UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING APPEAL BOARD

In the Matter of	)	
	)	
PUGET SOUND POWER & LIGHT COMPANY, et al.,	)	DOCKET NOS. STN 50-522 50-523
	)	
(Skagit Nuclear Power Project, Units 1 and 2)	)	

INTERVENOR SCANP'S TESTIMONY ON FINANCIAL QUALIFICATIONS

by

JIM LAZAR

August 8, 1979

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Q: What is your name, address, and occupation?

A: My name is Jim Lazar, 317 E. 17th Ave., Olympia, WA 98501. I am a self-employed consulting economist, specializing in utility rate structures and energy conservation.

Q: Are you a member of any professional organizations?

A: I am a member of the American Economics Association, the Association for Evolutionary Economics, and the American Nuclear Society.

Q: What materials have you reviewed in preparation for your testimony?

A: I have reviewed the prefiled testimony of the applicants, and that of Mr. Gittleman, Dr. Winters and the panel on alternative sites for the NRC Staff. I have also reviewed extension documents relating to the Washington applicants in the course of various rate proceedings before the Washington Utilities and Transportation Commission, and of Portland General Electric before the Public Utility Commissioner of Oregon.

Q: Has your review of this data given you reason to believe that the applicants will be unable to successfully finance the Skagit nuclear projects?

A: It appears that the applicants will be unable to secure financing for a number of reasons. First, the cost and schedule estimates they have used in their presentation before the Board are unrealistic. Their anticipated financing costs are considerably underestimated. The cost

obligations which they face for other projects is far in excess of that which has been reported to the Board. Finally, the ability of the applicants to attract capital for a nuclear project of any type is questionable.

Q: What are some of theproblems with the schedule estimates which the applicants have proposed for construction?

A: The planned operation dates for the project, (September, 1986, and September, 1988) are unachieveable. Operation in 1986 would require a construction period of only 72 months, much less than that which has been estimated by various other generic studies of nuclear power plant construction. All of the structured models which I have reviewed on construction duration have indicated that a much longer construction period would be required. These studies, compiled by the RAND Corporation for the Department of Energy (Cost Analysis of Light Water Reactor Power Plants) by the General Accounting Office of Congress (Tennessee Valley Authority Can Improve Estimates and Should Reassess Reserve Requirements of Nuclear Power Plants), and by the Washington Public Power Supply System (Nuclear Power Plant Cost Schedule and Productivity, an Overview of the Industry and Implications for the Future), have all analyzed nuclear power plant construction schedules, and indicate that a construction period considerably in excess of that proposed by the applicants will be required to build a nuclear plant during the 1980's.

Q: Could you describe the RAND study and its impliccations for the Skagit projects?

A: The RAND study, which has been discussed by Mr. Carstens at some length, provides regression model for the actual construction duration of nuclear plants which have been constructed in the United States. The formula developed, when used together with the data available for the Skagit plant, indicates that a 107-month construction period would be required, less a small adustment for the experience of the Architect/Engineer. While Bechtel is a highly experienced constructor of nuclear plants, their responsibilities for Skagit are not as encompassing as those which they have undertaken in thepast, having been hired for procuremant and management only. I have thus not made the adjustment for A/E experience which the model provides for. This would result in a fuel load date of February, 1989, followed by commercial operation in October, 1989, based on an LWA in September, 1979, as requested by the applicants. This is approximately three years longer than that anticipated by the applicants.

Q: What was the conclusion of the GAO study?

A: The GAO study, completed in March, 1979, concluded that the construction cost and schedule estimates of the Tennessee Valley Authority were unreasonably optimistic. Their analysis of construction history showed construction duration rising from an average of 46 months for plants

completed prior to 1970, to 90 months for plants completed in 1977, as shown below.

Table 1

Completion Date	Number of Reactor Units	Average Construction Duration for First Units
Before 1970	12	46.0 months
1970	4	47.6 months
1971	4	54.9 months
1972	5	66.0 months
1973	7	68.0 months
1974	10	66.9 months
1975	3	78.7 months
1976	4	91.4 months
1977	4	90.4 months

A regression analysis of the data above provides a surprisingly good linear fit, with R^2=.94; a completion data advancement of one year is accompanied by an increase in time of construction of 6.18 months. The trend, applied to Skagit, would indicate that for completion in 1986, a construction permit would have had to be issued in 1974. While extending this trend to predict a completion date based on a 1980 construction permit may be a meaningless exercise in linear extrapolation, it is clear that a construction period of only 72 months is inconsistent with recent experience in the nuclear industry.

In evaluating the schedule problems being experienced by TVA, the GAO noted with respect to the Sequoyah power plant that:

> "The first unit at TVA's second plant, Sequoyah, is scheduled for fuel loading in April, 1979, after a construction period of about 120 months. The Authority does not consider the Sequoyah time typical, because rework to satisfy new NRC requirements has extended the construction time. <u>However, the Sequoyah experience is consistent with the trends in private industry</u>." (emphasis added)

Q: How did the Supply System study address the question of construction duration?

A: The Supply System analyzed all nuclear plants under construction or completed in the United States. The Supply System had just undergone an extensive budget and schedule revision, in which their estimated costs had escalated by $1.6 billion, and their completion dates for the five projects advanced by an average of eleven months. They found themselves in the difficult predicament of being no closer to completion, either in terms of physical progress or expenditures, then they had been in 1978.

Their study divided the period required for construction into five identifiable segments. The first (duration from Nuclear Steam Supply System award to PSAR) and the second (from PSAR to Construction Permit) are not relevant to this testimony. The next three segments will be undertaken if a construction permit is issued, and should be considered in establishing a likely operational date for the project under consideration.

The Supply System estimates an elapsed time of about seven months from issuance of CP to placement of the first structural concrete. The period between first concrete and fuel load, longest of the three periods, is estimated at approximately 100 months for a large plant constructed under 1979 conditions. They have forecast this duration to increase to as long as 125 months for projects loading fuel in 1982. They note that the present fuel load dates for projects now under construction are optimistic by as

much as four years. They have not made a specific forecast beyond 1983, as they have surmised that the construction interval between first concrete and fuel load will not be subject to eternal extension, and will eventually level at about 90-100 months. Finally, they have estimated a six-month period between fuel load and commercial operation. The total of these three periods indicates a plant authorized for construction in 1979 would require between 103 and 138 months for construction. Even with a 103-month completion date, according to the study, the earliest commercial operation date for Skagit would be October, 1988, some two years later than that proposed by the applicant. The other end of the estimate, 138 months, would delay initial operation to September, 1991. The model suggests the same range of construction duration as noted by the GAO as being "consistent with the experience of private industry." It is also very consistent with the estimate derived through use of the RAND regression model. The Supply System Commentary in their abstract was not encouraging to other potential builders of nuclear plants:

> "Plants committed in 1966 took 7 years to build. Today they will take 15 unless conditions change appreciably."
>
> "Most plants will now attain commercial operation as much as 2 to 3 years later than their current schedules."

Q: What is the impact of these construction period extensions on the ability of the applicants to finance the projects?

A: It is acknowledged by all parties that construction delay results in increased cost. The Trojan plant, completed in 1975, cost under $500 million to construct. The Supply System plants are presently budgeted at $1.7-2.7 billion each. As costs have escalated, the financing requirements have also risen. A realistic assessment of financing requirements must be based on realistic project completion dates. As we have seen repeatedly across the nation, schedule and budget revisions accompany one another in nearly every nuclear power project.

Q: Have you evaluated the project cost estimates of the applicants?

A: I have reviewed the cost estimates provided by both the applicants and of the staff. They appear to be inconsistent with the experience of the power industry, and are inconsistent with the generic estimates of project cost which I have reviewed.

Q: Can you describe some of the generic cost estimates you have seen?

A: The RAND study discussed earlier included a regression analysis for project cost, using the date of issuance of construction permit, plant size, location, and the experience of the A/E. Excluding both the location and A/E factors, my use of the model established a cost per kw of $2266, if a construction permit were issued in March, 1980, following an LWA in September, 1979. The location factor added cost for a plant built in the Northeast, due

to the higher labor costs in that market. Washington's labor costs exceed the national average by 20%, and should be considered a high cost area. The experience of the A/E should help to offset this factor, however, and since it is not possible to utilize theA/E factor in the manner suggested by the model, due to the more limited role being played by Bechtel, both factors have been excluded in my analysis.

The Supply System model described earlier provides a detailed method of estimating cost which cannot be utilized in a generic mode without tremendous amounts of information. Their conclusions are easier to follow, however, and merit consideration:

> "...under present conditions, plants will now take 15 years rather than 7 to come on line, and one committed in 1979 will cost in excess of $3 billion to construct. Perhaps this is a fair and reasonable price to pay for the protection of our society, but it must be emphasized that this is a social price, not a technical one. <u>It is a price that nuclear construction management can neither control nor be held accouuntable for</u>."
> (Emphasis added.)

Escalating the cost of WNP-5 to 1989, the year of most probable operating for Skagit 1, at a 16% rate of inflation yields a cost/kw of $3465 and a total project cost of $8.9 billion, nearly three times the staff estimate. A 16% rate of inflation is not unresonable for this industry; Theodore Barry and Associates identified a 13-19% annual inflation rate for the industry in their evaluation of the Washington Public Power Supply System for the Bonneville Power Administration. The causes of this inflation - high

interest rates, rapid wage inflation, and continuing regulatory changes in the nuclear power field - do not seem to be abating. A review of the cost inflation at WPPSS bears this out significantly:

Table 2

PROJECT	ORIGINAL BUDGET	REVISED BUDGET	$/KW	ESCALATION RATE	COMPLETION DATE
WNP-1	$622	$2341	$1878	27%	12/83
WNP-2	$405	$1822	$1668	19%	9/81
WNP-3	$789	$2256	$1827	23%	12/84*
WNP-4	$1009	$2580	$2064	27%	6/85
WNP-5	$1251	$2753	$2220	21%	6/86

*WPPSS Consultant study by Holmes and Narver recommended 1985 operating date for WNP-3; 12/84 adopted as official target date

A generic study was completed by Ebasco Services, A/E for the Supply System at Satsop, in September, 1978. They concluded that a project authorized in 1978 would be completed in 1988 at a cost of $1648/kw. (Dramatic Increases in the Cost of Nuclear and Fossil-Fueled Plants, EBASCO, September, 1978)

In making this estimate, they utilized a 7% rate of inflation during the study period, which appears low in view of recent national experience with double-digit inflation. The EBASCO study concludes that the eventual power would cost 63.8 mills, with a fuel cost of 16.3 mills/kwh. This study concludes that nuclear generation is cheaper than coal, using a 70% capacity factor; dropping both capacity factors to 60% grants the edge to coal.

A study done by Stone and Webster Engineering Company, the nation's leading nuclear A/E, was presented to the Atomic Industrial Forum in February (The Economics of Nuclear Power, Stone and Webster, 1979). The conclusion of this report was that plants scheduled for completion in 1990 would cost $1937/kw, including a $50/kw allowance for future regulatory changes. They concluded that power at the bus would cost about 90 mills/kwh at 60% capacity factor, virtually identical to the cost they estimated for coal. The Stone and Webster study also applied an inflation rate of 7%. Business Week (May 28, 1979) reported an estimate from the Edison Electric Institute of $1861/kw for a project on-line in 1987, although no additional information was given. Charles Komanoff, in testimony before the New Jersey Board of PUblic Utilities in October, 1978, estimated cost of a project on-line in 1985 at $1575/kw. It would be necessary to escalate this estimate to a 1989 completion date in order to provide comparability.

Q: Have you compiled the various generic estimates in tabular form, so that the estimates can be easily compared?

A:

Estimator	Completion Date	Cost/ kw	Skagit Project Cost (billions)
Staff	1986	$1239	$3.191
Applicant	1986	1291	3.325
Komanoff	1985	1575	4.057
EBASCO	1988	1648	4.245
Pacific (WUTC B-3)	1986	1744	4.492
Edison Electric Inst.	1987	1861	4.794
Stone & Webster	1990	1937	4.990
WPPSS (WNP-5)	1986	2220	5.719
RAND	1989	2266	5.837
EEI @ 13% inflation	1989	2376	6.121
Komanoff @ 13% infl.	1989	2568	6.615
WPPSS @ 13% inflation	1989	3203	8.252

Q: Can you explain why the staff and applicant estimates are so much lower than the generic estimates?

A: The staff has used the CONCEPT model exclusively in preparing their estimates. CONCEPT has been widely questioned as a predictive tool, and is described in the RAND study with the following comments:

"In 1967, ERDA began an independent examination of LWR capital costs that eventually culminated in the creation of the CONCEPT model. The CONCEPT model is a machine-operated computer code that adjusts the cost of a base case LWR at a hypothetical site to the cost of an LWR at any selected location, in any selected year, and in a variety of configurations. The model relies on the base case cost estimate and on appropriate cost-adjustment factors that reflect locational economic factors and time-related escalation. There is no evidence that results from the CONCEPT model have been used as data; however, the base case inputs, which have been prepared by United Engineers and Constructors, are widely quoted, usually without making note of the fact that they are minimum cost estimates of a plant at an ideal hypothetical site." (emphasis added)

Instead of a conservative approach, to balance the bias of the applicants, it appears that the NRC has used a "best possible" cost model to evaluate a "best possible" estimate provided by the applicants. Moreover, the CONCEPT model does not appear to adjust the completion date in order to reflect realistic construction scenarios.

Q: Have you discussed the CONCEPT model with any persons involved in the nuclear plant construction field?

A: I have discussed it with staff of the Supply System. They indicated that one reason for developing their own model was the CONCEPT's inability to accurately predict the problems which they and others in the field have encountered. Since the development of their model, and GAO

report on TVA, they have made their model available to TVA, which is now using the Supply System model instead of CONCEPT.

Q: What is the impact of this increase in capital costs on the ability of the applicants to finance the projects?

A: As costs increase, two things happen. First, the amount which needs to be financed increases, leading to greater demands on both internal cash generation and external financing. Second, higher cost power becomes more difficult to sell, and the demand forecasts must be revised downward. Reduced sales eventually result in lowered revenue, which compounds the problem. It is possible to get into an elasticity spiral making it impossible to support a construction program at all

Q: Have the applicants provided conflicting estimates of eventual project capital costs in recent months?

A: Yes. In their various reports, they have indicated widely differing capital cost estimates, some much higher than those used by the staff and applicants in this case. A listing of the estimates I have seen in recent months are tabulated below

Table 4

Source		w/AFUDC	w/o AFUDC
Puget:	ASLB Docket 50-522	$1291	$1079
	WUTC Cause U-78-05 (FERN #1)	1373	
	(Staff B-3)	1201	1053
	Bond Prospectus 7/11/78	1126	
	SEC Form 10-K 12/31/78	1514	
Pacific:	ASLB Docket 50-522		1139
	WUTC Cause U-78-05 (FERN #1)	1618	
	(Staff B-3)	1744	1298
	Bond Prospectus 3/28/79	1618	
	SEC Form 10-K 12/31/79	1618	
Water Power:	ASLB Docket 50-522		1087
			1021
	WUTC Cause U-78-05 (Staff B-3)	1293	938
	(FERN #1)	1294	
	Stock Prospectus 9/21/78		923

1029 168

Q: Can you explain this divergence of estimates on the part of the applicants?

A: Not in any way. My only hint of a reason for Pacific's more realistic estimate lies in the fact that Pacific reacted more moderately than other utilities to suggestions of cancellation of the Pebble Springs plant before the Oregon Senate on May 22, 1979. Pacific may view a realistic assessment of potential cost as a prerequisite to cancellation.

Q: Have the applicants provided conflicting estimates for other generating projects in which they are involved?

A: All of the applicants are involved in one or more of the Supply System projects. They have outlined their anticipated expenditures on these plants in this proceeding on tables 3-1, 3-2, 3-3, and 3-4 of their prefiled testimony. Additionally, they have provided responses to inquiries from the UTC (except for PGE) in Cause U-78-05 on these expenditures. Finally, the 1980 Supply System Construction budget provides cash flow from each of the participants by month for two years, and quarterly thereafter. These various reports are fully detailed in Table 5 of this testimony. It is apparent that the applicants have underestimated by as much as 50% their cost obligations for the Supply System plants in their report to the ASLB.

Q: Even if the cost estimates used by the staff and applicants were accepted as correct, do you believe that the

TABLE 5

REPORTED CONTRIBUTION TO WPPSS CONSTRUCTION PROGRAM

WNP 3	to 2/79	1979	1980	1981	1982	1983	1984	1985	1986	Total	Difference W/WPPSS (80-
WPPSS 10% share	31350	18467	21814	25534	24637	25506	17309	4519	1053	170189	
Pacific ASLB		26778	20397	22428	15506	14285	7807	2224	804	110229	(36,291)
PGE ASLB		26442	20647	22242	14816	13294	6032	---	---	103473	(43,341)
WPPSS 5% Share	15675	9234	10907	12767	12318	12753	8654	2260	526	85094	
Puget ASLB		13216	10314	11102	7647	6175	2989	----	---	51443	(21958)
WUTC	16415	10862	10012	12660	7447	3458	---	----	---	60854	(26608)
WWP ASLB		13554	10057	10634	8054	2871	1238	383		46791	(26948)
WUTC	14947	10847	10094	9461	6613	3662	1644	---	---	57268	(28711)
WNP-5											
WPPSS 10% share	22975	13709	24407	25355	27377	23007	23248	18501	4243	182822	
Pacific ASLB		15027	21030	22661	27021	18597	13828	23622	2708	144494	(16671)
Pacific 3&5 WUTC	52905	43507	48539	44159	41203	24048	15710	5350	1370	276791	(86131)

1029 170

applicants would be able to finance the projects?

A: I believe it is extremely doubtful that conventional financing, as has been proposed, could be arranged. The applicants have inadequate internal cash generation, have underestimated their future capital costs, and have underestimated the rate increases which would be required in order to make conventional financing available. Increasing the rate hike estimates would further reduce demand. The demand estimates presented to the ASLB are not those which have been reported elsewhere by the applicants.

Q: Can you describe the inadequacy of internal cash generation by the applicants?

A: A general rule of investment is that 25% of any project must be funded from internally-generated funds, or else the construction project is classified as speculative. Historically, the utility industry has been regarded as low-risk, and has been able to finance projects with as little as 15% internal funding. In the closing arguments for cause U-78-21, a Puget Power rate case, Counsel for Puget (Mr. Beighle) indicated that Puget would require this percentage:

> "The staff case with rate relief effective April 1 provides less than 6% internal cash flow - well below the 15% which is the absolute minimum that the company must have to preserve any type of financial flexibility in 1979 in meeting its construction program." (TR 3740) (emphasis added)

In their exhibits (Tables 2-1, 2-6, 2-9, and 2-11), the applicants have shown much less than 15% internal generation

1029 171

of construction funds as the Puget testimony and the general investment rule would require. Puget has shown internal generation ranging from 2% in 1984 to 10% in 1980; internal generation improves after 1986 when Puget predicts the first unit to come on line, join their rate base, and thus begin paying for itself; as noted earlier, however, this is an unrealistic assumption. Pacific actually shows internal funds in a negative standing for most of the years of construction. They will apparently have to borrow in order to meet their dividend obligations, and will be totally unable to meet the 15% operating rule. PGE and Water Power present more optimistic data, but they will be dependent on substantial rate relief in order to actually generate the revenue they are anticipating.

Q: Have there been any changes in the ability of utilities to finance nuclear projects in recent years?

A: Nuclear projects have become regarded as more speculative in recent years, as costs have escalated rapidly, performance has fallen short of expectation, and utility commissions have adhered rigidly to the"used and useful" clause in determining revenue requirements. Last year I prepared a study for presentation to the WUTC on relative bond ratings of utilities with and without heavy commitments to nuclear energy. My findings were that the average nuclear-dependent utility was rated one step lower than the average non-nuclear utility, with substantial

ownership in Trojan. It is a symptom of the problems faced by nuclear-dependent utilities that PGE was not permitted to pass through the cost of replacement power during the 8 months of 1978 that Trojan was shut down, and is now in litigation with Bechtel over those power costs.

Q: Have changes resulted from the accident at Three Mile Island?

A: The financial fallout from Three Mile Island appears to be reaching the point where it is doubtful that any utilities will be able to finance large nuclear projects. Since the accident, I know of no "baa" rated utilities building nuclear plants which have been to the bond market. Cleveland Electric, a nuclear-dependent Aa rated firm sold common stock on August 1, 1979, but had to pay a 10.8% yield, getting 80% of book value for their stock. The investment counselors I deal with have uniformly stopped trading in nuclear utility stocks and bonds, citing them as speculative investments. They prefer gambling stocks, since the casinos at least have no restriction on their earnings if things go well, while utilities are so restricted. It is certain that utilities will have a difficult time raising money for nuclear projects, and that they will pay very dearly for the funds they are able to borrow. None of the applicants are currently able to sell stock at book value; it does not appear that this trend will be reversed soon.

Q: Have you made any estimates of the financing cost which will be required if the projects are approved?

A: I have relied considerably upon the investment counselors I exchane information with, on the testimony of Portland Electric in their present rate case, and on the testimony of William G. Kuhns (Chairman, General Public Utilites) before the Senate Committee on Environment and PUblic Works in evaluating the possible financing which the applicants might be able to procure if the projects were approved.

The staff has assumed a return to equity of 13%, and a cost of borrowed funds of 10% in developing a 16.3% fixed charge rate for the projects. The applicants have all shown much lower borrowing rates in their testimony before the Board. These estimates are alll far too low in light of the recent developments following the accident at Three Mile Island.

In the June 1, 1979 testimony of C.D. Hobbs (Assistant to the Vice President, Finance for PGE) the company has offered the following commentary of their potential financing costs:

"I have assumed that PGE could sell mortgage debt securities during the test year at a yield of 10.5% to 11.0%. This is consistent with the yields assumed in this rate filing. Since the Three Mile Island incident has emphasized the increase in perceived riskiness of utilities with nuclear generating facilities, this range is, in my judgment, conservative and probably understates the actual yield the Company will have to provide." (emphasis added)

In a separate part of their case before the Oregon Public Utility Commissioner, PGE has submitted testimony by Dr. Brigham, and has established the proper spread between debt and equity to be 4.91%. This would result in a return to equity of nearly 16%, compared with the 13% estimated by the staff and the applicants.

The position of PGE that an 11% return understates what they will have to pay is confirmed by my contacts with investment specialists. The information I have obtained indicates a range of 11.5-12.5% would be required to obtain mortgage financing on a nuclear project for any of the "Baa" rated participants. Water Power, with its superior bond rating, could presumably do somewhat better. Adding the spread supplied by PGE to the PUC, the return to equity may have to equal 17.4% in order to finance the projects. This is consistent with the testimony of Mr. Kuhns, who indicated that NERA had determined that an 18% return to equity would be required to reward the risk a nuclear dependent utility assumes.

Q: Have any of the applicants indicated that a return to equity exceeding 13% will be required in the future?

A: Pacific has assumed a 14% return to equity in their long-run incremental cost study submitted to the WUTC. This estimate was made prior to the incident at Three Mile Island, and will presumably have to be raised. PGE is requesting an increase to 14-1/2% in their present rate request before the Oregon PUC.

Q: Would the return to equity you have estimated be expected to be fully implemented by the regulatory authorities in the near future?

A: No; this return is only to compensate for the nuclear investment. The utilities will continue to have low-risk components of their rate bases, including distribution plan, coal and hydro generators, and administrative facilities. These would continue to merit only a 13% return, so the melded cost of capital would remain lower. On an incremental basis, however, investment in nuclear plants would add to costs at a rate of 16+%.

Q: Would you alter the fixed charge rate used by the staff in determining the eventual cost of power from the projects?

A: I would raise it considerably, in order to reflect the increased borrowing costs demonstrated in the PGE and GPU testimony identified above. The Stone and Webster study discussed earlier utilized a 20% fixed charge rate; Rossin and Rieck, of Commonwealth Edison, used a 20% rate in an article in Science last fall, which figure has been widely quoted throughout the industry. While I hesitate to raise the fixed charge rate that high, I believe that the 4% increase in return to equity, and the 2% increase in return to debt together justify raising the fixed charge rate to approximately 19%.

Q: Would this fixed charge rate apply to any project the applicants might undertake?

A: No; the information suggested by PGE in their testimony before the Public Utility Commissioner indicates that the market is only downgrading nuclear-dependent utilities. While PGE as owner of Trojan will remain a nuclear-dependent utility, the other applicants have very little nuclear investment outside the projects now before the ASLB and the Oregon Siting council. Cancellation of these projects would considerably reduce their borrowing costs.

Q: Using a 19% fixed charge rate, what cost of energy can we expect from the projects?

A: Depending on the capacity factor used, the cost of power can vary quite widely. At a 60% capacity factor, as used by Stone and Webster, we can expect busbar power at approximately 100/mills/kwh based on the capital cost estimate from the RAND model ($2266/kw). If, as the staff of the Oregon PUC has suggested, these costs are assigned only to the water conditions for which the projects are being built, the realized capacity factor could drop to as little as 35%, and the busbar power rise to over 150 mills/kwh. Using the staff capital cost estimate and a 60% capacity factor, the busbar cost would rise to 62 mills/kwh from the current staff estimate of 54 mills/kwh. As I have indicated, these are unachieveable estimates. Using the $1744/kw estimate provided by Pacific in their recent filings, the cost would be 78 mills/kwh. All of these estimates use the 14.5 mill/kwh fuel plus O&M estimate made by staff. Using Mr. Carstens' fuel and O&M estimates, the cost would be much higher.

1029 177

Q: Have the applicants allowed for costs such as you have described in their reported anticipated rate hikes?

A: None have allowed for any increase over their anticipated cost of the plants. All would have to have more rapid rate relief than projected if the projects were to be financed and built. Puget and Water Power have estimated 12% annual rate hikes, PGE has indicated that 9.9% annually would be required, while Pacific, with its highly diversified resource base and limited nuclear investment, only forecasts about 8% annual hikes. In adjusting these to reflect actual projects, it would not be unreasonable to assume an additional 3-5% annually for Puget and PGE, and 2-3% for Water Power and Pacific.

Q: Is it likely that these rate hikes will produce the needed revenue?

A: It is difficult to determine what effect elasticity will have. PGE is the only Northwest utility with a prolonged history of rate hikes of any significant magnitude. A result has been that their sales per residential customer have dropped steadily since 1968, as indicated in their 1978 annual report. Puget has reported anticipated sales growth of 5.32% in their filings on financial qualifications (table 2-2), but only 4.8% in Mr. Knight's testimony, in their annual report and in the 1979 West Group Forecast. With higher rates required, it is likely that the continuing drop in electrical demand forecasts, which have characterized the region for about ten years during

relatively stable price conditions, will be rapidly accelerated. It is my estimation that the "Alternate Scenario" published by ERDA in 1977, showing a decline in regional electrical use after 1985, can easily become a reality in the face of 16% annual rate hikes. We will have an opportunity to observe short-run elasticity this winter when the PUD's all face 50% rate hikes in response to the BPA 90% wholesale rate increase, largely needed to pay the first installment on the WPPSS nuclear projects.

Q: What impact will all of this have on the ability of the applicants to maintain the required coverage on their bond interest and preferred dividends?

A: The rapid increase in construction cost will make it very difficult for the applicants to maintain the required coverages. Puget, Portland, and Pacific are already showing themselves very close to the limit of coverage, as indicated in the table below, compiled from the data in their statement on financial qualifications. As construction costs increase and while the utilities are unable to recover any return from the unfinished plant, it will become impossible to maintain coverage. With financing costs much higher than anticipated, coverage will drop as well. It will be impossible to maintain coverages without the inclusion of Construction Work in Progress in the utility rate base . Ballot Measure 9 in Oregon last year strictly prohibits such charges, whther direct or indirect. Litigation is presently pending in Washington to test the

authority of the WUTC to permit charging a fraction of CWIP in rate base, although the WUTC has not permitted the utilities anywhere near the inclusion they have requested.

Table 6

Participant	Interest Coverage Requirement	Interest Coverage Projected	Preferred Dividend Coverage Requirement	Preferred Dividend Coverage Projected
Puget	2.0X or more	2.1-2.9X	1.5 or more	1.5-1/9
PGE	2.0X or more	2.2-4.1X	1.5X or more	1.3-2.2X
Pacific	2.0X or more	2.1-2.5X	1.5X or more	1.7-1.9X
Water Power	2.0X or more	2.9-3.6X	1.5X	5.9-8.2X

Q: Are there any new considerations in financing which have developed since the Three Mile Island incident?

A: Prior to the incident, most investment analysts were primarily concerned with coverage ratios and regulatory environment. Now a third primary concern has developed. GPU was able to absorb the loss of TMI from its rate base, primarily because it was a small part of their total holdings. With 60 million shares of stock outstanding, and $230 million in insurance, GPU has absorbed the entire loss through insurance and a reduction in stockholder equity. The average share of stock in GPU has dropped by about 8 points since the incident, leveling two months after the incident at about 10. Puget, for example, could not absorb such a loss. A look at their reported 1988 capital structure shows them to have too little common equity to absorb the loss of the Skagit plant.

Table 7 Reported Puget 1988 Capital Structure
(thousands)

Debt:	$2897
Preferred:	792
Common:	2186
Total	$5875

Adjusting this structure to show the cancellation or deferral of Pebble Springs, and increasing the capital costs for Skagit to reflect the estimate derived from the RAND study, would result in the following capital structure:

Table 8

Debt:	$3016
Preferred:	862
Common:	2277
Total	$6155

Under this scenario, Puget's investment in Skagit, $2.335 billion, would exceed the entirety of stockholder's common equity. This turns Puget's bonds into truly speculative offerings, and would undoubtedly be accompanied by a downgrading of their already precarious credit rating; as Mr. Beighle stated in his closing argument earlier this year:

"This company, Puget Power, is in the spotlight nationally. In Mr. King's opening testimony he cited two Wall Street Journal articles, one of which pointed out that it has the largest construction program for its size of any electric utility in the United States...We do have the bottom of the barrel rating as it is. We are rated Baa on both our bonds and preferred stock. And we are on the bottom step to nowhere." (Transcript 3872-3873, cause U-78-21)

It is clear from this passage that Puget was in a precarious position prior to the incident in Pennsylvania, as well as

prior to the most recent cost escalation on the Supply System projects and others like them. The Supply System is not alone in their problems. The Shoreham project of Long Island Lighting is now scheduled for completion about the same time as the first Supply System unit, at a cost of $1880/kw, for a 1981 operational date. The Greene County unit of the Power Authority of the State of New York was cancelled in April, with an estimated capital cost at the time of cancellation of $2558/kw. Two units in Iran were cancelled by the new government which were to have cost $2541/kw. The cost estimates for Skagit are sure to rise, and the applicants lack the ability to finance them at their present cost.

Q: Is it your position that even under the best of circumstances the applicants would be unable to secure the required financing for the projects?

A: Even if the present applicant cost estimates, financing costs, and rate hikes were all realistic, I think it is unrealistic to believe that a facility 90% owned by utilities with Baa/BBB bond ratings could go to the market for financing in the wake of the incident at TMI. In any event, it is unlikely that they would be able to sell the power from the projects at a price which would cover costs. Under any reasonable cost and schedule estimate, financing costs and amortization would place the projects even further from feasibility.

Q: What alternatives do you feel should be considered by the applicants in meeting future power requirements?

A: The primary resource we have in the Northwest is conservation. Since we have the lowest power rates in the nation, we waste more energy than other areas. Our cost of new power is no less expensive than others, so we should concentrate on bringing our consumption down to the national average before initiating new construction projects. The Skidmore, Owings, and Merrill conservation study is a part of the record in this proceeding, and discusses conservation opportunities equal to the output of about twelve large nuclear plants. I would only point out that the cost of new resources has risen rapidly since 1976, when the SOM study was completed, and as Dr. Winters has indicated, an increase in cost is associated with additional conservation opportunities becoming cost effective. I estimate that a retrofit of every resistance heated home in the Northwest with heat pumps would be cost-effective, when compared with new generating capacity, something which was not considered by the SOM study. Additionally, if new generation does become necessary, it appears that at 100 mills/kwh, virtually any other technology is less expensive than the Skagit projects would be, including coal, wind, and even oil or natural gas fired combined-cycle plants. The EPRI coal-fired combined cycle plant now under development appears to be a very promising technology.

Q: Why do you think the applicants are continuing with this project if it is so clearly beyond the realm of prudent utility practice as you have suggested?

A: The regulatory system provides no incentives for efficient management. A return to ratebase insures only that ratebase will be maximized. The Averch-Johnson effect is very much in evidence. Additionally, the applicants are unable to recover any of the sunken costs which they have incurred in the projects unless it becomes "used and useful" in providing utility service. For that reason, they are reluctant to write off the approximately $200 million which they have invested to date. A bill to allow the Oregon utilities to write off the sunken costs of Pebble Springs was introduced, but dismissed by Mr. Frisbee, in part due to the fact that it could not provide any relief to Puget, which is a participant in that project.

The regional power bill proposed by Rep. Weaver would provide the BPA with the ability to assume the sunken costs while cancelling the projects. It may be an irresistible attraction to the applicants if they are unable to get the Jackson bill enacted. The Jackson bill would make it possible to finance the projects by a BPA bond guarantee, but only if they could be shown to be the most cost-effective energy resource once the regional energy plan has been approved. That process would take

at least two years, and offers no real hope for this project. It is evident that the Skagit plant is not the most cost-effective resource, and therefore would not qualify for relief under the Jackson bill.

Q: Does this conclude your testimony?

A: Yes.

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