type of resource for new electrical generation. As stated earlier, the spot market price of gas was in the $1.00 to $1.50/MMBtu throughout the winter of 1994-95. For the latest generation of CTs, these gas prices translate into an operating cost of between 8 and 12 mills/kWh. If gas prices continue to fall, or stay at current levels, this could place additional pressure on utilities in the region to shut down high operating cost base-load thermal power plants. Plants at the greatest risk of closing are nuclear and coal plants with high operating costs.

Increases in natural gas costs below the level that would change the resource mix for the PNW would affect BPA, though, by increasing the cost at which customers would choose to purchase from other suppliers rather than from BPA. Higher gas prices would tend to increase BPA loads and shift resource acquisitions to BPA from other suppliers.

4.5 Market Responses and Impacts of Modules

The sections that follow describe the market responses and environmental impacts of the policy modules described in chapter 2. Table 4.5-1 presents a summary of the impacts of the modules as they apply in each alternative.

Table 4.5-1: Market Responses and Environmental Impacts of Modules by Alternative

Module	Status Quo	BPA Influence	Market-Driven BPA	Maximize BPA's Financial Returns	Minimal BPA	Short-Term Marketing
Fish and Wildlife						
Status Quo (FW-1)	Intrinsic to alternative. Undefined BPA role/uncertain cost control could encourage BPA customers to seek other power suppliers, possibly leading to increased thermal generation impacts.	Not applicable.	Not applicable.	Not applicable.	Not applicable.	Not applicable.
BPA-Proposed Fish and Wildlife Reinvention (FW-2)	Not applicable.	Intrinsic to alternative. Increased potential to predict/control costs; less potential for load loss.	Intrinsic to alternative; effect same as in BPA Influence alternative.	Same as in BPA Influence alternative.	Same as in BPA Influence alternative.	Intrinsic to alternative; effect same as in BPA Influence alternative.
Lump-Sum Transfer (FW-3)	Not applicable.	Impacts probably similar to those of proposed Fish and Wildlife Reinvention.	Same as in BPA Influence alternative.	Intrinsic to alternative; effect same as in BPA Influence alternative.	Intrinsic to alternative; effect same as in BPA Influence alternative.	Same as in BPA Influence alternative.
Rate Design						
Seasonal Rates—Three Periods (RD-1)	Not applicable.	More loads placed on BPA in spring/ summer; more reliance by BPA customers on purchased (thermal) power in fall/winter, with related thermal power impacts.	Intrinsic to alternative; impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.

Table 4.5-1 (continued): Market Responses and Environmental Impacts of Modules by Alternative

Module	Status Quo	BPA Influence	Market-Driven BPA	Maximize BPA's Financial Returns	Minimal BPA	Short-Term Marketing
Rate Design (continued)						
Streamflow Seasonal Rates—Real Time (RD-2)	Not applicable.	BPA load loss and increased use of thermal generation from other sources with related thermal power impacts.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.
Streamflow Seasonal Rates—Historical (RD-3)	Not applicable.	Intrinsic to alternative: more loads placed on BPA in spring/summer; more reliance by BPA customers on purchased (thermal) power in fall/winter, with related thermal power impacts.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.
Eliminate Irrigation Discount (RD-4)	Not applicable.	Intrinsic to alternative; loss of some irrigation load; less irrigated agriculture, less irrigation water use; some farm losses.	Intrinsic to alternative; effects similar to impacts described for BPA Influence alternative.	Intrinsic to alternative; effects similar to impacts described for BPA Influence alternative.	Similar to impacts described for BPA Influence alternative.	Intrinsic to alternative; effects similar to impacts described for BPA Influence alternative.
Variable Industrial Rate (RD-5)	Intrinsic to alternative; under certain market conditions, could stabilize DSI load on BPA, lead to less resource development by other suppliers.	Similar to effect in Status Quo.	Similar to effect in Status Quo.	Similar to effect in Status Quo.	Similar to effect in Status Quo.	Similar to effect in Status Quo.

Table 4.5-1 (continued): Market Responses and Environmental Impacts of Modules by Alternative

Module	Status Quo	BPA Influence	Market-Driven BPA	Maximize BPA's Financial Returns	Minimal BPA	Short-Term Marketing
Rate Design (continued)						
Load-Based Tier 1 (RD-6)	Not applicable.	Less likelihood that winter-peaking utilities would turn to sources of power other than BPA; perhaps less likelihood of CT development and operation.	Intrinsic to alternative; impacts as described for BPA Influence alternative.	Similar to impacts described for BPA Influence alternative.	Not applicable.	Similar to impacts described for BPA Influence alternative.
Resource-Based Tier 1 (RD-7)	Not applicable.	Intrinsic to this alternative; more likelihood that winter-peaking utilities would turn to sources of power other than BPA; perhaps more likelihood of CT development and operation.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.	Not applicable.	Impacts as described for BPA Influence alternative.
Market-Based Tier 1 (RD-8)	Not applicable.	Impacts probably mid-way between Load- and Resource-Based Tier 1 modules.	Impacts as described for BPA Influence alternative.	Not applicable.	Not applicable.	Intrinsic to alternative; impacts as described for BPA Influence alternative.
Direct Service Industries						
Renew Existing Firm Contracts (DSI-1)	Intrinsic to alternative; assumed to cause some load loss in this alternative.	Increase BPA DSI load; increase revenue and reduce rates slightly; reduce new thermal generation by other entities; increase existing thermal generation.	Decrease BPA DSI load; increase in-lieu deliveries by same amount; displace existing thermal generation.	Same as in Market-Driven BPA alternative.	Not applicable.	Not applicable.

Table 4.5-1 (continued): Market Responses and Environmental Impacts of Modules by Alternative

Module	Status Quo	BPA Influence	Market-Driven BPA	Maximize BPA's Financial Returns	Minimal BPA	Short-Term Marketing
Direct Service Industries (continued)						
Firm DSI Power in Spring Only (DSI-2)	Not applicable.	Intrinsic to alternative; leads to loss of almost one-half of DSI load; increased new thermal generation by other entities.	Substantial loss of BPA DSI load partially replaced by increased in-lieu deliveries; increased cost and rate pressure; increased new thermal generation by other entities.	Approximately the same as under Market-Driven BPA alternative.	Similar to effect in Market-Driven BPA alternative but smaller in scale.	Similar to effect in Market-Driven BPA alternative but smaller in scale.
Declining Firm Service (DSI-3)	Not applicable.	BPA regains some DSI loads in the short term, increasing BPA revenues and reducing rates slightly.	Intrinsic to this alternative; leads to some increase in BPA DSI load in short term.	Probably little effect on BPA DSI loads in this alternative.	Intrinsic to alternative; similar to effect shown in Market-Driven BPA alternative.	Intrinsic to alternative; similar to effect shown in Market-Driven BPA alternative.
No New Firm DSI Power Sales Contracts (DSI-4)	Not applicable.	Loss of all BPA DSI firm load; substantial loss of revenue and increase in BPA rates; increase new thermal generation by other entities; displace existing thermal generation.	Same as in BPA Influence alternative (but greater magnitude).	Same as in BPA Influence alternative (but greater magnitude).	Intrinsic to alternative; impacts probably comparable to effects in Market-Driven BPA alternative.	Intrinsic to alternative; impacts probably comparable to effects in Market-Driven BPA alternative.
100-Percent Firm Service (DSI-5)	Not applicable.	Increase BPA DSI loads; increased revenue; reduce BPA rates slightly; less development of new thermal generation by other entities; more existing thermal generation.	Little effect on BPA DSI loads and revenues in short term; sustains higher DSI loads on BPA in long term.	Intrinsic to alternative; increases BPA DSI loads.	Not applicable.	Increase in BPA DSI loads, but little effect on BPA revenues.

Table 4.5-1 (continued): Market Responses and Environmental Impacts of Modules by Alternative

Module	Status Quo	BPA Influence	Market-Driven BPA	Maximize BPA's Financial Returns	Minimal BPA	Short-Term Marketing
Conservation/Renewable Resources						
"Fully Funded" Conservation (CR-1)	Intrinsic to alternative.	Intrinsic to alternative.	Increase BPA conservation by 140 aMW, regional conservation by 30 aMW; increase BPA rates; small reduction in environmental impacts of thermal generation.	Increase BPA conservation by 140 aMW, regional conservation by 230 aMW; increase BPA rates slightly; small reduction in environmental impacts of thermal generation.	Not applicable.	Increase BPA conservation by 250 aMW, regional conservation by 140 aMW; increase BPA rates; small reduction in environmental impacts of thermal generation.
Renewable Resource Incentives (CR-2)	Not applicable.	Intrinsic to alternative; probably has little effect on renewable resource acquisition.	Probably would have little effect.	Probably would have little effect.	Not applicable.	Probably would have little effect.
Maximize Renewable Resource Acquisitions (CR-3)	Not applicable.	Intrinsic to alternative; BPA would acquire 300 aMW additional wind and geothermal; BPA would try to sell resulting surplus power but would increase rates; small decrease in thermal generation impacts and increase in land use impacts.	BPA would acquire 300 aMW additional wind and geothermal; BPA would try to sell resulting surplus power but would increase rates; small decrease in thermal generation impacts and increase in land use impacts.	Comparable to Market-Driven alternative.	Not applicable.	BPA would acquire 380 aMW additional wind and geothermal. BPA would try to sell resulting surplus power, but would increase rates; small decrease in thermal generation impacts and increase in land use impacts.
"Green" Firm Power (CR-4)	Not applicable.	Intrinsic to alternative; BPA would acquire up to 80 aMW of wind and geothermal; would increase purchasers' average retail rates somewhat; slight decrease in thermal generation impacts and increase in land use impact.	Intrinsic to alternative; effect same as in BPA Influence alternative.	Intrinsic to alternative; effect same as in BPA Influence alternative.	Not applicable.	Same as in BPA Influence alternative.

4.5.1 Fish and Wildlife

There are three sets of issues regarding BPA's fish and wildlife program administration, related to its choices about 1) the level of responsibility and accountability BPA asserts for how program funds are spent; 2) how the agency attempts to control its fish and wildlife costs; and 3) who administers the program. The three modules developed to respond to the issues assume that the issues are inter-related; that is, that a particular level of responsibility and accountability for results may imply a particular administrative role.

Any of the fish and wildlife modules can be applied to any alternative, except the Status Quo alternative, which, as the no-action alternative, does not contemplate any new policies. All the modules are expected to implement the Council's F&W Program, the ESA Recovery Plan, and other mandated actions. At issue is not whether BPA will fulfill these responsibilities, but how it will be done and how the choices affect its ability to control its costs.

BPA cannot predict a hard and fast "x action leads to y consequence" of its fish and wildlife administrative choices. The analysis assumes the following:

- If BPA cannot control its costs, including fish and wildlife costs, it must raise rates. Raising rates motivates customers to buy from other suppliers rather than from BPA.
- If BPA loses a significant share of its firm load, its fixed costs will be spread among fewer customers, leading to rate increases. At some point, further rate increases will not increase revenue due to load losses. This is the maximum sustainable revenue level.
- If BPA cannot pay its full costs from maximum revenues, either some BPA activities will have to be curtailed, or BPA will have to receive additional funds or revenues to supplement power sales revenues.
- The amount of BPA load shifting to other suppliers could affect the development of conservation and generation resources in the region. To the extent customers move load away from BPA, such development would shift toward the resource choices of non-BPA suppliers and could also increase the need for transmission facilities.

This scenario assumes that customer responses are determined only by projected rates based on current estimates of BPA's costs. A complicating factor is that customers are considering suppliers other than BPA because they perceive that fish and wildlife costs are unpredictable, and they fear that, if they maintain their contracts with BPA, they will be subject to unknown additional costs in the future. They expect that actual BPA costs will be unpredictably higher than estimates. They are searching for alternative suppliers that will not be subject to the cost uncertainties that accompany BPA's fish and wildlife mission.

For BPA's competitiveness, market responses to how it administers its fish and wildlife responsibilities depend on the following:

- How the modules contribute to BPA's ability to control its costs
- How the modules improve customers' perception of BPA's ability to control costs.

Environmental impacts would vary with customer decisions to continue to use BPA to supply power or to find other suppliers. To the extent they stay with BPA, BPA's resource development choices would be maintained and impacts primarily would be those related to hydropower operations and planned new BPA resources (see section 4.3.4). If BPA customers were to shift to other suppliers, impacts that resulted would be those of other resources, predominantly CTs that the non-BPA suppliers would develop to serve their loads.

Contrary to implications in the initial Draft EIS, BPA has concluded that there is little evidence to support the conclusion that one particular administrative strategy will achieve greater or lesser improvements fish and wildlife populations compared with another. This analysis does not debate which measures to fund—those decisions are made as part of the Council's F&W Program development, the NMFS Recovery Plan, and as a result of other Federal agency and court decisions. Nor can this analysis claim that one entity in the region is more capable than another to achieve fish and wildlife improvements. As a consequence, BPA cannot predict any difference in environmental impacts to fish and wildlife from these modules. Any consequences would be indirect: if the worst case scenario were to occur and BPA had to curtail some activities, less money would be available for fish and wildlife measures, and it is unclear whether another entity would fill the funding gap. If replacement funding were not available, the region's ability to achieve its fish and wildlife goals could be impaired.

4.5.1.1 Status Quo (FW-1)

If BPA were to continue its current fish and wildlife administrative policies, the likelihood is high that its fish and wildlife costs would remain unstable and unpredictable, because it would not be comprehensively and systematically consulting with other regional entities to define and limit the size of its financial obligation for fish and wildlife enhancement and mitigation. BPA would not have a clearly defined set of criteria nor a regionally accepted role to help set funding priorities. Its fish and wildlife costs could be controlled more by entities whose responsibilities are focused on only one aspect of BPA's role—its role in regional fish and wildlife enhancement—rather than on its multiple roles, including assuring the region an adequate, economical, efficient and reliable power supply.

With the scope of BPA's responsibility and accountability remaining undefined, and with its control over its costs uncertain, some of BPA's customers would begin to act on their need for predictability of their power supply and its costs, and would switch to other suppliers. Depending on the number and size of customers who left BPA, impacts of CTs and other thermal resources might be greater than if customers remained with BPA and its hydropower. Under the worst-case scenario, fish and wildlife could be indirectly affected if BPA's revenues could no longer support funding all necessary fish and wildlife measures.

4.5.1.2 BPA-Proposed Fish and Wildlife Reinvention (FW-2)

Under this module, BPA might exert some additional control over its fish and wildlife costs, although probably not full control. With a recognized responsibility to administer funds, to consult on funding priorities and to monitor project success as input to continued funding decisions, BPA could more systematically assert influence on how ratepayer money is spent than under the Status Quo (Accountability Level I, figure 2.4-4). Agreements on base-level funding could substantially increase the predictability and stability of fish and wildlife costs, which could have the effect of increasing customer confidence that BPA rates would stay competitive, while at the same time assuring an adequate longer-term funding level for mitigation and enhancement. Tying additional funding for fish and wildlife measures to BPA's revenue success could provide for long-term support for fish and wildlife financed by trust fund earnings.

With emphasis in the fish and wildlife program on results, customers could be more confident of BPA's future fish and wildlife costs, and would have less incentive to shift load to other suppliers. If so, generation impacts would more closely follow BPA's resource acquisition choices.

The risk exists, however, that costs would increase, even with controls as described. If mitigation measures continued to show poor results and fish populations continue to decline, BPA and the fisheries interests could conclude that more spending is necessary, despite prior agreements. Then market responses and impacts could be similar to those described for Status Quo, unless BPA's financial obligation were limited, or other funds were made available to support additional actions to enhance fish survival.

4.5.1.3 Lump-Sum Transfer (FW-3)

The potential for control of BPA's fish and wildlife costs could be similar in this module to that of the proposed fish and wildlife reinvention (FW-2). The chief difference between the two modules is that, with a lump-sum transfer (assuming it could be accomplished legally), BPA would not be held accountable for project results because it would transfer its role in setting funding priorities and in monitoring to other entities (Accountability Level III, figure 2.4-4). Without BPA's involvement, some BPA customers might have slightly less confidence that ratepayer funds were being spent effectively (although there is no evidence to suggest they would not be); however, market responses of customers would probably depend primarily on the module's success in predicting and containing costs. BPA's financial responsibility would be defined in a multi-year agreement, as in the proposal, which could provide cost stability; however, the risk, as in the proposal, exists that lack of results could put pressure on BPA to increase funding levels despite prior agreements.

Impacts would be similar to those described for the proposed fish and wildlife module (FW-2).

4.5.2 Rate Design

This EIS addresses eight policy modules concerning rate design. Three address different ways to vary rates over the seasons of the year. Two address rate features directed at specific types of consumers: discounts to irrigators, and the variable rate to aluminum DSIs. The last three are different approaches to tiered rates.

4.5.2.1 Seasonal Rates - Three Periods (RD-1)

Module Description

In this module, BPA would design its power rates for utility customers to incorporate three separate rate periods or seasons of 3 to 5 months each. The goal of this rate design would be to achieve a closer linkage between BPA's wholesale rates and the price of power on the open market. Priority Firm, Industrial Firm and the New Resource rates would be seasonalized in this manner. Generally, rates would be highest in the winter when loads and power costs are high, low during the spring flow augmentation, and somewhere in between during the rest of the year. The differential between winter and spring rates could be as much as 15 mills/kWh.

Effect of Module on Alternatives

In general, the closer BPA's rates are to the market price of power, the more accurate the price signal sent to BPA's customers. By responding to market price signals, consumers can make more efficient use of electric generation and transmission resources. However, the effect of changes in rate structure can be overshadowed by changes in methods used to allocate costs among BPA's customer classes and between high and low load-factor customers.

Depending on the degree of seasonal differentiation in rates, BPA could be at risk of losing load from the generating public utilities and DSIs during the high-rate periods. In that case, these customers might increasingly rely on purchases during the winter months (probably supported by regional or extraregional thermal generation), and place more of their load on BPA in spring and summer months.

This module is evaluated as a variant to the BPA Influence, Minimal BPA, Short-Term Marketing, and Maximize Financial Returns alternatives; it is intrinsic to the Market-Driven alternative. Impacts of this module would be the same in kind among all alternatives to which it applies: customers would be likely to place more of their load on BPA during the low-rate period (spring and summer), and less during the higher-rate periods. During periods when they do not place load on BPA, these customers are likely to rely on power purchases, probably supported by existing thermal generation or CTs. The extent to which customers place more load onto BPA in low-rate periods and take load off BPA in high-rate periods would depend on the extent to which rates vary by period compared to the rates for alternative power supplies during those same periods.

Environmental Impacts

The operations of the hydroelectric system are being evaluated and determined through the System Operation Review (SOR) process, which will determine operational constraints for Federal hydro projects. Therefore, seasonal rates would have no impact on hydro operations; rather, they might help BPA shape its loads more closely to the capabilities of the hydroelectric system that result from the SOR process.

The primary environmental impact would stem from utility and DSI decisions about whether to place load on BPA given the seasonal rates. As noted above, it is possible that seasonal rates would result in more load placed on BPA in the spring when the seasonal rate is lowest, and less load in the winter when the rate would be higher. This could result in increased reliance on power purchases to meet utilities' and DSIs' peak winter needs. Power purchases are most likely to be supported by existing or new thermal generation (primarily CTs). Increased operation of CTs would lead to increases in NOx, SO2, CO, and CO2 emissions, water use, and land use impacts (identified on a per-megawatt basis in Table 4.3-1, Typical Environmental Impacts From Power Generation and Transmission).

4.5.2.2 Streamflow Seasonal Rates - Real Time (RD-2)

Module Description

BPA received several comments suggesting that linking power prices to streamflows would help to match BPA's loads to the capability of hydro generation. The advocates of streamflow rates suggested that they could be used to reflect the availability (or scarcity) of water by tying rates to existing hydrological conditions as they develop during the operating year. The rate structure evaluated for this module would have BPA rates changing monthly, based on projected streamflows. Projected rates would be developed and published by July 1 of each year for the upcoming 12 months. Each month, the streamflow would be re-estimated for the next month and all remaining months of the year, revising the rates accordingly. For BPA's firm power customers only, a balancing account would capture any over/under collections due to streamflow variances from projected flows. When hydropower generation is scarce due to low streamflows, rates would be higher; rates would be lower when hydropower generation is plentiful due to high streamflows.

Effects of Module on Alternatives

For a hydro-based power system like BPA's, water availability is a major, but not the only, driver of power costs. The recent completion of the Third AC Intertie has increased the PNW/PSW transfer capability to almost 8,000 MW. This increase, combined with the development of Regional Transmission Groups (RTGs) and the gradual reduction in barriers to transmission access, has helped create a vibrant west-coast market for electricity. The amount of runoff is no longer the prime determinant of west-coast power prices. Other major drivers of power costs are temperature, the economy, oil and gas prices, thermal generation availability, intertie availability and the demand for electricity.

While streamflows are an important determinant of the price of power in the PNW, basing the price of electricity solely on the level of streamflows would not fully reflect how the price of electricity is set in the wholesale market. Under real-time streamflow pricing, there could be long periods of time when BPA's streamflow rate and the wholesale market price of electricity would be different. In the short term, marketing and extraregional customers would do some "reshaping" of their own resources and modify purchases to respond to streamflow rates and to any disparity between streamflow rates and the market price of electricity. Non-marketing customers do not have the same flexibility; the resulting load changes would be small, but could lead to significant load loss to other utilities or self-generation if customers chose the greater certainty of power pricing from other resources. Because streamflows are volatile, this rate would create greater pricing volatility and uncertainty for BPA customers than rates fixed for specified periods of time.

For example, if the PNW experienced an abnormally wet year, a streamflow-based pricing methodology would set the price of electricity low to signal the low "cost" of water. If this occurred during an abnormally cold winter, an event such as the loss of a portion of the Intertie capacity or a shutdown of one or more large thermal resources could result in BPA seriously under-pricing its power. Under this scenario, demand for electricity would be very high, and the ability of the power system to supply electricity to meet this demand would be severely constrained. The low rates called for under real-time, streamflow-based rates would signal BPA customers to increase power consumption at a time when conditions would warrant discouraging consumption.

Another concern with streamflow rates is revenue stability. BPA's cost structure is about 85 percent fixed, and does not change with the amount of electricity sold. Streamflow-based electricity rates which change monthly would add to BPA's financial risk because of the increased variability of BPA's revenues.

BPA would lose load among the non-generating publics, who would be unable to predict BPA rates. They would seek the stability of long-term contracts with IOUs or possibly self-generation. Generating publics and DSIs would most likely purchase from BPA during wet years and other times when BPA streamflow rates are low, and purchase on the open market when power is available at rates below BPA's rates. Load loss could range from 800 to 1,200 aMW in 2002. Most of this firm power surplus would be sold to the nonfirm market. The difference between the average PF and the nonfirm market price would be about 17 mills/kWh. This could lead to a revenue loss of about $120 to $180 million annually. However, BPA could deliver up to 900 aMW of this power to IOUs under the in-lieu provisions in the residential exchange contracts. Because in-lieu power would be delivered to the IOUs at the PF rate, most of the lost revenues would be replaced by the in-lieu power sales. In addition, BPA's Residential Exchange costs would decrease by up to $70 million annually. Depending on the amount of load loss and the quantity of in-lieu power delivered, the net effect of this module could range from a $20 to $70 million reduction in BPA's costs, to a $180 million reduction in BPA's revenues. The rate effects range from a slight decrease to a 1.75 mill increase in BPA rates.

If BPA PF customers pass through this rate increase to their customers, extensive price-induced conservation could result, as customers reduce usage to avoid paying the higher rates.

This module is a variant to all alternatives except Status Quo. It would have similar effects in all alternatives; that is, both generating and non-generating customers would turn to sources of power other than BPA (IPPs, other utilities, and self-generation, probably supported by CT generation), and BPA would have substantial surplus power, which could be used to serve in-lieu loads of IOUs or would be sold at low nonfirm prices. The amount of revenue loss or cost reduction to BPA would depend on the amount of surplus in each alternative, the degree to which in-lieu loads could be served, and the amount of power that would have to be sold at nonfirm rates.

Environmental Impacts

The environmental impacts of this module would be similar to those of module RD-1 (Seasonal Rates-Three Periods); however, the rates uncertainties associated with this module may lead more utilities to shift load away from BPA and turn to other power sources throughout the year, not just during winter months. The result could be additional regional development of new generating resources, particularly CTs (with their air quality, water use, and land use impacts), and increased BPA surpluses. To the extent that BPA could use surplus load to serve in-lieu loads of IOUs, the BPA surplus could offset some portion of those utilities' new resource requirements.

4.5.2.3 Streamflow Seasonal Rates - Historical (RD-3)

Module Description

In this module, BPA's firm power rates would be seasonally differentiated, and would be higher in months with higher streamflows (spring and summer) and lower in months with lower streamflows (fall and winter). In contrast to the previous module (Streamflow Seasonal Rates—Real Time), rates would not be set on a month-by-month rate to reflect actual streamflows; rather, they would be based on historical average flows in each month. This would allow rates to reflect normal year streamflows, but with more predictability than if rates were adjusted monthly to reflect actual streamflows.

Effects of Module on Alternatives

The effects of this module would be comparable to those of the Seasonal Rates - Three Periods module described above. This module is a variant under all alternatives except BPA Influence. In all cases, impacts would be similar: generating publics would be likely to place more of their load on BPA in spring and summer months, when rates are lower, and less during fall and winter months, when rates are higher. During periods when they do not place load on BPA, these utilities are likely to rely on power purchases, probably supported by existing thermal generation or CTs. The extent to which utilities place more load onto BPA in low-rate months and take it off BPA in high-rate months would depend on the extent to which rates vary by month compared to the rates for alternative power supplies during those same months.

Environmental Impacts

The impacts would be largely comparable to the three-period historical rate described above—that is, increased seasonal reliance on power purchases supported by the development and operation of combustion turbines, with consequent impacts on air quality and land and water use.

4.5.2.4 Eliminate Irrigation Discount (RD-4)

Module Description

BPA received comments during review of the DEIS suggesting that it eliminate the irrigation discount in the current rate structure, in order not to encourage the diversion of water from the Columbia and Snake River systems for irrigation. BPA currently provides a rate discount of approximately 5 mills/kWh to preference customer utilities to serve loads used to irrigate or drain fields for agricultural purposes.

Effects of Module on Alternatives

The market and environmental impacts of the irrigation discount were addressed in BPA's 1993 Wholesale Power and Transmission Rate Environmental Assessment (DOE/EA-0838, or BPA publication DOE/BP-2204, July 1993). According to that document, eliminating the irrigation discount could lead to a total regional irrigation load decline ranging from 5 to 10 percent, or up to approximately 30 aMW (total irrigation loads on BPA vary considerably, but are estimated to be approximately 300 to 350 aMW in 1995). Effects on BPA's total firm loads would be considerably smaller, because irrigation loads are only a small proportion of BPA total loads. The elimination of the irrigation discount would have a very small positive impact on BPA's revenues and rates to other BPA customers; however, the rate increase to irrigating utilities would be offset somewhat by a loss in irrigation loads. The overall impact on BPA's revenues and rates probably would be less than 0.1 mill/kWh.

This module would have essentially the same effect if implemented in any of the alternatives. In all cases, impacts on BPA's revenues and rates would be very minor.

Environmental Impacts

Implementation of this module (that is, elimination of the irrigation discount) would have several environmental impacts—it could motivate some irrigators to increase the efficiency of irrigation, thereby reducing water use for farming; it could lead to some changes in crops (to crops that require less water); and it could increase farming costs, potentially to the point that some farms could no longer operate economically and would go out of business. To the extent that irrigators are able to obtain replacement power from other suppliers at prices comparable to BPA's rates with the irrigation discount, the effects described below will not occur.

The 1993 Rates EA predicted that for each 10 aMW of irrigation load reduction, up to 3,000 hectares (ha) (7,500 acres) of land might be removed from production and up to 0.2 km3 (0.15 MAF) less irrigation water might be used. If, in extreme cases, elimination of the irrigation discount reduced loads as much as 30 aMW as a result of curtailments, irrigation water use might be reduced by up to 0.6 km3 (0.5 MAF), and up to 8,000 ha (20,000 acres) of land might be removed from production. In the unlikely event that all of the irrigation water came from surface water or from groundwater hydrologically connected to surface water sources (which is not the case), up to a half-million acre feet of water might be returned to surface water, including the Columbia and Snake River systems. Some of this water could be available for flow augmentation to enhance downstream passage of anadromous fish, even though the quantity is not substantial.

Farmers faced with increased costs of pumping would shift to less energy-intensive methods of farming. Generally, such a shift also reduces water consumption, as farmers use more water-conserving irrigation methods (such as higher-efficiency sprinkler systems) and grow less water-intensive crops. Farms where irrigation involves high-head pumping operations could become uneconomical, and farmers in such situations could go out of business. Most of these operations are located in arid parts of the region in areas of sandy soils. Without irrigation, grazing would be the likely alternative agricultural use of these lands.

4.5.2.5 Variable Industrial Rate (RD-5)

Module Description

BPA currently serves the DSI aluminum smelters under the Variable Industrial (VI) Rate, through which the price of electricity varies (with a lower and an upper limit) with the price of aluminum. Aluminum ingots are a commodity that is traded on international exchanges. The aluminum price is subject to considerable volatility, and ranged from $.45/lb. to $1.20/lb. between 1986 and 1994. Aluminum production is very sensitive to electricity costs because they account for about one-third of the cost of production, and electricity is the only component of the cost of producing aluminum that varies significantly throughout the world. Because the aluminum DSI loads account for about 30 percent of BPA's revenues, the swings in the smelter load caused severe financial problems for BPA due to uncertainty in revenues before it implemented the VI rate in 1986.

The current VI rate ranges from about 20 mills/kWh during periods of low aluminum prices, to about 33 mills/kWh when aluminum prices are high, with a plateau set at the base or 7(c)(2) DSI rate. Implementation of the VI rate in 1986 led to the reopening of three closed smelters under new ownership, and the restart of another that had been closed for over a year. The VI rate stabilized BPA's smelter load and provided significantly more revenue in the first 5 years of the rate than BPA would have received without it, although BPA's aluminum DSI revenues have been lower recently due to over-supply in the international market.

The VI rate stabilized the loads of aluminum DSIs and reduced the uncertainty of BPA's revenues due to unpredictable changes in the price of aluminum. This revenue uncertainty caused concern among BPA's utility customers because of the effect on BPA's firm power rates when additional revenues were required during periods of low aluminum prices. Although there is some variability in DSI revenues under the variable rate, the revenue reduction is less than if they curtailed production or shut down permanently when aluminum prices dropped, as they did under the IP rate. In addition, under the variable rate, BPA has the opportunity to recoup revenue losses when aluminum prices are high. Under the IP rate, the revenue variation is always down.

This module assumes that the VI rate would continue in its current form. Assuming a base (plateau) DSI rate in 2002 of about 29 mills/kWh, the VI rate would range from 19 mills/kWh during periods of low aluminum prices to 39 mills/kWh during periods of high aluminum prices.

Effect of Module on Alternatives

Estimating the effect of the VI rate depends on a large number of factors that are difficult to predict. The effectiveness of the VI rate depends on the profitability of the PNW smelters at the basic DSI rate, the long-term price of aluminum, BPA's load/resource balance, the price of power in the nonfirm and surplus firm market, and BPA's financial condition.

Scenarios for a VI rate that would have any effect on the level of BPA's DSI loads would require that the smelters could operate profitably at the base DSI rate, that BPA be in load/resource balance or surplus, and that rates in the nonfirm market be at or below the lower limit of the VI rate. If gas prices remained low and BPA continued to lose PF load to other utilities and self-generation, the VI rate could be a way of preventing a similar defection of DSI load and lead to greater revenue stability for BPA.

However, if (1) BPA were not able to set the base DSI (or plateau) rate at a level that would allow profitable operation for the smelters with BPA power instead of other power sources, (2) nonfirm prices were above 20 mills/kWh, and (3) BPA were successful in maintaining PF load, a VI rate might not offer benefits to BPA and its other non-DSI customers.

Because of the great number of uncertainties associated with this module, specific impacts for each alternative cannot be estimated. The types of impacts associated with this module would be similar among all alternatives to which it applies as a variant (all alternatives except Status Quo, for which the VI rate is intrinsic).

Environmental Impacts

DSI operations likely would remain unchanged, because the current predictions of aluminum prices and DSI products and the costs of alternative power suggest that DSIs will continue to operate whether or not they are served by BPA. Only if major unpredicted changes occurred in aluminum prices or alternative power costs would this module affect the level of DSI operations.

The primary effect of this module would be on the amount of DSI load served by BPA or by other power sources such as power purchases, self-generation, IPPs, or other utilities (most likely supported by the development and operation of CTs). Implementing this module might, under the right market conditions, lead to higher DSI loads on BPA and therefore less development of alternative supplies.

4.5.2.6 Load-Based Tier 1 (RD-6)

Module Description

BPA would develop the size of Tier 1 based on a percentage (for example, 90 percent) of historical loads for each customer. In a month when Federal system resources were not sufficient to meet Tier 1 loads, BPA would purchase power on the open market to equalize the FBS resources and the Tier 1 load. The balance of the load (for example, 10 percent) would be served at Tier 2.

Effects of Module on Alternatives

Effects of this module would be similar among all the alternatives to which it applies—BPA Influence, Maximize Financial Returns, and Short-Term Marketing (it is intrinsic in Market-Driven BPA and would be incompatible with the objectives of Status Quo and Minimal BPA alternatives).

In any tiered rate structure, utilities with rapidly growing loads would purchase increasing amounts of more expensive Tier 2 power. As a consequence, they would have greater incentives to implement their own conservation programs or to turn to sources of power other than BPA (to the extent that other sources would be less costly than BPA’s Tier 2 rate). Utilities with slow or no load growth would have fewer incentives to implement their own conservation programs or to turn to other sources of power.

In a load-based tiered rate structure, conservation incentives and incentives to turn to other power sources would be more evenly spread across winter-peaking utilities and customers with flatter load shapes than under a resource-based structure.

Environmental Impacts

The primary environmental impacts of this module stem from the differing environmental impacts of different conservation and generating resource types (which are described generically in section 4.3 of this chapter). To the extent that a load-based Tier 1 rate led utilities experiencing load growth to continue to put loads on BPA, regional load growth would be served by the mix of resources BPA selects in its resource programs, which emphasizes conservation, renewables, and CTs. It is likely that if growing utilities put less load on BPA, they might rely more on meeting load growth with CTs or power purchases, which are predicted to be the lowest-cost resources available to serve load.

4.5.2.7 Resource-Based Tier 1 (RD-7)

Module Description

BPA would base the size of Tier 1 on a fixed percentage of FBS capability. The size of the resource-based Tier 1 would vary from month to month based on streamflows and the availability of other FBS resources. All additional power would be purchased at Tier 2. The allocation of this power would be based on the customers' historical loads. Purchased power would not be allocated to Tier 1. Under this proposal, BPA would assign a fixed set of resources to serve a portion of the customers' loads at the cost of those resources, and assign other firm resources to serve Tier 2 loads.

Effects of Module on Alternatives

The effects of this module would be similar among all the alternatives to which it applies—the Market-Driven BPA, Maximize Financial Returns, and Short-Term Marketing alternatives (This module would be intrinsic to BPA Influence, and is incompatible with the objectives of the Status Quo and Minimal BPA alternatives). Like load-based tiered rates, the effects of this module would be more pronounced for faster-growing utilities that would purchase greater amounts of BPA power at Tier 2 prices.

A resource-based Tier 1 would provide relatively greater price incentives to utilities with winter-peaking loads to implement their own conservation programs or find sources of power other than BPA, and smaller such price incentives to utilities with summer-peaking or flat loads. All BPA customer utilities would experience higher costs of increased Tier 2 purchases during winter low-flow months. Therefore, this module could affect the regional distribution of conservation development and the degree to which utilities place load on BPA.

Environmental Impacts

The environmental impacts of this module would depend on the degree to which the resource acquisitions of utilities shifting load away from BPA would differ significantly from BPA's resource acquisitions. In this module, utilities would face higher BPA rates in winter, and in response, might look to other power sources (such as CTs) or implement their own conservation programs.

4.5.2.8 Market-Based Tier 2 (RD-8)

Module Description

BPA would price power from Tier 2 based largely on the price of power on the wholesale market. BPA would hope to avoid defection of load to other suppliers and self-generation by pricing power slightly below the prevailing rate. If necessary, the price of Tier 1 would be increased to accomplish this pricing goal.

Effects of Module on Alternatives

BPA would set the Tier 2 rate slightly below the price of long-term power or the cost of alternative resources that existing customers could purchase for use as an alternative to BPA power; Tier 1 might absorb Tier 2 costs. This module would help BPA to maintain competitive prices for Tier 2 sales even when Tier 2 costs are above the market price, by supporting Tier 2 sales with Tier 1 revenues. Conversely, Tier 2 sales at the market price could reduce Tier 1 rates if Tier 2 costs were below the market price. When the market price is falling, this module would add to the uncertainty of Tier 1 prices and increase the loss of BPA utility firm loads.

Effects of this module would be similar among all the alternatives to which it applies—the BPA Influence and the Market-Driven alternatives. (This module would be intrinsic to Short Term Marketing and is incompatible with the objectives of the Status Quo, Maximize Financial Returns, and Minimal BPA alternatives.)

Environmental Impacts

The effect of this module on customers' decisions about placing growing loads on BPA probably would be mid-way between the Load-Based Tier 1 and the Resource-Based Tier 1 modules. As in those modules, the primary environmental impacts of this module would stem from the differing environmental impacts of different conservation and generating resource types (see section 4.3). To the extent that a market-based Tier 2 rate would lead utilities with growing loads to continue to place them on BPA, regional load growth would be served by the mix of resources BPA selects in its resource programs, which emphasize conservation, renewables, and CTs. If utilities put less load on BPA, they might tend to rely more on CTs to serve load growth.

4.5.3 Direct Service Industries Service

Under current market conditions, 2,700 aMW of DSI load is assumed to operate across all modules. The major question is whether BPA serves the DSI load, or whether it is served by other suppliers or self-generation. Increased competition in the generation market, increased access to BPA's transmission system, low natural gas prices and improved efficiency of CTs has made purchasing power from other suppliers or self-generation an increasingly attractive option for the DSIs. Prices for short-term power were in the 10 to 20 mill range during the winter of 1994-95, and the first-year cost for new CTs currently is at or below BPA's PF rate.

Therefore, the analysis of impacts of DSI rate and contract alternatives focuses on effects on BPA loads (and resulting impacts on generation and conservation development and operations). However, if market conditions changed substantially, DSI operations (which are expected to be the same across all Business Plan alternatives) could change. In that case, there could be increases or decreases in the environmental impacts of DSIs, shown on a per-megawatt basis on table 4.3-1. Table 4.5-2 shows DSI loads and rates for the six EIS alternatives which provide the "base case" for evaluating the DSI modules discussed below.

Table 4.5-2: Direct Service Industries Operations, Loads, Resources, and Rates
Base Case for Evaluating Effects of DSI Modules (Nominal $ in 2002)

	Status Quo	BPA Influence	Market-Driven	Maximize Financial Returns	Minimal BPA	Short-Term Marketing
Total PNW DSI load (aMW)	2,700	2,700	2,700	2,700	2,700	2,700
BPA DSI load - firm (aMW)	1,600	400	2,500	2,500	1,900	1,900
BPA DSI load - nonfirm (aMW)	300	800	0	0	0	0
BPA DSI load - total (aMW)	1,900	1,200	2,500	2,500	1,900	1,900
DSI rate (mills/kWh)	30-34	28-32	27-31	27-31	26-30	27-31
Average nonfirm rate (mills/kWh)	15	15	15	15	15	15
PF rate for "in-lieu" sales	32-36	30-34	29-33	29-33	28-32	29-33
BPA "in-lieu" sales to IOUs (aMW)	900	900	0	0	0	300
BPA firm surplus (aMW)	1,600	1,900	0	0	0	0

The discussion of DSI policy modules below includes references to some special features of DSI service that affect BPA's sales and revenues. The following is a brief explanation of these features.

The DSI load, most of which is comprised of aluminum smelters which operate at almost 100-percent load factor, provides some important benefits to the Federal hydroelectric system. (Load factor is the ratio of the average usage to maximum (or peak) usage for a particular customer or customer class.)

One of these benefits arises from the interruptibility provisions in the current DSI power sales contracts. These contracts permit BPA to interrupt the DSI load for energy shortages (such as those resulting from low river flows during dry years), system emergencies, and loss of major generating plants or the interties. Without these interruption provisions, BPA would have to arrange for equivalent amounts of reserves from generation, such as gas- or oil-fired combustion turbines, which other utilities use to provide reserve power. The rate BPA charges DSIs (as required by the Northwest Power Act) reflects the value to BPA of the reserves provided by the DSIs.

Aluminum smelters and some of the other DSIs operate continuously, 7 days a week, 365 days a year. This constant load can be served at lower cost than the more variable loads of commercial or residential consumers, which require enough generation to meet total loads during peak hours of the day, but leave much of the same generation idle during the hours of lowest consumption in the middle of the night and on weekends.

The constant DSI load also allows BPA to make full use of hydro generation from the required minimum nighttime flows on the Columbia River. Without the large block of DSI nighttime loads, it might be necessary to spill water to maintain required flows, and lose the potential to generate power. The large nighttime loads also allow BPA to increase its revenues through power sales or exchanges with other utilities, both within the Northwest and in other regions, by allowing BPA to deliver power during the day when it has higher value, and to accept returns during the night. These transactions include capacity sales, capacity for energy exchanges, and seasonal exchanges (which help BPA to adapt to higher springtime flow requirements by exchanging springtime generation from the Columbia River system for wintertime generation from other resources).

4.5.3.1 Renew Existing DSI Power Sales Contracts (DSI-1)

Module Description

This module assumes that when the current DSI power sales contracts (PSCs) expire in 2001, the PSCs would be renewed in the same basic form as the existing contracts. The new contracts would serve three quartiles of the DSI load as firm for operations and planning purposes, and the fourth quartile subject to the interruption rights and provisions of the current DSI contracts. The rate provisions of section 7(c) of the Regional Act would continue to be the basis for setting the DSI rate.

Occasionally the DSIs have disagreed with BPA over the exact meaning of the top quartile restriction rights contained in the existing PSCs. The DSIs have wanted a more precise description of when and under what conditions the top quartile would be curtailed. Also, the DSIs have wanted a better description of their rights to and pricing of purchased power when the top quartile service is restricted, and have been concerned with limitations on power purchases from other suppliers. The DSIs, like large industrial customers elsewhere, would like to be able to purchase some portion of their load on the open market, and not be tied exclusively to BPA. These disputes over PSC interpretations suggest that renewing existing contract terms would meet with some objections from the DSIs.

Section 7(c)(2) of the Regional Act states that the DSI rate is to be based on the PF rate and the typical margins included by preference customers in their retail industrial rates, taking into account the size, character and other items including retail industrial rates. The DSI rate under Section 7(c)(2) is set by calculating the 7(b) or preference rate at the DSI load factor, adding the “typical margin” paid by retail industrial customers of preference customers, and subtracting the credit for value of reserves. This module assumes that the typical DSI margin calculation also remains unchanged from the current formula.

The DSI rate has averaged about 2 mills/kWh less than the average PF rate since the 1985 rate case. Although this differential may change over time, the 2-mill differential is assumed to continue in this module.

Effects of Module on Alternatives

This module is evaluated under the BPA Influence, Market-Driven BPA and Maximize Financial Returns alternatives. It would be intrinsic in the Status Quo alternative and would not be considered in either the Minimal BPA or Short-Term Marketing alternatives because renewing existing DSI power sales contracts would be inconsistent with the basic assumptions of those two alternatives.

Status Quo

This module is intrinsic to the Status Quo, and its implementation is likely to lead to a significant drop in the amount of DSI load served by BPA because of the unresolved issues between BPA and the DSIs over contract interpretation, the high cost of power to replace interrupted top quartile deliveries, and uncertainty of power supply. The amount of DSI load served by BPA would decline by about 600 aMW from current forecasted levels, to 1,900 aMW, due to DSI use of other sources of power (self-generation and purchases from other suppliers).

BPA Influence

The module that is intrinsic to this alternative is DSI firm service in the spring only, with interruptible service for the rest of the year. If BPA instead offered to renew the DSIs' existing power sales contracts in 2001, the portion of DSI load served by BPA would increase because the certainty of power supply would be more acceptable to DSIs than spring-only firm service.

If this module were implemented—that is, if tiered rates were not implemented, the existing DSI rate structure and contractual terms remained in place, and the limitation of firm service in the spring only removed—the DSI load served by BPA could increase to about 1,200 aMW of firm load and 700 aMW of nonfirm load. At this operating level, BPA's firm surplus would decrease to about 1,200 aMW. The increase in BPA's DSI load of about 700 aMW in this module would generate additional revenues for BPA because the DSI rate would be about 15 mills/kWh higher than the nonfirm rates for which the surplus would most likely be sold. This would generate about $90 million in additional revenues to BPA, reducing the rate increase otherwise predicted for this module by about 1 mill/kWh.

Market-Driven

In the Market Driven alternative, the percentage of DSI load served as firm declines over time. By substituting renewal of the existing DSI PSCs in 2001 for the tiered rates and declining firm service, BPA would see a drop in the amount of DSI load it served because of the interruptibility provisions of the existing PSCs, which (as noted above) are not favored by the DSIs because of the supply uncertainty they cause.

Implementing this module instead—that is, replacing the tiered rate structure planned for the long term with the existing DSI contracts—would result in a BPA DSI load loss under this alternative of about 600 aMW. The reason for this DSI load loss is that under current and forecasted market conditions, the DSIs increasingly find that the interruptibility conditions of the current DSI contract make it difficult to plan and operate. With the price of alternative power sources dropping, DSIs would find it easier to contract with other sources than to be subject to the uncertainties of BPA's interruptible top quartile service. BPA would probably deliver this power at the PF rate to utilities under the in-lieu provision of the residential exchange contracts. Doing so would increase BPA revenues by about $10 million annually because the average PF rate is estimated to be about 2 mills/kWh above the DSI rate. In addition, BPA would save about $40 million in Residential Exchange payments. There would be some additional costs because of the need to replace the reserves that had been provided by the DSIs, and also the potential for some operating difficulties because of the difference in the load shape of the residential exchange and DSI loads. However, the overall benefit to BPA of implementing this module would be about $50 million annually, potentially leading to approximately a 0.25 to 0.50 mill reduction in the PF rate.

Maximize Financial Returns

Impacts in this alternative would be similar in kind and magnitude to those described for the Market-Driven alternative.

Environmental Impacts

As described in section 4.4.3.7, under DSI Load Effects, current projections of aluminum prices and the costs of alternative energy sources suggest that approximately 2,700 aMW of DSI loads will operate in all alternatives, whether or not this load is served by BPA. Therefore, implementation of this module would not affect levels of DSI operations (and associated air quality impacts); it would affect only whether the DSIs were served by BPA or other sources.

Moving DSI load from BPA to other power sources (such as power purchases, IPPs, or other utilities) probably would increase the development and operation of CTs, leading to predictable increases in NOx, CO, and CO2 emissions from these new thermal generating resources. However, BPA would also be left with surplus firm and nonfirm power, at least at certain times of the year. This surplus could be used by BPA to serve in-lieu loads of IOUs that participate in the residential exchange program, thereby reducing their need to develop new resources to serve load growth. The surplus might also be available regionally to displace higher-cost thermal resources (e.g., coal). The net impact of increased development and operation of inexpensive and relatively clean gas-fired CTs and the displacement of existing older thermal resources and coal might be a positive impact on air quality.

The effect of moving DSI load from other sources back on to BPA would be the opposite of the effects just described (e.g., less CT development and operation, and potentially, more operation of existing higher cost thermal resources).

4.5.3.2 Firm DSI Power in Spring Only (DSI-2)

Module Description

BPA would offer firm service to the DSIs during the 4-month flow augmentation period each spring. For the rest of the year, BPA would serve the smelters on an interruptible basis. To the extent that BPA could not supply the DSIs' power needs, they would purchase power on the open market. The DSI load served by BPA under this module is estimated to be about 400 aMW of firm power and 800 aMW of interruptible power. The balance of DSI load probably would be served from other sources or through self-generation. The DSI companies could decide to abandon BPA altogether if firm service were offered only in the spring. Aluminum smelters in particular require a stable and certain power supply for producing primary aluminum, and are very sensitive to changes in electricity price. The uncertainty of having half their load interruptible, forcing them into the open market, could prove to be too risky for the companies, which could instead decide to place all their load on other, more predictable sources.

Effects of Module on Alternatives

This module is considered intrinsic to the BPA Influence alternative, and a variant that could be applied to all other alternatives (except Status Quo, which assumes current DSI contract provisions).

BPA Influence

This module is intrinsic to the BPA Influence alternative. The aforementioned concerns over certainty of power supply would lead to a loss of about 1,300 aMW of BPA DSI load. BPA would serve about 400 aMW of firm DSI load and 800 aMW of nonfirm DSI load in this alternative. The DSIs' production processes, particularly aluminum smelting, require large amounts of electricity with a high degree of certainty of delivery. Offering firm service in the spring only would result in a large loss of load to other suppliers and self-generation, primarily because of DSI concerns over certainty of supply.

Market-Driven

DSI service under the Market-Driven alternative uses tiered rates with the percentage of DSI service declining over time. Substituting the firm DSI power in spring only module in this alternative would result in a significant drop in the amount of DSI load served by BPA because of DSI concerns over interruptions in power supply. Under DSI service conditions intrinsic to this alternative, the DSI load in 2002 served by BPA is estimated to be about 2,500 aMW. Implementing this module instead would reduce BPA loads by about 1,300 aMW. BPA probably would deliver 900 aMW of this power at the PF rate to utilities under the in-lieu provision of the residential exchange contracts. Doing so would increase BPA revenues by about $15 million annually because the average PF rate is estimated to be about 2 mills/kWh above the DSI rate. In addition, BPA would save about $65 million annually because of reduced Residential Exchange payments to utilities. BPA would incur some additional costs to replace the reserves provided by the DSIs. There would also be some potential to lose capacity sales and seasonal exchanges due to the reduction in BPA's DSI nighttime loads, which allow the Northwest power system to accept nighttime energy returns. There could also be operating problems because of the difference in the load shape of the residential exchange and DSI loads, which would increase daily peaking demands on BPA. The costs of replacing reserves, losing some capacity sales and exchanges, and addressing operating problems might total about $125 to $150 million annually.

BPA would have a surplus of about 400 aMW if this module were implemented in this alternative. Most of this surplus would probably be sold as nonfirm power on the open market. The difference between the DSI rate and the nonfirm rate would be about 15 mills/kWh in 2002. This would result in a revenue loss to BPA of about $50 million annually.

The total effect would be to increase BPA's revenue requirement about $100 to $125 million annually, leading to a rate increase of about 1 mill/kWh if rates could be increased without exceeding the maximum sustainable revenue level. If not, BPA would need to adopt response strategies to balance costs with revenues.

Maximize Financial Returns

The effects on BPA of implementing this module in this alternative would be almost the same under this alternative as under Market-Driven. The effect could be about a $100- to $125-million loss in BPA revenues annually, leading to a rate increase or revenue shortfall.

Minimal BPA

DSI service conditions intrinsic to the Minimal BPA alternative would use rates slightly below those in the Status Quo with the amount of power sold as firm declining over time to about 1,400 a MW in 2002, because BPA would not be acquiring new resources to meet preference customer load growth.

If this module were implemented instead—adding a restriction of firm service in the spring only—BPA would probably lose an additional 700 aMW of DSI load to other suppliers or to self-generation because of DSI concerns over interruptions in power supply. The power not sold to the DSIs would be delivered to the IOUs at the PF rate under the in-lieu provisions of the residential exchange contract, resulting in an increase in BPA revenues of about $12 million annually because the average PF rate is about 2 mills/kWh above the DSI rate. In addition, BPA would save about $50 million annually because of reduced Residential Exchange payments to utilities. There would be additional costs of replacing reserves and problems associated with load shapes and nighttime returns (mentioned above under Market-Driven BPA), resulting in cost increases totaling about $125 to $150 million annually. The total effect would be to increase BPA's revenue requirement about $65 to $90 million annually. This would result in a net increase of BPA rates of about 0.75 mills/kWh, or a revenue shortfall if increased rates were to exceed the maximum sustainable revenue level.

Short-Term Marketing

The Short-Term Marketing alternative assumes that the amount of DSI firm load served by BPA would decline over time to about 1,900 aMW in 2002. If, in addition, firm service were restricted to the spring, BPA would probably lose another 700 aMW of DSI load to other suppliers or to self-generation. Because BPA would already serve 300 aMW of in-lieu load in this alternative, 600 additional aMW of the DSI load would be sold to utilities under the in-lieu provision of the residential exchange contracts at the PF rate and 100 aMW would be sold on the open market, probably at nonfirm rates. The increase in revenues from sale of power at the PF rate, which is about 2 mills/kWh higher than the DSI rate, would offset the revenue loss of the 100 aMW of

DSI firm power sold at nonfirm rates. BPA would also save about $50 million annually from reduced Residential Exchange payment to participating utilities. Replacing reserves and problems associated with load shapes and nighttime returns (mentioned above under Market-Driven), would lead to additional costs of about $125 to $150 million annually, and a net rate increase of about 0.75 mills/kWh (if such an increase would not exceed maximum sustainable revenues).

Environmental Impacts

Current projections of aluminum prices and the costs of alternative energy sources suggest that approximately 2,700 aMW of DSI loads will operate in all alternatives, whether or not this load is served by BPA. Therefore, implementation of this module would have no effect on levels of DSI operations (and associated air quality impacts), but would only affect whether the DSIs are served by BPA or other sources. The types of environmental impacts that might result from DSI loads' moving from BPA to other sources are described above (4.5.3.1, Renew Existing DSI Power Sales Contracts): increased development of CTs, increased in-lieu energy deliveries to IOUs' residential exchange loads (reducing their need for new resources), and displacement of existing higher-cost thermal resources such as coal. This module would have no impact on the operation of the hydroelectric system, because the future hydroelectric operations are being decided through the System Operation Review process, which will set hydroelectric operations parameters within which all BPA operations will occur.

4.5.3.3 Declining Firm Service (DSI-3)

Module Description

In this module, the amount of DSI firm load served by Tier 1 power would decline over time, with the goal of keeping the percentage of DSI load served at the Tier 1 price comparable to the percentage of preference customers' loads served with Tier 1 power. Under tiered rates based on historical loads, as the preference customers' loads grow, a declining percentage of preference customer loads would be served by Tier 1 power. Because the DSI load is limited under the Northwest Power Act, it would not grow like the preference customer load. Without some mechanism to reduce the DSI Tier 1 allocation, DSIs could eventually receive a greater percentage of Tier 1 power than PF customers. Declining firm service is an attempt to address this issue.

At least three methods could be used to achieve a declining DSI Tier 1 allocation:

- The proportion of DSI load covered by the DSI Tier 1 allocation could decline at the same rate as the proportion of preference customer load covered by Tier 1 allocation.
- Portions of the DSI Tier 1 allocation could be subject to recall if needed to serve Tier 1 loads of preference customers.
- The DSI Tier 1 allocation could decline at a fixed percentage over time, e.g., the DSIs could start out with an initial Tier 1 allocation of 75 percent, and Tier 1 service would decline by 1 percent per year until it reaches 55 percent.

Effects of Module on Alternatives

This module is considered intrinsic to the Market-Driven BPA, Minimal BPA, and Short-Term Marketing alternatives, and could be applied as a variant to the BPA Influence and Maximize Financial Returns alternatives. It is incompatible with the assumptions of the Status Quo alternative, which reflects current DSI contract terms.

BPA Influence

Under DSI service conditions intrinsic to this alternative, the DSIs would be offered firm service in the spring only and would be served with interruptible power for the balance of the year. BPA's DSI load in 2002 would be about 400 aMW of firm load and 800 aMW of interruptible load.

If DSIs were instead offered a larger amount of power as firm (e.g., 75 to 90 percent), even if the amount declined over time, BPA's DSI loads would increase because of the DSIs' increased certainty of power supply. It is likely that DSI load level would therefore be more like that of the Status Quo alternative; that is, BPA would regain perhaps 700 aMW of loads that would otherwise be lost in this alternative. BPA's firm surplus would decline from approximately 1,800 aMW to 1,100 aMW. Since most of this surplus would probably be sold at nonfirm rates, if this module were implemented, BPA's revenues could increase approximately $100 million annually because the DSI rate is about 15 mills/kWh higher than the nonfirm rate. The effect could be to reduce BPA's rates by approximately 1 mill/kWh.

Market-Driven BPA

This module is intrinsic to the Market-Driven alternative. BPA's efforts toward controlling costs and offering competitive rates and improved contract conditions lead to about 2,500 aMW of DSI load served by BPA in the short term; over time, this amount of DSI firm load would decline with the declining firm service. This represents an increase in the amount of DSI load served by BPA of about 600 aMW compared to the Status Quo. By keeping rates to the DSIs at or below the cost of alternative suppliers, the DSIs would find leaving BPA a less attractive option, at least in the short term.

Maximize Financial Returns

Under assumptions intrinsic to this alternative, DSIs are offered 100-percent firm service, and BPA keeps rates low enough so that BPA serves about 2,500 aMW of DSI load in 2002. This amount is the same as in the Market-Driven alternative. Replacing the assumption that DSIs are offered 100-percent firm service with the assumption of this module, that DSIs are offered declining firm service, would probably result in little or no change in DSI load served by BPA in 2002 under this alternative, because the schedule for reductions in BPA firm power allocated to DSIs declines by only 1 percent per year and would not exceed DSI load already lost to BPA by 2002. Consequently, there should be very minor effects on BPA revenues and rates.

Minimal BPA and Short-Term Marketing

Declining Firm Service is assumed to be intrinsic to these two alternatives. Effects in these alternatives would be similar in kind and magnitude to those described in the Market-Driven alternative.

Environmental Impacts

This module is likely to affect only whether DSI loads are served by BPA or other energy suppliers, and not the level of operations of DSIs. In the short term, in most alternatives, this module would lead to increased DSI loads on BPA, and less load placement on other suppliers. This would probably mean less development of new generating resources (probably CTs) and more operation of existing thermal generation with somewhat greater air quality impacts. In the longer term, DSI loads would move off BPA to other suppliers—leading in the long term to increased development of generating resources by energy suppliers other than BPA and a long-term improvement in air quality.

4.5.3.4 No New Firm DSI Power Sales Contracts (DSI-4)

Module Description

Some commenters suggested that BPA should not offer long-term firm service to the DSIs when the existing power sales contracts expire in 2001. Under this module, BPA would not offer firm power contracts to DSIs, but they would be able to purchase nonfirm power when it is available. In 2002, the base DSI rate is estimated to be about 29 mills/kWh and the average price of nonfirm power about 14 mills/kWh. To the extent BPA could not supply the DSIs with nonfirm power, the DSIs would be expected to purchase power on the open market or install CTs for self-generation.

Effects of Module on Alternatives

This module could apply as a variant to all alternatives except Status Quo (which is limited to provisions of the current DSI contracts).

BPA Influence

Intrinsic to this alternative is that the DSIs would be offered firm service in the spring only and would be served with interruptible power for the balance of the year. If instead BPA were to decline to offer new PSCs to the DSIs and only allow them to purchase nonfirm power when available, it is likely that most if not all of the smelters would seek out alternative suppliers or install their own generation. Under the BPA Influence alternative, the amount of DSI load served by BPA in 2002 is estimated to be about 400 aMW of firm load and 800 aMW of interruptible load. Denying the DSIs access to firm power would cause a loss of an additional 400 aMW of firm power sales and most, if not all of the nonfirm load.

If BPA were to lose 400 aMW of firm DSI load, given the statutory restrictions on sales to non-preference and out-of-region customers, BPA would have difficulty finding alternative purchasers for this quantity of power at prices near the DSI rate. Assuming that the difference between the DSI rate and nonfirm power is 15 mills/kWh, the revenue loss to BPA would be about $50 million annually. The loss of 800 aMW of nonfirm power would probably be revenue-neutral because the price BPA charged the DSIs for nonfirm power would probably be close to the market price for nonfirm power. BPA would likely experience a 0.5 mill increase in rates to other customers.

Market-Driven BPA

DSI service intrinsic to the Market-Driven alternative uses tiered rates in the long term, with the DSI load served as firm declining over time to about 2,500 aMW in 2002. Denying the DSIs access to BPA firm power would cause a loss of 2,500 aMW of firm power sales and would probably result in most, if not all, of the DSIs shifting to alternative suppliers or self-generation.

The 2,500 aMW of power not sold to the DSIs would be difficult for BPA to sell at firm power prices because of the legal constraints on BPA’s long-term firm power sales. BPA would exercise the in-lieu provisions of the Residential Exchange contracts and deliver about 900 aMW of in-lieu power at the PF rate. Because the PF rate is about 2 mills/kWh higher than the DSI rate, in-lieu deliveries would result in a $15 million increase in BPA revenues. BPA also would save about $65 million annually because of reduced Residential Exchange payments to participating utilities. The rest of the power, or 1,600 aMW, probably would be sold as nonfirm. Assuming a 15-mill difference between the DSI rate and the average nonfirm rate, the revenue loss to BPA could be about $210 million annually. The combined effect of these in-lieu deliveries and nonfirm sales could be about a $125 million decline in BPA revenues. In addition, the costs of replacing reserves, losing some capacity sales and exchanges and addressing operating problems might be $125 to $150 million annually. The total reduction in BPA revenues might be about $250 to $275 million annually, leading to about a 2.5 mill/kWh increase in other BPA rates, limited by the maximum sustainable revenue rate level.

Maximize Financial Returns

Impacts in this alternative would be similar in kind and magnitude to those described for the Market-Driven BPA alternative.

Minimal BPA

DSI service conditions intrinsic to the Minimal BPA alternative would result in rates slightly below those in the Status Quo, with the amount of power sold as firm declining over time to about 1,900 aMW in 2002 (because BPA would not be acquiring new resources to meet preference customer load growth). If BPA instead were to implement this module and decline to offer new PSCs to the DSIs, allowing them to purchase nonfirm power only when available, it is likely that most if not all of the smelters would seek out alternative suppliers or install their own generation.

With loss of the DSIs' 1,900 aMW of firm load, BPA would deliver about 900 aMW of power to the participating utilities under the in-lieu provisions of the residential exchange contracts. Because the PF rate is about 2 mills/kWh higher than the DSI rate, in-lieu deliveries would result in about a $15 million increase in BPA revenues compared to DSI service intrinsic to this alternative. As in Market-Driven, BPA also would save about $65 million annually because of reduced Residential Exchange payments to participating utilities.

The balance of the former DSI load could be sold on the open market as nonfirm power. However, assuming a 15-mill difference between the DSI rate and the average nonfirm rate, BPA would lose about $130 million in annual revenues. The combined effect of in-lieu deliveries and nonfirm sales would be a $50 million decline in BPA revenues. The additional costs of replacing reserves, losing some capacity sales and exchanges and addressing operating problems might total about $125 to $150 million annually. Therefore, the total reduction in BPA revenues would be about $175 to $200 million annually, or about a 2 mill/kWh increase in other BPA rates.

Short-Term Marketing

The Short-Term Marketing alternative assumes that the DSIs would be served under a market-based tiered rate structure, with the amount of firm power declining over time to about 1,900 aMW in 2002. If BPA were to implement this module instead, as in other alternatives most if not all of the smelters probably would seek out alternative suppliers or install their own generation.

With loss of the DSIs' 1,900 aMW of firm load, BPA would deliver an additional 600 aMW of power to the IOUs under the in-lieu provisions of the residential exchange contracts. With the higher PF rate, in-lieu deliveries would result in about a $10 million increase in BPA revenues. In addition, BPA would save about $47 million annually because of reduced Residential Exchange payments to IOUs. The balance of the former DSI power (1,300 aMW), would be sold on the open market as nonfirm power, with the 15-mill rate difference leading to a BPA revenue loss of about $170 million annually. The combined effect of in-lieu deliveries and nonfirm sales means an overall $125 million decline in BPA revenues. However, the costs of replacing reserves, losing some capacity sales and exchanges and addressing operating problems might be about $125 to $150 million annually. As a result, the total reduction in BPA revenues would be about $250 to $275 million annually, leading to about a 2.5-mill/kWh increase in other BPA rates.

Environmental Impacts

The effect of this module would be to decrease DSI loads on BPA, but not the level of DSI operations. More DSI load would be served by energy suppliers other than BPA, and as a result, there might be more development of new generating resources (probably CTs). Environmental impacts would be similar to those described for DSI-1 but far greater, due to the larger firm load loss.

4.5.3.5 100-Percent Firm Service (DSI-5)

Module Description

This module examines offering the DSIs 100-percent firm service. Under the current DSI power sales contract, three quartiles of the DSIs' power is firm, and one quartile is interruptible at BPA's discretion. Under a 100-percent firm service option, the DSI rate would be increased by up to 2 mills/kWh because the top quartile would now be served with firm power, instead of by nonfirm power. BPA would have 2,500 aMW of DSI load in this module.

Effects of Module on Alternatives

This module is intrinsic to the Maximize Financial Returns alternative, and could be a variant applied to all others except Status Quo (which reflects the provisions of the current DSI contracts) and Minimal BPA (in which there would not be enough resources available to serve all DSI load).

BPA Influence

Intrinsic to this alternative is that the DSIs would be offered firm service in the spring only and would be served with interruptible power for the balance of the year. Under those conditions, the DSI load in 2002 served by BPA is estimated to be about 400 aMW of firm load and 800 aMW of interruptible load because of the uncertainty of supply related to firm service in the spring only.

If this module were implemented instead, it is likely that most of the DSI load lost by BPA to alternative suppliers and self generation would be avoided because of the DSIs' certainty of power supply. As a result, the increase in BPA's DSI loads would be about 1,300 aMW. BPA's firm surplus would decline from 1,800 to 500 aMW. The sale of BPA surplus to the DSIs would result in an increase in BPA revenues of about $150 million because the DSI rate is about 15 mills/kWh higher than nonfirm prices. In addition, BPA would gain about $125 to $150 million from increased firm capacity and seasonal sales and by not having to replace DSI reserves. The total increase in BPA revenues as a result of implementing this module in the BPA Influence alternative would be about $300 million annually and would reduce BPA rates by about 3 mills/kWh.

Market-Driven BPA

DSI service intrinsic to the Market Driven alternative uses tiered rates, with the percentage of DSI load served as firm declining over time. If, instead, BPA offered 100-percent firm service in this alternative, the DSI load would probably remain close to the level of the early years of DSI service in this alternative, and not decline over time.

Maximize Financial Returns

The 100-percent firm DSI service module is intrinsic to this alternative and is assumed to be in large part responsible for the high level of DSI load served by BPA, compared to the declining firm service which is intrinsic to this alternative, because of the higher quality and certainty of power supply. While the DSIs would lose the credit for nonfirm top quartile service currently contained in existing rates, BPA would still be able to offer the DSIs a rate that would be competitive with other suppliers. BPA would serve about 2,500 aMW of DSI load in this alternative.

Short-Term Marketing

The Short-Term Marketing alternative assumes that the DSIs would be served under a market-based tiered rate structure with the amount of firm power declining over time to about 1,900 aMW in 2002. If BPA were to implement this module instead and offer 100-percent firm service to the DSIs, the amount of DSI load served would likely increase to about 2,500 aMW, due to the increased certainty of power supply. BPA would meet its obligation to serve the increased DSI load primarily with short-term purchases, if power could be purchased at a cost below the rate the DSIs pay BPA for the power.

It is unlikely that BPA would experience any significant change in rates by implementing this module under this alternative, because the DSI rate would be about 2 mills/kWh higher with 100-percent firm service, increasing the likelihood that the additional power needed could be found on the short-term market. BPA would only serve additional DSI load if it could purchase power for it at or below the cost of service.

Environmental Impacts

The effect of this module would be to increase DSI loads on BPA, but not the level of DSI operations. Less DSI load would be served by energy suppliers other than BPA, and as a result, there might be less development of new generating resources (probably CTs), at least in the short term, and more operation of existing resources, including existing thermal generation, with their greater air quality impacts.

4.5.4 Conservation/Renewables

The policy modules discussed below lead to the development of different amounts of energy conservation and renewable resource generation. In general, the result of these developments is that these resources take the place of other types of generation that otherwise would be developed. Under current market conditions, most of the new generation planned is combustion turbines. The environmental effect of replacing new combustion turbines with conservation or renewable resources is to substitute the impacts of the conservation and renewables for the impacts of the combustion turbines. Figure 4.5-1 shows this effect in terms of the net impacts per average megawatt from replacing combustion turbines with energy conservation or wind or geothermal generation.

4.5.4.1 "Fully Funded" Conservation (CR-1)

Module Description

In this module, in addition to price-induced conservation resulting from BPA's tiered rates, BPA would continue to fund conservation at levels comparable to what it would fund under the Status Quo alternative without tiered rates. As shown in table 4.4-14 ("Additional BPA Efforts" category), BPA would acquire an additional 140 aMW of conservation by 2002 in the Market-Driven and Maximize Financial Returns alternatives, at a cost of about 41 mills/kWh. (The cost of conservation reflects the nominal 2002 cost of the resource, and should not be confused with the lower, real levelized values used in other BPA and Council planning documents.) In the Short-Term Marketing alternative, BPA would acquire an additional 250 aMW of conservation, at an annual cost of approximately $90 million.

Effect of Module on Alternatives

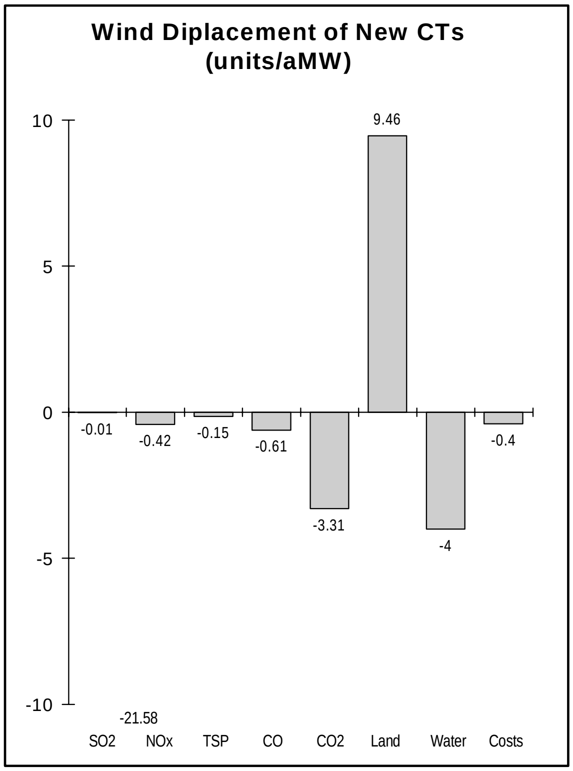
Implementing this module in the Market-Driven and Maximize Financial Returns alternatives by acquiring an additional 140 aMW of conservation would increase BPA's overall costs by approximately $50 million annually. This would result in approximately a half-mill/kWh increase in BPA's rates. In the Short-Term Marketing alternative, acquiring 250 aMW of additional conservation would cost approximately $90 million annually, increasing rates by almost one mill/kWh. Under the Market-Driven, Maximum Financial Returns, and Short-Term Marketing alternatives, the increased PF rate would lead to higher load loss among BPA's preference and DSI customers.

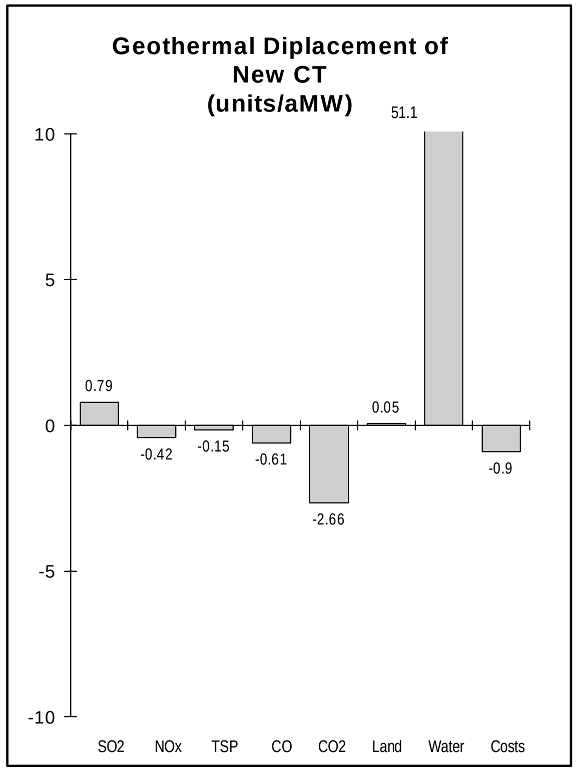
Environmental Impacts

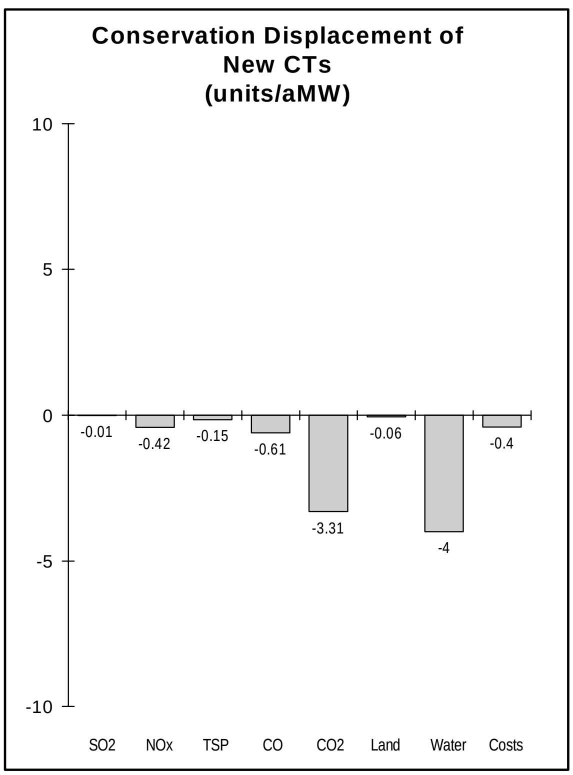
It is likely that increased conservation acquisition would reduce regional acquisition of combustion turbines and/or cogeneration. Reductions in CT and cogeneration acquisition and operation would reduce air quality, water use, and land use impacts of these resource types (identified on a per-megawatt basis in table 4.3-1, Typical Environmental Impacts From Power Generation and Transmission). The amount of the reduction would depend on the amount of conservation acquired and the corresponding reduction in CT and cogeneration acquisition. For example, if the Fully Funded Conservation module were applied to the Market-Driven BPA alternative, BPA would acquire approximately 140 aMW additional conservation, but it is likely that with BPA fully funding conservation programs, other regional utilities would not implement as many conservation programs (that is, regional utilities would have targeted the same conservation savings that BPA

FIGURE 4.5-1

Net Air, Land, and Water Impacts From Conservation/Renewable Resources Replacing CTs







SO2 (sulfur dioxide) - Tons/aMW
NOx (nitrogen oxides) - Tons/aMW
TSP (total suspended particulates) - Tons/aMW
CO (carbon monoxide) - Tons/aMW
CO2 (carbon dioxide) - 1000 Tons/aMW
Land - Hectares/aMW
Water - 1000 Meters^3/aMW
Environmental Costs - $1000/aMW

As conservation or renewable resources are used to meet portions of regional firm loads rather than new CTs, not only is their energy output substituted for CT output, but the environmental impacts of their operation are also substituted. Figure 4.5-1 shows the environmental impacts per average megawatt of energy for replacing new CTs with conservation or renewable resources. Impacts of new CTs would not be offset if conservation and renewable resource development contributed to a surplus of BPA energy resources.

pursues), and the total regional increase in conservation would be only 30 aMW (see table 4.4-14, "Total Conservation for BPA Loads in 2003" category).

If the regional increase in conservation acquisition were 30 aMW, CT operations would probably be reduced by the same amount. NOx, SO2, CO, and CO2 emissions would be reduced somewhat, although overall, air quality impacts of existing and new thermal resource operations (expressed in dollar terms as environmental cost estimates, based on the environmental costs shown in table 4.4-20) would be reduced by only approximately one-third of one percent (a reduction from about $332 to $331 million).

If regional conservation acquisition were greater, the reduction in CT operations impacts would be correspondingly larger. For example, in the Maximize Financial Returns alternative, the region is predicted to acquire 140 aMW additional conservation with the implementation of the fully funded conservation module (table 4.4-14). In that case, air quality impacts of new and existing thermal generation (as measured in terms of environmental costs) would be reduced by approximately 1.5 percent (from approximately $344 to $339 million).

4.5.4.2 Renewable Resource Incentives (CR-2)

Module Description

BPA would develop an incentive proposal for renewable resources that would equal up to 10 percent of the cost of the qualifying resource. The incentive would take the form of a discount on BPA rates and the services used to get the renewable resource power to load. The discount would be incorporated into separate tariffs for utilities that develop or purchase renewable resources, for such power-related services as transmission, shaping, and reserves. The maximum discount available to any utility for any single resource would be 10 percent of the total cost of the renewable resource.

BPA would also incorporate provisions in its resource acquisition program that would require that the estimated incremental cost of a renewable resource would not be treated as greater than any non-renewable resource unless the cost of the renewable resource were greater than 110 percent of the cost of the non-renewable resource.

The market transformation potential for renewable resources in the Pacific Northwest is estimated at between 450 and 600 aMW. BPA currently is acquiring 80 aMW, and the rest of the region is acquiring 100 aMW. For purposes of this module, it is estimated that no additional renewable resources would be acquired by BPA and regional utilities because the 10 percent incentive is not enough to reduce the cost of renewables to a level that is competitive with the cost of CTs. The combination of low gas prices, low prices for power on the wholesale market, and improvements in CT technology have increased the cost differential between CTs and renewables. The 10 percent incentive would reduce the cost of a 75 mill/kWh renewable resource by about 7.5 mills/kWh. Comparable current CT costs are about 25 mills/kWh, significantly below the lower renewable resource cost. If completion of demonstration renewable resources results in greater economies for further development, the cost of renewable resources could drop, perhaps by 25 percent. Their cost would then be about 55 mills/kWh, and a 10-percent incentive would reduce the cost to about 50 mills/kWh, still roughly twice the cost of new CT generation.

Effect of Module on Alternatives

Because this module would not result in additional acquisition of renewable resources by regional utilities or BPA, this module would have little or no effect on the amounts of renewables acquired regionally in each alternative.

However, BPA incentives could reinforce existing commitments by other power suppliers to develop renewable resources, by lowering the costs of those committed renewable resource projects. Incentives could potentially affect resource decisions that were not driven solely by economic reasons, for example, where a developer or utility was willing to construct renewable resources to achieve environmental benefits, to diversify their resource portfolio, or to avoid fuel price risk that would affect CT generation.

Environmental Impacts

As noted above, this module is not predicted to have much effect on the amount of renewable resources acquired in the region, and therefore would have little or no environmental effect.

If incentives did result in incremental additions to regional renewable resources, it is likely that additional renewable resource acquisition would replace or reduce the acquisition of CTs or cogeneration. The resulting environmental impacts would be a reduction in the air quality, water use, and land use impacts of these resource types (identified on a per-megawatt basis in Table 4.3-1, Typical Environmental Impacts From Power Generation and Transmission). This overall positive environmental impact would be offset to a slight extent by the greater land use impacts of renewables. (As shown in table 4.3-1, renewable resources tend to be fairly land-intensive.)

4.5.4.3 - Maximize Renewable Resource Acquisitions (CR-3)

Module Description

With the goal of accelerating market transformation and the development of renewable resource technology, BPA would acquire a significant amount of all available commercial renewable resources developed in the Pacific Northwest, regardless of cost. The increment of renewable resources acquired by 2002 would be 300 aMW in the BPA Influence, Market-Driven, and Maximize Financial Returns alternatives, and 380 aMW in the Short-Term Marketing alternative (in addition to renewable resource projects already in progress). BPA acquisition of renewables would occur in increments of about 45 aMW per year through 2002.

Renewables are assumed to consist of 60 percent wind and 40 percent geothermal resources. The nominal cost in 2002 of wind resources is projected to be between 60 and 75 mills/kWh, and the cost of geothermal resources between 80 and 100 mills/kWh. The melded cost in 2002 of this pool is estimated to be about 75 mills/kWh.

Effects of Module on Alternatives

Renewable resources would most likely replace CTs or short-term power purchases in BPA's resource portfolio. Acquisition of 300 to 380 aMW of renewables by 2002 would place BPA in the position of delaying conservation programs, changing its resource acquisition program, and/or creating a surplus. The assumption in this module is that BPA would continue with its conservation acquisition program and that the renewables would replace the 230 aMW of CT/cogeneration resources BPA had intended to acquire; the additional amount of renewables (the 70 to 150 additional aMW above the amount that would replace CT/cogeneration resources) would add to BPA's surplus.

With the continued fall in the price of natural gas and the increased competition in the independent power industry, the levelized cost of CTs is currently about one-third to one-half of the cost of renewable resources. In 2002, the cost of a CT is estimated to be 35 mills/kWh, and the average cost of renewables acquired by BPA would be 75 mills/kWh. If renewable resource costs drop by 25 percent as they become more commercialized, the average cost of renewables would be about 55 mills/kWh.

The incremental cost to BPA for the renewables it acquires in place of the CT/cogeneration resources it would otherwise acquire would be about 40 mills/kWh (the difference in the cost per kWh of CTs and renewables). The net annual increase in BPA's costs resulting from the 230 aMW of higher-cost renewable resources in place of CT/cogeneration resources would be about $80 million. The increase in BPA's costs resulting from the additional 70 to 150 aMW renewable resources would be between $45 and $100 million annually. The effect on BPA's costs from this module would be between $125 and $200 million annually. In 2002, this would increase the average PF rate by up to 2 mills/kWh or about 6 percent.

It is possible that some of the 70 to 150 aMW of surplus power resulting from the acquisition of additional renewables could be delivered to residential exchange loads of participating utilities as in-lieu energy. If this surplus could be sold at the PF rate, it would bring between $20 and $40 million annually. In addition, BPA's residential exchange payments would decline by $5 to $10 million because BPA does not make Exchange payments to utilities served with in-lieu power. This could reduce the 2 mills/kWh rate increase identified above to closer to 1.5 mills/kWh.

The effect on bills of ultimate consumers is uncertain for a variety of reasons. Retail rate effects would depend on the ratio of BPA purchased power costs to total costs and the total kWh sales for the utility.

The following example shows the retail rate effect for ultimate consumers at a hypothetical utility that is a full requirements customer of BPA:

Utility X - before renewables purchase

BPA purchased power costs	$10 million
Other utility costs	$11 million
Total costs	$21 million
Annual kWh sales	375 million kWh
Average retail rate	56 mills/kWh

Assume that the cost of BPA power increased by 1.5 mills/kWh and BPA purchased power cost increased by about $600,000. The results would be as follows:

Utility X - after renewables purchase

BPA purchased power costs	$10,600,000
Other utility costs	$11 million
Total costs	$21,600,000
Annual kWh sales	375 million kWh
Average retail rate	57.6 mills/kWh

The increase in the average cost of power at Utility X would be 1.6 mills, or about 3 percent.

The second example shows the retail rate effect for ultimate consumers at a hypothetical utility that is a partial requirements customer of BPA:

Utility Y - before renewables purchase

BPA purchased power costs	$ 59 million
Other utility costs	$147 million
Total costs	$206 million
BPA purchased kWh	2.2 billion kWh
Annual kWh sales	6.2 billion kWh
Average retail rate	33 mills/kWh

Assume that the cost of BPA power has increased by 1.5 mills/kWh and BPA purchased power cost has increased by about $3,300,000. The results would be as follows:

Utility Y - after renewables purchase

BPA purchased power costs	$62,300,000
Other utility costs	$147 million
Total costs	$209,300,000
BPA purchased kWh	2.2 billion kWh
Annual kWh sales	6.2 billion kWh
Average retail rate	33.75 mills/kWh

The increase in the average cost of power at Utility Y would be about 0.75 mills/kWh, or about 2.25 percent.

For other BPA customers the rate effect to ultimate customers could be greater or less depending on the ratio of BPA power costs to total costs.

Environmental Impacts

The environmental effect of this module would depend on the incremental amount of renewable resources acquired in each alternative, which would vary in this module from 300 aMW (in BPA Influence, Market-Driven, and Maximize Financial Returns) to 380 aMW (in Short-Term Marketing). It is likely that the additional renewable resources would replace or reduce the acquisition of CTs and/or cogeneration. The resulting environmental impact would be a reduction in the air quality, water use, and land use impacts of these resource types (identified on a per-megawatt basis in Table 4.3-1, Typical Environmental Impacts From Power Generation and Transmission, and figure 4.5-1). This overall positive environmental impact would be offset to a slight extent by the greater land use impacts of renewables. (As shown in table 4.3-1, renewable resources tend to be fairly land-intensive.)

As an illustrative example, if BPA (and therefore, the region) were to acquire an additional 300 aMW (180 aMW wind and 120 aMW geothermal) in the Market-Driven BPA alternative, land use impacts would increase approximately 6.5 percent (from 15,000 hectares to 16,000 hectares), while the air quality impacts of new and existing thermal generation (as expressed in terms of environmental costs) would decline approximately 2 percent (from $332 to $325 million).

4.5.4.4 "Green" Firm Power (CR-4)

Module Description

BPA would offer, as an optional power product, an amount of Tier 2 power supported by the acquisition of conservation and renewable resources that would not otherwise be acquired as a part of Tier 2 new resource additions. The amount of "Green" Firm Power that BPA would offer would depend on the willingness of BPA customers to commit to purchase the output for the economic life of the resources. BPA would develop a proposal that describes the resource pool composition and cost. BPA customers would respond indicating the quantity of the "Green" Firm Power. Contracts would be for 20 to 30 years depending on the type of resources included in the pool.

For purposes of this module, BPA was assumed to acquire up to an additional 80 aMW of renewable resources by 2002. The resources would be a mix of 60 percent wind and 40 percent geothermal. The nominal cost in 2002 of wind resources is projected to be between 60 and 75 mills/kWh, and the cost of geothermal resources is projected to be between 80 and 100 mills/kWh. The melded cost in 2002 of this pool is estimated to be about 75 mills/kWh.

Effects of Module on Alternatives

By developing a "Green" Firm Power resource pool, BPA would not acquire a like amount of CTs and/or power purchases. However, "Green" Firm Power could help reduce the load BPA loses to other suppliers by offering its customers a more environmentally benign resource pool that leads utilities who are interested in such resources to place load on BPA.

This module would be revenue-neutral to BPA because BPA would only acquire renewable resources in an amount equal to the commitments made by its customers for the "Green" Firm Power.

The effect on bills of ultimate consumers is uncertain for a variety of reasons. Retail rate effects would depend on how much of the "Green" Firm Power the utility acquired, the ratio of BPA purchased power costs to total costs, and the total kWh sales for the utility. For example, if a full requirements customer committed to purchase from the "Green" Firm Power and BPA purchased power costs represented 50 percent of its total costs, then a 10 percent increase in power costs would lead to a 5 percent increase in the utilities' total costs.

The following example shows the retail rate effect for ultimate consumers at a hypothetical utility that is a full requirements customer of BPA:

Utility X - before "Green" Firm Power purchase

BPA purchased power costs	$10 million
Other utility costs	$11 million
Total costs	$21 million
Annual kWh sales	375 million kWh
Average retail rate	56 mills/kWh

Assume that "Green" Firm Power made up 10 percent of Utility X's BPA purchases and that the cost of the "Green" Firm Power is about three times the standard BPA rate, or 75 mills/kWh. The results would be as follows:

Utility X - after "Green" Firm Power purchase

BPA purchased power costs	$11.9 million
Other utility costs	$11 million
Total costs	$22.9 million
Annual kWh sales	375 million kWh
Average retail rate	61 mills/kWh

The increase in the average cost of power at Utility X would be 5 mills, or 9 percent.

The second example shows the retail rate effect for ultimate consumers at a hypothetical utility that is a partial requirements customer of BPA:

Utility Y - before "Green" Firm Power purchase

BPA purchased power costs	$ 59 million
Other utility costs	$147 million
Total costs	$206 million
BPA purchased kWh	2.2 billion
Annual kWh sales	6.2 billion kWh
Average retail rate	33 mills/kWh

Assume that "Green" Firm Power made up 10 percent of utility Y's BPA purchases and that the cost of the "Green" Firm Power is about three times the standard BPA rate, or 75 mills/kWh. The results would be as follows:

Utility Y - after "Green" Firm Power purchase

BPA purchased power costs	$ 70 million
Other utility costs	$147 million
Total costs	$217 million
BPA purchased kWh	2.2 billion
Annual kWh sales	6.2 billion kWh
Average retail rate	35 mills/kWh

The increase in the average cost of power at Utility Y would be 2 mills/kWh, or 6 percent.

For other BPA customers the rate effect to ultimate customers could be more or less depending on how much "Green" Firm Power a utility purchased, and the ratio of BPA power costs to total costs.

Environmental Impacts

As in the other renewable resource modules, the primary effects of this module would be to decrease the impacts associated with CTs (air quality impacts and water and land use) and to increase the impacts associated with renewable resources (primarily land use). The magnitude of these changes would depend on the amount of renewable resources acquired and the amount of CT operations displaced.

As an illustrative example, if in the Short-Term Marketing alternative the region acquired an additional 80 aMW of renewable resources (for example, 48 aMW of wind and 32 aMW of geothermal), total land use impacts of new resources would increase slightly, while total air quality impacts of new and existing thermal generating resources (as measured in terms of the environmental costs shown in table 4.4-20) would decrease approximately 0.5 percent (from $339 million to $332 million).

4.6 Cumulative Impacts

This EIS evaluates the impacts of BPA actions on both BPA and on the region as a whole. The alternatives involve actions that are likely to contribute to cumulative environmental impacts. The development and operation of generation resources and transmission could impact land use, air, water, and fish and wildlife. These impacts in and of themselves may not be major, but may be significant when added to the impacts of other actions. The cumulative impacts of resource development and operation are addressed in the Resource Programs Final EIS (DOE, February 1993), which provides information about the cumulative environmental impacts of adding different sets of conservation and generation resources to the existing power system.

Alternative operations of the hydroelectric system could contribute to cumulative impacts on sensitive anadromous and resident fish stocks; however, future hydroelectric system operations will occur within the parameters established by the System Operations Review (SOR).

4.7 Relationship Between Short-Term Uses of the Environment and the Maintenance and Enhancement of Long-Term Productivity

All of the alternatives evaluated in this EIS involve the construction and operation of generation and transmission resources, and therefore require both long- and short-term uses of the environment. In the short-term, construction of generation and transmission resources would cause noise, soil compaction and erosion, the potential for water quality degradation, and degradation of air quality. Many of these short-term construction impacts can be substantially mitigated. In the longer term, there could be impacts on air quality, altered land uses, reduced water quality, and contributions to global warming.

Both the short-term and long-term uses of the environment will, however, have a beneficial effect on long-term productivity. Delivering cost-effective electric energy in a way that minimizes adverse effects on the environment will help maintain and enhance the productivity of the PNW and its economy.

4.8 Irreversible or Irretrievable Commitments of Resources

The acquisition and operation of new generation and transmission resources (an element of all alternatives) would require irreversible and irretrievable commitments of resources. Those alternatives with larger amounts of conservation acquisition (e.g., BPA Influence, Status Quo, and Market-Driven alternatives) would have fewer such commitments of resources, but even they would require substantial commitments associated with new generation and transmission facilities.

4.9 Key Factors That May Limit Implementation

The likelihood that any alternative could be implemented, would serve its projected load, and would meet its other objectives will depend on a number of key determinants. For example, if an alternative would require statutory changes, its likelihood of success is less than an alternative that could be implemented without such changes. This section seeks to indicate, in a general way, the relative likelihood of success among the six alternatives (see figure 2.7-1).

The analysis in this section is based on BPA's informed judgment about factors like legislative process or regulatory influences, market conditions, financial constraints, and other factors. It is intended to rank the alternatives against each other; it does not seek to precisely indicate how much more or less likely each alternative may be.

4.9.1 Factors Affecting All Alternatives

These factors affect the probability of success for all of the alternatives. First, BPA's fixed cost ratio of 80 to 85 percent, compared to an industry average of 50 to 60 percent, creates a risk that BPA would be unable to implement any of the alternatives successfully over the long term. As described in the Business Plan, because BPA must operate under a higher fixed cost ratio, BPA may be less flexible and less able to absorb costs than its competitors. This factor may result in a higher risk of BPA losing load compared to its competitors.

The second factor affecting all of the alternatives is the lack of regional consensus regarding BPA's fish and wildlife responsibilities and how BPA will meet energy conservation targets. One significant reason fish and wildlife and conservation issues are contentious is that both issues lack scientific or analytic precision for determining success, particularly in the near term. As a result, it will be difficult for the region to achieve a clear consensus on program direction or individual project designs for both programs. Without consensus, costs would likely rise.

A third factor is the continuing and dramatic decline in the market price for electric energy in the PNW. If prices reach a level significantly below BPA's costs and remain there for the long term, BPA will have difficulty achieving its missions under any alternative, because very low prices would not provide enough revenue to enable BPA to sustain its mandated activities.

All of these factors would decrease BPA's ability to succeed across all the alternatives.

4.9.2 Status Quo Alternative

The probability of continuing to implement the Status Quo alternative successfully is decreased by at least three factors. First, because this alternative does not include any explicit cost control mechanisms, BPA would have a difficult time instilling confidence in its customers that BPA would, over both the short and long term, control its costs. Second, lacking cost controls, BPA would also face a greater potential for rate increases. These rate increases would encourage customers to shift loads away from BPA. Third, if BPA continued to ignore market changes and signals, it might continue to develop unnecessary new resources when there is no corresponding increase in BPA load. This would result in increased costs and further erosion of BPA's low-cost hydro advantage, increasing rates and adding to power surpluses. For these reasons, the continued implementation of this alternative would reduce its effectiveness and lead to changes in BPA's policies or legislative authorities.

4.9.3 BPA Influence Alternative

The probability of successfully implementing the BPA Influence alternative is decreased by its high costs and requirements that would likely be borne by BPA's customers. Since this alternative would continue BPA's full funding of conservation target efforts, it would tend to increase BPA rates. More importantly, because this alternative also seeks to increase BPA's efforts to induce customers to implement the Council's F&W Program and Power Plan through conditions of service and other requirements, it might decrease the attractiveness of BPA services to many customers. High costs coupled with increased conditions of service (the "hassle factor") would reduce the potential effectiveness of this alternative. Customers would go to non-BPA suppliers for services previously provided by BPA, causing further BPA load reductions and increased rates, and lessening BPA's ability under this alternative to implement the Council's F&W Program or Power Plan.

4.9.4 Market-Driven Alternative

The probability of successfully implementing this alternative is higher than the other alternatives because the Market-Driven approach has the greatest potential to overcome barriers to implementation through improved customer relations, and focused efforts to control and stabilize costs. The chance of success could be reduced by BPA's inability to establish successful marketing practices to achieve business results, causing customers to seek non-BPA suppliers and reducing BPA loads. In addition, lack of consensus on fish and wildlife and conservation reinvention could jeopardize constituent support for the overall alternative. Changes from past practices that place costs with specific customer groups that were formerly spread over the system as a whole could alienate the customers bearing those costs and jeopardize implementation of the Market-Driven alternative.

4.9.5 Maximize Financial Returns Alternative

The probability of successfully implementing the Maximize Financial Returns alternative is small because BPA would need revisions to the Northwest Power Act and other statutes to achieve the key elements of the alternative. This alternative would require authority for BPA to recover revenues in excess of its costs, limit conservation investment, and transfer fish and wildlife responsibility to other entities. Despite the desire by different interests to alter various provisions of the Act, regional consensus regarding any specific amendments is necessary. In addition, the changes in BPA's business strategy to implement the Maximize Financial Returns alternative would likely be viewed as a departure from BPA's historical role of providing benefits to the region, and would probably alienate both customers and constituent groups.

4.9.6 Minimal BPA Alternative

Like the Maximize Financial Returns alternative, the probability of successfully implementing the Minimal BPA alternative is greatly reduced by the need for revisions to the Northwest Power Act and other statutes. Since under this alternative BPA would not accept load growth or increased transmission responsibility, would limit conservation investments, and would transfer fish and wildlife responsibility to other entities, changes in statutes would be required. As in the Maximize Financial Returns alternative above, despite the desire by some interests to alter various provisions of the Act, regional consensus regarding any specific amendments is necessary and does not appear probable. The significant curtailment of BPA's actions to provide benefits to the region could either create opposition to this approach, or engender proposals to eliminate BPA altogether and sell its assets.

4.9.7 Short-Term Marketing Alternative

This alternative would only provide sustainable BPA marketing if the bulk of BPA's customers would accept a short-term approach to BPA marketing. The chief limitation in this alternative is that it fails to meet the needs of those customers who desire long-term service and stability of power supplies. Confidence of environmental constituents and the remaining customers in BPA's ability to achieve the fish and wildlife and conservation results would be low due to the lack of certainty about BPA maintaining customer load, and limitations in investments for short-term paybacks.

4.9.8 Comparison of Alternatives

The Market-Driven alternative has the highest probability of successful implementation because it promotes customer confidence and constituent support for the goals BPA establishes for controlling costs and achieving its regional fish and wildlife and conservation missions.

The BPA Influence alternative has the second highest probability of successful implementation, but is lower than the Market-Driven alternative, because the BPA Influence alternative relies on BPA customers to accept restrictive conditions of service and higher costs during a time when the electric utility industry is becoming increasingly competitive.

The Short-Term Marketing alternative has less chance of successful implementation than the Market-Driven and BPA Influence alternatives because utilities would need to accept a high level of uncertainty about long-term costs. This is especially difficult in a time when the electric utility industry is becoming more and more competitive and utilities have more resource options. This would decrease the confidence of environmental constituents and the remaining customers in BPA achieving progress toward the regional fish and wildlife and conservation goals.

The Status Quo, Maximize Financial Returns, and Minimal BPA alternatives have the lowest probability of successful implementation. Continuing the Status Quo has a low probability because it lacks BPA cost controls, clearly identified business results, and stable rates. Maximize Financial Returns and Minimal BPA have little chance of successful implementation due to the requirement for legislative changes and significant changes in BPA's mission.