Maiorano

1995 LEAST COST PLAN

12/8/95

An Integrated Resource Plan

Washington Natural Gas
A Washington Energy Company

II. KEY ISSUES AND ACCOMPLISHMENTS

This is a time of unprecedented change, and much of what was "given" in the past is now under question. To plan effectively in this environment, it is necessary to examine the changing context under which least cost determinations must be made. Concepts that were once only formally applied to resource planning are now spreading to other aspects of utility operations. This is as it should be, and is the logical outcome of the often-stated cliché, "Least Cost Planning is an evolving process". With the increasing competitive pressures that are being brought to bear on LDCs, least cost planning can be an invaluable tool for remaining competitive. Good planning helps those that practice it, leave the cost-plus paradigm behind and find the least cost solutions that a competitive marketplace demands. The first half of this chapter provides an overview of the key issues that WNG faces with respect to least cost planning.

During the past planning cycle, WNG has attained many significant goals. The latter half of this chapter highlights WNG's key accomplishments in least cost planning since the filing of the 1993 Plan. Since that plan was filed, many new challenges have been encountered. WNG has prepared this plan to identify, understand and overcome these challenges.

A. KEY ISSUES

1. *The Northwest Energy Market*

Regulatory and economic influences will continue to shape the regional energy market as a whole (gas, electricity and other energy sources). Changes in the regulation of natural gas, in addition to changes in how electricity is provided and regulated in the Pacific Northwest (PNW), will continue to directly affect how LDCs plan and operate their business.

Despite the fact that energy prices in the PNW have historically been among the lowest in the nation, the cost of providing energy (particularly electricity) has increased since the early 1970s. Several factors caused this increase, including the cost of foreign oil, upward pressure on demand resulting from increasing economic growth, and environmental and safety concerns over the development of new nuclear and coal powered electrical plants. Environmental concerns have also affected the hydropower system.

As economic growth occurred in the region, particularly in the Puget Sound Basin, the demand for energy increased. In response to these pressures, utilities began to offer conservation programs and stringent energy codes were enacted. Decreased usage per customer due to conservation and codes was offset by the number of new customers being added. Regional growth in energy use continued during this time. Natural gas became more readily available form Canada and the Southwest due to additional pipeline infrastructure and an increasingly active and innovative market for supplies. These supply developments, coupled with regulatory changes, brought lower cost gas to the PNW. Electric utilities began to turn to cogeneration facilities or new gas-fired generation to meet expected new loads.

Together with new regulation and technology innovation, these factors have caused changes in the energy markets. These changes present both opportunities and new risks to LDCs. The future of the PNW energy markets has grown less predictable. We believe LDCs must continue to improve and challenge their planning to ensure that customer needs are met at the least cost.

The future of the electrical markets is at least as uncertain as that of the gas industry. With the current restructuring of BPA and actions of the Northwest Power Planning Council (NWPPC), regional planning for the electric industry is in a state of flux. The strong linkage of the gas and electric markets has the potential to significantly affect LDCs. For the moment, growth of gas-fired electric generation has slowed in the PNW. The impacts from current gas-fired electric generation projects are known. These projects have either secured firm gas capacity rights, made provisions for alternative on-peak fuels or are scheduled to run off-peak. Future gas-fired electric generation projects may have significant impacts on the cost and availability of supplies and transmission access. FERC's tacit approval of rolled-in versus incremental pricing of new pipeline expansions will adversely affect LDC customers if pipelines expand to accommodate future gas-fired electric generation.

The potential changes in the operation of the Columbia River Hydro System will also have an impact on LDCs if electricity producers use increased amounts of gas in response to any changes to the hydroelectric system operation. While a tentative agreement for pollution control seems to have been reached for the Centralia coal plant, the Clean Air Act may also affect pipeline costs and operations, which in turn would impact LDCs.

These issues underscore the need for strong and innovative planning on the part of LDCs in order to meet customers' needs at the least cost. LDCs are unable to meet the challenge alone. They must work proactively with regulators and stakeholders to shape an industry that can meet this goal.

2. *WUTC's Notice of Inquiry (NOI)*

The WUTC's NOI is another critical element to consider in the review of this plan. The NOI is a logical progression in the regulatory reform and industry restructuring that has been under way for several years. The NOI raises numerous issues relating to least cost planning and LDC regulation. How least cost planning is conducted in this period of change will directly affect how the gas industry, and LDCs in particular, will conduct and define their business.

The NOI represents the kind of opportunity required for LDCs to help shape the environment in which they must operate to meet customer needs at the least cost. WNG has filed direct comments in this process but will take this opportunity to briefly review some key points.

The NOI poses several questions about demand-side management (DSM) in the "new" environment. WNG remains committed to DSM as an integral part of our strategy to meet customer needs at the least cost. WNG is continuing to explore the potential for cost-effective gas DSM programs. While it is true that avoided costs are low for gas LDCs, WNG believes that innovative, well-managed programs can be accomplished cost-effectively. Some measures have not been fully studied, yet may offer significant avoided cost savings. Duct sealing is one such measure that shows promise. WNG is committed to determining the cost-effectiveness of potential DSM strategies. In some cases, this will require in-depth field work.

In order for DSM to "fit" with the evolving gas industry and the increasing level of competition, mechanisms to make LDCs whole for prudent program expenditures and lost revenues need to evolve in concert with other changes. The DSM tracker approved by the WUTC for WNG is one such mechanism. WNG will be studying and proposing other mechanisms to deal with the equity and competitive aspects of DSM programs. Developing approaches that facilitate participants bearing a significant portion of program costs is the next step. This needs to be done in a way that maintains cost-effective participation levels. Large scale programs will need to be more market-oriented than in the past. Low interest loans, energy service charges, participant fees and market transformation strategies will likely be integral components of future programs. These may, however, be inappropriate for research pilots.

3. *Natural Gas Futures*

The least cost planning rule requires LDCs to consider the role that natural gas futures can play in achieving least cost. Through the use of hedges, price risk can be monetized and price certainty attained. However, if this strategy were simply applied to all core market gas supply purchases, the net result would likely be higher costs over time. Under the current PGA process, the core market would realize no benefit from paying for price certainty. The PGA provides for core market price stability by averaging short-term cost variations over longer periods. In the event that the PGA process was to be eliminated, the core market would no doubt value price certainty differently.

Hedges do have a role to play in achieving least cost for the core market. Certain market participants, particularly large end users purchasing their own gas supplies, may require a fixed price. Hedges can be used to provide a fixed price to the off-system customer and to lock in a known gain for the benefit of the core market. It is important to understand that WNG does not expose itself to price risk when providing fixed price gas to an off-system customer. WNG includes the transactional costs of the hedge in the fixed price offered to the off-system customer.

Other futures based strategies exist. These involve price prediction. The accounting definition of speculation is to take either a physical or financial position for which you have no offsetting position. Taking a futures position that is backed with physical commodity is not considered speculation under this definition. However, the action is based on a belief about the difference between the currently-traded value of a future quantity of gas and the value that the market will place on that gas in the future.

Through careful study of particular economic and operational characteristics of the gas market, it may be possible to realize lower gas costs through the use of futures in certain instances. It is essential that all parties understand that such a strategy is probabilistic in nature. While it may be implied by study that a fixed price will provide a positive expected value in certain circumstances, it is not guaranteed. It is highly likely that some transactions will cost more than corresponding market priced purchases, while others will cost less. Simply put, least cost may be attained overall but some transactions will have higher costs than they would have otherwise had. A hedging program for the core market will need to be judged on its overall impact rather than on the basis of individual transactions. Without regulatory understanding and acceptance of this, LDCs engaging in this type of strategy may create serious risk for gas cost disallowance if individual transaction results are viewed in isolation when examining prudency. WNG intends to develop a specific action plan to be discussed with staff to explore the viability of this strategy. WNG further intends that such a strategy would come before the Commission in some form prior to implementation and application to core market gas purchases.

In order to achieve the lowest cost for customers, LDCs will need to continue to be more aggressive in representing the interests of their customers. These core market gas cost mitigation strategies require significant implementation costs. Mechanisms need to be developed that protect customers from imprudent action but that also reward LDCs for prudent risks taken and compensate them for the additional administrative costs. Without these mechanisms, LDCs may soon provide only the *safest* cost gas - gas bought at market index - as opposed to continuing their pursuit of least cost service.

4. <u>Peak Day</u>

Peak day was one of the more "engaging" topics discussed this planning cycle by WNG's least cost planning Technical Advisory Committee (TAC). WNG would like to thank all of those that contributed to those discussions.

WNG uses a 10 degree Fahrenheit average daily temperature, as its peak day planning standard (55 Heating Degree Days (HDD)). This average temperature was observed at the SeaTac weather station. WNG plans to meet firm loads under this condition. It should be noted that the SeaTac weather station is 2.11 degrees warmer than WNG's service area weighted average temperature. WNG does not use a "reserve margin" (safety factor) when determining the resources necessary to meet peak loads—all resources are assumed to be 100% reliable. WNG believes that this is an appropriate standard that has served both customers and the company well. If WNG's peak day planning standard were to be revised to a warmer temperature that has a higher frequency of occurrence, the policy of using zero reserve margin will need to be revisited. The operational costs of losing system pressurization are quite significant and can lead to unsafe conditions.

V. SUPPLY-SIDE RESOURCES

This chapter covers supply-side resource options. Specifically, this chapter describes:

- The supply-side resources available to meet customer demand;
- Marketplace strategies to lower the cost of resources to core customers; and
- The environment in which gas supply decisions and transactions are made.

Approximately two years have passed since Northwest pipeline (NWP) instituted new tariffs pursuant to FERC Order 636. New regulatory initiatives to deregulate the natural gas industry, and energy markets in general, have significantly changed the marketplace. The key changes and effects are listed below.

- Natural gas and, within certain limits, pipeline capacity are now tradable commodities and are functionally available to all.
- Competition among gas producers has resulted in continued downward pressure on the commodity cost of gas.
- The marketplace generates clearer price signals for producers while providing buyers greater choice and flexibility.
- LDCs are required to make more decisions and accept greater price risk to acquire supply to serve the core market at the least cost.
- Administrative costs in terms of labor and analytical tools have risen as LDCs attempt to manage supply risks and minimize the costs to consumers.
- Minimization of gas costs often increases an LDC's risk.

Potential changes from efforts to deregulate and unbundle the electric industry will bring new challenges. While the new relationship between gas and electricity is just beginning to take shape, it appears that they will become freely traded and interchangeable. The ability to optimize resources will require least cost decision-making in the context of all forms of energy.

The new gas supply environment is dynamic with gas prices changing by the minute. The array of supply options has expanded greatly as has the number of market participants. There is stiff competition for load and margins among buyers and sellers. Credit and credit worthiness have taken on new importance as the number of transactions and trading partners have increased.

The result of all of this change has been an increase in an LDC's level of risk. Gas price risk, upstream/downstream transport risk, supply risk, and credit risk are all greater than before.

WNG has successfully navigated through the new competitive market by assessing its needs and then responding to the market. In terms of gas supply, WNG identified 12 areas of importance in its 1993 Least Cost Plan. Each of these areas will have an impact on the portfolio of resources WNG ultimately chooses in the near term, mid term, and the long term. To understand the current and evolving gas supply environment it necessary to identify the issues that are having the greatest impact on WNG's ability to meet its gas supply and capacity objectives:

- Selection of Supply Regions (geographical location);
- Supply Availability and Diversity of Supply (deliverability);
- Capacity/Supply Utilization (exchanges and swaps);
- Capacity Off-system (Westcoast et al, firm or interruptible);
- Canadian Regulatory (federal and provincial impacts);
- Market Competition (who are we up against, what are the costs);
- Maintaining Market Share (buying power, how to stay competitive);
- Cost of Gas vs. Reliability (spot vs. firm);
- Pricing (market related vs. fixed vs. futures related);
- Capacity Release Market (impact on gas supply and cost);
- U. S. Regulatory (federal and state impacts); and
- Load Factor Management (off-system sales and special contracts).

These issues can be more generally categorized in the following seven topics to be discussed in this chapter:

- Supply;
- Demand;
- Price;
- Pipeline Capacity;
- Market Centers;
- Regulatory Issues;
- Supply Objectives and Strategies; and
- Additional or Emerging Supply Options.

A. SUPPLY

1. *Current Supply Outlook*

The overall supply picture for the near-term seems to indicate that gas will be available at lower costs. As was discussed in WNG's 1993 Least Cost Plan, the gas supply availability appeared to be tightening. Numerous reports and studies indicated that the so-called "gas bubble" (surplus) was depleting and the supply/demand balance was closer to equilibrium. However, the current supply/demand situation for the Pacific Northwest, which by extension, now includes market centers on all of the West Coast and much of the Mid-West appears to show a re-emergence of the gas bubble. Firm gas supplies are readily available from all supply basins: British Columbia (B.C.), Alberta and Domestic (U.S.). Gas supplies from all supply basins have experienced shifts away from traditional markets on a seasonal basis. The opportunity to arbitrage between a market that is short (deficit) and a market that is long (surplus) is possible given WNG's physical location between prolific supply basins and its capacity on Northwest Pipeline (NWP) and Pacific Gas Transmission pipeline (PGT). For example, San Juan Basin supplies compete with low cost Alberta supplies in California. This results in San Juan gas supplies being back-hauled to other markets, principally east. Gas supplies in B.C. have also been looking to expand into other markets, notably east to Alberta. Major supplies in B.C. seeking higher utilization and better market access are being aimed at East Coast and Midwestern markets placing a significance on higher load factors and different pricing structures. These factors have given WNG opportunities to source supplies at low prices. Moreover, WNG can switch from buyer to seller during off-peak periods to supply gas to others at market-driven prices that are higher than cost (thus offsetting gas costs to core customers). The continuing integration of gas supply markets across pipelines and international boundaries is evident. These factors strongly suggest a supply market that is presently long.

However, B.C. gas supplies, may be subject to variations in availability as producers await Westcoast pipeline availability or pursue better market opportunities in Canada and to the East . Many Canadian producers are availing themselves of a greater percentage of cross-provincial border trading (B.C. to Alberta and/or vice versa). In the U.S., gas flows to the market offering the highest net-back to the producer. However, net-back prices are influenced by many things including availability of firm take away capacity, storage, other competing supplies, and market demand. The following is a brief summary of the status of the deliverability and reserve situation in the Canadian provinces and the Western U.S. as gleaned from several published reports.

- British Columbia (B.C.)—The B.C. supply basin is vitally important to WNG, as a result of displacements and other arrangements 100% of all physical gas consumed in WNG's service territory originates in B.C. In addition, from a contractual point of view, WNG must source approximately 25% of its peak day requirements at Sumas (pipeline interconnect between Westcoast Energy (Westcoast) and NWP at the U.S./Canadian border.

  By certain accounts, including projections from Westcoast's five year forecast, much of the new B.C. gas deliverability is replacement for declining gas deliverability from existing wells. Further, new development activity including much of the Monkman Pass/Pine River development is potentially found in trend areas. However, Westcoast's forecast of total market is projected to increase from 547 Bcf in 1993 to 767 Bcf in 1999. This will be accomplished by drilling between 122 and 131 successful wells each year. Moreover, significant expansions are projected to occur at gas processing plants in the Fort Nelson, Pine River, Aitken Creek, and McMahon areas. Offsetting some of these robust projections is the uncertainty concerning the regulatory environment in Canada, particularly in B.C. The uncertainty involves the recent NEB (National Energy Board) decision on future pipeline and related facilities expansions and its jurisdiction over these facilities within B.C. (see regulatory discussion).

  The downside to all of the projected activity is that the average raw acid gas percentage (sulfur, etc.) in these areas is high. Processing and treatment costs of the higher raw acid gas translates into higher gas costs. Sulfur production may partially limit future gas development in certain areas. Moreover, according to Westcoast's five year plan, one third of northern British Columbia volumes would be directly transferred into Alberta via the NOVA system. Westcoast is hoping that Alberta will provide an additional outlet for growing British Columbia supplies.

  The greatest impact on future gas development may be the economic incentives or lack thereof from the buying community. Moreover, larger and more active environmental coalitions will continue to play a large role in the future development of gas reserves in British Columbia.

- Alberta—Alberta gas supply is similarly important to WNG. WNG's single largest gas supply contract (10.5% of WNG's estimated 1995/96 peak day requirements) is sourced in Alberta. The contract, while having considerable term remaining, will be affected by the supply situation in Alberta. WNG's ability to successfully conclude annual price re-determinations under the contract or to attract other Alberta producers to various types of arrangements will be influenced by the overall supply picture in Alberta.

  Complicating matters in Alberta are the uncertainties placed on both buyers and sellers as the large aggregated supply pools are separated through federal (NEB & FERC), state (California & Wyoming) and provincial (Alberta) government actions.

  Alberta supplies represent a huge supply resource which in 1994 was estimated to be 14.4 Bcf per day. This demand on NOVA, the largest pipeline in Alberta, is expected to peak at approximately 14.8 Bcf in 1997. The large increase in producer and NOVA 10 deliverability is due to many factors: strong price forecasts (which have not materialized), increased pipeline expansions to markets out of Alberta and strong demand forecasts. (NOVA predicts shortfalls in peak day pipeline deliverability relative to peak day supply deliverability in 1995 through 1997).

- U.S.—WNG has strategically spread its U.S. gas supply acquisitions at various locations on NWP. Domestic gas supplies are delivered into NWP from numerous individual plant and gathering systems interconnected with NWP or from other adjoining interstate pipeline systems. WNG has intentionally purchased gas supplies at several different market "hubs". This has several benefits. Market centers or hubs create the means by which gas may flow in many directions simultaneously. Among other advantages, hubs will allow WNG to take advantage of exchange and off-system sale opportunities, resulting in the potential for core market cost savings. Hubs also provide access to gas from other pipelines increasing the opportunity for lower cost gas purchases.

Gas supply availability has been influenced by the impact of recent pipeline interconnects, expansions, and hubs. Gas that was once captive to NWP has ready access to new off-system markets. In addition, new and proposed highly efficient gas-fired electric generating facilities, including high load factor cogeneration plants, have intensified the competition for existing gas supply. The need to contract for gas at higher load factors is one result of these new areas of competition. Also, the futures market has strongly impacted the supply equation (see Price discussion). Futures oriented hedging normally requires a 100% take commitment on the part of the buyer otherwise penalties would result. To the extent that gas suppliers only offer gas tied to the futures market, high load factor commitments will be the norm rather than the exception.

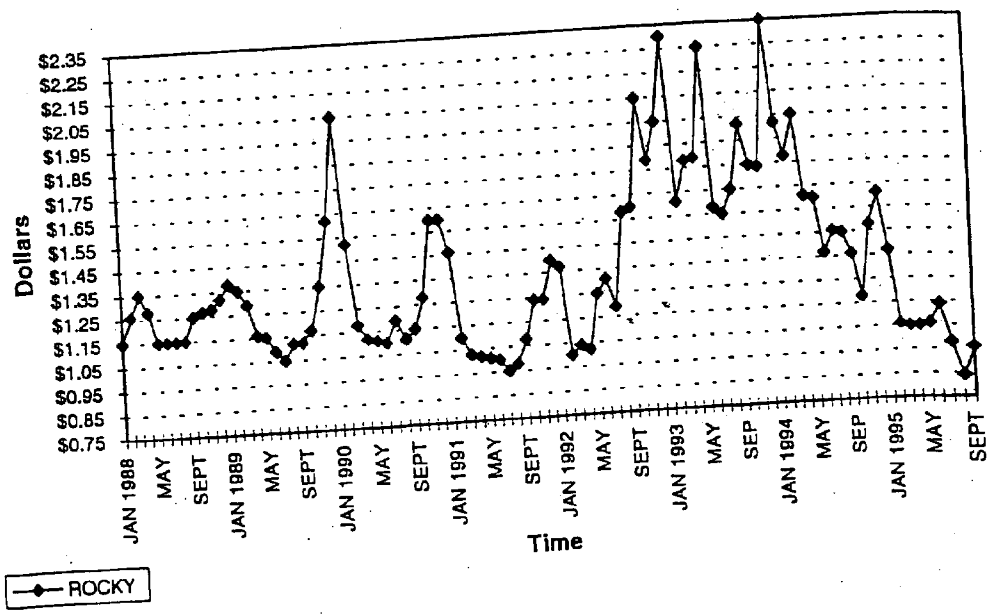
The supply situation in the near-term has also changed as a result of changing market dynamics. Many gas suppliers in the San Juan Basin have historically perceived the Pacific Northwest as a less attractive market than California. Gas suppliers in this region are now choosing to re-enter the Pacific Northwest market, or move their gas to Mid Western or Eastern markets. The primary motivation appears to be that prices in the Pacific Northwest and other regions are gaining parity with other market alternatives. Moreover, the California market is turning back supply and pipeline capacity from this region in favor of lower cost Alberta supplies.

Approximately 40% of remaining U.S. recoverable gas resources are contained in unconventional reserves. Over half of the remaining unconventional tight formations are located in the Rocky Mountain region, and just under 50% of all coal-bed methane gas is found in the San Juan basin. This is of paramount importance to WNG because NWP can access this gas now and in the future. Technological advancements such as three dimensional seismic and horizontal drilling have improved access to previously undeveloped resources, and have in many cases lowered the cost of natural gas development. These developments have allowed producers to shorten their time horizon on exploration and development, and has resulted in a production schedule that attempts to mirror demand. Further, WNG is well situated to access these unconventional resources given its diverse portfolio of supplies, varied pricing strategies, and capacity portfolio.

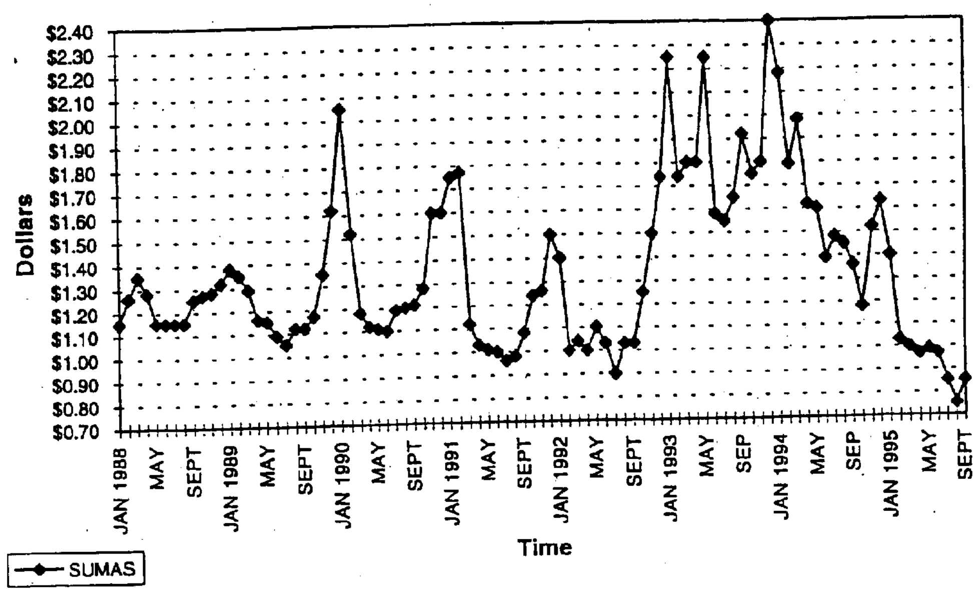
APPENDIX C
Supply-Side Resources

The following graphs indicates historical pricing trends.

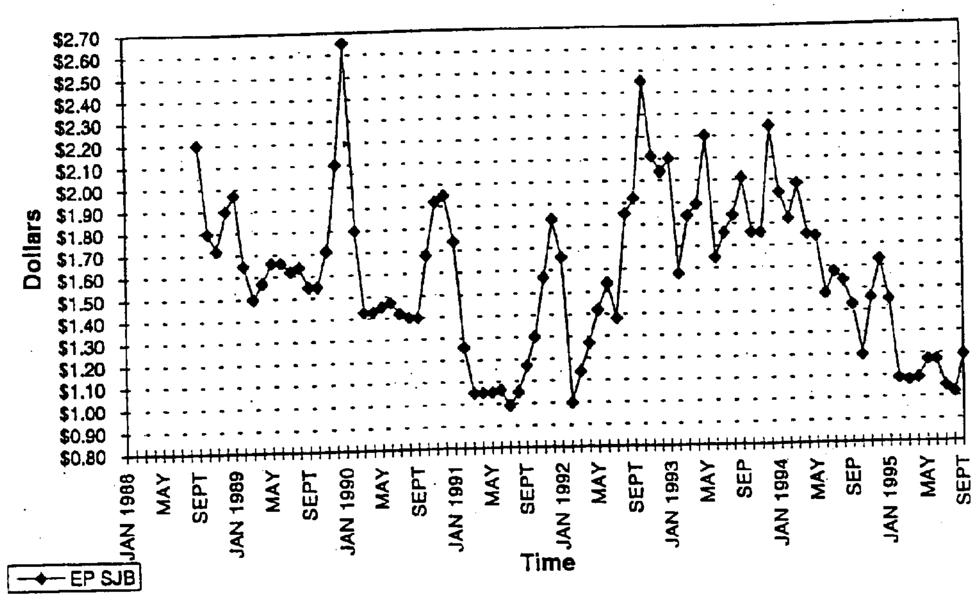
Actual Rocky Mountian Index



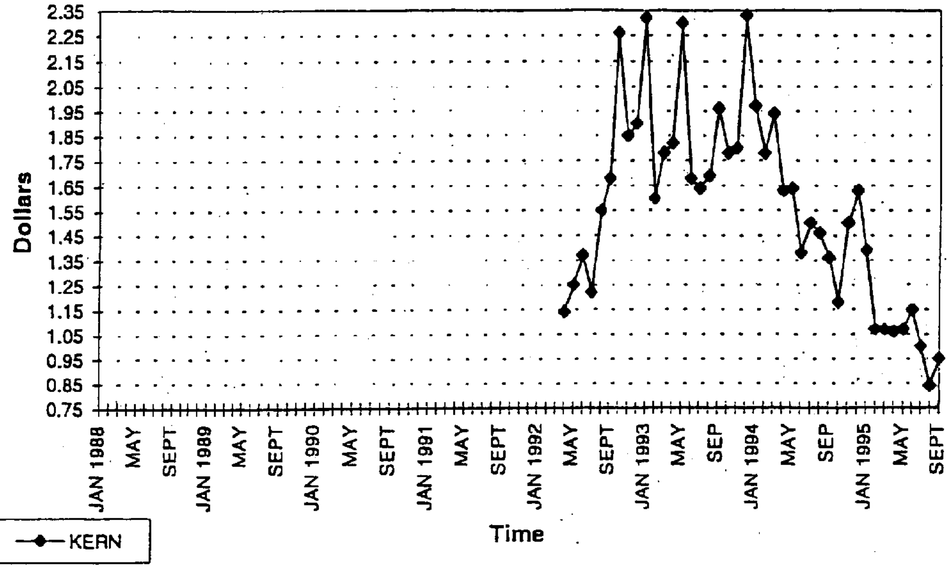
Actual Sumas Index



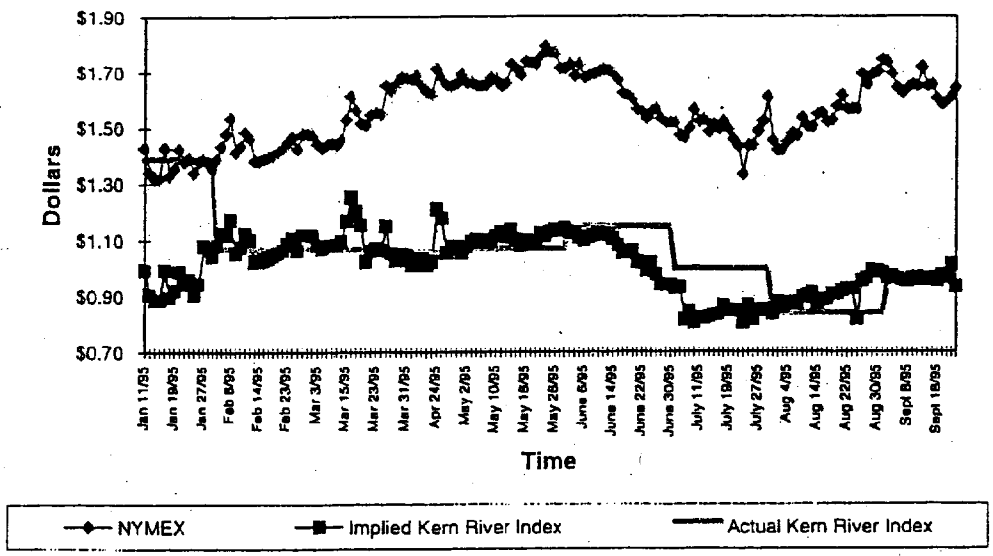
Actual San Juan Index



Actual Kern River Index



Kern versus NYMEX



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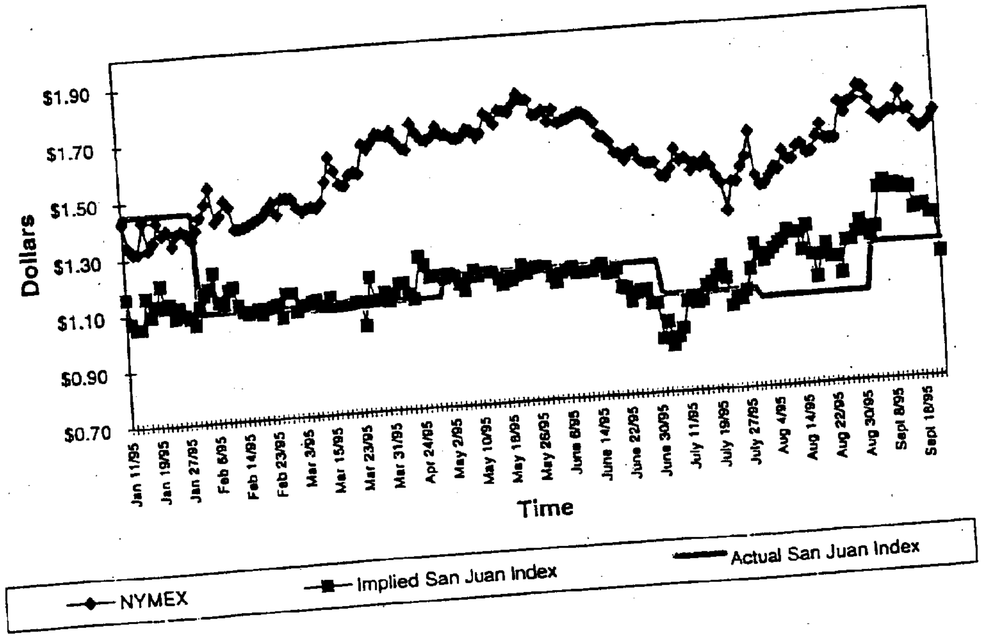
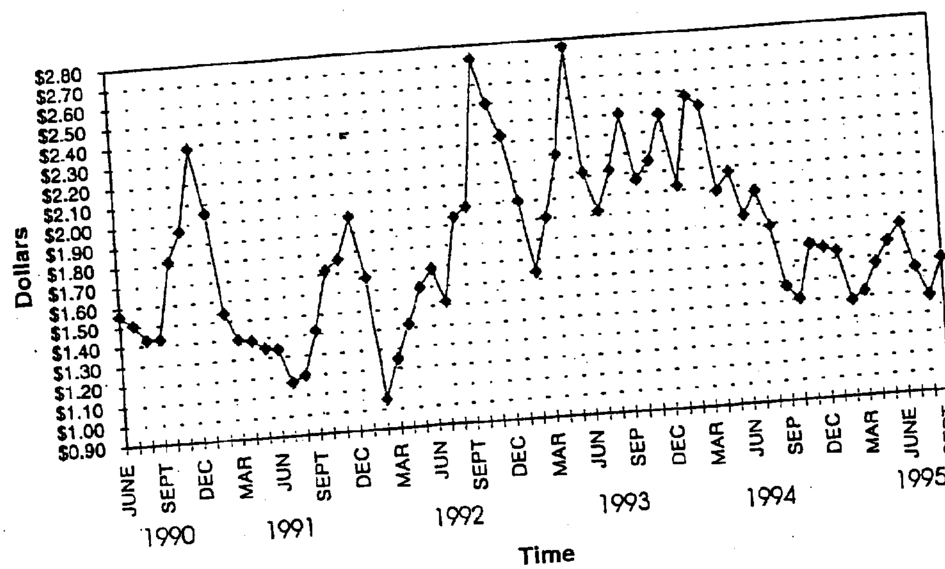
San Juan versus NYMEX



NYMEX Near Month Closing Figures



1995 - 1996
Integrated Resource Planning Update

Puget Sound Power & Light Company

Draft For TAC Review
February 24, 1995

INTRODUCTION

Nationwide, a natural collision is taking place between integrated resource planning and additional competition in the industry. Puget Power's prior Integrated Resource Plan was presented to the WUTC in May 1992, shortly before the passage of the 1992 National Energy Policy Act (NEPAct). That IRP, and those prior to it, developed effective resource strategies to address the utility planning environment at the time. In retrospect though, those environments now appear very traditional, an "old world" of utility planning.

Since publication of the 1992 IRP, the pace of change toward increased competition has been rapidly accelerating throughout the electric utility industry. Puget Power's 1990-91 IRP considered a number of "wild card" scenarios. We now find ourselves in what would have seemed, until recently, a "wild card" environment. One primary intent of integrated resource planning was the full consideration of certain social objectives under a traditional environment. The methods of achieving those social objectives are now threatened by the specter of certain forms of competition based primarily upon near-term pricing.

PURPOSE

This IRP update is a transitional document. The industry is undergoing rapid, fundamental structural change. It is very difficult to predict the future roles of, and obligations to be placed upon, investor-owned utilities. Events may occur that would render the plans in this document irrelevant.

This plan is premised on the requirements of WAC 480-100-251. The purpose of this document is to provide a snapshot (within the framework of the existing IRP rule) of the current planning environment and the effects of a changing industry structure on Puget Power's resource planning decisions. This document will update technical information on resource costs and needs, examine different futures related to economic and competitive conditions, review changes in resource strategies from those expressed in the prior IRP, and fulfill the requirements of WAC 480-100-251. It will do so in an abbreviated format.[1]

In addition, the future purpose of integrated resource planning is being reviewed both in national debate and in the current WUTC Notice of Inquiry (NOI, Docket No. UE-940932). While the current NOI activity will not be resolved for a number of months, this update is consistent with, and will supplement, Puget Power's February 17, 1995 response to the NOI.

[1]In support of this document, three appendices are included: Appendix A is a status report on Action Items from the prior IRP; Appendix B discusses public involvement; and Appendix C presents the company's proposed avoided cost going forward.

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INDUSTRY COMPETITION

Background

Since publication of the prior IRP, the pace of change in electric utility industry has rapidly accelerated. Wholesale energy markets have now become competitive and interest in retail competition has increased. Retail competition is by no means a foregone conclusion. However, competitive forces have introduced new pressures and uncertainties which have significantly altered planning criteria. At this time, the eventual forms this competition might take are very uncertain and may be quite varied across the country.

Continued low gas costs and technological advances, coupled with federal regulatory changes and increasing worldwide competitive pressures on commercial and industrial users of electricity, have led to strong interest in the provision of customer choice. Even in regions, such as the Northwest, where the economic advantages in new generation are not nearly so pronounced, or may not exist at all, customers are requesting more options and choices. Utilities are being strongly pressured to compete on the basis of both near-term price and service options.

Objectives of Integrated Resource Planning

Integrated resource planning arose as a method by which, among other things, the pursuit of public policy objectives could be addressed at the planning stage of utility resource acquisition efforts. It was hoped that a structure could be established by which these concerns could be incorporated into utility plans and as a result, lead to the avoidance, at an early stage, of costly "mistakes" of utilities taking actions contrary to the public interest. Some of the objectives of traditional integrated resource planning include:

- Consideration of a number of future conditions under which resources might be needed and acquired over a 20-year horizon
- Significant public involvement in the development and review of plans
- Consideration of energy efficiency as a resource
- Consideration of a wide variety of supply-side resource options including renewable resources
- Evaluation of resource options on a consistent basis according to the lowest long-term cost to the utility and its ratepayers. To Puget Power, this includes the consideration of issues such as environmental effects.

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The Conflict

Additional competition which gives the incentive for lowest near-term price naturally conflicts with integrated resource planning principles. As competitive forces have been increasing and uncertainty prevails, utilities have been responding by cutting non-essential costs, focusing on near-term rate minimization, and investigating individual customer service options. Such efforts are seen as necessary for continued survival. A utility with a long-term focus on environmentally-preferable resources will likely be unable to address short-term pricing pressures. Utilities who continue to take such a long-term approach may be punished by the market, in the short term, for doing so.

Further, with the introduction of increasing retail competition, fewer decisions would fall under the scope of long-term planning. As indicated below in the scenario analyses, utilities could take advantage of flexible options in the wholesale market to respond directly to customer needs, and other providers, not subject to such planning, may be satisfying customer needs as well. Finally, the requirement of an open planning process would place utilities at a competitive disadvantage because of the public dissemination of strategic information. Issues related to the future of integrated resource planning are further discussed in the company's response to the current NOI. Now is an appropriate time for interested parties to revisit the objectives on which integrated resource planning was established and assess methods by which current objectives can be accomplished.

Competitive Considerations In This Update

Traditional integrated resource planning typically focuses upon uncertainties related to overall economic conditions and resource costs and availability. This focus was appropriate in the past because those were the primary uncertainties affecting the welfare of all stakeholders (customers, shareholders, communities, regulators and others). Now, however, the set of fundamental uncertainties in utility planning has dramatically changed. New types of risk have arisen related to issues such as which customers will be served, how they would be served, possible non-recovery of investment, utility obligations, and the terms under which any possible increased future competition would occur.

It would be inappropriate to conduct resource planning without thorough consideration of issues such as these. Their exclusion would yield a resource plan that had no applicability to current decision making. The challenge is to address these elements of the transitional environment while at the same time meeting the formal rules of integrated resource planning, established almost a decade ago.

This scenario analysis discussion first presents natural gas assumptions and information on resource alternatives. Load forecasting is discussed next, followed by descriptions of each scenario. Scenario resource additions are then identified, criteria for their evaluation discussed, and resulting resource strategies are described. This update concludes with the two-year Action Plan.

Natural Gas

Natural gas prices have remained low, despite past projections of significant increases. Recent low natural gas prices can be cited as a fundamental driver of today's competitive environment. The importance of natural gas prices on new resource selection in the industry today cannot be overstated.

Future natural gas prices remain very uncertain. Like many other natural resources, the price and availability of natural gas have a history of volatility. Market relationships in the gas industry have been changing. A large number of forecasters continue to make a range of projections of future natural gas prices. However, all gas price forecasts are lower than they were at the time of the prior IRP.

A number of current forecasts were presented to the Technical Advisory Committee (TAC). Puget Power and the TAC came to agreement that the Northwest Power Planning Council's medium gas price forecast would be used for the purposes of current integrated resource planning. This forecast is presented in Table 1. It should be noted that recent prices in the gas spot market are much lower than this forecast. This market has developed significantly and shorter-term firming arrangements are taking place. However, the use a lower gas price forecast in this plan would not alter its conclusions.[3]

Resource Options

This process begins with the initial consideration of a large number of resource candidates. These candidates are typically "generic" in nature in that they do not represent specific proposals, contracts, sites, fuel supply arrangements or installed technologies. The focus is to evaluate the relative tradeoffs between resource types. Puget Power develops the list of resource candidates through consideration of sources such as the EPRI Technical Assessment Guide, Northwest Conservation and Electric Power Plans, various industry publications, Consumer Panel and TAC recommendations, and its own operational experience and judgment. The list of traditional resource candidates remains essentially unchanged since publication of the 1992-93 IRP and includes the resources listed in Table 2.

[3]As indicated in Table 3, gas-fired combustion turbines have a current cost advantage over all other identified supply-side resources. Use of a lower gas forecast would only increase this advantage.

Table 1

Natural Gas Price Assumptions
Northwest Power Planning Council Draft* Medium Case
"Burner-Tip" Utility Firm Natural Gas Prices

Year	Real Gas Price (1990$/mmBtu)	Nominal Gas Price ($/mmBtu)	Real Escalation Rate	Nominal Escalation Rate
1994	2.00	2.23		
1995	2.15	2.47	7.50%	10.65%
1996	2.23	2.64	3.72%	6.91%
1997	2.30	2.81	3.14%	6.45%
1998	2.37	2.98	3.04%	6.25%
1999	2.45	3.19	3.38%	6.86%
2000	2.52	3.39	2.86%	6.35%
2001	2.58	3.59	2.38%	5.81%
2002	2.64	3.79	2.33%	5.70%
2003	2.69	3.99	1.89%	5.21%
2004	2.75	4.21	2.23%	5.52%
2005	2.80	4.42	1.82%	4.93%
2006	2.85	4.64	1.79%	5.03%
2007	2.90	4.88	1.75%	5.23%
2008	2.95	5.14	1.72%	5.19%
2009	3.00	5.40	1.69%	5.15%
2010	3.05	5.68	1.67%	5.16%
2011	3.10	5.97	1.64%	5.11%
2012	3.15	6.27	1.61%	5.01%
2013	3.20	6.58	1.59%	4.92%
2014	3.25	6.90	1.56%	4.91%
2015	3.30	7.24	1.54%	4.89%

* Draft as of 11/19/94.

Going forward, however, this list is not sufficient. As generation markets have been opened to competition, a number of new resource options have rapidly developed. Power brokers and power marketers now provide viable and very flexible alternatives to traditional resource options for utilities currently acquiring resources. These options will continue to develop and their place in the region's resource portfolio has yet to be determined. Other resource options will likely evolve out of the competitive generation market as well; however, the characteristics of such options are currently difficult to predict because the market is advancing quite rapidly.

All resource candidates are screened according to a number of initial criteria so that a smaller number of resource options can be given more thorough analysis. These criteria include environmental issues, public acceptance, availability, development maturity, efficiency and risk. As discussed later, conservation as a resource option is currently being re-evaluated in consideration of possible future competitive environments. For the purposes of the traditional analysis here, however, conservation, as screened by the total resource cost test, is fully included as a resource option.

The traditional supply-side resource options that passed the initial screening process are included in Table 3. These options have been further analyzed and ranked according to levelized resource cost. Though focusing on "generic" resource options, Table 3 illuminates some of the current cost tradeoffs between traditional resource types. For instance, Table 3 displays the current cost advantage of combined-cycle combustion turbines (CCCT's) over all other identified supply resource options. This cost advantage reflects advances in combustion turbine technology and the influence of the current low gas price projections from Table 1. Upon review of this table, it is no surprise that natural gas fired combustion turbines are the current resource of choice nationwide.[4]

Brokered, marketed and other supply options arising from the competitive generation market are not included in this table because their price, availability and characteristics cannot be generalized at this time. The pricing of these options may be strongly influenced by conditions in the competitive generation market. However, current developments suggest that these options are proving to be a attractive alternatives to preferred traditional resources. In addition, a number of financial instruments are developing in this market. Hedging techniques can be used to change the nature of risk seen by utilities, and, potentially, to construct options for customers according to desired risk profiles.

[4]However, it should be noted that these resource cost estimates represent a number of baseline assumptions related to fuels, technology, financial and economic conditions, and many other factors. Any number of those assumptions could change in a manner that would significantly alter the relative rankings in Table 3. While certain assumptions are varied in the scenario analyses, many of these baseline assumptions are held constant through the scenarios. Developments that change these assumptions could have large impacts on the resource additions identified for each scenario.

ACTION PLAN

Puget Power has moved into a strong resource position to address the needs of a uncertain and changing environment. The company has no near-term need for energy resources. From this position, there is currently sufficient flexibility to delay any major resource acquisitions now, and to monitor events and policy development and re-evaluate options once more information can be assessed by the company.

- **Delay any major baseload power supply resource acquisitions.**
- **Monitor developments related to industry change.**
- **Continue participation in the current NOI process.**
- **Monitor developments and options in the wholesale generation market.**
- **Monitor developing generation technologies.**
- **Pursue opportunities to re-evaluate and restructure, as appropriate, the company's power supply portfolio to respond to market pressures and opportunities.**
- **Pursue changes in pricing policies to allow utilities the flexibility to respond to customers and potential competitors.**
- **Pursue mechanisms by which symmetry is established between utility risks and potential returns as appropriate to the company's business environment.**
- **Encourage the exploration and development of alternative acquisition and recovery mechanisms for conservation and renewables so that continued investment in each is not discouraged.**
- **Encourage the exploration and development of mechanisms by which any potential competitors are governed by the same set of rules.**
- **Pursue the establishment of regulation allowing symmetry between utility duty to serve and potential future customer choice.**
- **Participate in the revision of IRP and competitive bidding rules to meet the current utility business environment.**

Christine O. Gregoire
ATTORNEY GENERAL OF WASHINGTON
900 Fourth Avenue #2000 • Seattle WA 98164-1012

July 12, 1996

Steve King
Acting Commission Secretary
Washington Utilities and
Transportation Commission
Chandler Plaza Building
1300 S. Evergreen Park Drive S.W.
P.O. Box 47250
Olympia, WA 98054-7250

Re: Puget Schedule 48
Docket No. UE-960696

Re: Puget Power/WNG Proposed Merger
Docket Nos. UE-951270 and UE-960195

Dear Mr. King:

Enclosed are Public Counsel's comments on Schedule 48 as requested in the Commission's notice of June 19, 1996. A diskette in WP 5.1 is enclosed.

Copies are being sent to all parties in the merger case.

Very truly yours,

Robert F. Manifold
Assistant Attorney General
Public Counsel

cc: Merger case service list

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In Re: Puget Power Proposed Schedule 48.	DOCKET NO. UE-960696 PUBLIC COUNSEL COMMENTS

Public Counsel opposes Schedule 48 as filed. We recommend that Schedule 48 be suspended and set for hearing, with hearings consolidated or coordinated with the merger case.

We do not oppose industrial customers getting the benefits of market based power without paying Puget's above market stranded costs. We do oppose this being offered to only one customer class; similar arrangements should be offered to all classes. In addition Schedule 48 does not contain adequate safeguards to prevent cost shifting now and in the future.

Schedule 48 represents a negotiated settlement between Puget Power and some customers who are intervenors in the merger case. The issues involved in Schedule 48 overlap significantly with issues raised by Puget in the merger case, and which will likely be raised by others as well. There will be less duplication of effort by the parties and the WUTC to consider Schedule 48 in the context of the merger.[1]

These comments (1) amplify on our oral presentation of why Schedule 48 should not be approved at this time as filed and (2) suggest some of the issues that should be explored in further

[1]Although the merger case has 19 parties, it is not clear that all will be active participants. For instance, other than Public Counsel, Staff and the two industrial users group ("the usual players") only 1 party has submitted data requests to the utilities. Parties who are only interested in Schedule 48 can participate on that issue alone.

satisfy the statutory prohibition on unjust discrimination. RCW 80.28.090, 80.28.100. So far, the Company has not.

In response to a data request in the Intel proceeding, Puget did calculate delivery costs for other classes. For the residential class, these costs were estimated at 3.25¢ per kwh. Adding in Puget's own estimate of the average spot market rate, this would result in a total residential rate of about $4.6¢/kwh, which is a 34% reduction from the current average Schedule 7 tariff rate of $.0702/kwh.

II. Issues to be Explored.

A. Market rates for all. Puget is essentially guaranteeing market based[4] rates to a few customers at the same time as BPA is withdrawing market based rates from residential and small farm customers of Puget Power. These customers face a 16% increase in rates and already pay a greater premium in rates over their public power neighbors than do the industrial customers. Market based rates should be developed for all customers and offered at substantially the same time. For instance, Puget could offer its power at market based prices to residential and commercial customers (essentially Schedule 48 but with service obligations) and offer real retail access to its industrial customers.

Another option to consider is to first offer market based rates to those customers of Puget who are paying the most above their costs, the commercial customers of Schedule 24, 25, and 26.

[4]A more complete examination of the pricing basis is beyond these comments. Further proceedings, including the merger record, may develop the distinctions between embedded, long run, short run, and market costs and rates.

INDUSTRIAL
CUSTOMERS OF
NORTHWEST
UTILITIES

KEN CANON
EXECUTIVE DIRECTOR

UT-960696

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STATE OF WASH.
UTIL. AND TRANSP.
COMMISSION

RECEIVED BY FAX ON 7-15-96
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July 15, 1996

Mr. Steve McLellan
Washington Utilities and Transportation Commission
P.O. Box 47250
Olympia, WA 98504-7250

RE: Industrial Customers of Northwest Utilities' Comments on Puget Power's Schedule 48 Tariff

Dear Mr. McLellan,

Industrial Customers of Northwest Utilities (ICNU) offers the following comments on Puget Power's Schedule 48 tariff:

OVERVIEW

ICNU members view Schedule 48 as one transition step (of many) that Puget Power needs to take to survive in a more competitive electric power market. While not perfect, Schedule 48 incorporates a number of elements that recognize a balance between Puget's interests, the interests of core customers and the interests of industries exploring competitive options:

1. Puget's commitment to pursue legislation and a collaborative process to provide open access to all customers by 2000.

2. The movement of competitive, electric cost sensitive industries to a non-core status, with pricing based on equivalent margin rates. This will allow industry to assume more risk in the type of power supply that is purchased.

3. Hourly, index-based pricing, with pricing and power supply backup options.

4. A transition charge that allows Puget time to address competitive issues.

5. A five year power purchase commitment from industry, with the provision that if retail access becomes a reality in Washington within the 5 year time period, industry could move to full retail access.

(503) 239-9169 FAX (503) 239-0466
700 NE MULTNOMAH, SUITE 1000

BALL JANIK LLP

ATTORNEYS

ONE MAIN PLACE
101 SOUTHWEST MAIN STREET, SUITE 1100
PORTLAND, OREGON 97204-3219

TELEPHONE 503-228-2525
FACSIMILE 503-295-1058

July 26, 1996

VIA FEDERAL EXPRESS OVERNIGHT DELIVERY

Mr. Steve King, Acting Secretary
Washington Utilities and Transportation Commission
Chandler Plaza Building
1300 S. Evergreen Park Drive, SW
Olympia, WA 98504

Re: In re Puget Sound Power & Light Company Proposed Schedule 48, Docket No. UE-960696, Reply Comments of the Washington State Hospital Association

Dear Mr. King:

The Washington State Hospital Association (WSHA) submits the following Reply Comments for filing in the above-referenced proceeding. An electronic diskette in WordPerfect 5.2 for Windows is also enclosed.

I. REPLY COMMENTS

A. Procedural Scheduling of Puget's Proposals

WSHA appreciates the opportunity to respond to the comments submitted by other parties in this proceeding. Power supply costs are a significant expense for every medical facility, and WSHA's hospitals need access to competitive electric power markets in an expeditious fashion. The schedule adopted by the Commission should not impose any unnecessary delay in providing that access to Puget's customers. WSHA urges the Commission to:

- Accept Puget's offered alternative to change the effective date of Schedule 48 to August 30, 1996;

- Accept Puget's proposal to provide discovery on Schedule 48, but require that the discovery rights of Puget's customers be the same as the statutory parties, even if the rights of competitors to information should be narrowed;[1]

- Reject Public Counsel's request that this proceeding be consolidated or coordinated with the merger proceedings with Washington Natural Gas in Docket UE-960195; and

- Place proposed Schedule 48 on the Commission's schedule for a second workshop at a date late in August, 1996, providing an opportunity for questioning of Puget representatives. Alternatively, issue an order putting the rates into effect subject to refund and suspend the Schedule 48 filing for a full investigation with an expedited schedule allowing prompt, sequential testimony filings, and a single hearing on all testimony by December 1, 1996.

The Commission should reject all linkage of the Schedule 48 issues to Puget's proposed merger with Washington Natural Gas. Consolidation would procedurally complicate and unnecessarily lengthen both proceedings. The merger proceedings are already set for cross-examination hearings of Puget's direct case beginning July 31, 1996. Open access and market-based rates for Puget's customers deserve independent and prompt consideration by the Commission.

Amidst all of the oral and written comments received by the Commission in this proceeding, there is one single commonality -- Puget's customers need access to competitive electric power markets. Waiting upon the outcome of the merger proceeding to even talk, as suggested by Puget, is not the answer. Open access by 2001 is not the answer. WSHA reiterates its request that the Commission condition any approval of Schedule 48 with a requirement that Puget start an open access collaborative without waiting until six months after the merger is approved. The Commission should establish August 1, 1997 as the definitive date for an open access retail wheeling filing by Puget. The Commission should further require Puget to convene a collaborative process by September, 1996 to negotiate an open access program, with a report from the participants to the Commission by May 1, 1997.

B. Modifications Necessary for Schedule 48

In its initial comments and presentation before the Commission, WSHA raised four principal modifications required for approval of Schedule 48 under Washington law: (1) modify Schedule 48 to allow customers the option of presenting a third-party offer to Puget to establish an alternative price and terms, using the index as a default; (2) eliminate

[1] Puget's concerns about the confidentiality of customer load, revenue and power supply information can be addressed through a protective order from the Commission. In doing so, the Commission should not limit the rights of Puget's customers (as it may Puget's competitors).

6

PRESTON GATES & ELLIS
ATTORNEYS

July 26, 1996

<u>VIA FEDERAL EXPRESS</u>

Steve King, Acting Secretary
Washington Utilities and Transportation Commission
1300 S. Evergreen Park Dr. S.W.
P. O. Box 47250
Olympia, WA 98504-7250

Re: WUTC Docket No. UE-960696
Puget Sound Power & Light Company Proposed Schedule 48
Reply Comments of Air Liquide America Corporation

Dear Mr. King:

Submitted with this letter (in hard copy original and on electronic diskette in WordPerfect 5.1) are the reply comments of Air Liquide America Corporation in the above docket. We appreciate the opportunity to participate in the Commission's consideration of the issues relating to Schedule 48. Copies have been mailed to the parties of record in the merger proceeding.

Very truly yours,

PRESTON GATES & ELLIS

By
Douglas H. Rosenberg

RECEIVED
RECORDS MANAGEMENT
96 JUL 29 AM 11:12
STATE OF WASH.
UTIL. AND TRANSP.
COMMISSION

DHR:jal
Enclosure
cc: Service List (copy of list attached)
Edward Marlovits

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The issues in the Schedule 48 rate proceeding are separate and distinct from those in a merger proceeding.[1] In addition, the parties and interests differ. Whether a rate schedule is just, reasonable, and non-discriminatory can be determined without undertaking the broad inquiry necessary to determine a merger's impact on the public interest. Moreover, if the predicted merger savings fail to materialize, the Commission has other tools for holding Puget to its promise to protect other ratepayers from any adverse effects.

Air Liquide's position in the merger case will depend to some degree on how the Commission treats Schedule 48. Approval of Schedule 48 would allay most of the concerns Air Liquide would otherwise have about how the merger will affect competition. Schedule 48 sets out a clear path toward eventual open access to the market. Disapproval of Schedule 48 could lead Air Liquide to oppose Puget in the Merger Proceeding. By keeping the dockets separate, the Commission would facilitate a clearer delineation of the issues and positions of the parties.

Consolidating the two dockets would slow the entire process and obfuscate the issues. Parties such as Air Liquide who might oppose the merger but for the availability of Schedule 48 may be forced to become active participants in the Merger Proceeding. They may essentially have to advance alternative positions throughout the course of the proceeding, on the one hand supporting Schedule 48 and on the other hand finding fault with the merger absent Schedule 48. This result would unnecessarily complicate the already complex Merger Proceeding and consume significant amounts of the Commission's and all parties' time and resources.

As we described orally at the Commission's public meeting, Air Liquide cannot afford to wait any longer than absolutely necessary to achieve market-based rates. Air Liquide operates in a highly price-competitive business, and yet the cost of its primary "raw material" -- electricity comprises around 75% of its production cost-- is substantially higher than that of its competitors. It cannot continue for long under these conditions. If Puget's tariff is not modified, then Air

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1 The Commission recently recognized that a rate proceeding is different in character from a merger proceeding, holding that a broader range of interests can confer standing to intervene in a merger proceeding. Merger Proceeding, Third Suppl. Order Modifying Prehearing Order at pp. 6-7 (June 10, 1996).

8

ENRON CAPITAL & TRADE RESOURCES
WORLDWIDE ENERGY SOLUTIONS

ENRON'S PLAN TO LOWER ELECTRICITY PRICES IN WASHINGTON STATE

Competition Comes to Electricity

Over the last 20 years, regulated monopolies have become almost a thing of the past in the American economy. One by one, the airlines, trucking, natural gas, and telecommunications have been opened up to competition. As a result, consumers enjoy choices, which leads to lower prices and better service.

The last holdout against this trend is the industry that provides us with electricity. As to that commodity, we have no choice; we pay a government-established price to a monopoly provider.

But competition is coming to electricity. The Federal Energy Regulatory Commission recently ordered all utilities to open up the use of their high-voltage transmission lines in order to create a competitive wholesale electricity market. In other words, a utility may no longer block an electricity sale between two other utilities, or between an independent power plant and a utility, by refusing to allow the electricity to pass over its transmission lines. Instead, the utility that owns the transmission lines is paid a reasonable fee, but must provide the transmission service in the same manner that it provides such service to itself.

This FERC rule is a major breakthrough for competition because it allows utilities to shop for the least expensive power over a wide geographic region without fear that a transaction will be blocked by an intervening utility. For example, this will allow a Washington utility to shop for power throughout the West.

The FERC rule will undoubtedly save billions of dollars for utilities. However, the FERC rule does not extend the same market access to retail consumers; instead, they remain the captive customer of their local utility.

This is so because retail sales of electricity have traditionally been within the power of the states, not the federal government. Several states have already takes steps to allow retail consumers to choose their electricity provider, with California, New Hampshire, and Illinois leading the way. Other states are sure to follow.

The benefits of taking this next step as quickly as possible are enormous. A recent economic study shows that consumers in every region of the country will enjoy cost savings, even here in the Northwest where electricity costs are relatively low.

Achieving Consumer Choice in Washington State

In Washington State, we have an opportunity to be among the first to obtain the economic benefits of consumer choice. One approach is for customers to ask the regulators to end the monopoly status of utilities. According to its staff, the Washington Utilities and Transportation Commission has the authority to order utilities to open up their local distribution system so that retail consumers can receive power from another supplier.

In order for the Commission to exercise this authority, customers would first enter into a power purchase contract with Enron at a price significantly lower than the customer is currently paying. Customers would then request their local utility to transmit power over its lines so that Enron could fulfill the contract. Assuming that the request is denied, the customers would then file a complaint with the Commission requesting that the local utility be ordered to do so. This approach, if successful, would greatly accelerate the move to full competition.

Another approach to achieving competition is to create a new electric utility. Unlike most states, Washington law does not grant electric utilities exclusive service territories, and the process of creating a new electric utility is relatively straightforward.

The advantage of forming an electric utility is that it would be entitled to demand wholesale transmission service from other utilities under the new FERC rule. Of course, the new electric utility would be required to make certain filings with the Washington Commission, and follow Commission rules and regulations.

Contact Person

At this point, Enron is looking for an initial group of customers who will work with them to implement one or both of these approaches to achieving consumer choice in Washington. If you are interested in hearing more about this plan, contact Dick Ingersoll at (713) 853-5415.

Answers to Commonly-Asked Questions

1. *Question:* What is Enron?
Answer: Enron is a large, publicly-traded electricity and natural gas company based in Houston. Among other things, it is the largest private wholesaler of electricity in the country, selling about as much electricity as the Bonneville Power Administration.

2. *Question:* Is Enron interested only in serving big industrial customers?
Answer: No. Enron intends to sell electricity to all sizes and types of customers, including industrial, commercial, and residential. That's why Enron wants to work with a diverse group of customers to create competition in Washington State.

3. *Question:* Can you guarantee me that I'll save money on electricity if we're successful in urging the Washington Commission to open up my local utility?

Answer: Yes. The contract will provide that the customer has no obligation to Enron unless the Commission opens up the local utility and Enron is able to provide power at a lower price than the customer is currently paying.

4. *Question:* How *much* money would I save?

Answer: That depends largely on which local utility is currently serving you. Customers of Puget Power are likely to see the largest cost savings because Puget Power has the highest rates in the Northwest.

5. *Question:* I understand that electricity prices are low now, but what about the long-term? If I sign a contract with Enron, what happens if prices go back up?

Answer: Enron is so confident that increasing competition will keep electricity prices down for the foreseeable future that it is willing to enter into long-term contracts of 15-20 years.

6. *Question:* Would the reliability of my service be affected?

Answer: No. There are basically two types of reliability problems. First, there is the reliability of the wires that make up the local distribution system. For example, a wind storm may knock down power lines or a construction project may sever an underground cable. As to these types of problem, your local utility would continue to have responsibility because it would continue to operate and maintain the distribution system. Enron would simply pay the local utility a fee to use the local utility's lines.

The second type of reliability problem arises when the source of electricity (such as a gas generator or coal plant) is interrupted. Historically, the deregulation of other industries has increased reliability and improved customer service, and we expect this to hold true as deregulation comes to the electricity business.

Puget Sound Power & Light Company
Schedule 48
Docket Nos. UE-960696
WUTC Staff Data Request No. 27

Staff Request No. 27:

Please provide all workpapers, documents, and supporting analyses that address competitive alternatives (e.g., bypass / alternative delivery sources, open transmission access, municipalizations) for service for current high voltage and primary voltage customers which would be eligible for service under Schedule 48.

Response (Heidell):

Documentation and characterization of competitive alternatives in Whatcom County with regards to ARCO, Georgia Pacific, and Bellingham Cold Storage was provided in Docket No. UE-950599, Docket Nos. UE-960612 and UE-960613, and prefiled testimony of Kevin Owens in Docket No. UE-951270. In addition, please consult written comments provided by ICNU in Docket No. UE-960696. Finally, a letter from Enron to our customers is attached. The Company has no other written documents characterizing alternatives available to large customers.

Comprehensive Review of the Northwest Energy System
Final Report

Toward a Competitive Electric Power Industry for the 21st Century

December 12, 1996

PREAMBLE

The 20 members of the Steering Committee of the Comprehensive Review of the Northwest Energy System have worked for 11 months to develop the recommendations contained in this final report. These recommendations represent a consensus of 13 of the 14 voting members of the Steering Committee, a consensus that has been achieved only by compromise and sacrifice on the part of each of the members on the Committee. The 14th voting member acknowledges the significant progress made in many areas but does not believe that sufficient progress was made on issues related to fish and wildlife to constitute a real consensus. His views are presented in Appendix A.

We, the members who voted with the majority, support the report and will work to educate and persuade others, but our support here does not commit all of the groups we represent. These compromises, as difficult as some may find them, are worth making for a simple reason: we have more to lose as a region than we have to gain as disparate interests.

There is still much work to be done. This final report is specific in some areas and general in others. More detail and further refinement will be required to convert these recommendations into the contracts, legislative bills, rules and policies that will implement them.

As regional interests work further on these restructuring initiatives, there are bound to be disagreements and new issues to be resolved within the outlines of these recommendations. However, we believe that the principles outlined here must remain if any regional consensus is to be hoped for. With a consensus position, the Pacific Northwest has the best hope of retaining the benefits of the federal hydropower system and transitioning to a competitive electricity system that will maximize benefits for all consumers in the region. The work embodied in this report will not easily be replicated if the regional consensus is destroyed by unilateral actions of any party.

Finally, the Committee recognizes that electric utility restructuring is evolving rapidly and that efforts in Congress and the states almost certainly will change some of the assumptions underlying this report. Although our recommendations may not reflect the ultimate end-state of this restructuring, we nevertheless believe that it does reflect a workable outcome in itself and a very positive step in this process.

Charles Collins
Chair

Al Alexanderson
Portland General Electric Company

Sharon Nelson
Washington Utilities and Transportation Commission

Chuck Hedemark
Intermountain Gas Company

Ken Canon
Industrial Customers of Northwest Utilities

Jim Davis
Douglas County Public Utility District

Bill Drummond
Western Montana Electric Generating and Transmission Co-op, Inc.

Bob Gannon
Montana Power Company

Gary Zarker
Seattle City Light

Brett Wilcox
Northwest Aluminum Company

Jason Eisdorfer
Citizens' Utility Board

K. C. Golden
Washington State Department of Community, Trade and Economic Development

Rachel Shimshak
Renewable Northwest Project

John Saven
Northwest Requirements Utilities

accomplished in many different ways, including auctioning the power, requiring Bonneville to market its power at prices that are tied to a market index, or limiting Bonneville's marketing of products and services. However it is done, any cost-based regional benefits that are derived from public or regional preference are likely to be reduced.

Current electricity policy at the federal level reserves *retail* market competition decisions to the states. However, recent congressional initiatives leave the degree of future state control in question. In any case, the pressure for retail access and its momentum are not in question. In the absence of either fairly strong federal legislation or coordinated regional policy, individual states are likely to move at different rates toward various forms of retail access policy with large power consumers tending to get first access. Unless adequate safeguards are in place to ensure that the owners of monopoly distribution systems cannot unfairly influence consumers' retail energy service choices, the development of competitive retail energy service markets for all consumers will be inhibited. Inconsistent policies among states within an integrated electricity market will lead to market advantages for some areas, a less efficient market, and arbitrage opportunities for electricity traders and marketers.

Utilities under competitive pressure to retain their customers will find it difficult to support the various social and environmental goals they have supported in the past. Competitive markets will support some social and environmental activity, and recent legislative proposals in Congress suggest that some programs could be mandated at the national level. However, absent action to place the funding of such activities with the separate and regulated elements of the market (transmission or distribution), emphasis on conservation, renewable energy sources and low-income support will decline. The greater the differences among states and utilities in the funding of these activities, the more distorted and less efficient will be the electricity markets.

The "base case" just described has some undesirable features. However, the region has the ability to manage the transition to competition to avoid or mitigate the undesirable features *if* it can reach consensus on the key features of the energy system.

THE COMPREHENSIVE REVIEW

The governors of Idaho, Montana, Oregon and Washington convened the Comprehensive Review of the Northwest Energy System to seize opportunities and moderate risks presented by the transition of the region's power system to a more competitive electricity market. The governors appointed a 20-member Steering Committee that is broadly representative of the various stakeholders in the power system to study that system and make recommendations about its transformation. The members of the Steering Committee are listed in Appendix B. Each governor has a representative on the Steering Committee to make certain the public is educated about and involved in the Comprehensive Review. In establishing the review, the governors stated:

> *"The goal of this review is to develop, through a public process, recommendations for changes in the institutional structure of the region's electric utility industry. These changes should be designed to protect the region's natural resources and distribute equitably the costs and benefits of a more competitive marketplace, while at the same time assuring the region of an adequate, efficient, economical and reliable power system."*

Since January 1996, the Steering Committee has held 30 day-long meetings. In addition, almost 400 people have been involved in more than 100 meetings of various work groups reporting to the Steering Committee. Hundreds of citizens attended the 10 public hearings that were held throughout the region on the Committee's draft report. More than 700 written comments were received. This report is the product of that work. It is a recommendation for restructuring the Northwest electricity industry to meet the challenges and seize the opportunities inherent in the competitive transition.

forum would be established to track regional progress toward the achievement of regional goals and provide feedback and suggestions for improving the effectiveness of conservation and renewable resource development programs. Funding for these activities should be collected in part through Bonneville wholesale rates to the extent regional firm loads are served by power from Bonneville.

How the funds are collected is a matter for state or local decision, as appropriate. The Steering Committee expects that methods of collection that are competitively neutral and affect all participants in the market equally will be found to be preferable.

CONSUMER ACCESS TO THE COMPETITIVE MARKET

The goals of the recommendations on retail markets and customer choice are to encourage a more efficient power system, lower electricity costs, increased product choice and greater product innovation for all consumers. These goals were adopted subject to a commitment to maintain the reliability and safety of the electrical power system. The Steering Committee concluded that this goal could best be accomplished by putting in place a competitive electricity market that is driven by consumer choice. However, there is concern that the benefits of a competitive market may flow unevenly to different classes of consumers and that some small consumers may even suffer harm. The report recommends safeguards intended to help mitigate these concerns.

The Steering Committee recommends that regulators and local utility boards and commissions offer open access for all customers that desire it no later than July 1, 1999. The Committee recognizes that some of these regulatory bodies may choose to phase in full retail access. In these cases, a similar phase-in of the recommendations on conservation, renewable resources and low-income energy services may be effected.

Direct access may occur prior to July 1, 1999, however, for direct retail access to be implemented promptly, several activities must be accomplished. These include the identification of any stranded costs and, if any stranded costs are determined to exist, the creation of a stranded cost collection mechanism; unbundling and cost-based pricing of delivery services; pilot programs to explore aggregation for small commercial and residential customers; the exploration of market index pricing options for residential and small commercial customers; and implementation of public purposes funding, energy assistance funding and consumer protection mechanisms consistent with this report's recommendations.

To achieve a competitive retail electricity market requires separation of the distribution and electricity marketing functions of current retail utilities. This is necessary to ensure that consumers will have unimpeded access to alternative electricity suppliers, and vice versa, over the wires of the distribution utility. The distribution utility would continue to be a regulated monopoly responsible for the reliable and safe delivery of electricity from electric service companies to consumers over local distribution wires. Electricity service companies will offer a variety of electricity products and services (e.g., firm or interruptible power, power from renewable resources, peak or off-peak power, fixed or spot-market prices) to consumers on a competitive basis and may, in fact, offer other products unrelated to electricity markets. The electricity services portion of current integrated retail utilities could compete in this market if the distribution utility function is sufficiently separated from the electricity services business to ensure that control of distribution is not used to advantage the electricity services business.

Putting such a competitive market in place will require a significant transition and ongoing market maintenance procedures. There is a danger that, until competitive markets have fully developed for all consumers, some of the benefits of increased competition may be realized primarily by large consumers at the expense of small consumers. Therefore, the Steering Committee calls for active government oversight of the transition and active ongoing programs to facilitate and encourage the development of meaningful market access for all consumer classes and to prevent unwarranted cost shifts among consumer classes. Specifically, the policy calls for licensing of new electricity service providers, applicability of consumer protection laws, formal complaint processes, consumer information programs, and a "provider of last resort" to ensure

Final Report of the Comprehensive Reviw of the Northwest Energy System

A "green" power marketing program should be developed to introduce varied products to consumers and to provide an opportunity for renewable resources to compete in the retail electricity market based on their environmental characteristics and price.

Finally, a provider-of-last-resort mechanism should be maintained to accommodate those who cannot choose a supplier or for whom no suppliers materialize. Such a mechanism could include a last-resort supplier of energy at affordable rates, or could be a system of random assignment of electricity service providers to consumers who have not been able to effectively access the market.

Opportunity to recover stranded costs

Opening up the retail electricity market to competition raises the possibility that some utility costs become stranded; that is, a utility may not be able to recover the full costs of some previously rate-based assets. To the extent that stranded costs are a problem, utilities may resist competition and may attempt to shift stranded costs onto captive customers. To facilitate the transition and reduce cost shifting incentives, utilities should be given a fair opportunity to recover legitimate, non-mitigable stranded costs. Any policies on stranded cost recovery should preserve a strong incentive for utilities to mitigate stranded costs to the greatest extent possible. Recovery of non-mitigable stranded costs may be accomplished through exit fees or distribution access fees. However, it should be clear that stranded costs are transitional in nature and recovery provisions should be limited in duration and amount recovered.

Exh. T-191 (JWM-T)
Docket UE-960195
Witness: James W. Miernyk

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

IN THE MATTER OF THE APPLICATION OF PUGET SOUND POWER AND LIGHT COMPANY, A WASHINGTON CORPORATION; WASHINGTON NATURAL GAS, A WASHINGTON CORPORATION, TO MERGE INTO PUGET SOUND ENERGY CORPORATION, AND AUTHORIZING ISSUANCE OF SECURITIES, ASSUMPTION OF OBLIGATIONS, AND ADOPTIONS OF TARIFFS)	DOCKET UE-960195

TESTIMONY

JAMES W. MIERNYK

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

SEPTEMBER 1996

A. Puget's recent special contracts and proposed Schedule 48 would allow all large-use customers an opportunity for service at rates below current tariff rates, resulting in lost revenue. Under the Applicants' rate plan, remaining electric customers would not have similar opportunities. In fact, the Applicants propose annual one percent rate increases. For the reasons identified in this testimony, I conclude that the Applicants' rate plan for electric customers is inequitable, inappropriate, and inconsistent with the Commission's *Guiding Principles in an Evolving Electric Industry*, issued in Docket UE-940932.

Q. Please summarize the basis for your conclusion.

A. The primary cause for Puget's recent special rate arrangements with large use customers is the high cost of power embedded in current tariff rates, compared to the prices large users could obtain from access to market. From that perspective, Puget's embedded production costs are uneconomic. The price increases associated with Puget's PURPA resource contracts are a major source of continued upward rate pressure, and contribute to Puget having the highest retail electric rates in the region. The reality of these circumstances is that large-use customers, who have the economic means to pursue special rate arrangements or competitive alternatives, are unwilling to pay for service under current tariff rates, i.e., they are unwilling to pay for Puget's production costs.

Q. How does Staff recommend the Commission treat the lost revenues from Puget's special rate arrangements with large-use customers under its rate plan?

A. Staff believes that all PSE electric customers -- not just large-users -- should achieve lower rates than available under current tariff during the five-year rate plan period. This

Q. How does the embedded cost of power in Puget's large industrial customer rate compare to forecasted non-firm market prices during the merger rate period?

A. According to Puget's forecast, as reflected in my Exhibit 193 (JWM-2), average monthly regional non-firm prices are not expected to rise above 20 mills/kWH in any month through 2001.

Q. How would you characterize Puget's embedded power costs for large-use customers relative to the short-run market?

A. From the perspective of large-use customers, the cost of power in Puget's current tariff rate is uneconomic.

Q. What other conclusions have you reached regarding Puget's production costs and market prices?

A. The wide discrepancy between the embedded cost of power in rates and market prices, and power contract-related rate pressures, are occurring during a period of low short-run prices for power in the regional market. The low prices result from federal government open transmission access initiatives, a surplus of generating capacity in the region, the increasing presence of power marketers and brokers, and continued low natural gas prices. To the extent that the terms and conditions of its long-term PURPA contracts limit the Company's ability to take advantage of low wholesale spot market prices, core customers have little opportunity to achieve lower rates.