BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR APPROVAL TO ABANDON SAN JUAN GENERATING STATION UNITS 2 AND 3, ISSUANCE OF CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR REPLACEMENT POWER RESOURCES, ISSUANCE OF ACCOUNTING ORDERS AND DETERMINATION OF RELATED RATEMAKING PRINCIPLES AND TREATMENT,	)	
PUBLIC SERVICE COMPANY OF NEW MEXICO,	)	**CASE 13-00390-UT**
Applicant	)	

Direct Testimony of
Jeremy I. Fisher, PhD

On Behalf of
New Energy Economy

August 29, 2014

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name, business address, and position.

A My name is Jeremy Fisher. I am a Principal Associate with Synapse Energy Economics, Inc. (“Synapse”), which is located at 485 Massachusetts Avenue, Suite 2, in Cambridge, Massachusetts.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q Please summarize your work experience and educational background.

A I have ten years of applied experience as a geological scientist, and six years of experience working within the energy planning sector, including work on integrated resource plans; long-term planning for utilities, states, and municipalities; electrical system dispatch; emissions modeling; the economics of regulatory compliance; and evaluating social and environmental externalities.

I have provided consulting services for various clients, including the U.S. Environmental Protection Agency (“EPA”), the National Association of Regulatory Utility Commissioners (“NARUC”), the California Energy Commission (“CEC”), the California Division of Ratepayer Advocates (“CA

DRA"), the National Association of State Utility Consumer Advocates ("NASUCA"), National Rural Electric Cooperative Association ("NRECA"), the State of Utah Energy Office, the State of Alaska, the State of Arkansas, the Regulatory Assistance Project ("RAP"), the Western Grid Group, the Union of Concerned Scientists ("UCS"), Sierra Club, Earthjustice, Natural Resources Defense Council ("NRDC"), Environmental Defense Fund ("EDF"), Stockholm Environment Institute ("SEI"), Western Resource Advocates ("WRA"), Citizens Action Coalition of Indiana ("CAC"), Civil Society Institute, and Clean Wisconsin. I developed a regulatory tool for EPA and state air quality agencies, released by EPA in 2014 as the Avoided Emissions and Generation Tool ("AVERT"), and have provided technical support to EPA regarding electric utility planning practices.

I have provided testimony in electricity planning and general rate case dockets in Indiana, Louisiana, Kansas, Kentucky, Oregon, Nevada, Utah, Wisconsin, and Wyoming. I have reviewed and evaluated the energy planning practice of utilities in numerous dockets involving integrated resource plans ("IRP") and certificates of public convenience and necessity ("CPCN").

I hold a B.S. in Geology and a B.S. in Geography from the University of Maryland, and a Sc.M. and Ph.D. in Geological Sciences from Brown University. My full curriculum vitae is attached as Exhibit JIF-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of New Energy Economy ("NEE").

Q **Have you testified in front of the New Mexico Public Regulatory Commission previously?**

A No, I have not.

Q **What is the purpose of your testimony?**

A My testimony evaluates the economic modeling performed by Public Service Company of New Mexico ("PNM," or "the Company") in support of this application for certificate of public convenience and necessity for the acquisition of San Juan Generating Station (SJGS) unit 4 and Palo Verde 3 (PV3) as replacement resources for the abandonment of SJGS units 2 & 3.

Q **What was your charge from NEE?**

A I was tasked with reviewing the Company's economic modeling using the Strategist model, a common capacity-expansion model often used to evaluate long-term resource decisions, and to provide recommendations to this Commission regarding the disposition of the Company's resources and investments in energy and capacity resources.

The Company's application seeks permission to construct and recover the costs of selective non-catalytic reduction (SNCRs) at SJGS 1 & 4 (Jan 2016),[1] abandon SJGS 2 & 3 (Dec 2017) and place the stranded costs in a regulatory asset for full

[1] Direct Testimony of Gerard Ortiz, page 3 lines 3-7.

recovery,[2] acquire 132 MW of additional capacity at San Juan 4 (Dec 2017),[3] and acquire the Company's affiliate share in Palo Verde 3 (Jan 2018).[4] I was asked to review the Strategist modeling that, the Company contends, supports these decisions.

Q Please provide an overview of your testimony.

A My testimony reviews the Company's Strategist modeling from information provided in public discovery. I did not have access to, nor run, alternative Strategist scenarios; my opinions are informed by the input and output files provided by the Company and my experiences with similar modeling elsewhere. There are a number of key issues that stand out in the Company's modeling that I will discuss here. These issues lead the Company's modeling to conclude that procurement of SJGS 4 and Palo Verde 3 are cost-effective choices; I believe that an adjustment or correction of these issues could readily turn the Company's economic assessment. Issues include:

1. Regular ongoing capital expenditures at the Company's baseload units were excluded from the economic analysis.
2. The modeled cost of coal at SJGS does not represent a reasonable interpretation of PNM's costs or obligations today or in the future, vastly understating the variable cost of production at SJGS.
3. All operational and maintenance (O&M) costs at SJGS are modeled as fixed costs, again understating the variable cost of production at SJGS.

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[2] Direct Testimony of Gerard Ortiz, page 2 lines 10-15.
[3] July 15 Supplemental Testimony of Gerard Ortiz, page 6 lines 8-12.
[4] Direct Testimony of Gerard Ortiz, page 2 lines 16-20.

4. The costs of the proposed coal combustion residuals (CCR) rule are excluded from PNM's modeling in this case, biasing the selection towards high-risk coal assets.
5. PNM has modeled their generating assets and load in isolation from the rest of the West, or even New Mexico, excluding opportunities for economic market purchases and sales.
6. The Company's model does not take into account end effects, or an assessment of capital costs incurred after the end of the analysis period.
7. The Company's carbon price does not represent a reasonable range of risk for the regulation of carbon.

Even if the PNM's modeling was flawless, the Company's assessment indicates that the acquisition of PV3 provides very little benefit to ratepayers—and may, in fact, pose a net liability at a cost of $2,500 per kW. Similarly, assuming a flawless model, the Company's assessment of San Juan 4 indicates a fairly low value for PNM's ratepayers in acquiring the resource. Today, PNM has four years before the transfer of PV3 and SJGS would be executed, allowing ample opportunity for the Company to (a) correct its modeling, (b) issue a competitive bid for any resources able to meet its resource needs, and (c) issue a request for offers for its non-regulated share of PV3, rather than transferring it at "market value" to the Company itself.

Q What are your recommendations to this Commission with regards to the case at hand?

A I recommend that the Commission deny the approval for the acquisition of SJGS 4 and Palo Verde 3, deny pre-approval for the recovery of the SNCR controls, approve the abandonment of SJGS 2 & 3, require the Company to re-assess its need for capacity and energy and re-conduct Strategist modeling with appropriately characterized inputs, issue an all-source RFP for capacity and energy if required, and submit detailed justification for any long-term contracts negotiated with third-party providers.

I support each of these recommendations in turn.

Q Did you have access to the Company's final Strategist runs supporting Mr. O'Connell's July 1 supplemental testimony?

A No. I have only had access to the Company's Strategist runs supporting Mr. O'Connell's direct testimony on December 20, 2013. These Strategist runs list an execution date of December 16, 2013.[5] I have also reviewed the Strategist runs supporting Mr. O'Connell's July 1st supplemental, with runs listing an execution date of April 21, 2014.[6]

Both NEE and New Mexico Industrial Energy Consumers (NMIEC) requested that PNM provide the Strategist output files or results that were analyzed by the Company. Both of these requests instructed the Company to provide timely

[5] Provided as response to NEE DR 1-1, specifically PNM Exhibit NEE 1-1n. Question reads "please provide the Strategist input and output files, in machine readable format, for each alternative option the company evaluated in its economic analysis."

[6] Provided as response to NMIEC DR 1-4, specifically PNM Exhibit NMIEC 1-4, 14IRP_A05.REP Question reads "please provide a complete copy of the Strategist PROVIEW module results from each Strategist simulation analyzed."

updates if new information was made available.[7] Neither NEE 1-1 nor NMIEC 1-4 were updated by the Company to reflect its July 1, 2014 filing.

Regardless of this oversight, I believe that the issues I have identified are likely present in the Company's final analysis as well. They are all identified and supported by responses to discovery requests, and I would have expected the Company to indicate in Mr. O'Connell's supplemental testimony if its major assumptions underlying the model had changed significantly since the first application in December 2013.

Q What value does the Company place on Palo Verde 3 and San Juan 4?

A The implied value of PV3 and SJGS 4 assumed by PNM has changed as the Company has modified their modeling over time. We can assess the value that the Company would place on any given resource by examining an optimized plan with that resource in place against an optimized plan with that resource removed. If the present value of revenue requirements (PVRR) of the plan with the resource is lower than the PVRR of the plan without the resource, the resource can be said to have a value to ratepayers.

While I disagree with many of the modeling assumptions used by the Company, and will discuss those further below, it is illustrative to examine the implied value associated with PV3, SJGS 4, and SJGS as a whole.

Table 1, below, indicates the total PVRR of four plans as presented in Mr. O'Connell's July 1st revised testimony. The Company finds that the plans without

[7] See NEE DR request instructions, generally: "Each of these Interrogatories is deemed to be a continuing interrogatory. You are required to file supplementary answers if you obtain further or different information between the time your answers are served and the time of hearing."

PV3, SJGS 4, and SJGS as a whole are all more expensive than their preferred plan, and thus under their assumptions these resource all have a positive implied value.

Table 1. Present value of revenue requirements (PVRR) for various PNM options, based on July 1, 2014 supplemental testimony (Exhibit PJO-3) (M 2014$)

	Revised SIP w/ PV3 132 MW to SJ4	Revised SIP w/o PV3, 132 MW to SJ4	Revised SIP w PV3, no SJ4 addition	Four unit shut down
Total PVRR	$6,852	$6,857	$6,909	$7,235
Benefit (cost) of plan relative to SIP		**Value of Palo Verde 3**	**Value of San Juan 4 (132 MW)**	**Value of San Juan Plant**
PVRR(d)		$5	$56	$383
$/kW[8]		*$39/kW*	*$428/kW*	*$771/kW*

In Mr. O'Connell's July 1st testimony, PV3 has a value of just $5 million – or $39/kW to consumers, while SJGS 4 has a value of $56 million, and the remaining capacity that the Company will hold in SJGS has a value of $383 million.

As of July 15th, Mr. O'Connell's testimony revised the cost of the base case upwards, and revised the cost of the case without PV3 upwards slightly less, shrinking the value of PV3 to $3 million, and the value of SJGS to $372 million (see Table 2, below).

Table 2. Present value of revenue requirements (PVRR) for various PNM options, based on July 15, 2014 supplemental testimony (Table PJO-1) (M 2014$)

	Revised SIP w/ PV3 132 MW to SJ4	Revised SIP w/o PV3, 132 MW to SJ4	Four unit shut down
Total PVRR	$6,863	$6,866	$7,235
Benefit (cost) of plan relative to SIP		**Value of Palo Verde 3**	**Value of San Juan Plant**
PVRR(d)		$3	$372

[8] Assumes 134 MW at PV3, 132 MW incremental at SJ4, and 497 MW at SJ plant (170+195+132)

$/kW[9]	$22/kW	$748/kW

As I'll discuss below, as of August 14th, the Company provided a revised Strategist run to interveners adding in excluded ongoing capital, subsequently dropping the value of SJGS to $282 million.

The remainder of my testimony explores various concerns and errors in the Company's Strategist analysis, and evaluates if the values of these units would remain the same if costs were accounted for appropriately.

2. <u>REGULAR CAPITAL EXPENDITURES AT SJGS, PV3, AND FOUR CORNERS ARE NOT REPRESENTED IN STRATEGIST</u>

Q You stated that regular ongoing capital expenditures at the Company's baseload units were excluded from the economic analysis. Please explain.

A The maintenance and continued operation of large steam boilers requires significant ongoing capital expenditures. At coal-fired boilers, these may include large retrofit or refurbishment projects, such as new generator and boiler components, new infrastructure to support waste disposal, coal handling equipment, and control equipment. Some of these costs are considered expenses and part of the regular upkeep of equipment; others of these costs are large enough to represent a significant debt load, and thus are capitalized by the Company—i.e., put into rate base.

[9] Assumes 134 MW at PV3, 132 MW incremental at SJ4, and 497 MW at SJ plant (170+195+132)

In Strategist, capital expenditures may be represented either through a separate capital module or, as more commonly executed, as an element of fixed O&M (FOM). The Company, in this case, appears to group capital into FOM; we can see a significant spike in early year expenditures for the implementation of SNCRs, for example. However, it was not clear that FOM included ongoing regular capital expenditures, and discovery indicated that indeed it was not. In a May 30, 2014 response to a discovery request seeking a schedule of plan additions in Strategist, PNM stated that "for the Strategist modeling, PNM did not include any plant additions for Palo Verde Unit 3 or any of the San Juan Generating Station units."[10] Seeking clarity on this question, interveners asked if PNM expected not to have additional capital expenditures in the future; PNM stated that it did expect future capital expenditures.[11] Finally, interveners requested a Strategist run that "includes capital expenditures for San Juan, FCPP [Four Corners], and Palo Verde that…follow the actual plan in place for each facility through 2033."[12] On August 14, 2014, PNM provided the results of three runs (without accompanying Strategist reports), as shown in Table 4, below.

[10] See ABCWUA 3-11. Question "Please provide interim plant additions assumed within the Strategist model for each year of the forecast period for PNM's ownership interest in PV unit 3 and each San Juan Generating station unit (at PNM's current ownership percentages). For each San Juan generating station unit do not include any forecasted plant additions related to SNCR or SCR options being considered. In other words, only normal/routine interim additions for PNM's ownership interest in each SJGS unit is [sic] being sought with this request." Response: "For the Strategist modeling, PNM did not include any plant additions for Palo Verde Unit 3 or any of the San Juan Generating Station units."

[11] See CCAE 12-10(a). Question, citing to response to ABCWUA 3-11: "How likely is it that a zero capital assumption for these facilities in the future would be realistic?" Response: "Future capital investment in Palo Verde Unit 3 and all of the generators in PNM's portfolio will occur."

[12] See CCAE 12-10(b). Question, citing response to ABCWUA 3-11: "Please provide a Strategist run that includes capital expenditures for San Juan, FCPP, and Palo Verde that are in line with historical expenditures and are realistic and follow the actual plan in place for each facility through 2033. This Strategist run should also include the cost of decommissioning for Palo Verde units, as was done in PNM Exhibit 3-5b. Please provide the capital expenditure amounts included in this run by year for each facility."

Q Please describe the results of the Company's re-analysis with regular capital expenditures included.

A Relative to the costs presented in Mr. O'Connell's July 1 supplemental testimony (PJO-3, updated), the costs presented in response to CCAE 12.10 are approximately half a billion dollars higher (see Table 3, below), indicating that between SJGS, Palo Verde, and Four Corners, the analysis conducted by the Company excluded a significant amount of ongoing capital.

Table 3. Present value of revenue requirements (PVRR) for various PNM options, based on Table PJO-1 (July 15, 2014) and CCAE 12.10 (August 14, 2014) (M 2014$)

	Revised SIP w/ PV3 132 MW to SJGS 4	FIP ("4-SCR")	Four unit shut down
Table PJO-1 (7-15-2014)	$6,863	$7,640	$7,235
CCAE 12.10 (8-14-2014)	$7,394	$8,134	$7,676
Change from PJO-3	*$531*	*$494*	*$441*

Q Does this exclusion make a difference to the Company's analysis of a least cost option moving forward?

A Yes, but the extent to which it matters is unclear.

The Company responded narrowly to the request in CCAE 12.10, and provided only three runs of the eleven presented in PJO-3. As shown in Table 3, above, these three runs only contemplated the Company's base case (SIP, with PV3 and 132 MW of SJGS 4), the federal implementation plan (FIP) case in which SCRs are built at all four units, and a "four unit shut down" case in which all of San Juan is retired.

As would be expected, the cost of the San Juan SIP case increased the most of these three cases (as the most capital had been excluded from that case), while the full retirement case increased the least. Between these two cases, we can see that adding in regular, ongoing capital closed the gap between maintaining SJGS 1 & 4 and shutting down the whole plant by $102 million (NPV).

The "value" of a given resource can be extracted from reviewing the Company's assessment of the net present value of a case with and without that resource (only). If a resource plan without a specific asset is more expensive than the resource plan with the asset, the asset can be said to have a value equal to the difference between those plans. Thus, in Table PJO-1 (July 15, 2014), the Company would have estimated the value of proceeding with the SIP over retiring San Juan plant (all four units) at $383 million (see Table 1 on page 8). As of the submission of CCAE 12-10, this value is now decreased to $282 million (see Table 4, below).

Table 4. Present value of revenue requirements (PVRR) for various PNM options, based CCAE 12.10 (August 14, 2014) (M 2014$)

	Revised SIP w/ PV3 132 MW to SJGS 4	FIP ("4-SCR")	Four unit shut down
Total PVRR	$7,394	$8,134	$7,676
Benefit (cost) of plan relative to SIP		**Value of 4-SCR Plan**	**Value of San Juan Plant**
PVRR(d)		($740)	$282
$/kW			*566/kW*

Unfortunately, these three runs do not provide enough resolution on the impact of PNM's capital exclusion on the decision to acquire additional capacity at SJGS 4 or PV3, specifically. Since there is no pair of runs with and without the additional 132 MW at SJGS 4 or with and without PV3, we cannot determine the implicit value of each unit, respectively.

Q Are you able to discern the impact of the capital exclusion on the San Juan acquisition?

A Yes, in part. We see from Table 1 that the Company would assess the value of the 132 MW increment at SJGS 4 at $56.5 million NPV from PJO-3. In CCAE 12-10(b), the Company provided annual ongoing capital expenditures at SJGS 1-4 with no additional SJGS acquisition, and testing the acquisition of both 78 and 132 MW of SJGS 4. In total, these data show that the Company excluded $14.2 million NPV (2014$)[13] from SJGS 4. At the very best, even assuming that the rest of the Company's analysis is flawless, the Company would assess the value of SJGS 4 at $42.3 million.

Q Are you convinced that the Company has accounted for all capital or O&M costs in its CCAE 12-10 analysis?

A No. As I'll discuss below, the Company appears to have put O&M, SNCR capital, and the take-or-pay provisions of its coal contract into the "Fixed O&M" category of Strategist. And yet, even after all of these additions, the total capital and O&M for SJGS in Strategist is still lower in nearly every year after 2018 than in workbooks provided by Mr. Monroy, ostensibly showing O&M and capital (but not the fuel contract). The two are compared in Figure 1, below.

[13] Net present value from 2014-2033 with 8.18% discount rate.

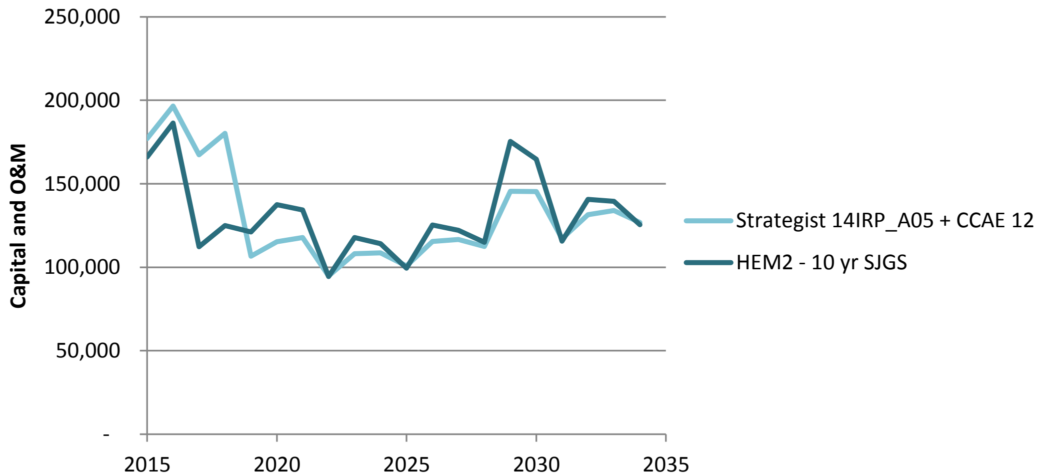

Figure 1. Capital, O&M and fuel clause contract in Strategist (14IRP_A05), plus additional capital as in CCAE 10.12(b) against capital and O&M only in Monroy workpapers.[14]

The higher cost in the Strategist model in 2017 and 2018 may represent the fixed cost of the existing coal contract (which I discuss in the next section), a cost that otherwise likely is not represented in the capital or O&M budget from Mr. Monroy. However, if this is the case, it is unclear why the coal contract fixed costs are not represented in Mr. Monroy's spreadsheets in 2014 or 2015, or 2019-2033.

Q Was the failure to include ongoing capital expenditures in the Company's initial and supplemental testimony an error?

A Yes. These costs are part of the regular operations and upkeep of thermal electric generating units, and were omitted erroneously. However, there is little excuse for these costs being excluded from Mr. O'Connell's supplemental testimony, filed July 15, 2014. In responding to ABCWUA 3-11 on May 30, 2014, Mr. O'Connell

[14] PNM_Exhibit_ABCWUA_1-29b--HEM-2-O&M Comparison_Twenty_Year_Forecasts_SNCR-vs-SCR_OM.xlsx

indicated that he was aware that ongoing capital had been excluded from the Strategist modeling. It is puzzling that this error was not corrected in the month and a half before the Company filed its supplemental testimony.

Q What conclusions can you draw about the capital budget as represented in Strategist?

A First, the capital budget represented in Mr. O'Connell's direct and supplemental testimonies significantly under-represent the actual forecast expenditures at San Juan, Four Corners, or Palo Verde by about $500 million. The Company has not made clear which of these expenditures are avoidable if they do not acquire SJGS 4 or PV3; however, the value of the San Juan plant to consumers has shrunk from $383 million to $282 million—a 26 percent decrease.

Unfortunately, as I explain in Section 4 (starting page 24), the Company has aggregated a large block of costs into the Strategist fixed O&M category, and has not provided adequate explanation of which costs are included therein. Therefore, it is nearly impossible at this stage to assess if Mr. O'Connell's assumptions are consistent with (a) his explanations in discovery responses and testimony or (b) Mr. Monroy's calculations.

3. COAL COSTS AT SJGS ARE NON-REPRESENTATIVE OF ACTUAL FUEL COSTS

Q You stated earlier that the modeled cost of coal at SJGS does not represent a reasonable interpretation of PNM's costs or obligations. What do you mean?

A In the Strategist model, the Company models the cost of coal at SJGS in two buckets: the vast majority appears to be modeled as a fixed cost (i.e., paid regardless of the operation of the unit), while a minority of the costs are modeled as variable costs (i.e., the generator pays for each unit of coal used). The effect of this assumption is to shift a large fraction of SJGS's costs into the fixed category, meaning that the unit has an extremely low variable operating cost and an extremely high fixed cost of operation.

From a modeling perspective, having a large fraction of costs represented as fixed costs means that the unit dispatches at a very high capacity factor—possibly well above its expected capacity factor if it were representing its coal costs as variable. Therefore, the unit appears more competitive on an hour-to-hour basis than it actually is.

Q How much of the cost of fuel at SJGS is represented as a variable cost?

A PNM models only a small fraction of its coal supply as variable. From the Strategist runs, we find that PNM models the variable cost of coal at about $1.00 MMBtu (real 2014$) from 2015 through 2034, inclusive. We can compare this against the cost of coal that SJGS self-reports to the Energy Information Administration (EIA). In 2013, SJGS reported a weighted average cost of coal at $2.30 per MMbtu,[15] or nearly two and a half times PNM's Strategist assumption. In discovery responses, the Company estimates coal prices of $2.40 per MMBtu in 2014,[16] while in the 2014 Draft IRP, the Company estimates base SJGS coal prices of $2.71 per MMBtu in 2014—nearly three times higher than the variable

[15] US Department of Energy, EIA Form 923, Fuel Costs and Receipts
[16] See PNM Exhibit NEE 1-17

price modeled in this docket.[17] The model, discovery responses, the IRP, and recent history are all inconsistent.

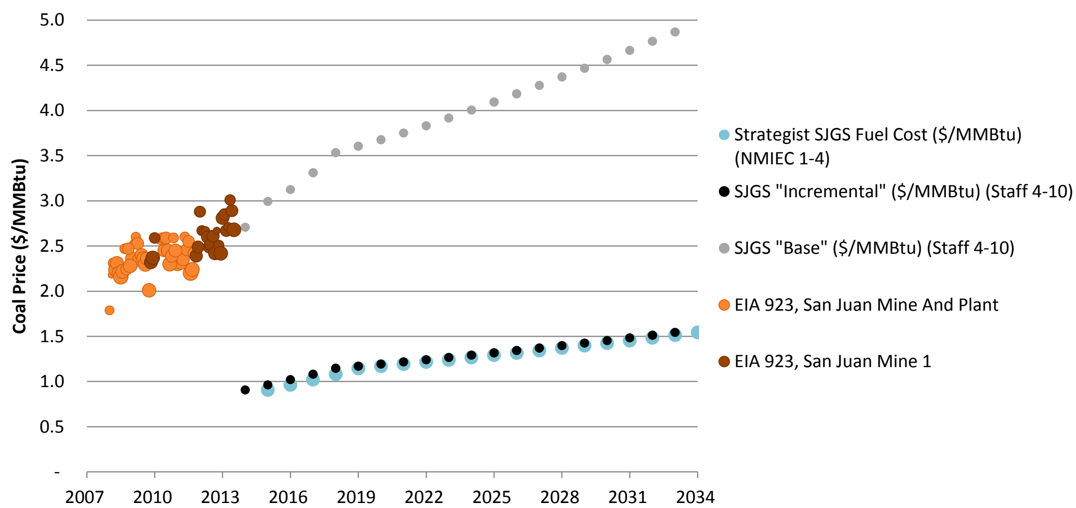

Figure 2. Cost of coal at SJGS, from historical records (EIA 923), the "base" and "incremental" prices reported in Staff 4-10, and the prices as modeled in Strategist from NMIEC 1-4.

Q Why did the Company use the very low cost of coal in Strategist modeling?

A The Company provides the following explanation:

> The fuel price for SJGS is based on two components: the base fuel cost and incremental pricing. The base fuel cost represents the minimum take or pay obligation in the coal contract. For modeling purposes, PNM has included the base fuel cost as a component of the fixed O&M costs for SJGS.[18]

What this means, in effect, is that the Company assumes that, because it has signed a take-or-pay agreement through 2017 with its coal supplier, the San Juan Coal Company (SJCC), the coal it receives under this contract is not avoidable

[17] See Draft PNM 2014 IRP, page 149.
[18] Response to Interrogatory CCAE 1.6

through reduced generation at SJGS—this apparently represents the vast majority of the fuel cost in the model. The remaining variable cost that the Company models is an "incremental" cost. It is not clear either through the Company's explanation, ancillary materials, or even its contract if the incremental cost represents a variable labor cost paid to SJCC for all the coal received, or the cost of the second tier of coal received after the minimum take. Regardless of the interpretation, modeling coal fuel costs as a fixed cost is still inappropriate.

Q In your experience, do most utilities model their fuel costs as fixed, variable, or a combination of both?

A In my experience, almost every utility model that I've examined considers fuel a fully variable cost. This is appropriate because, generally, the more a unit operates the more coal it consumes and thus the more it pays for that coal. Similarly, coal fuel costs can be avoided by reducing the output of a unit.

Q Why is modeling a take-or-pay contract as a fixed cost inappropriate?

A In almost all cases, forward system modeling should represent opportunity costs, or the costs of avoiding or pursuing particular outcomes. To the Company, its coal supply represents an avoidable cost.

In the near term, should the Company choose not to consume coal at SJGS, the Company could feasibly export or market its excess supply, or option to terminate or renegotiate its contract with SJCC. Such actions may have penalties or costs; to estimate the avoidable cost of coal, these costs would simply be deducted from the market value (or real value) of the coal. Essentially, PNM should model the market cost of its coal, rather than simply the incremental cost.

After the natural expiration of the current coal contract in 2017, all forward-looking costs of coal are fully and absolutely avoidable, and thus should be modeled as variable costs. To the extent that the high cost of coal at San Juan renders the unit (or units) non-economic to operate, or operate at a bare minimum, PNM should negotiate its next contract with a coal supplier, or arrange to self-supply, accordingly. The Company agrees that it is free to negotiate a new coal contract with SJCC.[19] Because the Company has the opportunity to avoid every ton of coal obtained after the expiration of the current contract, all coal costs after that date are variable. The coal contract expires in 2017;[20] thus, regardless of the Company's take on near-term avoidable coal costs, all coal costs at SJGS past 2017 should be considered variable.

Q Is it clear if the Company has modeled a take-or-pay contract after the expiration of the current contract at the end of December 2017?

A Not at all. The Company models a still very low variable cost of coal from 2018 through the end of the analysis period in 2033. However, as shown in Figure 1, above, the variable cost of coal remains very low through 2033, mirroring the "incremental" cost of the coal projection. It is not at all clear, however, that the take-or-pay component of the contract, which the Company considers fixed, is

[19] See CCAE 3.7
[20] See response to WRA 1.3. "no final agreement has been reached on a coal supply for SJGS beyond 2017."

modeled after 2018. If this is the case, then the Company has failed to include a substantial avoidable cost in the Strategist model.

Q What should the Company model as the variable cost of coal past 2017?

A PNM provided an estimated trajectory of coal costs for SJGS in Staff 4.10, identical to those provided in the Draft 2014 IRP, released July 2014. I have assumed that these are the most up-to-date coal trajectory prices known to the Company. These prices are higher than a series of prices provided in NEE 1.17, and the Company has stated that NEE 1.17 is consistent with the ranges estimated by an external consultant, PACE Global, in reviewing post-2017 coal supply options.[21] Therefore, I believe that the base coal prices provided in Staff 4.10 likely represent the most up-to-date coal projections available to the Company, and that the total all-in cost of coal should be considered for the variable cost after 2017.

Table 5. Coal variables costs as modeled by PNM compared against correct fuel costs (from Staff 4.10)

	Coal variable cost as modeled (nom $/MMBtu)[22]	Correct coal variable cost (nom $/MMBtu)[23]
2014	$0.91	$2.71*
2015	$0.96	$2.99*
2016	$1.02	$3.12*
2017	$1.08	$3.31*
2018	$1.15	$3.90
2019	$1.17	$3.98

[21] See ABCWUA 5.9(b). Question: "Provide the fuel analyses undertaken to date that demonstrate that it can be anticipated that remaining participants will be able to secure post-2017 fuel supply for San Juan at costs consistent with the inputs utilized in PNM's models in this case." Response: "PNM's consultant, PACE Global, has also conducted additional work that indicated future coal price ranges that were approximate to those included in Exhibit NEE 1-17."

[22] From Strategist output, provided in NMIEC 1.4, IRP_A05, also aligns with incremental cost from Staff 4.10

[23] From Staff 4.10

2020	$1.19	$4.06
2021	$1.22	$4.14
2022	$1.24	$4.23
2023	$1.27	$4.32
2024	$1.29	$4.42
2025	$1.32	$4.52
2026	$1.34	$4.62
2027	$1.37	$4.72
2028	$1.40	$4.82
2029	$1.43	$4.93
2030	$1.45	$5.04
2031	$1.48	$5.15
2032	$1.51	$5.26
2033	$1.54	$5.37

*May require adjustment for termination or market export.

This correction would increase the variable cost of coal by 340% in 2018.

Q Are there additional implications of the Company's current contract structure with regards to this case or the Company's forward-looking assessment?

A Yes. I understand that the Company is currently negotiating a new contract with SJCC for coal post-2017, and is also exploring alternative supply options.[24] The Company has stated that it is <u>not</u> willing to defer completion of the new contract until after the final decision in this case.[25] Therefore, prior to receiving approval for the current application, PNM may commit to a new coal contract or even a

[24] See response to ABCWUA 5.9(a). "A negotiating team, composed of various representatives of the owners of San Juan Generating Station, (SJGS) is engaged in discussions with San Juan Coal Company for procurement of coal for SJGS for the period of time following the current contract's December 31, 2017 expiration date. At the same time, exploration work on the Ute Mountain Ute coal reserve is continuing."
[25] See CCAE 3.8. Question: "Is PNM willing to defer completion of the new coal contract with BHP [SJCC supplier] until after the final decision on the replacement plan is approved by the PRC?" Answer: "No."

self-supply option, all of which would have significant ramifications for the commitment of capital and operational costs for years or decades to come. The net present value of the costs contemplated in the current docket, at about $213 million (NPV 2014$ from 2014-2034),[26] pale in comparison to the Company's impending commitment for a long-term coal contract. I estimate that a new similar deal at SJCC would represent a commitment of about $848 million (NPV in 2014$ from 2018-2034 only) by PNM, a cost that would then be sunk (and potentially stranded should the plant be retired prior to the end of the contract period).[27] It is deeply troubling that such a coal contract would likely not be subject to regulatory review prior to its execution, but could quickly commit PNM's ratepayers to decades of power from San Juan.

Q What would be the outcome of modeling San Juan coal as a variable, rather than fixed cost?

A Modeling the full, all-in cost of coal at San Juan would increase the dispatch cost of SJGS significantly. The Strategist model indicates that the dispatch cost of SJGS 4 is approximately $9.73 per MWh in 2014, representing only the incremental cost of coal (i.e., $0.91 per MMBtu)—in other words, not including emissions costs, the all-in cost of coal, or variable O&M.[28] If the full, all-in cost of coal were modeled instead, SJGS 4 would dispatch at $29.02 per MWh in

[26] Based on PNM Exhibit HEM-10 (July 15 Supplemental), 20-Year revenue requirement for various plans. RSIP with PV3, 132 MW of SJ4.
[27] Based on the base price projection from Staff 4-10 and estimated fuel consumption 2018-2034 from SJGS 1-4 in NMIEC 1.4 run 14IRP A05, and using an 8.18 percent discount rate.
[28] I assume that carbon costs are treated appropriately in the model as a variable cost of production. Strategist reports emissions costs separately.

2014, just $4.34 per MWh short of the annual all-hours market price of energy estimated by PACE.[29]

The variable cost of production at SJGS based on both incremental and base fuel costs, as well as the market energy price assumed by PACE are shown for 2014-2033 in Figure 3, below.

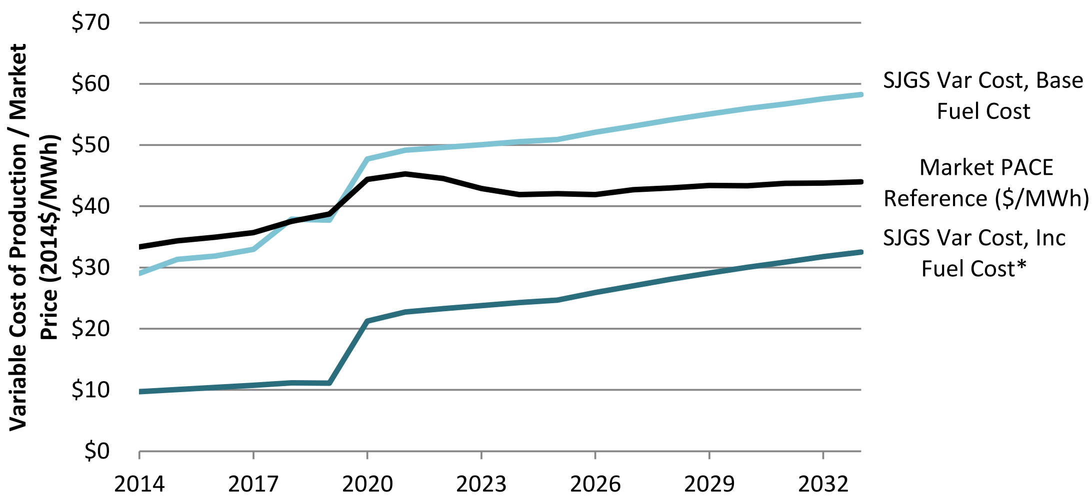

Figure 3. Variable production cost of SJGS as assumed by the Company based on the "incremental" fuel price (*), as based on the "base" fuel price, and all-hours market price from PACE.

In 2018, after the expiration of the current coal contract with SJCC, the forecast all-in cost of coal at SJGS drives the dispatch cost of SJGS above the all-hours market price of energy, again even assuming no emissions costs and no variable O&M. SJGS 4 would dispatch at $37.88 per MWh, but PACE estimates that market energy could be procured at $37.51 per MWh—$0.37 per MWh below the cost of SJGS (2014$). Under this circumstance, dispatching at a high capacity

[29] This still assumes no variable O&M cost and no emissions cost in 2014. PACE market energy prices from 2014 IRP Stakeholder meeting materials, Marketlink Scenarios Handout, September 2013. Available from PNM at https://www.pnm.com/documents/396023/428017/092613-pace-scenario.pdf/b57b867c-cebd-4921-aac4-b03cbfc4740a. Reference case.

factor would incur energy revenue losses at SJGS—not even accounting for all of the fixed costs associated with SJGS. A low capacity factor dispatch would mean that PNM's ratepayers would incur significant fixed costs without the benefit of energy from the station.

In later years, the addition of a carbon price assumption (again, from PACE in the reference case) drives the dispatch cost of SJGS well above market prices. By 2024, the dispatch cost of SJGS is $8.68 per MWh above market prices (2014$); this gap continues to open over time.

All of SJGS's coal procurement is avoidable after 2018; therefore, it should all be modeled as a variable cost. The forecast cost of coal for this plant is so high that it appears, even in the absence of additional modeling, that the procurement of additional SJGS capacity would be a significant net liability relative to market energy. The costs are so high, in fact, that it suggests that PNM faces a liability simply by continuing to hold its own assets at SJGS 1&4.

4. MODEL CONFOUNDS VARIABLE AND FIXED O&M

Q You indicated in the introduction and above that the dispatch cost of SJGS does not include the variable cost of operations and maintenance. Please elaborate.

A PNM's Strategist model appears to put all O&M costs (as well as some capital, and take-or-pay contracts for coal) in the fixed cost category. The model shows zero costs for variable O&M through all years and all scenarios at San Juan, Four Corners, and Palo Verde.

Q Are you absolutely certain that all O&M costs are in the fixed cost category in Strategist?

A No. I can only be certain that variable O&M costs are zero in the model, and I suspect, based on various discovery responses, that the equivalent of variable O&M has been incorporated into the fixed O&M category.

As far as I am able to discern, the fixed O&M category in Strategist incorporates all O&M, all capital improvements, and the "take or pay" provision of the Company's coal contract with SJCC.[30] However, despite numerous requests from various interveners,[31] PNM provided no workbooks that explicitly show the derivation of the costs found in the fixed O&M category of the Strategist model, and requests for clarity are confounding and confused.[32] These values are directly input by the model user; in my experience, an ancillary spreadsheet is usually used to compile fixed costs that are then input by the model user. As far as I am aware, no such spreadsheet was provided to interveners.

The Company indicated that Mr. Monroy's workpapers were used as the basis of the O&M costs found in Mr. O'Connell's Strategist modeling,[33] but there are no

[30] See response to CCAE 1.6. "For modeling purposes, PNM has included the base fuel cost as a component of the fixed O&M costs for SJGS."

[31] ABCWUA 1.1(b), ABCWUA 1.15, ABCWUA 4.4 (all), ABCWUA 5.2(b), ABCWUA 5.11, NEE 1.1, CCAE 1.1, CCAE 1.7.

[32] See, for example, CCAE 1.8 explaining the difference between discovery responses and reality. "The costs given in the September ERP meeting handout "Existing System Information" were based on actual O&M and fuel costs from 2012. Variable O&M costs for San Juan shown in PNM's exhibits responding to ABCWUA Interrogatory 1-15 reflect a calculated variable O&M for each year in the 20-year study period, and are not comparable to actual values from 2012." It should be noted that the response to ABCWUA 1-15 are Strategist runs, in which variable O&M costs for San Juan are listed consistently as zero, while "actual O&M" costs from 2012 as shown by the Company in the Draft 2014 IRP were not.

[33] ABCWUA 4.4 effectively asks for the Company to provide a detailed breakdown of which O&M costs were included in the Strategist modeling. The response provides a spreadsheet that shows total costs (PNM Exhibit 4.4c) but none of the costs here appear identical or even reasonably commensurate with the values found in the fixed O&M category of the Strategist model.

numbers in common between the fixed O&M costs derived from Strategist and Mr. Monroy's workpapers, and there is no indication as to how these workpapers were used. As I've described in the fuel and capital sections above, attempting to reverse engineer the O&M values did not result in a consistent story: it is unclear what costs are in the fixed O&M category in the Strategist model run by the Company.

Q Is it reasonable to assume that all O&M costs are fixed, rather than variable?

A No. Variable O&M costs include component replacement costs, costs for catalysts, chemicals and additives, water supply costs, plant scheduling costs, and some labor expenses—any cost that is incurred by incrementally running the unit. As one basic example of this type of cost assuredly present at San Juan is the cost of catalyst for the unit's flue gas desulfization (FGD) system. Every megawatt-hour of energy produced by SJGS produces sulfur, which must be scrubbed using the FGD's catalyst; avoiding generation thus avoids catalyst expense. This same logic is applicable to water, scheduling, wear-and-tear, and other costs.

Q What is the impact of failing to parse variable and fixed O&M expenses in the Company's Strategist model?

A As with assigning fuel costs to the fixed cost category, assigning variable O&M to a fixed cost category significantly underestimates the dispatch cost of SJGS, making it appear more economical to operate in the model.

Q What is a reasonable variable O&M cost for the Company to use in modeling?

A In my experience, most utilities have a fairly firm idea which of their costs are avoidable on a generation basis, and model these variable O&M costs accordingly. In the 2014 Draft IRP, the Company shows O&M costs for SJGS as $10.66 per MWh (i.e., on a variable basis).[34] It is confounding that these costs are cited as from FERC Form 1, which is, of course, self-reported by PNM, implying that PNM's planning and resources team (Mr. O'Connell) does not provide coordination between the generation and IRP teams. I suspect that these O&M costs in the 2014 Draft IRP are total O&M expenses, because FERC Form 1 does not explicitly break out fixed and variable costs.

The National Renewable Energy Laboratory (NREL) reviewed several public datasets to estimate average coal variable O&M costs (as well as other planning costs). In one figure, NREL shows costs from just under $2 per MWh to close to $5 per MWh for coal units (2007$).[35] If we conservatively assume that one third ($3.55 per MWh, 2012$) of the $10.66 per MWh shown by PNM are variable by nature, then PNM should model about a $3.73 per MWh (2014$) variable O&M cost in the Strategist model.

Using the reasonable assumption that all future SJGS coal is avoidable (and thus a variable cost), and that the company has variable O&M costs that impact its dispatch decisions, the dispatch cost of SJGS exceeds the all-hours market energy

[34] 2014 Draft IRP, Table 2-H: O&M Costs: Owned and Contracted Resources

[35] Tidball, R., J. Bluestein, N. Rodriguez, and S. Knoke. 2010. Cost and Performance Assumptions for Modeling Electricity Generation Technologies. ICF International for NREL. Table 16. Variable O&M in 2015 (2007$/MWh). http://www.nrel.gov/docs/fy11osti/48595.pdf.

price by $4.11 per MWh (2014$) in 2018 and by $12.42 per MWh (2014$) in 2025. Figure 4, below, shows the trajectory of variable production costs at SJGS from 2014-2033 under the base and incremental fuel price cost assumptions with variable O&M, against the PACE market price.

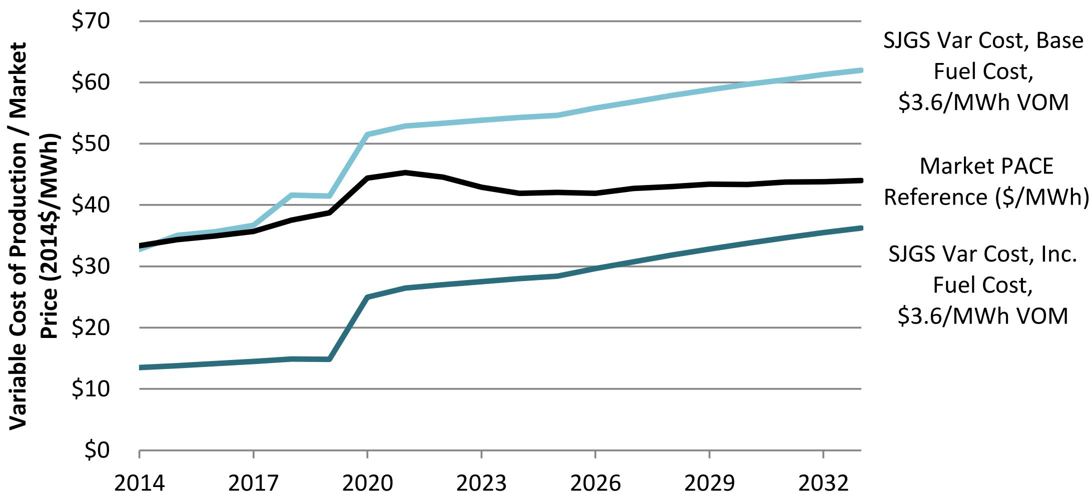

Figure 4. Variable production cost of SJGS as assumed by the Company based on the "incremental" fuel price (*) with $3.73/MWh VOM, as based on the "base" fuel price with VOM, and all-hours market price from PACE.

If PNM were representing the correct avoidable operational costs in its model, it is quite possible that the unit would show significant declining dispatch by 2018.

By 2025, SJGS would dispatch cost effectively only during peak hours,[36] at best, and dispatching during very few hours, if at all.[37]

Q What conclusions can you draw based on the Company's portrayal of variable and fixed O&M costs in Strategist?

A The Company's insistence that all O&M and the vast majority of fuel costs at SJGS are fixed in nature significantly underestimates the actual avoidable cost of generation at SJGS. The variable production cost of SJGS is far higher than portrayed by the Company, and thus SJGS should dispatch at a much lower capacity factor in the future.

I find it difficult to understand why the Company would take on the substantial risk of a unit that, according to reasonable assumptions, may not dispatch economically during many hours of the year in just four years from today. With a lower capacity factor, ratepayers will be paying for substantial fixed costs without the benefit of much generation, in contrast to the modeling performed by the Company. Under this circumstance, customers may have to pay for energy from non-PNM sources to provide their requirements, while still paying for the high fixed costs of SJGS.

[36] For example, the Company estimates the variable production cost of Luna Generating Station, a combined cycle unit, at $56.76/MWh (nominal) without CO_2 prices. Assuming a CO_2 emissions rate of 0.60t/MWh and a 2025 CO_2 cost of $17/ton, Luna would dispatch at $66.96/MWh (nominal), or $51.03/MWh (2014$). In contrast, according to the calculations above, SJGS 4 would dispatch at $54.30/MWh (2014$). In other words, barring transmission constraints and losses, Luna could be dispatched at a lower cost in 2024 than SJGS, a proposition likely to result in very low capacity factors for the coal unit.

[37] Coal units require significant periods to ramp up to full output, and are not well equipped to cycle to avoid generating during low cost hours. Committing a coal unit during marginal economic periods risks operating non-economically, and thus production cost models may choose not to operate marginal coal units at all to avoid non-economic commitments.

If the Company actually dispatches SJGS with the assumption that all O&M and most fuel costs are fixed, rather than variable, then customers would effectively be subsidizing a non-economic energy source: while the unit will produce more energy, customers will be committed to paying fixed costs that they should be able to otherwise avoid by using lower-cost energy resources.

5. <u>Market Purchases and Sales Excluded from Modeling</u>

Q You've stated that the Company should be able to acquire lower-cost market energy resources. Why doesn't the Company's model identify market energy as a resource if it is available at lower cost?

A The Company models PNM as an island, inaccessible by market energy resources and unable to buy from other utilities or generators, or to sell excess energy. PNM has access to a very active energy trading hub at Palo Verde—indeed, the Company's non-regulated share of Palo Verde 3 acts as a merchant generator that sells onto an open market. Despite this access, the Company assumes no market access to the regulated utility.

Q How are you able to tell that the Company has assumed no energy market access?

A The Generation and Fuel (GAF) module of the Strategist model has a line item report for "economic transactions," which represent open market purchases and sales.[38] These are not listed in the Company's Strategist outputs, and in every circumstance, the Company's own resources and PPAs match their requirements exactly (see Figure 5, below). In model runs that include economic market transactions, the Company's resources and PPAs may over- or under-supply energy requirements, where the remainder is provided to or from the open market.

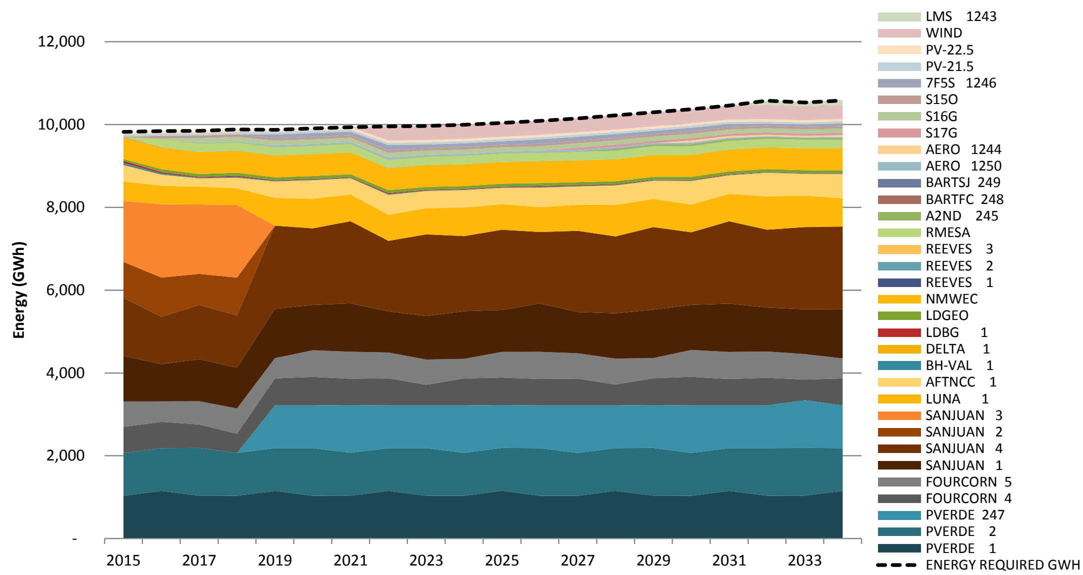

Figure 5. Energy requirements and generation provided by PNM resources in reference case (14IRP_A05, NMIEC 1-4)

Q What is the implication of not having market energy available in the Company's model?

A There are two critical implications. First, if in the long run market energy is available at a lower cost than from PNM's own avoidable resources, the Company should carefully evaluate this option. Second, if at any given time market energy is available at a lower cost than the variable production cost of any of the Company's resources, the Company should acquire the market energy resource

[38] Economic transactions ("ECON PURCH" and "ECON SALES") are different than contract transactions ("TRANS PURCH" and "TRANS SALES"), which represent fixed-term power purchase agreements (PPA).

and avoid the use of its higher-cost resource. In PNM's case, I've estimated that the appropriate variable cost of SJGS is higher than the all-hours projected cost of market energy after 2018, implying that the Company would be dispatching SJGS non-economically after 2018 relative to the market. This discrepancy does not show up in the Company's model because (a) most costs are characterized as fixed and (b) market energy is not made available in the model.

Q Did the Company explain if market energy purchases were available in the model?

A Yes, although not clearly. In one response to NMIEC, the Company provides two completely contrary model views in four different answers. NMIEC 1-17(a) asked the Company to identify any "economy interchange systems" used in the Strategist modeling (commonly understood to mean market purchase or sales nodes). The Company responded that the external market was represented by an hourly price curve, which implies that economic purchases and sales are available in the Strategist model. However, in part (b) of the same question, the <u>inclusion</u> of the market is affirmed by the statement that "the external market is representative of a[n] hourly price curve where purchases and sales can be made to meet the demands of the system." However, this same response then notes that the "external market is only used for risk analysis and not the optimization process," which implies that it is not included in the Strategist modeling. The <u>exclusion</u> of the market is then affirmed in the next response (c), which states that "PNM does not model any transmission links in Strategist." In Strategist, the absence of a transmission link means that imports and exports are impossible, thus a market is excluded. Finally, just to ensure a fully ambiguous response, PNM shows a diagram in (d) representing its system (as shown in Figure 6, below) that shows a bi-directional arrow between a PNM bubble and the "external market."

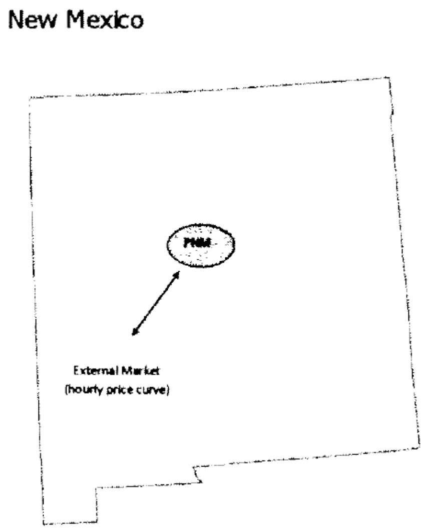

Figure 6. PNM's representation of their market system as represented in Strategist. Copied from Company response to NMIEC 1-7(d).

These responses are mutually inconsistent and unclear. To clarify: PNM has excluded an external energy market from the Strategist modeling that underlies this application. In reality, however, PNM operates as an open system, buying and selling on the energy market; if PNM does not engage in market transactions, it cannot guarantee a procurement of least-cost energy for its ratepayers.

6. End Effects Excluded from Modeling

Q Please explain "end effects."

A End effects take into account the long-term capital and production cost implications of extended investments. The end effects calculation freezes the system in its final state at the end of the planning period and reviews the long-term costs (and benefits) of that system. For example, when comparing resources that have low capital requirements but high operating costs against resources with high upfront capital requirements and low operating costs, end effects can be highly illustrative.

End effects are also important in the consideration of long-run environmental costs that are expected to increase over time, or costs that come into play near the end of the analysis period. In the Company's analysis, for example, carbon prices are implemented in 2020,[39] but the analysis ends in 2033/2034, meaning that carbon is priced for about 13 years. Over the long run, an assumption on the price of carbon may be quite important in the determination of an optimal portfolio.

Q How are you able to determine that the Company did not include end effects?

A In Strategist, the Study Period Plan Comparison report shows the present value of each optimal and suboptimal plan over the planning period, as well as the present value of the end effects period. In the PNM model, the end effects period consistently has a zero value,[40] and thus I infer that end effects were not included. In some utilities, end effects are calculated externally and implemented as part of the fixed cost calculation, resulting in a large spike in fixed costs for the last year of the analysis. This is not the case in the PNM analysis.

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[39] See Exhibit PJO-3, line "CO2 Pricing."

[40] See, for example, NMIEC 1-4, reference case 14IRP_A05.REP, line "end effects period" for any given plan.

Q What can you conclude about this analysis in the absence of an end effects calculation?

A While an end effects calculation unto itself should not make or break an analysis (because it represents costs and risks by definition further into the future), it is a reasonable mechanism of evaluating long-term risks and costs, particularly with plans that entail the procurement of long-term contracts or resources, especially when potential resources have a range of carbon implications. Excluding end effects calculations causes a bias towards the selection of carbon-intensive resources (such as the additional coal at SJGS 4) when long-run carbon prices are excluded.

7. COAL ASH REGULATIONS EXCLUDED FROM MODELING

Q Please describe the coal combustion residuals proposed rule.

A Coal-fired power plants generate a tremendous amount of ash and other residual wastes, which are commonly placed in dry landfills or slurry impoundments; regulations governing the structural integrity and leakage from these installations vary. However, the risk associated with these installations was dramatically revealed in the catastrophic failure of the ash slurry containment at the Kingston coal plant in Roane County, Tennessee in December 2008, releasing over a billion gallons of slurry and sending toxic sludge into tributaries of the Tennessee River. On June 21, 2010, EPA proposed regulation of ash and FGD wastes, or "coal combustion residuals" (CCR), as either a Subtitle C "hazardous waste" or Subtitle

D "solid waste" under the Resource Conservation and Recovery Act (RCRA).[41] The coal combustion rulemaking resulted from a combination of missed statutory deadlines and court orders. The current rulemaking is 30 years overdue.

If the EPA classifies CCR as hazardous waste, a cradle-to-grave regulatory system will apply to CCR, requiring regulation of the entities that create, transport, and dispose of the waste. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required; in addition, the EPA would also implement minimum requirements for dam safety at impoundments.

Under a "solid waste" Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners, and require standards for long-term stability and closure care.

Q How are coal wastes currently handled at San Juan Generating Station?

A According to the Company, coal ash is "hauled to the adjacent San Juan Coal Mine for disposal in the surface mine. The coal ash is used as reclaim material in the pits."[42] Furthermore, the Company states that the costs and mechanism for this disposal are handled by San Juan Coal Company (SJCC).[43]

[41] 75 Fed. Reg. 35127. June 21, 2010.
[42] See response to CCAE 7-4
[43] See response to CCAE 11-2. "PNM, pursuant to the Underground Coal Sales Agreement and Coal Combustion Byproduct Disposal Agreement with SJCC, puts the coal ash generated from SJGS to beneficial use for purposes of mine reclamation in accordance with SJCC's mine permit."

Q Does PNM model a compliance cost for coal wastes in anticipation of the coal combustion residuals rule?

A Not as far as I am able to tell. There is no indication through Strategist or the associated workpapers of Mr. Monroy that costs for coal combustion residuals are factored into the Company's analysis. The Company was asked explicitly how it takes into account risks associated with the coal combustion residuals rule, and replied in vague terms, indicating that "PNM considered that the costs associated with handling fly ash and using the fly ash generated by SJGS for surface mine reclamation may increase in the future in PNM's 2011 Integrated Resource Plan," but that "the proposed rule is not expected to address placement of coal ash into surface mine pits which is the practice employed by San Juan."[44]

Q What coal combustion residual costs were considered in the 2011 IRP?

A The Company states that "in the 2011 IRP, PNM assumed, for purposes of the base case, a cost of $10/ton for ash disposal. The 2011 IRP also examined scenarios from $20/ton to $100/ton for purposes of sensitivity analysis."[45] However, the Company further states that the rule, if imposing a cost on coal ash, is immaterial to the analysis at hand:

> The result of this analysis is that the cost of PNM's generation portfolio increased without affecting resource option selections. Since the cost is primarily associated with surface mine reclamation and PNM's surface mine reclamation obligation is not

[44] See response to NMIEC 1-31.
[45] See response to NMIEC 1-31.

> affected by the proposed abandonment of SJGS Units 2 and 3 or PNM increasing its capacity in SJGS Unit 4, this potential increase in cost is not unique to any of the modeled scenarios, except potentially the four unit shutdown case.[46]

Q Do you agree that a sensitivity of coal ash handling costs should "increase [costs] without affecting resource option selections?"

A No. Coal ash is produced proportionally to the coal consumed and burned—less production will result in lower coal ash and thus lower coal ash costs. Therefore, I would have expected coal ash costs to be modeled as a variable cost of production. This would, in turn, presumably impact the operating cost of resources that produce coal ash and resource option selections. The only ways in which this cost would not affect resource option selections are if the costs of coal ash were insufficient to impact production costs or if PNM did not test the cost of increased coal ash costs on the retirement of SJGS. Incorrectly modeling coal ash costs as fixed rather than variable costs would also tend to dampen the impact of this regulation.

Q Would the costs of coal ash be sufficient to impact production costs?

A Yes. I can derive from PNM's records that SJGS units 1-4 produce about 0.11 metric tons of coal ash per MWh of production.[47] At a cost of $10 per metric

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[46] NMIEC 1-31.

[47] Derived from data provided in CCAE 3.5 (coal ash production at SJGS 1-4, 2008-2013, presumed in short tons, translated to metric tons) and EPA's Air Markets Program Dataset (AMPD) annual generation at SJGS from 2008-2013. Slope = 0.108 tons/MWh.

ton,[48] this would add $1.1 per MWh of production cost. Similarly, at $20 and $100 per ton, the costs of production would be increased by $2.20 per MWh and $10.80 per MWh, respectively. My colleague, Mr. Van Winkle, indicates that the Company now estimates compliance disposal costs at $61 per ton, which if considered a fully variable cost would increase production costs by $6.59 per MWh. These are not insignificant variable production cost adders. Put in perspective, PNM asserts that the appropriate total variable cost of production at SJGS for Strategist modeling is about $10 per MWh in 2014.[49] Coal ash costs of $1 to $11 per MWh would assuredly impact production costs and dispatch.

Q Did PNM test the cost of increased coal ash costs on the retirement of SJGS in the 2011 IRP?

A No. PNM only tested two scenarios in the 2011 IRP in which SJGS was even considered for early retirement. In scenarios 14 and 24, PNM reviewed the retirement of SJGS 1 & 2 (340 MW) in 2022. Neither of these scenarios reviewed the higher coal ash costs.[50]

Q Is the cost of coal ash disposal a "mine reclamation obligation" that is "not unique to any of the modeled scenarios," as stated by PNM?

A Absolutely not. The coal combustion residuals rule would be promulgated under the Resource Conservation and Recovery Act (RCRA), which specifically requires that wastes, once produced, are disposed of properly. Therefore, coal ash

[48] PNM 2011 IRP, page 125 indicates that costs for coal ash are in metric tons.
[49] See response to NMIEC 3-2(a). "The costs of $9.50/MWh, $10.63/MWh, $10.32/MWh and $9.73/MWh are the annual incremental prices used for Strategist® modeling [at SJGS]."
[50] See PNM 2011 IRP, pages 205 and 207.

regulated under this rule would be a disposal cost for PNM, and not a problem that the Company can simply assume will be dealt with by SJCC. In particular, as the contract with SJCC comes to a close at the end of 2017, any coal ash disposal costs or liabilities will become PNM's sole responsibility. If PNM is able to negotiate a new deal with SJCC, I assume that this contract would include provisions to charge PNM for more expensive disposal if required under RCRA, and if SJCC continues to send waste products back to SJCC. Any potential to avoid additional coal ash costs is fully avoidable by generating less (or nothing) at SJGS, and thus is unique to each and every one of the modeled scenarios by PNM.

Q Is PNM facing additional costs for coal ash disposal today, even prior to the promulgation of the coal combustion residuals rule?

A Yes. In response to CCAE 7-3, the Company describes a legal settlement reached between PNM, SJCC, and Sierra Club obligating PNM and SJCC to construct a "recovery system" for effluents flowing from the San Juan mine ash disposal site. PNM describes that the system is estimated to cost $10.2 million ($4.5 million PNM share); PNM expects to recover these costs from ratepayers. The costs of coal ash disposal are already higher than baseline assumptions in the 2011 IRP.

Q What is your recommendation with respect to the coal combustion residuals rule?

A I recommend that, in this docket, the Company examine and then model appropriate proxy costs for coal ash disposal under the proposed coal combustion residuals rule. I further recommend that these costs are applied as a variable cost of production to the Company's coal units, and are made avoidable in full or in part through the retirement and/or curtailment of operation at any one or more of the Company's units.

8. <u>Carbon Price Does Not Represent Reasonable Range of Risk</u>

Q Does the Company have a position with regards to carbon price risk?

A Yes. Mr. O'Connell states that "it is simply not reasonable to assume that there will not be additional costs associated with greenhouse gas emissions during the twenty-year planning period."[51]

Q Do you agree with Mr. O'Connell's statement?

A Yes. The state of climate science continues to strongly indicate that carbon dioxide (CO_2) contributes to detrimental global climate change. I think that it is quite likely either the U.S. Environmental Protection Agency (EPA), or eventually Congress, will regulate CO_2 emissions during the Company's 20-year analysis window. On June 25, 2013, the President announced a series of initiatives to start regulating carbon emissions from new and existing fossil fuel fired electricity generators, and on June 2, 2014 the EPA released a proposed rule under section 111(d) of the Clean Air Act to regulate emissions of CO_2 from existing electric power generation units. The proposed rule, known as the "Clean

[51] Direct Testimony of Patrick O'Connell, page 18 at 4-6

Power Plan,"[52] is extensive and seeks to explicitly impact electric power planning and procurement practices.

Q Do you have a good sense of exactly what the regulation will entail when implemented in New Mexico?

A No. The Clean Power Plan bestows a tremendous amount of flexibility on states to engage in direct regulation of sources, influence and enforce utility planning activities, or engage in market-based emissions trading. States are currently figuring out mechanisms by which they can comply, and searching for cost-effective means of meeting the EPA's anticipated final regulations.

Q How should the Company anticipate the Clean Power Plan in this docket?

A In the absence of a firm state plan or further EPA guidance, the Company has two options: create a proxy plan for New Mexico that they believe would meet EPA requirements, with their own contribution explicitly stated, or use a proxy price (or prices) to represent a possible slate of activities that impact power sector CO_2 emissions. Generally, I think that for transparent planning purposes, utilities should continue using proxy "trading" prices until more information is known either on a federal or state level.

Q What prices does the Company use in this filing?

A The majority of the Company's runs are executed with a CO_2 price starting at \$11 per ton in 2020 (2014\$), rising to \$33 per ton in 2033. In response to discovery,[53]

[52] EPA 2014. See resources online at http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule

the Company shows that it also executed runs with a lower carbon price (starting at $10 per ton in 2027) and a higher carbon price (starting at $11 per ton in 2018, rising to $55 per ton in 2033). The results of these lower and higher priced runs are not presented in Mr. O'Connell's direct testimony, and when the Company provided supplemental testimony on July 1, 2014, runs were only executed with the reference case price.

These prices are markedly lower than the prices explored in the 2011 IRP, as shown in Figure 7, below. I see no reason why the Company's expectation of carbon prices should have fallen since the 2011 timeframe.

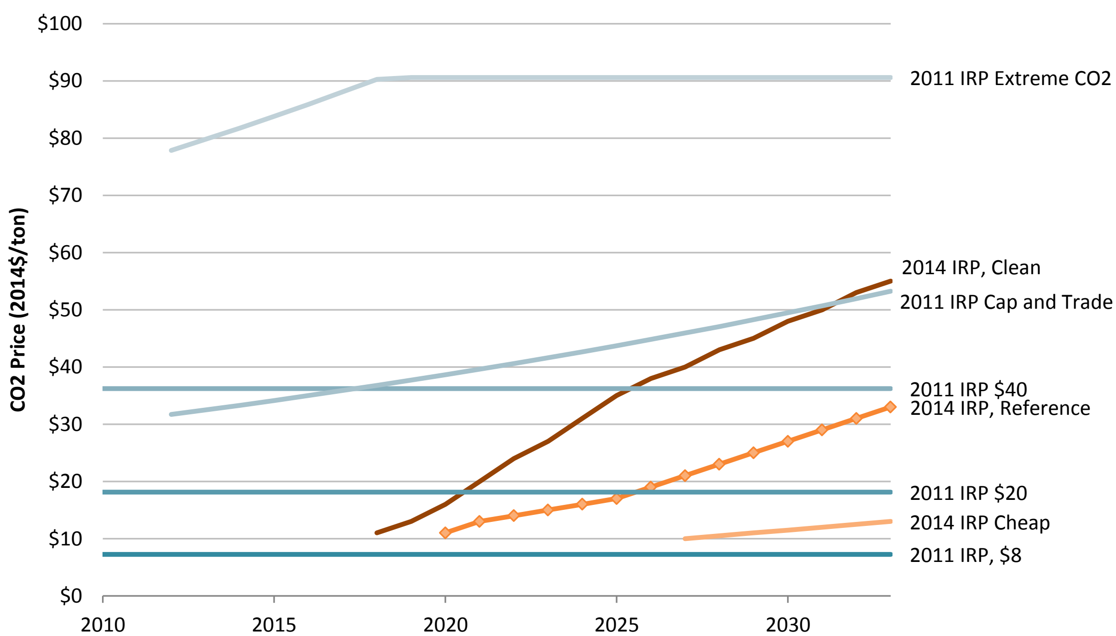

Figure 7. CO_2 prices as used in the 2011 IRP (blue tones) and the 2014 IRP and this docket (orange tones). The reference case used in this docket has annual diamond markers.

[53] NMIEC 1.4, "PNM Exhibit NMIEC 1-4 Legend," prices as in PNM Exhibit PJO-5, page 11.

Q What costs should have been explored by the Company?

A Carbon dioxide regulations (and possible eventual legislation) pose a serious risk to carbon-intensive resources. Runs executed by the Company should explore a wide range of prices, and the reference case should characterize a reasonable risk. My firm, Synapse, tracks the state of CO_2 policy and regulation and utility treatment of regulatory initiatives, and reports our findings in a paper that we make available to the public. Synapse has recently released an updated carbon price discussion paper and forecast, attached as Exhibit JIF-2. We break our forecast into a bounded region of likely prices, all starting in 2020. The mid-case starts at $15 per ton in 2020 and rises to $60 per ton by 2040 (2012$); this case represents our best estimate of a reasonable base case. The updated version of this paper, dated May 22, 2014, details the background and assumptions underlying the forecast.

Figure 8, below, shows the prices assumed by PNM compared to Synapse's 2014 CO_2 price forecast. PNM's reference case approximates the Synapse Low case, while the "Clean" case is between Synapse's Mid and High cases.

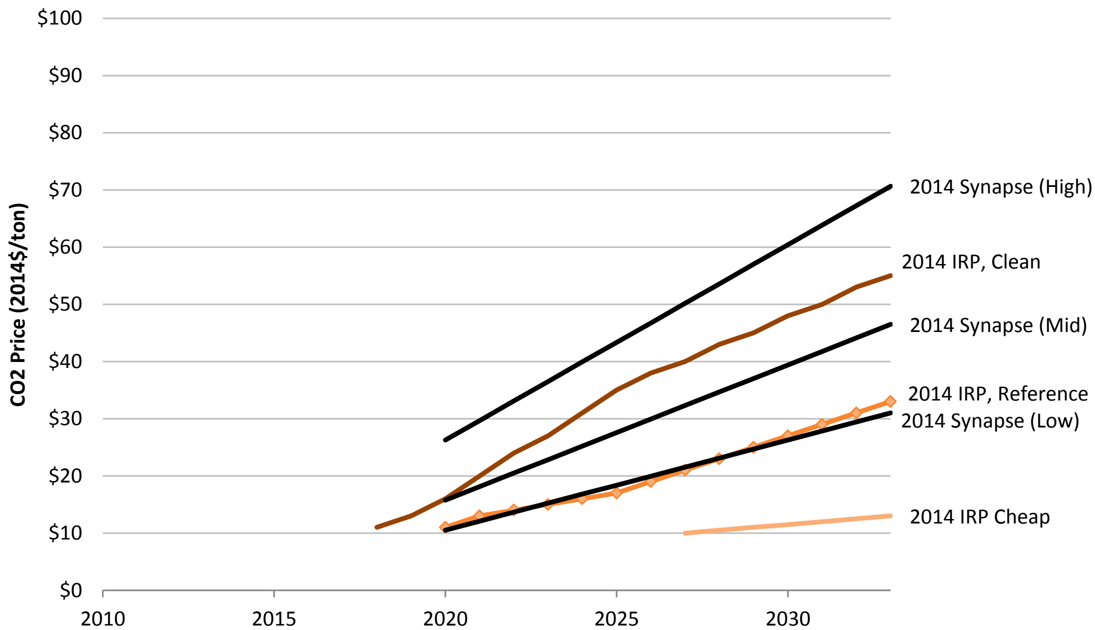

Figure 8. CO_2 prices used in this docket (and 2014 IRP) and Synapse prices (in black).

I recommend that the Company use a higher reference case to assess the economic merits of acquiring SJGS 4 and PV3 in this docket. The Synapse Mid case is a reasonable approximation.

9. <u>PALO VERDE ACQUISITION OFFERS NO CUSTOMER BENEFIT</u>

Q What is the value of acquiring a share in Palo Verde 3?

A There is little to no value of acquiring a share in Palo Verde 3, and evidence suggests that such an acquisition might actually pose a liability to the Company. As I showed in Table 2 (page 8), PNM would currently assess the value of acquiring the 135 MW share of PV3 at $3, or about $22 per kW. This value does not take into account annual ongoing capital expenditures at PV3,[54] resulting in a

[54] See response to ABCWUA 3-11.

similar problem as I discussed in Section 2 (page 9) with regard to capital expenditures at SJGS, and therefore likely over-values PV3. The value also fails to include the inevitable cost of decommissioning, an expensive prospect at nuclear facilities. PNM estimates that decommissioning expenses should add approximately $1.3 million per year to the costs of PV3, or a total unaccounted for expense of $9 million. The Company acknowledges that the "Palo Verde 3 decommissioning cost is approximately $9 million, which is more than the $3 million difference in NPV between the with- and without-Palo Verde Unit 3 cases presented on July 15," and that this results in a "net difference of $6 million."[55] Again, this $6 million difference does not account for ongoing capital not accounted for in the Strategist modeling, so the liability is likely significantly higher.

While the Company seeks to soften the impact of a $6 million liability of acquiring its affiliate's share of PV3 by claiming that it is "less than 0.1%" of the total system cost, this comparison is virtually meaningless. Regardless of the size of PNM's system—whether it is a $6 billion system or a $30 billion system—acquiring PV3 at $2,500 per kW (as assumed by the Company) is a loss of at least $44 per kW. On net, PNM should be willing to acquire PV3 for far less than $2,500 per kW.

[55] See response to ABCWUA 5-10.

10. CONCLUSIONS AND RECOMMENDATIONS

Q Please summarize your findings.

A The Company's application seeks permission to construct and recover the costs of selective non-catalytic reduction (SNCRs) at San Juan 1 & 4 (Jan 2016),[56] abandon San Juan 2 & 3 (Dec 2017) and place the stranded costs in a regulatory asset for full recovery,[57] acquire 132 MW of additional capacity at San Juan 4 (Dec 2017),[58] and acquire the Company's affiliate share in Palo Verde 3 (Jan 2018).[59]

With the exception of the Company's proposal to handle stranded costs and the creation of regulatory assets, these actions are all based on Strategist modeling, which I have argued is insufficient, flawed, and poorly documented.

I find that the Company, as late as its second supplemental filing in mid-July (a full eight months after the initial application was filed), maintained fundamental errors in its analysis regarding expected ongoing capital expenditures at San Juan, Palo Verde, and Four Corners. These capital expenditures are critically important to determining if the Company's plan to acquire additional shares of Palo Verde and San Juan are reasonable and prudent. To date, the Company has not provided corrected testimony incorporating these costs, only disclosing outcomes in late-filed discovery responses.

[56] Direct Testimony of Gerard Ortiz, page 3 lines 3-7.
[57] Direct Testimony of Gerard Ortiz, page 2 lines 10-15.
[58] July 15 Supplemental Testimony of Gerard Ortiz, page 6 lines 8-12.
[59] Direct Testimony of Gerard Ortiz, page 2 lines 16-20.

I have shown that the Company's fuel costs are inappropriately characterized as a largely fixed rather than variable cost (if incorporated at all after 2018), causing the model to assume an erroneously favorable production cost. Similarly, I find that the failure to break out variable versus fixed costs of O&M inappropriately favors the dispatch of San Juan over other units.

The failure to include off-system sales or purchases, or any market price or influence, prevents the Company's model from balancing owned resources against market-available resources, and obfuscates the poor performance of the Company's units if they were dispatched with appropriate variable costs.

Further, I find that the Company has inappropriately de-valued coal ash mitigation costs under the proposed coal combustion residuals rule from EPA, and has failed to robustly model risk associated with impending carbon regulations.

Finally, I find that a reasonable analysis of Palo Verde 3 indicates that at a purchase cost of $2,500 per kW, ratepayers will hold a liability rather than an asset.

As a result of these numerous and substantial flaws, the Company's model cannot be said to be an accurate portrayal of PNM operations, the real financial risks associated with acquiring either San Juan 4 or Palo Verde, or even a reasonable assessment of whether maintaining ownership of San Juan 1 & 4 is economically beneficial for ratepayers at all.

Q **Does the Company need to obtain approval for the acquisition of San Juan 4 or Palo Verde 3 in this filing?**

A No. I understand that the Company has been in active negotiations with San Juan partners about the divestment, transfer, and closure of units, and that these negotiations may require some assurances from this Commission that PNM will not be unduly harmed by making rational decisions to abandon non-economic and unnecessary units. I also understand that the Company requires approval to install SNCR at San Juan 1 & 4 to meet EPA compliance deadlines.

However, coupling this filing with the requirement that the Company be allowed to obtain San Juan 4 and Palo Verde 3, and recover costs on the SNCRs, is unnecessary at this time. Recovery of costs for the SNCRs should be deferred until after these controls are in service. The acquisition of San Juan 4 and Palo Verde 3, both slated for the end of 2017 or the start of 2018, are under no immediate pressure to proceed, and may safely be deferred as the Company executes improved modeling and re-examines its requirements.

Q **Should the Company's desire to move Palo Verde 3 into a regulated asset dictate its actions in this case?**

A No. The regulated arm of PNM may seek to sign power purchase agreements (PPAs) with Palo Verde 3, and the affiliate merchant arm of PNM may seek to sell Palo Verde 3 on a competitive market. If its value to PNM's ratepayers reasonably exceeds the value to any other potential buyer, then PNM should seek to transfer the asset to rate base. To determine if this is the case, PNM's merchant arm should offer the asset for sale to all buyers, and PNM's regulated arm should consider offering an RFP not exceeding the value to ratepayers. This offer for sale and offer to acquire should be conducted at arm's length.

Q Has the Company issued an RFP for capacity or energy?

A No. The Company explains that an RFP is unnecessary because the modeling conducted by the Company indicated that the least-cost baseload capacity would be the acquisition of its nuclear resource.[60] However, as I've shown, the Company's modeling is deeply flawed, and the issuance of an RFP would normally precede modeling to see if bids received are, on net, advantageous to the Company. The Company further explained that an RFP would be unnecessary and overly burdensome because it would likely select the nuclear capacity at Palo Verde 3. I think that when considering costs on the order of magnitude at issue in this case, the burden of issuing or evaluating RFPs is fairly minimal on a relative scale. The Company's circular logic should not be used as an excuse not to seek the least-cost option for PNM ratepayers.

Q Should the Company seek to acquire an additional share in San Juan 4?

A Not at this time, no. The Company's evaluation of San Juan 4 is flawed in multiple respects, and should be modeled correctly, re-examined, and audited carefully prior to the acquisition. The fact that the Company expects to acquire

[60] ABCWUA 4.8 Response regarding the issuance of an RFP: "No, PNM has not requested proposals for baseload or intermediate energy. The resource modeling has shown a combination of nuclear, solar and gas peaking capacity to be the best replacement option for SJGS. Of those three, only nuclear is considered baseload capacity. The only other potential baseload or intermediate capacity to replace coal baseload capacity would be natural gas combined cycle. The resource modeling has shown the cost of natural gas, the volatility of the price of that fuel and the associated greenhouse gas emissions makes nuclear the preferred replacement option. Having made that determination, an RFP is an unnecessary, overly burdensome process for both PNM and any potential bidders since the result of an RFP would have been to select the nuclear capacity that PNM already owns."

San Juan 4 at zero up-front cost does not necessarily render it a good deal. It is quite possible that San Juan 4 should actually be acquired at a negative cost—i.e., PNM's ratepayers should be compensated for taking additional shares of this unit. If San Juan 4 has a negative value, the Company should very carefully examine its costs and obligations at its existing shares of San Juan 1 & 4, and determine if ratepayers benefit from the continued use of these units.

Q What are your recommendations to this Commission with regards to the case at hand?

A I recommend that the Commission:

1. Deny approval of the acquisition of any additional capacity at San Juan 4 at this time;
2. Deny approval of the acquisition of PNM's merchant share of Palo Verde 3;
3. Deny pre-approval of the advanced recovery for the SNCRs at this time;
4. Approve the abandonment of San Juan 2 & 3 in compliance with the proposed revised State Implementation Plan;
5. Require the Company to re-assess its needs and requirements prior to requesting the acquisition of any additional or replacement resources;
6. If the Company determines, after careful examination, that additional resources are required, require that the Company issue an all-source RFP for capacity and energy, conducted at arm's length from its merchant affiliate;

7. Require that the Company submit detailed justification and support for any long-term coal contracts it negotiates with third-party providers prior to committing to such contracts; and finally,
8. Require the Company to re-run the Strategist model (or a similar capacity-expansion model) with correctly characterized variable production costs, avoidable future capital expenditures, and taking into account market sales and purchases, as well as reasonably foreseeable environmental costs and limitations, prior to requesting the acquisition of any additional or replacement resources.

Q **Does this conclude your testimony?**

A It does.