HURRICANE CITY
UTAH

Mayor
Nanette Billings

City Manager
Kaden C. DeMille

Power Board
Mac J. Hall, Chair
Jerry Brisk
Pam Humphries
Dave Imlay
Joseph Prete
Charles Reeve

Power Board Meeting Agenda

1/11/2023
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 December 2022

STAFF REPORTS

Scott Hughes/Power Director

BUDGET

OLD BUSINESS

1. Discussion and possible recommendation of approval of updated Solar Policy
2. Discussion and possible recommendation regarding additional Generation

NEW BUSINESS

1. Discussion and possible recommendation of approval of updated Interruptible Commercial Rate
2. Commercial EV Charging Stations Rate Discussion
3. UAMPS Updates
4. **Closed meeting** held pursuant to Utah Code section 52-4-205 to conduct a strategy session to discuss market conditions relevant to a business decision regarding the value of a project entity asset

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The Hurricane City Power Board met on December 7, 2022, at 3:00 p.m. at the Clifton Wilson Substation on 526 W 600 N.

In attendance were Charles Reeve, Pam Humphries, Jerry Brisk, Dave Imlay, Joseph Prete, Scott Hughes, Brian Anderson, Michael Ramirez, Jared Ross, Fred Resch, Kaden DeMille, Dayton Hall, Shane Minor, and Crystal Wright.

Mac Hall had contacted and requested Charles Reeve to chair the meeting in his absence. Charles Reeve welcomed everyone to the meeting; Dave Imlay led the Pledge of Allegiance and Charles Reeve offered the prayer. Dave Imlay motioned to approve minutes from the November 2022 meeting. Jerry Brisk seconded the motion. Motion passed unanimously.

Scott Hughes: Scott Hughes provided an update on employees. We are still looking for a journeyman lineman. Talmage, our Groundsman, hits his 6-month anniversary next week and we are looking at starting him in the apprentice program starting in January.

Brian Anderson: Brian Anderson reported on the Christmas decoration installation. It takes approximately a week to get everything organized and get it all installed. The installation happened on Sunday, December 27th. The 600 North Phase 3A project is continuing. We are still working on drilling holes. Some of the holes will have to be contracted out to dig. The 1150 West project has all the property descriptions. They are trying to get a meeting set up with Alpha Engineering to keep that project moving. Joseph Prete requested a board recommendation regarding the two routes proposed for the 1150 West project. He would like to take a recommendation back to the City Council as they discuss making a decision. Dave Imlay stated his recommendation is for the route to be the straightest, most economical route for power. It is not the role of the board to consider the political decision, but to consider a purely business decision to be judicious with taxpayer dollars. The members of the board overall agreed with that view. Dayton Hall provided an update on where the City is at in the process.

Mike Ramirez: Mike Ramirez provided an update to the board on the progress of the AMI metering system. There have been budgetary concerns and so we are researching grants to see if we can get some help to get that moving forward. They have a meeting set up to search for grants with a grant specialist. Charles Reeve asked if AMI meters would have helped during our high-power price event this previous fall. Scott Hughes replied that if the meters had been installed and a time-of-day usage rate had been implemented then it would have absolutely helped during that time.

Jared Ross: Jared Ross reported that the bid for the Three Falls Substation came in and was lower than the previous bid. Interstate Rock was awarded the bid for the foundation and control buildings. We are working on getting materials coming for the project. Most supplies will arrive in time, but there are some things that will make the schedule very tight for completion. Generator #8 was shipped off for repair and it was discovered that there was mechanical damage to a winding. This will probably require all new laminates and need to be re-wound. Questions about the striations on the laminations. Shane Minor said he will ask CAT for a report looking for a potential cause. That will be repaired and back in 2-3 months. We need to have everything back up and running for emissions testing in the spring. Generator #2 is being repaired and they came and fixed it in place and Jeff Jones is working on building a new fan shroud for it. This should be back up by the beginning of next month. #7 and #6 have turbo failures that will be fixed the first of January. Digging the holes along 600 North has been difficult on our equipment and we've been working hard to keep everything running well to keep that job moving along.

Scott Hughes asked the board to see if we could rearrange the order of topics under Old Business to move Generation Discussion up to the front to allow people to leave after that discussion who may want to.

Generation Discussion: Scott Hughes turned the time over to Shane Minor with Wheeler. Shane Minor discussed one-unit generator costs. With a bigger generation plant, some of the costs to build a generator are shared among all the units which decreases the cost per unit. Wheeler had put in an RFP for a 20-unit generation plant in Idaho. They were not awarded that bid but elected to keep the 20 units they'd placed on order in the queue. Those units have a delivery date of July 2023. The individual unit they had placed on order for us could swap slots with one of those units. This would save money on two, possibly three, price escalations due to an earlier completion date. Shane explained some of the features of the generator that we are having built. Scott Hughes explained that we have been talking about the one-unit generator to fill the spot available in our existing plant. This is the Generator #9 we have been talking about for some time. To add this generator, we would move from a category where we haven't had to pay transmission costs to a category where we would be required to pay those costs. Scott Hughes stated he would like to explore the option of building a new generation plant, possibly in conjunction with another city, for an eight-unit plant. We would potentially purchase five units and the other city would potentially purchase three. The cost to build the building and future maintenance would be shared accordingly. Discussion about varying costs, likelihood of prices continuing to increase, additional permitting required and lead times for completion. Shane Minor gave an overview of what the five units would look like for that generation plant. Joseph Prete asked Scott Hughes for a simple explanation to take back to City Council of the pros and cons of building a multi-unit plant. He would also like to see cost savings to determine a timeline for when each unit would pay for itself. Scott Hughes stated that resource availability is a large component. Resources are scarce and expensive. Our shortage of available resources exposes us to the market which is becoming increasingly volatile. He will create a list showing some of these to distribute.

Capacity Update: Scott Hughes reported that the City Council has now denied two separate preliminary plats out in the area south of town. That area is all on the same circuit. We are still working on getting our infrastructure out there to alleviate this capacity issue. Building permits have slowed which will help.

Solar Policy Update: Scott Hughes stated that we have been working with the Distributed Energy Resources (DER) sub-committee. Michael Ramirez stepped in to describe some of the discussions that were held in those meetings. There was time spent educating the sub-committee regarding some of the issues that surround grid-tied solar. There were discussions that surrounded base rates, compensation for energy, and the various sizes of systems. He discussed they would like to have the information obtained from those meetings to finalize an update to our solar policy. This could potentially be ready in time for our next Power Board. There was a discussion about what the base rates should be covering in comparison to the consumption usage rates cover.

Dave Imlay stated that there many be some information on the server from previous rate studies that will show where those different amounts were during those studies.

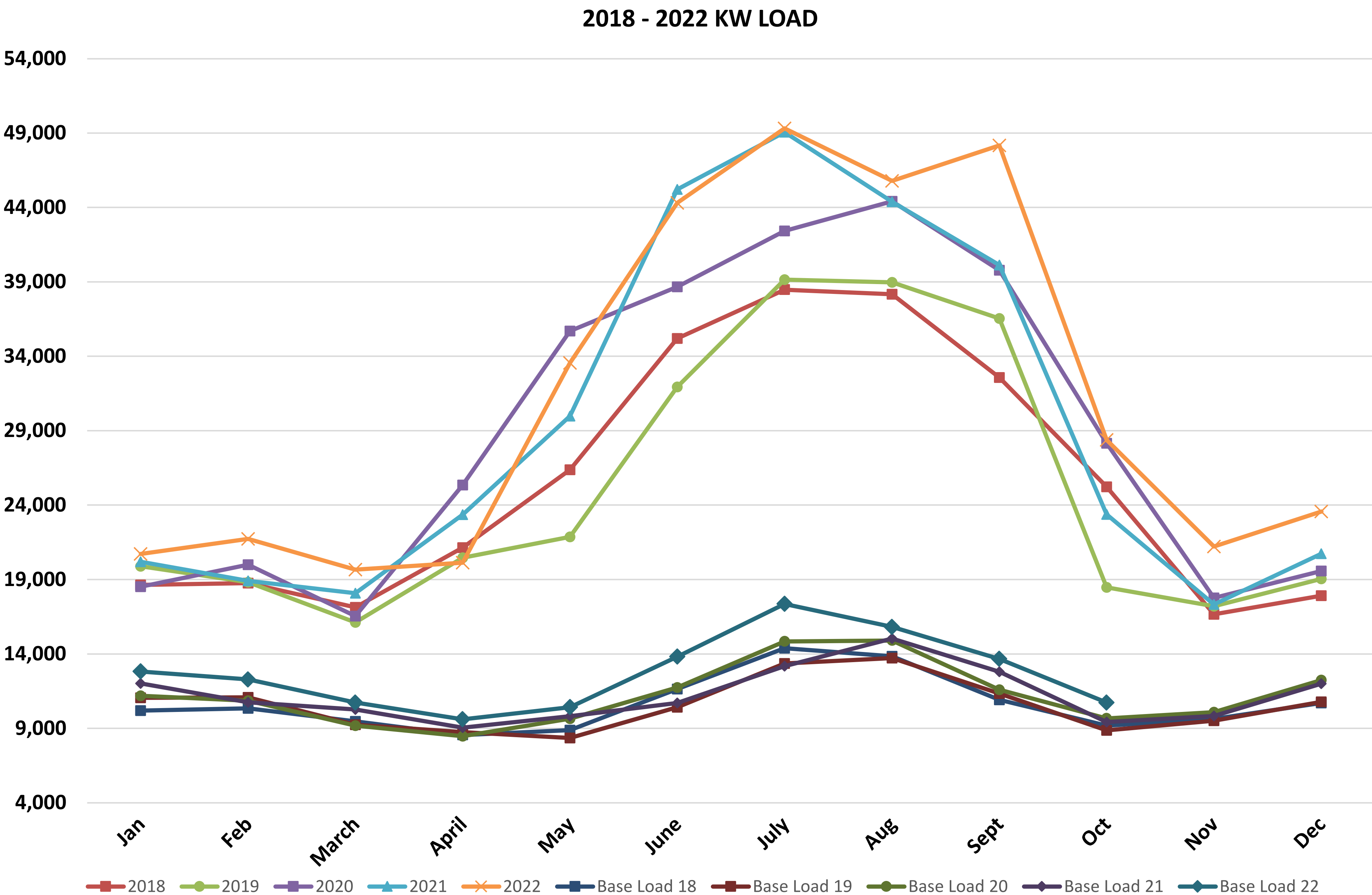
Summer Generation Run Report: Scott Hughes reported that we have been collecting data from the summer run and trying to use it to see what the final results were. A chart was shown showing costs of UAMPS bill and the costs of running generation vs cost without generation. Discussion about the difference between our load and firm resource availability which exposes us to the market and the volatility that is occurring increasingly. We still need to calculate repairs and overtime to show a more complete picture. This chart only shows the cost per MW without including calculations for repairs or overtime.

Budget: Scott Hughes showed the updated budget numbers. Joseph Prete wanted to caution against making financial decisions based on extreme events and look for long-term history instead. Dave Imlay showed the charts overall show the costs have been increasing at a consistent rate and substantially since 2020. This combined with firm resources that have been scarce make the outlook bleak without changes. Charles Reeve asked about updates for the UAMPS projects.

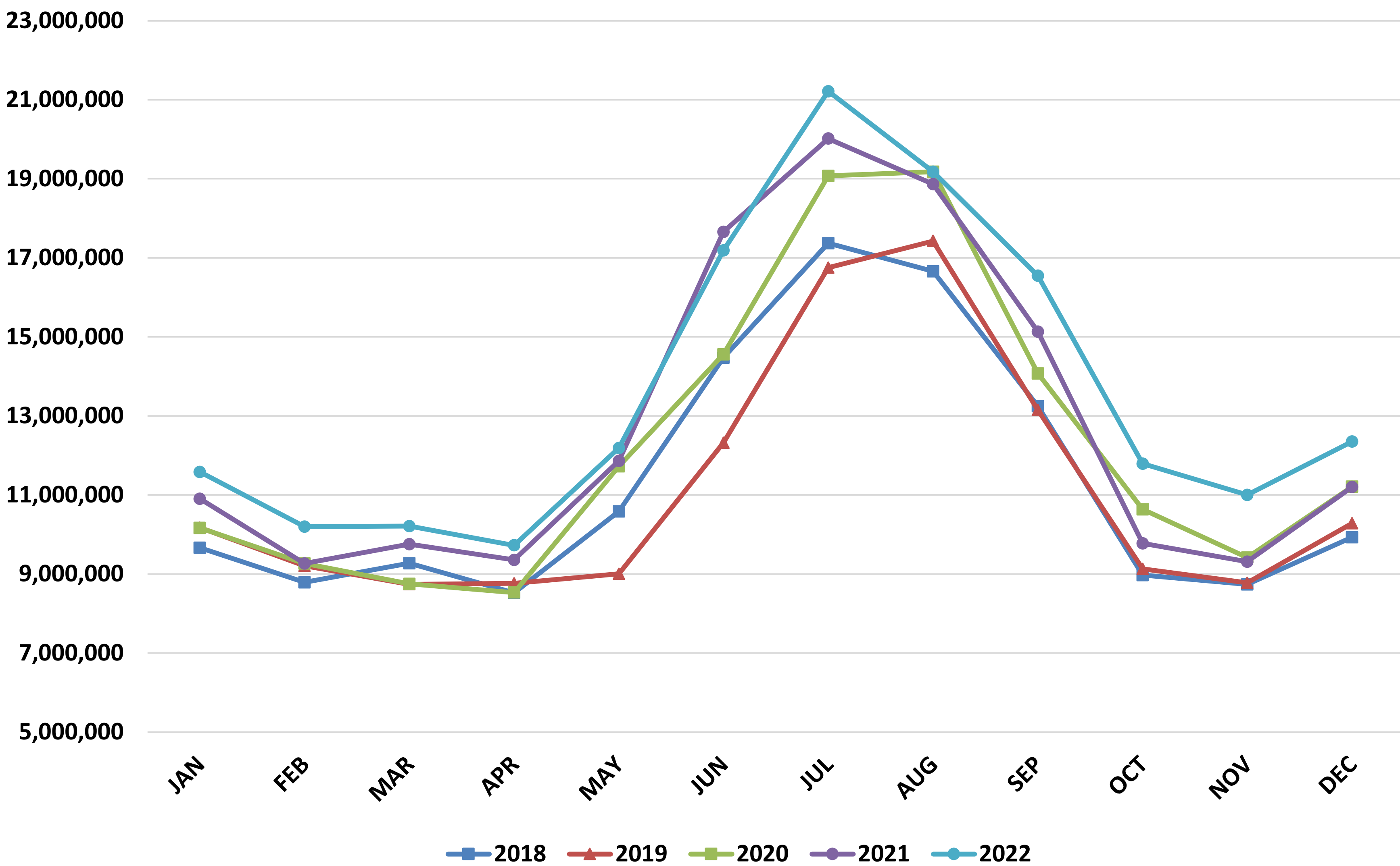
UAMPS Updates: Scott Hughes reported that we have made a block purchase for the month of December. Dave Imlay mentioned he never liked to make a block purchase above what our rates were, but the same logic is difficult to apply in these markets. UAMPS couldn't secure the full amount we had requested, but we did secure some of that block. Scott Hughes provided an update on the Central-St George Project. It was discovered that Rocky Mountain Power owed a refund to the group. A portion of that refund belongs to us. Dave Imlay provided a summary of that project. UAMPS is working on a line of theirs that runs down Sand Hollow Road. Showed graphs for the Unplanned Pool/PX for the month. An update on the IPP project shows what was saved during the summer by calling back our IPP shares. They have started to shut down the coal portion of their plant. They received a solicitation from a company that would like to capture the carbon. They have made binding agreements to shut down the plant. They are concerned that a violation of that contract would force them to shut down immediately and be fined. We will be calling back our 2023 summer season power as well. We've chosen at this point not to call it back for the rest of the year, but we will keep an eye on this. An update on the Hunter project provided shows they have chosen to stockpile the coal during winter months to save the coal to run more during the summer months. They are also considering curtailing March through May for the same reason. The update for CFPP is that the price has increased substantially. We're keeping an eye on that and the next few months will bring some major decisions for this project. The update for the Steel Solar project is they're still waiting for solar panels that are stuck in customs.

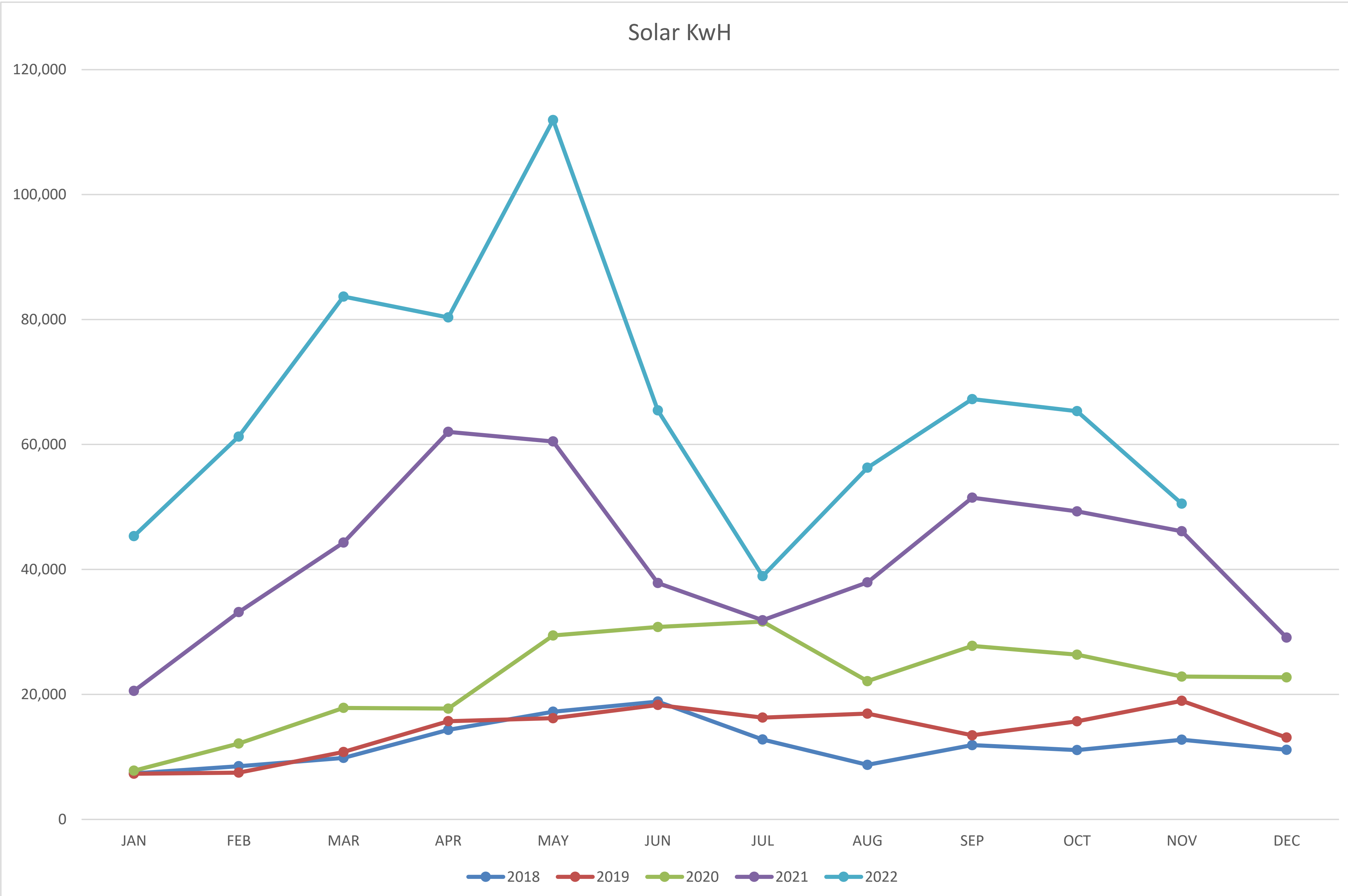
The Power Board adjourned at 6:00 p.m. The next Power Board Meeting is scheduled for January 4, 2023, at 3:00 p.m.

BUDGET


2018 - 2022 KW LOAD
54,000
49,000
44,000
39,000
34,000
29,000
24,000
19,000
14,000
9,000
4,000
Jan
Feb
March
April
May
June
July
Aug
Sept
Oct
Nov
Dec
2018
2019
2020
2021
2022
Base Load 18
Base Load 19
Base Load 20
Base Load 21
Base Load 22

2018 - 2022 KWH LOAD



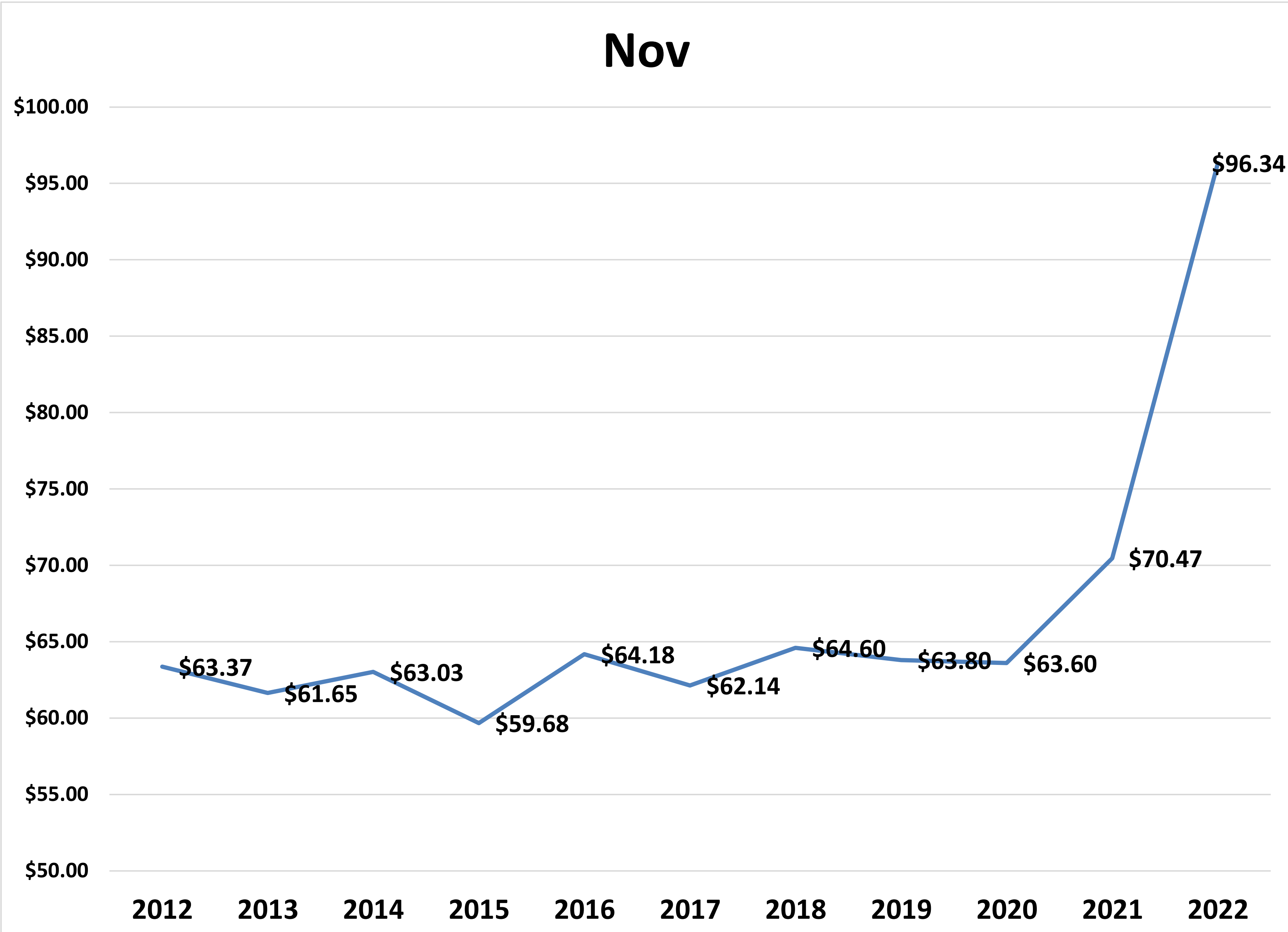

Solar KwH
120,000
100,000
80,000
60,000
40,000
20,000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
2018
2019
2020
2021
2022

AVERAGE YEARLY POWER PRICES

22-23 bdgt amount		**$0.00**
BDGT	Year to Date	**$74.87**

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Jan	$56.66	$60.76	$58.36	$59.86	$57.87	$59.07	$60.62	$59.75	$57.76	$60.14	$68.25
Feb	$59.78	$58.15	$64.45	$65.94	$62.38	$63.04	$60.96	$67.00	$60.67	$63.19	$70.88
Mar	$57.28	$63.50	$60.83	$62.03	$61.77	$60.99	$60.09	$65.17	$64.67	$63.64	$67.28
Apr	$55.43	$63.77	$63.75	$61.88	$59.71	$59.49	$55.02	$55.44	$55.92	$61.86	$82.63
May	$53.31	$60.28	$61.64	$64.71	$65.51	$60.32	$58.86	$58.55	$58.55	$59.69	$72.66
June	$50.09	$56.05	$59.15	$58.30	$65.51	$58.54	$52.17	$55.30	$53.44	$86.91	$77.60
Jul	$51.16	$55.62	$56.85	$56.91	$56.95	$58.29	$67.87	$54.29	$55.98	$81.04	$85.31
Aug	$51.57	$55.49	$56.84	$55.27	$57.67	$59.00	$66.55	$54.58	$78.40	$72.03	$90.89
Sep	$54.79	$58.80	$59.46	$56.06	$56.97	$62.36	$55.00	$54.34	$64.93	$82.38	$127.29
Oct	$62.68	$60.35	$61.42	$56.97	$59.23	$59.79	$59.36	$59.70	$62.82	$75.92	$83.45
Nov	$63.37	$61.65	$63.03	$59.68	$64.18	$62.14	$64.60	$63.80	$63.60	$70.47	$96.34
Dec	$56.02	$58.37	$60.91	$57.90	$61.51	$58.80	$61.61	$58.55	$60.33	$70.07	
Yr Avg	$56.01	$59.40	$60.56	$59.63	$60.64	$60.15	$60.23	$58.87	$61.42	$70.61	$83.87
Weighted Avg	$55.22	$58.80	$60.34	$58.99	$59.55	$59.90	$60.56	$58.11	$61.98	$72.46	$85.71
											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 associated with power resources.


Nov
$100.00
$95.00
$90.00
$85.00
$80.00
$75.00
$70.00
$65.00
$60.00
$55.00
$50.00
$63.37
$61.65
$63.03
$59.68
$64.18
$62.14
$64.60
$63.80
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$70.47
$96.34
2012
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2015
2016
2017
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2019
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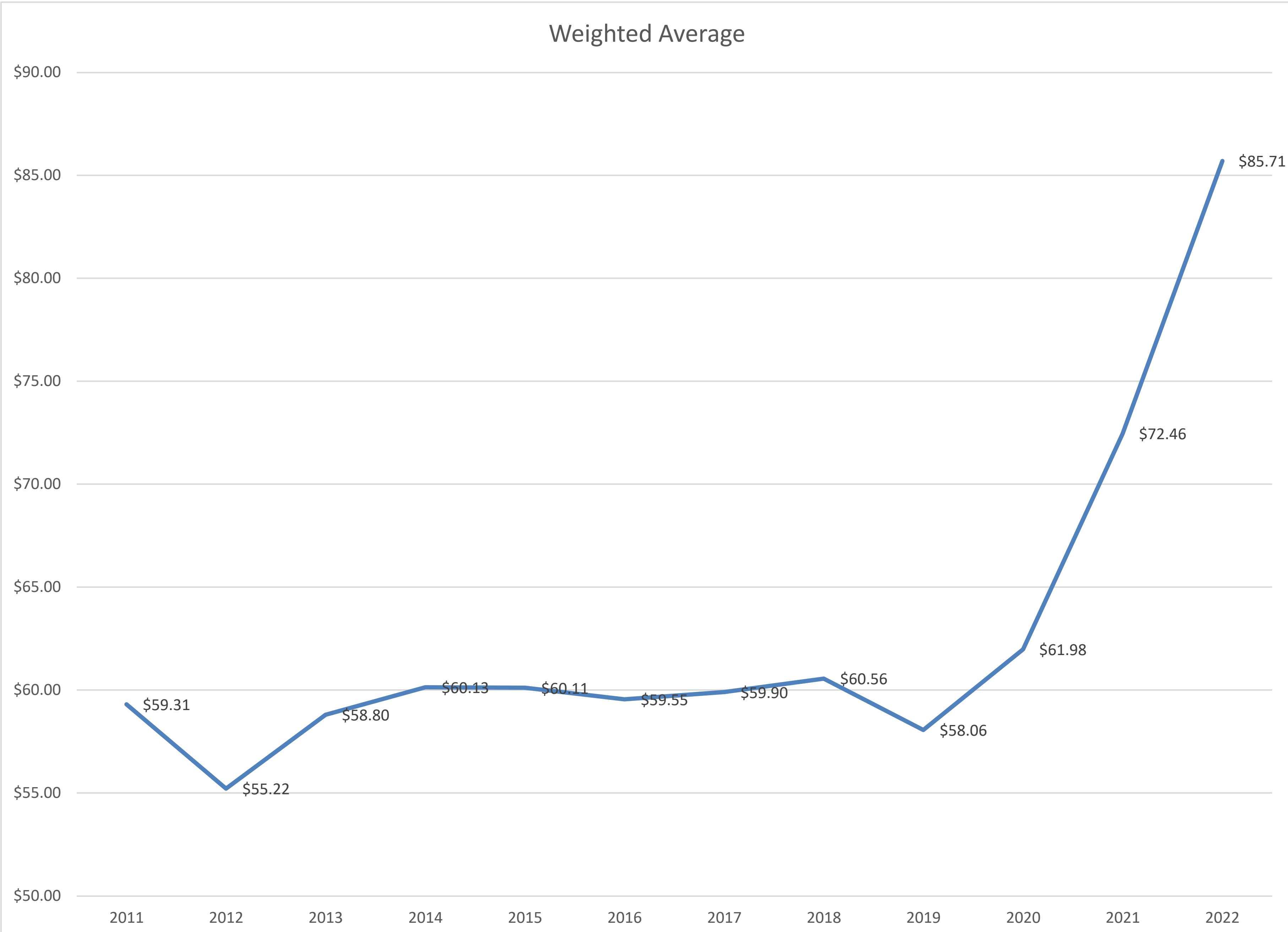
2021
2022


Weighted Average
$90.00
$85.00
$80.00
$75.00
$70.00
$65.00
$60.00
$55.00
$50.00
$59.31
$55.22
$58.80
$60.13
$60.11
$59.55
$59.90
$60.56
$58.06
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$85.71
2011
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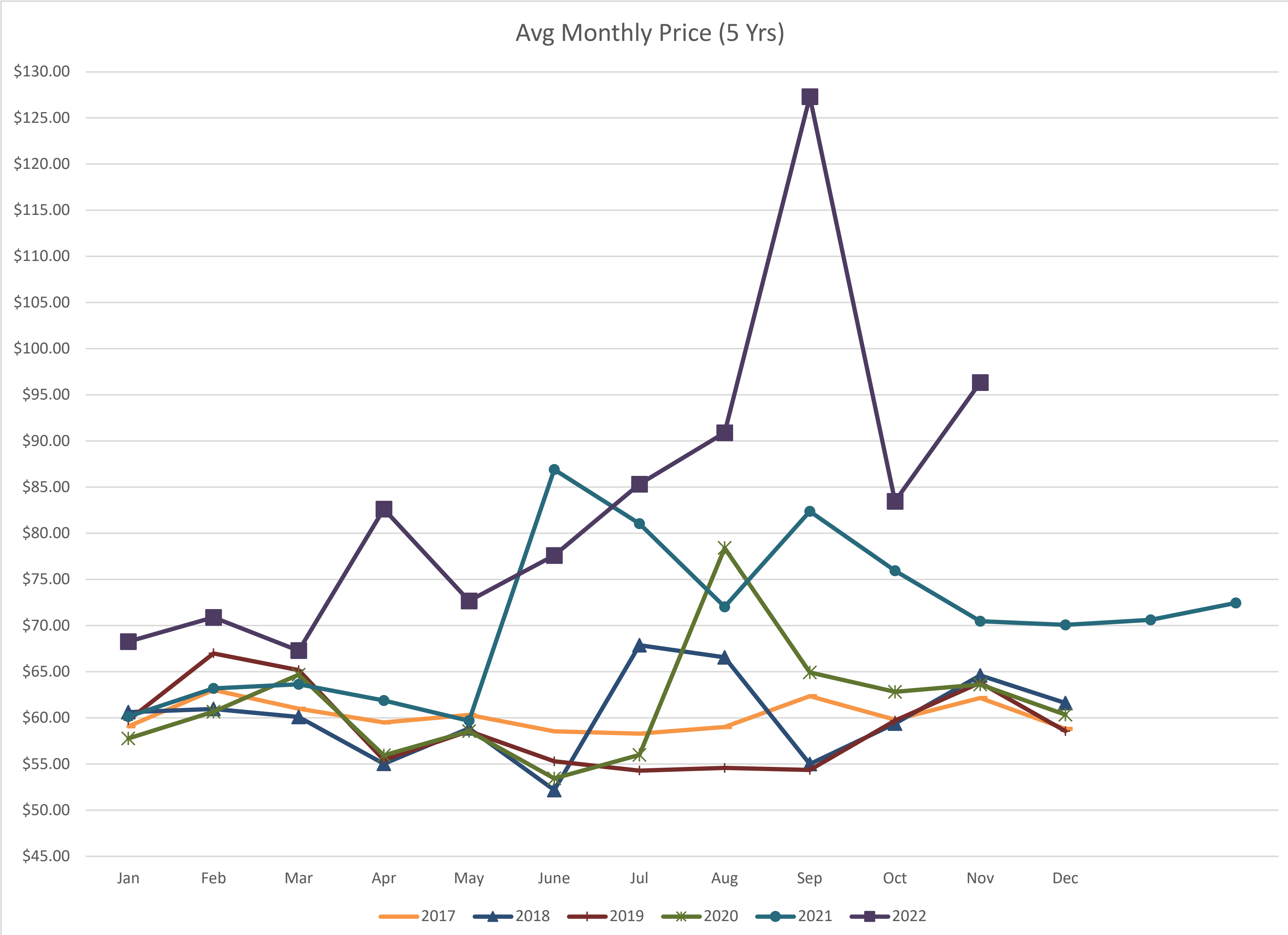
2020
2021
2022


Avg Monthly Price (5 Yrs)
$130.00
$125.00
$120.00
$115.00
$110.00
$105.00
$100.00
$95.00
$90.00
$85.00
$80.00
$75.00
$70.00
$65.00
$60.00
$55.00
$50.00
$45.00
Jan
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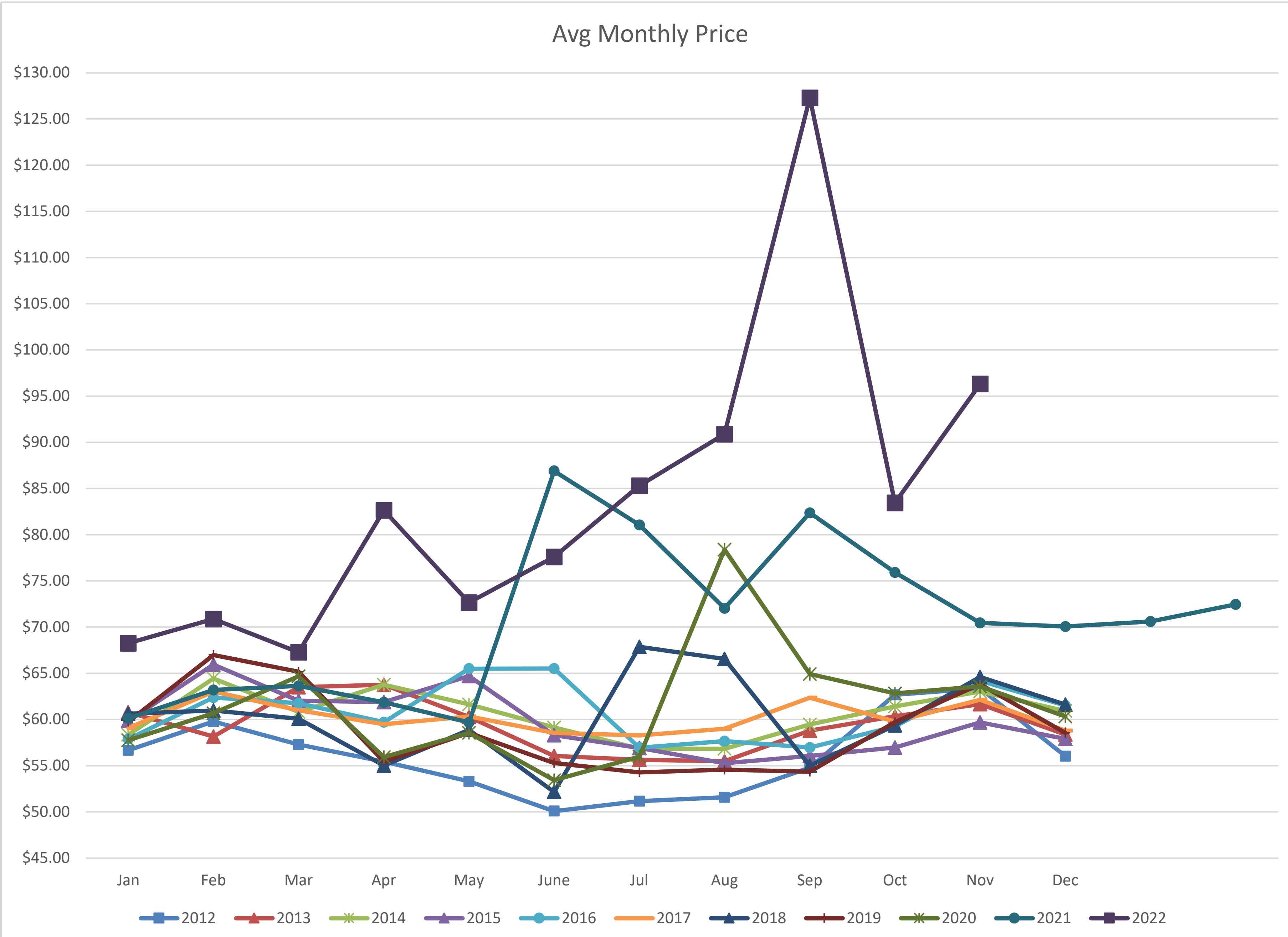
2020
2021
2022


Avg Monthly Price
$130.00
$125.00
$120.00
$115.00
$110.00
$105.00
$100.00
$95.00
$90.00
$85.00
$80.00
$75.00
$70.00
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$55.00
$50.00
$45.00
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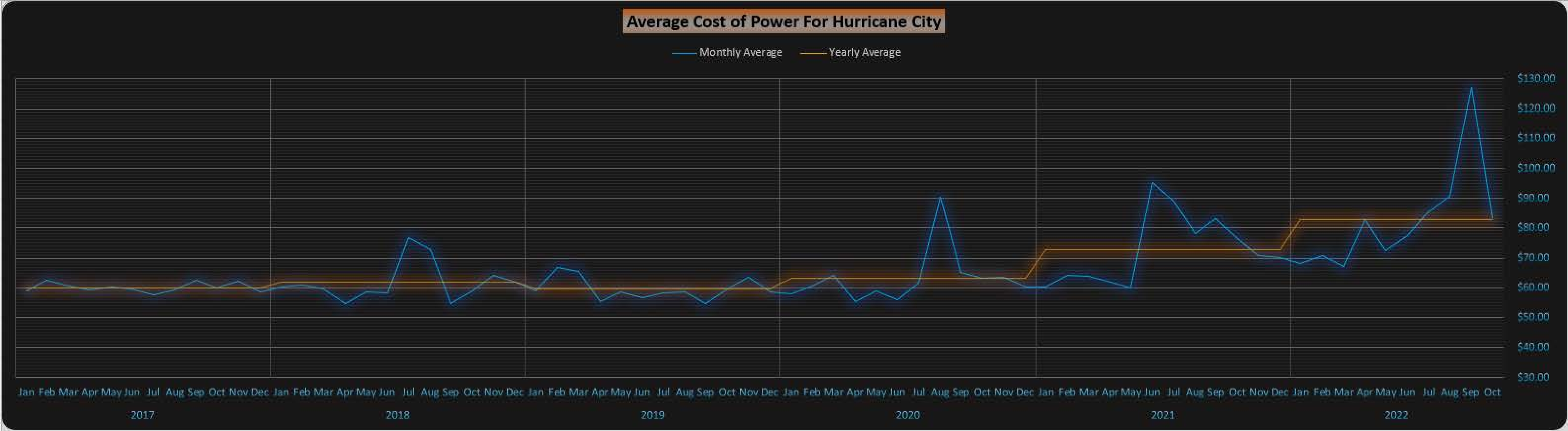


Average Cost of Power For Hurricane City
Monthly Average
Yearly Average
$130.00
$120.00
$110.00
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec
2017
2018
2019
2020
2021
2022

Power Indices

(day ahead prices)

Hub	HL	LL
Mona	-	-
Mid-C	$175.11	$177.50
Palo Verde	$160.00	$144.70
Mead	$173.00	$155.00

Future Power Market

PALO	23 Feb	23 Mar	23 Apr	23 May	23 Jun	23 Jul	23 Aug	23 Sep	23 Oct	23 Nov	23 Dec	24 Jan
HL	148	66	52	46	119	239	256	198	86	74	97	108
LL	125	67	52	46	69	90	114	101	77	72	92	107

MorningStar indices as of: 1/6/2023

POWER
HURRICANE CITY
UTAH

Grid-Tied Distribution Generation Policy

This Grid-Tied Distribution Generation Policy ("Policy") applies to all grid-tied distribution generation systems ("Systems") within the City of Hurricane ("City") operated by customers ("Customers") of Hurricane City Power ("HCP") in which the system is located on the Customer's side of the City's electric meter.

The City reserves all rights to refuse or deny an application that does not comply with all stipulations of this policy.

Application Procedures:
To begin the process of approval of a grid-tied distribution generation facility, the customer must obtain an application and complete all requirements including the Grid-Tied Distribution Generation Application Checklist.

Interconnection Review:
The City will review an application to interconnect a System that meets all of the following criteria:

1. Customer has paid the applicable fees.
2. Customer has contacted and listed a prequalified solar installer on application.

System Limits:
The City will allow a limited number of HCP Customers to install Systems, subject to all requirements and conditions of this Policy. The number of Customers' Systems allowed will be limited by the capacity of each distribution circuit, as determined by HCP.

The aggregate generation capacity on the distribution circuit to which the System will interconnect, including the capacity of the System, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level that is nearest the proposed point of common coupling as determined by the City.

A System's point of common coupling shall not be on a transmission line or a spot network.

If a System is to be connected to a radial distribution circuit, the aggregate generation capacity connected to the circuit, including that of the System, shall not exceed 15% of the circuit's total annual peak load, as most recently measured at the substation.

If a single-phase System is to be connected to a transformer center tap neutral of a 240-volt service or a three phase transformer, the addition of the System shall not create an imbalance between the two sides of the 240 volt service or an imbalance of the three phase transformer of more than 20% of nameplate rating of the service transformer.

Circuit/Distribution System Study:
A circuit/distribution system study may be needed to ensure any System installation is not detrimental to the City's power grid. Whether a circuit/distribution system study is required shall be determined by HCP at its sole discretion. The study will be completed by an engineer contracted by HCP, the cost of which shall be paid by Customer prior to any approval or acceptance of the Customer's System. System installations that would be detrimental to the City's power grid are not permitted.

Installation, Compliance, Energy Credits, and Meter Reading:
Systems shall be installed in accordance with all HCP and City codes, rules, regulations, and specification standards. HCP and the City's Building Department shall inspect the System prior to any power generation to ensure it complies.

The City will be the owner of the renewable attributes also known as Renewable Energy Credits (REC) of the electricity that is generated on or after the customer generating facility is installed and working.

HCP shall replace its normal metering equipment with bi-directional metering equipment on the meter base at the cost of the Customer. The bi-directional meter will measure energy that flows from the City's power grid to the Customer as well as the energy that flows from the Customer to the City's power grid. HCP will read the customer's meter on the City's normal meter reading schedule

HCP will apply a credit to the Customer's monthly bill for energy the customer delivers to the City's power grid during that billing cycle. The rate at which HCP will credit the energy delivered by the Customer is $.04/kWh. See HCP Rate Schedule. This rate schedule may be eliminated or adjusted at any time by the Hurricane City Council. Credits accrued each month are not eligible to be applied to electric base rate or any other utility/City rates or fees. Monthly credits may only be applied to electric kWh usage. Credits may roll over month to month until July 1 of each year, at this time all credits will be reset to zero.

Meters must be accessible to HCP and the City Meter Reader and shall not be hindered by animals, landscape, fences, or other obstacles or potential obstacles. HCP may, at its discretion, regularly inspect the System and shall be given unlimited access by the Customer to all Customer-owned generation and metering equipment.

Ground Mounted Solar Arrays:
Ground-mounted solar arrays shall be located on the residential lot behind the front setback line or behind front plane of home whichever is greater

The solar array shall not infringe on any easement or sight distance requirements and shall not violate any City Ordinance or subdivision CC&R's.

Maximum height for the solar array, measured from ground level to the highest point on the array shall not exceed fifteen feet (15').

The solar array shall be limited by Chart A under "System Size Limitations – Base Rates".

The following size limits shall also apply:

Lot Size:	**Maximum array surface area**
Less than 1 acre	200 square feet
1 - 2.5acres	400 square feet
Greater than 2.5 acres	1200 square feet

Solar array shall be located to maximize unobstructed line of sight.

System Size* Limitations - Base Rates:
The City limits Systems and charges base rates for Grid-Tied Distribution Generation as described in the following chart:

Chart A

System Type	Photovoltaic (PV) System Size*	Maximum Power Export Setting	Export Credit Rate	Monthly Base Rate
1 Phase System				
1P BASIC System	Up to 8.1 kW DC / 6 kW AC	6 kW AC	$.04/kWh	$30
1P LARGE System	Up to 16 kW DC / 12 kW AC	6 kW AC	$.04/kWh	$40
3 Phase System				
3P BASIC System (400A and below)	Up to 16 kW DC / 12 kW AC	12 kW AC	$.04kwh	$90
3P LARGE System (Over 400A)	Determined by Study	Determined by Study	**PPA	**PPA

*" System Size" is defined as the largest nameplate rating of any of the components, total panel array, total micro-inverter array, export limiter or inverter.
**"PPA" is defined as Power Purchase Agreement

1P Systems capable of more than 16 KW DC /12 KW of AC output with a 6 KW AC limiter will be considered by HCP staff on a case-by-case basis. If approved, a monthly incremental base rate increase will replace the 1P BASIC System base rate.

3P Systems will be required to conduct a study by an electrical engineer chosen by Hurricane Power Department for the connected circuit. The designs will be reviewed and approved by said electrical engineer. All costs will be at the expense of the applicant. 3 Phase system under 400A (3P BASIC) means the main service size to the building is 400 amps or less. 3 Phase system over 400A (3P LARGE) means the main service size to the building is 400 amps or larger and is CT metered

Export rates, base rates, and fees are subject to change upon approval of Hurricane City Council at any given time.

Ineligible Properties:
Properties with meters located in back yards are not eligible for a grid-tied System. Properties consisting of multi-unit buildings are not eligible for a grid-tied System.

Standards:

(a) IEEE 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems, as amended and supplemented, which is incorporated by reference herein. IEE Standard 1547 can be obtained through the IEE website at www.ieee.org; ***and***
(b) UL 1741, Inverters, Converters, and Controllers for use in Independent Power Systems) January 2001), as amended and supplemented, which is incorporated
by reference herein. UL Standards can be obtained through the Underwriters Laboratories website at www.ul.com.

Certification of customer-generator facilities:

An equipment package shall be considered certified for interconnected operation if it has been submitted by a manufacturer to a nationally recognized testing and certification laboratory and has been tested and listed by the laboratory for continuous interactive operation with an electric distribution system in compliance with the applicable codes and standards listed in (a) above.

System Operation and Responsibility:

Systems shall be installed, operated, and maintained by the Customer at the Customer's sole expense. The Customer will be responsible for an application review fee for each review and a one-time cost of the bi-directional meter in amounts established by HCP. HCP will install the meter onto the Customer's meter base and read and maintain the meter consistent with Hurricane City's Standard Operating Procedure at the City's expense.

Neither the City nor HCP shall be liable for, and Customer shall indemnify and defend the City and HCP, for all damages, claims, liabilities, losses, injuries, or deaths resulting from or relating to (1) the City permitting or continuing to allow an attachment of a grid-tied System to the City's power grid; (2) the Customer's System; (3) the Customer's generation of power; and (4) the acts or omissions of the Customer in generating power.

Customer and City Requirements

(a) Once a metering interconnection has been approved, the City will not require a Customer to test or perform maintenance on its facility except for the following:

1. An annual test in which the Customer-Generating Facility is disconnected from the City's distribution equipment to ensure that the inverter stops delivering power to the grid.
2. Any manufacturer-recommended testing or maintenance.
3. Any post-installation testing necessary to ensure compliance with IEEE 1547 or to ensure safety.
4. Documentation is required for testing done yearly and needs to be submitted to the City.

(b) The City shall have the right to inspect a Customer-Generating Facility after interconnection approval is granted, at reasonable hours and with reasonable prior notice to the Customer. If the City discovers that the Customer-Generating Facility is not in compliance with the requirements of this subchapter, and the noncompliance adversely affects the safety or reliability of the electric distribution system, the City may require the Customer to disconnect the Customer-Generating Facility until compliance is achieved.

(c) The City shall have the right to disconnect the Customer-Generating Facility in the event it causes system problems. The Customer will have the option on correcting the problem, at which time the system will be re-inspected before beginning operation again.

(d) The Customer shall be required to install a manual disconnect located within five feet of the meter.

Signature verifying acceptance of above terms required before start of project:

Customer ______________________________________ Date___________________

Pros & Cons To Purchasing Gen. 9 and Additional Plant With 5 More Units

Pros

1 Our Own Resource
2 Insurance Against Power Market
3 Quicker Than Most Options
4 Cheaper Resource Than Most Options
5 We Already Have Experience & Knowledge W/ Plants
6 Additional Resource for Emergencies
7 Can Hedge Natural Gas

1 Having our own resource that we have control of is a big advantage over being exposed to the market. The power market these last two years has been extremely volatile. That volatility can reduce our reserve cash very quickly. We don't know what the future will bring.

2 If the power market gets out of control like we saw in February 2021, July 2021, and September 2022 or even raises high for extended periods of time like we saw in December 2022, we have a solid resource that protects us from those high prices. This last summer we saved approximately $760,000 (Need to calculate overtime) running our generators. We haven't been able to calculate November and December yet.

3 We believe that we could have a plant built within 2 years (with the purchase of the already ordered generating units from Wheelers). The only other resource that I know of that reliably could be picked up faster than that is purchasing block power off the market which fluctuates daily with the market and is almost always higher than any firm resource.

4 This is very debateable right now. The gas market is very high, causing this to not be true. The idea of it being true is the idea of a good gas hedge. With a good gas price hedged, this resource will perform better than almost all resources that we can get a hold of (which is almost none anyway).

5 Currently we have most of our employees that have had exposure to the generating plants. The experience runs from limited understanding and good abilities to schedule, start, and stop the units, all the way up to certified mechanics and relay technicians that can handle most kinds of breakdowns and maintenance. These are huge asstes that other plants don't have. They save us money and cause the ownership to be less expensive in the long run.

6 Currently in the situation of a blackout, we have nameplate generation of about 14.6mW. We would only load them up to about 11.7mW as a safety factor to not trip them off. That would give us a 20% reserve as safety for fluctuating and in-rush load. The chart below shows the peak loads for our city in 2022. With the addition of Gen.#9 in our existing plant and 5 more units in a new plant, our nameplate capacity would be about 29.5mW and we would load the plants in an outage up to about 23.6mW for safety.

2022	
Month	MW Peak
Jan	19
Feb	18
Mar	17
Apr	19
May	32
Jun	37
Jul	49
Aug	39
Sep	32
Oct	20
Nov	21
Dec	23

These peaks are only looking from the 15th of each month through the 21st of each month.

So, they are not exact numbers or may not be technically the highest peak of the month.

They are meant to be a general idea of our peak loads only.

7 The current natural gas market could easily be considered a "con" because of its volatility. I chose to put it in the "pro" list because I believe that sometime within the next 2-3 years, it will return to some kind of normalcy, at least for some period of time. That is an opinion and therefore cannot be counted on and each has to decide their own opinion. If it does, then we would be ready to sign an agreement to hedge a block of gas to supply for our generators, protecting against the swings of the natural gas prices.

Cons

1 Big $ Up Front
2 Return On Investment Prolonged
3 Volatility of the Natural Gas Market
4 Transmission Expenses Rise W/ RMP

1 We are looking in the neighborhood of $20 million. That is a big expense up front. It would definitely require a bond with a large bond payment that, with current power prices, would put a large burden on our electric fund.

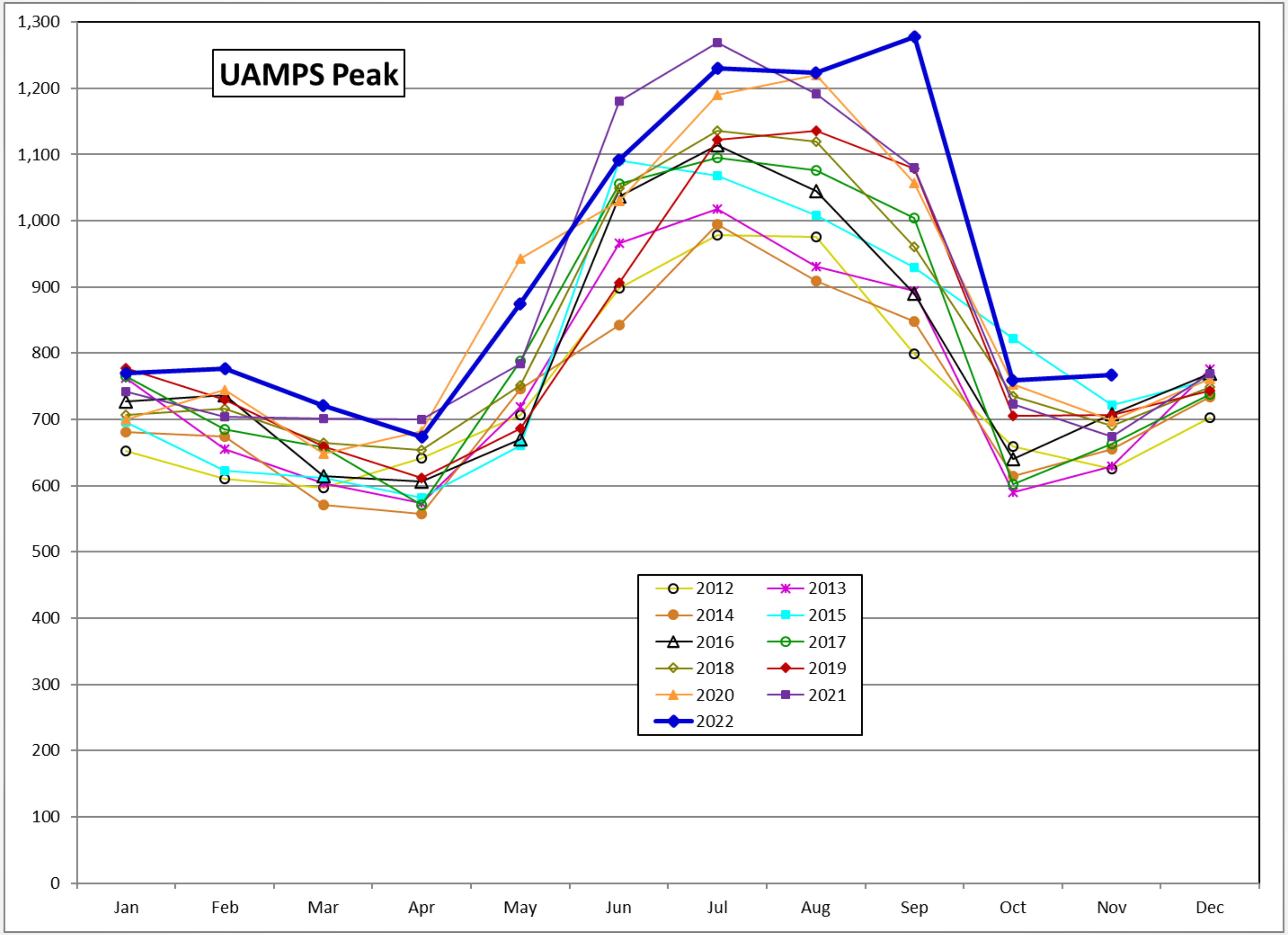
2 I can agree that the idea of ever getting a Return On your Investment(ROI) for these generators is very debateable. That is why it is here in the "con" list. The only assurance I believe that you could get a return would be the power market staying high or rising higher for a long period of time and a successful, great gas hedge for a long priod of time. Which is not an assurance, it is a gamble. Therefore, the idea of an ROI is likely to be very long if ever. Every year, we get a return, I believe (maybe Dave can verify if we have ever gone negative), but some years are minmal and others are greater amounts (it's a slow return of our investment).

3 The natural gas market has potential to be a huge "con" and currently is. Gas being the fuel, obviously plays an enormous role in these generators being able to run. If they don't run, they don't save money. In which case they are an emergency asset only (which is great, but debatably(depends on outages) not $20 million great).

4 If we add any generation to our grid, we will be placed into a category with Pacificorp that requires us to pay higher transmission rates. The only data that I have to give as an example, is that if we had been in that category in the summer of 2022, we would have paid approximately $65,000. So with this new plant we can guesstimate our fees would be approximately $130,000 a year. That eats in to our ROI for sure.

PX and Scheduling Report

November 2022


UAMPS Peak
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
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2013
2014
2015
2016
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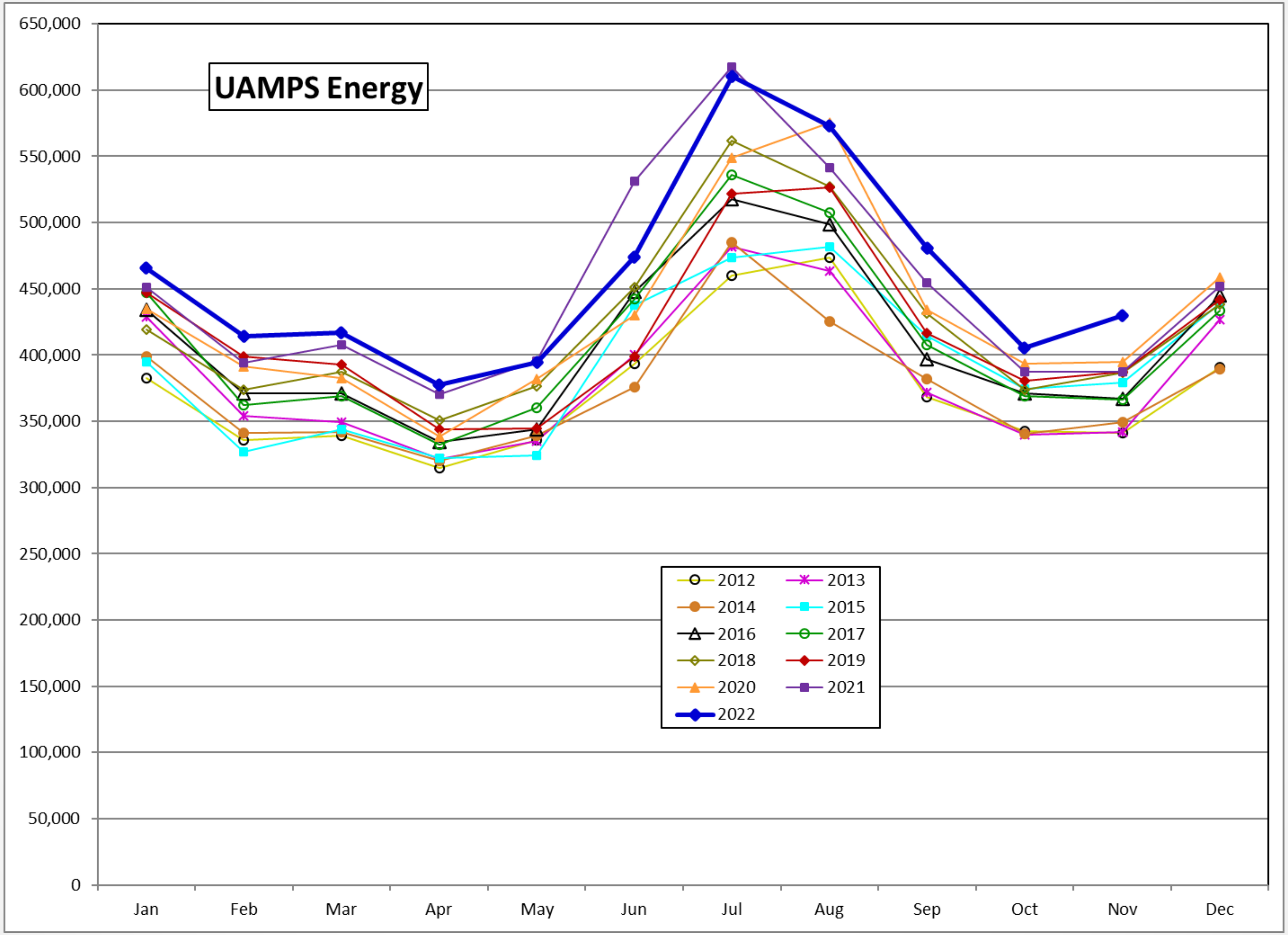
2018
2019
2020
2021
2022



UAMPS Energy
650,000
600,000
550,000
500,000
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Jan
Feb
Mar
Apr
May
Jun
Jul
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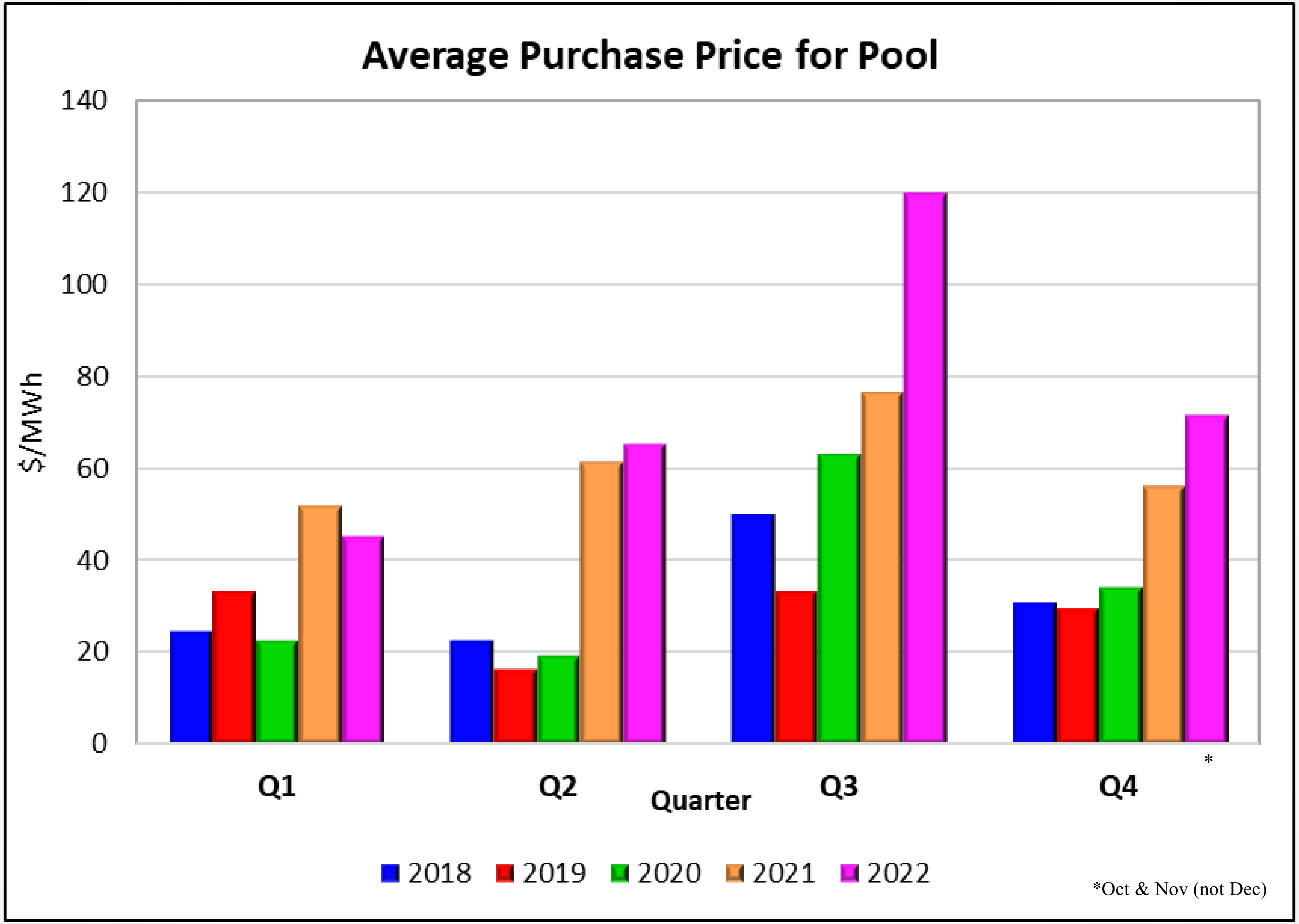
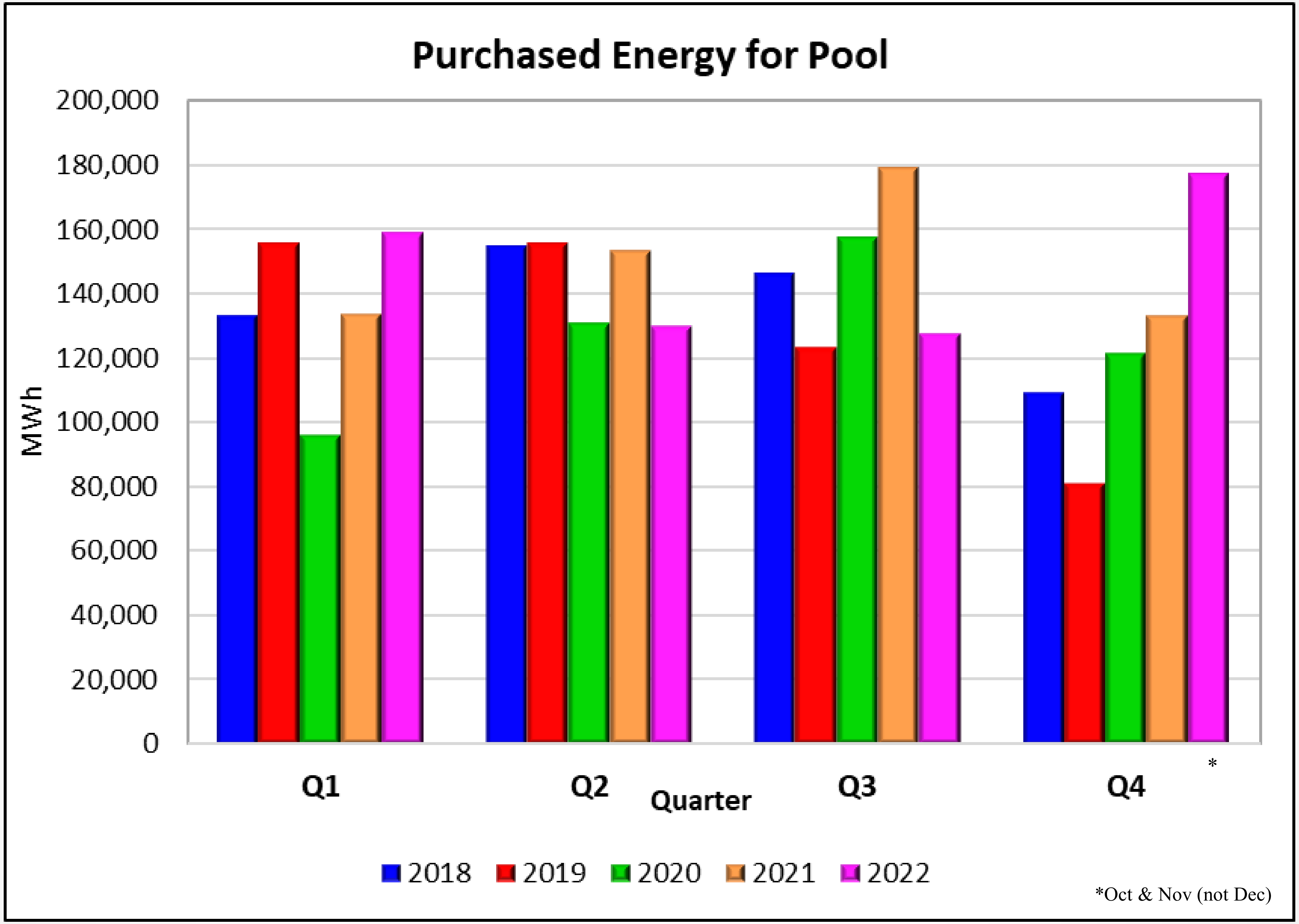
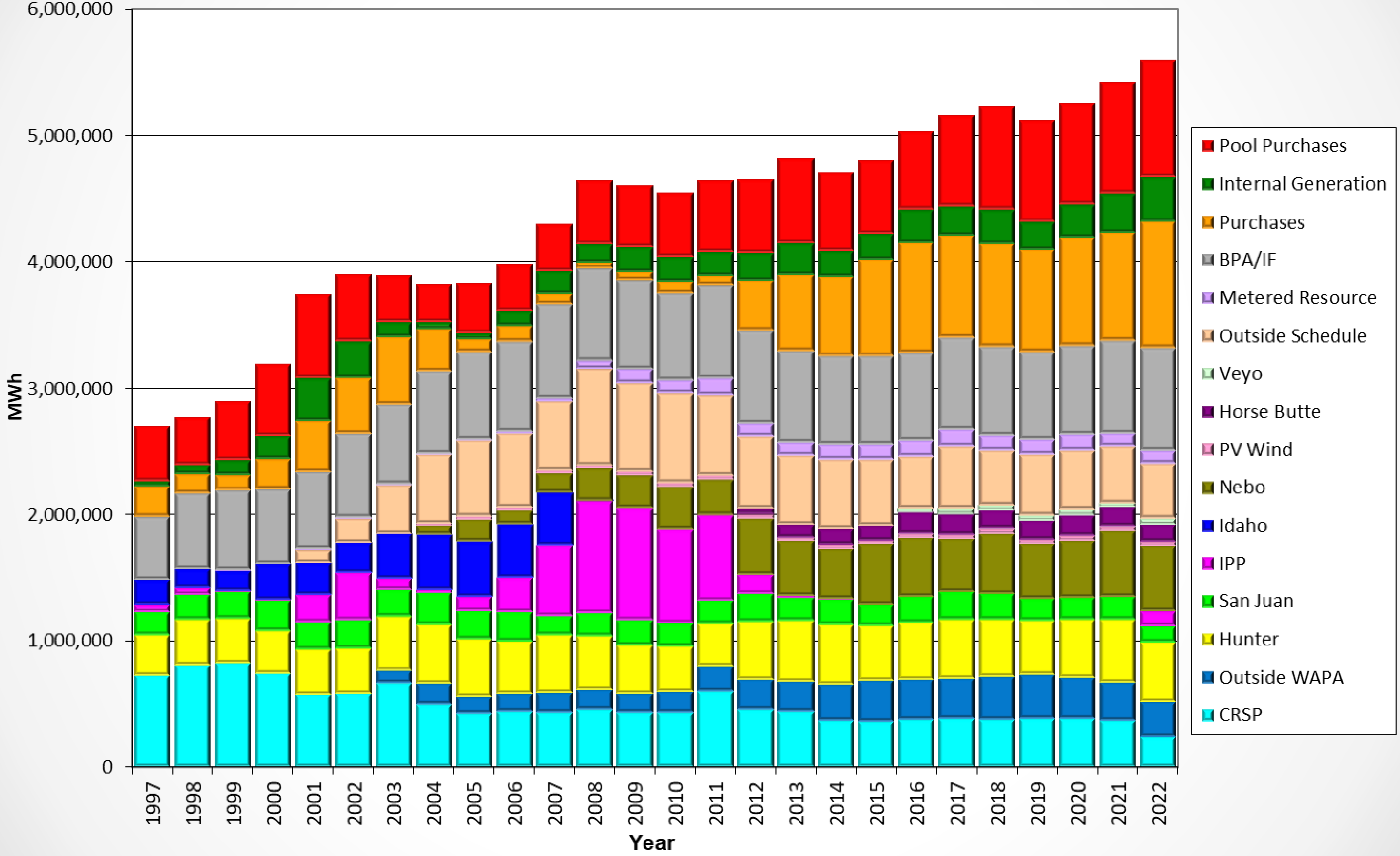
2018
2019
2020
2021
2022


Average Purchase Price for Pool
140
120
100
80
60
40
20
0
$/MWh
Q1
Q2
Quarter
Q3
Q4
*
2018
2019
2020
2021
2022
*Oct & Nov (not Dec)


Purchased Energy for Pool
200,000
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
MWh
Q1
Q2
Q3
Q4
*
Quarter
2018
2019
2020
2021
2022
*Oct & Nov (not Dec)

UAMPS Yearly Resource Usage



Steel Solar 1A and 1B PPA Update

Firm PMC

December 13, 2022

Steel 1A and 1B PPA Status Update

- Construction will slow down while waiting on panels
- No solar panel update
  - Monitoring LONGi progress with Customs and Border Protection
  - Production not anticipated to start yet for project panels
- SOLV is continuing to work on completing substation and transformer install
  - Approximately 98% complete
  - Completing surface rock over grounding grid
- Approximately 95% complete with AC trenching, wiring, and backfill
- DC Wiring is approximately 50% complete
- Except for termination, all inverter activities are marked at 100%

Resource PMC

December 13, 2022

MIG and Gas Study

Gas Feasibility Study

- Study kickoff held 12/1/2022
- Technology review
- Generation siting
- Transmission
- Environmental considerations
- State regulatory requirements
- LCOE modelling
- Operations
- Fuel procurement
- IRP planning process

Interest in Natural Gas Update

POTENTIAL NATURAL GAS INTEREST
As of November 18, 2022

Member	Natural Gas (kW)	Coordinated MIG Participation	Resource Project Allocation	Resource Adj for NG Study Participants
Beaver	1,800	Yes	1.2%	1.3%
Blanding	2,000	Yes	1.2%	1.4%
Bountiful	15,000	No	5.4%	6.0%
Brigham City	7,000	Yes	4.2%	4.7%
Ephraim	2,790	Yes	1.2%	1.4%
Enterprise	600	Yes	0.8%	0.9%
Fairview	100	No	0.8%	0.9%
Fallon	1,000	No	2.9%	3.3%
Fillmore	No	Yes	1.0%	1.2%
Heber	5,000	Yes	3.9%	4.3%
Holden	200	Yes	0.7%	0.8%
Hurricane	12,000	Yes	3.2%	3.6%
Kaysville	5,000	Yes	2.8%	3.2%
Lassen MUD	3,000	No	1.6%	1.8%
Lehi	20,000	No	8.6%	9.7%
Logan	20,000	Yes	7.4%	8.3%
Los Alamos	10,000	Yes	1.4%	1.6%
Monroe	100	Yes	0.9%	1.0%
Morgan	1,500	Yes	1.1%	1.2%
Mt. Pleasant	200	Yes	1.2%	1.3%
Murray	10,000	No	5.2%	5.8%
Oak City	150	No	0.7%	0.8%
Paragonah	50	No	0.7%	0.8%
Parowan	250	Yes	1.0%	1.1%
Payson	7,000	No	2.4%	2.7%
Plumas Sierra	5,000	No	1.7%	1.9%
Price	No	Yes	1.7%	1.9%
Santa Clara	3,000	No	1.6%	1.8%
Spring City	No	Yes	0.8%	0.9%
Springville	5,000	Yes	4.6%	5.1%
St. George	No	Yes	7.3%	8.1%
SUVESD	4,000	No	1.6%	1.8%
Truckee-Donner PUD	5,000	No	3.9%	4.4%
Washington	6,000	Yes	3.7%	4.1%
Weber Basin	500	Yes	0.9%	1.0%
TOTAL	**153,240**	**22**	**89.3%**	**100.0%**

Path Forward

TECHNOLOGY EVALUATION – Preliminary update late December 2022

- DELIVERABLE: Create a matrix summary of all generation technologies with their respective performance parameters and LCOE, along with their respective ranking, for UAMPS

SITING ANALYSIS

- DELIVERABLE: Create a matrix summary for viable generation sites with their respective parameters and rank them for UAMPS

OPERATIONAL COST OPTIMIZATION

- DELIVERABLE: Summarize staffing situation and related incremental labor cost for select generation technology alternatives

FUEL PROCUREMENT STRATEGIES

- DELIVERABLE: Summarize fuel arrangements, fuel basis, and fuel strategies for select generation technology alternatives with recommendations on preferred suppliers and pipelines

Next Steps

Informal mid-December update

Planning to meet with GDS on tech evaluation status prior to next PMC

A Resolution Closing the Enchant Study Project and Authorizing the True Up of Costs in June 2023

WHEREAS, Utah Associated Municipal Power Systems ("UAMPS") has been organized under the Interlocal Cooperation Act, Title 11, Chapter 13, Utah Code Annotated 1953, as amended, and the Utah Associated Municipal Power Systems Amended and Restated Agreement for Joint and Cooperative Action (the "Joint Action Agreement") as a separate legal entity and a political subdivision of the State of Utah to accomplish the purposes of its Members through joint and cooperative action and to provide a means to secure electric power and energy for the present and future needs of its Members;

WHEREAS, initially-capitalized terms used and not defined herein shall have the meanings specified in the Joint Action Agreement and the UAMPS Resource Project Agreement;

WHEREAS, one of the purposes of UAMPS, as specified in the Joint Action Agreement, is the planning, financing, development, acquisition, construction and operation of one or more Projects for the benefit of all or some of the Members;

WHEREAS, the purpose of the Firm Project is to review and analyze supply side and demand side resources and provide recommendations to Project Members pursuant to the UAMPS Firm Project Agreement;

WHEREAS, on April 21, 2021, the Project Management Committee for the Firm Project ("PMC") approved a resolution to investigate entering into a power purchase agreement to purchase power from the San Juan Generating Station in Waterflow, New Mexico upon the conversion of SJGS to a carbon-capture-sequestration power generation facility("Enchant Study Project");

WHEREAS, certain members of the Firm Project entered into agreements to participate in the Enchant Project;

WHEREAS, the Firm Project has incurred costs related to the Enchant Project within the budget amounts set by the PMC; and

WHEREAS, negotiations to develop the Enchant Project were unsuccessful and UAMPS staff has recommended closing Enchant.

NOW, THEREFORE, BE IT RESOLVED BY UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS AS FOLLOWS:

Section 1. *Closure of the Enchant Project*. The Enchant Project is hereby closed as a study project under the Firm Project.

Section 2. *Final Cost Allocation*. Enchant will no longer incur costs. Existing costs that have been incurred will be trued up against funds collected from Project Participants at the end of fiscal year 2023 (March 31, 2023), and presented to the Firm Project Management Committee in July 2023, with each Project Participant bearing the costs in proportion to its respective Project Study Agreement.

Section 3. *Effective Date*. This resolution shall be effective immediately upon its approval and adoption.

ADOPTED AND APPROVED by the Board of Directors of the Utah Associated Municipal Power Systems, this 13th day of December 2022.

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

Chairman

[SEAL]

ATTEST:

Secretary

San Juan Project - Budget Amendment #8

December 13, 2022

Background to San Juan Project FY2023Budget

- **October 2021** - Original San Juan Generating Station Budget provided by PNM - UAMPS FY2023 budget
- **February 2022** - PNM/owners had determined that the Unit 4 would operate an additional 3 months (July, Aug, Sep 2022)
  - UAMPS revised the original PNM budget to reflect the additional 3 operating months using prior months to fill these O&M amounts - July thru Sep 2022
- **May 2022** – Revised operating budget issued by PNM to reflect the extended 3-months operations

Budget Amendment Summary

- Revised Operating Budget including 3 additional months of operation (July thru Sep 2022) - $750K
- Overbudget Operations thru 10/31/2022 - $450K:
  - O&M - $170K
  - Energy – $250K
    - Poor operations due to high sulfur coal - $160K
    - Coal residual write-off - $90K
  - Transmission - $30K
    - Used 12-month avg for 4 of the 6 highest months of the year

Reasons for Revised Budget Pressures

- Overhaul on Unit 4 in May 2022 to prepare for 3 additional months of operations - $80K
- Unit 4 Operations for all 6 months of FY2023 (April thru Sept 2022) were more expensive than expected - $670K
  - Higher chemical costs – inflationary as well as higher sulfur content
  - Higher insurance costs for 3 additional months and pressure on overall premiums due to recent PNM claims
  - Hire temp PNM labor due to increased attrition

Staff Recommendation

- Increase overall budget by $1.2M
- Collect the budget amendment over the remaining 5 months power bills (Nov 2022 thru Mar 2023), or $240k per month
- Allocate to member participants based on the San Juan Project operation entitlements per FY2023 UAMPS budget.

Dated as of
January 5, 2023

GLOSSARY OF NUCLEAR TERMS

Boiling Water Reactor (BWR) – a common nuclear power reactor design in which water flows upward through the core, where it is heated by fission and allowed to boil in the reactor vessel. The resulting steam then drives a turbine-generator to produce electrical power. The CFPP is not a BWR design.

Budget and Plan of Finance (BPF) – a comprehensive budget and plan of finance for the development and construction costs during the licensing and construction periods. The BPF is a contractual term and condition for CFPP. A BPF is required prior at the beginning of each CFPP development phase and at certain other times, such as an increase in the budgeted cost of the CFPP.

Burns & McDonnell (BnM) – a full service engineering architecture, construction, environmental solutions firm. BnM represents UAMPS as an owner's engineer for the CFPP.

Carbon Free Power Project (CFPP) - UAMPS' project to develop and construct a small modular reactor project as a long-term source of reliable, carbon-free electricity to replace carbon based resources.

CFPP LLC – a limited liability company formed to develop, construct, operate and decommission a nuclear facility located at INL. UAMPS is the sole Member of the CFPP LLC.

Combined Operating License Application (COLA) – an application to the NRC for the construction and operation license of nuclear power plant at a specific site. The CFPP is currently completing the necessary work to submit a COLA in January 2024.

Combined Operating License (COL) – an NRC issued license that authorizes a licensee to construct and operate a nuclear power plant at a specific site. A COL is usually valid for 40 years (with the possibility of a two 20 year renewals).

Department of Energy (DOE) – governmental authority and owner of the INL site. The DOE has the right and ability to assign, sell, lease or otherwise make available the site to construct and operate the CFPP on the site. DOE is also providing cost-share support for the CFPP to support commercialization of NuScale technology.

Design Certification Application (DCA) – an application to the NRC for approval of a nuclear power plant design independent of an application to construct or operate a plant. Design certification is achieved through the NRC's rulemaking process and is founded on the NRC staff's review of the application. The application addresses the various safety issues associated with the proposed nuclear power plant design independent of a specific site. NuScale has received a design certification for a 50 MW 12 module plant from the NRC.

Development Cost Reimbursement Agreement (DCRA) – an agreement between UAMPS and NuScale in which NuScale agrees to reimburse UAMPS for a portion of the development costs if a defined project price target or defined subscription target are not achieved and UAMPS elects to withdraw from the project. The price target criteria apply until UAMPS would issue the final notice to proceed to construction and the subscription target criteria apply until submittal of the COLA to the NRC.

Economic Competitiveness Test (ECT) – evaluates the cost to finance, construction, operate and decommission the CFPP utilizing a 40 year levelized cost of energy model and is used to compare to the DCRA price target.

Emergency Planning Zone (EPZ) – an area surrounding a nuclear power plant where predetermined strategies and actions are established for protective actions during a plant emergency situation. The NRC has approved an EPZ at the site boundary for the NuScale Voygr SMR Plants.

Engineering, Procurement and Construction Development Agreement (EPCDA) – an Agreement between UAMPS and Fluor for the initial phases of engineering, procurement and construction of the CFPP.

Final Notice to Proceed (FNTP) – a notice to be issued by UAMPS at the point in time to authorize the construction of the CFPP.

Final Safety Analysis Report (FSAR) – applicants submitting a DCA or COLA to the NRC include a final safety analysis report to provide the technical and safety basis for the NRC's approval of the requested COL or DC.

First of a Kind Engineering (FOAKE) – component and system level engineering and testing needed for new and novel designs that have not been deployed before.

Fluor – the company performing the engineering, procurement and construction (EPC) scope for the CFPP.

Idaho National Laboratory (INL) – a laboratory of the Department of Energy Office of Nuclear Energy located in southeast Idaho near Idaho Falls. UAMPS has entered into a long-term (99 year) Site Use Permit with the DOE for the selection, development and use of an appropriate site at the INL for the CFPP.

Inspections, Tests, Analysis, and Acceptance Criteria (ITAAC) – standards that must be satisfied at the conclusion of constructing a nuclear power plant that confirm the as-constructed plant meets the design and criteria defined in the COL. The plant cannot operate until the ITAAC are completed.

Levelized Cost of Energy (LCOE) – the cost of energy over a specific period of time. The CFPP LCOE is based on a not to exceed price over a 40 year period.

Limited Work Authorization – an application submitted to the NRC to allow for early non-nuclear work at the plant site while the COLA review is underway. CFPP is working with the NRC and DOE on the LWA review process.

Low-level Radioactive Waste (LLW) – a general term for a wide range of items that have become contaminated with radioactive material or have become radioactive through exposure to neutron radiation.

MPR Associates (MPR) – a leading engineering and technology consulting firm aimed at developing and deploying next generation solutions for the electric utility industry. MPR represents UAMPS as an owner's engineer for the CFPP.

Nuclear Energy Institute (NEI) – is the policy organization of the nuclear energy and technologies industry. NEI participates in both the national and global policy making process. NEI's objective is to ensure the formation of policies that promote the beneficial uses of nuclear energies and technologies in the United States and around the world.

Nuclear Regulatory Commission (NRC) – regulates commercial nuclear power plants and other uses of nuclear material, such as in nuclear medicine, through licensing, inspection and enforcement of its requirements.

NuScale - a private commercial company formed to develop, license, and market the small modular nuclear reactor concept commonly referred to as the NuScale VOYGR.

NuScale Integral System Test (NIST) – a facility designed by NuScale to test a scaled representation of a NuScale reactor design.

Power Sales Contract (PSC) – a contract between UAMPS and its members for the development, construction, operations and decommissioning of the CFPP.

Pressurized Water Reactor (PWR) – a common nuclear power reactor design in which water is heated by fission, kept under high pressure (to prevent from boiling), and used to heat water in a separate system to make steam which is then used to drive a turbine-generator to produce electrical power. The CFPP is a PWR design.

Price Cost Estimate (PCE) – the estimated cost to design, license, and construct a facility. The PCE typically matures and uncertainty is reduced as engineering and the design are completed. The CFPP had a Class 4 PCE, then completed additional engineering to develop a Class 3 PCE. Future work will perform additional engineering to develop a Class 2 PCE and eventually a Class 1 PCE (the most accurate).

Probalistic Risk Assessment (PRA) – a systematic method for assessing three questions that designers and the NRC use to define "risk". These questions consider (1) what can go wrong, (2) how likely it is, and (3) what its consequences might be. These questions allow the NRC to understand likely outcomes, sensitivities, areas of importance, system interaction, and areas of uncertainty, which the staff can use to identify risk-significant scenarios. The NRC uses PRA to determine a numeric estimate of risk to provide insights into the strengths and weaknesses of the design and operation of a nuclear plant.

Regulatory Issue Summary (RIS) – generic communication from the NRC to give licensees, applicants for a license, holders of certifies compliance, and their contractors guidance on meeting NRC expectations and requirements.

Seismic Safety Hazards Analysis (SSHAC) – evaluation of the probability of earthquakes and resulting safety concerns for nuclear facility installations.

SCRAM – an emergency shutdown of a nuclear reactor. The term and acronym are derived from "Safety Control Rod Axe Man" for the first nuclear reactor at the University of Chicago's Stagg Field.

Standard Design Approval (SDA) – NRC approval of a standard design for a nuclear power plant (or portions of a plant) that can be referenced and used in subsequent applications. An application for an SDA is an SDAA. NuScale submitted an application to the NRC in December 2022 for the CFPP configuration of six pack of 77 MW reactors.

Small Modular Reactor (SMR) – a nuclear reactor design that is less than 300 MW and typically designed to include large amounts of content manufactured in factories rather than constructed on-site.

Xcel Energy (Xcel) – is the utility company to be the Operations Partner for the CFPP. They are responsible to ensure the CFPP is prepared to operate when constructed. They also assist with the NRC review and approval of the COLA.