HURRICANE CITY
UTAH

Power Board Meeting Agenda

3/5/2025

3:00 PM

Power Department Meeting Room – 526 W 600 N

Notice is hereby given that the Power Board will hold a Regular Meeting in the Power Department Meeting room located at 526 W 600 N, Hurricane, UT. A silent roll call will be taken, along with the Pledge of Allegiance and prayer by invitation.

AGENDA

1. Pledge of Allegiance
2. Prayer
3. Approval of minutes from February 2025

STAFF REPORTS

Scott Hughes/Power Director
Brian Anderson/Transmission & Distribution Superintendent
Mike Ramirez/Service Superintendent
Jared Ross/Substation & Generation Foreman

OLD BUSINESS

NEW BUSINESS

1. Discussion regarding the **Impact Fee Analysis & Capital Facilities Plan Draft** – Scott Hughes
2. Discussion regarding the **installation of overhead power lines** – Scott Hughes
3. UAMPS Updates – Scott Hughes
4. **Closed Meeting pursuant to Utah Code Section 52-4-205, upon request**

ADJOURNMENT

The above notice was posted to the Hurricane City website, the Utah State Public Notice Website, and at the following locations:

1. Hurricane City Office – 147 North 870 West, Hurricane, UT
2. US Post Office – 1075 West 100 North, Hurricane, UT
3. Washington County Library (Hurricane Branch) – 36 South 300 West, Hurricane, UT

The Hurricane City Power Board met on February 5, 2025, at 3:00 p.m. at the Clifton Wilson Substation located at 526 W 600 N.

In attendance were Mac Hall, Dave Imlay, David Hirschi, Tony Certonio, Kerry Prince, Scott Hughes, Brian Anderson, Mike Ramirez, Jared Ross, Fred Resch, Dayton Hall, Mike Vercimak, Bruce Zimmerman, and Crystal Wright.

Mac Hall welcomed everyone to the meeting. Dave Imlay led the Pledge of Allegiance and Kerry Prince offered the prayer. Dave Imlay motioned to approve minutes from the January 2025 meeting. Kerry Prince seconded the motion. Motion passed unanimously.

Scott Hughes: Scott Hughes provided an update on employees. We started a substation apprentice this year and his supervisor is recommending he be allowed to take his first-step test in March. We also extended an offer to a Journeyman Lineman who will be starting at the beginning of March. He passed out Conflict of Interest forms to be reviewed annually, information about a UAMPS scholarship opportunity that is available to seniors in high school, and a Utah Public Power Reception that will be held at the Capital building in Salt Lake City. He informed the board that we are beginning an official rate study. Our finances are in a much better place, and to gain valuable insight regarding our rate structure we are completing a thorough study. It has been almost 10 years since our last official rate study and it’s time to complete another one. We are getting close to completing our Capital Facilities Plan and Impact Fee Analysis, which we have been working on for a couple of years. We may have information ready to go for this at next month’s board meeting. He informed the board that after the last meeting we are continuing to do some research on the multi-unit solar policy research. Another city had reached out researching the same thing. They offered to share their results with us, and we will share ours with them when we finish. Dave Imlay asked if we’ve gone out to bid for the rate study and asked who is completing the Capital Facilities Plan and Impact Fee Analysis. Scott Hughes replied that we have requested a bid from Utility Financial Services for the rate study and ICPE is completing the Capital Facilities Plan and Impact Fee Analysis. Dayton Hall asked if we would include him in the Impact Fee Study draft emails. In the past he couldn’t review them early enough and we ended up needing to make last-minute changes that could have been avoided.

Brian Anderson: Brian Anderson reported that our Line Crew removed a tree for a homeowner as a long-term agreement to remove it from our annual tree trimming list for future maintenance. We cut it and chipped the tree for them, but they are handling the wood and cleaning it up. He stated we are continuing to work on adding bird guard to poles that were identified as potentially beneficial as part of our participation in the Eagle Take Permit project. This helps reduce outages and protect birds in our area, which in turn helps the Horse Butte Wind Project which does have some bird deaths due to their wind turbines. We have terminated a portion of line for the Balance of Nature Garden off-site work along 2400 West. The irrigation project being completed along 1300 South has required us to go out and relocate some of that underground line, as well as identify some abandoned lines that have been found.

Mike Ramirez: Mike Ramirez stated he doesn’t have anything specific to report on for this meeting, but if the board has any questions regarding any subdivision projects, they are welcome to ask questions anytime. Dave Imlay asked about capacity due to the growth coming in the area between 3400 West and from State St north to 600 North. Scott Hughes replied that the Sky Mountain Substation is going to continue to be worked on and will be needed sooner rather than later. The Three Falls Substation has helped, by allowing us to transfer loads between the Three Falls, Clifton Wilson, and Brentwood Substations. We need to keep the Sky Mountain Substation moving forward in phases.

Jared Ross: Jared Ross reported on the work done at Three Falls Substation. We finished the redline plans to get the as-built plans completed and provided those to ICPE. They completed some cable tray covers and cleaned up the building. They'd found some black widows they had to take care of. He then reported on some work done at the Anticline Substation due to some insulators that had burned up. A fox had gotten in and done the damage a couple years ago. We had transferred the load to a different circuit until we had time to fix this. It's all fixed now and back to normal. He reported on work done at the Brentwood Substation including a meter that had been damaged. We installed the replacement meter and tested it. We cleaned up the MOS 023 switch that had arced this past year since the parts will take a while to get. We completed some battery cleanup. That battery bank is reaching its life span of 20 years and is starting to require more maintenance due to some additional leaking and corrosion. The Substation Crew provided some assistance to Beaver City by helping run tests on their generators to identify issues they had been having.

Discussion and possible recommendation for approval to appoint Michael Ramirez as an additional UAMPS Alternate Representative: Scott Hughes presented this item and stated our Alternate Representative has been listed as Brian Anderson for quite some time. He's getting closer to retirement and is still willing to serve as the Alternate, but it's time for us to begin getting someone else used to the UAMPS processes and procedures and bring them up to speed. David Hirschi made a motion to appoint Michael Ramirez as an additional UAMPS Alternate Representative. Tony Certonio seconded the motion. Motion passed unanimously.

UAMPS Updates: Scott Hughes provided the updates in the packet. He couldn't attend the meetings in person this month due to some health complications, however Brian Anderson and Michael Ramirez both attended the meetings remotely through Zoom. He reported briefly on some of the topics that had been relayed to him after those meetings. One of the bigger things happening at UAMPS is the Extended Day Ahead Market (EDAM) which will require UAMPS, and each member, to always maintain 115% of our load profile as an available resource. If we're unable to provide that, we will be fined. We know that resources aren't coming online fast enough before the deadline to meet the requirement so market purchases will be necessary. We discussed a forward market purchase we had submitted and some of the thought and reasoning that had gone into that solicitation for market purchase. Dave Imlay stated it will be interesting to see if the fine ends up being more harmful than having to pay for a high market purchase. He provided updates regarding the UAMPS natural gas projects. The Power County project, which is the base load project, has not reached its subscription in part due to Logan not getting approval for their participation. There are other entities interested in participating so they feel like the subscription will be obtained. The Millard County project, which is the peaking project, is moving forward and they have found a property owner willing to sell their property for a potential site. We are still investigating a couple geothermal projects and wind projects. UAMPS is changing the format of their monthly board meetings. Meetings will only be held in person every other month. The opposite months will be held by Zoom meeting to discuss anything that's needed in the interim.

Tony Certonio has a question regarding the conduit the city installed along 2800 West in the 600 North area. Has TDS Communications contacted anyone about requesting room in that pipe? He wondered if we have any other conduit in that area.

Meeting adjourned at 4:03 p.m. The next Power Board meeting is scheduled for March 5, 2025, at 3:00 p.m.

HURRICANE CITY
UTAH

February 5, 2025 – 3:00 pm

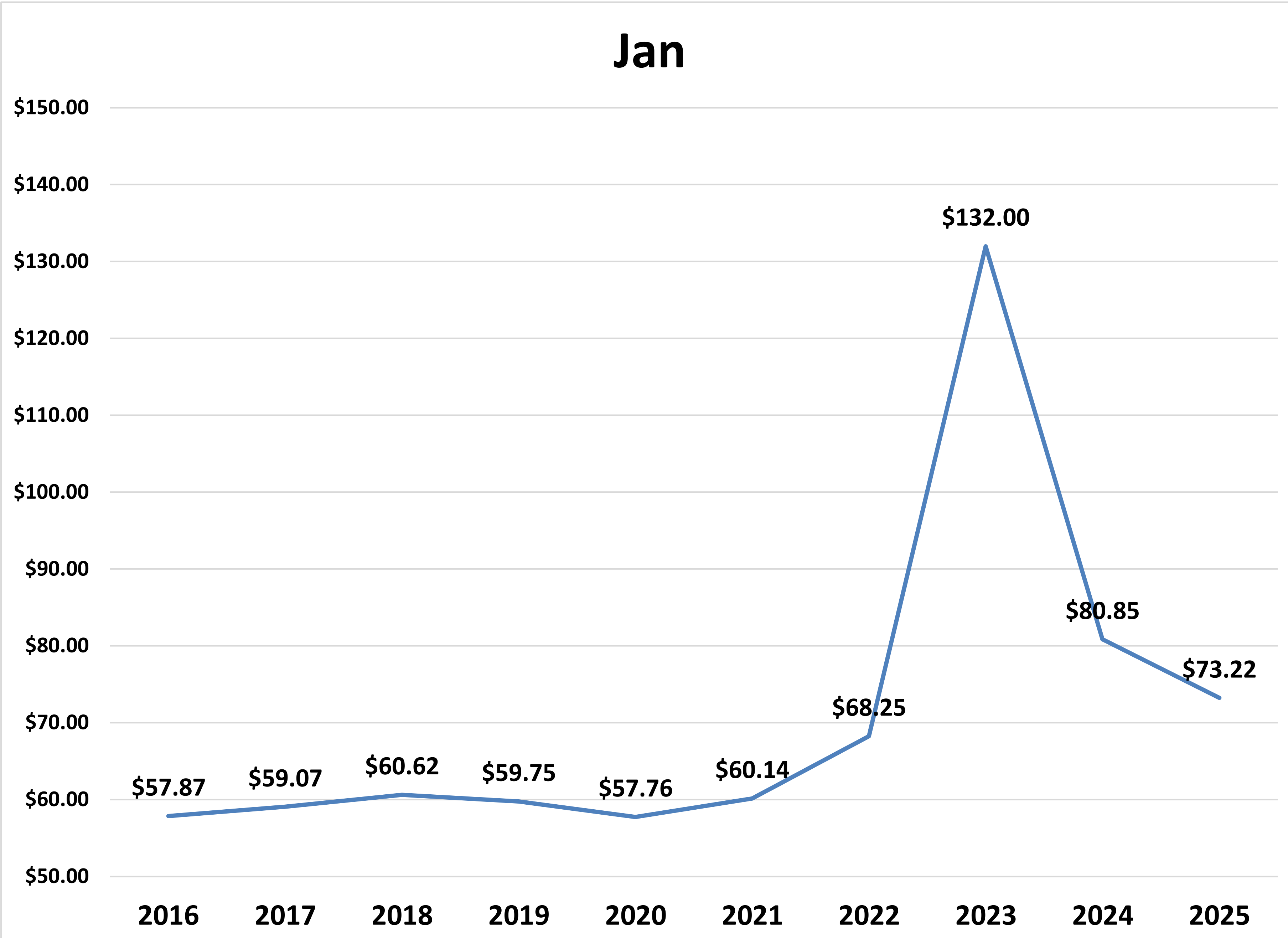
POWER BOARD SIGN-IN SHEET

Please PRINT

First and Last Name	Company (if applicable)
BRUCE ZIMMERMAN	

526 West 600 North • Hurricane, Utah • 84737
Phone (435) 635-5536 • Fax (435) 635-4127 • www.cityofhurricane.com

BUDGET


Jan
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$140.00
$130.00
$120.00
$110.00
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$57.87
$59.07
$60.62
$59.75
$57.76
$60.14
$68.25
$132.00
$80.85
$73.22
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025

AVERAGE YEARLY POWER PRICES

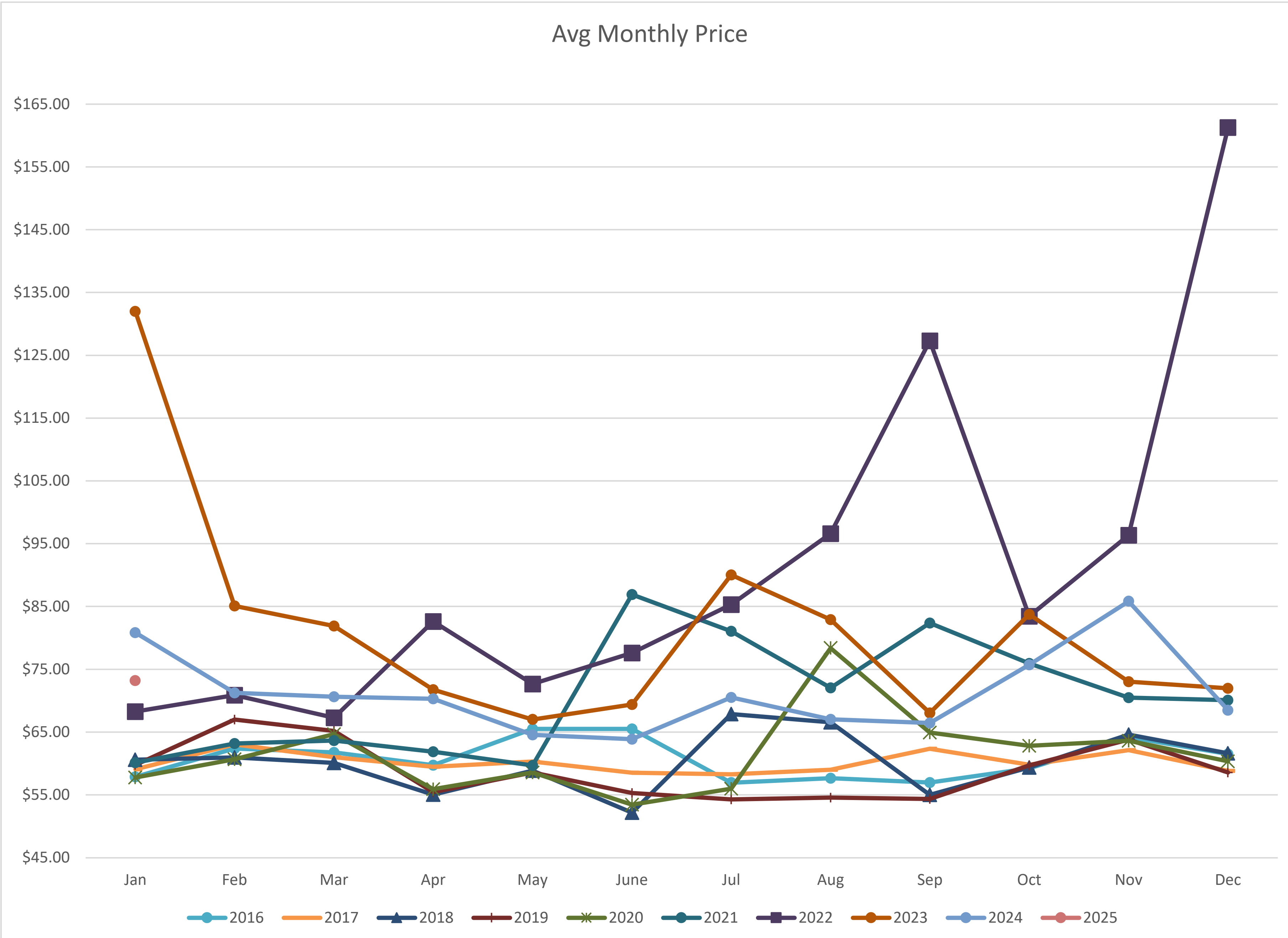
24-25 bdgt amount (thru Dec 2024) **$71.24**

BDGT Year to Date **$71.49**

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Jan	$57.87	$59.07	$60.62	$59.75	$57.76	$60.14	$68.25	$132.00	$80.85	$73.22
Feb	$62.38	$63.04	$60.96	$67.00	$60.67	$63.19	$70.88	$85.08	$71.23	
Mar	$61.77	$60.99	$60.09	$65.17	$64.67	$63.64	$67.28	$81.89	$70.62	
Apr	$59.71	$59.49	$55.02	$55.44	$55.92	$61.86	$82.63	$71.74	$70.32	
May	$65.51	$60.32	$58.86	$58.55	$58.55	$59.69	$72.66	$67.01	$64.54	
June	$65.51	$58.54	$52.17	$55.30	$53.44	$86.91	$77.60	$69.40	$63.88	
Jul	$56.95	$58.29	$67.87	$54.29	$55.98	$81.04	$85.31	$90.02	$70.51	
Aug	$57.67	$59.00	$66.55	$54.58	$78.40	$72.03	$96.60	$82.90	$67.05	
Sep	$56.97	$62.36	$55.00	$54.34	$64.93	$82.38	$127.29	$68.06	$66.46	
Oct	$59.23	$59.79	$59.36	$59.70	$62.82	$75.92	$83.45	$83.76	$75.70	
Nov	$64.18	$62.14	$64.60	$63.80	$63.60	$70.47	$96.34	$73.03	$85.85	
Dec	$61.51	$58.80	$61.61	$58.55	$60.33	$70.07	$161.27	$71.99	$68.50	
Yr Avg	$60.64	$60.15	$60.23	$58.87	$61.42	$70.61	$90.80	$81.41	$71.29	$73.22
Weighted Avg	$59.55	$59.90	$60.56	$58.11	$61.98	$72.46	$92.09	$81.92	$70.49	$73.22

Cy to Date

These figures capture the total cost of power to the power department.
The power department uses costs only associated with the purchasing
and generation of power and includes debt payments and interest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$145.00
$135.00
$125.00
$115.00
$105.00
$95.00
$85.00
$75.00
$65.00
$55.00
$45.00
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Mar
Apr
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2016
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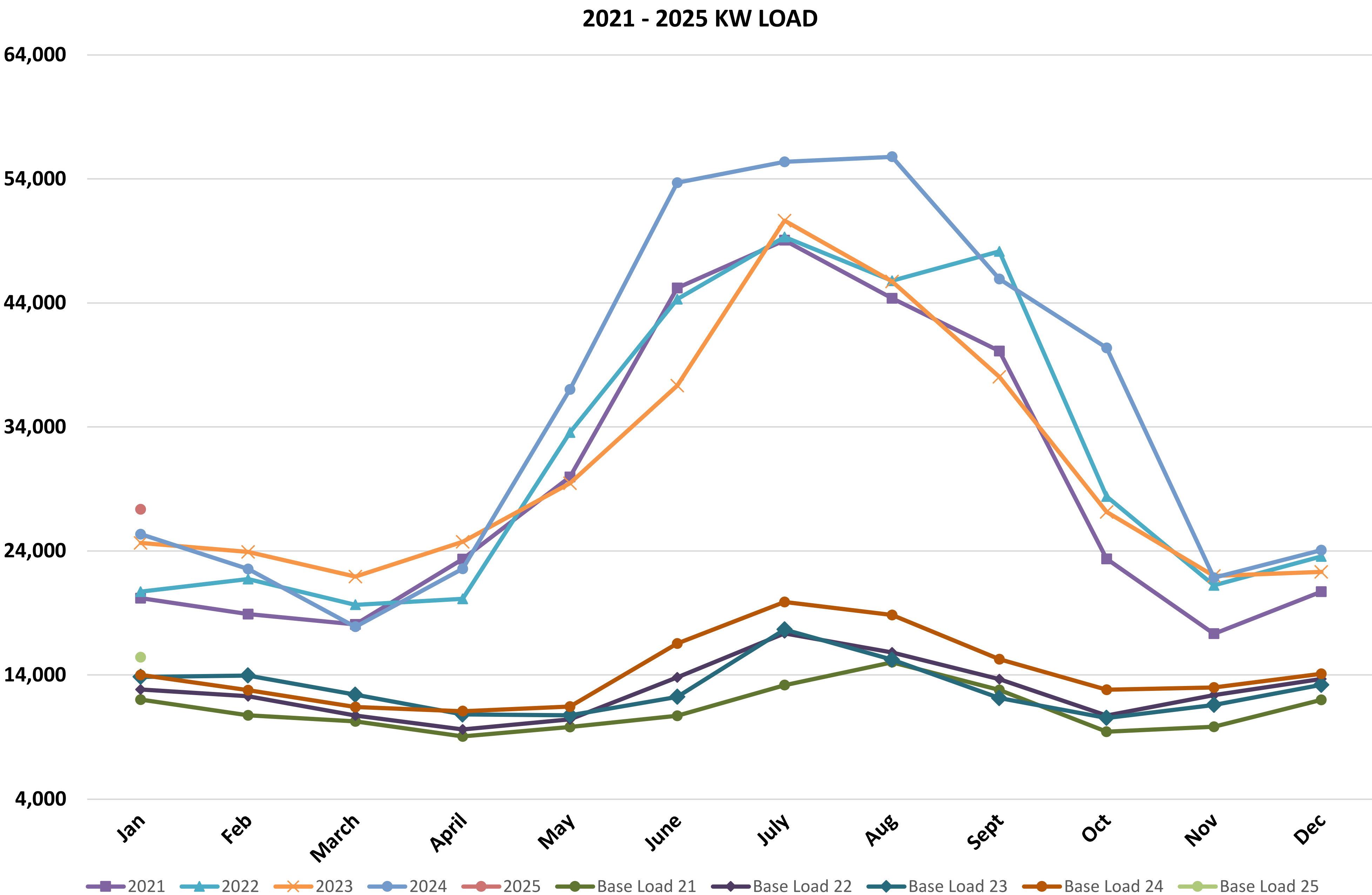
2021 - 2025 KW LOAD
64,000
54,000
44,000
34,000
24,000
14,000
4,000
Jan
Feb
March
April
May
June
July
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Sept
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Dec
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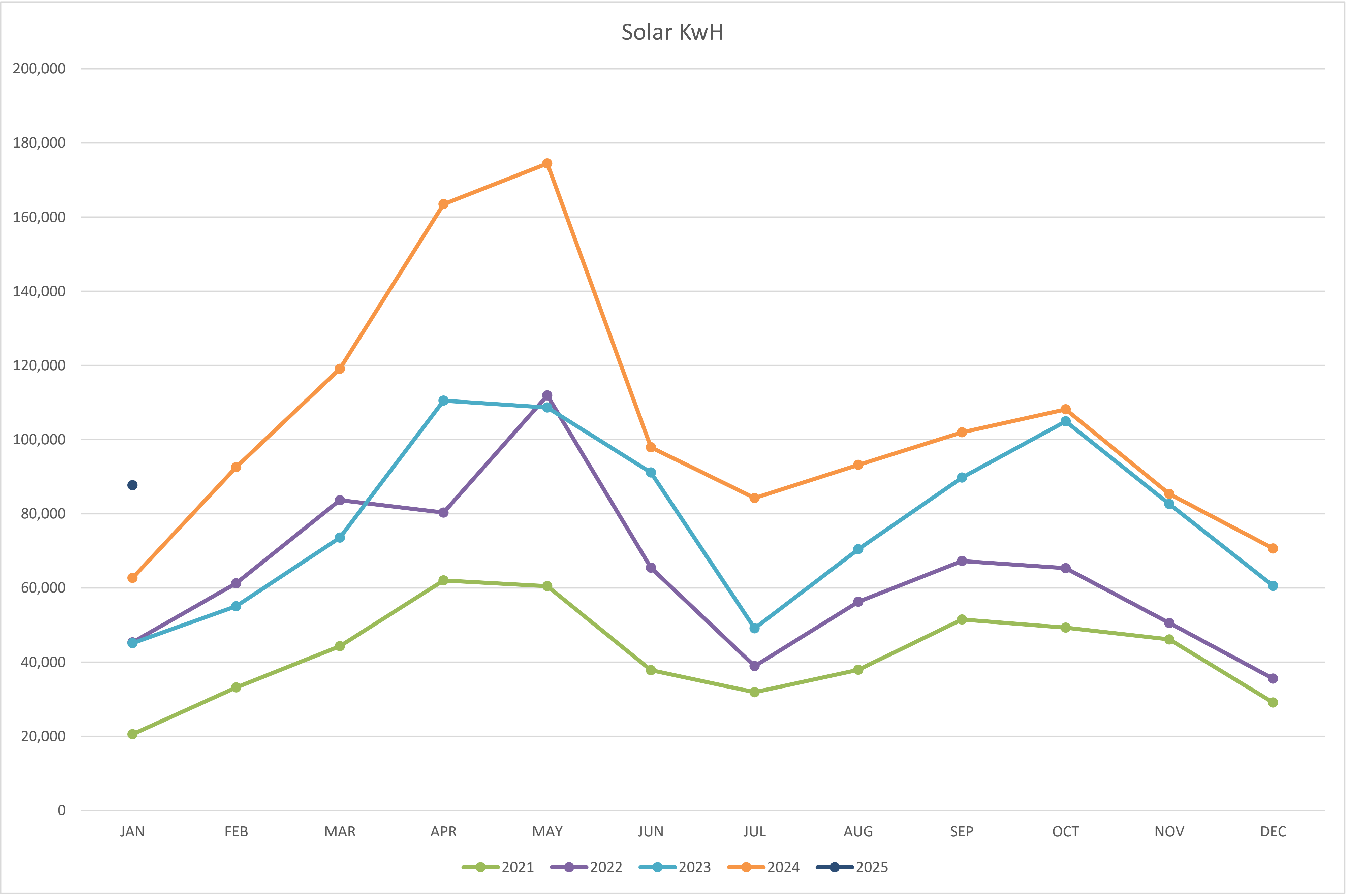
2022
2023
2024
2025
Base Load 21
Base Load 22
Base Load 23
Base Load 24
Base Load 25


Solar KwH
200,000
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
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FEB
MAR
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MAY
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AUG
SEP
OCT
NOV
DEC
2021
2022
2023
2024
2025

HURRICANE UTAH

DECEMBER 2024

IMPACT FEE ANALYSIS (IFA)

ELECTRICAL TRANSMISSION AND SUBSTATIONS

PREPARED BY:

LRB PUBLIC FINANCE ADVISORS

FORMERLY LEWIS YOUNG ROBERTSON & BURNINGHAM INC.

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IMPACT FEE CERTIFICATION

IFA CERTIFICATION

LRB Public Finance Advisors certifies that the attached impact fee analysis:

1. includes only the costs of public facilities that are:
    a. allowed under the Impact Fees Act; and
    b. actually incurred; or
    c. projected to be incurred or encumbered within six years after the day on which each impact fee is paid;
2. does not include:
    a. costs of operation and maintenance of public facilities;
    b. costs for qualifying public facilities that will raise the level of service for the facilities, through impact fees, above the level of service that is supported by existing residents;
    c. an expense for overhead, unless the expense is calculated pursuant to a methodology that is consistent with generally accepted cost accounting practices and the methodological standards set forth by the federal Office of Management and Budget for federal grant reimbursement;
3. offsets costs with grants or other alternate sources of payment; and,
4. complies in each and every relevant respect with the Impact Fees Act.

LRB Public Finance Advisors makes this certification with the following caveats:

1. All of the recommendations for implementations of the IFFP made in the IFFP documents or in the IFA documents are followed by City Staff and elected officials.
2. If all or a portion of the IFFP or IFA are modified or amended, this certification is no longer valid.
3. All information provided to LRB is assumed to be correct, complete, and accurate. This includes information provided by the City as well as outside sources.

LRB PUBLIC FINANCE ADVISORS

DEFINITIONS

The following acronyms or abbreviations are used in this document:

IFA:	Impact Fee Analysis
IFFP:	Impact Fee Facilities Plan
kVA:	Kilo-volt-amperes
kW:	Kilowatt
LOS:	Level of Service
LRB:	LRB Public Finance Advisors (Formerly Lewis Young Robertson & Burningham, Inc.)
M:	Million
MW:	Megawatt

SECTION 1: EXECUTIVE SUMMARY

The purpose of the electrical transmission and substation Impact Fee Analysis ("IFA") is to fulfill the requirements established in Utah Code Title 11 Chapter 36a, the "Impact Fees Act", and assist Hurricane City (the City) in financing and constructing necessary capital improvements for future growth. This document will address the appropriate impact fees the City may charge to new growth to maintain the level of service (LOS) as defined in the Impact Fee Facilities Plan, dated August 2024.

- **Impact Fee Service Areas:** The impact fees identified in this document will be assessed within the proposed Service Area, as discussed in **Section 3**.
- **Demand Analysis:** A total of 35,832 additional kilowatts (kWs) of demand will be generated within the current Service Area in the IFFP planning horizon. See **Section 3** for details regarding growth in kWs.
- **Level of Service:** The LOS is based on loading to the base rating on substation transformers and system voltage criteria. **Section 3** provides the LOS information used in this analysis. New facilities are designed to maintain the diversified kW LOS.
- **Excess Capacity:** This analysis includes excess capacity related to substations and the transmission system.
- **Capital Facilities Analysis:** The IFFP has identified the growth-related projects needed within the next ten years. The total construction year cost related to growth is **$38.6M**, based on an inflation rate of four percent annually.
- **Financing of Future Facilities:** This analysis assumes the City will not utilize bond financing to fund future infrastructure.

SUMMARY OF PROPOSED IMPACT FEES

The impact fees proposed in this analysis will be assessed within the Service Area. The tables below illustrate the calculated impact fee for electric transmission and substation facilities.

Table 1.1: Illustration of Cost per New kW

	Total Costs	% Growth Related and Impact Fee Funded	Growth Related & City Funded Costs	Growth Related kW	Cost per New kW
Buy-In: Existing Substation Transformers	$13,191,976	26%	$3,376,392	35,832	$94.23
Future System Improvements	$49,006,901	79%	$38,621,695	35,832	$1,077.85
Financing	$0	79%	$0	35,832	$0.00
Professional Expense	$73,925	82%	$60,363	22,689	$2.66
Interest Credit	($270,000)	100%	($270,000)	35,832	($7.54)
TOTALS:	**$62,002,802**		**$41,788,450**		**$1,167.20**

Professional expense is based on the cost to complete the IFFP and IFA.

Table 1.2: Illustration of Impact Fee by Panel Size

Panel Rating	Line-to-Line Voltage	100% Panel kVA	Avg Panel Loading	Avg Peak Demand @ Panel (kVA)	Power Factor	Estimated Diversified kW	Proposed Fee	Existing Fee	% Change
Residential (120/240, 1 phase)									
125	240	30	12.50%	3.75	95%	3.56	$4,158	$1,622	156%
200	240	48	12.50%	6.00	95%	5.70	$6,653	$2,595	156%
400	240	96	12.85%	12.34	95%	11.72	$13,679	$5,190	164%
600	240	144	12.85%	18.50	95%	17.58	$20,518	$7,785	164%
Commercial (120/240, 1 phase)									
200	240	48	25.00%	12.00	90%	10.80	$12,606	$4,902	157%
400	240	96	25.00%	24.00	90%	21.60	$25,212	$9,803	157%
600	240	144	25.00%	36.00	90%	32.40	$37,817	$14,705	157%
800	240	192	25.00%	48.00	90%	43.20	$50,423	$19,607	157%
Commercial (120/208, 3 phase)									
200	208	72	25.00%	18.01	90%	16.21	$18,923	$7,358	157%
400	208	144	25.00%	36.03	90%	32.42	$37,845	$14,715	157%
600	208	216	25.00%	54.04	90%	48.64	$56,768	$22,073	157%
800	208	288	25.00%	72.05	90%	64.85	$75,691	$29,431	157%
1,000	208	360	25.00%	90.07	90%	81.06	$94,613	$36,788	157%
1,200	208	432	25.00%	108.08	90%	97.27	$113,536	$44,146	157%
1,600	208	576	25.00%	144.11	90%	129.70	$151,381	$58,861	157%
1,800	208	648	25.00%	162.12	90%	145.91	$170,304	$66,219	157%
2,000	208	721	25.00%	180.13	90%	162.12	$189,226	$73,577	157%
2,500	208	901	25.00%	225.17	90%	202.65	$236,533	$91,971	157%
3,000	208	1,081	25.00%	270.20	90%	243.18	$283,840	$110,365	157%
Commercial (277/480, 3 phase)									
200	480	166	25.00%	41.57	90%	37.41	$43,668	$16,979	157%
400	480	333	25.00%	83.14	90%	74.82	$87,335	$33,958	157%
600	480	499	25.00%	124.71	90%	112.24	$131,003	$50,938	157%
800	480	665	25.00%	166.28	90%	149.65	$174,671	$67,917	157%
1,000	480	831	25.00%	207.85	90%	187.06	$218,338	$84,896	157%
1,200	480	998	25.00%	249.42	90%	224.47	$262,006	$101,875	157%
1,600	480	1,330	25.00%	332.55	90%	299.30	$349,341	$135,834	157%
1,800	480	1,496	25.00%	374.12	90%	336.71	$393,009	$152,813	157%
2,000	480	1,663	25.00%	415.69	90%	374.12	$436,676	$169,792	157%
2,500	480	2,078	25.00%	519.62	90%	467.65	$545,845	$212,241	157%
3,000	480	2,494	25.00%	623.54	90%	561.18	$655,015	$254,689	157%

A detailed explanation of the increase in the proposed impact fee is in **Section 6** of this report.

Non-Standard Impact Fees

The proposed fees are based upon growth in kWs. The City reserves the right under the Impact Fees Act to assess an adjusted fee that more closely matches the true impact that the land use will have upon public facilities.[1] A developer may submit studies and data for a particular development and request an adjustment. This adjustment could result in a higher or lower impact fee if the City determines that a particular user may create a different impact than what is standard for its land use. The following formulas will help determine the non-standard impact fee.

Estimated Diversified kW Usage * $1,167.20

The formula for a non-standard impact fee should be included in the impact fee enactment (by resolution or ordinance). In addition, the impact fee enactment should contain the following elements:

- A provision establishing one or more service areas within which the local political subdivision or private entity calculates and imposes impact fees for various land use categories.
- A schedule of impact fees for each type of development activity that specifies the amount of the impact fee to be imposed for each type of system improvement or the formula that the local political subdivision or private entity will use to calculate each impact fee.
- A provision authorizing the local political subdivision or private entity to adjust the standard impact fee at the time the fee is charged to:
  - Respond to unusual circumstances in specific cases or a request for a prompt and individualized impact fee review for the development activity of the state, a school district, or a charter school and an offset or credit for a public facility for which an impact fee has been or will be collected.
  - Ensure that the impact fees are imposed fairly.
- A provision governing calculation of the amount of the impact fee to be imposed on a particular development that permits adjustment of the amount of the impact fee based upon studies and data submitted by the developer.
- A provision that allows a developer, including a school district or a charter school, to receive a credit against or proportionate reimbursement of an impact fee if the developer:
  - Dedicates land for a system improvement.
  - Builds and dedicates some or all of a system improvement.
  - Dedicates a public facility that the local political subdivision or private entity and the developer agree will reduce the need for a system improvement.
- A provision that requires a credit against impact fees for any dedication of land for, improvement to, or new construction of, any system improvements provided by the developer if the facilities:
  - Are system improvements; or,
  - Dedicated to the public and offset the need for an identified system improvement.

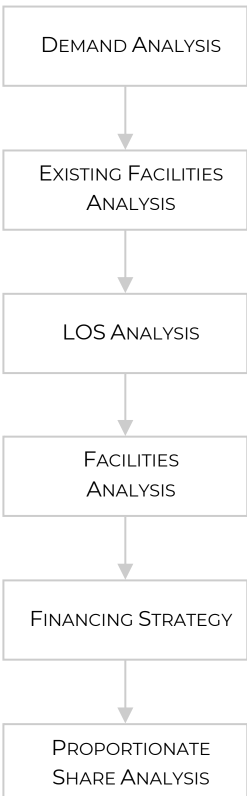
Other provisions of the impact fee enactment may include exemption of fees for development activity attributable to low-income housing, the state, a school district, or a charter school. Exemptions may also include other development activities with a broad public purpose. If an exemption is provided,

[1] UC 11-36a-402(1)(c)

the entity should establish one or more sources of funds other than impact fees to pay for that development activity. The impact fee exemption for development activity attributable to a school district or charter school should be applied equally to either scenario.

SECTION 2: GENERAL IMPACT FEE METHODOLOGY

Figure 2.1: Impact Fee Methodology



The purpose of this study is to fulfill the requirements of the Impact Fees Act regarding the establishment of an IFFP and IFA. The IFFP identifies the demands placed upon the City's existing facilities by future development and evaluates how these demands will be met by the City. The IFFP is also intended to outline the improvements, which are intended to be funded by impact fees. The purpose of IFA is to allocate the cost of the new facilities and any excess capacity to new development, while ensuring that all methods of financing are considered. The Impact Fee Act requires that the IFFP and IFA consider the historic level of service provided to existing development and ensure that the proposed impact fees maintain the existing level of service. The following elements are important considerations when completing an IFFP and IFA.

Demand Analysis

The demand analysis serves as the foundation for the IFFP and IFA. This element focuses on a specific demand unit related to each public service – the existing demand on public facilities and the future demand as a result of new development that will affect system facilities.

Existing Facility Inventory

In order to quantify the demands placed upon existing public facilities by new development activity, to the extent possible the IFFP provides an inventory of the City's existing system facilities. The inventory valuation should include the original construction cost and estimated useful life of each facility. The inventory of existing facilities is important to determine the excess capacity of existing facilities and the utilization of excess capacity by new development.

Level of Service Analysis

"Level of service" or LOS means the defined performance standard or unit of demand for each capital component of a public facility within a service area. Through the inventory of existing facilities, combined with the growth assumptions, this analysis identifies the existing LOS that is provided to a community's existing residents and ensures that future facilities maintain these standards.

Excess Capacity and Future Capital Facilities Analysis

The demand analysis, existing facility inventory and LOS analysis allow for the development of a list of capital projects necessary to serve new growth and to maintain the existing system. This list includes any excess capacity of existing facilities as well as future system improvements necessary to maintain the LOS. Any excess capacity identified within existing facilities can be apportioned to new development. Any demand generated from new development that overburdens the existing system beyond the existing capacity justifies the construction of new facilities.

FINANCING STRATEGY

This analysis must also include a consideration of all revenue sources, including impact fees, future debt costs, alternative funding sources and the dedication of system improvements, which may be used to finance system improvements.[2] In conjunction with this revenue analysis, there must be a determination that impact fees are necessary to achieve an equitable allocation of the costs of the new facilities between the new and existing users.[3]

PROPORTIONATE SHARE ANALYSIS

The written impact fee analysis is required under the Impact Fees Act and must identify the impacts placed on the facilities by development activity and how these impacts are reasonably related to the new development. The written impact fee analysis must include a proportionate share analysis, clearly detailing each cost component and the methodology used to calculate each impact fee. A local political subdivision or private entity may only impose impact fees on development activities when its plan for financing system improvements establishes that impact fees are necessary to achieve an equitable allocation of the costs borne in the past and to be borne in the future (UCA 11-36a-302).

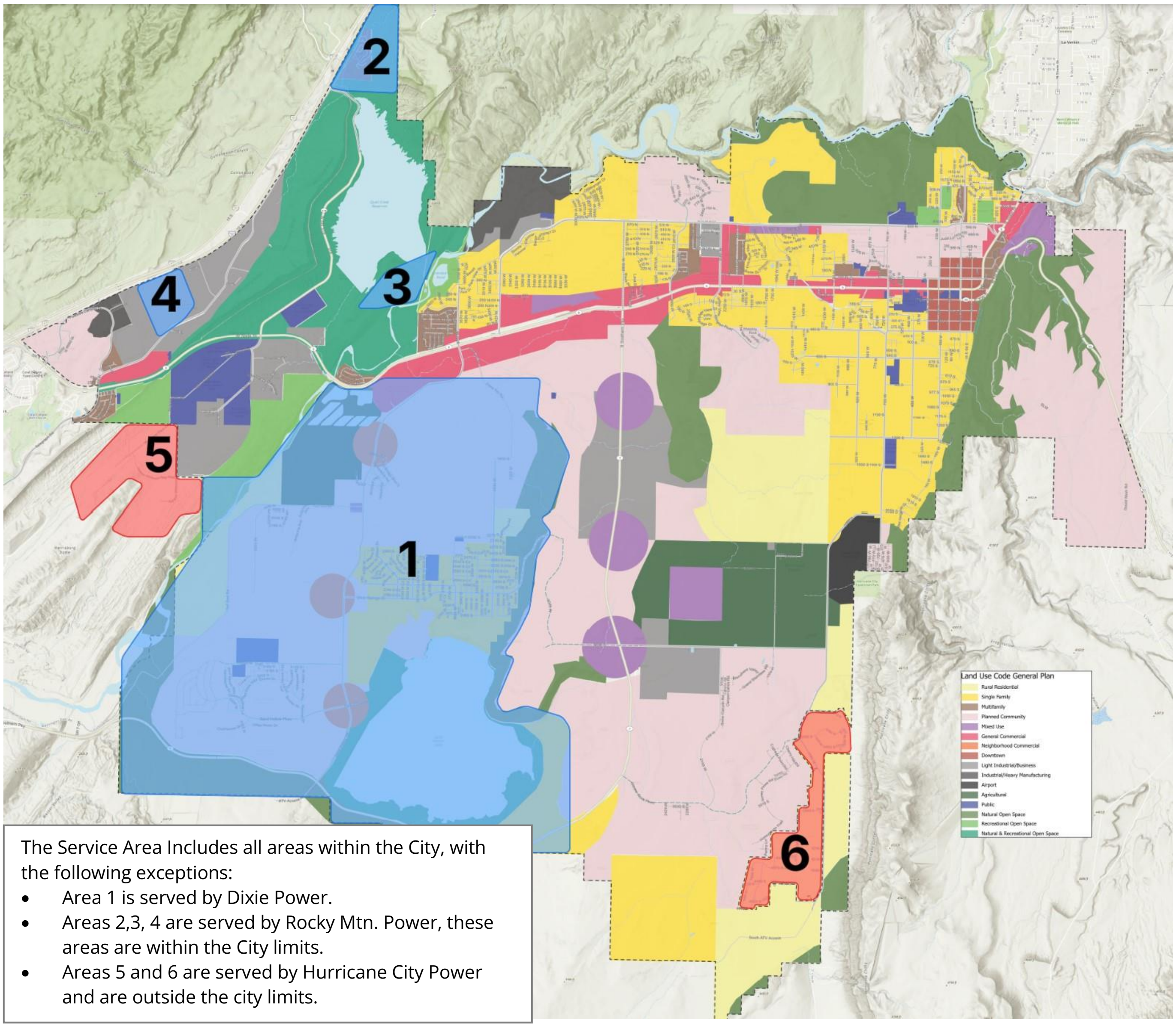
[2] 11-36a-302(2)
[3] 11-36a-302(3)

SECTION 3: SERVICE AREA, DEMAND, AND LOS

SERVICE AREA

Utah Code requires the impact fee enactment to establish one or more service areas within which impact fees will be imposed.[4] This document identifies the necessary future system improvements for the Service Area that will maintain the existing LOS into the future. According to the 2024 IFFP, the Service Area includes areas within the City boundary as shown in **Figure 3.1**.

FIGURE 3.1: POWER SERVICE AREA



[4] UC 11-36a-402(1)(a)

DEMAND

The City's electrical system requires expansion to maintain the existing LOS as new growth and development activity occurs within the Service Area. To accurately determine the portion of the costs of future capital infrastructure that should be included in the impact fees, this analysis projects the future growth in megawatts (MW) and kilowatts (kW). The demand unit used in the calculation of the electrical impact fees is the estimated MW and kW at a power factor of 95 percent for residential and 90 percent for commercial.[5] **TABLE 3.1** summarizes the projected annual increase in kWs within the Service Area.

TABLE 3.1: PROJECTED DEMAND

DESCRIPTION	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total System CP Demands (kW)	54,686	59,061	63,786	68,888	74,399	77,375	80,470	83,689	87,037	90,518
Ten Year Demand	**35,832**									

It is anticipated that new growth will have an impact on the City's existing services. Electrical facilities will need to be expanded to maintain the existing LOS. The IFFP, in conjunction with the impact fee analysis, are designed to accurately assess the true impact of a particular user upon the City's infrastructure.

LEVEL OF SERVICE STANDARDS

Impact fees cannot be used to finance an increase in the LOS to current or future users of capital improvements. Therefore, it is important to identify the LOS within the Service Area to ensure that the new capacities of projects financed through impact fees do not exceed the established standard. According to the most recent IFFP, the City plans, designs and operates its system based on the following criteria:

- Transformer ratings under varying load levels and loading conditions must remain below their ONAN/ONFA/ONFA 55-degree rating.
- Dual bay substations loading shall not exceed 75% of combined ONAN/ONFA/ONFA 55-degree MVA rating of power transformers.
- The system must be able to adequately serve load under single contingency (N-1) situations, where "N" is a power system element such as a transformer or line.
- The system switching required under an N-1 contingency should remain as simplified as possible to ensure that switching orders do not become unnecessarily complex.
- Distribution circuit loading criteria must remain below 90% of its maximum current rating.
- Transmission circuit voltage must remain between 95% and 105% of its nominal value.
- Distribution circuit voltage must remain between 98% and 105% (at loads) of its nominal value.
- Distribution circuit mains must be able to serve additional load under N-1 contingencies.

The above criteria were used to determine Hurricane City's facility needs based on the amount of load (i.e., demand) placed on the existing system over the study planning horizon.

[5] Power factor (p.f.) is the ratio of working power, measured in kilowatts (kW), to apparent power, measured in kilovolt amperes (kVA). The power factor of the present system is acceptable, above 0.95. The system power factor is primarily influenced by the types and level of loads on the system and the amount of shunt capacitors installed in the system.

SECTION 4: EXISTING FACILITIES & EXCESS CAPACITY

This section is intended to summarize the existing public facilities related to electric transmission and substation infrastructure. The IFFP indicates the City is served by PacifiCorp's Purgatory Flat Transmission Substation with two radial 69kV lines, one line feeds Anticline substation and the other line feeds the other three 69kV substations. The radial 69kV line interconnects Hurricane City's four Distribution substations. Hurricane City's electrical system currently has four power distribution substations: Anticline Substation, Brentwood Substation, Clifton Wilson Substation, and Three Falls Substation. It is noted that during the time of this study Three Falls Substation was under construction but was not yet operating. So, the peak loading for Three Falls Substation was estimated.[6]

VALUE OF EXISTING INFRASTRUCTURE

Based upon data provided by the City using the electric utility depreciation schedule, the existing system is valued at approximately $42M, based on original cost as shown in TABLE 4.1. Generation is excluded from the calculation of buy-in. Project improvements and non-eligible values are excluded from the analysis.

TABLE 4.1: VALUE OF EXISTING SYSTEM

Total System Value	$42,235,807
Eligible Distribution/Transmission	$4,951,860
Eligible Substations	$8,240,115
Subtotal of Eligible Value	**$13,191,976**
Estimate of Buildout Demand	140,000
IFFP Demand	35,832
% of Total	**26%**

EXCESS CAPACITY

The City maintains a network of transmission and distribution infrastructure. TABLE 4.2 and 4.3 illustrate the capacity analysis for the existing transformers and feeder loads. Based on this analysis, there is excess capacity related to existing infrastructure. The excess capacity is assumed to serve development through buildout.

MANNER OF FINANCING EXISTING INFRASTRUCTURE

The City has funded its existing capital infrastructure through a combination of different revenue sources, including user fee revenues, service fees, and impact fees. Therefore, the City's existing LOS standards have been funded by the City's existing residents. The City does not foresee receiving revenues from other entities (i.e., grants, federal or state funds, other contributions, etc.) to fund new facilities.

[6] IFFP p.7. This station is now in operation.

SECTION 5: CAPITAL FACILITY ANALYSIS

The capital project and engineering data, planning analysis, and other information related to future capital needs can be found in the 2024 IFFP. The accuracy and correctness of this plan is contingent upon the accuracy of the data and assumptions. Any deviations or changes in the assumptions due to changes in the economy or other relevant information used by the City for this study may cause this plan to be inaccurate and may require modification to this analysis to ensure accuracy.

SUMMARY OF FUTURE CAPITAL FACILITIES

Based upon the projected increase in kWs and demand on the system, the City has identified the future capital projects that must be constructed over the next ten years to serve future development. The costs of these projects are summarized in **TABLE 5.1**. The percentage of the total cost that is attributable to growth is based upon the ratio of the capacity available for meeting future growth in the 10-year IFFP demand period to the total capacity provided by the project. All the projects listed in the table below have a life expectancy of more than 10 years.

TABLE 5.1: SUMMARY OF FUTURE CAPITAL PROJECT COSTS

PROJECT # & TITLE	OPINION OF PROBABLE COST	YEAR	CONSTRUCTION YEAR COST	% TO IFFP DEMAND	COST TO GROWTH
Replace Anticline T1	$1,943,675	2025	$2,021,422	50.0%	$1,010,711
New 138kV line from Purgatory to Future Sub 1	$6,404,366	2026	$6,926,962	75.0%	$5,195,222
New Future Substation 1	$7,690,408	2027	$8,650,663	100.0%	$8,650,663
New 138kV line from Future Sub 1 to Three Falls	$3,100,207	2027	$3,487,311	75.0%	$2,615,483
Three Falls Substation Bay 2	$3,728,421	2029	$4,536,194	80.0%	$3,628,955
New 69kV line to Sky Mountain	$200,805	2029	$244,310	95.0%	$232,094
New Sky Mountain Substation	$5,503,354	2030	$6,963,498	95.0%	$6,615,324
New 138kV line to 600 North	$685,450	2031	$902,005	75.0%	$676,504
New 138kV line from 600 North to Three Falls	$1,339,409	2032	$1,833,074	75.0%	$1,374,805
Three Falls substation Bay 1 Upgrade	$2,119,390	2032	$2,900,532	60.0%	$1,740,319
New 138kV line to Future Substation 2	$210,848	2033	$300,102	75.0%	$225,077
New 138kV-69kV Future Substation 2	$7,195,069	2033	$10,240,827	65.0%	$6,656,537
Total	**$40,121,402**		**$49,006,901**		**$38,621,695**

The projected resource needs for the next several years are detailed in the following paragraphs. The estimated costs of future capital projects are based on historical experience with the system and projected growth patterns for the system.

SYSTEM VS. PROJECT IMPROVEMENTS

System improvements are defined as existing and future public facilities that are intended to provide services to service areas within the community at large.[7] Project improvements are improvements and facilities that are planned and designed to provide service for a specific development (resulting from a development activity) and considered necessary for the use and convenience of the occupants

[7] 11-36a-102(20)

or users of that development.[8] The Impact Fee Analysis may only include the costs of impacts on system improvements related to new growth within the proportionate share analysis. However, impact fees will be used for the substations, etc. since these are considered system improvements.

FUNDING OF FUTURE FACILITIES

Future facilities are generally funded using the following resources:

UTILITY RATE REVENUES

Utility rate revenues serve as the primary funding mechanism within enterprise funds. Rates are established to ensure appropriate coverage of all operations and maintenance expenses, debt service coverage, and capital project needs not related to growth.

GRANTS AND DONATIONS

The City does not anticipate receiving grants or donations to fund improvements currently contemplated in this IFFP. However, the impact fees will be adjusted if grants become available to reflect the grant monies received. A donor may be entitled to reimbursement for the value of the system improvements funded through impact fees if donations are made by new development. SECTION 6 further addresses proposed credits available to development.

IMPACT FEE REVENUES

Impact fees are charged to ensure that new growth pays its proportionate share of the costs for the development of public infrastructure. Impact fee revenues can also be attributed to the future expansion of public infrastructure if the revenues are used to maintain an existing level of service. Increases to an existing level of service cannot be funded with impact fee revenues. Impact fee revenues are generally considered non-operating revenues and help offset future capital costs. The City is opting to include the unincumbered impact fee fund balance, estimated at $2,932,150, as a credit against future impact fee capital costs.

DEBT FINANCING

In the event the City has not accumulated sufficient impact fees to pay for the construction of time sensitive or urgent capital projects needed to accommodate new growth, the City must look to revenue sources other than impact fees for funding. The Impact Fees Act allows for the costs related to the financing of future capital projects to be legally included in the impact fee. This allows the City to finance and quickly construct infrastructure for new development and reimburse itself later from impact fee revenues for the costs of issuing debt. Debt financing costs are not included in this analysis.

EQUITY OF IMPACT FEES

Impact fees are intended to cover the costs of system improvements (infrastructure) that relate to future growth. The impact fee calculations are structured for impact fees to fund 100 percent of the growth-related facilities identified in the proportionate share analysis as presented in the impact fee analysis. Even so, there may be years when actual impact fee revenues cannot cover the annual growth-related expenses. In those years, growth-related projects may be delayed, or other revenues

[8] 11-36a102(13)

such as general utility rate revenues may be borrowed to make up any annual deficits. Any borrowed funds are to be repaid in their entirety through subsequent impact fees.

NECESSITY OF IMPACT FEES

An entity may only impose impact fees on development activity if the entity's plan for financing system improvements establishes that impact fees are necessary to achieve parity between existing and new development. This analysis has identified the improvements to public facilities and the funding mechanisms to complete the suggested improvements. Impact fees are identified as a necessary funding mechanism to help offset the costs of new capital improvements related to new growth. In addition, alternative funding mechanisms have been identified to help offset the cost of future capital improvements.

SECTION 6: ELECTRICAL IMPACT FEE CALCULATION

The calculation of impact fees relies upon the information contained in this analysis. Impact fees are calculated based on many variables centered on proportionality and LOS. The following paragraph briefly discusses the methodology for calculating impact fees. Impact fees can be calculated using a specific set of costs specified for future development. The improvements are identified in the IFFP as growth-related projects. The total project costs are divided by the total demand units the projects are designed to serve. Under this methodology, it is important to identify the existing LOS and determine any excess capacity in existing facilities that could serve new growth.

Impact Fee Calculation

Based on the growth-related projects, as well as the applicable buy-in fee, the cost per new kW is estimated at $1,167.20, as shown in **Table 6.1**.

Table 6.1: Estimate of Impact Fee Cost per kW

	Total Costs	% Growth Related and Impact Fee Funded	Growth Related & City Funded Costs	Growth Related kW	Cost per New kW
Buy-In: Existing Substation Transformers	$13,191,976	26%	$3,376,392	35,832	$94.23
Future System Improvements	$49,006,901	79%	$38,621,695	35,832	$1,077.85
Financing	$0	79%	$0	35,832	$0.00
Professional Expense	$73,925	82%	$60,363	22,689	$2.66
Interest Credit	($270,000)	100%	($270,000)	35,832	($7.54)
TOTALS:	**$62,002,802**		**$41,788,450**		**$1,167.20**
Professional expense is based on the cost to complete the IFFP and IFA.					

The fee per kW is then applied to the general usage statistics for residential and commercial users, as shown in **Table 6.2**. The higher impact fee base cost per kW in this analysis comes from the type of proposed projects in this analysis, the higher cost of system components and the increased costs construction labor since the last analysis was done.

Table 6.2: Illustration of Impact Fee by Panel Rating

Panel Rating	Line-to-Line Voltage	100% Panel kVA	Avg Panel Loading	Avg Peak Demand @ Panel (kVA)	Power Factor	Estimated Diversified kW	Proposed Fee	Existing Fee	% Change
Residential (120/240, 1 phase)									
125	240	30	12.50%	3.75	95%	3.56	$4,158	$1,622	156%
200	240	48	12.50%	6.00	95%	5.70	$6,653	$2,595	156%
400	240	96	12.85%	12.34	95%	11.72	$13,679	$5,190	164%
600	240	144	12.85%	18.50	95%	17.58	$20,518	$7,785	164%
Commercial (120/240, 1 phase)									
200	240	48	25.00%	12.00	90%	10.80	$12,606	$4,902	157%
400	240	96	25.00%	24.00	90%	21.60	$25,212	$9,803	157%
600	240	144	25.00%	36.00	90%	32.40	$37,817	$14,705	157%
800	240	192	25.00%	48.00	90%	43.20	$50,423	$19,607	157%
Commercial (120/208, 3 phase)									
200	208	72	25.00%	18.01	90%	16.21	$18,923	$7,358	157%
400	208	144	25.00%	36.03	90%	32.42	$37,845	$14,715	157%

PANEL RATING	LINE-TO-LINE VOLTAGE	100% PANEL KVA	AVG PANEL LOADING	AVG PEAK DEMAND @ PANEL (KVA)	POWER FACTOR	ESTIMATED DIVERSIFIED KW	PROPOSED FEE	EXISTING FEE	% CHANGE
600	208	216	25.00%	54.04	90%	48.64	$56,768	$22,073	157%
800	208	288	25.00%	72.05	90%	64.85	$75,691	$29,431	157%
1,000	208	360	25.00%	90.07	90%	81.06	$94,613	$36,788	157%
1,200	208	432	25.00%	108.08	90%	97.27	$113,536	$44,146	157%
1,600	208	576	25.00%	144.11	90%	129.70	$151,381	$58,861	157%
1,800	208	648	25.00%	162.12	90%	145.91	$170,304	$66,219	157%
2,000	208	721	25.00%	180.13	90%	162.12	$189,226	$73,577	157%
2,500	208	901	25.00%	225.17	90%	202.65	$236,533	$91,971	157%
3,000	208	1,081	25.00%	270.20	90%	243.18	$283,840	$110,365	157%
Commercial (277/480, 3 phase)									
200	480	166	25.00%	41.57	90%	37.41	$43,668	$16,979	157%
400	480	333	25.00%	83.14	90%	74.82	$87,335	$33,958	157%
600	480	499	25.00%	124.71	90%	112.24	$131,003	$50,938	157%
800	480	665	25.00%	166.28	90%	149.65	$174,671	$67,917	157%
1,000	480	831	25.00%	207.85	90%	187.06	$218,338	$84,896	157%
1,200	480	998	25.00%	249.42	90%	224.47	$262,006	$101,875	157%
1,600	480	1,330	25.00%	332.55	90%	299.30	$349,341	$135,834	157%
1,800	480	1,496	25.00%	374.12	90%	336.71	$393,009	$152,813	157%
2,000	480	1,663	25.00%	415.69	90%	374.12	$436,676	$169,792	157%
2,500	480	2,078	25.00%	519.62	90%	467.65	$545,845	$212,241	157%
3,000	480	2,494	25.00%	623.54	90%	561.18	$655,015	$254,689	157%

NON-STANDARD IMPACT FEES

The proposed fees are based upon growth in kWs. The City reserves the right under the Impact Fees Act to assess an adjusted fee that more closely matches the true impact that the land use will have upon public facilities.[9] A developer may submit studies and data for a particular development and request an adjustment. This adjustment could result in a higher or lower impact fee if the City determines that a particular user may create a different impact than what is standard for its land use.

Estimated Diversified kW Usage * $1,167.20

[9] UC 11-36a-402(1)(c)

CALCULATION OF IMPACT FEE INTEREST CREDIT

This analysis calculates projected interest earnings and applies a credit in the fee calculation. The table below illustrates that the proposed impact fee revenue collections compared to impact fee expense, with interest credit applied.

TABLE 6.3: IMPACT FEE INTEREST CALCULATION

YEAR	KW	NEW KW	FEE PER KW	PROJECTED REVENUE	PROJECTED EXPENSE	PROJECTED BUY-IN EXPENSE	NET	CUMULATIVE	INTEREST EARNED
2024	54,686								
2025	59,061	4,375	$1,167	$5,106,500	($1,010,711)	($412,256)	$3,683,533	$3,683,533	$36,835
2026	63,786	4,725	$1,167	$5,515,020	($5,195,222)	($445,237)	($125,438)	$3,594,930	$35,949
2027	68,888	5,102	$1,167	$5,955,054	($11,266,147)	($480,761)	($5,791,854)	($2,160,975)	($21,610)
2028	74,399	5,511	$1,167	$6,432,439	$0	($519,302)	$5,913,138	$3,730,553	$37,306
2029	77,375	2,976	$1,167	$3,473,587	($3,861,050)	($280,428)	($667,891)	$3,099,968	$31,000
2030	80,470	3,095	$1,167	$3,612,484	($6,615,324)	($291,642)	($3,294,481)	($163,514)	($1,635)
2031	83,689	3,219	$1,167	$3,757,217	($676,504)	($303,326)	$2,777,386	$2,612,237	$26,122
2032	87,037	3,348	$1,167	$3,907,786	($3,115,124)	($315,482)	$477,179	$3,115,539	$31,155
2033	90,518	3,481	$1,167	$4,063,023	($6,881,614)	($328,015)	($3,146,606)	$89	$1
Total				**$41,823,110**	**($38,621,695)**	**($3,376,449)**			

Assumes interest earnings based on one percent interest rate.

CONSIDERATION OF ALL REVENUE SOURCES

The Impact Fees Act requires the proportionate share analysis to demonstrate that impact fees paid by new development are the most equitable method of funding growth-related infrastructure. See SECTION 5 for further discussion regarding the consideration of revenue sources.

EXPENDITURE OF IMPACT FEES

Legislation requires that impact fees should be spent or encumbered within six years after each impact fee is paid. Impact fees collected in the next five to six years should be spent or encumbered on only those projects outlined in the IFFP as growth-related costs to maintain the LOS or to reimburse existing development for excess capacity used. The existing impact fee fund balance is included in this analysis and will be spent on the projects that are shown here that were identified in the prior Impact Fee Facilities Plan (also included in this analysis).

PROPOSED CREDITS OWED TO DEVELOPMENT

Credits may be applied to developers who have constructed and donated system facilities to the City that are included in the IFFP in-lieu of impact fees. Credits for system improvements may be available to developers up to, but not exceeding, the amount commensurate with the LOS identified within this IFA. Credits will not be given for the amount by which system improvements exceed the LOS identified within this IFA. This situation does not apply to developer exactions or improvements required to offset density or as a condition of development. Any project that a developer funds must be included in the IFFP, if a credit is to be issued.

In the situation that a developer chooses to construct system facilities found in the IFFP in-lieu of impact fees, the decision must be made through negotiation with the developer and the City on a case-by-case basis.

GROWTH-DRIVEN EXTRAORDINARY COSTS

The City does not anticipate any extraordinary costs necessary to provide services to future development.

SUMMARY OF TIME PRICE DIFFERENTIAL

The Impact Fees Act allows for the inclusion of a time price differential to ensure that the future value of costs incurred at a later date are accurately calculated to include the costs of construction inflation. A four percent annual construction inflation adjustment is applied to projects completed after 2023 (the base year cost estimate).

Summary for Item #2

Currently, as development has installed new subdivisions, the Power Department (PD) works with developers to install the power infrastructure needed to support the subdivision.

If the infrastructure needs to be underground, the PD will ask them to hire one of the contractors from our pre-qualified list. That contractor will install the conduit, equipment and cable according to the PD's design and standards. Then our linemen will terminate and complete the installation.

If the new infrastructure needs to be overhead, then the PD will consider the timelines, safety, hot work (working on or near energized equipment or conductors), manpower, costs, etc. and decide if the PD can do it in-house or if we should hire a contractor.

The PD does not have a list of pre-qualified overhead contractors but could create one. The PD would reach out to reputable overhead contractors and have them build it to PD design and specs. We are currently working toward having Overhead Standards & Specs engineered to assist also. We have been presented with the idea of an ordinance or policy that 100% of new construction, potentially only distribution, which would be required to be contracted out. The Power Department linemen would perform maintenance only.

Good afternoon everyone,

I wanted to take a moment of your time and offer you some data that will be helpful in considering the topic of contracting 100% of the City's new power infrastructure installations.
There have been questions about how often other power companies in Southern Utah hire contractors. We spoke directly to Power Directors, Superintendents, and high-ranking administrators of each company and compiled the following data:

Representatives spoken with	Power Company	OVERHEAD		UNDERGROUND	
		Distribution	Transmission	Contractor	In-House
Russ Condie	Dixie Power	2/3 in-house 1/3 contracted	all contracted	trenching, conduit, cable	equipment, terminations
Lonnie Hoggard	Rocky Mountain Power	mostly in-house, little contracted	mostly contracted, little in-house	trenching, conduit	cable, terminations, equipment
Rick Hansen	Washington City Power	all in-house	some in-house, some contracted	all development installation	all City projects
Gary Hall	Santa Clara City Power	all in-house	some in-house, some contracted	trenching, conduit	cable, terminations
Ryan Bowler & Tyler Kel	St. George Energy	all in-house	all in-house	all installation	
Justin Miller	Garkane Energy	all in-house	all contracted	some in-house, some contracted	
Brian Anderson	Hurricane City Power	mostly in-house, little contracted	mostly in-house, little contracted	trenching, conduit, cable, equip.	terminations & all City projects(contract trenching)

Overhead Contract Companies Hired (Mentioned)	Southern Ut. Shop
Cache Valley Electric	No
Summit/Probst	No
Parr	No
Hunt Electric	No
Sturgeon	No
Wasatch Electric	No

This data shows that each Power Company decides for itself which portions of installation it chooses to perform in-house, and which portions and when to hire contractors. I am confident if all power companies across Utah and even the nation were surveyed, you would receive very similar data. Each utility confirmed that the decision of when to hire contractors is made considering multiple factors such as deadlines, manpower, specialty equipment, hot work (which means working on and/or near energized equipment or conductors), cost to utility, safety, etc.
This process has proven to be prudent. To remove the decision and tie our own hands with a new ordinance would be unnecessarily restrictive and counterintuitive. And vice versa, if there was a proposed ordinance change or discussion of 100% in-house construction of new infrastructure, we would oppose that also. The ability to choose according to the needs of the department has worked well for 50 years and is the wise way to continue.
There has been information provided during discussion of this topic that we should not be installing private infrastructure on private property. Please understand that most of our entire electric infrastructure grid is currently on private property. Most of the grid on private property has a utility or power easement, but most service drops, whether underground or overhead, are on private property without easements. The limited portions of our electrical grid that are not on private property are either on public facilities (mostly substations) or in or across roadway dedications. Our normal process for developing new infrastructure on, along, or across private property includes first acquiring the proper easements. Without the easements we do not install the infrastructure. With the proper easements, there are no issues with us installing the infrastructure as a municipal power department that I am aware of.
As you consider this topic, please take into consideration some of the following points of data gathered from myself, other Hurricane City Power employees, and other neighboring power professionals. All these people are professionals and experts in their field of work, which is what is being discussed. I respectfully request that you consider this data with the respect that you would hope for if the Council was discussing a topic related to your own line of work. You know that you are an expert in your field of work and as such, your opinions, and the data you offer is extremely valuable to those of us that are not experts in your field.

Quality and Reliability:

Our Linemen are highly qualified and very well trained in the craft of linework. They work here and most live here, and all take extreme pride in the quality of their work. For that purpose, we allow them the time necessary to achieve that quality. It benefits the City in the form of reliability. Low frequency of outages mean less loss of revenue, and less frustrated and upset residents and business owners. Several years ago, St. George Energy hired one of the contractors listed above to construct a transmission line. After the installation it was discovered that the bolts and nuts had not been properly tightened. The City linemen split into two crews and spent a week to a week and a half re-tightening all the fixtures on all the structures. Recently, Washington City recounted a situation where in one subdivision, upon inspection of the installation of underground primary power, there were three elbows that had not been terminated even close to correctly. That situation for sure would cause outages and potentially injure or kill someone. In another situation, a local pre-qualified underground contractor recounted that he was required by a Southern Utah power company to pull in cable into an energized underground vault. He stated he called his wife and told her, “If I die in there, sue them bas#!&@*!”. He knew he wasn’t qualified to be in that situation. I tell these stories, which I am sure that there are many more, to demonstrate instances of likely liability, low quality work and poor craftsmanship that will result in low reliability and possible injuries or death. Some have said we will mitigate these types of issues with inspections. The simple truth is that you can’t catch every nut and bolt and connection, and contractors make more profit the faster they complete a job. There is no dispute that contractors are pushed by their ownership and management to complete the job as fast as possible. This does not mean that every installation performed by contractors will fail tomorrow. There are many poor electrical connections and physical installations that may last a few years or even many. But, over time, through natural heating, cooling, and wind the electrical and physical connections loosen and then the amperage heats up the electrical connection to the point of thermal failure or physical/mechanical failure.
Less than a month ago, we received notification that our Hurricane City Power received the designation of 'Platinum' RP$_3$® (Reliable Public Power Provider) status for reliability from the APPA (American Public Power Association) RP3 committee! This prestigious designation is the result of awesome power employees performing their duties through years of extremely high-quality infrastructure installation and maintenance.

Hurricane City Employees:

To operate an electrical transmission and distribution grid, we are required to have trained, licensed, and qualified employees. Each Journeyman Lineman has completed at a minimum 7800 hours of on-the-job training, a Department of Labor accredited apprenticeship, including an additional 576 minimum hours of “related training” from college level classes with mid-terms and finals tests, pole-yard simulation trainings with rigorous and easily failed practical exams, and multiple transformer math calculation exams. They are required to stay “pole top and bucket truck rescue” certified annually. They are required to maintain a CDL driver’s license, CPR/First Aid/AED certification, Enclosed Space qualification, and several others. If a high voltage electrical employee is injured in their workspace, the First Responders are not qualified to rescue them. We must rescue in-house and deliver the injured to the First Responders. Choosing to demote our Linemen to “maintenance only” demoralizes their professional careers. It gives me the impression of sending an employee to POST to become a certified Police Officer and then hiring rent-a-cops to patrol and protect our City and using our highly qualified Officers to inspect their work. The thousands of dollars and thousands of hours spent in qualifying the employee and the high level of skill and craft of doing a job efficiently and professionally will be sorely diminished. As an example, I learned Spanish fluently once and after not using it for a period I became far from fluent. The age-old adage of “use it or lose it” is true. To accomplish the certification of Journeyman Lineman, an apprentice will take a minimum of 4 years of training and work hours. If we contract all of our installs and the apprentice only does maintenance, it will take substantially longer to achieve the requirements for

Journeyman. This is a detriment to his career and to the City. The City needs the employees to be qualified, and the City will have a difficult time finding employees willing to come train here where it takes substantially longer to complete an apprenticeship. While discussing contractors with Dixie Power, Russ Condie was telling us about when they made the decision to start contracting some of their overhead projects. Dixie Power employees were extremely discouraged and demoralized because they were down in the trenches installing underground conduits, while watching outside contractors come into their yard to load up material and going out to build overhead power lines, setting poles with digger derrick trucks, climbing poles, stringing conductor and flying bucket trucks. Arguably, overhead powerlines may be the biggest reason that young people choose the profession.

Managing and Inspecting Contractors:

Contractors have proven to hire the minimum number of qualified employees to satisfy the law and/or our requirements. We battle this almost daily with our pre-qualified underground contractors. Two of our employees are daily "dealing with" contractors breaking the rules and incorrectly installing underground infrastructure. Many days, those issues are escalated to my workload, and I am required to assist them. They have reported to me that even the "best" contractors we have, "mess things up quite often". And I can vouch for the fact that, there is a massive void between the "best" ones and the others. The others are constantly eating up these two employees' workdays and plenty of mine. I have brought to the table, multiple times, the idea of installing our own underground because of all the headaches and problems we encounter from our own pre-qualified contractors.

Our pre-qualified underground contractor list includes many companies that are Southern Utah owned and operated. The others that are from outside the area have proven to be extra problematic. When something isn't correct or needs to be addressed, it becomes more of a problem than it ever should have been. When the 1-year inspection comes around, it's like pulling teeth to get them to pull away from their profit generating jobs to travel to Southern Utah to "fix" issues that have arisen in a long past, profit generating, job. At least local contractors won't "lose" as much money/time slipping over to fix things, but they still don't care to leave a "paying" job to go fix something essentially for "free". Currently, there are no known overhead contractors based out of southern Utah. I have spoken with one local person that is working on creating one. That will help with the issue I am speaking about but cannot entirely solve it.

Wise Stewardship of Impact Fees:

Currently, we are looking at a 157% increase in Power Impact Fees. Whatever level of fee is adopted, those funds are finite. Some aspects of spending those funds are out of our control, such as the cost of materials and perhaps the cost of engineering. Others, we have a form of control by choosing how to spend them, such as labor, equipment, mobilization and demobilization, and of course, profit. If we choose to build a transmission line with our own employees and our own equipment, then we choose a specific, known level of cost. We know that if we choose to hire a contractor, we will likely be looking at anywhere from 1.5 to 3 times the cost on labor and equipment, full cost of mobilization and demobilization and the full cost of the contractor's absolute requirement to make a healthy profit. Therefore, we choose for our impact fee money to produce less infrastructure, which in turn requires a sooner and larger increase of fees or a lack of adequate facilities. If anyone has any doubt or question whether a Power Company can construct their own infrastructure cheaper than a contractor, I encourage you to dig into it. Survey the other Power Companies around. Don't just ask the linemen, ask the managers and those dealing with the finances. There was a sentiment floating around that perhaps, Hurricane City Power didn't complete Three Falls Substation any cheaper than they could have hired it out. After Mayor Billings verified for herself by speaking with Bryan Dial, St. George Energy Director, she felt confirmed that yes, we can build substations much cheaper in-house than hiring contractors. Towards the end of the Three Falls Substation construction, we received data from our engineering firm that we likely saved ourselves $3.5 - $4.5 million constructing it ourselves (well deserved kudos to Jared

Ross and Team). I know that it is before calculating our labor and benefits and use of our equipment, but even after that, we are still in the millions. Along 600 North, we have rebuilt several sections of ***complex*** transmission and distribution power lines. I highlight “complex” because, in the world of contractors, “complex” builds are gold mines! For one section, we considered contracting it out. The purchase of all materials and supplies were already accomplished, so the contractor was bidding labor, equipment, and mobilization. Their bid was $290,505.00. In-house it cost us between $90,000 and $100,000 (well deserved kudos to Brian Anderson, and Kyle Fenn, and Team).

As we discuss and consider the idea of 100% contracting, I ask you to consider all the points mentioned in this letter and do not tie the hands of the City. Allow us to retain autonomy to consider all factors and choose individually which projects we build in-house and which projects we contract out. The Power Department employees are highly competent, trained professionals. We plead with you to let us do our job and continue to serve Hurricane City residents and businesses at a high level of reliability and fiscal responsibility.

Thank you for your consideration,
Scott Hughes

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

February 2025

Project Meeting Overview Report

CARBON FREE POWER PROJECT (CFPP)

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. Discussed in Executive Session:
   a. Project wind down status, timeline and DOE engagement.

CENTRAL-ST. GEORGE PROJECT

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. Discussed in Executive Session:
   a. Litigation update including current status and next steps.
3. Discussed the St. George 2nd Transformer installation including a cost estimate, scope of work (SOW) and next steps.
4. Discussed the Snow Canyon-Santa Clara Transmission Line including the proposed plan, cost and timeframe for rerouting.
5. Discussed the Operations Report including substation reports for the month of January.

COLORADO RIVER STORAGE PROJECT (CRSP)

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. Discussed CRSP and CREDA information including CRSP hydrology, water temperature, potential thermal curtain, -12-mile Slough work and WAPA workforce.
3. Discussed the Operations Report including output for each resource for the month of January.

CRAIG MONA PROJECT

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. Discussed the Operations Report including transmission line usage for the month of January.

FIRM POWER SUPPLY PROJECT

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. Discussed the Steel Solar 1(A) & 1(B) Scholarship details and extending the deadline.
3. Discussed the Operations Report including output and scheduling from each resource for the month of January.

GOVERNMENT AND PUBLIC AFFAIRS PROJECT (GPA)

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. Discussed Federal & State Legislation including Executive Branch and Congressional Updates:
   a. Federal including Executive and Congress updates.
   b. Utah State update including the 2025 General Session and Bill tracking/status.
   c. Review of Large New Load Bills including SB 132 and SB 227.
   d. Review of Idaho House Bill 146 including the impact on the Horse Butte Wind Project.
3. **Reminder about the Legislative Reception at the Utah State Capitol on February 18, 2025.**
4. **Reminder about the UAMPS Webinar for a briefing on the 2025 APPA Legislative Rally on February 20, 2025.**
5. **Reminder about the 2025 APPA Legislative Rally scheduled for February 24 – 26, 2025.**

HORSE BUTTE PROJECT (HBW)

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**

2. Discussed Major Overhaul Reserve Account Analysis including routine maintenance and cost projections.
3. Discussed software upgrades including LCOE cost/benefit and staff's recommendation not to pursue further until TSR with BPA is approved.
4. Discussed the Operations Report including production output for the month of January.

HUNTER PROJECT

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. Discussed Major Overhaul Reserve Account Analysis including cost projections.
3. Discussed the Operations Report including plant scheduled output for the month of January.

INTERMOUNTAIN POWER PROJECT (IPP)

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. Discussed the Operations Report including scheduled output for the month of January.

MEMBER SERVICES PROJECT

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. **Approved the Brigham City MIG Service, as discussed.**
3. Discussed the member survey results regarding current and new services provided by UAMPS.

MILLARD COUNTY PROJECT

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. Discussed in Executive Session:
    a. Project update including current status, site control efforts and next steps.

3. **Approved resolution regarding a Credit Agreement to provide funding for the Development Costs of the Millard County Power Project, pledging certain revenues and accounts to repayment of the Credit Agreement, the initial budget and plan of finance, the project description, and other matters related to the Project.**

NATURAL GAS PROJECT

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. Discussed the Operations Report including the MMBtu scheduled for the month of January.

NEBO PROJECT

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. Discussed Major Overhaul Reserve Account Analysis including future outages and cost projections.
3. **Approved Payson City's Nebo O&M Agreement including material changes and continued development.**
4. Discussed plant operations including January statistics, operational item highlights, plant maintenance/safety highlights, future maintenance outage dates and plant water updates.
5. Discussed the Operations Report for the month of January including Nebo energy breakdown and Nebo sales margins.

POOL PROJECT

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. Discussed in Executive Session:
   a. EDAM including policy approach, implementation, scheduling coordinator and UAMPS internal approach.
3. **Approved Utilicast Consulting Service Agreement and Statement of Work, as discussed.**
4. Discussed the PX & Scheduling Report including long-term and short-term purchases by counterparties and resource generation by month.

5. Discussed the Operations Report for the month of January including load peak and energy.

RESOURCE PROJECT

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. Discussed in Executive Session:
   a. Power County Natural Gas including current status, subscription update, site activity and next steps.
   b. Rodatherm & Cove Fort 2 Geothermal Study Project including current status and next steps.
   c. Uinta Wind Study Project including current status and next steps.
   d. HBII Study Project including current status and next steps.
   e. Fremont Solar & Storage including current status and next steps.
   f. Transmission Strategic Initiatives including objectives, planning, construction options, The Western Transmission Consortium (TWTC), TSR analysis and new large load analysis.
3. **Approved resolution to authorize and delegate authority to the Project Management Committee to approve the Joint Operating Agreement with Utah Municipal Power Agency (UMPA).**

SAN JUAN PROJECT

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**

VEYO HEAT RECOVERY PROJECT

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. Discussed Major Overhaul Reserve Account Analysis including future outages and planned maintenance.
3. **Approved resolution regarding the annual sale of Renewable Energy Credits (RECs) during the fiscal year when a viable and profitable market is available and to track them by participant.**

4. Discussed the Operations Report including scheduling Veyo for the month of January with peak output and tripped/restricted hours.

BOARD OF DIRECTORS MEETING

1. **Approved resolution adopting the 2025-2026 Fiscal Operating Budget.**
2. Guest Speaker:
    a. Chip Reagan with McGriff Energy discussed insurance updates including average commercial rate change, wildfires, social inflation, energy transition, natural disasters and other UAMPS specific insurance programs.
3. **Approved resolution approving a credit agreement to provide funding for the development costs of the Millard County Power Project, pledging certain revenues and accounts to repayment of the credit agreement, the initial budget and plan of finance, the project description, and other matters related to the project.**
4. Discussed the Operations Report:
    a. Natural Gas including regional storage and gas consumption for electricity generation.
    b. Seasonal outlook including February forecast and forward-looking forecasts.
    c. Transmission update including PacifiCorp formula rate overview and next steps.
    d. Outage notifications including contact information for current RMP regional business managers.
5. Discussed EIM Funding Cap including staff recommendation to establish a $5M cap and a review of the UAMPS FY2026 Budget Policy.
6. Approved all action items for the Project Meetings.
7. **Next UAMPS Board Meeting details: April meeting date, location and tentative agenda.**

St. George 2nd Transformer Installation

Central-St. George Project

Rachel Stanford

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

Summary

- Transformer is on order – expected delivery Q3 2026
- Planned In-Service Q3 2027
- High level SOW & cost estimate received from PacifiCorp
- Project scope, terms & cost allocation will be addressed in stand-alone construction agreement
- Still awaiting proposed JOOA from PacifiCorp (to replace JOA & ITS)

Proposed Cost Allocation

- 100% allocation to PacifiCorp
  - Red Butte Substation
  - St. George Substation
- 100% allocation to UAMPS
  - Central Substation
- 50/50 UAMPS / PacifiCorp
  - RedButte-St. George Transmission Line

Draft Cost Estimate

Scope	Total Cost	UAMPS Cost	% Responsibility
Central Sub	$ 144,147	$ 144,147	100%
Red Butte- St George 345kV	$ 3,582,744	$ 1,791,365	50%
Total UAMPS Cost		$ 1,935,512	

Problematic SOW

- Continually refers to “upgrading” line from 138kV to 345kV
  - Already constructed to 345kV – operated at 138kV
- Central Transformers connections to Red Butte 345kV north & south bus’s
  - Already connected – not sure if proposing to reconfigure and, if so, why
- Proposed work on the 138kV Central & Red Butte bus’s & jumpers
  - Unnecessary
- St. George substation notes need for a new bay
  - Whole new 345kV Sub and 345kV to 138kV transformer, not just a new 345kV bay
- LIDAR surveys
  - Already designed and constructed to 345kV, no new survey required
- Installation of fiber, foundations, steel poles, shield wire, 345kV bay at Red Butte
  - Already in place
- For removal of joint owned assets – flagged salvage value should be shared

Next Steps

- Redlines to the draft with comments sent to PacifiCorp
- Requested meeting, on site if necessary, with PM to ensure understanding of what work has already been completed in previous phases and existing infrastructure
  - Refine SOW to accurately reflect work under this phase
  - Using refined SOW, revise cost estimate and provide detailed breakdown of all costs where UAMPS has a cost obligation
- Proposed on-site April 9/10 to coincide with SWUTTF Meeting
- Flagging – if CSG assets transferred to PacifiCorp will want to ensure mechanism in the construction agreement that provides for recovery of UAMPS costs under this project

UAMPS-Santa Clara 69kV Line Re-route

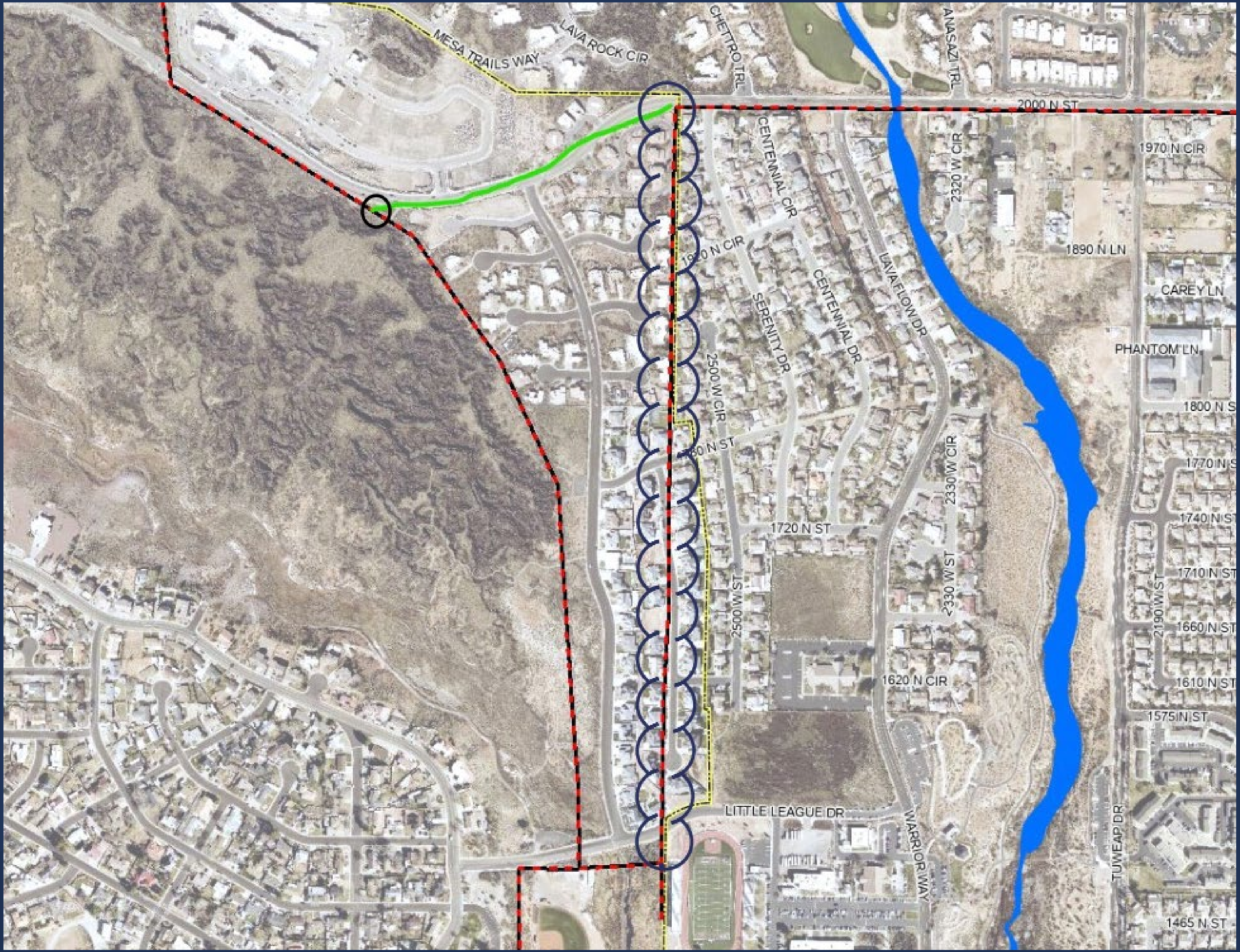
Central-St. George Project

Rachel Stanford

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

Summary

- Investigating option to re-route existing UAMPS 69kV transmission line segment - 2000 N south to Santa Clara
- New route would extend west on Pioneer Parkway to proposed 3-way switch
  - Approx. 1,500 ft. with 5-6 supporting structures
- Benefits:
  - Removes residential encroachment issues
  - NIMBY
  - Line less than half the length of existing – reduction in future maintenance costs
    - Backyard access eliminated – road accessible
  - Received recommendation to replace the aging insulators on this line segment to prevent flashovers and outages (est. $92,808)
- Considerations – securing ROW, cost, and timing to re-route vs. risk exposure with aging insulators
- ~$285,000 per mile to construct 69kV overhead transmission @ 1,500 ft (0.3 miles) approx. $85,500
  - Does not include removal



UAMPS
UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

CRSP / CREDA Report
February 2025

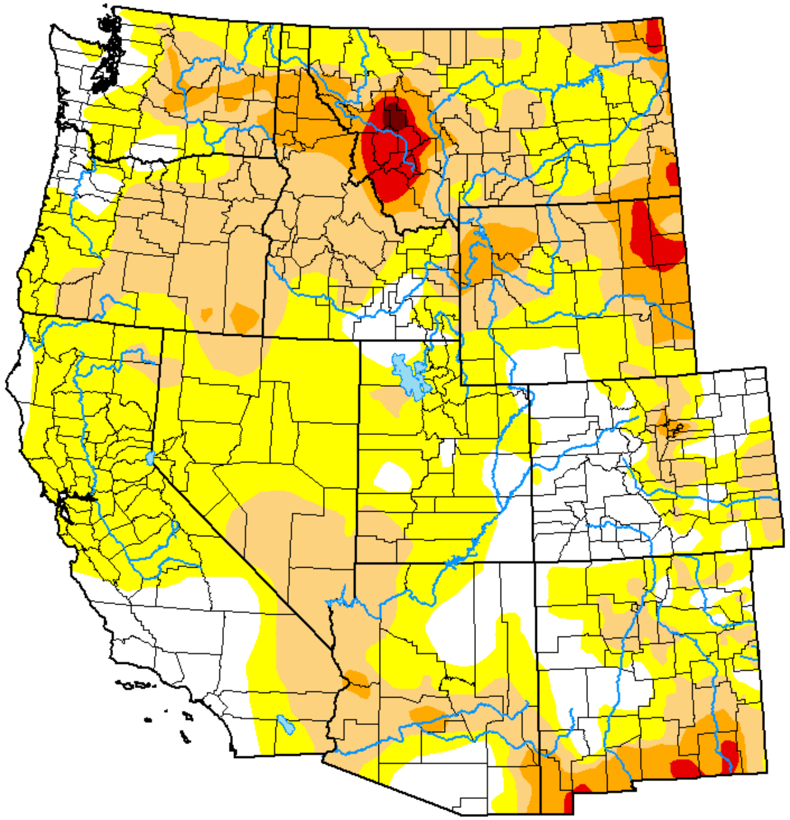
Colorado River Storage Project

UAMPS

Kelton Andersen

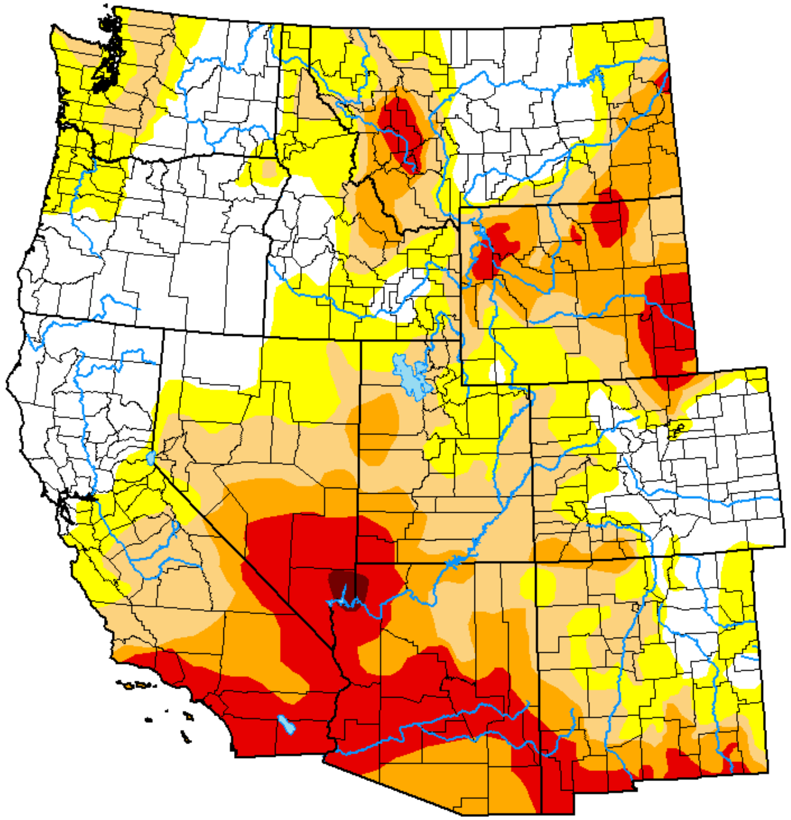
Drought Monitor

September 2024



9/12/2024

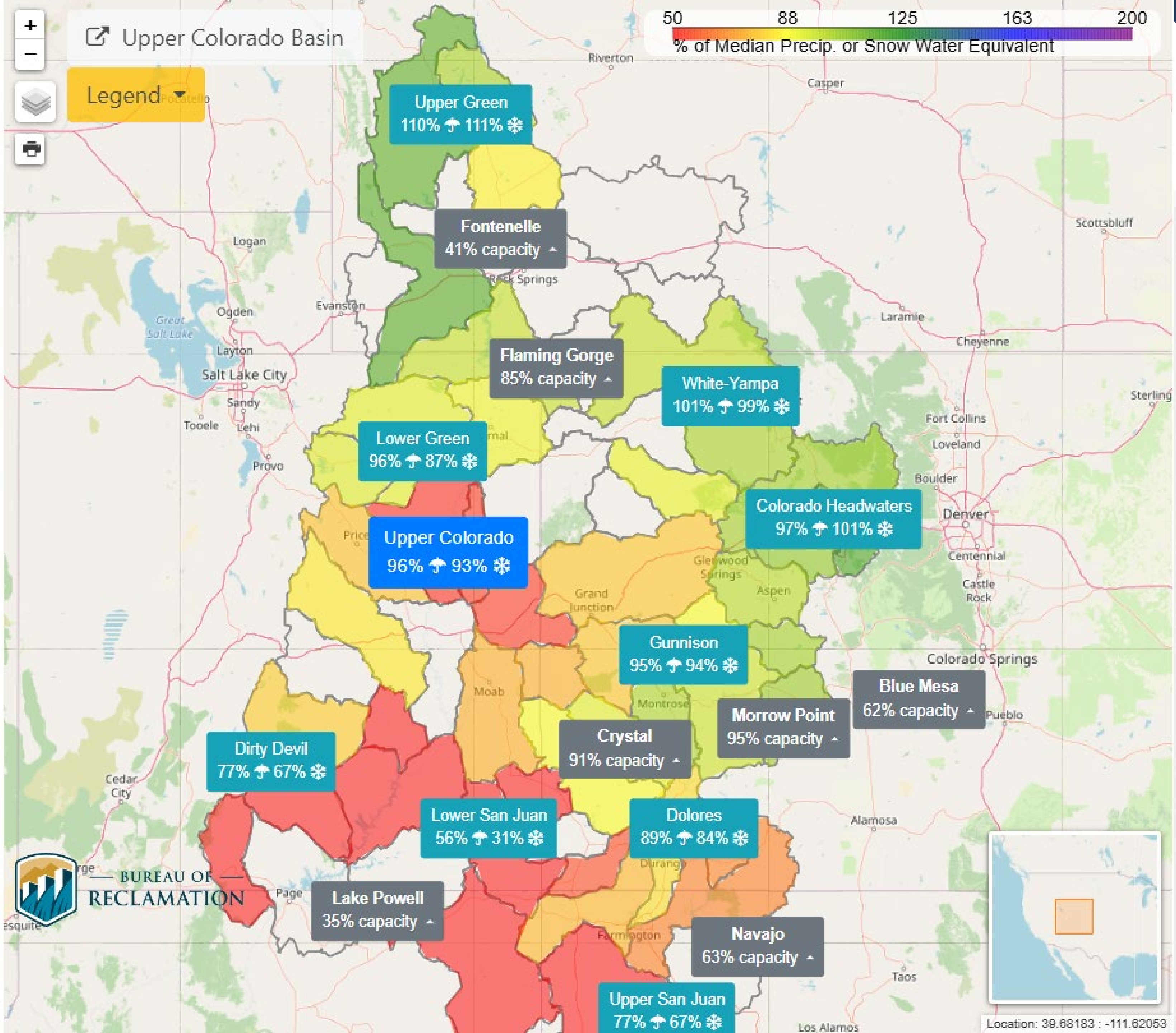
February 2025



2/13/2025

Intensity:

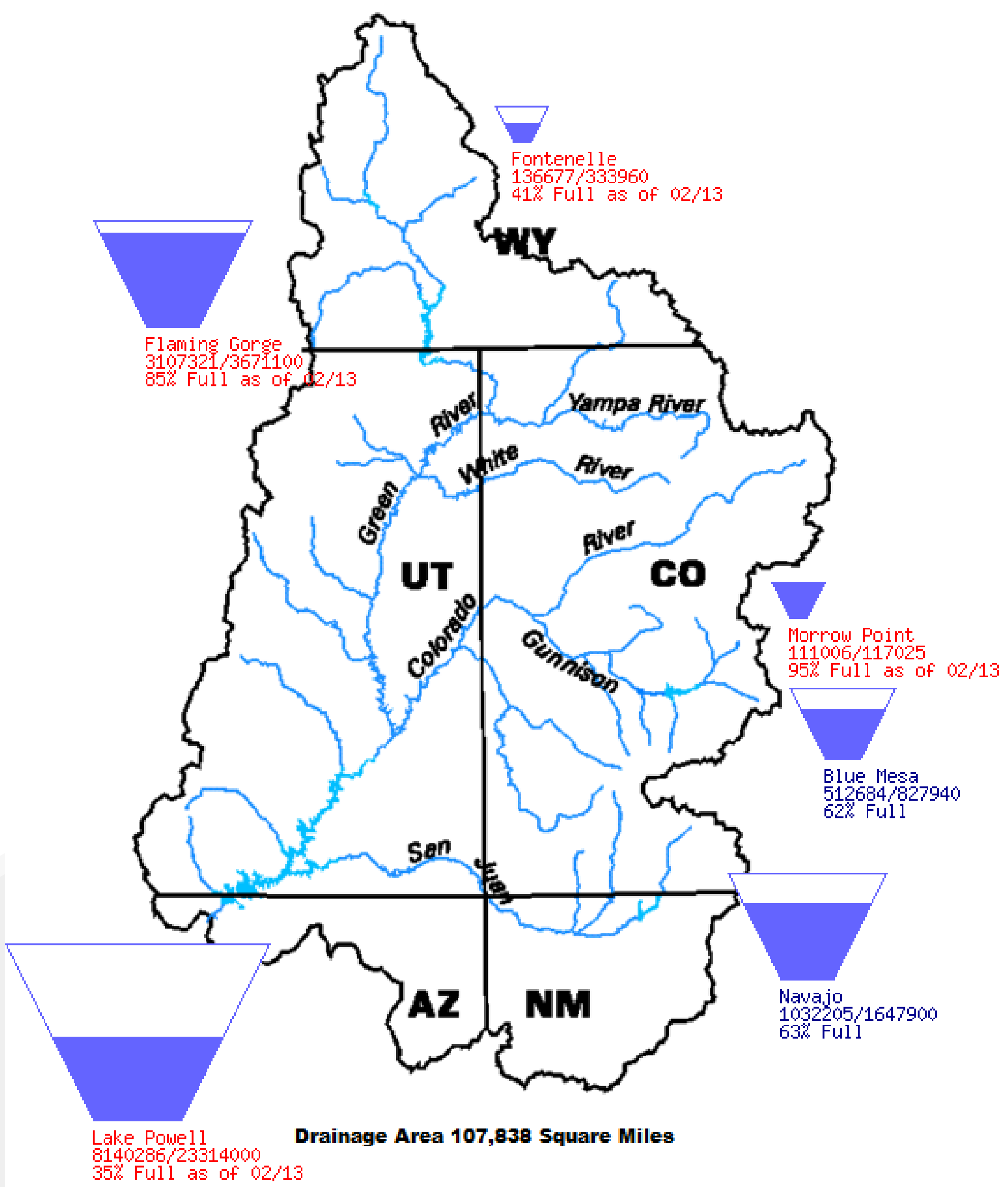
- None
- D0 Abnormally Dry
- D1 Moderate Drought
- D2 Severe Drought
- D3 Extreme Drought
- D4 Exceptional Drought

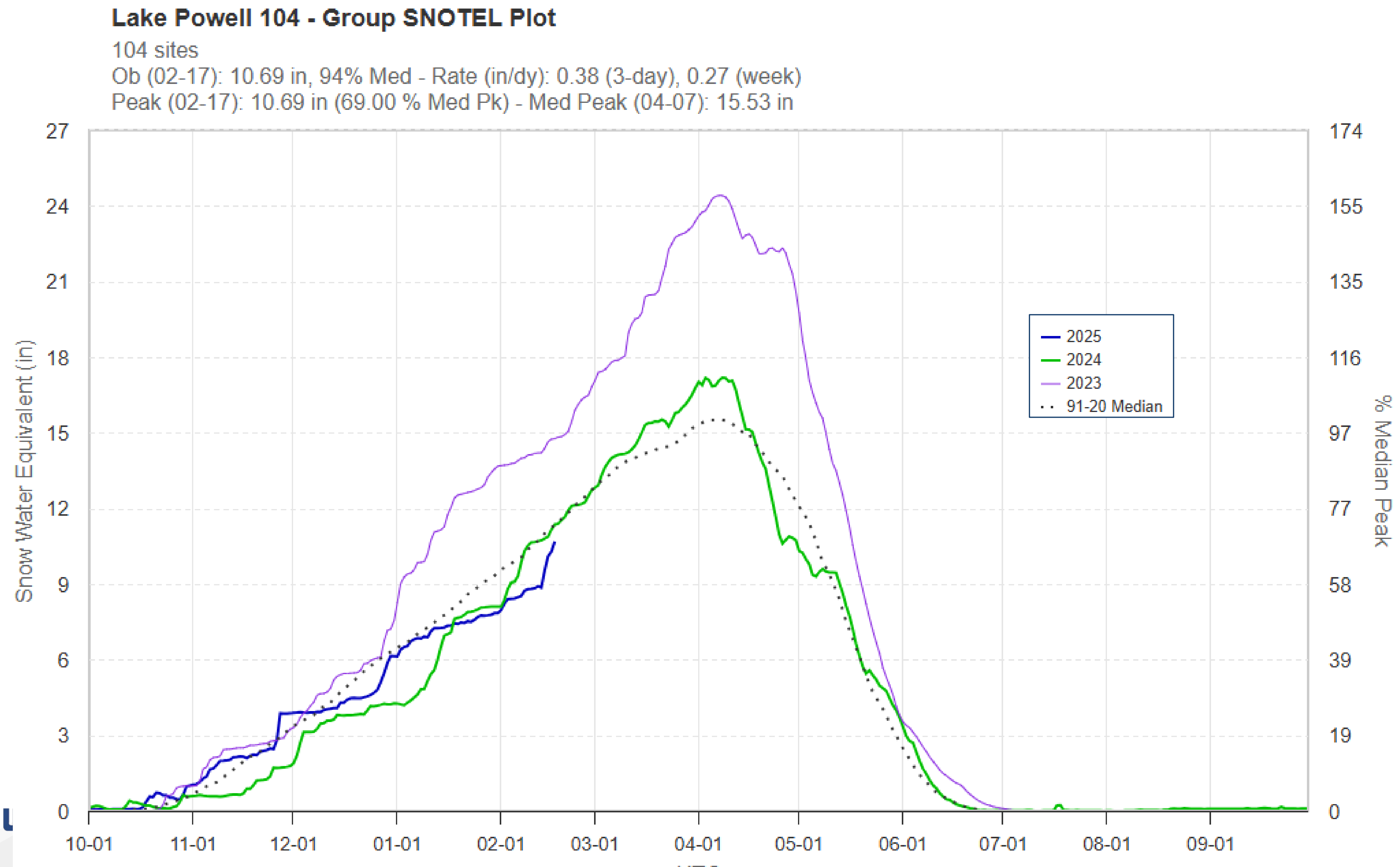

Upper Colorado Basin
Legend
50 88 125 163 200
% of Median Precip. or Snow Water Equivalent
Upper Green
110% 111%
Fontenelle
41% capacity
Flaming Gorge
85% capacity
White-Yampa
101% 99%
Lower Green
96% 87%
Colorado Headwaters
97% 101%
Upper Colorado
96% 93%
Gunnison
95% 94%
Blue Mesa
62% capacity
Morrow Point
95% capacity
Crystal
91% capacity
Dirty Devil
77% 67%
Lower San Juan
56% 31%
Dolores
89% 84%
Lake Powell
35% capacity
Navajo
63% capacity
Upper San Juan
77% 67%
BUREAU OF RECLAMATION
Location: 39.68183 : -111.62053

UAMPS

Data Current as of:
02/16/2025

Upper Colorado River Drainage Basin





Lake Powell 104 - Group SNOTEL Plot
104 sites
Ob (02-17): 10.69 in, 94% Med - Rate (in/dy): 0.38 (3-day), 0.27 (week)
Peak (02-17): 10.69 in (69.00 % Med Pk) - Med Peak (04-07): 15.53 in
Snow Water Equivalent (in)
% Median Peak
0
3
6
9
12
15
18
21
24
27
0
19
39
58
77
97
116
135
155
174
10-01
11-01
12-01
01-01
02-01
03-01
04-01
05-01
06-01
07-01
08-01
09-01
2025
2024
2023
91-20 Median

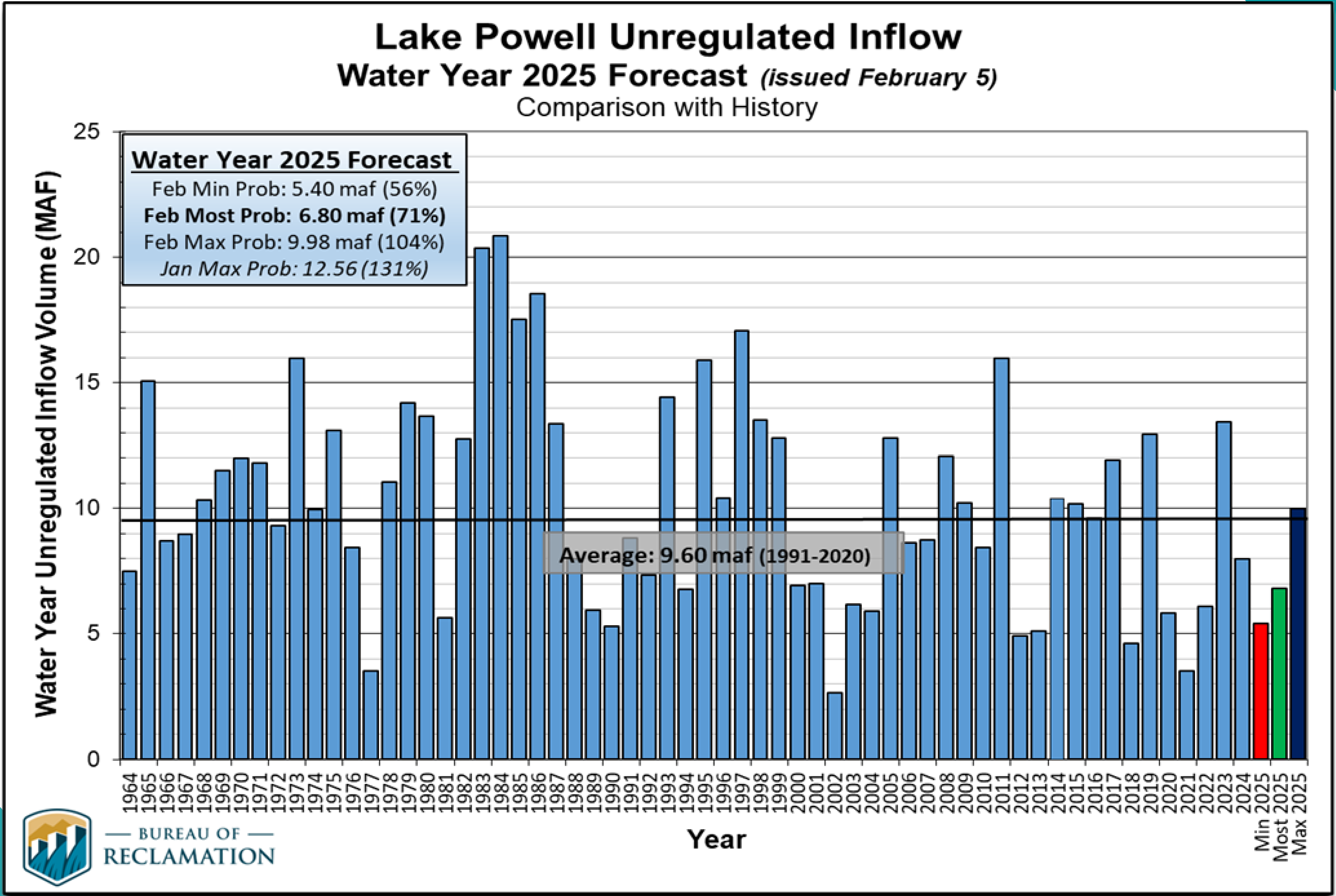
Lake Powell Conditions

- Status of Lake Powell
  - Current lake elevation = 3,565 feet
    - = 135 feet below the spillway
    - =   75 feet above penstock intake level
  - Current storage is 8.2 million acre-feet
    - = 35% of reservoir capacity

Lake Powell Inflow

- Unregulated inflow by water-year
  - 2016 = 89% of average
  - 2017 = 110%
  - 2018 = 43%
  - 2019 = 120%
  - 2020 = 54%
  - 2021 = 32%
  - 2022 = 63%
  - 2023 = 140%
  - 2024 = 83% of avg.
  - 2025 = 71% of avg. forecasted (probable range of 56% to 104%)

- 2024/2025 inflow:
  - Actual
    - Nov = 93%
    - Dec = 93%
    - Jan = 70%
  - Forecast
    - Feb = 93%
    - Mar = 70%
    - Apr = 64%

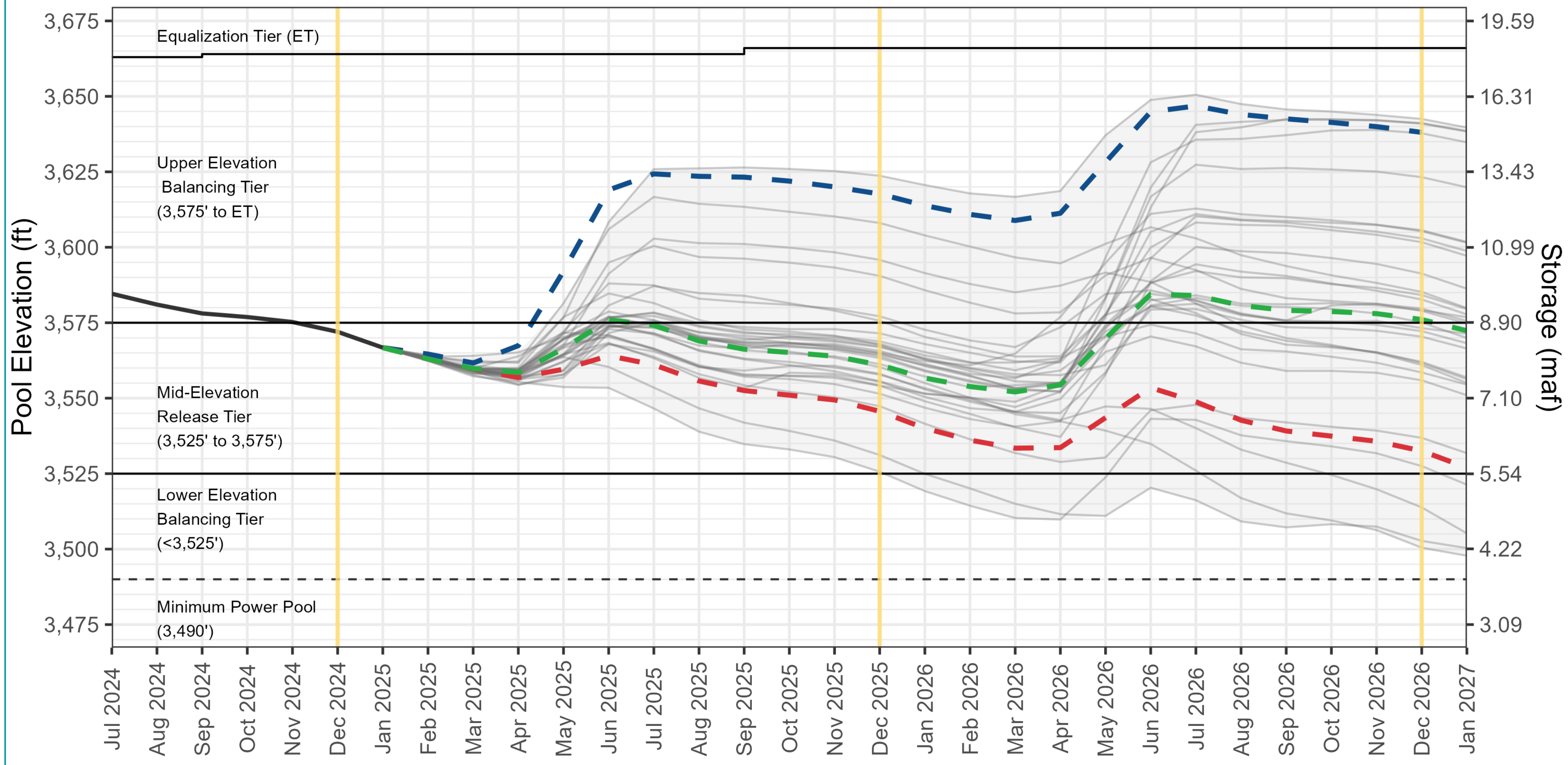


Lake Powell Unregulated Inflow
Water Year 2025 Forecast (issued February 5)
Comparison with History
Water Year 2025 Forecast
Feb Min Prob: 5.40 maf (56%)
Feb Most Prob: 6.80 maf (71%)
Feb Max Prob: 9.98 maf (104%)
Jan Max Prob: 12.56 (131%)
Average: 9.60 maf (1991-2020)
Water Year Unregulated Inflow Volume (MAF)
Year
Min 2025
Most 2025
Max 2025
BUREAU OF
RECLAMATION

UAMPS

Lake Powell End-of-Month Elevations[1]

CRMMS Projections from January and February 2025

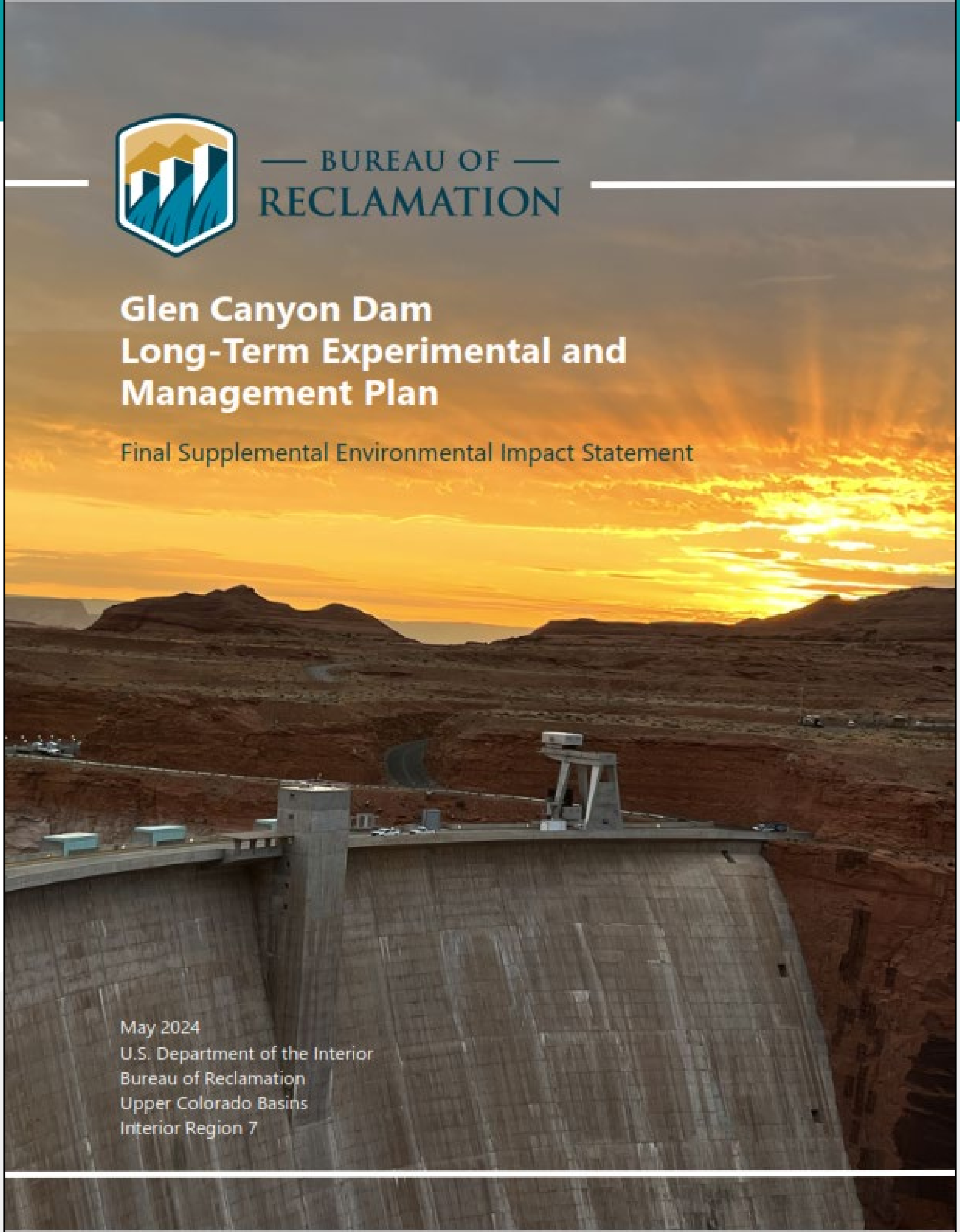


- January 2025 Probable Maximum 24-Month Study
- February 2025 Most Probable 24-Month Study
- February 2025 DROA Probable Minimum 24-Month Study
- Historical
- CRMMS-ESP Projection (30 traces)
- CRMMS-ESP Projections Range

[1]For modeling purposes, simulated years beyond 2026 assume a continuation of the 2007 Interim Guidelines including the 2024 Supplement to the 2007 Interim Guidelines (no additional SEIS conservation is assumed to occur after 2026), the 2019 Colorado River Basin Drought Contingency Plans, and Minute 323 including the Binational Water Scarcity Contingency Plan. With the exception of certain provisions related to ICS recovery and Upper Basin Demand management, operations under these agreements are in effect through 2026. Reclamation initiated the process to develop operations for post-2026 in June 2023, and the modeling assumptions describe here are subject to change.

BUREAU OF RECLAMATION

UAMPS

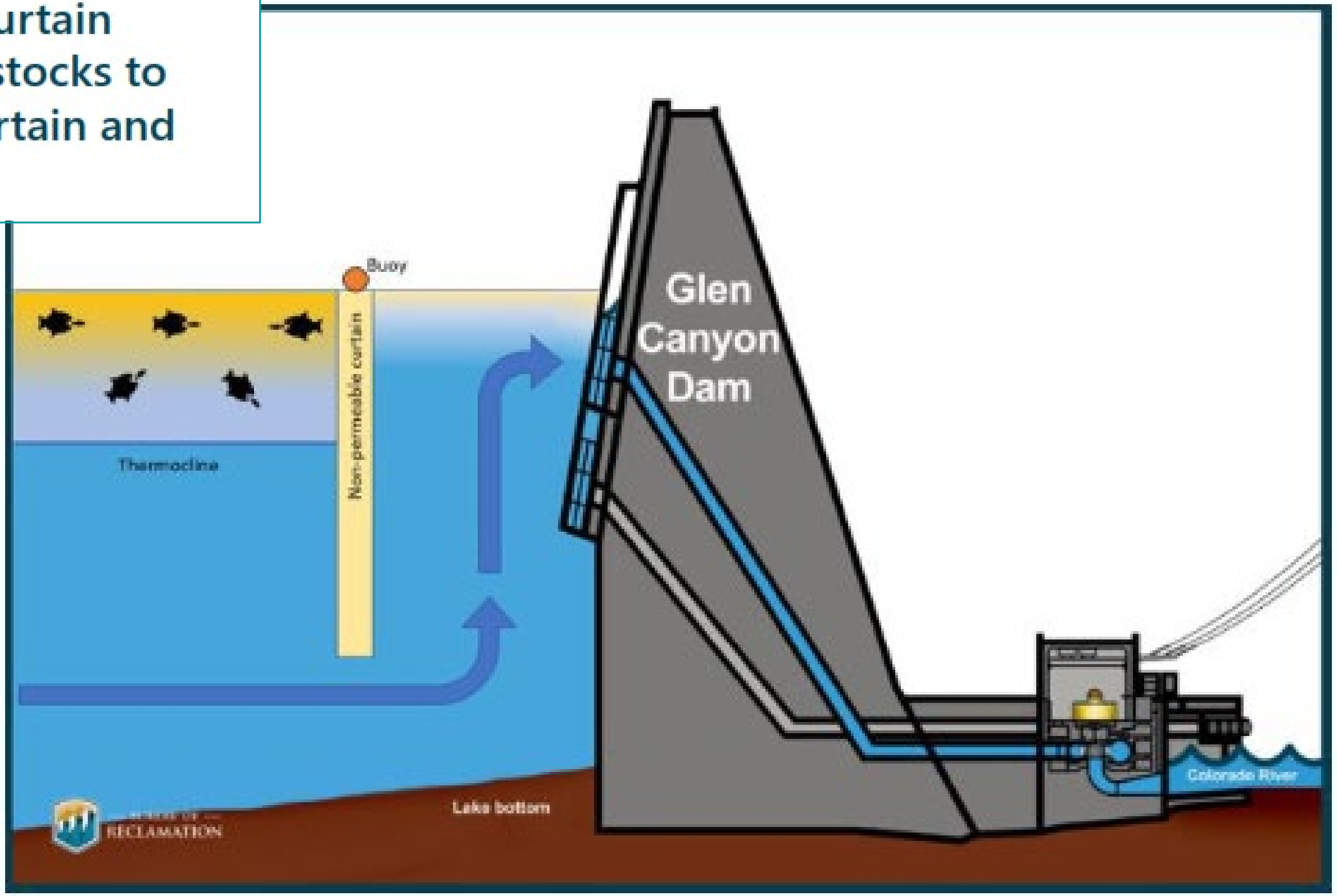


Smallmouth Bass Issue

Water Temperature

Thermal Curtain

- A nonpermeable barrier that spans across the reservoir and extends below the thermocline. The curtain forces hypolimnetic water up through penstocks to create a cold-water barrier between the curtain and the dam.



- Completed value study
- Currently on hold

Slough

- Work to begin on slough on Feb. 24, 2025
- 10-week project
- Open entryway to water flow
- Narrow channel to speed flow

WAPA Workforce

- Federal government hiring freeze applicable to WAPA
- Probationary employees subject to termination
  - Probationary means in position for less than one year
  - Applicable to long-term employees that changed position recently

WAPA Workforce

- CREDA concern about losing WAPA employees
  - WAPA costs are self-funded
  - Energy security / reliability issue
  - Energy affordability

Government and Public Affairs Project

Mike Squires
Managing Director of Government Affairs

UAMPS
UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

Executive Update

- Trump nominees –Doug Burgum/DOI; Chris Wright/DOE, and Lee Zeldin/EPA
- President Trump announced 25% tariffs on Canada and Mexico; 10% on China
    - Tariff on Canadian energy is 10%
    - Canada and Mexico tariff start date delayed a month
- Federal funding freeze announced and then rescinded
    - However, there is still a hold on all money authorized by the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA)

Why this matters Trump moved swiftly issuing many executive orders on various things from women's sports as well as the IRA, IIJA that are relevant to UAMPS' interests.

Congressional Update

- Budget reconciliation negotiations are ongoing
  - Current Continuing Resolution (CR) to fund federal government goes through mid-March
  - Senate moving ahead with budget reconciliation markup next week they will do two-bill approach; energy first
  - House considering one-bill approach

TITLE II—RECONCILIATION

SEC. 2001. RECONCILIATION IN THE HOUSE OF REPRESENTATIVES.

(a) COMMITTEE ON AGRICULTURE.—The Committee on Agriculture of the House of Representatives shall report changes in laws within its jurisdiction that reduce the

Why this matters The House and Senate are united in the final goal – Tax Cuts and Jobs Act (TCJA) extension (maybe making it permanent), but the strategy isn't and that could be a problem for Republicans.

Filed and Potential Energy Bills

Bill	Short Title	Sponsor
HB 57	Residential Solar Panel Consumer Protection Amendments	Jack
HB 70	Decommissioned Asset Disposition Amendments	Jack
HB 72	Electricity Rate Amendments	Albrecht
HB 85	Environmental Permitting Modifications	Clancy
HB 157	Energy Education Amendments	Jack
HB 201	Energy Resource Amendments	Jack
HB 212	Grid Enhancing Technologies	Watkins
HB 241	Solar Power Plant Amendments	Jack
HB 249	Nuclear Power Amendments	Albrecht
HB 264	Tax Incentives Amendments	Christofferson
HCR 5	House Concurrent Resolution on Permitting Reform	Ballard
SB 61	Energy Corridor Amendments	Owens
SB 132	Electric Utility Amendments	Sandall
SB 192	Commercial Wind and Solar Incentives Amendments	Owens
SB 227	Electricity Supply Amendments	Cullimore
SCR 3	Concurrent Resolution Regarding Utah's Authority to Determine its Energy Future	Harper

Bill Status as of 2/17/25

Bill	House Rules	House Cmte	House	Senate Rules	Senate Cmte	Senate
HB 57						
HB 70						
HB 72						
HB 85						
HB 157						
HB 201						
HB 212						
HB 241						
HB 249						
HB 264						
HCR 5						

Bill	Senate Rules	Senate Cmte	Senate	House Rules	House Cmte	House
SB 61						
SB 132						
SB 192						
SB 227						
SCR 3						

SB 61 Explained

SB 61 Unamended:

- Siting analysis requires that one “prioritize the use of federal public lands”
- Little detail on feasibility
- Examine federal land within 1 mile of the proposed route – YELLOW zone
- No federal land management agency shot clock

SB 61 Amended:

- Siting analysis “considers first the use of federal public lands”
- Analysis of feasibility – cost, delay, terrain, safety, size and complexity of route – must be considered
- Examine federal land within ¼ mile of the proposed route – PINK zone
- Eminent domain proceedings can commence if federal land management agencies do not respond within 60 days

Large New Load

Sen. Sandall SB 132

SB 132: Electric Utility Amendments:
("Large load bill")

Summary: SB 132 provides a process for a "large-scale customers" seeking electric service of 50 megawatts or greater to procure new energy either through Rocky Mountain Power or through another "large-scale generator provider.".

UPDATE: UAMPS continues to monitor this bill and suggested changes to ensure that UAMPS ratepayers and member service territories are not harmed.

VS

Sen. Cullimore SB 227

SB 227: Electricity Supply Amendments

Summary: This bill authorizes alternative electrical service providers in the state to provide electrical energy to qualifying customers and establishes requirements for alternative electrical service providers. Establishes requirements for certain public electric utilities to provide transmission and other services and creates provisions for flexible load tariffs and partial electrical services.

UPDATE: UAMPS continues to monitor this bill and suggested changes to ensure that UAMPS ratepayers and member service territories are not harmed.

2025 Public Power Reception Handout

UAMPS
UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

PUBLIC POWER DELIVERS FOR
UTAHNS

UTAH MUNICIPAL POWER AGENCY

ACOUNTABLE

Public power utilities are owned and accountable to the people they serve.

NOT-FOR-PROFIT

A portion of every dollar goes back into Utah communities.

RELIABLE

Reliable and affordable electric service to Utah communities is our bottom line.

Horse Butte Wind Project

February 18, 2025 Update

UAMPS SMARTENERGY

Scott Messersmith

Software Upgrade

$2MM software upgrade from Vestas

- Analyzed whether it was worth upgrading without the grid cap
- Grid cap currently sits at 57.5 MW
- Software would provide an extra 6 MW of generation

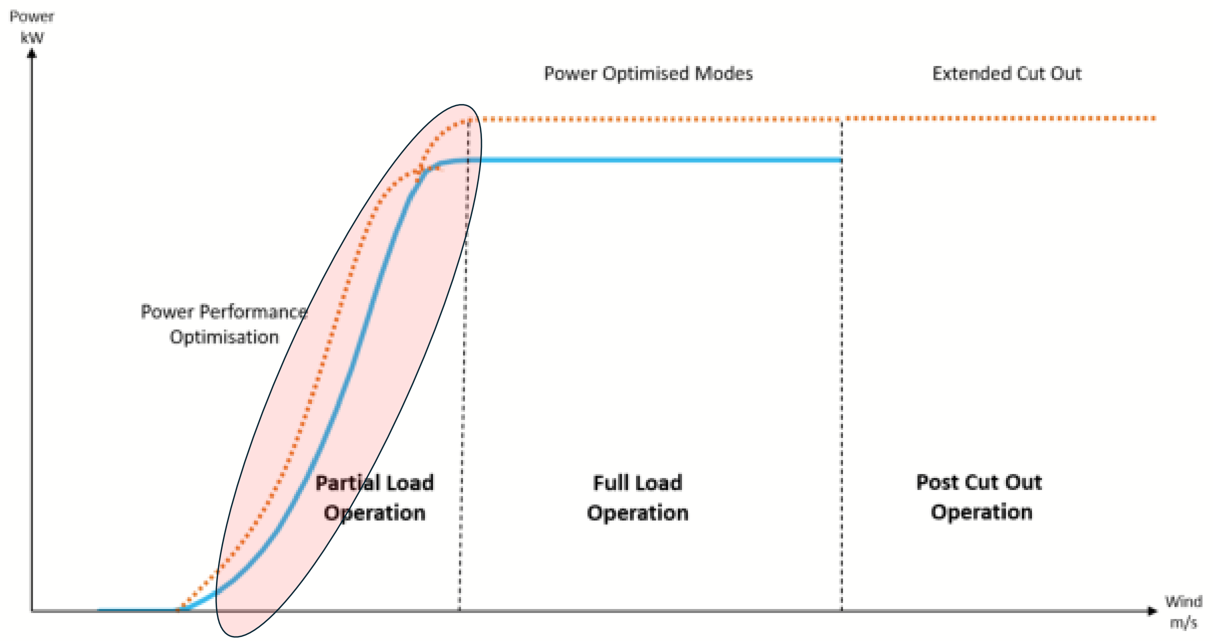


Figure 1: Upgrades on power curve control regions (power curve for illustrative purpose only).

Software Upgrade

- Upgrade is an improvement to as built – 2.56 % vs 3.92%
- Original LCOE benefit was $57/MWh, with grid cap ~$95/MWh
- Do not recommend moving forward without cap being lifted

	As Built		PowerPlus	
	With Grid Cap	Without Grid Cap	With Grid Cap	Without Grid Cap
Capacity [MW]	58.08		64	
Annual Energy Production [GWh/Y]	174.48	174.48	178.95	181.32
Overall PowerPlus AEP gain [%]	-	-	2.56	3.92
Overall PowerPlus AEP gain [GWh/Y]	-	-	4.47	6.84

Grid Cap Status

BPA Halts Some Tx Planning Processes Amid Surge of Service Requests

Agency Pauses to Consider Process Changes

The Bonneville Power Administration has paused certain transmission planning reforms in light of increased demand for new resources and loads. | *Shutterstock*

Feb 11, 2025 | Henrik Nilsson

BPA Employees Confront Trump's 'Fork in the Road'

Staff Caught up in President's Effort to Shrink Government Despite Agency's Self-funding

- UAMPS has received notice that BPA has paused their TSR process indefinitely

Next Steps

- UAMPS will not pursue the software upgrade until the TSR with BPA is approved
- Continue to track BPA's process and its impact on H.B.

Replacement of Nebo Operations & Maintenance Agreement

Nebo Project

Rachel Stanford

UAMPS
UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

Summary

- SESD previously held the O&M responsibilities for Nebo Transmission Assets
- SESD provided notice to terminate effective March 1, 2025
- Payson has agreed to take over the O&M responsibilities and will utilize existing mutual assistance agreements with local Members as necessary

Material Changes

- Payson will procure spare parts to keep in inventory in the event of needed replacement
  - 16 poles of varying heights
  - Insulators and miscellaneous equipment
  - To be stored within Nebo yard
- Exhibit A – description of facilities and NERC standards

Continued Development

- Exhibit B – Maintenance Schedule
  - Payson currently working to draft schedule consistent with NERC standards
- Exhibit C – Maintenance Procedures
  - Payson currently working to draft procedures consistent with NERC standards
- Exhibit D – Budget
  - Annual budget has been set at $70,000. Upon completion of Exhibit B this budgeted item will be further refined into a monthly schedule
- Exhibit E – Siting, ROW, Environmental Permits & Licenses
  - Currently engaged with consultants to investigate and collect all relevant documentaion as it relates to the Project and input into UAMPS GIS
- Exhibit F – Call Out List
  - Payson currently working to draft consistent with Mutual Assistance Agreements
- Exhibit G – Documentation for Billing
  - UAMPS accounting working with Plant Manager to identify standards for invoice submittals and supporting documentation

All Exhibits expected to be finalized by March 1, 2025

PMC OPERATIONS REPORT

Nebo Project

January 2025

UAMPS
UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

January Statistics

Equiv. Availability Factor	100.00%
Net Plant Heat Rate	8606.82
Net Capacity Factor	92.81%
CTG Starts	0
Days Plant Ran	31
Hours of Operations	744
Average Hours/Day	24.00
Average Plant Load	126.41
Total Net MWh Output	94,047.14

January Statistics

	January FY 2025			Fiscal Year-to-date		
	Actual	Budget	Variance	Actual	Budget	Variance
Plant Starts	0	4	(4)	38	48	(10)
Avg. On-line hours	24.00	24	0.00	22.82	24	(1.18)
CTG On-line hours	744	744	0.00	6155.93	8016	(1,860)
Average Plant Load	126.41	103	23.41	107.63	107	0.18
Net MWh Produced	94,047	76,632	17,415	677,153	864,944	(187,791)
Net Capacity Factor	92.81%	68.67%	24.14%	66.37%	65.79%	0.58%
Availability	100%	97.00%	3.00%	87.39%	92.75%	-5.36%
Net Heat Rate	8,607	8,500	107	8,697	8,500	197
MMBtu Consumed	809,447	651,372	158,075	5,820,506	7,352,024	(1,531,518)

Water

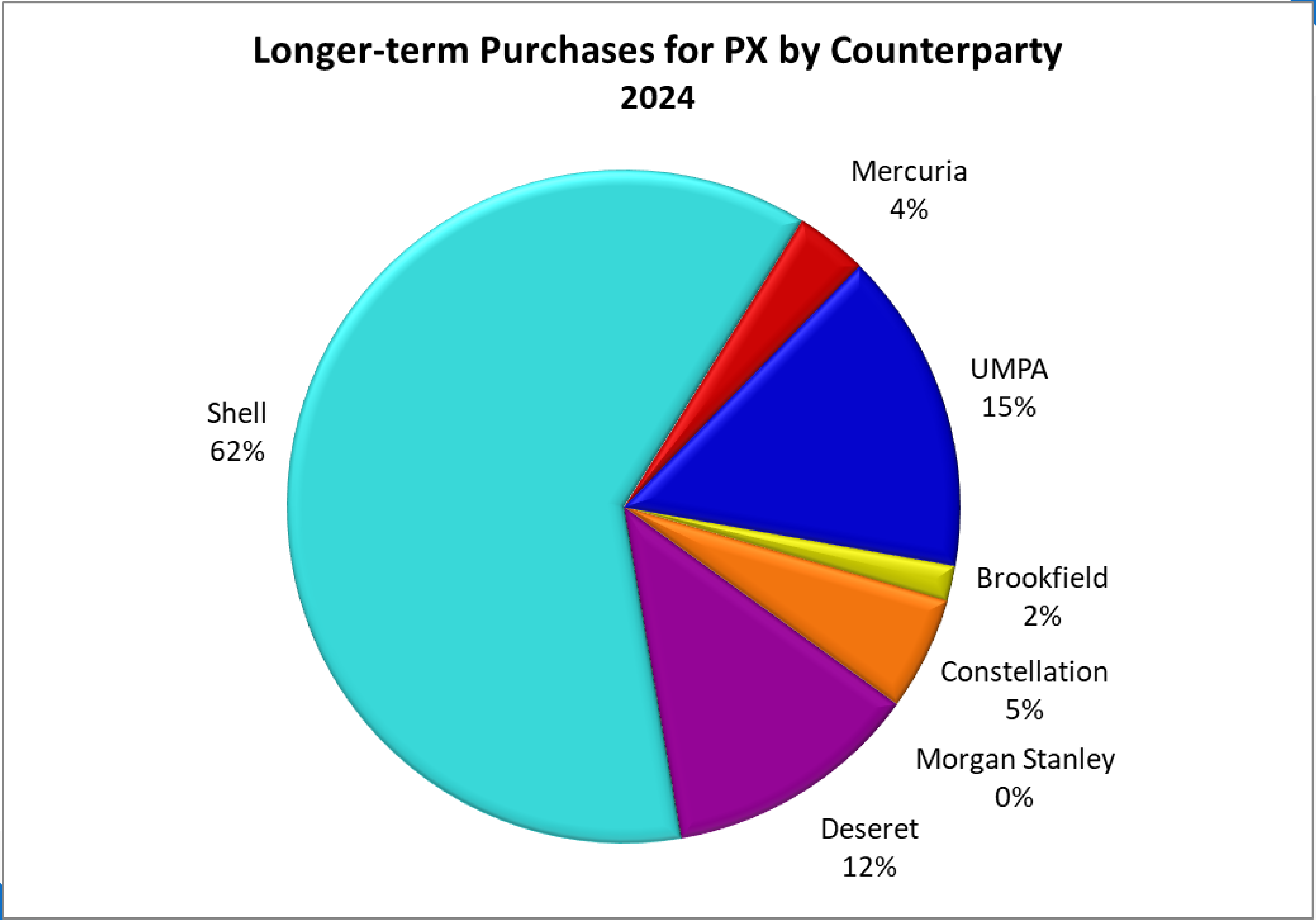
- Nebo has been running strictly on Culinary Water due to sewer departments tertiary water quality for the past 2 weeks.
  - 2/13/25 (10:42) – Payson City notified Nebo of it loosing 1 of there 2 operating wells that supply culinary water to both Nebo and Payson City residents. Payson asked if the plant would start blending tertiary water to help maintain what level in the water supply to city. (conserving as much culinary water as possible)
  - (15:45) - After blending tertiary water for just 5 hrs. Cooling Tower chemistry went from very clean to 70 ppm of TSS and smelling of raw sewage.
  - (17:47) - After blending tertiary water for 7 hrs. Cooling Tower chemistry was then at 87 ppm of TSS and still smelling of raw sewage. <u>(Nebo's – Daily Maximum allowable discharge limit for TSS is 100).</u>
  - ***At this time UAMPS was investigating / looking at impacts and options at bringing plant offline to not run into violations of UPDES permit.***
    - ***Levels leveled out and started dropping as Nebo flush system(s) with heavy blowdown.***
- Payson was hoping to have 2 additional wells up and running in summer of 2024, then was moved to December of 2024. (Waiting on SCADA) It appears additional wells are still not online.

PX & Scheduling Report
January 2025

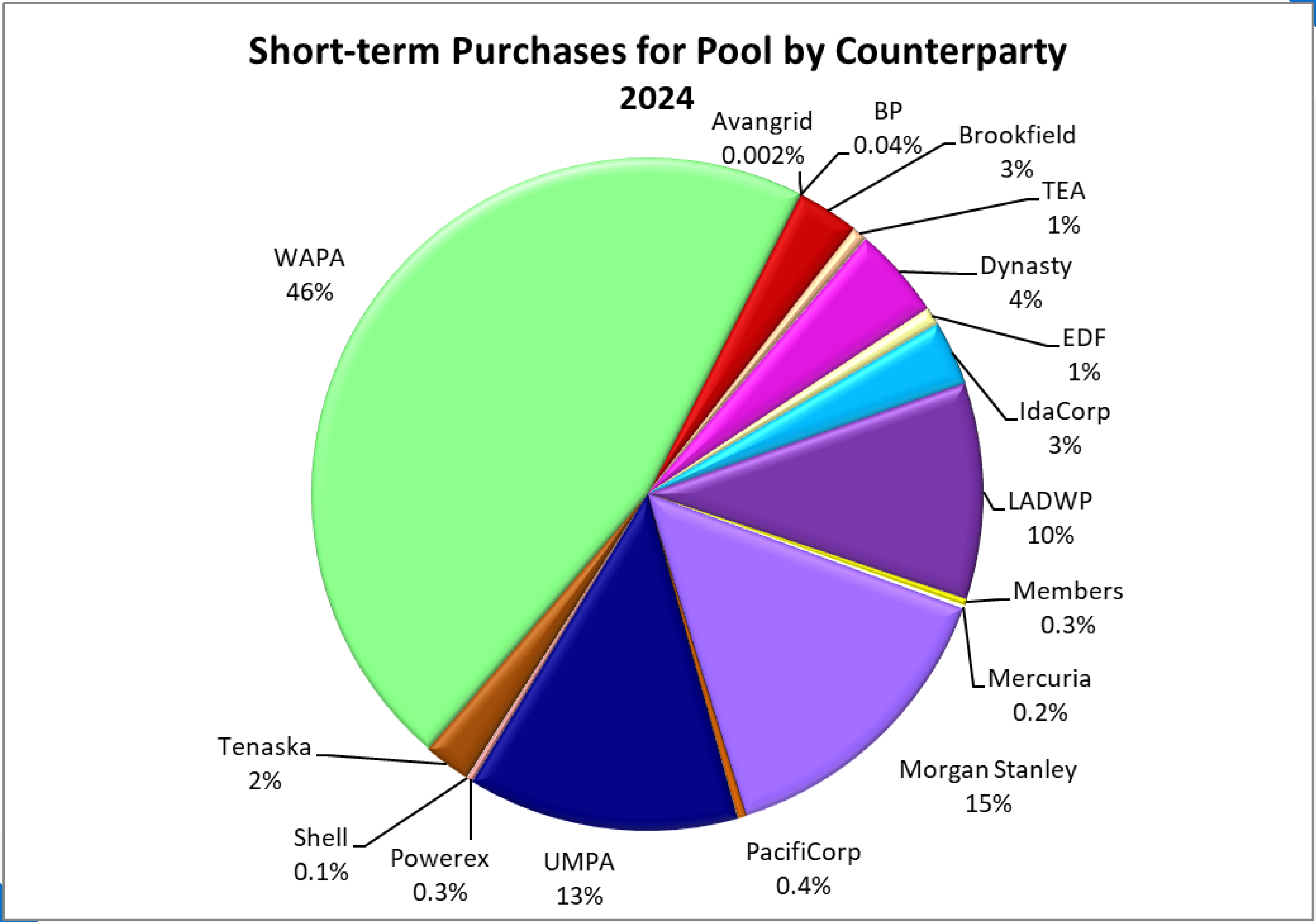
Pool Project

UAMPS

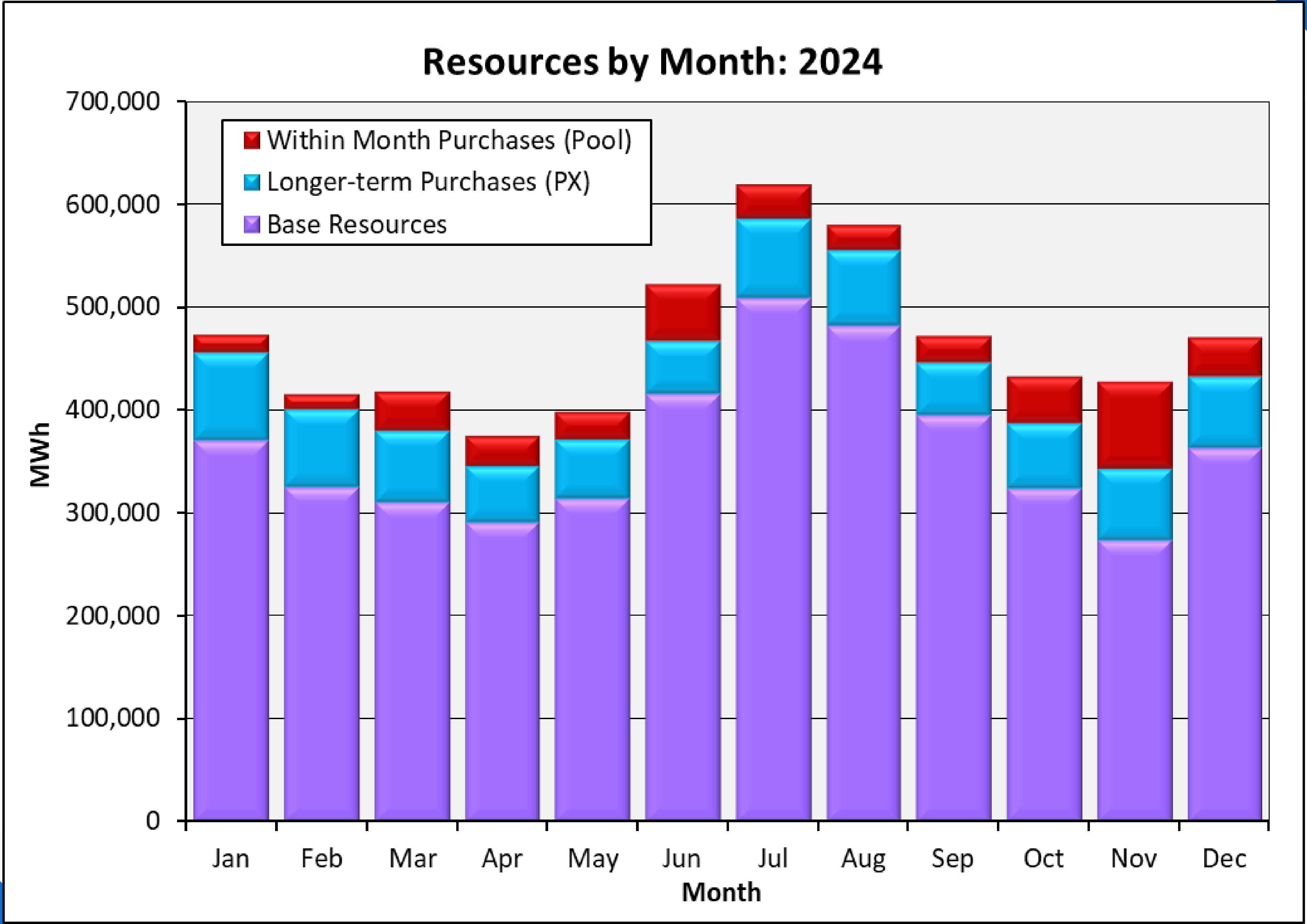
Kelton Andersen


Longer-term Purchases for PX by Counterparty
2024
Mercuria
4%
UMPA
15%
Shell
62%
Brookfield
2%
Constellation
5%
Morgan Stanley
0%
Deseret
12%

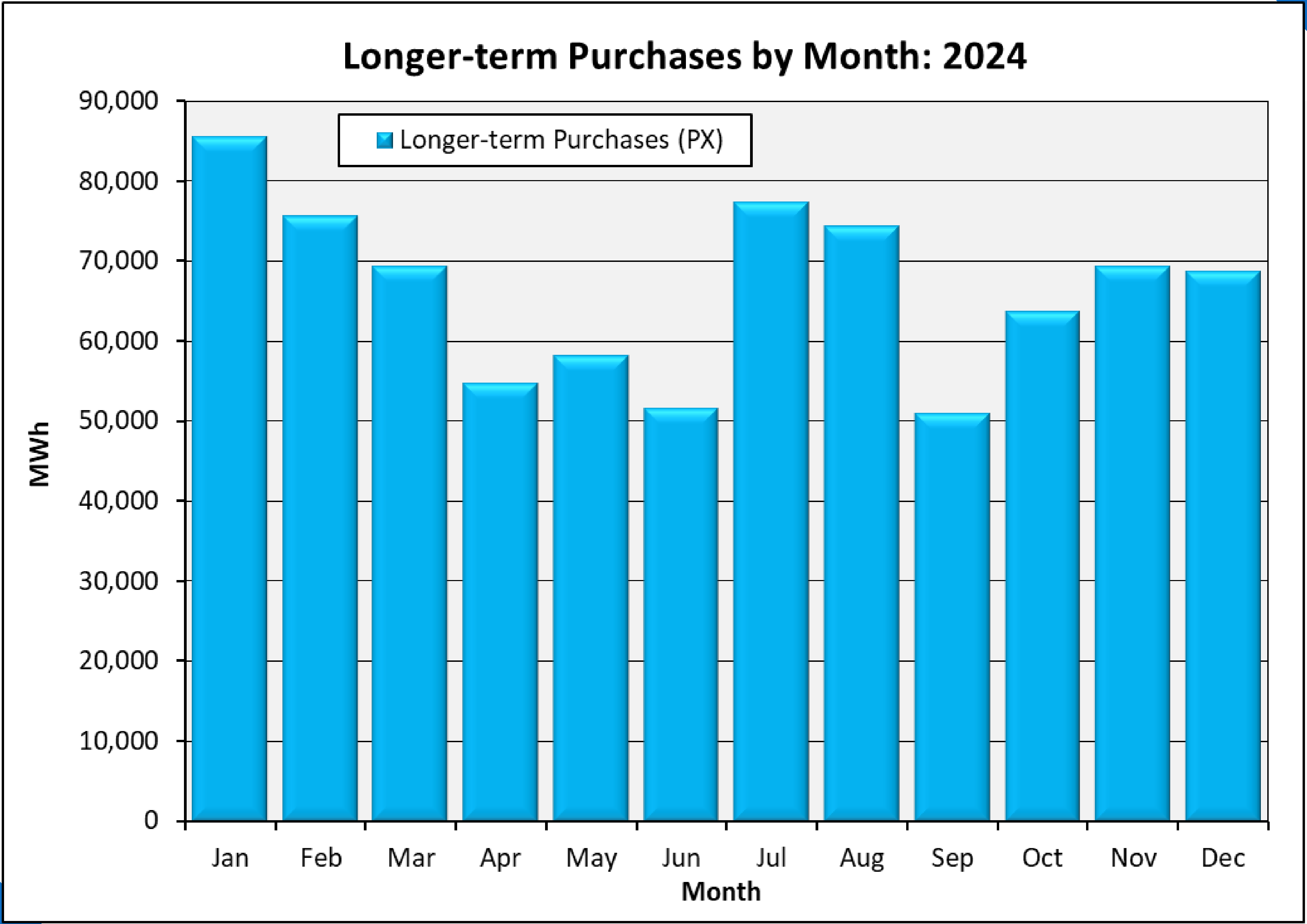
UAMPS


Short-term Purchases for Pool by Counterparty
2024
Avangrid
0.002%
BP
0.04%
Brookfield
3%
TEA
1%
Dynasty
4%
EDF
1%
IdaCorp
3%
LADWP
10%
Members
0.3%
Mercuria
0.2%
Morgan Stanley
15%
PacifiCorp
0.4%
UMPA
13%
Powerex
0.3%
Shell
0.1%
Tenaska
2%
WAPA
46%

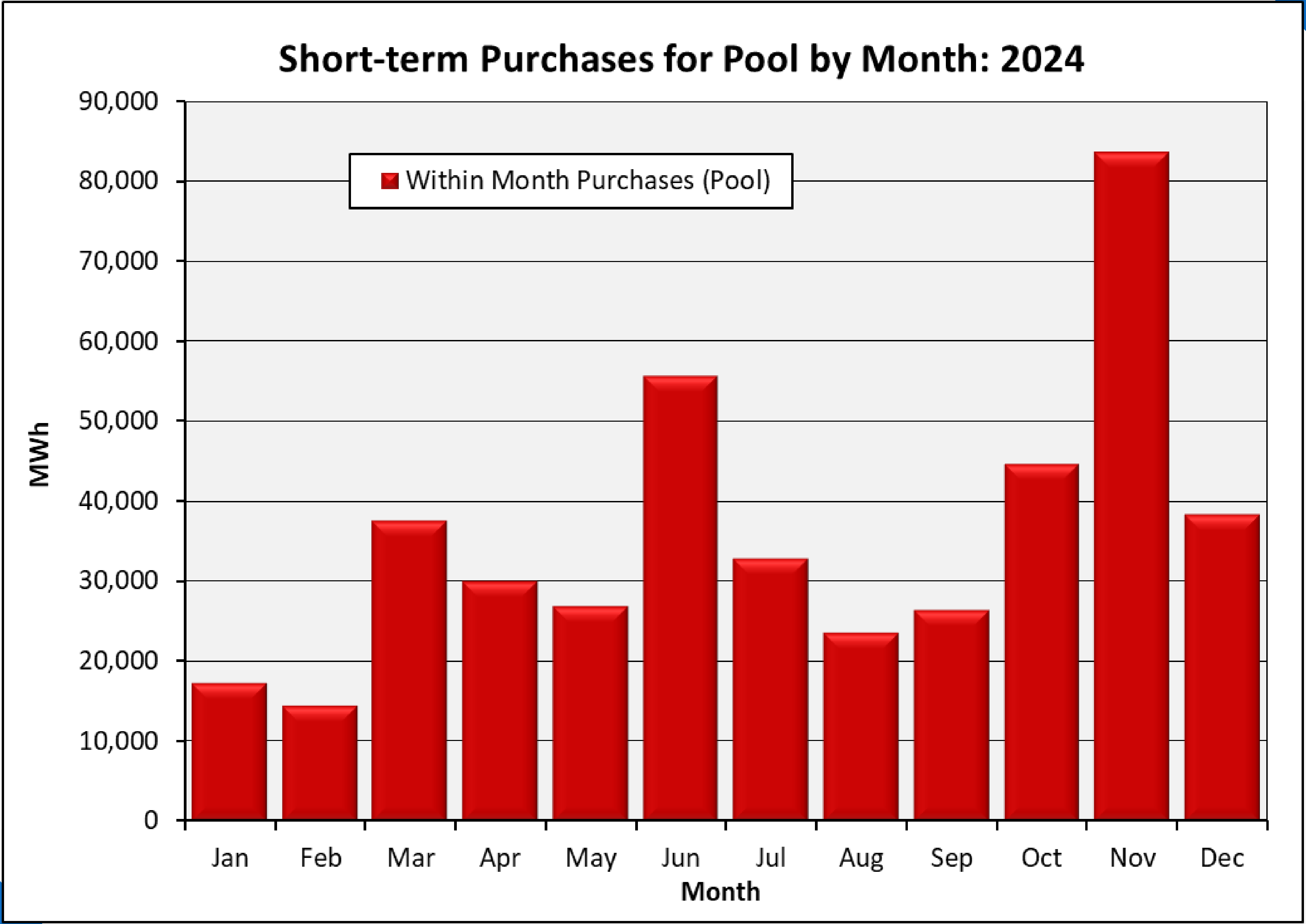
UAMPS



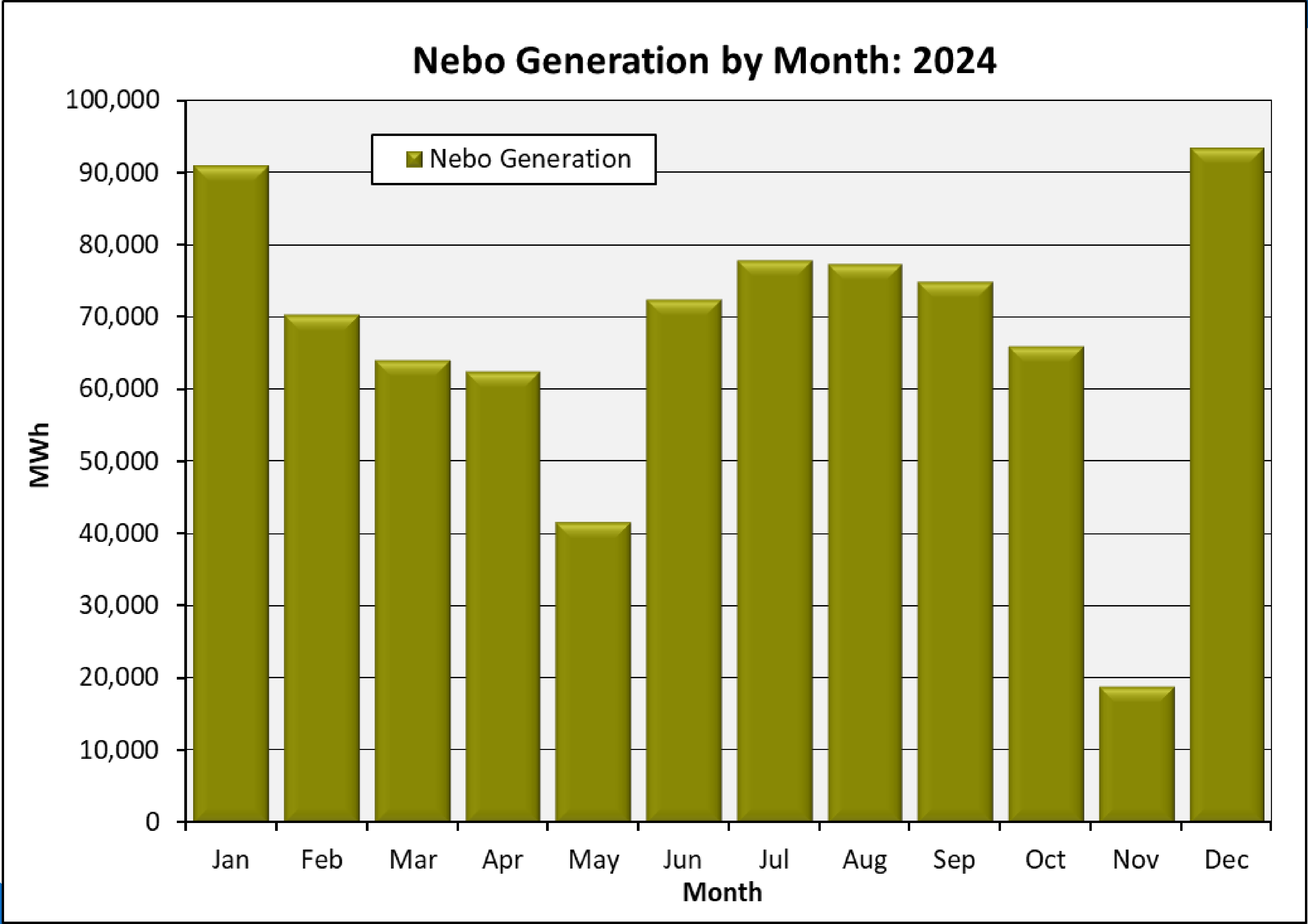
Resources by Month: 2024
Within Month Purchases (Pool)
Longer-term Purchases (PX)
Base Resources
MWh
700,000
600,000
500,000
400,000
300,000
200,000
100,000
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month

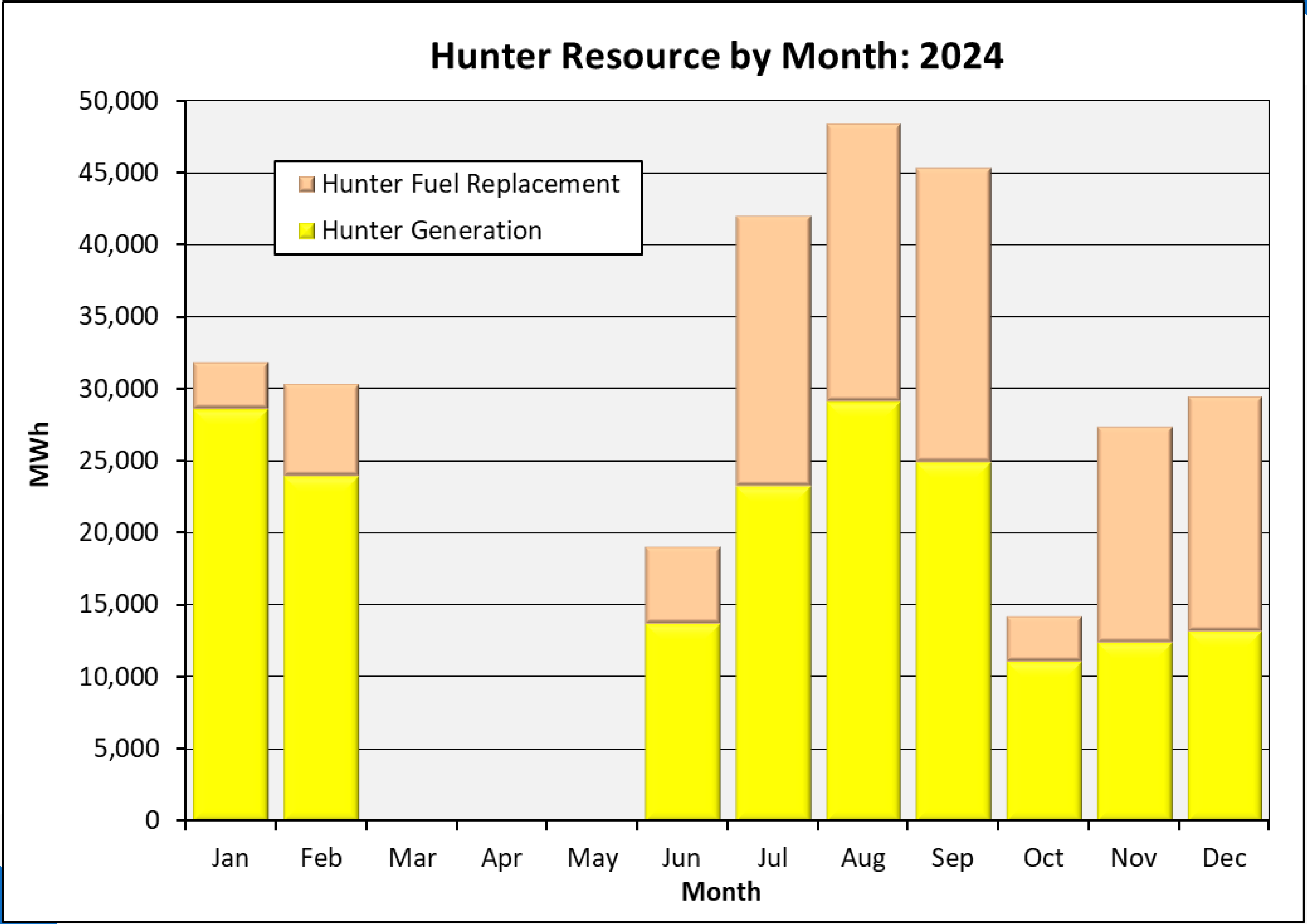

Longer-term Purchases by Month: 2024
Longer-term Purchases (PX)
MWh
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month

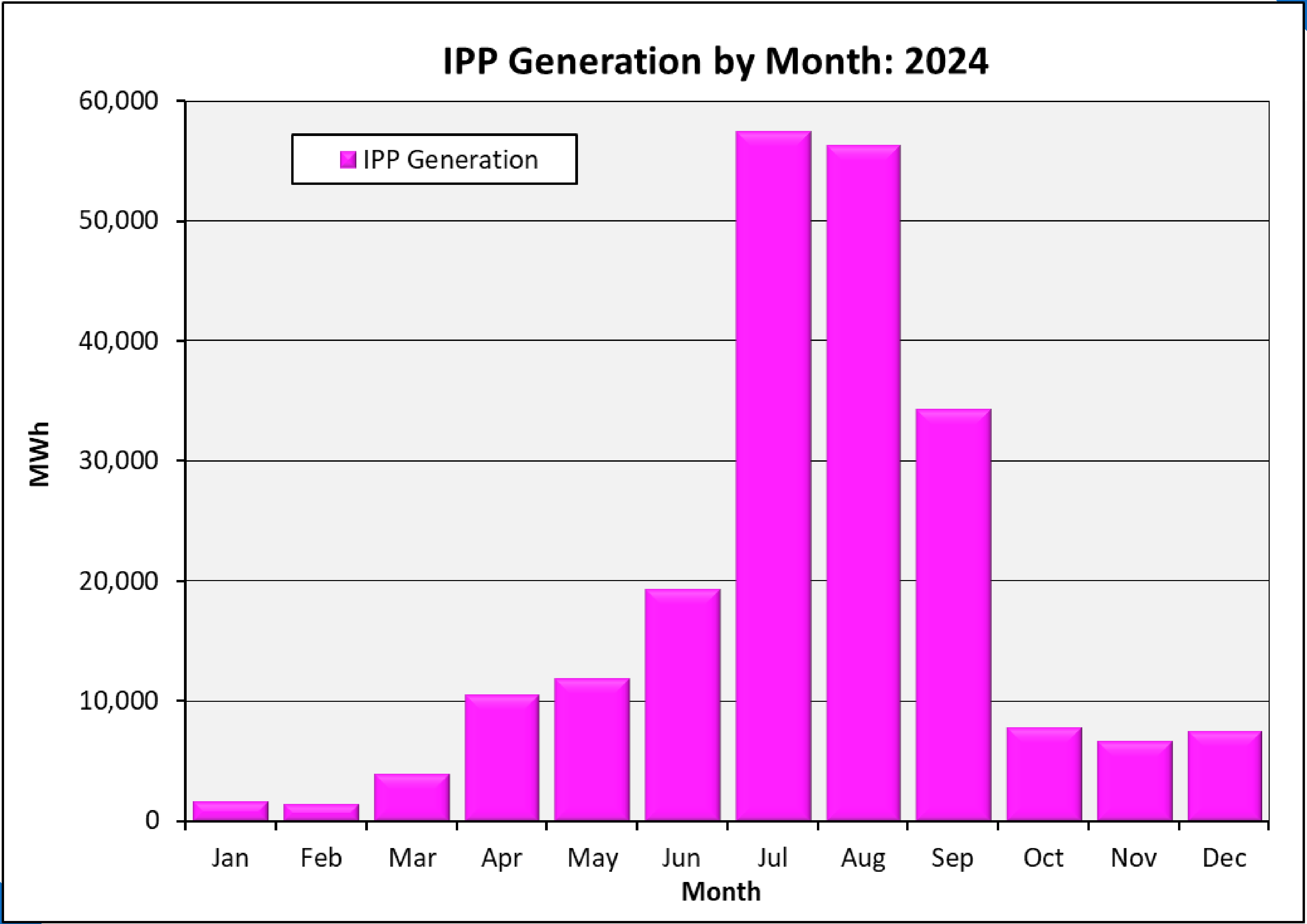
UAMPS

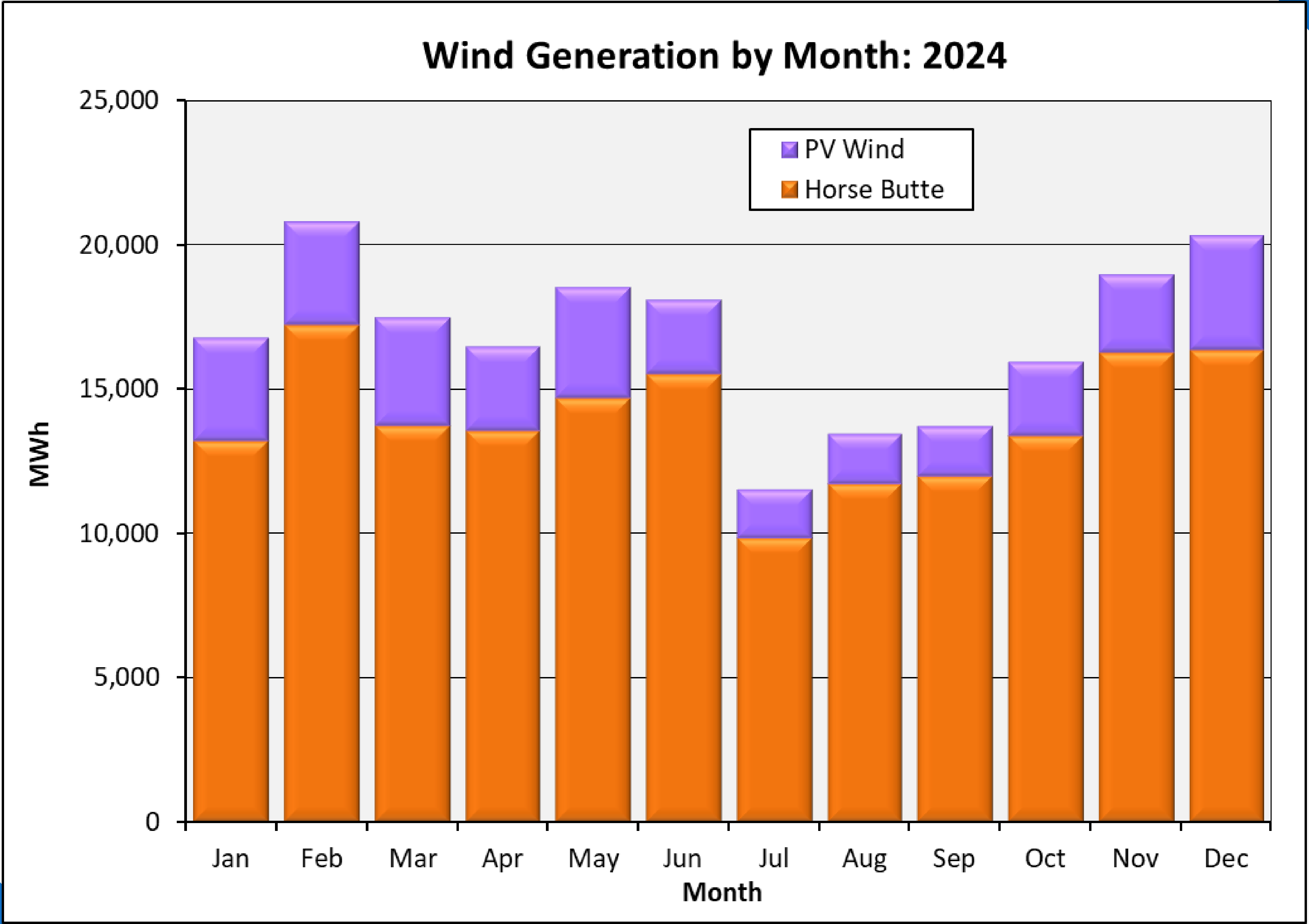


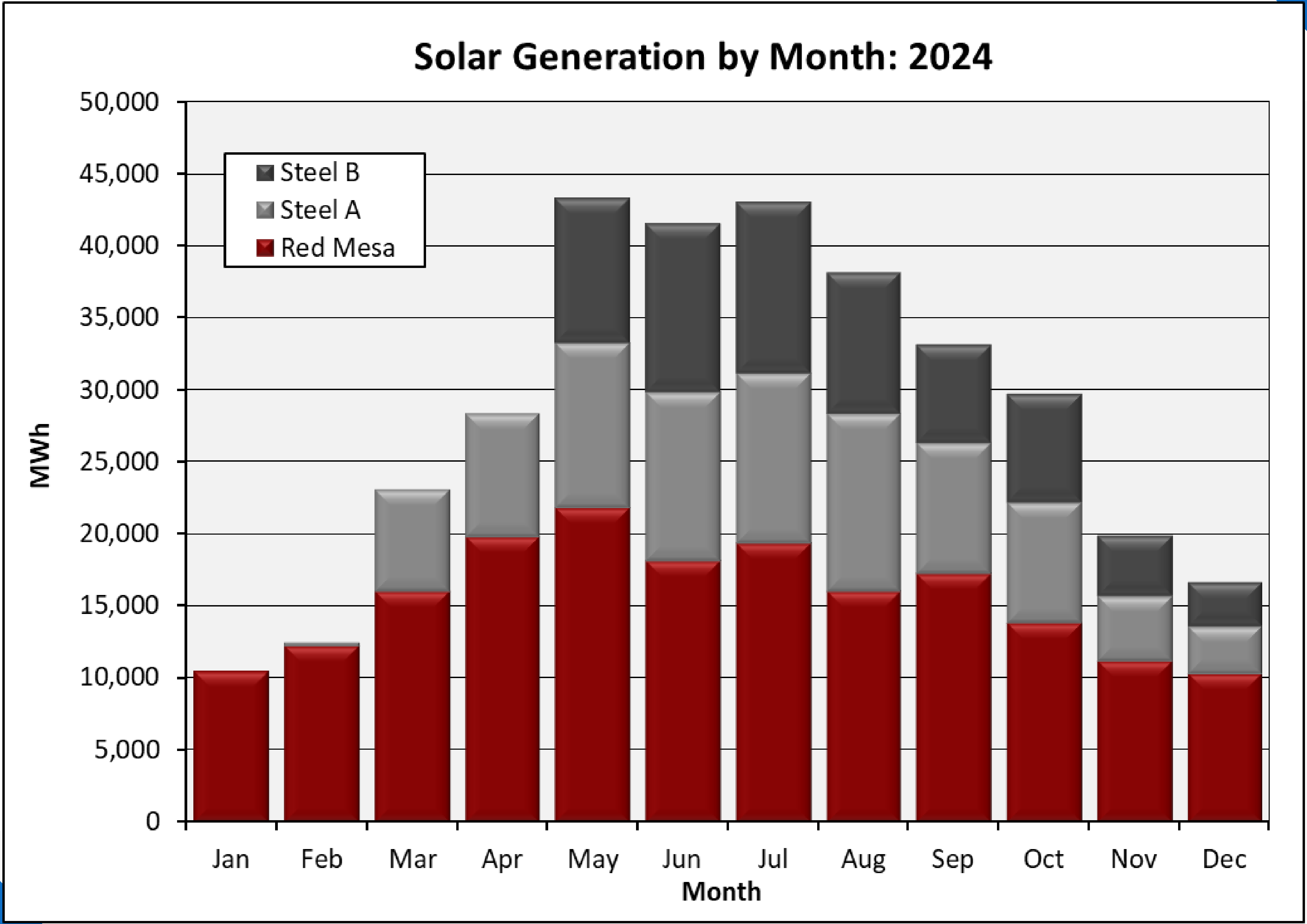
Short-term Purchases for Pool by Month: 2024
Within Month Purchases (Pool)
MWh
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month


Nebo Generation by Month: 2024
Nebo Generation
MWh
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month


Hunter Resource by Month: 2024
Hunter Fuel Replacement
Hunter Generation
MWh
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
UAMPS


IPP Generation by Month: 2024
IPP Generation
MWh
60,000
50,000
40,000
30,000
20,000
10,000
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
UAMPS


Wind Generation by Month: 2024
PV Wind
Horse Butte
MWh
25,000
20,000
15,000
10,000
5,000
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month


Solar Generation by Month: 2024
Steel B
Steel A
Red Mesa
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MWh
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month

EDAM Update

Pool Project

Matt Hastings

February 19, 2025

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

EDAM Update

- This is the first of a series of educational EDAM presentations
- Slides will be shared for Pool PMC review
  - Additional meetings will be scheduled to further review the material

EDAM Update BLUF

- Policy approach: UAMPS is challenging harmful aspects of the proposed PacifiCorp EDAM Tariff

- Implementation approach: UAMPS retaining Utilicast to help with implementation

- Scheduling coordinator approach: UAMPS retaining TEA for SC services

- UAMPS internal member billing approach
    - PacifiCorp TSOA charges
    - PacifiCorp EDAM/EIM pass-through charges
    - CAISO-direct EDAM charges

PacifiCorp EDAM Tariff Considerations

- UAMPS filed comments expressing concerns with EDAM Tariff
  - Congestion revenue allocation
    - Network customers would receive congestion revenue based on total system use but would be charged for use based upon location of load and resource
  - Resource sufficiency evaluation
    - PacifiCorp is unfairly transferring BA obligations to network customers
    - Network customers penalized for insufficiency even if PACE were sufficient
  - Stakeholder process requirements
    - None are included in current tariff
- Unknown if FERC will approve EDAM Tariff
  - Must prepare for tariff as proposed to meet implementation timing

PacifiCorp EDAM Tariff Comments

- The following submitted protests and generally aligned with UAMPS
- UMPA and DGT
- BPA
- Interwest, American Clean Power, Renewables NW [joint comments]
- WPTF and Northwest Intermountain Power Producers Coalition [joint comments]
- Public Power Council
- Puget Sound Energy
- WRAP Entities
- Powerex
- Salt River Project
- Calpine
- Southwest Power Pool
- Shell Energy
- Tacoma Power

PacifiCorp EDAM Tariff Comments

- The following submitted comments supporting PacifiCorp
  - Portland General Electric, NV Energy, Balancing Authority of Northern California [joint comments]
  - Pacific Gas and Electric [conceptual support for EDAM]
  - CAISO [general support]

Utilicast Implementation Approach

- Negotiated
  - Consulting Services Agreement
  - Statement of Work – budgeted by fiscal year effort
- Requesting approval of contracts today
- Constructing implementation schedule
- Creating systems diagram for all logic and data flow

Utilicast Implementation Approach

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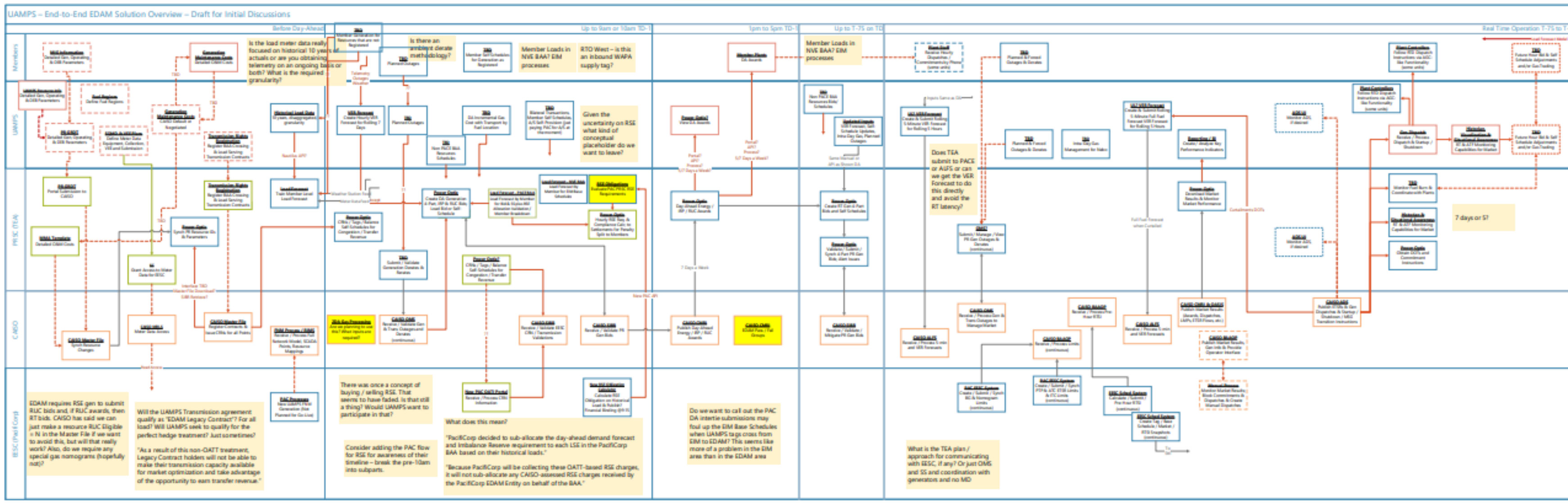


TEA Negotiation

- Negotiating
  - Resource Management Agreement
  - Two task orders for implementation and ongoing Scheduling Coordinator support
    - Working to define the scope at a more granular level
  - TEA Board approval in March
  - UAMPS Pool PMC has delegated authority to approve – interim meeting planned for March
- Prior to contract execution working on a limited basis
  - Identify roles and responsibilities
  - IT technical coordination

EDAM Resource Economics

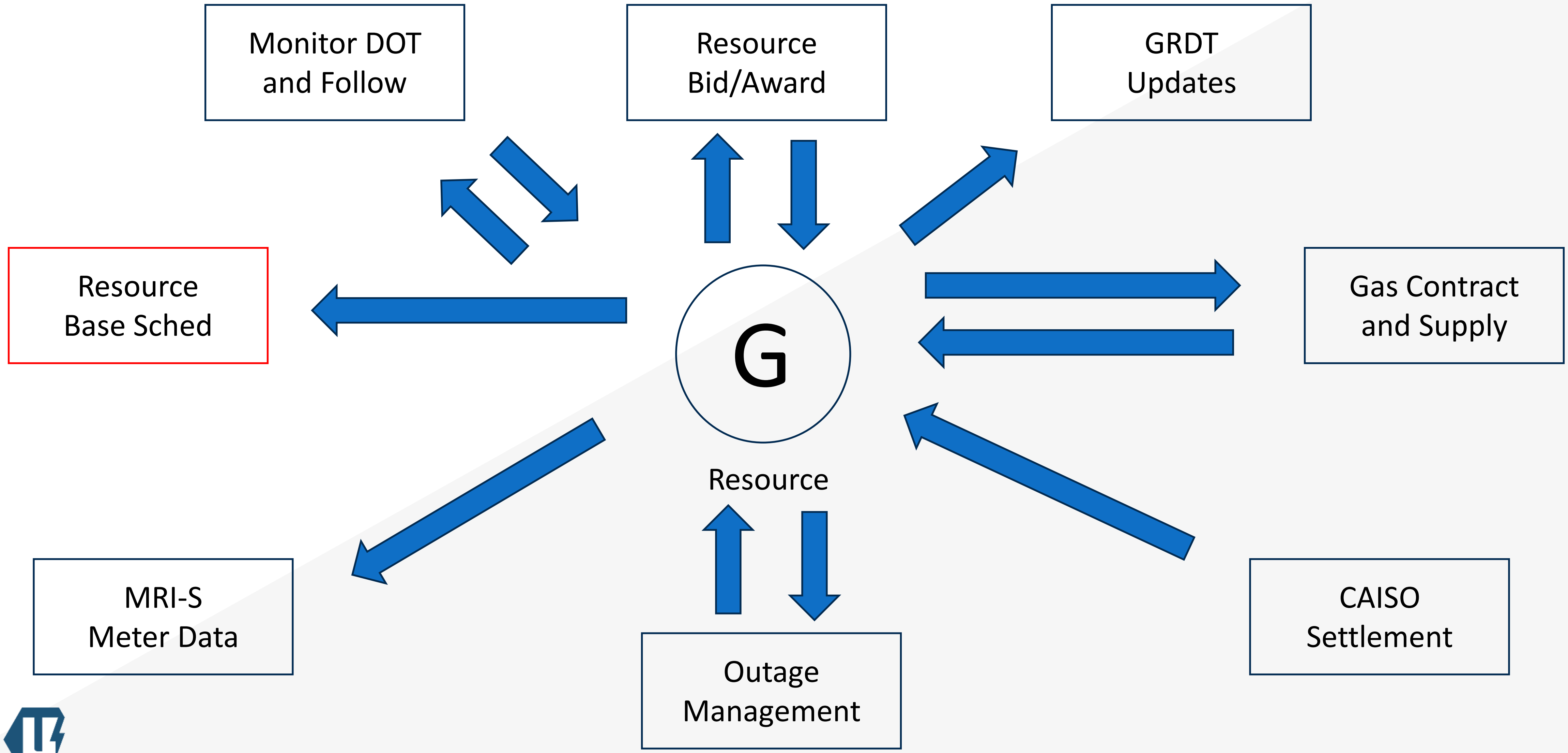
- Only dispatchable generation in CAISO's Full Network Model (FNM) can be dispatched through EDAM

- Generation currently in the FNM
  - Gem State
  - Horse Butte Wind
  - Hunter – dispatchable, special case
  - Hyrum NG – dispatchable
  - Lehi NG – dispatchable
  - Nebo – dispatchable
  - Red Mesa – special case
  - Santa Clara NG – dispatchable
  - SLC Landfill
  - St. George NG – dispatchable
  - Steel
  - TransJordan Landfill
  - Veyo

- Future generation applicable to the FNM
  - Idaho Falls NG
  - Logan NG
  - Payson NG

**Separate MIG meeting will be scheduled

EDAM Resource Responsibilities



Current TSOA Billing Practice	Post-EDAM TSOA Billing Practice
1. Monthly billing based upon project budgets	1. Monthly billing based upon project budgets
2. Monthly transmission postage stamp billing	2. Monthly transmission postage stamp billing (revised calculation – some TSOA schedules modified or removed)
3. Interchange (between BAA) and intrachange (inside BAA) socialized to a $/MWh charge	3. Interchange and intrachange socialized to a $/MWh charge
4. EIM charges applied to EIM account (TSOA and generator imbalance)	4. Most EIM and EDAM charges applied at the load and generator level directly to member • UAMPS pays these charges weekly – TBD on frequency of charge to member – will be based upon cost benefit analysis

Current TSOA Billing Practice	Post-EDAM TSOA Billing Practice
1. Monthly billing based upon project budgets Fixed and Variable at $50/MWh	1. Monthly billing based upon project budgets Fixed and Variable at $50/MWh
2. Monthly transmission postage stamp billing Applied at $10/MWh	2. Monthly transmission postage stamp billing (revised calculation – some TSOA schedules modified or removed) Example: $4/MWh plus $3100/MW peak consistent with energy/peak billing in TSOA
3. Interchange (between BAA) and intrachange (inside BAA) socialized to a $/MWh charge Combined into $10/MWh above and EIM account	3. Interchange and intrachange socialized to a $/MWh charge Example: $2/MWh
4. EIM charges applied to EIM account (TSOA and generator imbalance)	4. Most EIM and EDAM charges applied at the load and generator level directly to member • UAMPS pays these charges weekly – TBD on frequency of charge to member – will be based upon cost benefit analysis • Example: Average load paid at $30/MWh, average resource paid at $25/MWh, average congestion revenue allocation at $2/MWh

Changes to TSOA Invoice from PacifiCorp to UAMPS

Current TSOA Billing Practice

Billed on

A. System peak demand
B. Schedule 1, 2, 3, 4, 5, 6

C. Losses

Post-EDAM TSOA Billing Practice

Billed on

A. System peak demand
B. Schedule 1, 2, 3 (revised), 5, 6
   - Schedule 4 goes away
C. Losses are included in LMP and ELAP pricing

Schedules defined:

A. Sched 1 – Scheduling, system control and dispatch (MW)
B. Sched 2 – Reactive supply and voltage control (MW)
C. Sched 3 – Regulation and frequency response (MW)
D. Sched 4 – Load vs Resource Imbalance (MWh)
E. Sched 5 – Spinning Reserves (MWh)
F. Sched 6 – Supplemental Reserves (MWh)
G. Appendix C – Firm Transmission Service Charge (MW)
H. Appendix D – Distribution Delivery Charge (MW)

Current Generator Practice	Post-EDAM Generator Practice
1. No participating resources 2. All settlement to EIM account (including imbalance)	1. All resources are “participating resources” but not necessarily bidding (many are self scheduled) 2. EIM and EDAM charge codes allocated to member a. Base schedule or DA award b. Instructed Imbalance c. Uninstructed Imbalance

Post-EDAM Generator Practice

1. All resources are "participating resources" but not necessarily bidding (many are self scheduled)
2. EIM and EDAM charge codes allocated to member
   a. Base schedule or DA award
   b. Instructed Imbalance
   c. Uninstructed Imbalance

Resources can identify what they will generate (via schedule or VER forecast)

Example:

- Generator sched is 10 MW, DA price is $20/MWh, resource is paid $200
- Charge code 6011

Instructed imbalance occurs when a resource bids, bid is accepted, and CAISO instructs generator to move to a new set point

Example:

- Generator is told to increase by 5 MW
- Price at that interval is $25/MWh
- Resource is paid for instructed imbalance $125
- Charge code 64600 (FMM IE) and 64700 (RT IE)

Takes sum of base schedule and instructed imbalance and compares it to metered generation - in essence the difference between what the resource was supposed to generate and the generation meter

Example:

- Generator needed total of 15 MW (examples in other boxes), metered generation was 14 MW, price is $30/MWh
- Generator pays $30 for missing target
- Charge code 64750 (UIE)

Post-EDAM Generator Considerations

1. Members impacted by
   a. Scheduling accuracy
   b. Price separation for congestion
      Accepted EIM/EDAM bids
   c. Pricing at various time intervals (DA, FMM, RT) – members have no control after DA or relative pricing
   d. Instructed Imbalance for infeasible schedules (advanced topic)
2. Members will not self schedule bidding generators – they benefit from economic operation (i.e. Hunter and Nebo)

Post-EDAM Generator Considerations

1. Members impacted by
   a. Scheduling accuracy
   b. Price separation for congestion Accepted EIM/EDAM bids
   c. Pricing at various time intervals (DA, FMM, RT) – members have no control after DA or relative pricing
   d. Instructed Imbalance for infeasible schedules (advanced topic)
2. Members will not self schedule bidding generators – they benefit from economic operation (i.e. Hunter and Nebo)

In the previous slide's example:

- Generator sched is 10 MW, DA price is \$20/MWh, resource is paid \$200
- Consider load is 10 MW and price is \$25/MWh
  - Member pays \$250 for load but is paid \$200 for generation
  - Price separation is the result of congestion
  - In an optimal market, congestion could be hedged, and member would be paid \$50 for congestion
    - ✓ Currently providing comments in PacifiCorp tariff - there is no certainty for the \$50 congestion payment

Current RA/RS Practice

1. Load serving entities (LSE) expected to come to table resource sufficient
2. No tariff impact for the degree to which you are over/under sufficient
   - UAMPS purchases intraday for balancing to load
3. PacifiCorp has EIM resource sufficiency tests ahead of each hour but does not pass to UAMPS impact of test failure
   - No separation of load and resource settlement

Post-EDAM RA/RS Practice

1. Resource sufficiency test (RSE) at 10:00 am day ahead
2. Current tariff indicates that LSEs will pay associated energy cost for lack of passing RSE each hour, whether or not the BAA fails RSE
3. UAMPS plans to have member by member version of RSE day ahead to ensure resource sufficiency
   - Members that were not resource sufficient will pro rata share the cost to become sufficient
   - Member to member benefit and compensation if available
   - UAMPS will purchase a capacity or energy product as required
   - Pool agreement update required to allow for RS procurement

Current Day in the Life (DITL) Practice

1. DA schedules and purchases/sells enough energy to be within 50ish MW of forecast load
2. RT purchases/sells to meet forecast load

Post-EDAM DITL Practice

1. 2 days ahead members identify MIG schedule
2. DA Schedules and purchases/sells energy and capacity to meet forecasted load
3. Resource sufficiency test (RSE) at 10:00 am day ahead
4. Communication with the SC
5. RT operates gen per the self schedule and EDAM dispatch
6. Scheduling procedures and agreements will have to be modified

Overall Operations Report

Board of Directors

Rachel Stanford

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

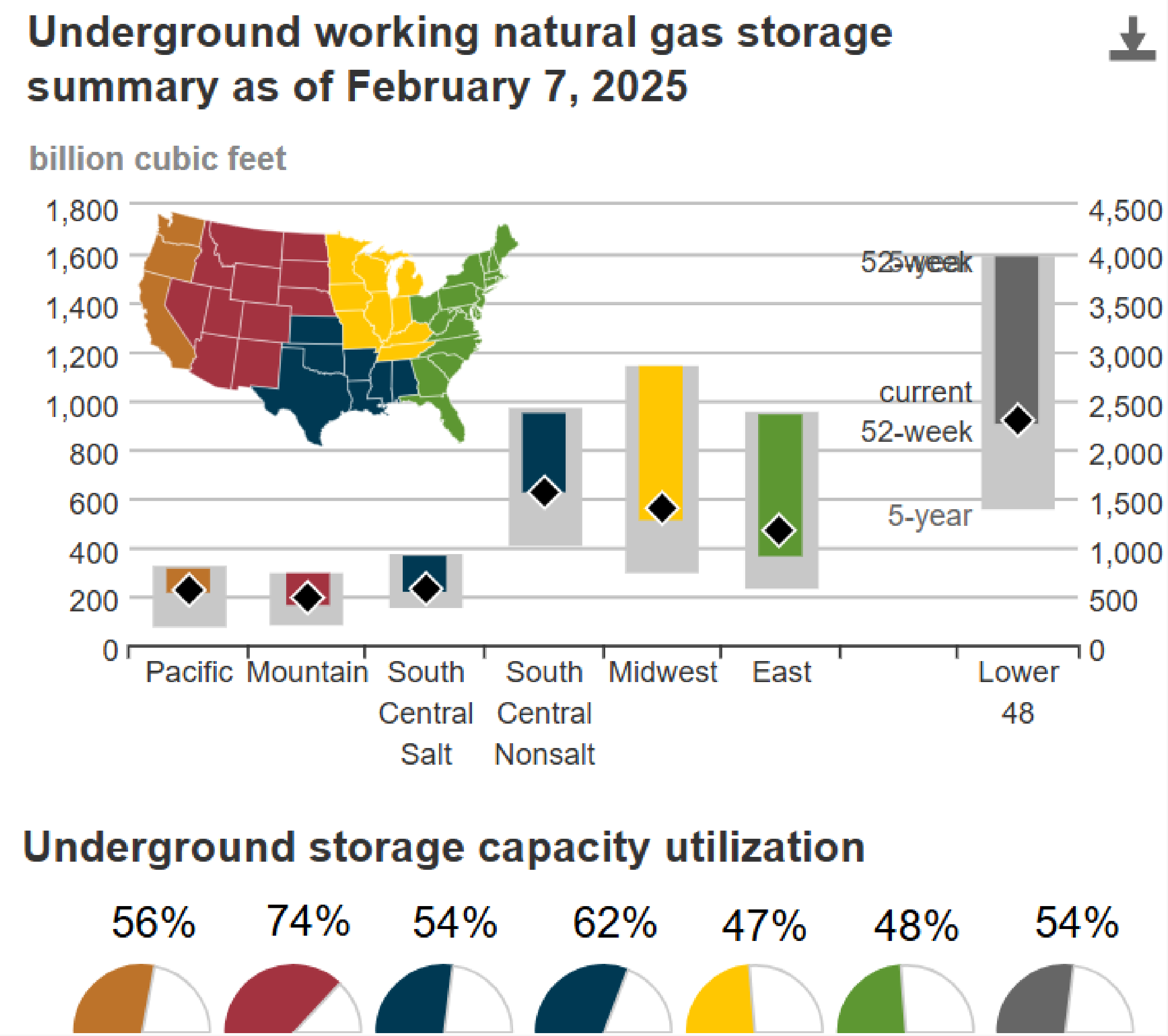
Topic Discussions

- Natural Gas
  - Storage
  - Gas Consumption for Electricity Generation
- Seasonal Outlook
  - February Forecast
  - 3-month Seasonal Outlooks
- Transmission
  - Strategic Initiatives
  - PacifiCorp Formula Rate
- Outage Notifications

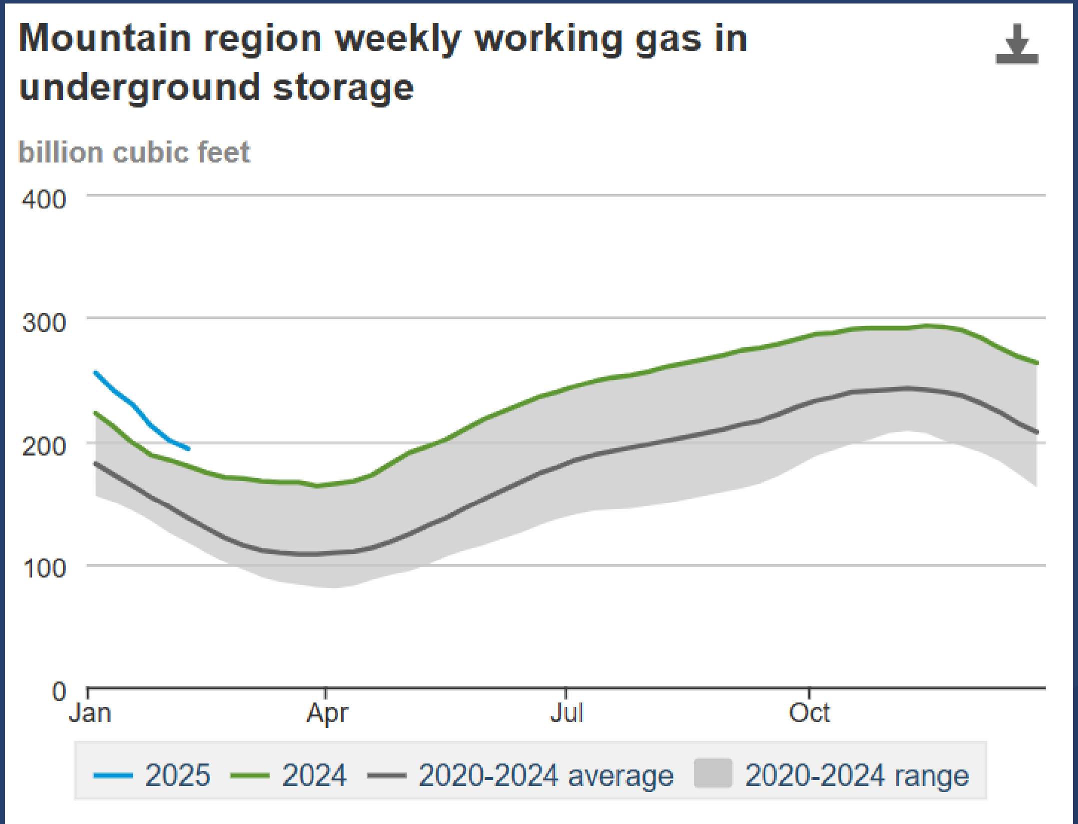
Natural Gas

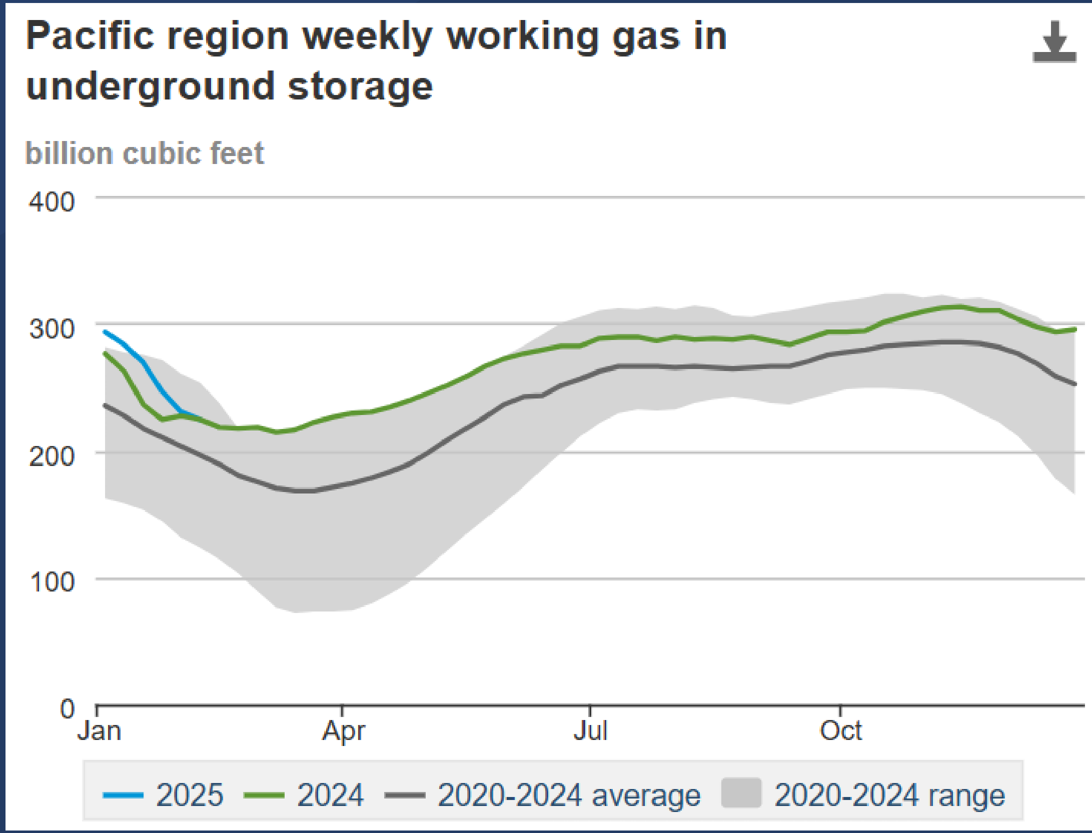
National Gas Storage

- Mountain region saw a 24% decrease and Pacific region saw 17% decrease from the January reporting



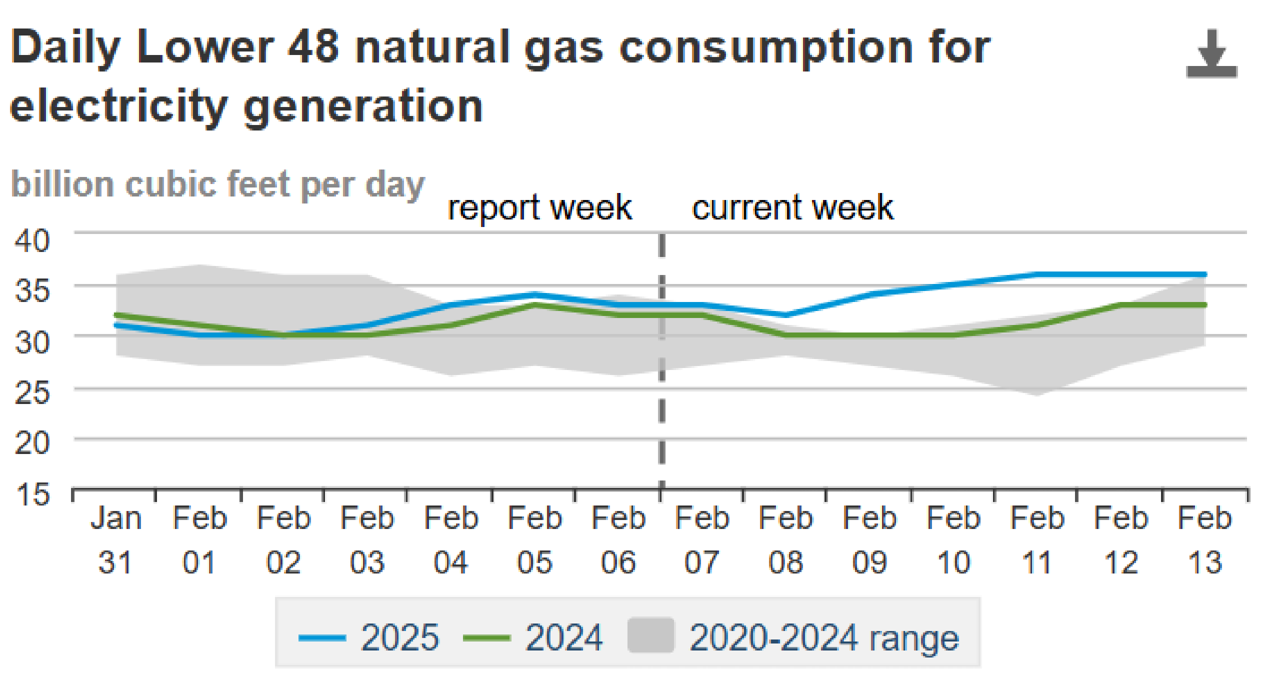
Pacific Region





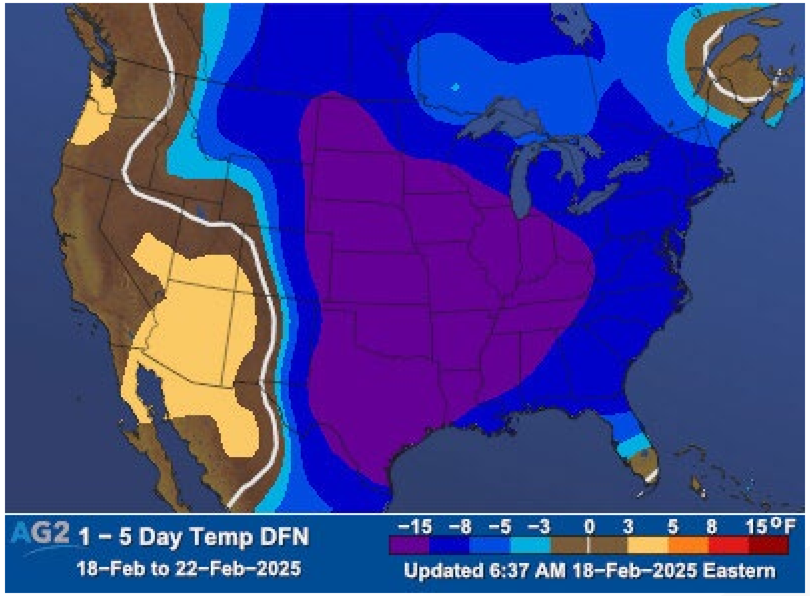
Mountain Region

Gas Consumption for Electricity Generation

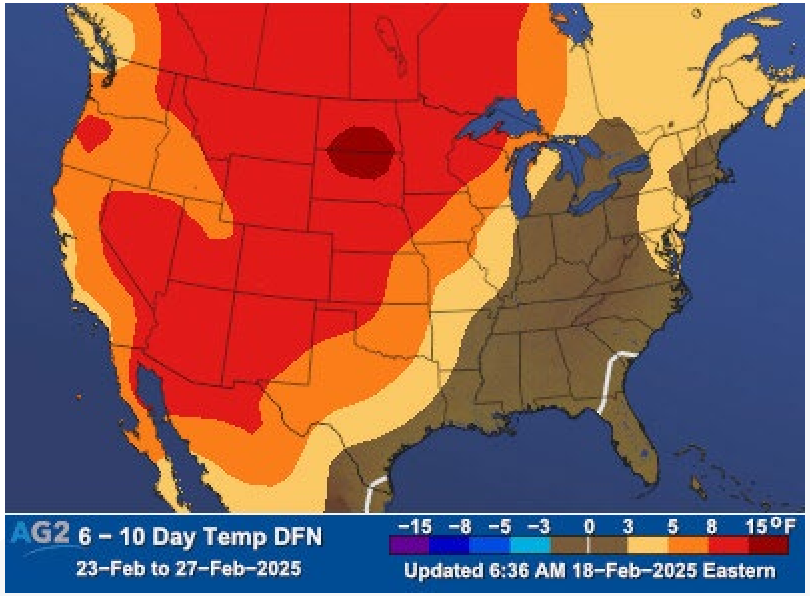


Seasonal Outlook

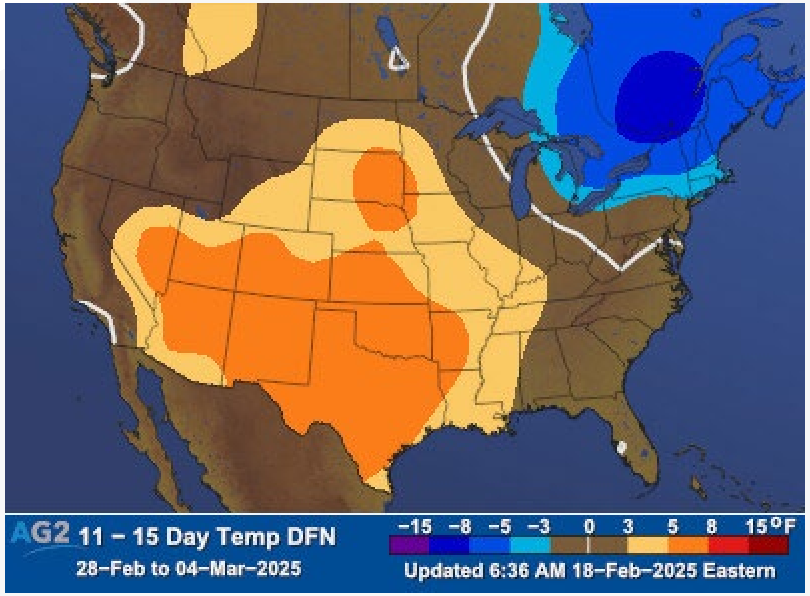
February Forecast



1-5 Day Forecast



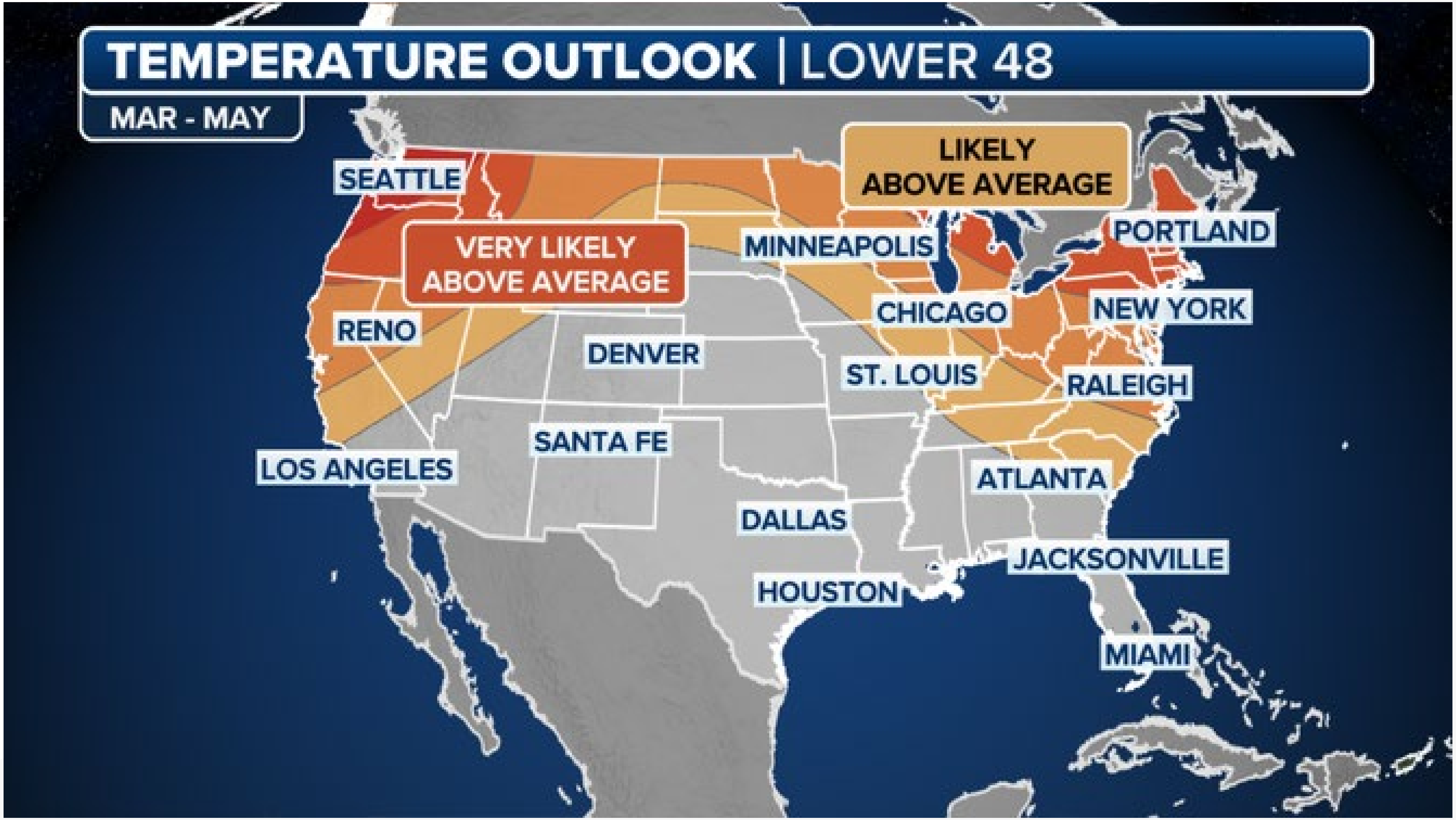
6-10 Day Forecast



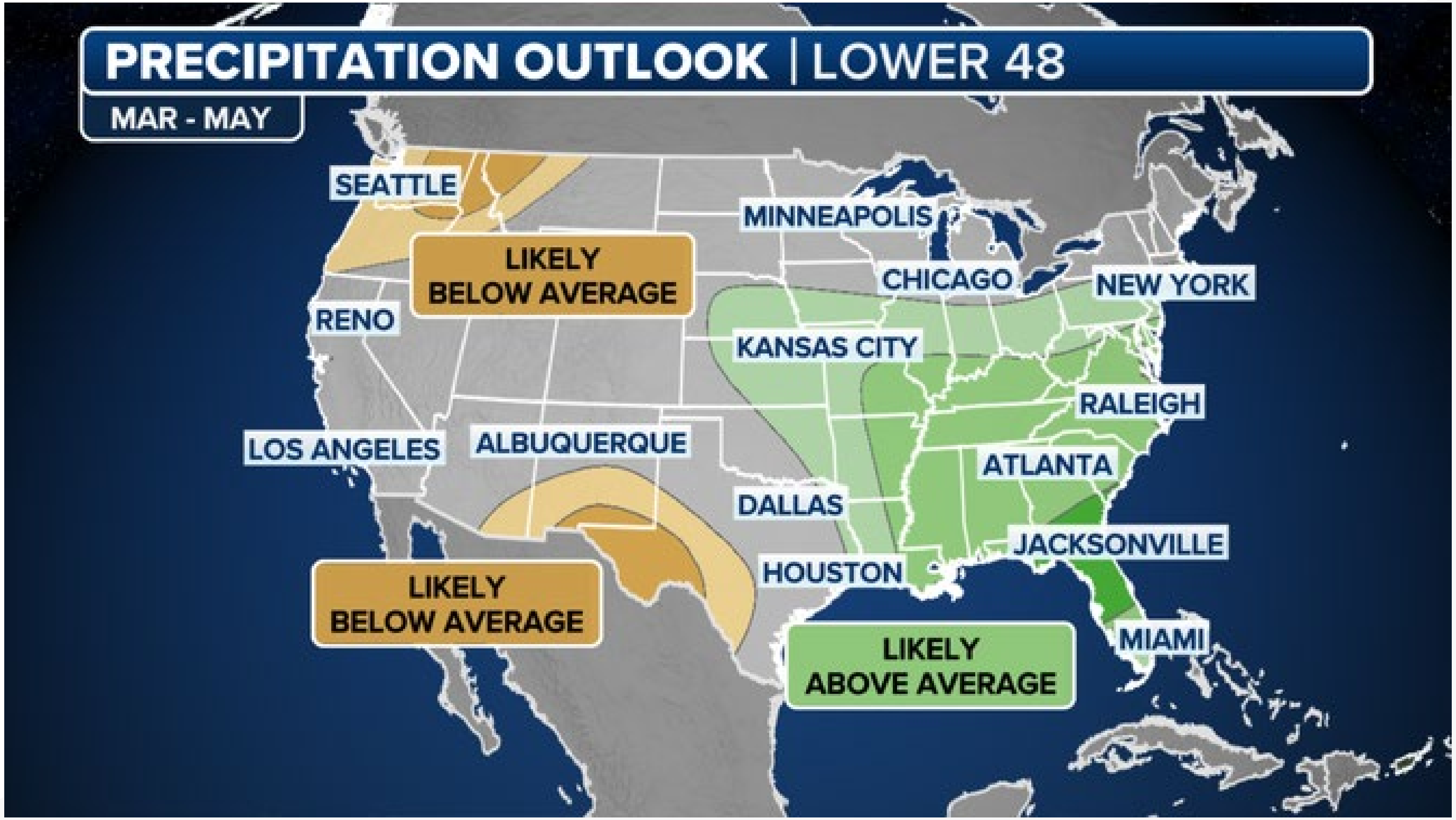
11-15 Day Forecast

UAMPS
UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

3-Month Temperature Outlook



3-Month Precipitation Outlook




Transmission

PacifiCorp Formula Rate Update

- Initially over $48B in wildfire related lawsuits
- PacifiCorp has reached settlements in over 2000 claims at approximately $2.7B
- There are still over 1,500 suits still pending hearing
- Federal Government is now suing PacifiCorp for damage to federal lands (Archie fire)
- Over 40 wineries are waiting for their day in court – hearing delayed

PacifiCorp Formula Rate Next Steps

- UAMPS, together with UMPA and Deseret, submitted Preliminary Challenges on January 30, 2025.
- PacifiCorp to respond in writing within the next 60 days, or before March 31, 2025. PacifiCorp may offer to resolve the challenges or explain why it disagrees.
- If unable to resolve the Preliminary Challenges, which we expect to be the case for at least the inclusion of the wildfire costs, then Protocols allow for a 30-day period for Senior Management to resolve the open issues.
- At the end of the 30-day period, UAMPS can file Formal Challenges with FERC. However, at any time, UAMPS can bypass the Preliminary Challenges and Senior Management period and file Formal Challenges with FERC.
- Once Formal Challenges are filed, FERC will set a date for PacifiCorp to answer. UAMPS can move to respond. Typically, FERC issues an order on Formal Challenges within 6-12 months of the filing but there is not a set date for FERC to act.
- UAMPS continues to dispute the transmission service invoices for amounts attributable to the wildfire litigation. Disputed amounts are being paid to an escrow account - $11,106,101
- Very high likelihood this will go to FERC for formal challenge

Outages – RMP Regional Business Managers

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- Steve Liechty, 801-678-1428
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  - Salt Lake
- Merlin Rushton, 435-650-6616
  - Carbon, San Juan
- Craig Bruderer, 801-721-0245
  - Box Elder
- Tyson Barber, 801-707-3457
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Text Rachel @ 385-977-8498 for additional assistance