**BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION**

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| 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, | ) ) ) ) ) | |
| | | **CASE 13-00390-UT** |
| PUBLIC SERVICE COMPANY OF NEW MEXICO, | ) ) ) | |
| Applicant | ) | |

# Direct Testimony and Exhibit in Opposition to PNM's Original and Supplemental Stipulation Agreements

**of**
**Patrick W. Luckow**

**On Behalf of**
**New Energy Economy**

**September 25, 2015**

## 1. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A My name is Patrick Luckow. I am a Senior Associate at Synapse Energy Economics ("Synapse"), based in Cambridge, Massachusetts.

**Q Have you previously filed testimony in this proceeding?**

A No. My colleague Dr. Jeremy Fisher filed direct testimony in this docket on August 29, 2014, direct testimony in opposition to the stipulation on November 25, 2014, and surrebuttal in opposition to the stipulation on December 29, 2014, in addition to his Declaration on January 8, 2015. I provided Dr. Fisher with support for the review of PNM's Strategist modeling, based on my knowledge of the Ventyx (now ABB) tools.

**Q What is your role at Synapse?**

A I focus on calibrating, running, and modifying industry-standard economic models to evaluate long-term energy plans, and the environmental and economic impacts of policy/regulatory initiatives. Through the course of this docket, my colleagues and I have provided consulting services to New Energy Economy with regard to electric system planning. I have provided testimony on behalf of state consumer advocates in electricity planning dockets in California and Hawaii. I have reviewed and evaluated the energy planning practices of utilities in dockets involving long-term planning and rate cases.

**Q Please describe your educational background and experience.**

**A** I hold a Bachelor of Science degree in Mechanical Engineering from Northwestern University and a Master of Science degree in Mechanical Engineering from the University of Maryland. Prior to joining Synapse, I worked as a scientist at the Joint Global Change Research Institute, a division of Pacific Northwest National Laboratory ("PNNL"). In this position, I evaluated the long-term implications of potential energy policies, both internationally and in the United States, across a range of energy and electricity models. Since 2012, I have been at Synapse, where I run a range of electricity dispatch and capacity expansion models, including Strategist. My full resume is attached as PWL-1.

**Q Please describe the purpose of your testimony.**

**A** My testimony reviews the modeling behind the testimony of Mr. Patrick O'Connell, in which he supports the Supplemental Stipulation entered into between Public Service Company of New Mexico ("PNM" or "the Company") and other parties.

**Q Please describe the structure of your testimony.**

**A** My testimony reviews several key elements of the Strategist modeling performed by the Company. I begin with a discussion of the proper treatment of modeling fuel costs in long-term planning models, with attention to the way the Company has modeled the Westmoreland contract. I then discuss several inconsistencies between the Stipulation Portfolio and the alternative plans, including the treatment of Palo Verde, assumed retirement dates at San Juan, and post-hoc adjustments to the Strategist costs. Lastly, I address specific elements of the Stipulation, including the requirement to purchase emissions credit and PNMR-D's acquisition of 65MW of San Juan 4, to ensure SJGS is fully subscribed.

**Q You noted that Dr. Fisher previously testified in this case. Do your findings comport with his at all?**

**A** Yes, my findings are consistent with those of Dr. Fisher. In December 2014, Dr. Fisher testified that Mr. O'Connell had inappropriately incorporated stipulation elements into Strategist modeling, and in doing so convoluted appropriate utility decision making and PNM-specific claimed benefits. He further testified that these benefits claimed in the model did not exist, or more specifically, also existed in the absence of the stipulation, and were therefore inappropriate to include as benefits the stipulation.

It is my opinion that PNM has once again misconducted appropriate utility decision making and modeling in an effort to bolster the apparent benefit of the stipulation. PNM has, figuratively speaking, put their thumb on the scale by claiming benefits of the stipulation that are not unique to the stipulation, and hiding other costs that will accrue as an outcome of their plan. In doing so, their modeling suffers from fundamental math errors, characterizes significant "benefits" that are not benefits at all, and mischaracterizes the coal contract significantly. Overall, I find misrepresentations in the Company's model worth at least $304 million. That is likely an underestimate.

My adjustments to the post-hoc "San Juan Investment Recovery" cost modifiers as well as proper treatment of Palo Verde reduce the difference between the Stipulation portfolio and the *4 Unit Shutdown* portfolio from $380 million to $76 million, an 80 percent reduction. Further modeling analysis to (a) better incorporate variable fuel costs and (b) assume consistent retirement dates would further reduce this cost difference, or possibly make the *4 Unit Shutdown* portfolio a net benefit. I will describe each of these adjustments in turn.

I also find PNM's characterization of the Stipulation requirement to purchase emissions credits to offset generation at the newly acquired capacity of SJGS mistaken. These credits would be required by the U.S. Environmental Protection Agency's Clean Power Plan regardless and provide no additional environmental benefit beyond what is included in the legal mandate.

**Q** **Please remind us why PNM should not claim benefits of the stipulation in the evaluation of specific resources?**

**A** Despite all of its moving parts, this case serves to answer a single overriding question: is the continued operation of SJGS 1 & 4 fundamentally in the best interests of PNM ratepayers? In most utilities, this type of question would have a simple solution: if the optimal plan that includes SJGS 1 & 4 is lower cost than the optimal plan that excludes SJGS 1 & 4, then SJGS should be considered an economic resource. However, and this is a big "however," that initial assessment needs to evaluate the resource on a fair playing field – no tinkering with the relative merit of other resource (i.e. Palo Verde), stranded cost adjustments or other post-hoc changes. Dr. Fisher described that PNM should seek to evaluate the “absolute” value of SJGS in absence of the stipulation.

This type of assessment is conducted regularly by vertically integrated utilities. I have evaluated numerous models and cases in which major utilities across the country have assessed the economic merit of maintaining existing coal units. Again, these evaluations stand independently of any other settlement terms.  This is important because PNM bears a responsibility of transparency to both their ratepayers and shareholders, a responsibility which is violated by the method used here by PNM.

To their ratepayers, they owe an obligation to seek a least cost solution. To their shareholders, PNM bears a fiduciary responsibility to use shareholder funds for their best possible use. Thus, all parties should be in a position to know if PNM’s decisions are fundamentally correct from a utility planning perspective.

Once the fundamental costs are clear, PNM shareholders are welcome to offer other ratepayer benefits if they want to pursue a non-optimal outcome. In this case, PNM portrays that their shareholders will offer two distinct benefits, a cheaper sales price for Palo Verde than could be secured on the open market, and a 50:50 split of stranded investments. I do not believe that either of these are real benefits of the stipulation. First, Palo Verde’s evaluated market cost is highly inflated: PNM’s shareholders should not condone the sale of Palo Verde 3 at less than half of its market value if another buyer actually existed. Thus, Palo Verde 3’s real market value is what PNM’s shareholders are willing to part with it at – it’s book value. Second, the treatment of stranded assets is an issue for the Commission to decide. While PNM is welcome to offer to split their stranded costs with ratepayers 50:50, they have no standing to indicate that the

Commission would not force them to do the same in any other circumstance aside from the stipulation.

Much of PNM's valuation of SJGS rides on the inappropriate use of a higher Palo Verde 3 cost in the case where SJGS is fully retired, and the incorporation of stranded costs as a benefit to ratepayers in the stipulation – neither is appropriate.

Finally, Mr. O'Connell has used values from Mr. Monroy's analysis that include a fundamental math error in the stranded cost "benefit" calculation, an error known to modelers as "end effects." Mr. Monroy truncated the valuation of a 36-year depreciation period by only looking at the first 20 years. Such an error should not, and cannot, be portrayed as a benefit.

### 2. <u>VARIABLE COSTS FOR SAN JUAN REMAIN INAPPROPRIATELY CHARACTERIZED</u>

**Q** **In Dr. Fisher's August 29, 2014 direct testimony and December 29, 2014 supplemental testimony, he expressed concern that PNM had confounded fixed and variable costs of operation at San Juan. Is that still the case today?**

**A** Yes. The Company's modeling supporting the original case and this Stipulation both continue to model variable costs as fixed. This leads to SJGS operating more than it otherwise would in the Company's modeling runs.

**Q How does the Company model fixed and variable costs?**

**A** The coal contract requires fixed monthly payments for a specified minimum quantity of fuel, followed by an incremental per unit cost after that minimum quantity has been used. In the Strategist runs supporting the July 31st 2015 testimony of Patrick O'Connell, as well as the August 28th 2015 runs, these take-or-pay fuel contract prices (as well as variable operations and maintenance costs) are included as fixed costs. The minimum amount of fuel to be purchased monthly specified in the contract is modeled as a "Tier 1" cost, which Strategist incorporates as a fixed cost. The Company's "Tier 2" costs are modeled as variable and represent only a quarter to a third of the Company's fuel costs.

The relative impacts of modeling the contract in this way are clear. When choosing which plants to dispatch in any given hour, the Strategist model dispatches plants based on lowest marginal cost. No variable O&M costs are modeled at SJGS, and only the very low "Tier 2" fuel costs are included on an operational timeframe. As a result of these unrealistically low hourly operational costs of the plant, the SJGS is utilized more than it otherwise would be. This makes the Strategist model runs that include additional capacity at SJGS appear more cost effective than they otherwise would.

**Q Does PNM have the opportunity to avoid burning coal after 2022?**

**A** Yes. The new coal contract expires in 2022. PNM has the opportunity to avoid burning coal at San Juan after this date, as well as the opportunity to dictate the terms of the contract (particularly volume requirements) based on modeled operation of the plant. The revised coal contract with Westmoreland includes take-or-pay provisions through July

2022, based on new and lower coal prices from the Company's earlier filings. After this date, the supplier, contract price, and terms are completely unknown. PNM has agreed to not enter into a binding post-2022 coal supply agreement until the conclusion of a case to be initiated by a filing in 2018 to determine the extent to which SJGS should continue to serve PNM's load after June 30, 2022. There is no obligation to take any coal past the expiration of the Westmoreland contract in 2022 and no contract considerations for the post-2022 timeframe are specified in the Supplemental Stipulation. These costs cannot reasonably be considered fixed and should be considered variable. Therefore, after 2022, all costs should be considered avoidable regardless of the nature of this contract. Modeling these costs as fixed is inappropriate.

**Q Does the take-or-pay nature of the revised coal contract imply that all "Tier 1" costs should be modeled as fixed costs before 2022?**

**A** No. The coal contract (CMO-12, July 31 2015 Supplemental) provides for the termination of the contract via Default or Environmental Force Majeure, under which the utility would pay the purchase price ($125,000,000) multiplied by a factor that decreases over time.[1] The proper way to model such a coal contract is to assume liquidated damages as fix costs and all other costs as avoidable (or variable, in the modeling context). The purchase price appears to be substantially less than the total fixed costs assumed by Mr. Monroy over the course of the contract. The total spent on coal through this contract through June 2022 is $559 million, of which $250 million are based on fixed

[1] "Force Majeure" is a common contract clause to reduce or remove liability for events, usually outside of the control of the parties, that may inhibit them from fulfilling contract obligations, and in this case includes existing or new federal or state environmental policies or any settlement agreement that may limit the operation of SJGS

costs.[2] The $125 million (nominal) could be assumed to represent $19.2 million per year of fixed costs, roughly half of the fixed costs assumed in Mr. Monroy's workpapers, based on Discovery response NEE 21-5(B).[3]

**Q Of the non-fuel O&M costs, which were included as fixed, and which were modeled as variable?**

**A** PNM provided a breakdown of these costs in response to NEE 21. Costs modeled as "Fixed" at SJGS included Fixed O&M as well as take-or-pay coal contract costs. The fixed O&M costs include O&M costs (both fixed and variable), fuel handling, taxes, coal reclamation, and incremental decommissioning costs. No costs were modeled as variable at SJGS, beyond Tier 2 fuel costs.

**Q What impact would shifting some costs from fixed to variable costs have on the Company's model runs?**

**A** As modeled by the Company, SJGS has no variable operational costs beyond the "incremental" coal contract costs, which represent up to a third of the total per mmbtu coal costs in each year. Strategist lacks the capability to endogenously retire SJGS if overall costs are uneconomic. In other words, the model cannot choose to retire SJGS within the course of its optimization –retirements are analyzed by conducting a series of model runs with retirement dates "hard coded" into the model by analysts. As a result, when the model sees an artificially low operational cost it dispatches the plant at a high

[2] PNM Exhibit NEE 21-5(B)

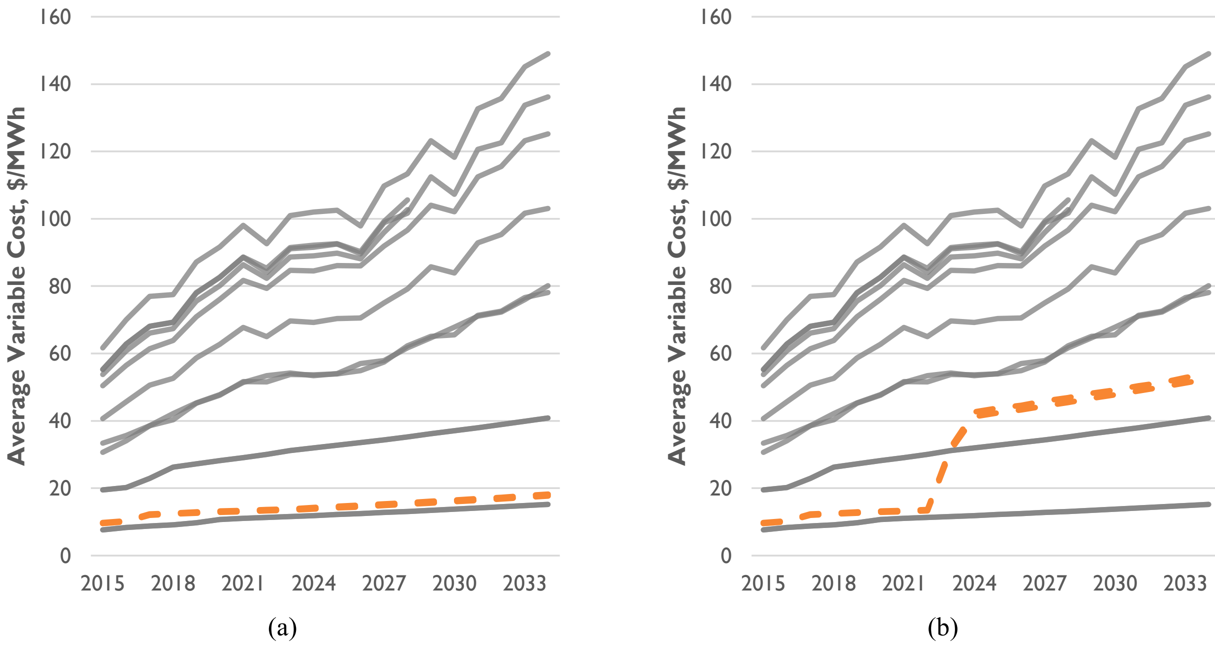
[3] This approach is different than that proposed by my colleague Dr. Fisher, to model SJGS as two units for each single unit in reality, splitting the fixed and variable portions amongst these units. While that solution may be workable, I believe my proposed approach more accurately reflects the latest details of the coal contract.

level, and cannot choose to retire the plant, even if the fixed costs are higher than other alternatives. This results in misleading model outcomes, showing the plant as operational even when it is uneconomic. Shifting some costs to variable costs would reduce SJGS annual dispatch levels. Figure 1 demonstrates how variable costs shift SJGS from being one of PNM's lowest cost resources, to being a much more marginal resource. Reduced operation on an hourly basis resulting from higher variable costs could also result in improved economics for the many potential alternatives to continued operation at SJGS. The Company's model runs show a number of alternative resources are economic to add, even in early years, including wind, solar PV, and gas turbines.[4,5]

[4] PNM continued to model a 100MW limit on wind development, consistent with earlier model runs. Dr. Fisher and Mr. Van Winkle have demonstrated that this constraint has not been adequately supported and further wind capacity would reduce costs.

[5] Mr. Van Winkle further indicates in his Direct testimony that solar PV costs in particular have fallen well below the level assumed in PNM's analysis

**Figure 1**. **San Juan variable costs (orange) as compared to other PNM units (gray) (a) as modeled and (b) adjusted to incorporate all coal contract costs as variable after expiration of contract in 2022**



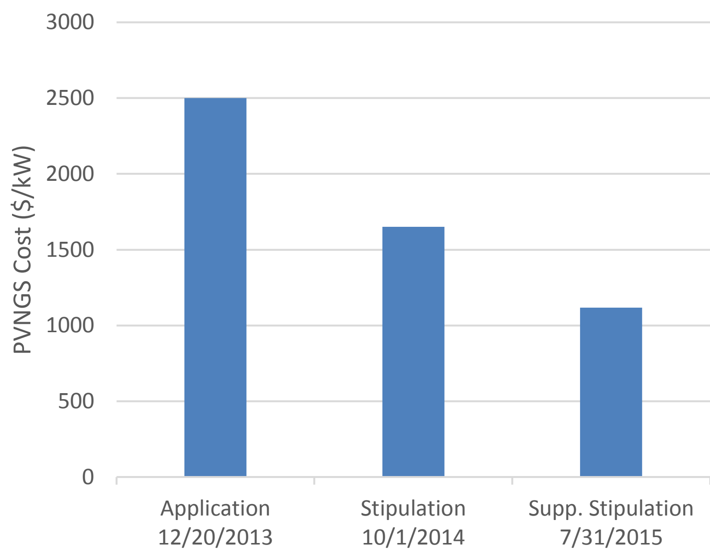

### 3. San Juan should be Evaluated Independently of Palo Verde

**Q Has the Company adequately characterized Palo Verde in its Strategist runs?**

**A** No. As in its 2014 model runs, the Company continues to model Palo Verde at a cost of $2,500/kW, an amount that no buyer seems willing to pay, for the case in which SJGS is shut down. These issues are unrelated and the comparison unnecessarily handicaps alternative options. This value is used in comparison to a Stipulation portfolio with a value of $1,118/kW (formerly $1,650/kW). Despite its incorporation into the Stipulation agreement, the value associated with Palo Verde has little to do with the value of San Juan. San Juan should be evaluated among model runs with consistent values for Palo Verde.

In his August 31, 2014 testimony, Mr. Dauphinais (NMIEC) testified that Palo Verde at $2,500 was not part of a cost effective portfolio. However, PNM's shareholders appear willing to sell PV3 at $1,118/kW, unable to find another customer at a higher price anywhere near $2,500/kW (as indicated by the continually decreasing assumed value of Palo Verde, shown in Figure 2). Alternatives to the Stipulation portfolio should not be saddled with an unrealistic higher cost resource.

**Figure 2: Palo Verde Nuclear Generating Station Costs over time, in dollars per kW**




**Q What is the approximate value of this difference?**

**A** The Supplemental Stipulation revised the cost downwards from $1,650 to $1,118/kW, valued by Mr. O'Connell at another $38 million. I calculate a total net present value impact of the Supplemental Stipulation revisions of $118 million, based on the $2,500/kW estimate used in other scenarios. In order to evaluate resources on a level playing field, PNM should not be using different values for Palo Verde across these model runs. If the $118 million difference between the plans resulting from this cost differential was removed, the cost difference between the *4 Unit Shutdown* scenario and Stipulation portfolio would decline to $262 million, before accounting for further inconsistencies I discuss later in this testimony. This is a 31% difference between the Supplemental Stipulation with corrected adjustments versus the Supplemental Stipulation with an inflated an unrealistic value for Palo Verde.

### 4. SJGS ASSUMED RETIREMENT DATE IS INCONSISTENT AND UNREALISTIC

**Q What is the Company's assumption with regards to retirement dates for the *4 Unit Shutdown* scenario?**

**A** While O'Connell states that "I have prepared a portfolio analysis of a four unit shutdown assuming that all units are retired at the end of 2017" (July 31 Supplemental, pg 7), the four unit retirement scenario modeled by the Company assumes retirement at the end of 2016.[6] The EPA-approved Revised State Implementation Plan ("RSIP") called for shutdown of SJGS 2 and 3 by Dec 31st, 2017, and installation of SNCR at Units 1 and 4 by February 2016. Mr. O'Connell has failed to conduct a Strategist analysis with an accurate retirement date to understand the implications of this decision.

Units 2 and 3 could operate an additional year under the terms of the RSIP. With regards to Units 1 and 4, PNM could have attempted to negotiate a one year extension in

[6] This was corrected in Errata to Mr. O'Connell's testimony filed on September 8th.

exchange for a firm commitment to retire in 2017.[7] PNM has had ample opportunity to go to EPA and ask for this extension. Given the challenges with the 2016 retirement date PNM witnesses have identified, the failure to pursue a 2017 retirement date is simply imprudent. At the very least, PNM should conduct an analysis of a 2017 retirement date to understand the implications of this assumption.

### 5. San Juan Investment Recovery

**Q What is the "San Juan Investment Recovery" term in O'Connell Exhibit PJO-1 (July 31, 2015)?**

**A** San Juan Investment Recovery is a post-hoc adjustment to the Strategist total plan cost conducted by Mr. O'Connell in order to represent several costs that could not be directly modeled, including the accelerated depreciation of San Juan assets from a 36 year timeframe to a 20 year timeframe, the 50% split in stranded asset costs specified in the Stipulation, and an addition $102 million in closure costs for the *4 Unit Retirement* scenario that have not been supported elsewhere in this docket. The workpapers behind these values were provided in response to NEE 10-10c in spreadsheet "SJ Stranded Costs Summary for Stipulation Filing.xlsx" and I have several concerns with this calculation.

[7] At this point, PNM could continue to operate Unit 1 through 2017 as well, as it already has the necessary emissions controls.

**Q Do the San Juan Investment Recovery terms for the cases presented by the Company include different items?**

**A** Yes. I will explain the $130 million cost associated with the *4 Unit Shutdown* scenario first. This cost includes both incremental closure costs and the impacts of an accelerated depreciation schedule, from 36 years to 20 years. I will then explain the $56 million savings associated with the Stipulation portfolio analysis. This analysis calculates the incremental costs associated with an accelerated depreciation from 36 years to 20 years, and assumes a 50 percent reduction due to Stipulation terms. Together, the San Juan Investment Recovery adjustments lead to a post-hoc delta between the Stipulation and *4 Unit Shutdown* portfolios of $186 million.

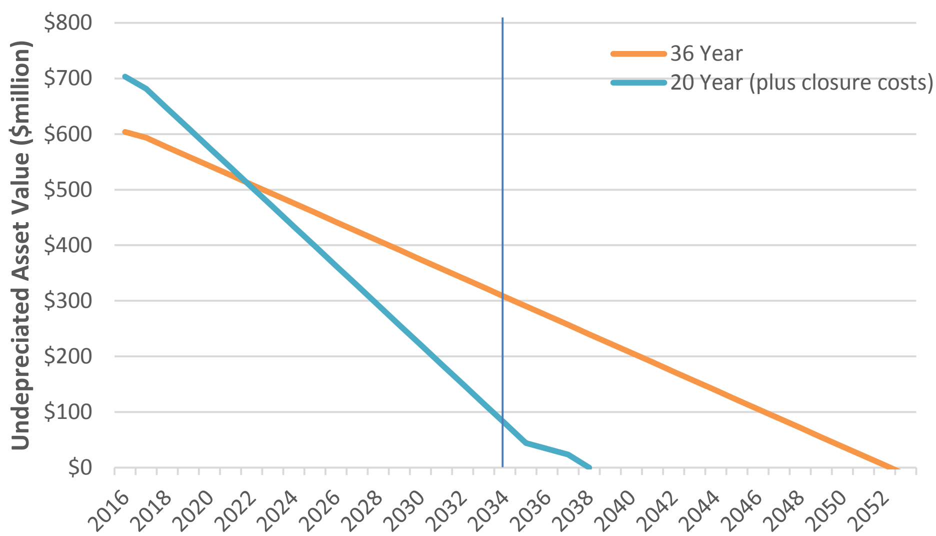
**Q How is the $130 million cost associated with the *4 Unit Shutdown* case calculated?**

**A** The $130 million cost includes two components: accelerated depreciation of SJGS, and incremental closure costs associated with the *4 Unit Shutdown* case. Mr. Monroy's workpaper provided in response to ABCWUA 5-2d indicates that San Juan 1-4 have an estimated book value of $606,039,778 in 2016.[8] This workpaper calculates annual revenue requirements to recover this value, plus a return on investment, over a 36-year period. Mr. Monroy then calculates the cost to recover a somewhat higher value $708,059,647 over a shorter, 20-year, timeframe. Based on a comment in the Excel workbook, this represents the $606 million book value, plus an additional $102 million in closure costs. These closure costs have not been supported in this docket. The difference between these two cost streams is then multiplied by 97.5 percent, to account for

[8] Workbook PNM Exhibit ABCWUA 5-2d.xlsx, Worksheet "4 Unit" Cell F43

changing load, and is intended to represent the incremental cost of recovery of four San Juan units over a shorter time period. The net present value of this cost stream is $130,429,849. If one were to compare just the accelerated depreciation schedule from 36 years to 20 years, this penalty would be reduced to $56 million, based on Mr. Monroy's math. These costs are summarized in Figure 3.

**Figure 3. Undepreciated asset value of San Juan in 20-year and 36-year timeframes. All value after the blue line was unaccounted for.**




**Q Do you have concerns with how this $130 million value was calculated, independent of the additional and unsupported "closure costs"?**

**A** I do. The $56 million number I mention above is calculating assuming a 20 year depreciation for both scenarios, which is a mistaken assumption. Despite indicating that SJGS would be depreciated over 36 years, Mr. Monroy's workbook cuts off in 2034, the end of the Strategist analysis period. This leaves 19 years for recovery – substantially less than the full 36. All value to the right of the vertical line in Figure 3 is ignored. I would expect to see this recovery extend to 2052. I would expect that—over the full recovery period— the 36-year and 20-year timeframes would show about the same net present value, other than changes resulting from income taxes. By not counting the extra 19 years of this analysis, Mr. Monroy has undercounted the cost of this recovery by about $61 million. The planning community is well familiar with this problem – we call it end effects. The correct cost adder should be $83 million, not $130 million. As shown in Table 1, without including the unsupported closure costs, the correct adder should be a net savings for the *4 Unit Shutdown* scenario of $5.5 million rather than a net cost of $130 million.

**Table 1: Summary of San Juan Investment Recovery for 4 Unit Shutdown case**

| | **20 year NPV Calculation** | **36 Year NPV Calculation** |
|---|---|---|
| *36 Year Depreciation* | $384,349,525 | $446,099,181 |
| *20 Year Depreciation (w/ $102M Closure Costs)* | $514,771,374 | |
| *20 Year Depreciation (w/o $102M Closure Costs)* | $440,601,199 | |
| | | |
| **Cost difference between depreciation schedules** | | |
| *20 yr Calculation, both w/ $102M* | $130,421,849 | |
| *20 yr Calculation, w/o $102M* | $56,251,674 | |
| *Matched Depreciation and Calculation, w/o $102M* | $(5,497,982) | |

**Q How is the negative $56 million cost associated with the stipulation calculated?**

**A** Mr. Monroy's workpaper provided in response to NEE 2-3, labeled "Exhibit HEM-4 – 36 year 2&3 (2)" determines the annual revenue requirements for the recovery of San Juan Units 2 & 3, whose value is stated as $231.5 million.[9] Similar to the case of the *4 Unit*

[9] It appears these values have been updated by Mr. Monroy in NEE 25-2, but Mr. O'Connell's exhibit continues to use the same values presented with the initial Stipulation in 2014, so I reference those as well.

*Shutdown*, the annual revenue requirements associated with this recovery are based on a 36-year period. These values are compared to an accelerated depreciation based on a 20-year period, this time with an initial starting value of $116 million.

**Q Should the San Juan Investment Recovery term include a 50% split in stranded costs with customers?**

No. The lower, $116 million, value above is based on a 50 percent reduction due to the Stipulation term that splits the stranded cost of San Juan between ratepayers and PNM. PNM previously asked customers to bear this full cost. As a result, this manifests as a benefit to ratepayers, based on a reduced stranded asset cost that PNM assumes ratepayers will pay. The problem with including this 50% split in comparing two plans is that PNM cannot mandate full recovery of all stranded costs – this is an issue for the commission to decide. In long term planning, resources should be compared with consistent assumptions about stranded costs. Similar to the need for Palo Verde to be evaluated on a consistent basis across plans, in order to compare resources adequately they should use consistent assumptions about stranded asset recovery.

Without this adjustment for stranded costs, the accelerated depreciation from 36 years to 20 years would result in an incremental cost of $19 million, as compared to a savings of $56 million (based on Mr. Monroy’s math). However, similar to the *4 Unit Shutdown* case, Mr. Monroy’s calculations stop at 2034. Had Mr. Monroy more appropriately extended his net present value calculations to 2052 to account for end effects, my $22 million adjusted calculation would be reduced to savings of $5.9 million. These values are summarized in Table 2.

**Table 2: Summary of San Juan Investment Recovery for Stipulation case**

| | **20 year NPV Calculation** | **36 Year NPV Calculation** |
|---|---|---|
| *36 Year Depreciation* | $130,760,385 | $ 155,587,918 |
| *20 Year Depreciation SJ 2&3 (w/ 50% asset recovery)* | $74,848,214 | |
| *20 Year Depreciation SJ 2&3 (w/o 50% asset recovery)* | $149,696,428 | |
| | | |
| **Cost difference between depreciation schedules** | | |
| *20 yr Calculation, w/ 50% asset recovery* | $(55,912,171) | |
| *20 yr Calculation, w/o 50% asset recovery* | $18,936,043 | |
| *Matched Depreciation and Calculation, w/o $50% reduction* | $(5,891,490) | |

**Q** **In your view, is it reasonable to compare a plan with a 50 percent stranded asset recovery to another plan with full stranded asset recovery from ratepayers?**

**A** No. The level of stranded asset recovery is an issue for this Commission, not PNM, to decide. There is no guarantee that a four unit shutdown would receive 100 percent recovery of the stranded assets in San Juan 2 & 3. For meaningful planning purposes, the most reasonable approach is to assume the same level of recovery for all plans. Stranded asset recovery is a sunk cost and should not be considered in planning analysis. The value of San Juan should be considered before any provisions associated with the Stipulation.

**Q** **What is the combined impact of the San Juan Investment Recovery adjustments?**

**A** If all the modeled scenarios used a consistent assumption about stranded asset recovery, it would be possible for the Commission to adequately compare these different scenarios. PNM's failure to do so makes this a challenge, but we can estimate the impact by removing these post-hoc adjustments and correcting mistakes related to end-effects.

The initial difference between the Stipulation portfolio and the *4 Unit Shutdown* portfolio was $380 million, reduced to $262 million based on my analysis of Palo Verde 3 costs. The San Juan Investment Recovery adjustments I discuss here reduce that difference by an additional $186 million, leaving the Stipulation portfolio only $76 million dollars more cost effective than the *4 Unit Shutdown* case. This represents about 1% of the 20 year NPV of the Stipulation portfolio, and would be less after appropriate treatment of variable costs. Furthermore, Mr. Van Winkle, in his Testimony in Opposition to the Supplemental Stipulation, found that PNM's cost of new wind energy in Strategist at 4.4 ¢/kWh, rising with inflation and capped at 100MW, did not properly reflect recent PPA prices of 3.7 ¢/kWh, and solar costs, assumed at 6.8 ¢/kWh, again rising with inflation, did not reflect more realistic prices of 5 ¢/kWh. Mr. Van Winkle found these items to reduce the cost of the alternatives to the Stipulation by $160 million (when 300 MW more wind was installed) and $26 million, respectively.[10] These cost adjustments would be incremental to my adjustments above, and make the Stipulation portfolio a net liability to PNM's ratepayers.

### 6. Purchase of Emissions Credits Provides No Additional Environmental Benefit

**Q How would the purchase of ERCs lead to an environmental benefit?**

**A** In the final Clean Power Plan rule, released August 3, 2015, EPA allowed for states to purchase credits generated from the production of renewable energy, energy efficiency,

[10] Testimony in Opposition to PNM's Original and Supplemental Stipulation Agreements of David Van Winkle. Sep 25, 2015. Page 36.

or incremental gas generation to be used for compliance with rate-based targets. These Emissions Rate Credits ("ERCs") give states additional flexibility in compliance, and allow states to trade without formal multi-state plans. The Supplemental Stipulation calls for PNM to purchase ERCs for every MWh produced by 197MW of SJGS, up to a total cost of $7 million. Mr. Ortiz, in his August 28th 2015 Testimony, stated that these ERCs provide "additional environmental benefits" tied to the 197MW of additional capacity at San Juan. This statement is incorrect. The purchase of ERCs (or mass allowances, if New Mexico opts for a mass-based Clean Power Plan compliance pathway) is required by law. These ERCs (or allowances) provide an additional benefit if, and only if, they are in excess of the number of credits needed by PNM to demonstrate compliance at San Juan. Nothing in the Supplemental Stipulation indicates that PNM could not use all of these purchased ERCs for compliance with regulations for which they are legally bound, and as such this agreement provides little or no benefit.

**Q How did the company model this requirement in its analysis?**

**A** The Company included a carbon price in all Strategist runs, which appears to be consistent with Clean Power Plan requirements. As the ERC purchase requirement is not incremental to the Company's legally mandated compliance obligations, no further modifications are needed to the Company's Strategist model. This is a reasonable approach.

**Q** **Would the purchase of ERCs required by the Stipulation be sufficient for PNM to demonstrate compliance with the Clean Power Plan?**

**A** No. The Clean Power Plan requires compliance at each unit in the system covered under the regulation. The ERC purchase requirement in the Supplemental Stipulation is specific to generation at San Juan, and does not include other covered PNM units such as Afton, Four Corners, and Luna. As such, Mr. O'Connell's comparison in his August 28th testimony of this $7 million cost to the total carbon cost of each of his modeled portfolios (PJO-1, Supplemental Stipulation) is an inaccurate and uninformative comparison.

**Q** **Is the requirement to purchase ERCs in the stipulation meaningful?**

**A** No. This is a meaningless component of the stipulation. PNM will have to comply with the Clean Power Plan regardless of the stipulation. There is little reason to have something in this agreement that is already a separate legal requirement. Its presence in this Stipulation gives the impression of additional environmental benefits that do not exist, and thus is disingenuous.

## 7. PNMR-D'S ACQUISITION OF 65MW OF SAN JUAN 4

**Q** **What are the plans for the unsubscribed 65MW of San Juan Unit 4 resulting from Farmington Electric Utility's decision to not acquire it?**

**A** A PNM affiliate company, PNMR Development and Management Corporation ("PNMR-D") will acquire the capacity to assure that SJGS is fully subscribed. The PNMR-D share of SJGS 4 will be treated as an excluded merchant plant. PNMR-D is a subsidiary of PNM Resources, as is PNM.

**Q** **Is it your understanding that PNM could acquire this 65MW of SJGS capacity at a later date from PNMR-D?**

**A** Yes. In his August 28th testimony, Witness Ortiz clarifies that this element of the Stipulation "also provides the Commission the flexibility to grant a CCN for any type of generation in the future, including the 65MW of merchant capacity in SJGS Unit 4".[11]

**Q** **Has PNMR-D acquired merchant capacity in the past and transferred it to PNM's regulated operations?**

**A** Yes. The Luna Energy Facility was initially operated as a merchant facility, and the company's share of the plant (190MW) was sold on the wholesale market. In its 2008 Electric Rate Case, PNM proposed that Luna be included in its jurisdictional assets and recovered through rates. This was approved by NMPRC in 2009.[12]

**Q** **Does the 65MW of San Juan Unit 4 show up in the Company's modeling at all?**

**A** No.

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[11] Testimony in Support of the Supplemental Stipulation of Gerard T. Ortiz. Aug 28, 2015. Page 19. Lines 10-12.
[12] PNM Form 10-K for the Period Ending 12/31/09

**Q What might the implications be of including this capacity in the Company's modeling?**

**A** From a planning perspective, treating SJGS as a merchant plant, with future costs not born by ratepayers, is beneficial. On December 19, 2014 NMIEC witness Dauphinais submitted testimony comparing 134MW and 197MW incremental purchases of SJGS 4, and found the incremental capacity to be a $38 million liability prior to modeling a market. With market purchases and sales allowed, the incremental capacity was an $84 million liability.

No parties have completed such comparisons with the latest updated coal costs. Based on the earlier analysis, the only reason PNMR-D is acquiring this capacity is because SJGS would not be fully subscribed otherwise, and the remainder of the Company's plans would fall through. This additional capacity would seem to provide no benefit to PNMR-D.

## 8. Conclusions and Recommendations

**A** I believe the PNM analysis has not adequately supported the addition of incremental capacity at San Juan generation station. I find several errors and inconsistencies in the Company's modeling that have persisted throughout this case. The issues around Palo Verde and post-hoc model adjustments alone reduce the cost differential between the Stipulation portfolio and the *4 Unit Shutdown* scenario 80%, from $380 million to $76 million. Another key issue is the large uncertainty regarding the level at which San Juan would dispatch if more coal costs were assumed to be avoidable, which they seem to be. A lower level of dispatch could further weaken the economics of the Stipulation. Retiring

San Juan a year later than originally assumed by the Company would also make it easier for the Company to find replacement power sources and reduce costs, although that opportunity seems to have passed due to poor planning at PNM.

Despite the many varied elements of the Stipulation, the focus of this case is whether or not the continued operation of SJGS results in a least-cost plan. Without evaluating resources on a level playing field, the Commission has no way of know if that is the case.

Once such an evaluation has been made, PNM could certainly offer other benefits if they want to pursue non-optimal outcomes. In this case, two of those purported benefits included in the Supplemental Stipulation increase my concerns. The requirement to purchase emissions credits to offset generation is disingenuous and ineffective, as this is a legal requirement independent of the Stipulation. The purchase of the unsubscribed 65MW at San Juan by a PNM affiliate company, despite earlier analysis demonstrating that this is likely to be a liability, poses other serious concerns. This 65MW resource is not included in the Company's modeling.

As a result of the concerns identified above, the economics of the Company's decision to pursue additional capacity at SJGS are placed in doubt. The Commission should reject the Company's application to acquire additional capacity at San Juan 4.

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## PROFESSIONAL EXPERIENCE

**Synapse Energy Economics Inc.**, Cambridge, MA. *Senior Associate,* 2015 – present*, Associate*, May 2012 – June 2015.

Provides consulting services, conducts research, and performs analysis of energy investments. Calibrates, runs, and modifies industry-standard economic models to evaluate long-term energy plans, and the environmental and economic impacts of policy/regulatory initiatives.

**Joint Global Change Research Institute**, College Park, MD. *Scientist*, 2009 – 2011.

Evaluated the long-term implications of potential climate policies, both internationally and in the US, across a range of energy and electricity models. Modeled large-scale biomass use in the global energy system. Led a team studying global wind energy resources and their interaction in the Institute's integrated assessment model. Utilized updated global wind supply curves to help understand both onshore and offshore wind deployment, and issues associated with transmission requirements, intermittency, and technology costs.

**DaimlerChrysler,** Auburn Hills, MI. Stress Lab & Durability *Development Intern*, 2007.

Completed load and vibration data acquisition and analysis on various Chrysler vehicles, and contributed to the development of an improved generic body vibration profile.

**Northrop Grumman,** Rolling Meadows, IL. *Defensive Systems Division Co-op*, 2005 – 2007.

Designed new enclosures and mounting structures for electronic components, silenced existing enclosures, and conducted thermal testing of complete systems.

## EDUCATION

**University of Maryland**, College Park, MD
Master of Science in Mechanical Engineering, 2009.

**Northwestern University**, Evanston, IL
Bachelor of Science in Mechanical Engineering, 2007.

## PUBLICATIONS

Buonocore, J. J., P. Luckow, G. Norris, J. D. Spengler, B. Biewald, J. Fisher, J. I. Levy. 2015. "Health and climate benefits of different energy-efficiency and renewable energy choices." *Nature Climate Change,* August 2015: doi:10.1038/nclimate2771.

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**California Public Utilities Commission (Docket No. A.14-01-027):** Testimony examining San Diego Gas & Electric's proposal to change time-of-use periods in its application for authority to update its electric rate design. On behalf of the California Office of Ratepayer Advocate. November 14, 2014.

**California Public Utilities Commission (Docket No. R.12-06-013):** Rebuttal testimony regarding the relationship between California investor-owned utilities hourly load profiles under a time-of-use pricing and GHG emissions in the WECC regions in the Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations. On behalf of the California Office of Ratepayer Advocate. October 17, 2014.

**California Public Utilities Commission (Docket No. R.13-12-010):** Direct and reply testimony on Phase 1a modeling scenarios in the Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans. On behalf of the California Office of Ratepayer Advocate. August 13, 2014 and October 22, 2014.

**Hawaii Public Utilities Commission (Docket No. 2012-0185):** Direct testimony and exhibits regarding the proposed Aina Koa Pono Biofuel Project. On behalf of the State of Hawaii Division of Consumer Advocacy. March 2013.

*Resume dated August 2015*