The Economic Case for Retiring North Valmy Generating Station

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Executive Summary

This report provides an assessment of the recent and forward-going economics of the North Valmy Generating Station, a 522 megawatt (MW), two-unit coal plant located in Valmy, Nevada. Assessments performed by the plant's co-owners, NV Energy and Idaho Power, as well as more recent information on alternatives to operating the plant, point to an early retirement benefitting both the co-owners and their ratepayers.

In 2012, NV Energy proposed retiring Valmy unit 1 in 2021; however, the request was rejected by the Nevada Public Utilities Commission, which instead approved a 2025 retirement date for both Valmy units.[1] The Commission cited "system reliability" concerns, as well as loss of fuel diversity and inability to hedge against high gas prices as reasons for forcing the company to keep Unit 1 online past its economic life. However, since the Commission's decision, the following has happened:

- **Significant transmission investments now obviate the reliability argument for keeping Valmy on-line.** The on-going Southwest Intertie Project (SWIP) including the One Nevada line (ON line) is connecting the northern and southern grids in the state and complementing renewable energy development in Nevada.
- **The decline in natural gas prices and renewable energy costs have left Valmy unable to compete.** Recent operating data show the plant operating at less than one-third of its capacity in 2015. With low natural gas prices and solar energy costs expected to continue, the plant is likely to run even less frequently in the coming years.
- **The longer the plant operates, the greater the risk that it will need to invest in major emission controls.** NV Energy sought earlier retirement of Valmy Unit 1 in part because of the costs of compliance with environmental regulations—which are becoming more stringent as time goes on.

The other owner of the Valmy plant, Idaho Power, found in its 2015 Integrated Resource Plan (IRP) that retiring Valmy Unit 1 in 2019 instead of 2025 would save Idaho ratepayers $74 million. In the IRP development process, Idaho Power conducted risk analyses that found early retirement of Unit 1 was the least cost plan under 100 different combinations of different risk factors. Despite this conclusive finding, Idaho Power chose not to retire Unit 1 early for several flawed reasons, including:

- **Showing that the plant was needed for reliability, but only if two large transmission projects (Boardman to Hemingway and Gateway West) failed to be completed as anticipated.** If either line is completed in the expected timeframe, Valmy Unit 1 can retire in 2019 with no material capacity shortage in Idaho.

[1] PUCN Docket 13-06004, Final Order Dec. 18, 2013.

- **Assuming high natural gas prices and costs for renewable energy.** In its analysis, the company prohibited its model from choosing resources that would be less costly than operating Valmy by setting the prices for these resources unrealistically high. As these prices continue to fall, the cost of delaying retirement of Valmy Unit 1 has only increased. In fact, it is likely that Unit 2 is now also uneconomic given the changing market landscape.
- **Assuming "sunk costs" would have to be recovered from ratepayers before the units could retire.** Idaho Power assumed that capital it had already invested in Valmy would have to be recovered by ratepayers before the plant was retired. By including these "sunk costs" in determining whether the plant should retire or not, the company ties itself and its ratepayers to a sinking ship that will ultimately cost ratepayers more.

Perpetual uncertainty of Valmy's future and the failure of its owners to work together on a solution that is in the best interest of all ratepayers is leading to poor planning decisions and higher costs to consumers. Despite the substantial evidence that Valmy is uneconomic and that reliability concerns have been addressed, there is still no firm commitment to retire the plant. A secure near-term retirement date would allow for enough lead time to develop a cost-effective, coordinated plan for ensuring capacity is in place and reliability concerns (if any) are being managed. The co-owners and their respective regulators have a common interest and should work together. The sooner they coordinate on issues related to their joint ownership, the sooner they can conduct more prudent planning going forward. This will allow them to pursue more cost-effective options while reducing costs and risks to ratepayers.

INTRODUCTION

This report provides an assessment of the recent and forward-going economics of the North Valmy Generating Station, a 522 megawatt (MW) coal plant located in Valmy, Nevada. Valmy Unit 1 is 254 MW and came on-line in 1981. Valmy Unit 2 is 268 MW and came on-line in 1985.[2] The plant is co-owned by Idaho Power Company and NV Energy. It serves those companies' service territories in Idaho, Nevada, and Oregon. Each company owns half of the plant while NV Energy is the designated operator. Because these companies serve load in three states, the plant's operations are regulated by laws and regulations in all of those states. While the positions between the regulators or the companies in those states can sometimes be in conflict, evidence points to an early retirement of the plant as the best option for all involved. This report discusses the recent regulatory history of the plant and documents the many reasons that the plant should be retired, including:

- Co-owner NV Energy's attempt to begin retirement of the plant in 2021 due to environmental compliance risk
- Co-owner Idaho Power's recent modeling showing that it is more economic to begin retirement in 2019
- The lack of true barriers to retiring the plant and
- The plant's unfavorable economics and high risk compared to other clean energy options going forward.

NV ENERGY PREVIOUSLY SOUGHT TO RETIRE THE PLANT EARLIER

In 2006, the Public Utility Commission of Nevada (PUCN) ordered NV Energy to develop a process for evaluating the lifespan of its existing generating units.[3] In its 2007 Integrated Resources Plan (IRP), NV Energy established a 40-year lifespan for the Valmy plant, consistent, it said, with typical lifespan

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[2] NVEnergy, North Valmy Generating Station, available at: https://www.nvenergy.com/company/energytopics/images/Valmy_Fact_Sheet.pdf

[3] PUCN Docket 06-11023, Final Order May 24, 2007.

assumptions in the industry.[4] This plan presumed a 2021 retirement date for Valmy Unit 1 and a 2025 retirement date for Valmy Unit 2.

In 2012, NV Energy filed a recommended retirement date for Valmy Unit 1 of 2021 based on the findings of the Commission-approved Life Span Analysis Process in which the company evaluated the remaining life of the unit.[5] The study took into consideration environmental risks, infrastructure implications, economic value, and unit condition. The company found that there was the potential need for selective catalytic reduction (SCR) and flue gas desulfurization (FGD) technologies to control nitrogen oxide and sulfur dioxide, respectively. It concluded that with the risks of these expensive emission controls, it did not make sense to extend the retirement date of Valmy Unit 1 beyond 2021. The company did not identify which environmental regulations might lead to the need for these controls. Indeed, there are conflicting outlooks among the companies and their respective regulators on how to treat the inherent environmental risks of the Valmy plant. Later in this report, we will discuss why the plant continues to be at risk for needing costly emission controls.

In 2013, Commission staff and the Attorney General's office raised concerns about the increase in common costs that would result from operating only one of the two units for four years. In response to those concerns, the Commission rejected NV Energy's proposed date to retire unit 1 in 2021 and instead approved a 2025 retirement date for both Valmy units.[6] The Commission stated that if NV Energy wanted to deviate from the 2025 retirement date, it would have to file an IRP amendment. The company since followed up with an amended IRP that had a planned retirement date of 2025 for both units.

In hindsight, the decision to push the retirement date out for unit 1 was a mistake because the economics of the plant have continued to deteriorate. To the extent that the Commission continues to have concerns about increased common costs that result from single-unit operation, an economic evaluation of the plant (discussed in more detail below), indicates that it would be better to at a minimum *advance* the retirement of unit 1. Furthermore, given the continuing decline in value of the plant compared to alternative resources, it is quite likely that an updated economic analysis would also show that advancing the retirement of unit 2 to 2019 is similarly advantageous.

[4] PUCN Docket 07-06049.

[5] NV Energy *2012 LSAP Supplement*, p 3.

[6] PUCN Docket 13-06004, Final Order Dec. 18, 2013.

IDAHO POWER SHOWED THAT EARLIER RETIREMENT WAS LOWER COST

Idaho Power does not perform the kind of comprehensive life span analysis that was required of NV Energy. Instead, it conducts depreciation analyses that consider factors such as unit condition, maintenance practices, projected capital expenditures, and infrastructure improvements. Its analyses do not typically include environmental implications, economic constraints, or social/political considerations.[7] On its books, Idaho Power sets the lifespan of the Valmy plant at 50 years, putting the retirement date for Valmy Unit 1 at 2031 and Unit 2 at 2035. However, other filings made by Idaho Power addressing the economic value of Valmy indicate that a much earlier retirement date would likely be advantageous. For example, in a 2013 filing before the Oregon Public Utilities Commission, Idaho Power acknowledged that if additional controls such as an SCR and FGD were required at Valmy, it would likely not make economic sense to continue to operate the units beyond 2018.[8] Similarly, Idaho Power's most recent 2015 IRP showed that Valmy is not a least-cost option for its customers.

In ruling on the previous IRP (conducted in 2013), the Idaho Public Utilities Commission (IPUC) ordered that the company should "be actively involved in matters relating to Valmy, and to promptly apprise us of developments that could impact the company's continued reliance on that coal-fired resource."[9] In that 2013 IRP, the company had evaluated portfolios that included retiring Valmy Units 1 and 2 in 2021 and 2025, respectively—the same timeframe NV Energy had proposed previously. Idaho Power, however, did not choose the portfolio with these retirement dates in its 2013 IRP because "it did not perform well from a cost and risk perspective."[10]

Idaho Power's 2015 IRP included additional modeling that evaluated portfolios that included varying retirement dates for the Valmy units—with most variations using 2025 or earlier. This modeling showed that a portfolio in which Valmy Unit 1 retires in 2019 and Valmy Unit 2 retires in 2025 was the second least costly portfolio ("2019/2025 portfolio").[11] The least cost portfolio, according to Idaho Power, assumed no coal retirements and no restrictions due to the U.S. Environmental Protection Agency (EPA)'s Clean Power Plan. However, those assumptions are unrealistic over a 20-year timeframe.

Idaho Power's 2015 IRP conducted two sets of risk analyses in order to test its portfolios' cost under future uncertainty. First, it evaluated the portfolios under several Clean Power Plan compliance scenarios based on the method of compliance (mass-based or rate-based) and performance of the

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[7] NV Energy *2012 LSAP Supplement*, p 5.

[8] Oregon PUC Docket LC 53, *Supplemental Application*, filed Feb. 14, 2013.

[9] IPUC Case No. IPC-E-13-15, Final Order No, 32980. p.16.

[10] IPUC Case No. IPC-E-13-15, Final Order No, 32980, p.14.

[11] Idaho Power 2015 Integrated Resource Plan (2015 IRP), p.117.

Langley Gulch natural gas plant. The results of this test showed that under every Clean Power Plan compliance scenario, the 2019/2025 portfolio was the lowest cost of the 23 portfolios tested.[12] Second, Idaho Power conducted a stochastic risk analysis with variations in natural gas prices, customer load, and hydroelectric power. This test allowed for all three variables to fluctuate over many iterations of the modeling. The results showed the range of portfolio costs under many combinations of uncertainties. A portfolio that was well-balanced in the face of these uncertainties would have a tighter distribution of results than one that was not well-balanced. The 2019/2025 portfolio was "the least-cost portfolio for the full set of 100 iterations."[13]

According to Idaho Power's modeling, retiring Valmy Unit 1 in 2019 instead of 2025 would save ratepayers $74 million in net present value from 2015 through 2034.[14] This means that delaying Unit 1's retirement would cost more than $12 million per year. As we will explain further in this report, more recent market developments have rendered the plant even less economic. Thus the cost of delaying Valmy Unit 1 retirement has only increased.

Idaho Power also found that early retirement of Valmy Unit 1 was the lowest cost of any portfolio under two sets of risk analyses. Retiring both units in 2019 was only slightly more expensive than the company's chosen portfolio and is premised upon outdated economic data (such as natural gas prices that are outdated and too high, which are discussed further). Despite these findings, Idaho Power chose a portfolio in the 2015 IRP in which the Valmy units are both retired in 2025. In the next section of the report, we will discuss the various "barriers" that have been used to justify not choosing the lower cost, lower risk, and early retirement of Valmy Unit 1.

THERE ARE NO TRUE BARRIERS TO RETIRING THE PLANT

The plant is not needed for reliability

Nevada Reliability

NV Energy has not shown that retiring Valmy would present a reliability issue. The company's "preferred plan" in its 2013 IRP was to fill any capacity need with new natural gas combined-cycle (NGCC) plants.[15] It determined that Valmy would provide the "only plausible brownfield site" for a new natural gas

[12] 2015 IRP, p.119-120.

[13] 2015 IRP, p.123.

[14] 2015 IRP, p.117. The net present value revenue requirement of the company's chosen portfolio (listed as "P6(b)") is $178 million compared to $104 million for the 2019/2025 portfolio (listed as "P9").

[15] NV Energy IRP, Volume 11 of 16, available at: https://www.nvenergy.com/company/rates/filings/IRP/SPPC_IRP/images/Vol.11SPPCIRPsupplynarrativeta383pgs.pdf

combined cycle plant (NGCC) and that new transmission upgrades would not be required if the Valmy units' capacity were replaced in 2021 and 2025, respectively.[16] However, as explained above, the PUCN rejected NV Energy's request to establish 2021 as the retirement date for Valmy Unit 1. The Commission cited "system reliability" concerns raised by intervenors, as well as loss of fuel diversity and inability to hedge against high gas prices as the reasons for forcing the company to keep Unit 1 online past its economic life.[17] However, since the Commission's decision, significantly more transmission has come on-line and both natural gas prices and renewable energy costs have gone down—as we discuss further.

Intervenors cited concerns about increased costs related to retiring the units separately, claiming that retiring Unit 1 early would lead to higher depreciation costs and would make Unit 2 less economic to operate.[18] This is far from the case. Many coal plants across the United States retire a subset of coal units at a given plant. Nevertheless, the PUCN order forced the company to change the planned retirement dates for both units to 2025 in its amended IRP but did include the option of coming back with an updated Life Span Analysis Process (LSAP) in which the company could seek to adjust the retirement dates for the Valmy units. In February of 2016, the company stated that it would file an updated LSAP later in the year that would support a retirement date of 2021 for Valmy unit 1.[19]

As part of that filing, the company is likely to cite significant new transmission infrastructure development that further obviates the need to continue to operate the Valmy plant for reliability reasons. Since the PUCN's decision rejecting a 2021 retirement date for Valmy Unit 1, significant new transmission capacity has come on line. For example, the One Nevada line ("ON line") began operating in January 2014, connecting the northern and southern Nevada grids for the first time. This line is part of the larger Southwest Intertie Project ("SWIP")—shown in Figure 1, below. The northern portion ("SWIP North") will connect northern Nevada to Idaho and is projected to come on line in 2021. The SWIP lines will further improve energy transfer among utilities in the region, including NV Energy, Idaho Power, and Pacificorp.[20] It does not appear that these lines were taken into account when the PUCN made its decision to maintain Valmy for reliability purposes.

[16] Id. p. 17, p. 252

[17] PUCN Docket 13-06004, Final Order Dec. 18, 2013, pp.45-46.

[18] *Id*.

[19] PUCN Docket 15-06065, Modified Final Order, Feb. 12, 2016, p.14.

[20] LS Power, Southwest Intertie Project (SWIP) North, April 12, 2016.

Figure 1: Southwest Intertie Projects (SWIP)[21]

Idaho Reliability

When Idaho Power chose not to select the lowest-cost option of retiring the Valmy plant early in its IRP, it did so, in part, due to concerns about reliability. However, Idaho Power did not provide any details about the nature of these concerns and did not include any transmission system modeling which demonstrated that there would be reliability issues if Valmy were to retire. This type of modeling should include the impacts of recently added, under-construction, and proposed new transmission lines, including two major transmission projects being developed by Idaho Power itself that would further alleviate any existing constraints in the region. The Boardman to Hemingway line, which is also being developed by Idaho Power and others, would add 500 MW of summer capacity to the region and is expected to be on line no later than 2025.[22] The Gateway West line, being developed by Idaho Power

[21] *Id.*

[22] Boardman to Hemingway (B2H) Project, available at: http://www.boardmantohemingway.com/

and its affiliate, Rocky Mountain Power, would add 1,500 MW of summer capacity in its first phase (500 MW dedicated to Idaho Power) and is expected to be on line between 2019 and 2024.[23]

Instead, in its IRP analysis, Idaho Power assumed that these projects would not happen when making the case that retiring Valmy earlier would lead to a capacity shortage. Idaho Power's share of Valmy is 262 MW capacity. Each of the transmission projects mentioned provides 500 MW. Therefore, either project's completion provides about double the company's share of Valmy. In the company's pessimistic planning case, the region is short on capacity only because it assumes that neither the Boardman to Hemingway nor the Gateway West transmission lines are available when planned. In reality, if either line is completed in the expected timeframe, Valmy Unit 1 can retire with no significant capacity shortage.[24]

The Gateway West and Boardman to Hemingway lines provide "bulk" power on the system. At this regional transmission level, there appear to be no issues with retiring Valmy. The Western Electricity Coordinating Council (WECC)—which ensures reliability in the west—has already assumed early retirement of Valmy (2021 for Unit 1; 2025 for Unit 2) in its most recent reliability assessment.[25] If the companies or other parties were truly concerned with reliability, they should conduct modeling to define these issues and identify potential solutions. For instance, if the retirement of Valmy would lead to voltage concerns, there are several options available for supporting voltage on the grid without the presence of a larger generator, including static var compensators (SVCs) and synchronous condensers that could provide reactive power at a fraction of the cost of keeping an uneconomic coal plant online.

In describing why it did not choose the lower cost, lower risk plan of early retirement, Idaho Power claimed that there was "uncertainty related to retirement planning for a jointly owned power plant."[26] Given that both companies have individually identified later retirement as financially risky, they have little excuse not to deal with that uncertainty sooner rather than later: the sooner the co-owners of the Valmy plant coordinate on issues related to their joint ownership, the sooner they can conduct more prudent planning going forward. This will allow Idaho Power and NV Energy to pursue other options while reducing economic costs and risks to ratepayers.

Recovering "sunk costs" should not be a barrier to retirement

One of Idaho Power's most misguided presumptions is that retirement of the Valmy plant would necessarily entail a rate shock to customers. The company is clear that shedding the plant by 2019 would provide substantial savings to consumers. Nevertheless, it clings to its assertion that an "early

[23] Gateway West Transmission Project, available at: http://www.gatewaywestproject.com/project_info.aspx

[24] The company did identify a potential shortage if both Valmy units were to retire in 2019 and the Gateway West line were completed in 2024—which is the latest year that is planned.

[25] https://www.wecc.biz/Reliability/2015PSA_WECC.xls

[26] 2015 IRP, p.10

shutdown will cost approximately $95 million more between 2015 and 2019."[27] To support this point, the company includes the accelerated recovery of depreciation expense as an additional cost to consumers that prevents it from retiring the units.[28] Simply stated, the company believes that it has to be able to get back its investment before it can shut the plant down. Economists call this the "sunk cost fallacy." If you invest in a new transmission in your car but could save money through buying a more efficient car, which is the right thing to do—regardless of the money you already spent on the transmission. Deciding not to sell your old car because you will not get back the money you spent on a new transmission is succumbing to the sunk cost fallacy. Following the same logic, no power plant owner, or any other competitive business, should count those sunk costs as a barrier to making an economically efficient decision. By including the sunk costs in determining whether the plant should retire or not, the company ties itself and its ratepayers to a sinking ship that will ultimately cost ratepayers more.

The question of recovery of undepreciated plant balance is separate from least-cost planning. Neither Idaho Power nor NV Energy should necessarily be expected to forgo recovery of the money already spent keeping Valmy operational for its consumers, but the decision to retire or continue operating should not be tied to expectations that the remaining plant balance (i.e. everything invested thus far) needs to be recovered before that time. The decision of how to treat the remaining balance of sunk investments is a decision that rightfully falls to the regulatory commissions charged with ratemaking, after an economically efficient decision has been made by the utility. In many cases, the preferred option by regulators is actually to create what is called a "regulatory asset," a mechanism of allowing the utility to continue recovering costs along a previously agreed-to schedule that extends beyond the useful life of the actual plant. For example, in neighboring Utah, Rocky Mountain Power determined that the Carbon Plant was unlikely to be economically viable after 2015, and requested permission to shutter the plant. Parties and the Commission agreed, and allowed the company to depreciate Carbon to 2020, minimizing ratepayer impacts.[29] Similarly, Georgia Power Company was authorized to retire three units that were determined to be non-economic on a going-forward basis. In this case, the Commission allowed the company to continue collecting depreciation expenses over an extended period, well

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27 Idaho Power Company 2015 IRP, Page 9.

28 Idaho Power Company 2015 IRP, Page 98.

29 "The Parties agree that the amortization of the prudently incurred Remaining Carbon Balances shall be as set forth in Paragraph 11 of the company's pending application for a Deferred Accounting Order for the Carbon Plant in Docket No. 12-035-79 resulting in the Remaining Carbon Balances being amortized from the date of transfer of the net plant balances to the regulatory asset through 2020. The Parties agree that the Commission's order approving this Stipulation should authorize recovery from Utah ratepayers of Utah's allocated share of the prudently incurred Carbon Removal Costs from the retirement date of the Carbon Plant, currently estimated to occur in April 2015, through 2020." In the Matter of the Application of Rocky Mountain Power for an Accounting Order to Defer the Costs Related to the Decommissioning of the Carbon Plant. Utah Docket 12-035-79. Order available at: http://www.psc.state.ut.us/utilities/electric/elecindx/2012/documents/23403911035200RO.pdf.

beyond the near-term retirement date.[30] The same treatment was provided to Alabama Power in a similar case,[31] and Public Service Company of New Mexico ("PNM") requested that the New Mexico Commission allow it to recover existing plant balance over a 20-year period.[32] The option is popular because it provides the utility the ability to recover costs, while minimizing rate impacts. These requests and findings are also consistent with the idea that sunk or stranded costs should be dissociated from the decision to retire.

The dollars spent in the Valmy plant have already been invested, and either they will be recovered from ratepayers eventually, or borne by the company's shareholders. But the decision of who pays lies outside the decision of what is best for ratepayers going forward from today. On this count, Idaho Power's own analysis is unequivocal: shutting down the plant is a substantial benefit for ratepayers.

THE PLANT'S ECONOMICS ARE WORSENING AND ITS RISKS ARE INCREASING

Recent market trends make the plant less economic

Since each of the co-owners last publicly evaluated Valmy, the economics of operating the plant have only gotten worse. This is primarily due to low natural gas prices. Natural gas price assumptions are critical to the economics of Valmy, primarily because natural gas generation competes directly with coal generation. The natural gas prices are also highly correlated with energy prices, which help determine whether the plant should operate or stand idle.

In its 2015 IRP, Idaho Power used the Energy Information Administration's 2014 Annual Energy Outlook (AEO) for natural gas price assumptions, including a Henry Hub natural gas price of $4 per MMBtu in 2015. This is significantly higher than the actual 2015 average price of $2.63 per MMBtu. As shown in

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[30] "The Commission finds that the remaining net book value of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C shall be classified as a regulatory asset and that the costs be amortized over a period equal to the respective unit's remaining useful life approved by the Commission in Docket No. 31958." Georgia PSC Docket 34218, Order. March 26, 2012. Page 6. Available at http://www.psc.state.ga.us/factsv2/Docket.aspx?docketNumber=34218.

[31] "Authorization to establish a regulatory asset on its balance sheet in which it would record the unrecovered investment cost associated with full or partial unit retirements caused by such regulations, including the unrecovered plant asset balance and the unrecovered cost associated with site removal and closure." Alabama PSC Docket U-5033, Order: September 7, 2011. Page 2.Available at: https://www.pscpublicaccess.alabama.gov/pscpublicaccess/ViewFile.aspx?Id=132f89da-98f5-4c6d-b218-c7a116224e1e

[32] "The Company is seeking Commission approval to record the actual undepreciated investment as of December 31, 2017, as a regulatory asset and to amortize it over a twenty-year time period with a carrying charge equal to the Company's pre-tax weighted average cost of capital." New Mexico Docket 13-00390-UT. Direct Testimony of Thomas Sategna, page 5. December 20, 2013. Available at https://www.pnm.com/documents/396023/1201269/testimony_sategna/fe6f1db4-b6aa-4b8c-af05-ca498cd83460

Figure 2, the actual and near-term natural gas prices are far below Idaho Power's base case natural gas prices assumed in its IRP. NYMEX, the natural gas futures market, predicts that natural gas will be below $3 per MMBtu through 2018. The more up-to-date AEO 2016 Early Release is lower than its 2014 forecast (used by the company) in every year. In fact, even the company's low gas price forecast is higher than what is predicted in the next several years.

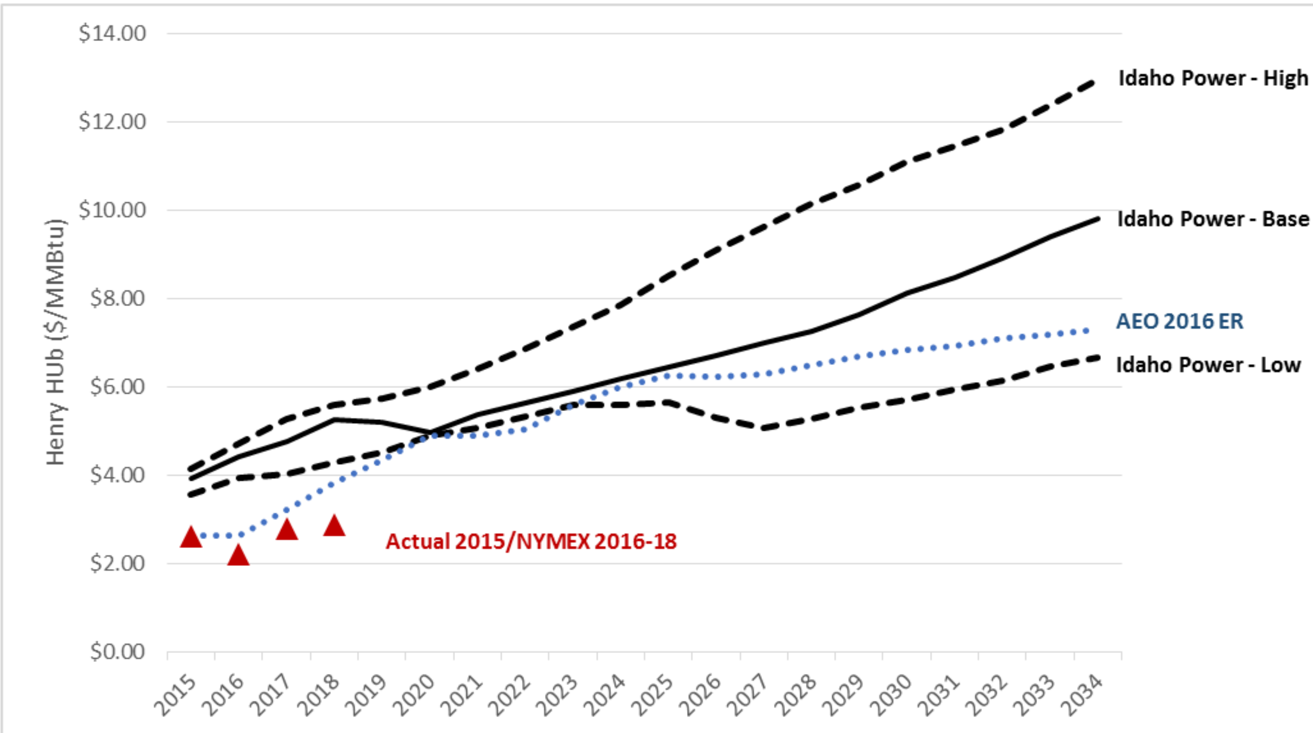

Figure 2: Recent Natural Gas Prices and Expected Prices[33]

The Idaho Power 2015 IRP showed an implied cost of delaying Valmy's retirement of $74 million. This assessment, however, was based on the company's base case natural gas prices (shown above). Under a higher gas price regime, the Valmy plant would operate more often. Conversely, under a low gas price regime, the plant would run less often. Figure 3 shows the plant's capacity factor compared to the average natural gas price in each year. This shows a high correlation between natural gas prices and Valmy's operations. In 2015, the plant ran at a 31 percent capacity factor, which was about half its

[33] 2015 IRP, p.85. Idaho Power used the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2014 Henry Hub forecasts (reference, high oil and gas resource, low oil and gas resource cases), available at: http://www.eia.gov/oiaf/aeo/tablebrowser/; AEO 2016 Early Release (ER) http://www.eia.gov/forecasts/aeo/er/index.cfm; NYMEX Henry Hub futures pulled on March 28, 2016, available at: http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html.

operating level in the previous year. With recent market conditions, the plant is operating far less often and it is unlikely that it is recovering all of its fixed and capital costs.

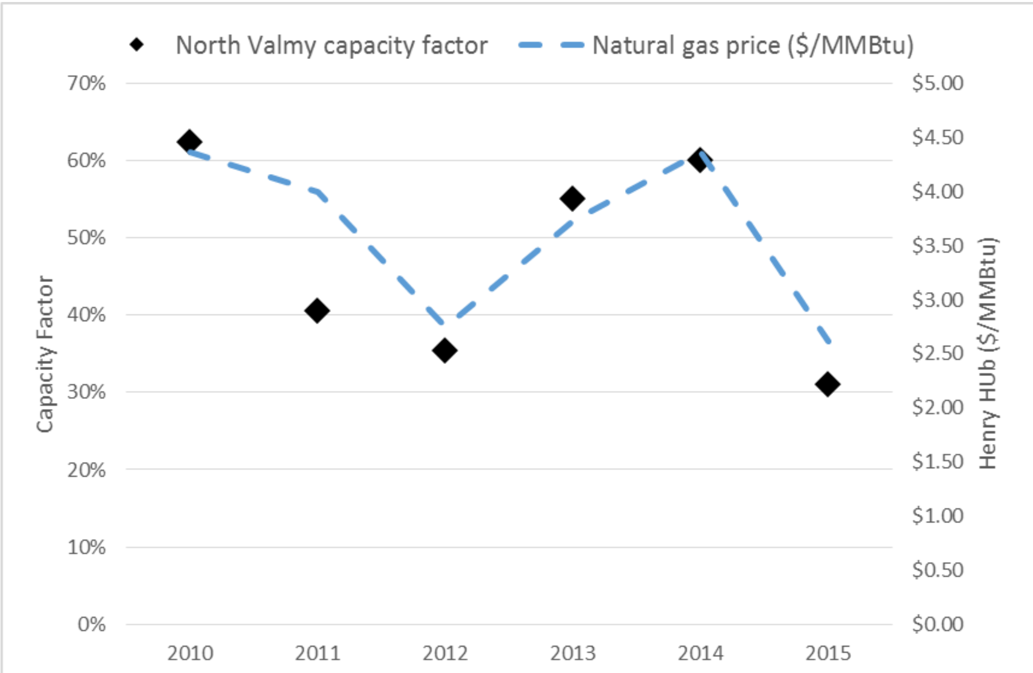

Figure 3: North Valmy Capacity Factor Compared to Natural Gas Prices[34]

A sober assessment of the plant's future shows that its near-term economics are bleak. Based on the data presented on the historical performance of the plant and natural gas price expectations, one would expect North Valmy to operate at between 30 and 40 percent capacity factor in the next few years. Therefore, we expect that updated modeling of the plant by either NV Energy or Idaho Power will show that the plant has even less value than previously thought.

Retiring the plant earlier avoids costly environmental compliance

The Valmy plant burns coal in two coal-fired steam units. Unit 1 is equipped with a fabric filter to reduce particulate matter emissions and low-NO_X burners to reduce nitrogen oxides (NO_X). Unit 2 has the same controls plus a dry flue gas desulfurization system (FGD), which reduces sulfur dioxide (SO_2) emissions by up to 70 percent. Idaho Power identifies the plant as a zero liquid discharge facility, which means it is not supposed to release any wastewater effluent into the environment. Despite these controls, the Valmy units still emit large quantities of pollutants. In 2014, the plant emitted over 7,800 tons of SO_2

[34] EIA Henry Hub prices, available at: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm; North Valmy generation, available at: http://www.eia.gov/electricity/data/browser/#/plant/8224?freq=M&ctype=linechart&ltype=pin&pin=&maptype=0&linechart=ELEC.PLANT.GEN.8224-ALL-ALL.M&columnchart=ELEC.PLANT.GEN.8224-ALL-ALL.M.

and 4,500 tons of NO_X. It also released nearly 3 million tons of carbon dioxide and significant quantities of coal ash, which is landfilled onsite.

As one of the state's last remaining coal plants, Valmy is subject to a number of environmental regulations that may require installation of expensive retrofits. The national ambient air quality standard (NAAQS) for SO_2, which was revised in 2010, requires large emitters of SO_2 to reduce their emissions. Under a consent decree entered into in May 2015, EPA must designate as nonattainment: (a) any area with a power plant that has not been announced for retirement that, in 2012, emitted 16,000 tons of SO_2, or (b) a source that emitted more than 2,600 tons of SO_2 and had an emission rate equal to or greater than 0.45 lbs/MMBtu. These designations must be made by July 2016. EPA must designate areas that do not plan to install an SO_2 monitoring network by the end of 2017 and all remaining areas by the end of 2020.

In 2012, the Valmy plant emitted over 3,600 tons of SO_2 and had an average SO_2 rate of 0.4515 lbs/MMBtu. Unit 1 had an SO_2 emission rate of 0.72 lbs/MMBtu, while the scrubbed second unit had a much lower emission rate of 0.18 lbs/MMBtu. Since 2012, the emissions have increased and the emission rates have worsened.

Despite these statistics, it does not appear that EPA is planning to designate the Valmy plant as a nonattainment area for SO_2 in the first round. However, due to these significant emissions, it is likely that the plant will be captured in the next round of designations and that Unit 1 would, therefore, require an FGD before 2021. We estimate that this would cost $171 million.[35] The FGD would also increase the unit's operating costs, making it even less competitive than it is currently.

Other options are less expensive

According to Idaho Power, Valmy's recent variable operating cost is more than $47 per megawatt hour (MWh).[36] With existing fixed costs and on-going capital, the "all-in" cost of the plant is likely more than $56 per MWh. As we discussed previously, coal generators are currently having difficulty competing with natural gas. Coal operators see these market risks and are buying coal on short-term contracts or on the spot market instead of through long-term contracts. Berkshire Hathaway Energy, the parent company for NV Energy, recently stated that its Nevada operations:

[35] This was developed using Synapse's Coal Asset Valuation Tool (CAVT). The number represents the upfront cost in 2012 dollars. For information see: http://www.synapse-energy.com/tools/coal-asset-valuation-tool-cavt.

[36] Direct Testimony of Kelly K. Noe, p.6, line 12. In the Matter of Idaho Power Company's 2016 Annual Power Cost Update. Before Public Utility Commission of Oregon. October 23, 2015.

> …have no coal commitments for 2016 or beyond and will rely on spot market solicitations for any coal supplies needed during 2016 and regularly monitor the western coal market for opportunities to meet these needs.[37]

In a recent Energy Supply Plan, NV Energy stated that:

> However, coal requirements are far more difficult, if not impossible, to predict with any accuracy in contrast to the past when coal was consistently the low cost option and was base loaded. The level of uncertainty surrounding coal unit operations complicates managing coal supply, transport and inventories…coal supply planning needs to be flexible to allow the Company to respond to changing markets and to highs and lows of coal demand caused by swings in natural gas prices and other factors.[38]

At recent natural gas prices, an efficient combined-cycle (CC) gas plant operate in the range of $20 to $25 per MWh.[39] Indeed, Idaho Power's own Langley Gulch natural gas CC costs slightly less than $20 per MWh which is less than half the operating cost of Valmy.[40]

Renewable energy is also becoming more attractive on a cost-basis alone, compared to coal generation. In its recent 2015 IRP, Idaho Power Company makes a number of assumptions about wind and solar that bias the company against choosing these alternatives. First, the company did not anticipate the extension of the federal renewable energy Production Tax Credit (PTC) and Investment Tax Credit (ITC), which benefit wind and solar (respectively). These tax credits provide certainty for wind and solar developers, making such systems financially feasible and supporting these resources as they move toward cost parity with conventional resources. According to Lazard's *Levelized Cost of Energy Analysis — Version 9.0*, released in November 2015, the costs for wind and solar have fallen 61 percent and 82 percent, respectively, over the past six years. This has put some wind and solar projects on par with or even better than new gas-fired generation.

Currently Idaho has nearly 1,000 MW of wind and over 3 MW of solar installations reducing emissions, providing clean, renewable energy, and creating jobs.[41] Nevada has 1,240 MW of solar (the fifth highest in the United States) and 152 MW of wind.[42] Idaho has significant hydroelectric resources.

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37 Berkshire Hathaway Energy Company, Securities and Exchange Commission (SEC) Form 10-K, available at: https://www.berkshirehathawayenergyco.com/assets/upload/financial-filing/BHE%2012.31.15%20Form%2010-K_FINAL%20_with%20hyperlinks-1.pdf.

38 Direct Testimony of Joseph R. Brignola, Before the PUCN, 2014-2016 Energy Supply Plan, p.2.

39 This operating costs assumes a heat rate of 6.8 MMBtu per MWh, a range of gas prices from $2.50 to $3.00 per MMBTU and a non-fuel variable operating cost of $4 per MWh.

40 Direct Testimony of Kelly K. Noe, p.15, line 23. In the Matter of Idaho Power Company's 2016 Annual Power Cost Update. Before Public Utility Commission of Oregon. October 23, 2015.

41 NREL *2014 Renewable Energy Data Book*, available at: http://www.nrel.gov/docs/fy16osti/64720.pdf; Solar Energy Industries Association (SEIA), available at: http://www.seia.org/state-solar-policy/idaho.

42 NREL 2014 and SEIA.

Unfortunately, neither of the co-owners of Valmy have fully embraced these resources. Because Idaho has very few policies supporting renewable energy, most renewable energy projects in the state have been supported through the federal Public Utility Regulatory Policies Act (PURPA). Recently, however, Idaho Power led an effort to change the state's interpretation of the law to shorten PURPA contracts from 20 years to two years.[43] This change in policy means that renewable energy developers have all but abandoned efforts to build new renewables in Idaho. In the last few years in Nevada, NV Energy has built utility-scale solar energy mainly to comply with SB 123, which mandated coal retirements and partial replacement with renewable energy; and to provide renewable energy to entities seeking a greener footprint. The company recently awarded two PPAs for 100 MW of solar each—one PPA starts at $46 per MWh and the other at $39 per MWh.[44]At the same time, it has clamped down on the growth of small-scale solar PV installation in Nevada by imposing significant and increasing fixed charges on the electric bills of those who install small-scale solar PV, and decreasing credits received for delivery of energy to the grid.

A recent review of solar costs by Lawrence Berkeley National Laboratory (LBNL) shows the rapid decline in solar costs in recent years—depicted in Figure 4. At this rate, the levelized costs of power purchase agreements (PPAs) for solar PV are on par with the costs of the Valmy plant, even without the consideration of the potentially significant additional costs due to environmental retrofits that may be needed at Valmy. Solar not only carries the advantages of low environmental cost risk and protection from fuel price fluctuations; it is now cost competitive with traditional sources like Valmy.

[43] IPUC Case No. IPC-E-15-01, AVU-E-15-01, PAC-E-15-03. Available at: http://www.puc.idaho.gov/press/150820_PURPAfinal_files.pdf.

[44] Bolinger, Mark and Joachim Seel, Lawrence Berkeley National Laboratory (LBNL), *Utility-Scale Solar 2014.* September 2015, p.34, available at: https://emp.lbl.gov/sites/all/files/lbnl-1000917.pdf.

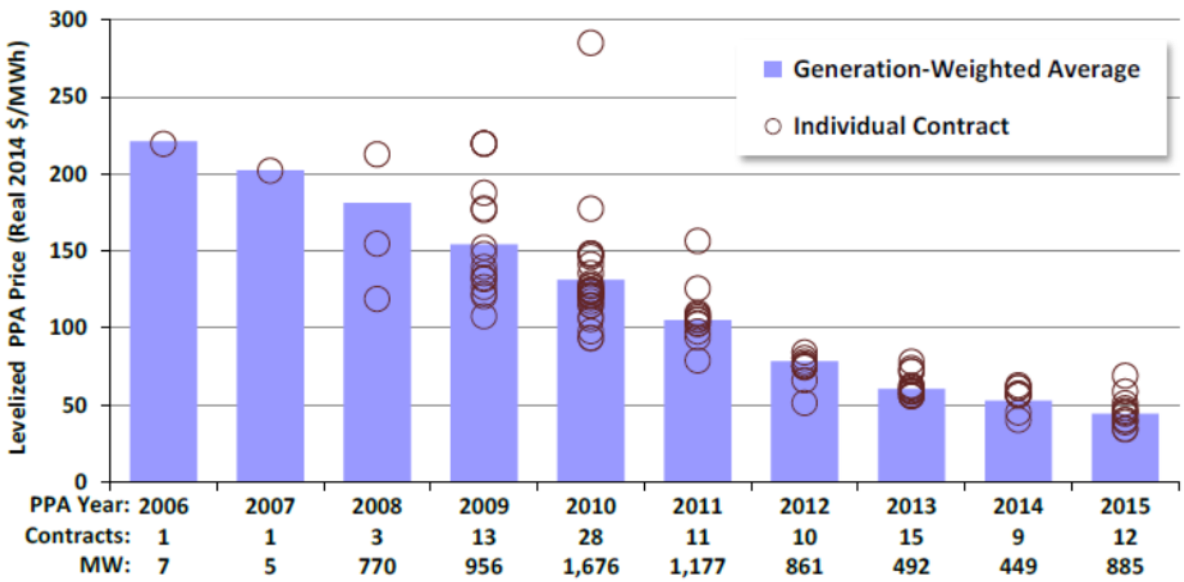

Figure 4: LBNL Levelized PV PPA Prices by Contract Vintage[45]

In the meantime, new transmission investments in the region are facilitating the transfer of renewable energy on the regional system. The One Nevada line ("ON line") has brought new renewable energy development in northern Nevada to serve load in the south--where there is more electricity demand. Likewise, the ON line and the upcoming the Southwest Intertie Project ("SWIP") North line are expected to allow for the shift of solar energy from the south to the north during the afternoon while reversing the flow of other energy sources from north to south after the sun sets.[46]

CONCLUSION

Advocates for Valmy's early retirement (including NV Energy, its operator and co-owner) are met with unsubstantiated concerns about uncertainty, reliability, and the need for fuel diversity. These are largely red herring arguments. There have been substantial transmission investments that have recently come on-line or are being planned within the region to shore up reliability and facilitate renewable energy development. These investments obviate the need to keep Valmy operating beyond 2019. In recent years, the risks and costs of operating Valmy have only gotten worse compared to other options.

Perpetual uncertainty of Valmy's future is leading to poor planning decisions, especially in light of increasingly cost competitive alternative resource options. Despite substantial evidence that Valmy has

[45] LBNL, p.37.

[46] LS Power, Southwest Intertie Project (SWIP) North, April 12, 2016.

become increasingly uneconomic, there has been no firm commitment to retire the plant. A secure retirement date would allow for enough lead time and more prudent, coordinated planning. The companies and their respective regulators have a common interest and should work together. An early, firm retirement date for both units of the Valmy plant is likely the best option for both companies and their ratepayers.