NON-WIRES SOLUTIONS
TO LOWER VALLEY POWER AND LIGHT
TRANSMISSION SYSTEM REINFORCEMENT PROJECT

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EXECUTIVE SUMMARY

This report provides an assessment of non-construction alternatives. Its purpose is to determine whether it is feasible to use these alternatives to defer a planned transmission line investment in the Lower Valley area to a later date. This study complements and does not replace existing transmission planning. The goals of this study are the following:

1. Evaluate a broad set of non-construction alternatives.
2. Identify the most promising set of alternatives for the Lower Valley area.
3. Determine if it is feasible to deploy non-construction alternatives to defer transmission construction to a later date.

WHAT ARE NON-CONSTRUCTION ALTERNATIVES?

Non-construction alternatives encompass all activities not directly related to transmission facility construction, which may allow the deferral of transmission facilities.

These include:

- Energy efficiency measures that reduce peak demand.
- Generation at or near loads.
- Loads selling back power at peak, either under contract or in response to periodic offers to pay a set amount for load reductions. This set of activities is referred to as "demand response."
- Actions taken by transmission operators that can squeeze more out of the existing transmission. (Not considered in this report)

SUMMARY OF APPROACH

Our approach consists of four steps. Each of the four steps is described briefly below, and in more detail in the main report.

Step 1: Collect Local and System Avoided Cost Data for the Study Area

The local and system cost data for Lower Valley includes forecasts of market prices of electricity, natural gas, and diesel; the avoided cost of the transmission line; number of customers; forecasted growth and area load pattern during the peak winter season; and other information. We describe each of these inputs in the report.

We relied on public sources of information, such as the Northwest Power and Conservation Council's data, rather than proprietary Bonneville data and assumptions. We performed sensitivity analyses when key inputs were uncertain.

We used the Present Worth Method to determine the Lower Valley transmission reinforcement project deferral value. This approach measures the decrease in the Bonneville Power Administration's Transmission Business Line revenue requirement if the project is deferred. The Lower Valley reinforcement project is actually a number of investments over some 12 years beginning in 2008.

Step 2: Refine Cost and Performance Assumptions

We evaluated three main categories of non-construction alternatives:

1. Energy efficiency measures,
2. Distributed generation, and
3. Demand response.

The distributed generation input assumptions are taken from a set of recent National Renewable Energy Laboratory[1] studies for each main technology type. The energy efficiency measure costs and performance are taken from the Northwest Power and Conservation Council's Regional Technical Forum database.[2] The demand response costs are from a recent Xenergy report[3] commissioned by Bonneville and Bonneville's experience with the Demand Exchange Program.

Step 3: Evaluate Economics of Each Alternative from Various Stakeholder Perspectives

Using information from Steps 1 and 2, we calculated the cost and benefits for each alternative from the various stakeholders' perspectives. We calculated costs and benefits from the five different perspectives listed below.

- Total Resource Cost Test (Net direct costs and benefits to all stakeholders)
- Transmission Utility Cost Test (Impact on revenue requirement)
- Societal Cost Test (Net social costs and benefits including externalities)
- Participant Cost Test (Net financial impact on customer)
- Ratepayer Impact Measure (Impact on rates)

The Total Resource & Societal Cost Tests are the only cost test perspectives that indicate whether the total costs of the system have been lowered. The other tests are a measure of who pays and who benefits. That is, they measure how the costs and benefits of a cost-effective measure get allocated. These cost tests offer important information about how difficult it may be to implement the measures needed to defer the transmission project. For example, if cost-effective measures also benefit individuals and utilities, it would be easier to enlist their help in implementing the alternatives. If individuals are harmed, even though the alternative might be best for the region, it might be difficult to get support for the measures.

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[1] U.S. Department of Energy Office of Distributed Energy Resources. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. Sept. 2003 <http://www.eere.energy.gov/der/>.

[2] Conservation Resource Comment Database. Northwest Power and Conservation Council. Sept. 2003 <http://www.nwcouncil.org/comments/default.asp>.

[3] A Comparative Assessment of Bonneville Power Administration's Demand Exchange Program. Portland: KEMA-XENERGY, 2003.

In this report, we use the Total Resource Cost test as the main cost test to screen alternatives. Measures that pass the Total Resource test are included in the package of alternatives that can be used to defer transmission construction.

We tested all of the alternatives against each of the five tests. A benefit to cost ratio greater than 1.0 for the Total Resource, Participant, and Transmission Utility Cost tests would indicate that we may have willing partners in implementing the identified measures. For example, if the participant's benefit to cost ratio is greater than one, the participant is better off, and may be a willing collaborator. The same is true for the other "allocation" tests. The reverse might be true if the ratios are less than one, even if the measure is cost-effective from a total resource cost and a societal perspective.

Step 4: Develop and Test Alternative Strategies

We examined several conceptual options for deferring the Lower Valley transmission construction projects. In previous analyses we assumed a three-year minimum deferral period. Three years is likely the smallest acceptable deferral period given load and load forecast uncertainties.

However three years may not be the optimal deferral period. Deferral options that include large capital investments need a longer period in which to recover the investment. In such instances, shorter deferral periods work against the non-construction alternative. This is the case with many energy efficiency investments, all direct load control investments, and distributed generation investments that do not make use of existing generators.

In Lower Valley other factors come into play as well. The transmission project is actually a series of investments stretching over some 12 years. Part of the project must be built and cannot be delayed. In addition, natural gas has limited distribution. But there is a plan to build a gas pipeline. The pipeline would greatly expand the possibilities for highly efficient uses of gas for combined-heat-and-power, providing additional interesting peak load management possibilities. It would also burden the Lower Valley area with a capital investment that would be recovered through sales. The capital investment for the pipeline is estimated between $12 million and $15 million.

We did not analyze or judge the relative societal benefit vs. costs of building the various transmission projects compared to building the pipeline. Such an analysis will likely be completed as part of the environmental review of each project.

We contrast the initial option developed in Step 3 against two new alternative strategies. The first alternative we examined was a longer deferral. We looked at a 10-year deferral with the same initial project "must build" items as the three-year deferral. The second strategy looked at a twelve-year deferral where, in fact, the first two transmission construction phases are built. This latter alternative has the advantage of providing additional lead-time for scoping the alternatives, determining the pipeline actuality and timing, and engaging the local community.

The latter strategy is our preferred option. It provides the needed near-term reliability and the maximum long-term benefits. It essentially caps peak electricity use and transforms the Jackson Hole area into a highly efficient, multi-fuel based, sustainable community. This option is the only option in which renewable resources have a positive benefit to cost ratio.

SUMMARY OF FINDINGS (PREFERRED OPTION)

Based on the economic screening and sensitivity analysis, we came to the following conclusions for each of the main alternatives.

DISTRIBUTED GENERATION

Existing reciprocating engine units and combined-heat-and-power pass the benefit to cost screen assuming a 250-hour operations cap. Combined-heat-and-power operations however demand increased run times because they serve multiple purposes. The higher efficiencies available from these applications provide a distinct benefit compared to the 250-hour peak-only assumption. When we increase the operating hours to a more heat-and-power conducive 6000-hours[4] even new distributed generation resources look cost effective.[5]

Interestingly, renewables and storage look very good at 6000-hours. However, a more reasonable run-time for these technologies is about 3,000 hours. At this lower plant factor, photovoltaic and small wind drop to about 0.85 benefit to cost ratio, while storage still looks positive.

Beyond the Total Resource test, the transmission Utility Cost Test results are nearly positive at a benefit cost ratio of 0.93.

ENERGY EFFICIENCY

Some conservation programs are cost-beneficial under both Total Resource and transmission Utility Cost tests for all three scenarios. Significantly more measures are available using the Total Resource test than the Utility Cost test.

The challenge with the energy efficiency approach is to achieve sufficient on-peak load reductions to contribute to the transmission line deferral. Approximately 1.6 MW of load reduction can be achieved annually. Most peak targeted efficiency potentials are in the heating, shell, and lighting end-uses.

DEMAND RESPONSE

When tested using the 10-year deferral option and higher avoided costs of the later phases of the transmission project, Demand Response is cost-effective (Total Resource Cost test) but only if dispatched for 200 hours or less. It is cost-effective to the participant under a

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[4] In fact combined-heat-and-power applications begin to look cost-effective at about 2500 hours.

[5] We assumed that internal combustion engine generation would be gas-fired not diesel.

wide range of incentive structures. However, its transmission system benefit (Utility Cost test) is marginal.

The other challenge of the demand response approach is to estimate the peak load reduction that can be achieved. At our estimated cost of a customer to reduce load ($150/MWh) the program appears cost effective, but without more experience in demand response we will not know how much "firm" capacity reductions we can count on during the extreme winter peaks. The demand response pilot on the Olympic Peninsula will help clarify participation and performance of demand response type programs.

FUTURE REFINEMENTS TO THE ANALYSIS

DETERMINE A BASE LINE FOR LOWER VALLEY ENERGY EFFICIENCY

The ability to achieve sufficient capacity savings to defer the proposed transmission line with energy efficiency measures depends on the current efficiency of Lower Valley homes, commercial buildings, and industrial plants. If all end-users are already at the cutting edge of efficiency, energy efficiency measures may offer little more to our ability to defer the transmission investment.

EXPLORE POTENTIAL DISTRIBUTION CAPACITY VALUE

Our analysis has focused on alternatives to the proposed transmission line project for the Lower Valley area. When non-construction alternatives reduce peak loads on the transmission system, they necessarily also reduce loads on the distribution system. By locating technologies and programs in the right place, it may be possible to also defer capacity upgrades that distribution utilities have. In subsequent analyses, we plan to work with distribution utilities to explore the potential distribution capacity value.

CLARIFY GAS PIPELINE PLANS

The longer-term transmission deferral is more likely if the planned gas pipeline is built. In addition, planning the electric transmission system while ignoring the potential for natural gas offsetting electricity use may create an underused asset, either electric or gas.

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Based on the results of this screening study, it is possible to cost-effectively defer the planned transmission investment in the area if the proposed gas pipeline is built. We recommend creating a Local Integrated Resource Plan for the Lower Valley area and use it to clarify the economic and environmental trade-offs between transmission construction options and the alternatives.

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Table 6: Generation Technologies Included in NCA Screening Analysis

Large Scale Generation	Internal Combustion Engines	Microturbines	Fuel Cells	Renewables	Storage Technologies
Combined Cycle Combustion Turbine	DE-K-30 (30 kW)	Capstone Model 330 – 30 kW w/ CHP	200 kW PAFC Fuel Cell	PV-5	Lead-acid Batteries (flooded cell)
Simple Cycle Combustion Turbine	DE-K-60 (60 kW)	IR Energy Systems 70LM – 70 kW w/ CHP	10 kW PEM Fuel Cell	PV-50	Lead-acid Batteries (VRLA)
Mobile Gas Turbine Generator (GE TM2500)	DE-K-500 (500 kW)	Bowman TG80 – 80 dW w/ CHP	200 kW PEM Fuel Cell	PV-100	Ni/Cd
	DE-C-7 (7.5 kW)	Turbec T100 – 100 kW	250 kW MCFC Fuel Cell	Bergey Windpower WD – 10 kW	Regenesys
	DE-C200 (200 kW)	Capstone Model 330 – 30 kW	2000-kW MCFC Fuel Cell		High Temp Na/S
	GA-K-55 (55 kW)	IR Energy Systems 70LM – 70 kW	100-kW SOFC Fuel Cell		Pumped Hydro
	GA-K-500 (500 kW)	Bowman TG80 – 80 kW	200-kW PAFC Fuel Cell CHP		Pumped Hydro Variable Speed
	MAN 150 kW – 100 kW	Turbec T100 – 100 kW	10-kW PEM Fuel Cell CHP		Compressed Air Energy Storage
	Cummins GSK 19G – 300 kW	Capstone Model 330 – 30 kW w/ CHP	200-kW PEM Fuel Cell CHP		
	Caterpillar G3516 LE – 800 kW	IR Energy Systems 70LM – 70 kW w/ CHP	250-kW MCFC Fuel Cell CHP		
	Caterpillar G3616 LE – 3 MW	Bowman TG80 – 80 dW w/ CHP	2000-kW MCFC Fuel Cell CHP		
	Wartsila 5238 LN – 5 MW	Turbec T100 – 100 kW	100-kW SOFC Fuel Cell CHP		
Large Scale Generation	**Internal Combustion Engines**	**Microturbines**	**Fuel Cells**	**Renewables**	**Storage Technologies**
	MAN 150 kW – 100 kW w/ CHP				
	Cummins GSK 19G – 300 kW w/ CHP				
	Caterpillar G3516 LE – 800 kW w/ CHP				
	Caterpillar G3616 LE – 3 MW w/ CHP				
	Wartsila 5238 LN – 5 MW w/ CHP				
	DEK 2100 (existing diesel)				

4.1.2 Existing Distributed Generation

In addition to the new distributed generation, this study explores the possibility of employing diesel engines that may be available in the area for peak period generation. In evaluating this alternative, a very low capital cost was assigned to securing this generation, thus making existing generation more cost-effective than new generation.

4.1.3 Renewable Generation and Emerging Technologies

Although renewable generation, such as wind and solar, was considered in the analysis, its resource characteristics (e.g., intermittence, relatively low capacity factors, and unreliable winter peak load coincidence), may make it a poor option for deferring a transmission investment. Fuel cells and microturbines do not have many of the disadvantages of the truly renewable resources, but these still emerging technologies are not yet widely available, and their high cost can eliminate them as viable alternatives.

The capital and other cost assumptions for each technology are shown in the Appendix. There are a number of technology assumptions other than capital costs and operating efficiencies that will have a significant effect on the cost tests results. These are presented in Table 7.

Table 7: Distributed Generation Assumptions

Technology	Annual Load Factor	DG Interconnection Point	Behind the Meter	Customer Class (Res, Com, Ind, or Merchant Plant)	# Months of Peak Demand Reduction for Transmission Billing
Combined Cycle GT	90%	Bulk System	No	Merchant	0
Single Cycle GT, Mobile Gas Turbine Generator	56	Bulk System	No	Merchant	0
Internal Combustion Engines (non-diesel)	90	Primary	Yes	Com	11
Diesel Combustion Engines	6	Primary	Yes	Com	11
Fuel Cells	90	Primary	Yes	Com	11
Microturbines	90	Primary	Yes	Com	11
Small Photovoltaic (PC-5)	30	Primary	Yes	Res	0
Large Photovoltaic (PV-50, PV-100)	30	Primary	Yes	Com	0
Wind	45	Primary	Yes	Com	0
Pumped Hydro	66	Bulk System	No	Merchant	0
Compressed Air Energy Storage	50	Bulk System	No	Merchant	0
Other Storage Technologies	50	Primary	Yes	Com	11

The ***Annual Load Factor*** of each technology determines the amount of energy that will be available to sell into the wholesale market (for merchant generators) or to offset retail purchases from the distribution utility. Each technology’s load factor is set at the level that maximizes the Participant test results, subject to regulatory and technical considerations. Emissions considerations limit diesel generators to only 500 hours. Photovoltaic, wind, and storage technology load factors are limited by technical considerations. Each technology’s generation is first allocated to higher value hours. For example, the Single Cycle Gas Turbine operates 4,928 hours (56.26% load factor), and these hours are assumed to occur in the super-peak and peak tariff periods. This optimistic assumption improves the Total Resource, Societal, and Participant tests because generation is assumed to occur in higher value periods.

The ***Interconnection Point*** indicates the electricity grid level at which the generator connects. This determines whether each technology reduces the revenues of the transmission company. Technologies that interconnect at the secondary or primary level reduce transmission system usage and result in transmission company revenue losses. Since technologies that interconnect at the transmission or bulk system level would still pay for transmission system use; they do not reduce the transmission company's revenues. Only the larger technologies (Combined Cycle Gas Turbine, Single Cycle Gas Turbine, mobile generator, pumped hydro, Compressed Air Energy Storage) are assumed to interconnect at the transmission level.

Technologies are considered ***Behind the Meter*** if they are implemented by residential, commercial or industrial customers to reduce the amount of electricity they purchase from the distribution utility. If a technology is considered "behind the meter", its energy output (based on the *Load Factor* assumption explained above) reduces the amount of electricity purchased from the distribution utility. "Behind the meter technology " has better Participant test results because the benefits are accounted for at retail rather than wholesale electricity rates.

Customer Class determines the retail rates that the customer avoids for "behind the meter" technologies. Residential rates are highest, followed by commercial and then industrial.

The ***Number of Months of Peak Demand Reduction for Transmission Billing*** shows the number of months the technology reduces peak load (and revenues) on the transmission system. Most of the technologies interconnected at the secondary or primary level are assumed to reduce transmission peaks 11 months of the year, since they would operate all year long, with one month of maintenance downtime. Photovoltaic and wind generators are not assumed to reduce transmission peaks, because their generation cannot reliably be made to occur at peak times.

4.2 OVERVIEW OF ENERGY EFFICIENCY MEASURES

Energy efficiency measures are typically considered for their energy benefits rather than their potential to reduce peak loads. However, certain measures that save energy coincident with local peak periods, such as heating efficiency and weatherization, can provide capacity benefits as well.

The analysis began with over 1500 discrete energy efficiency measures described in the Northwest Power Planning Council Database,[8] which include market indicators and performance parameters (e.g., baseline technology alternative, costs, energy impacts, peak demand impacts, etc.) for each measure. This database was reduced to 52 measures that seemed best suited to the specific customer characteristics of the Lower Valley area.

To constrain the analysis, the measures were screened for applicability to transmission construction deferral in the Lower Valley area. Measures that would not contribute to winter peak reduction were removed (e.g., air-conditioning efficiency upgrades), along with end uses that do not have significant penetration (e.g., furnace with central AC). Also screened out were end uses that are better suited to and represented under load control programs, such as water heating and industrial motors. The remaining measures were grouped by end-use type and market segment (e.g., economic sector, building type, housing vintage, etc.), which resulted in 13 categories of measures. Table 8 shows the EE groupings by sector (residential, commercial, etc.) and end-use (heating, lighting, appliances, etc.). Finally, we examined each measure and selected the best from each category according to the following criteria:

- “Best” defined by the most cost-effective measure in each category. The Total Resource test was used to define the economic perspective for cost effectiveness.
- “Best” defined by the largest magnitude of demand reduction of any measure in each category that passes the cost-effectiveness test.

[8] http://www.nwppc.org/comments/default.asp

Table 8: Summary of Energy Efficiency Measures Groupings

Group	Rate Class	Measure Type	Example Application
1	Commercial	Envelope	Insulation
2	Commercial	Appliances	Multifamily common area or commercial laundromat
3	Commercial	Exit Signs	Energy Star Exit Sign
4	Commercial	Vending Machines	Vending Machine Controller
5	Public	Traffic Signals	LED Signals
6	Residential	Lighting	Energy Star CFL
7	Residential	Appliances	Biradiant Oven
8	Residential	Appliances	Energy Star Dishwasher
9	Residential	Appliances	Energy Star Clothes Washer
10	Residential	Appliances	Energy Star Refrigerator
11	Residential	Heating	PTCS duct sealing
12	Commercial	New Commercial Lighting	Beyond Code
13	Commercial	Existing Commercial Lighting	Generic efficiency improvement

There are a number of assumptions that impact the cost tests, other than measure costs, energy, and demand savings. These include:

- Number of months per year that demand reduction occurs because of the measure. This will impact the estimation of Bonneville Transmission's lost revenues.
- Whether the measure is an early replacement or failure replacement. Early replacement measures are assigned the full cost of the efficient device; failure replacement measures are only assigned the incremental cost over the less efficient alternative.
- Incentive levels. Higher incentive levels increase the participant benefits but also increase Bonneville's costs.

4.3 OVERVIEW OF THE TYPES OF DEMAND RESPONSE PROGRAMS

Demand Response programs provide a potential load reduction resource that can be exercised during peak hours. These options include: Direct Load Control, interruptible or curtailable (non-firm) rates, and the Demand Exchange™ to reduce loads during system peaks. These types of solutions are effective approaches to load reduction because they directly address the capacity nature of the problem.

Demand Response programs can also be categorized into two major types: 1) Price-based dispatch programs that offer customers incentives to voluntarily curtail load during the peak; and 2) Pre-arranged contracts (such as interruptible/curtailable rates or direct load control) that require customers to reduce loads during the system peak for a fixed price at the utility's request. These programs differ in their implementation and potential for providing load relief, as discussed below. This analysis evaluates the capability of both "price-based dispatch" and "interruptible/curtailable" programs to provide the needed capacity for Bonneville.

4.3.1 PRICE-BASED DISPATCH

Price dispatch programs are voluntary, market-based programs that allow for efficient load reduction during peak periods, emergencies, or when costs are highest for the load-serving entities. The prices for curtailment or interruption are determined through a price convergence mechanism (i.e., auction, bidding system) between load-serving entities and customers. Customers can choose the point at which the price available to them is high enough to offset their productivity losses from reducing or shutting-off their load. The curtailment can be specified for any appropriate period, e.g. real-time, day-ahead, etc.

These programs tend to have low utility transaction costs once implemented, since individual contracts are not required for each curtailment. A large number of customers can participate because the marginal cost of including more customers is low. While price-based dispatch programs are efficient ways to reduce load, they do not always provide firm or guaranteed reductions in system load when needed.

The probability of achieving load reduction during the required time period is an important consideration. During extreme weather for example, it is unlikely that residential or commercial retail customers would curtail their heating load. Because there is no guarantee that the customer will reduce these loads, Bonneville would be ill advised to target them. On the other hand, customers do have loads that can be reduced with minimal interruption of their lives or businesses. Water heating loads may be curtailable during peak hours. Some commercial or industrial refrigeration may be cycled for short durations. Exterior lighting may be reduced. More experience with these types of programs will increase our knowledge of appropriate applications.

4.3.2 INTERRUPTIBLE/CURTAILABLE AND DEMAND RESPONSE CONTRACTS

Interruptible/curtailable contracts differ from the price-based dispatch programs because the terms (i.e., number of times/year the customer can be curtailed, maximum hours per interruption, and notification period for interruption) and the price (fixed component) are pre-determined and bound with an enforceable contract. Since peak load relief is more certain under this type of program, it provides a good basis for planning, and is generally better suited as an alternative to a line construction project.

As with price-based dispatch programs, the curtailment period and notification time frame can be tailored to the needs of both the load-serving entity and the customer. The price is typically higher when there is less notification time. Since the transaction costs for these contracts are higher than the price-based contracts, they are better applied to customers with larger loads.

Over 30 utility Demand Response programs were analyzed during the alternatives screening process.[9] However, due to the individualized nature of these alternatives, only two of the programs were evaluated in detail: the Conceptual Demand Response Program and the Conceptual Water Heater Load Control Program. These were both designed specifically for Bonneville. The cost-effectiveness of the other programs was evaluated to determine whether they might be useful to Bonneville.

4.3.3 CONCEPTUAL DEMAND RESPONSE ASSUMPTIONS

The main assumptions for the Conceptual Demand Response programs are number of hours Bonneville has the right to curtail the customer, incentive payments to the customer, and whether the curtailments result in lost revenues to the transmission utility.

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[9] See Summary Benefit Cost Ratios for Demand Response & Direct Load Control Programs in Table 21.

The analysis assumes that Bonneville curtails participants up to 200 hours per year. This number affects the results of the Total Resource, Societal, and Participant tests since curtailment is assumed to cost $150 per MWh in lost productivity. The load projections predict that system loads will exceed the technical capability of the system for 6 hours in 2011, and 260 hours in 2020. Our analysis found that annual curtailments were cost effective for periods no longer than 200 hours.

All of the cases studied assume that Bonneville pays out 50% of the transmission-avoided cost as an incentive to curtail participating customers for up to 200 hours per year. The incentives affect the Participant and Transmission Utility Cost tests because they are a source of revenue for participants and a cost for Bonneville. Higher incentive payments improve the results of the Participant test and negatively affect the Transmission Utility Cost test.

The incentive level must be set high enough to outweigh the cost of load curtailment for participating customers. Bonneville's preliminary discussions with industries located in the Olympic Peninsula indicated that the minimum cost of curtailment is approximately $125 per MWh. In Lower Valley, there is one industrial customer and several commercial accounts that appear suitable for such a contract, whereas nearly all of the 18,000 residences have electric water heaters that could potentially come under a Direct Load Control program.

5.0 COST-EFFECTIVENESS RESULTS – THREE SCENARIOS

This section summarizes the Total Resource Cost test results for the sets of non-construction alternatives evaluated in this study. We analyzed individual technology applications. They included distributed generation, demand response and direct load control, and peak oriented energy efficiency. Although the applications are analyzed and compared independently, they would be implemented in combinations.

We compared three specific scenarios. First a three-year deferral, then a ten-year deferral, and a 10-year deferral following construction of the first two phases of the transmission project. And finally we looked at a combined-heat-and-power option within the last scenario. This latter option assumed longer run-times for the resources.

Table 9: Benefit / Cost Ratios for Key Program Measure Scenarios

Measure	3-Year Deferral	10-Year Deferral	10-Year Deferral with Building 1st Two Phases	
MWs/Hours	**18MWs @ 96Hrs**	**47MWs @ 463Hrs**	**30MWs @ 262Hrs**	**30MWs @ 6000Hrs**
30kW Capstone with CHP	0.28	0.46	0.62	1.71
30kW Capstone w/o CHP	0.46	0.65	0.44	1.2
DEK2100 Diesel (Existing)	0.88	2.60	1.60	16.9
DEK500 Diesel	0.45	1.05	0.81	8.61
Conceptual Demand Response	0.91	0.63	0.88	0.47
Single Family Duct Sealing	1.04	1.07	1.08	1.08
PV100	0.27	0.36	0.32	1.41
Storage CAES	0.61	0.82	0.73	3.58
Fuel Cell 10kW PEM with CHP	0.27	0.36	0.34	0.94
2000kW MCFC	0.35	0.50	0.53	1.32
Conceptual Water Heater Load Control	0.37	0.88	1.13	1.13

Most of the technology applications examined benefit from longer deferrals and longer operating hours. Two exceptions appear. The energy efficiency measure maintains a positive benefit to cost ratio across all scenarios. The conceptual demand response benefit to cost ratio (already marginal) worsens with the longer operating hours assumed in the longer deferral scenarios. Of course, all resources would not be required to fulfill all operating hours, so demand response would likely still have a role in deferral, simply not for hundreds of hours.

Some surprising technologies appear cost effective in the longer deferral scenarios. Fuel cells and energy storage applications grow from very negative ~0.3 benefit to cost ratios to slightly to very positive benefit to cost ratios. Photovoltaic applications fit this pattern as well.

5.1 DISTRIBUTED GENERATION RESULTS SUMMARY

This section summarizes the cost-effectiveness of Distributed Generation from two cost test perspectives, the Total Resource test and the Transmission Utility test. Over 50 alternatives were analyzed. These alternatives include small internal combustion engines and microturbines, in combined-heat-and-power and generation-only configurations, as well as energy storage technologies. In each analysis, the baseline incentive payments were set to 50% of the maximum incentive level shown in Table 5. The tables in this section show the specific benefit/cost ratios for each of the alternatives. When the economic benefits of the alternative exceed the costs, the ratio is greater than 1.0.

The cost-effectiveness of distributed generation depends on the size of the capital investment and whether the capital investment must be repaid solely from the benefit of the transmission offset. This is a heavy burden for all new generation, a fact reflected in the benefit to cost ratios. However, two circumstances mitigate this otherwise poor showing; existing generation such as emergency back up that can be also used for peak load offsets (because the capital cost is already covered) and the combined-heat-and-power application (because the resource serves multiple uses and therefore has addition values).

Table 10 assumes a 10-year deferral. The DEK2100, a natural gas-fired diesel engine in generation-only configuration, is assumed to run about 250 hours for transmission peak offset only. The Total Resource test is very positive at 1.60 benefit to cost ratio. The Transmission Utility Cost Test is less favorable. The Transmission Benefit to cost Ratio is 0.93 and the Distribution Utility Test is 3.32 suggesting that while operating the resource to offset investments does have positive value, the assumed 50/50 cost share between the distribution utility and the transmission utility benefits the distribution utility disproportionately.

Table 10: Detailed Benefit / Cost Results for DEK2100 – Preferred Scenario

	Program Benefits	Program Costs	Net savings	B/C Ratio
RIM Test - Transmission Co.				
Transmission Capacity Savings	$110.49		$110.49	
Transmission Revenue Loss		$188.33	($188.33)	
Transmission Co. Incentive Payments		$118.22	($118.22)	
Transmission Co. Admin Costs		$0.00	$0.00	
Total	$110.49	$306.56	($196.07)	0.36
Utility Cost Test - Transmission Co.				
Transmission Capacity Savings (kW)	$110.489		$110.489	
Transmission Co. Incentive Payments		$118.22	($118.223)	
Transmission Co. Admin Costs		$0.00	$0.000	
Total	$110.49	$118.22	($7.73)	0.93
TRC Cost Test				
Generation Capacity Savings (kW)	$0.000			
Generation Energy Savings (kWh)	$238.986			

	Program Benefits	Program Costs	Net savings	B/C Ratio
Generator Energy Sales of Merchant Plant (kWh)	$0.000			
Transmission Capacity Savings (kW)	$110.489			
Distribution Capacity Savings (kW)	$0.000			
Reliability Benefits	$273.606			
Transmission Co. Admin Costs		$0.00		
Distribution Co. Admin Costs		$0.00		
Avoided Energy Loss Savings (by deferral)		$7.493		
DG Capital Costs		$100.00		
DG Fuel Costs		$204.75		
DG Fixed O&M		$61.65		
DG Variable O&M		$15.41		
Total	$623.08	$389.31	$233.78	1.60
Societal Cost Test				
Generation Capacity Savings (kW)	$0.00			
Generation Energy Savings (kWh)	$264.24			
Transmission Capacity Savings (kW)	$120.16			
Distribution Capacity Savings (kW)	$0.00			
Reliability Benefits	$404.67			
Transmission Co. Admin Costs		$0.00		
Distribution Co. Admin Costs		$0.00		
Avoided Energy Loss Savings (by deferral)		$8.157		
DG Capital Costs		$100.00		
DG Fuel Costs		$360.44		
DG Fixed O&M		$102.97		
DG Variable O&M		$25.74		
Total	$789.08	$597.31	$191.77	1.32

	Program Benefits	Program Costs	Net savings	B/C Ratio
Participant Cost Test				
Transmission Co. Incentive Payments	$118.22			
Distribution Co. Incentive Payments	$0.00			
Energy Sales (merchant plant)	$0.00			
Revenue Reduction (behind the meter installation)	$96.41			
Equipment Rebate	$0.00			
Reliability Benefits	$273.61			
DG Capital Costs		$100.00		
DG Fuel Costs		$204.75		
DG Fixed O&M		$61.65		
DG Variable O&M		$15.41		
Total	$488.24	$381.81	$106.43	1.28
RIM Test - Distribution Utility				
Transmission Savings (Reduction in T Tariff)	$188.33			
Distribution Capacity Savings (kW)	$0.00			
Generation Energy Savings (kWh)	$238.99			
Distribution Revenue Loss (kWh)		$128.87		
Distribution Co. Incentive Payments		$0.00		
Distribution Utility Admin Cost $/measure one time cost		$0.00		
Total	$427.32	$128.87	$298.45	3.32

Table 11 also assumes a 10-year deferral. Large-scale generation technologies were evaluated along with the distributed generation technologies. Those analyzed include a generic combined cycle combustion turbine (base load, >100 MW), a simple cycle combustion turbine (peak, >50 MW), and a mobile gas turbine generator (22 MW). None of the technologies listed pass either the Total Resource or Participant cost tests, primarily because the capital and operating costs are too high relative to the value of energy generated. The technology closest to positive result is the combined cycle combustion turbine.

Table 11: Benefit / Cost Ratios for Large Scale Generation

	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.	RIM Test - Distribution Utility
Combined Cycle Combustion Turbine	0.99	0.99	**1.28**	0.93	0.93	**NA**
Simple Cycle Combustion Turbine	0.78	0.78	0.96	0.93	0.93	**NA**
Mobile Gas Turbine Generator (GE TM2500)	0.77	0.78	0.91	0.93	0.93	**NA**

Table 12 illustrates the benefit/cost ratios for 17 internal combustion engine configurations, ranging from 7.25-kW to 3-MW capacity ratings. Several engines were analyzed using a combined-heat-and-power configuration; waste heat use is an added benefit. However this table does not reflect the longer run time associated with effective combined-heat-and-power applications. The benefit to cost tests therefore likely understate the benefits. Four of the configurations passed the Total Resource Cost test.

Table 12: Benefit / Cost Ratios for Internal Combustion Engines

	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.	RIM Test - Distribution Utility
DEK 2100 (existing diesel)	**1.60**	**1.28**	**1.32**	0.36	0.93	**3.32**
DE-K-500 (500kW)	**1.21**	0.69	**1.10**	0.40	0.93	**1.62**
DE-C-200 (200kW)	**1.20**	0.69	**1.09**	0.40	0.93	**1.62**
DE-C-7 (7.5kW)	**1.16**	0.66	**1.06**	0.40	0.93	**1.62**
DE-K-60 (60kW)	0.91	0.52	0.81	0.40	0.93	**1.62**
DE-K-30 (30kW)	0.87	0.49	0.77	0.40	0.93	**1.62**
Caterpillar G3616 LE -3MW w/CHP	0.87	0.49	0.79	0.40	0.93	**1.62**
Wartsila 5238 LN - 5MW w/CHP	0.81	0.46	0.72	0.40	0.93	**1.62**
Caterpillar G3516 LE - 800kW w/CHP	0.81	0.64	0.76	0.36	0.93	**3.32**
Wartsila 5238 LN - 5MW	0.74	0.42	0.65	0.40	0.93	**1.62**
Caterpillar G3616 LE -3MW	0.74	0.42	0.67	0.40	0.93	**1.62**
MAN 150 kW - 100 kW w/ CHP	0.74	0.59	0.71	0.40	0.93	**3.31**
Caterpillar G3516 LE - 800kW	0.69	0.39	0.63	0.40	0.93	**1.62**
Cummins GSK19G - 300kW	0.63	0.36	0.56	0.40	0.93	**1.62**
GA-K-500 (500kW)	0.62	0.49	0.61	0.36	0.93	**3.32**
GA-K-55 (55kW)	0.49	0.39	0.51	0.36	0.93	**3.32**
MAN 150 kW - 100 kW	0.38	0.22	0.30	0.40	0.93	**1.62**
Cummins GSK19G - 300kW /w CHP	0.37	0.29	0.39	0.36	0.93	**3.32**

Table 13 shows the benefit to cost ratios for fuel cell technologies. The fuel cell technologies included in this analysis are phosphoric acid, proton exchange membrane, molten carbonate, and solid oxide. Although all the calculations include the benefit of waste heat recovery, they do so only for the same operating hours where peak generation is needed. In the base-load operating scenario analysis, we extended the operating hours to a more likely 6,000. In this scenario, the benefit to cost ratios were nearly twice those listed below. In some cases, this made the technologies cost beneficial.

Table 13: Benefit / Cost Ratios for Fuel Cells

	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.	RIM Test - Distribution Utility
2000kW MCFC Fuel Cell CHP	0.53	0.30	0.55	0.40	0.93	**1.62**
100kW SOFC Fuel Cell CHP	0.50	0.29	0.55	0.40	0.93	**1.62**
200kW PEM Fuel Cell CHP	0.49	0.28	0.54	0.40	0.93	**1.62**
2000kW MCFC Fuel Cell	0.48	0.27	0.50	0.40	0.93	**1.62**
100kW SOFC Fuel Cell	0.45	0.26	0.49	0.40	0.93	**1.62**
200kW PAFC Fuel Cell CHP	0.42	0.24	0.46	0.40	0.93	**1.62**
200kW PEM Fuel Cell	0.41	0.23	0.44	0.40	0.93	**1.62**
200kW PAFC Fuel Cell	0.36	0.20	0.39	0.40	0.93	**1.62**
250kW MCFC Fuel Cell CHP	0.35	0.20	0.38	0.40	0.93	**1.62**
10kW PEM Fuel Cell CHP	0.34	0.19	0.38	0.40	0.93	**1.62**
250kW MCFC Fuel Cell	0.33	0.19	0.35	0.40	0.93	**1.62**
10kW PEM Fuel Cell	0.30	0.17	0.32	0.40	0.93	**1.62**

Table 14 and Table 15 show the benefit to cost ratios for microturbines. Four models were screened, ranging from 30-kW to 100-kW. The analyses were done for each microturbine using both standard and combined-heat-and-power configurations, resulting in eight assessments. In addition, the eight configurations were analyzed for both 260 and 6000 operating hours. All configurations have very positive Total Resource benefit to cost ratios at the longer operating hours. In addition, the combined-heat-and-power configuration adds about 1/2 point to the positive benefit. The Transmission Utility Cost test is marginal for both configurations and both scenarios.

Table 14: Benefit / Cost Ratios for Microturbines (260 hours of operation)

	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.	RIM Test - Distribution Utility
Turbec T100 – 100kW w/ CHP	0.76	0.43	0.80	0.40	0.93	**1.62**
Bowman TG80 - 80kW w/ CHP	0.72	0.41	0.77	0.40	0.93	**1.62**
IR Energy Systems 70LM - 70kW w/ CHP	0.70	0.40	0.75	0.40	0.93	**1.62**
Capstone Model 330 - 30kW w/ CHP	0.62	0.35	0.66	0.40	0.93	**1.62**
Turbec T100 – 100kW	0.56	0.32	0.57	0.40	0.93	**1.62**
IR Energy Systems 70LM - 70kW	0.55	0.31	0.57	0.40	0.93	**1.62**
Bowman TG80 - 80kW	0.52	0.30	0.54	0.40	0.93	**1.62**
Capstone Model 330 - 30kW	0.44	0.25	0.45	0.40	0.93	**1.62**

Table 15: Benefit / Cost Ratios for Microturbines (6000 Hours of Operation)

	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.	RIM Test - Distribution Utility
Turbec T100 - 100kW w/ CHP	**2.10**	**1.78**	**2.35**	0.40	0.93	**1.62**
Bowman TG80 - 80kW w/ CHP	**1.99**	**1.68**	**2.26**	0.40	0.93	**1.62**
IR Energy Systems 70LM - 70kW w/ CHP	**1.93**	**1.63**	**2.18**	0.40	0.93	**1.62**
Capstone Model 330 - 30kW w/ CHP	**1.71**	**1.44**	**1.95**	0.40	0.93	**1.62**
Turbec T100 - 100kW	**1.54**	**1.30**	**1.67**	0.40	0.93	**1.62**
IR Energy Systems 70LM - 70kW	**1.51**	**1.28**	**1.66**	0.40	0.93	**1.62**
Bowman TG80 - 80kW	**1.44**	**1.22**	**1.58**	0.40	0.93	**1.62**
Capstone Model 330 - 30kW	**1.20**	**1.02**	**1.32**	0.40	0.93	**1.62**

Table 16 presents the benefit to cost ratios for both photovoltaic and wind power distributed generation technologies. Three sizes of photovoltaic technologies were analyzed, along with a small wind turbine. Since no detailed local area renewable resource information is available, the economics are estimated assuming optimistic conditions for both solar and wind energy. Gross operating hours are assumed at 6000. The annual capacity factor used for photovoltaic is 30%, and for wind 45%. With these assumptions, these alternatives pass the Total Resource Cost test, but are marginal for the Transmission Utility Cost test.

Table 16: Benefit / Cost Ratios - Renewable Energy Technologies (6000 hours of operation)

	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.	RIM Test - Distribution Utility
PV-100	**1.41**	**1.26**	**2.35**	0.93	0.93	**1.69**
PV-50	**1.41**	**1.26**	**2.34**	0.93	0.93	**1.69**
Bergey Windpower WD -10kW	**1.16**	**1.04**	**1.57**	0.93	0.93	**1.66**
PV-5	**1.08**	1.00	**1.78**	0.93	0.93	**1.20**

Table 17 displays the benefit to cost ratios for several energy storage technologies. While most of these technologies are not viable as individual deferral options due to their limited capability, they would be useful as a partial solution. Due to their high capital costs, the storage solutions are a cost-effective alternative to a transmission line investment at an assumed 6000 operating hours.

Table 17: Benefit / Cost Ratios for Energy Storage Technologies (6000 hours of operation)

	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.	RIM Test - Distribution Utility

CAES	**3.58**	**3.60**	**4.28**	0.93	0.93	**NA**
Pumped Hydro Variable Speed	**3.33**	**3.34**	**3.98**	0.93	0.93	**NA**
Pumped Hydro	**3.31**	**3.32**	**3.90**	0.93	0.93	**NA**
Lead-acid Batteries (flooded cell)	**2.97**	**2.71**	**3.06**	0.50	0.93	**1.81**
Regenesys	**2.62**	**2.32**	**2.79**	0.40	0.93	**1.82**
High Temp Na/S	**1.91**	**1.70**	**2.16**	0.40	0.93	**1.82**
Lead-acid Batteries (VRLA)	**1.20**	**1.09**	**1.33**	0.53	0.93	**1.82**
Ni/Cd	0.98	0.87	**1.19**	0.40	0.93	**1.82**

5.2 ENERGY EFFICIENCY RESULTS SUMMARY

This section summarizes the cost-effectiveness of energy efficiency from each cost test perspective. The Lower Valley analysis focuses on a smaller number of energy efficiency measures than the Olympic Peninsula analysis. This is primarily because a simpler methodology was used. In all, 52 energy efficiency measures were analyzed in 13 groups.

The measures selected were those from each group that passed the Total Resource test and had the highest peak kW impact. In general, many energy efficiency measures pass the Total Resource, Societal, and Participant Cost tests because they offer a significant amount of energy savings relative to their cost.

Table 18 shows the detailed cost test calculations for Single Family Duct Sealing. This measure is a proxy for Performance Tested Comfort Systems[10] duct-sealing measures generally applicable to all forced air heating systems. Duct sealing had one of the highest peak kW reduction potentials given the analysis penetration assumptions. The Transmission Utility Cost test for this measure is 1.0 because the incentive payment has been set to equal the benefit. The Total Resource Cost test is very positive at nearly 1.7.

Table 18: Detailed Benefit / Cost Results - Single Family Duct Sealing

	Program Benefits	Program Costs	Net savings	B/C Ratio
RIM Test - Transmission Co.				
Transmission Capacity Savings	$36.71		$36.71	
Transmission Revenue Loss		$87.02	($87.02)	
Transmission Co. Incentive Payments		$0.00	$0.00	
Transmission Co. Admin Costs		$0.00	$0.00	
Total	**$36.71**	**$87.02**	**($50.31)**	**0.42**
Utility Cost Test - Transmission Co.				

[10] Performance Tested Comfort Systems is an initiative of the Northwest Energy Efficiency Alliance. Additional information on the initiative can be found at http://www.nwalliance.org/.

	Program Benefits	Program Costs	Net savings	B/C Ratio
Transmission Capacity Savings (kW)	$36.71		$36.71	
Transmission Co. Incentive Payments		$0.00	$0.00	
Transmission Co. Admin Costs		$0.00	$0.00	
Total	**$36.71**	**$0.00**	**$36.71**	**1.0**
TRC Cost Test				
Transmission Capacity Savings (kW)	$36.71		$36.71	
Generation Capacity Savings (kW)	$0.00		$0.00	
Generation Energy Savings (kWh)	$726.52		$726.52	
Distribution Capacity Savings (kW)	$0.00		$0.00	
Cost of Original Device	$0.00		$0.00	
Transmission Co. Admin Costs		$0.00	$0.00	
Distribution Co. Admin Costs		$0.00	$0.00	
Avoided Energy Loss Savings (by deferral)		$2.49	($2.49)	
Cost of Replacement Device		$448.26	($448.26)	
Total	**$763.23**	**$450.75**	**$312.48**	**1.69**
Societal Cost Test				
Transmission Capacity Savings (kW)	$39.92		$39.92	
Generation Capacity Savings (kW)	$0.00		$0.00	
Distribution Capacity Savings (kW)	$0.00		$0.00	
Generation Energy and Environmental Savings (kWh)	$980.88		$980.88	
Cost of Original Device	$0.00		$0.00	
Transmission Co. Admin Costs		$0.00	$0.00	
Distribution Co. Admin Costs		$0.00	$0.00	
Avoided Energy Loss Savings (by deferral)		$2.71	($2.71)	
Cost of Replacement Device		$448.26	($448.26)	
Total	**$1,020.80**	**$450.97**	**$569.83**	**2.26**
Participant Cost Test				
Transmission Co. Incentive Payments	$0.00		$0.00	
Distribution Co. Incentive Payments	$36.71		$36.71	
Distribution Energy Savings (kWh)	$551.61		$551.61	
Cost of Original Device	$0.00		$0.00	
Cost of Replacement Device		$448.26	($448.26)	
Total	**$588.32**	**$448.26**	**$140.06**	**1.31**
RIM Test - Distribution Utility				

	Program Benefits	Program Costs	Net savings	B/C Ratio
Transmission Savings (Reduction in T Tariff)	$87.02		$87.02	
Distribution Capacity Savings (kW)	$0.00		$0.00	
Generation Energy Savings (kWh)	$726.52		$726.52	
Distribution Revenue Loss (kWh)		$840.15	($840.15)	
Distribution Co. Incentive Payments		$0.00	$0.00	
Distribution Utility Admin Cost $/measure one time cost		$0.00	$0.00	
Total	**$813.54**	**$840.15**	**($26.61)**	**0.97**

A number of measures offering significant peak reduction potential passed the Total Resource Cost tests, as shown in Table 19. The "Number of Groups" in the last column refers to the number of energy efficiency measure groups that have at least one measure that passes the costs test (for example, 12 out of 13 groups had measures that passed the test). We estimate that 1.6 MW annual peak load reduction can be obtained from measures passing the test. The total peak kW impact is derived by taking the "best" measure from each group and assuming 100% saturation of that end use in the applicable customer sector, based on the customer demographics presented in Table 3 and Table 4. It is also assumed that there has been 0% historical penetration of the measure in the sector, and that there will be a 20% annual future penetration. These assumptions are used in lieu of available penetration data.

Table 19: Number of Energy Efficiency Groups that Passed the Cost Test and Associated Demand and Energy Reductions

	kW Reduction at Constraint	MWh Reduction at End-Use	Number of Groups
RIM Test - Transmission Utility	67	1,702	1
Utility Cost Test - Transmission Utility	282	2,839	2
TRC Cost Test	1,675	19,024	12
Societal Cost Test	1,678	19,111	12
Participant Cost Test	1,680	19,213	13
RIM Test - Distribution Utility	32	955	4
TRC and Participant Cost Test	1,675	19,024	12

Table 20 gives the benefit to cost ratios for the measures with the highest kW impact potential. As mentioned above, these kW impacts are based on assumptions of end-use saturation and measure penetration.

Table 20: Energy Efficiency Measures Passing Total Resource Cost Test with Highest kW Impact

Name	Peak kW Impact at Constraint from Measures Passing TRC	Sector	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.
HEATING - Single Family Duct Sealing	1,139	Residential	**1.08**	**1.00**	**1.49**	0.18
Existing Commercial Lighting - generic	266	Commercial	**1.88**	**1.48**	**2.45**	0.21
ENVELOPE - Small Retail Weatherization Attic Insulation - R4> R38 blown	124	Commercial	**1.98**	**1.31**	**2.89**	0.39
TRAFFIC SIGNALS - Existing and new traffic signals - LED Traffic Signals - Replace 12 inch Red Incandescent Left Turn Bay with 12 inch Red LED module	64	Industrial	**1.42**	**1.95**	**1.71**	0.85
VENDING MACHINES - Existing and new vending machines with illuminated fronts - Vending Machine Controller-Large Machine w/Illuminated Front	24	Commercial	**2.21**	**1.85**	**2.77**	0.19
EXIT SIGNS - Building or structure where exit signs are required - Energy Star Electro-luminescence (EL) Exit Sign - Incandescent Exit Sign Base Case Fixture	17	Commercial	**1.05**	**1.00**	**1.33**	0.26
LIGHTING - Residential Lighting - Energy Star CFL Weighted Average - Whole House Savings	17	Residential	**1.85**	**1.68**	**2.32**	0.21
New Commercial Lighting - generic	15	Commercial	**1.87**	**1.48**	**2.44**	0.20
APPLIANCES - Multifamily common area or commercial Laundromat w/Electric Dryer and Electric Water Heat - Energy Star Clothes Washer - Commercial Laundry - Electric Water Heater & Dryer	7	Commercial	**1.03**	**1.00**	**1.15**	0.03
APPLIANCES - Residential - Energy Star Dishwasher (EF58) - PNW DHW Fuel Average	1	Residential	**1.73**	**1.55**	**2.16**	0.24
APPLIANCES - Residential - Energy Star Clothes Washer (MEF 1.27) - Weighted Average DHW & Dryer	0	Residential	**2.18**	**1.83**	**2.84**	0.02
APPLIANCES - Residential - Energy Star Refrigerator with Side-by-Side Model - No Ice	0	Residential	**2.11**	**1.62**	**2.83**	0.12

5.3 DEMAND RESPONSE & DIRECT LOAD CONTROL RESULTS SUMMARY

As shown in Table 21 and Table 22, the Conceptual Water Heater direct load control Program and 28 of the demand-response and direct load control programs implemented by other utilities performed well in the total resource test, because reductions in energy usage only occur when they are needed to mitigate peak load. Seventeen of the programs analyzed performed well under the Transmission Utility test because the reduction in transmission revenues is minimal. (Bonneville's Conceptual Demand Response Program, with a score of 0.88, does not pass the benefit to cost ratio >1 threshold under the Total Resource test.)

The programs performed well under the Societal, and Participant tests, because the value of the transmission avoided costs and corresponding incentive payments are high relative to the costs of curtailment (e.g., lost productivity and business interruption). The assumed cost of curtailment used in this analysis is $0.15 per kWh of curtailment. Of course, the true cost of curtailment will be different for every customer, so this is simply an approximation to determine the potential cost effectiveness of Demand Response as an alternative solution.

Table 21: Cost Test Results of Conceptual Demand Response – Direct Load Control Programs

Name	Utility	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.	RIM Test - Distribution Utility
Conceptual DR Design	None	0.88	1.29	1.02	0.33	0.33	1.84
Conceptual Water Heater DLC	None	1.13	6.02	1.25	0.28	0.28	1.31

Table 22: Summary Benefit to Cost Ratios for Demand Response – Direct Load Control Programs

Name	Utility	Firm Capacity Reduction?	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.	RIM Test - Distribution Utility
Demand Buy Back	Portland General Electric	N	1.41	1.19	1.58	0.83	0.83	1.84
Energy Exchange Program	PacificCorp	N	2.52	0.86	2.76	2.94	2.94	1.84
Voluntary Load Reduction	Exelon - ComEd	N	1.53	1.19	1.71	0.94	0.94	1.84
The Alliance Option A - Interruptible	Exelon - ComEd	Y	1.36	0.65	1.53	1.69	1.69	1.84
The Alliance Option B - Curtailable	Exelon - ComEd	Y	2.16	0.91	2.38	2.18	2.18	1.84
The Alliance Option C - Curtailable	Exelon - ComEd	Y	2.45	0.93	2.69	2.55	2.55	1.84
Energy Cooperative (Curtailment Service Cooperative)	Exelon - ComEd	Y	1.36	2.14	1.53	0.40	0.40	1.84
Interruptible Service	Exelon - ComEd	Y	0.83	3.49	0.96	0.10	0.10	1.84
Demand Relief Program	CAISO	Y	1.57	9.08	1.75	0.11	0.11	1.84
Emergency Demand Response Program	NYISO	Y	1.53	3.53	1.71	0.28	0.28	1.84
Day-Ahead Demand Response Program	NYISO	N	1.53	0.73	1.71	1.74	1.74	1.84

Name	Utility	Firm Capacity Reduction?	TRC Cost Test	Participant Cost Test	Societal Cost Test	RIM Test - Transmission Co.	Utility Cost Test - Transmission Co.	RIM Test - Distribution Utility
Demand Bidding Program	CA - SCE	N	1.53	0.43	1.71	4.03	4.03	1.84
Com/Ind. Base Interruptible Program	CA - SCE	Y	1.36	4.86	1.53	0.17	0.17	1.84
Scheduled Load Reduction Program	CA - SCE	N	1.03	0.86	1.18	0.73	0.73	1.84
Emergency Response Program	PJM	N	1.53	3.53	1.71	0.28	0.28	1.84
Capacity Program - Interruptible Tariff	Wisconsin Power & Light	Y	0.83	1.22	0.96	0.31	0.31	1.84
Economy Program - Interruptible Tariff	Wisconsin Power & Light	N	1.01	0.54	1.15	1.35	1.35	1.84
Reliability Program Rider	Wisconsin Power & Light	N	1.19	2.99	1.34	0.22	0.22	1.84
Demand Exchange	BPA	N	1.53	1.11	1.71	1.03	1.03	1.84
Demand Response Program	ISO-NE	Y	1.09	8.13	1.24	0.07	0.07	1.84
Voluntary Load Response Program	Baltimore Gas & Electric	N	1.53	0.50	1.71	3.04	3.04	1.84
Voluntary Load Response Program - Rider 24 Firm Capacity Initiative	Baltimore Gas & Electric	N	1.53	0.50	1.71	3.04	3.04	1.84
Discretionary Load Curtailment Program	CAISO	N	1.53	2.53	1.71	0.40	0.40	1.84
Participating Load Program	CAISO	N	1.53	0.58	1.71	2.43	2.43	1.84
Price Response Program	ISO-NE	N	1.53	0.58	1.71	2.43	2.43	1.84
Economic Load Response Program	PJM	N	1.53	0.58	1.71	2.43	2.43	1.84
Call Option	Cinergy	N	1.53	0.58	1.71	2.43	2.43	1.84
Quote Option	Cinergy	N	1.53	0.58	1.71	2.43	2.43	1.84
Market Valued Reduction Program	Entergy	N	1.53	0.58	1.71	2.43	2.43	1.84
Experimental Energy Reduction Program		N	1.53	0.58	1.71	2.43	2.43	1.84

6.0 CONCLUSIONS AND RECOMMENDATIONS

The investigation of non-construction alternatives for the Lower Valley reinforcement demonstrated how the analysis of alternatives to transmission expansion can take on a more creative, strategic direction then was demonstrated in either of the two earlier studies of Kangley - Echo Lake or the Olympic Peninsula. The Lower Valley study looked at three differing options; a 3-year deferral, a 10-year deferral and a 10-year deferral with completion of the first two phases of the transmission project.

6.1 SUMMARY FINDINGS

The 3-year deferral analysis revealed that the program time horizon was too short to effectively capture the higher avoided costs of deferring or postponing indefinitely the later phases of the Lower Valley transmission project. Few measures with the exception of cost effective energy efficiency measures, demand response programs or use of existing distributed generation proved effective from the perspective of the Total Resource Cost test. The other non-construction alternatives performed poorly in a benefits-cost sense when compared with the transmission project itself. Further, it raised questions about the effectiveness of untested program measures that would have to be tested and implemented in time to meet winter 2007-2008 peak loads

Given the significantly higher transmission project costs after the 3-year deferral period of the first scenario studied, it seemed advisable to test a 10-year deferral period to see which measures would pass given the higher avoided costs. Increasing the deferral period (all other things remaining equal) resulted in improved benefit to cost performance.

But by increasing the deferral period, we are increasing the size of the peak and the number of hours the measures would have the cover in order to avoid the transmission expansion. Besides the relative avoided costs, the benefit to cost ratio for many of the non-construction alternatives tested varied according to the number of hours the measure was designed to cover. For some measures longer hours worsened the ratio; for others, longer operating hours were better. Further, the 10-year deferral did not address the need to perform unavoidable maintenance on the transmission system by 2007.

The required transmission maintenance investment suggested a third study approach that took into account a 10-year deferral period plus the additional capacity provided by the early phases of the transmission project. Further, the discovery that a new natural gas pipeline was in the early planning stages made this a robust strategy. A natural gas fuel source for distributed generation would mean greater likelihood that effective alternatives to future transmission expansion could be found. The resulting analysis of this scenario showed that the following measures have positive benefit to cost ratios:

- Conceptual Demand Response programs based on BPA's Demand Exchange program, but only if limited to the first 200 hours of the sum of annual peak demand periods
- Conceptual Water Heater Load Control program
- Single Family Residential duct sealing program
- Distributed generation, existing diesel for peak loads

- Microturbine distributed generation with and without combined-heat-and-power if constructed to serve base loads as well
- Some renewable measures (photovoltaic), storage technologies and fuel cells if longer operating timeframes are possible

6.2 CONCLUSIONS

Using the Total Resource Cost and Transmission Utility Total Cost tests results in marginally differing findings since the Total Resource Cost test takes into account a broader range of costs and benefits then the Transmission Utility Total Cost test. The Total Resource Cost test approach puts the emphasis on energy savings while the Transmission Utility Cost test emphasizes capacity costs and savings only. Study areas that have greater access to alternative fuels, natural gas, have improved opportunity to demonstrate the effectiveness of non-construction alternatives by employing a portfolio of options, an integrated resource planning approach. In the case of Lower Valley, the longer deferral period and the potential for natural gas are key in making non-construction alternatives effective. Further, some measures are more effective from a base load perspective. Analysis should consider how each measure would likely be used and its benefit-cost performance evaluated accordingly.

The Lower Valley study suggests that non-construction alternatives can effectively defer transmission expansion beyond the first two phases for a period in excess of 10-years, assuming the completion of the natural gas pipeline.

APPENDIX A

METHODOLOGY

Our goal was to conduct a high-level screening of potential alternatives to a proposed transmission line construction solution (the "wires" solution) for a specific need on Bonneville's system. There are a very large number of potential alternatives available. These alternatives include distributed generation technologies, demand response programs, and energy efficiency measures, all of which have varying characteristics and costs. It would be extremely expensive to conduct a detailed analysis of each alternative to determine if it could contribute to a non-construction alternative. Thus, the analytical process described below is designed to identify which alternatives have the greatest potential for successful implementation. Those alternatives that pass through this high-level screen can then be analyzed further to determine their potential penetration and feasibility for successful implementation.

The screening criterion used in this analysis to identify cost-effective alternatives was that a cost-effective alternative must have a benefit to cost ratio greater than one. A ratio greater than one indicates that the non-wires alternative has a benefit greater than its cost, and therefore is a potentially cost-effective option to transmission line construction. Suggesting that a measure is "cost-effective," however, immediately raises the question, "cost effective to whom?"

To answer that question, each alternative was analyzed from different stakeholder perspectives. Obtaining results from numerous perspectives allows for a greater understanding of the decision of whether to build the line or implement a non-construction alternative. There are competing views on what is the appropriate criterion for determining cost-effectiveness. The principal debate is between the Rate Impact Measure and the Total Resource Cost tests. Rate Impact compares the alternative's cost impact on rates against the capital and maintenance costs of a proposed solution. Total Resource compares the costs and benefits of alternatives with all the costs and benefits of a proposed solution. It includes energy and generation benefits.

Bonneville has consistently used a Pacific Northwest version of the Total Resource Cost test, the Regional Cost test, to determine which alternatives should be considered. Bonneville also recognizes that others gain benefits from implementing alternative, and therefore uses the Utility Cost test to guide its decisions on how much to pay toward alternatives. Therefore, these two tests, applied in the context of Bonneville's Transmission Business, are the primary tests relied on for this screening study.

COST-EFFECTIVENESS TESTS

Bonneville's ratepayers are not the only stakeholders in a transmission line expansion. Its cost effectiveness is evaluated from a number of different perspectives, such as: total resource cost, societal, participant, and local utility impacts. Looking at all perspectives aids in program design.

In this analysis costs and benefits are calculated from the five different perspectives listed below. Each cost test perspective is described in detail in the report.

- Total Resource Cost Test (TRC) (Net direct costs and benefits to all stakeholders)
- Societal Cost Test (SCT) (Net social costs and benefits including externalities)

- Transmission Utility Cost Test (UCT) (Impact on revenue requirement)
- Participant Cost Test (PCT) (Net financial impact on customer with NCA)
- Rate Impact Measure (RIM) (Impact on rates)

In a sense only the total resource and societal cost tests are cost-effectiveness tests. That is, these two tests tell whether the total costs of the system have been lowered or not. The other tests are measures of who pays and who benefits. That is, they measure how the costs and benefits of a measure get allocated. They also offer important information about how difficult it may be to implement the measures needed to defer the transmission project. For example, if a cost-effective measure benefits both individuals and utilities, it would be easier to enlist the help of both groups in implementing the non-construction alternative. On the other hand, if individuals are harmed, it might be difficult to get support for the measure, even though it is best for the region.

A special word about the rate impact test is in order. The rate impact test measures the impact on rates, in this case to transmission rates. Bonneville has used the test historically to choose between competing transmission projects that provide similar services. The one that has the smallest impact on rates is the one pursued. In this context, the test makes sense.

However, when considering energy efficiency measures against supply side resources such as transmission, distribution, and generation, the test should not be used to make decisions about whether to implement the measures. Since rates are generally costs divided by kWh sold, any energy efficiency measure that reduces sales of kWh of transmission, even if it has no costs, will not pass the test. If the rate impact test were used in this way, no cost-effective energy-efficient measures based on total resource or societal cost tests would be deployed in the region, because no energy-efficiency measures can pass the rate impact test.

Total Resource Cost Test

The total resource cost test measures the costs and benefits from a broader perspective, and includes all of the direct cash costs associated with the non-wires alternative. The benefits include the avoided costs of transmission, distribution, generation capacity and energy, including losses. The costs include the lifecycle costs of the measure, operations and maintenance costs, program administrative costs, and the lost opportunity to realize a reduction in transmission losses from building the line. Transfers such as incentive payments, as well as bill savings, are not included from this perspective, since the net cost of transfers between the utility and customers is zero.

Societal Cost Test

The Societal Cost test includes the broadest set of costs and benefits. In addition to the direct cash costs accounted for in the Total Resource cost test, any environmental externalities, such as reduced air emissions, are included as a benefit.

Utility Cost Test - Transmission Company

This test measures the impacts on the transmission company’s revenue requirement. The benefits included for this test are the avoided transmission costs, including operations and maintenance savings. The costs are the incentive payments and administrative costs. If the program's benefit to cost ratio is less than one, the program will increase the revenue requirement. This test is different than the rate impact test, because the lost sales due to any measures that reduce sales will generally not alter the transmission company revenue requirement.

PARTICIPANT COST TEST

The Participant Cost test measures the lifecycle net benefits for the participant. The participant is the customer that installs the energy efficiency, curtails load, or owns the distributed generation. The benefits included in this test are the incentives paid to the customer and the customer's bill savings due to the measure. The costs included are the life-cycle costs of the measure to the participant. This cost test is a good indicator of how acceptable a program will be to individual customers who might participate in the program.

RATE IMPACT MEASURE - TRANSMISSION COMPANY

This benefit to cost test measures the impacts on transmission rates. The benefits included are the transmission cost savings from the deferral of the line and changes in operations and maintenance costs. The costs included are the incentive payments paid to the providers of the non-wires solution(s), administrative costs, and lost revenues due to reduced sales. If the program benefit to cost ratio is less than one, this program would tend to increase the per unit rates that the transmission company would charge to meet its revenue requirement. Measures that have a high reduction in sales relative to peak load reductions, such as conservation, are generally not cost-effective from the rate impact perspective, as discussed above.

RATE IMPACT MEASURE - DISTRIBUTION COMPANY

The Distribution rate impact test measures the impacts on the rates of the distribution utilities served by the transmission system. The benefits included for this test are the transmission avoided costs, while the costs are the incentive payments paid by the utility to the providers of the non-wires solution(s), the utility's administrative costs, and the utility's lost revenues due to reduced sales. If the program benefit to cost ratio is less than one, the program would tend to increase the per unit rates that the utility charges to meet its revenue requirement. Measures that significantly reduce sales relative to peak demand reductions, such as conservation, generally are not cost-effective from the rate impact perspective.

Table A-1 outlines the program costs and benefits attributed to each test perspective.

Table A-1: Costs & Benefits for Each Test Perspective

Tests and Perspective	Program Costs	Program Benefits
Rate Impact Test Transmission	Transmission Paid Incentive Transmission Revenue Loss Admin Costs	Transmission Avoided Cost
Utility Cost Test Transmission	Transmission Paid Incentive Admin Costs	Transmission Avoided Cost
Total Resource Cost Test	Measure / Program Costs Admin Costs Avoided Loss Savings	Gen Capacity Savings Energy Savings Transmission Avoided Cost Distribution Avoided Cost
Societal Cost Test	Measure / Program Costs Admin Costs Avoided Loss Savings Environmental Externalities	Gen Capacity Savings Energy Savings Transmission Avoided Cost Distribution Avoided Cost
Participant Cost Test Distribution Utility Customers	Participant Measure / Program Costs	Transmission Incentive Dist. Utility Incentive Dist. Revenue Loss
Rate Impact Test Distribution Utility	Dist. Utility Incentive Dist. Revenue Loss Utility Admin	Gen Capacity Savings Energy Savings Transmission Revenue Loss D Avoided Cost

TRANSMISSION AVOIDED COST DEFINITION

As stated above, the basic benefits of non-traditional alternatives on the transmission system are measured as the change in revenue requirement that can be achieved by the deferral of a transmission line (or other wires) investment. Calculating the avoided costs of the project is a way of estimating the forward-looking incremental cost of building the line. If the transmission line can be avoided or deferred for a year or longer, it will result in a reduction of future revenue requirements. The avoided transmission cost is just one component of the total system benefits of implementing an alternative solution; however, from the transmission perspective, it is the only benefit of reducing peak loads. The focus in this section is on calculating the transmission avoided cost component, but the method is similar for the other components of avoided cost.[11]

This method of calculating the long run incremental costs is also referred to as the "differential revenue requirement" method, because it is based on the difference in revenue requirements before and after deferral of the transmission project.

Step 1: Estimate the Revenue Requirement and Timing of the Planned Transmission Investment.

Table A-2 shows the revenue requirements for the planned traditional project. The costs are shown at revenue requirement levels (direct investment dollars have been scaled up to account for administrative and general costs, debt repayment, tax effects, and operations and maintenance expenses) so that the economic savings to the rate base can be estimated.

[11] For more detail, see *Costing Methodology for Electric Distribution System Planning*, prepared by E3 and Fred Gordon of Pacific Energy Associates for the Energy Foundation.

Table A-2: Revenue Requirement of Planned Expenditures

Energized Year		Present Value Dollars ($000)	Base Year / Inflation	Cost in Nominal Dollars (Adjusted up for discounting)
			2007	
2007	Lower Valley	6,124	1.25%	6,712
2008		800	1.25%	800
2010		5,000	1.25%	5,000
2012		12,300	1.25%	12,877
2019		29,850	1.25%	32,716
Total Cost		55,605		58,106

Step 2: Evaluate the Load Reduction Required on the Transmission Path to Defer the Project

Table A-3 shows the forecast of load reduction requirements. If this amount of load reduction can be achieved during the critical load periods, Bonneville can maintain its system reliability criteria and defer the project.

Table A-3: Overload of the Lower Valley System

	3-Year Deferral Scenario		Preferred Option (10-Yr Deferral with Build of 1st TX Phases)	
Year	**MW**	**No. Hours**	**MW**	**No. Hours**
2007	--	--	--	--
2008	1	1	--	--
2009	8	14	--	--
2010	15	40	--	--
2011	23	96	4	6
2012	27	134	8	9
2013	31	181	12	17
2014	35	248	16	35
2015	39	310	20	62
2016	43	378	24	91
2017	47	463	28	126
2018	51	579	33	163
2019	56	684	36	211
2020	60	820	40	262

Step 3: Calculate the Change in Revenue Requirement per kW of Load Reduction

Table A-4 shows the calculation of the reduction in revenue requirement from postponing the traditional transmission line project, if the alternatives can achieve the required amount of load reduction.[12] Column A shows the revenue requirement of the expenditures (from Table A-2). Column B is the required annual load reduction from Table A-3. Column C shows the assumed amount of load reduction. Column D shows the deferral length in years achieved by the load reductions in column C. This deferral length can vary by year, depending on the load growth in each year. Column E shows the value of the deferral for each year. The deferral value is calculated as the difference in the present value of revenue requirement under the original and deferred schedule. [13]

The method for calculating the deferral value is based on the concept that the value of a load change is equal to the difference between the present value of the original investment plan and the present value of the deferred plan.[14] The cost of a deferred investment increases with the inflation rate, but decreases by the cost of capital (discount rate). Since the discount rate is higher than the inflation rate, this results in a net present value savings:

$$\text{Deferral Value} = \text{Nominal Cost in Year(i)} \times (1 - ((1+\textit{Inflation Rate})/(1+\textit{Discount Rate}))^{\wedge}\Delta t)$$

Where Δt is the deferral length in years.

Table A-4: Calculation of Lower Valley Transmission Deferral Value

Year	*A* Scaled Nominal Cost ($000)	*B* Load Reduction (MW)	*C* Deferral Length (yrs)	*D* Deferral Value ($000)	*E* Marginal Cost ($/kW)
	(see prior table)		*Col E / Col D)*	*(A*(1-((1+inflation)/(1+discount rate))^C))*	*(Col D / Col B)*
2010	5,000	6.0	1.00	224	37.34
2011	0	3.0	1.00	0	0.00
2012	12,877	3.0	1.00	577	192.35
2013	0	3.0	1.00	0	0.00
2014	0	3.0	1.00	0	0.00
2015	0	3.0	1.00	0	0.00
2016	0	3.0	1.00	0	0.00
2017	0	3.0	1.00	0	0.00
2018	0	3.0	1.00	0	0.00
2019	32,716	3.0	1.00	1,466	488.69
2010	0	3.0	1.00	0	0.00

Step 4: Adjust for Changes in operations and maintenance Costs

If avoided operations and maintenance costs can be associated with deferring the traditional transmission project, then they are added to the total deferral value prior to calculating the

[12] This load reduction could be due to distributed generation, curtailable load, EE or other strategy.

[13] The inflation rate and weighted average cost of capital (WACC) used in the calculation of Column E are 2.7% and 9%, respectively.

[14] See Area Specific Marginal Costing for Electric Utilities: “A Case Study of Transmission and Distribution Costs”, R. Orans Ph.D. Dissertation, 1989.

total transmission marginal cost in $/kW. Dividing the total deferral value by the amount of load reduction required, gives the value per kW of load reduction.

Step 5: Calculate the Total Transmission Avoided Costs

These calculations suggest the maximum that Bonneville could pay without increasing the revenue requirement. Table A-5 shows the value of additional load reduction to achieve additional years of deferral. For each consecutive year after the initial expenditure is made, the incentive level in present value terms would be discounted further because the inflation rate is lower than the discount rate.

Table A-5: Base Case Incentive Levels Using $28 Million Dollar Avoided Investment Cost

Minimum Contract Length	2 Year	4 Year	6 Year	8 Year	10 Year
Minimum Total MW Required	12	24	30	36	42
Maximum Incentive		$224,057	$1,219,536	$2,678,976	$4,010,548
$/kW (PV Contract Payments)		$9.34	$40.65	$74.42	$95.49
$/kW-yr (Level and Annual Payments)		$2.50	$7.57	$10.86	$11.64

SYSTEM INPUT DATA

FINANCING AND INFLATION ASSUMPTIONS

The inflation, discount, and financing rates applied throughout the economic screening analysis are shown in Table A-6.

Table A-6: Financing and Inflation Assumptions

Applied Rates	Percentages
BPA Discount Rate (Real prices)	4.69%
Real Societal Discount Rate	3.00%
Financing Rate of Generator (DG)	12.50%
Customer Discount Rate	10%
Distribution Utility WACC	4.69%

ENVIRONMENTAL ADDERS

Throughout the economic analysis, only tangible financial impacts that are applicable to each measure are included in the benefit-cost model. An estimation of tangible financial impacts for environmental externality effects is not readily available for the Lower Valley area. However, many of the alternatives analyzed have positive environmental effects for each measure within the Societal Cost test perspective. Consequently, to reflect the environmental benefits of the measures tested, the Regional Technical Forum's recommended environmental monetary estimate of $15/ton of carbon dioxide emissions was used. This estimate stems from the conclusion by the RTF that there exists "a risk that serious damage will result from continued increases in greenhouse gas concentrations in the atmosphere." The $15/ton of carbon dioxide represents the reduction in this risk.

The environmental externality value is only used in calculating the Societal Cost test, and is not applied to any other cost test perspective in the economic analysis.

Table A-7: Environmental Externalities

Environmental Externalities	$/MWh
Super-Peak	$ 6.00
Peak	$ 6.00
Off Peak	$ 6.00

UTILITY RATES

For the economic screening analysis, average rates are used for the three major customer classes: residential, commercial, and industrial. While average rates do not exactly match the rates in each distribution utility's territory, they do provide a reasonable approximation for a screening study. A more detailed program design (for implementing a cost-effective program) would use the utility-specific rates. Table A-8 outlines the average $/MWh rates used in the analysis. The rates are intended to be representative of current posted rate schedules and not to accurately reflect billing rates for particular customers.

Table A-8: Distribution Utility Rates for 5 Years

Year	1	2	3	4	5
Distribution Utility Residential Rate $/MWh	$54.78	$49.70	$43.78	$44.56	$45.08
Distribution Utility Medium Commercial Rate $/MWh	$52.52	$48.51	$42.59	$43.37	$43.89
Distribution Utility Industrial Rate $/MWh	$44.23	$35.65	$ 29.73	30.51	$31.03
Distribution Utility Other Rate $/MWh	$93.14	$61.76	$ 55.84	56.62	$57.14

The unavoidable components of rates are fixed costs associated with electric service. They may be charges as base usage fees, meter fees, etc. They are shown in Table A-9.

Table A-9: Unavoidable Components of Distribution Utility Rates

	1	2	3	4	5
Residential Unavoidable Component $/MWh	$ 8.71	$ 8.71	$ 8.71	$ 8.71	$ 8.71
Commercial Unavoidable Component $/MWh	$ 19.91	$ 19.91	$ 19.91	$ 19.91	$ 19.91
Industrial Unavoidable Component $/MWh	$ 6.74	$ 6.74	$ 6.74	$ 6.74	$ 6.74

LOSS FACTORS

The energy loss factors for the transmission and distribution systems for the various time-of-use periods are shown in the Tables A-10 and A-11.

Table A-10: Average Losses to the Generator

Average Marginal Energy Losses by TOU Period	Customer Meter to Generator	Distribution Sub to Meter	Primary Transmission Sub to Generator	Bulk Transmission to Generator
Super-Peak	15%	8%	8%	8%
Peak	15%	8%	8%	8%
Off-Peak	15%	8%	8%	8%

Table A-11: Allocation of Capacity Costs

	Dist Cap Losses (meter to dist constraint)	Trans Cap Losses (meter to trans constraint)	Gen Losses (meter to gen)
Capacity Losses at Peak Hour	8%	8%	15%

DISTRIBUTED GENERATION TECHNOLOGY COST AND PERFORMANCE

Table A-12 below contains the capital and operating cost assumptions for the distributed generation alternatives.

Table A-12: Distributed Generation Capital and Operating Cost Assumptions

Technology	Capital Cost $/kW	Heat Rate (Net Heat Rate for CHP Applications) or Efficiency (for storage options)	Fixed O&M $/kW-yr	Variable O&M $/kWh
Combined Cycle Combustion Turbine	$523	7,618	$23.23	$0.0006
Simple Cycle Combustion Turbine	$370	11,380	$11.14	$0.0001
Mobile Gas Turbine Generator (GE TM2500)	$250	10,940	$2.78	$0.0010
200 kW PAFC Fuel Cell	$4,500	10,428	$6.50	$0.0290
10 kW PEM Fuel Cell	$5,500	12,507	$18.00	$0.0330
200 kW PEM Fuel Cell	$3,600	10,725	$6.50	$0.0230
250 kW MCFC Fuel Cell	$5,000	8,723	$5.00	$0.0430
2000-kW MCFC Fuel Cell	$2,800	8,162	$2.10	$0.0330
100-kW SOFC Fuel Cell	$3,500	8,338	$10.00	$0.0230
200-kW PAFC Fuel Cell CHP	$4,500	5,346	$6.50	$0.0290
10-kW PEM Fuel Cell CHP	$5,500	7,007	$18.00	$0.0330
200-kW PEM Fuel Cell CHP	$3,600	5775	$6.50	$0.0230
250-kW MCFC Fuel Cell CHP	$5,000	6,303	$5.00	$0.0430
2000-kW MCFC Fuel Cell CHP	$2,800	5,720	$2.10	$0.0330
100-kW SOFC Fuel Cell CHP	$3,500	5,731	$10.00	$0.0230
Capstone Model 330 – 30 kW w/ CHP	$2,604	5573	$0.00	$0.0200
IR Energy Systems 70LM – 70 kW w/ CHP	$1,929	7640	$0.00	$0.0110
Bowman TG80 – 80 dW w/ CHP	$1,962	6,598	$0.00	$0.0130
Turbec T100 – 100 kW	$1,765	6,166	$0.00	$0.0150
Capstone Model 330 – 30 kW	$2,201	1,5443	$0.00	$0.0200
IR Energy Systems 70LM – 70 kW	$1,663	13,544	$0.00	$0.0110
Bowman TG80 – 80 kW	$1,692	14,103	$0.00	$0.0130
Turbec T100 – 100 kW	$1,485	13,127	$0.00	$0.0150
DE-K-30 (30 kW)	$1,290	11,887	$26.50	$0.0000
DE-K-60 (60 kW)	$864	11,201	$26.50	$0.0000
DE-K-500 (500 kW)	$386	10,314	$26.50	$0.0000
DE-C-7 (7.5 kW)	$627	10,458	$26.50	$0.0000
DE-C200 (200 kW)	$416	9,944	$26.50	$0.0000
GA-K-55 (55 kW)	$970	12,997	$26.50	$0.0000
GA-K-500 (500 kW)	$936	12,003	$26.50	$0.0000
MAN 150 kW – 100 kW	$1,030	11,780	$0.00	$0.0184
Cummins GSK 19G – 300 kW	$771	10,967	$0.00	$0.0128
Caterpillar G3516 LE – 800 kW	$724	10,246	$0.00	$0.0097
Caterpillar G3616 LE – 3 MW	$702	9,492	$0.00	$0.0093
Wartsila 5238 LN – 5 MW	$727	8,758	$0.00	$0.0093
MAN 150 kW – 100 kW w/ CHP	$1,491	4,717	$0.00	$0.0184
Cummins GSK 19G – 300 kW w/ CHP	$1,172	4,687	$0.00	$0.1280
Caterpillar G3516 LE – 800 kW w/ CHP	$971	4,771	$0.00	$0.0097
Caterpillar G3616 LE – 3 MW w/ CHP	$864	4,857	$0.00	$0.0093

Technology	Capital Cost $/kW	Heat Rate (Net Heat Rate for CHP Applications) or Efficiency (for storage options)	Fixed O&M $/kW-yr	Variable O&M $/kWh
Wartsila 5238 LN – 5 MW w/ CHP	$873	4,913	$0.00	$0.0093
PV-5	$8,650	0	$14.30	$0.0000
PV-50	$6,675	0	$5.00	$0.0000
PV-100	$6,675	0	$2.85	$0.0000
Bergey Windpower WD – 10 kW	$6,055	0	$5.70	$0.0000
Lead-acid Batteries (flooded cell)	$783	70%	$15.00	$0.0000
Lead-acid Batteries (VRLA)	$2925	75%	$5.00	$0.0000
Ni/Cd	$6,125	65%	$5.00	$0.0000
Regenesys	$1,475	65%	$15.00	$0.0000
High Temp Na/S	$2,550	70%	$20.00	$0.0000
Pumped Hydro	$1,224	75%	$2.50	$0.0000

FUEL PRICES

Natural gas and distillate oil prices are inputs to the running costs of distributed generation and other generation resources. These prices are also used in the forecasts of electricity market prices. For this analysis, the fuel forecasts are taken from draft natural gas and distillate oil price forecasts supplied by the Northwest Power Planning Council in its *5th Power Plan* of April of 2003.[15] The Council forecasts U.S. wellhead prices through 2025, and then adjusts these prices to reflect the costs of delivering power to end-users. This study uses the Council's forecast of delivered natural gas prices for Eastside electricity generators and utility distillate oil prices, adjusted for inflation to 2003 dollars. Fuel price forecasts are shown graphically in Figures A-1 and A-2.

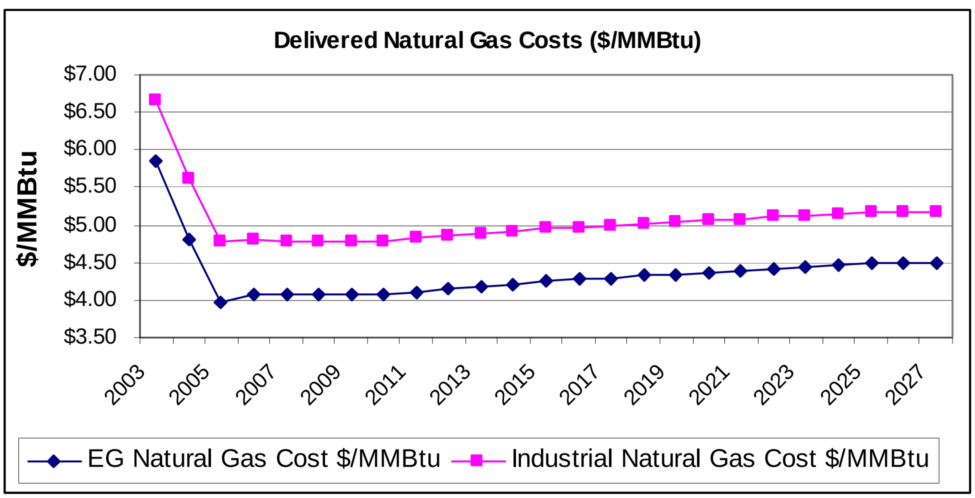

Figure A-1: Natural Gas Prices

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[15] Northwest Power Planning Council, *Draft Fuel Price Forecasts for the 5th Northwest Conservation and Electric Power Plan*, April 25, 2002, p. F-1.

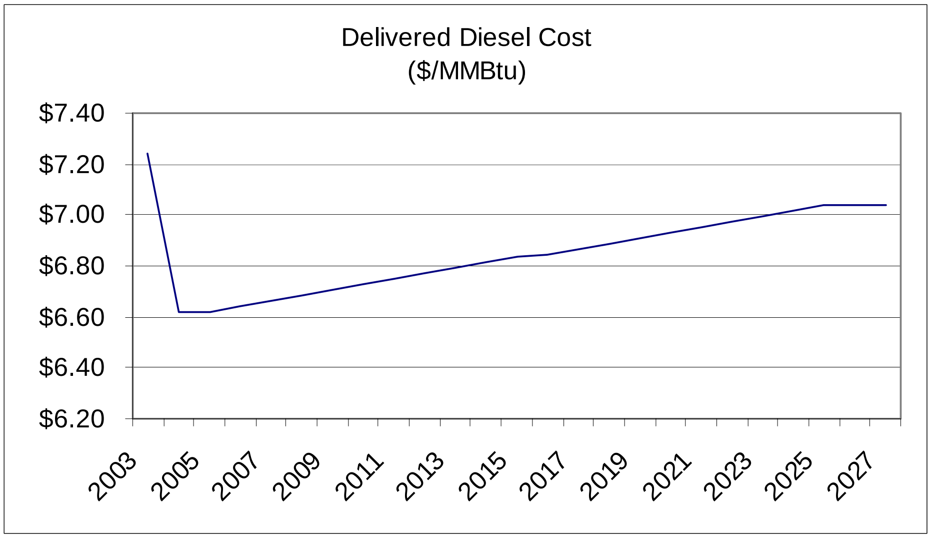

Figure A-2: Diesel Prices