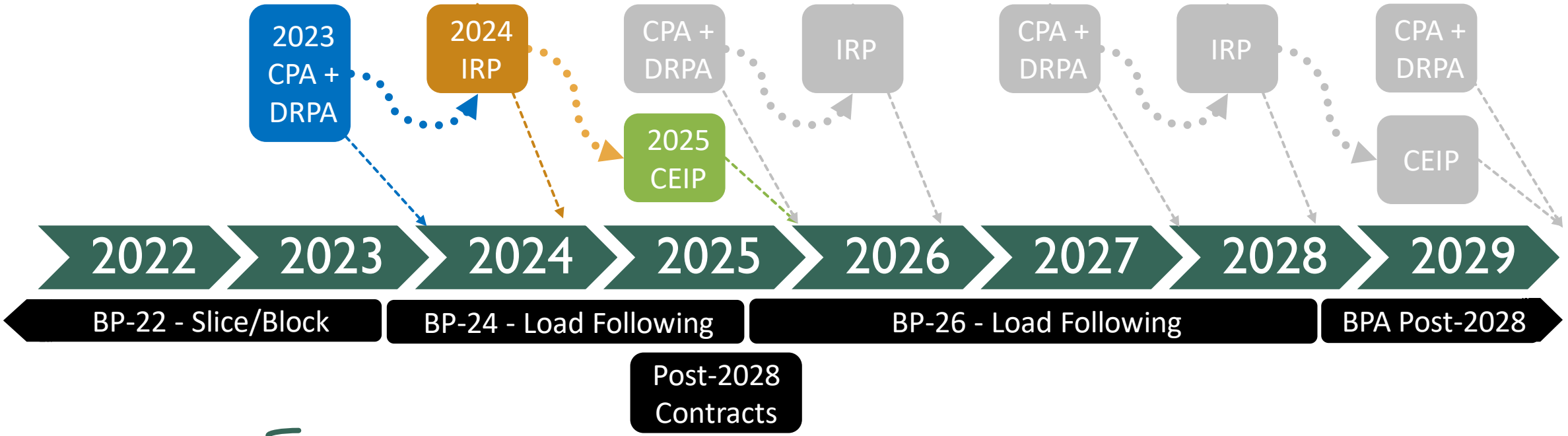
Employee and Customer Education

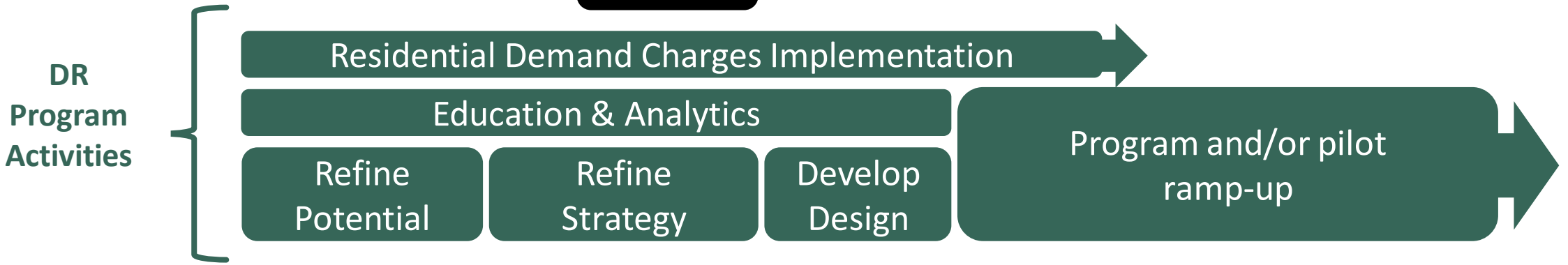
Load Segmentation Analytics

#6 - TIMELINE

When should the District develop a demand response program?

Demand Response Activity Timeline





Note: BP-##=BPA Rate Period, BPA=Bonneville Power Administration, CEIP=Clean Energy Implementation Plan, CPA=Conservation Potential Assessment, DR=Demand Response, DRPA=DR Potential Assessment, IRP=Integrated Resource Plan. ***Timeline is preliminary for facilitating planning discussions.***