2005 Electric Default Supply Resource Procurement Plan

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Executive Summary
2005 Electric Default Supply Resource Procurement Plan

Montana is fast approaching a time when significant resource decisions must be made – decisions that will in large part determine the type of electricity portfolio that will serve default supply customers for years to come. Every two years, NorthWestern Energy (NWE) completes an Electric Default Supply Resource Procurement Plan (Plan) following Montana Public Service Commission Guidelines. The 2005 Plan explains the risks that face customers when major supply contracts with PPL Montana expire in 2007. The two primary PPL Montana contracts provide about 55% of the current energy needs of Default Supply customers. Since these contracts were entered in 2001, market prices have increased significantly.

With the 2007 expiration of the PPL contracts firmly in mind, NWE is actively exploring opportunities and discussing with market participants a variety of supply options that would span the need between 2007 and the availability of long-term resource alternatives in 2010-2012 and beyond. The effect of new supply on customers' rates is NWE's greatest concern as alternatives are explored. The results of these discussions with market participants will also influence the scope and timing of NWE's next Request For Proposal RFP.

The Plan explains how total customer energy requirements are estimated for a 20 year period. When this requirement is determined, it is compared to the resources that are available to NWE for the planning period. The difference between electricity requirements and available resources is called the resource need. NWE has understood and has been working to address this resource need for some time. NWE began a RFP in 2004 to obtain resources that would replace the PPL contracts in 2007, and that would serve other needs identified in the 2003 Plan. The Guidelines encourage acquisition of a diverse portfolio of

resources that includes conservation and renewable resources, along with contracts from traditional resources such as coal-fired plants, natural gas-fired plants and hydroelectric facilities.

NWE has been acquiring resources for the past few years, with diversity as a central objective. The 50 MW Basin Creek natural gas-fired plant south of Butte, MT is nearing completion. The Judith Gap wind project, totaling 135 MW, will be in service this year. NorthWestern Corporation has committed 90 MW from its share of Colstrip Unit 4 to default supply service at a rate that is well below current market prices.

However, these resources will replace less than half of the energy currently provided by PPL. Much work remains to be done in the immediate future.

The new potential resources considered in this Plan (including their costs) have been taken from the Northwest Power and Conservation Council's (NPCC) Fifth Power Plan, which was finalized earlier in 2005. This Plan uses "generic" costs developed by a widely-respected entity that has provided energy leadership in the Pacific Northwest for several decades.

The resources from the NPCC's work were analyzed in various portfolio mixes and combinations with NWE's existing long-term resources. In addition to portfolio costs, the analysis considered risks and uncertainties, particularly the significant recent increases in natural gas and electric prices in the Northwest. Following extensive analysis, explained in the Plan, NWE concludes that, to lesson risk, the current path of resource diversification must continue.

The portfolio analysis presented in the Plan clearly identifies coal resources as an important part of any portfolio of preferred resources. Coal is an essential piece in helping to hold down future electric customers' costs and risk. Other preferred portfolio resources include wind and natural gas-fired plants.

In order to analyze risks associated with coal resources, the 2005 Plan considers the impact on resource costs if "carbon taxes"--a potential U.S. tax on CO_2 emissions—were to be imposed. These taxes are no longer considered a remote possibility. Analysis demonstrates that a moderate tax rate would not remove coal resources from consideration, but a high tax rate would likely make conventional coal unattractive.

The plan concludes that the Judith Gap wind project must be fully integrated into the NWE system and the effects of an intermittent generation source of this size carefully measured and fully understood before additional wind resources are acquired.

NWE's conservation program, which is similar in scope and cost to the program described in the 2003 Plan, is beginning to show results. The savings of 5 aMW per year cuts the forecasted energy growth of Default Supply customer load nearly in half.

Future resources for Default Supply, such as coal plants, take many years to design, finance and build. The Plan assumes that these resources can be available no earlier than 2012, but defers the decision on the precise nature of those resources until short-term resource needs have been addressed.

The Plan also invites discussion of the possibility that NWE might itself build and own generation.

Stable prices are an important objective. But it is likely that, no matter what resources are selected in the future, electricity prices will be not be as low as they are today. NWE is working hard to minimize price increases.

VOLUME 1

2005 ELECTRIC DEFAULT SUPPLY RESOURCE PROCUREMENT PLAN

Introduction

Northwestern Energy (NWE or Company) presents its 2005 biennial Electric Default Supply Resource Procurement Plan (Plan). NWE acts as the non-profit purchasing agent for default supply customers, those customers who can not or have not chosen a competitive electric supplier.

Consistent with the Montana Public Service Commission's (MPSC or Commission) Electric Default Supply Resource Planning and Procurement Rules (Guidelines), this 2005 Plan details NWE's systematic efforts to plan for procurement of an adequate, reliable supply of electricity that is stably and reasonably priced at the lowest long-term total cost. The Guidelines are formal administrative rules of the MPSC. Adopted in 2003, they provide the regulatory expectations for the acquisition of default supply resources. They are intended to facilitate: the long-term interests of electric Default Supply customers, and NWE's on-going financial health. The Guidelines, which can be thought of as a framework for considering and acquiring an appropriate portfolio of electric resources, state the Commission's objectives for the portfolio. As such, the Guidelines provide NWE with an understanding of the MPSC's expectations, while serving as a basis for judging NWE's performance as Default Supplier.

This Plan explains NWE's planning process within this framework. NWE seeks a broadly-understood and widely-supported electric portfolio. At the same time, fair, reasonable, and adequate regulatory treatment through full recovery of electric supply costs is extremely important to the Company and its customers. This Plan attempts to serve these two very important outcomes.

Certain planning objectives in the Guidelines can be in conflict. For example, supply resources that have the lowest long term cost might not be the resources with the least environmental impact. In many instances, the Plan's development required policy judgments that weighed competing objectives inherent in the Guidelines. NWE has attempted to communicate its analysis as clearly as possible so parties can determine how competing policies have been considered and addressed.

The resources considered in this Plan (including their operating characteristics as well as their capital and operating costs) have been taken from the Northwest Power and Conservation Council's (NPCC) Fifth Power Plan, which was finalized earlier this year. Resources chosen from a RFP or that might result from bilateral negotiations will determine actual Default Supply costs. This universe of resources was then analyzed in various combinations with the existing long-term resources. The analysis considered costs and risks, and resulted in a set of preferred portfolio resource types and sizes that are believed beneficial to Default Supply customers.

Volume 1 is a stand alone summary of the Plan, with more technical discussion and supporting data provided in Volume 2. Volume 1 describes NWE's planning process, the steps taken to satisfy the Guidelines, and the results of NWE's planning analyses. The basic analytical steps involved in developing this Plan are:

- Forecasting the load to be served over the next twenty years, including an average of an additional 5 aMW of energy conservation per year for the planning horizon;
- Accumulating a data base of resource options and model inputs;
- Creating various portfolios of resources (the resources that NWE may pursue);
- Analyzing the costs of the various portfolios and selecting the best options (considering the costs and major risk factors inherent in each);

- Uncertainty analyses of the best subset of portfolios selected from the cost analysis;
- Conducting assessments of different load forecasts and the effect of potential CO_2 taxes on portfolio costs;
- Selecting and performing a qualitative analysis of the best portfolios; and,
- Creating an Action Plan outlining steps to implement the conclusions reached in this Plan.

NWE has considered a wide variety of generic resources, and modeled them in various portfolio combinations and quantities, including portfolios suggested by members of the Electricity Technical Advisory Committee (ETAC). To determine the effects a potential carbon tax[1] would have on resource costs, two carbon tax scenarios were developed. The best portfolios were then subjected to an uncertainty analysis, including market volatility, price changes, changes in load forecast, and CO_2 tax scenarios. The resulting mix of resources in the selected portfolios combine demand side and supply side, including traditional and renewable resources.

The Preferred resource portfolios that have been selected in this process are as follows:

All four of the preferred portfolios contain some level of a coal resource. Three of the portfolios contain additional quantities of wind, as well as some amount of natural gas-fired generation. These characteristics are illustrated in Table 1.

[1] A carbon tax would impose a monetary exaction cost or assessment on industrial processes in proportion to the volume of carbon dioxide (CO_2) released. Carbon taxes are often discussed in the context of greenhouse gases, global warming and the direction of energy policy. The effects of various levels of carbon tax are routinely considered by electric utilities in the U.S. when they conduct long term planning.

Table 1

Preferred Portfolios					
Resource Combinations in MW's					
Resource	MT Coal	MT Nat gas Combined Cycle	MT Nat gas Simple Cycle	Wind	Total
Portfolio #					
2	600				600
14	200	264		100	564
18	200	264		200	664
31	400		100	200	700

The expected cost of the preferred portfolios is displayed in Table 2 below.

Table 2

Preferred Portfolios Expected Costs and Risk		
Medium Price Forecast–Stochastic Basis		
Portfolio	**Expected Cost**	**Expected Risk**
2	$ 6,239,946,928	$ 6,681,141,884
14	$ 6,424,155,136	$ 7,119,362,452
18	$ 6,520,126,464	$ 7,139,935,855
31	$ 6,399,432,192	$ 6,899,576,881
Expected Cost is the 20-year mean portfolio cost for the medium price case (stochastic basis).		
Expected Risk is the average at the highest 10% cost outcomes (stochastic basis).		

Note: The costs in Table 2 do not contain a CO_2 tax.

In this Plan, NWE took into account the MPSC's August 2004 Comments (Comments) on NWE's initial Electric Default Supply Plan (2003 Plan), which recommended a number of refinements of the planning process.

This Plan is intended as both a near term and long term framework for supply decisions. Key outcomes of this Plan are to provide a foundation for developing and evaluating new RFPs and to guide short term acquisitions in a way that the

ability to execute long term acquisitions consistent with this Plan are not compromised.

Overview

The 2005 Plan was developed during a period of significant (and continuing) uncertainty. Planning for an electricity supply portfolio during a period of elevated market and supply uncertainty emphasizes the need to quantify and account for risk. The concern is that even informed or prudent decisions taken today may turn out to have large unintended cost differentials because of unanticipated future outcomes. There are no risk free supply alternatives. Thus, our analysis places a value on risk as well as identified resource costs. It is important to fully understand potential risk factors and identify costs.

The most obvious and pressing uncertainty facing NWE's electric customers is the resource requirement created in mid-2007 due to the expiration of two primary PPL Montana (PPL) contracts. These two contracts currently provide approximately 55 percent of the total energy needs of the default supply. These contracts, negotiated in 2001, average $32 per MWh. Current market prices are significantly higher than these contracts. While NWE believes there likely will be sufficient quantity of power available in the market to replace these key contracts, the price, term and structure of replacement contracts are subject to market and transmission constraints. NWE will continue its current efforts to replace these contracts.

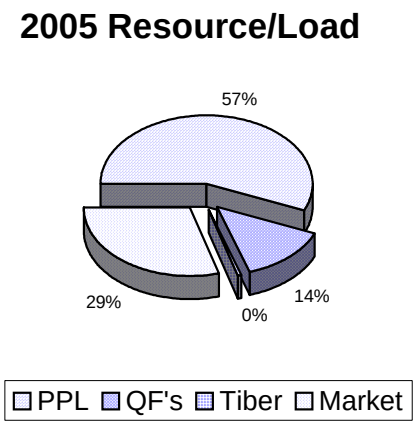
The Federal Energy Regulatory Commission (FERC) is conducting an investigation under section 206 of the Federal Power Act (FPA) into the PPL Companies' presumed market power in the NWE control area.[2] NWE and the Montana Consumer Counsel (MCC) each have been active parties in the proceeding. If the FERC ultimately finds that the PPL Companies have market

[2] *See PPL Montana, LLC, et al.,* Docket No. ER99-3491-002, *et al.,* 112 FERC ¶ 61,237 (2005) ("September 1 Order").

power, the PPL Companies would have an opportunity to either (1) file a mitigation proposal tailored to the particular circumstances of the market power (*e.g.*, limited seasonal mitigation), (2) adopt the default cost-based rates, or (3) propose other cost-based rates and submit cost support for such rates. While the eventual outcome of the proceeding cannot be determined at this juncture, one thing is certain–the FERC process may not be completed before NWE is required to obtain supplies to replace the 450 MW under the PPL Companies' Power Purchase Agreements (PPAs) that terminate on June 30, 2007.

Figure 1, 2005 Resource/Load, below represents a typical Default Supply year with the two PPL contracts, other PPAs and our existing Qualifying Facility (QF) resources[3]. Figure 2, 2008 Resource/Load, reflects the loss of these two PPL contracts, with the addition of Colstrip Unit 4 (CU4)[4], and current contracts with Tiber, Basin, and Judith Gap resources.

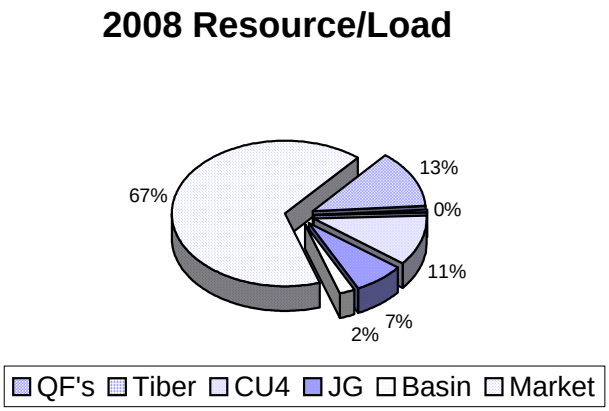
Figure 1



[3] Qualifying Facility (QF): A cogeneration or small power production facility that meets the criteria established by the FERC pursuant to the Public Utility Regulatory Policies Act (PURPA) for which NWE has entered into a valid contract for purchases under an appropriate MPSC approved contract or Tariff.

[4] The Colstrip Unit 4 resource is a proposal by NorthWestern Corporation to supply power to Default Supply that is discussed below.

Figure 2



The simultaneous expiration of the two PPL contracts presents both a risk and a lesson for the Default Supply. Because significant supply must be replaced in a relatively short time, price risk is a concern. All other factors remaining equal, the portfolio should, in the future, avoid simultaneous expirations of significant quantities of resources so that exposure at any one time to any set of unfavorable market conditions will be limited. While not a strong concern in 2001, when these contracts were signed, the importance of this consideration now is clear.

A second critical uncertainty is the elevated and highly volatile natural gas market. For example, the market price for natural gas at Henry Hub (an active trading point) was $13.91 a dekatherm[5] (dkt) in October 2005. In June 2005, the price was $6.12 per dkt. In October of 2003, the price was $4.43 per dkt. Natural gas is important to electricity customers since a natural gas fired turbine is often the marginal resource that many utilities in the Pacific Northwest turn to

[5] A dekatherm is 1,000,000 Btus, and is abbreviated dkt. One Btu is the amount of heat energy required to raise the temperature of a pound of water one degree Fahrenheit.

when they need additional electricity generation. Thus, natural gas economics often set the marginal price of electricity.

Another major uncertainty is the declining margin between the amount of electric generation capacity available to utilities and the growing demand for electricity in the Pacific Northwest. The Pacific Northwest Utility Coordinating Council (PNUCC) reports that the Pacific Northwest will, in 2006, be near load-resource balance (the amount of available electricity supply equaling the amount of consumer demand) for the first time in over a decade (see Volume 2, Chapter 1, Sources). Absent new generation becoming available, or a decrease in demand, the electricity market may experience increased pressure on prices as available electricity supply tightens.

The management and growth of the transmission systems in the Pacific Northwest, including Montana, and in the Mid-Continent Area Power Pool (MAPP) is another uncertainty. The development of new electricity generation is dependent on access to markets. If a significant amount of new generation is to be developed, transmission infrastructure must be enhanced. In any case, NWE's Default Supply represents a relatively small market potential as generation and transmission developers weigh future investment opportunities and risks. The value to Default Supply in having additional market participants should not be underestimated, however. Also, efforts in the Pacific Northwest to develop a more efficient transmission planning paradigm have encountered substantial road blocks (see Volume 2, Chapter 1).

In the face of these uncertainties, supply planning for the Default Supply obligation must be flexible and capable of responding to ever changing conditions. For example, resources contained in the preferred resource portfolios identified in this analysis may ultimately not be the resources actually available or selected to provide electricity to default supply customers. This Plan does, however, provide insight into the types of resources or characteristics that

best serve Default Supply customers' needs, include recognition of the specific resources costs and risks, and will shape any RFPs NWE develops in the future.

Obviously, NWE must address the short-term issue–obtaining new reasonably priced and low risk contracts to replace the PPL Montana contracts. But NWE must also be aware of the long-term needs facing Default Supply. The dominant long-term need is access to an adequate, affordable, and stably priced electricity supply to carry customers beyond any interim arrangements, and in a way that complements recent portfolio additions.

Several considerations not addressed in the 2003 Plan have gained significance. One is the financial mechanism used to acquire resources for the long-term portfolio.

While PPAs have been the vehicle by which NWE has procured resources for Default Supply, it is important to investigate other means to serve Default Supply customers. It is increasingly important to understand the interrelationship between Default Supply resource arrangements and NWE's financial capabilities as the Default Supplier, and, specifically, the way in which PPAs will be analyzed by financial rating agencies.

As explained below, since PPAs tend to be analyzed as debt of the power purchaser, the alternative of NWE owning generation needs to be considered. While NWE's analysis of this issue is not complete, it is possible that capital costs for NWE and the resulting rates paid by its customers would be lower if Default Supply had less reliance on PPAs.

A paper prepared by Lands Energy Consulting of Bellevue, WA (Lands), (see Volume 2, Chapter 1 Sources), addresses the issue of the treatment of PPAs as debt, along with other procurement-related issues. The Lands paper notes that rating agencies are treating long-term fixed obligations taken on by utilities

through PPAs as contributing debt to their balance sheets, with a resulting need for an infusion of common equity in order to avoid negative credit consequences. NWE receives neither a positive return on PPA costs nor compensatory adjustment for additional common equity. Lands concludes that: "NorthWestern and the PSC should jointly investigate the effect of Montana law regarding advanced approval of procured resources on this issue to inform future procurement decisions regarding the desirability of PPAs compared to resources owned directly by the utility."

While it appears that current law contains no explicit prohibition on the Default Supplier owning generation (but only requires functional separation – Section 69-8-204, MCA), electric supply costs, by definition in law, contemplate the use of PPAs. Section 69-8-103(13), MCA. Additionally, the advanced approval process adopted in 2003 is confined to "advanced approval of a power supply purchase agreement …" Section 69-8-421(1), MCA. HB 389, Section 6, in the 2005 Montana Legislative Session would have provided a new procedure for advanced approval of generation investments. However, the bill was not approved. The absence of advanced approval for rate based generation investments is a significant hurdle if rate basing is believed to be an outcome worth pursuing.

NWE encourages public discussion regarding the desirability of securing generation assets with the intent that they be placed into rate base. NWE believes that a fully informed discussion of this issue prior to the 2007 Montana Legislature would be desirable.

If vertical integration is an outcome that NWE, the MPSC and others believe is in the public interest, that result would move Montana back toward the traditional electric utility industry structure.

The Short Term Challenge

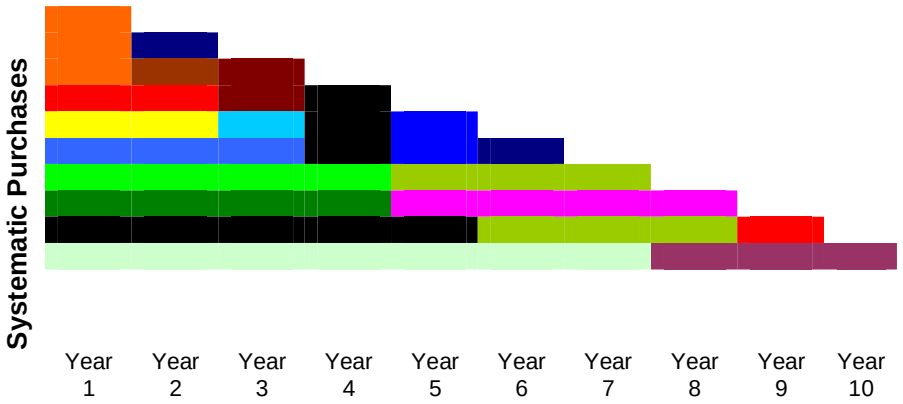
This 2005 Plan identifies significant resource needs beginning in 2007, while providing the vision for a long-term portfolio. The immediate challenge will be to meet the short-term needs without hindering the long-term approaches. For the short term, load serving obligations should be met in large part by undertaking market bridging contracts.[6] Long-term market risk reduction and price stability demand that reliance on short-term market purchases be reduced.

Bridging to a Long Term Portfolio

A bridging approach is most likely to consist of the acquisition of a mix of PPAs with regard to quantities and term. With the PPL PPAs expiring on June 30, 2007, NWE has secured 40% of the energy that may no longer be available from PPL Montana. The balance of the deficit could be procured through a systematic acquisition of replacement contracts. Figure 3 depicts a systematic approach. NWE could begin acquisition of blocks of power to replace or fill the deficit. For example, purchases of blocks of power could be made and could extend for periods of time that straddle the expected date for procurement of new long-term resources. Purchasing options are currently being explored and would continue until the needs are met with long-term resources.

[6] The term "bridging contracts" refers to market purchases of varying volumes and differing duration that are likely to be procured to "bridge" the period between the termination of the PPL contracts and procurement of new long term resources. Staggered terms will prevent a major loss of resources at one time such as currently faces NWE and its customers on July 1, 2007 and will preserve flexibility.

Figure 3



In contrast with this relatively systematic approach, NWE could seek to meet its default supply needs on a more opportunistic basis. If sellers presented appealing prices, NWE would execute agreements.

The most prudent path may lie somewhere between the systematic and opportunistic approaches.

NWE is actively exploring market opportunities that would span the need between 2007 and the availability of long-term resource alternatives. A number of significant potential resource additions exist. Also, discussions with PPL continue.

Current forward prices for mid-2007 are expensive compared to the current Default Supply costs. The 2010 forward prices are more in line with marginal plant costs. (i.e., projected costs of new resources). However, higher prices are likely.

This Plan's identification and analysis of new resources, including costs and risks, will be helpful as NWE contemplates price, term, and quantity of PPAs for the short term.

Development of Long Term Electric Procurement Plan

What follows is a description of each of the primary elements of NWE's planning process.

Conservation

The Guidelines require the development of energy conservation or Demand Side Management (DSM) resources as part of the electric default supply portfolio. NWE has made substantial progress implementing DSM programs. These programs will be expanded and the goals for each program increased as NWE continues ramping up DSM acquisition to a sustainable level of 5 aMW/year.

Compared to the 2003 Plan, some minor revisions to the DSM projections have been made as a result of changing future electricity prices and associated avoided costs, and energy code changes and commercial non-availability of certain equipment. DSM annual budgets have increased somewhat as a result of higher avoided costs used in the updated DSM Assessment, and consequent inclusion of more expensive, but cost-effective DSM measures. However, the overall level of expected DSM savings remains the same as identified and targeted in the 2003 Plan.

In its 2003 Plan, NWE detailed the steps taken to assess the achievable potential for cost-effective DSM. The DSM Assessment performed by KEMA included modeling that screened individual DSM measures for cost-effectiveness using then current avoided electricity costs. Measures with a minimum benefit/cost ratio of 0.9 using a Total Resource Cost Test (TRC) were selected for further analysis to determine a total achievable cost-effective DSM potential, and to develop annual DSM Program targets and budgets. The results of this work produced a DSM Plan target of approximately 102 aMW to be acquired over a 20-year period. The annual targets were set at 5 aMW per year following a ramp-up period in Year 1 and Year 2 of 2.6 aMW and 3.7 aMW, respectively.

Because wholesale electricity supply costs have increased substantially in the past two years, it was appropriate to update the DSM assessment to determine the effect of higher prices on DSM potential. For the 2005 Plan (see Volume 2, Chapter 2), NWE selected $45/MWh as the avoided cost[7]. This was based on internal discussions and price forecasts and represented NWE's view of the market at the time the assessment update work was performed in late October 2005. This work was completed before the 2005 Plan's portfolio modeling was completed.

NWE reviewed the list of possible DSM measures that were included in the original DSM Assessment and determined that it would be too time-consuming and expensive to update the costs of the measures prior to KEMA performing an updated measures screening analysis with a new avoided cost. Some measures were excluded in the updated DSM Assessment analysis because of code changes affecting minimum appliance performance standards, or lack of commercial availability of the equipment. KEMA ran its DSM Assyst™ models again with these changes to the list of measures and the updated avoided cost. Tables 3 and 4 show the measures passing the TRC test at 0.9 or greater.

[7] The avoided cost of $45/MWh is based on the forecast of the levelized price of electricity at the Mid-Columbia trading hub for the time period 2005 to 2025 (see NPCC Fifth Northwest Electric Power and Conservation Plan, Executive Summary, p. 20). That value of $38/MWh expressed in terms of 2004 dollars, when escalated at 2.42% and discounted at NWE cost of capital at 8.46% over 20 years equates to approximately $45/MWh.

Table 3: Residential Measures Passing Updated Economic Screening

Program	Measures with TRC > 0.9
Lighting	Compact Fluorescent Indoor Fixtures Compact Fluorescent Lamps Compact Fluorescent Outdoor fixtures
Insulation	Ceiling Insulation R0 – R38 Ceiling Insulation R0 – R49 Ceiling Insulation R11 – R38 Ceiling Insulation R11 – R49 Ceiling Insulation R19 – R38 *Ceiling Insulation R19 – R49 Foundation/Slab Insulation R10 Foundation/Slab Insulation R5 Infiltration Reduction Blower Door Air Sealing Programmable Thermostat (Energy Star) Wall Insulation R0 – R11 Wall Insulation R0 – R13 High Density
Water Heating	Low-Flow Fixtures Tank / Pipe Wrap
Fuel Switching	Electric to Natural Gas Heating Electric to Natural Gas Hot Water
New Construction	Compact Fluorescent Indoor Fixtures Compact Fluorescent Outdoor Fixtures Foundation/Slab Insulation R10 High Performance Energy Star Windows (low-e) Low-Flow Fixtures Programmable Thermostat (Energy Star) Tank / Pipe Wrap ESHNW standard
Other	*Energy Star Dehumidifier

*Denotes new measure passing updated screening

Table 4: Commercial Measures Passing Updated Economic Screening

Program	Measures with TRC > 0.9
Lighting	Compact Fluorescent Fixture Compact Fluorescent Lamp Exit Signs (LED) High Output T8 Lamps and Electronic Ballasts T8 Lamps and Electronic Ballasts Fluorescent T5 lamps in hi-bay applications Mercury Vapor to High Intensity Discharge Fixtures Occupancy Sensors & Sweep Controls Photocell Controls
HVAC	High Efficiency AC/Chiller *Chiller Optimization High Efficiency Heat Pump HVAC Servicing Variable Air Volume Control (VSD) *Demand Control Ventilation
Other	Compressed Air Audit ECM evaporator fan motor PSC evaporator fan motor Economizer for Walk-in Coolers High Efficiency Motors Low Flow Fixtures High Efficiency Ice Makers PC and Network Power Management Irrigation System Maintenance Scientific Irrigation Scheduling *Night Covers (Grocery) *Energy Management Systems

*Denotes new measure passing updated screening

NWE adhered to the approach of screening individual measures for cost effectiveness. An alternative approach of combining cost-effective measures with non cost-effective measures into program "bundles" and then evaluating the cost-effectiveness of the bundle, would result in a program with a mix of measures, some of which individually are not cost-effective. The NPCC takes a similar approach and does not include individual measures with a B/C ratio less than 1.0 in its DSM Programs[8].

[8] From NPCC paper, "Conservation Cost-Effectiveness Determination Methodology), May 2005, Fifth Power Plan, Appendix E, page E-2.

KEMA repeated the 2003 analysis of different utility incentive levels (33%, 50% and 100%) to develop updated estimates of achievable cost-effective DSM. Modeling results indicate that 99.4 aMW of DSM is achievable (this compares to 102 aMW in the previous Plan). The combination of a higher avoided cost and exclusion of certain measures from the analysis results in essentially no change in the long range DSM goal of approximately 100 aMW.

KEMA will continue its work updating the DSM Assessment at avoided cost levels ranging from $35 to $70 per MWh at $5 increments, and will produce measures, screening tables, and penetration runs for each. This will provide NWE with a DSM supply curve that will be useful in estimating future DSM potential in a changing price environment.

Because the updated DSM Assessment resulted in approximately the same long-term DSM goal of about 100 aMW of achievable DSM potential, there is no reason to modify the targets for DSM acquisition. NWE will continue on its present schedule of DSM acquisition. NWE is in the second of two ramp-up years of its DSM Plan, and is working to raise its DSM Program capability to a sustained acquisition level of 5 aMW per year. Figure 4 illustrates the incremental and cumulative energy savings of NWE's DSM Plan.

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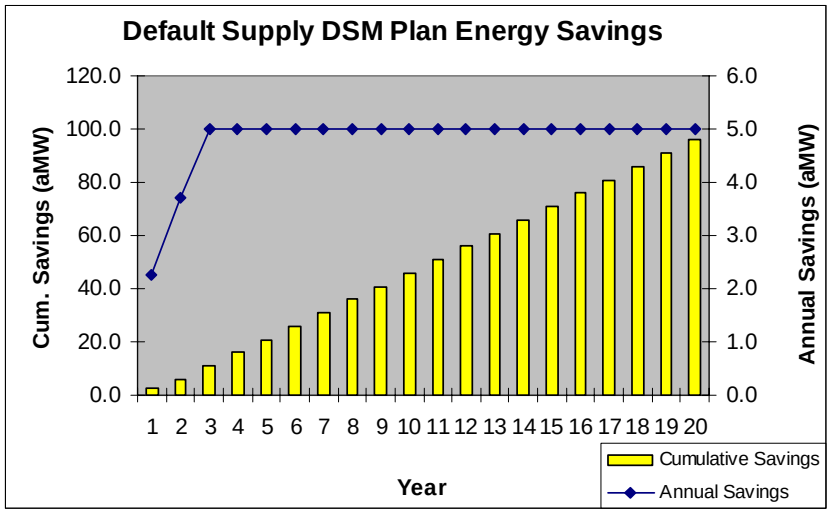
http://www.nwcouncil.org/energy/powerplan/plan/Appendix%20E%20(Conservation%20Cost-Effectiveness%20Methodology).pdf

Figure 4: Default Supply DSM Plan Energy Savings



Budgets associated with the DSM Plan are somewhat higher as a result of the higher avoided cost used in the Assessment update. With higher avoided costs, the value of the conserved energy is greater, and is estimated at an average levelized cost of about $20/MWh over the 20-year Plan period. The total 20-year costs for the DSM Plan are about $189 million; annual budget estimates are presented in Figure 5 and Table 5.

Figure 5: Default Supply DSM Plan Estimated Cost

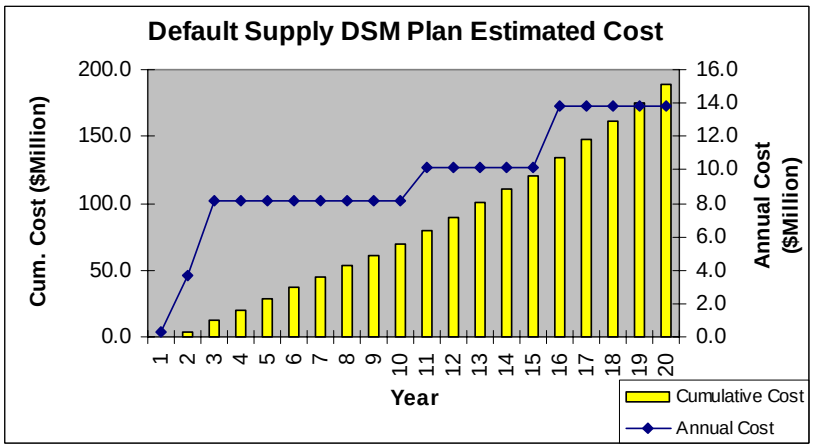


Table 5: DSM Savings Targets and Annual Cost

DSM Program Year	Tracker Year	Annual Savings (aMW)	2003 Plan Annual Cost ($Million)	2005 Plan Annual Cost ($Million)
1	2004-05	2.3	0.3	0.3
2	2005-06	3.7	3.7	3.7
3	2006-07	5.0	7.4	8.2
4	2007-08	5.0	7.4	8.2
5	2008-09	5.0	7.4	8.2
6	2009-10	5.0	7.4	8.2
7	2010-11	5.0	7.4	8.2
8	2011-12	5.0	7.4	8.2
9	2012-13	5.0	7.4	8.2
10	2013-14	5.0	7.4	8.2
11	2014-15	5.0	9.6	10.1
12	2015-16	5.0	9.6	10.1
13	2016-17	5.0	9.6	10.1
14	2017-18	5.0	9.6	10.1
15	2018-19	5.0	9.6	10.1
16	2019-20	5.0	12.7	13.8
17	2020-21	5.0	12.7	13.8
18	2021-22	5.0	12.7	13.8
19	2022-23	5.0	12.7	13.8
20	2023-24	5.0	12.7	13.8
		96.0	174.7	189.1

Note: Plan year 1 savings and costs are actuals recorded and reported.
Plan year 2 costs taken from D2005.5.88 Exhibit (WMT-2).

The DSM plan proposes acquisition of 5 aMW per year over a 20-year period[9]. In general, NWE will continue the DSM Programs introduced in 2005, but it is possible minor modifications to the programs will be made in 2006, as the results of the first full year of operation become known. Additional programs will be implemented. There will be increased contractor activity and additional effort put into customer education and program marketing to increase customer participation.

[9] Section 38.5.8218 (4) of the Default Electric Supplier Procurement Guidelines states, "A DSU should develop and strive to achieve targets for steady, sustainable investments in cost-effective, long-term demand-side resources."

A program closely linked to NWE's DSM program has recently seen changes that are worth noting. The MPSC Interim Order 6679a in Docket. D2005.6.106 changed the future course for Universal Systems Benefit (USB) Programs that encouraged energy conservation. Available funding for Market Transformation has been eliminated from USB allocations. Prior to this development, NWE had expected to blend USB with DSM funding where it made sense, for example by using the Energy Star Home/Products budget to help market and promote the ESHNW building standards, and leveraging the activities of the Northwest Energy Efficiency Alliance with E+ Business Partners and E+ Commercial Lighting Programs. Going forward, the following actions are planned with respect to coordination with USB Programs:

A. E+ Residential Audit/Commercial Pilot Audit – direct installation of CFLs funded through default supply DSM will continue.
B. E+ Business Partners – budget remains in USB for choice customers only, and for irrigation projects. The majority of this program was moved to default supply DSM in 2005 and general promotion of the Business Partners will be primarily funded through the default supply DSM budget.
C. E+ Commercial Lighting – a small amount of budget remains in USB for choice customers only. The majority of this program was moved to default supply DSM in 2005. KEMA administers the USB choice customers lighting program for NWE in conjunction with the default supply Energy Efficient Lighting Programs.
D. Northwest Energy Efficiency Alliance – NWE is considering moving funding for this program to default supply DSM in 2006.

Analysis of the actual performance of the DSM program is important. NWE will continue to maintain DSM program records on participating customers for: building/premises information, historical energy consumption, measures installed, costs, and energy savings estimates for each DSM measure installed. This data will be useful in program evaluations to be conducted by an independent third-party service provider.

A program evaluator will be contracted in the second half of 2006 to analyze NWE's DSM program records and data, conduct a survey (sample) of program participants, conduct site visits to inspect the DSM measures and determine whether the facility use has changed or is no longer used, analyze energy consumption historical data, and calculate of the amount of DSM savings actually produced versus projected at the time DSM measures were first installed.

Results of the program evaluation will be used to refine energy savings estimates for each DSM program measure, revisit the cost-effectiveness tests used to determine approved measures for future program offerings, improve accuracy of annual DSM program budgeting, and increase the accuracy of the adjustment factors used in the DSM tracking mechanism to determine net energy savings. Findings will also be useful in performing true-up of lost revenue calculations for previous and future default supply tracker filings.

Demand Response Program Investigation

Utilities are experimenting with various types of Demand Response (DR) Programs to determine whether customer usage patterns will change in response to changing prices (rates or tariffs) or utility incentives at times when wholesale market prices exceed utility supply prices, and in ways that allow utilities to manage loads and reduce overall resource costs. These programs can be categorized as follows:

Operational-Based (Load-Response) Programs

1) Direct load control programs – modulate or cycle equipment on and off
2) Interruptible programs – entire customer load is shed
3) Curtailable load control programs – load is reduced but not shed completely
4) Distributed generation – customer's on-site generation activated

Market-Based (Price Response) Programs

1) Demand bidding (or buy-back) – customer submits a bid for a specific amount of load shedding for a specified period
2) Time differentiated pricing
    a) Time of Use (TOU) pricing
    b) Dynamic pricing
    c) Real-time pricing
    d) Critical Peak pricing

NWE has completed some initial steps and will continue its examination and evaluation of potential DR Programs to determine whether these kinds of programs, together with the DSM Programs described above, can cost effectively contribute to the electric Default Supply portfolio (see Volume 2, Chapter 2, Sources).

NWE evaluated a DR Load Control Program and is making preparations for a pilot field study of Time of Use pricing. The intent of the study was to examine a DR load control program, to gain a sense of the requirements for delivery of such a program to a large number of customers, and then to quantify the benefits and costs expected from implementation and ongoing administration of the effort.

The results from the DR Load Control Program evaluation indicate that the benefits do not exceed the costs for a mass-market commercial load control program. The primary reason for this is that the amount of load per customer that can reasonably be reduced during a demand event is small, and the consequent total amount of avoided market purchases of energy is small, compared to the per customer cost of operating a large scale program with large participating customer counts.

One conclusion that can be drawn from these results is that a DR load control program of this type for the majority of General Service customers is not likely to prove cost-effective. The results also suggest that there may be ways for NWE

to work with the very largest non choice customers to achieve economic results from load control activities using smaller scale and less costly systems to mediate the demand events and perform the necessary post-event settlement and billing adjustments. Also, there may be ways to work with non choice large customers (e.g., hospitals) that have on-site generation that can be called upon during peak events. NWE intends to continue its investigation into these possibilities.

In a July 22, 2005 discussion with the MPSC, NWE agreed to initiate a residential TOU pilot program in 2006 (see Volume 2, Chapter 2, Sources). The pilot program is intended to examine residential customer willingness to adopt a time-of-use rate structure and gather data on the levels and patterns of energy consumption changes that may result from TOU rates. The project will produce information necessary to evaluate the benefits, costs and potential for system-wide implementation of TOU rates. Experience gained from this work will help NWE determine how it can respond to the provisions of the Energy Policy Act of 2005 (EPAct 2005) that relate to time-based rates[10].

NWE is still in the process of defining details of the pilot program. However, NWE has initiated discussions with a services provider to identify the technology and systems needed to gather and process interval electric consumption data and integrate it with the NWE billing system.

Recovery of Conservation Costs

Through its Interim Order No. 6574 in Docket D2004.6.90, the MPSC authorized DSM program costs to be recovered through Default Supply rates. DSM program costs are treated as an expense (not capitalized) and are included in the

[10] Subsection 1252 (a) of the EPAct 2005 created a requirement that utilities offer customers time-based rates or, in the case of large customers, with capacity credits. There is an accompanying requirement that the utility must provide a suitable meter to any customer requesting such rate, or demonstrate why compliance cannot be achieved. This section is an amendment of PURPA and the MPSC will have the opportunity to assess whether this requirement is cost-effective.

Default Supply tracker. The Default Supply tracker is the model presented to the MPSC for approval of all reasonably incurred costs necessary to secure resources to meet the Default Supply obligation.

A decision on recovery of Lost Revenues associated with DSM programs is still pending. NWE continues to seek favorable resolution of this issue. As mentioned above, NWE intends to complete a rigorous DSM program evaluation and use the results to reconcile, or "true-up", the estimated Lost Revenues filed in Default Supply tracker proceedings.

NWE is watching developments in other states with regard to recovery of Lost Revenues associated with DSM programs. The positions among interest groups are diverse–there is both support for and opposition to Lost Revenue recovery–but the dialogue on this important issue is open and ongoing. Different mechanisms, including decoupling, incentives, revenue normalization adjustments, and other approaches are being examined by other utilities and other regulatory bodies.

Cost Allocation and Rate Design

In its 2003 Plan, NWE stated it was premature to develop a cost allocation and rate design (CA&RD) study. However, even though future Default Supply costs remain largely unidentified, NWE needs to proceed with a basic study. NWE expects to fill an internal Allocated Cost of Service/Rate Design Analyst position and will initiate a search for a qualified and experienced consultant to be retained in 2006 to begin to develop the CA&RD study, provide training to the new analyst, and participate in the associated regulatory activities. This will allow NWE to evaluate next steps related to cost allocation and rate design.

Resource Needs – Methodology

To determine resource needs for Default Supply customers, their electricity usage is estimated on a weather normalized basis. Customer electricity needs

cannot be fully known in advance given weather, growth uncertainty, and uncertainty surrounding customer choice. Nonetheless, reasonable estimates are essential. The DSM Program resource estimates are also factored into the load forecast, reducing the need for additional supply side resources.

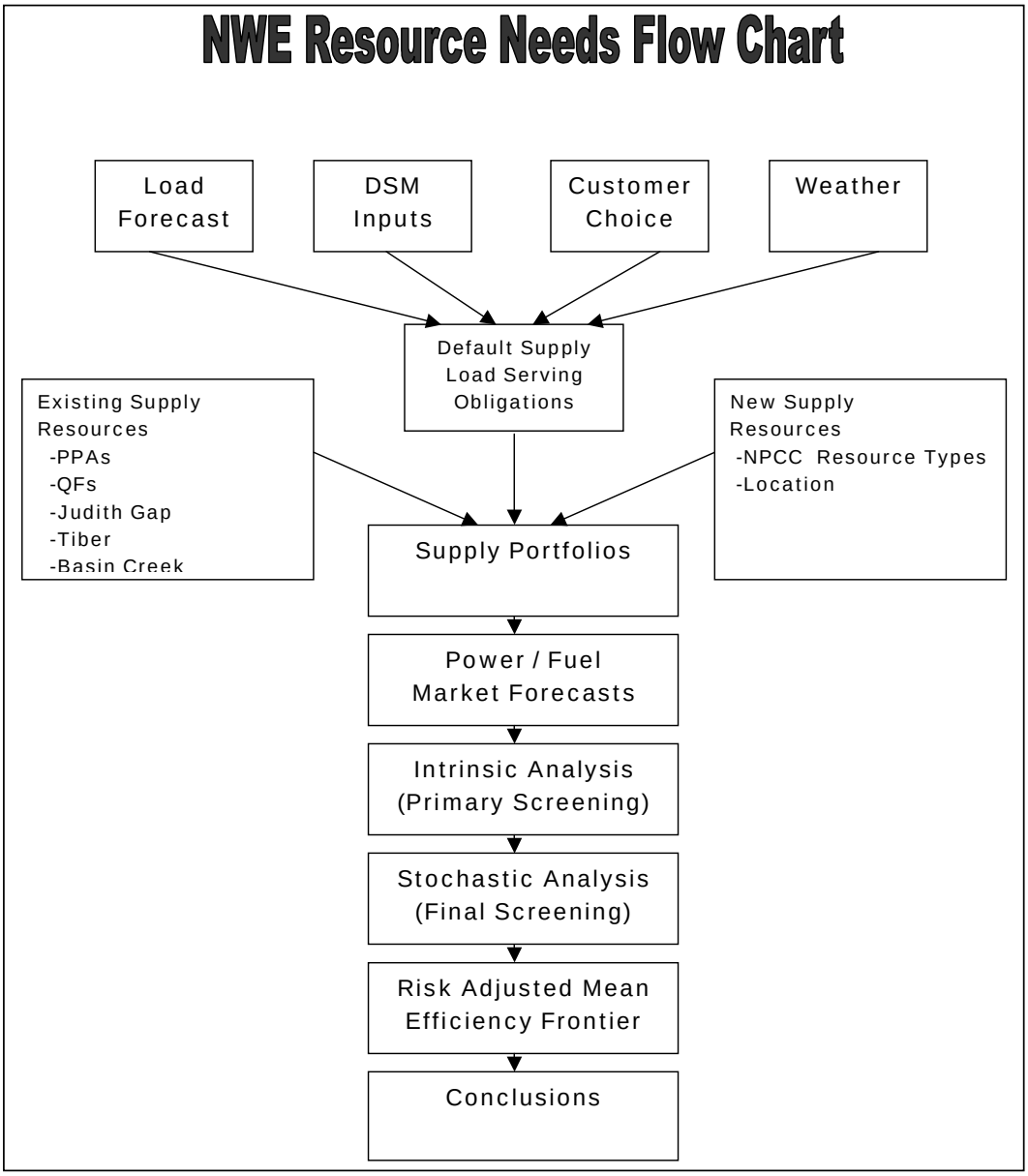
Next, potential resources and their respective characteristics (price, quantity and term) are examined. Various resource combinations that could satisfy the resource needs in an economical manner are evaluated using an analysis that calculates relatively simple cost comparisons (referred to as an intrinsic analysis)[11].

Finally, selected new resources (including PPAs) are combined with the existing portfolio to provide a resource base. As PPAs expire or when the useful life of an electricity generator is expected to end, they are removed from the portfolio and replaced by appropriate electric supply resources chosen to meet those needs. Conservation measures are adjusted in a similar manner. To determine the relative responses of the different resources to uncertainties, the resulting mixes of resources, or portfolios, are compared through an extensive modeling effort that is referred to as stochastic modeling.[12] In this way, electric resource portfolio strategies emerge that will provide reliable service to customers at a relatively stable cost.

This process is captured and presented in Figure 6 below.

[11] Intrinsic modeling employs fixed market prices and static resource assumptions.
[12] Stochastic modeling incorporates price volatility and uncertainty in Monte Carlo simulations that perform thousands of model iterations.

Figure 6



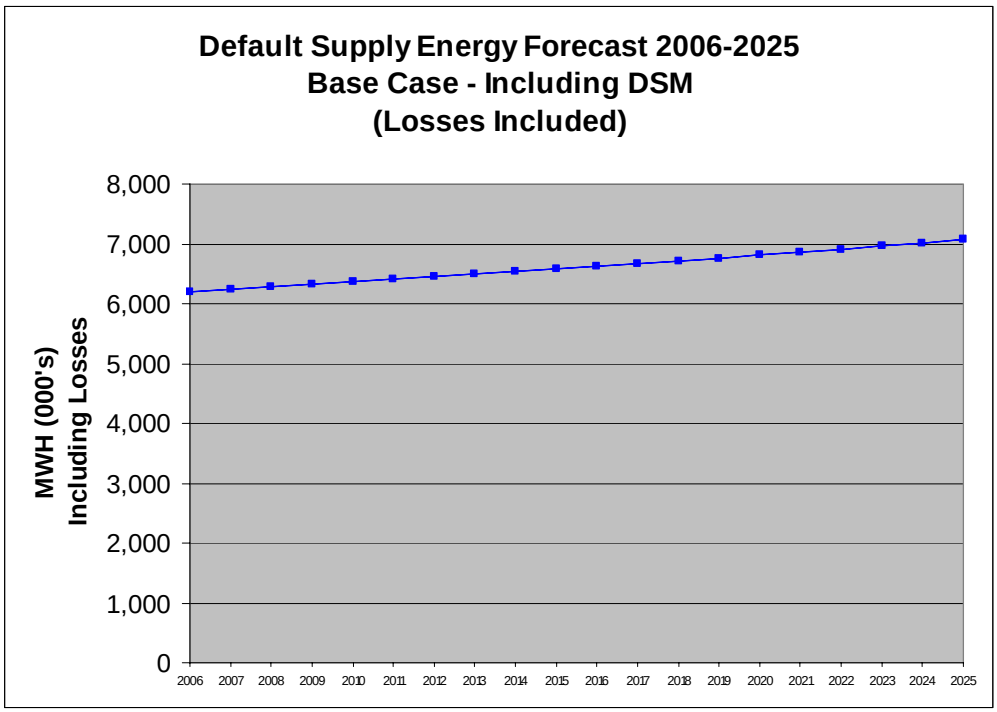
Load Forecast

Annual estimates of energy required to meet the Default Supply obligation are based on "normal" weather. Actual weather conditions will cause energy usage

to vary above or below forecast normal values on an annual, monthly, and even a daily basis. An energy forecast is just one of the pieces of information that must be formulated as future resource needs are forecasted and evaluated (see Volume 2, Chapter 3).

For analytical purposes, NWE separates its default supply customers' loads into three group sizes (small customers – less than 50 kW; large customers with less than 5 MW demand; and large customers with over 5 MW demand). Loads are separately estimated for each of the rate classes that comprise each group, and are then combined. The sum (net of conservation program effects) represents the estimated electric resource requirement, which is the Default Supply obligation. From this work, a "base case load forecast," the scenario considered most likely to occur, has been developed. Portfolios are then constructed that could serve the base case. The base case load forecast for years 2006 through 2025 is shown in Figure 7.

Figure 7



The Default Supply load is comprised primarily of residential and GS-1 Secondary (small commercial) customers with a combined annual energy requirement that represents approximately 85% of the total Default Supply load. The remaining portion of the Default Supply load is comprised of larger commercial (GS-1 Primary) customers, GS-2 Substation and Transmission level customers, and irrigation and lighting customer accounts. The load shape of residential and small commercial customers is the dominant determinant of the Default Supply load shape.

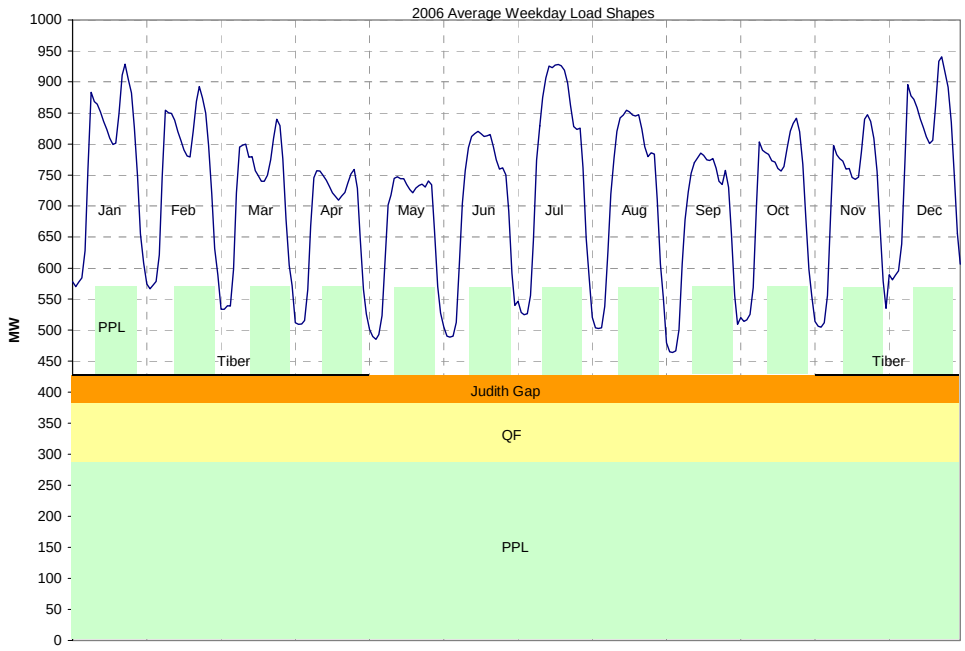
A “load shape” is a function of the fluctuations of load throughout the day, indicating the degree of flexibility that is required from the electric supply resource portfolio if it is to supply that load efficiently and completely. The load shape is the hourly level of energy consumed by customers, indicating the variability inherent in the Default Supply loads.

Figure 8, “2006 Average Weekday Load Shapes”, illustrates the typical daily load for each month and the major resources that NWE has under contract to meet this supply obligation for the 2006 calendar year. The differential between the sum of the resources and the load shape illustrates the flexibility and variability necessary to serve default supply load. It is more costly to supply energy to a load containing variability than it is to supply energy to a load that is “flat” or unchanging from hour-to-hour or from daytime to nighttime.

The higher cost to supply variable load can be explained in two parts. First, the market for purchasing energy is defined by 2 primary periods of time: on-peak and off-peak. On-peak is the 16-hour period in the middle of the day Monday through Saturday, excluding National Energy Reliability Council (NERC) holidays, when electricity consumption typically reaches its “peak”. Here, the forces of supply and demand have greater influence on the price of power due to elevated resource utilization and a limited pool of supply resources.

The second part of the higher “peak load” supply cost explanation is the use of higher cost intermediate or peaking resources that possess ramping or dispatchable plant characteristics. These resources are suited to meet peak loads because of their operating characteristics and flexibility. By contrast, lower cost base load units are designed for continuous operation at high capacity factors.

Figure 8



Based on historical data from NWE Default Supply customers, the load forecast includes detailed hourly estimates of energy consumption that define the shape of the load of default customers. To illustrate the expected range of the load shape in a “normal year”, Figure 9, the “January 2008 Default Supply Loads and Resources,” and Figure 10, the “July 2008 Loads and Resources” are presented below. For the months of January and July 2008, each hour of the day can be evaluated for minimum, maximum, and average load conditions. By observation, it is reasonable to expect an hourly variation of load in the range of approximately 25 to 300 megawatts. This variation can represent a substantial percentage of

the total load, and must be carefully considered when selecting resources and resource portfolios to serve the Default Supply load obligation.

Figure 9

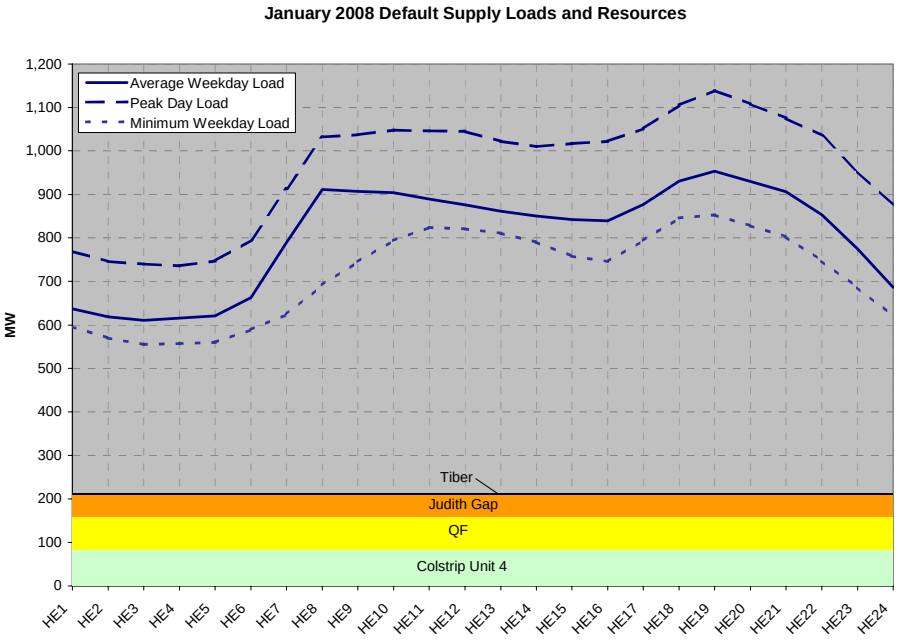
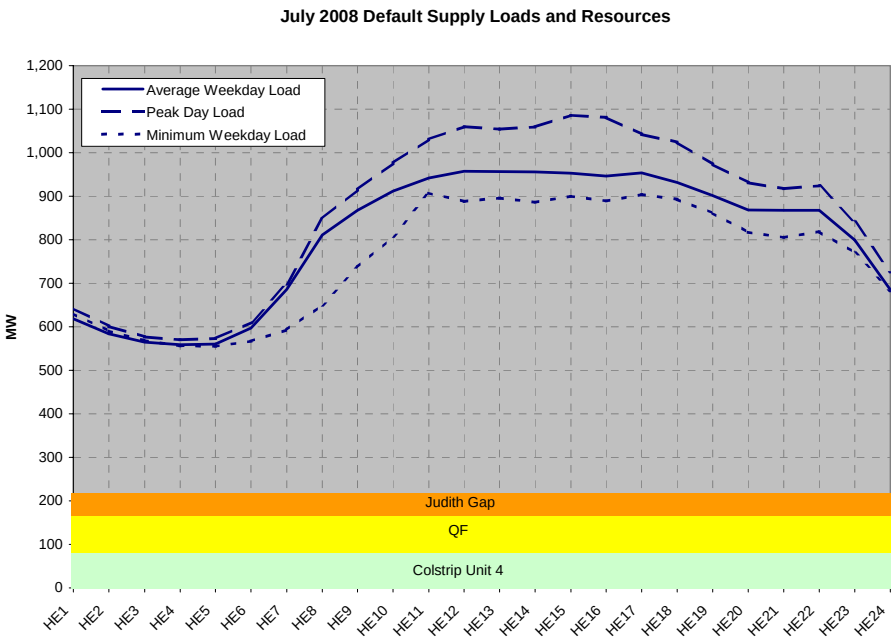


Figure 10



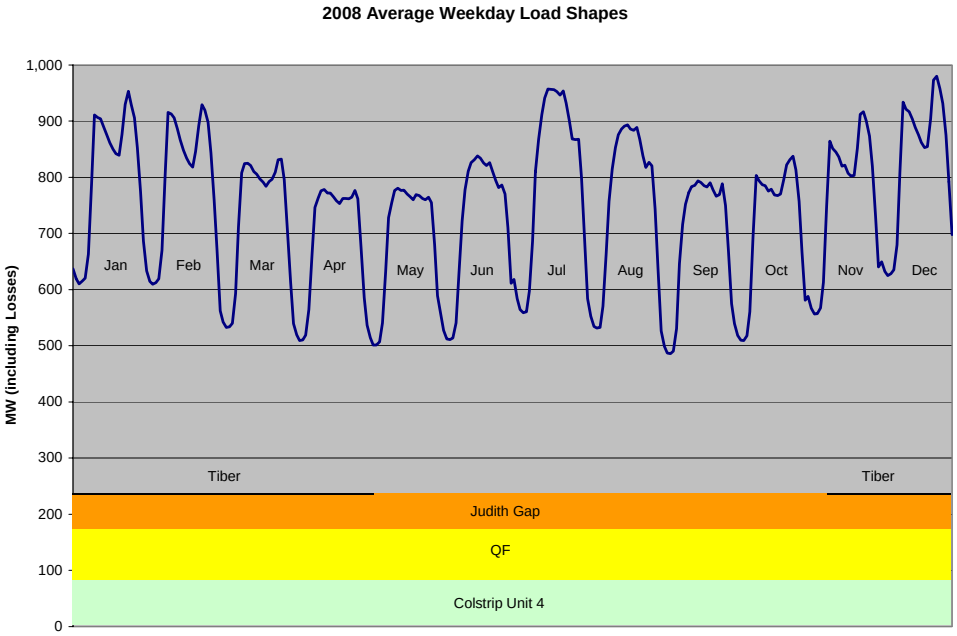
There is also uncertainty in forecasting customer load growth. The error band increases as the forecast extends in time – the longer the forecast, the greater the uncertainty. To analyze this uncertainty, NWE conducted two sensitivity analyses: increasing the base case load by 10 percent, and decreasing the load by 10 percent. The base case load forecast was modified by changing the first year value by 1%, followed by 2% in the second, and so on, until reaching a 10% change in year 10 of the evaluation. For the last 10 years of the study period, the forecast values were changed by 10% compared to the base forecast, in each year. Using this methodology, NWE constructed a high and low load sensitivity scenario to test resource and portfolio performance on a select group of portfolios over a well-defined range of load (see Volume 2, Chapter 3).

Resources Expiring

On June 30, 2007, two contracts between NWE and PPL Montana, a 150 MW heavy load contract and a 300 MW base load contract, expire. These contracts

currently provide, on an annual basis, about 3 million MWh out of the total default supply need of over 6 million MWh. Figure 11, below, shows the effect in 2008 of the expiration of those contracts.

Figure 11



New Resources

Following submission of the 2003 Plan, NWE initiated an all source RFP process in March 2004. Thirty-five long-term submissions by 29 bidders were received. NWE and Lands thoroughly analyzed the price and non-price factors of the most promising proposals.

NorthWestern's RFP selections fell into two categories:

- Intermediate Resources – resources of less than eighteen months in duration, and
- Long-Term Resources – resources of more than eighteen months.

A number of intermediate resources bid into the RFP were selected by NWE. Due to their short terms, PPAs were executed without employing the preapproval process. NWE also selected the following long-term proposals:

- 90 MW of unit contingent base load power from NorthWestern Corporation's unregulated interest in CU4
- 135 MW of wind power from Judith Gap Energy, LLC

The CU4 proposal consisted of 90 MW (unit contingent) for 11.5 years at an average price of $35.80/MWh beginning July 1, 2007, timed to coincide with the expiration of the PPL Montana contracts. This proposal was submitted to the MPSC for advanced approval, together with the Judith Gap Energy agreement.

The CU4 offer was withdrawn from PSC consideration in April of 2005, due to uncertainty regarding the use of the discovery process by competitors to obtain commercially sensitive information of other bidders. The CU4, 90 MW base load proposal will help fill a portion of the resource gap created by the expiration of the current PPL contracts.

Taken together, Judith Gap, Basin Creek, Tiber, and CU4 are estimated to provide forty percent of the energy that the two PPL Montana contracts now provide.

The Judith Gap wind project was approved in March 2005. Judith Gap, Montana's first major wind farm, with an average energy cost of $31.60 per MWh for the 20-year life of the agreement, represents an attractive addition to the portfolio.

A central issue in the hearing before the Commission was the cost of "integrating" the Judith Gap project into the portfolio. Given the size of the project relative to NWE's load, the variability of the project's output presents a challenge for system operators. The testimony predicted a cost of integration of

an additional $5-7 per MWh. NWE's Action Plan, presented below, includes an item to develop longer-term integration arrangements. It should be noted, that integration costs may increase over time and the current costs may not accurately represent future costs.

Judith Gap represents a major step for NWE and Montana. In the next several years, system planners and operators will work to ensure that this resource is incorporated into the portfolio without adversely affecting transmission or system operations. Once NWE gains a better understanding of the effects of substantial amounts of wind on utility operations, NWE will determine the advisability of obtaining greater quantities of wind.

Selected in an earlier RFP, NWE's contract with the Basin Creek project, 51.75 MW dispatchable resource in the form of nine 5.75 MW reciprocating engines, was approved by the MPSC in September 2004. Basin Creek was the first resource approved by the MPSC under the advanced approval authority provided by the Montana Legislature in 2003, Sec. 69-8-421, MCA. The Basin Creek contract, which extends for a 20-year period, also offers options for two 5-year extensions that can be exercised solely at NWE's election. The expected commercial service date is mid-2006. The Basin Creek project will permit supplemental power to be supplied to default supply when economical as compared to alternatives.

Tiber Montana, L.L.C. is a small 7 MW hydro facility that will sell generation to the Default Supply during the months of October through March inclusive.

An estimate of default supply load and resources balance to meet that load in the July 2005 – June 2006 time period is shown in Table 6 below.

Table 6

LOAD RESOURCE BALANCE, July 2005 – June 2006	
	MWh's
Est. default supply load 7/05-6/06	5,639,348
Total contract supply	4,586,972
Est. short term purchases	1,479,659
Net Total Delivered Supply	6,120475*

Note: *Includes transmission and distribution line losses.

July 2007 presents a very different picture after the PPL Montana contracts expire. The effects are illustrated below in Figure 12.

Figure 12

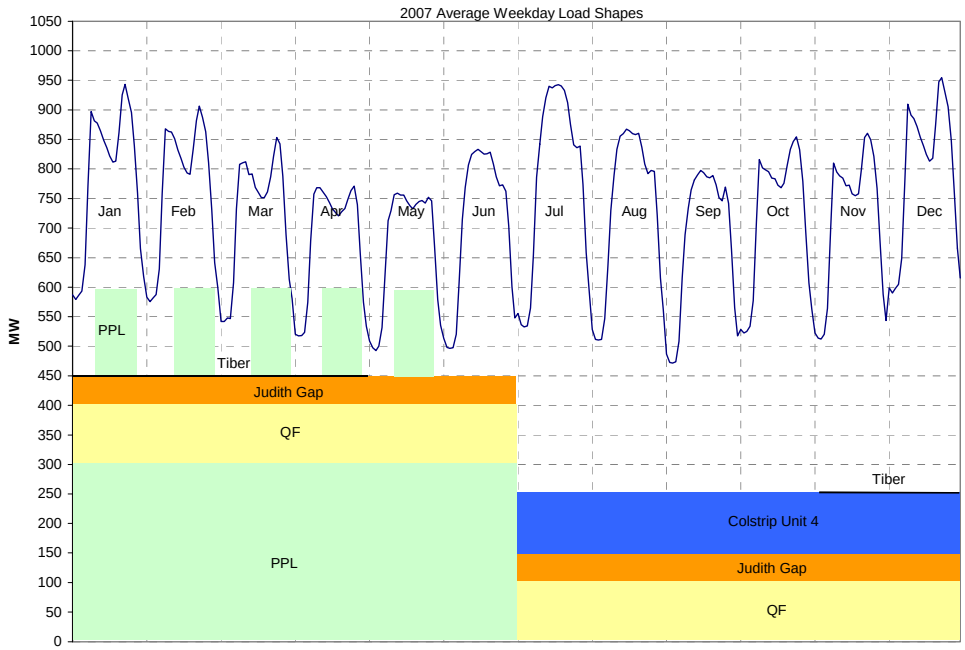


Figure 12 illustrates the primary short-term risk and resource uncertainty for NWE's Default Supply customers, and the continued urgent focus of NWE for the short term.

Resource Need

Once the resource need is calculated, the question becomes: What resources should NWE choose to fill the need? The Guidelines prefer an RFP process for adding resources to meet default supply needs. Modeling of different portfolios, with differing resources, costs, and risk characteristics, provides substantial guidance to NWE as the utility designs appropriate RFP(s) and evaluates bids.

Modeled Resources

The NPCC has assembled information on numerous resources types. These resources were considered in the development of this Plan. With the assistance and advice of the ETAC, the number of resources considered by NWE was narrowed. For example, some resource types were rejected due to their improbable nature, or because they were obviously not cost effective. While some transmission costs were included for out of state resources the actual availability of transmission was not addressed. Transmission access would be an integral part of any PPA that NWE would enter into. The new resources selected for portfolio construction (see Volume 2, Chapter 4, Sources) were:

- Montana Coal (MTC),
- Wyoming Coal (WYC),
- Montana Natural Gas Combined Cycle (CCCT),
- Montana Natural Gas Simple Cycle (SCT),
- Montana Integrated Coal/Natural Gas Combined Cycle Turbine (CGT),
- Alberta Tar Sands Cogeneration (TS), and
- Wind (W).

The costs for these resource types were extracted from the NPCC data and computed on a nominal levelized basis, factoring in the in-service year, the expected life of the facility, and NWE's cost of capital. In the case of coal projects, the fuel costs were also computed on a levelized basis using the same

factors. For each resource, the on-line date is assumed to be the earliest date the resource type could be engineered, sited, and constructed per the NPCC's estimates plus one year. The one year addition is intended to account for the RFP and MPSC pre-approval process leading to the completion of a PPA. This information is shown in Table 7 below.

Table 7

	MTC	WYC	CG	CCCT	SCT	TS	W
Year in Service	2012	2011	2012	2010	2010	2012	2010
Cost w/o fuel	$44.00	$46.40	$61.80	$20.60	$15.60	$24.60	$61.60
Fuel Cost	$8.00	$8.00	$7.60	$40.00	$60.00	$34.00	$0.00
Total Cost	$52.00	$54.40	$69.40	$60.60	$75.60	$58.60	$61.60
Unit Size	400	400	400	270	100	180	100

Note: All costs are in equivalent $/MWh with fixed costs converted to energy production rates assuming the plant is run at its availability factor. The modeling runs may result in actual dispatch lower than availability.

Montana Coal (MTC), Wyoming Coal (WYC)

The Montana Coal and the Wyoming Coal are identical mine mouth units. A transmission charge is added to the Wyoming unit to account for the additional cost of transmission to Montana. They are both computed at the cost of a 400 MW conventional sub-critical pulverized coal plant. This technology is mature and well understood.

Combined Cycle Combustion Turbine (CCCT)

The natural gas fired 270 MW combined cycle unit is based on one GE F-class gas turbine generator and one heat recovery steam generator configuration, commonly referred to as a one-on-one configuration. The output is adjusted for Montana's conditions, including temperature and elevation. This technology is also mature and widely used.

Simple Cycle Turbine (SCT)

The gas fired simple cycle turbine is an industrial turbine with lower capital costs than the aeroderivative turbine that is also commonly used for electricity generation. These units are generally easy to site and develop compared to most other power generating facilities, but come with a lower efficiency rating and have a higher relative heat rate.

Integrated Coal Gasification (CG)

The integrated coal gasification unit uses coal as the feedstock for a gasification process to produce a synthetic gas fuel to fire a gas turbine (which may also be supplemented with natural gas). A CO_2 separation process results in very low net CO_2 emissions, and, therefore, provides benefits in the scenarios with higher CO_2 taxation rates. While there are currently two such plants operating in North America, the technology is not mature and its actual capital and operating costs are uncertain.

Tar Sands Cogeneration (TS)

The tar sands generation is based on a combustion turbine cogeneration installation in 180 MW increments, in northern Alberta, capitalizing on Alberta's unique tar sands deposits near natural gas fields. Tar sands are oil deposits that are mixed with a significant quantity of sand and water and require mining and processing prior to refining. Northern Alberta has large deposits of these tar sands. A cogeneration facility located in this region could use the locally available natural gas for the primary fuel, but supply the waste heat to the tar sands refining process, which results in a significant cost benefit. While 2,000 MW of this form of cogeneration is already in operation, transmission constraints must be considered as part of the inclusion of these resources in NWE's portfolio. Plans are presently being developed for direct current (DC) transmission lines linking the Tar Sands with California. One option under discussion has the lines going through Montana. The partial cost associated with

the development of a DC transmission line is included in the cost estimate for this resource.

Wind (W)

The NPCC's wind resource is based on tower mounted 1.5 mw wind generators as have been installed in recent wind developments, including the Judith Gap site. The costs are based on recent experience in the region, assuming an installation of 100 MW at a single site. The technology is maturing and is relatively dependable.

Portfolio Construction

For purposes of the modeling analysis, it was important to construct a wide range of realistic portfolios for consideration. NWE, in conjunction with the ETAC, developed a set of 32 resource portfolios for review and consideration. By selecting many diverse portfolios that span the range of resource alternatives, NWE believes that a reasonable range of outcomes were considered in the modeling and analysis.

Each of the portfolios includes the following resources through their contract expiration date:

1. The PPL Base Load Contract
2. The PPL High Load Hour Contract
3. QF Contracts
4. DSM
5. Basin Creek
6. Colstrip Unit 4, 90 MW starting in July 2007
7. Judith Gap Wind Project
8. Tiber Montana

These known resources were combined with different combinations of the modeled resources discussed above. Each combination is referred to as a portfolio. The portfolios represent a spectrum of reasonable options that NWE could pursue to meet the long-term needs of the Default Supply obligation.

Certain themes were followed in the portfolio construction. For example, the first seven Portfolios contain a single resource (coal, wind, etc.) and market purchases. Single resource additions allow conclusions to be drawn regarding the impact of certain resource types on costs and risks to the default supply.

The majority of the portfolios generally represent a combination of two of the basic resource types (for example: coal/natural gas and natural gas/wind). Attention was paid to combining varying levels of different resources. Portfolios with three different resource combinations were also constructed (coal/natural gas/wind).

In addition, three portfolios were constructed that avoided market exposure by creating a near load resource balance (Portfolios 23 and 24), and one resulted in a resource surplus (Portfolio 25).

Table 8 provides the detail of the portfolio compositions.

Table 8

Intrinsic Analysis Portfolios								
Resource Combinations in MW's								
Resource	**MTC**	**WYC**	**CG**	**CCCT**	**SCT**	**TS**	**W**	**Total**
Portfolio #								
1	Market Reference							
2	600							600
3		600						600
4			602					602
5				528				528
6						360		360
7							500	500
8	200			264				464
9	200				100	180		480
10			401		100			501
11			401			180		581
12	200			264			50	514
13	200				100	180	50	530
14	200			264			100	564
15	200				100	180	100	580
16	200			264			150	614
17	200				100	180	100	580
18	200			264			200	664
19	200				100	180	200	680
20				528			100	628
21			401		100		150	651
22				264	100		200	564
23	200		401		100	180	50	931
24				528	100	360	50	1038
25	400		401					801
26			401		100		100	601
27			401		100		200	701
28			200				100	300
29			200				150	350
30			200				200	400
31	400				100		200	700
32			200		100			300

In considering development timeframes or on-line dates for new resources, it is obvious that a significant resource need will remain between the termination of the PPL contract supplies in 2007 and the earliest on-line dates contemplated for new long term resources. In order to address this resource shortfall in the modeling, a generic bridging contract was incorporated into the supply portfolio. The bridging contract was assumed to start as a baseload 450 MW supply

commencing in July 2007, ramping down from 2010 through 2012. The cost of this bridge supply was computed to reflect the current forward market. The supply declines from 2010 to 2012 when new resources could come on line. By fixing the price for the period of remaining resource deficit, during the "bridge" period, NWE was able to discern the cost effects of various resources with and with-out the influence of different market prices.

Modeling

The objective of NWE's portfolio modeling was to identify the best portfolio characteristics when considering both cost and uncertainty. This is accomplished by performing multiple portfolio simulations and analyzing the results. With uncertainty surrounding many of the key inputs that impact costs, it is most likely that no single portfolio will consistently display the lowest cost and lowest risk. The goal, therefore, is to find portfolios that perform well across a range of risk scenarios (market prices), and to identify the areas of uncertainty that have the greatest impact on portfolio selection.

For purposes of this Plan, NWE employed the PCI GenTrader® model to calculate the energy supply costs resulting from different proposed resource portfolios over a 20-year study period. GenTrader® is a widely used energy supply portfolio modeling and generation dispatch tool that evaluates complex power portfolios that include both generators and energy contacts. The PCI GenTrader® model does not have the capability to develop an optimal portfolio composition through iterative modeling techniques. NWE recognizes that the Commission, in its Comments, noted that while GenTrader® is a powerful analytical tool, alternative modeling tools may be available that better analyze and evaluate dynamic resource portfolios (see Volume 2, Chapter 4).

NWE, however, has found that a cost effective optimizing model tool is not yet widely used for resource planning activities by other utilities in the region. It appears that use of such models may become more pervasive in the future. In

order to address the optimization issue, NWE analyzed many diverse portfolios, including some portfolios suggested by ETAC members, to increase the likelihood that some optimum portfolio construction would be represented among the portfolios.

By design, GenTrader® effectively models the various energy supply portfolios that were developed for review as part of the Plan. Nonetheless, an evaluation of alternative models will take place after the submittal of this Plan to the MPSC. This evaluation will be informed by Lands' benchmarking efforts.

NWE used GenTrader® in a two-step model process for its analysis of costs and risks. The first step was the use of intrinsic analysis. The second step was a stochastic analysis. Prior to running the model, price forecasts for both natural gas and electricity had to be developed.

Market Price Inputs

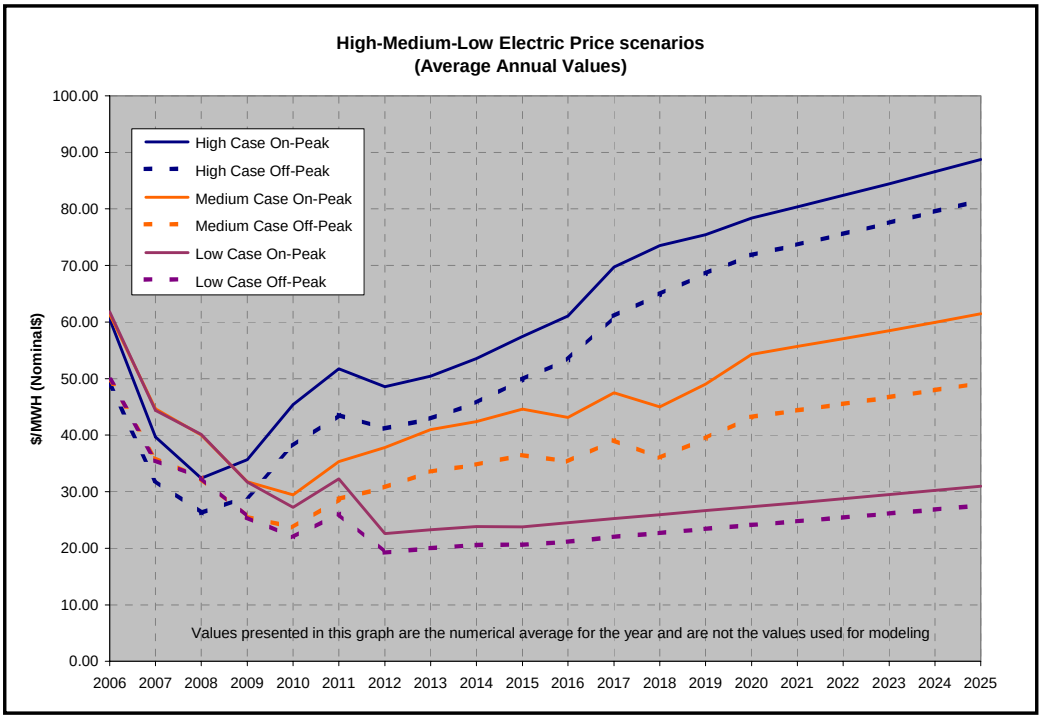
The natural gas and electric market price projections for the intrinsic and stochastic analyses were obtained by NWE from Cambridge Energy Research Associates (CERA)[13], a nationally recognized energy consulting firm. CERA's price forecasts were made reflecting impacts on energy infrastructure of a range of scenarios for world and US economic conditions. These forecasts represent a medium projection, bounded on either side by a low and a high projection.

NWE developed the electric price forecast used in the model by transforming the CERA monthly on-peak and off-peak electric price forecasts into multiple peak periods which are consistent with NWE's experience. CERA's electricity price forecast reflects the perspective that the current high spot prices for electricity will not be sustained beyond the next few years, and then will decline until a more typical trend is reached. The electricity price forecasts for the study period (see Volume 2, Chapter 4) are shown in Figure 13.

[13] www.cera.com/home/

In the modeling for the Plan, natural gas and electricity prices are varied stochastically with a correlation of 0.6. A positive correlation value of 0.6 means that as electric prices move up and down in the stochastic price sampling process, natural gas prices move in the same positive or negative direction with a limited degree of freedom (see Volume 2, Chapter 5).

Figure 13



Intrinsic Analysis

GenTrader® was first run in intrinsic mode for the 32 different portfolios to perform the initial screening of resource portfolios. In the intrinsic mode, the model utilized the defined resource and contract portfolios to meet the Default Supply load over a projected 20-year period. In this mode, the model utilized the

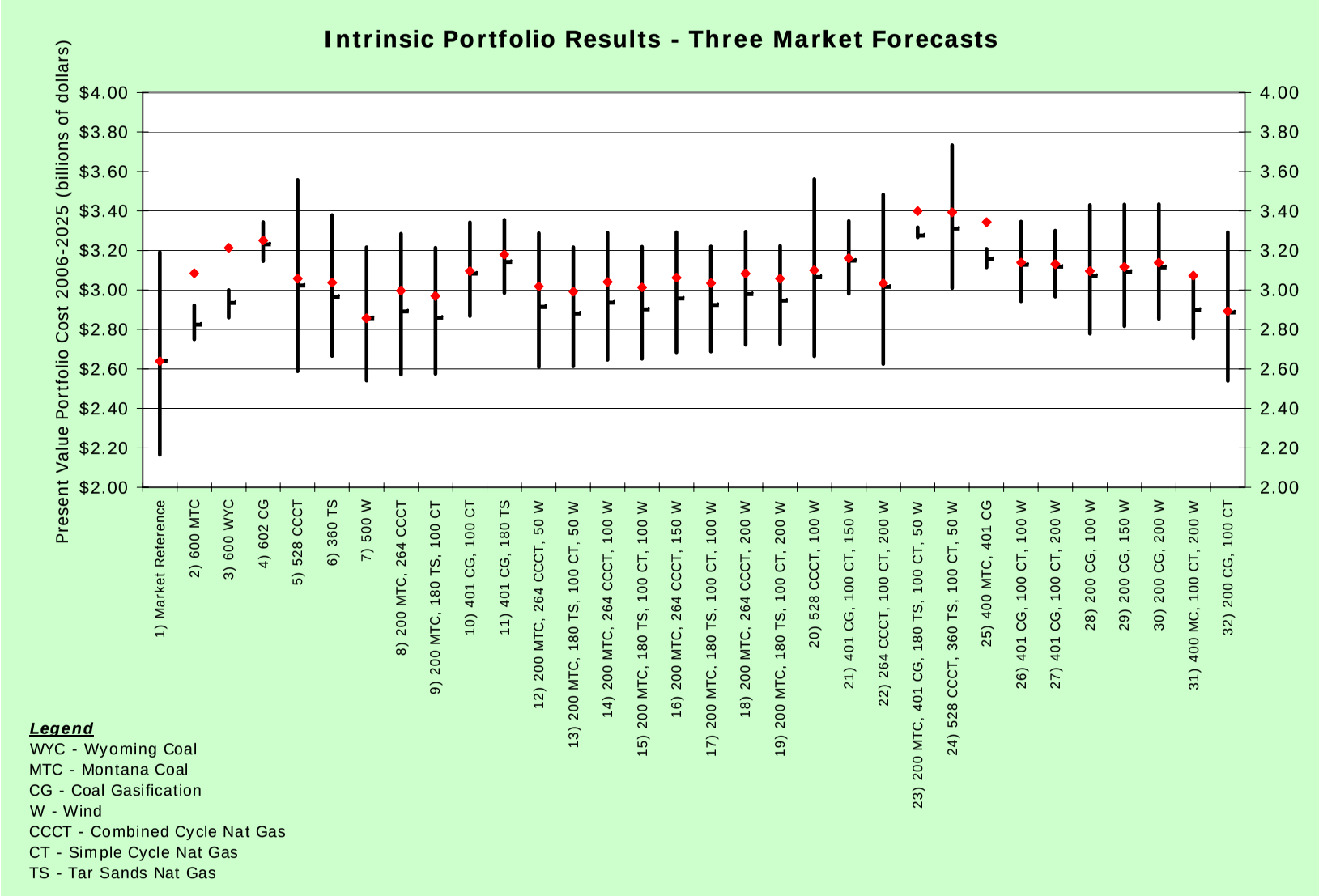
portfolio resources on a merit dispatch order[14] for five distinct periods per week. Three runs were made to capture the various portfolio costs under 3 different sets of electric and natural gas market price projections. While the market prices were not allowed to vary on a probabilistic basis at this stage of the review, the three different price runs per portfolio allowed conclusions to be drawn regarding how a particular portfolio performed under different electric and natural gas price scenarios.

The 20-year present value cost for each of the portfolios was calculated for each of the price forecasts. This provided information on the total costs for each portfolio and an understanding of how the portfolio costs would vary, depending on the price forecasts. The resulting financial outcomes for each portfolio were then compared. The results of this portfolio analysis over each of the price forecasts are in Figure 14.

This Figure displays information on each of the 32 portfolios modeled in a way that facilitates comparison of the portfolios. For each of the portfolios across the x-axis, the outcomes in the low, medium and high price scenarios are charted. The y-axis shows the calculated cost of each portfolio in billions of dollars. For each portfolio, the medium price case produces the middle tick mark, while the low and high market cases are shown by the upper and lower ends of the vertical black bar. This allows a visual means to compare the expected costs of the set of portfolios under the three different price forecasts. Portfolios 1 and 2 have the lowest expected costs in the medium forecast.

[14] Economic or merit dispatch is the start-up or shutdown of generating units to accomplish the most economic production of electricity.

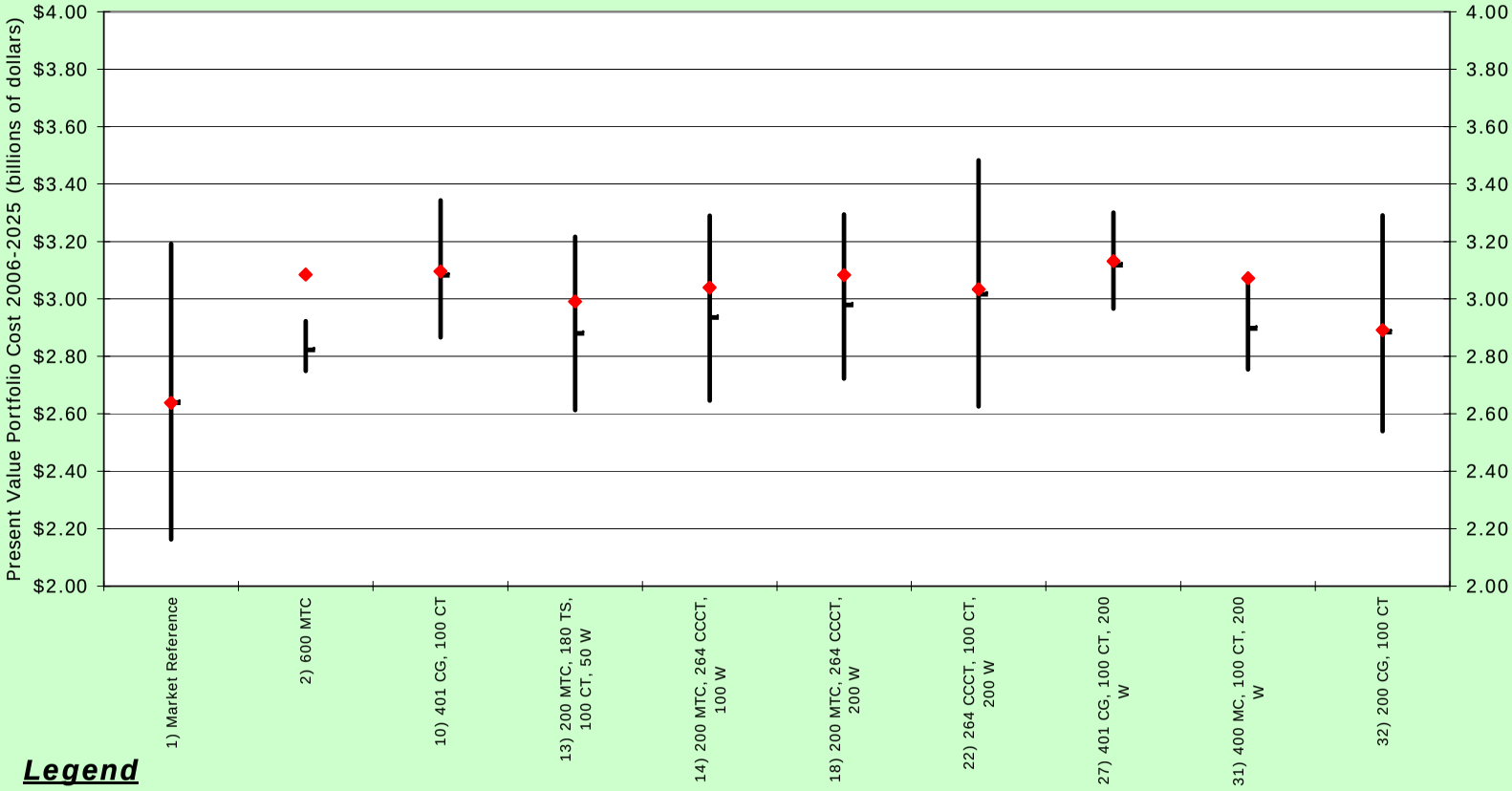
Figure 14


Intrinsic Portfolio Results - Three Market Forecasts
Present Value Portfolio Cost 2006-2025 (billions of dollars)
$4.00
$3.80
$3.60
$3.40
$3.20
$3.00
$2.80
$2.60
$2.40
$2.20
$2.00
1) Market Reference
2) 600 MTC
3) 600 WYC
4) 602 CG
5) 528 CCCT
6) 360 TS
7) 500 W
8) 200 MTC, 264 CCCT
9) 200 MTC, 180 TS, 100 CT
10) 401 CG, 100 CT
11) 401 CG, 180 TS
12) 200 MTC, 264 CCCT, 50 W
13) 200 MTC, 180 TS, 100 CT, 50 W
14) 200 MTC, 264 CCCT, 100 W
15) 200 MTC, 180 TS, 100 CT, 100 W
16) 200 MTC, 264 CCCT, 150 W
17) 200 MTC, 180 TS, 100 CT, 100 W
18) 200 MTC, 264 CCCT, 200 W
19) 200 MTC, 180 TS, 100 CT, 200 W
20) 528 CCCT, 100 W
21) 401 CG, 100 CT, 150 W
22) 264 CCCT, 100 CT, 200 W
23) 200 MTC, 401 CG, 180 TS, 100 CT, 50 W
24) 528 CCCT, 360 TS, 100 CT, 50 W
25) 400 MTC, 401 CG
26) 401 CG, 100 CT, 100 W
27) 401 CG, 100 CT, 200 W
28) 200 CG, 100 W
29) 200 CG, 150 W
30) 200 CG, 200 W
31) 400 MC, 100 CT, 200 W
32) 200 CG, 100 CT
Legend
WYC - Wyoming Coal
MTC - Montana Coal
CG - Coal Gasification
W - Wind
CCCT - Combined Cycle Nat Gas
CT - Simple Cycle Nat Gas
TS - Tar Sands Nat Gas

Next, sensitivity analysis in the intrinsic mode was performed regarding future potential costs for CO_2 on the costs for each portfolio. The NPCC's CO_2 mitigation costs were reviewed and a projection developed based on the NPCC estimate that there is a 67% chance of a CO_2 mitigation charge of $6.00/ton of emission, which will rise to $14/ton of emission in 2017. These costs were converted to an equivalent $/MWh adder for each of the resources used in the analysis, and then applied to the medium price forecast run to determine the impact on portfolio energy costs. This result is plotted as a red diamond for each run, which shows the increases to the medium price forecast with the addition of a CO_2 tax (see Volume 2, Chapter 4, Sources).

Based on NWE's review of the results and discussions with the ETAC, ten of the portfolios were selected for stochastic modeling. These ten were selected with the intent of maintaining a diverse set of resource portfolios, while selecting for further analysis, portfolios that were low cost or low risk, or a mix of low cost and low risk. The resource portfolios selected for stochastic modeling are shown in Figure 15 below.

Figure 15



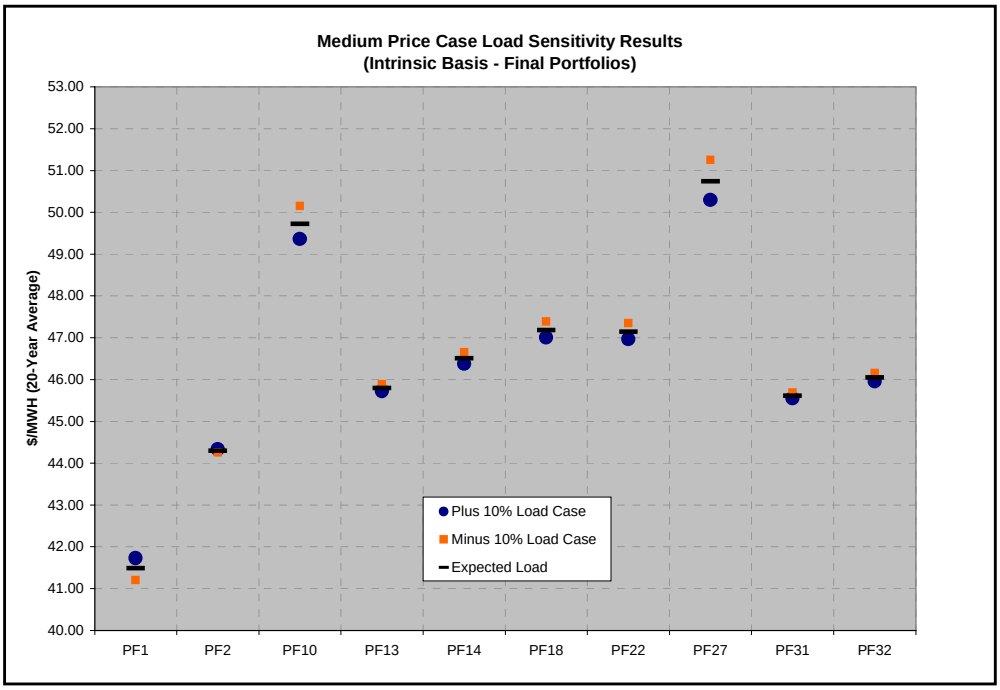
Legend

WYC - Wyoming Coal
MTC - Montana Coal
CG - Coal Gasification
W - Wind
CCCT - Combined Cycle Nat Gas
CT - Simple Cycle Nat Gas
TS - Tar Sands Nat Gas

Note: Portfolio 27 reduced to 150 mw installed wind for stochastic run

The initial intrinsic model performed a sensitivity analysis to determine how the 10 selected portfolios performed under different forecast load assumptions. An intrinsic model was prepared and run for two alternate load cases; base case load plus 10 percent and base case load minus 10 percent. The purpose of these model runs was to determine the magnitude of portfolio cost change based on known changes to load for the medium price case. The results are presented in Figure 16. NWE, after reviewing the results, concluded that portfolio costs on a 20-year average cost basis are not load sensitive using a +/- 10 percent load assumption. As shown in Figure 15, in all ten portfolios, the cost sensitivity was less than $1 per MWH on a 20-year average basis for the base case price scenario.

Figure 15



Stochastic Analysis

In the stochastic mode, GenTrader® runs the 20-year analysis period in a Monte Carlo simulation with multiple draws made for each portfolio. In each draw, the model selects certain variables from a distribution curve in order to replicate the potential uncertainty of certain variables on the overall cost of the resource portfolio. The model is capable of treating multiple variables using correlation coefficients between and among variables.

The stochastic ranges were developed based on observed price volatility for regional markets and reflect the impacts of fundamental variables that drive energy price volatility, such as weather, hydro-electric production conditions, and regional economic factors. It is in this way that the impacts of these other regional conditions are factored into the resource analysis performed for the Plan. If NWE owned hydro-electric production or was exposed to these fundamental drivers in a direct fashion, the stochastic analysis would need to be expanded accordingly; instead, hydro-electric variability is factored into the electric price forecast. In the stochastic mode, GenTrader® generally performs close to 3,000 separate draws. This allows the results to be reviewed in a probabilistic manner with consideration given not only to the average outcome, but also to the range and frequency of financial results that are dispersed from the average outcome.

The stochastic model runs conducted by NWE as part of this Plan varied market prices in two ways. First, three separate cases of natural gas and electricity price behavior over the 20-year analysis window were considered. Secondly, in the stochastic runs, the prices were allowed to vary from run to run allowing the model to replicate the volatile nature of the energy markets. It is from these stochastic runs that the risk versus cost comparisons were developed.

GenTrader® produces graphical probability distributions that show the range of possible financial outcomes, and the probability distributions, indicating the

likelihood that each result will depart from the expected financial outcome by a specified quantity. Graphically, the wider the distribution, the greater the resource cost uncertainty.

The stochastic analysis is undeniably complex but provides substantial additional information that NWE has analyzed. Much of the information concerns the risks and uncertainties that any portfolio could be asked to contend with over the next twenty years and the resulting cost impacts.

Risks and Uncertainties

In accordance with Rule 38.5.8219, ARM, NWE employs risk evaluation, management, and mitigation practices to address the risks inherent in the uncertainty of electric supply markets and load characteristics. NWE incorporates risk analysis into this Plan in several ways.

The analysis for this plan incorporated industry standard practice for stochastic review and consideration of the potential range of financial outcomes using GenTrader®. The results of the GenTrader® runs were reviewed in a manner consistent with recent developments in power risk management that have been adopted by the NPCC (the comparison of expected financial outcomes with the average of the worst 10% of the outcomes).

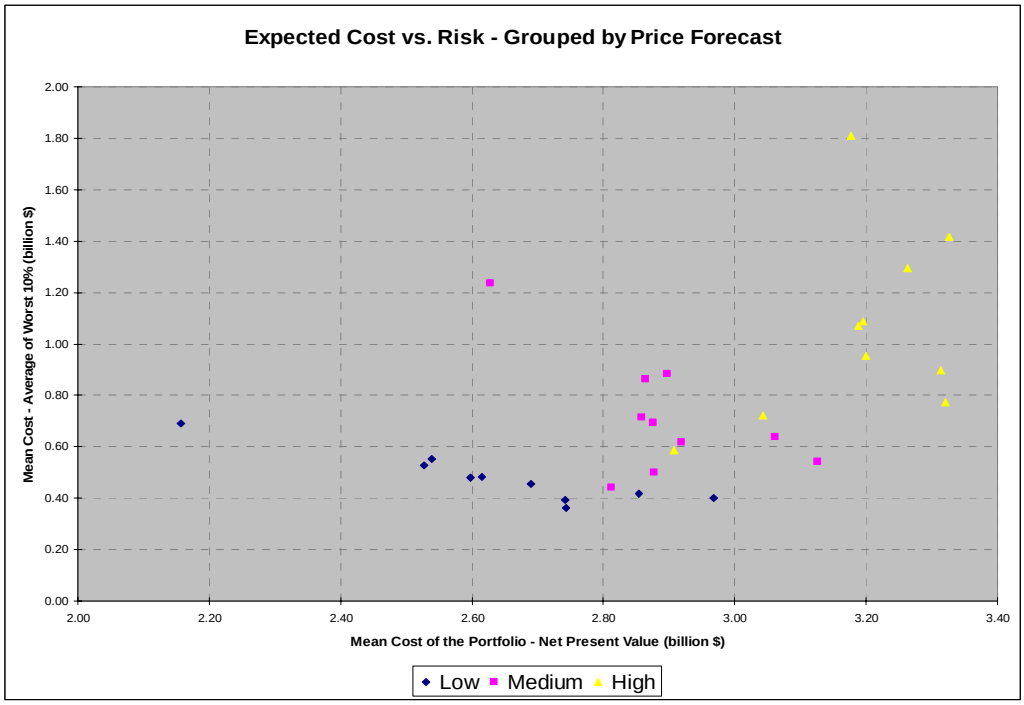
The potential implementation of a CO_2 tax was also reviewed in the stochastic mode by applying an expected CO_2 charge to the various portfolios and reviewing the impact of these additional charges on the risk metric for the portfolios. This allowed the utility to make judgments concerning the potential risk of this environmental externality on the default supply resource mix.

There are a number of ways to quantify the probabilistic outcomes to facilitate comparative review. These risk metrics are a relatively new development within the power industry, and have been the focus of discussion over the last few

years. The NPCC and others have used a risk metric by which the expected outcome (the mean) is compared to the difference between the mean and the average of the worst 10% of the outcomes. This gives a measure of the departure from the mean for those stochastic draws with the worst financial outcomes to the utility and customers (i.e., outcomes with the most risks).

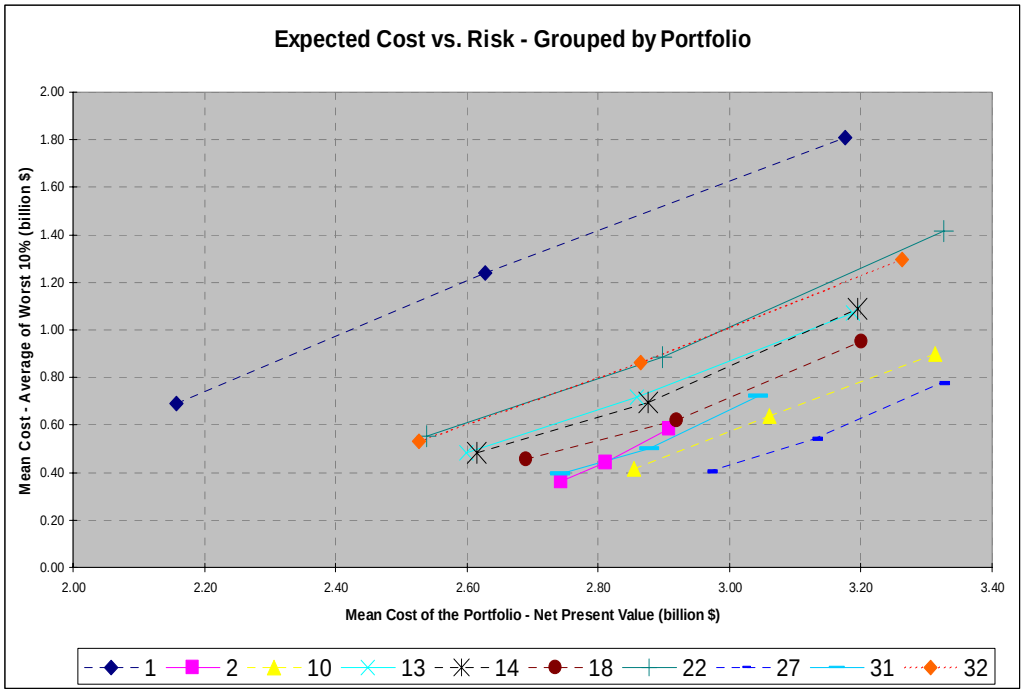
The results are shown on a graph with the expected 20-year cost plotted on the x-axis and the difference between the mean and the worst 10% plotted on the y-axis. As the expected cost of a portfolio increases, it moves to the right, while an increase in a portfolio's risk results in a move up the y-axis. A lower risk/lower cost portfolio will be closer to the origin of the chart. The resulting ten selected portfolios are shown below in Figure 17.

Figure 17



The 30 plots show the relative costs and risks of the ten portfolios with the three price forecasts. The blue diamonds represent the low energy market price forecast, while the magenta squares and yellow triangles show the medium and high forecasts, respectively. The Figure shows that as the overall market prices increase, the expected costs of the portfolios begin to group, but the risk performance of the portfolios varies widely. While this Figure is useful to demonstrate the effect of the overall price projections on the risks and costs of the portfolios, it is less instructive regarding how a portfolio's risks and costs perform under uncertainty. In order to more clearly observe the tradeoffs between risk and cost of each portfolio, the information was modified and follows as Figure 18.

Figure 18



This Figure helps identify those portfolios that offer NWE the greatest risk reduction over a disparate range of market outcomes. For example, the results for Portfolio 2 (all coal) demonstrate that the financial outcomes vary much less over the 3 price scenarios than do the results for Portfolio 1 (market reference).

In reviewing these results, two portfolios are more effective in mitigating risk over the range of market outcomes that were defined for the analysis. These are Portfolios 2 (all coal) and 31 (coal, natural gas, and wind). In the low market price scenario, it is not clear that these portfolios are preferred because market reference Portfolio 1 is much less expensive, and the other portfolios seem to form a nearly linear trend line of negative slope (i.e., the results for each of the price cases tend to follow a line that increases as it moves to the right). As the medium and high price cases are reflected, the cost and risk profile for market reference Portfolio 1 increases dramatically, and the linear nature of the plots begins to erode. It is in considering the results across all three price scenarios that the superior risk mitigating effects of Portfolios 2 and 31 are observed.

Portfolio 2 relied entirely on pulverized coal as a source of new resources, and Portfolio 31 has significant amounts of new coal, in addition to natural gas and wind. The compositions of these portfolios are:

- Portfolio 2: 600 MW of Montana conventional coal
- Portfolio 31: 400 MW of Montana conventional coal, 100 MW of simple cycle CT, and 200 MW of wind generation

To reiterate, for all portfolios, when default supply resource requirements are greater than the resources contained in the portfolio, the model automatically acquires the necessary energy supply at market (each portfolio also contains the base resources).

In reviewing the remaining portfolios, Portfolios 14 and 18 mitigate both cost and risk in a more balanced manner than the rest of the portfolios, with the clearest demonstration of this mitigation shown in the results for the high market price scenario. The composition of 14 and 18 are:

- Portfolio 14: 200 MW of Montana conventional coal, 264 mw of combined cycle CT, and 100 MW of wind generation
- Portfolio 18: 200 MW of Montana conventional coal, 264 mw of combined cycle CT, and 200 MW of wind generation

Some conclusions may be drawn from these results. It appears that coal resources mitigate risk the best and have the lowest cost in the high market scenarios. But, as coal resources are added, the lower cost outcomes that result from lower market prices are foregone. In other words, the cost savings that result in the very low cost outcome in lower market scenarios would be foregone to gain assurance that the higher cost/higher risk outcomes of the high market scenario are mitigated. The mitigating effect of the coal based portfolios is likely a factor of the fixed price nature of mine-mouth coal facilities. The portfolios with relatively higher reliance on natural gas additions tend to mitigate risk better than strict reliance on electricity markets, but the volatile nature of the natural gas markets offer less risk mitigation than result from coal additions.

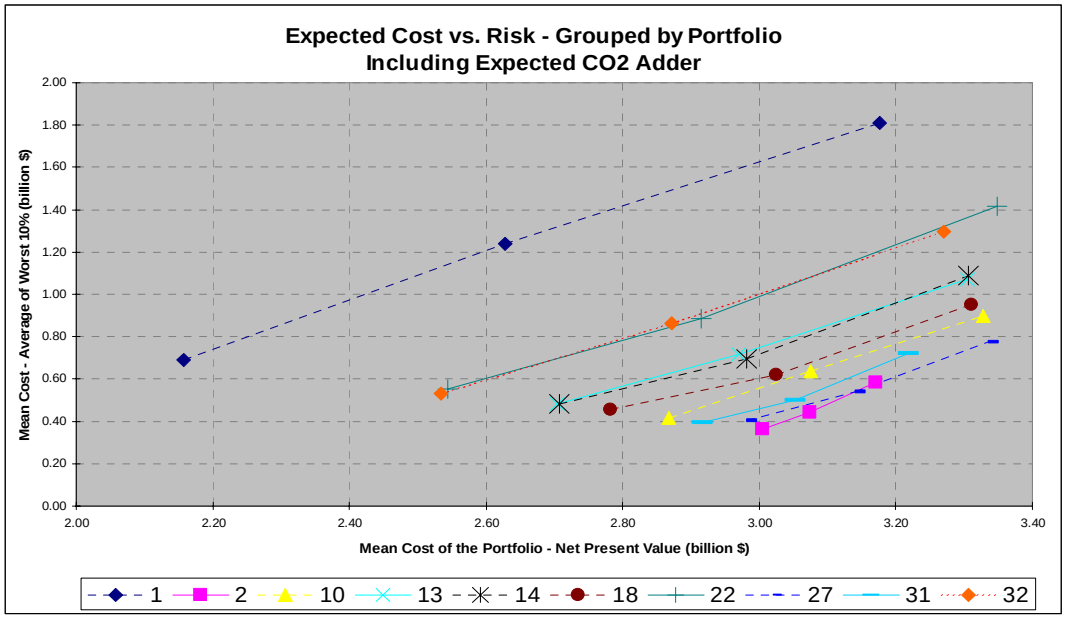
The effect of a CO_2 tax was also analyzed in the stochastic mode. As in the intrinsic runs, a CO_2 cost was added to each of the portfolios based on the CO_2 emissions of the particular resources.

The results changed the distribution of the cost versus risk information as shown below in Figure 19.

In this case, the results of each price scenario are more linear than in the previous Figures. The risk for portfolios that contain a significant amount of pulverized coal resource has increased relative to the range for portfolios with

less of this resource. It is interesting to note that Portfolios 2 and 31 both mitigate greater levels of supply cost risk than the other portfolios, particularly in the high market scenario. This is true despite the relatively higher impact of the CO_2 taxes on these portfolios.

Figure 19



It is less clear in this analysis, however, whether Portfolios 14 and 18 provide risk protection to a greater degree than the remaining portfolios as the results in the higher market case are now nearly linear and the expected costs for all portfolios are nearly the same (although the risk metric varies). As was noted, these results were computed with an "expected level" of CO_2 taxes as defined by the NPCC. A third run of results was made with the very high CO_2 charge. NWE believes that while such a high scenario is possible, it is not highly likely.

Figure 20 shows this analysis with the high CO_2 charges resulting in the following efficiency frontier:

Figure 20

Deleted: <sp>

These results show that the coal portfolios drop from consideration. Despite the relatively tight grouping of the outcomes for Portfolios 2 and 31, the overall costs are higher than other portfolios in all cases. This result demonstrates the potential downside of an over-reliance on conventional coal plants, and highlights the importance of resource diversity as a planning consideration.

Figure 20 shows Portfolios 10 and 27 overtaking the other portfolios in terms of mitigating both costs and risks. These portfolios include the emerging Integrated Coal Gasification technology with CO_2 capture. The relatively lower costs associated with this low CO_2 emitting resource is not surprising in the higher CO_2 taxation case. On a relative basis, however, the market reference case remains cheaper than the other portfolios in this future scenario. It should be noted that the high CO_2 tax scenario is more closely aligned with the assumptions CERA utilized to develop its high market case. In fact, the CERA lower market case reflected greater development of conventional coal units without regulatory cost adders. Therefore, in the high CO_2 sensitivity scenarios, the high market price case should be given more emphasis.

Table 9 provides a ranking of the portfolios in the medium forecast without a CO_2 tax. The table uses a simple summation of each Portfolio's expected cost in the medium price forecast (20 year present value) and the risk var to provide the relative rankings.

Table 9

Medium Market Mean 20 Year Present Value Portfolio Cost in Billions $				
Portfolio #	**Cost**	**Risk Var**	**Sum**	**Least Cost Rank**
2	2.812	0.441	3.253	1
31	2.877	0.500	3.377	2
18	2.919	0.620	3.539	3

14	2.876	0.695	3.571	4
13	2.859	0.715	3.574	5
27	3.126	0.541	3.668	6
10	3.062	0.639	3.700	7
32	2.864	0.863	3.728	8
22	2.898	0.886	3.784	9
1	2.628	1.238	3.866	10

Table 10 reflects the rankings with the addition of the CO_2 tax.

Table 10

	No CO2	Expected CO2	High CO2
Best Portfolios	2, 31	2, 31	10, 27
Better Portfolios	14, 18	14, 18	

Based on the summary results in Tables 9 and10, the best approach for NWE and its default supply customers would be to acquire some level of pulverized coal generation and additional natural gas and wind as a mitigation against future CO_2 taxation. Unless there develops a strong basis for assuming a high CO_2 tax, the higher cost coal gasification plants should be avoided.

It should also be noted that all of these portfolios leave a certain amount of resource need to be supplied by the electricity market, although Portfolios 2 and 31 are less exposed to market than Portfolios 14 and 18. The bounds of the market variations as defined in the forecasts are lower than those that were witnessed during the recent West Coast energy crisis. Therefore, any decision to leave more of the portfolio on the market must be carefully considered.

The lead times required to put resources in place to serve the Default Supply portfolio are also important considerations. Coal projects will take the longest, while natural gas plants will come on-line sooner. Wind projects require the shortest lead times. NWE proposes to stagger the resource procurements based on these expected lead times. Coal (or other fixed price resources) would be

secured first and natural gas and wind projects would then be pursued. After obtaining operating experience with Judith Gap, a decision will then be made on how best to size and add additional wind. Finally, revisions to this analysis should proceed to determine how to add natural gas generation – by type and size. Importantly, due to the gap in time between the termination of the PPL Montana contracts and the commencement of these alternate supplies, efforts are under way to bridge the expiration of the PPL Montana contracts and future supply contracts as soon as possible.

Plan Conclusions

The conclusions reached from the planning process are wide-ranging and will guide NWE's acquisition activities on behalf of Default Supply customers, while providing the basis for a discussion by Montanans of their electricity future.

1. The Plan shows a significant amount of new resources required by Default Supply in 2007. NWE has acquired resources that diversify its resource portfolio while reducing the risks posed by expiration of the PPL contracts. While contract replacement risks remain high, particularly if increased regional power demands exceed near-term supplies, those risks have been partially mitigated. As the analysis shows, however, much more work is needed.

   NWE is actively exploring market opportunities that would span the need between 2007 and the availability of long-term resource alternatives. The results of these discussions with market participants will influence the scope and timing of NWE's next RFP.

   A number of significant potential resource additions exist, and discussions with PPL continue. However, higher prices appear to be inevitable.

2. Actions taken to fill the 2007 resource need must be consistent with the acquisition of long-term resources, as indicated by NWE's analysis. Short-term actions should not preclude the long-term opportunities.

3. Actions taken to fill the 2007 resource need must be consistent with the acquisition of long-term resources, as indicated by NWE's analysis. Short-term actions should not preclude the long-term opportunities.

4. The Plan's quantitative and qualitative analyses of the four best-performing portfolios provide valuable insights about desirable resource characteristics. All four portfolios contain some level of new coal resource.
    a. The lowest expected cost portfolio is Portfolio 2, 600 MW of Montana baseload coal. This portfolio would best serve customer's interests in low costs, and it presents the lowest risk in all scenarios except that involving a high CO2 tax outcome.
    b. Portfolio 31 offers the next best set of performance characteristics. This portfolio is a combination of 400 MW of coal, a 100 MW gas fired simple cycle unit, and 200 MW of additional wind. This portfolio performs better than Portfolio 2 if high CO2 taxes are assumed. The diversity offered by this portfolio is attractive. Because this portfolio adds additional wind, the added firming capability offered by the gas unit would provide operational certainty as NWE continues to integrate wind.
    c. Next, Portfolio 14 consists of 200 MW of Montana coal, 264 MW of combined cycle gas, 100 MW of additional wind, and a higher level of market purchases than Portfolio 18, discussed next. The higher level of market purchases offers a cost benefit, but also brings greater risk.
    d. Finally, Portfolio 18 consists of 200 MW of coal, 264 MW of combined cycle gas, and 200 MW of additional wind. The expected

cost of this Portfolio closely resembles that of Portfolio 31 in most conditions, but it has a somewhat lower risk profile because of its reduced exposure to a CO2 tax.

The range of expected costs for all of the four best-performing portfolios is only five percent. Based on experience in the 2004 RFP, NWE expects resource costs in a future RFP to vary by a greater amount than is the case in this Plan. The RFP will be a critical step because the Plan's analysis does not present a compelling case for any particular resource, or any combination of resources, to the exclusion of others.

5. NWE's conservation and DSM program, expanded at the strong urging of the Commission and the ETAC in 2002 and 2003, shows promise in terms of acquisition of conservation resources and benefits to customers through lower bills. The program is working—it has the potential to reduce the growth rate for Default Supply load from about 1.3% to 0.7%. These results will become more tangible and widely-appreciated as programs are better understood by the public.

6. Despite the considerable value of the planning process, the inputs to the modeling have inherent limitations and, as a result, conclusions regarding portfolio performance must be tested under market conditions. For example, key inputs to the model, such as price forecasts, are simply an informed guess of what will happen in the future. Recent events have demonstrated the limited predictive value of natural gas price forecasts as prices have far surpassed what the best-informed analysts could foresee. Other inputs have similar limitations.

7. When bids are submitted and fully analyzed in NWE's next RFP, the Commission and the public should not be surprised if the available resources selected differ somewhat from those that appear in the Plan's

best-performing portfolios. Uncertainties discussed in the Plan such as the regional load balance, court ordered reduction of hydro system output and the status of a CO_2 tax may have greater influence on resource choice in the future.

8. While additional wind is likely, NWE believes it is prudent to first evaluate the impact of the Judith Gap project on NWE's operations. This information should be available by early 2008. If an RFP is issued in 2008, additional wind may be available for inclusion in the portfolio by 2010.

9. Inclusion of analysis of the potential impacts of regulation or taxation of greenhouse gas emissions provides valuable risk insight regarding potential portfolio additions. The Plan analyzed the impacts of two carbon tax scenarios developed from NPCC data ($10.60 and $29.70 per ton of CO_2 emissions) and suggests that the higher tax, if imposed, would change the composition of the preferred portfolios by making conventional pulverized coal technology less attractive. Technological advances, now in the experimental stage, may alter that conclusion.

10. Financial issues such as imputed debt need further study. PPAs are being analyzed by financial rating agencies as if they were debt of the purchaser. Since increased levels of debt raise financial risks, this analysis could have significant impacts on the cost of obtaining capital, impacting both NWE and its customers. This issue needs further study.

11. A discussion of the merits of vertical integration by NWE should take place among the MPSC, NWE and interested parties. Vertical integration could reduce risks, substituting known costs for the uncertainties of contract renewals and volatile market conditions.

12. Future electricity supply costs will be higher—perhaps substantially higher. Customers should take higher future costs into account when they make decisions about home construction, insulation, appliance purchases and their consumption behavior.

13. The 2005 Plan satisfies NWE's planning responsibilities under Montana statutes and the Guidelines. The Default Supply planning process provides NWE and its stakeholders a great deal of information regarding electric industry trends, potential responses to those trends, and the potential impacts of resource decisions on customers and NWE for years to come.

Action Plan

NWE's Action Plan provides the specific steps that implement the Plan.

Primary Action Items

1. NWE will continue to actively explore opportunities and discuss with supply options with market participants. The effect of new supply on customers' rates is NWE's greatest concern as alternatives are explored. The results of these discussions with market participants will influence the scope and timing of NWE's next RFP.

2. Unless new bridge contracts are acquired that influence the timing of acquiring long-term resources, NWE expects to issue an RFP in 2006 or early 2007.

3. NWE will seek opportunities to partner with other utilities on resource developments.

4. NorthWestern Corporation will provide 90 MW of base load, unit contingent power from its unregulated share of Colstrip Unit 4 Default Supply.

5. NWE will evaluate and discuss with stakeholders the pros and cons of ownership of generation by the Default Supplier. A determination will be made whether Montana legislation is required before proceeding, or whether a modification of the advanced approval provisions to include review of utility-owned generation would be sufficient.

6. NWE will evaluate whether legislation to eliminate customer choice statutes for all but the largest customers is in the public interest and will discuss this issue with other stakeholders.

7. NWE will immediately begin an evaluation of the impact of the Judith Gap wind project on the NWE transmission system and Default Supply operations. Areas to be evaluated include: performance of the project, transmission impacts, effectiveness of forecasting tools, and the costs of integration. These areas should be evaluated for a period of two years of operations. Conclusions should be available in early 2008, at which time an RFP for additional wind could be considered if it is supported by the analysis.

8. As additional wind is developed, demand for ancillary services will grow. NWE will be a participant in regional discussions regarding ancillary services markets and reliability criteria.

9. DSM and Regulatory personnel will proceed with the Time of Use Pilot Rate Project described in Volume 2, Chapter 2. The ETAC and the MPSC will be kept informed of important project milestones, modifications of the pilot, data collection and analysis.

10. NWE will continue to participate in regional transmission initiatives, monitor new transmission projects closely, and will enter discussions with resource developers that might not have considered Montana markets absent new transmission projects.

11. An evaluation of the impacts on NWE and its customers of imputed debt associated with power purchase agreements will go forward.

12. Resource portfolio computer models other than GenTrader® will be evaluated to determine what value each might lend to the biennial Default Supply Planning Process. In particular, a model that suggests an optimal portfolio will be sought for study.

13. NWE will evaluate resource planning refinements in the form of a forecast of peak demands and the impact on default supply requirements of higher prices (i.e., inclusion in forecasts of a price elasticity of demand factor). NWE will keep ETAC informed of these activities and seek appropriate input and advice.

Stakeholder Input

Electric Technical Advisory Committee

NWE works closely during the two-year planning cycle with its ETAC. ETAC membership includes representatives of stakeholder entities that are active participants in electric utility issues in Montana. Current members include representatives of the MPSC Staff, the MCC, NPCC, Montana Department of Environmental Quality, Renewable Northwest Project, Montana Environmental Information Center, District XI Human Resource Council, and the Natural Resources Defense Council. The primary purpose of the Committee is to provide technical and policy advice to NWE concerning resource planning, the process of

acquiring electric resources for customers, and specific resource selections (see Volume 2, Chapter 1, Sources).

Meetings are held throughout the planning cycle, with agendas prepared by NWE's planning staff. A memorandum from Gerald Mueller of Consensus Associates, the Committee facilitator, provides a summary of the Committee's activities in the past two years. This memorandum is included in Volume 2, Chapter 1, Sources.

Communications with Broader Stakeholders

To encourage public input in the planning process, NWE intends to take the following steps:

- As opportunities arise and requests are received, public meetings will be scheduled for the purpose of presenting and explaining the Plan. Examples of possible meetings for this purpose include joint events with ETAC member organizations, and civic group meetings.
- The Plan and supporting information will again be placed on the Internet at www.montanaenergyforum.com Readers will be encouraged to ask questions and post comments. The site is being developed and is expected to be available in January 2006. The web-based presentation was endorsed by the MPSC following its review of the 2003 Plan.
- The website will provide a separate summary document of the Default Supply plan designed to communicate the important aspects of the plan in a concise and understandable "plain English" version targeted for non-technical readers.
- Advertising through selected media, including bill inserts, will communicate the various methods available to the public for reviewing the Plan and providing comments.
- An FTP site will be developed to facilitate access to the entire Plan.