Expansion of BPA Transmission Planning Capabilities

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Table of Contents

List of Tables

List of Figures

Executive Summary

Transmission Planning and Expansion Framework

Bonneville Power Administration's (BPA) Transmission Power Line (TBL) has proposed transmission infrastructure investments totaling $775 million above previously planned capital expenditures. Should TBL choose to move forward with any or all of these additions, it will have to take them through the National Environmental Policy Act (NEPA) process. In that process, TBL will need to determine how these projects affect the environment relative to alternative actions it could take, and it will have to justify these transmission additions to a variety of stakeholders.

TBL has added virtually no circuit miles to its transmission system since the late 1980s. During this lengthy period, however, electrical demand in the Pacific Northwest has continued to grow (BPA has experienced a 1.8% annual growth in demand over the past 15 years). Equally important, the increasingly competitive nature of wholesale electricity markets is leading to energy transactions and power flows that differ substantially, both in magnitude and directions, from historical practice. Transmission planning has to evolve to keep up with this changing environment.

The future promises more changes in utility practice and transmission planning with the introduction of RTOs. In October 2001, FERC held a series of workshops (called "RTO Week") to discuss electricity market design and structure. From the panel discussion on transmission planning and expansion the following points of consensus were identified:[1]

> A regional transmission plan with representation from all stakeholders is the best way to perform transmission planning and expansion.
>
> Market driven solutions [to transmission problems] are best.

Before proceeding with the construction of transmission projects, BPA wants to ensure that there is a clear and compelling demonstration of project need and that it is providing the most cost-effective solution to the region's transmission problems from an engineering, economic and environmental standpoint. As part of its evaluation, BPA must consider whether non-transmission options can be employed as viable alternatives to transmission expansion. Non-transmission solutions can include pricing strategies, demand reducing strategies, and strategic placement of generators.

In many respects these nonwires activities have been outside of TBL's purview and TBL has had to be passive with respect to them. If they happen, TBL can account for them, but it cannot make them happen. Other regional stakeholders that control nonwires activities and, in so doing, affect system costs and topology, include BPA's Power Business Line (PBL), other regional utilities, merchant generators, state regulatory commissions, loads, and possibly others. This separation of

[1] FERC Docket No. RM01-12-000

responsibilities, without coordination, has made it difficult to develop a bulk power system that in its entirety, from generation to retail-customer loads, provides the lowest-cost electricity and delivery system to retail consumers in the region.

If TBL and other regional players acted in concert, it is much more likely that they could create a system that is lower-cost and more reliable than would be the case if each acted alone. It may be possible to achieve these goals through market discipline when RTO West is operational. However, an operating RTO may be several years away, and we believe that the following recommendations apply both to BPA today and to RTO West in the future.

Summary of Conclusions

We recommend that TBL engage regional stakeholders in its planning process with the goal of sharing information that would lead to a more efficient region-wide system. The report suggests an approach for BPA to provide these stakeholders with the information they need to identify and construct potentially lower-cost and reliable alternatives to transmission expansion. In addition, TBL could employ transmission-pricing strategies that encourage economically efficient behavior, including the suitable location of new generating units and the timing of electricity use.[2]

Proposed Planning Process and Its Implementation

In Sections 1 and 2 of this report, we recommend that TBL adopt two new elements to its already comprehensive planning process (Fig. ES-1):

1) The production of a biennial system-wide report that describes the expected use of BPA's transmission facilities over the following 10 years. The report will be used to produce the information required for long-term transmission-price signals and to educate BPA's transmission customers on the transmission costs and benefits of different actions that market participants might take that would affect the need for transmission expansion, such as building new generation in certain locations.

2) The refinement and implementation of TBL's existing planning process to screen specific proposed transmission projects against the costs of various forms of suitably located and operated generation, load management, and transmission pricing.

These steps are included in Figure ES-1, which depicts the entire planning process.

[2] Implementing non-postage-stamp transmission-pricing strategies now could provide a good test for RTO West of the efficacy of its contemplated locational pricing scheme, and would help to make the RTO a more effective steward of the transmission system.

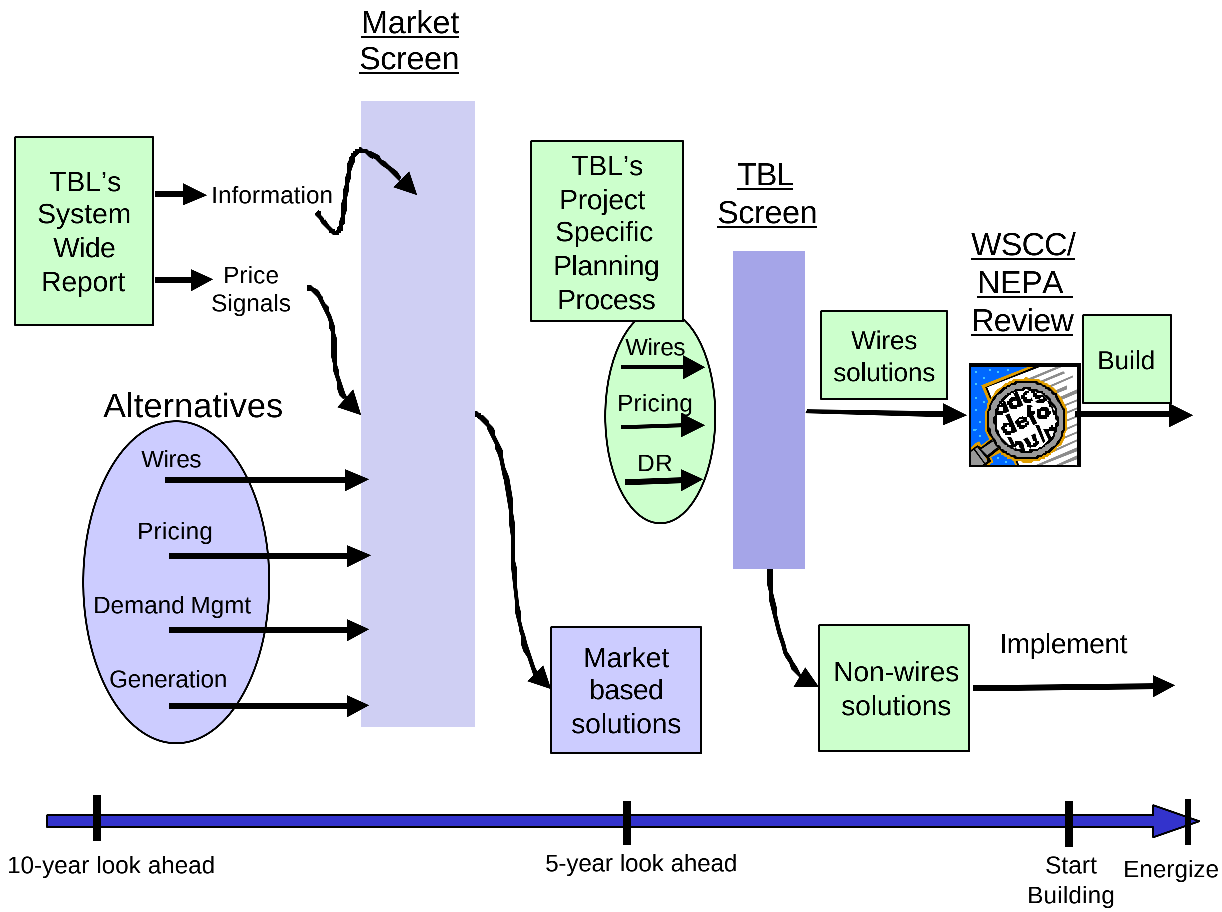

Figure ES-1: The Multiple Screening Process

Specific Recommendations

TBL can take the lead in developing a regional transmission plan, but both development and implementation of the plan should be a regional effort involving many interested and affected players. Ultimately, these regional choices should be made in concert with other Northwest interests. We suggest a detailed approach to coordinated decision making, throughout the planning process, moving from longer-term region-wide perspective to a shorter-term project-specific screening process as the time for action nears.

Revised Transmission Planning: Region-Wide Perspective.

TBL can be the catalyst that brings regional decision makers together to educate each other about the ramifications of their individual actions on the actions of others and the cost that everyone pays for delivered power. A proposed set of steps follows:

1. TBL should produce a long-term view of the transmission plan that includes expected congestion points, and the associated long-run differential costs of delivering power to various points on the grid. (See Section 2 for a detailed discussion of the long-run incremental costs of transmission expansion.) At this stage, TBL could raise the idea and

the possible range of differential transmission rates that could be proposed in its next transmission rate case.

2. TBL should conduct a scoping workshop with interested parties to display and discuss the results of Step 1. In the workshop, TBL might also find that it has additional information that would be helpful to others. In order to ensure a complete picture of the Northwest grid, the potential reinforcement plans identified by other parties should be incorporated into the long-term view. This might be done through regional planning coordination forums such as the NWPP.

3. Ask interested parties to analyze the results of the workshop, and be prepared to enter into detailed discussions of alternative cost-effective and reliable nonwires actions that they could take individually and collectively.

4. Conduct a second workshop wherein all regional stakeholders can discuss options within their jurisdiction that can help to alleviate the problems identified in TBL's initial long-term view. An important part of this workshop will be a continuing discussion about the uncertainties of acquisition and reliability in operation of all proposed alternatives to wires and of their cost effectiveness. These uncertainties are a consequence of factors such as fuel prices, load growth, federal and state regulation of the electricity industry, wholesale market structure, and market design.

5. TBL will have a number of options available to it at this point, as follows:

    a. It may conclude that there are no economic and reliable options to wires, in which case planning for grid expansion continues through the project-specific screening process proposed herein. As suggested in Figure ES-1, there is still opportunity at this stage to discover previously unrecognized alternatives, although they are fewer, due to the short time left to implement a solution.

    b. It may decide to issue RFPs for wires or nonwires solutions that can be implemented at lower cost by others.

    c. It may decide that locational and time-sensitive pricing of transmission can defer construction of new transmission and propose them in its next rate case.

    d. It may want to discuss with and lobby its customer utilities and state regulators to implement retail-pricing options that will decrease the need for transmission expansion.

    e. It might consider a broad package of alternatives that includes all of the activities listed above as well as other ideas that surface during the planning process.

Revised Transmission Planning: Project Specific Perspective

We identified a need to broaden TBL's consideration of nonwires alternatives. As the need for investment in specific wires or nonwires solutions nears, *the project-specific screening process* should be implemented. To refine this process, we recommend taking two of the currently proposed G-20 projects through this screening process. (The screening process is discussed in Section 2.) The two projects would be put through all steps of the screening process in concert with TBL staff. This effort would refine the proposed screening process and help decide whether economic and reliable alternatives exist to delay transmission construction of either or both projects.

The first stage of the project-specific screening process identifies those projects that cannot be solved by nonwires alternatives and those that have viable alternatives. (See the discussion screening projects into “buckets” in Section 2.) Many of the projects included in TBL’s proposed projects are driven by the need to interconnect new generators or are too far along in the process to identify suitable alternatives to them.

Of the remaining G-20 projects, we identified two for detailed projected specific screening that will address different issues that arise with respect to transmission expansion.

- G-8 is a project that crosses sensitive environmental areas, and the decision to construct is far enough out in time to provide a potential benefit from a search for alternatives. That is, if alternatives exist, there is a possibility that they can be implemented in time to delay the October 2003 decision date to proceed with grid expansion. The primary drivers for G-8 is the Canadian Entitlement return and load service within the Puget Sound.

- G-12 is proposed to serve expected load growth on the Olympic Peninsula. We recommend that G-12 be the other project that is put through the full screening process, again, in concert with TBL staff.

In summary, this project reviewed BPA’s current transmission-planning process and identified potential additions to that process to strengthen its relevance to expanding wholesale power markets in the Northwest. Our recommendations focus on nonwires solutions to transmission problems, with suggestions on how to consider such alternatives to traditional “wire in the air” projects in both long-term and project-specific planning.

List Of Acronyms

BPA	Bonneville Power Administration
DG	Distributed generation
DSM	Demand-side management
EUE	Expected unserved energy
FERC	Federal Energy Regulatory Commission
ISO	Independent system operator
LICR	Long-run incremental cost
NEPA	National Environmental Policy Act
NWPP	Northwest Power Pool
PBL	Power Business Line
RTO	Regional transmission operator
TBL	Transmission Business Line
VOS	Value of service
WSCC	Western Systems Coordinating Council

Section 1: Proposed Planning Process

1.0. Introduction

The purpose of the suggested changes to TBL's transmission planning process is to make the process more proactive and expansive in identifying and resolving transmission problems at the lowest cost to the transmission system, thereby improving TBL's ability to meet the needs of its customers. This process could be implemented over the next three years, in time for full implementation for projects with start dates in 2004. The recommended process includes the addition of two new functions and the modification of several others.

The two new functions are:

1. The production of a biennial system-wide report that describes the expected use of TBL's transmission facilities over the following 10 years. The report will be used to produce the information required for long-term transmission-price signals and to educate TBL's transmission customers on the transmission costs and benefits of different actions that market participants might take that would affect the need for transmission expansion, such as the location of new generation plants.

2. A two-part screening process for TBL's transmission projects to identify those projects that have viable nonwires alternatives. This can be viewed as a "backstop" project-specific screen performed by TBL to find nonwires alternatives that may have been missed in the system-wide market process initiated by the biennial report described above as function 1.
    a. The first is a high level screen to identify transmission problems that cannot be solved by nonwires alternatives. These are transmission projects that do not have viable alternatives because of generation interconnection, contract, or safety obligations.
    b. The remaining transmission projects, for which viable alternatives might exist, will be screened against the costs of strategically located and operated generation, demand management, and transmission-pricing programs.

For all planned investments with start dates before 2004, we propose an interim screening approach that includes the high level screen described above in 2a, and also identifies transmission projects that do not have viable alternatives because they require immediate solutions. The application of this interim screening process is described in Section 2.1 and the process is applied to the TBL planned projects G1 through G20.

1.1. Existing Transmission Planning Process

Figure 1 shows a simplified version of TBL's existing transmission planning process. While designed to meet the anticipated needs of its transmission customers, the process is reactive in that it is almost always driven by events external to TBL. These events are called project drivers and include requests for generation or customer interconnection, or the need to comply with legal, regulatory, safety or reliability requirements.[3] These drivers then lead to screening, evaluation, development of options, selection of the preferred plan, various reviews to ensure compliance with NERC and WSCC reliability requirements, regional planning processes under WSCC and NWPP and with the National Environmental Policy Act, and finally an implementation process that includes construction and rate-making[4].

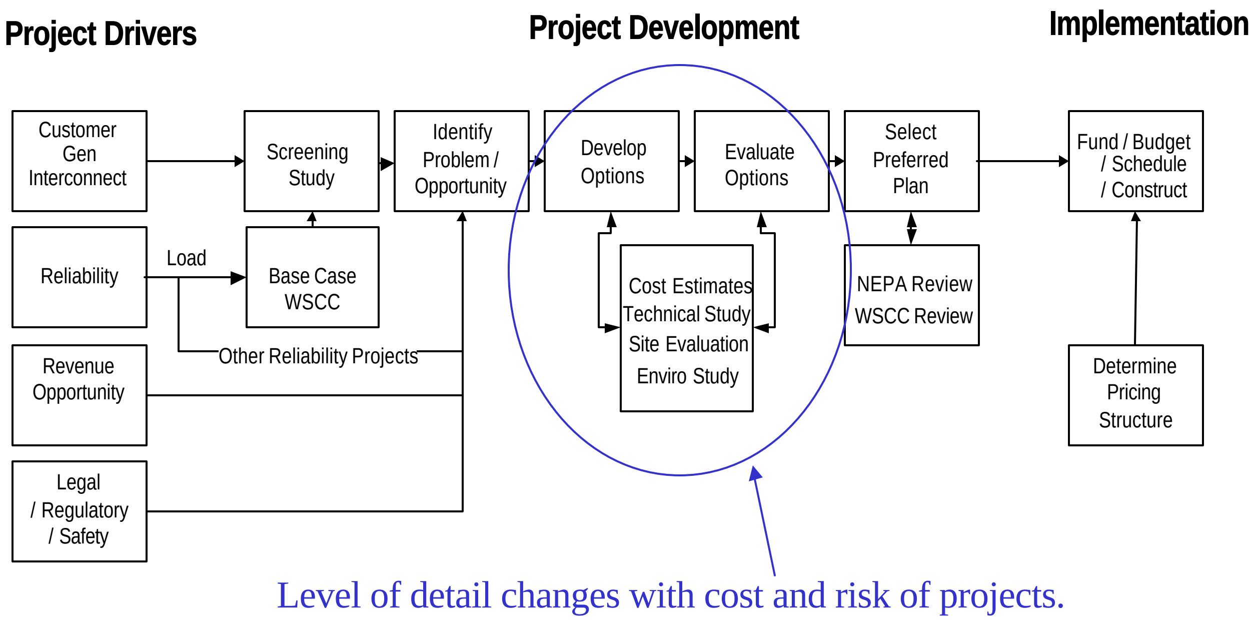

Figure 1: Simplified Existing TBL Planning Process

Although the existing TBL planning process is consistent with best practice industry standards, it identifies transmission needs on a schedule that is too late for implementation of nonwires alternatives. For example, a TBL-funded load-reduction program, designed to solve one of its transmission constraints and replace a wires expansion project, would have to be put in place long before the project's in-service date. The in-service dates for the current set of G1-G9 projects are four years or less in the future, whereas a coordinated demand reduction project may take five years to fully implement and therefore may be a nonviable alternative.

Reactive transmission planning processes are not conducive to finding cost-effective and feasible nonwires alternatives. A longer term, system-wide planning process is needed as a supplement to the existing process.

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[3] In a few cases new revenue opportunities may drive the need for new construction.

[4] See, for example, the BPA Infrastructure Addition Summary at: http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/defaultfiles/slide0001.htm

1.2. Creating a 10-Year Planning Study

The goal of the suggested system-wide transmission planning study is to identify future problems and requirements on the transmission system in sufficient time to solicit market-based solutions that are less expensive than transmission expansion. These market-based solutions will be funded by private investors who accept all risks for the project's success. That is, the returns on the investment will not be determined or guaranteed by a government regulator, but rather by competitive markets. The system-wide transmission planning study should look out over a 10-year horizon and be updated on a regular basis, i.e., biennially. This will allow sufficient time for market response and for the implementation of long-lead-time projects, such as the construction of large generation facilities.

The study should develop a broad consensus on new transmission and/or nonwires projects that are needed and that get built in a timely and cost-effective fashion. The categories of potential transmission and nonwires activities include the following:

1. Transmission expansion that is built within rate base for a FERC-regulated entity (or the equivalent) with regulated transmission rates;
2. Merchant transmission financed through market-based revenues;
3. Wholesale and retail pricing strategies for energy and transmission that reflect temporal and locational variations in costs;
4. Demand Management:
    a. Energy efficiency programs
    b. Load-shifting programs,
        i. Reliability management (energy and ancillary services),
        ii. Economics (price) based
5. Strategically placed generation plants within the transmission grid or underlying distribution system, including distributed generation.

The goal is to rely primarily on market-based solutions to transmission problems that are engendered by information from TBL that informs expectations of prices. However, BPA transmission operators should continue the existing TBL project planning process. This on-going process will be used to manage transmission problems that are serious and persistent, do not have a market based solution, and require a timely intervention and resolution.

We understand that TBL already has plans to resurrect its long-term planning process to produce better market information. The system-wide study we are proposing should be a natural extension of that effort.

Under this proposed process, once every other year TBL will produce a System-Wide Planning Study. The study will consist of the following steps:

1. Describe the current electricity situation, covering bulk-power operations, wholesale markets, and transmission pricing. Include transmission projects to which commitment has already been made.

2. Perform a 10-year load forecast that produces a range of plausible load scenarios. (Refer to Section 1.3 for recommendations on conducting a load growth forecast.)

3. Identify existing and potential problems (e.g., reliability, congestion, losses, generator market power) that are caused by the current and anticipated limitations of the transmission system. Report on the conditions under which the problems appear (e.g., certain hours, seasons, weather conditions, load forecasts, etc.).

4. Determine if the problems identified in Step 3 are chronic, and whether they are expected to persist without transmission upgrades or expansions, or without the implementation of nonwires solutions.

5. Based on steps 1 through 4, construct a set of alternative TBL expansion plans over the ensuing 10 years, under different scenarios of loads, generation development, transfers, regional power-flow patterns, etc.

6. Translate base-case expansion plans into expected long-run incremental costs (LRIC) of transmission expansion by zone or across major flowpaths. (See Section 2 for an explanation of the LRIC estimation.)

7. Identify feasible ways to provide efficient transmission-price signals (including charges for access, congestion, and losses) and conduct an aggressive public outreach to ensure as broad an understanding[5] as possible. Potential methods for pricing include cooperative programs with BPA's customers and structural pricing solutions.[6]

The implementation of this seven-step process would result in the following time line. Every potential transmission project would appear on the market participants' radar screens at least ten years before the project need date. The information would be updated on a biennial basis. TBL would develop a variety of incentives to encourage efficient behavior for the period running up to the project need date.

At least five years prior to the projected need date, TBL would run its project specific planning process. Closer to an expansion need date, TBL would produce more refined forecasts of load growth and other requirements on the transmission system, and would screen for smaller scale generation resources and other nonwires solutions in addition to transmission construction. A transmission project would undergo regional and NEPA reviews only after it has been exposed to (a) market forces to identify and encourage market solutions and (b) TBL's supplemental programs and screening processes. This multiple screening process is depicted in Figure 2.

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[5] This transmission-planning information should help market participants understand how the actions that they might take (e.g., build a new generating unit or implement a voluntary demand exchange) affect their transmission costs.

[6] See Appendix 1 for a description of one structural pricing program that Energy and Environmental Economics, Inc. implemented in British Columbia, Canada.

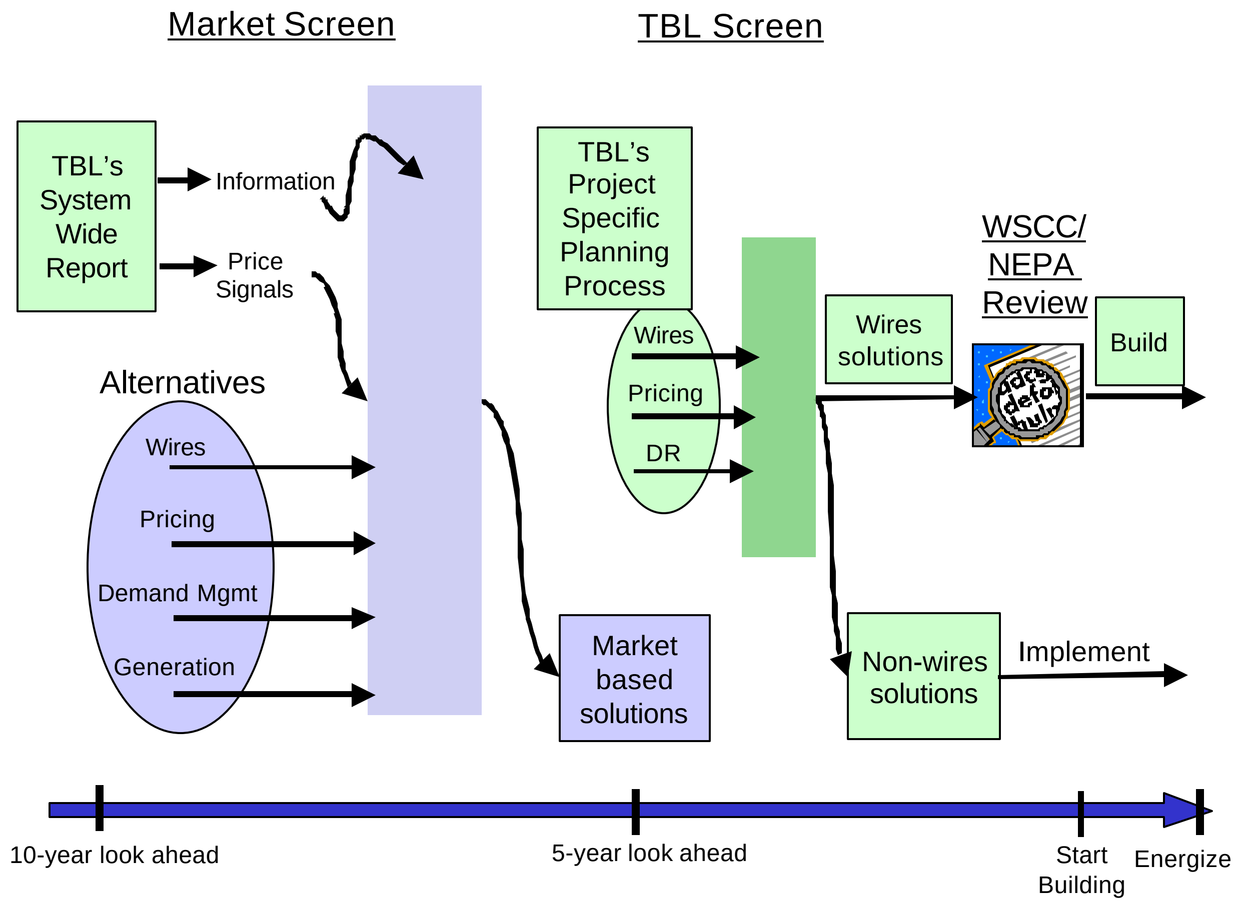

Figure 2: The Multiple Screening Process

1.3. Project-Specific Planning Process

In addition to the on-going proactive work in the longer-term planning horizon, we recommend that TBL supplement its existing project-specific planning process. In particular, TBL should develop the capability to screen transmission projects against the costs of strategically placed and operated generation resources and other nonwires solutions. Initially BPA would screen larger projects (e.g., more than $10 million in capital investment), and progressively include smaller projects as experience is gained. This supplemental task would require modifications to the current planning process that would:

1) Improve load forecasts for the biennial report and the project-specific planning process. The current process for forecasting the capacity requirements for the transmission system combines a BPA forecast for full-requirement customers (municipalities, PUDs, REAs, and cooperatives) with a growth projection provided by seven investor-owned utilities, and 14 public utilities with significant generation. The BPA forecast covers only 25% of the winter peak load, with forecasts provided by others making up the remaining 75%. Since these load forecasts drive the need for investments, their accuracy and consistency are extremely important. The recommended changes to the process include:

a) Remove the incentive for the utilities that submit their forecast to over-estimate their peak load requirement.[7] A comparison of past forecasts and loads could determine if there is a systematic bias in the forecasts that are submitted.

b) Analyze a range of high, base-case, and low peak loads in the forecasting process. This will allow for a meaningful analysis of alternative investment approaches. If a low forecast has a reasonable probability of occurring, a smaller, incremental investment approach may be cost-effective because it allows TBL to install capacity and observe the loads before committing to a large project.[8]

c) While transmission problems may be identified based on annual or seasonal peaks, as proscribed in NERC and WSCC criteria, analysis of nonwires alternatives should be based on hourly load-duration curves, rather than only on the annual peak. The load duration curve is important when evaluating alternative solutions because TBL will need to know when and how often generation or load reduction is required to solve the capacity problem. This is not typically part of traditional transmission planning since transmission lines provide capacity continuously once constructed.

2) Quantify the cost and reliability consequences of not building suggested projects. An important question in any review of a transmission plan is what will happen if the project is not built. The TBL planning process should address this by explicitly quantifying the degradation in reliability of the system, the number and types of customers that would be affected, and the potential economic impact on customers. Many projects are built to comply with the WSCC planning criteria. The quantification of the 'do-nothing' case should describe how far short a system will be of these criteria without the project. Depending on the type of customers, there are a number of ways to estimate the economic impact of not building a project. These include estimating the expected unserved energy (EUE) and value of service (VOS), and estimates of market power impacts on prices, and lost sales opportunities for generators[9].

3) Evaluate alternatives such as demand management, distributed generation (DG), interruptible/curtailable rates, and transmission pricing solutions to transmission problems. Are any nonwires alternatives more cost-effective than the proposed transmission project? In the project-specific planning process, we recommend that TBL perform a high-level

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[7] The incentive to submit high forecasts is caused by the payment structure for transmission. The payments are not linked to the load forecasts, but are based on actual metered usage. Therefore, a high forecast ensures excess capacity at no additional cost.

[8] On the other hand, there are large economies of scale in transmission construction that argue for overbuilding ahead of need.

[9] For further discussion on EUE and VOS refer to 'How Much Do Electric Customers Want to Pay for Reliability? New Evidence on an Old Controversy', Energy Systems and Policy, Volume 15, pp. 145-159 1991 by Woo, C.K, Pupp, R.L, Flaim, T. and Mango, R. and 'Costs of Service Disruptions to Electricity Consumers', Energy Vol. 17, No. 2, pp. 109-126, 1992 by Woo, C.K., and Pupp, R.L..

economic screening of a wide range of alternative solutions. This screening approach would start with a simple evaluation using optimistic assumptions about the cost-effectiveness of these nonwires options to allow TBL to look at as wide a set of alternatives as possible. For those measures that have some potential, more time can be devoted to refining the input assumptions and making a more detailed analysis of potential program designs. Section 2 presents an example of an easily implementable high-level economic screen for four different types of nonwires options.

4) Evaluate potential market impacts of new transmission investments. Beyond improving the reliability of the transmission system, many projects are built to allow increased trade and generation interconnection, and to improve market efficiency. In order to describe the complete benefits of a new transmission project, particularly those that are proposed for market reasons, TBL should estimate the effect on the regional energy markets. For example, adding new capacity into an existing load pocket could eliminate the need for standing contracts (such as Reliability Must Run contracts) with generators inside the load pocket and provide regional economic benefits. Because of the market power issues seen in the last few years, several jurisdictions including the California ISO and ISO New England have begun to look at transmission investments with respect to mitigation of market power and reduction of market prices.

5) Implement the modifications suggested by BPA to the scoring and selection of preferred transmission plans. TBL's current investment decision process (called "Matrix") ranks and prioritizes projects for consideration in the capital budgeting process. A number of improvements have been suggested that will significantly improve this process. The most important improvements are developing more specific financial and performance metrics to compare plans, and ranking projects with other projects in the same general category. This approach will make the budgeting process easier to explain since explicit criteria have been used to select projects for funding. Some of the other suggested modifications will provide additional criteria such as EUE, VOS, and impact on market power to supplement existing financial and reliability metrics that are already evaluated in the existing process.

Collectively, these new functions fit directly into the existing process as shown in Figure 3.

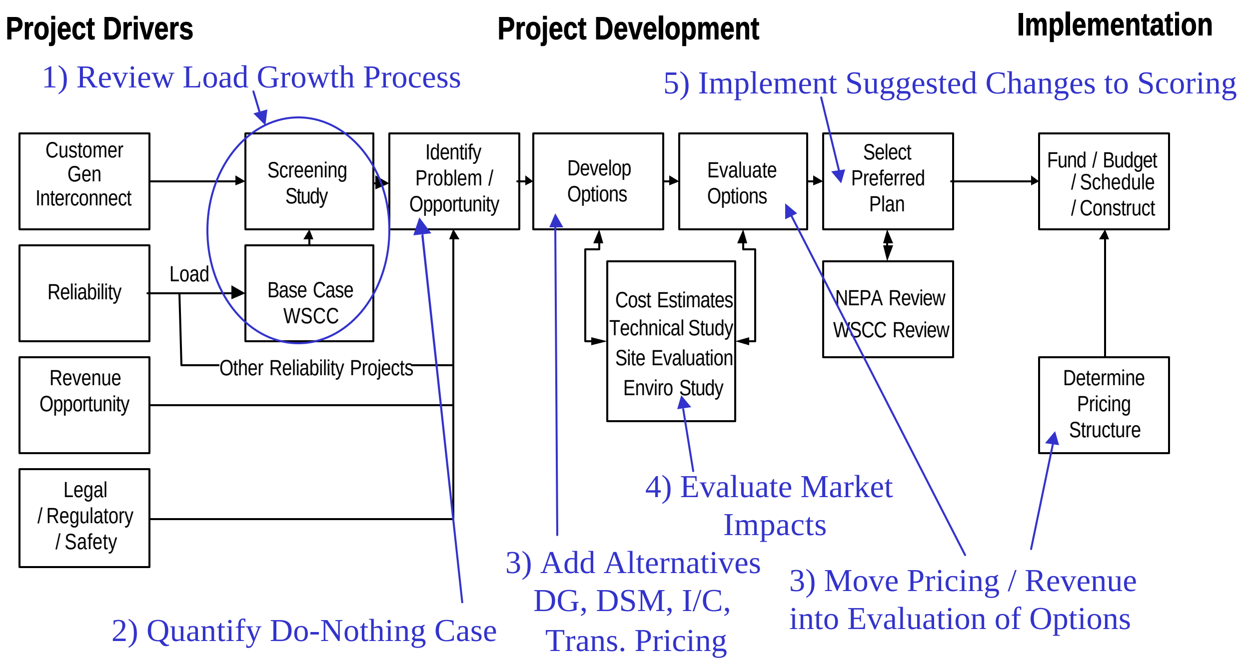


Figure 3: Suggested Modification to TBL's Planning Process

If market constraints or reliability problems are serious, persistent, and do not have a market solution, TBL's on-going project-specific planning process will identify suitable transmission projects to correct the problem. Because this initiates a centralized (rather than market) fix to the problem, the amount of accountability is now greater than if market solutions provided the fixes. TBL's recommended plan should include discussion of the following issues:

1) What is the existing transmission need?

2) Is the proposed project the lowest cost <u>transmission investment</u> to meet that need?

3) Is the recommendation based on realistic assumptions about the future? That is, have the various uncertainties about the input assumptions been adequately considered in assessing alternative solutions to transmission problems?

4) Based on the costs of <u>nonwires alternatives</u> is the plan the <u>least cost alternative</u>? This type of "backstop" screening requires that TBL produce a cost-effectiveness study of every large project that has the potential to be replaced by a nonwires alternative. While this may sound like an unneeded and onerous process, our experience with other utilities indicates that it will not be difficult to implement. If the long-term process is effective, most of the plans should be either the only option left or the most cost effective by the time it shows up on the project-specific planning process radar screen. Moreover, the screening process can be readily automated with relatively simple software and screening processes.

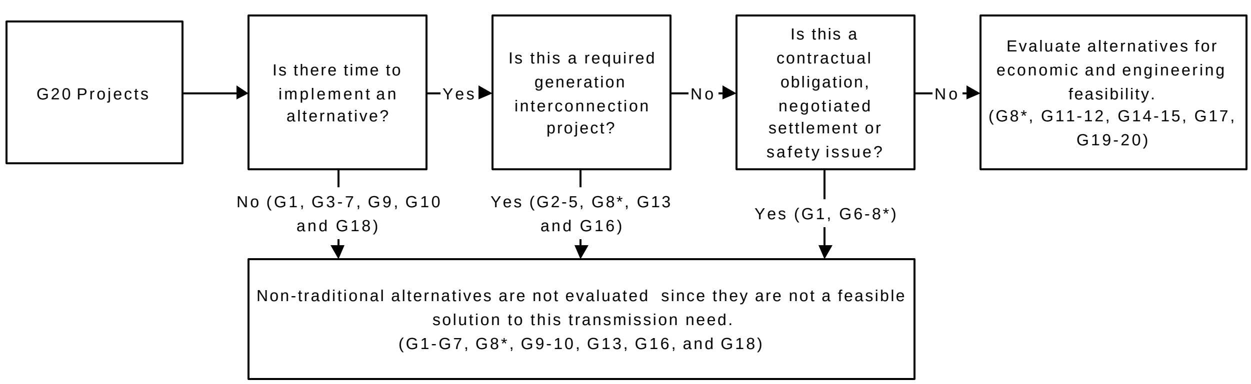
Section 2: Review of Existing Plans

2.1. Initial Screen of the G20 Projects for Evaluation of Alternatives

This section reviews the transmission projects that TBL currently has planned to estimate the potential for nonwires alternatives. Each of the G20 projects has its own particular considerations, and for some projects there has been significant engineering and economic analysis, public workshops and forums, and other work completed. The projects can generally be divided into four categories that are useful to assess whether non-traditional alternatives are a viable solution.

There are three general categories of TBL's transmission needs that non-traditional alternatives will not solve. These are: (1) problems that require an immediate solution; (2) generation interconnection: and (3) contract, negotiated settlement, or safety obligations. Each of these categories is described in more detail below, along with the list of projects for which it applies. All told, 11 of the G20 projects fall into one or more of these three categories. The remaining projects fall into the fourth category: (4) further analysis of the economic and engineering feasibility of alternatives should be conducted. The following diagram illustrates this high-level screening process.

Initial Screen of G20 Projects



* G8; The primary driver for this project is the Canadian Entitlement return, and service of loads to the Puget Sound area. If the Canadian Entitlement return is purchased within the US, non-traditional alternatives may effect this plan.

The following sections describe each of these categories in more detail.

2.1.1. Timing of the Project

Since transmission planning at TBL is an on-going effort, there are a number of projects whose decision date is very near, and it would be impossible to replace the project with a non-traditional alternative and not violate WSCC reliability criteria. The timing of the decision dates, and in-service dates is included in Table 1 below.

Table 1: TBL Transmission Projects - Updated Schedule (9/26/01)[a]

	Project	Type	Decision	Energization
G1	Kangley - Echo Lake 500 kV line	EIS	Jan-02	Nov-02
G2	Schultz - Black Rock 500 kV line	EIS	Jan-03	Oct-04
G3	McNary - John Day 500 kV line	EIS	Sep-02	Oct-04
G4	Lo Monumental – Starbuck 500 kV line	EIS	Sep-02	Oct-04
G5	Smiths Harbor - McNary 500 kV line	EIS	Sep-02	Oct-04
G6	Schultz series capacitors	CX	Oct-01	Nov-03
G7	Celilo Modernization	CX	Oct-01	Dec-02
G8	Monroe - Echo Lake 500 kV line	EIS	Oct-03	Oct-05
G9	Bell – Coulee 500 kV line	EIS	Nov-02	Oct-04
G10	Pearl Transformer	CX	Apr-02	Oct-03
G11	South Seattle Transformer	CX	TBD	Oct-05
G12	Shelton Transformer and line addition	EIS	Oct-03	Oct-05
G13	Paul – Troutdale 500 kV line	EIS	Oct-04	Apr-06
G14	Hanford – Ostrander loop-in	CX	Apr-04	Apr-06
G15	Libby – Bonners Ferry rebuild	EIS	Oct-04	Oct-06
G16	McNary tap to Ashe - Marion 500 kV line	EIS	Oct-03	Apr-06
G17	Little Goose – Starbuck 500 kV line	EIS	Oct-04	Oct-06
G18	Hatwai – Lolo 230 kV line	EIS	Oct-02	Apr-05
G19	McNary – Brownlee 230 kV line	EIS	Oct-03	Jun-05
G20	Libby – Bell 230 kV line	EIS	Oct-04	Oct-06

[a]The shaded projects have decision dates before January 2003.

As a practical matter, those projects that must be committed to by the end of 2002 to avoid reliability problems are so near-term that it is not feasible to replace them with nonwires alternatives. The decision date is the critical date since even though it is possible to cancel at any point up until the project is in service, there will be a significant amount of money and staff time invested in the project.

The projects that fall into the near-term are G1, G3-7, G9-10, and G18. The rest are far enough in the future that there is time to consider nonwires approaches.

Generation Interconnection and Transmission Service

There is a second group of projects that are necessary to provide transmission network capacity to new generation that is being interconnected at customer request. These types of projects will not generally be able to be avoided by load reduction or distributed generation, since TBL must have enough capacity for these customers once they decide to interconnect and request long-term transmission service. These generation interconnection projects include G2-G5, G8 (although G8 is primarily driven by other factors), G13, and G16.

Negotiated Settlement, Contractual Obligation, Safety

Finally, a third category of transmission investment is necessary because of prior contractual obligations, such as the Canadian Entitlement return, negotiated settlement, or safety. A good example of a negotiated settlement project is G7. This project would upgrade the north terminal of the HVDC line to Southern California and is the result of extensive public collaboration.

The Canadian Entitlement return is the commitment made by the US government as part of the Columbia River Treaty of 1964 to return power to Canada. This agreement was made when Canada built three large storage dams that increase the output of dams in the US. The return of power back to Canada began in 1998, and will increase through 2003. The Canadians may decide to take delivery of the power within the US, thereby reducing the need to deliver power to the Canadian boarder, but under the current agreement a number of new lines would be required. The projects that are at least in part influenced by the Canadian Entitlement return are G1, G6, and G8. Because of its timing, the G8 project is the only one of these that might be avoidable by a future agreement with Canada and/or non-traditional alternatives.

Economic / Reliability

After examining the G20 projects using the three considerations described above the remaining projects have potential for non-traditional alternatives, no explicit legal requirement to build if a reliable alternative exists, and time to complete the analysis before a decision is made on the final project. The candidate projects include G8, G11-G12, G14-15, and G17-G20 (9 of the 20 projects).

2.2. Economic Screening of G12 Olympic Peninsula Additions

In this section we present an illustrative analysis of the avoided costs that appropriately located load reduction or generation could provide to the BPA transmission system. The example is based on the G12 transmission investments for the Olympic Peninsula that was placed in the economic screening 'bucket' from the previous analysis. While we have incorporated the available data as much as possible, this is an illustrative example only and we have simplified the data to better explain the underlying screening process.

The basic calculation behind the economic screening is the change in BPA-TBL revenue requirement that can be achieved by the deferral of a wires investment. If a deferral of a wires investment lowers[10] the revenue requirement then this potential “savings” can be used to “buy” a nonwires alternative. The cost of the alternative should not exceed the savings achieved from the deferral of the wires project.[11] Estimation of avoided transmission costs would be performed by TBL and included in its 10-year planning document (and perhaps implemented with a new pricing mechanism).

The avoided transmission cost is just one component of the total system benefits of implementing an alternative solution. The backstop screening analysis of nonwires alternatives to a transmission investment, proposed for TBL’s project-specific planning process and discussed in Section 1, should also include the avoided generation capacity and energy costs, and distribution avoided costs. While TBL could pay no more than its avoided transmission costs for a nonwires solution, an economic screen needs to incorporate all avoided costs that can be achieved by a nonwires project. [12]

This section focuses on the calculation of the transmission avoided cost component, however the method is similar for the other components of avoided cost[13].

2.2.1. Transmission Avoided Costs

Step 1: Estimate the revenue requirement and timing of the planned transmission investment.

Table 2 shows the revenue requirements for the planned G12 project. This project increases capacity for service to the Olympic Peninsula and is comprised of a conductor upgrade in 2005 and capacitor additions in each of the years 2011 through 2015. 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 BPA ratebase can be estimated.[14] The revenue-requirement amounts shown in column C for the capacitors in years 2011 through 2014 are in 2001 dollars. These are

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[10] A deferral of a wires investment that resulted in increased O&M costs could potentially increase the revenue requirement.

[11] All other things being equal, e.g., reliability, environmental externalities, etc.

[12] For example, a load reduction program planned in a specific area to reduce loading on a transmission line would also reduce loads on the local distribution system and generation market. If the total incentive paid to the customer were based on transmission avoided costs it may not be attractive to the customer nor would the payment reflect all of the benefits of the load reduction. However, by adding any offset wholesale power purchases, and adding local distribution company incentives based on distribution avoided costs, the backstop screen may find the program cost-effective.

[13] 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.

[14] The cost numbers listed here include an increase of 30% to account for indirect costs and overhead (provided by BPA), and an additional increase of 10% for allowance of funds used during construction.

inflated using the assumed annual inflation rate of 2.7% to get the nominal revenue requirements dollars shown in column E.

The approach described here has been used in dozens of case studies including those referenced earlier. 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.

Table 2: Revenue Requirement of Planned Expenditures

A	B	C	D	E
Year	Investment	Constant Base Year Dollars ($1000s)	Base Year	Revenue Requirement in Nominal Dollars ($1000s)
Investment data from BPA				
2005	G12 project			40,908
2011	capacitors	1,300	2001	1,697
2012	capacitors	1,300	2001	1,743
2013	capacitors	1,300	2001	1,790
2014	capacitors	1,300	2001	1,838

Step 2: Evaluate the load reduction on the transmission path that would be required to delay the project.

Table 3 shows the load growth forecast in the area affected by G12. The project has been planned to meet the expected load in the winter of 2004/2005, so if the load is kept at or below 2004/2005 levels the transmission project can be delayed. Column B gives the forecasted load projection. The highlighted numbers (2004 to 2009) in column B were provided by TBL, and the remaining peak load numbers were projected by E3 using an assumption of 2% growth rate. The load growth per year is shown in column C.

Table 3: Load Growth Estimate for G12

A	B	C
Year	Peak Load (MW) Escalated 2%	Total Growth (MW) *Col B - Col*
2002	1,367	
2003	1,394	27.34
2004	1,422	27.88
2005	1,451	29.00
2006	1,480	29.00
2007	1,509	29.00
2008	1,540	31.00
2009	1,571	31.00
2010	1,602	31.42
2011	1,634	32.05
2012	1,667	32.69
2013	1,701	33.34
2014	1,735	34.01
2015	1,769	34.69
2016	1,805	35.38
2017	1,841	36.09
2018	1,877	36.81
2019	1,915	37.55
2020	1,953	38.30
2021	1,992	39.07
2022	2,032	39.85
2023	2,073	40.65
2024	2,114	41.46
2025	2,157	42.29
2026	2,200	43.13
2027	2,244	44.00
2028	2,289	44.88

<u>Step 3: Calculate the change in revenue requirement per kW of load reduction based on the deferral value.</u>

Table 4 calculates the reduction in revenue requirement for the G12 project due to a load reduction.[15] Column A shows the revenue requirement of the expenditures (from Table 2). Column B is the projected annual growth from the load forecast in Table 3. Column C shows the assumed amount of load reduction, which has been set to equal the growth from 2004/5 to 2005/6, i.e. one year of load growth.

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

In this example, we assumed a sustained reduction of 29 MW of load through the planning horizon, which would be achievable with a long-life measure such as installation of wall and ceiling insulation in a building that is expected to remain in use for many years. However, only load reductions in years with expenditures affect the revenue requirement, i.e., the 29-MW load reduction will delay the $41 million investment in 2005 until 2006, with a deferral value of over $2 million, but there are no further expenditures planned until 2011 so the deferral value is zero in 2006-2010. If we were evaluating a short–term load reduction measure, such as a three-year curtailable rate option, then this measure would not be credited with the deferral values in years 2011 through 2014.

The assumption on the amount of load reduction is important but subtle. We are estimating the incremental value of load reduction on the constrained path for a **meaningful** increment of load[16]. Column D shows the deferral length in years achieved by the load reductions in column C and this value varies by year depending on the load growth that year. Column E shows the deferral value of the load reduction for each year. The deferral value is calculated as the difference in the present value of revenue requirement before and after the investment is deferred. [17]

This 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.[18] A deferred investment is increased by the inflation rate, but the costs are discounted an additional year. Since the discount rate is higher than the inflation rate, this results in a net savings:

Deferral Value = Nominal Cost in Year(i) $\times$ (1 – ((1+*Inflation Rate*)/(1+*Discount Rate*))^Δt)

Where Δt is the deferral length in years.

For example, the 29 MW of load reduction prior to 2005 results in a savings of $2.364 million dollars of revenue requirement. Column F divides this total value by the amount of load reduction required to get the value per kW of load reduction, giving a marginal cost of $81.53/kW in 2005. This means that each kW of the 29 MW of total reduction in 2005 is worth $81.53/kW[19] because of the value of deferring the expenditures in that year.

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[16] For systems that have a radial configuration, the amount of load reduction on the constrained path will be the same as the total resource that is implemented (adjusted for losses). In network systems, flow distribution factors can be used to estimate load reduction achieved on the constrained path from a reduction at a particular point on the system.

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

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

[19] Note that the $81.53/kW value only holds if the full 29 MW of load reduction can be achieved.

Table 4: Calculation of Transmission Deferral Value

	A	*B*	*C*	*D*	*E*	*F*
Year	Scaled Nominal Cost ($000)	Load Growth (MW)	Load Reduction (MW)	Deferral Length (yrs)	Deferral Value ($000)	Marginal Cost ($/kW)
	(see prior table)			*(Col C / Col B)*	*(A * (1-((1+inflation)/(1+WACC))^D))*	*(Col E / Col D)*
2003	0	27.3	29.0	1.06	0	0.00
2004	0	27.9	29.0	1.04	0	0.00
2005	40,908	29.0	29.0	1.00	2,364	81.53
2006	0	29.0	29.0	1.00	0	0.00
2007	0	29.0	29.0	1.00	0	0.00
2008	0	31.0	29.0	0.94	0	0.00
2009	0	31.0	29.0	0.94	0	0.00
2010	0	31.4	29.0	0.92	0	0.00
2011	1,697	32.0	29.0	0.90	89	3.07
2012	1,743	32.7	29.0	0.89	90	3.09
2013	1,790	33.3	29.0	0.87	90	3.11
2014	1,838	34.0	29.0	0.85	91	3.14
2015	0	34.7	29.0	0.84	0	0.00
2016	0	35.4	29.0	0.82	0	0.00
2017	0	36.1	29.0	0.80	0	0.00
2018	0	36.8	29.0	0.79	0	0.00
2019	0	37.5	29.0	0.77	0	0.00
2020	0	38.3	29.0	0.76	0	0.00
2021	0	39.1	29.0	0.74	0	0.00
2022	0	39.8	29.0	0.73	0	0.00
2023	0	40.6	29.0	0.71	0	0.00
2024	0	41.5	29.0	0.70	0	0.00
2025	0	42.3	29.0	0.69	0	0.00
2026	0	43.1	29.0	0.67	0	0.00
2027	0	44.0	29.0	0.66	0	0.00
2028	0	44.9	29.0	0.65	0	0.00

Step 4: Calculate the total transmission avoided cost.

Table 5 shows the calculation of the total avoided costs of deferral of the G12 project over the life of the load reduction that achieves the deferral. Column B shows the marginal cost in $/kW from Table 4. Columns C, D, E and F show the avoided costs for load reduction measures that last for 3, 5, 10 and 15 years respectively. Row 14 calculates the net present value of the avoided cost stream, which is equivalent to the total avoided cost per kW over the horizon of 3, 5, 10 and 15 years respectively. For example, a load reduction of 29 MW for 3 years is worth $68.62 per kW, which is the sum of the marginal values in years 2003, 2004 and 2005 discounted by the weighted average cost of capital (WACC). The value for a 5-year reduction is the same as the 3-year reduction because there are no further avoided costs in the years 2006 and 2007. The longer-term measures of 10 and 15 years have higher values as they are capturing the value of avoided cost in years 2011 through 2014.

Table 5: Calculation of the Total Marginal Cost Over the Life of the Load Reduction

	A	B	C	D	E	F	G
Row			Measure Duration in Years				
1	Year	Marginal Cost ($Nominal/kW) *From Col H*	3	5	10	15	Comment
2	2003	0.00	0.00	0.00	0.00	0.00	*Marginal Costs included match the*
3	2004	0.00	0.00	0.00	0.00	0.00	*duration of the measure indicated in*
4	2005	81.53	81.53	81.53	81.53	81.53	*Row 1*
5	2006	0.00		0.00	0.00	0.00	
6	2007	0.00		0.00	0.00	0.00	
7	2008	0.00			0.00	0.00	
8	2009	0.00			0.00	0.00	
9	2010	0.00			0.00	0.00	
10	2011	3.07			3.07	3.07	
11	2012	3.09			3.09	3.09	
12	2013	3.11				3.11	
13	2014	3.14				3.14	
14	Total Marginal Cost (NPV$/kW)		$68.62	$68.62	$71.59	$74.12	*NPV(WACC,Rows 2 to 11)*(1+WACC)*

These calculations suggest that TBL could pay up to $74.12/kW for a program that cut demand by 29 MW in 2003 and maintained that reduction for 15 years. If TBL can acquire such load reductions for a lower price, it should do so and defer the transmission project. If not, it should go ahead and build the G12 project. Programs lasting 3, 5, or 10 years should be evaluated on the same principle.

2.2.2. Application to Screening Non-Wires Alternatives

After calculating the avoided costs achievable by a load reduction, TBL should perform an economic screening analysis on a wide-range of nonwires alternatives to the transmission project. This screening process will help determine if a program to encourage nonwires alternatives warrants consideration, or if the economics make such projects clearly non cost-effective. Using optimistic assumptions for the nonwires alternatives, measures that are not cost-effective in this broad level screen will not warrant closer examination in a detailed screening study. The goal of the screening level analysis is to allow consideration of a broad set of options without requiring intensive analysis. For options that look promising after a screening study has been completed, a more refined analysis can be conducted. Appendix 1 provides an example of this screening analysis, calculating the lifecycle costs and benefits of a number of different alternatives including demand side management (DSM), DG, Fuel Switching, and Curtailable Programs in comparison to the G12 transmission project.

Benefit/Cost Perspectives

Suggesting that a measure is "cost-effective" immediately raises the question, "cost effective to whom?" The cost-effectiveness of a potential measure is evaluated from a number of different perspectives, which are described briefly below.

Ratepayer Impact Measure (RIM) - Transmission Company

This benefit/cost test measures the impacts on TBL's rates. The benefits included for this test are the transmission avoided costs, and the costs included are the incentive payments paid by TBL to the providers of the nonwires solution(s) to the transmission problem, TBL's administrative costs and TBL's lost revenues due to reduced sales. If the program benefit/cost ratio is less than one, this program would tend to increase the per unit rates that TBL charges to meet its revenue requirement. Measures that significantly reduce sales, such as conservation, generally appear not cost-effective from the RIM perspective.

Utility Cost Test - Transmission Company

This test measures the impacts on TBL's revenue requirement. The benefits included for this test are the transmission avoided costs, and the costs included are the incentive payments and administrative costs. If the program benefit/cost ratio is less than one, the program will increase the revenue requirement. This test is different than the RIM test because the lost sales due to any measures that reduce TBL sales do not affect the revenue requirement; this depends, of course, on the transmission rate design.

Total Resource Cost Test (TRC)

The TRC test measures the costs and benefits from a broader perspective and includes all of the direct cash costs due to the measure. The benefits include the transmission, distribution, generation capacity and energy avoided costs, and the costs included are the lifecycle costs of the measure and administrative costs. Transfers such as incentive payments between TBL and its customers, as well as bill savings are not included from this perspective since the net cost between TBL and customers is zero.

Societal Cost Test

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

Participant Cost Test

The participant cost test measures the lifecycle net benefits for the participant. The participant is the customer that is installing the DSM, curtailing their load, or who owns the DG. The benefits included for this test are the incentives paid to the customer and the customer's bill savings due to the measure, and the costs included are the life-cycle costs to the participant of the measure. This cost test is a good indicator of how acceptable a program will be to a customer.

Each of these tests has value to some market participants. An interesting, but not yet resolved issue, concerns the appropriate tests to use in RTO-dominated competitive wholesale electricity markets.

Program Design Issues

The value of load reduction will be the economic basis of any incentives that TBL would use to encourage alternative solutions in the market place. The design of the program will depend on the type of alternative to the transmission project, and will have the following considerations in mind;

- Payments made by TBL for the program should reflect the value of load reduction with the objective of minimizing overall transmission costs for TBL customers.
- Level and timing of payments made by TBL should reflect TBL's confidence that the required level of load reduction will be achieved.
- Programs are designed to attract participants.

Incentive Payments

The transmission-avoided cost based on revenue requirement savings as calculated in Section 2.2.1 represents the total value of load reduction or generation. An assessment must be made on how to share these benefits between the participants and non-participants in the program. If the entire avoided costs are paid to the participants (for example to get a higher penetration level) then the revenue requirement remains unchanged, and transmission users in general do not share any of the benefits of the deferral. While paying the maximum incentive may maximize uptake of alternative solutions, the objective of the program is to minimize transmission costs. Therefore TBL wants to pay the lowest incentive that is required to induce an alternative solution. The typical starting point for this analysis is an incentive level set at 50% of the avoided cost, which represents an equal sharing between participants and non-participants.

Locational Nature of the Avoided Costs

The example shown in this section calculates only the transmission avoided costs of a specific investment in the G12 Olympic Peninsula Additions. Therefore, the value is only meaningful for load reductions or generation that reduce loads on the constrained path that is the target of the load reduction.

Required Amount of Load Reduction

This example is based on an incremental amount (29 MW) of load reduction. Investments are built to meet the forecasted peak loads, so typically a deferral is only meaningful if it is in one-year steps. For example, rather than an in-service date of fall 2005, the project is moved to an in-service date of Fall 2006. Therefore, if less than the amount required for a one year deferral is achieved, and the project must still be energized according to the original schedule, and there is no deferral benefit to the load reduction.

It is questionable if a project delay of less than a year has any meaningful value. Experience shows that projects are almost always scheduled to be energized in the season prior to the forecasted peak, which for most of BPA is the winter season (hence the schedule to energize in the fall). If the load reduction falls short of what is required to lower the peak load for that winter then the project still needs to be energized in the fall. Energizing in the spring will be too late, if TBL has gone through the winter it might as well wait until the following fall to energize.

Section 3: Implementation of Planning Process

3.1. Long-Term Transmission Planning

TBL can take the lead in developing a long-term transmission plan, but both development and implementation of the plan should be a regional effort involving all interested players. The options open to TBL cover a wide range of possibilities. Ultimately, the path chosen should be done in concert with other Northwest interests.

At one end of the spectrum, TBL could simply publish information about the transmission grid today and the expected conditions in the future. Developing this option would require TBL to identify the kinds of information about the grid that would be useful to market participants. At the other end of the spectrum, TBL could actually run demand-side programs and build generating units to solve transmission problems. This second option seems extremely unlikely because it is so antithetical to the creation, design, and operation of competitive wholesale markets and, therefore, will not be discussed further. However, TBL could achieve the objective of solving transmission problems at least cost in other ways, for example, by issuing RFPs for nonwires and merchant-transmission solutions to transmission problems.

From the spectrum discussed above, TBL should develop the details necessary to implement two options: 1) provision of information useful to market participants; and 2) acquisition from the market of least-cost solutions to transmission problems.

For the first option, TBL should identify the specific data elements and forms of presentation needed by generating companies, power marketers and brokers, load-serving entities, transmission owners, representatives of consumer and environmental groups to make informed decisions on generation and demand-management programs. The range of information TBL could provide encompasses simple maps showing the desirable and undesirable locations for new generation from the perspective of the transmission system to detailed results from load-flow studies (voltages, real- and reactive-power flows, and phase angles) and real-time operating data.

For the second option, TBL should review the experience that other utilities and ISOs have had with the acquisition of nonwires solutions to transmission problems. For example, all the existing U.S. ISOs operate demand-management programs intended to provide reliability resources and to reduce wholesale-power costs. This review will form the basis of TBL's decision on whether and, if so, how to proceed with potential acquisition from market participants of transmission solutions.

3.1.1. Recommendation.

TBL can be the catalyst that brings together regional decision-makers to educate each other about the ramifications of their individual actions on the actions of others and the cost that everyone pays for delivered power. Recommended steps include:

1. TBL should produce a long-term view of the transmission system that includes expected congestion points, and the associated long-run differential costs of delivering power to

various points on the grid. At this stage, TBL could raise the idea and the possible range of differential transmission rates that could be proposed in its next transmission rate case.

2. TBL should conduct a scoping workshop with interested parties to display and discuss the results of Step 1. In the workshop, TBL might also find that it has additional information that would be helpful to others. In order to ensure a complete picture of the Northwest grid, the potential reinforcement plans identified by other parties should be incorporated into the long-term view. This might be done through regional planning coordination forums such as the NWPP.

3. Ask interested parties to analyze the results of the workshop, and be prepared to enter into a detailed discussion of alternative cost-effective and reliable nonwires actions that they could take individually and collectively.

4. Conduct a second workshop wherein all regional stakeholders can discuss options within their jurisdiction that can help to alleviate problem areas identified in TBL's initial long-term view. An important part of this workshop will be a continuing discussion about the uncertainties of acquisition and reliability in operation of all proposed alternatives to wires and of their cost-effectiveness. These uncertainties are a consequence of factors such as fuel prices, load growth, federal and state regulation of the electricity industry, wholesale market structure, and market design. In order to stimulate ideas among stakeholders and provide for more productive workshops, industry professionals experienced with the economics and feasibility of wires and nonwires options should be invited to participate.

5. TBL will have a number of options available to it at this point, as follows:

   a. It may conclude that there are no economic and reliable options to wires, in which case planning for grid expansion continues through the short-term screening process proposed herein. As suggested in Figure 2, there is still opportunity at this stage to discover previously unrecognized alternatives, although they are fewer, due to the short time left to implement a solution.

   b. It may decide to issue RFPs for wires or nonwires solutions that can be implemented at lower cost by others.

   c. It may decide that locational and time sensitive pricing of transmission can defer construction of new transmission and propose them in its next rate case.

   d. It may want to discuss with and lobby its customer utilities and state regulators to implement retail-pricing options that will decrease the need for transmission expansion.

   e. It might consider a broad package of alternatives that includes all of the activities listed above as well as other ideas that surface during the planning process.

3.2. Project-Specific Screening.

We recommend taking two of the G-20 projects through the project-specific screening process described in Section 2 of this paper. Each of the projects would be put through all of the steps of the screening process in concert with TBL staff. Through this process, TBL will refine the screening process, and will determine if economic and reliable alternatives exist to delay transmission construction of either or both projects.

Because different issues arise with respect to transmission expansion driven by generation interconnection requests versus other reasons, we propose that TBL run two of the G-20 projects through the project-specific planning process (e.g., G-8 and G-12). G-8 is a project that crosses sensitive environmental areas, and the decision to construct it is far enough out to potentially benefit from a search for alternatives. That is, if alternatives exist, there is a possibility that they can be implemented in time to delay the October 2003 decision date to proceed with grid expansion. The primary drivers for G-8 is the Canadian Entitlement return and load service within the Puget Sound area.

Another good candidate is G-12. A brief example of how the marginal cost on a per kW-year basis would be calculated for G-12 is contained in Section 2.

3.3 Future Uncertainties

Finally, given all the uncertainties about the future of the electricity industry, we recommend that TBL develop, test, and deploy methods for dealing with these uncertainties in its planning and decision-making concerning new long-lived transmission projects. The focus should be both on the analytical process TBL might use to assess uncertainties and on presentation methods to aid interested stakeholders in understanding the implications of uncertainties related to load growth, fuel prices, new generation, demand management programs, industry restructuring, RTO formation, and government regulation.

Appendix 1: Sample Screen of Non-Traditional Alternatives

This Appendix shows how to derive the benefit/cost ratios of four nonwires alternatives to transmission projects: fuel switching, DG, DSM and interruptible/curtailable load programs. Please note that these examples are illustrative only and do not relate to any specific TBL projects.

Summary of Cost-Effectiveness

The alternatives for delaying the G12 transmission project are evaluated from each of the cost-effectiveness perspectives described in section 2.2.2. The measures evaluated include;

- Customer-owned distributed generation; generation that is not metered by BPA. This could be generation located at an end-users site, or within a local distribution utility. Assumed installed cost is $600/kW with a heat rate of 10,000 MMBtu/kWh and annual load factor of 10%.

- Merchant plant distributed generation; generation located on BPA's transmission that injects power and is subject to the TBL transmission tariff. Assumed installed cost is $600/kW with a heat rate of 10,000 MMBtu/kWh and annual load factor of 10%.

- Conservation DSM; based on a general mix of commercial energy conservation measures. The assumed cost is $3 million per average MW conserved (8760MWh per year).

- Fuel-switching DSM; based on switching from electric heating to natural gas heating for residential end-users. The assumed energy savings is 2500kWh per year, with a winter peak load reduction of 2kW.

- Curtailable Load; based on a three-year curtailable program. Each participant is assumed to be interrupted 30 hours per year with an incentive payment of $100/MWh.

Table 6, below, summarizes the benefit/cost ratio for each of these measures. The relationship of the benefit/cost ratios for each of the measures is typical. From the RIM perspective, any measures that significantly reduce sales such as DSM, fuel switching, or behind the meter generation are not cost-effective because of the lost sales component. The DG merchant plant and curtailable load program are cost effective from RIM because they do not result in significant revenue losses and the incentives are paid based on a percentage (approximately 50%) of the deferral value. For these two measures the RIM results are very similar to the utility cost test (UCT), since the only difference between the tests is the lost sales component. On the other hand, the customer DG bypass and fuel switching look much better from a UCT perspective than RIM.

The Total Resource Cost (TRC) test is the usual test of cost-effectiveness from a traditional least-cost planning perspective. If the TRC benefit/cost ratio is greater than one, incentive payments, public purpose charges, and other mechanisms can potentially be designed to make all other perspectives cost-effective. Fuel switching, and curtailable programs are the only cost-effective measures from the TRC perspective. The societal cost test is an extension of the TRC, which includes additional non-cash benefits. Similar to the TRC, if public purpose charges are levied on the same group that accrue the non-tangible benefits, all perspectives can be made cost-effective if the societal cost test benefit/cost ratio is greater than one.

The participant cost test is critical because it indicates whether a measure is likely to be acceptable to the participants. If the benefit/cost ratio is lower than one, participants are worse off after having implemented the measure and therefore they are unlikely to adopt it. The fuel switching, conservation, and curtailable programs are cost-effective to the participant given the input assumptions of costs and incentive levels made to develop this example.

Table 6: Summary of Cost-Effectiveness

Benefit Cost Ratios	DG Customer Bypass (includes revenue loss)	DG Merchant Plant (no revenue loss)	Residential Switch to Natural Gas Heating	Generic Conservation Measure (Office Lighting, Shell Retrofit, etc.)	1kW of Curtailable Load (Demand Exchange Program)
RIM Test Transmission Company	1.31	2.05	0.45	0.02	5.17
Utility Cost Test Transmission Company	2.05	2.05	1.85	0.02	5.17
TRC Cost Test	0.42	0.42	1.22	0.25	7.25
Societal Cost Test	0.42	0.42	1.35	0.30	7.28
Participant Cost Test	0.52	0.03	1.19	1.06	1.16

Of the five measures evaluated, only the curtailable load program is cost-effective from every perspective. The measure is clearly 'cost-effective' from the broadest definition. Other programs are less clear. For example, the fuel switching to natural gas heating is cost-effective from all but the RIM test. Under traditional least cost planning, this measure might be pursued with the loss in revenue made up with a public benefits charge assessed to all customers.

The examples for all four alternatives use the same set of basic assumptions. These assumptions are outlined in Table 7 below. The transmission lifecycle avoided costs are from row 14 of Table 5, above.

Table 7: General Assumptions

Input Variable	Value
Utility Discount Rate	9.00%
Financing Rate of Generator (DG)	12%
	Annual Value ($/yr)
Generation Capacity $/kW-yr	0
Local Distribution Company $/kW-yr	20
Energy (Mid-C) $/MWh	30
Environmental Adder $/MWh	6
Total Average Rate $/kWh	$0.0800
Transmission Average Rate $/kW-month	$2.5600

Transmission Lifecycle Avoided Cost$/kW				
Measure Life (Years)	3	5	10	15
Transmission Lifecycle Avoided Cost $/kW	$68.62	$68.62	$71.59	$74.12

The following four tables present the detailed calculations of the five cost tests for various non-traditional alternative scenarios. The first half of each table contains the inputs and intermediate calculations that are used in the calculation of the cost tests in the second half of the table. Input variables not included in Table 7 are highlighted, and calculated values are left clear. Where necessary, the derivation of the inputs is explained in parentheses, with items referenced by row numbers.

Table 8: Cost Tests of Distributed Generation

		DG Customer Bypass (includes revenue loss)	DG Merchant Plant (no revenue loss)
1	DG Device	Gas Turbine Peaker	Gas Turbine Peaker
2	Utility Incentive Cost $/kW	$30.00	$30.00
3	Generator Life (Years)	10	10
	Generator Cost Assumptions		
4	Fuel Cost $/MMBtu	$5.00	$5.00
5	Heat Rate Btu/kWh	10,000	10,000
6	Fuel Cost $/kWh ($/MMBtu [4] * Heat Rate [5] / 10^6)	$0.05	$0.05
7	Capital Cost $/kW	$500.00	$500.00
8	Install Cost $/kW	$100.00	$100.00
9	Fixed O&M $/kW-yr	$10.00	$10.00
10	Variable O&M $/kWh	$0.005	$0.005
11	Annual Fuel and O&M Costs $/kW ({fuel cost [6] + var. O&M [10]} * annual load factor [14] * 8760 hrs in a yr + fixed O&M [9])	$58.18	$58.18
12	Environmental Externality Benefit? 1= yes, 2=no	0	0
	Generator Operating Assumptions		
13	Peak Period kW Savings	1.00	1.00
14	Annual Load Factor	10%	10%
15	Monthly Peak Demand Reduction (kW) (for billing determinants)	1.00	1.00
	Lifecycle Generator Costs		
16	Lifecycle Capital Cost ($/kW) (cap. cost [7] + install cost [8])	$600.00	$600.00
17	Lifecycle Fuel and O&M Cost ($/kW) (Discounted at Generator WACC)	$328.73	$328.73
18	Total Lifecycle Cost ($/kW)	$928.73	$928.73
	Per Unit Lifecycle Avoided Costs		
19	Generation Capacity $/kW	$0.00	$0.00
20	Transmission $/kW (total 10-year trans. marginal cost discounted at utility discount rate)	$71.59	$71.59
21	Local Distribution Company $/kW (local distr. marginal cost accruing over 10 years, discounted at utility discount rate)	$139.90	$139.90
22	Energy $/kWh ($MWh marg. cost accruing over 10 yrs discounted at utility disc. rate / 1000)	$0.21	$0.21
23	Energy + Environmental Adder (If Clean Generation) $/kWh (energy per unit cost [22] + {$MWh env. adder cost accruing over 10 yrs discounted at utility disc. rate} / 1000)	$0.21	$0.21
	Rates and Lost Revenue		
24	Total Average Rate $/kWh	$0.0800	$0.0000
25	Transmission Average Rate $/kW-year	$2.5600	$0.0000
26	Total Electricity Revenue Loss $/year (total avg rate [24] * annual load factor [14] * 8760 hrs in a yr)	$70.08	$0.00
27	Transmission Revenue Loss $/year (trans. avg. rate [25] * monthly peak demand reduction [15] * annual load factor [14] * 12 months)	$3.07	$0.00

	Lifecycle Avoided Costs per kW, Revenue per kW, Incentive per kW		
28	Generation Avoided Cost (gen. capacity per unit cost [19] * peak period kW savings [13])	$0.00	$0.00
29	Transmission Avoided Cost (trans. per unit cost [20] * peak period kW savings [13])	$71.59	$71.59
30	Local Distribution Company (local distr. per unit cost [21] * peak period kW savings [13])	$139.90	$139.90
31	Energy (energy per unit cost [22] * annual load factor [14] * 8760 hrs in a yr)	$183.84	$183.84
32	Energy w/ Environment (energy & env. adder per unit cost [23] * annual load factor [14] * 8760 hrs in a yr)	$183.84	$183.84
33	Total Electricity Revenue Loss (total annual loss [26] accruing over 10 years, discounted at utility discount rate)	$449.75	$0.00
34	Transmission Revenue Loss (total annual loss [27] accruing over 10 years, discounted at utility discount rate)	$19.72	$0.00
35	Lifecycle Incentive Payment	$30.00	$30.00
36	Lifecycle Admin Cost	$5.00	$5.00

		DG Customer Bypass (includes revenue loss)	**DG Merchant Plant (no revenue loss)**
	RIM Test - Transmission Delivery Company		
37	Program Cost (Incentive+T Rev. Loss+Admin)	$54.72	$35.00
38	Program Benefit (T Savings)	$71.59	$71.59
39	Net Savings	$16.87	$36.59
40	BC Ratio	1.31	2.05
	Utility Cost Test - Transmission Delivery Company		
41	Program Cost (Incentive + Admin)	$35.00	$35.00
42	Program Benefit (T Savings)	$71.59	$71.59
43	Net Savings	$36.59	$36.59
44	BC Ratio	2.05	2.05
	TRC Cost Test		
45	Program Cost (DG Cost+ Admin)	$933.73	$933.73
46	Program Benefit (Gen Savings + T Savings + D Savings)	$395.33	$395.33
47	Net Savings	($538.40)	($538.40)
48	BC Ratio	0.42	0.42
	Societal Cost Test		
49	Program Cost (DG Cost + Admin)	$933.73	$933.73
50	Program Benefit (Gen Savings + T Savings + D Savings + Environment)	$395.33	$395.33
51	Net Savings	($538.40)	($538.40)
52	BC Ratio	0.42	0.42
	Participant Cost Test		
53	Program Cost (DG Costs)	$928.73	$928.73
54	Program Benefit (Incentive + Electricity Bill Reduction)	$479.75	$30.00
55	Net Savings	($448.98)	($898.73)
56	BC Ratio	0.52	0.03

Table 9: Cost Tests of Fuel Switching

		Residential Switch to Natural Gas Heating
1	Cost of Original Device	$300.00
2	Replacement Device	$500.00
3	Utility Incentive Cost $/measure	$30.00
4	Measure Life (Years)	15
	Annual Demand and Energy Impacts	
5	Peak Period kW Savings	2.00
6	Annual kWh/measure	2500.00
7	Monthly Peak Demand Reduction (kW) (for billing determinants)	1.00
	Lifecycle Avoided Costs per kW or kWh	
8	Generation Capacity $/kW	$0.00
9	Transmission $/kW (total 15-year trans. marginal cost discounted at utility discount rate)	$74.12
10	Local Distribution Company $/kW (local distr. marginal cost accruing over 15 years, discounted at utility discount rate)	$175.72
11	Energy $/kWh ($MWh marg. cost accruing over 15 yrs discounted at utility disc. rate / 1000)	$0.26
12	Energy + Environmental Adder $/kWh (energy per unit cost [11] + {$MWh env. adder cost accruing over 15 yrs discounted at utility disc. rate} / 1000)	$0.32
	Rates, Administration Costs, and Lost Revenue	
13	Total Average Rate $/kWh	$0.0800
14	Transmission Average Rate $/kW-year	$2.5600
15	Alternative Fuel Rate ($/Replaced kWh)	$0.0500
16	Alternative Fuel Cost ($/Replaced kWh)	$0.0200
17	Alternative Fuel Bill ($/measure per year) (alt. fuel rate [15] * annual kWh/measure [6])	$125.00
18	Alternative Fuel Cost ($/measure per year) (alt. fuel cost [16] * annual kWh/measure [6])	$50.00
19	Admin Cost $/measure one time cost	$50.00
20	Total Electricity Revenue Loss $/year (total avg rate [13] * annual kWh/measure [6])	$200.00
21	Transmission Revenue Loss $/year (trans avg rate [14] * monthly peak demand reduction [7] * 12 months)	$30.72
	Lifecycle Avoided Costs, Revenue, Incentive per measure	
22	Generation Avoided Cost (gen. capacity per unit cost [8] * peak period kW savings [5])	$0.00
23	Transmission Avoided Cost (trans. per unit cost [9] * peak period kW savings [5])	$148.24
24	Local Distribution Company (local distr. per unit cost [10] * peak period kW savings [5])	$351.45
25	Energy (energy per unit cost [11] * annual kWh/measure [6])	$658.96
26	Energy w/ Environment (energy & env. adder per unit cost [12] * annual kWh/measure [6])	$790.75
27	Alternative Fuel Bill $/measure	$1,007.59
28	Alternative Fuel Cost $/measure	$403.03
29	Total Electricity Revenue Loss	$1,612.14
30	Transmission Revenue Loss	$247.62
31	Lifecycle Incentive Payment	$30.00
32	Lifecycle Admin Cost	$50.00

		Residential Switch to Natural Gas Heating
	RIM Test - Delivery and Alternative fuel Company	
33	Program Cost (Incentive+Trans. Rev. Loss+ Admin)	$327.62
34	Program Benefit (Trans Savings)	$148.24
35	Net Savings (Max. Incentive)	($179.38)
36	BC Ratio	0.45
	Utility Cost Test - Delivery	
37	Program Cost (Incentive + Admin)	$80.00
38	Program Benefit (Trans Savings)	$148.24
39	Net Savings (Max. Incentive)	$68.24
40	BC Ratio	1.85
	TRC Cost Test	
41	Program Cost (Measure Cost + Alternative Fuel Cost + Admin)	$953.03
42	Program Benefit (Gen Savings + T Savings + D Savings)	$1,158.65
43	Net Savings (Max. Incentive)	$205.61
44	BC Ratio	1.22
	Societal Cost Test	
45	Program Cost (Measure Cost + Alternative Fuel Cost + Admin)	$953.03
46	Program Benefit (Electric Gen Savings + Trans Savings + Environment)	$1,290.44
47	Net Savings (Max. Incentive)	$337.41
48	BC Ratio	1.35
	Participant Cost Test	
49	Program Cost (Buy Device + Alternative Fuel Bill)	$1,507.59
50	Program Benefit (Incentive + Electricity Bill Reduction+ Replace Conv. Device)	$1,792.14
51	Net Savings (Max. Incentive)	$284.55
52	BC Ratio	1.19

Table 10: Cost Tests of DSM

		Generic Conservation Measure (Office Lighting, Shell Retrofit, etc.)
1	Cost of Original Device	$2,000,000.00
2	Replacement Device	$8,000,000.00
3	Utility Incentive Cost $/measure	$3,000,000.00
4	Measure Life (Years)	10
	Annual Demand and Energy Impacts	
5	Peak Period kW Savings (for T&D capacity savings)	1,000
6	Annual kWh/measure	8,760,000
7	Monthly Peak Demand Reduction (kW) (for billing determinants)	1,000
	Lifecycle Avoided Costs per kW or kWh	
8	Generation Capacity $/kW	$0.00
9	Transmission $/kW (total 10-yr marginal cost discounted at utility discount rate)	$71.59
10	Local Distribution Company $/kW (local distr. marginal cost accruing over 10 years, discounted at utility discount rate)	$139.90
11	Energy $/kWh ($MWh marg. cost accruing over 10 yrs discounted at utility disc. rate / 1000)	$0.21
12	Energy + Environmental Adder $/kWh (energy per unit cost [11] + {$MWh env. adder cost accruing over 10 yrs discounted at utility disc. rate} / 1000)	$0.25
	Rates, Administration Costs, and Lost Revenue	
13	Total Average Rate $/kWh	$0.0800
14	Transmission Average Rate $/kW-year	$2.5600
15	Admin Cost $/measure one time cost	$50,000.00
16	Total Electricity Revenue Loss $/year (total avg rate [13] * annual kWh/measure [6])	$700,800.00
17	Transmission Revenue Loss $/year (trans avg rate [14] * monthly peak demand reduction [7] * 12 months)	$30,720.00
	Lifecycle Avoided Costs, Revenue, Incentive per measure	
18	Generation Avoided Cost (gen. capacity per unit cost [8] * peak period kW savings [5])	$0.00
19	Transmission Avoided Cost (trans. per unit cost [9] * peak period kW savings [5])	$71,590.00
20	Local Distribution Company (local distr. per unit cost [10] * peak period kW savings [5])	$139,904.94
21	Energy (energy per unit cost [11] * annual kWh/measure [6])	$1,838,350.88
22	Energy w/ Environment (energy & env. adder per unit cost [12] * annual kWh/measure [6])	$2,206,021.06
23	Total Electricity Revenue Loss	$4,497,494.52
24	Transmission Revenue Loss	$197,150.44
25	Lifecycle Incentive Payment	$3,000,000.00
26	Lifecycle Admin Cost	$50,000.00

		Generic Conservation Measure (Office Lighting, Shell Retrofit, etc.)
	RIM Test - Delivery Company	
27	Program Cost (Incentive+Trans. Rev. Loss+ Admin)	$3,247,150.44
28	Program Benefit (Trans Savings)	$71,590.00
29	Net Savings (Max. Incentive)	($3,175,560.44)
30	BC Ratio	0.02
	Utility Cost Test - Delivery	
31	Program Cost (Incentive + Admin)	$3,050,000.00
32	Program Benefit (Trans Savings)	$71,590.00
33	Net Savings (Max. Incentive)	($2,978,410.00)
34	BC Ratio	0.02
	TRC Cost Test	
35	Program Cost (Measure Cost + Admin)	$8,050,000.00
36	Program Benefit (Gen Savings + T Savings + D Savings)	$2,049,845.82
37	Net Savings (Max. Incentive)	($6,000,154.18)
38	BC Ratio	0.25
	Societal Cost Test	
39	Program Cost (Measure Cost + Admin)	$8,050,000.00
40	Program Benefit (Electric Gen Savings + Trans Savings + Environment)	$2,417,516.00
41	Net Savings (Max. Incentive)	($5,632,484.00)
42	BC Ratio	0.30
	Participant Cost Test	
43	Program Cost (Buy Device)	$8,000,000.00
44	Program Benefit (Incentive + Electricity Bill Reduction+ Replace Conv. Device)	$8,497,494.52
45	Net Savings (Max. Incentive)	$497,494.52
46	BC Ratio	1.06

Table 11: Cost Tests of I/C Programs

		1kW of Curtailable Load (Demand Exchange Program)
1	Customer Cost of Dropped Load ($/kWh) (Lost Productivity)	$0.15
2	Customer Cost of Dropped Load ($/kW lifecycle) ([1] accruing over 3 yrs)	$12.42
3	Utility Incentive Cost $/MWh	$100.00
4	Utility Incentive Cost $/kW lifecycle ([3] accruing over 3 yrs, discounted at utility discount rate)	$8.28
5	Measure Life (Years)	3
	Annual Demand and Energy Impacts	
6	Peak Period kW Savings (for T&D capacity savings)	1.00
7	Annual kWh/measure (Number of hours per year)	30
8	Monthly Peak Demand Reduction (kW) (for billing determinants)	0.00
9	Months in Peak Load Season for Curtailment	4
	Lifecycle Avoided Costs per kW or kWh	
10	Generation Capacity $/kW	$0.00
11	Transmission $/kW (total 3-year marginal cost discounted at utility discount rate)	$68.62
12	Local Distribution Company $/kW (local distr. marginal cost accruing over 3 years, discounted at utility discount rate)	$55.18
13	Energy $/kWh ($MWh wholesale energy cost accruing over 3 yrs discounted at utility disc. rate / 1000)	$0.08
14	Energy + Environmental Adder $/kWh (energy per unit cost [13] + {$MWh env. adder cost accruing over 3 yrs discounted at utility disc. rate} / 1000)	$0.10
	Rates, Administration Costs, and Lost Revenue	
15	Total Average Rate $/kWh	$0.0800
16	Transmission Average Rate $/kW-month	$2.5600
17	Admin Cost $/measure one time cost	$5.00
18	Total Electricity Revenue Loss $/year (total avg rate [15] * annual kWh/measure [7])	$2.40
19	Transmission Revenue Loss $/year (trans avg rate [16] * monthly peak demand reduction [8] * months in peak load season [9])	$0.00
	Lifecycle Avoided Costs, Revenue, Incentive per measure	
20	Generation Avoided Cost (gen. capacity per unit cost [10] * peak period kW savings [6])	$0.00
21	Transmission Avoided Cost (trans. per unit cost [11] * peak period kW savings [6])	$68.62
22	Local Distribution Company (local distr. per unit cost [12] * peak period kW savings [6])	$55.18
23	Energy (energy per unit cost [13] * annual kWh/measure [7])	$2.48
24	Energy w/ Environment (energy & env. adder per unit cost [14] * annual kWh/measure [7])	$2.98
25	Total Electricity Revenue Loss	$6.08
26	Transmission Revenue Loss	$0.00
27	Lifecycle Incentive Payment	$8.28
28	Lifecycle Admin Cost	$5.00

		1kW of Curtailable Load (Demand Exchange Program)
	RIM Test - BPA TBL	
29	Program Cost (Incentive+Trans. Rev. Loss+ Admin)	$13.28
30	Program Benefit (Trans Savings)	$68.62
31	Net Savings (Max. Incentive)	$55.34
32	BC Ratio	5.17
	Utility Cost Test - BPA TBL	
33	Program Cost (Incentive + Admin)	$13.28
34	Program Benefit (Trans Savings)	$68.62
35	Net Savings (Max. Incentive)	$55.34
36	BC Ratio	5.17
	TRC Cost Test	
37	Program Cost (Cost of Dropped Load+ Admin)	$17.42
38	Program Benefit (Gen Savings + T Savings + D Savings)	$126.29
39	Net Savings (Max. Incentive)	$108.87
40	BC Ratio	7.25
	Societal Cost Test	
41	Program Cost (Cost of Dropped Load + Admin)	$17.42
42	Program Benefit (Gen Savings + Trans Savings + Environment)	$126.78
43	Net Savings (Max. Incentive)	$109.37
44	BC Ratio	7.28
	Participant Cost Test	
45	Program Cost (Cost of Dropped Load)	$12.42
46	Program Benefit (Incentive + Electricity Bill Reduction)	$14.35
47	Net Savings (Max. Incentive)	$1.94
48	BC Ratio	1.16