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Testimony of Seth Schwartz
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House Subcommittee on Energy and Mineral Resources
Hearing on "The Benefits of the Navajo Generating Station to Local Economies"
April 12, 2018

Introduction

My name is Seth Schwartz. I am the President of Energy Ventures Analysis, Inc. ("EVA"). EVA is a consulting firm which specializes in the analysis of energy markets in North America. We regularly perform analyses of electric power, natural gas, coal, petroleum and emission allowance markets, including forecasts of supply, demand and prices. We have published long-term forecasts of these energy markets in an annual report, called FUELCAST, for over 25 years. EVA prepares forecasts of future electric power markets based upon commercially-accepted modeling used in the industry by power companies and other professionals.

EVA has been in business since 1981 and I have been President since 2008. EVA provides analyses of energy markets for a wide variety of participants and interested parties. Our clients include Federal agencies (Department of Energy, Environmental Protection Agency, Department of Interior), energy regulatory agencies (such as public utility commissions), energy producers (electric power, coal, oil & gas), energy transporters (railroads, pipelines, barge companies), energy consumers (industry, consumer advocates), electric power reliability councils, investors, and lenders. EVA is committed to independent analyses on the energy markets, based on sound data, science, and economics.

EVA was retained by Peabody Energy to provide analysis of the economics of the Navajo Generating Station ("NGS"), including the costs and benefits to the Central Arizona Water Conservation District ("CAWCD") and its customers. EVA has previously published a report titled "Economic Benefit Analysis of the Navajo Generating Station to the Central Arizona Water District and its Customers in January 2018. In our analysis, EVA has relied upon publicly-available data and its proprietary modeling. EVA is committed to transparency in its analysis and makes our sources of data and calculations available for others to examine our work.

Summary and Conclusions

EVA has reached the following conclusions in its analysis:

- The Navajo Generating Station ("NGS") was sanctioned by the U.S. Congress in the late 1960s to provide a stable, long-term power source for the Central Arizona Project ("CAP") and bring jobs and revenues to tribal communities in northern Arizona. CAP is a massive federal infrastructure project developed to move water across the central and southern parts of the state to sustain and grow the economy.

- Power from NGS pumps CAP water uphill through a complex system of canals that deliver the state's share of Colorado River water to metropolitan areas including Phoenix, Casa Grande and Tucson. The CAP spans over 335 miles and is the state's largest power user.
- In 1968, President Lyndon Johnson authorized construction of the CAP, and the following year, the U.S. Secretary of the Interior determined that the most economical plan to supply the electric power needed for the CAP was by building a thermal power plant on tribal lands using tribally-owned coal. In 1971, the Central Arizona Water Conservation District ("CAWCD") was formed to manage the CAP and to create one single entity to pay back the federal loan to the U.S. Bureau of Reclamation ("BOR"). In 1974, the first NGS unit came online.
- For decades, NGS has been one of the most economic electric generating resources in the Desert Southwest Power Pool ("DSW"), delivering enormous savings to the CAWCD. By purchasing electricity from NGS rather than on the open market, EVA estimates that CAWCD has saved almost $900 million over the 16-year period ending in 2016, or approximately $50 million each year.
- EVA projects that continued operation of NGS will yield an additional $370 million in cost savings to CAWCD if it continues to purchase electricity from NGS through 2030.
- The competitiveness of NGS has kept CAP water rates to municipal and industrial (M&I) customers as much as 45 percent lower than if CAWCD had purchased its power on the open market over the last 16 years. According to EVA's analysis, water rates to CAWCD's M&I customers would increase by more than 30 percent on average over the next ten years, should NGS close at the end of 2019.
- The CAP "2016 Case Study" (which represented that CAP would have saved $26.5 million dollars in 2016 had NGS been closed and that these savings would be representative of the future) was not a reasonable comparison of the economics of the alternatives of operating NGS vs. closing.
    - First, 2016 was a year with very low power and natural gas prices and is not representative of future power markets;
    - Second, CAP compared firm power supply from NGS with non-firm spot market purchases;
    - Third, CAP's recent soliction for new firm power supplies to replace NGS shows that the cost of replacement power will not be lower-cost than NGS.
- The closure of NGS will deprive CAP of its primary source of revenues (over $20 million annually) to repay the federal obligation of approximately $1.1 billion. Without the revenues from the sale of surplus power from NGS, CAP will have to increase water prices to its customers to repay the federal government.

Response to CAP "2016 Case Study" of NGS Impact on CAP Costs

In February 2017, CAP published a summary analysis of 2016 costs and benefits of NGS to CAP during the calendar year 2016. CAP concluded that "If NGS been closed as of January 1, 2016 and CAP purchased replacement energy at prevailing market prices, the net impact would have been" a net savings of $26.5 million to CAP. The CAP "Case Study" further asserted "Because cost of generation at NGS is expected to remain higher than market for a number of years, the net impacts to CAP identified in the 2016 Case Study should be representative of impacts going forward."

EVA has reviewed CAP financial records and independent data on the power markets and NGS operating costs and disagrees with the CAP analysis and its conclusions, based upon the following:

- The calendar year 2016 was highly unusual in electric power and natural gas markets. Market prices for natural gas and electric power in 2016 were much lower than in prior years. There is no reason to believe that 2016 was representative of the future as asserted by CAP.
- CAP's own Biennial Budget, prepared in November 2017, shows that CAP does not expect the 2016 NGS costs and power market purchases to be representative of future years.

- The comparison of the cost of firm power capacity from NGS with spot market power prices is an "apples-and-oranges" comparison by CAP. Wholesale spot power market prices are not reliable or stable. No power system, including CAP, would rely solely on spot market purchases to supply its load. While in one low-priced year like 2016, this may appear to provide a savings, such a strategy risks not having power (and thus water) at all. Firm power supply is, and will be, more expensive than the 2016 spot power market.

The primary reasons why Desert Southwest power market prices were much lower than normal in 2016 were the combination of unusually low natural gas prices due to extremely mild winter weather and unusually high generation from hydroelectric power in the West. Neither of these factors are representative of likely future power markets.

The extremely low price of natural gas in 2016 is shown on Exhibit 1. The cause of these low natural gas prices was the mild winter weather of 2015/16, which was the 2nd-warmest winter on record in the 123 years monitored by the National Oceanic and Atmospheric Administration ("NOAA").[1] The mild winter weather caused low demand for natural gas for residential and commercial heating and the gas surplus drove 2016 gas prices down to the lowest level since 1995. Natural gas prices have a direct influence on electric power prices in the DSW region, due to the high dependence on natural gas for power generation. Natural gas prices have been well above the 2016 level and are not representative of future prices.

EXHIBIT 1: NATURAL GAS MARKET PRICES AT HENRY HUB $ PER MILLION BTU[2]

The sales of surplus energy from NGS provide CAWCD with most of the funds used to repay the federal obligation. Most of the revenues come from the sale of power to Salt River Project ("SRP") under a long-term contract, net sales of surplus power at market prices (power market revenues less average NGS costs), plus other NGS revenues for reliability payments. The historical actual net revenues from NGS surplus power sales are shown on Exhibit 2, from CAP documents. While the actual net revenues in 2016 were very low, due to low power market prices, the historical and projected net revenues from NGS show that CAP itself expects that NGS will generate substantially greater revenues in the future than in 2016.

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1 www.ncdc.noaa.gov/temp-and-precip/climatological-rankings/

2 http://www.eia.gov/dnav/ng/ng_pri_fut_s1_w.htm

EXHIBIT 2: ANNUAL REPAYMENT OBLIGATION REVENUES FROM NGS ($ MILLION)[3]

	2015 Actual	2016 Actual	2017 Actual	2018 Budget	2019 Budget
SRP contract revenues	$ 27.12	$ 27.59	$ 28.77	$ 29.30	$ 30.10
Net surplus power sales	(10.80)	(17.03)	(9.08)	(6.70)	(6.80)
Other NGS revenues	0.22	0.42	0.50	0.20	0.20
	$ 16.55	**$ 10.98**	**$ 20.20**	**$ 22.80**	**$ 23.50**

The projected costs to operate NGS do not consider cost savings proposed for future operation of NGS, including the reduced cost of coal proposed by Peabody Energy.

The Results of CAP's Power Supply Solicitation Shows NGS Can Be Economic for CAP

In November 2017, CAP solicited offers for power supply to replace NGS power supply beginning January 2020. CAP has provided a summary of the solicitation results in a presentation at its meeting on March 15, 2018.[4] CAP adopted as a strategic goal that it would "hedge" (i.e., contract for) 75% to 90% of CAP's base load energy needs prior to the delivery year, but hedge only 40% of its variable load prior to the delivery year. CAP's baseload energy requirements are 125 MW of capacity and 1,000 GWh of energy during a calendar year.

CAP summarized the offers which it received into 5 alternative portfolios. In 4 of these portfolios, the primary source of baseload capacity was a 5-year power purchase agreement ("PPA") from an Arizona utility fleet, with a range of 25 MW to 50 MW of firm capacity (the 5th alternative relied upon a PPA for solar power "firmed" with battery storage or gas-fired power). In addition, CAP proposes to contract for non-firm solar PPAs for 30 MW of capacity. Despite the stated goal of hedging 75% - 90% of the baseload energy needs, these alternatives would only hedge 27% - 47% of CAP's baseload energy.[5]

Even at this low level of firm capacity purchases, the cost of power to CAP under any alternative would be nowhere near as low as its power market purchases were in 2016, which shows that the "2016 Case Study" was not representative of the future savings to CAP if NGS were closed. The average power cost to hedge only less than half of the CAP baseload energy needs was $34.24 - $44.37 per MWh. The hedge from the utility PPA would only last for 5 years. In contrast, the actual full cost of power from NGS in 2017 was $35.12 per MWh, prior to the large credit earned from the sale of NGS surplus power to SRP.[6] Had CAP tried to replace its full baseload energy needs under comparable long-term PPAs, the cost would have been much higher than the cost of power from NGS, prior to any cost savings at NGS in the future.

The Benefits of a Reliable Baseload Coal-Fired Power Plant to CAP and its Customers

CAP has not provided the underlying data and documentation upon which it reached its conclusions in the "2016 Case Study". It appears that CAP has used power market prices which reflect the advantage

[3] Sources: 2015 – 2017 Actual from CAP 3rd Quarter 2017 Financial Review; 2018 – 2019 Budget from CAP Biennial Budget, November 2017.

[4] CAP, FAP Agenda Number 6, March 15, 2018.

[5] CAP assessed its minimum baseload to be 100 MW in the summer and assumed that the non-firm solar would be a firm power supply in the summer, so that the combination of a utility PPA for 35 MW, plus 30 MW of solar, plus 25 MW from Hoover dam would provide 90 MW of firm power (90% of baseload) at the time of summer peak power prices.

[6] 2015 – 2017 Actual from CAP 3rd Quarter 2017 Financial Review, page 32.

which it has by having NGS available to dispatch when its variable costs are below wholesale power market prices.

While NGS has large annual fixed costs, its variable costs to operate (known as "dispatch") are primarily the cost of coal. The cost of coal is based upon actual production costs and is stable. The cost of power generation at NGS can be predicted reliably and is not subject to Variations in energy market prices.

In contrast, the market price for wholesale power is highly volatile. The power market price varies during the day (afternoon prices are much higher than overnight prices), during the week (weekday prices are higher than weekend prices), and by season (summer and winter prices are higher than spring and fall). The reason for these large swings in power prices is that power demand varies widely over these time periods. Also, power market prices are volatile due to the availability of large power sources with low dispatch costs (hydroelectric and nuclear). For example, when hydroelectric power generation is high (due to snowpack), power prices are much lower, but during drought conditions, prices are higher.

Finally, the primary cause of power price volatility is the dependence on natural gas for power generation. As shown on Exhibit 1, natural gas prices are highly volatile and are heavily dependent upon winter weather. While natural gas prices are low when winters are mild, they can be very high when winters are colder than normal, as happened in 2014. The wholesale power market price is dependent upon factors completely outside the control of CAP and other market participants in the DSW power region. Cold winters in the Northeast will cause power prices to spike in Arizona.

NGS can be dispatched at high levels when power market prices are high and its dispatch can be reduced to minimum levels when power market prices are low. This ability to dispatch makes NGS a valuable "hedge" against future natural gas prices. If natural gas prices are high, CAP can increase dispatch of NGS and supply power at lower cost; while if natural gas prices are low, CAP can reduce operation of NGS and purchase spot power on the open market. The reliable capacity supplied by NGS gives CAP the ability to take advantage of purchased power when spot prices are low.

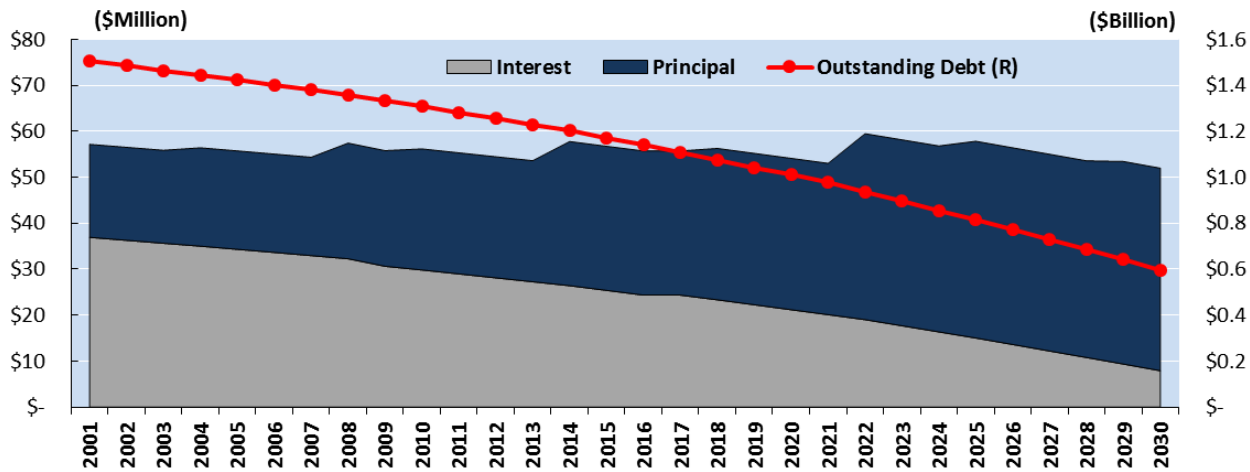
The heavy and increasing reliance of power supply in the DSW region increases the risk of power supply interruptions and high power prices. The California electricity crisis in 2001 occurred because of the confluence of low hydroelectric power generation I the West and cold winter weather which drove shortages of natural gas and high prices. These events can occur again in the future. The continued operation of NGS provides CAP with a reliable source of baseload power unaffected by such events outside of CAP's control.

CAWCD Financial Obligation to the U.S. Bureau of Reclamation

Debt Repayment

In 1971, at the request of the U.S. Secretary of the Interior, CAWCD was created to manage the CAP and to provide a single entity to repay the federal government for the reimbursable costs of construction and contract for the delivery of CAWCD water. By far the most significant cost items were the construction and operation of NGS and the CAWCD water pumping system from the Colorado River. The initial total CAWCD Repayment Obligation was settled at $1.6 billion. CAWCD's remaining repayment obligation to the Bureau of Reclamation from 2017 through 2044 is $1.1 billion. The debt repayment schedule from 2008 until 2030 is shown in Exhibit 3.

EXHIBIT 3: CAWCD DEBT REPAYMENT SCHEDULE TO THE U.S. BOR



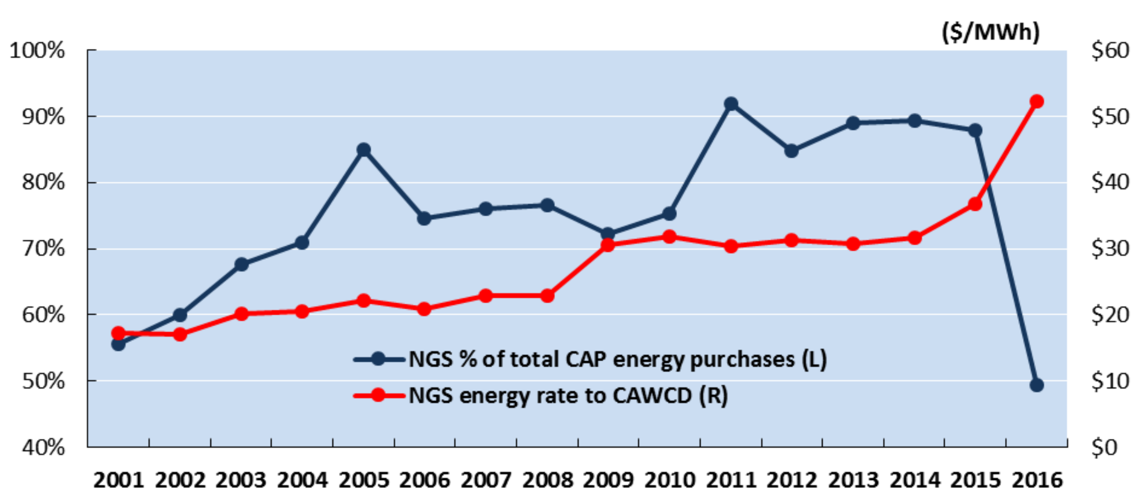
Source: CAWCD annual budget

Operation and Maintenance of Navajo Generating Station

The BOR charges CAWCD the full fixed cost for operating and maintaining the BOR's share of NGS annually, regardless of the amount of energy purchased for water pumping needs. Therefore, the energy rates for NGS to CAWCD consist of ~24 percent of NGS's fixed costs plus the variable cost (fuel and consumables) of power generation for the amount purchased by CAWCD for pumping needs. As a result, CAWCD's power rates for electricity bought from NGS are inversely related to the amount of energy purchased.

As shown in Exhibit 4, the amount of electricity that CAWCD purchased from NGS, as well as the power rate, were roughly flat between 2007 and 2015. In 2016, as CAWCD energy purchases from NGS dropped from 88 percent in 2015 to 49 percent in 2016, the corresponding power rate spiked 42 percent, from $37/MWh to more than $52/MWh, due to the inclusion of NGS's fixed costs. Therefore, the more energy CAWCD purchases from NGS to cover their energy needs to pump the water, the more economic NGS becomes.

EXHIBIT 4: CAWCD'S HISTORICAL NGS PURCHASES AND ENERGY RATE

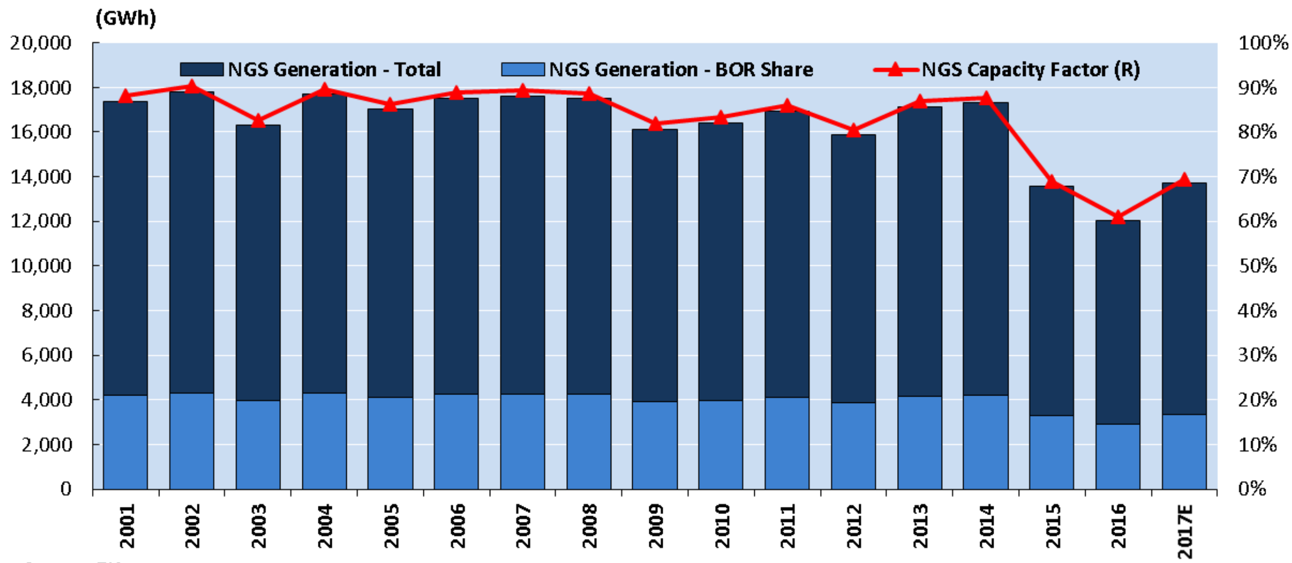


Source: CAWCD annual budgets

Historical Cost & Performance of NGS and its Benefit to CAWCD

For decades, NGS has been one of the most economic electric generating resources in the Desert Southwest Power Pool (DSW). Over the last 16 years, NGS's capacity utilization rate has averaged just under 85 percent, as shown in Exhibit 5, which compares to the DSW fleet capacity factor of 75 percent.

EXHIBIT 5: HISTORICAL PERFORMANCE OF NAVAJO GENERATING STATION

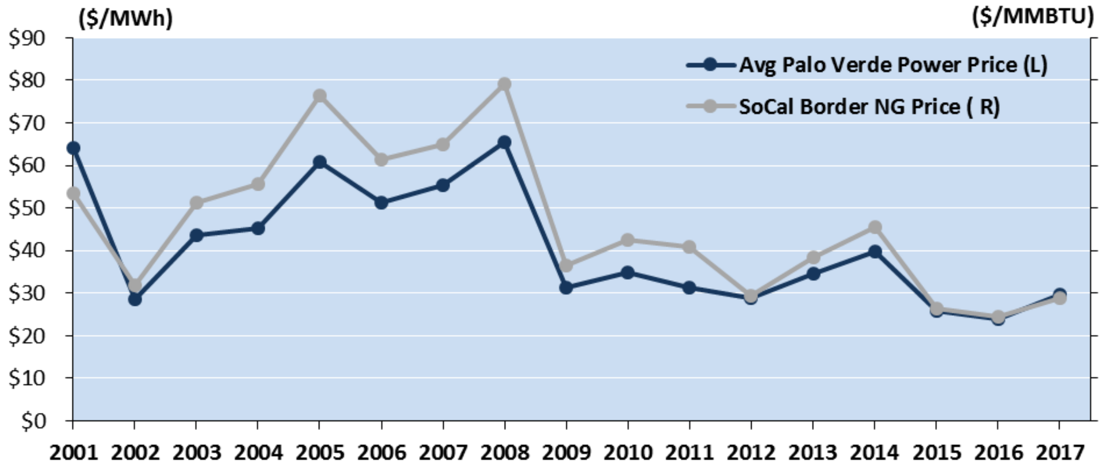


Source: EIA

The plant's high capacity utilization rate indicates that NGS is the most economical option for the CAWCD and the other plant utility owners. Even when power prices (and CAWCD energy purchases from NGS) dropped to historically low levels in 2016, NGS's capacity factor remained well above 60 percent and will likely rebound to 70 percent this year.

The primary driver of CAWCD's decision to increase its energy purchases from the open market in 2016 at the expense of NGS was the decline in wholesale power prices driven by lower natural gas prices. Exhibit 6 shows annual average power prices for the past sixteen years at the Palo Verde hub, the most liquid trading point in the region, as well as regional natural gas prices. The chart shows how annual power prices have declined from a high of $64/MWh in 2001 to a low of $24/MWh in 2016, following the same trend as natural gas. During this time, the cost CAWCD paid to NGS for electricity drifted upward from less than $20/MWh in 2001 to $32/MWh in 2014 before jumping sharply to $52/MWh in 2016, though this number is inflated due to much-reduced energy purchases from the plant.

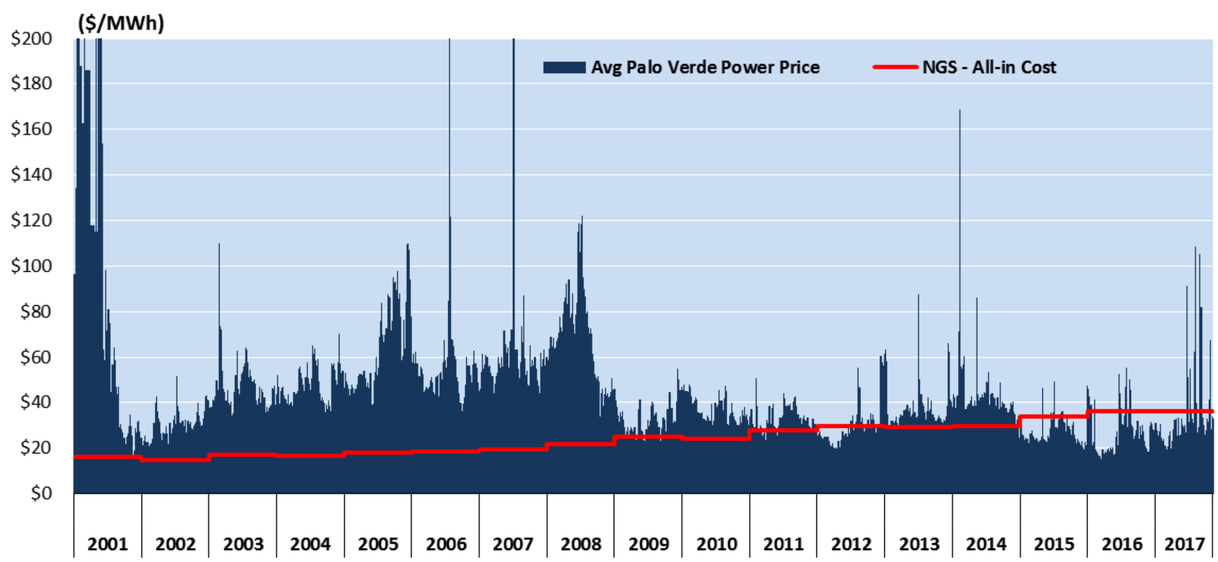
EXHIBIT 6: HISTORICAL PALO VERDE AND SOCAL BORDER PRICES



Source: EIA

Exhibit 7 contains historical daily prices for the last decade at the Palo Verde hub alongside historical prices for NGS. The data indicate that between 2001 and 2017, daily average prices at Palo Verde were more expensive than the cost to dispatch NGS on 3,519 days, or 86.3 percent of the time (note that only trading days are being considered - ~66 percent of total number of days).

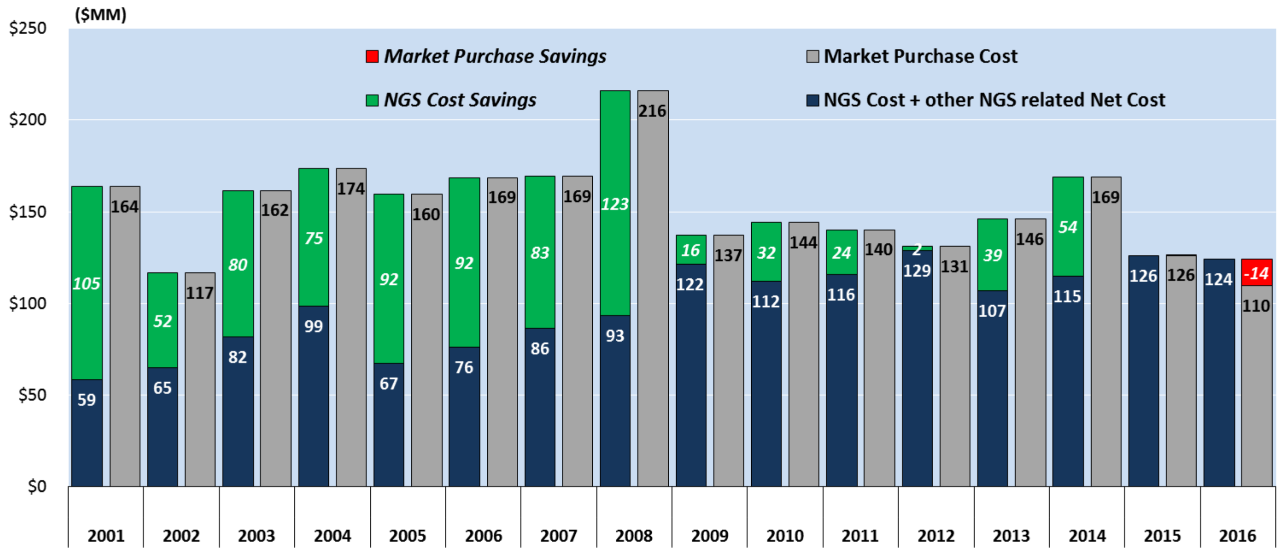
EXHIBIT 7: HISTORICAL COMPARISON OF DAILY PALO VERDE PRICE AND NGS COST



Sources: ICE, EIA & FERC data

In addition to the energy cost savings that CAWCD realized by purchasing from NGS, it also received a benefit from incremental revenues earned through selling surplus power from NGS into the open market. These revenues help offset the debt repayment that CAWCD makes to the U.S. Bureau of Reclamation and further improve the economics of NGS as an option. Exhibit 8 shows the total cost to the CAWCD for its energy needs for pumping water and its debt repayment to the BOR, with and without the cumulative benefits of NGS.

EXHIBIT 8: TOTAL COST TO CAWCD FOR PUMPING WATER AND DEBT REPAYMENT



Note: NGS related Net Costs include revenues from selling surplus energy,shaping and displacement revenues, among others *Source: EVA Analysis*

As shown in Exhibit 8, CAWCD has saved an average of more than $50 million per year over the last sixteen years (2001-2016) by purchasing most of their energy needs from NGS, while also taking advantage of other NGS-related revenue streams. Due to historically low wholesale power prices and CAWCD's decision to only purchase 49 percent of its energy needs from NGS, 2016 marks the only year in which CAWCD would have saved money by satisfying all of its energy requirements through the regional electricity market rather than through NGS.

CAWCD has saved almost $900 million over the last sixteen years by purchasing electricity from NGS instead of from the open market. Due to recent changes in market conditions and CAWCD's decision to buy only 49 percent of their energy needs from NGS, cumulative savings have flattened. However, with natural gas prices increasing, CAWCD will continue to save money by purchasing electricity from NGS instead of from the open market.

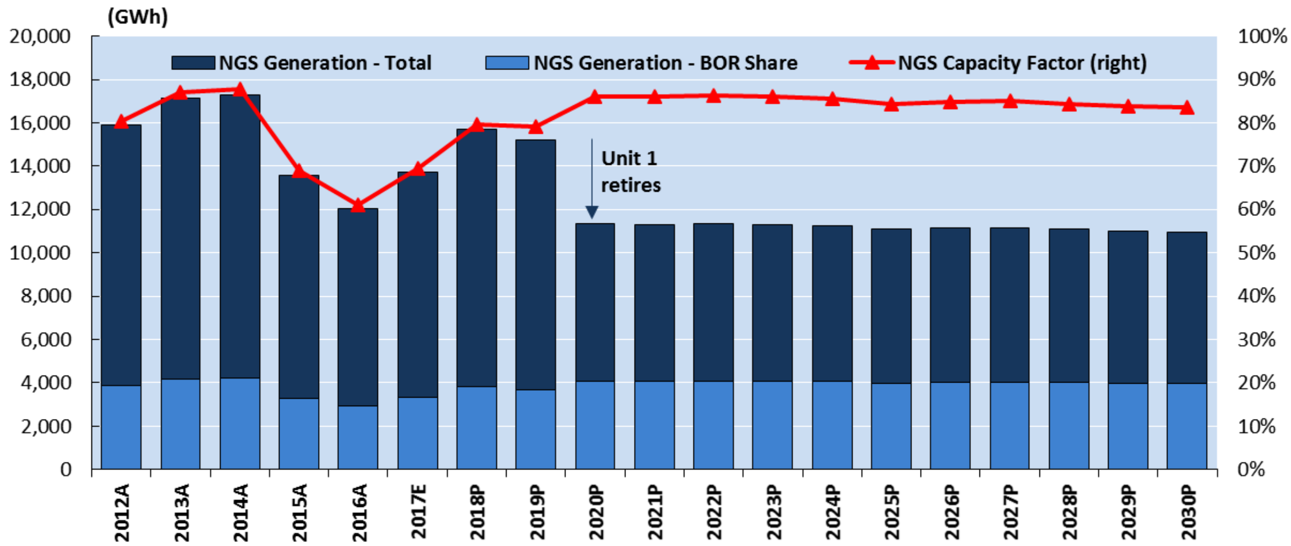
Current Versus Future Market Conditions Affecting NGS

Based on EVA's expectations for future market conditions in DSW, 2016 will remain the low point regarding the utilization rate of NGS going forward. EVA's forecast for plant utilization is shown in Exhibit 9.

Assuming the scenario with the retirement of NGS unit 1 at the end of 2019, total plant generation will drop by 25 percent.[7] However, with increasing natural gas prices, NGS's capacity factor will quickly return to historical levels and remain in the low- to mid-80 percent range throughout the forecast period. Because the plant uses locally sourced coal from the nearby Kayenta Mine, it has consistently been and will continue to be one of the lowest-cost and most competitive resources in the DSW region.

[7] While the retirement of unit 1 at the end of has been announced, this decision could change under a new plant owner.

EXHIBIT 9: NGS HISTORICAL AND FORECASTED OPERATION PROFILE

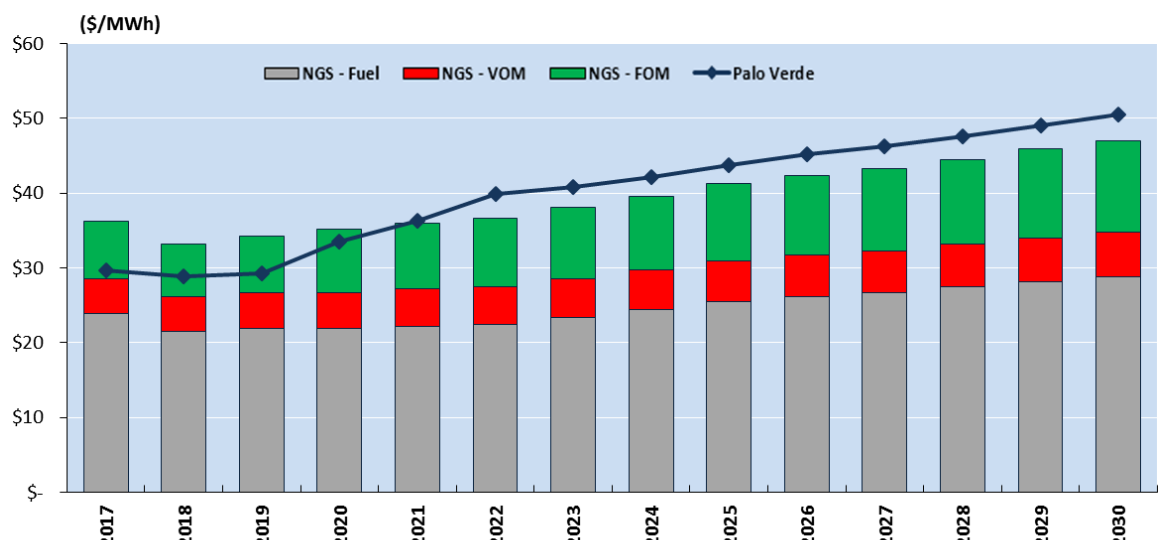


Source: EIA, EVA

EVA's commodity price forecasts for DSW indicate that the market conditions that drove power prices to historic-lows in 2016 will not continue. EVA forecasts power market operations using Aurora, an hourly electric dispatch model that incorporates fuel prices, electricity demand, and existing electric supply to project plant-level performance and wholesale power prices, among other things.

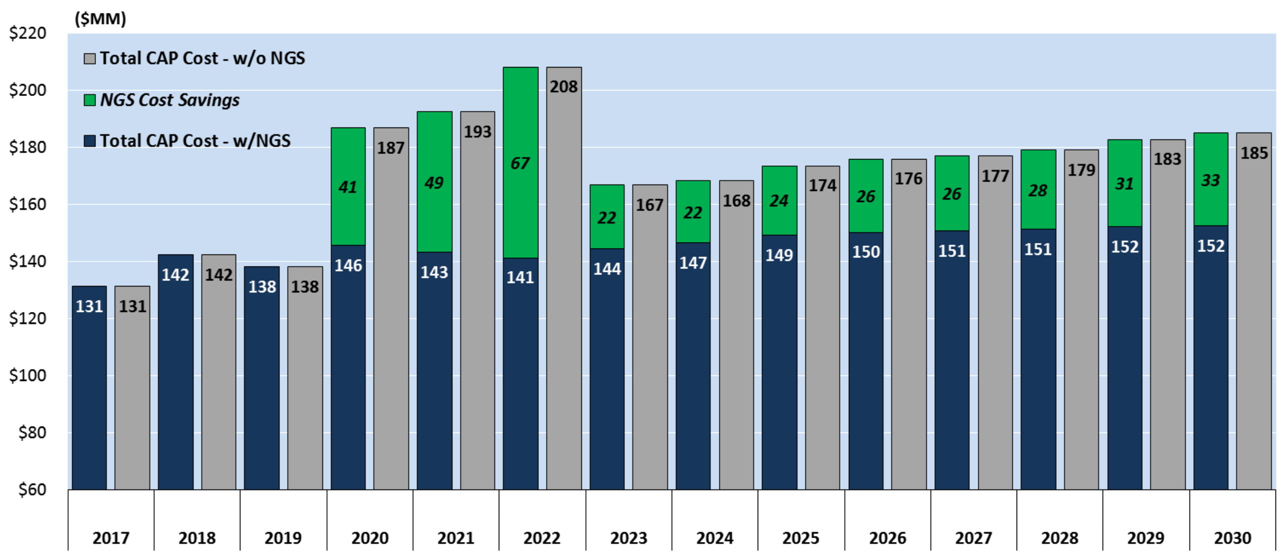
As shown in Exhibit 10, increasing gas prices and declining regional reserve margins will put upward pressure on Palo Verde prices, causing them to rise at a faster rate than NGS's costs. Starting in 2021, power prices will rise above the total cost of generation of NGS, marking the time when NGS will become the lower cost option from which to buy power.

EXHIBIT 10: ANNUAL PRICE COMPARISON – NGS COST OF GENERATION VS. AVG PALO VERDE POWER



Going forward, the BOR will have to decide what to do with its share in NGS. This decision will largely depend on CAWCD's decision on where it will source its future power. If NGS retires, CAWCD will be responsible for the BOR's share of the plant's decommissioning costs. According to CAWCD documents, the decommissioning costs are projected to be $109 million to $151 million, likely spread out over three years following the retirement in 2019. Accounting for the decommissioning costs and the improving market conditions for NGS, continued operations of NGS versus its full retirement should be the preferred alternative for CAWCD.

EXHIBIT 11: TOTAL COST TO CAWCD WITH CONTINUED NGS OPERATION VS. NGS RETIREMENT



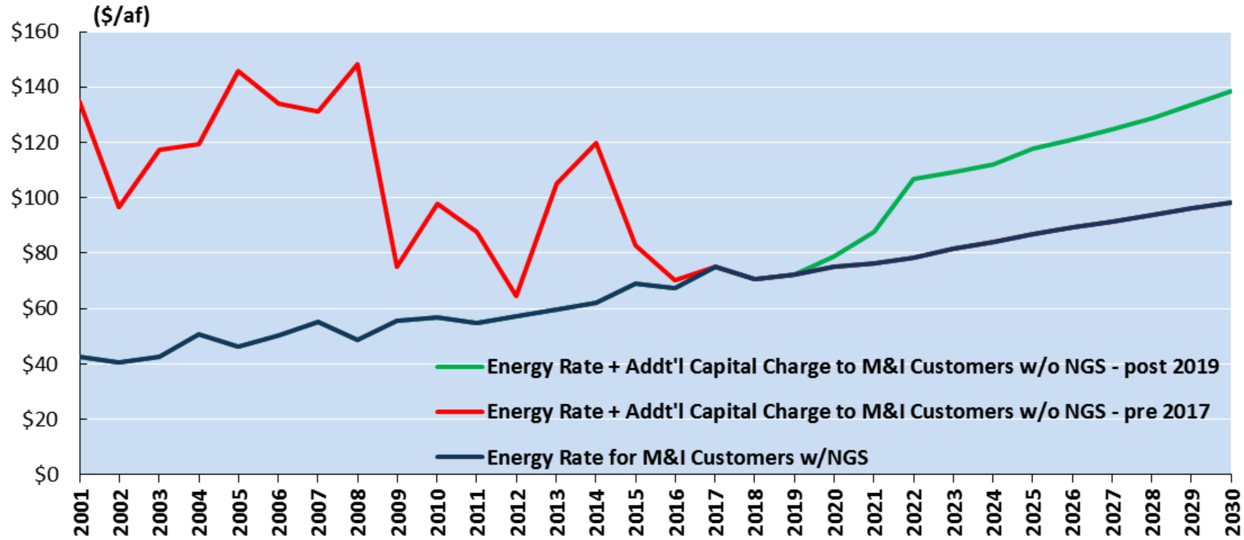
Note: This data is based on CAWCD purchasing 90% of their energy needs from NGS & includes $130 million NGS decomissioning cost

Source: EVA Analysis

As shown in Exhibit 11, CAWCD is projected to save an average of $26 million per year between 2023 and 2030 when compared to the retirement and decommissioning of all three units at NGS.

Should NGS retire at the end of 2019, all potential savings will be more than offset by the loss of NGS-related revenue that is being used for debt repayment to the BOR. Currently, the only possibility to recoup these lost NGS-related debt repayment revenues is through increases in capital charges for CAWCD's municipal and industrial (M&I) customers. The historical and projected energy rate to CAWCD's M&I customers and the additional capital charges to recoup the lost revenue is shown in Exhibit 12.

EXHIBIT 12: ENERGY RATE + ADDITIONAL CAPITAL CHARGES TO CAWCD M&I CUSTOMERS



Source: CAWCD Budgets, EVA

As shown in Exhibit 12, without NGS and its related revenues to repay the debt to the BOR, CAWCD's M&I customers would have seen water charges on average almost double over actual rates since 2001. And since M&I customers would carry the sole responsibility to cover the lost revenues related to the operation of NGS if NGS is prematurely retired at the end of 2019, water charges to CAWCD M&I customers would be higher by more than 30 percent for the next ten years.

It is more financially advantageous for CAWCD and its customers to procure a higher amount of electricity from NGS. The higher the amount of energy purchases from NGS, the higher the savings to CAWCD. Should CAWCD decide to return to pre-2016 purchase levels, when approximately 90 percent of its energy needs were sourced from NGS, CAWCD customers will save almost $370 million through 2030. On the other hand, should CAWCD continue to purchase only 50 percent of its energy needs from NGS, as it did in 2016, these cumulative savings are less than $40 million through 2030.

Further, if NGS were to retire, incremental capacity would eventually be needed in the region as reserve margins continue to dwindle. Expected reserve margins for DSW indicate that in the absence of new builds, the region could experience a capacity shortfall by 2023. Higher peak demand growth could accelerate this timeframe. NGS's replacement capacity would likely come in the form of a combined cycle gas turbine (CCGT) with dispatch costs above those of NGS. EVA estimates that a new CCGT would cost roughly $700 million in the mid-2020s. Because gas prices are expected to approach $4/MMBtu during that time, the plant's dispatch cost would likely be close to $30/MWh, well above that of NGS.

Historically, CAWCD was able to buy from the open market with the knowledge that it had NGS as a fallback resource. If NGS retires, CAWCD would likely be forced to enter into another agreement to ensure sufficient generating capacity is available to cover its baseload energy needs. Depending on the type of resources are available, the new agreement may be more expensive than CAWCD's existing one with NGS.