NM PSC 1794

BEFORE THE NEW MEXICO PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF THE PUBLIC SERVICE COMPANY OF NEW MEXICO FOR A CERTIFICATE OF CONVENIENCE AND NECESSITY TO CONSTRUCT AND MAINTAIN A 345 KV TRANSMISSION LINE, ASSOCIATED SWITCHING EQUIPMENT AND DC CONVERTING FACILITIES, PURSUANT TO AN INTERCONNECTION AGREEMENT WITH SOUTHWESTERN PUBLIC SERVICE COMPANY; FOR CERTAIN RATE TREATMENT FOR THE TRANSMISSION LINE AND FOR THE "INVENTORIED CAPACITY" USED FOR ENERGY SALES UNDER THE SERVICE SCHEDULE D TO THE INTERCONNECTION AGREEMENT.

CASE NO. 1794

PRE-FILED TESTIMONY OF PAUL CHERNICK

Q: Please state your name, occupation, and business address.

A: My name is Paul Chernick. I am employed as a Research Associate by Analysis and Inference, Inc., 10 Post Office Square, Suite 970, Boston, Massachusetts.

Q: Mr. Chernick, please briefly summarize your professional education and experience.

Q: I received a S.B. degree from the Civil Engineering Department of the Massachusetts Institute of Technology in June, 1974, and a S.M. degree from the Massachusetts Institute of Technology in February, 1978, in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, the engineering honorary society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

During my graduate education, I was the teaching assistant for courses in systems analysis, including such topics as cost-benefit analysis and optimization. I served as a consultant to the National Consumer Law Center on two projects: teaching part of a short course in rate design and assisting in preparation for an electric time-of-use rate case. I was a Utility Analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and evaluation of power supply options.

In my current position, I have advised a variety of clients on utility matters. My resume is attached to this testimony as Appendix A.

Q: Mr. Chernick, have you testified previously in utility proceedings?

A: Yes. I have testified approximately twenty times on utility issues before such agencies as the Massachusetts Energy Facilities Siting Council, the Atomic Safety and Licensing Board of the Nuclear Regulatory Commission, the Illinois Commerce Commission, the Massachusetts Department of Public Utilities, the District of Columbia Public Service Commission, the Texas Public Utilities Commission, and the New Hampshire Public Utilities Commission. A detailed list of my previous testimony is contained in my resume. Subjects I have testified on include cost allocation, rate design, long range energy and demand forecasts, the costs of nuclear power, the cost and effectiveness of conservation, ratemaking for conservation programs, fuel efficiency standards, generation system reliability, capacity planning, and benefit-cost analysis.

Q: What is the purpose of your testimony?

A: I have been asked to review PNM's filing in this case and to determine whether the proposed Eastern Interconnection Project (EIP) appears to be in the public interest. Specifically, I have attempted to evaluate the economic impact on ratepayers; particularly those of PNM, but also those of SPS.

Q: What were your expectations when you started that review?

A: I really expected that there would be considerable advantages from economy exchanges between PNM and SPS, or indeed between almost any two members of largely isolated power pools. I expected PNM to present an analysis which demonstrated such benefits, and ratemaking proposals which would insure that the sponsor of the interconnection would be adequately repaid for the investment from the total benefits to the interconnected utilities. I foresaw the possibility of questions regarding PNM's assumptions and modeling, and regarding its proposals for retail ratemaking. It also seemed possible that the length of the line, the necessity for DC conversion, and the similarity of the resource mix on the two systems, might result in costs which outweighed the benefits of the line.

Q: What are the results of your review?

A: Strangely enough, PNM's analysis does not attempt to quantify the total benefits of the interconnection, or even to show that there are sufficient real benefits to justify the line. Instead, PNM makes some assumptions about the rates to be paid for firm power, and produces an analysis which purports to demonstrate the economic advantages of the EIP to its firm customers. I have identified six problems in that analysis or in PNM's documentation of its claims (it is sometimes difficult to determine whether it is the analysis or the documentation which is at fault):

1. The proposed treatment of the Schedule D sale to SPS does not fully cover the cost of the new transmission line, contrary to PNM's assertions.

2. It is not clear that sales of energy at less than PNM's marginal cost are prohibited under Schedule D. Such sales may be advantageous to SPS and to PNM shareholders, but disadvantageous to PNM customers.

3. The cost-effectiveness of the EIP (particularly under Schedule C) for PNM customers is dependent on some projections which are questionable or not well documented, including:

   a. PNM's load forecast
   b. the price for SPS' sales, relative to PNM's marginal running costs
   c. the cost of building the EIP

4. PNM incorrectly uses its own discount rates to discount costs its <u>customers</u> must pay; customer discount rates are probably higher, and their net present value from the same revenue stream is thus probably lower than that for PNM.

5. PNM fails to recognize the value of NMGS beyond the end of its analysis period: this biases the analysis towards EIP by overstating the cost of NMGS.

6. PNM has not provided any evidence that Schedule C will be advantageous to SPS or its customers, and thus that it will be desirable for SPS's New Mexico customers, or acceptable to SPS's other regulators.

I will discuss each of these problems in turn.

Q: What are your recommendations to the Commission regarding PNM's petition in this proceeding?

A: I have three basic recommendations:

1. The Commission should certainly revise and clarify the proposed ratemaking treatment for Schedule D, to prevent ratepayer subsidies to shareholders and to prevent PNM from selling power below cost.

2. The Commission should require PNM to correct the identifiable errors in its cost-benefit analysis, to substantially improve the documentation of several of its critical assumptions and of the sensitivity of savings to the uncertainties, and to submit the revised savings estimates, prior to committing ratepayers to pay for any fixed portion of the EIP.

3. If the Commission wishes to allow PNM to proceed with the line prior to adjudication of all the cost issues, it should indicate that PNM is proceeding at its own financial risk with regard to the errors, undocumented assumptions and uncertainties.

Q: Please explain why PNM's proposal for a transmission credit to firm customers does not cover the cost of the EIP during the duration of Schedule D.

A: PNM's proposal is explained on pp. 8-9 of Mr. Brenner's testimony and in his Exhibit GLB-1. This approach takes the entire cost of the PNM transmission system, including EIP, and divides it among all users of the transmission system. Thus, firm customers would pay for most of the cost of EIP, since they represent most of the load on the transmission system. If EIP is considered to serve only the shareholders during the term of Schedule D, then the shareholders should pay all the costs of EIP during this period. In addition, since Schedule D will also require the use of a portion of the existing transmission network, the credit should include a portion of those facilities, as well.

Also, EIP will be financed at PNM's incremental cost of capital, which PNM estimates at 14.1%, rather than the embedded rate of 11.72% used in Exh. GLB-1. PNM's approach would subsidize the shareholders' transmission line, by forcing the ratepayers to share existing low-cost financing with the shareholders. (A similar error appears in Exhibits CDB-11 and CDB-13; the carrying costs of EIP, and possibly NMGS, are understated by the used of embedded costs of capital.) Table 1 corrects the computation of the transmission credit so that it covers the full cost of the EIP, at PNM's incremental cost of capital, given PNM's other assumptions.

PNM not only places some of the cost of the EIP on the ratepayers, by specifying a fixed monthly credit it also would leave the ratepayers with all the risks of the earlier completion date: construction costs, O&M costs, financing costs, and utilization. For example, delays in EIP service, delays in Palo Verde operation, and low Palo Verde availability may reduce the period of Schedule D, and increase the resulting cost to ratepayers.

Finally, PNM has not clarified who will pay for the EIP between the end of the Schedule D sale (12/31/89 or 5/31/90, at SPS's option) and the beginning of the Schedule C purchase (6/1/91). If the line is moved forward in time for the benefit of the shareholders, it is hardly fair to expect the ratepayers to carry the line for this 12 or 18 month elipsis with no compensation. This is particularly true if the ratepayers are bearing the risks of delayed operation: the carrying charges in the elipsis may actually outweigh the advantages of avoided inflation and prepaid depreciation which make the earlier inservice date appealing in PNM's projections. The carrying costs of the EIP during the elipsis are calculated in Table 2.

Q: Are there any ways in which PNM's analysis understates the benefits to ratepayers of moving forward the in-service date of the EIP?

A: There may be some reliability and economy-transaction benefits for the firm customers during the period 1/1/85 to 5/31/91; PNM has not attempted to quantify such benefits. Also, the ability to sell inventoried capacity may reduce the cost of capital; unless the Commission believes that it can isolate the ratepayers from this indirect effect of excess capacity, it may wish to consider sales of inventoried capacity to be of some value to firm customers.

Q: What actions should the Commission take with respect to the ratemaking for the EIP?

A: First, the Commission should change the terms of the Schedule D transmission credit so that the shareholders pay the full cost of the line while it is primarily serving them. This can be accomplished by revising the computation of the transmission credit, so that it covers the full cost of the EIP at the incremental cost of capital, and by defining it in terms of actual costs, rather than a projected fee. Alternatively, these costs can be placed on the shareholders by taking the EIP out of rates until it is used and useful for firm customers. The latter alternative is somewhat similar to the inventorying of generation capacity, but with some important modifications. For example, it would be inappropriate to include any provision for AFUDC in the post-operation period, since the line is being moved forward in time for the benefit of shareholders, not ratepayers, and since the economic analyses PNM presents to justify this acceleration exclude such AFUDC. On the other hand, so long as stockholders are paying the carrying costs and depreciation on the EIP, it seems fair to allow them to retain any savings the "inventoried" line affords to ratepayers. In any case, it seems appropriate to guarantee that the line, when it becomes used and useful, will not cost the customers more than it would have cost if it had been completed on that date (e.g., the actual cost plus inflation to the start of Schedule C).

Second, the Commission must decide who will pay for the EIP during the elipsis. If the shareholders are to pay, PNM may wish to reconsider its decision to speed up the project. If the customers are to pay, PNM's analyses in this case must be modified to reflect the dead loss of the carrying charges during the elipsis, and the guarantee discussed previously becomes much more important.

Q: What is your concern regarding sales of energy at less than PNM's marginal cost under Schedule D?

A: Schedule D allows PNM to discontinue sales on a day's notice if the power would be provided from oil or gas. Since the rates under Schedule D will easily cover the running costs of coal and nuclear plants, PNM will not be forced to sell much power below its running costs. Nonetheless, there is the possibility that PNM would be required to generate power from oil or gas (especially at peak periods) and sell it to SPS below cost, backing off less expensive SPS generation. This problem can be solved by amending Schedule D to allow PNM to buy surplus SPS power at cost to meet its delivery requirements.

A more serious problem lies in the fact that PNM has not committed itself to discontinuing sales whenever marginal costs appear likely to go above the sale price.

Q: Why would PNM want to sell power below cost?

A: When making sales from inventoried capacity, the PNM shareholders pay the running cost of the inventoried capacity and receive the sale price of the power, pocketing the difference. At the same time, the ratepayers save the running cost of the inventoried capacity (which is paid by the shareholders), but must pay for the running cost of the more expensive marginal unit which is fired up to replace the power sold. Thus, if the inventoried capacity costs 10 mills/kwh to run, the sale rate is 50 mills, and the cost of replacement power is 100 mills, the PNM shareholders can save 40 mills/kwh while the ratepayers are losing 90 mills/kwh. This is approximately the situation which would arise if PNM sells Palo Verde power to SPS, and uses gas-fired generation to make up the difference in supply to firm customers.

The Commission should require, as a condition of certification of the EIP, that PNM promise not to sell power over the line below cost, or equivalently warn PNM that fuel charges will be calculated without such sales. This problem should also be resolved in the more general context of the inventoried capacity proceeding (PSC Case No. 1804).

Q: You mentioned that the cost-effectiveness of the EIP is dependent on the validity of the PNM load forecast: why is this?

A: As PNM discusses (Exh. CBD-10), the SPS purchase is not competitive with the existing oil/gas plants until some time after the mid-1990's under PNM's low load growth projection. PNM has not explained when, if ever, the purchase would be competitive under this low-load projection, nor has PNM estimated the net costs of Schedule C in this circumstance. It should be noted that, in addition to any losses resulting from the SPS contract itself, the customers would be burdened with the costs of the EIP, which might see very little use if Schedule C is phased out.

Q: Is there any reason to believe that PNM's load growth will actually be below the base case?

A: The schedule for this case certainly precludes a detailed review of the load forecast, and the documentation I have received from PNM to date raises more questions than it answers. Nonetheless, there are several reasons for believing that PNM's projections are inflated. The first is the general observation that PNM's forecasts (like those of most other utilities with rising costs) have been overstated fairly consistently in the last decade, especially for utilities experiencing rising prices. This record should encourage some skepticism regarding the reliability of PNM's current forecasting effort.

Second, PNM's expectation for its prices seems to be optimistic, especially in light of the cost of the Palo Verde units. Some of this optimism may result from the use of totally unrealistic capacity factors for Palo Verde of 78%-79%, after two immature years at about 64% (Table 7, Exh. 8-1 in response to AG's Second Set of Interrogatories). By contrast, in a recent study for the NRC, Easterling (1981) derived regression results suggesting that a Palo Verde sized PWR might expect a mature capacity factor of about 51%, after a few years of operation in the mid- to high-40% range. Other recent analyses (Perl, 1982, ESRG, 1982) have produced similar results. Not only are PNM's capacity factors assumptions unrealistic for average performance, but they are fabulously high even for an individual good year; large PWR's rarely break 70% capacity factor. Since Palo Verde will be subject to a seasonal thermal limitation on cooling water (Exh. 8-1, p. 4), its capacity factor may be even lower than the industry average.

Q: Before you describe the rest of the problems you have identified in the forecast, do these excessive capacity factor estimates have any other effects on the economic analysis of the EIP, other than through the load forecast?

A: Yes. On the one hand, a realistic appraisal of Palo Verde availability would reduce the expected sales under Schedule D, since oil and gas would be the marginal fuels on PNM's system for more hours of the years (at any given load growth). On the other hand, the frequent, prolonged, and often coincident outages of the Palo Verde units will make Schedule C more valuable (again, at a given load level), and will also increase the importance of the EIP for emergency and economy interchange. When PNM is short of power (or burning gas) due to an outage at Palo Verde, many of its neighbors will be in the same position. Therefore, it is hard to tell whether the overoptimism in Palo Verde capacity factor overstates or understates the value of the EIP.

Q: Would a realistic capacity factor for Palo Verde have much effect on PNM's price forecast?

A: It certainly should. Replacing the unrealized nuclear output with gas or oil fired generation would increase production costs by about 30% in 1990.

Q: Please continue your discussion of PNM's price forecast.

A: Other questionable aspects of PNM's electricity price forecast would include:

1. The construction cost for Palo Verde: there is no indication in the load forecast as to which estimate was used, and even PNM's most recent estimate is likely to be optimistic, given historical experience in nuclear cost estimation.

2. O&M expense for Palo Verde: PNM's estimates for the whole plant seem to be comparable to 1980 O&M expense at some single and double units, and appear to entirely ignore the rapid escalation in nuclear O&M, which has been on the order of 10% annually in real terms.

3. Gas prices for generation: PNM's projections for escalation in gas prices for their generating plants appear to be much lower than the comparable figures for retail gas prices.

Q: Are there other problems with PNM's load forecast, besides its price forecast?

A: Yes. Continuing my previous list, the third problem would be that the discussion of conservation effects and programs in the forecast document (Exh. 24-2, PNM response to the AG's Second Set of Interrogatories) is really minimal. While there are references to conservation reducing sales growth, the only specific source of conservation identified is solar energy, and this is anticipated to have "minimal" impact. There is simply no way of knowing whether PNM has adequately recognized the effects of more efficient buildings, appliances, and equipment on load growth, or even of knowing how PNM attempted to model these effects. The failure to recognize conservation potential is probably the major cause of utility overforecasting in the last decade.

Fourth, there are serious problems in the modelling of price elasticity. PNM appears to have estimated short-run elasticities (which are unrealistically large for the residential and commercial sectors, probably due to the failure to reflect long-run price effects), and then to have used these elasticities as if they were long-run elasticities, for which purpose they are far too low. PNM has employed a particularly complex approach of combining two separate econometric studies, and it is not clear why or exactly how this was done. This may be why the backcasts tend to underforecast in 1979 (a high-priced year) and to overforecast in 1980 (a slightly lower-priced year) for both the residential and commercial sectors.

Fifth, it is probably not correct to model industrial price elasticity on the basis of the ratio of electric price to gas price. For most industrial purposes, electricity and gas are not close substitutes, and electricity's major competitor in most applications is conservation, not gas. While electricity may pick up some of the end-uses now served by gas, higher electricity prices will tend to encourage more efficient lighting, motors, air conditioning, and other electric uses.

Sixth, the customer number logic in the forecast is at best obscure and at other times incorrect. For the residential class, it is a tautology that:

$$\text{Cust.} = \frac{POP - POP_x}{HSZ} - HHD_x$$

where POP = population
POP_x = population not in households (e.g., nursing homes)
HSZ = household size

HHD_x = households which are not customers (e.g., master-metered apartments)

Rather than follow this sort of simple accounting, PNM uses a regression equation which postulates that customer number decreases as the 1.4 power of household size. This relationship, which postulates that halving household size would multiply customer number by 2.64, is intrinsically implausible; there is no reason to believe that halving household size would do more than double customer number. The historical equation may be folding independent trends (master metering, group housing, and errors in population and household estimates) into the household size variable.

With respect to the commercial class, PNM asserts that it forecasts customer number "by a ratio to total housing units", without explaining what that ratio is or how it is derived. In fact, the number of commercial customers appears to have been rising much more slowly than household number. This is to be expected, as stores and firms expand, and as larger businesses replace smaller ones. Since this size trend is captured in the projection of usage per commercial customer, the forecast is overstated by leaving it out of the customer number projection.

Finally, the entire forecast, as provided to date, is very poorly documented. This appears to be symptomatic of PNM's attitude towards outside review. Good examples of this problem are the treatment of conservation, the extrapolation of industrial sales, and the projection of mining sales. It is also unclear how the econometric models were specified; that is, what other equations were estimated and how the final equations were selected.

Q: What is your concern about the rates to be charged under Schedule C?

A: Quite simply, there is no guarantee of any particular rate level, or of any particular method for calculation the rates. This is in stark contrast to the fixed rates to be charged under Schedule D. PNM is taking all the risk of building the line, the bulk of the risk of changes in economic conditions under Schedule D, and essentially all the risk under Schedule C. It is not clear why this should be necessary.

In addition, it is not clear that the assumptions underlying the estimates of the rates to be charged under Schedule C are consistent with those used in estimating the costs of the alteratives. Important assumptions would include general inflation levels, costs of capital, costs of coal-plant construction, the prices paid for fuel (especially gas, but also coal), and coal plant availability. There is no indication that the Stone & Webster and PSCO estimates of SPS costs are in any way consistent with PNM's internal assumptions about fuel price and inflation, nor does PNM explain why annual escalation of less than 2.5% in the demand charge is a reasonable assumption. There also seems to be considerable difference of opinion in the estimates of SPS sale rates, as demonstrated in Table 3.

Perhaps most importantly, PNM has not explained why the relative economics of the PNM and SPS systems can be expected to reverse at the end of the decade, so that PNM will switch from a selling position to a buying position. SPS appears to be gas-fired at the margin for the foreseeable future; why should it be cheaper to burn gas in Texas and transmit the power to New Mexico than to burn it in PNM's own plants?

From the excerpt of the Stone & Webster report provided on discovery (Exhibit 8-9, PNM response to AG's Second Set of Interrogatories), it appears that the low rates assumed for the SPS purchase are based on average-cost pricing, which may well result in a subsidy from SPS' firm customers to PNM. The Commission must decide whether it desires such a subsidy, especially from the viewpoint of SPS's customers in New Mexico. Of course, if SPS really does have some currently unidentified source of inexpensive power, so that it will not lose money on Schedule C, this particular concern can be dismissed.

There is another problem with the average-cost ratemaking approach. If SPS's load growth is lower than projected, the average price of power may rise, at least in the short term. Continued conservation throughout the Southwest would thus increase the cost of Schedule C power while decreasing PNM's need for it. This relationship increases the sensitivity of EIP's economics to demand growth.

The same excerpt indicates that S&W did not derive SPS's carrying charges as they would be reflected in normal FERC ratemaking, including forecast test years, pancaking, and CWIP in rate base. Instead, S&W appears to have estimated investment and the demand charge and then backed out a carrying charge ratio.

Q: You expressed suprise that the economics of the PNM/SPS relationship is expected to reverse so dramatically about 1990. Does the PNM August 1982 O&M Budget Run (PNM Exhibit 8-1, op. cit.) clarify this issue?

A: No. On the contrary, it raises further questions. The Budget Run, which is supposed to be part of the analysis underlying PNM's position in this case, indicates that a 200 MW sale is not feasible until well into 1988: prior to that time, approximately 100 average MW of economy coal sales would be available, but probably not in the proper time pattern for delivery over the EIP. Lower PNM load growth would free up some capacity, while realistic nuclear capacity factors would reduce available capacity by an average of about 100 MW, and the variability of nuclear reliability would further reduce the firm deliverable power. It is hard to see how PNM expects to meet its goals for delivering power to SPS unless it expects to burn more gas or experience lower load growth. Reduced growth would, as previously noted, place the economics of Schedule C in jeopardy.

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Q: What questions do you have regarding the costs of the EIP?

A: The central question is whether cost estimates of this sort are reliable. By "this sort", I mean estimates for transmission projects of this technology (345kV, AC/DC conversion, etc.) and at this preliminary stage of planning. For nuclear power plants at any stage of construction, the answer is emphatically no; costs are always higher than projected. While my familiarity with coal plant cost estimates is more limited, it is my impression that those projections are subject to more limited uncertainty than those for nuclear plants, and some even come in below their original cost estimates. PNM has not yet demonstrated that its cost estimate for the EIP is consistent with recent experience, nor has it provided any evidence on the reliability of past cost estimates for lengthy transmission lines and AC/DC converters. The Commission may want to have some idea of the validity of current estimates before it commits the ratepayers to supporting the EIP.

Q: What problems arise in PNM's estimation of a discount rate?

A: PNM uses its own estimated discount rate to convert the annual costs of Exhibit CDB-11 and CDB-13 to present worth terms. However, the costs involved here are customer expenses, rather than expenses for the company, so PNM's discount rate is irrelevant. The estimation of consumer discount rates may be somewhat more difficult than estimation of PNM's discount rate, but there is little point in estimating the wrong parameter, no matter how precisely.

PNM's industrial and commercial customers, as a whole, are probably higher risk companies with higher costs of capital than PNM. It is not uncommon to see allegations that corporations require paybacks on discretionary nonproductive investments (such as an investment in higher electricity costs today to provide lower electricity costs in the future) on the order of 2-4 years; recently, hurdle rates may have been even higher. Thus, business ratepayers may be thought of as having discount rates in excess of 25%, at least. Similarly, residential customers appear to have high discount rates. Hausman (1979) estimates that households also discount conservation investments at about 25% in _real_ terms; even if this is an overestimate, it is clear that many people are willing to finance through credit cards at annual rates of 18% or more, and others would presumably take these rates if they could get them. As Hausman notes, discount rate varies inversely with income, so wealthy consumers may have much weaker time preferences for money than poor ones, although there should be a floor at the level of market returns of comparable risk. (Hausman also notes that a utility's investments, financed by the utility, should be evaluated at the utility's discount rate; it is only when _rate levels_ are compared over time that customer discount rates matter.)

So long as the annual savings are projected to be comparable to those portrayed in CDB-11 and CDB-13, the discount rate used hardly matters. If lower PNM load growth, higher Schedule C rates, and other factors produce negative savings in the early years, the discount rate may be very important. Examples of such "other factors" would be the subsidy from ratepayers to shareholders implicit in PNM's proposal for a $730,000 annual transmission credit, if the Commission does not change the ratemaking proposed by PNM, and the ratepayers' share of the carrying costs of the EIP during the elipsis.

Q: Why is PNM's treatment of the cost of NMGS improper?

A: In the cost-benefit analyses of Exhibits CDB-11 and CDB-13, PNM counts the costs of the expensive early years of NMGS, with high carrying charges, low reliability, and low displaced fuel prices, and not the later years, when depreciation and inflation would tend to make it a better deal compared to oil, gas, or newly constructed coal plants. This problem can be resolved by levelizing the cost of NMGS power in real terms (that is, so that it rises with anticipated inflation throughout the plant's life, rather than declining in real terms), or by including in each scenario a credit equal to the replacement value of NMGS at the end of the time horizon.

PNM's use of this particular presentation approach is somewhat ironic, since it is usually used by intervenors opposing utility construction of power plants, to overstating the cost of new generation by focusing on the first years of operation.

Q: How would you suggest that the Commission proceed with regard to PNM's application?

A: Throughout this testimony, I have made specific recommendations regarding revisions to PNM's proposal. These include:

1. increasing the transmission credit to cover the full cost of the EIP during the duration of Schedule D, or treating the EIP as inventoried capacity,

2. resolving the treatment of EIP costs in the elipsis, either by determining that the shareholders will pay them, or by determining that the ratepayers will pay them (and accordingly reducing the benefits shown in future analyses), and

3. ensuring that any sales of energy below PNM's marginal cost are not charged to the ratepayers.

In addition, I believe that PNM's analysis is so flawed that it would not be possible for the Commission to determine whether the EIP is really in the interests of its ratepayers. On the other hand, PNM's presentation has not eliminated my prior expectation that there may well be benefits from the project, so I would not advise PNM to drop its proposal at this point. Therefore, I would urge the Commission to take one of the following actions:

1. Postpone action on the application for certification and require that PNM conduct an appropriate cost-benefit analysis of the EIP, including:

   a. estimation of the total benefits which the line can provide,
   b. consistent accounting for EIP costs, prior to Schedule C effectiveness,
   c. realistic nuclear capacity factors,
   d. a range of consistent fuel price assumptions,
   e. a range of realistic (e.g., generally lower than PNM's base case) load forecasts,
   f. a range of reasonable consumer discount rates (if needed),
   g. appropriate treatment of the terminal value of NMGS, and
   h. realistic, well documented projections for SPS sale rates to PNM consistent with the assumptions for PNM costs.

2. Grant the application, with the aforementioned revisions to PNM's ratemaking proposals (e.g., increasing the credit, resolving the treatment of elipsis costs, and preventing sales below cost), and with the understanding that the economics of the line have been approved only for the purposes of PNM shareholders, and that ratepayers will only pay for the EIP if (and to the extent that) it proves to be cost-effective. That is, the customers will not pay more than the line saves them in avoided costs, using incremental costs of capital and reasonable customer discount rates. An order of this sort will allow PNM to proceed with the line if management truly believes that it will pay for itself, without waiting for any further hearings. However, if PNM is doubtful about the advantages of the line (except for its obvious attraction in creating a market for inventoried generation), this warning would encourage more careful study of the EIP, both within PNM and before the Commisssion. In some ways, this would be a deregulated approach to capacity planning.

Q: Do any of your recommendations substantially reduce the attractiveness of the proposed arrangements to SPS?

A: I do not foresee that any would. The only specific recommendation that I make which directly affects SPS would simply allow PNM to fulfill its delivery requirements to SPS with SPS's own capacity, at cost; this provision should not increase SPS's net expenses.

Q: Does this conclude your testimony?

A: Yes, at this time. To the extent that subsequent PNM discovery responses clarify any testimony to I have raised, I will submit an update of my testimony to the Commission.

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		PNM Proposal	Full Cost Recovery		
			System Net of EIP	EIP	Total
	{Notes}	{4}	{5}	{6}	
Plant in Service	{1}	$211,197	$133,735	$77,462	$211,197
Cost of Capital:	{2}				
Debt		9.03%	9.03%	12.50%	
Preferred		10.68%	10.68%	11.75%	
Common		15.50%	15.50%	16.60%	
Return & Taxes	{3}				
Rate		18.81%	18.81%	21.59%	
Dollars		$39,716	$25,149	$16,724	$41,873
Other Fixed Charges					
O & M (1%)		$2,112	$1,337	$775	$2,112
Deprec. (3.48%)		$7,350	$4,654	$2,696	$7,350
Gen. Taxes (0.7%)		$1,478	$936	$542	$1,478
Revenue Requirements		$50,656	$32,077	$20,737	$52,813
Transmission Peak (MW)		1,156	1,156	200	
Transmission Credit					
$/kw-yr		$43.82	$27.75	$103.68	$131
$/kw-month		$3.65	$2.31	$8.64	$11
Total Credit/Month		$730,333	$462,465	$1,728,048	$2,190,512

Table 1: Computation of a Fair Transmission Credit

Notes:
1. Except as noted, all data is from Exhibit GLB-1. Cost of EIP is from C.D. Bedford testimony.
2. Rates for existing financing from Exhibit GLB-1. Rates for incremental financing from PNM response to AG Interrogatory 2-27.
3. Tax rate from PNM Exhibit 20-1, p. 9.
4. Exactly as Exhibit GLB-1, except for minor difference in rounding return.
5. Assumes that 1985 cost of capital for existing system is the same as in 1982.
6. Assumes that EIP is financed at PNM's estimated incremental cost of capital, at 1982 capital structure.

Start of Period	Starting Cost	Depreciation (3.48%)	Other Fixed Costs (23.29%)*	Total Cost In Period
01-Jan-85	$77,462	$2,696		
01-Jan-86	$74,766	$2,696		
01-Jan-87	$72,071	$2,696		
01-Jan-88	$69,375	$2,703		
01-Jan-89	$66,672	$2,696		
01-Jan-90	$63,976	$1,115	$6,164	$7,279
01-Jun-90	$62,861	$1,580	$8,584	$10,164
01-Jan-91	$61,281	$1,115	$5,904	$7,020
01-Jun-91	$60,165			
Total Costs During Elipsis If Sale Ends:				
	31-Dec-89	$3,811	$20,652	$24,463
	31-May-90	$2,696	$14,488	$17,184

Table 2: Cost of Carrying EIP During Elipsis (k$)

*Assumes PNM incremental cost of capital: 21.59% for return & taxes, 1% for O&M, 0.7% for General Taxes, based on start-of-period rate base.

Also assumes (optimisticly) no capital additions.

Source of Estimate	PNM		Stone & Webster		PSCO	
	Demand	Energy	Demand	Energy	Demand	Energy
Year:						
1984			$7.90			
1985			$7.90			
1986			$10.40			
1987			$10.40			
1988			$10.40		$10.00	$55.2
1989			$12.65		$10.00	$53.9
1990			$12.65		$12.00	$56.8
1991	$9.00	$63.7	$12.65		$12.00	$63.9
1992	$9.00	$68.8	$15.00		$15.00	$65.2
1993	$9.68	$74.3	$15.00		$15.00	$68.7
1994	$9.68	$80.2			$15.00	$76.0
1995	$9.68	$86.7			$15.00	$79.4
1996	$10.40	$93.6			$20.00	$85.2
1997	$10.40	$101.1			$20.00	$93.7
1998	$10.40	$109.2			$20.00	$98.9
1999	$11.18	$117.9				
2000	$11.18	$127.3				

Table 3: Comparison of Estimates for SPS Sale Prices

Sources: All from PNM Response to AG Second Set of Interrogatories. PNM from Table 7-5, Stone & Webster from Exh. 8-9, PSCO from Exh. 8-2, Firm Capacity, Energy without PNM.

Demand in $/kw-mn, energy in $/MWH.
Blanks were not provided.

Start of Period	Starting Cost	Depreciation (3.48%)	Other Fixed Costs (23.29%)*	Total Cost In Period
01-Jan-85	$77,462	$2,696		
01-Jan-86	$74,766	$2,696		
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Table 2: Cost of Carrying EIP During Elipsis (k$)

*Assumes PNM incremental cost of capital: 21.59% for return & taxes, 1% for O&M, 0.7% for General Taxes, based on start-of-period rate base.
Also assumes (optimisticly) no capital additions.