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,	)	**Case No. 13-00_______-UT**
PUBLIC SERVICE COMPANY OF NEW MEXICO,	)	
Applicant	)	

DIRECT TESTIMONY AND EXHIBITS

OF

JOHN J. REED

December 20, 2013

NMPRC CASE NO. 13-00______-UT
INDEX TO THE DIRECT TESTIMONY OF JOHN J. REED
WITNESS FOR
PUBLIC SERVICE COMPANY OF NEW MEXICO

DIRECT TESTIMONY OF
JOHN J. REED
NMPRC CASE NO. 13-00______-UT

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, JOB TITLE, EMPLOYER AND BUSINESS ADDRESS.

A. My name is John J. Reed. I am the Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc. and CE Capital Advisors (together "Concentric"). My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE IN THE ENERGY AND UTILITY INDUSTRIES.

A. I have more than 35 years of experience in the energy industry, and have worked as an executive in, and consultant and economist to, the energy industry for the past 30 years. Over the past 25 years, I have directed the energy consulting services of Concentric, Navigant Consulting and Reed Consulting Group. I have served as Vice Chairman and Co-Chief Executive Officer of the nation's largest publicly-traded consulting firm and as Chief Economist for the nation's largest gas utility. I have provided regulatory policy and regulatory economics support to more than 100 energy and utility clients and have provided expert testimony on regulatory, economic and financial matters on more than 150 occasions before the Federal Energy Regulatory Commission ("FERC"), Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and arbitration panels in the United States and Canada. My background is presented in more detail in PNM Exhibit JJR-1.

Q. PLEASE DESCRIBE CONCENTRIC'S AND CE CAPITAL'S ACTIVITIES IN ENERGY AND UTILITY ENGAGEMENTS.

A. Concentric provides financial and economic advisory services to many energy and utility clients across North America. Our regulatory, economic and market analysis services include utility ratemaking and regulatory advisory services, energy market assessments, market entry and exit analysis, corporate and business unit strategy development, demand forecasting, resource planning, and energy contract negotiations. Our financial advisory activities include both buy and sell side merger, acquisition and divestiture assignments, due diligence and valuation assignments, project and corporate finance services, and transaction support services. CE Capital is a fully registered broker-dealer securities firm specializing in merger and acquisition activities. As Chief Executive Officer of CE Capital, I hold several securities licenses that cover all forms of securities and investment banking activities.

Q. HAVE YOU PREVIOUSLY APPEARED BEFORE THIS COMMISSION?

A. Yes. Most recently, I served as an expert witness before the New Mexico Public Regulation Commission (the "Commission" or "PRC") in Case No. 12-00350-UT on behalf of Southwestern Public Service Company in support of that company's requested regulated return on equity.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by Public Service Company of New Mexico (the "Company" or "PNM") to provide an assessment of a reasonable value of its 10.20 percent ownership stake in Unit 3 of the Palo Verde Nuclear Generating Station ("PVNGS") for ratemaking purposes, assuming that the buyer is a regulated integrated utility with a cost of capital consistent with PNM's current costs of debt, equity, and preferred equity and capital structure. The purpose of my testimony is to discuss how I estimated a reasonable value of 10.20 percent of PVNGS Unit 3 and the conclusions reached from those analyses.

Q. WHAT IS YOUR FAMILIARITY WITH THE VALUATION OF NUCLEAR GENERATING FACILITIES IN THE UNITED STATES?

A. I have been involved in most of the 25 nuclear plant sales that have taken place in the U.S since the 1990s. On behalf of the utility plant sellers, I have been extensively involved with the sales of Pilgrim, Oyster Creek, Salem, Peach Bottom, Hope Creek, Nine Mile Point Units 1 and 2, Ginna, Duane Arnold, Palisades, Point Beach Units 1 and 2, and a small share of Seabrook. In addition, I have worked for bidders on several other nuclear plant sales. I also have extensive experience advising clients on capital investment strategy and life cycle management of nuclear generating facilities, along with the myriad regulatory considerations surrounding those issues.

II. SUMMARY OF KEY CONCLUSIONS

Q. WHAT CONCLUSION HAVE YOU REACHED REGARDING THE REASONABLE VALUE OF 10.20 PERCENT OF PVNGS UNIT 3?

A. A reasonable value of PNM's 10.20 percent ownership stake in PVNGS Unit 3, assuming PVNGS Unit 3 is incorporated into the assets of a regulated integrated utility company, such as PNM, and relying on the Discounted Cash Flow ("DCF") Approach, is between approximately $341 million and $352 million, depending on the assumptions used in the valuation.

Q. PLEASE SUMMARIZE THE REMAINDER OF YOUR DIRECT TESTIMONY.

A. The remainder of my testimony is divided into five sections. In Section III, I describe the recent factual context which necessitates a valuation of 10.20 percent of PVNGS Unit 3. In Section IV, I provide a brief description of PVNGS, including its operating characteristics and ownership structure. Section V discusses the underlying assumptions related to the disposition of the facility that I have incorporated into the development of my estimate of a reasonable value for PVNGS Unit 3. Section VI provides an overview of my DCF Approach, including the inputs used and the derivation of certain key assumptions. Finally, Section VII summarizes my analyses and presents my conclusions as to a reasonable value of 10.20 percent of PVNGS Unit 3 under regulated integrated utility ownership.

III. <u>PNM'S NEED FOR ADDITIONAL REGULATED GENERATING CAPACITY</u>

Q. WHAT EVENTS PRECIPITATED THE NEED TO CONSIDER THE VALUE OF PNM'S 10.20 PERCENT OF PVNGS UNIT 3?

A. Company Witnesses Darnell and Olson describe the complicated negotiation and coordination process the Company has undertaken to comply with federal visibility requirements under the Clean Air Act at the coal-fired San Juan Generating Station ("SJGS").

As part of the resolution to those discussions, the Company has negotiated the shutdown of two units at SJGS. Moreover, in order to partially replace the generating capacity of those two coal-fired units, the Company is proposing that the PRC approve the transfer of the Company's 10.20 percent unregulated interest in PVNGS Unit 3 into rate base at the value of these assets to PNM as of the time that capacity will be needed. Concentric was retained by PNM to determine the value of PNM's interest in PVNGS Unit 3 for the purpose of assisting PNM in the preparation of its Application to the PRC, and to provide testimony in support of that valuation.

IV. DESCRIPTION OF PVNGS

Q. PLEASE DESCRIBE PVNGS.

A. Located about 50 miles west of Phoenix, Arizona, PVNGS consists of three identical pressurized water reactors, each generating approximately 1,314 megawatts of electricity. Combined, all three units generate approximately 3,941 megawatts of electricity. The license for PVNGS Unit 3 was issued by the U.S. Nuclear Regulatory Commission ("NRC") on November 25, 1987 and PVNGS Unit 3 has been granted an extended operating license which expires on November 25, 2047.

PVNGS is operated by Arizona Public Service Company ("APS") on behalf of all the facility's owners. Ownership is split evenly across all three operating units according to the following shares:

- Arizona Public Service Company (29.10 percent)
- Salt River Project (17.50 percent)
- El Paso Electric Company (15.80 percent)
- Southern California Edison Company (15.80 percent)
- Public Service Company of New Mexico (10.20 percent)
- Southern California Public Power Authority (5.90 percent)
- Los Angeles Department of Water and Power (5.70 percent)

For the purposes of my analysis, I assumed that the assets that would be conveyed to a regulated integrated utility buyer are a 10.20 percent undivided interest in PVNGS Unit 3 (and a commensurate interest in common and water reclamation facilities), the rights and obligations of a co-owner pursuant to the Arizona Nuclear Power Project Participation Agreement ("ANPPA") and its various amendments, and the decommissioning obligation and all funds expected to be held in the PVNGS Unit 3 decommissioning trust fund as of January 1, 2018. As noted by Company Witness Horn, the PVNGS Unit 3 decommissioning trust fund held approximately $68.7 million as of September 30, 2013.[1]

Q. WHAT RECORDS, INFORMATION AND DATA ABOUT PVNGS UNIT 3 DID YOU REVIEW IN ORDER TO DEVELOP AN OPINION ABOUT ITS VALUE?

A. As described in more detail in Section V, my staff and I have reviewed an extensive amount of historical and projected information related to the facility, including output, operating cost data, operating performance, age, location, and capital expenditures.

[1] See, Direct Testimony of Terry R. Horn, at 25.

Q. IN YOUR OPINION, HAVE YOU STUDIED PVNGS IN SUFFICIENT DETAIL TO RENDER AN OPINION AS TO ITS REASONABLE VALUE FOR RATEMAKING PURPOSES?

A. Yes.

V. THE VALUE OF PVNGS UNIT 3 TO PNM

Q. PLEASE DESCRIBE THE APPROACH YOU TOOK IN ESTIMATING A REASONABLE VALUE FOR PVNGS UNIT 3.

A. I estimated the reasonable value of PVNGS Unit 3 for ratemaking purposes based on incorporating these assets into the rate base of a regulated integrated utility company, such as PNM. Because PNM has proposed bringing PVNGS Unit 3 into its rate base, my approach considered the costs of capital and capital structure of an integrated regulated utility, such as the Company, in order to estimate the value of PVNGS Unit 3 to the Company as a part of its ongoing operations.

Q. IS YOUR ESTIMATE OF A REASONABLE VALUE AFFECTED BY PNM'S CURRENT OWNERSHIP OF PVNGS UNIT 3?

A. No, it is not. My estimate of a reasonable value represents the value that reasonably would be expected to be achieved in an arm's length transaction between two independent parties. In my analysis, I have assumed that the buyer would be a regulated integrated utility, with a cost of capital consistent with PNM's own such cost. As described in the next section, however, I have used operating costs and market revenues in my analysis that assume PVNGS Unit 3 operates independently.

VI. DCF APPROACH TO ESTIMATING VALUE

Q. HOW IS THE DCF APPROACH DEFINED?

A. The DCF Approach (also known as the Income Approach) is defined as the measurement of "the present value of the future benefits of property ownership."[2] The DCF Approach is used to value all types of revenue producing assets (such as electric generation facilities) and is applicable to all types of businesses, including utilities. The DCF Approach uses the DCF model to quantify the present value of the expected future cash flows to be generated from an asset over a specified period of time plus any residual (or resale) value, and less any demolition costs that the asset may have at the end of the specified time. While the most significant element of value for an income producing property or asset is the present value of the expected future cash flow, the residual value for the asset, if any, must also be considered in the valuation of the asset. The premise of any DCF analysis is that the value to an investor of an asset or investment is the cash that is able to be derived from owning that asset or investment.

Q. WHAT ARE THE ADVANTAGES OF USING THE DCF APPROACH?

A. The primary advantage of the DCF Approach is that it provides the framework in which the numerous benefits and risks of the specific assets being valued – and thus the future

[2] The Appraisal of Real Estate, Eleventh Ed., Appraisal Institute, 1996, p. 91.

ongoing economic value of those assets – can be quantified. Conducting a DCF analysis is an element of any due diligence effort when a potential purchaser is evaluating an income-producing asset.

Q. WHAT ARE THE OTHER PRIMARY APPROACHES TO VALUATION?

A. The other primary approaches are the Sales Comparison Approach (valuing an asset by considering the sales prices in transactions involving the sale of comparable assets) and the Current Cost Approach (valuing an asset by considering its replacement cost, adjusted for its current condition). While the applicability of each of these measures depends upon the nature of the asset, one or more of these approaches often are used to make an independent third-party evaluation of an asset's value.

Q. HAVE YOU CONSIDERED EITHER THE SALES COMPARISON APPROACH OR THE CURRENT COST APPROACH IN YOUR ESTIMATE OF THE VALUE OF 10.20 PERCENT OF PVNGS UNIT 3?

A. No. Company Witness Horn addresses the use of the Sales Comparison Approach by considering the value established by bids placed by PNM on leased portions of PVNGS. The use of the Current Cost Approach is not a reasonable approach, given the high level of construction costs for a new nuclear generating facility. Also, given the long lead times necessary for building new nuclear generation, a new nuclear plant would not be available in the time needed for new capacity under these circumstances. Therefore, I have not considered that approach. I have relied on the DCF for the purpose of estimating a reasonable value of 10.20 percent of PVNGS Unit 3.

Q. PLEASE EXPLAIN HOW YOU HAVE CONDUCTED THE DCF APPROACH.

A. I have developed a DCF model to calculate the value to a regulated integrated utility buyer that would be derived from the projected after-tax operating cash flows that would be generated by a 10.20 percent ownership of PVNGS Unit 3 during its remaining useful life, assuming also that its electric energy was to be sold at market-based prices. In my study, I have used a valuation date of January 1, 2018. In very simple terms, net operating cash flow for the plant is calculated as follows:

Energy Revenue (at market-based prices)
- Dispatch Cost (including fuel and variable operating expenses)
- Fixed Costs (including fixed operating expenses, administrative and general expenses, insurance and property taxes)
- Income Taxes

= Net Operating Income
- Capital Expenditures

= Net Operating Cash Flow

The DCF Approach uses assumptions based on the historical operating experience of PVNGS Unit 3 as well as projected future market conditions in order to project the net operating cash flows over the complete useful life of the facility. Decommissioning costs were assumed to be covered by the balance of the decommissioning trust fund at the end of PVNGS Unit 3's operating license. As such, I assumed no extra residual cost or value at the end of the facility's operating life. The total DCF value of the assets is the sum of the present value of the net operating cash flows.

Q. HOW DID YOU CALCULATE THE PRESENT VALUE OF NET OPERATING CASH FLOWS?

A. I employed the following formula in order to determine the present value of the net operating cash flows generated by 10.20 percent of PVNGS Unit 3 over the remainder of its useful life starting in 2018:

$$PV = \sum \frac{E_t}{(1+k)^t}$$

Where:
PV = present value
E_t = net operating cash flow in year t
k = discount rate or cost of capital
t = period in the future when net operating cash flow is to be received

This formula reflects the time value of money where a dollar received today is worth more than a dollar received at some future date. The regulated cost of capital for PNM, which is discussed later in my testimony, is the discount rate or k used in the formula above to discount future net operating cash flows to the present. My DCF model assumes that net operating cash flows are generated on an annual basis and received by the owner on June 30th of each year. This is a reasonable assumption given that in reality, PVNGS Unit 3 will generate net operating cash flows on a continuous basis throughout a calendar year.

Q. HOW IS THE VALUE OF A NUCLEAR GENERATING FACIILITY, SUCH AS PVNGS UNIT 3, AFFECTED BY THE ASSUMPTIONS RELATED TO DECOMMISSIONING?

A. In my experience, the value determined in the sale of a nuclear generating facility is highly dependent on the terms of transfer of the decommissioning trust fund associated with the facility. Given PNM's proposal for the Company's customers to fund the PVNGS Unit 3 decommissioning trust fund through the life of the facility, the value estimated by using the DCF Approach is lower than it would be if no such contributions were to be made. Accordingly, the adequacy of funding does not enter into consideration of PVNGS Unit 3's reasonable value and any excess or shortfall in the decommissioning trust fund at the end of PVNGS Unit 3's useful life would be for the account of the Company's customers and is not reflected in my estimate of the value of the facility.

Q. WHAT DID YOU ASSUME TO BE THE USEFUL LIFE OF PVNGS UNIT 3?

A. PVNGS Unit 3 currently operates under a license granted by the NRC that extends until November 25, 2047. For the purposes of my DCF analysis, I assumed that PVNGS Unit 3 would be retired at that date.

Q. WHAT ARE THE KEY ASSUMPTIONS THAT ARE INCLUDED IN THE DCF APPROACH?

A. The key assumptions in the DCF Approach include forward energy market price projections, general inflation and discount rate assumptions, and specific operating and financial statistics for PVNGS Unit 3.

Q. PLEASE DESCRIBE THE SOURCE OF YOUR ENERGY PRICE FORECAST.

A. I relied on a series of energy price forecasts for the New Mexico control area which were produced by Pace Global ("Pace") and provided to me by PNM.[3] These forecasts were developed using a detailed production costing model. I reviewed the assumptions and the methodology behind the forecasts and found them to be reasonable.

Q. PLEASE DESCRIBE YOUR REVIEW OF THE PACE ENERGY PRICE FORECASTS.

A. PNM provided me with access to the underlying assumptions used by Pace to generate the energy price forecasts used in my DCF analysis. I checked those underlying assumptions for reasonableness against a variety of integrated resources plans ("IRP") recently issued by several regulated utility companies in a number of different jurisdictions nationwide. In cases where there was overlap between the inputs used by Pace and those used in my analyses, I considered the consistency of our respective assumptions and the reasonableness of any deviations.

Q. WHAT WAS THE RESULT OF YOUR REVIEW OF THE PACE FORECAST ASSUMPTIONS?

A. I found that the assumptions Pace used in the development of the price scenarios were generally consistent with those used in recent IRP filings. Moreover, I found that the

[3] While PVNGS Unit 3 operates at the Palo Verde market hub, I used the New Mexico control area prices to remain consistent with the Company's other analyses and because there are negligible differences between the two price points.

inputs we held in common were consistent with one another and reasonable in the context of estimating the value of PVNGS Unit 3 to PNM.

Q. WHAT ARE THE KEY CHARACTERISTICS OF THE PACE REFERENCE ENERGY PRICE FORECAST?

A. As a preliminary matter, the Pace forecast is provided in real dollars as of 2012. As such the values used in my DCF model are escalated at the annual inflation rate to calculate the relevant value in any given year.

The Reference Case assumes the implementation of Mercury and Air Toxics Standards ("MATS") in 2016 with gradual tightening of emissions restrictions in the long-term (2026-2035) and a modest CO_2 regime starting in 2020 ($11.00 per metric ton). Real natural gas prices range from $5.00 per MMBtu to $6.00 per MMBtu in the mid-term (2016-2025) and increase to $6.00 per MMBtu to $7.00 per MMBtu in the long-term. Coal plant retirements are projected at 10 to 15 gigawatts in the mid-term and 30 to 50 gigawatts in the long-term. Load growth is 1.5 percent in the short-term (2013-2015), 1.0 percent in the mid-term and 0.5 percent in the long-term. Electricity prices range between $37 per megawatt-hour and $55 per megawatt-hour in the medium-term, escalating to $71 per megawatt-hour in the long-term.

Q. WHAT OTHER PACE SCENARIOS DID YOU CONSIDER?

A. I also considered two additional energy price forecasts produced by Pace: the "Low Gas and Carbon Scenario" and the "High Gas and Carbon Scenario." Pace's Low Gas and Carbon Scenario assumes less stringent environmental regulations than the Reference

Case with a CO_2 regime not introduced until the long-term, lower natural gas prices, fewer coal plant retirements and stronger load growth. Natural gas prices are approximately $1.00 lower over the course of the forecast period. Some announced coal plant retirements are reversed in the short-term, less than five gigawatts are retired in the mid-term and 10 to 15 gigawatts of coal-fired capacity are retired in the long-term. Load growth is 0.05 percent in the short-term, 1.5 percent in the mid-term and 2.0 percent in the long-term. Electricity prices are subsequently lower, ranging between $34 and $42 per megawatt-hour in the medium-term and escalating to $59 per megawatt-hour in the long-term.

Pace's High Gas and Carbon Scenario assumes stricter environmental regulations than the Reference Case with a federal CO_2 regime starting in 2018, higher natural gas prices, more coal plant retirements and weaker load growth. Carbon prices reach $35.00 per metric ton by 2025 and reach $55.00 per metric ton in the long-term. Natural gas prices start and end the forecast period at similar levels to the Reference Case but spike in the medium term to $10/MMBtu. Coal plant retirements are significantly higher than the Reference Case at 140 gigawatts by 2025 and an additional 30 gigawatts are retired by 2035. Load growth is 1.25 percent in the short-term, 0.50 percent in the mid-term and -0.50 percent in the long-term. Electricity prices are the highest in this scenario, ranging between $40 and $80 per megawatt-hour in the medium-term, with a maximum value of approximately $89 per megawatt-hour over the long-term.

Q. HOW IS IT POSSIBLE TO DETERMINE MARKET-BASED PRICES FOR A REGULATED COMMODITY LIKE ELECTRIC ENERGY?

A. Because of the formation of competitive power markets, it is possible to value electric utility property using a forecast of generation market prices. Sales of energy at market-based prices take place on a regular basis throughout the country. Therefore, it is possible to determine the current and projected future market price of electric energy in each region of the country. These markets make it possible to use the DCF model to value 10.20 percent of PVNGS Unit 3.

Q. WHY IS A MARKET-BASED PRICING MODEL APPROPRIATE WHEN PNM IS REQUESTING BRINGING 10.20 PERCENT OF PVNGS UNIT 3 INTO THE COMPANY'S REGULATED RATE BASE?

A. As noted above, the purpose of this analysis is to estimate a reasonable value for 10.20 percent of PVNGS Unit 3 as a component of a regulated integrated utility such as PNM. However, it is appropriate to consider the intrinsic value of the facility in a competitive market, because resources in the market represent the set of alternatives for PNM. This approach is reasonable for three reasons: (1) determining the value of PVNGS Unit 3 as part of the Company's regulated revenues would be circular without an independent estimate of the revenues the facility could derive from the competitive wholesale marketplace; (2) there is a demonstrated value for the power generated by PVNGS Unit 3 in the wholesale market and, as such, wholesale market operations represent the alternative best use of the facility for the Company; and (3) because purchasing from the wholesale market represents PNM's best alternate source for its power requirements, the value established using market prices represents a break even valuation of PVNGS Unit 3, given the various assumptions employed in my DCF analysis.

Q. HOW DID YOU USE THE THREE DIFFERENT PRICE FORECASTS FROM PACE IN DEVELOPING YOUR ESTIMATE OF VALUE FOR 10.20 PERCENT OF PVNGS UNIT 3?

A. I used two approaches in estimating the value of PVNGS Unit 3 to PNM. First, I considered what the value of the facility would be under the Reference Case price forecast. The use of the Reference Case in this manner is consistent with PNM's reliance on the Reference Case in its IRP analyses. Second, I considered the value derived from a weighted average of the three price forecasts. I weighted each of the three energy price forecasts provided by Pace according to my view of a reasonable long-term outlook for electricity prices. To that end, I weighted the Reference Case at 65.00 percent, the Low Gas and Carbon at 25.00 percent and the High Gas and Carbon at 10.00 percent. As noted above, the Reference Case represents PNM's base case and is the middle path between the two alternative scenarios. As such, I allocated the most weight to that forecast. In order to reflect a reasonable mix of alternative electricity price scenarios, I considered the likelihood of significant increases or declines in the long-term price of energy, along with what would drive those changes. The greater weighting of the Low Gas and Carbon Scenario as compared to the High Gas and Carbon Scenario reflects my view that the price of natural gas, and in turn the price of electricity, is likely to remain relatively low for an extended period of time. There is a reasonable chance that electricity prices will remain below levels established by even the Reference Case for the long-term. Finally, allocating 10.00 percent to the High Gas and Carbon Scenario reflects the possibility that electricity prices could spike upwards in the future, even though that possibility does not seem likely given today's energy market dynamics. My weights for the three scenarios provides a reasonable recognition of the upside and downside risks inherent in today's energy markets.

Q. WHAT WAS YOUR SOURCE FOR THE FORECASTED OPERATING ASSUMPTIONS FOR PVNGS UNIT 3 USED IN THE ANALYSIS?

A. I developed my estimates of the forecasted operating assumptions using historical and near-term projected operating information provided by the Company.

Q. HOW DID YOU ESTABLISH THE LEVEL OF GENERATION EXPECTED FOR EACH YEAR OF YOUR ANALYSIS?

A. In order to estimate the number of megawatt-hours generated by PVNGS Unit 3 in the future, I considered the most recent five years of historical performance (2008-2012). I obtained capacity and generation data for PVNGS Unit 3 from the FERC Form 1 of APS. As noted earlier, APS owns 29.1 percent of PVNGS and operates PVNGS on behalf of the other six owners. In its FERC Form 1, APS reports data for its share of each of the three units at PVNGS separately. I calculated the capacity factor for PVNGS Unit 3 for 2008-2012 based on the amount of net generation reported by APS and on APS' share of PVNGS Unit 3's capacity. In order to calculate a "base" capacity factor, I then added back the hours of generation lost to refueling outages. The durations of the 2008, 2009, 2010 and 2012 refueling outages were obtained from PNM.[4]

[4] Please note that the 2008 refueling outage began in September 2007 and ended in January 2008.

**Table 1: 2008-2012 Capacity and Generation
(APS's 29.1% Share of PVNGS Unit 3)**

	2012	2011	2010	2009	2008
APS' 29.1% Share of PVNGS Unit 3					
Net Continuous Plant Capability (MW)	382.0	382.0	382.0	383.0	383.0
Net Generation, Exclusive of Plant Use (KWh)	2,937,257,125	3,297,465,946	2,979,546,822	2,782,718,242	3,105,911,005
Days per Year	366	365	365	365	366
Capacity Factor	87.54%	98.54%	89.04%	82.94%	92.32%
Refueling Outage Duration					
Hours	759	-	957	1,290	437
Percent	8.64%	0.00%	10.93%	14.73%	4.98%
Capacity Factor + Refueling Outage Duration	96.17%	98.54%	99.97%	97.67%	97.30%
2008-2012 Median	97.67%				

Based on that analysis, I calculated a range of base capacity factors for 2008 to 2012 of 96.17 percent to 99.97 percent and I applied the median value of 97.67 percent as the base capacity factor (before refueling outages) for every year of the study period (2018-2047).

After establishing a base capacity factor for PVNGS Unit 3, I then examined the facility's recent refueling history to determine a reasonable estimate of the duration of refueling outages going forward. Table 2 below presents the duration of the last four refueling outages.

Table 2: PVNGS Unit 3 Refueling Outage History

Refueling Outage	Duration	
	Days	Percent
Mar-2012 – Apr-2012 (RFO16)	31.6 days	8.64%
Oct-2010 – Nov-2010 (RFO15)	39.9 days	10.93%
Apr-2009 – May-2009 (RFO14)	53.7 days	14.73%
Sept-2007 – Jan-2008 (RFO13)[5]	109.0 days	29.78%

Based on my review of the historical performance of PVNGS Unit 3 refueling outages and the Company's public pronouncements on future refueling outage duration

[5] The 2007 – 2008 outage also encompassed the replacement of PVNGS Unit 3's steam generator, which significantly extended the duration of the outage.

expectations, in future years in which a refueling outage will occur I reduced the base capacity factor of 97.67 percent by 9.32 percent. This assumes a refueling outage duration of 34 days.[6] Because refueling outages occur every 18 months, they therefore affect the capacity factor of two of three consecutive years in the analysis.

Q. HOW DID YOU FORECAST NUCLEAR FUEL EXPENSES FOR PVNGS UNIT 3?

A. Nuclear fuel purchases for 2018 and onward are based on PNM's uranium price forecast, the heat rate of PVNGS Unit 3 and the capacity factor forecast discussed above. PNM's uranium price forecast is equal to $0.76/MMBtu in 2012 and escalates in annual increments until 2033. After that date, I escalated those prices for the 2034 to 2047 period using an inflation rate of 2.50 percent. Based upon APS' 2012 IRP, I established that the heat rate for PVNGS Unit 3 is 10,377 Btu/kWh.

Finally, because nuclear fuel purchases are considered capital expenditures, they are amortized over five years for tax purposes. Nuclear fuel amortization for 2018-2047 is calculated based on the beginning balance of the nuclear fuel inventory as of January 1, 2018 ($24,607,643) and the additional nuclear fuel purchases each year. The beginning balance of the nuclear fuel inventory, as of January 1, 2018, is equal to the ending balance, as of December 31, 2017, which was estimated by PNM as part of its five-year long-range planning process. A five-year Modified Accelerated Cost Recovery System ("MACRS") depreciation schedule is used per Internal Revenue Service ("IRS")

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6 A 34-day refueling outage is consistent with PNM's recent investor relations presentations, which present a forecast of near-term PVNGS Unit 3 refueling outages.

Publication 946 "How To Depreciate Property" with the remaining balance of the nuclear fuel inventory expensed in 2047 at the end of the facility's useful life. Separately, the fuel handling charge for 2018 is equal to the five-year inflation adjusted average for 2013-2017, while the fuel handling charge for 2019-2047 is equal to the inflation adjusted value from 2018.

Q. HOW DID YOU CALCULATE THE OPERATING AND MAINTENANCE ("O&M") EXPENSE OF PVNGS UNIT 3 OVER THE ANALYSIS PERIOD?

A. PNM provided me with three years of historical O&M expenses along with five years of forecasts broken out into 13 separate O&M categories. These 13 categories are consistent with the FERC accounts for power production expenses contained in Table 3 below.

Table 3: O&M Expense FERC Accounts

FERC Account	Title
Nuclear Power Generation	
517	Operation Supervision and Engineering
519	Coolants and Water
520	Steam Expenses
523	Electric Expenses
524	Miscellaneous Nuclear Power Expenses
525	Rents
528	Maintenance Supervision and Engineering
529	Maintenance of Structures
530	Maintenance of Reactor Plant Equipment
531	Maintenance of Electric Plant
532	Maintenance of Miscellaneous Nuclear Plant
Other Power Generation	
546	Operation Supervision and Engineering
Other Power Supply Expenses	
556	System Control and Load Dispatching

The O&M expense used for 2018-2047 is equal to the inflation adjusted value from 2017, escalating annually at the rate of inflation.

Q. WERE ADMINISTRATIVE AND GENERAL EXPENSES INCLUDED IN THE VALUATION OF 10.20 PERCENT OF PVNGS UNIT 3?

A. Yes. PNM provided me with three years of historical administrative and general expenses along with five years of forecasts broken out into 11 separate categories. Seven of these categories are consistent with the FERC accounts for administrative and general expenses contained in Table 4 below.

Table 4: Administrative and General Expenses FERC Accounts

FERC Account	Title
922	Administrative Expenses Transferred-Credit
923	Outside Services Employed
924	Property Insurance
925	Injuries and Damages
926	Employee Pensions and Benefits
928	Regulatory Commission Expenses
930.2	Miscellaneous General Expenses

In addition to the seven categories listed above, the estimate for administrative and general expenses includes an allocation of expenses from PNM Resources, Inc. and PNM and a credit for capitalized administrative and general expenses. The annual administrative and general expense for 2018-2047 is equal to the inflation adjusted value from 2017.

Q. DID YOU ASSUME ANY DECOMMISSIONING FUND CONTRIBUTIONS IN YOUR DCF ANALYSIS?

A. Yes. Consistent with the level of decommissioning fund contributions proposed by Company Witness Horn, I assumed annual contributions in the amount of $1.30 million to the decommissioning trust fund for 10.20 percent of PVNGS Unit 3. As discussed earlier, underlying this assumption is the premise that the decommissioning obligation is fully funded by the end of the plant's expected life.

Q. WHAT ASSUMPTIONS DID YOU MAKE WITH RESPECT TO GENERAL INFLATION?

A. I assumed an inflation rate of 2.50 percent per year. That estimate is consistent with the inflation rate used in the Company's other analyses in this proceeding, as well as Pace's long-term inflation assumption used in the development of the energy price forecasts. My estimate is also consistent with Blue Chip Financial Forecasts' long-term estimate for inflation of 2.40 percent per year.[7] I used the general inflation rate to escalate fixed and variable operating and maintenance expenses, property taxes, insurance, and capital expenditures in periods beyond the Company's explicit forecasts for these items. Similarly, uranium prices were assumed to escalate at the annual inflation rate beyond PNM's explicit forecast range.

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[7] Blue Chip Financial Forecasts, Vol. 32, No. 6, June 1, 2013, at 14. Blue Chip Financial Forecasts publishes long-term forecasts twice per year (June and December) and as of June 2013, the long-term period includes 2020 to 2024. Inflation is measured by the Consumer Price Index.

Q. HOW WAS DEPRECIATION FACTORED INTO THE ANALYSIS?

A. Depreciation is a permissible deduction for tax purposes using IRS-prescribed accelerated tax depreciation rates. As noted earlier in my testimony, I have assumed that a buyer has acquired 10.20 percent of PVNGS Unit 3 at the valuation date, thereby increasing the tax basis of that asset to the level of the purchase price. I have, therefore, assumed that the utility buyer may then depreciate the full value of the transaction for tax purposes. This assumption creates an iterative step in the valuation process, as the value of the tax depreciation is added to the asset value, and this process is repeated until negligible value is added by the next iteration. In addition, projected capital improvements in each year were depreciated going forward in the DCF model. For both purposes, I have assumed a 15-year MACRS depreciation rate. It is important to note that, in the DCF analysis, depreciation is deducted as an expense in order to calculate income taxes, but is not deducted for cash flow purposes because it is a non-cash item. Therefore, the amount of depreciation in any year affects operating cash flows solely through its effect on income taxes.

Q. WHY DID YOU USE TAX DEPRECIATION RATHER THAN BOOK DEPRECIATION IN THE DCF MODEL?

A. The purpose of the DCF analysis is to calculate the future stream of cash generated by the facility. The depreciation amount that determines the cash needed to pay income taxes is the depreciation deductible on the income tax return. Book depreciation expense may be quite different from tax depreciation expense due to the differences in the accounting methods that are used for these purposes.

Q. WHAT ASSUMPTIONS DID YOU USE REGARDING TAX RATES?

A. Income tax rates were based on the composite federal and state income tax rate of 38.62 percent, used by PNM in its IRP analyses. Property taxes were calculated using the Arizona property tax expense schedule as provided by the Company and the calculated value as the tax base.

Q. DOES THE ANALYSIS CONSIDER FUTURE CAPITAL ADDITIONS?

A. Yes. PNM provided me with 16 years of historical capital expenditures and a 10-year forecast of capital expenditures for 2014-2023 which includes PVNGS Unit 3-specific capital expenditures as well as capital expenditures related to common facilities and the water reclamation facility, which support all three units at PVNGS. The forecast is in real dollars (as of 2013) which I escalated assuming the 2.50 percent inflation rate. I included 10.20 percent of the PVNGS Unit 3 specific capital expenditures and 10.20 percent of one third of the common capital expenditures which benefit all three units.

PNM's 10-year forecast exhibits a seven year "trough-to-trough" spending pattern, which I have incorporated into the long-term capital expenditure projections for my DCF Analysis. As such, capital expenditures for 2024 are equal to the inflation adjusted value from 2017 and capital expenditures for 2025 are equal to the inflation adjusted value from 2018 and so on. PNM confirmed that the capital expenditure forecast the company provided includes all amounts necessary to meet the NRC's Maintenance and Aging Management Rules for plants that have been granted operating life extensions. Finally, I increased the annual capital expenditure forecast for each year by 10.00 percent to accommodate unexpected incremental capital that may be required over the life of PVNGS Unit 3. That level of increased capital requirement is based on my experience in helping clients manage and track ongoing life cycle maintenance and capital expenditures in facilities that have been granted operating life extensions by the NRC. I note that the steam generators in PVNGS Unit 3 were replaced in the fourth quarter of 2007.

Q. DOES YOUR CONSIDERATION OF FUTURE CAPITAL ADDITIONS MEAN THAT YOU INCLUDED PROPERTY THAT IS NOT CURRENTLY IN SERVICE IN YOUR ESTIMATE?

A. No, quite the contrary. I deducted future capital expenditures at PVNGS Unit 3 because these expenditures reduce cash flow. As I indicated previously, capital expenditures are deducted from net operating income. The result is net operating cash flow.

Q. HAVING DERIVED ALL OF THE PROJECTED CASH FLOWS FOR 10.20 PERCENT OF PVNGS UNIT 3, HOW DID YOU ARRIVE AT A VALUE FOR THESE ASSETS?

A. I used a discount rate to express these cash flows in the value of 2018 dollars.

Q. HOW DID YOU DEVELOP THE DISCOUNT RATE FOR YOUR DCF ANALYSIS?

A. As I noted previously, the DCF analysis produces a value for an asset in current dollars based on that asset's future cash flow stream. In order to convert those future cash flows into current dollars, the cash flows must be discounted using a rate that is appropriate for the asset, *i.e.*, a discount rate. The discount rate represents the rate of return an investor would seek for the asset being valued.

Q. HOW DID YOU CALCULATE THE DISCOUNT RATE FOR THE DCF ANALYSIS?

A. As discussed earlier, my valuation approach considered the value of PVNGS Unit 3 as part of the asset base of a regulated integrated electric utility company. For that reason, the discount rate I adopted to estimate a reasonable value for PVNGS Unit 3 incorporates the Company's after-tax weighted average cost of capital ("ATWACC"). The ATWACC is composed of the after-tax costs of the individual components of the Company's capital structure multiplied by their respective weights. The resulting discount rate is used to calculate the net present value of after-tax cash flows in the DCF model.

Q. WHAT COST OF EQUITY DID YOU USE IN YOUR ANALYSIS?

A. I chose to use the Company's 10.00 percent cost of equity in my analysis. This represents the return on equity authorized by the Commission in PNM's last rate case, Case No. 10-00086-UT. I have not conducted an independent cost of equity analysis for PNM like the one I performed to recommend a cost of equity of 10.25 percent in Case No. 12-00350-UT for Southwestern Public Service in September 2013. At this time, for purposes of this analysis, I believe that the Company's current cost of equity expectations are the best forecast of the incremental cost of equity that the Company will face in 2018.

Q. DID YOU ALSO RELY ON THE COMPANY'S COST OF DEBT?

A. Yes.

Q. WHAT COST OF DEBT DID YOU USE?

A. Similar to the cost of equity, I used the Company's current cost of long-term debt, 6.35 percent. In order to test the reasonableness of using this estimate as the incremental cost of long-term debt in 2018, the Company obtained a current market quote from one of its investment bankers, indicating that the current incremental cost of new 30-year debt would be approximately 5.66 percent. Given the likelihood that interest rates will rise over the intervening period, using the Company's current embedded cost of debt of 6.35 percent as its incremental cost of debt in 2018 is a reasonable approach when estimating the value to PNM of PVNGS Unit 3. Using this higher cost of debt increases the discount rate and in turn reduces the resulting valuation, again contributing to a conservative valuation.

Because of the deductibility of interest expenses for income tax purposes, I adjusted the cost of debt to account for PNM's expected income tax rate of 38.62 percent. As shown in Table 5, below, the resulting after-tax cost of debt of 3.90 percent was then used in the calculation of the ATWACC.

Q. DID YOU ADOPT THE COMPANY'S COST OF PREFERRED EQUITY?

A. Yes. As shown in Table 5, below, the company has a small portion of its capital structure funded by preferred equity. I have adopted the Company's cost of preferred equity of 4.62 percent.

Q. WHAT OVERALL REGULATED UTILITY COST OF CAPITAL DID YOU EMPLOY?

A. In order to estimate the value of PVNGS Unit 3 as part of the assets of a regulated utility, as shown in Table 5, below, the ATWACC used in my DCF analysis is 6.98 percent.

Table 5: Regulated Utility After-Tax Weighted Average Cost of Capital

	Weight	Pre-Tax Cost	Pre-Tax Weighted Cost	After-Tax Cost	After-Tax Weighted Cost
Debt	49.00%	6.35%	3.11%	3.90%	1.91%
Preferred Equity	0.46%	7.53%	0.03%	4.62%	0.02%
Common Equity	50.54%	16.29%	8.23%	10.00%	5.05%
			11.38%		6.98%

Q. IS THE ATWACC USED IN YOUR DCF ANALYSIS MEANT TO BE EQUAL TO THE COMPANY'S AUTHORIZED RETURN ON RATE BASE?

A. No. The Company's return on rate base is a regulatory concept that represents a weighted average of pre-tax (debt) and after-tax (equity) costs of capital. While that measure is often used by utilities in evaluating ratemaking impacts and determining revenue requirements, it is not a measure that is used by asset purchasers to evaluate whether a project's purchase price will offer a level of return that exceeds the acquirer's hurdle rate or cost of capital. The ATWACC that I have used, which represents all of the same capital components and costs of capital as are reflected in the return on rate base figure, is a financial metric that reduces all capital costs to an after-tax basis, because the discount rate is being used to adjust after-tax cash flows. The approach I have used reflects the correct discount rate for a corporate acquirer that is taxable, although it may not reflect the appropriate discount rate for a tax exempt acquirer or an individual investor.

Q. WHAT WERE THE RESULTS OF THE DCF APPROACH?

A. The DCF Approach resulted in a range of overall value for 10.20 percent of PVNGS Unit 3 of $351.76 million, or an average of $2,625 per kilowatt based on the Reference Case market price forecast, and $340.67 million, or $2,542 per kilowatt, based on the weighted average of the three different price forecasts provided by Pace. This is a reasonable valuation range for regulated integrated utility ownership using the DCF Approach.

VII. SUMMARY AND CONCLUSION

Q. WHAT IS YOUR FINAL CONCLUSION AS TO THE RANGE OF REASONABLE VALUE OF PVNGS UNIT 3?

A. I have based my recommended value on my review of the available historical and forecasted operating information and my consideration of the alternative electricity price forecasts. Based on those analyses, a reasonable range of value for PNM's ownership stake of 10.20 percent in PVNGS Unit 3 is between $2,542 per kilowatt to $2,625 per kilowatt. At 134 megawatts, that represents a range of value between approximately $341 million and $352 million. Because the proposed use of PVNGS Unit 3 is for a regulated utility to be included in rate base as the lowest cost alternative, it is my opinion that the weighted average value, i.e. $2,542 per kilowatt is a reasonable valuation for ratemaking purposes. As such, PNM's proposed valuation of $2,500 per kilowatt provides benefits to PNM's customers as well as the portfolio benefits described by Mr. O'Connell.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

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