

**THE ELECTRICAL UTILITY INDUSTRY RESTRUCTURING
TRANSITION ADVISORY COMMITTEE**

A Report to the Governor and the 58th Legislature

December 2002

Prepared by
Jeff Martin, Lead Staff, Research Analyst
Todd Everts, Attorney

Members of the Transition Advisory Committee

Senate Members

Sen. Fred Thomas, Presiding Officer
Sen. Alvin Ellis, Jr.
Sen. Walter McNutt
Sen. Linda Nelson
Sen. Don Ryan
Sen. Emily Stonington

House Members

Rep. Tom Dell, Vice Presiding Officer
Rep. Roy Brown
Rep. Stan Fisher
Rep. Steve Gallus
Rep. Jim Keane
Rep. Alan Olson

Montana Legislative Services Division
Room 110, State Capitol
PO Box 201706
Helena MT 59620-1706
(406)444-3064
FAX (406)444-3036
Internet Homepage: <<http://leg.mt.gov>>

TABLE OF CONTENT

PREFACE	ii
CHAPTER 1 RESTRUCTURING REVISITED	1
INTRODUCTION	1
PROLOGUE TO COMPETITION	2
RESTRUCTURING IN MONTANA--1997	3
RESTRUCTURING IN MONTANA--2001	6
ASSERTION OF AUTHORITY	10
PRELUDE TO THE PORTFOLIO	11
MONTANA POWER COMPANY BIDS ADIEU	16
HOUSE BILL NO. 474 REJECTED BY THE VOTERS	17
COMMITTEE ACTION	18
PROPOSED GENERATION PROJECTS	18
"THE STRANGE AND TERRIBLE SAGA"	20
CHAPTER 2 ELECTRICAL ENERGY TRANSMISSION	21
INTRODUCTION	21
REGIONAL TRANSMISSION ISSUES	21
FERC AND COMPETITION	24
SOME SUCCESS, SOME FAILURE	25
WORK IN PROGRESS: STANDARD MARKET DESIGN	27
WHAT'S NEXT?	28
MONTANA RESPONDS TO STANDARD MARKET DESIGN	28
CHAPTER 3 UNIVERSAL SYSTEM BENEFITS PROGRAMS	31
BACKGROUND	31
STATUTORY REQUIREMENTS	32
USBP INFORMATION PRESENTED TO THE SUBCOMMITTEE	32
USBP SUBCOMMITTEE FINDINGS AND RECOMMENDATIONS	39
COMMITTEE ACTIONS	39

PREFACE

This report is submitted in accordance with the provisions of section 69-8-501(9), MCA, that requires the Transition Advisory Committee (Committee) to provide an annual report on the status of electric utility restructuring to the Governor, the Speaker of the House, the President of the Senate, and the Montana Public Service Commission.

The Committee is also submitting a second report, *Electricity Policy Options for Montana--A Report and Discussion of Policy Options*, written by Matthew Brown, Energy Program Director, National Conference of State Legislatures. In early 2002, the Committee engaged Mr. Brown to conduct an independent analysis of Montana's energy situation and restructuring policy and to provide policy options to address electricity services for small customers in Montana. This report and Mr. Brown's report are intended to complement one another.

Since Montana restructured its electric utility industry in 1997, the transition to customer choice has been fitful and unpredictable. The Montana Power Company, which provided electricity and natural gas services in the state for over 80 years, is gone. Montana is now served by energy companies that we did not know existed until just a few years ago. During the 2001 legislative session, the Montana Legislature had to address an energy crisis that at the time seemed insurmountable and not of our making. The crisis abated, but a new one may be looming. The state has passed a significant milestone: since July 1, 2002, all Montana customers are exposed to wholesale energy markets. What effect that exposure has on the state's electricity customers may depend significantly on the policy decisions of the Legislature and the Montana Public Service Commission. The Legislature will also have to decide how it wants to deal with voter rejection of House Bill No. 474, the major piece of restructuring legislation enacted in 2001.

The state continues to be influenced by regional and national events that are seemingly outside of the state's control. It is uncertain how the state will respond to those outside forces.

This report is divided into three chapters. The first chapter provides a broad overview of restructuring in Montana since 1997, with particular focus on developments since 2001. It also presents a brief history of the national trend to competition. As such, the report plows over familiar ground, but the purpose is to provide a general context of looking at the current energy situation.

The first chapter also discusses legislation submitted at the request of the Transition Advisory Committee. In April 2002, the Committee decided there were policies contained in House Bill No. 474 that may be worth reconsideration in the event voters rejected that measure. The Committee drafted legislation regarding customer choice and the ability to return to the default supply, continuing default supply obligation after the transition period, electricity supply costs, and the extension of universal system benefits charges through December 31, 2005. The Committee submits those proposals, *without recommendation*, for consideration by the 58th

Legislature. The Committee is also submitting legislation to revise the structure and function of the Committee.

The second chapter discusses issues related to transmission. A smoothly operating transmission system is essential to providing electricity efficiently and reliably, whether under a competitive market or regulated structure. This chapter focuses on regional transmission systems and the policies of the Federal Energy Regulatory Commission. Matthew Brown's report contains some policy recommendations on transmission over which the state has control.

The third chapter presents Committee recommendations regarding universal systems benefits programs. Section 69-8-501(15), MCA, directed the Transition Advisory Committee to conduct a reevaluation, in cooperation with the Montana Public Service Commission, of the ongoing need for universal system benefits programs and annual funding requirements and to make recommendations to the 58th Legislature regarding the future need of the programs. The reevaluation and recommendations were to be completed by July 1, 2002.

This report, Matthew Brown's report, and other information related to the Transition Advisory Committee are on the Committee's website at http://www.legmt.gov/css/committees/interim/2001_2002/trans_adv_com/default.asp.

CHAPTER 1 RESTRUCTURING REVISITED

INTRODUCTION

Restructuring of the electric utility industry is not for the impatient, the weak-kneed, or the fainthearted. Many states, including Montana, have adopted proposals to develop retail competition, but the transition to competitive markets in Montana and in other states has often been turbulent and unpredictable. At the same time, the electric utility industry has undergone significant changes that include the divestiture of generation plants by investor-owned utilities, mergers among electric utilities, and the emergence of power marketers, nonutility generators, and organizations that are managing the transmission systems in various parts of the country.

Montana entered the competitive arena during the 1997 legislative session with the enactment of the Montana Electric Utility Industry Restructuring and Consumer Choice Act (Ch. 505, L. 1997). Although the new legislation had little immediate effect on small customers, large industrial customers were able in 1998 to obtain electrical energy from cheaper suppliers than the Montana Power Company (MPC). Otherwise, regulators, MPC, public interest groups, the Transition Advisory Committee, and others muddled through the arcana of transition plans, stranded costs, rules for the licensure of "can't wait to market in Montana" power suppliers, and the inevitable litigation. Except for noticing that our electricity bills detailed the separate costs of energy generation, transmission, and distribution, most of us were blithely unaware of the awesome choice awaiting us.

In mid-2000, a power crisis stunned the Pacific Northwest. The electricity restructuring debacle in California, high summer temperatures, inadequate water supply for the hydrosystem, higher demand for electricity, and rising natural gas prices all contributed to a dramatic increase in wholesale electricity prices. Enron and other power marketers and suppliers were suspected of gaming the California system to maintain high electricity prices. In Montana, large industrial customers were exposed to higher prices because of the expiration of contracts, as would be residential and commercial customers because of the expiring rate moratorium in July 2002. The 2001 Legislature considered a wide variety of energy bills to stave off the crisis. The most significant legislation enacted during the session was House Bill No. 474 (Ch. 577, L. 2001). The bill went through a variety of versions but finally settled on, among other things, extending the period for transition to customer choice until July 1, 2007, providing financing mechanisms (including low-interest loans and revenue bonds) for developing new generation in the state, specifying the default supplier (the Montana Power Company and its successor, NorthWestern

Energy), implementing a method for recovering electricity supply costs, and allowing customers who had chosen another supplier to return to the default supply. This chapter reviews national events that influenced the development of competitive energy markets, restructuring efforts and outcomes in Montana, proposed energy projects, and Committee recommendations regarding voter rejection of House Bill No. 474.

PROLOGUE TO COMPETITION¹

Historical events, federal legislation, the Federal Energy Regulatory Commission (FERC), technological innovation, and a renewed optimism in competitive markets have all contributed to the transformation of the electric utility industry from a heavily regulated vertically integrated natural monopoly to a more competitive industry.

The precursors to competition in electrical energy markets began in the early 1970s. In 1973, the OPEC oil embargo caused a threefold increase in the price of oil. In addition, new federal and state environmental regulations were being imposed on American industries. Because oil fueled many generating plants, the cost of electricity soared. Many electric utilities filed for an unprecedented number of rate hikes. Consumer protests caused public service commissions in many states to reduce the amount requested. As a result, electric utilities could not recover their costs of capital, and they scaled back the construction of new generating capacity. In the late 1970s, ambitious plans for the construction of nuclear power plants were hampered by opposition on a variety of environmental, economic, and safety concerns. Regulatory and legal challenges often required expensive modifications to nuclear power plants.

The federal government attempted to address a number of energy and environmental issues through legislation. The Public Utility Regulatory Policies Act of 1978 was designed to encourage the development of alternative energy sources such as solar, wind, biomass, and other “environmentally friendly” energy sources. The Act required states to determine a “net avoided cost” as the price at which utilities would be required to purchase electricity from “qualified facilities”.² Qualified facilities were allowed to provide alternative energy to electric utilities at a price equal to the so-called “avoided cost” of the utility or the amount that the utility could save by not generating its own power from conventional sources. Qualified facilities generally received a price higher than the utilities’ true avoided cost because avoided cost was tied to long-

¹Much of the historical background was derived from Peter Navarro, “A Guidebook and Research Agenda for Restructuring the Electricity Industry,” in Energy Law Journal, Vol. 16:347, 1995, pp. 347-354 and from “Restructuring the Electric Industry,” in The CQ Researcher, Vol. 7, No. 2, Jan. 17, 1997, pp. 33-39.

²William S. Pierce, Economics of the Energy Industries, (Westport, CT: Praeger Publishers, 1996) p. 200.

range petroleum prices, which were forecasted to be \$100 a barrel by the late 1990s.³ An unintended consequence of the Act was that utilities built qualifying facilities to cash in on the avoided cost subsidy.⁴

Although utilities relied increasingly on qualified facilities and other nonutility generators, any move toward competition was impeded by the fact that vertically integrated utilities controlled access to the transmission grid. Electric utilities could exact large transmission charges from other energy producers to effectively block competition. The control of transmission was radically altered with the enactment of the Energy Policy Act of 1992. The Act was designed to encourage competition in the wholesale electricity markets by authorizing FERC to order wholesale wheeling.⁵ The Act also created a new class of exempt wholesale generators that can compete with fewer regulatory constraints in the electricity generation market. Wholesale generators do not operate within a specified service territory.

RESTRUCTURING IN MONTANA--1997

Restructuring in Montana got off to an unexpected start in 1997 with the enactment of Senate Bill No. 390 (Ch. 505, L. 1997), the Montana Electric Utility Industry Restructuring and Consumer Choice Act. The legislation passed 36-14 in the Senate and 78-21 in the House of Representatives. Montana joined several other states that had already enacted legislation or adopted policies to implement customer choice. Besides Montana, California, Nevada, New Hampshire, Maine, Oklahoma, Pennsylvania, and Rhode Island had developed proposals to provide for the orderly transition from a regulated monopoly of electricity markets to a more competitive environment. Although about half the states now have some form of electrical utility restructuring, several states, including Arkansas, Montana, Nevada, New Mexico, Oklahoma, and West Virginia have either delayed the restructuring process or the implementation of retail access; California has suspended restructuring.⁶

³Navarro, *op. cit.*, note 18.

⁴Navarro, *op. cit.*, p. 351.

⁵"Wheeling" is the transmission by a utility of electricity produced or owned by another entity. Wholesale wheeling is transmitting bulk power over the grid to power companies. The transmission grid serves as a common carrier. Retail wheeling provides power companies direct access to retail customers.

⁶Energy Information Administration, *Status of State Electric Industry Restructuring Activity*, (December 2002) pp. 1-2, at http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html.

Restructuring and customer choice applied primarily to the Montana Power Company service territory. Rural electric cooperatives were allowed to determine whether their customers would be offered a choice of electricity supplier. Because North Dakota is the primary service territory of Montana-Dakota Utilities, the utility was allowed to defer customer choice until July 1, 2006. Some of the salient features of the Act included:

- allowing large electric utility customers the choice of electricity supplier by July 1, 1998;
- providing all other electric utility customers the choice of electricity supplier by July 1, 2002;
- allowing a public utility to recover transition (or stranded) costs through a nonbypassable charge on customers;⁷
- requiring the functional separation of a vertically integrated public utility's electricity supply, retail transmission, and distribution;
- requiring that energy supply charges, transmission and distribution charges, transition costs, and universal system benefit charges be shown separately on a customer bill;
- allowing rural electric cooperatives to offer their customers the choice of electricity supplier;
- imposing a rate moratorium on electric supply-related costs through June 30, 2002;
- utilizing market information to determine price;
- continuing the Public Service Commission regulation of transmission and distribution services;
- establishing a transition advisory committee to monitor electric utility restructuring; and
- directing the [former] Revenue Oversight Committee to analyze state and local tax revenue derived from previously regulated electricity suppliers and address the establishment of comparable state and local tax burdens on all market participants in the supply of electricity.⁸

In Appendix 3 of its November 2000 annual report, the Transition Advisory Committee noted several positive results of the transition to competition. First, most large industrial customers in

⁷Transition costs include generation-related and electricity supply costs that are unrecoverable as a result of competition. Under Senate Bill No. 390 these costs include, among others, regulatory assets and deferred charges; certain power purchase contracts, including QF contracts; and generation and supply commitments made before the enactment of Senate Bill No. 390. The rationale for the recovery of transition costs is that the utility cannot sell energy at a high enough price to earn a reasonable return on investment because of lower-priced electricity under competition.

⁸Based on the recommendation of the Revenue Oversight Committee, the 56th Legislature reduced the property tax rate on centrally assessed generation facilities from 12% to 6% and imposed a wholesale electricity transaction tax on electricity transmitted within the state to partially offset the loss in state and local property tax revenue (Ch. 556, L. 1999).

the state obtained electricity from suppliers other than Montana Power at cost savings of 5 to 10%. The switch to choice by large industrial customers represented about 25% of Montana Power's load. Second, both Glacier Electric Cooperative and Flathead Electric opened their systems to competition. Flathead Electric purchased the distribution system of PacifiCorp and is serving PacifiCorp's former customers. Third, the Montana Power Company (MPC) sold its generation assets to Pennsylvania Power and Light for \$757 million. The sales price was a little over \$150 million higher than the estimated book value of the generation assets. As a result, MPC proposed a 4% rate reduction in energy supply through the remainder of the transition period (June 30, 2002). In addition, the sale at above book eliminated stranded costs associated with generation and regulatory assets, leaving only transition charges associated with power purchases from qualifying facilities to be resolved (see below).⁹

The Committee's November report also described the energy crisis unfolding in California. The report noted that wholesale energy prices in California had increased by 270% from the previous year.¹⁰ Several factors contributed to the price increases, including higher demand (economic growth and weather) for electricity throughout the region, a decline in production from dams because of dry weather, rising natural gas prices, and other circumstances that limited power supplies.¹¹ California's restructuring plan itself contributed to the crisis. The restructuring legislation (California law AB 1890) capped retail prices until 2002 or until the utilities recovered certain stranded costs. This was at a time when western states as a whole had excess generating capacity of about 20%,¹² and wholesale prices were expected to remain low. As wholesale prices rose, however, Pacific Gas and Electric and Southern California Edison were forced to sell purchased power at a loss. (San Diego Gas and Electric had recovered its stranded costs in 1999. It was allowed to charge its customers market prices, about three times higher than the previous year.)¹³ Although utilities were granted rate increases, Pacific Power and Gas filed for Chapter 11 bankruptcy. Excess capacity in the region had dwindled, but the construction of new generation capacity in California was held back because the retail price-freeze mitigated

⁹Stephen Maly, The Shock of the New: Changes in the Generation, Transmission, and Distribution of Electricity in Montana, Appendix 3, (Helena, Montana, Legislative Services Division), pp. 78-79.

¹⁰ *Ibid.*, p.17.

¹¹The Congress of the United States, Congressional Budget Office, Causes and Lessons of the California Electricity Crisis, (Washington, DC, September 2001), p. viii.

¹²*Ibid.*, p. viii.

¹³*Ibid.*, p. viii.

against long-term contracts. Finally, Enron and other power marketers and suppliers were suspected of gaming the California system to maintain high electricity prices.¹⁴

The power crisis spilled over into other states as California scrambled to secure out-of-state power. Wholesale energy prices in the Pacific Northwest rose to unprecedented levels. Spot prices were orders of magnitude above (reaching close to \$3,000 a megawatt hour¹⁵ in mid-December 2000) the \$20 to \$30 a megawatt hour that were typical for the region. Although nonchoice customers in Montana were protected by the rate moratorium through June 30, 2002, the prospect of volatile wholesale prices¹⁶ at the end of the transition period was more than troublesome for policymakers in the state. Large industrial customers whose contracts expired or were tied to wholesale price indices were forced to curtail production or cease operations because of high energy prices.

RESTRUCTURING IN MONTANA--2001

The 58th Legislature faced the daunting task of dealing with an energy crisis that ostensibly loomed well into the future. The Legislature considered a variety of energy bills in an effort to stem the crisis. The most comprehensive legislation enacted during the 2001 legislative session was House Bill No. 474 (Ch. 577, L. 2001). As introduced, the legislation would have increased the wholesale energy transaction tax from 0.015 cent a kilowatt hour to 0.5 cent a kilowatt hour, or by over 3,000%. A portion of the increased revenue would have been used to provide low-income energy assistance, and the balance would have been deposited in the state general fund. The default supplier would have been allowed a credit against corporation license taxes due for the increased tax. The credit would have been based upon the difference in the new and old rate at which the default supplier purchased electricity.

The bill was significantly revised during the legislative session. The revisions were based on changing perceptions of the energy situation and incorporated provisions of other proposed legislation. As enacted, House Bill No. 474 included the following provisions:

¹⁴An Enron employee has recently admitted complicity in the California energy crisis "in order to maximize profit for Enron."

¹⁵Weighted average of firm peak and firm off-peak prices for the Mid-Columbia.

¹⁶In December 2000, wholesale electricity spot prices for firm power on the Mid-Columbian Index were 10-150 times higher than they were for the same period in the previous year.

- Extended the transition period to competition to July 1, 2007.
- Designated the default supplier as the customers' distribution supplier and required that the distribution services provider have an ongoing regulated default supply obligation beyond the end of the transition period.
- Allowed customers who elected an alternative electrical energy supplier (primarily large industrial customers) an opportunity to receive electrical energy from the default supplier. Provided that electrical energy purchased from the default supplier by a default customer must be used for a consumptive purpose and may not be remarketed.
- Prohibited an electricity buying cooperative from serving as a default supplier but allowed it to serve as a supplier or promoter of alternative energy and conservation programs.
- Required the default supplier to provide for the full electricity supply requirements of all default supply customers. To meet these requirements, the default supplier must procure a portfolio of electricity supply using industry-accepted procurement practices, which may include negotiated contracts or competitive bidding. The Montana Public Service Commission (PSC) may develop reasonable requirements for the use of competitive bidding in the procurement process. A default supplier may submit material related to proposed bids or contracts concerning electricity supply to the PSC before the default supplier enters into the contract. The PSC may comment on the material. In reviewing electricity supply contracts, the PSC must consider only those facts that were known or should reasonably have been known by the default supplier at the time the contract was entered into and that would have materially affected the cost or reliability of the electricity supply to be procured.
- Allowed the default supplier to recover all statutorily defined electricity supply costs subject to a prudence test by the PSC. The PSC was not required to grant preapproval of electricity supply costs. The term "electricity supply costs" means actual costs of the electricity. Actual costs include fuel, ancillary service costs, transmission costs, including congestion and losses, and any other costs directly related to the purchase of electricity and management of electricity costs or a related service. Revenue from the sale of surplus electricity must be deducted from the costs. Total transmission costs are recoverable only once in electricity supply costs. The terms used in the definition of "electricity supply costs" must be construed according to industry standards.

- For the period beginning July 1, 2002, required the PSC to establish procedures and terms under which customers may choose an electricity supplier other than the default supplier or may choose to be served by the default supplier. The procedures must provide conditions for leaving and returning to the default supplier. The procedures must provide for the recovery of costs associated with those customers who choose an alternative electricity supplier and who wish to return to the default supplier.
- Authorized the Montana Power Authority to purchase, construct, and operate electrical generation facilities or electrical energy transmission or distribution systems and to enter into joint ventures for these purposes. The Board of Examiners was authorized to issue revenue bonds (not to exceed \$500 million) for the Montana Power Authority to acquire electrical generation facilities and build electrical energy transmission or distribution systems. The principal and interest on the bonds would be payable from the sale of electrical energy from the facilities and from electrical energy transmission and distribution charges.¹⁷
- Allowed the Montana Board of Investments to provide low-interest loans to facilitate up to 450 megawatts from the construction of new generation projects in Montana and allowed the purchase of 120 megawatts from existing qualifying facilities.¹⁸
- Extended the duration of the universal system benefits programs (USBP) and required that 6% of the USBP funds be spent on irrigated agriculture energy conservation and efficiency programs. Clarified the definition of "universal system benefits programs" to include irrigated agriculture. Required a public utility to offer a separately marketed renewable energy product.
- Provided for a consumer electricity support program that consists of financial support or the assignment of electricity supply. In the event that an excess revenue tax was imposed, up to \$100 million could be used to provide an affordable and reliable electricity supply to customers of the default supplier (see discussion below on the excess revenue tax).¹⁹

¹⁷The Montana Power Authority, chaired by Lieutenant Governor Karl Ohs met several times during the interim, but the initiative to refer House Bill No. 474 to the voters, among other things, limited its ability to act.

¹⁸The Thompson River Cogeneration Facility is the only entity to receive a loan under this provision.

¹⁹These provisions were rendered void by the voters on November 5, 2002.

Other significant legislation enacted during the 2001 session included the following:

- **SB 19 (Ch. 584)**. Revised the laws governing customer choice in electrical energy supply; extended the transition period to June 30, 2007; extended the dates requiring residential and small commercial customer participation in the selection of an electricity supplier.
- **SB 269 (Ch. 175)**. Allowed an integrated, multistate public utility operating outside the Columbia River basin (Montana-Dakota Utilities) to defer indefinitely the transition plan (previously July 1, 2002) and transition period to customer choice (previously July 1, 2006).
- **SB 398 (Ch. 588)**. Provided for the operation of temporary power generation units under the air quality permitting laws.
- **SB 521 (Ch. 593)**. Generally revised the emergency powers of the governor; revised the definition of "energy emergency"; clarified the energy emergency powers of the governor; extended the duration of an energy emergency; and clarified that proceedings undertaken during an energy emergency may be completed.
- **SB 506 (Ch. 591)**. Provided incentives for the development of alternative energy generation.
- **SB 508 (Ch. 592)**. Provided property tax incentives for new natural gas and coal generation facilities.
- **HB 643 (Ch. 541)**. Provided incentives for electrical generation on Indian reservations.
- **HB 645 (Ch. 582)**. Implemented an electrical energy pool; authorized the Public Service Commission to require a default supplier, a distribution services provider, and a public utility serving Montana customers to participate in the electrical energy pool; provided exceptions; required the default supplier, the distribution services provider, and the public utility to allow customers to participate in the electrical energy pool; and authorized the electrical energy pool to market the electrical energy made available by the customers participating in the pool to other Montana customers.²⁰

The 2001 session ended on something of a controversy. On the penultimate day of the session, the Montana Power Company (MPC) and PPL Montana announced that they had reached a tentative agreement in which PPL Montana would sell unit-contingent power (i.e., if available) to MPC for \$40 a megawatt hour (or 4 cents a kilowatt hour) for a period of 5 years beginning July

²⁰A detailed summary of energy legislation enacted during the 2001 session may be found on the Transition Advisory Committee's website at http://www.leg.mt.gov/css/committees/interim/2001_2002/trans_adv_com/default.asp.

1, 2002. Although the offer was less than market prices at the time (and less than the original offer from PPL Montana of \$60 a megawatt hour), it was well above the rate moratorium price of around \$24 a megawatt hour. MPC would have to purchase electricity from other sources to meet the balance of the load.

The agreement was contingent upon three conditions. First, the Montana Legislature would reject Senate Bill No. 512 that would have imposed an "excess revenue" tax on revenue derived from the sale of electrical energy in Montana that was sold above a base price. Second, the Montana Legislature would guarantee the Montana Power Company the ability to recover all prudently incurred power supply costs. The purpose of this condition was to avoid the situation that occurred in California in which utilities could not recover power supply costs above the retail rate cap. The third condition was that the Montana Public Service Commission drop its assertion of regulatory authority over PPL Montana.²¹

The ability to recover prudently incurred supply costs was included in House Bill No. 474, while Senate Bill No. 512 "died in the process". The announcement of the agreement contributed to the impression that the enactment of House Bill No. 474 was a "backroom" deal. That impression caused two legislators to begin the process of referring the measure to the Montana voters (see below).

ASSERTION OF AUTHORITY

The Montana Public Service Commission (PSC) concluded that there was a conflict in House Bill No. 474 in that the purpose of the legislation is to both protect ratepayers and to foster the financial integrity of the Montana Power Company as a public utility and as a distribution services provider.²² As such, the PSC determined that it has authority (Order 5986t) over the Montana Power Company's electricity supply obligations under Senate Bill No. 390, as amended by House Bill No. 474.²³ In particular, the PSC contended that generation has not been separated

²¹In March 2001, based on Senate Bill No. 390, the Montana Public Service Commission asserted its authority to set cost-based rates over MPC's electricity supply-based generation assets still in the rate base through the extended transition period. The Public Service Commission had extended the transition period to June 30, 2004, under 69-8-201(2).

²²For an analysis of the Public Service Commission's assertion of regulatory authority over the default supplier's electricity supply obligation under House Bill No. 474 and contrary view of the apparent conflict in legislative intent under House Bill No. 474, see Greg Petesch, letter to Senator Fred Thomas, June 7, 2001, in Transition Advisory Committee, Minutes, June 19, 2001.

²³Montana Public Service Commission's Regulation of MPC's Electricity Supply Obligation under SB 390 (1997) and after HB 474 (2001)", Executive Summary, May 30, 2001 at <http://www.psc.mt.gov/pdf/PSC390-474synopsis.pdf>.

from the rate base and would not be until the PSC signs the final order for electrical energy competition.

PPL Montana and the Montana Power Company filed complaints against the PSC in federal district court and state district court, respectively, challenging the PSC's assertion of authority. The PPL Montana complaint contended that PPL Montana, as an exempt wholesale generator, is subject to regulation by the Federal Energy Regulatory Commission and not by the PSC. The federal District Court Judge in Missoula granted a motion by the PSC to dismiss the complaint on jurisdictional grounds. The decision to dismiss was upheld by the Ninth Circuit Court of Appeals. However, based on an unrelated U.S. Supreme Court decision, the case has been remanded to the federal District Court in Missoula to be considered on the substantive issues raised by the complaint. At this time, the complaint has yet to be resolved. The MPC complaint, related to the PSC interpretation of section 68-8-211(8) that during the transition period, a public utility "may not charge rates . . . at a level higher than the public utility would reasonably expect to recover in rates had the current regulatory system remained intact." The MPC complaint also has yet to be resolved.

PRELUDE TO THE PORTFOLIO

Many observers anticipated that electricity prices in the summer of 2001 would be as high if not higher than those of 2000. At its June 19, 2001, meeting, the Transition Advisory Committee reviewed price data from the Dow Jones Mid-Columbia Electricity Index for the first 2 weeks in June that indicated that wholesale energy prices may be stabilizing.²⁴ On June 1, 2001, the weighted average price (on-peak, firm) of electricity traded in Columbia was \$148.85 a megawatt hour, and on June 14, it was \$55.50. Prices exhibited considerable variability over the 2-week period. Recognizing that 2 weeks of data is not a trend, Paul Farr, PPL Montana, and a Committee member at that time, speculated that the lower prices may have reflected less demand for energy due to conservation measures, cooler-than-expected weather, and the effect of the Federal Energy Regulatory Commission's wholesale energy price mitigation plan.²⁵ In addition, aluminum smelters in the Pacific Northwest had shut down, many of them finding they could make more money by selling their electricity than they could from producing aluminum.

²⁴Dow Jones Mid-Columbia Electricity Index (TM), June 2001, reported by energyonline.com, Transition Advisory Committee, Minutes, ATTACHMENT #4 (Helena, Montana, Legislative Services Division, June 19, 2001).

²⁵Transition Advisory Committee, Minutes, (Helena, Montana, Legislative Services Division, June 19, 2001), p. 4.

The decline in wholesale prices continued through the summer. For the first 17 days of August 2001 wholesale prices for firm, on-peak electricity ranged from a high of \$67.30 to a low of \$39.71 a megawatt hour. By February 2002, wholesale prices averaged around \$20 for the entire month.²⁶ The trend in wholesale energy prices caused MPC to rethink its agreement with PPL Montana.

In June 2001, MPC indicated that it was still committed to the agreement to buy 500 megawatts of electricity from PPL Montana. However, it never signed a contract with PPL Montana. The trend in wholesale prices of electricity in the early summer of 2001 caused MPC to reevaluate its position. MPC believed that the original agreement, given market trends, may not be in the best interest of its default supply customers. At the Committee's August 23, 2001, meeting, Bill Pascoe, Vice President of Energy Supply, described the initial profile of the company's energy supply portfolio that would go into effect July 1, 2002. He said that MPC had to obtain approximately 1,150-1,200 megawatts of power plus a reasonable reserve for peak requirements. The portfolio would consist of energy produced from existing in-state generation (50%), new generation from such sources as wind and natural gas (25%), and from market purchases (25%). In-state generation would include power from PPL Montana and from qualifying facilities. Pascoe noted that the proposed agreement between MPC and PPL Montana that was announced on April 21, 2001, for "unit-contingent" power was dead. However, negotiations with PPL for a new power contract were continuing. Pascoe said that he anticipated that the average price of electricity would rise from 6.7 cents a kilowatt hour to 8.5 cents, or about a 29% increase.²⁷

In the meantime, MPC was negotiating portfolio supply contracts with several other suppliers. It filed several applications with the Public Service Commission regarding power purchase agreements with Rocky Mountain Power, Inc., NorthWestern Generation 1, LLC, (otherwise known as Montana First Megawatts), and Thompson River Co-Gen, LLC. The PSC declined to take action on any of these agreements, but instead directed MPC to make one portfolio filing for PSC review.²⁸ On October 29, 2001, MPC filed an application with the PSC requesting to

²⁶Dow Jones Mid-Columbia Electricity Index (TM), February 2002, published by Energy On Line at <http://www.energyonline.com/dji/0202/djmid0202.asp>. Energy On Line previously provided the Dow Jones indices for all trading hubs free of charge. It is now provided through a subscription service.

²⁷Transition Advisory Committee, Minutes, August 23, 2001, pp. 18-19.

²⁸Montana Public Service Commission, Final Order, Docket No. D2001.10.144, Order No 6382d, June 21, 2002, p. 5.

establish new rates effective July 1, 2002, to reflect a default supply portfolio to serve customers that had not chosen another supplier.²⁹

At the Committee's November 16, 2001, meeting, Pascoe described the anticipated portfolio supply sources for the transition period. The sources are summarized in the table below.

DEFAULT SUPPLY SUMMARY: WINTER PEAK LOAD 2003-2004				
New Montana Generation	Megawatts	Total	% of Total Supply	Power Type
New Generation				
NorthWestern Energy--Montana	150		13.3%	Peak
First MegaWatts (Natural Gas)	(75-summer)			
Rocky Mountain Power (Coal)	100		8.9%	Baseload
Thompson River Cogeneration	10		0.9%	Baseload
Tiber Dam	5		0.4%	Baseload
Wind	63		5.6%	Baseload
	(30-summer)			
Total--New Generation		328	29.1%	
Existing Montana Generation				
PPL Montana	450		39.9%	Baseload (300) Heavyload (150)
Milltown Dam	2		0.2%	Baseload
Qualifying Facilities	100		8.9%	Baseload
Total--Existing Generation		552	48.9%	
Market Purchases		249	22.0%	Peak
Total Supply		1129		

Source: Montana Power Company
Staff Memorandum, Attachment 1, "Default Supply Portfolio", Montana Public Service Commission,
Docket No. D2001.10.144, May 31, 2002.

Of the total supply, 1,042 megawatts would have served the default supply load, while 87 megawatts, or 8.4%, would have been for reserve requirements. The contract period for energy

²⁹*Ibid*, p. 5.

purchases would range from 5 years (PPL Montana) to 30 years (qualifying facilities); the contract with Montana First Megawatts would have been for 20 years. MPC signed a 1-year contract with Duke Energy for 111 megawatts for the period before proposed new generation would have come online.

Under this scenario, the energy supply costs for the average residential customer,³⁰ would have increase from about 2.6 cents a kilowatt hour to 4 cents a kilowatt hour, or by about 54%. The overall increase in the cost of a kilowatt hour would increase from 6.7 cents to 8 cents or by about 20%. Other adjustments to the cost of electricity would include the imposition a competitive transition charge associated with qualifying facilities (0.26 cent), a small reduction in transmission charges, and a Bonneville Power Administration supply credit.³¹ In addition, the total increase in the overall energy bill in the first year would be offset by a \$30 million credit derived from the proceeds of the sale of MPC's transmission and distribution assets to the NorthWestern Energy (NWE), a subsidiary of NorthWestern Corporation based in South Dakota.

On June 21, 2002, the PSC issued its final order on the NWE default supply portfolio. The PSC approved the portion of the portfolio consisting of electricity from PPL Montana, Duke Energy, and electricity available from qualifying facilities and the Milltown Dam. However, the PSC concluded that each of the other "contracts" for electricity was not a procurement of default supply under 69-8-210(3)(b)³² "because each 'contract' contains 'regulatory out' language which binds NWE to the 'contract' only after certain specific approval by the Commission."³³ The PSC also concluded that "[t]o the extent that additional electricity supply is needed NWE will be required to purchase it in the short term market. NWE may enter into other power purchase contracts at any time."³⁴

Since the PSC's order, NWE has obtained electricity from the market to meet supply requirements that would have been met under the original default energy supply portfolio. The table on the following page compares the moderated rate design for residential customers under Order 6382d that was effective July 1, 2002, with the moratorium rates that were in effect since

³⁰Based on 750 kilowatt hours of consumption a month.

³¹Transition Advisory Committee, Minutes, Attachment 6, November 16, 2001.

³²This subsection was rendered void by voter rejection of House Bill No. 474.

³³Montana Public Service Commission, Final Order (Order No 6382d), June 21, 2002, p. 15.

³⁴*Ibid*, p. 15.

May 8, 2001. Energy supply costs for residential customers increased by 43.8% while supply and supply-related costs increased by 52.2%. Supply-related costs include the competitive transition charge (CTC) associated with qualifying facilities. Transmission, distribution, and universal system benefits charges remain the same under the new rate design. The overall increase in electricity rates was ameliorated by the Bonneville Power Administration credit and the \$30 million credit associated with the sale of MPC's transmission and distribution facilities to NorthWestern Energy. The overall increase in the kilowatt hour charge for a residential customer using 750 kilowatt hours a month is 9.96%. Because the fixed service charge of \$4.60 is figured into the kilowatt hour charge, the overall percentage change may be slightly higher or lower depending on whether a customer uses fewer than or more than 750 kilowatt hours in a month.

Comparison of Electricity Moratorium Rates with Portfolio Rates					
	Rates in Effect Prior to 7/01/02		Moderated Rate Design Compliance Filing Order 6382d		
Service Category	Kilowatt Hour Charge Effective 5/8/01	Total Bill Amount	Kilowatt Hour Charge Effective 7/1/02	Total Bill Amount	Percent Change
Service Charge	\$4.60	\$4.60	\$4.60	\$4.60	
Electricity supply	\$0.025973	\$19.48	\$0.037366	\$28.02	43.84%
Transition charge	NA	NA	0.002171	1.63	
Subtotal--energy	\$0.025973	\$19.48	\$0.039537	\$29.65	52.21%
Transmission	\$0.008107	\$6.08	\$0.008107	\$6.08	
Distribution	0.025234	18.93	0.025234	18.93	
USBC	0.001334	1.00	0.001334	1.00	
BPA credit	NA	NA	(0.002435)	(1.83)	
Sale credit	NA	NA	(0.004468)	(3.35)	
Total kilowatt hour charge	\$0.060648	\$45.49	\$0.067309	\$50.48	10.97%
Total bill (with service charge)	\$0.066781	\$50.09	\$0.073442	\$55.08	9.96%

Source: NorthWestern Energy

MONTANA POWER COMPANY BIDS ADIEU

The original restructuring legislation required a vertically integrated public utility entering the competitive market to functionally separate its generation, transmission, and distribution activities (69-8-204, MCA). Section 69-8-204 also allowed the public utility to divest itself of generation assets. In October 1998, the Montana Power Company announced the sale of most of its generation assets to Pennsylvania Power & Light Global Resources. The sale was completed in December 1999.

Surveying the economic landscape, MPC concluded that being a competitive telecommunications service provider seemed financially more attractive than being a default supplier of electricity. In early October 2000, MPC announced that it had entered into a purchase agreement with NorthWestern Corporation, based in Sioux Falls, South Dakota, to sell its electric and natural gas utilities to NorthWestern. On December 28, 2001, following an extended process to determine whether NorthWestern would be a "fit, willing, and able provider of adequate service and facilities at just and reasonable rates", MPC, NorthWestern, the Montana Consumer Counsel, the Large Customer Group (choice customers for the most part), and Commercial Energy filed a stipulation agreement with the Public Service Commission.³⁵ The agreement contained a provision that the PSC must approve the stipulation as presented or all bets were off. The principal elements of the stipulation included:

- NorthWestern is a fit, willing, and able provider of adequate service and facilities;
- MPC and NorthWestern will establish an account of \$30 million for providing a credit against kilowatt electricity charges beginning July 1, 2002;³⁶ and
- the net present value of MPC's transition costs would be \$244.7 million, or \$60 million less than previously calculated.³⁷

³⁵STIPULATION, Docket No. D97.7.90 and Docket No. D2001.1.5, December 28, 2001.

³⁶The credit is derived from gain on the sale to NorthWestern.

³⁷The transition costs, which will be included on customer bills through 2029, are related exclusively to qualifying facilities contracts and do not include environmental liabilities associated with the Milltown Dam. The settlement of transition costs resolved the so-called "Tier II" issues.

On January 31, 2002, the Public Service Commission issued a final order, adopted unanimously and in accordance with the stipulation, to allow the sale of MPC's electric and natural gas utility assets to NorthWestern Corporation.³⁸

Shortly after the sale was complete, the Montana Power Company disappeared after having served the state for over 80 years. NorthWestern began advertising its energy services in Montana as NorthWestern Energy.

HOUSE BILL NO. 474 REJECTED BY THE VOTERS

Shortly after the end of the 2001 legislative session, Representatives Michelle Lee of Livingston and Christopher Harris of Bozeman initiated a petition to refer House Bill No. 474 to the voters at the November 5, 2002, general election. They argued that the legislative process that led to the enactment of the legislation was flawed and was closed to public scrutiny. In addition, Montana taxpayers would be on the hook for a default on any energy loans provided by the Montana Board of Investments.

The effort to refer House Bill No. 474 was delayed when Attorney General Mike McGrath concluded that the proposed referendum was unconstitutional because the legislation included an appropriation. Article III, section 5, of the Montana Constitution prohibits referring an act of the Legislature that includes an appropriation of money. House Bill No. 474 statutorily appropriated up to \$100 million each year from the revenue derived from the excess revenue tax that would have been imposed by Senate Bill No. 512 for the consumer electricity support program. The sponsors of the referendum appealed the Attorney General's interpretation to the First District Court in Helena. District Court Judge Jeffrey Sherlock rejected the Attorney General's interpretation stating that the appropriation was unfunded (because Senate Bill No. 512 was not enacted) and the measure could be referred to the voters. The referendum qualified for the ballot as Initiative Referendum No. 117.

On November 5, 2002, the voters rejected House Bill No. 474 by a 60% to 40% margin. Finding out why voters rejected the measure may make a good thesis topic for a graduate student. However, one thing rejection did not do was overturn restructuring in Montana: restructuring is about where it was when the Legislature convened in January 2001. No other bill related to restructuring was directly affected by voter rejection. For example, Senate Bill No. 19 extended the transition period to June 30, 2007, and Senate Bill No. 269 indefinitely delayed transition to

³⁸Montana Public Service Commission, **Final Order**, Oder No 6353c, January 31, 2002.

competition for Montana Dakota Utilities. Rejection opened the opportunity for multiple default suppliers and allows full cost recovery for the default supply.

COMMITTEE ACTION

At its April 26, 2002, meeting, the Transition Advisory Committee discussed the legal implications of voter rejection of House Bill No. 474.³⁹ The Committee decided at that time there were elements of House Bill No. 474 that should be preserved if House Bill No. 474 bit the dust. It recommended that:

- a customer who chose another supplier may return to the default supply;
- the sunset date for universal system benefits charges be extended to December 31, 2005; and
- a buying cooperative may not also be a default supplier.

On November 21, 2002, the Committee voted to submit, *without recommendation*, the following bill drafts for legislative consideration that would restore or refine several provisions contained in House Bill No. 474:

- LC 396: providing for the recovery of electricity supply costs.
- LC 397: allowing a customer to return to default supply, providing for customer choice, and maintaining default supply obligations beyond the transition period.
- LC 398: restricting the purpose of electric buying cooperatives to supplying or promoting alternative energy and conservation programs.
- LC 399: extending universal system benefits charges to December 31, 2005.

The committee also requested a bill draft (LC 671) to revise the structure and function of the Transition Advisory Committee.

PROPOSED GENERATION PROJECTS

At the November 16, 2001, Committee meeting, representatives of four different electrical energy concerns described the progress of their respective electrical energy generation projects. Dan Rapkoch, Continental Energy, discussed the Silver Bow Energy project. The generation facility would be a 500-megawatt combined cycle natural gas-fired power plant, located in the Silicon Mountain industrial park west of Butte. It would be a base-load unit intended primarily for Montana customers, with excess power sold out of state. The price of electricity would be

³⁹See Todd Everts, Legal Impacts of Rejection of HB 474 by Montana Voters, Memorandum to the Transition Advisory Committee, April 22, 2002, at http://www.leg.mt.gov/css/lepo/subcommittees/energy_policy/default.asp.

cost-based, including a reasonable rate of return. Pending completion of an environmental impact statement, project developers anticipated that construction would begin in the fall 2002. The construction phase would employ 700 workers. Commercial generation of electricity would commence in late 2004, and the plant would employ 25 permanent workers.

Mike Schmechel discussed the proposed Comanche Park project (Black Hills Corp.), located near Broadview, Montana. This project would include two coal-fired generation units, each with a capacity of 80 to 100 megawatts. Construction of the first unit is scheduled for mid-2004, and the second unit is scheduled for mid-2005. Again, the sale of electricity is intended primarily for Montana customers. The goal of project developers is to provide electricity for the default supply portfolio but may also provide electricity to Montana cooperatives, including the Flathead Electric Cooperative. Schmechel noted that coal-fired generation units are more labor and capital intensive than natural gas generation but that fuel costs are more stable. Because of the proximity of the plant to the Broadview substation, Schmechel does not anticipate problems with transmission.

Joe Dickey, FGS & Associates, described a proposed coal-fired generation project in the Roundup area. Two 350-megawatt units would be built. Construction of the units was anticipated to begin in 2002, with the first unit scheduled for operation by October 2005 and the second unit scheduled for operation by June 2006. The Bull Mountain coal mine would provide fuel for the projects. Although underground coal is more expensive to mine than surface coal, transportation costs are minimal. In addition, the heat content of the coal is 20% higher than other Montana coal. According to Dickey, electricity supply costs would be 3¢ or less a kilowatt hour. Transmission lines would be connected to the Broadview substation or to the rural electric cooperatives grid. Dickey said that electricity from the proposed projects would enhance the stability of the transmission system. Some electricity from the project would be sold out of state.

Clark Fritz provided a press release that described a joint project of Great Northern Power Development, LP, and Kiewit Mining, Inc. Project developers plan constructing one or more 500-megawatt coal-fired generation plants in eastern Montana. Coal would be supplied by nearby coal mines. According to the press release, each project would take 5 to 7 years to develop and would employ up to 150 workers to operate the combined mine and power plant. Electricity supply costs would be about 3¢ a kilowatt hour. Electricity would be sold to Montana customers as well as to regional customers. The go-ahead for the project may be contingent on the results of the transmission upgrade study conducted by the Western Area Power Administration (see

Chapter 2). Project developers said that they intended to take advantage of the production and tax incentives enacted during the 2001 legislative session.

"THE STRANGE AND TERRIBLE SAGA"

It is a truism that restructuring has altered the contours of the energy landscape in Montana. The Montana Power Company is gone. We are supplied with electricity from companies that we probably did not know existed until just a few years ago. PPL Montana now owns most of the generation facilities in the state and is actively engaged in wholesale energy markets.

NorthWestern Energy has taken over the transmission and distribution system of the former MPC service territory and has been putting together an electricity supply portfolio from a variety of different electricity sources; the company is known as a default supplier.

Although the transition period was extended to June 30, 2007, most Montana customers are now exposed to the vagaries of the wholesale energy markets. Some small customers in Montana may choose a different supplier, but it is likely many will stay with the default supplier. That choice may be affected by whether the Montana Public Service Commission continues its policy to make the default supplier the least-cost supplier or adopts a new policy to make it the supplier of last resort. On the other hand, Montana-Dakota Utilities, as a regulated utility, still provides bundled services to its customers in eastern Montana, and all but two rural electric cooperatives provide electricity in the same manner as they always have.

Despite the relative stability of energy prices,⁴⁰ the Northwest Power Planning Council has forecast a 15% chance of power shortages during the winters of 2005 and 2006.⁴¹ In November 2001, the probability of power shortages in the winter of 2002 was 1%, while in March 2001 the probability was 24%.⁴² There are several bill draft requests that have been submitted for the 2003 Legislature that would revise electric utility laws. Fortunately, the Legislature will have a better opportunity to reflect on what it wants to do related to energy policy than it had in 2001.

⁴⁰The Mid-Columbia Index has been in the mid-forty dollar price range per megawatt hour during December 2002.

⁴¹Helena Independent Record, "Power could be short in near future", December 14, 2002, p. 1C.

⁴²John Hines, Northwest Power Planning Council, **EQC Presentation: Electricity Markets in the Pacific Northwest**, December 10, 2001.

CHAPTER 2

ELECTRICAL ENERGY TRANSMISSION

INTRODUCTION

Supporters of retail competition maintain that wholesale energy markets have not sufficiently "matured" to allow deregulation to thrive. A significant component of wholesale energy markets is the ability to move a lot of power over transmission lines. In many parts of the country, including the Pacific Northwest, the transmission system is beyond mature and may be more accurately described as decrepit. Federal and state agencies, transmission owners, electrical generation owners, and rural electric cooperatives have been working to improve the transmission system in the Pacific Northwest. This chapter highlights some of those efforts.

On November 16, 2001, Transition Advisory Committee staff presented the *Draft Work Plan for the 2001-2002 Interim*. Because of existing and potential "bottlenecks" in the transmission system in Montana and surrounding states, the Committee decided to review the technical and regulatory aspects of transmission, especially as they relate to restructuring and the development of new generation in Montana. Senator Fred Thomas appointed Dave Wheelihan to chair a Transmission Subcommittee. Other members of the subcommittee included Representatives Roy Brown, Steve Gallus, and Alan Olson, and Senators Don Ryan, Emily Stonington, and Fred Thomas.

REGIONAL TRANSMISSION ISSUES

The Transmission Subcommittee held its first meeting on January 24, 2002. Representatives from the Northwest Power Planning Council, the Montana Power Company, and the Bonneville Power Administration presented reports on the status of the state's transmission system as well as the regional system.

John Hines, Northwest Power Planning Council, discussed the importance of the transmission system to Montana.¹ He noted, among other things, that:

- an effective retail energy market requires a competitive wholesale market, which in turn requires an efficient transmission system;
- the regional transmission system is operating near capacity;
- transmission congestion problems may affect delivery and lead to system failure;

¹Transmission Subcommittee, Minutes, Attachment 3, January 24, 2002.

- Montana needs access to "load" centers if it is to develop new generation; and
- federal open-access transmission policies are not fully implemented and generators may not be able to obtain reliable and firm transmission.

Mr. Hines also discussed the role of the Federal Energy Regulatory Commission in the development of transmission policy. He noted that FERC Order 888 requires open and equal access to the transmission system. In addition, FERC Order 2000 requires that transmission owners consolidate into regional transmission organizations (RTOs). Mark Donaldson, Montana Power Company (MPC), described the difference between point-to-point transmission and tariffs and network transmission and tariffs. Under point-to-point transmission, a customer chooses a point of entry on the system and a point of delivery to an end-user. Firm and nonfirm transmission is available for point-to-point transmission on a first-come, first-served basis. Preference is given to longer-term commitments, and payment has to be made in order to reserve access to the transmission system. Users of point-to-point transmission pay a specified rate for use of the system. Network transmission typically serves the native load of a generator. A customer pays for its share of the cost of the system instead of a specified rate. Under FERC Order 888, transmission service providers are required to electronically post information about the transmission system, rates, available capacity, and the ability to reserve access to transmission.

Vickie VanZandt, Bonneville Power Administration (BPA), described the current situation in the Bonneville service territory. According to VanZandt, load growth in the BPA service territory has been increasing by 1.8% a year, but little transmission has been added since 1987. BPA has developed a proposal to enhance the transmission infrastructure and to increase the capacity of the transmission grid. The purpose of the proposal is to integrate additional generation facilities, reduce congestion on the transmission lines, and increase the reliability of the system. Improvements to the transmission system would reduce the chances for cascading blackouts, facilitate the development of wholesale energy markets, and increase the flexibility of the system. Ms. VanZandt said that BPA plans to spend \$800 million to upgrade transmission corridors in the Pacific Northwest.²

At the Subcommittee's February 14, 2002, meeting, panelists from the BPA, MPC, a western Montana rural cooperative, the governor's office, and the Columbia Falls aluminum plant discussed the formation of a regional transmission organization (RTO West) that would include Washington, Oregon, Idaho, Nevada, Utah, most of Montana and Wyoming, and a small area of

²Transmission Subcommittee, Minutes, Attachment 4, January 24, 2002.

California and Canada. Participants in the development RTO West include BPA, a Canadian power authority, eight investor-owned utilities, and other stakeholders. The purpose of RTO West would be to enhance wholesale and retail competitive markets and to ensure a secure and reliable transmission system for the region. Although ownership of transmission lines would not change, the operation of the regional transmission system would be managed by a nonprofit entity that would be responsible for tariff administration and design. RTO West would eliminate the distinction between firm and nonfirm transmission and would allow customers more opportunity to gain access to the transmission system. According to a preliminary benefit-cost analysis, the establishment of RTO West would have a net benefit to the region of \$350 million, but Montana customers may experience increased costs. Benefits to the system include eliminating "pancaked" (or different charges imposed in different service territories) transmission charges and the coordination of maintenance and scheduling of transmission and generation. Panelists generally agreed that the concept of a regional transmission organization is a good one but pointed out that the proposal is complicated. Details such as the rate structure, cost shifting, benefits and costs, the level of state involvement, and whether existing transmission contracts will be honored need to be worked out.

Congress authorized the Western Area Power Administration (WAPA) to conduct a study of transmission expansion options in the Upper Great Plains Region, including Montana. Transmission capacity in the region is insufficient to support new electrical generation capacity. In October 2001, WAPA solicited suggestions from interested parties for the sites in Montana that should be studied as potential locations for new generation. Ed Weber and Robin Johnson, WAPA project staff, discussed the scope of the Montana portion of the study. Based on suggestions received at the "scoping" meeting, the generation options would include 1,000-megawatt generation facilities at Colstrip (coal) and Great Falls (natural gas), 500 to 600-megawatt generation facilities at Billings (thermal) and Ft. Peck (wind), and 100-megawatt wind generation facilities at various locations in the state. Transmission options would include 230 to 500-kilovolt transmission lines running to Spokane, Pocatello, Denver, and Salt Lake.³

Larry Taylor, FGS & Associates, described the advantages of direct current transmission lines including transmitting power directly from one point to another, limited right-of-way requirements, lower line losses, and less expensive construction costs.

³At the Subcommittee's September 13, 2002, meeting, Ed Weber presented a summary of the WAPA study. The results of the study may be found at <http://www.wapa.gov/ugp/study/Results.htm>.

FERC AND COMPETITION

The Subcommittee spent considerable time discussing federal policy related to transmission and what options Montana could pursue.⁴ Since the enactment of the Energy Policy Act in 1992, the Federal Energy Regulatory Commission⁵ (FERC) has been promoting efficiency in the wholesale energy markets, including enhancement of transmission infrastructure and the establishment of independent operators to manage regional transmission systems. Even before the enactment of the Energy Policy Act, FERC had recognized that control over transmission can effectively block competition in wholesale energy markets.

In 1996 FERC issued two notices of proposed rulemaking. The first rule (Order 888) required that electric utilities provide open, nondiscriminatory access to their transmission capacity.⁶ Theoretically, vertically integrated utilities would no longer be able to use their transmission facilities to favor their own generation over the new class of wholesale generators. The order also provided that utilities could recover wholesale "stranded costs" on power plants if their customers moved to other suppliers. Stranded costs include generation-related and electricity supply costs that are unrecoverable as a result of competition. As noted in Chapter 1, these costs include, among others things, regulatory assets and deferred charges; certain power purchase contracts, including qualified facilities contracts; and generation and supply commitments. The rationale for the recovery of stranded costs is that the utility cannot sell energy at a high enough price to recover prudently incurred costs because of lower-priced electricity under competition.⁷

⁴At the Subcommittee's April 25, 2002, meeting, Matthew Brown, National Conference of State Legislators, presented some policy options related to state jurisdiction of transmission. Those options are discussed in the Electricity Policy Options for Montana: A Report and Discussion of Policy Options, the companion report to this document.

⁵FERC is a five-member quasi-independent federal agency appointed by the president, and confirmed by the Senate, to staggered 5-year terms. No more than three members may be from the same political party.

⁶FERC has jurisdiction over investor-owned utilities because the wholesale sale of electricity is considered as interstate commerce, regardless of whether electricity moves across state lines. The important factor is that the utility is connected to an interstate grid. FERC jurisdiction does not now apply to public utility districts, the Bonneville Power Administration, or the Tennessee Valley Authority.

⁷Under the FERC order, the recovery of stranded costs associated with retail competition would be resolved by a state's public service commission. The Montana Public Service Commission allowed recovery of stranded costs (or competitive transition charges) associated with MPC contracts for the purchase of electricity from qualified facilities. They are now an itemized cost on our NorthWestern Energy bills. These are the only stranded costs passed on to customers under Montana's restructuring scheme.

FERC also asserted exclusive jurisdiction over rates, terms, and conditions of unbundled retail transmission in interstate commerce up to the point of local distribution.⁸ FERC allowed state regulatory authorities or policymakers to maintain control over applicable generation costs, siting of new generation facilities and transmission lines, and service territories and allowed them to determine whether the state decided to restructure its retail electricity markets.

FERC also issued a companion rule (Order 889) that required public utilities to post available transmission capacity on the Internet under the Open Access, Sametime Information System (OASIS). It also required that power marketers of the utility obtain information about available transmission capacity of the utility from OASIS. This functional separation of generation and transmission was intended to prevent the utility's power marketers from obtaining preferential access to transmission capacity.⁹

FERC recommended that regional utilities establish an independent system operator (ISO) as one way to effect functional separation and to promote competition. FERC set out principles for the creation of independent system operators that included system governance, operational control, transmission reliability, and transmission pricing.¹⁰ One advantage of the ISO would be to eliminate multiple transmission charges, or pancaking, as electricity flows through different utilities' transmission lines.

SOME SUCCESS, SOME FAILURE

Shortly after the adoption of Order 888, transmission providers in California, in Pennsylvania-New Jersey-Maryland, New England, and New York, in the Midwest, and in Texas established ISOs in their respective "power pool areas". Except for Texas and California, the ISOs were established in relatively small geographic areas. In total, the ISOs encompassed about 25% of electrical generation capacity in the United States.¹¹ As such, most of the transmission facilities operated outside a regional organization. There was very little progress in the development of

⁸"Commission Orders Sweeping Changes for Electric Utility, Requires Wholesale Markets to Open to Competition", p. 11, at http://www.converger.com/fercnopr/888_889.htm. The title of the article hints at why Order 888 has been referred to as the "mega-NOPR".

⁹"Commission orders" *op cit.*, p. 3.

¹⁰Prepared Statement of Shelton Cannon, Director, Office of Electric Power Regulation, Federal Energy Regulatory Commission, before the Virginia General Assembly Joint Subcommittee, July 9, 1998, p. 2.

¹¹Andrew Weissman, FERC 101/102: The Battle Over Open Access, Round 1, Vol. II, (Washington, DC, energybusinesswatch), p. 84.

regional transmission systems during the years following the creation of the initial ISOs. Efforts to create ISOs in the Pacific Northwest (Independent Grid Operator), the Mid-American Power Pool, and the Southwest (Desert STAR) came to nought.

Disappointed in the progress in the development of ISOs, FERC decided a more focused approach was required to enhance the management of the nation's transmission systems and to promote competition in electricity markets. On May 13, 1999, FERC released a proposed rule on regional transmission organizations for the operation and expansion of the transmission system. FERC noted that the transmission system operates as a "single machine" and that the multiple management of the machine inherently leads to inefficiencies, at best, and system failure at worst. FERC also concluded that many utilities were less than diligent in providing open access to their transmission facilities.

On December 20, 1999, FERC adopted the proposed rule as Order 2000 (Docket No. RM99-2-000). The rule calls for the "voluntary" formation of regional transmission organizations (RTOs). Transmission owners would turn over the operation of their transmission facilities to the regional organization. The rules specified that an RTO would have responsibility for the operation and expansion of the transmission system under its control, maintaining short-term reliability, establishing and managing tariffs, and responding to requests for service (e.g., interconnection service).¹² The RTO would also be responsible for eliminating rate pancaking (by imposing a single charge for using the transmission system) and for congestion management. The key characteristic of the RTO is that it would operate independently from market participants.

In the order, FERC stated that it expected utilities to voluntarily form RTOs. If they did not, FERC would "reconsider what further regulatory steps are in the public interest."

Eight utilities (Avista, Idaho Power Co., Montana Power Co. Nevada Power Co., PacifiCorp, Portland General Electric Co., Puget Sound Energy Co., and Sierra Pacific Resources) operating in eight states,¹³ the Bonneville Power Administration (BPA), and British Columbia Power Authority formed RTO West and developed a proposal for complying with Order 2000. Because BPA owns about 80% of the transmission lines in the Pacific Northwest and about 50% in the RTO West service territory, its participation in the RTO proposal was critical. Whether BPA

¹²Hyde M. Merrill, "Regional Transmission Organizations: FERC Order 2000", IEEE Power Engineering Review, July 2000, p. 1.

¹³The states include all or part of Washington, Oregon, Idaho, Montana, Nevada, Utah, Wyoming, and a small part of California near the Oregon border.

participates in the operation of the RTO depends on how it assesses the impact of the RTO proposal on its customers. On September 18, 2002, FERC approved many of the aspects of the RTO West proposal.

WORK IN PROGRESS: STANDARD MARKET DESIGN

The Commission's goal, which may be the only consistent feature of restructuring, is "to promote efficiency in wholesale electricity markets and ensure that electricity customers pay the lowest price possible for reliable service". Well, not quite true. FERC has consistently been disappointed with the implementation of its various orders, and Order 2000 was no exception. In March 2002, FERC issued a working paper¹⁴ that detailed its concern about the slow pace of RTO development and what it intended to do about it. FERC still fretted over transmission owners favoring their own generation, the lack of regional coordination that contributed to congestion and to transaction curtailments, and the fact that market design flaws are evident in every region of the country. The solution: standard market design.

On July 31, 2002, FERC issued a notice of proposed rulemaking to implement standard market design. The goal of the new rule would be to establish a framework that promotes transmission system reliability and expansion, mitigates market control by an energy supplier, and increases choices for wholesale market participants. The new rule would require that any transmission owner must use an independent transmission provider (ITP) regardless of whether the transmission owner provides bundled services or is a member of an RTO. The rule would apply to "nonjurisdictional" public power entities owned, for example, by municipalities and counties. The new rule would also revise transmission pricing to encourage the sale of power from low-cost areas to high-cost areas. Congestion management would be handled through a locational marginal pricing scheme. It is beyond the scope of this report to describe the pricing scheme, but it would allocate transmission capacity to those who value it the most. FERC believes that price signals under standard market design would encourage short-term efficiency for wholesale energy markets and promote long-term efficiency for new generation, changes in demand response, and the development of transmission infrastructure.

Under the standard market design proposal, FERC would expand its jurisdiction well beyond what it has asserted in the past to all aspects of the electrical energy markets. In addition to establishing the legal framework within which electrical energy markets would operate, FERC is

¹⁴"Working Paper on Standardized Transmission Service and Wholesale Electric Market Design," Federal Energy Regulatory Commission. The working paper is available on the FERC website at <http://www.ferc.gov>.

creating pricing mechanisms, getting involved in technical and engineering details, and perhaps, most important, limiting state public service commission regulatory authority. States in a region would be involved in the oversight of RTOs through regional state advisory committees. The advisory committees would be consulted on such things as resource adequacy standards, transmission planning and expansion, rate design, and market monitoring, but they would have no real legal authority.

WHAT'S NEXT?

The initial deadline for comments on the proposed rule was October 15, 2002. However, it didn't take that long for some state and federal officials to begin hurling epithets in FERC's direction. One commentator likened the proposed rule to economic planning in the Soviet Union. The chairman of FERC, Pat Wood, shot back, admonishing critics to read the "dang" rule before commenting on it. Naysayers aside, there is a lot of legitimate concern about the proposed rule. Representatives in low-cost states are worried that energy prices will go up under the new rule. Others are concerned about the effect on existing transmission contracts and the potential for cost-shifting. Many state public service commissions resent the apparent usurpation of their regulatory authority and argue that FERC is exceeding its statutory authority. Public pressure caused FERC to delay the comment period until November 15, 2002, and to further delay the comment period on certain parts of the rule until January 10, 2003.

Representatives of RTO West are working on how to integrate standard market design with the recent FERC order approving many aspects of the regional transmission organization. Almost everyone is imploring FERC to slow down and work more closely with the various regions to devise a structure that will work in the respective regions.

The Transmission Subcommittee did not develop any specific policy proposals. It did recommend to the Transition Advisory Committee that it send a letter to the Montana congressional delegation requesting that the delegation persuade FERC to proceed deliberately with standard market design and to extend the comment period on the proposed rules. The Committee adopted the recommendation and sent a letter to the Montana delegation.

MONTANA RESPONDS TO STANDARD MARKET DESIGN

Shortly after FERC issued its proposed rules on standard market design, representatives of the Governor's office, the Northwest Power Planning Council, the Public Service Commission, the Montana Consumer Counsel, Central Montana Electric Cooperative, and Western Montana Generation and Transmission Cooperative created an standard market design working group to

develop consensus comments on the proposed rules. On November 27, 2002, the working group filed comments with FERC related to issues designated for comments on November 15, 2002.

The comments addressed the following issues:

- allow market participants and stakeholders in RTO West to develop a regional structure compatible with the Pacific Northwest;
- ensure that customers of one state do not incur higher costs in order to provide benefits to customers in other parts of the region;
- review policy regarding the presentation of existing contracts; and
- assess marketing and mitigation strategies.

CHAPTER 3
UNIVERSAL SYSTEM BENEFITS PROGRAMS
2001-2002 ACTIVITIES

BACKGROUND

Senate Bill No. 390 (Ch. 505, L. 1997) established universal system benefits programs (USBP). In order to ensure continued funding of USBP, the Legislature required that, beginning January 1, 1999, each utility and rural electric cooperative must contribute 2.4% of its 1995 retail sales revenue cooperative as its annual USBP funding level. A utility's or cooperative's minimum annual funding requirement for low-income energy and weatherization assistance is 17% of its annual USBP funding level. The USBP costs are recovered through a USBP charge assessed at the meter for each local utility customer. The USBP funding mechanism must remain in effect until July 1, 2003. Utilities, cooperatives, and large customers are allowed credits against their contributions to the USBP fund, and cooperatives may collectively pool their statewide credits.

The purpose of the USBP fund is “to ensure continued funding of and new expenditures for energy conservation, renewable resource projects and applications, and low-income energy assistance during the transition period and into the future” (69-8-402(1), MCA). USBP public purpose programs include:

- cost-effective local energy conservation;
- low-income customer weatherization;
- renewable resource projects and applications, including those that capture unique social and energy system benefits or provide transmission and distribution system benefits;
- research and development programs for energy conservation and renewables; and
- market transformation to encourage competitive markets for public purpose programs low-income energy assistance.

Senate Bill No. 390 required the Transition Advisory Committee to make recommendations before July 1, 2002, to the 2003 Legislature regarding the ongoing need of USBP and the annual funding requirements. The Committee is also required to monitor and evaluate USBP and comparable levels of funding for the region and make recommendations to the 2003 Legislature to adjust funding levels to coincide with the region.

At its November 16, 2001, meeting, the Committee established the USBP Subcommittee. The purpose of the Subcommittee was to analyze the ongoing need of USBP and comparable funding issues and to make recommendations to the Committee.

STATUTORY REQUIREMENTS

Sections 69-8-501(14) and (15), MCA, require that:

- (14) The Transition Advisory Committee shall monitor and evaluate the universal system benefits programs and comparable levels of funding for the region and make recommendations to the 58th Legislature to adjust the funding level provided for in 69-8-402 to coincide with the related activities of the region at that time.
- (15) On or before July 1, 2002, the Transition Advisory Committee, in coordination with the [Public Service] Commission, shall conduct a reevaluation of the ongoing need for universal system benefits programs and annual funding requirements and shall make recommendations to the 58th Legislature regarding the future need for those programs. The determination must focus specifically on the existence of markets to provide for any or all of the universal system benefits programs or whether other means for funding those programs have developed. These recommendations may also address how future reevaluations will be provided for, if necessary.

USBP INFORMATION PRESENTED TO THE SUBCOMMITTEE

The USBP Subcommittee met three times during the interim and gathered an extensive amount of information. Set out below is a summary of that information.

Chronology of USBP:

1996:

- Governor's comprehensive regional review of energy recommended that public purpose funding (USBP) in Montana, Oregon, Idaho, and Washington be at 3% of 1995 revenues from the sale of electricity services in the region.¹⁵

1997:

- Senate Bill 390 established the universal system benefits charge for all electric distribution utilities at 2.4% of 1995 electric utility revenues to begin January 1, 1999.

¹⁵Northwest Power Planning Council, Comprehensive Review of the Northwest Energy System: Final Report, Document No. CR96-26, (1996) at <http://www.nwcouncil.org/library/1996/cr96-26.htm>.

- Public purpose categories include low-income weatherization and bill assistance, energy conservation, market transformation, renewable energy resources, and research and development.
- For large customers, those with loads greater than 1000 kW, the USBC rate is 0.9mills/kWh and large customers are allowed to self-direct to qualifying public purposes.
- The minimum funding level for low-income activities is 17% of total funds collected.
- Rural electric cooperatives are allowed to pool expenditures to achieve 2.4% of total cooperative revenues.
- Unspent funds were transferred to low-income USBP or state USBP funds.

1999:

- USBP rates were fixed at the initial funding level.
- The large customer definition was clarified.
- The Department of Revenue (DOR) was established as the entity to whom reports are submitted, a timeline for rules was established, a challenge process was defined, state USBP fund administrators were named (Department of Environmental Quality for the USBP fund and Department of Public Health and Human Services for the low-income USBP fund).
- DOR established USBP rules for 2000 and beyond.

2001:

- The Legislature clarified that amortized and nonamortized power purchase costs associated with conservation and renewable energy are qualifying USBP activities.
- The Legislature required that 6% of total funds be directed to conservation for irrigated agriculture starting July 1, 2001 (for utilities that have filed transition plans: NorthWestern Energy, Glacier Cooperative, and Flathead Cooperative).
- The Legislature extended the statutory USBP sunset date from July 1, 2003, to December 31, 2005.

2002:

- On November 5, 2002, voters through referendum rejected House Bill No. 474. The voters nullified the Legislature's attempt to extend the USBP sunset date to December 31, 2005. The voters also nullified the requirement that 6% of the USBP funds be directed to conservation measures for irrigated agriculture.

How does the USBP funding mechanism work?

The recovery of all universal system benefits programs costs is authorized through the imposition of a universal system benefits charge assessed at the meter for each local utility system customer. The customer's distribution utility is required to collect USBP funds from the customer. The PSC sets USBP rates for utilities subject to its jurisdiction and the governing boards of cooperatives set rates for cooperatives. All utilities and cooperatives are required to file an annual report with the Department of Revenue detailing their USBP expenditures. Large customers claiming credit for USBP activities must also file a report with DOR.

What is the total USBP obligation?

For the year 2001 the total USBP obligation was:

Montana Power Company (NorthWestern Energy)	\$8,200,994
Montana-Dakota Utilities	\$574,668
Montana Rural Electric Cooperatives	\$3,805,195
Columbia Falls Aluminum Company	<u>\$500,000</u>
Total:	\$13,080,857

How are USBP funds allocated?

For the year 2001 USBP funds were allocated as follows:

Montana Power Company (NorthWestern Energy) :	
Conservation	19%
Market Transformation	11%
Renewable Energy	12%
Research and Development	3%
Low-Income Programs	21%
Irrigation	1%
Large Customers (self-directed USBP)	<u>33%</u>
Total:	100%
Montana Rural Electric Cooperatives:	
Energy Conservation Programs	81.5%
Low-Income Programs	15.6%
Renewable Resource Projects	2.4%
Research and Development	<u>0.5%</u>
Total:	100.0%

Montana-Dakota Utilities:

Low-Income Programs	61.5%
Conservation Programs	4.5%
Research and Development	18.0%
Percentage of Unspent Money Directed to the State	<u>16.0%</u>
Total:	100.0%

Who implements low-income USBP?

There are private and governmental programs in Montana that assist low-income electricity consumers. Mechanisms for assisting low-income consumers include bill discounts, deferred or delayed payment, direct financial assistance, and home weatherization programs. Many of the low-income electricity programs are funded either through federal money allocated to the state or through universal system benefits program charges assessed to electricity consumers. The entities that provide these low-income electricity assistance services are described below.

Low Income Energy Assistance Program (LIEAP): LIEAP is a federal program, administered by the state of Montana, that pays a portion of eligible households' winter heating costs. In most cases, payments are made directly to utility companies and fuel vendors. With the exception of Montana's seven Indian reservations, the state Department of Public Health and Human Services (DPHHS) administers LIEAP throughout Montana. LIEAP is administered by DPHHS and operated by 10 private, nonprofit Human Resource Development Councils (HRDCs) and one Area Agency on Aging. Eligibility for LIEAP funds is limited to those at or below 150% of the federally defined poverty level. For a family of four to be eligible for LIEAP funds in 2002, it cannot earn more than \$26,475.

LIEAP also provides funding for low-income household weatherization. Weatherization includes heating system tuneups, air infiltration reduction, and attic, wall, and floor insulation. The weatherization program is operated statewide by 10 private, nonprofit HRDCs and two tribal governments.

Energy Share of Montana: Energy Share of Montana is a nonprofit organization funded by USBP dollars and private donations. Energy Share helps Montanans faced with energy emergencies to meet their needs by providing bill assistance and furnace safety services. Energy Share works with HRDCs to determine eligibility. In order to receive assistance from Energy Share, an individual or family must meet the following guidelines:

- Annual income must be at 150% or less of the federally defined poverty level; exceptions to this guideline must be documented.
- The household's source of heating is threatened.

The recommended maximum amount of financial assistance from Energy Share is \$500. Assistance from Energy Share is provided only once in a lifetime, unless there are unusual or extreme circumstances or a portion of assistance is repaid.

Local Human Resource Development Councils: Local HRDCs are private, nonprofit local organizations that play a critical role in operating LIEAP programs and determining LIEAP and Energy Share eligibility. The HRDCs also operate the low-income weatherization programs across the state.

Public Utilities and Electric Cooperatives: Public utilities and electric cooperatives assist low-income Montanans by providing their LIEAP customers with an additional discount on their electric bills. Discounts range from 13% to 15%. Some utilities and cooperatives also provide flexible payment options and make every effort to avoid discontinuing electric service. Public utilities and electric cooperatives also help fund low-income weatherization.

Statistics for low-income energy assistance

The LIEAP program served 16,824 low-income households during the 2001-2002 winter. Of these households, 4,284 were occupied by senior citizens, 5,674 were occupied by disabled individuals, and 9,834 were occupied by female heads of household. During the 2002-2003 winter, the LIEAP program anticipates helping 21,500 households. This winter, contingent upon federal funding, benefit payments will range from \$63 to \$1,822. The level of assistance depends on household income, fuel type, fuel costs, local climate, and type and size of dwelling. The average LIEAP benefit payment will be about \$352.

Energy Share of Montana provided \$733,164 in bill assistance during the 2000-2001 winter to 2,241 households. In addition, Energy Share contributed \$63,581 to 120 households for furnace safety measures.

USBP conservation and renewable energy

The Subcommittee heard extensive testimony on conservation, renewable energy, and market transformation projects that are using USBP funds. The National Center for Appropriate Technology (NCAT) provided testimony on some of the uses of NorthWestern Energy's renewable energy and market transformation USBP funds. USBP funds helped pay for renewable

energy systems across the state. NCAT helped install systems in 17 schools, 14 ranches, 74 homes, two public buildings and four businesses. There are over 24 businesses across the state that sell, service, and install renewable energy systems.

The Subcommittee heard from appliance dealers on the success of the *Energy Star* program (a market transformation program). The *Energy Star* program is voluntary national labeling program designed to identify and promote energy efficient products.

How do other states in the region fund USBP?

Nationally, 21 states and the District of Columbia have instituted USBP. The total USBP funding is about \$2 billion a year. Regionally, the Bonneville Power Administration (BPA) has instituted a \$40 million a year rate discount program for its utility customers to help them fund energy efficiency and renewable resources. The BPA has also budgeted at least \$75 million a year for low-income energy assistance, energy efficiency, and market transformation programs; bought power on a long-term basis from five different wind projects; and committed to purchasing power from a geothermal project. BPA is also reviewing as many as seven other wind projects.

California and Oregon are the other states in the region that have instituted USBP. The California program has been in existence for 4 years and was recently extended through 2011. The USBP charge averages 3% of retail revenues from electricity sales and funds energy efficiency, low-income programs, renewable energy, and research and development. Total expenditures are more than \$525 million a year, which accounts for about 25% of all USBP funds in the United States. Between 40% and 45% of California's USBP funds are directed to energy efficiency programs. Another 25% are dedicated to developing renewable resources. About 20% of the USBP funds are earmarked for low-income programs. Research and development programs receive the remainder.

The system benefits charge (SBC) in Oregon is set at 3% of retail revenues from electricity sales to fund energy efficiency, low-income weatherization, and renewable resource development. Implementation of the charge was delayed until March 1, 2002. The charge will be in effect through 2012. Large customers can self-direct most of their SBC requirement, but most of the funds will be directed to a central fund. A new entity, The Energy Trust of Oregon, will establish and direct the programs relying on the central funding. The SBC in Oregon is expected raise between \$50 million and \$70 million a year. Fifteen percent of the funds are directed to energy efficiency efforts in schools and publicly funded housing. Broader energy efficiency efforts will receive about 55% of the funds, with 17% going to developing new renewable energy sources

and the remainder going to low-income weatherization programs. Beyond the 3% SBC, an additional \$10 million a year is collected to support programs providing bill-paying assistance to low-income ratepayers. Including these additional funds from bill assistance programs, the effective USBP charge in Oregon will be about 3.5% for most consumers.

The states adjacent to Montana do not have statutorily mandated USBP. However, these states expended the following amounts on USBP in 2001:

- Wyoming: \$4.9 million in LIEAP funds; donations to Energy Share and some internal PacifiCorp conservation and renewable energy program expenditures.
- North Dakota: \$10.9 million in LIEAP funds and some donations to Energy Share. There is very little activity in terms of state-funded or utility-funded conservation and renewable energy.
- South Dakota: \$8.9 million in LIEAP funds and some donations to Energy Share. There is very little activity in terms of state-funded or utility-funded conservation and renewable energy.
- Idaho: \$10.3 million in LIHEAP funds and some donations to Energy Share. There is very little activity in terms of state-funded or utility-funded conservation and renewable energy.

Have markets developed for USBP?

The Subcommittee heard testimony on whether markets have developed for low-income energy assistance and renewable energy and conservation services and products. The information presented clearly documented that markets have not yet developed for low-income energy assistance. The Subcommittee heard mixed testimony on whether markets have developed for conservation and renewable energy services and products. Markets have started to develop for energy efficient appliances. Although testimony indicated that in general markets have yet to develop for certain types of renewable energy projects, markets in Montana have developed for renewable energy projects such as solar-power livestock water pumps.

USBP SUBCOMMITTEE FINDINGS AND RECOMMENDATIONS

After extensive testimony, the USBP Subcommittee made the following recommendations to the Committee on April 26, 2002:

1. It is the finding of the Subcommittee that fledgling markets exist for certain types of energy efficiency and alternative energy applications. Markets do not exist for low-income energy assistance.
2. The Subcommittee finds that there is an ongoing need for USBP.
3. The Subcommittee finds that the current funding for USBP is adequate at 2.4%.
4. The Subcommittee supports the governor's recommendation that:
 - (a) any USBP funding money deposited in state special revenue accounts be expended in the utility service territory from which the money was received;
 - (b) in assessing USBP funding needs, the state departments administering the funds should be required to solicit utility and public comment from the utility service territory from which the money was received; and
 - (c) LC 93 implementing the governor's recommendations be adopted and requested by Committee.
5. The Subcommittee recommends that the USBP irrigation statutory allocation funding mechanism be revisited and made more flexible to meet the realistic needs of the utility and its customers.

COMMITTEE ACTIONS

The Committee adopted the USBP Subcommittee recommendations at its April 26, 2002, meeting. The Committee also requested that if voters rejected House Bill No. 474 a bill be drafted to extend the USBP. Subsequently, the Committee reviewed and requested LC 399 to extend the USBP to December 31, 2005.

CI2255 2357jfea.

**THE ELECTRICAL UTILITY INDUSTRY RESTRUCTURING
TRANSITION ADVISORY COMMITTEE**

A Report to the Governor and the 58th Legislature

December 2002

Published By



Legislative Services Division
PO Box 201706
Helena, MT 59620-1706
PHONE: (406) 444-3064
FAX: (406) 444-3036
<http://leg.mt.gov/>