DIRECT TESTIMONY OF BRAD J. ALBERT

On Behalf of Arizona Public Service Company

Docket No. E-01345A-19-0236

October 31, 2019

Table of Contents

ATTACHMENT LIST

DIRECT TESTIMONY OF BRAD J. ALBERT
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
Docket No. E-01345A-19-0236

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Brad J. Albert. I am the Vice President of Resource Management for Arizona Public Service Company (APS or Company). In this position, I oversee the Company's resource planning, energy commodity trading activities, long-term resource acquisition, fuel supplies, and fuel transportation.

Q. DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Mechanical Engineering from New Mexico State University in 1984 and a Master of Business Administration degree from Arizona State University in 1990.

I have worked at APS for 35 years and held a variety of roles with increasing management responsibilities in the areas of resource planning, resource acquisitions, risk management, energy trading and nuclear power plant licensing.

II. SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE A SUMMARY OF YOUR DIRECT TESTIMONY.

A. My direct testimony describes the Ocotillo Modernization Project (OMP) that was placed in service in May 2019. I address the importance of the Ocotillo Power Plant (Ocotillo or Plant) in providing reliable service to our customers, especially during peak periods, as well as its critical role to support the integration of additional renewable resources on our system. I discuss the history, purpose and economics of the project and explain the numerous benefits this project has for our customers. My testimony shows that the decision to modernize Ocotillo was prudent, in the best interests of customers, and reflects APS's commitment to a cleaner energy future going forward.

In addition, I will discuss the Company's Resource Comparison Proxy (RCP) rooftop solar export rate established in the Value of Solar[1] docket and our 2016 Rate Case,[2] and provide a methodology and estimate of the avoided costs of rooftop solar required by Decision No. 75859 (January 3, 2017). This RCP pricing is intended to provide a path to reduce and eventually eliminate the cost shift from customers with newly installed rooftop solar systems to our non-solar customers. While we are not proposing to use the avoided cost methodology at this time, in the interest of equity for solar as well as non-solar customers, it is important to stay on the path toward compensating rooftop solar exports at avoided cost. The use of the RCP with annual updates strikes a reasonable balance toward that goal for both solar and non-solar customers.

III. <u>OCOTILLO MODERNIZATION PROJECT</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE OCOTILLO POWER PLANT.

A. Ocotillo has been critical to providing reliable electric service to APS's customers since 1960, when two 110 MW gas-fired steam units were placed in service. In the early 1970s, two 55 MW combustion turbine (CT) units were added to the plant for a total of 330 MW. Ocotillo's location in Tempe, Arizona provides APS customers with much needed generation capacity inside the Phoenix area load pocket and it supports local transmission infrastructure. Its location makes it key to the reliable operation of the APS system. The plant is served by an El Paso Natural Gas pipeline.

---

[1] Docket No. E-00000J-14-0023.

[2] Docket No. E-01345A-16-0036, *et al.*

Figure 1.

Ocotillo Steam Units

Q. WHAT IS THE OCOTILLO MODERNIZATION PROJECT?

A. The OMP refers to a project to modernize Ocotillo by retiring 220 MW of nearly 60-year old steam units (shown in Figure 1 above) and replacing them with 510 MW of state-of-the-art, CT technology (shown in Figure 2 below). The project results in additional generation in the Phoenix load pocket that is both cleaner and more flexible than the old steam units. The new CTs are more efficient than the steam units. They have lower nitrogen oxides (NOx) and carbon monoxide (CO) emission rates, and they use less water per kWh.

Figure 2.

Ocotillo Modernization Project

Q. WHY DID APS NEED THE OMP?

A. There are a number of reasons the OMP was necessary. First, the old steam units had become difficult to repair and maintain. Second, the OMP offered a unique opportunity to add capacity at an important location within the Phoenix load pocket to support the local transmission system and provide necessary generation capacity to meet peak loads, especially in the summer months. Third, the project was necessary to support the integration of increased levels of renewable energy on APS's system, which enables a cleaner future for APS customers. Finally, the OMP provided a unique opportunity to gain additional and more efficient use of existing infrastructure. As explained below, the OMP was also the least cost, best fit solution for a cleaner future.

Q. CAN YOU EXPAND ON WHAT YOU MEAN BY OMP PRESENTING A UNIQUE OPPORTUNITY?

A. The Ocotillo site had existing natural gas pipeline, transmission, and water infrastructure. Utilizing this existing infrastructure allowed APS to meet the needs of its customers at a reduced cost compared to a new build site, providing economic benefits to APS's customers. Additionally, the plant's location in the Phoenix load pocket provides necessary reliability and transmission system benefits for customers.

Q. PLEASE DESCRIBE THE LOCATIONAL BENEFITS OF THE PLANT.

A. OMP provides voltage support for valley load, which is especially important when transmission outages result in a drop in voltage on the system. Having generation close to the load is beneficial because the voltage support declines rapidly as the generation is farther away from the voltage need.

Second, Ocotillo's location on the transmission system makes it important in maintaining Phoenix Area Maximum Load Serving Capability (MLSC). MLSC is the maximum load that can be served inside a load pocket with all local generation online at full output and the transmission imports at their limit. The Phoenix Area MLSC must be maintained at *greater than* maximum Phoenix Area load *plus* Phoenix Area planning reserves. Ocotillo's location aids in reducing the impact of key transmission line outages. Under the most impactful 500 kV line outage, OMP increases MLSC and provides important reliability benefits in a contingency situation.[3]

Q. CAN YOU EXPLAIN SOME OF THE OTHER BENEFITS OF THE OMP?

A. Yes. The additional generation capacity provided by the OMP is needed to meet growing customer needs. The CTs selected for the project also provide increased operational flexibility that is needed to manage APS's evolving load shape due to continuing additions of renewable energy, including rooftop solar. Specifically, these CTs are capable of multiple starts and stops each day and have fast-ramping capabilities. They start providing power to the grid within six minutes and can be at full capacity in less than ten minutes. The quick start feature is essential as more variable generation is added to the grid.

Q. ARE THERE ANY ENVIRONMENTAL BENEFITS TO THE OMP AND IF SO, CAN YOU EXPLAIN THOSE BENEFITS?

A. Yes. The new combustion turbines are more efficient than the steam units, have lower NOx and CO emission rates, and they use less water per kWh. Figure 3 below shows a comparison of the emission rates of OMP General Electric turbine model GE LMS100 units and the old steam units. The GE LMS100s employ Best Available Control Technology (BACT) to reduce emission of NOx by approximately 90% using Selective Catalytic Reduction (SCR), and reduce CO by

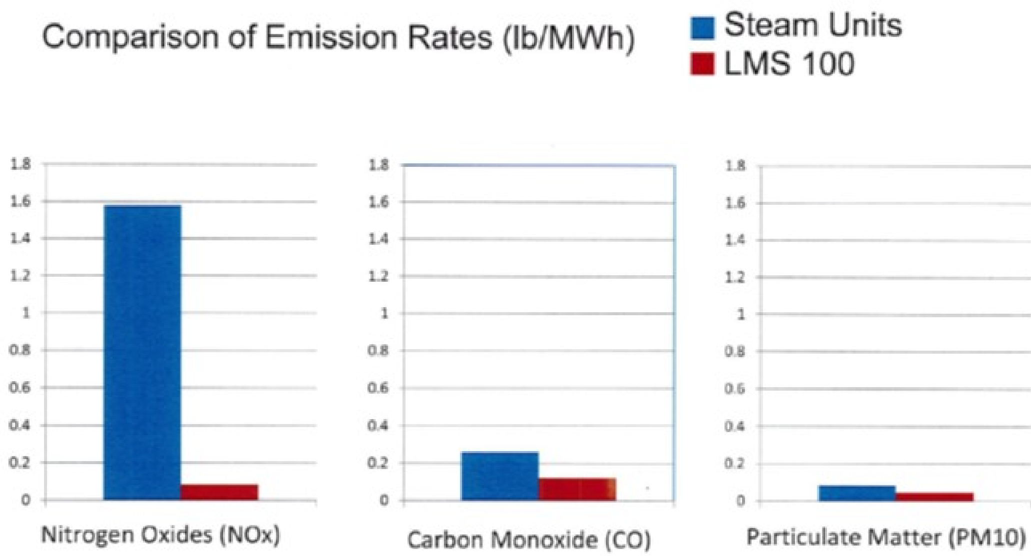
---

[3] *See* Application for Certificate of Environmental Compatability, Docket No. L-00000D-14-0292-00169.

approximately 90% and volatile organic compounds (VOC) by approximately 30% using an oxidation catalyst.

Figure 3.

Comparison of Emission Rates



Q. WHAT FACTORS DID APS TAKE INTO ACCOUNT WHEN CONSIDERING RETIREMENT OF THE OCOTILLO STEAM UNITS?

A. The generators at Ocotillo have long provided reliable power for APS customers, that is especially valuable because of their location in the Valley. Due to the age of the Ocotillo steam units (they were constructed in 1960 and were over 58 years old when they were retired in fall 2018), there were concerns of safety, obsolete equipment and availability. They were becoming increasingly difficult to maintain, and the availability of parts was becoming an issue. Because of these issues and Ocotillo's critical role in providing reliable power to the Valley, APS decided it was in the best interests of our customers to retire the existing units and replace them with modern technology.

Q. DID THE COMPANY ISSUE AN RFP RELATED TO THE OMP?

A. Yes. In January of 2015, APS issued a peaking RFP to assess whether the market could provide a better alternative than the OMP. APS received 27 proposals, including six self-build proposals developed by the APS team working on the OMP, as well as external bids for several other potential projects and technologies, including combustion turbines, batteries and reciprocating engines. The APS team was required under the procurement rules to independently bid into the RFP. The APS team submitting the bid, was walled off from the team that ran the RFP and assessed the bids. The entire RFP process was overseen by an Independent Monitor and followed the appropriate bid protocols for a self-build bid into the RFP. In addition, APS also did an RFP to select the Engineering, Procurement and Construction contractor.

Q. WHY WAS THE APS SELF-BUILD PROPOSAL SELECTED?

A. APS's proposal for GE LMS100 units with a 2019 Commercial Operation Date (COD) met the requirements of the RFP at the lowest cost.

Q. PLEASE DESCRIBE THE CONSTRUCTION TIMELINE AND BUDGET FOR THE PROJECT.

A. The budgeted cost of the project was $530,490,000 (direct cost plus overhead loads) with a target in-service date of spring 2019. Construction was planned to take approximately two and one-half years. Construction activities began in January of 2017, and the project was completed on schedule and on budget in May of 2019. The units were placed in service by May 30, 2019 and were available to meet 2019 summer peak loads. Project costs are not yet finalized, however, total cost for the project as of September 30, 2019 was approximately $524 million.[4]

[4] Direct cost plus overheads. Does not include Allowance for Funds Used During Construction (AFUDC).

Additional financial details and a pro forma containing the deferral amount are contained in the direct testimony of APS witness Elizabeth A. Blankenship.

Q. WHAT WAS DRIVING THE NEED FOR NEW GENERATING CAPACITY?

A. There were two drivers for new generating capacity—expiring existing purchase power agreements and customer load growth. The largest component was over 2,000 MW of expiring purchase power contracts.

Q. DID YOU CONSIDER REPLACING THE EXPIRING CONTRACTS WITH MARKET PURCHASES RATHER THAN REPLACING THEM WITH NEW NATURAL GAS GENERATION?

A. Yes. We always consider the market to fill our capacity and energy needs to determine if it is more economical for our customers. In this instance, there were no uncommitted existing units in the region that could provide the flexibility required to operate our system in light of the dramatic increases in solar generation.

Q. PLEASE EXPLAIN WHY APS NEEDS "FLEXIBLE" GENERATION.

A. Flexible generation is required to reliably serve our customers' changing load shape. APS's load is seasonally driven. It is characterized by very high loads in the summer months as customers use a large amount of electricity to run their air conditioners, and much lower loads in the shoulder months when the mild weather doesn't require much heating or cooling. Residential rooftop solar produces large amounts of energy during the middle of the day, which has the effect of reducing the amount of load to be served by APS in the middle of the day. In the spring and fall months, load rapidly increases later in the afternoon as customers use more energy and solar energy is declining. When APS was considering how to address the aging steam units, the amount of solar generation in our service territory and the region had started growing rapidly, and the trend was expected to continue. These circumstances gave rise to the developing duck curve that is well recognized throughout the industry. Given these circumstances, quick start capability and an ability to start and stop several times per day are important characteristics of flexible generation that help manage the duck curve.

Q. HOW MUCH GROWTH IN DISTRIBUTED SOLAR GENERATION HAS OCCURRED ON APS'S SYSTEM?

A. As of December 31, 2013, there were 361 MW of distributed solar generation (DG) on our system,[5] comprised of both residential and commercial systems. As of September 30, 2019, DG has grown to 992 MW.

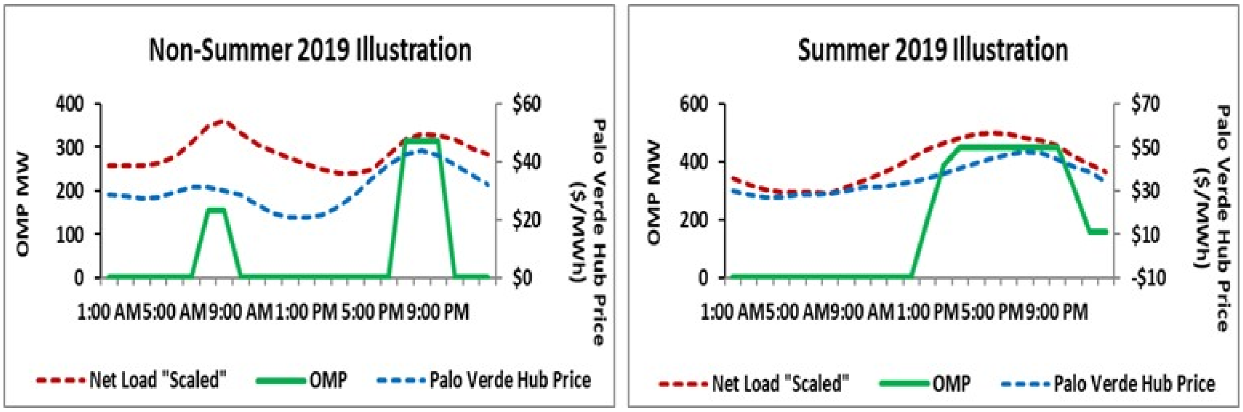
Q. WHY IS THE ABILITY TO START AND STOP OMP SEVERAL TIMES PER DAY IMPORTANT?

A. This is especially important in the non-summer months when we experience morning and evening peak loads, with low load in the middle of the day. That means that some units need to run in the morning, be taken off-line in the middle of the day, and then run again in the late afternoon. Figure 4 below illustrates how we anticipated flexible generation such as OMP may start and stop to meet morning and afternoon peaks in the non-summer months as well as how we anticipated they would be operated in the summer to meet afternoon peak loads.

[5] Values are reported as AC nameplate capacity ratings at the meter.

Figure 4.

Illustration of OMP Operation



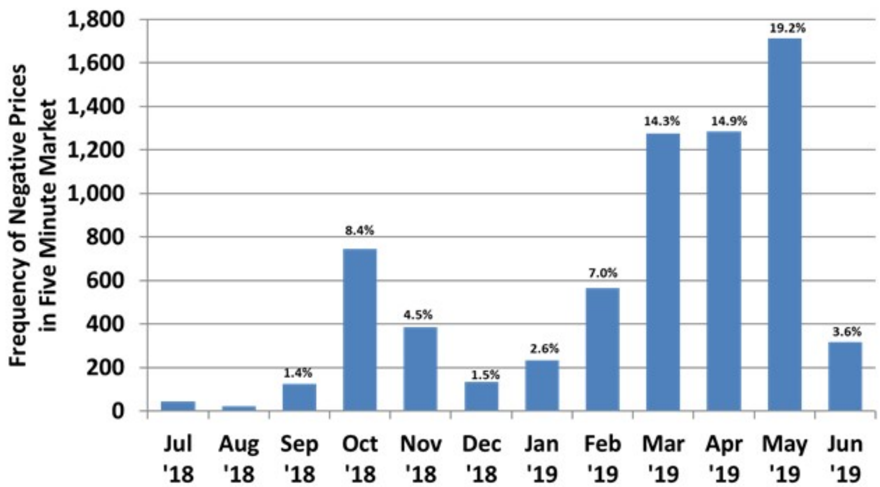
If units cannot be taken off-line during the middle of the day (due to limiting operating parameters, such as long minimum off-line times and start-up times), excess power, or overgeneration, may be created on our system that could need to be sold to the market, often times at negative prices. In addition, excess generation creates reliability risk when there are no takers for the power, even at negative prices. That means flexible units, such as the OMP, can easily be taken off-line in the middle of the day to help APS capture market opportunities that benefit our customers. In other words, flexible generation may be easily turned off to allow APS to be paid to take excess energy from other utilities, rather than to keep inflexible generation online and pay others to take our excess energy.

Q. HOW OFTEN DO THESE MARKET OPPORTUNITIES OCCUR?

A. Negative market pricing has become quite common in the non-summer months as shown in Figure 5 below. Overall, negative power prices occurred 6,840 times in the five-minute market at the Palo Verde hub during the Test Year. In the months from March 2019 through May 2019, prices were negative 14.3% to 19.2% of the time in the five-minute market. For the most part, negative prices occur in the middle of the day when solar resources are producing at high levels. We expect this trend to continue, and it will offer opportunities for flexible generation such as OMP to reduce our fuel and purchase power costs. These savings will flow directly to our customers through the Power Supply Adjustor (PSA).

Figure 5.

Frequency of Negative Market Prices at Palo Verde



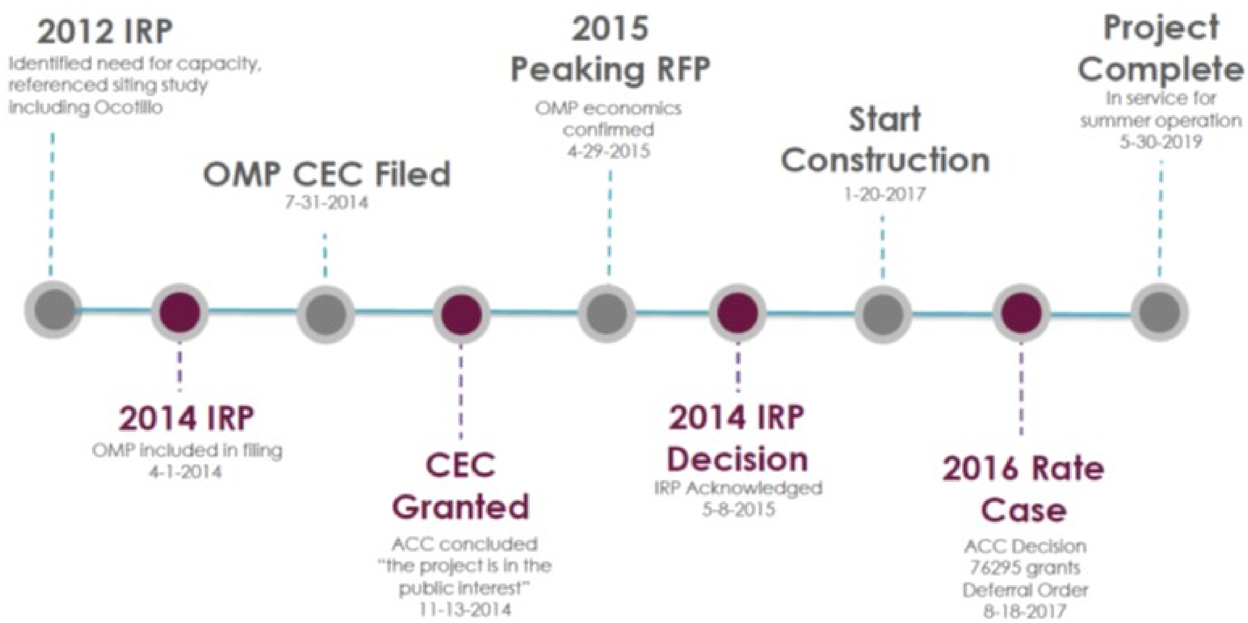
IV. REGULATORY REVIEW PROCESS AND PRUDENCE

Q. PLEASE DESCRIBE GENERALLY THE TIMELINE FOR THE OMP PROJECT AND HOW IT WAS ADDRESSED IN THE COMMISSION'S INTEGRATED RESOURCE PLAN AND LINE SITING PROCESSES.

A. Figure 6 below highlights the key filings and Commission decisions regarding the OMP.

Figure 6.

Key Filings and Commission Decisions



In 2011, APS first identified the need to address the aging Ocotillo steam units due to the risks they presented to plant safety, reliability and anticipated high levels of investment needed to keep the units operational going forward. APS spent much of 2011 and 2012 studying potential options and alternatives to meet these needs. At about the same time, through its IRP process, APS identified a need for additional peaking capacity generation in the 2018-19 timeframe. These issues were first raised in the Company's 2012 IRP and then were discussed extensively in APS's 2014 IRP that was acknowledged by the Commission in Decision No. 75068 (May 8, 2015). Decision No. 75068 states:

> Staff believes that the Ocotillo Modernization Project ("OMP") may offer a unique opportunity to add capacity at a strategic location within the Phoenix Load Pocket. In addition, existing Ocotillo site attributes such as the availability of water, natural gas, and transmission infrastructure support the redevelopment

> activities proposed in the OMP. Further, Staff recognizes that APS conducted a variety of economic feasibility studies which point to the economic viability of the OMP.

See Decision No. 75068 at 4-5.

In July of 2014, APS filed an application for a Certificate of Environmental Compatibility (CEC) with the Arizona Power Plant and Transmission Line Siting Committee. In November of 2014, the Commission unanimously approved the CEC. *See* Decision No. 74812 (Nov. 13, 2014). The Commission, in reaching its decision to grant the CEC:

> balanced all relevant matters in the broad public interest, including the need for an adequate, economical and reliable supply of electric power with the desire to minimize the effect thereof on the environment and ecology of this state, and finds that granting the Project a CEC is in the public interest.

See Decision No. 74812 at 1.

In APS's 2016 Rate Case, Commission authorized a Deferral Order for the project. The Commission ordered that APS

> is hereby authorized to defer, for possible later recovery through rates, all non-fuel costs (as defined herein to include all O&M, property taxes, depreciation, and a return at APS's embedded cost of debt in this proceeding) of owning, operating, and maintaining the Ocotillo Modernization Project and retiring the existing steam generation at Ocotillo. . . . The interest component of the deferral shall be set at the embedded cost of debt established in this Decision.

See Decision No. 76295 (Aug. 18, 2017) at 108.

Q. OMP WENT INTO OPERATION AT THE END OF MAY 2019. WAS THE PROJECT COMPLETED ON TIME AND ON BUDGET?

A. Yes.

Q. ARE THE NEW UNITS USED AND USEFUL?

A. Yes. The units are used and useful in a number of ways:

- All five units were placed in service by May 30, 2019. During this past summer period (June 1, 2019 through August 31, 2019), they were started 360 times and provided 232,000 MWHs to the grid at an average capacity factor of 20.6% for the benefit of APS customers. All five units were used to serve customers on the peak day of August 5, 2019.
- OMP was used to supply ancillary services to the system. The units were used to provide regulation and off-line reserves necessary to meet NERC reliability requirements. Because of their quick start capabilities, they were also used to help APS system reliability when other units experienced outages.[6]

Q. IS THERE ANY COMMISSION REGULATION THAT ADDRESSES THE PRUDENCE OF A UTILITY'S INVESTMENT IN PLANT TO SERVE THE PUBLIC?

A. Yes. A.A.C. R14-2-103(A)(3)(l) states that prudently invested means investments that are "reasonable and not dishonest or obviously wasteful."

Q. HOW IS IT DETERMINED WHETHER AN INVESTMENT IN ASSETS SUCH AS OMP IS PRUDENT?

A. Prudence is determined based on whether the decision to construct an asset was reasonable based upon the information that was known or reasonably could have been known at the time the decision was made. Such information includes demonstrating a need for the asset, consideration of alternatives, and evidence that the asset cost-effectively meets the identified need.

---

[6] NERC reliability standards require utilities to recover from unit trips within a fifteen-minute window.

Q. DOES THE OMP MEET THE REQUIREMENTS TO BE CONSIDERED A PRUDENT INVESTMENT?

A. Absolutely. As discussed throughout my testimony, the OMP was the least cost, best fit alternative to meet our customers' needs for additional, fast ramping, and flexible generation to meet load and support renewable integration.

V. <u>RESOURCE COMPARISON PROXY – RESIDENTIAL ROOFTOP SOLAR EXPORT RATE</u>

Q. WHAT IS THE RCP?

A. The RCP is one of two methodologies established by the Commission used to determine the value of, and the price paid, to residential rooftop solar customers for energy exported to the grid. It uses actual prices paid for utility-scale solar energy projects going into service in a historical five-year window, adjusted for losses and transmission and distribution savings, to determine the value of the residential rooftop solar exports. The rate is adjusted annually as new projects go into service and older projects fall off, and the new rate applies to solar customers filing new interconnection requests during a one-year period. Customers lock in for ten years the rate in effect when they applied for interconnection. The RCP rate for the next annual tranche of new rooftop solar customers may not be reduced by more than 10% from the previous year's value.

Q. WHAT IS THE AVOIDED COST METHODOLOGY?

A. Avoided cost is the other methodology established by the Commission to determine the value of residential rooftop solar energy exported to the grid. It is a forecast of costs the utility would have paid to serve load in the absence of the exported energy. It uses the same methodology that has been in existence for decades in PURPA filings or EPR-2 rate filings made with this Commission, with adjustments.

Q. WHAT IS THE PURPOSE OF HAVING TWO METHODOLOGIES?

A. Decision No. 75859 stipulated that the RCP methodology be initially used to set the rate to be paid to residential rooftop solar customers for energy exported to the grid. It also ordered the development of an avoided cost methodology with five-year forecasting, within a time frame that will allow its implementation to occur no later than December 31, 2019. Once the five-year avoided cost methodology is finalized, the Commission will have the flexibility to utilize either the avoided cost methodology or RCP methodology (or a combination of both) in setting a formula for the DG export rate in subsequently filed electric utility rate cases for use in annual updates to the export rate.[7]

VI. RCP RATES AND PROPOSED AVOIDED COST RATES

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR CURRENT RCP RATE.

A. The current RCP rate rider was approved in Decision No. 77421 (Sept. 13, 2019) and applies to customers who submit interconnection requests between October 1, 2019 and August 31, 2020. It is based on four solar projects that went into service during the five-year historical period of 2014 to 2018. Those projects have a levelized cost of $0.06869/kWh including an adjustment for line losses. According to Decision No. 75859, however, the RCP rate rider cannot be reduced by more than 10% below the previous year's value, which in this case, and in every case since the RCP's inception, is the limiting factor. Since the rate for the 2018 tranche was $0.11610/kWh, and the calculated RCP rate for 2019 has declined by more than 10%, the rate for the 2019 tranche is capped at a 10% reduction, or $0.10450/kWh.

[7] Decision No. 75859 at 177.

Q. HAS THE AVOIDED COST METHODOLOGY BEEN FINALIZED?

A. No. The Commission ordered that it be developed within a timeframe that would allow its implementation to occur no later than December 31, 2019.[8] Therefore, APS is developing an avoided cost methodology in accordance with the principles outlined in Decision No. 75859 and is asking the Commission to approve the methodology for potential use in future APS rate cases.

Q. WHAT ARE THE KEY AVOIDED COST PRINCIPLES OUTLINED IN DECISION NO. 75859?

A. Several key principles are as follows:[9]

- Utilize a five-year forecast of avoided costs;
- Avoided costs include energy savings;
- Utilize an Effective Load Carrying Capability (ELCC) assessment to identify and analyze the costs and capacity savings from generation, transmission and distribution resulting from rooftop solar exports; and
- Include the impact of generation, transmission and distribution losses.

Q. HOW DOES APS PROPOSE TO IMPLEMENT THE COMMISSION'S PRINCIPLES IN AVOIDED COST METHODOLOGY?

A. Attachment BJA-1DR contains the information and calculations required to determine the avoided costs for residential solar export energy. APS developed avoided costs for the five-year period 2020 to 2024, based on the most current information available. Historical information is from the Test Year while projected information is that which is currently being prepared for the Company's 2020 IRP filing.

---

[8] *Id*.

[9] *Id*. at 147-152.

Q. HOW DID YOU CALCULATE THE AVOIDED ENERGY COSTS?

A. Avoided energy costs are calculated using the same production cost models and techniques utilized in the resource planning process and in the Company's PURPA avoided cost and EPR-2 filings. The basic idea is to estimate what production sources (and associated costs) would be displaced by the rooftop solar export energy. Avoided energy costs are grossed up based on the Company's line loss study conducted as part of the cost of service study filed in this rate case.

Q. PLEASE DESCRIBE THE ELCC METHODOLOGY USED TO IDENTIFY AND ANALYZE CAPACITY SAVINGS.

A. Capacity savings for generation, transmission and distribution are determined using ELCC methodology along with the cost of facilities that may be deferred, if any. ELCC is a probabilistic Loss of Load Probability (LOLP) approach that determines the ability of all resources – including variable resources such as wind and solar up to fully dispatchable and available generation (subject to forced outages) – to meet peak load requirements and their contribution to system reliability. APS uses a "top 90 hours proxy" to approximate the ELCC value.

Q. HOW DO YOU INCLUDE THE IMPACT OF LOSSES?

A. Avoided capacity costs are grossed up based on the Company's line loss study conducted as part of the cost of service study filed in this rate case.

Q. WHAT IS THE VALUE OF THE AVOIDED COST RATE AND HOW DOES IT COMPARE TO THE CURRENT RCP RATE RIDER?

A. Based on the above methodology and current information, the avoided cost rate is \$0.02254/kWh. With the RCP rate rider for the 2019 tranche at \$0.10450/kWh, the RCP rate rider exceeds the avoided cost by \$0.08196/kWh.

Q. HOW SHOULD THE AVOIDED COST BE USED?

A. We believe that the avoided cost methodology proposed herein is sound and consistent with Commission direction, and that the methodology should be approved to provide information sought by the Commission in future rate cases. The Commission should continue to close the gap between the export rate paid to rooftop solar customers and the avoided cost. At this time, continued use of the RCP with annual updates stays on the path of closing the gap between rates paid to residential rooftop solar customers for their export energy and the avoided cost.

Q. DOES THIS END YOUR WRITTEN DIRECT TESTIMONY?

A. Yes.

Rooftop Solar Export Energy Avoided Cost Calculation

Line			2020	2021	2022	2023	2024	Comments
	Rooftop Solar Additions							
1	MW_{AC}		86	150	189	232	276	Forecast
2	MWH		166,940	290,632	367,836	449,533	535,654	Forecast
3	Exports MWH	57.30%	95,655	166,529	210,765	257,577	306,923	Test Year export % * line 2
	Generation Capacity Value							
4	ELCC Per Cent		6.0%	5.7%	5.6%	4.9%	4.8%	Based on net load forecast
5	MW (Customer) [4*1]		5.2	8.6	10.6	11.3	13.4	
6	Losses (%)		6.42%	6.42%	6.42%	6.42%	6.42%	G & T capacity losses from energy losses study filed in last rate cast
7	MW (System) [5/(1-6)]		5.5	9.1	11.3	12.1	14.3	
8	Avoided Cost ($/kW-yr)		52.5	63.4	64.9	83.1	85.1	Avoided generation cost consistent with PURPA
9	Avoided Cost ($millions) [7 * 8 / 1000]		0.3	0.6	0.7	1.0	1.2	
	Transmission Capacity Value							
10	ELCC Per Cent		6.0%	5.7%	5.6%	4.9%	4.8%	Same as Generation Capacity Value at this time
11	MW (Customer) [10*1]		5.2	8.6	10.6	11.3	13.4	
12	Losses (%)		6.42%	6.42%	6.42%	6.42%	6.42%	Same as Generation Capacity Losses at this time
13	MW (System) [11/(1-12)]		5.5	9.1	11.3	12.1	14.3	
14	Avoided Cost ($/kW-yr)		-	-	-	-	-	No transmission can be deferred per 2019 BTA.
15	Avoided Cost ($millions) [13 * 14 / 1000]		-	-	-	-	-	
	Distribution Capacity Value							
16	ELCC Per Cent		7.6%	7.2%	7.3%	6.5%	6.7%	ELCC based on system load (not net load)
17	MW (Customer) [16*1]		6.5	10.7	13.9	15.0	18.6	
18	Losses (%)		0.35%	0.35%	0.35%	0.35%	0.35%	Substation losses only.
19	MW (Generation) [17/(1-18)]		6.5	10.8	13.9	15.1	18.7	
20	Avoided Cost ($/kW-yr)		-	-	-	-	-	APS has not identified any distribution deferrals at this time[1].
21	Avoided Cost ($millions) [19 * 20 / 1000]		-	-	-	-	-	
	Avoided Capacity Cost							
22	G+T+D Total (Millions) [9 + 15 + 21]		0.3	0.6	0.7	1.0	1.2	
	Avoided Energy							
23	Losses (%)		3.32%	3.32%	3.32%	3.32%	3.32%	G & T energy losses from energy losses study filed in last rate cast
24	Energy (MWH System) [3/(1-23)]		98,939	172,247	218,003	266,423	317,463	
25	Avoided Cost ($/MWH)		17.92	16.64	18.06	18.45	19.47	Based on production cost simulations consistent with PURPA
26	Millions [24*25/1000000]		1.8	2.9	3.9	4.9	6.2	
27	Metering and Customer Costs		-	-	-	-	-	Negative value, not included at this time[2].
	Total Avoided Cost							
28	$Millions [22+26]		2.1	3.4	4.7	5.9	7.4	
29	$/kWh (Customer) [28*1000/3]		$ 0.02155	$ 0.02070	$ 0.02216	$ 0.02298	$ 0.02411	
30	5 Year Levelized $/kWh	0.02254						NPV Line 29 * 1,000 / NPV Line 3
	Discount Rate	7.50%						After tax weighted cost of capital used in IRP

Notes: (1) Avoided transmission costs are very feeder specific. It may be possible to defer an upgrade for a year, however this may be offset by mitigation costs due to high penetration feeders backflowing energy into the system.

(2) Customer costs are estimated to be $0.01508/kWh, and if included in the avoided cost formula would reduce the five year levelized cost to $0.00746/kWh.