BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition to Request Exemption under Rule 25-22.082(18), F.A.C., From Issuing a Request for Proposals (RFP))	**Docket No.** **Dated May 26, 2006**

FLORIDA POWER & LIGHT COMPANY'S PETITION TO REQUEST EXEMPTION UNDER RULE 25-22.082(18), F.A.C., FROM ISSUING A REQUEST FOR PROPOSALS (RFP)

Pursuant to Rule 25-22.082(18), Florida Administrative Code ("F.A.C."), Florida Power & Light Company ("FPL") respectfully petitions the Florida Public Service Commission ("PSC" or the "Commission") for an exemption from Rule 25-22.082, the "Bid Rule," which rule would otherwise direct the issuance of a Request for Proposals ("RFP") in connection with FPL's proposed advanced technology coal project, consisting of a supercritical pulverized coal power plant with advanced emissions control equipment (the "Project").

Granting the requested exemption will accelerate the schedule for constructing and operating the Project by at least six months compared with undergoing the RFP process, which in turn will result in sooner: (i) utilization of lower cost fuel for FPL's customers; (ii) increased supply of reliable electricity for FPL's customers; and (iii) serving the public welfare by diversifying the generating technologies, fuel delivery methods and fuel types used to serve FPL's customers, and by decreasing reliance on natural gas as a fuel. If an exemption is granted, the Project would remain subject to a detailed PSC review and approval process through a future proceeding to determine the need for the plant as provided for in Rules 25-22.080 and 22.081, F.A.C.

I. Preliminary Information

1. The Petitioner's name and address is:

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3. FPL is a Florida corporation with headquarters at 700 Universe Boulevard, Juno Beach, Florida 33408. FPL is a utility as defined in Sections 366.02(1) and 366.082(1), Florida Statutes.

4. This Petition does not involve any prior agency determination or decision, or seek reversal or modification of any proposed agency action. FPL is not aware of any disputed issues of material fact with respect to the matters stated in this Petition.

II. Preliminary Statement

5. The Bid Rule provides that it is appropriate to exempt a utility from complying with the rule under specific circumstances, which circumstances FPL believes exist at the present time. The Bid Rule's exemption provision states:

> (18) Upon a showing by a public utility and a finding by the Commission that a proposal not in compliance with this rule's provisions will likely result in a lower cost supply of electricity to the utility's general body of ratepayers, increase the reliable supply of electricity to the utility's general body of ratepayers, or otherwise will serve the public welfare, the Commission shall exempt the utility from compliance with the rule or any part of it for which such justification is found.

Rule 25-22.082(18), F.A.C.

6. An exemption from the Bid Rule in connection with the construction of the Project is necessary to accelerate the Project's benefits which include substantial additional fuel diversity. Recent experience regarding the RFP process demonstrates two important facts: the RFP process would significantly delay the addition of the Project and the Project's benefits, including substantial fuel diversity, and it is highly unlikely that the RFP process will result in a more cost-effective solid fuel alternative to the Project that FPL proposes to build.

7. Granting the exemption with respect to the Project will serve the public welfare by permitting FPL to proceed much more expeditiously with respect to the Project, which will provide enhanced diversity in generation technology and fuel supply, improved system reliability, lower fuel costs and reduced fuel price volatility. Expediting the schedule through exemption from the Bid Rule process also will enable FPL to more quickly resolve and reduce project uncertainties, and their attendant costs, which will further benefit the public.

8. FPL believes that the RFP process would not result in the identification of any lower cost alternative to FPL constructing and operating the Project. First, recent RFP experience shows that there are relatively few qualified entities capable of undertaking such a project, and that there is no assurance that such entities would provide firm rather than indicative bids. Second, any alternative proposal would be faced with similar land, equipment, engineering, labor, fuel and other costs as would be encountered by FPL, making savings or cost reductions in these areas unlikely. Third, any alternative proposal would need to be priced so as to allow for a substantial risk premium taking into account the complexity, schedule and budget uncertainties inherent in such a project -- even if a proposing entity was willing to provide a firm bid. For these reasons, going through the RFP process would carry with it the certainty for customers of incurring the detriment of at least six months of time required for the process (assuming no litigation, appeals or other RFP process delays) without any likely benefit for customers being achieved through the process.

III. The Project will Provide Significant and Predictable Fuel Diversity Benefits to FPL Customers

9. The FPL generation system has experienced strong and historic peak load growth for the past ten years, and that growth rate is projected to continue into the future. As it is required to do, FPL has met and projects to meet that load growth with cost-effective resources. Analyses prior to the most recent changes in the natural gas fuel markets clearly indicated large natural gas fired combined cycle generation as the most cost-effective generation technology to meet the growing need. However, the most recent developments regarding fuel markets suggest that advanced technology coal generation is emerging as a cost-effective technology choice

under certain fuel market and emission requirement projections.[1] Additionally, diversity of generation technologies and an improved balance of fuel supply provides FPL customers with greater reliability and cost stability.

10. The Project, when complete, will significantly increase the coal component of FPL's fuel mix. The Project will provide both system reliability and fuel cost benefits to FPL customers. The value of fuel diversity has always been a consideration in generation planning, but based upon continued evaluations over the past eight years it is only recently that the addition of this coal plant is indicated potentially to be more cost-competitive than in the past.

11. There are significant system reliability benefits derived from the advanced coal technology and design proposed by FPL. This is a very reliable technology that is expected to operate as a baseload facility with a high availability factor. Diversification of technologies used in the system reduces exposure to a common failure mode specific to a single technology.

12. The choice of coal fuel will provide fuel supply reliability benefits as well. The Project will add capacity fueled by an energy source delivered by rail, rather than pipeline, for which many days' supply will be stockpiled on-site, providing a means of mitigating the impact of fuel supply disruptions. The design of the Project will allow additional fuel source flexibility by the use of coals from domestic and international sources, and may allow the use of limited amounts of low cost petroleum coke, a byproduct of petroleum refineries. Finally, the development of solid fuel transportation infrastructure (including rail and port facilities) to deliver coal to central and southern Florida will further support the future fuel diversity of this region.

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[1] *See* ***FPL's Report on Clean Coal Generation*** (Mar. 10, 2005).

13. The cost and price volatility of solid fuels are projected to be lower compared to natural gas and fuel oils. Therefore, the benefit of a lower priced fuel that also is more stable in price is expected to be directly reflected in a lower and more stable system fuel cost paid by FPL customers. For the reasons discussed in FPL's Report on Clean Coal Generation submitted in March 2005, it cannot be concluded at this time, considering total costs, that the Project would produce the overall lowest cost source of power compared to other options, including natural gas fired options; however, the most recent developments in the fuel markets and advanced coal technology warrant continued development of the Project and an exemption from the Bid Rule. It is clear that acceleration of the Project through an exemption from the RFP process will enable an earlier realization of fuel diversification benefits, reduce the cost escalation effects of delay, and expedite the delivery of any overall cost benefits that may be available. The Commission itself would review the overall project costs in relation to the projected benefits at the time of a proceeding to determine the need for the Project.

14. As discussed in FPL's 2006 Ten Year Site Plan, higher load forecasts driven primarily by growth in population have resulted in increased capacity needs beyond what FPL had previously projected. An accelerated path to bringing the Project into service as early as possible is the best means to bring these benefits to customers earlier, by adding needed generation capacity while enhancing fuel diversity.

15. Under ordinary circumstances, FPL would not be in a position to file for a determination of need for the Project until after what would be -- at a minimum -- a six month RFP process, even assuming that no delays were to occur. Moreover, it is only after approval of local zoning, finding of need by the Commission and approval through the Florida site certification process that FPL would be in a position to complete contracts with suppliers,

engineers, construction contractors and others necessary to implement the Project. In short, by providing an exemption from the Bid Rule for the Project, the Commission will be reducing the overall critical path by at least six months. FPL cautions that even if an exemption is granted, and a petition for a determination of need for the Project is granted, there still remain substantial local and state governmental approvals that are outside of FPL's control that could at a minimum delay the Project. In this regard, FPL also believes that a clear finding by the Commission in response to this Petition that it is in the best interest of the public to grant the Project an exemption from the Bid Rule may have an ancillary benefit, in the public interest, of helping send a clear message of the importance and value to the public of helping advance and expedite the Project. This will also aid in FPL's negotiations with the major equipment vendors who will be targeting their efforts in jurisdictions where they see the clearest path to a successful project. This will become increasingly important as global competition increases for the major components of a coal plant.

IV. The RFP Process Is Not Likely to Yield a Lower-Cost Coal-Fired Alternative

a. <u>The Bid Rule is Not the Exclusive Method for Determining Cost-Effectiveness</u>

16. The Commission's Rule 25-22.082(1), F.A.C., specifies the use of the RFP process as "an *appropriate* means to ensure that a public utility's selection of a proposed generation addition is the most cost-effective alternative available." (Emphasis added). While the RFP process is one method available to determine cost-effectiveness, it is not and was never intended to be the *exclusive* means of making such a determination. In fact, from its inception, the Commission intended for the Bid Rule to include flexibility and to allow for an exemption from the RFP process if issuing an RFP would be unproductive.

17. When the Bid Rule was initially discussed as a proposed rule, Commission staff expressed the Commission's intention that the rule should include flexibility such that a utility could be excused from the RFP process. In the first rulemaking hearing regarding Rule 25-22.082, F.A.C., held September 29, 1993, Mr. Tom Ballinger of the Commission staff testified, "The rules also provide flexibility to the utilities by allowing for a case-by-case waiver from issuing an RFP based on the demonstration by a utility that a waiver would be in the best interest of the general body of ratepayers." *In re: Proposed Amendment of Rule 25-22.081, F.A.C., Contents of Petition; and Proposed New Rule 25-22.082, F.A.C., Selection of Generation Capacity*, Hearing Transcript, Docket No. 921288-EU (Sept. 29, 1993), p. 20.

18. In the Special Agenda Conference at which the original Bid Rule was approved, the Commissioners acknowledged that circumstances may exist in which bidding is a needless exercise in selecting a capacity resource and that it would be inappropriate to consume precious time and resources in what was bound to be an unproductive endeavor:

> Chairman Deason: . . . if the utility, which is otherwise required to bid, if they believe it's in the best interest not to have a bidding procedure whatsoever, they would have the authority to petition for such a waiver; and the Commission, depending upon the merits of that petition, could grant a waiver of the entire bidding process.
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> . . .
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> Chairman Deason: Well, my concern is that we keep – in all the comments, practically every one of the comments and I think all of the comments from investor-owned utilities, there's always the word "flexibility, flexibility, flexibility, flexibility." *And my concern is that if there is a case where the utility believes and they can demonstrate that it would be a waste of time and resources, not only for the utility and the Commission but for the people that otherwise have to file a response to an RFP, to not have bidding whatsoever, that the Commission should have that flexibility*; and the parties should understand that that is contemplated within the rule, that if there is a certain set of facts and circumstances, that it may be best for all involved not to have a bid process whatsoever. That's what my concern is, and that it is clear in the rule that that is an avenue that the Commission perhaps could take on a case-by-case basis.
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> . . .

> Chairman Deason: Well, that's my concern. I just think the Commission needs that flexibility. And I think the majority of the comments which we received certainly indicated that *there may be cases where it's fairly obvious that it would not make practical sense to go through a bidding process.*

In re: Proposed Amendment of Rule 25-22.081, F.A.C., Contents of Petition; and Proposed New Rule 25-22.082, F.A.C., Selection of Generation Capacity, Special Agenda Conference Transcript, Item No. 1, Docket No. 921288-EU (Dec. 6, 1993), pp. 18-22 (emphasis added).

b. <u>An RFP Issued by FPL for Coal-Fired Generation is Unlikely to Result in a Lower Cost Alternative</u>

19. An exemption from the Bid Rule is appropriate because it has lately become apparent, based on FPL's recent experience in generation capacity RFPs, that issuing an RFP would be unproductive. FPL is unlikely to receive a cost-competitive alternative to FPL's proposed self-build coal plant. It is certain, however, that the RFP process will take a significant period of time and is not likely to yield the benefits intended by the Bid Rule.

20. In FPL's last three RFPs to solicit alternative proposals to compare to its self-build units which used simpler and more familiar gas-fired technologies, with fewer uncertainties and shorter lead times than solid fuel plants, no bidder has come close to matching the cost competitiveness of FPL's self-build alternatives.[2] Also, the ability of bidders to provide FPL with competitive bids in general has diminished significantly in the past several years, due in part to the increasingly shallow pool of companies that have the financial strength to undertake these types of projects. For even more capital-intensive projects such as advanced coal technology, in which the uncertainties are much greater and the lead times longer, FPL would expect even less chance of receiving competitive bids relative to the self-build alternative.

[2] These solicitations, conducted since 2001, represent over 6,000 MW of electric generation.

21. The RFP is ill-suited to capital-intensive, long lead-time projects, such as coal plants. The capital requirements for an advanced technology pulverized coal plant are three to four times greater than the capital requirements for a similarly sized natural gas-fired combined cycle plant. Further, development time for coal projects is about twice as long as other technologies due to the complex design and permitting challenges of coal plants. Because of these factors, the capital risk of a coal plant is significantly higher than for less capital-intensive projects. Bidders cannot take on the risk without expectation of reward and, therefore, the bid prices must be increased compared to more rapidly constructed and less capital-intensive alternatives. For example, in Xcel Energy's Comanche Unit 3 project (located in Colorado), it was recognized that whether coal generation facilities could be successfully developed through a competitive bidding process was uncertain, due to high capital costs, siting issues, permitting risks, and long development and construction lead times. It was determined that bypassing the RFP process would save a significant amount of time (in that case, nearly two years), resulting in substantial benefits to customers. *See* Comanche Unit 3 project materials, attached as Exhibit A.

22. In fact, in responding to FPL's recent RFPs, some bidders have been unable to submit firm price proposals based on the uncertainties of their projects. These bidders, instead, have submitted "indicative" bids, which offered an estimate of the ultimate costs, but did not guarantee a price. Indicative bids cannot be considered "firm" and cannot support a fair comparison to a self-build alternative. If an RFP was issued for the coal-fired generation, which has far more siting, zoning, construction, environmental and operational uncertainties than the other projects for which FPL has issued RFPs, FPL would anticipate that any proposals received would likely be "indicative" bids of no real value for purposes of moving forward with a viable project. Thus, in all probability, issuing an RFP to solicit alternatives to the Project likely would

be a fruitless endeavor whose only outcome would be the delay in realizing the potential benefits of fuel diversity to FPL's customers. As Commissioner Deason said, "[I]t would not make practical sense to go through a bidding process."

V. Granting FPL an Exemption from the Bid Rule Complies with Rule 25-22.082(18), F.A.C.

23. The Commission's flexibility to permit an exemption to the Bid Rule was maintained and enhanced when the rule was revised in 2003. Originally, the exemption provision was contained in subsection (9) of the Bid Rule.[3] In 2003, the Commission amended the Bid Rule and, among other changes, added subsection (18) to recognize that it is appropriate to exempt a utility from complying with the Bid Rule if:

> (18) Upon a showing by a public utility and a finding by the Commission that a proposal not in compliance with this rule's provisions will likely result in a lower cost supply of electricity to the utility's general body of ratepayers, increase the reliable supply of electricity to the utility's general body of ratepayers, or otherwise will serve the public welfare, the Commission shall exempt the utility from compliance with the rule or any part of it for which such justification is found.

Rule 25-22.082(18), F.A.C.[4]

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[3] Rule 25-22.082(9), F.A.C., adopted pursuant to Order No. PSC-93-1846-FOF-EU, Docket No. 921288-EU (Dec. 29, 1993), read as follows:

> The Commission may waive this rule or any part thereof upon a showing that the waiver would likely result in a lower cost supply of electricity to the utility's general body of ratepayers, increase the reliable supply of electricity to the utility's general body of ratepayers, or is otherwise in the public interest.

[4] This is an exemption authorized by the rule itself under specific circumstances; it is not a waiver. Therefore, the requirements of Section 120.542, Florida Statutes, do not apply.

24. Also, in 2003, the terminology was changed from "waive" to "exempt," clearly establishing an exemption process distinct and separate from a statutory waiver under Chapter 120, Florida Statutes.[5] The Notice of Change, published in the Florida Administrative Weekly on April 16, 2003, explained the changes to subsection (18) as follows:

> Subsection (18) of the rule has been modified to clarify that the Commission shall exempt, rather than waive, a public utility from compliance with the rule or any part of the rule, upon an appropriate factual showing by the public utility and a finding by the Commission that justification is found for such exemption.

25. Based on subsection (18) and the flexibility it was designed to allow, if FPL demonstrates that an exemption from the issuance of an RFP would either: (1) likely result in a lower cost of electricity to its customers, *or* (2) likely result in an increase in the reliable supply of electricity to its customers, *or* (3) otherwise serve the public welfare, then the Commission *shall* grant the exemption. An exemption requires only one of the three criteria must be met. For the reasons described below, FPL believes that subsection (18) items (2) and (3) discussed above will clearly be satisfied by granting an exemption.[6]

a. <u>Granting FPL an Exemption Will Likely Increase the Reliable Supply of Electricity to FPL's Customers</u>

26. FPL is specifically pursuing advanced supercritical pulverized coal generation, rather than some other technology or fuel, in order to increase the system reliability. As mentioned previously, the reliability benefits derived from the advanced coal technology and

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[5] At the time of the adoption of the revised Bid Rule and the addition of subsection (18), the issue of statutory authority for an exemption was discussed by the PSC and the Joint Administrative Procedures Committee ("JAPC") and was resolved through correspondence and conversations between Ms. Jennifer Brubaker of the Commission staff and JAPC staff attorney, Mr. John Rosner. The Commission deleted all the language that JAPC found objectionable and replaced it with the language currently in the rule at subsection (18).

[6] While there can be no assurance that the Project would likely result in a lower cost of electricity to FPL's customers (the standard under subsection (18), item (1) discussed above), FPL believes that the Project at a minimum would decrease customers' fuel costs and provide fuel diversity.

design are that the technology will operate with a high availability factor as a baseload facility and offers diversification that protects the system from being overly exposed to a common mode of failure specific to a single technology. Accelerating the implementation of the Project will bring these reliability benefits to FPL's customers sooner.

27. The choice of coal fuel will provide critical fuel supply reliability benefits as well. Coal may be stockpiled on-site, providing a means of mitigating the impact of fuel supply disruptions. The design of the Project will allow fuel source flexibility by the use of coal from domestic and international sources, as well as allow the use of limited amounts of low-cost petroleum coke. The development of a transportation infrastructure to deliver coal would also increase fuel source and electric reliability. While coal deliveries can still be interrupted by a variety of factors, coal does provide an alternative fuel source that will not likely be affected in the same way or at the same time as supply deliveries of foreign oil or natural gas. Granting an exemption from the Bid Rule and accelerating the coal-fired generation will provide these fuel supply, and therefore electric supply, reliability benefits sooner.

b. Granting FPL an Exemption Will Serve the Public Welfare by Increasing the Diversity of the Fuel Mix and by Decreasing the Reliance on Natural Gas

28. In large measure, for the reasons discussed above, the public welfare[7] would be served by the granting of an exemption of the Bid Rule to FPL because doing so will expedite the development, construction and operation of the Project, bringing greater diversity to FPL's

[7] The Bid Rule does not define the term "public welfare." Research of Commission Orders also did not disclose a definition of the term by the Commission, although at least one order equated "public welfare" with "public interest." *See In re: Application of Continental Country Club, Inc. for rate increase in Sumter County*, Docket No. 881178-WS, Order No. 21680 (Aug. 4, 1989). Black's Law Dictionary (7th ed. 1999) defines "public welfare" as "[a] society's well-being in matters of health, safety, order, morality, economics, and politics."

fuel supply mix sooner and reducing reliance on natural gas sooner, both of which serve the public welfare.

29. Granting an exemption, and proceeding with the Project, will serve the public interest by providing for fuel diversity that will result in more stable electricity costs to FPL's customers. This is because a greater proportion of fuel supply would be provided from solid fuels that are projected to have less price volatility. As mentioned previously, solid fuels are currently projected to maintain a lower overall fuel cost and to experience less price volatility compared to natural gas and fuel oils. Acceleration of the Project by an exemption from the RFP process will deliver these benefits sooner.

30. Exempting FPL from the lengthy RFP process also would reduce the effect of escalation on the total cost of building advanced coal generation technology, and thus make this addition more cost-effective than if the Project is completed at a later date. Also, an increase in natural gas and/or oil prices above the current forecast would result in even greater benefits from the Project for FPL's customers due to the Project's use of solid fuel. Accordingly, granting an exemption would serve the public welfare.

31. The Commission has recognized the public benefit of fuel diversity. In its final order approving the unit power sales ("UPS") agreements between Southern Company and FPL, the Commission acknowledged that fuel diversity is critical – on par with and possibly even outweighing cost-effectiveness. *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*, Order No. PSC-05-0084-FOF-EI, Docket No. 050001-EI (Jan. 24, 2005). In that order, the Commission lauded the new UPS agreements, which included the purchase of 165 MW of coal-fired capacity and energy, because through the

agreements "some fuel diversity is preserved for FPL at a time when Florida's utilities are highly dependent on natural gas-fired generation." *Id.* at 3.[8]

32. Individual Commissioners have also supported the concept of fuel diversity as a benefit to the public welfare. At the agenda conference to discuss the UPS agreements, Chairman Braulio Baez stated his position that there was "a growing need to really pay attention to fuel diversity . . . ." *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*, Agenda Conference Transcript, Item No. 9, Docket No. 040001-EI (Jan. 4, 2005), p. 16. Commissioner Davidson stated, "I am a huge supporter personally of at least considering coal options and trying to get to having a greater coal capacity in this state. We really have got to do something on this sort of increasing lack of fuel diversity." *Id.* at 10. Commissioner Deason commented that the "strategic advantages" of approving the UPS agreements "outweigh[ed] any potential dollars and cents considerations in terms of cost-effectiveness." *Id.* at 14. He also congratulated FPL on pursuing fuel diversity, saying that "maintain[ing] 165 megawatts of coal given the situation was commendable." *Id.*

33. In addition to the Commission, the Governor and State Legislature have recognized that fuel diversity is an important part of the state's energy future. Governor Jeb Bush and the Department of Environmental Protection noted that fuel diversity enhances system reliability. *See* 2006 Florida Energy Act, available at http://www.floridaenergy.org (recognizing that a diverse fuel base enhances system reliability and recommending that statutes be amended to direct the Commission to consider fuel diversity and fuel reliability). The Florida Legislature, following that recommendation, passed legislation amending Section 403.519, Florida Statutes,

[8] Commission staff also highlighted the importance of fuel diversity in a report issued in December 2004, which recognized Florida's dependence on natural gas for fuel and acknowledged the need for a "more balanced generation fuel mix" in order to stabilize state energy prices. *See* ***Coal-Fired Generation: Proven and Developing Technologies*** (Dec. 2004).

which would require the Commission to take into account "the need for fuel diversity and supply reliability" in making a determination of need for an electrical power plant, in addition to the other statutorily specified factors. *See* Fla. CS/CS/CS for SB 888 § 43 (Enrolled, passed by the House May 3, 2006; passed by the Senate May 5, 2006).[9]

34. The public welfare of the citizens of the state as a whole will be served by increasing fuel diversity and reducing the state's reliance on natural gas for electric generation sooner. The aggregate reliance on natural gas for electric energy in Peninsular Florida is expected to increase from 32 percent in 2005 to 45 percent in 2011, according to the Florida Reliability Coordinating Council. The Commission has stated that pursuing coal generation reduces the state's exposure to natural gas price volatility. Accelerating the in-service date of the Project would reduce the state's vulnerability to the price volatility of natural gas and therefore serves the public welfare of the state's citizens. Fuel market projections and new coal-fired technology now provide greater confidence that the benefits of fuel diversity can be achieved at a reasonable cost.

VI. FPL's Request for an Exemption is Timely

35. FPL's request for an exemption from the Bid Rule is timely. Any request for an exemption prior to this time would have been premature. The most recent changes in fuel markets and coal-fired technology, coupled with FPL's development of the Project, now support initiating the regulatory approval process for coal-fired generation. A request for a determination of need for advanced coal technology generation would not have been supportable based on the information available prior to this time.

[9] At the time this Petition was filed, the legislation had been passed by the Legislature, but had not yet been sent to the Governor for his signature.

36. Responses to FPL's latest RFP solicitations, including the 2005 RFP, indicate that the RFP process would yield no competitive alternatives to the Project. FPL's 2005 RFP process solicited alternative proposals to be compared to FPL's West County projects. No coal-fueled proposals were offered, even though the period covered was four to six years into the future. The proposals received were based on known gas-fired generation technologies, with fewer uncertainties and shorter lead times than an advanced coal project, but no proposal was close to being competitive with the self-build alternatives. The lack of coal-fueled proposals in general, and the lack of competitive proposals for the more certain gas-fired generation technology, in particular, demonstrate the overall unlikelihood that an RFP would disclose a better solid fuel alternative.

37. FPL has been diligent in its investigation to determine whether coal generation is prudent, cost-effective and in the best interest of FPL's customers. FPL has routinely evaluated the economics of adding solid fuel to its fuel mix; however, it was not until late 2003 that analyses began to indicate that adding solid fuel at some future date potentially could be cost-justified. Throughout 2004 and 2005, FPL continued its investigations and analyses.[10] Part II of

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[10] Since 1992, FPL has routinely evaluated the economics of adding solid fuel generation to its fuel mix. However, it was not until late 2003 that FPL's analysis began to indicate that adding solid fuel could be beneficial to FPL customers at some future point. This initial indication was reflected in FPL's 2003 Ten Year Site Plan. In 2004, FPL analyses confirmed that advanced coal technology generation held some promise, but that further investigation was necessary before FPL could conclude that advanced coal technology generation should be constructed. FPL's study and final analyses of the advanced coal technology generation was completed in 2005. FPL reported its findings in its Report on Clean Coal Generation, which concluded that adding advanced technology coal generation was in the best interests of its customers and should be pursued. *See **FPL's Report on Clean Coal Generation***. The Commission, in December 2004, also released a report prepared by Commission staff discussing coal-fired plants, coal technologies and the benefits associated with the use of coal in order to stabilize the price of energy in the state. *See **Coal-Fired Generation: Proven and Developing Technologies***. FPL's 2005 Ten Year Power Plant Site Plan set forth a comprehensive generation plan, which included a mix of future natural gas and coal-fueled technologies. *See **FPL's Ten Year Power Plant Site***

FPL's 2005 RFP included a description of FPL's capacity needs in 2012 through 2014, highlighting the need for fuel diversity and indicating FPL's proposal to build a supercritical pulverized coal power plant.

38. The original schedule contemplated by FPL to issue an RFP for its capacity and fuel diversity needs was in early to mid-2006. At the time that this schedule was developed, FPL was engaged in constructive efforts to obtain land use and zoning designations for a St. Lucie County site. FPL was confident that it could issue an RFP that would identify the site selected for the St. Lucie coal project, within the early to mid-2006 timeframe. However, efforts to obtain the appropriate land use and zoning designations at the St. Lucie County level were unsuccessful, with the final determination against FPL's proposal being made in November 2005. These unsuccessful efforts in St. Lucie County resulted in a setback in the timely development of advanced coal generation technology. However, with or without this setback in the schedule, it is clear that the public interest would be served by granting an exemption in this proceeding and thereby helping expedite placing the Project into service in as timely a way as is reasonably possible.

39. The St. Lucie rejection, the resulting need to locate alternative sites, the significant and growing global competition for the major components of a coal plant (e.g., the boiler) and the inherent challenges in obtaining local approvals are among many factors outside of FPL's control that have significantly decreased the likelihood that FPL can realistically place

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Plan 2005-2014, pp. 39-67 (Apr. 2005). In keeping with its 2005 Ten Year Site Plan, in September 2005, FPL issued an RFP, which encouraged proposals for fuel diversity. However, no coal proposals were received. In its 2006 Ten Year Power Plant Site Plan submitted in April 2006, FPL once again set forth a comprehensive generation plan that included a mix of future natural gas and coal-fueled technologies to help enhance fuel diversity and the reliability and cost-effectiveness of FPL's current system. *See* ***FPL's Ten Year Power Plant Site Plan 2006-2015***, pp. 43-72 (Apr. 2006).

a portion of the Project into service by June 1, 2012. For the reasons explained in this Petition, the likelihood of meeting the 2012 date will be further diminished absent an exemption from the Bid Rule.

40. An exemption likewise sends an important message to potential site owners and major equipments vendors that the Commission is supportive of the development of advanced coal generation technology in Florida. This is particularly useful given the increasing global competition for the major components of a coal plant, as vendors will seek to focus their efforts in jurisdictions that appear to be providing the clearest path to a successful project.

VII. Conclusion and Statement of Relief Requested

The Commission should grant FPL an exemption from the Bid Rule, in accordance with Rule 25-22.082(18), F.A.C. An exemption is appropriate to promote and facilitate fuel diversity, and the associated reliability and fuel cost stability benefits. All other things being equal, granting the requested exemption will accelerate the schedule for constructing and operating the Project by at least six months compared with undergoing the RFP process. An accelerated schedule will result in earlier: (i) utilization of expected lower cost fuel; (ii) increased supply of reliable electricity for FPL's customers; and (iii) diversification of generating technologies, fuel delivery methods and fuel types used to serve FPL's customers and resulting decreased reliance on natural gas as a fuel. As discussed in this Petition, it is highly unlikely that the RFP process would result in a more cost-effective alternative to the self-build option.

For the foregoing reasons, FPL requests that the Commission exempt FPL from the Bid Rule as provided for in Rule 25-22.082(18) and determine that FPL is not required to issue an RFP to solicit proposals for comparison to the Project described in this Petition, based upon a finding that an exemption would likely increase the reliable supply of electricity to FPL's customers, and would serve the public welfare.

Respectfully submitted this 26th day of May 2006.

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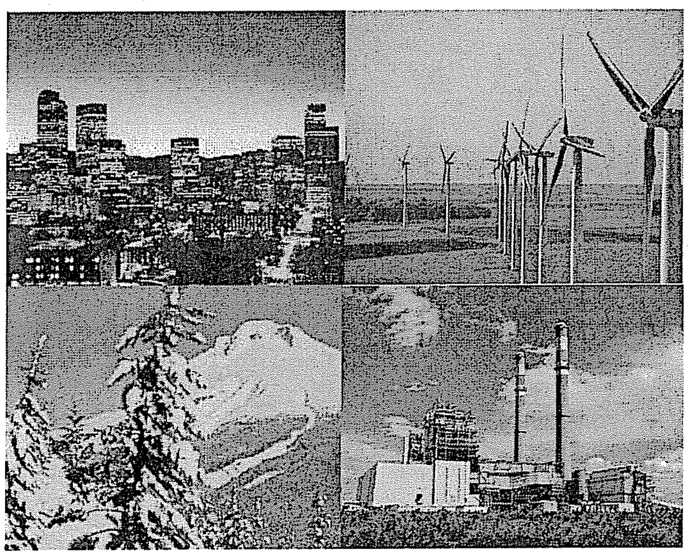
Public Service Company Of Colorado

2003 Least-Cost Resource Plan



Volume 1 of 4

April 30, 2004

Xcel Energy[SM]

Acquisition of Base-load Generation

It is unproven whether Independent Power Producers ("IPPs") can successfully develop new base-load coal generation facilities, through a competitive bidding process. This is largely due to the high capital cost associated with these plants, various siting issues, permitting risks, and long development and construction lead times. Even if IPPs could successfully develop new coal generation through a competitive bid process, PSCo can construct the Comanche 3 unit at least two years earlier than coal generation could be obtained through a competitive acquisition process, saving customers an estimated $100 million on a present value basis.

Transmission

Over the last twenty years PSCo has added approximately 3,700 MW of new generation facilities within eastern Colorado. As a result, we have effectively used up the transmission infrastructure that was planned and developed more than two decades ago. The growing energy needs of Colorado (approximately 2,000 MW new construction for PSCo and 500 MW for other Colorado suppliers) over the next ten-years requires Colorado suppliers to examine substantial transmission infrastructure developments in order to continue providing reliable electric service. PSCo's transmission planning group has taken the lead, through the Colorado Coordinated Transmission Planning Group, to initiate studies for a ten-year planning period throughout the State. These studies serve as the basis for a forward looking transmission infrastructure plan that will serve the best interests of all of the electric utilities in Colorado.

Peak Demand Forecasts and Reserve

The Company has recently re-assessed its demand forecasting process and further examined the weather factors that affect it's summer peak demand and resource planning requirements. Based on the results of recent modeling of demand variability, transmission import capacity, and generation availability, the Company is recommending in this LCP use of a higher planning reserve margin than has been used historically. Use of a higher planning reserve margin will increase the amount of new supply and demand side resources the Company acquires over the next ten years.

Market Impact of Purchased Capacity

PSCo currently purchases almost one-half (48%) of its electric generation capacity resources from IPPs and other utilities. When evaluating the financial strength of the utility, rating agencies and Wall Street analysts are increasingly considering a portion of these fixed contract obligations to be the equivalent of company debt. Construction of Comanche 3 as a new rate-base plant will begin to mitigate the Company's increasing imputed debt associated with its purchased capacity obligations. This will help maintain the financial integrity of the Company and contribute to lower electricity rates for customers in the future.

To reflect this reality, the Company proposes to use, as one bid evaluation criterion, an "evaluation equity adjustment factor" in order to fully consider the real cost of various purchased power alternatives. Because this resource plan includes the potential for acquiring up to

1.11 COAL PLANT OPTIONS ANALYSIS

The Company's screening analyses identified significant economic benefits associated with adding coal-fired resources to the PSCo system. This section discusses the range of options that were analyzed to identify the type, size and location of a new coal resource, as well as how the resource should be procured. It also describes the general design characteristics, environmental impacts and costs associated with the proposed plant.

Coal Procurement Options – Bidding versus Self-Building

In making decisions about how to add new coal resources to the PSCo system, the Company considered the risks and benefits of using a competitive acquisition process versus a self-build approach. The Company also examined lessons learned from recent attempts to acquire coal resources through a competitive bidding process at another Xcel Energy operating company – Northern States Power Company. To gain national perspective on methods used to acquire new coal resources, PSCo conducted a national survey of coal plant development and procurement practices. Through these evaluations, PSCo has concluded that a self-build option achieves greater benefits with lower risk for our customers and PSCo than using a competitive acquisition process.

Consequently, PSCo is asking the Commission for a waiver of the 250 MW limit in 4 CCR 723-3 Rule 3610(b) to permit PSCo to construct and own approximately 500 MW in the proposed 750 MW Comanche 3 coal plant.

PSCo's decision to use a self-build option rather than a competitive acquisition process hinges largely on the fact that coal plant development does not fit within the framework of competitive acquisition processes, and this creates considerable uncertainty that coal can win a bidding process and ultimately be developed and constructed, even when resource planning analysis concludes it is a preferred resource. The main factors that make coal plant development a poor fit with bidding processes include:

- capital risk
- long development lead time
- complex design and permitting challenges
- incompatibility with joint ownership arrangements

The following discussion elaborates on these four factors.

Capital Risk

Coal plant development exposes developers to considerably more financial risk than developers of other currently available technologies. Because developers typically offset financial risk by increasing their prices, coal developers must increase their prices relatively more than with less capital intensive projects. Coal's greater financial risk arises from coal's capital requirements being about double those of non-coal, competing technologies and its development time being twice as long - 4 to 6 years - than non-coal, competing technologies. Interest rate risk and inflation risk create the extra risk. Potentially higher interest rates and inflation rates impact the construction financing costs and labor and material costs to build plants. To manage these risks, a coal developer must increase its prices relatively more than a less capital intensive competitor; hence making coal less competitive.

The extra risk of coal plant development can be shown by comparing the impact of interest and inflation rate increases for two hypothetical plants, a coal and combined cycle (CC) plant. Suppose both plants are 500 MW, the coal plant costs $750 million ($1500/kw) to build and the combined cycle plant costs $325 million ($650/kw) to build. Further suppose that both these estimates had the same inflation and interest rate assumptions. Postulate the coal developer bids a capacity price of $225/kw-year (15% x investment / kw) and the combined cycle developer bids a capacity price of $97.50/kw-year. (Obviously the coal bid must be cheaper than the combined cycle bid in the variable and fuel cost categories to prevail.). Now assume that inflation turns out to be 1% higher than estimated and that the full investment is subject to inflation. The coal plant now costs $758 million to build, and the combined cycle plant costs $328 million. The coal plant "loses" $2.25/kw-month from its bid (.01x$225); the combined cycle plant "loses" $0.98/kw-month about 40% of the loss coal experiences. Inflation obviously has a much greater impact on coal costs than it does on a combined cycle costs. Thus, coal must pass significantly more inflation risk onto the buyer than combined cycle through a higher bid price that passes all or some of the inflation risk onto the purchaser. This makes coal less competitive.

Interest rate risk works similarly to inflation risk. Developers typically borrow most of the cost of building a plant ("construction financing"). If interest rates on construction financing are higher than anticipated when the bid was submitted, the impact is more severe for the capital-intensive project. Because interest rates and inflation rates are positively correlated, the coal project is doubly impacted by these risks than the combined cycle plant. Coal must hedge this risk by increasing its bid relatively more than a less capital intensive competitor, therefore reducing its competitiveness.

Long Development Lead Times

Coal's longer development time also subjects it to more interest and inflation risk than other technologies. Using the same example as above, suppose a coal plant takes four years to construct and combined cycle plant takes two years to construct. Obviously, coal has twice the time to encounter inflation or interest rate perturbations, thus doubling the risk it will suffer a financial setback.

Commercial operation date delay also poses greater risk for coal than it does for combined cycle. At the end of construction, coal has $750 million invested and combined cycle has $325 million. Suppose both are ready to go, but a permitting snag delays both three months. Suppose construction financing costs 5% per year. The extra cost for the coal plant is $750 million x .05/4 = $9.4 million. The extra cost for the combined cycle plant is $325 million x .05/4 = $4.1

million. The coal developers lose a lot more. Coal bidders account for this risk by raising their bid price relatively more than its competitors and thereby reducing their competitiveness.

A competitive bid process aggravates these financial risks. A bid process adds 12-18 months to the development lead-time. Given coal's already greater sensitivity to inflation and interest rate risk, adding time to the development process increases coal's financial risk. The added time for a competitive acquisition process disproportionately affects the financial risks of coal development.

Simply put, a coal developer has twice as much time and twice as much investment exposed to inflation and interest rate risks than its competitors, which is compounded by the additional time required for a competitive acquisition process. A coal bidder must account for these risks through a relatively higher bid prices Thus, coal bids are distinctly disadvantaged in a competitive bidding process.

The management of this capital and development time risk decreases coal's chances of prevailing in a competitive acquisition process. PSCo has concluded that our system needs coal resources. We do believe we should not risk losing a new coal addition to our resource mix because of the unbalanced financial risk impacts a competitive acquisition process imposes on coal developers.

Although capital and lead-time risks exist for the self-build plan, they can better managed with a traditional utility-regulatory compact than with a competitive bidding process. PSCo's plan assures the addition of a coal plant to its resource mix and does not subject this outcome to the uncertainties of a competitive acquisition process. PSCo customers will pay the actual costs incurred by the Company to build the plant including actual financing cost. If capital and lead-time risk do not materialize, the customer does not pay for them through a bid price that increased to cover these risks. If capital and lead-time risk is lower than expected, the customer benefits. Of course, if capital and lead-time risk is higher than expected, the customer will pay more than PSCo estimates today because within the utility-regulatory compact the customer bears these risks. This is a prudent trade-off considering the economic advantages a new coal resource would provide to our customers.

Complex Design and Permitting Issues

To develop "bid quality" estimates of total costs and to identify permitting requirements and feasibility, a coal developer should make significant expenditures on engineering design and permitting plans before the developer bids. This may cost in the $10-20 million range. Because there is no guarantee that the coal plant will prevail, a large amount of money is at risk, and coal bidders are reluctant to take this risk.

Xcel Energy's experience suggests this expenditure is too much for coal developers to risk. In Xcel Energy's 2001 Northern States Power Company ("NSP") All Source RFP, NSP received two coal bids that appeared competitive. However, one of the bids was an "indicative" offer. The developer basically offered a reasonable guess at the ultimate costs, but refused to guarantee the offer. The developer's terms were that if selected they would spend about a year refining their plant's design, cost estimate and permit potential and then give NSP a firm offer for the coal power. In other words, the coal developer was not willing to undertake the investment risk of refining its bid until it was selected on the basis of an indicative offer. The second coal offer at first appeared "solid," but during due diligence the developer reserved the right to change its price anytime during the development phase, thereby passing all price risk onto NSP. Considering the uncertainty of their bids, NSP could not accept either offer as part of the competitive acquisition process and rejected both bids.

Another example occurred in NSP's 2001 Prairie Island Contingent RFP in which NSP received several coal bids as possible replacements for its Prairie Island nuclear plant. NSP elected to pursue a contract with one coal plant developer only to learn that the developer had not done sufficient homework on its proposed site. During the negotiation process, the developer was forced to explore other locations for the proposed plant. Obviously, this increased the cost and development risk of the facility for NSP. Ultimately, before a contract was executed, new legislation enabled the continued operation of Prairie Island and made this competitive bid process moot.

PSCo's self-build plan mitigates these risks by already identifying the plant site and thoroughly researching the feasibility of obtaining permits for Comanche 3. This allows a coal plant to be built two yeas earlier than a coal plant that would arise from a competitive bid process, even if such a process can attract coal bids.

Incompatibility with Joint Development Arrangements

Considerable interest exists in the joint development and ownership of coal plants in Colorado. Given the very large investment requirements and long lead times, joint development is a way to share risk across several companies and enable smaller utilities to supply their customers with this cheaper electric supply. The interest in joint development for a coal plant inhibits the successful use of a bidding process to procure the resource because of different interests, different timing, and the length of time needed to negotiate a joint development agreement.

Joint development arrangements are incompatible with bidding processes. First, some entities interested in joint development are not bound by regulatory rules requiring bidding. These entities would prefer owning and controlling their own power plant development rather than yield it to a bid process. Obviously, if one wanted to develop with such a partner, a competitive bidding process would be a large impediment. Second, different parties have different needs and interests. These must be resolved within the joint development agreement. However, the many compromises inherent in such arrangement may thwart the use of a competitive bidding process because the design and in-service date of a plant offered in a competitive bidding process may not match the objectives of each party. Finally, joint development agreements take considerable time to negotiate. Adding this amount of time to the length of a competitive bidding process would delay the in-service date of the desired plant and add time-delay risk to getting the desired plant.

Suppliers could form joint arrangements and bid "excess" capacity into a PSCo bid process. This approach reduces chances for successful development. As one might expect, negotiating a joint development contract is a difficult task. It takes time to arrange the joint development, and time is the enemy of successful participation in a bid process. If joint development is desired, but cannot be worked out before the due dates of the bid process, it loses its bid opportunity. Or, the joint developer may bid and lose. Either way, assuming serving PSCo was critical to the success of the development, the joint developers and PSCo lose their opportunity for coal's cheaper and more stable electric supply until a need for the next "large resource" is needed.

A self-build plan can accommodate joint development much easier than a competitive acquisition process can. It simply eliminates all the complexities a bidding process adds to the already complex negotiations joint development requires.

National Coal Plant Development Survey

To test its hypothesis that coal plants do not fare well in competitive bidding processes, PSCo had Platts Research & Consulting ("Platts") review the development of U.S. coal plants scheduled for in-service between 2000 and 2010 to see if any were selected by way of a competitive acquisition process. The survey was limited to plants that had passed a noteworthy permitting hurdle, either an air permit or the equivalent of a CPCN. Of the twenty-one plants that were reviewed, "no major coal plant has been successful in a competitive power supply bid process." Eleven of the twenty-one plants originated from a "utility self-development process." Ten originated from an "independent developer-driven process" that "has little connection with competitive bidding processes on the part of off-takers." Platts wrote "it is likely that potential power off-takers are contacted and surveyed [by the independent developers] before significant money is invested in the projects. Our research indicates that air permits are frequently obtained before PPAs are finalized, and it might be noted that the obtainment of an air permit is a relatively low hurdle to meet as compared to the full cost of a completed coal plant." One 10 MW coal cogeneration plant received a PPA through a competitive bidding process in Montana. "The process has been marked by conflict and debate..." The Montana Public Utilities Commission rejected the PPA for this coal-fired project. Platts' report supports PSCo's hypothesis that it is difficult for a coal plant to prevail in a competitive bidding process. Details about this survey are included in Section 1.11 of the Volume 4 Technical Appendix.

Conclusion

Considering the factors outlined in this section, PSCo has determined that a self-build approach is better than a competitive bidding approach for adding a new coal resource to its system. In summary, a self-build approach will:

- Allow PSCo to manage financial, economic and development risks that are inherent with coal plant development rather than pay a third party an inflated, risk adjusted bid price to manage these risks even if the risks never materialize.

- Rely on the traditional utility-regulatory compact where the risks are thoroughly examined through a CPCN process and where regulatory bodies can review the ultimate cost of the project.

- Enable PSCo to take advantage of its ownership and control of a development site with existing generation facilities that can be shared with a new plant and thereby minimize siting and permitting risk.

- Create a deal structure that accommodates the strong interest in joint development and ownership of a new coal plant in Colorado.

- Ensure consistency with best practices and lessons learned at other utilities in the U.S. that are adding new coal resources.

PSCo has concluded that coal resources cannot compete well in a competitive bidding process, particularly to meet resource needs prior to 2010. PSCo has also concluded that its system needs a coal-fired resource to re-balance the fuel characteristics of its supply portfolio, Consequently, PSCo is asking the Commission to waive the 250 MW limit in 4 CCR 723-3 Rule 3610(b) and allow PSCo to construct a 750 MW coal plant with 500 MW owned by PSCo.

The All-Source RFP that is included with this LCP permits the bidding of coal resources . The resource screening process shows that more coal than just the 500 MW from Comanche 3 would likely result in the least-cost expansion plan. In light of PSCo's resource needs through 2013, sufficient lead-time exists for a developer to bid coal for in-service after 2010 and to develop it if selected. While PSCo is skeptical that a coal proposal could prevail in a competitive solicitation for the reasons just discussed, the Company is willing to let the market test our hypothesis. PSCo has structured the solicitation to permit up to 30 year contract terms in order to increase the chance of acquiring a coal based PPA.

Coal Technology Options

PSCo examined four coal generation technologies to inform its decision about which self-build alternative to pursue. These technologies represent the range of commercially available coal-fired plant configurations available today: (1) subcritical natural circulation pulverized coal ("PC") plants; (2) supercritical once-through PC plants; (3) circulating fluidized bed plants; and (3) integrated gasification combined cycle ("IGCC") plant. The following summarizes some of the key issues with each technology:

1. Subcritical Units. The traditional boiler technology used is subcritical PC units operating at approximately 2,400 psig, 1,005°F/1,005°F steam conditions. These units range in size from very small up to 900 MW. The units have steam drums and work on the principal of natural circulation. This type of unit is still being supplied as the technology of choice in numerous new plants in Europe, Southeast Asia and China, with the typical size

EXHIBIT A
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*2004 Colo. PUC LEXIS 1449, *; 239 P.U.R.4th 177*

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2003 LEAST-COST RESOURCE PLAN; IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER APPROVING A REGULATORY PLAN TO SUPPORT THE COMPANY'S 2003 LEAST-COST RESOURCE PLAN; IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE COMANCHE UNIT 3 GENERATION FACILITY

Decision No. C05-0049; DOCKET NO. 04A-214E; DOCKET NO. 04A-215E; DOCKET NO. 04A-216E

Colorado Public Utilities Commission

2004 Colo. PUC LEXIS 1449; 239 P.U.R.4th 177

December 17, 2004, Adopted; January 21, 2005, Mailed

CORE TERMS: settlement, emission, settlement agreement, wind, bid, energy, generation, ratepayer, technology, environmental, reduction, mercury, carbon, air, coal, solicitation, cap, scenario, savings, rate case, customer, plant, staff, least-cost, approve, acquisition, expenditure, renewable, pre-construction, intervenor

PANEL: **[*1]** POLLY PAGE, Commissioner; CARL MILLER, Commissioner; CHAIRMAN GREGORY E. SOPKIN ꞆNCURRING, IN PART, AND DISSENTING, IN PART

OPINION: ORDER APPROVING SETTLEMENT

I. BY THE COMMISSION

A. Statement

1. On April 30, 2004, Public Service Company of Colorado (Public Service or Company) filed an application for approval of its Least Cost Resource Plan (LCP). On that same date, Public Service also initiated Docket Nos. 04A-215E and 04A-216E, by filing applications for approval of a regulatory plan to support the LCP and for a certificate of public convenience and necessity (CPCN) to construct a 750 MW coal-fired, base load power plant known as Comanche 3.

2. The Commission's Electric Least-Cost Resource Planning Rules, 4 Code of Colorado Regulations (CCR) 723-3-3600 through 3615, require jurisdictional electric utilities to file a least-cost resource plan on or before October 31, 2003 n1, and every four years thereafter. In addition to the four-year cycle, a utility may file an interim plan. Each investor-owned electric utility is required to file a LCP that includes:

a) a statement of the utility-specified resource acquisition period and planning period;

b) an annual electric **[*2]** demand and energy forecast developed pursuant to rule 3606;

c) an evaluation of existing resources developed pursuant to rule 3607;

d) an assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to rule 3608;

e) an assessment of need for additional resources developed pursuant to rule 3609;

emissions from the Comanche units and in other locations in Pueblo.

57. The Parties further agree not to contest the pre-construction air permit or operating permit for Comanche 3. In addition to the intervenors in these consolidated dockets, **[*37]** several other entities agreed to these terms by signing the CECP Stipulation. These entities include Better Pueblo, Diocese of Pueblo, Smart Growth Advocates, Sierra Club, and Environmental Defense. Though these entities are not intervenors in this consolidated docket, it is important that they are signatories to the CECP Stipulation. With these additional groups, the Settlement includes the primary environmental and Pueblo area community groups. The Settlement thus reduces the risk that construction of Comanche 3 will be delayed by further litigation.

58. Public Service states that the air permit approval timing can have a very large impact on the expected benefits of Comanche 3. While the Parties recognize that groups outside this docket can contest the air permit, they argue that approval of the Settlement should help to mitigate air permit delays.

D. Approval of Comanche 3 with a Construction Cost Cap

59. In its application Public Service proposed to construct Comanche 3 as a rate-based facility, with all prudently incurred costs recoverable from ratepayers. Public Service provided detailed cost estimates for Comanche 3, which it characterized to be within the accuracy of **[*38]** plus or minus 20 percent. However, Public Service requested approval to construct Comanche 3 without a limit on the level of recoverable costs -- even if the prudently incurred actual costs exceeded its estimate by more than 20 percent.

60. In its Answer testimony, Staff did not take a position on whether the Commission should approve Comanche 3, but instead recommended that the Commission impose a construction cost cap if it did approve the plant. The OCC also recommended that the Commission approve Comanche 3, but only with a construction cost cap. The OCC recommended that the actual dollar value of the cap be established in a separate docket in the future.

61. In Rebuttal testimony, Public Service argued that it would be improper for the Commission to disallow prudently incurred costs for a rate-based plant. Further, Public Service represented that its cost estimates did not include any contingency amounts necessary to cover the risk of future cost increases. As such, Public Service stated that it would not be fair to limit the Company to a regulated return on actual costs, while placing it at risk for prudently incurred costs that exceed a capped amount. Public Service pointed **[*39]** out that many factors such as the price of steel, cost of capital, and inflation are not within its control and could impact its ability to maintain costs within a capped amount.

62. The Parties propose in the Settlement that the Commission approve Comanche 3 with a construction cost cap, although the actual amount of the cap is not specified. Rather, the Parties propose to use a formula-based method to establish the level of the construction cost cap. This cap will be based on the future bid prices of certain major components of Comanche 3 and will be adjusted based on other factors. The Settlement specifies the details of the construction cost cap calculation in confidential Attachment C.

63. The Settlement proposes that the Commission approve Comanche 3 before establishing a final construction cost cap amount. There could be the possibility that Comanche 3 would be built within a cap that is higher than costs analyzed in this case. In accordance with the Settlement, neither the Parties nor the Commission would be able to re-evaluate whether Comanche 3 is still a least-cost resource at the time the level of the cap is determined. That is, if the bids for the Comanche 3 components **[*40]** come-in higher than anticipated, the construction cost cap will still allow Public Service to recover these higher costs, through the application of the formula method which would adjust the cap accordingly, without a subsequent review of the cost-effectiveness of the project.

64. We find that Public Service has adequately demonstrated that Comanche 3 will provide savings compared to other base load generation options. Because Comanche 3 is a "brownfield" expansion of an existing **coal plant,** the common use of existing coal handling, rail, and general site facilities provide many cost savings when compared to greenfield options. In addition to these cost savings, there are potential savings in operation and maintenance costs from the combined Comanche operations. Another advantage of Comanche 3 is the potential for it to be operational one to two years before a greenfield **coal plant.** This

earlier in-service date for Comanche 3 is projected to save ratepayers hundreds of millions of dollars.

65. We find that the formula approach proposed in the Settlement provides a reasonable method to establish the amount of the construction cost cap. The potential costs of delaying the approval of **[*41]** Comanche 3 until the construction cost cap price is known outweigh the risks of the construction cost cap price being substantially higher than is currently anticipated. The cost savings associated with the brownfield Comanche 3 unit warrant approval before the construction cost cap is finalized.

66. The Comanche 3 construction cost cap provides a reasonable means of ensuring that runaway Comanche 3 costs are not imposed on ratepayers. The construction cost cap limits ratepayer exposure, and provides incentives for Public Service to properly manage the project. We find the construction of Comanche 3, with a formula-based cost cap, will likely provide significant cost savings to ratepayers

E. Demand Side Management (DSM)

67. In its original application Public Service did not propose any company-sponsored DSM. Instead Public Service proposed to solicit DSM bids as a part of its All-Source RFP, and accept only those bids that were selected as part of the least-cost portfolio based on NPV rate impact analysis, consistent with Commission Rules.

68. Several intervenors recommended that Public Service implement company-sponsored DSM programs. Intervenors further recommended that the **[*42]** Commission direct Public Service to use the Total Resource Cost (TRC) test instead of the Net Present Value (NPV) rate impact test to evaluate these DSM programs. The intervenors argued that the utility is in the best position to implement DSM, and a bid-only DSM program would be inadequate. They also asserted that the NPV rate impact test unnecessarily restricts DSM and that the TRC test is an industry standard which must be used in order to properly evaluate the cost-effectiveness of DSM programs.

69. In its Rebuttal testimony, Public Service proposed a total of 150 MW of DSM, including company-sponsored DSM evaluated under the TRC test. DSM bids would still be solicited and would be evaluated under the NPV rate impact test. Public Service proposed that any DSM bids it accepted would reduce the amount of company-sponsored DSM.

70. In the Settlement, the Parties propose 320 MW of cost-effective DSM, up to a maximum cost of $ 196 million. The Company will target 40 MW of DSM per year for eight years. This $ 196 million maximum cost includes $ 2 million for an initial DSM market study and $ 2 million for ongoing study and measurement/verification of the DSM that is implemented. Public **[*43]** Service will use its best efforts to implement 40 MW (and 100 GWh) of cost-effective DSM per year, up to a maximum level of 320 MW (and 800 GWh) between January 1, 2006 and December 31, 2013. This 320 MW level will be reduced, if necessary, to limit the total cost to $ 196 million, or if less than 320 MW can be implemented on a cost-effective basis. In the event that the 320 MW level is achieved at a cost lower than $ 196 million, Public Service will nevertheless limit the DSM to 320 MW. According to the Settlement, the Company will strive to implement programs that give all classes of customers an opportunity to participate. Additionally, Public Service will hire up to 18 full-time employees, in addition to current staff, to implement the program. The cost for these additional employees, as well as other labor costs for the expanded DSM, are included within the $ 196 million limit.

71. Public Service agrees to use the TRC test to determine the cost-effectiveness of the company-sponsored DSM programs. Costs for these DSM programs will be recovered through the existing DSMCA cost adjustment mechanism with an 8-year amortization period. Public Service will report specific DSM parameters **[*44]** within its annual DSMCA filing. The Parties agree that Public Service may make an out-of-period adjustment in its 2006 rate case for DSM labor up to 18 full-time equivalent employees and other related costs. These costs will not be recovered through the DSMCA.

72. We have several observations regarding the proposed company-sponsored DSM program. Rule 3610(f) requires the utility to select its final resource plan with the primary objective to minimize the NPV of rate impacts. While the TRC test would minimize utility costs, rates may nonetheless increase compared to a scenario where the utility implements generation resources instead of the DSM. This is because the TRC test maintains the same utility cost as with the avoided generation. But this cost would be spread over