Assessment of National EHV Transmission Grid Overlay Proposals:

Cost-Benefit Methodologies and Claims

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EXECUTIVE SUMMARY

Christensen Associates Energy Consulting ("CA Energy") conducted an independent review and assessment of a study undertaken by American Electric Power (AEP) of the costs and benefits of a national 765 kV transmission overlay (hereafter "AEP Study").[1] AEP's cost-benefit study was based on a scaling up of regional findings in a report prepared by CRA International that examined the costs and the benefits of a 765 kV transmission overlay for the Southwest Power Pool ("SPP") (hereafter "CRA Study").[2]

This review of assessment methods and claims about the costs and the benefits for a nationwide Extra High Voltage ("EHV") transmission overlay comes amidst growing concerns that, with wind as the renewable resource of economic choice at least for the foreseeable future, rapid wind power development will require substantial additions to the nation's transmission infrastructure. However, wind power developers claim that they will not be able to shoulder the cost of needed transmission capacity, nor do potential transmission developers want to bear all these costs. This raises significant public policy questions. How much will the transmission build-out cost, and over what time horizon will the cost be incurred? Will the benefits of the build-out exceed the costs? And how will costs and benefits be distributed? The answers to these questions are critical in determining how Congress and the nation's regulators should develop transmission policy so as to encourage the development of renewable and other clean sources of energy where they provide societal benefits, with the lowest possible cost to the nation's consumers.

The AEP Study attempts to quantify the costs and benefits to the nation of one approach to transmission investment – i.e., the construction of a 765 kV transmission overlay across the country. It assumes the costs of such transmission expansion will be assessed to all electric consumers regardless of the extent to which they benefit. The AEP Study finds that such a national policy will have positive net benefits to society. In this paper, CA Energy evaluates the AEP Study's analysis of the costs and the benefits of a national EHV grid overlay. We find the AEP Study to be deficient in multiple respects and therefore unable to accurately portray the costs of such an overlay.

In particular, we reach the following conclusions about the assumptions made and methods used in the AEP Study and in the CRA Study upon which it builds to derive the estimates of the costs and the benefits of the proposed national EHV overlay:

The AEP Study significantly underestimates the potential costs of a 765 kV national grid overlay. The AEP Study's national grid overlay cost estimate cannot be reconciled with other, more credible studies of national scope, and with estimated per mile costs for recently proposed 765 kV projects. These recent, more thorough (engineering based) studies conclude that a grid overlay is significantly more costly than the AEP Study assumed. Estimates of the costs for new 765 kV transmission lines, which figure prominently in several recent proposals for large transmission investments are much higher than the costs per mile that the AEP Study assumes –

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[1] American Electric Power, *Analysis of Benefits and Costs for a U.S. Interstate EHV Transmission System*, May 2009.

[2] CRA International, *First Two Loops of SPP EHV Overlay Transmission Expansion Analysis of Benefits and Costs*, September 26, 2008, for Electric Transmission America, OGE Energy Corp., and Westar Energy.

in some cases twice as much or more. Some of the more recent cost per mile estimates, compared to the costs per mile estimates used in the CRA Study and AEP estimates from other projects and studies are summarized in Table ES-1.[3] Appendix A to this report provides a more detailed description of the projects for which these estimates were made and the sources for those estimates.

Table ES-1

765 kV Transmission Line Projects and Projected Costs per Mile

Project/Study Name	Date of Estimate	Cost per Mile (millions)
CRA Study[4]	9/26/08	$1.7 - $2.1
Other AEP Estimates		
SPP EHV Overlay Study	3/3/08	$2.1-2.2
Prairie Wind Transmission	5/19/08	$2.6
Tallgrass Transmission	7/15/08	$2.9
Pioneer Transmission (AEP-Duke)	8/15/08	$4.1[5]
Third Party Estimates		
Green Power Express	2/9/09	$3.3–4.0
ATC Stakeholder Update - 2009 Economic Planning Projects	7/10/09	$4.8
Transmission Alternatives to Interconnect Wind Generation into SPS System -Summary	7/31/09	$2.1
Midwest Regional Generation Outlet Study	9/17/09	$4.2-4.8

Table ES-1 shows that even AEP's own engineering estimates of EHV costs for projects that AEP is currently sponsoring are significantly higher than those used in the AEP Study. The

[3] While Table ES-1 presents the imputed per mile costs used in the CRA Study in determining its total transmission cost estimates, it is not at all clear, as explained in this report, that AEP used these same estimates in coming up with its national EHV overlay cost estimates of $60-$100 billion. The AEP Study never discusses the basis for this cost estimate.
[4] Imputed from the CRA Study as discussed in Section III.A.1.
[5] Includes "related" facilities.

studies done by others range in per mile costs from $2.1 to $4.8 million and with one exception are significantly higher than the AEP estimates. In addition, with the one noted exception, the cost estimates in Table ES-1 do not include costs of necessary substations and other related facilities, nor do they include **the costs of any necessary upgrades to the existing underlying system,** contingency costs or any of the other costs associated with transmission planning, sitting and construction discussed in Appendix B of this report.

Moreover, the data in Table ES-1 illustrates costs for new projects escalating rapidly. For these reasons, we believe that the AEP Study's cost estimate for a national EHV overlay of $60-$100 billion is considerably understated. Based on more recent and realistic cost figures, we estimate costs for a national 765 kV EHV overlay to be between $150 billion and $220 billion, more than double those estimated in the AEP Study.

The AEP Study's estimate of costs per customer of a nationwide EHV transmission overlay does not follow accepted ratemaking practices and consequently is misleading. The AEP Study's approach to computing the cost per customer compounds the underestimation of the cost of a grid overlay. Specifically, the AEP Study suggests that a simple way to pay for the transmission investment is to do away with principled ratemaking practice and simply add a flat surcharge levied on all customers' monthly bills. In actual practice costs would be allocated to regions, sub-regions, utilities within sub-regions, customer classes within utilities, and ultimately individual customers based on some measure of the costs that each level of aggregation imposes on the overall system or based on some ratio of benefits received. The effect of the AEP Study's highly over-simplified methodology, coupled with its significant understating of the costs of a national EHV overlay, is to make a very expensive proposition look reasonable by spreading the (understated) costs as far and wide as they can, regardless of the allocation of costs and benefits from such investment

The AEP Study does not utilize best practices in estimating the benefits of a 765 kV overlay (as set forth in this report). The AEP Study does not independently estimate national benefits; instead it borrows a regional estimate based on the CRA Study's analysis of a much smaller proposed 765 kV project within the nine-state territory of the Southwest Power Pool (SPP) and extrapolates it to represent an EHV grid covering all three of the nation's interconnections.

The AEP Study overestimates the benefits of a 765 kV national grid overlay. Many of the assumptions that the AEP Study borrowed from the CRA Study are questionable or should have been examined through more rigorous analysis. As a prime example, the AEP Study used an estimate of benefits that failed to net out the cost of developing the wind power for which the transmission was being built. Had the wind power capital costs been considered correctly, the net benefit number that the AEP Study borrowed from the CRA Study would have been close to zero, even assuming AEP's cost estimates were accurate. The AEP Study and the CRA Study also improperly include Production Tax Credits as a societal benefit, ignoring the fact that a tax break for wind developers is a cost to taxpayers, who must make up the "lost" tax revenue.

AEP's "top-down" estimate of the costs and the benefits and of a nationwide EHV transmission overlay are inherently problematic, because of the many factors that will affect both of these measures at the regional and interconnection-wide level. Better benefit estimates could be produced by applying a "bottom-up" approach using power flow modeling and extensive scenario analyses. Transmission cost estimates could also be improved through additional detailed engineering studies that take account of the regional differences in terrain and other characteristics of the likely paths of the transmission lines. This more rigorous approach also requires much greater attention to details. Such studies are more costly to perform than the kind of "back of the envelope" analysis presented in AEP Study. Furthermore, we would not expect the costs and benefits to fall uniformly across all customers in the nation's three electrical interconnections. Costs and benefits will vary widely across the regions, states within regions, and across customer classes, depending upon the relative electricity consumption, the density and topology of existing transmission interconnections, contributions to peak demand and the policies of federal, state and local regulators regarding how such costs will be borne by customers.

I. INTRODUCTION

This report summarizes the work undertaken by Christensen Associates Energy Consulting and its' affiliated consultants, (hereafter referred to as "CA Energy") assessing a report entitled "Analysis of Benefits and Costs for a U.S. Interstate EHV Transmission System", prepared by the American Electric Power Company ("AEP") ("AEP Study"). The AEP Study was based on a transmission expansion study conducted by CRA International entitled "First Two Loops of SPP EHV Overlay Transmission Expansion Analysis of Benefits and Costs" (CRA Study). CA Energy concludes that the determination made in the AEP Study that the benefits of the EHV transmission build-out studied by AEP outweigh the costs is not reliable.

The remainder of this report is organized as follows. Section II summarizes the AEP Study and the CRA Study. Section III critiques the AEP Study. Section IV concludes the report. Appendix A provides more information on the projects and studies used in this report to estimate per mile transmission costs. Appendix B provides an in-depth review of appropriate methods for conducting cost and benefit evaluations of transmission expansion projects, provided as a point of reference for the concerns and issues regarding the AEP Study and the CRA Study that are raised in this report.

II. SUMMARY OF EHV OVERLAY COST-BENEFIT ANALYSES

A. CRA International SPP 765 kV Overlay Study

The CRA Study analyzed the expansion of the Southwest Power Pools' ("SPP's") EHV network in order to accommodate upwards of 14 GW of potential wind power capacity additions in Kansas, Oklahoma and the Texas Panhandle. The 14 GW was targeted as the incremental amount of wind power capacity that would be needed to provide 20% of SPP's total generation from wind. The two loops considered were 600 miles of 765 kV lines assumed to be in service by 2013/2014 in western Kansas and Oklahoma (i.e., the 1st loop) and 600 miles of 765 kV lines assumed to be in service by 2015/16 in the Texas Panhandle and southwest Oklahoma (i.e., the 2nd loop).

The CRA Study's quantitative and qualitative benefits for the SPP region consisted of reduced power supply costs; reduced transmission line losses; reduced CO_2 emissions; economic incentives for construction of new wind power; and secondary impacts consisting of increased local employment and earnings, increased tax revenues, and increased economic output. In particular, the CRA Study indicates that the benefits would accrue to the SPP region from the two-loop overlay in the following areas:

- Power Supply Cost Reductions: $2.8 billion (2008 $) annually;
- CO_2 emissions - nearly 30 million tons of CO_2 emissions per year avoided,
- Transmission Line Losses - $100 million per year in reduced power losses,
- Secondary local economic impacts:

- Over 10,000 SPP jobs created during construction, and 5,000 created when lines are made operational,
- $60 million per year in increased property taxes,
- $500 million per year in increased economic output,

■ Renewable Portfolio Standard ("RPS"): more than 20% of SPP demand supplied by renewable energy.

On the cost side, the CRA Study finds that the two-loop project would cost $400 to $500 million per year and that the 14 GW of new planned wind power capacity to which it would provide access would cost $1.73 billion per year net of a federal Production Tax Credit ("PTC") of $0.713 billion.

The CRA Study estimates of the two-loop project benefits and costs are summarized in Table 1.

Table 1

Annual Benefits, Costs and Net Benefits of SPP Two-loop 765 kV Overlay

Energy Benefits/(Costs) (millions 2008 $)			
Supply Cost Savings		$2,766	
Reduced Loss Benefits		$96	
Wind Energy Revenue		($1,867)	
	Total	$995	
Wind Cost Credit/(Shortfall) (millions 2008 $)			
Wind Energy Revenue		$1,867	
Wind Revenue Requirement		($2,447)	
Wind Production Tax Credit		$713	
Wind Market Revenue net of Cost		$133	
	Transmission Cost (millions 2008 $)	$400	$500
	Net Benefits	$728	$628

The CRA Study makes the following claims about the estimated benefits and costs:

Wind energy revenues are more than sufficient to cover the fixed cost of the new wind capacity.

The wind PTC is an important factor in the Power Supply Cost benefits to SPP.

RPS considerations would make the economic comparison more favorable to the Two Loop project as the cost of the new wind resources would be compared to the cost of other renewable capacity.

Local economic impacts and the public benefits of responding to current and potential future state RPS standards are in addition to the Power Supply Cost benefits.

Production cost reduction benefits were estimated in the CRA Study through the application of GE MAPS.[6] Estimates were made for the year 2016 assuming CO_2 emission costs (i.e., the price for emission credits) to be $18 per metric ton (2008 $). The emission credit price was factored directly into fuel price predictions, increasing the price for natural gas and decreasing the price for coal. This reflects an assumption that a cap and trade program that initially increases the price of coal relative to natural gas ultimately would increase the attractiveness of natural gas-fired generators relative to coal, and therefore increase market prices of gas and decrease prices of coal. The $2.766 billion (2008 $) decrease in production costs estimated by the GE MAPS model relative to a base reference expansion case was mostly attributed to the assumption that wind power was dispatched at zero production cost.

Benefits from the reduction in transmission power line losses were separately analyzed and estimated to be $96 million (2008 $). This value was obtained by assuming that line losses would decrease from 5% to 1% (i.e., saving 1,600 GWh) in moving to the 765 kV overlay compared to double-circuit 345 kV lines. The energy savings were valued at $60 per MWh.[7] Thus transmission line loss reductions are also attributed entirely to wind power production.

Wind power capital and operating and maintenance ("O&M") costs were obtained for the CRA Study by using the U.S. Department of Energy's Jobs and Economic Development Impact ("JEDI") Model, initially developed by MRG & Associates in 2002 for the National Renewable Energy Laboratory ("NREL"). According to the description in the spreadsheet, the JEDI model was developed to "demonstrate the economic benefits associated with developing wind power plants in the United States. The primary goal in developing the initial state level model was to provide a tool for wind developers, renewable energy advocates, government officials, decision makers and other potential users, to easily identify the local economic impacts associated with constructing and operating wind power plants."[8] In addition to the capital and O&M cost estimates, the CRA Study used the local economic impacts portion of the JEDI spreadsheet to estimate secondary impacts of the construction of 14 GW of wind power that included employment and income impacts, increases in economic output and local tax revenues in the states of Kansas, New Mexico, Oklahoma and Texas.[9]

The CRA Study assumed that the price of CO_2 emission credits would be $15 per metric ton in 2012 and would increase 5% per year in real terms. The CO_2 emission credit prices were assumed to cause an increase in demand for natural gas, leading to a prediction that natural gas prices would reach nearly the $10 per MMBtu level by 2013. In contrast, all of the recent analyses of significant increases in domestic natural gas supplies suggest that the long-term outlook for natural gas prices, even in the face of greenhouse gas legislation, would keep prices

[6] The GE Multi-Area Production Simulation Software (GE MAPS) is a detailed, chronological simulation model that calculates hour-by-hour production costs that recognize the constraints on generation dispatch imposed by the transmission system. GE MAPS performs a transmission-constrained production cost simulation, which uses a detailed electrical model of the entire transmission network of interest, along with generation shift factors determined from a solved AC load flow, to calculate the real power flows for each generation dispatch.

[7] The $60 per MWh avoided cost was obtained by dividing the production cost savings of $2.76 billion by the 46,000 GWh of wind energy produced.

[8] JEDI Spreadsheet model: 01D_Wind_Model_rel._W1.09.03e.xls, obtained at http://www.nrel.gov/analysis/jedi/ .

[9] Since the model was originally developed in 2002, CRA International updated the impact multipliers by using the most current IMPLAN multipliers.

in the neighborhood of $5 to $7 per MMBtu. The CRA Study also assumed that inter-regional trades were limited by hurdle rates—a “seams charge”—that are designed to capture the inefficiencies in unit commitment and dispatch and in making power trades between regions. This assumption is typically made in studies of this kind and tends to be reasonable in view of the restrictions in modeling such inefficiencies within the context of production cost models.

B. AEP Overlay Study

The AEP Study estimated the cost of the build-out of a 765 kV Extra High Voltage (“EHV”) transmission overlay system for the entire contiguous United States. The study purportedly “demonstrates that as long as costs are allocated broadly across all customers (regardless of the method), the build-out of an interstate EHV transmission system that enables the integration of wind and other new energy resources will provide economic benefits that outweigh the costs.”[10]

The AEP Study based its estimate of benefits of the 765 kV overlay on the analysis performed by CRA International (“CRA Study”) of a two-loop 765 kV project within the Southwest Power Pool (“SPP”), discussed above. The two-loop project has been considered as one way to provide access for up to 14 Giga Watts (“GW”) of wind power capacity planned for parts of SPP’s territory.

The AEP Study’s simple extrapolation of the CRA Study results to a national overlay system cannot be supported for a number of obvious reasons. The two-loop proposal that the CRA Study evaluated differs markedly from the national overlay in terms of shear numbers of system miles, number of substations required, the much more variable topology and population densities that the national overlay would cover, as well as the number of GW of resources that it is expected to provide access to, and the much longer timeframe for the buildout, all of which will affect the costs to implement the AEP Study scheme.

The gross economic benefits derived in the CRA Study consist of generation production cost and congestion and transmission line loss savings totaling $11.90 per megaWatt hour (“MWh”). The AEP Study assumed that half that amount would be saved at the national level (i.e., $5.95 per MWh) for a 20-year 765 kV overlay build-out to accommodate 20% nationwide wind penetration by 2030. The AEP Study assumed that the cost of the 765 kV overlay would be in the range of $60 billion (low cost scenario) to $100 billion (high cost scenario), reflected in a levelized investment stream between $3 and $5 billion per year.[11] Using load data obtained from the Energy Information Administration (“EIA”),[12] and assuming annual load growth equal to 1%, the AEP Study calculated that the “cost to the average residential customer would be a flat $0.70 - $1.15/month for 20 years, with the benefits increasing to $5.95/MWh over 20 years.”[13]

The AEP Study also presented a proposal for allocating the national overlay capital costs on a per customer meter basis with cost recovery coming from all consumers nationwide through a

[10] American Electric Power, *Analysis of Benefits and Costs for a U.S. Interstate EHV Transmission System*, May 2009, page 1.
[11] AEP Study does not provide any detail or references to support its estimated range of transmission costs for a national overlay.
[12] EIA data referenced were for 2007.
[13] AEP Study, page 3.

unique, non-traditional flat-rate surcharge added to transmission tariffs under the Federal Energy Regulatory Commission's jurisdiction.

III. ANALYSIS OF THE AEP AND CRA EHV GRID OVERLAY STUDIES

A. The CRA Study's and the AEP Study's Cost Assumptions Are Not Reasonable

1. Transmission Costs

The AEP Study asserts that the costs of the proposed national EHV overlay would range from $60-$100 billion. The AEP Study does not, however, reference the source of this estimate or describe how it was derived. While the national benefit estimates in the AEP Study were clearly scaled up from the SPP benefits cited in the CRA Study, it is not clear how the cost estimates were derived. Thus, we can only compare this estimate in the AEP study to estimates that have been made elsewhere for a national EHV overlay, and with our own estimates. This work is critical in order to evaluate the net benefits AEP claims the EHV overlay will produce.

The CRA Study does not provide a cost per mile assumption for the transmission upgrades studied, but does estimate that the total cost is expected to be $400-$500 million per year. If we first assume that this cost estimate includes interconnection (substation) costs, and assume a very low estimate for substation costs of 25% of the total costs, then the costs for the lines themselves would appear to be $300 - $375 million per year. Assuming an annual carrying charge of 15%, that would imply a total transmission capital cost for the 765 kV Overlay in SPP of $2.0 billion to $2.5 billion, which in turn translates to a per mile cost of $1.7 million to $2.1 million. In view of other per mile estimates that appear to us to be more credible, including some recently advanced by AEP itself in connection with specific projects, it appears that current cost estimates of 765 kV EHV lines are closer to $4 million per mile or more. (See Table ES-1 for a summary of other per mile cost estimates)

As discussed above, we don't know whether the AEP Study used the CRA Study cost results in any way to reach its national $60-$100 billion national EHV overlay cost estimate. There have been estimates made by AEP and others elsewhere of the costs of a national EHV grid overlay. AEP elsewhere has put the national cost at $60 billion.[14] Examples of other such studies are the Joint Coordinated System Plan ("JCSP") study conducted in 2008[15] and more recent report by ISO New England issued in 2009.[16]

The JCSP study examined two resource and transmission paths to serve a total of 745,000 MW of coincident peak load in the Eastern Interconnection, except Florida in 2024. JCSP's Reference Scenario assumed that present RPS requirements are met through local on-shore wind

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[14] Testimony of Susan Tomasky, President, AEP Transmission Before the United States Senate Committee on Energy and Natural Resources. July 31, 2008.

[15] Joint Coordinated System Plan 08. http://www.midwestmarket.org/publish/Document/20b78d_11ef44fc9c0_-7bad0a48324a/JCSP_Report_Volume_1.pdf?action=download&_property=Attachment.

[16] ISO New England, Draft New England 2030 Power System Study: Report to the New England Governors. September 8, 2009.

resources equal to 58,000 MW, and 10,000 miles of new extra high voltage transmission (7,109 miles of EHV AC at 345 kV and higher plus 2,870 miles of HV DC lines) would be added to accommodate it at a total cost of about $48.5 million.[17] The Reference Scenario assumed that 5% of the Eastern Interconnection's energy would be derived from wind and 54% from base load steam generation.

Under the alternative resource and transmission path, referred to as the "20% Wind Energy Scenario," the JCSP Study assumed that a 20% national RPS requirement would be met through on-shore wind development of 229,000 MW with approximately 15,000 miles of new EHV transmission (6,898 miles of EHV AC at 345 kV and above and 7,582 miles of HV DC lines) added to accommodate it at a total cost of about $79.9 million.[18]

In September of 2009, ISO New England (ISONE) issued a report that examined the potential for renewable energy development in New England and associated transmission requirements. As a part of that study, the ISONE also looked at alternatives to local renewable development and in particular, the possible development of renewable resources in the Midwest with an EHV grid overlay to move the power from the Midwest to New England. The ISONE used the JCSP EHV grid overlay study results as a starting point for developing scenarios involving importation of renewable power from other regions and added to the JCSP study results the transmission upgrades that would be needed within New England to accommodate the increased imports. There were many interesting conclusions to the ISONE study, including its' finding that renewable importation scenarios with an EHV national grid overlay were significantly more expensive to New England consumers than local renewable resource development. In reaching these findings, ISO New England also concluded that the costs of an EHV national grid overlay were significantly understated by the JCSP study. ISONE pegged the cost of the JCSP Eastern Interconnection proposal at $160 billion using New England cost per mile estimates.

Our conclusion that AEP's cost estimate for the 765 kV Overlay is substantially understated thus follows from the following observations: (1) CRA Study's cost estimate may be only half of currently projected per mile costs for 765 kV lines (and assuming that there is a relationship between the CRA Study and the AEP Study transmission cost estimates); (2) JCSP puts the cost of a grid overlay for the Eastern Interconnection alone above AEP's national cost estimate; and, (3) ISO New England believes the real costs for the Eastern Interconnection are closer to $160 billion.

We also note that many of the other costs of transmission projects, discussed at length in Appendix B, have not been included in most of the national estimates of grid overlay costs. These costs include: (1) the costs of interconnecting the high voltage lines into the grid; (2) other integration costs associated with variable generation; (3) planning, regulatory and siting costs; (4) contingency costs; and (5) the costs of improvements needed to the existing grid to maintain reliability or resolve congestion issues. Contingency costs alone can add a minimum of 30% to the total costs of EHV projects. Integration costs and planning, siting and regulatory costs are

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[17] Transmission cost estimate is expressed in 2024 dollars and includes substation costs of $6 billion, JCSP Study, Table 1-1, p. 6.
[18] Transmission cost estimate is expressed in 2024 dollars and includes substation costs of about $7 billion, JCSP Study, Table 1-1, p. 6.

likely to be considerable for a national project, not to mention escalation costs during the time that it may take to construct an EHV overlay on a national scale.

Developing a more accurate and reasonable estimate of the costs for a national EHV grid overlay would require a comprehensive analysis, including detailed engineering studies that take account of the regional differences in terrain and other characteristics of the likely paths of the transmission lines. Such a detailed analysis is beyond the scope of this report, but some inferences can be drawn as to the possible order of magnitude of the costs of a national EHV overlay from the multiple studies and analyses reviewed for this report.

Nonetheless, based on (1) our examination of the estimated costs per mile of other EHV transmission projects in the United States relative to estimates from the AEP Study and CRA Study; and (2) our review of the JCSP Study (and ISO New England comments on the JCSP Study), we have developed what we believe to be more reasonable estimates of the potential costs of an EHV national grid overlay.

First with respect to the costs per mile comparative analysis, to derive an estimate of the range of costs for a nationwide EHV overlay that we believe to be reasonable, we assumed that the $60 billion to $100 billion estimate in the AEP Study for grid overlay costs was scaled up in some way from the CRA Study per mile transmission costs, since the AEP Study also relied on the benefit estimates from the CRA Study. As previously discussed, the per mile cost of transmission that can be imputed from the total transmission cost estimates of the CRA Study ranges from $1.7 million to $2.1 million per mile. Our own review and analysis of transmission cost factors including AEP's own more recent project per mile cost estimates, and others, as summarized in Table ES-1 suggests that actual per mile costs are about twice as high as those implied by the CRA Study or about $3-$4 million per mile.

Applying this doubling factor of the per mile transmission costs to the AEP Study estimates results in a $120 billion to $200 billion dollar range for national EHV overlay costs. In addition, if we assume that substation costs are not included in the AEP Study estimates, that cost factor would add at least 25 percent to the total costs, resulting in a range from $150 billion to $250 billion. And even this cost range does not include any of the other costs of transmission expansion discussed above and in more detail in Appendix B. Consequently, we believe the $150 billion to $250 billion range is quite a conservative estimate.

Second, we examined the JCSP and ISONE studies to derive a second, independent estimate of national EHV overlay costs. The JCSP study estimated the cost of a national EHV grid overlay, sufficient to accommodate a 20% share of variable generation to be $80 billion for the Eastern Interconnection alone. Extrapolating the JCSP Eastern Interconnection result to a national grid overlay cost estimate is fraught with difficulties, but for our purposes, we will assume that the costs of a national EHV overlay in each of the three Interconnections is proportional to the relative peak loads within each Interconnection. The peak load of the Eastern Interconnection is about 74 percent of the peak load for the continental U.S., so assuming transmission expenditures for a national overlay are proportional to peak loads and extrapolating the JCSP results, the costs for the U.S. of a national overlay would be about $110 billion. This is again a very conservative estimate, because we would expect that the costs of transmission in the Western Interconnection, in particular, are much higher relative to peak load than in the Eastern

Interconnection due to lower population densities and the nature of the transmission systems in the West.

The JCSP Study was also not exclusively made up of 765 kV lines- it considered EHV to include 345 kV and above and included much more expensive HV DC lines, so a cost per mile comparison is difficult. But the cost per mile apparently used by the JCSP for 765 kV lines was about $1,000 per MW-mile, including substation costs.[19] JCSP estimated a typical loading on the 765 kV lines of about 2,600 MW, which translates into a cost per mile of $2.6 million including substations. The JCSP cost per mile without substations would be about $2.1 million per mile (again assuming that substations make up 25 percent of total costs). This is on the low side of most estimates we have presented in this report. Our review of the probable costs of 765 kV transmission based on recent projections (see Table ES-1) shows cost estimates to be between $3 million and $4 million per mile (on the conservative side), excluding substations. The ISONE study also found that JCSP significantly underestimated the costs per mile of EHV transmission—by a factor of two. Thus, we believe it is reasonable to conclude that the JCSP estimated cost per mile is at least 50 to 100 percent below our best estimate for a 765 kV transmission overlay.

The JCSP study projected 4,000 miles of 765 kV lines, out of a total of 15,000 miles of new transmission of various sizes required. We will assume for purposes of this report that the per mile costs of other voltage classes of transmission were similarly underestimated. Based on this assumption, and using our best estimates for 765 kV costs per mile, the JCSP study would have resulted in a cost range of $167 billion (assuming transmission costs per mile are 50 percent higher than the JCSP extrapolated result of $110 billion for the nation) to $220 billion (assuming transmission costs per mile are 100 percent higher) for the nation.

The two calculations presented above come to similar results for a range of likely national EHV transmission overlay costs - $150 - $250 billion in the first estimate based on applying more reasonable cost per mile estimates to the AEP Study and $167 to $220 billion in the second estimate based on applying these same cost per mile estimates to the JCSP study. For purposes of this report, we base our estimate of national EHV overlay costs on the lower number of each of these two ranges to present an estimate on the conservative side. Thus, we conclude for purposes of this report that a likely cost range for a national 765 kV transmission overlay will be in the range of $150 billion to $220 billion, subject to the caveat that this is a greatly simplified analysis based solely on an extrapolation of the JCSP Study, the AEP Study, and the CRA Study. However, note that these conclusions indicate costs are more than double the range assumed in the AEP Study for its EHV overlay benefit calculations.

Thus, both the costs of transmission estimated for the SPP 765 kV overlay that were used in the calculation of net benefits to SPP in the CRA Study (and scaled up nationally in the AEP Study), and the national EHV overlay costs assumed in the AEP Study are significantly understated. With respect to the costs of the SPP 765 kV overlay, we estimate that costs will likely be twice that estimated by the CRA Study, and with respect to the national EHV overlay, likely costs may be two to three times greater than that estimated by the AEP Study. In both cases, the prime drivers behind these differences are our conviction that realistic costs per mile will be

[19] Joint Coordinated System Plan 2008. Economic Assessment, Appendix 5, Table A5-1.

significantly higher than estimated in these studies and the need to account for substation and other costs that were not explicitly included in the CRA Study and the AEP Study estimates.

2. Wind Generation Costs

Aside from the costs of transmission, the CRA Study attempts to estimate the costs of generation from the wind capability enabled by the EHV overlay. These costs for SPP are estimated at $1.75 billion per year net of the PTC. The CRA Study estimates an annual revenue requirement associated with these costs of $180/kW-year. As discussed below, we believe these costs for wind are on the low side.

The CRA Study based its estimate of $180 per kW year on capital and operating costs from a model developed for wind power generation by the U.S. Department of Energy. DOE used an annual fixed charge rate of 11 percent based on a 20-year operating life, five-year tax life, and financing assumptions (80% debt at 10% interest and 20% equity with a return of 16% per year) and a capital cost of $1,400 per kW. This resulted in an annual carrying cost of $154/kW-year. The DOE model also adds $26 per kW-year for operating costs to reach the total of $180/kW-year.

In a 2008 study, the Department of Energy estimated that, for projects constructed in 2007, capital costs for wind ranged from $1,240/kW to $2,600/kW, with an average cost of $1,710/kW.[20] Moreover, the same study notes that even higher installed costs are likely in the near future. The average installed cost for proposed projects (most of which were expected to be built in 2008) was $1,910 per kW. This suggests that the CRA Study may have underestimated the capital costs of wind in 2008 dollars by as much as 35 percent ($1,910/kW vs. $1,400/KW).

Also, the CRA Study assumes a 37% capacity factor for the wind power that is enabled by the grid overlay. As discussed in Appendix B, high-end estimates for wind capacity factors currently range from 30–35% and there is evidence to suggest that even this may be too high. A recent Luminant study of wind capacity values in ERCOT found average capacity factors of 23.7% for all hours during the summer of 2009 and 13.2% for the system peak hour. We would not expect very different results for wind built in SPP.[21] The use of a 37% capacity factor in the CRA Study results in a significant over-estimate of the potential benefits of the EHV overlay and the accompanying increase in wind energy in SPP, given that more realistic capacity factors are closer to 25%.

It also appears that the CRA Study simply took the DOE assumptions regarding debt structure, interest rates, and operating lives directly from a DOE spreadsheet. The 11% carrying charge that they used to estimate the cost per kW-year is low. It's interesting to note that the CRA Study uses a 15% annual charge rate for transmission (which one would expect to have a lower

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[20] U.S. Department of Energy, Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007, Washington, D.C., May 2008, p. 21.

[21] Henry Durrwachter, Luminant Corporation. *Capacity Value of Wind: An Examination of Historical Data*, Presentation to ERCOT Generation Adequacy Task Force Meeting, November 3, 2009, .http://search.ercot.com/search?q=capacity+value+of+wind&btnG=Search+%3E&site=ercot-com&client=ercot-com&proxystylesheet=http%3A%2F%2Fwww.ercot.com%2Fstyles%2Fgoogle.xslt&output=xml_no_dtd&ie=utf8&oe=utf8&getfields=title.description .

carrying charge rate than wind). The CRA Study does not explain the difference in carrying charge rates it uses in its study.

The CRA Study also assigns a $6/kW-year capacity credit that offsets the $180/kW-year annual revenue requirement based on a "10 percent wind capacity value and new capacity being needed in SPP after 2020."[22] While no basis is given for the 10 percent capacity credit or its value, it does not appear to be unreasonable.

B. The AEP Study Costing Method Does Not Conform To Best Practices.

We believe the inputs used in the CRA Study were not based on the best information available, and that in many cases costs may have been significantly understated. In addition, as discussed below, there were benefits (such as the Production Tax Credit) that should not have been included. At the very least, when the AEP Study scaled the CRA Study results to the national level, it should have excluded the PTC from the benefits calculation, where the objective is to capture net social benefits. The PTC might be considered a partial regional benefit (in a regional cost-benefit analysis) to the extent it is paid for by taxpayers outside the region, but it certainly cannot be considered a benefit at the national level when all taxpayers are included in the analysis.

Thus, we do not believe that the results of either the CRA Study or the AEP Study are valid for reaching conclusions about federal or state policy designed to encourage transmission investment or wind power development.

C. Costs Were Not Properly Allocated To Estimate Per Customer Costs.

The AEP Study attempts to take its nationally scaled results for costs and benefits and apply them to individual customers using two different methods. The first method was a "simplified alternative approach" allocating a flat charge per customer meter and thus finding a progressively increasing net savings to around $5/month for the average residential customer. The AEP Study further assumed that the $60 billion lower end of capital costs resulted from an expenditure of $3 billion per year for 20 years and the higher end of $100 billion resulted from an expenditure of $5 billion per year for 20 years. Apparently for purposes of "demonstrating" the method, the AEP Study assumed that the total annual charge would be evenly divided between residential, commercial, and industrial customers.

In adopting this method, the AEP Study produces a very low cost per meter for residential customers ($0.70 and $1.15 per month respectively), which thus allows them to make the claim of a cost of $1 per residential customer per month. For industrial customers, on the other hand, because of the method chosen, costs range from $105 per meter per month to $175 per meter per month. For estimating net benefits, the AEP Study then takes this per meter cost for residential customers and applies it against gross benefits in two snapshot years (2020 and 2030) to find net benefits in those years which range from $1.83 per month per customer to $5.25 per month per customer.

There are substantial problems with this method. First, the AEP Study assumes that the costs of the EHV Overlay will be evenly divided across all U.S. customers regardless of where the investments are made. But, to complete a national EHV overlay, actual investments will be

[22] CRA Study, p. 14.

made in each of the three electrical interconnections. At a bare minimum, transmission investment costs should be assessed only on an interconnection-wide basis. It would be more appropriate to allocate those costs to regions in which the investments are made. It is not at all clear what kind of mechanism could be applied to customers who are not beneficiaries of the transmission service provided that would require them to pay for these facilities, short of a federally mandated nationwide tax..

A second major error is that the AEP Study assumes that a $60 billion capital investment results from payments of $3 billion per year for 20 years (or $100 billion from $5 billion per year over the same time period). This ignores the time value of money, and the process by which costs will be recovered. As discussed earlier, the proper way to analyze the annual costs of a capital investment is with an annual carrying charge. Assuming a conservative annual carrying charge (at the low end of reasonable estimates) of 15%, the annual costs of a $60 billion investment would be $9 billion per year and the annual costs of a $100 billion investment would be $15 billion per year. Thus, the annual fixed per meter charge for transmission, assuming the AEP Study's total capital investment assumptions are reasonable (which we have disputed), is at least three times greater than the AEP Study has calculated. This error by itself decreases net benefits in the AEP Study's 2020 calculations to a range of $0.78 per customer per month in the best case to a negative $0.37 per customer per month in the worst case. For 2030, the net benefits are reduced to $3.85 per customer per month in the best case to $2.50 per customer per month in the worst case. Once a correction is made for the fact that transmission costs are probably understated by nearly half and that production cost savings are significantly overstated, it is <u>not</u> clear that the benefit-cost ratio exceeds one for the national EHV overlay as suggested by the AEP Study.

The AEP Study also allocates costs on the basis of meter numbers in this first case. Using flat per meter charges is not the way transmission investment costs would ever be allocated in the real world, because it bears no relationship to the costs of service by customer class, whether measured by usage or peak load ratio share. The problem is further compounded by the assumption that total annual costs are evenly divided among customer classes. It is not clear why the AEP Study made this assumption, even for demonstrative purposes, when it would have been just as easy to divide costs among relative kilowatt-hour usage by the three customer classes—a number that is readily available. The end result of the method used by the AEP Study is probably to understate the costs to residential customers and overstate the costs to industrial customers—but since the AEP Study only presents the cost benefit results for the residential class, the overall impacts are unclear.

Perhaps tacitly admitting the problems associated with a per meter flat customer surcharge approach, the AEP Study also estimates per customer charges using a "traditional ratemaking" approach. In this case, the AEP Study adopts a carrying charge (16%) and allocates costs based on load-ratio shares. However, the AEP Study continues to assume that costs will be added to rate base at a rate of $3 billion or $5 billion per year, rather than applying the carrying charge to the total cost of the project. That fact notwithstanding, this method is a significant improvement over the flat per meter charge approach. Nonetheless, this approach is also flawed. The CRA Study assumed that costs across customer classes would be the same on a per MWh basis and net benefits are provided for all customers—not just for residential customers. The method for allocation of total costs based on load ratio shares is not presented. Thus it is impossible to compare the net benefit results using the "traditional ratemaking" method with the results obtained in the per meter charge case. A more reasonable assessment would have been to look at the costs for each customer class based on some kind of weighted average of peak-load ratio shares by customer class. However, the necessary data may not be available on the geographic scale for which such estimates are being sought, and developing such averages may be difficult. An alternative, less precise method (but still more reasonable than the method used in the AEP Study) would be to divide total costs by total retail sales for the geographic region for which the cost estimates were developed, and then attribute an average cost to a customer in each customer class based on the average use per customer in that customer class.

In sum, the method used by the AEP Study to assess a per customer charge and per customer net benefit cannot be expected to provide a reasonable estimate, and should not be used to reach any policy conclusions about transmission investment.

D. The Methodology For Determining Benefits Was Not Reasonable.

1. Benefits Were Not Properly Identified.

The AEP Study simply relied on the benefits calculated in the CRA Study of the SPP 765 kV two-loop overlay and attempted to scale them upwards to obtain a national benefits estimate. The problems involved in the scaling of regional results to get national results are discussed in the following section. In this section we discuss the benefits assessment in the CRA Study to determine if they are reasonable. While the CRA Study does not explicitly indicate the level of benefits being considered, it appears that they are attempting to estimate total societal benefits and costs—including environmental benefits and indirect local economic benefits.

The CRA Study identified the following kinds of benefits to the SPP region from the proposed 765 kV overlay:

- power supply cost reductions in SPP;
- reduced transmission losses
- reduced carbon emissions;
- increased employment;
- increased property tax revenues;
- increased economic output; and,
- ability to meet RPS requirements.

In addition, the CRA Study appears to count the Production Tax Credit (PTC) for wind energy construction as a benefit (or at least as an offset to revenue requirements).

Of these categories of benefits, power supply cost reductions in SPP, reduced carbon emissions, reduced transmission losses, and indirect economic benefits such as increased employment and economic output are valid potential benefits. All of these do result in a positive societal impact and do not double count other benefits. But property tax revenues, the ability to meet RPS requirements, and the inclusion of PTCs as an offsetting benefit are all problematic.

The inclusion of the Production Tax Credit is the most obvious error in the benefits calculation. In a societal cost-benefit analysis of the type conducted in the CRA Study, taxes are simply transfer payments—they represent a cost to the taxpayer that show up as a benefit to the wind power developer and net each other out. The production tax credits will be paid by taxpayers both within and outside the region, but for purposes of a societal cost benefit analysis, the location of the costs (or benefits) is not relevant. This is particularly important because even if the PTC could be considered a partial benefit to the SPP region because the region receives PTC benefits paid by taxpayers outside of the region, when the AEP Study scaled the SPP results up to a national level, there is no justification for considering the PTC as a benefit—it is clearly a transfer payment at the national (societal) level.

With respect to property taxes, the problem is much the same. First, property taxes should be considered to be an operating cost of the new transmission facilities, and thus in a societal cost benefit analysis, the property tax cost in the transmission costs ledger cancels out the property tax revenue on the benefits side and thus the net effect is zero. It is unclear whether property taxes were explicitly included as a transmission cost in the study, but, if they were not, they should have been. A second problem is that the indirect benefits of increased employment and economic output also have a cost associated with them that was not included. Increased employment and economic activity means that there are governmental costs incurred such as the need for more classrooms, roads, and social services. These are precisely the kinds of costs that property tax receipts are meant to cover. Thus, even if property taxes were an appropriate category of benefits, they should have been reduced to reflect increased governmental costs. In any event, the $60 million dollars claimed as a benefit were not large enough relative to the other benefits and costs to significantly affect the analysis.

With respect to the ability to meet a 20% renewable portfolio standard, there is no societal benefit from achieving a renewable standard per se. The benefits from meeting such a regulation are primarily any reduction in power supply costs and the benefit in reduced carbon emissions, both of which are already counted. There could be other benefits to a national RPS (such as national security benefits from reductions in the use of foreign oil), which, although difficult to quantify, could have been included. While naming a national RPS as a benefit, the CRA Study did not attempt to quantify the value of the benefit and incorporate it into the benefit cost calculations.

2. All The Benefits Were Not Considered.

There are some potential benefits that were not considered in the CRA Study. For example, besides the carbon emissions reductions included as a benefit, there are potential reductions in other emissions such as SO_x, NO_x, and particulates. Some other possible benefits include reduced water use to cool fossil fuel generation and reduced risk associated with the volatility of fossil fuel costs.

While the CRA Study listed employment and economic output as potential benefits, they did not attempt to include them in the net benefit calculations. However, we do not believe that including any of these additional benefits would have made a substantial difference in the overall cost benefit analysis.

3. Not All The Identified Benefits Are Likely To Be Realized.

Aside from the employment and economic output benefits that do not appear to have been included in the overall cost-benefit calculation made in the CRA Study, we also believe that the reduced transmission loss benefits were reasonably assessed and likely to be realized by the 765 kV EHV overlay. We also believe that the benefits from carbon emissions reductions are reasonable because CO_2 prices used begin at $15/ton in 2012 and increase at 5% per year in real terms. While $15/ton in 2012 is at the low end of estimates of CO_2 prices, it is certainly within the range of prices considered reasonable in similar projections prepared by both federal agencies and academic institutions.[23]

However, we believe supply cost savings and transmission costs, which are the two most significant components of the CRA Study, are not accurately formulated or calculated.

Supply cost savings represent the largest benefit found in the CRA Study. We do not, however, believe that the estimated level of supply cost savings is likely to be realized. First, as discussed in the preceding section, the capital costs for wind generation may have been underestimated by as much as 35 percent. Capacity factors for wind were over-stated in the CRA Study which also resulted in over-stated benefits. In addition, the production tax credit should not have been considered as a benefit. Using more realistic cost estimates and eliminating the production tax credit in the calculations would by themselves turn the net benefits found by the CRA Study to net costs or even to sizeable losses.

4. Benefit Estimates Are Not Attributed To The Right Beneficiaries.

The CRA Study attempts to assign power supply cost savings to individual states. A more accurate assessment would have required multiple runs of the GE MAPS model with and without wind generation in each individual state. We cannot tell how accurate the CRA Study's simplified method might be, but the state allocations do not ultimately affect the results that are summarized in the AEP Study for the nation as a whole. Thus, while the state allocation method is questionable, we did not spend a lot of time analyzing what the CRA Study did in this regard.

Besides the attempt to make individual state estimates, the CRA Study does not distinguish between societal and regional or local benefits. In fact, they ignore some costs that would occur outside of the region (such as increased taxes) that they claim as benefits within the region. The AEP Study also ignores these regional differences in its national assessment.

5. Benefits Were Not Properly Compared To Costs.

Because the CRA Study conducted a societal benefit-cost study, to obtain net benefits and determine whether they were positive or negative, all that was necessary was to add up all of the benefits of the proposed SPP 765 kV overlay and subtract total costs. The CRA Study's mistake

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[23] See for example, Energy Information Administration. "Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009" at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/figurees3.html.

in this regard involved counting items as benefits that are not really benefits. The primary "benefit" that should have been excluded was the PTC. In the case of wind energy revenue, the CRA Study counted it as both a cost on the "benefits side" of the ledger and a benefit on the "cost side" of the ledger. As with the treatment of taxes, wind energy revenues are a benefit to the recipient (the project developer) but a cost to the customer, and thus are neither a benefit nor a cost. Their inclusion only confuses the issue of the true costs and benefits of the transmission overlay.

These errors were then compounded when the net benefits found by the CRA Study were scaled up to a national level by the AEP Study

6. Local And Regional Results Were Not Properly Scaled To Determine Macroeconomic Impacts.

As discussed previously, the AEP Study used the results of the CRA Study analysis to estimate costs and benefits of a national EHV overlay to accommodate a 20% penetration of wind energy in the United States. The AEP Study took the CRA Study gross benefits in terms of $/MWh for the SPP region (which is primarily based on production cost savings) and assumed that 50 percent of these benefits would be achievable when wind penetration is scaled up to 20% nationally. The AEP Study provides a reason for discounting the benefits in a footnote "…To account for regional differences in applying the analysis nationwide, we estimated the benefits shown in the CRA Study analysis to be for the entire 2,400 miles proposed for the SPP EHV Overlay, thus discounting the benefits to 50%."[24] This rationale makes no sense because the benefits estimated for the 765 kV overlay in the CRA Study were made only for 1,200 miles—not 2,400 miles. There is no economic rationale for assuming that production cost savings and transmission loss savings estimated for the 1,200 mile overlay in SPP would remain the same if the overlay were scaled up to a national level—and there is certainly no basis for assuming that half the benefits of the 1,200 mile overlay would be realized once the EHV overlay is scaled to the national level. Without further explanation, it is impossible to tell why this 50% discount rate was used.

The AEP Study compounds the problem by "assuming" a 20-year build-out of a national EHV transmission overlay beginning in 2011, and assuming the costs to range from $60 - $100 billion. The AEP Study makes no attempt to tie this cost estimate even to the transmission cost estimates in the SPP study or to explain where these numbers come from. JCSP did come up with $80 billion (although for the Eastern Interconnection only) and AEP has used $60 billion in past publications, but neither of these sources is specifically referenced in the AEP Study. Thus, there is no way to assess the validity of this cost estimate based on the information provided, yet it is the key to all of the conclusions reached in the AEP Study.

The AEP Study also makes a serious error in the way in which it scales up the gross and net benefits of the CRA study to the national level, resulting in a significant overestimate of net benefits at the national level. The AEP Study starts with the $11.90/MWh of gross benefits found in the CRA study and divides by two to estimate national gross benefits of $5.95/MWh.

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[24] American Electric Power, Analysis of Benefits and Costs for a U.S. Interstate EHV Transmission System, op. cit., p. 2.

The AEP Study then subtracts its range of estimates of transmission costs from gross benefits to obtain its range of net benefits from a 20 percent wind penetration and accompanying national 765 kV overlay. But in doing this, the AEP Study fails to consider the capital costs of the wind production itself, which was properly subtracted from gross benefits in the CRA Study. The CRA Study's estimate of the annual wind revenue requirement was $2,447 million or $1,734 million if the PTC is taken into account. And while not explicitly stated in the CRA Study, it appears that the $11.90/MWh gross benefit was derived by taking the supply cost savings of $2,766 million and dividing it by total SPP load, which by inference is estimated to be 232,436 MWh.

Thus, given the estimated revenue requirement for the 14 GW of wind in SPP of $2,447 million, the $/MWh cost of new wind capacity in SPP would be $2,447 million divided by 232,436 MWh, which equals $10.53/MWh. Even if one assumes that the PTC is considered a benefit (which we question elsewhere) the costs of wind would be $1,734 million divided by 232,436 MWh, which equals $7.46/MWh. This would reduce the gross benefits of $11.90/MWh to either $1.37/MWh or $4.44/MWh, before transmission costs are deducted. But the AEP Study, in scaling the CRA Study results to the national level, deducted only transmission costs from the gross benefits per MWh, and did not deduct the annualized wind capital costs. Had the AEP Study correctly derived net benefits from gross benefits by subtracting all relevant costs, it would have shown a benefit to cost ratio of less than one, once transmission costs were considered.

Finally, the AEP Study assumes that the benefits (expressed as $/MWh) will increase linearly each year until 2020 when they reach a final total of $5.95/MWh in 2020 (50% of the *gross benefits* found in the CRA Study). This benefit estimate is compared to the cost per meter of the $60-$100 billion to find that there is a net savings of about $4/month for the average residential customer. The AEP Study ignores the fact that this $4/month savings, if realized, does not accrue until 2020, and in fact under AEP's own method, residential customers are likely to be worse off in the early years of the buildout. It is curious that the AEP Study made no attempt to estimate the net present value to customers of the costs and benefits, which would have been the proper way to account for costs and benefits over time and the time value of money.

In short, the method used to scale the regional result to a national result in the AEP Study is entirely opaque, and should be viewed with skepticism. Until AEP provides further explanation for the scaling of cost and benefit numbers, the proffered values should not be relied upon to entertain serious discussions about federal or state policy regarding transmission investment and cost allocation.

IV. CONCLUSIONS

For the reasons we have given in this report, we do not believe the AEP Study has produced a reasonable estimate of the costs of a national EHV grid overlay. On the costs side, our conclusion is that the AEP Study has significantly understated the costs of the proposed EHV overlay, perhaps by as much as 250 percent, and the AEP Study's cost per customer estimates are even more significantly understated.

The key deficiencies in the AEP Study with respect to EHV grid overlay costs are as follows:

- Per mile transmission line costs appear to be significantly underestimated. Per mile costs based on other projections are 50 to 100 percent higher than that used.

- Scaling of line costs from a regional level to a national level is unsupported.

- Several important overlay cost factors, such as substation costs, integration costs, contingency costs, and planning, regulatory and siting costs, have not been considered.

- The method used to calculate per customer costs bears no relationship to how costs would be allocated in the real world, and thus presents a totally unrealistic picture of the actual costs that customers of different types and in different locations would bear as a result of the construction of an EHV national grid overlay.

- The financial assessment of transmission investment costs ignores the time value of money.

On the benefits side, the AEP Study contributes little analysis, but instead draws upon the benefit estimate obtained by the CRA Study for the SPP two-loop 765 kV project, which is highly specific to the SPP region. Moreover, the CRA Study also suffers from methodological and referential problems. There is significant uncertainty attached to the benefit estimate computed by the CRA Study and that uncertainty is magnified many times over when the AEP Study attempts to extend the result to the entire country.

In summary: the key deficiencies on the benefits side in the AEP and CRA Studies include:

- Benefit estimates based on the CRA Study, even if reasonable for the SPP territory, cannot be reasonably scaled up to a national level.

- Factors considered in the CRA Study as offsetting transmission costs, such as the Production Tax Credit and the ability to meet a 20% RPS requirement, are problematic.

- Even considering the bottom-up approach taken by the CRA Study, it is doubtful that the full benefits estimated will be achieved.

Overall, “top-down” estimates of the benefits and costs of a nationwide EHV overlay, such as attempted by AEP are inherently unreliable, in view of the many factors that will affect both of these measures at the regional and interconnection-wide level. The AEP Study could have produced better benefit estimates by applying a “bottom-up” approach using power flow modeling and extensive scenario analyses. Transmission cost estimates could be improved through additional detailed engineering studies that take account of the regional differences in terrain and other characteristics of the likely paths of the transmission lines, and reliance on more recent cost data and other cost projections. This approach also requires much greater attention to details, and in both cases, such studies are likely to be more costly to perform than the kind of “back of the envelope” analysis presented in the AEP Study. But such detailed analyses should be conducted if studies such as these are to form the basis for public policy decisions that require the expenditure of hundreds of billions of dollars.

APPENDIX A:
TRANSMISSION PROJECTS/STUDIES USED IN COSTS PER MILE COMPARISON PRESENTED IN TABLE ES-1

SPP EHV Overlay Study
An updating of an earlier study performed to evaluate the effect of intensifying wind development activity in portions of the SPP system. Reviewed four "Mid-Point" Designs for transmission upgrades within AEP, including several EHV projects within each Design.

Source of Cost Data: Quanta Technology. Final Report on the Southwest Power Pool (SPP) Updated EHV Overlay Study, Prepared for SPP, March 3, 2008.

Prairie Wind Transmission
Prairie Wind is a 180-mile 765 kV transmission line and substation project proposed by ITC Great Plains and Prairie Wind Transmission, a joint venture formed by Westar Energy Inc. and Electric Transmission America—which is in turn a joint venture of American Electric Power and MidAmerican Holdings, Inc. The project will consist of a line from Spearville, Kan. to Commanche County, then back through Medicine Lodge and ending outside of Wichita. ITC Great Plains is to build the first two sections of the 765-kilovolt line and Prairie Wind Transmission is to build the third leg from Medicine Lodge to Wichita.

Source of Cost Data: Before the State Corporation Commission of Kansas, Direct Testimony of Kelly B. Harrison, Westar Energy on Behalf of Prairie Wind Transmission, LLC, May 19, 2008.

Tallgrass Transmission
Tallgrass Transmission is a joint venture between OGE Energy Corporation and Electric Transmission America. Tallgrass Transmission's first proposed project is to build approximately 170 miles of 765-kilovolt transmission facilities extending from Woodward 120 miles northwest to Guymon in the Oklahoma Panhandle and from Woodward 50 miles north to the Kansas border.

Source of Cost Data: http://www.tallgrasstransmission.com/about.aspx

Pioneer Transmission (AEP-Duke)
Pioneer Transmission, LLC is a joint venture formed by Duke Energy and American Electric Power (AEP) to build and operate 240 miles of extra-high-voltage 765-kilovolt (kV) transmission lines and related facilities in Indiana. The project would link Duke Energy's Greentown Station (near Kokomo, Ind.) with AEP's Rockport Station (east of Evansville, Ind.).

Source of Cost Data: Duke Energy. News Release: "Duke Energy and AEP Form Joint Venture to Build Transmission," Charlotte, NC, August 11, 2008.

Green Power Express
The "Green Power Express" is a broad network of 765 kilovolt (kV) transmission facilities that has been proposed by ITC Transmission to efficiently move up to 12,000 MW of renewable energy in wind-rich areas to major Midwest load centers. Once built, the Green Power Express transmission project will traverse portions of North Dakota, South Dakota, Minnesota, Iowa,

Wisconsin, Illinois and Indiana and will ultimately include approximately 3,000 miles of extra high-voltage (765 kV) transmission.

Source of Cost Data: http://www.itctransco.com/projects/thegreenpowerexpress.html

ATC Stakeholder Update - 2009 Economic Planning Projects
As a part of its 10 year planning process, American Transmission Company examines potential economic transmission projects. In 2009, ATC incorporated a Genoa to North Monroe 765 kV Project in their planning studies. The estimated costs for this project were included in Table ES-1.

Source of Cost Data: Ghodsian, Arash. “ATC Stakeholder Update 2009 Economic Planning Projects,” American Transmission Company, July 10, 2009.

Transmission Alternatives to Interconnect Wind Generation into SPS System
Study prepared by Quanta Technology to examine the costs of various alternatives for Southwestern Public Service to integrate wind energy into its system.

Source of Cost Data: Morrow, Don *et. al*., “Transmission Alternatives to Interconnect Wind Generation into SPS System–Summary,” Study prepared for Southwestern Public Service, July 31, 2009.

Midwest Regional Generation Outlet Study
The Regional Generator Outlet Study (RGOS) was initiated to ensure that Midwest ISO members and stakeholders can meet their renewable energy mandates and goals by developing a robust transmission plan to reliably and economically interconnect renewable resources across the Midwest. The Study examined numerous transmission alternatives for the Midwest ISO footprint.

Source of Cost Data: Midwest ISO. “Regional Generation Outlet Study Technical Review Group Presentation,” revised 9/17/09.

APPENDIX B:
BEST PRACTICE FOR DETERMINING BENEFITS AND COSTS OF TRANSMISSION PROJECTS

Methodology for Conducting Benefit-Cost Assessments of Transmission Expansion Projects: Principles

Transmission planning processes must be responsive to the changing demands of a restructured power industry that is making increasing use of demand side initiatives and alternatives to conventional thermal generating technologies. Consequently, over the last several years, transmission planning processes have begun to consider a broader perspective in planning for expansion and enhancement. These changes are driven in part by a growing concern that wind development will require substantial additions to the nation's transmission infrastructure, beyond what would be necessary to maintain reliability levels in the absence of that resource but consistent with conditions of secular long-term growth in both load and generation. There is a broad range of methods used to evaluate both the costs and, for at least a limited number of studies, the benefits of transmission expansions.

The importance of transmission to the success of remotely located generation, especially the vast amount of wind power currently under development or planned in the U.S. today, has been widely recognized. Wind resources especially are locationally dependent on transmission because of the wide geographic dispersion of desirable wind sites. In addition, wind resources (as well as many other renewable resources) exhibit relatively low capacity factors, and suffer from a mismatch between their shorter construction lead times and the much longer lead times necessary to construct transmission.

Economic analyses of potential transmission expansion options to accommodate normal load growth and provide access to generating capacity additions to serve that load, especially capacity additions from alternative resources such as wind power, need to comprehensively account for:

1. multiple perspectives with respect to transmission project benefit estimates;
2. strategic market behavior of generators and consumers trading over the network;
3. uncertainty regarding key drivers and risk factors; and
4. alternatives to transmission.

Methods for evaluating the benefits of a proposed transmission expansion project, especially the high voltage 765 kV overlay type, are considered to be at the heart of the debate about federal policies regarding energy, climate change and infrastructure investment. Accordingly, methods used in the assessment of such projections should take account of the following issues:

Public good aspect of transmission: Once new transmission facilities are placed in service, there is no way to exclude use of or sequester the facility short of denying access to the entire grid itself.[25]

Investment lumpiness: transmission comes in fixed sizes and long-range planning may determine that the optimal capacity to add creates a capacity surplus in the short run.

Externalities: transmission investment can impose both positive and negative externalities. For example, reliability benefits of transmission expansion can be distributed widely, and changes in power flows may mean that congestion appears in the system in places that it had not been occurring before the expansion.

Uncertainty: benefits and costs of a transmission projects occur far into the future. The size of net benefits, in particular, is driven by exogenous factors in the future. As a result, future benefits are highly uncertain with respect to both the overall level and their distribution among stakeholders and across retail consumers. Key factors over the future include load growth, the entry of new generation, primary fuel costs, and hydro power availability. For example, if federal legislation were passed that accelerated a wave of nuclear power plant investment in key locations in the Eastern Interconnect, there may be significantly less need to build transmission to provide access for wind power capacity and less need for wind capacity in general. Or similarly, if offshore wind in the Atlantic becomes very cost-effective, then there will be less need to ship wind energy long distances. Had the investment been made in an EHV grid overlay nonetheless, that investment cost would become stranded and would still have to be recovered from transmission customers.

In view of the aforementioned important issues, the ideal valuation methodology would do five things:

Consistently and fully account for benefits: the method should be able to clearly differentiate the benefits of a transmission expansion project among the various participants and stakeholders: consumers (i.e., consumer surplus), producers (i.e., producer surplus), and transmission owners (i.e., revenue recovery with return of and on investment). Since some transmission projects are inter-regional in scope, the method should also take account of the economic benefits from both a regional and societal (e.g., national) perspective.

Assess viable expansion candidates: plan evaluation should explore viable candidates including alternative routes, and facility sizing and specification.

Accurately represent the network model: the transmission network and its physical constraints must be reasonably well represented on the scale for which the expansion is being considered, in order to estimate the impact of the project on network power flows, generation commitment and dispatch, market prices, losses, and costs of production (i.e., not simply extrapolating results from a smaller region to a national scale).

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[25] The public good nature of the grid is more problematic in the Eastern Interconnection which is a more highly meshed network than in the Western Interconnection where the network is more radial.

Accurately forecast market prices and the impact of strategic bidding behavior on prices: market prices affect the siting decisions and bidding behavior of generators, which in turn impact market prices to the extent that generators have market power with or without the project.

Incorporate uncertainty about future states of the world: design scenarios that contain parameter sets for key assumptions, including load growth, fuel costs, generator retirements, and other key drivers of benefit and cost measures. The least cost expansion candidate, stated in terms of expected value, may also have higher risks in terms of the range of net benefits. Hence, value of risk should be accounted for.

Consider alternatives to transmission expansion: consider scenarios in which generation substitutes for transmission, or "pipes" versus "wires" (i.e., gas pipeline expansion) scenarios, scenarios involving greater demand response, energy efficiency, and renewable and distributed (behind-the-meter) generation, and scenarios involving alternative transmission enhancements.

In brief, the above factors strongly overlap, such that the transmission expansion planning problem cannot be readily compartmentalized and separated from market phenomena regarding generation and loads. Indeed, the value-maximizing expansion plan cannot be determined in the absence of the analysis framework that simultaneously accounts for the above factors.

Methodological Limitations of Transmission Studies

Arguably, no transmission study fully satisfies the above planning standards and criteria. All studies will have limitations, and it is essential to be mindful of those limitations that are most relevant to study results.

Determining responsibility for transmission project costs

The consideration of complementary fossil-fired generation is important in the assessment of transmission projects aimed at improved accessibility to renewable resources. The intermittency of many forms of renewable resources implies the need for complementary generation in order to obtain supply continuity, particularly where such renewable resources are remotely located. Assigning transmission cost responsibility to generation and load using, for example, peak load responsibility share, would understate the cost responsibility and share attributable to those renewable resources. This is because some expanded thermal generation is necessary for reserves in order to maintain continuity of power supply in the presence of this intermittency.

On the other hand, if there are other beneficiaries to transmission expansion besides generation (i.e., producers), a study that attributes all cost responsibility to generation would of course overstate the transmission costs attributable to generation (e.g., renewable resource capacity).

Accounting for lumpiness of transmission investment

In most transmission expansion studies, because of the lumpiness (capital indivisibility) of transmission, the project cannot be optimally sized to exactly match year-by-year generation capacity or load additions. This is particularly the case for high voltage transmission, where the end result is that transmission capacity often exceeds requirements during near-term years. Yet, it may be less costly and appropriate to install larger capability rather than subsequently upgrading to larger capability when it is needed for additional generation in the future. Attributing all transmission expansion cost to the immediate generation capacity made accessible generally overstates the costs attributable to those resources. Conversely, a study that assumes the transmission capacity is exactly matched to the additional generation capacity, thus overlooking the lumpiness of investment, tends to understate the costs of transmission that must be borne by generation and other parties. A schedule for capacity release may be an appropriate strategy.

An Approach to Estimating Benefits of Transmission Projects Uses Production Cost Modeling and Power Flow Case Constructions

The most reliable, basic method for estimating the benefits of a transmission project that has inter-regional and Interconnection-wide implications would integrate production cost and power analysis under security-constrained economic dispatch. The analysis would draw on a data base includes the transmission branch data, and generator dispatch parameters, loads, fuel costs, and environmental costs including projected prices for CO_2, SO_2, and NO_X. The analysis would be performed hourly, or for day types of months over regions, possibly covering the relevant regions of generation and loads. The security constrained dispatch process would simulate the optimum economic generation schedule to satisfy the expected loads (including transmission losses) and interchange schedules, while observing security, and reserve criteria. For regions that currently are not within organized regional markets administered by RTOs, the dispatch process can assume that economically viable power transactions take place across the larger control areas of the region. The security constrained dispatch would be performed for selected years (test years) over the study period.

Such an approach provides the basis to determine within-electricity market impacts, and constitutes a partial equilibrium analysis. The analysis framework would be solved iteratively for net impacts over sets of parameters for the test years to obtain a potential range of estimated benefits. Because such studies cover long-term future periods, entry by new generators must be accounted for with proxy units. The analysis framework cannot adequately foresee where generators will be located, though the analysis can anticipate that the “low hanging fruit” will be selected first; generation entry will take place in locales that have reasonable proximity to fuel supplies (e.g., pipelines), have least interference with existing and expected infrastructure (i.e., least infrastructure density), and have the highest market prices due to congestion, line losses, and reliability costs.

In short, the data base for selected future years will need to be populated, through some algorithm, with new generators. Ideally, this would involve the application of an algorithm that models investment siting decisions. Given the location- or area-specific nature of many of the factors shaping costs and benefits, and the constraints imposed by the transmission network, the results of a production cost study on a given region and specific transmission expansion project do not automatically “scale up” in a straightforward fashion to allow prediction of costs and benefits for a larger region and more extensive transmission expansion.

Benefit Calculations

Possible benefits from transmission projects

The literature regarding transmission planning as well as the myriad reports on planned and executed transmission projects list many potential benefits that can accrue to various stakeholders (consumers, producers, and transmission owners). Benefits come in the form of direct benefits and indirect (i.e., secondary) benefits. Direct benefits are those outcomes directly attributable to the project and pertain to some change in the measures of the performance or the cost of the production and transmission of electricity.

Secondary impacts refer to the global economic effects realized within a macro economy as a result of the actions of individual agents (households, firms, and government entities) within the economy. Actions by agents can cover a number of dimensions, including the expansion of an industrial plant (investment), addition of a third production shift, a large public event or facility, or a change in local government tax policy. Changes such as these can perturb the macro economy in ways that result in multiplier effects, effects that chain through the larger economy over time.[26] The dimensions of impacts are several including employment and population effects, upward (and downward) movements in price levels across economic sectors, increases (and decreases) in exports and imports across regions, changes in household income, impacts on the relative costs of doing business, and changes in the level of output, referred to as gross regional product ("GRP"). Actions of agents can cause both positive and negative impacts, and the distribution of impacts may be uneven across firms and households.

The list of benefits of transmission projects typically includes the following items under the "Direct Benefits" category:

> **Improvements in transmission system reliability**: although quantifying reliability benefits is extremely difficult to do within a benefit-cost study, reliability benefits are invariably cited as significant contributions from transmission expansion projects. One way in which reliability benefits can be quantified is through the estimation of the reduction in the frequency (i.e., probability) of outages multiplied by an estimate of the value of lost load.

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[26] For regional economies impacted by transmission projects, a "change case" constitutes an exogenous change to an assumed equilibrium state (i.e., a base or reference case). Such a change can result in a number of highly diffused effects across many sectors, including changes in labor force, population, wage rates, employment, regional purchases as shares of total transactions, and regional imports. Changes in output prices of an economic sector, in private investment, or in local government tax policy will have different impacts. Such effects will also vary in size depending on the region that is the focus of the study. Simulation studies suggest that, depending upon the sector, the type of change, and the impact of interest, the total chain of impacts can range from 1.2 to above 2.0 depending on the analysis approach. The chain of impacts are highly specific to circumstances and the sectors that are most intensively involved. Calculating regional economic impacts requires care to avoid overstating the true *net* effects of the proposed project relative to the alternative base case in which the project is not undertaken. For example, the analysis should account for the extent to which the proposed investment simply replaces other investments that would otherwise have been made. Generally speaking, impacts perturbed by a one-time event such as investment tend to dampen out over future years, while impacts that are ongoing can either lessen or expand over time.

Increased fuel diversity: transmission projects can enable renewable resources to have access to the grid from remote locations. Greater fuel diversity may provide improvements in mitigation of gas price risks.

Reduced congestion: reduced congestion goes hand in hand with price stability within the wholesale markets subject to locational prices. In cases where the expansion implicates inter-regional trading, reduced congestion could mean both a reduction in costs and a reduction in curtailment level (i.e., less use of Transmission Loading Relief procedures in the Eastern Interconnection).

Price stability: a reduction in price volatility in wholesale markets, especially ones that are subject to locational prices follows from reduced congestion and may reduce the need for price risk hedging.

Decreased production costs: increased transmission may give lower cost generation access to the grid and result in a lower-cost regional dispatch of generation; this often leads to the implication that market prices will also be lower.

Reduction in unmitigated market power: increased transmission transfer capability may increase the access of upstream generation to downstream load pockets (as it reduces congestion that keeps upstream generation out of downstream markets). The reduction in market concentration in the downstream markets reduces the market power of generators within the load pockets. If this market power was previously unmitigated, the result would be lower market prices for the downstream generators, higher prices for the upstream generators, and ostensibly lower prices for consumers in the load pockets.

Increased liquidity: increased access to markets increases numbers of buyers and sellers and consequently increases the liquidity of the short-term and the long-term markets.

Increased flexibility for maintenance: increased transmission and greater access for generation to wider markets may allow for more flexible schedules of maintenance on both transmission lines and for generators.

Benefits that may be described as indirect or secondary impacts include:

Employment: increased employment during the construction phase of the project, which is obviously a temporary benefit; increased employment after project completion associated with the utility maintaining the asset.

Income: income from employment and expenditures for local/regional goods and services are manifest in higher household income (personal income). This category is often associated with so-called multiplier effects.

Tax revenues: transmission investment will invariably involve payments of taxes that accrue to local and state governments on assessed values of transmission property (rights of way).

Expenditures on goods and services: the short- and long-term employment and earning impacts result in expenditures on goods and services out of the income earned by labor;

the transmission project will require local goods and service particularly during construction but also once the line is put in service.

Factors determining whether the projected benefits for a given project will be realized.

The factors that determine whether benefits of transmission expansion projects will be realized are the very factors that are assumed to be driving the need for the project in the first place. These are also the factors about which assumptions are made in order to conduct a benefit-cost study and therefore enable a calculation of project viability. For example, benefit-cost studies will make assumptions about the quantity of new wind resources that will need access to the grid, the changes to existing generation through retirements, the quantity of new gas-fired or coal-fired generation that actually enters service and their locations relative to load and wind resources. The expected rate of load growth, penetration of demand response, and energy efficiency are also critical values about which assumptions are made. Any of the underlying values assumed for these factors could turn out to differ by significant margins from the realized values, which means that actual benefits also may differ from the projected benefits by significant amounts. This is the main reason that benefit-cost studies should examine the sensitivity of the benefits estimate to variations in the assumptions of key factor values.

Assumptions regarding wind plant capacity factors can underestimate or overestimate energy produced annually by the wind capacity by as much as a third to one half.[27] Results will also be quite sensitive to over or under-estimation of the capital and construction costs of wind projects. Given that transmission project net benefits depend on project costs, the regular renewal of the PTC and the size of the credit granted upon renewal will impact the financial viability of wind power projects such that without it or with lower per MW credits awarded, a significant amount of planned wind capacity may not materialize.

Additional factors that will shape the ultimate benefit outcome of any high-voltage transmission project analyzed within the current uncertain environment are the extent to which: (1) NIMBY opposition to high-voltage transmission lines succeeds in blocking a project or results in substantial delays and/or increases in project costs; (2) in cases where a project is being blocked, the Federal Energy Regulatory Commission ("FERC") and the U.S. Department of Energy ("DOE") are able to exercise their backstop siting authority granted in the Energy Policy Act of 2005; (3) federal greenhouse gas legislation is passed by Congress and the timing of emissions limits and the ultimate disposition of permits is resolved, and the impact of resulting higher electricity prices on demand; (4) the PTC is renewed in subsequent years and the terms defining qualifying wind projects for such credits differ from what exists today.

The aforementioned potential problems with assumptions about key drivers of the benefits (and costs) of an EHV transmission project make clear why an ideal study should take account of uncertainty and risk associated with the factors driving both benefits and costs of a particular project by conducting scenario analyses.

[27] Actual wind capacity factors worldwide have been found to fall typically in the range of 15% (France) to 40%, (Morocco), with recent studies in Europe and in Texas providing estimates of capacity factors in the neighborhood of 20% or less, which is considerably lower than the 37% assumed in CRA Study.

Proper attribution of benefits

The ideal method should be able to clearly differentiate the benefits of a transmission expansion project among the various participants: consumers (i.e., consumer surplus), producers (i.e., producer surplus), and transmission owners (i.e., revenue recovery with return of and on investment).

Since some transmission projects are inter-regional in scope, the method also must be capable of measuring the economic benefits from both a regional and societal (e.g., national) perspective. It is important for studies conducted at the national level to acknowledge the various participants and potential benefit recipient groups, such as consumers, producers and transmission owners, even though the perspective taken may be societal. The benefit shares will vary across participant groups and across regions for national level studies, so it is important to gain an understanding of the relative sizes of the benefit shares, in particular when considering the policy question of allocation of transmission project costs.

Planning and Costing Transmission Projects—Traditional Practice

Estimating costs per mile

Necessary or economically desirable transmission projects are generally identified in planning studies conducted by individual utilities, independent generators, market participants, Independent System Operators ("ISOs") or Regional Transmission Operators ("RTOs"), or regional reliability councils. As part of the planning process, the economic feasibility and desirability of possible projects is usually determined before a final plan is proposed. The proper method to accurately assess the costs of a proposed transmission project is to conduct a detailed study of the costs of land acquisition, towers, conductors, insulators, labor and other materials for the specific route chosen. But these analyses can only be done after a route has been chosen so as to get a fairly specific estimate of the costs based on terrain, land uses, and other factors. The costs of transmission can vary significantly based on specific routes—particularly because of terrain variations and/or land acquisition costs. It can cost three to four times as much to build transmission in mountainous regions versus on flat terrain. And obviously, building through or near cities is significantly more expensive than in rural areas.

But specific routes and engineering details of a project are not yet developed in the planning process. To examine the initial feasibility of a project before all of the details are known, shortcuts must be taken. In fact, in most instances there are several different cost estimates associated with a project to aid in the evaluation process, with differing levels of specificity, made at different stages in the development process. These estimates range from initial "order of magnitude" estimates to detailed estimates constantly updated while the project is under construction. Initial order of magnitude estimates, besides being the first step in the planning process, are also used quite frequently used in policy papers to assess the costs and benefits of a specific policy proposal, such as that of a 765 kV EHV overlay proposal developed in the AEP Study.

It is interesting to note that initial order of magnitude estimates have typically been found to range from -50% (below the cost estimate) to 200% (above the cost estimate) compared to final cost estimates.[28] As projects develop, it is axiomatic that estimated costs tend to increase. This finding is a key to understanding the potential value and use of order of magnitude estimates, which are used in estimating costs of the proposed EHV overlays in both the AEP Study and the CRA Study.[29]

To account for these changes during a project's consideration, engineers typically add a contingency cost factor to early cost estimates. For simplified estimates at the initiation of the project, the Electric Power Research Institute ("EPRI"), for example, recommends a 30% to 50% contingency adder which goes down to 5% to 10% as construction bids are received and contracts finalized.[30] The order of magnitude estimates typically cited in policy papers do not usually include this contingency adder. It does not appear to be included in the AEP Study or the CRA Study.[31]

In developing order of magnitude cost estimates, the three most commonly used shortcuts for analyzing transmission line costs are—an estimated cost per mile (which varies according to the voltage level of the facilities and between short and long lines) based on prior experience or engineering studies conducted by others, a cost per MW or MW-mile (which takes into account voltage level and the amount of generating capacity that is interconnected with, or which can be transferred over, the line), or a cost per MWh (which takes into account the voltage level, the generating capacity connected, and the capacity factor of that generation). The most commonly used shortcut, likely because it is the simplest, is an estimated cost per mile. The CRA Study and the AEP Study that we have been asked to review rely on a cost per mile metric, and we will focus on that metric here.

There are, of course, problems with relying on cost per mile estimates. First, they are by definition averages, and may not reflect the specific conditions of the region where a project is proposed. Topology of the proposed route has a significant impact on costs as mentioned previously. The time period for planned construction also has a major impact, as costs of construction labor and materials have been escalating rapidly over the past decade. Per mile cost estimates may become quickly out of date.

Transmission cost per mile estimates are often based on recent construction experience (i.e., the total costs of actual projects are divided by the length of the transmission lines). For lower voltage lines, there is a wealth of experience on which to base such estimates. The same is not true for EHV projects. In fact, only one 765 kV project has been energized in the U.S. in the past decade—the AEP Wyoming-Jacksons Ferry Project. This line, energized in June 2006, took

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[28] ISO New England, Draft Project Cost Estimating Guidelines, Revision No. 2, April 27, 2009, p. 8.

[29] We cannot be certain as there may be more detailed cost studies behind the AEP and CRA analyses that are not publicly available.

[30] ISO New England. Draft Project Cost Estimating Guidelines, Revision No. 2, April 27, 2009, p. 11.

[31] The CRA Study did include a 25% adder to provide a range of transmission costs to account for increases in costs between the time the original estimate was made and the time of the CRA Study. However, this is different than a contingency cost adder.

thirteen years to permit and complete, so it may not even be an accurate indicator of the costs of a line that is initiated today. The cost per mile for this line was $3.4 million.[32]

In the absence of real data on construction costs, it is necessary to rely on published cost estimates for proposed projects. There is a problem here, as well, for 765 kV lines in particular. Almost all of the 765 kV lines being proposed today include AEP as a participant, and thus many of these proposals rely on AEP's own cost estimates. Table A-1 below shows some currently proposed projects and their estimated costs, with a reference as to whether AEP is a participant. Except where noted, these are line costs only, excluding transformer and interconnection costs. Appendix A presents a description of the specific project or study listed and the source documents.

Table A-1.

765 kV Transmission Line Projects and Projected Costs per Mile

Project/Study Name	Date of Estimate	Cost per Mile (millions)
CRA Study	9/26/08	$1.7 - $2.1
Other AEP Estimates		
SPP EHV Overlay Study	3/3/08	$2.1-2.2
Prairie Wind Transmission	5/19/08	$2.6
Tallgrass Transmission	7/15/08	$2.9
Pioneer Transmission (AEP-Duke)	8/15/08	$4.1[33]
Third Party Estimates		
Green Power Express	2/9/09	$3.3–4.0
ATC Stakeholder Update - 2009 Economic Planning Projects	7/10/09	$4.8
Transmission Alternatives to Interconnect Wind Generation into SPS System -Summary	7/31/09	$2.1
Midwest Regional Generation Outlet Study	9/17/09	$4.2-4.8

Three specific items of interest can be drawn from Table A-1. First, there is a wide range of costs presented for 765 kV lines on a per mile basis, ranging from $2.1 million to $4.8 million.

[32] http://www.aep.com/about/transmission/Wyoming-Jacksons_Ferry.aspx.
[33] Includes "related" facilities.

Second, there is variation even within the projects in which AEP is involved, although their estimates tend to be lower than those for projects in which they are not involved. Third, with one exception, the more recent estimates are significantly higher than estimates even only one or two years old—suggesting perhaps a rapid cost escalation.

AEP, in addition to estimating costs for its proposed projects listed in Table 3, has made several generic estimates of 765 kV per mile costs. In its paper entitled "AEP Interstate Project: 765 kV or 345 kV Transmission," it estimated costs per mile for a proposed 765 kV Overlay at $2.6 million per mile in 2007 for rural terrain with rolling hills, including siting, right-of-way and construction, but not including (sub-) station costs.[34] More recently, AEP has broadened the cost range to include $2.6 million to $4.0 million per mile,[35] perhaps to reflect the estimated costs of the AEP/Allegheny Energy PATH ("PATH") project described below.

All of the cost estimates described above are "Order of Magnitude" type estimates. Aside from the actual costs of the Wyoming-Jacksons Ferry line, the only detailed project cost estimates that have been prepared in the past several years that we could find are cost studies for the PATH project planned for West Virginia, Virginia and Maryland. In this case, PATH has actually filed for regulatory approval in the three states for this 290 mile 765 kV project. Thus, a review of those regulatory filings might shed some light on what AEP (and Allegheny Energy) believe to be the current cost estimates for this 765 kV project.

In their filing in West Virginia, PATH estimated the total cost of the West Virginia segments at $998 million excluding substation costs.[36] The West Virginia segment runs 225 miles, resulting in an estimated cost per mile of $4.4 million. In their Maryland filing, PATH estimated the cost of the 20 mile 765 kV segment in Maryland at $111 million or $5.5 million per mile.[37] And in their Virginia filing, PATH estimates the cost of that 31 mile segment at $177 million, resulting in a cost per mile of $5.7 million.[38]

The three filed cost estimates average (on a distance weighted basis) about $4.4 million per mile, a number that is closer to more recent estimates of costs per mile for 765 kV transmission, including the estimate for the AEP/Duke Pioneer transmission project estimate of $4.1 million per mile. AEP does not explain in any of its filings why the per mile costs in its PATH filings are significantly greater (by almost 70%) than its earlier estimate of $2.6 million. Part of the explanation may be that the terrain for the PATH project is fairly mountainous which can result in significantly higher costs. It is also possible that as AEP has delved into the economics of

[34] American Electric Power, AEP Interstate Project: 765 KV or 345 kV Transmission, April 24, 2007, p. 14.

[35] http://www.aep.com/about/transmission/docs/transmission-facts.pdf, p. 2.

[36] PATH West Virginia Transmission Company, et al., Joint Application for certificates of public convenience of necessity under W. Va. Code §24-2-11a authorizing the construction and operation of the West Virginia segments of 765 kV electric transmission lines and related facilities in Putnam, Kanawha, Roane, Calhoun, Braxton, Lewis, Upshur, Barbour, Tucker, Preston, Grant, Hardy, Hampshire and Jefferson Counties including modifications to the Amos substation in Putnam County and a new substation in Hardy County and for related relief. Direct Testimony of Ronald L. Poff, May 15, 2009, pp. 18, 25-26.

[37] Before the Public Service Commission of Maryland, In the Matter of the Application of Potomac Edison Company on Behalf of PATH Allegheny Transmission Company, LLC for a Certificate of Public Convenience and Necessity to Construct the Maryland Segments of a 765 kV Electric Transmission Line and a Substation in Frederick County, Maryland. Direct Testimony of Ronald L. Poff, May 19, 2009, p. 23.

[38] *Ibid*. p. 17 and p. 23.

specific projects, it has found that costs are significantly greater than earlier Order of Magnitude estimates, which is to be expected. At the very least, the significant difference calls into question the use of *average* cost estimates in aggregating the costs of major grid additions, especially those encompassing the entire nation. And it suggests strongly that the AEP Study's estimates used for costing a national grid overlay may be significantly understated.

Interconnection costs

In addition to the costs of the transmission line wire and supporting structures and construction and right-of-way acquisition costs that mostly comprise the per-mile costs described above, any new transmission line project requires interconnection to the existing grid. Interconnection costs depend on the voltage levels that are being interconnected and on the number of substations needed to transform the voltage of the new line to the voltage at the various points of interconnection. Costs for interconnection are particularly significant where 765 kV must interconnect with voltages of 345 kV or less. There is not a wealth of information on the costs of interconnecting 765 kV transmission projects because there have been so few projects completed. For lower voltages, engineers have often used a 25% adder as a rule of thumb for interconnection costs—thus, the interconnection costs for a $1 million project would be estimated to be about $250,000. However, it is not known if that same relationship holds for EHV lines.

The best source of data again may be the filings made by AEP and Allegheny with the West Virginia, Virginia, and Maryland Commissions for approval of the PATH transmission lines. The applicants spelled out added substation costs in these filings. The costs for the three planned substations in the PATH project are estimated at an additional $563 million on top of the $1,286 million for the transmission lines, for a total project cost of $1,849 million.[39] Thus, interconnection increases project costs by about 40% in the PATH project case.

In the Technical Study Report for a proposed 765 kV Transmission Infrastructure Expansion in Michigan, AEP and ITC Transmission also made estimates of both line costs and station costs. Five separate 765 kV lines were evaluated with estimated total costs at $2,626 million, of which $2,106 million was line costs and $520 million was (sub)station costs.[40] Thus, for the Michigan project, interconnection costs increased total costs by about 25%.

There are not many other studies that clearly delineate interconnection costs versus costs of the transmission lines themselves. From the little evidence that does exist, it appears that interconnection costs add at least 25% and possibly up to 40% of costs to a transmission project.

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[39] PATH West Virginia Transmission Company, et al., Joint Application for certificates of public convenience of necessity under W. Va. Code §24-2-11a authorizing the construction and operation of the West Virginia segments of 765 kV electric transmission lines and related facilities in Putnam, Kanawha, Roane, Calhoun, Braxton, Lewis, Upshur, Barbour, Tucker, Preston, Grant, Hardy, Hampshire and Jefferson Counties including modifications to the Amos substation in Putnam County and a new substation in Hardy County and for related relief. Direct Testimony of Ronald L. Poff, May 15, 2009, p 25.

[40] American Electric Power and ITC Holdings, AEP & ITC Technical Study Report: Proposed 765 kV Transmission Infrastructure Expansion. July 27, 2007, p. 7.

Integration costs

In addition to interconnection costs, there are integration costs associated with new transmission lines. Because of the characteristics of the AC networks in the U.S., an added transmission (or generation) facility within one of the three asynchronous networks will change the electrical characteristics of the network. Added transmission facilities thus may create the need to make changes in other parts of the network so that such facilities can be integrated into the network reliably. And as discussed in the next Section, there are integration costs associated with particular types of generation that may be interconnected to new lines—particularly intermittent or variable generation sources such as wind and solar.

The types of integration improvements that may be necessitated by new transmission facilities include new substations (in other parts of the network), capacitor banks, static var compensators ("SVCs"), or static synchronous compensators ("STATCOMs") to maintain voltage (discussed in the following Section in more detail), phase shifters to control power flows, or even added lines to satisfy reliability standards. It is not possible to estimate these kinds of integration costs without detailed engineering studies of the effects of specific projects on the existing grid. Order of Magnitude estimates of transmission investment costs do not include these potential integration costs and therefore again probably understate the real costs of new transmission investments.

Planning and siting costs

Planning and siting costs are the costs incurred by a utility before construction of a project begins. These include the costs of all the planning and engineering studies necessary to decide what transmission needs to be built, coordinating with surrounding transmission systems, deciding on the preferred and alternative routes, allowing for public participation in the siting process, the costs of preparing regulatory filings, and the costs of the regulatory process itself. Again, these costs are quite specific to projects, and are generally not included in Order of Magnitude estimates of transmission costs of the type we are examining in this report. But such costs can run into the millions of dollars and are not insignificant.

Cost implications to existing grid

In addition to the integration costs discussed above that are necessary to reliably integrate new transmission into the grid, there are also economic impacts to the existing electric system that may result from new transmission investments. Adding new facilities to the grid will change power flows within the interconnected networks to some degree. These changed power flows will impact network congestion. These impacts could be both positive and negative. Congestion on some parts of the system will certainly be relieved, but congestion can be increased elsewhere in the system. And the impacts are not always expected. For example, adding new lines in one corner of the system may have power flow impacts hundreds of miles away.

The costs (or benefits) of such changes are not generally counted as a cost of new transmission per se, but do affect the cost/benefit analysis of adding new facilities. Ideally, one would subtract the costs of increased congestion in parts of the system from the benefits of reduced congestion in other parts of the system. Again, however, a detailed engineering impact study is needed to determine how new facilities are likely to affect power flows throughout the system.

These studies need to be done at the regional or multi-regional level. These kinds of studies were not conducted in any of the analyses we examined for this report, but again may represent a major component of an overall cost/benefit study regarding new transmission facilities and could result in an under-statement of project costs or over-statement of project benefits.

Other costs

The costs for new transmission projects described above should not be considered to be all inclusive. Specific projects may have other associated costs. For example, projects to be built in urban areas or in environmentally-sensitive areas may require undergrounding, which can increase per mile costs by a factor of 10. Other projects may require specific environmental mitigation, such as hiding substations, or using more attractive towers or towers with coloring to match backgrounds. Some projects may require wider than normal rights of way because of EMF or other environmental concerns.

There are also operating and maintenance costs associated with transmission facilities, including vegetation clearance which can add significantly to the costs of projects. All of these types of costs are usually excluded from the Order of Magnitude estimates typically used in policy studies of the type we reviewed for this report.

Planning and Costing Transmission Projects—Issues in Renewable Integration

Among the well-recognized challenges of integrating renewable resources (wind generation in particular) into overall grid operations is the intermittent nature of these generators' output. For wind, this intermittency has engineering and cost impacts at the individual turbine level, in the aggregate for the wind farm, and ultimately at the grid integration level. These issues are partially addressed in characterizing costs in the CRA Study and in the AEP Study that draws upon the CRA Study's results. However, at least one critical wind performance value assumed in the CRA Study is unrealistically optimistic, thereby overestimating benefits (potentially significantly). In addition, costs associated with several more subtle technical issues are overlooked.

The electric power industry has made significant progress in developing means to appropriately characterize the value of intermittent wind resources into generation markets. The CRA Study reflects appreciation for efforts to date in this regard, in its attempts to estimate wind energy revenues through wind capacity credit, and through the availability of the PTC. However, a critical component in these calculations is the value assumed for capacity factor, characterizing the ratio of actual energy output achieved, to maximum energy production possible based on nameplate rating. The CRA Study assumes a wind capacity factor of 37%. This is already higher than the range of capacity factors typically cited by the American Wind Energy Association, whose literature quotes capacity factors for wind plants as ranging 30-35%.[41] However, a recent academic study of wind farm historic data in the European Union provides very thorough evidence demonstrating that this often quoted 30% to 35% figure is itself very optimistic, and is not justifiable based on recent wind operating data. In this recent article, one researcher examining wind power performance writes: "For two decades now, the capacity factor of wind power measuring the average energy delivered has been assumed in the 30–35% range

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[41] American Wind Energy Association, *Wind Energy Fast Facts*, obtained at www.awea.org.

of the name plate capacity. Yet, the mean realized value for Europe over the last five years is below 21%; accordingly private cost is two-thirds higher and the reduction of carbon emissions is 40% less than previously expected."[42] This same research paper reports data for the U.S. wind generation, though the author indicates that the U.S. data is not as complete as that collected for the EU; the 2003–2007 performance history indicates an average U.S. wind farm capacity factor of 25.7%. While it is plausible that the quality of wind resources in the U.S. sites assumed for the CRA Study may be *somewhat* higher than these 2003-2007 figures for the E.U. and U.S., it is extremely unrealistic to assume that the sites in question could yield an average capacity factor more than 1.75 times higher than that of recent experience in the EU. Hence, the CRA Study must be judged to have overestimated production cost reduction benefits associated with wind energy production, perhaps by as much as 75%.

A secondary impact of wind power intermittency, not captured in assumptions about capacity factors, or even more conservative capacity credit methodologies, is its impact on reactive power support needs. When analyzing the reactive support needed to maintain reliable voltage stability within the grid, the potential for rapid variability of wind power output and output from other intermittent resources requires that a higher percentage of reactive power production come from voltage support (VAR) resources that provide fast, continuously controllable power output, as opposed to the slow, fixed-step characteristics associated with switched capacitor banks.[43] In particular, as wind production becomes a significant percentage of overall generation within a given region, a larger portion of reactive compensation must come from much more expensive power electronically controlled equipment, such as static Var compensators ("SVCs") or static synchronous compensators ("STATCOMs") (i.e., devices that can provide rapid voltage support services).

While these needs for fast-acting, controllable reactive support are increasingly being recognized and incorporated in interconnection standards for wind, such grid standards are still evolving, and are likely to become more stringent as wind penetration grows. If these needs are fully reflected in grid standards, the added dynamic reactive support costs may be borne by the wind farm developer. However, as noted by Zavadil *et al*,[44] it is often the case that the most favorable location for dynamic reactive support may be at substations a considerable distance from the wind farm connection substation, and hence may incur additional costs for the transmission system. For example, "Aragonne Mesa wind plant in New Mexico has a distributed static

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[42] N. Boccard, "Capacity Factor of Wind Power: Realized Values vs. Estimates," *Energy Policy*, 37 (7) (2009), pp. 2679–2688.

[43] Reactive power, also referred to as Volt Amperes-Reactive (VAR), is a measure of power in Alternating Current (AC) networks and is important because it supports the real power that gets work done. In a simple Alternating Current (AC) circuit consisting of a power source and a linear load, the current and voltage are sinusoidal. If the load is purely resistive, the two quantities reverse their polarity at the same time, and the direction of energy flow does not reverse. In this case, only real power flows. If the load is purely reactive, the voltage and current are 90° degrees out of phase and there is no net energy flow. That is, the peaks of voltage are centered at the times when the current crosses zero and is half positive and half negative. In this case, only reactive power flows - no net transfer of energy to the load occurs. Most loads, such as an electrical motor, are both resistive and reactive. For the electrical motor to do work requires real power. Because the motor is also a reactive load, it requires reactive power to enable it to use real power in order that work is performed. Various devices can supply reactive power or VAR support, as discussed later in this report.

[44] R. Zavadil, N. Miller, A. Ellis, E. Muljadi, E. Camm, B. Kirby, "Queuing Up: Interconnecting Wind Generation into the Power System," *IEEE Power and Energy Magazine*, pp. 47- 58, Nov/Dec 2007.

compensator ("DSTATCOM"), which controls the power factor to unity at the point of interconnect at the Guadalupe 345-kV substation bus. The DSTATCOM, along with four mechanically switched capacitor banks, are located in the collector substation some 22 miles away from the interconnect substation." Whether borne by the wind developer, or by the transmission grid operator, the growing requirements for fast acting power electronic controlled reactive support equipment such as the DSTATCOM add potential for significant additional costs for wind power projects that appear not to have been accounted for in the CRA Study.

In addition to requirements for added grid hardware to address reactive power and voltage control challenges associated with wind integration, there is newly evolving recognition by the North American Electric Reliability Corporation ("NERC") that a high penetration of wind and other electronically coupled resources can result in declining quality of grid frequency regulation.[45] As noted by Zavadil *et al*, "Most grid codes now require that wind power plants assist the grid in maintaining or regulating the system voltage. Wind power plants are starting to be required to assist the grid in maintaining or regulating the system frequency as well. However, explicit grid code requirements for frequency control are still rare." The recent attention that NERC is devoting to the issue suggests that within the next several years grid interconnection mandatory standards for wind resources are very likely to carry requirements that wind generation assist in frequency regulation, through control that mimics the standard governor action of existing synchronous generators. However, for wind generators, such fast time scale governor control of frequency carries both additional costs in control hardware and maintenance, and loss of revenue through reductions in energy production. The reduction in net energy production arises because the ability to control active power output upward and downward, which is necessary for effective governor action, inherently carries with it the requirement to "spill" a small amount of wind energy in the steady state. It is conceivable that markets will be developed to provide a compensation mechanism to reward governor control, but to date, perhaps because such governor control is such a long-standing, nearly universal feature in traditional generating plants, no such markets have yet been developed or even prototyped. Within the time frame of the CRA Study and the various AEP transmission project cost studies considered here, it seems likely that wind plants will face requirements to provide governor on par with that of existing synchronous power plants, and that this control function will impose additional costs and reductions in energy production revenue. These governor control related costs and revenue reductions for wind power are not reflected in the CRA Study, and hence not reflected in the AEP Study.

Calculating per Customer Costs

Advocacy studies regarding the costs and benefits of transmission expansion often attempt to determine the cost impacts to individual customers. The purpose is usually to demonstrate that the cost impacts of large projects, when considered at the individual level, are relatively small. But it is important that these calculations be done correctly to ensure that an accurate picture is given of the rate or cost impacts of large projects on individual customers or customer classes.

[45] R.W. Cummings, *NERC Reliability Initiatives and Smart Grid: Late Breaking News*, presentation from IEEE Power & Energy Society General Meeting, July 2009. Obtained at: http://ewh.ieee.org/cmte/pes/etcc/B_Cummings_Latest_Developments_on_NERC_Stand

To accurately determine such impacts, a basic knowledge of the rate setting process is important.[46]

When a regulated utility completes a construction project, it will seek to add the costs of the project to its rate base in its next rate case. If the facilities are state jurisdictional, the utility will seek recovery at the state regulatory commission. If the facilities are built within an RTO or ISO, usually the projects will be added to the charges of the RTO or ISO and approved by FERC as part of their budget approval of RTO/ISO charges.

When the total costs of a project are added to the utility's rate base, the regulatory authority will determine an annual revenue requirement for the utility based on an allowed return on equity, an actual cost of debt, an authorized capital structure, and the depreciation schedules for assets within the rate base.

For simplification purposes when estimating the annual revenue requirements of new capital expenditures, the total capital costs of new projects are usually assigned an annual revenue requirement based on a carrying charge in the range of 15–20 percent (the exact carrying charge depends on allowed returns, which can vary greatly among regulatory authorities). Thus, for example, if a project costs $1 million, the annual revenue requirement would be $150,000 to $200,000 per year.

The annual revenue requirement is then allocated to customer classes—usually on the basis of the costs to serve each customer class, which, in turn, is based on the customer class's share of load during the time of system peak (known as the load ratio share)—but often such allocations are based on negotiated settlements. For the types of broad cost estimates reviewed for this report, it is probably reasonable to assume that the cost of new transmission is allocated to customer classes based on a load-ratio share (i.e., the customer class's share of the utility's peak demand at the time of system peak). Thus, for the example above, if one assumed that the residential customer class comprises 50% of the load (demand) of a utility, the residential class would be responsible for paying $75,000 to $100,000 per year of the total revenue requirements.

The annual revenue requirements per customer class then must be allocated to individual customers based on the utility's approved rate design. This allocation to customers is usually done on a cost per kilowatt-hour consumed (volumetric) basis, or on a cost per kW demanded (a fixed charge) basis, or some combination of these. In any event, costs per customer are likely to vary based on the characteristics of the customer. But again, if per customer costs are to be estimated, some simplifying assumptions need to be made. Probably the approach that makes the most sense in the absence of actual measures of loads and costs is to use a volumetric charge. A volumetric charge rate ($ per kWh per billing period) for each customer class would be equal to the annual revenue requirement for the customer class divided by the kWh use of that class, multiplied by the average per period use per customer in that class. Developing the cost per kWh also allows for estimates of increased costs for different users, should that be desired.

[46] The discussion here pertains to projects built by regulated entities where cost recovery is sought from either federal or state regulatory authorities based on the costs of the project and an authorized rate of return. There are so-called merchant transmission projects where costs may be recovered in other ways.

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