Cities 123

DOCKET NO. 9491
DIRECT TESTIMONY AND EXHIBITS OF
DANIEL J. LAWTON
ON BEHALF OF
CERTAIN CITIES SERVED BY
TEXAS-NEW MEXICO POWER COMPANY
PRUDENCE PHASE
AUGUST 10, 1990
VOLUME I

Docket No. 9491
Direct Testimony and Exhibits of
Daniel J. Lawton
On Behalf of
Certain Cities Served by
Texas-New Mexico Power Company
Prudence Phase
August 10, 1990

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

A. My name is Daniel J. Lawton. My business address is 7800 Shoal Creek Boulevard, Suite 246 South, Austin, Texas 78757. I am a principal in the firm of Diversified Utility Consultants, Inc. ("DUCI").

Q. ARE YOU THE SAME DANIEL J. LAWTON WHO PREVIOUSLY SUBMITTED TESTIMONY IN THE REVENUE REQUIREMENTS PHASE OF THIS PROCEEDING?

A. Yes, on July 6, 1990 I submitted revenue requirement testimony in Phase I of these proceedings.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS, THE PRUDENCE PHASE OF THESE PROCEEDINGS?

A. I will be presenting testimony on the issue of the TNP ONE facilities. These issues address the prudence of constructing TNP ONE as well as, the problems associated with TNP's ownership of these facilities. In addition, I will be providing testimony on the issue of performance factors.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

A. The following are my recommendations with regard to the TNP ONE issues:

INTRODUCTION

Q. PLEASE DESCRIBE THE PRUDENCE ISSUES SURROUNDING THE TNP ONE PROJECT.

A. Before getting into the various prudence issues, it is important to describe how this case has been presented by Texas-New Mexico Power Company ("TNP" or "Company") and how these issues need to be addressed.

Q. WHAT IS THE STATUS OF THE TNP ONE UNIT I ISSUE IN THIS CASE?

A. Quite simply, this is one of the most unusual cases I have ever analyzed. First, at the time of writing this testimony, no party knows if the PUCT will grant a final CCN.[1] In other words, the plant is built but the Company has yet to receive permission to start construction.

* where is the Order

Second, the Company does not own the plant at this time. Even if TNP ONE Unit I becomes commercial or if a CCN is in fact ever issued the plant is owned by a subsidiary, not TNP. The Company has formed a wholly owned subsidiary, Texas Generating Company ("TGC"), which will hold legal title to the plant but TNP will hold the CCN if one is granted. However, TNP wants the plant in rate base even though the Company will not own the facility. Furthermore, I do not believe TGC is a utility authorized to sell electricity in Texas. In my opinion, some of the issues above are not only unusual, but are legal issues that will have to be resolved by the Commission and/or the courts. These issues are discussed in detail below.

check PURA

1 At this time an Examiner's report issued on August 1, 1990 does recommend approval of the CCN.

for setting rates, the enormous rate increase in this case and the results of the increase should not be ignored.

In summary, the circumstances surrounding this case are unusual at best, and depending upon whether a CCN is issued and how this Examiner and Commission view the TNP ONE ownership issue in this case, the prudence issues are premature or should be approached somewhat differently.

In other words, if a CCN is not granted by this Commission, then obviously, there is no need for a prudence inquiry. If the Company does in fact receive a CCN, it will hold a CCN for a plant it does not own. Since the Company is effectively leasing or renting these facilities from a wholly owned subsidiary, TGC, when and if ownership is transferred to TNP, a Section 63 of PURA inquiry is necessary. Documents I have reviewed indicate that the Company and the financial institutions involved in this project knew a Section 63 review would be required. Thus, given the circumstances in this case one of the ways I have approached the issues is a Section 63 approach and I have relied on what I believe are the appropriate standards and Commission precedent for such a review. Cities' witness, Stowe, does address the ownership issues and prudence issues in a traditional ratemaking manner.

Q. EARLIER YOU DESCRIBED THIS CASE AS UNUSUAL PLEASE DESCRIBE HOW THIS CASE IS UNUSUAL.

A. The Company is requesting rate recognition for a plant for which TNP does not have a CCN. The Company is requesting rate recognition for a plant which they do now own. The Company has created a subsidiary, TGC, which will own the plant, while TNP will hold the CCN if one is in fact issued. The Company expects to transfer 100 percent ownership of the plant from TGC to TNP by late 1993. In the interim, TNP is effectively leasing these facilities from TGC until full ownership is transferred to the utility. It is the above set of facts which make this case unusual and complex from a ratemaking perspective.

Q. PLEASE SUMMARIZE HOW THE COMPANY CAME TO BE IN THIS SITUATION.

a. First, the plant is being constructed by a group of entities known as the construction Consortium ("Consortium"). The deal to build these facilities is based on a fixed price contract. The project is based on a turnkey proposal whereby the facilities are to be constructed and operating at a specified performance level before the ownership responsibility is turned over to the utility or some other entity.

Second, the financing of the project during construction would be the responsibility of the Consortium and not the Company. The Consortium created a wholly owned subsidiary, Project Funding Corporation ("PFC") to finance and own this plant until the facility was capable of operating at specified performance levels and then the facility would be turned over to the Company or some other entity.

Third, because the Company would have to finance the entire project at the time of completion, the Banks, who put up the funds through PFC, agreed that the total cost obligation could be paid off by the Company in installments over a 39 month period for Unit I.

Fourth, due to restrictions contained in TNP's indenture, the Company created a wholly owned subsidiary to own the TNP ONE facilities. In this way, TNP could provide the lending institutions a first mortgage lien on these facilities during the 39 month period allowed for permanent financing. After the permanent financing had been completed, the Banks would have been fully repaid and the lending institutions would no longer be concerned with having a lien on these facilities.

Fifth, while the lending institutions originally required that TNP first get PUCT approval for subsidiary ownership and the necessary CCN amendments for such ownership arrangements, such requirements were later dropped in favor of accepting the regulatory risk of going forward without PUCT approval. I discuss later in this testimony how the Company changed contracts with the Banks regarding the uncertainty with the CCN for the plant resulting from the PUCT order in Docket NO. 6992.

Given the above five factors the PUCT and ratepayers are faced with the following situation today:

(a) the Consortium completed construction on Unit I;

(b) the minimum operating performance of these facilities was not met on June 8, 1990;

(c) PFC transferred ownership of Unit I to TGC and the debt responsibility, which must be paid off in the next 39 months, is on TGC but guaranteed by TNP;

Based on TNP's various life cycle analyses, this plant, on a total cost basis, could cost ratepayers $306 million in additional rates or possibly save ratepayers $329 million. The above reflects a very wide range especially when one considers the questionable assumptions in these studies. On an incremental cost basis, (ie) complete or abandonment, the savings range from a positive $701 million to a negative $800 million.

While the Company has continued to present a case that over the life of the generating facility, ratepayers will save money relative to a purchased power alternative, data available to me on present day forecasts indicate TNP's decision to self generate will cost ratepayers more money relative to the purchased power alternative. In addition, data available to the Company back in 1987 indicated the economic viability of this project was not only uncertain but further analysis would have shown the plant to be more costly than other alternatives. This issue of life cycle costs is also discussed in this testimony.

Q. WHAT IS THE RATE IMPACT TO RESIDENTIAL CUSTOMERS OF TNP'S PRUDENCE QUANTIFICATION AND DECISION TO INCLUDE THE PLANT IN RATES?

A. If TNP's proposed summer rate were in place at this time TNP would have the HIGHEST residential rates per 1,000 Kwh of usage in Texas. I have included this calculation in my Exhibit ____, Schedule (DJL-1). In addition, once the second unit is placed in rates, it is my opinion that TNP's summer rate will be well in excess of $100 per 1,000 Kwh of usage. Thus, it is likely that TNP's residential customers will be paying the HIGHEST rates in Texas for some time. Obviously, this is a number one rating that customers would prefer not to have. I do not believe the Company wants the distinction of charging the highest rates in Texas but nonetheless this is the result of TNP's prudence analysis on customers.

Q. ASIDE FROM THE RATE ISSUE DESCRIBED ABOVE ARE THERE OTHER SIGNIFICANT PROBLEMS FACING THE COMPANY?

A. Yes. The key problem facing the Company at this time is the financing of these facilities. As will be explained later in this testimony, even though TNP will not own the facilities, the Company has guaranteed payment for the investment. Thus, TNP is responsible for the ownership payment of its subsidiary, TGC.

It must be remembered that TNP and its wholly owned subsidiary, TGC, must permanently finance the entire investment in Unit I over the next 39 months and next year TNP (and ratepayers) will have Unit II to finance. Given that the financing of these facilities during construction has been the responsibility of a subsidiary of the Consortium, Project Funding Corporation ("PFC"), none of Unit I or Unit II has been paid for by the Company. While there were benefits of off balance sheet construction of these facilities during construction, the detriment of that approach is that all financing must take place now.

RATEMAKING PROBLEMS ASSOCIATED WITH TNP ONE FACILITIES

Q. PLEASE DESCRIBE THE VARIOUS RATEMAKING PROBLEMS ASSOCIATED WITH TNP ONE FACILITIES IN THIS CASE.

A. Before a prudence determination of the amount of TNP ONE facilities that can be included in rate base, there are, in my opinion, two hurdles that must be overcome to determine whether any of the facilities can be included in rate base. The first issue that needs to be addressed is the CCN issue. While the determination of a final CCN is a matter for Docket No. 6992 on remand, nonetheless, the Company still doesn't have a CCN. Thus, if the Company is denied a CCN for TNP ONE it would appear that a prudence determination in this case is unnecessary. While the CCN determination, no matter which way the Commission decides the facts, is likely to continue to be a contested matter, obviously, I do not recommend that these facilities be included in rates if the PUCT denies the CCN.

where is the order — then, rehearing

not administrative final!

Q. WHAT IS THE SECOND MAJOR RATEMAKING PROBLEM THAT NEEDS TO BE ADDRESSED IN THIS PHASE OF THE PROCEEDING?:

A. The next major problem that needs to be addressed is the ownership of the TNP ONE facilities. There is no question in this case that TNP will not own these facilities once the plant is ready for commercial operation. A wholly owned subsidiary of TNP has taken ownership of TNP ONE under the contemplated financing arrangement. While it is expected that the Company will own the plant once the construction loan is paid-off, the issue is that TNP does not hold legal title to the plant, and depending upon the timing of future the PUCT authority to disallow costs. In addition, these facilities could be pledged as collateral on possibly risky non-regulated ventures, or for that matter, sold. Needless to say ratepayers could face increased risks in the future. Thus, TNP's request in this case for TNP ONE could be precedent for ratemaking problems in the future and may not be in compliance with PURA. In addition, it is not prudent to subject ratepayers to unnecessary risk.

Thus, the issue of ownership of TNP ONE, is a problem because, in my opinion, the plant doesn't belong in TNP's rate base. Therefore, there is no plant investment to which a prudence disallowance is to be applied. While this plant will come into TNP's rate base over time as the loan is paid off, obviously any prudence determination made at this time can be applied to TNP's ownership share in some subsequent case. As I stated earlier, the most reasonable way to view the TNP/TGC transaction is as a lease purchase agreement with an affiliate. TGC will own the facilities until such facilities are purchased over time. Given these sets of circumstances, a Section 63 review by this Commission appears to be the most reasonable approach to evaluate the transaction. While such an approach does not solve the problem with including these facilities in rate base, it does provide a means of determining or providing an evaluation of the rental/purchase transactions in terms of the public interest impacts.

If TNP is allowed to include the facilities in rate base, the Company will be allowed an excessive return. As I will show later in this testimony TGC's cost of ownership of these facilities is, at least, approximately $9.0 million less than TNP proposes to charge ratepayers by rate base inclusion of these same facilities.

SECTION II <u>PRUDENCE ISSUES</u>

Q. ASSUMING THIS COMMISSION DOES ISSUE A CCN AND ASSUMING TNP IS ABLE TO GET AROUND THE OWNERSHIP HURDLE DISCUSSED ABOVE, WHAT ISSUES NEED TO BE ADDRESSED REGARDING PRUDENCE OF THIS PROJECT?

A. Mr. Jack Stowe will be addressing a number of issues regarding the cost increases of this project. Mr. Stowe will also address the numerous change orders, as well as the issues of common plant allocation. In addition, Mr. Stowe will be addressing the TGC ownership issue discussed above. Based on my discussions with Mr. Stowe, it is my understanding that he is recommending that the entire plant be disallowed because of the TGC ownership problem. This issue is fully discussed in his testimony.

In this testimony I will be addressing some of the issues noted above, as well as, the decisional prudence issue of whether TNP should have built TNP ONE rather than seeking other alternatives. In addition, I will also be addressing the <u>prudence</u> of the Company's decisions to proceed with the plant knowing the problems with the CCN, as well as TGC ownership. I will also be providing testimony based on Section 63 of PURA given that TNP is effectively renting or leasing and at some point plans to transfer ownership of this plant.

Q. IF A CCN IS ISSUED BY THIS COMMISSION FOR TNP ONE, HAS THE PUCT EFFECTIVELY DECIDED THE PRUDENCE ISSUE IN FAVOR OF CONSTRUCTING THE PLANT?

A. Not in my opinion. While the PUCT may allow TNP management a certificate to construct the project, TNP still has the burden of proving the decision to become a generating utility relative to maintaining its status as a distribution utility was prudent. For example, in recent years there have been a number of utility companies that have had prudence hearings regarding the inclusion of generating plant investment in rate base. The fact that these utilities had a CCN did not preclude a challenge on decisional prudence. In addition, at page 3 of the Supplemental Examiner's Report in Docket No. 6992 remand, the following is stated with regard to the prudence issue:

> The ALJ expressly excluded from the scope of this proceeding consideration of the prudence of TNP's actions or the conditioning of the grant of the CCN on any cost limitations or performance standards, or specific ownership arrangements.

Thus, not only was prudence excluded from the CCN process but so were the ownership issues.

Q. WILL YOU BE ADDRESSING ANY OTHER PRUDENCE ISSUES IN THIS PHASE OF THE PROCEEDING?

A. Yes. Two additional issues need to be addressed. The first issue is TNP ONE Unit II prudence issues need to be addressed even though rate recognition is not being requested at this time. Second, as I stated earlier, given that the Company does not own the TNP ONE facility but will be leasing and taking ownership in installments over the next 39 months, I will be recommending a standard for review and an adjustment to the costs so as to insure ratepayers are left indifferent in terms of costs.

Q. WHY WILL YOU BE ADDRESSING TNP ONE UNIT II ISSUES IN THIS CASE?

A. The Company in its testimony has put forth the issue of Unit II prudence. Thus, even though we do not know how much this unit will cost, whether it will ever operate or for that fact even be completed, I believe this issue needs to be addressed. I would not want to leave the impression with this Commission that Cities accept TNP's testimony on the Unit II issues. While, obviously Unit II issues are at best premature, the Company has brought these issues up in this case and therefore these issues need to be addressed along with the Unit I issues.

Section III <u>Historical Overview of the TNP ONE Project</u>

Q. HAVE YOU PERFORMED A REVIEW OR ANALYSIS TO DETERMINE WHETHER THIS COMPANY SHOULD HAVE BUILT THIS PROJECT IN THE FIRST PLACE?

A. Yes. I have attempted to review as much of the history as possible concerning the decision making process by TNP over the years regarding the TNP ONE facilities. In the following pages, I discuss the relevant Board of Directors meetings and documents that have been provided by the Company. As I discuss below, there are three key time periods where significant decisions were made by TNP regarding the construction of this project. The three time periods which are the focus of my analysis are:

Period I	The Company's decision leading up to the signing of the contract with the Consortium at December 30, 1985;
Period II	The Company's facts and circumstances leading up to the TNP decision to proceed with construction of Unit I in September 1987;
Period III	The Company's decision to go forward with Unit II construction in August, 1988.

The results of the above decisions have led to the situation that the Company and its ratepayers are in today; (ie) a plant TNP does not own, no CCN, and a question of whether the Company can finance the plant while maintaining the ability to sell electricity at competitive rates. Meanwhile TNP claims no matter what the PUCT does, the Company has an unconditional obligation to pay for TNP ONE.

Period I TNP's Decision to Enter into the Construction Contract

Q. PROCEED WITH YOUR REVIEW OF THE HISTORY OF THE DECISION MAKING PROCESS WITH REGARD TO THE CONSTRUCTION OF THE TNP ONE PROJECT FOR THE FIRST PERIOD I - THE DECISION TO SIGN THE CONSORTIUM CONTRACT.

A. The basis for my examination of the history regarding the decision making process on the TNP ONE project by the Company has been a review of numerous documents provided in discovery. The key to those documents are the Board of Director's Meeting Minutes which were provided to Cities in response to Cities Data Request 2-96 and 2-97. The various meeting minutes are contained in the Appendix to my testimony. I have included an index of these documents and I source each meeting by TAB number.

The following reflects an overview of what I consider key Board of Director's Meetings where specific decisions were made regarding the decision to sign the contract in December 1985 with the Consortium.

Board Meeting dated February 7, 1984.[3]

At this Board Meeting the power supply of TNP was discussed. Mr. Tarpley provided the Board of Director's a report regarding the Company's power supply. His conclusion was that the supplies for all of the TNP divisions, except the southeast division were firm. HL&P was the sole supplier to TNP in the southeast division. Mr. Tarpley's view this was a matter of concern for 1990 and beyond because the contract with HL&P would expire in July of 1991. It should be noted that the southeast division is the division of the Company TNP ONE was built to serve. In Mr. Tarpley's power supply report provided to the Board of Director's at the February 1984 meeting, contained in the Appendix of my testimony, under TAB 8, a number of sources or alternatives were considered to provide a supply of power for the southeast division.

- The first alternative was participation in future Texas Utilities Electric Company coal plants.
- The second alternative discussed in Mr. Tarpley's report was the possibility of purchasing power from Central Power & Light Company.
- The third possibility considered was Southwestern Public Service Company, which was not an alternative because of the problem regarding a path to supply power in TNP's southeast division, given that Southwestern Public Service Company did not have the transmission capacity to serve southeast load.
- The fourth alternative considered were the cities of Austin and San Antonio, and an examination of Texas Municipal Power Association as potential suppliers.
- The fifth option was a potential purchase of excess capacity from Gulf States Utilities Company. While Gulf States Utilities Company had sufficient capacity to supply the southeast division, there was no way to get the power to the Company, other than the construction of a transmission line from the Gulf States service area to the ERCOT system.

---

3 See Testimony Appendix at TAB 7.

- A sixth option was a Combustion Engineering-Westinghouse-Zachry Consortium proposal made to TNP regarding the construction of a facility so that TNP could self generate.

- An additional option was total cogeneration from various cogeneration suppliers.

One of Mr. Tarpley's recommendations was to immediately negotiate with Gulf States Utilities and a second recommendation made by Mr. Tarpley, considering the time frames and time limitations given the HL&P contract would end in 1991, was to make a management commitment at this time to initiate studies for a lignite power plant with first unit to have a 400 to 500 Mw capacity. Thus, Mr. Tarpley was recommending the Company study either build a plant or build a transmission line to GSU.

Mr. Tarpley also discussed in his report the HL&P negotiations regarding the existing contract. His report to the Board of Directors states:

> After two and one-half years, HL&P has now indicated a willingness to negotiate wholesale supply on their terms, which in fact was the official position stated two and one-half years ago. When this is coupled with the opinion of Ansel Maddox that HL&P's position is subject to change any day, and on any item, I have no confidence that it would be possible to finalize any negotiation prior to the time when it is too late for TNP to exercise any other option. If, in fact TNP has no other option, it is certain that we would have to negotiate on HL&P's terms.[4]

Apparently, Mr. Tarpley's position in February 1984 was that contract negotiation with HL&P was unlikely. Mr. Tarpley reported that the Company had to seek other alternatives so as to either (a) force HL&P to negotiate on

[4] (See Tarpley Power Supply Report 2/84 contained in the Appendix at TAB 8).

a more reasonable terms, if in fact HL&P was not negotiating on reasonable terms, or (b) to seek alternative power supplies for the southeast division. February 1984 Board Meeting is the first place where the Consortium is discussed as an alternative power supply option for TNP southeast division.

Q. BEFORE GOING ON IN YOUR DISCUSSION OF OTHER BOARD MEETINGS, WAS THERE A PROPOSAL FROM THE CONSORTIUM?

A. Yes. The documents I have reviewed contained a December 1983 proposal from the Consortium consisting of Combustion Engineering, Inc., Westinghouse Electric Corporation, and H. B. Zachry Company (See Appendix to testimony at TAB 9). While this proposal was not the final proposal relied upon by the Company, it was a proposal for a turnkey project with a fixed price. The proposal indicated that the Consortium would assist in financing, although it does not indicate that they would finance. My understanding of this proposal is that TNP would be responsible for financing the project, but the Consortium would be furnishing performance warranties and completion guarantees in conjunction with the firm price for this facility.

Q. PLEASE PROCEED WITH YOUR REVIEW OF THE BOARD OF DIRECTOR'S MINUTES.

A. **<u>Board of Director's Meeting April 27, 1984.</u>**

- ♦ The power supply report of Mr. Tarpley was discussed.
- ♦ It was reported to the Board by Mr. Tarpley that the cost of self generation would be approximately $750 million.
- ♦ The cost of transmission systems to deliver the power to the southeast division from other points in the state such as Gulf States Utilities would cost approximately $100 million.

- Both of these projects were being studied in depth and the Board was to receive reports on these matters at a later date. (See Testimony Appendix at TAB 10)

<u>Board of Director's Meeting July 11, 1984.</u>

- The power supply study was again discussed. Self generation alternatives were considered with Robertson County as being the most favorable site with Lubbock, Texas a close second.

- Again, purchases from Gulf States Utilities were still being considered by the Company.

- The management indicated that current negotiations with HL&P for a long-term contract were unsatisfactory because of "stringent conditions" allegedly imposed by HL&P, which would result in TNP losing control of the southeast division.

- At this same Board Meeting management recommended a contract for what is referred to as a Phase One of the Consortium Agreement at a cost not to exceed $675,000.

- These funds were approved by the Board at that meeting to evaluate the project.

- Mr. Tarpley also noted at that same meeting that after Phase One is completed and that the Company decides not to continue, then the only alternative available to the Company at that time for the southeast division power supply was the Gulf States Utilities alternative. (See Testimony Appendix at TAB 11)

The Consortium supplied a proposal for engineering procurement and construction of a fossil fired station to TNP for this meeting. This proposal was dated June of 1984. Under this June 1984 proposal from the Consortium the following were designated as financial features of this proposal:

(a) The Consortium will assume turnkey responsibility for the design, supply and erection, and furnish technical direction of start-up of the plant.

(b) A firm price will be established based on the reference design, which will be approved in advance by Texas-New Mexico Power.

(c) A proper form of performance completion instrument, will be provided by the Consortium until satisfactory performance of the plant is proven.

(d) The Consortium will extend equipment warranties and system performance guarantees.

(e) Texas-New Mexico Power will be the primary equity owner.

(f) The financial plan will be based on a priced cost, which includes a plant completion contingency fund to cover unforeseen regulatory and force majeure items, increases in the interest rates, and other items out of the control of the Consortium or Texas-New Mexico Power. If these funds are not used, the permanent financing principal commitment will be reduced accordingly.

(g) Insurance will be purchased to cover force majeure items, start-up delays, regulatory changes and/or any other unforeseen event that would cause the increased cost of the plant to exceed the plant completion contingency fund.
(See Testimony Appendix at TAB 12)

<u>Board of Director's Meeting March 26, 1985 meeting.</u>

- At this meeting Mr. Tarpley reported that the Board had authorized the $675,000 expenditure at the July 11, 1984 Board Meeting for the purpose of studying the feasibility of a large power plant to supply a portion of the Company's needs when the HL&P supply contract expires in 1991.

- The results of the studies indicated that a plant of that size being studied would require an expenditure from $1.2 to $1.6 billion.

- Such an amount is about double the $750 million Mr. Tarpley indicated at the April meeting.

- Mr. Tarpley proposed and discussed various options and one such option was the construction of plants at the size from 75 to 150 Mw using fluidized bed boilers.

- Mr. Tarpley concluded that the Company's power requirements could be met by four 150-Mw units, the first unit to cost about $150 million.
(See Testimony Appendix at TAB 17)

Thus, at the time of Mr. Tarpley's report, the Company was estimating such units would be in the range of 1,000 a Kw. The actual TNP ONE Unit I facility costs are a bit more than double Mr. Tarpley's estimate. It is also interesting to note that at this meeting Mr. Tarpley was of the opinion that a Consortium of the boiler and generator unit suppliers would undertake to construct the plant and bring it into full operation with <u>no</u> money to be supplied by the Company until the plant is operating at agreed specifications. Thus, as of March 26, 1985 it appeared, that at least, Mr. Tarpley knew that the Consortium would finance this project. The Board of Director's passed a resolution authorizing expending an amount not to exceed $300,000 to study the feasibility of acquiring four 150 Mw units by the Consortium.

<u>Board of Director's Meeting April 30, 1985.</u>

- Mr. Tarpley reported to the Board that the Consortium of H. B. Zachry, Westinghouse, and Combustion Engineering proposed an initial agreement to design and build the plant, at a turnkey price to TNP.

- The first unit was to be completed by July 1990, so as to be on-line for the 1990 peak, and the proposed location would be the Robertson County lignite field owned by Phillips Coal Company.

- In addition, it was also indicated that there were no other serious proposals by other entities because such entities had not considered Texas-New Mexico Power Company's inquiries to be serious since TNP had spent very little on engineering studies for this project.

- It is further reported in the Board Minutes that the Consortium considered the environmental studies and other preliminary work to be proprietary to the Consortium since the Consortium had expended funds for these items.

- If the Company decided to have an independent and separate offer for comparison, such an offer would require an additional six months to one year and possibly $1 to $1.5 million to employ an engineering consultant to design the specifications necessary to obtain competitive bids.
  (See Testimony Appendix at TAB 18)

As can be seen from the above, by April 30, 1985, the Company was moving forward with the analysis of the Consortium, but not with any competitive bids for this major project. Despite not having any competitive bids the Board of Directors resolved at the April 30, 1985 Board Meeting to proceed on the current course with the Consortium and to discuss the generation plans with other contractors to assure them of the seriousness of the Company's intent to become a generating utility. It would appear that the Company, while indicating they were serious about becoming a generating utility was not exploring the purchase power alternative.

Board of Director's Meeting June 25, 1985.

- The construction Consortium made a presentation to the Board of Director's regarding the construction of four 150 Mw circulating fluidized bed combustion power generating units.

- The Board of Director's at that meeting resolved that the Company's attorneys and accountants were authorized to negotiate on behalf of the Company the necessary or required agreements with the Consortium.

- There is no indication that any contractors considered TNP any more serious about construction of facilities in June than they did in April.
  (See Testimony Appendix at TAB 19)

In a period starting at February 1984, where Mr. Tarpley's power supply study was presented and discussed, the Company had decided to go forward with the TNP ONE Project and sign the contract by December 1985. at 12/30/85 There were no Board discussions in the Minutes regarding continuation of the HL&P negotiations as an alternative. In addition, I have found no evidence in these documents which indicates that the Company seriously pursued alternative bids to the Consortium. Thus, this project appears to be a sole source bid project.

Q. PLEASE SUMMARIZE YOUR REVIEW OF THE BOARD MINUTES AND ACTIONS TAKEN BY THE BOARD OF DIRECTORS OF TNP FOR THE PERIOD FEBRUARY 1984 AND DECEMBER 30, 1985.

A. Based on my review, it appears to be a sole source project with the Consortium. There is no evidence that other bids were received by TNP regarding the construction of its own generating units. Moreover at the October 30, 1984 Board Meeting Mr. Tarpley stated:

> ...the Company must get into power generation because PUCT is moving towards marginal cost pricing in fixing rates as opposed to the embedded cost of the supplying company. (See Testimony Appendix at TAB 15)[5]

Mr. Tarpley's statement clearly indicates that the Company, or at least Mr. Tarpley, was set on developing TNP into a generating company rather than considering any and all of the possibilities of maintaining its position as a distribution company. I have found no documentation that the Commission in Texas was moving towards marginal cost pricing for wholesale customers.

5 See TAB 12, last page for 2nd page of October 30, 1984 Meeting Minutes.

This Commission sets rates under the PURA which requires just and reasonable rates for all customers. Thus, Mr. Tarpley's concern of marginal cost pricing was misplaced and does not appear to be a concern to others in this state, or at least I have found no evidence of such concern.

There is no solid, well developed analyses evaluating self generation relative to other alternatives which could include cogeneration, continuation of purchases with HL&P or other wholesale suppliers.

Interestingly, the day after the contract was signed between the Company and the Consortium, the Examiner's Report in Docket No. 6397 was issued. Thus, on December 31, 1985 the PUCT Examiner issued a report regarding TNP's NOI Request regarding the construction of its TNP ONE units. The Examiner's Report states:

> With respect to purchase power, the examiner concludes that TNP seriously considered it as an alternative to the proposed plant. But the examiner is of the opinion that TNP failed to show that power is not available from HL&P and failed to show that power from the proposed plant would cost less than power from HL&P. (E.R. p. 42)
>
> •••
>
> Since TNP failed to show that it seriously considered cogeneration and failed to show that the plant is preferable to power purchased from HL&P, the examiner recommends that the Commission deny the notice of intent. (E.R. p. 42)

The day after the Company signed its contract with the construction Consortium, the Examiner at the PUCT recommended that the Company had not met its burden regarding the construction of the TNP One Project. With regard to the approach employed by TNP in evaluating the TNP ONE Project relative to HL&P purchase power the Examiner in Finding of Fact 37:

> It appears that in the mathematical model used by TNP to compare its generating cost with the cost of HL&P power, HL&P's projected rate base was overstated as a result of double counting CWIP, not properly accounting for deferred taxes and depreciation, and incorrectly scheduling HL&P's generating units to come on-line.

In addition in Finding of Fact 38 the Examiner stated the following:

> While the mathematical model used by TNP to compare its generation costs with the cost of HL&P power is an appropriate method for analyzing and comparing cost in a notice of intent proceeding, the data and assumptions used in the model were not sufficiently accurate to give much weight to the model's projections of cost.

Finally, at Finding of Fact 39 the Examiner stated the following:

> TNP failed to show that the cost of power from the proposed plant would be less than the cost of power purchased from HL&P.

The Examiner, who heard the evidence in the NOI proceeding, concluded that TNP had not properly evaluated this project as of December 31, 1985. Yet, the Board of Directors had gone forward on December 30, 1985 and signed a contract with the construction Consortium. Again, this is an indication that there is some serious question regarding the evaluation of the project relative to purchased power.

With regard to the purchase power issue of HL&P, the Company in the NOI proceeding, claimed that the purchased power option is not a good alternative to the proposed TNP ONE Project for two basic reasons. First, TNP claimed to be unable to renegotiate the power supply contracts with HL&P. Second, TNP also claimed that its cost analysis shows that purchased power would cost more than power from the proposed plant. With regard to the second issue the Examiner clearly confirmed that the evidence in this proceeding indicated that the Company's analyses were substantially in error and that there was no evidence to show that this plant proposed was cheaper than HL&P's purchased power costs. With regard to the claim that power supply contracts could not be negotiated, the Examiner at page 33 indicated that HL&P apparently planned on selling power to TNP, where he states the following:

> For example, in HL&P, Docket No. 6064 (Avoided Costs), HL&P filed a forecast that shows it providing power to TNP through the year 2000. Examiner's Exhibit No. 2. and in a capacity-demand-reserve table filed in the same case, HL&P forecasted at least 20-% reserves through 1994. Examiner's Exhibit No. 1. this evidence appears to show that HL&P is able to and plans to sell power to TNP. (emphasis in original)

While negotiations between TNP and HL&P may have been difficult for Mr. Tarpley it appears that his frustration in the negotiation got in his way regarding the ability to procure a continuation of the purchased power contract with HL&P. In the alternative, Mr. Tarpley was intent on building a generation facility and a successful negotiation with HL&P would mean the plans to build TNP ONE would have to be delayed - possibly forever.

Q. DID THE COMMISSION ACCEPT THE EXAMINER'S REPORT THAT YOU REFER TO ABOVE?

A. No, it did not. On February 7, 1986 the Commission modified and effectively overturned the Examiner's Report by changing the Findings of Fact and Conclusions of Law such that the Company's NOI request was accepted and approved.

It should also be noted that the Commission, in its decision to overturn the Examiner's Report of December 31, 1985, indicated the following in Conclusion of Law No. 7:

> As required by Section 54(d) of PURA, TNP demonstrated that the proposed plant is appropriate as compared to the alternatives, taking into consideration such factors as environmental integrity, reliability, financial risk to the utility and consumers, and health and safety risks.

The final order does not indicate that the plant is a lower cost alternative relative to the alternatives. It appears that the Examiner's findings in this case, Docket No. 6397, the Company had not shown that the plant was cheaper than any other alternative, were not changed by the Commission. Rather, it appears that the Commission approved the NOI based upon other considerations such as environmental integrity, reliability and health and safety risks. Therefore, by year end 1985 the Company still has not proposed any reliable analyses to this Commission that demonstrated that the construction of TNP ONE, as a generating unit, is a lower cost alternative for ratepayers to purchased power.

Thomas indicated that such issues could be revisited in the CCN hearings.

PERIOD II <u>TNP's Decision to to forward with construction in September 1987</u>

Q. PLEASE DESCRIBE THE NEXT STEP IN THE DECISION TO CONSTRUCT TNP ONE.

A. On August 15, 1986 the Company filed for a Certificate of Convenience and Necessity ("CCN") to construct the TNP ONE Project . The Company's application for a CCN requested certification of a four unit project of 150 Mw's each, for a total of 600 Mw's of lignite fired electrical generation. At the time of the filing of the CCN request, the Company estimated that the total estimated cost of Unit I, including various change orders, was to be $253,517,000 and the estimated total cost of all four units was estimated to be $973,747,000. The Unit I estimate described above consisted of two cost components. The non-fixed portion of the unit cost was estimated to be $58,095,000 and the fixed contract turnkey price for Unit I was estimated at $195,422,000. It is interesting that between the signing of the contract in December 1985 and the filing of the CCN request in August 1986 the fixed price for Unit 1 had increased from $179,372,000 to $~~194,422,000.~~ 195,422,000. The fixed price included the construction, the equipment, and the material costs. Mr. Stowe will be discussing the change orders that affect the fixed cost price.

Q. WOULD YOU PLEASE SUMMARIZE THE EXAMINER'S FINDINGS WITH REGARD TO THE CCN REQUEST BY TNP?

A. Yes. The following are excerpts from the ALJ's Recommendation-Overview found at page 11 and 12 of the Examiner's Report.

> The ALJ's recommendation in this Docket is to grant TNP its requested certificate. However, that recommendation is in spite of TNP's presentation and is based upon factors, delineated in the sections below, which look at the issues from a policy perspective.
>
> The Examiner states:
>
> The ALJ's recommendation rests upon the fact that certification of the proposed plant will not adversely effect the state in terms of excess capacity, since it represents such a small fraction of overall expected reserves in 1995, and that the plant will benefit TNP's ratepayers on a long term basis. At worst, the plant will in the long run most likely cost no more than purchased power. Also weighing in the ALJ's decision is the fact that only one utility, HL&P, has offered a long term supply of power, and its

> cost versus Robertson is questionable. In relation to that offer, it will also be necessary for HL&P to do some construction to come on line at least by 1997 and possibly as early as 1995, depending on load growth. Thus, this case is more a question of whether TNP or HL&P constructs a power plant to serve TNP's long term needs. (E.R. p. 12)

In other words, there was still a question whether the overall cost of constructing this project relative to maintaining purchase power benefitted ratepayers. The Examiner, as noted above, indicated that it was questionable whether the project would provide lower cost than purchased power, but he goes on to state that at worst the plant in the longer run most likely wouldn't cost more than HL&P's purchased power. I will be discussing the various analyses in terms of the quantification of savings from construction of this project later in this testimony. The Examiner apparently relied upon policy issues such as, excess capacity impacts and other factors rather than putting much weight on the questionable economics in granting the CCN.

At this point, TNP continually questioned whether the purchased power alternative from HL&P was even possible. As I stated earlier in this testimony, Mr. Tarpley, at a Board of Director Meeting, indicated a very significant concern with regard to the ability to get HL&P to continue to serve the Company on reasonable terms. Again in addition, in the instant case, Docket No. 9491, the Company has questioned whether or not HL&P is a viable alternative regardless of the cost. The Examiner in Docket 6992 put this issue to rest. At page 13, the Examiner stated the following:

> Because of TNP, the parties spent a great deal of time at the hearing and in their briefs arguing about phantom issues. For example, TNP began its analysis that utility purchased power

cannot meet TNP's needs by saying that no utility offered an acceptable contract. To support this allegation TNP presented its letter request sent to some 300 utilities seeking purchased proposals. That letter (TNP Ex. 54, Schedule RO-16) required power that any proposals made be 41 years in length, among other requirements. TNP's president admitted that such a request was abnormally long in terms of typical purchased power requests. See TR.3312. It is no wonder that TNP received few responses.

The Examiner went on:

> With respect to HL&P, TNP President Tarpley finally admitted to the ALJ that the only problem with the contract offers from HL&P were that they did not provide for termination of the contract in 1990 or shortly thereafter, as did TNP's purchased power agreement with Texas Utilities Electric Company (TUEC). See TR.2828-2829. Why TNP thought HL&P would negotiate a contract with an expiration date sooner that the date in its currently in force contract is unexplained. If TNP had signed any of the offers made by HL&P the instant application could not have been filed. TNP's primary reason for not signing was the economic advantages of Robertson. The arguments that the HL&P offers were unreasonable or contained onerous provisions are irrelevant; the Commission has jurisdiction over wholesale rates.

First of all, by bringing up the HL&P contract issues, TNP is again attempting to litigate phantom issues as the Examiner indicated in Docket 6992. The Examiner in that case put the issue to bed and while I will discuss some of the points regarding the HL&P contract, it is clear that the Examiner believed that the power was available and the terms of the contract are regulated by the Public Utility Commission. Moreover, the Examiner, in the NOI proceeding discussed earlier, also indicated that HL&P had produced documents which indicated HL&P planned on continuing to serve the TNP load. Lastly, HL&P, itself, was in the CCN case and indicated that it could serve the load more cheaply than the Robertson units. Therefore the TNP argument that no purchase power was available is not a valid argument for this case.

Q. HAVE YOU REVIEWED CORRESPONDENCE REGARDING THESE CONTRACT NEGOTIATIONS?

A. Yes. Contrary to claims made by TNP, I did not find HL&P to be unwilling to supply power on a long term basis. In addition, HL&P provided analyses comparing the proposed TNP ONE units to HL&P's estimated purchased power costs. HL&P indicated alternatives other than the TNP ONE facilities exist for meeting the long-term needs of the Southeast division. The following is an excerpt of a letter from HL&P to TNP dated August 12, 1986:

> We look forward to meeting with TNP to discuss this proposed Agreement which will provide TNP with security of supply well into the twenty first century. As an important new feature, this contract allows TNP to build generation in the future and reduce its contract purchases from HL&P if such construction is in the best interest of TNP's ratepayers.[6]

Thus, it does not appear that HL&P was either unwilling to provide TNP with a firm supply, or flexibility for the future.

Q. WHAT WAS TNP'S RESPONSE TO HL&P'S OFFER OF AUGUST 12, 1986 DESCRIBED ABOVE?

A. On September 26, 1986, Mr. Ownby of TNP responded to HL&P by indicating that TNP was ". . .becoming more committed to the Robertson County Plant . . ." TNP sent a proposed contract which included a 30 year term and a proposed rate to be set at 99 percent of TNP's projected costs of the

---

6 See Schedule (DJL-2) for a complete copy of the letter without attachments.

proposed TNP ONE facilities. Furthermore, TNP proposed that these rates would be retroactively reduced if other power purchases would result in lower rates than the HL&P rate.[7] I have included in the Testimony Appendix at TAB 5, a comparison of two HL&P contract proposals compared to TNP's proposal. As can be seen from this schedule, the HL&P offers were based on PUCT determined rates while TNP wanted a guarantee of lower rates as well as retroactive recognition of other lower costs should such lower costs occur.

In my opinion, the TNP contract offer was not serious given the request for a rate guarantee and the potential requirement for HL&P to charge a rate other than the PUCT tariff rate. Documents I have reviewed indicate that even the Company's attorney, Mr. Shirley, in a letter to TNP indicated to the company that he believed that such a rate proposal was not possible given HL&P's requirement to charge PUCT approved tariff rates.

Clearly a long-term contract with HL&P could have been negotiated. As offered by HL&P, TNP could have received flexibility to construct generation in the future if in fact such generation was economically viable. Furthermore, the rates charged to TNP would have been based on PUCT approval and scrutiny, thus it is difficult to believe such rates would not have been fair, just and equitable and cost based.

With regard to TNP's request for a rate guarantee tied to the TNP ONE costs, I believe such a request was unreasonable. This request alone shows

7 See Schedule (DJL-3) for a copy of Mr. Ownby's response and proposed rate for a new contract.

that TNP was not seriously considering alternatives or at least the HL&P alternative.

Q. HAVE YOU REVIEWED TNP'S REQUEST FOR OTHER ALTERNATIVE POWER SUPPLIES?

A. Yes. TNP sent out over 300 inquiries for alternative power suppliers in early 1986. I find it interesting that TNP began this canvassing after the contract with the Construction consortium had been signed in December 1985. The TNP request of potential power suppliers was for eight proposals which consisted of four different capacity amounts at two different delivery points. The term of the contract was proposed to be 41 years[8]. As I stated earlier, documents indicate even TNP President Tarpley thought a 41 year request to be unusually long.

In addition, in the February 28, 1986 solicitation for a proposal, TNP stated the following:

> TNP also realizes that because of the saturation technique being used by TNP in its solicitation of proposals, a great number of these letters have been issued to utilities with no such provisions for providing power to another utility. Should this be the case, please accept my apology, but I would still request a written response to this solicitation even though you may be incapable of providing such power. (emphasis added)
> (See Schedule DJL-4)

TNP was apparently intent on having a response knowing full well many of their solicitations for purchased power could not be met by entities that were also distribution utilities. It makes little sense to send such requests

8 Schedule (DJL-4) contains a copy of TNP's solicitation letter.

to many of these entities, but based on this canvassing, TNP can claim that it sent out over 300 requests for purchased power, and no response was satisfactory.

Q. WHAT HAPPENED WHEN TNP RECEIVED A RESPONSE TO ITS REQUEST?

A. The Company appeared to be more concerned about the impact on the CCN process than the merits of the proposal. For example, the following is an excerpt from a memo written by Mr. Ownby to TNP management regarding one response:

> As a result of the solicitations of some 350 utilities, we have one response that may merit some serious consideration. I have in hand a proposal from the Rockdale Power Project (see attachment) <u>that could cause some problems in our CCN filing</u>...
>
> I don't consider their proposal a serious problem, but to be safe I am suggesting that we discuss before making any response to them. (emphasis added)
>
> (See April 15, 1986 memo from Ownby to Tarpley, Chambers, Wright, Shirley contained in Schedule DJL-5)

It appears that TNP was surprised to get a response that might meet their requirements, and the Company appeared more concerned with the TNP ONE CCN at this point. Thus, TNP's claims of effectively searching the countryside for purchased power alternatives does not appear to be a serious search. Many of the proposals were sent to entities which could not possibly supply the power. In addition, when TNP received a request, the Company appeared more concerned with the CCN case than developing a workable alternative. The only thing the Company received from its canvassing campaign is the ability to tell this Commission that out of 350 requests for power the Company received very few positive responses. Clearly, if this Company was serious about alternatives, they could do a better job than send a request for 600 Mw's for 41 years of firm power to the University of Texas[9] or some other small distribution utility.

Q. DID THE EXAMINER IN DOCKET NO. 6992 PROVIDE ANY OTHER INDICATIONS THAT HE DID NOT TOTALLY RELY UPON THE ECONOMICS OF THE PROJECT IN THE DETERMINATION OF THE GRANTING OF THE CERTIFICATE FOR TNP ONE?

A. Yes, he did. At page 30 of the Examiner's Report, the Examiner did discuss many of the life-cycle analyses, which I will be addressing later in this testimony, but the Examiner stated the following:

> TNP's application could be denied on a finding that the uncertainty surrounding the possible future benefits of building the plant does not provide a sufficient foundation to grant the certificate in the face of available short term capacity at lower prices and in long term purchased power at possibly the same price (long-run) of Robertson. <u>However, after considering factors other than the cost/benefit analyses presented by TNP, HL&P, and staff, the ALJ</u> recommends approval of the certificate.
> (emphasis added)

Thus, once again the Examiner has indicated that factors other than the economics of the project led to his recommendation that the plant should be certificated. As I will discuss later in this testimony the economics of the project are uncertain at best, even at the point of deciding to go forward with this project.

9 The University of Texas was one of over 300 different entities which received TNP's proposal. See Docket No. 6992 Exhibit RO-16, page 5 of 40.

Q. AFTER THE ISSUANCE OF THE CCN EXAMINER'S REPORT AND THE FINAL ORDER BY THE COMMISSION WAS THERE A CONTROVERSY REGARDING THE CCN IN THIS CASE WITH REGARD TO WHETHER OR NOT IT WAS IN FACT A FINAL ORDER?

A. Yes, and that controversy has continually been addressed since the issuance of the order in Docket No. 6992. Obviously the CCN was very important to this Company as it would be important to any Company in constructing a large asset addition. If TNP could not get permission from the Commission to put such an asset in rates because of the lack of a CCN, then TNP would face financial difficulties.

Q. WAS TNP AWARE OF THE PROBLEMS OF THE CCN ISSUE AND WERE THESE PROBLEMS BROUGHT TO THE BOARD OF DIRECTOR'S OF TNP?

A. Yes. While I will not go into depth on this issue the Company did indicate at the August 1987 Board Meeting that there was a problem with the CCN. The following excerpt from the August 14, 1987 Board Meeting summarizes the Company's concerns:

> Mr. Tarpley informed the Board that the Commission had approved a Certificate of Convenience and Necessity for all four units of the Robertson County Project, but they had requested some language be placed in the Order to place limitations upon when Units Three and Four could be released for construction. The limitations consisted of a hearing prior to the release to determine the prudence of releasing Units Three and Four for construction. He informed the Board that this type of language, if not carefully drafted, could result in an Order that was not final and, therefore, not appealable. Further, that since the Order would not be final, there would be no Certificate of Convenience and Necessity issued and it basically would leave the Company in limbo. He also informed the Board that it appeared that there were at least two options open to the Company which could

~~OPCPOD4-15-007516~~

> solve the problem of whether or not the Order was final and, therefore, appealable. He explained that the options consisted of dividing the Order into two separate orders with the first order being for Units One and Two and having no conditions, and the second order being for Units Three and Four and having the conditions already expressed. The second option was to have a single order for all four units and to draft the language so that it did not require additional action of the Commission as it concerned the Certificate of Convenience and Necessity, but would put the Company on notice that in the next rate case, release of any of these units for construction could result in the Commission considering such action to be imprudent.

The Board Minutes also states:

> The Board, after discussing the pros and cons of the two options, expressed a desire that the option of having one order with four units be the preferred option, with the two separate orders being the second option. Mr. Tarpley advised the Board that the Company would pursue the type of order they preferred and that the Company had developed, however, the Commission could, of course, act in any way they desired and they may not accept our recommendation.
> (See Testimony Appendix at TAB 34)

Apparently after the discussion regarding the order in which the Board realized there were problems, the Board asked Mr. Tarpley about what funds would be necessary to keep the project on schedule through September of 1987. Mr. Tarpley indicated then that the project needed approximately $16.5 million in additional commitment in costs for the plant pursuant to the contract and an additional $4 million with regard to the cost of land, so construction could begin. After receiving this news, the Board elected to go forward with funding the construction of Unit I of the project and committed the funds necessary to do so.

Despite all its concerns regarding the CCN, the Board elected to take the risk and go forward even though they knew the order would leave the

Company in "limbo". Therefore, the Company elected to accept the regulatory risk regarding the construction of the project. The situation as of August 1987 was that not only were there no economic analyses produced by the Company and accepted by the Commission which showed a two unit case economically beneficial to ratepayers. In addition, the CCN problem left the Company in limbo. However, the Board elected to go forward with the project despite all the risks and questionable economics. hindsight

The Examiner's Report issued August 1, 1990 in the CCN Remand Docket recommended approving the Company's CCN request based not upon a complete economic analysis, but rather a "to go" cost economic cost analysis. The Examiner concluded a "to go" cost analysis was appropriate because the plant was built and the Company claimed it had an unconditional obligation to pay for the project. In spite of the fact that the Company knew the risk when they got into the project, the ALJ in the CCN remand case is recommending that the Commission eliminate the risk taken by the Company by applying a "to go" cost analysis for determining whether a CCN should be issued.

Q. WERE THE BANKS AWARE OF THE PROBLEMS ASSOCIATED WITH THE LANGUAGE IN THE CCN ORDER?

A. In my opinion, yes. Chase Manhattan Bank agreed to change the requests for the initial drawdown of the Credit Facility regarding Unit I construction. Contained in the Testimony Appendix at TAB 3, is a September 23, 1987 letter from Chase which was amended to address the problems associated with the

CCN. As can be seen from this letter, the Banks originally requested, "...a final and administratively nonappealable Certificate...." This required language was changed to, "... an administratively final order granting a Certificate...."

see tab

Banks and TNP merely got together and changed the agreements to get around the problems in the PUCT order. Thus, by contract TNP and the Banks took the project out of "limbo" and agreed to go forward with a CCN in limbo.

Q. ARE THERE OTHER AREAS WHERE CONTRACTS OR AGREEMENTS WERE CHANGED THAT HAVE A SIGNIFICANT IMPACT ON THIS CASE?

A. Yes. Obviously, the change orders have an impact on this case, and this is an issue addressed by Mr. Stowe. Another major change is also contained in the September 23, 1987 Chase letter contained in the Testimony Appendix at TAB 3. It is on this date that TNP agrees to create a subsidiary to own these facilities so that the banks can have a first lien on these facilities. Given the problems with the CCN discussed above, it is obvious why the Banks want a first lien. While I will discuss this issue in more detail later, it is important to note that the Company is agreeing to a subsidiary ownership arrangement for these facilities that in my opinion, is not consistent with ratemaking principles in Texas.

Q. PLEASE SUMMARIZE THE SECOND PERIOD OF TNP'S DECISIONS OF THIS PROJECT?

A. One day after TNP signed the construction contract with the Consortium the Examiner in Docket No. 6397 recommended denial of the NOI. The PUCT approved of the NOI on February 7, 1986, but any discussion of the economic advantage of the project is conspicuously absent from the PUCT Order.

Next, the Company filed for a CCN and met considerable opposition from customer groups, HL&P and the PUCT staff. The Examiner in Docket No. 6992 recommended a CCN based not on economics, but apparently policy considerations. There is no clear cut economic analysis that showed that TNP ONE was superior to HL&P or other alternatives. As I discussed earlier, HL&P had on the table long term contract offers to TNP whereby the rates would be subject to PUCT approval. There is no documentation that supports TNP's claim that alternatives were thoroughly pursed during this time frame. Lastly, the PUCT approved a CCN that TNP itself questions, because the language put the Company and the project in limbo. The Company elected to take the regulatory risk associated with a non-final CCN by agreeing to the changes in the requirements for access to the Credit Facility. In addition, the Company, at this point, agreed to create a subsidiary to own the facilities so as to provide a first lien to the Banks.

PERIOD III <u>Circumstances Leading Up to Unit II Construction</u>

Q. PLEASE DESCRIBE TNP'S DECISIONS IN THE PERIOD YOU HAVE DESIGNATED AS PERIOD III.

A. The TNP Board of Directors were faced with the facts described above after the CCN in Docket No. 6992 was issued. At an October 13, 1987 meeting[10], Mr. Tarpley informed the TNP Board that Chase Manhattan Bank ("Chase") would not fund an interim loan until an administratively Final Order was issued in Docket No. 6992 and because of the failure to negotiate certain terms of the interim loan with Consortium.

At this same meeting, the Board of Directors were concerned about the need to go forward at this time or in a compressed schedule. In addition, the TNP Board at this meeting requested its lawyers to discuss the rights of the Company to cancel or delay and for an evaluation of the probability of arriving at a final negotiated business arrangement with Chase and the Consortium.

It appears that the TNP Board itself was becoming concerned with this project at this point. It should be noted that there is no evidence of a discussion of the economics of the project or the progress and/or potential of an HL&P contract. All other factors discussed above including the problems with the CCN obviously raised serious questions at the TNP Board level.

The next TNP Board meeting reviewed is the September 7, 1988[11]. At this meeting the Board addressed the issue of allowing Unit II go to construction. Mr. Tarpley informed the Board that while HL&P had excess capacity to serve TNP, this excess power was not expected to last beyond the mid 1990's. I don't know where Mr. Tarpley got his information regarding

10 See Testimony Appendix at TAB 35.

11 See Testimony Appendix at TAB 41.

power availability, but his statement to the TNP Board was totally inconsistent with both actual data available at the time and HL&P's previous contract offers to serve TNP.

The TNP management informed the Board of the difficulty in negotiating a firm price for Unit II. One of the problems was in defining the common facilities for Unit I and Unit II. One Board member inquired as to the consequences if Unit II were not built. Mr. Tarpley indicated that the purchased power would need to be purchased at the market rate as an alternative, and that the PUCT could give the Company some difficulty as the PUCT had approved a four unit scenario. I find it amazing that the Company could actually tie the need to build Unit II to the Commission because the PUCT considered a four Unit facility. Ironically TNP had no such concern with the PUCT when TNP abandoned its request for Unit III and Unit IV.

Obviously, there was continued uncertainty with a fixed price turnkey project when half way through the project a Unit II fixed price could not be determined. At the September 1988 Board Meeting, it was noted that the Unit II final contract price would be somewhere between $194 million and $204 million. The Board resolved to attempt to get all agreements for Unit II in place by October 3, 1988, and if that could not be done, there would be no liability of any nature to the Company with respect to Unit II. The negotiations and other Unit II discussions were in response to an August 25, 1988 letter from the Consortium setting forth the Consortium's calculation or estimate of Unit II costs.

On September 28, 1988 a TNP Board meeting was held to approve going forward with Unit II[12]. One of the first items discussed was Amendment No. 2 to the Credit Agreement. This amendment deleted the requirement of PUCT approval for transfer of the CCN to the subsidiary TGC, prior to the release of Unit II for construction. This was a very important decision in that not asking for PUCT approval has put the Company in the position they are in today, (ie) requesting rate base treatment for a plant they do not own.

At this same meeting, it was discussed that the Credit Agreement would be further amended to provide the Company the flexibility to elect to take ownership of Unit I either directly from PFC or TGC, if at the time of such election TNP believed such action to be in its best interest. As I understand this amendment, the banks will obtain a second lien right on TNP's Texas properties after TGC takes ownership and provides a first lien. The following is an interesting excerpt from the Board meeting:

> When the Board questioned Mr. Barnard on why the lending banks should be able to maintain a second lien against the Texas properties, he explained that it was the result of a trade off in order to gain flexibility in dealing with the ownership of the generating facilities. He explained that the flexibility provided in exchange for the second lien gave the Company the opportunity to respond to regulatory concerns and provided a good bargain on the Company's behalf.

Evidently, Mr. Barnard recognized that the PUCT might have problems regarding the ownership question of these facilities. In my opinion, it is apparent that the Banks and TNP were willing and did change the contractual

12 See Testimony Appendix at TAB 42.

requirements regarding this project to keep things going no matter what the PUCT did or required. This amendment eliminated the requirement that the PUCT approve the CCN transfer. The net result was that Unit II could be let for construction without further delay, such as a PUCT public interest finding under Section 63 of PURA. This change represented a significant change on the part of the Banks from the requirements put forth in the September 1987 Chase letter discussed in the next Section of my testimony.[13]

Q. WHAT CONCLUSIONS HAVE YOU REACHED AFTER REVIEWING THE PERIOD III PERIOD DESCRIBED ABOVE?

A. Based on my review of documents during that period, it is obvious that the Board, at least at the beginning of this period, had serious concerns regarding the continuation of this project. In addition, the Board had additional concerns with regard to going forward with Unit II construction. Given that, it was difficult at best to arrive at a fixed price which was reasonable for all parties. Probably the most important development during this period was the continual changes of contracts by the banks and TNP to get around the regulatory problems. For example, as I will discuss in the next section of my testimony, in September 1987 the banks required that the Company set up a subsidiary now known as TGC to take ownership of the plant. In addition, one of the other requirements was that if the Company elected to not set up a subsidiary but chose some other alternative, the construction of Unit II could not take place until September 1989. That September 1987 agreement

---

13 This September 23, 1987 letter from Chase Manhattan Bank is contained in the Testimony Appendix at TAB 3.

between Chase and the Company also indicated that the TNP would be required to get PUCT approval of a "round-trip" transfer of the CCN to TGC and then back to TNP. When the Company filed its Section 63 case to remand and transfer the CCN, the PUCT elected to hold a hearing. Rather than risk a hearing TNP elected to withdraw its case. Such hearing to determine the public interest impacts of such a "round-trip transfer" would have taken too long in terms of allowing Unit II go to construction in a "timely manner". Therefore, the Company was able to get the Banks to drop the requirement of the PUCT approval of the "round-trip" transfer. This is just one example of contracting away problems that are created by original contracts. In addition, the Company was able to renegotiate who would own the TNP Unit I facilities at the time they were accepted by the Company. In other words, the Company had the choice of either transferring the facilities from PFC to TNP or to TGC. In the first instance, the Company would directly own the facilities without a subsidiary holding Company. In the second instance, PFC would transfer the facilities to TGC, and TGC could transfer these facilities to TNP at any time. This, then is another instance of the bank and the Company contracting away problems created by these contracts in the first place.

The current status is that, TGC does own these facilities and any transfer to TNP, requires a Section 63 review.

Q. AFTER REVIEWING ALL OF THE DATA REGARDING THE DECISIONS MADE TO CONSTRUCT THIS PROJECT, WHAT ARE YOUR CONCLUSIONS?

A. First of all, I have found nowhere in any proceeding the acceptance of any of the Company's analyses regarding the economic viability of this project. The analyses apparently relied upon in the original CCN case Docket No. 6992 were those of the PUCT staff which were, as the witness stated, inconclusive regarding this project.[14]

In addition, it does not appear that TNP seriously considered negotiating with HL&P as an alternative to this project. At page 13 of the examiner's report, the examiner specifically indicated that if TNP had accepted any of HL&P's offers, TNP could not have gone forward with its CCN application. In addition, TNP's search for alternative power supply such as the 350 letter requests for proposals were not serious and unrealistic requirements such as a 41 year term practically insured no offers. When TNP did receive a proposal that it thought might be a serious alternative much to its surprise, the proposal apparently was viewed by TNP staff as a problem in the CCN case rather than a viable alternative for this project.

TNP appears to have ~~ben was~~ been obsessed with the construction of its own power plant to become a generating utility. I have seen no document which seeks proposals of alternative power supplies on more reasonable terms than the proposal sent out to 350 distribution and generating utilities.

Q. WHAT HAVE YOU CONCLUDED WITH REGARD TO THE ECONOMICS OF THE PROJECT?

---

[14] See direct testimony of staff witness Griffey, Docket No. 6992.

A. With regard to the Company's economic analyses it is very important to scrutinize the assumptions and cash flows of the various alternatives. The Company's most recent economic analyses viewed at a more reasonable discount rate, indicate that the project will cost ratepayers substantial amounts of money relative to the purchase power alternative. With regard to the Company's analysis made in 1987 in the CCN case, it would appear that even if we accept the Company's model the ratepayer savings are not achieved on a present value basis until the next century. Therefore, ratepayers can only hope that the assumptions hold true to derive any benefit from the substantial cost or investment made into the TNP facilities. Furthermore, with regard to that TNP 1987 analysis, when more reasonable discount rates and other reasonable assumptions are employed to evaluate the project, then the project does not appear economical. It should be noted that in neither the NOI docket nor the original CCN case did the Commission accept the Company's analyses.

In conclusion, with regard to the status of this case, as can be seen from the description of the history of the decision-making process, the position the Company is in today, i.e., constructed plant and no CCN as well as ratebase request yet no ownership of the facilities, is the position the Company has put itself in over time. The Company could have stopped the construction of this facility back in 1987 when the problems with the CCN were first realized. At that time the Company did not have to take a chance and continue to construct this project and TNP could have waited to determine whether or not the economic viability of the project improved and/or the Commission's CCN language was straightened out to the Company's satisfaction. Rather than wait, the Company went forward and changed the contractual agreements to meet the changing circumstances. Had the Company waited, it could have sought other purchase power alternatives and gone into this plant a little more slowly. The position the Company's in today is of its own making and for the Company to claim that it has an unconditional obligation to pay for this plant, whether it has a CCN or not, is the Company's own fault. It is not the fault of ratepayers. Therefore, approval of a CCN or full ratebase treatment of this plant should not be based upon the Company's claim of an unconditional guarantee to pay for these facilities. In the next section of my testimony I discuss the Company's life cycle analyses, and show that had the Company done a reasonable sensitivity analysis on the 1987 study, such analysis would have indicated that the TNP ONE project was not economically viable.

SECTION IV LIFE CYCLE ANALYSES

Q. PLEASE PROVIDE AN OVERVIEW OF THE LIFE CYCLE ANALYSES DONE BY THE COMPANY.

A. In the following section I describe the analyses performed by TNP to evaluate the economic viability of TNP ONE.

Q. WHAT APPROACH HAS THE COMPANY EMPLOYED IN EVALUATING THE ECONOMICS OF THE TNP ONE PROJECT?

A. The Company and all intervenors who have performed economic analyses have employed what is referred to as a "Life Cycle" analysis. It should also be noted that the Examiner in Docket 6992 and in the remand case determined that the life cycle analysis approach was the appropriate tool to evaluate the economics of the TNP ONE project. I also agree that the life cycle approach is the appropriate methodology to employ in these types of evaluations.

Q. WHAT IS A LIFE CYCLE ANALYSIS?

A. A life cycle analysis is a method by which the costs of two competing alternatives (such as constructing a plant versus maintaining purchased power) can be compared on an equivalent basis. For example, in this case whether or not there are savings over the life of the project the cost of TNP ONE will obviously be more expensive than purchased power in the initial years of operation because in ratemaking generally costs are front end loaded. As facilities are depreciated through time the capital requirements on the initial investment will decrease all else being equal. On the other hand, the cost of purchased power alternative can increase, decrease or stay the same over time. Thus, given the nature of differing cash flow requirements from these alternatives, the best way to evaluate such projects is to evaluate the total cost of each alternative - in this case over the expected life of the TNP ONE facilities. These annual costs for each alternative are present valued employing some discount rate - and the two cumulative present value time it has presented life-cycle analyses to justify the decision to construct TNP ONE in particular with regard to the discount rate assumption. I believe that rather than basing a decision upon a very narrow set of assumptions it is necessary to consider numerous possible scenarios and then basing one's decision upon the aggregate of these results.

Q. WHAT TYPES OF ALTERNATIVE SCENARIOS DO YOU BELIEVE SHOULD HAVE BEEN CONSIDERED BY TNP?

A. When attempting to project the potential revenue requirements of a generation facility which has yet to be built, one should consider alternative scenarios. These alternatives include the possibility that the eventual construction costs may be higher than originally estimated, that capacity factors and prices of alternatives may vary. Giving the appropriate consideration to these alternative scenarios is especially critical in the case of TNP ONE since all life-cycle analyses conducted by the Company and this Commission's staff have indicated that in the short-run energy from these units will cost substantially more than purchased power.

Q. WHY DOES THE EXPECTED HIGHER COSTS IN THE SHORT-RUN MAKE IT EVEN MORE ESSENTIAL TO CONSIDER ALTERNATIVE SCENARIOS?

A. With any forecast the further out one goes the less confidence there is that the projected numbers will ever be realized. In other words, one would have more confidence in the accuracy of the first or second year of a forecast than in the thirtieth. In the case of all analyses on TNP ONE, the short run forecast period, in which we should have the most confidence, indicate that power

costs can be compared to determine the most economically viable or lower cost alternative.

Q. ARE LIFE CYCLE ANALYSES RELIABLE MEANS FOR EVALUATING ALTERNATIVES?

A. A life cycle analysis is as reliable as the inputs which form the basis of the results. For example, in the case of TNP ONE versus HL&P purchased power - one of the first requirements is to estimate HL&P's cost for the next 38 years. Second, one has to estimate TNP ONE cost of service for the next 38 years. Thus, all such analyses rely upon predictions of the future. Given that we are trying to establish costs over the next 38 years the best the analyst can do is employ reasonable forecasts based on the best information available. Third, one must consider all costs known so as to not bias the analysis one way or the other. For example, if a major TNP ONE related O&M component was not included in the life cycle analysis obviously such an occurrence would bias the analysis in favor of the TNP ONE project. Thus, given the above caveats, a life cycle analysis is the appropriate evaluation tool - but all such analyses are only as good as the assumptions used. Given that the results of such analyses are very dependent upon uncertain forecasts of the future, sensitivity analyses should be employed so as to determine factors that can substantially influence the results. I will discuss this issue in detail below.

Q. WHAT HAVE THE RESULTS OF THE COMPANY'S LIFE CYCLE ANALYSES BEEN OVER TIME?

from this plant will cost ratepayers more than purchased power. Only by considering the long-run, the period over which we have the least confidence, is there any potential that these facilities may benefit the Company's ratepayers. Yet, in spite of the uncertainty of what the future may be, TNP has consistently taken a very narrow view of the alternatives and has asked the Commission to accept their constrained perception of the future.

Q. PLEASE EXPLAIN HOW YOU HAVE CONDUCTED THE TYPE OF SENSITIVITY ANALYSIS YOU PREVIOUSLY DISCUSSED ON THE MARCH 1987 ANALYSIS DEVELOPED BY TNP?

A. I have conducted analyses which consider alternative levels of purchased power costs, plant capital costs, and various present value rates. As the basis for these analysis I have replicated the life-cycle models developed by TNP in March of 1987. The March 1987 analyses was conducted by TNP in association with the Company efforts to obtain a certificate for the project in the original Docket No. 6992.[15]

Q. WHY HAVE YOU RELIED UPON THE COMPANY'S ANALYSES PRESENTED RATHER THAN ON THE ANALYSES PRESENTED BY THE COMMISSION'S STAFF?

A. I do not mean to imply that I have ignored the analyses conducted by the Commission's Staff in the original Docket No. 6992 and on Remand. I have reviewed the testimonies of Charles Griffey in Docket No. 6992 and of Paul Bellon in Docket No. 6992 on Remand. In these cases it was Staff's

---

15 TNP's March 1987 model is contained in the Testimony Appendix at TAB 1.

determination that the economics of the project was at best questionable and more recent analyses show the economics are significantly detrimental to TNP's ratepayers. However, by basing my sensitivity analyses on the Company's model there is not question that I will be relying upon information available to TNP at the time of their analyses which should have been considered in their decision making.

Q. WOULD YOU PLEASE STATE YOUR APPROACH IN CONDUCTING YOUR SENSITIVITY ANALYSES?

A. As previously stated, I began by replicating the Company's March 1987 2-unit life-cycle models. Using this model as a basis I then conducted a series of runs which adjusted the level of purchased power costs, the capital cost and the present value rates employed by TNP. These elements of the life cycle analysis were adjusted because they represent key assumptions in the results of each life-cycle analysis.

The following table illustrates the results of my analysis based on the Company's March 1987 life-cycle model:

TABLE 2
Texas-New Mexico Power Company
Life Cycle Impact of 2-Unit Project
Based on March 1987 Model
Savings/(Costs)

Purchase Power Adj	Present Value Rates 9.00% ($000)	10.00% ($000)	11.00% ($000)	12.00% ($000)	13.00% ($000)
0.00%	241,426	170,158	115,080	72,457	39,459
-5.00%	148,945	91,420	47,480	13,959	(11,541)
-10.00%	56,463	12,682	(20,120)	(44,539)	(62,540)

The Company's March 1987 analyses presented an estimated cumulative present value savings over the life of TNP ONE equal to $241.4 million assuming a 9 percent discount rate. The previous table illustrates the significant impact on the Company's results which occur when one changes the cost of purchased power or the present value rate. As can be seen from this table, reducing the cost of purchased power by 10 percent results in a range of cumulative present value savings from $241.4 million to $56.5 million. Varying the present value rate between 9 to 13 percent results in a range of cumulative present value savings between $241.4 million to $39.5 million. The combination of these factors produces a range of cumulative present value savings between a positive $241.4 million and a negative (increased costs) of $62.5 million.

Q. WHAT IS THE SIGNIFICANCE OF PRESENTING THIS RANGE OF SAVINGS?

A. The significance is to illustrate that alternations to the assumptions contained in the Company's life-cycle model produce significant changes in the results.

Q. ON WHAT BASIS HAVE YOU CHOSEN YOUR 9 TO 13 PERCENT PRESENT VALUE RATES?

A. Numerous arguments can be made to justify a wide range of alternative present value rates. Present value rates for individuals are generally considered to range between approximately 5 percent, which is the current interest on passbook accounts, to as much as 18 to 20 percent, which is the range of interest rates charged by credit card companies. One could also argue that the Company's requested cost of capital would be the most appropriate present value, which is 12.44 percent when this model was estimated in the 1987 case. For TNP to present its analyses based on only one discount rate especially at the lower end of the range provides an unjustifiably narrow view when considering the potential economic impact of this project. The 9 to 13 percent range I have chosen at least attempts to address the fact that it is difficult to identify any one specific present value rate as being the most appropriate.

Q. IS THE PRESENT VALUE RATE REALLY THAT IMPORTANT TO THE RESULTS OF A LIFE-CYCLE ANALYSIS?

A. Yes. As an example, let us accept all of the assumptions employed by TNP in its March 1987 analysis, their projected fuel cost, O&M expenses, wheeling and standby costs, and even their purchased power costs, but change the present value rate. If we can assume, as previously discussed, that the actual rate ranges somewhere between 5 to 20 percent, then the mid-point of this range would be 12.5 percent which also happens to approximately equal their 1987 cost of capital estimate. If I employ this mid-point in the Company's March 1987 life-cycle model, and change nothing else, then the cumulative present value savings from TNP ONE is reduced from $241.4 million to only $54.9 million. Thus at a 12.5 percent discount rate even a slight reduction in the Company's projected purchased power rates or a slight increase in capital costs would result in a negative present value savings.

Q. BASED ON YOUR ANALYSIS OF THE COMPANY'S MARCH 1987 LIFE-CYCLE MODEL WHAT CONCLUSIONS HAVE YOU REACHED?

A. My analysis indicates that at best the economics associated with the construction of TNP ONE was highly questionable even in early 1987. When we consider the uncertainty associated with any long-term forecast and the fact that any potential savings associated with the construction of these facilities relied upon the long-term, I believe that the Company should not have proceeded with the construction of TNP ONE.

Q. WERE THE ESTIMATED CAPITAL COSTS FOR TNP ONE ALSO CHANGING SIGNIFICANTLY DURING THE 1987 TIME FRAME?

A. Yes. The estimated cost of Unit I in Docket No. 6397 was $231,000,000 and the cost of all four units was estimated at $916,040,000[16]. In Docket No. 6992 these estimated costs had increased to $253,517,000 for Unit I and $973,747,000 for all four units[17]. Thus, in just over a 1½ year period the costs of Unit I had increased 9.7% and the total cost of the facility by 6.3%. This type of increase is especially significant in light of the purported fixed price nature of the construction contract. Nonetheless, not only did TNP not examine the sensitivity of the economics of this project with regard to discount rates and alternative purchased power, but they appeared to have also ignored the impact of increasing capital costs.

Q. YOU DISCUSS ABOVE THE IMPACT OF INCREASED CAPITAL COSTS ON THE MARCH 1987 MODEL. WOULD YOU PLEASE DESCRIBE THE RESULTS OF THIS ANALYSIS?

---

16 Examiner's Report Docket No. 6397 page 43.

17 Examiner's Report Docket No. 6992 page 62.

A. I considered the impact of a 10 percent increase in the capital costs associated with TNP ONE. When one considers the increase in costs most utilities constructing generation facilities had experienced in the past and considering the size of this project, I believe the use of a 10 percent adjustment factor is appropriate for a sensitivity analysis. In addition, as I noted above, capital cost estimates for Unit 1 had already increased 10 percent in a short period of time. The following table presents the range of cumulative present value savings assuming a 10 percent increase in the capital cost of TNP ONE as employed by the Company in its March 1987 life-cycle model.

TABLE 3
Life Cycle Impact of 2-Unit Project
Cumulative Present Value Savings
Capital Cost Increased 10%[18]

Purchase	Present Value Rates				
Power Adj	9.00% ($000)	10.00% ($000)	11.00% ($000)	12.00% ($000)	13.00% ($000)
0.00%	186,119	119,868	69,157	30,360	731
-5.00%	93,637	41,130	1,557	(28,138)	(50,268)
-10.00%	1,156	(37,608)	(66,043)	(86,636)	(101,268)

It is evident from the data contained in this table that the Company's decision to proceed with the construction of TNP ONE was not a desirable alternative even at the time of their original request for certification in 1987. Given that the approximate discount rate should be at the upper end of the range with TNP's overall return of approximately 12.5 percent and that the Company's alternative purchased power costs were substantially higher than

18 All gross plant costs, including related facilities, and tax basis costs increased by 10%.

any of the other analyses presented in Docket 6992 TNP should have concluded negative savings would result.

Q. WHAT HAVE YOU CONCLUDED FROM YOUR ANALYSES REGARDING THE PRUDENCE OF THE DECISION TO GO FORWARD WITH CONSTRUCTION OF TNP ONE?

A. Based on all the factors discussed earlier in Section II, the decision to go forward was questionable at best. As I stated earlier, the Board of Directors appeared to be having second thoughts in the fall of 1987. In addition, the Company recognized that the CCN was effectively in "limbo". Also, the Company should have realized from the CCN case that the economics of this project were significantly challenged and questioned. Further, the PUCT staff clearly told the Company that the economic analyses performed by TNP did not justify construction of the facility. Lastly, as can be seen from Table 3, when capital cost increases are considered, and more reasonable discount rates, this project is either marginally economical (less than $1 million) or very costly to ratepayers depending upon the alternative purchased power cost assumptions.

Given the above, I have concluded that the decision to go forward and construct TNP ONE facilities was not a prudent decision. I have quantified, a recommended prudence disallowance in Section VI.

Q. HAVE YOU ALSO CONDUCTED AN ANALYSIS OF THE COMPANY'S APRIL 1990 LIFE-CYCLE MODEL?

A. Yes. I conducted the same sensitivity analysis on TNP's April 1990 life-cycle model as was done on the March 1987 run[19]. The model that is the focus of my analysis is the Company's mid-range purchased power alternatives. It is important to remember that all of my analyses are based on the Company's 2-unit life cycle models and therefore rely upon the assumptions made by and information available to the Company at the time of their analyses, in this case early 1990. The following table illustrates the results of varying the present value rate between 9 to 13 percent.

TABLE 4
Texas-New Mexico Power Company
Life Cycle Impact of 2-Unit Project
Based on April 1990 Model

Purchase Power Adj	9.00%	10.00%	11.00%	12.00%	13.00%
	($000)	($000)	($000)	($000)	($000)
0.00%	2,372	(102,214)	(177,060)	(230,129)	(267,212)

As is evident from this table, under the majority of scenarios TNP ONE will result in net increase in costs to the Company's ratepayers versus the option of continued purchased power. As an additional analysis I have also conducted a series of runs under the assumption that the cost of Unit 1, as estimated by the Company in April of 1990, does not increase, but that the final cost of Unit 2 increases by 10 percent over the Company's April 1990 estimate. Considering the cost increases which have occurred on Unit I, and the period of construction remaining on Unit 2, I believe this is a very reasonable scenario. The following table illustrates the cumulative present

19 The April 1990 Analyses are contained in my testimony Appendix at TAB 2.

value savings under the assumption of once again varying present value rates.

TABLE 5
Texas-New Mexico Power Company
Life Cycle Impact of 2-Unit Project
Based on April 1990 Model
Capital Cost Increased 10%[20]

Purchase Power Adj	9.00%	10.00%	11.00%	12.00%	13.00%
	($000)	($000)	($000)	($000)	($000)
0.00%	(28,860)	(131,488)	(204,575)	(256,057)	(291,705)

Based on my analysis of the Company's April 1990 life-cycle model it is obvious that even TNP's own model does not support their decision to build these units or their claims of ratepayer savings in the future.

SECTION V SECTION 63 REVIEW IS REQUIRED GIVEN THAT TNP DOES NOT OWN THE FACILITIES FOR WHICH RATE BASE RECOGNITION IS BEING REQUESTED

Q. EARLIER YOU STATED THAT TNP WILL NOT OWN THESE FACILITIES, PLEASE EXPLAIN THE RATEMAKING ISSUE THAT IS CREATED BECAUSE TNP DOES NOT OWN THESE FACILITIES.

A. As will be explained in detail below, a wholly owned subsidiary of the Company, TGC owns these facilities since such facilities were transferred from the Consortium funding subsidiary, PFC. Given that the utility, TNP, is requesting a return on investment and recovery of costs for a facility it does now own, a significant ratemaking problem is created. The issue before this Commission is whether rates for a utility can be set so as to allow a return on

[20] Only Unit 2 gross plant and tax basis costs increased by 10%.

investment not owned by the utility. The PURA at Section 41(a) defines Invested Capital as original cost and further defines original cost as follows:

> Original cost shall be the actual money cost, or the actual money value of any consideration paid other than money, of the property at the time it shall have been dedicated to public use, whether by the utility which is the present owner or by the predecessor, less depreciation. (emphasis added)

My understanding of the PURA requirements for rate base recognition is that the utility is assumed to own the property for which a reasonable opportunity to earn a reasonable return on this invested capital will be provided pursuant to Section 39 of PURA. Obviously, the above is not a legal opinion but rather the interpretation of a ratemaking expert familiar with the ratemaking process in Texas as well as other state regulatory commissions.

Thus, if the Company does not own this facility such investment and associated costs should not be included in rate base and the return requirements excluded from cost of service. Therefore, a prudence review of TNP ONE is complicated given that the owner of the facility is TGC, a firm not requesting a rate increase in this case.

Q. WHO CURRENTLY OWNS THE TNP ONE INVESTMENT?

A. At this time Project Funding Corporation, a wholly owned subsidiary of the construction Consortium owns the Unit II facilities. The Unit I facilities are owned by TGC.

Q. WHEN DID TGC TAKE OWNERSHIP OF THE TNP ONE UNIT I FACILITIES?

A. When Unit I met certain minimum standards regarding operating performance which are outlined in the construction contract, TGC assumed ownership of

Unit I and also assume the obligation of the construction loan. Such transfer was to take place by June 1, 1990 based on the Company's testimony. It is my understanding that TGC did in fact accept ownership of Unit I on June 8, 1990 and the closing on these facilities took place in July 1990.

Q. WHY WILL TGC OWN THE FACILITY RATHER THAN TNP TAKING LEGAL TITLE?

A. The testimony of Company witness Smith indicates that TGC ownership during the repayment period results in an interest rate savings of 25 basis points on the construction loan. The reason for TGC ownership or a higher interest rate is that TNP ownership would not allow the banks (construction note holders) to obtain a first lien on Unit I facilities. Mr. Smith's testimony explains this issue as follows:

> "Provisions in TNP's Indenture of Mortgage and Deed of Trust dated November 1, 1944 (the Indenture) have the effect of limiting the amount of debt that may be secured by a first lien on TNP property (which is subject to the lien of the Indenture) to no more than 10% of the aggregate principal amount of the bonds issued and outstanding under the Indenture. Because Unit I would constitute part of the Trust property covered by the lien created under the Indenture if owned directly by TNP, and because the amount of borrowings under the Credit Facility for Unit I will far exceed 10% of the outstanding bonds under the Indenture, TNP could give the Banks a first lien on Unit I to secure repayment of the Credit Facility only if all of the bonds under the Indenture were refinanced or if the Indenture were amended.[21] (emphasis in original)

Thus, TGC as the owner and obligor under the Credit Facility circumvents the indenture restrictions of TNP. TNP is required to guarantee

---

21 See Smith testimony at page 7.

the debt of TGC to the Banks, while at the same time TGC provides the Banks a first lien on the facilities.

Mr. Smith's testimony would have this Commission believe that by creating the TGC subsidiary the Company is saving ratepayers 25 basis points in interest costs relative to direct TNP ownership and that interest rate savings is the key issue. This is just not the case and the documents I have reviewed indicate it is misleading to imply that TGC was created to save interest costs.

Q. PLEASE EXPLAIN THE CIRCUMSTANCES SURROUNDING THE INDENTURE PROBLEMS AND THE CREATION OF TGC.

A. First, contained in the Testimony Appendix at TAB 6, is a June 23, 1987 letter from Chase Manhattan Bank outlining the terms and conditions for the $345 million Credit Facility which would be used to construct Unit I of the project. At page 4 of the terms and conditions, the lenders have the right of a first mortgage on Facility One as a condition of security . Regarding the various security requirements of the lender it is stated also at that same page that these requirements are; "Subject to Legal Review of TNP Indenture."

Further, at page 17 of this same letter, the terms and conditions clearly states that the commitment regarding financing is made subject to the following conditions:

> 5) Satisfactory Legal Review of TNP Indentures, Preferred Stock, Articles of Incorporation and other relevant TNP financing documents.

Thus, at the time of Chase Manhattan Bank's offer to arrange the lending for the project, there apparently had been no complete review by this group of TNP's indenture restrictions. It should be noted that the terms and conditions presented in this offer were accepted by TNP on June 29, 1990. 1987

Q. WERE THESE TERMS AND CONDITIONS REVISED?

A. Yes. Contained in my Testimony Appendix at TAB 3, is a September 23, 1987 letter from Chase Manhattan Bank with some revised terms and conditions as well as three alternatives for dealing with the indenture restrictions regarding the first lien issue on these facilities. It is apparent from reviewing this letter, that by September 23, 1987 the problems regarding the restrictions contained in the indenture were discovered.

The three alternatives offered to TNP as a means of dealing with the first lien problem were as follows:

ALTERNATIVE I	Establish a Subsidiary to own the facilities.
ALTERNATIVE II	Amend the TNP Indenture
ALTERNATIVE III	TNP under the existing indenture will take ownership.

It should also be noted that the bank put additional restrictions on Alternative III other than a higher interest rate. First, under Alternative III, construction of Unit III and Unit IV would <u>not be permitted</u>. Second, under Alternative III, construction of Unit II would not be allowed to commence prior to September 1989. This is a very important issue because such a requirement not only increases Unit II costs but possibly delays construction even further depending upon the commitments of the Consortium. Lastly, TNP agreed to use best efforts to first comply with Alternative I, second comply with Alternative II. Alternative III was viewed as a back-up alternative.

The greatest detriment associated with Alternative III appears to be that Unit II construction could not commence until September 1989 under this scenario. Given that the Company has stated that the economic benefits of this project are realized with a two unit facility, the entire benefits of self generation would be in question under Alternative III. Further, given that when the Company decided to let Unit II go to construction in August 1988, the question of any delay was a problem given that delay meant increased capital costs, questions of further delay, and cost increases depending upon the Consortium's other construction commitments. Thus, while selection of Alternative III did result in increased interest costs, construction delays would potentially put the economics of the entire project in jeopardy.

Q. WHY DIDN'T THE COMPANY SELECT ALTERNATIVE II?

A. Alternative II would have required either refinancing all outstanding debt or the approval of a majority of its bondholders. Based on the testimony of Mr. Smith such an approach would increase costs, and TNP determined it would not be in the best interest of its shareholders or ratepayers to pursue this approach.[22] It should also be noted that TNP agreed to use best efforts to satisfy Alternative I requirements first.

[22] See Smith testimony at page 7-8.

Q. DID THE BANKS INITIALLY HAVE OTHER REQUIREMENTS UNDER ALTERNATIVE I?

A. Yes. First, under Alternative I, TNP was required to set up a subsidiary to take ownership of the facility when completed. Second, TNP would provide an unconditional guarantee to the banks of the obligations of the subsidiary. Third, TNP was required to execute a Facility Purchase obligation with the subsidiary whereby TNP would purchase undivided ownership interests in the facilities as the payments became due.

Fourth, TNP was to get PUCT approval of the "round trip" transfer of the necessary rights of TNP under the CCN to the subsidiary (TGC) and back to TNP. The application of the transfer was to indicate that TNP intends to file a rate case to include the total plant in TNP's rate base notwithstanding which entity TNP or TGC owns the facility.

Fifth, TNP was to receive approval from the PSC of New Mexico of TNP's guarantee to TGC's obligations as well as, approval for the formation of TGC. Thus, as can be seen from the above, the Banks required much more than just creating a subsidiary to own the facilities.

Q. DID TNP COMPLY WITH ALL OF THE FIVE REQUIREMENTS YOU DISCUSSED ABOVE?

A. TNP set up the subsidiary TGC, guaranteed the debt of TGC and developed a Facility Purchase Agreement with TGC. In addition, TNP did receive PSC of New Mexico permission to set up the subsidiary. With regard to item four, PUCT approval of a round-trip transfer of these facilities and associated CCN amendments, TNP did not complete that part of the agreement.

Contained in my Testimony Appendix at TAB 4, is a letter to the TNP Board of Directors which discusses the issue of the round-trip transfer. As I understand this letter, the Chase Manhattan Bank dropped the requirement for PUCT approval of CCN transfer. It is my understanding that TNP did file a case regarding the CCN transfer but as is stated in the September 23, 1988 letter to the Board of Directors it was decided not to pursue the transfer. The following is stated in the letter to the TNP Board:

> ...it was decided not to seek a transfer of the CCN to the subsidiary of TNP. With the assistance and guidance of the outside counsel for TNP and the review of the Public Utility Regulatory Act, it was decided to file a notification under Section 63 of the act which would allow for the transfer of the assets to the subsidiary, and as the loan is funded the assets would be transferred in a proportionate amount to TNP. In such case the PUCOT has the right to require a hearing, <u>and elected to do so in this instance.</u> Because of the scheduled time for such a hearing, it would not have been possible to complete such hearing in time to release Unit Two for a 1988 construction start. (emphasis added)

Thus, as can be seen from the above, the Company and the lenders knew that such a transfer would come under a Section 63 review and a hearing on the merits of such a transfer may be required to determine if such transfer is in the public interest. Apparently the Company and the lenders decided to take the regulatory risk of attempting such a transaction without first receiving Commission approval.

Thus, while a Section 63 hearing to determine whether or not TNP's proposed facilities "round-trip" transfer is in the public interest may take too long, TNP proposes to include TNP ONE facilities in their rate base notwithstanding the fact the Company does not own these facilities. It should also be noted that the Company's argument for not having a public interest finding (ie) that it would interfere with Unit II construction confirms the importance the Company placed on getting this facility completed.

Q. GIVEN THAT TNP DOES NOT OWN THE FACILITIES, WILL TNP EARN AN EXCESSIVE RETURN FROM RATEPAYERS UNDER THE TGC/TNP TRANSACTION?

A. Yes. TNP is requesting the entire amount of Unit I in rate base at an overall return of 11.11 percent. It is the Cities position that no amounts may be placed in rate based because TNP does not own the unit nor does the amount represent investment by TNP. That aside, TNP's proposed rate treatment includes a windfall. In reality these facilities will be owned by TGC, and TGC's carrying cost on these facilities is 10 percent pursuant to the construction loan. Thus, TNP proposes to charge ratepayers an 11.11 percent return plus taxes on Unit I facilities, but TGC's costs to the banks will actually be less given that the true carrying cost on the Unit I facilities is 10 percent.

Q. HAVE YOU QUANTIFIED THE IMPACT TO RATEPAYERS OF THE EXCESS RETURN TNP WILL EARN?

A. Yes. Schedule (DJL-6) reflects a calculation of the ratepayer overcharges. As can be seen from Schedule (DJL-6) ratepayers will overpay Unit carrying costs by $9.0 million to $12.5 million in the first year depending upon the assumptions one uses for the TNP carrying costs.

Q. IN YOUR OPINION, IS IT PRUDENT TO SET UP A SUBSIDIARY RELATIONSHIP AND CHARGE RATEPAYERS COSTS IN EXCESS OF WHAT IS ACTUALLY BEING INCURRED BY THE SUBSIDIARY?

A. No I do not believe that it is fair or prudent business practice. There is no question that ratepayers are being overcharged under this transaction between TNP and TGC and at the very least those amounts of excess return should be disallowed as unreasonable and unnecessary pursuant to PURA Section 41(c)(1).

Q. IS YOUR RECOMMENDATION TO DISALLOW THESE COSTS CONSISTENT WITH THE TESTIMONY OF THE COMPANY IN THIS CASE?

A. Yes. At page 10 of TNP witness Smith's testimony, he states the following:

> The accounting for transactions between TNP and TGC will be structured such that TGC will not recognize a profit or a loss so long as TGC owns Unit I. To the extent TGC incurs expenses related to Unit I, <u>it will be reimbursed at cost by TNP</u>. (emphasis added)

Thus, my calculation of TGC's carrying cost - associated adjustments to federal income taxes and revenue related taxes is consistent with the Company's testimony in this case.

It should be noted that this adjustment described above is not a disallowance of costs. Instead it is an adjustment to reflect actual expenses.

Q. GIVEN THE OWNERSHIP ARRANGEMENT OF THESE FACILITIES AND THE FACT THAT TNP IS EFFECTIVELY LEASING OR RENTING THE TNP ONE

FACILITIES WHAT APPROACH CAN BE USED TO EVALUATE THIS TRANSACTION?

A. I have approached this part of my analysis from a PURA Section 63 approach. Given that the plant should not be included in rate base, and that the Company is effectively renting these facilities, and has every intention of transferring the plant from TGC to TNP Section 63 of PURA seems most appropriate. Furthermore, as I stated earlier, the Company and the Bank recognized the requirements of a Section 63 review as far back as 1987. Indeed the Company actually filed a request or notification under Section 63 of PURA, but later withdrew that filing. Therefore, given the above, it appears that a review under Section 63 seems most appropriate.

<u>STANDARD BY WHICH TNP ONE TRANSFER SHOULD BE EVALUATED</u>

Q. WHAT DOES SECTION 63 OF PURA REQUIRE?

A. Section 63 of PURA states the following:

> No public utility may sell, acquire, lease, or rent any plant as an operating unit or system in this state for a total consideration in excess of $100,000 or merge or consolidate with another public utility operating in this state unless the public utility reports such transaction to the commission within a reasonable time. All transactions involving the sale of 50 percent or more of the stock of a public utility shall also be reported to the commission within a reasonable time. On the filing of a report with the commission, the commission shall investigate the same with or without public hearing, to determine whether the action is consistent with the public interest. In reaching its determination, the commission shall take into consideration the reasonable value of the property, facilities, or securities to be acquired, disposed of, merged or consolidated. If the commission finds that such transactions are not in the public interest, the commission shall take the effect of the transaction into consideration in the ratemaking proceedings and disallow the effect of such transaction if it will unreasonably affect rates of

> service. The provisions of this section shall not be construed as being applicable to the purchase of units of property for replacement or to the addition to the facilities of the public utility by construction.

Given that the Company is leasing or renting these facilities, it appears that Section 63 applies now. Moreover, given that TGC will transfer to TNP these facilities it seems obvious that Section 63 will also be applicable in the future. Thus, it would make sense to evaluate this entire transaction under Section 63 now, and determine whether or not such transactions are in the public interest. Again, as I stated earlier, even TNP recognized the need for a Section 63 review. Therefore, I do not believe there should be any question that this is the appropriate approach on which to evaluate this transaction.

Q. HAVE YOU REVIEWED ANY CASES OR COMMISSION ORDERS WHICH ADDRESSED SECTION 63 FINDINGS REGARDING?

A. Yes, I have reviewed the final order and Examiner's Report in Docket No. 8059 often referred to as the "Swap Docket."

First, Docket No. 8059 involved a request by HL&P to amend its Certificate of Convenience and Necessity (CCN) to reflect the proposed changes in ownership interests in the South Texas Project (STP) as well as, the Limestone Lignite facility in order to finalize a settlement with the City of Austin (COA). The request by HL&P to amend the CCN was granted by the Commission. In my opinion, this situation of amending the CCN is very similar to the "round trip" transfer contemplated by the banks which I discussed earlier and is shown in my Testimony Appendix at TAB 3.

Q. WHAT WERE THE EXAMINER'S FINDINGS ON THE PUBLIC INTEREST ISSUE IN DOCKET NO. 8059?

A. The Examiner's findings are stated at page 2 of the Examiner's summary as follows:

> I have further found that if reasonable assumptions are substituted for the above assumptions, the settlement agreement between HL&P and COA, if consummated, will produce no economic benefit to HL&P's ratepayers and in fact, will likely result in a very substantial economic detriment to those customers. Consequently, I have recommended that the Commission not enter a finding in this proceeding that the proposed exchange of assets is consistent with the public interest, but that, in the event HL&P proceeds with the settlement without having first obtained that finding, the Commission permit the public interest issue to be relitigated in HL&P's next general rate case.

The final order adopted the Examiner's recommendation in that case.

Q. WAS THE HL&P REQUEST EVALUATED ENTIRELY FROM A SECTION 63 PROSPECTIVE?

A. Yes. At page 12 of the Examiner's report the following is stated:

> No party in this proceeding disputes the proposition that Section 63 is applicable to the sale or exchange of a partial ownership interest in a generating plant.

Thus, Docket No. 8059 like the issue of the TNP's renting/leasing and proposed transfer of TNP ONE should be evaluated under the same standard (ie) a public interest finding pursuant to Section 63 of PURA.

Q. GIVEN THAT SECTION 63 OF PURA REQUIRES A PUBLIC INTEREST FINDING, HOW HAVE YOU DEFINED PUBLIC INTEREST?

A. I will be relying on the definition of public interest used by the Examiner in Docket No. 8059. At page 20 of the Examiner's report the following is stated:

> The heart and soul of this proceeding is the issue of whether the proposed settlement agreement is consistent with the public interest while the public interest is inherently a somewhat nebulous concept. HL&P has unambiguously defined its meaning for purposes of this docket and there is no real disagreement by the other parties as to the appropriateness of HL&P's definition. HL&P witness McClanahan testified that the <u>term "public interest" implies that by performing or consummating the transaction, the public is benefitted, and that, in the context of an electric utility, public interest equates to electric utility rates</u>. (Emphasis added)

The Examiner goes on to discuss non-quantifiable factors as follows:

> While Mr. McClanahan suggested that the Commission could consider non-quantifiable factors in weighing the public interest, the reasonableness of HL&P's economic analysis should constitute the primary basis for making a finding that the proposed settlement agreement is consistent with the public interest.

In my opinion, the definition of public interest used in Docket No. 8059 should also be used in this case.

In other words, to determine whether the renting or leasing of the plant or the contemplated sale and transfer of TNP ONE is in the public interest the Commission should look to a life cycle or revenue requirements analysis comparing the revenue requirements associated with the transfer to some other supply alternative, such as HL&P's wholesale rate.

It must be remembered that Docket No. 9491 is somewhat similar to the HL&P case where the issue was the status quo versus the proposed settlement.

In summary, this Commission, in determining whether the transfer is in the public interest, should consider whether the transfer of TNP ONE relative to other reasonable alternatives results in lower rates.

Q. ARE THERE OTHER CASES WHERE A SECTION 63 REVIEW IS BEING CONDUCTED TO DETERMINE THE PUBLIC INTEREST?

A. Yes. For example, the current Texas Utilities ("TU") case, Docket No. 9300 has a Section 63 issue. In that case TU's purchase of additional nuclear capacity from former Comanche Peak minority owners is being evaluated from a Section 63 perspective. In that case, various intervenors and the PUCT staff have proposed substantial adjustments based on a current analysis of the effect of the TU purchase relative to other alternatives. Thus, a Section 63 review is not an unusual or extraordinary approach to employ in evaluating a specific transaction which will impact ratepayers.

Q. WHAT TYPE OF QUANTIFIABLE STUDY DID HL&P EMPLOY IN DOCKET NO. 8059?

A. In Docket No. 8059 the Company quantified the economic impact of the proposed exchange of assets with the City of Austin by examining and comparing the revenue requirements from two scenarios. First, an analysis of the revenue requirements from a base case which reflected the impact on customers of no exchange of assets was examined. Second, a revenue requirement analysis of the proposed settlement or exchange of assets was calculated.

Thus, the analysis performed in the HL&P case to determine economic impact of the settlement was a comparison of the revenue requirements of the status quo relative to the revenue requirements which would result from the exchange of assets, ie, the settlement. Assuming all the assumptions underlying both analyses are reasonable, then the lower revenue requirement alternative would result in lower rates, provide economic benefit to ratepayers and be in the public interest. As I stated earlier, it was determined that the status quo and not the proposed settlement which was the least cost alternative in that case. Thus, given the economically unfavorable impact of the proposed HL&P/City of Austin settlement no public interest findings were made regarding the settlement.

Q. IF THE PUCT WERE TO RELY ON A LIFE CYCLE ANALYSIS BASED ON TODAY'S INFORMATION WHAT WOULD BE THE RESULT OF SUCH AN ANALYSIS IN YOUR OPINION?

A. As I discussed earlier, a life cycle comparison of the TNP costs relative to maintaining purchased power indicates that the TNP ONE facilities are more costly over the life of the unit. This same conclusion was reached by the PUCT staff in Docket No. 6992 remand when total costs were considered[23]. Thus, information available today would indicate that such a transfer is not in the public interest given the impact on rates. The PUCT at that time could and should disallow the rate impact differential between TNP ONE and the most reasonable alternative so as to assure that the transfer is in the public interest.

Q. IS THERE ANY BASIS FOR USING THE 1990 LIFE CYCLE ANALYSES ON TNP ONE?

[23] See Paul Bellon testimony filed in Docket No. 6992 remand.

A. Yes. Given that the Examiner in the remand case relied on 1990 data and that TNP took the regulatory risk of going forward with the project without a CCN, there is a strong argument for using current data to evaluate the project. As I stated earlier, the Company realized that the wording of the CCN left the Company in "limbo" with regard to having a certificate for this project. Thus, if this Commission determines that the Company should accept the regulatory risk of constructing before a final CCN was issued then the 1990 data would be appropriate for evaluating the economics of the project.

SECTION VI <u>QUANTIFICATION OF DISALLOWANCE</u>

Q. BASED ON YOUR ANALYSES WHAT IS YOUR RECOMMENDED DISALLOWANCE IN THIS CASE?

A. First, if the Commission determines that the decision to construct was imprudent as I have recommended, then the economic impact to the customers is the difference between the purchased power alternative and the cost of TNP based on a life cycle analysis. As I stated earlier, the PUCT staff has estimated this amount to be between $300 and $500 million when a 10 to 12 percent discount rate is employed. My analysis, based on TNP's models, indicates such a disallowance is in the range of $177,060,000 to $267,212,000 employing discount rates of 11 to 13 percent respectively. These calculations are shown in Table 4 discussed earlier. Given these are cumulative present value costs, I have calculated an equivalent rate base disallowance that would be necessary to bring these detrimental ratepayers costs to zero. Thus, the necessary rate base disallowance in this case is in

see p. 65

the range of $136,317,000 to $232,194,000. Given that my analysis has been very conservative in favor of the Company and that in my opinion a 13 percent discount rate is very reasonable, I am recommending the $232,194,000 disallowance. These calculations can be found in my Exhibit ____, Schedule (DJL-7).

construction costs that would equate to a net PV of zero

Given that Unit II is not in rate base, then the disallowance should be applied equally to both facilities. Thus, if the PUCT applies the disallowance in this case to Unit I then the necessary rate base reduction is $116,097,000.

Q. IF THE COMMISSION DETERMINES THAT ON A SECTION 63 ANALYSIS IS APPROPRIATE AS YOU DESCRIBED EARLIER, WHAT IS YOUR RECOMMENDED DISALLOWANCE?

A. My recommended disallowance under a Section 63 criteria would be the same $232,194,000 I calculated above based on the 1990 analyses. In my opinion, the Company took the regulatory risk to go forward and proceed knowing full well a CCN transfer and Section 63 review would be required.

In my opinion, an analysis based on current data would be consistent with the cases I described earlier in this testimony. Thus, the rate treatment under this approach is to construct a rental rate in cost of service to be paid to TGC which assumes that $232,194,000 of TNP ONE plant is disallowed. When this facility is transferred to TNP, then only the depreciated value of the plant net of the disallowance should be allowed in rate base. In this way ratepayers are indifferent over the life of the project to TNP ONE or purchased power alternatives.

PERFORMANCE STANDARD FOR TNP ONE FACILITIES

Q. WHY IS IT NECESSARY TO ADDRESS PERFORMANCE STANDARDS IN THIS CASE?

A. As a theoretical consideration performance standards for generating units should not be necessary. Obviously, regulated utilities are required to provide reliable service at the lowest reasonable cost. Thus, regulators, if they hold utilities to the requirements noted above, are implicitly evaluating generating performance, given the mandate of lowest reasonable cost for service.

Given that TNP ONE represents the only generating unit for the Company and it will be a base load facility, such facility will have a significant impact on TNP's rates for many years to come. It must be remembered that about two thirds of the Company's entire investment will be comprised of TNP ONE related investment. Therefore, the performance of this plant can have a substantial impact on ratepayers.

Q. WAS THE DECISION TO BUILD THIS FACILITY BASED UPON ACHIEVING SUPERIOR PERFORMANCE RELATIVE TO OTHER TYPES OF FACILITIES?

A. Yes. It is my understanding based on document reviews that one of the reasons TNP selected the fluidized bed technology is the perceived higher load factor which the plant was expected to operate. The life cycle analyses performed by TNP in evaluating the economics of the project were in most part based on a 90 percent capacity factor. Thus, the Company's analysis of the economic viability of this facility was dependent upon a high level of efficient operation. Obviously, if the plant operated at significantly lower load factors less purchased power would be displaced and the economics of the project would have been even worse than described earlier.

Q. WHY IS A PERFORMANCE STANDARD NECESSARY FOR THIS CASE GIVEN THAT YOU ARE RECOMMENDING A PRUDENCE DISALLOWANCE?

A. It must be remembered that the prudence disallowance was based on a life cycle analysis evaluation of this project over the life of the facility. Implicit in my calculations were the assumed operating levels of the plant made by the Company in their model. I have included the projected operating performance factors for the unit in my Exhibit Schedule (DJL-8). As can be seen from Schedule (DJL-8) the expected performance of this plant is in the range of the mid eighties to the low nineties. Any deviation from these expected performance levels means even higher rates for customers because less generation from the plant means TNP will have to replace this power with other purchases.

Q. WHAT PERFORMANCE STANDARD ARE YOU RECOMMENDING THAT THIS COMMISSION ADOPT?

A. First the Company should be held accountable for its representations to this Commission regarding the performance of this facility, thus ratepayers should not be penalized for the risk taking of TNP. The Company shareholders are adequately compensated for risk and ratepayers need not pay double. Thus, based on the Company's claims of performance I would recommend the following performance standard:

> If TNP ONE's capacity factor is ever below 83 percent then all fuel costs will be absorbed by the Company.

This standard is conservative in favor of the Company in that the 83 percent standard set forth above represents the lowest capacity factor that the Company has estimated for the life of the facility. In this way the Company will be held accountable for its representations and ratepayers will ~~note~~ not be faced with increased risk of this plant.

It is worth noting that the 83 percent capacity factor provides TNP a great deal of flexibility in that the claimed operating levels are consistently in the upper 80 percent and lower 90 percent levels.

Q. WHAT METHOD SHOULD BE USED TO EVALUATE AND MONITOR THE PERFORMANCE OF TNP-ONE?

A. The Company should be required to track and document TNP ONE performance on an annual basis and report such performance in either a fuel reconciliation case or a rate case, and all increased fuel costs incurred because of operating below an 83 percent capacity factor should be absorbed by TNP.

Q. IF THE PUCT DOES NOT ADOPT A PERFORMANCE STANDARD AS YOU HAVE OUTLINED ABOVE, SHOULD THE TNP ONE DISALLOWANCE BE LARGER THAN YOU HAVE RECOMMENDED?

A. Yes. As I noted above, my calculation of life cycle costs and impact on ratepayers was based on the <u>Company's</u> assumptions regarding unit performance. If this Commission decides that TNP should not be held accountable for its representations to the public then I would recommend recalculating the life cycle costs employing a more conservative capacity factor in the 80 to 85 percent range.

It should be noted that the performance factor approach does result in a lower disallowance than the alternative just discussed, thus again I believe I am being conservative in favor of the Company.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

TEXAS-NEW MEXICO POWER COMPANY
DOCKET NO. 9491

EXHIBIT _____
SCHEDULE (DJL-1)
PAGE 1 OF 1

RESIDENTIAL RATE COMPARISON
SUMMER MONTHS (1,000 KWH)

UTILITY	PRESENT RATES (1)	RANK	REQUESTED RATES (2)	RANK
TEXAS-NEW MEXICO PWR.	$78.31	6	$94.84	1
AUSTIN	$73.14	11		
BLUEBONNET EC	75.12	8		
CENTRAL PWR & LT	78.64	5	88.77	3
CPS (SAN ANTONIO)	66.34	16		
DENTON COUNTY EC	78.14	7		
EL PASO ELEC.	92.50	1		
GULF STATES UTIL.	79.12	4	87.44	4
HOUSTON LT & PWR	85.81	3		
KPUB	63.66	19		
MID-SOUTH EC	67.62	15		
PEDERNALES EC	65.18	17		
SESCO	70.29	13		
S.W. PUBLIC SERVICE	64.60	18		
S.W. ELEC. PWR.	74.82	9		
TRI-COUNTY EC	70.20	14		
TEXAS UTILITIES	72.40	12	80.01	7
UPSHUR-RURAL EC	57.16	20		
VICTORIA EC	73.32	10		
WEST TEXAS UTIL.	87.12	2		
AVERAGE BILL	$73.67			

(1) Present rate comparison obtained from the Texas Public Utility Commission. Comparison is for July, 1990.
(2) Requested rates per tariffs contained in current utility rate filings before the Texas PUC. Requested rates do not include PCRF adjustments.

Exhibit __________

Schedule (DJL-2)

Page 1 of 2

[illegible] TIEC 56th
Question 83
Page 81 of 505

The Light company Houston Lighting & Power P.O. Box 1700 Houston, Texas 77001 (713) 228-9211

August 12, 1986

Mr. Randy Ownby
Manager-Contracts and Regulatory Affairs
Texas-New Mexico Power Company
4100 International Plaza
Fort Worth, Texas 76113

Dear Randy:

Enclosed please find a proposed Agreement for Electric Service which we have previously discussed. As you are aware, the rate case has prevented our complete management team which normally reviews these matters, from being together to approve this proposal. Release of this proposal has now been approved.

As we have stated on a number of prior occasions, HL&P believes that capacity alternatives other than the Robertson County Plant exist for meeting TNP's long term capacity needs in the Southeast Division. The enclosed power supply agreement represents one such alternative, an alternative which offers TNP an economical and flexible means of meeting their power needs now and in the future. Specifically, the proposed Agreement for Electric Service (Attachment A) provides long term, reliable service for TNP's Southeast Division while providing TNP with planning flexibility through a provision for reducing Contract KVAs should TNP receive a certificate to construct its own generating plant. For your convenience, a revised tariff sheet reflecting rates as proposed by the Company in Docket No. 6765 has been included as Attachment B to reflect the proposed billing changes. Our estimate of the projected cost of this contract as provided to you on April 15, 1986, indicates it is less expensive than the proposed Robertson County Plant. Also, with certain notice provisions, HL&P has committed to serve load in the Southeast Division that had been served by cogeneration.

Sections 3.1.1 and 3.1.2 contain blanks for the initial Contract KVAs at Texas City and West Columbia. The initial Contract KVAs would be the 1986 Annual On Peak KVAs in effect as of the date of execution of the Agreement. We estimate the initial Contract KVAs to be 231,859 KVA and 112,500 KVA for Texas City and West Columbia respectively based on demands set through June 30, 1986. As stated in Section 2.1, the initial Contract KVAs would be revised at such time as a Final Order is issued in HL&P's first general rate filed after January 1, 1987, in order to remove AMOCO's contribution, if any, to such Contract KVAs.

HL&P is still reviewing the latest impact studies provided by TNP for wheeling service from the Robertson County Plant. We have some questions concerning the interpretation of these studies and will be contacting you shortly for clarification. We expect to be able to provide TNP with that contract proposal in the very near future.

HL&P would also, if requested by Capitol or TNP, provide wheeling for Capitol to destinations other than the Southeast Division. Contract provisions and pricing would be per tariffs filed pursuant to Substantive Rule 23.66. HL&P would offer a firm (PCW) wheeling contract for 150 to 350 MW of power from Capitol Cogeneration to be signed not later than December 1986 and effective no later than July 1991 in order to assure transmission capacity for the movement of Capitol power to other destinations.

We look forward to meeting with TNP to discuss this proposed Agreement which will provide TNP with security of supply well into the twenty first century. As an important new feature, this contract allows TNP to build generation in the future and reduce its contract purchases from HL&P if such construction is in the best interest of TNP's ratepayers.

We regret any inconvenience the delay in getting this proposal to you might have caused, however, we wanted to carefully develop a document tailored to address TNP's needs and which would serve as an economical alternative to Robertson County in the Southeast Division. At such time as you have had an opportunity to review the enclosed agreement, please contact me so that we might discuss this matter in further detail.

Very truly yours,

JM Edwards

J. M. Edwards

JME/vs

Enclosure

Texas-New Mexico Power Company

4100 International Plaza
Fort Worth, Texas 76109
P.O. Box 2943
Fort Worth, Texas 76113
(817) 731-0099

September 26, 1986

Mr. John Edwards
HOUSTON LIGHTING & POWER COMPANY
P. O. Box 1700
Houston, Texas 77001

Dear Mr. Edwards:

We are in receipt of the proposed draft contract provided by your office on August 12, 1986. Although this proposal was received well beyond any period in which TNP could seriously consider an alternate power supply arrangement other than the Robertson County Power Plant, we are prepared to pursue, in earnest, negotiations of an acceptable arrangement for power supply with HL&P. As we have made very clear in the past, any serious negotiations must be pursued in a timely fashion since TNP is becoming more committed to the Robertson County Plant as time progresses. As discussed in Mr. Tarpley's letter to Mr. Sykora, discussions between TNP and HL&P have been on-going for some time with little actual progress toward an acceptable agreement.

I have attached a draft contract that more accurately reflects the requirements of TNP as have been discussed in the past few months with HL&P.

We would expect a substantive response from HL&P before the end of September. Your cooperation and attention is appreciated.

Very truly yours,

Randy Ownby, Manager
Contracts & Regulatory Affairs

RO/twr

CC: J. M. Tarpley
J. V. Chambers
D. R. Spurlock
R. J. Wright
Michael G. Shirley, Esq.

Attachment

Attachment TIEC's 6th
Question 83
Page 102 of 505

Exhibit ____
Schedule (DJL-3)
Page 2 of 3

AGREEMENT FOR ELECTRIC SERVICE

Texas-New Mexico Power Company, a Texas Corporation (hereinafter called "customer") and Houston Lighting & Power Company, a Texas Corporation (hereinafter called "company"), with its principal offices in the City of Houston, Texas, in consideration of the mutual covenants and agreements herein contained, and of the mutual benefits to be derived herefrom, hereby covenant and agree as follows:

1. Purpose. The purpose of this agreement is to set out terms and conditions under which HL&P will provide electric power and energy to each of the points of delivery as outlined in Exhibit A of this agreement. Said terms and conditions apply to each such point of delivery separately and individually and any action taken hereafter by either party hereto under said terms and conditions shall apply only to the points of delivery specifically covered by such action and no others.

2. General Duty of Parties. HL&P agrees to provide and TNP agrees to purchase and pay for a portion of the electric power and energy required by customer as specified by TNP and delivered at the locations described on Exhibit A unless otherwise specifically provided in this agreement. Electric power and energy provided under this agreement will be furnished by HL&P to TNP under and pursuant to such applicable Rate Schedule and Service Regulations of HL&P as may from time to time be fixed and approved, in HL&P's Tariff for wholesale Electric Service, by regulatory authorities as may have jurisdiction at the locations described in Exhibit A.

3. Description of Power Available. HL&P will provide electric power up to the maximum electrical load (contract KW) specified for each point of delivery, respectively, shown on Exhibit A. The electric service to be delivered hereunder will be the character commonly described as three-phase, 60 hertz, at a voltage for each point of delivery as specified on Exhibits A and B, and with reasonable variation in voltage and frequency to be allowed.

OPCPOD4-15-007566

4. Rate Schedule. The electric power and energy to be delivered by HL&P to TNP will be provided in accordance with terms and conditions of the appropriate rate schedule and/or rider as indicated for each point of delivery on Exhibit A. Such rate schedules and/or riders may from time to time be amended or succeeded by regulatory authorities as may have jurisdiction at the locations described in Exhibit A.

The wholesale rates applicable to TNP for the term of this agreement shall be designed in a manner mutually agreeable and shall not produce annual revenues to HL&P in any year which are in excess of 99% of TNP's projected total cost (fixed, variable O&M, and fuel) of its Robertson County Units One-Four as stated in TPUC Docket No. 6992.

In determining revenue requirement and subsequent rates applicable to TNP for wholesale firm service, HL&P agrees that the relative rate of return applicable to TNP will not exceed 1.0 nor will any rate increase applicable to TNP exceed either, a) the system average percent rate increase or, b) the percent rate increase request applicable to any other class of customer.

If rates applicable to TNP as determined in the immediate two preceding paragraphs produce annual revenues to HL&P in any calendar year that are in excess of revenues which would have been produced had rates been applied based upon the weighted average cost per KW of billing demand and per KWH of energy, from TNP's other Texas suppliers from which it purchases wholesale firm service, HL&P agrees to apply such rates as determined herein in lieu of rates as determined in the immediate two preceding paragraphs. The rates so determined in this section shall be applied retroactively to the beginning of the calendar year in which the determination was made. Such calculations and determinations shall be made and applicable annually during the term of this agreement.

5. Term of Agreement. The term of this agreement will be for 30 years from ____________________. Unless written notice is given by either party hereto to the other not less than three years before expiration of

Exhibit ______

Schedule (DJL-4)

Page 1 of 4

Voluminous Response
Cities

DOCKET NO. 6992
Exhibit RO-16
Page 1 of 40

Texas-New Mexico
Power Company

P.O. Box 2943
Fort Worth, Texas 76113
(817) 731-0099

February 28, 1986

▼ADDRESS▼

Dear ▼NAME▼:

Texas-New Mexico Power Company (TNP) is currently evaluating its alternatives with regard to future power supply requirements in the state of Texas. Two of TNP's major contracts for the supply of wholesale power to TNP expire in the early 1990s. Those two contracts are with Texas Utilities Electric Company (TUEC), serving our Northeast and Central Divisions, and portions of our Western Division; and with Houston Lighting & Power Company (HL&P), serving our Southeast Division.

One of the areas of assessment is the possibility of continued purchase of power from other generating utilities. Two other alternatives available to TNP are the purchase of cogenerated power, and TNP ownership in its own generating facility. Currently TNP purchases approximately 300 megawatts of cogenerated power for delivery to its Southeast Division. In addition, TNP has proposed the construction of 4-150 megawatt generating units to be built in Robertson County, Texas. To complete the evaluation of all of TNP's alternatives, each must be weighed in consideration of its economic, reliability, flexibility, and availability attributes. Therefore, to this end, TNP is requesting proposals from other utilities to supply wholesale power to TNP at two points of delivery in Texas. In order that all proposals be comparable, TNP is asking that the proposals be in a form to be compared to the generating units that TNP is currently proposing.

In general, the specifications for delivery to TNP are noted below.

1. Deliveries of firm purchased power are to be priced for the following amounts of power delivered to two points of service: a) Lewisville, Texas (currently served in the TUEC service area); and b) Texas City, Texas (served in the HL&P service area).

2. For each of the points of delivery, the cumulative amounts of firm power are to be given for each of the Lewisville and Texas City delivery points, up to a maximum of 600 MW as follows::

   a. 150 megawatts - 1990
   b. 300 megawatts - 1991
   c. 450 megawatts - 1992
   d. 600 megawatts - 1993

Attachment Cities 11
Question 11
Page 1 of 375

OPCPOD4-15-007568

February 28, 1986
Page #2

TNP is therefore soliciting eight (8) separate proposals as described above, each to be a non-binding proposal on the behalf of your utility but merely to serve as an aid in the evaluation of alternatives.

3. The term for each delivery shall be for forty-one (41) years beginning in 1990.

4. Each point of delivery as described above shall be planned on the basis of a single contingency outage. Therefore, should there be any failure of the primary method of delivery, a secondary method of delivery shall be substituted.

This general list is to be by no means all-inclusive but does give the basis of the need for deliveries to the TNP service areas. In addition to the above, TNP would request the following information for the further evaluation of each proposal.

1. Each projected cost as described above shall include the assumptions dealing with:

   a. fuel cost and the utilities anticipated fuel mix by year;

   b. the most recent capacity, demand, reserve planning criteria used by your utility;

   c. anticipated regulatory treatment of the proposals included in your answer;

   d. the estimated wheeling cost necessary if any to transfer the power from your system to the TNP system;

   e. anticipated escalation factors for each specific item of costing.

2. General terms and conditions expected for a contract with TNP.

3. Your utility's treatment of cogeneration purchases by TNP throughout the term of the contract.

4. A copy of your current wholesale tariff if any.

5. A copy of your annual report and/or a map of your service area.

6. A brief description of your current interconnection with other utilities and the proposed method of transmission/wheeling to TNP's points of delivery.

TNP does realize the amount of effort necessary to make such a proposal. Obviously there are a great number of questions that will arise as you evaluate any anticipated proposals. As an aid in your deliberations, TNP has furnished the following information for your use.

1. Ten-Year Load Forecast

2. A brief description of the current supply arrangements with other utilities throughout the State of Texas, and a description of the TNP system itself.

3. A map of the TNP service areas.

4. TNP's current estimate of avoided cost projections utilizing the Robertson County proposed generating plant as its proxy unit.

TNP also realizes that because of the saturation technique being used by TNP in its solicitation of proposals, a great number of these letters have been issued to utilities with no such provisions for providing power to another utility. Should this be the case, please accept my apology, but I would still request a written response to this solicitation even though you may be incapable of providing such power. Please feel free to forward this letter to the person responsible for such activities in your organization. However, should you have some desire in offering a proposal to TNP, we are requesting that all responses be received no later than April 14, 1986. Realizing that TNP has a schedule restriction for its proposed generating facility, should this date be unacceptable, please advise TNP in writing as to when a proposal will be forthcoming.

TNP will use a two-phase evaluation of all proposals received. The first phase will be an evaluation primarily of the economic acceptability of your proposals as compared to other alternatives available to TNP. These alternatives would include cogeneration and TNP-owned generation. The target for completion of this phase 1 is by April 21, 1986. All offers from phase 1 that are acceptable from an economic standpoint will move forward into phase 2 for further consideration with regard to reliability and contingencies. During phase 2, TNP would anticipate several meetings with utilities making favorable proposals and an estimated target for completion of Phase 2 evaluation by May 5, 1986. At this point, one of the major considerations to be reviewed by TNP would be the jurisdictional aspects and interconnections between utilities should wheeling be a major issue. From this point, TNP would expect final evaluation and negotiations for power supply agreements while not thoroughly complete, to be in a form acceptable to both Parties no later than June 30, 1986.

February 28, 1986
Page #4

Finally, TNP is looking forward to any responses that may be forthcoming. Obviously, if you have any questions or require any further information, please don't hesitate to contact me.

Sincerely,

Rickey J. Wright

RICKEY J. WRIGHT
Manager, Power Resources

RJW:bb

cc: R. D. Woofter
J. M. Tarpley
M. G. Shirley

Exhibit ________

Schedule (DJL-5)

MEMORANDUM

DATE: April 15, 1986

TO: J. M. Tarpley
J. V. Chambers
R. J. Wright
M. G. Shirley

FROM: T. R. Ownby

CONTRACTS & REGULATION DEPT.
CENTRAL FILE
DATE 4-21-86
FILE CCN - Filing

As a result of the solicitations of some 350 utilities, we have one response that may merit some serious consideration. I have in hand a proposal from the Rockdale Power Project (see attachment) that could cause some problems in our CCN filing. Although as you will note in the proposal, they are initially only offering 38 MW of power, they are suggesting various alternative arragements that could entail a great deal of work in analyzing.

I don't consider their proposal a serious problem, but to be safe I am suggesting that we discuss before making any response to them.

[signature]

TRO/tjl

TNP/PRG 0024

CALCULATION OF TNP OVER-RECOVERY OF CARRYING COST ASSOCIATED WITH RATE BASE TREATMENT OF TNP ONE FACILITIES OWNED BY TGC

The purpose of this schedule is to demonstrate how TNP over-collects revenue requirements from ratepayers by including TNP ONE in TNP's requested rate base. This over-collection is shown with two different assumptions.

CALCULATION I

In this calculation, it is assumed that TNP's requested ROR of 11.11 percent wiold not change whether or not TNP ONE facilities are included in rate base.

TNP Requested Rate Base	$575,931,548	See Schedule B
TNP Requested Rate of Return	11.11%	See Schedule F
TNP Requested Return	$63,985,995	See Schedule F
TNP Requested FIT	13,706,769	See Schedule G
Total Requested Return & FIT	$77,692,764	See Schedule A

Now, given that the TNP ONE facilities investment is about $335 million and TGC owns these facititles and is responsible for a 10 percent carrying cost, if one develops a cost of service assuming the TNP ONE facilities are held not in TNP's rate base but rather by TGC - and a 10 percent carrying cost is paid by TNP to TGC rather than including the plant in TNP's rte base the following is the result.

Description	TGC	TNP	Total
Rate Base	$335,000,000	$240,931,548	$575,931,548
Carrying Cost	10.00%	11.11%	NA
Return	$33,500,000	$26,767,495	$60,267,495
FIT	NA	4,939,921	4,939,921
Total	$33,500,000	$31,707,416	$65,207,416

Calculation of FIT in the previous table is based on the same methodology shown in Schedule G 7.8 of the rate filing package. The items which change are return, interest synchronization and total FIT liability.

FIT Calculation

(a)	Return	$26,767,495
(b)	Interest	(14,528,172)
(c)	Other Items	(679,617)
(d)	Subtotal	$11,559,706
(e)	Tax Factor	0.515152
		$5,955,000
(f)	Other Items	(1,015,079)
(g)	Total FIT	$4,939,921

Thus, when TGC's carrying costs are recognized separately as they should be at a 10 percent carrying cost, the resulting return and taxes are $65,207,416 versus the Company's requested $77,692,767. This implies that TNP's affiliate transaction with TGC is resulting in a ratepayer overcharge of $12,485,351.

CALCULATION II

It could be argued by TNP that the capital structure and overall return would be different if TGC was treated as an affiliate as it should be in this case. Thus, I have gone through the same calculation assuming the necessary adjustments (ie) removing short-term debt from TNP's capital structure. The following is the result of this alternative calculation.

Description	TGC	TNP	Total
Rate Base	$335,000,000	$240,931,548	$575,931,548
Carrying Cost	10.00%	11.40%	NA
Return	$33,500,000	$27,466,196	$60,966,196
FIT	NA	7,682,898	7,682,898
Total	$33,500,000	$35,149,094	$68,649,094

CALCULATION OF TNP OVER-RECOVERY OF CARRYING COST ASSOCIATED WITH RATE BASE TREATMENT OF TNP ONE FACILITIES OWNED BY TGC

Thus under the most conservative example, the return and tax requirement is $68,649,094 rather than TNP's requested $77,692,764, thus implying a $9,043,670 adjustment.

FIT Calculation

Return	$27,466,196
Interest	(9,902,287)
Other Items	(679,617)
Subtotal	$16,884,292
Tax Factor	0.515152
	$8,697,977
Other Items	(1,015,079)
Total FIT	$7,682,898

Plant Disallowance
$0
****

Exhibit _____
Schedule (DJL-7)
Page 1 of 4

1990 Model
Life Cycle Impact of 2-Unit

Year Ending 12/31	Avoided Purchased Power	2-Unit Revenue Reqmt.	Savings	Present Value Rate 11.00% Annual	Cummulative
	(000s)	(000s)	(000s)	(000s)	(000s)
1989	$0	$0	$0	$0	$0
1990	21,176	51,032	(29,856)	(29,856)	(29,856)
1991	56,881	133,425	(76,544)	(68,959)	(98,814)
1992	81,534	173,889	(92,355)	(74,958)	(173,772)
1993	90,067	174,099	(84,032)	(61,444)	(235,216)
1994	96,641	174,639	(77,998)	(51,380)	(286,595)
1995	92,404	173,575	(81,171)	(48,171)	(334,766)
1996	96,792	173,982	(77,190)	(41,269)	(376,035)
1997	107,821	175,847	(68,026)	(32,765)	(408,800)
1998	117,377	177,313	(59,936)	(26,008)	(434,808)
1999	124,756	179,116	(54,360)	(21,251)	(456,059)
2000	131,989	179,695	(47,706)	(16,801)	(472,860)
2001	142,021	181,005	(38,984)	(12,369)	(485,229)
2002	157,557	184,613	(27,056)	(7,734)	(492,963)
2003	171,596	187,483	(15,887)	(4,091)	(497,054)
2004	186,904	190,758	(3,854)	(894)	(497,948)
2005	203,478	194,598	8,879	1,856	(496,093)
2006	217,667	198,069	19,598	3,690	(492,402)
2007	237,049	203,192	33,857	5,743	(486,659)
2008	262,858	210,537	52,320	7,996	(478,663)
2009	286,157	216,458	69,699	9,596	(469,067)
2010	311,647	222,950	88,697	11,001	(458,066)
2011	339,204	230,127	109,078	12,189	(445,877)
2012	358,178	235,227	122,951	12,377	(433,500)
2013	383,076	241,384	141,692	12,850	(420,650)
2014	422,163	251,829	170,334	13,917	(406,733)
2015	459,180	261,541	197,639	14,548	(392,185)
2016	499,280	272,221	227,059	15,057	(377,128)
2017	543,878	282,874	261,003	15,593	(361,535)
2018	592,034	294,654	297,380	16,005	(345,529)
2019	636,522	305,168	331,354	16,067	(329,463)
2020	692,056	318,805	373,251	16,305	(313,158)
2021	763,565	334,477	429,088	16,886	(296,272)
2022	830,965	349,280	481,685	17,078	(279,194)
2023	904,184	365,077	539,107	17,219	(261,975)
2024	983,329	382,459	600,870	17,290	(244,685)
2025	1,071,570	399,587	671,983	17,420	(227,264)
2026	1,152,499	415,580	736,919	17,210	(210,054)
2027	1,255,054	435,483	819,572	17,244	(192,810)
2028	971,442	311,301	660,141	12,513	(180,297)
2029	287,114	97,568	189,546	3,237	(177,060)

Plant Disallowance
$136,317,000
****

Exhibit ______
Schedule (DJL-7)

1990 Model
Life Cycle Impact of 2-Unit

Year Ending 12/31	Avoided Purchased Power	2-Unit Revenue Reqmt.	Savings	Present Value Rate 11.00% Annual	Cummulative
	(000s)	(000s)	(000s)	(000s)	(000s)
1989	$0	$0	$0	$0	$0
1990	21,176	40,004	(18,828)	(18,828)	(18,828)
1991	56,881	111,616	(54,735)	(49,311)	(68,139)
1992	81,534	151,234	(69,700)	(56,570)	(124,709)
1993	90,067	151,973	(61,906)	(45,265)	(169,974)
1994	96,641	153,043	(56,402)	(37,154)	(207,127)
1995	92,404	152,508	(60,104)	(35,669)	(242,796)
1996	96,792	153,445	(56,653)	(30,289)	(273,085)
1997	107,821	155,840	(48,019)	(23,129)	(296,214)
1998	117,377	157,836	(40,458)	(17,556)	(313,770)
1999	124,756	160,169	(35,413)	(13,844)	(327,614)
2000	131,989	161,277	(29,288)	(10,315)	(337,929)
2001	142,021	163,117	(21,095)	(6,693)	(344,622)
2002	157,557	167,254	(9,697)	(2,772)	(347,394)
2003	171,596	170,654	942	243	(347,151)
2004	186,904	174,459	12,445	2,887	(344,264)
2005	203,478	178,829	24,649	5,152	(339,112)
2006	217,667	182,829	34,838	6,560	(332,552)
2007	237,049	188,481	48,568	8,239	(324,314)
2008	262,858	196,357	66,501	10,163	(314,151)
2009	286,157	202,807	83,350	11,475	(302,675)
2010	311,647	209,829	101,818	12,629	(290,047)
2011	339,204	217,535	121,669	13,596	(276,451)
2012	358,178	223,165	135,013	13,592	(262,859)
2013	383,076	229,852	153,225	13,896	(248,963)
2014	422,163	240,826	181,337	14,816	(234,147)
2015	459,180	251,068	208,112	15,319	(218,828)
2016	499,280	262,277	237,002	15,716	(203,112)
2017	543,878	273,460	270,417	16,155	(186,956)
2018	592,034	285,770	306,264	16,484	(170,473)
2019	636,522	296,814	339,708	16,472	(154,001)
2020	692,056	310,980	381,076	16,646	(137,355)
2021	763,565	327,182	436,383	17,173	(120,181)
2022	830,965	342,515	488,451	17,318	(102,864)
2023	904,184	358,841	545,342	17,419	(85,445)
2024	983,329	376,753	606,576	17,454	(67,991)
2025	1,071,570	394,411	677,160	17,554	(50,436)
2026	1,152,499	410,933	741,565	17,319	(33,117)
2027	1,255,054	431,366	823,689	17,331	(15,787)
2028	971,442	309,375	662,067	12,550	(3,237)
2029	287,114	97,568	189,546	3,237	(0)

Plant Disallowance
$0
****

Exhibit ______
Schedule (DJL-7)

1990 Model
Life Cycle Impact of 2-Unit

Year Ending 12/31	Avoided Purchased Power	2-Unit Revenue Reqmt.	Savings	Present Value Rate 13.00% Annual	Cummulative
	(000s)	(000s)	(000s)	(000s)	(000s)
1989	$0	$0	$0	$0	$0
1990	21,176	51,032	(29,856)	(29,856)	(29,856)
1991	56,881	133,425	(76,544)	(67,738)	(97,594)
1992	81,534	173,889	(92,355)	(72,328)	(169,922)
1993	90,067	174,099	(84,032)	(58,238)	(228,160)
1994	96,641	174,639	(77,998)	(47,838)	(275,998)
1995	92,404	173,575	(81,171)	(44,056)	(320,054)
1996	96,792	173,982	(77,190)	(37,076)	(357,130)
1997	107,821	175,847	(68,026)	(28,915)	(386,045)
1998	117,377	177,313	(59,936)	(22,545)	(408,590)
1999	124,756	179,116	(54,360)	(18,096)	(426,686)
2000	131,989	179,695	(47,706)	(14,054)	(440,740)
2001	142,021	181,005	(38,984)	(10,163)	(450,903)
2002	157,557	184,613	(27,056)	(6,242)	(457,145)
2003	171,596	187,483	(15,887)	(3,244)	(460,388)
2004	186,904	190,758	(3,854)	(696)	(461,085)
2005	203,478	194,598	8,879	1,420	(459,665)
2006	217,667	198,069	19,598	2,773	(456,892)
2007	237,049	203,192	33,857	4,240	(452,653)
2008	262,858	210,537	52,320	5,798	(446,855)
2009	286,157	216,458	69,699	6,835	(440,020)
2010	311,647	222,950	88,697	7,697	(432,323)
2011	339,204	230,127	109,078	8,377	(423,946)
2012	358,178	235,227	122,951	8,356	(415,589)
2013	383,076	241,384	141,692	8,522	(407,067)
2014	422,163	251,829	170,334	9,066	(398,001)
2015	459,180	261,541	197,639	9,309	(388,692)
2016	499,280	272,221	227,059	9,465	(379,228)
2017	543,878	282,874	261,003	9,628	(369,600)
2018	592,034	294,654	297,380	9,708	(359,892)
2019	636,522	305,168	331,354	9,572	(350,320)
2020	692,056	318,805	373,251	9,542	(340,778)
2021	763,565	334,477	429,088	9,708	(331,070)
2022	830,965	349,280	481,685	9,644	(321,426)
2023	904,184	365,077	539,107	9,552	(311,874)
2024	983,329	382,459	600,870	9,421	(302,453)
2025	1,071,570	399,587	671,983	9,324	(293,129)
2026	1,152,499	415,580	736,919	9,049	(284,080)
2027	1,255,054	435,483	819,572	8,906	(275,174)
2028	971,442	311,301	660,141	6,348	(268,825)
2029	287,114	97,568	189,546	1,613	(267,212)

Plant Disallowance
$232,194,000
****

Exhibit ______
Schedule (DJL-7)

1990 Model
Life Cycle Impact of 2-Unit

Year Ending 12/31	Avoided Purchased Power	2-Unit Revenue Reqmt.	Savings	Present Value Rate 13.00% Annual	Cummulative
	(000s)	(000s)	(000s)	(000s)	(000s)
1989	$0	$0	$0	$0	$0
1990	21,176	32,248	(11,072)	(11,072)	(11,072)
1991	56,881	96,277	(39,395)	(34,863)	(45,935)
1992	81,534	135,299	(53,765)	(42,106)	(88,041)
1993	90,067	136,411	(46,344)	(32,119)	(120,160)
1994	96,641	137,853	(41,212)	(25,276)	(145,436)
1995	92,404	137,691	(45,287)	(24,580)	(170,017)
1996	96,792	139,000	(42,208)	(20,273)	(190,290)
1997	107,821	141,768	(33,947)	(14,430)	(204,720)
1998	117,377	144,136	(26,759)	(10,066)	(214,785)
1999	124,756	146,842	(22,086)	(7,352)	(222,137)
2000	131,989	148,323	(16,334)	(4,812)	(226,949)
2001	142,021	150,535	(8,514)	(2,220)	(229,169)
2002	157,557	155,045	2,512	580	(228,589)
2003	171,596	158,817	12,779	2,609	(225,980)
2004	186,904	162,995	23,909	4,320	(221,661)
2005	203,478	167,737	35,741	5,715	(215,946)
2006	217,667	172,110	45,557	6,446	(209,500)
2007	237,049	178,135	58,914	7,377	(202,123)
2008	262,858	186,383	76,475	8,474	(193,648)
2009	286,157	193,205	92,952	9,115	(184,533)
2010	311,647	200,600	111,047	9,637	(174,896)
2011	339,204	208,679	130,526	10,024	(164,872)
2012	358,178	214,681	143,497	9,753	(155,119)
2013	383,076	221,741	161,336	9,703	(145,416)
2014	422,163	233,088	189,075	10,064	(135,352)
2015	459,180	243,702	215,478	10,149	(125,203)
2016	499,280	255,284	243,996	10,171	(115,032)
2017	543,878	266,839	277,038	10,219	(104,813)
2018	592,034	279,521	312,512	10,202	(94,612)
2019	636,522	290,938	345,584	9,983	(84,628)
2020	692,056	305,477	386,579	9,883	(74,745)
2021	763,565	322,051	441,514	9,989	(64,756)
2022	830,965	337,756	493,209	9,875	(54,882)
2023	904,184	354,456	549,728	9,740	(45,142)
2024	983,329	372,739	610,590	9,574	(35,568)
2025	1,071,570	390,770	680,800	9,447	(26,121)
2026	1,152,499	407,665	744,834	9,146	(16,975)
2027	1,255,054	428,470	826,584	8,982	(7,993)
2028	971,442	308,020	663,421	6,380	(1,613)
2029	287,114	97,568	189,546	1,613	(0)

Exhibit ________

Schedule (DJL-8)

Attachment TIEC 1st
Question 27E5C
Page 1 of 1

TIEC 1ST RFI
DOCKET NO. 9491
QUESTION 27(e)(5)(c)

TEXAS-NEW MEXICO POWER COMPANY
NET GENERATION BY YEAR USED IN DOCKET NO. 6992: DECEMBER, 1986

	UNIT 1			UNIT 2			UNIT 3			UNIT 4		
	Established Availblty Factor	Net Capacity (MW)	Net Energy (MWh)	Established Availblty Factor	Net Capacity (MW)	Net Energy (MWh)	Established Availblty Factor	Net Capacity (MW)	Net Energy (MWh)	Established Availblty Factor	Net Capacity (MW)	Net Energy (MWh)
1990	0.90	147.039	680,519									
1991	0.88	147.039	1,131,517	0.90	147.435	682,353						
1992	0.91	147.039	1,175,346	0.88	147.435	1,141,360	0.90	147.229	681,399			
1993	0.92	147.039	1,185,015	0.91	147.435	1,175,293	0.89	147.229	1,143,157	0.90	147.435	682,353
1994	0.92	147.039	1,185,015	0.92	147.435	1,188,208	0.91	147.229	1,176,866	0.96	147.435	1,243,267
1995	0.87	147.039	1,120,612	0.92	147.435	1,188,208	0.92	147.229	1,186,548	0.91	147.435	1,175,293
1996	0.90	147.039	1,162,430	0.87	147.435	1,126,710	0.92	147.229	1,186,548	0.92	147.435	1,188,208
1997	0.90	147.039	1,159,254	0.90	147.435	1,162,378	0.87	147.229	1,122,062	0.92	147.435	1,188,208
1998	0.90	147.039	1,159,254	0.90	147.435	1,162,378	0.90	147.229	1,163,934	0.87	147.435	1,126,710
1999	0.90	147.039	1,159,254	0.90	147.435	1,162,378	0.90	147.229	1,160,754	0.90	147.435	1,162,378
2000	0.85	147.039	1,097,851	0.90	147.435	1,165,562	0.90	147.229	1,160,754	0.90	147.435	1,162,378
2001	0.88	147.039	1,133,493	0.85	147.435	1,097,801	0.90	147.229	1,160,754	0.90	147.435	1,162,378
2002	0.88	147.039	1,133,493	0.88	147.435	1,136,547	0.85	147.229	1,099,271	0.90	147.435	1,165,562
2003	0.88	147.039	1,133,493	0.88	147.435	1,136,547	0.88	147.229	1,134,959	0.85	147.435	1,097,801
2004	0.88	147.039	1,136,598	0.88	147.435	1,139,661	0.88	147.229	1,134,959	0.88	147.435	1,136,547
2005	0.88	147.039	1,133,493	0.88	147.435	1,136,547	0.88	147.229	1,134,959	0.88	147.435	1,136,547
2006	0.85	147.039	1,094,851	0.88	147.435	1,136,547	0.88	147.229	1,138,069	0.88	147.435	1,139,661
2007	0.88	147.039	1,133,493	0.85	147.435	1,097,801	0.88	147.229	1,134,959	0.88	147.435	1,136,547
2008	0.88	147.039	1,136,598	0.88	147.435	1,139,661	0.85	147.229	1,096,267	0.88	147.435	1,136,547
2009	0.88	147.039	1,133,493	0.88	147.435	1,136,547	0.88	147.229	1,134,959	0.85	147.435	1,097,801
2010	0.88	147.039	1,133,493	0.88	147.435	1,136,547	0.88	147.229	1,138,069	0.88	147.435	1,139,661
2011	0.88	147.039	1,133,493	0.88	147.435	1,136,547	0.88	147.229	1,134,959	0.88	147.435	1,136,547
2012	0.83	147.039	1,072,019	0.88	147.435	1,139,661	0.88	147.229	1,134,959	0.88	147.435	1,136,547
2013	0.85	147.039	1,094,851	0.83	147.435	1,071,971	0.88	147.229	1,134,959	0.88	147.435	1,136,547
2014	0.85	147.039	1,094,851	0.85	147.435	1,097,801	0.83	147.229	1,073,406	0.88	147.435	1,139,661
2015	0.85	147.039	1,094,851	0.85	147.435	1,097,801	0.85	147.229	1,096,267	0.83	147.435	1,071,971
2016	0.85	147.039	1,097,851	0.85	147.435	1,100,809	0.85	147.229	1,096,267	0.85	147.435	1,097,801
2017	0.85	147.039	1,094,851	0.85	147.435	1,097,801	0.85	147.229	1,096,267	0.85	147.435	1,097,801
2018	0.85	147.039	1,094,851	0.85	147.435	1,097,801	0.85	147.229	1,099,271	0.85	147.435	1,100,809
2019	0.83	147.039	1,069,090	0.85	147.435	1,097,801	0.85	147.229	1,096,267	0.85	147.435	1,097,801
2020	0.85	147.039	1,097,851	0.83	147.435	1,074,908	0.85	147.229	1,096,267	0.85	147.435	1,097,801
2021	0.85	147.039	1,094,851	0.85	147.435	1,097,801	0.83	147.229	1,070,473	0.85	147.435	1,097,801
2022	0.85	147.039	1,094,851	0.85	147.435	1,097,801	0.85	147.229	1,099,271	0.83	147.435	1,074,908
2023	0.85	147.039	1,094,851	0.85	147.435	1,097,801	0.85	147.229	1,096,267	0.85	147.435	1,097,801
2024	0.85	147.039	1,097,851	0.85	147.435	1,100,809	0.85	147.229	1,096,267	0.85	147.435	1,097,801
2025	0.85	147.039	1,094,851	0.85	147.435	1,097,801	0.85	147.229	1,096,267	0.85	147.435	1,097,801
2026	0.83	147.039	1,069,090	0.85	147.435	1,097,801	0.85	147.229	1,099,271	0.85	147.435	1,100,809
2027	0.85	147.039	1,094,851	0.83	147.435	1,071,971	0.85	147.229	1,096,267	0.85	147.435	1,097,801
2028	0.85	147.039	1,097,851	0.85	147.435	1,100,809	0.83	147.229	1,070,473	0.85	147.435	1,097,801
2029				0.85	147.435	1,097,801	0.85	147.229	1,096,267	0.83	147.435	1,071,971
2030							0.85	147.229	1,099,271	0.85	147.435	1,100,809
2031										0.85	147.435	1,097,801