

Introduction to the Fifth Power Plan

The Council's first power plan, adopted in 1983, was developed in the aftermath of the region's effort to construct five nuclear power plants. Although only one of the power plants was completed, the costs of these plants were the primary reasons for a 66 percent real increase in retail rates in the region in the early 1980s. This caused demand to plummet and caused economic hardship for many in the region. In response to this experience, the Council's first plan brought innovations to electricity system planning. These included recognition of the price elasticity of demand in forecasting and methods for assessing and managing the risks associated with capital-intensive, long lead-time generation. It also furthered electricity policy innovations such as treating conservation, the more efficient use of electricity -- as a resource comparable to generation.

The Fifth Power Plan has many parallels. It comes on the heels of the 2000-2001 Western electricity crisis. This crisis manifested itself in extremely high wholesale power prices (Figure 1-1) and the threat of blackouts that persisted for almost a year.

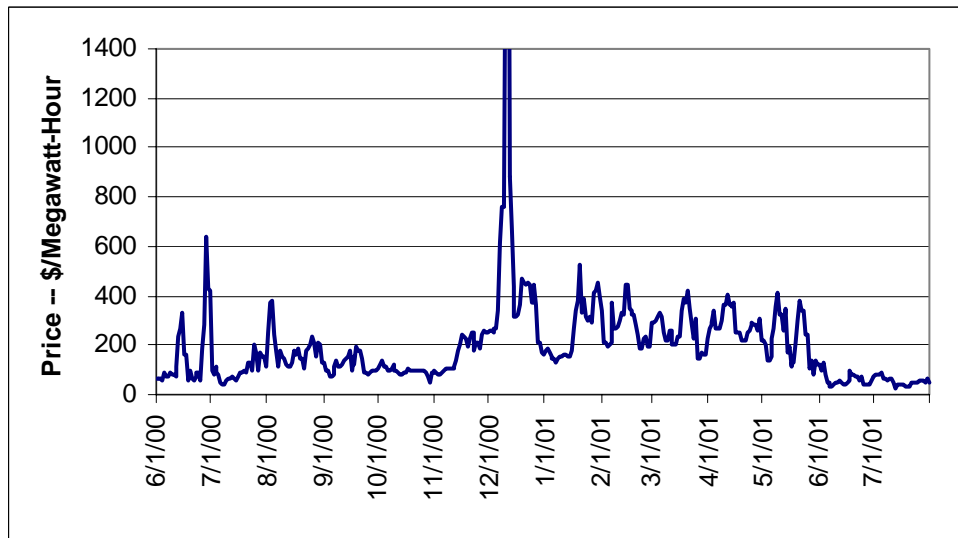


Figure 1-1 – Daily Average Firm Prices at Mid Columbia

The high wholesale prices eventually caused retail prices to increase by 25 to 50 percent. Many utilities entered into long-term contracts for power supply at high prices at the height of the crisis. As a consequence, although wholesale prices have returned to normal levels, retail rates have not yet returned to pre-crisis levels (Figure 1-2).

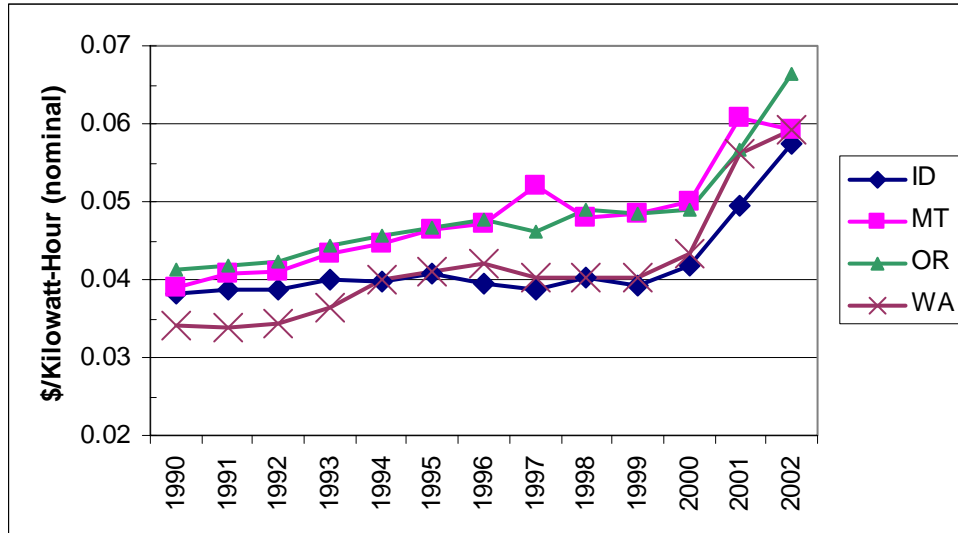


Figure 1-2: Average Retail Rates – All Sectors

Similarly, demand remains well below pre-crisis levels (Figure 1-3). Most of this is due to the fact that much of the electricity-intensive aluminum industry remains shut down. However, other industries and economic activities have also been affected.

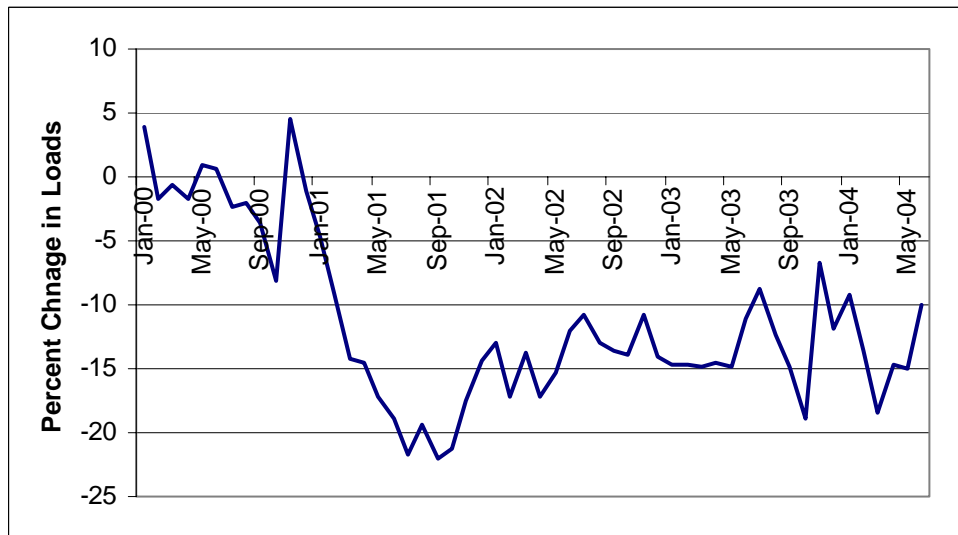


Figure 1-3: Percent Change in Regional Loads from Same Month in 1999

The challenges we face as a region are similar to those we faced when the first power plan was published: to build on the lessons of the recent past and to provide leadership in planning and policy that will help assure the region an adequate, efficient, economic and reliable power supply in the years ahead.

WHAT CAUSED THE WESTERN ELECTRICITY CRISIS?

The Western electricity crisis has been referred to as the “perfect storm” – the result of the confluence of a number of adverse trends and events. It had its roots in several years of under-investment in generating and conservation resources. It was triggered by the onset of poor hydro conditions in the later spring of 2000 leading to the second-worst water year since 1929. It was made much worse by a deeply flawed electricity market design in California and opportunism by some of the participants in that market. And many believe it was prolonged by the reluctance of the Federal Energy Regulatory Commission to impose West-wide price caps.

The poor hydro conditions in 2001 resulted in almost 4,000 average megawatts less hydroelectric energy available than in an average year, and even less compared to the relatively wet years of 1995-1999. The reduced hydro generation affected not only the Northwest, but California and the Desert Southwest as well. Net exports from the Northwest Power Pool Area¹ for May through September averaged 2,700 average megawatts less in 2000 and 2001 than in the preceding three years.

However, the poor hydro conditions and the flawed California market were unlikely to have triggered the Western electricity crisis had it not been for the extremely tight resource situation in the Northwest and West leading into 2000. Here in the Northwest, the critical water load-resource balance was increasingly negative (loads greater than regional resources) throughout the 1990s (Figure 1-4).² By the year 2000, the deficit had reached 4,000 average megawatts.

¹ The Northwest Power Pool Area encompasses Alberta, British Columbia, Washington, Oregon, Idaho, Montana, Wyoming, Utah and Northern Nevada.

² “Critical water” is the historical volume and temporal pattern of river flows that results in the lowest energy production from the hydropower system.

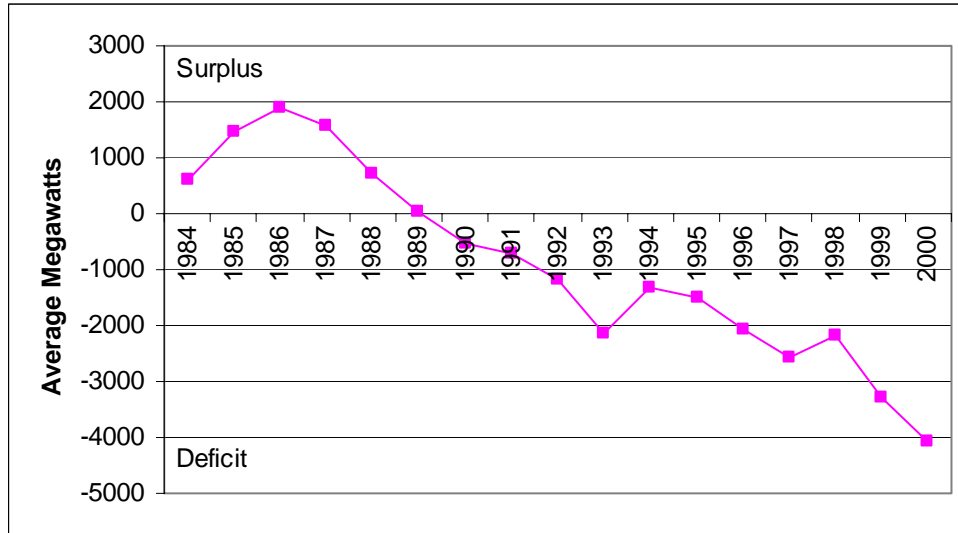


Figure 1-4: Northwest Load/Resource Balance – Critical Water

During most of the late 1990s, the development of generation in the Northwest and, for that matter, the rest of the West, was effectively at a standstill. Similarly, utility investment in conservation during that period was less than half the cost-effective levels identified by the Council.

Concerned by the growing deficits, the Council undertook a study of regional power supply adequacy. That study, released in early 2000, estimated that the probability of being unable to fully serve Northwest load (the “loss of load” probability) would climb to 24 percent by 2003, even when accounting for the ability to import power in the winter and to draft reservoirs beyond normal limits in emergencies. The analysis also indicated that 3,000 megawatts of new resources would be necessary to bring the loss of load probability down to the acceptable industry criterion of 5 percent.³ What the report failed to emphasize was that the probable leading indicator of such resource scarcity would be price volatility. The prices of 2000-2001 brought that lesson home very clearly.

Contributing Factors

Neither the Council’s study nor any of the other indicators of growing resource inadequacy stimulated a rush to develop new resources. Some new resources were under development. However, they were not enough, soon enough, to avert the crisis. Why did the Northwest and the rest of the West allow loads and resources to get so far out of balance?

Naive Faith in “The Market”

One explanation is the infatuation with the competitive wholesale power market that was prevalent in the late 1990s. Why should a load-serving entity build new resources or enter into long-term contracts when the invisible hand of the competitive market would take care of long-term supply? A long period of low spot market prices seemed to validate this view. However, it should have been clear that the market was not taking care of supply. Deficits

³ [Northwest Power Supply: Adequacy/Reliability Study Phase I Report](#), March 2000.

continued to grow, but very few new power plants were being built. Wholesale prices in the years immediately preceding the summer of 2000 were generally below what it would take for a new generator to fully recover its costs, in part because of greater-than-average hydro production during that period. Few independent power producers were willing to undertake the risk of building a plant without having a significant portion of a plant's capability committed to long-term contracts. This was particularly so in the Northwest where good hydro conditions can depress market prices for extended periods.

Fear of Retail Competition and Stranded Costs

Another factor keeping utilities from making commitments to new resources was fear of retail competition. During the mid-to-late 1990s, there was a great deal of discussion of retail competition. Some states, such as Montana and, on a more limited basis, Oregon, opened their retail markets to competition. Others were considering it and there was speculation that Congress might impose retail competition. In the face of these developments, utilities were concerned that if they were forced to open their service territories to competition, they might lose customers to competitors and their investments in new resources would be "stranded," i.e., the utility would not be able to fully recover costs of new resources or long-term contracts. Consideration of the growing deficits should have suggested that a reasonable level of investment in new resources would not become stranded. Nonetheless, concerns about retail competition and stranded costs undoubtedly played some part in retarding resource development.

Uncertainty Regarding the Role of Bonneville

Another contributing factor was uncertainty with regard to the role Bonneville would play in serving future Northwest loads. Most utility and DSI contracts with Bonneville were to expire in October of 2001. Decisions about the signing of new contracts for subsequent service did not begin until 2000. This meant that both Bonneville and its customers were uncertain about who would have the responsibility for acquiring new resources until the Western electricity crisis was practically upon us. In the end, Bonneville found itself in the position of having to acquire 3,300 megawatts in a relatively short time during a period of extremely high prices. Had there not been the uncertainty, Bonneville or the utilities may have taken steps to acquire resources earlier that would have lessened the impacts of 2000-2001.

Failure of Planning

Finally, it seems clear that planning in the 1990s, including that of the Council, failed to fully appreciate and factor into its decisions the risks facing the industry. In particular, these included the risks associated with reliance on a potentially volatile wholesale market and risks associated with gas-fired generation that depends on the also volatile natural gas market. If planning had done a better job of reflecting the risks and their potential impacts, might load-serving entities have taken action to mitigate those risks? In February of 2000 the Council released a report that put a spotlight on the region's worsening resource condition. However, by then it was too late to elicit much of a response from the region.

THE RESPONSE TO THE CRISIS

Ultimately, Northwest utilities, independent developers, businesses, governments and citizens responded to the electricity crisis with ingenuity and effectiveness. There were three primary responses: new generation, both small-scale and larger conventional generation; load reduction

through both efficiency improvements and, primarily, demand reduction; and changes in the operations of the hydroelectric system.

Generation

By December of 2001, almost 1,300 megawatts of new permanent generation had entered service, approximately 1,100 megawatts of which was gas-fired combustion turbines. Another almost 3,800 megawatts was under construction, almost 2,900 megawatts were permitted, and over 10,000 megawatts were in the permitting process. The great majority were gas-fired plants, and most of those were combined-cycle units. However, there were several hundred megawatts of wind power developed as well. The developers were primarily Independent Power Producers (IPPs). This pattern was seen throughout the West.

One of the surprises was the amount and speed with which smaller-scale generation appeared in the region. This generation primarily came in the form of trailer or skid-mounted reciprocating engine generator sets and small gas turbine generators. Between the beginning of the crisis and December 2001, over 700 megawatts of temporary generation came into service in the region. More was planned. With the fall in market prices in the summer of 2001, much of the temporary generation was retired. Of the 700 megawatts put in service, over 180 megawatts was “retired” by December of 2001 and almost all was retired by December 2002.

At the present time, approximately 4,000 megawatts of new capacity has come on line in the Northwest since January of 2000. An additional 1,400 megawatts is partially complete, although construction has been suspended. With the exception of approximately 500 megawatts of wind, the great majority of the generation is gas-fired. While the amount of new generation is impressive, most of it effectively “missed the party.” By the time the generation became operational, prices had fallen and along with them, the profits anticipated by the developers. At present there are hundreds of megawatts of under-utilized new generating capacity in the region, most developed and owned by independent power producers. The good news is that the capital risk associated with this capacity is borne by the investors rather than the consumers of the region. The bad news is that the credit ratings of independent power producers have declined precipitously. The industry is not dead, but it has been severely wounded.

Load Reduction

Demand for electricity in the region began falling in late 2000. By 2002, loads were 2,800 average megawatts below loads in 2000 on an average annual basis, a drop of 13 percent.⁴ This load reduction was accomplished through two means: efficiency and, primarily, demand response.⁵

In 1999, Northwest utilities implemented 37 average megawatts of efficiency improvements in their customers’ homes, offices, stores, factories, farms and so on. This was a little more than one third of what the Council estimated to be cost-effective in the Fourth Power Plan. Although

⁴ Demand reductions on a monthly basis were even more dramatic. July 2001 loads were 4,675 average megawatts lower than the same month in 1999, a 22 percent reduction.

⁵“Demand response,” as will be discussed later, is a change in the service (level, quality or timing) that is chosen voluntarily by the consumer, which reduces electricity use or shifts it to a different time. If the change in service were imposed on the consumer involuntarily it would be “curtailment.”

high wholesale prices began hitting in May and June of 2000, annual savings for 2000 were only increased by about a third as it took some time to ramp up efforts. However, for 2001, efficiency savings increased to 150 average megawatts. Much of the savings came as a result of rebates on efficient compact fluorescent lights. Over 9 million were sold in the Northwest in 2001. Fortunately, the groundwork for this program had largely been laid in the preceding years so that the program could be rolled out relatively quickly. It's not clear that we could do that again.

While the efficiency response was impressive, demand response made up the great majority of the load reduction. Demand response means a reduction in electricity use unrelated to the efficiency of the facility, equipment or process. It can be accomplished through a reduction or cessation in the electricity-using activity (e.g., making sure unnecessary lights are turned off, only running one shift in a factory or shutting down entirely) or by switching to a different source of electricity (installing self-generation) or a different energy source altogether (e.g., switching to direct use of natural gas). All three methods were employed in 2000-2001.

Demand response was accomplished through a number of different inducements. These included appeals to the public-spiritedness of consumers by public figures, price signals, and utility "buyback" offers – offers by utilities to pay for reduced consumption. The governors of the Northwest states raised the visibility of the severity of the electricity situation and made public appeals for cutbacks. Some industrial customers exposed to market prices responded in a variety of ways to the sharp increases in wholesale prices, including fuel switching, self-generation, cutbacks and shutdowns, albeit at some significant economic expense. Sixty-three percent of the load reductions came about through various forms of buybacks, over 90 percent of which came from the aluminum industry. In the residential sector, programs like "20-20" and its variants offered ratepayers a percentage reduction in their bill for reducing their consumption by the same percentage relative to the same period in the previous year. None of these load reductions came cheap, but they were cheaper than the alternative of paying the market price for the electricity.

As impressive as the load reductions were, they came too late to avoid several months of extreme wholesale prices. As shown in Figure 1-5, load reduction did not really begin taking effect in a significant way until more than seven months after the onset of wholesale prices that were several hundred percent higher than normal. Had there been a more rapid response of loads to wholesale prices, it might have partially mitigated the high wholesale prices that the region was experiencing. Similarly, had investment in conservation continued at cost-effective levels throughout the 1990s there would have been at least a couple hundred megawatts fewer loads exposed to the high prices.

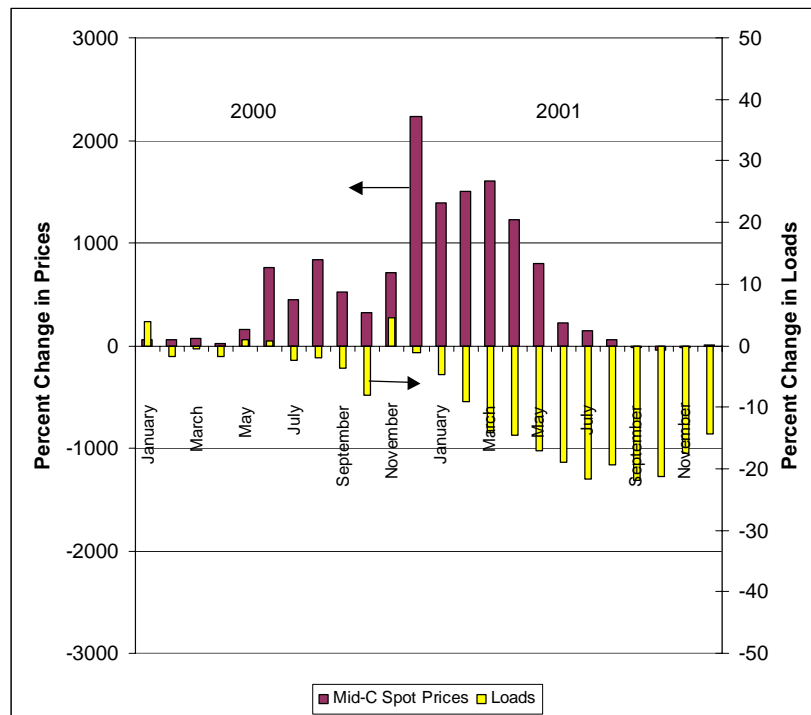


Figure 1-5: Percent Change in Mid-Columbia Spot Prices and Northwest Loads from Same Month in 1999

Hydro Operations

The third leg of the response to the electricity crisis was changes to the operation of the hydroelectric system that increased generation. The most significant change was reduction in bypass spill at the John Day, The Dalles, and Bonneville projects. Bypass spill (running water over a dam’s spillways instead of through the turbines) is intended to reduce injury and mortality of out-migrating juvenile salmon and steelhead. However, from a power supply standpoint, spill is energy lost. Most of the spill reduction took place in 2001. In total, reducing spill called for in NOAA Fisheries’ 2000 Biological Opinion (BiOp) added an additional 4,500 megawatt-months to the region’s energy supply, much of that coming in late spring and early summer when power prices were still at extremely high levels. It also allowed storing additional water in Canadian reservoirs in case poor water conditions continued into the winter of 2001-2002.

The use of spill reduction also highlighted the conflict between fish and power. Some viewed it as an example of the power system being willing to violate fish operations instead of making the needed investments in an adequate power supply. Others viewed it as a reasonable and prudent step given the high cost and poorly demonstrated biological effectiveness of spill. The debate continues today.

THE CHALLENGES GOING FORWARD

It is tempting to believe that the factors that led to and prolonged the Western electricity crisis are no longer of concern. Have we learned our lesson? Certainly the possibility of additional

jurisdictions moving to retail competition is much diminished if not eliminated. There is also a renewed enthusiasm on the part of many utilities and their regulators for the vertically integrated utility where the utility owns generation and is less reliant on “the market.” Similarly, many utilities now have experience with demand management programs that could, if maintained, serve them in good stead should another crisis begin to emerge.

In many respects these are positive developments that represent a retreat from excesses of the late 1990s. However, we believe it would be a mistake to think it could not happen again. It seems likely that we will have sufficient resources for several years. Combine this with a few years of good water and the resulting low market prices could make the lessons of the past few years fade unless those lessons have been built into the structure of our electricity system.

It is likely we will continue to see a mix of vertically integrated utilities, a federal power-marketing agency, local distribution utilities and competitive wholesale suppliers in the regional power system for the foreseeable future. This mix will have elements of federal, state and local regulation and competition. This mix results in uncertainty regarding roles and responsibilities and lacks some of the elements necessary for it to function effectively. The challenge for this power plan is to provide insights into what will make such a system function effectively and equitably not only now, when the experience of 2000-2001 is fresh in our minds, but in the longer term.

Vision for the Northwest Power System

Our vision is a well-functioning (adequate, economical, efficient, reliable) electrical system comprised of a mix of independent and utility-owned generation, regulated transmission and distribution, and an effective consumer demand response mechanism. It is a system in which efficiency and renewable resources compete on an equal footing with conventional generation and that includes environmental considerations when making resource decisions. It is a system that recognizes the risk inherent in the power industry, and plans and implements actions in ways that effectively manages that risk. The characteristics of that system are:

1. Resource Planning and Adequacy
 - The region puts in place resource adequacy standards or targets and the necessary monitoring and planning functions.
 - Resource planning includes robust assessment of risk and the options for risk mitigation.
 - There are clearly defined responsibilities and accountability for resource adequacy, reliable power system operation, and transmission system expansion.
2. Market Rules and Regulation
 - The wholesale power market is transparent, with open transmission access and fair rules for all participants, including the demand side of the market.
 - There are reasonably consistent wholesale power market and transmission access rules across the integrated electrical grid.

- There is active market oversight and monitoring to ensure efficient operation and to prevent market power abuse ensuring the accountability of market participants to the consumers ultimately served by those markets.
 - The system preserves state authority and accountability over retail electricity markets to ensure fair and reasonable consumer prices for monopoly customers.
 - Electricity pricing and regulation provide adequate incentives for efficient utilization and expansion of the region's generating resources and transmission system.
 - Electricity pricing and regulation provide incentives for efficient uses of electricity by consumers; promote cost effective demand-side measures, including customer-owned generation as alternatives to transmission system expansion; and do not create barriers to cost effective distributed generation or renewable resources.
3. Conservation, Renewables and High Efficiency Resources
 - The region continues to pursue and acquire cost-effective conservation, renewables and high efficiency resources through regional, Bonneville, utility and state programs that supplement competitive market incentives where necessary.
 4. Fish and Wildlife
 - The region fulfills its fish and wildlife protection and mitigation responsibilities as they relate to the hydroelectric system effectively and efficiently.
 5. The Bonneville Power Administration
 - A sustainable role is defined for Bonneville in which it markets the existing Federal Columbia River Power System resources on an allocation basis, provides equitable benefits to the residential and farm customers of the region's investor-owned utilities, and meets additional load growth only through conservation and bilateral, incrementally priced contracts with individual customers or groups of customers.

Focus for the Fifth Power Plan

The Fifth Power Plan can help the region achieve this vision. The challenge for the Fifth Power Plan is two-fold. The first relates to the Council's traditional power planning role. It is to develop more robust planning methods for assessing and managing the risks inherent in the industry structure and to use these methods to develop resource strategies that will meet the region's electricity needs at lowest cost with acceptable risk.

The second and related challenge is to provide insights into the resolution of some of the key issues affecting the industry in the Northwest that are impediments to achieving the vision. These issues include at least the following:

- Determining what constitutes resource adequacy and identifying the incentives (regulatory or financial) for assuring resource adequacy;
- Contributing to improving the way we plan and pay for transmission system expansion, and how we ensure transmission is operated reliably, efficiently and equitably;

- Identifying the necessary and sufficient steps to enable effective demand side participation in the market;
- Identifying the means of sustaining investment in cost-effective conservation and renewable resources;
- Determining the value of resource diversity for the region and the means of achieving it;
- Determining how to meet the requirements for power and fish recovery effectively and efficiently; and
- Helping define the future role of the Bonneville Power Administration in power supply. Experience of the last few years suggests that Bonneville is, by nature of the requirements and constraints under which it operates, ill suited to managing the financial and political risks of a large role in resource development. An alternative is required that limits Bonneville's risk exposure in resource development while still ensuring that cost-effective conservation and renewable energy and fish program goals continue to be met.

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