TRANSMISSION BENEFITS EVALUATION

INTRODUCTION

In response to Commission feedback to PacifiCorp's 2011 Integrated Resource Plan ("IRP"), the Company committed to a revised action plan, which included the following action item for transmission:

> *"In the scenario definition phase of the IRP process, the Company will address with stakeholders the inclusion of any transmission projects on a case-by-case basis.*
>
> > *Develop an evaluation process and criteria for evaluating transmission additions.*
> >
> > *Review with stakeholders which transmission projects should be included and why.*
> >
> > *Based on the outcome of these steps, PacifiCorp will provide appropriate transmission segment analysis for which the Company requests acknowledgement."*

PacifiCorp has since worked diligently to develop a new transmission System Operational and Reliability Benefits Tool ("SBT") for the purpose of identifying and quantifying transmission benefits that are not captured using traditional IRP analysis tools. Traditional means of least cost transmission planning and net power cost modeling help identify the IRP scenario with the lowest present value revenue requirement but have historically failed to capture the full range of benefits associated with additional transmission capabilities. The SBT identifies, measures and monetizes benefits that are incremental to those identified via models used in the IRP process.

In response to the directives of Federal Energy Regulatory Commission ("FERC") Order No. 1000, and to feedback from state regulators and stakeholders, the Company is working to improve its ability to quantify these additional transmission benefits. However, as any regulator, stakeholder or utility involved in transmission planning can confirm, transmission benefit evaluation is no simple task. There is no "off the shelf" transmission benefit calculator for the Company to turn to. Development of the SBT is a long-term objective that requires stakeholder input. Ultimately, this tool, in addition to traditional IPR modeling and analysis, will be used to provide a complete picture of the costs and benefits of additional transmission capability that can be applied to each IRP scenario and will help inform optimal system planning and investment decisions.

In the near term, these quantified benefits will help justify continued progress on transmission segments for which PacifiCorp is seeking regulatory acknowledgement. While some stakeholders have expressed concern that the Company's Energy Gateway projects are "predetermined" in the IRP and that the SBT is being used to justify them after-the-fact, it is important to note two things:

(1) Energy Gateway is in fact the result of several robust local and regional transmission planning efforts that are ongoing and have been conducted multiple times over several

years. Given the long periods of time (seven to 10 years) necessary to successfully site, permit and construct major new transmission lines, these projects need to be planned and sited based on long-term customer needs, or projects like Energy Gateway will not be placed in-service in time to be viable transmission resource options for meeting customer need. Please see the supplemental white paper on Transmission Planning and Investment for important background information on the planning and design of Energy Gateway, and the short-term improvements that have helped maximize efficient use of the Company's existing system and defer the need for larger scale infrastructure investment.

(2) The SBT is a nascent tool being developed in response to recent regulatory directives, so historically it did not play a role in the planning of Energy Gateway; however, its purpose is to identify, today, transmission benefits that would otherwise go unmeasured. Applying the SBT to these projects is a prudent course to validate the full range of benefits for customers over the life of the assets.

The purpose of this white paper is to describe the methodology of the SBT approach, which will be reviewed in greater detail during planned stakeholder meetings on this topic as PacifiCorp's 2013 IRP is developed.

TRANSMISSION SYSTEM BENEFITS TOOL

BACKGROUND

Regulators and stakeholders have voiced a need for a more robust analysis of transmission benefits. The traditional IRP System Optimizer and Planning & Risk models identify the IRP scenario with the lowest present value revenue requirement from an energy delivery view, but these models fail to capture a broader range of "day to day" operational and reliability benefits provided by transmission. A new approach is required to identify and quantify the benefits not captured by these traditional tools, and to better inform the Company's transmission planning process in the context of integrated resource planning.

While there is no "off the shelf" transmission benefit calculator to turn to, there are various approaches used by other transmission planning entities that are informative. PacifiCorp, both independently and as part of the Northern Tier Transmission Group's FERC Order 1000 compliance effort, looked to other regional transmission planning groups to understand how various metrics are used to evaluate transmission project benefits, impacts to their existing transmission system and customer benefits. These groups include the Southwest Power Pool, California Independent System Operator ("ISO"), Midwest ISO, New York ISO, ISO New England, PJM Interconnection, and Georgia Power. By no means have these groups perfected the measurement of transmission benefits, nor is there a "one size fits all" approach for assessing these benefits, but their efforts are several years in the making and, through their own stakeholder processes, they have developed and vetted several common metrics that are also considered as part of PacifiCorp's efforts to determine transmission project benefits.

Informed by these approaches, PacifiCorp is developing the SBT to help quantify the operational and reliability benefits directly associated with new transmission projects and their integration into the existing transmission system. The metrics that comprise the SBT will continue to improve and develop over time, with stakeholder input and through utility industry experience.

Provided below is a high-level description of the current SBT metrics the Company is working with initially, each of which will be discussed in detail during the November 5, 2012 IRP stakeholder workshop.

THE SBT SUMMARY SHEET

SYSTEM OPERATIONAL AND RELIABILITY BENEFITS TOOL

PROJECT TITLE

PROJECT SEGMENT IF APPLICABLE

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
	Segement(s)	Segement(s)	Segement(s)	Segement(s)
Benefit Category				
Sub Category	**Millions $**			
Operational Cost Savings				
Savings				
Sub Total				
Wheeling Revenue Opportunity				
ATC Firm				
ATC Non Firm				
Path Transfer Capabilty (MW)				
Path Transfer Capability (MW)				
Sub Total				
Segment Loss Savings Benefits				
Energy				
Capacity				
Sub Total				
Segment Reliability Benefits				
N-1				
N-1-1				
Load loss				
System Disturbance & Islanding				
Sub Total				
Customer & Regulatory Benefits				
Disturbance Cost for Regulatory Inquiry/Compliance				
Customer Costs Derived from Industry Data				
Sub Total				
Avoided Capital				
Sub Total				
Improved Generation Dispatch				
Generating Resources behind constraint (MW)				
Capacity Contribution				
Contingency Reserves				
Sub Total				
Total Scenario Benefits (minus Wheeling Revenue)				
Total Scenario Benefits (minus Wheeling Revenue & minus Net Power Costs)				
Capital Cost By Segment (Total $M)				
Benefit to Cost (Present Value Total Benefits minus Wheeling)/Segment Capex 2012)				
Capital Cost Paid by Other Network Customers (%)				
Benefit to Cost (Present Value Total Benefits minus Wheeling/Net Network Contribution)				

Please note that each transmission project has its own unique set of objectives and benefits, and therefore may require a unique set of metrics for evaluation. A larger, more complex project may involve more metrics—or derive higher values from the same metrics—than a smaller, less complex project.

OPERATIONAL COST SAVINGS

A system production cost modeling program may be used to determine the detailed operational benefits gained by the addition of new transmission, or sub-segments of a proposed transmission project. These benefits are derived using a production cost model's detailed system topology and assumptions, and comparing the results of a base case with change cases to determine line segment benefits.

It is important to note that net power cost savings will only be included as part of the SBT analysis to the extent they are proven to be incremental and not already captured in the production cost benefits identified through the IRP modeling process. The purpose of the SBT is to identify and measure transmission benefits NOT captured via the IRP modeling—*i.e., no duplication of benefits*.

An output of this modeling is generation dispatch, which captures the ability of the transmission system to deliver current and planned resources to customer load. In constrained transmission areas, the Company may be unable to utilize the most economic resource options to meet customer needs. New transmission infrastructure can work to alleviate these conditions and improve generation dispatch.

In addition to production cost modeling, operational cost savings may be derived as a result of avoiding the addition of a new generation resource or by avoiding wheeling and purchase of firm energy in order to comply with NERC mandatory transmission system standards and performance criteria.

SEGMENT LOSS SAVINGS

Energy

One benefit gained from the addition of a new and discrete transmission project is a reduction in transmission line energy losses. The addition of a new transmission line (or segment of a line) operated in parallel with an existing line(s) reduces the electrical impedance of the transmission system, resulting in lower energy line losses (megawatt-hours) over the life of the project. Depending on the amount of power flow, line loss savings can be substantial. These individual transmission line or line-segment losses are a separate analysis and quantified differently from traditional "system loss studies" conducted for the Company to determine system loss factors.

Losses for any transmission line are determined according to the formula I^2R (where I is the current flow and R is resistance). To calculate current (I), megavolt amperes are divided by ($\sqrt{3}$ x voltage). Since the predominant flow on the Company's transmission lines is real power (megawatts), the difference when calculating current is small between megawatts (MW) and megavolt amperes (MVA). Hence, megawatt flow can be used rather than megavolt amperes as a close approximation. Factors such as line length and conductor type, material and size determine transmission line change in system impedance. The electrical impedance of parallel lines is determined by calculating an equivalent resistance ($R_{equivalent}$) before and after a transmission project is placed in service.

In the SBT analysis, the Company's assessment of energy line losses is based on actual power flow (megawatts) as a proxy for a typical year, with line flow increasing in future years as determined by network customers' load forecast submittals. Line losses are compared before and after the addition of a new line(s) and are calculated between the connection points, with the difference being the loss savings attributed to the new line(s). The Company used a forward energy price curve to monetize the value of line loss energy savings as an avoided market purchase of energy and the present value[1] of the annual savings was then calculated. While the forward price curve used for the Sigurd-Red Butte Certificate of Public Convenience and Necessity valuation is confidential, going forward, efforts will be made to use a publicly available forward price curve that can be verified by all stakeholders. The SBT can easily accommodate a different price curve in the future, as deemed appropriate to the analysis.

<u>Capacity</u>
There is also a capacity component associated with line loss savings. Lower line segment losses reduce the overall system demand and the amount of generation capacity needed to meet that demand, thereby reducing the need for new incremental generation. To determine generation capacity related savings due to reduced line segment losses, the SBT calculated average demand savings (megawatts) for a segment using each hour in the five highest system power flow days in a year. To monetize these savings, the base capital cost of a combined cycle gas generating plant ($1,067 per installed megawatt)[2] is multiplied by the capacity value (megawatts) of the line loss savings. This is a one-time savings and therefore a present value calculation is not applicable.

<u>SEGMENT RELIABILITY BENEFITS</u>

The SBT calculates system reliability benefits gained by adding new transmission segment(s) between points in the existing system. These benefits are derived using Company historical transmission line outage data, for both scheduled and unscheduled line outages, and then determining the improved system performance with the new segment(s) in service. The addition of new transmission lines results in new incremental transmission capacity, but also results in improved performance of the existing system. This metric quantifies the performance benefits to the existing system due to the addition of a new line or segment of a line. The benefits are derived from three reliability measures:

1) Avoidance of transmission system capacity reductions, or "derates" (MW)

2) Reductions in forced generator outages caused by transmission outages or limitations (MW)

[1] All present value calculations for Sigurd-Red Butte line losses are based on a 20-year time horizon starting in 2015, using a 6.88% discount rate, which was PacifiCorp's weighted average cost of capital on the day the analysis was undertaken.

[2] Cost from PacifiCorp's 2011 Integrated Resource Plan

3) Reduced exposure to loss of customer firm load (MW), based on calculation of avoided loss of retail revenue from customers during system outages.

These benefit measures are derived from the resulting system performance during outages of a single transmission line (N-1) or multiple transmission lines (N-1-1). The system performance criteria used by the Company is specified in the mandatory NERC and WECC basic Transmission System Planning Standards and Performance Criteria. The addition of new transmission segment(s) in areas identified as being at risk can alleviate these issues by improving the overall performance of the system.

Capacity Reduction

In calculating the first measure (avoiding reduced transmission capacity, or "derates"), the new system capacity rating is determined with the new segment(s) placed into service and then each existing interconnected transmission line is removed from service, one at a time, and the resulting system capacity increase associated with the new segment is determined. This new system capacity is compared to the system's capacity with the same lines out of service but without the new segment in-service. The difference between capacities (megawatts) is the "derate" benefit.

Similarly, for calculating the second measure, reductions in forced generator outages (MW), the same segment methodology is performed as stated above, but this time the analysis looks at impacts to generation resources in the impacted system. During this analysis the amount of generation (MW) that is reduced due to transmission system capacity limitations is determined with and without the new segment(s) in service.

Next, the impacts from transmission capacity reductions and the reductions in forced generator outages are compared. To avoid double counting, only the highest megawatt value between the two impacts is selected for valuation. This megawatt value is then priced using historical line outage data and a weighted average yearly price comprised of light-load and heavy-load hours using a suitable forward price curve. The present value is then determined. For calculation of multiple line outages, it is assumed that it takes a fixed amount of time—based on historical information—to restore affected generation. Since it is impossible to determine the exact time of day when an outage will occur, the megawatt value for multiple line outages is priced using the weighted heavy-load and light-load hour average of the entire forward price curve. This value is then multiplied by the probability of the outage and the present value is then determined.

The third measure, reduced exposure to loss of customer load, is calculated where appropriate. The system is evaluated with the new segment in service and compared against the existing system. If the configuration with the new segment enables load service that would otherwise be lost during outage conditions, this difference is the reduction in risk to customer load loss. Load is assumed to be lost for two hours for each outage occurrence; for multiple outages, the probability of such an occurrence is utilized. The value is developed by multiplying the loss in customer demand by the probability of the outage condition by the Company's average Retail Energy Rate (dollars per kWh) for the state where the new transmission segment is placed in service. Based on this, the present value is determined.

CUSTOMER AND REGULATORY BENEFITS

As growing demand depletes excess transmission capacity, the likelihood of impacting large industrial or commercial customers increases due to a need to curtail load to maintain a safe and reliable operating system under certain, abnormal conditions. Such circumstances can result in lost retail sales of energy, lost sales for retail customers, equipment damage, lost product due to spoilage, and potentially a negative economic development value for areas impacted by poor transmission system reliability. The risk of such circumstances can be significantly reduced with new transmission capacity that supports customer load growth across the operating system. The Company has not yet completed a recommendation on how to value the cost to customers associated with an outage, but is currently investigating how this metric is used in other regions and how it may be applied as part of the SBT evaluation approach.

AVOIDED CAPITAL COST

This metric considers capital investment that may be avoided by a transmission alternative, where the addition of a new transmission project resolves underlying issues identified by planning studies. In this case, the transmission project avoids underlying upgrades for load service or reliability needs and the avoided cost of those projects are included as benefits. The avoided cost of replaced or deferred investments is a commonly used metric in transmission benefit analysis. The SBT factors in the one-time capital investment avoided costs, as applicable, for projects displaced by new transmission.

IMPROVED GENERATION DISPATCH

Without adequate transmission capacity, the system may not be able to fully utilize generation resources in constrained areas. As a result of this congestion, the Company may be unable to dispatch the most economic resources to meet customer needs, increasing costs to customers. New transmission infrastructure can alleviate these conditions and improve overall generation dispatch to meet system reliability requirements. Additionally, the same generation resources which are constrained by transmission limitations can also provide capacity benefits that may be used for system contingency reserves through the addition of transmission capability. The SBT calculates the value of thermal generation that may be online but not at full output and could otherwise be dispatched up to full nameplate capacity for operating reserve purposes when new segment(s) reduce or eliminate transmission congestion. The benefits associated with increased access to existing, dispatchable generation for reserves purposes is calculated as the difference between the minimum unit operating limit and the amount of increased transmission capacity provided by the new segment(s) up to the maximum output of each unit. The benefit value of this generation is based on the reduced need for incremental new generation at the cost of acquiring generation or market purchases, whichever is lower.

WHEELING REVENUE OPPORTUNITY

Transmission services sold to system users can provide a wheeling revenue opportunity derived from selling new incremental transmission capacity. The SBT reviews new incremental transmission capacity for each segment or sub-segment analyzed and identifies the value of this new capacity. The present value of each of the segment's or sub-segment's wheeling revenue, is based on PacifiCorp's currently filed long-term point-to-point wheeling charge (Schedules 7, 1 and 2[3]) of $26,535 per megawatt-year and the new transfer capability (megawatts) is used to determine the benefit. Incremental system capacity for each segment or sub-segment is determined by comparing the initial path transfer capability with the improved path capacity after adding the new segment(s). This present value wheeling revenue opportunity is mutually exclusive from the other benefits shown above.

COST BENEFIT ANALYSIS

The SBT benefit metrics attempt to quantify the transmission benefits that would otherwise not be captured within the existing IRP analysis process. As existing "off-the-shelf" analytical tools are not available, it is important to work with stakeholders to develop a tool that better evaluates and captures the benefits related to transmission projects. This is a work in progress and will continue to evolve as refinements are made and valuable input from stakeholders is received.

[3] At a minimum, these rate schedules would be applicable to purchasers of long-term point-to-point transmission service.