Environmental Implications Associated with Integrated Resource Planning by Public Utilities in the Western United States

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The Western Area Power Administration is about to impose integrated resource planning requirements on its 612 public-power customers as part of its Energy Planning and Management Program (EPAM) and consistent with the Energy Policy Act of 1992. EPAM will affect public utilities over a 15-state region stretching from Minnesota to California, Montana to Texas. In this study, an assessment is made of the environmental impacts of the IRP requirement. Environmental impacts are calculated based on modelled changes in electric power generation and capacity additions.

Introduction

The Western Area Power Administration (Western) is an agency of the U.S. Department of Energy charged with marketing and transmitting federally produced electricity throughout a 1.3 million-square-mile geographic area. The majority of this electricity comes from federally owned and operated hydroelectric plants. Western's service region represents the largest geographic area served by a federal power marketing agency. It covers 15 states from Minnesota in the northeast to California in the southwest. The organization is headquartered in Golden, Colorado. Western's five area offices are in Billings, Montana; Loveland, Colorado; Phoenix, Arizona; Sacramento, California; and Salt Lake City, Utah. Over one-half of all of Western's customers are cities or towns. Cooperatives (co-ops), public utility districts (PUDs), and irrigation districts account for another 20 percent of the customer base.

Western proposes to establish an Energy Planning and Management Program (EPAMP) to replace its now concluded Conservation and Renewable Energy (C&RE) Program. Western's former C&RE Program objectives included increased energy production from renewable resources and improved efficiency in energy utilization. These objectives were to be fulfilled by requiring each customer to participate in the program through the administration of a minimum number of activities that comply with Western's criteria. The number of activities vary according to customers' size and percentage of Western power purchased. The acceptable activities encompass energy consumption efficiency improvements and use of renewable energy resources in addition to large-scale hydropower, load management techniques, cogeneration, rate design improvements, and production efficiency improvements. Program activities vary from major retrofit programs to "bill-stuffers."

The EPAMP would require Western's long-term firm customers to implement integrated resource planning (IRP) to help enhance efficient electric energy use. Pacific Northwest Laboratory (PNL) is helping Western to assess the environmental impacts of its proposed program. PNL is one of DOE's national multiprograrn research laboratories and is operated by Battelle Memorial Institute.

Western proposed the Program in April 1991 (56 FR 16093). A year and a half later, in October 1992, the Energy Policy Act of 1992 (the Act) (Public Law No. 102-486) gave much of Western's proposal the force of law by requiring its customers to prepare and implement IRPs. The legislation made Western more of an evaluator and enforcer than the role the agency had sought administratively.

Program Description

EPAMP comprises two parts, the Power Marketing Initiative (PMI) and the Energy Management Program (EMP). The PMI provisions include the ways that Western proposes to market its power, such as the length of contracts, how allocations are made, and how the contracts may be modified. This paper addresses the EMP portion of EPAMP.

The proposed EMP would require each customer to conduct IRP, which would be applicable to all customer power resources and not just the Western allocation. The Proram may include special provisions for certain small customers with total annual energy sales or usage of 25 GWh or less that are not members of a joint action agency or a generation and transmission cooperative with power supply responsibility.

In an environmental impact statement (Western 1994), potential program components have been combined to form 12 alternatives. These alternatives are listed in Table 1. A no-action alternative, was based on existing program features as defined in the C&RE program. The program alternatives were grouped according to their PMI provisions as follows:

- **PMI Extension Alternatives** - The first group, known as the PMI extension alternatives, would give Western's existing customers relatively long-term extensions of a major percentage of the Federal power resource currently committed to them subject to certain provisions. These provisions include the percentage of the allocation, the term of the contracts, establishment of a resource pool, and the manner in which the pool would be used. Contracts for resource extensions would be signed upon receipt of a customer's initial IRP by Western.

- **PMI Limited Extension Alternatives** - The second set, known as the PMI limited extension alternatives, would extend resources for 10 years from the date of IRP approval, a relatively short time period. This short extension period is intended to provide Western's existing long-term firm power customers with a term adequate to facilitate the development of an IRP and effectuate associated action plans. The extension would act as a bridge to give Western time to "develop project-specific marketing plans and the customers time to develop and implement alternative resources in reaction to any change of marketable resources as identified in the project-specific marketing plan. Contracts for resource extensions would be signed upon approval of a customer's initial IRP by Western.

- **PMI Non-Extension Alternatives** - The third set, known collectively as the PMI non-extension alternatives, would not feature any marketing of resources under the proposed Program. Customer integrated resource planning would take place in accordance with the Energy Policy Act of 1992, and marketing criteria would be separately developed on a project-specific basis.

We found that Western's requirement of its customers to conduct IRP was the dominant cause of environmental effects, all of which were beneficial in comparison with the no-action alternative. This paper compares the effects of IRP, as represented in the non-extension alternatives, alternatives 11 and 12, in the draft EIS, with those of the no-action alternative.

As defined in Section 114 of the Act, IRP is a planning process for new energy resources that evaluates the full range of possible resource alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to electric customers. Electric utilities have been engaged in planning to meet the needs of their customers for many years. However, IRP expands the scope and nature of the planning process and the subject of the analysis. At utilities already employing IRP, the scope of planning has expanded to consider energy efficiency and load management programs as resources, the environmental aspects of energy production, and a variety of resource selection criteria beyond electricity price (Hirst et al. 1990).

Western would accept IRPs from individual customers or the member-based association (MBA) to which they belong. IRPs prepared for other governmental agencies would be acceptable as long as they meet Western's criteria. Western also may allow customers to join together to prepare and submit joint IRPs. Western's acceptance would be based on adherence to the planning process and inclusion of defined elements. The size and complexity of individual IRPs would vary depending on customer size, type, and demographic nature. IRPs must contain goals, schedules, expected quantifiable benefits, milestones, and expenditures. The IRPs would apply to all customer resources, not just those purchased from Western. An updated submittal would be required every 5 years. The following seven elements are Western's requirements for a well-developed plan, as set forth in the Act:

1. Identify and accurately compare all practicable energy efficiency and energy supply resource options available to the customer.

2. Include a 2-year action plan and a 5-year action plan that describe specific actions the customer will take to implement its IRP.

Table 1. Summary of Energy Planning and Management Program Alternatives

	Program Alternatives											
	No Action	PMI Extension							PMI Limited Extension		PMI Non-Extension	
Program Components	1	2	3	4	5	6	7	8	9	10	11	12
EMP	C&RE G&AC	IRP	IRP	IRP	IRP[a]	IRP[a]	IRP[a]	IRP	IRP	IRP[a]	IRP	IRP[a]
Extension Period	varies[b]	15 yrs[c]	25 yrs[c]	35 yrs[c]	15 yrs[c]	25 yrs[c]	35 yrs[c]	25 yrs[c]	10 yrs[d]	10 yrs[d]	varies[b]	varies[b]
Percentage Allocation	varies[b]	98%	95%	90%	98%	95%	90%	98%	100%[f]	100%[f]	varies[b]	varies[b]
Resource Pool	none[e]	2%	5%	10%	2%	5%	10%	2%	none[f]	none[f]	none[e]	none[e]
Adjustment Provisions	none[e]	ltd.	1 adj.	2 adj.	ltd.	1 adj.	2 adj.	5 yr notice	none	none	none[e]	none[e]
Penalty Provision	10% Withdraw	10% to 30% surcharge, see Figure 2.1 and Table 2.4 Optional 10% power reduction										

a IRP with small customer provision.
b To be determined by project-specific marketing plan.
c Contract extension begins at time of current contract expiration.
d Contract extensions begin when IRP approved; extension guaranteed first 10 years, then determined by project-specific marketing plans.
e Unless provided by project-specific marketing plan.
f For this analysis assume a 90% allocation after expiration of the 10-year extension period.

3. Designate least-cost options to be utilized by the customer for the purpose of providing reliable electric service to its retail consumers and explain the reasons why such options were selected.

4. To the extent practicable, minimize adverse environmental effects of new resource acquisitions.

5. In preparation and development of the plan (and each revision or amendment of the plan) provide for full public participation, including participation by governing boards.

6. Include load forecasting.

7. Provide methods of validating predicted performance in order to determine whether objectives in the plan are being met.

One of the IRP elements is the consideration of environmental effects of resource choices. To the extent practicable, customers must consider and document the environmental effects of resource options in their IRPs. The documentation could be quantitative and statistically based or the effects could be described qualitatively, depending on each customer's circumstances.

Analytical Approach

This section provides a brief overview of the analysis of utility systems in response to IRP requirements and the accompanying environmental analysis.

Utility Systems

The principal focus of the utility analysis was on policy simulations to assess impacts on existing and new generation resources and on consumers' and businesses' electric energy service demands, which could be met with either conventional generation resources or with demand-side management (DSM) resources (see Kavanaugh et al. 1993). While least-cost principles and rational decision making are presumed, the model was not intended as an IRP for Western's region. Each Western area was modeled and simulated under the alternative policy scenarios to determine probable impacts on power resources and on peak demands and consumption.

The analysis adapted an existing model used for regional policy simulation analysis of policies of a nature similar to that contained in Western's Program. The existing model, the Conservation Policy Analysis Model (CPAM), was developed for the Bonneville Power Administration (Ford and Geinzer 1986) to examine resource and rate impacts of alternative conservation programs at an aggregate level for the Pacific Northwest. New versions of CPAM continue to evolve and are actively maintained for planning analyses at Bonneville. We refer to the revised model as RRIM, or the Resources and Rates Impact Model. A similar although far more comprehensive model from an energy and geographical standpoint called FOSSIL2 served as the basis for the integrating framework for the 1991 National Energy Strategy (EIA 1991).

The key features of RRIM are as follows:

- It is an integrated model that balances loads and resources through price elasticities and treats DSM resources comparably to conventional generation resources.
- Conservation programs are represented in detail; cogeneration and small power production resources could also be treated in detail.
- The model was designed to be used for policy analysis (producing simulations of a utility system's or region's behavior with and without a proposed policy or strategy).
- It is an integrated "screening" model for resource acquisitions.
- The model was developed, compiled, and executed in a PC-based environment.

The model is comprised of five sectors that represent different aspects of a single or composite electric utility system. The most detailed of the sectors is the electricity demand sector, which uses an end-use modeling approach to forecast electricity demand and conservation. This sector kept track of the growth in the demand of energy services and electricity based on the growth in the region's economy, changes in the price of electricity, and the combination of user-specified conservation investments to be tested with the model. The most important determinants of electricity demand were the growth rates for residential housing, commercial floor space, industrial activity, and irrigated acreage/cropland. A fundamental assumption was that consumers would select the most cost-effective combination of fuel, appliance type, and efficiency in order to satisfy their need for energy services.

The resulting electricity demand was sent to the rest of the model, which computed short-term power purchases or sales, calculated construction of new power plants, dispatched existing and new plants, and derived new electricity prices that were passed back through the demand sectors.

The capacity expansion options spanned five generic options for new utility generation: coal-fired power plants; gas-fired combined-cycle combustion turbine plants; gas-fired simple-cycle combustion turbine plants; hydroelectric plants; and other renewable using wind and geothermal technologies. RRIM refers to all coal plants built after 1985 as "new coal." For purposes of calculating environmental impacts, all new coal generation is combined with conventional coal in 1995. For generation from new coal built between 1995 and 2015, the analysis assumes that 50% is produced from conventional technology, 40% is produced from atmospheric fluidized bed coal plants, and 10% is produced from combined-cycle coal gasification plants.

For purposes of our analysis, we assumed that the IRP requirement resulted in an increased investment cap that varied by area. We used these caps to approximate existing investment levels and investment levels resulting from IRP that are close to the marginal cost of new resources. In the absence of IRP, we assumed that in the areas of Billings, Loveland, and Salt Lake City, building energy efficiency programs were instituted up to a cost of 20 mills (1 mill=0.001 dollars) under the no-action alternative. In the Phoenix and Sacramento areas, the cost cap for comparable measures was established at 45 mills.

After the EPAMP is implemented, we assumed that for the Billings, Loveland, and Salt Lake City Areas, the conservation program costs would be capped at 35 mills/kWh. The Sacramento and Phoenix areas faced a cap of 50 mills/kWh. Due to regional generation surpluses in the Upper Midwest, the model assumed that programs in the Billings Area are implemented starting in the year 2000. In other areas, the model assumed a 1995 start date. In new buildings, utilities were predicted to provide 50% of the capital cost associated with conservation measures that cost up to the investment caps. For existing buildings, industrial facilities, and irrigated agricultural land, utilities were assumed to offer subsidies of 50% to those who voluntarily enter the program. Participation rates and limits were specified by end-use sector.

Calculating Environmental Consequences

The environmental analysis of the alternatives analyzes those impacts that are predictable without knowing the specific locations that would be affected. For example, the quantity of air pollutants that may be emitted under each of the alternatives is estimated. As specific actions are established, detailed environmental analyses would be developed by those initiating the projects as required by State and Federal legislation.

The environmental analysis involves the straightforward approach of multiplying an environmental impact factor by the generation or capacity associated with energy resources deployed under each of the alternatives. The result is an estimate of certain environmental impacts such as air emissions and solid waste production.

Table 2 summarizes environmental and planning information for the generation portion of the fuel cycle. The information is generic in nature; it does not apply to any particular plant, but rather represents a range of plants or calculated values. Resources included in the model are pulverized coal, fluidized-bed coal, integrated gasification combined-cycle, simple-cycle combustion turbine, gas-fired combined-cycle combustion turbine, hydroelectric, flashed-steam geothermal, and wind. The coal resources were modeled as a combination of the three technologies listed in Table 2. For some resources, Table 2 contains blank spaces for most environmental factors. For example, hydroelectric power does not emit significant ambient pollutants once installed. Resources with blank spaces may still produce impacts, but their impacts may be difficult to quantify generically.

Table 2. Planning and Environmental Profiles for Energy Resources

Envir. Impact Factors	Pulv. Coal	Fluid. Bed Coal	IGCC Coal	Simple Cycle CT	Gas-Fired CCCT	Hydro	Geo-therm	Wind
Air Pollutants, lb/MWh								
CO2	1970	2150	1810	1390[e]	1300		160	
SO2	1.6[a]	1.5[c]	0.66[c]	0.009	0.006			
NO2	3.2[b]	1.5	0.61[d]	1.064[b]	0.519			
VOC	0.036	0.058	0.048[d]	0.016	0.27		0.001	
CO	0.217	0.351	0.13	0.387	0.19			
TSP	0.3	0.11	0.04	0.06	0.031			
PM10	1.260							
N2O	0.34	0.325	0.302	0.24	0.063			
H2S							0.0664	
Total Trace El.	0.054	5.146	0.2E-4				0.449	
Water Pollut's, lb/MWh	a	f	g		h			
Waste Water	520	1200	270	45	510			
TDS	2.6	5.8	2.7	0.227	2.55			
TSS	7.8E-3	0.017	1.1E-4	6.8E-3	7.7E-3			
TOC		0.045		0.0018	0.02			
BOD		0.012		0.00045	0.0051			
Total Hardness	0.33	0.73		0.029	0.32			
Total Trace Pollutants	1.88	0.4E-5	1.9131	0.1608	1.819		0	
Consump. acre-ft/MWh	0.0012	0.0019	0.0018	0.5E-4	3.8E-4	0.0	0.005	0.0
Solid Waste, lb/MWh	a	a	c					
Ash	30	45	87					
Sulfur		1.6						
Total Metals	0.029	0.015	0.625					
Land Use								
Construction (acres/MW capacity)	1	1.5	0.6		0.1	NQ	0.2	5.9
Employment								
Construction (emp years/MW capacity)	4.7	5.1	5.7		1.4	9.3	4.1	1.9
Operations (emp/MWh generation)	7.6E-5	8.4E-5	1.3E-4		1.7E-5	6.8E-5	4.3E-5	2.3E-4

Blank signifies no reported quantity.
BOD = biological oxygen demand
PM10 = particulate matter ≤10 microns
TOC = total organic chemicals
VOC = volatile organic compounds
IGCC = integrated gassification combined-cycle
TDS = total dissolved solids
TSS = total suspended solids

a. 90% sulfur removal by flue gas desulfurization
b. Use of low NOx burner
c. 95% sulfur removal
d. Fuel gas moisturization process
e. Water injection process
f. 70% sulfur removal
g. 95% sulfur removal with waste water treatment
h. Steam injection

Choosing the factors or multipliers from the literature proved difficult. Often it is unclear how a source obtained its emission values or what, if any controls were accounted for. Also many values were given in different units sometimes making it difficult to convert for comparison. Choosing the environmental factors involved a set of qualitative and quantitative criteria: source credibility, study focus, empirical data, calculated estimates, and date of publication. In most cases we calculated our own estimates to include in the data set. We tended to choose values near the mean of the values available for a particular technology, and we attempted to select sources that best represent the power plants in Western's service region. Literature sources included the following: Bradley et al. (1991); Chernick and Caverhill (1989); Fluor Daniel Inc. (1988, 1991); Gleick et al. (1989); Kinsey (1992); NWPPC (1991); Ottinger et al. (1990); Public Service Commission of Nevada (1991); Shankle et al. (1992); California Energy Commission (1992); DOE (1983); and EPA (1985).

The analysis yields impacts that are generic in nature, rather than those that are site specific. For example, the quantity of air pollutants that may be emitted under each of the alternatives is estimated. However, the dispersion of pollutants, atmospheric reactions, and impacts on specific receptor populations can only be assessed on a case-by-case basis. As another example, the acres required to build new generating facilities are estimated, but specific impacts to land uses cannot be predicted.

We calculated environmental impacts results for the entire Western service region. This approach emphasizes the trends identified in comparing how the alternatives affect the environment. Considering an area of Western's complexity and the uncertainties surrounding our analysis, these trends are more important than the actual estimated numbers. Further, we could approximate the types of resources that may be built or implemented, but could not identify specific locations. Thus, a customer's need may be met by a plant built outside that customer's service area.

The environmental baseline from which impacts were predicted was the anticipated future condition that would exist through the end of the year 2015 if none of Western's proposed alternatives were implemented. Because the environmental baseline occurs as a period of time, and not a point in time, assumptions and predictions of future changes must be made to provide a reasonable projection of future conditions. The important point to be made here is that the no-action alternative, which is based on this anticipated future environment, does not mean an unchanged environment.

Environmental Consequences

This section describes the environmental impacts of Western's proposed IRP. Environmental effects were evaluated for: air quality (carbon dioxide [CO_2], sulfur oxides [SO_x], oxides of nitrogen [NO_x], and total suspended particulate [TSP]), waste water production and water consumption, thermal discharge, solid waste (ash from combustion of coal), and land-use. Environmental impacts were found to be less than those anticipated for the no-action alternative under every other scenario we examined.

General Trends

Several general trends are apparent from the analysis. First, all program alternatives would tend to result in fewer adverse impacts in comparison to the no-action alternative. This trend is true for all of the physical environmental impacts analyzed and most of the economic impacts, and can be attributed to increased customer investment in demand-side resources instead of power plant construction.

Another trend is seen in the quantities of impacts over time. Impacts that are tied to coal combustion, such as SO_x emissions and ash production, tend to peak in the year 2005, then decline or remain constant, as shown in Figure 1. This trend mirrors the quantity of electricity

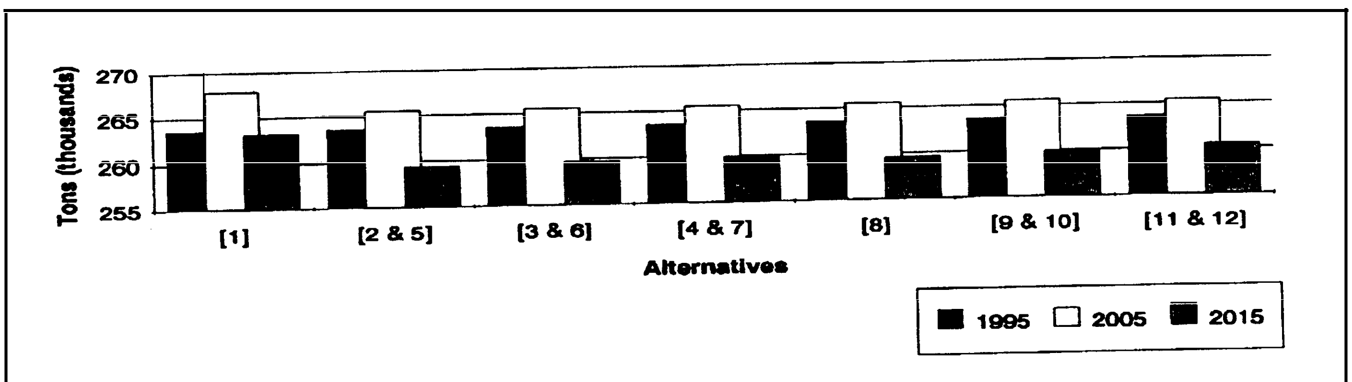

Figure 1. Total SO_x Emissions for Three Study Years

generated from coal plants. Between 1995 and 2005 generation from coal plants tends to increase as these plants are used to meet increasing loads in areas that currently have generation capacity surpluses. After 2005, the use of coal plants tends to decline as the plants age and are replaced with less capital-intensive new technologies, such as combined-cycle combustion turbines. With all alternatives, impacts that tend to result from all thermal power plants, such as thermal discharge and CO_2 emissions, show a steady increase over time, although the program alternatives are estimated to result in fewer impacts than the no-action alternative.

A final trend is found in the distinction between impacts resulting from generation and those resulting from the construction of new capacity. Impacts related to new capacity include land use and construction employment. The differences among each alternative's effects on these categories tend to be slightly magnified in comparison to the effects resulting from generation. This is due to the focus on only new development, without the influence of existing generation plants. Existing plants, which tend to dominate the effects of new plants, have a much greater influence on the effects resulting from electricity generation. The effects shown for land use illustrate this trend most clearly.

Impacts Directly Related to IRP

A review of the alternatives analyzed in the EIS shows that about 80% of predicted environmental impacts are attributable to IRP. The remaining 20% is attributable to power marketing decisions about terms of contracts and other factors. The impacts of IRP in isolation are best represented by Alternatives 11 and 12 which are referred to as the Non-Extension Alternatives in the Draft EIS (Western 1994). Environmental impacts were driven by changes in electrical generating capacity as measured through predicted generation. These changes are shown for the year 2015 in Table 3. Reductions in Environmental Impacts are shown in Table 4. In both Tables 3 and 4 capacit. changes are cumulative from 1995, and generation is represented on an annual basis.

Conversions for the values in the tables are as follows: 1 ton = 0.907185 metric tons, an acre-foot is the volume covering 1 acre to a depth of 1 ft, 1 acre-foot = approximately 43,574 ft^3, 1 ft^3 = 0.028317 m^3, 3.96832 Btus = 1 kcal.

Discussion

When compared to emissions of the entire public and private utility industry in Western's service region, the reductions shown in Table 3 appear small. However, in absolute terms, the reductions are important. For example, a typical 500-MW coal plant produces 2,600 tons (1 ton = 0.907185 metric tons) of SO_x, 5,200 tons of NO_x, 500 tons of TSP, and about 3.2 million tons of CO_2 annually. In the years 2005 and 2015, the program alternatives would reduce annual emissions by about the equivalent of one and one-half to two coal plants in 2015. A similar comparison with natural gas-fired simple cycle combustion turbines results in offsetting between 11 and 14 of the 250-MW units when SO_x is ignored. Natural gas combustion turbines produce little SO_x in comparison with coal plants.

An analysis of this type, relying on generic emission factors, is useful when conducting broad research to determine trends associated with programmatic decisions. This is the type of decision challenge confronted by Western. The generic approach is appropriate for requirements established in the regulations for implementing the National Environmental Policy Act (49 CFR Section 1500-1508), which puts an emphasis on concentrating on the issues that are truly significant to the action in question rather than amassing needless detail (Section 1500. 1).

Our reliance on RRIM to predict future changes in utility actions added a level of sophistication and complexity to the analysis that other approaches may have avoided. Several modelling and system averaging approaches are discussed in the literature (see Vine et al. 1991). Another approach would have been to use system averages of existing technologies. Using this approach at its simplest, any reduction in generation would be assumed to be spread equally across the mix of generation technologies employed in any given utility system. However this approach tends to misapply DSM activities that are time-dependent. DSM activities that are used to shape loads will affect some generation resources more profoundly than others. Another shortcoming is' that IRP actions by their nature affect technology selections in the future. Thus the most profound impacts on emissions will occur at the margin in the selection of new resources, not just with the operation of existing plants.

Regardless of which approach is used for estimating utility responses, some form of environmental factors must be applied to estimates of electricity generation and capacity additions. Pulverized coal-fired plants (PFCs) were one technology that exhibited a broad range of data on emissions. These plants were one of the more difficult data sets to evaluate. The values ranged from less than 1 lb/MWh of SO_x (1 lb/MWh = 0.0006 kg/MWs) to more than 45 lb/MWh of SO_x for data from 12 different sources listing 22 values (many incorporating varying degrees of control).

The factors that cause this inconsistency in emissions data are systematic as opposed to random. Systematic errors

Table 3. 2015 Generation (MWH)

Technology	No-Action	IRP Only	Change Due to IRP Only	Percent Change
Main Hydro	58,791,510	58,791,510	0	0
Small Hydro	2,278,990	2,242,658	-36,332	0.0618
Conventional Coal	302,841,082	299,501,082	-3,340,000	1.10
New Coal	27,637,107	27,589,020	-48,087	0.174
Combined Cycle CT	154,079,417	149,798,776	-4,280,641	2.78
Simple CT	32,940,079	31,339,343	-1,600,736	4.86
Renewables (Wind, Solar, etc.)	14,943,866	12,618,009	-2,325,857	15.6
Nuclear	58,052,300	58,052,300	0	0
Total	651,564,351	639,932,698	-11,631,653	1.79

Table 4. Environmental Impacts

Pollutant	No-Action	IRP-Only	Difference	Percent Change
CO_2 (tons x 10^6)	388.21	384.04	-4.17	1.07
SO_x (tons x 10^3)	267.89	265.32	-2.57	0.959
NO_x (tons x 10^3)	558.44	553.18	-5.26	0.942
TSP (tons x 10^3)	51.29	50.83	-0.47	0.916
Waste Water Production (tons x 10^6)	106.45	105.27	-1.18	1.108
Water Consumption (acre-feet x 10^3)	570.35	565.52	-4.83	0.847
Thermal Discharge (btu x 10^{12})	2,239.11	2,218.56	-20.55	0.918
Ash (tons x 10^6)	5.11	5.05	-0.06	1.17
Construction Land Use (acres)	1,252.08	1,218.68	-33.40	2.67

are the differences observed in data from different plants, operating conditions, fuels, and technologies. Some of the specific systematic differences that may occur among emissions data are fuels containing different percentages of sulfur and ash, different emissions controls, and plants with varying efficiencies. These errors make it difficult to define accurate emissions levels.

Conclusions

Because of uncertainties on both the utility and environmental side, our assessment may not serve as a valid basis for diversifying a stock portfolio or choosing a resource portfolio. However, the analysis does help to provide guidance on whether a federal action will tend to enhance or degrade the environment within a reasonable time frame and budget. Further, in providing a structure, the very questions that the analysis raises may serve to enhance the actual IRPs that Western's customers produce.

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