BEFORE THE
ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION
OF THE
STATE OF CALIFORNIA

In the Matter of:

Rulemaking to Consider Modification of Regulations Establishing a Greenhouse Gases Emission Performance Standard For Baseload Generation of Local Publicly Owned Electric Utilities

Docket No. 12-OIR-1

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SAN JUAN PARTICIPANTS
COMMENTS ON QUESTIONS IN
NOTICE OF RULEMAKING WORKSHOP

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TABLE OF CONTENTS

Page

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I. INTRODUCTION.

The Southern California Public Power Authority ("SCPPA")[1] participants in the San Juan Project ("San Juan Participants") appreciate this opportunity to respond to questions raised in the California Energy Commission ("Commission") Notice of Rulemaking Workshop issued on March 6, 2012, in the captioned proceeding. The SCPPA San Juan Participants are the City of Anaheim ("Anaheim") and SCPPA. Anaheim holds a 10.04 percent ownership interest in San Juan Project Unit 4. SCPPA holds a 41.8 percent interest in Unit 3. The SCPPA members which participate in San Juan Unit 3 through SCPPA are the Imperial Irrigation District and the cities of Azusa, Banning, Colton and Glendale. The SCPPA San Juan Participants operate publicly owned electric utilities ("POUs").

[1] SCPPA is a joint powers authority. The members are Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Los Angeles Department of Water and Power, Imperial Irrigation District, Pasadena, Riverside, and Vernon. This comment is sponsored by Anaheim, Azusa, Banning, Colton, Glendale, and Imperial Irrigation District.

The threshold matter that should be considered in this proceeding is whether the Commission should reevaluate the need for its greenhouse gas ("GHG") Emission Performance Standard ("EPS") regulation. The EPS regulation[2] was adopted by the Commission in 2007 under authority of Senate Bill ("SB") 1368.[3] Section 8341(f) of the Public Utilities Code ("PUC") as promulgated in SB 1368 requires that the Commission "shall reevaluate and continue, modify or replace the greenhouse gases emission performance standard when an enforceable greenhouse gases emissions limit is established and in operation, that is applicable to local publicly owned electric utilities." An enforceable cap-and-trade greenhouse gas emissions limit has been established by the California Air Resources Board ("CARB") pursuant to Assembly Bill ("AB") 32, the California Global Warming Solutions Act of 2006,[4] and will become enforceable on January 1, 2013. Accordingly, the reevaluation of the EPS regulation that is mandated by PUC section 8341(f) should be undertaken now.

Upon reevaluation, EPS regulation should be revised to include a sunset provision that terminates the regulation when the CARB's cap-and-trade declining cap starts to be enforced on January 1, 2013. There is no need to wait for the ARB to verify the efficacy of the declining cap before terminating the EPS regulation. The CARB has already explained that a central design feature of the cap-and-trade program is that, upon imposition of the declining cap, emissions reductions will occur as a matter of law: "Emissions reductions would be ensured by the establishment of the mandatory, declining cap."[5] If the CARB had adopted an alternative mechanism such as a carbon tax to achieve the AB 32 emissions reduction goal indirectly, there

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[2] 20 California Code of Regulations sections 2900-2913.

[3] Stats. 2006, Ch. 598 *codified* as Public Utilities Code §§8340-8341.

[4] Assembly Bill ("AB") 32, Stats. 2006, Ch. 488, *codified* as Health and Safety Code ("HSC") §§38500 *et. seq*.

[5] CARB, Supplement to the AB 32 Scoping Plan Functional Equivalent Document ("FED Supplement"), p. 51 (June 13, 2011).

would be less certainty about the AB 32 target being met, but there is no such uncertainty about the efficacy of the cap-and-trade declining cap.[6]

Upon deciding that the EPS regulation should sunset on January 1, 2013, the Commission should close this rulemaking proceeding. It would not make sense to spend time and effort revising the EPS regulation to change definitions or to expand filing and reporting requirements if the regulation is going to expire at the end of this year, 2012.

Even if the Energy Commission were to find that there is some need to continue the effectiveness of the EPS regulation after the CARB's enforceable GHG emissions limits become effective, there is no need to change the regulation. The SCPPA San Juan Participants have fully complied in good faith with the regulation, and the SCPPA San Juan Participants understand that all other POUs that are affected by the regulation have done the same. The existing filing and reporting requirements and definitions have been sufficient to achieve the purpose of the regulation.

If there were to be any changes to the EPS regulation, the changes should be narrowly crafted to address specific perceived deficiencies in the current regulation. Also, the changes should be applied prospectively only. Entities that are subject to the EPS regulation should be responsible for compliance with regulations that are in effect at the time that they undertake an investment, not regulations that may be promulgated and become effective at some time in the future.

II. SCPPA SAN JUAN PARTICIPANTS' RESPONSE TO QUESTIONS RAISED IN NOTICE OF RULEMAKING WORKSHOP.

SCPPA San Juan Participants respond below to the nine questions that are raised in the March 6, 2012 Notice of Rulemaking Workshop in the captioned proceeding.

[6] *Ibid*, p. 99.

A. Response to Question 1: POUs Should Not Be Subject to a Reporting Requirement for Any Investment in a Non-EPS Compliant Powerplant.

Question 1: Whether to establish a filing/reporting requirement for local publicly owned electric utilities' (POU) investments in non-deemed compliant powerplants, regardless of whether the investment comes within the meaning of "covered procurement." (See Regs., §§2901, subd. (d), 2907.)

Question 1 effectively asks whether POUs should be subject to some filing or reporting requirement for *any* investment in a non-EPS compliant powerplant. POUs should not be subject to such a sweeping requirement. Such a requirement would go beyond the scope of both SB 1368 and the EPS regulation, and it would be unduly burdensome for both POUs and the Commission.

1. Requiring POUs to Meet a Filing or Reporting Requirement for Any Investment in a Non-EPS Compliant Power Plant Would Go Beyond the Scope of Both SB 1368 and the EPS Regulation.

Requiring POUs to meet a filing or reporting requirement for *any* investment in a non-EPS compliant power plant would go beyond the scope of both SB 1368 and the EPS regulation. The explicit purpose of SB 1368 was to prevent "new long-term financial commitments" in non-EPS compliant power plants to reduce the potential financial risk and reliability risk to California consumers that could arise if enforceable GHG emission limits were imposed, as will occur on January 1, 2013.[7] The Commission elaborated on the purpose of SB 1368 in the Final Statement of Reasons ("FSOR") for the EPS regulation:

> The purpose of SB 1368 is to take steps to meet greenhouse gases emissions reduction goals, reduce potential financial risk to California consumers for future pollution-control costs, and reduce

[7] Section 1(i) of SB 1368 states: "A greenhouse gases emission performance standard for new long-term financial commitments to electrical generating resources will reduce potential financial risk to California consumers for future pollution-control costs.

Section 1(j) of SB 1368 states: "A greenhouse gases emission performance standard for new long-term financial commitments to electric generating resources will reduce potential exposure of California consumers to future reliability problems in electricity supplies."

> potential exposure of California consumers to future reliability problems in electricity supplies.[8]

The Commission further explained the potential financial risk and reliability risk to California consumers that could arise if enforceable GHG emission limits were imposed as follows:

> [The] purpose [of SB 1368] is to reduce future problems specifically associated with investments in power plants that emit high amounts of greenhouse gases. The future problem SB 1368 is trying to address is the following: it is foreseeable that power plants, in the near future, will be required to mitigate their greenhouse gases emissions. Whether this mitigation takes the form of technological improvements to the power plant itself or the purchase of offsets, it is likely to be costly. If POUs have invested a large amount in high-GHG emitting power plants, then they will likewise be required to pay a large amount to mitigate for these high-GHG emitting power plants. If they cannot afford to mitigate, then the power plants may have to shut down, raising reliability concerns.[9]

Thus, as the Commission itself has recognized, the legislative intent underlying SB 1368 was to *mitigate* financial and reliability risk. The intent was not to *create* financial and reliability risk for California consumers by impeding investment in routine maintenance of existing powerplants. Impeding routine maintenance would create financial risk and reliability risk for consumers by rendering inoperable plants in which consumers have a substantial investment and on which they depend for reliable supplies of power.

The definitions in the EPS regulation were designed by the Commission to be consistent with the legislative intent to mitigate rather than to create financial and reliability risk. Accordingly, the definitions are designed so that POUs are not "required to allow non-EPS compliant plants to atrophy."[10] The Commission defined "covered procurement" as including a

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[8] FSOR, CEC Docket No. 06-OIR-1, Notice File No. Z07-0227-01, OAL File No. 07-0601-04S, p. 41 (August 31, 2007).

[9] *Ibid*.

[10] *Ibid*.

"new ownership investment in a baseload generation power plant."[11] The term "new ownership investment," in turn, was defined to *exclude* investments in routine maintenance. "New ownership investment" is defined as follows:

> (1) Any investments in construction of a new power plant;
>
> (2) The acquisition of a new or additional ownership interest in an existing non-deemed compliant powerplant previously owned by others;
>
> (3) Any investment in generating units added to a deemed-compliant powerplant, if such generating units result in an increase of 50 MW or more to the powerplant's rated capacity; or
>
> (4) Any investment in an existing, non-deemed compliant powerplant owned in whole or part by a local publicly owned electric utility that:
>
> (A) is designed and intended to extend the life of one or more generating units by five years or more, *not including routine maintenance*;
>
> (B) results in an increase in the rated capacity of the powerplant, *not including routine maintenance*; or
>
> (C) is designed and intended to convert a non-baseload generation powerplant to a baseload generation powerplant.[12]

The Commission explained the exclusion for investments in routine maintenance from the definition of "new ownership investment" as follows:

> SB 1368 is not intended to shut down currently operating power plants; its focus is ensuring that substantial investments are not made that would lead to further costs when AB 32, or a similar program establishing a greenhouse gases emissions limit, its implemented.[13]
>
> * * *
>
> The allowance for routine maintenance would encompass most 'necessary' expenditures and addresses CMUA's concern the

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[11] 20 CCR §2901(d)(1).

[12] 20 CCR §2901(j) (emphasis added).

[13] FSOR, *ibid*, p. 16.

> POUs would be required to let their non-EPS compliant powerplants deteriorate….[14]

The Commission's EPS regulation should not now be revised to require reporting of investments in routine maintenance. Imposing such requirements would be inconsistent with the purpose and scope of both SB 1368 and the EPS regulation. Reporting should be limited to investments that are within the scope of SB 1368 and the EPS regulation, not investments that are beyond the scope.

2. Requiring POUs to Meet a Filing or Reporting Requirement for Any Investment in a Non-EPS Compliant Powerplant Would Be Unduly Burdensome.

Additionally, imposing a filing or reporting requirement that would extend to any and all investments in non-EPS compliant power plants would be unduly burdensome both for POUs and for the Commission. Routine maintenance occurs regularly at San Juan. Requiring POUs to report on all instances of routine maintenance including those that are typically covered by an operations and maintenance ("O&M") budget would unduly burden the staffs of POUs. The staffs are already stretched thin as they endeavor to meet new regulatory mandates and reporting requirements associated with the CARB's cap-and-trade program, the Renewable Portfolio Standard established under authority of SBX1 2,[15] and other programs that are moving California and utilities toward a low carbon future. Adding an additional and unnecessarily expansive requirement to report on all investments in existing non-EPS compliant power plants would counterproductively distract staff from the important work they are doing to meet the new mandates.

The Commission would be unduly burdened as well. Requiring POUs to report on all investments in non-EPS compliant power plants would provide the Commission with a large

[14] FSOR, *ibid*, p. 56.

[15] Chap. 1, Stats. 2011, First Extraordinary Session.

volume of new information that would most likely be unusable due to its sheer bulk without adding or reallocating staff to review the information. Although, to date, administration of the EPS regulation has apparently not imposed an undue burden on the Commission, that could change if the Commission were to impose a reporting requirement on POUs that covered all instances of routine maintenance and were to attempt to actually review the reported information.

The Commission should avoid imposing a requirement that POUs report all instances of investment at a powerplant, including investments in routine maintenance, both because requiring such reporting would go beyond the intended scope of SB 1368 and because the imposition of such a requirement would unduly burden POUs and the Commission.

B. Response to Question 2: There Is No Need to Expand the Definition of "Covered Procurement."

Question 2: Whether to establish additional criteria for a "covered procurement." (Regs., §2901, subd. (d).)

There is no need to expand the definition of "covered procurement" in section 2901(d) of the EPS regulation. SB 1368 explicitly applies exclusively to baseload generation: "No load-serving entity or local publicly owned electric utility may enter into a long-term financial commitment unless any *baseload generation* supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission…."[16] The ways in which a POU can enter into a long-term commitment for baseload generation are (1) through direct ownership or (2) through a contractual commitment. The definition of "covered procurement" in the EPS regulation covers both alternatives by defining "covered procurement" as meaning either (1) "a new ownership investment in a baseload generation powerplant," or, alternatively, (2) "a new or renewed contract commitment, including a lease, for the procurement of electricity with a term of five years or greater by a local

[16] PUC §8341(a) (emphasis added).

publicly owned electric utility…."[17] Thus, the definition of "covered procurement" already covers both routes that a POU may take to enter into a long-term financial commitment to baseload generation and requires no further expansion.

C. Response to Question 3: There Is No Need to Expand the Definition of "New Ownership Investment."

Question 3: Whether to refine the meaning of "new ownership investment" by, for example, defining the phrase "designed and intended to extend the life of one or more generating units by five years or more, not including routine maintenance" or defining the term "routine maintenance." (Regs., §2901, subd. (j)(4)(A).)

Question 3 asks whether the Commission should refine the definition of "new ownership investment" by attempting to define the phrase "designed and intended to extend the life of one or more generating units by five years or more, not including routine maintenance" as that phrase appears in section 2901(j)(4)(A) of the EPS regulation. The phrase contains two prongs that the Commission might attempt to define further. One prong is the term "designed and intended to extend the life."

The Commission has already answered its own question as the question applies to the tern "designed and intended to extend the life." The Commission explicitly found in the FSOR for the EPS regulation that the term should not be further defined. The Commission explained that any attempt to further define "designed and intended to extend the life" would be "fraught with difficulties" and have a "high likelihood of unintended consequences:"

> To attempt to further define the phrase "designed and intended to extend the life" would be fraught with difficulties and a high likelihood of unintended consequences, because whether an investment will extend the life of a powerplant, or more relevant, is designed and intended to, is heavily dependent upon the factual circumstances of that investment. Given the complexity of this issue, there is no way to simplify all the factors that go into such a

[17] 20 CCR §2901(d).

> determination and condense them into a concise and workable rule.[18]

Given the Commission's emphatic rejection of the suggestion that it attempt to define the sub-phrase "designed and intended to extend the life" and the absence of any new information indicating a need for further definition, it seems apparent that the Commission would be disinclined to reverse course and attempt a definition now.

The second prong of the phrase, "designed and intended to extend the life of one or more generating units by five years or more, not including routine maintenance," is the term "routine maintenance." The Commission provided guidance in the FSOR to assist stakeholders to interpret its regulations, including the term, "routine maintenance." The Commission explained that, "as with all regulations," a "term is to be taken literally."[19] The Commission further explained that terms "as used in these regulations" are to be ascribed a meaning "as generally understood elsewhere…."[20]

Following the Commission's guidance on regulatory interpretation, there is no need for any further definition of "routine maintenance" beyond going to a dictionary to see how the terms "routine" and "maintenance" are generally understood. Webster's Dictionary defines the adjective "routine" as "occurring at fixed times or predictable intervals" or "found in the ordinary course of events."[21] The noun "maintenance," in turn, is defined as "activity involved in maintaining something in good working order."[22]

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[18] FSOR, *ibid*, p. 26; *see also* FSOR, *ibid*, p. 40.

[19] FSOR, *ibid*, p. 39.

[20] *Ibid*.

[21] www.webster-dictionary.org/definition/routine

[22] www.webster-dictionary.org/definition/maintenance

D. Response to Question 4: SCPPA Has Found Activities to Be Routine Maintenance.

Question 4: How and in what instances have POUs applied the terms "routine maintenance" and "designed and intended to extend the life" in deciding whether investments in non-deemed compliant powerplants are consistent with the Commission's EPS regulations and SB 1368? Is there an industry custom or practice that guides these determinations? Provide supporting documentation.

The Commission emphasized in the FSOR that "routine maintenance does not trigger the provisions of these regulations…."[23] Thus, activities that fit the description of being routine maintenance "are not considered designed and intended to extend the life of a powerplant by five years or more."[24] Likewise, activities that fit the description of being routine maintenance are not considered to constitute "an ownership investment" even when they might result in "an increase in the rated capacity of the powerplant."[25]

1. Decisions About Whether or Not an Activity Constitutes Routine Maintenance.

In most cases, particularly activities that are expensed as O&M, there is no question about whether the activity constitutes routine maintenance. However, there are instances when more deliberate consideration is appropriate, as when routine maintenance of some sort may result in a slight increase in rated capacity. For example, in its April 24, 2007 comments on the Commission's March 9, 2007 Notice of Proposed Action in Docket No. 06-OIR-1, the M-S-R Public Power Agency ("M-S-R") noted: "As part of routine operation and maintenance of the [San Juan Generating Station], boiler components are regularly replaced as are elements of the

[23] FSOR, *ibid*, p. 40.

[24] *Ibid*, p. 40.

[25] 20 CCR §2901(j)(3)(B).

steam turbine and the electric generators."[26] M-S-R stated that San Juan Unit 4 "owners plan to replace turbine blades" which would increase net capacity by 27 MW.[27]

Like M-S-R, SCPPA was confronted with the need for a rotor replacement at San Juan Unit 3 in 2009. In SCPPA Resolution No. 2009-23, which is appended as Attachment 1, the SCPPA Board of Directors ("Board") observed that "San Juan Unit 3 has been exposed to numerous start-up and shut-down situations as well as partial load conditions, which have worn the High Pressure/Intermediate Pressure rotor…."[28] The operator of San Juan "proposed to replace the San Juan Unit 3 High Pressure/Intermediate Pressure rotor to remediate damage due to [solid particle erosion] and mitigate risk of blade failure, catastrophic damage to internal turbine components and asset failure…."[29] Furthermore, the Resolution observes that "the San Juan Unit 3 turbine is 25 years old and turbine rotors of this vintage are being routinely replaced in the industry…."[30] Lastly, the Board found that "replacement of the San Juan Unit 3 High Pressure/Intermediate Pressure turbine is consistent with prudent utility practice."[31] Accordingly, the Board concluded in its Resolution "that the proposed San Juan Unit 3 High Pressure/Intermediate Pressure turbine replacement project is consistent with prudent utility practice, constitutes routine maintenance and is not a 'Covered Procurement' pursuant to the [EPS regulation]."[32]

Resolution No. 2009-23 is a paradigm of an instance in which POUs, namely, the SCPPA members that participate in San Juan Unit 3 through SCPPA, considered whether an investment

[26] M-S-R Public Power Agency Comments, p. 1, *quoted in* FSOR, *ibid*, p. 33.

[27] *Ibid*.

[28] Attachment 1, SCPPA Resolution No. 2009-23, p 2.

[29] *Ibid.*

[30] *Ibid.*

[31] *Ibid.* p. 3.

[32] *Ibid*.

in a non-deemed compliant powerplant constitutes "routine maintenance" and, as a result, is consistent with the Commission's EPS regulation. The turbine rotor replacement certainly met the Webster's definitions of "routine" and "maintenance." Rotor replacements occur at "predictable intervals," are "found in the ordinary course of events," and are "an activity involved in maintaining something in good working order."[33] As explained in the Resolution itself, the Board was further guided by routine industry practice and norms of prudent utility practice. While more unusual than the countless instances of routine maintenance which do not result in any increase in rated capacity, the investment in the turbine rotor replacement was a clear example of an investment in routine maintenance that is excluded from the definition of "new ownership investment" in the EPS regulation.

The Commission agrees that a turbine rotor replacement constitutes routine maintenance. In the FSOR the Commission specifically referred to replacement of "turbine blades" in stating:

> Routine maintenance may include replacing parts when they wear out. New parts are sometimes made better than previous iterations and improvements in some parts (e.g., *turbine blades*) can lead to an increase in efficiency and capacity. The Energy Commission determined that is necessary to ensure that POUs are not prohibited from maintaining the operation of their power plants simply because there might be an incidental increase in capacity resulting from such maintenance.[34]

In their November 14, 2011 Joint Petition for Initiation of a Rulemaking Proceeding ("Petition") that led to the establishment of this rulemaking proceeding, the Natural Resources Defense Council ("NRDC") and the Sierra Club contend that Resolution No. 2009-23 "is an example of … non-uniform and *ad hoc* interpretation" of the EPS regulation by the POUs,[35] but the

[33] www.webster-dictionary.org/definition/routine; www.webster-dictionary.org/definition/maintenance.

[34] FSOR, *ibid*, p. 17 (emphasis added.)

[35] Petition, *ibid*, p. 5.

Commission would clearly disagree, given the Commission's statement about replacing turbine blades in the FSOR.

The replacement of the turbine rotors at San Juan led to a subsequent SCPPA decision to reject a project that would result in an increase in rated capacity and would not be routine maintenance. Although the replacement of the turbine rotors was projected by GE to result in a slight increase in rated capacity as an incidental benefit, the increase did not materialize. Subsequently, GE proposed further work that would yield the expected increase in capacity. SCPPA rejected GE's proposal to undertake the project specifically because the work was designed solely to provide an increase in rated capacity and would not be routine maintenance.

2. An Alternative to Finding that an Activity Constitutes Routine Maintenance: Exemption Under Section 2913.

SCPPA had an alternative to finding that the rotor replacement at San Juan constituted routine maintenance. In addressing M-S-R's April 24, 2007 comment, the Commission explained that as an alternative to finding the work at San Juan constituted routine maintenance, "M-S-R can request an exemption under [section] 2913 because it is part of a pre-existing multi-party commitment."[36]

Section 2913 of the EPS regulation permits a POU to petition the Commission for an exemption from the regulation for procurements that are "required under the terms of a contract or ownership agreement that was in place January 1, 2007." Under section 2913, the Commission may exempt procurements from the EPS regulation when the procurements "are required under the terms of the contract or ownership agreement" and "the contract or ownership agreement does not afford the local publicly owned electric utility applying for the exemption the opportunity to avoid making such covered procurements." Section 2913 provides as follows:

[36] FSOR, *ibid* , p.33.

§2913. Case-by-Case Review for Pre-Existing Multi-Party Commitments.

(a) A local publicly owned electric utility may petition the Commission for an exemption from application of this chapter for covered procurements required under the terms of a contract or ownership agreement that was in place January 1, 2007. The Commission may exempt covered procurements from application of this chapter if the local publicly owned electric utility demonstrates that:

(1) The covered procurements are required under the terms of the contract or ownership agreement; and

(2) The contract or ownership agreement does not afford the local publicly owned electric utility applying for the exemption the opportunity to avoid making such covered procurements.

(b) Upon receipt of a petition under this section, the executive director shall review and make a recommendation to the full Commission on whether to grant the petition. The executive director may, within 14 days after receipt of a petition, notify the local publicly owned electric utility in writing of any additional information needed to review the petition. The Commission shall consider the executive director's recommendation and shall issue a decision on whether to grant the petition within 30 days after receipt of the complete petition.[37]

The San Juan Participation Agreement (Attachment 2) is a pre-January 1, 2007 multi-party commitment that meets the criteria of section 2913 for an exemption. Under section 28.3.1 of the San Juan Participation Agreement, the Operating Agent for San Juan, the Public Service Company of New Mexico ("PNM"), must: "Perform the Operating Work in accordance with the Project Agreement and Prudent Utility Practice."[38] The term "Operating Work" is defined as follows:

OPERATING WORK: Engineering, contract preparation and administration, purchasing, repair, supervision, training, expediting, inspection, testing, protection, operation, use, management, replacement, retirement, reconstruction and

[37] 20 CCR §2913.

[38] Attachment 2, San Juan Participation Agreement, section 28.3.1.

> maintenance of and for the benefit of the San Juan Project pursuant to this Agreement, including the administration of this Agreement and of any other Project Agreements, environmental compliance activities and the procurement of fuel and water and other necessary materials and supplies.[39]

Prudent Utility Practice is defined as follows:

> PRUDENT UTILITY PRACTICE: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in the light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Prudent Utility Practice is intended to be acceptable practices, methods or acts generally accepted in the industry, as such practices may be affected by special operational design characteristics of the San Juan Project, the quality and quantity of fuel delivered in accordance with the Underground Coal Sales Agreement or successor agreement, the rights and obligations of the Participants in accordance with this Agreement and any other special circumstances affecting the Operating Work.[40]

The rotor replacement at San Juan clearly falls within the definitions of "Operating Work" and "Prudent Utility Practice" in the San Juan Participation Agreement.

If the San Juan Project Coordination Committee fails to reach agreement on any matter, including Operating Work, the Operating Agent is "authorized and obligated to take such reasonable and prudent action, consistent with Prudent Utility Practice, as is necessary to the successful and proper operation and maintenance of the San Juan Project, pending the resolution by arbitration or otherwise, of any such inability or failure to agree."[41] Thus, participants in San Juan such as SCPPA cannot block work which is necessary to the successful and proper operation and maintenance of the San Juan Project, such as the turbine rotor replacement, and an

[39] *Ibid*, section 5.35.

[40] *Ibid*, section 5.42.

[41] *Ibid*, section 18.6.

exemption would have been warranted under section 2913. SCPPA did not pursue an exemption under section 2913 because the turbine rotor replacement so clearly constituted routine maintenance.

E. Response to Question 5: For the Period 2007 to Present, SCPPA San Juan Participants Have Not Made Any "New Ownership Investments" in the San Juan Project.

Question 5: For the period of 2007 to the present and based on your understanding of existing law, identify all covered procurements for which a POU made or plans to make a "new ownership investment" in an existing, non-deemed compliant powerplant owned by the POU in whole or in part, where the investment was for "routine maintenance." For each such investment, describe the nature and scope of the maintenance. Provide supporting documentation.

For the period of 2007 to the present, the SCPPA San Juan Participants have not made any "new ownership investments," as the term is defined in the EPS regulation, in the San Juan Project. Their investments have constituted routine maintenance, including the turbine rotor replacement discussed above in response to Question 4. As also discussed above, when an opportunity for an investment that would constitute a "new ownership investment" arose at San Juan, SCPPA rejected the opportunity. Insofar as the investments that have been made at San Juan have been for routine maintenance, the investments are not "new ownership investments" as defined in section 2901(j) of the EPS regulation.[42]

Prospectively, the SCPPA San Juan Participants may be called upon to fund the installation of federally mandated Best Available Retrofit Technology ("BART") pollution controls, specifically, selective catalytic reduction ("SCR") equipment, at San Juan in response to a August 4, 2011 United States Environmental Protection Agency's Federal Implementation

[42] In their Petition, the NRDC and the Sierra Club contend that an investment in a pollution upgrade project was made at San Juan in response to a 2005 Consent Decree, and that investment was an example of an investment at San Juan that did not meet the standards set forth in the EPS regulation. Petition. *ibid.* p. 3. That investment was undertaken before the EPS regulation took effect and, thus, is inapposite.

Plan ("FIP") for San Juan.[43] The SCPPA San Juan Participants have not made any decisions about the SCR installation. However, even if the SCR project were found to constitute a "new ownership investment," the installation of SCR equipment at San Juan would, like the turbine rotor replacement, be eligible for exemption under section 2913 of the EPS regulation. Under section 28.3.8 of the San Juan Participation Agreement, the Operating Agent for San Juan, PNM, must: "Comply with any and all laws and regulations applicable to the performance of Operating Work."[44] "Operating Work" includes "environmental compliance activities."[45] If the San Juan Project Coordination Committee fails to reach agreement on any matter, including Operating Work, the Operating Agent is "authorized and obligated to take such reasonable and prudent action, consistent with Prudent Utility Practice, as is necessary to the successful and proper operation and maintenance of the San Juan Project, pending the resolution, by arbitration or otherwise, of any such inability or failure to agree."[46] Thus, the work mandated by the FIP would qualify for an exemption under section 2913 of the EPS regulation.[47]

F. Response to Question 6: The Public Is Informed About SCPPA Board Consideration About Whether Proposed Investments Constitute Routine Maintenance.

Question 6: Is the public informed or notified about proposed POU investments that are either "routine maintenance" or "designed and intended to extend the life of one or more generating units by five years or more"? Provide supporting documentation.

[43] *Approval and Promulgation of Implementation Plans; New Mexico; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determination.* EPA-R06-OAR-2010-0846 (August 4, 2011).

[44] San Juan Participation Agreement, section 28.3.8.

[45] *Ibid*, section 5.35.

[46] *Ibid*, section 18.6.

[47] NRDC and the Sierra Club contend that under the San Juan Participation Agreement the California public entities that have ownership interests in the San Juan Project could block compliance with the EPA's August 4, 2011 FIP: "If the California owners do not vote to approve the capital investments in SCR, which is prohibited under California law, then the improvements should not go forward and California owners should not have to pay the costs of those improvements." NRDC/Sierra Club Petition at 9. NRDC and the Sierra Club are misinformed.

The public was informed about the SCPPA Board's consideration of Resolution No. 2009-23. In accordance with California's Brown Act,[48] notice of the SCPPA Board's consideration of the Resolution was posted on February 13, 2009, at Pasadena City Hall, providing the public with an opportunity to attend the Board's meeting on February 19, 2009, at which Resolution 2009-23 was to be considered and to comment on the Resolution. No representatives from either NRDC or the Sierra Club, the two parties who filed the petition that resulted in the initiation of this proceeding, appeared at the meeting to comment on the Board's action.

G. Response to Question 7: The Commission Should Reevaluate the EPS Regulation and Terminate the Regulation on January 1, 2013.

Question 7: Whether the requirements of Public Utilities Code section 9341, subdivision (f), have been triggered by the State Air Resources Board's (ARB) recent adoption of cap-and-trade regulations or whether ARB must first verify the efficacy of and compliance with its cap-and-trade regulations before Section 8341, subdivision (f) is triggered. Section 9341, subdivision (f), provides that

> *The Energy Commission, in a duly noticed public hearing and in the consultation with the [California Public Utilities] commission and the State Air Resources Board, shall reevaluate and continue, modify, or replace the greenhouse gases emission performance standard when an enforceable greenhouse gases emissions limit is established and in operation, that is applicable to local publicly owned electric utilities. (Emphasis added).*

The Commission has already found that when an enforceable GHG limit is put into place in California under AB 32, the Commission must reevaluate the EPS regulation as mandated in section 8341(f) of SB 1368. In the FSOR, the Commission stated:

> SB 1368 requires the Energy Commission to reevaluate these regulations when an enforceable greenhouse gases limit is put into place in California. AB 32, which requires California to reduce greenhouse gases emissions to 1990 levels by 202 [sic], will be fully implemented in 2012. When the enforceable limit is established, the Energy Commission will determine whether

[48] Cal. Gov. Code §§54050-54963.

> modifications should be made to these regulations to better comport with AB 32 implementation or whether to rescind the regulations altogether.[49]

The CARB's cap-and-trade regulation became effective on January 1, 2012, and compliance obligations to enforce the GHG emissions limit under the cap-and-trade regulation will commence on January 1, 2013. Thus, the EPS regulation should now be reevaluated to determine whether the regulation should continue in effect after January 1, 2013.

Upon reevaluation, the Commission should revise the EPS regulation to include a sunset provision that will terminate the regulation on January 1, 2013. When the Commission promulgated the EPS regulation in 2007, the Commission anticipated that the "regulations will only have a five year life span."[50] The Commission assumed at the time that the CARB's cap-and-trade program would go into effect and become enforceable on January 1, 2012. The CARB subsequently determined that the first compliance period should start on January 1, 2013, rather than on January 1, 2012.[51] That action by the CARB adds a year to the lifespan of the EPS regulation, but the regulation should still terminate when the cap-and-trade cap becomes enforceable. Continuing the regulation in effect after January 1, 2013, would be both unnecessary and counterproductive.

1. Continuing the EPS Regulation in Effect After January 1, 2013, Is Unnecessary.

Continuing the EPS regulation in effect after January 1, 2013 is unnecessary. A central benefit of implementing AB 32 through a cap-and-trade program rather than through some other alternative is that "emissions reductions would be ensured by the establishment of the

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[49] FSOR, *ibid*, p. 36.

[50] FSOR, *ibid*, p. 36.

[51] 17 CCR §95840(a).

mandatory, declining cap.[52] Given that attaining GHG emissions reductions through the cap-and-trade declining cap will be assured as a matter of law, there will no longer be a need for the EPS regulation after January 1, 2013.

Likewise, there is no need to wait for the CARB to "first verify the efficacy of and compliance with its cap-and-trade regulations," as surmised in Question 7, before deciding that the EPS regulation should sunset on January 1, 2013. The CARB selected the cap-and-trade approach over other alternatives to reduce GHG emissions precisely because a cap-and-trade program ensures GHG emission reductions that are sufficient to attain the legally mandated AB 32 goal of reducing emissions to the 1990 level by 2020.

Other alternatives do not have the capability of ensuring attainment of the AB 32 goal. The CARB has observed that while alternatives such as, particularly, a carbon tax "would reduce GHGs, it is important to note that a central drawback of this type of program is that the fee or tax addresses environmental goals or emissions limits indirectly (i.e., without a defined emissions cap) resulting in less certainty that such are being met (i.e., AB 32 2020 GHG emissions reduction target)."[53] If one of the alternatives to the cap-and-trade program such as a carbon tax had been adopted to achieve the AB 32 goal, it might be necessary to wait for the CARB to "first verify the efficacy of and compliance with" that alternative program, but waiting is unnecessary now, given that a key feature of the cap-and-trade program is that it ensures attainment of the AB 32 goal.

2. Continuing the EPS Regulation in Effect After January 1, 2013, Would Be Counterproductive.

Continuing the EPS regulation after the cap-and-trade declining cap becomes enforceable would be counterproductive as well as unnecessary. In addition to providing certainty about

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[52] FED Supplement, *ibid*, p. 51.

[53] *Ibid*, p. 99.

achieving the AB 32 goal, the cap-and-trade program achieves the goal in the most economically efficient manner by having covered entities make decisions about the operation of emitting sources in response to the price of carbon as established through operation of the cap-and-trade program. Under the cap-and-trade program, not only would emission reductions be "ensured by the establishment of the mandatory, declining cap," but, importantly, "reductions would be expected to occur in the most cost-effective manner, because the cost of reductions or the cost of allowances that can be purchased are determined by the market."[54] The economic efficiencies that are expected to be attained by having market forces determine the most economical means to comply with the declining cap would be distorted by retaining the EPS regulation after the cap-and-trade becomes enforceable.

Thus, in addition to becoming redundant after the cap-and-trade program becomes effective, the EPS regulation may become counterproductive. Accordingly, as SCPPA urged in its January 11, 2012 Comment on the draft Order Instituting Rulemaking ("OIR") in this proceeding and at the Commission's January 12, 2012 hearing on the draft OIR, reevaluation *and termination* of the EPS regulation when the CARB's cap-and-trade cap becomes enforceable on January 1, 2013, should be the first issue to be considered by the Commission in this rulemaking proceeding.

H. Response to Question 8: Since the Effective Date of the EPS Regulation, the SCPPA San Juan Participants Have Made No Investments in San Juan that Could Be Considered to Be a "New Ownership Investment," and No Such Investments Have Been Alleged by the Petitioners.

Question 8: Whether the Petitioners' concerns regarding possible violations of the EPS would be better addressed through initiation of the Commission's complaint and investigation proceedings found at Regulations sections 1230 through 1237.

[54] *Ibid*, p. 51.

Question 8 seems to reflect a view that the NRDC and the Sierra Club alleged "possible violations" in their November 14, 2011 Petition. However, there are no allegations of actual violations in the Petition. For example, NRDC and the Sierra Club specifically say that "we make no judgment at this time on SCPPA's determination regarding the applicability of SB 1368" to the turbine rotor replacement that was the subject of Resolution No. 2009-23.[55] Instead, NRDC and Sierra Club limit themselves to contending that Resolution No. 2009-23 "is an example of the type of non-uniform and *ad hoc* interpretation that raises concern."[56] The Petition claims to be seeking changes to the EPS regulation that would be prospective in effect rather than sanctions for past violations. Accordingly, the Petition does not raise issues which would properly be the subject of any complaint or investigation proceedings under the EPS regulation.

However, regardless of how a reader might interpret the Petition, there have been no violations of the EPS regulation by SCPPA participants in San Juan. Since the effectiveness of the EPS regulation, no investments have been made that could be considered to be a "new ownership investment" as that term is defined in section 2901(j) of the EPS regulation. No complaint or investigation proceeding would be in order.

I. Response to Question 9: No Changes Should Be Made to the EPS Regulation Beyond Including a Sunset Provision to Terminate the Regulation on January 1, 2013.

Question 9: Whether any other changes to the Energy Commission's EPS regulations are necessary to carry out the requirements of SB 1368.

The only change in the EPS regulation that should be made at this time, given that the CARB's AB 32 limit on GHG emissions will become enforceable on January 1, 2013, should be to revise the regulation to include a section that provides for the regulation to sunset as of January 1, 2013. It would not be administratively efficient to expend Commission and

[55] Petition, *ibid*, p. 5 .

[56] *Ibid*.

stakeholder resources on any additional revisions to a regulation that has accomplished its objective and should terminate in a matter of months.

III. CONCLUSION.

For the reasons set forth above, SCPPA urges the Commission to revise the EPS regulation to include a section that provides for the regulation to sunset as of January 1, 2013 and to make no further revisions to the regulation at this time.

Respectfully submitted,

/s/ Norman A. Pedersen

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Attorney for the **SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY**

Dated: March 26, 2012

ATTACHMENT 1

RESOLUTION NO. 2009-23

RESOLUTION OF THE SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY MAKING CERTAIN FINDINGS WITH RESPECT TO COMPLIANCE WITH GREENHOUSE GASES EMISSION PERFORMANCE STANDARDS (SAN JUAN UNIT 3 PROJECT)

WHEREAS, the California Energy Commission has adopted regulations under Docket 06-OIR-1, pursuant to Senate Bill 1368 (Stats. 2006, Ch. 598) (Regulations), implementing a greenhouse gases emission performance standard for local publicly owned electric utilities; and

WHEREAS, SCPPA, on behalf of its Members wishes to demonstrate compliance with the greenhouse gases emission performance standard as it may be applicable to the San Juan Unit 3 Project; and

WHEREAS, the San Juan Unit 3 Project is SCPPA's 41.8% ownership interest in San Juan Unit 3, a coal fired steam electric generating unit located in Waterflow, New Mexico, and acquired from the Century Power Company in 1993; and

WHEREAS, the San Juan Project's expected annual average carbon dioxide emission rate is about 2,100 pounds of carbon dioxide per megawatt hour of electricity produced, and the emission performance stand define in Section 2902 of the Regulations for baseload generation is 1,100 pounds of carbon dioxide per megawatt hour of electricity produced, which classifies the San Juan Project as an existing non-deemed compliant powerplant; and

WHEREAS, "Covered Procurements" as defined in Section 2901(d) of the Regulations include new investments in existing non-deemed compliant powerplants, but exclude "routine maintenance" pursuant to Section 2901(j) of the Regulations; and

WHEREAS, the California Energy Commission Electricity Committee's "Explanation of Changes to Regulations Establishing and Implementing a Greenhouse Gases Emission Performance Standard for Local Publicly Owned Utilities in Response to the Office of Administrative Law's Disapproval Decision" notes "routine maintenance may include replacing parts when they wear out. New Parts are sometime made better than previous iterations and improvements in some parts (e.g., turbine blades) can lead to an increase in efficiency and capacity," and "the Energy Commission determined that it is necessary to ensure that [Publicly Owned Utilities] are not prohibited from maintaining the operation of their power plants simply because there might be an incidental increase in capacity resulting from such maintenance;" and

WHEREAS, the routine preventive maintenance program instituted by PNM, the San Juan Generating Station Operating Agent, is designed to minimize any chance of asset failure occurring at the San Juan Generating Station and includes proactive maintenance involving the replacement of vintage turbine rotors and blades; and

WHEREAS, normal major outage inspections require routine maintenance involving the performance of non-destruction testing on the blade root attachments and the rotor which can reveal the presence of cracking or fault indications; and

WHEREAS, San Juan Unit 3 has been exposed to numerous start-up and shut-down situations as well as partial load conditions, which have worn the High Pressure/Intermediate Pressure Rotor and contributed to the reduction of the reliability of the turbine; and

WHEREAS, the San Juan Generating Station has experienced significant amount of solid particle erosion (SPE) across all four units which has been discovered during the routine maintenance inspections; and

WHEREAS PNM has proposed to replace the San Juan Unit 3 High Pressure/Intermediate Pressure Rotor to remediate damage due to SPE and mitigate risk of blade failure, catastrophic damage to internal turbine components and asset failure, and

WHEREAS, routine maintenance activities may include a total High Pressure/Intermediate Pressure turbine flow path replacement approach as the only method to address and mitigate the extensive SPE damage for the purpose of preventing breakdowns and ensuring unit reliability; and

WHEREAS, the 1970's era design of the turbine rotor did not adequately address the impact of SPE damage and overall turbine damage will continue to occur regardless of the turbine maintenance approach; and

WHEREAS, the original equipment manufacturer, General Electric, has recommended replacement of the High Pressure/Intermediate Pressure turbine rotor with a modern design, thereby addressing SPW issues by improving steam path geometry, increasing blade spacing and increasing the number of blade rows to compensate for individual losses of efficiency per blade row, also resulting in improved efficiency across the entire turbine; and

WHEREAS, the improved efficiency is an incidental benefit to the actual purpose of replacing the worn and deteriorating turbine; and

WHEREAS, the San Juan Unit 3 turbine is 25 years old and turbine rotors of this vintage are being routinely replaced in the industry; and

WHEREAS, the Electric Power Research Institute, Inc., has determined that the economic life of the San Juan Generating Station may extend beyond the year 2050; and

WHEREAS, SCPPA has covenanted to operate and maintain the San Juan Project in the most efficient and economical manner consistent with prudent utility practice; and

WHEREAS, replacement of the San Juan Unit 3 High Pressure/Intermediate Pressure turbine is consistent with prudent utility practice.

NOW, THEREFORE BE IT RESOLVED by the Board of Directors of the Southern California Public Power Authority, that the proposed San Juan Unit 3 High Pressure/Intermediate Pressure turbine replacement project is consistent with prudent utility practice, constitutes routine maintenance, and is not a "Covered Procurement" pursuant to the regulations promulgated by the California Energy Commission in Docket 06-OIR-1, pursuant to SB 1368.

THE FOREGOING RESOLUTION is approved and adopted by the Authority, this 19th day of February, 2009.

PRESIDENT
Southern California Public
Power Authority

ATTEST:

SECRETARY
Southern California Public
Power Authority

ATTACHMENT 2

AMENDED AND RESTATED

SAN JUAN PROJECT PARTICIPATION AGREEMENT

AMONG

PUBLIC SERVICE COMPANY OF NEW MEXICO

TUCSON ELECTRIC POWER COMPANY

THE CITY OF FARMINGTON, NEW MEXICO

M-S-R PUBLIC POWER AGENCY

THE INCORPORATED COUNTY OF LOS ALAMOS, NEW MEXICO

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

CITY OF ANAHEIM

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

March 23, 2006

TABLE OF CONTENTS

IV. ADMINISTRATION

V. BUDGETS AND OPERATING EXPENSES

VI. OPERATING AGENT

VII. DEFAULTS, LIABILITY AND ARBITRATION

VIII. RETIREMENT AND RECONSTRUCTION

IX. MISCELLANEOUS PROVISIONS

PART I

PARTIES AND INTRODUCTORY MATTERS

1.0 PARTIES:

The parties to this Amended and Restated San Juan Project Participation Agreement ("Agreement") are: PUBLIC SERVICE COMPANY OF NEW MEXICO, a New Mexico corporation ("PNM"); TUCSON ELECTRIC POWER COMPANY, an Arizona corporation ("TEP"); THE CITY OF FARMINGTON, NEW MEXICO, an incorporated municipality and a body politic and corporate, existing as a political subdivision under the constitution and laws of the State of New Mexico ("Farmington"); M-S-R PUBLIC POWER AGENCY, a joint exercise of powers agency organized under the laws of the State of California ("M-S-R"); THE INCORPORATED COUNTY OF LOS ALAMOS, NEW MEXICO, a body politic and corporate, existing as a political subdivision under the constitution and laws of the State of New Mexico ("LAC"); SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY, a joint exercise of powers agency organized under the laws of the State of California ("SCPPA"); THE CITY OF ANAHEIM, a municipal corporation organized under the laws of the State of California ("Anaheim"); UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS, a political subdivision of the State of Utah ("UAMPS"); and TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC., a Colorado cooperative corporation ("Tri-State"). These parties are the participants in the San Juan Project, and are hereinafter sometimes referred to individually as a "Participant" and collectively as "Participants."

2.0 RECITALS: This Agreement is made with reference to the following facts, among others:

2.1 PNM is an electric utility engaged in the generation, transmission and distribution of electric power and energy in a part of the State of New Mexico.

2.2 TEP is an electric utility engaged in the generation, transmission and distribution of electric power and energy in a part of the State of Arizona.

2.3 Farmington operates a municipal electric utility engaged in the generation, transmission and distribution of electric power and energy in a part of the State of New Mexico.

2.4 M-S-R is a public entity engaged in the generation, transmission, purchase and sale of electric power and energy in the western United States for the benefit of its member public agencies.

2.5 LAC operates a municipal electric utility engaged in the generation, transmission and distribution of electric power and energy in a part of the State of New Mexico.

2.6 SCPPA is a public entity created to acquire, construct, finance, operate and maintain generation and transmission projects on behalf of its members.

2.7 Anaheim operates a municipal utility in the State of California engaged in the generation, transmission and distribution of electric power.

2.8 UAMPS is a public entity created to plan, finance, develop, acquire, construct, improve, better, operate and maintain projects, or ownership interests or capacity rights therein, for the generation, transmission and distribution of electric energy for the benefit of its members.

2.9 Tri-State is a cooperative corporation created pursuant to the laws of the State of Colorado. Tri-State's primary functions involve the generation, transmission, transformation and sale of electricity to its member distribution cooperatives.

2.10 PNM and TEP each has an undivided one-half (1/2) ownership interest in the real property associated with the San Juan Project, which real property is described in Exhibit I, attached hereto and incorporated herein, and is identified therein as Parcels A through F.

2.11 PNM and TEP entered into the Coal Sales Agreement with San Juan Coal Company ("SJCC"), pursuant to which SJCC agreed to supply the San Juan Project with coal. PNM and TEP also entered into the Transportation Agreement with San Juan Transportation Company ("SJTC") dated April 30, 1984, under which coal was transported from the La Plata Mine. Subsequently, PNM and TEP entered into the Underground Coal Sales Agreement with SJCC, pursuant to which SJCC agreed to supply coal to the San Juan Project beginning January 1, 2003. The Underground Coal Sales Agreement superseded and replaced the Coal Sales Agreement, except for certain provisions of the Coal Sales Agreement which survived through the provisions of the Coal Sales Agreement Buy Out Agreement. The Transportation Agreement was terminated effective December 31, 2002, except for certain provisions which survived through provisions of the Transportation Agreement Buy Out Agreement.

2.12 PNM contracted with the United States Department of the Interior, Bureau of Reclamation, under the Colorado River Storage Project Act to purchase 20,200 acre feet of water per year from Navajo Reservoir under Contract 14-06-400-4821 dated April 11, 1968. Said contract was amended by an amendatory contract dated September 29, 1977, wherein the United States Department of the Interior, Bureau of Reclamation (i) acknowledged PNM's assignment to TEP of an undivided one-half (1/2) interest in PNM's rights and obligations imposed under the April 11, 1968, contract; and (ii) revised the amount of water available for consumptive use by the San Juan Project from the Navajo Reservoir from 20,200 acre feet per year to 16,200 acre feet per year. Upon expiration of the above-referenced contract with the United States Department of the Interior, Bureau of Reclamation, on December 31, 2005, water from the Navajo Reservoir is delivered to the San Juan Project under contractual arrangements with the Jicarilla Apache Nation. From time-to-time, contracts for surplus water supply may also be entered into by the Operating Agent for supply to the San Juan Project. Additional water for use at the San Juan Project is based on a Grant of Authority for 8,000 acre-feet of water, dated August 18, 1980, from Utah International (predecessor in interest to SJCC) to PNM and TEP.

2.13 The San Juan Project Co-Tenancy Agreement was executed as of February 15, 1972, effective as of July 1, 1969. The original Co-Tenancy Agreement was modified by joint action of PNM and TEP, as follows: Modification No. 1 on May 16, 1979, Modification No. 2 on December 31, 1983, Modification No. 3 on July 17, 1984, Modification No. 4 on October 25, 1984, Modification No. 5 on July 1, 1985, Modification No. 6 on April 1, 1993, Modification No. 7 on April 1, 1993, Modification No. 8 on September 15, 1993, Modification No. 9 on January 12, 1994 and Modification No. 10 on November 30, 1995 (the original of such Co-Tenancy Agreement, as amended by Modifications 1 through 10, is referred to herein as the "Co-Tenancy Agreement").

2.14 The San Juan Project Operating Agreement was executed as of December 21, 1973, effective as of July 1, 1969. The original Operating Agreement was modified by joint action of PNM and TEP, as follows: Modification No. 1 on May 16, 1979, Modification No. 2 on December 31, 1983, Modification No. 3, on July 17, 1984, Modification No. 4 on October 25, 1984, Modification No. 5 on July 1, 1985, Modification No. 6 on April 1, 1993, Modification No. 7 on April 1, 1993, Modification No. 8 on September 15, 1993, Modification No. 9 on January 12, 1994 and Modification No. 10 on November 30, 1995 (the original of such Operating Agreement, as amended by Modifications 1 through 10, is referred to herein as the "Operating Agreement").

2.15 A San Juan Project Construction Agreement was executed as of December 21, 1973, effective as of July 1, 1969, to govern the construction of the San Juan Project; this agreement was thereafter modified from time to time and was terminated in 1995 by action of PNM and TEP.

2.16 On May 16, 1979, TEP and PNM entered into an agreement whereby on that date TEP conveyed to PNM TEP's 50 percent undivided ownership interest in Unit 4.

2.17 On November 17, 1981, PNM transferred an 8.475 percent undivided ownership interest in Unit 4 to Farmington.

2.18 On December 31, 1983, PNM transferred a 28.8 percent undivided ownership interest in Unit 4 to M-S-R.

2.19 On October 31, 1984, TEP transferred its 50 percent undivided ownership interest in Unit 3 to Alamito Company, which later changed its name to Century Power Company ("Century").

2.20 On July 1, 1985, PNM transferred a 7.2 percent undivided ownership interest in Unit 4 to LAC.

2.21 On July 1, 1993, Century transferred a 41.8 percent undivided ownership interest in Unit 3 to SCPPA.

2.22 On August 12, 1993, PNM transferred a 10.04 percent undivided ownership interest in Unit 4 to Anaheim.

2.23 On June 2, 1994, PNM transferred a 7.028 percent undivided ownership interest in Unit 4 to UAMPS.

2.24 On January 2, 1996, Century transferred an 8.2 percent undivided ownership interest in Unit 3 to Tri-State.

2.25 Farmington, M-S-R, LAC, SCPPA, Anaheim, UAMPS and Tri-State were classified as "Unit Participants" in the San Juan Project, pursuant to the Co-Tenancy Agreement.

2.26 As of April 29, 1994, PNM, TEP, Century, SCPPA, Farmington, M-S-R, LAC and Anaheim executed the San Juan Project Designated Representative Agreement (the "DR Agreement") to implement the requirements of the federal Clean Air Act Amendments of 1990; the DR Agreement was thereafter accepted by UAMPS and Tri-State at the time of their respective purchases of ownership interests in the San Juan Project.

2.27 As of October 27, 1999, the Participants entered into the San Juan Project Participation Agreement ("Original San Juan PPA"). The purpose of the Original San Juan PPA was to amend and restate, and to replace in their entirety, the Co-Tenancy Agreement and the Operating Agreement and to set out in one instrument all of the matters previously included in the Co-Tenancy Agreement and the Operating Agreement.

2.28 The Participants desire, in this Agreement, to amend and restate the Original San Juan PPA to reflect certain amendments agreed to by the Participants including, but not limited to, changes to the provisions of the Original San Juan PPA pertaining to fuel supply.

3.0 AGREEMENT: The Participants, for and in consideration of the mutual covenants to be by them kept and performed, agree as follows.

4.0 EFFECTIVE DATE AND TERMINATION:

4.1 Except as otherwise provided in Section 4.3, this Agreement shall become effective upon the later of the following dates: (a) the date upon which the FERC accepts for filing this Agreement; provided that, if the FERC orders a hearing to determine whether this Agreement is just and reasonable, this Agreement shall not become effective until the date when an order, no longer subject to judicial review, has been issued by the FERC determining this Agreement to be just and reasonable without changes or modifications unacceptable to the Participants; or (b) the date upon which the Rural Utilities Service ("RUS") approves this Agreement on behalf of Tri-State or is deemed to have approved this Agreement on behalf of Tri-State by virtue of its failure to object to this Agreement within the time prescribed in the Tri-State loan contract with RUS, if such approval is required.

4.2 Following execution by all Participants, PNM shall file a copy of this Agreement with the FERC in a timely manner. In such filing, PNM shall request waiver of applicable FERC notice requirements in order to allow this Agreement to become effective as of the earliest feasible date. All other Participants shall support PNM's filing by the prompt filing of a certificate or letter of concurrence or intervention in support of the filing.

4.3 Following (a) an order by the FERC or any other regulatory agency having jurisdiction, or (b) a letter or other communication from the RUS, if any, the Participants shall each review such order, letter or communication to determine if the FERC, RUS or any agency having jurisdiction has changed or modified a condition or conditions, deleted a condition or conditions, or imposed a new condition or conditions with regard to this Agreement; or has conditioned its approval of this Agreement upon changes or modifications to a condition or conditions, deletion of a condition or conditions or imposition of a new condition or conditions. The Participant receiving such order, letter or communication shall promptly provide a copy of such order, letter or communication to the other Participants. Within fifteen (15) business days after receipt by the other Participants of the copy of the order, letter or communication, the Participants shall indicate to each other in writing their acceptance or rejection of this Agreement based upon any changes, modifications, deletions or new conditions required by the FERC, RUS or any agency having jurisdiction. A failure to notify within said fifteen (15) day period shall be the equivalent to a notification of acceptance. If any Participant rejects this Agreement because the FERC, RUS or any agency having jurisdiction has modified a condition, deleted a condition or imposed a new condition in this Agreement, or has conditioned its approval on such a change, modification, deletion or new condition, the Participants will be deemed to have rejected this Agreement and they shall attempt, in good faith, to renegotiate the terms and conditions of this Agreement to resolve such changed, modified, deleted or new condition to the satisfaction of the Participants within one hundred twenty (120) days after the date of such order, letter or communication and thereafter to obtain requisite regulatory approval of such renegotiated agreement.

4.4 This Agreement shall continue in force and effect until July 1, 2022, unless otherwise agreed in writing by the Participants.

5.0 DEFINITIONS: The following terms, when used herein with initial capitalization, and whether in the singular or the plural, shall have the meaning specified:

5.1 ACCOUNTING PRACTICE: Generally accepted accounting principles in accordance with FERC Accounts applicable to electric utility operations.

5.2 AGREEMENT: This Amended and Restated San Juan Project Participation Agreement, including all exhibits and attachments hereto, and as may be modified or amended from time to time.

5.3 AUDITING COMMITTEE: A committee which is described in Section 21.

5.4 AVAILABLE OPERATING CAPACITY: The maximum net electrical capacity of each installed and operating Unit which is available at any given time to the Participants at the 345 kV buses.

5.5 CAPACITY: Electrical rating expressed in megawatts ("MW").

5.6 CAPITAL IMPROVEMENTS: Any property, land or land rights added to the San Juan Project or the substitution, replacement, enlargement or improvement of any Units of Property, structures, facilities, equipment, property, land or land rights constituting a part of the San Juan Project, which in accordance with Accounting Practice would be capitalized, and also including the costs of removal, salvage or disposal of any Units of Property being replaced or substituted.

5.7 COAL SALES AGREEMENT: Agreement between PNM, TEP and SJCC executed on August 18, 1980, as amended or modified from time to time and which was replaced by the Underground Coal Sales Agreement. However, certain provisions of the Coal Sales Agreement survive through the provisions of the Coal Sales Agreement Buy Out Agreement dated August 31, 2001.

5.8 COAL SALES AGREEMENT BUY OUT AGREEMENT: Agreement between PNM, TEP and SJCC executed on August 31, 2001, as may be amended or modified from time to time.

5.9 COMMON PARTICPATION SHARE: Each Participant's percentage ownership interest as set forth in Section 6.2.6.

5.10 CONTROL AREA: An area comprised of an electric system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedules with other control areas while maintaining frequency regulation of the interconnection.

5.11 COORDINATION COMMITTEE: A committee which is described in Section 18.

5.12 CO-TENANCY AGREEMENT: The agreement described in Section 2.13.

5.13 DR AGREEMENT: The agreement described in Section 2.26, as amended from time to time.

5.14 EMERGENCY COAL STORAGE PILE: The coal storage pile for the San Juan Project, sometimes referred to as the "minimum coal storage pile," or as the "force majeure pile," which is to be drawn upon when fuel deliveries are interrupted.

5.15 EMERGENCY SPARE PARTS: Spare parts or auxiliary equipment, the cost of which is capitalized, which are stocked for emergency use for the San Juan Project and which are not scheduled for periodic replacement.

5.16 ENERGY: The accumulated amount of power produced over a stated time interval, expressed in kilowatt hours ("kWh") or megawatt hours ("MWh").

5.17 ENGINEERING AND OPERATING COMMITTEE: A committee which is described in Section 19.

5.18 FC LINE: That 345 kV transmission line between the San Juan generating station and the Four Corners generating plant.

5.19 FIXED FUEL EXPENSE: Those expenses itemized on Exhibit IX, attached hereto and incorporated herein.

5.20 FERC: The Federal Energy Regulatory Commission or any successor thereto.

5.21 FERC ACCOUNTS: The FERC Uniform System of Accounts prescribed for Public Utilities and Licensees (Class A and Class B). References in this Agreement to a specific FERC account number shall mean the number in effect as of the date of this Agreement and any successor account number.

5.22 FUELS COMMITTEE: A committee which is described in Section 20.

5.23 MATERIALS AND SUPPLIES: Those materials and supplies, the cost of which is charged to FERC Account 154, which are stocked for use in the operation and maintenance of the San Juan Project.

5.24 MINIMUM ANNUAL TONS: The quantities of coal, also defined as Minimum Annual Tons ("MAT") in Section 8.2(F)7 of the Underground Coal Sales Agreement, and set forth in Exhibit H to the Underground Coal Sales Agreement, which amounts are shown on Exhibit II, attached hereto and incorporated herein.

5.25 MINIMUM NET GENERATION: The lowest net load at which each Unit can be reliably maintained in service on a continuous basis on coal fuel.

5.26 MONTHLY MINIMUM TONS : Monthly Minimum Tons ("MMT") as also defined in Section 8.2(F)8 of the Underground Coal Sales Agreement, shall be allocated each year to each Participant pursuant to a monthly schedule approved annually by the Fuels Committee as provided in Section 20.3.3, such that the annual sum of each Participant's Monthly Minimum Tons equals its Common Participation Share of MAT as defined in Section 8.2(F)7 of the Underground Coal Sales Agreement. In the event that a monthly allocation of MMT has not been approved by the Fuels Committee, MMT shall be allocated to each Participant based on Common Participation Share.

5.27 NET EFFECTIVE GENERATING CAPACITY: The maximum continuous ability of each Unit to produce power, less auxiliary power requirements.

5.28 NET ENERGY GENERATION: The Energy generated by each Unit which is available to the respective Participants at the 345 kV bus.

5.29 OPERATING ACCOUNT: The bank account(s) in the names of the Participants established by the Operating Agent pursuant to Section 28.

5.30 OPERATING AGENT: The Participant or other entity which has been selected by the Participants as the entity responsible for the operation and maintenance of the San Juan Project pursuant to this Agreement.

5.31 OPERATING AGREEMENT: The agreement described in Section 2.14.

5.32 OPERATING EMERGENCY: An unplanned event or circumstance at the San Juan Project which reduces or may reduce the availability of Capacity or Energy from a Unit.

5.33 OPERATING FUNDS: Monies advanced to, and disbursed by, the Operating Agent on behalf of the Participants in accordance with this Agreement.

5.34 OPERATING INSURANCE: Policies of insurance secured or to be secured and maintained in accordance with Section 31.

5.35 OPERATING WORK: Engineering, contract preparation and administration, purchasing, repair, supervision, training, expediting, inspection, testing, protection, operation, use, management, replacement, retirement, reconstruction and maintenance of and for the benefit of the San Juan Project pursuant to this Agreement, including the administration of this Agreement and of any other Project Agreements, environmental compliance activities and the procurement of fuel and water and other necessary materials and supplies.

5.36 ORIGINAL SAN JUAN PPA: The San Juan Project Participation Agreement dated October 27, 1999.

5.37 PARTICIPANT: PNM, TEP, Farmington, M-S-R, LAC, SCPPA, Anaheim, UAMPS or Tri-State.

5.38 PARTICIPANT COAL CONSUMPTION: Each Participant’s total San Juan Project coal consumption in tons as determined by the Operating Agent. In principle, a Participant’s Coal Consumption is comprised of its share of coal consumed in its Unit(s) plus its share of coal consumed for common loads, auxiliary loads and start-up for all Units.

5.39 PARTICIPATION SHARE: Each Participant’s percentage ownership interest in the various elements of the San Juan Project as set forth in Section 6.

5.40 PROJECT AGREEMENTS: This Agreement and such other agreements as are determined by the Coordination Committee to be necessary to define the rights and duties of the Participants with respect to the San Juan Project.

5.41 PROJECT COAL INVENTORY: The sum of coal in the Emergency Coal Storage Pile, silos, conveying systems, hoppers, and all other coal stored at the San Juan Project as accounted in FERC Account No. 151.

5.42 PRUDENT UTILITY PRACTICE: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in the light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Prudent Utility Practice is intended to be acceptable practices, methods or acts generally accepted in the industry, as such practices may be affected by special operational design characteristics of the San Juan Project, the quality and quantity of fuel delivered in accordance with the Underground Coal Sales Agreement or successor agreement, the rights and obligations of the Participants in accordance with this Agreement and any other special circumstances affecting the Operating Work.

5.43 SAN JUAN PROJECT: The four unit, coal-fired electric generation plant located in San Juan County, New Mexico, near Farmington, New Mexico. The San Juan Project includes all facilities, structures, transmission and distribution lines incident to the four-unit electric generating plant. The San Juan Project does not include distribution lines, transmission lines, equipment in the Switchyard Facilities or other facilities owned exclusively by a Participant.

5.44 SWITCHYARD FACILITIES: The switchyard facilities required for the San Juan Project as shown by materials listed in Exhibit III, attached hereto and incorporated herein.

5.45 TOTAL MONTHLY COAL COST: The amount charged the Operating Agent each month in accordance with the Underground Coal Sales Agreement, the Coal Sales Agreement Buy Out Agreement and the Transportation Agreement Buy Out Agreement.

5.46 TRANSPORTATION AGREEMENT BUY OUT AGREEMENT: Agreement between PNM, TEP and San Juan Transportation Company ("SJTC") executed on August 31, 2001, as may be amended or modified from time to time, terminated the Transportation Agreement with SJTC dated April 30, 1984.

5.47 UNDERGROUND COAL SALES AGREEMENT: Agreement between PNM, TEP and SJCC executed on August 31, 2001, as amended or modified and as may be amended or modified from time to time.

5.48 UNIT: Unit 1, Unit 2, Unit 3 or Unit 4.

5.49 UNIT 1: The second operating unit of the San Juan Project, which was placed in commercial service on December 31, 1976 and which presently has a net capacity rating of 327 MW.

5.50 UNIT 2: The first operating unit of the San Juan Project, which was placed in commercial service on November 30, 1973 and which presently has a net capacity rating of 316 MW.

5.51 UNIT 3: The third operating unit of the San Juan Project, which was placed in commercial service on December 31, 1979 and which presently has a net capacity rating of 497 MW.

5.52 UNIT 4: The fourth operating unit of the San Juan Project, which was placed in commercial service on April 27, 1982 and which presently has a net capacity rating of 507 MW.

5.53 UNITS OF PROPERTY: Property as described in the FERC's list of units of property for use in connection with the Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, contained in 18 CFR Part 116, in effect on the effective date of this Agreement, as thereafter modified or amended.

5.54 UTILITY PAYMENT STREAM ("UPS"): Those payments defined in Section 8.5(C) of the Underground Coal Sales Agreement

5.55 VARIABLE FUEL EXPENSE: Those expenses itemized on Exhibit X, attached hereto and incorporated herein.

5.56 WATER CONTRACT(S): The applicable contract or contracts under which water is delivered to the San Juan Project, as more fully described in Section 2.12.

5.57 WILLFUL ACTION:

5.57.1 Action taken or not taken by a Participant (or the Operating Agent), at the direction of its directors, members of its governing body, officers or employees having management or administrative responsibility affecting its performance under a Project Agreement, which action is knowingly or intentionally taken or not taken with conscious indifference to the consequences thereof or with intent that injury or damage would probably result therefrom; or

5.57.2 Action taken or not taken by a Participant (or the Operating Agent) at the direction of its directors, members of its governing body, officers or employees having management or administrative responsibility affecting its performance under a Project Agreement, which action has been determined by final arbitration award or final judgment or judicial decree to be a material default under a Project Agreement and which action occurs or continues beyond the time specified in such arbitration award or judgment or judicial decree for curing such default, or if no time to cure is specified therein, occurs or continues beyond a reasonable time to cure such default; or

5.57.3 Action taken or not taken by a Participant (or the Operating Agent), at the direction of its directors, members of its governing body, officers or employees having management or administrative responsibility affecting its performance under a Project Agreement, which action is knowingly or intentionally taken or not taken with the knowledge that such action taken or not taken is a material default under a Project Agreement.

5.57.4 The phrase "employees having management or administrative responsibility," as used in this Section 5.57, means employees of a Participant who are responsible for one or more of the executive functions of planning, organizing, coordinating, directing, controlling and supervising such Participant's performance under a Project Agreement; provided however, that, with respect to employees of the Operating Agent acting in its capacity as such and not in its capacity as a Participant, such phrase shall refer only to (i) the senior employee of the Operating Agent on duty at the San Juan Project who is responsible for the operation of the Units, and (ii) anyone in the organizational structure of the Operating Agent between such senior employee and an officer.

5.57.5 Willful Action does not include any act or failure to act which is merely involuntary, accidental or negligent.

PART II

OWNERSHIP OF SAN JUAN PROJECT

6.0 OWNERSHIPS AND TITLES:

6.1 PNM and TEP, respectively, each has an undivided one-half (1/2) ownership interest in the real property interests described in Exhibit I as Parcels A through F.

6.2 Unless otherwise provided in Exhibit IV, the Units and other facilities of the San Juan Project and Capital Improvements shall be owned and title held by the Participants, in the following percentages:

6.2.1 For Units 1 and 2 and for all equipment and facilities directly related to Units 1 and 2 only, in accordance with the following percentages:

6.2.1.1 PNM: 50 percent
6.2.1.2 TEP: 50 percent
6.2.1.3 M-S-R: 0 percent
6.2.1.4 Farmington: 0 percent
6.2.1.5 Tri-State: 0 percent
6.2.1.6 LAC: 0 percent
6.2.1.7 SCPPA: 0 percent
6.2.1.8 Anaheim: 0 percent
6.2.1.9 UAMPS: 0 percent

6.2.2 For Unit 3 and for all equipment and facilities directly related to Unit 3 only, in accordance with the following percentages:

6.2.2.1 PNM: 50 percent
6.2.2.2 TEP: 0 percent
6.2.2.3 M-S-R: 0 percent
6.2.2.4 Farmington: 0 percent
6.2.2.5 Tri-State: 8.2 percent
6.2.2.6 LAC: 0 percent
6.2.2.7 SCPPA: 41.8 percent
6.2.2.8 Anaheim: 0 percent
6.2.2.9 UAMPS: 0 percent

6.2.3 For Unit 4 and for all equipment and facilities directly related to Unit 4 only, in accordance with the following percentages:

6.2.3.1 PNM: 38.457 percent
6.2.3.2 TEP: 0 percent
6.2.3.3 M-S-R: 28.8 percent
6.2.3.4 Farmington: 8.475 percent
6.2.3.5 Tri-State: 0 percent
6.2.3.6 LAC: 7.20 percent
6.2.3.7 SCPPA: 0 percent
6.2.3.8 Anaheim: 10.04 percent
6.2.3.9 UAMPS: 7.028 percent

6.2.4 For equipment and facilities common to Units 1 and 2 only, in accordance with the following percentages:

6.2.4.1 PNM: 50 percent
6.2.4.2 TEP: 50 percent
6.2.4.3 M-S-R: 0 percent
6.2.4.4 Farmington: 0 percent
6.2.4.5 Tri-State: 0 percent
6.2.4.6 LAC: 0 percent
6.2.4.7 SCPPA: 0 percent
6.2.4.8 Anaheim: 0 percent
6.2.4.9 UAMPS: 0 percent

6.2.5 For equipment and facilities common to Units 3 and 4 only, in accordance with the following percentages:

6.2.5.1 PNM: 44.119 percent
6.2.5.2 TEP: 0 percent
6.2.5.3 M-S-R: 14.4 percent
6.2.5.4 Farmington: 4.249 percent
6.2.5.5 Tri-State: 4.1 percent
6.2.5.6 LAC: 3.612 percent
6.2.5.7 SCPPA: 20.9 percent
6.2.5.8 Anaheim: 5.07 percent
6.2.5.9 UAMPS: 3.55 percent

6.2.6 For equipment and facilities common to all of the Units in accordance with the following percentages:

6.2.6.1	PNM: 46.297 percent
6.2.6.2	TEP: 19.8 percent
6.2.6.3	M-S-R: 8.7 percent
6.2.6.4	Farmington: 2.559 percent
6.2.6.5	Tri-State: 2.49 percent
6.2.6.6	LAC: 2.175 percent
6.2.6.7	SCPPA: 12.71 percent
6.2.6.8	Anaheim: 3.10 percent
6.2.6.9	UAMPS: 2.169 percent

6.2.7 San Juan Project equipment and facilities not included in Sections 6.2.1 through 6.2.6 which were in service as of May 16, 1979, remain in individual one-half (1/2) ownership, with each of PNM and TEP retaining title to an equal undivided one-half (1/2) interest therein; provided, however, that subsequent to the in-service date of Unit 4, PNM, on behalf of itself and the Participants to which PNM conveyed ownership interests and generation entitlements in the San Juan Project, shall have the right to use sixty-five percent (65%), and TEP, on behalf of itself and the Participants which succeeded to TEP-conveyed ownership interests and generation entitlements in the San Juan Project, shall have the right to use thirty-five percent (35%) of the real property associated with the San Juan Project, the water, the coal inventory, the then existing oil for ignition and flame stabilization, and the use of the 345 kV switchyard capacity up to the combined installed capacity of Units 1, 2, 3 and 4, except as otherwise provided in Section 7, and except that, subject to Section 15.2.3, PNM and TEP shall each be entitled to use 50 percent (50%) of switchyard capacity in excess of the combined installed capacity of Units 1, 2, 3 and 4 for the San Juan Project.

6.2.8 Exhibit IV (a through h), attached hereto and incorporated herein, is a partial list of equipment and facilities of the San Juan Project and reflects the

Participants' ownership interests therein. This exhibit is to provide the Engineering and Operating Committee, the Auditing Committee, the Fuels Committee and the Coordination Committee with guidelines for carrying out their duties under this Agreement.

6.2.9 In areas where ownership of equipment and facilities is not clearly defined by Sections 6.2.1 to 6.2.7, the Engineering and Operating Committee shall make a determination of such ownership in accordance with Section 19. Disputes arising from such determination shall be resolved by the Coordination Committee in accordance with Section 18.

6.2.10 Materials and Supplies shall be owned by the Participants in proportion to their respective current investments in the Materials and Supplies.

6.3 The Emergency Coal Storage Pile shall be owned by the Participants in accordance with Common Participation Shares.

6.4 In the event that a Participant transfers or assigns any of its rights, titles or interests in and to the San Juan Project in accordance with the terms and conditions of this Agreement, the Participants (including the transferee or assignee of a Participant) shall jointly make, execute and deliver a supplement to this Agreement in recordable form which shall describe with particularity and in detail the rights, titles and interests of each Participant following such transfer or assignment.

6.5 PNM and TEP own as tenants in common the Switchyard Facilities described in Exhibit III in equal, undivided one-half (1/2) interests.

7.0 CAPITAL IMPROVEMENTS AND RETIREMENTS OF SAN JUAN PROJECT AND PARTICIPANTS' SOLELY OWNED FACILITIES:

7.1 The Participants recognize that from time to time it may be necessary or desirable to make Capital Improvements to and retirements of facilities comprising the San Juan Project.

7.2 Any such Capital Improvements and retirements shall be noted by an appropriate revision in or supplement to the appropriate exhibits hereto attached.

7.3 The rights, titles and interests, including Participation Shares, of a Participant in and to any Capital Improvements shall be as provided for the respective classes of property described in Section 6. The Participants shall be obligated for the costs of such Capital Improvements in the same percentages as their Participation Shares.

7.4 All Capital Improvements, and a contingency allowance for capital expenditures necessitated by an Operating Emergency or otherwise deemed justifiable by the Operating Agent, shall be included in the annual capital expenditures budget. The Engineering and Operating Committee may authorize Capital Improvements not included in the annual capital expenditures budget; provided, that such Capital Improvements shall not exceed the sum of five hundred thousand dollars ($500,000) for each such Capital Improvement, unless also authorized by the Coordination Committee.

7.5 The Operating Agent shall submit to the Participants a forecast of cash requirements by months for Capital Improvements. Said forecast will be submitted on a yearly basis after final budget approvals have been made. A revised forecast shall be submitted when the capital expenditures budget is revised, or when significant changes in monthly expenditures from those previously forecast are anticipated. The Operating Agent shall be authorized to make additional expenditures related to Capital Improvements; provided, however, that such additional expenditures for Capital Improvements shall not exceed the sum of one hundred thousand dollars ($100,000) or cause the total expenditure limit contained in the capital expenditures budget to be exceeded, unless also authorized by the Engineering and Operating Committee, or by the Coordination Committee if the total expenditure for such Capital Improvement exceeds five hundred thousand dollars ($500,000).

7.6 In the event of the removal or retirement of any facilities comprising part of the San Juan Project, any proceeds realized from the salvage of such facilities shall be distributed to the Participants in accordance with their Participation Shares therein, or shall be applied on account of the Participant's obligations to pay for Capital Improvements replacing facilities removed or retired. Units of Property retired from service shall be disposed of by the Operating Agent on the best available terms as soon as practicable.

7.7 Each Participant shall have the right, at its own expense, to add facilities to the Switchyard Facilities, provided the Engineering and Operating Committee approves the design of such additional facilities and determines that space is available therefor, and that such committee also determines that such additional facilities will not (i) infringe upon the rights of another Participant in the Switchyard Facilities, (ii) unreasonably interfere with future expansion plans at the San Juan Project, (iii) impair or interfere with the contractual rights of another Participant, or (iv) jeopardize the reliability of another Participant's system. The Engineering and Operating Committee shall have authority to impose conditions on a Participant allowed to make such additions in order to protect the other Participants consistent with applicable rules and regulations of the FERC. Such facilities shall be and remain the sole and exclusive property of the Participant installing same until and unless the Coordination Committee determines that such facilities are necessary and beneficial for operation of the San Juan Project as a whole. In the event of such determination, the facilities shall be acquired as a part of the San Juan Project by the Participants and compensation shall be paid to the selling Participant by the Participants acquiring such interest based on the net book value of such facilities.

7.8 Each Participant shall have the right, at its own expense, to add protective relay or communication equipment to facilities solely owned by it, if the Participant determines the protective relay or communication equipment is needed for the protection of its electric system, provided the Engineering and Operating Committee approves the design of such additional equipment and determines that space is available therefor, and that such committee also determines that such additional facilities will not (i) infringe upon the rights of another Participant in the facilities, (ii) unreasonably interfere with future expansion plans at the San Juan Project, (iii) impair or interfere with the contractual rights of another Participant, or (iv) jeopardize the reliability of another Participant's system.

7.9 Transportation and motorized equipment which is to be utilized by the Operating Agent for Operating Work may be purchased or leased by the Operating Agent upon receipt of the approval referred to in Section 19.3.4. Ownership of such purchased equipment and the purchase price thereof shall be allocated between and paid by the Participants in proportion to the percentages established in Section 6. Lease payments made by the Operating Agent for such leased equipment shall be apportioned between and paid by the Participants in accordance with Section 22.1. No allowance to the Operating Agent for administrative and general expense shall be included in or added to such lease payments for transportation and motorized equipment which, in lieu of acquiring such equipment by purchase, has been leased on a long-term basis.

7.10 Upon retirement of leased transportation and motorized equipment utilized for Operating Work, an amount, which shall be treated as a charge (or credit), shall be determined by multiplying the difference between the salvage value and the unamortized balance owing to the leasing company for each piece of such equipment by a fraction, the numerator of which is the sum of the monthly lease payments for such equipment charged to Operating Work and the denominator of which is the sum of all monthly lease payments made by the Operating Agent for such equipment. Such charge or credit shall be allocated among the Participants in accordance with the applicable percentages set forth in Section 22.

7.11 Administrative and general expenses which have been incurred by the Operating Agent which are applicable to authorized Capital Improvements, shall be applied monthly to construction costs incurred during the preceding month. A rate will be developed by the Operating Agent every three (3) years in conjunction with the administrative and general ("A&G") expenses study referenced in Attachment A to Exhibit VI. The current methodology for calculating the A&G Ratio for Capital Improvements is set forth in Exhibit VI, Attachment E. If any Participant believes that the method used in determining the A&G Ratio for Capital Improvements results in an unreasonable burden on such Participant(s), such Participant(s) may request that said method used in determining said ratio be submitted to the Auditing Committee for review in accordance with the procedures set out in Sections 22.6.1 through 22.6.4.

7.12 Excluded from the charges in Section 7.11 are expenses incurred under Section 36.2.

8.0 WAIVER OF RIGHT TO PARTITION:

8.1 The Participants accept title to their respective interests in the San Juan Project, water rights, lands, land rights and improvements thereon as tenants in common, and agree that their interests therein shall be held in such tenancy in common for the duration of the term of this Agreement, including any extensions thereof. While this Agreement, including any extensions thereof, remains in force and effect, each Participant agrees as follows:

8.1.1 That it hereby waives the right to partition the San Juan Project, water rights, lands, land rights or the improvements built thereon (whether by partitionment in kind or by sale and division of the proceeds thereof), and

8.1.2 That it will not resort to any action at law or in equity to partition (in either such manner) the San Juan Project, water rights, lands, land rights or the improvements built thereon and waives the benefits of all laws that may now or hereafter authorize such partition.

9.0 BINDING COVENANTS:

9.1 Except as otherwise provided in Section 9.3, all of the respective covenants and obligations of each of the Participants set forth and contained in the Project Agreements shall bind and shall be and become the respective obligations of:

9.1.1 Each Participant;

9.1.2 All mortgagees, trustees and secured parties under all present and future mortgages, indentures and deeds of trust, and security agreements which are or may become a lien upon any of the properties of each Participant;

9.1.3 All receivers, assignees for the benefit of creditors, bankruptcy trustees and referees of a Participant;

9.1.4 All other persons, firms, partnerships or corporations claiming through or under any of the foregoing; and

9.1.5 Any successors or assigns of any of those mentioned in Sections 9.1.1 to 9.1.4, inclusive,

and shall be obligations running with the Participants' rights, titles and interests in the San Juan Project, with all of the rights, titles and interests (if any) of each Participant in, to and under this Agreement and with their rights, titles and interests in the water rights, lands, land rights and the improvements thereon. It is the specific intention of this provision that all of such covenants and obligations shall be binding upon any party which acquires any of the rights, titles and interests of any of the Participants in the San Juan Project, in, to and under this Agreement, and/or in the water rights, lands, land rights or the improvements thereon, and that all of the above-described persons and groups shall be obligated to use such Participant's rights, titles and interests in the San Juan Project, in, to and under this

Agreement, and in the water rights, lands, land rights and the improvements thereon, for the purpose of discharging its covenants and obligations under this Agreement.

9.2 The rights, titles and interests of each Participant in the San Juan Project, its rights, titles and interests in, to and under this Agreement and its rights, titles and interests in and to the water rights, lands, land rights and improvements thereon, shall inure to the benefit of its successors and assigns.

9.3 Any mortgagee, trustee or secured party, or any receiver or trustee appointed pursuant to the provisions of any present or future mortgage, deed of trust, indenture or security agreement creating a lien upon or encumbering the rights, titles or interests of any Participant in the San Juan Project, in, to and under this Agreement and/or in the water rights, lands, land rights or the improvements thereon, and any successor thereof by action of law or otherwise, and any purchaser, transferee or assignee of any thereof, shall not be obligated to pay any monies accruing on account of any of the obligations or duties of such Participant under this Agreement incurred prior to the taking of possession or the initiation of foreclosure or other remedial proceedings by such mortgagee, trustee or secured party.

9.4 In the event that any or all of the provisions of this Section 9 shall not be legally effective as to any Participant, or its mortgagees, trustees, secured parties, receivers, successors or assigns, then such Participant shall not be deemed in violation of this Section 9 by reason thereof.

9.5 Nothing in this Section 9 or in this Agreement shall be deemed to change any rights, titles or interests to water rights, lands, land rights and the improvements thereon.

10.0 MORTGAGE AND TRANSFER OF PARTICIPANTS' INTERESTS:

10.1 The Participants shall have the right at any time and from time to time to mortgage, create or provide for a security interest in or convey in trust their respective rights, titles and interests in the San Juan Project, their respective rights, titles and interests in, to and under a Project Agreement and/or their rights, titles and interests in the water rights, lands, land rights or the improvements to be built thereon to a trustee or trustees under deeds of trust, mortgages or indentures, or to secured parties under a security agreement, as security for their present or future bonds or other obligations or securities, and to any successors or assigns thereof without need for the prior consent of the other Participants, and without such mortgagee, trustee or secured party assuming or becoming in any respect obligated to perform any of the obligations of the Participants.

10.2 Any mortgagee, trustee or secured party under present or future deeds of trust, mortgages, indentures or security agreements of any of the Participants and any successor or assign thereof, and any receiver, referee, or trustee in bankruptcy or reorganization of any of the Participants, and any successor by action of law or otherwise, and any purchaser, transferee or assignee of any thereof may, without need for the prior consent of the other Participants, succeed to and acquire all the rights, titles and interests of such Participant in the San Juan Project, in, to and under the Project Agreements and/or the rights, titles and interests of such Participant in the water rights, lands, land rights and improvements thereon, and may take over possession of or foreclose upon said property, rights, titles and interests of such Participant.

10.3 Except as otherwise provided in Sections 10.1, 10.2 or 10.4 or, with respect to a transfer or assignment by a Participant to another Participant as provided in Section 11, no Participant shall transfer or assign its respective rights, titles and interests in the San Juan Project, in, to and under this Agreement and/or in the water rights, land, land rights and the improvements thereon, without the prior written consent of the other Participants, which consent shall not be unreasonably withheld.

10.4 Each Participant shall have the right to transfer or assign its respective rights, titles and interests in the San Juan Project, in, to and under this Agreement and/or in the water rights, land, land rights and the improvements thereon, without the need for prior consent of the other Participants, at any time to any of the following:

10.4.1 To any corporation or other entity acquiring all or substantially all of the property of such Participant; or

10.4.2 To any corporation or entity into which or with which such Participant may be merged or consolidated; or

10.4.3 To any corporation or entity the stock or ownership of which is wholly owned by a Participant; or

10.4.4 To any corporation or other entity which owns all of the outstanding common stock or other ownership interest of a Participant (its "Parent"); or

10.4.5 To any corporation or other entity the common stock or other ownership interest of which is wholly owned by the Parent of a Participant.

10.5 Except as otherwise provided in Sections 10.1, 10.2 and 9.3, any successor to the rights, titles and interests of a Participant in the San Juan Project, to the rights, titles and interests of a Participant in, to and under the Project Agreements and/or in the water rights, lands, land rights or improvements thereon shall assume and agree to fully perform and discharge all of the obligations hereunder of such Participant, and such successor shall notify the other Participants in writing of such transfer, assignment or merger, and shall furnish to the other Participants evidence of such transfer, assignment or merger. Any such successor shall specifically agree in writing with the remaining Participants at the time of such transfer, assignment or merger that it will not transfer or assign any rights, titles and interests acquired from the assigning Participant without complying with the terms and conditions of Section 11.

10.6 No Participant shall be relieved of any of its obligations and duties to the other Participants by a transfer, assignment or merger under this Section 10 without the express prior written consent of the remaining Participants, which consent shall not be unreasonably withheld.

10.7 Except as otherwise provided in Section 10.5, any transfer, assignment or merger made pursuant to the provisions of this Section 10 shall not be subject to the terms and conditions set forth and contained in Section 11.

11.0 RIGHTS OF FIRST REFUSAL:

11.1 The purpose of this Section 11 is to set forth the manner in which all existing or future rights of first refusal, pertaining to the transfer of interests in the San Juan Project, shall be exercised. Except as provided in Section 10, PNM has a right of first refusal with respect to the proposed transfer of any ownership interest in the San Juan Project by any Participant and TEP has a right of first refusal with respect to PNM's proposed transfer of an interest in Unit 1 or Unit 2 and associated common property. The existence of other rights of first refusal shall be as provided in other instruments to which Participants are parties. Nothing in this Section 11 shall be construed to limit or expand the rights of first refusal of any Participant.

11.2 Except as provided in Section 10, should a Participant desire to assign, transfer, convey or otherwise dispose of (hereinafter collectively referred to as "Assign") its rights, titles and interests in the San Juan Project, or its rights, titles and interests in, to and under the Project Agreements, or its rights, titles and interests in the water rights, lands, land rights or the improvements thereon or any part thereof or interest therein (hereinafter referred to as "Transfer Interest"), to any person, company, corporation or governmental agency (hereinafter referred to as "Outside Party"), the Participant desiring to Assign shall first make an offer to sell the Transfer Interest to a Participant(s) having a right of first refusal, on the basis of the applicable amount as set out in either Section 11.2.1 or Section 11.2.2:

11.2.1 Where the Outside Party proposes to purchase for a specified monetary amount, from the Participant desiring to Assign, an interest only in the San Juan Project and/or in contract rights, water rights, lands, land rights and improvements associated therewith, the amount of (i) a bona fide written offer from an Outside Party ready, willing and able (subject to obtaining any required regulatory approvals) to purchase the Transfer Interest; or, in the absence of a bona fide written offer, (ii) a purchase price set out in a bona fide purchase and sale agreement between the Participant desiring to Assign and an Outside Party ready, willing and able (subject to obtaining any required regulatory approvals) to purchase the Transfer Interest; or

11.2.2 Where the Outside Party proposes to purchase from the Participant desiring to Assign, (i) as part of a non-monetary offer (such as in the case of an asset swap) or (ii) when a segregated value for the Transfer Interest is not available (such as in the case of a bundled or packaged sale of assets), or (iii) where the Outside Party proposes to purchase an interest not only in the San Juan Project and/or in contract rights, water rights, lands, land rights and improvements associated therewith, but also in other property of the Participant desiring to Assign, the fair market value of the Transfer Interest. As used herein, the term "fair market value" means the amount of money which a purchaser, willing but not obligated to buy the property, will pay to an owner, willing but not obligated to sell it, taking into consideration all of the uses to which the Transfer Interest is adapted and might in reason be applied.

11.3 At least three (3) months prior to its intended date to Assign, and after its receipt of a bona fide written offer, or execution of a bona fide purchase and sale agreement, of the type described in Section 11.2, the Participant desiring to Assign its Transfer Interest shall serve written notice of its intention to do so upon the Participant(s) having a right of first refusal, in accordance with Section 42. Such notice shall: (i) have attached as an exhibit a copy of the bona fide offer of an Outside Party or of the bona fide purchase and sale agreement between the Outside Party and the Participant desiring to Assign (an "Outside Offer"); and (ii) shall contain a statement of the approximate proposed date to Assign.

11.4 The Participant(s) having the right of first refusal shall signify its (their) desire to purchase the entire Transfer Interest, or not purchase the entire Transfer Interest, by serving written notice of its (their) intention upon the Participant desiring to Assign pursuant to Section 42 within sixty (60) days after such service pursuant to Section 11.3 of the written notice of intention to Assign. Failure by a Participant to serve notice as provided hereunder within the time period specified shall be conclusively deemed to be notice of its intention not to purchase the Transfer Interest.

11.5 When intention to purchase the entire Transfer Interest has been indicated by notices duly given hereunder by the Participant(s) desiring to purchase the Transfer Interest, the affected Participants shall thereby incur the following obligations:

11.5.1 The Participant desiring to Assign and a Participant desiring to purchase the Transfer Interest shall be obligated to proceed in good faith and with diligence to obtain all required authorizations and approvals to Assign;

11.5.2 The Participant desiring to Assign shall be obligated to obtain the release of any liens imposed by or through it upon any part of the Transfer Interest and to Assign the Transfer Interest at the earliest practicable date thereafter; and

11.5.3 A Participant desiring to purchase the Transfer Interest shall be obligated to perform all terms and conditions required of it to complete the purchase of the Transfer Interest.

The purchase of the Transfer Interest shall be fully consummated within six (6) months following the date upon which all notices required to be given under this Section 11 have been duly served, unless the Participant is then diligently pursuing applications to appropriate regulatory bodies (if any) for required authorizations to effect such assignment or is then diligently prosecuting or defending appeals from orders entered or authorizations issued in connection with such applications.

11.6 If the intention to purchase the entire Transfer Interest has not been indicated by notices given within the time periods specified in this Section 11 by a Participant desiring to purchase the Transfer Interest, the Participant desiring to Assign shall be free to Assign all, but not less than all, of its Transfer Interest to the Outside Party that made the Outside Offer, upon the terms and conditions set forth in the Outside Offer. If such assignment of the entire Transfer Interest to the Outside Party is not completed within three (3) years after the approximate proposed date to Assign specified in the notice given pursuant to Section 11.3, the Participant desiring to Assign its Transfer Interest must, unless it is then diligently pursuing its applications to appropriate regulatory bodies (if any) for required authorizations to effect such assignment, or is then diligently prosecuting or defending appeals from orders entered or authorizations issued in connection with such applications, give another complete new right of first refusal to the Participant(s) desiring to purchase pursuant to the provisions of this Section 11, before such Participant shall be free to Assign a Transfer Interest to said Outside Party.

11.7 No assignment of a Transfer Interest, whether to another Participant or to an Outside Party, shall relieve the assigning Participant from full liability and financial responsibility for performance after any such assignment: (i) of all obligations and duties incurred by such Participant prior to such assignment under the terms and conditions of the Project Agreements; and/or (ii) of all obligations and duties provided and imposed after such assignment upon such assigning Participant under the terms and conditions of the Project Agreements, unless and until the assignee shall agree in writing with the remaining Participants to assume the obligations and duties of a Participant hereunder; provided further, however, that such assignor shall not be relieved of any of its obligations and duties by an assignment under this Section 11, without the express prior written consent of the remaining Participants, which consent shall not be unreasonably withheld.

11.8 Any transferee, successor or assignee, or any party who may succeed to the Transfer Interest pursuant to this Section 11, shall specifically agree in writing with the remaining Participants at the time of such transfer or assignment that it will not transfer or assign all or any portion of the Transfer Interest so acquired without complying with the terms and conditions of this Section 11.

11.9 The provisions of Section 11.8 shall not be applicable to any assignment of a Transfer Interest by one Participant to another Participant, provided that payment in full of such Transfer Interest, as defined in Section 11, has been made by the Participant who is the assignee thereof.

11.10 A Participant may, for the purpose of financing its interest in pollution control systems and facilities at the San Juan Project, sell, transfer or convey such interests pursuant to the New Mexico Pollution Control Revenue Bond Act, and any such sale, transfer or conveyance shall not be deemed as an assignment, transfer, conveyance or other disposal within the meaning of this Section 11.

12.0 RIGHTS OF PNM AND TEP IN WATER AND COAL:

12.1 If, pursuant to the terms and conditions of the Underground Coal Sales Agreement, or the sublease dated August 18, 1980 (as amended to date and as such sublease may be amended from time to time), between Western Coal Company and Utah International, Inc. or their successors ("Sublease"), PNM and TEP succeed to any interest in coal lands, coal leases, water rights, or other property, the rights, titles and interests of PNM and TEP therein shall be held as tenants in common, with each of PNM and TEP having an equal undivided one-half (1/2) interest therein, and such rights, titles and interests shall be subject to all the terms and conditions set forth and contained in this Agreement.

13.0 SEVERANCE OF IMPROVEMENTS:

13.1 All facilities, structures, improvements, equipment and property of whatever kind and nature constructed, placed or affixed on the rights-of-way, easements, patented lands, fee lands and leased lands as part of, or as Capital Improvements, to the San Juan Project, as against all parties and persons whomsoever (including, without limitation, any party acquiring any interest in the rights-of-way, easements, patented, fee or leased lands or any interest in or lien, claim or encumbrance against any of such facilities, structures, improvements, equipment and property of whatever kind and nature) shall be deemed to be and remain personal property of the Participants, not affixed to the realty.

PART III

ENTITLEMENTS TO OUTPUT OF SAN JUAN PROJECT

14.0 ENTITLEMENT TO CAPACITY AND ENERGY:

14.1 Subject to the provisions of Section 16, the Participants shall be entitled to the Net Effective Generating Capacity of each of Unit 1, Unit 2, Unit 3 and Unit 4 in proportion to their respective Participation Shares. Each Participant shall be entitled to schedule its Energy up to the Available Operating Capacity.

14.2 The Operating Agent shall keep the system dispatcher of each Participant advised of the Available Operating Capacity.

14.3 When a Participant's request for its share of the Available Operating Capacity necessitates the operation of a Unit, each Participant shall schedule for its account not less than its share of Minimum Net Generation. If, however, a Participant has scheduled an amount of Energy in excess of its share of the Minimum Net Generation, the other Participants shall be allowed to reduce their scheduled Energy to an amount that will maintain the Unit at the Minimum Net Generation level.

14.4 The delivery of Energy from the San Juan Project shall be scheduled by each Participant in advance with the Operating Agent and accounted for on the basis of integrated hourly actual generation, all in accordance with any operating procedures which may be established or approved by the Engineering and Operating Committee. Such operating procedures shall provide for modifying such schedules to meet the needs of day-to-day and hour-by-hour operation, including emergencies on a Participant's system.

14.5 The Operating Agent shall, to the extent possible, generate Energy at the San Juan Project in accordance with schedules submitted by each Participant, as such schedules may be revised from time to time, as long as such schedules do not jeopardize the operation of the San Juan Project.

14.6 The Participants shall revise their schedules in the event of an Operating Emergency or other incident beyond the control of the Operating Agent to reflect the actual Energy available from the San Juan Project during the period of the Operating Emergency or incident.

14.7 The Energy generated at the San Juan Project shall be controlled within PNM’s Control Area; provided, that such control shall not diminish the rights of any Participant to receive its entitlement of Energy from the San Juan Project.

15.0 CAPACITY ALLOCATION OF SWITCHYARD FACILITIES:

15.1 The electrical capacity in the Switchyard Facilities shall be made available to PNM and TEP in the manner and in the amounts as set forth in Section 6.2.7. For the purposes of this Agreement, the FC Line shall be considered a part of the Switchyard Facilities.

15.1.1 The transmission capacity of the FC Line shall measured at the Four Corners terminal. PNM and TEP each shall be entitled to fifty percent (50%) of the designated FC Line Capacity.

15.1.2 The transmission capacity of the FC Line termination and other contract matters concerning the Four Corners Project shall be handled individually by PNM and TEP.

15.2 The points of attachment to the San Juan 345 kV Switchyard Facilities for the purposes of this Section 15 are:

No. 1: TEP/PNM No. 1 345 kV transmission line;

No. 2: TEP/PNM No. 2 345 kV transmission line;

No. 3: PNM/TEP Four Corners Generating Plant 345 kV switchyard (through the FC Line);

No. 4: PNM's WW 345 kV transmission line;

No. 5: PNM's OJ 345 kV transmission line;

No. 6: Colorado Public Service Company/Western Area Power Administration/Tri-State Rifle 345 kV transmission line;

No. 7: Western Area Power Administration-Shiprock 345 kV transmission line.

15.2.1 The Participants collectively shall not schedule more Power and Energy through any of the foregoing individual points of attachment than the established rating of that facility.

15.2.2 The Participants' individual transmission capacity rights into or out of the Switchyard Facilities attachment points shall be the same as the ownership or contract rights of the Participant(s) in the attached facility up to the limits specified in this Section 15.

15.2.3 Any transmission capacity in the Switchyard Facilities specified to be available in Section 15.2.1 or otherwise determined to be available by the Engineering and Operating Committee, but not allocated to the individual Participants under Section 15.2.2, shall be declared "excess capacity" by the Engineering and Operating Committee. The Engineering and Operating Committee shall allocate such excess transmission capacity to PNM or TEP or such Participants having an ownership interest in the Switchyard Facilities, upon request in the amount requested for specified periods of time to the extent and for such time as the Engineering and Operating Committee finds such excess capacity to be available.

16.0 USE OF FACILITIES DURING CURTAILMENTS:

16.1 If the Net Effective Generating Capacity of all Units is reduced because of factors (including, but not limited to, equipment failures, scheduled or unscheduled outages, fuel or fuel deliveries, water supply, air quality limitations) which commonly influence the total output of all Units, each Participant's entitlement to Capacity during such period shall be reduced in proportion to the percentages specified in Section 6.2.6 during each hour of such curtailment unless otherwise specified in a separate agreement.

16.2 If factors which influence the operation of a Unit cause a curtailment of that Unit, then the capacity entitlement from that Unit for each Participant in that Unit shall be in proportion to the Participant's Participation Share of that Unit.

16.3 If, because of factors which influence the operation solely of Units 1 and 2, or solely of Units 3 and 4, there shall be a curtailment of Units 1 and 2, or of Units 3 and 4, as the case may be, the curtailment for each Participant in Units 1 and 2, or Units 3 and 4, shall be allocated in proportion to the percentages specified in Sections 6.2.4 and 6.2.5, respectively.

16.4 To the extent that a curtailment results from scarcity of resources and not from mechanical or legal limitations, Participants may agree in writing to modify their schedules to allocate the use of such resources to such Unit(s) or to such times as to make the most efficient use thereof, consistent with Prudent Utility Practice, during the pendency of such curtailment. Notwithstanding the provisions of Section 23.2, the Operating Agent shall, during such curtailments, account for coal inventory on a Participant by Participant basis. Upon the conclusion of such curtailment, the provisions of Section 23.2 shall apply to any remaining coal inventory.

16.5 Curtailment of the transmission capacity in the Switchyard Facilities shall be allocated to the Participants in the manner and in the amounts as set forth in Section 6.2.7.

16.6 No Participant shall exercise its rights relating to the San Juan Project so as to endanger or unreasonably interfere with the operation of the San Juan Project or the right of any other Participant to use its share of Capacity and Energy from the San Juan Project.

17.0 START-UP AND AUXILIARY POWER AND ENERGY REQUIREMENTS:

17.1 Each Participant shall be obligated to provide its Participation Share of the Energy requirements to start up and operate each Unit, and such requirements shall be provided by the Participants based upon the Participant's percentage of operating costs in accordance with Section 22.1. Appropriate metering facilities shall be installed to assure measurement of such Energy. Such requirements for Energy shall be scheduled in advance by the Operating Agent in accordance with operating procedures approved by the Engineering and Operating Committee.

PART IV

ADMINISTRATION

18.0 COORDINATION COMMITTEE:

18.1 As a means of securing effective cooperation and interchange of information and of providing consultation on a prompt and orderly basis among the Participants in connection with various administrative and technical problems which may arise from time to time under this Agreement, the Coordination Committee shall remain in existence during the term of this Agreement. Except as otherwise expressly provided in this Agreement, the Coordination Committee shall have no authority to modify any of the provisions of this Agreement.

18.2 The Coordination Committee shall consist of one representative from each Participant who shall be an officer or other duly authorized representative of a Participant. Any of the Participants may designate an alternate or substitute to act as its representative on the Coordination Committee in the absence of the regular representative on the Coordination Committee or to act on specified occasions or with respect to specified matters. Each Participant shall notify the other Participants promptly, in writing, of the designation of its representative and alternate representative on the Coordination Committee and of any subsequent changes in such designations. The chairperson of the Coordination Committee shall be a representative employed by the Operating Agent.

18.3 The Coordination Committee shall have the following functions and responsibilities:

18.3.1 Provide liaison between and among the Participants.

18.3.2 Exercise general supervision over the Engineering and Operating Committee, the Fuels Committee and the Auditing Committee.

18.3.3 Consider and act upon all matters referred to the Coordination Committee by the Engineering and Operating Committee, the Fuels Committee and the Auditing Committee.

18.4 Any action or determination of the Coordination Committee shall require a vote of the Participants in accordance with Sections 18.4.1, 18.4.2 or 18.4.3. A Participant's Coordination Committee representative shall be entitled to vote on all matters except those actions or determinations which relate solely to a Unit or to common property in which such Participant does not have a Participation Share or as provided in Section 35.4.1. If a Participant's right to vote has been suspended pursuant to Section 35.4.1, the requisite majorities for actions or determinations specified in Sections 18.4.1, 18.4.2 and 18.4.3 shall be adjusted in proportion to the number of Participants whose right to vote has not been suspended. An example of such an adjustment is provided in Exhibit VIII, attached hereto and incorporated herein. Maintenance scheduling and operation during periods of curtailment of the total San Juan Project are not matters which relate solely to a Unit, but are deemed to be matters affecting all Units.

18.4.1 Except as provided in Sections 18.4.2 and 18.4.3, any actions or determinations brought before the Coordination Committee shall require the following vote:

(a) More than a sixty-six and two thirds percent (66 2/3%) majority of the Participation Shares of the Participants in a Unit or common property as defined in Section 6.2; <u>and</u>

(b) More than a sixty-six and two thirds percent (66 2/3%) majority of the number of individual Participants having a Participation Share in a Unit or common property as defined in Section 6.2.

18.4.2 Any action or determination of the Coordination Committee related to common property as set forth in Section 6.2.6 and involving an expenditure greater than five million dollars ($5,000,000) shall require the following vote:

(a) More than an eighty-two percent (82%) majority of the Common Participation Shares of the Participants; <u>and</u>

(b) A minimum of sixty-six and two thirds percent (66 2/3%) majority of the number of the individual Participants.

18.4.3 Any action or determination of the Coordination Committee regarding any amendment of the Underground Coal Sales Agreement, replacement of the Underground Coal Sales Agreement with a new agreement or any interim coal pricing agreement related to the Underground Coal Sales Agreement (or its successor) shall require the following vote:

(a) More than an eighty-two percent (82%) majority of the Common Participation Shares of the Participants; <u>and</u>

(b) A minimum of sixty-six and two thirds percent (66 2/3%) majority of the number of individual Participants.

18.5 The Coordination Committee shall keep written minutes and records of all meetings. Any action or determination made by the Coordination Committee shall be reduced to writing and shall become effective when signed by the representatives of the

Participants entitled to vote thereon, representing a voting majority of the members of the Coordination Committee, as defined in Section 18.4; provided, however, in the event of an Operating Emergency, actions or determinations may be made on the basis of oral agreements among duly authorized representatives of the respective Participants entitled to vote thereon, and such action or determination subsequently shall be reduced to writing. Coordination Committee representatives may, by prior arrangement with the chairperson of the Coordination Committee, attend a meeting of the Coordination Committee by conference call or video conferencing. A Coordination Committee representative who is unable to attend a meeting of the Coordination Committee may vote in absentia by delivering to the chairperson of the Coordination Committee, at least twenty-four (24) hours prior to the scheduled commencement of the meeting, a written statement, including by e-mail or facsimile, identifying the matter to be voted on and how the representative desires to vote.

18.6 Except for matters subject to the voting requirements of Section 18.4.3, in the event the Coordination Committee fails to reach agreement on any matter, which such committee is authorized to determine, approve or otherwise act upon after a reasonable opportunity to do so, then the Operating Agent shall be authorized and obligated to take such reasonable and prudent action, consistent with Prudent Utility Practice, as is necessary to the successful and proper operation and maintenance of the San Juan Project, pending the resolution, by arbitration or otherwise, of any such inability or failure to agree.

18.7 In the event the Coordination Committee fails to reach agreement on a matter subject to the voting requirements of Section 18.4.3, then an impasse shall be deemed to exist and the Participants which are signatories to the Underground Coal Sales Agreement then in effect shall have the obligation and the responsibility, consistent with Prudent Utility Practice, to maintain a supply of coal to the San Juan Project.

19.0 ENGINEERING AND OPERATING COMMITTEE:

19.1 The Engineering and Operating Committee shall remain in existence during the term of this Agreement. Except as expressly provided in this Agreement, the Engineering and Operating Committee shall have no authority to modify any of the provisions of this Agreement.

19.2 The Engineering and Operating Committee shall consist of up to two representatives from each Participant who shall collectively have one vote. Any of the Participants may designate an alternate or substitute to act as its representative on the Engineering and Operating Committee in the absence of a regular representative on the Engineering and Operating Committee or to act on specified occasions or with respect to specified matters. Each Participant shall notify the other Participants promptly, in writing, of the designation of its representatives and alternate representative on the Engineering and Operating Committee and of any subsequent change in the designation. The chairperson of the Engineering and Operating Committee shall be a representative employed by the Operating Agent.

19.3 The Engineering and Operating Committee shall have the following functions and responsibilities:

19.3.1 Review and approve the following items related to the performance of Operating Work.

19.3.1.1 Capital Improvements and the annual Capital Improvements budget.

19.3.1.2 The annual staffing table.

19.3.1.3 The annual operation and maintenance budget.

19.3.1.4 Such written statements of operating or maintenance procedures as may be submitted to the Engineering and Operating Committee.

19.3.1.5 The planned annual maintenance schedule.

19.3.1.6 The policies for establishing the Emergency Spare Parts inventory.

19.3.1.7 The policies for establishing the inventory for Materials and Supplies.

19.3.1.8 The statistical and administrative reports, budgets and information and other similar records, and the form thereof, to be kept and furnished by the Operating Agent, in accordance with Section 28.3.15 (excluding accounting records used internally by the Operating Agent for the purpose of accumulating financial and statistical data, such as books of original entry, ledgers, work papers and source documents).

19.3.1.9 The determination of Net Effective Generating Capacity, Minimum Net Generation and Net Energy Generation of the San Juan Project, based upon recommendations of the Operating Agent.

19.3.1.10 The principles and procedures for establishing communication channels among Participants.

19.3.1.11 The operating procedures for performance and efficiency testing.

19.3.1.12 The operating procedures for maintaining complete and accurate Capacity and Energy accounting.

19.3.1.13 The Operating Agent's estimate and analysis of the total expenditures resulting from an Operating Emergency, as provided in Section 29.7.

19.3.1.14 The results and expenditures of programs and contracts on environmental control and data collection for which the Operating Agent has contracted.

19.3.2 Establish procedures for the operation of the San Juan Project during any period of curtailed operations which reduces or may reduce the Net Effective Generating Capacity.

19.3.3 Except for an Operating Emergency, as provided in Section 29, designate a construction agent responsible for the design, construction and acquisition of Capital Improvements.

19.3.4 Approve the list of transportation and motorized equipment to be purchased or leased by the Operating Agent for use in the performance of Operating Work.

19.3.5 Perform such other functions and responsibilities as may be assigned to it from time to time by the Coordination Committee.

19.4 Any action or determination of the Engineering and Operating Committee shall require a vote of the Participants, in the manner provided for in Sections 18.4.1 and 18.4.2. A Participant's Engineering and Operating Committee voting representative shall be entitled to vote on all matters except those actions or determinations which relate solely to a Unit or to common property in which such Participant does not have a Participation Share or as provided in Section 35.4.1. If a Participant's right to vote has been suspended pursuant to

Section 35.4.1, the requisite majorities for actions or determinations specified in Sections 18.4.1 and 18.4.2 shall be adjusted in proportion to the number of Participants whose right to vote has not been suspended. An example of such an adjustment is provided in Exhibit VIII. Maintenance scheduling and operation during periods of curtailment of the total San Juan Project are not matters which relate solely to a Unit, but are deemed to be matters affecting all Units.

19.5 The Engineering and Operating Committee shall keep written minutes and records of all meetings. Any action or determination made by the Engineering and Operating Committee shall be reduced to writing and shall become effective when signed by the representatives of the Participants entitled to vote thereon, representing a voting majority of the members of the Engineering and Operating Committee, as defined in Section 19.4; provided, however, in the event of an Operating Emergency, actions or determinations may be made on the basis of oral agreements among duly authorized representatives of the respective Participants entitled to vote thereon, and such action or determination subsequently shall be reduced to writing. Engineering and Operating Committee representatives may, by prior arrangement with the chairperson of the Engineering and Operating Committee, attend a meeting of the Engineering and Operating Committee by conference call or video conferencing. An Engineering and Operating Committee representative who is unable to attend a meeting of the Engineering and Operating Committee may vote in absentia by delivering to the chairperson of the Engineering and Operating Committee, at least twenty-four (24) hours prior to the scheduled commencement of the meeting, a written statement, including by e-mail or facsimile, identifying the matter to be voted on and how the representative desires to vote.

19.6 In the event that less than a requisite majority of the Engineering and Operating Committee is obtained, the matter shall be referred to the Coordination Committee for decision upon the request of any Participant's Engineering and Operating Committee representative.

19.7 In the event the Engineering and Operating Committee fails to reach agreement on any matter which such committee is authorized to determine, approve or otherwise act upon after a reasonable opportunity to do so, then the Operating Agent shall be authorized and obligated to take such reasonable and prudent action, consistent with Prudent Utility Practice, as is necessary to the successful and proper operation and maintenance of the San Juan Project, pending the resolution, by arbitration or otherwise, of any such inability or failure to agree.

20.0 FUELS COMMITTEE:

20.1 As a means of establishing a centralized forum to facilitate the timely and candid consideration and discussion between all Participants of policies and issues associated with the procurement of coal for the San Juan Project, there is hereby established a Fuels Committee, which shall remain in existence during the term of this Agreement. The Participants do not intend that the operation of the Fuels Committee shall affect the day-to-day fuels-related operational responsibilities of the Operating Agent, except as otherwise specifically provided in this Section 20. The Fuels Committee shall have no authority to modify any of the provisions of this Agreement.

20.2 The Fuels Committee shall consist of one representative from each Participant. Any of the Participants may, by written notice to the other Participants, designate an alternate or substitute to act as its representative on the Fuels Committee in the absence of the regular representative on the Fuels Committee or to act on specified occasions or with respect to specified matters. Each Participant shall notify the other Participants promptly in writing of the designation of its representative on the Fuels Committee and of any subsequent change in such designation. The chairperson of the Fuels Committee shall be a representative employed by a Participant that is a signatory to the Underground Coal Sales Agreement. The Fuels Committee shall meet regularly, but in no event less than semiannually. Special meetings shall be called by the chairperson if requested in writing by any three (3) Participants.

20.3 The Fuels Committee shall have the following functions and responsibilities:

20.3.1 To conduct studies, or cause studies to be conducted, regarding criteria pertaining to the acquisition of coal supplies and the negotiation and approval of coal agreements. Such studies and recommendations may include, but are not limited to:

20.3.1.1 Annual fuel supply budgets

20.3.1.2 Coal cost

20.3.1.3 Coal delivery rates and minimum take obligations

20.3.1.4 Coal quality

20.3.1.5 Contract terms

20.3.1.6 Economic requirements

20.3.1.7 Negotiation strategies

20.3.1.8 Potential coal suppliers

provided, however, that prior to any such study being conducted, the Participant(s) desiring that the study be performed shall have made suitable arrangements therefor, including payment arrangements with the provider of the study. Nothing in this Section 20.3 shall be construed to require the Operating Agent or any Participant which is a signatory to the Underground Coal Sales Agreement to undertake any uncompensated or unfunded study which it would not otherwise perform.

20.3.2 To obtain input from all Participants regarding individual criteria and economic requirements necessary to vote on matters entrusted to the Fuels Committee or to make collective recommendations to the Coordination Committee.

20.3.3 To approve Participant Monthly Minimum Tons delivery schedules and pricing pursuant to Annual Interim Invoicing Agreements as defined in Section 8.7 of the Underground Coal Sales Agreement.

20.3.4 To receive progress reports from and provide recommendations to negotiators acting on behalf of Participants in the negotiation and administration of coal supply and related agreements.

20.3.5 To provide regular progress reports to the Engineering and Operating and to the Coordination Committees, as requested by such committees.

20.3.6 To establish the amount of coal to be maintained in the Emergency Coal Storage Pile.

20.3.7 To establish operating procedures for delivery of coal to the Emergency Coal Storage Pile.

20.3.8 To establish procedures for the determination of Participant Coal Consumption.

20.3.9 To perform such other functions and responsibilities as are identified in Sections 23.4.2.8, and 23.4.2.10.

20.3.10 To perform such other functions and responsibilities as may be assigned to it from time to time by the Coordination Committee.

20.4 The following special procedures shall apply to all negotiations or discussions with SJCC regarding amendment, interim pricing agreements, termination or succession of the Underground Coal Sales Agreement, related agreements, or with any other coal supplier or potential supplier. No Fuels Committee representative or Participant shall engage in bilateral negotiations or discussions concerning coal supply or related matters for the San Juan Project with SJCC or any other coal supplier or potential supplier; provided, however, that nothing herein shall be construed to prevent the Operating Agent or the Participants which are signatories to the Underground Coal Sales Agreement, in the conduct of its or their day-to-day operational responsibilities, from performing Operating Work, engaging in business contacts and communications with SJCC or other coal suppliers or potential suppliers to the San Juan Project or in the administration of the Underground Coal Sales Agreement and related agreements.

20.4.1 Each Participant which is a signatory to the Underground Coal Sales Agreement shall be entitled to have at least two (2) representatives present at any such negotiations or discussions. Participants not signatories to the Underground Coal Sales Agreement or its successors (for purposes of this Section 20.4.1, the "Remaining Participants") shall have the collective right to have two (2) representatives present at any such negotiations or discussions. The Remaining Participants may jointly or separately designate representatives, but in no case may the total number of representatives so designated by all of the Remaining Participants exceed two (2). Any dispute among the Remaining Participants regarding the naming of representatives shall be subject to resolution pursuant to Section 37 and shall not restrict the rights of any other representatives to engage in any ongoing negotiations or discussions. Representatives shall be designated in writing by the Participants which are signatories to the Underground Coal Sales Agreement and Remaining Participants. If such representatives are not employees of a Participant or a Remaining Participant, such fact shall be disclosed in writing to all Participants and Remaining

Participants. Representatives shall agree in writing to: (i) avoid any conflict of interest that would be detrimental to the operation of the San Juan Project; and (ii) maintain all proprietary information obtained through such negotiations and discussions in confidence. The form of such confidentiality agreements shall be prepared by the Fuels Committee, and shall be subject to the approval of the Participants which are signatories to the Underground Coal Sales Agreement, such approval not to be unreasonably withheld. Such confidentiality agreements shall be executed by a Participant's Coordination Committee representative or, as appropriate, the person authorized by such Participant or Representative to execute such documents. Representatives may be changed by Participants or Remaining Participants by the giving of written notice to all other Participants and Remaining Participants.

20.4.2 Representatives shall make regular reports to, coordinate with, and obtain the recommendations of the Fuels Committee regarding the progress of and issues involved in such coal negotiations or discussions.

20.5 Any proposed action or determination regarding any amendment of the Underground Coal Sales Agreement, replacement of the Underground Coal Sales Agreement with a new agreement or any interim or other annual coal pricing agreement related to the Underground Coal Sales Agreement (or its successor) or any other action or determination of the Fuels Committee shall be submitted to the vote of the representatives of the Participants on the Fuels Committee. Any such action or determination shall require the affirmative vote as established in Section 18.4.3, except that if a Participant's right to vote has been suspended pursuant to Section 35.4.1, the requisite majority for actions or determinations specified in Section 18.4.3 shall be adjusted in proportion to the number of Participants whose right to vote has not been suspended. An example of such an adjustment is provided in Exhibit VIII.

20.5.1 If, upon such vote, the requisite votes are obtained, the Participants which are signatories to the Underground Coal Sales Agreement then in effect or the Operating Agent, as applicable, shall proceed in accordance with the affirmative vote of the Fuels Committee without further action of any other San Juan Project committee.

20.5.2 If, upon such vote, the requisite votes are not obtained, the matter giving rise to the vote shall, not later than thirty (30) days after the negative vote of the Fuels Committee, be submitted to the Coordination Committee for its vote in accordance with Section 18. If the requisite majorities are obtained in the Coordination Committee vote, the Participants which are signatories to the Underground Coal Sales Agreement then in effect or the Operating Agent, as applicable, shall proceed in accordance with the affirmative vote of the Coordination Committee.

20.5.3 If the requisite votes are not obtained in the Coordination Committee vote, then consistent with Section 18.7, the Participants which are signatories to the Underground Coal Sales Agreement then in effect or the Operating Agent, as applicable, shall have the obligation and the responsibility, consistent with Prudent Utility Practice, to maintain a supply of coal to the San Juan Project.

20.6 The Fuels Committee shall keep written minutes and records of all meetings. Any action or determination made by the Fuels Committee shall be reduced to writing and shall become effective when signed by the representatives of the Participants representing a voting majority. Fuels Committee representatives may, by prior arrangement with the chairperson of the Fuels Committee, attend a meeting of the Fuels Committee by conference call or video. A Fuels Committee representative who is unable to attend a meeting of the Fuels Committee may vote in absentia by delivering to the chairperson of the Fuels Committee, at least twenty-four (24) hours prior to the scheduled commencement of the meeting, a written statement, including by e-mail or facsimile, identifying the matter to be voted on and how the representative desires to vote.

21.0 AUDITING COMMITTEE:

21.1 The Auditing Committee shall remain in existence during the term of this Agreement. The Auditing Committee shall have no authority to modify any of the provisions of this Agreement.

21.2 The Auditing Committee shall consist of one representative from each Participant. Any of the Participants may designate an alternate or substitute to act as its representative on the Auditing Committee in the absence of the regular representative on the Auditing Committee or to act on specified occasions or with respect to specified matters. Each Participant shall notify the other Participants promptly, in writing, of the designation of its representative and alternate representative on the Auditing Committee and of any subsequent changes in such designation.

21.3 The Auditing Committee shall have the following functions and responsibilities under this Agreement:

21.3.1 Review accounting, financial and internal control aspects of Operating Work and Capital Improvements, and implementation of procedures established pursuant to Section 20.3.8, and, not less than every two years, audit the records maintained by the Operating Agent in its performance of Operating Work, Capital Improvements and any other records maintained by the Operating Agent in support of its billings to the Participants.

21.3.2 Review and approve the format and content of the Operating Agent's accounting records and reports for Operating Work and Capital Improvements.

21.3.3 Certify to the Participants, for management purposes and for the use of the Participants only, that the Operating Agent's results of operations and accounting methods and records, including any allocations for Operating Work and Capital Improvements, are in accordance with the Project Agreements and Accounting Practice.

21.3.4 Review and make recommendations to the Coordination Committee regarding a Participant's administrative and general expense allowance and other normal loadings when such Participant acts as construction agent for Capital Improvements.

21.3.5 Review and approve the Operating Agent's cost and expense allocations between (i) electric generation and related functions and (ii) unrelated functions.

21.3.6 Advise and make recommendations to the Coordination Committee and Operating Agent on matters involving auditing and financial transactions.

21.3.7 Develop procedures for proper accounting and financial liaison between Participants in connection with the Operating Work and Capital Improvements.

21.3.8 Perform such functions and responsibilities as may be assigned to it from time to time by the Coordination Committee or as otherwise provided in this Agreement.

21.4 Any action or determination of the Auditing Committee shall require a vote of the voting Participants in accordance with Section 18.4.1. A Participant's Auditing Committee representative shall be entitled to vote on all matters except those actions or determinations which relate solely to a Unit or common property in which such Participant does not have a Participation Share except that if a Participant's right to vote has been suspended pursuant to Section 35.4.1, the requisite majority for actions or determinations specified in Section 18.4.1 shall be adjusted in proportion to the number of Participants whose right to vote has not been suspended. An example of such an adjustment is provided in Exhibit VIII.

21.5 The Auditing Committee shall keep written minutes and records of all meetings, and any action or determination by the Auditing Committee shall be reduced to writing and shall become effective when signed by the representatives of the Participants entitled to vote thereon, representing a voting majority of the members of the Auditing Committee. Auditing Committee representatives may, by prior arrangement with the chairperson of the Auditing Committee, attend a meeting of the Auditing Committee by conference call or video conferencing. An Audit Committee representative who is unable to attend a meeting of the Audit Committee may vote in absentia by delivering to the chairperson of the Audit Committee, at least twenty-four (24) hours prior to the scheduled commencement of the meeting, a written statement, including by e-mail or facsimile, identifying the matter to be voted on and how the representative desires to vote.

21.6 In the event less than a requisite majority of the Auditing Committee is obtained, the matter shall be referred to the Coordination Committee for decision upon the request of any Participant's Auditing Committee representative.

21.7 In the event the Auditing Committee fails to reach agreement on a matter which such committee is authorized to determine, approve or otherwise act upon after a reasonable opportunity to do so, then the Operating Agent shall be authorized and obligated to take such reasonable and prudent action, consistent with Prudent Utility Practice, as is necessary to the successful and proper operation and maintenance of the San Juan Project, pending the resolution, by arbitration or otherwise, of any such inability or failure to agree.

PART V

BUDGETS AND OPERATING EXPENSES

22.0 OPERATION AND MAINTENANCE EXPENSES:

22.1 The expenses for the operation and maintenance of the San Juan Project in the performance of Operating Work (which, for purposes of this Section 22, and as defined more particularly herein, are referred to as the "O&M Expenses") shall be apportioned among the Participants, in accordance with the following percentages:

22.1.1 For Units 1 and 2 and for all equipment and facilities directly related to Units 1 and 2 only, in accordance with the following percentages:

22.1.1.1 PNM - 50 percent
22.1.1.2 TEP - 50 percent
22.1.1.3 M-S-R - 0 percent
22.1.1.4 Farmington - 0 percent
22.1.1.5 Tri-State - 0 percent
22.1.1.6 LAC - 0 percent
22.1.1.7 SCPPA - 0 percent
22.1.1.8 Anaheim - 0 percent
22.1.1.9 UAMPS - 0 percent

22.1.2 For Unit 3 and all equipment and facilities directly related to Unit 3 only, in accordance with the following percentages:

22.1.2.1 PNM - 50 percent
22.1.2.2 TEP - 0 percent
22.1.2.3 M-S-R - 0 percent
22.1.2.4 Farmington - 0 percent
22.1.2.5 Tri-State - 8.2 percent
22.1.2.6 LAC - 0 percent
22.1.2.7 SCPPA - 41.8 percent
22.1.2.8 Anaheim - 0 percent
22.1.2.9 UAMPS - 0 percent

22.1.3 For Unit 4 and for all equipment and facilities directly related to Unit 4 only, in accordance with the following percentages:

22.1.3.1	PNM - 38.457 percent
22.1.3.2	TEP - 0 percent
22.1.3.3	M-S-R - 28.8 percent
22.1.3.4	Farmington - 8.475 percent
22.1.3.5	Tri-State - 0 percent
22.1.3.6	LAC - 7.20 percent
22.1.3.7	SCPPA - 0 percent
22.1.3.8	Anaheim - 10.04 percent
22.1.3.9	UAMPS - 7.028 percent

22.1.4 For equipment and facilities common to Units 1 and 2 only, in accordance with the following percentages:

22.1.4.1	PNM - 50 percent
22.1.4.2	TEP - 50 percent
22.1.4.3	M-S-R - 0 percent
22.1.4.4	Farmington - 0 percent
22.1.4.5	Tri-State - 0 percent
22.1.4.6	LAC - 0 percent
22.1.4.7	SCPPA - 0 percent
22.1.4.8	Anaheim - 0 percent
22.1.4.9	UAMPS - 0 percent

22.1.5 For equipment and facilities common to Units 3 and 4 only, in accordance with the following percentages:

22.1.5.1	PNM - 44.119 percent
22.1.5.2	TEP - 0 percent
22.1.5.3	M-S-R - 14.4 percent
22.1.5.4	Farmington - 4.249 percent
22.1.5.5	Tri-State - 4.1 percent
22.1.5.6	LAC - 3.612 percent
22.1.5.7	SCPPA - 20.9 percent
22.1.5.8	Anaheim - 5.07 percent
22.1.5.9	UAMPS - 3.55 percent

22.1.6 For the Switchyard Facilities except as otherwise provided in Section 15, in accordance with the following percentages:

22.1.6.1	PNM - 65 percent
22.1.6.2	TEP - 35 percent
22.1.6.3	M-S-R - 0 percent
22.1.6.4	Farmington - 0 percent

22.1.6.5	Tri-State - 0 percent
22.1.6.6	LAC - 0 percent
22.1.6.7	SCPPA - 0 percent
22.1.6.8	Anaheim - 0 percent
22.1.6.9	UAMPS - 0 percent

22.1.7 Except as provided in Exhibit V(g), attached hereto and incorporated herein, for equipment and facilities common to all of the Units, and all San Juan Project expenses not identifiable by Unit and not otherwise listed above, in accordance with the following percentages:

22.1.7.1	PNM - 46.297 percent
22.1.7.2	TEP - 19.8 percent
22.1.7.3	M-S-R - 8.7 percent
22.1.7.4	Farmington - 2.559 percent
22.1.7.5	Tri-State - 2.49 percent
22.1.7.6	LAC - 2.175 percent
22.1.7.7	SCPPA - 12.71 percent
22.1.7.8	Anaheim - 3.10 percent
22.1.7.9	UAMPS - 2.169 percent

22.1.8 In the event of a permanent shutdown of either of Unit 1 or Unit 2, the expenses incurred in connection with the shutdown (which may include removal, salvage, cleanup and protection service) shall be allocated as set forth in Section 22.1.1. In the event of a permanent shutdown of Unit 3, said expenses shall be allocated as set forth in Section 22.1.2. In the event of a permanent shutdown of Unit 4, said expenses shall be allocated as set forth in Section 22.1.3. Expenses which are attributable to equipment and facilities common to more than one Unit shall be apportioned in accordance with Section 22.1, as applicable.

22.1.9 Exhibit V, attached hereto and incorporated herein, is a partial list of equipment and facilities of the San Juan Project for use by the Engineering and

Operating Committee as a guideline in determining the allocation of operation and maintenance costs among the Participants.

22.1.10 In areas where the allocation of costs of operation and maintenance of equipment and facilities among the Participants is not clearly defined by Sections 22.1.1 to 22.1.8, the Engineering and Operating Committee shall make a determination of such allocation of costs.

22.1.11 The following shall apply in the event of a declaration of default against a Participant and a suspension of that Participant's right to receive all or any part of its proportionate share of the Net Effective Generating Capacity, as provided for in Section 35.4.1: those non-defaulting Participant(s) having a Participation Share in each affected Unit, who are entitled to schedule and receive for their accounts proportionate shares of the Net Effective Generating Capacity of the defaulting Participant, shall bear proportionate shares of the defaulting Participant's responsibility for expenses of the operation and maintenance of the San Juan Project, as provided in Section 35.5.

22.2 O&M Expenses chargeable to the following FERC Accounts shall be apportioned among the Participants in accordance with Sections 22.1.1, 22.1.2, 22.1.3, 22.1.4, 22.1.5 and 22.1.7, as applicable:

22.2.1 Power Production/Steam Power Generation: FERC Accounts 500, 502, 505, 506, 507, 509 and 510 through 514 (charged by on-site San Juan Project employees and operations-related departments located off-site); provided, however, that limestone costs (chemicals) chargeable to FERC Account 502 shall be apportioned among the Participants in accordance with Section 23.5.

22.2.2 Administrative and General Expenses directly chargeable to FERC Accounts 920, 921, 923, 926, 930.2, 931 and 935, by on-site San Juan Project employees and by A&G related departments located off-site as set forth in Exhibit VI, Attachment A, which have not been included as a part of the A&G Ratio or charged to FERC Account 935, in accordance with Section 22.4. Such direct A&G charges must be supported by the Operating Agent and are subject to audit and approval by the Auditing Committee. If the Auditing Committee is unable to agree on the appropriateness of direct A&G charges, the Auditing Committee shall submit the entire matter to the Coordination Committee.

22.2.3 O&M Expenses chargeable to FERC Account 501 shall be apportioned among the Participants in accordance with Section 23.

22.2.4 The cost of the property insurance for the San Juan Project chargeable to FERC Account 924 and any uninsured loss or expense thereunder and the cost of general liability or workers' compensation insurance for the San Juan Project chargeable to FERC Account 925 shall be apportioned among the Participants according to Section 22.1.

22.2.5 Costs or revenues chargeable to the following FERC Operating and Non-Operating Accounts: 411.8, 411.9, 412, 421 and 426.

22.3 Power Production Expense chargeable to FERC Account 500 (for employees of PNM's fuels management department), Non San Juan Project Specific, shall be allocated among all of PNM's fossil-fueled power plants, including the San Juan Project, based on the percentage of labor charged to each fossil-fueled power plant as a percentage of labor charged to all of PNM's fossil-fueled power plants.

22.4 The O&M Expenses for the Switchyard Facilities chargeable to FERC Accounts 560 through 573 and FERC Account 935 shall be apportioned among the Participants in accordance with Section 22.1.6.

22.5 The O&M Expenses for the portion of system control and load dispatching expenses (allocated between PNM and the San Juan Project based on the number of megawatts of San Juan Project capacity as a percentage of PNM's total generating capacity) chargeable to FERC Accounts 556, 560 and 561 shall be apportioned among the Participants in accordance with Section 22.1.7.

22.6 Payroll loads for administrative and general expenses, payroll taxes, injuries and damages and pension and benefits, shall be added to the monthly billings in proportion to the dollars of direct labor billed and apportioned among the Participants in accordance with Sections 22 and 23. The current methodologies for calculating the A&G Ratio, Payroll Tax Ratio, Injuries and Damages Ratio and Pension and Benefits Ratio are set forth in Exhibit VI (Attachments A, B, C and D thereto), attached hereto and incorporated herein.

22.6.1 If any Participant believes that the method used in determining A&G Ratio, Payroll Tax Ratio, Injuries and Damages Ratio and Pension and Benefits Ratio, in accordance with Exhibit VI (Attachments A, B, C and D thereto), results in an unreasonable burden on such Participant(s), such Participant(s) may request that said method used in determining said ratios be submitted to the Auditing Committee for review. After any such request, the Auditing Committee shall review said method and shall endeavor to agree upon whether or not said unreasonable burden does actually exist. If, after such review, the Auditing Committee determines that the application of said method does result in an unreasonable burden on the Participant, the Auditing Committee shall determine and recommend a modified method to the Coordination Committee to eliminate such unreasonable burden. If, after such review, the Auditing Committee is unable to agree upon whether or not such unreasonable burden does exist or is unable to agree on a modified method for eliminating said unreasonable burden, the Auditing Committee shall submit the entire matter to the Coordination Committee.

22.6.2 The Coordination Committee shall review the recommendation of the Auditing Committee pursuant to Section 22.6.1. If, as a result of such review, the Coordination Committee agrees that such unreasonable burden does exist and that a modified method eliminates such unreasonable burden, the Coordination Committee shall adopt said modified method.

22.6.3 If the Auditing Committee has not submitted a recommended modified method and the Coordination Committee agrees that such unreasonable burden does exist, the Coordination Committee shall endeavor to agree on a modified method. If, after such review, the Coordination Committee is unable to agree that such unreasonable burden does exist or on a modified method which will eliminate such unreasonable burden, upon request of a Participant, either matter may be submitted to arbitration pursuant to Section 37.

22.6.4 Any modified method adopted by the Coordination Committee or determined through arbitration shall be retroactive for the length of the period of inequity up to a maximum period of three (3) years and shall become effective on the first day following such date of adoption.

22.7 As soon as possible after the end of each calendar year, the Operating Agent shall calculate the actual ratios for: A&G, payroll tax, injuries and damages, and pension and benefits for such year in accordance with the methodologies described in Exhibit VI (Attachments A, B, C and D thereto). To the extent such expenses are more or less than those already paid by the Participants during said year, the Operating Agent shall bill or credit the Participants for the amount of such difference.

22.8 At the start of each calendar year, the Operating Agent shall calculate new ratios for: A&G, payroll tax, injuries and damages and pension and benefits. Such ratios shall be calculated in accordance with the methodologies described in Exhibit VI (Attachments A, B, C and D thereto). Such ratios may be adjusted to more nearly reflect the anticipated expenses of the current year because of tax legislation, labor contract negotiations or other factors not reflected in the prior year's costs.

22.9 The Operating Agent shall bill to the requesting Participant(s) the costs and expenses, including A&G expenses, incurred by the Operating Agent (including, but not limited to, fees of outside legal counsel or consultants, time of in-house legal counsel and other employees and agents of the Operating Agent) in performing tasks requested by a Participant in relation to (i) the offering or sale of bonds or other type of security by a Participant in connection with the acquisition or ownership of an interest in the San Juan Project; and (ii) the attempted or contemplated sale by a Participant of any portion of its ownership interest in the San Juan Project. The Operating Agent shall establish and maintain appropriate accounting procedures to identify such costs and expenses incurred by the Operating Agent.

23.0 FUEL COSTS:

23.1 The quantity of coal delivered to the San Juan Project shall be determined by the belt scales, in accordance with the Underground Coal Sales Agreement.

23.2 The Operating Agent shall maintain the Project Coal Inventory wherein ownership shall be apportioned among the Participants based on Common Participation Share. Coal inventory shall be accounted for in FERC Account 151.

23.3 All Participants acknowledge and recognize the terms and conditions of the Underground Coal Sales Agreement which was entered into by PNM and TEP on behalf of the Participants. Exhibit VII, attached hereto and incorporated herein, contains example "Interim Invoices", "UG-CSA Invoices", and "UPS Invoices" prepared and defined pursuant to Section 8 of the Underground Coal Sales Agreement.

23.4 Monthly costs of the Project Coal Inventory and fuel expense shall be apportioned among and paid for by the Participants on the following basis:

23.4.1 UG-CSA Invoicing Allocations

In the event that UG-CSA Invoices are rendered and payable pursuant to Section 8.7 (A) of the Underground Coal Sales Agreement, amounts due thereunder shall be allocated and paid for by the Participants as Fixed Fuel Expense and Variable Fuel Expense as described in: Exhibit IX, Fixed Fuel Expense; and Exhibit X, Variable Fuel Expense and as provided below:

23.4.1.1 Costs that are classified as Fixed Fuel Expense shall be charged to FERC Account 501, or to such FERC Account number as may be applicable in the future if fuel deliveries terminate, and shall be apportioned among and paid for by the Participants in accordance with Common Participation Share.

23.4.1.2 Costs that are classified as Variable Fuel Expense shall be charged to FERC Account 151 and such costs shall be apportioned among and paid for by the Participants on the basis of Common Participation Share. Monthly cost for coal withdrawn from Project Coal Inventory (equivalent to total monthly Participant Coal Consumption) shall be credited to FERC Account 151 and charged to FERC Account 501 on an average price basis as determined by dividing the total number of tons of coal in Project Coal Inventory at the beginning of the month, plus the coal delivered during the month, into the total recorded cost in FERC Account 151 and multiplying the cost per ton so derived by the number of tons withdrawn. The cost for coal withdrawn charged to FERC Account 501 shall be apportioned among and paid for by the Participants on the basis of the percentage that each Participant's monthly Participant Coal Consumption bears to the total monthly Participant Coal Consumption of all Units. The cost for coal withdrawn thusly credited to FERC Account 151 shall be apportioned among the Participants on the basis of Common Participation Share.

23.4.1.3 Any other Total Monthly Coal Cost not currently classified in Exhibits IX or X as Fixed Fuel Expense or Variable Fuel Expense shall be deemed to be Fixed Expense until reclassified by the Coordination Committee.

23.4.2 Interim Invoicing Allocations

In the event that Interim Invoices are rendered and payable pursuant to Section 8.7 (B) of the Underground Coal Sales Agreement, such costs shall be allocated and invoiced to the Participants as described below.

23.4.2.1 The Base Price ("Base Price") band shall be based on the Minimum Annual Tons. The annual allocation of the coal tonnage in the Base Price band shall be made among the Participants on the basis of Common Participation Share. The monthly allocation of the coal tonnage in the Base Price band shall be made among the Participants on the basis of each Participant's share of Monthly Minimum Tons. The cost of the monthly Base Price band will be allocated among and paid for by the Participants by multiplying each Participant's share of Monthly Minimum Tons by the Base Price.

23.4.2.2 The Incremental Price ("Incremental Price") band(s) shall be based on (an) annualized band(s) of tons of coal delivered in excess of Minimum Annual Tons. The cost of the monthly Incremental Price band(s) will be allocated among and paid for by the Participants by multiplying each Participant's consumption of Incremental Price band coal(s) by the Incremental Price for such band(s). Participants shall only be eligible for allocation of Incremental Price band coal pricing if their monthly Participant Coal Consumption exceeds their share of Monthly Minimum Tons.

23.4.2.3 At the end of each year, the Operating Agent shall reconcile the sum of each Participant's monthly Interim Invoice-related payments to a properly allocable share of Base Price band tons, Incremental Price band or bands tons, and cost associated with any change in Project Coal Inventory and invoice or refund any such reconciliation amounts to each Participant. This reconciliation will be exclusive of any year-end true up required pursuant to Section 23.4.2.6.

23.4.2.4 In the year-end reconciliation process of Section 23.4.2.3, any amount credited by SJCC for tons invoiced but not delivered shall be credited to FERC Account 501 and apportioned to the Participants on the basis of the percentage that each Participant's annual Incremental Price Band(s) consumption bears to the total annual Incremental Price Band(s) consumption for all Units. Any net consumption of Project Coal Inventory tons shall be charged to FERC Account 501 and apportioned among and paid for by the Participants on the basis of the percentage that each Participant's annual Incremental Price Band(s) consumption bears to the total annual Incremental Price Band(s) consumption for all Units. The price for such tons shall be determined by dividing the total recorded cost in FERC Account 151 by the total number of tons of coal in Project Coal Inventory, both as recorded on January 1 of said year. The total amount of any such payment for consumed Project Coal Inventory tons shall subsequently be credited to FERC Account 151 and apportioned to the Participants based on Common Participation Share.

In the year-end reconciliation process of Section 23.4.2.3, the costs of any net addition to Project Coal Inventory tons, as invoiced by SJCC, shall be charged to FERC Account 151 and apportioned to and paid for by the Participants based on Common Participation Share.

23.4.2.5 If, at the end of any year, the Operating Agent has collected amounts in excess of those due SJCC pursuant to Section 8.7(B) of the Underground Coal Sales Agreement, but not including any year-end true up required pursuant to Section 23.4.2.6, such over-collection shall be refunded to the Participants. The refund to each Participant shall be an amount equal to the total amount of the over-collection multiplied by the tons each Participant's Coal Consumption was less than its total annual Monthly Minimum Tons divided by the total amount by which all such Participants' Coal Consumption was less than their shares of Minimum Annual Tons.

23.4.2.6 The Interim Invoices shall be annually reconciled to invoices prepared pursuant to Section 8.7(A) of the Underground Coal Sales Agreement. Any adjustment required by this reconciliation, in accordance with Section 8.7(B) of the Underground Coal Sales Agreement, will be passed through to the Participants as correcting invoices and will be apportioned among and paid for by, or credited to, the Participants on the basis of Common Participation Share.

23.4.2.7 Monthly UPS payments shall be apportioned among and paid for by the Participants on the basis of Common Participation Share

23.4.2.8 Any other component of Total Monthly Coal Cost which is not classified as Base Price or Incremental Price shall be apportioned among and paid for by the Participants on the basis of Common Participation Share unless otherwise annually approved by the Fuels Committee.

23.4.2.9 If during any year, payable Interim Invoices cease to be rendered by SJCC pursuant to Section 8.7(B) of the Underground Coal Sales Agreement, the Participants acknowledge and recognize that Interim Invoicing cannot be in effect for a partial year, and that all allocations of Total Monthly Coal Costs for the year shall then be made pursuant to Section 23.4.1. Amounts previously allocated to the Participants pursuant to Section 23.4.2 in the effected year shall be reallocated pursuant to the provisions of Section 23.4.1.

23.4.2.10 The Fuels Committee may terminate allocation of costs to the Participants pursuant to Section 23.4.2 despite the continued receipt of payable Interim Invoices from SJCC, if the Fuels Committee determines that coal cost allocation pursuant to Section 23.4.1 better serves the interests of the San Juan Project. Such termination may only be made upon action of the Fuels Committee pursuant to Section 20.5. In the event of such termination, costs shall continue to be apportioned to and paid for by the

Participants pursuant to Section 23.4.2. However, for information purposes, the Operating Agent shall also provide cost allocations to the Participants pursuant to Section 23.4.1. At the end of such year, the amounts paid by the Participants shall be reconciled to those amounts allocated pursuant to Section 23.4.1 for each month of the affected year (Section 23.4.1 allocations being determinative) and the Operating Agent shall invoice or refund any such reconciliation amounts to each Participant.

23.5 Limestone costs (chemicals) chargeable to FERC Account 502 shall be apportioned among and paid for by the Participants on the basis of the percentage that each Participant's monthly Participant Coal Consumption bears to the total monthly Participant Coal Consumption of all Units.

23.6 All other fuel-related expenses which are chargeable to FERC Account 501 shall be apportioned among and paid for by the Participants on the following basis:

23.6.1 Variable fuel-related expenses (including, but not limited to ash and gypsum disposal) on the basis of the percentage that each Participant's monthly Participant Coal Consumption bears to the total monthly Participant Coal Consumption of all Units.

23.6.2 Fixed fuel-related expenses (including, but not limited to fuel handling) on the basis of Common Participation Share.

23.6.3 Fuel oil purchased for use at the San Juan Project is first delivered into one of two storage tanks. Tank 1 and 2 storage tank feeds Units 1 and 2 and Tank 3 and 4 storage tank feeds Units 3 and 4. When oil is withdrawn from a storage tank for consumption, it is metered by Unit. Costs for fuel oil usage shall be separately accounted for by these two storage tanks as follows:

23.6.3.1 Costs for fuel oil purchases to Tank 1 and 2 shall be charged to FERC Account 151 and such costs shall be apportioned among and paid for by the Units 1 and 2 Participants on the basis of Section 6.2.4. Monthly cost for fuel oil withdrawn from Tank 1 and 2 shall be credited to FERC Account 151 and charged to FERC Account 501 on an average price basis as determined by dividing the total number of gallons of fuel oil in Tank 1 and 2 at the beginning of the month, plus the fuel oil delivered during the month, into the total recorded cost in FERC Account 151 and multiplying the cost per gallon so derived by the number of gallons withdrawn from Tank 1 and 2. The cost for fuel oil withdrawn from Tank 1 and 2 charged to FERC Account 501 shall be apportioned among and paid for by the Units 1 and 2 Participants first on the basis of the individual Unit metered consumption and then on the basis of Section 6.2.1. The cost for fuel oil withdrawn from Tank 1 and 2 thusly credited to FERC Account 151 shall be apportioned among the Units 1 and 2 Participants on the basis of Section 6.2.4.

23.6.3.2 Costs for fuel oil purchases to Tank 3 and 4 shall be charged to FERC Account 151 and such costs shall be apportioned among and paid for by the Units 3 and 4 Participants on the basis of Section 6.2.5.

Monthly cost for fuel oil withdrawn from Tank 3 and 4 shall be credited to FERC Account 151 and charged to FERC Account 501 on an average price basis as determined by dividing the total number of gallons of fuel oil in Tank 3 and 4 at the beginning of the month, plus the fuel oil delivered during the month, into the total recorded cost in FERC Account 151 and multiplying the cost per gallon so derived by the number of gallons withdrawn from Tank 3 and 4. The cost for fuel oil withdrawn from Tank 3 and 4 charged to FERC Account 501 shall be apportioned among and paid for by the Units 3 and 4 Participants first on the basis of the individual Unit metered consumption and then on the basis of Section 6.2.2 or Section 6.2.3, as applicable. The cost for fuel oil withdrawn from Tank 3 and 4 thusly credited to FERC Account 151 shall be apportioned among the Units 3 and 4 Participants on the basis of Section 6.2.5.

23.7 The Operating Agent shall provide the Participants a monthly written report on the following items related to coal deliveries at the San Juan Project:

23.7.1 Minimum Annual Tons for the year.

23.7.2 Minimum Annual Tons allocated among the Participants.

23.7.3 Total actual coal deliveries by SJCC to the San Juan Project for each month and for the year to date.

23.7.4 Total actual coal deliveries to the San Juan Project for each month and for the year to date, allocated to the Participants.

23.7.5 Total cost and tonnage of inventory allocated to the Participants.

23.7.6 Fixed Fuel Expense and Variable Fuel Expense totals as allocated to each Participant for each month and for the year to date if UG-CSA Invoicing is, or will be, required for said year pursuant to Section 23.4.1.

23.8 The Operating Agent shall work diligently with SJCC under the terms of the Underground Coal Sales Agreement to manage Project Coal Inventory so as to maintain the Emergency Coal Storage Pile at target levels pursuant to Section 20.3.6 and to maintain appropriate working levels of Project Coal Inventory to facilitate San Juan Project Operations.

23.9 In the event that SJCC defaults in its obligations under the Underground Coal Sales Agreement or otherwise fails to maintain deliveries of coal, the Operating Agent may assume or make such arrangements for the assumption of such of SJCC's operations as permitted by the Underground Coal Sales Agreement or may procure, subject to the Underground Coal Sales Agreement, an alternate coal supply. Costs associated with such assumed coal operations or the procurement and supply of alternate coal shall be deemed a part of Total Monthly Coal Cost and, with the costs and expenses of fuel and emission residuals (gypsum) and ash disposal, shall be apportioned between and paid for by the Participants in accordance with: (i) Section 23.4.1 with regard to coal costs; and (ii) Section 23.6.1 with regard to fuel-related costs.

23.10 The monthly costs of fuel allocated among the Participants in accordance with this Section 23 shall be estimated by the Operating Agent as soon as practicable after the end of each month and a preliminary bill shall be presented and paid in the manner set forth in Section 30.3.3. Adjustments and corrections to the estimated preliminary bill shall be made in the next succeeding month or on the earliest possible billing thereafter.

23.11 In the event of a catastrophic occurrence which results in a sustained outage of a Unit and a determination that an "Uncontrollable Force" exists under the Underground Coal Sales Agreement, then in such event, FERC Account 151 will be allocated to the operable and non-operable Units. The portion of FERC Account 151 allocated to the non-operable Unit(s) shall remain frozen until such time as such Unit(s) is restored to operable condition. New costs of coal chargeable to FERC Account 151 will be apportioned among the Participants on the basis of the Participants' Participation Shares in the generating capacity of the operable Units. At such time as a damaged Unit is restored to operable condition, the frozen portion of Account 151 will be merged into the operable unit(s) portion of Account 151 and to the extent that a Participant is adversely impacted by an incremental increase in the average unit cost of coal an allocation of such incremental cost will be made and the net difference paid by the Participant having a credit balance.

23.12 The accounting practices and billing and accounting principles as stated in this Section 23 are applicable at the present time. If, however, at a later time these practices or principles are proven to be inadequate or other practices or principles later prove to be more equitable in the opinion of the Auditing Committee, the Coordination Committee, upon the recommendation of the Auditing Committee, may authorize changes and revisions to such practices and principles.

23.13 Any other fuel-related costs not currently classified in this Section 23 shall be apportioned among and paid for by the Participants on the basis of the percentage that each Participant's monthly Participant Coal Consumption bears to the total monthly Participant Coal Consumption of all Units until classified by the Coordination Committee.

24.0 ANNUAL BUDGETS:

24.1 Not less than ninety (90) days prior to the beginning of each calendar year, the Operating Agent shall prepare and submit to the Engineering and Operating Committee for its review and approval the proposed capital budget, manpower budget and a budget for the performance of Operating Work for such calendar year.

24.2 The Engineering and Operating Committee shall approve the budgets described in Section 24.1 in final form not less than thirty (30) days prior to their effective date. In the event that any such budget is not so approved, the Operating Agent will nevertheless continue to perform Operating Work in a manner consistent with Prudent Utility Practice until such time as a budget has been approved.

24.3 Any information required from the Participants by the Operating Agent in preparing such proposed budgets will be supplied by the Participants, if possible, within thirty (30) days following a request by the Operating Agent.

24.4 The Engineering and Operating Committee may at any time during the year approve revisions to the approved capital expenditures budget, manpower budget and a budget for the performance of Operating Work.

25.0 PAYMENT OF TAXES:

25.1 The Participants shall use their best efforts to have any taxing authority imposing any taxes or assessments on the San Juan Project, assess and levy such taxes or assessments directly against each Participant in accordance with its respective Participation Share in the property taxed.

25.2 All taxes or assessments levied against each Participant's ownership interest in the San Juan Project, excepting those taxes or assessments levied against an individual Participant on behalf of other Participants, shall be the sole responsibility of the Participant upon whom said taxes and assessments are levied.

25.3 If any property taxes and other taxes and assessments are levied and assessed in a manner other than specified in Section 25.1, it shall be the responsibility of the Coordination Committee to establish equitable standard practices and procedures for the apportionment among the Participants of such taxes and assessments and the payment thereof.

26.0 MATERIALS AND SUPPLIES:

26.1 The Operating Agent from time to time may increase or reduce the inventory of Materials and Supplies by changing the maximum or the minimum quantities to be maintained in inventory in accordance with the procedures established by the Engineering and Operating Committee.

26.2 The Operating Agent shall prepare a list of the items for inclusion in Materials and Supplies for the operation and maintenance of each Unit. The list shall include the estimated cost of each individual item of such Materials and Supplies and specify the maximum and minimum quantity of each such individual item to be maintained in inventory. The list shall be submitted to the Engineering and Operating Committee by the Operating Agent for review and approval.

26.3 The Operating Agent shall purchase and take control of Materials and Supplies for inventory, so that the total inventory of Materials and Supplies on hand remains in accordance with the policies established by the Engineering and Operating Committee.

26.4 Materials and Supplies withdrawn from inventory and used in the operation and maintenance of the San Juan Project shall be accounted for as a component of operation and maintenance expense and allocated among the Participants in accordance with Section 22.

26.5 Materials and Supplies withdrawn from inventory and used in connection with Capital Improvements shall be accounted for as a capital expenditure and allocated among the Participants in accordance with Section 7.

26.6 Materials and Supplies removed from service shall be returned to inventory if reusable, or if junk or obsolete, shall be disposed of by the Operating Agent under the best available terms. The proceeds, if any, received shall be credited or distributed to the Participants in the same proportion as their Participation Shares therein.

26.7 A separate Materials and Supplies account and undistributed stores expense account will be established by the Operating Agent in accordance with FERC Accounts. Such charges and credits so allocated to Materials and Supplies shall be allocated to the Participants as a component of operation and maintenance expense in accordance with Section 22, or as a Capital Improvement in accordance with Section 7, as the case may be.

26.8 The inventory value of any item withdrawn from or returned to Materials and Supplies shall be the average cost of like items in inventory.

27.0 EMERGENCY SPARE PARTS:

27.1 The Operating Agent shall prepare a list of the Emergency Spare Parts for each Unit and common facilities. Such list shall include the estimated costs for each individual item of such Emergency Spare Parts and shall specify the quantity of each such individual item to be maintained in inventory. Such list shall be submitted to the Engineering and Operating Committee by the Operating Agent for review and approval.

27.2 The Operating Agent shall purchase Emergency Spare Parts from time to time as replacements for those withdrawn from inventory in accordance with the policies established by the Engineering and Operating Committee.

27.3 Emergency Spare Parts shall be owned by and the costs thereof shall be allocated between the Participants in accordance with their respective Participation Shares.

27.4 The Operating Agent shall notify the Participants promptly after Emergency Spare Parts are withdrawn from inventory and shall also notify the Participants of the value of such parts so withdrawn and of the accounting treatment with respect thereto.

PART VI

OPERATING AGENT

28.0 OPERATION AND MAINTENANCE:

28.1 PNM is the Operating Agent, unless replaced in accordance with Section 33.

28.2 All Participants hereby appoint PNM as their agent, and PNM agrees to undertake, as the agent of the Participants and as principal on its own behalf, the responsibility for the performance of Operating Work in accordance with this Agreement.

28.3 Subject to the provisions, conditions, limitations and restrictions of this Agreement, the Operating Agent shall:

28.3.1 Perform the Operating Work in accordance with the Project Agreements and Prudent Utility Practice.

28.3.2 Contract for, furnish or obtain the services and studies necessary for performance of Operating Work.

28.3.3 Arrange for the placement and maintenance of Operating Insurance.

28.3.4 Execute all contracts in the name of the Operating Agent, acting as principal on its own behalf and as agent for the Participants, in connection with the performance of Operating Work.

28.3.5 Furnish and train the necessary personnel for performance of Operating Work.

28.3.6 Have the coal replaced which has been removed from the Emergency Coal Storage Pile at the earliest practical time following resumption of normal coal deliveries.

28.3.7 Enforce and comply with all contracts entered into for the performance of Operating Work.

28.3.8 Comply with any and all laws and regulations applicable to the performance of Operating Work.

28.3.9 Maintain the Operating Account and expend the Operating Funds only in accordance with this Agreement.

28.3.10 Keep and maintain records of monies expended and received, obligations incurred, credits accrued and contracts entered into in the performance of this Agreement, and make such records available for inspection by the Participants at reasonable times and places.

28.3.11 Not suffer any liens to remain in effect unsatisfied against the San Juan Project (other than the liens permitted under Section 10.1, for taxes or assessments not yet delinquent, for labor and material not yet delinquent or undetermined charges or liens incidental to the performance of Operating Work); provided, that the Operating Agent shall not be required to pay or discharge any such lien as long as a proceeding shall be pending in which the lawfulness or validity of such lien shall be contested in good faith and which shall operate during the pendency thereof to prevent the collection or enforcement of such lien so contested.

28.3.12 Recommend minimum notification times and lead times for changing scheduled Energy required for the Participants to the Engineering and Operating Committee for its approval.

28.3.13 Act as operating representative or agent in connection with the administration and enforcement of the Underground Coal Sales Agreement.

28.3.14 Recommend programs to the Engineering and Operating Committee to make environmental studies and, upon approval of the Engineering and Operating Committee, supervise the performance of such programs.

28.3.15 Provide the Engineering and Operating Committee with all written statistical and administrative reports, written budgets, information and other records relating to Operating Work which may be necessary to permit such committee to perform its responsibilities under this Agreement.

28.3.16 Provide the Fuels Committee with all written reports, written budgets, information and other records relating to Operating Work which may be necessary to permit such committee to perform its responsibilities under this Agreement.

28.3.17 Provide the Auditing Committee with all accounting records, information, reports and other records relating to Operating Work, which may be necessary to permit such committee to perform its responsibilities under this Agreement.

28.3.18 Perform Operating Work so as to comply with the Water Contract(s) and make such tests and measurements and keep such records as are required by applicable agreements, regulations and statutes.

28.3.19 Keep the Participants fully and promptly advised of material changes in conditions or other material developments affecting the performance of Operating Work and furnish the Participants with copies of any notices given or received pursuant to the Project Agreements.

28.3.20 Present claims to any insurer for losses and damages covered by valid and collectible Operating Insurance procured by the Operating Agent directly from the insurer. Investigate, adjust, settle, decline and defend claims against the Participants arising out of the performance of Operating Work when said claims or portions thereof are not covered by valid and collectible Operating Insurance; provided that the Operating Agent shall obtain the agreement of the Participants, acting through the Coordination Committee, prior to disposing of any claims or combination of claims arising out of the same occurrence which exceeds one hundred thousand dollars ($100,000).

28.3.21 Assist, as requested, other Participants and their insurers in the investigation, adjustment and settlement of any loss or claim arising out of Operating Work for which payment may be made on account of valid and collectible additional insurance applicable thereto procured by any such Participant; provided, that the Operating Agent may agree (by separate agreement) that a Participant procuring any policy or policies of additional insurance shall have the authority and the responsibility to (i) present, investigate, adjust, settle, decline and defend claims or potential claims covered by said policies in favor of the Participants and against any one or more of said insurers; and (ii) present, investigate, adjust, settle, decline and defend claims against the Participants arising out of the performance of Operating Work when said claims or portions thereof are not covered by said policies; and provided further, that such Participant shall obtain the agreement of the Participants, acting through the Coordination Committee, prior to the settlement of any claim or combination of claims arising out of the same occurrence which exceeds one hundred thousand dollars ($100,000).

28.3.22 Notwithstanding anything in Section 28.3.20 and 28.3.21 to the contrary, any Participant may at any time, at its own expense, employ its own counsel to assist in investigating, adjusting, settling, declining and defending claims of the types referred to in Sections 28.3.20 and 28.3.21 and the Operating Agent and its employees and counsel shall cooperate fully with such counsel and permit such counsel to participate fully in all of the foregoing activities.

28.3.23 Keep the Participants fully and promptly informed of any known default under the Project Agreements.

28.3.24 Determine switching and clearance procedures to be followed by the Participants at the San Juan Project.

28.3.25 Determine Available Operating Capacity from time to time and make recommendations to the Engineering and Operating Committee regarding items referenced in Section 19.3.1.9.

28.3.26 Upon the request of a Participant, provide such Participant, in reasonable quantity without direct charge therefor, a copy or copies of any report, record, list, budget, manual, accounting or billing summary, classification of accounts, or other documents or revisions of any of the foregoing items, all as prepared in accordance with this Agreement.

28.3.27 In the event of the failure of the Participants which are signatories to the Underground Coal Sales Agreement then in effect to reach agreement on a matter described in Sections 18.7 and 20.5.3, maintain a supply of coal to the San Juan Project, consistent with Prudent Utility Practice.

28.3.28 Manage the activities of the "designated representative" pursuant to the DR Agreement.

28.3.29 Perform all of the duties and obligations set out in this Agreement as duties and obligations of the Operating Agent.

28.4 The Participants shall lend and be properly reimbursed for all necessary and available assistance as may be requested by the Operating Agent in the performance of Operating Work.

28.5 The Operating Agent shall be the agent of the Participants and shall exercise only such authority as is conferred upon it by this Agreement. The Operating Agent shall not receive any fee or profit hereunder, unless otherwise agreed unanimously by the Participants.

29.0 OPERATING EMERGENCY:

29.1 In the event of an Operating Emergency, the Operating Agent shall take any and all steps reasonably necessary and required to terminate the Operating Emergency, subject to the provisions of this Section 29.

29.2 As soon as practicable after the commencement of an Operating Emergency, the Operating Agent shall advise the Participants of the occurrence of the Operating Emergency, its nature and the steps taken or to be taken to terminate the Operating Emergency, including a preliminary estimate of the expenditures required to terminate the Operating Emergency.

29.3 In the event that the estimated cost to cure an Operating Emergency with respect to any Unit or to any equipment and facilities common to any of the Units does not exceed two hundred and fifty thousand dollars ($250,000), the Operating Agent shall have the authority to expend, in its discretion, no more than two hundred and fifty thousand dollars ($250,000) to terminate such Operating Emergency.

29.4 In the event the Operating Agent determines that the estimated amount required to terminate the Operating Emergency exceeds the amount which it is authorized to expend, the Operating Agent shall immediately notify the affected Participants following such determination. The Operating Agent shall provide the following information:

29.4.1 The estimated date when the Operating Emergency can be terminated.

29.4.2 The person or persons who would perform the work and furnish the materials required to terminate the Operating Emergency.

29.4.3 The estimated amount of overtime, if any, which would be necessary in order to expedite the termination of the Operating Emergency.

29.4.4 The costs that are proposed to be capitalized, and salvage realized.

29.4.5 The costs that are proposed to be charged as maintenance expense.

29.4.6 The proposed administrative and general expense allowance applicable to such repair or reconstruction.

29.4.7 Such other information as may be necessary and required by the Engineering and Operating Committee to determine the manner in which the Operating Emergency is to be terminated.

29.5 The Engineering and Operating Committee shall review and approve the proposed repair or reconstruction, including the estimated cost thereof or shall agree upon an alternative.

29.6 Costs incurred in terminating an Operating Emergency may be billed to the Participants by the Operating Agent on the basis of its estimate of such costs with adjustment to be made in accordance with Section 29.8 when final cost determination has been made.

29.7 Following the termination of the Operating Emergency, the Operating Agent shall submit to the Participants a report containing a summary of the costs incurred and expenditures made in connection with the repair or reconstruction and such other information as may be required by the Engineering and Operating Committee.

29.8 The Operating Agent shall allocate to the Participants the costs incurred or expenditures made in such repair or reconstruction, as follows: (i) costs charged as maintenance expense, in accordance with Section 22; and (ii) any other such repair or reconstruction costs, in accordance with Section 7.

30.0 PAYMENT OF EXPENSES BY PARTICIPANTS:

30.1 All amounts required to be advanced by the Participants in accordance with this Agreement shall be made payable to the Operating Account established by the Operating Agent. The Operating Funds shall be owned by the Participants in proportion to their respective balances therein at any given time, and the Operating Agent in its capacity as such shall not have any right or title therein except to maintain custody of and to disburse the Operating Funds as a conduit between the Participants and those to whom such disbursements shall be made.

30.2 The Engineering and Operating Committee shall establish a minimum amount for the Operating Funds which will be available to pay for expenditures or obligations incurred by or on behalf of the Participants in accordance with this Agreement. Such minimum amount of Operating Funds may be revised by the Engineering and Operating Committee at any time. The minimum amount of the Operating Funds and any increases therein shall be advanced by the Participants in accordance with the percentages set forth in Section 22, and shall be due and payable within fifteen (15) business days following notification of the establishment of the minimum amount to be kept in Operating Funds or the date on which any increase in such amount authorized by the Engineering and Operating Committee shall become effective. In the event the Engineering and Operating Committee decreases such minimum amount, then each Participant shall receive a credit which shall be equal to the product of its percentage, as set forth in Section 22, and the amount of any such decrease.

30.3 Each Participant shall advance Operating Funds on the basis of notices (hereinafter called bills) submitted by the Operating Agent reflecting such Participant's share of costs and expenses in accordance with this Agreement, as follows:

30.3.1 Expenses described in Sections 30 and 22 shall be billed in writing as follows:

30.3.1.1 The payroll costs to be paid to the Operating Agent's employees for each pay period.

30.3.1.2 On the 20th day of each month, the total expenses incurred the previous month and described in Section 22 less those expenses billed under Section 30.3.1.1.

30.3.2 Bills submitted under Section 30.3.1 shall be due and payable within seven (7) business days following receipt of the bill.

30.3.3 Expenses described in Sections 31 and 23 shall be billed in writing at least ten (10) business days prior to their due date, and funds therefor shall be deposited with the Operating Agent not less than three (3) business days prior to their due date. If such bills do not have a specific due date, they shall be billed within a reasonable time following their incurrence.

30.3.4 Expenses described in Sections 7, 26, 27 and 29 shall be billed monthly, except when such expenses exceed the minimum amount in the Operating Funds in which case billing will be made immediately and payable within seven (7) business days following receipt of the bill.

30.4 Except as expressly provided herein, nothing in this Agreement shall be deemed to require the Operating Agent to advance its own monies on any other basis than in its role, if any, as a Participant.

31.0 OPERATING INSURANCE:

31.1 Unless otherwise specified by the Coordination Committee, during the performance of Operating Work, the Operating Agent shall procure and maintain in force, or cause to be procured and maintained in force, policies of Operating Insurance providing coverage against the following risks, hazards and perils:

31.1.1 Risks covered by the standard form of commercial liability insurance, including bodily injury, personal injury and property damage risk, hazards of automobiles liability, contractual liability, contractor's protective liability and liability for products and completed operations, in an amount not less than twenty-five million dollars ($25,000,000).

31.1.2 Risks covered by the standard form of "all risk" property insurance providing coverage against all risk of loss, except those risks excluded in the standard form of "all risk" property insurance. Such insurance shall provide boiler and pressure vessel coverage, including reasonable expediting expense.

31.1.3 Risks covered by the standard form of workers' compensation and employers liability insurance, covering employees of the Operating Agent engaged in the performance of Operating Work, or other compliance by the Operating Agent with requirements of the laws of the State of New Mexico as to such coverage.

31.1.4 Risks covered by the standard form of employee dishonesty bond covering loss of property or funds due to dishonest or fraudulent acts committed by an officer or employee of the Operating Agent.

31.2 Except for Operating Insurance described in Sections 31.1.3 and 31.1.4, each Participant shall be a named insured individually and jointly and in accordance with its

Participation Share as established in Section 6. Operating Insurance referred to in Section 31.1.1 shall carry cross-liability coverage.

31.3 In the event that another Participant's insurance program affords equal or better coverage on a more favorable cost basis than that available to the Operating Agent, the Participants may agree (by separate agreement) that such insurance program may be utilized to afford all or part of the insurance coverage required by Section 31.1.

31.4 The insurance company used, the insurable values, limits, deductibles, retentions and other special terms, covenants and conditions of the Operating Insurance shall be agreed upon by the Coordination Committee.

31.4.1 Any deductibles shall be shared by the Participants in accordance with the percentages established in Section 22.1.

31.5 The Operating Agent shall furnish each of the Participants with either a certified copy of each of the policies of Operating Insurance or a certified copy of each of the policy forms of Operating Insurance, together with a line sheet therefor (and any subsequent amendments) naming the insurers and underwriters and the extent of their participation. When the policies or policy forms of Operating Insurance have been approved in writing by all of the Participants, said policies or policy forms shall not be modified or changed by any Participant without the prior written consent of all of the Participants, except for minor and insubstantial changes or modifications, as to which notification shall be given by the Operating Agent to the Participants.

31.6 Each of the Operating Insurance policies shall be endorsed so as to provide that all named insureds shall be given thirty (30) days notice of cancellation or material change.

31.7 Operating Insurance policies shall be primary insurance for all purposes and shall be so endorsed. Any insurance carried by a Participant individually shall not participate with the Operating Insurance as respects any loss or claim for which valid and collectible Operating Insurance shall apply. Such other insurance shall apply solely as respects the individual interest of the Participant carrying such other insurance.

31.8 Nothing herein shall prohibit the Operating Agent or any Participant from furnishing a policy of Operating Insurance which combines the coverage required by this Agreement with coverage outside the scope of that required by this Agreement. If the Operating Agent or any Participant furnishes a policy of Operating Insurance which combines the coverage required by this Agreement with coverage outside the scope of that required by this Agreement, the Coordination Committee shall agree on the portion of the total premium cost which is allocable to Operating Insurance. If the Participants are unable to agree on such allocation, the Operating Agent may make an estimated allocation and bill the Participants on the basis thereof, with adjustment to be made when the dispute is resolved.

31.9 If a Participant desires changes in any Operating Insurance policy, such Participant shall notify the Operating Agent and the other Participants in writing of the desired changes. Upon agreement of the Coordination Committee to such change, the Operating Agent shall obtain the insurance within sixty (60) days from the date of agreement. If the Operating Agent is unable to obtain the type of policy or coverage required herein or believed by the Operating Agent to be adequate, then the Operating Agent shall immediately notify the Participants.

31.10 In the event the Coordination Committee is unable to agree upon any matters relating to the Operating Insurance, the Operating Agent, pending the resolution of such disagreement, shall procure or cause to be procured such policies of insurance, consistent with Prudent Utility Practice, as are necessary to protect the Participants against the insurable risks for which Operating Insurance is required. During any period of negotiations with an insurer, or other negotiations which are pending at the expiration of the period of coverage of an Operating Insurance policy, or in the event an Operating Insurance policy is canceled, the Operating Agent shall renew or bind policies as an emergency measure, or may procure policies of insurance which are identical to those which were canceled, or may to the extent possible secure replacement policies which will provide substantially the same coverage as the policy expiring or canceled.

31.11 Each Participant shall have the right to request that any mortgagee, trustee or secured party be named on all or any of the Operating Insurance policies as loss payees or additional assureds as their interests may appear. Such request shall be submitted to the Operating Agent specifying the name or names of such mortgagee, trustee or secured party and such additional information as may be necessary or required to permit it to be included on the policies of Operating Insurance.

31.12 On an annual basis, the Operating Agent shall advise the Participants on the status of insurance coverage for the San Juan Project and shall make appropriate recommendations concerning insurance issues to the Coordination Committee.

32.0 SURPLUS OR RETIRED PROPERTY:

The Operating Agent shall dispose of surplus property or property no longer used or useful in the operation of the San Juan Project and report such disposal to the Participants, both in accordance with practices and procedures established by the Engineering and Operating Committee. The proceeds from such disposition shall be credited to the Participants in accordance with their Participation Shares.

33.0 REMOVAL OF OPERATING AGENT:

33.1 The Operating Agent shall serve as such during the term of this Agreement unless it resigns as Operating Agent by giving notice to the Participants at least one (1) year in advance of the date of resignation or until receipt by the Operating Agent of notice of its removal as provided in Section 33.2.

33.2 The Operating Agent may be removed as Operating Agent for any one of the following reasons:

33.2.1 The Operating Agent may be removed by action of the Coordination Committee if, in the judgment of the Coordination Committee (voting as provided for in Section 18.4), the best interests of the San Juan Project require that a new Operating Agent be selected. Any Participant seeking a Coordination Committee determination to remove the Operating Agent shall provide to the Operating Agent and to all of the Participants a written statement, detailing the reasons why, in the judgment of the initiating Participant, the Operating Agent should be removed. Within thirty (30) days after receipt by the Operating Agent of this written statement, the Operating Agent shall prepare and serve upon all of the Participants its response which shall contain a detailed rebuttal of the allegations made in the initiating statement. Within the same thirty (30) day period, any other Participant may also prepare and serve upon the Operating Agent and the Participants a statement responding to the allegations in the initiating statement. Within twenty (20) days after service of all such response statements, the Coordination Committee shall meet to consider what action, if any, to take with regard to the removal of the Operating Agent. If, pursuant to this Section 33.2.1, the Coordination Committee removes the

Operating Agent, such removal shall be effective upon the date established by the Coordination Committee. If the Operating Agent or any Participant is dissatisfied with the action of the Coordination Committee, it shall have the right to seek arbitration under Section 37, but no demand for arbitration shall stay the decision of the Coordination Committee to remove the Operating Agent.

33.2.2 If, pursuant to the provisions of Section 34, it is determined that the Operating Agent is in default of its obligations under this Agreement, the Operating Agent may be removed by written notice given by any Participant under Section 34.1.2, which notice shall state the effective date of the removal of the Operating Agent.

33.2.3 Notwithstanding the pendency of any actions to remove the Operating Agent, the Operating Agent shall continue in good faith to exercise its obligations as Operating Agent.

33.3 Prior to the effective date of a resignation of the Operating Agent, or prior to the date of removal of the Operating Agent in accordance with Section 33.2, the Coordination Committee shall by written agreement designate a new Operating Agent, which may, but need not, be a Participant. The Coordination Committee may designate an interim Operating Agent pending selection of a permanent Operating Agent. Acceptance by the new Operating Agent of its appointment as such shall constitute its agreement to perform the obligations of the Operating Agent under this Agreement.

34.0 DEFAULTS BY OPERATING AGENT:

34.1 The following provisions shall apply solely in regard to violations or allegations of violations of this Agreement by the Operating Agent on the basis of which removal of the Operating Agent is sought:

34.1.1 In the event any Participant shall be of the opinion that an action taken or failed to be taken by the Operating Agent constitutes a violation of this Agreement, it may give written notice thereof to the Operating Agent and the other Participants, together with a statement of the basis for its opinion. Thereupon, the Operating Agent may prepare a statement of the reasons justifying its action or failure to take action. If agreement in settling the dispute is not reached between the Operating Agent and such Participant which gave such notice, then the matter shall be submitted to arbitration in the manner provided in Section 37. During the continuance of the arbitration proceedings, the Operating Agent may continue such action taken or failed to be taken in the manner it deems most advisable and consistent with this Agreement.

34.1.2 If it is determined that the Operating Agent is violating this Agreement, then the Operating Agent shall act with due diligence to end such violation and shall, within thirty (30) days or within such lesser time following the determination as may be prescribed in the determination, take action or commence action in good faith to terminate such violation. In the event that the complaining Participant is of the opinion that the Operating Agent has not taken such action to correct, or to commence action to correct, the violation within such allowed period, the complaining Participant shall be entitled to submit the question of the Operating

Agent's good faith action to terminate such violation to arbitration as provided in Section 37. If it is determined that the Operating Agent has not acted with due diligence or good faith to terminate such violation, it shall be deemed to be in default and shall be subject to removal, after the arbitration determination, within fifteen (15) days after receipt of notice executed by the complaining Participant in accordance with Section 42.

34.1.3 The provisions of Section 35, excepting Sections 35.8 and 35.9, shall not apply to disputes as to whether or not an action or non-action of the Operating Agent, in its capacity as Operating Agent, is a violation or default under this Agreement.

PART VII

DEFAULTS, LIABILITY AND ARBITRATION

35. DEFAULTS:

35.1 Each Participant shall pay all monies and carry out all other performances, duties and obligations agreed to be paid or performed by it pursuant to all of the terms and conditions set forth and contained in the Project Agreements, and a default by any Participant in the covenants and obligations to be by it kept and performed pursuant to the terms and conditions set forth and contained in any of the Project Agreements shall be an act of default under this Agreement.

35.2 In the event of a default by a Participant in any of the terms and conditions of this Agreement to be performed by that Participant, the following shall apply:

35.2.1 The Operating Agent shall give a written notice of the default to the defaulting Participant and the other Participants in accordance with Section 35.2.2.

35.2.2 The notice of default shall specify the existence, nature and extent of the default. Upon receipt of the notice of default, the defaulting Participant shall immediately take all steps necessary to cure the default as promptly and completely as possible.

35.3 In the event that any Participant shall dispute an asserted default by it, then such Participant shall pay the disputed payment or perform the disputed obligation, but may do so under protest. The protest shall be in writing, shall accompany the disputed payment or precede the performance of the disputed obligation(s), and shall specify the reason upon which the protest is based. Copies of such protest shall be mailed by such Participant to all other Participants and to the Operating Agent. Payments not made under protest shall be deemed correct, except to the extent that periodic or annual audits may reveal over or under payment by a Participant or may necessitate adjustments. In the event it is determined by arbitration, pursuant to the provisions of this Agreement or otherwise, that the protesting Participant is entitled to a refund of all or any portion of a disputed payment or payments, or is entitled to the reasonable equivalent in money of non-monetary performance of a disputed obligation theretofore made, then, upon such determination, the non-protesting Participant(s) shall reimburse such amount to the protesting Participant, together with interest thereon at the rate of ten percent (10%) per annum, or the maximum legal rate of interest, whichever is lesser, from the date of payment or of the performance of a disputed obligation to the date of reimbursement.

35.4 In the event a default shall continue for a period of ten (10) days or more after the notice given by the Operating Agent in accordance with Section 35.2 without having been cured by the defaulting Participant, or without such defaulting Participant having commenced or continued action in good faith to cure such default, the following shall apply:

35.4.1 If the defaulting Participant has failed to cure such default or to commence such good faith action during said ten (10) day period, the Operating Agent shall make a written report to the Engineering and Operating Committee concerning the status of the default and shall, on the next working day after such ten (10) day period, notify the defaulting Participant in writing that the Operating Agent intends to declare the defaulting Participant in default under the Project Agreements unless there is a prompt cure of the default. Seven (7) days after the giving of such notice to the defaulting Participant, the Operating Agent shall make a second written report to the Engineering and Operating Committee concerning the status of the default and the efforts, if any, of the defaulting Participant to cure the default. If, within seven (7) additional days, the defaulting Participant has neither cured nor reasonably commenced to cure the default, the Operating Agent shall declare the defaulting Participant in default under the Project Agreements and shall provide written notification of the declaration of default to the defaulting Participant and to the Engineering and Operating Committee. Thereafter, and for so long as the default is not remedied and the declaration of default is not revoked by the Operating Agent, all rights of the defaulting Participant under the Project Agreements shall be suspended, including the right to vote on all committees and to receive all or any part of its proportionate share of the Net Effective Generating Capacity.

35.4.2 Within seventeen (17) days after the notice by the Operating Agent, as provided for in Section 35.2, the Operating Agent shall prepare special operating procedures for approval by the Engineering and Operating Committee that will apply during the period of suspension under Section 35.4.1. Upon approval by the Engineering and Operating Committee, the Operating Agent shall provide notice to each Participant of such special procedures. These special procedures shall include:

35.4.2.1 A tabulation in form similar to Section 6.2 of the percentages of costs to be borne by the non-defaulting Participants pursuant to Section 35.5;

35.4.2.2 Billing and accounting of such costs;

35.4.2.3 Dispatch and scheduling of the defaulting Participant’s proportionate share of Net Effective Generating Capacity; and

35.4.2.4 Any other items required for the optimal use of the San Juan Project and the mitigation of damages by the non-defaulting Participants.

35.4.2.5 If the Operating Agent proposes to broker all or a portion of the defaulting Participant's proportionate share of Net Effective Generating Capacity on behalf of one or more non-defaulting Participants, the form of such an agreement shall be incorporated in such procedures.

35.4.3 Within twenty (20) days after the declaration of a default, as provided for in Section 35.4.1, the defaulting Participant and the non-defaulting Participants shall convene a meeting to address the defaulting Participant's situation and its intentions with regard to curing its default. The defaulting Participant shall promptly prepare a cure plan for approval by the members of the Coordination Committee entitled to vote thereon. The cure plan shall address the defaulting Participant's plan to cure the default and restore itself to full participation as an owner of the San Juan Project. The Coordination Committee, by vote of the members of the Coordination Committee entitled to vote thereon, will monitor the defaulting Participant's compliance with the terms and conditions of the cure plan and if it appears to the Coordination Committee that the defaulting Participant is or will be unable to comply with the terms of an approved cure plan, the Coordination Committee shall consider what actions may be required to address such inability, including, but not limited to, directing the Operating Agent to take such actions as may be appropriate. It is the intent of the Participants that any defaults shall be cured on as expeditious a basis as reasonably possible.

35.4.4 A demand for arbitration of an asserted default pursuant to Section 37 shall not stay the suspension of the rights of the defaulting Participant, but in the event that the board of arbitrators shall determine that the asserted default did not in fact exist or occur, the arbitrators shall specify a method of fully and fairly compensating the Participant which, under Section 35.4.1, was denied the right to vote on committee actions and to receive all or any part of its proportionate share of the Net Effective Generating Capacity.

35.5 During any period when the suspension provided for in Section 35.4.1 is in effect, the non-defaulting Participant(s) having a Participation Share in the affected Unit or Units: (i) shall bear a proportionate share of all expenses, including but not limited to, the operation and maintenance costs, insurance costs, fuel costs, capital expenditures and other expenses otherwise payable by the defaulting Participant under the Project Agreements, including any obligations related to common equipment and facilities, based upon the relation of the Participation Share of each such non-defaulting Participant(s) to the Participation Shares of all non-defaulting Participants in the specific Unit or Units; and (ii) shall be entitled to schedule and receive for their accounts their proportionate share of the Net Effective Generating Capacity of the defaulting Participant.

35.6 In connection with its cure of the default, the defaulting Participant shall pay promptly upon demand to the non-defaulting Participant(s) the total amount of money (and/or the reasonable equivalent in money of non-monetary performance) paid and/or made by such non-defaulting Participant(s) pursuant to Section 35.5 in order to cure any default by the defaulting Participant, together with interest thereon at the rate of ten percent (10%) per annum, or the maximum legal rate of interest, whichever is the lesser, from the date of the expenditure of such money (or the making of such other performance) by the non-defaulting Participant(s), to the date of such reimbursement by the defaulting Participant, or such greater amount as may be otherwise provided in the Project Agreements. Any payment obligation of the defaulting Participant shall be reduced by mitigation measures undertaken by the non-defaulting Participants; provided, however, that the payment obligations of the defaulting Participant shall not be reduced by any profits or gains achieved by the non-defaulting Participants as the result of taking a proportionate share of the Net Effective Generating Capacity due to the default of the defaulting Participant.

35.7 The suspension of a defaulting Participant shall be terminated and its full rights under the Project Agreements restored when the default(s) have been cured and all compensable costs incurred by the non-defaulting Participant(s) hereunder have been paid by the defaulting Participant or other arrangements acceptable to the non-defaulting Participant(s) have been made.

35.8 No waiver by a non-defaulting Participant of its rights with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall be effective unless the non-defaulting Participant(s) waive in writing their respective rights and any such waiver shall not be deemed to be a waiver with respect to any subsequent default or matter. No delay short of the statutory period of limitations in asserting or enforcing any right hereunder shall be deemed a waiver of such right.

35.9 The rights and remedies provided in this Agreement shall be in addition to the rights and remedies of the Participants as set forth and contained in any other Project Agreement or any rights and remedies the Participants have in law or equity.

36.0 LIABILITY:

36.1 Except for any judgment debt for damage resulting from Willful Action and except to the extent any judgment debt is collectible from valid insurance, and subject to the provisions of Sections 36.1.1, 36.4, 36.5, 36.6 and Section 37, each Participant hereby extends to all other Participants, their directors, members of their governing bodies, officers and employees, its covenant not to execute, levy or otherwise enforce a judgment obtained against any of them, including recording or effecting a judgment lien, for any direct, indirect, or consequential loss, damage, claim, cost, charge or expense, whether or not resulting from the negligence of such Participant, its directors, members of its governing body, officers, employees or any person or entity whose negligence would be imputed to such Participant from (i) Operating Work, the design and construction of Capital Improvements or the use or ownership of the San Juan Project or (ii) the performance or nonperformance of the obligations of any Participant under any of the Project Agreements, other than the obligation to pay any monies becoming due.

36.1.1 In the event any insurer providing insurance refuses to pay any judgment obtained by a Participant against any other Participant, its directors, members of its governing body, officers or employees on account of liability referred to in Section 36.1, the Participant, its directors, members of its governing body, officers or employees against whom the judgment is obtained shall, at the request of the prevailing Participant and in consideration for the covenant granted in Section 36.1, execute such documents as may be necessary to effect an assignment of its contractual rights against the nonpaying insurer and thereby give the prevailing Participant the opportunity to enforce its judgment directly against such insurer. In no event when a judgment debt is collectible from valid insurance shall the Participant obtaining the judgment execute, levy or otherwise enforce the judgment (including recording or effecting a judgment lien) against the Participant, its directors, members of its governing body, officers or employees against whom the judgment was obtained.

36.1.2 To the extent that Section 41-3-5, New Mexico Statutes Annotated, 1978 compilation (as such section may be amended), shall be applicable and for the purpose of relieving each Participant, its directors, members of its governing body, officers and employees of any liability to make contribution to other non-Participant tortfeasors, the foregoing covenant not to execute hereby effects a reduction of all injured Participants' damages recoverable against all other non-Participant tortfeasors to the extent of the pro rata share (as referred to in Section 41-3-5, New Mexico Statutes Annotated, 1978 compilation, as such section may be amended) of the other Participants, their directors, members of their governing bodies, officers and employees.

36.1.3 Each Participant agrees, upon request by any other Participant, to make, execute and deliver any and all documents or take such other action as may reasonably be required to effectuate the intent of this Section 36.1.

36.2 Except as provided in Sections 36.4, 36.5 and 36.6, the costs and expenses of discharging all work liability imposed upon one or more of the Participants, for which payment is not made by insurance, shall be allocated among the Participants in proportion to their respective Participation Shares in the property giving rise to the work liability. Work liability is defined as liability of one or more Participants for any loss, damage, claim, cost, charge or expense of any kind or nature (including direct, indirect or consequential) suffered or incurred by any party other than a Participant, whether or not resulting or to result in the future from the negligence of any Participant, its directors, members of its governing body, officers, employees or any other person or entity whose negligence would be imputed to such Participant, that has resulted or may result in the future from (i) performance or nonperformance of the work herein described, (ii) operation, maintenance, use or ownership of the San Juan Project, and (iii) past or future performance or nonperformance of the obligations of any Participant under any of the Project Agreements.

36.3 If it cannot be determined which property gave rise to work liability, the allocation for discharging costs and expenses associated therewith shall be as specified in Section 22.1.7.

36.4 Except for liability resulting from Willful Action (which subject to the provisions of Section 36.6 shall be the responsibility of the willfully acting Participant), any Participant whose electric customer shall have a claim or bring an action against any other Participant for any death, injury, loss or damage arising out of or in connection with electric service to such customer caused by the operation or failure of operation of the San Juan Project or any portion thereof shall indemnify and hold harmless such other Participant, its directors, members of its governing body, officers and employees from and against any liability for such death, injury, loss or damage.

36.5 Each Participant shall be responsible for any damage, loss, claim, cost, charge or expense that is not covered by insurance and results from its own Willful Action as defined in Section 5.57.2 and shall indemnify and hold harmless the other Participants, their directors, members of their governing bodies, officers and employees, from any such damage, loss, claim, cost, charge or expense.

36.6 Except as provided in Section 36.5, the aggregate liability of any Participant to all other Participants for Willful Action not covered by insurance shall be determined as follows:

36.6.1 All such liability for damages, losses, claims, costs, charges or expenses of such Participant shall not exceed ten million dollars ($10,000,000) per occurrence. Each Participant extends to each other Participant, its directors, members of its governing body, officers and employees its covenant not to execute, levy or otherwise enforce a judgment against any of them for any such aggregate liability in excess of ten million dollars ($10,000,000) per occurrence.

36.6.2 A claim based on Willful Action must be perfected by filing suit in a court of competent jurisdiction within three (3) years after the Willful Action occurs. All claims made thereafter relating to the same Willful Action shall be barred by this Section 36.6.2. The award to each nonwillfully acting Participant from each Participant determined to have committed Willful Action shall be determined as follows: (i) Each Participant who successfully files suit for remuneration shall receive the lesser of (a) its final judgment awarded (or settlement made) or (b) its pro rata Participation Share of the ten million dollar ($10,000,000) maximum recovery established in Section 36.6.1; (ii) When all pending suits are resolved, those Participants who were awarded judgments or reached settlements but whose claims were not fully satisfied pursuant to Section 36.6.2(i) shall be entitled to participate in any remaining portion of the ten million dollar ($10,000,000) maximum recovery limit, based upon the ratio of the unsatisfied portion of such Participant's judgment or settlement to the total unsatisfied portion of all such judgments and settlements. Such participation shall be limited to the Participants' unsatisfied judgments or settlements.

36.7 The provisions of this Section 36 shall not be construed so as to relieve any insurer of its obligation to pay any insurance proceeds in accordance with the terms and conditions of valid and collectible insurance policies.

36.8 If a court of competent jurisdiction determines upon a challenge by a Participant or third party that the provisions of Section 56-7-1, New Mexico Statutes Annotated, 1978 Compilation, as amended, are applicable to this Agreement, the Participants agree that any agreement to indemnify contained in this Agreement shall be enforced only to the extent it requires the indemnitor to indemnify or hold harmless the indemnitee, including its officers, employees or agents, against liability, claims, damages, losses or expenses, including attorney's fees, only to the extent that the liability, damages, losses or costs are caused by, or arise out of, the acts or omissions of the indemnitor or its officers, employees or agents.

36.9 The Participants agree that the aggregate liability limit of ten million dollars ($10,000,000) referenced in Sections 36.6.1 and 36.6.2 may be determined in the future to be inappropriate and shall, at the request of any Participant, make a good faith effort to evaluate and, if appropriate, revise said limit.

37.0 ARBITRATION:

37.1 If a dispute between or among any of the Participants (which term, for purposes of this Section 37, shall be deemed to include the Operating Agent) should arise in relation to any aspect of the San Juan Project, any Participant(s) may call for submission of the dispute to arbitration, which call shall be binding upon all of the other affected Participant(s).

37.2 The Participant(s) calling for arbitration shall give written notice to all other Participants, setting forth in such notice in adequate detail the entity(ies) against whom relief is sought, the nature of the dispute, the amount or amounts, if any, involved in such dispute, and the remedy sought by such arbitration proceedings. Within twenty (20) days after receipt of such notice, any other Participant(s) involved may, by written response to the first Participant(s), as well as the other Participant(s), submit its or their own statement of the matter at issue and set forth in adequate detail additional related matters or issues to be arbitrated. Thereafter, the Participant(s) first submitting its or their notice of the matter at issue shall have ten (10) days in which to submit a written rebuttal statement, copies of which shall be provided to all other Participants.

37.3 Within ten (10) days following delivery of the last written submittal pursuant to Section 37.2, the affected Participant(s), acting through their respective representatives, shall meet for the purpose of selecting arbitrators. Each affected Participant, or group of Participants, representing one side of the dispute, shall designate an arbitrator. The arbitrators so selected shall meet within twenty (20) days following their selection and shall select additional arbitrator(s), the number of which additional arbitrators shall be one (1) less than the total number of arbitrators selected by the affected Participants. If the arbitrators selected by the affected Participants, as herein provided, shall fail to select such additional arbitrator(s) within said twenty (20) day period, then the arbitrators shall request from the American Arbitration Association (or similar organization if the American Arbitration Association should not exist at the time) a list of arbitrators who are qualified and eligible to serve as hereinafter provided. The arbitrators selected by the affected Participants shall take turns striking names from the list of arbitrators furnished by the American Arbitration Association, and the last name(s) remaining on said list shall be the additional arbitrator(s). All arbitrators shall be persons skilled and experienced in the field which gives rise to the dispute, and no person shall be eligible for appointment as an arbitrator who is an officer or employee of any of the Participants to the dispute or is otherwise interested in the matter to be arbitrated.

37.4 Except as otherwise provided in this Section 37 or otherwise agreed by the Participants to the dispute, the arbitration shall be governed by the rules and practices of the American Arbitration Association (or rules and practices of a similar organization if the American Arbitration Association should not exist at that time) from time to time in force, except that if such rules and practices, as modified herein, shall conflict with New Mexico Rules of Civil Procedure or any other provisions of New Mexico law then in force which are specifically applicable to arbitration proceedings, such New Mexico laws shall govern.

37.5 Included in the issues which may be submitted to arbitration pursuant to this Section 37 is the issue of whether the right to arbitrate a particular dispute is permitted under the Project Agreements.

37.6 The arbitrators shall hear evidence submitted by the respective Participants or group or groups of Participants and may call for additional information, which additional information shall be furnished by the party having such information. The decision of a majority of the arbitrators shall be binding upon all the Participants and shall be based on the provisions of the Project Agreements and New Mexico law.

37.7 This agreement to arbitrate shall be specifically enforceable and the award of the arbitrators shall be final and binding upon the Participants to the extent provided by the laws of the State of New Mexico. Any award may be filed with the clerk of any court having jurisdiction over the Participants or any of them against whom the award is rendered, and, upon such filing, such award, to the extent permitted by the laws of the jurisdiction in which said award is filed, shall be specifically enforceable or shall form the basis of a declaratory judgment or other similar relief.

37.8 Each Participant or group of Participants shall be responsible for the fees and expenses of the arbitrator selected by that Participant or group of Participants, unless the decision of the arbitrators shall specify some other apportionment of such fees and expenses. The fees and expenses of the neutral arbitrators shall be shared among the affected Participants equally, unless the decision of the arbitrators shall specify some other apportionment of such fees and expenses. All other expenses and costs of the arbitration, including attorney fees, shall be borne by the Participant incurring the same.

37.9 In the event that any Participant(s) shall attempt to institute or to carry out the provisions herein set forth in regard to arbitration, and such Participant(s) shall not be able to obtain a valid and enforceable arbitration decree, such Participant(s) shall be entitled to seek legal remedies in a court having jurisdiction in the premises, and the provisions in this Section 37 referring to arbitration decisions shall then be deemed applicable to final decisions of such court.

PART VIII

RETIREMENT AND RECONSTRUCTION

38.0 DESTRUCTION, DAMAGE OR CONDEMNATION OF A UNIT:

38.1 If all, or substantially all, of a Unit is destroyed, damaged or condemned, then the Participants with Participation Shares in that Unit by unanimous agreement may elect to repair or reconstruct the damaged, destroyed or condemned Unit in such a manner as to restore the Unit to substantially the same general character or use as the original, or to such other character or use as the Participants may then mutually agree. In the event of such election, it shall be the obligation of the Participants to pay for the costs of such repair or reconstruction in accordance with the Participation Shares of the respective Participants in such Unit, and, upon completion thereof, the Participants' rights, titles and interests therein shall be as provided in this Agreement.

38.2 Failure to reach unanimous agreement as provided in Section 38.1 shall be deemed to be an election not to repair or reconstruct the damaged, destroyed or condemned Unit, in which event the proceeds from any insurance or from any award shall be distributed to the Participants in accordance with their respective Participation Shares in such Unit. The facilities not destroyed, damaged or condemned shall be disposed of by the Participants in a manner to be mutually agreed upon, and the proceeds from such disposition shall be distributed in accordance with the Participation Shares of the respective Participants in such Unit. Nothing in this section shall be deemed to preclude any Participant or group of Participants in the Unit from agreeing to repair, reconstruct or replace the damaged, destroyed or condemned Unit.

38.3 In the event that less than substantially all of a Unit is destroyed, damaged or condemned, then it shall be the obligation of the Participants having a Participation Share in such Unit to repair or reconstruct such Unit. Each Participant shall be obligated to pay its proportionate share of the costs of such repair or reconstruction in accordance with Section 6.2.

38.4 In the event that any common equipment and/or facility is destroyed, damaged or condemned, then it shall be the obligation of the Participants having a Participation Share in such common equipment and/or facilities to repair or reconstruct such damaged, destroyed or condemned equipment and/or facilities. Each Participant shall be obligated to pay its proportionate share of the costs of such repair or reconstruction in accordance with Section 6.2.

39.0 RIGHTS OF PARTICIPANTS UPON TERMINATION:

39.1 In the event the Participants by unanimous agreement abandon, retire or otherwise terminate or suspend operation of the San Juan Project prior to the termination of this Agreement, the facilities forming the San Juan Project shall be disposed of by the Participants in a manner to be unanimously agreed upon and the proceeds from such disposition shall be distributed to the Participants in accordance with their respective Participation Shares.

40.0 DECOMMISSIONING OF THE PROJECT:

The Participants acknowledge the appropriateness of incorporating in a future amendment to this Agreement, or in another appropriate contractual instrument, provisions which address the decommissioning of the San Juan Project and/or of one or more Units. It is recognized, however, that the resolution of issues associated with San Juan Project decommissioning will require protracted study. The Participants therefore agree to establish a task force or other forum for the careful and deliberate consideration of decommissioning issues so that these issues may be addressed and resolved in a timely manner. The Operating Agent shall propose to the Participants a methodology and a schedule for addressing decommissioning issues.

PART IX

MISCELLANEOUS PROVISIONS

41.0 RELATIONSHIP OF PARTICIPANTS:

41.1 The covenants, obligations and liabilities of the Participants are intended to be several and not joint or collective, and nothing herein contained shall ever be construed to create an association, joint venture, trust or partnership, or to impose a trust or partnership covenant, obligation or liability on or with regard to any one or more of the Participants. Each Participant shall be individually responsible for its own covenants, obligations and liabilities as herein provided. No Participant or group of Participants shall be under the control of or shall be deemed to control any other Participant or the Participants as a group. No Participant shall be the agent of or have a right or power to bind any other Participant without its express written consent, except as expressly provided herein.

41.2 The Participants hereby elect to be excluded from the application of Subchapter “K” of Chapter 1 of Subtitle “A” of the Internal Revenue Code of 1986, or such portion or portions thereof as may be permitted or authorized by the Secretary of the Treasury or its delegate insofar as such subchapter, or any portion or portions thereof, may be applicable to the Participants hereunder.

42.0 NOTICES:

42.1 Any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be deemed properly served, given or made (i) when delivered personally or by prepaid overnight courier, with a record of receipt, (ii) the fourth day if mailed by certified mail, return receipt requested, or (iii) the day of transmission, if sent by facsimile or telecopy during regular business hours or the day after transmission, if sent after regular business hours (provided however, that such facsimile or telecopy shall be followed on the same day or next business day with the sending of a duplicate notice, demand or request by a nationally recognized prepaid overnight courier with record of receipt), to the persons specified below:

42.1.1 Public Service Company of New Mexico
c/o Secretary
Alvarado Square
Albuquerque, New Mexico 87158

42.1.2 Tucson Electric Power Company
c/o Secretary
Post Office Box 711
Tucson, Arizona 85702

42.1.3 City of Farmington
c/o City Clerk
800 Municipal Drive
Farmington, NM 87401

42.1.4 M-S-R Public Power Agency
c/o General Manager
P. O. Box 4060
Modesto, CA 95352

42.1.5 Southern California Public Power Authority
c/o Executive Director
225 South Lake Ave, Suite 1250
Pasadena, CA 91101

42.1.6 City of Anaheim

c/o City Clerk
200 South Anaheim Boulevard
Anaheim, CA 92805

with a copy to:

Public Utilities General Manager
201 South Anaheim Boulevard
Suite 1101
Anaheim, CA 92805

42.1.7 Incorporated County of
Los Alamos, New Mexico
c/o Utilities Manager
P.O. Drawer 1030
901 Trinity Drive
Los Alamos, NM 87544

42.1.8 Utah Associated Municipal Power Systems
c/o General Manager
2825 E. Cottonwood Parkway
Suite 200
Salt Lake City, UT 84121

42.1.9 Tri-State Generation and Transmission
Association, Inc.
c/o Executive Vice President and General Manager
1100 West 116th Avenue
Westminster, CO 80234
Or P. O. Box 33695
Denver, CO 80233

42.2 A Participant may, at any time or from time to time, by written notice to the other Participants, change the designation or address of the person so specified as the one to receive notices pursuant to this Agreement.

42.3 The Operating Agent shall provide to each Participant a copy of any material notice, demand or request given or received by it in connection with the San Juan Project.

43.0 OTHER PROVISIONS:

43.1 Each Participant agrees, upon request by another Participant, to make, execute and deliver any and all documents reasonably required to implement the terms of this Agreement.

43.2 No Participant shall be considered to be in default in the performance of any of the obligations hereunder (other than obligations of a Participant to pay costs and expenses) if failure of performance shall be due to uncontrollable forces. The term "uncontrollable forces" shall mean any cause beyond the control of the Participant affected, including but not limited to failure of facilities, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, labor dispute, sabotage, restraint by court order or public authority, or failure to obtain approval from a necessary governmental authority which by exercise of due diligence and foresight such Participant could not reasonably have been expected to avoid and which by exercise of due diligence it shall be unable to overcome. Nothing contained herein shall be construed so as to require a Participant to settle any strike or labor dispute in which it may be involved. Any Participant rendered unable to fulfill any obligation by reason of uncontrollable forces shall exercise due diligence to remove such inability with all reasonable dispatch.

43.3 The captions and headings appearing in this Agreement are inserted merely to facilitate reference and shall have no bearing upon the interpretation of the provisions hereof.

43.4 This Agreement is made under and shall be governed by the laws of the State of New Mexico, without regard to conflicts of law principles.

43.5 The covenants and obligations set forth and contained in this Agreement are to be deemed to be independent covenants, not dependent covenants, and the obligation of a Participant to perform all of the obligations and covenants to be by it kept and performed is not conditioned on the performance by another Participant of all of the covenants and obligations to be kept and performed by it.

43.6 In the event that any of the terms or conditions of this Agreement, or the application of any such term or condition to any person or circumstance, shall be held invalid by any court having jurisdiction in the premises, the remainder of this Agreement, and the application of such terms or conditions to persons or circumstances other than those as to which it is held invalid, shall not be affected thereby.

43.7 All costs or expenses, including all taxes that the Operating Agent is required to pay (but not specifically referred to in other sections of this Agreement), which are incurred by the Operating Agent in connection with the performance of its obligations under this Agreement and which are not specifically allocated to the Participants in accordance with this Agreement shall be equitably allocated among the Participants in a manner to be established by the Coordination Committee.

43.8 Should a change in circumstances, economic factors, or basic technology occur which results or may result in a substantial increase or decrease in the benefits to or expenses incurred by a Participant, including the Operating Agent, which such change was not within the reasonable contemplation of the Participants at the time of the execution of this Agreement, the Participants, including the Operating Agent, shall negotiate in good faith in order that an appropriate and equitable adjustment shall be made in the reimbursement of the Operating Agent and in the allocation of expenses among the Participants. Such adjustment shall be fair and equitable as to both the Operating Agent and the other Participants.

43.9 This Agreement shall be subject to filing with, and to such changes or modifications as may from time to time be directed by, competent regulatory authority, if any, in the exercise of its jurisdiction.

43.10 It is the intent of the Participants in executing this Agreement to set out in one instrument the entire agreement of the Participants with respect to the subject matter hereof, and on the effective date hereof to explicitly amend and restate, and to replace in their entirely, the Original San Juan PPA, the Co-Tenancy Agreement, the Operating Agreement and all modifications thereto. Accordingly, on the effective date hereof, the Original San Juan PPA, the Co-Tenancy Agreement and the Operating Agreement are no longer in force and effect except as incorporated herein; provided, however, that the interim coal billing arrangements reflected in side agreements shall continue in effect through their stated term.

43.11 The execution of this Agreement shall not affect any rights or obligations of the Participants which shall have accrued prior to the effective date of this Agreement, including any obligation to pay money or take other actions in accordance with the Original San Juan PPA, the Co-Tenancy Agreement, the Operating Agreement or any other agreement.

44.0 EXECUTION IN COUNTERPARTS:

44.1 This Agreement may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument as if all the Participants to the aggregated counterparts had signed the same instrument. Any signature page of this Agreement may be detached from any counterpart thereof without impairing the legal effect of any signatures thereon and may be attached to any other counterpart of this Agreement identical in form thereto but having attached to it one or more additional pages.

45.0 AMENDMENTS:

45.1 Except as provided in Section 45.2, this Agreement may be amended only by written instrument executed by all of the Participants with the same formality as this Agreement.

45.2 The Coordination Committee, by unanimous vote, may amend any one or more of the exhibits attached to this Agreement. In the event of any such action by the Coordination Committee, a copy of the new exhibit shall be attached to this Agreement to replace the old or superseded exhibit, without the necessity of formally amending this Agreement. Any such action shall not affect other provisions of this Agreement, including other exhibits thereto.

IN WITNESS WHEREOF, the Participants, by their duly authorized representatives, have caused this Agreement to be made as of this 23rd day of March, 2006.

PUBLIC SERVICE COMPANY OF NEW MEXICO

By Hugh W. Smith
Its Senior Vice President Energy Resources

TUCSON ELECTRIC POWER COMPANY

By______________________________
Its______________________________

THE CITY OF FARMINGTON, NEW MEXICO

By______________________________
Its______________________________

M-S-R PUBLIC POWER AGENCY

By______________________________
Its______________________________

THE INCORPORATED COUNTY OF LOS ALAMOS, NEW MEXICO

By______________________________
Its______________________________

STATE OF NEW MEXICO)
)ss.
COUNTY OF BERNALILLO)

The foregoing instrument was acknowledged before me on this 23 day of March 2006, by Hugh W. Smith, Senior VP of Public Service Company of New Mexico, a New Mexico corporation, on behalf of the corporation.

Joni Hardy
Notary Public

My commission expires:

1-26-10

OFFICIAL SEAL
JONI HARDY
Notary Public
State of New Mexico
My Commission Expires 1-26-10

STATE OF ARIZONA)
)ss.
COUNTY OF PIMA)

The foregoing instrument was acknowledged before me on this ____ day of ________, 200 , by ________________________, ____________________ of Tucson Electric Power Company, an Arizona corporation, on behalf of the corporation.

____
Notary Public

My commission expires:

____

IN WITNESS WHEREOF, the Participants, by their duly authorized representatives, have caused this Agreement to be made as of this 23rd day of March, 2006.

PUBLIC SERVICE COMPANY OF NEW MEXICO

By______________________________
Its______________________________

TUCSON ELECTRIC POWER COMPANY

By [signature]
Its Sr. V.P. Energy Resources

THE CITY OF FARMINGTON, NEW MEXICO

By______________________________
Its______________________________

M-S-R PUBLIC POWER AGENCY

By______________________________
Its______________________________

THE INCORPORATED COUNTY OF LOS ALAMOS, NEW MEXICO

By______________________________
Its______________________________

STATE OF NEW MEXICO)
)ss.
COUNTY OF BERNALILLO)

The foregoing instrument was acknowledged before me on this ____ day of ________, 200 , by ______________________, ______________________ of Public Service Company of New Mexico, a New Mexico corporation, on behalf of the corporation.

____
Notary Public

My commission expires:

____

STATE OF ARIZONA)
)ss.
COUNTY OF PIMA)

The foregoing instrument was acknowledged before me on this 31st day of January, 2006, by Michael J. DeConcini, SR. VP, Energy Resources of Tucson Electric Power Company, an Arizona corporation, on behalf of the corporation.

____
Notary Public

My commission expires:

7-31-07

Notary Public State of Arizona
Pima County
Melissa R Martinez
Expires July 31 2007

IN WITNESS WHEREOF, the Participants, by their duly authorized representatives, have caused this Agreement to be made as of this 23rd day of March, 2006.

PUBLIC SERVICE COMPANY OF NEW MEXICO

By______________________________
Its______________________________

TUCSON ELECTRIC POWER COMPANY

By______________________________
Its______________________________

THE CITY OF FARMINGTON, NEW MEXICO

By Maude Grantham-Richards
Its Electric Utility Director

M-S-R PUBLIC POWER AGENCY

By______________________________
Its______________________________

THE INCORPORATED COUNTY OF LOS ALAMOS, NEW MEXICO

By______________________________
Its______________________________

STATE OF NEW MEXICO)
)ss.
COUNTY OF SAN JUAN)

The foregoing instrument was acknowledged before me on this 9th day of February, 2006, by Maude Grantham-Richards, Electric Utility Director of The City of Farmington, New Mexico, a New Mexico municipal corporation, on behalf of the municipal corporation.

Nancy A Krause
Notary Public

My commission expires:
10/25/2008

STATE OF CALIFORNIA)
)ss.
COUNTY OF STANISLAUS)

The foregoing instrument was acknowledged before me on this ____ day of ________, 200 , by ________________________, ____________________ of M-S-R Public Power Agency, a California joint powers agency, on behalf of said joint powers agency.

____
Notary Public

My commission expires:

____

IN WITNESS WHEREOF, the Participants, by their duly authorized representatives, have caused this Agreement to be made as of this 23rd day of March, 2006.

PUBLIC SERVICE COMPANY OF NEW MEXICO

By_______________________________

Its_______________________________

TUCSON ELECTRIC POWER COMPANY

By_______________________________

Its_______________________________

THE CITY OF FARMINGTON, NEW MEXICO

By_______________________________

Its_______________________________

M-S-R PUBLIC POWER AGENCY

By Graser

Its General Manager

THE INCORPORATED COUNTY OF LOS ALAMOS, NEW MEXICO

By_______________________________

Its_______________________________

STATE OF NEW MEXICO)
)ss.
COUNTY OF SAN JUAN)

The foregoing instrument was acknowledged before me on this ____ day of ________, 200 , by ________________________, ____________________ of The City of Farmington, New Mexico, a New Mexico municipal corporation, on behalf of the municipal corporation.

____
Notary Public

My commission expires:

____

STATE OF CALIFORNIA)
)ss.
COUNTY OF SACRAMENTO)

The foregoing instrument was acknowledged before me on this 18th day of January 2006, by George Fraser, General Manager of M-S-R Public Power Agency, a California joint powers agency, on behalf of said joint powers agency.

Kathleen Grindstaff
Notary Public

My commission expires:

July 18, 2008

KATHLEEN GRINDSTAFF
Commission # 1501461
Notary Public - California
Sacramento County
My Comm. Expires Jul 18, 2008

IN WITNESS WHEREOF, the Participants, by their duly authorized representatives, have caused this Agreement to be made as of this 23rd day of March, 2006

PUBLIC SERVICE COMPANY OF NEW MEXICO

By________________________________

Its________________________________

TUCSON ELECTRIC POWER COMPANY

By________________________________

Its________________________________

THE CITY OF FARMINGTON, NEW MEXICO

By________________________________

Its________________________________

M-S-R PUBLIC POWER AGENCY

By________________________________

Its________________________________

THE INCORPORATED COUNTY OF LOS ALAMOS, NEW MEXICO

By Robert H. Mandry

Its Utilities Manager

STATE OF NEW MEXICO)
)ss.
COUNTY OF LOS ALAMOS)

The foregoing instrument was acknowledged before me on this 3rd day of February 2006, by Robert J. Monday Utilities Mgr of The Incorporated County of Los Alamos, New Mexico, a New Mexico Class H County, on behalf of said county.

Lisa D. Torres
Notary Public

My commission expires:
5/21/2007

STATE OF CALIFORNIA)
)ss.
COUNTY OF LOS ANGELES)

The foregoing instrument was acknowledged before me on this ____ day of ________, 200 , by _________________________, _____________________ of Southern California Public Power Authority, a California joint powers agency, on behalf of said joint powers agency.

____
Notary Public

My commission expires:

____

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

By Phyllis E. Currie
Its PRESIDENT

CITY OF ANAHEIM

By____________________
Its____________________

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

By____________________
Its____________________

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

By____________________
Its____________________

STATE OF NEW MEXICO)
)ss.
COUNTY OF LOS ALAMOS)

The foregoing instrument was acknowledged before me on this ____ day of ________, 200 , by ________________________, ____________________ of The Incorporated County of Los Alamos, New Mexico, a New Mexico Class H County, on behalf of said county.

____
Notary Public

My commission expires:

____

STATE OF CALIFORNIA)
)ss.
COUNTY OF LOS ANGELES)

The foregoing instrument was acknowledged before me on this 19 day of January, 2006, by Phyllis E. Currie, President of Southern California Public Power Authority, a California joint powers agency, on behalf of said joint powers agency.

Manuel A Robledo
Notary Public

My commission expires:

1/2/07

MANUEL A. ROBLEDO
Comm. # 1388501
NOTARY PUBLIC - CALIFORNIA
Los Angeles County
My Comm. Expires Jan. 2, 2007

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

By____
Its____

CITY OF ANAHEIM

By Marcie S. Edwards
Its Public Utilities General Manager

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

By____
Its____

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

By____
Its____

APPROVED AS TO FORM:
JACK L. WHITE, CITY ATTORNEY
BY Lucina Lea Moses
LUCINA LEA MOSES
ASSISTANT CITY ATTORNEY

STATE OF CALIFORNIA)
)ss.
COUNTY OF ORANGE)

The foregoing instrument was acknowledged before me on this 1st day of February 2006 by Marcie L. Edwards Public Utilities General Manager of the City of Anaheim, a California municipal corporation, on behalf of the said municipal corporation.

Eugenia M. Molina
Notary Public

My commission expires:

November 26, 2006

EUGENIA M. MOLINA
Commission # 1387598
Notary Public - California
Orange County
My Comm. Expires Nov 26, 2006

STATE OF UTAH)
)ss.
COUNTY OF SALT LAKE)

The foregoing instrument was acknowledged before me on this ____ day of ________, 200 , by ________________________, _____________________ of Utah Associated Municipal Power Systems, a political subdivision of the State of Utah, on behalf of said entity.

____
Notary Public

My commission expires:

____

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

By______________________________________
Its_____________________________________

CITY OF ANAHEIM

By______________________________________
Its_____________________________________

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

By______________________________________
Its General Manager

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

By______________________________________
Its_____________________________________

STATE OF CALIFORNIA)
)ss.
COUNTY OF ORANGE)

The foregoing instrument was acknowledged before me on this ____ day of ________, 200 , by ________________________, ____________________ of the City of Anaheim, a California municipal corporation, on behalf of the said municipal corporation.

____
Notary Public

My commission expires:

____

STATE OF UTAH)
)ss.
COUNTY OF SALT LAKE)

The foregoing instrument was acknowledged before me on this 7th day of Feb., 2006, by Douglas Hunter, General Manager of Utah Associated Municipal Power Systems, a political subdivision of the State of Utah, on behalf of said entity.

Pamela Beckstead
Notary Public

My commission expires:

July 8, 2009

NOTARY PUBLIC
PAMELA BECKSTEAD
2825 E. Cottonwood Pkwy. Ste 200
Salt Lake City, Utah 84121
My Commission Expires
July 8, 2009
STATE OF UTAH

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

By____
Its______________________________________

CITY OF ANAHEIM

By____
Its______________________________________

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

By____
Its______________________________________

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

By J. M. Shafer
Its Executive VP/General Manager

STATE OF COLORADO)
)ss.
COUNTY OF ADAMS)

The foregoing instrument was acknowledged before me on this 31st day of JANUARY, 2006, by J.M. SHAFER, EXECUTIVE VICE PRESIDENT and GENERAL MANAGER of Tri-State Generation and Transmission Association, Inc., a Colorado cooperative corporation, on behalf of the said cooperative corporation.

Marylin Shaw
Notary Public

MARYLIN SHAW
NOTARY PUBLIC
STATE OF COLORADO
My Commission Expires 09/04/2009

My commission expires:

9/4/09

rhc0021

REFERENCES TO EXHIBITS IN

PARTICIPATION AGREEMENT

Exhibit No.	References in Agreement	Subject Matter
I	§§ 2.10, 6.1	Real Property
II	§ 5.24	Annual Minimum Coal
III	§§ 5.44, 6.5	Switchyard Facilities
IV	§§ 6.2, 6.2.8	Ownership of Equipment
V	§§ 22.1.7, 22.1.9	O&M of Equipment
VI	§§ 7.11, 22.2.2, 22.6, 22.6.1, 22.7, 22.8	A&G Expenses
VII	§ 23.3	Coal Allocation and Billing
VIII	§§ 18.4, 19.4, 20.5, 21.4	Adjustment of Voting
IX	§§ 5.19, 23.4.1, 23.4.1.3	Fixed Fuel Expense
X	§§ 5.55, 23.4.1, 23.4.1.3	Variable Fuel Expense

EXHIBIT I

EXHIBIT I TO PARTICIPATION AGREEMENT

This Exhibit I to the Amended and Restated San Juan Project Participation Agreement contains a map of the San Juan Project Generating Station site and the River Weir site, showing Parcels A, B, C, C-1 D, E and F, the parcels of real property underlying the San Juan Project and River Weir sites. Also included in the Exhibit are property descriptions and separate maps showing Parcels A through F. PNM and TEP each has a one-half undivided ownership interest in the parcels described as Parcels A, B, C, D, E and F; and PNM and TEP each has a one-half leasehold interest in Parcel C-1.

PARCEL A

The following portions of Township 30 North, Range 15 West, N.M.P.M., San Juan County, New Mexico:

Section 16: SW 1/4
Section 20: NW 1/4, N 1/2 SE 1/4, SW 1/4SE 1/4
Section 21: NW 1/4 NW 1/4
Section 29: NE 1/4

PARCEL B

The following portions of Township 30 North, Range 15 West, N.M.P.M., San Juan County, New Mexico:

Section 19: SE 1/4 SW 1/4, SW 1/4 SE 1/4
Section 20: E 1/2 NW 1/4, NE 1/4 SW 1/4
Section 29: NW 1/4, N 1/2 SW 1/4
Section 30: NE 1/4, E 1/2 NW 1/4 , N 1/2 SE 1/4

PARCEL C

That part of Lot 6 in Section 4 and of Lot 5 in Section 3, Township 29 North, Range 15 West, N.M.P.M., San Juan County, New Mexico, described as follows:

Beginning at a point which is 772.69 feet, South 88º12’03” East from Northwest Corner of Lot 6:

Thence, S. 55º50’29” E., 205.55 feet; thence, N. 78º21’34” E., 457.06 feet; thence N. 88º29’07” E., 746.61 feet; thence, S. 25º38’00” W., 1,177.50 feet; thence, N. 54º32’00” W., 1,291.70 feet; thence, N. 32º1’00” E., 372.20 feet to the point of beginning. Containing 21.039 acres, more or less.

PARCEL C-1

A tract of land situated adjacent to the southerly side of the San Juan River in Sections 3, 4, 9 and 10, Township 29 North, Range 15 West, N.M.P.M., San Juan County, New Mexico, and more particularly described as follows:

Beginning at point A, from which the corner common to Sections 33 and 34, T.30 N., R. 15 W., and Sections 4 and 3, T. 29 N., R 15 W., bears N. 06º09’45” E., 4,966.7

feet; thence N. 49º00’00” E., 351.95 feet to point B located on the approximate centerline of the San Juan River; thence along the centerline of the River S. 50º44’26” E., 268.63 feet to point C; thence continuing along the centerline of the River, S. 41º18’31” E., 263.59 feet to point D; thence S. 21º12’40” E., 678 feet to point E; thence S. 51º00’00” W., 209 feet to point F; thence N. 39º00’00” W., 1,160.00 feet to the point of beginning; containing 9.376 acres, more or less.

PARCEL D

The following portions of Township 30 North, Range 15 West, N.M.P.M., San Juan County, New Mexico:

Section 17: SE 1/4 SW 1/4, S1/2 SE 1/4

PARCEL E

The following portions of Township 30 North, Range 15 West, N.M.P.M., San Juan County, New Mexico:

Section 19: SE 1/4 SE 1/4
NE 1/4 SE 1/4
E 1/2 NW 1/4 SE 1/4
S 1/2 S 1/2 SE 1/4 NE 1/4

Section 20: SE 1/4 SW 1/4
SW 1/4 SW 1/4
NW 1/4 SW 1/4
S 1/2 SW 1/4 SW 1/4 NW 1/4

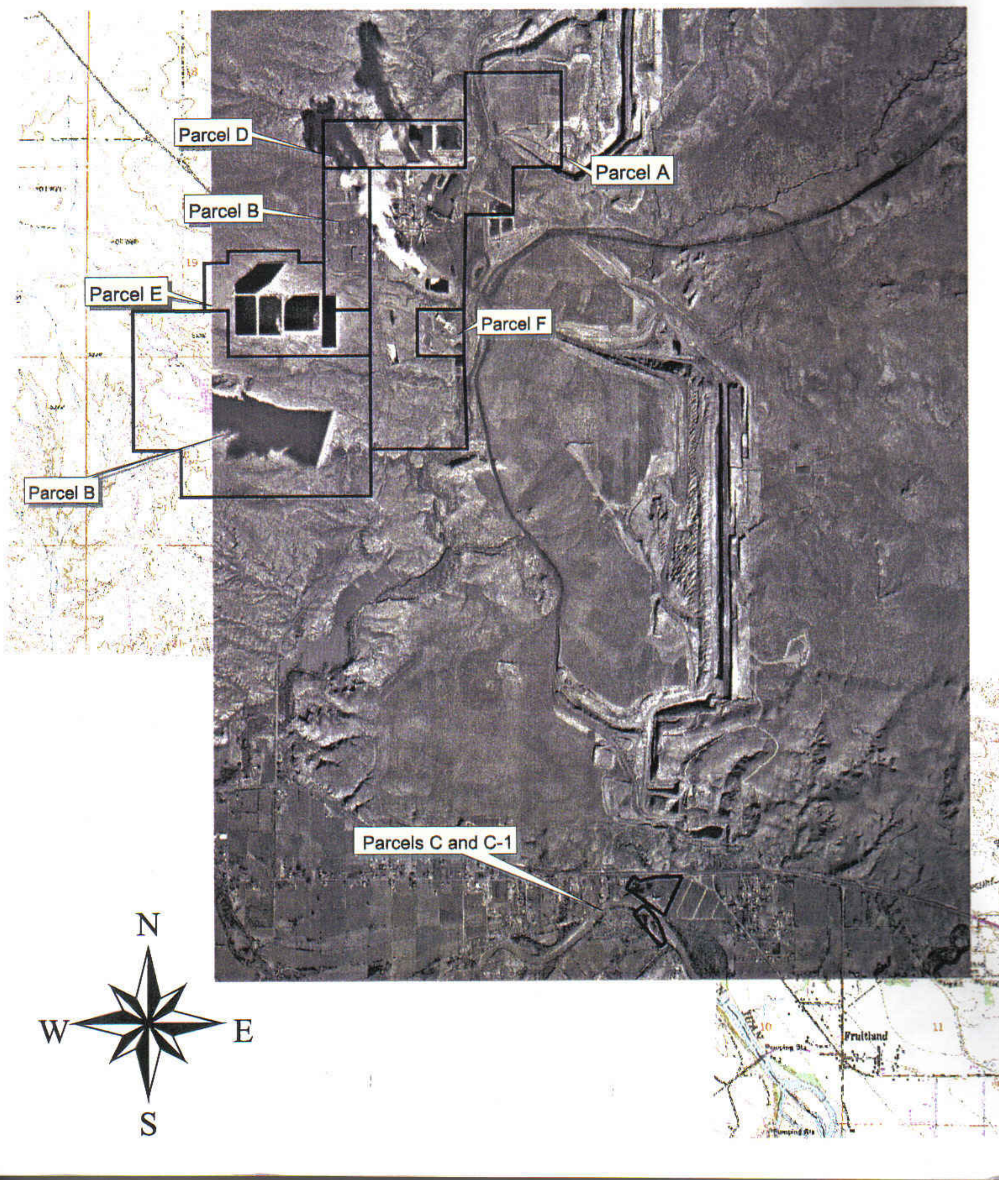
Containing 235 acres, more or less.

PARCEL F

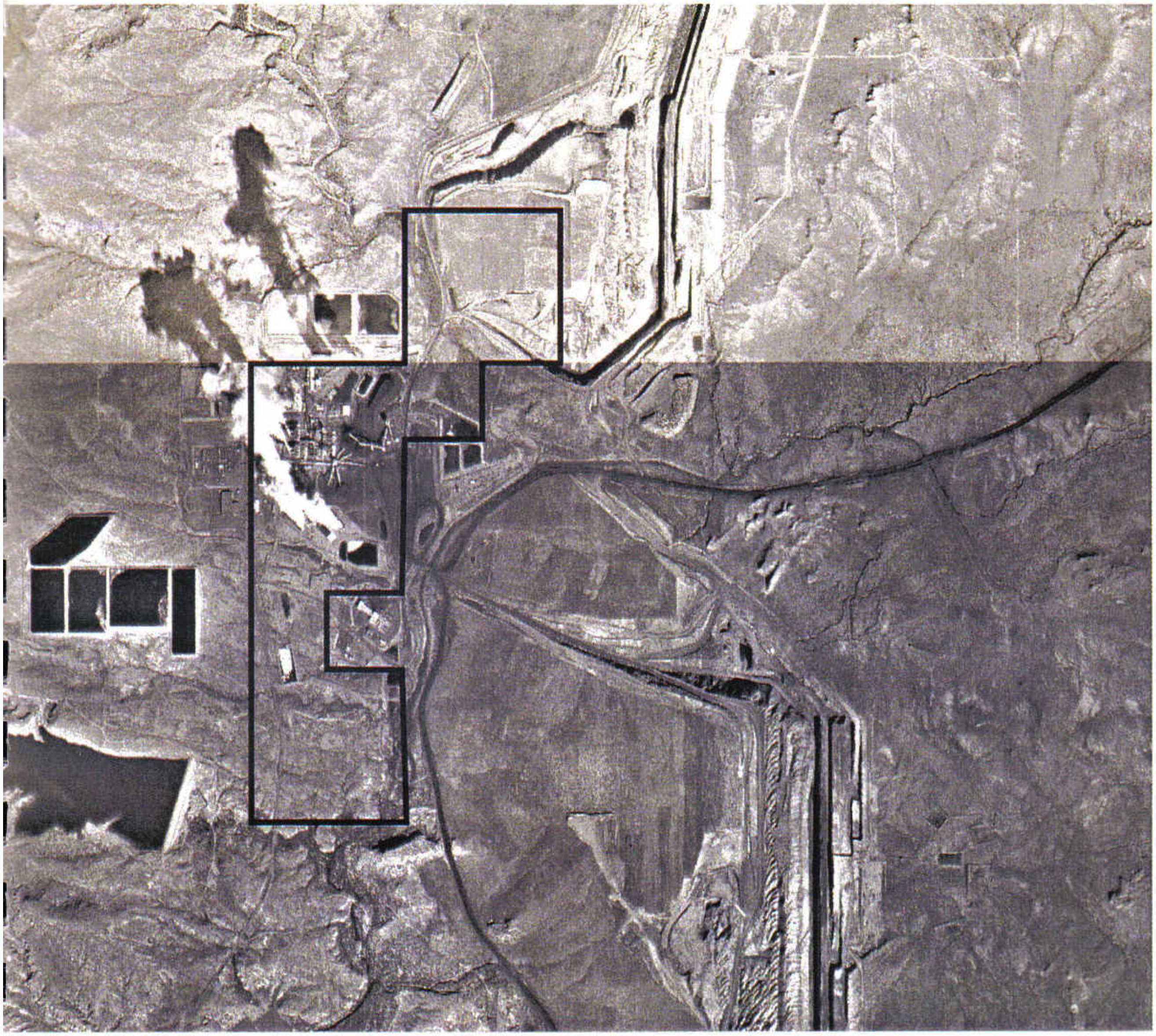
The following portions of Township 30 North, Range 15 West, N.M.P.M., San Juan County, New Mexico:

Section 20: SE 1/4 SE 1/4

San Juan Plant Properties
Overview of Parcel Location



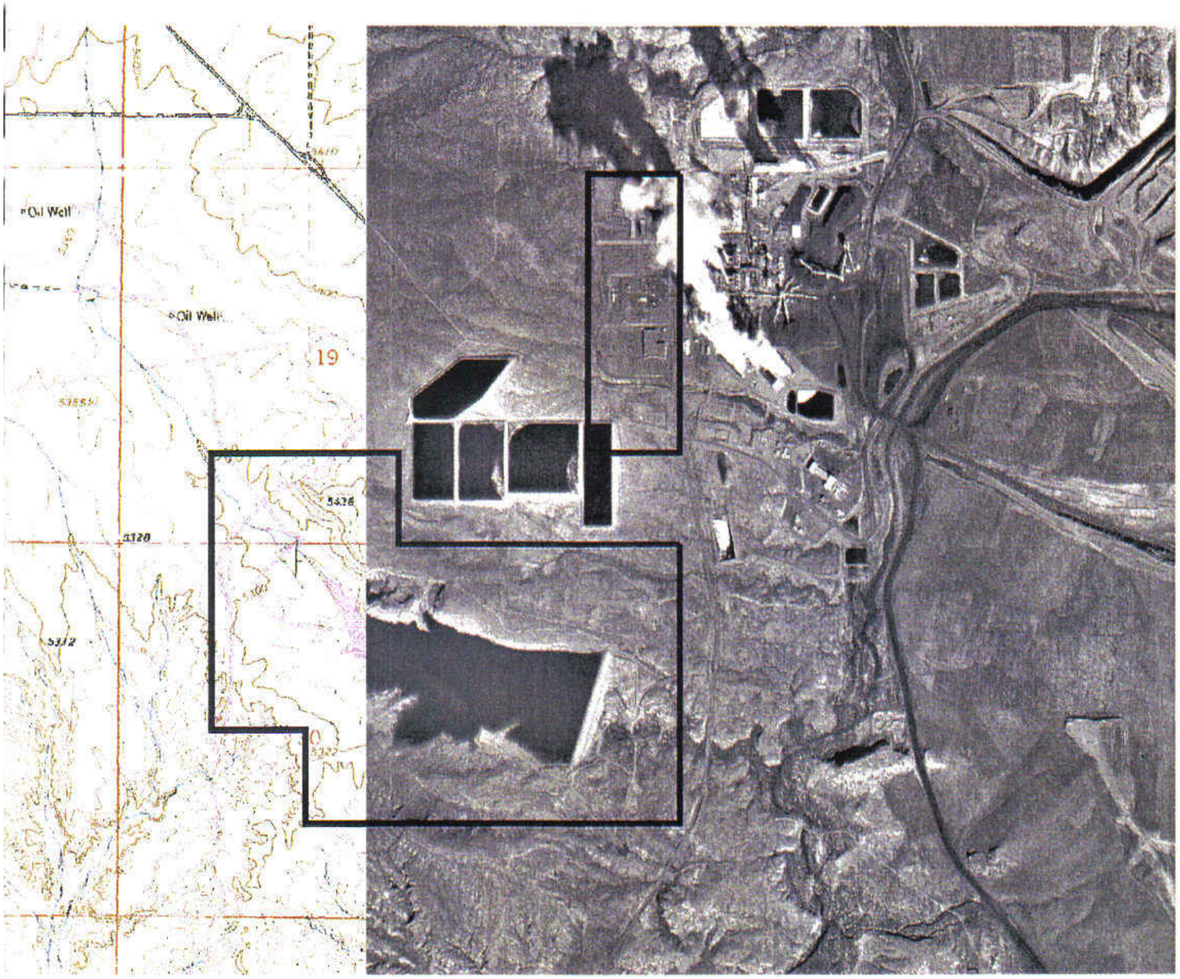
San Juan Plant Properties
Parcel A



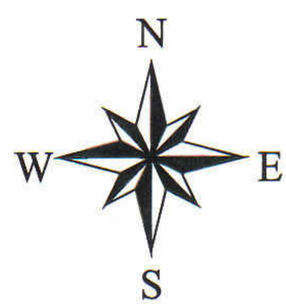
Parcel A as described in Warranty Deed 718/193

San Juan Plant Properties

Parcel B

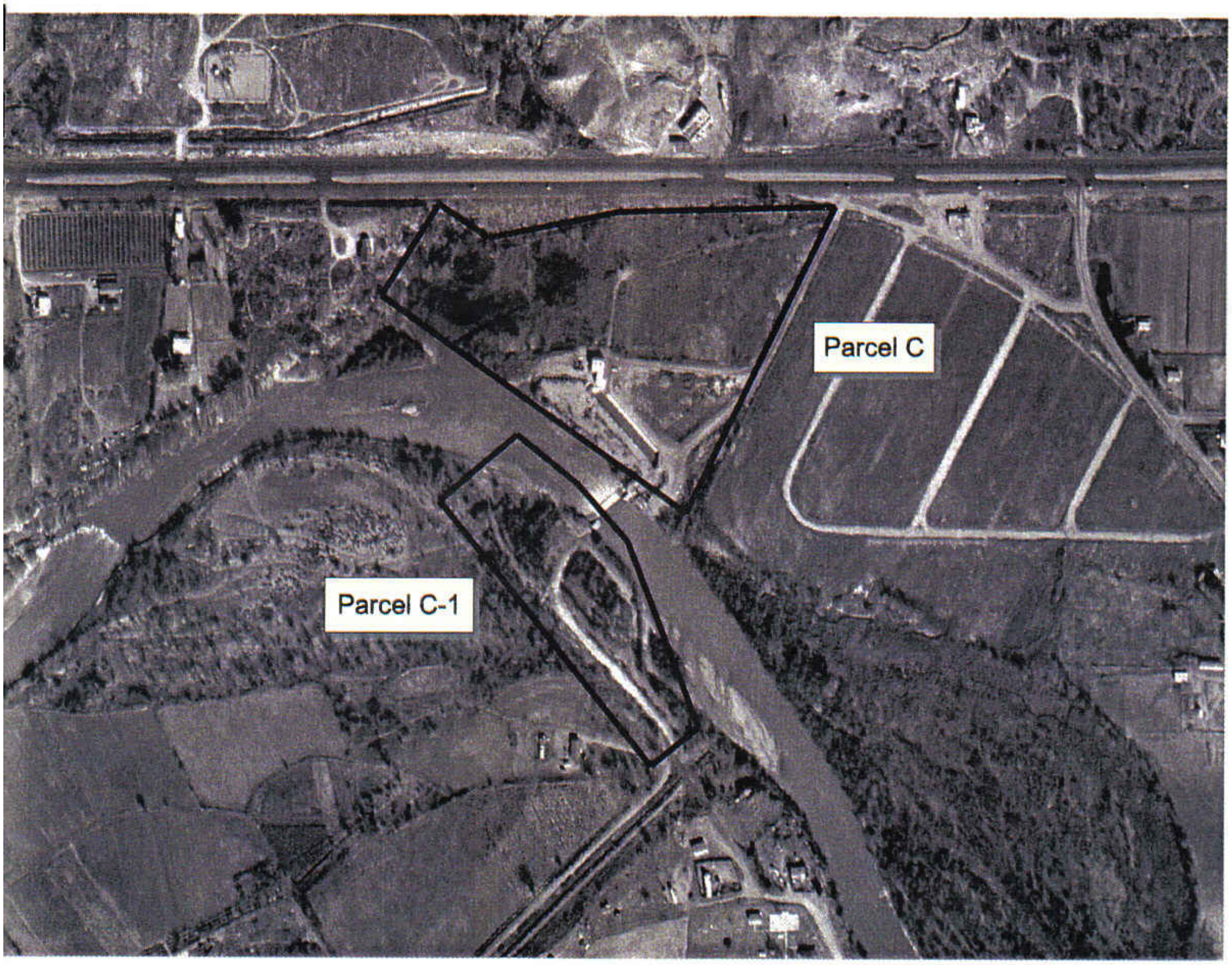


Parcel B as described in Warranty Deed Bk 706/Pg409



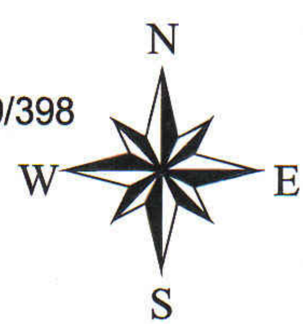
San Juan Plant Properties

Parcel C and C-1



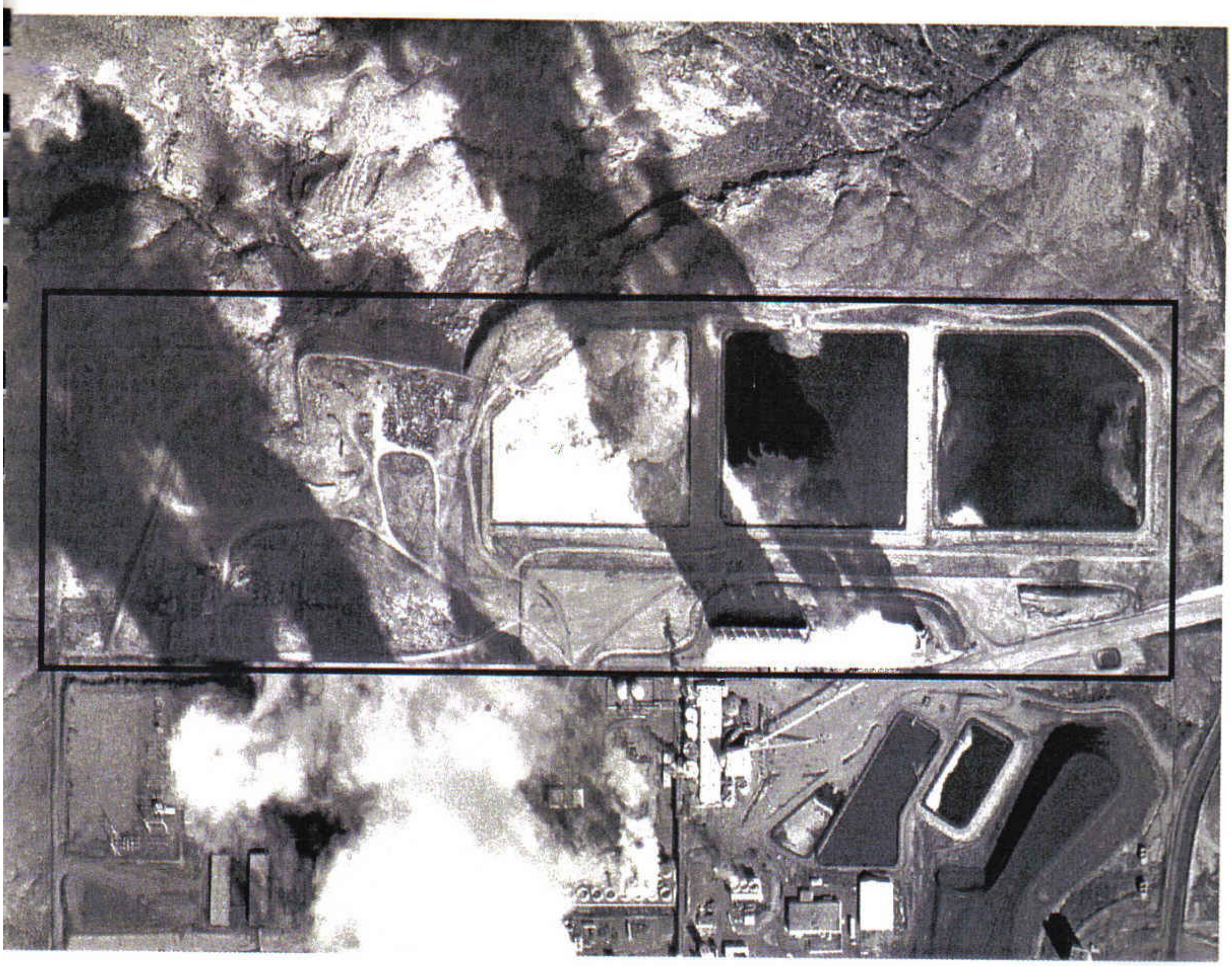
Parcel C as described in Warranty Deeds 706/407 and 919/398

Parcel C-1 - Navajo Lease dated 7-09-71

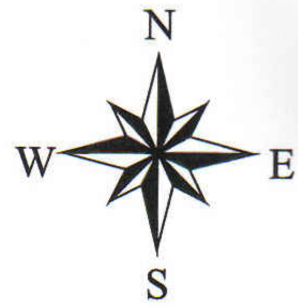


San Juan Plant Properties

Parcel D

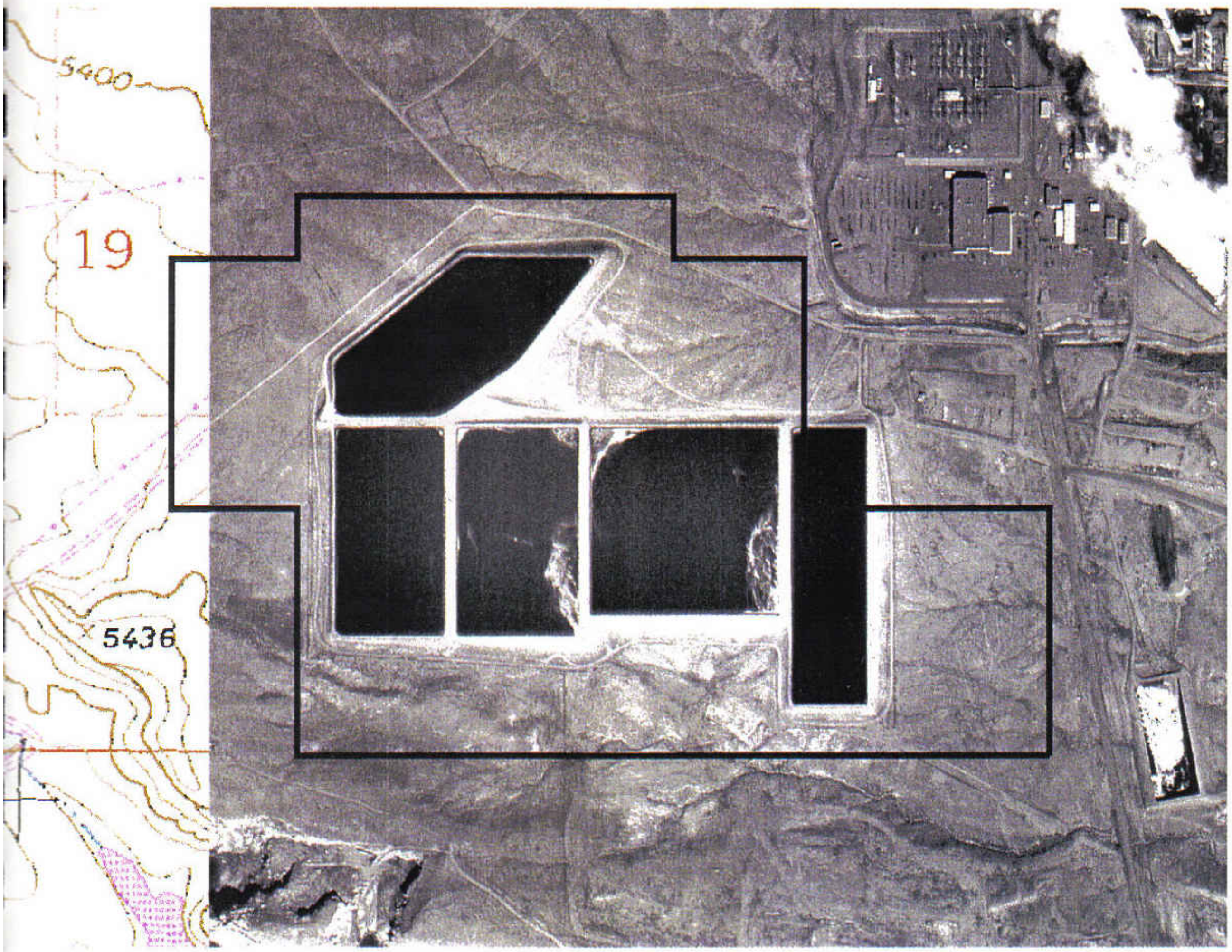


Parcel D as described in US Patent 30-81-0006

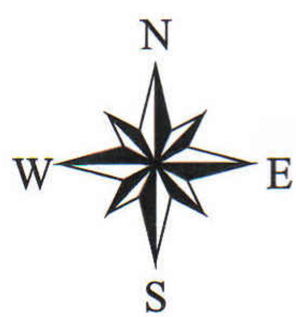


San Juan Plant Properties

Parcel E

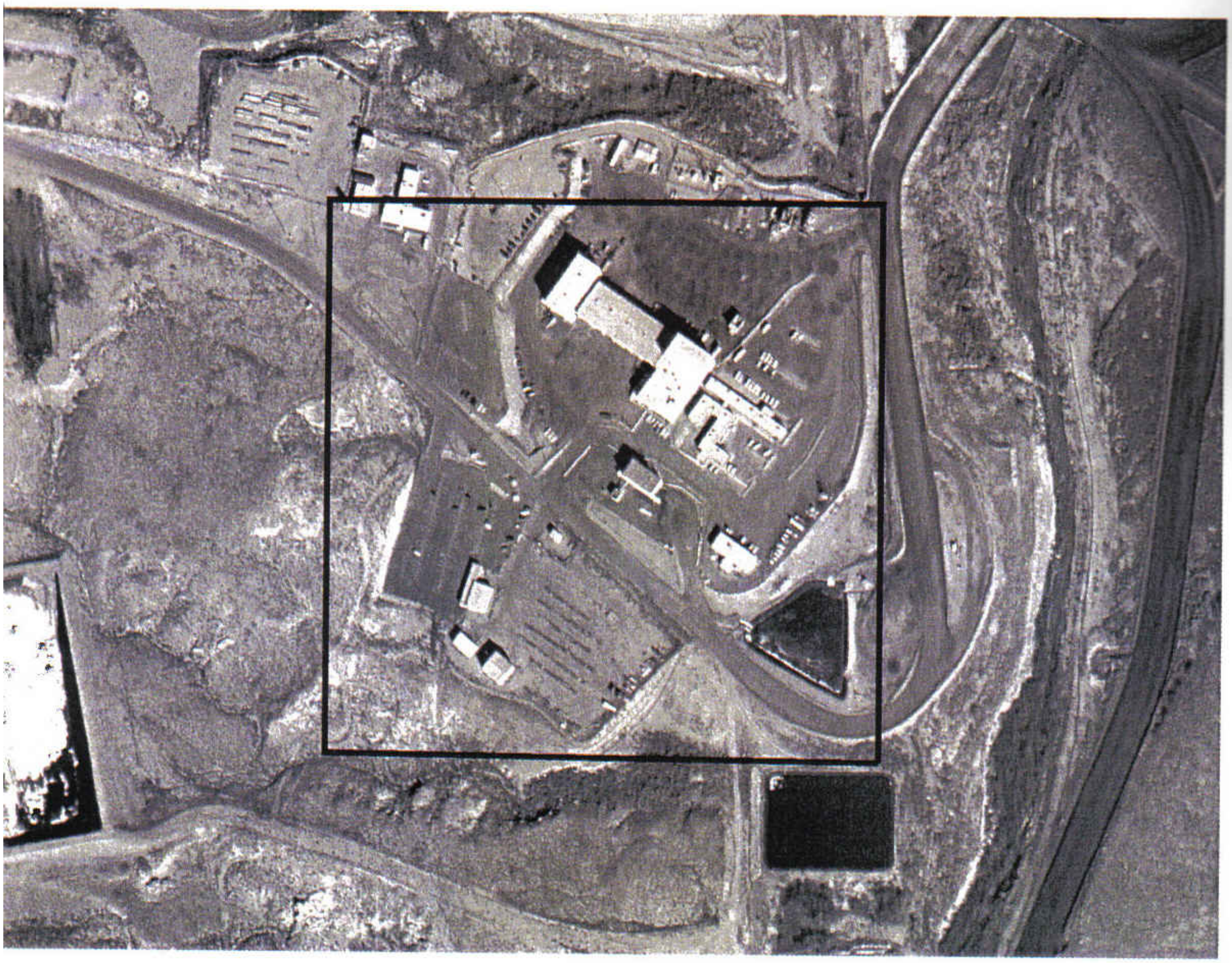


Parcel E as described in Warranty Deed 1022/328



San Juan Plant Properties

Parcel F



Parcel F as described in Warranty Deed 717/293

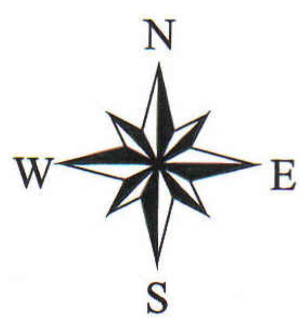


EXHIBIT II

EXHIBIT II

EXHIBIT H TO UNDERGROUND COAL SALES AGREEMENT

SAN JUAN STATION MINIMUM DELIVERIES

2003-2017

Column 1	Column 2	Column 3
Year	**Minimum Annual Tons**	**Annual Processing Tons**
2003	5,600,000	5,480,500
2004	5,600,000	5,480,500
2005	5,600,000	5,126,000
2006	5,600,000	5,126,000
2007	5,600,000	5,126,000
2008	5,600,000	5,118,000
2009	5,600,000	4,810,000
2010	5,600,000	4,810,000
2011	5,600,000	4,810,000
2012	5,600,000	4,810,000
2013	5,600,000	4,500,000
2014	5,600,000	4,500,000
2015	5,600,000	3,860,000
2016	5,600,000	3,860,000
2017	5,600,000	1,086,500
	84,000,000	68,503,500

EXHIBIT III

EXHIBIT III

SAN JUAN PROJECT SWITCHYARD FACILITIES

Material List

Phase I – Project (DWG, ED-54, ED-55)	
QUANTITY	***DESCRIPTION***
5	**345 kV Circuit Breakers – (G.E. A.T.B.'s)**
16	**345 kV Motor Operated Disconnect Switches with Stands**
2	**345 kV S&C Circuit Switches with Stands**
Lot	**Strain Bus and Fittings**
Lot	**Rigid Bus and Fittings**
4	**Line Deadend Towers**
5	**Intermediate Bus Towers**
1	**Start-Up Transformers 345/12.47/4.16 kV, 24/32/40 MVA**
1	**Set of 4.16 kV Switchgear**
1	**4.16 kV Start-Up Cable Run into Plant**
2	**4.16 kV Station Service Transformers**
1	**Set of 12.45 kV Switchgear**
3	**12.47 kV Zig-Zag Grounding Transformer**
6	**345 kV PCM Potential Transformers with Stands (Bus #1, Bus #2)**
6	**345 kV Bus Lightning Arresters with Stands**
1	**Control House 40' x 72'**
2	**Sets of Batteries & Chargers, 125 v and 48 v**
1	**Microwave Tower**
Lot	**Cable Troughs, Equipment Controls, Breaker Failure Relaying, Fault Recorder**
Lot	**Metering – Indication, Billing and Telemetry Transducers**
Lot	**Switchyard Foundations, Fencing, Grading, Grounding**
1	**Line Trap (FC Line)**
1	**345 kV PCM Potential Transformer/Coupling Capacitor with Stand**
3	**345 kV Line Lightning Arresters with Stands**
Lot	**Line Relaying, Carrier, Microwave**
1	**345-69-12470 Transformer**
1	**345/230-12470 Transformer, 230 yard**
1	**Reactor – 12.47 kV, 345 yard**

Phase 2 – Project (DWG. SK-135)	
QUANTITY	***DESCRIPTION***
4	**345 kV Circuit Breakers**
3	**345 kV Motor Operated Disconnect Switches with Stands**
Lot	**Strain Bus and Fittings**
Lot	**Rigid Bus and Fittings**
1	**Intermediate Bus Tower**
Lot	**Cable Troughs, Equipment Controls, Breaker Failure Relaying**
Lot	**Metering – Indication, Billing and Telemetry Transducers**
Lot	**Switchyard Foundations, Grounding**
Phase 3 – Project (DWG. SK-316)	
3	**345 kV Circuit Breakers**
6	**345 kV Motor Operated Disconnect Switches with Stands**
Lot	**Strain Bus and Fittings**
Lot	**Rigid Bus and Fittings**
1	**Line Deadend Tower**
2	**Intermediate Bus Towers**
Lot	**Cable Troughs, Equipment Controls, Breaker Failure Relaying**
Lot	**Metering – Indication, Billing and Telemetry Transducers**
Lot	**Switchyard Foundations and Grounding**
Phase 3 – Project (DWG. SK-317)	
2	**345 kV Circuit Breakers**
4	**345 kV Motor Operated Disconnect Switches with Stands**
Lot	**Strain Bus and Fittings**
Lot	**Rigid Bus and Fittings**
1	**Intermediate Bus Tower**
Lot	**Switchyard Foundations, Grounding**

EXHIBIT IV

EXHIBIT IV(a)

FACILITIES AND EQUIPMENT SPECIFIC
TO SAN JUAN UNIT NO. 1

Ownership

PNM -	50%	TEP -	50%
M-S-R -	0%	Farmington -	0%
Tri-State -	0%	LAC-	0%
SCPPA -	0%	Anaheim -	0%
		UAMPS -	0%

1. Turbine Generator

2. Condenser

3. Condensate and Feedwater System

   a. Condensate Pumps
   b. Feedwater Heaters
   c. Boiler Feed Pumps
   d. Storage Tanks

4. Boiler including: Air Heaters, Pulverizers, Bunkers, Feeders and Blowdown Tanks

5. Forced Draft Fans and Primary Air Fans

6. Precipitator

7. Stack and Stack Monitoring System

8. Cooling Tower

9. Circulating Water Pumps

10. Main, Start-Up, Unit Auxiliary, and SO2 Scrubber Transformers

11. Bottom Ash System (Up to but not including Dewatering Tank or Ash Water Pump building and equipment.)

12. Fly Ash System

EXHIBIT IV(a)
(continued)

13. Building HVAC System

14. SO_2 Absorbers, Scrubbers, Transfer Pumps, Booster Fans, and Flue Gas Reheat System including the 650-pound Reheat Steam Line and Desuperheater from the Plant Main Steam Line but not including the 165-pound Control Valve and Branch Line to the Chemical Plant

15. Emergency Diesel Generator

16. Electrical and Control Systems

17. SSR Protection System

18. Unit Specific Piping for all Air Systems, Chemical Feed Systems, and Hydrogen

EXHIBIT IV(b)

FACILITIES AND EQUIPMENT SPECIFIC
TO SAN JUAN UNIT NO. 2

Ownership

PNM -	50%	TEP -	50%
M-S-R -	0%	Farmington -	0%
Tri-State -	0%	LAC -	0%
SCPPA -	0%	Anaheim -	0%
		UAMPS -	0%

1. Turbine Generator

2. Condenser

3. Condensate and Feedwater System

    a. Condensate Pumps
    b. Feedwater Heaters
    c. Boiler Feed Pumps
    d. Storage Tanks

4. Boiler including: Air Heaters, Pulverizers, Bunkers, Feeders and Blowdown Tanks

5. Forced Draft Fans and Primary Air Fans

6. Precipitator

7. Stack and Stack Monitoring System

8. Cooling Tower

9. Circulating Water Pumps

10. Main, Start-Up, Unit Auxiliary, and SO2 Scrubber Transformers

11. Bottom Ash System (Up to but not including Dewatering Tank or Ash Water Pump building and equipment.)

12. Fly Ash System

EXHIBIT IV(b)
(continued)

13. Building HVAC System

14. SO2 Absorbers, Scrubbers, Transfer Pumps, Booster Fans, and Flue Gas Reheat System including the 650-pound Reheat Steam Line and Desuperheater from the Plant Main Steam Line but not including the 165-pound Control Valve and Branch Line to the Chemical Plant

15. Emergency Diesel Generator

16. Electrical and Control Systems

17. Unit Specific Piping for all Air Systems, Chemical Feed Systems, and Hydrogen

EXHIBIT IV(c)

FACILITIES AND EQUIPMENT SPECIFIC
TO SAN JUAN UNIT NO. 3

Ownership

PNM -	50%	TEP -	0%
M-S-R -	0%	Farmington -	0%
Tri-State -	8.2%	LAC -	0%
SCPPA -	41.8%	Anaheim -	0%
		UAMPS -	0%

1. Turbine Generator

2. Condenser

3. Condensate and Feedwater System

    a. Condensate Pumps
    b. Feedwater Heaters
    c. Boiler Feed Pumps
    d. Storage Tanks

4. Boiler including: Air Heaters, Pulverizers, Bunkers, Feeders and Blowdown Tanks

5. Forced Draft Fans and Primary Air Fans

6. Precipitator

7. Stack and Stack Monitoring System

8. Cooling Tower

9. Circulating Water Pumps

10. Main, Unit Auxiliary 3A and 3B Transformers*

11. Bottom Ash System including: Hopper, Dewatering Tank, Setting Tank, Surge Tank, Storage Tank, and Pump House

12. Fly Ash System

EXHIBIT IV(c)
(continued)

13. Building HVAC System

14. SO2 Absorbers, Scrubbers, Transfer Pumps, Booster Fans, and Flue Gas Reheat System

15. Emergency Diesel Generator

16. Electrical and Control Systems

17. Fuel Oil Ignitor Heaters and Unit Specific Piping

18. Unit Specific Piping for all Air Systems, Chemical Feed Systems, and Hydrogen

19. Coal Reclaim Hoppers, Feeders, Feeder Belts, Belt Scales, Fire Protection System, and 3C Conveyor to the Secondary Crusher Building

20. SSR Protection System

21. Auxiliary Steam Header Piping System:

    a. Including the Unit Specific Branch Line to the Reheat System
    b. Not included is the Branch Line to the Chemical Plant

* PNM and TEP each owns a 50% interest in the main unit transformer

EXHIBIT IV(d)

FACILITIES AND EQUIPMENT SPECIFIC
TO SAN JUAN UNIT NO. 4

Ownership

PNM -	38.457%	TEP -	0%
M-S-R -	28.8%	Farmington -	8.475%
Tri-State -	0%	LAC -	7.2%
SCPPA -	0%	Anaheim -	10.04%
		UAMPS -	7.028%

1. Turbine Generator

2. Condenser

3. Condensate and Feedwater System

    a. Condensate Pumps
    b. Feedwater Heaters
    c. Boiler Feed Pumps
    d. Storage Tanks

4. Boiler including: Air Heaters, Pulverizers, Bunkers, Feeders and Blowdown Tanks

5. Forced Draft Fans and Primary Air Fans

6. Precipitator

7. Stack and Stack Monitoring System

8. Cooling Tower

9. Circulating Water Pumps

10. Main, Unit Auxiliary 4A and 4B Transformers

11. Bottom Ash System including: Hopper, Dewatering Tank, Setting Tank, Surge Tank, Storage Tank, and Pump House

12. Fly Ash System

EXHIBIT IV(d)
(continued)

13. Building HVAC System

14. SO2 Absorbers, Scrubbers, Transfer Pumps, Booster Fans, and Flue Gas Reheat System

15. Emergency Diesel Generator

16. Electrical and Control Systems

17. Fuel Oil Ignitor Heaters and Unit Specific Piping

18. Unit Specific Piping for all Air Systems, Chemical Feed Systems, and Hydrogen

19. Coal Reclaim Hoppers, Feeders, Feeder Belts, Belt Scales, Fire Protection System, and 3D Conveyor to the Secondary Crusher Building

20. Auxiliary Steam Header Piping System:

    a. Including the Unit Specific Branch Line to the Reheat System
    b. Not included is the Branch Line to the Chemical Plant

EXHIBIT IV(e)

FACILITIES AND EQUIPMENT SPECIFIC
TO SAN JUAN UNITS NO. 1 AND 2

Ownership

PNM -	50%	TEP -	50%
M-S-R -	0%	Farmington -	0%
Tri-State -	0%	LAC -	0%
SCPPA -	0%	Anaheim -	0%
		UAMPS -	0%

1. Bearing Cooling Water System

2. Bottom Ash Dewatering Facility including: Dewatering Tank, Settling Tank, Surge Tank, Storage Tank, and Pump House

3. Demineralizer System including: Clarifier, Storage Tanks, and Sump Pump

4. Fuel Oil System (Fuel Oil for Ignition and Flame Stabilization)

5. Premix Tank Facility (This was the wastewater neutralizer facility and is now operated as part of the Water Management System.)

6. Instrument Air system, except Unit Piping

7. Chemical Feed System, except Unit Piping

   a. Condensate and Feedwater System
   b. Boiler
   c. Bearing Cooling Water System
   d. Cooling Tower Systems
   e. Chlorination System

8. Plant Air System, except Unit Piping

9. Sootblowing Air System, except Unit Piping

10. Hydrogen Storage System, except Unit Piping

EXHIBIT IV(e)
(continued)

11. Coal Handling Reclaim Systems A and B including: Hoppers, Feeders, Reclaim Conveyors, Belt Scales, and Sprinkler System

12. Coal Tripper System south of column, Line 12 including Dust Collection System

13. Turbine Lube Oil Storage and Transfer System

14. Control Room, Equipment Rooms, and Associated HVAC System

15. Turbine Crane south of column, Line 12

16. Fuel Oil, Ash, and Water Pipe Racks

17. Boiler Fill System for Units 1 and 2

18. All spare parts common to either unit

19. SO2 Backup Scrubber-Absorber Transformer

20. SAR Multiplexer Control System

EXHIBIT IV(f)

FACILITIES AND EQUIPMENT SPECIFIC
TO SAN JUAN UNITS NO. 3 AND 4

Ownership

PNM -	44.119%	TEP -	0%
M-S-R -	14.4%	Farmington -	4.249%
Tri-State -	4.1%	LAC -	3.612%
SCPPA -	20.9%	Anaheim -	5.07%
		UAMPS -	3.55%

1. Bearing Cooling Water System

2. Demineralizer System: including Sump Pumps, Filter Beds, and Storage Tanks

3. Fuel Oil System (Fuel Oil for Ignition and Flame Stabilization except Ignitor Heaters and Unit Specific Piping)

4. Wastewater Neutralizer Facility (This facility is operated as part of Water Management System.)

5. Instrument Air System except Unit Piping

6. Chemical Feed System except Unit Piping

    a. Condensate and Feedwater System
    b. Boiler
    c. Bearing Cooling Water System
    d. Cooling Tower Systems
    e. Chlorination System

7. Plant Air System except Unit Piping

8. Sootblowing Air System except Unit Piping

9. Start-Up Transformers and Nonseg Bus to Units 3 and 4 Switchgear

10. Hydrogen Storage System except Unit Piping

11. Coal Tripper System Serving Units 3 and 4 including Dust Collection Systems

EXHIBIT IV(f)
(continued)

12. Turbine Lube Oil Storage and Transfer System

13. Control Room, Equipment Rooms, and Associated HVAC System

14. Boiler Fill System for Units 3 and 4

15. Auxiliary Cooling Systems including Auxiliary Cooling Tower No. 1 and Pumps, but excepting No. 4 Tower Pumps and Piping which is Unit Specific

16. CO2 Storage System

17. Start-Up Boiler Feed Pump

18. Turbine Bay Crane north of column, Line 12

19. Fuel Oil, Ash, and Water Pipe Racks

20. Fire Water Booster and Jockey Pumps

21. Halon Fire Protection System

22. Cooling Tower Multiplex Control System

23. All spare parts common to either unit

EXHIBIT IV(g)

FACILITIES AND EQUIPMENT
COMMON TO ALL FOUR SAN JUAN UNITS

Ownership

PNM -	46.29%	TEP -	19.8%
M-S-R -	8.7%	Farmington -	2.559%
Tri-State -	2.49%	LAC -	2.175%
SCPPA -	12.71%	Anaheim -	3.10%
		UAMPS -	2.169%

1. River and Raw Water System including:

   a. Diversion and intake structures, including all equipment and pump building.
   b. Raw Water line to reservoir.
   c. Reservoir, pump buildings, and all equipment.
   d. Raw water lines to plant yard.
   e. All above and underground fire protection system to each vendor supplied or unit specific fire protection system.

2. Auxiliary Boiler

3. SO2 Removal System except Absorbers

NOTE: The new SO2 Absorber Feed System is being placed in-service to replace the SO2 Chemical Plant previously used by the Project. The SO2 Chemical Plant facilities will be retired in place and will be salvaged or decommissioned at a later date. Section 3.1 describes the new SO2 Absorber Feed System while Section 3.2 describes the old SO2 Chemical Plant.

3.1 SO2 Absorber Feed System

   a. Limestone Handling System
   b. Limestone Preparation System
   c. Dewatering System
   d. Gypsum Stack Out System

EXHIBIT IV(g)
(continued)

3.2 SO_2 Chemical Plant

a. Double effect evaporator train systems.
b. Fly ash filter system.
c. Absorber product and feed tanks.
d. Condensate collection, storage, and transfer systems.
e. Soda ash storage, mixing, and distribution systems.
f. Sulfate purge system including: crystallizers, centrifuges, evaporators, and salt cake system.
g. Sulfuric acid plant system including storage tanks and load out system.
h. Auxiliary. No. 2 cooling tower, pumps, and systems.

4. Spare-Main Transformer 345/24 kV for all units.

5. Maintenance, Office, and Warehousing Facilities

6. Chemical Laboratory

7. Coal and Ash Handling Control Facilities

8. Roads and grounds such as fencing, yard lighting, guard facilities, drainage, and dikes.

9. Potable Water System

10. Environmental Monitoring systems including Air, Water, and Ground. Excludes Stack Monitoring Systems which are unit specific.

11. Transportation such as trucks, cars, and dozers (not otherwise charged).

12. Water Management System

a. Wastewater Recovery System -- Northside

1. Reverse osmosis system including lime/soda softening clarifier system.
2. Brine concentrator Nos. 4 and 5.
3. Process pond No. 3 and pump system
4. North evaporation ponds 1, 2, and 3.

EXHIBIT IV(g)
(continued)

b. SO2 Waste Treatment System -- Southside

1. Process ponds 1A, 1 B, 2 and pumping system.
2. Premix tank and clarifier system.
3. Oxidation towers.
4. Brine concentrator Nos. 2 and 3.
5. South evaporation ponds Nos. 1, 2, 3, 4, and 5.

c. Data Acquisition System
d. Solid Waste Disposal Pit
e. Coal pile runoff pond

13. Coal Transfer Facilities from the Reclaim Conveyors to the Head-End of Plat Belts 4A and 4B and Dust Suppression Systems

14. Maintenance Bay Facilities including: Bay Bridge Crane, all Offices, and Support Facilities

15. Sewage Treatment Facilities

16. On each of Units 1 and 2, the Chemical Plant 165-pound Control Valve, and Branch Line from the Unit Specific 650-pound Rehear Steam Line

17. On each of Units 3 and 4, the Chemical Plant Branch Steam Line from the Unit Specific Auxiliary Steam Header System

EXHIBIT IV(h)

SAN JUAN PROJECT
SWITCHYARD FACILITIES

Cost Allocation (%)

	Installed Cost		Replacements/Improvements Betterments	
	PNM	TEP	PNM	TEP
345 kV Bus 1 & 3 (East Bus)	50	50	50	50
Bus 2 (West Bus)	50	50	50	50
Circuit Breakers				
06582 (345/230)	50	50	50	50
05482	50	50	50	50
04382 (OJO)	50	50	50	50
12982 (McKinley)	50	50	50	50
11882	50	50	50	50
10782 (Unit 4)	50	50	50	50
09882 (McKinley)	58.33	41.67	62.5	37.5
08782	54.16	45.84	56.25	43.75
07682 (Unit 3)	50	50	50	50
15282 (Four Comers)	50	50	50	50
14182	50	50	50	50
13082 (Unit 2)	50	50	50	50
18582 (West Mesa)	50	50	50	50
17482	50	50	50	50
16382 (Unit 1)	50	50	50	50
20782	50	50	50	50
Shunt Reactors				
Ojo	100	0	100	0
McKinley 1	5.36	94.64	5.36	94.64
McKinley 2	16.67	83.33	25	75
WW (BA)	100	0	100	0

EXHIBIT IV(h)

(continued)

	Installed Cost		Replacements/Improvements Betterments	
	PNM	TEP	PNM	TEP
Transformers				
Station Aux. No. 2 400 MVA, 345/230-12.5	100	0	100	0
Station Aux. No. 1 345/4.16-12.5	50	50	50	50
Station Aux. No. 3 90 MVA, 345/69-12.5	50	50	50	50
Future Facilities				
345/69/12 kV	66.67	33.33	66.67	33.33
2-345 kV Bkrs (Durango)	50	50	50	50
Lower Voltage				
230 kV Control Hse	83.33	16.67	83.33	16.67
230/69 kV Trf	66.67	33.33	66.67	33.33
Shiprock 230 kV line	100	0	100	0

EXHIBIT V

EXHIBIT V(a)

FACILITIES AND EQUIPMENT
SPECIFIC TO SAN JUAN UNIT NO. 1

Operation and Maintenance Costs

PNM -	50%	TEP -	50%
M-S-R -	0%	Farmington -	0%
Tri-State -	0%	LAC -	0%
SCPPA -	0%	Anaheim -	0%
		UAMPS -	0%

1. Turbine Generator

2. Condenser

3. Condensate and Feedwater System

   a. Condensate Pumps
   b. Feedwater Heaters
   c. Boiler Feed Pumps
   d. Storage Tanks

4. Boiler including: Air Heaters, Pulverizers, Bunkers, Feeders and Blowdown Tanks

5. Forced Draft Fans and Primary Air Fans

6. Precipitator

7. Stack and Stack Monitoring System

8. Cooling Tower

9. Circulating Water Pumps

10. Main, Start-Up, Unit Auxiliary, and SO2 Scrubber Transformers

11. Bottom Ash System (Up to but not including Dewatering Tank or Ash Water Pump building and equipment)

12. Fly Ash System

EXHIBIT V(a)
(continued)

13. Building HVAC System

14. SO_2 Absorbers, Scrubbers, Transfer Pumps, Booster Fans, and Flue Gas Reheat System including the 650-pound Reheat Steam Line and Desuperheater from the Plant Main Steam Line but not including the 165-pound Control Valve and Branch Line to the Chemical Plant

15. Emergency Diesel Generator

16. Electrical and Control Systems

17. SSR Protection System

18. Unit Specific Piping for all Air Systems, Chemical Feed Systems, and Hydrogen

EXHIBIT V(b)

FACILITIES AND EQUIPMENT
SPECIFIC TO SAN JUAN UNIT NO. 2

Operation and Maintenance Costs

PNM -	50%	TEP -	50%
M-S-R -	0%	Farmington -	0%
Tri-State -	0%	LAC -	0%
SCPPA -	0%	Anaheim -	0%
		UAMPS -	0%

1. Turbine Generator

2. Condenser

3. Condensate and Feedwater System

   a. Condensate Pumps
   b. Feedwater Heaters
   c. Boiler Feed Pumps
   d. Storage Tanks

4. Boiler including: Air Heaters, Pulverizers, Bunkers, Feeders and Blowdown Tanks

5. Forced Draft Fans and Primary Air Fans

6. Precipitator

7. Stack and Stack Monitoring System

8. Cooling Tower

9. Circulating Water Pumps

10. Main, Start-Up, Unit Auxiliary, and SO2 Scrubber Transformers

11. Bottom Ash System (Up to but not including Dewatering Tank or Ash Water Pump building and equipment)

12. Fly Ash System

EXHIBIT V(b)
(continued)

13. Building HVAC System

14. SO_2 Absorbers, Scrubbers, Transfer Pumps, Booster Fans, and Flue Gas Reheat System including the 650-pound Reheat Steam Line and Desuperheater from the Plant Main Steam Line but not including the 165-pound Control Valve and Branch Line to the Chemical Plant

15. Emergency Diesel Generator

16. Electrical and Control Systems

17. Unit Specific Piping for all Air Systems, Chemical Feed Systems, and Hydrogen

EXHIBIT V(c)

FACILITIES AND EQUIPMENT
SPECIFIC TO SAN JUAN UNIT NO. 3

Operation and Maintenance Costs

PNM -	50%	TEP -	0%
M-S-R -	0%	Farmington -	0%
Tri-State -	8.2%	LAC -	0%
SCPPA -	41.8%	Anaheim -	0%
		UAMPS -	0%

1. Turbine Generator

2. Condenser

3. Condensate and Feedwater System

    a. Condensate Pumps
    b. Feedwater Heaters
    c. Boiler Feed Pumps
    d. Storage Tanks

4. Boiler including: Air Heaters, Pulverizers, Bunkers, Feeders and Blowdown Tanks

5. Forced Draft Fans and Primary Air Fans

6. Precipitator

7. Stack and Stack Monitoring System

8. Cooling Tower

9. Circulating Water Pumps

10. Main, Unit Auxiliary 3A and 3B Transformers

11. Bottom Ash System including: Hopper, Dewatering Tank, Setting Tank, Surge Tank, and Pump House

12. Fly Ash System

EXHIBIT V(c)
(continued)

13. Building HVAC System

14. SO2 Absorbers, Scrubbers, Transfer Pumps, Booster Fans, and Flue Gas Reheat System including the Reheat Steam Line from the Auxiliary Steam Header

15. Emergency Diesel Generator

16. Electrical and Control Systems

17. Fuel Oil Ignitor Heaters and Unit Specific Piping

18. Unit Specific Piping for all Air Systems, Chemical Feed Systems, and Hydrogen

19. SSR Protection System

20. Auxiliary Steam Header Piping System:

    a. Including the Unit Specific Branch Line to the Reheat System
    b. Not included is the Branch Line to the Chemical Plant

EXHIBIT V(d)

FACILITIES AND EQUIPMENT
SPECIFIC TO SAN JUAN UNIT NO. 4

Operation and Maintenance Costs

PNM -	38.457%	TEP -	0%
M-S-R -	28.8%	Farmington -	8.475%
Tri-State -	0%	LAC -	7.2%
SCPPA -	0%	Anaheim -	10.04%
		UAMPS -	7.028%

1. Turbine Generator

2. Condenser

3. Condensate and Feedwater System

    a. Condensate Pumps
    b. Feedwater Heaters
    c. Boiler Feed Pumps
    d. Storage Tanks

4. Boiler including: Air Heaters, Pulverizers, Bunkers, Feeders and Blowdown Tanks

5. Forced Draft Fans and Primary Air Fans

6. Precipitator

7. Stack and Stack Monitoring System

8. Cooling Tower

9. Circulating Water Pumps

10. Main, Unit Auxiliary 4A and 4B Transformers

11. Bottom Ash System including: Hopper, Dewatering Tank, Setting Tank, Surge Tank, and Pump House

12. Fly Ash System

EXHIBIT V(d)
(continued)

13. Building HVAC System

14. SO_2 Absorbers, Scrubbers, Transfer Pumps, Booster Fans, and Flue Gas Reheat System including the Reheat Steam Line from the Auxiliary Steam Header

15. Emergency Diesel Generator

16. Electrical and Control Systems

17. Fuel Oil Ignitor Heaters and Unit Specific Piping

18. Unit Specific Piping for all Air Systems, Chemical Feed Systems, and Hydrogen

19. Auxiliary Steam Header Piping System:

    a. Including the Unit Specific Branch Line to the Reheat System
    b. Not included is the Branch Line to the Chemical Plant

EXHIBIT V(e)

FACILITIES AND EQUIPMENT
COMMON TO SAN JUAN UNITS NO. 1 AND 2

Operation and Maintenance Costs

PNM -	50%	TEP -	50%
M-S-R -	0%	Farmington -	0%
Tri-State -	0%	LAC -	0%
SCPPA -	0%	Anaheim -	0%
		UAMPS -	0%

1. Bearing Cooling Water System except Unit Piping

2. Bottom Ash Dewatering Facility including: Dewatering Tank, Settling Tank, Surge Tank, Storage Tank, and Pump House

3. Fuel Oil System (Fuel Oil for Ignition and Flame Stabilization)

4. Instrument Air System, except Unit Piping

5. Chemical Feed System, except Unit Piping

    a. Condensate and Feedwater System
    b. Boiler
    c. Bearing Cooling Water System
    d. Cooling Tower Systems
    e. Chlorination System

6. Plant Air System, except Unit Piping

7. Sootblowing Air System, except Unit Piping

8. Hydrogen Storage System, except Unit Piping

9. Coal Tripper System including Dust Collection System

10. Turbine Lube Oil Storage and Transfer System

11. Control Room, Equipment Rooms, and Associated HVAC System

EXHIBIT V(e)
(continued)

12. SO2 Backup Scrubber-Absorber Transformer

13. Turbine Crane south of column, Line 12

14. Fuel Oil, Ash, and Water Pipe Racks

15. Boiler Fill System

16. SAR Multiplexer Control System

EXHIBIT V(f)

FACILITIES AND EQUIPMENT
COMMON TO SAN JUAN UNITS NO. 3 AND 4

Operation and Maintenance Costs

PNM -	44.119%	TEP -	0%
M-S-R -	14.4%	Farmington -	4.249%
Tri-State -	4.1%	LAC-	3.612%
SCPPA -	20.9%	Anaheim -	5.07%
		UAMPS -	3.55%

1. Bearing Cooling Water System except Unit Piping

2. Fuel Oil System (Fuel Oil for Ignition and Flame Stabilization except Ignitor Heaters and Unit Specific Piping)

3. Instrument Air System except Unit Piping

4. Chemical Feed System except Unit Piping

   a. Condensate and Feedwater System
   b. Boiler
   c. Bearing Cooling Water System
   d. Cooling Tower Systems
   e. Chlorination System

5. Plant Air System except Unit Piping

6. Sootblowing Air System except Unit Piping

7. Start-Up Transformers and Nonseg Bus to Units 3 and 4 Switchgear

8. Hydrogen Storage System except Unit Piping

9. Coal Tripper System including Dust Collection Systems

10. Turbine Lube Oil Storage and Transfer System

11. Control Room, Equipment Rooms, and Associated HVAC System

EXHIBIT V(f)
(continued)

12. Boiler Fill System

13. Auxiliary Cooling Systems including Auxiliary Cooling Tower No. 1 and Pumps, but excepting No. 4 Tower Pumps and Piping which is Unit Specific

14. CO_2 Storage System except Unit Piping

15. Start-Up Boiler Feed Pump except Unit Piping

16. Turbine Bay Crane north of column, Line 12

17. Fuel Oil, Ash, and Water Pipe Racks

18. Fire Water Booster and Jockey Pumps

19. Halon Fire Protection System

20. Cooling Tower Multiplex Control System

EXHIBIT V(g)

FACILITIES AND EQUIPMENT
COMMON TO ALL FOUR SAN JUAN UNITS

Operation and Maintenance Costs

PNM -	46.297%	TEP -	19.8%
M-S-R -	8.7%	Farmington -	2.559%
Tri-State -	2.49%	LAC -	2.175%
SCPPA -	12.71%	Anaheim -	3.10%
		UAMPS -	2.169%

1. River and Raw Water System including:

   a. Diversion and intake structures, including all equipment and pump building.
   b. Raw Water line to reservoir.
   c. Reservoir, pump buildings, and all equipment.
   d. Raw water lines to plant yard.
   e. All above and underground fire protection system to each vendor supplied or unit specific fire protection system.

2. Auxiliary Boiler

3. SO2 Removal System except Absorbers

NOTE: In April 1998 the new SO2 Absorber Feed System went in-service and replaced the SO2 Chemical Plant previously used by the Project. The SO2 Chemical Plant facilities are retired in place and will be salvaged or decommissioned at a later date. Section 3.1 describes the new SO2 Absorber Feed System while Section 3.2 describes the old SO2 Chemical Plant.

3.1 SO2 Absorber Feed System

   a. Limestone Handling System
   b. Limestone Preparation System
   c. Dewatering System
   d. Gypsum Stack Out System

3.2 SO2 Chemical Plant

a. Double effect evaporator train systems.
b. Fly ash filter system.
c. Absorber product and feed tanks.
d. Condensate collection, storage, and transfer systems.
e. Soda ash storage, mixing, and distribution systems.
f. Sulfate purge system including: crystallizers, centrifuges, evaporators, and salt cake system.
g. Sulfuric acid plant system including storage tanks and load out system.
h. Auxiliary No. 2 cooling tower, pumps, and systems.

4. Spare-Main Transformer 345/24 kV for all units.

5. Maintenance, Office, and Warehousing Facilities

6. Chemical Laboratory

7.* Coal and Ash Handling Control Facilities

8. Roads and grounds such as fencing, yard lighting, guard facilities, drainage, and dikes.

9. Potable Water System

10. Environmental Monitoring systems including Air, Water, and Ground. Excludes Stack Monitoring Systems which are unit specific.

11. Transportation such as trucks, cars, and dozers (not otherwise charged).

12. Water Management System

a. Wastewater Recovery System -- Northside

1. Neutralization system including premix tank, neutralization tank, clarifier/thickener, and pumps.
2. Reverse osmosis system including lime/soda softening clarifier system.
3. Brine concentrator Nos. 4 and 5.
4. Process pond No. 3 and pump system.
5. North evaporation ponds 1, 2, and 3.

EXHIBIT V(g)
(continued)

b. SO_2 Waste Treatment System -- Southside

1. Process ponds 1A, 1B, 2 and pumping system.
2. Premix tank and clarifier system.
3. Oxidation towers.
4. Brine concentrator Nos. 2 and 3.
5. South evaporation ponds Nos. 1, 2, 3, 4, and 5.

c. Data Acquisition System
d. Solid Waste Disposal Pit
e. Coal pile runoff pond

13.* Coal Handling Equipment -- all equipment from all reclaim hoppers ending at the chutes to the tripper conveyors. This includes: hoppers. feeders. feeder belts, reclaim conveyors, plant conveyors, belt scales, fire protection systems, dust suppression systems, magnetic separators, all electrical and controls, and heating and ventilation systems.

14. Maintenance Bay Facilities including: Bay Bridge Crane, all Offices, and Support Facilities

15. Sewage Treatment Facilities

16. All Demineralizer Systems including: Clarifier, Storage Tanks, Sump Pumps, Filter Beds, and Control Systems.

17. The Chemical Plant 165-pound Control Valve and Branch Line from each of Units 1 and 2 Unit Specific 650-pound Reheat Steam Line.

18. The Chemical Plant Branch Steam Line from (but not including) the Unit Specific Auxiliary, Steam Header System on each of Units 3 and 4.

*Maintenance Only

EXHIBIT V(h)

FACILITIES AND EQUIPMENT
COMMON TO ALL FOUR SAN JUAN UNITS

Operation Costs Only

PNM	
M-S-R	
TEP	Variable split based on generation by unit
Farmington	
Tri-State	
LAC	
SCPPA	
Anaheim	
UAMPS	

1. Coal and Ash Handling Control Facilities

2. Coal Handling Equipment

   All equipment from all reclaim hoppers ending at the chutes to the tripper conveyors. This includes: hoppers, feeders, feeder belts, reclaim conveyors, plant conveyors, belt scales, fire protection systems, dust suppression systems, magnetic separators, all electrical and control, and heating and ventilation systems.

EXHIBIT V(i)

SWITCHYARD FACILITIES AND EQUIPMENT

OPERATION AND MAINTENANCE COSTS

PNM - 65%	TEP - 35%

EXHIBIT VI

A&G RATIO APPLICABLE TO OPERATION AND MAINTENANCE FOR THE SAN JUAN GENERATING STATION ("SJGS")

The Operating Agent determines, in accordance with Accounting Practice, the appropriate A&G expense incurred for the benefit of the SJGS and to be billed to the SJGS as follows:

1. A&G expenses directly chargeable by on-site San Juan Project employees as set forth in Section 22.2.2;

2. A&G expenses directly chargeable by A&G related departments located off-site as set forth in Section 22.2.2; and

3. Indirect A&G expenses included in the development of the A&G ratio.

Except as set forth in Section 22.0, individuals located off-site must either charge their time and expenses direct to the SJGS or be included in the A&G pool in the development of the A&G Ratio. Costs incurred for the same purpose must be either all charged direct to the SJGS or all be included in the A&G pool, e.g., all staff persons within the same department must either charge direct to the SJGS or to the A&G pool.

A. The Operating Agent conducts an A&G study every three years. However, periodic reviews will be performed to determine if significant organizational changes have occurred that may require the Operating Agent to conduct an A&G study on a basis more frequently than three years. This study determines the appropriate amount of indirect A&G expense to utilize in the development of the A&G Ratio described below.

The FERC A&G accounts included in the A&G study are: 920, 921, 923, 930.2, 931 and 935.

Background

The responsibility for the SJGS resides in the Operating Agent's Bulk Power Business Unit. The A&G expenses charged to this Business Unit are derived from two areas. The first component is an allocation of A&G expenses from the Operating Agent's Corporate Office to the Bulk Power Business Unit. These allocations are based on pre-determined methodologies. The second component of costs are A&G expenses that are directly charged to the Bulk Power Business Unit. Note: Any A&G expenses charged directly to the SJGS are excluded from the determination of the A&G Ratio and are not subject to the A&G Ratio.

A questionnaire is sent to all managers that have A&G charges to the Bulk Power Business Unit to determine what percentage of their A&G expenses should be included in the development of the A&G Ratio.

The percentages derived from the questionnaires are then applied to the actual A&G amounts charged to the Bulk Power Business Unit for the study year. Amounts are split between labor and other.

B. Labor Ratios for Payroll Taxes (FERC Account 408), Injuries and Damages (FERC Account 925) and Pension and Benefits (FERC Account 926) <u>(See Exhibit VI Attachments B, C and D)</u> are applied to the labor portion of the A&G determined above.

C. Other costs included in the development of the A&G Ratio are Depreciation of General Plant (FERC Account 403), Property Insurance (FERC Account 924) and Property Taxes (FERC Account 408) for the Operating Agent's headquarters buildings and energy management facility and Amortization of Computer Software (FERC Account 404) for certain software applications that provide benefit to the SJGS.

The portion of the costs related to the Operating Agent's headquarters buildings included in the development of the A&G Ratio are derived by applying certain ratios obtained from the A&G study questionnaires. The costs included in the A&G Ratio for the Operating Agent's energy management facility are based on the number of MW of SJGS capacity as a percentage of the Operating Agent's total generating capacity. In addition, ratios for determining the amount of software costs to include in the A&G Ratio are based on the specific software application. For example, if the Operating Agent installed a new payroll system, the amount of costs for this system that would be included in the A&G Ratio calculation would be based on the number of employees at the SJGS as a percent of the Operating Agent's total employees. The Operating Agent reviews each specific software application to determine the method for assigning the appropriate amount of costs to be included in the A&G Ratio calculation.

The A&G ratio shall be applied to the following SJGS costs:

1) Labor charged to the operation and maintenance expenses included in Sections 22.2.1, 22.3, 22.4, 22.5 and 23.3.3 of the San Juan Project Participation Agreement. Such labor dollars are utilized as the denominator in the calculation of the A&G Ratio described below.

The A&G Ratio shall be derived annually based on the preceding year's experience, as set forth herein unless otherwise agreed to by the participants. The A&G Ratio will be adjusted to actuals at year-end and the adjustment will be used in the computation of the A&G Ratio for the following year.

A&G Ratio = A/B

Where A = Administrative and general expense chargeable to FERC Accounts 920, 921, 923, 930.2, 931 and 935, including Labor Ratios for Payroll Taxes (FERC Account 408), Injuries and Damages (FERC Account 925) and Pension and Benefits (FERC Account 926) plus other related costs for the Operating Agent's headquarters buildings and energy management facility for Property Taxes FERC Account (408), Depreciation of General Plant FERC Account (403), and Property Insurance FERC Account (924) plus amortization of certain Computer Software costs charged to FERC Account (404).

B = Total SJGS operation and maintenance labor paid and accrued excluding labor expenses chargeable to FERC accounts 920 through 935 inclusive.

Note: Any modifications to the methodology utilized for calculating the A&G Ratio described above shall be developed by the San Juan Auditing Committee and approved by the San Juan Coordination Committee.

PAYROLL TAX RATIO FOR THE SAN JUAN GENERATING STATION ("SJGS")

The Payroll Tax Ratio shall be applied to the following SJGS costs:

1) Labor charged to operation and maintenance expenses included in Sections 22.2.1, 22.2.2, 22.2.4, 22.2.5 22.3, 22.4, 22.5 and 23.3.3 of the San Juan Project Participation Agreement.
2) Labor charged to other primary accounts including, but not limited to, FERC Accounts 107, 108, 163, 183, 186 and 188.

The Payroll Tax Ratio shall be determined annually on the basis of the Operating Agent's preceding years experience adjusted for known changes to comply with regulations applicable to Social Security and Unemployment Compensation as set forth herein unless otherwise agreed to by the participants. The Payroll Tax Ratio will be adjusted to actuals at year-end and the adjustment will be used in the computation of the ratio for the following year.

$$\text{Payroll Tax Ratio} = T/P$$

Where T = The Operating Agent's total payroll tax expense chargeable to FERC Account 408.

P = The Operating Agent's total base labor paid and accrued, less wages paid for time-off allowances plus accruals for time-off allowances.

Notes: (1) Base labor is defined as an employee's hourly rate times the number of hours worked plus an accrual for time-off allowances. In addition, base labor also includes overtime pay and special pay.

(2) Time-off allowances are defined as vacation, illness and holiday time.

(3) Special pay is defined as any other compensation an employee receives that is not part of his/her regular base pay. Examples include employee recognition awards as well as results based pay, the Operating Agent's bonus pay plan.

(4) Any modifications to the methodology utilized for calculating the Payroll Tax Ratio described above shall be developed by the San Juan Auditing Committee and approved by the San Juan Coordinating Committee.

INJURIES AND DAMAGES RATIO FOR THE SAN JUAN GENERATING STATION ("SJGS")

The Injuries and Damages Ratio shall be applied to the following SJGS costs:

1) Labor charged to operation and maintenance expenses included in Sections 22.2.1, 22.2.2, 22.2.4, 22.2.5 22.3, 22.4, 22.5 and 23.3.3 of the San Juan Project Participation Agreement.
2) Labor charged to other primary accounts including, but not limited to, FERC Accounts 107, 108, 163, 183, 186 and 188.

The Injuries and Damages Ratio shall be determined annually on the basis of the Operating Agent's preceding year's experience as set forth herein unless otherwise agreed to by the participants. The Injuries and Damages Ratio will be adjusted to actuals at year-end and the adjustment will be used in the computation of the ratio for the following year.

$$\text{Injuries and Damages Ratio} = I/P$$

Where I = The Operating Agent's total injuries and damages expense chargeable to FERC Account 925, including payroll taxes, and pension and benefits on labor chargeable to FERC Account 925. The amount of payroll taxes and pension and benefits to be added are based on the ratios included in Exhibit VI, Attachments B and D, respectively. Note: Any injuries and damages expense charged direct to the SJGS are excluded from the determination of the Injuries and Damages Ratio.

P = The Operating Agent's total base labor paid and accrued, less wages paid for time-off allowances plus accruals for time-off allowances less special pay and wages charged direct to FERC Account 925.

Notes: (1) Special pay is defined as any other compensation an employee receives that is not part of his/her regular base pay. Examples include employee recognition awards as well as results based pay, the Operating Agent's bonus pay plan.

(2) Any modifications to the methodology utilized for calculating the Injuries and Damages Ratio described above shall be developed by the San Juan Auditing Committee and approved by the San Juan Coordination Committee.

San Juan Operating Agreement
Exhibit VI-Attachment D

PENSION AND BENEFITS RATIO FOR THE SAN JUAN GENERATING STATION ("SJGS")

The Pension and Benefits Ratio shall be applied to the following SJGS costs:

1) Labor charged to operation and maintenance expenses included in Sections 22.2.1, 22.2.2, 22.2.4, 22.2.5 22.3, 22.4, 22.5 and 23.3.3 of the San Juan Project Participation Agreement.
2) Labor charged to other primary accounts including, but not limited to, FERC Accounts 107, 108, 163, 183, 186 and 188.

The Pension and Benefits Ratio shall be determined annually on the basis of the Operating Agent's preceding year's experience as set forth herein unless otherwise agreed to by the participants. The Pension and Benefits Ratio will be adjusted to actuals at year-end and the adjustment will be used in the computation of the ratio for the following year.

Pension and Benefits Ratio = B/P

Where B = The Operating Agent's total pension and benefits expense chargeable to FERC Account 926, including payroll taxes, and injuries and damages on labor chargeable to FERC Account 926. The amount of payroll taxes and injuries and damages to be added are based on the ratios included in Exhibit VI, Attachments B and C, respectively.

P = The Operating Agent's total base labor paid and accrued, less wages paid for time-off allowances plus accruals for time-off allowances, less overtime, part-time, special pay not eligible for pension and benefits and wages charged direct to FERC Account 926.

Notes: (1) Special pay is defined as any other compensation an employee receives that is not part of his/her regular base pay. Examples include employee recognition awards as well as results based pay, the Operating Agent's bonus pay plan. Employee recognition awards are not eligible for pension and benefit loadings.

(2) Any modifications to the methodology utilized for calculating the Pension and Benefits Ratio described above shall be developed by the San Juan Auditing Committee and approved by the San Juan Coordination Committee.

CAPITALIZED A&G RATIO APPLICABLE TO CAPITAL PROJECTS FOR THE SAN JUAN GENERATING STATION ("SJGS")

The Operating Agent determines the appropriate A&G expense incurred for the benefit of the SJGS and to be billed to the SJGS as follows:

A. The Operating Agent conducts an A&G study every three years. However, periodic reviews will be performed to determine if significant organizational changes have occurred that may require the Operating Agent to conduct an A&G study on a basis more frequently than three years. This study determines the appropriate amount of indirect A&G expense to utilize in the development of the Capitalized A&G Ratio described below.

The FERC A&G accounts included in the A&G study are: 920, 921, 923, 930.2, 931 and 935.

Background

The responsibility for the SJGS resides in the Operating Agent's Bulk Power Business Unit. The A&G expenses charged to this Business Unit are derived from two areas. The first component is an allocation of A&G expenses from the Operating Agent's Corporate Office to the Bulk Power Business Unit. These allocations are based on pre-determined methodologies. The second component of costs are A&G expenses that are directly charged to the Bulk Power Business Unit. Note: Any A&G expenses charged directly to the SJGS are excluded from the determination of the Capitalized A&G Ratio. Two Capitalized A&G Ratios are calculated, one for major construction projects (Projects greater than $10,000,000) and one for minor construction projects (Projects less than $10,000,000).

A questionnaire is sent to all managers that have A&G charges to the Bulk Power Business Unit to determine what percentage of their A&G expenses are capital-related and should be included in the development of the Capitalized A&G Ratios. Amounts are split between labor and other.

B. Labor Ratios for Payroll Taxes (FERC Account 408), Injuries and Damages (FERC Account 925) and Pension and Benefits (FERC Account 926) (see Exhibit VI Attachments B, C and D) are applied to the labor portion of the A&G determined above.

The Capitalized A&G Ratios, shall be applied to all SJGS construction costs except for long-term leased transportation and motorized equipment. The total amount of these construction dollars are utilized as the denominator in the calculation of the A&G Ratio described below.

Capitalized A&G Ratio = A/B

Where A = Administrative and general expense chargeable to FERC Accounts 920, 921, 923, 930.2, 931 and 935, including Labor Ratios for Payroll Taxes (FERC Account 408), Injuries and Damages (FERC Account 925) and Pension and Benefits (FERC Account 926) as categorized separately in the A&G questionnaire for major and minor construction expenditures for the study period.

B = Total SJGS capital project amounts for the Bulk Power Business Unit as categorized between major and minor construction projects for the study period chargeable to FERC Accounts 107 and 108.

Note: Any modifications to the methodology utilized for calculating the A&G Ratio described above shall be developed by the San Juan Auditing Committee and approved by the San Juan Coordination Committee.

EXHIBIT VII

Example "Interim Invoice"

bhpbilliton

San Juan Coal Company

June 10, 2005

Public Service Company of New Mexico
2401 Aztec Rd NE
Albuquerque, NM 87107

Attention: Vivian Laws, Fuel Accounting

Dear Ms. Laws:

Below is the current billing for coal sales for the month of May 2005.

INVOICE	**SJCC**
Base	$ 20,503,916.00
Tier A Incremental	$ 57,165.00
Ash Disposal	$ 599,995.00

TOTAL PAYMENT DUE $ 21,161,076.00

If you have any questions, please call me at (505) 598-4241.

Regards,

Michelle Nakai

Michelle Nakai

REMIT TO: SAN JUAN COAL COMPANY
BANKING DETAILS:

Bank of America
ABA# 1110 0001 2
Credit A/C San Juan Coal Company
Account Number 3752174935

San Juan Coal Company
P.O. Box 155
Fruitland, NM 87416

Invoice No.: **Base 05-05**
Invoice For Month Ending: **May 31, 2005**

Base Interim Invoice

To: Public Service Company of New Mexico
414 Silver Ave. SW - MS/0406
Albuquerque, NM 87102

Tons Delivered			494,000
MBTU's Fuel Delivered			9,685,364
Base Price per MBTU: *			1.889903
Total Coal Sales:		$	18,304,398
Less Invoice:			-
Net Coal Sales:		$	18,304,398
Reclamation Act Levy per MBTU:	0.017852		172,900
Blacklung Tax per MBTU:	0.028053		271,700
Severance Tax per MBTU:	0.060186		582,920
Total Subject to Gross Receipts Tax:		$	19,331,918
Gross Receipts per MBTU:	0.121007		1,171,998
Total Invoice	2.117000	$	20,503,916

*Base price includes all royalties, REI's, toll fees, and resource excise and conservation taxes

San Juan Coal Company
P.O. Box 155
Fruitland, NM 87416

Invoice No.: Tier A 05-05
Invoice For Month Ending: May 31, 2005

Tier A Interim Invoice

To: Public Service Company of New Mexico
414 Silver Ave. SW - MS/0406
Albuquerque, NM 87102

Tons Delivered			6,366.12
MBTU's Fuel Delivered			124,814.1
Base Price per MBTU: *			0.385918
Total Coal Sales:		$	48,168
Less Invoice:		$	-
Net Coal Sales:		$	48,168
Reclamation Act Levy per MBTU:	0.017851	$	2,228
Blacklung Tax per MBTU:	0.028050	$	3,501
Total Subject to Gross Receipts Tax:		$	53,897
Gross Receipts per MBTU:	0.026183	$	3,268
Total Invoice	0.458000	$	57,165

*Base price includes all royalties, REI's, toll fees, and resource excise, conservation, and severance taxes.

San Juan Coal Company		**Invoice No.:**	**Ash 05-05**
P.O. Box 155		**Invoice For Month Ending:**	**May 31, 2005**
Fruitland, NM 87416			

Waste Disposal Agreement

To: **Public Service Company of New Mexico**
414 Silver Ave. SW - MS/0406
Albuquerque, NM 87102

May 2005 Coal Deliveries	533,678		
Ash Disposal Rate per Ton Including Inflation	0.888	$	473,906.00
Gypsum Rate per Ton	0.172	$	91,793.00
		$	565,699.00
Plus: Gross Receipts Tax	6.063%	$	34,296.00
	Total Invoice	$	599,995.00

IPD-GDP Calculation - Ash		
1st Quarter 2005 IPD-GDP	109.95	
x Base GDP 2nd Qtr 1992(1987=100)	99.80	
/ Base GDP 2nd Qtr 1992(2000=100)	86.19	
1st Quarter 2005 IPD-GDP Adjusted	127.31	1.276
IPD-GDP Calculation - Gypsum		
1st Quarter 2005 IPD-GDP	109.95	
x Base GDP 1st Qtr 1998 (1987=100)	112.32	
/ Base GDP 1st Qtr 1998 (2000=100)	96.09	
1st Quarter 2005 IPD-GDP Adjusted	128.52	1.144

Example “UG-CSA Invoice”

SAN JUAN COAL COMPANY
P.O. BOX 155
FRUITLAND, NM 87416

INVOICE NUMBER: S2005 05
INVOICE DATE: May 31, 2005
COAL SALES MONTH: May 2005

SAN JUAN COAL SALES AGREEMENT

To:
PUBLIC SERVICE COMPANY OF NEW MEXICO
P.O. BOX 2267
ALBUQUERQUE, N. M. 87103

Contract Reference				Schedule Reference
	MINING AND RECLAMATION			
8.2 (A)	Mining CIE	$	4,743,704.00	Sch A
8.2 (C)	Reimbursable Operating Cost		9,472,719.79	Sch C
8.2 (D)	Administration Element		132,919.57	Sch A
8.5 (E)	Sub-Contractor Cost		0.00	Sch C
	SUBTOTAL MINING AND RECLAMATION	**$**	**14,349,343.36**	
8.3	**COAL PROCESSING**			
8.3 (A)	Processing CIE	$	898,758.67	Sch B
8.3 (B)	Reimbursable Processing Cost		416,221.60	Sch B-2
8.3 (C)	Processing Administration Element		41,691.79	Sch B
	SUBTOTAL COAL PROCESSING	**$**	**1,356,672.06**	
8.4	**NON-SJCC COAL AND ALTERNATE COAL COST**	**$**	**-**	Sch D
8.5 (E)	**ROYALTIES & LEASE COSTS**	**$**	**1,178,994.30**	Sch R
	TOTAL SALES VALUE BEFORE TAXES	**$**	**16,885,009.72**	
8.5 (E)	**TOTAL MINING TAXES**	**$**	**1,226,839.51**	Sch T
	OTHER NON FUEL COSTS			
8.5 (A)	Transportaton - Reclamation	$	25,489.51	Sch C
8.5 (B)	Substitute REI		-	Sch F
8.5 (D)	Ute ROW - Toll Fees		-	Sch H
8.5 (E)	Other Costs		31,783.69	Sch C
	SUBTOTAL OTHER	**$**	**57,273.20**	
	TOTAL BEFORE GROSS RECEIPTS TAXES	**$**	**18,169,122.43**	
8.5 (E)	**TOTAL GROSS RECEIPTS TAXES**	**$**	**1,048,031.11**	Sch T
Amend 1	**UPS GROSS RECEIPTS TAXES**	**$**	**40,951.14**	UPS Statement
	TOTAL INVOICE AMOUNT	**$**	**19,258,104.68**	

REMIT TO: SAN JUAN COAL COMPANY
BANKING DETAILS:
Bank of America
ABA# 1110 0001 2
Credit A/C San Juan Coal Company
Account Number 3752174935

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SAN JUAN COAL COMPANY

SCHEDULE A

INVOICE: S2005 05
DATE: May 31, 2005
MONTH: May 2005

BASE CAPITAL INVESTMENT ELEMENT

TONS DELIVERED (SCH A-1)
TIMES: (SCH A-1)

	Tons	Rate	
Base CIE	494,000	$ 9.442	$ 4,664,348.00
Incremental CIE	39,678	$ 2.00	$ 79,356.00
TOTAL CAPITAL INVESTMENT ELEMENT			**$ 4,743,704.00** To Invoice

ADMINISTRATION COMPONENT

AMOUNT APPLICABLE TO MINEABLE COAL

= $125,613 x D2 (1.114) x TA (0.95018) = $ 132,919.57
(FROM SCHEDULE S-1)

AMOUNT APPLICABLE TO TRANSPORTATION
= Total Admin Component X NMOS % (Trans)
$132,920 X 0% $ -

TOTAL ADMINISTRATION COMPONENT **$ 132,919.57** To Invoice

SAN JUAN COAL COMPANY

SCHEDULE A-1

INVOICE: S2005 05
DATE: May 31, 2005
MONTH: May 2005

BASE CAPITAL INVESTMENT ELEMENT

Base CIE

Base CIEoriginal			=	$	8.478
Capital True Up Adjustment			=		-
Base CIEtrue up adj Base CIEoriginal + Capital True Up Adjustment			=	$	8.478

$$\text{Base CIEtax adj} = \text{Base CIEtrue up adj} \times \frac{\text{Madj}}{\text{Moriginal}} = \$\ 8.478$$

$$\text{Base CIE} = \text{Base CIEtax adj} \times \frac{\text{D1}}{\text{D0}} = \$\ 9.442$$ **To Sched A**

INCREMENTAL CAPITAL INVESTMENT ELEMENT

Incremental CIE = $ 2.00 **To Sched A**

TONS APPLICABLE TO BASE CAPITAL INVESTMENT ELEMENT:

Minimum Monthly Tons (MMT) = May 2005 MONTHLY TONS 494,000

Base Monthly Tons (BMT) = MMT, but if NMS>0 and SMS<MMT then BMT = MMT - NBMT
Base Monthly Tons (BMT) = 494,000 **To Sched A**

TONS APPLICABLE TO INCREMENTAL CAPITAL INVESTMENT ELEMENT:

Incremental Monthly Tons (IMT) = if SMS > MMT, IMT = SMS-MMT, otherwise = 0
Incremental Monthly Tons (IMT) = 39,678 **To Sched A**

TOTAL TONS 533,678

SAN JUAN COAL COMPANY

SCHEDULE B

INVOICE: S2005 05
DATE: May 31, 2005
MONTH: May 2005

PROCESSING CAPITAL INVESTMENT ELEMENT

TONS APPLICABLE (SCH B-1)
TIMES: (SCH B-1)

	Tons *		Rate *		
Eligible Processing CIE	427,167	$	2.104	$	898,758.67
Non-Eligible Processing CIE	0	X	2.252	=	-

TOTAL PROCESSING CAPITAL INVESTMENT ELEMENT **$ 898,758.67** **To Invoice**

*** from Schedule B1**

PROCESSING ADMINISTRATION COMPONENT

AMOUNT APPLICABLE TO ELIGIBLE COAL (Eligible for Depletion Allowance)

= $39,400 x D2 (1.114) x TA (0.95018) x % ELIGIBLE (100%) $ 41,691.79
(FROM SCHEDULES S-1 & B-1)

AMOUNT APPLICABLE TO NON ELIGIBLE COAL (Not Eligible for Depletion Allowance)

= $39,400 x D2 (1.114) x % NON-ELIGIBLE (0%) $ -
(FROM SCHEDULES S-1 & B-1)

TOTAL PROCESSING ADMINISTRATION COMPONENT **$ 41,691.79** **To Invoice**

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SAN JUAN COAL COMPANY

SCHEDULE B-1

INVOICE: S2005 05
DATE: May 31, 2005
MONTH: May 2005

PROCESSING CIE CALCULATIONS

PROCESSING CAPITAL INVESTMENT ELEMENT ELIGIBLE FOR DEPLETION ALLOWANCE

$$\text{Processing CIEEligible-Org} = \frac{2.577 - 1.042\,(T)}{(1-T) + (T)(PD)} \times 0.57 \times \frac{\text{Proc D1}}{\text{Proc D2}} = 2.518$$

$$\text{Processing CIEEligible-Adj} = \text{Processing CIEEligible-Org} = \times \frac{D1}{D0} = 2.804$$

$$\text{Processing CIEEligible} = \text{Processing CIEEligible-Adj} - \$0.70 = 2.104$$ To Sched B

PROCESSING CAPITAL INVESTMENT ELEMENT NOT ELIGIBLE FOR DEPLETION ALLOWANCE

$$\text{Processing CIENonElg-Org} = \frac{\text{Processing CIEEligible-Org}}{TA} = 2.649$$

$$\text{Processing CIENonElg-Adj} = \text{Processing CIENonElg-Org} = \times \frac{D1}{D0} = 2.952$$

$$\text{Processing CIENonElg-Adj} = \text{Processing CIENonElg-Adj} = - \$0.70 = 2.252$$ To Sched B

BREAKDOWN OF PROCESSING MINIMUM TONS BETWEEN MINEABLE AND ALTERNATE & NON-SJCC:

	MINIMUM TONS		PERCENTAGE	
ANNUAL PROCESSING TONS (Exhibit H Col 3)	5,126,000			
MONTHLY CIE PROCESSING TONS (1/12)	427,167			
MONTHLY ELIGIBLE PROCESSING TONS	100.0%	=	427,167	To Sched B
MONTHLY NON-ELIGIBLE PROCESSING TONS	0.0%	=	-	To Sched B

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SAN JUAN COAL COMPANY

SCHEDULE B-2

INVOICE: S2005 05
DATE: May 31, 2005
MONTH: May 2005

SCHEDULE OF REIMBURSABLE PROCESSING COSTS

		ELIGIBLE COAL	NON-ELIGIBLE COAL	ALTERNATE COAL	NON-SJCC COAL	TOTAL	
TONS SOLD		533,678	-	-	-	533,678	
% OF TONS		100.0000%	0.0000%	0%	0%	100%	
(Schedule-O) PROCESSING COSTS		$ 481,344.98	$ -	$ -	$ -	$ 481,344.98	
REIMBURSEMENT RATE		85.0180%	90.0000%	90.0000%	90.0000%	88.6200%	
REIMBURSEABLE PROCESSING COSTS		$ 409,229.88	$ -	$ -	$ -	$ 409,229.88	
(Schedule-B) PROCESSING CIE		$ 898,758.67	$ -	$ -	$ -	$ 898,758.67	
(Schedule-B) PROCESSING ADMIN		$ 41,691.79	$ -	$ -	$ -	$ 41,691.79	
TOTAL PROCESSING COSTS		$ 1,349,680.34	$ -	$ -	$ -	$ 1,349,680.34	
PROPERTY TAX ALLOCATED TO PROCESSING		$ 6,991.72	$ -	$ -	$ -	$ 6,991.72	
CIE-MINING ALLOCATED TO OUTSIDE COAL (Schedule D)				$ -	$ -	$ -	
(Schedule-O) OUTSIDE COAL PURCHASES				$ -	$ -	$ -	
DIRECT OUTSIDE COAL COSTS				$ -	$ -	$ -	
COST PER TON				$ -	$ -		
SUB-TOTAL COSTS ALLOC. TO PROCESSING		$ 1,356,672.06	$ -	$ -	$ -	$ 1,356,672.06	
AMOUNT SUBJECT TO TAXES		$ 1,356,672.06	$ -	$ -	$ -	$ 1,356,672.06	
RESOURCE EXCISE TAX	0.75%	$ 10,175.04	$ -	N/A	N/A	10,175.04	
CONSERVATION TAX	0.19%	2,577.68	-	N/A	N/A	2,577.68	
TAXES ALLOCATED TO PROCESSING		$ 12,752.72	$ -	$ -	$ -	$ 12,752.72	
AMOUNT SUBJECT TO GROSS RECEIPTS TAX		$ 1,369,424.78	$ -	$ -	$ -	$ 1,369,424.78	
GROSS RECEIPTS TAX	6.063%	83,021.38	-	-	-	83,021.38	
TOTAL PROCESSING COSTS ALLOCATION		**$ 1,452,446.16**	**$ -**	*** $ -**	**$ -**	**$ 1,452,446.16**	*** To Sch R**
REIMBURSEABLE PROCESSING COSTS (from Above)		$ 409,229.88	$ -	$ -	$ -	$ 409,229.88	
PROPERTY TAX ALLOCATED TO PROCESSING (from Abov		6,991.72	-	-	-	6,991.72	
TOTAL REIMBURSEABLE PROCESSING COST		**$ 416,221.60**	**$ -**	**$ -**	**$ -**	**$ 416,221.60**	**To Invoice**

Prepared on 6/10/2005 8:13 AM

SAN JUAN COAL COMPANY

SCHEDULE C

INVOICE:	S2005 05
DATE:	May 31, 2005
MONTH:	May 2005

SCHEDULE OF COSTS

REIMBURSEABLE OPERATING COSTS			
Total Reimbursable Operating Costs (Sch O)	$ 9,131,011.29		
TIMES: Reimbursement Factor (Sch S-1)	0.95018		
REIMBURSEABLE OPERATING COSTS		$ 8,676,104.31	
RETAINED ECONOMIC INTEREST (Sch F)		$ 797,397.67	
MANAGEMENT FEE			
Management Fee Credited to San Juan Mine from Transportation		$ (782.19)	
TOTAL REIMBURSABLE OPERATING COSTS		$ 9,472,719.79	To Invoice
OTHER COSTS			
Sub-contracting Costs (Sch O)		$ -	To Invoice
Non-Fuel Costs (Sch O)		$ 31,783.69	To Invoice
TOTAL OTHER COSTS		$ 31,783.69	
TRANSPORTATION COSTS			
Administraton Applicable to Transportation (Sch A)		$ -	
Transportation Costs (Sch O)		$ 5,214.59	
Management Fee	15%	$ 782.19	
Property Tax (Sch O)		$ 19,492.73	
TOTAL TRANSPORTATION COSTS		$ 25,489.51	To Invoice

Prepared on 6/10/2005 8:13 AM

SAN JUAN COAL COMPANY

SCHEDULE D

INVOICE:	S2005 05
DATE:	May 31, 2005
MONTH:	May 2005

NON SJCC AND ALTERNATE COSTS

BASE CAPITAL INVESTMENT ELEMENT CALCULATIONS

	Tons		Rate		
Non SJCC Base CIE	-	X	$ -	$ -	
Non SJCC Incremental CIE	-	X	-	$ -	
TOTAL NON SJCC & ALTERNATE CIE					$ -

BASE CAPITAL INVESTMENT ELEMENT

Non SJCC Base CIE $ -

INCREMENTAL CAPITAL INVESTMENT ELEMENT

Non SJCC Incremental CIE $ -

TONS APPLICABLE TO NON SJCC BASE CAPITAL INVESTMENT ELEMENT:

Non-SJCC Base Monthly Tons (NBMT) = 0, but if SMS < MMT, NBMT = LESSOR OF MMT - SMS OR NMS
Non-SJCC Base Monthly Tons (NBMT) = -

TONS APPLICABLE TO NON-SJCC INCREMENTAL CAPITAL INVESTMENT ELEMENT:

Non-SJCC Incremental Monthly Tons (NIMT) = NMS - NBMT
Non-SJCC Incremental Monthly Tons (NIMT) = -

PROCESSING CAPITAL INVESTMENT ELEMENT

Non-Eligible Processing CIE (Alternalte & Non SJCC) $ -

PROCESSING ADMINISTRATION COMPONENT

Amount Applicable to Alernate & Non-SJCC Coal

= $39,400 x D2 x %ALTERNATE & NON-SJCC COAL $ -

OPERATING COSTS ASSOCIATED WITH NON-SJCC & ALTERNATE COAL

NON-SJCC & ALTERNATE COAL OPERATING COSTS (SCHEDULE O) $ -

NON-SJCC COAL AND ALTERNATE COAL COST $ - **To Invoice**

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SAN JUAN COAL COMPANY

SCHEDULE F

INVOICE:	S2005 05
DATE:	May 31, 2005
MONTH:	May 2005

REI CALCULATION

TONS SOLD	Current Month May 2005	Quarter Adjustment n/a	n/a	Quarter Payment
FRUITLAND TONS SOLD	188,421	n/a	n/a	n/a
BASE REI RATE $/TON	$ 2.10	n/a	n/a	n/a
x Current GDP-IDP Index	109.95	n/a	n/a	n/a
/ GDP/IPD Base (3rd Qtr 1980)	54.56	n/a	n/a	n/a
ADJUSTED REI RATE $/TON	$ 4.232	n/a	n/a	n/a
ACTUAL REI INVOICED	$ 797,397.67	$ -	$ -	$ -
ACTUAL AMOUNT PAID	$0.00			
LESS: ACTUAL REI INVOICED	797,397.67			
QUARTER ADJUSTMENT	n/a			
CURRENT MONTH ACCRUAL	$ 797,397.67			
TOTAL REI EXPENSE	**$ 797,397.67**	**To Schedule C**		

FRUITLAND TONS SALES SUMMARY

	CURRENT MO.	YR-TO-DATE
FRUITLAND TONS SOLD	188,421	2,030,036

CBOV-TBOV ROYALTY BASIS CALCULATION

CBOV-TBOV Royalty Basis @ $0.75 per Fruitland Ton **$ 141,315.75 To Sch R**

REI SHORTFALL CALCULATION

ANNUAL MINIMUM TONS 4,100,000

	YR-TO-DATE	PREVIOUS YR-TO-DATE	CURRENT MO.
Fruitland Tons Sold	2,030,036	1,841,615	188,421
Shortfall Tons	1,708,333	1,366,667	-
REI Shortfall Tons	-	-	-
BASE REI RATE $/TON	$ 2.10	$ 2.10	
1st Quarter 2005 GDP-IDP Index	109.946	109.971	
/ GDP/IPD Base (3rd Qtr 1980)	54.56	54.56	
ADJUSTED REI RATE $/TON	$ 4.232	$ 4.233	
REI Shortfall to Accrue	$ -	$ -	
Current Month Accrual	**$ -**	**To Invoice**	

YEAR END RECONCILIATION

Jan	0.00
Feb	0.00
Mar	0.00
Apr	0.00
May	
Jun	
Jul	
Aug	
Sep	
Oct	
Nov	
	0.00
Yearend Pymt	
Dec	0.00

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SAN JUAN COAL COMPANY

SCHEDULE H

INVOICE:	S2005 05
DATE:	May 31, 2005
MONTH:	May 2005

UTE TOLL FEE CALCULATION

1st Quarter 2005		109.95
3rd Quarter, 1985 GDP-IPD		69.84
Inflation Adjustment Factor		1.5743
Tolling Fee per Ton	$	0.25
Adjusted Tolling per Ton	$	0.3936
Total Tons Hauled Current Month		0
May 2005 Tolling Fee Earned	$	-
Actual Toll Fee Paid		n/a
Less: Amount per Invoice		n/a
Adjustment to Invoiced Amount	$	-
Other Adjustments		
	$	-
TOTAL UTE TOLL FEE EXPENSE	$	- To Invoice

UTE TOLL FEE SHORTFALL CALCULATION

ANNUAL MINIMUM TONS		1,000,000		
		YTD		Previous YTD
Minimum Tons		416,667		333,333
Actual Tons Sold		0		-
Shortfall Tons		-		-
TOLLING FEE PER TON	$	0.25	$	0.25
1st Quarter 2005 GDP-IDP Index		109.95		109.97
3rd Quarter, 1985 GDP-IPD		69.84		69.84
ADJUSTED REI RATE $/TON	$	0.39	$	0.39
Ute Toll Fee Shortfall	$	-	$	-
Cimarron Shortfall to Accrue	$	-	$	-
Current Month Accrual	**$**	**-**		

YEAR END RECONCILIATION

Jan	-
Feb	-
Mar	-
Apr	-
May	-
Jun	-
Jul	-
Aug	-
Sep	-
Oct	-
Nov	-
	$ -
Yearend Pymt	
Dec	-

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INVOICE: S2005 05
DATE: May 31, 2005
MONTH: May 2005

SAN JUAN MINE OPERATIONS			
Dragline Stripping		0.00	
Shovel Stripping		39,138.30	
Mining		265,668.79	
Coal Hauling		408,138.50	
SJM Reclamation		31,609.18	
SJM Auxilliary Reclamation		11,470.02	
Reclamation & Environmental Quality		87,536.73	
Surface Mine Maintenance		221,476.00	
Surface General & Administrative		366,603.11	
NMOS Charges		559,804.76	
Longwall Mining		2,187,849.83	
Underground Development		1,843,187.21	
Underground Services		1,303,309.93	
Underground Mine Maintenance		399,617.99	
Underground General & Administrative		499,859.20	
Total Mining Operating Costs	$	8,225,269.55	
LA PLATA MINE OPERATIONS			
Shovel Stripping		0.00	
Mining		0.00	
Coal Hauling		0.00	
Shovel Reclamation		460,241.82	
Auxilliary Reclamation		18,989.92	
Reclamation & Environmental Quality		6,075.10	
Mine Maintenance		98,156.54	
General & Administrative		222,913.86	
NMOS		99,364.50	
Total La Plata Mining Operating Costs	$	905,741.74	To Sched R-1
Total Reimburseable Operating Costs	**$**	**9,131,011.29**	To Sched C
PROCESSING OPERATIONS			
Processing Plant		297,175.04	
Processing Mine Maintenance		74,949.78	
Processing General & Administrative		77,241.84	
NMOS Charges		31,978.32	
Property Tax		6,991.72	To Sched B-2
Total Processing Costs	**$**	**488,336.70**	
Total Processing Costs (excl Property Tax)	$	481,344.98	To Sched B-2
TRANSPORTATION OPERATIONS			
Truck Hauling		0.00	
Reclamation & Environmental Quality		5,214.59	
Maintenance		0.00	
General & Aministrative		0.00	
NMOS		0.00	
Total Reimburseable Operating Costs	$	5,214.59	To Sch C
Taxes and Toll Fees			
Property Tax		19,492.73	To Sched C
Gross Receipts Tax (Sch T)		1,545.30	
Ute Toll Fee Minimum (Sch H)		0.00	
Total Taxes and Toll Fees	$	21,038.03	
SAN JUAN TRANSPORTATION TOTAL	**$**	**26,252.62**	

SAN JUAN COAL COMPANY

SCHEDULE O

INVOICE:	S2005 05
DATE:	May 31, 2005
MONTH:	May 2005

TAXES			
San Juan Property Tax		116,297.58	
La Plata Property Tax		47,224.90	
Reclamation Act Levy (Sch T)		76,063.52	
Blacklung Benefits Tax (Sch T)		557,799.18	
Severance Tax (Sch T)		278,899.59	
Conservation Tax (Sch T)		30,431.28	
Gross Receipts Tax (Sch T)		1,046,485.81	
Resource Excise Tax (Sch T)		120,123.46	
Sub-Total Taxes	$	2,273,325.32	
ROYALTIES & LEASE COSTS			
Royalties (Sch R)		1,178,994.30	
Retained Economic Interest (Sch F)		797,397.67	
Substitue REI (Sch F)		0.00	
San Juan Annual Payments		2,804.70	**To Sched R**
San Juan Other Lease Costs		0.00	
La Plata Annual Payments		0.00	
La Plata Other Lease Costs		0.00	
Sub-Total Royalties	$	1,979,196.67	
TOTAL TAXES & ROYALTIES	$	4,252,521.99	
OTHER 100% REIMBURSEABLE COSTS			
Costs Assoc. Outside Coal		1,948.60	
Outside Coal Purchases		0.00	
SJGS Miscellaneous Services		1,380.80	
Non Fuel CBM Recovery		28,454.29	
Contract Mining-100% Reimb.		0.00	
Other 100% Costs (Royalty Bearing)		0.00	
Total Other 100% Reimbursable	$	31,783.69	
TOTAL 100% REIMBURSABLE COSTS	**$**	**4,284,305.68**	
GRAND TOTAL	**$**	**13,929,906.29**	

SAN JUAN COAL COMPANY

SCHEDULE P

INVOICE:	S2005 05
DATE:	May 31, 2005
MONTH:	May 2005

TONNAGE SUMMARY BY COAL SOURCE

	CURRENT MO.	YR-TO-DATE
ALTERNATE COAL	0	0
REMNANT COAL	0	0
SAN JUAN TONS DELIVERED	533,678	2,698,467
SJCC TONS DELIVERED (SMS & SAS)	533,678	2,698,467
NON SJCC COAL (Non Normal Conditions) NMS & NAS	0	0
TOTAL MONTHLY SALES (TMS & TAS)	533,678	2,698,467

TONNAGE SUMMARY BY COAL TYPE

		YR-TO-DATE	
	CURRENT MO.	PRIOR MONTH	CURRENT MO.
UNDERGROUND & CHM	533,678	2,164,789	2,698,467
SAN JUAN MINE SURFACE	0	-	0
LA PLATA MINE SURFACE	0	-	0
TOTAL	533,678	2,164,789	2,698,467

SAN JUAN COAL COMPANY

SCHEDULE R

INVOICE: S2005 05
DATE: May 31, 2005
MONTH: May 2005

Royalty Calculation
May 2005

Total Invoice: S2005 05			$	**19,258,104.68**
Plus: TBOV-CBOV @ $0.75 per Fruitland Ton				141,315.75
Less: Other Non Fuel Costs				(33,710.58)
Less: Subtitute REI (20% Non Royalty Bearing)				-
Less: Transportation Costs				(27,034.81)
Less: Utility Payment Stream GRT				(40,951.14)
Allocated La Plata Revenue (Sch R-1)		1,220,371.88		
Processing Cost Allocated (Sch B-2)		-		
Total Allocated La Plata Revenue		1,220,371.88		(1,220,371.88)
Percentage Revenue Allocated to Federal Leases	53%	646,797.10		
Audit and other Adjustments/(Credits)				
Gross Value for Royalties (San Juan Mine)			**$**	**18,077,352.02**

	Tons Sold	Gross Value Allocated		Royalty	
Federal SurfaceRoyalties	-	$ 646,797.10	$	80,849.64	
Federal Undeground Royalties	229,927	7,788,350.50		580,889.88	
State Surface Royalties	-	-		-	
State Underground Royalties	303,751	10,289,001.52		514,450.08	
Private Royalties	-	-		-	
Elliot Riggs	-	-		-	
Lease Costs (Sch O)	-	-		2,804.70	
Total	**533,678**	**$ 18,724,149.12**	**$**	**1,178,994.30**	**To Invoice**

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SAN JUAN COAL COMPANY

SCHEDULE R-1

INVOICE: S2005 05
DATE: May 31, 2005
MONTH: May 2005

LA PLATA OPERATIONS

BASE CAPITAL INVESTMENT ELEMENT					
TONS DELIVERED (SCH A-1)					
TIMES: (SCH A-1)	Tons	Rate			
Base CIE	-	$ 9.44200	$ -		
Incremental CIE	-	$ 2.00	$ -		
TOTAL CAPITAL INVESTMENT ELEMENT			$ -	$ -	
ADMINISTRATION COMPONENT					
AMOUNT APPLICABLE TO LA PLATA MINE					
Total Admin Component (Sch A)	X	NMOS % (LPM)			
$132,919.57	X	15%	$ 20,036.56		
TOTAL ADMINISTRATION COMPONENT			$ 20,036.56	$ 20,036.56	
REIMBURSEABLE OPERATING COSTS					
TOTAL REIMBURSABLE OPERATING COSTS (SCHEDULE O)			$ 905,741.74		
TIMES: REIMBURSEMENT FACTOR (SCHEDULE S-1)			0.95018		
REIMBURSEABLE OPERATING COSTS			$ 860,617.69	$ 860,617.69	
MANAGEMENT FEE CHARGED FROM SAN JUAN MINE		15%	$ 135,861.26	$ 135,861.26	
MANAGEMENT FEE CHARGED TO TRANSPORTATION			$ -	$ -	
PLUS: OTHER 100% COSTS (ROYALTY BEARING) @ 25%			$ -	$ -	
TAXES					
PROPERTY TAX (Sch O)		$ 49,701.00			
RECLAMATION ACT LEVY (Sch T)		$ -			
BLACKLUNG EXCISE TAX (Sch T)		$ -			
SEVERANCE TAX (Sch T)		$ -			
TOTAL TAXES		$ 49,701.00			
TIMES: REIMBURSEMENT FACTOR (SCH S-1)		0.95018			
REIMBURSEABLE TAXES		$ 47,224.90	$ 47,224.90		
ROYALTIES					
ROYALTIES (Sch R)			$ 80,849.64		
LEASE COSTS (Sch O)			$ -		
TOTAL TAXES & ROYALTIES			$ 128,074.54	$ 128,074.54	
LESS EXEMPTIONS: ROYALTIES (exclude Private Leases)			$ (80,849.64)		
TOTAL AMOUNT SUBJECT TO CONSERVATION & RESOURCE TAXES			$ 1,063,740.41		
CONSERVATION TAX	0.19%		$ 2,021.11		
RESOURCE EXCISE TAX	0.75%		$ 7,978.05		
TOTAL RESOURCE & CONSERVATION TAX			$ 9,999.16		
TIMES: REIMBURSEMENT FACTOR (SCH S-1)			0.95018		
REIMBURSEABLE RESOURCE & CONSERVATION TAX			$ 9,501.00	$ 9,501.00	
MINING COSTS AMOUNT SUBJECT TO GROSS RECEIPTS TAX			$ 1,154,091.05		
Non - Reimburseable GRT			$ (3,475.25)		
NET COSTS SUBJECT TO GROSS RECEIPTS TAX			$ 1,150,615.80		
GROSS RECEIPTS TAX ON MINING COSTS	6.063%		$ 69,756.08		
TIMES: REIMBURSEMENT FACTOR (SCH S-1)			0.95018		
REIMBURSEABLE GROSS RECEIPTS TAX ON MINING COSTS			$ 66,280.83	$ 66,280.83	
TOTAL REVENUE ALLOCATED TO LA PLATA				$ 1,220,371.88	To Sch R

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SAN JUAN COAL COMPANY

SCHEDULE S-1

INVOICE: S2005 05
DATE: May 31, 2005
MONTH: May 2005

VALUES COMMON TO ALL CALCULATIONS

T = CONTRACT TAX RATE T = (F X (1-NE)) + NE	=	0.39591
F = FEDERAL CORPORATE INCOME TAX RATE	=	0.35
N = NEW MEXICO CORPORATE INCOME TAX RATE	=	0.076
NE = NEW MEXICO EFFECTIVE CORPORATE INCOME TAX RATE NE = N X (1-NE)	=	0.07063
PD = PERCENTAGE DEPLETION RATE	=	0.080
INDEX BASE (JUNE 2000) WPU, CODE 112	=	148.600
DEFLATOR BASE (JUNE 2000) GDP/IPD	=	99.75
PROC D2 DEC88 INDEX	=	345.16
PROC D1 JUN00 INDEX	=	447.78

INFLATION INDEX (D0)

INDEX WPU, CODE 112

/ (D0) BASE (JUNE 2000) 1982 =100 = 148.600

DEFLATOR GDP/IPD

/ (D0) BASE GPD/IPD (JUNE 2000) 2000 =100 = 99.745

INFLATION INDEX (D0) = [.65 x INDEX] + [.35 x DEFLATOR]
D0 = [.65 x 148.60] + [.35 x 99.75] = 131.501

INFLATION INDEX (D1)

INDEX WPU, CODE 112

(D1) CURRENT INDEX = Apr 2005 Prelim = 166.10

DEFLATOR GDP/IPD

(D1) CURRENT GDP/IPD = 1st Quarter 2005 = 109.946

INFLATION INDEX (D1) = [.65 x INDEX] + [.35 x DEFLATOR]
D1 = [.65 x 166.10] + [.35 x 109.95] = 146.446

INFLATION INDEX (D2)
INFLATION INDEX (D2) = D1 / D0
D2 = 146.446 / 131.501 = **1.114**

TAX ADJUSTMENT (TA)

$$TA = \frac{1-T}{(1-T) + (T)(PD)} = 0.95018$$

REIMBURSEMENT FACTOR (RF)

Standard RF =	TA		0.950180
MAF (Market Adjustment Factor)		+	0.000000
ADJUSTED REIMBURSEMENT FACTOR			0.950180

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SAN JUAN COAL COMPANY

SCHEDULE T

INVOICE NO.:	S2005 05
DATE:	May 31, 2005
MONTH:	May 2005

SCHEDULE OF TAX

PROPERTY TAXES

PROPERTY TAXES		
SAN JUAN MINE (Sch O)	$ 122,395.31	
LA PLATA MINE (Sch O)	$ 49,701.00	
PROPERTY TAXES	$ 172,096.31	
TIMES: REIMBURSEMENT FACTOR (SCH S-1)	0.95018	
REIMBURSEABLE PROPERTY TAX		$ 163,522.48

TAXES BASED ON SALES VOLUME

		RATE	TONS	TOTAL TAXES	
BLACKLUNG EXCISE TAX					
UNDERGROUND & CHM	$	1.10	533,678	$ 587,045.80	
SAN JUAN MINE SURFACE	$	0.55	-	$ -	
LA PLATA MINE SURFACE	$	0.55	-	$ -	
TOTAL				$ 587,045.80	
TIMES: REIMBURSEMENT FACTOR (SCH S-1)				0.95018	
REIMBURSEABLE BLACKLUNG EXCISE TAX				$ 557,799.18	
RECLAMATION ACT LEVY					
UNDERGROUND & CHM	$	0.15	533,678	$ 80,051.70	
SAN JUAN MINE SURFACE	$	0.35	-	$ -	
LA PLATA MINE SURFACE	$	0.35	-	$ -	
TOTAL				$ 80,051.70	
TIMES: REIMBURSEMENT FACTOR (SCH S-1)				0.95018	
REIMBURSEABLE BLACKLUNG EXCISE TAX				$ 76,063.52	
SEVERANCE TAX	ANN THREHOLD				
UNDERGROUND & CHM BASE TAX	$	0.55	-	$ -	
SAN JUAN MINE SURFACE BASE TAX	0 $	0.57	-	$ -	
LA PLATA MINE SURFACE BASE TAX	0 $	0.57	-	$ -	
UNDERGROUND & CHM SURTAX	$	0.59	-	$ -	
SAN JUAN MINE SURFACE SURTAX	$	0.61	-	$ -	
LA PLATA MINE SURFACE SURTAX	$	0.61	-	$ -	
UNDERGROUND & CHM EXEMPT	$	0.55	533,678	$ 293,522.90	
SAN JUAN MINE SURFACE EXEMPT	$	0.57	-	$ -	
LA PLATA MINE SURFACE EXEMPT	$	0.57	-	$ -	
TOTAL				$ 293,522.90	
TIMES: REIMBURSEMENT FACTOR (SCH S-1)				0.95018	
REIMBURSEABLE BLACKLUNG EXCISE TAX				$ 278,899.59	
TAXES BASED ON SALES VOLUME					$ 912,762.29

TAXES BASED ON SALES VALUE

RESOURCE EXCISE TAX (Sch T-1)	$ 120,123.46		
CONSERVATION TAX (Sch T-1)	$ 30,431.28		
TOTAL TAXES BASED ON SALES VALUE		$ 150,554.74	
TOTAL MINING TAXES		$ 1,226,839.51	**To Invoice**

GROSS RECEIPTS TAXES

GROSS RECEIPTS TAXES (Sch T-1)			
MINING & PROCESSING COST	$ 1,044,558.92		
NON FUEL COSTS	$ 1,926.89		
TRANSPORTATION	$ 1,545.30		
TOTAL GROSS RECEIPTS TAXES		$ 1,048,031.11	**To Invoice**
TOTAL TAXES		$ 2,274,870.62	

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INVOICE NO.: S2005 05
DATE: May 31, 2005
MONTH: May 2005

SCHEDULE OF TAX con't

TAXES BASED ON SALES VALUE

CONSERVATION & RESOURCE EXCISE TAX		MINING COSTS	PROCESSING COSTS	
SALES VALUE BEFORE TAX (INVOICE FACE)		$ 16,885,009.72		
TAXES & OTHER COSTS				
PROPERTY TAXES		$ 163,522.48		
VOLUME MINING TAXES		$ 912,762.29		
COSTS ALLOCATED TO PROCESSING (Sch B-2)		$ (1,356,672.06)	$ 1,356,672.06	
OTHER 100% COST (Royalty Bearing)		$ -		
OTHER NON FUEL COSTS (Cimarron Coal Assignment)		$ -		
SUBTOTAL COSTS INCLUDING OTHER TAXES & COSTS		**$ 16,604,622.43**		
LESS EXEMPTIONS:				
TOTAL ROYALTIES LESS PRIVATE ROYALTIES		$ (1,176,189.60)		
TOTAL AMOUNT SUBJECT TO RESOURCE EXCISE & CONSERVATION TAX		**$ 15,428,432.83**	**$ 1,356,672.06**	
RESOURCE EXCISE TAX	0.75%	$ 115,713.25	$ 10,175.04	
TOTAL RESOURCETAX		$ 115,713.25	$ 10,175.04	
TIMES: REIMBURSEMENT FACTOR (SCH S-1)		0.95018	1.00000	
REIMBURSEABLE RESOURCE EXCISE TAX		**$ 109,948.42**	**$ 10,175.04**	$ 120,123.46
CONSERVATION TAX	0.19%	$ 29,314.02	$ 2,577.68	
TOTAL CONSERVATION TAX		$ 29,314.02	$ 2,577.68	
TIMES: REIMBURSEMENT FACTOR (SCH S-1)		0.95018	1.00000	
REIMBURSEABLE CONSERVATION TAX		**$ 27,853.60**	**$ 2,577.68**	$ 30,431.28
TOTAL REIMBURSEABLE RESOURCE EXCISE AND CONSERVATION TAX		**$ 137,802.02**	**$ 12,752.72**	**$ 150,554.74**

GROSS RECEIPT TAX		MINING COSTS	PROCESSING COSTS	NON FUEL COSTS	TRANSPORTATION COSTS
COSTS SUBJECT TO GROSS RECEIPTS TAX		$ 16,742,424.45	$ 1,369,424.78		$ 25,489.51
OTHER NON FUEL COSTS (Other Costs; Substitue REI)				$ 31,783.69	
Non - Reimburseable GRT		$ (50,415.50)			
NET COSTS SUBJECT TO GROSS RECEIPTS TAX		**$ 16,692,008.95**	**$ 1,369,424.78**	**$ 31,783.69**	**$ 25,489.51**
GROSS RECEIPTS TAX	6.063%	$ 1,011,953.04	$ 83,021.38	$ 1,926.89	$ 1,545.30
TIMES: REIMBURSEMENT FACTOR (SCH S-1)		0.95018	1.00000	1.00000	1.00000
REIMBURSEABLE GROSS RECEIPTS TAX		$ 961,537.54	$ 83,021.38	$ 1,926.89	$ 1,545.30
TOTAL REIMBURSEABLE GROSS RECEIPTS TAXES					**$ 1,048,031.11**

Example “UPS Invoice”

bhpbilliton
San Juan Coal Company

June 10, 2005

Public Service Company of New Mexico
414 Silver Ave. SW - MS/0406
Albuquerque, NM 87102

Attention: Vivian Laws, Fuel Accounting

Dear Ms. Laws:

Below is the calculation for Utility Payment Stream for the month of May 2005.

1st Quarter 2005 GDP-IDP Index		109.946		
GDP/IPD Base (4th Qtr 2002)		104.752		
x CIMARRON BASE AMOUNT	$	445,050.00		
ADJUSTED CIMARRON PAYMENT			**$ 467,117.26**	
1st Quarter 2005 GDP-IDP Index		109.946		
GDP/IPD Base (4th Qtr 1979)		51.117		
x AU BASE AMOUNT	$	96,875.00		
ADJUSTED AU PAYMENT			**$ 208,365.49**	
SUBTOTAL			$ 675,482.75	
GROSS RECEIPTS TAX		6.06%	$ 40,951.14	**To Invoice**
OTHER ADJUSTMENTS			$ -	
TOTAL UTILITY PAYMENT STREAM			**$ 716,433.89**	

If you have any questions, please call me at (505) 598-4241.

Regards,

Michelle Nakai

Michelle Nakai

cc: File

Prepared on 6/10/2005 9:12 AM

EXHIBIT VIII

EXHIBIT VIII

Proportional Adjustment of Voting Requirements
in Case of a Default and Suspension of the Rights of a Participant
to Vote Pursuant to Section 35.4.1.

Example Calculation Based on Hypothetical Ownership Percentages:

In the following table, Participant D with Participation Shares in Units 3 and 4 is assumed to be the defaulting Participant. Participation Shares for Voting and Number of Participants for Voting are shown under original or pre-default conditions and are then adjusted as provided in Sections 18.4, 19.4, 20.5, and 21.4 after the right of Participant D to vote is suspended pursuant to Section 35.4.1.

Participation Shares for voting pursuant to Sections 18.4.1(a), 18.4.2(a), and 18.4.3(a) are adjusted as follows:

For Units:

The Adjusted Participation Share for a Participant = (That Participant's Participation Share)/(The sum of the Participation Shares of all non-defaulting Participants in the affected Unit)

For Common Facilities:

Adjustments related to common facilities shall be proportional to any differing Participation Shares between Units. The above formula would be applied to each Unit and then summed and normalized over the applicable common facilities. Because San Juan Units are of unequal ratings, the normalization will be in proportion to each Unit's rating rather than the even fractions in the example below where equally sized units were used for simplicity.

The numbers of Participants used for voting purposes pursuant to the requirements of Sections 18.4.1(b), 18.4.2(b), and 18.4.3(b) are adjusted by subtracting the number of defaulting Participants from the total number of Participants voting under those Sections.

Unit or Facility	Original Participation Shares for Voting: §18.4.1(a), §18.4.2(a), and §18.4.3(a)	Original Number of Participants for Voting Purposes: §18.4.1(b), §18.4.2(b), and §18.4.3(b)	Adjusted Participation Shares for Voting - §18.4.1(a), §18.4.2(a), and §18.4.3(a)	Adjusted Number of Participants for Voting Purposes - §18.4.1(b), §18.4.2(b), and §18.4.3(b)
Unit 1		2		2
Participant A	50.00%		50.00%	
Participant B	50.00%		50.00%	
Unit 2		2		2
Participant A	50.00%		50.00%	
Participant B	50.00%		50.00%	
Unit 3		4		3
Participant A	20.00%		28.57%[1]	
Participant B	20.00%		28.57%	
Participant C	30.00%		42.86%	
Participant D	30.00%		0.00%	
Unit 4		5		4
Participant A	10.00%		12.50%[2]	
Participant B	10.00%		12.50%	
Participant C	20.00%		25.00%	
Participant D	20.00%		0.00%	
Participant E	40.00%		50.00%	
Unit 1 & 2 Common		2		2
Participant A	50.00%		50.00%	
Participant B	50.00%		50.00%	

[1]Computed on Unit 3 Participation Shares as follows: (Participant A) / (Participant A + Participant B + Participant C) = 20%/(20%+20%+30%) = 28.57%

[2]Computed on Unit 4 Participation Shares as follows: (Participant A) / (Participant A + Participant B + Participant C + Participant E) = 10%/(10%+10%+20%+40%) = 12.50%

Unit 3 & 4 Common		5		4
Participant A	15.00%		20.536%[3]	
Participant B	15.00%		20.536%%	
Participant C	25.00%		33.928%	
Participant D	25.00%		0.00%	
Participant E	20.00%		25.000%	
Plant Common		5		4
Participant A	32.50%		35.268%[4]	
Participant B	32.50%		35.268%	
Participant C	12.50%		16.964%	
Participant D	12.50%		0.00%	
Participant E	10.00%		12.500%	

[3]Computed on Unit 3 and 4 Common Participation Shares as follows: Unit 3 Contribution = (Participant A) / (Participant A + Participant B + Participant C) = 20%/(20%+20%+30%) = 28.571%; Unit 4 Contribution = (Participant A) / (Participant A + Participant B + Participant C + Participant E) = 10%/(10%+10%+20%+40%) = 12.500%.

Unit 3 & 4 Common = (Unit 3 Rating)/(Sum of Unit 3 and 4 Ratings) * (Unit 3 Contribution) + (Unit 4 Rating)/(Sum of Unit 3 and 4 Ratings) * (Unit 4 Contribution) = ½ (28.571%) + ½ (12.500%) = 20.536%

[4]Computed on Plant Common Participation Shares as follows: Unit 1 Contribution = (Participant A) / (Participant A + Participant B) = 50%/(50%+50%) = 50.000%; Unit 2 Contribution = (Participant A) / (Participant A + Participant B) = 50%/(50%+50%) = 50.000%. Unit 3 Contribution = (Participant A) / (Participant A + Participant B + Participant C) = 20%/(20%+20%+30%) = 28.571%; Unit 4 Contribution = (Participant A) / (Participant A + Participant B + Participant C + Participant E) = 10%/(10%+10%+20%+40%) = 12.500%. Plant Common = (Unit 1 Rating)/(Plant Rating) * (Unit 1 Contribution) + (Unit 2 Rating)/(Plant Rating) * (Unit 2 Contribution) + (Unit 3 Rating)/(Plant Rating) * (Unit 3 Contribution) + (Unit 4 Rating)/(Plant Rating) * (Unit 4 Contribution) = 1/4 (50.000%) + 1/4 (50.000%) + 1/4 (28.571%) + 1/4 (12.500%) = 35.268%

EXHIBIT IX

EXHIBIT IX

FIXED FUEL EXPENSE

SAN JUAN UNDERGROUND COAL SALES AGREEMENT (As Amended)

SECTION 7.3
Reclamation. (Any applicable post-expiration or post-termination reclamation costs described in said section.)

SECTION 8.2(A)
Base CIE Amount

SECTION 8.2(C)
Reimbursable Operating Costs enumerated in Exhibit “F” Paragraph I(1)

SECTION 8.2(D)
Administration Element

SECTION 8.2(E)
That part of CIE Reconciliation Amount associated with Base CIE or Non-SJCC Base CIE

SECTION 8.3(A)
Processing CIE Amount

SECTION 8.3(C)
Processing Administration Element

SECTION 8.3(D)
Processing CIE Reconciliation Amount

SECTION 8.5(A):
Other Reclamation (These are reclamation costs associated with former activities to supply surface-mined coal.)

SECTION 8.5(B)
Substitute REI

SECTION 8.5(C)
Payment of the Utility Payment Stream

SECTION 8.5(D)
Payments under the Ute ROW

SECTION 8.5(E)
Other Miscellaneous Costs

SECTION 8.5(F)
Dispute Costs

COAL SALES AGREEMENT BUY OUT AGREEMENT

SECTION 4.4:
Payment of SJCC Costs

TRANSPORTATION AGREEMENT BUYOUT AGREEMENT

SECTION 3.4:
Payment of SJTC Costs

Any costs allocated as Fixed Fuel Expense pursuant to Section 23.4.1.3 of this Agreement.

Applicable taxes and royalties on the above items shall be deemed Fixed Fuel Expense.

Capitalized Terms used in this Exhibit, not otherwise defined in this Agreement, are as defined in the above captioned agreements.

EXHIBIT X

EXHIBIT X

VARIABLE FUEL EXPENSE

SAN JUAN UNDERGROUND COAL SALES AGREEMENT (As Amended)

SECTION 8.2(B)
Incremental CIE Amount

SECTION 8.2(C)
Reimbursable Operating Costs except those enumerated in Exhibit "F" Paragraph I(1) and only those reclamation costs directly associated with disturbance attributable to the underground mine.

SECTION 8.2(E)
That part of CIE Reconciliation Amount associated with Incremental CIE or Non-SJCC Incremental CIE

SECTION 8.3(B)
Reimbursable Processing Costs

SECTION 8.4
Non-SJCC Coal and Alternate Coal Costs

Capitalized Terms used in this Exhibit, not otherwise defined in this Agreement, are as defined in the above captioned agreements.