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March 8, 2016

BC HYDRO
2015 RATE DESIGN **EXHIBIT A2-4**

Mr. Tom Loski
Chief Regulatory Officer
Regulatory & Rates Group
British Columbia Hydro and Power Authority
16th Floor – 333 Dunsmuir Street
Vancouver, BC V6B 5R3

Dear Mr. Loski:

Re: British Columbia Hydro and Power Authority
Project No. 3698781/Order G-156-15
2015 Rate Design Application Module 1

Commission staff submit the following document for the record in this proceeding:

The Mendota Group, LLC
Benchmarking Transmission and Distribution Costs
Avoided by Energy Efficiency Investments
for Public Service Company of Colorado
October 23, 2014

Yours truly,

Laurel Ross

/nd

Enclosure
cc: registered interveners

THE MENDOTA GROUP, LLC
the power of bright ideas

Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments

for Public Service Company of Colorado

October 23, 2014

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Executive Summary

Energy efficiency (EE) program cost-effectiveness evaluations assess the value (benefits) of these programs to a utility's system and aim to determine whether benefits exceed costs. The value of the generation and delivery system investments *avoided* or *deferred* by EE are components of the estimates of such benefits. Although estimates of avoided investments in and operation of generating units are fairly straightforward and tend to focus on a limited number of types of such units estimates of avoided investments in and operation of transmission and distribution (T&D) system components tend to be less straightforward. The following analysis examines ways in which utilities in the United States estimate EE program avoided transmission and distribution costs and provides a survey of current estimates.

Utilities have used a number of methods for estimating avoided T&D and there is no one "best" approach to developing these estimates. This report conducts a fairly broad benchmarking study of other utilities' estimates of avoided T&D costs. The benchmarking study produced a wide range of estimates for avoided T&D, underscoring the diverse nature of the methods used to calculate avoided costs. Although the process of estimating avoided transmission and distribution costs for EE programs has a long history it appears that it remains a dynamic area that will continue to evolve in the years to come. With this in mind, it would serve PSCo well to revisit this issue in the coming years.

A. Study Purpose

Xcel Energy (the "Company" or "PSCo") uses estimates of transmission and distribution facilities avoided or deferred by investments in energy efficiency in its EE cost-effectiveness evaluations. However, these estimates were developed nearly 10 years ago. It is useful at this point to refresh the Company's understanding of the way that U.S. utilities are calculating their avoided T&D for use with EE program cost-benefit analyses. The Company has requested assistance in researching other utilities' T&D estimates and the basis for those values.

To this end, the consultants sought to accomplish the following tasks:

- **Task 1. Research methods of estimating avoided T&D costs** – Consultant will survey methods used in most recent estimates of T&D avoided costs.
- **Task 2. Identify comparable utilities/systems and benchmark** – Consultant will identify at least five comparable utilities with which to compare and benchmark estimates for the Company.
- **Task 3. Conduct surveys/research of comparable utilities** – T&D cost assumptions and the methodologies used to derive them are often not readily available through publicly available information. Thus, Consultant may need to contact some of utilities to determine avoided T&D information.

The following report is the product of these tasks and seeks to answer each of the questions raised.

B. Issue Overview

Utility-administered electric energy efficiency programs benefit utility ratepayers by reducing the amount of electricity end-use customers consume for a given amount of production (e.g. lumens, cooling load, production from an assembly line, etc.). For the utility, this reduced electricity use translates to less electricity that its power plants must produce (or that the utility must purchase) to meet customer requirements. Over the longer term, it also reduces the need to construct new or expand existing generating facilities. These investments in end-user energy efficiency may also reduce the T&D system capacity needed to transport electricity from power plants to customers.

With respect to T&D systems, it is feasible that EE can avoid or delay T&D upgrades, and reduce construction and associated operations and maintenance costs, including cost of capital, taxes and insurance. If EE measures help reduce demand during peak periods, EE investments can also reduce the timing of maintenance, because frequent peak loads at or near design capacity will reduce the life of some types of T&D equipment.[1]

EE program administrators typically use estimates of investments in generation, transmission, and distribution (GT&D) "avoided" to calculate the cost-effectiveness of investments in energy efficiency programs. According to the *California Standard Practice Manual,* "the benefits calculated in the Total Resource Cost Test are the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction."[2] The *National Action Plan for Energy Efficiency* (NAPEE) explains,

> The resource benefits of energy efficiency fall into two general categories:
> (1) Energy-related benefits that affect the procurement of wholesale electric energy and natural gas, and delivery losses,
> (2) Capacity-related benefits that affect wholesale electric capacity purchases, construction of new facilities, and system reliability.[3]

However, while estimates of avoided supply costs associated with the reduction in generation and capacity costs have more narrowly focused on capacity costs associated with a natural gas-fueled combustion turbine (CT) generating unit (and occasionally a combined cycle unit) and system-wide marginal energy costs,[4] estimates of avoided costs associated with T&D have varied

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[1] "Assessing the Multiple Benefits of Clean Energy, A Resource for States," U.S. Environmental Protection Agency, Revised September 2011, p. 75.

[2] "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects," California Public Utilities Commission, October 2001, p. 18.

[3] "National Action Plan for Energy Efficiency," U.S. Department of Energy, U.S. Environmental Protection Agency, July 2006, p. 3-3.

[4] "Best Practices in Energy Efficiency Program Screening," Synapse Energy Economics for National Home Performance Council, July 23, 2012, p. 23. In some states, administrative rules dictate what type of generating unit will be used to calculate costs (see Iowa and Texas as examples).

widely. Although some of this variation may result from actual cost differences between utilities, much appears to also relate to variations in the way utilities calculate such costs.

Estimating avoided transmission and distribution costs is inherently more complex than generation because T&D benefits from EE tend to be location-specific, system-wide and time dependent. In other words, large amounts of EE investment in a specific part of the distribution grid could more significantly impact, say, required upgrades to a specific substation. On the other hand, system-wide energy efficiency investments can effectively reduce overall loading on transmission and distribution lines but still may not affect T&D investments unless the measures are coincident with system peaks.

Transmission and distribution systems are designed to carry extreme peak loads, which increases costs. States that use marginal cost of service studies to set rates regularly look at the cost to add T&D capacity. Put plainly,

> The capital cost of augmenting transmission capacity is typically estimated at $200 to $1,000 per kilowatt and the cost of augmenting distribution capacity ranges between $100 and $500 per kilowatt. Annualized values (the average rate of return multiplied by the investment over the life of the investment) are about 10% of these figures, or $20 to $100 per kilowatt-year for transmission and $10 to $50 per kilowatt-year for distribution. There are also marginal operations and maintenance costs for transmission and distribution capacity, but these are modest in comparison to the capital costs.[5]

But not all forecast T&D investments are deferrable or avoidable. "Some will be required to address time-related deterioration of equipment or other factors that are independent of load."[6] One of the primary drivers of investment is the growth in the number of customers, which is not avoidable load growth. Other investments only a portion of which may be deferrable/avoidable from EE include modernization projects to improve technology, reliability improvements related to changes in reliability or safety standards, and projects to accommodate non-native load or supply, among others.

Authors Chris Neme and Rich Sedano categorize the manner in which efficiency programs can defer T&D investments as "passive" or "active". Passive refers to deferred investments in transmission and distribution that occur as a byproduct of EE investments whereas active deferrals are those that result from EE initiatives targeted at specific locations. Active deferrals have the express purpose of deferring T&D investments. The authors cite a host of reasons as to why active deferrals are uncommon.[7]

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[5] "Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements," Jim Lazar, Xavier Baldwin, Regulatory Assistance Project, August 2011, p. 6.

[6] "US Experience with Efficiency As a Transmission and Distribution System Resource," Chris Neme (Energy Futures Group), Rich Sedano (Regulatory Assistance Project), February 2012, p. i.

[7] "US Experience with Efficiency As a Transmission and Distribution System Resource," p. i. Among the reasons active deferrals lack popularity are: utility disincentives, difficulty in conducting T&D planning holistically, technical limitations, system engineers biased against demand resources, and risk aversion, among others.

Further to this point, "passive deferral occurs when the growth in load or stress on feeders, substations, transmission lines, or other elements of the T&D system is reduced as a result of broad-based (e.g., statewide or utility service territory-wide) efficiency programs."[8] Estimates of savings from EE investments "are typically developed by dividing the portion of forecast T&D capital investments that are associated with load growth (i.e., excluding the portion that is associated with replacement due to time-related deterioration or other factors that are independent of load) by the forecast growth in system load."[9] Section C discusses in more detail the different ways that utilities estimate avoided transmission and distribution costs.

It bears repeating that investments in transmission and distribution systems have other benefits beyond meeting load growth, including providing reliable service and meeting the needs of a growing number of customers. Investments in system improvements can also provide production cost savings through reduced line losses and reduced congestion, generation capacity cost savings by providing access to lower cost resources, and increased employment activities, among others.[10] This is relevant because it points out that while energy efficiency investments may defer or avoid transmission and distribution investments that such investments may provide other benefits that contribute (and are economically valuable) to the electricity system (thereby arguing that avoided cost estimates may be mitigated somewhat by ancillary benefits associated with these improvements). The next section discusses some common methods for calculating avoided T&D costs.

C. Common T&D Avoided Cost Calculation Methodologies

As previously discussed, there is little consistency between jurisdictions in terms of how avoided T&D costs are calculated. Unlike estimates of avoided energy and generating capacity, estimates of avoided T&D tend to require a fair amount of subjectivity in determining what to include in and what to exclude from calculations. Each utility has a different take on the topic and regulators to the extent they become involved in the issue also differ. Some utilities do not include estimates of avoided T&D in their evaluations, believing that EE does not defer T&D investments.[11] Other utilities, like those in Idaho, may include avoided transmission costs in calculations but place the value at zero because the generating unit avoided is close to load, thereby deferring no transmission.[12]

As such, determining what constitutes "best practice" becomes difficult, particularly because none of the different approaches are necessarily *wrong*. It is just that there are a variety of methods for developing the estimates, and each <u>may</u> be capable of producing valid estimates.

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[8] "US Experience with Efficiency As a Transmission and Distribution System Resource," p. 3.

[9] "US Experience with Efficiency As a Transmission and Distribution System Resource," p. 3.

[10] "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," The Brattle Group, July 2013, p. 10.

[11] See "Consumers Energy: 2012-2015 Amended Energy Optimization Plan," Submitted to Michigan Public Service Commission (Case No: U-16670), August 1, 2011, p. 25.

[12] "Reviving PURPA's Purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies in Supporting Alternative Energy Development and A Proposed Path for Reform," Prepared by Carolyn Elefant, 2011, p. 31.

The uncertainty stems, in part, from the nature of energy efficiency as relying upon the counterfactual (i.e., the determination of what would have happened on the system if the EE program did not exist). To devise an analytical tool that enables one to assess the benefits and costs of EE requires that practitioners develop "good" estimates of the benefits EE investments produce. Good estimates are those based on sound principles as discussed in the following sections. The following section outlines a number of the methods while Appendix A provides an assessment of the strengths and weaknesses of the different approaches. Section D follows with a survey of a number of utilities' avoided cost estimates.

a. System Planning Approach

According to the U.S. Environmental Protection Agency's (EPA's) "Assessing the Multiple Benefits of Clean Energy (September 2011)," the *system planning approach* is the best way to estimate avoided T&D costs. "The system planning approach uses projected costs and projected load growth for specific T&D projects based on the results from a system planning study—a rigorous engineering study of the electric system to identify site-specific system upgrade needs. Other data requirements include site-specific investment and load data. This approach assesses the difference between the present value of the original T&D investment projects and the present value of deferred T&D projects."[13]

The U.S. EPA endorses this approach and suggests use of proprietary models of T&D system operation (two cited are PowerWorld Corp's model and the Siemens [PSS®E] model) to identify location and timing of system stresses. The system planning approach may well be the best way to estimate avoided T&D costs; however, the approach seems primarily to have been used to analyze investments in specific T&D projects rather than to analyze the system as a whole. The approach has been used to estimate the value of distributed generation and energy efficiency at ConEdison, Bonneville Power Administration, Efficiency Vermont, Detroit Edison, and Southern California Edison, among others.[14] However, these projects all appear to be aimed at "active" deferrals rather than the more typical passive deferrals.

b. Mix of Historical and Forecast Information Approach[15]

The ICF Tool, developed by ICF International, Inc. best exemplifies the Mix of Historical and Forecast Information approach. ICF developed a calculation methodology as part of a 2005 report prepared for the Avoided-Energy-Supply-Component (AESC) Study Group, whose members included utilities in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.[16] The report was commissioned to review energy supply costs avoided in the Northeast through energy efficiency programs. The AESC report has been updated biennially since 2005, but there have been no substantive changes to the calculator.

At its core, the ICF Tool collects data on historical and forecast T&D investments, determines what portions are due to load growth, and weights the historical and forecast contributions to

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[13] "Assessing the Multiple Benefits of Clean Energy," p. 76.

[14] "Best Practices in Energy Efficiency Program Screening," p. 25.

[15] This is a made-up label. Some have called this "projected embedded cost analysis" (see "Best Practices in Energy Efficiency Program Screening," p. 24.

[16] "Avoided Energy Supply Costs in New England: 2005 Report," Prepared for Avoided-Energy-Supply-Component (AESC) Study Group by ICF Consulting, December 23, 2005.

arrive at transmission and distribution T&D capacity marginal costs in $/kW-year. The tool takes the form of an Excel spreadsheet with four schedules (Schedule 1 is a summary) and an appendix. The Tool recommends that the user input 15 years of historical data and 10 years of forecast data for T&D capital investments and peak load. In addition, the user must input a variety of values from their FERC Form 1, including: property taxes, insurance costs, and operation and maintenance expenses. The user must also estimate the portions of investments identified in FERC Form 1 that are related to increasing load. [17]

The benefits of this methodology are that the Tool is well established, much of the data is available through FERC Form 1, and utilities and Commissions in the Northeast have been vetting it for nearly ten years. Many utilities continue to use the approach. The concerns with this method are that despite data being available from the FERC Form 1, the Tool still requires the user to make a subjective analysis of the proportion of investments resulting from increasing load. In addition, the 2009 AESC Report pointed out a number of potential calculation errors in the spreadsheet.[18]

c. Current Values Approach

The Current Values approach is well exemplified by MidAmerican Energy Company in its multiple state demand-side management (DSM) filings. MidAmerican has a standardized approach to calculating T&D capacity avoided costs in each of the states where it offers energy efficiency programs including Iowa, Illinois and South Dakota. This methodology is detailed in the direct testimony of Jennifer L. Long, in Iowa Docket No. EEP-2012-0002.

MidAmerican calculates T&D avoided costs as follows,

> The average cost to serve existing load is calculated for both the transmission and distribution systems by dividing each system's net cost by each system's peak capability. MidAmerican's Federal Energy Regulatory Commission (FERC) Form 1 data is used to calculate the net costs of the transmission and distribution systems by taking MidAmerican's original cost of plant less accumulated depreciation for each respective system. Yearly, MidAmerican load data and generation capability data is used to approximate the capacity of each system. The end result of the calculation is a $/kW cost for each system.[19]

The biggest strength of this method is its simplicity, which lends itself to frequent updates.

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[17] FERC Form 1, submitted annually by large utilities, provides comprehensive financial and operating results of the utility for the previous year. Investments specifically targeted for addressing load growth are not identified therein.

[18] "Avoided Energy Supply Costs in New England: 2009 Report," Prepared for Avoided-Energy-Supply-Component (AESC) Study Group by Synapse Energy Economics, Inc., August 21, 2009, p. 6-67.

[19] "Direct Testimony of Jennifer L. Long," Application for Approval of Energy Efficiency Plan for 2014-2018 (Docket EEP-2012-0002), Submitted to Iowa Public Utilities Board by MidAmerican Energy Company, Feb. 1, 2013, p. 4. Note that MidAmerican modified its approach to incorporate on peak load data instead of generation capability data.

d. Rate Case Marginal Cost Data with Allocators Approach

There are a few variations on the theme of using most recent marginal cost of service data from the utility rate case to develop estimates of avoided transmission and distribution costs. In California, T&D avoided costs are considered unique among other types of avoided costs in that both the value and hourly allocations are location specific. This information is combined with utility rate case information to calculate avoided costs separately for each utility.

As discussed in the 2011 update to the state's avoided costs,

> … the value of deferring distribution investments is highly dependent on the type and size of the equipment deferred and the rate of load growth, both of which vary significantly by location. Furthermore, some distribution costs are driven by distance or number of customers rather than load and are therefore not avoided with reduced energy consumption. However, expediency and data limitations preclude analysis at a feeder-by-feeder level for a statewide analysis of avoided costs. The costs taken from utility rate case filings are used as a reasonable proxy for the long-run marginal cost T&D investment that is avoided over time ...[20]

The avoided cost calculations also allocate T&D capacity values in each climate zone to the hours of the year during which the system is most likely to be constrained and require upgrade (the hours of highest local load). Although these values were previously based on hourly temperature values for the individual climate zones the information has since been updated for cost-effectiveness calculators (but not yet incorporated into the EE calculator) due to the availability of utility information on actual substation load data.[21]

e. Rate Case Marginal Cost Data Approach

Ameren Missouri goes through a fairly detailed review of its distribution and transmission system investments to determine the marginal cost of system capacity as it relates to load growth. However, this is complicated by the fact that "projects serve a variety of purposes; capacity upgrades to serve incremental system load, capacity upgrades to serve relocated system load, and refurbishment or replacement of equipment to avoid imminent failure."[22] As Ameren points out, analyzing the system in aggregate rather than focusing on specific areas further complicates the estimates, mainly because energy efficiency programs are designed to target specific areas.

PacifiCorp includes avoided T&D credits in its assessment of resources as part of its IRPs filed in Oregon, Washington, Idaho, California, Wyoming, and Utah. Specifically, PacifiCorp uses a cost of service study to derive the estimates. As part of the study, PacifiCorp estimates the demand-related substation costs by taking the total substation capacity expansion investment for the subsequent five years, dividing by the total increased capacity in kVA and then annualizing this number by multiplying by a carrying charge. The method of estimating demand-related transmission costs is similar. All "growth-related" transmission investment (with some

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[20] "Energy Efficiency Avoided Costs 2011 Update," by Brian Horii, Eric Cutter (Energy and Environmental Economics, Inc.), December 19, 2011, p. 24.

[21] "Energy Efficiency Avoided Costs 2011 Update," p. 26.

[22] "Ameren Missouri - 2011 Integrated Resource Plan," File No. EO-2011-0271, February 23, 2011.

exceptions like bulk power lines) over the subsequent five years is divided by the forecasted change in peak over the same period and this value is annualized.[23]

In its 2013 IRP, Nevada Energy uses the marginal cost study associated with the utility's 2010 rate case (Docket No. 10-06001) to determine its avoided T&D costs. As the utility states in its filing, "the adopted valuation process reduces potential difficulties regarding uncertainty in load forecasts and T&D construction budgets, and takes into account the ripple effect or the effect of deferred construction investments during the useful life of energy efficiency measures."[24] The Company, in turn, utilizes the conservative value of 25 percent of $47.50/kW (annual revenue requirement for the marginal cost of transmission facilities and distribution system, not accounting for the distribution beyond substation) or $11.88/kW in cost effectiveness analysis, and escalates it in each year by applying a cost construction index. The company further acknowledged that this is a low value when compared to other states like California.

Selection of Other Approaches

Averaging Method

In a note to the Vermont Public Service Board, a consultant outlines the various options available for calculating avoided T&D costs and cites among the options the "New England Average Method."[25] This method proposes using a New England average avoided T&D cost of $83 calculated from the figures identified in the 2011 AESC report. Although Vermont did not adopt this method other utilities have used a similar approach. Wisconsin Focus on Energy, which does not have explicit avoided T&D costs in its cost-effectiveness calculations, used an Iowa average for its market potential study.[26] In the Pacific Northwest, the Northwest Conservation and Electric Power Plan uses an average of avoided costs from a selection of utilities.[27]

IRP Approach

Some utilities use a variant of the System Planning Approach by conducting with and without DSM analyses to estimate avoided T&D costs.[28] Tucson Electric Power (TEP) conducts a decrement study to assess how transmission costs are avoided and uses this calculation in the utility's EE cost-effectiveness evaluations. It does not appear that TEP includes avoided distribution costs in its calculations and the utility only publishes its total avoided capacity costs. The utility considers the details proprietary and, therefore, specific information is not available.

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[23] Correspondence with PacifiCorp representatives, August 22, 2014.

[24] Sierra Pacific Power Company d/b/a NV Energy Integrated Resource Plan 2014-2033, Demand Side Plan 2014-2016," p. 48.

[25] "List of Possible Methods for Determining Avoided Transmission and Distribution Costs," Submitted to Vermont Public Service Board, June 28, 2012, http://psb.vermont.gov/docketsandprojects/eeu/avoidedcosts/2011.

[26] "Minutes and Informal Instructions of the Open Meeting of Thursday, July 10, 2014," Public Service Commission of Wisconsin, p. 3.

[27] "Appendix E – Conservation Supply Curve Development" in Sixth Northwest Conservation and Electric Power Plan, February 1, 2010, p. E-13, https://www.nwcouncil.org/energy/powerplan/6/plan/.

[28] This version of the System Planning Approach is more frequently associated with calculations of avoided generation energy and capacity costs. See "The Role and Nature of Marginal and Avoided Capacity Costs in Ratemaking: A Survey," Hethie Parmesano and William Bridgman, National Economic Research Associates, January 1992, p. 13.

Others
The memo to the Vermont Public Service Board also identified a method termed the "Simple Method" which relies on taking representative samples of recent T&D upgrade projects, dividing by increased capacity and annualizing.[29] The formula follows:

(Cost of Upgrades) ÷ (Additional Capacity Achieved by the Upgrade) ÷ (Economic Life of Upgrade)

A final method entails looking at each potential cost category of T&D capital costs and operations and maintenance expenses and making educated guesses as to the percentage of the cost category that is deferrable by EE. This can be applied to historical and, if available, forecast costs to determine the annualized value as it applies to load growth.

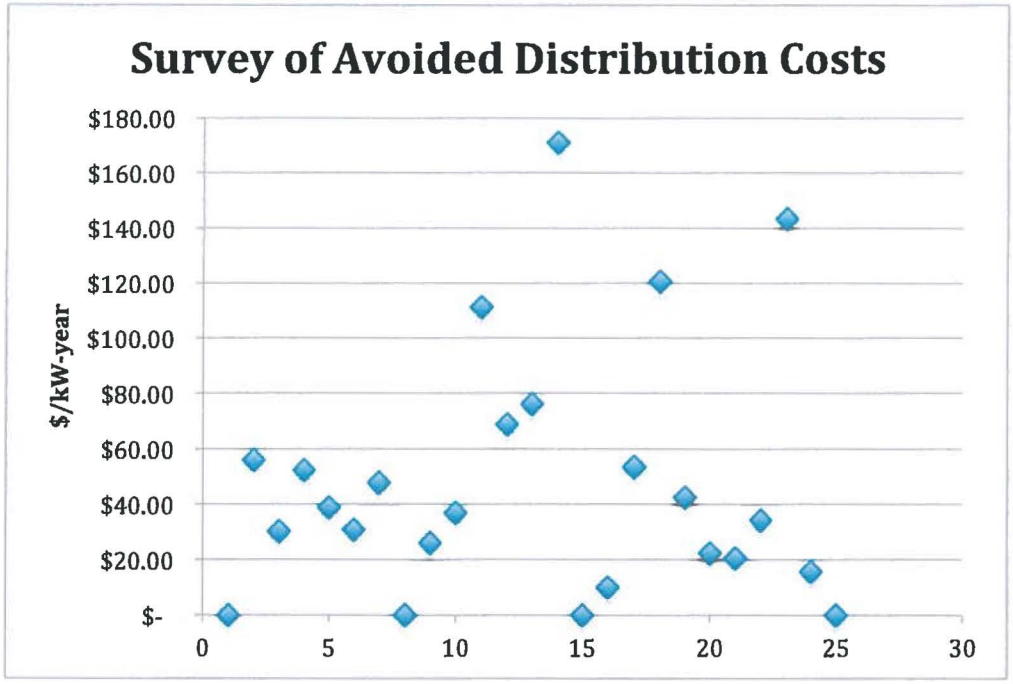
D. Survey of Other Utilities / Benchmarking

As part of Tasks 2 and 3, the authors collected avoided T&D data from a fairly broad cross-section of utilities. Data collection efforts sought to maximize the number of data points while also making an attempt to include utilities that might be most relevant to PSCo. However, it is unclear whether utility size or region has any bearing on estimated avoided costs and, therefore, the effort did not concentrate on the Rocky Mountain region or on comparably sized utilities. The survey does include some results from mountain states such as Arizona, Utah, Idaho and Nevada and also includes information from comparably sized (customers, sales) utilities (Consumers Energy [MI], Northern States Power [MN], Arizona Public Service [AZ]). Appendix B provides the detailed results of the survey. The range of data points for avoided Distribution cost estimates are provided below. The first section focus on distribution system estimates and it is followed by estimates of transmission system avoided costs. Combined estimates of avoided T&D are included in the final section.

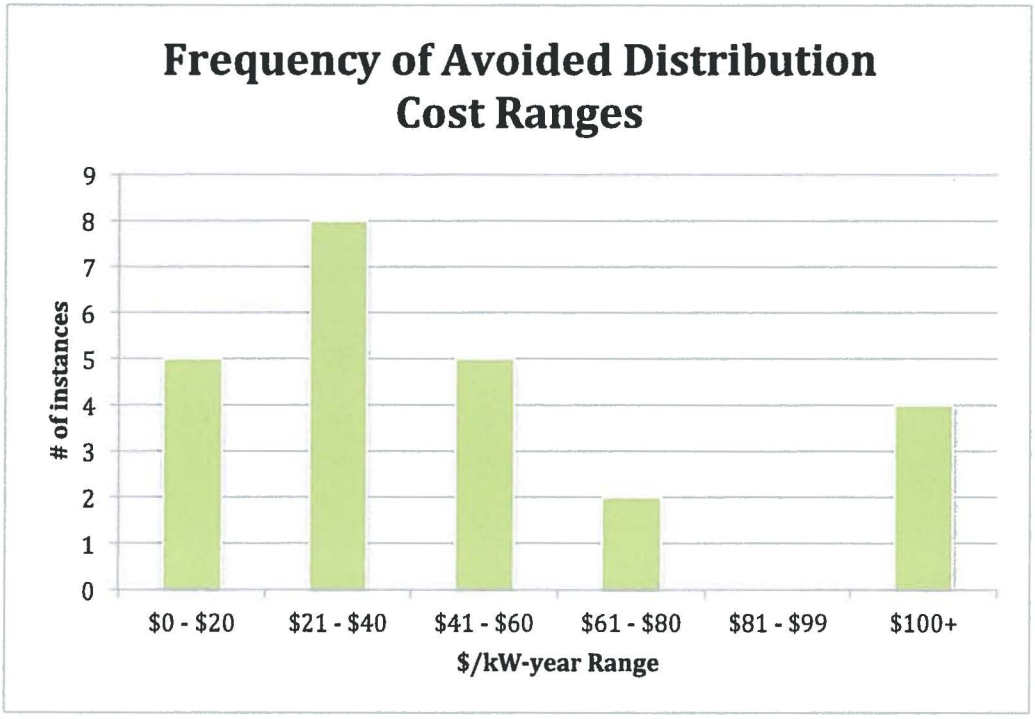
Estimates of Distribution System Avoided Costs

The average avoided distribution costs are $48.37 with a range from $0 to $171/kW-year.

[29] "List of Possible Methods for Determining Avoided Transmission and Distribution Costs," p. 2.

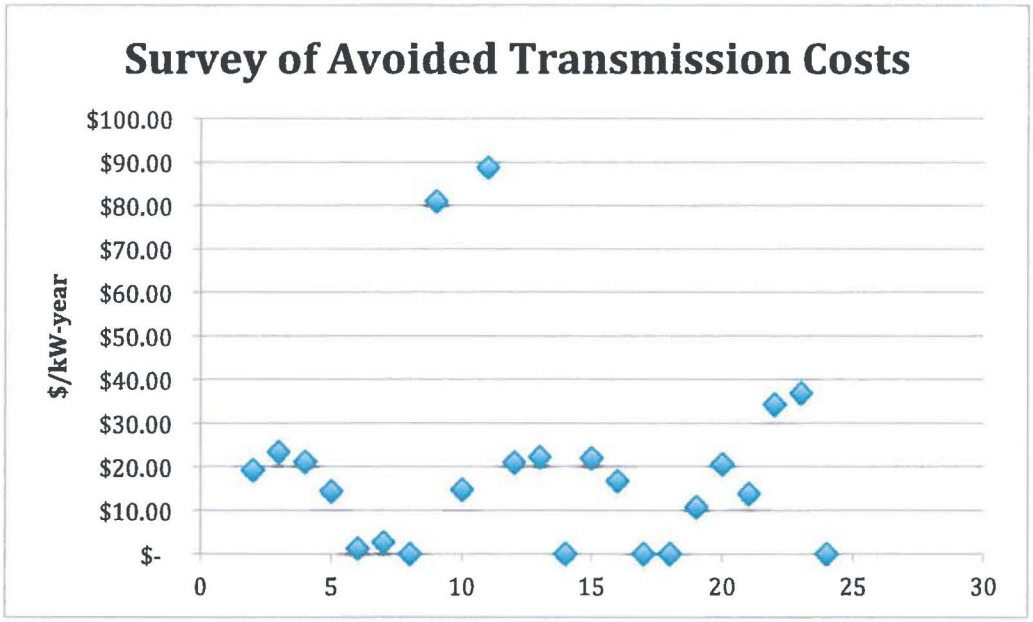


The values are most heavily concentrated in the $21 to $40 range with 8 of the samples falling in this range.

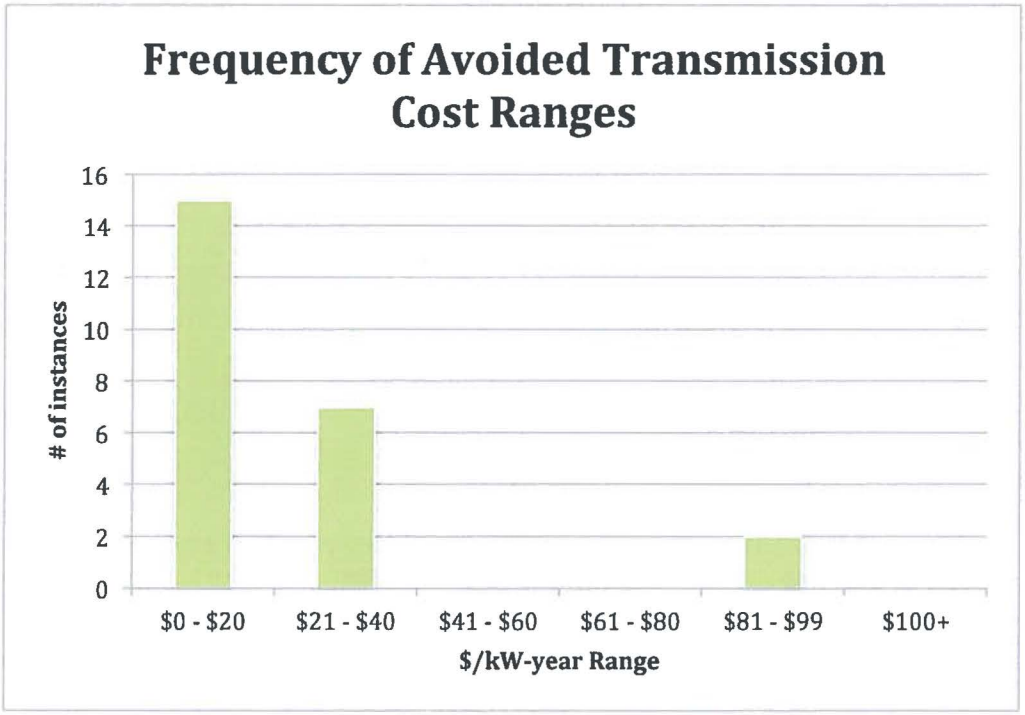


Estimates of Transmission System Avoided Costs

Average avoided transmission costs are $20.21 with a range from $0 to $88.64/kW-year.

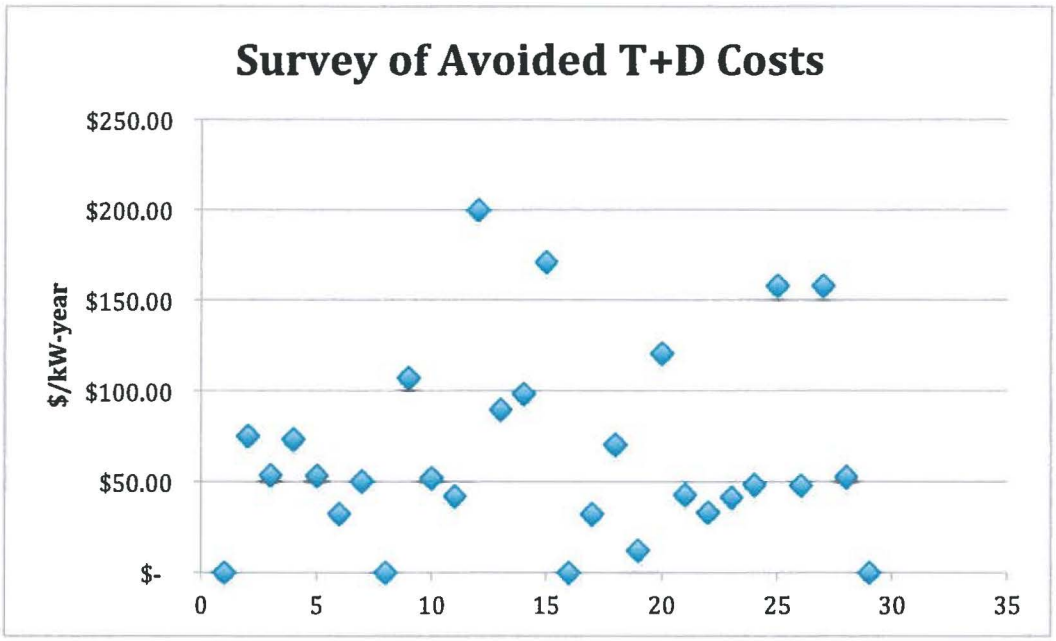


Transmission values are most heavily concentrated in the $0 to $20 range with 15 of the samples falling in this range

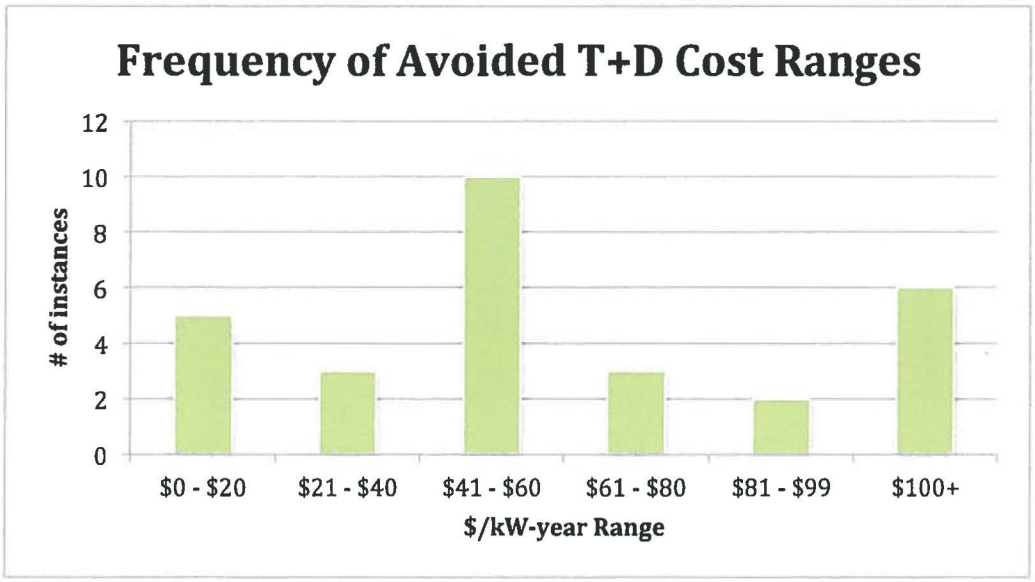


Estimates of T&D System Avoided Costs

Finally, the average avoided transmission + distribution costs are $66.03 with a range from $0 to $200.01/kW-year. It should be noted that there are more combined T&D results because some utilities did not break out T&D.



The values are most heavily concentrated in the $41 to $60 range with 10 of the samples falling in this range.



It should be further noted that the values for each entry were not adjusted for the applicable years, mainly because escalators were not available for all samples. The "oldest" data point is for 2011, so adjustments for inflation would not likely be significant.

Although this study did not explore the reasons for the differences between utility avoided costs, it is difficult to correlate relative values with overall utility retail rates or method of calculation. There can certainly be other factors that drive avoided T&D cost calculations. This is just to say that it is difficult to generalize and points out that there is a large amount of variability in estimated costs.

E. Conclusion

This study sought to investigate different ways that utilities in the United States estimated avoided transmission and distribution costs for energy efficiency cost-effectiveness evaluations that could inform its next DSM plan. The survey of methodologies and benchmarking determining that there are a variety of ways to estimate such values and a very broad range of estimates among the 35 utilities included. Given the dynamic state of the methodologies used to develop these estimates it is recommended that PSCo periodically revisit this issue and update the survey of current estimates and the methodologies used.

Appendix A – Selection of Approaches to Calculating Avoided T&D Costs

Method	Brief Description	Examples	Strengths	Weaknesses
System Planning Approach	• Uses costs and load growth for specific T&D projects based on a system planning study	• Vermont Electric Company (2003) – focused on specific transmission upgrade	• Potentially more accurate • Uses specific project data to develop estimates • Forces consideration of DER effects on project-by-project basis	• Costly and time consuming • May not be appreciably more accurate than other approaches • Dependent upon individual projects included in analysis
Mix of Historical and Forecast Information	• Uses data on historical and forecast T&D investments, determines what's related to load growth, and weights the historical and forecast contributions	• ICF Tool used in the Northeast, Vermont DPS variation	• Uses publicly available FERC Form 1 data • Easily calculated and updated • Uses a form of marginal costs • Addresses "lumpiness" of T&D investments • Used by multiple other states • Relies upon historical as well as forecast information	• Assumes it's possible to differentiate amount of T&D investment that corresponds to load growth rather than maintenance, reliability and customer growth • Does not incorporate variability associated with time/location differences • Can't readily handle low forecast growth
Current Values	• Develops average cost to serve existing load by dividing each system's net cost	• MidAmerican Energy (IA, IL, SD), Commonwealth Edison (IL)	• Uses publicly available FERC Form 1 data • Easily calculated and updated	• May tend to undervalue • Does not incorporate variability associated with time/location differences

Method	Brief Description	Examples	Strengths	Weaknesses
Rate case marginal cost data with allocators	• Uses T&D marginal cost of service data from utility rate cases and apply time and locational factors related to weather or specific substation loadings	• California IOUs	• Uses publicly available data (rate case portion) • Uses approach consistent with ratemaking • Uses time and location differentiated data • Uses marginal cost information	• Potentially costly and time consuming • May not be appreciably more accurate than other approaches • Somewhat assumes use of hourly avoided costs for Generation • Requires estimation of investments deferred by EE
Rate case marginal cost data	• Use T&D marginal cost of service data from most recent rate case	• Ameren (MO), PacifiCorp (OR, UT, WA), Nevada Energy, Consolidated Edison (NY)	• Uses publicly available data • Is approach consistent with ratemaking • Uses marginal cost information	• May not be appreciably more accurate than other approaches • Requires estimation of investments deferred by EE
IRP Method	• Uses without and without EE runs to determine avoided transmission costs	• Tucson Electric Power	• Is consistent with integrated resource plan	• Is highly dependent on IRP's model ability to calculate transmission costs • Requires integrated resource plan • Only updated as frequently as resource plan • Typically can only provide transmission
Averaging method	• Take simple average of a selection of similar	• Wisconsin Focus on Energy Market Potential Study (used Iowa)	• Uses publicly available data • Very easily calculated	• Must pick appropriate proxy utilities for averaging

Method	Brief Description	Examples	Strengths	Weaknesses
	jurisdictions	• Northwest Conservation and Electric Power Plan (used 8 utilities)		• Not specific to one utility
Simple Method	• Take representative sample of recent T&D upgrade projects, divide by increased capacity and annualize	• Unknown	• Very simple • Provides real information from specific example • Can be done for transmission, distribution and sub-transmission	• Project may not be system representative • Must still determine what portion of increased capacity relates to load growth

Appendix B – Survey of Utility Avoided Transmission and Distribution Costs

Estimated Values

State	Utility	Date of Estimate	Transmission	Distribution	O&M	Total T&D	Units
AZ	TEP	2013	N/A	N/A		$100.00	$/kW-year
AZ	APS	2013	$0	$0		$0	
CA	PG&E-Com	2011	$19.60	$55.97		$75.57	$/kW-year
CA	PG&E-Res	2011	$18.77	$55.85		$74.62	$/kW-year
CA	SCE-Com	2011	$23.39	$30.10		$53.49	$/kW-year
CA	SCE-Res	2011	$23.39	$30.10		$53.49	$/kW-year
CA	SDG&E-Com	2011	$21.08	$52.24		$73.32	$/kW-year
CA	SDG&E-Res	2011	$21.08	$52.24		$73.32	$/kW-year
CA	Weighted Average	2011	$21.20	$44.38		$65.59	$/kW-year
CT	CL&P	2013	$1.30	$30.94		$32.24	$/kW-year
CT	United Illuminating	2013	$2.64	$47.82		$50.46	$/kW-year
ID	Idaho Power	2014	$0	$0		$0	
IA	Interstate Power & Light	2014	$81.00	$26.00		$107.00	$/kW-year
IA	MidAmerican	2013	$14.85	$37.01		$51.86	$/kW-year
IL	Commonwealth Edison	2014	N/A	N/A		$42.00	$/kW-year
MA	National Grid	2013	$88.64	$111.37		$200.01	$/kW-year
MA	NSTAR	2011	$21.00	$68.79		$89.79	$/kW-year
MA	WMeco	2011	$22.27	$76.08		$98.35	$/kW-year
MA	Unitil	2013	$0	$171.15		$171.15	$/kW-year
MI	Consumer's Energy	2012	$0	$0		$0	
MN	Xcel	2014	$14.31	$38.85		$53.17	$/kW-year
MO	Ameren	2014	$22.00	$10.00		$32.00	$/kW-year
NH	PSNH	2013	$16.70	$53.35		$70.05	$/kW-year
NW	NW Conservation and Electric Power Plan utilities	2010	$0	$23.00		$66.59	$/kW-year

Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments

State	Utility	Date of Estimate	Transmission	Distribution	O&M	Total T&D	Units
NV	Sierra Pacific Power dba Nevada Energy	2013	N/A	N/A		$12.23	$/kW-year
NY	Consolidated Edison (Network)	2013	$0	$120.52		$120.52	$/kW-year
NY	Consolidated Edison (Non-Network)	2013	$0	$42.63		$42.63	$/kW-year
OR	PacifiCorp	2011	$36.89	$15.75		$52.64	$/kW-year
OR	PGE	2011	$10.80	$22.40		$33.20	$/kW-year
RI	National Grid	2013	$20.62	$20.62		$41.24	$/kW-year
SD	MidAmerican	2012	$13.79	$34.37		$48.16	$/kW-year
UT	PacifiCorp	2011	$36.89	$15.75		$52.64	$/kW-year
VT	Burlington Electric Department (Prescriptive Programs)	2013	N/A	N/A		$158	$/kW-year
VT	Burlington Electric Department (Custom Programs)	2013	N/A	N/A		$48	$/kW-year
VT	Efficiency Vermont	2013	$34.25	$93.25	$50.00	$158.15	$/kW-year
WA	PacifiCorp	2011	$36.89	$15.75		$52.64	$/kW-year
WI	Focus on Energy		$0	$0		$0	

N/A refers to instances where the utility did not break out the individual transmission and distribution values.

Methods and Data Sources

State	Utility	Method	Data Source for Calcs	Notes
AZ	TEP	Calculated avoided G&T using IRP. Developed $/kW-year based on G&T costs avoided by selected DSM portfolio.	IRP	TEP considers the avoided capacity costs confidential as part of their Resource Plan. They do not provide detail in their EE Plan beyond the SCT (Societal Cost Test). Not included in averaging calcs.
AZ	APS			Does not specifically incorporate an avoided capacity value for T&D. Includes line losses for energy and capacity.
CA	PG&E-Com	The costs taken from utility rate case filings are used as a reasonable proxy for the long-run marginal cost T&D investment that is avoided over time with the addition of distributed energy resources.	General Rate Case	Only included PG&E Com/Res average in averaging calcs and graphs.
CA	PG&E-Res			
CA	SCE-Com		FERC Form 1	Only included one SCE in averaging calcs and graphs.
CA	SCE-Res		FERC Form 1	
CA	SDG&E-Com	The costs taken from utility rate case filings are used as a reasonable proxy for the long-run marginal cost T&D investment that is avoided over time with the addition of distributed energy resources.	General Rate Case	Only included one SDG&E in averaging calcs and graphs.
CA	SDG&E-Res			They are the same values used for the 2011 CEC California Building Energy Standards, and the CPUC CSI and DR proceedings.
MN	Xcel		Internal	
CT	CL&P	ICF Tool	FERC Form 1	
CT	United Illuminating	Black & Veatch Report		United Illuminating Avoided Transmission & Distribution Cost Study Report, Black & Veatch, September 2009.
IA	Interstate Power & Light		MISO Att. O for T.	
IA	MidAmerican	The average cost to serve existing load is calculated for both the transmission and distribution systems by dividing each system's net cost by each system's peak capability. MidAmerican's Federal Energy Regulatory Commission (FERC) Form 1 data is used to calculate the net costs of the transmission	FERC Form 1	Iowa EE rules do not required avoided T&D. Is done as an alternative calculation - rules dictate use of a CT for avoided capacity costs and provides the formula. Ratepayer advocates currently advocating for use of MISO Attachment O rates for avoided transmission

Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments

State	Utility	Method	Data Source for Calcs	Notes
		and distribution systems by taking MidAmerican's original cost of plant less accumulated depreciation for each respective system. MidAmerican T&D avoided costs are calculated using depreciated original cost figures listed in FERC Form 1.		(Docket INU-2014-0001)
IL	Commonwealth Edison	ComEd conducted an updated analysis to place a value on the avoidance or deferral of new transmission and distribution capacity as a result of energy efficiency. The most recent analysis determined that an avoided T&D cost of $42/yr. is appropriate for cost-effectiveness analysis.		8-27-14: The avoided T&D cost is from an internal study and does not have a breakdown between T and D.
MA	National Grid	ICF Tool	FERC Form 1	
MA	NSTAR	ICF Tool	FERC Form 1	
MA	WMeco	ICF Tool	FERC Form 1	
MA	Unitil	ICF Tool	FERC Form 1	
MI	Consumer's Energy			*While the cost of building transmission and distribution systems -- by either building with less capacity or avoiding building completely – theoretically might be avoided, Consumers Energy's current transmission and distribution systems are typically adequate to meet customers' needs. The current situation, relative to numbers of customers and demand, would need to substantially change before costs of building transmission and distribution systems could be avoided.*
MN	Xcel		Internal	
MO	Ameren	Rate case marginal costs	2010 Rate Case	
NH	PSNH	ICF Tool	FERC Form 1	
NW	NW Conservation and Electric Power Plan utilities	Used benchmarked data to come up with "representative" value. Estimated a value of $25 for transmission, but did not adopt. See notes.	Regional Technology Forum (RTF)	Is part of 6th 5-year Power Plan. Planning for 7th began in 2014. "The Council adopted the RTF recommended value for distribution system avoided cost. However, because the value of avoiding the transmission system investments is

State	Utility	Method	Data Source for Calcs	Notes
				already included in the wholesale market prices produced by the AURORA model the Council did not use the RTF estimate of the benefits of deferring transmission system expansion so as to avoid double counting." (p. E-14).
NV	Sierra Pacific Power dba Nevada Energy	Is the annual revenue requirement for T&D impacted by EE. Submitted as marginal cost study with rate case. 13-06002	Rate case T&D costs	Uses "conservative value" of 25% of T&D revenue requirements of $49.92 (was $47.50 in 2010 rate case). Does not account for distribution costs beyond the substation. Uses "PortfolioPro" cost benefit model developed for them by Cadmus. However, in IRP NVEnergy recognizes that its T&D costs are low based on Synapse's best practices study.
NY	Consolidated Edison (Network)	Marginal costs associated with load growth	Utility marginal cost data	Study developed in response to requirement from NY Public Service Commission. Network resources are associated with underground low-voltage distribution systems such as in downtown NYC. Emergence of T avoided costs do not occur until 2017.
NY	Consolidated Edison (Non-Network)	Marginal costs associated with load growth	Utility marginal cost data	Study developed in response to requirement from NY Public Service Commission. Non-Network resources are associated with radial distribution systems. Emergence of T avoided costs do not occur until 2017.
OR	PacifiCorp	Regulation Department provides as input to the IRP. Represents "an average of the values from a marginal cost of service study from the company's last 5 general rate cases for demand-related substation and transmission costs."	Rate case T&D revenue requirements	The resource deferral fixed cost benefit is comprised of the deferred capital recovery and fixed operation and maintenance costs of a "next best alternative" resource—a combined- cycle combustion turbine (CCCT).
OR	PGE	ICF Tool	FERC Form 1	
RI	National Grid	ICF Tool	FERC Form 1	
SD	MidAmerican	Avoided distribution costs are calculated by determining the economic carrying charge associated with MidAmerican's net distribution investment on a $/kW basis; Avoided transmission capacity costs are calculated by determining the economic carrying charges associated with MidAmerican's net transmission investment on a	FERC Form 1 and utility discount rates	Same values as Iowa and, therefore, not duplicated in averaging calcs

State	Utility	Method	Data Source for Calcs	Notes
		$/kW basis, where kW refers to the total transmission system capacity.		
UT	PacifiCorp	See OR		Same values as Oregon, and, therefore, not duplicated in averaging calcs
VT	Burlington Electric Department (Prescriptive Programs)			Different values for prescriptive and custom programs. Prescriptive values decline over time. Is 2012 $. Order on 12/13/2012 in Docket EEU-2011-02
VT	Burlington Electric Department (Custom Programs)	VT Department of Public Service adapted ICF Tool. Method used by AESC 2013, applicable to Vermont.		
VT	Efficiency Vermont	VT Department of Public Service adapted ICF Tool. Method used by AESC 2013, applicable to Vermont.		The statewide estimates are based on load-related investments in the last decade for which Vermont experienced significant load growth, ending in 1996. Adds O&M and then subtracts a "T&D offset". Order on 12/13/2012 in Docket EEU-2011-02, See values below through 2040
WA	PacifiCorp	See OR		Same values as Oregon and, therefore, not duplicated in averaging calcs
WI	Focus on Energy	$-	$-	Does not currently include avoided T&D in FOE cost effectiveness evaluations. Discussed possibility but felt that the effort would require considerable analysis to determine what was avoided. Uses MISO forecasted LMPs as primary energy avoided costs (no capacity apparently). But LMPs theoretically incorporate all (G, T&D). ECW 2009 market potential study incorporate $30/kW-year value in its analysis based on Iowa utilities' calculations.