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

J. EDWARD CICHANOWICZ

December 20, 2013

NMPRC CASE NO. 13-_______-UT
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WITNESS FOR
PUBLIC SERVICE COMPANY OF NEW MEXICO

DIRECT TESTIMONY OF
J. EDWARD CICHANOWICZ
NMPRC CASE NO. 13-00_______-UT

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is J. Edward Cichanowicz. I am an independent consultant providing engineering and analytical services to the electric utility and energy industries, and aligned investors. My address is 236 N. Santa Cruz Avenue, Suite # 202, Los Gatos, California, 95030.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN UTILITY REGULATION PROCEEDINGS?

A. I have previously provided testimony in three hearings regarding permit applications for proposed power stations. Other forums where I have provided testimony concerning environmental controls have addressed contractual disputes over technology cost, performance, and deployment schedules. I have twice delivered Congressional testimony – before the House Subcommittee on Energy and Environment, within the Committee on Science, Space and Technology, and more recently before the House Subcommittee on Energy and Power, within the Committee on Energy and Commerce. I have also testified before the New Mexico Environmental Improvement Board regarding control technology and mitigation measures related to proposed greenhouse gas regulations. A copy of my resume is attached as PNM Exhibit JEC-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of the Public Service Company of New Mexico ("PNM" or "Company").

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to address the installation of selective non-catalytic reduction ("SNCR") technology at the San Juan Generating Station ("SJGS" or "San Juan") required as a result of the best available retrofit technology ("BART") determination recently adopted by the New Mexico Environmental Improvement Board ("NMEIB" or "Board") in its revised Regional Haze State Implementation Plan ("Revised SIP"). I also address the accuracy and reasonableness of the estimated costs for installation of SNCR at San Juan. I then describe the relationship between the existing air pollution controls at SJGS and SNCR. I define other environmental benefits that will result from the implementation of the Revised SIP, which requires installation of SNCR on San Juan Units 1 and 4 and the retirement of San Juan Units 2 and 3. In addition, I address San Juan's position with respect to anticipated future emissions regulation subsequent to installing SNCR.

Q. HOW DOES YOUR TESTIMONY RELATE TO THE TESTIMONY PRESENTED BY OTHER COMPANY WITNESSES?

A. My testimony provides independent support for the testimony by other PNM witnesses that states SNCR is the required technology under the Revised SIP. I also confirm that

PNM's estimated costs for the installation and operation of SNCR, including conversion to balanced draft, at SJGS are accurate and reasonable.

Q. DOES YOUR TESTIMONY ADDRESS ANY OTHER ISSUES?

A. Yes. I explain what SNCR is and describe generally how it operates. I describe the original SJGS environmental control equipment and how it has been upgraded over the years. I also describe the need to convert the present gas handling equipment from forced draft to balanced draft. I explain the relationship between operation of the SNCR and the existing control equipment. Further, I cite the emissions of carbon dioxide ("CO_2") and nitrogen oxide ("NOx") from a natural gas-fired combined cycle unit that are avoided by deploying the equivalent power output from an existing nuclear power plant.

II. SUMMARY OF KEY CONCLUSIONS

Q. WHAT ARE YOUR KEY CONCLUSIONS?

A. My key conclusions can be summarized as follows:

- SNCR technology for control of NOx emissions from SJGS Units 1 and 4 is required under the Revised SIP adopted by the NMEIB.
- PNM has taken appropriate steps to ensure that the costs for installation of SNCR at SJGS are reasonable.

- Following installation of SNCR at SJGS, PNM will still be required to operate the existing emissions controls in order to maintain compliance with applicable air quality regulations.
- Converting the gas handling system from forced draft to balanced draft will significantly reduce the intrusion of combustion products prior to environmental controls into the ambient air, improving ambient air quality in the working environment and immediate plant vicinity.
- The recently retrofitted low NOx burners, which are a complementary control means for NOx at the SJGS, are critical in that they enable the use of SNCR to achieve the outlet emissions rate of 0.23 lb/MMBtu.
- The existing environmental controls will allow SJGS to meet the emission limits recently mandated by the EPA's Mercury and Air Toxics Standards ("MATS") rule.
- The installation of SNCR and conversion to balanced draft, coupled with the upgraded emission controls and the retirements of Units 2 and 3, provides a robust platform to better comply with anticipated future air emission regulations.
- Nuclear power can be used to avoid generating CO_2 and NOx emissions from a natural gas-fired combined cycle generating unit.

III. THE REVISED SIP REQUIREMENTS

Q. CAN YOU PLEASE DESCRIBE THE GENERAL REQUIREMENT APPLICABLE TO SAN JUAN UNDER THE BOARD'S REVISED SIP?

A. The Term Sheet – as agreed to by PNM, the U.S. Environmental Protection Agency ("EPA"), and the NMED – calls for a Revised SIP which requires the application of SNCR NOx control to Units 1 and 4 of the SJGS. The outlet NOx emission rates from these units is to be controlled to 0.23 lb/MMBtu, as measured on a 30-day rolling average. The SNCR process equipment is to be installed and operated within 15 months of EPA's final approval of the Revised SIP, but not before January 31, 2016.

The revised SIP also requires SJGS Units 2 and 3 to terminate operation by December 31, 2017.

Once installed on Units 1 and 4, the SNCR process is to be evaluated in a test program to establish a realistic level of NOx control that can be achieved. Specifically, short-term tests are to be completed and results reported to the NMED by April 2016, and longer-term (9-month) tests are to be completed by February 28, 2017. These results will be used to determine if a long-term achievable NOx emission rate less than the 0.23 lb/MMBtu can be attained.

Q. WHAT IS THE SIGNIFICANCE OF THE BOARD'S REQUIREMENTS RELATING TO NOx EMISSIONS FROM SAN JUAN?

A. NOx emissions from San Juan will be significantly reduced. Both aspects of the Revised SIP – retrofitting SNCR to Units 1 and 4 and terminating operation of Units 2 and 3 – together will lower total NOx emissions from a station-wide total of about 21,000 tons per year to about 8,011 tons per year. These actions reduce the NOx emissions by about 62% compared to present levels.

The flexibility of the rule – allowing PNM to conduct long-term demonstration tests between May 1, 2016, and February 28, 2017, and prior to finalizing a NOx emissions rate – enables the SJGS to potentially further minimize NOx without compromising the reliability of the units.

Q. CAN YOU PLEASE EXPLAIN WHAT SNCR IS?

A. Selective non-catalytic reduction – SNCR – is a control technology for NOx emissions. SNCR is based on the reaction of ammonia with nitrogen oxides to form molecular nitrogen and water. Ammonia is created in the gas stream for reaction with NOx by the decomposition of urea, which is injected as an aqueous mixture. As perfect mixing of the ammonia derived from the injected urea with NOx is not achievable, some ammonia does not contact with and react with NOx. This ammonia – typically referred to as residual or "slip" ammonia – escapes the SNCR process. This residual or slip ammonia must be managed so it does not interfere with plant operation.

The SNCR process is carried out in the high temperature gas stream within the confines of the boiler. The NOx removal achieved depends on quickly injecting and dispersing ammonia within the gas stream. Present-day SNCR designs achieve approximately 20-40% NOx removal on a coal-fired boiler. The most recent state-of-art designs exploit relevant experience and powerful predictive tools to define the appropriate design.

Q. CAN YOU DESCRIBE HOW THE SNCR PROCESS WILL WORK AT SAN JUAN?

A. The SNCR process will be deployed at SJGS by installing special-purpose injection lances within the upper sections of the boiler, exploiting high gas temperatures to prompt the desired reactions. PNM Exhibit JEC-2 depicts for a typical SNCR process the relationship between NOx removal and the temperature of the gas to be treated. PNM Exhibit JEC-2 shows how NOx removal changes with gas temperature as the gas proceeds through the boiler. Ideally, urea is injected so it mixes where temperatures are between 1,650 to 1,800 ºF – maximizing NOx reduction.

Any ammonia formed from urea in the gas stream at temperatures greater than typically 1,800 ºF is counterproductive to controlling NOx, as it actually oxidizes to NOx – compromising removal efficiency. Conversely, ammonia formed from urea that is introduced into the gas stream at less than 1,650 ºF does not have adequate time and temperature to react and remove much NOx. Most of this ammonia becomes residual or slip ammonia.

Sophisticated computer models are used to define where in the boiler the injectors for urea should be installed to create ammonia at the location and temperature that maximizes NOx removal and minimizes residual NH_3. The general approach is to avoid producing ammonia in the gas stream at temperatures on the right side of the curve shown in PNM Exhibit JEC-2, corresponding to the red band and within the circle, and to also on the left side of the temperature curve, corresponding to the blue band.

Q. DOES THE REVISED SIP IMPOSE ANY OTHER EMISSION REDUCTION REQUIREMENTS ON SAN JUAN?

A. Yes. The Revised SIP also requires a reduction in permitted emissions of sulfur dioxide ("SO_2") from the present value of 0.15 lbs/MMBtu, to 0.10 lb/MMBtu, as measured on a 30-day rolling average basis. PNM will effect this reduction in SO_2 emissions within six months of when the NMEIB adopts the revised SO_2 emission limits in the Interstate Visibility Transport State Implementation Plan. NMEIB adopted the interstate transport plan on September 5, 2013 and Units 1 and 4 will be required to meet these revised SO_2 emission limits by March 5^{th} of 2014.

Q. IN YOUR OPINION, WILL THE SNCR TECHNOLOGY SELECTED BY PNM MEET THE REQUIREMENTS, INCLUDING THE NOx EMISSIONS LIMITS, UNDER THE REVISED SIP?

A. Yes. The SNCR process as proposed for Units 1 and 4 presents a high probability of meeting the targeted outlet levels of 0.23 lb/MMBtu for NOx, as measured over a 30-day rolling average.

There are three requisites for successfully deploying SNCR: (1) identify where the optimal temperature zone is located in the boiler, (2) inject urea reagent quickly and mix thoroughly in the gases to be treated, and (3) design the injectors to be flexible to account for changes in gas temperature with boiler operation. The probability of successfully providing these desired process conditions at the SJGS is high.

First, there is significant world-wide operating experience with SNCR for units of about 350 MW of generating capacity. The SNCR design for Unit 1, generating 370 gross MW, can directly apply this experience. For larger units – such as Unit 4 generating 544 gross MW – there is less experience with SNCR. However, as noted previously, sophisticated modeling techniques enable predicting the best locations to inject urea with a high payoff in reducing NOx.

Most importantly, a series of demonstration trials using "proof-of-concept" injection lances was successfully completed on both units in June of 2013. On Unit 1, tests conducted at both full and 60% load demonstrated NOx outlet emissions of 0.22 lb/MMBtu, achieving the target value with a small margin. Residual or "slip" ammonia was near the desired value of 5 ppm. On Unit 4, NOx emissions with this "demonstration" caliber equipment ranged between 0.22-0.23 lb/MMBtu, achieving the targeted values also with little margin. Similar to Unit 1, the residual or "slip" ammonia was near the desired maximum value of 5 ppm. As noted, these tests were conducted with "demonstration" caliber equipment – not optimized for the boiler or gas conditions. Thus, achieving the target NOx limit with this equipment suggests success with an optimal system.

The SNCR commercial design for SJGS Units 1 and 4 will utilize injectors that are more sophisticated compared to the demonstration equipment used for these tests.

Also, SJGS staff will operate the boiler to maximize the probability of success in meeting NOx targets. Rigorous and consistent boiler tuning practices will be applied, which aid SNCR performance by providing a uniform NOx concentration in the gas stream, and minimizing the concentration of carbon monoxide ("CO"), the latter which can inhibit SNCR reactions.

IV. THE COST OF SNCR AT SAN JUAN

Q. ARE YOU FAMILIAR WITH PNM'S ESTIMATES FOR THE COST OF THE INSTALLATION AND OPERATION OF SNCR AT SAN JUAN?

A. Yes I am. I have reviewed the cost analysis conducted by Sargent & Lundy that is reported in the April 2013 Revised BART Analysis prepared for PNM by Black & Veatch. I have also reviewed the revised cost estimates based on bids for equipment received in April of 2013.

Q. WHAT ARE YOUR CONCLUSIONS ABOUT WHETHER THE ESTIMATED SNCR COST REPRESENTS A NECESSARY COST OF DOING BUSINESS?

A. The Revised SIP, which limits the SJGS units to a NOx outlet rate of not more than 0.23 lb/MMBtu, is cost-effectively achieved by SNCR. Considering the NOx reduced by SNCR in Units 1 and 4, and the NOx eliminated by terminating operation of Units 2 and

3, the Revised SIP provides a cost-effectiveness of NOx reduction between $1,000 and $1,100 per ton. The cost for SNCR equipment and operation to meet this NOx emission rate is clearly necessary for continued operation.

Q. WHAT ARE YOUR CONCLUSIONS ABOUT THE REASONABLENESS OF PNM'S COST ESTIMATES FOR THE INSTALLATION OF SNCR AT SAN JUAN?

A. The cost estimates developed for PNM are valid and reasonable. PNM engaged a respected engineering firm with deep expertise in this field – Sargent & Lundy – to develop cost estimates as part of the required BART analysis. As dictated by EPA, Sargent & Lundy utilized EPA's Cost Control Manual as the basis for this first-phase, preliminary analysis.

Subsequent to completing the BART analysis, Sargent & Lundy refined the cost analysis in a second phase. In this follow-on analysis, Sargent & Lundy solicited budgetary cost bids for key process equipment, and used their in-house expertise to estimate installation cost. Most recently, PNM issued a competitive Request for Proposal for SNCR process equipment from two of the leading suppliers. Bids were received for capital equipment in April of 2013. These firm bid costs, coupled with estimates for installation charges and all other indirect charges, correspond to an SNCR investment of about $51 and $37/kW for Units 1 and 4, respectively.

These capital costs are legitimate as the constrained site imposes significant demand for labor and equipment. The SNCR capital cost cited for the Units 1 and 4 should not be compared with "partial scope" cost estimates that are frequently cited in the public domain for other units – the costs for Units 1 and 4 describe a complete system for reagent receiving, storage, measurement and control, and sophisticated state-of-art injection lances. Advanced process instrumentation is included that enables meeting the NOx outlet rates with minimal ammonia "slip". The Unit 1 and Unit 4 reported costs do fully account for engineering, construction and project management, startup, and other indirect charges. These costs are consistent with the costs reported by Chris Olson in his testimony.

Q. ARE THERE OTHER LESS COSTLY AIR POLLUTION TECHNOLOGIES THAT CAN ACHIEVE THE REQUIRED REDUCTIONS IN NOx EMISSIONS FROM SAN JUAN UNDER THE REVISED SIP?

A. No. Further manipulating the design of burners and combustion air injection ports – known as combustion controls – cannot materially achieve lower NOx emissions from the SJGS units than presently measured. A commonly used technology to lower NOx emissions from present rates, selective catalytic reduction ("SCR"), can meet the targeted outlet values, but at much greater capital cost.

Q. HOW DO THE REQUIRED CAPITAL COSTS OF SNCR COMPARE TO THE CAPITAL COSTS ASSOCIATED WITH SCR?

A. The required capital cost for SNCR is a small fraction – about one-tenth – of the cost for conventional SCR. The capital cost for SCR is high because a separate catalytic reactor is required to house catalyst and provide residence time for NOx reduction reactions.

V. EXISTING SJGS ENVIRONMENTAL CONTROLS

Q. PLEASE DESCRIBE THE INITIAL ENVIRONMENTAL CONTROLS AT SJGS.

A. PNM Exhibit JEC-3 depicts the initial design of the steam generator and the major components of the environmental control system for a typical unit at SJGS. Both Coal (A) and Combustion Air (B), the latter moved by Forced Draft Fan (C), are introduced to the Steam Generator (D) on the left side of the graphic. The resulting Steam produced (E) is sent to the steam turbine (not shown). Combustion products exiting the Steam Generator (D) enter the environmental control system, the first component in PNM Exhibit JEC-3 being the hot-side electrostatic precipitators ("Hot-Side ESPs"), denoted as (F). The combustion products – the gas stream to be treated – upon existing the Hot-Side ESP (F) then pass through a special-purpose heat exchanger known as an "Air Heater" (G), which captures remaining useful heat, and then to the flue gas desulfurization or "Scrubber" tower (H) to remove SO_2.

Q. HAVE YOU REVIEWED THE UPGRADES TO THE ENVIRONMENTAL CONTROLS AT SJGS SINCE IT WAS ORIGINALLY CONSTRUCTED?

A. I have reviewed the more significant upgrades to San Juan's environmental control equipment implemented to satisfy the 2005 Consent Decree. Some of the original control equipment shown in PNM Exhibit JEC-3, specifically the Hot-side ESP (F) and Scrubber (H), has been either replaced or upgraded to state-of-the-art capability. PNM Exhibit JEC-4 includes the 2005 Consent Decree upgrades. This exhibit shows the original Hot-Side ESPs (F) – which are presently de-energized and no longer carry the full burden of removing fly ash from the flue gas – remain in the gas flow path. As a result, these devices provide only modest particulate matter removal from particle "settling". The primary responsibility to control particulate matter, as well as mercury, is provided by the state-of-the-art baghouse, also known as pulse-jet fabric filter. Also shown is Activated Carbon Injection (K) to elevate mercury capture beyond that attained by inherent carbon in fly ash. PNM Exhibit JEC-4 shows where the baghouses (I) fit into the gas flow path, between the Air Heater (G) and the Scrubber (H). PNM Exhibit JEC-4 also shows the planned location of a second fan, known as an Induced Draft Fan (J), to augment the action of Forced Draft Fan (B). The Induced Draft Fan (J) is needed to create a "balanced draft" system to move combustion air and gas products. PNM Exhibit JEC-5 replicates PNM Exhibit JEC-4 but includes a perspective view of the Baghouse (I), which employs the relatively compact "pulse-jet" design.

Q. CAN YOU FURTHER EXPLAIN WHAT BALANCED DRAFT IS?

A. Yes. Simply stated, the type of "draft" system describes the forces that move the combustion air and the products of combustion through the boiler and environmental control system. A "forced" draft system – as shown in PNM Exhibit JEC-3 and representing the present equipment – uses "forced draft" fans preceding the boiler to push or "force" air and product gases through the following equipment: steam generator, a first particulate control device, air heater, a second particulate control device, scrubber, and up the stack. Solely "pushing" combustion air and product gases through the entire system requires relatively high gas pressures throughout almost the entirety of this equipment.

In contrast, "balanced" draft gas handling uses an additional induced draft fan near the exit of the environmental control system to supplement the actions of the first fan by "pulling" the air and gases, thus balancing the forces.

Q. WHAT ARE THE BENEFITS OF BALANCED DRAFT AT SAN JUAN?

A. A balanced draft gas handling system limits intrusion of combustion products from the ductwork into the ambient and the bypassing of environmental controls. Completely isolating the combustion products and ambient air is not always possible, due to imperfect sealing between high temperature tube sections, expansion joints, and ductwork transitions. The integrity of these seals is compromised with time due to wear, particularly in load-following or cycling duty.

Q. WHY IS GAS INTRUSION IMPORTANT?

A. Even an insignificant volume of gas intrusion can compromise ambient air quality in the immediate vicinity of the station. The migration of a small fraction of untreated combustion products into the ambient air introduces particulate matter, SO_2, NOx, and – because of the presence of SNCR – ammonia in the ambient air surrounding the equipment.

Balanced draft gas handling eliminates this concern by limiting the gas pressure within the ductwork. As noted previously, the Induced Draft Fan – Item (J) in PNM Exhibit JEC-4 – "pulls" gases from the steam generator and environmental controls and creates a slight negative pressure compared to the ambient atmosphere. The slight negative pressure within the boiler assures any migration of gas is from ambient air into the combustion products.

Q. WHY CAN'T THE UNIT CONTINUE TO OPERATE IN THE SO-CALLED "FORCED DRAFT" MODE?

A. The New Source Review permit for the SJGS requires balanced draft gas handling to support air quality compliance, most notably for particulate matter (PM). If left unchecked, the present level of gas intrusion could compromise PNM's efforts to comply with the recently revised Primary Annual $PM_{2.5}$ National Ambient Air Quality Standard ("NAAQS") of 12 ug/m^3 and/or the Primary 1 hour SO_2 NAAQS of 75 ppb. The reliability of the gas handling system could also be compromised.

The environmental controls installed at the time San Juan was built – the hot-side ESP and regenerable flue gas desulfurization (FGD) system – did not require nearly as much power to move the combustion air and gas products. The environmental control system upgrades required since then demand significantly more power.

I am not aware of an operating plant employing only forced draft gas handling that features two particulate collectors, activated carbon injection, FGD for 95% SO_2 removal, and extended ductwork to route flue gas to the stack.

Q. HAVE YOU ANALYZED WHETHER THE COST FOR CONVERSION TO BALANCED DRAFT IS REASONABLE?

A. Yes. The cost to convert Units 1 and 4 to balanced draft gas handling is significant due to the extensive scope of work, affecting ductwork from the combustion air inlet to the stack. Further, the crowded site elevates labor costs.

The balanced draft conversion will move the gas "zero pressure point" – where the gas pressure is the same as atmospheric – from the forced draft fan to within the boiler itself. The following equipment or modifications will be required: new motors for existing forced draft fans; boiler stiffening to sustain possible sub-atmospheric pressure; ductwork stiffening; new induced draft fans and motors; greater auxiliary power delivery and control system; modifications to the operators control systems.

The cost for these modifications is presented in PNM Exhibits CMO-3 and CMO-4, introduced by the testimony of Mr. Chris Olson.

Q. CAN YOU PLEASE DISCUSS THE CAPABILITIES OF THE UPGRADE TO PARTICULATE CONTROL WITH THE BAGHOUSE?

A. Baghouses are capable of providing extremely high removal of particulate matter, typically exhibiting more than 99.9% removal of fly ash from the flue gas. The baghouse installed at SJGS is state-of-the-art, featuring an air/cloth ratio – a key design variable that dictates particulate control efficiency – of a conservative (i.e. low) value of 3.6 ft/min. This conservative value of air/cloth ratio assures high particulate removal. In addition, the filter media from which the collecting bags are fabricated is state-of-the-art to maximize fine particle capture and resist abrasion.

Q. WHY ARE BAGHOUSES NECESSARY FOR OPERATION OF THE SJGS?

A. The SJGS must comply with two strict particulate matter emission limits that are best attained with a baghouse. One emission limit is for filterable particulate matter and is equal to 0.015 lb/MMBtu. The second emission limit addresses total particulate matter (including particles less than 2.5 microns in size and condensed trace gases). This emissions limit, referred to as the Total PM "2.5" is equal to 0.034 lb/MMBtu. The "hot-side' ESPs that are original equipment would not be able to meet these limits.

Q. CAN YOU ELABORATE AS TO HOW BAGHOUSES CONTRIBUTE TO CONTROL OF MERCURY AT SJGS?

A. Yes. Mercury is typically removed from flue gas by adsorption onto residual carbon contained in fly ash – even for effective and complete combustion, carbon can comprise up to 5% of fly ash by weight. Baghouses collect fly ash, and in doing so accumulate a permeable ash "cake" on the filter media, through which flue gas will flow. The flow of flue gas through the "cake" exposes mercury to the carbon, prompting removal.

Injecting activated carbon into the flue gas, by supplementing the inherent carbon, further enhances mercury removal. The effectiveness of injecting activated carbon in removing mercury depends on many conditions, including the chemical form of the mercury (e.g. be it elemental or "oxidized" state), exposure time, and how the gas flows over the sorbent particles. Injecting activated carbon into a baghouse allows the sorbent to collect on the filter material, increasing both exposure and contact of sorbent with mercury.

PNM Exhibit JEC-4 shows the location where activated carbon (K) is injected – specifically between the Air Heater (G) and the inlet of the baghouse (I). The activated carbon particles, after removing mercury from the gas stream, are collected with the fly ash.

Q. YOU ALSO DESCRIBED UPGRADES TO THE FLUE GAS DESULFURIZATION, OR FGD TECHNOLOGY, AT SJGS. CAN YOU PLEASE ELABORATE?

A. The original FGD equipment was upgraded in the late 1990s to employ state-of-the-art SO_2 removal chemistry and byproduct production. The original FGD equipment – employing an at-the-time innovative desulfurization concept that converted sulfur in the flue gas to a marketable sulfuric acid byproduct – could not provide the necessary reliability and SO_2 removal to meet present-day emission limits. The upgrade of equipment converted the process to "forced oxidation" FGD chemistry, which transforms SO_2 captured from the flue gas to gypsum. The result of this upgrade is increased process reliability, lower operating costs, and elevated SO_2 removal. The FGD unit operates with zero-water discharge, eliminating environmental risk due to water or liquid-media discharge.

Collected fly ash and FGD solid byproduct material is returned to the San Juan Coal Mine and managed consistent with reclamation obligations.

Q. DO THE UPGRADES TO THE FLUE GAS DESULFURIZATION TECHNOLOGY AT SJGS HAVE ANY IMPLICATIONS WITH RESPECT TO REGIONAL HAZE REQUIREMENTS?

A. Yes, they do. Under the Revised SIP, San Juan is required to meet an SO_2 emissions limit of 0.10 lb/MMBtu on a 30-day rolling average basis. Given the content of sulfur that has been historically observed in the coal fired at SJGS – about 0.76% by weight – an SO_2 removal exceeding 90% is required to achieve this SO_2 limit.

The sulfur content of coal fired at the SJGS is increasing as new seams are encountered. Specifically, in April of 2013 the sulfur content of the coal was observed to increase – at times exceeding 0.80%. The sulfur content that can be expected over the long-term from the San Juan mine could be as high as 0.90%. Based on this sulfur content, achieving an outlet SO_2 emission rate of 0.10 lb/MMBtu will require a 95% reduction, perhaps requiring 96% reduction as an operating target to provide margin. The existing FGD process equipment should be able to provide 96% SO_2 removal from sulfur content of 0.90%, although minor adjustments to equipment and operations may be required. At present, it appears that increasing the use of dibasic acid – a so-called "pH buffering" agent – will be adequate to enable SJGS meet the 0.10 lb/MMBtu SO_2 limit while firing coal with sulfur content of approximately 0.90%. Minor modifications to the absorber tower spray headers –typically low in cost – could also be used to assure the required performance is attained.

Q. WILL THE INSTALLATION OF SNCR AT SJGS MEAN THAT THE EXISTING EMISSIONS CONTROLS ARE NO LONGER NECESSARY?

A. No. San Juan will still need to operate all the functional components of the existing air emission controls for required compliance even after the installation of SNCR.

Q. WILL THE EXISTING SJGS EMISSIONS CONTROLS HAVE ANY IMPACT ON THE USE OF SNCR?

A. Yes, in a positive way. Most importantly, the retrofit of new burners to Units 1 and 4 that are designed to lower NOx – referred to as low NOx burners – enable using SNCR in lieu of SCR. The low NOx burners can be considered a necessary "trigger" that enables significant cost savings by avoiding the need for SCR.

Specifically, the low NOx burners reduce boiler NOx from historical levels of 0.40 lb/MMBtu to less than 0.30 lb/MMBtu. PNM Exhibit JEC-6 shows the 30-

day average NOx emissions from Units 1 and 4 are typically 0.28 lb/MMBtu. Achieving a NOx emission limit of 0.23 lb/MMBtu, measured on a 30-day rolling average basis, requires targeting a short-term emission rate less than 0.23 lb/MMBtu – perhaps to 0.21 lb/MMBtu – to account for hour-by-hour variations. If the low NOx burners were not installed, the boiler NOx rate would be 0.40 lb/MMBtu – thus requiring a 48% reduction to achieve a short-term NOx emission rate of 0.21 lbs/MMBtu. This extent of reduction is beyond the capability of SNCR for generating units of this size. However, lowering boiler NOx to 0.30 lbs/MMBtu reduces the required NOx reduction to 30% – achievable with SNCR. Thus, low NOx burners enable using SNCR instead of SCR.

Q. HOW WILL THE EXISTING NOx CONTROLS, COUPLED WITH THE INSTALLATION OF SNCR, POSITION SAN JUAN TO ACCOMMODATE OTHER SOURCES OF COAL WHILE STILL MEETING APPLICABLE EMISSIONS REQUIREMENTS?

A. The low NOx burners, SNCR, and full suite of environmental controls for SO_2, particulate matter, mercury, and other trace species will position the SJGS to accommodate other sources of coal available in the Southwest.

The wet FGD system – capable at present of 95% SO_2 reduction with an increase to 96% likely feasible with higher rates of dibasic acid injection – will be able to meet an outlet value of 0.10 lbs/MMBtu with most sources of western bituminous or subbituminous coal in the Southwest. The baghouse for particulate control as previously noted is designed with a conservative air/cloth ratio, enabling removal of particulate matter by 99.9% and greater. The baghouse also creates conditions on a collected ash layer that provide high mercury removal, which can be augmented by injecting activated carbon. Also, given the high solubility of hydrogen chloride, it is probable the SJGS wet FGD process will continue to derive 98% removal of hydrogen chloride. Thus, emissions of hydrogen chloride will likely remain at the value of 0.00010 lb/MMBtu, as determined by tests conducted to satisfy the 2010 EPA Information Collection Request. This emission rate of hydrogen chloride is anticipated for most coals available in the western states.

Regarding NOx, boiler production rates with the coal presently used from the San Juan mine are approximately 0.28 lbs/MMBtu. Given the ability of SNCR to provide about 35% NOx reduction on boilers of this size, achieving the target outlet rate of 0.23 lbs/MMBtu will not be compromised unless the boiler NOx rate exceeds about 0.33 lb/MMBtu. Most western bituminous and subbituminous coals have similar fuel properties that affect NOx production, thus it is likely the SNCR process as specified will meet the targeted NOx limits.

VI. OTHER ENVIRONMENTAL BENEFITS UNDER THE REVISED SIP

Q. APART FROM THE REDUCTION OF NOx AND SO_2 EMISSIONS DISCUSSED ABOVE, ARE THERE ANY OTHER EMISSION REDUCTIONS THAT WILL BE REALIZED UNDER THE REVISED SIP?

A. In addition to reducing NOx and SO_2 on Units 1 and 4 with SNCR and potential changes to the FGD system, retiring San Juan Units 2 and 3 will significantly reduce emissions. Specifically, retiring Units 2 and 3 will eliminate their potential NOx emissions, which at an 85% capacity factor equals in a typical year approximate 4,100 and 6,400 tons per year, respectively. Retiring Units 2 and 3 will also eliminate the potential SO_2 emissions. These emissions, based on an 85% capacity factor and the historical SO_2 emissions rate of 0.15 lbs/MMBtu, are estimated for Units 2 and 3 to be approximately 2,060 and 3,216 tons per year, respectively.

Q. WILL THE RETIREMENT OF UNITS 2 AND 3 HAVE ANY OTHER ENVIRONMENTAL BENEFITS?

A. Yes. Emissions of trace species limited by the MATS rule will be eliminated. Based on tests conducted for the 2010 EPA Information Collection Request, facility-wide mercury will be reduced from approximately 8.6 lb/yr by about 2 lbs per year with the retirement of Unit 2, and an additional 2.3 lbs per year with the retirement of Unit 3.

Emissions of hydrogen chloride and hydrogen fluoride will be reduced. Based on data obtained for the 2010 EPA Information Collection Request tests, retiring Unit 2 will eliminate 1.7 and 3.5 tons per year, respectively, of hydrogen chloride and hydrogen fluoride. The same data suggests retiring Unit 3 will eliminate 2.1 and 2.4 tons per year, respectively, of hydrogen chloride and hydrogen fluoride.

Emissions of total filterable particulate matter for all SJGS units are below the SJGS permit limit of 0.015 lb/MMBtu; if Units 2 and 3 emitted at this rate their retirement would eliminate filterable particulate matter emissions of about 200 and 320 tons per year, respectively.

Finally, terminating operation of Units 2 and 3 will eliminate emissions of CO_2 by 2.88 and 4.50 million tons per year, respectively.

Q. WHILE NOT PART OF THE REVISED SIP, AS PART OF THIS PROCEEDING PNM IS OFFERING TO INCLUDE ITS INTEREST IN UNIT 3 OF THE PALO VERDE NUCLEAR GENERATING STATION ("PVNGS") IN ITS NEW MEXICO JURISDICTIONAL GENERATION PORTFOLIO RATHER THAN BUILDING A NATURAL GAS COMBINED CYCLE GENERATING UNIT. CAN YOU PLEASE DESCRIBE THE EMISSIONS FROM A STATE-OF-ART COMBINED CYCLE GENERATING UNIT THAT WOULD BE AVOIDED BY INCLUSION OF PNM'S PALO VERDE SHARE IN THE NEW MEXICO JURISDICTIONAL GENERATION PORTFOLIO?

A. PNM, by directing its share (134 MW) of Palo Verde Unit 3 to New Mexico customers, would avoid the need to provide an equivalent energy output – 1,056,456 MWh – by a natural gas-fired combined cycle unit. The avoided fossil emissions from a state-of-art natural gas-fired combined cycle generator can be estimated by analogy to the Russell Energy Center in Hayward, California, which began operation in August of 2013. This unit, operating under a permit issued by the Bay Area Air Quality Management District, is restricted in emissions of NOx to 0.00735 lb/MMBtu and carbon monoxide to 0.0045 lb/MMBtu. Further, the Russell Energy Center is the first unit in the U.S. to be limited in CO_2 emissions – as measured by a restriction in operating heat rate to 7,730 Btu/kWh.

Using an annual capacity factor of 90%, thus producing 1,056,456 MWh of power annually, the avoided fossil emissions from a unit similar to the Russell Energy Center due to PNM's share of Palo Verde Unit 3 would be approximately 30 tons of NOx, 18.4 tons of carbon monoxide, and 473,651 tons of carbon dioxide.

VII. <u>FUTURE AIR QUALITY REGULATIONS</u>

Q. DO YOU KNOW OF OTHER AIR QUALITY REGULATIONS THAT SJGS WILL NEED TO ADDRESS IN THE NEAR FUTURE?

A. Yes – the EPA final MATS rule was recently issued. The MATS rule is intended to reduce emissions of heavy metals and acid gases from new and existing coal- and oil-fired boilers. One of the heavy metals limited by the MATS rule – mercury – has already been addressed. Others include arsenic, chromium, and nickel. The acid gases include hydrogen chloride, discussed previously in this testimony. The requirements under the MATS rule will become effective on April 16, 2015.

Q. HOW IS SJGS PRESENTLY POISED TO MEET THE MATS RULE?

A. The recently retrofit fabric filters and FGD upgrade equip the SJGS to meet the requirements of the MATS rule with little risk. There are many aspects of MATS compliance – but perhaps most relevant to SJGS are limits on emissions of mercury and hydrogen chloride.

The MATS limit for mercury emissions is 1.2 lb/TBtu, and for hydrogen chloride is 0.002 lb/MMBtu. Tests conducted for the 2010 EPA Information Collection Request show emissions of mercury are controlled to about $1/10^{th}$ of the MATS limit. As discussed previously, low mercury emission is achieved by absorption by inherent carbon in the fly ash, further augmented by activated carbon. The fabric filter removes the absorbed mercury as particulate matter. Hydrogen chloride is reduced by two means: (a) reaction with alkali in fly ash both in the flue gas and on the fabric filter media, and (b) the wet FGD process.

I should also note that the MATS rule restricts emissions of filterable particulate matter to 0.030 lb/MMBtu – twice the value of the existing 0.015 lb/MMBtu limit already required by the State of New Mexico for all SJGS units.

San Juan can readily comply with these emissions limits because of the recent environmental upgrades.

Q. WHAT ROLE DOES THE FLUE GAS DESULFURIZATION EQUIPMENT PLAY WITH RESPECT TO MEETING THE REQUIREMENTS OF THE MATS RULE?

A. The FGD equipment removes both the soluble species of mercuric chloride and hydrogen chloride. Regarding mercury, it is well known that elemental mercury – once oxidized in the flue gas to soluble mercuric chloride ("$HgCl_2$") – is removed by the FGD absorber. The removal of mercury in this manner by the FGD absorber is a so-called "co-benefit" of the FGD process.

Hydrogen chloride is also highly soluble and is removed to a very high degree – more than 98% with the San Juan coal – by the alkaline sprays of the FGD absorber.

Q. WILL THE RETROFT AND OPERATION OF SNCR NOx CONTROL AFFECT THE ABILITY OF SAN JUAN'S ENVIRONMENTAL CONTROL SYSTEM TO MEET THE REQUIREMENTS OF THE MATS RULE?

A. The SNCR equipment will not materially affect the performance of the environmental control system in meeting the mandates of the MATS rule.

The only process impact attributable to SNCR is introducing residual ammonia into the flue gas, in concentrations that will likely be about 5 ppm but could approach 10 ppm. Any impact of residual ammonia will likely be positive – such as reducing the already-low levels of hydrogen chloride by producing ammonium chloride on the fabric filter material. Similarly, ammonia will react with any sulfur trioxide ("SO_3") in the flue gas and form sulfates and bisulfates of ammonia, perhaps within the air heater or baghouse. Sootblowing of the air heater and cleaning of the baghouse filter removes this material from the gas stream.

Q. HOW WILL THE RETIREMENT OF SAN JUAN UNITS 2 AND 3 POSITION SAN JUAN WITH RESPECT TO THE EXISTING GREENHOUSE GAS REGULATION AND THE RECENTLY ANNOUNCED FEDERAL PLAN TO REQUIRE FOSSIL FUEL FACILITIES TO REDUCE GREENHOUSE GAS EMISSIONS?

A. Future regulations may limit CO_2 emissions. The EPA has stated that CO_2 emission limits for existing plants will be proposed by June 1, 2014. The magnitude of such reductions is not known. One possible option is a first phase requiring modest reduction followed by a second phase mandating greater reductions, pending commercial demonstration of carbon capture and storage.

A first phase CO_2 reduction could be based solely on heat rate improvements. SJGS Units 1 and 4 operated at net plant heat rates from 2009 through 2012 that averaged 10,565 and 10,779 Btu/kWh, respectively. Modest reductions in CO_2 may be possible by changes to instrumentation and control systems, the steam turbine, heat exchangers, and other boiler ancillary equipment. Such reductions are likely limited to several percentage points – from 1% to perhaps as high as 4 or 5%.

A second phase of CO_2 reduction requiring carbon capture and storage technology is unlikely, based on recent pronouncements by the current Administration. Even if such an unlikely event were to occur within the next decade – such as lowering CO_2 emissions to the approximate 1,000 lb/MWh typical of a natural gas-fired combined cycle generating unit – the SJGS will be on equal footing to other coal-fired units. In fact, it is likely the SJGS would be at a relative advantage due to its location, which enables nearly "zero-cost" disposal of carbon captured from flue gas.

Q. HOW DOES SAN JUAN'S LOCATION ASSIST WITH DISPOSAL OF CARBON?

A. The San Juan site is located within 25 miles of Kinder-Morgan's Cortez CO_2 pipeline that provides CO_2 for enhanced oil recovery in Southwestern Colorado. This pipeline is located east of Farmington, NM and can be linked to the San Juan station. Sargent & Lundy have estimated the capital cost for such a pipeline to approximate $50,000,000. SJGS-produced CO_2 could be transferred to Kinder-Morgan without revenue. The CO_2 could be used for enhanced oil recovery, alleviating PNM of responsibility for developing, operating, and maintaining a sequestration site.

Q. ARE THERE OTHER POTENTIAL FUTURE AIR QUALITY REGULATIONS THAT MAY REQUIRE ADDITIONAL EMISSION CONTROLS?

A. The Clean Air Act ("CAA") requires EPA to set NAAQS for air pollutants considered harmful to public health and the environment. EPA has set NAAQS for six principal "criteria pollutants" which are carbon monoxide, lead, NOx, ozone, particulate matter and SO_2. The NAAQS undergo a periodic scientific review process and can be modified as a result of this review. Changes in the NAAQS require a rulemaking process which provides for public comments and public hearings. It is possible that stricter NAAQS standards could impose additional requirements on the SJGS if it were shown that emissions resulted in a violation of a new standard.

For example, SJGS may be required in the future to demonstrate compliance with the recently revised Primary Annual $PM_{2.5}$ NNAAQS of 12 ug/m^3 and/or the Primary 1 hour SO_2 NAAQS of 75 ppb. Two years ago SJGS conducted $PM_{2.5}$ modeling that showed SJGS meets the $PM_{2.5}$ annual standard by a small margin. In conducting this calculation PNM utilized realistic assumptions defining the gas leakage rate from SJGS units, operating under forced draft conditions. There is no EPA standard method for calculating emissions due to duct leaks from positive pressure boilers, and it is possible the State, EPA or an environmental group could challenge PNM's methods. The balanced draft conversion will eliminate this concern; however this case presents an example of how NAAQS limits could be revised.

Q. WOULD ADDITIONAL LIMITS DUE TO NAAQS COMPROMISE THE VIABILITY OF THE SJGS?

A. As I've described, the SJGS is equipped with a state-of-art environmental control "platform". Reasonable additional reductions in particulate matter, NOx, SO_2, and MATS-limited emissions should be achievable, albeit at additional cost.

Q. DO YOU HAVE ANY THOUGHTS ON HOW SAN JUAN WILL BE POSITIONED TO MEET FUTURE AIR QUALITY REGULATIONS AFTER INSTALLATION OF SNCR?

A. As I've described, the nature of the regulations and their requirements will dictate SJGS feasibility. Let me repeat – the SJGS is equipped with state-of-art environmental controls that provide a solid "platform". Further reductions in particulate matter, NOx, SO_2, and MATS-affected emissions – if modest and reasonable – should be achievable, albeit at additional cost.

VIII. <u>CONCLUSIONS</u>

Q. DO YOU HAVE ANY CONCLUDING OBSERVATIONS?

A. Yes. To summarize, under the Revised SIP the SJGS is a viable generating station that meets all present and near-term environmental mandates, while competitively providing power in the Southwest. The environmental control system is state-of-art, and features sufficient flexibility to accommodate additional mandates that could arise.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

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