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Serving the Rocky Mountains and Desert Southwest

November 7, 1996

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Attn: Rhonda
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Arizona Corporation Commission
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RE: Docket No. U-0000-94-165

Dear Rhonda,

Enclosed for filing in the above referenced docket is the original and 10 copies of the Comments of the Environmental Group on the Commission's Proposed Rules Regarding the Introduction of Retail Electric Competition.

Thank you for your time and attention to this and other matters. I am sure I will be talking with you again. Please do not hesitate to contact me at 303-444-1188 ext. 221 if you have any questions.

Sincerely,

Wendy R. Hansen
Legal Assistant
Energy Project

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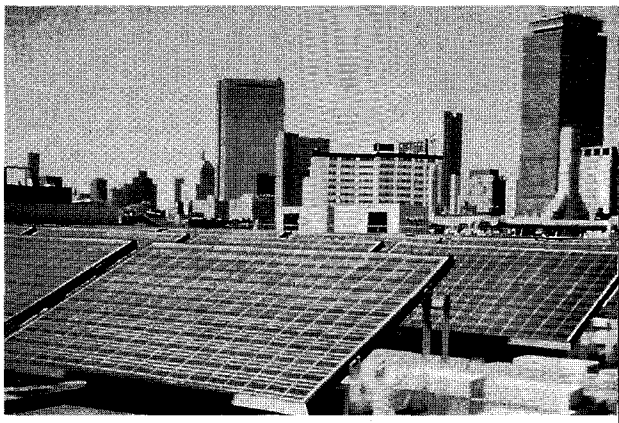
How the West Can Win

A Blueprint for a Clean & Affordable Energy Future



The Energy Project

Land and Water Fund of the Rockies

How the West Can Win

A Blueprint for a Clean and Affordable Future

The Energy Project

Land and Water Fund of the Rockies

Land and Water Fund of the Rockies
2260 Baseline Road, Suite 200
Boulder, Colorado 80302

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Published in 1996 in the United States of America by the Land and Water Fund of the Rockies, 2260 Baseline Road, Suite 200, Boulder, Colorado 80302.

Copy Editor: Phil Murray, PM Editorial, 2915 Baseline Road, Suite 420, Boulder, Colorado 80303

Cover Design: Polly Christensen, Christensen & Son Design, 410 Judson Street, Longmont, Colorado 80501

Production Management, Design, and Typesetting: Jon Brooks and Andrew Davis, Letra Libre, 1705 Fourteenth Street, Suite 391, Boulder, Colorado 80304

♻ This book is printed on recycled paper using soy-based ink.

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Preface

The Land and Water Fund of the Rockies ("LAW Fund"), a non-profit organization with offices in Boulder, Colorado, and Boise, Idaho, was founded in 1990 with the mission to provide legal and policy assistance to community groups throughout the Rocky Mountain and Desert Southwest region. In 1991, the LAW Fund's Energy Project was established to advocate for sustainable energy policy and practices in a variety of state and national forums. Today, the Energy Project has an interdisciplinary staff of attorneys, economists, and policy, research, and outreach organizing specialists who work together in a region that includes Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming.

This report, *How The West Can Win: A Blueprint for a Clean and Affordable Energy Future*, is based on our belief that satisfying today's energy demands need not imperil tomorrow's quality of life. Put quite simply, our report is about how the electric industry, a major contributor to the region's environmental problems, can play a constructive role in the protection of the natural environment while continuing to add to the region's economic well-being.

Before the writing process began, the LAW Fund held outreach meetings to get input from electric industry stakeholders and public interest advocates throughout the region. We appreciate the lively discussions, the variety of perspectives, and the constructive ideas furnished by hundreds of individuals (listed in Appendix A) during these meetings and throughout the development of this report. However, the views expressed in *How The West Can Win* were developed on behalf of LAW Fund by the staff of the Energy Project.

Most importantly, this project would not have been possible without funding from the Joyce Mertz-Gilmore Foundation and the support of Stacey Cumberbatch and Robert Crane. The Energy Foundation provided additional financial assistance as well as the advice and guidance of Hal Harvey and Eric Heitz.

How The West Can Win was researched and written by: Eric Blank, Energy Project Director; Bruce Driver, special counsel; John Nielsen, policy advisor; Mark Chalfant, senior attorney; Rick Gilliam, senior technical advisor; Rudd Mayer, research associate; Bill Vandenberg, regional outreach organizer; and Christine Gingras, administrative assistant. Significant help on the project also came from Gregg Eisenberg, former staff policy analyst, Randy Udall, Director of the Community Office for Resource Efficiency, Jim Cannon of Energy Futures, Inc., and Julius Dahne and Mike Eisenfeld, former LAW Fund interns.

We hope that you find this report informative and interesting.

Eric Blank, Director
The Energy Project
Land and Water Fund of the Rockies
March 1, 1996

Bruce Driver, Special Counsel
The Energy Project
Land and Water Fund of the Rockies
March 1, 1996

Summary of Key Findings

- Utilities in Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming expect to need over 15,000 megawatts of new capacity by 2015—enough to power six cities the size of Denver, Colorado, at a cost well in excess of $15 billion.

- Utility resource plans show a continued reliance on fossil fuel based technologies to meet close to 90 percent of this resource need. As a result, the environmental footprint of the electric industry—its impact on, for example, visibility impairment in our national parks and poor urban air quality—is likely to get significantly worse.

- An alternative strategy—relying much more heavily on energy efficiency, renewable resources, natural gas, clean coal, and the cleaning of the region's dirtiest power plants—would lower utility costs by $2.2 billion, reduce key pollutant emissions 20 to 40 percent, and diversify the region's energy mix.

- In addition to these direct economic and environmental gains, a clean energy future would also lead to a net gain of over 12,000 jobs and add $180 million annually to the region's wage base. Because this cleaner alternative would maintain coal generation at existing levels, there should be no reductions in the total number of coal jobs in the region through 2010.

- The potential for industry restructuring—whereby today's end-use customers could select their own electric supplier—has created financial incentives that are discouraging electric utilities from adopting a long-term perspective and pursuing a cleaner energy future.

- In response to these financial incentives, policymakers have two viable choices. First, they can use regulation and legislation to encourage monopoly utilities to promote clean energy. Or, alternatively, they can accelerate the transition to a new industry structure by encouraging retail wheeling and the disaggregation of today's utilities into separate generation and transmission/distribution entities.

- A third option, favored by many utilities—relaxing regulatory oversight, while retaining their status as vertically integrated monopolies—is poor public policy and should be firmly rejected.

- To achieve a clean and affordable energy future, all stakeholders—including regulators, legislators, utilities, customers, resource developers, environmentalists, and many others—must pull together. Our quality of life depends upon it.

How the West Can Win A Blueprint for a Clean and Affordable Energy Future

Executive Summary

Basis of the Blueprint

In June 1891, a switch was flipped at the Ames hydropower plant in a deep mountain gorge outside of Telluride, Colorado, and electricity began flowing to the Gold King Mine three miles away. By shaving $24,000 off the mine's annual energy bill, hydropower saved the owners from bankruptcy. Thus was born the electric industry in the western United States.

Since its origin a century ago, the West's electric industry has become an economic giant. In 1994, electric utilities in the Rocky Mountains and Desert Southwest had revenues of close to $10 billion. In Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming—the six states analyzed in this report—the industry directly employs over 35,000 people. Thousands more work in coal mining, natural gas extraction, and other energy-related industries. The region's utilities have over $20 billion in assets and pay roughly $1 billion annually in local, state, and federal taxes.

The electric industry directly accounts for 4 percent of regional economic activity, but its influence is much larger. Today, energy surges forth from the Hoover Dam, the Laramie River coal station, the Palo Verde nuclear units, and other large generating stations in the region. Without this power to pump water, run factories, cool and heat offices, light homes and run computers, the West would be dramatically different and much poorer.

Affordable, reliable electricity is central to the region's economic health and quality of life. Yet the tremendous benefits provided by the electric industry must not blind us to the many pressing regional environmental problems caused by the generation, transmission, and consumption of electricity. In fact, the industry's environmental footprint—its impact on western landscapes, air and water, and human health—is enormous. Today, the industry contributes to:

- regional haze that limits visibility in Grand Canyon, Arches, Canyonlands, Rocky Mountain, and other national parks as well as in countless other natural areas critical to the region's quality of life
- urban air quality problems, linked in a number of cities to utility emissions
- the risk of global climate change, resulting in part from utility emissions of carbon dioxide
- alteration of major rivers with hydroelectric dams that harm fish, wildlife, and recreation
- the adverse land and water impacts associated with strip mining for coal and drilling for natural gas
- the storage of nuclear waste from the nation's largest nuclear power plant

Without foresight, planning, and cooperation, these problems will worsen as the region's population grows.

Impacts of Growth

Its reputation as "the last, best place" makes the West a magnet for people attracted to its unparalleled quality of life. Five of the seven fastest-growing states are in the Rocky Mountains and Desert Southwest. The fastest-growing city in the nation is Las Vegas, and Phoenix, Salt Lake City, Albuquerque, and Denver are not far behind. Resort towns near national parks and ski areas—Moab, Santa Fe, Jackson, Telluride, Park City—are booming.

With robust growth expected to continue, the region's utilities expect to need over 15,000 megawatts of additional capacity by 2015—enough to power six cities the size of metropolitan Denver at a cost well in excess of $15 billion.

The implications of growth—for both the industry and the environment—are staggering. If the industry continues to rely almost exclusively on fossil fuel power plants, the industry's growth will seriously exacerbate existing air quality and other environmental problems.

On the other hand, growth also creates an exciting opportunity to promote a cleaner energy future. Expanding capacity needs provide a window of opportunity for the integration of cleaner power resources into the regional electricity mix. If the electric industry successfully incorporates clean power technologies, over the long run it can help solve a whole range of environmental problems. For instance, electric cars powered by clean renewable resources could dramatically improve urban air quality.

Resource Alternatives

A wide range of technologies could be tapped to meet growing electricity needs. Conventional sources include coal, natural gas, hydroelectricity, and nuclear power. New, cleaner sources include energy efficiency, wind, solar, geothermal, biomass, and fuel cells. From this menu of old and new, the West must select a blend that meets our needs as well as those of our children and grandchildren.

Conventional Resources

Today, virtually all electricity provided in the region is generated from coal, nuclear, natural gas, and large hydroelectric plants.

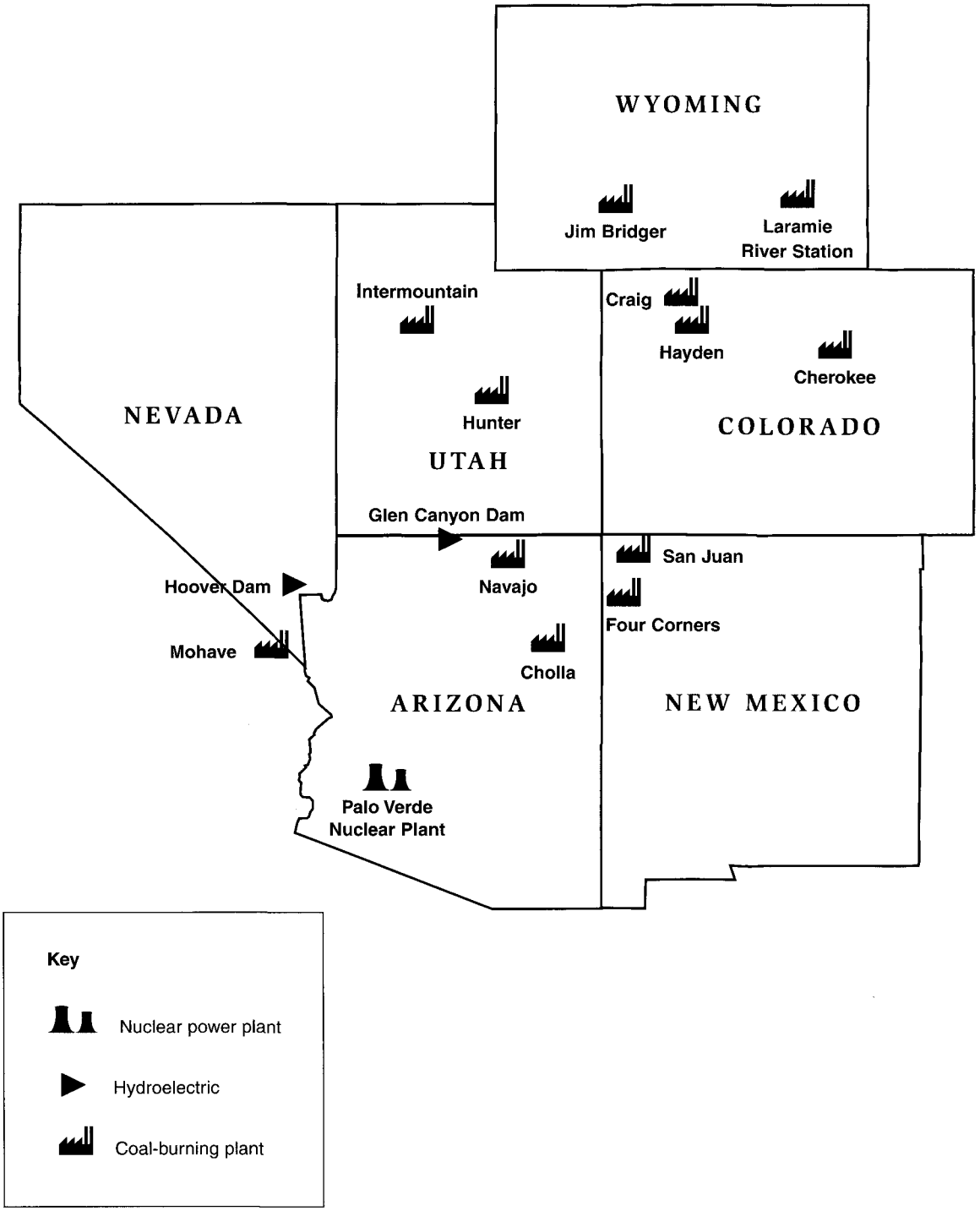
Coal provides over 70 percent of the region's electricity. Although new coal plants are relatively expensive, the coal itself is remarkably cheap and abundant in the region. Coal costs only a penny a pound, and the West has over 300 years of coal in the ground at current levels of extraction.

Unfortunately, coal burned to produce power in conventional power plants is relatively dirty, accounting for almost all of the industry's contribution to visibility degradation, the risk of climate change, and other air quality problems. Although new cleaner-burning coal technologies are under development, they are expensive and still emit more air pollutants than other available technologies. Nonetheless, there is promise that costs will fall and emissions will be reduced.

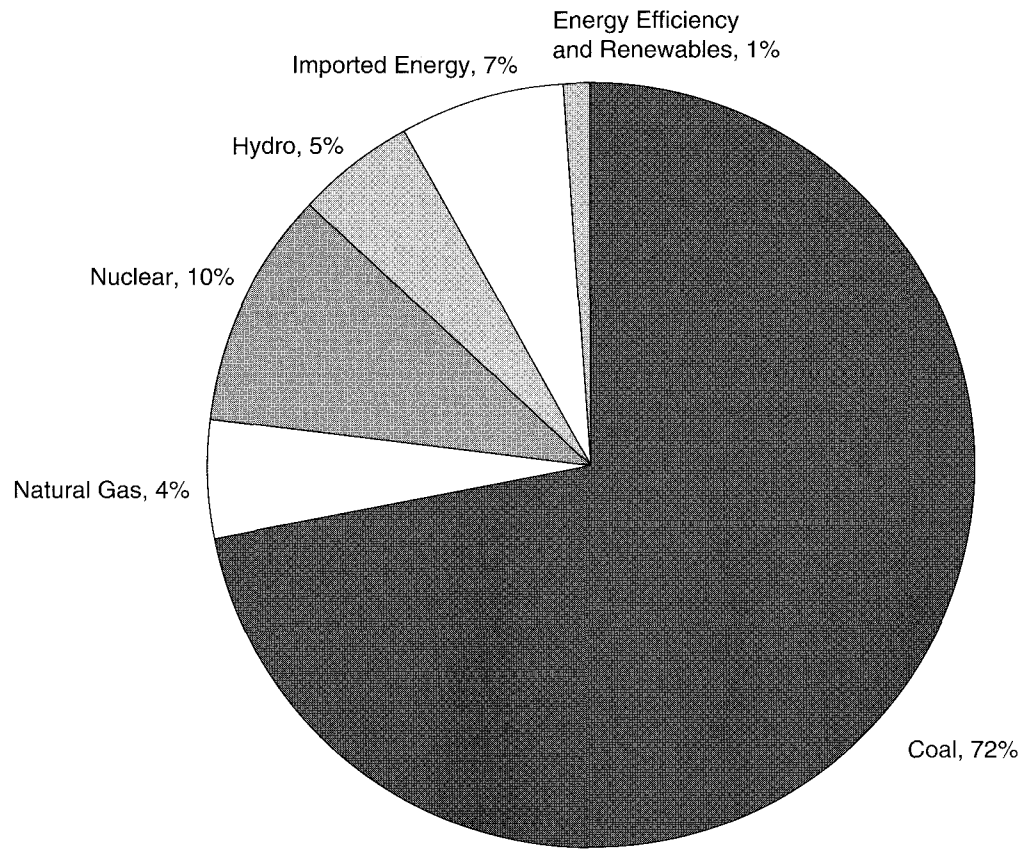
Only one *nuclear* power plant is in operation in the region—the Palo Verde plant near Phoenix. This nuclear plant, the largest in the nation, produces roughly 10 percent of the electricity provided in the region at a cost nearly double the average cost of electricity from coal-fired units. Although nuclear power does not worsen air quality, serious radioactive waste disposal issues remain unresolved.

Natural gas currently provides only about 4 percent of the region's electricity. However, its share is poised to increase. New, more efficient technologies—based on jet engine designs—can obtain significantly more electricity from a given amount of natural gas. And natural gas is, at least for the time being, abundant and inexpensive. But natural gas is not without its problems. Over time, the risk of price escalation is substantial. Also, natural gas drilling and exploration can create adverse land and water impacts, although its combustion results in a significant reduction in emissions compared with coal.

The Largest Power Plants in the Region: Coal, Nuclear, and Hydroelectric



Regional Electric Generation Mix in 1995 (percent of total, by resource)



Note: Numbers do not sum to 100 because of rounding.

Power from large *hydroelectric* dams provides roughly 5 percent of regional electricity. This power is cheap and helps to sustain rural economies. However, there are virtually no sites left in the region where large, new conventional hydroelectric dams can be built without serious environmental damage to aquatic and riparian ecosystems. Some potential exists for nontraditional hydro technologies, such as pumped storage and smaller facilities, but it is limited by siting and cost considerations.

Emerging Technologies

This category of technologies includes energy efficiency, renewable resources (from wind, geothermal, solar, biomass and municipal solid waste) and fuel cells.

Energy efficiency improvement refers to increases in the work that a given amount of electricity can perform in, say, heating or cooling a house, running an electric motor, or lighting a building. In this region the efficiency resource is enormous and largely untapped. Increases in regional energy efficiency could avoid the need to build new power plants and would do so at a fraction of their cost with virtually no adverse environmental impacts. Only one problem arises with energy efficiency—it can reduce utility retail sales and revenues.

Our region possesses a large *wind* power resource. Indeed, Wyoming boasts some of the best wind sites in the world. Although wind power compares favorably in cost with energy from natural gas plants, it is an intermittent resource—when the wind does not blow, no electricity is generated—and as a result wind is somewhat less valuable than

a fossil fuel plant for which output can be adjusted on demand. Environmental problems resulting from bird fatalities must also be addressed. These problems can likely be solved by the careful siting of wind turbines.

The most significant renewable resource in this region is *solar*. Arizona, Nevada, and New Mexico possess the best solar power resource in the country. This resource is also abundant in parts of Colorado, Utah, and Wyoming. Although the production of electricity from sunlight is relatively benign environmentally, solar power is expensive. However, solar technologies are maturing, and great potential exists for further technological advances and cost decreases.

Geothermal power plants tap hot water or steam from within the earth to generate electricity. Already a well-developed technology, geothermal electric power production provides a substantial amount of reliable power in California. Our region also possesses significant geothermal resources, especially in Utah and Nevada. The cost of electricity from these plants is roughly comparable to the cost of electricity from coal plants, depending on site-specific factors. Eventually there may be cost-effective technologies to extract heat from even deeper goethermal resources that are virtually inexhaustible.

Burning crop residues, trees, manure and other forms of *biomass* to generate electricity is also a well-developed technology. But because the region is arid, it does not possess a large, naturally replenished biomass supply. Another mature renewable resource technology is the combustion of *municipal solid waste* (MSW) to generate electricity. However, MSW is relatively expensive when compared with fossil fuel technologies, and there are serious concerns about air emissions from MSW generators.

Fuel cells burn hydrogen to generate electricity. The process is pollution-free, with water as the main by-product. Today, power from fuel cells is expensive and the technology is in its infancy. Eventually fuel cells will begin to be used commercially to power buildings and motor vehicles.

Preparing to Choose

The choice between conventional and emerging energy technologies hinges on how core concerns—including economic well-being and environmental quality—are valued. Conventional technologies produce cheaper energy but are subject to fuel price volatility and have adverse environmental impacts. Cleaner technologies are generally more expensive right now but have long-term economic and environmental benefits.

In 1993 and 1994, the LAW Fund held a series of 15 meetings with stakeholders in the electricity industry to help develop a vision, or blueprint, of a cleaner and more affordable energy future. Attending were representatives from the region's coal, gas, renewable, and energy efficiency industries; senior utility managers; public utility commissioners and their staffs; consumer advocates; Native Americans; state legislators; governors' aides; representatives from federal agencies; environmentalists; and concerned citizens.

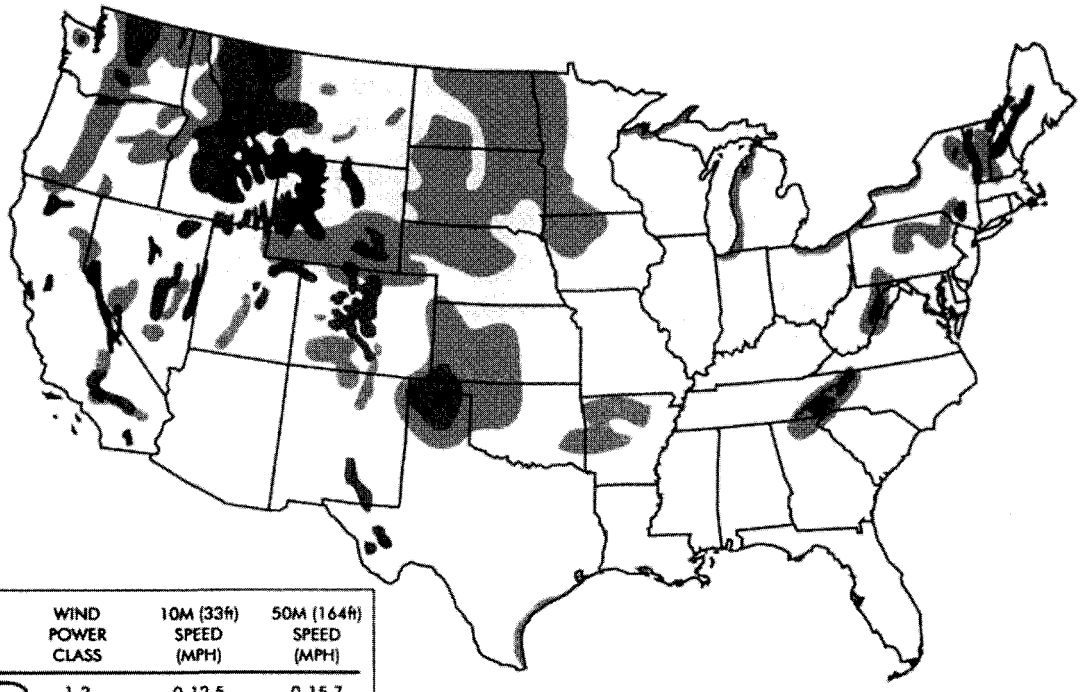
Although no consensus was reached on exactly what mix of technologies should be used to meet the region's new energy needs, virtually everyone agreed that these decisions should balance five key objectives:

1. *Environmental quality:* The generation, transmission, and consumption of electricity often damage the environment. A blueprint should show how these impacts will be contained and ameliorated.

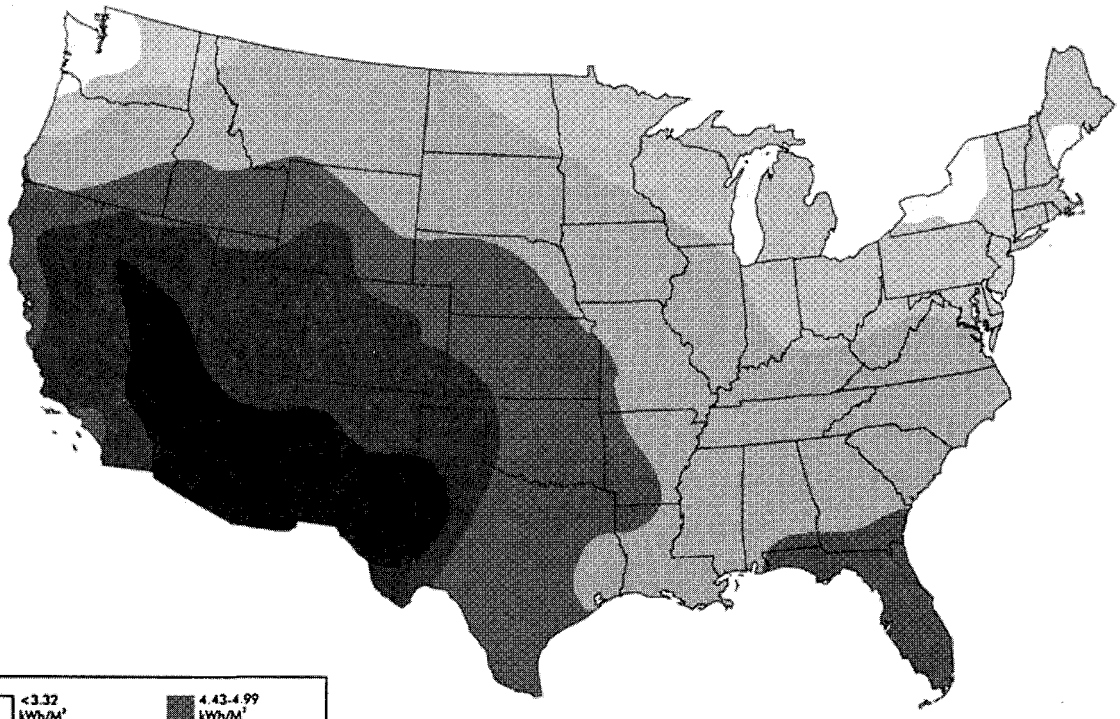
2. *Economic opportunity:* An affordable and reliable supply of electricity is vital to a healthy economy and quality of life. A blueprint should lower electric bills, develop attractive new jobs, and expand the region's tax base.

3. *Equity:* Equity consists of fairness between today's and tomorrow's residents, among utility customer classes (including low-income customers), among competing

Average Annual Wind Power in the Western States



WIND POWER CLASS	10M (33ft) SPEED (MPH)	50M (164ft) SPEED (MPH)
1-3	0-12.5	0-15.7
4	12.5-13.4	15.7-16.8
5	13.4-14.3	16.8-17.9
6-7	>14.3	>17.9



<3.32 kWh/M²	4.43-4.99 kWh/M²
3.32-3.88 kWh/M²	4.99-5.54 kWh/M²
3.88-4.43 kWh/M²	>5.54 kWh/M²

electric technologies, and between those who live in energy-producing regions and those who live elsewhere. A blueprint must be fair.

4. *Risk management:* Resource decisions must incorporate the risks of an uncertain future, including the possibility of fuel price increases and stricter environmental regulations. A blueprint should show how these risks will be managed.
5. *Sustainability:* Today's electric industry which depletes finite fossil fuel resources and is implicated in significant environmental problems, is limiting the options available to later generations and therefore is not sustainable. However, there is time to make a transition to a more sustainable industry. A blueprint should put the industry on a path to a sustainable energy future now.

In the long run, it is possible for the electric industry to achieve all of these objectives. In the short term some may conflict. For example, a cleaner energy industry could quickly be achieved through massive substitution of renewable and energy efficiency resources for conventional ones. But such a hasty transformation would be costly and thus inconsistent with the economic goals. The most sensible course is to implement the blueprint with an eye to balancing these five objectives.

A Clean and Affordable Energy Future

Can the West develop a sustainable energy future in the face of rapid population and economic growth? The answer is clearly yes. Although we cannot afford the cleanest possible energy supply immediately—we *can* afford to pursue a long-term blueprint that will accomplish the five objectives identified by stakeholders in the region.

Meeting this challenge will not be easy. It will take an unprecedented level of vision, courage, coordination, and cooperation on behalf of utility executives, independent power producers, public utility regulators, state and federal legislators, governors, Native American tribes, business leaders, environmentalists, and many others.

The decision cannot be postponed. This is a fateful moment in the West's history. As the regional surplus of electricity evaporates, a stark choice looms: Do we replicate the status quo by building another round of relatively dirty power plants? Or do we forge a new path by integrating cleaner technologies into the resource mix?

By choosing a clean, affordable energy future over "business as usual," we can relieve the competing economic and environmental tensions surrounding energy growth, thereby helping to preserve the West as a place where there exists, in novelist Wallace Stegner's words, "a society to match the scenery."

The Blueprint

Over the next 20 years, the region must add over 15,000 megawatts of new generating capacity. A review of utilities' resource acquisition plans shows that utilities intend to meet 90 percent of these needs with fossil fuels. In contrast, investments in energy efficiency are expected to be small, while funding for renewable energy is projected to be almost nonexistent.

The LAW Fund's blueprint offers a comprehensive, cost-effective alternative. If implemented, it will dramatically change the way electricity is generated in the Rocky Mountains and Desert Southwest and will place the region firmly on the path to a sustainable energy future.

Resource Recommendations

The blueprint proposes that the region meet its new energy needs with an intelligent blend of conventional resources and new, emerging technologies. These recommendations are summarized below.

Energy Efficiency

Because the region's enormous, inexpensive, and clean efficiency potential has only begun

to be tapped, the blueprint embraces it to meet approximately 40 percent of the region's new power needs by 2015. If this target is met, energy efficiency would account for roughly 9 percent of the region's energy mix at that time. This would avoid the need to spend $6 billion on new power plants, substantially reduce utility pollution emissions, and create over 10,000 new jobs.

Natural Gas

The LAW Fund's blueprint treats natural gas as a "transition" fuel, one that can provide relatively clean, cost-effective electricity during the period when natural gas prices should remain low and renewable resources are realizing their potential. Specifically, the blueprint proposes that, between 1996 and 2005, nearly half of the region's new capacity—or about 2,200 megawatts—be natural gas. Between 2005 and 2010, only 10 percent of capacity additions would be gas-fired—unless renewable resources fail to meet their price targets, in which case gas will play a larger role.

Renewable Resources

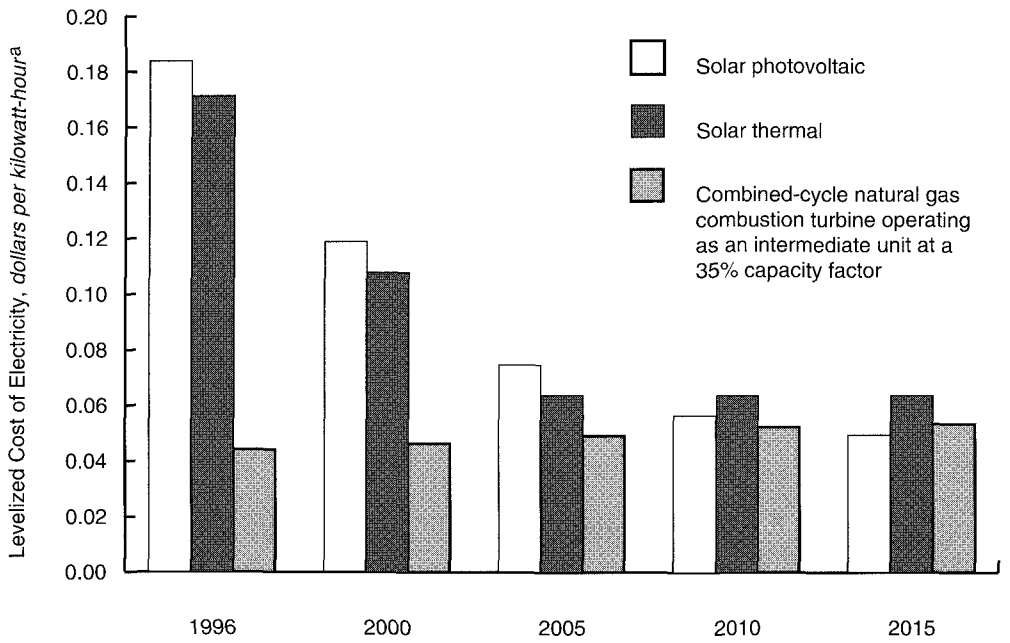
Between 1996 and 2005, the blueprint proposes that utilities make small, modest investments in renewables to drive down their costs. Larger investments follow as renewables become cost-competitive.

The *wind* production tax credit, slated to expire in 1999, creates a window of opportunity to begin developing the region's best wind sites. By the year 2000, wind should play a small but growing role in meeting our energy demands. By 2015, wind should supply 1,400 megawatts of new capacity.

Economies of scale could lower the costs of *geothermal* power if today's projects, which range in size from 25 to 50 megawatts, are expanded to 100 to 250 megawatts and new technologies can be successfully deployed. Over the next five to ten years we propose that 225 megawatts of geothermal capacity be built. Between 2005 and 2015 we advocate adding another 1,650 megawatts.

The costs of *solar thermal* and *solar photovoltaic* (PV) technology have declined

The Cost of Solar Power Versus the Cost of Fossil Fuel



Note: a. 30-year levelized cost of electricity in constant 1996 dollars.

sharply. Although PV is cost-effective in niche applications, neither PV nor solar thermal can yet compete in large-scale utility applications. However, solar technologies should become economically competitive sometime between 2005 and 2010.

Consistent with that time line, the LAW Fund proposes that the majority of the region's investments in solar power come after 2005. In the near term, there are attractive opportunities to gain experience with solar power. For example, utilities in Arizona and Nevada are planning to add approximately 40 megawatts of solar capacity by 2001. As solar becomes cost-competitive, roughly 5,000 megawatts are brought on-line by 2015.

Coal

Because the region is so richly endowed with coal reserves, the LAW Fund advocates continued development of *clean coal* technologies that reduce pollutant emissons. By 2015 we propose that close to 1,400 megawatts of clean coal power plant capacity be on-line in the region. Clean coal may play a central role in meeting regional energy needs, especially if solar and other renewable resources do not fulfill their promise.

Conventional coal-fired power plants are the primary source of the electric industry's environmental impacts. As a result, the blueprint proposes that no new conventional coal plants be built in this region. However, because existing coal plants provide inexpensive power, the blueprint proposes that most of them continue operating. In addition, we suggest that almost all of the cleaner-burning conventional coal plants have their lives extended beyond their scheduled 40-year lifetimes.

A disproportionate share of regional air pollution is caused by a handful of older coal plants. The blueprint proposes that approximately 2,000 megawatts of the region's dirtiest coal plants be retired when they turn 40. An additional 1,500 megawatts of these coal plants should be repowered with natural gas or solar thermal technologies, or retrofitted with pollution control equipment.

Other Resources

We project that *fuel cells* will begin to be used commercially within the next 20 years. The exciting prospect of a pollution-free energy cycle is enough to support a significant effort to overcome the barriers to commercialization.

The blueprint opposes the addition of new *large hydro* facilities because of environmental limitations. However, the blueprint presumes the continued operation of most of today's regional hydro capacity.

If, in the future, a new generation of safe and inexpensive *nuclear* plants are developed and if safe nuclear waste storage facilities are in operation by that time, nuclear power may undergo a renaissance. But the prospect seems remote. Other than the continued operation of the Palo Verde nuclear plant near Phoenix, nuclear power plays no role in the blueprint through 2015.

Evaluating the Blueprint

Compared with a business-as-usual strategy, the LAW Fund proposal does a much better job of balancing the five objectives Westerners told us were important in crafting our energy future.

Environmental Quality

The blueprint creates a far cleaner power industry by:

- Significantly reducing emissions of sulfur dioxide, oxides of nitrogen, carbon dioxide, and other harmful air pollutants.
- Ensuring that no new conventional coal-fired capacity is built. This will protect visibility in the region's many parks and natural areas.
- Repowering Nevada's Mohave power plant to improve visibility at Grand Canyon National Park.
- Cleaning the Hayden power plant in Colorado to reduce visibility degradation

and acid deposition in the Mount Zirkel Wilderness area.

- Alleviating utility emissions that contribute to the brown clouds that plague Denver and other cities.
- Putting the electric industry on the road to abating transportation-energy pollution by advocating the use of renewable energy resources to provide the electricity for electric cars and the hydrogen for fuel-cell vehicles.
- Avoiding investment in new large hydroelectric or nuclear facilities.

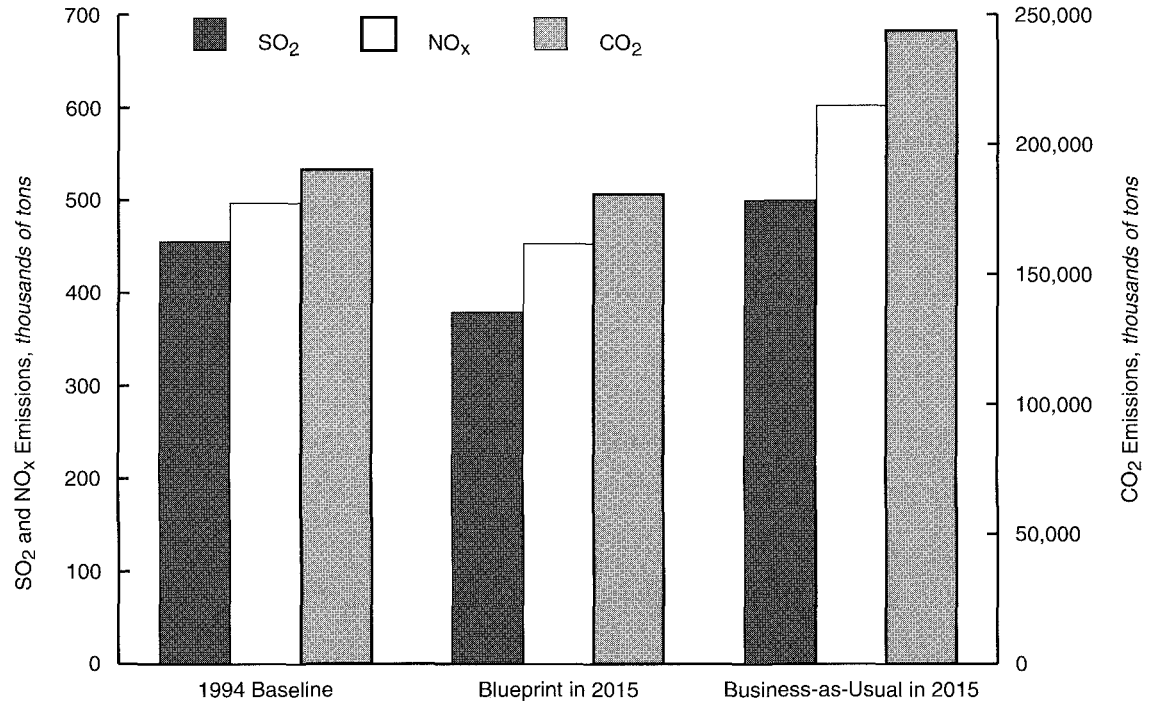
Economic Opportunity

The blueprint is economically sensible. It does not call for an overnight transformation of the industry to meet environmental goals at the expense of the region's economy. Instead, it integrates cleaner technologies into the resource mix as they become cost-effective.

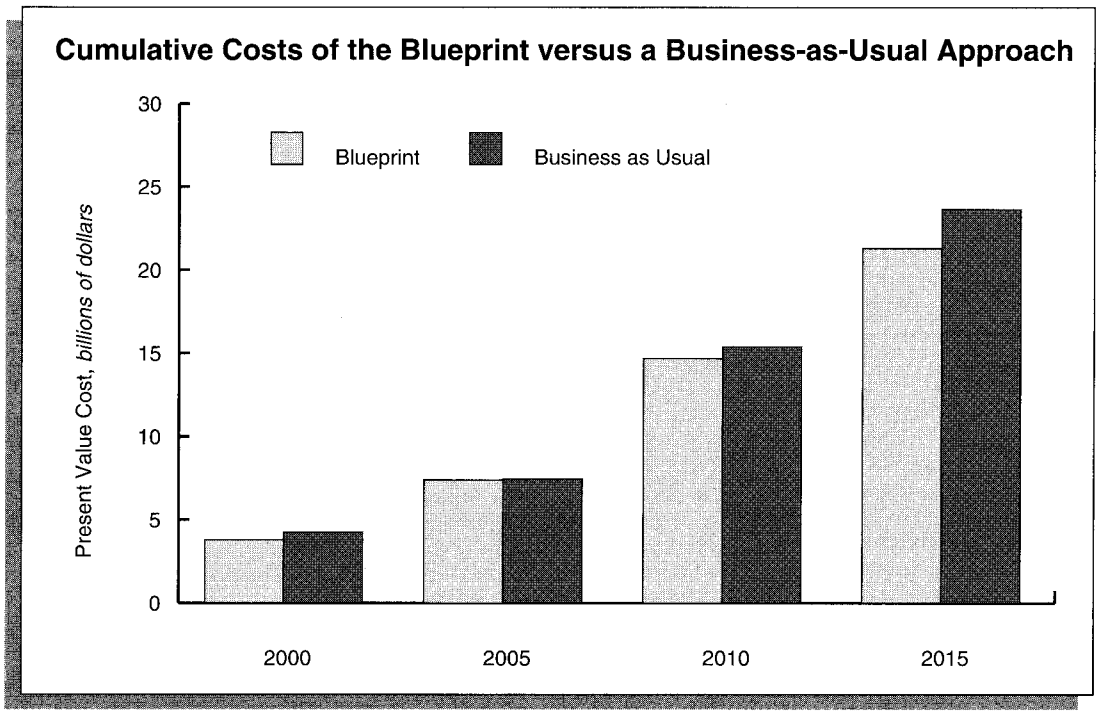
- Existing coal, natural gas, nuclear, and hydro plants would continue to operate, and most would have their lives extended beyond a 40-year retirement date.
- From 1996 to 2005, the blueprint relies heavily on natural gas to take advantage of today's low gas prices.
- During the same period, small investments in renewable energy help lower the costs of these technologies. Then, as natural gas prices rise and the costs of renewable energy fall, larger investments in renewables are made.
- The large and continuing role the blueprint assigns to energy efficiency will reduce customers' energy bills by roughly $3 billion over the next 20 years.
- Although some features of the blueprint—renewable resources, pollution control retrofits, and repowerings—impose additional costs, they will be more than offset by savings from the efficiency investments. Overall, the LAW Fund estimates that the blueprint will save the region roughly $2.2 billion.

In addition to these direct economic gains, investments in energy efficiency and renewable resources create new jobs. We estimate that the implementation of the blueprint over the next 20 years will create

Comparison of Annual Emissions from Electric Utilities



Note: SO_2 and NO_x emissions use the left axis. CO_2 emissions use the right axis.



over 12,000 net jobs in the region and increase wages and salaries $180 million annually.

Our analysis also shows that net generation from the region's coal plants would remain constant at today's levels over the next 15 years. Essentially, the generation lost from cleanup of the dirtiest power plants is offset by increased utilization of the remaining ones. As a result, we expect no reductions from today's levels in the total number of coal-mining jobs within the region through 2010.

Equity

The LAW Fund proposal equitably distributes the economic and environmental costs and benefits of electricity production.

- Energy costs can be a significant burden for the poor and elderly, consuming up to one-third of their monthly income. The LAW Fund's energy efficiency proposals will help lower energy costs for low-income families.
- Although the production of electricity has unquestionably brought economic benefits to tribal communities and other rural areas in our region, it has also left environmental damage. The blueprint will help to promote economic opportunity in these areas but with less environmental impact.
- Our six-state region is an energy exporter, sending substantially more energy out of the region than it imports. Electricity flows to other states—but the resulting pollution remains behind. The blueprint should help to end the practice of building dirty power plants here to serve loads elsewhere.
- The environmental hazards of electricity generation sometimes fall most heavily on urban low-income and minority populations. The blueprint's plan to repower the region's dirtiest coal plants with natural gas should help to alleviate this imbalance.

Risk Management

Today's power industry has nearly all its eggs in the fossil fuel basket. By integrating clean energy resources into the electricity mix, the blueprint greatly reduces the region's exposure to fuel price hikes or stricter environmental regulation.

- Although natural gas prices are low today, over time they will rise. This rise could be abrupt and steep if there is another oil crisis, and prolonged if natural gas becomes widely used as an automotive fuel or if the nation's electric utilities develop an over-reliance on gas.
- A diversified energy mix protects the region from the risk of more stringent environmental regulations. Already, pollution control

equipment accounts for 10 to 30 percent of a new coal plant's cost, depending on the type of equipment installed.

- The likelihood of a carbon tax on fossil fuels is currently remote, but the pressure to reduce global carbon dioxide emissions will continue to mount. If even a modest carbon tax of $10 per ton is imposed, by 2015 the region would save $600 million annually by having adopted the blueprint's proposals.

Sustainability

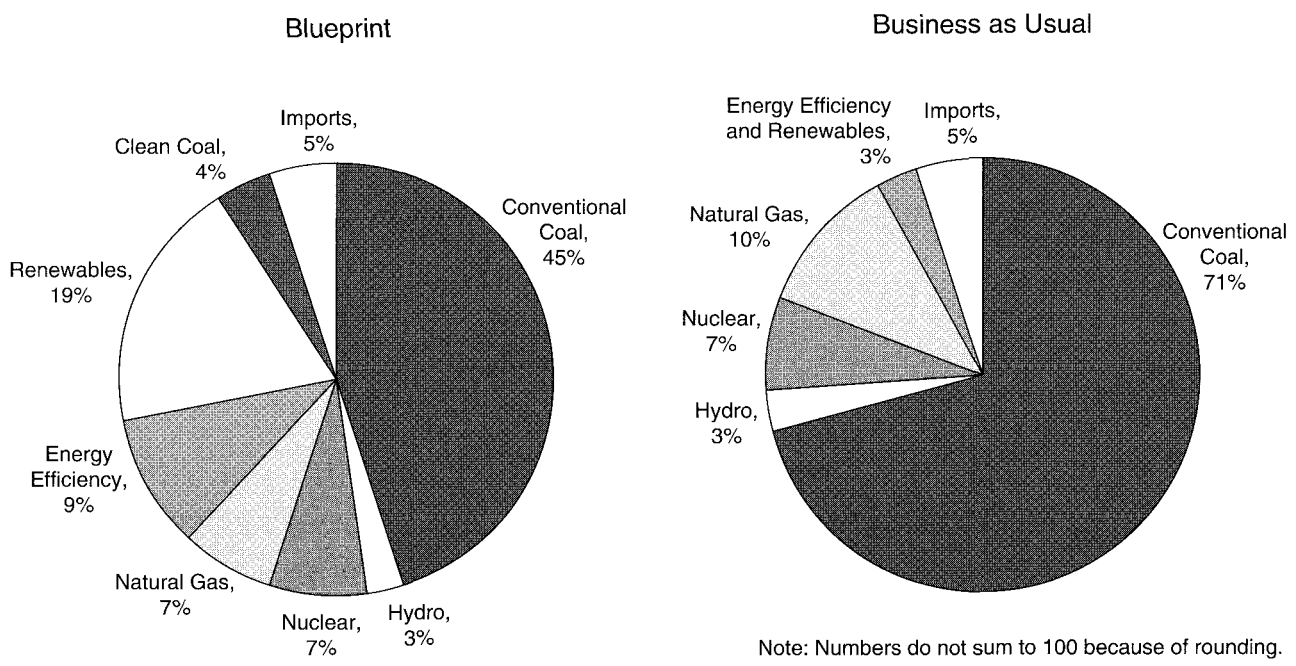
The LAW Fund's blueprint does not just preserve options and resources for later generations, it enlarges them.

- First, by helping the region climb the renewable energy "learning curve," the blueprint unlocks the economic development potential of these abundant resources.
- Second, by reducing emissions of pollutants and greenhouse gases below what they otherwise would be, the blueprint protects public health and climate stability.
- Third, by greatly increasing the efficiency with which we use electricity, the blueprint preserves coal, natural gas, and other nonrenewable resources for our children and grandchildren.
- Fourth, by making a concerted effort to develop clean technologies in the next 20 years, the blueprint places the region in a position to meet growth in demand for power after 2015 without serious environmental damage.

Implementing the Blueprint

The blueprint is a schedule of electric resource investments over a 20-year period. Its implementation depends on a sustained flow of capital and other support. Where will this support come from? As in the past, the support will come primarily from electric customers paying their utility bills. However, increasing competition in the electric industry has undermined the confidence utilities have in their ability to recover the costs of new electric resources from their customers. This development has important consequences for implementation of the blueprint.

Electric Generation Mix in 2015 (percent of total generation, by resource)



Note: Numbers do not sum to 100 because of rounding.

Implications of Competition

During recent decades many industries—airlines, telecommunications, trucking, banking, and natural gas—have been deregulated. It is now the electric industry's turn to face increased competition and potentially significant restructuring.

In the future, rather than being required to purchase power from a regulated utility operating within a monopoly franchise service territory, electricity customers may be able to choose among a host of providers in the same way that they now choose among AT&T, Sprint, and MCI. Customer choice of electric supplier (also known as "retail wheeling" or "direct access") is now under consideration in many states. To prepare for that day, many utilities have taken steps to lower their costs, in some cases laying off thousands of workers, merging with neighboring utilities, and cutting rates for valued industrial customers.

This relentless focus on the bottom line has had the unanticipated effect of making utilities reluctant to invest in energy efficiency and renewable energy, critical elements of the blueprint. Although these resources have significant long-term economic and environmental benefits, they can raise costs and electric rates in the short run. In today's competitive market environment, utilities are increasingly unwilling to make long-term investments because there is no longer any guarantee they will recoup the costs of their investments from customers who may be lost to competitors in the future. Indeed, utilities in Nevada, Arizona, and Colorado are now reevaluating their prior commitments to energy efficiency and renewable resources.

The LAW Fund embraces competition. However, competitive electricity markets must not be allowed to undermine the attainment of the five objectives Westerners say they want from their electric industry: environmental quality, economic opportunity, equity, risk management, and sustainability. Free markets are good at producing short-term economic benefits but not as good at safeguarding the environment and protecting other public interests.

Policy Options to Promote the Blueprint

In this changing industry, we believe policymakers have two choices as they contemplate how to protect the public interest. They can use regulation and legislation in a way that is consistent with an increasingly competitive industry to encourage monopoly utilities to promote clean energy. Alternatively, through disaggregation and retail wheeling, they can accelerate the transition to a new industry structure that favors clean energy technologies. A third option, favored by many of the region's utilities—relaxing regulation while maintaining the utilities' status as vertically integrated monopolies—creates a situation of unregulated monopoly and should be firmly rejected as poor public policy.

Regulating Monopolies to Promote the Blueprint

If a state chooses to stay with regulated monopoly utilities, at least for the time being,

Leaving the Local Utility

The City of Las Cruces is a town of 65,000 people in southern New Mexico whose citizens have purchased power from El Paso Electric (EPE) for many years. Las Cruces recently formed a new municipal utility and is now attempting to leave the EPE system, which, because of investments in the expensive Palo Verde nuclear plant, has some of the highest rates in the state. This move to purchase cheaper power, if successful, will cut the city's electric bills by 20 percent while forcing EPE to raise rates for its remaining customers. Proposals like this one are placing additional pressure on utilities to lower their costs and prices.

new tools are needed to encourage investment in the clean energy resources in the blueprint. In our view, the most promising tools include:

- a wires charge, paid by all electric customers who use the local transmission and distribution system, that is used to fund energy efficiency, renewable resources, and low-income energy assistance programs
- market-based green pricing programs that satisfy customer desires to purchase clean, renewable energy
- conditions attached to regulatory approval of, for example, utility mergers, requiring companies to clean up dirty power plants and invest in clean energy resources
- utility energy efficiency programs that actively transform energy efficiency markets and that recover more of their costs from program participants
- implementation of portfolio management standards by state public utility commissions (PUCs) that encourage utilities to invest in clean power technologies
- creation of competitive wholesale markets that protect long-term public interests during the transition to a new industry structure

Obsession with Price

Public Service Company of Colorado (PSCO), in response to changing financial incentives, is now proposing to eliminate its energy efficiency investments after 1996 and to limit its commitment to wind and solar power. PSCO has also been reluctant to clean up power plants that appear to be linked to a number of environmental problems. As Del Hock, chairman of the board and former chief executive officer of PSCO, bluntly puts it: "Price is everything."

In contrast, others recognize that factors beyond price are relevant. For example, the Colorado Public Utilities Commission recently found that regulated utilities must be concerned with much more than their short-term rates. For the commission, environmental quality, public health and safety, and the economic vitality of the state were particularly important.

Moving Beyond Vertically Integrated Monopolies

Although these tools are critical, they do not fully solve deeper problems. First, today's vertically integrated electric utilities contain both monopoly (transmission and distribution) and competitive (generation) functions within the same corporate entity. The LAW Fund believes that this situation has already created the potential for abuse of market power. In essence, vertically integrated utilities can use their monopoly control over transmission and distribution lines to enhance the competitive position of their generation assets. This would prevent the benefits of competition from flowing to electric customers. The solution is to encourage utilities to "disaggregate" into separate generation and transmission/distribution companies. As described in Chapter 3 of this report, disaggregation may have significant financial benefits for all interests.

Second, these tools do not address a fundamental problem with utility regulation as it exists today: Existing regulation imposes large risks on electric customers that are more equitably and efficiently borne by investors. The solution to this problem is customer choice, or retail wheeling. However, as Chapter 3 explains, retail wheeling has large problems of its own.

Three problems raised by retail wheeling are: (1) Who is responsible for costs already incurred by utilities that are "stranded" by retail wheeling? (2) How can *all* customers, not just the largest and most powerful, benefit from retail wheeling? and (3) How will the clean power resources contained in the blueprint be funded under retail wheeling?

When utility customers depart a utility through retail wheeling, they may leave behind or strand investment costs that the utility has incurred. Just who is responsible for these costs—the utility, the departing customers, or those customers who remain with the utility—is controversial and unre-

solved. Because large industrial electric customers are in the best position to find new cheaper electric supplies, they may leave the utility, imposing stranded costs on smaller commercial and residential customers. Even if large customers bear their fair share of stranded costs, they are still likely to receive most of the benefits of retail wheeling.

These issues raise serious questions of equity. The LAW Fund proposes that the implementation of retail wheeling be gradual so that these issues may be resolved with fairness. The idea is to make retail wheeling available to customers only to meet the need for *new* resources. In this way, a utility's ability to recover past costs would not be directly undercut. Chapter 3 describes a "voucher" system that would spread the benefits of retail wheeling to all customers. We believe these proposals offer a way for the region to begin to reap the benefits of retail electric competition in a way that is fair to all interests.

As to the third problem—how to fund investment in clean energy resources in a retail wheeling regime—we depend on disaggregation, the gradual implementation of retail wheeling, and some of the tools, such as green pricing, described above. But these tools will not get the job done by themselves. New institutions and funding sources will be necessary. In particular, utilities and independent power producers will need to come together to share the risks and financial burdens associated with clean energy resources. Federal and state support of these ventures will be important, as will equitable tax and fiscal policies.

Role of Stakeholders

Given the changing nature of the industry and the policy issues that are raised, the blueprint cannot be implemented without the active support of key stakeholders. The LAW Fund suggests the following actions.

State utility regulators

Regulators must play a critical leadership role in guiding the transition to a more competitive industry. PUCs should encourage utility managers to moderate their tendency to behave as if their utility's short-term financial health were the only interest at stake in industry restructuring. PUCs should also ensure that, during this critical transition, utilities do not become "unregulated monopolies," wholly abandoning clean power even while they retain monopoly rights and are not yet subject to vigorous retail competition. In addition, PUCs should make a special effort to protect low-income electric customers from being hurt by the onset of competition.

Utilities

The efforts of PUCs to commercialize clean energy technologies would be greatly facilitated by utility leadership. The LAW Fund understands the financial pressure utilities face. However, to allow these pressures to become the sole determinant of energy policy, as some utilities suggest, is shortsighted. The utility business is, and will continue to be, inextricably intertwined with the public interest as articulated by western stakeholders. For that reason, the LAW Fund urges utilities to assume leadership in devising new approaches to promote clean power. Enlightened utility leadership will allow companies to survive and grow in an increasingly competitive environment. The sorts of tools available to creative utilities include green pricing, wires charges, new approaches to energy efficiency, and similar initiatives.

State Legislatures

Most legislatures are now, or soon will be, debating restructuring proposals. In their deliberations, legislators must be sensitive to the broader implications of energy policy and must adopt a long-term vision. To accelerate the development of clean energy, we urge legislators to:

- link a utility's recovery of "stranded" costs to its willingness to mitigate pollution at existing plants and to invest in clean power resources
- require utilities to implement wires charges to fund investments in clean energy and low-income energy assistance programs
- use tax and fiscal policy to encourage utilities and independent power producers to invest in clean power
- support state and regional risk-sharing clean power development consortia, especially those that promote economic development
- consider how to encourage the disaggregation of vertically integrated utilities
- protect the most vulnerable of utility customers from the downside of competition through low-income energy assistance programs.

State Governors

We urge governors to develop plans to encourage clean power technologies through regulatory, fiscal, and tax policy and to present these plans to state legislatures. We also encourage governors to use their offices as bully pulpits to tout the economic and environmental benefits of clean power, especially for rural areas. State agencies dealing with energy conservation, environmental regulation, consumer protection, and economic development also have a clear stake in utility restructuring. We urge them to be at the table.

Federal Energy Regulatory Commission

As the agency responsible for regulating wholesale power transactions and the nation's transmission system, the actions of the Federal Energy Regulatory Commission (FERC) will affect the ability of PUCs and legislatures to promote clean power. The LAW Fund urges the FERC, in its rulemakings and adjudications, to bolster states' abilities to promote environmental and public interest goals and support the authority of the states to encourage utilities to acquire clean power resources.

Federal Lawmakers

Fiscal, tax, and regulatory policies under debate in Congress will have a profound impact on the clean power industry. For example, elimination of the wind production tax credit before its scheduled 1999 expiration would hurt wind development in this region. Additional cuts in the budget of the National Renewable Energy Laboratory and other federal agencies working on these issues would also be counterproductive. We also urge Congress to promote clean power technologies as it begins its work on utility-restructuring legislation.

Western Area Power Administration

The Western Area Power Administration, a federal power-marketing agency, can play a constructive role by making its transmission capacity available to renewable energy developers, by using small increments of its hydro resources to increase the reliability of energy efficiency and renewable resources, by buying small amounts of clean power to supplement its hydro resources, and by acquiring energy efficiency and renewable resources to replace peaking capacity lost at federal hydro facilities.

Coalition Building

Adoption of the LAW Fund's blueprint will require a great deal of work by citizens and other stakeholders, including utilities, regulators, power developers, business leaders, customer groups, environmentalists, Native American tribes, and others. A significant role exists for a regional organization, as well as strong individual state organizations, to promote clean power. These organizations would link the interests of the many people who want a stake in a clean and more affordable energy future for the region.

Conclusion

Diversifying the electric resource base to include energy efficiency and renewable energy promises enormous benefits. By

pursuing this path, the region can reduce pollution and environmental damage, promote economic opportunity, enhance equity, and move toward a sustainable energy future. However, achieving a more diversified energy industry will not be easy, nor is it the path of least resistance, especially in an industry that increasingly responds only to short-term financial incentives.

The urgency of making this transition is as great as the perceived difficulty in achieving it. The region has a window of opportunity to switch from near-exclusive reliance on fossil fuels to a more diversified, resilient energy system. But time is short. Research, development, and commercialization activities pursued in the next five to ten years will determine whether or not emerging clean energy technologies will be ready in the middle of the next decade when large new resource needs must be met.

The stakes are high. If the region does not move now in the direction of clean energy, utilities and independent power producers are likely to do what they know best—construct another round of conventional fossil fuel power plants—and a unique opportunity will have been lost.

To the many industry stakeholders and others who care about this region, the LAW Fund offers this challenge: Our actions today will determine what is possible tomorrow. A cleaner energy future beckons—now is the time to deliver.

Introduction

The electric industry in the West operates in the dramatic setting of the Rocky Mountains and the Desert Southwest, which have long occupied a powerful place in the American imagination. No other region in the country can be so harsh and forbidding, yet so fragile and beautiful—contrasts that lend it an awe-inspiring quality.

National parks and monuments such as Arches, Bryce, Canyonlands, Grand Canyon, Grand Teton, Mesa Verde, Monument Valley, Rocky Mountain, Yellowstone, and Zion contain only the most well known of the region's natural jewels. Outside these parks are places too numerous to name, comprising hundreds of millions of acres of public and private lands, all dependent on the West's clear vistas to be enjoyed.

As much as or more than in any other part of the country, this region's natural environment is critical to its economy and its quality of life. Whether to ensure that tourist dollars continue to flow or simply to act on a sense that a better quality of life depends on a clean environment, protection of the natural environment is critically important.

As the region has become more populated, protecting the natural environment while maintaining a robust economy has become an increasingly tough balancing act. Regional haze, urban brown clouds, and acid snow and rain are only a few of the many ways in which the strain on the environment manifests itself. The evidence is incontestable that we are fouling our region's air, land, and water. If we permit such environmental degradation to continue, the result will be not only an unhealthy environment but fewer economic opportunities and a poorer quality of life for ourselves, our children, and future generations.

The impetus for this report—which covers a six-state region including Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming—is the Land and Water Fund's belief that, because the electric industry is implicated in most of the region's environmental problems, it can also be a part of the solution to those problems.

The Basis of the Blueprint

One

In June, 1891, a switch was flipped at the Ames hydroelectric facility in a deep mountain gorge outside of Telluride, Colorado. Electricity coursed through 2.6 miles of transmission cable to power milling equipment at the Gold King Mine. All told, the 100-horsepower plant generated 3,000 volts for 30 straight days, ultimately reducing the mine's energy costs from $2,500 to $500 a month and saving it from bankruptcy. Thus was born the electric industry in the western United States.[1]

Since its origin over a century ago, the electric industry in the West has become an economic giant. In 1994, electric utilities operating in the six-state region covered in this report had revenues of close to $10 billion from retail sales, constituting about 4 percent of the region's total economic activity. The net value of their assets is more than double this amount—over $20 billion. The financial impact of the industry reverberates throughout the region: it employs over 35,000 people directly and supports thousands more jobs in the coal-mining, natural gas extraction, and railroad industries. Annually, the region's electric utilities pay almost $1 billion in local, state, and federal taxes. Table 1-1 lists the key characteristics of the utilities in each of the region's six states.

For the last 40 years, utilities in the West have relied almost exclusively on three resources—coal, nuclear, and hydroelectric—to meet the majority of the region's energy needs. Of these three resources, coal is by far the most important. Currently, coal-burning power plants provide close to 70 percent of the region's electricity. Much of the remainder is generated by nuclear power, although hydroelectric and natural gas also provide significant energy, particularly during peak demand periods. Figure 1-1 shows the current regional energy mix.

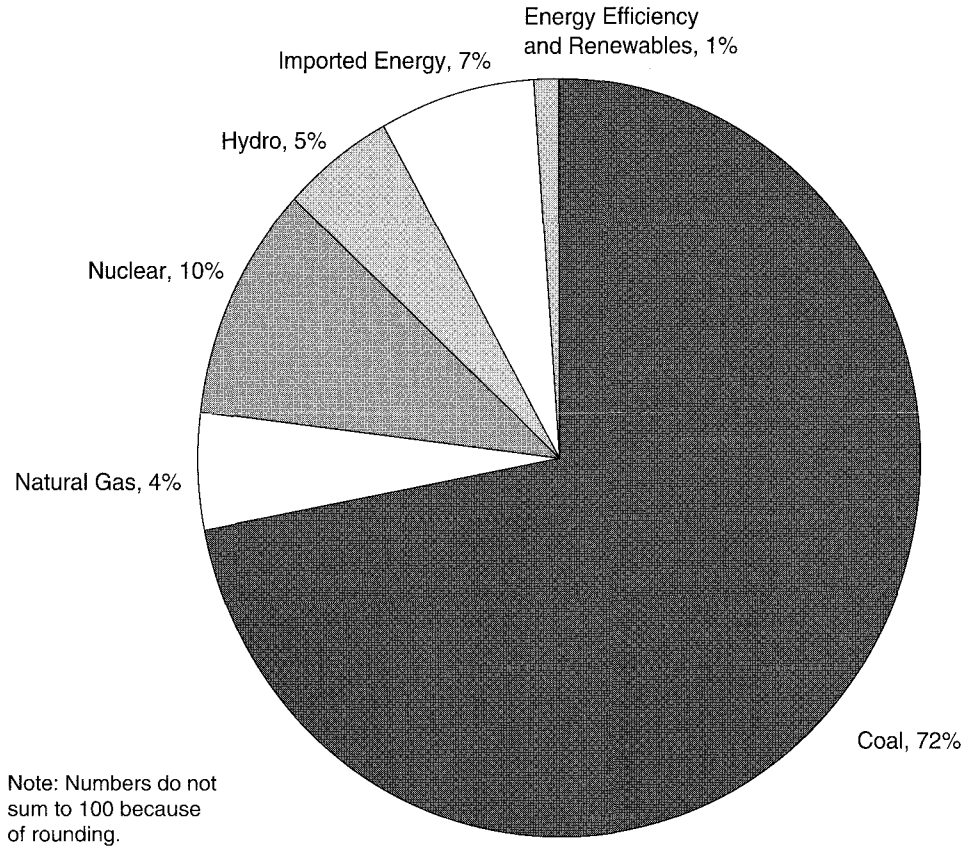
"... the electric industry in the West has become an economic giant."

The energy that surges daily from plants like the Hoover Dam, the Laramie River coal station, and the Palo Verde nuclear units makes it possible for people to inhabit the desert, pump water over the mountains, power factories, and run computers. Without

Table 1-1. The Region's Utilities: A Snapshot, 1994

	Retail Sales Revenues, *billions of dollars*	Price of Electric Power, *cents per kilowatt-hour*	Number of Employees (1993)
Arizona	3.9	8.1	15,000
Colorado	2.1	6.1	12,000
Nevada	1.3	6.4	3,500
New Mexico	1.1	7.2	3,000
Utah	1.0	5.4	4,500
Wyoming	0.5	4.2	1,500
	9.9 (total)	6.6 (ave.)	39,500 (total)

Figure 1-1. Regional Electric Generation Mix in 1995 (percent of total, by resource)



Note: Numbers do not sum to 100 because of rounding.

"... an affordable and reliable source of electricity is central to the region's economy."

electric power, the life we know here simply would not be possible. Indeed, an affordable and reliable source of electricity is central to the region's economy.

Although the electric industry is important for the region's economic health, its heavy reliance on coal, nuclear, and hydro technologies also contributes to many of the region's most serious environmental problems. Visibility degradation, adverse impacts on human health linked to degraded air quality, the risk of global climate change, destruction of free-flowing rivers, and the accumulation of nuclear waste are among the region's most contested environmental problems—all of which can be traced, in some way, back to the electric industry.

This chapter first describes the environmental footprint of the electric industry—its impact on the western landscape. These impacts are what motivated the LAW Fund to undertake this report. The chapter then discusses the environmental threat, and the opportunity for improving environmental quality created by rapid population and economic growth in the region. This discussion concludes that the resource choices made to meet growing electric demands involve difficult value judgments. To provide some insight into these choices, the chapter summarizes the results of an extensive outreach effort to key stakeholders in the region.

The Industry's Environmental Footprint

The electric industry is implicated in a wide range of adverse environmental impacts on air, land, and water. At the same time, the industry can and should play a central role in helping to solve these problems.

Degraded Air Quality

A number of the region's worst environmental problems—impaired regional visibility, urban brown clouds, elevated levels of respiratory illness, and even premature mortality—are rooted in degraded air quality. The electric industry contributes to these problems in varying amounts and, through its future power resource decisions, can take a decisive step toward solving them.

Regional Haze and Brown Clouds

Central to our enjoyment of the outdoors, visibility is vitally important to the quality of life in the region. Visibility is also critical to the power of western vistas to continue to attract tourists and to support tourist-dependent state and local economies.

Most visibility impairment in the West is attributable to the suspension of five substances in the air: sulfates, nitrates, organic compounds, elemental carbon, and road dust.[2] Although the general causes of visibility impairment are well understood, it is often difficult to link visibility impairment at any one place with a particular pollution source. Indeed, a pervasive cause of visibility degradation in the Golden Circle of national parks in Utah, Colorado, and Arizona (including Grand Canyon, Canyonlands, and Mesa Verde) is something known as regional haze.

Regional haze is an atmospheric soup of sulfates, nitrates, and other substances of indeterminate origin. It is a sufficiently significant problem on the Colorado Plateau to have prompted Congress in 1990 to create the Grand Canyon Visibility Transport Commission (GCVTC).[3] The recent work of the GCVTC, as well as the National Research Council of the National Academy of Sciences, has substantially expanded our knowledge of the quality of regional visibility and the causes of regional haze. This work has resulted in a number of conclusions.

First, the region's visibility is the best in the country.[4] However, the superb visibility is possible only when the air is extremely clean and particle concentrations are low. Even small increases in particle concentrations can degrade regional visibility substantially.[5] On the Colorado Plateau, the heart of the region, pollution significantly reduces the natural visibility. As the National Research Council of the National Academy of Sciences observed in 1993, "Many visitors to America's national parks and wilderness areas are unable to enjoy some of the beautiful and dramatic views that would prevail in the absence of air pollution."[6]

A second conclusion is that regional visibility on the Colorado Plateau appears to have improved since 1970, although the pace of improvement has slowed since 1980.[7] Baseline projections of regional visibility made by the GCVTC show some potential for additional improvement if southern California and other areas come into compliance with Clean Air Act requirements. However, by about 2010, economic growth in the region could overwhelm the effect of Clean Air Act compliance, especially if increasing demand for electricity is met by new, conventional coal-fired power plants.[8]

The analysis also shows that sulfates are responsible for about one-third of visibility degradation on the Colorado Plateau.[9] Sulfates form primarily from sulfur dioxide (SO_2) emissions; electric utilities are responsible for about 40 percent of such emissions in this region.[10] Almost all electric utility emissions of SO_2 are attributable to the burning of coal in conventional power plants.[11] Thus, electric utility SO_2 emissions from coal power plants make a significant contribution to regional haze. Because these studies implicate utilities as a principle contributor to regional haze, the utilities must be involved in solving this problem.

Another prime example of visibility problems in the region concerns urban brown clouds. The air over many western cities, including Albuquerque, Denver, Las Vegas,

"Many visitors ... are unable to enjoy some of the beautiful and dramatic views that would prevail in the absence of air pollution."

Phoenix, Salt Lake City, and even some smaller towns, is periodically fouled by what has become commonly known as brown clouds. These clouds are a brew of ozone, particulate matter, and sometimes suspended road sand. Often, motor vehicles are the primary culprit. On occasion, brown clouds may be attributable partly to emissions of particulate precursors—SO_2 and oxides of nitrogen (NO_X)—from utility power plants.[12] These precursors, especially SO_2, are the same substances that contribute to regional haze and, as discussed later, to levels of small particulate matter that appear to harm human health.

Whatever their exact role in contributing to the formation of brown clouds, electric utilities can help to solve the problem. As described in Appendix B, over the long run utilities can profitably play a major role in cleaning up vehicular contributions to small particulate matter by helping to develop cleaner electric or fuel-cell (hydrogen-driven) motor vehicles.

"The ability of several western cities to comply with standards ... in the future is questionable as continued population growth leads to more emissions."

Threats to Human Health

Under the Clean Air Act, the U.S. Environmental Protection Agency (EPA) is required to issue National Ambient Air Quality Standards (NAAQs) for pollutants to protect the public health with an adequate margin of safety. The ability of several western cities to comply with standards for small particulate matter, carbon monoxide, and other pollutants in the future is questionable as continued population growth leads to more emissions of a wide range of pollutants.[13]

More troubling, however, is recent evidence that one of these standards, the 24-hour standard for small particulate matter (particulate matter [PM] with a diameter of 10 microns or less—PM-10), does not adequately protect human health.[14] The adverse health effects attributable to breathing PM are well known and include impairment of lung function and increased mortality rates among individuals with respiratory disorders.[15] Primary components of PM-10 are sulfates and nitrates, both of which are products of fossil fuel combustion in motor vehicles and power plants.

Recent evidence from dozens of studies has found a strong correlation between (1) human respiratory ailments and premature death attributable to them, and (2) levels of PM-10. According to one leading expert, recent studies have

> consistently demonstrated increased death rates, increased hospital admissions for respiratory conditions, increased emergency room admissions for asthma, increased respiratory symptoms, decreases in lung function, and increased medication use among asthmatics associated with increased levels of particulate air pollution. These associations have occurred at levels *below* the current National Ambient Air Quality Standard.[16] [Emphasis in original.]

These studies do not, by themselves, establish a causal relationship between increased illness and premature mortality and PM-10 levels that comply with the federal standards. Instead, they show a repeated, statistically significant correlation between such PM-10 levels and these conditions. However, these studies do establish a strong case that the existing standards may need to be tightened.[17] The American Lung Association has recently estimated that Colorado could save more than $224 million each year in health costs associated with particulate-related illness if the state lowered its particulate pollution levels to meet California standards, which are tougher than federal guidelines.[18]

Contribution to PM-10 levels by type of source varies from city to city. In many western cities, PM-10 is primarily the product of gasoline combustion in motor vehicles. In some places, utility fossil fuel combustion appears to be an important source of PM-10. Whatever their contribution to PM-10 levels, utilities may be able to help solve the problem in the short term by reducing pollutant

emissions and, in the long run, by contributing to the development of electric and hydrogen-driven cars.

The Risk of Global Climate Change

For more than a decade, scientists and policy makers around the world have debated the theory of global climate change attributable to human behavior. The risk of global climate change results from the accumulation of certain gases in the atmosphere that trap solar radiation in a manner suggestive of the way in which glass traps heat in a greenhouse. Thus, this phenomenon is called the greenhouse effect. Carbon dioxide (CO_2) is by far the most important greenhouse gas; CO_2 emissions from combustion of fossil fuel are responsible for roughly 60 percent of the warming attributable to human activities.[19]

Based on a wide range of scientific evidence, the Inter-Governmental Panel on Climate Change (IPCC)—a distinguished group of 2,500 leading atmospheric chemists, physicists, climatologists, and biologists from 60 countries—concluded in 1990, "We are certain ... that emissions from human activities are substantially increasing the atmospheric concentrations of the greenhouse gases. ... These increases will enhance the greenhouse effect, resulting on average in an additional warming of the Earth's surface."[20] The IPCC reaffirmed this finding in 1992[21] and strengthened it in 1995.[22] As a result of the 1995 IPCC report, the *New York Times* reported, "The experts are now more confident than before that global climate change is indeed in progress and that at least some of the warming is due to human action, specifically the burning of coal, oil and wood, which releases carbon dioxide into the atmosphere."[23]

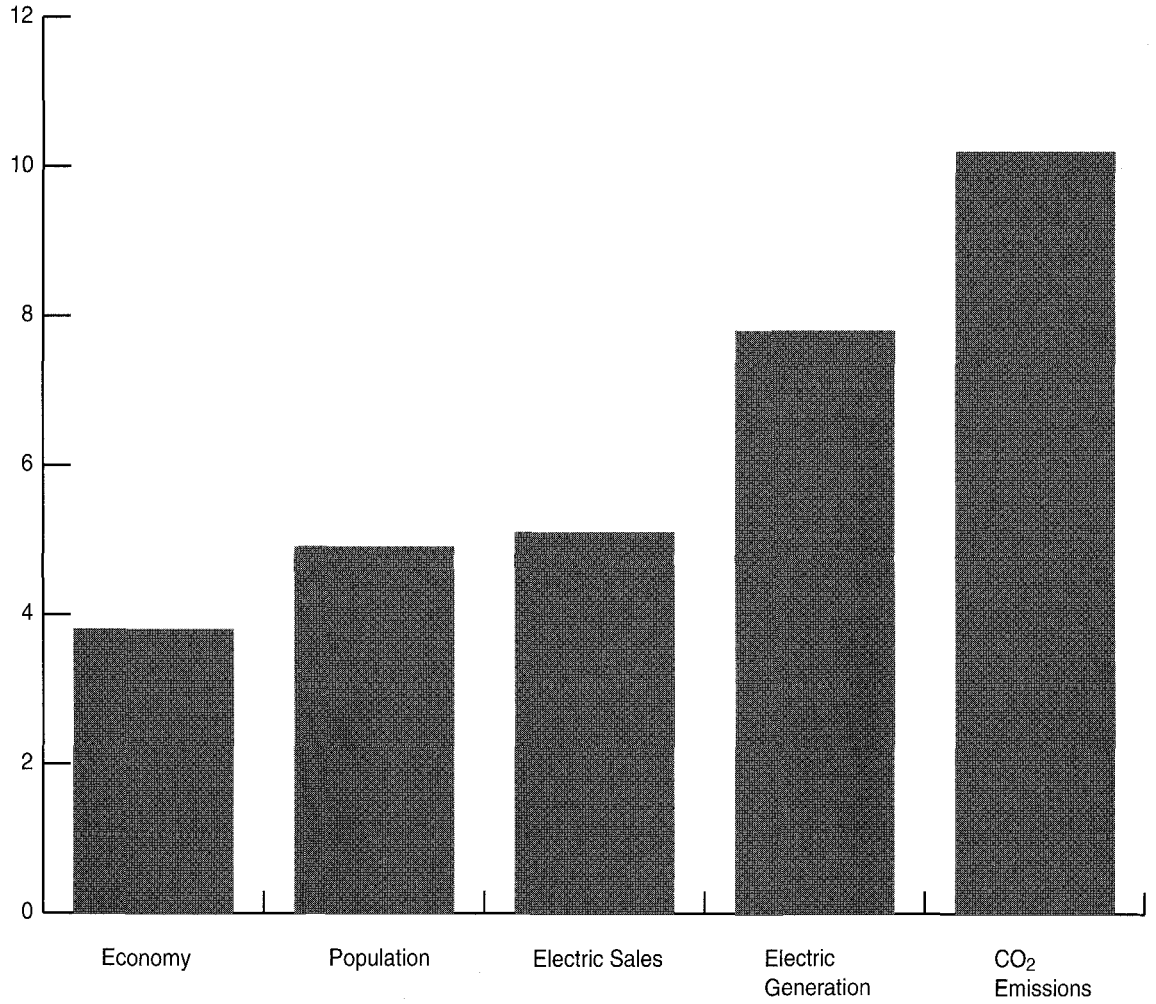
Latest estimates by the IPCC are that, if nothing is done to curtail greenhouse gas emissions, sea-level rises caused by the melting of ice caps could inundate up to 3 percent of the Earth's land area and a larger percentage of its crop area, thereby forcing scores of millions of people to relocate. Other forecasted effects of global climate change include an increase in the frequency and severity of storms, disruption of patterns of agricultural production, reduction of forest lands and biodiversity, collapse of some fisheries, the loss of forests, famine and hunger in developing countries, the spread of tropical diseases into the world's temperate zones, and major changes in the availability of fresh water resources.[24]

Concerned with consequences such as these, 151 nations, including the United States, signed the Climate Convention Treaty in which industrialized countries committed to reducing and stabilizing greenhouse gas emissions at 1990 levels. This treaty has been a catalyst for a worldwide effort to curb emissions. In the United States, President Clinton's Climate Change Action Plan, issued in October 1993, serves as the nation's key global warming initiative.[25] This initiative depends almost wholly on voluntary steps to reduce greenhouse gas emissions, such as investments in energy efficiency, renewable resources, and highly efficient combustion of natural gas. Recent evidence is that these voluntary measures are not working.[26]

The possibility of global climate change creates both risks and opportunities for the Rocky Mountains and the Desert Southwest. Although the region accounts for only 4 percent of the electric load in the United States, it generates about 10 percent of the total carbon dioxide produced through electricity generation because of its extensive reliance on coal-fired generation as Figure 1-2 shows. Indeed, utilities are responsible for about 50 percent of regional carbon dioxide emissions.[27] As a result, if additional taxes or regulatory measures were to be imposed to control carbon dioxide emissions, the economic impact on the region would be disproportionately high.

"The experts are now more confident than before that global climate change is indeed in progress and that at least some of the warming is due to human action ..."

Figure 1-2. Rocky Mountain Region as Percentage of United States



On the other hand, this region stands poised to benefit economically as a leading exporter of renewable technologies and expertise. International efforts to address global climate change are creating a worldwide market for renewable resources and other alternatives to conventional fossil fuel-based generation. The electric industry in the Rocky Mountains and the Desert Southwest should be at the center of this nation's efforts to reduce its contribution to the problem. If the electric industry in this region will seize this opportunity, it can do well by doing good.

Threats to Land and Water

The electric industry has other significant impacts on the environment, particularly in regard to adverse impacts on land and water quality. For example, acid rain and snow, in which utility emissions of SO_2 and NO_X attributable to coal burning are implicated, is one such problem. The most highly acidified snow west of the Mississippi River has been found at higher elevations of the Rocky Mountains, especially at the Mount Zirkel Wilderness Area in north central Colorado, which is downwind from two coal-fired power plants.[28]

With regard to land impacts, the predominant share of coal used by utilities in this region, as well as that exported for use elsewhere, is strip-mined. Strip-mining for coal is regulated under the Surface Mining Control and Reclamation Act of 1977

Air Quality Problems:

The Role Of Power Plant Emissions

Sulfates, nitrates, and carbon dioxide play a prominent role in triggering, to a greater or lesser extent, impaired regional visibility, brown clouds, and the threat of global climate change. Table 1-2 shows the contributions of electric utilities to emissions of these three pollutants in each of the six states. This table shows that there can be no question that electric utility power plant combustion of coal is responsible for a major proportion of these air emissions.

(SMCRA). It is still not clear whether this legislation prevents lasting damage to land and water resources in the West.[29] Studies have shown that exploration and drilling for natural gas have had adverse impacts on land, water, and wildlife adjacent to national parks[30] and wetlands.[31] In addition, drilling for coalbed methane, a nonconventional source of natural gas, may be harming groundwater quality in New Mexico and western Colorado.[32]

The generation of electricity from hydroelectric plants is associated with additional impacts on water resources. In particular, dams destroy natural river conditions, threatening extinction of native fish species. Indeed, in part because of the 12 dams that interrupt its flows, virtually the entire Colorado River has been designated as critical habitat for endangered or threatened fish under the Endangered Species Act.[33]

Finally, nuclear waste from the region's one nuclear power plant—the Palo Verde station outside of Phoenix, the largest nuclear power plant in the nation—creates waste disposal problems that are aggravated by the possibility that waste from outside the region will be deposited here. Considerable controversy surrounds the siting of nuclear waste storage facilities because such waste is extremely toxic and retains its toxicity for thousands of years.

Environmental Problems and Regional Growth

Over time, the impact of the electric industry on the region's environment and quality of life could potentially get significantly worse as a result of extremely rapid growth. Indeed, during the 1990s, five of the seven fastest-growing states in the nation in terms of population were in the six-state Rocky Mountain and Desert Southwest region described in this report. All told, this region's population grew more than that of Texas, California, or Florida.

Both population and economic growth are expected to continue to be robust over the next two decades. Most of this growth will be concentrated in the large urban areas of Albuquerque, Denver, Las Vegas, Phoenix, and Salt Lake City. Additional growth is expected to occur in tourist and recreational areas, for example, adjacent to mountain ski areas and in areas near the Grand Canyon, Rocky Mountain, and Yellowstone national parks. Utility resource planning documents show that by 2015 the region will need over 15,000 megawatts of new capacity—enough to power six cities the size of the Denver metropolitan area. Overall, utilities expect that over $15 billion will be required to meet this demand.

"By 2015 the region will need over 15,000 megawatts of new capacity—enough to power six cities the size of the Denver metropolitan area."

The Impacts of Growth

This growth clearly has the potential to exacerbate air quality and other environmental problems to which the electric industry contributes or that it can help solve. In the short run, the utilization of existing power plants is likely to increase somewhat, further increasing SO_2, CO_2, and NO_X emissions. Over time, most utilities will need to build or buy power from new power plants, which could significantly increase air pollutant

emissions and adverse land and water impacts. Indeed, most utilities currently expect to rely primarily on traditional supply-side resources such as coal and natural gas to meet growing demands.

Despite this threat, however, growth also creates opportunities to promote a cleaner energy future. Expanding resource needs afford electric utilities the chance to integrate cleaner resources into the region's resource mix. In addition, growth increases utility revenues, which can be used to offset the costs of cleaning up existing utility power plants. The net effect of growth on the electric industry's impact on the environment will depend in large part on the types of resources that are selected to meet expanding electricity demands.

Resource Alternatives

Utilities currently have a choice among a wide range of technologies to meet growing demands. Although each of these technologies has different environmental and economic impacts, they can generally be divided into two groups: conventional sources and emerging clean energy technologies. Coal, natural gas, large hydroelectric, and nuclear power plants fall within the former category. Energy efficiency and renewable resources (e.g., windpower, geothermal, solar, biomass, and municipal solid waste) as well as fuel cells, storage, and fusion fall within the latter. This section briefly describes the environmental and economic characteristics of the major resource types available to the industry. These descriptions are based on far more detailed explanations found in Appendices C and D.

Conventional Sources

The combustion of *coal* is a well-known and reliable technology for generating electricity. Although the capital costs of coal power plants are high relative to those associated

Table 1-2. Estimated Emissions from Electric Utilities in the West, 1990

State	Pollutant	Total Regional Emissions,[a] *thousands of tons/year*	Total Emissions from Electric Utilities,[b] *thousands of tons/year*	Utility Emissions from Coal-fired Units,[b] *thousands of tons/year*	Percent of Regional Emissions from Electric Utilities	Percent of Utility Emissions from Coal Units
Arizona	SO_2	203	123	123	61	100
	NO_x	351	66	66	19	100
	CO_2	69,789	34,980	33,435	50	96
Colorado	SO_2	109	80	80	74	100
	NO_x	304	85	84	28	99
	CO_2	73,060	31,948	31,611	44	99
Nevada	SO_2	57	48	47	85	98
	NO_x	112	45	40	40	89
	CO_2	34,235	15,084	13,374	44	89
New Mexico	SO_2	176	58	58	33	100
	NO_x	257	61	58	24	95
	CO_2	59,913	29,420	27,862	49	95
Utah	SO_2	103	31	31	30	100
	NO_x	191	77	77	40	100
	CO_2	59,790	31,708	31,611	53	100
Wyoming	SO_2	140	82	82	59	100
	NO_x	226	85	85	38	100
	CO_2	62,175	35,655	35,461	57	99
Total	SO_2	789	424	423	54	100
	NO_x	1,440	420	411	29	98
	CO_2	358,963	178,796	173,354	50	97

Notes: a. From Radian for SO_2 and NO_x. From EIA ("State Energy Data Report" and "Annual Outlook") for CO_2. b. Derived for SO_2 and NO_x (based on gross figures in Radian data and percentages from "Electric Power Annual").

with other power generation technologies such as natural gas, the coal fuel itself is inexpensive. Coal burned conventionally is relatively dirty and, as discussed previously, accounts for a large share of utility pollutant emissions. Although there are promising "clean coal" technologies that reduce the adverse environmental impacts associated with coal burning, these technologies are still relatively expensive and may still cause significant environmental problems.

Natural gas burns more cleanly than coal, emitting virtually no SO_2 and less NO_X. New combustion technologies permit the extraction of a much larger fraction of the heat energy in natural gas than even 10 years ago. And natural gas, for the time being, is inexpensive. However, the risk of fuel price escalation in natural gas over time is substantial. In addition, natural gas burning still creates about 50 percent as much CO_2 as coal burning, and natural gas exploration and drilling can harm sensitive areas.

Hydroelectricity from large existing dams is inexpensive and has some environmental advantages. Because of site and environmental limitations, however, there is no significant potential for new, large conventional hydro dams in the region.

Utility experience with *nuclear power* in this region has been extremely negative. These plants have been expensive; operational safety and waste disposal problems remain unresolved; and there will be significant decommissioning expenses at the ends of these plants' useful lives. However, the nuclear industry is working on new power plant designs that are less costly.

Clean Energy Technologies

Energy efficiency refers to increases in the "work" that a given amount of electricity can perform in, say, heating a house, running an electric motor, or lighting a building. There exists an enormous and untapped resource of inexpensive investments to promote energy efficiency in houses, commercial buildings, and factories in the region. This resource, which is environmentally benign and inexpensive, can postpone the need for large amounts of new generating capacity. The problem with energy efficiency is that the associated sales and revenue reductions can cause financial problems for utilities under current regulation and can put upward pressure on short-term electric rates.

There are four types of nonhydroelectric *renewable* electricity-generating technologies: wind power, geothermal power, solar power, and biomass combustion. In general, while these resources tend to be somewhat more expensive than their conventional counterparts, they have significant environmental and risk diversification benefits.

Electricity from *wind* is the cheapest of the renewable sources. Over time, the cost of energy from wind at the best sites compares favorably with energy from natural gas-fired power plants. However, because wind is an intermittent resource—when the wind does not blow, no energy is generated—it is less reliable than fossil-fuel technologies. And wind is not without its environmental problems, in particular, the potential for raptor kills. It is expected that this problem will be resolved either through design alterations or by siting wind turbines where the potential for bird kills is minimal.

"Electricity from wind is the cheapest of the renewable sources."

The extraction of the heat of the earth for purposes of generating electricity is a well-developed technology. Because *geothermal* energy is a highly reliable, baseload electric resource with relatively high capital costs and very low "fuel" and operating costs, it is similar to coal, although much less polluting and somewhat more expensive, depending on site-specific factors. However, geothermal resources are sometimes found in areas that are environmentally sensitive or unique.

The Rocky Mountain and Desert Southwest region possesses an enormous *solar* power resource. The production of electricity from the sun is nearly environmentally

benign. Although the cost of solar technologies has fallen steadily in the last 20 years, it is still considerably more than that for energy from natural gas, coal, geothermal, or wind power. In addition, when the sun is not shining, no electricity is available unless there is storage capacity, which increases the cost of solar power generation. However, solar technologies are still maturing, and there is great potential for technological advances to bring the costs down.

The combustion of *biomass* (i.e., plant and animal materials) is another well-developed electric generation technology. Since the region is arid, it does not possess a large, naturally occurring resource of biomass. And although the combustion of *municipal solid waste* (MSW) to generate electricity is also a well-developed technology, unresolved environmental issues make siting of MSW facilities difficult near urban areas where waste disposal fees might be high enough to make such facilities economical.

"The Rocky Mountain and Desert Southwest region possesses an enormous solar power resource."

Fuel cells "burn" hydrogen gas, producing only water, to generate electricity. Fuel cells are an ideal source of generation capacity in urban areas, such as for motor vehicles, because they are pollution-free. The problem is cost: fuel cell and hydrogen fuel capital costs are high compared with fossil fuel capacity. A variety of storage technologies—such as batteries, compressed air, and pumped storage hydro—also exist. These options may become particularly relevant in providing back-up power during periods when the sun does not shine or the wind does not blow. Other technologies such as *fusion* require major technological breakthroughs before they can be used to generate electricity commercially.

Value Trade-offs

The choice among these technologies depends on how core concerns—such as those involving environmental quality and economic well-being—are balanced. Conventional technologies tend to produce cheaper energy but are subject to fuel price volatility and environmental risks. Cleaner technologies generally are more expensive in the short term but are superior from an environmental perspective and help diversify long-term risks.

To help guide the LAW Fund's analysis and to develop a blueprint for the electric industry, the LAW Fund consulted with a broad spectrum of stakeholders about what values they considered important and how they would resolve situations in which core values come into conflict. The following section discusses the views of these stakeholders.

Drafting the Blueprint

In 1993 and 1994, the LAW Fund held a series of 15 meetings in its six-state region to hear from a broad cross section of interests regarding a vision for the electric industry's future. The purpose was to obtain advice from regional stakeholders in the industry regarding the content of the vision. The LAW Fund also conducted polling and survey work to assess the attitudes of the general public.

Outreach to Environmentalists

The LAW Fund met with environmentalists and others who share the LAW Fund's core concern of environmental protection. Meetings were held in Arizona (Flagstaff, Tucson); Colorado (Boulder); Nevada (Las Vegas, Reno); New Mexico (Santa Fe); Utah (Salt Lake City); and Wyoming (Lander). It was evident from these meetings that there is a strong and widespread concern about the electric industry's environmental impacts.

The most common concern expressed by environmentalists was the effect of utility coal combustion on local and regional visibility, human health, and global climate change. Indeed, many of the region's environmentalists were opposed strongly to new coal power plants and, in some cases, to the

continued operation of the dirtiest existing plants. Moreover, environmentalists shared a common view that the federal government has shown a bias toward the development of certain energy technologies by subsidizing coal, nuclear power, and hydroelectric facilities to a much greater degree than renewable resources. As a result, environmentalists tend to believe that the federal government's policies have penalized the development of cleaner, renewable resources.

Although environmentalists expressed a nearly universal concern about the electric industry's role in creating environmental problems, many shared a positive vision for the industry. First, many understood the potential of the industry to improve the environment by its resource decisions, especially if action is taken before large new power plants are needed. Second, most were aware that the jobs provided by the industry are important and that any initiatives to reform the industry must account for economic impacts. Third, some believed that electric utilities could help ameliorate pollution caused by other sectors, particularly transportation.

For environmentalists in the region, energy efficiency and solar power are the linchpins of a strategy to improve the impact of the industry on the environment. There was a strong appreciation that solar-generated electricity remains expensive relative to conventional fossil fuels such as coal and natural gas. However, many believed that the economic comparison of the costs of these resources is unfair because it fails to account for the environmental impacts of conventional resources.

Outreach to Other Stakeholders

In the fall of 1993 and winter of 1994, the LAW Fund held another series of meetings, one in each of the six states, with a much broader range of people interested in the future path of the electric industry. Senior utility managers; public utility commissioners and their advisory staffs; consumer advocates; coal, gas, renewable, and efficiency industry representatives; low-income advocates; governors' offices; state legislators; Native Americans; federal agencies and laboratories; environmentalists; and others were invited.[34] The meetings were well attended and capably facilitated by the Keystone Center of Colorado. Most important, they provoked a vigorous discussion of the contents of a vision for the industry. Because all perspectives were sought and heard, the debate was intense and vital and provided a broad record of the sentiments of many key players about the electric industry and its direction in this region.

Objectives of the Blueprint

For the LAW Fund, the most valuable feature of the broader outreach was the focus on what the objectives of an industry blueprint should be. The LAW Fund began with a focus on environmental protection and enhancement. No one disagreed that the environment is a legitimate objective of this report. But most warned us that other objectives, especially economic ones, were relevant. As a result of these six meetings, the LAW Fund adopted five core objectives that virtually all meeting participants agreed were important:

- *Environmental quality*. A number of environmental impacts result from the generation and consumption of electricity. A blueprint for the industry must show how these impacts will be addressed and ameliorated.
- *Economic opportunity.* An affordable and reliable supply of electric energy services is vital to a healthy economy and quality of life in this region. Utility customers want their bills to be reasonable and they want reliable electric service. A blueprint for the industry must show how the industry can contribute to a healthy economy and quality of life.
- *Equity.* In the context of the electric industry, equity includes fairness between today's and tomorrow's residents, among

"Energy efficiency and solar power are the linchpins of a strategy to improve the impact of the industry on the environment."

utility customer classes, between utility customers and shareholders, among competing resources, and between those who reside in energy-producing regions and those energy users who live elsewhere. A blueprint for the industry must ensure that equity is enhanced, in part, by ensuring access to important resource decisions to all affected persons.

- *Risk management.* Today's resource decisions must be made with a view toward managing the risks associated with an uncertain future, such as fuel price increases and changing environmental requirements. A blueprint for the industry must show how risks can be managed acceptably.
- *Sustainability.* Today's electric industry is not sustainable. However, time remains to make the transition to a sustainable industry. A blueprint for the industry must include recommendations for how the industry can move toward sustainability while still meeting the other goals.

The blueprint is premised upon the LAW Fund's belief that the electric industry can meet all of these objectives simultaneously in this region over time, in part through reliance on the region's abundant solar resources. However, in the short term, these objectives may clash. For example, environmental objectives might be achieved rapidly by massive, near-term substitution of zero-emission renewable and energy efficiency resources for conventional resources. However, adopting such an approach would be inconsistent with the economic objective in light of the approach's high cost in the short term relative to partial continued reliance on fossil fuels. Understanding the potential for the goals to clash in the short term, many meeting participants urged that the goals be pursued in balance with each other, rather than in isolation. It is the LAW Fund's contention that implementation of the blueprint contained in Chapter 2 strikes such a balance.

What is Sustainability?

Inherent in the concept of sustainability is the notion of preserving options for later generations. A widely used definition of *sustainable development* is "development that meets the needs of the present without compromising the ability of future generations to meet their needs."[35] The ethical notion that those of us who live today should consider the potential for adverse consequences attributable to our use of natural resources for those who follow us is a fundamentally novel idea. In the past, humankind saw little need to consider whether our cumulative use of resources and their environmental impacts might circumscribe options for later generations. However, the press of world population growth, together with our much greater per capita claim on the earth's resources, seems to many to make such consideration appropriate. The LAW Fund embraces the principle of maintaining options for those who follow as an important criterion for developing recommendations to move the industry toward sustainability.

Diverse Visions

Not all of the discussion at the outreach meetings was about goals. Much was about substantive visions for the industry, which were very diverse. The following are some examples of visions that were advanced:

- "Carbon-free in 2033."
- "Put utility customers on a coal-only diet for the next 50 years, and tax the kilowatt-hours sold to raise a huge fund to subsidize renewable resources."
- "Wean utilities from reliance on coal as a solid fuel now and move rapidly to a gaseous fuel-based economy."
- "Be totally dependent on renewable resources within 30 years."
- "Use fossil fuels for at least 200 years—after that we can rely on renewable resources."

The differences in vision for the electric industry in the region stem, first, from the fact that people place different relative weights on the objectives. In addition, the differences exist because of the dearth of hard information regarding the economic and

environmental impacts of the major utility resources—namely, coal, gas, efficiency, and renewable resources. Differences also arose because of uncertainty about what the future will bring. For example, participants held varying opinions about the probability of global climate change and whether the industry should take concrete actions now to respond to this threat. The lack of reliable information agreed upon by all participants left the door open for ideology to influence the discussion.

Stakeholder Advice

Even though ideology sometimes dominated the discussions, the LAW Fund was heartened by the amount of hard, value-neutral advice that meeting participants offered about how to develop a blueprint to meet the five goals. Key suggestions are summarized below, encapsulating ideas that were nearly unanimously supported even if they are not altogether internally inconsistent:

- Do not exclude any resources from potentially helping to meet the blueprint's goals.
- Focus on a process by which all resources can compete equally and fairly to meet the goals.
- Be flexible because no one knows what the future will bring. Since we don't know all the facts yet, don't narrow the choices.
- Build on and keep reminding stakeholders of the overarching goals and objectives that they can all agree upon.
- A blueprint that discusses only goals without suggesting the investments and changes in regulation to meet those goals in both the short and long run is worthless. The plan risks being unachievable if it refrains from advising specific actions on individual resources. At the same time, be cautious and incremental in your advice.
- A proposal that does not make hard choices is not worth considering. The LAW Fund cannot be all things to all people: Take a stand!
- There is no substitute for a focused comparison of the environmental and economic impacts of the principal resources the industry can use to meet the need for energy services in the future. Avoid ideology in this analysis.
- The blueprint must examine the impact of possible regulatory and other changes in the electric industry on the attainment of the stated goals. In particular, the impact of competition on the industry and its regulation must be scrutinized.
- Each state in the region is different in terms of the problems its utilities face, the regulatory culture, the available resources, and the surrounding politics, among others. Allow for these differences in your recommendations.
- The blueprint should describe what links the region together so that, in each of the states, stakeholders can take advantage of the regional opportunities.

The LAW Fund has endeavored to follow this advice throughout this report.

Polling and Survey Data

In addition to the outreach meetings, the Pew Charitable Trusts also sponsored survey and polling research in the region. This research showed how strongly the public cares about environmental quality. Two-thirds of the people surveyed were willing to pay more on their electric bills for electricity from sources that are less harmful to the environment.[36]

Subsequent Events: A Changing Industry

Soon after the completion of the outreach effort, the context for this report changed dramatically. In April 1994, the California Public Utilities Commission proposed new regulations that would have provided retail customers with direct access to bulk power markets on an accelerated two-year time frame, a proposal that would undo an industry structure that has persisted for well over 50 years.[37] In the wake of this proposal, a national dialogue has been initiated about the different possible futures for the electric industry. Our ideas about how to promote an environmentally and economically sustainable energy future in a more market-oriented, competitive industry are presented in Chapter 3.

"The LAW Fund was heartened by the amount of hard, value-neutral advice that meeting participants offered. ..."

Conclusion

The long-term challenge facing the Rocky Mountain and Desert Southwest region—the real frontier that exists today—is how to live here sustainably. This challenge is twofold in the midst of accelerated population growth in the region: to protect the natural environment and at the same time to bolster recent trends toward a more diverse and stable economy. At stake is the region's quality of life for current and future generations. The remainder of this report is dedicated to the view that the electric industry can serve as a model for how the region can reconcile the competing economic and environmental tensions surrounding growth, maintaining a place where there exists, in novelist Wallace Stegner's words, "a society to match the scenery."

"At stake is the region's quality of life for current and future generations."

Notes

1. See generally Robertson, L., "The Birth and Growth of Electricity in Colorado," IEEE Power Engineering Review, Vol. II, No. 1, Jan. 1982, pp. 3–4; More specifically, the Ames Power Plant provided the world's first long-distance transmission of AC electric power for commercial purposes.

2. Scientists know that sulfates and nitrates are formed in the atmosphere from invisible gaseous precursors, such as sulfur dioxide (SO2) and oxides of nitrogen (NOX), which are by-products of fossil fuel combustion.

3. The commission was established to develop recommendations to the Environmental Protection Agency (EPA) administrator regarding what, if any, actions should be taken to remedy adverse impacts on the Grand Canyon National Park (and, as further specified by EPA, parks in Arizona, Colorado, Utah, and New Mexico) attributable to emissions in an eight-state region (Arizona, California, Idaho, Nevada, New Mexico, Oregon, and Wyoming). The commission's report is now due in May 1996. Among the many options under consideration are setting visibility standards under the Clean Air Act for the Colorado Plateau, a regional cap limiting total pollutant emissions in the region, additional restrictions on emissions in certain "clean air" corridors where good visibility is deemed particularly important, and new control technology requirements.

4. See "Protecting Visibility in National Parks and Wilderness Areas," Committee on Haze in National Parks and Wilderness Areas, Board on Environmental Studies and Toxicology, Commission on Geosciences, Environment and Resources, National Research Council, p. 30.

5. "Protecting Visibility," p. 19.

6. "Protecting Visibility," p. 1.

7. Houghton, Filho, Callender, Bruce, Lee, Haites, Harris, Maskell (eds.), Climate Change: The Second IPCC Assessment, 1996, Cambridge University Press, Cambridge, U.K.

8. "Options for Improving Western Vistas," Draft Contractor's Report, Grand Canyon Visibility Trust Commission, November 4, 1995, Vol. I, Overview, pp. I-8 to I-11.

9. "Options for Improving Western Vistas," Vol. III, Figure III-4, p. III-7.

10. "An Emissions Inventory for Assessing Regional Haze on the Colorado Plateau," Prepared for Emissions Subcommittee, Grand Canyon Visibility Transport Commission, January 23, 1995, Table S-4, p. S-9.

11. See Table 1-2.

12. In Denver, for example, Public Service Company in 1993 was responsible for 73 percent of all emissions of sulfur dioxide, a precursor to sulfates (Michael Silverstein, testimony on behalf of the Land and Water Fund in Docket No. 93I-098E, Colorado Public Utilities Commission, Denver, CO, March 4, 1994, p. 8).

13. The electric utility industry also faces possible regulation of some hazardous air pollutants (HAPs). See the coal section of Appendix C for an explanation of this issue.

14. Particulate matter refers to a broad category of naturally occurring and human-caused particles that are suspended in the air.

15. See testimony of Karen Shapiro for the LAW Fund in Docket No. 91M-642EG, Colorado Public Utilities Commission, Denver CO, 1993.

16. Testimony of Karen Shapiro, p. 7.

17. To force reconsideration of the existing PM-10 standards, the American Lung Association obtained a court order to compel the EPA to complete a review by January 1997 of whether the existing PM-10 standards protect public health.

18. "Particulates in the Air Prove Costly," *The Denver Post*, Wednesday, June 28, 1995.

19. Direct testimony of Gordon MacDonald, Research Director for Environmental Studies, Institute on Global Conflict and Cooperation, University of California, San Diego, for the LAW Fund in Docket No. 91M-642 EG, Colorado Public Utilities Commission, Denver, CO, 1992.

20. The IPCC Scientific Assessment, Cambridge, England: Cambridge University Press, 1990.

21. Climate Change 1992: The Supplemental Report to the IPCC Scientific Assessment, J.T. Houghton, B.A. Callander, and S.K. Varney (eds.), 1992.

22. Climate Change: The Second IPCC Assessment, 1996.

23. "Scientists Say Earth's Warming Could Set Off Wide Disruptions," William K. Stevens, New York Times, September 18, 1995.

24. See "Report of IPCC Working Group II—Analysis of Impacts, Adaptation, and Mitigation," October 20, 1995, and papers issued by U.S. Climate Change Action Network, November 1995. Not all changes are likely to be adverse. For example, some regions of the world may see gains in agricultural production.

25. At the 1992 Rio Earth Summit, the United States pledged to reduce greenhouse gas emissions to 1990 levels by the end of the decade. However, Undersecretary of State Tim Wirth recently announced that there will be about a 30-million-ton "shortfall" in the 100-million-ton reduction needed for the United States to meet the nonbinding treaty. As a result, the United States will fall about 30 percent short of its goal to reduce CO2 and other gases to combat global warming. *USA Today,* March 14, 1995.

26. See "With Energy Tug of War, U.S. Is Missing it Goals," William K. Stevens, *New York Times,* November 28, 1995.

27. Energy Information Administration, "State Energy Data Report" and "Annual Energy Outlook," 1990.

28. Letter from Elizabeth Estill, Regional Forester, to Governor Roy Romer, formally certifying impairment of visibility and aquatic ecosystems in the Mount Zirkel Wilderness Area, July 14, 1993, p. 28.

29. Questions remain regarding whether certain states are adequately implementing SMCRA, whether arid lands that have been strip-mined can be revegetated on a sustainable basis, and whether strip-mining may damage aquifers. See, for example, Cumulative Hydrological Impacts of Surface Mining in the Eastern Powder River Structural Basin, Northeastern Wyoming, U.S. Geological Survey, 1988.

30. Sources and Migration Pathways of Natural Gas in Near-Surface Ground Water Beneath the Animas River Valley, Colorado and New Mexico, U.S. Geological Survey, Report 94-4006, Executive Summary, 1994, p. 1.

31. Natural Gas 1992: Issues and Trends, U.S. Energy Information Administration, March 1993, p. 29.

32. See testimony of Kathleen C. Zimmerman before the Colorado Public Utilities Commission, Docket No. 93A-564E, p.14 (referring to the adverse impacts of coal-bed methane).

33. Larry MacDonnell and Bruce Driver, "Thinking the Unthinkable: Modernizing the Law of the Colorado River and Other Basin Institutions," Draft, November 30, 1995, p. 7.

34. A list of the participants in these meetings is included in Appendix A.

35. *Our Common Future,* World Commission on Environment and Development, New York: Oxford University Press, 1987, pp. 4, 8.

36. "Attitudes Toward Energy Efficiency, the Environment, and the Electric Utility Industry in a Changing Regulatory Climate," prepared for the Land and Water Fund of the Rockies in conjunction with Ogilvy Adams and Rinehart by Cambridge Reports/Research International, March 1995.

37. California Public Utilities Commission Decision No. 96-01-009, Docket Nos. R. 94-04-031 and I. 94-04-032, December 20, 1995.

The Blueprint

Two

"If we don't change direction we're likely to end up where we're headed."
—Lao-Tse

The LAW Fund's blueprint describes an electric power industry able to meet the region's growing demand for electricity in a way that protects the environment, creates economic opportunity, and enhances our quality of life. At its heart is a 20-year resource plan that integrates energy efficiency, new clean-burning natural gas technologies, and, as they become cost-competitive, increasing amounts of renewable energy and clean coal technologies into the region's electric resource base. The first section of this chapter presents the blueprint's resource plan and compares it with an alternative strategy that relies primarily on conventional fossil fuel-fired resources. The second section shows that, relative to a fossil-fuel-based plan, the LAW Fund proposal strikes a much better balance among the five core values important to the region—environmental protection, economic opportunity, risk management, equity, and long-term sustainability. The third section describes in more detail how the LAW Fund evaluated each of the individual resources that make up the blueprint. The final section speculates on what the region's electric power industry might look like by 2035 if the LAW Fund's blueprint is adopted.

Understanding the Blueprint

As described in Chapter 1 and explained in more detail in Appendix B, over the next 20 years, the region is expected to need over 15,000 megawatts of new capacity to meet increasing electricity demands caused by rapid population and economic growth.[1] To put this figure in perspective, this is enough capacity to power six cities the size of Denver, Colorado.

The need to invest in these new resources presents a tremendous opportunity to ensure that cleaner power technologies will be integrated into the regional electric resource base. At the same time, the danger exists that this opportunity will slip away, and that instead of embarking on the path to a sustainable energy future, the region will adopt a business-as-usual approach that relies on another round of relatively dirty fossil fuel-burning power plants to meet its electricity needs.

"... over the next 20 years, the region is expected to need ... enough capacity to power six cities the size of Denver, Colorado."

A review of utility resource plans reveals that the business-as-usual approach is, by and large, the strategy of choice for the majority of the region's electric utilities. Table 2-1 summarizes utility resource plans over the next 20 years and shows that utilities are currently planning to meet 90 percent of the region's future capacity needs with fossil fuel-fired power plants. In contrast, utility investments in energy efficiency make up less than 10 percent of planned resource additions, and even these investments are increasingly under attack (as described in Chapter 3). Investments in renewable energy are almost nonexistent.

Under the fossil fuel-based strategy favored by the region's utilities, the break-

Table 2-1. Currently Planned Resource Additions by Rocky Mountain and Desert Southwest Utilities, 1996–2015 (megawatts)

	Fossil Fuel	Renewable Energy	Energy Efficiency	Total
Major investor-owned utilities[a]				
Arizona	3,000	60	300[b]	3,360
Colorado	2,600	20	250[b]	2,870
New Mexico	100	0	10	110
Nevada	3,700	20	0	3,720
Utah	700	10	300	1,010
Wyoming	0	5	100	105
Investor-owned total	10,100	115	960	11,175
Estimated additions by publicly owned utilities	4,000	60	400	4,460
Total	14,100	175	1,360	15,635
Percentage of total	90	1	9	100

Notes: a. The data for the investor-owned utilities are from utility integrated resource plans (IRPs). See Arizona Public Service, 1993 IRP; Tucson Electric Power, 1992 IRP; Public Service Company of Colorado, 1993 IRP and 1995 IRP Annual Progress Report; Nevada Power Company, 1994 IRP; PacifiCorp, Resource and Market Planning Program, RAMPP-4, 1995. b. These energy efficiency investments are increasingly under attack.

down of total capacity additions between coal-burning and natural gas-burning power plants will depend largely on the evolution of fossil fuel prices over time. For example, in their 1993 integrated resource plans (IRPs), the region's utilities forecast the need for over 3,000 megawatts of new coal-fired power plants. By 1995, however, falling natural gas prices had shifted much of this new capacity to natural gas-burning power plants.

Although uncertainties surrounding the evolution of future fossil fuel prices make it impossible to predict the exact percentage of capacity additions that would be coal or gas fired under a business-as-usual approach, several factors suggest that in the near to medium term—roughly the next 5 to 10 years—nearly all capacity additions would be natural gas-burning. These factors (discussed in more detail in Appendix B) include expectations of relatively low natural gas prices over this period, the region's primary need for new intermediate and peaking power, and the region's current excess supply of coal-fired baseload capacity.

After 2005, because of expected increases in natural gas prices and the fact that growing electricity demands will have absorbed the region's excess coal-fired capacity, it is likely that in a business-as-usual approach conventional coal-fired power plants would once again begin to be built in the region. Between 2005 and 2010, nearly half of the new fossil fuel-fired capacity added under a business-as-usual approach is apt to be coal fired. After 2010, because of expected further increases in the price of natural gas, coal-fired power plants are likely to make up the majority of capacity additions.

Overall, we believe that if a business-as-usual approach is adopted, almost 8,500 megawatts of natural gas-fired capacity and roughly 5,500 megawatts of conventional coal-fired capacity would be added to the regional resource base over the next 20 years. In five-year increments, Table 2-2 illustrates how future resource needs are likely to be

met in a business-as-usual approach; this table serves as a benchmark for comparison to the blueprint.

The LAW Fund's blueprint is an alternative to the business-as-usual approach. It includes the following proposals:

- significant investments in energy efficiency programs to meet up to 40 percent of the region's new resource need
- small initial investments in wind, solar, and geothermal renewable resources to drive down their costs, followed by larger acquisitions (as these resources become cost-effective) to meet a growing portion of regional electricity demands
- construction of highly efficient combined-cycle natural gas-fired power plants to take advantage of today's low gas prices
- retention and life extension of most existing power plants, with the oldest and dirtiest units repowered with cleaner fuels, scrubbed to remove sulfur dioxide (SO_2), or retired when they turn 40 years old

Table 2-2. The Business-As-Usual Resource Acquisition Schedule

	Capacity Additions in Five-Year Increments, *megawatts*				
	1996–2000	2001–2005	2006–2010	2011–2015	Total by Resource
Conventional coal	0	(135)[a]	2,000	3,600	5,465
Natural gas	2,150	2,210	2,575	1,550	8,485
Energy efficiency	225	200	450	500	1,375
Renewable energy resources	25	50	50	50	175
Clean coal	100[b]	0	0	0	100
Net capacity additions	2,500	2,325	5,075	5,700	15,600

Note: a. Represents Public Service Company of Colorado's planned natural gas repowering of units 1-3 of the Arapahoe power plant in Denver, Colorado. b. Represents the Piñon Pine clean coal power project near Reno, Nevada, scheduled to begin operating in 1998.

Table 2-3. Resource Acquisitions Proposed as Part of the Blueprint

	Capacity Additions in Five-Year Increments, *megawatts*				
	1996–2000	2001–2005	2006–2010	2011–2015	Total by Resource
Conventional coal[a]	0	(235)	(1,315)	(1,950)	(3,500)
Natural gas[b]	1,275	960	965	150	3,350
Energy efficiency	1,000	1,000	1,900	2,100	6,000
Wind[c]	50	150	500	700	1,400
Solar[d]	50	150	1,825	3,000	5,025
Geothermal	25	200	700	950	1,875
Clean coal	100[e]	100	500	750	1,450
Net capacity additions	2,500	2,325	5,075	5,700	15,600

Notes: a. Reductions represent repowerings and retirements of the following coal-fired generating units: Repowerings: Arapahoe 1-4, Mohave 1-2, Four Corners 1-3, San Juan 2. Retirements: Naughton 1-2, Dave Johnston 1-4, Reid Gardner 1-2, Four Corners 4-5. The blueprint also proposes that the Hayden and Cherokee power plants be retrofitted with pollution control equipment or fuel-switched to burn natural gas. b. Includes stand-alone capacity and repowered coal capacity. Additional natural gas capacity in renewables/hybrid configurations is not included in this figure. c. The wind capacity additions shown here represent effective capacity. See the *Methodological Attachment* for a discussion of effective versus installed capacity. d. Includes solar photovoltaic, stand-alone solar thermal, solar thermal repowered coal capacity, and solar thermal/natural gas hybrid units. e. Represents the Piñon Pine clean coal power project near Reno, Nevada, scheduled to begin operating in 1998.

- significant investments in clean coal technologies to better utilize the region's vast coal reserves, as well as experimentation with fuel cells and storage technologies

The resource acquisitions that make up the LAW Fund plan are shown in Table 2-3. Although not meant to be taken as absolute, they do outline what the LAW Fund believes to be a realistic approach for integrating clean power technologies into the region's electric resource base. If implemented, the blueprint will dramatically change the way electricity is generated in the Rocky Mountains and Desert Southwest and will place the region firmly on the path to a more environmentally and economically sustainable energy future. Figure 2-1 shows how the LAW Fund proposal would transform the regional capacity base over the next 20 years. Figure 2-2 compares the regional generation mix that would result in 2015 if the blueprint is implemented with the mix that would result in 2015 if the business-as-usual approach is adopted. See the Methodological Attachment for a discussion of how the regional generation mix was determined.

"The LAW Fund plan ... will help protect visibility at the Grand Canyon and other national parks on the Colorado Plateau."

Evaluating the Blueprint

As described in Chapter 1, the LAW Fund's outreach efforts identified five core values important to stakeholders in the region—environmental protection, economic opportunity, long-term risk management, equity, and sustainability. This section evaluates the blueprint in terms of these five values and explains why the LAW Fund believes that the blueprint strikes a significantly better balance among them than the business-as-usual approach.

Environmental Protection

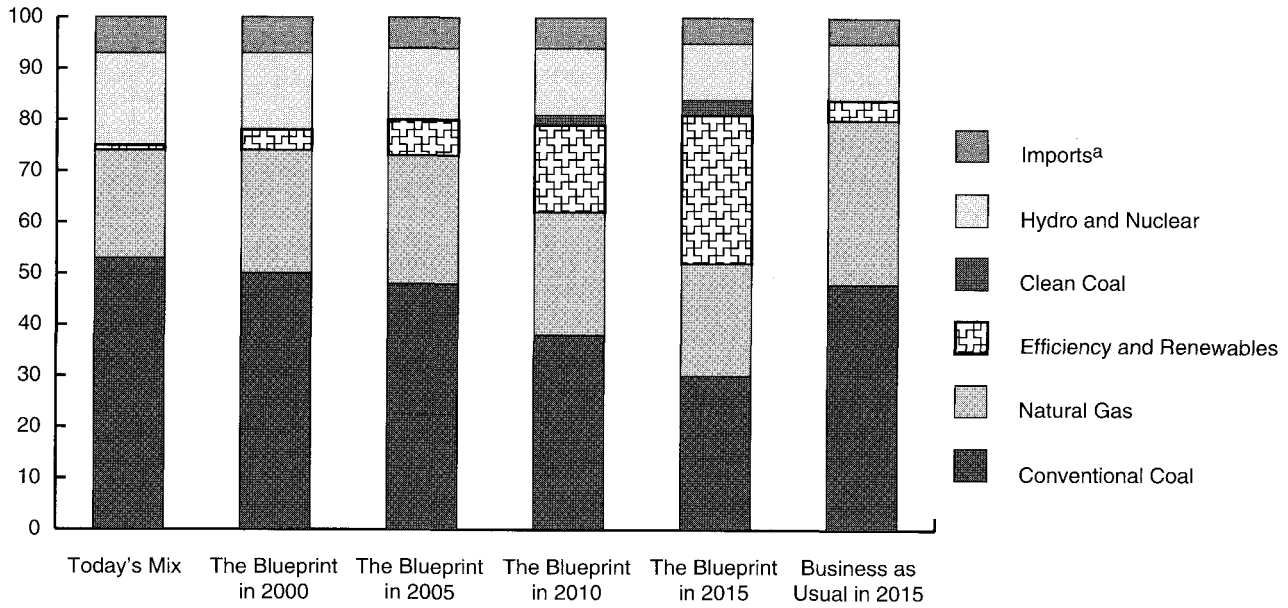
Implementation of the blueprint will result in a much cleaner electric power industry by significantly reducing emissions of air pollutants that are at the heart of many of the region's most pressing environmental problems. Along Colorado's front range, for example, the blueprint's investments in clean power resources eliminate the need to construct new conventional coal-fired generating capacity. The emissions avoided by not building these units, together with repowering or installing pollution control equipment at the dirtier existing coal plants along the front range, will improve air quality and reduce the adverse health impacts of air pollution in this urban corridor.

The LAW Fund plan also ensures that no new conventional coal-fired capacity will be needed on the Colorado Plateau to meet regional loads. Limiting the construction of conventional coal-fired capacity in this area together with repowering the Mohave coal-fired power plant in southern Nevada will help protect visibility at the Grand Canyon and other national parks on the Colorado Plateau. Similarly, installing pollution control equipment at the Hayden power plant in northwestern Colorado will reduce that plant's pollutant emissions. This should reduce acid deposition in the Mount Zirkel Wilderness Area, improve surrounding visibility, and help to ensure that the ecosystem in this area is preserved. When compared with the business-as-usual strategy, the blueprint's less extensive reliance on natural gas-fired generation also contributes to lower emissions of carbon dioxide (CO_2) and oxides of nitrogen (NO_x)—the principal pollutants emitted by the combustion of natural gas.

Figure 2-3 compares the LAW Fund's estimates of annual emissions of sulfur dioxide, oxides of nitrogen, and carbon dioxide under both the blueprint and the business-as-usual scenario in 2015 relative to 1994 levels. The methodology and assumptions used in estimating the emissions are described in the Methodological Attachment. As Figure 2-3 shows, by 2015, the blueprint's investments in clean power technologies and its cleanup of the region's dirtiest existing power plants would cut sulfur dioxide

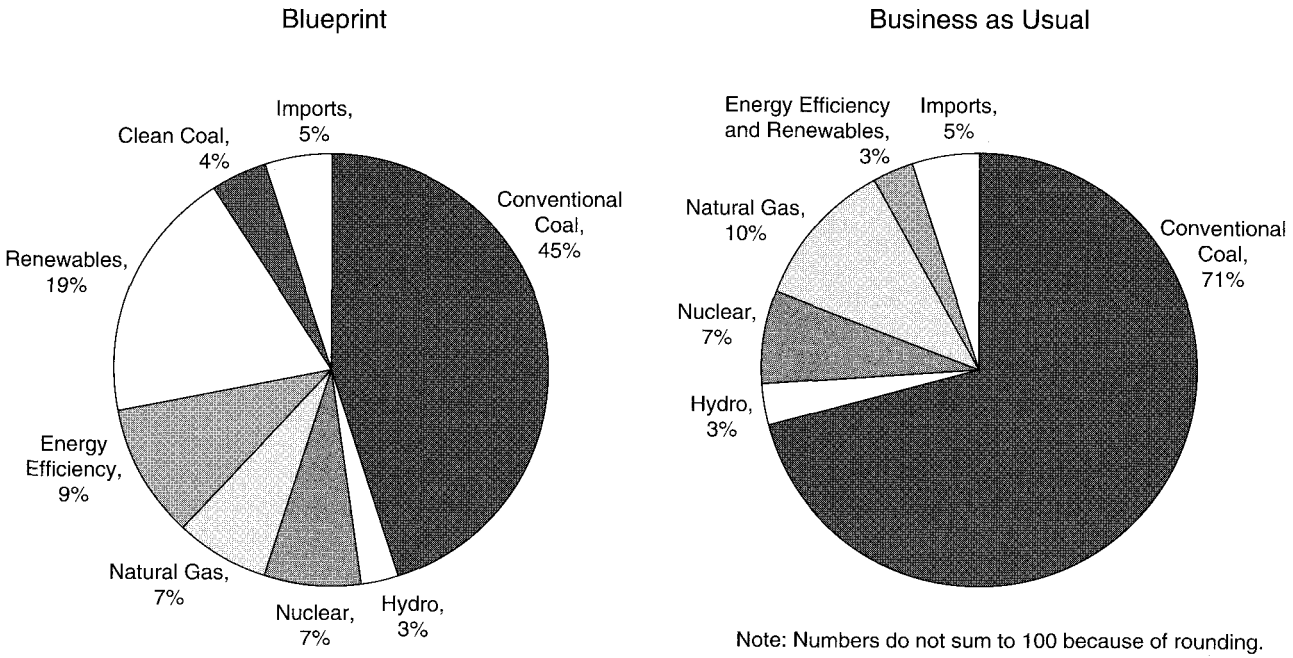
emissions by roughly 15 percent from their 1994 levels and by nearly 25 percent from what they would be if the business-as-usual approach is adopted. Emissions of oxides of nitrogen would be roughly 8 percent lower than in 1994 and almost 25 percent lower than they would be under the business-as-usual approach. Emissions of carbon dioxide, the most significant greenhouse gas, would be close to 5 percent lower than in 1994 and

Figure 2-1. Comparison of Regional Capacity Mix Options



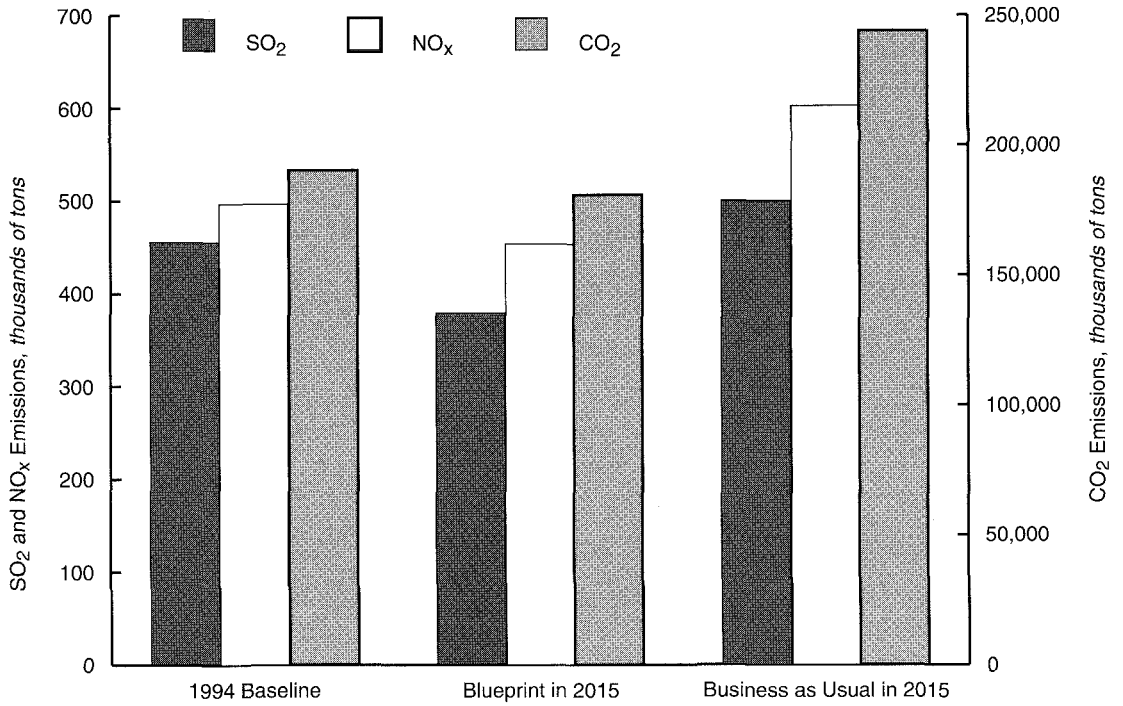
Note: a. Capacity available from the Pacific Northwest to help meet peak day demands in the region.

Figure 2-2. Electric Generation Mix in 2015 (percent of total generation, by resource)



Note: Numbers do not sum to 100 because of rounding.

Figure 2-3. Comparison of Annual Emissions from Electric Utilities



Note: SO_2 and NO_x emissions use the left axis. CO_2 emissions use the right axis.

approximately 25 percent lower than for business as usual.

In addition to air quality improvements, adverse impacts on land and water quality will be alleviated as coal mining and natural gas drilling are reduced. And an environmentally sound electric power industry can potentially help solve environmental problems attributable to motor vehicles by generating clean electricity to recharge batteries for electric cars or to produce hydrogen through electrolysis for use in fuel cells to power motor vehicles. Both of these technologies could, before 2015, begin to play a significant role in reducing urban brown clouds, human health impacts, and other environmental problems traceable to automobiles.

Although there are environmental impacts associated with the clean power resources in the blueprint, they are significantly less than those associated with conventional fossil fuel-fired technologies. Energy efficiency and solar photovoltaic resources have virtually no adverse environmental impacts. Some solar thermal technologies do require water for cooling purposes and, because the best sites are in arid climates, could place stress on local hydrological systems. However, the water use impacts of solar thermal power plants are likely to be no worse than those of coal plants operating in arid regions. The most serious environmental issue surrounding wind power is bird fatalities caused by wind turbines. Changes in the design of wind turbine towers and the avoidance of sites with large raptor and other bird populations can help solve this problem. Finally, although geothermal power plants do produce some harmful emissions, they are clean relative to fossil fuel-fired plants. Appendix D provides more information on the environmental impacts of the blueprint's clean power technologies.

Economic Opportunity

The LAW Fund plan is also economically sensible. It does not call for an overnight

transformation of the region's electric power industry to meet environmental goals at the expense of the region's economy. Instead, it advocates integrating cleaner power technologies into the resource mix gradually as they become cost-effective.

Investments in energy efficiency are already the region's most cost-effective resource option—costing less than half as much as building new power plants. As a result, energy efficiency plays an important role in meeting a major portion of the region's resource needs at the beginning of and throughout the 20-year planning horizon.

In contrast to the blueprint's energy efficiency investments, which are large and immediate, its proposed investments in renewable energy resources and clean coal technologies are initially small because of these power sources' higher near-term costs relative to conventional fossil fuel-fired resources. In the near term, investments in renewables and clean coal focus on the best opportunities to gain experience with these technologies and to drive down their costs. During this period, savings from the energy efficiency investments offset the higher costs of other emerging clean power technologies. The blueprint also relies more heavily on natural gas-burning technologies in the near term to take advantage of today's low gas prices. Over time, as natural gas prices rise and the costs of renewable energy and clean coal technologies fall, investments in the latter resources increase.

The blueprint's treatment of the region's existing fossil fuel-fired generation also takes into account economic impacts. Existing coal plants not directly implicated in the region's worst environmental problems would continue to operate as they currently are, and in most cases would have their lives extended beyond 40-year retirement dates. In addition, all of the region's natural gas-fired power plants would have their lives extended. Relative to building new generating resources, these life extensions provide inexpensive capacity to meet regional electricity demands. Finally, the blueprint recommends that pollution control retrofits and repowerings be undertaken at the region's most environmentally damaging coal plants. This effort yields the largest environmental benefit per dollar spent.

To shape and evaluate the blueprint, the LAW Fund conducted a present value analysis comparing the costs of the blueprint with the costs of the business-as-usual scenario. The analysis takes into account the timing of the resource acquisitions, the expected declines in the costs of the renewable and clean coal technologies, and expectations of rising fossil fuel prices over time. The principal assumptions for this analysis are presented in the Methodological Attachment. The results of the analysis are summarized in Figure 2-4. The figure shows that, prior to 2005, primarily because of the savings from the blueprint's energy efficiency investments, the blueprint costs no more than the business-as-usual approach despite the higher costs of the emerging clean power technologies. After 2005, the falling cost of the clean power technologies and the increases in fossil fuel prices (particularly the price of natural gas), together with continued savings from the blueprint's energy efficiency investments, give the blueprint a clear cost advantage over the business-as-usual approach. Over the entire period, when compared with the business-as-usual approach, we estimate that the 20-year resource plan proposed in the blueprint will reduce utility costs and customer bills by approximately 2.2 billion dollars in present value terms.

The blueprint's energy cost reductions and investments in energy efficiency and other clean power technologies are likely to have impacts beyond the confines of the region's electric power sector. A recent study funded by the U.S. Department of Energy (DOE), the National Renewable Energy

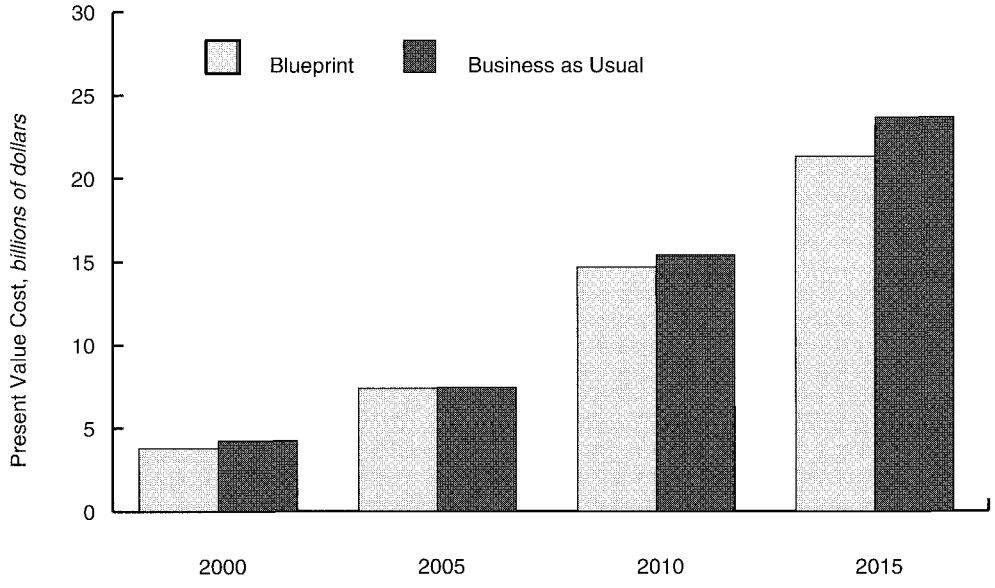
"Investments in energy efficiency are already the region's most cost-effective resource option ..."

Laboratory (NREL), and the Colorado Office of Energy Conservation has estimated that, in Colorado, the investments and energy cost savings of an energy strategy relying on energy efficiency and renewable energy technologies would create over 8,500 net jobs in the state by 2010 and increase wages and salary compensation by roughly $160 million dollars.[2] Similar economic benefits can be expected for the region as a whole if the blueprint is implemented. For example, the LAW Fund estimates that, based on the Colorado study and other analyses both within and outside the region, implementing the blueprint could lead to approximately 12,000 net jobs in the region by 2015, with corresponding annual wage and salary increases of approximately 180 million dollars.[3]

Our analysis also indicates that generation from the region's existing conventional coal plants will remain roughly constant over the next 15 years. In essence, the generation lost from retiring, retrofitting, or repowering the dirtiest coal plants is offset by increased utilization of the remaining plants arising from growing electric demands. Under these circumstances, we believe that the amount of coal burned will not decrease over the next 15 years as a result of the implementation of the blueprint. Consequently, we expect no reductions in the total number of coal-mining jobs within the region. After 2010, overall coal generation does decline somewhat, as additional conventional coal-fired plants are retired or replaced. However, by this time much of the lost conventional coal-fired generation is offset by generation from new clean coal capacity.

The one potential economic problem with the blueprint is that increased reliance on energy efficiency can reduce retail sales and ultimately the total revenues collected from end-use customers. As a result, retail prices may be slightly higher under the blueprint as the fixed costs of the system are spread over a smaller sales base. The exact price impact will depend on the specific types of energy efficiency efforts that are developed. For example, as Chapter 3 discusses in more detail, energy efficiency efforts that are funded by participants will have a smaller rate impact than others. As the industry undergoes a potentially radical restructuring,

Figure 2-4. Cumulative Costs of the Blueprint versus the Business-as-Usual Approach



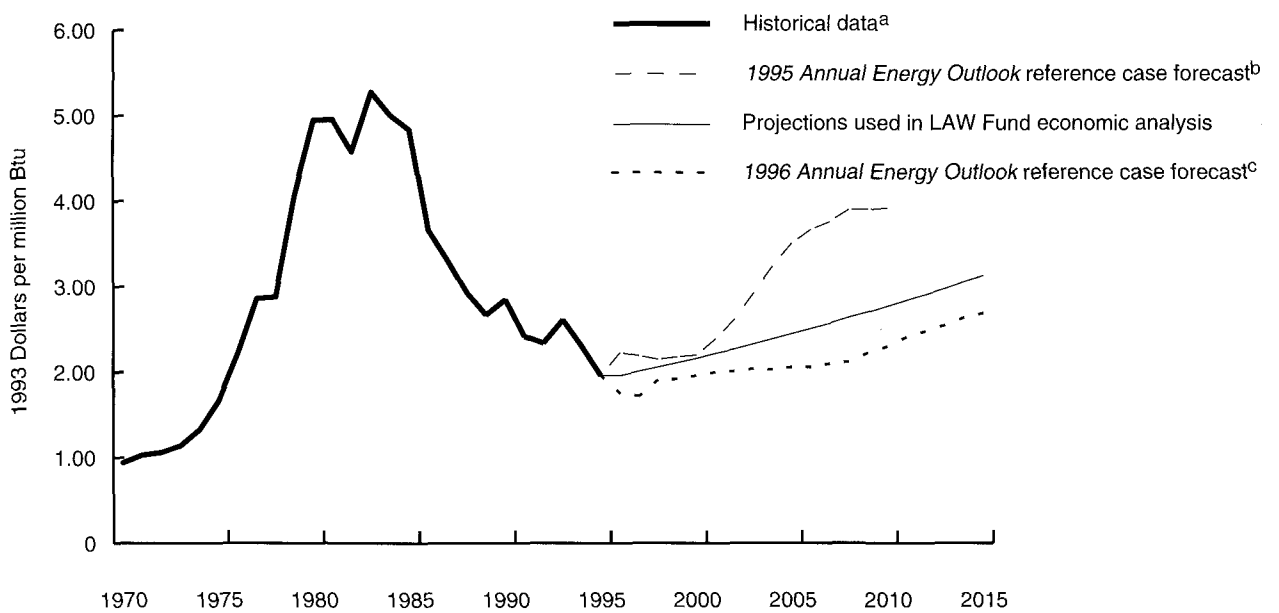
this issue of lost revenues from demand side management-induced sales reductions may disappear entirely.

Risk Diversification

Portfolio diversification, whether for an individual's financial portfolio or a utility's portfolio of electricity generation resources, is the key to managing risk. The blueprint's strategy of integrating a variety of resources into the regional resource mix results in a far more diversified resource portfolio than the business-as-usual approach, which relies almost entirely on fossil fuels. Therefore, we believe the blueprint does a far better job of reducing the region's exposure to the two principal risks resulting from the resource choices made by its electric power industry: (1) increased electricity costs caused by increases in the price of fossil fuels, and (2) the long-term risk of damaging the natural environment.

The principal fuel price risk faced by the region comes from uncertainty surrounding natural gas prices. Figure 2-5 presents historical and projected delivered natural gas prices to electric generators in the Rocky Mountain region. As the figure shows, natural gas prices today are at their lowest levels in almost 20 years. Largely because of this, natural gas has emerged as the fuel of choice for electric utilities in the region. Based on an analysis of utility resource plans, we estimate that the business-as-usual approach would add almost 8,500 megawatts of natural gas-fired capacity to the region's resource base by 2015—over 50 percent of the expected capacity needed during this period. Although natural gas prices are low today, Figure 2-5 shows that over time they are expected to rise

Figure 2-5. Delivered Natural Gas Price for Electric Generators in the Rocky Mountain Region
(Arizona, Colorado, Montana, Idaho, New Mexico, Nevada, Utah, and Wyoming)



Notes: a. *1994 Natural Gas Annual,* Volume 2, Table 31, Energy Information Administration. Prices were converted from dollars per thousand cubic feet to dollars per million Btu and to 1993 dollars. b. *Supplement to the Annual Energy Outlook 1995,* Table 18, Energy Information Administration. Projections available only through 2010. c. *Supplement to the Annual Energy Outlook 1996,* Table 18, Energy Information Administration. Prices were converted from 1994 to 1993 dollars.

in real terms.[4] Thus, there is an upside price risk associated with a heavy reliance on natural gas-fired capacity.

In the LAW Fund proposal, because of investments in energy efficiency and renewables, less than 3,400 megawatts of natural gas-fired resources are added. We do anticipate that some additional natural gas-fired capacity will be used in solar hybrid configurations, and that the stand-alone natural gas-fired capacity in the blueprint will run at higher utilization rates than the natural gas-fired capacity in the business-as-usual scenario. But overall, electricity generation from natural gas-fired resources will be lower than under the business-as-usual scenario. Over the 20 year planning horizon we estimate that, on average, annual generation from natural gas-fired power plants will be 25 to 30 percent lower under the blueprint than under the business-as-usual scenario.

"... under the business-as-usual approach ... little or no effort is made to develop ... energy efficiency, renewable energy, or clean coal technologies ..."

This lower reliance on natural gas-fired generation makes the blueprint less sensitive to rising natural gas prices than the business-as-usual approach. For example, the present value cost analysis conducted by the LAW Fund shows that, on average, for each 1 percent increase in the rate of growth of natural gas prices, the blueprint saves the region roughly $300 million in energy costs in present value terms.

The LAW Fund recognizes that, if natural gas prices rise faster than expected, electric utilities will have the option of substituting away from natural gas-fired resources in an attempt to mitigate the adverse cost impacts of rising natural gas prices. However, under the business-as-usual approach, because little or no effort is made to develop and gain experience with energy efficiency, renewable energy, or clean coal technologies, the primary alternative resource will very likely be conventional coal-fired generation. As a result, the region will be faced with a no-win situation: either to continue to rely extensively on natural gas-fired generation and suffer the adverse economic consequences of high electricity costs, or to once again begin to rely on less expensive conventional coal-fired generation at the risk of damaging the natural environment.

If the LAW Fund plan is implemented, the region will not be forced to make this choice. Instead, because of the blueprint's proposal to develop and integrate energy efficiency, renewable energy, and clean coal technologies into the resource mix, the region will be able to rely on these clean power technologies to help meet regional resource needs.

The benefits of not having to rely on conventional coal-fired generation in the event of higher-than-expected natural gas prices are likely to extend beyond protecting the natural environment. Because of the risk of stricter environmental regulations in the future, there could be significant financial benefits as well. To date, the majority of environmental regulations affecting electric power production have centered on controlling sulfur dioxide, oxides of nitrogen, and particulate matter. For human health reasons, future regulations could impose controls on toxic air pollutants or further controls on SO_2.[5] If utilities must comply with these regulations, it will increase the cost of electricity generated in coal-fired power plants.

The largest financial risk associated with future environmental regulations, however, may come from efforts to limit emissions of carbon dioxide, the most significant greenhouse gas. In the near term, because of the current political climate, the likelihood of a CO_2 tax is remote. However, the evidence linking CO_2 emissions to global climate change continues to mount, and therefore the likelihood of efforts to limit CO_2 emissions can be expected to increase in the future.

As part of its most recent integrated resource plan, one of the region's major utilities (PacifiCorp) has modeled the impact

of a CO_2 tax on its resource acquisition plans, assuming a tax rate ranging from $10 to $40 per ton of CO_2 emissions.[6] Using the low-range figure of $10 per ton, we estimate that if the CO_2 tax were in place in 2015 the blueprint's lower CO_2 emissions—roughly 60 million tons per year—would protect the region from bearing $600 million annually in additional costs.

Despite these attractive risk diversification benefits, the blueprint also has the potential to create its own set of risks. For example, if growth in demand for electrical energy services is slower than expected, natural gas prices remain low, or renewable energy costs do not decline, then the blueprint may be more expensive than our analysis suggests. The blueprint, however, has been developed to be as flexible as possible. By keeping initial renewable resource investments relatively small, it should be possible to respond to changing economic conditions without incurring large costs. Energy efficiency efforts can also be adjusted in response to higher or lower demand growth. Thus, if circumstances change, the blueprint can be adjusted quickly and at a reasonable cost.

Equity

Implementing the blueprint will also more equitably distribute the costs and benefits of electricity production throughout the region and among its people. The equity issues surrounding electricity production have both environmental and economic aspects.

The environmental hazards associated with electricity generation often fall most heavily on low-income populations. For example, in urban areas, power plants often are surrounded by low-income neighborhoods, placing populations in these locations at a higher risk of suffering health impacts due to power plant emissions and other wastes. Public Service Company of Colorado's Cherokee power plant just north of Denver offers a good example of this problem. The blueprint's strategy of repowering the dirtiest plants in urban areas with cleaner fuels will help to mitigate the effects of this imbalance.

Issues of equity also surround the cost of obtaining energy services. According to a report by the National Consumer Law Center, the elderly, the disabled, and poor families pay a much higher percentage of their monthly income on energy services than do others in the region.[7] For example, energy costs for a middle-class family average less than 4.1 percent of monthly income, whereas for a household receiving Aid to Families with Dependent Children (AFDC) this figure is between 19.7 percent (Colorado) and 29.1 percent (Arizona). For the elderly in the region whose major source of income is social security, energy costs as a percentage of monthly income range from 14.7 percent (Colorado) to 23.0 percent (Arizona).

These statistics indicate that for many of the region's low-income residents, monthly energy costs are a significant burden on already limited incomes. Because of a periodic inability to pay their monthly electricity bills, many low-income households experience disconnections of their electricity service. These disconnections, which can force families from existing residences, can lead to homelessness, often during times of the year when weather conditions are most severe.[8]

The LAW Fund's proposed energy efficiency investments and the creation of expanded low-income energy assistance programs can help lower the costs of energy for low-income families. Also, utility programs that partner with federal efforts can greatly increase the number of low-income homes that are weatherized and the types of measures installed. Public Service Company of Colorado, for example, is spending $2–3 million annually in 1995 and 1996 to supplement existing federal programs.[9] This partner-

"... for many of the region's low-income residents, monthly energy costs are a significant burden on already limited incomes."

ship will weatherize an additional 1,500 Colorado homes and result in lower utility bills and less housing instability for poor families. There are also a variety of low-income energy assistance programs that have been developed by utilities to help manage the impacts of utility bills on low-income customers. These programs should be maintained and expanded.

Native American communities present other equity issues. For example, a significant portion of Hopi and Navajo tribal revenues are raised by levies on the extraction of coal from their lands. And coal mining operations provide jobs for tribal members as did the mining of uranium ore two decades ago. On the other hand, these economic benefits do not come without a penalty. In particular, at Black Mesa in northern Arizona, land is strip-mined and the sole source of water for the Hopi—an aquifer underlying their lands—is drained to transport coal by slurry to a power plant. Members of both tribes are concerned about these impacts on tribal resources. The development of clean power resources on tribal lands may provide a way to continue to reap the economic benefits of power production while protecting tribal land and water resources.

"... the blueprint will unlock the economic development potential of the region's abundant renewable resources."

In addition to the equity issues involving low-income and minority communities, there are inter-regional equity issues associated with the current electric power industry. Today, as described in more detail in Appendix B, the Rocky Mountain and Desert Southwest region is a net energy exporter, sending more energy and capacity to other regions than it imports. Much of the exported energy is from coal-fired power plants. Although these exports do provide economic development benefits to the region, they also cause adverse environmental impacts to the region's air, land, and water.

As written today, the blueprint's investments in renewable energy and clean coal technologies are made to serve loads within our region. If these technologies prove that they can successfully serve regional loads, additional clean capacity can be built in this region to serve loads in California, the Pacific Northwest, and elsewhere. Exporting energy from these clean power sources, rather than from conventional coal-fired power plants, would both contribute to regional economic activity and alleviate the environmental impacts and inequities associated with the region's current energy exports.

Sustainability

As defined in Chapter 1, sustainability refers to the objective of preserving options for later generations. Thus, it is not sustainable to take actions today that threaten either the economic well-being or the quality of life of those who follow us. We think it is clear that the quality of life in this region depends on protecting the natural environment as well as public health and safety.

The LAW Fund's blueprint not only preserves options for later generations—it amplifies them. First, by greatly increasing the efficiency with which we use electricity in the region, it preserves coal, natural gas, and other nonrenewable resources for later use. Second, by proposing that the region begin to "climb the learning curve" on inherently sustainable renewable energy technologies now, the blueprint will preserve nonrenewable fossil fuels while unlocking the economic development potential of the region's abundant renewable resources. Third, by reducing emissions of pollutants and greenhouse gases below the levels they would otherwise reach, the blueprint protects public health and safety and begins the process of making a regional contribution to limiting global climate change.

The Individual Resources in the Blueprint

The following section describes how the LAW Fund evaluated each of the individual

resources that make up the blueprint, and it identifies what we believe to be the challenges that must be met for each resource if it is to be successfully integrated into the regional resource base. A more comprehensive treatment of energy efficiency and renewable energy technologies can be found in Appendix D. More detailed information on natural gas, conventional coal, and clean coal technologies can be found in Appendix C.

Energy Efficiency

Utility experience in Colorado and Utah demonstrates that energy efficiency investments can meet growing electricity demands at about half the cost of conventional supply-side technologies with virtually no adverse environmental impacts. Consequently, energy efficiency—whether promoted by utilities or some other entity—is a cornerstone of the blueprint's resource plan. We estimate that the additional energy efficiency investments proposed in the blueprint will save the region nearly $3 billion in real terms over the next 20 years when compared with conventional fossil fuel-fired resources.[10] The savings play an important role in helping to offset the relatively higher costs of some of the blueprint's other clean power technologies, particularly solar power, making it possible to begin integrating these resources into the resource mix immediately without placing an unreasonable burden on the region's economy.

Along with these benefits, however, energy efficiency investments also reduce electricity sales and, with them, utility revenues and profits. For this reason, utilities will not invest in energy efficiency unless they are somehow compensated for these losses. To overcome this problem, regulators in Arizona, Colorado, Nevada, and Utah have developed special cost recovery and incentive mechanisms to provide utilities with partial net lost revenue recovery.

Largely because of these cost recovery mechanisms, as of 1995 utilities in the region had committed to spend roughly $60 million annually to encourage their customers to use energy more efficiently. (See Appendix D for a discussion of current utility energy efficiency programs). As described in Chapter 3, however, these investments are increasingly coming under attack. Although cost recovery and incentive mechanisms allow utilities to recover the costs and lost revenues associated with energy efficiency programs, they can also raise utility rates and the bills of nonparticipating customers. Faced with the threat of industry restructuring and the possibility of having to compete for customers based on rates, many of the region's utilities are increasingly unwilling to implement energy efficiency programs.

Thus, the immediate challenge facing the region is to develop mechanisms to mitigate these adverse rate impacts so that utilities will continue to support energy efficiency programs. In the near term, utility involvement in energy efficiency programs is important because of existing market barriers that prevent typical electricity customers from investing in energy efficiency without utility support (Appendix D discusses these market barriers in detail). In the longer run, the challenge for the region is to remove these market barriers so that utility involvement in energy efficiency programs is no longer needed. Chapter 3 describes ways in which this can be accomplished.

If these challenges are met, we believe that energy efficiency can be used to meet up to 40 percent of the region's incremental resource need over the next 20 years. In total, the blueprint proposes that energy efficiency investments be used to avoid the need to build 6,000 megawatts of new capacity. As a result, energy efficiency accounts for over 9 percent of the region's energy mix and for about 12 percent of the regional capacity base by 2015. Table 2-4 summarizes the blueprint's proposed resource acquisition schedule for energy efficiency.

"... energy efficiency investments can meet growing electricity demands at about half the cost of conventional ... technologies ..."

Natural Gas

Because of historically low natural gas prices, the recent development of highly efficient natural gas-burning technologies, and the environmental advantages of natural gas relative to coal, many electric utilities today are planning to rely extensively on natural gas-fired capacity to meet the region's growing need for intermediate and peaking power, and possibly to meet baseload needs as well. Although there are economic and environmental advantages of using natural gas to generate electricity, there are also some disadvantages.

The most important drawback is the risk of rising natural gas prices over time. One of the uncertainties surrounding natural gas in this decade and beyond is the level at which the demand for natural gas will grow and how that growth will affect both short- and long-term market conditions. Based on an analysis of natural gas markets, described more fully in Appendix C, we believe that probable increases in the demand for natural gas in the utility, industrial, and transportation sectors of the economy will cause natural gas prices to rise over time. Thus, there is a significant price risk associated with natural gas-fired capacity.

"Although there are economic and environmental advantages of using natural gas to generate electricity, there are also some disadvantages."

Although natural gas does have environmental benefits relative to coal as a fuel for electricity generation—most notably virtually no emissions of sulfur dioxide and lower emissions of oxides of nitrogen—it still causes some important environmental problems. First, combustion of natural gas generates carbon monoxide (CO) in quantities comparable to or greater than burning coal, and burning natural gas still creates about 50 percent as much carbon dioxide as burning coal. Second, natural gas exploration and drilling can have significant impacts on wildlife and groundwater quality.

Thus, although the efficiency of new natural gas technologies and the environmental advantages of natural gas relative to coal make it an important part of the LAW Fund plan, the risk of rising prices and the environmental disadvantages of natural gas relative to energy efficiency and renewable energy technologies caution against over-reliance on this fuel, particularly as a baseload resource.

In the blueprint, natural gas-fired capacity has three applications. First, it is used in stand-alone combined-cycle and combustion turbine configurations to meet loads during peak and intermediate hours. Second, it is used to repower some of the region's most environmentally troublesome coal-fired power plants. Third, it may serve as a source of occasional backup capacity for intermittent renewable resources such as wind and solar power.

Today, natural gas-fired power plants generate about 5 percent of the electricity used in the region. In the blueprint, this

Table 2-4. Proposed Energy Efficiency Resource Acquisition Schedule

Period	Capacity Additions, *megawatts*	Cumulative Capacity, *megawatts*[a]	Percent of Regional Capacity Base	Percent of Total Regional Generation
1996–2000	1,000	1,100	2.9	2.2
2001–2005	1,000	2,100	5.2	3.8
2006–2010	1,900	4,000	8.8	6.6
2011–2015	2,100	6,100	11.9	9.3

Note: a. Includes existing capacity in place in the region prior to 1996.

percentage would increase over the next 10 years, peaking at about 10 percent in 2005. After 2005, because of expected declines in the costs of the renewable energy technologies and expected increases in the price of natural gas, renewable energy begins to play an increasingly important role in meeting regional electricity demands; thus the percentage of the region's electricity generated by natural gas falls to about 7 percent by 2015.[11]

Consequently, natural gas is viewed as a transition fuel, playing its most important role in the first 10 years of the planning horizon by providing a cost-effective and relatively clean supply of electricity until the other clean power technologies, particularly the renewable energy resources, become cost-competitive. Table 2-5 summarizes the blueprint's resource acquisition schedule for natural gas.

The principal challenge facing the region with respect to natural gas is to reap the environmental and cost-saving benefits of natural gas through combustion in highly efficient combined-cycle and combustion turbine power plants, without ignoring the need to increase regional efforts to acquire energy efficiency and bring down the cost of renewable energy technologies. Natural gas producers can help by using methods to find and develop new natural gas supplies that minimize the environmental damage caused by exploration and drilling. Discovery of new supplies will help to keep natural gas prices low, giving the region time to gain experience with renewable technologies and bring down their cost.

Renewable Resources

Today, higher capital costs and historically low natural gas prices make renewable energy technologies somewhat more expensive than conventional fossil fuel-fired resources. Over time, however, we expect the relative cost of renewable resources to fall for a number of reasons. First, renewable energy technologies are relatively young and the potential for research and development to reduce costs has yet to be fully realized. Second, as more renewable energy comes on line, manufacturing economies of scale and increased utility experience with renewable technologies will act to lower costs. Third, the costs of generating electricity with fossil fuels are expected to rise. For natural gas-fired resources, this is primarily due to expected increases in the price of natural gas. For coal-fired power plants, the greatest impact is likely to be from stricter environmental regulations, with the greatest risk coming from the possibility of a tax on carbon dioxide emissions.

As their costs fall relative to fossil fuel alternatives, renewable energy resources will become increasingly cost-competitive.

"Over time ... the ... cost of renewable resources will fall for a number of reasons."

Table 2-5. Proposed Natural Gas Resource Acquisition Schedule[a]

Period	Capacity Additions, *megawatts*	Cumulative Capacity, *megawatts*[b]	Percent of Regional Capacity Base	Percent of Total Regional Generation
1996–2000	1,275	9,025	23.8	5.7
2001–2005	960	9,985	24.8	10.3
2006–2010	965	10,950	24.1	9.7
2011–2015	150	11,100	21.7	7.4

Notes: a. Includes stand-alone and repowering applications. Does not include natural gas used in hybrid combinations with renewables. b. Includes existing capacity in place in the region prior to 1996.

Initially, the blueprint's investments in renewables are modest. This allows utilities and independent power producers (IPPs) to gain experience with these resources without imposing an unreasonable economic burden on the region. As the costs of renewable technologies fall, investments in these resources increase substantially and renewables become a major component of the region's resource base.

The challenge is to begin investing modestly in these technologies immediately, despite their higher near-term costs. Without this effort, commercialization of these technologies will be delayed or foregone, costs will not fall as expected, and the region will not be able to rely on these resources in the future.

"... the move toward industry restructuring has left most utilities in the region unwilling to begin investing in renewable energy."

Unfortunately, as with energy efficiency, the move toward industry restructuring has left most utilities in the region unwilling to begin investing in renewable energy. This reluctance is the result of the technological and financial risks associated with these emerging technologies and the fear that renewable energy investments will increase utilities' costs in the near-term and put them at a competitive disadvantage. To give utilities incentives to invest in these resources in the near term, new institutions and funding mechanisms must be developed. One possible solution involves arranging for a consortium of utilities to invest in a single renewable energy project so that each individual utility bears only a share of the risks. Other approaches involve setting up enterprise zones to help commercialize promising technologies or developing "green pricing" programs in which customers pay a premium to obtain clean power from renewable resources. These approaches are described more fully in Chapter 3.

Wind

Of all the renewable energy technologies, wind is currently one of the most promising and cost-effective alternatives to conventional intermediate and peaking fossil fuel-fired power plants. Figure 2-6 compares the costs of electricity from wind with the cost of electricity from a combined-cycle natural gas-fired power plant.[12] As the figure shows, with the production tax credit in place, wind becomes nearly cost-competitive before the year 2000. After the production tax credit expires in 1999, declining wind costs and improvements in wind turbine efficiency, together with rising natural gas prices, are likely to make wind a cost-effective resource in its own right sometime after 2005.

Figure 2-6 highlights the fact that the federal wind production tax credit provides a window of opportunity to begin developing the region's wind resources immediately. Two Colorado utilities, Public Service Company of Colorado and Tri-State Generation and Transmission Association, have already committed to acquiring approximately 15 megawatts of wind capacity at the Arlington, Wyoming, wind site, perhaps the best site in the country. PacifiCorp, the largest utility in both Utah and Wyoming, has committed to acquiring an additional 10 to 15 megawatts at Arlington to serve loads in Utah and Wyoming. An additional 40 megawatts at this site will serve loads in the Pacific Northwest.[13]

Before 2000, we propose that wind play a small but growing role in meeting the region's energy demands. Commitments at the Arlington site are expected to grow gradually during this period. We also propose that the best wind resources in eastern Colorado begin to be developed. Because of transmission constraints between Wyoming and Colorado, these resources are likely to be better suited than Arlington to meet the demand for electricity along Colorado's front range. Nevada and New Mexico also have abundant wind resources that could be developed. Overall, by 2000 we propose that 150 megawatts of effective wind capacity be added to the regional resource base.

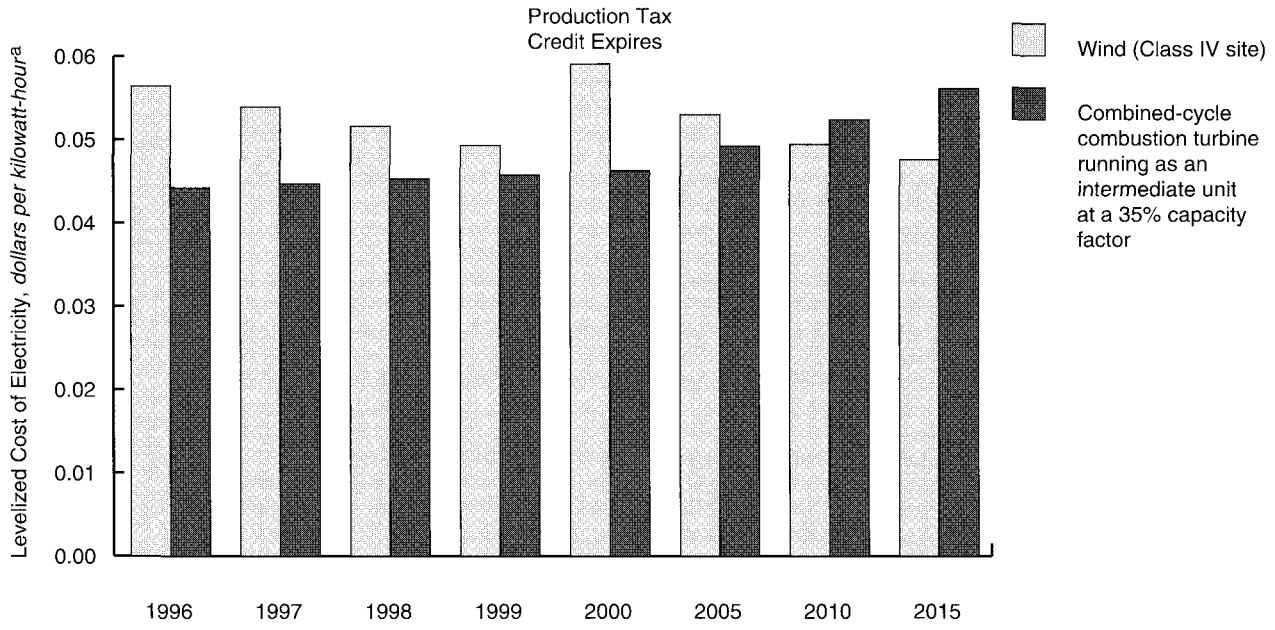
As wind becomes increasingly cost-effective, acquisitions of wind capacity increase substantially. By 2015, the blueprint proposes that 1,400 megawatts of effective capacity be built in the region, giving wind approximately a 3 percent share of the regional capacity base and a 5 percent share of the regional generation mix. Table 2-6 summarizes the blueprint's resource acquisition schedule for wind.

If this resource schedule is to be realized, several challenges must be met. To take full advantage of the production tax credit before it expires and ensure that wind capacity begins to be built in the region immediately, risk-sharing arrangements among groups of utilities should be developed. In Colorado, the LAW Fund has begun to address this issue by working with local wind developers to sell small portions of a wind project to as many as five utilities.

The region's wind developers, environmental organizations, and federal and state environmental and wildlife agencies must also work to address the issue of bird fatalities caused by wind turbines. Failure to deal with this issue could slow or stop development of wind projects in the region.

Finally, reliability issues must be addressed. Because wind is an intermittent resource it is less reliable than a typical fossil-fuel power plant. Thus, care must be taken to maintain adequate reliability standards when integrating wind into a utility system. As long as the installed wind capacity in a system is less than 2–3 percent of the system's total installed capacity, reliability is not a significant problem.[14] Because the blueprint's wind investments do not approach this level until after 2010, in the near term reliability issues are unlikely to pose much of a problem. In the long term a better understanding of the relationship between wind patterns and system peak loads—as well as backing up wind capacity with natural gas, hydro, or storage technologies—can help solve this problem.

Figure 2-6. Illustrative Comparison of Electricity Costs from Wind and Natural Gas



Note: a. 30-year levelized cost of electricity in constant 1996 dollars.

Table 2-6. Proposed Wind Resource Acquisition Schedule

Period	Capacity Additions,[a] *megawatts*	Cumulative Capacity, *megawatts*	Percent of Regional Capacity Base	Percent of Total Regional Generation
1996–2000	50	50	0.1	0.2
2001–2005	150	200	0.5	0.7
2006–2010	500	700	1.5	2.5
2011–2015	700	1,400	2.7	4.6

Note: a. The capacity additions shown here are in terms of effective capacity. See the Methodological Attachment for a discussion of effective versus installed capacity.

"... Utah and Nevada have the region's best geothermal resource ..."

Geothermal

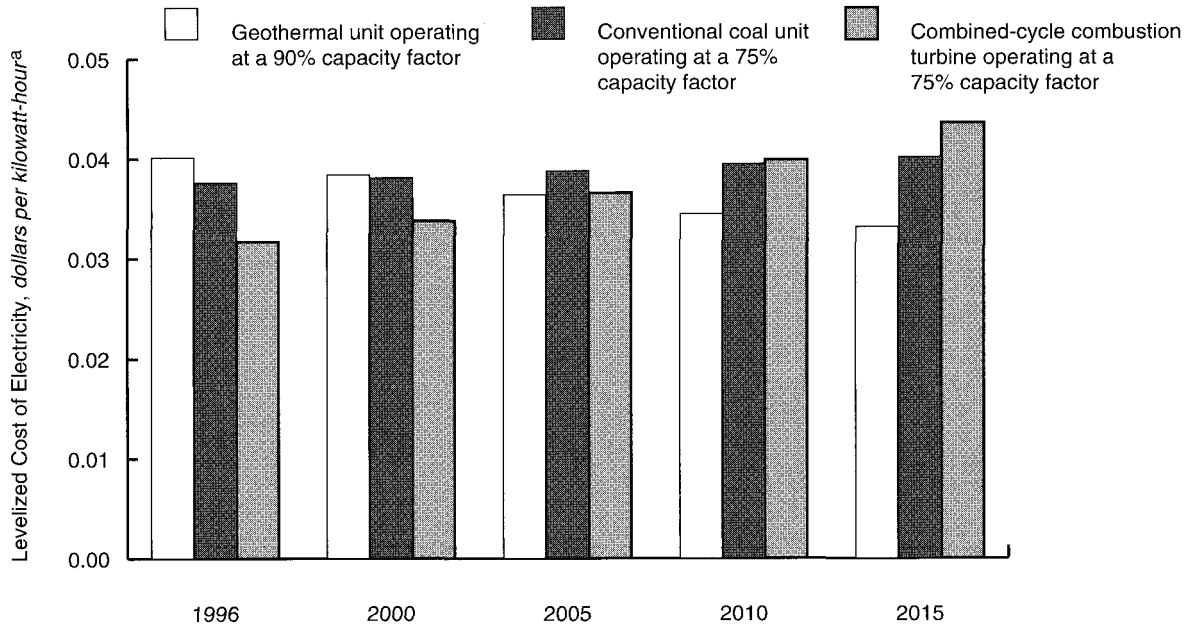
Unlike solar and wind power, which are primarily peaking and intermediate resources, geothermal power is a baseload resource that has traditionally been seen as an alternative to coal-fired generation. However, utilities are now considering using combined-cycle natural gas plants in baseload applications because of the recent advances in these technologies. As a result, geothermal power may have to compete with both coal and natural gas in the future.

Because of the excess coal and nuclear baseload capacity that exists in the region today, the baseload capacity that geothermal technologies would provide is not immediately needed. Sometime between 2000 and 2005, however, this excess capacity will be absorbed and the region will once again need to build baseload power plants. Figure 2-7 shows that by 2000, geothermal power will be roughly cost-competitive with conventional coal-fired power plants. Beyond 2000, economies of scale are expected to lower the costs of geothermal power further as geothermal projects, which typically range in size from 25 to 50 megawatts, are expanded to projects in the 100- to 250-megawatt range (see Appendix D). By 2005, falling geothermal costs together with increases in fossil fuel prices (particularly natural gas) are expected to make geothermal power a cost-effective resource.

Table 2-7 shows the blueprint's resource acquisition schedule for geothermal resources. In total, the LAW Fund plan recommends that almost 1,900 megawatts of geothermal capacity be added to the region by 2015. Most of this capacity would be added after 2005, corresponding to the region's larger need for baseload capacity during this period. Because Utah and Nevada have the region's best geothermal resource, most of the geothermal capacity additions would occur in these states. Appendix D contains more information on the extent of the region's geothermal resource.

Developing the geothermal resources in the Rocky Mountains and Desert Southwest presents the region with a number of challenges. In the near term, continued efforts must be made to find and develop geothermal basins in the region. And because geothermal resources are most often located in remote locations away from load centers, arrangements among geothermal developers, utilities, and power-marketing agencies such as the Western Area Power Administration must be made to ensure that transmission is available to move the electricity generated at geothermal sites to market. In the longer term the most significant challenge will be to

Figure 2-7. Illustrative Cost Comparison of Baseload Resources



Note: a. 30-year levelized cost of electricity in constant 1996 dollars.

develop new technologies to economically tap into deeper and much larger heat sources within the earth.

Solar

As explained in Appendix D, there are two primary types of solar power technologies: solar thermal and solar photovoltaic (PV). The costs of both solar technologies have declined sharply since the 1980s. Today, solar PV resources are cost-effective in many small non-grid-connected applications. Neither technology, however, is yet cost-competitive with fossil fuel-fired resources in large-scale utility applications. For large-scale generation, solar thermal technologies are further along in the development process than solar PV and are currently able to produce electricity at lower cost. Although the costs of both technologies are expected to decline over time, we expect solar PV costs to fall more rapidly. Figure 2-8 compares the cost of electricity from solar thermal and solar photovoltaic technologies with the cost of

Table 2-7. Proposed Geothermal Resource Acquisition Schedule

Period	Capacity Additions, *megawatts*	Cumulative Capacity, *megawatts*[a]	Percent of Regional Capacity Base	Percent of Total Regional Generation
1996–2000	25	175	0.5	0.8
2001–2005	200	375	0.9	1.5
2006–2010	700	1,075	2.4	4.0
2011–2015	950	2,025	4.0	7.0

Note: a. Includes existing capacity in place in the region prior to 1996.

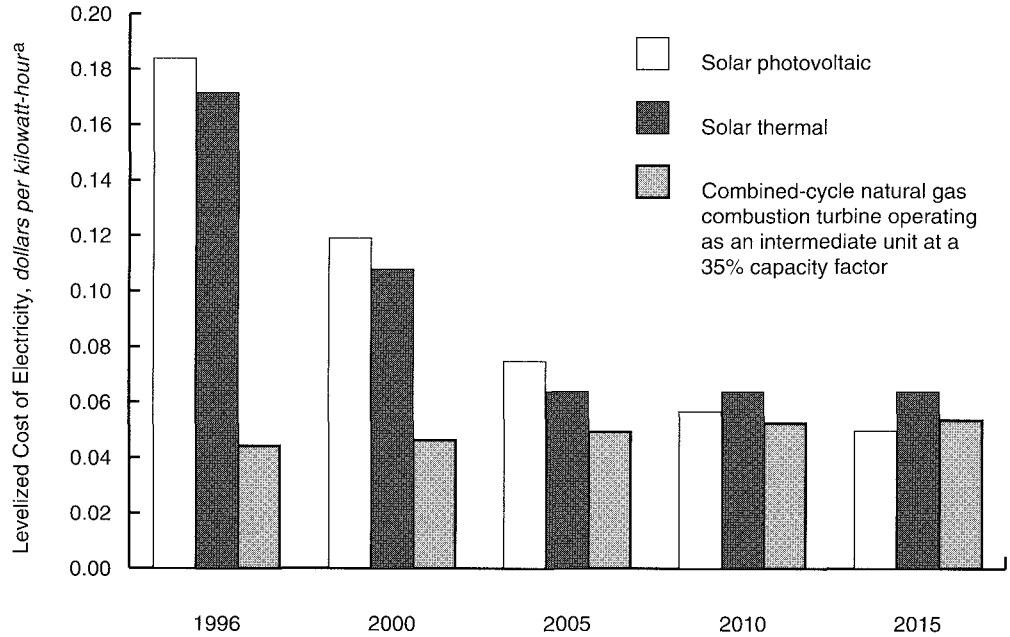
electricity from a combined-cycle natural gas-fired power plant running as an intermediate unit. The figure shows that although today solar power is significantly more expensive than conventional fossil fuel-fired resources, over the next 20 years this cost disadvantage should decrease dramatically.

Consistent with our renewables strategy, the LAW Fund proposes that the majority of the region's investments in solar power come after 2005. However, in the near term there are a number of attractive opportunities for utilities to begin gaining experience with solar power. Utilities in Arizona have already committed to acquiring 19 megawatts of renewable energy capacity (mostly solar) by 2001 and utilities in Nevada another 19 megawatts. By 2005, we anticipate the construction and operation of at least one large 100-megawatt solar thermal plant and as much as 50 megawatts of additional smaller solar thermal units in the southern states of the region. Another opportunity for regional acquisition of solar power resources in the near term is the Solar Enterprise Zone in southern Nevada (discussed in Chapter 3.)

After 2005, the blueprint's investments in solar power capacity increase substantially. Between 2006 and 2010 the blueprint proposes that over 1,800 megawatts of solar capacity be added to the region. Between 2011 and 2015, 3,000 more megawatts are added. Table 2-8 shows that, in total, over 5,000 megawatts of solar power are added to the region over the next 20 years, making solar the central new supply-side resource in the blueprint.

Solar power's central place in the blueprint is the result of the LAW Fund's belief that significant investments in solar power over the next 10 to 15 years can lower costs to the point where solar power can economically meet a substantial portion of the region's electricity demands before 2015. Developing the region's vast solar resource is important because in the longer run, unless we learn to harness nuclear fusion or a much larger share of the earth's heat, there is no

Figure 2-8. The Cost of Solar Power Versus the Cost of Fossil Fuel



Note: a. 30-year levelized cost of electricity in constant 1996 dollars.

Table 2-8. Proposed Solar Resource Acquisition Schedule[a]

Period	Capacity Additions, *megawatts*	Cumulative Capacity, *megawatts*[b]	Percent of Regional Capacity Base	Percent of Total Regional Generation
1996–2000	50	65	0.2	0.1
2001–2005	150	215	0.5	0.3
2006–2010	1,825	2,040	4.5	3.2
2011–2015	3,000	5,040	9.9	7.1

Notes: a. Includes solar photovoltaic and solar thermal of all kinds, including repowerings and hybrid configurations. b. Includes existing capacity in place in the region prior to 1996.

other environmentally sound resource that can provide the amount of energy necessary to sustain the region's growing population and economy.

For solar power, the challenge is clear. The region must continue to work on bringing the cost of solar energy down. If the cost of solar power does not fall further, the region will not be able to afford to invest in solar technologies and develop its solar resource. Instead, the region will most likely be forced to continue to rely on environmentally damaging conventional coal-burning power plants to meet the majority of its electricity demands. However, as discussed in the next section, it is possible that clean coal could emerge as a viable alternative for meeting regional electricity demands if solar power does not live up to its potential.

Coal-Fired Resources

There are three types of coal resources: existing coal units, new conventional pulverized coal plants, and clean coal technologies.

Conventional coal-fired generation

As explained in Chapter 1, the region's existing coal-fired power plants are the primary source of the electric power industry's environmental impacts in the region. Combustion of coal by electric utilities is a major source of regional emissions of sulfur dioxide, oxides of nitrogen, and carbon dioxide. As a result, coal-fired power plants contribute to acid deposition and regional visibility degradation, threaten human health, and increase the risk of global climate change. Coal-fired power plants also emit toxic and radioactive air pollutants and generate substantial quantities of solid waste, principally ash and flue gas desulfurization wastes. Surface mining of coal can also cause lasting damage to the region's land and water.

Because of these environmental problems, and the LAW Fund's view that they cannot be solved through further advances in conventional coal-fired technologies, the blueprint proposes that no new conventional coal-fired power plants be built to serve loads in the region. However, because of the relatively inexpensive and reliable power they provide, the blueprint recommends that the majority of the region's existing coal-fired plants be kept in service and operated as originally built for their entire lifetimes. Furthermore, the LAW Fund plan proposes that the region's cleaner-burning coal plants that reach 40 years of age before 2015 have their lives extended. Relative to building new power plants, life extensions are a low-cost source of additional capacity.

The blueprint proposes that roughly 2,000 megawatts of the region's dirtiest coal-fired power plants be retired when they turn 40 years old. It also proposes that, by 2015,

"... the challenge is clear. The region must continue to work on bringing the cost of solar energy down."

an additional 1,500 megawatts of coal-fired capacity be repowered with natural gas or solar power or retrofitted with pollution control equipment. These retirements, repowerings, and retrofits are a large source of emissions reductions. We estimate that by 2015 they would eliminate over 90,000 tons of sulfur dioxide emissions, over 70,000 tons of emissions of oxides of nitrogen, and over 28 million tons of carbon dioxide emissions each year.

Whether a plant should be retrofitted or repowered depends on a number of plant-specific factors. If a plant is near a natural gas pipeline or in a location with a good solar resource, repowering with these fuels may be the most economical option. If cleaner fuels are not readily available, installing pollution control equipment may be the best solution.

"... developing the region's solar resource promises significantly greater environmental benefits than developing the region's clean coal resource."

The region faces two principal challenges in dealing with its conventional coal-fired resources. In the near term the challenge is to clean up the most polluting facilities through pollution control retrofits and repowering. In the longer term the challenge is to wean the region from its heavy reliance on conventional coal-fired generation while minimizing any adverse economic impacts resulting from this change. In particular, issues regarding employment reductions in the coal industry and losses in tax revenue from coal production must be addressed. Because of these economic concerns the blueprint has been structured to ensure that total regional coal generation does not decline during the next 15 years. Beyond 2010, although conventional coal genereation does decline, the reduction is largely offset by generation from the blueprint's proposed clean coal capacity additions. As a result, on average we expect few losses in coal-mining jobs.

Clean Coal Technologies

Given our region's enormous coal reserves, clean coal technologies must be considered as potential options to help meet the region's electricity needs. However, as described in detail in Appendix C, there are both economic and environmental issues that must be resolved if clean coal is to become a part of the region's resource base.

From an economic perspective, clean coal has many parallels with solar power. Like solar, clean coal is currently an expensive technology. Today, the capital costs of clean coal are over 50 percent higher than for conventional coal-fired power plants. However, clean coal is still in the early stages of development, and, like solar power, costs can be expected to fall as research and development and further commercialization efforts continue. Finally, just as the solar resource in the region is enormous, so too are the region's coal reserves. Thus, each resource could potentially meet a large portion of the region's electricity needs.

Despite these similarities, the blueprint focuses more heavily on solar technologies than on clean coal technologies because the LAW Fund believes that developing the region's solar resource promises significantly greater environmental benefits than developing the region's clean coal resource. Although clean coal promises significant emissions reductions relative to conventional coal burning—SO_2 and NO_x emission levels that are 50 percent lower than for conventional units equipped with pollution control devices, and CO_2 levels that are roughly 20 percent lower—it is still dirty compared with zero-emission solar technologies. Clean coal technologies also produce substantial amounts of solid waste that require disposal. Finally, the environmental impacts of coal mining remain a problem for clean coal technologies.

Because of these environmental disadvantages, clean coal plays a lesser role in the blueprint than solar power and other renewable energy technologies. Clean coal, however, is not ignored. Before 2005, the LAW Fund plan calls for continued research into clean coal technologies and advocates a number of clean coal projects to provide

experience with these technologies and help drive down their costs. After 2005, because of expected declines in clean coal costs and because the region's current excess baseload coal capacity will have been absorbed, the blueprint proposes larger acquisitions of clean coal. Table 2-9 shows that if the LAW Fund plan is implemented, over 1,400 megawatts of clean coal capacity would be added to the regional resource base over the next 20 years, and that by 2015 roughly 4 percent of the region's electricity would be generated by clean coal technologies.

As with the renewable resources, the region faces the challenge of bringing down the cost of clean coal so that it can compete in the market with other resources. Equally important is the need for developers and manufacturers to reduce the environmental impacts of clean coal. If these challenges are met, clean coal could become a major source of electricity for the region well into the next century.

Nuclear and Hydroelectric Resources

Although the blueprint proposes that no new nuclear or large hydroelectric power plants be built in the region, it does assume the continued operation of the region's one nuclear power plant (the Palo Verde plant west of Phoenix) and most of the region's existing hydroelectric capacity. The LAW Fund does support the reoperation of the region's hydroelectric facilities to protect recreational values and river ecosystems. In developing the capacity requirements for the blueprint, the LAW Fund assumed the loss of 700 megawatts of peaking capacity at the Glen Canyon Dam. Appendix C describes the region's nuclear and hydroelectric resources in more detail.

Fuel Cells

Fuel cells generate pollution-free electricity through the chemical reaction of hydrogen and oxygen to form water. The hydrogen fuel for fuel cells can be obtained chemically from natural gas or by application of electricity to water to form hydrogen and oxygen through electrolysis. Appendix D describes fuel cell technology in detail.

In small power plants and in motor vehicles, fuel cells have enormous potential to reduce pollution in urban areas. They also have potential advantages in remote areas and near transmission-constrained load centers, where they can be used to reduce the need to build transmission lines.

"In small power plants and in motor vehicles, fuel cells have enormous potential to reduce pollution in urban areas."

Fuel cells are also a way of storing the intermittent energy generated from renewable resources such as solar and wind. Under this system, energy generated during off-peak periods could be used to produce hydrogen through electrolysis. The hydrogen would be stored in underground reservoirs or pressure tanks until periods of peak demand when it would be used as a fuel for fuel cells in

Table 2-9. Proposed Clean Coal Resource Acquisition Schedule

Period	Capacity Additions, *megawatts*	Cumulative Capacity, *megawatts*	Percent of Regional Capacity Base	Percent of Total Regional Generation
1996–2000	100	100	0.3	0.4
2001–2005	100	200	0.5	0.7
2006–2010	500	700	1.5	2.2
2011–2015	750	1,450	2.8	4.2

stand-alone power plants or in fuel cells to run electric cars. The result is a fuel cycle that is entirely pollution-free.

Although their promise is enormous, fuel cells are in the early stages of development and are not in broad commercial use. Before widespread market entry can take place, difficult technological hurdles must be overcome and costs must fall significantly. Nonetheless, we foresee the possibility that fuel cells can begin to reduce urban pollution and provide other system benefits within the next 20 years.

Storage

Storage technologies such as compressed air, improved batteries, and flywheels will become more important in the years ahead, especially to store off-peak energy generated by intermittent renewable resources for use at peak. Appendix D describes the technologies, their potentials, and the barriers to commercialization in detail. We have not included megawatt targets for storage in the blueprint itself, but it is possible that various advanced storage technologies will provide hundreds of megawatts of peak capacity by 2015.

The Electric System in 2035

In this section we look beyond 2015, and with the humility that comes from realizing we are making no more than an educated guess, we speculate on the makeup of the electric system in 2035 under the base-case peak load growth assumptions described in Appendix B.

Under these assumptions, and assuming the need for a 15 percent reserve margin, our six-state region will need roughly 82,000 megawatts of capacity in place to meet peak loads in 2035, provided that other factors do not limit growth. Under low peak load growth assumptions, the region will need about 64,500 megawatts of capacity and under high growth assumptions 127,000 megawatts.

Table 2-10 presents a regional resource mix that would meet the base-case peak load target of 82,000 megawatts in 2035. This scenario would build on the resource mix embodied in our blueprint through 2015, together with continued vigorous investments after 2015 in solar, wind, geothermal, energy efficiency, and clean coal technologies.

The keystone of the scenario in Table 2-10 is solar and other renewable resource capacity, operated in intermediate and baseload configurations with storage and backup, to meet conventional loads as well as to produce hydrogen for use in fuel cells.[15] This arrangement is based on our view that by 2035 there is a real possibility that a zero-

Table 2-10. Estimated Electric Resource Mix in 2035

Resource	Capacity, *megawatts*	Percentage
Solar[a]	30,000	36
Efficiency	20,000	24
Clean coal[b]	12,000	15
Geothermal	7,000	9
Natural gas[c]	4,000	5
Wind	5,000	6
Hydro	3,000	4
Biomass	1,000	1
Total	82,000	100

Notes: a. Includes solar photovoltaic and solar thermal of all kinds, including hybrid configurations. b. Does not include the use of coal gas in hybrid configurations with renewables. c. Includes only stand-alone capacity. Additional natural gas capacity in renewables/hybrid configurations is not included in this figure.

emissions hydrogen transportation economy will be in full swing. Solar power is the key renewable resource. As Appendix D shows, the solar resource in our region is enormous. We believe it is large enough to support 30,000 megawatts of solar thermal and solar photovoltaic capacity. The major limiting factor, beyond the need for solar costs to come down, may be water for cooling.

We note that geothermal electricity production plays a prominent role in 2035, attributable to our belief that, by then, we shall have at least begun to learn how to economically tap into the deep heat of the earth, the potential of which is virtually unlimited, as described in Appendix D. Energy efficiency also carries a heavy load in 2035. Essentially, the scenario in Table 2-10 implies roughly a linear continuation through 2035 of the role ascribed to energy efficiency in the blueprint through 2015.

The LAW Fund proposes that an additional 3,600 megawatts of wind capacity be added to the regional resource base between 2015 and 2035. This brings the total effective capacity in the region to 5,000 megawatts. This amount is not larger because of our belief that the best sites for wind power facilities in the region may have been exhausted at this point, even if wind technology continues to improve.

Stand-alone use of natural gas to generate electricity grows very little between 2015 and 2035, although its use in hybrid and backup configurations with renewables may grow considerably by 2035 if solar energy storage systems do not fulfill their promise. Our tentative role for natural gas in 2035 stems from our opinion that natural gas prices may be quite high by 2035.

Our belief that there is little additional hydro potential in our region, together with the likelihood that existing hydro capacity will be reoperated, and therefore provide less capacity during regional electric system peaks, causes hydro's role to shrink by 2035. Biomass plays a minor role in the region through 2035 because large-scale regional biomass production would require significant quantities of scarce water supplies for irrigation.

The electric system in 2035 shows no conventional coal-fired capacity at all. The scenario in Table 2-10 retires all existing conventional coal-fired capacity by then and proposes that no new conventional capacity be constructed between now and 2035. However, clean coal technology plays a prominent role in 2035. The region possesses abundant coal resources that, in our view, will be used to meet electric loads, albeit in cleaner technologies. Nonetheless, clean coal will play a much smaller role than we assign it in Table 2-10 unless the industry learns how to bring CO_2 emissions down to a level at or below that attributable to the combustion of natural gas.

The resource mix set forth in Table 2-10 would be cleaner than the mix in place now. It would also be affordable, provided that the costs of clean power technologies continue to decline.

What happens if the promise of solar, wind, geothermal, efficiency, and clean coal is not fulfilled? As long as natural gas prices rise as expected, we believe that the region will take one of two paths: (1) it will begin to build a new round of conventional coal-fired power plants after 2005; or (2) it will build more nuclear power plants. We believe construction of new conventional coal-fired power plants is inconsistent with a balanced implementation of the five blueprint objectives. Nuclear power plants are environmentally sustainable only if safe and inexpensive technologies, as described in Appendix C, are developed and if safe, sustainable nuclear waste storage is at hand. We have more confidence that the first condition can be achieved than the second.

The scenario presented in Table 2-10 shows what is at stake in rebuilding this

"... by 2035 there is a real possibility that a zero-emissions hydrogen transportation economy will be in full swing."

region's electric power system. It shows how important it is that we make significant strides toward installation of a clean and affordable power system well before 2015. If we do not, we shall be forced to build power plant capacity after 2010 that will cause major environmental and other problems.

Conclusion

This chapter has presented the LAW Fund's blueprint for the electric power industry in the Rocky Mountains and Desert Southwest. It has shown that implementing the plan will yield environmental and economic benefits, help the region better manage risks, help redress inequities associated with electricity production and use, and place the region firmly on the path to a more sustainable energy future.

"Implementing this proposal, however, requires a long-term perspective."

Implementing this proposal, however, requires a long-term perspective. The blueprint's energy efficiency programs require investments today to avoid higher costs for new power plants in the future. Attaining the long-term risk diversification and environmental benefits of renewable energy technologies requires the region to begin investing in these resources now, despite the fact that they are currently more expensive than conventional fossil fuel-fired alternatives. Likewise, coal plant pollution control retrofits and repowerings involve incurring costs in the near term to reduce environmental risks in the future.

Today, because of a growing movement toward increased competition in the electric power industry, many utility decision makers are increasingly taking a short-term outlook that threatens the goals of the blueprint and the benefits it will provide. To address this issue, Chapter 3 presents a strategy for implementing the blueprint in the face of a potentially dramatic industry restructuring.

Notes

1. The need for roughly 15,000 megawatts of new capacity is based on estimated growth in regional peak demand of 2.4 percent per year and annual growth in energy requirements of 1.7 percent. Appendix B discusses the base-case load growth assumptions more fully and also presents estimated capacity needs for high and low demand growth rate scenarios based on utility resource plans. Some believe that new resource needs will be significantly lower in the future because of falling reserve margins due to increased competition, and slower economic growth. In contrast, others argue that the development of electric cars, continued rapid economic growth, and increased reserve margins caused by the chaos of industry restructuring will increase future resource needs. On balance, the risks to the demand forecast contained in the blueprint seem roughly symmetric.

2. "Colorado's Energy Future: Energy Efficiency and Renewable Energy Technologies as an Economic Development Strategy," Skip Laitner and Marshall Goldberg, February 1996. Prepared for the U.S. Department of Energy, the National Renewable Energy Laboratory, and the Colorado Office of Energy Conservation.

3. Based on the Colorado study cited above, every gigawatt-hour of electricity saved through energy efficiency programs is estimated to create roughly 0.6 net jobs and increase wage and salary compensation by $8,600. By 2015, the blueprint's energy efficiency investments reduce electricity generation in the region by over 21,000 gigawatt-hours. These figures imply a net job gain of roughly 12,600 jobs and an increase in wage and salary compensation of approximately $180 million.

4. The Energy Information Administration's 1995 forecast presented in Figure 2-5 shows delivered natural gas prices to the region's utilities rising in real terms at 2.9 percent over the period 1993–2010. Appendix C presents estimates from various other analysts showing average wellhead prices in the lower 48 states rising by as much as 5 percent over the next 15 years. On the other hand, the data from the Energy Information Administration's 1996 forecast suggests that natural gas prices will grow more slowly than previously thought—roughly 1.5 percent between 1994–2015. The key point is that natural gas prices are volatile and extremely difficult to forecast with any degree of accuracy. Actual gas prices have often been outside the boundaries of the low and high projections of many of the forecasters. For the purposes of the LAW Fund's economic analysis it was assumed that natural gas prices would escalate at a real rate of 2.5 percent per year. We assumed an initial 1996 delivered gas price of $2.00 per million Btu in 1996 dollars.

5. Sulfur dioxide is a precursor to fine particulate matter. Recent studies have shown a

strong correlation between particulate matter and human respiratory ailments. See the discussion in Chapter 1 on the threats to human health and the sources cited there.

6. Resource and Market Planning Program (RAMPP-4), PacifiCorp, November 1995, pp. 159–162; Inputs and Results Appendix, pp. 92–93.

7. "Energy and the Poor: The Crisis Continues," National Consumer Law Center, January 1995.

8. Direct testimony of Roger Colton, staff attorney for the National Consumer Law Center, on behalf of the LAW Fund in Docket No. 91A-783EG, Colorado Public Utilities Commission, 1992.

9. Conversation with Tricia Gallegos, Executive Director, Energy Conservation Associates (ECA), fall 1995. (ECA is the weatherization agency serving Denver.)

10. The blueprint proposes $3 billion in energy efficiency investments in constant 1996 dollars over the 20-year planning horizon. Monitoring and evaluation results from Colorado and Utah show that utility energy efficiency programs have a rough benefit/cost ratio of 2 to 1. Thus, the blueprint's $3 billion energy efficiency investment can be expected to yield benefits of roughly $6 billion, giving the region a net savings of $3 billion. (See Appendix D for more detail.)

11. The generation figures for natural gas capacity do not include generation from units that may be used to back up renewable resources during peak demand periods. The amount of generation that would be required for this purpose will depend on the intermittency of the renewable resources and on the extent to which emerging storage technologies become available.

12. The levelized cost of electricity calculations presented in Figure 2-6, and the corresponding calculations in Figures 2-7 and 2-8 comparing the cost of geothermal and solar power with the cost of conventional fossil fuel-fired resources are based on the LAW Fund's economic analysis described in the Methodological Attachment. To calculate the levelized costs, the 30-year present value cost of each resource was calculated, and the fixed annual payment over the 30-year period yielding this present value was computed. The annual payment was divided by the annual generation from the resource to obtain the levelized cost of energy. The calculations incorporate capital costs, fuel costs, and fixed and variable operating and maintenance costs. The analysis does not incorporate federal and state income taxes, property taxes or depreciation expenses.

13. See the Arlington, Wyoming Wind Project, Docket No. 93A-563E, Before the Colorado Public Utilities Commission, 1994. Capacity figures cited are in terms of installed rather than effective capacity.

14. For a discussion of reliability issues associated with integrating wind into utility systems see Appendix D and the sources cited there; in particular, "Wind Energy: Resources, Systems and Regional Strategies," Michael Grubb and Niels Meyer, *Renewable Energy*, Island Press, 1993, pp. 176–185.

15. As discussed in Appendix B, the use of electricity to produce hydrogen may increase regional peak loads, or at least regional load factors.

Implementing the Blueprint

Three

"Price is everything."
—Del Hock, Chairman of the Board, Public Service Company of Colorado[1]

"In order to fulfill [its] public interest mandate, the Commission must be concerned with much more than ... short-term [utility] rates. ... The Commission must also be cognizant of ... environmental quality, public health and safety, and the economic vitality of the state."
—Colorado Public Utilities Commission, December 1995[2]

The emergence of competition in the electric industry is only the most recent development in the national trend toward increased reliance on market forces. Over the past two decades, a number of major domestic industries—such as airlines, telecommunications, trucking, banking, and natural gas—have undergone restructuring and have moved from a regulated environment to a more competitive one. In response to legal, technological, and economic changes, the decades-old structure of the electric industry is eroding, and we are witnessing yet another industry in transition.

Because the period of transition to more competitive markets in the electric industry could be long and uneven, action needs to be taken now to ensure that this transition, with its uncertain length and outcome, proceeds according to the five core values delineated in the LAW Fund's blueprint—environmental protection, economic opportunity, fairness, risk management, and long-term sustainability. Because it may be possible in the future for customers, particularly larger ones, to choose their own supplier rather than purchasing from a regulated monopoly, utilities are increasingly taking steps to provide the lowest possible near-term prices to large customers in an effort to retain them. One of the impacts of this strategy is the reduction of utility investments in energy efficiency, renewable resources, and environmental mitigation—investments that produce long-term benefits and that are at the core of a sustainable energy future for the region.

In the near term, while the industry continues to be characterized by vertically integrated monopolies (handling power generation, transmission, and distribution), electric utilities must be regulated to protect these long-term public interests. This chapter identifies a number of important tools for accomplishing these aims in a way that is consistent with utility needs to retain existing customers. These tools include, among others:

- a wires surcharge used to fund the development of energy efficiency and low-income energy assistance programs
- market-based approaches that satisfy customer desires to purchase clean, renewable energy
- conditions attached to, for example, utility mergers to clean up dirty power plants
- the creation of competitive wholesale markets that protect long-term public interests during the transition to a more competitive industry structure

These tools and fixes, however, do not solve the deeper problem: the current industry structure—vertically integrated utilities housing both monopoly functions (transmission and distribution) and competitive functions (generation) within the same corporate entity—limits choice and forces customers to bear large risks inappropriately. Although the short-term fixes described

"... the decades-old structure of the electric industry is eroding, and we are witnessing yet another industry in transition."

above are critical, over the longer term policy makers must restructure the industry to address these underlying problems. Over time, this means placing monopoly and competitive functions into separate corporate entities. It also means that customers should eventually be allowed to choose their own supplier of electricity. This chapter contains specific suggestions for realizing these goals.

Presently, policymakers have two viable alternatives for promoting a cleaner energy future. First, they can continue to regulate monopoly utilities to protect long-term public interests in a manner compatible with an increasingly competitive industry. Alternatively, regulators and legislators can accelerate the transition to a new industry structure, one that is not characterized by vertically integrated monopolies, and do so in a way that encourages investments in clean energy technologies. A third possibility, favored by many of the region's utilities—to relax or eliminate regulation while maintaining vertically integrated monopolies—creates a situation of unregulated monopoly and should be firmly rejected as poor public policy.

"... to relax or eliminate regulation while maintaining vertically integrated monopolies ... should be firmly rejected as poor public policy."

Given the changing nature of the industry and the policy choices that are raised, the blueprint cannot be implemented without active and sustained support from key stakeholders. State utility regulators and legislators must play a critical leadership role in rejecting unregulated monopoly and in guiding the transition to a more competitive electric industry consistent with the public interest. In addition, federal regulators, utilities, fiscal policy makers, customers, resource developers, environmentalists, and many others must pull together to support efforts to create a clean and affordable energy future for the region: our quality of life depends upon it.

A Changing Industry

The potential for industry restructuring—whereby customers can bypass their local utility supplier and purchase power on the open market—has created financial incentives that are discouraging utilities from investing in resources (such as energy efficiency and renewables) that are beneficial over the long term.

The Economics of Change

Under state law, as Appendix B explains in more detail, *retail* (end-use) customers are obligated to purchase electricity from their local utility at prices that allow the utility to cover the administrative, capital, and operating and maintenance (O&M) costs associated with its prior investments. In contrast, utilities can purchase power from each other and from independent power producers (IPPs) at market-based *wholesale* prices that reflect current market conditions. A number of forces have combined to drive wholesale market prices in the six-state region covered by this report to very low levels, while retail prices remain comparatively high.[3]

On the wholesale market side, a new generation of efficient gas-burning technologies has enabled utilities and independent power producers to take advantage of low natural gas prices to produce electricity very cheaply. And federal legislation—beginning with the Public Utilities Regulatory Policy Act of 1978 (PURPA) and continuing with the Energy Policy Act of 1992—has begun to open the electric transmission grid to non-utility as well as utility suppliers. These developments have permitted non-utility companies to profitably introduce new gas-fired technologies into wholesale power markets. The combination of increased transmission access and the availability of cheap power has made it possible to purchase or generate electricity very cheaply.

Standing in sharp contrast, the retail prices paid by end-use customers remain significantly higher. These retail prices reflect the average costs associated with the entire mix of resources owned by any given utility.

Because many utilities built expensive nuclear and coal plants in the past, the region's utilities have disparate and, relative to wholesale prices, high retail rates. As Table 3-1 shows, wholesale prices for firm power now generally range from 1 to 4 cents per kilowatt-hour; at the same time, retail prices based on the average costs associated with prior utility investments almost always exceed 4 cents per kilowatt-hour, and several of the higher-cost utilities in the region have average costs and prices that exceed 8 cents per kilowatt-hour.

Under these economic conditions, today's end-use customers have a substantial financial incentive to leave their current utility and to acquire power on the open market at lower wholesale prices. Access to this cheaper power offers bill reductions to customers in excess of 50 percent at times, depending on the host supplier. This incentive is particularly strong in high-cost states such as Arizona and New Mexico where end-use customers are racing to obtain cheap power at marginal cost-based wholesale prices.

In this market environment, utilities in the region are experiencing trouble retaining their wholesale, and sometimes retail, customers. Entities such as WestPlains Energy (WPE) in Colorado, the Navajo Tribal Utility Authority in Arizona, and several municipal utilities in Wyoming have all been able to leave or reduce purchases from their long-term suppliers and negotiate cheaper contracts with new utility suppliers.[4]

More recently, utilities have also begun to lose their end-use loads. In Colorado, several large customers—including the University of Colorado, Total Petroleum, and Coors[5]—have begun to generate their own electricity and reduce or eliminate purchases from their local supplier. Other customers, particularly those close to the border of two utility service territories such as Utah State University in Logan, may be able to choose between two utility suppliers.[6] Even more dramatic, some retail customers are finding ways to reorganize themselves to become utilities in order to leave their host supplier. For example, the City of Las Cruces in New Mexico has formed a municipal utility in an attempt to sidestep the high retail prices of its current supplier, El Paso Electric.

In light of the financial incentives for retail customers to leave their host supplier, a number of large electric users have sought regulatory or legislative changes that would, by eliminating the legal barriers that require them to purchase from a single local utility, allow them direct access to wholesale markets. As Appendix B describes, most states in this region have direct access proposals under consideration in either legislative or regulatory forums that could eventually allow retail customers to purchase cheaper power on the open market and have it transmitted or "wheeled" to them by their former supplier—so-called retail wheeling. Although many of these proposals have substantial problems as currently drafted, they further increase utility concerns about retaining customers, particularly larger ones.

Utility Responses

In response to this changing environment, utilities have become increasingly concerned

Table 3-1. Average 1994 Regional Electricity Prices

Utility	Average Retail Price, *cents per kilowatt-hour*
Southwestern Public Service Company (NM)	4.4
PacifiCorp (UT, WY)	4.7
Public Service Company of Colorado (CO)	6.0
Nevada Power Company (NV)	6.4
El Paso Electric (NM)	8.1
Tucson Electric Power Company (AZ)	8.2
Public Service Company of New Mexico (NM)	8.5
Arizona Public Service Company (AZ)	8.6
Wholesale prices for firm power	1–4

Source: The Edison Electric Institute Database, 1995.
Note: Even if the additional costs of distribution included in retail prices are taken into account, there is still a dramatic difference between wholesale and retail prices.

about retaining both their existing retail and wholesale customers. For most utilities in the region, the primary focus has been on providing customers—particularly larger ones who can most easily find a new provider—with the lowest possible short-term prices. To this end, the region's utilities have been cutting costs, slashing investments that produce long-term benefits, avoiding long-term commitments, and lowering the price of power provided to large customers. Such utility behavior is threatening the ability of the region to acquire the kinds of resources recommended in the LAW Fund blueprint.

"... utilities have become increasingly concerned about retaining both their existing retail and wholesale customers."

Shareholder Incentives

Protected by state law for over 70 years, most of the region's utilities have had the exclusive right to provide electric power to customers within a fixed service territory. Under this regulatory compact, utilities have been able to adopt a long-term perspective with substantial likelihood of cost recovery. As the threat of industry restructuring has expanded, the certainty with which utilities can recover these costs from customers over time has diminished because retail customers may eventually be able to purchase their power from different generation companies. If existing large customers can sidestep the system, then utilities and their captive customers may be responsible for any unrecovered costs incurred to achieve long-term public interest benefits. In this environment, even iron-clad regulatory approvals of cost recovery do not carry the same weight that they have in the recent past, giving rise to a newfound fear among utilities that they will invest in resources and not be able to recover their costs. This fear of creating stranded regulatory assets[9] has become increasingly important to many utilities.

Utility concerns about cost recovery are compounded by the short-term rate impacts potentially associated with clean energy investments. To invest in energy efficiency, renewable resources, and environmental mitigation involves incurring costs today to avoid or delay building new power plants and to diversify against fossil fuel price and environmental risks over time. Even though these costs are economical in the long term, they put upward pressure on prices now, which may increase utility fears about losing customers. Utilities, therefore, increasingly appear to believe that investments to produce public interest benefits over the longer term

Walking Away from the Local Utility

The City of Las Cruces is a town of 65,000 people in southern New Mexico whose citizens have purchased power from El Paso Electric (EPE) for many years. Las Cruces recently formed a municipal utility and is now attempting to sidestep the EPE system, which, because of investments in the expensive Palo Verde nuclear plant, has some of the highest rates in the state. This move to purchase cheaper power, if successful, will cut the electric bills of the retail customers in the city by more than 20 percent.

EPE, having just emerged from bankruptcy proceedings, is concerned that the city's proposal will raise rates for all remaining utility customers because the fixed costs of the preexisting nuclear investments will be spread over a smaller sales base. Las Cruces, which accounts for about 8 percent of the entire EPE demand, is currently in the process of trying to condemn the local EPE distribution system. Las Cruces wants to acquire the distribution system at its book value of about $20 million; in contrast, EPE contends that the city should be responsible for 8 percent of the total system costs (including the nuclear assets)—about $170 million.[7] As of early 1996, this dispute remains unresolved pending both federal and state judicial decisions on bankruptcy, condemnation, and financing issues.[8]

will create increased financial risk for them and their shareholders.

Recent Experience

There is now a growing trend among the region's utilities to rely on short-term purchased power to meet growing demands, to significantly cut energy efficiency and renewable resource budgets, and to generally avoid all other long-term resource commitments. These actions are defended as logical responses to increased competition and the need to minimize short-term prices.

For example, Nevada Power Company (NPC), in a 1995 resource-planning case, proposed to substitute short-term purchased power for the acquisition of capacity under long-term bids to meet rapidly growing demand. The utility also proposed to slash its energy efficiency budget by two-thirds and to stop considering the long-term environmental impacts of its actions. In the words of NPC Vice President Steven Rigazio, "Given the increased business risk associated with competition and potential industry changes, sound financial planning at this point dictates avoiding, to the extent practical, increased long-term obligations."[10]

In response to the same financial incentives, Public Service Company of Colorado (PSCO) is proposing to eliminate its energy efficiency investments after 1996 and is trying to limit its commitment to renewables.[11] PSCO is also reluctant to clean up power plants that appear to be linked to a number of the state's more difficult environmental problems.[12] As Del Hock, chairman of the board and former chief executive officer of PSCO, bluntly puts it: "Price is everything."[13]

The proposals put forward by NPC and PSCO essentially create a situation of *unregulated monopoly.* These utilities want to retain their monopoly status while abandoning their public interest responsibilities. In contrast, other companies recognize that factors beyond price are also relevant. For example, Micron Technologies—a microchip manufacturer planning to build a $2.4 billion semiconductor plant in Lehi, Utah—chose to purchase power from PacifiCorp even though its price was higher than the bid of the local municipal utility. According to Micron, reliability was more important than price.[14] Similarly, a recent policy statement by the Colorado Public Utilities Commission clearly demonstrated commitment to a number of environmental and economic public interest concerns that extended well beyond short-term rates.[15]

Regulated Monopolies and Clean Energy

For an industry structure that continues to be characterized by vertically integrated monopolies, there are a variety of tools that can help to maintain funding for the clean energy investments in the LAW Fund blueprint and, at the same time, help to move the industry toward a future where such funding is greatly reduced.[16] Indeed, the purpose of continued utility funding for these clean energy resources is to prepare for a competitive future where such funding comes from other, non-utility sources.

"Utilities ... appear to believe that investments to produce public interest benefits ... will create increased financial risk ..."

Resource-Specific Strategies

Over time, each of the individual resources contained in the LAW Fund blueprint can be acquired in a manner compatible with the changing structure of the industry. This section presents individualized approaches for promoting energy efficiency, renewable resources, and power plant cleanups that address the financial concerns of vertically integrated utilities in an increasingly competitive industry.

Encouraging Energy Efficiency

Utility investments in energy efficiency are a cost-effective and environmentally sound way to meet growing electricity demands. Currently, energy service companies (ESCOs)—private entities that work with customers to

evaluate and install energy-efficient equipment—have had success convincing more sophisticated utility customers to install efficiency measures that have relatively short payback periods. Examples include the relamping of commercial buildings, such as supermarkets, and improved production processes for very large industrial customers. In these markets, utility financial and technical support is generally not needed.

In most other markets—involving less sophisticated customers and longer payback measures (i.e., those over a year)—the evidence indicates that the existing market is not sufficiently mature to be able to take advantage of these opportunities without utility support. As explained in Appendix D in more detail, there are proven and persistent market barriers that must be overcome for the typical utility customer to invest in energy efficiency measures to the degree that will be cost-effective over the long run for the electric system. To achieve the level of savings described in the blueprint, it is critical to reach these less sophisticated customers because the existing efforts of ESCOs to work with these customers will capture only a tiny fraction of the available savings. Until new approaches can be developed to realize these opportunities without utility involvement, utilities and their customers will need to continue to support investments in energy efficiency financially. Utilities should use existing customer funding for energy efficiency to develop so-called market transformation programs that accelerate the transition to a time when utility customer funding is no longer required.

Perhaps the best opportunity for reducing customer funding is for utilities and other energy service providers to recover additional funds from program participants. Several utilities have been successful at using bill adders to recover the costs of energy efficiency from customers. For example, PacifiCorp has taken the lead in developing demand-side management (DSM) programs in both Utah and the Pacific Northwest that collect additional funds (through participant surcharges) from the bill savings of only those customers who benefit from the installation of energy-efficient equipment. Utilities in Arizona and Colorado are now experimenting with participant surcharges.

Variations on the PacifiCorp approach also offer considerable promise. One alternative is for the utility to provide a customer with an up-front cash "bonus" payment. In return for this payment, the utility should be able to attach a larger surcharge to recover a significant portion of that customer's bill savings. Evidence suggests that this approach

Demand-Side Management in Utah:
Using Cheap Loans to Increase Industrial Competitiveness

Geneva Steel owns and operates a large integrated steel mill outside of Provo, Utah. The company has 2,700 employees and annual revenues of $460 million. As part of a plant modernization and expansion, Utah Power & Light provided subsidized loans of over $600,000 to enable Geneva to install energy-efficient baghouse and water cooling equipment. Geneva will pay back this loan over time out of the bill savings resulting from these measures.

Indeed, because of this investment, Geneva's electric use has been reduced by 24,000 megawatt-hours—enough electricity to power 3,000 new homes in Utah. Ultimately, Geneva will realize annual bill savings of close to $700,000, a roughly 4–5 percent improvement in bottom-line profits. Thus, this energy efficiency effort adds to profits, protects jobs, and makes Utah businesses more competitive.

should be attractive to both customers and the utility. From the customer's perspective, this approach produces positive cash flow from the day the energy efficiency measures are installed, thereby removing almost all risk and uncertainty from the transaction. As a result of the funds collected through the participant surcharge, this program design can greatly reduce or eliminate lost revenues for utilities.[17]

All these approaches to designing energy efficiency programs should be focused on efforts that fundamentally transform markets so that customers will begin to install energy-efficient equipment on their own without utility financial incentives. The idea is to work with dealers and other key trade allies, and in conjunction with changing efficiency standards, so that customer behavior is comprehensively altered to favor purchasing the energy-efficient equipment. If successful, this approach can reduce customer electricity usage at extremely low costs.

The region's utilities can also use DSM programs and financial incentives to help retain large or other at-risk customers. In this way, DSM can become an important part of a pro-competitive strategy designed to keep at-risk customers on the system. The PacifiCorp effort to increase the competitiveness of Geneva Steel is a good example of this approach. Given the benefit in terms of improved customer relations, utility shareholders should be willing to support these programs.

Similarly, DSM efforts targeting transmission and distribution (T&D)-constrained areas can help avoid the need for expensive new T&D investments, as well as new generation investments. The large cost savings resulting from the avoidance of building expensive new T&D assets can produce benefits for all customers. Pacific Gas & Electric in California and Central Maine Power have taken the lead in pioneering this approach.[18] In this region, utilities in Arizona are now trying to determine whether similar opportunities exist here.

Finally, there should be special attention given to the needs of low-income customers. Cost-effective programs to promote energy efficiency for low-income customers have been developed through utility partnerships with federal weatherization and low-income energy assistance efforts. For example, Public Service Company of Colorado is working with a number of federally-funded agencies in Colorado to weatherize more homes and install additional energy-efficient measures.

Taken as a whole, these new approaches to energy efficiency have great potential to reduce the need for customer funding and perhaps, over time, eliminate it.

Promoting Renewable Resources

Ensuring the availability of renewable resources to meet the region's growing demand depends, in large measure, on making investments now to help reduce the costs of these resources in the future. Unless new approaches, institutions, and funding mechanisms for renewables are developed, the commercialization of key renewable technologies will be delayed or foregone. In a more competitive electric industry, market-based strategies can play a key role in promoting the commercialization of renewable resources. At least two such strategies are available. The first involves enhanced risk sharing among regional utilities. The second approach recognizes customer willingness to pay a small premium to purchase cleaner power.

Risk-Sharing Arrangements. Even in today's changing industry, the joint development of renewable resource projects can make it possible to mitigate utility investment risks. This practice involves obtaining utility funding for renewables projects from a consortium of utilities, thereby limiting any one utility's investment share to a modest portion of the overall project.

"... market-based strategies can play a key role in promoting the commercialization of renewable resources."

The Arlington, Wyoming, wind project—for which a number of utilities acquired relatively small portions of a large 70-megawatt project—is a good example. In this project, PacifiCorp took the lead in identifying four other utilities—the Bonneville Power Administration, the Eugene Water and Electric Board, Public Service Company of Colorado, and Tri-State Generation and Transmission Association—who were interested in exploring the benefits of wind. This allowed the developer to lower total project costs by taking advantage of economies of scale associated with a larger project. At the same time, each individual utility's contribution was small enough to be manageable and the risk of developing the project was shared. In Colorado the risk-sharing element of this project proved essential in obtaining regulatory approval for the acquisition.

The Solar Enterprise Zone

A private nonprofit development corporation called CSTRR (Corporation for Solar Technology and Renewable Resources) was incorporated in February 1995 and later capitalized with a $3 million grant from Department of Energy (DOE) defense conversion funds. Along with several utilities and the DOE, CSTRR is examining the feasibility of developing a Solar Enterprise Zone (SEZ) in southern Nevada. Toward this end, CSTRR issued a request for proposals (RFP) for 100-megawatt solar electric projects in the summer of 1995 as a first phase of a mandate to issue RFPs for 1,000 megawatts by 2003.

To help find a buyer for this capacity, the state of Nevada has agreed to provide $160 million in tax-exempt bonding authority to project developers, thereby effectively reducing financing costs by roughly a third. Several sites in southern Nevada have been earmarked for potential development, although bidders can choose other sites if they so desire. The most likely site is in the Eldorado Valley near Boulder City, which has access to existing transmission lines, water, natural gas pipelines, high levels of solar radiation, and cheap land.[20]

Efforts are under way to replicate this approach for a Colorado wind project. A number of utilities, already collaborating to enhance wind-monitoring capability in the state, are currently discussing the possibility of developing a site in Colorado before the federal wind production tax credits expire in 1999. As with the Wyoming site, the risk sharing enabled the discussions to begin. No utility is willing, by itself, to purchase the 25 megawatts needed to take advantage of production economies.

Nevada and Arizona offer opportunities for utilities to develop similar projects for using the region's immense solar resource. In Arizona, four utilities have agreed to jointly develop 19 megawatts of solar energy by the end of the decade.[19] In southern Nevada, a number of entities are exploring the possibilities for jointly creating a solar enterprise zone that would help commercialize several promising technologies.

Green Pricing. Green pricing approaches appear to be a promising tool to promote the commercialization of renewable resources. Numerous surveys have shown that a large majority of utility customers are willing to pay more on their electricity bills to purchase power from renewable sources and to protect the environment.[21] For many people, this is the easiest way to reduce the environmental impacts associated with their energy use. For example, by paying an additional $5 per month to replace coal with wind power, a typical Colorado household could annually eliminate the need to burn 6,000 pounds of coal, the resulting air pollution, and as much carbon dioxide as is produced by driving 12,000 miles.

At least three utilities nationwide, including Public Service Company of Colorado, have developed green pricing programs that attempt to tap the market for cleaner power. To date, however, these programs have not raised nearly enough funds to make a meaningful difference in the commercializa-

tion of key renewable resource technologies. Several factors appear to account for low subscription in these programs. One is that these green pricing programs have focused exclusively on obtaining funding from a relatively small number of residential customers. Also, utilities have been reluctant to spend the advertising and marketing dollars necessary to create sufficient market awareness of their programs.[23] A third factor is that the utilities running these programs have not clearly developed and defined a "green product" that provides sufficient value to interest either residential or larger customers.[24] Finally, utilities have not sought partnerships that would enable them to create greater product awareness more economically.

Various proposals are being developed to remedy these shortcomings. In the Vail and Roaring Fork Valleys of Colorado, a partnership is being formed among utilities, local community groups, renewables advocates, and wind developers to create a model green pricing program targeted toward not only residential customers but also small and large commercial and industrial customers. This approach will likely raise substantially more money. Initial customer responses suggest that many Colorado businesses—including ski areas, municipalities, and high-tech companies—would pay a small premium to purchase clean power. The results of this experiment should be available in late 1996.[25]

Green Pricing: A Market-Based Approach

Green pricing offers environmentally concerned customers the choice of purchasing clean energy. Customers already have the option to choose green products ranging from paper goods made of recycled materials to pesticide-free fruits and vegetables and dolphin-safe tuna. Simply put, green pricing applies the marketing strategy used by Ben & Jerry's Ice Cream, Patagonia, and a long and growing list of businesses to the electric industry. Conceptually, green pricing is straightforward. The green customer pays a premium, perhaps 5 or 10 percent of a normal bill, to buy power from a clean source. In return, the utility uses these funds to offset the incremental price difference between the renewable resource and the fossil fuel alternative.[22]

Cleaning Up Dirty Power Plants

As discussed in Chapter 1, the electric utility industry in our region contributes to a number of existing environmental problems. The potential for industry restructuring offers a number of ways to address these problems. Funding the cleanup of the region's dirty power plants can be accomplished by attaching conditions to regulatory approval of various transactions, for example, merger proceedings such as the one involving Public Service Company of Colorado and Southwestern Public Service Company (SPS) in Colorado, Texas, and New Mexico. In addition to producing significant cost savings, this merger will likely affect the operation of existing power plants in ways that could exacerbate air quality concerns in the region. Under these circumstances, and in the context of regulatory approval proceedings at both the state and federal levels, some fraction of the merger-related savings should be targeted to clean up power plants and improve air quality.

Likewise, there are a number of ongoing proceedings in the region designed to provide incentives for utilities to lower costs. For example, Arizona Public Service Company (APS) and state regulators have negotiated a deal that would allow the utility to realize substantial overearnings in return for cutting costs and rates. In return for these earnings, however, utilities like APS should be required to fund clean energy investments. Another way of encouraging utilities to address such problems is to link recovery of "stranded costs" (costs that a utility cannot recover after retail wheeling has been implemented) to a finding by the public utilities commission (or, alternatively, a pollution control agency)

that the utility has taken, or is taking, all necessary and appropriate steps to mitigate the environmental problems in which its power plant operations are implicated. A draft version of retail wheeling legislation in Colorado encourages this kind of linkage.

Finally, the privatization of the federal power-marketing agencies could offer a unique opportunity to promote sustainable energy policies. Over the next few years, Congress is expected to consider a number of proposals to sell all or portions of the hydroelectric assets of agencies such as the Western Area Power Administration. As part of any legislation authorizing such transfers, Congress should require the new owners to promote environmental goals.[26]

Other Regulatory Mechanisms

Throughout the country there are a number of ongoing efforts to abolish fuel adjustment clauses and to implement performance-based regulation.

"The ... solution ... is to allow utilities to recover fuel costs in the same manner as all other costs."

Abolishing Fuel Adjustment Clauses

Many utilities in the region have had automatic fuel adjustment clauses that provide dollar-for-dollar recovery of fossil fuel-related expenses between their rate cases before the public utilities commissions (PUCs). For the most part, these regulatory mechanisms insulate utilities from the risks associated with changing fuel costs and, often, purchase power expenses. If fossil fuel prices increase, the extra costs are transferred to utility customers without a full regulatory examination of the other factors affecting utility costs and revenues. Under these circumstances, utilities have an inappropriate incentive to invest in fossil fuel technologies because, under the fuel adjustment clause, the fuel and environmental risks of these technologies are borne by the utilities' customers, not their shareholders. Conversely, shareholders would bear the costs of capital-intensive resources such as energy efficiency and renewables. The easiest solution to this problem is to allow utilities to recover fuel costs in the same manner as all other costs. Such an approach would be consistent with the incentive that utilities would otherwise have under competition to cut costs and promote innovation. As a result, automatic fuel adjustment clauses should be abolished. Several states, including Arizona, Utah, and Colorado, have moved or are moving in this direction.

Performance-Based Regulation

Many states are experimenting with what is known as performance-based regulation (PBR) in which utilities are allowed to keep what would otherwise be considered "overearnings" under traditional regulatory principles if they meet certain public interest policy goals established by a PUC. The objective of PBR is to encourage utilities to be innovative in attaining these goals.

PBR, usually implemented with the objective of encouraging utilities to reduce costs of service, also has potential for meeting the objectives of the blueprint. For example, a utility could be rewarded through PBR for implementing clean power acquisition programs that help to commercialize a renewable resource technology that promises significant long-term value on the utility's system. Or PBR could be structured to encourage DSM programs that are both low in cost and market transforming.

Other Funding Mechanisms

Cost-effective energy efficiency, the commercialization of renewable technologies, low-income energy assistance programs, and general research and development (R&D) have been integral parts of the services historically provided by most electric utilities. These investments may become casualties of the transitional period without a general mechanism to maintain and expand them in a more competitive industry. Although there is considerable promise that each of these activities can ultimately be funded by non-

utility sources, in the short term some utility funding will be necessary.

One of the better approaches for dealing with utilities' reluctance to invest in clean energy technologies is to place the costs associated with such investments on a portion of the business that cannot easily be bypassed by customers. Under these circumstances, utilities could be reasonably assured that they would recover their prudently incurred costs and that they would not be creating an incentive for customers to leave their system.

A wires surcharge (or systems benefits charge) appears to be an effective way to accomplish this objective. In essence, the costs associated with clean energy investments are placed on the monopoly assets—the transmission and distribution system—which cannot easily be bypassed. Even in a world where customers can choose their own supplier, they will still need to use the existing T&D system if they want to continue to take advantage of the reliability and other benefits of the interconnected utility grid. Almost all of the region's utilities have developed T&D tariffs that charge at least some customers separately for the use of these facilities. Under the wires surcharge proposal, utilities would add an additional increment to the T&D component of all current retail customer bills to recover the costs associated with clean energy investments. This charge could be in terms of demand (dollars per kilowatt), energy (cents per kilowatt-hour), or a flat monthly fee (dollars per month) depending on the individual characteristics of the local utility. Even a customer who obtained a new supplier would still be subject to the surcharge. In this way, chances are that the local utility will recover its prudently incurred investments in resources that promote long-term public interests.

At least one utility has already implemented a wires surcharge. Washington Water Power has received approval from the Washington Utilities Transport Commission (WUTC) to implement a surcharge in the form of an adder on the energy component of its distribution tariff.[27] Likewise, recent proposals have been made in California and Oregon for funding energy efficiency, renewable resources, and low-income energy assistance efforts through a wires surcharge. In this region, both the Colorado Public Utilities Commission and the Colorado legislature have considered similar approaches.

The question remains, however, as to what entity is best suited to spend these dollars. The obvious solution is to let the entity that owns and operates the monopoly transmission and distribution facilities determine how these funds are best spent, subject to regulatory oversight. Alternatively, the utility could sponsor competitive bidding processes that would allow third parties to help fulfill public interest functions.

"At least one utility has already implemented a wires surcharge."

Competitive Resource Acquisition Processes

As the potential for industry restructuring expands, many regulators are increasingly reluctant to mandate utility investments in clean technologies through integrated resource planning (IRP) or other regulatory processes (see Appendix B for a discussion of IRP and other regulatory tools available to state utility regulators). However, among state regulators there is a growing trend toward developing market-oriented pooling or competitive bidding processes for selecting new resources. For example, in May 1995 and again more strongly in December 1995, the California PUC implemented a mandatory wholesale electric power pool. As part of a larger effort to increase competition in wholesale power markets, the pool would require the state's utilities to turn over management of their transmission assets to an independent system operator that would operate them as a unified grid.[28]

Within the Rocky Mountain and Desert Southwest region, the Colorado PUC recently proposed regulations, modifying a pre-existing planning rule, that would implement a utility-sponsored competitive bidding process to meet new resource needs.[29] A similar proposal may be considered by the New Mexico PUC as part of an inquiry into industry restructuring in the spring of 1996. These draft regulations, which focus attention on the bidding criteria to be used by utilities, can and should be tailored to ensure that long-term environmental and risk diversification values are fully incorporated into utility resource acquisition decisions. Indeed, the Colorado PUC's proposal contains such a requirement.[30]

Toward a New Industry Structure

Though there are a variety of tools to help maintain clean energy investments during the transition to a more competitive industry structure, several questions remain. For instance, when is the transition to a new industry structure complete? What characteristics of the new structure are central to the completion of the transition? Are there ways to guide the transition so that the industry continues to invest in clean energy after the transition is complete?

In the LAW Fund's view, preliminary answers to these questions are available. The long-term transition to a new, more competitive electric industry structure will be complete when two key objectives are achieved: (1) the breakup of vertically integrated utilities so that competitive (generation) and monopoly (T&D) functions are no longer contained in the same corporate structure; and (2) the implementation of a regime that allows retail customers to choose their own supplier. In fact, there are several new ideas for creating an industry structure within the region that meets these two objectives in a way that allows investments in clean energy technologies to continue.

One involves the breakup of the vertically integrated utility to form a separate, nonprofit T&D entity and a for-profit generation company. Quantitative analysis is showing that disaggregation can produce substantial tax and financing benefits, some of which can be used to promote a clean energy future. Another idea involves a new approach to retail wheeling that provides customers direct access to wholesale power markets to meet incremental rather than total resource needs.

"The disaggregation of ... utilities into separate generation and T&D companies can produce substantial financial and regulatory benefits."

Disaggregation

The disaggregation of vertically integrated utilities into separate generation and T&D companies can produce substantial financial and regulatory benefits.

Problems with Vertical Integration

The electric industry has been characterized for over 70 years by for-profit vertically integrated utilities that combine generation, transmission, and distribution functions within the same corporate structure and provide power to an exclusive monopoly franchise service territory. Over time, as a result of both technological and legal changes, the generation function of the electric industry has become reasonably competitive, whereas the T&D functions have remained natural monopolies. As a result, the vertically integrated utilities of today contain both competitive and monopoly functions within the same corporate structure. This reality creates the possibility that vertically integrated utilities can use their control over monopoly facilities to protect and enhance their position in competitive markets for the benefit of shareholders and at the expense of long-term public interests. Indeed, this potential is either causing or exacerbating several major regulatory problems involving clean energy investments, transmission access, and equity concerns.

Clean Energy Investments. This chapter has already described how the potential for customers to leave their local supplier discourages utilities from investing in clean energy technologies. Given the future threat that customers can potentially avoid purchasing generation from their current supplier, vertically integrated utilities have become reluctant to acquire resources that might raise their short-term costs or prices.

Disaggregation can significantly lessen the financial pressures that discourage utility investments in clean power technologies. The utility that remains after disaggregation—owning only T&D assets—will no longer be under pressure to use its monopoly power to provide a market for the output of generation assets. As a result, it will be freer (if not entirely free) to purchase the output of clean power technologies from the wholesale market for a portion of the needs of its T&D customers.

Of course, it is true that once a T&D entity enters into a power purchase contract to provide resources to meet the needs of its T&D customers, it will be liable for the recovery of the costs of these power purchases. Because the T&D entity will worry about recovering purchase power costs from its customers, it will not be entirely free of the financial pressures that are presently driving vertically integrated utilities to avoid clean power investments. However, we are optimistic that the emerging wholesale market in the West will provide rapidly expanding opportunities for the new T&D entity to minimize its exposure to future stranded costs.

For example, it should be possible for the T&D entity to purchase less than all of the output of a whole power plant and for shorter time periods than the life of the plant. We are also optimistic that wholesale markets will provide contractual instruments that permit the new T&D entity to transfer some of the cost risk associated with clean power technologies to independent power companies.

These features of the wholesale market should significantly lessen the exposure of the new T&D entity to stranded power purchase costs, especially relative to the exposure of most vertically integrated utilities today to stranded power generation costs. For these reasons, as well as others pertaining to the organization of the T&D entity and its charter, which we explain below, we believe that disaggregation should be an integral part of the LAW Fund's blueprint.

Other Problems. The problems associated with vertically integrated utilities also extend to disputes involving transmission access, pricing, and control. Indeed, as the Federal Energy Regulatory Commission (FERC) has observed in its recent "mega-NOPR"[31] on open access and stranded cost recovery, the vast majority of transmission-controlling utilities have not agreed to give up their market power voluntarily because these utilities are profit maximizers and monopoly suppliers to their native load. The FERC's proposed regulations explicitly address the scope and magnitude of this potential problem:

> Transmission-owning utilities have an incentive to deny access. ... This is particularly true for those utilities that emerged ... as high-cost generation companies. Open access transmission places their existing generation at risk because their wholesale customers may seek alternative lower price suppliers. It is in their self-interest to maintain and use market power to retain (or expand) market share for their existing generation facilities.[32]

Although the FERC is seeking to mitigate this problem by requiring the filing of open-access transmission tariffs, disaggregation can help solve the underlying problem. That is, the new T&D entity would have no reason to use its transmission assets to favor sale of its generation because it owns no generation. Again, it is true that there may still be an incentive to use the T&D assets to market power purchased by contract, but, as ex-

"Disaggregation can significantly lessen the financial pressures that discourage utility investments in clean power technologies."

plained above, this incentive should be less for the new T&D entity than for today's vertically integrated utility. As a result, disaggregation can accelerate the timetable for the occurrence of real open access.

As competition expands, at least one equity concern arises because utilities can shift costs from larger, at-risk customers to smaller, captive ones. This equity concern stems from the increasing ability of large retail energy users to bypass their local utility and obtain direct access to cheap wholesale power more quickly than other customers. In fact, some of these larger customers already have the economic and technological means to self-generate. With an eye toward recovering at least some fixed costs from large industrial customers, vertically integrated utilities have sought to extend special rate breaks to their large users, sometimes at the expense of other customers. Again, disaggregation can help solve this equity concern because the T&D entity that is not in the generation business may have less of an incentive to shift costs to captive customers.

"Disaggregation produces substantial tax and financing benefits ..."

A Disaggregation Proposal

Despite the problems with vertical integration, it is likely to be difficult to break apart today's electric utilities. Under current law, neither federal nor state regulators have clear authority to require a utility to disaggregate. And even if there were a clear authority, the takings clause of the Fifth Amendment to the U.S. Constitution might inhibit the ability to exercise that authority. Because of these legal barriers, most of the existing approaches to industry restructuring have relied upon "functional unbundling," essentially regulatory or accounting mechanisms that, for the purposes of given transactions, separate out competitive and monopoly functions on paper. For example, the FERC has proposed to regulate transmission and distribution access and pricing to handle the problems associated with joint utility control of generation and T&D facilities.[33] The California Public Utilities Commission has proposed a similar mechanism for that state's T&D facilities.

Both of these proposals, however, address the symptoms of the problem, rather than its underlying cause. Even after final decisions have been made in both the FERC and California PUC cases, utilities will still have both competitive and monopoly functions within the same corporate entity, and the financial incentive to protect the competitive position of their generation assets will remain. No regulatory regime may be able to produce a level playing field given the informational asymmetries that exist; utilities generally have the best access to customer load and energy resource data. As a result, regulators and others may have difficulty, at least with respect to time and resources, developing the information and expertise necessary to successfully regulate vertically integrated monopolies. This informational problem may be exacerbated by the growing utility trend to keep confidential the energy supply and demand data considered to be competitively sensitive.

Given the barriers to disaggregation, an approach is needed that makes a breakup financially appealing to the utility or its shareholders. Disaggregating utilities through market mechanisms is one such approach. The remainder of this section introduces a LAW Fund proposal to encourage utilities to disaggregate that produces substantial tax and financing benefits, part of which can be used to provide a shareholder premium.[34]

This disaggregation proposal involves splitting existing utilities into two new organizations, a competitive for-profit generation company and a nonprofit T&D entity. Following a transition period governed by a long-term purchase power contract between the two companies, the disaggregated structure allows the generation company to compete in profit-oriented supply markets, whereas the T&D entity remains a regulated monopoly. The feature that makes this proposal attractive is the creation of immedi-

ate and ongoing financial and tax benefits.[35] Given the potential size of these benefits, it should be possible in a number of circumstances to convince shareholders, customers, and other stakeholders that disaggregation is in their financial interest.

The benefits of this proposal come from two sources. First, as a nonprofit company, the new T&D entity will not be subject to federal income taxes.[36] Our analysis suggests that these tax savings can be as high as 5 percent of a given utility's annual revenues. In addition to the tax savings, disaggregation could result in a more highly leveraged T&D entity financed with low-cost capital.

To explore these potential benefits further, the LAW Fund has been working with local public interest groups, investment bankers, customers, and accountants to develop a disaggregation proposal for Nevada Power Company, an investor-owned utility serving the metropolitan Las Vegas area of southern Nevada. Disaggregation would result in a separate, nonprofit, more highly leveraged T&D entity, supported by a strong lending institution with a diverse portfolio. This diversification allows the new debt of the T&D entity a AA rating, as compared to NPC's current BBB rating, thereby reducing financing costs.[37] Based on a quantitative analysis, the combination of these financing and tax benefits reduces NPC's immediate cost of providing service by close to 10 percent (more than $60 million annually) and provides additional reductions over time. The magnitude of these benefits for NPC suggests that this idea should be transferable to other utilities.

In the case of NPC, the financing and tax benefits generated by the creation of a nonprofit T&D entity are great enough to be utilized to (1) finance and amortize a shareholder premium of $300 million (about a 30 percent premium on total equity and a 65 percent premium on T&D-related equity);[38] (2) invest roughly $30 million per year in renewable and demand-side resources; and (3) still reduce existing rates on average by 2–3 percent ($17 million the first year). Given these benefits and the potential for creating substantial shareholder value, this proposal could potentially provide an attractive, market-oriented mechanism for disaggregating utilities, particularly those that are in financial trouble.

Similar proposals have been developed outside the Rocky Mountains and Desert Southwest. For example, Governor Pataki's office in New York has recently proposed to disaggregate Long Island Lighting Company (LILCO). Initial analysis suggests that many of the benefits associated with the governor's proposal arise from using tax-free municipal bonds to finance the acquisition. The LILCO plan would result in the sale of the generation and natural gas operations of the current company and in the purchase of the $4.5 billion T&D assets. Although there are a number of unresolved issues, such as what entity would control the T&D assets, the overall savings from the plan appear to be significant and roughly comparable to those associated with the NPC disaggregation proposal.[39]

In addition to the financial benefits, disaggregation provides an opportunity to structure the new T&D entity so that one of its primary objectives is to promote economically and environmentally sustainable resource choices. To ensure that these goals are attained, the articles of incorporation, the bylaws, and the board of directors of the new T&D entity can be carefully set up to require that, among other things, the new T&D entity focus on encouraging increased use of energy efficiency and renewable resources. These and other benefits of disaggregation make it a key feature of the LAW Fund's vision of how the region may implement the blueprint in a restructured industry.

Providing Customer Choice

As discussed above, there is growing pressure to allow retail electric utility customers to

"... it should be possible ... to convince shareholders, customers, and other stakeholders that disaggregation is in their financial interest."

choose their power supplier. In this section we discuss the pros and cons of allowing customer choice, that is, "retail wheeling" or "direct access." We conclude that retail wheeling can resolve some thorny problems with the existing system, but not without creating problems of its own, especially relating to the question of the recovery of stranded costs.

Retail wheeling also presents challenges to the implementation of the blueprint. Opening the provision of electricity to retail markets could shift the focus even further away from investments that have future benefits and higher short-term prices. Nonetheless, the LAW Fund believes that it is possible to implement the blueprint in a world characterized by customer choice. We offer the following suggestions for how this objective can be accomplished.

"... retail wheeling can resolve some thorny problems with the existing system, but not without creating problems of its own ..."

Problems with Regulation

There are at least three flaws in the existing electric industry structure that could be helped by retail wheeling. These flaws have to do with risk allocation, average cost pricing, and customer choice and service.

Risk Allocation. The first problem with the status quo arises because the allocation of risk between utility shareholders and utility customers creates inefficiencies. Typically, utility investments in new generation assets—the large majority of total utility costs—are subject to a wide range of uncertainties involving, for example, volatile fuel prices, fluctuating interest rates, and the potential for stricter environmental, health, and safety regulations. There are also risks that loads will be quite different than those forecast by utilities, thereby creating unexpected costs. In New Mexico and Arizona—where many of the utilities purchased substantial shares of the Palo Verde nuclear units—the impact on electric prices attributable to such supply risks has been enormous.

The transfer of risk to final customers stands in sharp contrast to the prevailing practice in the rest of the domestic economy. For example, suppose General Motors decides to construct a new plant to build cars. If the overall demand for cars slackens or if customer tastes change and no one wants GM's cars, GM will not be able to recoup its investment. GM and its private investors typically bear the risk and, conversely, receive the rewards associated with investing in new plants. This makes sense because GM is best situated to understand and evaluate the risks associated with the new plant. Indeed, many think that a utility's private investors are better situated than customers to bear generation risks.

Given the variety of resource choices now available, imposing most of these risks on ratepayers is not only unfair but inefficient. It is unfair because utility customers are less able to diversify against the risks. It is inefficient because utilities have no incentive to insure against risks; they know that if they make mistakes, the customer will likely pay, although competitive pressures are reducing the ability of utilities to rely on ratepayers to reimburse them for their mistakes. Conversely, if utilities make smart decisions, utility shareholders may see little of the benefit, since retail prices are based on historical costs, not market forces. For the same reason, important risks have tended to be ignored. For example, utilities have done too little to manage the risk of more stringent regulation to improve regional visibility or to guard against global climate change, in part, because at least some of the extra costs that may be imposed later can likely be passed on to ratepayers under current regulation.

Average Cost Pricing. A second problem with the existing industry structure arises because retail electric prices reflect historically based average costs. Consequently, utilities in the region have wide price disparities based on prior investment decisions. Within the state of New Mexico retail prices can vary enormously—from a low of 4.5

cents per kilowatt-hour for Southwestern Public Service Company (SPS) to about 8.5 cents per kilowatt-hour for Public Service Company of New Mexico (PNM). These disparities create inefficiencies. In this example, a new customer choosing between the service territories of PNM and SPS will select SPS, all other things being equal. SPS has far lower electric prices, close to half of those of PNM. However, PNM has excess capacity, whereas SPS appears to need new capacity relatively soon. As a result, PNM can most likely serve a new customer at a lower marginal cost. Thus, from an efficiency perspective, this customer should locate in PNM's territory.

As this simplified example shows, the existing structure of average cost pricing in this region creates perverse financial incentives that may distort customer siting and energy use decisions. At a minimum, a better industry structure would foster the equalization of prices between utilities such as SPS and PNM.

Customer Choice and Service. Under current regulation, utility customers have no choice of electricity supplier—they must buy from the local monopoly. This may discourage utilities from developing new services that are more sensitive to customer needs. There is some evidence from the telecommunications industry that, after customers were given enhanced choices, suppliers developed new technologies and services in an attempt to retain their customers. Again, the issue is efficiency and customer service, and the current structure does not appear to be the best one for providing customer choice.

The Benefits of Retail Wheeling

Conventional retail wheeling proposals—whereby customers can obtain direct access to cheaper wholesale power—can help solve each of the three problems associated with the status quo. First, retail wheeling enables the consumer to enter into contracts or rely on open market purchases in a way that places the majority of supply-side resource risks on suppliers. Under a retail wheeling regime, generators who incorrectly forecast market trends involving fuel prices, demand growth, or interest rates will likely suffer the consequences and have to write down their assets. In this way, customers will be protected from poor choices made by individual suppliers. Another example from the telecommunications industry illustrates this point. If MCI builds too much fiber optic capability and its prices rise, customers can always turn to AT&T or Sprint, forcing MCI to write off a portion of its investment. With retail wheeling, customers will bear far less of the risk associated with excess supply, fuel price volatility, and stricter environmental regulations.

Allocating risks to generators should also yield improved efficiency. That is, resource suppliers should be better situated than customers (or regulators) to appreciate and mitigate the risks associated with their individual projects. And the debt and equity holders who finance these projects will be able to diversify their risks by investing in a balanced portfolio of energy and non-energy investments. Gains in efficiency should result because those on whom the risks have been imposed are in a position to insure against them.

Second, retail wheeling proposals move away from a world in which retail prices are based on the average historical costs of the local utility. Under retail wheeling, all customers should be able to purchase power from competitive wholesale markets. As a result, retail wheeling proposals move quickly into a marginal cost-based pricing system. This will tend to equalize prices within the region and will send better price signals to customers, particularly as they make facility siting and energy use decisions.

Finally, retail wheeling should provide customers, particularly larger ones, with a choice of suppliers. As competition to serve

"... the existing structure of average cost pricing in this region creates perverse financial incentives that may distort customer siting and energy use decisions."

these new customers grows, a variety of new products and services may be developed that better match customer and supplier needs. For example, new pricing structures involving individualized time-of-day or seasonal rates could arise to the benefit of both customers and suppliers in much the same way that new services and pricing arrangements were offered with the deregulation of both the phone and natural gas monopolies during the 1980s.[40]

Problems with Retail Wheeling

While retail wheeling has a number of positive attributes, it raises several important issues for equity, efficiency, and implementation of the LAW Fund's blueprint.

Stranded Costs. Under the current regulatory compact, utilities have incurred enormous costs to meet the region's demand for electricity. In this region these costs are mainly associated with large coal and nuclear plants. As industry economics change, a substantial portion of these utility assets have become uneconomic; i.e., they cost more than market alternatives. In many cases, regulators have determined that these investments were prudently incurred. It is often these uneconomical, but prudently incurred, costs of power that retail wheeling proponents seek to avoid. In any event, retail wheeling proposals have large implications for who bears these stranded costs.

The question of who might pay these costs under retail wheeling is already contentious. Under conventional retail wheeling proposals, those who leave the utility system for cheaper power first may not pay for the costs their departure strands. Indeed, large customers (or some small subset of the total customer base) are likely to acquire power on wholesale markets before other customers. Under these circumstances, large customers may sidestep the local utility and may avoid paying for the costs their departure strands, leaving smaller customers vulnerable to paying them.

"... large customers may sidestep the local utility and may avoid paying for the costs their departure strands ..."

A variety of approaches have been suggested to deal with this problem. The December 1995 California PUC regulation to implement a "competition transition charge" —in essence, an exit fee—ensures that departing customers do not unfairly place the costs associated with stranded investment on remaining customers.[42] In practice, however, a number of unresolved legal and economic questions remain. For example, how do regulators calculate stranded investment costs? Once calculated, is it legal to impose an exit fee on customers? On only some customers? Can utilities recover stranded investment in T&D charges? In backup power

Estimating Stranded Costs

Estimates of stranded costs—the difference between the book value and the replacement costs of these assets—vary across a wide range nationally. The Edison Electric Institute (EEI), the lobbying and policy research arm of the investor-owned utilities, has estimated that they may be as high as $200 billion nationally; in contrast, others think that the actual amount may be significantly lower.[41] The problems with stranded investment in this region vary dramatically by state and by utility. In general, those utilities that invested in expensive nuclear and coal-fired power plants between 1975 and 1985—such as many of the Arizona and New Mexico utilities—have substantial amounts of prior investment that could be stranded by retail wheeling. In contrast, other utilities that have relied more heavily on purchased power—PacifiCorp, Public Service Company of Colorado, and Nevada Power Company—have less potential stranded investment.

rates? In wheeling charges? The jurisdictional issues may be even more difficult. Under what circumstances do the states and the FERC have jurisdiction to require payment for stranded costs? As of early 1996, many of these questions remain unanswered.

System Operating Efficiency. In addition to the problems associated with stranded cost recovery, retail wheeling creates concerns about the functioning of voluntary power-pooling arrangements that currently exist within the industry. As described in Appendix B, under the current industry structure, most utilities in the region are voluntary participants in both the Inland Power Pool and the Western Systems Coordinating Council. A number of utilities are also participating cooperatively in regional transmission groups (RTGs) recently accepted by the FERC. These voluntary arrangements produce significant benefits for the region's utilities and their customers.

To date, power pooling has been premised on cooperative arrangements among regional utilities. In a retail wheeling world, with utilities likely competing for each other's retail customers, utilities may find that they can gain a competitive advantage by curtailing their commitments to these voluntary organizations. At a minimum, retail wheeling will create financial incentives for utilities that will put existing voluntary arrangements under additional stress.

As part of a general industry restructuring package, however, it may be possible to create functioning markets for backup power, regional reliability, voltage stability, and other key functions that are currently being performed pursuant to voluntary arrangements. Accordingly, a number of preliminary proposals for "poolcos," "transcos," and other new institutions have been appearing in the industry press over the last year. These institutions may have the capability of providing services now rendered solely by vertically integrated utilities. However, the issues are substantial and, as of early 1996, without resolution.

Acquiring Clean Power Resources. Retail wheeling presents major challenges to the implementation of the LAW Fund's blueprint. Over the last 10 years, as discussed in Appendix B, integrated resource planning (IRP) and supporting financial arrangements have evolved at the state level as a means to encourage utilities to acquire energy efficiency resources through DSM programs, as well as a small amount of renewable resources. The efficacy of IRP depends on a utility's ability to plan (implying a stable customer base) and to recover costs with predictability over an extended period of time.

Because retail wheeling reduces the certainty of utility loads as time passes, it erodes the ability of utilities to plan and their ability to recover costs over a long period of time. As a result, retail wheeling threatens, if not eliminates, IRP as a viable tool by which to promote clean power technologies. Other institutions must be developed and bolstered for clean power acquisitions to occur under retail wheeling, especially if it is made available to all utility customers.

"... retail wheeling threatens, if not eliminates, IRP as a viable tool by which to promote clean power technologies."

Making Retail Wheeling Work

To address stranded costs and related equity problems in a region where rapid load growth is occurring, the LAW Fund puts forward for discussion an approach to customer choice that is limited solely to meeting the region's incremental resource needs through retail wheeling. This approach is intended to complement the formation of nonprofit T&D entities focused on, among other things, the promotion of clean energy technologies and is also intended to help avoid the problems associated with having competitive and monopoly facilities in the same corporate structure.

The approach of restricting retail wheeling to meeting only incremental resource needs should allow for most of the benefits of

retail wheeling. At the same time, limiting retail wheeling to meeting incremental resource needs has the advantage of not stranding costs as a result of potentially immediate customer bypass. As a result, this approach causes the equity issues associated with recovery of stranded costs to essentially disappear. The utility should be able to continue to recover all or most of its prudently incurred costs for a specified time, and smaller captive customers should not bear an unfair portion of the preexisting stranded costs.

For example, a utility projecting future load to exceed resources by 20 percent at the end of five years can allow retail wheeling into its system up to that amount. In theory at least, the utility is not adversely affected because it has not lost any load, nor has it been burdened by stranded assets. The utility need not plan to serve load that customers contract to receive directly from an energy supplier other than the utility, not unlike existing interruptible industrial load.

"The gradual implementation of retail wheeling ... should ... buy time ... to ensure that the goals of the blueprint can be obtained ..."

The issue then becomes one of developing a way of equitably allocating the 20 percent retail wheeling opportunities to customers. One approach is to allow all customers direct access to alternative energy suppliers up to 20 percent of their own loads. If each customer were given access to alternative supplies, then in theory, each customer could receive a resource benefit. Realistically, however, small customers may be unwilling to incur the transaction costs to gain access to non-utility suppliers, or they may simply be uninterested. Conversely, large energy-intensive customers may desire to meet more than 20 percent of their load with retail wheeling, up to 100 percent.

To bring these complementary interests together, a retail wheeling voucher system is suggested. For the above example, each retail customer would receive a voucher equivalent to 20 percent of its individual load. Small customers that cannot take advantage of alternative supplies would be able to sell their vouchers. Larger customers could aggregate vouchers to reach 100 percent retail wheeling for their load. In this way, a market is created for retail wheeling "rights," and all customers receive an economic benefit whether or not they can actually gain access to alternative energy supplies.

Implementing retail wheeling slowly allows additional time to develop the mechanisms necessary to supply backup, unit dispatch, and other power-pooling services. In sum, this combined proposal, in which retail wheeling is used to meet incremental resource needs under a voucher system, would mitigate stranded cost risks for utilities, provide economic benefits to all customers, and help move the industry toward full competition among energy suppliers.

The gradual implementation of retail wheeling described above should also buy time for state governments and others in the region to develop mechanisms to ensure that the goals of the blueprint can be obtained in a world without broad IRP. Although disaggregation will help to encourage implementation of the blueprint, disaggregation, by itself, is not enough to ensure the benefits of the blueprint in a world characterized by retail wheeling. Other steps must be taken, transitional and ongoing, to achieve the blueprint's goals. The electric industry is affected with the public interest in terms of environmental and economic risk management, sustainability, and equity. The protection of these interests requires support from institutions beyond the market, even under disaggregation. Although state PUCs will continue to have a large role in protecting public interest values, as time passes, other instruments of government and new market-based institutions will grow in importance if retail wheeling is implemented.

The Role of Policy Makers

This chapter has described two potential industry structures, one with vertically

integrated monopolies and the other without. The first involves continuing the core underlying industry structure, where vertically integrated monopolies operate in legally protected franchised service territories. Within this traditional structure, there are a variety of tools available to encourage clean energy investments. Alternatively, an industry structure is possible in which the competitive and monopoly portions of the business have been placed in separate corporate entities and customers can choose their own supplier. This new industry structure can also be used to promote clean energy investments if the new T&D entities are structured to focus on clean energy issues.

Another possibility—relaxing or avoiding regulation, especially IRP, and maintaining the existing structure of vertically integrated monopoly utilities—is conceivable. Under this approach, utilities would be allowed to greatly reduce regulation of their resource acquisition, ratemaking, and environmental mitigation activities. At the same time, little or no action would be taken to segregate monopoly and competitive functions and to provide customers with a meaningful choice of suppliers. As discussed previously, the LAW Fund believes that this approach creates a situation of *unregulated monopoly,* is poor public policy, and should be firmly rejected by decision makers.

State PUCs and Utilities

State regulators have the authority to encourage regulated electric utilities to invest in clean power resources. Although market forces may increasingly complicate the use of PUC rate, siting, merger approval, and resource-planning authorities to encourage utilities to make investments that manage long-term economic and environmental risks, they do not eliminate them. Indeed, state PUCs remain the primary force available to encourage utility management to moderate its present tendency to behave as if its short-term financial health were the only interest at stake.

In the short term, the most important step PUCs can take is to prevent utilities from becoming *unregulated monopolies.* To prevent this situation, there are a number of tools that PUCs can use in the near term. These include:

1. Requiring competitive bidding for wholesale resource acquisition, pursuant to portfolio management standards that encourage a utility to acquire resources to meet the long-term goals set forth in the blueprint.
2. Requiring the implementation of wires surcharges to help recover the costs of clean power technologies.
3. Requiring the development and implementation of green pricing mechanisms that work.
4. Requiring the implementation of increasingly self-funding energy efficiency (DSM) programs and ensuring that special attention is paid to low-income customers.
5. Experimenting with performance-based regulation that encourages utilities to acquire clean power resources.

Obviously, the efforts of PUCs to help commercialize clean energy technologies would be greatly facilitated by utility cooperation. Whereas the LAW Fund acknowledges the financial pressure under which utilities operate in this increasingly competitive era, to let these pressures become the exclusive determinant of resource acquisition policy, as some utilities in our region are suggesting, is short-sighted. The utility business, especially while it is characterized by vertically integrated monopolies, is one that continues to be affected with the public interest. Its resource choices over time have vast economic and environmental impacts. Under these circumstances, the LAW Fund urges utilities to find ways to encourage and promote clean power resources that are compatible with the competitive pressures they face.

"In the short term, the most important step PUCs can take is to prevent utilities from becoming unregulated monopolies."

"... the PUC should investigate approaches for moving ... utilities more expeditiously into a fully competitive environment ..."

If a utility is unwilling to promote clean power and is committed to shedding its long-term public interest responsibilities (or if the state legislature decides, as a matter of policy, to promote competition), the PUC should investigate approaches for moving such utilities more expeditiously into a fully competitive environment, including disaggregation and direct access. Since many state PUCs do not have full authority to implement these types of industry restructuring proposals, cooperation with the legislature will be essential.

State Government

Most state legislatures in our region are considering various restructuring proposals. It is essential that legislators make such proposals sensitive to the need to encourage the development of clean energy technologies. If it proves difficult to obtain restructuring legislation that is sensitive to environmental and other long-term goals, then legislators should find alternative means to promote clean power. The following are some suggestions to state legislators:

- Tie a utility's recovery of stranded costs either to its willingness to mitigate pollution at existing power plants and to its investments in clean power resources.
- Require utilities to implement wires surcharges to fund clean energy investments and low-income energy assistance.
- Encourage utilities, independent power producers, and other market players to invest in clean power resources through tax and fiscal policy.
- Support the formation of statewide and regional risk-sharing clean power development consortia, especially those that encourage local economic development.
- Promote the disaggregation of vertically integrated utilities, that is, the spinning off of competitive generation assets into an organization that is separate from the one controlling T&D assets.
- Consider implementing a new approach to direct access that focuses on meeting only incremental load growth and a voucher system as a way of limiting the adverse impacts of stranded cost recovery on utility customers.

State governors and executive branch agencies can also play an important role in encouraging clean power development. In particular, we urge the governors of our six states to use their offices as bully pulpits to promote the long-run economic and environmental benefits of clean power development, especially for rural areas in our region. State energy conservation, environmental and consumer protection, and economic development agencies also have a clear stake in the promotion of clean power. We urge them to become or remain involved in this activity.

Federal Energy Regulatory Commission

As explained in more detail in Appendix B, the FERC has regulatory authority over wholesale power transactions as well as over transmission access and pricing. Since the implementation of restructuring depends on power flowing over the transmission system, the actions of the FERC will affect the ability of state PUCs and legislatures to promote clean power resources in a competitive environment.

The LAW Fund urges the FERC to be careful to avoid erecting roadblocks to the states' ability to encourage clean power resource acquisitions; in fact, the FERC should seek to bolster the states' ability to promote long-term environmental and public interest goals. In particular, we offer the following suggestions to the FERC:

1. Be careful to define the distinction between "transmission" facilities (over which the FERC has jurisdiction) and "local distribution" facilities (over which the states have jurisdiction) so that states know clearly to which facilities they may attach wires surcharges to help pay for clean power resources.
2. Clarify that the states are not preempted by the Federal Power Act or PURPA from

encouraging utilities to acquire resources for their long-run economic and environmental values (such as wind or solar power) at wholesale to meet retail loads.

3. Promote open transmission access, encourage power pooling, and take other steps to overcome the market power of vertically integrated utilities.
4. Consider and attempt to mitigate the environmental impacts of major FERC regulatory proposals before promulgating them.

United States Congress

Fiscal, tax, and regulatory policies under debate in the United States Congress can have a major impact on this region's ability to invest in clean power resources. For example, elimination of the wind production tax credit before it would otherwise expire in 1999 would hurt wind development in the region, as would deep funding cuts in the budget of the National Renewable Energy Laboratory (NREL). We offer the following suggestions to Congress:

1. Retain the wind production tax credit at least through 1999.
2. Although we understand that all federal R&D and other programs must undergo review in trying to balance the federal budget, Congress must be mindful of the importance of the DOE, NREL, and other federal laboratory programs in bringing down the cost of clean energy technologies.
3. Look for ways to leverage private support for clean power, for example, by participating in and lending support to risk-sharing clean power development consortia.
4. In considering national restructuring legislation, implement ways to promote clean power resources and maintain funding for low-income energy assistance.
5. Clarify the jurisdictional boundaries between state and federal electric regulatory agencies in a manner that allows states to protect long-term public interests.
6. If Congress considers the transfer of management, ownership, or control over the facilities of the Western Area Power Administration it should require nonfederal interests to use the hydro resource to support clean power resources.

Western Area Power Administration

The Western Area Power Administration (Western), in its current structure as a federal power-marketing agency, can play a constructive role in encouraging investments in clean power resources. Building on initiatives already under way, as described more fully in Appendix C, Western could make a special effort to make its transmission capacity available to renewable energy developers. Western could also use small increments of its hydro resources to help firm customer utility investments in energy efficiency and renewable resources. And to help replace the peaking capacity lost at Glen Canyon and other dams, Western could begin to acquire energy efficiency and renewable resources. Finally, the agency should participate in and lend support to regional risk-sharing consortia.

Regional Initiatives

Other regional entities, such as the two existing RTGs, the Grand Canyon Visibility Transport Commission (GCVTC), and the Western Systems Coordinating Council (WSCC), can also help implement the blueprint. The RTGs, like Western, can make a special effort to plan for, operate, and build transmission capacity to promote clean energy goals established by the states. In any event, the RTGs and the WSCC should be sensitive to the impact of their activities on clean power development. And the final report of the GCVTC, due to the EPA in 1996, offers a major opportunity to promote clean power resources as a means to help the region cap and reduce visibility-degrading emissions.

Risk-Sharing Consortia

The LAW Fund also supports statewide and regional development consortia, such as the

"Fiscal, tax, and regulatory policies under debate in the United States Congress can have a major impact on this region's ability to invest in clean power resources."

Solar Enterprize Zone (SEZ) in southern Nevada. The SEZ is an example of how a wide range of interests—the states, federal agencies, developers, and utilities—can work together to share the financial risk of clean power technologies. Other examples of risk-sharing arrangements in this region are the Solar Two consortium, which is investigating solar thermal technologies; a separate group of utilities focused on promoting photovoltaics (the Utility PhotoVoltaic Group); and the development of the Arlington, Wyoming, wind site by five utilities. As restructuring takes hold, the importance of these ventures to the commercialization of clean power technologies will increase. These consortia can also aid the region's Native American tribes in developing renewable resources, if a tribe has decided to pursue such an approach. We urge that state and federal legislators redouble their efforts to support these initiatives through fiscal and tax policy.

"The urgency of making the transition to a cleaner energy future is as great as the perceived difficulty in achieving it."

Coalition-Building

Implementation of the LAW Fund's blueprint will require a substantial amount of work by a diverse range of stakeholders—including utilities, regulators, developers, customer groups, environmentalists, Native American tribes, and others. There is likely a role for a regional organization or, perhaps, state organizations to link the efforts of these diverse interests to promote clean power technologies at the state and federal level. The LAW Fund has been looking into the nature of such organizations and hopes to use the release of this report as a catalyst for their formation.

Conclusion

Diversifying our electric resource base to include energy efficiency and renewable resources promises enormous benefits. By pursuing these resources, the region can encourage economic development, manage economic and environmental risks, redress inequities between energy-producing and energy-using communities, and move toward a sustainable energy future. The transition to a more diversified electric energy economy will not be easy, however, especially in an industry that increasingly seems to respond to short-term financial incentives rather than managing long-term risks that often involve payoffs five or more years away.

The urgency of making the transition to a cleaner energy future is as great as the perceived difficulty in achieving it. In reality, the region has a limited window of opportunity in which to begin to switch from an electric system relying primarily on fossil fuels to a more diversified system. The research, development, and commercialization activities pursued in this time period will determine whether or not the emerging technologies that utilize clean, nondepleting resources will be ready for large-scale use sometime in the middle of the next decade (when there will be large new resource needs).

If the region does not move decisively in the direction of clean energy, then utilities, investors, and other resource developers will not have the confidence in renewable energy and efficiency resources to commit a large portion of available capital to them. As a result, they will likely do what they know best—construct another round of conventional and dirty fossil fuel power plants—and a significant opportunity will have been lost at great cost to the region and its quality of life.

To the many utility managers, regulators, customers, federal and state agency officials, environmentalists, developers, and others who care about the future of this region's environment and economy, the LAW Fund offers this challenge: Because our actions today will determine what is possible tomorrow, now is the time to deliver.

Notes

1. *Rocky Mountain News,* August 24, 1995, p. 51A.

2. Colorado PUC Decision No. C95-1305, Docket No. 93A-199EG, December 20, 1995, pp. 29–30.

3. This distinction between wholesale and retail transactions is a legal one, embedded in federal law. See Appendix B.

4. See, e.g., Docket No. 94A-516E, Before the Colorado PUC, Application of WestPlains Energy for Regulatory Approval to Build a New Plant, 1994. The new plant will enable WPE to avoid continued purchases from its prior supplier.

5. In Colorado, Coors Brewing Company recently struck an energy-outsourcing deal with a joint venture owned by Tucson Electric Co. and Trigen Energy Corp. Under a deal that expands Coors' self-generation capability, the joint venture has agreed to spend $40 million to supply all of Coor's power and steam heating needs. Denver-based Public Service Company of Colorado will be deprived of as much as $12 million in annual revenue. See *The Wall Street Journal,* July 10, 1995, p. 1.

6. "USU Switch Shakes City," *Salt Lake City Tribune,* May 26, 1995, p. B-12.

7. *The Wall Street Journal,* May 9, 1994, pp. A1–A6.

8. "A Brief History of Las Cruces' Fight for Lower Electric Rates," City of Las Cruces, January 18, 1996.

9. Stranded costs are those expenses incurred by utilities that cannot be recovered from customers because of the possibility or actuality that those customers can choose an alternative supplier. Indeed, accountants are becoming increasingly concerned that regulatory assets—promises by regulators of future cost recovery—will have little value as the industry becomes increasingly more competitive.

10. 1994 Nevada Power Company Refiled Resource Plan, Testimony of Steven Rigazio, February 1995, p. 8, lns. 23–26.

11. See, e.g., the Direct and Rebuttal Testimonies of Frederic C. Stoffel, DSM Incentives Proceeding, Before the Colorado PUC, Docket No. 94A-199EG, Summer 1995.

12. "EPA Raps PSCO Pollution," *The Denver Post,* January 19, 1996, p. B1.

13. *Rocky Mountain News,* August 24, 1995, p. 51A.

14. "Micron Won't Buy Lehi Electricity," *Salt Lake City Tribune,* November 10, 1995.

15. Colorado PUC Decision No. C95-1305, Docket No. 93A-199EG, December 20, 1992, pp. 29–30.

16. Many of these tools would also be useful in a restructured electric industry.

17. "Minimizing Non-Participant DSM Rate Impacts—Without Harming Participation," Eric Blank, 6 *Electricity Journal* 32, May 1993; "Bonus Payments Solve a Real Problem: Responding to Critics," Eric Blank, 6 *Electricity Journal* 41, July 1993.

18. See, e.g., "Targeting DSM for T&D Benefits: A Case Study of Pacific Gas & Electric's Delta Project," Electric Power Research Institute Report TR-0100487, May 1992; Targeted Marketing Program Plan, Central Maine Power, September 1, 1995.

19. Arizona IRP Proceedings, Arizona Corporation Commission Opinion and Order, Docket No. U-0000-93-052, April 1994, pp. 44–46. A 19-megawatt short-term renewable resource set-aside was determined to be appropriate.

20. See, generally, Nevada Solar Enterprise Zone Development Study, December 1994.

21. "Attitudes Toward Energy Efficiency, the Environment, and the Electric Utility Industry in a Changing Regulatory Climate," Cambridge Reports/Research International for Ogilvy Adams and Rinehart, March, 1995; "Earning Customer Loyalty Through Environmental Stewardship," Edison Electric Institute, September, 1994; Platte River Power Authority Customer Survey, September, 1994.

22. "Green Pricing: Customer Choice Moves Beyond IRP," David Moskovitz, *The Electricity Journal,* October 1993, p. 43.

23. Renewable Energy Trust Program, Public Service Company of Colorado, launched in November 1993. PSCO found that, after one year, only 3.7 percent of its residential customers were aware of the program.

24. Municipal utilities in both Traverse City, Michigan, and Sacramento, California, have programs that have successfully raised funds from residential customers. However, the amount of renewable resources that were acquired as a result of these efforts was small.

25. "A Proposal for Marketing Renewables Directly to End-Use Customers," Mayer, Udall, Neilsen and Blank, Joint U.S. DOE/LAW Fund Report, July 1996, forthcoming.

26. See the hydroelectric power section of Appendix C for more details.

27. Washington Water Power, Application for DSM Tariff Revisions, Section V, pp. 21–25; Washington Water Power Tariff Sheet, Schedule 91, Experimental DSM Rider Adjustment, filed October 26, 1994.

28. California PUC, Decision No. 95-12-063 as modified by Decision No. 96-01-009, Docket Nos. R.94-04-031 and I.94-04-032, December 20, 1995.

29. Colorado PUC Decision No. C95-1264, Docket No. 95R-071E, Proposed New IRP Rules, December 13, 1995.

30. Investigation into the Possible Modification of the Rules Concerning Integrated Resource

"Because our actions today will determine what is possible tomorrow, now is the time to deliver."

Planning, 4 CCR 723-21, and the Rules Implementing Sections 201 and 210 PURPA, Small Power Production and Cogeneration Facilities, 4 CCR 723-19, Docket No. 95R-071E, Colorado PUC.

31. FERC Notice of Proposed Rulemaking, Promoting Wholesale Competition through Open Access and Recovery of Stranded Costs, Docket Nos. RM95-8-00 and RM94-7-001, April 1995, pp. 67–68, (hereinafter, FERC Notice). See Appendix B for more detail.

32. FERC Notice, pp. 67–68.

33. FERC Notice, p. 88.

34. "Breaking Up May Not Be So Hard to Do: A Disaggregation Proposal for Accelerating Electric Industry Restructuring," Blank, Gilliam, and Wellinghoff, *Electricity Journal,* April 1996, This article provides more detail on the benefits of disaggregation.

35. The idea that the creation of a nonprofit T&D entity could produce tax and financing benefits grows out of the authors' analysis of a proposal developed by the Conservation Law Foundation and David Moskovitz for New England (which has since been altered). Although different in its details, the tax and financing benefits identified in the New England proposal are also important for ours.

36. Additional savings will be possible if the T&D entity can issue tax-exempt bonds. Since this tax exemption is under some scrutiny in Congress, however, we did not assume that these benefits would accrue to the formation of a new T&D entity.

37. See the Direct Testimony of David Hedberg Before the Nevada Public Service Commission, Docket No. 94-7001, June 20, 1995.

38. Nevada Power Company stock has been worth roughly $20 per share for most of the past year. Under our proposal each share of utility stock would be exchanged for (1) one share of common stock in a new company that continues to own the generation facilities, worth roughly $8 per share, (2) one share of preferred stock in the new T&D entity worth roughly $5 per share, paying an annual dividend of 8 percent, and (3) roughly $13 per share in cash. Thus, each shareholder receives roughly $26 of value for every share of NPC stock valued by the market at $20.

39. "Pataki Offers Details on Lilco Breakup," D. Carvajal, *The New York Times,* December 7, 1995, p. B6.

40. "Affected with the Public Interest: Electric Utility Restructuring in an Era of Competition," Hamrin et al., National Association of Regulatory Utility Commissioners report, September 1994, pp. 74–101.

41. "Estimating Potential Stranded Commitments for U.S. Investor-Owned Utilities," Baxter and Hirst, Oak Ridge National Laboratory Report, ORNL/CON-406, January 1995, pp. v-vi; "Electric Utilities: The Argument for Radical Deregulation," Navarro, *Harvard Business Review,* January-February 1996, p. 116.

42. Docket Nos. R.94-04-031 and I.94-04-032, Policies Governing Restructuring of California's Electric Services Industry, December 20, 1995.

Appendix A: Acknowledgments

A

The Energy Project of the Land and Water Fund of the Rockies is enormously grateful for the input and insight provided to us by hundreds of individuals throughout the research, writing, and release of *How the West Can Win.*

This report is the product of the LAW Fund and we take sole responsibility for its contents. However, we could not have undertaken this project were it not for the interest in and suggestions from the region's energy stakeholders and advocates.

The following list includes the people (along with organizational affiliation at the time we worked together) who have played a role in the development of this project, either by attending one of our outreach meetings or by offering us comments on an earlier draft. Although the appearance of a name on this list is not meant to imply either suppport or opposition to the contents of the report, we do extend a heartfelt thank you to everyone listed.

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Appendix B: The Electric Power Industry

B

This appendix briefly describes the characteristics of the electric industry in the six-state region. The first part discusses the key players—the utilities, state and federal economic regulatory institutions, independent power producers (IPPs), and other related organizations that comprise the industry. The second part presents load growth and resource need information on a regional basis for the next 40 years.

The Current Industry

The electric industry is currently characterized by vertically integrated utilities that provide power to retail monopoly franchise service territories secured by state law. In return for this franchise, utilities are subject to regulation at both the state and federal level. Over the past few years, however, legal and economic changes have threatened to undermine this industry structure that has prevailed for close to 70 years in the region.

The Electric Utilities

End-use electric demands in our six states are served by three kinds of utilities: investor-owned utilities (IOUs), utilities owned and operated by municipalities and related organizations (municipal utilities), and rural electric cooperative associations (cooperatives).

For-Profit Entities

As their name implies, IOUs are owned by their shareholders and managed with the intention of turning a profit. In our six states all but one of the 14 IOUs are vertically integrated, that is, they own generation, transmission, and distribution equipment. IOUs supply roughly two-thirds of the electricity sold to end users in the region. Table B-1 displays the IOUs by state and load center, by annual revenues, by peak load and energy supplied, and by average electricity prices.

The region's IOUs tend to serve loads in the larger, urban areas. This is no coincidence. Those who founded IOUs understood that it would be easier to profit from the sale of electricity in urban areas where economic activity is more concentrated. The IOUs typically left the less profitable rural area and small-town loads to be served by local and state government and nonprofit user associations subsidized by the federal government. IOUs tend to rely overwhelmingly on coal or nuclear generation.

Beyond these similarities, the IOUs in our region are quite different from one another. As Table B-1 indicates, they vary markedly in size, ranging from very small utilities such as CU in Arizona, WPE in Colorado, and CLF&P in Wyoming (each with peak loads less than 300 megawatts) to the large and growing PacifiCorp, serving loads in two of our states through its subsidiaries in Utah and Wyoming.

Average system prices for power from these utilities also vary, ranging from about 4–5 cents per kilowatt-hour (for SPS and PacifiCorp) to 8–9 cents per kilowatt-hour (for PNM, APS, EPE, and TEP). The reasons for this variation include the investments of PNM, EPE, and APS in expensive power from the Palo Verde nuclear units, as well as acquisition during the 1980s of new capacity that was significantly in excess of need. In contrast, PSCO, NPC, PacifiCorp, and SPS

"... legal and economic changes have threatened to undermine [an] industry structure that has prevailed for close to 70 years ..."

Table B-1. Characteristics of Regional Investor-Owned Utilities

State	Utility	Major Load Center	1993 Electric Revenues, *millions of dollars*	1993 Electric Retail Sales, *gigawatt-hours*	Average Retail Price, *cents per kilowatt-hour*	1993 Peak Load, *megawatts*	Total Employees
Arizona	Arizona Public Service Company (APS)	Phoenix	1,686	20,050	8.41	3,851	7,040
	Citizens Utilities (CU)	Phoenix	77	840	9.17	170	—
	Tucson Electric Power (TEP)	Tucson	662	9,346	7.08	1,449	1,389
		Total	2,425	30,236	8.02	NA	8,429
Colorado	Public Service Company of Colorado (PSCO)	Denver	1,306	22,491	5.81	3,972	6,313
	WestPlains Energy (WPE)	Pueblo	180	3,082	5.84	219	643
		Total	1,486	25,573	5.81	NA	6,956
Nevada	Nevada Power Company (NPC)	Las Vegas	652	11,155	5.84	2,681	1,711
	Sierra Pacific Power (SPP)	Reno	433	6,495	6.67	1,074	1,781
		Total	1,085	17,650	6.15	NA	3,492
New Mexico	Public Service Company of New Mexico (PNM)	Albuquerque	471	5,447	8.65	1,104	1,563
	Southwestern Public Service (SPS)	Roswell	233	5,819	4.00	750	261
	El Paso Electric (EPE)	El Paso	90	1,036	8.69	192	138
	Texas–New Mexico Public Service		80	1,408	5.68	206	133
		Total	874	13,710	6.37	NA	2,095
Utah	PacifiCorp	Salt Lake City	702	13,589	5.17	2,251	3,011
Wyoming	Cheyenne Light, Fuel & Power (CLF&P)	Cheyenne	33	741	4.45	131	97
	PacifiCorp	Casper	470	9,460	4.97	1,300	1,397
		Total	503	10,201	4.93	NA	1,494
		Investor-owned Utility	**7,075**	**110,959**	**6.38**	**NA**	**25,477**

Note: NA: Not applicable. —: Data not available. *Source:* Utility annual reports.

generally relied on purchased power to avoid overbuilding new capacity. These utilities have relatively low prices.

There is also wide variation among the IOUs in terms of profitability. EPE declared bankruptcy in 1992, and TEP is in the fourth year of a "workout" of its financial problems. Although APS appears to have rescued itself from the brink of bankruptcy, PNM has not declared a dividend in a number of years. Other utilities, such as PacifiCorp and SPS, appear to be in good financial health.

The Nonprofits

The remaining one-third of electric load in the region is served by municipal utilities and cooperatives. Municipal utilities, meeting the electric needs of numerous small towns and cities, have their roots in the public power movement in the United States, which took hold in the early twentieth century. These utilities are usually run by local government, subject to review by a city council or, in some cases, the board of an agricultural improvement district. Our region contains dozens of municipal utilities, ranging in size from a few megawatts of load to the large Salt River Project (SRP), which serves areas in and around Phoenix and has a peak load approaching 4,000 megawatts. The loads of some municipal utilities are growing rapidly. All told, municipalities in our six states sold close to 30,000 gigawatt-hours and collected revenues of about $1.7 billion in 1993.

Cooperatives were established primarily in the 1930s to serve rural loads ignored by both IOUs and municipalities. They were given impetus by enactment of the Rural Electrification Act of 1935, which made low-interest loans available to them. These utilities brought electricity to very large areas of the region where no power had been available. The service areas of cooperatives cover almost three-quarters of the region, although the total power sold by cooperatives in 1993 was only about 25,000 gigawatt-hours for revenues of slightly under $1.2 billion. Cooperatives are typically run by managers serving a board of directors comprised of local power users.

Although municipal utilities and cooperatives have different origins, we are struck more by their similarities than their differences. First, both are nonprofit; they are managed by those who they serve. Second, most municipal utilities and virtually all cooperatives engage solely in the distribution of electricity to end-use customers. With some notable exceptions (e.g., the City of Colorado Springs and SRP), they rely on other entities to provide all generation and transmission services. Third, though both initially depended most heavily on hydroelectricity, most now take substantial amounts of power from coal-fired power plants, some of which they own, often through generation and transmission associations or public power authorities. Fourth, both municipal utilities and cooperatives are "preference power" customers of the federal government. That is, they have first call on the subsidized and relatively inexpensive power generated at federal irrigation and hydroelectric facilities constructed in our region by the U.S. Bureau of Reclamation. These hydroelectric resources are marketed by the Western Area Power Administration ("Western"), an agency within the U.S. Department of Energy (DOE). Western, charged with marketing the electrical output of approximately 10,600 megawatts of hydroelectric generation capacity at federal dams in the West,[1] markets power to hundreds of municipal and cooperative customers in the region. A discussion of Western's role in marketing federal hydropower appears in Appendix C.

Most municipal and cooperative utilities participate in public power authorities and generation and transmission cooperatives. These organizations were formed to provide the financial strength to enable their members to meet generation and associated transmission needs over and above those that

"Municipal utilities ... have their roots in the public power movement in the United States, which took hold in the early twentieth century."

could be met by federal resources. Most of the new generation capacity these entities have constructed is coal-fired. Tables B-2 and B-3 set forth selected public power and cooperative associations in the six states, as well as some of the largest municipal utilities, showing peak loads, energy delivered, annual revenues, and average prices.

Construction by these agencies of incremental coal-fired capacity—some of it in excess of their needs—proved to be financially burdensome for them, especially the cooperative generation and transmission (G&T) associations. Colorado-Ute, a G&T association serving load in Colorado until 1992, went bankrupt largely because it overbuilt expensive coal-fired capacity. Construction of too much generation capacity has also plagued the Deseret G&T Association in Utah. Similarly, Plains Electric G&T in New Mexico is struggling to overcome heavy debt payments associated with an expensive coal plant, for which demand collapsed in the wake of the disappearance of uranium mining load in the 1980s.

"... the utilities are economic giants in this region."

Overall Utility Impacts

Taken together, the utilities are economic giants in this region. Their annual revenues total close to $10 billion, or roughly 4 percent of the region's economic activity. The net value of their assets is more than twice as much—over $20 billion. The regional utilities also account for somewhat under $1 billion annually in local, state, and federal taxes. Historically, utilities have contributed to a high quality of life in the region by providing a reliable and low-cost source of power. Of special significance is the regional importance of low-cost federal hydropower to the economies of rural areas and small towns. Table B-4 summarizes some financial and operating characteristics of the region's utilities.

The utilities, directly employing over 35,000 people in the region, indirectly support several thousand jobs in the coal, gas, and railroad industries. Even the relatively modest new demand-side management (DSM) programs the IOUs have launched have helped to create a market for energy efficiency in many regional urban centers, thereby producing additional jobs.

The utilities are also major players in terms of environmental impacts. The operation of coal-fired power plants makes them responsible for large shares of both sulfur dioxide (SO_2) and carbon dioxide (CO_2) emissions in the region. As indicated in

Table B-2. Selected Municipal Electric Systems

State	Utility	1993 Electric Revenues, *millions of dollars*	1993 Electric Retail Sales, *gigawatt-hours*	Average Retail Price, *cents per kilowatt-hour*	1993 Peak Load, *megawatts*
Arizona	Salt River Project	1,296	19,316	6.71	3,440
Colorado	Colorado Springs	143	3,160	4.53	545
	Platte River Power Authority	93	1,795	5.18	300
	Arkansas River Power Authority	10	270	3.70	56
New Mexico	Farmington Electric	41	555	7.39	99
Utah	Murray City Power	18	287	6.27	65
	Provo City Department of Energy	33	518	6.37	110
	Utah Assn. Municipal Power (1992)	35	1,042	3.36	302
	Utah Municipal Power Agency	30	790	3.80	135
	Total of Selected Municipal Systems	1,699	27,733	6.13	NA

Note: NA: Not applicable because utility peak loads are not coincident and therefore cannot be totaled.

Table B-3. Selected Rural Cooperative Electric Systems

State	Cooperative	1993 Electric Revenues, *millions of dollars*	1993 Electric Sales, *gigawatt-hours*	Average Price, *cents per kilowatt-hour*	1993 Peak Load, *megawatts*
Arizona	Arizona Electric Power Coop.	154	3,239	4.75	499
	Mohave Electric Coop.	31	382	8.12	103
	Navajo Tribal Utility	34	502	6.77	109
	Total	219	4,123	5.31	NA
Colorado	Holy Cross Electric	50	742	6.74	169
	Intermountain Rural Elec.	62	772	8.03	171
	KC Electric Assn.	9	134	6.72	51
	La Plata Electric Assn.	38	520	7.31	90
	Tri-State G & T	417	10,332	4.04	1,330
	Total	576	12,500	4.61	NA
Nevada	Valley Electric Assn.	17	258	6.59	53
New Mexico	Plains Electric G & T (1992)	122	2,078	5.87	290
	All other New Mexico Coops.	202	2,709	7.46	NA
	Total	324	4,787	6.77	NA
Utah	Deseret G & T	125	4,020	3.11	NA
Wyoming	Tri-County Electric Assn.	60	1,087	5.52	176
	Selected Rural Cooperative Systems	**1,304**	**26,517**	**4.92**	**NA**

Note: NA: Not applicable because utility peak loads are not coincident and therefore cannot be totaled.

Chapter 1, these emissions are implicated in a number of environmental problems and risks important to the region's economy and quality of life.

Economic Regulation

Utilities and related entities today are subject to an amalgam of state and federal law that has been developed over the previous century. This law includes economic regulation at both the state and federal levels, implemented to control utility market power as well as to regulate the environmental impacts of generation and transmission facilities. It also includes major federal environmental statutes such as the Clean Air and Clean Water acts. In this section we focus on economic regulation.

The question of the relative authority of state and federal regulators over utility rates

Table B-4. Summary of Revenues, Sales, and Prices for Regional Utilities, 1993

	Revenues, *millions of dollars*	Sales, *gigawatt-hours*	Average Price, *cents per kilowatt-hour*
IOUs	7.1	110,959	6.63
Municipal Utilities	1.7	27,733	6.13
Cooperatives	1.6	26,517	5.07[a]
Total	10.4	165,209	6.30

Note: a. The prices for cooperatives often do not include distribution costs.

and other transactions is complicated and is evolving rapidly. To describe it in detail is beyond the scope of this report. For our purposes, it suffices to say that state and local governments have authority over the establishment of electric rates for the sale of power to end use customers (so-called retail sales), as well as over the siting of generation and transmission facilities. Under the Federal Power Act (FPA) and related statutes, the federal government has authority over wholesale transactions between utilities and between independent power producers and utilities. It also has the power to regulate access by utilities and independent power producers (IPPs) to transmission capacity, as well as to set the rates for such service. The federal government has only limited authority over generation (except hydroelectric plants) and transmission facility siting.

"... the relative authority of state and federal regulators over utility rates and other transactions is complicated and is evolving rapidly."

State and Local Regulation

The relationship between utilities and their *retail* customers is governed by state and local regulation known as the regulatory compact. Typically, a utility operates within a legally protected monopoly franchise service territory. In return for this privilege, a utility is obligated to serve all customers in the franchise area subject to both pricing and siting regulation.

In all six of our states, implementation of the regulatory compact for IOUs is carried out by state public utility commissions (PUCs), run by full-time appointed or, in Arizona, elected officials. Economic regulation of retail municipal utilities and cooperatives is implemented by city councils for the former and by local boards comprised of end users for the latter. Under a loophole in the Federal Power Act, Arizona and New Mexico regulate rates for the wholesale sales of cooperative G&T associations. Otherwise, rates for these sales and the wholesale sales by public power authorities to their members are self-regulated.

States in our region are actively questioning the validity of the regulatory compact (as discussed in more detail later). Responding to the technological and regulatory changes previously cited and described more fully in Chapter 3, they are considering making it lawful for end-use electric customers to buy power from a wide range of suppliers.

Retail rate regulation. PUCs, city councils, and cooperative boards in the region establish retail prices to allow utilities to recover capital and operating costs as well as the cost of raising the capital associated with past investments.[2] As a result, utility revenues are based on their average, embedded costs, the lion's share of which are associated with investments made years before the rates are set. Setting prices on the basis of historically incurred costs stands in sharp contrast to the way the rest of the economy operates. In competitive markets, prices are based on marginal rather than average costs.

Once allowed revenues have been established, utilities allocate portions to individual customer classes based on the estimated costs of serving each class. In reviewing utility allocation proposals, the role of regulators has been primarily to ensure equity among different customer classes. To make sure that this occurs, a variety of consumer, industrial, and other affected stakeholders participate in PUC processes. The final price is calculated by dividing each class's assigned portion of the revenue requirement by total estimated sales to that class.

Under this system, utilities have an incentive to increase sales, as long as the incremental revenues from such additional sales exceed any additional costs in making them. They also have an incentive to avoid investing in their customer's energy efficiency programs because to do so would create "lost revenues" on which they depend to cover their costs, including the cost of capital. In

our view, these incentives are particularly perverse in an era when energy efficiency investments can bring significant economic and environmental benefits. Since 1990, Utah, Colorado, Nevada, and Arizona have taken steps to overcome these problems of traditional regulation. Appendix D provides more detail on this issue.

Certification and Integrated Resource Planning. Because new investments by utilities affect the size of a utility's revenue requirement and thus its rates, PUCs and local governing bodies have always had an interest in utility resource planning. The states in our region, except Utah (other than in atypical situations), require that a utility obtain a certificate of convenience and necessity (CCN) from the PUC before constructing a large generation or transmission facility.

In response to a number of changes that rocked the electric industry during the 1970s and 1980s—involving, among other things, volatile fuel prices and interest rates, competition from third-party power producers, stricter environmental regulation, and new supply and demand technologies—it became clear that an expansive approach to utility resource planning and acquisition was needed. Many realized that utility resource acquisitions have significant impacts beyond the short-term financial health of utilities, including effects on the environment and on long-term economic risk. These realizations led to the development of a new way of planning for utility resource acquisitions called integrated resource planning, or IRP.

IRP is characterized by the following elements:

- explicit and fair treatment of a wide variety of demand- and supply-side options for meeting growing demands over a 10- to 20-year period
- explicit consideration of the environmental costs and risks of resource options
- broad opportunities for public participation in the development of a utility long-range plan
- review of utility IRPs by the PUC, city council, or cooperative board

Four states in the region—Arizona, Colorado, Nevada, and Utah—require that resource plans be submitted by their regulated utilities, principally the IOUs and, in Colorado and Arizona, the G&T associations. Where IRP is in place, it typically serves as the basis for a PUC's consideration of applications for CCNs. Some municipal utilities and cooperatives have adopted IRP on their own. And as Appendix C explains, in October 1995, Western promulgated a rule requiring many of its customers to file IRPs with Western every five years.

The effect of IRP is to draw a broad array of environmental, economic, equity, risk management, and even sustainability considerations into a utility's planning process in order to encourage "portfolio management" by utilities. That is, a key effect of IRP is to encourage utilities to acquire resources not only for short-term financial advantage, but also to help address long-term economic and environmental risks. Under IRP, an electric utility is viewed as helping to manage a portfolio of society's interests, from short-term cost and rate objectives to long-term goals such as environmental protection and sustainability.

"... utility resource acquisitions have significant impacts beyond the short-term financial health of utilities ..."

Other Significant State and Local Authorities. The siting of major generation and transmission facilities by utilities is regulated in all states but Utah.[3] Siting authority is the principal tool available to control the local environmental impacts of these facilities. However, as the next section elucidates, decisions regarding siting of transmission facilities, increasingly made to facilitate regional power flows encouraged by federal economic regulation, could potentially undercut local environmental protection. As a result, the interests of state and local regula-

tors can conflict with the interests of utilities, IPPs, and federal regulators.

All states in the region must approve mergers and acquisitions involving regulated utilities within their boundaries. Both Wyoming and Utah had to approve the merger of PacifiCorp with Utah Power & Light. New Mexico must consider whether to approve Central and Southwest Corporation's acquisition of El Paso Electric; Nevada must evaluate Washington Water Power's acquisition of Sierra Pacific Power Company; and Colorado, Wyoming, and New Mexico must review the merger between PSCO and SPS. The power to approve or reject mergers and acquisitions is an opportunity for states to protect the public interest by attaching conditions to approval.

Recent Developments. As Chapter 3 describes, the California PUC's proposal in April 1994 to allow retail utility customers subject to its jurisdiction to select their utility power suppliers helped to trigger a widespread review of the regulatory compact within the United States. In our region, New Mexico was the first state to consider retail wheeling issues. Legislation was introduced in 1994 in the New Mexico legislature to authorize retail wheeling. Although a special interim committee has held extensive hearings on the matter, no action has been taken legislatively. Now the New Mexico PUC is considering whether to implement some form of retail wheeling under existing authority.

"In our region, New Mexico was the first state to consider retail wheeling issues."

In Arizona, utilities and interested parties, including the PUC staff, have been engaged in a review of the pros and cons of retail wheeling. In Nevada a bill authorizing retail wheeling under very narrow conditions was signed into law. In Colorado a member of the Colorado House of Representatives has introduced legislation directing the implementation of retail wheeling for all Colorado utilities within three years.

The shape of regulation in a retail wheeling world is unknown and would likely vary considerably by state. Only one state, California, has adopted retail wheeling on an all-customer basis so far. On December 20, 1995, the California PUC promulgated regulations that will make retail wheeling available in 1998 to a limited number of customers of the three electric IOUs regulated by the PUC. By 2003 all customers may choose retail wheeling. The PUC's opinion also creates a consolidated wholesale power grid, including an independent power exchange (PX) to be operated by an independent system operator (ISO). For public interest programs, such as utility DSM, the PUC intends to maintain the status quo for the time being but expects to work with the legislature and stakeholders to determine where changes might be made. Stranded costs, primarily net uneconomic generation costs, may be recovered through a nonbypassable competition transition charge (CTC).

The implementation of California's new regulations depends on the operation of a competitive, wholesale market for power and thus on the active support by and cooperation with the Federal Energy Regulatory Commission (FERC). We turn next to a review of the FERC's authority.

Federal Economic Regulation

This section describes federal regulation of wholesale power and transmission markets and introduces the major players in these markets. It also summarizes the evidence that the electric industry is evolving into a regional entity.

Overview of FERC Authority. Economic regulation of wholesale transactions as well as of transmission capacity is implemented by the FERC, a five-member board within the Department of Energy (DOE). Federal regulation of the rates for wholesale power transactions was initiated in 1935, under the Federal Power Act (FPA). Later court cases clarified that Congress had also intended in the FPA

that the federal government regulate most aspects of the use of the transmission system, including wholesale power rates.

Despite these general and long-standing powers, until recently the FERC had no authority to order utilities to make their transmission capacity available to each other and to nonutility power generators. The result was that the potential for competition to lower the cost of power was curtailed by utilities that would not agree to provide access to their transmission lines to other utilities and nonutility generators.

This situation changed recently, when the Energy Policy Act of 1992 (EPAct) was enacted. The primary purpose of the electric utility regulatory title of EPAct was to encourage competition in wholesale bulk power markets. In § 721 of EPAct, Congress gave the FERC the authority, upon application, to order utilities to provide transmission services ("wheeling") to utilities and others generating power *for resale* if such an order would not unreasonably impair reliability and would be in the public interest. Under § 205 of the FPA, the FERC also has the authority to regulate the price of such transmission services, including transmission to retail customers. These authorities set the stage for a significant expansion in our region of what is already a well-established wholesale power market.

On March 29, 1995, the FERC proposed 315 pages of regulations under these and related authorities that, if promulgated, will greatly encourage competition in wholesale power markets. First, the FERC proposed to eliminate anticompetitive practices among owners of transmission capacity by requiring utilities, among other things, to file open access transmission tariffs with the FERC. Of note is the provision in the proposed regulations that would require a utility posting such a tariff to charge itself on the basis of the same tariff for use of its own transmission lines. Second, the FERC proposed to allow utilities the opportunity to recover legitimate and verifiable wholesale "stranded costs." Wholesale stranded costs are generation and other costs incurred by utilities to meet wholesale contractual obligations that cannot be recovered under competitive market conditions facilitated by open access.

The FERC has jurisdiction over transmission facilities, but not over local distribution facilities, which remain within the jurisdiction of the states and local governments. It is important to know whether a particular facility is "transmission" or "local distribution." If deemed to be local distribution, a state or local government may require payment for stranded costs or "stranded benefits" as a consequence of using the facility.[4] If a facility is deemed to be transmission, no such opportunity is present. The FERC has proposed seven tests by which it would ascertain whether a facility is deemed to be transmission or local distribution.[5] If promulgated, these tests may require FERC interpretation in real world situations to remove uncertainty from this area of the law.

Market Institutions and Players. A functioning wholesale power market has existed for decades in the West. Until very recently, the only players in this market were utilities. Utilities have dealt with each other in three basic ways to create a market: (1) through mostly bilateral arrangements for the sale of power, (2) through power pools, and (3) through the Western Systems Coordinating Council (WSCC), a regional power reliability organization that is part of the North American Reliability Council. There are now new players in the wholesale market, in particular, independent power producers and regional transmission groups. Also, the New York Mercantile Exchange has established a futures market in the western United States to facilitate power transactions.

"A functioning wholesale power market has existed for decades in the West."

a. Inter-utility Transactions

For many years utilities in the region have been buying and selling to each

other on the wholesale market. Inter-utility exchanges, mostly bilateral, have enabled the purchasing utilities to avoid building thousands of megawatts of new generation capacity in the West at cost savings likely running into the billions of dollars. For example, rather than focusing on building its own plants, Public Service Company of Colorado has been able to purchase close to 1,500 megawatts of power—roughly 40 percent of its total resource base—from neighboring utilities over the last 15 years. These transactions enabled PSCO to avoid building a new plant and have allowed the selling utilities to find a market for their excess power.

b. **The Power Pools**

"... Utilities in our six states participate in a number of power pools ..."

The utilities in our six states participate in a number of power pools regulated loosely under the FPA. These pools are multilateral arrangements including IOUs, municipalities, cooperative and municipal G&T groups and Western; they are designed to provide for capacity sharing, reliability, and the economic operation of existing power plants. Membership in pools allows utilities in the region to carry significantly less capacity for reserve margins relative to what each utility would have to carry if it operated in isolation. These pools also provide other services, (e.g., voltage stability, reactive power, and transmission access) according to prearranged voluntary terms. The principal pools in our six states are the Inland Power Pool, the Rocky Mountain Power Pool, the Southwest Power Pool, and the Western Power Pool.

c. **The Western Systems Coordinating Council**

The WSCC, one of the nine electric utility industry reliability councils that was formed in the wake of the 1965 New York blackout, is another important entity that promotes the reliability and adequacy of interconnected transmission and generation facilities throughout the West. Its approximately 70 members (consisting of utilities, federal agencies, and a few IPPs) provide electric service to nearly 60 million people in the western United States, western Canada, and Baja, California. The WSCC indicates that it fulfills its mission "by coordinating the operating and planning activities of its members."[6]

d. **Independent Power Producers**

More recently, IPPs have become important players. The term *IPP* refers to any entity other than a utility (including an affiliate of a utility) that produces electricity. IPPs represent a significant and growing force in wholesale markets. At present, in our six-state region they may sell their electricity only to utilities for resale rather than directly to retail customers.

The first significant step toward the creation of an independent power industry was taken in 1978 when President Carter signed into law the Public Utility Regulatory Policy Act of 1978 (PURPA). Title II of PURPA requires electric utilities to purchase the electrical output of "qualifying facilities" (QFs) at their "avoided cost," that is, the cost they would incur but for the purchase. PURPA QFs were restricted to "cogeneration" and "small power production" facilities, essentially small power plants using renewable resources.

In the 1980s, many states, including Colorado and Nevada, began to experiment with competitive systems

for utility acquisitions of QF power. In essence, these states guaranteed QFs long-term contracts based on forecasts of future avoided costs. As a result of these guarantees, a substantial amount of QF capacity—ultimately close to 1,000 megawatts by the end of the 1990s—will have been acquired by the region's utilities, mostly in Colorado and Nevada.

Finally, in § 711 of EPAct, Congress created a new class of IPPs called electric wholesale generators (EWGs). EWGs are any facilities that generate electricity for sale in the wholesale market but do not sell to end-use customers. This designation exempted EWGs from the extensive filing and regulatory requirements associated with the Public Utilities Holding Company Act.

e. **Regional Transmission Groups**

The increasing competition in wholesale electricity markets and the issues it raises for the sufficiency and governance of transmission capacity have led many to believe that new organizations are needed at the regional level. Thus were born regional transmission groups (RTGs). RTGs are voluntary organizations of utilities and other power providers designed to resolve transmission use and capacity issues on a regional basis. On July 30, 1993, the FERC issued a policy statement on RTGs encouraging their formation and setting forth minimum components.[7]

Subsequently, two western RTGs have filed agreements with the FERC. The first to do so was the Western Regional Transmission Authority (WRTA), filed on May 20, 1994, by PacifiCorp, an organization of California municipalities, and an organization of California IPPs.[8] The second RTG to file with the FERC from this region was the Southwest Regional Transmission Association (SWRTA). SWRTA's members include APS, EPE, Plains Electric G&T, PNM, SRP, TEP, Western, and two large IPPs. Both WRTA and SWRTA filings have been accepted by the FERC. Over time, if the RTGs gain control over transmission access and pricing decisions, as the FERC has indicated is its intent, they will have the potential to become crucial players in the electric industry.

Regionalization of the Power System. The western power system has been "regionalizing" for the past two decades. Arizona utilities now own shares of large power plants in Nevada, Colorado, and New Mexico. Over half of the Palo Verde nuclear power plant near Phoenix is owned by utilities serving load in New Mexico and California. Coal-fired generation located in Colorado is owned by California and Arizona utilities as well as by PacifiCorp. Western uses the output of a Colorado coal-fired power plant owned by an Arizona utility to meet its contractual obligations to customers in Utah. SPS, whose load center is Amarillo, Texas, which only 15 years ago was isolated from other utilities, has sold electricity to the Bonneville Power Administration in the Pacific Northwest. Other interstate activities have also engendered regionalization. In 1987, PacifiCorp merged with Utah Power & Light. The merger enables the combined system to be operated more efficiently and at higher capacity factors. The SPS and PSCO merger, announced in 1995, will be able to link assets and loads in Texas, New Mexico, and Colorado if and when the two systems are connected by transmission capacity.

"Coal-fired generation located in Colorado is owned by California and Arizona utilities as well as by PacifiCorp."

Regional Resource Needs: 1995–2035

We estimate that electric loads in our six-state region will require about 15,600 mega-

watts of additional resources by 2015 under utility "reference" or "base-case" assumptions. We project that the region may need an additional 58,000 megawatts of new resources between 2015 and 2035 for a total of about 73,600 megawatts of new resources between now and 2035. This section provides the basis of these estimates. To set the stage for the resource need estimates, we describe the recent past, analyze today's load and resource balance, and estimate future peak loads at five-year increments through 2015.

The Recent Past

For most parts of the region, the 1970s were boom years, especially in mining and manufacturing. Population growth was also robust. As a region rich in fossil fuels, the enormous hikes in the price of oil triggered by the Arab oil embargo in 1973–1974 and the Iran/Iraq War in the late 1970s created a market not only for the region's oil and gas, but also for coal and uranium. The impact on utility electricity sales was dramatic. For example, electric sales to the mining, milling, and manufacturing sectors in New Mexico grew at over 10 percent per annum between 1975 and 1980. As a result, many utilities forecast future demand growth in excess of 5 percent annually.

"... robust growth in demand for electricity has returned ..."

Based on these forecasts, a number of the region's utilities formulated plans for large additions to electric generating capacity. Between 1978 and 1986, utilities in our region added 7,400 megawatts of new coal-fired capacity and 3,000 megawatts of nuclear capacity. Roughly another 5,000 megawatts of coal and nuclear capacity was constructed in the region to serve loads in California.

During the time much of this new capacity was under construction, economic conditions were changing. The country entered a recession after 1980, which, this time, included the West. Notwithstanding a population that continued to grow in all of our states except Wyoming, growth in demand for electricity slowed precipitously. To a significant degree, the slowdown resulted from a sharp reduction in the pace of industrial activity, which had created the illusion of high long-term growth rates. For example, industrial electricity consumption in Arizona and Colorado decreased in the early 1980s for the first time in years. Even before the last of the large new baseload generating units was coming on line, it had become apparent that the region had overbuilt baseload electrical generation capacity. Coal plants designed to run at 75–80 percent capacity factors were running between 45 and 55 percent in 1986 and 1987. In 1996, the region's coal plants, on average, are still operating below design criteria.

Not surprisingly, there has been little power plant construction in this region since the mid-1980s. Now robust growth in demand for electricity has returned, but its composition is different than that of the

Table B-5. State Contributions to the Regional Peak Load in 1994

State	Contribution, *megawatts*	Percent of Total
Arizona	10,500	39
Colorado	5,800	21
Nevada	3,900	14
New Mexico	2,500	9
Utah	3,100	12
Wyoming	1,200	5
Total	27,000	100

1970s. This time, system growth is linked more to the increase in residential, commercial, and light manufacturing demand for electricity (which shows pronounced daily fluctuations in load) than to the round-the-clock demands of heavy industry.

Current Trends in Supply and Demand

The LAW Fund's analysis of demand for electricity in our region is pegged to events in 1994, the last year for which there is reliable data available. Record heat blistered the Desert Southwest during the summer of 1994. On June 29, 1994, temperatures in excess of 120°F resulted in utilities in Nevada, Arizona, and New Mexico shattering their previous highest peaks by substantial amounts. APS, PNM, and NPC all reached peak demand levels in 1994 that, earlier in the year, were not expected until 1998.

Hot temperatures throughout the intermountain West on June 29, 1994, also produced significant electrical demands for utilities in Colorado, Utah, and Wyoming. Although no peak day records were set for these utilities, demand was at about 90 percent of peak hour loads. The peak demand experienced by our six state region in June 1994, as well as the probability of the occurrence of such extreme summer temperatures in the future, is driving the need for new generating capacity.

Based on this understanding of utility peak demands, we believe that the region experienced a 1994 peak load of roughly 27,000 megawatts. Table B-5 shows that, of our six states, Arizona contributes the most toward the region's peak load.

To meet this peak demand, utilities in the region need about 31,000 megawatts of capacity, assuming a reserve margin of 15 percent.[9] Because of the overbuilding of baseload coal and nuclear capacity that occurred in the 1970s and 1980s, utilities in the region currently have roughly 36,200 megawatts of capacity available. This amount includes about 2,500 megawatts of capacity in the Pacific Northwest that was available in 1994, and which we assume to remain available, to help meet peak day demands in our six-state region. The result is that in 1994 the region had roughly 5,000 megawatts of resources surplus to loads plus a 15 percent reserve margin. Table B-6 shows how this existing capacity is distributed by state.

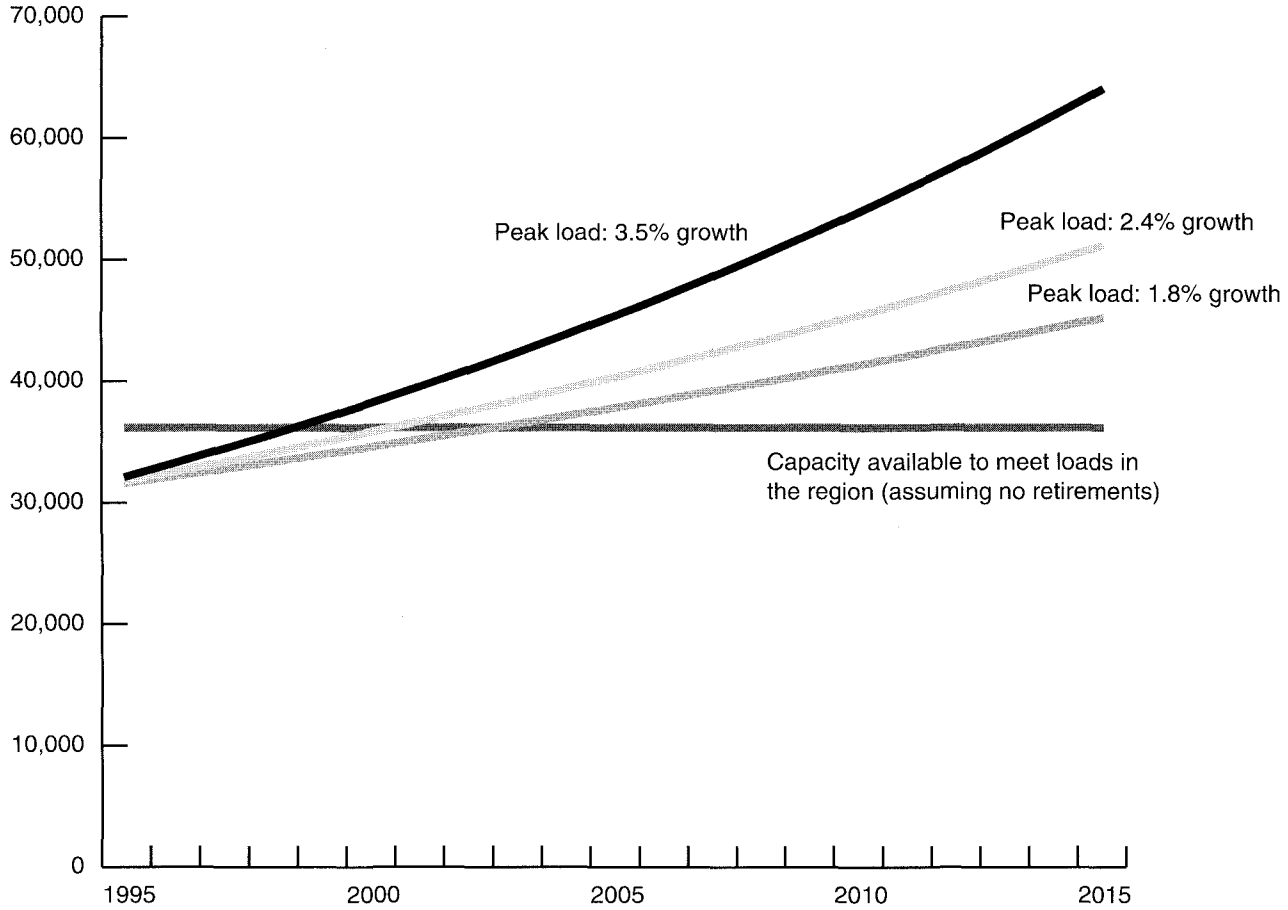
Not all of the regional capacity that is surplus to regional peak loads is available to meet loads anywhere in the region. In particular, transmission constraints prevent movement of power from Wyoming and Utah to the south and east. These constraints may cause utilities in the region to need to acquire additional resources even though a regional surplus exists.

"APS, PNM, and NPC all reached peak demand levels in 1994 that ... were not expected until 1998."

Table B-6. Existing Capacity by State

State	Contribution, *megawatts*	Percent of Total
Arizona	12,200	34
Colorado	6,300	17
Nevada	3,200	9
New Mexico	3,800	11
Utah	3,000	8
Wyoming	5,200	14
Imports	2,500	7
Total	36,200	100

Figure B-1. Peak Load Growth[a] and Available Capacity



Note: a. Includes 15 percent reserve margin.

Growth in Regional Peak Demand

Figure B-1 shows our estimate of peak loads, plus a 15 percent reserve margin, in our six states at five-year intervals through 2015. We show estimates for base, low, and high cases. We calculated regional peak load growth using the forecasts of the 22 utilities and organizations of utilities in the region that have produced such forecasts. We grew each of these utilities' 1994 peak loads at the rate that each utility forecast its load would grow under base-case assumptions. Since the forecasts available ended in 2015 or earlier, we estimated loads on each of the utilities according to these rates of growth only through 2012.

The weighted average growth rate for these utilities through that period under their base-case assumptions was 2.4 percent per annum. Thus, we grew utility peak loads in 1994 at a 2.4 percent rate of growth through 2012. For the period after 2012, we applied 2.4 percent per annum to grow base-case regional peak load in 2012 at a constant rate through 2035.

The 2.4 percent rate of growth in peak demand for a regional base case is high relative to the 1 percent and lower growth rates many utilities in this region experienced in the 1980s and, for a few, are experiencing today. However, urban areas—such as Phoenix, Las Vegas, Salt Lake City, Albuquerque, and Denver—are seeing rapid economic growth in the high-tech industrial, commercial, and residential sectors, resulting in utility peak demand growth in the 2–3

percent range. Even more rapid growth is expected in tourist and recreational regions, where utilities expect demand increases of 4–5 percent. Indeed, the region's peak load grew about 750 megawatts in 1994 from 1993, implying a growth rate closer to 3 percent. Thus, we believe that the 1994 regional base-case utility weighted average of 2.4 percent annual growth in peak loads is an acceptable forecasting tool. Of course, any number of events, such as a lasting recession, could alter this estimate.

Regional utility estimates of low and high rates of peak load growth were not as readily available. Those utilities that did make such estimates assumed on average that low load growth would be roughly 75 percent of base-case growth rates, or 1.8 percent per annum on a weighted average basis for the region. High rates assumed growth at just under 150 percent of base-case growth rates, or 3.5 percent per annum. These assumptions were used to calculate both low and high peak regional demand growth rates through 2035.

Because of the potential demands associated with increased reliance on electric vehicles, the high load estimates are more likely than the low after 2015, all else being equal. Together electricity and transportation account for the lion's share of energy use in the United States, yet they are almost completely distinct energy sectors with little overlap.[10] Nearly all energy used in transportation is obtained from oil. Electric vehicles are a rarity confined to a few prototype road vehicles, and the use of electricity in other transportation applications, including subways, trolleys, and golf carts, is small.

The combustion of oil by motor vehicles is a major contributor to air quality degradation in urban areas, with impacts on both human health and visibility. These impacts are beginning to create significant opportunities for alternative fuels to power motor vehicles, especially natural gas vehicles, battery-charged electric cars, and fuel cell electric cars. As we describe further in the natural gas section of Appendix C, it is possible, perhaps likely, that natural gas-powered vehicles will emerge first among these options, thereby putting upward price pressure on natural gas. However, battery-powered electric cars and fuel cell electric cars will likely capture some of this market, especially toward and after 2015.

Battery-powered electric vehicles

Our analysis indicates that a modest battery-powered electric car market—less than 10 percent of the region's existing fleet of cars and other vehicles—could be accommodated without significant expansion of electric generation in this region. In part, this follows from the fact that most vehicles would be recharged in off-peak hours, especially if off-peak recharging rates were available. This battery-charged electric vehicle demand would have the effect of increasing regional load factors and justifying more baseload capacity, rather than peaking or intermediate capacity. On the other hand, a complete

"If the cost of power from clean resources can be brought down significantly, hydrogen-powered vehicles may become economical ..."

Table B-7. Resource Needs Assuming No Retirements Until After 2015 (megawatts)

	1996–2000	2001–2005	2006–2010	2011–2015	1996–2015	2016–2035
Resource need	2,500	2,325	5,075	5,700	15,600	31,010
Capacity retirements	0	0	0	0	0	27,000
Total resource need including retirements	2,500	2,325	5,075	5,700	15,600	58,010

transition from oil-powered to battery-powered electric vehicles within the region would increase regional power capacity needs by up to 50 percent. We think that such a complete conversion is highly unlikely, even by 2035. Nonetheless, the possibility of even a partial conversion is supportive of high load growth rate, especially after 2015.

The Production of Hydrogen by Electrolysis

Appendix D describes the use of hydrogen in fuel cells. Fuel cells generate electricity by "burning" hydrogen to create water. One way to produce hydrogen for use in fuel cells is by electrolysis, that is, by use of electric power to break water molecules into hydrogen and oxygen. If hydrogen could be produced by clean power resources (for example, solar power facilities), fuel cell-powered motor vehicles would be emission-free from start to finish.

The benefits and potential of what has been called the "hydrogen transportation economy" are enormous and clearly worth pursuing.[11] At the moment, generation of hydrogen by clean power resources for use as a clean-burning fuel in motor vehicles is expensive. If the cost of power from clean resources can be brought down significantly, hydrogen-powered vehicles may become economical, especially if demand for them increases. We believe that production of hydrogen from clean power resources will have its effect on electric loads in this region mostly after 2015. This use of electricity is another reason to think that peak load growth after 2015 may approach the high estimate.

"The benefits and potential of what has been called the 'hydrogen transportation economy' are enormous and clearly worth pursuing."

New Resource Needs

The need for new resources is a function of the amount of surplus capacity in the region at the beginning of the forecast period, growth in regional peak demand and reserve margins, and assumptions regarding retirement of power plant capacity. Table B-7 presents an estimate of new resource needs at five-year intervals between 1996 and 2015 and for 2035. It shows that the region needs about 15,600 megawatts of resources between now and 2015[12] and lists the values used in the business as usual case in Chapter 2. The estimate it presents embodies the following assumptions:

- that peak load will grow at 2.4 percent throughout the 40-year period; in other words, the load will grow at base case rates
- that no fossil fuel power plants now in operation will be retired between now and 2015
- that all fossil fuel power plants operating in 1995 will have been retired by 2035
- that all resources of whatever kind built or acquired between 1995 and 2015 will still be operating in 2035

Table B-8. Resource Additions in the Blueprint Including Those Due to Repowerings and Capacity Retirements Before 2015 (megawatts)

	1996–2000	2001–2005	2006–2010	2011–2015	1996–2015	2016–2035
Resource need from Table B-7	2,500	2,325	5,075	5,700	15,600	31,010
Repowerings	0	235	940	310	1,485	0
Capacity retirements under the blueprint	0	0	375	1,640	2,015	23,500
Total resource additions in the blueprint	2,500	2,560	6,390	7,650	19,100	54,510

As indicated previously, we believe there were about 5,000 megawatts of surplus capacity in 1994 at a 15 percent reserve margin. At a base-case rate of demand growth of 2.4 percent, it will take about six years of load growth to fully absorb this surplus generating capacity. Thus, if utilities were to forego the construction of additional generation capacity when a surplus is available anywhere in the region, no new capacity would be built in the region until after 2000. However, because of transmission constraints and other factors, some utilities will seek to build new capacity before then. For example, transmission constraints in the Denver metro area have already created a need for new supply- and demand-side capacity in Colorado. Similarly, other utilities may build new capacity to gain a competitive advantage or for financial reasons.[13]

All told, by the year 2000, we expect that utilities in our region may seek to build as much as 2,500 megawatts of new resources to meet growing demand, notwithstanding the regional surplus. Indeed, utility IRPs in our region indicate that utilities plan to build close to this amount of new resources in this time period. As a result, it will take somewhat longer than six years for the excess capacity in the region to be absorbed. At the same time, as Appendix C explains, the region is likely to lose up to 700 megawatts of hydroelectric generating capacity at the Glen Canyon Dam as a result of its reoperation to accommodate environmental and recreational values. Because of the foregoing considerations, we believe that the regional surplus will persist beyond 2000 but will certainly have been absorbed by 2005.

Table B-8 serves as the basis for the blueprint's resource additions. In addition to the resource needs due to load growth that are shown in Table B-7, it shows the effects of retiring roughly 2,000 megawatts of conventional coal-fired generation which has reached 40 years of age before 2015, as well as the effects of repowering approximately 1,500 megawatts of conventional coal-fired capacity with cleaner fuels. The capacity retired or repowered is among those power plants with the highest SO_2 emission rates in the region and is located near some of the region's most environmentally sensitive areas. Although the net capacity additions under the blueprint remain at 15,600 megawatts, because of these retirements and repowerings the total amount of new capacity added in the blueprint is 19,100 megawatts.

"... We believe that ... regional surplus [capacity] will persist beyond 2000 but will certainly have been absorbed by 2005."

Notes

1. Western used to market the output of about 500 megawatts of the coal-fired Navajo power plant at Page, Arizona. SRP now markets this power.

2. For an IOU, the cost of raising the capital includes a return on equity, or profit, and the cost of debt. For nonprofits, the cost is limited to the cost of debt.

3. In Colorado, siting regulation is implemented at the county level. In New Mexico and Nevada the PUC regulates siting, whereas in Wyoming and Arizona, authority over siting is shared between the PUC and other officials or commissions.

4. In footnote 230 of the FERC Notice of Proposed Rulemaking, Promoting Wholesale Competition through Open Access and Recovery of Stranded Costs, Docket Nos. RM95-9-000 and RM94-7-001 (FERC MEGA-NOPR), April 1995, the FERC says "States may also use their jurisdiction over local distribution facilities to address potential stranded benefits, e.g., environmental benefits associated with conservation, load management and other demand side management (DSM) programs."

5. FERC MEGA-NOPR, p. 285.

6. Background Paper for Regional Planning, Policy Committee Advisory Group, WSCC, January 1994, p. 1.

7. Policy Statement Regarding Regional Transmission Groups, 64 FERC ¶61, 138, issued July 30, 1993.

8. FERC Docket No. ER94-1288-000.

9. A margin of 15 percent appears consistent with the WSCC and Inland Power Pool analyses of regional reserve margins.

10. About 29.1 quadrillion Btu (quads) of energy, 35 percent of the nation's total primary energy consumption, is expended annually in the

United States to generate electricity. Another 22.5 quads of energy, 27 percent of the nation's primary energy, is consumed in the transportation sector, mainly to propel the 193 million vehicles on America's roadways. U.S. Energy Information Administration, *Annual Energy Review: 1992,* Washington, D.C., June 1993, p. 3.

11. For an expansive treatment of the hydrogen transportation economy, see "Harnessing Hydrogen, the Key to Sustainable Transportation," James S. Cannon, INFORM, Inc., New York, 1995.

12. A review of IRPs developed by regional utilities with loads comprising about 70 percent of 1994 regional loads indicates plans to build about 11,000 megawatts of capacity by 2012. These IRPs assume that no fossil fuel capacity in existence in 1994 will have been retired by 2015. This result is consistent with our estimate that about 15,600 megawatts of new capacity is needed in the region by 2015 by utilities serving 100 percent of regional load, assuming no fossil fuel generation capacity retirements before 2015.

13. WestPlains Electric (a small IOU that serves the Pueblo, Colorado, area) is planning to build a 140-megawatt combined-cycle unit in part to lessen its dependence on purchased power. Similarly, Black Hills Power & Light (a small IOU that primarily serves the Rapid City area of South Dakota) is constructing an 80-megawatt coal-fired power plant in Wyoming to build its rate base and improve its position on wholesale power markets.

Appendix C: Conventional Technologies

C

The Rocky Mountain and Desert Southwest region relies on four primary technologies—coal, natural gas, hydroelectric, and nuclear—to meet virtually all of its electric energy needs. This appendix describes each of these technologies and their prospects for meeting growing electricity needs in the region.

King Coal

A half century ago, the label "King Coal" referred to the hold of the coal industry over the politics, economy, people, and environment of the main coal-producing Appalachian states of West Virginia and Kentucky. The slogan still rings true in 1996, but it applies as much to the West as Appalachia. It is coal, more than any other energy resource, that has boomed in the West in the last 20 years.

Coal resources have provided the backbone of the western electrical generation system for several decades, and they have consistently proven to be inexpensive, abundant, and reliable. As described in Appendix B, these attributes precipitated a period of rapid construction of large, base-load coal plants all over the western United States between 1975 and 1985. Over 7,000 megawatts of coal-fired power plants were built in this time period to serve growing energy demand both in this region and in California and the Pacific Northwest.

Though they are nonrenewable, coal resources are abundant in the Rocky Mountain region. Huge reserves are located close to the surface in thick seams that are recoverable cheaply and easily with surface mining technology. The coal is low in sulfur, so compliance with air pollution regulations for sulfur dioxide (SO_2) is easier and less costly than when higher-sulfur coals are burned. Because coal combustion technology is well developed, coal plants are reliable. And the overall cost of generating electricity with coal has, until recently, been lower than that associated with other fuels.

Given coal's prominence in this region, the economic and environmental issues related to its use pose particularly challenging public policy questions. As Chapter 1 describes, coal is implicated in many of the environmental problems and risks associated with the electric utility industry. SO_2 emissions contribute to regional haze and local visibility problems. Sulfates and nitrogen oxides (NO_x) may contribute to human health problems, especially in urban areas. In our region, coal plant carbon dioxide (CO_2) emissions are the single largest contributor to the risk of global climate change. Coal plants emit mercury and other hazardous substances. And many believe that surface mining of coal, even though regulated, may cause permanent damage to land and water resources.

In our view, these concerns imply that no new conventional coal-burning facilities should be built in this region. This does not mean that coal should be abandoned as a utility resource, either in today's power plants or in new ones which utilize cleaner-burning technologies. As for today's power plants, we advocate that those with the largest adverse impacts on the environment be repowered with natural gas or retrofitted with additional pollution control equipment. The remainder of the plants should continue for their useful

"Coal resources have provided the backbone of the western electrical generation system for several decades ..."

lives and, in many cases, have their lives extended. Thus, the cleanest of today's coal plants can help manage the risk that the costs of cleaner technologies may not decrease enough to meet growing resource needs economically. We also conclude that certain clean coal technologies show promise, especially those (e.g., integrated coal gasification) that remove most sulfur and nitrogen from the coal and reduce the amount of carbon emitted to the atmosphere. These technologies should compete equitably with other power sources.

This section describes regional coal resources, tells the story of utility coal use in the region, describes its costs, discusses the employment benefits and economic contributions that result from the use of coal by utilities, evaluates the environmental impacts of coal, and explains clean coal technologies and their environmental impacts and costs.

"The coal reserve base in our six states is 95 billion tons—enough coal to last well over 300 years if mined at today's levels."

The Coal Resource in the West

The demonstrated coal reserve base in our six states is 95 billion tons—enough coal to last well over 300 years if mined at today's levels.[1] About 70 percent of the reserve is in Wyoming, with most of the rest in Colorado. Nevada has no demonstrated reserves and Arizona only 250 million tons. Nationally, demonstrated reserves are about 470 billion tons. There is nearly four times more energy in the demonstrated coal reserves than there is in the proven reserves of the other two fossil fuels, oil and natural gas, combined.[2]

The federal government is the largest coal owner in the United States. About 80 percent of the demonstrated coal reserves in the West lie on federal and Native American lands. About 20 billion tons of these reserves are now under lease, often under terms that cost coal developers only a few cents per ton of coal. In 1990, 209 million tons of coal were mined from federal land and 25 million tons from Native American land in our six states, accounting for 78 percent of the total production in those states, up from 50 percent in 1971.[3] The remaining coal was produced from privately owned or state lands.

Western coal is generally easier and cheaper to mine than coal found in most other places because it often occurs in thick seams close enough to the surface to be recoverable by inexpensive surface mining technology. In 1991, 87 percent of the coal in the Rocky Mountain states was surface mined, compared with 59 percent of national coal production. The remaining 13 percent was mined by conventional underground mining technologies, which are relatively more complex, labor intensive, and expensive. Most regional underground mining occurs in Utah and Colorado.

In large part because of the lower costs associated with surface mining, the average price of coal at the mine site in the Rocky Mountain states is about $10.00 per ton below the national average. In Wyoming, where 99 percent of the coal is mined with surface mining technology, the average price is less than one-third the national average.

Coal is the cheapest fossil fuel available to utilities, and for 20 years it has been getting cheaper. In 1991 the national average mine price of coal [per million British thermal units (Btu) of energy] was 33 percent less than the wellhead price of natural gas and almost one-third the price of crude oil. Correcting for inflation, the price of coal has actually dropped 4 percent since 1971, whereas wellhead natural gas prices (although showing recent stability) have nearly tripled and oil prices have jumped 48 percent.

Compared with coal produced in other regions, western coal is attractive because its low-sulfur content eases compliance with SO_2 pollution control requirements contained in the Clean Air Act. The average sulfur content of coal mined in our region is only 0.49 percent, about half the average throughout the West and far less than the national average of 1.29 percent. In energy and ash

content, Rocky Mountain coal on the whole is typical of the national average. The average ton of Rocky Mountain coal contains 10,267 Btu of energy, only slightly below the national average, despite the relatively low energy content of Wyoming coal. The amount of ash which must be removed by washing prior to combustion or captured by air pollution control equipment after combustion, is about 10.72 percent in Rocky Mountain coal, a full percentage point higher than the national average (mostly because of the high ash content of coal in New Mexico and Utah).

As a result of these factors—abundance, ease of mining, accessibility of federal and Native American lands, low production cost, and lower sulfur concentration—electric utilities across much of the nation have flocked to western coal fields for energy to supply their power plants. About 91.4 million tons of coal produced in the Rocky Mountain region are consumed by electric utilities at power plants in the region. However, about 64 percent of all coal produced in the Rocky Mountain states, or about 162.1 million tons, is exported to utilities in states outside of the region. Wyoming is the leading regional coal exporter; 84 percent of its coal production is shipped outside the Rocky Mountain region, mostly to states in the Midwest.[4]

Utility Reliance on Coal

Coal mining in the West over the last 25 years is an industrial development success story. In 1971 less than 10 percent of the nation's total production was mined west of the Mississippi; by 1991, western production had soared to 41 percent of the nation's total output. Coal production in the Rocky Mountain region grew from 26 million tons in 1971 to 268 million tons in 1991. Whereas national coal production rose 78 percent during the 20-year period, coal production in the Rocky Mountain states jumped 886 percent.[5]

More than one-fourth of the nation's coal production now occurs in the Rocky Mountain region. In the mid-1980s, Wyoming usurped the title as the largest coal-producing state from the perennial champion, West Virginia. By 1991, 24 of the 50 largest coal mines in the United States were located in the Rocky Mountain region, compared with 4 in 1971.[6]

Electric utilities currently use about 94 percent of all the coal burned for industrial processes in our six states.[7] Nationally, electric utilities are responsible for about 87 percent of coal use.[8] The average price of coal delivered to electric utilities in the Rocky Mountain states in 1991 was $23.66 per ton, 19 percent below the national average. Prices are low because the average transportation cost from the coal mine to the power plant is far below the national average ($4.64 per ton versus $7.87 per ton) because many power plants in our region are located at or near coal mines.[9]

Under these circumstances, it is not surprising that most utilities in our region concentrated on coal in the 1970s and 1980s. Between 1971 and 1991, the amount of electricity generated from coal burning in the Rocky Mountain states grew from 30 percent of total energy (less than the national average of 44 percent) to 76 percent (far higher than the national average of 56 percent). In 1992, 91.4 million tons of coal were burned at power plants in our six states.[10] Coal power provides more than 90 percent of the electrical energy in Wyoming, Utah, and Colorado, and nearly 90 percent in New Mexico. Only in Arizona, where the Palo Verde Nuclear Generating Station is located, does coal provide less than half of the energy.[11]

In terms of generation capacity, there is roughly 28,500 megawatts of coal-fired generation capacity currently in place in our six states, with roughly 7,000 megawatts committed to at least partial use outside the region. Coal-burning electrical generating stations account for 62 percent of the generating capacity of all types of power plants in

"Coal power provides more than 90 percent of the electrical energy in Wyoming, Utah, and Colorado ..."

our six states, compared with 43 percent nationally.[12]

The 10 largest coal plants in the region account for about 60 percent of the region's coal-fired capacity (Table C-1). These coal plants are truly a regional western power resource. As shown in Table C-1, it is common for ownership of these plants to be shared by a number of utilities, one of which is the predominant owner and plant operator.

Table C-1. The 10 Largest Coal-Fired Power Plants in the Rocky Mountain Region

	Operating Utility (% ownership)	Joint Owners
Navajo State: Arizona Size: 2,250 megawatts	Salt River Project (21.7%)	Arizona Public Service (14.0%), Tucson Electric (7.5%), Los Angeles (21.2%), Nevada Power (11.3%), Bureau of Reclamation (24.3%)
Jim Bridger State: Wyoming Size: 2,040 megawatts	PacifiCorp (80%)	Black Hills Corp. (20%)
Four Corners State: New Mexico Size: 2,038 megawatts	Arizona Public Service (units 1–3, 100%; units 4 and 5, 15%)	Units 4 and 5: Southern California Edison (48%), Public Service NM (13%), Salt River Project (10%), El Paso Electric (7%), Tucson Electric (7%)
Intermountain State: Utah Size: 1,781 megawatts	City of Los Angeles	Intermountain Power Agency (100%)
San Juan State: New Mexico Size: 1,779 megawatts	Public Service Co. of N.M. (units 1–3, 50%; unit 4, 55.52%)	Units 1 and 2: Tucson Electric Power (50%); Unit 3: Century Power (50%); Unit 4: MSR Public Power Agency (28.8%), Farmington (8.48%), Los Alamos County (7.2%)
Laramie State: Wyoming Size: 1,710 megawatts	Basin Electric Power Coop. (42.27%)	Tri-State Gen. & Trans. Assn (24.13%), Missouri Basin Mun. Power Agency (16.47%), Lincoln Electric System (12.76%), Heartland Consumers Power (3%), Wyoming Mun. Power Agency (1.37%)
Mohave State: Nevada Size: 1,580 megawatts	Southern California Edison (56%)	Los Angeles (20%), Nevada Power (14%), Salt River Project (10%)
Craig State: Colorado Size: 1,356 megawatts	Tri-State Generation & Transmission Assn. (units 1 and 2, 24%; unit 3, 100%)	Units 1 and 2: Salt River Project (29%), Platte River Power Authority (18%), PacifiCorp (19.28%), Public Service Colorado (9.72%)
Hunter State: Utah Size: 1,338 megawatts	PacifiCorp (unit 1, 93.75%; unit 2, 60.31%)	Unit 1: Provo City Corp. (6.25%); Unit 2: Deseret Gen. & Trans. Coop. (39.69%)
Cholla State: Arizona Size: 940 megawatts	Arizona Public Service (units 1–3, 100%)	Unit 4: PacifiCorp (100%)

Source: Inventory of Power Plants in the U.S. 1992, U.S. Energy Information Administration.

For example, six utilities in four states share ownership of the Four Corners Power Plant in New Mexico, although Arizona Public Service Company (APS) is the principal owner and operator. And California utilities, particularly Southern California Edison and the City of Los Angeles, rely on our region for close to 3,000 megawatts of coal-fired power.

Almost all of these plants were placed in service in the 1960s through the 1980s. For financial and rate regulatory purposes, coal plants are often assumed to have a "useful life" of 40 years. Under this assumption, the process of retiring these coal plants will begin shortly after the turn of the century and will be largely completed by 2020. However, most utilities plan on operating their coal plants well beyond 40 years. In the absence of further environmental regulations, today's stock of coal plants may be available to generate power well into the next century.

The Cost of Generating Electricity with Coal

The total expense of generating electricity at a power plant is the sum of three primary cost components: plant construction costs, fuel costs, and operating and maintenance (O&M) costs.

Throughout the 1960s and 1970s, coal power plants were cheaper to build than plants using other fossil fuels, nuclear power, or renewable energy resources. The capital cost of coal plants have risen, however, in large part because of the expense of installing complex pollution control systems, whereas the costs of some of the alternatives, especially natural gas and wind power plants, have dropped sharply. Pollution costs now account for an average of one-third of the capital cost of a new coal-burning power plant. In one extreme case, about 45 percent of the capital cost of adding a new coal-burning power unit to the San Juan Generating Station in New Mexico in the early 1980s was spent on the plant's pollution control systems.[13] Notwithstanding these extra capital costs associated with pollution control technologies, coal units are responsible for roughly 40 percent of SO_2 emissions in this region, as well as a significant portion of regional emissions of NO_X.

The direct capital costs of coal-burning power plants have also steadily risen in the last 20 years, from $228 per kilowatt of capacity in 1975, to $541 in 1980, to $912 in 1985, and to $1,244 in 1990 (in current dollars).[14] The capital cost of a new coal-burning station is now about $1500 per kilowatt. This is over twice the $650 per kilowatt capital cost of a combined-cycle natural gas power plant and greater than the cost of a new wind generation facility by $500–$600 per kilowatt. On the other hand, coal-fired power plants are now cheaper to build than nuclear or solar power plants, and cost reductions projected for new coal technologies could reverse the trend toward more expensive coal plants, perhaps reducing the cost of new coal plants to $1,000 per kilowatt or even lower, provided no further pollution control requirements are imposed. At least for the near future, however, coal power is no longer the least-capital-cost option for electric utilities.

Capital costs account for $0.02–$0.04 of the average cost of producing a kilowatt-hour of electricity at a coal-burning power plant. Operating and maintenance expenses, including disposal of waste captured by pollution control equipment, add less than $0.01 per kilowatt-hour. At delivered prices of slightly less than $30.00 per ton, the cost of coal contributes about $0.02 per kilowatt-hour.[15]

Adding the components together yields an average price of $0.05–$0.07 per kilowatt-hour for generating electricity at a coal plant. Older plants are at the low end of this range; new plants are at the high end.[16] This is a little more than the total cost of power generated from wind technology, and it is

"Pollution costs now account for an average of one-third of the capital cost of a new coal-burning power plant."

higher than the $0.04–$0.05 per kilowatt-hour for generating electricity at combined-cycle natural gas power plants. On the other hand, coal power is still considerably cheaper than electricity generated at solar thermal power stations. The nuclear power produced at the Palo Verde plant is almost twice as expensive as coal power.

"... coal power is still considerably cheaper than electricity generated at solar thermal power stations."

Pollution Control Technologies

A variety of SO_2 control technologies have been developed that remove sulfur at various stages of the production process:

1. Precombustion
   - Coal beneficiation removes 20–30 percent of total sulfur by suspending coal particles in water.
   - Solvent refining is an expensive technology that removes sulfur from coal by dissolution in organic solvents, but it is still in the pilot plant stage.
   - Gasification and liquefication allow sulfur to be removed during conversion of coal to gases or liquids.
2. Combustion
   - Fluidized bed combustion uses limestone to react with SO_2, water and oxygen to produce calcium sulfite and sulfate.
3. Postcombustion
   - Flue gas desulfurization (FGD) can take the form of either wet or dry scrubbing.

Over the last 20 years, more than 50 FGD wet and dry processes have been developed. Wet scrubbers, which process flue gases in a liquid or liquid/solid slurry, have received greatest acceptance; dry processes use solid sorbents.

The wet absorption process can achieve SO_2 removal efficiencies of 90 percent or more. Ninety percent of all utility FGD operating capacity utilizes a throwaway lime/limestone slurry process. Dry scrubbing, which can remove 80 percent of SO_2 from low-sulfur coals, brings a dry alkaline sorbent such as lime or sodium carbonate into contact with flue gases. The resulting mixture of flyash, sulfates, and dry sorbent is removed, usually by fabric filter dust collectors (baghouses).

According to U.S. Energy Information Administration statistics, the average installed cost of an FGD system in the mountain states region in 1990 was $154 per kilowatt of coal capacity, a figure that showed little change over the previous five years.[17] There is some evidence that technology improvements may enable a reduction in the cost of FGD units.

Power Plant Efficiency Improvements

A number of low-cost projects are often available to utilities to increase the operational efficiencies of their existing coal plants. These projects might involve the installation of boiler controls, variable speed-fan drives, and improved heating/cooling systems. Although utilities have initiated extensive programs to identify and take advantage of these opportunities, there are additional opportunities that remain untapped.[18]

For example, supply-side efficiency investments at existing plants that increase net output can be viewed as an additional resource available to meet growing demand. This alternative typically is cost-effective and lessens pollutant emissions.

Employment and Economic Development Impacts

The coal industry is now a significant source of employment, tax revenue, and economic development for the region. Total sales of coal mined in the Rocky Mountain states in 1991 were nearly $3 billion. The revenues from the electricity generated at coal-burning power plants in the Rocky Mountain states was about $10.5 billion. In 1992, approximately 9,500 coal miners worked in the Rocky Mountain states.[19] At least an equal number of indirect jobs were created by the coal-mining industry, for example, in the mine equipment manufacturing and servicing industries.[20]

In addition to taxes collected from coal miners, companies, and activities indirectly resulting from coal mining, coal production is, in some areas, a major contributor of direct government revenues in the Rocky Mountain states. For example, in 1990, more than $250 million was collected in royalties from coal production on federal and Native American lands in the Rocky Mountain states. Half of the $200 million in federal coal royalties collected from production on public lands in the Rocky Mountain states was returned to the states, and much of the federal share was spent by the federal government within the region. The Navajo and Hopi Nations collected nearly $60 million in royalties from coal mining on their lands in Arizona and New Mexico. More than 50 percent of the Navajo Nation's total tax revenue comes from coal production and use.

In addition to royalties, states impose a variety of taxes on coal production within their borders. Colorado and Wyoming charge severance taxes, whereas New Mexico levies resource use and conservation taxes in addition to a severance tax. Direct state taxes on coal mining in the Rocky Mountain states exceed $100 million per year.

Finally, the federal government and the private sector have invested more than $7 billion in developing and demonstrating a variety of "clean coal" technologies. Some of the money has been spent in this region, creating jobs and additional taxable revenues.

Environmental Impacts

Concern over the environmental impacts and risks of coal burning have limited the ability of the industry to increase its hold on utility markets. Black lung disease, acid rain, visibility degradation, land and water impacts from strip-mining, impacts on human health, solid waste disposal, water pollution, and the risk of global climate change are among the many problems linked to coal mining and combustion. For all its economic advantages, coal burned in conventional power plants is relatively dirty.

Air Emissions

Combustion of coal by electric utilities is a major source of regional SO_2, NO_X, and CO_2 emissions. It also produces carbon monoxide, particulate matter, hazardous air pollutants (HAPs), and radioactive materials. During the mining of coal methane is released into the atmosphere. All of these substances create problems or risks for the natural and human environment. Chapter 1 explained the relationship between utility air emissions and regional and global environmental problems and risks. The following subsections summarize and supplement that information.

Sulfur Dioxide, Nitrogen Oxides, and Particulate Matter. Sulfur dioxide, nitrogen oxides, and small particulate matter are significant contributors to regional haze, urban brown clouds, and other local visibility problems. Utilities in our region emit significant quantities of these substances, especially SO_2, as a result of their reliance on conventional coal-burning technologies. These problems exist despite the compliance of most utility coal power plants with applicable air quality regulations.

It is often difficult to link a particular source of these emissions with a local visibility problem. However, there are times when such linkage is feasible, for example, with respect to visibility degradation in the Mount Zirkel Wilderness Area in Colorado.

In 1993 the U.S. Forest Service certified visibility impairment at Mount Zirkel. The technical background document providing the basis for this certification indicated that the Craig and Hayden power plants account for 99.6 percent of SO_2, 91.1 percent of NO_X, and 62 percent of total suspended particulate matter emissions of stationary sources in the three counties immediately upwind of Zirkel. Although determination of the precise cause of visibility degradation at Zirkel awaits publication of a study in June 1996, the

"... the environmental impacts and risks of coal burning have limited the ability of the industry to increase its hold on utility markets."

Forest Service has already stated that it is reasonable to believe that the Hayden and Craig power stations are causing or contributing to the problem.[21]

SO_2 and NO_X are also precursors of acid rain, with SO_2 being the more important of the two. Mount Zirkel and possibly even Rocky Mountain National Park are examples of places affected by acid deposition likely attributable to utility combustion of coal.[22] In fact, Mount Zirkel Wilderness Area has recently been said to have the most acidified snow in the Rockies:

> recent data indicate that part of the chemical change [in the snowpack and in the lakes in and near Mount Zirkel Wilderness Area] is an increase in acidity of the snowpack ... in northwest Colorado relative to all other high-elevation snowpack sampled in Colorado. Increased deposition of sulfate, nitrate, and acidity may extend to the vicinity of Rocky Mountain National Park.[23]

"Mount Zirkel Wilderness Area has recently been said to have the most acidified snow in the Rockies."

The acid rain provisions of the Clean Air Act Amendments of 1990 establish a cap on national emissions of SO_2 at 8.9 million tons by January 1, 2000. Utilities must obtain allowances to emit SO_2 within the cap as a function of emissions during a baseline period. However, the cap will not prevent local acid deposition. Nor will it prevent a worsening of regional haze. In our region, most utilities may expand their present emissions of SO_2 and still remain in compliance because the law allows for additional emissions to accommodate growth where emission rates are low (as they are here because of the low sulfur content of the coal).

Chapter 1 explained the statistical relationship between human health and small particulate matter, a relationship that has been found repeatedly in recent years. Based on their 1994–1995 review of six data sets, the Health Effects Institute (HEI) stated that "it is reasonable to conclude that, in these six data sets, daily mortality from all causes combined, and from cardiovascular and respiratory cause in particular, increased as the level of particulate air pollution indexes increased."[24]

According to the American Lung Association, the risk to health attributable to exposure to ambient levels of particulate matter of diameter less than or equal to 10 microns (PM-10) exists at levels above 55 micrograms of PM-10 per cubic meter, rather than at the level of 150 micrograms now codified in the national standard of the Environmental Protection Agency (EPA). The association has computed that about 8.5 million people in our six-state region live in counties with PM-10 levels exceeding the lower value.[25]

Greenhouse Gases. Carbon dioxide is the principal gas created when coal is combusted in utility boilers. CO_2's contribution to the risk of global climate change was described in Chapter 1. Although methane actually is a much more potent greenhouse gas than carbon, it is released in far smaller quantities. However, some methane is released to the atmosphere during coal mining, which can exacerbate problems with global climate change.

Some utilities and independent power producers (IPPs) are not waiting for universally accepted scientific certainty to take steps to address global climate change. Applied Energy Services, a Virginia-base IPP, may have been the first to volunteer to offset incremental CO_2 emissions attributable to a coal plant it sought to build by working with farmers in Guatemala to encourage them to keep trees on their land to provide a "sink" for carbon. In this region, Pacificorp has been investigating the propriety of buying and maintaining forest lands in Russia as a carbon sink. Investing in demand-side management (DSM) and renewable resources provides other, less exotic alternatives for utilities and IPPs. As part of the Clinton administration's Climate Challenge, most utilities in the region have agreed voluntarily

to try to reduce CO_2 emissions by 2000 to 1990 levels. However, it is not clear that this objective will be obtainable as the output of idle coal capacity increases to meet steady electric load growth. As described in Chapter 2 and Appendix B, if the need for new resources is met primarily by new fossil fuel electric capacity, any reduction of CO_2 emissions to 1990 levels will surely be short-lived.

There has always been a small minority of scientists and others who have contested the theory of global warming. The best evidence these people have had that global warming attributable to human causes may not be occurring is the difference between what computer models of warming predicted and actual temperature records. Indeed, the world's climate has not warmed as much in recent decades as the models had indicated. Recently, however, it appears that an explanation has been found for the lag between global temperatures and computer-based predictions. A new report by the Intergovernmental Panel on Climate Change (IPCC) finds that when atmospheric sulfates, which have a dampening effect on solar gain attributable to their reflectivity, are taken into account, the difference between predicted and observed global temperatures is explained.[26] The effect of the new evidence is to increase the accuracy of computer model predictions, which continue to show significant increases attributable to human activities in the years to come, although these increases are somewhat lower because of sulfates.[27]

As a result of the relationship between sulfates and temperature, one might be tempted to add more sulfates to the air to dampen global climate change. However, sulfates are a pollutant, responsible in part for regional haze, urban brown clouds, the risk of ill health, and acid rain. National limits on SO_2 emissions to control sulfates are now in place as a result of the Clean Air Act Amendments of 1990; similar controls are in effect in Canada, Japan, and Europe. And sulfates remain in the atmosphere for only a few days, whereas carbon dioxide, once emitted, may remain in the atmosphere for many years.

A final note on global climate change: a few advocate doing nothing about global climate change in this region on the grounds that, without action by other countries such as China and India (which they deem unlikely), action in this region would be futile.[28] We reject this argument as opportunistic cynicism. First, as the evidence of human-caused climate change and its potentially devastating effects mounts, other countries are acting. Second, as a region of the world's most prosperous country, we believe we have a moral obligation to lead by example. The rest of the world is, in part, waiting to see whether the United States, as the leading source of greenhouse gases, will take serious steps to control these emissions. We note that it may in fact be easier to carry out this obligation since doing so is likely to result in a large economic payoff for the region.

"... most utilities in the region have agreed voluntarily to try to reduce CO_2 emissions ..."

Hazardous Air Pollutants. Combustion of coal results in the emission of small amounts of toxic pollutants including arsenic, beryllium, cadmium, chromium and mercury. Coal combustion also generates uranium and thorium.

Chronic exposure to arsenic in low doses can cause liver damage and irritation of the digestive system as well as various cancers. Exposure to beryllium can injure the respiratory tract and may cause cancers. Chronic exposure to cadmium can cause pulmonary disease and kidney dysfunction. Acute exposure to two forms of cadmium, both of which are emitted in fossil fuel combustion, is associated with cancer.[29]

Among the toxics, most attention has been given to mercury, in part because gaseous mercury can travel long distances and accumulate in the tissues of living organisms, especially fish.[30] In this country as

of 1990, 20 states had issued health advisories for fish caught in local lakes and rivers because of mercury contamination. According to the U.S. Geological Survey, Wyoming, New Mexico, and Utah coal contain between 5.07 and 6.15 milligrams of mercury per million Btu, as much as found in coal in many midwestern and Appalachian deposits.[31]

Hazardous air pollution emissions by electric utilities are not presently regulated under the Clean Air Act. Congress charged the U.S. EPA in 1990 with studying public health hazards resulting from emissions of HAPs from fossil fuel-fired steam-generating units over 25 megawatts. The agency was also charged by Congress to regulate utility emissions of HAPs if, based on the study, it finds such regulation to be "appropriate and necessary." In June 1995, the U.S. EPA completed a peer review draft of its report.[32]

"Hazardous air pollution emissions by electric utilities are not presently regulated under the Clean Air Act."

Another attribute of coal used in utility boilers is its content of trace levels of thorium and uranium, which remain in ash after coal is burned. This ash is commonly stored unprotected on plant sites. According to nuclear physicists at Oak Ridge National Laboratory, coal-burning power plants release more radioactive material into the environment nationwide than nuclear power plants.[33] According to a 1993 report, in 1982 U.S. coal units burned 616 million tons of coal, releasing 801 tons of uranium and 1,971 tons of thorium into the environment.[34]

Surface Mining

Over 233 million tons, or about 87 percent of the coal removed from the ground in our six states in 1991, was strip-mined.[35] Since 1977, coal strip-mining has been regulated under the provisions of the Surface Mining Control and Reclamation Act (SMCRA), a program containing federal standards but implemented primarily by the states. Although this statute represented a major step toward preventing lasting damage to the land and water affected by strip-mining, significant questions remain regarding its efficacy. In short, confidence is lacking among some that the statute and its implementation are avoiding damage.

In particular, there is concern whether some of the western states are enforcing the law. In Utah, the Southern Utah Wilderness Alliance (SUWA) requested that the Office of Surface Mining (OSM) in the Interior Department take over the operation of the Utah program after it was revealed that the OSM Director has written to the governor complaining that Utah's performance under the program has been "less than adequate."[36] Similar discontent with state enforcement of SMCRA has been voiced in Wyoming, where the National Wildlife Federation and other environmental organizations requested a federal takeover of SMCRA implementation, contending that the Wyoming revegetation standard could have potentially devastating impacts on native wildlife.[37] Similar concerns have been voiced in New Mexico and Colorado.[38]

There is some worry that compliance with the statute does not prevent lasting damage. Of particular concern is that, even after 20 years of experience, it is not clear that strip-mined land can be successfully revegetated over the long term, especially under very arid conditions.[39] Non-native grasses are used in some areas to produce a fast-growing cover for the land. Will these species endure abnormal aridity or cold? What are the effects of planting these non-native species on wildlife? The answers are not clear.

There is also fear of permanent loss of near-surface water aquifers and widespread soil contamination with heavy metals.[40] Water running through mine sites and tailing piles can become highly acidic and contaminate both surface and underground supplies.

Solid Waste

Coal-fired power plants produce substantial quantities of waste. In 1984, about 70 million tons of ash and 16 million tons of flue gas desulfurization wastes were generated in the

United States.[41] By 2000, the amount of ash waste is expected to increase by 75 percent to 120 million tons annually. Production of FGD wastes is expected to triple to about 50 million tons annually. Some coal wastes can be marketed as aggregate materials, for use in bricks, concrete, and road base. For example, about 180,000 tons of coal ash were used in the construction of Denver International Airport. Most coal waste, however, is disposed in landfills.

Utility waste management sites are currently exempt from the hazardous waste requirements of the Resource Conservation and Recovery Act (RCRA), but the U.S. EPA is concerned that some unregulated wastes still pose some danger to water quality and human health.[42]

"Clean Coal" Technologies

A number of new technologies that burn coal to generate electricity are under development that could reduce environmental impacts and improve the efficiency and economics of coal use. These technologies, the development of which is primarily sponsored by the U.S. Department of Energy (DOE), could play a role in this region if their promise is fulfilled.

The U.S. DOE Clean Coal Program

The Clean Coal Program, a partnership between the federal government and the private sector, hopes to develop coal technologies that can meet the environmental and economic challenges ahead.[43] Begun in 1986, the $7 billion program has funded 45 demonstration projects that test advanced coal technologies in 21 states. Through five rounds of project solicitations, the federal government has contributed about $2.5 billion, and private industry has added more than $4.0 billion in matching funds. Six of the 45 clean coal projects are located in the Rocky Mountain region, with three in Colorado, two in Wyoming, and one in Nevada.

In our view, the two most promising technologies developed by the program are integrated gasification/combined-cycled combustion (IGCC) and fluidized bed combustion (FBC). IGCC technology appears to hold the greater potential. IGCC power generation involves the gasification of coal by reacting coal with steam and a limited amount of oxygen under pressure. Under these conditions, a gaseous fuel is produced containing a mixture of carbon monoxide, methane, and hydrogen. Most of the contaminants in the coal are left behind in a solid residue, and a gas-cleaning unit removes much of the remaining contamination found in the gaseous fuel mixture. The cleaned fuel is comparable to natural gas and can be burned in a combined-cycle power plant.

Energy and Equity:
The Kayenta Mine

Many of the most serious land and water impacts associated with the West's energy policies occur in low-income communities and areas that are largely populated by people of color. In particular, the region's Native lands are often mineral rich and, as tribes work to expand economic development, these lands are often exploited by non-Native interests.

In the arid deserts of northern Arizona, a region where less than 12 inches of precipitation fall annually, tribal water is being used to slurry coal from the Kayenta Mine to the Mohave Generating Station, a power plant on the Nevada-California border. In 1993, to slurry the coal—via a 250-mile-long pipeline—over 1 billion tons of water were pumped from a deep aquifer on which local tribes have relied for agriculture for over 400 years.

Leaders of the Hopi tribe have protested to the U.S. Department of the Interior that the sacred springs that have long sustained their communities are now drying up. At the same time, tribal communities are heavily dependent on the revenues and employment from mining and other natural resource industries. This tension is inherent in many energy policy decisions.

Using IGCC technology creates increased efficiency compared with conventional coal-burning technology. The gain occurs because clean gasified coal can be burned in combined-cycle power systems. Because some of the energy in the coal is consumed during the gasification process, however, IGCC technology, although greater than 40 percent efficient, is not as efficient as combined-cycle systems using natural gas.[44]

Southern California Edison built the first 100-megawatt IGCC demonstration plant in the United States in 1983 at the Cool Water facility in Daggett, California. Sierra Pacific Power is planning the second plant using this technology at Pinon Pine, a 95-megawatt facility to be built east of Reno and due on line in 1998.

In FBC technology, complete combustion of coal is augmented by burning it in a rapidly churning jet of air within the combustion chamber. Air pollution from fluidized bed combustors is less than the emissions from conventional coal burners, in part because the churning air promotes complete fuel burning and because pollution-absorbing materials (such as limestone) can be injected with the coal. The absorbants react with pollution released by coal burning, capturing it in solids that can be removed from the combustion chamber. Efficiencies of fluidized bed systems are generally over 40 percent, representing an increase over conventional coal technologies, but less than that for IGCC. Pollution reductions are also less dramatic for FBC than IGCC. One demonstration FBC facility in our region, Tri-State's 110 megawatt Nucla power station, is near Montrose, Colorado.

"Clean coal technologies offer ... important environmental advantages over conventional coal combustion."

Environmental Impacts of Clean Coal Technologies

Clean coal technologies offer two important advantages over conventional coal combustion. The first is the environmental advantage resulting from the removal of far more SO_2 and NO_X than for pollution control devices operating on conventional coal units. Overall SO_2 and NO_X emissions from clean coal technologies are 50 percent lower than for conventional coal units equipped with pollution controls. Second, the increased efficiencies of a clean coal system produce economic benefits and additional environmental advantages. About 20 percent less coal is needed to generate the same amount of electricity as in a conventional coal combustor. Environmental impacts from coal mining are reduced because less fuel is needed. Consequently, CO_2 emissions from coal burning are also lessened between 17 and 27 percent relative to conventional coal burning, according to U.S. DOE estimates.[45]

Nonetheless, the word clean in "clean coal" refers only to pollution *reductions* compared with conventional coal combustion technologies. Even the best clean coal technologies still create significant environmental impacts relative to the use of most renewable energy resources and the use of natural gas in combined cycle power generators. In particular, SO_2 and CO_2 emissions are still high relative to natural gas combustion.

And there are environmental problems specifically caused by clean coal technologies. Air toxics appear to be one of them. Clean coal technologies, particularly IGCC plants, in many ways resemble oil refineries. Coal is "cooked" at high temperatures and pressures during gasification, and various gas streams are piped to secondary units where gas cleaning occurs prior to combustion. This complex system is not absolutely airtight and leaks can occur from pipe fittings and processing units. The pollution of water with toxic materials is also a concern as is the disposal of solid waste.

Between 20 and 40 percent of the original weight of coal used at a clean coal plant might remain as solid waste. The exact amount of solid waste depends on the ash content of the original coal. In fluidized bed combustion processes, gypsum, added to the

coal in the combustion chamber, also appears as solid waste.

Carbon Recovery

Concerns regarding high carbon emissions of coal fuels has sparked research into technologies capable of reducing these emissions. A number of approaches are under development that would capture a portion of the carbon in coal either before, during, or after combustion in order to reduce emissions of CO_2.[46]

These approaches fall into two categories: pre- and postcombustion recovery. A small demonstration of one of the precombustion techniques recovered 88 percent of the carbon contained in the coal. However, 19 percent of the energy value of the fuel was lost. Whether captured in pre- or postcombustion techniques, the carbon must be safely disposed of. One method being considered is to pump the CO_2 into depleted underground gas reservoirs. Another proposes transforming the CO_2 into dry ice and dumping it into the ocean; this approach is of limited practicality in the inland Rocky Mountain and Desert Southwest region.

The Economics of Clean Coal Technologies

Currently, clean coal technologies are only in the demonstration phase. Their capital costs, therefore, are significantly higher than for conventional coal plants or combined-cycle power plants burning natural gas. The IGCC projects in the Clean Coal Program are estimated to cost well above $1,000 per kilowatt by the time they are completed. Analysts at the Princeton Center for Energy and Environmental Studies estimate the current cost for IGCC technology to be above $1,500 per kilowatt,[47] whereas Public Service Company of Colorado's 1993 Integrated Resource Plan (IRP) estimates that costs for a new coal IGCC unit may be in the range of $2,200 per kilowatt. Electric Power Research Institute (EPRI) estimates current IGCC costs to be $1,777 per kilowatt.

Fluidized bed combustion may be even more expensive. The capital cost for the Nucla fluidized bed combustor, for example, was $1,123 per kilowatt of capacity, even though a substantial portion of an existing power plant was applied to the project. A 1993 study performed for Pacificorp by Sargent and Lundy places the cost of a pressurized FBC system at $2,663 per kilowatt. IGCC and FBC units built in the future may benefit from cost reductions as these technologies mature, perhaps ultimately falling below $1,500 per kilowatt in the case of IGCC, but today's costs are considerably higher than for natural gas-fired combined-cycle units.

Operating and maintenance costs for clean coal plants are also on the order of 50 percent higher than for conventional plants and twice as high as for natural gas combined-cycle power plants because of their additional complexity. On the other hand, fuel costs are about 20 percent less than for conventional coal plants and thus significantly less than the cost of natural gas. This fuel cost advantage might overcome the higher capital and O&M costs. One 1991 study, produced by an alliance of four environmental and energy organizations, concluded that both IGCC and FBC technologies, in the period 2010–2040, would provide cheaper power than natural gas combined-cycle power plants.[48]

There would be a dramatic impact on the cost of coal-based generation if, for environmental reasons, carbon recovery systems were required. The cheapest method known, according to a Princeton University study, would add at least 30 percent to the cost of coal use.[49] A study by the Electric Power Research Institute places the figure at 60 percent.[50] These estimates translate to costs of $75–$200 per ton of captured carbon.

Efficiency losses from precombustion carbon recovery are similarly large. The Princeton study cited above estimates that

"Currently, the capital costs of clean coal technologies are significantly higher than for conventional coal plants ..."

the efficiency of an IGCC plant will drop from 43.6 percent to 37.9 percent with the addition of carbon removal.[51] Postcombustion carbon removal is even worse. Researchers at the Massachusetts Institute of Technology estimate that the efficiency of a conventional coal plant would be cut nearly in half, from 35 to 18 percent, with the addition of post-combustion carbon removal.[52]

Summary for Clean Coal

Two key questions remain unanswered at this time. From the environmental perspective, will IGCC systems be clean enough to justify their use in a new generation of baseload generation applications? From the economic perspective, will they be cost-effective compared with other generation options, especially those that produce less environmental harm? In short, to make coal clean enough to compete with other resources may render coal too expensive. However, it is still unclear whether certain renewable technologies (especially solar), though cleaner than clean coal, will remain too expensive. Given these uncertainties, we believe that clean coal may have a role in meeting future demand for power and certainly should be encouraged to compete with other resources.

"Natural gas ... has ... recently emerged as the new fuel choice for the electric power industry ..."

Natural Gas: A Transitional Fuel

Natural gas, which has always been the "little brother" to the behemoth oil industry, has recently emerged as the new fuel choice for the electric power industry in the 1990s. Most electric utilities in the United States are turning to natural gas to fuel new peak and intermediate load power plants over the next 10 years.

In this region, nearly 4,500 megawatts of new gas capacity is planned for construction in the next decade, over 90 percent of the new capacity needed. Most of the new gas capacity will initially be in the form of single-cycle combustion turbines (CTs), which will run relatively infrequently to meet peak loads. Over time, an increasing portion of the new capacity will be higher-efficiency combined-cycle units that will run at 30–40 percent capacity factors to meet intermediate loads. Depending on prices and new technologies, natural gas is also under consideration as a fuel source for baseload capacity.

Natural gas is currently abundant in the region. Although on a Btu basis it is still more expensive than coal, it can be used to generate electricity in combined-cycle units at a total cost significantly less than *new* coal power plants because of lower initial capital costs. The natural gas industry is also an important source of tax revenues and employment.

Relative to coal, natural gas has distinct environmental advantages. Its combustion generates virtually no SO_2, about half the CO_2 per Btu produced by burning coal, and much lower toxic and particulate matter emissions. However, natural gas combustion does contribute to the risk of global climate change, and gas exploration and drilling damage wetlands, wildlife habitat, and water supplies.

The primary economic problem with natural gas is its price volatility both in the short and long run. There is reason to think that the price of natural gas will exhibit some short-term volatility, in response to oil price shocks, natural disasters, and seasonal demand spikes, although to a lesser degree than in the past. In the long run, there may not be enough readily available natural gas to avoid price hikes. Natural gas is not immune to increased environmental regulation, which may assert some upward pressure on prices.

Given these realities, we support an expansion in utility reliance on natural gas in this region—but with caveats. The fact that natural gas prices are currently low must *not* be used as an excuse for the region to avoid learning about and developing its renewable and energy efficiency resources. Although many utilities facing short-term competitive pressures may prefer to rely solely on natural gas resources, over time there is a significant

risk that gas prices will rise. As a result, we believe that a more balanced utility portfolio that includes a mix of natural gas, energy efficiency, renewables, and clean coal would be better for the region.

We begin this section with a brief review of the plans of the region's utilities to use natural gas to generate electricity. We then examine the supply and demand for gas and its possible effects on price. Following a discussion of the employment and economic benefits of natural gas we conclude with a passage on the environmental effects.

Natural Gas Use by the Region's Electric Utilities

As described in Chapter 2, the region has more than enough baseload capacity for the foreseeable future, but it lacks enough peak and intermediate generation capacity to meet growing electric demands. Natural gas burned in combustion turbine and combined-cycle configurations is well suited to meet this need for several reasons:

- The new CTs can reach full capacity in 10–20 minutes and ramp down just as quickly.
- Combined-cycle units (CCs), in which otherwise wasted heat from CTs is used to generate steam for additional electricity production, can use 50 percent or more of the heat value of the gas.
- Gas units have short lead times (1–3 years for construction), an important feature when the impacts of competition on load are difficult to predict.
- Capital costs for new CTs and CCs are low compared with coal-fired or nuclear capacity, running in the range of $400–$800 per kilowatt in 1994. Gas prices have been low for the past few years, and a number of forecasts are optimistic about this trend continuing. Presently, electricity from combined-cycle units costs as little as 30 to 40 mills/kilowatt-hour exclusive of transmission and distribution charges.
- The environmental impacts associated with natural gas are significantly less than with coal.

For these reasons, utilities in our region are planning to add around 7,000 megawatts of gas-fired capacity over the next 15 years. A very large portion of the capacity built by IPPs and self-generators likely will be natural gas-fired. The largest proposed use of natural gas by a utility in the region is by Public Service Company of Colorado, which, in 1994, received approval to construct 471 megawatts of CC capacity. Nevada Power Company, Arizona Public Service Company, Tucson Electric Power, WestPlains Electric, the Salt River Project, Public Service Company of New Mexico and other regional utilities all show at least one CT or CC coming on line on their systems in the next five to ten years.

The Supply of Natural Gas

Natural gas supplies in the West and in areas linked by pipeline to the West are significant. Supplies are stated in terms of "proved reserves" and "potential resources." The sum of these equals the "total resource base." Of these three categories, proved reserves are the most important, for they represent the total gas supply that is cost-effective if current technology is used for development and extraction. The quantity of proved reserves is not constant; it increases and decreases as a function of price fluctuations, technology improvements, changes in federal and state tax credit policy for new wells, and annual reserve depletion.

Table C-2 provides historical data for regional and nationwide proved reserves of natural gas. At 164 trillion cubic feet (Tcf), the total 1994 natural gas proved reserves in the United States were equivalent to less than the nine years of national consumption prior to 1994. This table does not include proved reserves in Canada. Proved reserves in Canada, some of which are available to domestic markets, are about 95 Tcf—one-third of which is in frontier areas not currently under production.[53]

"The environmental impacts associated with natural gas are significantly less than with coal."

Table C-2. Natural Gas Proved Reserves

Year	U.S. Total Reserves, *Tcf*[a]	U.S. R/P[c] Ratio	Four-State Rocky Mountain Reserves,[b] *Tcf*	Regional R/P[c] Ratio	Percentage of U.S. Reserves in the Rocky Mountains
1978	208	11.0	20	17.9	9.5
1982	202	11.5	24	21.6	11.5
1984	197	11.5	24	20.6	12.0
1986	192	12.3	24	25.0	12.5
1988	168	10.0	29	26.5	17.5
1990	169	9.8	30	21.8	18.0
1992	165	9.5	35	18.8	21.0
1994	164	8.9	37	13.2	23.0

Source: All data from Energy Information Association, *Annual Energy Outlook 1995.*
Notes: a. The figures in this column include Federal Off-shore reserves and the Alaskan North Slope but do not include unconventional resources (such as coalbed methane or tight gas sands). b. The Rocky Mountain region is Wyoming, Colorado, Utah, and New Mexico. c. "R/P" refers to annual reserves-to-production ratio.

"Though ... the natural gas resource base seems immense, some of it will be expensive to bring to market."

Table C-2 shows that national proved reserves have gone down steadily for 15 years. The table also shows the increasing importance of the gas fields located in the Rocky Mountain states. Whereas national reserves were depleted from 1978–1994, the regional reserve increased from 20 Tcf in 1978 to 37 Tcf in 1994, or from less than 10 to over 20 percent of the nation's supply. In the United States, New Mexico, Wyoming, and Colorado ranked third, fifth, and seventh, respectively, for proved natural gas reserves, and in 1992 produced 10 percent of the nation's dry natural gas. Over 27 percent of the natural gas well completions in 1992 were in the Rockies, and a full 12 percent of the national well completions occurred in Weld County, Colorado.[54] Furthermore, over 50 percent of the new natural gas pipeline capacity built in 1992 was in the Rockies and the West.[55]

Coalbed methane and tight gas sands are important sources of nonconventional natural gas in the Rockies. Together, the reserves of nonconventional gas supplies in this region are over 22 Tcf, nearly two-thirds the size of the regional reserve of natural gas.[56] In 1992, about 7 percent of *all* domestic gas production (1.3 Tcf) was from tight gas sands, and 3 percent (0.5 Tcf) was from coal beds.[57]

The *total* resource base (proved plus potential reserves) for all conventional and nonconventional natural gas fields is substantially greater. Estimates of total resources in the United States (including the Federal Off-shore and the Alaskan North Slope) span from 850 Tcf (Potential Gas Committee) to roughly 1,300 Tcf (Enron Corporation and National Petroleum Council).[58]

Though this resource base seems immense, some of it will be expensive to bring to market. According to one estimate, half of undeveloped gas reserves will cost more than $3.00 per million Btu to develop, compared with the $2.00 per million Btu average wellhead price in 1993.[59] More than a third of it may cost above $5.00 per million Btu. The National Petroleum Council (NPC) estimates that only half of the gas resource base will be recoverable at wellhead prices below $3.50 per million Btu (in 1990 dollars, given 1990 technology).[60] Assuming technology advances continue for two decades, the NPC estimates that as much as two-thirds, or 800 Tcf, of the gas resource will be recoverable at those prices. The Energy Information Admin-

istration estimates "the remaining economically recoverable gas resource base of the United States, including proved reserves (165 Tcf)" to be over 900 Tcf (by 2010).[61]

The question is: How much gas is easily and relatively cheaply available to our region? No one knows the answer. Simply looking at Table C-2 might encourage a conclusion that inexpensive supplies might begin to run out soon, within a couple of decades. However, the supply of gas is unquestionably a rather elastic function of price: "Reserves" seem to float with price. And there is always natural gas from Canada and the potential of additional gas from Alaska's North Slope and the Outer-Continental Slope. We think that there is likely enough natural gas to meet demands for many decades. The real question is: At what price?

The Demand for Natural Gas

One of the uncertainties regarding natural gas in this decade and beyond is the level at which demand will grow and how that growth will affect both short- and long-term market conditions. Sources of uncertainty surrounding gas demand include the price of natural gas compared with alternative fuels, mainly oil and coal, and the extent to which environmental regulations will encourage or compel different sectors to switch both to and from natural gas.

Table C-3 presents a range of estimates for natural gas demand growth developed for EIA's *Annual Energy Outlook 1995*. Though the spread between low and high total consumption (23.9–26.6 Tcf) does not seem particularly severe, the 2.7 Tcf difference in 2010 represents more than 10 percent of the year's projected consumption. And the EIA estimates do not include demand arising from the transportation sector, which, as described below, could add up to another 1 Tcf to annual demand. There is also the potential for nearly explosive growth in demand for natural gas by both utilities and independent power producers toward the end of the 15-year forecast period. As a result, a high case might show even higher demand than that portrayed by EIA.

Utility Demand

Until very recently, the role of natural gas in electricity generation had been declining for two decades. In 1973, the year of the Arab oil embargo, 18 percent of the nation's electricity was generated by natural gas. By 1990, gas accounted for less than 10 percent of the electric power fuel market. Almost 90 percent of that volume was used for power generation in only six states (the Gulf states,

"The question is: How much gas is easily and relatively cheaply available to our region?"

Table C-3. Projections for Natural Gas Demand by Sector, Average Annual Growth Rate from 1995–2010

Sector	Reference Case	High Case	Low Case
Residential	–0.2%	–0.1%	–0.4%
Commercial	0.2%	0.4%	0.0%
Industrial	1.2%	1.4%	1.0%
Electric Utility	3.4%	3.8%	2.4%
Transportation	0.3%	0.4%	0.1%
Year	Total Consumption, *Quadrillion Btu per Year*		
1995	21.27	21.50	21.07
2010	25.30	26.60	23.86
Annual Growth Rate	1.2%	1.4%	0.8%

Source: Energy Information Administration, *Annual Energy Outlook 1995.*

California and New York). Currently, about 15 percent of the total natural gas market is directed to electric generation. The other 85 percent is used for industrial, commercial, and home heating purposes. But gas consumption to generate electricity may double in the next 15 years[62] and could account for 25 percent of the end-use market for natural gas by 2010, making it the most important new market.[63]

There is, however, considerable uncertainty regarding electric industry demand for natural gas. In our view, there may be such a large demand for natural gas as a fuel source for electric generation that actual usage may exceed EIA's high-demand forecast. Currently, between 90,000 and 125,000 megawatts of new gas-fired electric generating capacity is expected to be constructed nationwide by 2010 by both utilities and IPPs. The large range in forecasts for total new gas-fired power plants (35,000 megawatts, or almost 40 percent of the lower estimate) is itself an example of the uncertainty surrounding future demand. If natural gas prices stay low and if the price and efficiency of combined-cycle configurations continue to improve, experts believe that the total megawatts and capacity factors of new gas-fired capacity could be higher.

"There is ... considerable uncertainty regarding electric industry demand for natural gas."

Repowering (converting) existing oil or coal units to be capable of running on natural gas is an important option being considered in metropolitan areas with air quality problems. Because gas-fired plants have lower emissions at the stack, conversions may occur near urban areas even where there is no demand for new, incremental capacity.[64] Conversions in rural areas may occur to improve local or regional visibility. And if concerns involving global climate change increase, additional coal plants may be converted to natural gas to reduce CO_2 emissions.

Industrial Demand

Large industry currently relies on natural gas for one-third of its energy needs, with the remainder being met by coal, oil, and electricity. Gas use in this sector is expected to grow over the next 20 years, keeping the industrial sector the largest end-user of natural gas. Increased cogeneration during peak electric seasons accounts for much of the steady and rapid growth in industrial demand for gas, averaging an expected 1.2 percent per year through 2010.

What is not reflected in these demand projections is the fact that a large number of industry boilers rely on residual fuel oil as an energy source *and can switch to natural gas.* As of 1993, approximately one-third of the nation's industrial boilers ran on oil. In the past, when oil prices increased, many industries switched their boilers to natural gas. Depending on oil prices, industry may once again make substantial switches to natural gas.

At the moment world oil prices are stable, and increasing petroleum production outside of the Organization of Petroleum-Exporting Countries (OPEC) threatens OPEC's ability to mount an effective embargo or to raise world prices. However, the United States is now more dependent on imported petroleum than at any other time, including in 1973. As a result, the risk of short-term price run-ups has not completely disappeared. In the long run, oil price increases seem inevitable as easily available petroleum begins to become exhausted. Thus, there remains the possibility that industrial demand for natural gas will exceed projections, both over short periods of time as well as over the long run.

Transportation Sector Demands

Urban brown clouds, regional visibility, and related environmental considerations are prompting a serious look at alternative fuels for vehicles, especially in the West. A number of alternatives fuels are available, including propane, ethanol, electricity, and natural gas. Compressed natural gas, already available in service stations in several western cities, may be the near-term alternative fuel of choice

because of its relatively low life-cycle costs. If so, what does this imply for the demand for natural gas?

Complete replacement of the domestic automotive fleet would require about 10 Tcf of new supply annually. If 25 million vehicles, a projected 10 percent of the vehicles on the road in 2005, ran on natural gas, the total *new* demand for natural gas would be about 1–2 Tcf.[65] Most industry analysts expect that actual replacements will be nowhere near even this 10 percent level in the short run. For example, the American Gas Association estimates there will be only 2.5 million new natural gas vehicles by 2000.[66] The Gas Research Institute has estimated that about 0.5 Tcf will be needed to provide automotive fuel in 2010.[67] In sum, it does not appear that the transportation sector has the potential for natural gas use to exceed 1 Tcf through 2010. However, no one today has a clear idea of this sector's potential demand for natural gas 20 to 30 years from now.

Natural Gas Prices

Since the incremental deregulation of the gas industry, which began with the Natural Gas Policy Act of 1978 and culminated with FERC Order 636 in April 1992, industry analysts have found it even more challenging to predict the price of natural gas to the end user. Order 636 fundamentally changed the way that natural gas is purchased and transported. In the past, natural gas pipeline companies were regulated and served the functions of securing gas supplies at the wellhead, transporting them to local distribution companies, balancing supplies with demand, and providing storage services. Order 636 mandated the unbundling of services so that each segment of the industry could be served by separate providers with prices set by the marketplace rather than by regulation. Most analysts agree that these changes will create a more efficient and competitive natural gas market. However, the market is still adjusting and is therefore volatile.

Short-Run Price Volatility

Table C-4 shows average monthly wellhead prices for 1994 and the first half of 1995. In 1994 prices varied significantly around the mean price of $1.82, in a manner similar, if less pronounced, to short-run price variability in the 1980s and early 1990s. In early 1995 the price settled down. Though volatility should diminish as the market equilibrates and additional storage is built, short-run gas prices may still show volatility in response to seasonal shifts in demand, natural disasters,[68] and, one would assume, interruptions in the supply of or price run-ups in alternative fuels. Thus, even in the short term, prices are particularly sensitive to changes in supply-and-demand conditions.

Table C-4. Monthly Average Wellhead Prices, January 1994 to June 1995

Month	Wellhead Price, *dollars/1,000 cubic feet*	Difference from Mean, *dollars/1,000 cubic feet*
1994		
January	2.00	0.18
February	2.13	0.31
March	2.12	0.30
April	1.91	0.09
May	1.94	0.12
June	1.75	–0.07
July	1.84	0.02
August	1.74	–0.08
September	1.56	–0.26
October	1.48	–0.34
November	1.68	–0.14
December	1.72	–0.10
1994 Average	1.82	
1995		
January	1.67	0.10
February	1.50	–0.07
March	1.53	–0.04
April	1.48 (R)	–0.09
May	1.65 (R)	0.08
June	1.58 (E)	0.01
1995 Average	1.57	

Source: Energy Information Administration, *Natural Gas Monthly,* August 1995, Table 4.
Notes: (R) = revised data. (E) = estimated data.

Long-Run Price Projections

In 1984, the average U.S. wellhead price was $3.25 per million Btu (in 1990 dollars). By 1990 it had fallen steadily to $1.71, but it climbed back up to $1.97 per million Btu in 1993. The years 1994 and 1995 have seen a reduction in these prices. No one knows precisely where prices will go in the future. Table C-5 shows average U.S. wellhead prices projected by various analysts in 1995.

The average of one "reference" case and four "average acquisition price" forecasts is $3.24 per thousand cubic feet in 2010. This is about double the average wellhead price in the first six months of 1995, as depicted in Table C-4, and implies about a 5 percent real annual growth rate between now and 2010.

We note that the prices set forth in Table C-5 are lower than wellhead price estimates made only two years ago. At the moment, many forecasters seem to think that wellhead prices will stay relatively low through 2010. But, of course, no one really knows where gas prices may go over the next 15 to 20 years because easily available reserves are not well tied down, nor is natural gas immune to developments in world oil markets.

"... it is unsound for utilities to plan to buy only natural gas power plants to meet new resource needs."

The significance of this information is that there is price risk associated with the rapidly increasing dependence on natural gas within the electric utility sector. Strategies exist for managing this risk. Utilities can try to impose the risk of fuel price increases upon gas-fired independent power producers selling to utilities in the wholesale market. Or, utilities can execute contracts with gas suppliers that fix the price for a period of time. An ENRON Corporation witness testified in 1994 that "a 10 year firm gas supply can be acquired on a fixed price basis in the $2.70 range and a 20 year firm gas supply can be acquired on a fixed price basis in the $3.50 range."[69] Note that these prices exceed the gas prices that utilities in our region have been using in base-case scenarios to justify investments in natural gas capacity.

Summary: Supply, Demand, and Price

Natural gas supplies appear to exist in abundance, well beyond the amount thought likely available only ten years ago. The question is: What will gas cost 10, 15, and 20 years from now? In our view, there is enough risk in the answer to this question that, apart from environmental and other reasons, it is unsound for utilities to plan to buy only natural gas power plants to meet new resource needs. Instead, utilities should diversify their resource portfolio to include other resources, including energy efficiency, renewables, and clean coal.

Employment Impacts and Economic Benefits

The economic, tax, and employment benefits of the natural gas industry in the West are substantial. The following examples pertain to Colorado, but similar, if slightly lower, benefits can be assumed for New Mexico and

Table C-5. Natural Gas Price Forecasts by Various Analysts
(1993 dollars per thousand cubic feet)

Year	EIA			WEFA	GRI	DRI	AGA
	Base Case	Low	High	Base Case			
2000	2.29	2.12	2.50	2.55	2.53	2.44	2.60
2010	3.37	3.04	3.72	3.47	2.71	3.56	3.09

Sources: Energy Information Administration, *Annual Energy Outlook 1995* (1995). WEFA: The WEFA Group, *Natural Gas Service Long Term Forecast* (Summer 1994). GRI: Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, 1995 Edition* (August 1994). DRI: *DRI/McGraw-Hill Energy Review* (Spring–Summer 1994). AGA: *American Gas Association 1994 AGA-TERA Base Case* (January 1994).

Wyoming, the two other gas-producing states in our region. (We say slightly lower because more gas is produced in Colorado and because many of the headquarters for the independent gas companies are located in Colorado.) The three primary areas of economic impact on Colorado relate to taxes (at both state and local levels), jobs (both direct and generated), and capital formation (which stimulates the economy).[70]

In 1992, the gas industry (and its employees) paid over $200 million in taxes to state and local coffers in Colorado. This includes over $100 million paid in direct taxes from industry (e.g., valorem, corporate income, severance, and sales taxes), $80 million in taxes generated by employment (based on the industry's nearly 15,000 employees—individual income tax, residential property tax, etc.), and another $26 million paid to state and county governments for the use of state and federal lands.

The gas industry provided 15,000 direct jobs in Colorado in 1992. According to the government-established multiplier, over 53,000 indirect jobs (jobs created in other sectors) were created. Together, the 68,000 direct and indirect jobs made up approximately 4 percent of the state's 1.6 million jobs. Note that these job numbers appear to far outpace those linked to the coal industry. Equally significant, the industry generated over $500 million in capital in the past two years to fund primarily Colorado gas exploration and recovery operations. Expenditures made by these businesses create a significant stimulus for the economy.

Environmental Impacts

Relative to coal, natural gas has many environmental benefits as a fuel choice for electric generation. On a Btu basis, natural gas combustion generates about 50 percent as much CO_2 as coal, less PM, and little SO_2 or HAPs.

Notwithstanding these benefits, natural gas poses some important environmental problems. First, natural gas combustion in new combined-cycle units may generate NO_X and carbon monoxide (CO) in quantities comparable to or greater than coal burning. Second, the drilling, transporting, and use of natural gas produces a large quantity of methane (as do coal mining, livestock, and landfills) that escapes into the atmosphere. As discussed previously, methane is a potent greenhouse gas. Methane from natural gas drilling can also pollute water. Third, natural gas drilling and exploration can have significant impacts on wilderness habitat, wildlife, public open space, and adjacent private land.

Carbon Monoxide

Carbon monoxide is a colorless, odorless gas that is harmful to human health and, at sufficient levels of concentration, is fatal. Neither natural gas nor coal combustion is a major contributor to carbon monoxide levels in the United States. However, natural gas used in combined-cycle units emits CO at three times the rate of a conventional coal plant on a Btu basis. This suggests that the industry should be careful about siting these units in or close to areas where ambient air quality standards for CO are not met or are close to not being met.

Methane

Natural gas consists principally of methane. On a unit basis, methane is much more potent than CO_2 and second only to CO_2 in its contribution to global warming. At various stages of exploring for, drilling, and transporting natural gas there are regularly occurring methane leaks into the atmosphere. The U.S. EPA estimates that methane emissions from natural gas systems may be as high as 5.0 Tg per year by 2000,[71] making this source of methane roughly comparable in volume to coal mining, although less in volume than landfills and even livestock.

Methane also leaks to groundwater and surface water supplies and to soil in large amounts, particularly in producing regions

"The economic, tax, and employment benefits of the natural gas industry in the West are substantial."

where exploration and drilling are pronounced. This has been a concern for residents living in the Animas River Valley in the San Juan Basin of Colorado and New Mexico, where drilling for coalbed methane has made the area the second-largest gas-producing region in the country. Seventy of the 205 groundwater samples (i.e., 34 percent) collected by the U.S. Geological Survey (USGS) in 1990 had methane concentrations that exceeded the reporting limit. A USGS report concludes that "manmade conduits (i.e., gas wells) probably account for most of the upward migration of gas to the near-surface environment."[72]

"The adverse environmental effects of gas production involve soil, water, hazardous waste, plants and wildlife, visibility, and air quality."

Impacts on Wilderness, Wildlife, and Public and Private Lands

Gas production has various environmental effects throughout the life of a well, from the initial exploration operations, to construction of the roads and well pad, to drilling of the well, to preparation for production, to the actual production of gas. These effects involve soil, water, hazardous waste, plants and wildlife, visibility, and air quality. Such impacts have pitted environmental forces against natural gas developers in a number of areas in our region. A separate though related set of problems has arisen out of the severance of mineral from surface estates. We review the principal problems here, noting that most of them can be alleviated by careful planning or avoiding sensitive areas.

Soil. Exploration activity, construction of the roads and well pad, and installation of pipelines can cause mixing of soils and loss of vegetative cover as a result of the use of explosives and the required digging, leveling, and scraping of the earth. The results can be erosion, loss of soil productivity, increased runoffs, landslides, and flooding.

Water. Both surface water and groundwater may be adversely affected by drilling operations. Surface waters may be polluted by increased sediment levels due to erosion, increased flows from runoff, and the construction of road crossings. Groundwater may be contaminated if drilling fluids and chemicals from the well escape into underground reserves or minerals migrate between geological formations during drilling.

Hazardous waste. Drilling for oil and gas often involves or produces toxic materials, including cadmium, lead, and benzene, as well as naturally occurring radioactive materials (NORMs). Injection wells are often used to dispose of these wastes, but wastewater is sometimes simply placed in adjacent bodies of water or may migrate to them.

Certain radioactive materials form a currently unregulated set of substances that may be brought to the surface during natural gas drilling. Radium, radon gas, and their decay products (e.g., lead 210 and polonium 210) are the NORMs sometimes found in the produced waters, natural gas and natural gas liquids, pipelines, and sludge generated during the exploration for and production of natural gas.[73] The uptake of radionuclides into the food chain exposes the general public to risk because people consume the meat of animals that grazed or drank in areas contaminated by NORMs. Incidents involving the use of NORM-contaminated drill pipe for park fencing and playground equipment have been documented in Louisiana, Mississippi, and Alaska.[74]

Plants and wildlife. The earth moving required in exploration and the construction of roads and well pads destroys vegetation. And virtually all activities associated with natural gas production can affect local wildlife populations. Because natural gas exploration is occurring in some fragile areas of our region, there is heightening concern regarding its impacts.

In a number of cases, drilling has been done or is proposed in areas near or adjacent to national parks and monuments. The National Park Service has raised concerns with both federal and state regulators on numerous occasions regarding potential

environmental impacts to national parks and monuments in the Rocky Mountain states.[75] Of particular concern are proposed exploration drills near the Bridger-Teton Wilderness in Wyoming.

Water Power

One of the more remarkable stories of the West is the development of water resources to meet electric load in this, the most arid, region of the United States. In this section, we describe the developed hydroelectric resource available to the region and its benefits and environmental impacts. We focus on the large federal hydro resource marketed by the Western Area Power Administration ("Western"), still the backbone of public and cooperative systems throughout the region. This resource will probably shrink marginally in coming years because some federal facilities will need to be reoperated to address environmental impacts. We also review the potential for new hydro resources in the region, concluding that, with the exception of a few small hydroelectric facilities and possibly some pumped storage plants used to back up intermittent renewable generation capacity, there is little potential for growth.

The Developed Hydro Resource

About 5,500 megawatts of nameplate hydro capacity is in place in our six-state region. About 4,900 megawatts of this capacity is federally owned, operated by the U.S. Bureau of Reclamation, and marketed by Western. Most of this capacity is available to meet loads in the region.

The remaining hydro capacity is owned and operated primarily by individual utilities such as the Salt River Project and Public Service Company of Colorado. PacifiCorp makes hydro resources available to the region during summer months from its dams in the Northwest, both to its own service area in Utah and Wyoming and to Arizona Public Service Company.

"One of the more remarkable stories of the West is the development of water resources to meet electric load in this ... arid region ..."

Table C-6. Existing Federal Dams as of September 30, 1993 (24 megawatts or larger)

Plant Name	River	Maximum Installed Cabability (FY 1993), *megawatts*	Net Generation (FY 1993), *kilowatt-hours*
Hoover (AZ/NV)	Colorado	2,074	3,222,153,321
Davis (AZ)	Colorado	269	858,878,000
Parker (CA)	Colorado	69	181,386,797
Estes (CO)	Trans. Mountain Div.	58	89,309,056
Flatiron (CO)	Trans. Mountain Div.	106	236,320,264
Green Mountain (CO)	Blue	29	52,393,600
Pole Hill (CO)	Trans. Mountain Div.	10	178,055,600
Mt. Elbert (CO)	Arkansas	211	164,627,000
Alcova (WY)	North Platte	44	80,480,800
Seminoe (WY)	North Platte	45	79,438,566
Fremont Canyon (WY)	North Platte	58	175,634,780
Glendo (WY)	North Platte	38	71,314,290
Kortes (WY)	North Platte	46	121,106,210
Glen Canyon (AZ)	Colorado	1,356	3,659,594,867
Blue Mesa (CO)	Gunnison	96	335,169,600
Morrow Point (CO)	Gunnison	156	431,548,792
Crystal (CO)	Gunnison	32	178,742,665
Elephant Butte (NM)	Rio Grande	24	155,822,120
Flaming Gorge (UT)	Green	150	326,260,450

Table C-6, which sets forth the federally owned hydroelectric facilities located in the region, shows that the Colorado River is the workhorse of Western's system. Two Colorado River dams, Hoover (2,074 megawatts) and Glen Canyon (1,356 megawatts), account for nearly 70 percent of the total federal hydro capacity in our six states. And most of the rest of the capacity and energy marketed by Western is attributable to other dams on the Colorado River, on tributaries to the river, or on waterways or pipelines that are recipients of river water diverted for use in other drainages.

The federal capacity located in the region generated 10,600 gigawatt-hours of energy in 1993, implying a capacity factor of only 4 percent. Because the capacity factor varies annually with precipitation and snowmelt, drought conditions can and have reduced capacity factors well below those set forth in Table C-6 for 1993. Drought also puts pressures on the Bureau of Reclamation to divert water that might be used for power to irrigation, a use that often has a higher priority than power.

The size of the federal hydro resource in this region is shrinking because of environmental concerns, which we describe below.

"The size of the federal hydro resource in this region is shrinking because of environmental concerns ..."

Western and other federal agencies have already indicated that several hundred megawatts of the capacity of Glen Canyon Dam may be lost to reoperation implemented to protect the river beneath the dam pursuant to the Grand Canyon Protection Act (GCPA) of 1992.[76] Although capacity may be lost as a result of reoperation, energy typically is not lost because reoperation affects the timing and magnitude, but not usually the average annual amount, of the flows through the power turbines.

The loss of capacity from Glen Canyon Dam presents challenges to both Western and its customers. Though the loss of several hundred megawatts of capacity in a region with 38,000 megawatts of resources may not seem like much, it represents roughly 10 percent of Western's regional—and inexpensive—capacity. Western is required by the GCPA to implement a public process, in part to develop substitute resources for the lost capacity. Some of Western's customers are not waiting for Western to find new resources. For example, Tri-State has already contracted to acquire 40 megawatts of capacity from San Juan coal unit 3 in New Mexico to make up for its loss of capacity from Glen Canyon Dam.

Building Hoover Dam: Public Works on a Grand Scale

Hoover Dam is one of several large federal dams in the West (including Grand Coulee, Bonneville, Fort Peck, and Shasta) for which construction was begun in the 1930s. At the time, these structures were the largest human-made objects in the world. Indeed, the construction of Hoover Dam set a number of world records. When finished it contained more concrete than all the previous Bureau of Reclamation dams combined. Along its narrow crest, the dam arches 1,244 feet from one canyon wall to the other. It is 726 feet tall and, at its base, an incredible 660 feet thick. Just upstream from the dam, two enormous intake towers, each as tall as a forty-story building, admit water into 30-foot-diameter penstocks, sending water to 16 electric-generating turbines. Completed in 1935 (ahead of schedule and under budget) by over 3,000 workers in 22 months, Hoover Dam was one of the major accomplishments of the public works programs under the New Deal. Most of the costs of the original dam have been recovered from electric ratepayers and others. Most of the costs of the $120 million Hoover Dam Visitor's Center still remain to be recovered.

Table C-7. Sales of Hydropower by Western Area Power Administration (Fiscal year 1993, by State)

State	Total Sales, *gigawatt-hours*	Total Revenue, *thousands of dollars*	Average Price, *cents per kilowatt-hour*
Arizona	2,284	34,605	1.52
Colorado	2,924	53,674	1.84
Nevada	1,876	29,417	1.57
New Mexico	882	14,466	1.64
Utah	1,651	31,187	1.89
Wyoming	946	18,003	1.90
Regional total	10,563	181,352	1.72

Source: Statistical Appendix to *1993 Western Area Power Administration Annual Report*, p. 37.

Marketing the Power

As indicated in Appendix B, the capacity and energy from these facilities are marketed by Western primarily to municipalities and rural cooperatives pursuant to long-term contracts. The contracts raise a host of economic, equity, and environmental issues.

At the core of the economic and equity issues raised by the sale of power from the federal dams are the rates at which Western sells the power. Power rates are set by Western to recover certain costs of the projects, including a large share of project costs attributable to irrigation. Table C-7 sets forth the average rates for power in each of our six states. By regional standards, these rates are low. As a result, the opportunity to buy power from Western is prized.

Eligible Customers

The legislation authorizing the projects from which Western typically markets power specifies that the power must first be made available to municipalities, cooperatives, and other nonprofit entities, including the federal government and Native American tribes. As described in Appendix B, investor-owned utilities (IOUs) were typically disinterested in providing power to small towns and rural areas in the region. As a result, the federal government took the lead in providing electricity to rural areas that were typically served by nonprofit entities.

Some experts now question whether such preferential treatment remains justifiable in an age when power is widely available from a variety of sources. For example, preference power may encourage industry to locate where such power is available, thereby depriving other areas of economic growth. As cities expand into less densely populated areas and selected rural areas become tourist meccas, it is becoming increasingly difficult to distinguish preference utility loads from those of IOUs.

On the other hand, preference entities contend that many rural areas in our region have not shared in the wave of economic growth that is sweeping the region. The availability of cheap power provided from the dams and Western's transmission lines has supported rural and small town economies across our region and has unquestionably improved the quality of life in these places. To jeopardize these gains by ending the preference might be poor public policy. And an act of Congress would be necessary to eliminate the preferences since they are codified in federal statutes.

Power Versus Other Uses

The projects from which Western markets power are multi-purpose facilities. Many of

"At the core of the economic and equity issues raised by the sale of power from the federal dams are the rates at which Western sells the power."

them provide water for irrigation, for river regulation, for flood control, to meet compact entitlements, for municipal and industrial uses and for fish, wildlife and recreation. Nearly all of the projects were constructed by the Bureau of Reclamation under the authority of the Reclamation Act of 1902, the central purpose of which was to settle the West by providing federal support for water for irrigation. Especially in the earlier projects, hydroelectricity was often seen as providing incidental, but not primary, benefits. Nonetheless, it was recognized early that sales of power were a "cash cow" available not only to pay for the cost of the turbines and transmission facilities, but also to pay for the capital costs attributable to the irrigation functions of the dams. As a result, most project pool power rates cover a large portion of irrigation costs.[77] In a rough sense, there has been equity in this arrangement, if not efficiency, in that the irrigation and other types of economic activity the projects support pay for the electricity. In some projects, a significant portion of the load was, and still is, for pumping. To this extent, irrigated agriculture has been paying for the power. However, some now question the subsidy as the rural West changes, its towns grow, its economic activities diversify, and its economy is based less on irrigation.

"The availability of cheap power provided from the dams ... has supported rural and small town economies across our region ..."

Integrated Resource Planning and Contract Extensions

On October 20, 1995, Western adopted final rules for its Energy Planning and Management Program (EPMP).[78] In these rules Western requires its firm-power customers to implement Integrated Resource Planning (IRP). Western also sets forth policy regarding the extension of power sales contracts for the Loveland Area and Pick-Sloan Missouri Basin—Eastern Division customers.

Section 114 of the National Energy Policy Act of 1992 required Western to promulgate IRP rules for its customers. In essence, Western's rules implementing section 114 require its customers to compare supply- and demand-side resource options on an equitable basis, to consider the environmental impacts of their plans, and to prepare a five-year action plan. Failure to submit a plan to Western can lead to rate surcharges. Small customers (with less than 25 gigawatt-hours of usage per annum over five years) are exempt from formal IRP requirements. Since many of Western's customers in our region are not otherwise covered by IRP, Western's rule should encourage its customers to think about how new, expensive supply-side resources might be postponed or reduced as a result of energy efficiency investments.

Western also announced that it would extend contracts for the Loveland Area and Pick-Sloan for 20 years. The size of the resource to be available for extension in 2001 (for Pick-Sloan—Eastern Division) and 2004 (the Loveland Area) will depend on river conditions existing at the time of extension. Western also decided to create resource pools of up to 6 percent of the available resource to be available for new customers, including Native American tribes.

Environmental Impacts

The generation of electricity by means of falling water does not create any visibility-impairing, toxic, or global warming emissions. Unlike the other conventional alternatives, hydroelectric power does not create solid or liquid wastes, involve drilling deep into the earth through aquifers, the storage and transport of radioactive materials, or the removal of vegetation and topsoil from hundreds of thousands of acres. Notwithstanding these attributes, the construction and operation of big dams in the West has produced some of the most protracted and heated environmental battles in the last century. It is no exaggeration to say that the fight over the federal dams on the Colorado in the 1950s and 1960s is one of the two or three defining moments of the modern environmental movement. This struggle was

over plans to dam the Grand Canyon as well as to place a dam within Dinosaur National Park. Ultimately, a deal was struck in which Glen Canyon and several other dams were built on the Upper Colorado. However, it was not until the 1980s that the dam across the Grand Canyon was deauthorized by Congress.

The opposition to big dams in the West springs from a sense that in corking a wild and flowing river and flooding the area behind it, something spiritual, wild, and truly important is lost. When Hetch Hetchy Valley in California was flooded and turned into a reservoir in the first decades of this century, John Muir wrote,

> These temple destroyers, devotees of ravaging commercialism, seem to have a perfect contempt for Nature, and instead of lifting their eyes to the God of the mountains, lift them to the Almighty Dollar. Dam Hetch Hetchy! As well dam for water-tanks the people's cathedrals and churches, for no holier temple has ever been consecrated by the heart of man.[79]

Muir spoke at the beginning of the modern dam-building era. Now that most rivers in the West and elsewhere in the country have been tamed, others lament the much larger loss.

Opposition to dams also stems from a greater understanding of how they affect riverine ecosystems. Many ecological problems are attributable to the three principle ways that dams alter a river's course:

- The operation of hydroelectric dams for peaking purposes causes a river's natural flow patterns to fluctuate between a trickle and a flood, disrupting the regimen to which native species have adapted.[80]
- Silts and nutrients, vital to downstream life both in the river and along its floodplain, are kept behind the dam and settle to the bottom of the reservoir.[81]
- The temperature of the water, both behind the dam and downstream from it, is altered in ways that affect fish and biological activity.

The Colorado, now brought to a halt at 12 major dam sites, is the focus of considerable attention as a result of the better understanding of these issues that science has provided in recent years. We describe here two related disputes on the Colorado.

Glen Canyon Dam, 30 years after construction, remains the focus of controversy. Troublesome impacts include the destruction of habitat for endangered fish species, beach erosion and the destruction of archaeological and sacred sites, loss of sediment in the river's floodplain, loss of water through evaporation and increased salinization of the Colorado River.

To address some of these issues, the U.S. Department of Interior has prepared an environmental impact statement (EIS) for Glen Canyon Dam and its impacts on Grand Canyon National Park.[82] Begun in 1989, the department's work was reenforced when Congress passed the Grand Canyon Protection Act. Essentially, the GCP Act requires the Bureau of Reclamation to reoperate the dam to protect against certain downstream impacts. This major change requires an end to the operation of Glen Canyon solely to meet peak demand—which entails enormous fluctuations in flows passing through the turbines—and results in the dam operating more like a baseload plant.

"... the construction and operation of big dams ... has produced some of the most ... heated environmental battles in the last century."

Pending the implementation of the preferred alternative from the EIS, the bureau has implemented interim operating criteria for Glen Canyon Dam.[83] These criteria spread the energy value of the river at Glen Canyon over more hours and reduce the capacity of the facility at peak. According to former Bureau Commissioner Dan Beard, the plan, including these criteria, "represents the difference between the old way we treated America's rivers and the way of the future. I am here to say to the millions of people who believe the Grand Canyon is a piece of God's art, the cathedral will be protected."[84]

The Colorado is also the home of a major endangered fish recovery program. Histori-

cally, the Colorado squawfish, bonytail chub, humpback chub, and razorback sucker were the dominant fishes in the mainstem of the Colorado River system. However, all four are now threatened with extinction as a result of several factors, including regulation of natural flows, temperature and sediment regimes attributable to dams on the river, and the diversion of water for consumptive use, especially irrigated agriculture.

To reverse the trend, an ambitious Recovery Implementation Program (RIP) has been created and is run by the U.S. Fish and Wildlife Service.[85] Its central feature is an open scientific forum to establish habitat needs for the fish as the basis for, among other things, operating federal reservoirs. A fundamental element of habitat need is the reestablishment of more natural flows, governed primarily by releases from the federal dams. These flows may entail further loss of peaking capacity in hydro resources on the Colorado and its tributaries.

"We believe ... that there will be no new large hydropower plants built in the West."

Since similar concerns exist on the Platte and Missouri river systems, these problems demonstrate that, for all of its benefits, hydropower carries with it significant environmental problems. We believe these problems mean that there will be no new large hydropower plants built in the West. Indeed, the resource will slowly shrink to accommodate environmental concerns.

The Proposed Defederalization of Western

In early 1995 the Clinton administration proposed that the ownership, management, or control of the assets used to generate and transmit power marketed by Western and two other power marketing agencies (PMAs) be transferred out of federal ownership. One objective apparently was to achieve savings for the federal treasury; some people see no reason why the federal government should continue to be in the business of generating and marketing power. Other proposals were made by investor-owned and preference power utilities and their organizations. Most of these proposals exempted new owners of the dams or power-generating facilities from compliance with all or some of federal environmental laws.

Both the House and Senate considered these proposals. The House Resources Committee reported a bill to sell dams and impoundments operated by the U.S. Army Corps of Engineers, from which power is marketed by the Southeastern Power Administration, to the highest bidder. A study of the transfer of Western's assets was included in this legislation, which did not survive consideration by the Senate. Most observers at the end of 1995 expect Congress to pay further attention to this issue in 1996 and beyond.

Even defederalization of just the power-generating and transmission assets at the federal dams from which power is marketed by Western could have devastating impacts not only on the environment but also on irrigation and municipal, industrial, and recreational uses of water developed by these projects. Because the federal dams from which Western markets power provide benefits well beyond power, the dams on the Colorado River are often operated to meet nonpower interests first. Transferring control over just the power features of these dams to nonfederal ownership could jeopardize nonpower uses, not to mention the availability of low-cost power to preference power customers.

Nonetheless, the LAW Fund does not unalterably oppose defederalization, because transfer to nonfederal ownership offers some opportunities to improve operation of the dams as well as the rivers themselves. In short, whether defederalization makes sense depends on the terms and conditions under which it is carried out. In our view the following are minimum, critical elements of sound Western asset defederalization:

1. No federally owned asset used in the generation and transmission of power

marketed by Western should be transferred to nonfederal ownership for less than the net present value of the repayment obligation remaining on such asset. Payment should appropriately reflect the market value of the asset.

2. Transfers and operation of such assets must not be exempted from compliance with environmental laws and regulations.
3. No transfers should be allowed except pursuant to facility-specific plans developed by the Secretaries of Energy and Interior; transfers should establish minimum terms and conditions requiring transferees to
   a. protect other uses that could be harmed by such transfer, including agricultural and environmental uses;
   b. restore and protect instream, riparian, and wetland resources harmed by the construction and operation of the federal dams, including by sustained contributions to river basin funds used for native fish species protection and recovery; and
   c. use the transferred assets consistent with sound stewardship and with national energy policy, including by use of the hydro resource to firm up and provide marketing opportunities for nonhydro renewable resources.
4. Once minimum terms and conditions have been established, the choice of transferee should be made on the basis of an auction in which both price and nonprice factors are bid and evaluated.

Small Hydro and Pumped Storage

Because of its aridity, this region's small streams and waterways have been spared the small hydro development that was unleashed in the early 1980s on other parts of the country by the Federal Energy Regulatory Commission regulations under PURPA. Some potential for small hydro exists here, but such development usually can be found in conjunction with existing irrigation or transmountain diversions or at existing dams, rather than on undeveloped streams. We believe the potential in the region for small hydro is less than several hundred megawatts and may be much less.

Pumped storage units use cheap energy from existing plants during off-peak hours to pump water uphill for release and generation of energy during high-load hours. Together, Public Service Company of Colorado and Western own about 550 megawatts of pumped storage capacity in this region. A few independent power producers have proposed pumped storage units in Colorado and Wyoming. Appendix D, which is an analysis of all storage technologies, describes pumped storage in more detail. Because of both economic and environmental problems with pumped storage, however, we do not include it in our blueprint, except when paired with intermittent renewable resources such as wind.

Nuclear Energy: Expensive and Risky

The story of nuclear energy in our region does not inspire optimism. Two nuclear power plants have been constructed here, Fort St. Vrain by Public Service Company of Colorado (PSCO) and Palo Verde by a consortium of utilities led by Arizona Public Service Company. PSCO's plant is now being converted to a combined-cycle natural gas plant. Palo Verde has contributed heavily to the bankruptcy of one utility and helped to push three others into serious financial distress.

Although some utilities in the United States have built and successfully operated nuclear power plants at low cost, for most the experience with nuclear power—once thought to be "too cheap to meter"—has been a financial nightmare. Nuclear power is one of the primary causes of the drive toward retail wheeling—which we describe in Chapter 3. Although nuclear energy is far superior to coal from an air quality perspective, it raises a wide variety of other environmental and

"Transferring control over ... these dams to nonfederal ownership could jeopardize ... the availability of low-cost power ..."

safety risks. This region, from which most of the uranium that powers domestic reactors has been taken, has inherited a legacy of abandoned mines and mill tailing sites that are radioactive. And uncertainties remain regarding the operational safety of nuclear plants as well as the storage of their waste materials.

It is possible that nuclear energy will be generated more cheaply in the future at standardized plants and new standardized plant designs may also enable safer reactor operation. However, even with the new plant designs, safety concerns remain. Nor does it appear that an acceptable solution exists to the problem of waste storage. Finally, given the financial losses they have incurred, the region's utilities are likely to be reluctant to once again invest in nuclear power. For these reasons, nuclear energy does not appear in our blueprint.

"... given the financial losses ... the region's utilities are likely to be reluctant to once again invest in nuclear power."

This section briefly describes nuclear electric technologies, sets forth uranium resource data, evaluates the costs of nuclear power, discusses the environmental and safety issues, relates the experience with reactors in this region, and reviews efforts to reduce nuclear power's costs.

Nuclear Power Plant Technology

Basically, a conventional nuclear power plant is a complex way to raise steam with heat generated by the instability of uranium atoms. The uranium is contained in fuel rods that are placed under water and separated by control rods to regulate the rate of the reaction. The uranium contained in the fuel rods is unstable and gives off neutrons. The escaping neutrons hit other uranium atoms, causing more neutrons to be released and triggering a chain reaction that produces heat. The heat boils water which produces steam to run a turbine to generate electricity.

Uranium Resources and Production

Uranium is the primary element that fuels both the nuclear energy and nuclear weapons industries. Uranium is refined from uranium oxide ore, which is in abundance in this region. Approximately 75 percent of known domestic deposits of uranium oxide ore are located in New Mexico and Wyoming. Arizona, Utah, and Colorado together account for an additional 12 percent of the known deposits.[86] About two-thirds of all known uranium reserves lie on Native American land.

Uranium prices peaked at $43 a pound in 1979. In early 1995, because of a worldwide glut, the price for uranium in the United States fell to about $10 a pound. This drop in prices, accompanied by lower demand from utilities, led to a collapse of the uranium industry in this country. There are currently no operating surface or underground uranium mines in the United States. Some uranium is still produced, but primarily from in-situ leaching processes.

Imported uranium now supplies over 40 percent of domestic utility needs, with Canada our largest foreign supplier. Industry forecasters predict that utilities will rely increasingly on imported uranium as domestic inventories are drawn down. The U.S. Energy Information Administration expects imports to increase to meet up to 75 percent of utility needs by the end of the 1990s.[87]

The share of the nation's electricity generated by nuclear power steadily increased from the early 1970s through the 1980s. In 1982, nuclear power accounted for just over 12 percent of the nation's electricity generation. By 1992, that figure had increased to 22 percent.[88] In the United States there are presently 109 operating commercial nuclear power reactors in 33 states.

However, no nuclear power reactors have been ordered since 1978. Every nuclear reactor ordered since 1973 has been canceled and more than 100 plants were canceled or abandoned during the 1970s and 1980s.[89] The Tennessee Valley Authority (TVA), having planned a 17-reactor system, has just four

reactors operating, with only one more still under construction.[90] By the year 2010 the U.S. Energy Information Administration foresees the closure of 20 more nuclear power plants and assumes that by 2010, the share of electricity nationwide generated by nuclear power will decline to 17 percent.[91]

The Cost of Nuclear Power

When utilities made commitments to build nuclear power plants in the early 1970s, industry and federal government studies showed that nuclear power had a significant cost advantage over coal-fired power. Reactor construction, O&M and fuel, and decommissioning set-asides together cost only 2.89 cents/per kilowatt-hour (in 1990 dollars) between 1968 and 1973. Indirect costs, including plant cancellation costs, added only about one-fifth of a penny to the cost of a kilowatt-hour during this time period.[92]

Even before the accident at the Three Mile Island (TMI) nuclear plant in Pennsylvania, however, costs had begun to rise. Between 1973 and 1978 total costs rose approximately 25 percent to just under 4 cents/per kilowatt hour. In the wake of TMI, nuclear plant capacity factors plummeted while O&M, capital additions, and plant cancellations skyrocketed. The result was an average cost of 6.27 cents/per kilowatt-hour between 1980 and 1983, which made nuclear power uncompetitive with most coal plants. Then, from 1984 through 1990, nuclear costs further skyrocketed to an average of 9.06 cents/per kilowatt-hour.[93]

In addition to the energy costs of nuclear power generation, there are also decommissioning costs, which pose many uncertainties for the nuclear industry. Although no one has a good idea of what will be required and what the cost will be, some information is available. For example, a 1990 study by Public Citizen reported that the median estimates used by utilities for the cost of decommissioning large reactors (700–1,299 megawatts) were between $191 million and $268 million, depending upon the size class of the reactor. One plant came in at a high of $466 million.[94] When Yankee Atomic Electric Company closed the Yankee Rowe nuclear plant in Massachusetts (in 1992), it estimated the decommissioning cost at $247 million. In recent testimony before the Nuclear Regulatory Commission, company officials said they expect the cost to be $370 million.[95]

Environmental and Safety Issues

The story of nuclear energy in our region goes beyond the impacts of Fort St. Vrain and Palo Verde because most of the uranium ore that has been used in reactors in the United States has been mined here. The environmental and safety impacts of nuclear energy begin with the front end of the nuclear fuel cycle—mining and milling.

Mining and Milling Impacts

A U.S. EPA report in 1983 stated that there were 3,288 abandoned uranium mines in the nation, most of which were in our region.[96] Some of these mines have been reclaimed, but many have not. The Navajo Nation estimates there are at least 1,104 abandoned uranium mines on Navajo land alone.[97] Unless reclaimed, uranium mines continuously emit radioactive radon gas and constitute a threat to the health of humans and livestock in the area.[98]

From the 1940s to the 1970s, mining conditions were often hazardous to the health of uranium miners. Timothy Benally, manager of the Office of Navajo Uranium Workers in Shiprock, New Mexico, said that of the 3,000 Navajos who worked in the uranium mines, more than 400 died of lung disease.[99]

Once mined, uranium ore is taken to a mill where the uranium oxides are separated from the rest of the ore. Mill tailings include sands and liquids left over after the uranium ore has been crushed and the uranium minerals removed by chemical solvents and

"Every nuclear reactor ordered since 1973 has been canceled ..."

leaching agents. In 1985, the tailings resulting from domestic uranium mining and milling were estimated at almost 200 tons. Over two-thirds of those tailings were a result of commercial contracts, which were predominantly for nuclear power.[100]

Mill tailings retain 85 percent of the radioactivity of the original ore and can contaminate surface water and groundwater. A 1983 study by the Southwest Research and Information Center of 27 mill sites found that, at most of them, groundwater had been contaminated by seepage from wastewater ponds.[101] Of 24 inactive milling sites in the United States, twenty-three are in the West, and most of these are in our six states. Under the Uranium Mill Tailings Control Act of 1978, the U.S. DOE is charged with undertaking remediation at inactive sites. Remedial actions at ten of the sites are completed; remediation is in progress at eight more sites, and it is expected to begin at the remaining six sites in two years.[102]

"Unless reclaimed, uranium mines continuously emit radioactive radon gas and constitute a threat to the health of humans and livestock ..."

In 1979, the same year as the Three Mile Island accident, a much greater release of radioactive materials than that at TMI occurred at the United Nuclear uranium mill at Church Rock, New Mexico. A mill pond wall broke and 94 million gallons of radioactive water and 1,100 tons of solids poured out into the Rio Puerco.[103] This river had served as the single source of water for almost 1,700 Navajos.[104]

Effects of Reactor Operation

Radioactive gases known to be released from nuclear power plants include carbon-14, iodine-131, and noble gases such as krypton and xenon.[105] Because nuclear power plants release *no* CO_2, SO_2, NO_x, CO, or trace-metal toxics such as mercury, nuclear energy has certain significant environmental advantages over fossil fuels, especially coal.

Like other conventional thermal power plants, nuclear reactors release approximately two-thirds of the heat generated by the nuclear reaction to the environment, often into local bodies of water. Liquid effluents from nuclear power plants that may be released into the aquatic environment include tritium and corrosion inhibitors used in the plant.[106]

The generation and storage of nuclear waste is a significant unresolved problem faced by the industry. Solid radioactive wastes are divided into two categories: low-level and high-level waste. Low-level waste includes many small items, such as gloves, safety clothing, and filters that become irradiated during the normal course of operation at the plant.[107] High-level waste includes the spent fuel assemblies from the reactors. In an operating commercial reactor, used nuclear fuel is removed and replaced with fresh fuel once every 12 to 18 months. Spent nuclear fuel is highly radioactive and takes many thousands of years to become benign. As of 1993, almost 28,000 metric tons of spent nuclear fuel was stored at commercial nuclear reactors around the country. Because domestic reactors produce another 2,000 metric tons of spent nuclear fuel every year, storage space is running out.[108]

Under the Nuclear Waste Policy Act of 1982, the federal government agreed to begin accepting spent nuclear fuel from utilities in January 1998. However, there have been many scientific and political problems associated with the site DOE has chosen for the waste—Yucca Mountain in Nevada—and the 1998 date is now uniformly considered all but impossible.[109] The year 2010 is widely cited as the earliest possible date that the site could open, if it opens at all. The U.S. General Accounting Office (GAO) predicts that it is unlikely that the U.S. DOE will be ready to begin disposing of waste in a repository until 2015 or later.[110]

As a result, the U.S. DOE and the nuclear power industry are looking for temporary storage for the waste at a monitored retrievable storage (MRS) facility. At an MRS facility, spent nuclear fuel would be stored

aboveground in metal or concrete containers. The MRS option that seems to be making the most progress is a cooperative venture between the Mescalero Apache tribe and a coalition of utilities. In this plan, which is not sponsored by the federal government, the Mescalero Apache tribal leadership and 34 utilities hope to build a private MRS facility on Mescalero land in New Mexico. Tribal members rejected this project in a public referendum in late 1994, but overturned the initial vote in March 1995. As this report goes to print, it appears that the Mescalero Apaches will attempt to construct an MRS on their reservation—the country's first—despite opposition to this project by a number of interests in New Mexico.

Reactor Safety

Reactor safety issues have plagued the nuclear industry for decades. The Three Mile Island nuclear accident in 1979 put a chill on the industry, the 1986 Chernobyl accident in the Ukraine dealt another blow, and nuclear core meltdown has become a commonly discussed topic. In a meltdown, a pipe carrying coolant water to the reactor core ruptures. Within a matter of seconds, the fuel rods begin to melt together under intense heat. The heat from the uncontrolled reaction melts everything it comes into contact with and could burn through the earth for an unknown distance: the China Syndrome. If a steam explosion accompanied this event, the plant's core might be blasted upward through the top of the reactor vessel, which would result in devastating contamination to the environment.

The odds of such an event are very slight, but not negligible. In 1985, as reported in the *New York Times,* the Nuclear Regulatory Commission estimated there was a 45 percent chance that, in a 20-year period, there would be a severe core meltdown accident in the United States.[111]

Regional Experience with Nuclear Power

The Palo Verde units, ordered in October 1973 (the same month as the Arab oil embargo) are the last U.S. nuclear units to be ordered that were not subsequently canceled. With three 1,270 megawatts reactors, Palo Verde is the largest nuclear power station in the United States. Seven utilities co-own the plant,[112] and Arizona Public Service Company (APS) manages the facility. Like dozens of other reactors, Palo Verde experienced delays and cost overruns during its construction. The total construction cost for the plant was somewhat under $10 billion.[113]

Although Palo Verde has set domestic production records—unit 3 holds the calendar-year record of 10.8 million megawatt-hours[114]—its operation has been riddled with problems. Early in its life, the plant had costly equipment and management problems. In 1993, a steam generator tube carrying radioactive water in unit 2 burst and triggered an emergency shutdown. Technicians then discovered that many more tubes had developed small cracks. Indeed, corrosion has reportedly caused cracks in more than 1,500 of the 66,000 steam generator tubes at Palo Verde.[115]

"Although Palo Verde has set domestic production records ... its operation has been riddled with problems."

To retard the spread of the cracking, APS reduced power at all three reactors to 86 percent. Company officials said initially that all three reactors would operate at less than full power well into 1995.[116] However, unit 3 was soon returned to 100 percent power. Power was also increased at the other two reactors. Unit 1 was increased back up to 98 percent and unit 2 to 100 percent.[117] Concerns have been expressed that the plant now represents a safety hazard, especially running at 100 percent power.[118] APS says that there is no safety risk.

The repair of steam tubes at Palo Verde has cost APS at least $40 million for replacement power and other costs. Other owners of

Palo Verde have also incurred costs attributable to the cracked steam tubes. One owner, Public Service Company of New Mexico, was considering selling its share of Palo Verde.[119]

Fort St. Vrain is the only other commercial nuclear power plant that has been built in this region. Located 35 miles northeast of Denver, the plant is the only commercial high-temperature gas-cooled reactor (HTGR) that has ever operated in the United States. Unlike all other domestic reactors, it used helium, rather than water, as a coolant in the reactor core.

Construction of the plant began in 1968 and was scheduled for completion in four years. The plant first generated electricity in 1976. In 10 years of commercial electricity generation, the plant operated only 13.8 percent of the time, giving it the worst record of any commercial nuclear reactor. PSCO paid $224 million of the total plant construction cost of over $350 million. It is expected that decommissioning the plant may cost $157 million.[120]

"In 10 years ... the Fort St. Vrain plant operated only 13.8 percent of the time, ... the worst record of any commercial nuclear reactor."

The plant was shut down in 1989 after it experienced problems with its control rods and hairline cracks were discovered in steam generator tubes. Its closure was the first instance of a utility voluntarily shutting down a reactor for economic reasons. In 1986, PSCO agreed to stop charging ratepayers for the plant's costs and reported a $110 million loss to its shareholders. Plans to convert the plant to natural gas have recently been approved by the Colorado PUC.

Developing Cheaper and Safer Nuclear Power Plants

One of the reasons for the increasingly high cost of nuclear power plants over the last 25 years was their one-of-a-kind designs. Many in the industry believe that standardization of plant design would help contain costs.[121] Four standard designs are under development in the United States. Two are large, in the 1,200–1,300 megawatt range, and two are smaller, in the range of 600 megawatts. According to the Nuclear Energy Institute (NEI), a 1992 study indicated that the larger plants could supply electricity at an average of 4.5 cents/per kilowatt hour. The same study found that the larger, 1,200 megawatt plants could supply power at an average cost of 3.8 cents/per kilowatt hour.

The 600 megawatt plants are said to rely on designs that use "passive" safety features. That is, they rely on natural forces, such as convection and gravity flow of emergency cooling water, which allow them to reduce reliance on pumps, emergency generators, and other features designed to ensure safety. For example, the Westinghouse entry in the new design competition stores cooling water above the reactor. In an emergency, NEI says that pressure and gravity would force this water into the reactor vessel and cool the core.

Two U.S. nuclear companies—ABB Combustion Engineering Nuclear Systems and General Electric—are designing new large pressurized reactors and boiling water reactors (BWRs), respectively. ABB's design is a refinement of the system in place at the Palo Verde units. The advanced design, which has a larger volume of cooling water, would operate at a lower temperature and with a lower nuclear fuel power density. The reactors would be housed within a large steel containment building. General Electric's design uses a building volume of only around 70 percent of the size of the more recent BWRs. Control rods would be electrohydraulic, rather than hydraulic, which, it is contended, reduces the probability of failure. Construction time for these advanced designs is said to be approximately four to five years. The Nuclear Regulatory Commission has approved the designs for these plants.

Two other advanced design reactors are under consideration within the industry. One is a gas-cooled reactor that, like Fort St. Vrain, would rely on helium for the coolant.

The other is a liquid metal-cooled plant. NEI says that the latter technology may be capable of "burning" actinides, the longest-lasting nuclear wastes, on site. If so, this might reduce the volume of nuclear wastes that need to be stored. Current unit sizes for these designs are 300 and 150 megawatts, respectively. These designs may be ready for use after the turn of the century.

Notwithstanding the developments discussed in this section, it is our view that nuclear technology has overwhelming financial, environmental, and safety hurdles to overcome before it will once again be accepted as a viable electric resource in this region. Though there is no reason advanced designs should not compete with other supply-side resources to meet baseloads after the turn of the century, we do not see nuclear energy winning this competition without a solution to waste storage and safety concerns, even if these designs' costs are as dramatically low as NEI indicates they could be.

"... nuclear technology has overwhelming ... hurdles to overcome before it will once again be accepted ... in this region."

Notes

1. Although recoverability rates differ by site, about 56 percent of the demonstrated reserve base is estimated to be currently recoverable. EIA, *Annual Energy Review 1992,* p. 345.

2. *Coal Production: 1992,* U.S. Energy Information Administration.

3. *Mineral Revenues 1990,* Minerals Management Service, U.S. Department of the Interior, 1991.

4. *Cost and Quality of Fuels for Electric Utility Plants: 1992,* U.S. Energy Information Administration.

5. *Keystone Mining Manual 1973* and *Keystone Mining Manual 1991,* McGraw-Hill Publications.

6. *Keystone Mining Manual 1973* and *Keystone Mining Manual 1991.*

7. *State Energy Data Report 1991* Energy Information Administration.

8. *Annual Energy Review 1992,* Energy Information Administration. The lower percentage comprised by utilities nationally is attributable primarily to steel industry coal use outside our region.

9. Based on data given in *Cost and Quality of Fuels for Electric Utility Plants 1992,* Energy Information Administration, 1993, p. 10 and from *Coal Production 1992,* Energy Information Administration, 1993, p. 50.

10. *Cost and Quality of Fuels for Electric Utility Plants,* U.S. Energy Information Administration. Plants in Wyoming burned 24.1 million tons, in Arizona 16.3 million tons, in Colorado 15.6 million tons, in New Mexico 14.8 million tons, in Utah 12.7 million tons, and in Nevada 7.9 million tons.

11. *State Energy Data Report 1991,* U.S. Energy Information Administration.

12. *Inventory of Power Plants in the U.S. 1992* and *Electrical Power Annual 1991,* U.S. Energy Information Administration.

13. Public Service Company of New Mexico, "San Juan Generating Station: Fact Sheet," Albuquerque, New Mexico, February 20, 1992.

14. *Electric Plant Cost and Power Production Expenses 1991,* Energy Information Administration, Washington DC, 1992, p.36.

15. *Electric Plant Cost and Power Production Expenses 1991,* p. 33.

16. Although the cost for coal figures identify averages, the actual costs of producing electricity from coal are highly site specific. Coal electricity costs depend heavily on the technology used, the age of the power plant, the extent of the pollution control equipment, and the delivered price of coal. For example, at $0.03 per million Btu, the coal burned at the Laramie Station in Wyoming is the cheapest among the region's 10 largest plants, or one-third the cost of the most expensive coal burned at the Intermountain station in Utah.

17. U.S. Energy Information Administration, *Electric Power Annual—1990,* Washington, D.C., 1992, p. 80.

18. See generally *Public Service Company of Colorado Integrated Resource Planning,* Volume IV, pp.4.2-26 to -28, filed October 1993.

19. The number of coal miners in Wyoming was 3,326, in Utah 1,997, in New Mexico 1,683, in Colorado 1,610, and in Arizona 888. From *Employment from Coal Production 1992,* U.S. Energy Information Administration.

20. The regional employment base is about 5.4 million jobs. Thus, when viewed regionally, the coal industry is not a significant employer. However, in local areas, such as eastern Wyoming, coal-based employment is a significant portion of total employment.

21. See "Letter to Governor Roy Romer from Elizabeth Estill, Regional Forester," July 14, 1993, p. 2.

22. *Certifying Visibility Impairment in the Mount Zirkel Wilderness Area: Technical Background Document,* Colorado Department of Health,

Environmental Protection Agency/Region VIII, and U.S. Forest Service, June 30, 1993.

23. *Certifying Visibility Impairment in the Mount Zirkel Wilderness Area: Technical Background Document,* p. 44.

24. HEI Statement, 1995. For general accord, see also "An Association Between Air Pollution and Mortality in Six U.S. Cities," Dockery and Pope, *New England Journal of Medicine,* Volume 329, No. 24, December 9, 1993.

25. "Dollars and Cents: The Economic and Health Benefits of Potential Particulate Matter Reductions in the United States," American Lung Association, June 1995, pp. 6–29.

26. *Climate Change: The Second IPCC Assessment,* 1996. Houghton, Filho, Callender, Bruce, Lee, Haites, Harris, Maskell (eds.), Cambridge University Press, Cambridge, U.K.

27. The new IPCC Report predicts that the midpoint of the range of temperature increases by 2100 is about 2.5 degrees Celsius. The earlier Reports had predicted that the mid-range increase would be about 3 degrees Celsius.

28. For an example of this thinking see "Petition to Intervene and Motion to Terminate of Western Fuels Association," Docket No. U-0000-90-088, Arizona Corporation Commission, August 4, 1994.

29. See Direct Testimony of Karen Shapiro, Tellus Institute, for the LAW Fund in Docket No. 91M-642E, before the Colorado Public Utilities Commission, pp. 27–30.

30. *Mercury Health Effects Update,* U.S. Environmental Protection Agency, EPA-600/8-84-019, 1984, p. 6-1; Direct testimony of Karen Shapiro p. 30. See also "Mercury in the Environment," *EPRI Journal,* December 1991, pp. 4–11, for an account of the effects of monomethyl mercury on human neural tissues.

31. *National Coal Database,* 1989, U.S. Geological Survey.

32. EPA asks that this draft not be cited or quoted and we honor that request here.

33. See "Coal Combustion: Nuclear Resource or Danger?" *Oak Ridge National Laboratory REVIEW,* Numbers 3 and 4, 1993, p. 25.

34. "Coal Combustion: Nuclear Resource or Danger?" p. 27.

35. *Coal Production 1992,* U.S. Energy Information Administration.

36. Letter from OSM Director Harry Snyder to Governor Bangerter, August 6, 1991.

37. See testimony ("Shrub Reclamation and Wildlife") by Stephen Torbit, Ph.D., Senior Scientist, National Wildlife Federation, before the Office of Surface Mining, Cheyenne, WY, June 8, 1993.

38. For examples, see "Bitter Waters," by Richard Parker, *Albuquerque Journal,* January 23, 1995, p. A-1.

39. See testimony of Steve Tessman, Environmental Biologist, Wyoming Game and Fish Department, on Shrub Standard Revision (EIS 6178), October 1, 1990.

40. See *Cumulative Hydrological Impacts of Surface Coal Mining in the Eastern Powder River Structural Basin, Northeastern Wyoming,* United States Geological Survey, 1988.

41. *Report to Congress: Wastes from the Combustion of Coal by Electric Utility Power Plants,* U.S. EPA Report to Congress, (PB88-177977), February 1988.

42. *Cumulative Hydrological Impacts,* Executive Summary.

43. The primary sources of information about clean coal technologies used in this section were three U.S. Department of Energy publications, *Clean Coal Technologies: Research, Development, and Demonstration Program Plan,* November 1993; *Clean Coal Technology Demonstration Program: Program Update 1993,* March 1994; and *Clean Coal Technology: The Investment Pays Off,* January 1994.

44. The largest IGCC power plant in the world, a 225-megawatt unit located in the Netherlands, has an efficiency of about 43 percent, compared with efficiencies of combined-cycle natural gas-fired power plants that approach 50 percent and higher.

45. U.S. DOE, "Clean Coal Technology Demonstration Program: Program Update 1993," Washington D.C., March 1994. pp. 1–2.

46. Principal sources for the discussion of carbon recovery technologies include K. Blok, et al., "Producing Fuel and Electricity from Coal with Low Carbon Dioxide Emissions," a paper published in June 1991 by the Princeton Center for Energy and Environmental Studies; two papers published in the *International Journal for Hydrogen Energy,* M. Steinberg, "Fossil Fuel and Greenhouse Gas Mitigation Technologies," August 1994, and G. Nihous, "A Strategy to Reduce CO_2 Emissions from Hydrocarbon-Fueled Power Plants by Precombustion Reforming and Deep Ocean Discharge of CO_2," April 1994; and C. Hendricks, "Carbon Dioxide Removal from Coal-Fuel Power Plants," Ph.D. Thesis, Dept. of Science, Technology and Society, Utrecht Univ., the Netherlands, 1994.

47. Shivan Kartha, Joan Ogden, and Deborah Lew, telephone conversation, November 18, 1994.

48. *America's Energy Choices: Investing in a Strong Economy and a Clean Environment,* Alliance to Save Energy, et al., 1991.

49. "Producing Fuel and Electricity from Coal," p. 1.

50. S. Smelser and G. Booras, "An Engineering and Economic Evaluation of CO_2 Removal from Fossil Fuel-Fired Power Plants," presented at the Ninth Annual Conference on Gasification Power Plants, October 17–19, 1990, Electric Power Research Institute, Palo Alto, California, cited in "Producing Fuel and Electricity from Coal," p. 7.

51. "Producing Fuel and Electricity from Coal," pp. 6–7.

52. D. Golomb, et al., "Feasibility, Modeling and Economics of Sequestering Power Plant CO_2 Emissions in Deep Oceans," MIT-EL-89-003, Massachusetts Institute of Technology, Cambridge, Massachusetts, 1989, cited in G. Nihous et al., "A Strategy to Reduce CO_2 Emissions," p. 388.

53. *Natural Gas Supply and Price,* Northwest Power Planning Council, July 1993, p. 7. Tcf means "trillion cubic feet."

54. *At the Threshold of Change,* Colorado Oil and Gas Association (COGA), 1993, p. 7.

55. *At the Threshold of Change,* p. 9.

56. *At the Threshold of Change,* pp. 80–82.

57. *Fuel Choice for New Electric Generation Capacity,* Energy Ventures Analysis, May 1994, pp. 4–6.

58. Various sources reviewed, including COGA, Potential Gas Committee, Gas Research Institute, National Petroleum Council, etc.

59. *Fuel Choice for New Electric Generating Capacity in the Next Century,* Energy Ventures Analysis, Inc., May 1994, pp. 1–6.

60. *The Potential for Natural Gas in the United States,* National Petroleum Council, 1992.

61. *Natural Gas 1992: Issues and Trends,* Energy Information Administration, March 1993, p. 35.

62. *Natural Gas for Electric Generation: The Challenge of Gas and Electric Industry Coordination,* EPRI TR-101239, September 1992, p. S-2.

63. *The Potential for Natural Gas in the United States,* National Petroleum Council, Executive Summary, December 1992, p. 12.

64. For example, over 11,000 megawatts of oil-fired units have been or are planned to be converted to dual-fuel capability between 1991 and 1996. (See *Fuel Switching On A Dime,* EPRI TR-102945, Exhibit 4-3).

65. This estimate is from calculations done internally by the LAW Fund based on data regarding the U.S. truck and auto fleet given in *Facts and Figures '93,* American Automobile Manufacturers Association, 1994. The range in this estimate depends on assumptions regarding fuel efficiency in vehicles in the future. The lower estimate (1 Tcf per year) assumes much greater efficiency in vehicles of the future compared with today's. The higher estimate (2 Tcf) assumes fuel efficiency in the future is similar to today's average.

66. *State of the World 1991,* Worldwatch Institute, p. 36.

67. *The Long-Term Trends in U.S. Gas Supply and Prices: 1993 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010,* Gas Research Institute, Chicago, Illinois, March 1994.

68. Hurricane Andrew sent prices up to the $4.00 per million/Btu range for a brief period in 1992.

69. ENRON Gas Services Testimony Before the Colorado Public Utilities Commission, Docket No. 93I-098, March 4, 1994.

70. This section is based on research presented in *At the Threshold of Change.*

71. *Opportunities to Reduce Anthropogenic Methane Emissions in the United States,* Report to Congress, Environmental Protection Agency, October 1993.

72. *Sources and Migration Pathways of Natural Gas in Near-Surface Ground Water Beneath the Animas River Valley, Colorado and New Mexico,* U.S. Geological Survey, Report 94-4006, Executive Summary, 1994, p. 1.

73. *Naturally Occurring Radioactive Materials in the Production of Oil and Gas,* An Issues Paper, New Mexico Environment Department, November 1992.

74. *Naturally Occuring Radioactive Materials,* p. 48.

75. For examples, see "Over a Barrel," in *National Parks,* March, 1995, pp. 28–32. Also see letter from National Park Service (Regional Director, Southwest Region) to State Director, Bureau of Land Management, regarding proposed oil and gas activity near Carlsbad Caverns National Park in New Mexico (dated November 18, 1992).

76. "Operation of Glen Canyon Dam: Final Environmental Impact Statement," March 1995, U.S. Department of the Interior, Bureau of Reclamation, p. 314. Many experts estimate that the amount of lost capacity will be closer to 700 MW.

77. In the Upper Basin of the Colorado River, power sales not only pay for existing irrigation-related capital costs at the federal dams, but they also pay into a fund to cover the capital costs of future irrigation projects.

78. Energy Planning and Management Program, 62 Federal Register 54151 (1995).

79. From *Yosemite,* John Muir, quoted in *The American Conservation Movement,* Stephen Fox, 1985, p. 144.

80. Because it uses the river to produce sudden bursts of energy, Glen Canyon Dam causes

the water level in the Colorado to fluctuate as much as 13 feet in one day.

81. The Colorado River's sediment load, before the construction of Glen Canyon Dam, averaged over 65 million tons per year—enough sand, silt, and clay to fill a freight train 75 cars long in just 1 hour.

82. "Operation of Glen Canyon Dam, Final Environmental Impact Statement," U.S. Department of the Interior, U.S. Bureau of Reclamation, March 1995.

83. It appears that the preferred alternative will result in operation of the dam in a mode very similar to that embodied in the Interim Operating Criteria.

84. Quoted in *National Parks,* Volume 68, No. 3–4, March/April 1994, p. 10.

85. The RIP is funded primarily through federal appropriations. Because Congress threatens to reduce these appropriations each year, the program is vulnerable. Some have proposed a fund generated by a standing fee assessed on power and other economic uses of the Colorado River's waters. See "Thinking the Unthinkable: Changing the Law of the River and Other Basin Institutions," Lawrence MacDonnell and Bruce Driver, Draft, December 1, 1995.

86. Based on an estimate of uranium oxide resources recoverable at various "forward cost categories," appearing as Table 4.12 in *Annual Energy Outlook 1992,* U.S. Energy Information Administration.

87. U.S. Council for Energy Awareness, "Energy Update; Nuclear Fuel Production: A Five-Step Process," September 1993, p. 6.

88. Nuclear Regulatory Commission, *Information Digest: 1994 Edition,* Washington, D.C.: Division of Budget and Analysis, Office of the Controller, U.S. Nuclear Regulatory Commission, 1994, pp. 19, 26.

89. Matthew L. Wald, "Cheap and Abundant Power May Shutter Some Reactors," *New York Times,* April 14, 1992, p. A1. One hundred nineteen proposed plants have been scrapped. See also TVA Press Release, December 12, 1994. Once construction on the Watts Bar Unit I (Spring City, Tennessee) is finished and an IRP is completed late in 1995, the United States will have reached the end of the current nuclear power plant era.

90. "Plagued Reactor Finally Signs On," Associated Press, October 11, 1995, *The Denver Post.*

91. U.S. Energy Information Administration, *Annual Energy Outlook 1994,* p. 26.

92. "Fiscal Fission: The Economic Failure of Nuclear Power," A Report on the Historical Costs of Nuclear Power in the United States for Greenpeace, by Komanoff Energy Associates, Executive Summary, p. 4.

93. "Fiscal Fission."

94. As reported in "Dreams Die Hard," Phillip A. Greenberg, *Sierra,* November/December 1993, p. 85.

95. Cited in *Public Power Weekly,* November 14, 1994.

96 . *Potential Health and Environmental Hazards of Uranium Mine Wastes,* Volume I, Executive Summary, U.S. EPA, 1983.

97. Testimony of the Navajo Nation before the Subcommittee on Oversight and Investigations and the Subcommittee on Native American Affairs, regarding abandoned uranium mines on the Navajo Nation, November 4, 1993.

98. Chris Shuey, "Uranium Mines and Their Problems," *The Workbook,* July/September, 1985, p. 114. *The Workbook* is a publication of the Southwest Research and Information Center, Albuquerque, New Mexico.

99. Michael D'Antonio, "Scars and Secrets: The Atomic Trail; Along the Nation's Bomb-making Circuit, Illness and Poisoned Land Mark the Cold War's Lethal Legacy," *Los Angeles Times Magazine,* March 20, 1994.

100. Table prepared by Chris Shuey from Southwest Research and Information Center in "U.S. Uranium Mills: Status, Tailings Volumes, and Financial Data," *The Workbook*, July/September, 1985, p. 104.

101. "Uranium's Legacy," *The Workbook,* Southwest Research and Information Center, April/June 1985, p. 67.

102. Testimony of Margo T. Oge, Director of the Office of Radiation and Indoor Air, U.S. Environmental Protection Agency, before the Subcommittee on Energy and Mineral Resources of the Committee on Natural Resources, U.S. House of Representatives, March 8, 1994.

103. *Struggle for the Land,* Ward Churchill, 1993.

104. *Struggle for the Land,* pp. 268–269.

105. Essam E. El-Hinnawi, "The Environmental Impacts of Nuclear Power Plants, " in Essam E. El-Hinnawi, ed., *Nuclear Energy and the Environment,* Oxford, England: Pergamon Press, 1980, pp. 58–60.

106. "The Environmental Impacts of Nuclear Power Plants," p. 60.

107. Nuclear power plants produce about half of all domestic commercial low-level waste (LLW). Congress has encouraged the states to create interstate "waste compacts" to dispose of their LLW. A site at Hanford, Washington, is open to states in the Northwest and Rocky Mountains, except Arizona, which is a member of the South-

west compact. The Southwest compact does not yet have a licensed LLW dump site.

108. Phillip Bayne, President and CEO of the Nuclear Energy Institute, said, at a 1994 conference, that in four years, 23 nuclear reactors will have exceeded their current storage space.

109. Opponents point to the potential for volcanic activity at the site, the possibility of groundwater contamination, and the release of radioactive carbon-14 to the atmosphere.

110. The Yucca Mountain depository is currently limited by law to accept a maximum of 70,000 metric tons of waste. By 2010, the GAO expects that 61,000 metric tons of waste will have accumulated. By 2015, there may be more than 70,000 metric tons of waste already accumulated, and the law may have to be changed to allow more waste at Yucca Mountain.

111. Matthew L. Wald, "Nuclear Agency Estimates Probability of a Meltdown," *The New York Times,* April 17, 1985.

112. The utilities are Arizona Public Service Company, the Salt River Project, Southern California Edison, El Paso Electric, Public Service Company of New Mexico, Southern California Power Authority, and the Los Angeles Department of Water and Power.

113. Elaine Hiruo, "SCE: San Onofre Cost-Effective But Maybe Not Competitive Yet," *Nucleonics Week*, March 31, 1994.

114. "SCE."

115. David Pasztor and John Dougherty, "Secrets of the Palo Verde Inn," *New Times*, Phoenix, Arizona, June 1–7, 1994, p. 18.

116. Pamela Newman, "Palo Verde Steam Generators to Cost APS," *The Energy Daily,* May 11, 1994.

117. Dan Nowicki, "Rising Mercury Forces Palo Verde to Boost Production; Despite Steam Generator Tube-Flaw Problems," *West Valley View* (Avondale, Buckeye, Goodyear, Litchfield Park and Tolleson, Arizona), July 6, 1994.

118. "The Palo Verde Papers."

119. Margaret L. Ryan and Richard R. Zuercher, "Stewart to Leave Virginia Power for Top Nuclear Post at Palo Verde," *Nucleonics Week*, March 31, 1994.

120. Stevenson Swanson, "Dismantling Nuclear Plant a Complicated Ritual," *The Times-Picayune*, April 17, 1994.

121. The factual material in this section regarding industry efforts to develop new nuclear power plant designs is taken from "Fact Sheet—Advanced-Design Nuclear Power Plants," Nuclear Energy Institute, July 1994.

Appendix D: Emerging Technologies

D

This chapter describes a broad range of technologies to conserve, generate, and store electricity; none of these technologies is in wide use in our six states. More specifically, these emerging technologies include energy efficiency; renewable resources such as wind, solar, geothermal, and biomass; technologies to store electricity; fuel cells; and nuclear fusion. With a few exceptions, these resources play a prominent role in our blueprint for the electric industry.

Energy Efficiency

In 1976, a then-unknown physicist named Amory Lovins published an article in *Foreign Affairs* called "Energy Strategy: The Road Not Taken." Lovins, in the article, challenged the prevailing idea that energy demand would continually increase with the economy. For Lovins, the principal solution to the nation's energy problems was to improve the efficiency with which energy is used so that each unit could accomplish more. Although Lovins was originally subject to severe criticism, by the early 1990s his vision had come to pass. Since 1976, the efficiency with which the U.S. economy uses energy has improved dramatically—by over 40 percent.[1]

Nationwide, electric utilities have moved aggressively to take advantage of efficiency opportunities, spending an estimated $3 billion in 1994, reducing peak demand by a cumulative 42,000 megawatts, and capturing 53,300 gigawatt-hours of energy savings.[2] Additional savings of roughly the same size are attributable to improvements in building codes and appliance efficiency standards.[3] Utilities in the Rocky Mountain and Desert Southwest region have also begun to take advantage of cost-effective opportunities to promote energy efficiency. As of 1995, the region's utilities had committed to spending about $60 million annually to encourage customers to use energy more efficiently.

Over the past two years, however, the threat of industry restructuring has created financial incentives that are discouraging the region's utilities from making these investments. As a result, the region's utilities are now re-evaluating their commitment to energy efficiency. The near-term challenge is to develop new approaches that permit continued utility involvement in energy efficiency in a way that is consistent with an increasingly competitive electric industry. Over the longer run new entities must be found to encourage and provide energy efficiency.

"... the region's utilities are now re-evaluating their commitment to energy efficiency."

The Resource

A kilowatt-hour (kWh) of electricity can light a 100-watt bulb for 10 hours, lift a ton of steel 1,000 feet into the air, or heat enough water for a five-minute shower. New technologies that use electricity more efficiently make it possible for that same kilowatt-hour to provide more light, lift more material, or heat greater amounts of water. For most customers, the energy services received—the lighting, temperature control, and motor drive services that result from electricity—are far more important than the source or number of kilowatt-hours used. Given this reality, energy-efficient equipment and technologies can be viewed as an alternative to building new power plants since customers do not perceive a difference between the two. The evidence demonstrates that there is an

enormous, largely untapped, and highly cost-effective energy efficiency resource available that can be used to meet the region's growing energy service needs.

"... evidence demonstrates that there is an enormous, largely untapped, and highly cost-effective energy efficiency resource available ... to meet the region's ... energy ... needs."

Economic Potential

A 1990 study published by the Electric Power Research Institute (EPRI) addresses the potential energy savings nationally.[4] This study shows that the maximum potential energy savings arising from using more efficient equipment range from 24 to 44 percent of projected electricity use in the year 2000, assuming all technically feasible measures are installed.[5] The range reflects the difference between the use of conservative and optimistic assumptions. Other studies estimate that even larger savings, as much as 75 percent of total electricity use by 2010, are possible.[6]

The six-state region covered in this report has a similar, or perhaps even greater, energy efficiency potential. Testimony of energy service companies (ESCOs) and other professionals involved in providing energy efficiency strongly suggests that this region has significant efficiency potential.[7] The abundance of new construction caused by rapid population and economic growth offers a particularly attractive opportunity to integrate more efficient technologies into the region's homes and businesses. Influencing customer energy use decisions up front enables the cost and effort involved in promoting increased energy efficiency to be greatly reduced.[8]

Most of the energy efficiency opportunities involve a few key technologies. Nationally, lighting services account for roughly a quarter of total electric demand. To reduce this demand, a broad range of energy-efficient lighting technologies are now available. For example, compact fluorescent lamps can replace incandescent bulbs while consuming 75 to 85 percent less electricity and lasting 10 times as long. Similarly, an integrated package of reflectors, lamps, ballasts, and controls can dramatically reduce electric use in fluorescent lighting applications. Although energy-efficient lighting costs more, the electricity savings generally produce payback periods of under two years.

After lighting, electric motors provide the best opportunities for saving electricity. Motors use 65 to 70 percent of industrial electricity and account for a significant share of the electricity generated nationally. A variety of approaches exist for improving the efficiency of motors. For example, many machines require variable output to accommodate changing process needs. This variable output is often provided by running equipment, such as pumps or fans, at full speed while "throttling" the output with a partly closed valve or damper. Electronic adjustable-speed drives can reduce this waste, and a new generation of high-efficiency motors can cut the amount of electricity used. Finally, improvements in the maintenance, control, and sizing of motors can lower electric demands.

Large electricity savings also can arise through greater use of energy-efficient appliances: refrigeration systems can now use 30 to nearly 50 percent less electricity, televisions 75 percent, photocopiers 60 to 90 percent, and computers and desktop printers 95 percent. Typically, these energy-efficient technologies provide more pleasing light, more reliable production, and higher standards of comfort and control.

Market Barriers

Given the economic benefits of energy efficiency, some customers—particularly larger, more sophisticated ones—have been able to work with ESCOs to successfully install energy-efficient equipment, especially measures with short payback periods (less than one year). Examples include commercial chains, such as supermarkets, relamping their floorspace and very large industrial customers improving their production processes. In these markets, utility involvement is often not needed. In contrast, in almost all other

markets—involving less sophisticated customers and longer payback measures—the evidence indicates that customers will generally not take advantage of energy efficiency opportunities. A number of informational, financial, and institutional market barriers explain this reluctance.

One of the chief barriers is lack of information. Key decision makers in regard to energy use—architects, plant managers, and homeowners—often do not have the time and expertise available to incorporate the most appropriate energy-efficient technologies. Usually consumers use very different financial criteria to evaluate electricity-saving devices than utilities use to assess new power plants. When consumers invest in electricity savings, they often want to recoup their investment within two years or less. In contrast, for utilities building new power plants, their technical and financial resources typically allow them to recover costs over a longer time period.

Another barrier exists because of "split incentives." Some buildings and equipment are owned by different entities than those who use the equipment. As a result, the owner is not paying the energy bills and will attempt to get by with the lowest capital costs because the energy savings accrue to the user. Because the energy costs are often hidden in lease costs and can be outweighed in importance by other considerations, energy efficiency will suffer. For all these reasons, customers on their own will typically not take advantage of the full economic opportunities associated with energy efficiency.

The Role of Electric Utilities

To address these market barriers, a number of utilities around the country have developed demand-side management (DSM) programs targeted at influencing the energy use decisions of their customers. DSM efforts involve a number of different activities including managing peak demands, encouraging more efficient energy use, and shifting usage to off-peak periods. Utilities have also developed a wide range of tools to accomplish these DSM objectives such as time-of-use rates, the provision of technical assistance, subsidized loans, and direct financial incentives to influence customer investment decisions.

Within this region, the investor-owned utilities (IOUs)—prodded by state regulators—have taken the lead in promoting energy efficiency. By early 1995, the largest IOUs in Colorado, Utah, and Arizona had significant energy efficiency programs. The smaller public and cooperatively owned utilities are just now initiating energy efficiency programs. These utility DSM programs have a number of common features. Generally, the utility provides a rebate or a subsidized loan that encourages customers to purchase energy-efficient equipment. Customers usually bear some portion of the up-front cost of the efficiency measure and, in return, realize reductions in their electricity bills.

All told, the region's utilities are planning to spend about $60 million *annually* to promote energy efficiency. Public Service Company of Colorado (PSCO) has budgeted about $20 million per year through the end of 1996 to encourage its customers to use energy more efficiently. PSCO's programs, which were designed collaboratively by a group of key stakeholders, tend to target commercial new construction, customer remodeling, and industrial process improvements. PSCO also runs a separate low-income DSM program, has promoted energy efficiency at Denver's new airport, and has a bidding effort for energy service companies targeted at the commercial retrofit market. All of these efficiency activities are supported by a cost recovery and financial incentive package that runs through the end of 1996.[9]

Utah Power & Light (UP&L), the Utah division of PacifiCorp, has begun to increase its attention to energy efficiency in the wake of recent regulatory changes approved by the Utah Public Service Commission.[10] In 1996,

"... customers on their own will typically not take advantage of the full economic opportunities associated with energy efficiency."

UP&L is seeking to reduce its energy requirements by over 80,000 megawatt-hours. To achieve these savings, UP&L estimates a resource commitment of somewhere between $10 million and $15 million. UP&L's efficiency investments are supported by an agreement that lasts until 1997.[11]

Regulators in Arizona made it financially possible in 1994 for that state's largest investor-owned utility—Arizona Public Service Company (APS)—to begin more aggressively investing in energy efficiency. As part of a 1994 settlement agreement, the Arizona Corporation Commission approved investments of up to $15 million per year in energy efficiency. This agreement extends through the end of 1996.[12]

Several municipal utilities also have begun to promote energy efficiency. For example, in Colorado the Platte River Power Authority expects to spend roughly 1 percent of its gross revenues in 1996 on encouraging greater energy efficiency. Other municipal and cooperative utilities are poised to follow their lead. In contrast to these leading utilities, most others appear to be either doing nothing or focusing on programs that reduce peak demand but do not significantly alter energy use.

"DSM programs have proven highly cost-effective for utilities in the region."

Table D-1 summarizes the projected savings resulting from the DSM programs of some of the larger utilities in the region if spending levels forecast in early 1995 are realized. However, utilities in Arizona and Colorado are now reevaluating their commitments to energy efficiency as described in more detail in Chapter 3.

The Economics

Utilities in this region have focused primarily on the most attractive energy efficiency opportunities, typically targeting DSM programs at new construction and replacement markets. These programs take advantage of a narrow window of opportunity when key decision makers are replacing or buying new energy-intensive equipment. Similarly, regional utilities have concentrated their efforts on larger commercial and industrial facilities where the efficiency opportunities are the most economic.

DSM programs have proven highly cost-effective for utilities in the region. Preliminary monitoring and evaluation results in Utah and Colorado, where regional utility DSM efforts are most advanced, indicate total resource benefit/cost ratios of between 1.5 and 2.5.[13] Similarly, utility resource plans

Table D-1. The Expected Role of DSM in Meeting Annual Demand Growth

Utility	Annual Load Growth, *megawatts*	Annual Role of DSM, *megawatts*	DSM as a Percentage of Load Growth
PSCO	90–95	25–30	25–30
PacifiCorp	80–85	20–25	25
APS	100	25	25
Nevada Power Company	90	10	10
Four utility totals	370	90	25
Regional total	750	110–150	15–20

Source: The most recent resource plans from each of these utilities. *RAMPP-4* (PacifiCorp) Inputs and Results Appendix, p. 2, Model Output Appendix, pp. 19–21; PSCO *1993 Integrated Resource Plan,* Volume 2, pp. 2.15–53, 54; APS *1993 Integrated Resource Plan,* p. 30; NPC *1994 Integrated Resource Plan,* p. 20.

show large DSM opportunities that are available at costs between 2 and 4 cents per kilowatt-hour.[14] Although DSM is not "too cheap to meter," monitoring and evaluation results do show that most DSM programs are cheaper than the least expensive supply-side alternatives.

In addition to the direct economic benefits, utility DSM investments can also improve environmental quality. Over a 20-year period, utility DSM programs can greatly reduce emissions. For example, one high-efficiency light bulb, over its life, can significantly reduce pollutant emissions by avoiding the need to burn over 500 pounds of coal. In addition to the air quality benefits, energy efficiency investments will reduce supply-side impacts from coal mining, natural gas drilling, transmission line construction, and waste disposal.

Utility DSM programs targeted toward low-income customers can also help to promote fairness. Most utility DSM dollars are typically allocated to the most cost-effective opportunities, generally in the large commercial and industrial sectors. By developing special programs that reflect the needs of the low-income community, utilities can help ensure that their energy efficiency efforts are equitable. For example, in a path-breaking program, Public Service Company of Colorado has partnered with various federal efforts to weatherize low-income housing. PSCO's current contribution to this partnership, between $2 million and $3 million annually, helps to lower customer bills, improve furnace safety and overall comfort, and reduce arrearages and homelessness among low-income customers.

DSM programs can also help to mitigate planning uncertainties for utilities. Most DSM efforts involve individual projects with small unit sizes and short lead times. In contrast, a typical coal plant may take five or more years to build and provides no benefits during the construction period. Supply-side units, all far larger than the size of the typical DSM program, range in size from roughly 100 megawatts to several hundred megawatts. Quantitative analysis estimating the benefits of DSM programs suggests that short lead times and small unit size create an additional 10 percent in the value of the resource.[15]

More recent evidence, however, indicates that utility energy efficiency programs also have risks. For example, national monitoring and evaluation results may show that the actual benefit/costs ratios of DSM programs are often smaller than the engineering estimates had originally indicated.[16] Issues surrounding snap-back effects, measure persistence, and usage assumptions lead some to suggest that actual DSM savings may be lower than utilities have forecast. Thus, although DSM is still cost-effective, some recent evidence suggests that these programs are more expensive than originally thought.

Finally, energy efficiency investments can produce significant economic development benefits. First, energy efficiency costs less than the alternative supply-side power plants. As a result, energy efficiency investments ultimately provide utility customers with more money to purchase goods and services, which in turn leads to additional jobs. This employment impact is known as the "income effect." Second, energy efficiency is a labor-intensive business involving, among others, auditors, architects, equipment manufacturers, and electrical contractors. In contrast, utility expenditures on supply-side capacity tend to be capital intensive. Because of this difference, a given dollar investment on energy efficiency will produce more jobs than an equivalent expenditure on a supply-side resource.

Relying generally on input/output models, a number of analysts have estimated either national or state-wide job and income benefits associated with promoting increased energy efficiency. Applying the results from these national studies[17] to this region, we

"In addition to the direct economic benefits, utility DSM investments can also improve environmental quality."

estimate that energy efficiency investments that meet 35 percent of future load growth would lead to roughly 10,000 additional jobs in our region.

Limited evidence tends to support the results obtained by applying the national data to our region. A study in Pitkin County, Colorado, found significant employment benefits associated with increased energy efficiency investments of roughly the same order of magnitude as those in the national studies.[18] Anecdotal evidence from the local ESCOs and electrical contractors suggests that some employment gains have already occurred.[19]

Managing DSM Rate and Competitive Impacts

Although less expensive than traditional supply-side alternatives, utility DSM programs are not without their problems. Utility DSM programs, by intention, reduce electric utility sales. Since utility revenues are linked to sales under current regulation, DSM-induced sales reductions will lower utility revenues and profits, creating what is commonly referred to as the "lost revenue" problem.

From the utility's perspective, this problem has created a negative financial incentive during the time period between rate adjustment opportunities. At the time of a rate case before the public utility commission, utility rates are adjusted to account for any reductions in sales due to DSM investments or any other cause. Between rate cases, however, utilities can experience reductions in earnings as a result of DSM-induced sales reductions. To obtain the economic and environmental benefits associated with utility-sponsored DSM, regulators in this region have begun to approve a variety of mechanisms to compensate utilities for the lost revenues associated with running DSM programs. In this region there is a direct cause-and-effect relationship between regulation that permits utility cost and lost revenue recovery and a utility's willingness to pursue DSM opportunities.[20]

Allowing utilities to recover their DSM-related costs and lost revenues, however, can potentially lead to higher utility prices in both the short and long run. The exact price impact associated with utility DSM programs reflects three factors—total lost revenues, utility DSM program costs, and avoided cost benefits—and is governed by the following formula:

price impact = total lost revenues (6 cents per kilowatt-hour) + utility DSM program costs (1–4 cents per kilowatt-hour) – avoided cost benefit (3–5 cents per kilowatt-hour)[21]

Of these three factors, total lost revenues is the largest based on average regional data.

Because of the lost revenue problem, several key stakeholders have opposed reforms designed to promote utility DSM programs. More recently, the specter of both wholesale and retail competition has forced utilities to focus on lowering prices and increasing the likelihood of recovering DSM (and other) expenses.

Holy Cross Rural Electric Cooperative

The economic development gains arising from energy efficiency investments may be particularly compelling in situations where utilities purchase power from outside their service territories. Holy Cross Rural Electric Cooperative in the mountains of Colorado provides a good example of such a situation. Holy Cross is currently a requirements purchaser from a large IOU located well outside its service territory. As a result, over $35 million per year leaves the community. In contrast, every dollar spent on energy efficiency reduces the utility's reliance on purchased power and keeps money in the community.

New, more competitive conditions are encouraging utility managers to place a high priority on offering lower prices than other utilities and independent power producers (IPPs) with whom they may soon compete. Because utility DSM programs may increase electricity prices, these managers appear to be reluctant to spend money on these programs even though recent regulatory reforms may protect their short-term earnings from DSM-induced sales reductions. As a result, utilities in Arizona, Colorado, and Nevada are now questioning their commitments to energy efficiency.

To respond to these competitive pressures, utilities both within and outside the region are trying to develop new approaches to energy efficiency that involve participant surcharges, market transformation efforts, and DSM targeted toward highly cost-effective opportunities. Both the problem and these potential solutions are described in more detail in Chapter 3.

Conclusion on DSM

Utility-sponsored DSM programs can produce substantial economic, environmental, risk mitigation, and economic development benefits. Given these benefits, energy efficiency investments are at the center of the LAW Fund's blueprint for a more sustainable energy future for the region. However, the resulting adverse price impacts can make it difficult to sustain these programs as competition in the industry expands. The challenge for utility and other DSM efforts in the future will be to create program designs and approaches that mitigate these adverse impacts.

Dealing with Lost Revenues

Most utilities that invest in energy efficiency must be able to recover some portion of their lost revenues. In general, lost revenues can be recovered in a variety of ways—through bounty payments based on energy savings, through several different approaches for "decoupling" utility revenues from sales, and through explicit net lost revenue adjustments. Commissions in our region have spent a substantial amount of time over the past few years evaluating these alternative approaches for recovering lost revenues. This effort has enabled utilities in Colorado, Utah, and Arizona to begin investing more heavily in energy-efficient technologies.

Renewable Resources: The Way of the Future

Renewable resources are those resources which are naturally replenished after they have been harvested, reaped, utilized, or consumed. One generation's careful consumption of them does not circumscribe their access and availability to future generations.

Our six state region is well endowed with hydroelectric, wind, solar, and geothermal renewable resources. This region has not only the best solar resource in the country but also the best technical infrastructures in the world to support its development.

"... energy efficiency investments are at the center of the LAW Fund's blueprint ..."

The benefits of harnessing new renewable resources in this region, especially solar, wind and geothermal, are many, but particularly important are the following:

- Renewable resources have low or zero fuel costs. As a result, these resources offer the region a way to manage the risk of higher fossil fuel costs described in Appendix C.
- Though not without their environmental problems, most renewable resources have far less environmental impact and risk than conventional fossil fuels, especially coal.
- The amount of available resources, especially of solar energy, is enormous.
- The economic benefits to the region, in terms of employment potential and contributions to the tax base, are also potentially enormous.

Despite this potential, it is ironic that the only renewable resource that has been developed to any degree in this arid region is hydroelectricity. The reasons for this are many, but three stand out. First, the region

has had surplus generating capacity over the past 10 years. During this period, the region's utilities generally have not needed to acquire new capacity of any kind, although, as Appendix B describes, the surplus is now being absorbed. Second, renewables have been more expensive than fossil fuel-fired resources. However, this situation is also changing because of the falling cost of renewables. Even with today's historically low natural gas prices, wind and geothermal are now nearly cost-competitive with conventional fossil fuel-fired resources. Solar remains the most expensive renewable resource, but its costs continue to come down. In non-grid-connected niche applications solar is economical now and can be an economical resource in grid-connected applications within 10–15 years. Third, utilities and regulators are unfamiliar with and lack confidence in renewable technologies. As a result, they tend to ignore the benefits of renewables and have been unwilling to make significant commitments to them. Over the last few years, however, the situation has changed. The need for new capacity, the falling costs of renewables, and the preference of many electric customers for environmentally sound resources should encourage utilities and IPPs to develop confidence in renewables. Consequently, over time these resources become an increasingly important component of the blueprint.

"... it is ironic that the only renewable resource that has been developed to any degree in this arid region is hydroelectricity."

In this section, we describe each of the non-hydro renewable resources available within the region.[22] Within 15–20 years solar should begin to compete with coal and natural gas for the largest amount of installed electrical capacity in the region.

Wind

Of all the renewable energy technologies, wind power is, in the near term, one of the most promising and cost-effective alternatives to conventional intermediate and peaking generating facilities. Whereas the concept of harnessing the wind's kinetic energy is not new, using wind to generate electricity for utility-scale applications is a relatively recent idea. In the 1980s, California took the first big steps and risks to turn this idea into reality. Today in California there are 16,000 wind turbines installed with a total generating capacity of approximately 1,500 megawatts. They now reliably generate over 2.5 billion kilowatt-hours of electricity annually while providing California residents with the benefits of a more diverse energy mix.

Since the installation of these turbines in California, private industry has worked cooperatively with national energy laboratories to improve the technology. This partnership has borne fruit. The newest generation of wind turbines have lower up-front costs, reduced operation and maintenance expenses, higher capacity factors, and longer lives. Even with natural gas prices at historically low levels, today wind is nearly competitive with natural gas-fired combined-cycle units in certain parts of the region. And wind costs are predicted to fall, giving wind an advantage over time.

Some utilities in the region have already committed to building a 70-megawatt wind project at Arlington, Wyoming—one of the best wind sites in the nation. Although transmission constraints may limit the amount of power from this site that can be provided to the urban load centers, the attractive economics of this project make it possible to eventually expand the project to several hundred megawatts. Project developers, utilities, and others are also investigating sites in eastern Colorado, New Mexico, and southern Nevada.

Wind, however, is not without its problems. Wind turbines can kill raptors and other birds. Also, because wind is intermittent, it has more economic value if it is firmed (backed up) by other resources.[23] Although neither of these problems is insurmountable, they add to project costs.

The Wind Resource

Wind resources are classified in terms of wind power density, measured in watts per square meter.[24] There are seven classes of wind power, representing densities of 100 (Class I), 150 (Class II), 200 (Class III), 250 (Class IV), 300 (Class V), 400 (Class VI), and 1,000 watts per square meter (Class VII) at a height of 10 meters.

Pacific Northwest Laboratories (PNL) has prepared estimates of the gross wind energy potential in the West.[25] In their 1987 wind atlas, Wyoming and Colorado both easily surpassed California in wind energy potential at Class V sites and greater.

Table D-2 shows the vast wind energy potential in each of the western states based on Class IV and higher wind resources. Wyoming, Colorado, and New Mexico have the wind potential to generate power for much of the West. Relative to the wind energy potential of other states in the country, these states rank seventh, eleventh, and twelfth, respectively. Even Arizona, with the least wind energy potential in the region, could use its wind resources to meet about 7 percent of its 1990 in-state electricity consumption. If our six states captured just 10 percent of the Class IV and higher wind energy potential in the region, over 76 million megawatt-hours could be generated annually, or the energy equivalent of 25 baseload coal plants with a capacity of 500 megawatts each running at a 70 percent capacity factor. By comparison, almost 50 percent of the Class IV or better wind resources have already been developed in California over the past 15 years.

The U.S. Department of Energy (DOE) produced a map (Figure D-1) that depicts the magnitude and class of wind resources in the United States. Although transmission capacity constraints, as well as local siting difficulties, reduce the actual resource available, the region still possesses abundant amounts of economically viable wind power.

Wind Technology and Costs

When we think of wind energy, the first image that may come to mind is the children's book illustration of heavy wooden blades turning slowly in the wind to pump

"... Wyoming and Colorado ... easily surpassed California in wind energy potential ..."

Table D-2. Estimates of Wind Energy Potential for the Western Region

State	Electricity Consumed (1990), *billion kilowatt-hours*	Wind Energy Potential: Average Power, *megawatts*	Wind Energy Potential: Annual Energy, *billion kilowatt-hours*	Wind Energy Potential: Percentage of 1990 Electricity
Arizona	40.4	384	3	7
Colorado	31.2	26,400	231	740
Nevada	16.9	4,620	40	237
New Mexico	13.7	5,240	46	336
Utah	15.2	2,110	18	118
Wyoming	11.7	49,800	436	3,727

Source: All data from "An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States," by D. L. Elliot, Pacific Northwest Laboratory, August 1991.

Note: For all wind resources greater than or equal to 320 watts per square meter at 30 meters, or Class 4 or greater. Furthermore, this table assumes 25 percent efficiency and 25 percent power losses. Land exclusions are also factored into these figures. This table assumes a land exclusion scenario of: 100 percent for urban areas and environmentally sensitive areas or restricted areas (parks, preserves, etc.); 50 percent exclusion for forest cover; 30 percent exclusion for agricultural areas; and 10 percent for range lands.

water. Modern wind farms are as far from this image as the latest supersonic jet fighter is from the first airplanes at Kitty Hawk. The modern wind farm—such as the one being developed now in Wyoming—consists of between 100 and 500 wind turbines connected to the transmission grid. A typical wind turbine begins to produce power at a wind speed of about 10–12 miles per hour, with power output increasing roughly with the cube of the wind speed up to the rated output at a wind speed of about 25 miles per hour.

Most of the wind turbines in use in the United States today rely on early 1980s technology. These are mostly three-bladed, rigid hub designs and have on average a maximum power output of 100 kilowatts. New designs, rated at 300–400 kilowatts, have incorporated innovative power electronics to improve costs and performance. The DOE is sponsoring the development of advanced wind turbines to cost-effectively use the wind at Class IV sites.

"The modern wind farm ... consists of between 100 and 500 wind turbines connected to the transmission grid."

As the technology has improved, the cost of energy from wind turbines has dropped from more than $1.00 per kilowatt-hour in 1978 to less than 10 cents per kilowatt-hour in 1988. Today, in this region, the installed capital cost of wind capacity is between $900 and $1,000 per kilowatt, with annual operation and maintenance (O&M) costs of about 1 cent per kilowatt-hour. On a levelized basis the cost of energy from wind farms located at Class IV sites or better is 5–7 cents per kilowatt-hour.[26]

Further improvements in technology will continue to lower costs. The U.S. DOE has projected that by the year 2000 the capital costs for a wind facility will fall to roughly $750 per kilowatt (1993 dollars).[27]

In the Energy Policy Act of 1992 (EPAct), Congress created a production tax credit of 1.5 cents per kilowatt-hour for wind energy projects. Unlike an investment tax credit, for which the benefits are received in the year of project installation, the production credit is tied to the actual energy production of the project, which encourages developers to make maximum use of the project. The tax credit, available to utility and IPP wind facilities installed before July 1, 1999, and lasting for 10 years, can significantly reduce the effective cost of wind energy.

Capacity Value

Wind energy is an intermittent resource. When the wind does not blow, energy is unavailable unless it has been stored. This does not mean that wind energy systems have no capacity value. But it does mean that, at any given wind farm, the resource is less reliable than a typical fossil fuel power plant.

Determining the capacity value of wind is a challenge for utilities at sites with little wind data available. However, as long as wind energy capacity is less than 2–3 percent of a system's total installed capacity, the capacity value of the wind can be calculated as a function of the expected average capacity factor of the wind during a utility's peak.[28] Using this method, PSCO determined that the capacity value of its Arlington wind site is 50 percent of the site's installed capacity.[29] In other words, PSCO assumed that, during its system peak, the Arlington site would be on average producing power at only half its total rated capacity.

When the capacity value considered for a wind plant (or plants) exceeds 2–3 percent of a utility's generation mix, it becomes extremely important to calculate the exact extent to which each wind plant could influence system stability. This value must be based on the size of the wind plant relative to the overall generation mix, and the time-of-day and seasonal correlation between wind regimes and system peak loads.[30]

Wind Versus Natural Gas

In 1994, the LAW Fund compared the costs of wind with (1) the capacity and energy costs

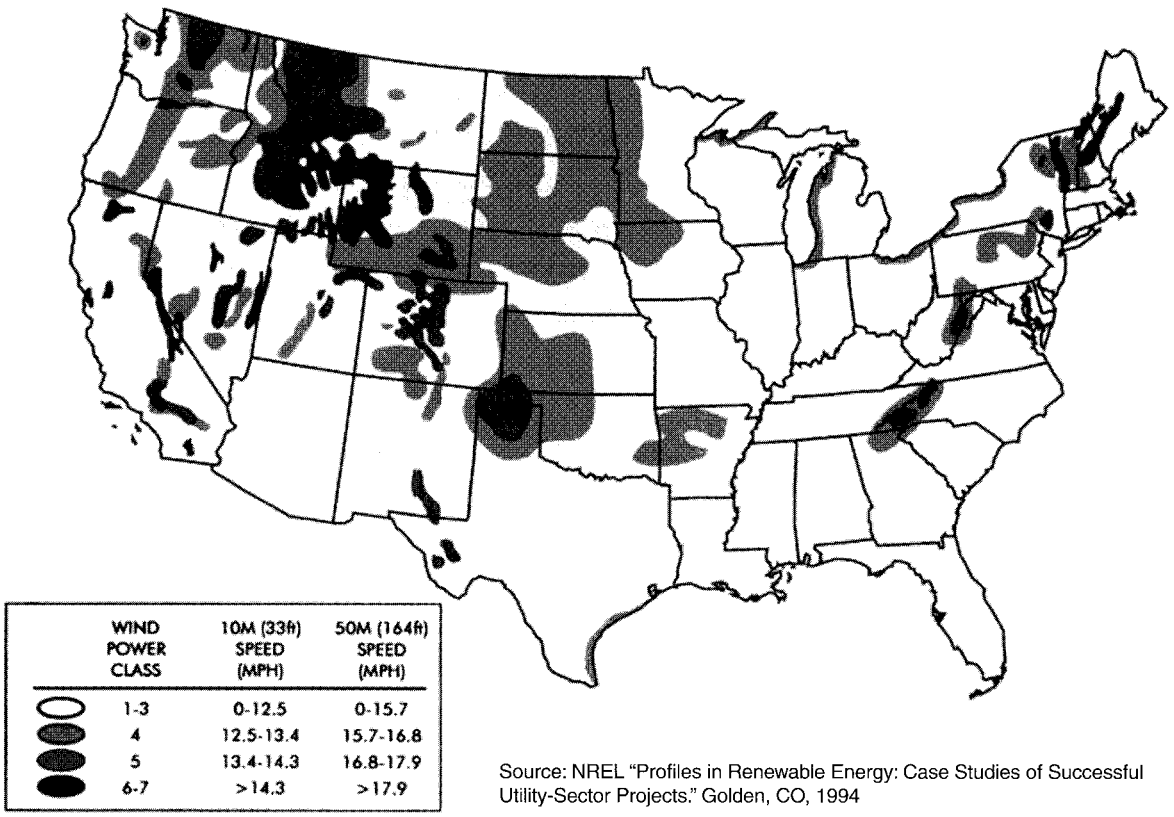
from a new gas-fired combined-cycle unit during intermediate hours on the PSCO system and (2) the energy from an existing coal plant during off-peak hours. Our analysis used capital and base-case fuel costs provided by PSCO in its 1994 Integrated Resource Plan filing and declining costs of wind consistent with those specified for us by the Director of the Wind Energy Program of the National Renewable Energy Laboratory (NREL). We also assumed the availability of the full 1.5 cents per kilowatt-hour tax credit. Consistent with PSCO's assignment of capacity value at its Arlington wind site, we compared the costs of 100 megawatts of wind capacity with 50 megawatts of gas combined-cycle capacity.

Under these assumptions, we found that at the best sites wind is competitive with conventional combined-cycle technologies under a range of alternative planning assumptions. This analysis helped to confirm our view that wind power is one of the most promising and cost-effective alternatives to conventional intermediate-and-peaking generating facilities in the near term. A copy of the analysis is available from the LAW Fund.

Employment and Economic Development Impacts

Wind energy, similar to most manufacturing-intensive industries, can provide important job creation and tax revenue benefits in our

Figure D-1 Average Annual Wind Power in the Western States



Source: NREL "Profiles in Renewable Energy: Case Studies of Successful Utility-Sector Projects." Golden, CO, 1994

region. This is particularly true for states that import fossil fuels for electricity generation, such as Nevada and Arizona, and for windy states such as Wyoming and Colorado. If utilities in any of these states commit to purchasing significant amounts of wind energy, developers will likely locate production and manufacturing facilities nearby, bringing employment, tax, and royalty revenues to state and county coffers.

According to estimates from outside our region, investments in wind energy systems will have almost three times the job creation impacts and will generate almost twice the amount of state tax revenues relative to investments in natural gas-fired combined-cycle units.[31] For example, for every 10 gigawatt-hours of output, wind energy systems are estimated to create 7.0 full-time jobs and $71,000 in state tax revenues. Combined-cycle plants, on the contrary, are estimated to create 2.6 jobs (per 10 gigawatt-hours of output) and only $42,000 in taxes.

"Wind energy ... can provide important job creation and tax revenue benefits in our region."

In another study performed for Wisconsin, an energy-importing state, investments in a 400-megawatt wind farm were shown to result in over 21,000 job-years, compared with investments in a 210-megawatt gas combined-cycle unit (CC) and a 90-megawatt combustion turbine (CT) that together would create 10,400 job-years.[32] Thus, investments in wind energy appear to create more full-time work than most other energy investments.

Environmental Issues

Wind energy systems emit no air pollution. They do not use water, nor does the land have to be torn up to extract resources to drive a wind system. Although there are environmental problems with wind, they are minor compared with those of conventional coal, nuclear, natural gas and hydroelectric technologies. Combined with the economic and risk management benefits, the environmental advantages of wind make it a valuable resource in this region.

The negative environmental effects of wind fall into three categories: visual, noise, and wildlife impacts. Because wind turbines are located atop tall towers and can often be seen for a long distance, some find turbines to be aesthetic nuisances. Wind turbines also emit noise at different frequencies that can be heard close to the turbines. High-pitched noises can often be eliminated by careful attention to blade design. Design consideration can eliminate or reduce low-pitched noises as well.

Concern for the impact of wind farms on wildlife is focused on avian populations. Although most wind farms have not reported problems, the Altamont Pass wind farms in California have been reporting significant numbers of raptor deaths the last several years. The avian mortality problem stems from the fact that raptors and wind developers are attracted to the same sites, the windiest areas with the greatest uplift. This factor could block the development of wind energy at some sites in the West.

Nonetheless, wind energy can have an overall positive effect on wildlife and wildlife habitat because of its environmental benefits relative to fossil fuel production and combustion. To achieve this benefit, however, the wind industry must develop technologies to mitigate bird fatalities. Alternatively, developers of wind energy should avoid areas where raptor or other bird populations are large. Finally, developers and fish and wildlife agencies should conduct biological studies of proposed sites and then construct projects in incremental phases so that the impacts on birds can be studied and minimized.

Solar

All renewable resources, except geothermal, derive their energy value from the sun. Even fossil fuels are merely the stored energy of the sun—solar energy "capital" accumulated through time. When we refer to solar energy, however, we mean techniques to use solar

energy, its light and heat, directly, before it has lifted water, stirred up winds or enabled plant or animal tissue to grow.

The sun's light and heat energy can be used to generate electricity or to meet other energy needs. In this section, we review solar thermal and photovolatic technologies that use the sun's energy directly to generate electricity, as well as passive and active uses of solar power in buildings to reduce electric loads.

Traditional perceptions of solar energy in the electric industry are that it is virtually limitless, environmentally benign, and very expensive. Only the first two perceptions are accurate today. Passive solar building design features that reduce utility loads have been economical in this region for decades. Solar thermal electric generating technologies do not compete yet with the direct, economic costs of fossil fuel plants; but with a coordinated regional effort they will be able to, within a decade or so. Photovoltaics already are cost-effective in non-grid-connected "niche" applications and show promise of being competitive for grid applications early in the next century. In short, solar's cost handicap, where it still exists, is disappearing.

Ultimately, we may have to depend on the region's vast solar resource for most of our energy needs. Unless we learn to harness nuclear fusion or a much larger share of the earth's heat, there is no other resource over the very long run that could provide sufficient sustainable power to meet the region's heating, lighting, motor drive, and even transportation needs. In our view, the issue is not whether solar technology will be integrated into our energy mix, but how fast this integration should occur.

Because there remain many decades' worth of fossil fuel energy supplies in the ground, there is no imminent energy crisis that requires an "overnight" conversion to a solar economy. However, attainment of every one of this report's objectives—with respect to the environment, economics, equity, risk management, and sustainability—militates in favor of dramatically expanding the region's efforts to use solar energy cost-effectively.

Solar technologies can also add wealth to the region, not only as a result of their widespread use here as the costs decline, but also as a potential for export. This region, with its abundant solar resources and unparalleled technical infrastructure, can and should lead the rest of the world in solar technology development. If it does, the economic benefits can be enormous. Clearly, development of solar energy in this region places us squarely on the road to sustainability and helps us ensure that future generations have the same options available that we do.

But for solar to achieve the lofty goals we create for it in this report, solar electricity generation costs have to decline substantially. Because the solar industry is technologically young, there is enormous potential for solar generation costs to decline. To reduce costs will require cooperation among a wide range of interests, including utilities, IPPs, developers, scientists, and federal and state governments.

In the following section, we describe the region's solar resource and the technologies for harvesting it, including their costs and environmental impacts. We also discuss employment impacts and other economic benefits of developing the solar resource.

"... the issue is not whether solar technology will be integrated into our energy mix, but how fast this integration should occur."

The Regional Solar Resource

Information on solar radiation (insolation) is now readily available from numerous local and national sources, such as the National Renewable Energy Laboratory, the National Weather Service, and state energy offices. Statistics from these sources show that the gross solar resource in our region is exceptionally large and generally available during regional summertime afternoon peak loads. The most current source is the National Solar Radiation Data Base (NSRDB) recently completed by NREL.[33] The NSRDB provides hourly values of measured (or modeled)

direct and diffuse radiation for 239 stations in the United States for the 30-year period from 1961 to 1990. Figure D-2 shows the average daily solar radiation that fell over a 30-year period on specific monitoring sites in the region in terms of watt-hours per square meter per day.[34] Given these values, just 1 percent of the land area of Arizona could supply the energy equivalent of over 17 times the state's 1991 electricity consumption at a 10 percent conversion efficiency.[35] Though Arizona and New Mexico[36] have the best solar resource in our region—indeed, in the nation—much of Nevada, Utah, and Colorado receive levels of insolation that far exceed the national average. Even southern Wyoming has a good solar resource, roughly 80 percent of that received in Phoenix, Arizona. Of course, this potential must be turned into electricity, and it is to the technologies that are under development to achieve this objective that we now turn.

"... Arizona and New Mexico have the best solar resource in our region—indeed, in the nation ..."

Solar Thermal Generation

Solar thermal electric systems convert the sun's light into heat by concentrating direct-beam radiation onto a receiver, where it is absorbed into a fluid. The heat in the fluid is transported to a heat engine that converts the thermal energy into electricity. The three most developed solar thermal technologies are the parabolic trough, parabolic dish, and central receiver; none of these is presently cost-competitive with new fossil fuel-powered generation capacity. Ironically, it may be in "hybrid" configurations with gas combined-cycle units that these technologies may find market entry on a widespread basis in this region.

Technology and Costs. The costs of a wide range of solar technologies are now falling. We discuss these technologies below.

Parabolic Trough Systems

Parabolic trough technology employs a field of solar collectors. Curved mirrors individually track the sun across the sky by means of microprocessors and light-sensing instruments. The mirrors focus sunlight on specially coated metal pipes suspended above the reflectors. The pipes, which are contained within vacuum-insulated glass tubes in order to reduce thermal loss, contain a heat transfer oil that absorbs the heat and transports it to a heat exchanger in order to generate super-heated steam. Conventional turbine generators convert the steam heat to electricity.

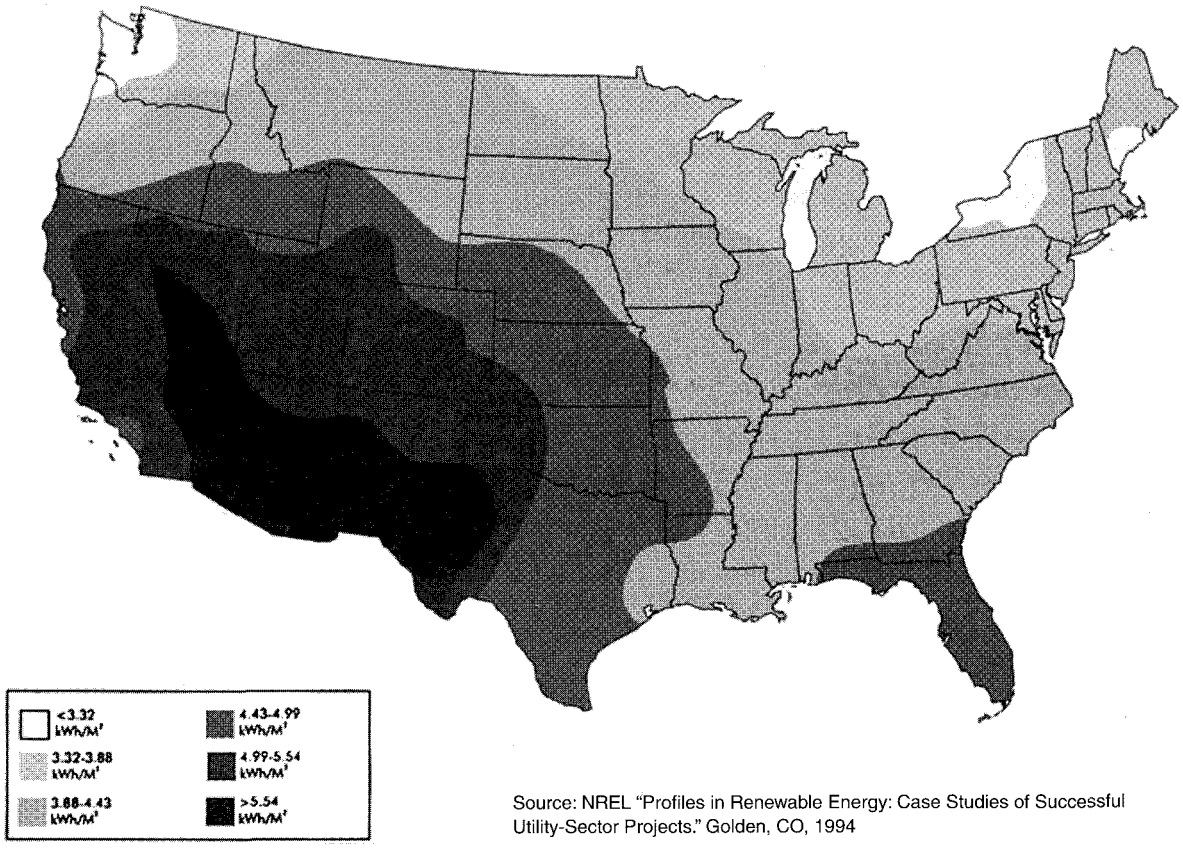
Troughs are modular in nature, and existing plants can easily be expanded. Between 1984 and 1990, nine units totaling 350 megawatts of generating capacity using parabolic trough technology (called Solar Electric Generating Systems, or SEGS) were built in the California desert by Luz International, Ltd. The systems incorporate a natural gas-fired boiler to ensure uninterrupted power during peak demand periods. Luz International could not meet its financial obligations in 1991, but the partnerships that own the plants continue to keep them in operation. Available at system peak, the SEGS reliably provide energy to Southern California Edison at a 36 percent capacity factor. More recently, a variety of solar and solar/gas hybrid projects have been proposed that would improve both the efficiencies and economics of parabolic trough technologies.[37]

The only field-tested cost figures available for trough technology in this country are those from the SEGS. Three generations of solar collectors were installed over the series of nine SEGS, the final two being 80 megawatts in size. Capital costs for the SEGS fell from about $4,500 per

kilowatt for the first plant constructed to $2,875 per kilowatt for the last 80-megawatt plant that began operation in 1990. Approximately 55 percent of the total capital costs are incurred in the solar receivers and field equipment and another 15 percent in the turbine and plant. The remainder of the capital costs cover the fluid transport systems, gas boiler, roads, and infrastructure. Without consideration of tax credits, the levelized cost of power from the SEGS is estimated to be about 13 cents per kilowatt-hour.[38] With tax credits, the levelized cost of power from SEGS plants is as low as 8–9 cents per kilowatt-hour.[39]

The Luz plants were sized at no more than 80 megawatts per unit to be able to qualify for regulatory benefits under the Public Utilities Regulatory Policy Act (PURPA). For the same reason, no more than 25 percent of the energy produced by the units was generated by burning natural gas. These restrictions contribute to the high cost of power from the SEGS. If the SEGS ran on 50 percent natural gas, the same units would be able to provide intermediate power at costs 1–2 cents per kilowatt-hour lower than systems running on 75 percent solar fuel. And it appears that economies of scale are

Figure D-2 Average Daily Solar Radiation, 1961–1990 (energy from the Sun on a tilted surface)



Source: NREL "Profiles in Renewable Energy: Case Studies of Successful Utility-Sector Projects." Golden, CO, 1994

still available at least up to a unit size of 150–200 megawatts.[40]

Current parabolic trough development is focusing on integrated solar combined-cycle system (ISCCS) technology. In this technology solar heat is used to preheat gas turbine inlet air as well as to augment the steam turbine power output. This enables use of solar heat at higher thermodynamic efficiencies, in the 10–40 percent range, depending on whether thermal storage is used.[41] Our understanding is that natural gas would provide most of the energy input to the generators in ISCC plants.

Central Receivers/Power Towers

Central receiver (or power tower) technology employs a large field of sun-tracking mirrors known as heliostats. Each heliostat is individually aimed by a computerized control system to reflect the sun's rays to a tower-mounted receiver containing a heat transfer fluid. The heated fluid is moved from the receiver and is used to generate electricity by raising steam (or by another thermal conversion process) or stored for later use. Unlike SEGS, which depend on fossil fuel-fired back up capacity, pure central receivers depend on heat storage for reliability. Like SEGS plants, central receivers do not lend themselves to small-scale projects because per-unit costs decrease as project size increases, largely because of the economies of scale obtained in the steam turbine power system.

"... a 10-megawatt pilot plant (Solar One) ... operated successfully for over six years."

Central receiver technology is in a demonstration mode. In the early 1980s, a 10-megawatt pilot plant (Solar One) was built using water as a transfer fluid. This plant, sponsored jointly by Southern California Edison, the Los Angeles Department of Water and Power, and the U.S. DOE, operated successfully for over six years. System energy conversion efficiencies were low (8 percent), but much was learned and important design improvements were identified.

Building on the experience with Solar One, DOE, Southern California Edison, and a number of other utilities launched the Solar Two project in the early 1990s. Solar Two is a reconstruction of the Solar One plant with several changes, including improved heliostats and substitution of molten salt for water as the heat transfer and thermal storage fluid. Solar Two will retain the 10-megawatt steam turbine power plant from Solar One, will have three hours of thermal storage capability and will achieve a capacity factor of about 20 percent.

With Solar Two scheduled to come on line in early 1996, its project costs are being shared between the DOE (50 percent) and a consortium of utilities.[42] The primary goal of Solar Two is to serve as a stepping stone to commercial-scale (100-megawatt) central receiver plants by 2000 and larger plants (200–300 megawatts) within a few years thereafter.[43] According to project sponsors, commercial plants will likely have larger mirror fields than Solar Two and may have up to 13 hours of storage with capacity factors of 60 percent.

Based on design studies, the capital costs for an initial commercial-scale 100-megawatt central receiver with a capacity factor of up to 40 percent have been estimated at about $3,000 per kilowatt. Operation and maintenance costs are estimated to be in the 1.5–2.0 cents per kilowatt-hour

range.[44] Levelized energy costs in 1993 dollars for this unit, planned by Solar Two project participants to be available by the turn of the century, are forecast to be 10–15 cents per kilowatt-hour.[45] As plant size and capacity factors increase over time, levelized costs are estimated to fall to 5–10 cents per kilowatt-hour for a 200-megawatt plant, anticipated to be available by 2005–2010.[46] As plant size increases to 300 megawatts, levelized energy costs could decrease to as low as 4 cents per kilowatt-hour.[47]

In one study, the costs of hybrid and gas/solar technologies are estimated to be much lower in the short run than for nonhybrid central receivers. For example, a 100-megawatt hybrid plant with an 85 percent capacity factor would produce energy at less than 7 cents per kilowatt-hour, a full 9 cents per kilowatt-hour less than a stand-alone central receiver of 100 megawatts (with a capacity factor of 40 percent). Similarly, a 300-megawatt hybrid project with an 85 percent capacity factor would produce energy at 5.9 cents per kilowatt-hour. Of course, these estimates depend on many assumptions—in particular, a relatively low price for natural gas.[48]

Parabolic Dish Systems

Parabolic dish systems reflect sunlight from dish concentrators onto a point-focus receiver that is filled with gases (hydrogen or helium) or liquid sodium. The gas or fluid is heated by the solar radiation to around 700 degrees Celsius and drives a small Stirling engine that generates electricity.

Stirling engines are rated from 5 to 25 kilowatts. As a result, dish technology is small in scale and modular. Dish systems can be used in remote applications, or, like individual wind turbines, they can be set in arrays to form utility-scale solar farms. Dish-Stirling systems have particularly high solar-to-electric efficiencies. Annual projections hover around 25 percent, and an early dish system achieved a 29 percent solar-to-electricity efficiency.[49]

Less than 1 megawatt worth of prototype dish-Stirling systems are in operation in the United States. Although significant research has been done, technical concerns involving heat pipe receiver lifetimes and engine design are still being addressed[50] by Cummins Power Generation, Inc. and Science Applications International Corporation (SAIC) through 50/50 joint development programs with DOE. Also, because it does not have a backup or storage component, dish technology may not always be available at system peaks. But like trough and central receiver technologies, hybrid natural gas/dish systems may prove attractive.

"Dish systems can be used in remote applications, or ... they can be set in arrays to form utility-scale solar farms."

Led by Arizona Public Service Company, a number of utilities in the region have formed the Utility Dish Stirling Group to assist in the commercialization of the dish. One utility, Nevada Power Company (NPC), announced plans in 1994 to install up to 20 megawatts of dish Stirling capacity in the next 10 years. These plans were approved by the Nevada Public Service Commission.

Though few dish systems have been built to date, their economics are promising. In particular, unit costs are predicted to be responsive to the demand for the dishes. At a production rate of only 100 units per year, it has been estimated that the unit cost

will be $5,000 per kilowatt, implying a levelized cost of energy of over 20 cents per kilowatt-hour. However, at a production rate of 1,000 units per year, the cost per kilowatt should slide to about $2,460 and the levelized energy cost to about 10.4 cents per kilowatt-hour. At 5,000 units, the levelized cost of energy should come down to 7.5 cents per kilowatt-hour and at 25,000 units to 5.9 cents per kilowatt-hour.[51]

Solar Thermal Repowering

"Repowering" a coal plant involves switching from coal fuel to a solar or a hybrid solar/gas resource. Repowering appears most promising when a coal-fired power plant is scheduled for retirement. Though much of the literature focuses on central receiver technology for repowering purposes, a recent study suggests that all solar thermal technologies are viable as repowering technology options.[52]

"Pure solar thermal plants ... have virtually no emissions of CO_2, SO_2, NO_x, HAPs, or CO."

Public Service Company of New Mexico (PNM) helped to create interest in repowering in the late 1970s when it undertook a study of the potential for solar thermal repowering in the Desert Southwest.[53] The PNM study analyzed the number of units (and total capacity) suitable for solar hybrid repowering, including only those then-existing plants that: (1) had sufficient available land nearby; (2) were due to be retired by 2000; (3) had capacity greater than 25 megawatts; and (4) had enough available capacity to make repowering economical. Given these criteria, the study found that 108 units in the region with a total capacity of almost 14,000 megawatts were suitable for repowering.

The advantage of solar thermal repowering is that it makes use of and extends the useful life of land, buildings, roads, transmission capacity, and other sunk capital and environmental costs associated with aging power plants. It also has the advantage of maintaining and potentially adding new employment at the plant.

Environmental Impacts. Pure solar thermal plants that have no natural gas capacity have virtually no emissions of carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NO_x), hazardous air pollutants (HAPs), or carbon monoxide (CO). Over a 20-year life, a 100-megawatt central receiver would avoid emitting more than 3 million tons of carbon dioxide and 140 tons of nitrogen oxides when compared with the *cleanest* combined-cycle power plants available today.[54] Solar systems also avoid mining activities or the shipping of fuels.

In general, the environmental impacts of solar thermal plants are attributable to the land and water required. In the late 1980s, installed solar trough units required almost 6 acres per megawatt of capacity. Increased efficiency has brought this figure down to slightly under 5 acres per megawatt. Today approximately 4,000–5,000 acres of solar fields would be required to supply enough steam to produce 800 megawatts of electric power.[55] This amount of land is not markedly different from the amount of land required to mine coal for electric power generation. For example, the 1,600-megawatt San Juan Generating Station in northwest New Mexico requires approximately 9,000 acres for the mining activities, a total that does not include the land occupied by the generating station or related infrastructure at the power plant.[56]

With the exception of the solar dish (which has no cooling water requirement), solar thermal power plants should use roughly the same amount of water per kilowatt-hour generated as either coal or nuclear plants.[57] However, large solar plants are most appropriately located in arid, sunny places where water may be scarce and where

using it for energy production may have adverse environmental impacts. Because concerns over water availability remain an issue, it may prove important for large-scale development of solar thermal technology that cooling water use efficiencies be improved.

Solar thermal systems can also have adverse impacts on local flora, fauna, wildlife habitat and soil. For example, Luz International's SEGS plants in southern California posed numerous problems for the desert tortoise.[58] Whereas some of these impacts can be mitigated by careful siting, some land and water impacts appear unavoidable. Solar trough plants may generate small quantities of hazardous waste as a result of oil spills, although ongoing work suggests that this problem can be addressed at low cost. These wastes, however, are much smaller and more manageable than the wastes generated at coal or, especially, nuclear powered stations.

Although hybrid solar thermal/natural gas plants generate some carbon dioxide and nitrogen oxides, these emissions are significantly less than those associated with plants that rely solely on fossil fuels. Compared with the utility alternatives, solar thermal systems appear to produce substantial environmental benefits.

Photovoltaic Systems

First developed for the space program 30 years ago, photovoltaic (PV) systems convert sunlight directly to electricity through the use of semiconductor materials. PV systems have no moving parts and do not heat water for steam. Their inherent modularity, low maintenance requirements, and size flexibility make them suitable for many applications, including small rooftop panels for residential homes and commercial buildings, remote stand-alone sites where connection to the grid would be expensive, and, as long as their costs are reduced, large arrays for central station utility power production.

PV operation emits no air pollutants, uses no water, and makes no noise. In small arrays, PVs often require no land. In short, PVs are environmentally superior to just about every other utility supply-side resource. PVs are expensive, but they are already cost-effective in niche applications. One of the most exciting stories in the electric industry is how rapidly their costs have come down and continue to come down, making them potentially competitive for distributed grid applications within a few years.

PV Technologies. PV system components include the PV modules, an invertor (or power conditioner), and mounting and interconnection equipment. PV modules generate direct current (DC) power, rather than the alternating current (AC) predominantly in use in the United States. The power conditioner inverts the electricity to AC while maintaining uniform voltage and protecting both the PV system and its loads from damage should components fail. The electricity generated can then be used on site or fed back into a grid system.

The expensive part of this system is the module. The cost is high because solar energy conversion efficiencies have been low and because the materials used to manufacture the cells, which must be of high purity, are expensive. Although systems commercially available today convert only 7–14 percent of the sun's energy to electricity, new developments in the fabrication and efficiency of solar cells are occurring extremely rapidly. For example, researchers at Amonix recently announced that they had set a new record of more than 20 percent for the efficiency of solar energy conversion in a concentrator system.[59] Others are experimenting with various thin-film technologies, including amorphous silicon, cadmium telluride and copper indium diselinide. Because these materials are expensive and need to be applied on glass to a thickness of only a few microns, thin-film technologies are not in wide use.

Even with the recent technological gains, PV, like wind, is an intermittent resource. But

"... PVs are environmentally superior to just about every other utility supply-side resource."

because of the rough coincidence of the solar resource with regional peaks (generally caused by extremely hot weather), PV, like solar thermal power, is more reliable at peak than wind. At remote locations, PV is often supplemented with battery storage systems. Improved battery storage capacity, as described below, would augment the attractiveness of PV.

PV Costs. Although the cost of PV has dropped about 100 times since the start of accelerated research in 1973, PV remains expensive relative to many other electric technologies, including wind, geothermal, coal, natural gas, and energy efficiency. At present, *module* prices in the United States range from $4,500 to $5,000 per kilowatt.[60] Total system costs, including other hardware and various interconnection, metering, labor and overhead costs, range upward from about $6,000 to as high as $20,000 per kilowatt.[61] Levelized energy from PVs ranges from 20 cents per kilowatt-hour to as high as 60 cents per kilowatt-hour, with the higher cost including a battery for stand-alone service.[62] Even at these relatively high costs, PV is already cost-effective in niche applications—for example, where distributed PVs help a utility avoid the expense of a line extension to a distant customer.[63]

"... there is every reason to believe that PV costs will continue to decline rapidly."

Additional significant cost reductions are likely. Several manufacturers have recently made public statements about module prices falling to $2,000 per kilowatt or less in the near future. For example, the Amonix technology described above may produce modules that cost less than $2,000 per kilowatt and produce energy at 5.5 to 6 cents per kilowatt-hour.[64] ENRON has stated that it may be able to deliver energy at a levelized cost of 5–6 cents per kilowatt-hour (escalated at 3 percent per annum) from a 10-megawatt facility by the end of the century.[65] The Electric Power Research Institute has forecasted similar PV costs shortly after the turn of the century.[66]

From all we can gather, there is every reason to believe that PV costs will continue to decline rapidly, as long as there is support for continuing research and development and if production volumes allow economies of scale to be achieved. We note that at the recent costs estimated by EPRI and others, PV would be competitive with fossil fuel in many more niche applications and even in some grid-connected ones, especially when the risk of fossil fuel price increases is fully taken into account.[67]

Environmental Impacts of PV Systems. Because virtually no pollutants are emitted during the productive life of PV cells (15–30 years), almost all of the environmental risks associated with PV systems stem from the production of the system modules. The remaining portion of environmental risk is related to the disposal of PV equipment after its useful life has expired. Because both these risks are small, we view PV as a particularly attractive resource from an environmental quality perspective.[68]

Solar Building Technologies[69]

Solar energy is capable of providing heating, cooling, and daylighting on the customer side of the meter in addition to electricity generated through PV systems. Much like energy efficiency measures in DSM programs, solar building technologies can be used to predictably reduce utility loads.

In passive design, a building is constructed to maximize solar heat gain in the winter and minimize it in the summer. The major advantage of this design is that it does not use control pumps, sensors, or other mechanical parts, so little or no maintenance is required over the lifetime of the system. Passive solar design is characteristically area-specific, varying with local climate and building type. In the residential sector, system components to hold heat gain include south-facing windows and moveable insulation, walls or floors that use masonry or water to store heat and a sunspace or greenhouse.

Components to reduce heat gain include overhangs or shades, vents, trees, and other landscaping. When energy efficiency features are integrated into the design, passive solar is at its most effective. Average payback for solar technologies in residential buildings ranges from 4.3 years for direct-gain passive design to 6.5–9.2 years for solar water heating (assuming an average residential electric rate of 7 cents per kilowatt-hour).

In the commercial sector, solar features include design of windows for daylighting, high-performance window glazing to reflect solar gain, proper building orientation and shading to either capture or reject heat, natural ventilation, evaporative cooling, and cool storage. When coupled with energy-efficient lighting, heating, ventilating, and air conditioning, these features reduce loads.

In both passive and active systems, solar energy is also used to heat water. In all solar water-heating systems, a transfer fluid is heated by solar energy from collector panels found on adjacent land or mounted on the building. The fluid is circulated to a water tank, where water is heated for use. Solar water-heating systems are usually designed to meet total hot water needs during summer months in most areas in our region. Often, a backup gas or electric water heater is needed to meet winter demand.

Our region has occasionally experimented with solar building technologies. Federal tax credits, available for solar water-heating systems until 1985, encouraged consumers to install such systems. Although a number of passive solar building design features are commonplace, especially in Arizona and New Mexico, no regional utility has shown a sustained interest by developing a program to help building owners pay for these measures. In contrast, utilities in other regions, such as the Sacramento Municipal Utility District, now offer loans and rebates for solar water heating as part of their energy efficiency program.

Employment and Economic Development Impacts

Solar energy can offer unique opportunities to the region for job creation and tax benefits, especially after the industry has had a chance to develop and mature. Like other renewable energy technologies, solar energy is manufacturing-intensive rather than construction-intensive, which leads to larger and more permanent job creation and tax revenues than most fossil fuel energy systems. Table D-3 shows that the relative labor intensity of solar energy (and other renewables) is roughly twice that of coal and nuclear power.

The potential for employment creation and economic development related to solar energy is limited only by overall demand for solar technologies both domestically and worldwide. According to a report by the Nevada Solar Enterprise Zone (SEZ) Task Force, "It appears that there are at least 15,000 megawatts in capacity additions in western states for which cost-effective solar technologies could compete in the ten years after the Solar Enterprise Zone planning period."[70] As for worldwide markets, there may be "approximately 250,000 megawatts of capacity additions over the period 2000–2010" in Mexico, China, India, North Africa, and certain Latin American countries. If domestic producers captured just 2 percent of these capacity additions, or 5,000 megawatts, this would "support a robust solar technology industry over the period."[71]

Given the magnitude of new capacity requirements both here and abroad, the employment benefits from solar energy could be immense. In addition to construction and operation of the power plants, there will be a need for heliostat production facilities, dish engine factories, PV concentrator factories, and a wide range of other manufacturing facilities. The SEZ Task Force estimates that job creation in the state of Nevada could be as much as 5,500 full-time jobs in 1997, leveling off at 5,000 jobs for the five follow-

"... solar building technologies can be used to predictably reduce utility loads."

Table D-3. Direct Employment in Electricity Generation

Technology	Full-time Jobs (Direct Only) *per 1000 gigawatt-hours/year*
Nuclear	100
Coal (includes mining)	116
Solar thermal	248

Source: Beyond the Petroleum Age: Designing a Solar Economy, Worldwatch Paper 100, Christopher Flavin, December 1990, p. 43.

ing years.[72] These jobs will be badly needed in southern Nevada as the number of Nuclear Test Site personnel is downsized. However, there is no reason why other states in the region could not create some portion (or all) of these jobs by creating the right development incentives.

"The potential for employment creation and economic development related to solar energy is limited only by overall demand ..."

Geothermal

Geothermal energy relies on the natural heat of the earth. The heat is brought near the surface by deep circulation of groundwater and by geologic intrusion of molten magma originating at great depth. Subsurface heat energy, contained in both rocks and fluids, can be converted to electricity.

The technology to use geothermal energy to generate electricity is well developed. There are currently 2,400 megawatts of geothermal electric capacity installed in the United States, mostly in California. Geothermal capacity is also on line in both Nevada and Utah, with additional untapped resources existing in both these states, especially Nevada. Pockets of geothermal capacity could be developed in all six states in the region. Although the capital costs of generating electricity from geothermal resources are much higher than those for a natural gas combined-cycle unit and somewhat higher than for coal baseload plants, geothermal plants have zero fuel costs and reasonable O&M costs. Given their high possible capacity factors (80 to 90 percent), these plants are cost-competitive with new coal units. When sited away from areas of superior recreational and aesthetic value, geothermal power is environmentally superior to fossil fuel plants, especially coal.

As a result of these considerations, we include 1,875 megawatts of geothermal power in the blueprint over the next 20 years. Most of this capacity would be located in Nevada and Utah.

Geothermal Resources

There are four different kinds of geothermal resources:

- hydrothermal systems that use naturally occurring hot water and steam
- geopressured systems that rely on highly pressured rock brines containing natural gas
- hot dry rock systems that depend on deep heat sources within 9 kilometers of the earth's surface
- magma

Although the heat energy from geothermal sources is virtually inexhaustible, most of it is currently economically inaccessible. Today hydrothermal systems are the only type in commercial production. Most estimates of the long term potential for geothermal power reflect the existence of large, untapped resources deep in the earth in non-liquid states.[73] Though the largest domestic reservoirs of geothermal resources are in California and Nevada, others are located in Oregon, Idaho, Wyoming, Utah, Colorado, northern New Mexico, and Arizona.

One of the most comprehensive discussions of geothermal potential on a site-by-site basis estimates that—given a favorable regulatory climate and a moderate level of

drilling and exploration success—4,800 megawatts of new capacity can be installed in the western United States over the next decade or two.[74] This total can be achieved from the following sites:[75]

- Imperial Valley (southern California), 750 megawatts
- the Geysers district (northern California), 500 megawatts
- the Cascades (Oregon), 750 megawatts
- the Basin and Range district (Nevada and Utah), 2,000 megawatts
- the Rio Grande Rift (New Mexico), 500 megawatts
- the Snake River Plain (Idaho), 100 megawatts
- the Northern Rocky Mountains (Wyoming and Colorado), 100 megawatts
- miscellaneous other areas, 100 megawatts

In a separate study for the state of Colorado, the Colorado Geological Survey identified 56 systems of hydrothermal energy in the state, with an estimated capacity of 500 to 1,000 megawatts.[76]

We conclude from these estimates that there is a significant geothermal resource in our six-state region that is available to meet baseload capacity needs over the next 20 years and beyond. We note, however, that most of the easily located geothermal systems, those with hot springs, fumaroles, and geysers at the surface, have already been located and developed. In order to identify additional geothermal systems that do not reach the surface, new approaches to exploration are needed. Increased exploration is one of the keys to developing the higher estimates of the geothermal resource over the next decade.

A problem faced by geothermal developers, as well as wind developers, is moving the power from the resource to a market. For example, Nevada Power Company (NPC) may be the first regional utility to need new baseload capacity, perhaps before 2005. Abundant geothermal capacity exists in northern Nevada, which can be a cost-effective, reliable baseload resource. However, the transmission capacity from the north to NPC is not in place to enable the delivery. To transport geothermal energy to NPC, a partnership among the developers, NPC, and other utilities such as the Western Area Power Administration (Western) may be necessary.

Geothermal Technologies

Hydrothermal systems are presently the only geothermal technology in commercial use. Although the energy content of nonhydrothermal resources is enormous, the technology to tap these resources is not yet advanced enough for commercial development.

The basic elements of a hydrothermal energy conversion system are (1) the production well, through which the geothermal resource is brought to the surface; (2) the conversion system, which turns the geothermal heat into useful energy; and (3) the injection well, through which the spent geothermal fluids are recycled back into the reservoir. Four basic conversion technologies exist to generate electricity, each suited to different temperature and pressure regimes. These technologies are (1) dry steam; (2) flash steam (single or double); (3) binary; and (4) hybrid.

The average construction time for geothermal well fields is 22 to 28 months, including drilling and installation of production wells, injection wells, and piping. Construction times for geothermal power plants can be as little as 6 to 12 months for 0.5- to 10-megawatt plants and two to three years for clusters of plants totaling 250 megawatts or more. The average time required for geothermal plant facilities, from siting to actual generation, is typically two to four years.

Because geothermal plants have the highest average annual capacity factor (90 percent or more) of any electric generating

unit, integration of output from geothermal facilities into utility operations generally has not been a challenge. With their high availability and capacity factors, geothermal electric plants furnish reliable, baseload power for Pacific Gas and Electric, PacifiCorp, and Sierra Pacific Power through purchases from IPPs. Long-term reliability is less certain. Any reservoir has a finite size and production rate, and excessive production, as in recent years at The Geysers in California, can extract heat or water faster than it is replenished.

Geothermal Economics

Cost estimates for construction and O&M of geothermal systems are dependent on site quality, technology choice, size of facility, assumed capacity factor, discount rate, and O&M expenses. Construction costs are estimated to be as low as $1,800 per kilowatt (1988 dollars) by the DOE (*Interlaboratory White Paper*) or as high as $3,000 per kilowatt (1990 dollars) by the Northwest Power Planning Council (*1991 Electric Power Plan*). Fixed O&M costs range from 100 to about 130 dollars per kilowatt, and variable O&M costs have been 1.0 cent per kilowatt-hour or less.

The Northwest Power Planning Council estimated the costs and performance characteristics of a 25-megawatt binary plant and 50-megawatt flashed steam plant in its 1991 electric power plan. Both plants are assumed to have 90 percent availability. The planning council estimates that the 25-megawatt binary plant will have a construction cost of over $2,900 per kilowatt (1990 dollars) and an operating life of 30 years. The fixed O&M cost (which includes both the costs of equipment replacement during the operation of the plant and decommissioning costs) is estimated to be around $130 per kilowatt. The variable O&M cost is 0.8 cents per kilowatt-hour and the energy from a 25-megawatt binary plant is estimated to be 5.3 cents per kilowatt-hour (1990 dollars).

The costs of the 50-megawatt flashed steam plant are lower: The construction cost is estimated to be under $2,500 per kilowatt, the fixed O&M cost is roughly $100 per kilowatt, and the variable O&M cost is around 0.5 cents per kilowatt-hour. The energy from the plant costs 4.8 cents per kilowatt-hour (real 1990 dollars). Given typical energy costs around 5 cents per kilowatt-hour, geothermal power offers a

Hot Dry Rocks

One of the most promising technologies for very large energy development involves hot dry rock (HDR) systems. These are high-temperature rock formations that not only lack fluid capable of carrying heat to the surface, but also lack extensive fractures and therefore do not have the necessary surface area for heat exchange with artificially injected water. To exploit HDR systems, an artificial reservoir, which is connected to two or more production/reinjection wells, must be constructed. Heat contained in the rocks is extracted by circulating water through the reservoir.

At this time, HDR technology is still in the experimental stage. The main technological problems, which have been only partly solved, are linked to the creation of the reservoir, its durability, and the recovery of the circulating fluid. Economic studies show that costs are strongly influenced by the zone's geothermal gradient and hence by the depth of the wells that must be drilled. Current assessments show that HDR systems can be economically competitive when the geothermal gradient is sufficiently high to permit fluid recovery at temperatures above 200 degrees Celsius and at depths no greater than 5 kilometers.[77] In the United States, a long-term flow test is under way at Fenton Hill, New Mexico. The project aims to evaluate reservoir potential at the site and to gauge the viability of commercialization.

cost-competitive and highly available resource for baseload electricity production.

Recent conversations with project developers suggest that the costs of geothermal energy may be even lower, around $1,500 per kilowatt, if it becomes possible to build larger projects in the 100- to 250-megawatt range. Toward this end, the industry is now seeking to develop regional projects in which individual utilities would have a small share of a larger project. Several such projects are currently being examined and marketed in California and Nevada.

Employment and Economic Development Impacts

Geothermal energy development holds promising job creation and tax benefits for states with significant geothermal resources. According to a 1994 study, which assumes that a total of 7,000 megawatts of geothermal power will be in operation by 2010, of which 4,900 will be added between 1994 and 2010, the economic activity due to direct investment will amount to about $14 billion.[78] When the impacts of secondary and tertiary effects are included, the benefit to the domestic economy increases to $34 billion. This value, which refers only to capital costs, amounts to 680,000 person-years over that time span.

O&M of geothermal plants also creates employment. At a projected level of 7,000 megawatts of geothermal power in 2010, it is anticipated that about $525 million will be spent directly on the operation of geothermal plants, with a direct employment impact of 10,500 jobs. Add to that about 15,000 jobs that will be generated within the economy due to purchases of equipment, supplies, and services for the maintenance of the projects, and the total is roughly 25,500 jobs. Assuming a 30-year project life, the 7,000 megawatts will generate a total of 765,000 person-years of labor over that time.

Environmental Impacts

Because the production of electricity from geothermal resources brings fluids and gases to the surface, geothermal energy production is not emission-free. Nonetheless, relative to coal and natural gas, geothermal is relatively clean.

For example, geothermal plants have no NO_x, and CO_2 emissions range from zero to only a fraction of those from fossil fuel power plants. The newest geothermal steam-flash plants emit less than 100 pounds of CO_2 per megawatt-hour of electricity produced. Binary geothermal plants have no CO_2 emissions. Hydrogen sulfide, found in geothermal steam at several fields, significantly varies in amount depending on location, and several technologies exist to control it. Although radon and mercury vapors may be present in geothermal steam, they are usually in such small concentrations that they do not pose health or environmental hazards.[79]

Although geothermal fluids can contain arsenic and mercury and often contain high concentrations of dissolved salts, groundwater may be protected from contamination by these fluids through casing and cementing, which prevent the comingling of fluids from different aquifers. Spent geothermal fluids are usually injected back into the geothermal reservoir to maintain reservoir pressures and fluid levels. Other less environmentally desirable disposal techniques have included evaporation ponds in areas with high evaporation rates.

Despite the air quality advantages of geothermal energy as a baseload resource, geothermal energy has occasionally been the focus of heated environmental disputes. Usually the problem has been that the resource has been found in proximity to land with high recreational, religious, or wildlife value, for example, at Crater Lake in Oregon or on the borders of Yellowstone Park in Wyoming. When geothermal development encroaches on these values, they should take precedence over such development's air quality and other benefits. Geothermal development should not occur in such places.

"... geothermal plants have no NO_x, and CO_2 emissions range from zero to only a fraction of those from fossil fuel power plants."

Biomass

Biomass energy resources include forestry and agricultural crops, crop processing wastes and residues, food processing wastes, animal manures, and landfill methane.[80] Although municipal solid waste (MSW) is also a form of biomass, we treat it separately because of its special problems.

With the exception of hydro, biomass is the renewable energy resource that has been used on the largest scale in the United States to generate electricity. By mid-1990, almost 8,000 megawatts of biomass electric capacity had been installed nationwide.

Biomass has certain environmental advantages over fossil fuels, including fewer emissions of air pollutants and the potential for a closed carbon cycle (no net change in carbon emissions over the long term). Biomass plant capital costs are roughly the same as for coal power plants. However, unlike other renewable resources, biomass fuel is usually not free and can vary substantially in price and availability.

"... our region is less endowed with biomass resources than other parts of the country ..."

Because our region is less endowed with biomass resources than other parts of the country—in particular, California, the Pacific Northwest, and the Southeast—biomass is rarely used as an electric generating fuel. As a result, we do not include biomass in the blueprint because it has significantly less potential in the region than wind, geothermal, or solar energy systems.

The Biomass Resource

Because much of the West is arid, it does not have the biomass material of the other regions. Of the available biomass resource in the region, wood and agricultural wastes exist in the largest quantities.[81] In 1991, the Electric Power Research Institute published estimates of the energy value of wood in eight western states.[82] Based on these estimates, the energy value of wood in our six states is 3.5 quadrillion Btu, or the equivalent of roughly 12,000 annual gigawatt-hours (or 12 million megawatt-hours). For comparison, the total demand for electricity in our six states in 1993 was 150,000 gigawatt-hours. Another study estimated the quantity of agricultural waste available for biomass energy production in the western states.[83] This study estimated that of the over 17 million tons of such waste generated annually, over 5 million tons were able to be collected and dried for use in a biomass energy system. The thermal value of this resource was calculated to be about 72 billion Btu, or roughly 6,000 gigawatt-hours.

Animal wastes are also a potential, albeit small, source of fuel in the West. Over 430,000 tons of cattle waste is generated every year, which has a thermal value of almost 2,800 billion Btu. Somewhere between 25,000 and 30,000 megawatt-hours could be generated with this amount of manure.

Cultivation of what are known as short-rotation woody crops (SRWCs), for harvest as a biomass energy fuel, is being researched in other regions of the United States and in developing countries. In our region, the semi-arid climate is less than ideal for this purpose. Regional growth of SWRC might require irrigation, placing a burden on already over-allocated water resources.

Like other renewable resources, biomass resources may be located long distances from urban load centers. For example, logging and agricultural residues are often produced at remote locations, and, in many cases, systems for collecting and transporting these materials to electric power plants do not exist. These bulky materials, especially agricultural residues, have low energy densities that increase the total amount of material to be handled. In general, it is typically not economical to transport biomass residue fuels more than 50 miles. These factors suggest that biomass in our region may best serve as a fuel for distributed generation facilities.

The Economics of Biomass

Conventional biomass power plants are similar to coal-fired power plants. As a result,

capital and O&M costs are similar. Construction costs of biomass power plants are estimated to be between $1,500 and $1,700 per kilowatt (in 1990 dollars).[84] Fixed O&M costs range from $40 to $50 per kilowatt per year, and variable O&M costs are roughly 0.4–0.5 cents per kilowatt-hour. Fuel costs ranging from 1.2 to 2.4 cents per kilowatt-hour are the largest variable in biomass electric systems. Though a stand-alone biomass residue plant could conceivably run at an 80–90 percent capacity factor, sufficient fuel might not be available in this region. The national average cost of electricity from a wood-fired plant is estimated to be between 6 and 7 cents per kilowatt-hour. In the Northwest, the average cost of electricity from biomass-fired plants is around 7.5 cents per kilowatt-hour.

Biomass can also be gasified for electricity generation in gas turbines or can be gasified to produce hydrogen.[85] Some believe that electricity generated with biomass-integrated gasifier/gas turbine power systems would be competitive with electricity produced from coal and nuclear energy under a wide range of circumstances and that these systems also offer major environmental benefits.[86]

The economics of all biomass uses in our region is affected by the intermittency of fuel supply; that is, the fuel supply may vary significantly, both seasonally and from year to year. The production of agricultural residues varies with the seasonal harvest cycle, and the rate of biomass resource production varies with the types of crops chosen, weather patterns, and the amount of rainfall. Logging sites often move from year to year, and variations in the market for wood bring about changes in the availability and price of logging residue.

Because of these problems, biomass resources are often not considered a firm fuel source for utilities. Like wind and solar energy, biomass needs to be firmed through mechanisms such as improved storage or use of backup fuels. Significant advancement of the use of biomass resources in the electric sector will likely require the development of collection and transportation systems to create a reliable market for logging and agricultural residues and a steady fuel source for electric utilities.

We question whether the market will develop such institutions in this region. If not, biomass development will be limited to small, distributed generation installations where animal or crop residues can be readily collected. Or, because biomass can be burned in plants designed to burn coal, biomass can supplement coal where biomass is cheaper than coal or where pollution abatement is necessary.

Environmental Impacts

Wood burning emits very little SO_2 and 45 percent less NO_x than coal-fired facilities. Wood and other biomass fuels, with the exception of MSW, do not contain heavy metals or generate hazardous waste. The main atmospheric concern with biomass fuels is the emission of particulate matter, but this can be controlled by current technology.

Wood can fix and recycle CO_2, with no net increase in CO_2 emissions when combusted. Short-rotation wood crops can recycle carbon faster than conventional forests, in some cases requiring as little as one-third the time, and burning forest residuals can avoid the methane (a greenhouse gas) that is produced during the decomposition of forest residue. If care is taken, smoke and particulates can be cleaned by means of baghouses and precipitators, and water runoff can be controlled.

Removing biomass residues from forests and agricultural lands can have negative impacts on the soil and productivity of the land if care is not taken to collect such materials at sustainable rates. Soil impact can be measured accurately, however, and

"... it is typically not economical to transport biomass residue fuels more than 50 miles."

potential problems associated with depletion of organic matter can be avoided.

Municipal Solid Waste

Approximately 180 million tons of MSW are collected annually in the United States. According to a recent report by the Battelle Institute, the energy resource contained in this annual amount is equal to about 60 million tons of coal.[87] The practice of burning refuse for electricity by electric utilities is at least two decades old in this country. Since 1975, 16 utilities have experimented with combusting refuse in utility boilers, and 8 continue to do so on a long-term basis. In the United States, the total generating capacity of refuse-burning plants (with capacities of 10 megawatts or more) is about 1,900 megawatts. Most of this capacity has been developed by qualifying facilities under PURPA. Another 1,000 megawatts or more of capacity is in the advanced planning stage.

Waste-to-energy facilities require special emissions control equipment to limit the discharge of trace metals (e.g., lead, cadmium, and mercury) and trace organics (e.g., dioxin). Although technologies for controlling emissions have matured over the last decade, the problems of plant residues and hazardous wastes still exist. A number of other technical problems also remain to be resolved, the greatest of which are corrosion of the boiler and stacks, ash contamination, storage of refuse-derived fuel, after-combustion wastes, and control of the air-fuel ratio to ensure efficient combustion.

With construction costs around $5,000 per kilowatt, MSW facilities are expensive to build. However, MSW fuel is obtained at negative costs, because urban trash typically has negative value, especially where landfill capacity is scarce. Because of uncertainty over future tipping fees charged by operators to dispose of the waste, the cost of MSW generation is difficult to forecast. Dwindling landfill space could substantially reduce the total costs of MSW projects in the future.

"MSW's environmental advantages over coal ... are usually lost in the conflict these facilities seem to breed."

Outside of California and Oregon, there are only two waste-to-energy facilities in the West (in Utah and Nevada). Relative to the rest of the country, few new waste-to-energy projects are being planned in this region. The cost of electricity from the California waste-to-energy facilities ranges from roughly 6 to 9 cents per kilowatt-hour. The facility in Reno, Nevada, generates electricity at 5.5 cents per kilowatt-hour.

MSW's environmental advantages over coal, largely in the form of reduced emissions of SO_2 and NO_x, are usually lost in the conflict these facilities seem to breed. The source of the conflict is twofold. First, to compete economically, MSW facilities usually have to be built near the fuel source, which means near or even within an urban area. Few city residents are willing to have a power plant of any kind constructed near them. Second, the MSW industry has not answered nagging concerns about toxic emissions from MSW stacks. These two factors have made siting of MSW facilities difficult and sometimes impossible.

In our view, MSW has little future in our region unless landfill costs increase enough to justify siting of MSW facilities away from densely inhabited areas. Even then, the industry will have to show that it can generate electricity from MSW without risk to human health and safety.

Storage of Electricity

A remarkable aspect of the electrical system is that nearly all electricity is consumed in millions of end-use applications virtually the instant that it is generated at relatively few power plants, often located hundreds of miles away. As demand for electricity fluctuates, the output of power plants is simultaneously adjusted so that the supply of electricity almost exactly matches the demand. To meet demand instantaneously and economically, utilities have devised a complicated system of dispatch for different kinds of power plants.

This system is necessary because electricity is very difficult to store. Electricity, like fire, is energy, not a substance such as coal or oil. It cannot be put in a tank until needed like gasoline, nor can it be stockpiled like coal. Although technologies exist that temporarily store electricity in an alternative form and then reconvert it to electricity when needed, these storage systems are generally sized to provide between 5 and 15 hours of electricity and they are rarely used today. Commercialization of systems to store electricity from power plants on a large scale has long been constrained by technical problems and high cost. According to EPRI, energy storage systems add between $425 and $1,500 per kilowatt of capacity to the price of a power plant,[88] although costs are dropping as technology improves, especially for compressed air storage. Electrical storage systems account for only about 3 percent of the electrical generating capacity in the United States today. Nearly all of this storage results from one technology—pumped hydroelectric storage—although other systems, including compressed air, batteries, and several more advanced technologies, are under development. The major electrical storage options available or under development today are discussed briefly below.[89]

One reason for the current interest in these systems is that the lack of storage capability, long a nuisance for an electrical system based on conventional generation technologies, is a much more serious drawback for intermittent solar and wind power generation. Without some way to store the electricity produced when the sun is shining or the wind is blowing, these energy sources are not as reliable as fossil fuel plants. Storage can turn intermittent resources into reliable ones at system peak.

Pumped Hydro Storage

Pumped hydro storage systems include an upper and lower reservoir connected by a pipe. The upper reservoir may be a conventional impoundment or, as has been proposed for some projects in this region, a natural or excavated cavern. When electricity demand is low, excess generating capacity is used to pump water to the upper reservoir. Conversely, when electricity demand is high, water is released from that reservoir to flow through a turbine to generate electricity.

There are both environmental and economic problems associated with many pumped storage units. The environmental problems are twofold. First, during off-peak hours water must be pumped uphill. In this region, the power for the pumps typically comes from under-utilized coal plants. As a result, the construction of new pumped storage projects will increase coal-fired generation in the short term and may accelerate the need for new baseload power plants in the medium term. The adverse environmental impacts of coal use are discussed in Chapter 1. The second problem occurs because the siting of two reservoirs, along with associated power lines and infrastructure, often has adverse environmental impacts.

Pumped storage capital costs are high, and because of friction and other factors there is about a 30 percent energy loss attributable to pumping the water uphill. Because of the high operating costs, neither PSCO nor Western uses its pumped storage units except on extraordinary occasions. Together, these factors make pumped storage expensive. For example, the City of Colorado Springs recently investigated the cost-effectiveness of a proposed 90-megawatt pumped hydro unit. Economic analysis of the project and its alternatives found that energy efficiency programs could achieve the same results as the pumped hydro project and save local customers tens of millions of dollars.

Notwithstanding these problems, we do see a role for pumped storage when paired with intermittent renewable resources, in

"Storage can turn intermittent resources into reliable ones at system peak."

particular wind. If wind energy can be used to pump water uphill for later usage, some of the environmental objections to pumped storage disappear. However, it is important to avoid locating the projects in pristine or protected areas and to minimize local impacts.

Compressed Air Energy Storage

Compressed air held in large underground caverns that can be quickly converted back to electricity can be used to store energy generated at a power plant. This is one of the most promising storage technologies that may be used to firm up intermittent renewable energy resources in the electric system of the future.

"Economic analysis ... found that energy efficiency programs could achieve the same results as the pumped hydro project and save local customers tens of millions of dollars."

In compressed air storage systems, electrically driven compressors are used to pump air into caverns created in naturally occurring salt or rock formations, in depleted natural gas or oil reservoirs, or in artificial excavations formed by underground explosions. When the cycle is reversed, the compressed air is allowed to pass through a turbine. The force of the air rushing from high to low pressure, like the air escaping from a balloon, turns the blades of a turbine and generates electricity. If small quantities of fuel, such as natural gas, are mixed with the air and burned before reaching the turbine, the output of the system can be increased. Because heating the air increases its pressure, the electrical output of the turbine is enhanced.

The first domestic commercial compressed air storage system opened in 1991 in Alabama. Built by the Alabama Electric Cooperative, the $65 million, 110-megawatt facility uses a salt dome to hold compressed air until it is needed to generate electricity. The cavern, which begins about 1,500 feet below the surface, is almost as large as the 100-story Empire State Building. It holds 19 million cubic feet of air compressed to between 650 and 1,050 pounds per square inch. When this air passes through the turbine it creates a force about equal to the thrust of a jet engine on a Boeing 747. This facility can generate electricity for 26 hours before the drop in air pressure forces a recharging cycle. The plant can be started up in less than 12 minutes and is used about 1,700 hours per year, or a portion of five days each week in the summer and three days per week in the winter.

Batteries

Batteries store electricity as electrochemical potential between molecules held within the battery. As these chemicals in the battery react, the electrochemical potential can be tapped by electrodes as electricity. Once depleted, the original electrochemical potential can be renewed by using electricity to drive the chemical reactions in reverse.

Batteries, of course, are a well-developed technology, especially in the transportation sector. Large-scale electrical storage by batteries is in its infancy, however, because of the high cost of batteries, long recharging times, rapid battery deterioration, and other technical problems. The few battery systems now in use by utilities have only limited electrical storage capabilities, ranging from 200 kilowatts for two hours to 20 megawatts for 30 minutes.

Batteries, however, are critical to the use of electric cars. EPRI has been sponsoring a battery development program since 1974 that seeks to develop a high-efficiency battery with a 30-year life of repeated recharging and discharging, as well as with a cost low enough to justify building systems with large storage capability. In the 1980s, battery research focused mainly on perfecting conventional lead-acid batteries. The world's largest lead-acid storage facility was built in 1988 at Southern California Edison Company's Chino electrical substation near Los Angeles. This 10-megawatt unit holds a four-hour supply of electricity. But technological

and economic problems with lead-acid battery technology have continued to surface. More recently, the focus of utility battery research has shifted to alternatives such as sodium-sulfur and zinc-bromine batteries. But these batteries remain expensive relative to other storage technologies.

Advanced Storage Systems

A number of advanced storage technologies are under development that have not yet reached the stage of technological maturity to warrant use in commercial applications, although they hold promise for the next century. Several of these advanced systems, all of which enjoy the advantage of being virtually pollution-free, are outlined below.

Hydrogen Storage

The hydrogen fuel cycle can form the basis of an energy storage system whereby electricity is temporarily stored as chemical energy in hydrogen molecules. This chemical energy can then be reconverted to electricity by a fuel cell or by burning hydrogen in a conventional boiler or combustion turbine. The hydrogen fuel cycle involves the electrolysis of water to produce hydrogen and oxygen. When these chemicals burn or are combined in a fuel cell, the water is re-created. Although energy is needed to split the water molecule, much of this energy is recovered when the hydrogen recombines with oxygen, replacing the water.

When used as a storage technology, hydrogen is produced by electrolysis of water using excess electricity generated at baseload power plants during periods of low demand. The hydrogen is then stored either in compressed gas canisters or in a liquefied form in specially insulated tanks. When demand for electricity is high, the hydrogen is used as a fuel to generate electricity. Because of their high efficiencies and pollution-free operation, fuel cells offer the most attractive method to generate electricity from hydrogen, although hydrogen can also be burned very cleanly in a conventional boiler or turbine.

Electrolysis processes are currently 70–80 percent energy efficient, and advanced fuel cells should approach efficiencies of 60 percent. Therefore, the overall efficiency of the hydrogen cycle used to store electricity is only 42–45 percent. This is far below the efficiencies of pumped hydroelectric, compressed air, or battery storage systems. Nevertheless, hydrogen storage may become attractive because such systems can be scaled to any size, are not subject to the site constraints presented by pumped hydro or compressed air storage, and operate pollution-free.

Superconducting Magnets

Arranged as part of a donut-shaped electromagnetic coil of superconducting wire, superconducting magnets offer a potential long-term electrical storage option. This system is based on the development of materials, such as niobium-titanium alloys, that can conduct electricity at very low temperatures essentially without any loss in power. If these materials, called superconductors, can be perfected, a superconducting storage system can be based on converting the alternating current electricity generated at a power plant to direct current during periods of low demand. As the DC electricity is fed into a coil of superconducting wire, the passage of the electricity around the coil would generate a magnetic field that would hold most of the electrical energy. When electricity is needed, the process is reversed, and DC electricity is drawn from the coils and converted back to alternating current, causing a gradual decrease in the magnetic field until the system is recharged.

Flywheels

Flywheels store electrical energy in a very high speed spinning wheel. Electricity generated during periods of low demand is used to accelerate a flywheel to incredibly high speeds. The current flywheel record, set in 1985, is 37,000 revolutions per minute. To

"The hydrogen fuel cycle can form the basis of an energy storage system ..."

achieve these speeds, flywheels are suspended in a magnetic field established in a vacuum to prevent frictional losses. When electricity is needed, a generator connected electronically to the flywheel gradually converts the energy of rotation into electricity, causing the flywheel to gradually slow down until it needs to be recharged.

Ultracapacitors

Ultracapacitors store electricity as electrostatic potential on a plate of carbon or metal alloys specially designed to maximize their potential to contain electricity. The plate, or electrode, is separated from another plate by a distance sufficiently wide to prevent an electrical spark from jumping the gap and completing an electrical current. Electricity is stored on the charging plate. When electricity is needed, conductivity between the plates is increased, for example, by moving the plates closer together, permitting the gradual discharge of electricity through a current.

Small capacitors are used in virtually every electronic appliance, accounting for the warnings that a person can experience a shock when tampering with the components of a TV even when it is unplugged. What currently stands in the way of commercialization of this technology is the difficulty in producing materials capable of holding much larger amounts of electricity in ultracapacitors suitable for use by utilities as a storage option.

"Over the long term ... fuel cells hold great promise for use in electrical generation."

Fuel Cells

Among the more exotic emerging technologies that may play a major role in electrical generation in the next century is the fuel cell. In a fuel cell, hydrogen and oxygen react chemically, directly producing electricity in the process. No combustion takes place, and the efficiency of conversion of chemical energy into electrical energy is very high. At first glance, fuel cells appear to be magic. With no moving parts, air pollution, or noise, a fuel cell generates up to twice as much electricity per unit of fuel consumed than conventional combustion-based electrical generation technologies.

First developed to power spacecraft in the 1960s, fuel cell electrical generation technology has remained a pipe dream because of technical problems and high cost. Over the long term, however, fuel cells hold great promise for use in electrical generation. Worldwide, there is now about 50 megawatts of demonstration fuel cell electrical generation capacity either operating or under construction, mostly in the United States and Japan.[90]

The electrolysis of water into its atomic constituents, hydrogen and oxygen, is a simple high school science class experiment. In electrolysis, the electrical energy from the power source does the work of splitting the water molecule. The electrical energy is sufficient to overcome the energy of the chemical bonds holding hydrogen to oxygen in water molecules. It does this without moving parts and with the generation of only a small amount of heat.

In essence, a fuel cell is an electrolysis unit that operates in reverse. Instead of electrical energy forcing hydrogen and oxygen apart in a water molecule as in electrolysis, hydrogen and oxygen merge in a fuel cell, forming water and producing energy as electricity.

Individual fuel cell units consist of two electrodes and an electrolyte. Each unit is capable of generating slightly less than one watt of electrical power. To provide significant quantities of electricity, hundreds or thousands of fuel cell units must be connected in a series of generating units called "stacks."

Capturing the reaction energy between hydrogen and oxygen directly as electrical energy in a fuel cell offers tremendous advantages. First, fuel cells use energy extremely efficiently. They should eventually

achieve efficiency levels greater than 60 percent, nearly double those of conventional coal generation and greater even than advanced combined-cycle natural gas plants. The theoretical, or scientifically possible, maximum efficiency of a fuel cell is 85 percent.[91] The only chemical by-product of a fuel cell is water. Because no combustion occurs in a fuel cell, there are no high temperatures generated, no formation of NO_x emissions, and little production of waste heat. From the standpoint of air pollution, fuel cells using hydrogen truly produce zero emissions.

Producing Hydrogen

Although a fuel cell is a pollution-free, highly efficient method of generating electricity, obtaining the hydrogen to power the fuel cell poses problems. Today, the most common way of producing hydrogen for fuel cells is through the steam reforming of natural gas. In steam reforming, natural gas is broken down in a two-step process under high temperatures and pressure to yield primarily hydrogen and carbon dioxide. Over 99 percent of the hydrogen produced commercially today is manufactured by steam reforming of natural gas. Steam reforming of methanol, which itself is produced from natural gas, is another way to extract hydrogen from hydrocarbons. Coal gasification processes also produce hydrogen, which can potentially be used as a feedstock for fuel cells.

Unfortunately, producing hydrogen from hydrocarbons such as natural gas or coal is not pollution-free. Significant quantities of carbon dioxide are produced, as are lesser amounts of hydrocarbons and NO_x. And a significant portion of the energy in fossil fuels is lost during conversion to hydrogen. Although technological advancement could improve efficiencies somewhat in the future, conventional steam reforming of natural gas is about 70–80 percent efficient. This compares favorably with the efficiency of coal gasification, which is only about 60–70 percent.

The hope for the future is that pollution-free hydrogen production processes using renewable energy resources may become viable. Electricity produced from any renewable energy resource can be used in electrolysis systems to produce hydrogen and oxygen from water. Recombining these elements in a fuel cell completes the cycle, re-creating water and electricity. The entire system is pollution-free and sustainable from beginning to end.

Other technologies (such as biomass gasification and direct photochemical or photobiological conversion) now under development are capable of producing hydrogen from renewable energy resources without the intermediate steps of generating electricity and operating electrolysis equipment. Direct photochemical conversion systems use the energy in sunlight to promote reactions that generate hydrogen from chemicals dissolved in specially designed solutions. Direct photobiological conversion systems provide sunlight (i.e., food) for bacteria, algae, and other microorganisms to enable them to produce hydrogen as part of natural biological processes.

Biomass gasification, the most technologically mature method of producing hydrogen from renewable resources, may provide the most cost-effective, direct method of producing hydrogen. Various gasification systems, including fixed-, fluidized-, and entrained-bed gasifiers, are capable of converting a variety of biomass materials into hydrogen-rich gases that, when cleaned, yield pure hydrogen. The fuel cycle efficiency of hydrogen production from biomass is about 60 percent.[92]

Status of Fuel Cell Technology

Although quite promising as pollution-free sources of electricity in the next century, fuel

"From the standpoint of air pollution, fuel cells using hydrogen truly produce zero emissions."

cells are not technologically mature and are not yet in widespread commercial use.[93] Difficult technological hurdles must be overcome and the cost of fuel cells must drop significantly before widespread market entry can take place. Maintaining high power output, reliability, and durability are currently among the key technological problems that, to one degree or another, apply to all fuel cell technologies.[94] Better electrodes and catalysts are needed to achieve fuel cell efficiencies consistently above 50 percent. There is a need for materials that are more resistant to sometimes harsh operating conditions to keep performance levels high during thousands of hours of use. Water management is also an issue because water buildup near an electrode reduces performance.

All fuel cell technologies are expensive, although dramatic price reductions are occurring as the technologies improve, especially for proton membrane systems. The cheapest fuel cells still cost above $3,000 per kilowatt. EPRI has a goal of demonstrating fuel cells that cost $1,000 before the end of the decade.

"EPRI has a goal of demonstrating fuel cells that cost $1,000 before the end of the decade."

Even if the $1,000-per-kilowatt target price for fuel cells is met and performance and durability improves, the high cost of hydrogen remains another economic obstacle. The cheapest source of hydrogen is steam reforming of natural gas. The current price of steam reformed hydrogen is between $7 and $10 per million Btu, making such hydrogen power three to five times more expensive than natural gas or coal power. Producing hydrogen from renewable energy resources is more expensive than steam reforming; renewable-derived hydrogen prices range from $18 to over $30 per million Btu depending on the renewable resource and hydrogen conversion technology. When considering these high costs, one must keep in mind that the use of hydrogen in fuel cells is more efficient than the use of fossil fuels in power plants. This greater efficiency of use offsets much of the price premium of hydrogen, especially for hydrogen produced from natural gas.

Commercializing Fuel Cells

Even though presently expensive, fuel cells offer a number of advantages to utilities. Because fuel cells consist of multiple stacks of individual cells, they are easy to build in modular units, and their quick start-up time makes them good candidates for supplying intermediate or peak power.

In highly polluted urban areas, fuel cells may be viable, despite their high cost, because they can produce electricity quietly and pollution-free. They are also ideal for use as part of distributed systems. Fuel cell units built in remote areas or near specific load centers can reduce the need to build new transmission lines and can lower power distribution costs.

Finally, fuel cells can increase the ability of utilities to store energy for peak demand periods. Electricity generated by conventional baseload power plants during off-peak periods, for example, can be used to produce hydrogen by electrolysis of water. This hydrogen can be stored in underground reservoirs or pressured tanks until periods of peak demand, when it can be used in fuel cells to generate electricity. This energy storage scheme possesses about the same overall energy efficiency as pumped hydro storage systems, but it is more widely applicable and will likely have fewer environmental impacts.

Electricity from Fusion

In nuclear fusion, the nuclei of small atoms such as hydrogen are fused together to form new, heavier atoms. In this process an enormous amount of energy is released; nuclear fusion involving hydrogen releases 1 million times more energy than a combustion reaction involving the same amount of fossil fuels. Most of the heat of the sun is generated

by nuclear fusion of hydrogen atoms. On the earth, the sole application of nuclear fusion to date has been to provide the explosive energy of the hydrogen bomb. Since the bomb, scientists have been attempting to develop peaceful applications of fusion reactions such as the use of these reactions as a source of heat for electrical generation. The main problem continues to be that the technology does not exist to produce controlled fusion reactions that generate, even for a second, more energy than it takes to trigger the reaction.

Fusion's Promise

Hydrogen atoms bond to form helium in fusion reactions. Much less radioactivity is released in this process than in fission. It seems possible to build a fusion reactor with up to 3,000 times less radioactivity than a fission reactor producing the same amount of power.[95] As a result, there is nothing comparable in a fusion reactor to the plutonium and other wastes created in conventional fission reactors. Although fusion reactors may have a higher probability of small accidents than conventional reactors, they should have a much lower probability of major accidents.[96] In part, this is attributable to the fact that fusion is not a chain reaction. Because hydrogen is an abundant element, fusion's potential energy is practically inexhaustible. And fusion, like conventional fission, releases no CO_2, NO_x, SO_2, or other emissions that are at the heart of this region's environmental problems.

Fusion's Problems

Even though the federal government has poured over $7 billion into fusion research, figuring out how to release fusion energy in a controlled fashion for use in generating electrical energy has remained elusive. The most promising approach involves heating hydrogen to an astonishing temperature of 180 million degrees centigrade, at which point fusion occurs. The current world record for creation of fusion energy is 1.7 million watts, produced at a European reactor for two seconds in 1991. Although this is a substantial amount of capacity, it was only one-tenth of the energy put into the system to trigger the fusion reaction that produced it.

Once the break-even threshold has been achieved, the next step will be to reach the point of ignition, where enough fusion is taking place to sustain ongoing and controlled fusion reactions without enormous amounts of supplemental energy. At that point, work might begin to find ways to reduce the cost, now thought to be exorbitant, of building a fusion power reactor.

Given these problems, the DOE's "optimistic" projection for fusion does not anticipate even a demonstration-scale fusion power reactor being built before 2025. Commercial fusion is not foreseen before 2040. Fusion power remains far out of reach of current technology. For this reason, fusion, although an exciting possibility, occupies no place in our blueprint.

"... scientists have been attempting to develop ... fusion reactions ... as a source of heat for electrical generation."

Notes

1. Christopher Flavin and Nicholas Lenssen, "Powering the Future: A Blueprint for a Sustainable Electricity Industry," Worldwatch Paper 119, June 1994, Figure 4-1, p. 77.
2. See Hadley and Hirst, "Utility DSM Programs from 1989 through 1998: Continuation or Crossroads," Oak Ridge National Laboratory Report, ORNL/CON-405, February 1995, p. 5.
3. Presentation by H. Geller, American Council for an Energy Efficient Economy, Sustainable Energy Conference, February 1995.
4. See Barakat & Chamberlin, "Efficient Electricity Use: Estimates of Maximum Energy Savings," EPRI CU-6746, March 1990.
5. This approach, focusing on technical feasibility, clearly overstates the amount of savings that are actually achievable. The study, however, made no provision for additional technological improvements occurring after 1987. This second assumption, which understates the savings, should offset the bias created by focusing on technical achievability.

6. See Fickett, Gellings, and Lovins, "Efficient Use of Electricity," *Scientific American,* September 1990, pp. 65–66.

7. See, e.g., Testimony of Claude Robbins before the Colorado PUC, Docket No. 91A-480EG, June 1992 (describing his experience promoting energy efficiency in Colorado).

8. See, e.g., Public Service Company of Colorado, "Final Report of a Collaborative Process to Design Demand-Side Management (DSM) Programs," February 16, 1993 (identifying new construction programs as a particularly attractive opportunity); PacifiCorp, Resource and Market Planning Program, RAMPP-3, April 1994, DSM Appendix (also showing a large economic potential for new construction markets).

9. See, e.g., Stipulation and Settlement Agreement, DSM Incentives for PSCO, Docket No. 93I-199EG, Colorado PUC.

10. See Utah Public Service Commission Report and Order (approving Joint Recommendation), issued February 10, 1994, Docket No. 92-2035-4.

11. See Joint Agreement for Treatment of DSM Expenses, Docket No. 92-2035-04, Utah PSC, filed March 1995.

12. See Order Approving Rate Settlement, Docket No. U-1345-94-120, Arizona Corporation Commission, adopted May 27, 1994.

13. See, e.g., Preliminary Results of Utah Custom FinAnswer Program Evaluation, December 1994, p. 4.4 (showing a benefit/cost (B/C) ratio in excess of 2.5); PSCO Collaborative Process, Final Report, February 1993, p. 5 (showing a total resource cost B/C ratio of 1.6 across all collaborative programs).

14. PacifiCorp, RAMPP-3 Report, filed in April 1994, Utah Public Service Commission, pp. 45–50.

15. See Testimony of Dr. Eric Hirst, Docket No. 91A-480EG, before the Colorado PUC, November 1991, p. 8 (describing the risk diversification benefits of DSM).

16. See, e.g., Joskow and Marron, "What Does a NegaWatt Really Cost?," *Electricity Journal,* July 1993, pp. 14–26.

17. See Testimony of Skip Laitner, Wisconsin Citizens Utility Board, before the Wisconsin Public Service Commission, Docket 05-EP-6, December 1991, pp. 18–19, Exh. SAL-5; Geller et al., "Energy Efficiency and Job Creation," American Council for an Energy Efficient Economy, October 1992, pp. 6–29.

18. See Laitner, "Economic and Environmental Analysis of the Pitkin County Energy Plan," September 1993, pp. 13–16 (prepared for Pitkin County Energy Committee).

19. Informal survey conducted by Bill Schroer, Colorado Business Alliance, August 1994.

20. Within this region, every increase in DSM spending by a large IOU followed a regulatory decision approving a cost recovery and incentive mechanism. See generally Schweitzer and Young, "How PUCs Affect Utility DSM," 8 *Electricity Journal,* October 1995, p. 37 (analyzing factors that lead utilities to invest in DSM).

21. The numbers in parentheses are estimates of the regional averages.

22. A discussion of the region's hydroelectric resource, already well developed to the point of build out, is found in Appendix C.

23. As part of an effort to develop a Colorado-based wind project, the LAW Fund is working with wind developers and the region's utilities to explore economically viable options to firm the region's wind resources. Alternatives being explored include the possibility of firming with natural gas-fired resources; working with power marketers to develop a bundled, firmed wind energy product; and using the Western Area Power Administration's hydro electric resource as a firming option.

24. Wind power density refers to the actual energy available in the wind in watts per square meter. The energy available is a function of wind speed and atmospheric density, primarily dependent on altitude and air temperature.

25. *An Assessment of the Available Windy land Area and Wind Energy Potential in the Contiguous United States*, D. L. Elliott, Pacific Northwest Laboratory, August 1991.

26. The precise cost of energy from wind farms depends on numerous factors, including wind resource availability, correlation with peak and intermediate loads, transmission distances, ownership and financing structures, etc.

27. U.S. Department of Energy, Office of Utility Technologies, "Renewable Energy Technology Characterizations," 1994.

28. Studies in the Netherlands and England have concluded that wind might represent as much as 10–15 percent of installed capacity before capacity value must be estimated more precisely. For more information, see "Wind Energy: Resources, Systems and Regional Strategies," Grubb and Meyer, *Renewable Energy,* ed. Johansonn, p. 179.

29. See Testimony of Susan Hock, Program Manager, Wind Energy Program, National Renewable Energy Laboratory, for the LAW Fund in Docket No. 93I-098E, before the Colorado Public Utilities Commission, p. 9.

30. If the *variance* in wind speeds during peak periods is historically low, or if wind turbine arrays are distributed across several sites, the overall reliability of the wind plant as a generation resource will be increased.

31. Draft *New York State Energy Plan*, Volume III: Supply Assessments, February 1994, p. 582.

32. *Powering the Midwest,* Union of Concerned Scientists, 1993, p. 108.

33. See *Solar Radiation Data Manual,* NREL, April 1994.

34. The limitations of this data base are that the monitoring sites may not represent the best sites or represent a large enough sample from which to precisely characterize the solar resource in a state. For example, only two sites in New Mexico and only four sites in Arizona were monitored.

35. See Direct Testimony of John Thornton, Arizona IRP, Docket No. U-0000-93-052, p. 2.

36. New Mexico's state energy policy of 1991 reports that the solar energy received on an area of only 18 square miles in New Mexico on an average day is equal to the average daily consumption of energy in the entire state. *New Mexico State Energy Policy,* Governor Bruce King, November 1991, p. 190. According to Sandia National Laboratory, the solar radiation falling on a specific area equivalent to only 10 percent of New Mexico's landscape could be used to meet 100 percent of the 1990 electricity needs of the United States.

37. See, e.g., *Solar Strategic Plan,* Nevada Power Company, Schaefer et al., January 1994, pp. 2–5; "Baseload Solar Power," David Mills (University of Sydney) and Bill Keepin, *Energy Policy,* August 1993, p. 841; "New Directions for Parabolic Trough Hybrid Gas/Solar Systems," NREL Solar Thermal Electric Workshop, David Kearney, November 1, 1994.

38. "Solar Electric Five-Year Program Plan, FY 1993 through 1997," U.S. DOE.

39. Communication from Mac Moore, Solar Energy Industries Association, August 7, 1995.

40. "Baseload Solar Power," Mills and Keepin, *Energy Policy,* August 1993, p. 841.

41. Communication from Pat De Laquil, Technology Manager, Commercial Development, Bechtel Corporation, August 17, 1995.

42. Primarily Arizona Public Service, Salt River Project, Los Angeles Department of Water and Power, Idaho Power Company, PacifiCorp, and Sacramento Municipal Utility District. We understand that Nevada Power Company has joined this group. Bechtel Corporation and Rockwell International are the prime contractors for the project.

43. As with trough technology, considerable attention is presently being given to adding central receiver technology to gas-fired combined-cycle systems to lower overall costs and improve reliability. See "Combined-Cycle Power Tower," Mark S. Bohn, Thomas A. Williams, Henry W. Price, NREL, October 1994.

44. *Renewable Energy: Sources for Fuels and Electricity,* Thomas Johansson, ed., Island Press, 1993, p. 280.

45. See "Impacts of Plant Size," handout from Solar Two Commercialization Advisory Board meeting, Irwindale, California, May 6, 1994 (assumptions include a 10.5 percent fixed charge rate and no investment tax credit).

46. "Impacts of Plant Size."

47. "Impacts of Plant Size."

48. "Combined-Cycle Power Tower."

49. "Solar Strategic Plan for Nevada Power Company," John C. Schaefer, David Kearney, Carlo La Porta, January 31, 1994, pp. 2:12-15.

50. "Solar Strategic Plan for Nevada Power Company," pp. 2-15.

51. *Utility-Scale Distributed Solar Thermal Electric Joint Venture Program,* proposal for Sandia National Laboratory by SAIC, Detroit Deisel, and Stirling Thermal Motors, Inc., October 1992.

52. See *Solar Thermal Repowering: A Technical and Economic Pre-feasibility Study,* Charles Bensinger (for The Energy Foundation), Santa Fe, 1993. Another analyst suggests that only central receiver and trough technologies lend themselves to repowering. Communciation received from John Schaefer, August 22, 1995.

53. *Solar Hybrid Repowering Project,* submitted by PNM to DOE (1978).

54. *Advanced and Renewable Technologies: Development Plan*, Sacramento Municipal Utility District, 1993, p. 43.

55. Based on insolation levels near the Four Corners area. See Bensinger, *Solar Thermal Repowering,* 1993, pp. 28-32.

56. *Solar Thermal Repowering,* p. 28.

57. One analyst believes that trough technologies may use more water than fossil fuel plants because trough technologies have lower thermal conversion efficiencies. Communcation from John Schaefer, note 52.

58. Desert tortoise problems, it appears, may be relatively easily mitigated. For example, Boulder City, Nevada, has set aside 6,000 acres for solar development but has also created a tortoise reserve in the Eldorado Valley. Communication from Mac Moore, note 39.

59. "Thirsty New Solar Cells Drink in the Sun's Energy," Matthew Wald, *New York Times,* December 4, 1994, Financial Section, p. 10.

60. Communication with Pat De Laquil, note 41.

61. Based on utility PV costs stated by the Sacramento Municipal Utility District, as reported in *The Solar Letter,* May 26, 1995, which are mostly in the $6,600-$8,800 per peak kilowatt range, and communications with various industry analysts.

62. Based on communcations with various solar energy industry analysts.

63. For a $6,000 PV water-pumping system, K.C. Electric found that the break-even point at which it becomes cheaper to install and maintain a PV unit on the customer site is between 0.5 and 0.6 miles of *reconstructed* line.

64. "Thirsty New Solar Cells Drink in the Sun's Energy."

65. "Thirsty New Solar Cells Drink in the Sun's Energy."

66. *Bringing Solar Electricity to Earth,* EPRI, 1990.

67. The Utility PhotoVoltaic Group (UPVG), an organization of 91 domestic utilities covering more than half the utility markets in the country, estimated a domestic utility market of 9,000 megawatts at a price of $3,000 per peak watt. "Summary Report, Photovoltaics: On the Verge of Commercialization, Report of the UPVG's Phase 1 Efforts," UPVG, June 1994.

68. *Gas Health and Safety Hazards and Controls Associated with the Production of Thin-Film Photovoltaic Cells,* P.H. Moskowitz et al., IEEE, 1985.

69. This section is derived primarily from the Direct Testimony of John Thornton, pp. 3-7.

70. *Nevada Solar Enterprise Zone Development Study,* Nevada Solar Enterprise Zone Task Force Work Group, December 1994, p. 6-6.

71. Nevada Solar Enterprise Zone Development Study.

72. Nevada and national estimates include direct, indirect, and induced employment.

73. For example, the Environmental Protection Agency estimates in a base-case scenario that 3,800 megawatts will be installed by 2000, and that 8,200 megawatts could be installed by 2000 under an enhanced market scenario. By 2010, the EPA enhanced-market scenario estimates nearly 20,000 megawatts of installed geothermal electric capacity. The DOE also estimates 3,800 megawatts of installed capacity by 2000 in a base-case scenario. Under the DOE intensified research and development scenario, 11,300 megawatts of installed capacity is projected by 2010.

74. "Exploration Potential For New Hydrothermal Resources for Electrical Power Generation in the 48 Contiguous United States," Philip Michael Wright, University of Utah Research Institute, printed in *TRANSACTIONS,* Vol. 15, October 1991.

75. "Exploration Potential."

76. *Geothermal Energy Development in Colorado: Processes, Promises and Problems,* Colorado Geological Survey, 1978.

77. *Renewable Energy: Sources and Fuels for Electricity,* Thomas Johansson, ed., Island Press, 1993, p. 571.

78. "The Impact of Geothermal Energy Development on Employment," Tsvi Meidav and Jack Pigott, *TRANSACTIONS,* Vol. 18, October 1994, p. 57.

79. The information for this section is based on "Geothermal: Clean Energy From the Earth," DOE, October 1994, DOE/GO/10094-003; "Profiles in Renewable Energy," DOE, August 1994; and *Cool Energy,* Michael Brower, Union of Concerned Scientists, 1994, pp. 150-154.

80. We do not treat landfill methane retrieval here, because it is usually not considered an electric resource, but rather a supplement to natural gas supplies.

81. Wood includes nonmerchantable wood, which is the portion of commercial forests that is not suitable for lumber or paper production, such as tops, branches, and small trees.

82. *Biomass State-of-the-Art Assessment,* Volume 2: Database on Resources, Electric Power Research Institute, 1991.

83. *Resource Assessment of Waste Feedstocks for Energy Use in the Western Regional Biomass Energy Area,* K. Shaine Tyson, Solar Energy Research Institute, February 1991.

84. Cost estimates for biomass conversion technologies are based on *1991 Northwest Conservation and Electric Power Plan,* Northwest Power Planning Council, and *The Potential of Renewable Energy: An Interlaboratory White Paper,* DOE, 1990.

85. For a brief discussion of the production of hydrogen from biomass, see the section on fuel cells in this appendix.

86. "Biomass-Gasifier Gas Turbine Power Generating Technology," R.H. Williams, E.D. Larson, Center for Energy and Environmental Studies, School of Engineering and Applied Sciences, Princeton University, 1993.

87. *Municipal Waste-to-Energy Technology Assessment,* Battelle Memorial Institute, January 1992.

88. Electric Power Research Institute, *Energy Storage: How the New Options Add Up,* 1989, p. 9.

89. The principal sources used for this section were: EPRI, *Energy Storage: How the New Options Stack Up*; F. Hardy et al., "Options in Energy Storage Technology," *The Electricity Journal,* July/August 1994; EPRI, "Compressed-Air Energy Storage," 1994; and "Alabama Cooperative Generates Power from Air," *The EPRI Journal,* December 1991.

90. *Fuel Cell News,* Winter 1994, p. 7.

91. D. Swan, "Fuel Cell Powered Electric Vehicles," SAE Technical Paper Series #189724, 1989.

92. R. Williams et al., "Methanol and Hydrogen Production from Biomass for Transportation,"

article submitted to *Energy for Sustainable Development* by the Princeton University Center for Energy and Environmental Studies, January 30, 1995.

93. Of the five principal types of fuel cells, only the phosphoric acid fuel cell is currently in commerical production; there are about 55 phosphoric acid fuel cell units operating worldwide today. A phosphoric acid fuel cell-powered bus is also operating in the United States. Other fuel cell technologies include the proton-exchange membrane fuel cell, now a leading contender for use in transportation; the alkaline fuel cell, originally used in the space program, but still very expensive in terrestrial applications; and the molten carbonate and solid oxide fuel cells, which operate at high temperatures and pressures and which are only now leaving the laboratory for demonstration in pilot projects.

94. The precise technological barriers differ among fuel cell technologies. Thus, phosphoric acid fuel cells are durable and reliable but operate at efficiencies below 50 percent. On the other hand, efficiencies above 60 percent have been achieved with molten carbonate cells, but their durability, so far, has been poor.

95. "The Trouble with Fusion," Lawrence M. Lidsky, *Technology Review,* October 1983, p. 42.

96. "The Trouble with Fusion."

Attachment: Methodology and Assumptions

This attachment briefly outlines the methodology and assumptions used by the LAW Fund to analyze the blueprint and the business-as-usual approach. We explain below how the regional generation mix was determined, how emissions in 2015 under the two plans were estimated, and the economic methodology used to compare the costs of the blueprint with the costs of the business-as-usual approach.

Generation Mix

As a starting point for developing the two scenarios, the LAW Fund estimated the capacity additions required over the next 20 years to meet regional loads. These capacity requirements were estimated in five-year increments for the periods ending in 2000, 2005, 2010, and 2015. Appendix B describes the assumptions and methodology used in determining the required capacity additions.

To calculate the generation mix for each scenario, regional generation requirements were projected for each of the period-ending years by growing 1995 retail sales at a 1.7 percent annual growth rate over the 20-year planning horizon.[1] The retail sales forecast was then scaled up by 8 percent to account for losses during transmission and distribution. This figure served as an estimate of the generation required to meet regional demands. The generation forecasts are shown in Table M-1.

The next step was to ensure that the available capacity in place at the end of each five-year period met the forecast generation target. All resources, with the exception of natural gas-fired units built after 1996, were assumed to operate at an appropriate given capacity factor. The generation from these resources was calculated using this capacity factor.

Because of wind's intermittent nature, during electric system peak hours, wind turbines may not be producing electricity at their full nameplate capacity. To account for this fact, the LAW Fund assumed a 40 percent capacity value for wind. This implies that to obtain one effective megawatt of capacity, 2.5 megawatts of actual installed capacity must be added to the regional capacity base. In determining the contribution of the wind acquisitions for meeting regional peak loads, the effective capacity measure was used. However, when calculating the energy generated from the wind resource acquisitions, the appropriate capacity measure is installed capacity, and it was used for this purpose.

Table M-1. Estimated Regional Generation Requirements (gigawatt-hours)

	2000	2005	2010	2015
Estimated generation required to meet regional electricity demands	178,172	193,840	210,886	229,431

The capacity factors for the new natural gas-fired units were treated as endogenous and were allowed to adjust to ensure that the generation requirements at the end of each period were met. As a result, the natural gas capacity factors in the blueprint will differ from those in the business-as-usual approach, depending on the resource mix in place in the scenario at the time.

Overall, the two scenarios are comparable in terms of both capacity and generation. Table M-2 shows the capacity and the generation mix for both the blueprint and the business-as-usual approach at the end of each five-year period.

Emission Methodology

To compare the emissions in the blueprint with those of the business-as-usual strategy, a 1994 baseline level for emissions of sulfur dioxide, oxides of nitrogen, and carbon dioxide was established using data from the Energy Information Administration's *Electric Power Annual 1994.*[2]

Once the baseline was established, the incremental emissions under the blueprint and the business-as-usual approach were estimated using the following procedure: (1) annual generation from the total capacity additions for each resource type was calculated using the appropriate capacity factor for that resource; (2) for each resource, emission factors for each of the three pollutants were obtained on a basis of pounds per million Btu;[3] (3) the emission factors were next converted to a basis of tons per gigawatt-hour using the appropriate heat rate for the resource;[4] (4) the annual generation figures were multiplied by the converted emission factor for each pollutant to calculate the change in emissions from that resource. The assumptions used for the specific resources and the estimated incremental emissions for the blueprint and the business-as-usual approach are shown in Table M-3.

Emissions in 2015 for each scenario were estimated by adding the incremental change to the 1994 baseline. Table M-4 shows the estimated emission levels in 2015 for each scenario, along with the 1994 baseline.

Economic Analysis

To compare the cost of the blueprint with the cost of the business-as-usual strategy, the LAW Fund conducted a present value cost analysis. The analysis takes into account the timing of the resource acquisitions, changing resource costs and performance over time, and changing fuel prices over time.

In performing the economic analysis, both the blueprint and the business-as-usual approach were viewed as 20-year resource plans made up of multiple resource acquisitions. A resource acquisition is defined by a resource type (e.g., wind, solar, natural gas, conventional coal), a resource amount (e.g., 50, 100, 500 megawatts), and an installation date (e.g., 1996, 2004, 2010).

The cost of each resource acquisition was measured on a per-kilowatt basis as the present value of overnight capital costs, fuel costs, and fixed and variable operating and maintenance costs over a 30-year lifetime. Once installed, a unit of capacity was as-

Table M-4. Summary of Emissions Estimates (tons/year)

Pollutant	1994 Baseline	Blueprint in 2015	Business as Usual in 2015
SO_2	455,000	378,478	499,617
NO_x	496,588	452,915	601,959
CO_2	190,208,842	180,771,138	243,800,783

sumed to operate with the cost and performance parameters in place at its installation date for its entire life. Fuel price inputs, however, do vary over the life of the unit. The total cost of a resource acquisition was calculated by multiplying the per-unit present value cost by the resource amount. To calculate the cost of the wind resource acquisitions, installed capacity, rather than effective capacity, was used.

To provide a common point of comparison across all resource acquisitions, all costs were discounted to the beginning of 1996. The total present value cost of each resource plan is simply the sum of the 1996 discounted present value costs of all resource acquisitions in the plan. Table M-5 presents the principal assumptions used in the present value analysis.

Notes

1. Historical regional retail sales figures from Energy Information Administration's *Electric Power Annual, 1990–1994* show historical retail sales growth of roughly 3 percent over the period 1990–1994. We estimated 1995 retail sales by growing the 1994 figure at this rate. Over the 20-year planning horizon, electricity sales are expected to grow at a slower rate. Based on regional utility integrated resource plan forecasts, we estimated that regional retail sales would grow at an average annual rate of 1.7 percent over the period 1996–2015.

2. The data from this source include only fossil-fueled steam-electric generating units. Emissions from natural gas turbine/internal combustion prime movers were estimated using generation figures for the six states in the region and generic emissions factors for uncontrolled natural gas units from "Power Plant Emission Factors," State of California Energy Resources and Conservation and Development Commission, 1994. Emissions from petroleum turbines and internal combustion prime movers are not included in the 1994 baseline. However, the amount of electricity generated by this source is negligible, making up less than 1/100 of a percent of the region's total generation in 1994.

3. The primary source for the emissions factors was "Power Plant Emission Factors," California Energy Resources Conservation and Development Commission, 1994. Additional information was obtained from regional utility integrated resource plans.

4. Heat rates for existing coal and natural gas-fired power plants were obtained from "Power Plant Emission Factors," California Energy Resources Conservation and Development Commission, 1994, and regional utility integrated resource plans. Heat rates for new fossil fuel-fired resources are from the *Technical Assessment Guide,* Volume 1, Revision 7, Electric Power Research Institute, 1993.

Table M-2. End-of-Period Capacity and Regional Generation Mix

Blueprint

Resource	1995			1996–2000			2001–2005			2006–2010			2011–2015			Net Capacity Additions 1996–2015, *megawatts*
	End-of-Period Capacity, *megawatts*	Capacity Factor	Annual Generation in 1995, *gigawatt-hours*	End-of-Period Capacity, *megawatts*	Capacity Factor	Annual Generation in 2000, *gigawatt-hours*	End-of-Period Capacity, *megawatts*	Capacity Factor	Annual Generation in 2005, *gigawatt-hours*	End-of-Period Capacity, *megawatts*	Capacity Factor	Annual Generation in 2010, *gigawatt-hours*	End-of-Period Capacity, *megawatts*	Capacity Factor	Annual Generation in 2015, *gigawatt-hours*	
Conventional coal	19,250	70%	118,041	19,250	75%	126,473	19,015	75%	124,929	17,700	75%	116,289	15,750	75%	103,478	(3,500)
New natural gas[a]	0	0%	0	1,275	26%	2,867	2,235	50%	9,845	3,200	36%	10,203	3,350	33%	9,792	3,350
Existing natural gas	7,750	11%	7,213	7,750	11%	7,225	7,750	15%	10,184	7,750	15%	10,184	7,750	11%	7,213	0
Energy efficiency	100	40%	350	1,100	40%	3,854	2,100	40%	7,358	4,000	40%	14,016	6,100	40%	21,374	6,000
Wind[b,c]	0	30%	0	50	30%	333	200	32%	1,404	700	34%	5,236	1,400	35%	10,602	1,400
Solar PV[b]	0	30%	0	0	30%	0	75	35%	230	900	35%	2,759	2,990	35%	9,167	2,990
Solar thermal[b]	15	25%	33	65	27%	151	140	32%	388	1,140	39%	3,892	2,050	39%	7,080	2,035
Geothermal	150	90%	1,183	175	90%	1,380	375	90%	2,957	1,075	90%	8,475	2,025	90%	15,965	1,875
Clean coal	0	70%	0	100	75%	657	200	75%	1,314	700	75%	4,599	1,450	75%	9,527	1,450
Hydro	3,600	28%	8,830	2,900	28%	7,113	2,900	28%	7,113	2,900	28%	7,113	2,900	28%	7,113	(700)
Nuclear	2,800	70%	17,170	2,800	70%	17,170	2,800	70%	17,170	2,800	70%	17,170	2,800	70%	17,170	0
Imports	2,500	50%	10,950	2,500	50%	10,950	2,500	50%	10,950	2,500	50%	10,950	2,500	50%	10,950	0
Total	36,165		163,770	37,965		178,172	40,290		193,840	45,365		210,886	51,065		229,431	14,900

(continues)

Table M-2. End-of-Period Capacity and Regional Generation Mix (*continued*)

Business as Usual

Resource	1995			1996–2000			2001–2005			2006–2010			2011–2015			Net Capacity Additions 1996–2015, *megawatts*
	End-of-Period Capacity, *megawatts*	Capacity Factor	Annual Generation in 1995, *gigawatt-hours*	End-of-Period Capacity, *megawatts*	Capacity Factor	Annual Generation in 2000, *gigawatt-hours*	End-of-Period Capacity, *megawatts*	Capacity Factor	Annual Generation in 2005, *gigawatt-hours*	End-of-Period Capacity, *megawatts*	Capacity Factor	Annual Generation in 2010, *gigawatt-hours*	End-of-Period Capacity, *megawatts*	Capacity Factor	Annual Generation in 2015, *gigawatt-hours*	
Conventional coal	19,250	70%	118,041	19,250	75%	126,473	19,115	75%	125,586	21,115	75%	138,726	24,715	75%	162,378	5,465
New natural gas[a]	0	0%	0	2,150	33%	6,127	4,360	49%	18,827	6,935	34%	20,948	8,485	23%	16,851	8,485
Existing natural gas	7,750	11%	7,213	7,750	11%	7,225	7,750	15%	10,184	7,750	15%	10,184	7,750	11%	7,213	0
Energy efficiency	100	40%	350	325	40%	1,139	525	40%	1,840	975	40%	3,416	1,475	40%	5,168	1,375
Wind[b,c]	0	30%	0	10	30%	67	20	32%	138	30	33%	215	40	33%	291	40
Solar PV[b]	0	30%	0	5	31%	14	25	34%	75	45	35%	136	65	35%	198	65
Solar thermal[b]	15	25%	33	25	26%	57	45	30%	120	65	33%	190	85	35%	260	70
Geothermal	150	90%	1,183	150	90%	1,183	150	90%	1,183	150	90%	1,183	150	90%	1,183	0
Clean coal	0	70%	0	100	75%	657	100	75%	657	100	75%	657	100	75%	657	100
Hydro	3,600	28%	8,830	2,900	28%	7,113	2,900	28%	7,113	2,900	28%	7,113	2,900	28%	7,113	(700)
Nuclear	2,800	70%	17,170	2,800	70%	17,170	2,800	70%	17,170	2,800	70%	17,170	2,800	70%	17,170	0
Imports	2,500	50%	10,950	2,500	50%	10,950	2,500	50%	10,950	2,500	50%	10,950	2,500	50%	10,950	0
Total	36,165		163,770	37,965		178,172	40,290		193,840	45,365		210,886	51,065		229,431	14,900

Notes: Figures listed in the table may not compute exactly due to rounding. a. Includes repowered coal capacity. b. To account for increasing capacity factors over time due to technological development the capacity factor shown is the capacity weighted average capacity factor of all units in place up to the end of the period. c. Capacity additions for wind are listed in terms of effective capacity. Based on an assumed capacity value of 40 percent the actual installed capacity is 2.5 times this amount. The generation from the wind resources was calculated using actual installed capacity.

Table M-3. Comparison of Estimated Change in Annual Emission Levels by 2015 in the Blueprint and the Business-as-Usual Approach

Blueprint

Air Pollutant Emitting Resources	Capacity Additions by 2015, *megawatts*	Capacity Factor	Generation, *gigawatt-hours*	Heat Rate, *Btu per kilowatt-hour*	Emissions Factors[a]: Sulfur Dioxide, *pounds per million Btu*	Sulfur Dioxide, *tons per gigawatt-hour*	Oxides of Nitrogen, *pounds per million Btu*	Oxides of Nitrogen, *tons per gigawatt-hour*	Carbon Dioxide, *pounds per million Btu*	Carbon Dioxide, *tons per gigawatt-hour*	Estimated Change in Emissions, *tons per year*: SO_2	NO_x	CO_2
Incremental emissions due to increased utilization of existing coal-fired capacity[b]	NA	NA	6,899	10,230	0.38	1.94	0.45	2.30	206	1,054	13,409	15,879	7,268,880
Retired or repowered coal capacity[c]	(3,500)	75%	(22,995)	10,260	0.66	3.39	0.54	2.77	206	1,057	(77,856)	(63,701)	(24,300,656)
Coal plant pollution control retrofits[d]	465	75%	3,055	10,400	0.58	3.04	0.35	1.82	206	1,071	(9,278)	(5,560)	(3,272,570)
New natural gas-fired capacity[e,f]	3,350	33%	9,792	7,500	0.00	0.00	0.10	0.38	118	443	0	3,672	4,332,920
Geothermal	1,875	90%	14,783	—	—	0.00[g]	—	0.00[g]	—	50[g]	0	0	739,125
Clean coal[h]	1,450	75%	9,527	8,255	0.08	0.33	0.23	0.93	165	680	3,146	8,847	6,480,175
Seasonal fuel switching[i]											(5,942)	(2,810)	(685,579)
										Total	(76,522)	(43,673)	(9,437,704)

(*continues*)

Table M-3. Comparison of Estimated Change in Annual Emission Levels by 2015 in the Blueprint and the Business-as-Usual Approach (*continued*)

Business-as-Usual

Air Pollutant Emitting Resources	Capacity Additions by 2015, *megawatts*	Capacity Factor	Generation, *gigawatt-hours*	Heat Rate, *Btu per kilowatt-hour*	Emissions Factors[a] Sulfur Dioxide *pounds per million Btu*	Sulfur Dioxide *tons per gigawatt-hour*	Oxides of Nitrogen *pounds per million Btu*	Oxides of Nitrogen *tons per gigawatt-hour*	Carbon Dioxide *pounds per million Btu*	Carbon Dioxide *tons per gigawatt-hour*	Estimated Change in Emissions, *tons per year* SO_2	NO_x	CO_2
Incremental emissions due to increased utilization of existing coal-fired capacity[b]	NA	NA	8,372	10,240	0.45	2.30	0.48	2.46	206	1,055	19,290	20,576	8,830,506
Retired or repowered coal capacity[c]	(135)	75%	(887)	11,800	0.83	4.90	0.95	5.61	206	1,215	(4,343)	(4,971)	(1,077,999)
New conventional coal[j]	5,600	75%	36,792	10,000	0.16	0.80	0.45	2.25	206	1,030	29,434	82,782	37,895,760
New natural gas[d]	8,485	23%	16,851	7,500	0.00	0.00	0.10	0.38	118	443	0	6,319	7,456,443
Clean coal[h]	100	75%	657	9,000	0.08	0.36	0.23	1.01	165	742	237	665	487,231
										Total	44,617	105,371	53,591,941

Notes: Figures listed in the table may not compute exactly due to rounding. a. Pounds per million Btu emission factors are from *Power Plant Emission Factors,* State of California Energy Resources Conservation and Development Commission, 1994, and utility integrated resource plans. b. Heat rate and pounds per million Btu emission factors are the capacity weighted average values for the coal-fired generating units operating in the scenario in 2015. c. Heat rate and pounds per million Btu emission factors are the capacity weighted average values for the coal-fired generating units retired or repowered in the scenario by 2015. d. Represents retrofitting the Hayden power plant with dry scrubbing and low-NO_x burners. Pounds per million Btu emission factor is the difference between the uncontrolled emission factor and the emission factor with pollution control equipment installed. e. Includes repowered coal capacity. f. Emissions factors for new natural gas capacity assume that this capacity is installed with selective catalytic reduction (SCR) pollution control equipment to control emissions of NO_x. g. *Source: Renewable Energy Technology Characterizations,* U.S. Department of Energy, Office of Utility Technologies, Draft, May 1994. h. SO_2 and NO_x emissions from clean coal technologies were assumed to be 50 percent lower than coal-fired power plants with pollution control equipment installed on a pounds per million Btu basis. Emissions of CO_2 were assumed to be 20 percent lower. Listed heat rate is the capacity weighted average heat rate of the clean coal capacity operating in the scenario in 2015. i. Represents 4-month winter season fuel switching of the Cherokee power plant. Emissions reduction calculations based on information from *Costs and Benefits of Fuel Switching,* Public Service Company of Colorado, System Planning Division, October 1995; and Public Service Company of Colorado's 1993 Integrated Resource Plan. j. Emissions factors for new conventional coal capacity assume that this capacity is installed with dry scrubbers for the control of SO_2 and low-NO_x burners for the control of NO_x.

—: Not available. NA: Not applicable.

Table M-5. Present Value Cost Analysis Input Assumptions

All figures in 1996 dollars. Capital costs include allowance for funds used during construction.

Inflation Rate	3.50%	**Fuel Price Assumptions**	**1996 Price,** *dollars*	**Real Escalation Rate**	
Nominal Discount Rate	9.50%	Natural Gas	2.00	2.50%	
Real Discount Rate	5.80%	Coal	1.10	1.00%	

	Energy Efficiency				
	1996	2000	2005	2010	2015
Program Cost, *$/kW*[a]	500	500	500	500	500

	Wind					Geothermal				
	1996	2000	2005	2010	2015	1996	2000	2005	2010	2015
Capital Costs, *$/kW*	944	809	800	783	775	2,494	2,434	2,312	2,154	2,092
Delivered Fuel Price, *$/MMBtu*	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
O&M Costs										
Fixed O&M, *$/kW-year*	4.53	4.32	4.32	3.34	2.82	118.25	108.79	101.70	96.97	90.86
Variable O&M, *mills/kWh*	10.79	8.63	7.55	6.47	5.91	3.84	3.84	3.84	3.84	3.84
Heat Rate	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Capacity Factor	30%	32%	35%	35%	35%	90%	90%	90%	90%	90%

	Solar Thermal[b]					Clean Coal				
	1996	2000	2005	2010	2015	1996	2000	2005	2010	2015
Capital Costs, *$/kW*	3,704	3,049	2,453	2,453	2,453	2,775	2,413	2,292	2,232	2,232
Delivered Fuel Price, *$/MMBtu*	NA	NA	NA	NA	NA	1.10	1.14	1.20	1.26	1.33
O&M Costs										
Fixed O&M, *$/kW-year*	61.49	53.21	29.56	29.56	29.56	55.32	53.11	52.00	50.89	50.89
Variable O&M, *mills/kWh*	29.56	23.65	8.28	8.28	8.28	3.54	3.43	3.32	3.21	3.21
Heat Rate	NA	NA	NA	NA	NA	9,000	8,700	8,400	8,100	8,100
Capacity Factor	25%	35%	40%	40%	40%	75%	75%	75%	75%	75%

	Solar PV					Conventional Coal[c]				
	1996	2000	2005	2010	2015	1996	2000	2005	2010	2015
Capital Costs, *$/kW*	7,095	5,321	3,311	2,483	2,168	1,553	1,553	1,553	1,553	1,553
Delivered Fuel Price, *$/MMBtu*	NA	NA	NA	NA	NA	1.10	1.14	1.20	1.26	1.33
O&M Costs										
Fixed O&M, *$/kW-year*[a]	6.27	6.27	6.27	6.27	6.27	46.47	46.47	46.47	46.47	46.47
Variable O&M, *mills/kWh*	0.00	0.00	0.00	0.00	0.00	2.43	2.43	2.43	2.43	2.43
Heat Rate	NA	NA	NA	NA	NA	10,000	10,000	10,000	10,000	10,000
Capacity Factor	30%	35%	35%	35%	35%	75%	75%	75%	75%	75%

	Combined-Cycle Natural Gas[d]				
	1996	2000	2005	2010	2015
Capital Costs, *$/kW*	655	655	655	655	655
Delivered Fuel Price, *$/MMBtu*	2.00	2.21	2.50	2.83	3.20
O&M Costs					
Fixed O&M, *$/kW-year*	29.32	29.32	29.32	29.32	29.32
Variable O&M, *mills/kWh*	0.89	0.89	0.89	0.89	0.89
Heat Rate	7,500	7,500	7,500	7,500	7,500
Capacity Factor[e]					
Blueprint	26%	26%	50%	36%	33%
Business as Usual	33%	33%	49%	34%	23%

Sources: Cost and performance data for the renewable energy technologies are based on data from *Renewable Energy Technology Characteristics,* U.S. Department of Energy, Office of Utility Technologies, Draft, May 1994, utility integrated resource plans, and the sources cited in Appendix D. Cost and performance data for conventional coal, combined-cycle natural gas, and clean coal technologies are based on data from *Technical Assessment Guide* (TAG), Volume 1, Electric Power Research Institute, 1993, utility integrated resource plans, and the sources cited in Appendix C.

The following specific technologies were used in the cost analysis: wind—Class IV horizontal axis wind turbine; solar thermal—solar parabolic trough power plant (prior to 2005), solar thermal power tower system (after 2005); solar PV—concentrating photovoltaic collector; geothermal—geothermal flashed steam electricity; clean coal—coal gasification/combined cycle; conventional coal—pulverized coal-lime spray dryer; natural gas—combined-cycle combustion turbine.

Notes: a. 30-year present value cost per kW in constant 1996 dollars. b. Capital costs for solar repowering were assumed to be two-thirds that of stand-alone solar thermal capacity. O&M costs for solar repowering were assumed to be the same as for stand-alone units. c. Conventional coal plant life extensions were assumed to cost $300/kW. d. Capital costs for natural gas repowering were assumed to be 90 percent those of stand-alone natural gas-fired capacity. Fuel and O&M costs were assumed to be the same for repowerings as for stand-alone capacity. e. In the model developed by the LAW Fund to conduct the cost analysis, the capacity factors of the natural gas units are endogenous and adjust over time depending on the resource mix up to that time and the forecast of regional generational requirements. Because of the different resource mix in each scenario the capacity factors at which the natural gas units run differ in the blueprint and the business-as-usual scenario.

NA = not applicable; kW = kilowatt; MMBtu = million Btu; mills = 1/1000 of a dollar.

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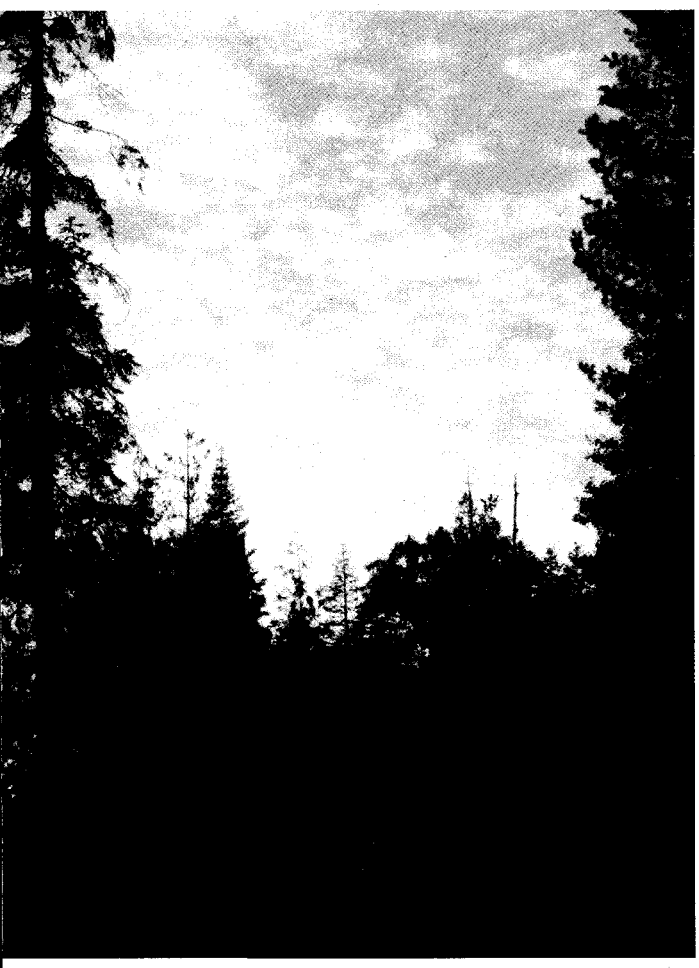

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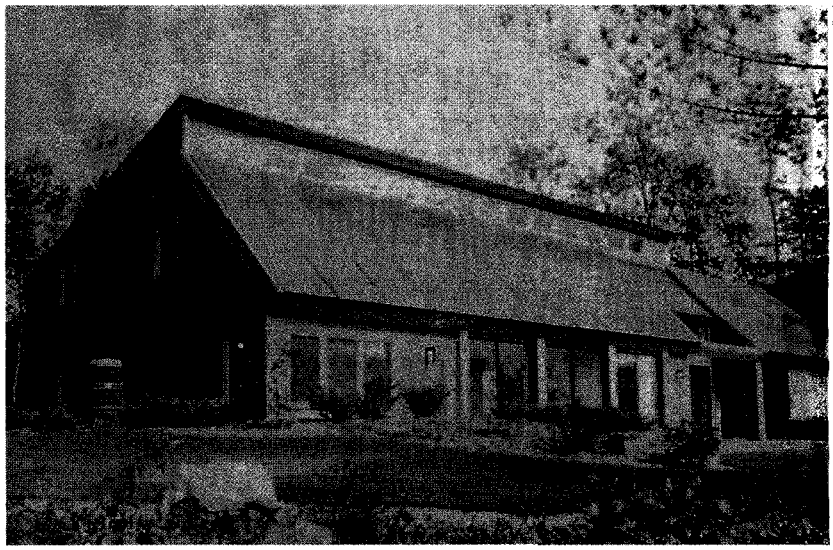
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