A Benefit Cost Study of the 2015 Wind Challenge:
An Assessment of Wind Energy Economics in Kansas for 2006–2034

Prepared by

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for the

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at the request of

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0.00 Introduction: The Governor's 2015 Wind Challenge and Request

Concerns about environmental degradation, power plant diversity, energy independence, exhausting non-renewable resources, energy-related economic development, and national energy security have spawned interest in possibly developing clean and domestically produced renewable energy sources. In that wide-ranging vein of concern, Governor Kathleen Sebelius has asked the Corporation Commission to "look at the full range of benefits that renewable energy brings to Kansas and how those relate to additional investment that may be needed to meet" what could be referred to as the Governor's 2015 Renewable Energy Challenge. That challenge is "to have 1,000 megawatts of renewable energy capacity installed in Kansas by 2015."

While the Governor's consideration of renewable energy sources is open to all types of renewables, arguably, the sources offering the greatest promise for generating electricity in Kansas are wind-powered, solar-based, and biomass- and/or bio-diesel-fueled generation. And, among those types, wind-powered generation currently offers the greatest potential for meeting the stated challenge. For instance, Kansas currently (late-2007) has approximately 364 megawatts (MW) of wind-powered generation connected to the grid, with only insignificant amounts of generating capacity fueled by other renewable sources. Furthermore, absent significant technological change and/or changes in relative market prices and/or government subsidies, it seems unlikely that renewables other than wind will play a significant role in meeting the challenge.[1] For those reasons, meeting the Governor's 2015 Renewable Energy Challenge with only wind-powered

[1] See Appendix B for a brief economic assessment of using renewable energy sources other than wind capacity for generating electricity in Kansas.

generation appears feasible. Given that apparent feasibility, we focus our attention on only wind powered-generation and, thus, slightly recast the Governor's Renewable Energy Challenge as the "2015 Wind Challenge" (hereafter, "Challenge").[2]

The Governor is clear that compliance with the stated challenge is strictly "voluntary;" however, we interpret her directive to the Commission as a request for a cost benefit analysis as *if* the Challenge *were met*.[3] Such a cost benefit analysis is useful because it can establish whether meeting the Challenge is likely to be cost effective for Kansas. Among other things, it also indicates whether utility rates and, thus, bills could be higher strictly as a consequence of the Challenge and whether voluntary compliance (with the Challenge) would be likely. Answers to these and other questions may be useful to policy makers as they deal with various energy issues that confront the state.

0.10 The Net Benefit of the Meeting the 2015 Wind Challenge is Uncertain

Whether the Challenge yields a positive net benefit to Kansans largely depends on the external cost savings attributable to wind energy production. In the vast majority of cases, we find that the estimate of external cost savings is a *pivotal* determinant of the cost effectiveness of the Challenge. Based on the latest available information (January 2008), our analysis shows that external cost savings per MWh of wind energy need to be approximately $40 (or more) for the Challenge to be cost effective, and that amount is inclusive of the federal production tax credit (PTC). Absent the PTC, the external cost

[2] In her 2007 State of the State Address, Governor Sebelius offered an updated version of the Challenge. The latest version calls for 1050 MW of wind capacity voluntarily installed by 2010, 2100 MW voluntarily installed by 2020. While the current version of the Challenge is not the subject of this study, it is our belief that most of the basic, qualitative results reported here would be largely replicated in a study of the updated version of the Challenge.

[3] This is necessary as a practical matter since the voluntary nature of the Challenge admits a multitude of possible outcomes. This assumption simply narrows the outcome to just one.

savings per MWh need to be about $58 (or more). Whether the *actual* external cost savings exceed those "threshold levels" is arguably the central, economic question. Unfortunately, since the level of actual external cost savings (attributable to wind energy production) is a matter of uncertainty, perhaps conjecture, so must be the final assessment of the Challenges' cost effectiveness.

Given an assumed level of external cost savings, meeting the Challenge could provide Kansans with a substantial positive net benefit, but such an outcome is not guaranteed. While positive net benefits are a possible outcome, so too are sizable negative net benefits. Overall, our analysis shows a wide range of (net benefit) outcomes is possible, with some more favorable to Kansans than others.[4] Viewed another way, pursuing the Challenge is comparable to placing a wager or bet – with winnings determined in the future. The question is whether the Challenge is a good bet for Kansans to take? We find that under certain conditions it is a good bet, but under other conditions it is unlikely to be an attractive wager. Thus, the real issue is not whether wind energy is cost effective (i.e., a good bet) for Kansans, rather it is whether *future conditions* in Kansas, and perhaps elsewhere, are likely to support a good (i.e., cost effective) outcome.

The uncertainty of the outcome stems from the most natural of sources: the uncertain future. On the cost side of the Challenge, for instance, we do not know what

[4] It should be noted the measure of net benefit used in this study incorporates *all* of the quantifiable costs and benefits associated with achieving that objective. Among the many costs are salaries paid to those actually operating and maintaining wind equipment, rental payments to landowners on whose property wind facilities are located, tax and lease payments. Those payments reflect salaries and incomes received by labor, farmers, landowners, and government entities that have a direct relation with installed wind facilities. Accordingly, those monetary measures capture the employment and tax revenue implications of meeting the Challenge. (Consistent with current economic theory, we assume the spending/employment multiplier associated with Kansas wind investments is close to 1.0.) The net benefit may also capture external cost savings, which could include lower health-care related expenditures. Lower expenditures in that sector of the economy would influence employment in that sector. The point is that all of the economic implications of the Challenge, which include the employment and local community development implications, are thoroughly embedded in the net benefit analysis. By design, the benefit cost analysis captures the *net effect* of the Challenge, *all* (feasibly measured) economic implications considered.

wind installation costs will be in six months, let alone in six years (when final investments needed to meet the Challenge may occur). Nor do we know for sure what it will cost to operate and maintain wind turbines, particularly when new turbine designs continue to be introduced, such as the 2.5-MW Liberty Wind Turbine by Clipper and V90 3-MW turbines by Vestas. With the continual introduction of new wind equipment, the uncertainty over wind O&M expenses is unlikely to fade any time soon. Moreover, there is considerable uncertainty about how wind equipment will perform once installed, and, thus, there is uncertainty about how much wind energy is likely to be produced. Initial capacity factor forecasts (for Kansas wind farms) in the low to mid-forties are not uncommon. Fortunately, as more investment in wind capacity occurs in Kansas, actual performance results from those investments will provide improved data sets for making new and perhaps less biased capacity factor forecasts.

On the benefits side of the Challenge, perhaps the most interesting sources of uncertainty are those pertaining to potential carbon regulation and the overall value of reduced power plant emissions. Because there are no emissions associated with wind energy production, then to the extent wind energy production would *reduce* emissions at conventional power plants, wind energy would enable Kansans to avoid the costs of carbon regulation and, as noted above, the environmental and health-related (i.e., external) costs associated power plant emissions. But the type, timing, and reach of carbon regulation are all uncertain and, by definition, the value of avoided external costs is hard to measure and, thus, subject to uncertainty.

Similarly, the fuel savings attributable to wind energy production are uncertain owing to both the volatility (and, thus, uncertainty) of fuel prices and the weather-driven

demand for natural gas-fueled generation. However, since Kansas uses a relatively small amount of natural gas as a generation fuel, the uncertainty surrounding its use is less than commonly perceived.

Given the voluntary nature of the Challenge, there is considerable uncertainty about the behavior of the relevant players. For instance, we do not know which utilities will take up the Challenge and, if they do, what their choice of wind options will be. Hence, the uncertainty of utilities' expected behavior contributes to the uncertainty of both the costs and benefits of the Challenge.

In recognition of the uncertainty surrounding both the costs and benefits of wind energy, it follows that its net benefit to Kansas is uncertain. Indeed, in a word, uncertain is perhaps the simplest and most direct characterization of the expected results of the Challenge.

Fortunately, there is a forecasting technique, which is now among the standard approaches, that enables us to measure the uncertainty associated with the Challenge's net benefit. That technique is Monte Carlo forecasting. By using Monte Carlo analysis, we can show the *range* of possible net benefits as well as the likelihood or *probability* that the Challenge would yield a positive net benefit. With that information, policy makers can determine whether meeting the Challenge would be a good bet for Kansans. That same information also enables policy makers to assess whether the Challenge is likely to be *cost effective*. And if it is, then we could conclude that the cost of providing electricity to Kansans would decrease strictly as a consequence of meeting the Challenge.[5]

[5] If the cost benefit analysis includes only costs internal to the utility (i.e., those cost reflected in monthly utility bills), then determining the cost effectiveness of the Challenge also reveals the *rate* implications of

0.20 What the Uncertainty of the Challenge's Net Benefit Looks Like

Over the relevant time horizon, consisting of future years 2006 through 2034, we forecast the (inflation adjusted) net benefit the Challenge is likely to deliver during each year. That is, we forecast the stream of annual net benefits arising from the Challenge. Each of the annual net benefit amounts, using appropriate discount factors, is then discounted to reflect the time value of money. Once discounted, the stream of annual net benefit forecasts is aggregated, yielding the *total net present value* (hereafter, NPV) of the Challenge. In short, our measure of the Challenge's net benefit is adjusted for both inflation and the time value of money. Accordingly, it provides a measure of the *real net benefit* or *profit* Kansans could earn if the Challenge were met.[6]

For various utility-types, each corresponding to *actual* KCC-jurisdictional utilities, we forecast the NPV of a particular utility-type meeting the Challenge under a wide range of different forecast scenarios. In fact, that "wide range of forecast scenarios" is designed to capture the actual uncertainty associated with both the costs and benefits of meeting the Challenge. In all we develop NPV forecasts for 32 different core case studies. The studies vary by: (1) the type of utility meeting the Challenge, (2) the wind option—buy or build—selected by the utility, and (3) whether estimated external cost savings are included in the forecasts. For each case study we evaluate 200,000 different forecast scenarios, and for each of those scenarios a different NPV forecast is derived.

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the Challenge. That is, when only internal costs are included in the analysis the Challenge's cost effectiveness, if the analysis shows the Challenge would be cost effective then meeting the Challenge would yield lower utility rates on average. However, if the cost benefit analysis includes both the internal and external associated with electric generation, then determining the cost effectiveness of the Challenge also reveals the *total cost* implications of the Challenge. In that case, if the Challenge is cost effective, meeting the Challenge would reduce the total cost of electricity (but its effect on rates could be higher, lower, or unchanged).

[6] In that sense, the economic evaluation of the Challenge is tantamount to an economic evaluation of a potential investment project. If nothing else, the Challenge calls for an *investment* in wind generating capacity and so it is natural to evaluate whether such an investment is economically reasonable.

Thus, by evaluating a wide range of possible future (i.e., forecast) scenarios, we obtain a more robust understanding of the Challenge's net economic potential for the state. More precisely, by using a Monte Carlo forecasting model, we can develop a range of possible NPV outcomes; and for that range of possibilities we can establish the likelihood or probability of any one NPV forecast prevailing in reality. Thus, for each of the 32 core case studies, rather than presenting a single NPV forecast, we offer policy makers with a *probability distribution of NPV forecasts*. By having an entire distribution of NPV forecasts, policy makers will have a clearer picture of the risk involved with the Challenge and, thus, will have more information by which to determine whether investment in wind capacity is a good bet for Kansans. In fact, we offer policy makers with *graphic representations* of the forecast results, as revealed in the next section.

0.30 The NPV Forecast Results for the Base Case: Based on December 2005 Input Forecasts

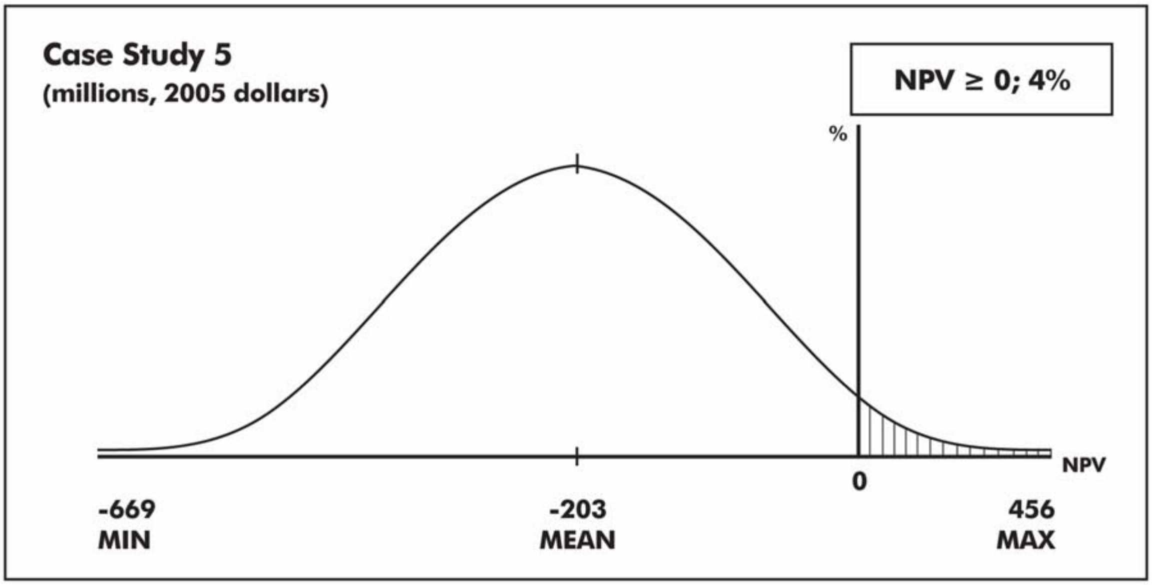
First, what do we mean by the "base case?" We mean that case study that is perhaps most fundamental or realistic among the 32 different core case studies we examined.[7] The base case consists of the "average-cost utility-type" meeting the Challenge by entering only wind purchase power agreements (PPAs) with wind developers. Between the two wind options faced by the utility – entering a PPA with a developer or investing in and, thus, owning its own wind capacity – we consider the former to be more fundamental. That is because, under general conditions, we find that purchasing wind energy is likely to cost the utility less compared to its owning wind capacity. Hence, we consider purchase option more fundamental than owning. As a utility-type, the average-cost utility is a

[7] In addition to the 32 core case studies, we also examine several special case studies.

(retail sales-weighted) composite of the state's five jurisdictional electric utilities and, in that sense, it represents the "average" or archetypical Kansas electric utility. Naturally, the archetype utility is fundamental. Lastly, since external costs are not explicitly included in policy considerations at this time, we see that as being more fundamental than their inclusion.

The graphic representation of the forecast results for this case is shown below. To be sure, for the base case, we examined 200,000 different forecast scenarios and for each an NPV forecast was developed. It is also worth emphasizing the forecast results shown are based on information available as of the start of 2006. All 200,000 NPV forecast results are plotted in a histogram, which we represent as a probability distribution – commonly referred to as a "bell curve." Through that representation we show both the *range* of forecast NPV results and the *frequency* (or probability) of specific forecast amounts. Hence, we show, for each case study in question, the range of forecast values, but also which forecast values are more likely to occur (i.e., more probable) and, therefore, may be interpreted as the most realistic.[8] Finally, that case study we characterize here as the "base case," we refer to in the body of the report as Case Study 5, as noted in the Graph A.

[8] For each graph, the forecast NPV values are measured by the horizontal axis; the probabilities of those forecast NPV values occurring are measured by the vertical axis.



Graph A: Average-Cost Utility, PPA Option, 736 MW Investment Base, Estimated External Cost Savings Not Included

As indicated by the graph, the forecast NPVs in the base case range from a high of $456 million (in 2005 constant dollars) to a low of -$669 million. The average forecast NPV comes in at -$203 million.[9] These forecast results show that things *may* turn out well by pursuing the Challenge, but they also show that the opposite may hold. They also show pursuit of the Challenge is not expected to turn out well, *on average*. More precisely, since only 4 percent of the forecast NPVs are positive, we would also conclude meeting the Challenge is not cost effective.[10] Furthermore, since potential external cost savings are not included in this case—that is, since only wind costs and benefits *internal* to the utility are included in this NPV analysis, we would conclude the Challenge is not cost effective for ratepayers. This is also revealed by the forecast change in utility rates.

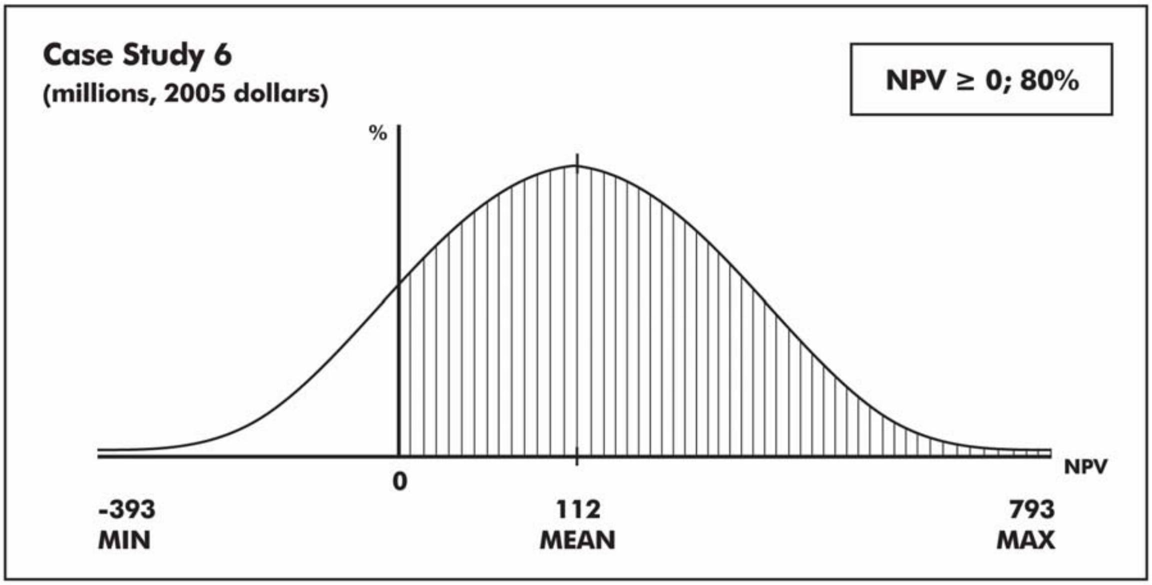
[9] These results are based on the Challenge being met with an additional installation of 736 MW of wind capacity and input variable forecasts as of late December 2005.

[10] Our criterion for cost effectiveness is the mass or density of forecast NPVs reaching 50 percent or more. By using that criterion policy makers can avoid pursuing a policy that amounts to "chasing lead with gold," that is, they can avoid pursuing economically inefficient (i.e., wasteful) policies and challenges. Alternative criterion certainly can be used. However, it is our opinion the criterion we use here is conservative, meaning it tends to favor finding the Challenge is cost effective.

In this case the average retail rate is forecast to increase by $0.46/MWh, on average, simply as a consequence of the utility meeting the Challenge.[11]

However, when estimated external cost saving are included in the analysis, the forecast results for this case change categorically. Based strictly on a study by the Environmental Protection Agency (EPA), we set the estimated external cost savings attributable to one MWh of wind energy at $20. Thus, for each MWh of wind energy generated under the Challenge, we assume a one-MWh reduction of conventional generation; and with that reduction we assume a corresponding reduction in the traditional emissions (SO_2, NO_X, $PM_{2.5}$, mercury), which reduces, among Kansans generally (not just ratepayers), the external costs – namely expected health-related costs – associated with those emissions by $20. Very simply then, we assume for *each* MWh of wind energy actually generated the expected health-related costs among Kansans will decline by $20. When that estimated external benefit of wind energy is *included* in the analysis, the NPV forecast results take on the following appearance. (In the body of this report, the "base case" with external cost savings included is identified as Case Study 6.)

[11] If meeting the Challenge is cost effective for the utility (i.e., its ratepayers), then meeting the Challenge would result in *lower* rates on average. In fact, the cost effectiveness of any measure pursued by the utility can be determined by assessing its influence on the average retail rate. A rate reduction indicates a cost effective measure taken, all else equal; a rate increase reveals the opposite.



Graph B: Average-Cost Utility, PPA Option, 736 MW Investment Base, Estimated External Cost Savings Included[12]

As indicated by the graph above, things *may* turn out well, with positive NPV forecasts ranging up to a maximal NPV forecast of $793 million, or they *may not,* with a negative forecasts ranging down to a minimal NPV forecast of -$393 million. Note, even when estimated external cost savings are included in the analysis, the uncertainty of the outcome remains. But with the inclusion of estimated external cost savings, the *average* forecast NPV is now positive, coming in at $112 million. More importantly, we see that 80 percent of the forecast NPVs take a positive value. Based on these forecast results, we would conclude that meeting the Challenge in this case is cost effective for Kansans generally.

The comparative results show that when the estimated external cost savings (at $20/MWh of wind) are included in the forecast analysis, the Challenge is pushed into the

[12] To be clear, the only modeling difference the forecast results shown in Graphs A and B is the inclusion of estimated external cost savings at $20/MWh of wind energy.

cost effective category.[13] However, the inclusion of external cost savings would not alter the utility's internal costs; therefore, ratepayers would still face higher rates. Thus, while utility rates and bills would be higher in this case, the *total cost* Kansans bear for their consumption of electricity would be lower. This result is specific to the case at hand, which can be characterized as the average-cost utility meeting the Challenge by only entering PPAs, and using input variable forecasts as of the start of 2006.

0.40 The NPV Forecast Results for the Base Case: Using January 2008 Input Forecasts

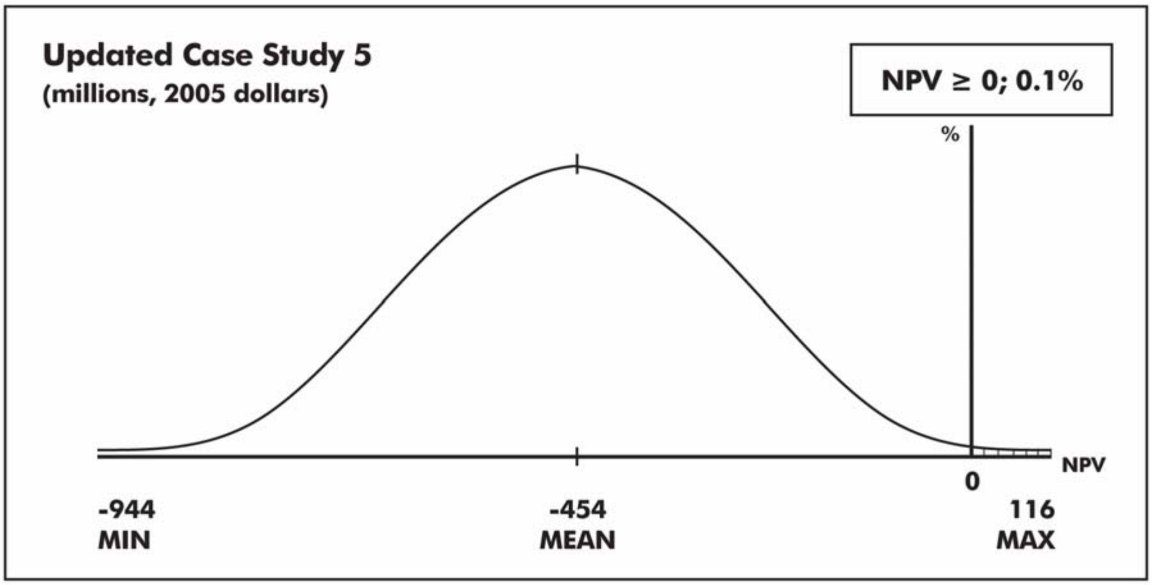
While there is uncertainty about what the future holds, recent history makes clear one thing: the cost of installing wind capacity in Kansas has nearly doubled in the last five years. Initial investments in Kansas were in the range of $1 million per MW of wind capacity. Now the price tag is in the neighborhood of $2 million per MW.[14] Other variables affecting the net value of wind energy have also changed over the last 18 to 24 months, these include: price of natural gas, wind O&M expense per MWh, wind integration cost (including the dispatch inefficiency costs), and interest rates (and, thus, the cost of capital). Given those changes, we decided to *update* several of the input

[13] Our analysis shows that when the average-cost utility meets the Challenge by entering wind PPAs, as long as estimated external cost savings exceed approximately $14/MWh, meeting the Challenge would be cost effective from the total cost perspective. Moreover, for this case, the $14/MWh external cost savings can be used as a threshold or benchmark amount to test the Challenge's cost effectiveness.

[14] It should be noted that at $2 million per MW, the cost of installed wind capacity is on par with that of installed, baseload coal capacity. But critical differences between the two remain: coal capacity is fully controllable and dispatchable; coal capacity has an expected economic life of 40 years rather than the 20 years for wind; coal capacity will be utilized at a capacity factor in the 75 to 80 percent range, wind capacity factors will fall in the 35 to 40 percent range. These differences translate to a significantly higher capacity cost per MWh (i.e., levelized capacity cost) for wind.

variable forecasts so that they would reflect the latest available information. Using those updated input forecasts, we are able to provide up-to-date NPV (i.e., output) forecasts.[15]

In particular, we offer an updated forecast for the base case study. Recall, that case study is the one where the average-cost utility meets the Challenge by entering only wind PPAs. And, as before, we begin by excluding the estimated value of external cost savings. The histogram below characterizes the updated, NPV forecast results.



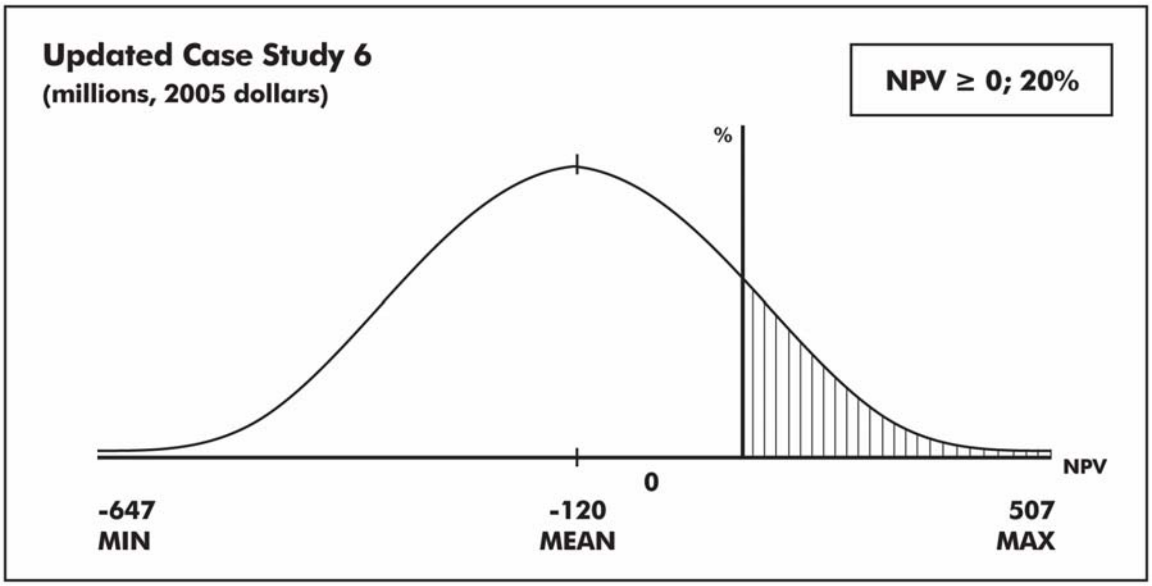
Graph C: UPDATED: Average-Cost Utility, PPA Option, 736 MW Investment Base, Estimated External Cost Savings Not Included[16]

The only difference between the forecast results shown in Graphs A and C is the updating of the input variable forecasts. As the Graph C shows, on an updated basis the maximal forecast NPV is $116 million, the minimal forecast NPV is -$944 million, and the average forecast NPV is -$454 million. On an updated basis, nearly all of the forecast NPVs take a negative value. The reason is straightforward: the near doubling of the wind

[15] Due to time and other constraints, we provide updated NPV forecasts for only the base case studies, that is, Case Studies 5 and 6.
[16] The only difference between the results shown in Graphs A and C is the updating of input variable forecasts.

installation cost. As the direct cost of wind energy increases, the probability of the Challenge providing Kansans with a net benefit is directly reduced.

However, as the following graph shows, when estimated external cost savings (at $20/MWh) are included in the analysis, the updated forecast NPVs certainly improve, as expected.



Graph D: UPDATED: Average-Cost Utility, PPA Option, 736 MW Investment Base, Estimated External Cost Savings Included

With the inclusion of estimated external cost savings, the updated maximal forecast NPV is $507 million, the updated minimal forecast NPV is -$647 million, and the updated average forecast NPV is -$120 million. The proportion of forecast NPVs that take a positive value is 20 percent. Thus, with the latest available forecast information, the inclusion of the estimated external cost savings (at $20/MWh) is not sufficient to put meeting the Challenge in the cost effective category.

However, given the uncertainty of external costs to begin with, this result simply begs the question, which is: *how large would the external cost savings estimate need to be in order for the Challenge to be cost effective in this case?* Our analysis shows that if

estimated external costs are about $28 or more per MWh, then the Challenge would achieve cost effectiveness for Kansas. To be clear, using the most up-to-date-forecasts, our analysis shows (for the base case) that external cost savings per each MWh of wind energy need to be at least $28 for the Challenge to achieve cost effectiveness. The level of external cost savings (per MWh) needed to push the Challenge into the cost effective category we refer to as the "threshold level."

Rather than calculating the threshold level for external cost savings, an alternative approach is to calculate how large a carbon tax[17] would need to be in order to accomplish the same objective; that is, putting the Challenge in the cost effective category. Our analysis shows that if the average-cost utility were subject to a carbon tax of about $37 per ton of CO_2 emitted, the resultant carbon tax savings attributable to wind energy would push the Challenge into the cost effective category.

For the Challenge to be cost effective using the updated forecasts we find there must be external cost (or carbon tax) savings of about $28/MWh of wind energy.[18] However, if the health-related external cost savings are set according to the EPA-based estimate of $20/MWh, then additional carbon tax savings of $8/MWh would be large enough to push the average-cost utility's pursuit of the Challenge into the cost effective category.[19] In most cases we find the cost effectiveness of the Challenge hinges on the magnitude of the external cost savings estimate and/or the assumptions made regarding potential carbon taxation. Given their critical nature, if policy makers want cost effective

[17] Here we use the term "carbon tax" somewhat generically. We do not specify what form carbon regulation(s) may ultimately take, be it cap and trade or direct taxation or some hybrid of the two. Rather we assume for whatever form it takes that at the end of the day it simply translates to a higher cost per ton of CO_2 emitted. That "higher cost" we refer to as the carbon tax.
[18] These threshold levels are inclusive of the federally granted production tax credit (PTC) on wind energy production through 2008. Absent the federal PTC the threshold levels are considerably higher.
[19] This would require a carbon tax of about $11/ton of CO_2.

wind development, they would do well by focusing their attention on the potential external cost and carbon tax savings attributable to wind energy.

0.50 The Levelized Cost of Wind Energy

Using results from our NPV analysis, we estimate what it costs to produce one MWh of wind energy. Like the NPV results, that cost estimate is forecast based. Moreover, since both the investments in wind capacity and wind PPAs are long lived, we calculate the cost of wind energy as an *average cost* per MWh over the relevant time horizon, 2006 through 2034.[20] Accordingly, we present the forecast levelized cost of wind energy per MWh.

Table 0.1 shows (in the first three columns) the forecast levelized cost of wind energy. We assume the utilities would largely face the same sets of wind developers and wind equipment vendors/installers, and would have nearly equal opportunities for selecting or choosing wind project sites; hence, the levelized cost forecasts among utilities is unlikely to vary.[21] Table 0.1 also shows that the levelized cost forecasts vary by the wind option: either the wind PPA or utility building/owning its own wind capacity. The forecasts also vary by when in time they were derived. The "Original Forecasts" are based on input variable forecasts as of start of 2006 (i.e., end of December 2005), while the "Updated Forecasts" are based on input variable forecasts obtained January 2008.

[20] The cost is "levelized" in the sense of being an average cost over both output levels and time.
[21] Because they have different fuel costs, the different utility-types do have different avoided costs. Therefore, the *benefit* each utility-type receives as a consequence of acquiring wind energy will differ; but the *cost* incurred to acquire that energy will not differ by much, if at all.

Table 0.1: Levelized Cost of Wind Energy
[in 2005 constant dollars per MWh]

	Column (1) Utility's Standalone Cost[1]	Column (2) Integration Cost[2]	Column (3) Total Levelized Cost[3]	Column (4) Average Retail Rate Change[4]	Column (5) Threshold External Cost Level[5]	Column (6) Threshold Carbon Tax[6]	Column (7) Total Levelized Cost w/o PTC
PPA/Purchase Option							
Original Forecasts	$32 - $33	$4.60	$37 - $38	+$0.46	$13 - $14	$17 - $18 [$0][8]	$55 - $56
Updated Forecasts	$48 - $49	$8.00[7]	$56 - $57	+$0.98	$27 - $28	$37 - $38 [$10 - $11][8]	$74 - $75
Build/Own Option							
Original Forecasts	$56 - $57	$4.60	$56 - $57	+$1.16	$31 - $32	$41 - $42 [$14 - $15][8]	$68 - $69
Updated Forecasts	$77 - $78	$8.00[7]	$77 - $78	+$1.90	$51 - $52	$68 - $69 [$41 - $42][8]	$95 - $96

Notes: (1) The cost amounts for the purchase option represent PPA prices and, therefore, do not embody the utility's estimated wind integration cost. The cost amounts for the build option reflect all costs incurred by the utility, including the estimated wind integration cost.

(2) Unless noted, our estimate of the estimated wind integration cost does not include any cost associated with dispatch inefficiencies cause by wind energy production.

(3) The total levelized cost reflects all costs associated with the utility's acquisition of wind options.

(4) Average forecast rate change is for the average-cost utility-type. The average forecast rate change varies by utility-type.

(5) This is the threshold external cost level for only the average-cost utility. The threshold external cost level does vary by utility-type.

(6) This is the threshold carbon tax per ton of CO_2 *for the average-cost utility*. The threshold carbon tax varies by utility-type. We assume the carbon tax would be applied on a "statewide basis" and, therefore, to the state's existing mix of electric generation. Since a large share (about 25 percent) of the state's electricity is generated by nuclear fuel, a $10/ton carbon tax would increase the state's average retail price of electricity by about $7.50/MWh.

(7) Recent research shows that integrating wind assets with the existing portfolio of Kansas generation assets is likely to create dispatch inefficiencies. (See Direct Testimony submitted Docket No. 08-WSEE-309-PRE.) That research shows dispatch inefficiencies are likely to fall within the range of $10 to $20 per MWh of wind energy. One way to take account of this is by including the cost of dispatch inefficiencies as a component of the estimated wind integration cost. This we have done by (very conservatively) increasing the wind integration cost to $8.00/MWh.

(8) This amount shows what the carbon tax would need to be for the Challenge to be cost effective if external cost savings are "credited" at $20/MWh of wind energy.

The levelized cost forecasts shown in Table 0.1 illustrate several important points:

- the wind PPA option is likely to be less costly than the utility build/own option,[22]
- the cost difference between the two wind options is case and data specific,[23]
- due to recent increases in wind installation costs, the cost forecasts using the January 2008 input forecasts generally exceed those using the December 2005 input forecasts,
- the total levelized cost of wind energy includes the wind integration cost, see Column (3),
- strictly as a consequence of meeting the Challenge, the average retail rate for the average-cost utility is forecast to *increase*, see Column (4). (This is due to the utility's forecast revenue requirement *increasing* as a consequence of meeting the Challenge, all else equal. The increasing revenue requirement is due to wind resources being more costly than the conventional alternatives.)
- there must be positive external cost savings (per MWh of wind energy) for the Challenge to be cost effective (from the total cost perspective). The level of external cost savings (per MWh) necessary for the Challenge to be cost effective, that is, the threshold amounts are shown in Column (5). [This is equivalent to saying that on a combined basis, the fuel savings, ranging between $20 and $25 per MWh, and capacity cost savings attributable to wind energy are *not enough* to make wind economic.]
- alternatively, there must be positive carbon tax savings per MWh of wind energy for the Challenge to be cost effective (from the total cost perspective). The

[22] This result depends on a number of different factors. For instance, it depends on any timing differences between the utility's actual investment in wind capacity and the formal inclusion of that investment in the utility's allowed ratebase. More specifically, the cost difference between the wind options is influenced by regulatory lag: cost recovery of wind PPAs is unlikely to be subject to regulatory lag while cost recovery of wind investments is likely to be subject to some regulatory lag, which makes the investment option more costly for ratepayers. The cost difference between the two options is also influenced by differences between the developers' and utilities' cost of capital, financial requirements, and ability to take advantage of various tax provisions. It also depends on the absolute level of wind installation costs – the ownership option is relatively more costly the higher that level. Using the original input variable forecasts (with an assumed wind installation cost of $1.6 million per MW), our analysis shows the build option, on a levelized basis and on average, costs $18 more per MWh than the PPA option. That result is shown in Column (5) of Table 0.1 as difference between external cost threshold levels: $31 - $13 = $18. However, with the updated input variable forecasts (with an assumed wind installation cost of $2.15 million per MW), our analysis shows the build option, on a levelized basis and on average, costs $24 more per MWh than the PPA option. That result is shown in Column (5) of Table 0.1 as difference between external cost threshold levels: $51 - $27 = $24. Again, actual, levelized cost differences between the two options will vary around these averages. See Appendix G for a detailed discussion of the cost difference.

[23] While not shown in Table 0.1, since the pricing terms of PPAs are usually structured in terms of amounts and escalation rates, the PPA option tends to be the less risky option for ratepayers. Our analysis shows, for ratepayers, the cost of PPAs tends to be both lower and less volatile than that of the build option.

threshold carbon tax (per ton of CO_2) levels necessary to bring about those savings are shown in Column (6).

- if wind energy is credited with an external cost savings of $20/MWh, then potential carbon tax savings (per ton of CO_2) of about $11 are required for the Challenge to be cost effective. (See bracketed [·] amounts in Column (6).)
- Column (7) shows the cost of Kansas wind energy absent the federal PTC (that is, in the NPV analysis setting the federal PTC equal to zero). This amount reveals the *actual resource cost* of wind energy in Kansas.

These forecast results clearly indicate that wind energy is far from being free, let alone inexpensive. They also show for the average-cost utility retail rates would, on average, increase as a consequence of the utility meeting the Challenge. Moreover, they show the importance of the federal subsidy of wind energy in the form of the PTC. If policy makers want to avoid economic waste in their endeavors to stimulate the development of renewable energy resources, keeping an eye on the actual, non-subsidized cost of those resources—at least as a reference point—may be advisable. The non-subsidized cost of wind energy reveals society's opportunity cost of pursuing wind development.

0.60 The Levelized Benefits of Wind Energy

The benefits of wind energy production fall under two categories: (1) savings *internal* to the utility's accounts and, thus, passed on to ratepayers, and (2) savings *external* to the utility. To the extent that wind energy production reduces the emissions associated with conventional generation, the resultant, estimated external cost savings can similarly be placed in two categories: (1) estimated savings due to reducing traditional emissions and (2) estimated savings due to reduced carbon emissions. The latter would also include avoided carbon taxes if such taxes are imposed.

The internal cost savings attributable to wind energy production are reasonably easy to estimate. For example, by acquiring wind energy the utility saves on, mainly, fuel and variable O&M expenses—which we characterize as the average annual system lambda.[24] Our estimate of the average-cost utility's levelized, average forecast lambda is about $25/MWh, in 2005 constant dollars. With respect to that estimate, once the utility has obtained a wind resource, then for each MWh of wind energy acquired from that resource the utility saves or avoids an incremental expense estimated at $25.

Because wind energy production is free of emissions, because it would displace production of electricity by technologies that do produce emissions, and because there are external costs associated with those emissions, wind energy production will yield some level of external cost savings. Unfortunately, *external cost savings are very difficult to estimate.* Nearly by definition, this is true for all externalities, be they related to traditional emissions or otherwise. Moreover, potential savings due to carbon tax avoidance are difficult to estimate since the timing, size, and likelihood of a carbon tax are mostly speculative at this point in time. Nonetheless, based on a Kansas-specific EPA-study of external costs due to traditional emissions, we incorporate in this study an external cost savings of $20/MWh of wind energy. Thus, for each MWh of wind energy acquired by the utility, we assume external costs borne by Kansans are *reduced* by $20.

0.70 Comparing Levelized Costs and Benefits: Another Check of Cost Effectiveness

If the Challenge is to deliver a cost-effective outcome to Kansans, then the levelized, average *benefit* per MWh of wind energy must match or exceed the levelized, average

[24] Consistent with generation capacity rating methods applied by the SPP we also include a seven percent capacity credit per investment in wind capacity. However, a more precise application of those methods would probably reduce that percentage. In fact, a zero capacity credit rating may not be unreasonable.

cost per MWh of wind energy. Referring back to Table 0.1, Column (5), the “Threshold External Cost Level” shows (for the two wind options and the alternative forecast dates) how large external cost savings need to be in order to push the Challenge into the cost effective category. However, if policy makers were to decide that the EPA-based estimate of external cost savings, at $20/MWh, is reasonable *as an estimate*, then for the Challenge to be cost effective, and depending on the case, there would need to be an *additional* source of estimated savings (for the Challenge to be cost effective). That additional source could be carbon-related savings. If wind energy is credited with an external cost savings of $20/MWh, then potential carbon tax amounts of between $10 and $42 per ton of CO_2 are required for the Challenge to be cost effective. (Those amounts are the bracketed figures shown in Column (6).) If there are no external cost savings attributed to wind energy, then potential carbon taxation per ton of CO_2 would need to be considerably larger for the Challenge to meet the cost effectiveness test. (Those amounts are the non-bracketed figures shown in Column (6).)

For wind energy to pay its way—that is, for pursuit of the Challenge to make economic sense and not result in a waste of scarce resources, the economic benefits from wind must match or surpass its cost. This study provides policy makers with an indication of the conditions that must prevail in order for the Challenge to be cost effective. Those conditions vary depending on the utility-type and the wind option selected by the utility.

0.80 The Forecast Results are Sensitive to Changing Conditions and Assumptions

We come back to what is undoubtedly the critical element of wind economics in Kansas: the significant uncertainty that surrounds it. At this time there is considerable uncertainty

regarding (1) future installation costs, (2) annual capacity factors, (3) Kansas-specific wind integration costs, (4) Kansas-specific wind O&M expenses, (5) the influence of wind energy production on the utilities' wholesale market transactions, (6) the utilities' capacity expansion paths, (7) the cost of network transmission upgrades required to accommodate investment in Kansas wind facilities, and (8) the prospects for a carbon tax.

If the current escalation of wind installation costs continues, which for a number of reasons seems likely, then the economic viability of wind energy is reduced. The same holds if wind capacity factors turn out to be lower than originally forecast (based on untested design specifications), which also seems likely. Because Kansas utilities are relatively dependent on baseload-type generators and fuels, the wind integration cost may be close to two or three time higher than the amount used in this study, again diminishing the economic prospects for wind energy. At this time there is very little data available per actual wind O&M expenses at Kansas locations. Absent any sort of historical track record, it is difficult to forecast what those expenses may be. To forecast O&M expenses for wind equipment that is 10 years or older is an even greater challenge. If Kansas wind energy production ends up being sold primarily to non-Kansas utilities (or ratepayers) in the wholesale electric market, then Kansas wind energy production may not deliver the estimated external cost savings to Kansans.[25] Instead, those savings may be realized in other states. However, if Kansas utilities pursue capacity expansion through greater reliance on natural gas-based generation (in an attempt, perhaps, to steer clear of new baseload coal units), then the economic prospect for wind energy is likely to improve. At any rate, there are numerous, different capacity-expansion paths available to utilities, and

[25] If Kansas wind energy is sold out-of-state so that the dispatch of Kansas generators and, thus, Kansas emissions is unaltered, then external cost savings will more likely occur in those locals where traditional generation is reduced.

it is difficult to forecast which paths will be taken. Some of those paths may include greater reliance on nuclear energy, and, if those paths are followed, the economic viability of wind energy could be significantly diminished (depending on the possible resolution of waste storage and/or recycling issues). The inclusion of network transmission upgrades required to maintain system reliability standards while accommodating new wind facilities will only add to the cost of wind energy. Lastly, a carbon tax would certainly improve the economic prospect for wind energy development. Indeed, in order to preserve the relative attractiveness of the Kansas business environment, it may be advisable to temper wind development initiatives depending on the actual implementation of carbon legislation.

0.90 Final Observation

While we have identified the conditions under which meeting the 2015 Wind Challenge is likely to be cost effective, it remains the case that those conditions remain far from stable. When it comes to forecasting the net benefit of Kansas wind energy, there is and there will likely remain a high degree of forecast error. The success of wind energy development policies is subject to a real degree of risk.

Chapter 1: Introduction to the 2015 Wind Challenge and Key Results

1.00 Introduction

Governor Kathleen Sebelius in her January 21, 2005, letter to the Chair of the Kansas Corporation Commission ("KCC"), Brian Moline, asks the Commission to "look at the full range of benefits that renewable energy brings to Kansas and how those relate to additional investment that may be needed to meet" what could be referred to as the Governor's 2015 Renewable Energy Challenge.[1] That challenge is "to have 1,000 megawatts of renewable energy capacity installed in Kansas by 2015."[2]

Arguably, the more promising renewable energy sources for electric generation in Kansas are wind, solar, biomass, and biodiesel. Among those sources, wind-powered generation appears to offer the greatest potential to meet the stated challenge. For instance, Kansas currently (mid-2007) has about 364 megawatts (MW) of wind-powered generation connected to the grid, with only insignificant amounts of generating capacity fueled by other renewable sources.[3] Furthermore, absent significant changes in technologies, market prices and/or government subsidies, it seems unlikely that renewables other than wind will play a significant role in meeting the challenge.[4] For

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[1] A copy of Governor Kathleen Sebelius' letter is provided in Appendix A.

[2] For the year 2005, 1,000 megawatts (MW) of nameplate capacity represented roughly 7.64 percent of the state's total generation capacity (inclusive of existing wind facilities) and, assuming an annual capacity factor of 40 percent for all wind facilities, that amount of capacity would yield approximately 8.34 percent of the state's total production of retail electric energy, measured in megawatt hours (MWh).

[3] This total includes the installed capacity amounts of 112.5 MW at Gray County (which we attribute to Aquila, Inc.), Empire District Electric Company's 150 MW at its Elk River site, and Westar Energy, Inc.'s 1.5 MW at its JEC site. As of late-2006, Kansas City Power and Light is installing 100.5 MW of wind capacity near Spearville. With that addition, total installed wind capacity in the state reaches 364.5 MW by the start of 2007.

[4] It is difficult to forecast with any degree of accuracy the changes in both technologies and investment incentives that may be necessary to induce, on a reasonably large scale, the economic viability of renewables other than wind. The Bowersock Dam, located on the Kansas River just behind Lawrence's City Hall, provides about 2 MW of hydro-based capacity. Only a very small fraction of electricity generated in Kansas is fueled by diesel; therefore the prospect of using biodiesel as an alternate to diesel (or possibly No. 6 oil) is quite limited. Kansans do have access to vendors of geothermal heat pump systems,

those reasons, we focus our attention on wind-powered generation and, thus, slightly recast the Governor's Renewable Energy Challenge as the "2015 Wind Challenge" (hereafter, Challenge).

While the Governor is clear that compliance with the stated Challenge is strictly "voluntary," we interpret her directive to the Commission as a request to perform a cost benefit analysis *as if* the Challenge were met. That analysis is useful because, among other things, it answers the questions of whether utility bills and total generation costs would likely be higher as a result of meeting the Challenge and whether voluntary compliance would be likely.[5] Answers to those questions may be useful to policy makers as they deal with various energy issues that confront the state. Our objective here is not to end the debate about the economic prospects of wind energy in Kansas, but rather to provide economic insight based on current and forecast market conditions and an analytical framework for further discussion and discovery.

1.10 Assessing the Cost Effectiveness of Meeting the Challenge

By performing a benefit cost analysis of the Challenge, we derive estimates of the possible net savings (or net benefit), and, depending on whether the expected net savings are positive or negative, we can determine whether meeting the Challenge is likely to be cost effective (i.e., economically efficient). However, because investments in wind capacity are long-lived assets, yielding benefits and inducing expenses over an extended

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which can displace the demand for electricity but, of course, are not perceived as alternatives for generating electricity. Biomass may offer an alternative to conventional fuels. However, given its low heat content relative to fossil fuels and given current coal prices, biomass is unlikely to have a cost advantage any time soon. Finally, solar-based power options may also be available to the public, but at this time offer limited potential as large-scale generation alternatives or energy substitutes.

[5] If compliance was likely to provide ratepayers with lower bills, all else the same, we expect utilities to seek compliance; however, if higher bills are the probable outcome, then utilities may resist compliance.

period of time, a more accurate measure of net savings is the net present value ("NPV"). Therefore, our assessment of whether the Challenge is likely to be cost effective is based on forecast NPVs.[6]

1.11 Developing NPV Forecasts on a Case Study Basis

Whether the Challenge is economically efficient depends on several different factors and considerations. For instance, it depends on (1) *which* utilities might take up the Challenge and to what extent, (2) whether they *decide* to purchase wind energy through purchase power agreements ("PPAs") with developers[7] or directly invest in wind capacity and obtain ratebase treatment in the process, (3) the estimation of *cost savings* (i.e., avoidable costs) attributable to the utility's wind decision, and (4) whether the estimated cost savings *include* estimates of external cost savings.[8] In this study we examine various combinations of these basic factors and develop summary NPV forecasts for thirty-two distinct cases, which we refer to as *case studies.*

1.12 Using Monte Carlo Simulation to Develop Forecast Scenarios

For each case study, using the techniques of Monte Carlo simulation, we examine 200,000 different forecast scenarios. For each forecast scenario, we derive an NPV forecast. Thus, for each case study, we actually derive 200,000 distinct NPV forecasts. From each sample set of 200,000 NPV forecasts, we calculate the *average* NPV forecast,

[6] Hereafter, references to the Challenge shall be within the context of Challenge having been met, absent indications to the contrary.
[7] Any entity supplying wind-based energy under the terms of a PPA is generically referred to as a "developer."
[8] External costs are those resulting from the utility's decisions, but not recorded in its internal accounts. Examples include damages, such as health-related costs stemming from power plant emissions. Since exposure to even the risk of those damages is detrimental to many members of the public, possible payments to avoid that risk can be included as part of the expected external cost calculations.

which is our primary summary NPV forecast.[9] Our determination of the cost-effectiveness of the Challenge hinges on the sign of the average NPV forecast: if it is positive, we infer a cost-effective outcome is likely; otherwise, we infer the opposite.[10] That is, if the benefit cost analysis indicates a positive NPV, *on average*, that is sufficient to conclude the Challenge is *likely* to be economically efficient. Other decision criterion for determining economic efficiency can be used, but this criterion is well accepted and widely used.[11]

1.13 The Requisite Amounts of Wind Capacity Needed to Meet the Challenge

In terms of *time horizons*, there are two separate vantage points from which to examine the Challenge. One is strictly forward looking in time, focusing on only the *new, incremental investment* needed to meet the Challenge. For purposes of this study, the future time period starts January 2006, at which point approximately 736 MW of new capacity is needed to meet the Challenge. The other vantage point looks both forward and backward in time. In also looking backward, an NPV evaluation of the historically given amount of wind investment, about 264 MW as of January 2006, must be included in the analysis. Hence, from the second vantage point, the examination of the Challenge's cost effectiveness includes *both* the historically given wind investments (264 MW) and the requisite investments in new capacity (736 NW). In this study we evaluate the net benefit

[9] The average NPV forecast, as implied by the name, is a summary statistic. Most of the basic forecasts presented and discussed in this study take the form of statistics.

[10] Since the probability distributions of the NPV forecasts, derived as a result of the Monte Carlo analysis, are effectively normal, this criterion is equivalent to the density of positive NPV forecasts being 50 or more percent. That is, if 50 percent or more of the forecast NPV are positive, then we find meeting the Challenge would be cost effective.

[11] Since this criterion does not require the average forecast NPV to be significantly larger than zero, arguably it represents a relatively lax standard because it allows up to a 50 percent probability that the actual NPV could be less than zero. This criterion does not take account of the options value lost as a consequence of resources being used to meet the Challenge.

of the Challenge from both vantage points. That is, we establish the net benefit associated with investing in an additional 736 MW of wind capacity and we do the same for the total 1,000-MW investment.[12]

1.14 Reliance on Utility-types Rather than Specific Utilities

As indicated above, the forecast NPVs depend upon which utilities might install or purchase wind capacity. Unfortunately, there is no good means of forecasting which *specific* utilities will build or buy wind, nor the respective *amounts* of either, nor *where* the wind facility might be located. To get around this forecasting problem, we model four different archetypal (or hypothetical) utilities, which we refer to as "utility-types." We then examine, for each utility-type, the NPV of that utility-type alone meeting the Challenge.[13]

Three of the utility-types have been carefully modeled after one or more of the state's jurisdictional electric utilities (hereafter, utilities). Just as the utilities have different generation costs, we distinguish among the utility-types by their *cost of generation*. Therefore, based upon relative costs of generation we model a low-cost utility-type, middle-cost utility-type, and high-cost utility-type. The low-cost utility-type is based upon the actual generation costs of Westar Energy, Inc. ("Westar") and Kansas

[12] More precisely, we perform an NPV analysis of the incremental 736 MW investment and do a separate NPV analysis of the historically given investment of 264 MW. Combining the results from those two analyzes we obtain the NPV results for the 1,000 MW case. The latter satisfy the Governor's request. However, we would note that the evaluation of only the incremental investment (736 MW) is economically meaningful for it indicates whether *maintaining* the Challenge make economic sense and the *likelihood* of economically meeting the Challenge given the amount of investment that has already occurred.

[13] Since we evaluate the NPVs as if each utility-type alone meets the Challenge, that is tantamount to effectively modeling the utility as if it is statewide in scope which mitigates any need to forecast precisely where in the state, that is, which utility's service area investment in wind capacity might occur. Throughout we assume the likelihood that wind investment will occur in geographic areas of the state where it is likely to be most productive, achieving the highest average annual capacity factor over the life of the project, wherever those areas might be.

City Power and Light, Inc. ("KCPL"); the middle-cost utility-type is modeled after MidWest Energy Cooperative ("MWE") and Empire District Electric Company, Inc. ("EDE"); and the high-cost utility-type's generation cost is based on actual generation costs of Aquila, Inc. (d/b/a, WestPlains) ("WestPlains").

1.15 What Wind Energy Substitutes For: Avoided Utility Costs

In this analysis the measure of generation cost can be critical. If and when a utility-type acquires wind energy, it can avoid its marginal or incremental cost of conventional generation.[14] The utility-type's incremental generation cost is largely determined by its portfolios of power plants and supporting fuel contracts. As the utility-type attempts to meet its retail load requirements through the least-cost, hourly dispatch of those two portfolios, its incremental generation cost (or, equivalently, its cost structure) is revealed through its hourly system lambda—the incremental cost of generating the last MWh needed to meet its total, hourly load obligation.[15] Thus, by acquiring one MWh of wind energy over a particular hour, we assume the utility-type will avoid and, thus, save an amount equal to its hourly system lambda. With that background and in summary, the system lambda of the low-cost utility-type is based upon the actual system lambdas of Westar and KCPL, the middle-cost utility-type is modeled after MWE and EDE, and the high-cost utility-type's lambda is based on WestPlains' lambda.[16]

[14] By conventional we mean the traditional coal, natural gas, and nuclear based generation technologies.
[15] Note that we define the system lambda through use of the utility's incremental dispatch process. This means the lambda is determined largely by the utility meeting its load obligation rather than providing, perhaps on its operating margin, an ancillary service such as load following.
[16] For each utility-type, the system lambda is calculated as an average annual lambda. All of the forecast average annual lambdas are based on (i.e., calibrated using) actual hourly system data over the 2004 calendar year.

Modeling the utility-type lambdas after the actual utility lambdas means that (1) the *level* of the model lambdas has been effectively matched with that of the actual utility lambda(s) and (2) the *sensitivity* of the model lambdas to *changes* in natural gas and other fuel prices has also been matched with that of the actual lambdas. In short, the utility-type (model) lambdas are consistent with the actual utility lambdas in both magnitude and fuel price sensitivity.[17] Moreover, by evaluating the NPV of the Challenge by utility-type, we can establish a meaningful *range* of results (i.e., forecast NPVs) across utility-types. That is, we show that the net benefit of meeting the Challenge does, in fact, depend on which utilities respond to the Challenge. This approach is also meaningful in the sense that the actual NPV of the utilities collectively meeting the Challenge, in whatever way it is actually met, is almost certain to fall within that "range of results."

1.16 The Average-Cost Utility-type as the Representative Kansas Electric Utility

While three of the model lambdas are based on actual utility costs, the lambda for the fourth utility-type is an average of those three lambdas. More precisely, the lambda of the average-cost utility-type is an annual sales-weighted average of the low-, middle-, and high-cost lambdas. The weights used to calculate that average also provide a proxy of the utility-type's relative size in the state. By using those weights to calculate the average-cost utility-type's lambda, that lambda also provides a good estimate of the statewide average system lambda.[18] By design, the average-cost utility-type's lambda would be the

[17] More generally, the model lambdas are, more precisely, lambda *forecast models*. For instance, the low-cost utility-type's lambda is the model we use to *forecast* Westar's/KCPL's system lambdas.

[18] Moreover, if each utility were to meet the Challenge so that its share of the 1,000 MW total equaled its proportion (i.e., share) of the state's annual retail energy sales, then in that case the average-cost utility-type's lambda would also provide a good estimate of the statewide average avoided cost of wind energy. For example, Westar's annual retail sales in 2004 comprised about 67 percent of the state's total, jurisdictional retail sales. Thus, if Westar were to take up the Challenge in an amount equivalent to its

representative statewide, average lambda (for evaluating wind economics in Kansas), provided utilities meet the Challenge proportional to their relative size. Thus, the forecast NPV results for the average-cost utility-type may offer the *most accurate* indication of the statewide implications of meeting the Challenge.[19] That said, we see the forecast results for the average-cost utility-type as providing the estimates of what the actual NPV will be when the utilities collectively meet the Challenge, assuming only that the utilities' relative sizes are likely to influence how the Challenge is actually met (with the relatively larger utilities taking relatively more of the targeted wind capacity).

1.17 What Wind Energy Substitutes For: Avoided External Costs

The forecast savings attributable to investment in wind capacity also depends on consideration of possible pollution-related costs that could be avoided when the utility acquires wind energy. Measuring or quantifying the external costs due to conventional generation is, by definition, complicated and plagued by an absence of relevant data and information, both empirical and theoretical.[20] Estimation of external costs is also plagued by the possible non-linearity of those costs and the presence of a threshold or "tipping point" past which costs could rapidly approach catastrophic levels.[21] Nonetheless, various estimates of those external costs do exist; however, most are not Kansas-specific

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market share of jurisdictional retail sales (in 2004), then it would end up installing about 667 MW of wind capacity by 2015. To complete the example, in computing the average-cost utility-type's lambda, the weight attached to low-cost utility-type's forecast lambda would be 0.880, which includes both Westar's and KCPL's retail market shares. Using statewide proportional annual energy sales would be one way to "allocate" or proportion the responsibilities of meeting the Challenge.

[19] We say "may" because this statement rests on the assumption that utilities acquire wind capacity proportional to their relative sizes.

[20] From our perspective, there is a need for additional government-sponsored scientific research quantifying possible external costs due to power plant emissions as borne by Kansans. That said, even with such an effort, we recognize that actual external costs may likely remain largely uncertain.

[21] See Pindyck (2006).

and most are for the more traditional pollutants like SO_2 and NO_X. Fortunately, the Environmental Protection Agency ("EPA"), as part of its analysis of President George W. Bush's Clear Skies Initiative, has performed a study of the possible external costs occurring in Kansas as a consequence of conventional power plant emissions. Owing *strictly* to the EPA's study, there is some factual basis for setting the forecast external cost savings (among Kansans) at $20 for each MWh of wind energy generated in Kansas. However, and it is worth emphasizing, any assessment of external costs is almost certain to possess a large margin of error; regarding the estimation of external costs considerable uncertainty remains.

1.18 Establishing Threshold External Cost Levels

In this study, we utilize two different forecasts of external cost savings. We forecast the net savings (i.e., NPV) from meeting the Challenge with the external cost savings forecast set equal to zero (0). The analysis is then repeated with the external cost savings set at $20/MWh of wind energy, based on EPA study. In addition, for all case studies, we also calculate the break-even or threshold external cost level. As implied by its name, the break-even external cost level indicates how large the external cost estimate needs to be, at minimum, in order for the Challenge to reach the threshold of cost effectiveness—that is, yield an average forecast NPV just equal to zero (0). Very simply, by calculating this threshold external cost savings level, we provide policy makers with an estimate of how large the external cost saving would need to be for the Challenge to be cost effective. That is useful information because it facilitates a quick assessment of the Challenge's probable cost effectiveness: if estimated external cost savings (whatever they may be)

exceed the “threshold levels,” then meeting the Challenge is likely to be cost effective for Kansans.

1.19 Brief Summary of the Case Studies

In summary, the 32 case studies we evaluate comprise the various combinations that follow from each of the four (4) utility-types meeting the Challenge by choosing one of the two (2) wind options, either directly investing in wind capacity or purchasing wind energy from developers through PPAs,[22] with forecast external costs savings set at zero or $20/MWh, and with either the forward-looking time horizon (where the utility-type acquires 736 MW of wind capacity) or combined historical and forward-looking time horizon (where it acquires the full 1,000 MW amount).

1.20 Some General Results and Findings

In this section, we discuss some of the main, qualitative findings of the study. Our intent is to provide a somewhat more detailed and extensive presentation of the key results than is found in the Executive Summary.

[22] The Challenge could be met with utilities collectively installing the requisite amount of wind capacity for themselves or wind developers making that same amount of investment and then selling the resultant energy to the utilities in accordance with PPAs. Of course, some combination of those two wind options, build or buy, could be used to meet the Challenge. Hereafter, references to either the build or buy options shall be within the context of the Challenge having been met with the utilities *only* investing or buying and not some combination. Wind developers are thought of as independent, third-party entities that would need to enter PPAs with the utilities as a basis for financing their investments in wind capacity; that is, developers are assumed to rely on project financing. Provided the Commission finds wind PPAs to be in the public interest, the financial integrity of those contracts (from the developer’s perspective) is assured by the utility’s ability to recover prudently incurred costs from its jurisdictional retail customers.

1.21 Firm Capacity Accredited to Installed Wind Capacity

Utility investments in wind capacity are likely to receive firm capacity credit from the Southwest Power Pool ("SPP"). But the amount of credit SPP grants is likely to be only a small fraction of the nameplate wind capacity.[23] Because of that, it is quite possible that even when utilities invest in wind capacity, the resultant SPP-accreditation of that capacity will have no practical effect on their planning to meet peak loads. In short, it is possible that utility investment in wind capacity will have no influence on the utilities' demand for conventional generating capacity.[24] That is, utility investment in wind capacity may not enable the utility to otherwise reduce its investment in the conventional generating capacity. In that case, investment in wind capacity is properly viewed *strictly* as a source of energy rather than a source of firm capacity.[25]

1.22 As an Energy Resource, Wind is More Costly than the Conventional Alternatives

As an energy resource, wind energy is likely to cost the utility more than producing energy via conventional means. That finding holds for all of the utility-types and for both wind options; on average, wind energy generally costs more than energy produced by conventional generators and fuels.

[23] In this study we assume SPP would grant a capacity credit of seven (7) percent of installed nameplate capacity.

[24] In terms of capacity planning, because they are likely to be small relative to the whole, capacity credits granted to wind capacity may be effectively "lost in the noise."

[25] Such a view begs a more complex question and that is: If investment in wind capacity fails to provide ratable capacity, is it capable of providing the sort of firm energy to which retail customers are accustomed and currently demand? If not, then even as an energy resource, it may be reasonable to discount the value of wind energy as a means of satisfying customer demands for reliable energy.

1.23 In most Cases, Meeting the Challenge Implies Retail Rates Must Increase

Because one MWh of wind energy costs more than what it costs the utility to produce one MWh of electricity via conventional means, when a utility acquires wind energy its total cost of serving its customers will increase, relative to its total cost if it does not pursue the Challenge. As a consequence, the utility must increase its retail rates strictly as a consequence of meeting the Challenge. That is tantamount to saying the utility's acquisition of wind energy is not cost effective from the ratepayers' perspective. The amount of rate increase does vary by the utility-type and wind option selected by the utility.

For the high-cost utility meeting the Challenge by entering (only) wind PPAs, the levelized, median forecast rate *increase* is only $0.01/MWh.[26] This is a small increase, but that it is an increase is the critical element. At the other extreme, when the low-cost utility meets the Challenging by taking wind energy under only PPAs, the levelized, average forecast rate *increase* is $0.57/MWh. This shows that even though wind energy is not economic for either the high- or low-cost utility, wind energy is a better deal for utilities with relatively higher internal generation (i.e., fuel and variable O&M) costs. That is, the low-cost utility's acquisition of wind resources will force a larger increase in its average retail rate compared to what would happen for higher-cost utilities. Equivalently, the higher the utility's fuel costs, the more attractive wind energy is.

The rate implications are a bit different when utilities choose the ownership (i.e., build) option. When the high-cost utility meets the Challenge through its own investment in wind capacity, the levelized, average forecast rate increase is larger, coming in at

[26] All rate forecasts are in 2005 constant dollar terms and, therefore, represent inflation-adjusted rate increases.

$0.71/MWh. For the low-cost utility, the respective number is $1.29/MWh. This also shows that the wind purchase option tends to be less costly than the build option (see Section 1.25 below).

1.24 Higher Retails Mean Higher Electric Bills

In this study we assume that the typical residential class customer in Kansas consumes about 11 MWh during a normal year. Using the forecast rate increases presented in Section 1.23, if the high-cost utility meets the Challenge using only PPAs, the annual electric bill for the typical residential customer would increase by $0.11, on average. That forecast increase would hold for each year of the investment horizon, 2006 through 2034. At the other extreme, if the low-cost utility pursues the Challenge by investing in its own wind capacity, the annual electric bill for the typical residential customer would increase by $14.19, on average. Over the 28 year investment horizon, that would mean a total electric bill higher by nearly $400. This is yet another indication that the Challenge would not be cost effective from the ratepayers' perspective.

1.25 Wind Energy Costs the Utility More When it Builds/Owns Wind Capacity

Our analysis shows that, on average, it is more costly for utilities to acquire wind energy through ownership of wind capacity than wind PPAs. Consequently, on average, it costs ratepayers more when the utility builds/owns wind capacity rather than purchasing wind energy from a wind developer through a PPA. However, that result depends on a number of different factors: for example, the differences between the utilities' and wind developers' capital structures, capital costs, and required returns. Since recovery of

investment expenses is more likely to be influenced by regulatory lag than recovery of wind PPA expenses, the cost differential also depends on the effects of regulatory lag and, thus, rate case timing. Finally, the cost differential also depends on the installation cost of wind capacity. Our analysis shows that the greater the installation cost, the greater the cost difference between the two wind options. All of that said, we also recognize that under certain conditions the two wind options have comparable costs.

In terms of actual forecasts of the cost differential, our NPV analysis (based on the December 2005 input variable forecasts) shows that the build option, on average, is about $18/MWh more costly than the PPA option.[27] A nearly identical forecast result (again based on the December 2005 input variable forecasts) is obtained using a more stylized analytical framework. That framework and the related forecast results are described in Appendix G. With both the NPV and "stylized" analyses, the *only* difference in the forecast modeling is the wind option selected by the utility. For both analyses we assume that for any year in which the utility makes (i.e., completes) an investment in wind capacity, actual cost recovery of that investment expense begins in the same year. That is, we assume there are no mismatches in the timing at which the utility actually invests in wind capacity and when that investment expense is formally granted ratebase treatment and, thus, recovered through allowed rates. We also assume that rate cases occur at four-year intervals after wind capacity investments are included in ratebase. If there are timing mismatches between the investment in and ratebasing of wind capacity and if rate case frequency is less than four years, then we expect the cost differential to be less than $18/MWh on average. But as a practical matter, timing mismatches are unlikely

[27] This amount is based on a levelization over the 2006-2034 time period and is measured in 2005 constant dollars.

and, for the next few years, rate case frequency in Kansas may average less than four years. In recognition of those practical considerations, the actual cost differential could turn out less than $18. (See the Direct Testimony in Docket No. 08-WSEE-309-PRE for a presentation of conditions under which the two wind options would be of comparable cost.) However, when the input variable forecasts are updated to reflect conditions as of January 2008, including wind installation cost forecasts of $2.15 million per MW, with all else equal, the cost differential increases to about $23/MWh. In summary, wind energy acquired through utility ownership of wind capacity is likely to cost more than wind energy acquired through PPAs. While there are certain conditions under which the two options may be of comparable cost, our analysis shows the probability of ownership costing less than PPAs is effectively nil. See Appendix G for a detailed discussion of these results and an explanation of the relative cost advantages held by wind developers generally.

1.26 External Cost Savings May Make the Critical Difference

What actually makes Kansas wind energy economically attractive is its potential to reduce the external costs associated with conventional generation. *Depending on the estimated level of external cost savings*, the combined external and internal (mainly fuel) cost savings may exceed the cost of acquiring wind energy. In that case, meeting the Challenge is cost effective from the *total cost* or “societal” perspective. While we recognize that Kansas ratepayers as a group may not be the only group affected by emissions from Kansas power plants, we assume that Kansas ratepayers are likely to bear the vast majority of costs associated with those emissions. With that simplifying

assumption, the ratepayers' perspective of the Challenge and its cost effectiveness would encompass consideration of both internal and external cost savings.[28]

The level of external cost savings needed to push the Challenge into the cost-effective category (per our criterion) is what we call the *threshold external cost levels*. As indicated in Table 1.1, the threshold external cost levels vary according to the utility-type and the wind option selected by the utility.[29]

Table 1.1: Threshold External Cost Levels
(per MWh, levelized in 2005 constant dollars)

	Wind option:	
Utility-type	PPA	Build/Own
Low-cost(1)	$16.25	$34.61
Average-cost(1)	$13.24	$31.00
Average-cost(2)	$27.79	$50.93
Middle-cost(1)	$5.00	$23.51
High-cost(1)	$1.22	$19.56

Notes: (1) Based on input variable forecasts as of December 2005.
(2) Based on input variable forecasts as of January 2008.

[28] As a matter of fact, the group of people subject to the external effects of Kansas power plant emissions will differ from the group that falls under the "Kansas ratepayer" label. In that more realistic case, the cost effectiveness of the Challenge from the ratepayers' perspective would be based entirely upon its effect on internal cost savings—that is, the savings received by just the utilities' ratepayers. With the assumption that Kansas ratepayers as a group effectively experience all of the external costs associated with Kansas power plant emissions, whether the Challenge is cost effective for ratepayers depends on how the Challenge affects the *total cost* of generating electricity for Kansans. Absent that assumption, whether the Challenge is cost effective for ratepayers depends on how the Challenge affects the *total revenue requirement* associated with generating electricity for Kansans. Alternatively, absent the assumption, the cost effectiveness of the Challenge is determined by evaluating its net influence on the statewide revenue requirement (SRR). If the Challenge causes a net increase in the SRR (based strictly on internal cost savings) and, thus, higher rates on average, then the Challenge would not be cost effective from the ratepayers' perspective.

[29] Table 1.1 also reveals, for each utility-type, the average cost differential for the two wind options. That differential for the low-cost utility is ($34.61 - $16.25 =) $18.36. Note that for the average-cost utility that same differential increases from $17.76 to ($50.93 - $27.79 =) $23.14 per MWh when the updated input variable forecasts are used. The increase in the cost differential is driven primarily by the higher wind installation cost, from $1.6 to $2.15 million per MW.

The results in Table 1.1 also show the influence of updating with the latest wind installation cost estimate. Using that estimate of \$2.15 million/MW, the threshold external cost levels for all utility-types and both wind options would be higher (as shown for only the average-cost utility-type).

The threshold external cost levels are critical because if the estimated external cost savings attributable to wind energy production match or exceed those levels, then meeting the Challenge would be cost effective. In fact, the test of the Challenge's cost effectiveness largely boils down to that comparison. For example, if the estimated external cost savings attributable to wind energy production are put at \$10/MWh, then (based on the December 2005 input variable forecasts) the Challenge would be cost effective for only the high- and middle-cost utilities and only if they acquire their wind resources through PPAs.

1.27 Updating the NPV Forecasts Will be Important Going Forward

As shown in the previous section, updating the input variable forecasts may considerably change the output forecasts. We fully expect that, with updating, the NPV, rate change, threshold external cost level, and other forecasts would all change, perhaps significantly. For one, there is considerable uncertainty about what various costs and benefits will be in the future, particularly wind installation and O&M costs. Given that uncertainty, we fully expect the input variable forecasts to change over time. Secondly, our analysis also shows that many of the output forecasts (namely the NPV and threshold external cost level forecast) are relatively sensitive to changes to (i.e., updating of) the input variable forecasts. What this means is that any assessment of the Challenge's cost effectiveness

and, more generally, any benefit cost assessment of wind resources should be based on the latest available information.

1.28 Uncertainty as the Defining Characteristic of the Challenge

Having used Monte Carlo analysis to develop the NPV forecasts, we are able to explicitly assess the risk associated with pursuing the Challenge. That risk is revealed through the probabilistic distribution of NPV forecasts that shows both the *range* of forecasts and the probability of any one forecast value being realized. For example, for the average-cost utility meeting the Challenge with only wind PPAs and without inclusion of estimated external cost savings, the maximal forecast NPV is $456 million (in 2005 dollars), but the minimal forecast NPV is -$669 million. While these two forecasts establish the possible range of possible NPV forecasts, the mean value forecast NPV (approximately -$203 million) represents the forecast value most likely to be realized based on our forecast methods and data sets. In fact, the maximal likelihood forecast for most case studies has a forecast probability just under eight (8) percent.[30]

Another measure of the risk associated with the Challenge is the standard deviation of the forecast NPVs. For the average-cost utility meeting the Challenge with PPAs without inclusion of estimated external cost savings, the estimated standard deviation is $114 million, suggesting the distribution of forecast NPVs is relatively dispersed.

The bottom line is that in no case do we find that the Challenge is *certain* to deliver a positive net benefit to Kansans. Rather, in every case we find a chance that it

[30] This roughly means there is an eight percent chance of the mean forecast value being realized. All other forecast values have less chance of being realized.

will provide a positive net, though in most cases that chance is small. Overall, unless the estimated external cost savings are quite high (in excess of $28/MWh), the chance of the Challenge supplying a positive net (using the updated forecasts) is less than 50 percent.

1.29 Potential Carbon Regulation

Certainly the potential for carbon regulation enhances the economic prospects of wind energy. In light of that potential, utility reliance on wind energy instead of fossil-fueled generatoin to serve its retail load obligations would enable the utility to avoid some of its carbon tax exposure.[31] Thus, another benefit of wind energy development going forward could be avoided carbon taxes.

It is possible that potential carbon tax savings would push the Challenge into the cost effective category. For example, again for the average-cost utility meeting the Challenge via wind PPAs but with external cost savings *included* in the analysis (at $20/MWh), if a carbon tax of approximately $11/ton of CO_2 were implemented (starting in 2006 and running through 3034), that would be just large enough to push the Challenge into the cost-effective category. If estimated external cost savings are not included in the analysis, then the carbon tax would need to be about $37/ton in order to push the Challenge into the cost effective category.[32]

To the extent that pursuit of the Challenge enables the utility to avoid either the estimated external costs (associated with the traditional emissions) and/or potential carbon taxation, this can make the *critical* difference in determining the cost

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[31] By "carbon tax" we mean any added cost per ton of CO_2 resulting from carbon regulation, whatever from that regulation takes.
[32] The estimated threshold external cost levels (for the various case studies) are easily converted to estimated threshold carbon tax levels by multiplying the former by 0.885.1.333. Also, see Table 0.1.

effectiveness of the Challenge. Accordingly, given some estimate of the utility's (internal) savings, testing the Challenge's cost effectiveness boils done to an assessment of the *potential* external cost and carbon tax savings. There are many combinations of estimated external cost savings and potential carbon taxes that could make pursuit of the Challenge economically attractive.

1.29.1 Availability of Renewable Energy Credits (RECs)

By acquiring wind PPAs and investing in its own wind capacity, the utility may be able to issue and then sell RECs. The revenue from those sales could be used to offset the cost premium associated with acquisition of wind resources. At this time, it is very difficult to estimate the future value of RECs; therefore, we have not included such forecasts in our analysis. Nonetheless, revenues from RECs may be available in the future and, if so, improve the economic case for wind. However, the future REC revenue may be relatively small and perhaps inconsequential.

1.29.2 Ratepayer Willingness and Ability to Pay Extra for Wind

We find that meeting the Challenge is likely to result in higher utility rates. If Kansas ratepayers are both willing and able to pay the higher rates, then meeting the Challenge would be cost effective from the perspective of consumer demand. That said, the proof of consumer willingness and ability to pay a premium for wind energy lies in the proverbial pudding. Claims of willingness are often unmatched when it comes time to actually pay the premium and bear the associated opportunity cost. When consumers realize that a higher, even a slightly higher, electric bill would cut into their vacation and/or college education budgets, etc., they balk. If utility acquisition of wind energy does push electric

bills higher, it immediately begs the question of affordability. If acquisition of wind energy makes bills less affordable in general, then policy makers should not expect a large reserve of willingness and ability to pay extra once the higher rates set in.

At any rate, if ratepayers are *actually* willing and able to pay a wind energy premium, then that would simply reduce the magnitude of potential external cost and carbon tax savings necessary for the Challenge to be cost effective. Since the actual willingness and ability to pay extra for wind would affect its cost effectiveness and the need to search for external and tax cost savings, it may be reasonable for policy makers to randomly survey ratepayers about their desire and means for paying a wind premium.[33]

1.30 Utility-type Specific Results

The more basic forecast results by utility-type are shown below in Table 1.2, all of which are based on the input variable forecasts as of December 2005. Unless stated otherwise, the indicated results are mean (i.e., average) forecast values. The forecasts are also based on the forward-looking, incremental (736 MW) investment needed to meet the Challenge.

The rate change forecasts in Table 1.2 are presented on a levelized, annual basis (per the 2006–2034 time period). That means the forecast rate changes are the average change over the relevant time period, and averaged over all retail sales.[34] By that method of averaging, we are effectively assuming the net cost of the Challenge is uniformly allocated over retail sales. The Commission, of course, could choose to allocate the cost

[33] Such surveys should be random and should provide potential respondents with an estimate of the wind premium so that they could determine for themselves whether acquisition of wind energy would be worth the added cost and, thus, sacrifice.

[34] The forecast rate changes are those that would result strictly as a result of meeting the Challenge. Therefore, they represent the difference in rates along two distinct paths, the business-as-usual path and the path along which the Challenge is met. A forecast rate increase means rates would be relatively higher along the Challenge path.

of wind energy among the customer classes differently. The forecast rate implications are adjusted for inflation, though they are not time discounted.

The forecast bill implication (Table 1.2) shows how the Challenge is likely to affect the average residential customer’s annual electric bill based on an assumed usage of 11 MWh/year. That billing implication is based on the average levelized rate change and so represents the average forecast influence of the Challenge on the typical residential annual bill.

The threshold external cost level in Table 1.2 is the amount of external cost savings (per MWh of wind energy) needed for the Challenge to be cost effective from the broader societal perspective. From that perspective all (internal and external) costs of generation are included in the analysis. That threshold level is important because if estimated external costs from conventional generation are expected to exceed the threshold level, then meeting the Challenge would likely provide Kansans with a *lower total cost* of electric generation.

The final column in Table 1.2 shows the average forecast NPV results: the expected net savings from the Challenge (in 2005 dollars), absent any consideration of possible external cost reductions attributable to wind investment (that is, with forecast external cost savings set equal to zero). When estimated external cost savings are not included in the analysis, there is a rather direct linkage between the NPV forecasts and the forecast rate changes. In cases where externalities are not included, the NPV forecasts are tantamount to revenue requirement *change* forecasts. When estimated external cost savings are not included in the analysis, a negative NPV forecast means the utility would experience a *relatively higher* revenue requirement strictly as a consequence of meeting

the Challenge. Negative NPV forecasts imply that it is more costly for the utility to pursue the Challenge than not. Forecasting revenue requirement increases, all else equal, translates to forecasting higher average retail rates. On the other hand, when the average forecast NPV is positive, meeting the Challenge would yield the utility a relatively lower revenue requirement (due to the positive net savings realized by the utility). In summary, negative NPV forecasts show that meeting the Challenge would necessarily force up the utility's revenue requirement and, consequently, its retail rates. Positive NPV forecasts imply just the opposite.

It is also worth noting the necessary linkage between economic efficiency gains and forecast rate changes. Forecast efficiency gains—as indicated by positive NPV forecasts—necessarily lead to forecast rate reductions. Efficiency losses necessarily imply higher rates. This general result holds for both agency and market regulated firms. Moreover, it highlights the importance of avoiding policy paths that are likely to result in negative NPV outcomes and, thus, higher retail rates.

Lastly, if the average forecast NPV is negative when potential external cost savings are not included in the analysis, and if an uneconomic outcome is to be avoided, then inclusion of external cost savings is necessary. The question then becomes whether those savings might be large enough to secure the desired results, which include a positive NPV, an efficiency gain, lower total cost, and an outcome that supports resource sustainability.

Table 1.2: Summary of Forecast Results by Utility-type
[Based on input variable forecasts as of December 2005. All results in 2005 dollars]

Utility-type: Wind Option	Levelized Rate Implication[1] ($/MWh)	Levelized Annual Residential Bill[2]	Threshold External Cost Level[3] ($/MWh)	Average Forecast NPV (million $)
Low-cost:				
Westar/KCPL				
Build/Own Capacity	+$1.29	+$14.19	$34.61	-$536
Wind PPA	+$0.57	+$6.27	$16.25	-$250
Middle-cost:				
EDE/MWE				
Build/Own Capacity	+$0.88	+$9.68	$23.51	-$361
Wind PPA	+$0.15	+$1.65	$5.00	-$73
High-cost:				
WestPlains				
Build/Own Capacity	+$0.71	+$7.81	$19.56	-$299
Wind PPA[4]	+$0.01	+$0.11	$1.22	-$13
Average-cost:				
Representative Kansas Utility				
Build/Own Capacity	$1.16	$12.76	$31.00	-$479
Wind PPA	$0.46	$5.06	$13.24	-$203

[1] Forecast *increase* in the average (i.e., mean) retail rate. [2] Forecast *increase* in the average residential customer's average annual electric bill. [3] The level of external cost savings needed for the Challenge to be just cost effective in terms of the *total cost* implications.[4] These results are based on median forecast values. The mean forecast values in this case are a little different. The levelized rate implication using mean forecast results shows a rate decrease of $0.02/MWh.

The results in Table 1.2 show, by the negative NPV forecasts, that meeting the Challenge is unlikely to be cost effective and, therefore, is likely to result in higher rates.

In order for it to be likely that the Challenge would be cost effective, some combination of expected external cost savings, potential carbon tax saving, REC revenues, and ratepayer willingness to pay extra must be at least as large as the indicated threshold levels. Yet even if the foregoing "combination" exceeds the threshold levels, the rate implications remain the largely same.[35] The capture of external cost savings will not result in lower utility rates, but if large enough may result in a lower *total cost* of generation.

1.40 The Possible Implications for the Average Kansan

Again, the forecast implications for the average-cost utility-type probably provide the best (i.e., most accurate) estimates of how the Challenge could affect the average Kansan. As Table 1.2 indicates (and as discussed above), utility bills for the average Kansan are likely to be higher as a result of meeting the Challenge. However, if external cost savings are large enough (either more than $13.24 or $31.00/MWh, depending on the wind option selected by the utility), the average Kansas may experience a lower total cost for the electricity she receives.

1.50 The Possible Employment Implications for the State

Estimating the expected long-run, statewide employment implications of meeting the Challenge is no easy task. In terms of the details, it is a problem that is largely, though not completely, distinct from that considered through this study, which is estimating the expected net benefit of meeting the Challenge. Nonetheless, we submit that the

[35] This depends on the magnitude of the REC revenues and carbon taxation.

Challenge's basic, long-run employment implication for the state *may* be reasonably deduced from the NPV analysis.

First, based on the forecast installation costs used in this study, to meet the Challenge will require additional investment of approximately $1.3 billion dollars between now and the start of 2015. In an economy with a total, annual income that currently is approximately $90 billion, the amount of economic activity induced by the Challenge, in any one year, would be but a very small fraction of the state's annual total. Thus, the overall employment implications of the Challenge are likely to be relatively small. Second, absent a more detailed study, we propose the expected NPV from meeting the Challenge may provide a reasonable *proxy*, but, admittedly, no more than a proxy for the net employment implications of the Challenge.

If we consider a case where meeting the Challenge yields an NPV equal to zero, then the Challenge provides the Kansas economy with no gain in *net* savings and, arguably, no improvement in the state's overall allocation and use of resources. That absence suggests no improvement in statewide economic efficiency. No improvement in economic efficiency implies that a *net* expansion of the overall economy and, thus, resource employment generally is *unlikely*. The argument is this: efficiency and productivity gains facilitate long-term economic expansions and *real* economic growth and, consequently, general expansions in factor employment. Therefore, NPV's at or close to zero suggest net gains in long-run employment are likely to be close to zero as well. It follows that positive NPVs are likely to support net expansions in employment, while negative NPV imply the opposite.

Like the expected NPV itself, whether meeting the Challenge is likely to yield an overall expansion of Kansas employment depends on the expected level of external cost savings. If the external cost savings are sufficient to yield a positive NPV, a (slight) expansion of employment is likely. But if external cost savings do not support a positive NPV, then a contraction is the more likely outcome.[36] But regardless of the sign and/or size of expected NPV of the Challenge, we expect the *statewide* employment implications to be small.

However, even when the statewide net employment implications of the Challenge are close to zero, there could be significant employment implications for *specific segments* of the Kansas labor market. For instance, the Challenge is likely to increase jobs in the utility sector (since utility expenditures would be higher), while possibly decreasing them in the health-care sector (lower externalities may reduce health-related damages and, thus, demand for health-related services). The Challenge is also likely to increase jobs in the rural areas of the state and decrease them in the urban areas.[37] (See Appendix C for a more detailed discussion of the Challenge's employment implications.)

[36] Since nearly all of the wind equipment required for the Challenge would be imported, that would reduce the state's net export position. However, offsetting that would be a reduction in the state's coal use and, since most coal consumed in Kansas is imported, this would be an improvement in the state's trade position. Whether overall net exports are likely to change is indicated by the expected NPV of Challenge when external cost savings are *not* included in the analysis. Our results show that when external cost savings are not considered, in all cases the expected NPVs are negative. Thus, in all cases, and regardless of the expected external cost savings, meeting the Challenge could reduce the state's net export sector. The reason: the amount Kansans would spend on imported wind equipment is likely to exceed the state's savings on Wyoming coal purchases; therefore, net imports would likely increase. Finally, we assume that all electricity generated by wind facilities installed in Kansas is consumed by Kansans—that is, we assume Kansas wind-energy production is for Kansans and that it would affect the dispatch and use of Kansas power plants, particularly coal plants. That is consistent with the assumption that any external cost savings resulting from Kansas wind energy production are more likely to accrue to Kansans.

[37] Since wind facilities are more likely to be located in rural areas, this forecast holds regardless of the forecast NPV. However, to emphasize, if the forecast NPV is close to zero, employment gains in the rural sector are likely to be largely offset by comparable losses in the urban sector.

1.60 Sensitivity Analysis: Which Variables are likely to Matter Most?

The NPV sensitivity analysis performed in this study shows which elements of the NPV formulation, when subject to change, have the greatest influence on the expected net savings due to the Challenge. We find that the elements having the greatest influence on the forecast net benefit of wind, in order of importance, are (1) wind installation cost, (2) wind capacity factor, (3) wind operations and maintenance expense, (4) utility fuel mix, (5) forecast price of natural gas, (6) wind capacity factor degradation, and (7) rate of return. (See Appendix H for a more detailed discussion of our sensitivity analysis.) These results suggest the cost effectiveness of the Challenge depends more on the characteristics of wind equipment itself. That is, it is the direct cost of wind (as measured by its installation cost) and its expected performance (as measured by its annual capacity factor) that have the greatest influence on the forecast NPVs. The forecast prices of natural gas and the utility’s relative reliance on natural gas have less influence on forecast NPVs. (See Section 5.0 and Appendix H for more detailed discussions of the forecast sensitivity analysis and results.)

We find it is the upfront investment cost of wind and its relatively limited capacity factor that most likely make it difficult for wind energy to compete against the conventional alternatives. Other factors, which are not wind characteristics in themselves, like the price of natural gas and the utility’s dependence on gas, are of less importance. In short, it is more the direct cost and relatively mediocre performance of wind as a generating option, and less its ability to avoid costs, that makes it difficult for wind to be *cost competitive*. If we ignore its possible external cost benefits, then for investment in wind capacity to be competitive with the conventional alternatives, *it must get better*.

Significantly higher gas prices and significantly greater use of natural gas by utilities may not significantly improve Kansas wind economics. And of those two factors, increasing the relative use of gas is likely to deliver a greater boost to wind economics than just gas price increases alone.[38] For wind to get better, the trends toward ever higher installation and O&M expenses must be reversed. Entry of new manufacturers of wind equipment is likely to dampen installation cost inflation. Technological improvement would yield better, more reliable equipment which would dampen wind O&M expense inflation.

At this time, it appears to us that the relative economic strength of wind energy is that it is clean. The exploitation of that fact alone probably offers the greatest support to the *economic* use of wind energy. In Kansas, since a relatively small amount of natural gas is used as a generation fuel, it is not wind energy's displacement of natural gas use that is likely to make investment in wind capacity economically attractive, but rather its displacement of coal and the associated reduction of external costs. Unfortunately, displacement of coal introduces the potential for greater dispatch inefficiencies (i.e., higher wind integration costs), which would offset some of the savings resulting from lower emissions.

1.70 Some Policy Observations

The Challenge is unlikely to be economically efficient, without some consideration given to the possible external cost and/or carbon tax savings attributable to relying on wind

[38] But it is worth noting that the relative reliance of Kansas electric utilities on natural gas as a generation fuel has been trending down over approximately the last two decades. We believe this trend may continue, especially if the relative price of natural gas increases over time, as we expect. The prospect of higher natural gas prices and relatively greater reliance on natural gas (as a generation fuel) occurring simultaneously is very unlikely. Increasing wind subsidies, such as increasing the PTC, are also unlikely to improve the economic case for wind, at least in the short run, since higher subsidies may have a tendency to increase the demand for wind, leading to ever higher installation costs.

energy. Of course, policy makers can play a role in making those considerations. However, even when some consideration of the possible external cost savings pushes the average forecast NPV into the positive category, Kansas ratepayers are likely to face higher electric rates as a result of meeting the Challenge. Thus, depending on the level of external cost savings, the Challenge could reduce Kansans' total and, thus, combined internal (i.e., utility) and external cost of electricity. The Challenge is likely to result in higher costs for the utility (and, thus, higher internal costs), but external cost savings may be large enough to *offset that increase* in utility costs.

The increase in utilities' net costs due to the Challenge necessarily leads to higher utility rates. Higher electric rates may erode the state's competitiveness, though any detriment could be relatively small, except for customers with intensive electricity use. Nonetheless, there are measures policy makers can apply to counter this downside risk associated with an increase in electric rates. For example, the sale of RECs by the utilities would offset some, perhaps all, of the higher cost due to wind development. It may be possible to allocate the higher cost of wind to customers that are more willing and able to pay the expected wind premium, which would serve to protect other (arguably, more price sensitive) ratepayers from paying that cost premium.

A federal carbon tax would also boost the economic case for wind, though such a tax would also result in higher electric rates across the board. Moreover, a federal carbon tax would advance economic support for the Challenge without the latter affecting the state's competitiveness. Whether a federal carbon tax should be supported by Kansas policy makers is a difficult question, lying well beyond the scope of this study.

At this time, it appears the voluntary approach to possibly meeting the Challenge is reasonable, especially if utilities select the wind purchase option rather than the wind investment option. With the PPA option, the Challenge is *closer* to being economically efficient and is more *likely* to be made economically efficient depending on considerations given to external cost savings, willingness and ability of ratepayers to pay extra for wind, possible REC revenues, actual or potential carbon taxes, and willingness to pay extra to avoid the risk of future health- and environmental-related damages.

If having economically efficient wind energy matters to policy makers, then it would be reasonable to complement policies like the Challenge with public policies designed to focus on the importance of quantifying and estimating the external cost savings attributable to wind energy. Of course, policy makers may have objectives other than achieving economically efficient outcomes, such as *achieving sustainable outcomes or simply conserving scarce resources*. But even then, if achieving sustainability or conserving resources are the outcomes that matter, then we submit that achieving economic efficiency is necessary for those outcomes to be realized, and, therefore, achieving cost effective outcomes should remain a critical objective.

Chapter 2: Overview and Framing of the 2015 Wind Challenge

2.00 Introduction

The Governor is clear that compliance with the stated challenge is strictly "voluntary;" therefore, we interpret her directive to the Commission as a request for a cost benefit analysis as *if* the Challenge *were met*.[1] Consistent with the Governor's request, our basic objective here is to establish whether the Challenge is likely to yield a net benefit to Kansans generally.

2.01 Assessing the Economics of Meeting the Challenge

In general, the purpose of performing a benefit cost analysis of a particular project or policy objective, like the Challenge, is to compare the monetary value of the project's total expected benefits with its total dollar cost. Of course, that comparison reveals the expected *net benefit* of the project. Decisions to implement projects that are expected to deliver positive net benefits are cost-effective decisions.[2] Our main purpose here is determining whether meeting the Challenge is likely to be cost effective.[3] To make that determination we provide forecasts of the Challenge's net benefit. However, forecast results, as usual, depend on the underlying conditions; that is, the forecast results depend on the forecast scenario as well as the specific case being studied—which we refer to simply as a *case study*.[4] Because there is a wide range of conditions under which investment in wind capacity may occur in Kansas, we evaluate 32

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[1] This is necessary as a practical matter since the voluntary nature of the Challenge admits a multitude of possible outcomes. This assumption simply narrows the outcome to just one.
[2] Note, policy decisions are either cost effective or not and, therefore, are either economically efficient or not. Consistent with the standard economic analysis, in this study economic efficiency is established categorically. Projects that are not likely to be cost effective could still be in the public interest based on equity or other non-economic considerations. However, making those considerations is strictly the purview of policy makers.
[3] More precisely, using Monte Carlo analysis, we provide an assessment of the likelihood or probability that meeting the Challenge would be cost effective. Equivalently, we establish the conditions under which the Challenge is likely to be cost effective.
[4] Note, we draw a distinction between the forecast scenario (which is discussed in greater detail in the next chapter) and case study.

distinct case studies, presenting net benefit forecasts for each. This method facilitates discovering those conditions that are likely to support the Challenge being cost effective.[5] In this introductory chapter, we outline the 32 case studies.

2.10 Investment Needed to Meet the Challenge: 736-MW and 1,000-MW Amounts

As of the start of 2006, Kansas already had about 264 MW of installed wind capacity; thus, to meet the Challenge as of January 1, 2006, an additional investment of 736 MW in wind capacity was required.[6] Using the historically given amount of wind investment as a point of departure, we forecast the net benefit of investing in the incremental amount of capacity needed to meet the Challenge. In addition to evaluating the net benefit of investing in 736 MW of wind capacity, to be consistent with a literal interpretation of the Challenge, we also estimate the net benefit associated with the full investment in1,000 MW of wind capacity.[7] The latter evaluation *combines* the forecast net benefit from the *existing* 264 MW of installed wind capacity with the forecast net benefit of investing in 736 MW of *new* capacity. Thus, we examine case studies with two different investment bases: one where only the required (736 MW) investment in new capacity is considered, the other where the new and existing investments are considered together as one.[8]

[5] Generally, this approach helps to identify conditions necessary for the Challenge to be cost effective and determine whether those conditions are likely to prevail in reality.
[6] Because this study was initiated in 2005, January 1, 2006 was taken at the starting point of the relevant time horizon.
[7] However, because the historical investments in wind capacity cannot be undone, arguably the only economically meaningful analysis is that which is performed on the potential *new* investment in wind capacity.
[8] In sixteen case studies, the 736 MW investment base is evaluated, while in the other sixteen case studies, the 1,000 MW investment base is examined.

2.11 The Pivotal Role of Jurisdictional Electric Utilities

While the Governor has collectively challenged the state's "electric industry," nearly 70 percent of the state's retail electric customers are served by the state's five largest, KCC-jurisdictional retail utilities: Westar Energy, Inc. ("Westar"), Kansas City Power and Light, Inc. ("KCPL"), Aquila, Inc. (d/b/a, WestPlains) ("WestPlains"), Midwest Energy, Inc. ("MWE"), and Empire District Electric Company, Inc. ("EDE").[9] As a group, these utilities also provide wholesale generation services to *numerous* municipal utilities within the state. Consequently, the generation costs of those municipals are likely to resemble those of the jurisdictional utilities.[10] Because of their relative importance at both the retail and wholesale levels, and because we find their generation costs, *as a group*, are representative of the generation costs at other KCC-jurisdictional and non-jurisdictional utilities, we focus our analysis on only the jurisdictional utilities.[11] This is not to suggest that non-jurisdictional utilities would not possibly acquire wind resources in the future, but only that the avoided generation costs of jurisdictional utilities provides a reasonable basis for estimating the *opportunity cost* and, thus, economic value of all electric utilities in the state participating in the Challenge.

[9] Hereafter, we refer to these five utilities collectively as the "jurisdictional utilities."

[10] As part of our analysis, we also reviewed the system lambdas of the state's two generation and transmission wholesale providers, Sunflower Electric Power and Kansas Electric Power Cooperatives, who provide generation services to most of the states' rural distribution coops, as well as the state's largest electric municipal utility, Kansas City Board of Public Utilities, and found their cost structures, based on an evaluation of their system lambdas, are *comparable* to those of the jurisdictional utilities.

[11] Given the voluntary nature of the Challenge, and given their significance in serving Kansas electric consumers generally, it seems unlikely the Challenge will be met without the jurisdictional utilities playing a significant, if not the pivotal role. It is also worth noting, if we assume the wind capacity installation cost is $1.6 million/MW, then, with the 736 MW investment base, nearly $1.2 billion is needed meet the Challenge. With a total financial requirement of that magnitude, the financial resources and standing of the jurisdictional utilities is likely to be *necessary* to make or support (as buyers of) the investment needed for the Challenge. Thus, in one way or another, the involvement of the jurisdictional utilities appears critical.

2.20 The Need for Evaluating and Modeling the Four Utility-types

The Governor makes clear the voluntary nature of the Challenge. However, as stated previously, to perform a meaningful economic analysis of the Challenge, it is necessary to presume it is in some way met. Since it is voluntary, the analytical problem is that we cannot know which, if any, of the jurisdictional utilities will take up the Challenge and, if they do, to what extent, either individually or collectively. This problem is compounded because the economics of the Challenge undoubtedly depend on, among other factors, which utilities invest in wind capacity. Because it is not possible to accurately predict how individual utilities will, going forward in time, respond to the Challenge and because there is an infinite number of ways the jurisdiction utilities could collectively meet the Challenge, it is necessary to introduce a minor simplification of the forecasting problem.

Since we cannot reasonably predict how individual, jurisdictional utilities might rise to meet the Challenge, one way to proceed with the analysis is by determining the net benefit of the Challenge as if it were met by each of the five jurisdictional utilities operating *on their own*. This approach would require us to determine the net benefit of the Challenge as if Westar alone met the Challenge, and to repeat the analysis as if KCPL alone met the Challenge, and so on, evaluating each of the five jurisdictional utilities in this way.[12] This is a sensible approach because, at the least, it would establish a meaningful *boundary* on the set of possible net benefit forecasts.[13] However, rather than evaluating the utilities on an individual basis, and depending on its reasonableness, we considered the possibility of

[12] We ignore for the moment the fact that the smaller-sized utilities would be incapable of operationally accommodating the required amount of wind capacity, to say nothing of their financial ability to make that investment.

[13] Because of differences in generation costs, it is widely recognized in Kansas that the case most favorable to wind investment would have WestPlains meeting the Challenge on its own (provided it was feasible); while the least favorable case would have either Westar or KCPL meeting the Challenge on their own.

grouping similarly structured utilities, thereby effectively reducing the number of "individual" utilities to be evaluated. Based largely on a comparison of average annual system lambdas, we find Westar and KCPL have very similar generation costs; to a lesser extent, the same is true for MWE and EDE, while WestPlains stands alone. [14] Furthermore, the evidence shows Westar and KCPL tend to have the lowest (incremental) generation costs on average, WestPlains the highest, with MWE and EDE falling in between. What our comparison of relative utility cost shows is that grouping the utilities, based on their incremental generation costs, is a useful way to simplify the analysis without diminishing the meaningfulness of the final, forecast results. Therefore, we evaluate three different utility-groups, which we refer to as "utility-types:" the low-cost utility-type is modeled after Westar and KCPL; the high-cost utility-type is based on WestPlains; and the middle-cost utility type represents MWE and EDE.

2.21 The Average-cost Utility-type

Since WestPlains, EDE, and KCPL have already responded to the Challenge, as a practical matter, it is clear that the jurisdictional utilities, if they do meet the Challenge, will meet it *collectively*. While there are an infinite number of ways the Challenge could be collectively met, we consider just one.[15] We evaluate a scenario in which an individual utility's share of meeting the Challenge is effectively based on its (market) share of annual, retail sales among the jurisdictional utilities. This effectively spreads the responsibility of the Challenge based

[14] The net benefit from any of the collective approaches to meeting the Challenge can be evaluated by using an appropriately weighted average lambda of the jurisdictional system lambdas.
[15] Of course, we are willing to evaluate any other "capacity allocation" scenarios. However, the one we have selected *may* be deemed the most fair because, by the design of the scenario, individual utilities would take up the Challenge in proportion to their relative size. This approach is the one most likely to spread the net financial, billing, and employment implications of the Challenge, be they positive or negative, *uniformly* across all Kansans, be they ratepayers or not. Achieving that uniform distribution of the net benefits may be seen as equitable by most and, therefore, by policy makers.

on the utility's relative size among the other jurisdictional utilities. So for 2004, among the jurisdictional utilities, Westar's retail sales were about 67 percent of the total retail sales, KCPL's were about 21 percent, WestPlains' was nearly 7 percent, MWE's was just under 5 percent, and EDE's was less than 1 percent. In this scenario, and based on the incremental amount of investment needed as of 2006, Westar would meet its share of the Challenge by acquiring (0.67×736 MW =) 492 MW or so of wind capacity, KCPL would take about 154 MW, WestPlains would acquire 50 MW, MWE would obtain 36 MW, and EDE would complete the task by taking about 6 MW.[16]

The net benefit of the jurisdictional utilities *collectively* meeting the Challenge, as just described, is easily determined by modeling a utility-type, referred to here as the average-cost utility-type. By taking a market share weighted-average of the jurisdictional utilities' individual system lambdas, we obtain a *statewide average* system lambda.[17] By using that average lambda in the benefit cost analysis, we can estimate the net benefit of the Challenge when it is collectively met on a relative market share basis. By its design, we consider the costs of the average-cost utility-type to be representative of the "average Kansas electric utility's" costs. For that reason, we interpret the forecast results for the average-cost utility-type as providing the best estimates of the *average*, *statewide* implications of meeting the Challenge.[18] Any possible guidance to policy makers is probably best founded on the average-cost utility-types' results.

[16] The respective MW shares for the requisite amount of 1,000 MW of wind capacity would be: 667 for Westar, 213 for KCPL, 66 for WestPlains, 45 for MWE, and 9 for EDE.
[17] We define system lambda as the utility's incremental dollar cost of generating one MWh at its (short run optimal) operating margin, subject to its obligation to serve and relevant operating constraints.
[18] Another advantage with relying on the average-cost utility-type's results is that they are based on an allocation or assignment of wind capacity that is likely to be operationally (and perhaps financially) feasible for each of the jurisdictional utilities. Undoubtedly, that would probably not be the case for the high- and middle-cost utility-types if they alone were to meet the Challenge.

In summary, we examine case studies for each of the four utility-types: low-cost, average-cost, middle-cost, and high-cost. For each utility-type we estimate the net benefit of the utility-type meeting the Challenge by acquiring either 736 MW of wind capacity or 1,000 MW. Since the forecasts are all based on the assumption the Challenge is met by a single utility-type at a time (as if it were the only utility in the state at that time), the net benefit results for each case study are effectively statewide in scope, revealing the implications for the whole of Kansas.[19] The analysis of four utility-types and two "investment" amounts for each yields eight distinct case studies thus far.

2.30 The Two Wind Options: Build or Buy

As outlined above, we assume jurisdictional utilities will play the pivotal role in meeting the Challenge; next we consider the two basic roles they may play: (1) build (and ratebase) their own wind capacity through direct investment or (2) buy wind energy from wind developers under the terms of purchase power agreements (PPAs).[20] Given the voluntary nature of the Challenge, we are again confronted with the problem of not having a reasonable basis to predict which wind option the utility might select, and in what proportion. We deal with this prediction problem by evaluating the net benefit of the Challenge assuming the utility-type chooses only the build option, and we repeat the analysis by assuming it chooses only the

[19] Again, we evaluate the net benefit of the Challenge per individual utility-types, as if only a single utility-type in the state takes up the Challenge. By using that basis, the forecast results hold for the entire state.

[20] We define a wind developer as any third-party entity that offers PPAs to utilities. The PPAs may serve as a basis for the developer obtaining the financial resources necessary to make investments in wind capacity. Wind developers may offer wind projects of any size—from the larger, "industrial-sized" projects to the smaller "community wind" projects. However, because installation costs are likely to vary depending on the size of the wind project, unless otherwise noted, our reference to wind developers shall be to developers of wind projects with 100 MW or more of nameplate capacity. As a special case, we do evaluate the net benefit of the average-cost utility-type meeting the Challenge by supporting (i.e., contracting with) only community wind developers.

buy option.[21] Thus, as before, we examine in full the two opposite cases. This approach is reasonable because it enables us to determine which of the two wind options is likely to be the utility's lower-cost option.

Again, to summarize, we examine case studies where each of the four utility-types meets the Challenge by either investing in the requisite amount of capacity (either 736 MW or 1,000 MW) or purchasing on a MWh-basis equivalent amounts of wind energy through PPAs. Four utility-types, with either the build-invest or buy option and with either the 736 MW or 1,000 MW amounts, now yield 16 different case studies. The comparison of the various net benefit forecasts under the build option with those under the purchase option provides a basis for possibly determining which wind option may be the lower-cost option. This approach also establishes a likely *range of forecast values* for scenarios where combinations of both wind options are relied upon to meet the Challenge.

2.40 The Inclusion of Avoided External Costs

So far we have discussed costs and benefits that are strictly internal to the utility, and thus its internal accounts and its customers' monthly utility bills. Yet perhaps the single most important, and undoubtedly the most interesting, feature of wind-based energy is that it is pollution-free and, therefore, not a source of pollution-related damages that give rise to so-called "external costs." Any economic analysis of wind energy production should include an assessment of the possible external cost savings attributable to that production. Before

[21] Implicit in those cases where utility-types only purchase wind energy from developers is the fact that it would be wind developers, not the utilities, making the required investment in wind capacity. Thus, in those case studies where the utility-type selects only the purchase option, the Challenge with its reference to "installed capacity" is effectively met by wind developers as a group. Since wind developers are forced to compete, we assume there are no significant economic differences among them in the long run. Incidentally, as of this time, nearly all of the development of wind capacity in the United States has occurred through the "buy option."

describing how we incorporate the possible external cost savings, we offer some additional background discussion of our basic benefit cost framework.

Because the entities facing the Challenge are subject to agency regulation(s), it is necessary to consider how that "constraint" may influence their behavior and decision-making. Equivalently, because the main participants in the Challenge are agency-regulated, it is necessary to reflect that constraint in modeling the benefits and costs of meeting the Challenge. Thus, before we continue our development and presentation of the different case studies, some clarification of how we actually *measure* the net benefit from the Challenge is now appropriate.[22]

2.41 Background for Net Benefit Analysis: The Role and Implications of Agency Regulation

Jurisdictional utilities have an obligation to serve whatever retail load is forthcoming at approved tariff rates. They are also required to serve that load subject to all legal and operating standards, such as quality of service (i.e., reliability) standards and environmental regulations, etc. We assume throughout that utilities meet their service obligations, while satisfying all applicable standards and operating constraints—whatever they may be—at the least cost. We also assume they meet this objective as a consequence (and not in spite) of being agency regulated. Therefore, it follows that utilities would, on a forward-going basis and subject to all relevant constraints, make economically efficient (i.e., least-cost) investment and purchase decisions. Moreover, we assert efficient decisions are made by utilities whether confronted with the said Challenge or not.

[22] Hereafter, unless indicated otherwise, we use the terms "utility" and "utility-type" synonymously.

2.42 Background for Net Benefit Analysis: Relative Cost Savings for the Utility

As a first step, it is necessary to measure the net benefit that meeting the Challenge is likely to provide the regulated utility and, subsequently, its customers. One way to measure net benefit of the Challenge is by *comparing two costs*: (1) the *total* cost required by the utility to simultaneously meet both its retail load obligations and the Challenge and (2) the *total* cost required by the utility to simply meet its retail load obligations, avoiding any reliance on wind options and, thus, simply "doing business as usual."[23] This comparison of the utility's total cost *with* the requisite amount of wind to its total cost *without* establishes the utility's "savings that would result due to the use of wind" *relative* to its next best, conventional alternative (see Kennedy, 2005, and Manwell, McGowan and Rogers, 2002).[24] Since the "next best, conventional alternative" is assumed to be a least-cost outcome, then any savings the utility achieves by meeting the Challenge would reflect economic efficiency gains due *strictly* to its subsequent reliance on wind options and the relative efficiency of those options.[25]

In summary, as a starting point we measure the net benefit of the Challenge by the relative savings it is likely to provide the utility.[26] Those savings are measured by comparing the total cost of the utility doing business when the Challenge is met with the total cost of "doing business as usual." If the utility's total cost is lower when the Challenge is met than

[23] Since it is assumed that the utility's "required" cost is subject to regulatory review, it constitutes an approved cost of service.
[24] By "conventional" we mean the fossil-fueled and nuclear-powered generation, or, essentially, any form of non-renewable generation.
[25] If meeting the Challenge provides the utility with *savings* relative to its next best conventional alternative, then that indicates the value of the Challenge to the utility exceeds its opportunity cost. That shows meeting the Challenge is economically efficient for the utility. Using this method of analysis (i.e., savings measure), the relative savings yielded by the Challenge are equivalent to the net benefit of the Challenge to the utility. Unless stated otherwise, hereafter we use "utility" and "utility-type" synonymously.
[26] To state the obvious, positive relative savings are equivalent to a positive net benefit, and, similarly, negative relative savings are equivalent to a negative net benefit.

when it is not, those relative savings are strictly the result of having met the Challenge. With this approach the savings attributable to the Challenge can be effectively isolated and, hence, measured.[27] In cases where utility savings are positive, meeting the Challenge would enable the utility to meet its load with a relatively *lower* revenue requirement and, consequently, relatively *lower* average revenue.[28] And under agency regulation, if the Challenge paves the way for relatively lower revenue requirements, ratepayers would be in line for relatively lower rates and thus relatively lower annual electric bills.[29]

2.43 Background for Net Benefit Analysis: Benefits beyond the Utility

Obviously, the net benefit of meeting the Challenge may well extend beyond the net benefit it provides the utility and its customers; the economic implications of generating electricity by conventional means may extend well beyond the utility's internal accounts, in which case the utility's internal cost of generation does not tell the complete story of electric generation cost. Accordingly, we measure the net benefit of meeting the Challenge when external cost savings are both included and, as discussed above, not included in the analysis.

Costs possibly stemming from pollutants and greenhouse gases ("GHGs") found in power plant emissions are an obvious example of "external costs," which, by definition, are not included as part of the utility's cost of generation and, therefore, are not reflected in or otherwise recovered through the utility's rates. External costs are, almost by definition,

[27] To emphasize, it is the relative, not absolute savings we measure. If the analysis shows the Challenge is likely to deliver relative savings, then that implies the likelihood that the total cost would be lower than what it would be absent the Challenge. Hereafter, we use "savings" and relative savings" interchangeably.
[28] Hereafter, any reference to "savings" implies they are positive unless otherwise noted. If meeting the Challenge yields savings to the utility, then by taking the Challenge utility rates will be lower compared to what they would have been along the *status quo* path. It does not imply an absolute reduction in rates.
[29] In this study we assume utilities would, in the future, mechanically submit rate applications every four years. Thus, whatever the utility's savings may be due to choosing wind options, we assume ratepayers *will* realize those savings (and nearly in *full*), but possibly after some regulatory lag.

difficult to quantify.[30] Nonetheless, *estimates* of the external costs associated with conventional power plant emissions have been developed and, therefore, can be included in an economic assessment of the Challenge. In this study we examine the external costs that may be avoided, that is, *saved* as a consequence of meeting the Challenge.[31] Estimates of external cost savings due to reliance on wind energy clearly depend on estimates of the external costs associated with conventional generation.

2.44 Estimates of External Costs Associated With Conventional Power Plant Emissions

In this study we make no effort to independently estimate the external costs Kansans bear as a consequence of emissions from the jurisdictional utilities' conventional power plants. Instead, we rely exclusively on the results of a study performed by the Environmental Protection Agency ("EPA"). Using Kansas-specific numerical estimates established through that study, we set the estimated average external cost of conventional generation at $20/MWh. The EPA's study of emission-related costs is confined to the more traditional emissions: SO_2, NO_X, particulate matter, and mercury. Based on the EPA study, we set the estimated external cost associated with one MWh of conventionally generated electricity at $20, on average. In terms of who is possibly exposed to that cost, consistent with the EPA

[30] With the existing environmental regulations, and even with full compliance, there can still be external costs associated with the existing levels of emissions. The implementation and enforcement of environmental standards/regulations have served to reduce emissions-related external costs and, therefore, have had the *effect* of internalizing some of those costs. Whether there are potential, new environmental regulations that would be *cost effective* to implement at this time is not examined in this study. This is an especially challenging issue with respect to GHG emissions.

[31] Since the generation of wind energy is free of emissions, meeting the Challenge *may* reduce the external costs of conventional generation and, consequently, may yield *additional savings* to Kansans. Consistent with Kennedy (2005), we model the energy produced by investments in wind capacity (i.e., wind energy output) as "negative load." Consequently, any acquisition of wind energy necessarily reduces the level of conventional generation used to meet the required load. Therefore, if there are external costs associated with conventional generation, any acquisition of wind energy necessarily reduces those external costs, representing savings external to the utility. Since we do model the utility's total load as given, we assume that total load will not change as a consequence of any rate changes caused by the utility's selection of wind options. In that regard, we implicitly assume zero price elasticity of demand for small rate changes.

study, we assume it is borne by Kansans generally. We make no claims about the *actual* level of external costs Kansans bear as a consequence of power plant emissions and which Kansans actually bear them; rather we use the $20/MWh estimate as a well-reasoned *point of reference*.[32] With that reference point in place, to the extent one MWh of wind energy displaces (or substitutes for) one MWh of conventional generation, we estimate that the external cost savings from that MWh of wind energy to be $20. (See Appendix G for a more detailed discussion of the EPA Study and our estimate of external cost savings in Kansas.)

2.45 External Costs Due to Greenhouse Gas Emissions

Estimates of possible damages resulting from GHG emissions are not included in our analysis of the Challenge. This is not to suggest we believe those possibilities are unimportant or irrelevant. Rather, it is more a question of having relevant, Kansas-specific evidence. To our knowledge, there is no study of the possible damages Kansans bear as a consequence of GHG emissions from Kansas power plants. Therefore, the possible magnitude of those damages is largely speculative at this time.

That said, it is our understanding that the World Bank has evaluated the possible economic implications of GHG emissions. That evaluation uses hypothetical "shadow prices," amounting to the prices that might be paid to emit carbon. The shadow prices used in the World Bank study are "$5, $10, and $40/metric ton of carbon," indicating prices that, hypothetically, could be charged for emitting one metric ton of carbon dioxide (CO_2). As indicated in the World Bank study, that range is "consistent with the marginal damage

[32] In order to estimate the total savings associated with the Challenge, it is necessary to rely on some estimate of the external cost of conventional generation. Our EPA-based estimate of $20/MWh suffices as a reasonable starting point. However, as previously discussed the "threshold" level of external costs are perhaps of more importance for decision-making purposes in Kansas and are estimated as part of our economic analysis of the Challenge.

estimates reported in the Intergovernmental Panel on Climate Change (IPCC) review of the literature on global impacts of climate change (Pearce *et al*., 1996)." (See the World Bank report: *The Effect of a Shadow Price on Carbon Emission in the Energy Portfolio of the World Bank – A Carbon Backcasting Exercise,* February 1999 (ESMP).) Therefore, within the context of the World Bank study, the shadow prices are roughly equivalent to the estimated (global) external costs due to the emission of one metric ton of carbon. Those shadow prices can be converted into estimates of the *average* external cost due to the carbon emissions from one MWh of coal-fueled generation.[33]

Rather than explicitly including estimates of damages due to CO_2 emissions of Kansas power plants, we take an alternative approach. In this study we establish how large a potential carbon tax or carbon related damages (per ton of CO_2 emitted) would need to be for the Challenge to be cost effective. As with the external costs associated with conventional emissions, we estimate the threshold level of carbon taxation. Policy makers can debate whether actual, carbon-related damages attributable to Kansas power plant emissions (in Kansas and perhaps elsewhere) exceed or fall short of the threshold level.

2.46 The Inclusion of Avoided External Costs: Summary

In this study we evaluate the net benefit of meeting the Challenge when possible external cost savings are both included and not. When those estimated savings are included, based on a study by the EPA, we set them at $20/MWh for each MWh of wind energy produced. That

[33] One metric ton is equivalent to 1.10 US tons. A $10/metric ton tax (or external cost) would equal a tax of $11/ton. If a statewide carbon tax of $11/ton of CO_2 were imposed, that would result in the state's average retail rate increasing by about $8/MWh. That increase reflects the fact that a large share of the state's electricity is nuclear generated and would not be subject to carbon taxation. Hence, the $8/MWh increase is a generation-weighted average for the state. For baseload coal generation, the simple rule-of-thumb is that a $10/ton carbon tax translates to a $10/MWh tax.

estimate captures only health-related costs due to certain power plant emissions, mainly NO_X (a key ingredient of ozone) and small particulate matter ($PM_{2.5}$). That estimate of external cost savings per MWh of wind energy can be modified to reflect possible savings due to lower carbon emissions. However, because there are no reliable, Kansas-specific estimates of dollar damages in Kansas due (strictly) to carbon emissions by Kansas power plants, to make any such modification at this time would be speculative.

2.50 Summary of Case Studies

We evaluate the net benefit of meeting the Challenge within the context of 32 distinct case studies. This we accomplish by estimating the net benefit of a specific utility-type meeting the Challenge by choosing either the "build" or "buy" option, with estimated "external cost savings" either included, at $20/MWh of wind energy, or not, and with an "investment base" of either 736 MW or 1,000 MW. Thus, for each of the four utility-types we examine eight different case studies that differ depending on the wind option selected, inclusion of possible external cost savings, and size of the investment base. The 32 case studies are listed and categorized in Table 2.0 and 2.1.

Table 2.0: Outline of Case Studies with 736 MW Investment Base

Utility-Type		Wind Option		Inclusion of External Benefit	Case Study No.
High-cost	→	Buy	→	No	(1)
			↘		
	↘			Yes	(2)
		Build	→	No	(3)
			↘		
				Yes	(4)
Average-cost	→	Buy	→	No	(5)
			↘		
	↘			Yes	(6)
		Build	→	No	(7)
			↘		
				Yes	(8)
Low-cost	→	Buy	→	No	(9)
			↘		
	↘			Yes	(10)
		Build	→	No	(11)
			↘		
				Yes	(12)
Middle-cost	→	Buy	→	No	(13)
			↘		
	↘			Yes	(14)
		Build	→	No	(15)
			↘		
				Yes	(16)

Table 2.1: Outline of Case Studies with 1,000 MW Investment Base

Utility-Type		Wind Option		Inclusion of External Benefit	Case Study No.
High-cost	→	Buy	→	No	(17)
			↘		
	↘			Yes	(18)
		Build	→	No	(19)
			↘		
				Yes	(20)
Average-cost	→	Buy	→	No	(21)
			↘		
	↘			Yes	(22)
		Build	→	No	(23)
			↘		
				Yes	(24)
Low-cost	→	Buy	→	No	(25)
			↘		
	↘			Yes	(26)
		Build	→	No	(27)
			↘		
				Yes	(28)
Middle-cost	→	Buy	→	No	(29)
			↘		
	↘			Yes	(30)
		Build	→	No	(31)
			↘		
				Yes	(32)

As the Table 2.1 indicates, Case Study 21 establishes the estimated net benefit of the average-cost utility-type meeting the Challenge when it selects the “buy” option (i.e., enters wind PPAs with a nameplate equivalency of 1,000 MW) and with estimated external cost savings not included in the analysis. In other words, this is the case of the average-cost utility-type meeting the Challenge by purchasing the requisite amount (i.e., 1,000 MW worth) of wind PPAs and where no consideration is made of potential external cost savings.

By using case studies and defining them as we have, we can accommodate the voluntary nature of the Challenge and avoid the need to somehow forecast how individual utilities would collectively take up the Challenge. Moreover, the case study approach provides a means to establish a reasonable range of forecast results. Having crafted the case studies as we have, we are confident that the best forecast of the Challenge’s net benefit will fall within the range of forecasts this study provides. In fact, the likelihood is that the smaller range of forecasts associated with the average-cost utility-type provides the most accurate range of forecast outcomes.

2.51 Why We Use a Case Study Approach

By using the case studies, we can easily show that the economics of meeting the Challenge varies by the utility—that is, we can show which utilities may be more willing to take up the voluntary Challenge and why. This approach also facilitates a direct comparison of the build and buy options and, therefore, provides a basis for determining which option is likely to be less costly to ratepayers and Kansans generally. It also provides a framework for determining the relative importance of the possible external cost savings. In fact, it enables us to evaluate whether inclusion of estimated external cost savings might be pivotal in terms of finding the

Challenge to be cost effective (on average). Perhaps most importantly, it allows us to determine how large the external cost savings may need to be (the threshold or critical level) for the Challenge to be a cost-effective pursuit. Finally, since the meeting the Challenge is an ongoing process and, therefore, is time sensitive, we provide some focus on the net benefit of the incremental investment (736 MW) needed to meet the Challenge as of January 1, 2006. That focus allows us to assess whether or under what conditions *continued* pursuit of the Challenge is economically efficient as of that date. Of course, that focus can and should be updated over time as steps toward meeting the Challenge are made.

2.52 The Likely Utility Bill Implications of the Challenge: Ratepayers' Welfare

Another advantage of the case study approach is that it enables us to identify how meeting the Challenge is likely to influence rates and, thus, monthly utility bills. Those case studies in which external cost savings are not included in the analysis measure the net benefit of the Challenge strictly in terms of the total *internal* cost savings. The internal cost savings provide the basis for determining the rate implications of the Challenge. Accordingly, the rate or utility-bill implications offer a reasonable indication of how meeting the Challenge is likely to influence the (collective) welfare of ratepayers. Arguably, those case studies that do not include the possible external cost savings provide an indication of how the Challenge is likely to affect the state's average ratepayer.

2.53 The Likely Total Cost Implications of the Challenge: Kansans' Welfare

When potential external cost savings *are* incorporated in the analysis the results reveal the expected *total cost savings* from the Challenge.[34] The total savings is important, indeed critical, because it provides the basis for determining whether the Challenge is likely to be cost effective or, equivalently, economically efficient for Kansas generally. To be clear, it is only when all of the estimated costs and benefits are included in the analysis that the likely cost effectiveness of the Challenge can be determined. And when the analysis considers all costs and benefits of the Challenge, by design it captures those costs and benefits that may be realized by Kansans other than ratepayers. Accordingly, the total cost implications offer a reasonable indication of how meeting the Challenge is likely to influence the (collective) welfare of all Kansans generally, whether or not they are ratepayers. Arguably, those case studies that do include the potential external cost savings provide an indication of how the Challenge is likely to affect the average Kansan.

2.54 The Utility Bill versus Total Cost Implications—Which Matters Most?

Being mindful that electric bills probably do not reflect all of the costs associated with generating electricity, one may question which measure of the Challenge's net savings matters more, utility-bill or total cost savings? Naturally the answer depends on one's perspective, including whether the relative welfare implications matter more than achieving an economically efficient outcome. For instance, some Kansans may be concerned *only* about the affordability of their utility bill, and may believe that external costs are either non-existent or of no consequence to them. For them, the utility bill implications are likely to determine whether going forward with the Challenge is reasonable. Commercial and

[34] Again, the total cost savings capture the savings that are both internal and external to the utility.

industrial customers, concerned about maintaining their competitiveness and, thus, controlling input costs, are likely to make a similar argument. Alternatively, other Kansans may perceive significant external costs (on a risk adjusted-basis or otherwise) associated with conventional generation and, consequently, believe measures should be taken to lower those costs—even if it means higher utility bills.[35] For them, the total cost implications are likely to be more critical. Other Kansans may be concerned about *both* the affordability of their electric bills and the possible damages that stem from power plant emissions. For them, both measures will matter. For these reasons, it is difficult, perhaps impossible, to objectively establish which measure of net savings and, hence, which implications of the Challenge are of relatively greater import.

From our perspective, both the total bill and total cost implications matter for policy makers. For example, if the study results show meeting the Challenge is likely to *reduce both* the state's total electric bill and its total cost of generation, then it is not clear what would stand in the way of voluntary compliance with the Challenge.[36] On the other hand, if the study results show the Challenge is likely to *increase both* utility bills and total cost, then it is not clear why the Challenge should be pursued at all. In short, the expected net benefit from meeting the Challenge is the basic economic *incentive* for voluntarily pursuing the Challenge.

However, the more difficult cases for policy makers occur when the Challenge leads to a *mixed result*—that is, when the incentives are mixed. For instance, meeting the Challenge could increase the state's electric bill, but decrease its total cost of generating

[35] Individuals may hold the perception that external costs are "significant" and that actions should be taken to reduce those costs, regardless of whether they directly bear those costs or not.
[36] Nor would it be clear that any form of prompting from government officials would be necessary to meet the Challenge.

electricity. That would occur whenever the external cost savings more than offset any increase in the total utility bill. In that case, there is a *trade-off* between (possibly) having a cleaner environment and having higher utility rates.[37] Whenever such a trade-off presents itself, undoubtedly utility management is not well positioned to evaluate that trade-off and, therefore, may seek guidance from policy makers.[38] However, whether they do or not, consideration of such welfare trade-offs is the domain of public policy makers.

Finally, from the perspective of economists, determinations of economic efficiency should be based on analysis of the total cost savings. Therefore, if it is the economic efficiency of the Challenge that matters to policy makers, then it is the calculation of (expected) net savings, inclusive of external cost savings, that provides the necessary guidance. However, since the Challenge's net savings depends on the estimated external cost savings attributable to wind energy, the economists' determination of cost effectiveness may be very sensitive to, indeed may pivot on, the estimate of external cost(s). And since the estimate of external cost is perhaps the most speculative estimate in the study, it follows that determining the cost effectiveness of the Challenge may be rather speculative. To reduce that speculative element, we also calculate the level of external cost savings necessary for the Challenge to just be economically efficient; that is, we establish how large the external cost savings would need to be, with all other variables held constant, in order for the estimated total cost savings (i.e., net benefit) to just equal zero: that level of external cost savings we refer to as the "threshold" level. With that information policy makers, on their own, can

[37] That is equivalent to the trade-off that exists between pursing the Challenge and not.

[38] Utilities may be reluctant to voluntarily pursue the Challenge if it results simply in higher rates for their customers. Furthermore, even if the Challenge results in lower external costs, utilities may also be reluctant to acknowledge that possible benefit. For one, the external cost savings may be realized by non-customers and, for another, acknowledging they are the source of damages that give rise to external costs may expose the utilities to certain liabilities.

assess the *likelihood* that actual external cost savings are larger or smaller than the threshold levels and, thus, determine whether the Challenge is *likely* to be cost effective or not.

2.60 Costs versus Risk: Does Taking the Challenge Offer a Good Bet?

As our discussion of the 32 different case studies reveals, our primary focus is on estimating the net benefit of meeting the Challenge. However, others may believe that *risk*, not cost should be the primary issue. Some maintain that utility reliance on wind options can reduce the utility's risks, but it is not clear to which specific utility risks they are actually referring. For instance, there are a number of different risk measures that may be influenced by the utility's reliance on a wind option: (1) fuel price risk, (2) reliability risk (i.e., the risk of not meeting peak-reliability requirements), (3) operations and maintenance (O&M) expense risk, (4) fuel deliverability risk, (5) financial risk, (6) risk of grid congestion, (7) regulatory risk, and (8) hourly output (or operating) risk, or some combination of all of these. And there may be yet *other* risk measures affected by reliance on wind. Nonetheless, it seems the overarching question is how reliance on wind might affect the regulated utility's *overall risk exposure*? Although we are not aware of any comprehensive analysis of this question, even if there were evidence showing utility reliance on wind options reduces the utility's overall risk exposure, this begs the obvious question of whether there are alternative and possibly less costly ways for the utility (or society) to achieve that same level of risk reduction? Again, we are not aware of any comprehensive analysis of this question.[39]

[39] Suggestions that investment in wind capacity is worthwhile simply because it apparently leads to a more diversified portfolio of generation assets are completely vacuous absent an assessment of how such investment influences the overall risk of the portfolio. At the operational level, given the need to maintain over short time intervals the balance between system load and the dispatched level of generation output, it is possible, if not likely, that "diversification" increases utility risk.

Some have argued that wind reduces the utility's fuel price risk. Because there is no fuel expense associated with wind energy, they maintain wind reduces the utility's exposure to fuel price volatility, particularly natural gas price volatility. The stock argument is that wind energy provides a "hedge" of natural gas price volatility. However, this is a peculiar argument because it is unknown, *ex ante*, whether wind energy would substitute for coal-, nuclear-, or gas-fueled generation or some combination of the three. Not knowing which generation fuel wind energy *actually* substitutes for makes it difficult—some would say impossible—to determine what it *actually* hedges. Furthermore, the five jurisdictional utilities are currently hedging their natural gas volatility via financial derivatives, effectively locking-in their natural gas prices *months in advance*. With respect to only this risk measure, the question is whether reliance on wind options or financial derivatives is less costly. For numerous reasons, derivatives are likely to be less costly. Thus, even if reliance on wind options reduces the utility's exposure to, say, natural gas prices, if wind is the more costly "hedge," then it is not clear why society would choose to rely on wind options to "hedge" that risk.[40] (For further discussion of issues various related to risk and the utilities reliance on wind options, see Appendix G.)

Still others believe that a reliance on wind options can reduce society's exposure to possible future costs stemming from degradation of the environment: that relying on wind offers a type of *insurance policy* against future environmental damages. The possibility that wind capacity may serve as a form of environmental insurance, as opposed to a hedge, is of

[40] At best wind options might serve as a *cross hedge* on natural gas prices. The literature shows that rarely are cross hedges *less costly* than direct hedging vehicles, such as financial derivatives. Thus, even if investing in wind options serves as a "hedge," it is a sure bet that using natural gas derivatives would be less costly way to achieve that same hedge. The literature also suggests that cross hedges are rarely as efficient as direct hedges. If wind does provide a cross hedge, it would have to be sufficiently less costly than the direct hedges in order to be cost competitive. That is, even if wind provides a cross hedge, it may need to be considerably cheaper in order to be a good deal (as a hedge).

some interest. However, to estimate the *value* of such an insurance policy, unfortunately, is quite complex and lies beyond the scope of this study. Nonetheless, we recognize meeting the Challenge may provide this insurance value, above and beyond the net benefit estimates presented in this study.

2.61 Net Benefit is the First Order Concern

Typically, policy makers and the public want to know, "what's it going to cost?" That is the obvious starting point and, therefore, we take the cost of meeting the Challenge to be a first-order consideration and have designed our evaluation accordingly. We fully recognize that risk matters; risk is important.[41] But even when the focus is on risk, the usual question is the cost of reducing or managing or hedging that risk—thus, even with a focus on risk, the discussion *usually comes back to cost*. As another example, if it could be shown that wind options reduce the utility's overall risk, that would justify paying extra for those options. Even there, estimating the proper size of the "extra" payments depends on a myriad of factors that are difficult to quantify.[42] For these reasons we concentrate our analysis on the monetary costs and benefits of meeting the Challenge.[43]

[41] In fact, we believe utility reliance on wind options may increase some utility risks, while possibly reducing others. Generally, we think it is probably just as likely that the utility's *overall risk* would increase as decrease. At any rate, whether reliance on wind increases or decreases the utility's overall risk exposure has not yet been empirically (or theoretically) established. The overall risk analysis is made even more complex when the scope of the analysis is expanded to include external costs and their associated risks.
[42] This analysis requires an estimation of the risk-return transformation frontier.
[43] Ideally, a *risk-adjusted cost analysis* of the Challenge would be performed; however, the complexity of that analysis and absence of the necessary data base render performing that analysis problematical. For that reason, risk is a second-order consideration and largely left as a subject for further research. In the concluding section of this report, we discuss the possible value of wind capacity as an environmental insurance instrument.

2.62 Incorporating Risk into the Analysis

While our focus is on the net benefit of the Challenge, for each of the 32 case studies we examine, we perform a Monte Carlo analysis. Through the use of the Monte Carlo analysis, we *explicitly incorporate* the influence various risks have on the estimated net benefit of the Challenge. There is no doubt that investment in wind capacity (like any investment in fixed capital assets) is risky to society.[44] That risk extends to any investor in wind capacity, utilities and wind developers (and their financial backers) alike. Wind investment is risky because the net benefit of wind itself depends on a number of different random variables: the future price of natural gas, the operating performance of wind assets, the future O&M expenses on wind equipment, the possibility of a carbon tax, to name just a few. Because wind investments are risky, even when the Challenge is expected or forecast to deliver a positive net benefit, that outcome *cannot be guaranteed*. By performing a Monte Carlo analysis, we can provide policy makers with an assessment of whether wind investment—that is, the Challenge—is likely to be a *good bet*. Hence, in addition to estimating the net benefit of the Challenge, we also estimate the probability that it will be cost effective and, consequently, whether it is a risk that may be worth taking. (A description of the Monte Carlo analysis is provides in Chapter 4.)

2.70 The Employment Implications

The employment implications of meeting the Challenge are another area of significant interest. There are a number of different ways, ranging from the more simple to the very

[44] While it is true that investment in wind capacity may mitigate some risks, to simply ignore the new risks that it introduces is obviously questionable. Again, the basic questions about wind risk should focus on how wind investments change *overall* risk and whether such changes are worth taking. Unfortunately, answering those questions lies beyond the scope of this study.

complex, to evaluate the potential employment implications. However, our analysis of the monetary savings attributable to the Challenge provides a measure of the *change in generation-related expenditures* that comes with meeting the Challenge. And as GDP accounting shows, one person's expenditures are another person's income. Thus, to the extent the Challenge changes expenditures in the state, it will change incomes and, consequently, employment levels. In short, our assessment of the savings generated by the Challenge also enables us to assess the *direct* employment implications of the Challenge.[45]

Therefore, the savings analysis, with its focus on net expenditures attributable to the generation of electricity, can be used to derive the *basic* income and, thus, employment implications of the Challenge. For that reason, we use the numerical results from our net benefit analysis as a basis for estimating the *first-order* employment implications of the Challenge.[46] (See Appendix C for a more complete discussion of the employment implications of the Challenge.)

[45] By "direct" we mean employment changes tied directly to generation-related expenditures, be they utility expenditures or those associated with external costs of generation. We consider these changes to be the first-order employment implications. In short, our measure of Challenge-related savings performs double-duty by also providing an indication of the first-order employment implications of the Challenge. The second-, third-, and subsequent-order employment implications—those tied to the "multiplier effect"—are of less importance, though we do offer some discussion of the possible higher-order implications.

[46] A discussion of the likely employment consequences of the Challenge are presented in Appendix C.

Chapter 3: Framing the Benefit Cost Analysis—Deriving the NPV Formulas

3.00 Introduction

In this chapter, we present the economic models we use to estimate the net benefit of meeting the Challenge.[1] The models take the form of mathematical equations. In the previous chapter (Section 2.42), we define the net benefit of the Challenge as the *total savings* it could deliver. Moreover, we indicate the total savings could be measured by *comparing* the total cost of providing Kansans with electricity when the Challenge is met, with the total cost when it is not – the latter being the "business as usual" approach. That relative cost difference is the net benefit of the Challenge.

In this chapter we offer an *equivalent*, though slightly more refined and definitely more detailed, version of that formulation. The formulation we present in this chapter, arguably, makes explicit all of the factors or variables that have a significant influence on the net benefit of the Challenge. We divide these variables between: (1) those that measure a specific *incremental savings* due solely to the Challenge and (2) those that measure a specific *incremental cost* due strictly to the Challenge. Put a different way, the variables are divided between those measuring a cost *reduction* or avoidance[2] and those measuring a *cost increase* strictly as a result of the utility acquiring a wind option, presumptively in response to the Challenge, with all else equal.

The aggregate of the avoided cost variables measures the gross savings or gross benefit of the Challenge, while the sum of the incremental cost variables measures the total

[1] Hereafter, implied in references to the Challenge is the condition of the Challenge having been met.
[2] These are usually referred to as *avoided cost* variables.

cost of the Challenge. The difference between the Challenge's gross benefit and its total cost provides a measure of the Challenge's net benefit. This relationship is shown by:

$$\text{Net Benefit} = \text{Gross Benefit} - \text{Total Cost}. \tag{1}$$

With Equation (1) as backdrop, we identify and define those specific variables that make up the gross benefit of the Challenge, and then do the same for those variables that make up its total cost. We refer to variables that make up either the gross benefit or total cost as input variables. The main focus of this chapter is defining all of the relevant input variables, thereby identifying all of the inputs needed to compute the Challenge's net benefit to Kansas.

Finally, because the real investment needed to meet the Challenge will have economic implications extending far into the future, our evaluation of the Challenge's net economic benefit necessarily involves an extensive use of forecasting. Many of the variables that influence our measure of the Challenge's net benefit are random variables. Therefore, in order to forecast the Challenge's net benefit it is necessary to develop forecasts (or, in some instances, estimates) of those random variables. While the description of our forecast methods (and parameters) is contained in the following chapter, in this chapter we do provide some groundwork, as introduction, for our subsequent discussion of forecasting.

3.10 The Gross Benefit of the Challenge: Identifying the Avoided Cost Variables

The avoided cost variables can be placed in two categories: those that measure savings *internal* to the utility and those that measure savings *external* to the utility. The former reduce the utility's revenue requirement and, all else equal, allowed rates.[3] The latter reduce damages and costs stemming from, mainly, pollutants in power plant emissions.

[3] We assume throughout that the utility's revenue requirement is recovered through allowed rates/tariffs. We also assume that allowed rates are established and allowed to change through the standard rate case process.

3.11 The Internal Avoided Cost Variables

The following variables measure specific costs the utility may possibly avoid and, thus, save by meeting the Challenge rather than pursuing business as usual: (1) avoided fuel expense,(2) avoided operations and maintenance (O&M) expense associated with conventional generation assets, (3) avoided O&M expense associated with pollution control equipment and/or other expenses needed to comply with *existing* environmental regulations,[4] (4) avoided purchase power expense, (5) avoided O&M expense associated with pollution control equipment needed to comply with currently expected *changes* (as of 2005) in existing environmental regulations,[5] and (6) avoided capacity (or capital equipment) expense.

Before discussing these six avoided cost variables, we offer a brief discussion of the assumptions we use to both structure and simplify the analysis at hand. These assumptions enable us to effectively reduce (through combination) the number of avoided cost variables without loss of generality.

3.12 Some Underlying Assumptions

A. Quantity Substitution Rule

Unless otherwise noted, throughout this analysis we assume each megawatt-hour (MWh) of wind energy produced or purchased by the utility will displace or substitute for one MWh of energy from the utility's conventional generators or existing purchase power

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Finally, we also assume the utility's incremental generation expenses, mainly the fuel, O&M, and purchases power expenses, are recovered through an annualized pass-through mechanism, such as an ECA mechanism designed in accordance with approved, tariff provisions.

[4] "Other expenses" could include, for example, emission allowances.

[5] Since our analysis is forward looking and because certain *changes* in environmental regulations are currently expected among the utility management and regulators, this variable captures forecast savings due strictly to the currently expected *changes* in environmental regulations.

contracts, used to meet its retail load obligation.[6] This is equivalent to treating the output from wind resources, regardless of their ownership, as "negative load," which effectively guarantees a one-to-one or *on par quantity substitution* between conventional and wind energy (see Kennedy, 2005).[7] With that quantity substitution "rule," the utility's acquisition of *one* MWh of wind energy, from whatever wind options it relies upon, enables it to avoid either producing or purchasing *one* MWh of conventional energy.

B. Utility Access to Wholesale Energy Market and Arbitrage Opportunities

As a practical matter, Kansas utilities have long had access to a wholesale electricity market. That market affords utilities, if nothing else, opportunities to buy and sell power. Recent and on-going efforts by the Federal Energy Regulatory Commission ("FERC") and certain states are directed at improving the rules by which the wholesale market operates thereby serving to assure its openness and, thus, competitiveness. The Southwest Power Pool, Inc. (SPP) is in the process of implementing its Energy Imbalance Market (EIM) to which all KCC-jurisdictional electric utilities (and other buyers and sellers) will have open access. For purposes of this study, we interpret markets like the EIM as wholesale *spot markets* for electricity.[8] We assume wholesale spot markets are competitive and operate at or near equilibrium in all time periods. Furthermore, we assume utilities behave optimally in the

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[6] If the output from Kansas wind generators is sold off-system to non-Kansas consumers, then wind production in Kansas may not alter the utilities' dispatch and purchase power decisions. In that case the utilization of Kansas' conventional generators and their consumption of fuel are both largely unaffected by wind energy production in Kansas. Unless we indicate otherwise, we will maintain the hypothesis, artificial as it may be, that the production of Kansas wind energy will be strictly for Kansas retail consumers.
[7] Alternatively, wind resources may be treated as "must run" resources and, thus, automatically included among generation resources placed first in the dispatch order. However, since wind capacity is neither controllable or dispatch, even when wind capacity is thought of as being first in the dispatch order, that is not sufficient to conclude that use of wind capacity materially alters the dispatch of any other power plants.
[8] Open access to markets like the EIM suggests they may be used for other purposes besides exchanging imbalance energy. Once fully established, markets such as the EIM may come to represent *reference pricing points* for all types of energy transactions, but particularly spot energy trades.

short run. This implies utilities will use all available options to minimize their short-run operating costs. Therefore, we assert utilities will dispatch their generation resources and use the available market opportunities for trade so that they equate their system lambda with the going wholesale market price.[9] When the utility's system lambda equals the going market price for electricity, the incremental *value* of avoiding either the production or the purchase of one MWh in the market is the same for the utility.[10]

C. Utility Decisions Subject to Cost of Service Agency Regulation

Our evaluation (i.e., costing) of all avoided cost variables is consistent with the principals and standards that are routinely applied through cost of service ("COS") regulation; therefore, the calculation of the regulated utility's total savings due to the Challenge is consistent with COS regulation. The same holds for our assessment of the utility's cost to acquire either wind option: the standard COS methodology is applied.

3.13 Definitions of Internal Avoided Cost Variables

In this section we define three internal avoided cost variables, which we denote by FOM, APC, and CAP. Both the FOM and APC variables are a function of the quantity of wind

[9] This assertion is simply that the utility exhausts all of its no-risk arbitrage opportunities. We assume all market prices are congestion-free prices. Following the current, standard commercial practice, we define system lambda as the utility's (non-congested) marginal cost of generating the last MWh needed to meet its retail, jurisdictional load obligation.

[10] Since we assume the utility is operating efficiently on the margin and that the spot energy market is in equilibrium, by itself the quantity substitution rule has no influence on estimated *monetary* savings per MWh of wind energy. Moreover, only to the extent that meeting the Challenge would influence the regional spot energy market price will it have an influence on the *marginal* value of electricity in the region. In short, we assume that total wind energy production under the Challenge, at any one moment in time, will not have a significant effect on the spot market price.

energy acquired by the utility from whatever wind options the utility has selected.[11] The CAP variable depends on the amount of wind capacity (in MW) installed by the utility.

A. Defining the FOM Variable: The Annualized Avoided Marginal Expense of Conventional Energy

The FOM variable measures the *total, annual savings* in fuel, O&M, and purchase power expenses the utility realizes by acquiring wind energy. In short, the FOM variable captures the primary "out-of-pocket" expenses the utility can *avoid* each year by taking wind energy. Of the six avoided cost variables listed above (in Section 3.11), the FOM input variable is designed to capture collectively the first four on that list: fuel, generation equipment O&M, existing pollution control equipment O&M, and purchased power.

The standard method of measuring the utility's system lambda includes the incremental fuel, O&M, and existing environmental compliance expenses – all measured in 2005 constant dollars[12] – associated with the utility's marginally produced MWh.[13] Again, we assume that for each MWh of wind energy acquired by the utility, it can avoid producing one MWh of energy by conventional means. We also assume that what is avoided is the

[11] We assume the amount of wind energy acquired by the utility is the total amount of energy produced by its wind options. In recognition wind options are neither controllable nor dispatchable, the amount produced by those options is equivalent to amount the utility takes. While we refer to wind energy as being acquired by the utility, more precisely it is simply taken. The utilities are assumed to take all output yielded by their wind options. Putting it a different way, wind options are exercised whether in the money or not.

[12] Unless stated otherwise, all dollar amounts presented in this report are in constant 2005 dollar terms. In those instances where we needed to convert nominal prices (forecasts) to real prices (in 2005 dollars), we assumed an average annual rate of inflation equal to 2.25 percent. We consider that to be a reasonable forecast of the average annual change in the GDP Deflator index. To convert historical given nominal prices, we used actual GDP Deflator index readings. Other inflation discount factors may also be reasonable. See footnote 51 below for the definition of the GDP Deflator index.

[13] Arguably, the incremental environmental compliance expense would also include the symbiotic load expense associated with running the control equipment. But because of the complexity of doing so, and because it is unlikely to make a significant difference, we have not done so here.

marginally produced MWh of conventional, spot energy.[14] Therefore, each MWh of wind energy acquired by the utility enables it to avoid an expense equal to its system lambda, which we denote by λ. It is that basic relationship that the FOM variable captures, which is shown mathematically by:

$$FOM = \lambda \times qw,$$

where, qw, denotes the quantity of wind acquired by the utility, measured in MWh. By that specification, it should be clear the FOM variable measures, *in aggregate*, three of the avoided expenses listed in Section 3.11: fuel, generation O&M, and existing environmental compliance. It also measures the savings due to an avoided power purchase (per MWh), net of transmission-related expenses.

Because the investment implications of the Challenge cover several decades, and because both the utility's avoided expenses and acquisition of wind energy are likely to *systematically* vary from one year to the next, we model both the utility's system lambda and the quantity of wind energy the utility takes on an average annual basis.[15] Showing that both

[14] We draw a distinction between energy produced for the purpose of (stochastic) load following, as an ancillary-type service, and energy produced on the spot to meet (non-stochastic) retail load obligations, as firm spot energy.

[15] Obviously, there are several alternatives to setting the time unit at one year. For modeling the utility's avoided fuel expense, arguably the most accurate approach would be to use an hour-based model and, thus, use the (unblended) hourly lambda data. However, the data requirements for modeling the Challenge on an hourly basis are significant and beyond existing means; hence our use of annual data. That said, we would note that with the exception of modeling/estimating the avoided fuel expense, for all other variable used in this study using annual data is likely to provide as much accuracy as hourly. Furthermore, regarding the method of averaging, the average annual lambdas we utilize in this study are *roughly* equivalent to the simple average of hourly lambdas for the year. Of course, there are several alternative methods for deriving an annual average, some of which we considered for use in this study. For example, one could use a wind-production-weighted average of hourly lambdas, which is likely to be a more accurate estimator than the simple average. However, because in Kansas there is *normally* more wind energy produced during the spring and fall seasons and less during the summer, corresponding to periods when hourly system lambdas tend to be lower and higher, respectively, the simple average of hourly lambdas is likely to be *larger* than the more accurate, wind-production-weighted average of hourly lambdas. Equivalently, using the simple average has the affect of overweighting the summer hourly lambdas and underweighting the fall and spring hourly lambdas. (See referenced report by John Olsen in Bibliography.) Thus, our use of simple average annual lambdas, blended as they are, is likely to introduce some estimation bias slightly *in favor of wind*. For other locations with different intra-year wind patterns, that bias could certainly be in a different direction of non-existent.

the lambda and quantity of wind are time period-specific (i.e., year-specific), we denote them:

$$FOM(t) = \lambda(t) \times qw(t).$$

Given our assumptions regarding the existence of a competitive electricity market and the utility's interest in using that market to pursue risk-free arbitrage opportunities, the utility's system lambda will be, on average, *equivalent* with the wholesale spot market price of electricity. Thus, whether taking wind energy enables the utility to avoid either producing conventional energy or purchasing it in the market, the utility's avoided dollar expense per MWh is the same. Thus, for utilities either using or contemplating use of the wholesale energy market to purchase energy to meet their retail load obligations, the price of the marginal MWh purchased equals their system lambda.[16] This means FOM(t) also captures any purchase power expense avoided as a consequence of the utility acquiring wind energy.

In summary, the FOM variable measures the aggregate fuel, O&M, existing incremental environmental compliance, and purchase power expense the utility saves, on average, in one year by acquiring wind energy in the amount of qw(t). Because those expenses may change over time due to, for example, changing fuel prices and changes in the amount of energy the utility takes in a year, the FOM variable is made time-dependent as indicated in the notation FOM(t).

The FOM variable also depends on the utility-type. Different utilities use different portfolios of generation assets, fuel, and purchase power contracts to meet their respective retail loads. This implies that, over the course of a year, different utilities will manifest different average annual lambdas. The differences are unlikely to be explained by the utilities

[16] This equivalence would hold for utilities buying energy to meet their retail obligation. It may not hold for utilities selling energy off-system having already satisfied their retail load, presumably at least-cost.

facing different fuel and/or purchase power prices, since it is likely that all the utilities effectively purchase their fuels and power (and transport services) in the same markets; therefore, we do not expect utilities to consistently face different input prices, on average. Rather, much of the differences in system lambdas are explained by the *composition* of their input portfolios.[17] In particular, utilities that have a relatively greater reliance on natural gas-fueled generation are likely to have higher system lambdas (over the course of a year) than those with relatively less dependence on gas. In fact, we find a significant positive correlation between the utility-type's gas mix and its average annual system lambda. We define "gas mix" as the proportion of the utility's annual retail sales (in MWh) that it serves through the use of natural gas-fueled generation.[18] Our analysis shows that the utility's gas mix, as an underlying variable, serves well to structurally *delineate* utility system lambdas and, therefore, provides a quantitative basis for distinguishing the utility-types. In short, system lambdas differ by utility-type, and we delineate utility-types by their gas mix. This we denote as follows:

$$\mathrm{FOM}(t, u(gm)) = \lambda(t, u(gm)) \times qw(t),$$

where the utility-type is indicated (or indexed) by, u(gm), being low-, average-, middle- or high-cost, and the average, annual gas mix for the respective utility-type is indicated by, gm.[19] As shown by the notation, the quantity of wind energy acquired in a year, qw(t), does not depend on or vary by the utility-type.[20]

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[17] The collective composition or structure of those three different input portfolios is frequently referred to as the utility's cost structure.
[18] Included in the gas mix calculation is the utility's use and expense of other petroleum products, such as No. 6 oil.
[19] A detailed discussion of how we calculate a utility-type's gas mix is contained in Chapter 4 of this report.
[20] For instance, there is no basis to presume the productivity of utility wind investments would somehow vary depending on the utility's cost structure.

Besides depending on the utility-type and the year, FOM also depends on several underlying random variables. For example, since the system lambda depends on fuel prices, so does FOM. Natural gas prices seem to be of particular interest in terms of assessing the economics of wind energy. The gas mix itself is a random variable because the utility's reliance on natural gas is likely to depend directly on weather conditions; for example, the hotter the summer, the greater the reliance on peaking units and, therefore, the higher the gas mix. The gas mix can also be indirectly affected by weather; for example, coal conservation efforts can lead to greater gas use depending on coal delivery conditions, which in turn depends on the weather. The quantity of wind energy acquired by the utility also depends on random variables. For instance, it depends on the productivity of the installed wind capacity and, therefore depends on the wind capacity factor, which in turn depends on weather conditions as well as the reliability of the wind equipment, which can also be influenced by weather conditions.[21] Thus, in our modeling of the FOM variable, we structurally embed a total of four (underlying) random variables: price of natural gas, utility-type gas mix, capacity factor, and degradation of the capacity factor.[22] And underlying those variables are additional random variables such as weather, international relations, and durability of equipment – which, of course, are not explicitly modeled here.

Thus, in order to determine an actual value for (i.e., to estimate) the FOM variable, it is necessary to first determine a value for each of the four random variables that are a part of

[21] The capacity factor for a specific generation asset, calculated on an annual basis, is the amount of annual energy production (in MWh) during a year divided by the product of asset's nameplate-rated capacity (in MW) and 8,760 hours. The annual capacity factor measures a generation asset's actual annual output in MWh as a proportion of its (absolute) maximal annual MWh output. Capacity factors may vary by location and other factors, but we assume they do not vary, *on average*, among utilities nor developers, nor do they vary between those two groups. For that reason we do not distinguish capacity factor by utility-type, effectively assuming that the best available wind technology is employed uniformly by all utilities and/or developers at any moment in time.

[22] Both the capacity factor and its degradation over time are discussed in greater detail later in this report.

its composition. We use a Monte Carlo analysis to establish forecast values for those four random variables. Moreover, by using the Monte Carlo process for forecasting, we are able to evaluate a large number of different possible forecasts.[23] Naturally, using different forecasts values for the four, underlying random variables results in a different FOM value (i.e., forecast FOM). In other words, establishing a forecast value for the FOM variable, as well as other input variables included in our formulation of the Challenge's net benefit, requires having a forecast for a *set* of several, *underlying* random variables or what we refer to as a "forecast scenario.[24]" Letting f denote a single forecast scenario, we denote the FOM variable by:

$$\text{FOM}(t, u(gm), f) = \lambda(t, u(gm), f) \times qw(t, f).$$

In summary, the FOM variable measures the total, combined incremental, constant dollar expense – of fuel, generation plant O&M, pollution control equipment O&M and purchase power – that is *avoided* or saved as a result of the utility's take of wind energy during one year. The FOM variable depends on the type of utility in question (denoted by u(gm), which indicates the utility-type is itself determined by the utility's average, annual gas mix, gm); the forecast scenario, f; and the specific year, t. It does not matter whether the utility-type acquires its wind energy from its own wind assets or developers (i.e., wind PPAs): the utility's incremental savings would be the same. Hence, the FOM variable is not dependent on the wind option selected by the utility. Lastly, and unless otherwise noted, any wind energy the utility obtains, either from its own wind assets or developers, is used to meet

[23] Again, the forecasting methods used in this study, including the means of deriving a forecast scenario are fully described in Chapter 4 of this report.
[24] To be clear, a single forecast scenario consists of having actual forecast values for the entire set of random variables that underlie (as component parts of) the input variables used in the net benefit formulations. Thus, a forecast scenario then consists of a specific set of forecasts that are used to develop actual forecasts of the input variables, which, in turn, are used to forecast the net benefit of the Challenge.

its retail load obligation. This is consistent with treating wind energy as negative load. Thus, by design, utilities do not sell wind energy off-system; all wind energy produced by or for the jurisdictional utilities stays with them.[25]

(i) An Aside: Describing the Wind Energy Output Variable, qw(t, f)

In addition to the FOM variable, several other avoided cost variables depend on the quantity of wind energy acquired by the utility-type during the year, qw(t, f). Therefore, it is worthwhile to consider the composition of the qw variable in more detail.

We define the qw variable as follows:

$$qw(t, f) = CF_a(t, f) \times iwc(t) \times 8{,}760.$$

This shows the average amount wind energy acquired during one year depends on two variables: the adjusted capacity factor, $CF_a(t, f)$, and the total quantity of installed wind capacity, iwc(t). We start with a discussion of the latter.

We denote the amount of wind capacity, measured in megawatts, installed *statewide,* by the variable, iwc. It measures the total, net nameplate amount of wind capacity installed in the state by either the utility-type or wind developers serving that utility-type.[26] As wind capacity is installed over time, in response to the Challenge, iwc will increase and as wind equipment becomes fully depreciated and is taken out of service, iwc will decrease.[27] The iwc variable captures the aggregate amount of installed wind capacity that is deemed used and useful. As points of reference, at the end of 2005, iwc(2005) = 264 MW, and if the Challenge is met, then at the start of 2015, iwc(2015) = 1,000. However, because there is no

[25] This "constraint" can be characterized as the Kansas wind, for Kansas consumers' constraint.
[26] Nameplate capacity is the maximal amount of capacity a generating unit can provide per design specifications adhered to by the manufacturer and/or subsequent design modifications.
[27] Consistent with current expectations of their useful economic lives, we assume investments in wind capacity have 20-year depreciable lives. Subsequent upgrades and re-investment will likely extend that time period.

meaningful way to forecast how or at what point in time the utilities might respond to the Challenge, we assume the Challenge is met in accordance with a specific capacity installation schedule or time line. In fact, the assumed time line for installing wind capacity is precisely what the iwc(t) variable shows.[28] For all variables whose definitions make use of the iwc(t) schedule, the schedule is the same.

Based on existing evidence, we assume the average, annual capacity factor associated with wind generation assets will change as that equipment ages. As that equipment ages we expect a reduction or degradation of its capacity factor. We use $CF_a(t, f)$ to denote the age-adjusted, average annual capacity factor that is applied uniformly to all wind assets in the state with the same vintage.[29] And for all input variables whose definitions make use of the $CF_a(t, f)$ variable, for a given forecast scenario we use the same CF_a forecast.

As shown by the equation above, the average quantity of wind energy acquired by the utility-type during a specific year is the product of the adjusted capacity factor, installed wind capacity statewide, and the total number of hours in a year.[30] Because the capacity factor depends on some random variables that are included among that set of random variables that makeup the forecast scenario, it follows that the quantity of wind energy produced during the year, qw, is similarly dependent on the forecast scenario, f, and is denoted qw(t, f).

[28] The assumed capacity installation schedule, iwc(t), is shown in Section 4.41 of this report.
[29] The degradation of the capacity factor is explained in greater detail in Chapter 4.
[30] The installed capacity is vintaged and, therefore, so is the adjusted capacity factor (on an overlapping basis). However, in order to simplify the notation this is not shown. Recall our analysis of the Challenge is structured around just a single utility-type, at a time, meeting the Challenge. In that sense, the analysis of the Challenge is always on a statewide basis.

(ii) A Look Ahead: Forecasting the FOM Variable

By way of summary, in order to derive actual forecasts of the FOM variable for a particular utility-type, there are several other random variables for which estimates, actually forecasts, must first be derived. For each utility-type these latter random variables include the annual gas mix, gm; the adjusted capacity factor, CF_a(t,), which, in turn, requires estimation of utility's gross, annual capacity factor and the applicable capacity factor degradation rate; and the estimated system lambda, which, in turn, requires an estimate of the real (i.e., inflation-adjusted) price of natural gas (which is likely to change over time). The process we use to estimate each of these random variables and, consequently, the FOM variable is described in Chapter 4. In short, to forecast the FOM variable, it is necessary to forecast several other underlying random variables. We use a Monte Carlo process to derive forecasts of the required underlying random variables. Once *actual forecasts* of underlying random variables have been drawn or selected, we refer to that *set* of forecasts as a forecast scenario, which we denote by, f. Once drawn, we use the forecast scenario to derive forecasts for both the average annual system lambda, λ(t, u(gm), f), and the average annual quantity of wind production, qw(t, f), their product yielding the forecast FOM variable.

B. Defining the APC Variable: The Expected Change in the Avoided O&M Expense of Pollution Control Equipment

In order to comply with *existing* environmental regulations, utilities have had to complement their use of conventional generators and fuels with investments in pollution control equipment. Once the control equipment is purchased and installed, there is an O&M expense associated with running that equipment. That O&M expense has been included in our measure of the FOM variable.

However, at this time, evidence has been presented to the Commission indicating possible changes in environmental regulations and standards pertaining to certain power plant emissions. Some of those changes are vis-à-vis existing standards; others may take the form of new regulations.[31] Any significant changes in environmental regulations are likely to require additional utility outlays in pollution control equipment, consequently increasing the utility's O&M expense. In Docket Numbers 05-WSEE-981-RTS, 04-KCPE-1025-GIE, and 06-KCPE-828-RTS, Westar and KCPL submitted, and the Commission reviewed, evidence regarding new investments in pollution control equipment that are likely to occur in response to expected changes in environmental regulations. In its docket Westar also submitted evidence showing by how much and when its O&M expenses could change over future years subsequent to its expected installation of new pollution control equipment.

In view of these possible changes, the APC variable measures the annual O&M expense, associated with *currently expected* investment in *new* pollution control equipment, which could be avoided as a consequence of the utility (subsequently) relying on wind energy. Because of the intermittent nature of wind energy production, we do not expect investment in wind capacity to enable the utilities to avoid investing in new pollution control equipment, but simply to avoid operating that equipment at certain times.[32]

We define the APC variable as follows:

$$\text{APC}(t, f) = \text{unit APC}(t) \times \text{qw}(t, f),$$

[31] Arguably, the changes discussed are those perceived by many in the industry as being *likely* to occur.

[32] This is consistent with the expectation that investment in wind capacity will need to be backed, nearly in full, with conventional generating capacity. In case wind energy is not available and conventional resources must be used in *toto* to meet load obligations, use of the requisite pollution control equipment will then be necessary. The utility will cover that contingency by recognizing that its investment in wind capacity will not enable it avoid investment in pollution control equipment.

where the unit APC is the annual average O&M, associated with currently expected investment in *new* pollution control equipment, which could be avoided per MWh of conventional generation and qw(t, f) is defined as before. Thus, conditional upon the expected investments in new control equipment being made, the unit APC measures the related O&M savings, on average, for each MWh of wind energy acquired by the utility. Like the system lambda, we measure the unit APC in constant 2005 dollars.

The APC variable captures the fifth item on the list of avoided costs in Section 3.11: the avoided O&M expense associated with pollution control equipment needed to comply with currently expected *changes* (as of 2005) in existing environmental regulations. While some may believe some type of carbon regulation applied to electric utilities is likely, we do not explicitly include avoidance of possible carbon taxation as part of our net benefit formulation, nor is it included as part of either the FOM or APC variable. It is not explicitly included because of its speculative nature; there are no good estimates of what the tax might be. More importantly, though, by not explicitly including it in the analysis, we can estimate how large that tax would need to be in order to have a significant or pivotal influence on Kansas wind economics. Nonetheless, we do see potential carbon taxation as an issue of real importance and discuss its potential implications below.[33]

Arguably, the APC variable is almost certain to vary by utility-type, although the differences may not be significant. Moreover, the only detailed information we have regarding the APC variable, namely the unit APC, is specific to Westar, and to a lesser extent KCPL. Because such information is limited (and difficult to obtain) and may not differ significantly among the utilities even if available in full, we assume the unit APC and, thus,

[33] In Chapter 5 we evaluate, as a special case, the net benefit of the Challenge given the imposition of a $10/ton (of CO_2) carbon tax.

the APC variable does not vary by utility-type.[34] Because the expected installation of pollution control equipment, whose operation gives rise to the unit APC, would occur over time (per an expected schedule), the unit APC is necessarily time dependent, as shown by the notation.

(i) A Look Ahead: Forecasting the APC Variable

Like the FOM variable, estimation of the APC variable depends on the previously described components, random variables and otherwise, that make up the qw(t, f) variable. More simply, forecasting the APC variable, like the FOM variable, requires the selection of a forecast scenario. However, estimating or forecasting the unit APC presents a somewhat unique challenge. By design, the estimated unit APC depends upon *when* investments are likely to be made in new pollution control equipment and the expected O&M expense associated with only that equipment. As a practical matter, forecasting the timing of those investments is not feasible. Therefore, we use information and data provided by Westar to establish an *assumed* unit APC time line. That time line or schedule shows, by year, the magnitude of the assumed unit APC. The assumed unit APC schedule (which is a function of the forecast installation of pollution control equipment) is discussed in Section 4.52. In summary, forecasting the APC variable requires the selection of forecast scenarios, f, which we accomplish through the Monte Carlo process, and the specification of a unit APC schedule.

[34] Since both Westar and KCPL currently have a relatively high dependence on coal as a baseload fuel, their unit APC estimates probably represent upper bounds for less coal dependent utilities (who may require less pollution control equipment generally). To base the statewide unit APC on Westar and KCPL information probably biases the results *slightly* in favor of wind.

C. Defining the CAP Variable: The Avoided Generation Capacity Cost

We use a two-part methodology to establish the dollar value of the conventional capacity avoided as a consequence of investing in wind capacity. One part determines the avoided capacity measured in megawatts; the other assigns a dollar value per MW.[35] Each part requires an assessment of the (technical) substitutability of wind capacity for conventional capacity.[36]

It is an analytical challenge to identify what installed wind capacity substitutes for among the conventional generation technologies and fuels. For instance, even though wind capacity is typically placed, perhaps by default, first in the dispatch order,[37] does that imply that it substitutes for baseload capacity? Since wind facilities may (*ex post*) have capacity factors similar to that of intermediate and/or peaking units, does that imply wind capacity is a substitute for those types of units, even though its *availability rating* may be considerably different (i.e., lower)? Absent knowing the specific kind of conventional generating capacity that wind capacity actually offsets, it is difficult to estimate the avoided generation capacity cost attributed to the installation of wind capacity.

Identifying a reasonable method for rating wind capacity is a topic of current research and may remain so for some time. Given the intermittent nature of wind-energy production, it can be argued that investment in wind capacity is completely unique given that it does not provide an operational substitute for *any type* of dispatchable and controllable generation

[35] The first part establishes the *quantity* of generating capacity that is saved as a consequence of investing in wind; the second part assigns a *dollar value* to the quantity of capacity saved.
[36] It should be noted that substitutability on the demand side (i.e., from the consumers' perspective) also matters. For a brief discussion of this and related matters see footnote 38.
[37] If a wind resource is first in the dispatch order, then that does not imply it is a dispatchable resource. Arguably, since wind capacity is not dispatchable in the usual sense of the term, its position in the dispatch order is by default.

capacity. Similarly, in terms of rated availability, wind units/facilities are unlikely to be *on par* with the measured availability of conventional generating units.[38]

The SPP has examined some of these issues in what may be characterized as a preliminary study of methods for establishing the ratable capacity of wind facilities.[39] We recognize SPP has not formally adopted any such method as of this time. While other rating methods certainly exist, for potential wind investments in the SPP region, there is little reason to apply rating methods other than what SPP uses or appears most likely to use. Therefore, for purposes of this study, we use the method described in the SPP study as the best available method for rating existing and potential future wind facilities in Kansas. That said, our assessment of the Challenge is easily modified to permit consideration of other rating methods, including different methods applied by SPP as well as those applied outside the SPP.

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[38] In terms of maintaining system reliability, the substitutability of wind capacity for conventional capacity from the *consumers' perspective* is a critical and oft-ignored consideration. Most consumers of electricity, particularly residential customers, have grown accustomed to and generally *demand* firm, reliable electricity and, consequently, effectively demand those generation sources capable of supplying that type of electricity (i.e., quality of service). Moreover, their demand for firm energy spans every minute of every day. In short, around-the-clock, consumers generally do not demand intermittently supplied electricity; they demand firmly supplied electricity. To the extent wind energy is less firm compared to the standard electricity service, this suggests it may need to be priced at a discount. For instance, to the extent that inclusion of wind capacity in a utility's portfolio of generation assets diminishes the reliability of that portfolio and the utility's operations generally, this suggests wind capacity should be sufficiently discounted in order to compensate consumers for any reduction in system reliability. Because it can change operating risk, the idea of burying a sufficiently small amount of wind capacity in the utility's generation asset portfolio (like mixing a small amount of water in the gasoline tank of an automobile) with the presumption that it can be *absorbed* without a *significant* reduction in system reliability and, therefore, is reasonable, is generally without economic merit. Consumers who expect and *demand* the usual quality of service should be compensated for *any* reductions in reliability and/or *any* increased risk of lower reliability due to greater reliance on wind capacity.

[39] Southwest Power Pool Generation Working Group, *Wind Power Capacity Accreditation White Paper,* September 9, 2004. In this study the SPP develops a method of rating the availability of installed wind capacity, given its expected performance under normal wind conditions, so that its expected availability would be roughly *on par* with or equivalent to that of conventional generators. The SPP uses a measure of statistical likelihood to establish that equivalence. Consistent with its application of rating methods to conventional generators, this wind capacity rating method is applied to *individual* wind generation units/facilities. It is worth emphasizing that the standard practice for rating generation capacity is generally on a *per-unit basis*, not a per-portfolio basis.

Using the SPP study as the basis, and given the current standards that define SPP's existing capacity requirements, as well as SPP's existing incentives for satisfying (i.e., penalties for failing) those requirements, we assign a seven (7) percent capacity credit to wind capacity installed by utilities. This means, within the context of this study, that for each MW of nameplate wind installed by the utility, the utility can avoid investing in 0.07 MW of conventional capacity.

The next step is to establish the dollar value of the avoided conventional capacity, which, once more, raises the question of what *type* of conventional generation is a reasonable substitute for wind capacity? Without attempting to answer that question, except to note again that wind capacity is operationally unique because it is neither dispatchable nor controllable,[40] on an annual basis, we assign a dollar value of $65,000 per MW of installed wind capacity.[41] Consistent with our measure of the utility's system lambda and its unit APC, we measure the dollar value of avoided conventional capacity in constant 2005 dollars.

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[40] Again, consistent with Kennedy (2005), we treat the supply of wind-based energy as "negative load." In terms of operations, adding the negative load supplied by wind capacity, whenever it arrives and in whatever amount, to the given total, jurisdictional load yields a *residual load* to which the usual dispatch and control of conventional power plants is then applied. Using this method necessarily implies wind capacity *does not* provide a substitute for load-following technologies. Likewise, it implies wind capacity *does not* offer a substitute for peaking capacity. This approach, because the output from wind capacity, whatever it may be, is effectively first in the dispatch queue, may leave the impression that wind capacity should be treated as a substitute for baseload capacity. However, that would be hardly a reasonable impression given the intermittency of wind production and its relatively low capacity factor, two characteristics that are not consistent with baseload-types of generating capacity.

[41] See *PJM 2004 State of the Market Report*, Market Monitoring Unit, March 8, 2005, page 82. In this report, PJM sets the first year, allowable fixed cost of a combustion turbine at $61,726. That figure is inclusive of all fixed costs whose recovery is allowed by COS regulation. The figure used in this study is based on the PJM's 2004 figure adjusted for one year of inflation, putting it on a 2005 dollar basis. While we submit that wind capacity probably does not provide a close substitute for peaking capacity (i.e., use of combustion turbines), installed wind tends to have an (*ex post*) annual capacity factor that is at least closer to that of peaking capacity than the other types of generating capacity. Arguably, it *may* be that similarity of capacity factors that provides some basis for PJM using the cost of peaking capacity/combustion turbines to assign a dollar value to the capacity avoided by investing in wind. However, based on a comparison of current installation costs for both peaking and baseload facilities, it is our opinion that the $65,000/MW/year amount may, in fact, be more reflective of the latter and, therefore, *may* be rather generous in favor of wind.

The following numerical example, which may be illustrative, shows how the SPP capacity rating method and the estimated dollar savings per MW come together to establish the value of conventional capacity that is avoided as a consequence of the utility installing wind capacity. With an approved investment in a 150-MW (nameplate) wind capacity going on-line at the end of 2005, the utility's avoided capacity expense would be (150 MW × 0.07 × $65,000 =) $682,500 starting in the first year.[42]

The CAP variable is designed to measure the sixth and final item on the list of avoided costs in Section 3.11: avoided capacity (or capital equipment) expense attributable to installation of wind capacity. The CAP variable measures the annual avoided capacity savings attributable to installing wind and would apply over the expected useful life of the wind assets. The CAP savings are available only when the utility chooses to build its own wind capacity. Equivalently, the CAP savings are not realized by utilities that obtain wind energy from developers. Since utilities rely on effectively the same "capacity markets," for both the wind and conventional generation assets, we assume the CAP savings do not vary by utility-type. Since the utility's CAP savings would depend on when it actually installs wind capacity, the CAP variable is time dependent.

Based on the referenced PJM Report and SPP Paper, we measure the total, annual capacity savings due to the Challenge by the following:

$$CAP(t) = iwc(t) \times 0.07 \times [\$65{,}000/MW],$$

where iwc(t) is defined as before (see Section 3.13) and the dollar savings per MW is set consistent with the PJM study. We measure the dollar savings per MW in 2005 constant dollars.

[42] We assume throughout that peak-load growth through 2015 would accommodate the new, ratable wind capacity that results as a consequence of meeting the Challenge. That is, we assume investment in wind capacity would not result in the jurisdictional utilities holding excessive amounts of rated capacity.

(i) A Look Ahead: Forecasting the CAP Variable

We assume the future cost of installing conventional generating capacity will change primarily due to inflationary forces.[43] In fact, given the relative importance of electricity as a commodity in the economy, it is possible that changes in the cost of installed capacity may have a significant influence on the general rate of inflation in the economy. (That is, in terms of simply measuring inflation, changes in capacity installation costs may be just as much a source of inflation as its result.) Because we assume changes in future installation costs are likely to be consistent with general inflationary changes (i.e., equal to, on average), and because our actual estimate of the capacity savings per MW ($65,000) is already measured in 2005 constant dollars, our "forecast" of future capacity savings per MW (i.e., the unit CAP savings) remains constant at the current, actual estimated level. Therefore, the only information needed to "forecast" the CAP variable is the (assumed) capacity installation schedule, iwc(t). Again, that schedule is shown and further discussed in Section 4.41.

3.14 Summary of Internal Avoided Cost Variables: FOM, APC, and CAP

In this section of the report, we started with a list of six different expense items that the regulated utility could avoid or save by acquiring wind energy or installing wind capacity. We define three different input variables, the FOM, APC, and CAP, designed to collectively capture by precise measurement those six avoided cost items. The FOM variable captures the total fuel (including emission allowance expenses), generation O&M, *existing* pollution

[43] If in the near future utilities decide to make a significant investment in nuclear facilities, this assumption would not hold up. Again, the challenge is to determine what type of conventional capacity wind capacity is likely to substitute for and, then, the rate at which the cost of that capacity might inflate. To the extent wind capacity is seen as a substitute for combustion turbines, being a relatively mature and conventional technology, our assumption that the avoided capacity cost (per MW) will inflate consistent with the national average rate may be reasonable.

control equipment O&M, and purchase power expense the utility-type avoids through its take of wind energy during the year. The APC captures the total O&M expense associated with the (currently projected) operation of *new* pollution control equipment that can be avoided annually by the utility's acquisition of wind energy. For utilities that choose to install and ratebase wind capacity for their own use, the CAP variable measures the annual capacity cost savings attributable to that choice. All three variables, FOM, APC, and CAP capture utility savings measured in 2005 constant dollars.[44] With agency regulation, those savings are eventually realized by the utilities' retail customers.[45]

3.15 Government Sources of Internal Cost Savings

In various forms, the government offers financial assistance to investors in wind capacity. The most widely known form of assistance is the federal government's production tax credit ("PTC"). Other forms include the federal accelerated depreciation allowance, Kansas' waiver of property taxes on new generation investment generally, and the *extra* rate of return on equity ("ROE," hereafter referred to as the ROE adder) that may be allowed by the Commission on utility investments in renewable energy.[46]

For reasons presently discussed, only the PTC is likely to provide a *significant* source of savings to utilities investing in wind capacity and, therefore, at this point we focus mainly on the PTC. That is not to suggest that we ignore the other incentives. For instance, for both

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[44] In terms of employment implications, and simply as a point of reference, a real reduction in the utilities' total expenditures (i.e., positive net savings) generally means an employment reduction in the utility sector, and possibly related sectors, such as the fuel and fuel delivery sectors. To the extent acquisition of wind energy reduces the utilities' expenditures that puts downward pressure on utility employment. Overall, the utility's realization of avoided costs dampens utility employment.

[45] With regulatory lag, some of the savings would effectively be allocated to utility shareholders. However, the ultimate allocation of wind-related savings among different members of the public is not of significance given the objective here, which is to simply quantify the *total* savings realized through the Challenge.

[46] For example, see K.S.A. 66-117e.

the utilities and wind developers, we evaluate and include both the tax and expenditure implications of the federal government's accelerated depreciation as part of our analysis of the total depreciation expense associated with their respective wind investments. Yet, because of the regulatory treatment of accelerated depreciation, this allowance is unlikely to provide the regulated utility with any cost savings *over the life of the asset*.[47] Rather it alters the *timing* of the utility's tax burden (over the life of the asset) and, therefore, is likely to provide the utility with only a time value of money savings.[48] Since the state's waiver of property taxes applies to all new investments in generation, it does not provide either the utility or developer investing in wind capacity with any savings *relative* to investing in conventional generation.[49] Therefore, it does not constitute a source of savings attributable to selecting a wind option and, consequently, is not included as part of the Challenge's net benefit analysis. Because achieving the "ROE adder" is conditional upon (1) the utility requesting the adder and (2) the Commission granting that request, we do not mechanically include the effects of this incentive in our analysis. We do evaluate, but only as a special case, the economic implications of utility shareholders being allowed to recover the existing ROE adder from ratepayers as a consequence of utility management choosing to invest in wind capacity.[50] By way of preview, recovery of the ROE adder simply makes renewable energy more expensive for ratepayers, while probably also failing to provide shareholders with an incentive sufficient to prompt significant investment in renewables. ROE adders are not without cost and seem likely to have a limited influence on decision-making.

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[47] However, for unregulated wind investors (i.e., developers) accelerated depreciation is likely to be a more significant incentive, enabling them to avoid some tax burden over the life of wind capacity investment. For a discussion of this, see Appendix G.
[48] This is also discussed in greater detail in Appendix G.
[49] In terms of the value of the utility selecting a wind option relative to choosing to do business as usual, the state's property tax waiver provides no additional benefit to the utility for selecting wind.
[50] The numerical results for this special case are presented in Chapter 5 of this Report.

A. Defining the PTC Variable: The Tax Savings from the Allowed Production Tax Credit

To encourage the production of electricity from renewable resources and, hence, the investment in those resources, a production tax credit was created by The National Energy Policy Act of 1992, Section 1914 (“NEPA 92”). NEPA 92 grants the producers of electricity from either wind or closed-biomass systems a *tax credit per MWh* produced (hereafter, unit PTC), applied against their federal income tax liability. For qualified investments, the allowable unit PTC applies to all production during the first ten years of the investment’s life. The initial unit PTC was set at $15/MWh and, except for a couple of instances, has been annually adjusted for inflation using the implicit GDP Deflator.[51] Qualifying time deadlines were also specified in NEPA 92. The original deadline was extended by two years; in the following years the deadline was either extended again or allowed to (briefly) lapse. The last extension of the deadline – now at January 1, 2008 – came as part of The Energy Policy Act of 2005. Deadline extensions have been accompanied by extensions of the provision to adjust the unit PTC for inflation.

We assume the PTC provisions extend uniformly among any investors responding to the Challenge, whether they are utilities or developers. Utilities that decide to enter wind PPAs do not qualify for the wind PTC; however, the developers on the other side of those agreements are assumed to qualify. Moreover, we assume all entities receiving the PTC are able to take full advantage of it; that is, we assume sufficiently large “tax appetites” among

[51] The GDP Deflator is an inflation index used to convert nominal measures of gross domestic production (GDP) into measures of real GDP. The GDP Deflator is like the widely known CPI, except that the former is based on a market basket consisting of all final goods and services produced by the economy, not just those in the representative consumer’s market basket. Because it is broadly based, the GDP Deflator is generally the better measure of overall inflation in the economy.

all investors responding to the Challenge. In this study we treat the PTC as a post- or after-tax incentive (or savings) and, therefore, it is not grossed up for income tax purposes.

Accordingly, we define the PTC variable so that it measures, consistent with the existing regulatory and statutory provisions, the total annual dollar post-tax savings received by the utility for the wind energy produced by its investments in wind capacity. Those tax savings are denoted by the following equation:

$$PTC(t, f) = \text{unit PTC} \times qw_{ptc}(t, f),$$

where $qw_{ptc}(t, f)$ is the amount of energy production from wind investment projects that still qualify for the incentive.[52] The unit PTC, when measured in nominal dollars, will change over time. In fact, it changes consistent with the GDP Deflator index. We assume this "inflation indexing" provision will not change going forward in time and, therefore, assume the nominal unit PTC changes *only* as a result of general inflationary forces (as measured through the GDP Deflator).

We measure the unit PTC, as with all the unit prices used in this study, in 2005 constant dollar prices. Since we effectively use the GDP Deflator to convert nominal prices to real prices (measured in 2005 dollars), provided we establish the unit PTC based on 2005 dollars, then the unit PTC will not change over time – as shown by the notation above. More simply, we assume the inflation-adjusted unit PTC is constant over time, presuming its initial value is properly selected. At the time we began this study, the allowed unit PTC was about \$19.00/MWh, extending to the first 10 years of new investments that become operational after December 2004 and prior to December 31, 2006. Clearly, when the actual unit PTC was

[52] Since the PTC does not necessarily apply to all of the installed wind capacity, but only the capacity that is 10 years or less of age, the $qw(t, f)$ cannot be applied. Rather we apply the $qw_{ptc}(t, f)$ variable which measures the total amount of installed wind capacity that qualifies for the PTC. The $qw_{ptc}(t, f)$ is an appropriately modified version of the $qw(t, f)$ variable.

given in or actually measured by 2005 dollars, it equaled \$19.00/MWh. Therefore, our measure of the PTC variable is simply:

$$PTC(t, f) = \$19.00 \times qw_{ptc}(t, f).$$

(i) An Aside: The net cost of the PTC to Kansas

Of course, the provision of government incentives is not without a cost. By granting a PTC, a larger federal budget deficit/debt could result, government spending in other areas could be reduced, or federal taxes could be increased. Undoubtedly, some combination of those three will occur, all else equal. We recognize the PTC has cost implications for Kansans generally, either as federal taxpayers or recipients of federal benefits or both. However, in this study we make no attempt to establish the net benefit of the PTC to Kansas. All of the PTC revenue received as a result of meeting the Challenge is treated as net savings (more accurately, a net benefit) for the state. Because Kansas is a relatively good location for wind investment compared to many other states, it is almost certain that the actual net benefit of the PTC to Kansas wind consumers is positive.

(ii) A Look Ahead: Forecasting the PTC Variable

Given the assumptions we make with regard to the unit PTC, forecasting the PTC input variable is very straightforward. As shown by the equation above, to forecast the PTC variable requires the selection of a forecast scenario, f, which is then used to develop a forecast for the $qw_{ptc}(t, f)$ variable. Again, we use a Monte Carlo process to derive or otherwise select the forecast scenarios.

3.16 Summary of Internal Avoided Cost Variables: FOM, APC, CAP, and PTC

Having defined the PTC variable simply as another avoided cost variable, we complete our discussion of the avoided cost variables used to measure the savings wind decisions can deliver to utilities. Those variables are the FOM, APC, CAP, and PTC. The first three capture relative savings available to the utility when it chooses a wind option instead of conventional generation. The PTC captures the same, except it is also based on the taxing authority of the federal government. All four variables deliver savings that are *internal to the utilities accounts* and, therefore, are reflected in their allowed revenue requirements and, thus, jurisdictional rates. We now turn to a discussion and examination of the external cost savings attributable to relying on wind energy. These are not savings that would be realized by the utility, nor would they ever be reflected in utility rates. Nonetheless, they would be realized Kansans generally, possibly taking many different forms: from fewer health-related costs and risks, fewer premature deaths, fewer birth defeats, to the savings associated with a cleaner and, some may argue, a cooler environment.

3.17 Definitions of Avoided External Cost Variables

Almost by definition, external costs are difficult to measure, and so it is for the avoided external cost attributable to meeting the Challenge. Identifying and then somehow quantifying the external costs Kansans bear as a result of power plant emissions from plants located in Kansas is clearly beyond the scope of this study. We make no attempt to independently quantify the possible external costs associated with Kansas' conventional power plant emissions. Rather, and essentially for benchmarking purposes, we rely

exclusively upon a study of external costs associated with certain power plant emissions performed by the Environmental Protection Agency (EPA).

A. The EPA Study of the Clear Skies Act of 2003

As part of its evaluation of the proposed Clear Skies Act of 2003 ("Clear Skies"),[53] the EPA studied the health- and environment-related cost savings in Kansas if the Clear Skies initiative were implemented.[54] In brief, as proposed, Clear Skies provided for the implementation of new "cap and trade" programs for NO_X and mercury emissions and incentives to alter the existing cap and trade program for SO_2 emissions, all applicable to only power plant owners/operators. Based on its evaluation of those newly proposed programs and proposed changes in existing programs, the EPA forecast *reductions* in NO_X, mercury, and SO_2 emissions.[55] The EPA also forecast reductions in small particulate matter ($PM_{2.5}$) and ozone, both as a direct consequence of reducing emissions under the Clear Skies initiative. Using its forecast reductions in emissions, $PM_{2.5}$, and ozone, the EPA then developed forecasts of the resultant external cost savings. Those savings were categorized by the EPA as either health- or environment-related. For a more detailed discussion of the EPA's Clear Skies study, check the EPA's website and see Appendix E.

[53] A description of the Clear Skies Act of 2003 is available online (http://www.epa.gov/air/clearskies/CSA2003shortsummary2_27_03_final.pdf).
[54] The Kansas results are available online (http://www.epa.gov/air/clearskies/); click on "Where you live," to access a U.S. map, then click on Kansas.
[55] The EPA quantified the "Kansas source" reductions for each of these three pollutants under the proposed provisions of the Act.

B. EPA Study: Assessing the Health-related External Cost Savings

The EPA provides two (point) estimates of the potential health-related savings in Kansas under the Clear Skies proposal: $180 million and $940 million *annually* by 2020.[56] Both are based on projected *reductions* of NO_X emissions (and, subsequently, ozone) and $PM_{2.5}$ levels that the EPA ascribes strictly to the provisions in the Clear Skies initiative.[57] Both estimates include evaluations of the reduced health-related costs and the value of reduced morbidity rates.[58]

C. *The EPA Study: Assessing the Environmental-related External Cost Savings*

Regarding potential reductions in environmental-related externalities due to implementation of Clear Skies, the EPA offers a *very limited* examination, focusing on benefits rather than external cost reductions. For example, the EPA estimates that improvements in "visibility" would yield a benefit of $22 million a year by 2020. Other environmental benefits (evaluated, but not monetized by the EPA) include fewer deposits of sulfur, nitrogen, and mercury. Reduced levels of ozone would also reduce damage (also not monetized) to the environment and man-made structures. Thus, while the EPA's study of Clear Skies offers some evidence of environmental-related damages due to power plant emissions, the EPA's assessment of the potential environmental-related external cost savings due to the Clear Skies initiative appears to be largely qualitative in nature.

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[56] The EPA also examined the health-related savings in Kansas by 2010. Based on our understanding of the EPA study results, the "by 2010" external cost reductions per year are nearly identical to those expected "by 2020." Therefore, it is our position these EPA estimates are reasonable for the time horizon utilized in this study. It may be worth emphasizing that all of the EPA's estimated savings are on an annualized basis.

[57] All reductions are relative to the base year, 2000. The smaller dollar estimate is based on a lower estimate of "premature deaths" caused by power plant emissions.

[58] Reducing power plant emissions, by EPA's estimation, would reduce both health-related expenditures and premature deaths. Through a rather complex methodology, the EPA estimates the monetary loss associated with premature death. Related-related costs and the cost associated with premature death are the primary external cost components identified by the EPA's study of power plant emissions.

D. Using the EPA Study as a Basis to Derive an Estimate of External Costs

We use the numerical results of the EPA's Clear Skies study to develop an *estimate* of the external cost associated with the emissions resulting from one MWh of conventionally generated electricity. First, we describe the derivation of that estimate, followed with a discussion of its relative strengths and weaknesses.

(i) An Estimate of External Cost per MWh of Conventional Generation

If we assume that the total external cost of conventional generation borne by Kansans per year is $940 million (per the EPA study) and that in a normal year 47 million MWh of electricity is generated in Kansas via conventional means,[59] then in a normal year the total external cost per MWh of conventional generation is $20 (assuming a *linear relation* between the level of total annual external cost and total, annual energy production from conventional power plants). The estimate, due to its linear construct, effectively represents the *average* external cost per MWh generated among Kansas' conventional plants.[60] Since we assume a one-to-one substitution of wind energy for conventionally produced energy, our estimate of external cost per MWh of conventional generation is *equivalent* to our estimate of the external cost savings attributable to one MWh of wind energy.

(ii) Strengths of the External Cost/Savings Estimate

The primary strength of the external cost/savings estimate is that it is based, in large part, on Kansas-specific data, which constitute, so far as we are aware, the only estimate of

[59] In 2004 net generation in Kansas was close to 47 million MWh.
[60] The use of an average external cost per MWh of conventional generation is consistent with our use of a "blended" or averaged system lambda to evaluate avoided fuel expenses.

externalities based primarily on "Kansas source" emissions.[61] The estimate is also relatively current in time, being based on data, forecasts, and emissions standards in existence as of 2000. Moreover, the numerical data used to derive the estimate is provided through an independent government agency that, arguably, performed unbiased scientific analysis.

(iii) Weaknesses of External Cost/Savings Estimate

The EPA's evaluation of external costs is based strictly upon potential *changes* in emissions conditional on the Clear Skies initiative being implemented. It does not provide any evaluation of the *total* external cost of power plant emissions. Similarly, it does not evaluate external costs resulting from *all* emissions – only NO_X (and, subsequently), ozone, and $PM_{2.5}$. For instance, it does not evaluate external costs resulting from SO_2, mercury, or carbon emissions. The EPA cost estimates are based on emission standards existing as of 2000. If those standards alone were to change in the future, which seems likely, the EPA's estimates would need to be updated to reflect those changes.[62] The EPA provides only point estimates of savings under the Clear Skies initiative; it does not offer a range of possible savings or an indication of the likelihood of achieving those savings.[63] Obviously, power plant emissions are not bound by state boundaries. And while most of the EPA's external cost estimates for Kansas are, as we understand it, based on power plant emissions within the

[61] There are many available estimates of external costs resulting from power plant emissions. It is certainly possible that some may be reasonable for use in studies of Kansas emissions and the cost implications of those emissions. However, making that assessment is both difficult and beyond the scope of this study.

[62] It seems more likely that existing standards (as of 2000) will be made more stringent and that new standards will be imposed and enforced. (In fact, the anticipation of such changes is the basis for including the APC variable in the analysis.) The result of having more stringent standards would effectively internalize some of the external costs. Thus, updates reflecting implementation of more stringent standards would lead to smaller estimates of external cost/savings. (It is likely that any such reductions would be offset somewhat by increases in the utility's internal costs.) Of course the EPA' external cost estimates would need updating owing to changes in a host of variables besides "standards."

[63] The two health-related external cost savings figures of $180 million and $940 million can be loosely interpreted as a range of possible outcomes. However, as we understand it, that range would be explained mainly by variations in the likelihood of emissions resulting in premature death.

state, not all are based on emissions from Kansas plants.[64] Furthermore, the EPA's estimated annual savings of $940 million capture only health-related savings, which means the $20/MWh estimate does not embody any of the environmental-related external costs. Finally, the $20/MWh estimate is based on an assumed linear relation between external cost and MWh production. The EPA study offers no indication of what type of relationship actually exists between those two variables.

(iv) An Assessment of the $20/MWh External Cost/Savings Estimate

As indicated, there are reasons why setting the external cost/savings estimate at $20 makes sense, and there are reasons why it does not. This estimate, however, is likely to possess a relatively large margin of error.[65] Nonetheless, because it is based on Kansas-specific data and was obtained through a recent, scientific study performed by an independent government agency, we believe it represents at least a reasonable, *initial* estimate of the external cost associated with conventional generation. And as discussed below, even if it were feasible to derive highly accurate estimates, the need for a high level of accuracy is mitigated by a number of considerations, not the least of which is the extreme difficulty of measuring external costs to begin with.

[64] Some of the externalities are result of emissions from out of state generators. Nonetheless, our simple method of deriving the $20/MWh estimate effectively treats Kansas power plant emissions as the sole source of external costs borne by Kansans.

[65] For a number of reasons, establishing a margin of error for this estimate is not possible given the available data.

E. Defining the EXT Variable: The Measure of External Costs Savings due to Wind Energy Production

The EXT variable captures the total annual avoided external cost that results from the utility taking wind rather than conventional energy. We define the EXT variable as:

$$EXT(t, f) = \text{unit } EXT(t) \times qw(t, f),$$

where the unit EXT is defined as the average avoided external cost per MWh of wind energy[66] and qw(t, f) is defined as before. For simplicity, we assume the unit EXT is not a function of utility-type, but that, as shown by the notation, it could change over time due to a number of different factors.[67] Of course, whether wind energy comes to the utility through a PPA or its own investment in wind capacity, the unit EXT would be the same. It is also widely recognized that the unit EXT may depend on the type of regulatory mechanisms used to enforce emission standards.[68] However, for simplicity, we assume any such dependence is negligible. Finally, as a practical matter, total external cost savings may also depend on where Kansas-produced wind energy is ultimately consumed. For example, wind energy

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[66] This is equivalent to assuming that the external cost per MWh of conventional energy output, across all conventional power plants in Kansas, *averages* $20. Of course, the external cost of a baseload-coal-generated MWh differs from that of a MWh generated by a gas turbine. Nonetheless, since we treat wind energy production as negative load, which is likely to displace a broad mix of conventional plants and fuels, we consider the use of an averaged avoided external cost to be reasonable.

[67] It is likely the unit EXT would be higher for utilities that are relatively more dependent on coal. Distinguishing the unit EXT by utility-type is complex and, in our opinion, any *overall* gain in accuracy is likely to be small. Other considerations, which are discussed in the body of the text, suggest that obtaining highly accurate estimates of external costs may not be all that feasible – desirable as that may be.

[68] For example, "cap and trade" and "baseline and credit" represent two types of emission regulation mechanisms. Depending on the type of emission regulation mechanisms in place, greater reliance on wind energy may not result in lower overall emissions levels. For instance, a utility increasing its reliance on wind energy may need fewer SO_2 emission allowances, selling its "excess" allowances into the market, resulting in possibly greater SO_2 emissions by *other* utilities that purchase those allowances. It is a distinct possibility that emission constraints that were binding prior to reliance on wind energy *will remain binding* even with greater reliance on wind energy. In that situation, total overall emissions and, therefore, external costs stemming from emissions may go *unchanged*, but the internal cost of complying with environmental costs is likely to be lower for all utilities. The basic point is that wind energy may reduce a utility's demand for emission allowances, which would reduce its emissions expense. But in aggregate, wind energy production may result in a lower allowance price, but leave the total quantity of allowances in the (national) marketplace unchanged. In that case wind energy output would not result in lower levels of emissions from conventional generators, but may yet result in a lower cost of complying with emissions regulations. That the resultant level of external costs would also be reduced is not clear.

produced in Kansas but sold to, say, an Arkansas utility and ultimately consumed in Arkansas may alter the dispatch and, hence, the emissions of conventional plants in Arkansas, but not Kansas. In that case, emissions in Kansas – and the external costs Kansans bear as a result – may go unchanged even when the Challenge is met, while emissions in Arkansas are likely to decrease. However, under our assumed quantity substitution rule (each MWh of Kansas-produced wind energy substitutes for exactly one MWh of Kansas-produced conventional energy), each MWh of Kansas-produced wind energy would reduce external costs in Kansas in the amount of one unit EXT. Although it may go without saying, since the external cost savings due to the production of wind energy are *not* internal to the utility, it is worth noting that those savings may not only accrue to ratepayers. It is difficult to anticipate what segment of the Kansas public is the likely beneficiary of reduced external costs.[69] For that reason one may assume any external cost savings are allocated uniformly among all Kansans, whether they are ratepayers or not. While utility (i.e., internal cost) savings due to wind energy collectively go to Kansas ratepayers, the external cost savings would be shared among all Kansans, ratepayers and non-ratepayers alike.[70] Therefore, the EXT variable provides a measure of the annual external costs savings Kansans collectively realize as a consequence of the Challenge having been met.

(i) A Look Ahead: Forecasting the EXT Variable

Arguably, the crux of forecasting the EXT variable is the selection (or forecast) of the unit EXT estimate. There are various and assorted estimates of the external costs associated

[69] Arguably, it is those Kansans that are potential victims of the harmful effects of power plant emissions that are the likely beneficiaries of the *reduced* emissions. Predicting who those beneficiaries may be is both unnecessary and beyond the scope of this study.
[70] As another point of reference, external cost savings are likely to reduce employment in the health-care sector of the state's economy.

with different conventional power plant emissions. But for reasons discussed above, it is our opinion that our EPA-based estimate of $20/MWh of the unit EXT is a reasonable starting point, especially in terms of setting a benchmark or "plug" estimate. Moreover, we take that estimate as being measured in 2005 constant dollars.[71]

Just as difficult as measuring external costs at any one moment in time is forecasting how (actual) external costs are likely to change over time, particularly on a MWh basis. Because our unit EXT estimate is based more on the effects of the more traditional pollutants, namely NO_X and $PM_{2.5}$, and because we expect the standards applied to those pollutants to be more stringent going forward in time, we have reason to believe our unit estimate would need to be reduced if applied to future time periods. In other words, the unit EXT could change at a rate less than the rate of inflation if emission standards are toughened. On the other hand, future health-care costs seem likely to increase well beyond the average rate of inflation. In that case, it is likely the unit EXT could change at a rate in excess of the rate of inflation. The same is likely to hold if carbon regulations are implemented. Thus, there are reasons to believe the unit EXT could either increase or decrease at a rate different from the economy-wide rate of inflation. For that reason and also for simplicity, and, again, because the need for precisely estimating the unit EXT is relatively limited, we assume the unit EXT increases at a rate that roughly matches the average annual rate of inflation (per the GDP Deflator index).

[71] While the EPA estimates are measured in 1999 dollars and the $940 million/year estimate – on which our $20/MWh estimate is based – is for the year 2020 (at which point the Clear Sky's provisions would be fully in place), we make no effort to modify our selected unit EXT estimate to reflect those facts. While making those modifications would be logical in terms of the analysis, it is not clear that our unit EXT estimate would *actually* be more precise as a result. Our only claims are that our estimate is based on a recently performed, Kansas-based study by an independent government agency and, therefore, is reasonable. Alternatively, those claims provide some basis for believing our unit EXT estimate is within the ballpark of actual external costs per MWh, per Kansas, during the time frame that includes 2005.

Thus, for those case studies in which the potential external cost savings from the Challenge are included in the analysis, we measure the EXT variable as follows:

$$EXT(t, f) = \$20.00 \times qw(t, f).$$

That specification clearly shows the unit EXT, as measured in 2005 constant dollars (i.e., on an inflation-adjusted basis), is effectively constant over future time periods, and forecasting the EXT input variable boils down to simply forecasting the qw(t, f) variable. That forecast simply requires the derivation of a forecast scenario, which we accomplish using a Monte Carlo process.

(ii) Deriving the Threshold or Pivotal Unit EXT Estimates

The need for a highly accurate estimate of the external cost may also be largely mitigated through the use of a type of sensitivity analysis. That analysis can be used to answer what is probably a more critical question: estimating what the external cost/savings would need to be for the Challenge to just be cost effective – that is, establishing the threshold or "critical" estimate of external cost/savings. The threshold estimate shows how large the external cost/savings per MWh would need to be in order for the Challenge to be cost effective. The derivation of these threshold estimates (of the unit EXT) further highlights the fact that the $20/MWh amount can be interpreted as a "plug" estimate of the unit external cost/savings per MWh. While we consider our selection of the $20/MWh estimate of the unit EXT to be reasonable, to some extent, it is selected strictly as a type of placeholder.

3.18 Summary of Avoided Cost Variables

In this section (3.10) we describe eight different costs or expenses the utility may avoid by its selection of a wind option. Six of those avoided expenses—fuel, generation equipment, O&M, existing pollution-control equipment O&M, purchase power, new (and effectively approved) pollution-control O&M, and capacity—are due to relative savings the utility can capture strictly by choosing a wind option instead of a conventional generation option. All of those savings accrue to the utility and, except for the capacity savings, go to utility regardless of which wind option they choose. The seventh avoided expense—federal income taxes—accrues to the utility only if it decides to invest in wind capacity (and so long as the federal government subsidizes those investments). Because all seven of these avoided expenses are internal to the utility's own accounts, the resultant savings are (ultimately) reflected in its allowed revenue requirement and, thus, rates. Consequently, those savings are realized by Kansas ratepayers. The eighth and last avoided expense, the avoided externalities, which is external to the utility, yields savings to all Kansans generally, whether or not they are utility customers.

The five different variables designed to precisely measure those eight different avoided expenses are the FOM, APC, CAP, PTC, and EXT. The eight avoided expenses are listed below, along with the avoided cost variables defined and designed to capture those expenses:

1) avoided fuel expense: contained in FOM variable,
2) avoided operations and maintenance (O&M) expense associated with conventional generation assets: contained in FOM variable,

3) avoided O&M expense associated with pollution control equipment and/or other expenses needed to comply with *existing* environmental regulations: contained in FOM variable, [72]

4) avoided purchase power expense: contained in FOM variable,

5) avoided O&M expense associated with pollution control equipment needed to comply with currently expected *changes* (as of 2005) in existing environmental regulations: APC variable,[73]

6) avoided capacity (or capital equipment) expense: CAP variable,

7) avoided federal income tax liability: PTC variable, and

8) avoided external costs: EXT variable.

By summing those five variables, it is easy to determine the total, annual *gross benefit* from meeting the Challenge. For example, for those case studies that involve the utility-types only investing in wind and include consideration of external cost savings, the annual gross benefit from meeting the Challenge is given by *aggregating* all eight variables. Different case studies call for different aggregations.

3.20 Total Cost of Meeting the Wind Challenge: The Direct Cost Variables

To establish the *net benefit* of meeting the Challenge, it is necessary to determine the direct cost of meeting the Challenge. As discussed above, Equation (1), the difference between the gross benefit and total cost of meeting the Challenge, yields the net benefit.

[72] "Other expenses" could include, for example, emission allowances. Hereafter, we refer to this avoided expense as the "incremental existing environmental compliance" expense.
[73] Since our analysis is forward looking and because certain *changes* in environmental regulations are currently expected among the utilities, this variable captures savings due strictly to the currently expected *changes* in environmental regulations having taken place.

The utility's cost of wind energy depends on whether it directly invests in wind capacity or simply purchases wind energy through PPAs. If the utility builds and operates the wind facility, it will incur depreciation, finance and operating costs,[74] as well as associated taxes. Building also brings with it lease or rent or royalty payments, and other payments, such as payments in lieu of taxes that are generally made to local government entities. Lastly, by building, the utility would also incur wind integration costs.[75] On the other hand, if the utility buys wind energy from a wind developer through the terms of a PPA, then the utility pays the contract price for the energy that is delivered under the contract.[76] In addition, depending on control area arrangements and contract provisions, the buying utility may also incur integration costs. Finally, whether the utility builds or buys, it may be responsible for making (and, thus, incurring expenses associated with) transmission capacity upgrades. However, because of the uncertainty of where on the grid future wind facilities might interconnect, the size of those facilities, when interconnection may be requested, and the complexity of evaluating the incremental need for transmission capacity upgrades generally, we set aside for now all transmission-related issues pertaining to the Challenge.[77]

In this study we evaluate the total cost of meeting the Challenge under both wind options. More precisely, we evaluate the total cost of meeting the Challenge when the installation of wind capacity is strictly through utility investment; and we also evaluate the total cost of meeting the Challenge when the installation of wind capacity is strictly by wind

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[74] Operations and maintenance of wind facilities can be provided to the utility under contract with an independent operating company.

[75] The integration costs associated with including wind as part of a utility's generation portfolio are discussed below.

[76] We assume the buying utility takes all of the quantity or production risk associated with the PPC. That is, we assume the seller, which we refer to as a "wind developer," does not provide guarantees or contingencies regarding the amount of energy ultimately sold under the contract; therefore, the commercial understanding is that wind contracts are for "intermittent energy," all of which the utility takes as delivered.

[77] Our primary discussion of transmission issues related to the Challenge is confined to Section 4.30 of this report.

developers who then sell their energy product to utilities. Admittedly, utilities may choose to both invest in wind capacity and purchase wind energy. However, as previously discussed, our approach serves to effectively set the cost boundaries on any combination of the two wind options selected by the utility. Moreover, this approach establishes which of the two wind options is *likely* to be less costly.

It is important to note, all expenses associated with meeting the Challenge are expenses taken *relative* to the utilities following the "business as usual" path, along which no wind options would be selected. In that sense, the wind expenses represent extra expenses, no different than the wind benefits represent extra savings for the utility. The key is that both the savings and costs strictly attributable to the Challenge are measured against the same baseline or reference, and that is the total cost of jurisdictional utilities meeting their retail load obligations along the *status quo,* or no-wind path.

3.21 The Utility's Two Wind Supply Options

If the utility opts to invest in wind capacity, consistent with being subject to COS regulation, the utility will recover the prudently incurred financial and operating costs associated with that investment through its revenue requirement and, thus, through its allowed rates. Alternatively, if the utility selects to acquire wind energy through a PPA with a wind developer, provided the contract is found prudent, the utility will be allowed to recover the costs associated with that contract through allowed rates. For both options, we use basic COS standards and methods to establish the allowable costs. However, in order to determine what it costs utilities to use wind energy contracts, it is first necessary to estimate the private developer's contract (or offer) price of wind energy. There are at least a couple of different

ways to arrive at that price estimate. For instance, one method would be to survey wind developers, soliciting a (random) *sample* of offer prices and use the sample average as an estimate of the representative contract price. Another method would be to analytically derive the developers' *required sale price* as a function of their expected financial and operating costs. In this study we rely primarily on the latter and, in Appendix G, provide a detailed discussion of the method we use to derivate the developers' required sale price.[78] However, we would note that over the course of this study, from time-to-time, we happened to have access to information (some on a confidential basis, some not) on developers' actual offer prices. The wind energy prices we analytically derive are certainly comparable with the wind energy prices we directly observed through our limited "survey" of offer prices; thus, it is our opinion the two methods we list for estimating wind energy offer prices would have (as of mid-2006 through mid-2007) yielded very similar numerical results.

We start with our assessment of what it is *likely* to cost utilities to meet the Challenge by only investing in wind capacity. We then estimate what it is likely to cost utilities to meet the Challenge by only purchasing wind from developers. Again, the latter depends on our derivation of forecasts of the representative, developer's offer prices, which is described in Appendix G.

3.22 Total Cost of the Challenge with Utilities Building and Owning Wind Capacity

We include the following expense items as part of the jurisdictional utility's cost of investing in and operating wind capacity:

1) land lease or rental expense,

[78] The method used to derive the private developer's sale price is consistent with the requirements of profit maximization in a competitive market. We assume that wind developers must compete as a basis for being awarded contracts with jurisdictional utilities.

2) payments to local governments in lieu of property tax,
3) wind integration cost,
4) wind equipment O&M expense,
5) allowed depreciation expense, and
6) allowed return on ratebase (grossed up for taxes).

Throughout we apply COS principles and standards for the purpose of determining the allowed recovery of these expenses—thereby establishing how each is likely to affect the utility's revenue requirement. Typically, at any one moment in time, the individual jurisdictional utilities have different capital structures and credit ratings. Those differences would affect allowed rates of return and, hence, their relative costs of investing in wind capacity. However, over the *long term* it is our expectation that the capital structures and credit ratings of the jurisdictional utilities would be *roughly equivalent*. Thus, we assume all utilities operate in the same financial markets and would be treated uniformly in terms of the allowed capital structure. Further, we assume the utilities would all have the same access to the relevant wind-equipment markets and the venders that specialize in operating and maintaining that equipment once it has been installed. With these assumptions, we expect the costs of building, owning, and operating wind facilities will not differ *significantly* by utility-type.

The following sections describe the variables used to measure the various expenses associated with utilities installing their own wind capacity.

A. Defining the LLE Variable: The Land Lease Expense

In order to secure access to land, utilities negotiate lease arrangements or contracts that cover the use of land tracts where wind turbines are installed. While there are a number of different ways to structure lease rates, using dollars/MW/year is not uncommon and consistent with the lease rate structure used in the National Renewable Energy Lab's ("NREL") JEDI model.[79]

Accordingly, we define the total, annual land lease (or rental) expense associated with meeting the Challenge as:

$$\text{LLE(t)} = \text{unit lease rate(t)} \times \text{iwc(t)},$$

where the "unit lease rate" is defined as the dollar lease expense per year per MW of installed capacity and the iwc(t) variable is defined as previously discussed (in Section 3.13). As shown by the notation, we assume the unit lease rate may change with time. Arguably, it could also vary by the utility. However, since wind facilities in Kansas, installed by either utilities or developers, are likely to be located in rural settings where land use is predominantly agricultural, we assume the land-use opportunity cost of wind development is relatively uniform. Similarly, we assume that Kansas possesses a large supply of reasonable building sites for wind facilities. For those reasons, it follows that the unit lease rate are unlikely to vary significantly by utility-type.

(*i) A Look Ahead: Forecasting the LLE Variable*

As indicated by the notation (t), we recognize the unit lease rate may change over time. However, given the wide availability of relatively favorable wind sites, we assume land

[79] Goldberg, M., K. Sinclair, and M. Milligan, *Job and Economic Development Impact (JEDI) Model: A User-Friendly Tool to Calculate Economic Impacts from Wind Projects*, National Renewable Energy Lab, U.S. Department of Energy, Golden, CO, March 30, 2004.

lease rates in Kansas are *likely* to be relatively stable over time and change primarily due to general inflationary forces, as opposed to structural changes.

Based on Kansas-specific information and data, as well as information provided by NREL, it is our understanding that, during the 2004 – 2006 time frame, land lease rates were in the range of $4,000/MW/year. Since that dollar amount is effectively measured in 2005 dollars, and because we assume lease rates will change only with general inflation, we set the (average) unit lease rate for each year going forward at $4,000/MW/year in 2005 constant dollars. With a constant, inflation-adjusted unit lease rate in place, to "forecast" the LLE variable requires only the specification of the presumed wind capacity installation schedule, iwc(t).

B. Defining the PIL Variable: The Payment to Local Governments

The state of Kansas has a property tax exemption on property related to or supporting renewable energy generation.[80] Nonetheless, for various reasons, local communities have generally sought and utilities have agreed to pay some "compensation" or payment in lieu of the property tax payments. These payments are usually made to county governments and local school districts. Like the land lease payment, this payment is typically on a per MW per year basis.

We specify the utility's payment in lieu of taxes ("PILOT") as:

$$\text{PIL}(t) = \text{unit payment rate}(t) \times \text{iwc}(t),$$

where the unit payment rate is the dollar payment per MW per year and the iwc(t) variable is defined as before. Thus, we define the PIL(t) variable as the annual PILOT expense

[80]This is provided for under Kansas statute, K.S.A. 79-201.

associated with the utility's net, allowed investment in wind capacity. The notation shows the unit payment rate may change over time.

(i) A Look Ahead: Forecasting the PIL Variable

Like unit land lease rates, given the wide availability of relatively favorable wind sites, we assume payment rates to local communities in Kansas are *likely* to be relatively stable over time and change primarily due to general inflationary forces, as opposed to structural changes.

Based on Kansas-specific information and data, it is our understanding that, during the 2004 – 2006 time frame, the unit PILOT payments were in the range of $3,000/MW/year. Because that dollar amount is effectively measured in 2005 dollars, and because we assume payment rates will change only with general inflation, we set the (average) unit payment rate for each year going forward at $3,000/MW/year (in 2005 constant dollars). With a constant, inflation-adjusted unit payment rate in place, to "forecast" the PIL variable requires only the specification of the assumed wind capacity installation schedule, iwc(t).

C. Defining the INT Variable: The Cost of Integrating Wind Investments

Utilities are required to operate their control areas so that all applicable system reliability standards are satisfied. Adding new generation assets to generation portfolios or new contracts to contract portfolios is likely to affect the costs of maintaining compliance with reliability standards (hereafter, control costs). Given the intermittent nature of wind-energy production and given that it is neither dispatchable or controllable, when wind-based

resources are added to a utility's portfolios, its control costs will usually increase.[81] Moreover, in the case of adding wind-based resources, the increases tend to be larger compared to comparably sized additions of conventional assets or contracts. This *relative* increase in control costs is referred to here and elsewhere as the wind "integration cost."

Our assessment of integration cost is based solely on a study and report issued by Xcel Energy, Inc. and the Minnesota Department of Commerce and prepared by EnerNex Corporation and Wind Logistics, Inc. (hereafter, MN study).[82] According to the MN study, accommodation of wind investments, either by the utility or a wind developer, is likely to affect three of the utility's operating functions: (1) regulation of output to maintain system voltage and frequency, (2) control of output for purposes of load following, and (3) scheduling of generation units for (day ahead) commitment purposes. As indicated before, relative to adding new conventional assets, adding new wind resources is likely to cause the utility to incur a *higher* cost to perform each of these operating functions. Primary reasons for the higher cost include: relatively higher output variability for wind units (due to minute-to-minute variations in wind velocity) and relatively greater forecast error in terms of establishing the (day ahead) availability of the generating unit. Using the operating functions affected by wind as a basis, the integration cost of wind can be described as consisting of three components: regulation cost, load-following cost, and scheduling cost.

[81] While it may be subject to negotiations, our understanding of standard commercial practice (based on conversations with utility managements) is that utilities that enter wind contracts are responsible for any increase in their control costs.

[82] Our assessment of wind integration costs does not include any "dispatch inefficiencies" resulting from the inclusion of wind resources in the utility's generation asset portfolio. Dispatch inefficiencies include the cost of reduced heat rate performance at conventional power plants and higher plant maintenance costs due to changes in start frequencies. These costs can be substantial and, depending on the utility, can be far in excess of the estimated wind integration cost used in this study. See the Direct and Rebuttal Testimony in Docket No. 08-WSEE-309-PRE for a more detailed discussion of the dispatch inefficiency costs associated with integrating wind with conventional resources.

The MN study found that the regulation cost of wind energy was about \$0.23 per MWh. It also found the regulation cost is almost certainly borne on a unit of output (i.e., MWh) basis since the regulation function has to be performed over a time frame that varies in length from a few seconds to a few minutes. Consequently, that cost of \$0.23 per MWh (of wind energy) should be interpreted as a stable, ongoing cost that is not subject to significant variation over time.

The MN study and a similar New York study[83] found the load-following cost to be *negligible*. For this study we assume the load-following cost of integrating wind energy is zero. What is significant about these MN and New York study results is that they show inclusion of wind *does not reduce* the utility's load-following costs. This necessarily implies wind energy does not provide a substitute for load-following technologies and fuels.

The MN study found the scheduling cost to be about \$4.37 per MWh of wind energy. That would be an expense incurred on a daily basis and, therefore, it should be interpreted as stable over the course of a year.

Based on the MN study and other background information, we calculate the utility's wind integration cost as:

$$\text{INT} = \text{unit INT} \times \text{qw},$$

where unit INT is the summation of the regulation, load-following, and scheduling costs that result from integration of wind energy, measured on an average MWh basis, and qw is defined as before. To be clear, whether the utility produces its own wind energy or take it from developers, we expect the utility to bear the same wind integration cost per MWh of

[83] GE Energy, Energy Consulting, *The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations, Report on Phase 2: System Performance Evaluation.* This study was prepared for the New York State Energy Research and Development Authority, Albany NY, March 4, 2005.

wind production.[84] Thus, the unit INT applies to all wind energy acquired or taken by the utility.

We define the INT variable as the utility's total, average annual wind-integration cost. While it is likely to vary by utility, at this time we are unable to make that assessment and, consequently, assume it to be uniform across utility-types. We assume the unit INT could possibly change over time. With those assumptions, the calculation of the INT variable is denoted by:

$$\text{INT}(t, f) = \text{unit INT}(t) \times qw(t, f).$$

(i) A Look Ahead: Forecasting the INT Variable

As the notation shows, we recognize the wind integration may change over time. It is worth noting that integration cost is largely an operations-based cost and, therefore, will be specific to the utility in question—the point being that integration costs are unlikely to be readily transparent. Given the difficulty in assessing/measuring the unit INT cost, and because it is a relatively small cost item, we assume it is relatively stable over time and changes only due to general inflationary forces.

Using the MN study as basis, we set the unit INT at $4.50/MWh. That amount is simply the summation of the MWh-basis integration costs evaluated in the MN study. Consistent with all other unit price estimates used in this study, we measure the unit INT in 2005 constant dollars.[85] In summary, having set the unit INT in accordance with the numerical results of the MN study and having assumed that the unit INT is only likely to

[84] This is the one cost variable the utility faces regardless of which wind option it selects.
[85] Mainly to simplify the discussion somewhat, we do not adjust the MN study numerical estimates, which we believe are offered in 2002-2003 dollar terms, for inflation. Thus, putting the estimated unit INT at $4.50, in 2005 constant dollars, results in slightly underestimated forecasts of the utility's annual integration cost.

change due to general inflation, forecasting the INT variable requires the selection of forecast scenarios, f, which we accomplish through the Monte Carlo process, which then enables forecasting qw(t, f).

D. Defining the WOM Variable: The Wind Equipment O&M Expense

Utilities that directly invest in wind capacity, becoming the owner/operator of that capacity as a result, will incur O&M expenses to maintain the productivity of their wind assets (perhaps especially during the first ten years of an asset's productive life, owing to the availability of the PTC over that period).[86] Taking a broad perspective, we view the necessary O&M expenses on wind equipment to include the cost of warranties, insurance, service contracts, employee training, equipment monitoring, spare parts and equipment in inventory, preventative maintenance, and repair and replacement, and the opportunity cost of being down due to equipment failure. The O&M expense is frequently categorized as either variable with output levels or fixed. However, because the more significant O&M expenses per wind equipment are dependent on the use of the equipment, because warranties, service contracts, and insurance (i.e., the typical fixed O&M components) are less significant and may apply to limited periods of time, because our analysis of the Challenge covers several decades (which implies a long-run perspective where all O&M expenses will become variable at some point in time), and because we measure the annual O&M expense (which implies averaging all O&M expenses over the year), we categorize the wind O&M expense as variable only. Accordingly, we measure the wind O&M expense on a per MWh of wind production basis. We denote the average annual O&M expense per MWh of wind energy as

[86] The performance of O&M activities can be performed either by its own employees or through third party vendors under contract(s). Either way, we assume the utility's average, annual WOM expenses would be comparable in size over the term of the project.

the “unit WOM.” To calculate the total, annual O&M expense associated with the utility’s wind equipment we use the following equation:

$$\text{WOM} = \text{unit WOM} \times \text{qw},$$

where qw is defined as before. With that formulation, we define the WOM variable as the utility’s average annual O&M expense on wind equipment. Because we measure the unit WOM expense as a variable cost, the WOM variable is a direct function of the utility’s annual wind energy production.[87] Only those utilities that install their own wind capacity would incur the WOM expense. On the other hand, consistent with current commercial practices, developers who offer wind PPAs would be responsible for maintaining their wind equipment and, we assume, include their expectations of WOM expenses as part of their offer price determinations.[88]

There is significant uncertainty about future wind O&M costs. This is due, in part, to the near constant change (typically, improvements) in wind production technologies. As new wind technologies enter commercial operations, there is unlikely to be a long history of its operating performance. And because performance can vary widely dependent on local weather conditions, for certain types of equipment at certain locations, there may be no historical data available by which to evaluate potential future performance and related O&M expenses. As a general proposition, for much of the wind equipment in current operation, especially the newest, a long history of location-specific operating performance, including O&M expenses, simply does not exist at this time. Very little prior information is likely to

[87] It may be worth noting, the WOM variable is also an implicit function of the utility’s investment in wind capacity. While we model the wind O&M expense as a variable cost, and believe it is more representative of reality to model it that way, we are not averse to treating it as a fixed cost. Either way, the net benefit results are unlike to differ between the two approaches.
[88] Since utilities and developers would purchase their wind assets from the same set of equipment vendors over the same time period, we assume both are likely to face the same average annual wind O&M expense.

exist for installations of new equipment in new locations. Moreover, in the case of wind equipment, there can be considerable uncertainty about the number of hours of operation due simply to uncertainty about weather conditions.[89] And if there are failures in equipment, particularly with new equipment, there can be additional uncertainty about how long repairs will take. A lack of historical data, difficult-to-predict extreme weather conditions and, thus, total operations, and the need to learn about wind new equipment installed in new locations, give rise to the uncertainty and risk associated with the wind O&M. For these reasons, we treat the unit WOM as a random variable.

Since all utilities have the same access to and would purchase equipment in the same wind equipment markets, we assume the unit WOM for wind equipment does not vary by utility-type.[90] However, it is at least possible that the unit WOM could change over time: as the wind equipment ages, the unit WOM could increase. With that, we denote the WOM variable as follows:

$$\text{WOM}(t, f) = \text{unit WOM}(t, f) \times qw(t, f).$$

This shows the utility's (or developer's) total, average annual wind O&M expense depends on both the unit WOM and wind quantity forecasts, both of which depend on the particular forecast scenario, f, and the specific year in question, t.

(i) A Look Ahead: Forecasting the WOM Variable

As the definition for the WOM input variable shows, to forecast the WOM variable for a particular year, first requires forecasts of the unit WOM and average annual output of wind energy, qw(f, t). We model the unit WOM as a random variable and use a Monte Carlo

[89] For instance, it is usually easier to predict the number of hours in a year a baseload facility will operate in contrast to a wind facility.
[90] For the same reasons, we assume wind developers would face the same wind O&M expenses as the utilities.

process to derive those forecasts. In fact, we include the forecast unit WOM as one element of that set of forecast variables that comprise the forecast scenario. Consistent with conventional wisdom, we also assume that as wind equipment ages it will be more costly to operate and maintain on a per MWh-basis. This increasing cost is an amount in excess of inflation; therefore, the assumed increase in the unit WOM over time is an increase in the real (inflation-adjusted) cost per MWh.

Forecasting the WOM input variable requires forecasting both the unit WOM(t, f) and the qw(t, f) variables. To forecast each of those variables, we use a Monte Carlo process. Once the initial unit WOM forecast is derived (via Monte Carlo forecasting), we assume that forecast value increases at 2.50 percent annually for each year thereafter (until the equipment is retired). In summary, as shown by the equation above, the WOM variable is the product of two random variables, both of which need to be forecast in order to develop an actual forecast of the WOM variable. These and other forecasting details are further explained in Section 4.59.0.

E. Defining the DEP Variable: The Allowed Depreciation Expense

Under COS agency regulation, the utility would be allowed to recover the (original) investment cost of its wind assets through a depreciation expense that is included in its allowed rates. Hence, utilities that respond to the Challenge by selecting the investment option would be allowed a depreciation expense on its investment in wind capacity, provided such investment is deemed prudent.

For this study we apply the current regulatory provisions, both those granted by the KCC and the federal government, to calculate the utility's allowed depreciation expense on

wind investment. Straight-line depreciation is the KCC standard for ratemaking purposes. The federal government allows accelerated depreciation (for income tax purposes) on wind investments.[91] At this time, wind generators are expected to have economic lives of between 20 and 30 years. In this study we use 20 years and assume a net terminal value of zero.[92] Consistent with the foregoing provisions and allowances, we define the DEP variable as the utility's allowed depreciation expense on its investment in wind capacity. By design, that expense is measured on an annual basis.

The annual, allowed depreciation expense on wind investment depends on a number of factors, but primarily the magnitude of the net book value of the utility's investment in wind-generating assets. That amount depends on how much wind capacity the utility has actually installed (i.e., its response to the Challenge) as well as the original cost of installing that capacity.[93] The amount of wind capacity installed by the utility and included as part of its ratebase changes over time as new investments are made and subsequent retirements occur after 20 years of service. Hence, the depreciation expense is a function of the assumed wind capacity installation schedule, iwc(t). The installation cost of wind capacity (in MW) is also subject to change over time. For instance, current installation costs are in the range of $2.0 million, having doubled over roughly the last seven years. We assume there would be uniform treatment of the utilities' wind-related depreciation expenses; therefore, we do not model the allowed depreciation expense as a function of utility-type.

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[91] In our calculation of the allowed depreciation expense per the utility's wind investments, we include both the depreciation and tax implications of this federal provision.

[92] Regarding the retirement of wind-generating assets in the United States, there simply does not exist a great deal of experience and, thus, information on potential terminal values. Advancements in wind-generating technology *may* extend the economic life beyond 20 years. Towers may be conducive to being retrofitted with new turbines, which would clearly extend tower life. Until better information is available, the assumption of zero terminal value is probably reasonable.

[93] In this study, installation cost covers the equipment (towers and turbines), installation and interconnection costs (which may include sub-station construction costs). It does not include the cost of any necessary transmission (network) upgrades.

While installation costs have clearly trended upwards over the last few years, the future trend is naturally uncertain. Sources of uncertainty include potential changes in wind technologies, public policy provisions (namely, wind subsidies), input prices (mainly steel), the worldwide demand for wind energy in what may be an increasingly carbon-constrained global economy, and the potential entry of new equipment manufacturers and/or expanding the capacity of existing manufacturers. Because these factors and "events" are properly viewed as random, we model the future wind installation price/cost of wind capacity as a random variable. Accordingly, the depreciation expense is modeled as a random variable whose realized value depends on the derivation or selection of a forecast scenario, which, again we denote by, f.

While the determination of the utility's allowed depreciation expense on wind assets is consistent with methods and standards applied by the KCC as well as existing federal tax provisions, nonetheless the calculation of that expense is rather formulaic and is complicated by the accelerated depreciation granted by the federal government. Therefore, we simply denote the utility's annual, allowed depreciation expense on its installed wind capacity as: DEP(t, f). By this notation we indicate the depreciation expense associated with the utility's ratebasing of wind investments is a function of time, t, and, because the installation cost per MW is modeled as a random variable, the forecast scenario, f. The notation also shows depreciation does not depend on utility-type.[94] Lastly, we measure the depreciation expense in 2005 constant dollars.

[94] Since all regulated utilities would purchase their wind equipment in the same markets and because all would receive the same regulatory treatment regarding the depreciation of that equipment, we assume uniformity of the depreciation expense among utility-types.

(i) A Look Ahead: Forecasting the DEP Variable

The forecast of the DEP(t, f) input variable depends on the assumed wind capacity installation/retirement schedule, iwc(t), and the forecast wind installation cost. We include the latter as one of the elements that makes up that set of random variables that comprise the forecast scenario. Therefore, and as indicated by the notation, forecasting the DEP variable requires the derivation of a forecast scenario, f, which we accomplish through Monte Carlo forecasting. A discussion of these and other forecasting details is contained in the next chapter in Section 4.59.1.

F. Defining the RET Variable: The Allowed Return on Installed Wind Capacity

Under COS agency regulation, the utility would have the opportunity to recover in its jurisdictional rates an allowed rate of return ("ROR") on ratebased investments. Like the depreciation expense, the return (i.e., profit) expense associated with the Challenge is directly related to installation costs; increasing installation cost necessarily implies increased utility ratebase and, therefore, greater profit expense for the utility. The same relationship holds for interest rates and the allowed return. Changes in installation costs and interest rates over time will induce changes in the allowed return on wind investments. In this study, both the installation cost and (real) interest rates are treated as random variables and both are included as elements of that set of variables that comprise the forecast scenario, f. Again, we assume each of the utility-types has the same capital structure and credit rating and that they have comparable access to all financial markets. Our determination of the utility's return on wind capacity investments is consistent with the methods and standards used by the KCC to set allowed rates of return. Accordingly, the rate of return used in this study is grossed up for

incomes taxes (per existing tax rates). Moreover, in this study we apply an inflation-adjusted, real rate of return, as opposed to a nominal rate. Lastly, we would note that jurisdictional utilities are permitted an increase, of between 50 and 200 basis points, on their allowed rate of return for certain investments in renewable energy sources.[95] As a special case, we examine the financial implications of utilities taking that "extra" incentive on behalf of their shareholders. Otherwise, in all other case studies, we do not include that ROR adder in the calculation of the utility's allowed return on wind investments.[96]

Consistent with the assumptions and regulatory provisions discussed above, we define the RET variable as the amount of annual profit the utility is allowed on its net investment in wind capacity. We denote the RET variable by, RET(t, f). By that notation we make clear the utility's annual profit on wind investment is determined by time, t, and the forecast scenario, f, but not utility-type. Lastly, because we use 2005 constant dollars to measure wind installation costs per MW and the ROR is treated as a real interest rate, it follows the RET input variable is measured in 2005 dollars.

(i) A Look Ahead: Forecasting the RET Variable

The forecast of the RET input variable depends on the assumed wind capacity installation/retirement schedule, iwc(t), and the forecasts of the wind installation cost and real (i.e., inflation-adjusted) rate of return. As stated above, the wind installation cost is one of the elements that we include in that set of (random variables) we refer to as the "forecast

[95] See K.S.A. 66-117e.

[96] We do not include the ROR adder because it is an *option* provided to utilities: they may or may not request it. This option is not provided to wind developers and, therefore, its inclusion in the analysis would bias the results in favor of developers. While the ROR adder may be attractive to shareholders, it would be costly to ratepayers and, in any case, is probably *unnecessary* to induce shareholder investment in renewable projects that would, in any case, be agency-approved.

scenario." The real rate of return is yet another one of those elements. Our discussion of deriving the forecast scenario and, thus, forecasts for the installation cost and real rate of return (among other random variables) is contained in the next chapter in Sections 4.59.1 and 4.59.2, respectively.

3.23 Summarizing the Total Cost of the Challenge when Utilities Invest in Wind Capacity

We began our discussion of the Challenge's costs by listing six individual cost items that would appear for a jurisdictional utility choosing the wind investment option. For each item we define a specific cost variable designed to measure the relevant cost. We show the list again, pairing the cost item with the cost variable:

1) land lease or rental expense: LLE(t) variable,
2) payments to local governments in lieu of property tax: PIL(t) variable,
3) wind integration cost: INT(t) variable,
4) wind equipment O&M expense: WOM(t, f) variable
5) allowed depreciation expense: DEP(t, f) variable, and
6) allowed profit expense on ratebase (grossed up for taxes): RET(t, f).

By summing these six variables, the total cost of utilities meeting the Challenge by their direct investment in wind capacity is easily established. That cost is the total expense above and beyond what it would cost utilities to meet their retail load obligations if they were to simply maintain the *status quo* approach.[97] That is, we measure the incremental cost of

[97] As yet another point of reference, expenditures undertaken by utilities to meet the Challenge represent expenditures in excess of those taken along the *status quo* path. By the standard macro accounting practices, expenditure increases yield equivalent increases in income. Therefore, all of the expenditures listed above provide a basis for potential (if not actual) employment *gains* in the utility and closely related sectors. Would such employment gains be properly interpreted as "external benefits" of the Challenge? Probably not, since the expenditure increases giving rise to the employment gains would be recovered through the utility's allowed

meeting the Challenge, which is equivalent to the difference between the utilities' revenue requirements when they meet both the Challenge and their total retail load obligations and their revenue requirements when they do not partake in the Challenge and simply meet their *status quo* retail service obligations.

3.24 The Total Cost of the Challenge with Utilities Purchasing Wind Energy from Developers

Rather than choosing to invest directly in wind capacity, utilities have the option of purchasing wind energy from developers through the terms of purchase power agreements (PPAs). Of course, under the purchase option the utility will incur a wind-energy purchase power expense, which we denote by PPE.

A. Defining the PPE Variable: The Wind-Energy Purchase Power Expense

In practice, there may be considerable variation in the structure of wind PPAs. As part of this study we have not attempted a broad survey of wind contracts in order to identify the standard (or average) commercial practice(s) and, hence, the standard contract structure. However, based on our understanding of wind PPAs that are currently operational, and our impression of contract terms that may be currently available in Kansas, we assume wind PPAs have basic terms *comparable* to the following: (1) 20 year term,[98] (2) fixed price per MWh with annual adjustments for inflation (possibly in accordance with changes in the GDP Deflator index), (3) buyer takes and pays for whatever level of output is actually provided,

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rates. Hence, the employment gains in question here would be internal to the utility's own accounts which implies there is nothing external about these potential employment gains.

[98] Given the current expectations of the economic life of wind equipment, the 20-year term is common with large-scale commercial wind projects. On a related note, for the average-cost utility-type in one of the base case forecast scenarios, we examine the influence of extending the depreciable life from 20 to 30 years, all else the same. We find that change is unlikely to have a significant influence on the overall NPV results; in other words, extending the depreciable lives of wind equipment is unlikely to be a significant source of net value.

and, therefore, faces all output risk, (4) buyer is responsible for all integration costs, (5) seller retains the federal PTC and other government incentives, (6) seller covers all interconnection costs, and (7) seller is responsible for performance of all required maintenance and any costs of decommissioning.[99]

Under the terms listed above, the utility's (nominal) purchase price of wind energy under a "standard" PPA will vary with time and the developer's input costs, mainly the wind installation cost. It will also vary with the developers' changing perception of their required real rates of return.

Not only is the contract price of wind energy likely to change over time, those changes are uncertain. Consistent with our modeling of installation costs for the utilities, we assume developers will also face uncertain installation costs in the future, as well as uncertain future real rates of return. Just as we do for utilities that invest in their own wind capacity, we model the developers' wind capacity installation cost and real rate return as random variables.[100] To denote that it can vary with time and that it is subject to the value of certain random variables, we denote the contract price of wind energy as P(t, f) per MWh. We assume developers are effectively homogenous and, therefore, there exists uniformity of contract prices among developers. Because its value is dependent on random variables, the contract price of wind energy is itself a random variable, the realized value of which depends on the specific forecast scenario, f, as shown by the notation.

[99] The buyer would also be responsible for any transmission network upgrade costs, but, again, these costs are not explicitly included in the analysis. In practice, interconnection costs may be negotiable in terms of who would incur the initial expense. If the developer incurs that expense, the recovery of that expense would then be reflected in the contract price.
[100] Since utilities and developers are assumed to operate in the same equipment and financial markets, we assume they all face the same random variables.

In Appendix G we describe the derivation of the contract offer price, P(t, f), which is based on, among other things, the developer's assumed required rate of return, capital structure, and government subsidies. To derive P(t, f), we also assume the representative developer, as an investor in wind-generation assets, faces the same costs as the utility investing in wind-generation assets. Thus, with basically one exception, as an owner/operator, the developer faces roughly the same wind-related cost variables as the utility: LLE(t), PIL(t), WOM(t), DEP(t), and RET(t). The exception is that, as an independent supplier connected to the grid, we assume the developer is generally not responsible for the wind integration cost, but rather the utility that enters PPA. (We also assume developers are generally not responsible for transmission network upgrades that may be necessitated by their investment in wind facilities). Other differences between utilities and wind developers pertain to different financial structures and requirements. Developers are likely to be more leveraged than utilities and, thus, require a higher rate of return. As a basis for deriving the developer's offer price for wind energy, we also describe the developer's assumed capital structure and financial requirements in Appendix G. For a more complete and detailed description of how we derive the contract price for wind energy, including a description of their assumed capital structure and financial requirements, see primarily Appendix G.

For those case studies where the utility meets the Challenge through the entry of PPAs with developers, we define PPE(t, f) as the utility's average annual wind purchase power expense. Based on the assumed contract terms specified above, that expense is measured as follows:

$$PPE(t, f) = P(t, f) \times qw(t, f),$$

where qw(t, f) denotes the total quantity of wind energy (in MWh) purchased under the contract during any one year.[101] The purchase price of wind energy, again denoted by P(t, f), shows that it depends on both time and the forecast scenario.

(i) A Look Ahead: Forecasting the PPE Variable

As shown by the equation above, in order to forecast the utility's annual wind-energy purchase expense, we must forecast P(t, f) and the quantity of wind energy the utility takes during the year, qw(t, f). We assume the nominal, contract price of wind energy inflates in accordance to a predetermined inflation index. Since we are interested in using inflation-adjusted prices, we effectively reverse-out the application of the inflation indexing. Therefore, the forecast wind energy contract prices in this study are estimated in 2005 constant dollars. That also has the effect of removing the time dependency from that variable. With that, the forecast of the utility's annual wind purchase expense is simply:

$$PPE(t, f) = P(f) \times qw(t, f).$$

Forecasts of both the wind purchase price and the quantity of wind taken by the utility from the developer depend on the selection of a forecast scenario. Since the quantity of wind depends on the assumed installation of capacity over time, it remains time dependent.

3.25 Summarizing the Total Cost of the Challenge when Utilities Purchase Wind Energy

When the utility pursues the Challenge by entering contracts with wind developers, it faces just two annual expenses, the wind integration cost, INT(t), and the total purchase expense,

[101] Since we assume all investors in wind capacity would face the same wind conditions *on average*, the quantity of wind energy acquired by the utility in any one year, which we have denoted throughout by qw(t, f), would be the *same* whether the utility opts to invest in wind capacity or purchase wind energy from developers.

PPE(t, f). Aggregating those expenses yields the utility's total, annual cost of purchased wind power; it can vary depending on the year and the forecast conditions.[102]

3.30 The Net Benefit of Meeting the 2015 Wind Challenge

Consistent with the Governor's request, we have developed an economic model *designed* to capture all direct benefits and costs associated with meeting the Wind Challenge. In Section 3.10, we identify all of the direct benefits that come with the Challenge, namely the costs, both internal to the utility and external, that can be avoided and, thus, *saved as a consequence.* In short, the total benefit of the Challenge is the total savings it can provide the state of Kansas.[103] In Section 3.20, we identify all of the direct costs that come with the Challenge, both those associated with utilities directly investing in wind capacity and those tied to signing purchase contracts with wind developers. In short, the total cost of the Challenge to Kansas is determined by simply aggregating all of the direct cost variables.

In this section, we bring together the benefits/savings and costs to establish the net benefit of meeting the Challenge for Kansas. The net benefit formulations shown in this section reveal the *annual* net benefits of the Challenge. And because the implications of the Challenge are long term and will hold for several years into the future, the equations presented in this section are used to develop the stream of all future annual net benefits from the Challenge. However, consistent with the standard practice, in order to derive the real economic implications of the Challenge, it is necessary to discount the annual net benefit streams. In discounting those streams, we derive the *net present value*, NPV, of the

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[102] The utilities' expenditures on wind PPAs directly supports expansion of labor employment by wind developers.

[103] Whenever savings are realized as a consequence of a net reduction in expenditures, that implies a smaller income stream and, therefore, possibly lower employment.

Challenge. The NPV equations, presented and discussed in Section 3.40, provide the evidence upon which inferences regarding the economic efficiency of the Challenge can be drawn.

As described in Chapter 2, we evaluate the net benefit of the Challenge within the context of 32 distinct case studies. Different case studies call for the application of different net benefit formulations. Although several different formulations could be applied, we apply just four basic net benefit equations, which are presented below.

3.31 Basic Net Benefit Formula One: Utility-Type Invests in Wind Capacity with External Savings Excluded

This formulation measures the annual net benefit of the Challenge when (1) the utility-type chooses only to *invest* in wind capacity and (2) the external cost savings are *not* included in the analysis. This formulation is important, in part, because it captures the annual net benefit of the Challenge to only the utility (sector). More specifically, this formulation serves to isolate the effects of the Challenge on the utility's revenue requirement. That is critical because it provides the *basis* for determining how the Challenge is likely to affect the average price of electricity in the state (in those case studies where the utility relies on only the investment option). If the annual net benefit is positive, meeting the Challenge would usher in a lower average rate for electricity.[104] Alternatively, a negative net benefit would bring higher rates, on average. This formulation also enables us to isolate the utility's decision to invest in wind capacity rather than purchase wind energy through PPAs. That isolation is also necessary in order to effectively compare the economic implications of the

[104] Since we model wind-energy production as negative load (and assume that whatever that negative load is, it has no influence on the gross load the utility faces), if meeting the Challenge yields a lower revenue requirement, then the required revenue by MWh must decrease. That is, whenever the Challenge is cost effective (when external cost savings have not been included in the analysis), utility rates must fall.

two wind options: invest or purchase. In summary, this formulation enables an evaluation of the probable utility rate and, thus, monthly billing implications of the Challenge when the utility relies strictly on the investment option. It also provides a basis for comparing the economics of the two wind options.

For case studies where the utility-type pursues the Challenge only through its own *investment* in wind capacity and external cost savings *are not included* in the analysis, the annual net benefit formula is:

$$\text{NB}(\text{I: t, u, f, ib}) = (\text{FOM}(\text{t, u(gm), f}) + \text{APC}(\text{t, f}) + \text{CAP}(\text{t}) + \text{PTC}(\text{t, f})) \\ - (\text{LLE}(\text{t}) + \text{PIL}(\text{t}) + \text{INT}(\text{t, f}) + \text{WOM}(\text{t, f}) + \text{DEP}(\text{t, f}) + \text{RET}(\text{t, f})). \qquad (2)$$

That this is the formulation for only utility *investment* in wind capacity is denoted by the notation *I,* located within the net benefit parenthesis. The notation also indicates the actual net benefit ("NB") depends on or is distinguished by the time period, t, the utility-type, u, and the forecast scenario, f. Finally, it also depends on the investment base, ib, which is either 736 MW, for just the incremental investment needed to meet the Challenge, or 1,000 MW, the total Challenge amount. All of the variables indicated in the equation have been previously defined and, by design, all have been defined on an annual basis and all are measured in 2005 constant dollars.

Equation (2) shows the gross annual benefit of the Challenge as well as the total annual cost. The gross annual benefit (exclusive of external cost savings) of the Challenge is given by the first term in parentheses on the right of the equality sign; the total annual cost of the Challenge is given by the second term in parentheses. Clearly, Equation (2) measures the annual net benefit of meeting the Challenge when utilities choose to install their own wind capacity and when external cost savings are not part of the consideration. Except for possible

regulatory lag, that annual net benefit would be realized by (i.e., allocated to) Kansas ratepayers generally. In that sense, Equation (2) provides a basis for evaluating how the Challenge may affect the welfare of the average, or typical, Kansas ratepayer.

3.32 Basic Net Benefit Formula Two: Utility-Type Invests in Wind Capacity with External Savings Included

This formulation is the same as Equation (2), except for one difference; it includes the annual, external cost savings attributable to the Challenge as measured by the EXT(t, f) input variable. This formulation of the annual net benefit captures the *total,* annual net benefit of the Challenge (in those case studies where the utility relies strictly upon the investment option). Therefore, it captures the annual net benefit that is internal to the utilities taking up the Challenge as well as the annual net benefit that is external to those utilities. That measure is important because it provides the *basis* for evaluating the cost effectiveness of Challenge.

For case studies where the utility-type pursues the Challenge only through its own *investment* in wind capacity and external cost savings *are* included in the analysis, the annual net benefit formula is:

$$NB(I, ext: t, u, f, ib) = (FOM(t, u, f) + APC(t, f) + CAP(t) + PTC(t, f) + EXT(t, f)) - ((LLE(t) + PIL(t) + INT(t, f) + WOM(t, f) + DEP(t, f) + RET(t, f)). \qquad (3)$$

That this is the formulation for those case studies covering only utility *investment* in wind capacity with *external* cost savings included as part of the analysis is denoted by the notation *I, ext,* located within the net benefit parenthesis. Except for the inclusion of the EXT input variable, Equation (3) is identical to Equation (2). Because it includes the possible external cost savings attributable to the Challenge, Equation (3) is a *broader* measure of the Challenge's annual NB than Equation (2). The broader measure provides a basis for

evaluating how the Challenge may affect the well-being of the average Kansan.[105] It may be worth noting, the utility rate implications are the same under both Equations (2) and (3); in other words, inclusion of external cost savings does not alter the possible utility rate implications of the Challenge.

3.33 Basic Net Benefit Formula Three: Utility-Type Buys Wind Energy From Developers with External Savings Excluded

This formulation allows us to determine the annual net benefit of the Challenge when (1) the utility-type chooses only to *buy* wind energy from wind developers through PPAs and (2) when the external cost savings are *not* included. This formulation, like Equation (2), serves to isolate the effects of the Challenge on just the utility's revenue requirement. Again, that is critical because it provides the *basis* for determining how the Challenge is likely to affect the average price of electricity in the state (in those case studies where utilities rely solely on the wind PPA option). In summary, this formulation enables an evaluation of the probable utility rate and, thus, monthly billing implications of the Challenge when the utility relies strictly on the wind purchase option. It also complements the results from Equation (2) and, thus, facilitates an economic comparison of the two wind options.

For case studies where the utility-type pursues the Challenge only through *buying* wind PPAs and external cost savings *are not included* in the analysis, the net benefit formula is:

$$NB(P: t, u, f, ib) = (FOM(t, u(gm), f) + APC(t, f)) - (PPE(t, f) + INT(t, f)). \qquad (4)$$

[105] It is a safe bet that the "average Kansan" differs, perhaps only slightly, from the "average Kansas ratepayer." The point is, to the extent the Challenge alters external costs associated with conventional generation, the economic implications of the Challenge are likely to extend beyond just the utility bill implications. In that sense, the Challenge will alter the welfare of Kansans through other channels than just their utility bill.

That this is the formulation for only utilities *purchasing* wind energy is shown by the notation *P,* located within the net benefit parenthesis. As before, the notation indicates the actual NB depends on the time period, t, the utility-type, u, the forecast scenario, f, and the investment base, ib. All of the variables indicated in the equation have been previously defined and, by design, all have been defined on an annual basis and measured in 2005 constant dollars.

Like Equation (2), Equation (4) isolates the implications of the Challenge to those affecting only the utility's revenue requirement and, hence, its average rate. Arguably, that provides a basis for assessing how the Challenge is likely to affect the welfare of the state's average ratepayer (when the utilities choose to meet the Challenge with only the wind option).

3.34 Basic Net Benefit Formula Four: Utility-Type Buys Wind Energy From Developers with External Savings Included

This formulation is the same as Equation (4), except for one difference; it includes the annual, external cost savings attributable to the Challenge as measured by the EXT(t, f) input variable. Since the external cost savings are included in the analysis, this allows us to assess the annual net benefit of the Challenge to Kansans generally (in those case studies where utilities opt for only PPAs). This formulation is important because it provides the *basis* for evaluating the cost effectiveness of Challenge (when only PPAs are utilized).

For case studies where the utility-type pursues the Challenge only through *buying* wind PPAs and external cost savings *are* included in the analysis, the net benefit formula is:

$$\text{NB(P, ext: u, t, f, ib)} = (\text{FOM(u, t, f)} + \text{APC(t, f)} + \text{EXT(t, f)}) \\ - (\text{PPE(t, f)} + \text{INT(t, f)}). \qquad (5)$$

That this is the formulation for those case studies covering only utilities *purchasing* wind energy through PPAs with *external* cost savings included in the analysis is denoted by the notation *P, ext,* located within the net benefit parenthesis. As noted above, except for the inclusion of the EXT input variable, Equation (5) is identical to Equation (4). Because it includes the possible external cost savings attributable to the Challenge, Equation (5) is a *broader* measure of the Challenge's annual NB than Equation (4). The broader measure provides a basis for evaluating how the Challenge may affect the well-being of the average Kansan. The utility rate implications are the same under both Equations (4) and (5); inclusion of external cost savings does not alter the possible utility rate implications of the Challenge.

3.40 The Net Present Value (NPV) of Meeting the 2015 Wind Challenge

Meeting the Challenge would have long-term implications for the state of Kansas. Investments in wind capacity are long lived, delivering benefits to Kansans for years into the future, and exposing them to various long-term commitments that obligate them, in some form, to pay for those investments. Equations (2) through (5) measure the NB of meeting the Challenge in any *one year*. To make a determination of the Challenge's expected cost effectiveness, it is necessary to calculate the *total, aggregate* net benefit generated by the wind capacity investments that are made in response to the Challenge. Furthermore, because annual net benefits would be delivered during years well into the future, it is reasonable to discount those future net benefits based on various time value of money considerations.[106] Upon discounting the future, annual net benefits and then aggregating them over the relevant time horizon, the net present value (NPV) of meeting the Challenge is firmly established.

[106] Note: to this point we have measured all monetary variables in 2005 constant dollars. Having done so, all future monetary variables are effectively discounted, but only for general inflation.

Before we present the NPV formulations, some additional background and foundation may be useful. To that end, we offer a brief explanation of the investment horizon used in the analysis as well as a brief discussion of discounting.

3.41 The Relevant Investment Horizon

We use the term "investment horizon" to characterize that period of time over which the wind investments made in response to the Challenge would be economically useful. As described more fully in the next section of this report, we assume the last investments made in response to the Challenge would go on-line January 1, 2015. And as stated above, we assume that all wind investments, regardless of when they are connected to the grid, have economic lives of 20 years. Hence, the final wind investments made in response to the Challenge are assumed to have useful lives through the end of 2034. For purposes of evaluating the total net benefit of the Challenge, we use the 2006 through 2034 time period as the relevant time period for analysis. The years 2006 through 2034, inclusive, constitute our investment horizon, and the annual net benefits are aggregated over that time period.

3.42 The Rationale for Discounting Future Net Benefits

There are a numbers of reasons why a dollar received (or taken) in the future is likely to be less valuable than a dollar received (or taken) right now. Inflation over time erodes the value of a dollar. Having investment opportunities that support expectations of positive profits imply having a dollar now to invest is likely to be more valuable than having a dollar to invest at some future date. Simply being less certain about the future than the present can also support consumer preferences for having a dollar now than in the future. Whether it is

general inflation and/or having opportunities to invest, present-day dollars tend to be more valuable than future dollars. Equivalently, there tends to be an opportunity cost associated with receiving dollars in the future rather than currently. In order to take account of this phenomenon, it is necessary to *discount* the value of dollars received in future time periods, thereby measuring their value in current dollar terms and, thus, gaining a better measure of their *real value*. By assessing an economic decision, that carries with it long-term implications, with the use of discounted dollars we are more able to judge the *real* economic value of that decision.

For the reasons stated above, we discount the future, annual net benefits delivered by the Challenge. By discounting, we are able to apply a *standard measure* of monetary value to all net benefits regardless of when they are received. In this study we use constant 2005 dollars as that standard measure. All of the input variables used to compute the annual net benefits (for the various case studies) are already measured in 2005 constant dollars. That means the dollar expenses and benefits associated with those variables have been adjusted for general inflation—that is, they are discounted but only for inflation. It follows that the annual net benefits, measured by Equations (2) through (5), are discounted for inflation but not for any of the considerations associated with the time value of money.

The discount rate we offer for this study is applied on an inflation-adjusted basis and, therefore, can be interpreted as a real rate of discount. We denote the discount rate by r. Given the collective nature of public projects and policies, it is well understood that the selection of a discount rate (for the purpose of evaluating such projects) has a subjective component. In that sense, we apply a social discount rate that could involve considerations

other than the time value of money.[107] That a social discount rate is effectively applied on behalf of the public welfare suggests a number of different discount rates could be applied. Moreover, social discount rates could vary over time. In this study we apply just a single discount rate over the entire investment horizon (see discussion in Section 4.63).

3.43 The NPV of the Utility-Type Investing in Wind Capacity with External Savings Excluded

In those case studies where the utility-type meets the Challenge by directly investing in wind capacity and where estimated external cost savings are not included in the formulation, we use the following NPV formula, which is simply the NPV transformation of Equation (2):

$$\text{NPV(I: u, t, f, ib)} = \sum_{t=1}^{T} [((\text{FOM(u, t, f)} + \text{APC(t, f)} + \text{CAP(t)} + \text{PTC(t, f)})$$

$$- (\text{LLE(t)} + \text{PIL(t)} + \text{INT(t, f)} + \text{WOM(t, f)} + \text{DEP(t, f)} + \text{RET(t, f)}))*1/(1+r)^t]. \qquad (6)$$

By this formula, the entire stream of annual net benefits from the Challenge are (fully) discounted and then summed, yielding the net benefit of the Challenge in present value, 2005 constant dollar terms. The annual net benefits are aggregated starting with year one, t = 1, which is year 2006 chronologically, through the terminal year of the investment horizon, T = 29, which is 2034.

For those case studies where utilities meet the Challenge through their direct investment in wind capacity, and where potential external cost savings are not considered, this formulation provides the basis for determining whether pursuing the Challenge is cost effective for utilities. This formulation also provides the basis to determine the influence of the Challenge on the average retail rate of electricity and, consequently, the average monthly

[107] For instance, considerations of intergenerational equity may influence the selection of a discount rate.

electric bill.[108] To the extent the collective welfare of ratepayers is measured by the average retail rate of electricity, this equation also affords the basis to determine whether the Challenge is cost effective for ratepayers.[109]

3.44 The NPV of the Utility-Type Investing in Wind Capacity with External Savings Included

For those case studies where the utility-type meets the Challenge through investment in its own wind capacity and where estimated external cost savings are included in the formulation, we use the following NPV formula, which is simply the NPV transformation of Equation (3):

$$\text{NPV(I: u, t, f, ib)} = \sum_{t=1}^{T} [((\text{FOM(u, t, f)} + \text{APC(t, f)} + \text{CAP(t)} + \text{PTC(t, f)} + \text{EXT(t, f)})$$

$$- (\text{LLE(t)} + \text{PIL(t)} + \text{INT(t, f)} + \text{WOM(t, f)} + \text{DEP(t, f)} + \text{RET(t, f)}))*1/(1+r)^t]. \qquad (7)$$

With its inclusion of external cost savings, this formulation arguably includes *all* costs and savings (i.e., benefits) attributable to the Challenge. Therefore, it provides a basis to determine, for the relevant case studies, whether the Challenge is cost effective for Kansas.

Equations (6) and (7) are identical except for the inclusion of the EXT input variable in the latter. Accordingly, Equation (7) offers the broader measure of the Challenge's net benefit and provides a better assessment of the Challenge's welfare implications. Arguably, Equation (6) measures the Challenge's welfare implications for the average ratepayer, while Equation (7), being broader in nature, measures the welfare implications for the average Kansan. Because it is inclusive of all the costs and benefits and because it offers a broader,

[108] Since we assume rates, over the investment horizon, are mechanically adjusted every fourth year through the rate case process, our assessment of the Challenge's "rate impact" does not include any time discounting other than for inflation over time. Therefore, what we evaluate and present is the Challenge's influence on inflation-adjusted, real retail rates. (To perform that evaluation, per Equation (6), we set the time discount rate to zero.)
[109] Mainly for simplicity, for the case studies involving utility investment in wind capacity, we assume the cost effectiveness of the Challenge for both the utility and ratepayers is established through Equation (6).

more comprehensive measure of social welfare, economists would argue that Equation (7) offers policy makers, for the relevant case studies, the best foundation on which to base policy decisions.[110]

Equation (7) is also used to determine how large the EXT input variable would need to be in order for the Challenge to be just cost effective.[111] When the EXT variable has exactly that value, any size larger would yield a positive NPV and, thus, a cost effective outcome, any size smaller yields a negative NPV. As discussed previously, we refer to that particular "estimate" of the EXT variable as the pivotal or threshold estimate of external cost savings. Around that estimate, policy makers can consider the likelihood of the *actual external cost per MWh* exceeding the threshold level estimate. In that vein, even though the actual external costs are not directly observable,[112] if policy makers are at least confident the actual external cost is likely to exceed the threshold level, they may be willing to conclude that the Challenge would yield a cost-effective outcome.

3.45 The NPV of the Utility-Type Purchasing Wind Energy from Developers with External Savings Excluded

In case studies where the utility-type meets the Challenge by entering PPAs with wind developers and where estimated external cost savings are excluded from the formulation, we use the following NPV formula:

[110] Unless stated otherwise, our assessment of the Challenge's cost effectiveness are based on the NPV formulations that include the EXT input variable.
[111] This is accomplished by using the data set necessary to solve Equation (6), but excluding the EXT input variable data. With that reduced data set, Equation (6) is then solved for the EXT input variable that yields an NPV value of zero. Equivalently, Equation (6) is set equal to zero and solved for the EXT variable, all other data the same.
[112] Perhaps it goes without saying, but the uncertainty associated with actual external costs extends to the probabilistic distribution of those costs.

$$\text{NPV(P: u, t, f, ib)} = \sum_{t=1}^{T} [((\text{FOM(u, t, f)} + \text{APC(t, f)}) - (\text{PPE(t, f)} + \text{INT(t, f)}))*1/(1+r)^{t}] \quad (8)$$

This formula is simply the NPV transformation of Equation (4). The numerical results obtained from this equation provide the basis for determining whether it is cost effective for utilities to meet the Challenge through (only) the use of PPAs. This formulation also provides the foundation for establishing the rate implications of the Challenge when utilities select only the wind purchase option. Finally, by comparing the NPV results from Equations (6) and (8), we can establish which of the two wind options, invest or purchase, is likely to be less costly for the utilities and, thus, ratepayers. To the extent one is less costly, ratepayers will prefer that option; however, policy makers may or may not share that preference, depending on other considerations.

3.46 The NPV of the Utility-Type Purchasing Wind Energy from Developers with External Savings Included

In those case studies where the utility-type meets the Challenge through PPAs and where estimated external cost savings are included in the formulation, we use the following NPV formula:

$$\text{NPV(P, ext: u, t, f, ib)} = \sum_{t=1}^{T} [((\text{FOM(u, t, f)} + \text{APC(t, f)} + \text{EXT(t, f)}) - (\text{PPE(t, f)} + \text{INT(t, f)}))*1/(1+r)^{t}] \quad (9)$$

This formula is the NPV transformation of Equation (5). It is nearly equivalent to Equation (8), the only difference being the inclusion of the EXT input variable. Equation (9) provides the basis to determine whether the Challenge is cost effective for Kansas when utilities

respond by entering only PPAs with wind developers. Like Equation (7), this equation can also be used to derive, for the relevant case studies, the threshold external cost (per MWh) estimate.

3.47 Summary of NPV Formula Derivations

Using a standard NPV analysis, like the one applied here, allows the computation of numerical results that provide a basis for evaluating the economic efficiency of meeting the Challenge. Given our specification of the NPV formulas, we can also determine the implications of the Challenge in terms of the average rate of electricity in the state and, thus, the average monthly bill. Furthermore, with the NPV formulas presented, we can determine which the two wind options, build or buy, is likely to be less costly. Finally, using the appropriate NPV formulas, we can determine how large external cost savings (per MWh) need to be for the Challenge to be cost effective for Kansas. In summary, and speaking generally, the NPV analysis allows us to identify those conditions where the Challenge is likely to be cost effective and where it is not. That leaves open the question of which *actual* conditions are most likely to persist over time and how they compare to the conditions that would support an efficient outcome.

3.50 A Brief Look Ahead to (Chapter 4 and) Monte Carlo Forecasting

With the preceding descriptions of the relevant NPV formulations and all of the input variables that make up those formulas, it should be clear what information is required to make an actual NPV determination. However, because the Challenge, by design, sets a target date well into the future and because wind assets are durable and long lived, any economic

analysis of the Challenge necessarily requires a look forward in time. Given the specification of the Challenge and various parameters contained in the NPV formulas, the relevant time period or forecast horizon is from 2006 through 2034; this we refer to the investment horizon. Clearly, any economic assessment of the Challenge necessarily requires the use of forecasting through the year 2034. All of the variables contained in the NPV formulas: those on the benefit side, FOM, APC, CAP, PTC, and EXT, and those on the cost side, LLE, PIL, INT, WOM, DEP, RET, and PPE, must be forecast through 2034.

Our next step—which is presented and discussed in Chapter Four—is to forecast each of the input variables and, for each input variable, establish a forecast for each year of the investment horizon. Once those forecasts are developed, plugging the input variable forecasts into the relevant NPV formulation, it is an easy matter to calculate the forecast NPVs. As shown in this Chapter, all of the input variables are defined through the use of formula. And as the formulas show, the composition of all the input variables depends either directly or indirectly on the value of certain random variables. Thus, in order to forecast the input variables it is necessary to derive forecasts of those component "random variables." A complete set of forecast values for the component random variables makes up what we call a "forecast scenario." With a single forecast scenario we calculate a single forecast value for each of the input variables described in this chapter and, in turn, calculate a forecast NPV value for each of the NPV formulations presented above. In short, to obtain an individual NPV forecast it is necessary to derive an individual forecast scenario.

For each of the 32 case studies we examine, we use a Monte Carlo process to derive the forecast scenarios. And for each individual case study, we draw 200,000 different forecast scenarios. Thus for each case study, we develop 200,000 different NPV forecasts.

Rather than developing the usual high-, low-, and base-case NPV forecasts, through the Monte Carlo analysis we present *thousands* more. By that approach we are better able to develop the full range of possible forecast outcomes as well as the probability of any one forecast value being realized. With this analysis we are able to develop a better understanding of the probability or likelihood that the Challenge will be cost effective.

Chapter 4: Monte Carlo Forecasting

4.00 Introduction

In this chapter we describe the Monte Carlo forecasting method we use to develop the NPV forecasts. As shown by the NPV formulas, in order to develop the NPV output forecasts it is first necessary to forecast each of the input variables. Obviously, the NPV forecasts are output forecasts. Everyone understands that actual forecast results depend on the underlying forecast scenario. In this study we use Monte Carlo analysis to establish the forecast scenarios on which the input variables forecasts are based. Clearly, since the input variable forecasts depend on the forecast scenarios derived from the Monte Carlo process, the NPV output forecasts also depend on the same Monte Carlo process. Because many readers may not be familiar with Monte Carlo analysis, and because we use it to forecast all but two of the NPV input variables, some background information pertaining to and discussion of Monte Carlo analysis may be useful.[1]

Monte Carlo forecasting is widely used among financial economists to evaluate private investment projects; however, it can be used just as well to evaluate investments projects that are premised on public policy objectives, such as the Challenge.[2] As far as we know, Monte Carlo analysis has not yet been used to evaluate the economics of wind capacity investments; nonetheless, for reasons presented below, Monte Carlo analysis seems ideally suited to the problem at hand.

[1] In this study references to a Monte Carlo *analysis, process, forecast method,* or *simulation* are synonymous.
[2] At a purchase price of approximately $1.6 million per MW of installed wind capacity, meeting the Challenge by investing anew in 736 MW of wind capacity is tantamount to a $1.18 billion investment project.

4.01 Motivation for Using Monte Carlo Forecasting: Some Preliminary Observations

If there is one characteristic of Kansas wind energy production on which perhaps everyone can agree, it is that it depends on the wind—an obvious random variable. That the net benefit of the Challenge depends on the random nature of weather is inescapable. That the economics of the Challenge also depends on highly variable natural gas prices and the uncertainty of future wind installation costs, both of which can be modeled as random variables, is also inescapable. Therefore, in order to perform a meaningful analysis of the Challenges' net benefit to Kansas, it seems necessary to fully embody within that analysis the random nature of the variables that are likely to influence the net benefit. Monte Carlo analysis provides one means of accomplishing just that.

Because there are several random variables that may influence the net benefit of the Challenge and because those same variables make take a wide range of possible values, it is plausible the forecast NPVs of the Challenge could vary over a very large range. In such a setting, point estimates or forecasts of the Challenge's NPV are unlikely to provide a high degree of confidence. One way to build confidence in the forecast results is by developing a large number of forecasts—perhaps hundreds of thousands of forecasts. Monte Carlo analysis, combined with inexpensive computing capacity, makes easy the derivation of thousands of forecast scenarios and, subsequently, thousands of actual, numerical forecasts, thus providing a greater understanding of the range of possible forecast outcomes.

Not only does the use of Monte Carlo forecasting provide a basis for having greater breadth of and, thus, greater confidence in forecast results, it enables us to derive a probabilistic distribution of the forecast results. In the context of this study, it allows us to model the forecast NPVs of the Challenge as a random variable that may be described as a

probability distribution function ("pdf"). Thus, by using Monte Carlo forecasting not only can we more fully forecast the range of possible outcomes to the Challenge, we can also gain some understanding of the *probability* that a particular forecast value will be realized. In that vein, the Monte Carlo analysis is also ideally suited to estimate the expected net benefit of the Challenge (i.e., the average forecast NPV).

Finally, and this is a critical point, by using Monte Carlo analysis we can acquire a better understanding of the *risk* associated with the Challenge. In recognition of all the uncertainty that underlies the Challenge and, thus, the uncertainty that surrounds quantification of its net benefit, it is simply unrealistic to suggest that the cost effectiveness of the Challenge could be categorically determined based on a *single* or just a handful of NPV forecasts. In a world of uncertainty, it is probably more meaningful to establish the probability or *likelihood of the Challenge being cost effective.* In that sense, the Monte Carlo analysis enables us to evaluate the *risk* of the Challenge not being cost effective; this provides an assessment of the Challenge's potential downside risk.

4.02 Background: Establishing a Statistical Basis for Evaluating the Challenge

Again, the primary objective of this study is to determine the net benefit of the Challenge. That objective might be satisfied by developing just a *single* forecast of the Challenge's NPV. Obviously, that would hardly be satisfactory: everyone recognizes the forecast NPV depends on the (assumed) forecast scenario selected; everyone also recognizes there could be an infinite number of reasonable forecast scenarios from which to choose; and everyone also recognizes the impossibility of knowing which single forecast scenario provides the best

representation of the future. For those reasons, it makes sense to develop not just one, but several different NPV forecasts.

Perhaps the most traditional approach to developing more than "just one" forecast involves the derivation of best, base, and worst-case *forecast scenarios* from which the best, base, and worst-case forecasts would be obtained. At first glance, that may appear to be a reasonable approach: at the very least, more than one forecast is considered and, if the scenarios are reasonably constructed, something that *resembles* a range of possible forecast outcomes, from worst to best, is established. However, this approach is based on a very limited number of forecasts, just three, and there is some risk the forecast scenarios are not well constructed. For instance, the forecast scenarios may not be based on a realistic assessment of future conditions and, therefore, may be subjective in nature, reflecting possible biases of the forecaster. It is well understood that forecasters who prefer a certain forecast outcome will select forecast scenarios accordingly.

To get around these potential shortcomings, Monte Carlo simulation carries this common forecasting approach through to its logical conclusion. With Monte Carlo simulation, typically *thousands* of forecast scenarios are constructed and, of course, for each scenario an output forecast is obtained. Thus, with Monte Carlo forecasting the sample size of forecast results is greatly expanded, in contrast with the traditional approach with its typical sample size of three. Moreover, the forecast scenarios are themselves *drawn at random*, meaning there is less chance for a biased construction of forecast scenarios and, thus, biased forecast results.

In addition, by using Monte Carlo forecasting we are able to use statistics to draw inferences about the Challenge's cost effectiveness. For example, by generating a large,

random sample of forecast results—in this case forecast NPVs—we are able to obtain reasonably good estimates of the *average forecast NPVs*. The average forecast NPV can be used, either by itself or in the construct of confidence intervals, to draw conclusions about whether the Challenge is likely to yield a cost-effective outcome.

4.10 Decision Criteria for Evaluating the Cost Effectiveness of the Challenge

To determine whether meeting the Challenge would be cost effective we use the following decision criteria: if the average forecast NPV is greater than or equal to zero, we conclude meeting the Challenge would be cost effective; if the average forecast NPV is less than zero we conclude the opposite. Since we also derive the distribution of forecast NPVs, if the density of forecast NPVs with a positive value[3] is 50 percent or greater, we would conclude the Challenge is cost effective.[4] Of course, alternative decision criteria are available. As an example, one could require the average forecast NPV to be larger than zero by some statistically significant margin. Relative to the alternatives, the decision criterion selected in our study is probably the most conducive to making decisions that support pursuit of the Challenge.

Finally, by deriving a distribution of forecast NPVs, we can also provide policy makers with a better understanding of the *risks* associated with pursuing the Challenge. While we might find meeting the Challenge would be cost effective, there could still be a high probability that a negative NPV could be the final result. Thus, we provide policy

[3] More precisely, this would include forecast NPV values that are zero and greater.
[4] Alternatively, if this criterion is satisfied, one may conclude meeting the Challenge is likely to be cost effective. Thus, rather than one drawing a definitive conclusion about the Challenge's cost effectiveness, one can refer to the *likelihood* of it being cost effective. Given that we are using a large sample of forecast NPVs as a basis for determining cost effectiveness of the Challenge, the likelihood of cost effectiveness actually conveys more information about the Challenge's economic prospects.

makers with an indication of the downside risk associated with favorable findings. This assessment of the Challenge's risk also enables policy makers to evaluate, at least subjectively, whether they believe pursuit of the Challenge offers Kansans a "good bet" in terms of favorable outcomes. For example, an assessment of the risks associated with the Challenge may provide policy makers with further guidance on whether pursuit of the Challenge might be reasonable.[5]

By using the Monte Carlo simulation, we are able to determine the cost effectiveness of the Challenge based on a robust statistic, the average forecast NPV; and we are able to provide an assessment (i.e., a measure) of the risk associated with the Challenge. This approach provides policy makers with at least two dimensions by which to evaluate the economic merits of the Challenge. By using the Monte Carlo simulation, policy makers and analysts alike are afforded a better foundation on which to base their conclusions.

4.20 The Use of Monte Carlo Simulation for Forecasting: Some Background

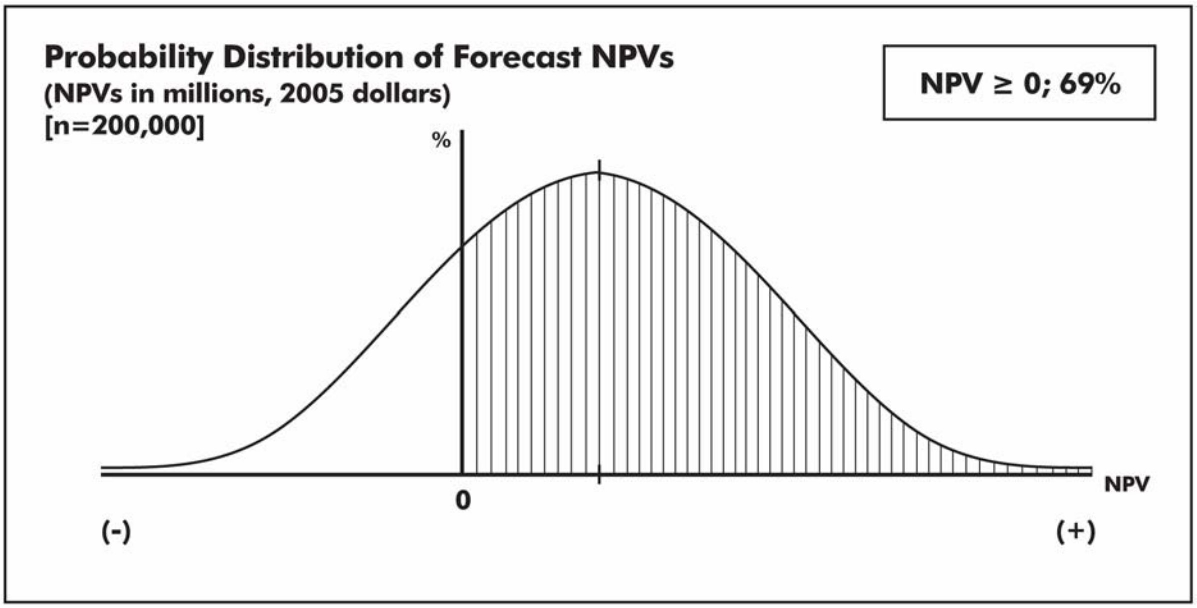
Several of the input variables used to determine the NPV of the Challenge are characterized by a high degree of either natural variability, which is intrinsic to the variable, or uncertainty, or both. An example of a variable with significant natural variability is the price of natural gas, which is embedded in the FOM input variable and widely recognized as being among the most volatile commodity prices. An input variable for which significant uncertainty exists is the wind O&M expense (per MWh), WOM. Similarly, the wind capacity factor, which is embedded in the wind output variable, qw, is a significantly uncertain variable. Within the

[5] Even if the forecast results suggest taking the Challenge is not a good bet to be cost effective, if the forecast results still showed there was some chance it would be cost effective, then policy makers could still decide to take that chance, small as it may be. Thus, the assessment of risk could be used to override decisions (either in support of the Challenge or not) made strictly in accordance with the selected decision criterion.

context of Monte Carlo analysis, the natural variability and uncertainty associated with certain input variables is captured by modeling those variables as probability distribution functions, which is precisely how we characterize several of the input variables.

Treating an input variable as a pdf facilitates a number of things. It permits the use of random selection to actually forecast the variables; therefore, this allows the random selection of forecast scenarios. It also facilitates deriving a large number of forecast scenarios.[6] It explicitly embeds random variability and uncertainty into the analysis. Finally, it is the basis for deriving the output variable—that is, the output variable forecast results as a probability distribution function. Graph 4.0 provides an example of the NPV forecasts results displayed through a probability distribution function. The graph indicates the range of possible forecast amounts and the probability of realizing a specific forecast value. Thus, by modeling the forecast results as a pdf, one can readily assess the likelihood or probability of realizing certain forecast outcomes. This also provides a basis for evaluating the possible risk associated with achieving specific outcomes.

[6] Coincidentally, because Monte Carlo simulation typically calls for generating a large sample of forecast results, it is not surprising that it began to displace other forecasting methods as computing costs started to decline.



Graph 4.0: Generic Presentation of Forecast NPV Results

Graph 4.0 shows, for a specific case study, the NPV forecast results as a histogram. It shows that of the 200,000 forecast scenarios evaluated for that case study, 69 percent or 138,000 of those scenarios yielded positive NPV forecasts; obviously, the remaining 31 percent or 62,000 yielded negative NPV forecasts. The strength of the Monte Carlo process is that it enables, for any one case study, the researcher to explore a large number of different forecast scenarios or contingencies, from the extreme (and thus unlikely) to the commonly expected. This enables us to gain a broader understanding of how the Challenge is likely to perform over the uncertain future. And as Graph 4.0 shows, the Monte Carlo approach provides an estimate of the chance or likelihood or probability that meeting the Challenge will yield a positive outcome, that is, positive NPV and, thus, an economically efficient result. As indicated in the graph that probability is 69 percent; that suggests taking the Challenge would be a good economic bet or risk worth taking. If the probability of a positive

payoff is less than 50 percent, consistent with our criterion for establishing economic efficiency, we would conclude the opposite.

In summary, by using Monte Carlo analysis we are able to provide policy makers with a probabilistic distribution of forecast results. This extends the analysis of the Challenge's economic potential far beyond that resulting from examining only the best, base, and worst-case forecast scenarios. It also provides a foundation for examining a very wide range of possible forecast scenarios, thereby mitigating the likelihood of basing policy conclusions on forecast results that are possibly significantly biased in one direction or another. By using the Monte Carlo analysis we provide policy makers with not only a comprehensive benefit cost analysis of the Challenge, but an explicit assessment of the risk associated with pursuing the Challenge as well.

4.21 Input Variable Forecasts Using Probability Distribution Functions

Of the twelve different input variables defined in Chapter 3, we use pdfs and Monte Carlo simulation to forecast nine: FOM, APC, PTC, INT, DEP, RET, WOM, EXT, and PPE.[7] The input variables not based on Monte Carlo simulation are CAP, LLE, and PIL. Of the nine input variables that are based on Monte Carlo simulation, all but one depends on two or more

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[7] As previously discussed, the input variable PPE(t, f) measures the annual cost of the utility taking wind energy through a PPA. Forecasting that input variable requires forecasting the contract price for wind energy, which we denote, P(t, f). There are at least a couple of different ways to develop forecasts for the price of wind energy: (1) conduct a price survey, perhaps in the current time period, and use the indicated sample prices as a basis for forecasting future prices and (2) model the developer's contracting problem and solve for a price that yields the developer's required return. Because we generally do not have ready access to contract prices in the market, we rely mainly on the latter forecast method. However, over the course of this study, on two different occasions we had access to market price information availed through utility RPF processes. That information took the form of price indications (as opposed to actual transaction prices). With those indications as a basis, we were able to examine whether our forecast method would provide comparable forecast results. In each instance our forecast results fell within the range of observed price indications. While that does not constitute a statistical test, it provides some assurance that our forecasting method for P(t, f) is probably reasonable. Because that method is sufficiently involved, we relegate our description of it to Appendix G.

random variables. In total we rely on seven different random variables to derive our input variable forecasts. For each of those seven random variables, we select a specific pdf, such as a normal distribution with a certain mean and variance, which then provides a basis for forecasting the respective random variable. Those forecasts, in turn, enable us to derive the input variable forecasts. Lastly, with a full set of input variable forecasts, which make up a complete forecast scenario, we are able to compute a single forecast NPV.

This section's description of our method of forecasting each of the twelve input variables supplements the groundwork already provided in Chapter 3, where definitions and means of calculating each of the input variables are discussed. To complete the description of our forecast methodology, all that remains is specifying the pdfs on which the input variables are based.[8]

4.30 The Exclusion of Transmission-Related Cost Forecasts

As noted in Chapter 3 of this report, we make no effort to incorporate the potential transmission related costs that, as a practical matter, may be unavoidable if the Challenge is to be satisfied. It is certainly true that if the Challenge is to be met while maintaining system reliability in accordance with existing standards—which is clearly the expectation—then investment in new transmission capacity, as well as expenditures to upgrade existing transmission capacity, are likely to be required.

The reason we have not included an assessment of transmission-related cost and benefits is simple. As a practical matter, such an assessment would need to be performed by

[8] For each of the random variables we model as pdfs, we assume zero (0) covariance among those variables. Therefore, between any two of those variables, there is no covariance. We make this assumption mainly to simplify the analysis. However, an empirical examination make reveal that is it not an unreasonable assumption. Such an examination is left for future research.

the SPP. The SPP has developed and currently uses a protocol for reviewing and evaluating the costs and benefits of potential transmission projects. Yet even the analysis of a single, *well-defined* transmission project is complex and time consuming. And by "well-defined" we mean in terms of a *precise* location, size, and expected timing of operations. Within the context of evaluating the Challenge, certain transmission upgrades could be required for every wind farm developed. That means in order to assess those upgrades we would need to know with a high degree of certainty when and where wind developments would take place. Moreover, to properly evaluate those wind-related upgrades, the SPP would also need to know when and where non-wind-related upgrades might be required in the future. It is widely recognized that an evaluation of the wind-related transmission projects needs to be within the broader, regional context that would include all other potential transmission projects. To do the required comparative analysis would involve evaluation of, arguably, *dozens* of different transmission projects, some related to wind projects and others related to conventional generation projects, all with time horizons well into the future. Absent knowing, with some certainty, where and when future generation projects are going to take root in Kansas, it is not feasible to properly evaluate the relative transmission cost implications of the Challenge.

Although, for the reasons state above, we did not include transmission-related costs in our analysis, it is our opinion that, had we done so, the cost of meeting the Challenge would have been higher. It is our position that, with respect to the transmission access issue, meeting the Challenge will very likely require relatively *higher* (net) expenditures and, thus, higher relative costs compared with the "business as usual" path. To be clear, the net cost of providing transmission capacity in Kansas is likely to be higher under the Challenge relative

to the status quo. Thus, in terms of the Challenge's forecast NPVs, it is our position that inclusion of transmission-related costs and benefits would, on average, result in lower NPVs. Equivalently, by not including the net cost of transmission expenditures induced by Challenge, our NPV results are biased in favor of the Challenge.[9]

For those that claim meeting the Challenge is not feasible due to an apparent lack of transmission capacity, it is important to recognize that putting in that capacity is almost guaranteed to make wind energy more costly. And if that increase in cost makes wind energy more costly than the alternatives, that will obviously impede the acceptance of wind energy among potential buyers, regardless of where the buyers might be located.

In summary, we do not include an assessment of the transmission-related costs and benefits that may be incurred if the Challenge were met. That assessment must be performed on a regional basis and requires a degree of certainty about when and where investment in both wind and traditional generating capacity will likely occur in the future. That information is not available at this time and attempts to "forecast" that information would amount to little more than attempts to speculate. Nonetheless, in daring to speculate at this point, it is our opinion that if transmission-related costs were included in the analysis the relative (forecast) cost of meeting the Challenge would be higher and the exclusion of these costs biases our overall results in support of the Challenge.

[9] Absent performing the requisite analysis, it is nearly impossible to gauge the possible bias. However, since wind, compared with traditional generation facilities are more likely to be located further from load centers this bias could be significant. Yet, since the cost of transmission services typically represents, depending on the individual utility, between 10 and 25 percent of the total cost of delivered electricity, it is conceivable the magnitude of the bias is not large in terms of absolute value.

4.40 Forecasting the Annual Quantity of Wind Energy Production: qw(t, f)

Several of the input variables depend on the quantity of wind energy produced during the year (in MWh), which we denote as qw(t, f). Those input variables include FOM, APC, PTC, EXT, INT, and WOM. The quantity of wind energy produced during any one year depends on both the total amount of installed wind capacity, which we denote by iwc(t), and the average annual capacity factor of the installed wind facilities, denoted CF(t, f). These relations are shown in the formula below:

$$qw(t, f) = iwc(t) \times CF(t, f) \times 8{,}760 \text{ hrs.}$$

Thus, all of the input variables whose calculations depend on qw(t, f) necessarily depend on the amount of installed wind capacity (in MW) and the forecast of the average capacity factor (over the installed wind facilities). Therefore, as background, we begin our discussion of the input variable forecasts with a preliminary discussion of our assumed wind capacity installation schedule and capacity factor forecast method. As shown, bringing those two components together enables us to forecast the amount of wind energy generated as a consequence of meeting the Challenge.

4.41 Background: Meeting the Challenge and Specifying an Installation Schedule

As January 1, 2006, to meet the Challenge from that date forward, an additional investment in 736 MW of Kansas wind capacity is required prior to January 2015. Since there are no meaningful ways to forecast when (or if) individual investment projects will be brought on line as a *voluntary* response to the Challenge, it is necessary to assume a set "installation schedule" for wind capacity investment. The assumed installation schedule is: 150 MW of *new* wind capacity brought on line by the start of each year 2007, 2009, 2011, and 2013, with

the final increment of new capacity (approximately 136 MW) added by the start of 2015, as required.[10]

In terms of historically given wind installations, as of January 2006, two commercial-scale projects were on line: FPL Energy's Gray County project, whose output is provided to Aquila under the terms of a PPA, and PPM Energy's Elk River project, supported by a PPA with EDE. Combining those existing installations with the assumed installation schedule for new projects, we have the installed wind capacity schedule by year, t, through 2015 (Table A).[11]

As discussed in Chapter 3, it is assumed that all turbines, regardless of their on-line dates, have 20-year economic lives. The first commercial-scale wind project in the state will reach the end of its economic life by the end of 2021. We also assume that as the wind turbines reach the end of their economic lives they will, in some way, be decommissioned, salvaged, or completely derated, at which point in time they will not be included as part of the state's installed wind capacity.[12] With that assumption, from the start of 2015 to the end of 2021, there would 1,000 MW of nameplate-rated wind capacity available for production. After 2021, the amount of installed wind capacity available for production would, through depreciation, reach 0 MW by the start of 2035.[13]

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[10] More precisely, in the final year prior to the stated deadline, the necessary incremental investment is 136.5MW. This investment schedule would apply to *collective* investment, which could include total investment by both the utilities and wind developers. Alternative installation schedules can be assumed; however, our analysis shows that realistic alternatives are unlikely to have a significant effect on the final numerical results. Thus far, the actual installation of wind capacity in Kansas has been rather uniform over time, with major projects (between 100 MW and 159 MW) going in every two years or so. The assumed installation schedule is consistent with that experience.

[11] The schedule includes 1.5 MW of wind capacity installed prior to 2002 by Westar Energy.

[12] This is not to suggest that towers and/or wind sites would not be re-used and, in the case of the latter, possibly maintained indefinitely. Advantageous sites are likely maintained over time.

[13] This study does not provide a "steady state" analysis of meeting the Challenge. (Which we believe is consistent with the Governor's January 2005 letter to the Chair.) A preliminary evaluation shows that if a steady state analysis was preformed – where 1,000MW of installed capacity would be maintained *indefinitely* starting in 2015 – the numerical results reported here would *not* be significantly different. This is due primarily to the

Table 4.0: Statewide Installed Wind Capacity: Actual and Projected	
Year	**iwc(t)**
2002	113.5 MW
2003	113.5 MW
2004	113.5 MW
2005	113.5 MW
2006	263.5 MW
2007	413.5 MW
2008	413.5 MW
2009	563.5 MW
2010	563.5 MW
2011	713.5 MW
2012	713.5 MW
2013	863.5 MW
2014	863.5 MW
2015	1,000 MW*
*Challenge met.	

Taking the assumed installation schedule and combining it with the effects of the assumed rate of depreciation, we derive the full installed wind capacity schedule as a function of time, iwc(t). The variable iwc(t) is completely described in Table B, which shows how we arrived at the analytically relevant time horizon, 2002 through 2034 (including the forecast horizon 2006 through 2034).

major investment implications of moving to the steady state being nearly 30 years in the future and, therefore, being highly discounted. The analysis presented here can be easily extended to that of that of a steady-state analysis.

Table 4.1: Assumed Statewide Installed Wind Capacity Schedule: iwc(t)	
Year	**iwc(t)**
2002	113.5 MW
2003	113.5 MW
2004	113.5 MW
2005	113.5 MW
2006	263.5 MW
2007	413.5 MW
2008	413.5 MW
2009	563.5 MW
2010	563.5 MW
2011	713.5 MW
2012	713.5 MW
2013	863.5 MW
2014	863.5 MW
2015	1,000 MW
2016	1,000 MW
2017	1,000 MW
2018	1,000 MW
2019	1,000 MW
2020	1,000 MW
2021	1,000 MW
2022	886.5 MW
2023	886.5 MW
2024	886.5 MW
2025	886.5 MW
2026	736.5 MW
2027	586.5 MW
2028	586.5 MW
2029	436.5 MW
2030	436.5 MW
2031	286.5 MW
2032	286.5 MW
2033	136.5 MW
2034	136.5 MW

4.42 Background: Forecasting the Capacity Factor: CF(t, f)

As stated previously, in this study we interpret the forecast capacity factors as *average* annual capacity factors. For any one year, we recognize that annual capacity factors among different wind facilities may vary for many reasons, such as location, tower heights,

equipment manufacturer, maintenance practices, etc. Variations such as those are efficiently resolved by using an *average* annual capacity factor that is then applied to all of the installed wind capacity.[14]

Our calculation of the wind capacity factor consists of two parts: (1) the unadjusted capacity factor and (2) the degradation adjustment. By combining these two parts—by making a degradation adjustment to the unadjusted capacity factor—the end result is an *adjusted* capacity factor (hereafter, capacity factor). The reason we make a degradation adjustment is to reflect the normal influence of aging equipment. Empirical evidence suggests that, as wind facilities age, some reduction in or degradation of capacity factors can be expected.[15] (See the Direct Testimony and Exhibit RHG-1 of Dr. Robert Glass in Docket No. 08-WSEE-309-PRE for a detailed discussion of the expected reliability and durability of wind equipment.)

Consistent with our formulation of the capacity factor, in order to forecast the average annual capacity factor, it is necessary to forecast (1) the unadjusted average annual capacity factor and (2) the annual degradation factor. In this study, variations in the unadjusted, average annual capacity factor are due strictly to weather variability, but mainly wind speed variance.[16] Because the unadjusted, annual capacity factor depends on random weather conditions, it is appropriate to model it as a random variable. Equivalently, it is appropriate to

[14] We also interpret the capacity factor as a *statewide* capacity factor. By simply taking a statewide perspective the use of a statewide average capacity factor is reasonable, if not necessary. Moreover, as long as the average capacity factor is not a biased estimator, applying it to the total amount of installed wind capacity will yield an unbiased estimate of total, annual wind energy production.

[15] Like generation equipment generally, equipment failure and replacement is expected to occur over the 20-year life of every wind project. The frequency and risk of equipment failure generally increases with the age of equipment. Because equipment failure reduces the facility-wide capacity factor, actual capacity factor readings are expected to decrease as the age of the equipment increases. It is through the inclusion of the degradation factor that we attempt to capture this phenomenon.

[16] Because it is interpreted as an average across different wind facilitates, variations due to factors other than weather are already built into the unadjusted capacity factor forecast.

base forecasts of the unadjusted, annual capacity factor on a reasonably selected random variable (i.e., probability distribution function). Evidence also suggests that the degradation factor also depends on random variables, like weather and age-related equipment failures; therefore, we model the degradation factor as a random variable as well.

Our forecasts of the unadjusted capacity factor are based on a triangular probability distribution function allowing values between 30.0 and 50.0 percent with an average value of 40.0 percent.[17] This means the annual, unadjusted capacity forecasts can take any value between 30 and 50 percent, but will average 40 percent. Our choice of that particular distribution is based, in part, on actual productivity data from FPL Energy's Gray County wind facility (located near Montezuma, Kansas) and information available from Aquila's FERC Form 1 Reports.[18] That body of evidence suggests an (unadjusted) average annual capacity factor of approximately 37 percent may be reasonable.[19] However, other evidence suggests newer turbine technologies are likely to be more productive and, therefore, may provide higher capacity factors on average. It is for that reason we set the expected annual, average unadjusted capacity factor forecast for the state at 40.0 percent. Because turbine design continues to change (particularly in areas affecting their reliability), an extensive body of both state- and design-specific evidence is not readily available. As additional experience

[17] The actual distribution of unadjusted capacity factors is difficult, if not impossible, to establish with certainty. Conventional wisdom suggests the capacity factor distribution is probably unimodal. Some of the more widely known probability distributions, such as the normal and chi-square, admit the possibility of selecting extremely large capacity forecasts, possibly greater than 100 percent. In order to avoid the possibility of extreme, unrealistic forecasts, while maintaining the unimodal characteristic, we employ the triangular distribution. Having specified a particular triangular pdf, the specification of the unadjusted, annual capacity factor as a particular type of random variable is complete. For completeness, we also examined using the lognormal distribution to forecast the unadjusted capacity factors and found the NPV forecast results to be effectively equivalent to the results obtained with the triangular distribution. That suggests the wind energy production forecasts are *possibly* robust per the selection of a pdf to represent the unadjusted capacity factor.

[18] Some of that data has been deemed confidential by Aquila and is being treated accordingly.

[19] FPL Energy LLC is a subsidiary of FPL Group, Inc., and the owner of the Gray County facility.

with commercial wind energy production in Kansas is accumulated, there will be an improved basis for specifying the unadjusted capacity factor pdf.

Our forecasts of the annual degradation factor are based on a lognormal distribution function with a median value of 1.0 percent and a range of possible values from zero (0) to five (5) percent.[20] This means, in terms of annual, degradation forecasts, they can take any value between 0.0 and 5.0 percent, but will average between 1.1 and 1.2 percent. Thus, the downward adjustments to the unadjusted capacity factor are between zero and five percent per year. Those adjustments reflect the consequences of the constantly aging equipment.

Having described the two components of our capacity factor forecasts, we bring them together as follows:

1. for the first three years (t = 1, 2, 3) of the wind facility:

   CF(t, f) =

   unadjusted capacity forecast (f), and

2. for the remaining 17 years (t = 4 through 20) of the wind facility:

   CF(t, f) =

   unadjusted capacity factor (f) – [(t - 3) × degradation factor forecast (f)].

Based on this CF forecast model, during the first three years of a wind facility's life, its forecast annual capacity equals the forecast annual unadjusted capacity factor forecast.[21] Thus, when the facility is relatively new—during the first three years of its life—we assume no degradation. After the third year, the forecast capacity factor reflects a possible, but likely,

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[20] The mean value of the distribution is between 1.1 and 1.2 percent. The distribution is actually truncated at 5.0 percent in order to limit the possibility of extreme forecast values.

[21] The unadjusted capacity factor forecast is determined by a random selection from the triangular pdf.

downward adjustment of the forecast unadjusted capacity factor.[22] Generally, the adjustment is determined by the degradation factor forecast and the age of the facility.[23]

As a numerical example, if the forecast (i.e., randomly selected) unadjusted capacity factor is 40.0 percent and the forecast (i.e., randomly selected) degradation factor is 1.1 percent, then the forecast capacity factor is 40.0 for the first three years. Starting in the fourth year of operation, the annual capacity factor forecast would be reduced 1.1 percent to approximately 39.55 percent. It would decrease 1.1 percent each year through year 20. Hence, in years five, six, and seven the forecast capacity factors would be about 39.12 percent, 38.69 percent, and 38.27 percent, respectively. In the twentieth year of operation the forecast annual capacity factor would be about 33.14 percent.[24] Note that the unadjusted capacity factor forecast, once made, is the same for each of the 20 years. The degradation factor forecast, once made, is the same for each year from the fourth to the twentieth. Thus, the unadjusted capacity and degradation factor forecasts are both made just once for the full 20-year investment horizon. Lastly, the degradation factor is not compounded, but applied as a simple annual average rate.

4.43 Repeated Random Sampling Means Repeated Forecasting: Drawing 200,000 Forecasts

By plugging the unadjusted capacity factor and degradation factor forecasts into the formulations presented in Sections 4.41 and 4.43, we obtain a single forecast of the average

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[22] The degradation factor can be zero, but it is likely to be positive.
[23] The degradation factor forecast is determined by a random selection from the lognormal pdf.
[24] For this numerical example, the average annual forecast capacity factor over the life of the facility is about 36.82 percent. For this numerical example, both the unadjusted capacity and degradation factor forecast values are assumed to equal their average forecast values, 40 percent and 1.1 percent, respectively. Thus, it is worth noting, the average annual capacity factor forecast for this example, 36.82 percent, equals the average capacity factor forecast across all forecast scenarios considered in this study. To put it very simply, over the relevant time horizon, we assume the forecast capacity factor will average just under 37 percent.

annual capacity factor for each year in the forecast horizon, 2002 through 2034. New forecasts of the average annual capacity factor for each year of the forecast horizon are easily derived—by simply repeating the random selections of the unadjusted capacity and degradation factor forecasts and reapplying the relevant formulations. For each case study we examine, we derive 200,000 different capacity factor forecasts. Obviously, those forecasts are themselves based on 200,000 different forecasts of the unadjusted capacity and degradation factors.

4.50 Forecasting the Input Variables

4.51 The FOM Input Variable Forecast Model: FOM(u, t, f)

Among the input variable forecasts, deriving the FOM forecast is the most involved. The FOM variable is the annual, incremental generation cost that the utility *avoids* or saves as a consequence of its reliance on wind energy production, qw(t, f). That savings amount includes fuel, O&M, purchased power, and environmental compliance cost (per existing regulations) savings. An accurate and convenient way to measure that cost savings is to multiply the utility's average, annual lambda by the quantity of wind energy taken during the year.[25] In Section 3.13, we denoted the FOM input variable:

$$\mathrm{FOM}(u(gm), t, f) = \lambda(u(gm), t, f) \times qw(t, f).$$

Since the system lambda, $\lambda(u(gm), t, f)$, is measured in dollars per MWh and qw(t, f) is measured in MWh, FOM measures the total dollar savings in fuel, O&M, and environmental compliance costs due to wind energy being substituted for traditionally generated energy.

[25] Previously we defined the utility's system lambda as its incremental cost of generating one MWh of electricity while operating at its output margin. We also assume the utility pursues arbitrage opportunities and, therefore, its system lambda tends to equal the price at which it can purchase one MWh.

This formulation makes clear that forecasting the FOM input variable requires a forecast of the utility's average, annual system lambda, λ, and the amount of wind energy production per year, qw(t, f). Having already described the forecasting of qw(t, f), we turn to the forecasting of the lambda.

A. Forecasting the Average, Annual System Lambda: Background

System lambdas normally vary by utility and, therefore, it is necessary to develop lambda forecasts by utility-type (as indicated by the notation). Accordingly, we develop lambda forecasts for each of the four utility-types. Lambdas among various utilities can differ for a number of reasons. However, in terms of sustained differences over long periods of time, possibly spanning decades, for Kansas utilities we find that the utility's relative reliance on natural gas as a generating fuel is likely to explain the significant differences in lambdas.[26] As discussed in Section 3.13, we measure the utility's relative reliance on natural gas by its gas mix (gm), which we define as that proportion of the utility's annual, retail sales served by natural gas-fueled generation.[27] The data shows a positive relationship between the utility's gas mix and its average annual system lambda: the higher the gas mix, the higher the average lambda. Consistent with maintaining that relationship, in order to forecast the lambda for a particular utility-type, it is necessary to forecast its gas mix.

B. Forecasting the Utility's Annual Gas Mix and Cost Structure

Since differences in gas mix effectively represent structural differences between utilities, the models we use to forecast the utility's gas mix are specific to the utility-type.

[26] In short, different cost structures among regulated utilities are largely explained by differences in fuel contract and generation asset portfolios.
[27] Recall, we also include in that calculation the utility's use of petroleum products generally.

Yet, relying on information from the jurisdictional utilities' 2000-2005 FERC Form 1 Annual Reports, for each utility-type we find considerable year-to-year variability in gas mix. That variability may be due to several factors: variations in annual weather (both over the year and during peak-load periods), changes in relative fuel prices, rail network congestion (possibly due to weather-related problems) that may affect coal inventory levels, occurrence of unplanned outages, and regional grid congestion that may affect the utility's dispatch. In accordance with the *random* nature of weather conditions, fuel price *changes*, and operating conditions generally, it is reasonable to model the utility-type's gas mix as a random variable. Accordingly, we model each utility-type's annual gas mix as a probability distribution function and then use that pdf to derive gas mix forecasts.[28]

For the low cost utility-type, modeled after Westar/KCPL, we assume the gas mix is distributed as a triangular distribution that ranges from 0.56 percent to 5.00 percent with a mean value of 2.00 percent. For the high cost utility-type, modeled after WestPlains, we again assume the gas mix is distributed in accordance with a triangular distribution function, but with a range from 7.54 percent to 40.76 percent and a mean value of 20.00 percent. The gas mix for the middle cost utility-type is lognormally distributed, with a range from 1.55 to 15.35 percent and a median of 5.00 percent. Lastly, gas mix for the statewide average-cost utility-type is assumed to be distributed lognormally with values ranging from 1.24 percent to 15.04 percent, with a median value of 4.00 percent.[29] In summary, by making random selections from these pdfs, we derive forecasts of each utility-type's annual gas mix.

[28] In other words, we take differences between one utility-type's gas mix and another's to be largely explained by their structural differences. But we believe the year-to-year variations in a specific utility's gas mix are due mainly to random variation.

[29] Attempting to achieve a better fit with the existing data sets, we use the lognormal distributions for the gas mixes that are more dispersed *relative* to the median value of the distribution. For example, for the statewide average utility, the maximal gas mix is nearly four times larger than the median. In contrast, for the high-cost utility-type the maximal gas mix is only twice the value of the median. The lognormal gas mix distributions are

C. The Initial System Lambdas: Points of Departure

For each utility-type, all of the lambda forecasts are, in part, based on an initial-year forecast lambda value. That is, the forecast lambdas for 2007 through 2034 are based partly on the forecast for the initial year, 2006. By design, the initial-year forecasts *average* \$21.40, \$32.70, \$42.50, and \$25.20 per MWh for the low, middle, high, and statewide average-cost utility-types, respectively. Those average values are based largely on actual system lambda information provided (confidentially) by the utilities, as well as public information contained in the utility's FERC Form 1 Annual Reports. More specifically, the average initial-year values were selected so that they effectively *matched* the actual average system lambdas as of the end of 2005. For example, at the end of 2005, based on information available at that time the system lambda for the low-cost utility-type (i.e., Westar/KCPL) was approximately \$21.40/MWh.[30] Furthermore, for each utility-type the initial, average lambda and average gas mix are effectively calibrated. That means, for instance, that when the low-cost utility-type's gas mix is forecast (for 2006) at exactly 2.00 percent, which is the average forecast value for that utility's gas mix variable, then its lambda forecast (for 2006) will be \$21.40/MWh, which is the average forecast value for that utility's lambda. For each utility-type, when the gas mix variable is forecast at its average value, its forecast lambda will be at its average value. Moreover, when the gas mix forecast for the low-cost utility exceeds (is

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actually truncated at the indicated maximal values. Lastly, the average annual gas mix for the statewide average-cost utility-type is based on data provided by the Energy Information Administration (EIA) showing total, annual generation (in MWh) by energy source. The EIA data show that Kansans get nearly 96 percent of their electricity from coal and nuclear sources. The same source shows that Kansas' relative reliance on natural gas as a generating fuel has *consistently decreased* in the last 15 years, being the highest during that span in 1991 at 10.01 percent. Given that the relative price of natural gas (and crude oil) has increased rather significantly in the last two years, it seems likely this downward trend will continue at least over the near term. Our gas mix forecasts *do not* take account of this historical trend toward relatively lower gas use (for electric generation) in Kansas.

[30] While we consider these respective, utility-type estimates to be reasonable, to be conservative in our derivation of forecast lambdas we believe these estimates probably have a slight upward bias.

less than) 2.00 percent, then its forecast lambda will exceed (be lower than) $21.40/MWh. The positive correlation between gas mix and average system lambda holds across utility-types: the more gas dependent utility-types have the relatively larger initial system lambdas.

In summary, by forecasting the utility's gas mix, we obtain a forecast of the economic intensity with which that utility uses natural gas to generate electricity. In that regard, gas mix forecasting is tantamount to forecasting change in the utility's cost structure. By construct, the larger the utility's gas mix forecast, the larger its forecast lambda. And the larger the utility's forecast lambda, the larger the forecast fuel savings due to wind-energy production, FOM. For each utility-type, the gas mix and lambda forecasts are calibrated one with the other; moreover, the respective lambda forecasts are all based on—that is, effectively pegged to—the actual lambdas that existed as of late 2005. The essence of the gas mix forecasting is that it enables us to forecast how possible changes in the utility's cost structure, as measured by gas mix, are likely to affect its system lambda.

D. Fuel Price Forecasts

Besides changes in cost structure (i.e., gas mix), utility lambdas are also influenced by changes in fuel (natural gas, coal, oil, and processed uranium) prices, incremental (i.e., variable) O&M expenses, and incremental environmental compliance expenses. By far the largest component of the system lambda is the fuel expense. In Kansas the primary fuel sources of electric generation are coal, nuclear and natural gas/petroleum. In 2004, approximately 74 percent of total generation (in MWh) came from coal-fired units, 22 percent from Wolf Creek, and 3.6 percent from the combined use of natural gas- and petroleum-fired generation. Moreover, for a given gas mix (or cost structure), the utility's

fuel expense components are largely driven by fuel price changes. Therefore, when the gas mix variable is taken as given, forecasting the system lambda is determined largely by fuel price forecasts. Since nearly 100 percent of traditional generation is now, and will likely continue to be, sourced by these three fuels, we concern ourselves with only coal, uranium, and natural gas price forecasts.

Before we turn to the discussion of price (or unit cost) forecasting, some additional background may be of use to make the distinction between forecasting nominal and real prices. All of our forecasts are strictly of the latter—that is, real prices.

E. Price Forecasts and Inflation Forecasts: An Aside

Since our objective is to forecast the *net present value* of meeting the Challenge, we choose to develop dollar value forecasts measured in real, not nominal, dollar terms.
For that reason, all expense forecasts in this study are in terms of 2005 constant dollars. This implies the expense forecasts are all *adjusted* for the inflation that is likely to occur over the investment horizon 2006 through 2034. That adjustment effectively removes the nominal effect inflation has on the value of a dollar over time. Because we use 2005 constant dollars as the basis for measuring real dollar value, inflation is included in the analysis, but its inclusion is implicit. For example, for any commodity whose price in 2005 is expected to inflate each year at a rate equal to changes in the GDP Deflator through 2034, if that expectation holds throughout and if the GDP Deflator is then used to reverse the effects of inflation, the real price of that commodity in 2034 will equal its price in 2005.[31] Thus, the

[31] The GDP Deflator is the price index used to deflate nominal measures of GDP, thereby converting them to measures of GDP in real dollars. The GDP Deflator is similar to the more widely known Consumer Price Index (CPI), the difference being the "market baskets" on which the two indices are based. Since it encompasses all

real prices of commodities whose nominal prices inflate at a rate consistent with a specific index remain unchanged over time if that same index is used as the deflator. Table C illustrates this point.

Table 4.2: Changes in Nominal vs. Real Prices			
Year	**Nominal Price**	**Rate of Inflation**	**Real Price**
2005	$10.00	---	---
2006	$10.23	2.3%	$10.00
2007	$10.60	3.6%	$10.00
2008	$10.79	1.8%	$10.00
2009	$11.09	2.8%	$10.00
2010	$11.18	0.8%	$10.00

On the other hand, if the commodity's nominal price increases at a rate in excess of (less than) the rate embedded in the price index used for deflating, then the real price of that commodity is increasing (decreasing) over time.

In this study we take the GDP Deflator as the benchmark inflation index and 2005 as the base year. Thus, our fuel price forecasts are vis-à-vis that index and in terms of 2005 constant dollars. With the exception of our natural gas price forecast, which is based on a more rigorous analysis, our fuel price and unit cost forecasts are essentially price assessments relative to the GDP Deflator. Thus, for instance, forecasting that a fuel price will inflate in excess of the GDP Deflator implies an increase in the utility's system lambda as measured in 2005 constant dollars. The size of that increase depends on the magnitude of fuel price inflation and the relative importance of the fuel in terms of the utility's fuel portfolio.

Finally, unless stated otherwise, all prices presented in this study are measured in 2005 constant dollars, and all expense forecasts are similarly based. Forecast changes in real

goods and services produced by the domestic economy, using the GDP Deflator offers the broadest measure of inflation – which, for simplicity, we hereafter refer to as the national rate of inflation.

costs are the basis for forecast price changes; changes in forecast expenses are based on changes in forecast real price and/or quantities.

F. The Delivered Coal Price Forecast

Based on an evaluation of coal price inflation over the last four decades, and given the *current*, relative abundance of domestic coal sources, we assume the delivered price of coal will inflate at a rate that, on average, roughly matches changes in the GDP Deflator (hereafter, national inflation rate) over time.[32] In other words, our delivered coal price forecast is simply that the price of delivered coal to utilities over the investment horizon will, on average, increase at the national inflation rate.[33] This necessarily implies that the coal cost component of the system lambda would inflate over the investment horizon at the national inflation rate. Furthermore, over the long term, we expect all Kansas utilities will pay the same price for delivered coal, *on average*. Therefore, we assume the same delivered coal price forecast for each of the four utility-types.

Our coal price forecast is based on historical trends and on the security of the supply source (being domestic) and the size of known reserves. It is hard to imagine significant, long-term disruptions in the domestic coal supply, though there could be occasional delivery disruptions given the length of time it takes to increase rail transport capacity.[34] As a

[32] The Energy Information Administration (EIA) provides historical time series information on numerous generation fuel prices, including unbundled and bundled (i.e., delivered) coal prices.

[33] Since the delivered coal price is a bundled price, if the bundled price does inflate at a rate that roughly equals the national rate, then it is possible that the unbundled price of coal would inflate at a rate below the national inflation rate. That would occur if the transportation component of the bundled coal price inflates at a rate above the national inflation rate, which may be likely. With our assumption about the bundled price, if the transportation component of the bundled coal price inflates above the national inflation rate, then the coal component must inflate below the national inflation rate.

[34] That said, when and where it is profitable to expand rail network capacity, we do expect those expansions would be forthcoming. However, if those expansions do not occur in a timely fashion, it is possible that delivered coal prices could inflate in excess of the national inflation rate.

commodity with a large amount of known reserves, arguably the production of coal is likely to display constant returns to scale. These factors also suggest the coal price series is likely to be mean reverting.[35] Coal's dominance as a fuel source for electric generation in the United States appears unlikely to change any time soon. Additionally, given coal's significance as a fuel source for electric generation, and given the significance of electricity to the economy as a whole, changes in the price of delivered coal may be as much a source (cost push) of inflationary forces in the economy as a consequence. All this suggests that whether there's upward pressure on the demand for coal due to a growing global economy or downward pressure on coal demand owing to environmental concerns with its use, the long-term secular trend in the *real* price of coal is likely to be flat. It is because of these considerations that we assume the delivered price of coal will inflate at a rate consistent with the national rate of inflation, whatever that rate reveals itself to be over time.

Since we forecast the real price of delivered coal to be unchanged over the investment horizon, provided the gas mix forecast is similarly unchanged, it follows that the coal expense component of the various forecast system lambdas, as measured in 2005 dollars, is not a source of change. Thus, for each utility-type, delivered coal price inflation is not forecast to be a basis for changing system lambda forecasts (measured in 2005 constant dollars).

G. The Processed Uranium Price Forecast

Only the low-cost utility-type's system lambda, the one modeled after Westar's/KCPL's lambda, reflects the cost of uranium. Quoting Westar's 2005 10K Form:

[35] With shocks to the demand for or short run supply of coal, to be mean reverting implies the coal market is able to restore equilibrium at a price that accurately signals the long-run marginal cost of production.

"We have 100% of the uranium and conversion services needed to operate Wolf Creek through September 2009 under contract. We also have 100 percent of the enrichment services required to operate Wolf Creek through March 2008 under contract. Letters of intent have been issued with suppliers for a majority of wolf Creek's uranium, conversion and enrichment requirements through 2017. Fabrication requirements are under contract through 2014."[36] It is also our understanding that Westar uses a portfolio approach for all of its uranium conversion and enrichment contracting. This implies Westar is continually entering new contracts with possibly differing and staggered terms. As we understand it, the contracts for uranium, conversion, and enrichment are typically long-term, fixed price contracts. Thus, while the 10K Form details the time periods where Westar has full contract coverage (at 100 percent), it currently has varying degrees of contract coverage in other future time periods (not *specifically* referred to in the 10K).[37]

At least for the next ten years or so, since Westar has entered fixed-price contracts, it appears Wolf Creek's (average annual) fuel cost is largely insulated from inflationary forces. Beyond that time period, of course, it is difficult to establish price forecasts with high confidence. And because there is no futures market for trading uranium, there are no market-based forecasts of uranium prices. While there is a spot market for uranium, spot prices appear to be especially volatile, being quite sensitive to changes in inventories and trade restrictions. Moreover, because the standard commercial practice appears to rely heavily on long-term, fixed-price contracts, it is not clear that current spot prices provide a good indication of uranium's long-term scarcity value. Nonetheless, they may offer some indication of the long term.

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[36] See page 10 of Westar's 2005 10K.
[37] Westar indicates on page 41 of its 2005 10K that it has "contractual obligations" in terms of its nuclear fuel requirements for the years after 2010.

The spot market price for uranium ore has increased dramatically in the last year. According to some assessments, the price could reach $45/pound in the next year or two.[38] Current media accounts suggest the future spot price of uranium may be affected by issues such as waste storage and security costs, global warming and the potential need for electric generation that is free of CO_2 emissions, the robustness of public opposition to nuclear energy, concerns about the domestic uranium supply and mining capacity, threats of terrorism, increased business risk for utilities choosing nuclear rather than other fuels, etc. These considerations, either individually or collectively, make it difficult to forecast future nuclear prices.

Putting those considerations aside for the moment, since uranium is the primary competitor of coal as a baseload generating fuel, economic theory suggests that *long-term* uranium prices should be constrained by long-term coal prices.[39] Thus, while spot uranium prices may not be strongly influenced by conditions in the coal market, the opposite is likely to hold for long-term uranium prices.

Because coal is a competitive alternative to uranium and because Westar's 2005 cost of nuclear fuel is largely locked in through the 2010 – 2015 time frame, our forecast of the bundled price of procuring, converting, and enriching uranium over the investment horizon is that it will inflate at an annual rate that, on average, equals the national rate of inflation. For the low-cost utility-type, this implies that the (finished) uranium cost component of its system lambda, like the coal cost component, will inflate at the national inflation rate. Thus,

[38] Forbes: http://members.forbes.com/forbes/2006/0619/150_2.html.

[39] This relation could change if, for example, CO_2 emission controls are implemented. Regulations to control CO_2 emissions from coal-fired generation, all else equal, will lead to a higher price of uranium relative to coal. Similarly, the development of carbon control technologies, like sequestration, will also influence the price of coal relative to uranium.

for the low-cost utility-type, the price of delivered, processed uranium is not forecast to be a basis for changing system lambda forecasts (measured in 2005 constant dollars).

H. The Natural Gas Price Forecast

In contrast to coal and uranium price forecasts, there is considerable evidence that suggests natural gas prices will increase relative to the average, national price level. Based on that evidence, we assume the delivered price of natural gas in the Mid-Continent region (hereafter, price of natural gas) will, on average, increase at an annual rate that exceeds the national rate of inflation. Not only do we expect it to increase relative to the other conventional fuel prices, we also expect the price of natural gas to exhibit the greatest volatility (within any given time period). For that reason, we examine a wide range of possible natural gas price scenarios.[40] In some forecast scenarios, the price of natural gas inflates at a rate greater than the national rate of inflation; in others it inflates at a rate lower than the national rate of inflation, though most of the price scenarios we construct fall in the former category.[41]

To provide some sense of the range of natural gas price forecast scenarios considered in this analysis (and for just the terminal year of the investment horizon, 2034), in the most "optimistic" price scenario, the 2034 forecast price is \$2.90/MMBtu and in the least optimistic scenario (from the consumer's perspective) the 2034 forecast price is \$191.67. The median gas price forecast for 2034 is \$9.42. However, it is worth noting, each of those price

[40] Equivalently, that volatility is the basis for modeling the price of natural gas as a random variable.
[41] All of our natural gas price scenarios have the same starting point, which is the average annual price of natural gas in 2005. Each of our natural gas price forecasts scenarios consists of a set or *path* of annual natural gas prices for the years 2006 through 2034. As might be expected, what determines a particular path of natural gas prices is the underlying forecast rate of inflation for those prices. Thus, developing a wide range of natural gas price forecast scenarios is the result of applying a wide range of possible natural gas price inflation rates.

forecasts are measured in 2005 constant dollars. In current dollar terms, the average forecast price of natural gas in 2034 is approximately twice the current price, coming in between $13 and $15/MMBtu.[42]

In part, to derive our natural gas price forecast in any one year of the investment horizon, we assume the average annual price of natural gas is distributed lognormally. Again using the year 2034 as an example, to obtain a natural gas price forecast for that year we use a lognormal probability distribution function with truncated tails, $2.90 and $191.67 for the lower and upper tails, respectively. The median value of that distribution is $9.42. Actual price forecasts for that year are obtained by random selection from that distribution.[43]

Focusing on just the terminal year natural gas price forecast, we based the distribution function used to develop that forecast on (1) basis-adjusted, NYMEX-traded Henry Hub prices as of 9:31a.m., October 14, 2005, (2) long-term gas price forecasts developed by the EIA, and (3) 10-year moving average prices calculated in-house (for the purpose of extending the published forecasts beyond 2025). See Appendix D for a more complete and detailed discussion of the natural gas price forecasts and forecasting method used in this study.

In summary, among the three fuel components of the FOM variable, the unit prices for two—coal and uranium—are forecast to inflate at rates that match the rate of inflation for the economy as a whole, while the price of natural gas is expected to inflate at a rate that exceeds, *on average*, the rate of inflation for the economy. All else equal, this implies that over the 2006 – 2034 investment horizon and for each utility-type, we forecast annual system

[42] For purposes of this numerical example we assume the Deflator changes at an average annual rate of 2.25 percent.
[43] More precisely, we model natural gas price *paths* running from 2006 through 2034. Those paths are lognormally distributed. From among those paths, a random selection of a single path is used to establish a natural gas price forecast for each year of the investment horizon.

lambdas will *increase* relative to the average price in the economy. Given the fuel price forecasts we make here, the basis for relative increase in lambdas and, thus, the price of electricity in Kansas is the forecast inflation of natural gas prices.

I. The Other Cost Components of FOM

The other components of the system lambda, the incremental O&M (per MWh) and environmental compliance costs, are minor in comparison with the fuel cost component. At this time we are not aware of any significant changes on the horizon that would cause the cost (on a per MWh-basis) of either component to inflate at a rate significantly different than the national rate of inflation.[44] For that reason we assume the unit cost of both O&M and environmental compliance for each year of the investment horizon will inflate at an annual rate that, on average, equals the average, annual rate of change in the GDP Deflator (over the investment horizon). Thus, we do not expect the “other cost components” of the utilities’ system lambdas to be a source of real inflation.

Lastly, we assume all of the system lambda-related savings attributable to the utility’s acquisition of wind energy are passed through (or realized) by retail customers on an annualized basis. This is consistent with the assumption that all utility-types rely on the provisions of an approved (annual) pass-through mechanism, like an energy cost adjustment (ECA) mechanism.

[44] As discussed previously, the environmental compliance costs in question here are those associated with only the environmental regulations in place as of the end of 2005.

J. Summary: Deriving FOM Input Variable Forecasts

The forecast of the FOM input variable is itself built upon several, subsidiary forecasts. It is also built upon several simplifying assumptions that reduce the need for additional subsidiary forecasts. Forecasting the FOM variable requires forecasts of the amount of wind energy produced each year over the investment horizon, qw(t, f). In turn, forecasting that variable requires forecasts of the unadjusted capacity factor as well as the capacity degradation factor. It also requires making an assumption about the timing of wind capacity installations—which is embedded in the specification of the iwc(t) variable. Forecasting the FOM variable for specific utility-types also requires forecasts of their respective system lambdas. The lambda forecasts, in turn, depend on gas mix forecasts and natural gas price forecasts. The lambda forecasts also depend on assumptions made regarding coal and uranium price inflation forecasts.

For each utility-type, an individual FOM forecast for each year of the investment horizon requires making four other forecasts: unadjusted capacity factor, capacity factor degradation, gas mix, and natural gas price (path) forecast. For each case study, we derive 200,000 different FOM forecasts (which provide a forecast FOM value for each year of the 29-year-long investment horizon). That is, for each case study we consider 200,000 randomly selected forecast scenarios, and for each scenario we obtain a single FOM forecast. That single FOM forecast consists of a set of 29 annual FOM forecasts. Equivalently, a single FOM forecast actually consists of a *set* of annual forecasts that lays out a *path* of annual forecasts over the investment horizon.

Across the set of FOM forecasts, the average forecast annual lambda, measured in 2005 constant dollars, is increasing over time. That forecast is based on an expectation that

real, inflation-adjusted fuel prices will increase, on average, over time due mainly to forecast increases in the real price of natural gas. Since wind energy production displaces the use of traditional fuels, *strictly in terms of that displacement* we forecast wind energy (per MWh) will be increasingly valuable over time. But whether that holds overall remains to be seen—as revealed through the analysis of forecast NPVs.

4.52 The APC Variable Forecast Model: APC(t, f)

As defined, the APC variable is the mathematical product of the avoided variable pollution control cost per MWh (referred to as the unit APC) and the amount of wind energy acquired by the utility during the year. We formulate that product as:

$$\text{APC}(t, f) = \text{unit APC}(t) \times qw(t, f).$$

Our forecasts of the unit APC are based, in part, on Westar-specific data (from Direct Testimony provided by Westar Energy witness, Mr. Kelly Harrison, KCC Docket No. 05-WSEE-981-RTS). Since the APC input variable captures the avoided cost associated with operating newly installed, post-2005 pollution control equipment, the 2005 unit APC is $0.00. The 2006 unit APC forecast is set at $0.075/MWh. Subsequent annual forecasts increase by $0.075/MWh each year until 2015, when the forecast unit APC reaches $0.750/MWh. The 2006 through 2015 unit APC forecasts are also based on the analysis performed by Mr. Harrison. Because Westar will be installing additional pollution control equipment over that eight-year time period, the forecast unit APC is expected to increase as additional investment in control equipment is made operational.[45] It is difficult to anticipate changes in environmental regulations and standards, particularly for years well into the

[45] As pollution control investment is made at the planned generating units, the symbiotic load at those units is expected to increase.

future. Nonetheless, for the traditional pollutants,[46] we assume that after 2015 emission standards will be ever more stringent, requiring additional (i.e., more intensive) investment in pollution control equipment and, thus, ever higher unit APCs. Therefore, after 2015 our forecast unit APCs increase by $0.005/MWh every year, reaching a 2034 forecast value of $1.320/MWh.[47] In short, our unit APC forecasts over the investment horizon amount to an assumed schedule where the unit APC mechanically takes a pre-determined value. Lastly, since the unit APC is assumed to be the same for all utility-types, we use the same forecast schedule for all.

It is worth emphasizing that, as defined, the APC input variable does not include consideration of operating costs associated with any form of carbon regulation. It is difficult to anticipate if and when such regulation might be implemented and, therefore, we make no effort to include that potential in our APC input variable forecasts. This does not suggest that we ignore that potential. Rather, we handle carbon regulation as a special case wherein we estimate the NPV of the Challenge in the presence of certain, hypothetical carbon tax levels.[48]

As the formulation of the APC input variable shows, the forecast APC, like the forecast FOM, depends on the forecast quantity of wind acquired by the utility, qw(t, f). Both the APC and FOM input variable forecasts utilize the same wind quantity forecast. Having already described the latter, as well as the unit APC forecast, we have now fully specified the APC input variable forecast model.[49] Again, for each case study, 200,000 forecast scenarios

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[46] Only CO_2 emissions are not included among the more "traditional" pollutants.
[47] By these forecasts we are assuming that the unit APC cost will inflate at a rate in excess of the average rate of inflation for the U.S. economy.
[48] See the results for Special Case 5 which is described in the next chapter.
[49] We assume the savings associated with the APC input variable would be realized by customers on an annual basis and, therefore, would be passed through via an ECA-type mechanism. This is basically in accordance with the current treatment of incremental pollution control costs, such as the cost of SO_2 allowances.

are evaluated. Thus, for each case study we derive 200,000 different forecasts of the APC input variable. Because the APC input variable is measured on an annual basis, each individual APC forecast (or, more precisely, forecast scenario) actually provides a set of numerical (forecast) APC values, one for each year of the investment horizon, 2006 through 2034.[50]

4.53 The CAP Input Variable Forecast: CAP(t)

In accordance with the definition of the CAP input variable, this variable is computed by taking the mathematical product of (1) SPP's rate capacity credit for wind facilities, (2) the total MW amount of installed wind capacity (which is determined by capacity installation and depreciation schedules), and (3) the dollar value (or cost) of one MW of generating capacity. While SPP's capacity rating method may change in the future, we have no indication of the potential direction of change. Therefore, we presume the current rating method, informal as it is, will nonetheless be used throughout the investment horizon. Using that presumption and based on our understanding of that method, we forecast a capacity credit rate of seven (7) percent for each MW of installed wind capacity.

As stated previously, in accordance with traditional cost of service regulatory standards, we set the 2005 value of one MW of avoided generation capacity at $65,000 per year. That value represents the capacity cost the utility can avoid by going down the wind path rather than the "business as usual" path. The avoided capacity value per MW is based on the cost of installing a combustion turbine, which is essentially an old-line technology that is fully developed, widely deployed, and well established in terms of operating performance.

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[50] Equivalently, like the FOM input variable forecast, a single APC input variable forecast is actually a forecast *path* over the investment horizon of annual savings.

The demand for combustion turbines will depend on many factors, but among them the relative price of natural gas may be critical. Since we assume a moderate increase in the relative price of natural gas, this alone is likely to put some downward pressure on turbine demand. On the other hand, the relative price of steel increasing over time would put upward pressure on turbine prices. While we see different forces that could alter the real cost of turbines over time, because it is an old technology involving the use of an increasingly scarce fuel, we forecast a balancing among those forces. Mainly for that reason we expect the real cost of turbine-based capacity to be roughly constant over the investment horizon. It follows directly that our forecast avoided capacity cost per MW per year ($65,000 in 2005 dollars) remains constant over the investment horizon.

The derivation of the CAP input variable forecasts is completely given by (1) the forecast avoided capacity cost per year per MW ($65,000), (2) the forecast capacity credit rate (0.07), and (3) the forecast quantity of installed wind capacity by year, which is simply the assumed installation schedule, iwc(t). All three "forecasts" have been previously described.[51]

Perhaps it is obvious, but the CAP input variable forecasts are not dependent on any particular forecast scenario, f. For each case study we derive a single forecast of the CAP variable. That forecast consists of a path of 29 different numerical (forecast) values; one for each year of the investment horizon. Among all the methods used to forecast the input variables, the method used to forecast the CAP variable is among the more mechanical.

[51] Mainly for simplicity we assume the forecast CAP-related savings would pass through to customers on an annual basis, through an ECA mechanism. We also see the capacity rating credit as more of an incentive offering by the regional reliability agency, here the SPP, rather than a *bona fide* displacement of real capacity requirements. Certainly it is possible that utilities would perceive the seven percent capacity credit as being so small that it would be effectively "lost in the noise." In that case, the capacity credit savings would, as a practical matter, be zero.

4.54 The PTC Input Variable Forecast: PTC(t, f)

Among the input variables, the PTC input variable is perhaps the easiest to forecast. By provisions in existing federal law, the unit PTC, currently at about $19.00/MWh, is inflated annually based on the annual rate of change in the GDP Deflator. Because it is a rare event for a government subsidy, once initiated, to be eliminated, we therefore presume the existing federal PTC provisions will be maintained over our investment horizon.[52] Since we specify the GDP Deflator as the relevant inflation index for converting nominal prices to real, by our presumption the current unit PTC, $19.00/MWh, becomes the forecast unit PTC, in 2005 dollars, over the entire investment horizon.

Like the FOM and APC input variables, forecasting the PTC input variable also requires a forecast of wind energy production, qw(t, f). All input variables whose definitions include the quantity of wind energy production, qw(t, f), use the same forecasts of that production. Since for each case study there are 200,000 forecast scenarios used to develop forecasts of qw(t, f), that necessarily generates 200,000 forecasts of the PTC input variable for each case study. For each forecast scenario there are 29 numerical (forecast) PTC values, one for each year of the investment horizon. Thus, like the FOM input variable forecast, a single PTC input variable forecast is actually a forecast *path* over the investment horizon of annual savings.[53]

4.55 The Avoided External Cost Forecast: EXT(t)

[52] Of course, there are several reasons for maintaining the current federal PTC for wind energy production.
[53] We assume the PTC would flow through an ECA mechanism.

As previously discussed, based on a study by the EPA, we set the external cost of generating one MWh of electricity at $20.00. We interpret that as the external cost associated with dispatching representative portfolios of conventional generation assets and their accompanying fuel contracts. That is, the $20 estimate is interpreted as the *average external cost* associated with the generation of one MWh of electricity using conventional means. Because the $20 estimate is an average, the external cost associated with one MWh of coal-fired generation is certain to exceed that estimate, whereas with gas-fueled generation it is likely to fall below, and with emission-free nuclear-fueled generation it would certainly be even less.[54] Since we are interested in forecasting the annual, statewide external cost associated with conventional generation, there is little need to disaggregate that cost.

In keeping with the EPA's study of externalities in Kansas, the $20 estimate is based almost exclusively on health-related costs and, therefore, is based on the cost of medical and health-related services as well as the monetary value of a statistically measured human life time.[55] We make no real attempt to assess or determine how inflationary forces are likely to affect the health-care and allied fields, nor the social value of life expectancy. Changing population demographics suggest proportionally larger amounts will be spent on health-care services, yet technological innovations will serve to reduce the unit cost of providing those services. Furthermore, as society spends proportionally larger amounts on health care, inflation within the health-care sector will be an ever larger determinant of economy-wide inflation. For these reasons, we assume health-related costs will inflate at a rate that matches

[54] The fact is that the $20 estimate is based strictly on coal plant emissions. However, given our use of annual, statewide MWh production as the basis for arriving at the $20 estimate, it works well for forecasting annual, statewide (i.e., aggregate) external costs, which is our objective. Similarly, compared to the other utility-types, the $20 estimate probably provides a better forecast of the annual external cost associated with the statewide, average-cost utility-type.

[55] Therefore, it captures the cost associated with reductions in life expectancy as a function of exposure to certain emissions.

the rate of inflation for the economy. In that case, the unit external cost will do the same. We assume the external cost of $20/MWh in 2005 will inflate each year consistent with changes in the GDP Deflator. Equivalently, we assume the average external cost per MWh of conventional generation remains constant over the investment horizon at $20, measured in 2005 constant dollars.

The EXT input variable forecast, like the FOM, APC, and PTC forecasts, depends on the forecast amounts of wind energy production, qw(t, f). Having described our forecast of the unit external cost and qw(t, f), our description of the EXT input variable forecast method is complete. For each case study we draw a total of 200,000 different forecast scenarios. Thus, for each case study we develop 200,000 different EXT variable forecasts. For each forecast scenario, the resultant EXT input variable forecast consists of 29 numerical (forecast) values, one for each year of the investment horizon—showing the forecast external cost savings by year.[56]

4.56 The LLE Input Variable Forecast: LLE(t)

Currently, owners of wind capacity typically pay for their use of (actually, access to) land through leases and, consequently, incur a rental or land lease expense. The terms of land lease arrangements are generally negotiated and could vary considerably from place to place. Nevertheless, consistent with our understanding of actual land lease payments by wind developers in Kansas and the estimated land lease expense used in NREL's JEDI model, we set the 2005 average land lease expense at $4,000/MW per year (per the average amount of land area required to install one MW of wind capacity).

[56] Of course any reduction in external costs would be realized by the public in real time.

Land rental rates are typically correlated with agricultural commodity prices. Accordingly, ag price forecasts probably offer a reasonable basis for forecasting land lease rates. With that in mind, we assume that lease expense per MW will inflate at a rate that, on average, roughly equals the rate of inflation as determined through the GDP Deflator.[57] Therefore, we effectively forecast the $4,000/MW lease rate, as measured in 2005 constant dollars, to be constant over the investment horizon.

As shown by its formulation, the LLE input variable forecast also depends on the pre-determined wind capacity installation schedule, iwc(t). Having already specified that schedule, as well as the forecast land lease rates per MW, we have now completed the description of the LLE input variable forecast model.

The LLE input variable forecasts do not depend on forecast scenarios nor do they depend on utility-types. For all case studies, a single LLE forecast (path) is derived. That forecast consists of the forecast annual lease payments made in support of meeting the Challenge, covering years 2006 through 2034.[58]

4.57 The PIL Input Variable Forecast: PIL(t)

The State of Kansas has a property tax exemption for property stemming from investments in renewable energy generation.[59] However, for various reasons, local government entities have generally sought and wind developers and utilities have generally agreed to pay some compensation in lieu of property tax payments, the so-called payment in lieu of property tax (PILOT). As we understand them, PILOT payments are usually made to county governments

[57] In order to maintain the real financial value of a land lease, we would expect to see most leases with a provision for payments to escalate based on a particular inflation index.
[58] For simplicity, and given that it is a relatively small cost item, we assume the recovery of the forecast LLE amount would be on an annual basis.
[59] K.S.A. 79-201.

and school districts. Based on our assessment of actual PILOT payments currently made vis-à-vis Kansas wind facilities and examples of PILOT payments made elsewhere, we set the 2005 estimated PILOT payment at $3,000/MW per year.[60] We assume future PILOT per MW will inflate at a rate that effectively matches the national average rate of inflation.[61] Thus in 2005 constant dollars, we assume the PILOT per MW is constant over the investment horizon.

Like the LLE input variable forecast, the PIL input variable forecast is fully described by the forecast unit PILOT amount and the assumed installed wind capacity schedule, iwc(t). The forecast PILOT amounts differ by year depending on the total amount of installed wind capacity, which varies with only time.[62]

4.58 The INT Input Variable Forecast: INT(t, f)

Based strictly on the recent MN study of wind integration costs, for each MWh of wind energy acquired by the utility, through either its own production or wind PPAs, we put the integration cost as of 2005 at $4.60.[63] As in the MN study, we assume a linear relationship between the utility's total wind integration cost and the amount of wind energy acquired over any given time period. As we understand the MN study, much of the integration cost of wind energy is an incremental cost based on the expense of conventional fuels. While we expect the average cost of conventional fuels (per MWh) to increase at a rate slightly in excess of the average rate of inflation for the economy, we assume the unit integration cost will

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[60] National Conference of State Legislators, January 2004 Briefing Paper, Vol. 12, No. 5, Lincoln County, MN.
[61] Like the LLE payments, PILOT payments are typically the result of private negotiations and, in order to maintain the real value of such payments, having an allowed escalation provision would be reasonable.
[62] For simplicity, and since it is a relatively small cost item, we assume the recovery of the forecast PIL amount would be on an annual basis.
[63] Based on conversations with Westar Energy officials, for Westar the wind integration cost (per MWh) could be significantly (perhaps two times) larger than the MN study-based estimate. Given that its cost structure is similar to Westar's, the same could hold for KCPL.

increase at an average rate that equals the rate of inflation for the economy.[64] Thus, once again, we assume a unit cost, measured in 2005 constant dollars, to be constant over the investment horizon.

The forecast model for the INT input variable is given by the forecast unit INT amount (of $4.60/MWh in 2005 constant dollars) and forecasts of annual wind energy production amounts, qw(t, f). As with every case study, we look at 200,000 different forecast scenarios and, thus, for each study make 200,000 different forecasts of the INT input variable. Each of those forecasts actual consists of a path of annual (forecast) amounts over the 29 years of the investment horizon, with each "path" establishing an annual forecast for each year.[65]

4.59.0 The Forecast WOM Input Variable: WOM(t, f)

One of the uncertainties associated with wind capacity installed in the field is its operational durability. The evolution of wind turbines with ever larger (nameplate) capacity ratings necessarily implies an evolution of reliability and O&M characteristics. And because of the near continual evolution of design, there appears to be little highly accurate historical evidence by which to assess the expected operating or reliability performance of the *newest* designs.[66] We believe it is possible that turbine design will continue evolving well into the next decade and perhaps beyond. This is based on the fact that turbines for the last two

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[64] This assumption is made for three reasons: one, the more realistic assumption is very difficult to incorporate in the model; two, while we regard the integration cost to be conceptually important, because of its relative size, the integration cost is unlikely to have a significant influence on the NPV results (to gain a sense for this see Appendix H, which describes the sensitivity analysis); three, the less realistic assumption favors the case for wind and, therefore, we consider it to be conservative.

[65] We assume the wind integration cost would be recovered on an annual basis through an ECA mechanism.

[66] In the course of this study we have discovered, for whatever reason, that actual O&M data is difficult to obtain. It is possible that the reason for this is simply because most investment in wind capacity has been by private developers selling the resultant production under contract. With most contracts wind developers have been at risk for reliability-related problems.

decades or more have faced and continue to face certain, critical reliability problems, such as those related to gearbox reliability.[67]

Because there is a high degree of uncertainty regarding wind equipment reliability and since the level of annual wind O&M expense is likely to have a significant effect on the NPV analysis, we use a probability distribution function to model the wind O&M expense. More precisely, consistent with our specification of the WOM input variable, we use a pdf to model the O&M cost per MWh of wind energy production. To forecast the unit WOM, we use a triangular distribution with a median value of approximately \$8.75/MWh and minimum and maximum values of \$4.00 and \$17.00/MWh. Obviously, that admits potential forecast values from \$4.00 to \$17.00/MWh, with 50 percent of the forecasts coming in at or below \$8.75/MWh.[68] These are statistical parameters consistent with those identified by NREL, which suggests a range from \$5.00 to \$10.00/MWh.[69] Note, by evaluating the wind O&M expense on a MWh basis rather than MW/year basis, we clearly interpret this expense as a variable, not fixed, operating expense.

Moreover, consistent with the available evidence on wind O&M expenses, we assume that as wind equipment ages the O&M cost per MWh will increase both nominally and in real terms. Continued evolution of equipment design, suggestive of continued non-standardization of equipment, may lead to holding of costly inventories of replacement parts and equipment and/or the risk of replacement equipment shortages in the future. To capture an increasing relative cost of wind O&M, due mainly to the effects of aging equipment and partly to non-standardization, we assume that the unit O&M expense will increase 250 basis points (2.50%) per year in *excess* of the average annual rate of inflation in the economy. In

[67] NA Windpower, Oct. 2006
[68] All forecast values derived from this pdf are measured in 2005 constant dollars.
[69] Conversation with Mr. Larry Flowers of NREL, April 2006.

real dollar terms, we assume the forecast unit O&M increases each year over the investment horizon.

To develop a forecast for the WOM input variable takes three steps. The first involves making a random selection from the unit wind O&M probability distribution. That selection can be thought of as the base unit WOM forecast; that forecast is also the unit wind O&M forecast for the first year of the investment horizon, 2006. The unit wind O&M forecasts for subsequent years are all based on the 2006 forecast, increasing at an annual rate of 2.5 percent each year until 2034.[70] The third step requires taking the product of the respective annual unit WOM and wind energy output forecasts.

Like several of the other input variables, the WOM input variable forecasts are derived within the context of 200,000 different forecast scenarios. Each scenario requires the random selection of a unit WOM forecast and, because the WOM forecast depends on the forecast qw(t, f), it also requires random selections of the unadjusted capacity and capacity factor degradation forecasts. Evaluation of each scenario yields WOM forecasts for each year of the investment horizon.[71]

4.59.1 The DEP Input Variable Forecasts: DEP(t, f)

Under COS agency regulation the utility recovers the cost of installing wind capacity (i.e., meeting the Challenge) through its allowed depreciation expense, which becomes one component of its allowed tariff rates. As previously defined, the DEP input variable captures the utility's annual, allowed depreciation expense associated with the Challenge. To forecast

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[70] As a randomly selected numerical example, if the 2006 unit wind O&M forecast were $8.50, then the respective 2007 and 2008 forecasts would be $8.71 and $8.93 per MWh. Under our assumptions, the forecast 2034 unit wind O&M expense (in 2005 collars) would be $17.39 per MWh. Our median value forecast for 2034 is approximately $17.91/MWh.

[71] The forecast annual wind O&M expenses are assumed to be recovered via an ECA mechanism.

that expense we need to forecast the relevant depreciation rate(s), initial dollar amounts invested in wind capacity (and subsequently ratebased), and the timing at which those investments are made.

For regulated, retail rate-making purposes, straight-line depreciation is the standard allowed method. For federal tax purposes, the federal government allows accelerated depreciation on certain investments in renewable energy forms, including wind.[72] As previously discussed, we assume wind turbines will have 20-year economic lives. Obviously, we use that life expectancy as the basis for setting the utility's depreciation rates.[73] However, experience with actual turbine installations (and the corresponding historically given data set) is showing that a 20-year expected life may be optimistic. For the major and, therefore, more costly components (gearboxes, bearings, generators), the actual economic life maybe be closer to 10 to 15 years. Equivalently, actual replacement of major components may be required if the originally forecast 20-year life expectancy is to be realized. And, of course, if major replacement is required (to actually meet the 20-year life expectancy), that simply becomes an additional expense that would need to be included in the analysis. While we believe it is a reasonable possibility that major replacement of equipment will be required to achieve 20-year economic life expectancies, we do not include an explicit (forecast) replacement cost component in the current analysis. That we leave for future research.

[72] Based on our understanding of the federal tax provisions and the KCC's possible rate-making treatment of them, we also include a tax savings amount due to the accelerated depreciation allowance.
[73] It is also the life expectancy built into the assumed installed wind capacity schedule, iwc(t). That schedule is a component of the forecast amount of wind energy production, qw(t, f), which in turn is a critical component of several input variable forecast models. Any changes in the forecast life expectancy of wind turbine life, but particularly reductions in that expectancy, are likely to result in significant changes in forecast results.

Finally, with the depreciation rates based on expected 20-year useful lives, we also assume a net terminal value of zero.[74]

Besides the allowed depreciation rates, the (forecast) annual depreciation expense associated with the utility meeting the Challenge depends on few other key factors. However, primary among those factors is the installation cost of wind capacity. At this time, there is considerable uncertainty about the level of future installation costs. In just the last five years or so, the installation cost has gone from around $1 million to over $1.6 million per MW of nameplate capacity. As of the current time period (September 2007), based on informal conversations with utility officials and wind developers, the actual installation cost is likely to be in the range of $2.1 – $2.2 million per MW.

Based on our observations, the annual rate of increase in the installed capacity cost has been far in excess of the average annual inflation rates. Some argue that renewal of the federal PTC and recent surges in the price of steel explain the near-term increase; they also argue the current installation costs reflect a disequilibrium price in the wind capacity market. The implication is that the capacity market will respond in time and, as a result, installed capacity prices will subsequently *decline* going into the future. What is not clear is how far into the future prices might decline and at what level they may settle once equilibrium is presumably re-established. Alternatively, others argue that the current installation prices are not disequilibrium prices and, therefore, a decline in prices should not be expected. Instead, they see continued strong, if not growing, demand for investment in wind capacity. They see

[74] Because we lack experience in Kansas with fully depreciated wind investments, it is difficult to accurately forecast terminal net salvage values. While operational wind turbines may be attractive to some Kansans, even placing aside all safety-related issues, it is not clear that anyone will find aged, non-operating turbines worth leaving in place. The question remains whether the decommissioning expense would exceed the final salvage value. One can certainly argue the net terminal value, as conditioned by use of the 20-year life expectancy, could and may *likely* be close to zero. We assume the latter and for simplicity set the final net value at exactly zero.

this potential for future demand growth based on continued support for the wind PTC, possibly growing support around the country for implementation of Renewable Portfolio Standards (RPS), and possibly increasing concerns about global warming. Under these conditions, installation costs could continue increasing at a rate in excess of the economy-wide rate of inflation.

For purposes of this study, we take a middle ground between these two opposing views of the future. We assume that the current wind installation costs are not reflective of disequilibrium market conditions. And going forward in time, we assume that installation costs will increase but at a rate no greater or less than the average annual rate for the domestic economy.[75] Equivalently, as measured in 2005 constant dollars, we assume the wind installation cost per MW (i.e., the unit installation cost) will be constant over the entire investment horizon.

Since there is a high degree of uncertainty regarding future wind installation costs and because the size of those costs is likely to have a significant effect on the NPV analysis, we use a probability distribution function to model the forecast wind installation cost per MW. We use a triangular distribution for that purpose. The assumed triangular distribution ranges from \$1.0 to \$2.2 million per MW of nameplate rated capacity, with a mean (and median) value of \$1.6 million. The mean value is based on the best information available during the

[75] To be sure, we see this as a very conservative assumption relative to the apparent price increases over the last few years. Based on recent experience, the real rate of installation cost inflation is probably in the area of 10 percent per annum. Again, whether that rate would prevail over an extended future period of time is hard to say. Nonetheless, for some the recent experience may provide compelling evidence that installation cost increases may well exceed the general rate of inflation for years to come.

fourth quarter of 2005.[76] Again, in recognition of current installation cost estimates, the distribution we use here may provide downward-biased forecasts of future installation cost.[77]

The timing at with certain investments are made in wind capacity is completely specified by the assumed wind installation schedule, iwc(t). That schedule determines, in conjunction with the timing of rate cases, the timing at which wind investments are included in the utility's allowed ratebase.

Derivation of the DEP input variable forecast is somewhat involved, but, in simple terms, it involves four basic steps. First, a random selection from the installation cost probability distribution function is made. That establishes the forecast installation cost (per MW) in 2005 constant dollars for the entire investment horizon. Second, the utility investment in wind capacity (measured in MW) is made in accordance with the iwc(t) schedule. Combining the forecast cost of installed wind capacity with the amount of capacity the utility actually invests in (that is, builds) yields the forecast cost (in 2005 dollars) of the utility's investment in wind capacity over the investment horizon. Third, those dollar amounts invested in wind capacity, presuming such investments are found prudent, are formally added to the utility's allowed ratebase. That would occur within the context (i.e., at the time) of a rate case proceeding. In this study we assume that inclusions in the allowed ratebase occur in the rate case that immediately follows the utility bringing a new wind project on line for the first time.[78] And in that rate case, the utility's (forecast) allowed

[76] The late-2005 estimated installation cost at KCPL's Spearville wind facility was approximately $1.6 million per MW.
[77] It may be more realistic to model installation cost per MW using a triangular distribution ranging from $1.7 to $2.7 million with a mean of $2.2 million. However, as this study is designed, with the investment or forecast horizon running from 2006 through 2034, basing the installation cost forecasts on 2005-based information is reasonable. A correctly updated version of our model would set the investment horizon between 2008 and 2034.
[78] Mainly for purposes of simplification, and because their influence is likely to be relatively minor, we do not include the possible influence of AFUDC or CWIP provisions on allowed rates. However, it is our position that

annual depreciation expense would also be determined by the Commission, as would the retail rates by which that expense would be recovered. As stated in the previous paragraph, we assume rate case proceedings would routinely occur during the entire investment horizon. More specifically, rate cases are assumed to occur in 2007 and every four years thereafter.[79] Since the allowed depreciation expense is not established through an annual pass-through-type mechanism, but rather through the rate case process, the DEP input variable forecast is conditional on the timing of future rate cases. This means that the DEP input variable forecasts used in this study are effectively updated at the time of a rate case. Under the assumptions made, the "updates" reflect only the additions to and subtractions from ratebase as indicated in the assumed iwc(t) schedule, as opposed, for example, to possible changes in depreciation rates or disallowances for sub-par operating performance.

Because the DEP input variable forecasts are primarily based on the installation cost forecasts, of which 200,000 are drawn for each case study, we generate 200,000 different DEP input variable forecasts with every case study. Given the time dependency of the DEP forecast, as embedded in the iwc(t) schedule, each individual DEP input variable forecast consists of 29 numerical values that establish the path forecast annual depreciation expense amounts over the investment horizon.

4.59.2 The RET Input Variable Forecast: RET(t, f)

As defined above, the RET input variable measures the allowed, COS-based profit the utility is allowed to recover from its customers for investments it makes in response to meeting the

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any and all regulatory provisions should be reflected in the analysis, though at this time we leave inclusion of AFUDC and CWIP provisions to future research.

[79] A recent history of rate applications by jurisdictional electric utilities shows a four-year average between rate cases to be reasonable.

Challenge. That profit depends chiefly on how much money the utility actually invests in wind capacity and its allowed rate of return (ROR). Rather than attempting to forecast each component of the utility's allowed rate of return—the utility's cost of debt, expected return on equity, corporate income tax rate, and capital structure—we forecast only the allowed tax-adjusted rate of return (ROR).[80] Given the variability inherent in that rate, we use a probability distribution function to derive our forecast ROR values. The pdf we employ for this purpose is a uniform distribution with values ranging from 7.6 to 9.6 percent, with a mean value of 8.6 percent. The forecast range is also based on an assumed effective corporate income tax rate of 39.775 percent, which matches the currently existing rate.

The range of potential RORs should be interpreted as the range of potential tax-adjusted, *real rates of return*—that is, inflation adjusted rates of return. However, since most of us are more familiar with nominal interest rates and, therefore, to gain a more familiar point of reference, the mid-point forecast ROR of 8.6 percent translates to a nominal forecast ROR of about 10.9 percent.[81] That nominal ROR is consistent with the RORs allowed by the KCC during the most recent 36 months.[82] At any point in time, capital structures are likely to vary among utility types and, consequently, so would their allowed RORs, all else equal. However, over the long run we expect variance among the utility's average capital structures to be minimal. For that reason we assume no variation in the forecast allowed ROR among the four different utility-types.

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[80] By design allowed rates of return are annualized rates.
[81] Current *nominal* rates of interest in various financial markets are assumed to include inflationary expectations of traders in those various markets. If a positive rate of inflation is expected, then subtracting that expected rate of inflation from nominal rates of interest yields the current *real* rate of interest. As this numerical example reveals, our forecast average annual rate of inflation over the investment horizon is 2.25 to 2.30 percent. As with the entire set of price forecasts used in this study, we assume that average rate holds in each time period and so it can be interpreted as a levelized rate of inflation over the investment horizon. This implies the levelized rate of real inflation over the entire period is zero.
[82] For instance, our mean value forecast ROR is similar to the ROR the KCC granted Westar Energy with new rates effective in January 2006 (see Docket No. 05-WSEE-981-RTS.)

Like the DEP input variable forecast, the RET input variable forecast depends on a wide range of variables and several assumptions. Deriving our RET input variable forecast requires four basic steps: (1) derivation of the installation cost (per MW in 2005 constant dollars) forecast, which holds through each year of the investment horizon; (2) in accordance with the assumed iwc(t) and the rate case schedules, derivation of forecast changes to the utility's allowed ratebase over the investment horizon; (3) derivation of the ROR forecast, which is also assumed to hold for each year of the investment horizon (this step is not dependent on the *timing* of rate cases); and (4) derivation of the utility's forecast allowed annual profit on its investment in wind capacity—which is the definition of the RET input variable. The final step occurs within the context of the scheduled rate cases.

And, again, like the DEP input variable forecast, the RET input variable forecast must be effectively updated (to reflect changes in the wind capacity-related amount of ratebase) at the time of a rate applications. The rationale underlying the need and method used to update the DEP input variable is the *same* for the RET variable. Together, the DEP and RET input variables capture the financial cost implications of utilities meeting the Challenge. Because the financial cost implications are recovered in rates that are set via rate case proceedings, the forecast changes in both the DEP and RET input variable forecasts are conditional on the assumed rate application schedule.

Finally, for each case study we construct 200,000 different forecast scenarios. In the RET input variable forecasting framework this involves deriving 200,000 different forecasts of both the wind installation cost and allowed ROR. Bringing those forecasts together, as described above, enables us to compute for each case study 200,000 different RET input

variable forecasts. Each of those individual forecasts provides a set of 29 (i.e., a path of) annual forecasts of the utility's allowed profit with respect to meeting the Challenge.

4.59.3 The PPE Input Variable Forecasts: PPE(t, f)

For those case studies in which the utility meets the Challenge by entering purchase power agreements (PPAs) with wind energy developers rather than investing directly in its own wind capacity, the utility would incur a wind purchase power expense. That expense we capture by the PPE input variable. Like any purchase expense, it is measured by multiplying the purchase price (in MWh) by the total amount of wind energy (in MWh) the utility takes under its PPAs during any one year. As with all prices used in this study, the purchase price of wind energy is measured in 2005 constant dollars.

To forecast the PPE input variable requires: (1) deriving forecasts of the utility's (volume weighted) average wind energy purchase price, $P_w(t, f)$, and (2) forecasting the total quantity of wind taken by the utility. The former depends, in part, on the terms of contracts held by the utility. Since we assume that both utilities and developers would use comparable wind technologies and place facilities at locations offering comparable productive performance (in terms of average annual capacity factors), we use the previously described annual wind energy output variable, qw(t, f), to forecast the total quantity of wind energy taken by the purchasing utility.

We take the basic terms of what we consider to be the average or representative PPA as the basis for our wind energy purchase forecast, $P_w(t, f)$. Consistent with the forecast 20-year life expectancy of the physical wind capacity, we assume wind purchase contracts have a 20-year term. For the standard contract, it is also assumed the purchase price is fixed over

the term. Since the prices we use in this study are measured in 2005 constant dollars, the fixed price (in real dollars) assumption is equivalent to assuming the contract provides an inflation escalation factor that enables the nominal price of wind energy to exactly keep pace with inflation. Such inflation escalators are currently a common feature of PPAs. Lastly, it is our understanding that PPAs are typically structured as must-take arrangements, where the purchasing utility, at every point in time, is require to take (i.e., purchase) all of the energy generated by the facilities under contract.

In terms of establishing (i.e., modeling) forecasts of the wind contract price, two distinctly different approaches can be used. With either approach we assume the underlying, contracted amount of nameplate rated capacity is 100 MW.[83] One approach involves modeling the representative developer's unit or MWh cost to perform under the contract, inclusive of the developer's assumed financial requirements. Alternatively, since there is an actual marketplace where PPAs are offered and requested through (repeated) RFP processes, the other approach involves the use of sampling PPA prices available in the marketplace.

The two approaches should yield similar results, provided both are based on comparable contract terms and the forecast model (of the purchase price) is itself well designed and capable of giving statistically unbiased forecasts. If the two approaches are equivalent, then we would expect the forecast price to provide an unbiased estimate of the sample average price. However, for purposes of this study, we developed a model to forecast the wind energy purchase price for the assumed contract structure. That is due to the fact that the wind energy market is typically driven by RFP processes engaged by regulated utilities that are interested in entering PPAs. At this time wind prices (bid, ask, or transaction) are not

[83] In terms of the installation-only cost, we presume economies of scale are effectively captured in full by facilities of 100 MW or more. Therefore, our analysis of price per MWh would be no different for large farms.

readily transparent to those outside the actual RFP process.[84] As chance would have it, over the course of this study, we were able to access the wind energy prices available in the marketplace as a consequence of two jurisdictional utilities issuing wind RFPs. Consequently, we were able to examine two distinct samples of actual wind energy (bid) prices. Using information available at the time, we found that our model of the wind energy price provided forecast values comparable with the actual sample average prices. Therefore, based on this very limited comparison of actual market-based average prices with forecast prices, it is our opinion that our forecast model of wind energy prices is reasonably constructed and likely to provide reasonably accurate forecasts.

To forecast the second component of the utility's wind purchase expense, which is the quantity of wind it takes each year under its PPAs, we use the same wind energy production variable, qw(t, f), previously described. Thus, in essence, we assume that regardless of who owns and operates one MW of wind capacity, and for a given location, the average annual capacity and degradation factors will be the same. In other words, with respect to annual wind energy production, there is no difference between developer and utility ownership.

More generally, we assume wind developers face nearly all of the same input costs and many of the same risks that the utilities face when they directly invest in wind capacity. That provides some basis for further evaluating our wind energy price forecast model. Because utilities are subject to system reliability standards, generally they bear the wind integration cost, including penalties for being out of balance due to wind facilities operating in their control area. Otherwise, wind developers face all of the same categorical costs of

[84] The non-public nature of the RFP-driven wind market actually necessitates reliance on modeled wind prices. To the extent wind purchase contracts are entered by regulated utilities (which is the usual practice), the price term of those contracts may be assessable by the public and may be available to evaluate price forecasting models.

installing and operating wind capacity as the utilities. Yet within specific cost categories, there are likely to be critical differences. For instance, developers will have a market-based *real* rate of return required to trigger investment decisions, which we assume to be about 19.0 percent per annum along with a commensurate level of risk; the utility has an agency-based rate of return that is based on less financial exposure. Developers are likely to be more leveraged than utilities and may,[85] on average, be better positioned to take full advantage of the federal PTC. Besides possible differences in financial costs, like the utility, developers would face the same land lease, PILOT, wind O&M, and installation costs.[86]

Consistent with current commercial practices, holding a wind purchase contract in its portfolio does not contribute toward the utility's required capacity. Therefore, for those case studies where the utility is assumed to meet the Challenge via purchasing wind energy PPAs, as opposed to when it opts to directly invest in wind capacity, there is no need to forecast the utility's avoided capacity cost. In short, in case studies where the utility builds its own wind capacity, it captures a small mount of capacity savings; otherwise, it does not.

For a detailed description of the method we use to forecast the utility's purchase price of wind energy over the investment horizon, please see Appendix G.[87] That appendix also briefly describes the Monte Carlo process used to forecast, $P_w(t, f)$.

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[85] The profit of wind developers depends on the productivity of their investments, which may not be the case for regulated utilities whose profit depends on the amount of investment in their allowed ratebase. This suggests the risk profiles faced by these two entities may not be the same. Having different risk profiles does not imply different capital structures, but the likelihood of having the same capital structures arguably is reduced.
[86] Large-scale developers, possibly with regional or national footprints, *may* be able to achieve lower installation costs by achieving better deals on relatively larger equipment orders.
[87] The method is more accurately described as that used to forecast the developer's required sale price of wind energy.

4.60 Forecasting the Output Variable: Deriving the NPV Forecast Values

At this point we have described the models we use to forecast each of the eleven input variables that comprise the NPV formations presented in Section 3.13. Deriving a forecast for each of those eleven variables and inputting those forecast values in the NPV equations enables us to derive the NPV forecasts. Very simply, inserting input values yields an output value. In this case, the output values are NPV forecasts.

4.61 Deriving a Single NPV Forecast Value

As an example of how we derive a single NPV forecast, we will consider the case in which the utility-type meets the Challenge by directly investing in wind capacity and the avoided external cost is included as part of the NPV analysis. That NPV formulation is discussed in Section 3.44 and explicitly shown by Equation (7) in that section. As that equation shows, in order to derive a single NPV forecast, it is necessary to develop a forecast for each of the *eleven* different input variables. In turn, those forecasts depend, in part, on using the Monte Carlo process to forecast values for *seven* random variables. Those random variables are effectively component parts for several of the input variables. Those random variables include the unadjusted capacity factor, degradation factor, gas mix per the specific utility-type, natural gas price per MMBtu, wind O&M expense per MWh, wind installation cost per MW, and rate of return. Besides the Monte Carlo forecasting, the eleven input variable forecasts also depend on certain assumptions: mainly the wind capacity installation schedule, iwc(t), and numerous implicit forecasts of fuel and other input prices, wind O&M real inflation rates, avoided capacity cost, etc. All of the input variables are measured in 2005 constant dollars which means that all of the forecast costs and benefits associated with the

Challenge have been adjusted for the effect of expected inflation. Clearly, the NPV forecasts depend on several random variables, many of which can take a wide range of different forecast values. Accordingly, by using the Monte Carlo process, we are able to evaluate a large number of different input variable forecast scenarios, and for each scenario compute a distinct NPV forecast.

4.62 Deriving a Single NPV Forecast Value: Defining a "Forecast Scenario"

Throughout much of this report we refer to the derivation and use of forecast scenarios without offering any clear definition of the term: forecast scenario. For the NPV equation specified in Section 3.44, within the context of a single case study, and for a specific utility-type, the input variables whose forecast values depend, in turn, on the forecasts of the seven random variables are: FOM (u, t, f), APC(t, f), PTC(t, f), EXT(t, f), INT(t, f), WOM(t, f), DEP(t, f), and RET(t, f). That dependence is shown by the notation, f, which denotes a single forecast scenario. The forecasts that are derived for each of the seven underlying random variables—that *set of forecasts*—enables the derivation of the forecasts of the eight input variables that depend on that set of forecasts, which constitutes a single forecast scenario. In other words, eight of the eleven input variables used in the NPV formula in question rely on the random drawing of a specific forecast scenario.

4.63 Deriving a Single NPV Forecast Value: Bringing it All Together

If eight of the eleven input variables used in the NPV formula in question rely on the random drawing of a specific forecast scenario, that leaves three input variables—CAP(t), LLE(t), and PIL(t)—that do not have that dependence. However, all eleven input variables are time

dependent, and that time dependency is driven largely by the assumed wind capacity installation schedule, iwc(t). Thus, the eight input variables that depend on the Monte Carlo process will change due to changing the forecast scenario and changes in the iwc(t) schedule. The three input variables that do not depend on forecast scenarios will change only with changes embedded in the iwc(t) schedule.

To derive an NPV forecast based on the amount of wind capacity investment needed to meet the Challenge as of 2005, which is 736 MW, we start with the "forecast" amount of wind capacity for the first year of the investment horizon, 2006. That forecast is mechanically given by the iwc(t) schedule for the year 2006, which we can denote by iwc(2006). The iwc(2006) forecast, along with structural assumptions made regarding the CAP(t), LLE(t), and PIL(t) input variables, determines the year-2006 forecasts for those three variables. Next, using the Monte Carlo process, we derive a single forecast scenario. That scenario, combined with the iwc(2006) forecast, as well as certain structural assumptions, yields the year-2006 forecasts for the eight input variables whose forecasts depend on the forecast scenario. What we have described, in very broad terms, is the derivation of all eleven input variable forecasts for the first year of the investment horizon, 2006. The annual forecasts for all eleven input variables for the remaining years of the investment horizon, 2007 through 2034, are all based upon their year-2006 forecasts with changes from those base year forecasts that are largely driven by changes in the assumed wind capacity installation schedule, iwc(t). By this process we end up with annual forecasts for each of the eleven input variables for each year of the investment horizon—these are the time path forecasts for all of the input variables. With those forecasts we can compute the forecast annual net benefit from meeting the Challenge for the years 2006 through 2034; that is, we

develop a stream of forecast annual *net saving* amounts over the investment horizon, all due to meeting the Challenge. That information, along with the prescribed time discount rate, enable us to compute a *single* NPV forecast, being a forecast of the net savings, in 2005 constant dollars, attributable to meeting the Challenge.[88] In this example, that net savings forecast includes forecasts of the both the internal and external cost savings attributable to meeting the Challenge

4.64 Deriving a Single NPV Forecast Value: Correlations among the Seven Underlying Random Variables

To perform our Monte Carlo forecasts, we assume the correlations among the seven underlying random variables are all zero. We recognize that the price of natural gas may be correlated with the utility's gas mix; the higher the price of gas, the lower the gas mix amount consistent with a negative correlation. However, by not explicitly modeling that negative correlation, our forecast FOM variable (which captures the forecast lambda) is systematically too large. That bias implies the NPV forecasts have an upward bias—which favors the case for meeting the Challenge. We also recognize the unadjusted capacity and degradation factors could also be correlated, or at least have that appearance. For instance, improvement in wind turbine technologies suggests higher capacity factors and lower degradation of those factors over time. But with ever-changing wind equipment technologies and, thus, nearly constant installation of new, non-widely applied technologies, it is not clear what the secular trend is with respect to average capacity factors over time. Because of that

[88] The discount rate used in this study is an inflation-adjusted rate; therefore, it constitutes a real, as opposed to a nominal rate of interest. In this study we set the discount rate equal to the forecast ROR. That is, we assume society would use a discount rate equal to the utility's allowed rate of return. We use that rate simply because it provides one indication of the financial investment opportunities that are likely to be available to all Kansans in future years. Of course, there are many alternative discount rates that could be used and we recognize the importance of policy makers providing guidance in that regard.

and because our degradation factor is measured in percentage terms, if those two variables are correlated, we expect it to be small in magnitude. Again, any possible correlations among the other random variables, arguably, are close to zero. Overall then, by assuming no correlation among the seven random variables whose forecasts are derived using Monte Carlo simulation, we believe the NPV forecasts are likely to be *slightly* biased in favor of the Challenge as a result.

4.65 Deriving 200,000 NPV Forecasts Using Monte Carlo Simulation

As previously discussed, we examine the economics of meeting the Challenge within the context of 32 distinctly different case studies. The case studies differ depending on which utility-type is meeting the Challenge, whether estimated external cost savings are included or not, whether the utility-type is meeting the Challenge through the entry of PPAs with wind developers or directly investing in its own wind capacity, and whether the wind capacity investment base is 736 MW or 1,000 MW (corresponding to the amounts of wind capacity required to meet the Challenge as of the end of 2005 or roughly the end of 2001, respectively). Because of all the factors that can influence the net benefit from meeting the Challenge and because of the uncertainty associated with the future magnitude of those factors (as manifested by the wide range of possible values all of those factors can take), we choose to consider a large number of forecast scenarios. In other words, there is no doubt that the net benefit of meeting the Challenge hinges on the future outcome or realization of several random variables. And in those random variables is both the *potential* promise and peril that would come from meeting the Challenge. In this study we make every reasonable attempt to fully capture the uncertainty of the future, the objective being to fully evaluate the

probable economic potential of meeting the Challenge. It is for that reason that we evaluate 200,000 different forecast scenarios for each case study.

4.66 Deriving a Probability Distribution of NPV Forecasts

Having admitted a wide range of future possibilities—some very favorable to the development of wind, others far less so—we have set the foundation for consideration of a wide range of forecast scenarios. Since we evaluate 200,000 different forecast scenarios for each case study, that necessarily implies the derivation of 200,000 forecast NPVs for each case study. Because we used a Monte Carlo forecasting method, that set or body of forecast results is easily presented as probability distribution. The NPV forecast distributions show the highest and lowest forecast NPVs across all 200,000 forecast scenarios; they also reveal the probability of hitting a forecast value between those two extreme forecasts; and they provide a convenient means of calculating the average forecast NPV. As previously discussed, we use the average forecast NPV to determine whether meeting the Challenge is likely to be cost effective for Kansas.

Lastly, by deriving probability distributions of forecast NPVs, we establish a basis for evaluating the *risks* associated with meeting the Challenge. For example, NPV distributions can be used to assess the *probability* that the NPV of meeting the Challenge will be positive. Having that type of information offers policy makers a different perspective with which to evaluate the policy issues. For instance, policy makers could decide that meeting the Challenge would be in the public interest if there is a better than 50 percent chance that the resultant NPV will be greater than zero. A policy decision based on assessing the probability of a successful outcome (expected NPV greater than zero) is necessarily based not on a

single NPV forecast, but, as in this study, thousands of forecasts. Any forward-looking policy decision based on thousands of different forecasts as opposed to just one, or just a handful, is likely to be a better policy decision. Finally, having a probability distribution of forecast NPVs also highlights the fact that there really are no guaranteed results associated with meeting the Challenge.

4.67 A Brief Summary and Look Ahead

The background we offer in Chapters 3 and 4 of this report should provide an understanding of the methods, assumptions, and data we use to forecast the NPVs associated with the Challenge. We have also described a criterion that can be used to determine whether meeting the Challenge would be economically efficient. That criterion is that 50 percent or more of the distributed (density of) forecast NPVs are greater than zero. A roughly equivalent criterion is the average forecast NPV must be greater than zero. By developing, for each case study, a probability distribution of forecast NPVs, we also provide a foundation for assessing the risk of the Challenge meeting with success or failure in terms of being cost effective *ex post*. That is, even if pursuing the Challenge, appears likely to be cost effective up front, there is no guarantee that it will be cost effective. With that, we turn to Chapter 5 where we present our NPV forecast results for each of the 32 case studies.

Chapter 5.0: The NPV Forecast Results

5.00 Introduction

The 32 case studies we analyze are described in Section 2.50 of this report, and further diagramed in Tables 2.0 and 2.1. The outline of case studies presented below offers both a review and an expanded description of how those studies differ from one another. The primary differences are: (1) the "investment base," which is either 736 MW, the amount of incremental investment needed to meet the Challenge as of January 2006, or 1,000 MW, which includes 264 MW of investment already made, (2) the wind option selected by the utility, either PPAs with wind developers, the "buy" option, or direct investment in its own wind capacity, the "build" option, (3) the inclusion of estimated external cost savings (at $20/MWh of wind energy) or not, and (4) the utility in question and, thus, utility specific avoided cost estimates.

5.01 Outline of the 32 Case Studies: 736-MW and 1,000-MW Investment Bases

The forecast NPV results for all 32 case studies are presented in this section of the report. We divide those cases between those based on the amount of capacity needed to meet the Challenge as of January 1, 2006—about 736 MW—and those based on the full 1,000 MW amount. That demarcation is made because, arguably, the results for 736 MW-based cases are more meaningful in terms of a *forward-looking assessment* of the Challenge's potential value to Kansas. The results for these cases also provide an economic basis for evaluating whether the Challenge should be mandated or left as a voluntary matter.

On January 1, 2006, the amount of installed wind capacity connected to the grid in Kansas was about 264 MW. That amount is almost completely attributable to two separate

wind facilities: Aquila’s Gray County facility near Montezuma (with total nameplate capacity of nearly 112 MW) and EDE’s Elk River facility near Beaumont (with total nameplate capacity of 150 MW).

In order to perform a benefit cost analysis of the full Challenge amount of capacity, it is necessary to do a benefit cost analysis of the historically given amount of wind capacity (264 MW), as well as the forward-looking amount (736 MW). To perform the NPV analysis of both the Gray Co. and Elk River facilities, we apply the NPV formulation presented in Sections 3.45 and 3.46. The same input variables included in those formulations are used to perform that NPV analysis, with one exception. Rather than having to estimate the purchase price of wind per those two facilities, $P_c(t, f)$, we use the *actual* price terms (in 2005 constant dollars) from the respective purchase contracts. The Gray County facility is (as of January 1, 2006) under contract with Aquila; the Elk River facility is under contract with EDE. We use the high-cost utility-type, whose system lambda is modeled after Aquila’s, to develop the NPV forecasts for the Gray Co. facility; and we use the middle-cost utility-type, whose system lambda is, in part, modeled after EDE’s, to develop the NPV forecasts for the Elk River facility.

By adding together the forecast NPV results for the historically given investments (Gray Co. and Elk River) with the forecast NPV results for the prospective investments (736 MW in total), we obtain the forecast NPV results for the 1,000-MW investment base cases. The forecast results for Case Studies 1 through 16 are all based on the 736-MW investment amount. The forecast results for Case Studies 17 through 32 are based on the full 1,000 MW amount of investment, which includes an NPV assessment of the wind capacity already

installed in the state as of January 1, 2006. All 32 case studies include an NPV analysis of the incremental investment needed to meet the Challenge.

5.02 Outline of the 32 Case Studies: Buy Through PPAs or Purchase Through Investment

Again, all of the 32 case studies incorporate an NPV analysis of the 736 MW of investment needed to reach the stated Challenge amount of 1,000 MW by 2015. For half of those case studies, we assume the Challenge is met by the utility-type directly investing in (and subsequently ratebasing) the full 736-MW amount. For the other half we assume the Challenge is met by the utility-type entering PPAs with developers that, in turn, invest in 736 MW of installed wind capacity. The only difference between these two categories of case studies is who owns and operates the 736 MW of wind capacity. In half of the case studies, the utility owns and operates that capacity, while in the other half developers own and operate. By comparing the forecast NPV results of those two categories of case studies, we can determine which of the two wind options, utility build or utility buy, is likely to be less costly.

5.03 Outline of the 32 Case Studies: Inclusion of Estimated External Cost Savings

Half of the 32 case studies include the estimated external cost savings of wind energy (at $20/MWh) as a benefit of meeting the Challenge, the other half do not include that estimated benefit. In all 32 case studies we determine the threshold level of external cost savings. That is, in every case, we establish how large the external cost savings per MWh (of wind energy) would need to be for the Challenge to be cost effective (from the societal perspective).

5.04 Outline of the 32 Case Studies: The Four Utility-types

Finally, for each of the four utility-types, there are eight case studies provided. The eight case studies cover all combinations of the utility-type meeting the Challenge by either investing in its own capacity or entering PPAs with developers, with estimated external cost savings (at $20/MWh of wind energy) included or not, and with either the 736 MW or 1,000-MW investment base amounts. The evaluation of these case studies allows us to determine (1) the utility-types for which taking up the Challenge makes economic sense (from either the perspective of their retail customers or the societal perspective), (2) where inclusion of external cost savings is likely to make a critical difference in that determination, and (3) which wind option, build or buy, is likely to be least costly for which utility-types.

5.05 Some Special Cases

In addition to the 32 basic case studies, we offer forecast NPV results for eight different *special cases*. Two of the special cases provide *updated* NPV forecasts for two of the basic case studies. Those updated NPV forecasts are based on input variable forecasts made using information available January 2008. Two other special cases provide NPV forecasts based on *modifications* made to two of the basic case studies to include (hypothetical) incentives for investment in wind capacity: an ROR adder for utility shareholders and a Kansas PTC for wind developers. The remaining four special cases examine: (1) the economic implications of a potential $10/MWh carbon tax, (2) community wind development, (3) how the choice of a discount rate is likely to influence the forecast NPVs, and (4) a utility-type that relies on significantly more natural gas for generation purposes than our high-cost utility-type (which we refer to as the Texas Utility example). These eight special cases are listed below.

Special Case Study 1: January 2008 Update of Case Study 5 (and 6)

Special Case Study 2: January 2008 Update of Case Study 7 (and 8)

Special Case Study 3: ROR Adder to Utility Investment in Wind Capacity

Special Case Study 4: Implementation of a Kansas-Based PTC (KPTC)

Special Case Study 5: Implementation of a Carbon Tax - $10/ton of CO_2

Special Case Study 6: A Brief Assessment of Community Wind

Special Case Study 7: Discount Rate Variations - Lowering the Discount Rate

Special Case Study 8: The Texas-type Utility Example

Each of the special cases is derived from one of the 32 basic case studies. That is, the special cases represent either an *updating* or *modification* of one of the 32 listed case studies. Accordingly, the special cases are designed to show how NPV forecasts might *change* as a consequence of updating input data, changing incentives and taxes, and changes to certain underlying conditions and assumptions.

5.07 Outline of the 32 Case Studies: A Brief Roadmap

We start with those Case Studies (1–4) that show the *most favorable*, though least realistic, forecast results. Those are the forecast results for the high-cost utility-type and, therefore, provide an indication of what the Challenge's NPV would be if only a utility like WestPlains were to meet the Challenge.[1] The forecast results are relatively more favorable for this utility-type because of its relatively greater reliance on natural gas as a generating fuel and, thus, the presence a relatively higher average fuel expense.

Case Studies 5–8 show the forecast results we consider to be the *most realistic.* Those are the NPV forecasts for the average-cost utility-type. As previously described, those results show the likely NPV if the responsibility of meeting the Challenge were spread among the

[1] It is important to recall that the similarity between the high-cost utility-type and WestPlains is their *cost structure*, not their size or coverage of the state, for the former is assumed to be statewide in operating scope.

jurisdictional utilities based on the relative size of their annual retail loads (in MWh). The forecast results of the average-cost utility-type provide what is probably the best indication of the *statewide average implications* of the Challenge.[2] Accordingly, we believe those results may offer policy makers the best foundation on which to evaluate the Challenge on a forward-going basis.

Next, Case Studies 9–12 show the NPV forecasts for the low-cost utility-type. The results for the low-cost utility-type are perhaps the most important, since the vast majority of Kansans are served by the two utilities that fall in that cost category, Westar Energy and KCPL. However, because the State's two low-cost utilities are so dominant in their coverage of the State, the results for the low-cost utility-type resemble those of the average-cost utility-type.

Case Studies 13–16 present the forecast NPVs for the middle-cost utility-type. Those results show the implications of utilities like EDE and MWE meeting the Challenge.

Case Studies 1–16 have 736 MW as the investment base, providing an indication of the net benefit attributable to that amount of investment needed to meet the Challenge as of January 1, 2006. In eight of those sixteen case studies, we include the estimated value of avoided external costs attributable to the generation of wind-based energy (unless stated otherwise, that estimated saving is set at $20 per MWh of wind energy. Similarly, in eight of the sixteen case studies, we assume the utility-type in question meets the Challenge strictly by investing in its own wind capacity; in the other eight we assume they meet the Challenge

[2] We use "best" in the sense of statistical accuracy, operational feasibility, and perhaps fairness to ratepayers. It is simply not operationally feasible to force the entire Challenge upon a utility the size of WestPlains, or EDE, or MWE. It may be feasible to force it upon a utility the size of Westar, though that may not be fair to its customers. Again, we must remember that the other real significance of the average-cost utility-type is that its cost structure represents an average cost structure among the state's five jurisdictional electric utilities. In that sense, the NPV forecasts for the average-cost utility-type are, as implied by the name, based on the state's (volume-weighted) average annual system lambda.

exclusively by entering PPAs with wind developers (who have made their own investments totaling 736 MW in nameplate capacity).

The remaining Case Studies, 17–32, have 1,000 MW of wind capacity as the investment base. With this one difference, these studies are *identical* in structure to Case Studies 1–16. The final 16 case studies simply add in the forecast NPVs associated with the Gray Co. and Elk River wind facilities. Accordingly, our descriptions of those cases are very brief.

5.10 NPV Forecasts: Case Studies 1–16: 736-MW Investment Base

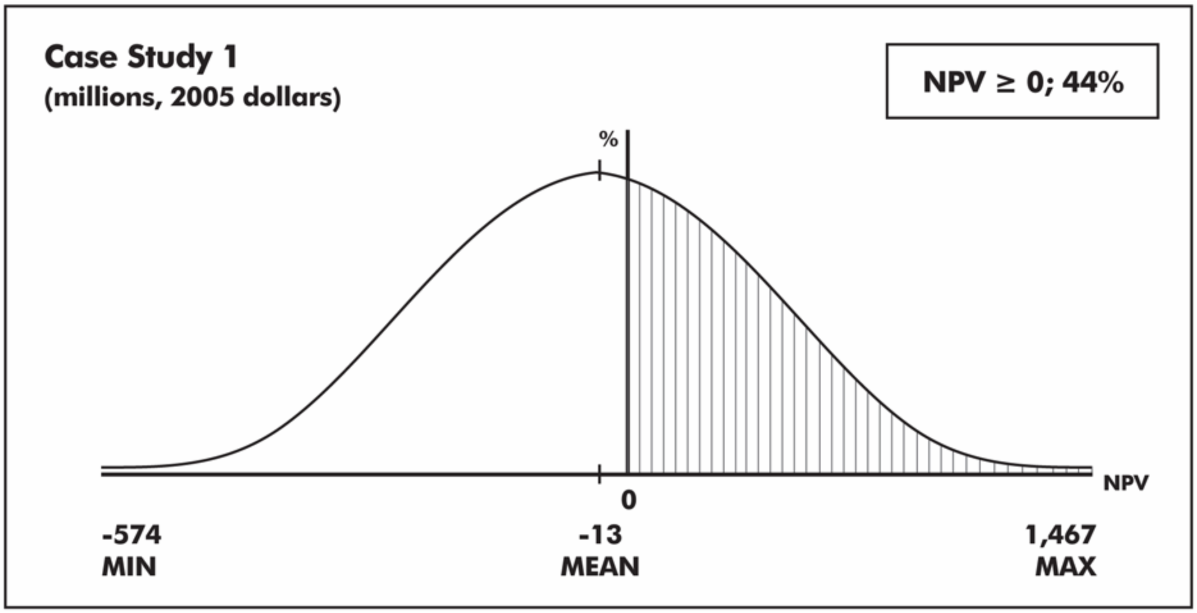
5.11 The High-Cost Utility-type

Case Study 1: High-cost Utility Enters PPAs, External Cost Savings Not Included

In this Case Study the utility-type meets the Challenge by entering PPAs with wind developers and, consistent with the more traditional regulatory approach, external cost considerations are not included in the formal analysis. Accordingly, estimated external cost savings are not incorporated in the NPV forecasts.

All of the NPV forecasts for this Case Study are generated using Equation (8) in Section 3.44.[3] Following the forecast methods described in Chapter 4 of this report, 200,000 different forecast scenarios were evaluated for this particular Case Study, and for each scenario an individual NPV forecast was derived. The entire collection of NPV forecast results for this Case Study are represented by the probability distribution shown below in Graph 1.

[3] All case studies in which the utility-type selects the purchase option and the estimated external cost savings are not formally incorporated in the analysis rely on Equation (8). As that equation shows, within that class of case studies, the distinction among utility-types is established by our method of forecasting gas mix. Otherwise, the input variable forecasts are categorically the same across utility-types.



Graph 1: 736 MW, High-cost Utility-type, PPA Option, External Cost Savings Not Included

As indicated by the graph, that distribution shows that a wide range of forecast outcomes is possible, with minimum and maximum forecast values of -\$574 million and \$1,467 million, respectively.[4] This distribution indicates that there is a good chance that meeting the Challenge would yield positive NPVs and, thus, turn out well. As shown in the graph, that probability is 44 percent. But it also shows there is a good probability the Challenge would not turn out so well. On average, the forecast outcome is negative, as shown

[4] Obviously, the distribution depicted in the graph is symmetric and unimodal and, therefore, may appear to resemble a normal distribution. Because we do not perform any statistical tests as part of our analysis, there was little need to formally test for normalcy of the forecast NPV distributions. Absent that testing, we make no claims about their normalcy. That said, all of the forecast NPV distributions derived in this study are clearly unimodal. And except for the case studies involving the high-cost utility-type, all of the forecast NPV distributions appear symmetric, since in every case the means and medians of those distributions are within a few pennies. That explains our general reliance on graphs showing a unimodal, symmetric distribution.

Again, the *actual*, forecast NPV distributions for the high-cost utility-type are not symmetric, they are skewed. Because the results presented in this study arguably could be used to make a one-time-decision—to pursue the Challenge or not—in the case of the high-cost utility-type, it may be better to base that decision on the median, rather than mean forecast values. For that reason, and only for the high-cost utility-type, we rely on and present some of the median forecast results. The source of the skew lies in the method we use to forecast the high-cost utility-type's gas mix. We assume that gas mix is distributed as triangular distribution, but one that is skewed to the left. The skew in that distribution, and by the Monte Carlo process, carries through to the forecast NPV distribution.

by the mean forecast NPV of -$13 million, although in the case of the high-cost utility-type, the median forecast NPV may provide a better indication of what the “average outcome” might be, coming in at -$22 million.

If we apply our criterion for cost effectiveness to these results, since 44 percent of the forecast NPVs are positive, which is obviously less than the 50 percent or more required by the criterion, we would conclude meeting the Challenge in this case is not cost effective from the perspective of the utility’s ratepayers. This result is also reflected in how the Challenge would influence the utility’s average retail rate and, subsequently, the average monthly bill of its customers.

In this report, we establish the rate implications of meeting the Challenge by its influence on the utility’s average retail rate.[5] In making that assessment, we assume that the utility’s net cost (or benefit) of meeting the Challenge would be recovered across all retail sales. That is, we assume all ratepayers would pay or receive the same amount on a per MWh basis. Although there are numerous ways available to the Commission for allocating the internal net cost of the Challenge, we choose this method for its simplicity.

[5] Our measure of the rate implication is the total net benefit of meeting the Challenge over the full investment horizon divided by the total generation (in MWh) over that time period. That measure shows how the Challenge would influence the utility’s allowed revenue per MWh, that is, its *average revenue*. Using that measure also presumes the net benefit of meeting the Challenge is spread uniformly across all MWh purchased through the PPA by the utility’s retail customers. Thus, the basis for allocating the Challenge’s net benefit among customer classes is strictly volumetric. Our measure of average revenue is adjusted for inflation and, thus, is measured in real (i.e., inflation-adjusted) dollars. However, it does not reflect time discounting and, therefore, is not measured in 2005 constant dollars. The reason we did not apply a time discounting is that ratepayers will see the forecast rate increase over the investment horizon and, thus, over time. To convert the forecast rate change into its present value probably is not meaningful, given the timing at which customers, through the regulatory process, would experience rate changes due to the Challenge. While customers may perceive their rates on inflation-adjusted terms, it seems very unlikely that customers view them in present value terms.

Lastly, for those readers familiar with the Rate Impact Measure (RIM) test, this result shows the Challenge failing that test. It also confirms the finding that meeting the Challenge in this case is unlikely to be economically efficient.

In this case, the average retail rate is forecast to *increase* just slightly, $0.01/MWh.[6] That average rate change holds for the entire investment horizon and, therefore, represents a (time) levelized amount. The basis of the forecast increase in the average retail rate is straightforward: pursuing the Challenge is likely to be more costly for the utility compared with the utility taking the business as usual path. By incurring that extra cost, as forecast, all of the utility's retail rates would be forced up by one cent, on average. That is an increase the utility would avoid by not taking up the Challenge.

If the average residential customer in Kansas consumes 11 MWh/year, on average,[7] then meeting the Challenge means that customer's annual electric bill would be higher by $0.11. Because the average forecast rate change is on a levelized basis, the forecast increase in the annual bill holds for each year of the investment horizon, 2006 through 2034. Since their average annual loads are larger, the forecast billing implications would be larger for the typical commercial and industrial class customers.

Another way to evaluate the relative value of wind energy to ratepayers is to compare, in this case, what it costs the utility acquire wind energy through a PPA with what it costs the utility's to generate energy via conventional means. Our analysis shows that the median forecast price for wind energy is $32.34/MWh.[8] Adding in the forecast wind integration expense of $4.60/MWh puts the utility's median total cost of wind energy at $36.94MWh.[9] More simply, that amount represents the utility's expected average cost of

[6] For reasons expressed in the previous footnote, we use the median rate change as our average forecast rate change. The median rate change of +$0.01/MWh is based on a median, total net benefit forecast of -$19.4 million.
[7] The assumed average annual MWh consumption by Kansas residential customers is based on EIA data for the 2000 through 2005 time period.
[8] The mean forecast price of wind energy is $32.69/MWh.
[9] As previously discussed, the forecast, contract price of wind energy as specified in PPAs includes the full realization of the federal PTC by the developers. Absent that allowed credit, developers' costs would be higher and they would be forced to charge (at least seek) higher contract prices. Our analysis shows that, absent the

wind energy. For the high-cost utility-type, our analysis sets the median forecast system lambda at $36.33/MWh.[10] That amount represents the utility's expected average cost of conventional generation. Comparing the utility's average cost to acquire wind energy with its average generation cost shows wind energy is more costly by ($36.94 - $36.33 =) $0.61/MWh. The amount by which the unit cost of wind energy exceeds the unit cost of conventional generation we refer to as the wind energy premium.[11] In this case, the median forecast wind energy premium is $0.61 for each MWh of wind energy acquired by the utility under the PPA.[12]

Finally, while the Challenge is not expected to be cost effective in this case, it is nearly so. If external cost savings were included in the analysis and if those (estimated) savings were expected to be $1.22 (or more) per MWh of wind energy produced, then meeting the Challenge would be cost effective from the broader, societal perspective. Thus, with a relatively small amount of additional savings per MWh, in the form of reduced external costs, meeting the Challenge could be pushed from the non-cost effective category to the cost effective. That amount of external cost savings per MWh is what we refer to as the threshold level of external cost savings.[13] For Case Study 1 the threshold level of external cost savings per MWh is $1.22, the lowest threshold level of all the case studies.

Employment Implications—Since customers would end up paying higher utility bills if the Challenge were met, that increase in real expenditures suggests, all else equal, an

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PTC, PPA prices would be approximately $18/MWh higher. Thus, without the federal subsidy, the utility's real cost of wind energy through a PPA would be closer to $55/MWh.

[10] The mean forecast system lambda is $37.98/MWh.

[11] The wind premium amounts are presented in real dollars, not 2005 constant dollars.

[12] While ratepayers effectively pay $0.61extra for each MWh of wind energy purchased by the utility, we assume that extra cost is recovered volumetrically and on total annual retail sales basis. Thus, when the wind premium expense is recovered across total retail sales, in this case, it results in all rates increasing by $0.01 per MWh, on average.

[13] Because the threshold level per MWh is determined by setting the relevant NPV formulation equal to zero, the threshold level is measured in 2005 constant dollars.

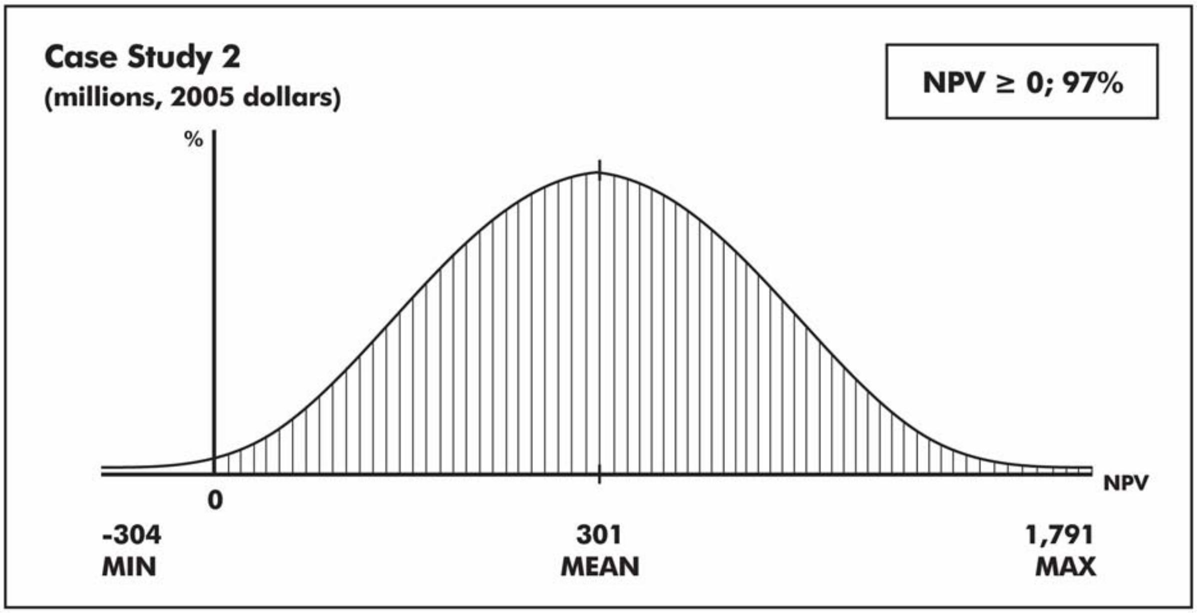
expansion of employment in the utility sector is likely.[14] However, the average annual, net increase in utility expenditures, measured in real dollars, is about a half million per year.[15] Arguably, that change in expenditures is unlikely to be felt by the statewide economy. On the other hand, expenditures in non-utility sectors may be reduced with subsequent contractions of employment in those sectors. Those contractions would likely be small as well. Thus, in this case, it appears that although a few new jobs may be created, some existing jobs could be lost, leaving the net employment implication close to zero.

Case Study 2: High-cost Utility Enters PPAs, External Cost Savings Included

Case Study 2 differs from Case Study 1 solely in the inclusion of forecast external cost savings. As noted previously, we set the forecast, external cost saving per MWh of wind energy taken by the utility under the PPA at $20. In other words, these external cost savings assume that the substitution of one MWh of wind-based generation for one MWh of conventional generation saves, among Kansans generally, $20 in external costs.

All of the NPV forecasts for this Case Study are generated using Equation (9) in Section 3.45.[16] Again, consistent with the forecast methods described in Chapter 4 of this report, 200,000 different forecast scenarios were evaluated for this particular Case Study, and for each scenario an individual NPV forecast was derived. The entire set of NPV forecast results for this Case Study are represented by the probability distribution shown below in Graph 2.

[14] We include wind energy developers and the jobs they create as part of the utility sector of the economy.
[15] The average annual increase in utility expenditures is about $558,800 in inflation-adjusted dollars.
[16] All case studies where the utility-type selects the purchase option and the estimated external cost savings are formally incorporated in the analysis rely on Equation (9). As that equation shows, within that class of case studies, the distinction among utility-types is established by our method of forecasting gas mix. Otherwise, the input variable forecasts are categorically the same across utility-types.



Graph 2: 736 MW, High-cost Utility-type, PPA Option, External Cost Savings Included

As indicated by the graph, that distribution shows that a wide range of forecast outcomes is possible, with minimum and maximum forecast values of -$304 million and $1,791 million, respectively. The graph also shows that the mean forecast NPV is $301 million and that 97 percent of the forecast NPVs exceed zero.[17] Clearly, from the broader, societal perspective, the forecast results show the Challenge is cost effective in this case. Moreover, with so many of the forecast NPVs being positive, it appears likely that the Challenge would be a very good bet for Kansans to take.

The rate, annual billing, and wind energy premium implications in this case are identical to those in Case Study 1. The reason for that is that the inclusion of estimated external cost savings to the analysis does not change the utility's internal costs or its revenues. In this case, while the Challenge would be cost effective from the societal

[17] The median forecast NPV is $292 million.

perspective, it remains non-cost effective strictly from the ratepayers' perspective—that is, it would lead to higher rates and monthly bills for ratepayers. Therefore, some or all ratepayers could still resist pursuing the Challenge. Nonetheless, our results show, very simply, that the total external cost savings would likely exceed the total increase in electric bills. That suggests the potential that Kansans generally could support the Challenge simply on economic grounds.[18]

Finally, since the only difference between Case Studies 1 and 2 is the inclusion of estimated external cost savings at $20/MWh, and because that amount exceeds the threshold level of external costs savings at $1.22/MWh, the inclusion of those savings pushes the Challenge, from the perspective of Kansans generally, into the cost effective category.

Employment Implications—As in the previous case, higher utility bills would likely expand employment in the utility sector and, all else equal, reduce employment in other sectors. With the inclusion of external cost savings, most of which are identified by the EPA as health-related expenses and costs, meeting the Challenge could reduce employment in the healthcare sector of the economy. The analysis shows a reduction in external costs of about $28 million per year, in real dollar terms. Much (but not all) of that reduction would translate to less employment in healthcare sector. However, lower expenditures on healthcare would allow greater expenditures and, thus, some employment growth in other sectors. Overall, the net employment implications are likely to be quite small. But since the forecast net effect of the Challenge is a net reduction of expenditures in the combined utility and healthcare sectors

[18] The Challenge would produce both winners—those that benefit as a consequence of reduced externalities—and losers—those made worse off by having higher electric bills. But when the Challenge is cost effective, yielding a positive net benefit overall, there is at least the *potential* that the winners could share some of their gain with the losers—leaving everyone better off than before. The latter is simply not feasible without a positive NPV; hence, the desirability and strength of that outcome.

of the economy (because meeting the Challenge would be cost effective), a slight reduction in overall employment in those two sectors is possible.

Comparison of Case Studies 1 and 2: Cost—As the analysis of Case Studies 1 and 2 shows, when the high-cost utility-type chooses to meet the Challenge through entering PPAs with wind developers, then consideration of potential external cost savings, all else equal, can be the critical difference between the Challenge being cost effective or not (from a societal perspective). These cases show that if the estimated external cost savings exceed $1.22/MWh, then meeting the Challenge would be cost effective from the societal perspective for the high-cost utility-type, even though it would leave ratepayers with relatively larger electric bills.

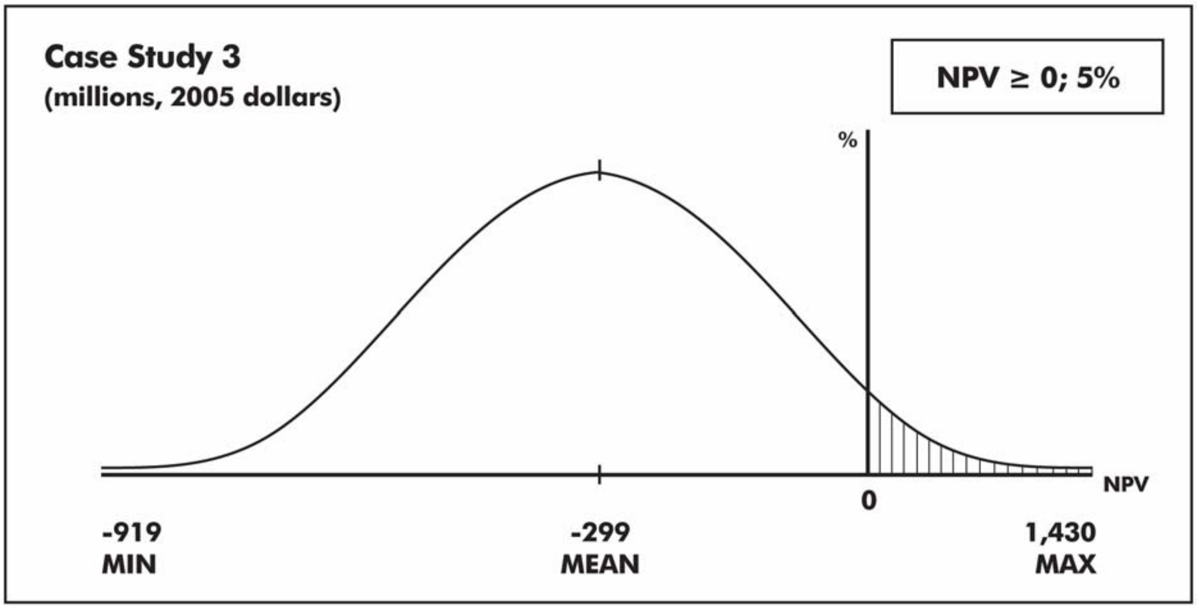
Case Study 3: High-cost Utility Builds Own Wind Capacity, External Cost Savings Not Included

The only difference between this Case Study 3 and Case Study 1 is the wind option selected by the utility. Instead of purchasing wind energy through PPAs, in this case the utility meets the Challenge by directly investing in its own wind capacity. In Case Study 3, then, the utility is the owner and operator of the installed wind capacity.

All of the NPV forecasts for this Case Study are generated using Equation (6) in Section 3.42.[19] Again, consistent with the forecast methods described in Chapter 4 of this report, 200,000 different forecast scenarios were evaluated for this particular Case Study, and for each scenario an individual NPV forecast was derived. The complete set of NPV forecast

[19] All case studies where the utility-type chooses to own wind capacity and the estimated external cost savings are not formally incorporated in the analysis rely on Equation (6). As that equation shows, within that class of case studies, the distinction among utility-types is established by our method of forecasting gas mix. Otherwise, the input variable forecasts are categorically the same across utility-types.

results for this Case Study are represented by the probability distribution shown below in Graph 3.



Graph 3: 736 MW, High-cost Utility-type, Build Option, External Cost Savings Not Included

As the results indicate, the Challenge is unlikely to be cost effective in this case, with only five percent of the forecast NPVs being zero or greater. The mean forecast NPV is -$299 million, and the median forecast NPV is -$305 million. While there is some chance the Challenge would be cost effective in this case, such an outcome does not appear to be a good bet.

The mean forecast rate change in this case is an *increase* of $0.71/MWh. For the average residential customer, that means an annual electric bill *higher* by $7.81, on average, for each of the 29 years of the investment horizon.[20] The basis for these forecast increases is the forecast of the utility's non-discounted, total net benefit of the Challenge, -$931

[20] Again, the forecast rate changes are in real dollar, inflation-adjusted terms. Thus, for example, forecast rate increases are increases in addition to those stemming from inflation.

million.[21] That is equivalent to saying it costs the utility, and therefore its customers, $931 million more to take the Challenge than to follow the business-as-usual path. Whenever it costs more to take the Challenge than maintain the *status quo*, higher rates and, consequently, higher annual bills can be expected. The median forecast rate increase is $0.73/MWh; that implies a median forecast increase in the typical residential customer's annual electric bill of $8.03 for each year of the investment horizon.

When the high-cost utility-type decides to invest in its own wind capacity rather than purchase wind energy through PPAs, the question becomes what does it cost the utility to supply its own wind energy? Our analysis in this case shows that it would cost the utility $55.00/MWh, on average, to produce its own wind energy.[22] Again, the utility's (median forecast) cost to produce one MWh by conventional means is $36.33. Hence, for the utility to meet the Challenge by investing in its own wind capacity it would incur a wind energy premium of ($55.00 - $36.33 =) $18.67/MWh of wind energy, on average.[23] That the utility would, on average, pay a positive premium to produce wind rather than conventional energy is the basis for the Challenge being more costly than the business-as-usual approach. That it would be "more costly" is equivalent to saying it would yield a negative net benefit to Kansas ratepayers.

Finally, while this Case Study by design excludes consideration of possible external cost savings, it can be used to set the threshold level of externalities. We find that if external cost savings were $19.46 or more per MWh, on average, then meeting the Challenge in this

[21] The median forecast of the total, net benefit over the investment horizon is -$962 million.
[22] The average used here is the median forecast value. The $55.00/MWh estimated cost of wind includes the utility receiving the federal PTC. If that credit were not available, the utility's cost to produce its own wind energy would increase to approximately $73/MWh.
[23] Using mean forecast values, the wind energy premium is $17.65/MWh.

case would be cost effective. Again, the level of estimated externalities may determine whether the Challenge is likely to be cost effective for Kansans generally.

Comparison of Case Studies 1 and 3: Cost—The only difference between those two studies is the high-cost utility-type's choice of wind option; therefore, except for that choice, all else is held constant between the two studies. In comparing the utility's cost to acquire one MWh of wind energy, our analysis shows that it costs the utility $18.06 more, on average, when it installs its own wind capacity rather than purchasing that energy through a PPA.[24]

Comparison of Case Studies 1 and 3: Risk—Not only does it appear that it is more costly for the utility to acquire wind energy through its own investment than through PPAs, it also appears to be riskier. With the purchase option, the forecast NPVs range from a high of $1,467 million to a low of -$574 million. The range of forecast outcomes has a magnitude of (1,467 + 574 =) $2,041 million.[25] However, with the build option, the range of forecast outcomes is larger, $2,349 million. Another indication that the build option is riskier than the purchase option is provided by the standard deviations of the respective forecast NPV distributions. With the purchase option, the standard deviation is $156 million; with the build option it is $171 million—the larger standard deviation shows greater risk.[26] Yet another indication that building is riskier than buying is the range of negative forecast NPVs, as a

[24] That average is the median forecast cost differential. The mean forecast differential is $18.34/MWh. A stylized and more rigorous analysis of the two wind options and what they are likely to cost ratepayers is presented in Appendix H. The analysis there shows that, in the case of the high-cost utility-type, the build option costs $18.71 more per MWh of wind energy. In short, it appears likely that it would cost the utility more when it builds rather than buys. Explanations for that probable cost difference are also offered in Appendix H.

[25] This holds in the case excluding external cost savings. The range of forecast outcomes is nearly the same when external cost savings are included.

[26] Both standard deviations are exclusive of external cost savings. When those savings are included both standard deviations are larger, but with no change in their rank.

proxy for the downside risk.[27] With the purchase option, the negative forecast NPVs range to -$574 million, with a 56 percent probability of a forecast falling in that range. With the build option, the negative forecast NPVs range to -$919 million, with a 95 percent probability of a forecast falling within that range.

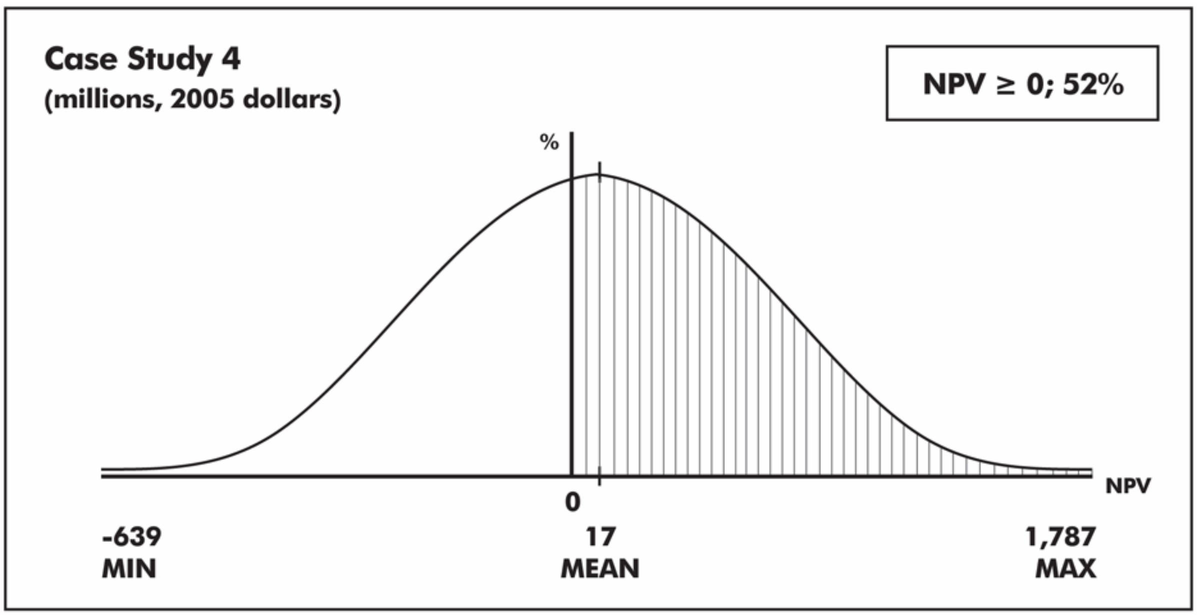
By various NPV-based measures of risk, it appears that the build option is the riskier option. That means that ratepayers would be exposed to greater risk, namely the risk of having to pay even higher rates, when the build option in selected.

Employment Implications—The main difference between Case Studies 1 and 3 is the utility's cost of meeting the Challenge. In Case Study 3 the utility faces a higher cost to meet the Challenge, which means utility bills must be that much higher. In Case Study 1 the Challenges forces the typical residential customer's annual electric bill up by a mere 11 cents, whereas in Case Study 3 it forces an increase of about $8. The upward pressure on utility bills may expand employment in the utility sector, but it could reduce employment in the non-utility sectors. However, if the higher utility bills in Case Study 3 are largely driven by higher financial costs associated with utilities investing in wind capacity, then employment expansion in the utility sector could be minimal. At any rate, in the case of the high-cost utility, where the Challenge comes closest to paying its own way, the net employment implications on a statewide basis are likely to be small. However, with the average forecast NPV being negative in this case, a small net contraction of employment may be the likely outcome.

[27] The figures presented for this "proxy" measure of risk are exclusive of external cost savings.

Case Study 4: High-cost Utility Builds Own Wind Capacity, External Cost Savings Included

This Case Study is identical to Case Study 3, except for one difference: the inclusion of estimated external cost savings of $20 per MWh of wind energy produced. The NPV forecasts for this Case Study are generated using Equation (7) in Section 3.43 of this report. As with all other case studies, we consider 200,000 different forecast scenarios, and for each an NPV forecast is obtained. All of those forecast results are represented in summary fashion by the following graph.



Graph 4: 736 MW, High-cost Utility-type, Build Option, External Cost Savings Included

With 52 percent of the forecast NPVs coming in positive, in this case, based on our criterion for cost effectiveness, we find meeting the Challenge would be economically efficient. For the high-cost utility-type, again we see that inclusion of the estimated external cost savings (at $20/MWh) makes the critical difference in terms of Challenge's cost effectiveness, at least from the broader, societal perspective.

The rate, annual bill, and wind energy premium implications in this Case Study are identical to those in Case Study 3. Rates and bills would be higher as a consequence of the Challenge. But the total reduction in external costs would more than offset the increase in bills, yielding a small net benefit to Kansans generally, about $17 million, on average, in net present value terms.

As presented with the previous Case Study, the threshold level of external cost savings when the high-cost utility-type chooses the wind investment option is $19.56/MWh, on average. Thus, if actual external cost savings exceed that amount we would expect the Challenge to be cost effective. Because our estimate of external cost savings at $20/MWh exceeds the threshold level, this pushes the Challenge into the cost effective category, even if just barely.

Employment Implications—Inclusion of external cost savings implies some reduction in healthcare-related jobs, but a potential expansion of jobs in the other sectors of the Kansas economy. Again, we conclude that the Challenge's net, statewide influence on Kansas employment would likely be small, particularly on an annualized basis.

Summary Points for the High-cost Utility-type

- For the high-cost utility, using either wind option to meet the Challenge would be cost effective from the societal (or total cost) perspective, provided estimated external cost savings are $19.56/MWh or more. Given the statistical nature of the analysis, that outcome is not guaranteed, but it appears likely. However, if the utility selects the PPA, then the external cost savings only need to be as high as $1.22/MWh for the Challenge to be cost effective.

- In other words, if external cost savings are as large as or larger than our EPA-based estimate of $20/MWh, then the Challenge would be cost effective by the societal perspective under *either wind option*.

- However, ratepayers are likely to face higher rates with either of the wind options, build or buy, and, consequently, higher annual bills due to the Challenge ($0.71/MWh and $0.01/MWh, respectively). Our analysis shows that the prospect for rates being higher is not certain, but nearly so. The reason for higher rates: the Challenge would result in a net increase in the utility's internal costs.

- In terms of which wind option appears best, our analysis shows that the PPA option is likely to be less costly for ratepayers than the build option. Our analysis also shows that the PPA option is less risky for ratepayers than the build option. With the build option, ratepayers are at risk for relatively larger rate increases.

- There is no question that the build option is best for utility shareholders: that is because the utility would earn an allowed profit on the utility's investment in wind capacity. With a PPA, utility shareholders would not receive any profit. All expenses associated with the PPA would be passed-through the utility's ECA mechanism, at cost and without a profit markup.

- Pursuing the Challenge presents a trade-off for Kansans generally: they would face slightly higher electric bills, but receive a cleaner, healthier (and, therefore, less costly) environment to live in. Making that trade-off would be worthwhile—that is, *provide a positive net benefit*—as long as external cost savings attributable to wind energy are about $19 to $20 or more per MWh (of wind energy).

- Whether the Challenge is likely deliver a net benefit to Kansans depends critically upon Kansans avoiding the externalities associated with the utility's conventional power plants. *In order to reduce those external costs, wind energy must reduce emissions at those conventional power plants. If, however, wind energy is effectively sold off-system, without affecting the utility's dispatch of conventional units, then wind energy cannot be credited with external cost savings for Kansans.*

- The net, statewide employment implications of the Challenge appear to be small. Some net gain in the utility sector, with a nearly contemporaneous net reduction in the non-utility sectors. Reductions in externalities are likely to reduce employment in the healthcare sector, but could increase it in the non-healthcare sectors. Again, overall the Challenge's net influence on job creation is likely to be small. However, to the extent wind facilities are located closer to rural communities, it seems likely the Challenge would boost employment in rural areas of the state but dampen employment in the urban job markets.

5.12 The Average-Cost Utility-type

The only difference between the average-cost and high-cost utility-types is their gas mix—that is, the proportion of their generation output fueled by natural gas, which is generally lower for the average-cost utility-type than for the high-cost utility-type.[28] Otherwise, the average-cost utility-type faces, on average, the same forecast costs as the high-cost utility-type, including purchase prices for wind energy and retail loads. The difference in gas mixes shows up in the utilities' respective annual fuel expenses and, accordingly, their average annual forecast system lambdas. In terms of our study, the average annual forecast system lambda for the average-cost utility-type comes in at $25.07/MWh. For the high-cost utility-type, it is $37.98/MWh. Clearly, with less relative reliance on natural gas, the incremental cost of generating electricity via conventional means is considerably lower. In this instance, it is about $13/MWh less. Thus, with the average-cost utility-type, the fuel savings attributable to its acquisition of wind energy are smaller, on average, than those of the high-cost utility. That implies that wind energy is probably relatively less valuable (as a means of saving scarce resources) to the average-cost utility and its ratepayers.

[28] For the average-cost utility-type, the median forecast gas mix is 4.0 percent, for the high-cost utility-type it is 20 percent.

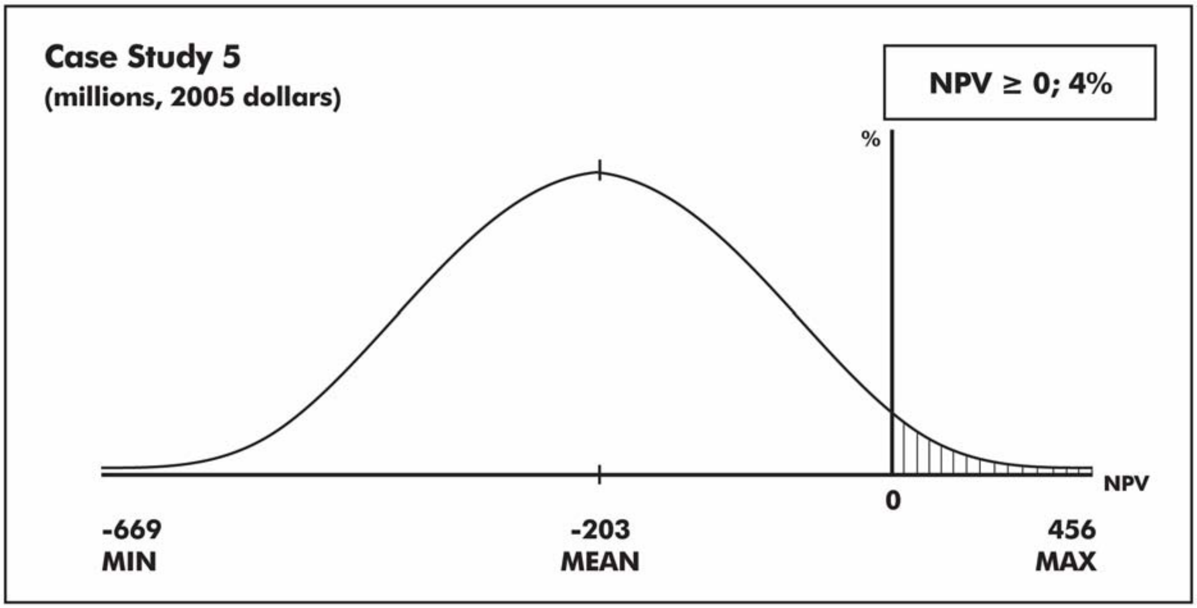
It is worth noting that the Case Studies involving the average-cost utility are of particular interest because the gas mix of this utility-type approximates the *statewide* average annual gas mix.[29] Consequently, the cost structure of the average-cost utility-type *approximates* that of the state's representative (or average) electric utility and, thus, the forecast results for the average-cost utility-type provide the best indication of what the Challenge is likely to mean for the *average Kansan*.

Case Study 5: Average-cost Utility Enters PPAs, External Cost Savings Not Included

As with Case Study 1, all of the NPV forecasts for this Case Study are generated using Equation (8) in Section 3.44. Thus, in terms of the basic NPV formulation and input variable forecasts, there is no difference in the analysis used to evaluate the two case studies other than the method used to forecast the utility's annual gas mix.

Consistent with the input variable forecast methods described in Chapter 4, 200,000 different forecast scenarios were evaluated for this Case Study, and for each scenario an NPV forecast was derived. All of those NPV forecast results are represented in summary form by the probability distribution shown below in Graph 5.

[29] From 2000 through 2004, inclusive, the statewide gas mix has averaged 3.78 percent.



Graph 5: 736 MW, Average-cost Utility-type, PPA Option, External Cost Savings Not Included

As the numerical results show, only 4 percent of the forecast NPVs come up positive, well below our 50 percent criterion for concluding that a cost-effective outcome would be likely. Thus, meeting the Challenge in this case is not cost effective from the ratepayers' perspective. Nonetheless, there is still some chance that meeting the Challenge would yield positive net benefits.

Meeting the Challenge in this case would, over the investment horizon, force the utility's retail rate up by $0.46/MWh, on average.[30] That forecast increase is on a levelized basis covering the investment horizon. For the typical residential customer, that implies annual electric bills would be higher by $5.06, on average, for each year of the investment horizon.

The utility's cost to acquire wind energy in this case is effectively identical to the high-cost utility's cost to acquire: $32.65/MWh is the average forecast price of wind energy

[30] Again , the average forecast rate increase is offered on a time-levelized basis.

acquired through a PPA and $4.60/MWh is the wind integration cost, which means the utility would face a total cost of $37.25/MWh.[31] Since all utilities would deal with the same set of wind developers and since we assume all utilities would have the same wind integration cost, this near equivalence of the wind energy cost among utility-types is to be expected.

As before, to compute the utility's forecast wind premium, we compare what it cost the utility to acquire wind energy (per MWh) under the PPA with its cost (per MWh) to produce energy via conventional means. The latter is captured by the utility's average forecast system lambda. For the average-cost utility, we derive an average forecast lambda over the investment horizon of $25.07/MWh. Therefore, the average-cost utility's forecast wind premium is ($37.25 - $25.07 =) $12.18/MWh. To be clear, on average, it costs the utility $12.18 more to acquire one MWh under the wind PPA than to generate 1 MWh by conventional means, which is why utility rates, on average, would be higher when the Challenge is met. Because the wind premium is larger for the average-cost utility compared with the high-cost utility ($12.18 versus $0.61 per MWh), the influence of the Challenge on rates is greater for the average-cost utility.

Lastly, in this case the (average forecast) threshold level of external cost savings is $13.24/MWh. That means that if estimated external cost savings were included in this case and were $13.24/MWh or higher, then, from the societal perspective, the Challenge would yield a cost-effective outcome.

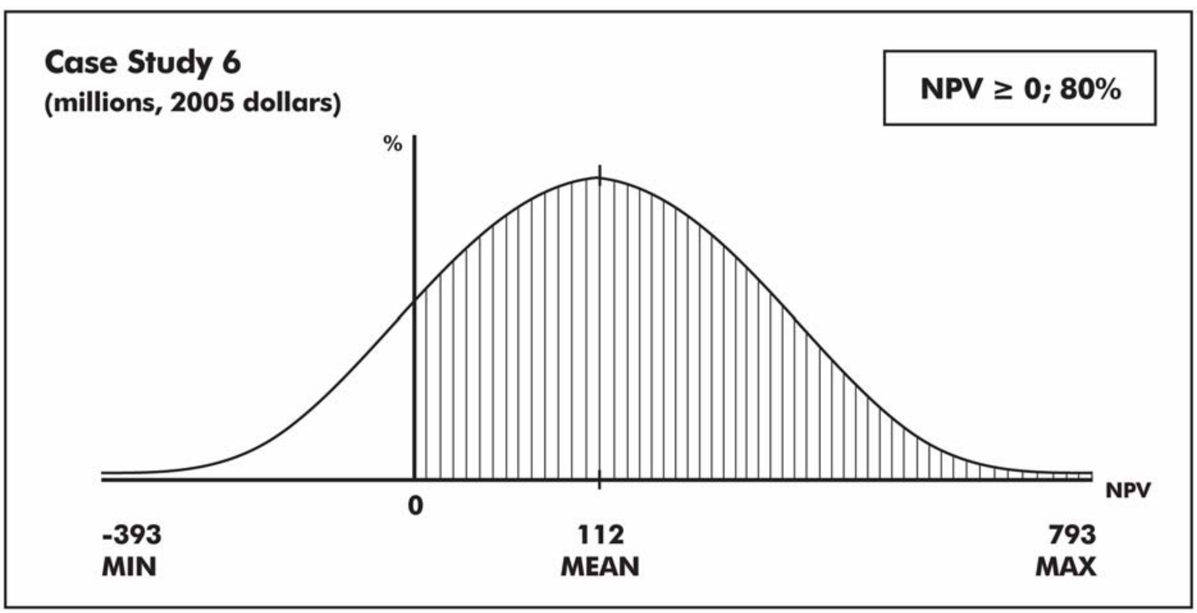
Employment Implications—Higher expenditures forced in the utility sector, concurrent with expenditure reductions elsewhere in the economy, suggests employment gains in the utility sector, but potential job losses elsewhere. It also suggests a reallocation of jobs among different sectors in the economy. However, over the investment horizon, the

[31] These averages are mean values.

levelized net benefit per year is forecast at -$17 million. Since that amount is relatively small on a statewide basis, the net employment implications of the Challenge have the same relative appearance. Within that general framework, the Challenge is likely to spur (small) employment gains in rural areas, near wind facilities, at the possible expense of the more urban areas of the state.

Case Study 6: Average-cost Utility Enters PPAs, External Cost Savings Included

The NPV forecasts for this Case Study are generated using Equation (9) in Section 3.45. Using that equation and the input variable forecast methods described in Chapter 4, including the gas mix forecast model for the average-cost utility-type in particular, we generate 200,000 different NPV forecasts for this Case Study, each dependent on a different forecast scenario. Those results are represented below in Graph 6.



Graph 6: 736 MW, Average-cost Utility-type, PPA Option, External Cost Savings Included

With the inclusion of external cost savings (estimated at $20/MWh of wind energy acquired by the utility), 80 percent of the forecast NPVs are greater than zero. Based on our decision criterion, these results show that meeting the Challenge would be cost effective in this case, at least from the societal perspective.

The rate and annual billing implications, as well as the size of the wind premium, for this Case Study are identical to those in Case Study 5. Thus, meeting the Challenge would bring higher electric bills for ratepayers, but the estimated total external cost savings that would be realized by Kansans generally would surpass the total increase in bills—leaving the state with a net benefit overall.

As identified in the previous Case Study, if the Challenge is met by the average-cost utility using PPAs, and if external cost savings are estimated at $13.24 or more per MWh of wind energy produced, then pursuit of the Challenge would be cost effective by our criterion. Since the estimated external cost of conventional generation is put at $20/MWh, on average, in this case, the external cost savings per MWh of wind energy clearly exceeds the threshold level of $13.24.

Employment Implications—The employment implications are similar to those in the previous Case Study, with one difference being lower total expenditures in the healthcare sector, but more expenditure elsewhere. Again, with those offsetting tendencies, and given the relatively small magnitude of the Challenge's net benefit on a statewide basis, the net change in employment is probably small.

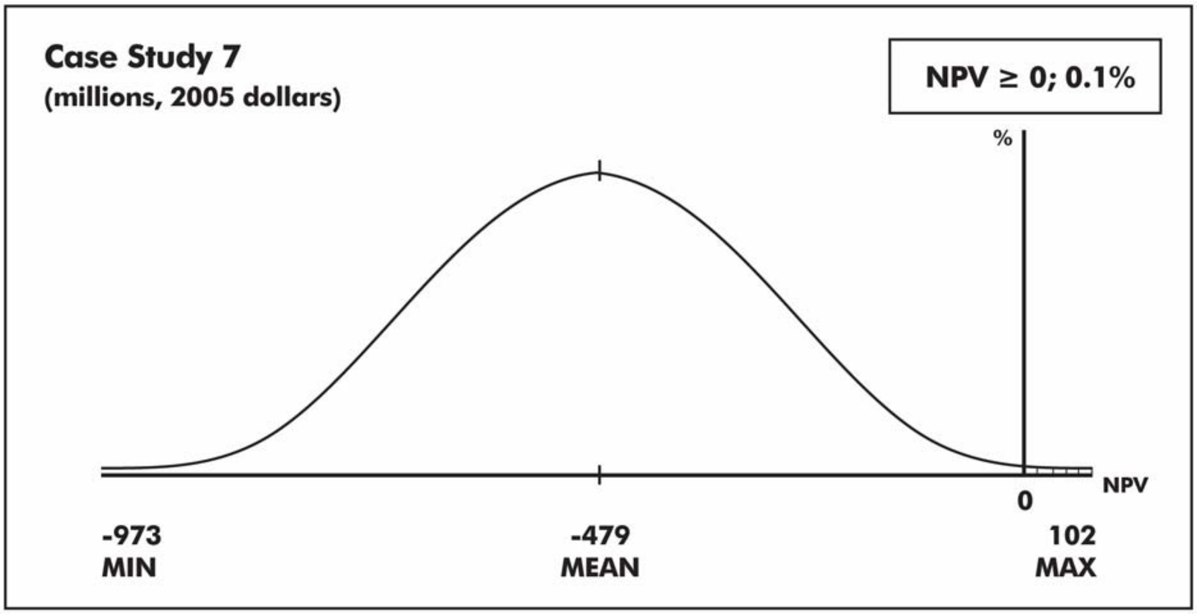
*Comparison of Case Studies 5 and 6: Cost—C*omparing the forecast NPV results from those two studies shows, once again, that when estimated external cost savings of $20/MWh are added to the analysis, meeting the Challenge becomes cost effective from the

broader, societal perspective. In testing for economic efficiency, the consideration of reduced external costs resulting from greater reliance on wind energy makes the critical difference in the case of the average-cost utility if, as discussed below, the utility selects the wind PPA option.

Case Study 7: Average-cost Utility Builds Own Wind Capacity, External Cost Savings Not Included

The NPV forecasts for this Case Study are generated using Equation (6) in Section 3.42. Using that equation and the input variable forecast methods described in Chapter 4 (including the gas mix forecast model for the average-cost utility-type in particular), we generate 200,000 different NPV forecasts for this Case Study, each dependent on a different forecast scenario. Those results are represented in Graph 7.

With nearly 99 percent of the forecast NPVs less than zero, then by our efficiency criterion we would conclude that meeting the Challenge in this case would not be cost effective. Moreover, as the distribution of forecast NPVs show, there is considerable downside risk of a negative net benefit outcome. Although, even in this case, there is still a positive chance of the Challenge being cost effective, but it is less than one percent.



Graph 7: 736 MW, Average-cost Utility-type, Build Option, External Cost Savings Not Included

Meeting the Challenge in this case would result in higher retail rates compared with business as usual. The retail rates would increase $1.16 per MWh, on average. For the average residential customer, that implies an annual bill larger by $12.76, on average, for each year of the 28-year investment horizon.

When the average-cost utility chooses to build its own wind capacity, its cost of wind energy is approximately ($32.65 + $4.60 + $18.76 =) $56.01/MWh, on average. That cost, not surprisingly, is nearly identical to the cost obtained for the high-cost utility-type: because we assume they face comparable costs (in terms of financing, purchasing wind equipment (from the same set of vendors), land leases, wind O&M, etc.), the cost of wind energy among utilities is comparable (if not equivalent).

The wind energy premium for the average-cost utility is ($56.01 - $25.07 =) $30.94/MWh. This represents the expense per MWh of wind energy above the utility's cost to generate one MWh of electricity via conventional means. It would be payment of that

premium that would force the utility to increases its rates (by $1.16/MWh) as a consequence of meeting the Challenge. We see that for the average-cost utility-type, the wind energy premium is higher than for the high-cost utility-type. The reason is straightforward: the high-cost utility has an average forecast lambda of $37.98/MWh, while the average-cost utility's average forecast lambda is $25.07/MWh. The lower-cost utilities, with their lower average annual lambdas, will incur a larger wind energy premium.

In this case, absent consideration of external cost savings, meeting the Challenge is unlikely to be cost effective. However, if they were included, and if external cost savings for each MWh of wind energy was $31.00 or more, then meeting the Challenge in this case would be cost effective under our criterion. That is, for the average-cost utility owning and operating its own wind capacity, the threshold level of external cost savings per MWh of wind energy is $31.00, on average. If estimated external cost savings match or exceed that threshold level, then meeting the Challenge would be cost effective (per our criterion) from the societal perspective.

Employment Implications—In this Case Study, meeting the Challenge requires even higher expenditures in the utility sector, accompanied by even lower expenditures in the non-utility sectors. This is simply the case of electricity consumers allocating more of their (fixed) incomes to their utility bill and, thus, allocating less elsewhere. The net employment gain overall, once again, is likely to be small.

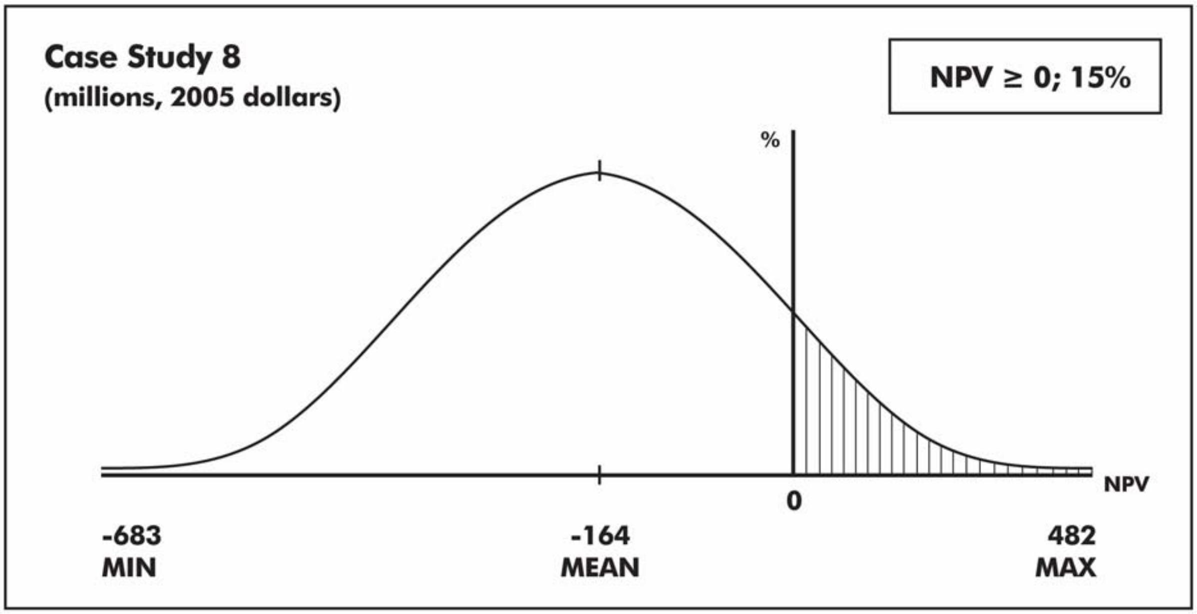
Comparison of Case Studies 5 and 7: Cost—The only difference between Case Studies 5 and 7 is the wind option selected by the utility; otherwise, all else is held constant (probabilistically). As with the high-cost utility-type, we see for the average-cost utility that the build option is more costly than the wind PPA option. Our analysis shows the build

option to be $18.76 more expensive, on average, for each MWh of wind energy acquired by the utility. Of course, that added cost would be incurred by ratepayers generally.

Comparison of Case Studies 5 and 7: Risk—Not only is it more costly for the utility to build than to buy, it is riskier for ratepayers. When the utility builds, the retail rate could increase by as much as $2.29/MWh, on average. But when they buy through a PPA, the maximal forecast rate increase is $1.40/MWh. Measures of risk other than the forecast maximal rate impact tells a similar story.

Case Study 8: Average-cost Utility Builds Own Wind Capacity, External Cost Savings Included

The NPV forecasts for this Case Study are generated using Equation (7) in Section 3.43. Using that equation and the input variable forecast methods described in Chapter 4, including the gas mix forecast model for the average-cost utility-type in particular, we generate 200,000 different NPV forecasts for this Case Study, each dependent on a different forecast scenario. Each of those scenarios includes an estimate of external cost savings of $20 for each MWh of wind energy acquired by the utility. The NPV forecast results for this Case Study are represented in Graph 8.



Graph 8: 736 MW, Average-cost Utility-type, Build Option, External Cost Savings Included

The forecast results show that meeting the Challenge would not be cost effective in this case vis-à-vis our efficiency criterion: about 85 percent of the forecast NPVs come in negative. Although inclusion of external cost savings improves the chance of the Challenge being cost effective—from about 1 percent to 15 percent—clearly, in this case, inclusion of estimated external cost savings does not render pursuit of the Challenge cost effective.

In this Case Study, the internal cost measures associated with the Challenge, the average forecast rate and billing impacts, and the average forecast wind energy premium remain unchanged from the previous case. As usual, the inclusion of external cost savings does not alter the utility's internal cost of using wind energy, though it does change the economics of wind energy from the broader, societal perspective. However, as noted above, the change is not enough to push the forecast outcome into the cost effective category. The estimated external cost savings at \$20/MWh obviously falls short of the threshold level of external cost savings at \$31.00/MWh.

Employment Implications—Inclusion of external cost savings implies some reduction in healthcare-related jobs, but a potential expansion of jobs in the other sectors of the Kansas economy. Again, we conclude that the Challenge's net, statewide influence on Kansas employment would likely be small, particularly on an annualized basis.

Summary Points for the Average-cost Utility-type

- For the average-cost utility, for either wind option to be cost effective, the external cost savings must be $31.00/MWh or more.

- If external cost savings meet or exceed our EPA-based estimate of $20/MWh, then the Challenge would be cost effective from the societal perspective, *only* when the utility selects the PPA option, in which external cost savings only need to be as large as $13.24 per MWh of wind energy. Thus, for the average-cost utility, meeting the Challenge is likely to afford Kansans with a positive net benefit if (1) actual external cost savings per each MWh of wind energy produced exceeds $13.24 and (2) utilities select the lower-cost wind PPA option.

- With either wind option, build or buy, *ratepayers are likely to face higher rates and, consequently, higher annual bills due to the Challenge.* The respective, average forecast rate increases are $1.16/MWh and $0.46/MWh. Our analysis shows that rates are nearly certain to be higher.

- As with the high-cost utility, *our analysis shows that the purchase option is likely to be less costly for ratepayers than the build option.*

- The build option would yield profit to shareholders; the PPA option would not. It is obvious which option shareholders would prefer, even if it would mean higher rates for jurisdictional customers.

- Not only is the build option more costly than the wind PPA option, it appears to be riskier as well. In terms of the forecast rate increase, with the build option there is the chance (or

risk) that it could be as large as $2.29/MWh. With the PPA option, the maximal forecast rate increase is $1.40/MWh.

- Pursuing the Challenge presents a trade-off for Kansans generally: they would face slightly higher electric bills, but receive a cleaner, healthier (and, therefore, less costly) environment to live in. Making that trade-off would be worthwhile—that is, *provide a positive net benefit*—as long as external cost savings attributable to wind energy are $13.24 or more per MWh and provided the utility selects the less costly, wind PPA option.

- Clearly, the realization of external cost savings is critical and implies that *Kansas wind energy must be used to actually reduce the level of energy and, thus, emissions, produced at Kansas' conventional power plants.* If Kansas wind energy is simply used to facilitate an increase in the utility's off-system, wholesale market sales—leaving the energy production levels at their conventional power plants unchanged—then Kansans may not capture the benefits of lower emissions *because Kansas emission levels will not have been reduced.*[32]

- The net, statewide employment implications of the Challenge appear to be small. Some net gain in the utility sector, with a nearly contemporaneous net reduction in the non-utility sectors. Reductions in externalities are likely to reduce employment in the healthcare sector, but could increase it in the non-healthcare sectors. Again, overall, the Challenge's net influence on job creation is likely to be small. However, to the extent wind facilities are located closer to rural communities, it seems likely the Challenge would boost employment in rural areas of the state but dampen employment in the urban job markets.

[32] It is worth reiterating that our NPV analysis assumes that all Kansas wind energy is used to fully displace and, thus, reduce, the level of generation at Kansas' conventional power plants. Because of utilities' participation in the wholesale electricity market, it is not clear that assumption will actually hold in practice.

5.13 The Low-Cost Utility-type

Before we discuss the low-cost utility-type results, we note, again, that the only difference among the four utility-types is their gas mix: the proportion of their generation output that is fueled by natural gas. As expected, *the gas mix for the low-cost utility-type is usually lower than the gas mix of both the average and high-cost utility-types.*[33] Otherwise, the low-cost utility-type faces, on average, the same forecast costs, including purchase prices for wind energy and retail loads, as the high-cost utility-type. The difference in gas mixes shows up in the utilities' respective annual fuel expenses and, accordingly, in their average annual forecast system lambdas. In terms of our study, the average annual forecast system lambda for the low-cost utility-type comes in at $21.35/MWh (compared to $37.98/MWh and $25.07/MWh, respectively for the high- and average-cost utility-types). Once again, we see that if the utility has relatively less reliance on natural gas consumption, then its incremental cost of generating electricity via conventional means is considerably less. Thus, with the low-cost utility-type, the fuel savings attributable to the utility's acquisition of wind energy, on average, is smaller compared with those of the other two utility-types. Consequently, wind energy is probably relatively less valuable (as a means of saving scarce resources) to the low-cost utility and its ratepayers.

The forecast results for the low-cost utility resemble those for the average-cost utility-type. This similarity stems from our method of computing the average-cost utility's average annual system lambda. Since that lambda is a retail sales-weighted average of the state's jurisdictional electric utilities, it bears a close resemblance to the state's two largest utilities, Westar and KCPL, both of which are characterized as low-cost utilities.

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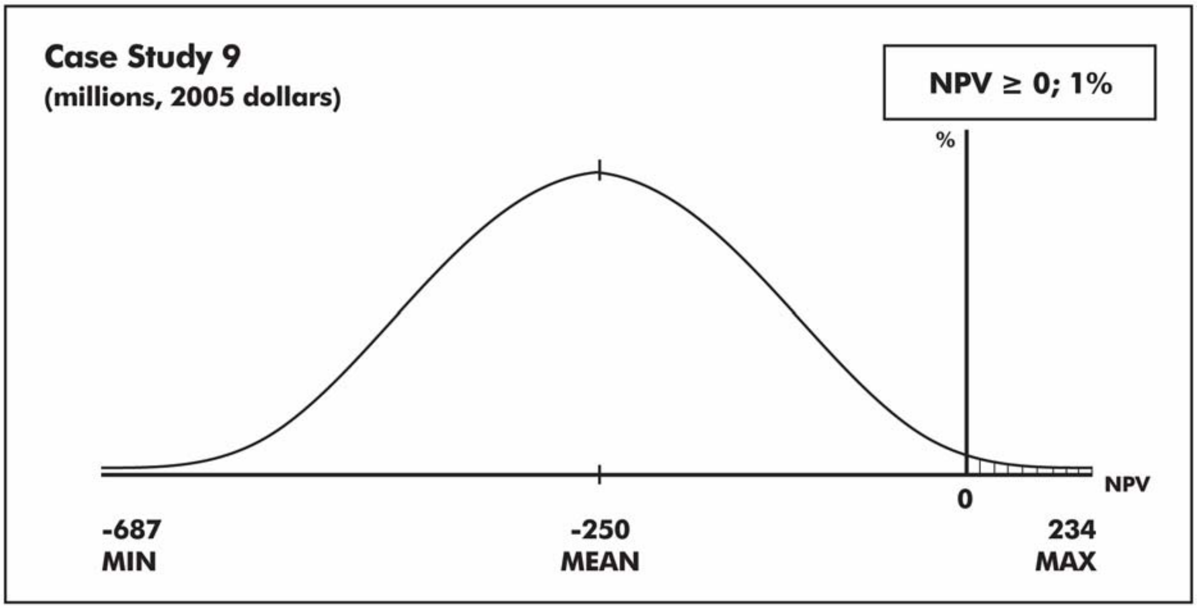
[33] For the low-cost utility-type, the mean forecast gas mix is 2.0 percent.

Case Study 9: Low-cost Utility Enters PPAs, External Cost Savings Not Included

The NPV forecasts for this Case Study are generated using Equation (8) in Section 3.44. As with the other Case Studies presented above, we consider 200,000 different forecast scenarios, and derive a forecast NPV for each scenario. Those NPV forecast results are represented in summary form by the probability distribution shown below in Graph 9.



Graph 9: 736 MW, Low-cost Utility-type, PPA Option, External Cost Not Savings Included

With 98 percent of the forecast NPV coming in at less than zero, we conclude that meeting the Challenge in this case is not cost effective for ratepayers, despite a one-percent chance of a positive NPV. The downside risk in this case appears to be considerable, with a minimal forecast NPV of -$687 million and 98 percent probability of realizing a negative NPV outcome.

Meeting the Challenge in this case would increase the retail rate by $0.57/MWh, on average, and increase the average residential customer's annual bill by $6.27. That increase would be for each year of the 28-year-long investment horizon. As expected, the non-cost

effectiveness of the Challenge, from the view point of ratepayers, shows up in the form of higher, not lower rates.

The wind premium for the low-cost utility is ($32.67 + $4.60 - $21.35 =) $15.92/MWh, on average. More specifically, it costs the utility, on average, $15.92 more to acquire one MWh of wind energy compared with its own cost to generate one MWh via conventional means. As expected, the low-cost utility, since it has the lowest forecast avoided (mainly fuel) cost per MWh, has the largest wind premium.

The threshold level of external cost savings in this case is $16.25/MWh, on average. Thus, when the low-cost utility meets the Challenge through PPAs, if external cost savings for each MWh of wind energy acquired are $16.25 or more, then from the societal perspective it would be cost effective for this utility to meet the Challenge. If actual external cost savings exceed the threshold level, then the total (internal and external) cost of providing electricity to Kansans is lower when the Challenge is met.

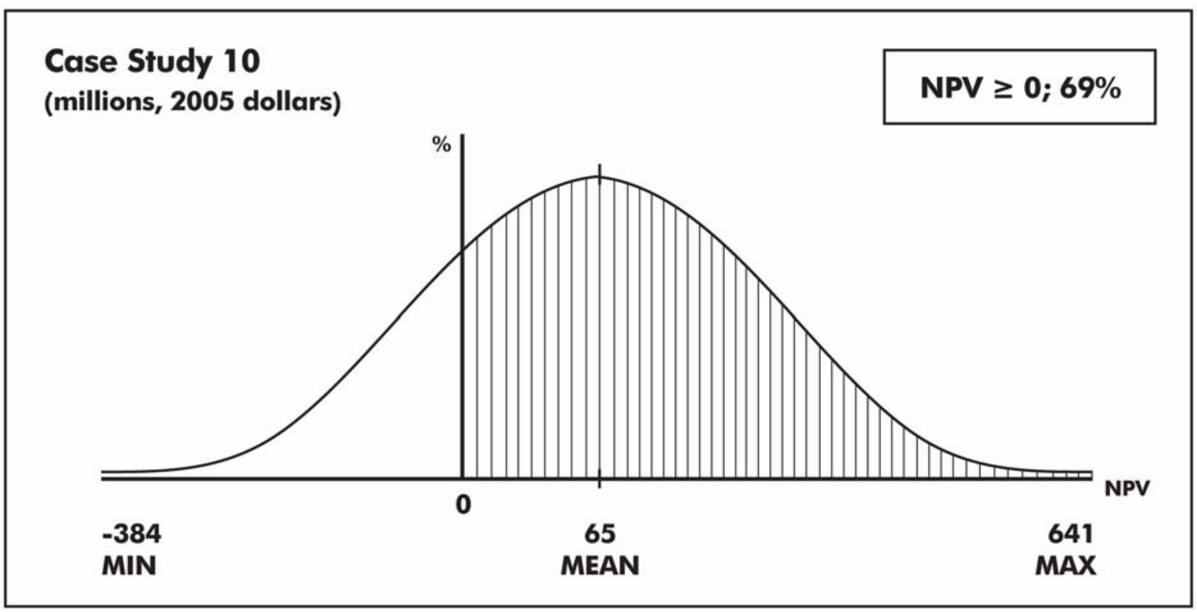
Employment Implications—The employment implications in this case are comparable to those for the average-cost utility when it meets the Challenge via entering PPAs. Gains are likely in the utility sector, but losses may occur elsewhere. Since meeting the Challenge is unlikely to result in an efficiency gain (from the utility ratepayers' perspective), the net employment gain overall, once again, is likely to be small.

Comparison of Case Studies 5 and 9: Cost—The only difference between Case Studies 5 and 9 is the utility's gas mix forecast. This comparison shows that the higher the gas mix, all else held constant (probabilistically), the more valuable wind energy is to ratepayers. Equivalently, the lower the gas mix, the higher the wind premium, and the larger the rate impact from meeting the Challenge.

Case Study 10: Low-cost Utility Enters PPAs, External Cost Savings Included

The NPV forecasts for this Case Study are generated using Equation (9) in Section 3.45. As with the other Case Studies presented above, we consider 200,000 different forecast scenarios, and for each scenario an NPV forecast was derived. Those NPV forecast results are represented in summary fashion by the probability distribution shown below in Graph 10.

With 70 percent of the forecast NPVs coming in at values greater than zero, meeting the Challenge would be cost effective by our criterion from the societal perspective. While positive NPV outcomes are not guaranteed, they are likely.



Graph 10: 736 MW, Low-cost Utility-type, PPA Option, External Cost Savings Included

The rate, billing, and wind energy premiums are unchanged from the previous Case Study. Hence, higher bills would prevail in this case, even though the total (combined internal and external) cost of providing electricity to Kansans is likely to be lower.

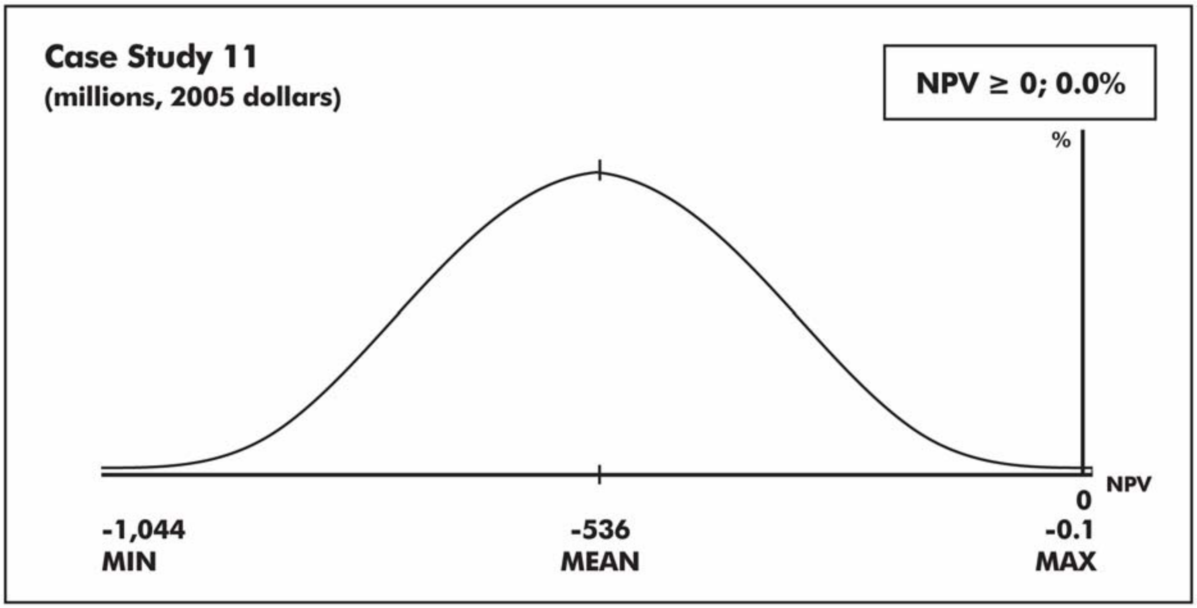
Obviously, since the estimated external cost savings set at $20/MWh of wind energy surpasses the threshold level needed (in this case, at $16.25, on average), we would expect meeting the Challenge to be economically efficient from the broader, total cost perspective. Again, this result is not guaranteed, but is expected.

Employment Implications—As before, inclusion of estimated external cost savings implies lower expenditures in the healthcare sector of the economy, but possible higher expenditures elsewhere in the economy. The net employment gain is likely to be positive, since an increase in overall efficiency would be realized, but it is likely to be small.

Comparison of Case Studies 9 and 10: Cost—We see that with the inclusion of estimated external cost savings, meeting the Challenge for the low-cost utility becomes cost effective from the broader, societal perspective. Once again we see that external cost savings, when considered, make the critical difference between the Challenge being cost effective and not.

Case Study 11: Low-cost Utility Builds Own Wind Capacity, External Cost Savings Not Included

The NPV forecasts for this Case Study are generated using Equation (6) in Section 3.42. As usual, we consider 200,000 different forecast scenarios, for each scenario an NPV forecast was derived. Those NPV forecast results are shown in summary fashion by the probability distribution shown below in Graph 11.



Graph 11: 736 MW, Average-cost Utility-type, Build Option, External Cost Savings Not Included

This is the only Case Study in which all 200,000 forecast scenarios, from the most optimistic to the least—in terms of favoring wind—yield negative forecast NPV values. To say the obvious, when the low-cost utility type selects the build option, and when external cost savings are not included in the analysis, our analysis shows there is no chance for a positive forecast. Clearly, pursuit of the Challenge is not cost effective under these conditions.

The rate implications of the Challenge are also largest in this case. The retail rate would increase by $1.29/MWh, on average (although, in this case, the average rate could increase by as much as $2.44/MWh). For the typical residential customer, that would force their annual electric bill up by $14.19, on average. And that increase in the annual cost of electricity would stay in place for each year of the investment horizon.

In this case, not surprisingly, the wind premium is largest. Again, we calculate the wind premium by taking the difference between what it costs the utility to acquire one MWh

of wind energy and the cost the utility can avoid as a result. In this case, the utility's cost to acquire wind is ($32.67 + $4.60 + $18.75 =)[34] $56.02/MWh. Note that the low-cost utility's cost to acquire wind energy, when it chooses to install its own wind capacity, is essentially identical to what it costs the other utility-types to acquire wind energy when they have selected the same option. That is, among all utility types, there is no difference in what it costs them to acquire wind energy through their investment in wind capacity. The difference is in what wind energy *saves them* in terms of incremental costs, mainly fuel cost. We measure the incremental costs avoided by the utility acquiring one MWh of wind energy by the FOM input variable, which is our measure of the utility's average annual system lambda. In the case of the low-cost utility, the average forecast FOM is $21.35/MWh. Thus, the wind energy premium in this case is ($56.02 - $21.35 =) $34.67/MWh. In contrast, the wind energy premium for the high-cost utility, when it selects the build option, is $18.67/MWh. In every case, larger wind energy premiums result in larger rate increases.

The threshold level of external cost savings in this case is $34.61/MWh, on average. As expected, among all utility-types, the threshold level of external cost savings is highest for the low-cost utility.

Employment Implications—In this case, expenditures in the utility sector experience the largest increase relative to the other comparable case studies, Case Studies 3 and 7. On the face of it, that would suggest the potential for the largest increase in employment in that sector. But it also implies the largest decrease in expenditures and, thus, employment in the non-utility sectors of the state. Yet even in this case, a significant net change in employment

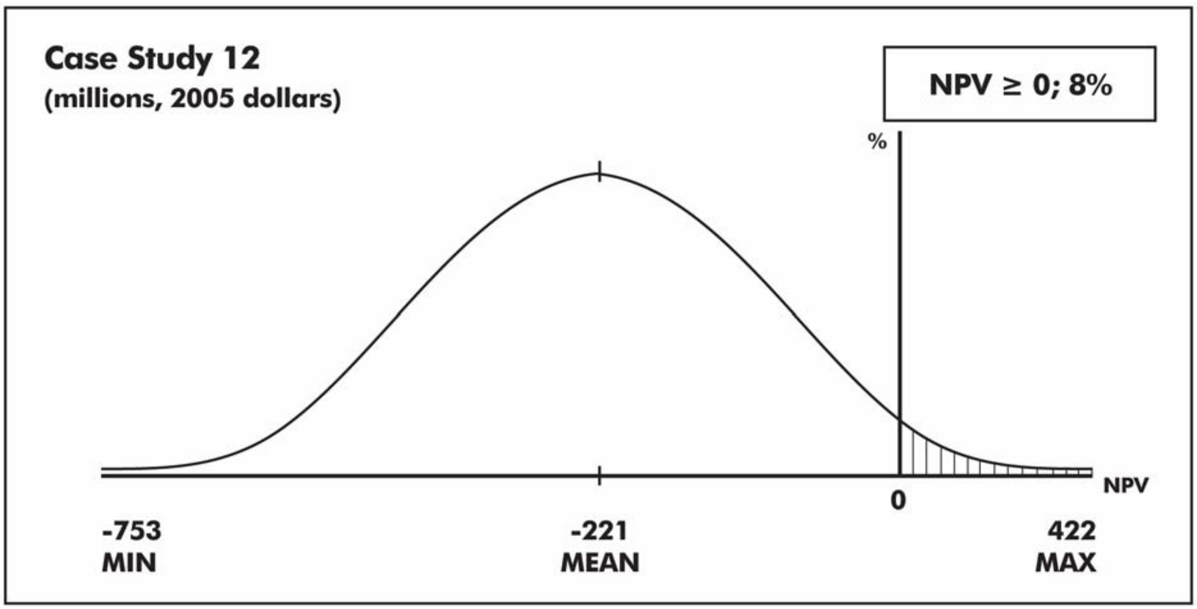
[34] Again, those amounts refer to the utility's average cost to acquire wind energy through a PPA, at $32.67/MWh; wind integration cost at $4.60/MWh of wind energy; and average premium associated with building rather than buying wind. The analysis in Appendix H shows that it would cost the low-cost utility $18.75 more to acquire one MWh of wind energy when it installs its own wind capacity, rather than purchasing it through a PPA.

on a statewide basis does not seem likely. However, since most of the higher cost of building rather than buying wind energy is associated with its (relatively higher) financial cost, the higher expenditures by ratepayers primarily go to shareholders and debt holders. To the extent that members of those two groups do not reside in Kansas, the higher payments Kansas ratepayers make as a consequence of the Challenge would be effectively leaving the state's economy. In that event, it seems likely the net gain in employment in this case would remain small, but it could also very well be negative. That the net employment gain in the state could turn out negative depends not so much on the forecast NPVs being negative, but whether the utility profits are likely to leave the state.

Comparison of Case Studies 9 and 11: Cost—The only difference between this case and Case Study 9 is the wind option selected by the utility: all else is held constant except the utility's choice of a wind option. Our analysis shows that when the utility selects the PPA option, the average forecast NPV is -$250 million. When it selects the build option, the average forecast NPV is -$536 million. Within the confines of the NPV analysis, that difference amounts to $18.36/MWh. That is, when the utility selects the wind investment option, it costs the utility $18.36 more to acquire one MWh of wind energy compared with taking that energy through a wind PPA. *To be more precise, one MWh of wind energy costs ratepayers about $18 more when the utility selects the build option over the buy option.* (Using the more stylized analysis presented in Appendix H, the build versus buy premium is $18.75/MWh for the low-cost utility.)

Case Study 12: Low-cost Utility Builds Own Wind Capacity, External Cost Savings Included

The NPV forecasts for this Case Study are generated using Equation (7) in Section 3.43. As usual, we consider 200,000 different forecast scenarios, and for each scenario an NPV forecast was derived. Those NPV forecast results are offered in summary fashion by the probability distribution shown below in Graph 12.



Graph 12: 736 MW, Average-cost Utility-type, Build Option, External Cost Savings Included

The inclusion of external cost savings in this case improves the forecast NPVs relative to those in the prior case. But obviously, even from the broader, societal perspective, meeting the Challenge is not cost effective.

The rate implications for this case are identical to those in the previous Case Study. The retail rate would increase by $1.29/MWh, on average; the typical residential customer’s annual bill would increase by $14.19, on average. That increase is also the levelized annual increase over the investment horizon. With that it is easy to compute the total net benefit of

the Challenge to the average residential customer, over the entire 28-year investment horizon. In this case, the typical households average forecast net benefit over the horizon is negative by about (28 × $14.19 =) $397.

The threshold level of external cost savings in this case is $34.61. Since the estimated external cost savings are put at $20/MWh, the estimated external cost savings are not sufficiently large to push meeting Challenge into the cost-effective category. That the estimated external cost savings do not rise to the threshold level of external cost savings only confirms that meeting the Challenge would not be cost effective, even form the societal perspective.

Employment Implications—The job implications in this case are the same as in Case Study 11, except that—with the inclusion of external cost savings—expenditures and, thus, jobs in the healthcare sector would be reduced. At the same time, expansion of both expenditures and employment would occur in the non-health-related sectors of the economy. However, any net changes in statewide employment due to the Challenge are likely to be small. That is because the economic magnitude of the Challenge, on an annual basis, is small relative to the size of the state's total annual income. It is also because the Challenge will induce expenditure changes and, thus, employment changes that tend to offset one another, yielding small net changes. For instance, installing wind capacity expands employment somewhat, but wind energy reduces fuel use and health-related damages, which reduces employment in the fuel and health services areas.

Summary Points for the Low-cost Utility-type

- For the low-cost utility, for either wind option to be cost effective, the external cost savings must be $34.61/MWh or more.

- If external cost savings are as large as or larger than our EPA-based estimate of \$20/MWh, then the Challenge would be cost effective from the societal perspective *only when the utility selects the PPA option.* Under the PPA option, external cost savings per MWh of wind energy only need to be \$16.25 or more. Thus, meeting the Challenge is likely to afford Kansans with a positive net benefit provided: (1) actual external cost savings per each MWh of wind energy produced exceeds \$16.25 and (2) utilities select the lower-cost wind PPA option.

- In other words, from the societal perspective, meeting the Challenge is cost effective only when utilities select the PPA option and external cost savings are \$16.25 or more. Although such an outcome is not guaranteed, it appears likely.

- With either wind option, build or buy, *ratepayers are likely to face higher rates and, consequently, higher annual bills due to the Challenge.* The average forecast rate increases are \$1.29/MWh and \$0.57/MWh, respectively, for the build or buy options. The prospect higher rates, though not certain, is nearly so.

- The build option is not only more costly than the wind PPA option, but also appears to be riskier. With the build option, there is the chance, or risk, that rates could increase as much as \$2.44/MWh. With the purchase option, the maximal forecast rate increase is \$1.51/MWh.

- As with the high- and average-cost utilities, the purchase option is likely to be less costly for ratepayers than the build option. We find that *the build option costs the low-cost utility about \$18 more per MWh of wind energy, on average, than the buy option*.

- As with the other utility-types, the build option more profitable for shareholders. Because of that, utility management has an obligation to its shareholders to pursue the Challenge by directly investing in wind capacity.

- Pursuing the Challenge presents a trade-off for Kansans generally: they would face slightly higher electric bills, but receive a cleaner, healthier (and, therefore, less costly) environment to live in. Making that trade-off would be worthwhile—that is, *provide a*

positive net benefit—as long as external cost savings attributable to wind energy are $20 or more per MWh and provided the utility selects the less costly option of acquiring wind energy: the PPA (or buy) option.

- The critical nature of external cost savings is, again, worth noting. For wind energy to have any chance of being cost effective in Kansas, *it is of critical importance that the production of Kansas wind energy be used to actually reduce the level of conventional energy and, thus, emissions, produced at Kansas' power plants.* If Kansas wind energy is simply used to facilitate an increase in the utility's off-system, wholesale market sales, leaving the energy production levels at their conventional power plants unchanged, then Kansans may not capture the benefits of lower emissions—*because Kansas emission levels will not have been reduced.*[35]

- The net, statewide employment implications of the Challenge appear to be small. The expected net gain in the utility sector is offset by a nearly contemporaneous net reduction in the non-utility sectors. Reductions in externalities are likely to reduce employment in the healthcare sector but could increase it in the non-healthcare sectors. *Again, overall, the Challenge's net influence on job creation is likely to be small.* However, to the extent wind facilities are located closer to rural communities, it seems likely that the Challenge would boost employment in rural areas of the state but dampen employment in the urban job markets.

5.14 The Middle-Cost Utility-type

Finally, we show the forecast results for the middle-cost utility-type. As its name implies, the average forecast gas mix for the middle-cost utility falls in between that of the high and low-

[35] In this analysis we model wind energy production as *negative load*, which means wind energy would deliver avoided cost benefits, including the benefits of avoided externalities. An alternative way to model/evaluate wind energy production is to estimate its wholesale *market value*. However, with that approach, it must be determined whether wind energy is marketable on a standalone basis. (Current indications are that, as a practical matter, wind is not marketable on a standalone basis.) If wind energy is not marketable on a standalone basis, then one must determine the cost of making it so. In recognition of that cost, the *net market value* of wind energy may be small. In fact, wind's value as a net revenue source may be much smaller than its value as a cost saver.

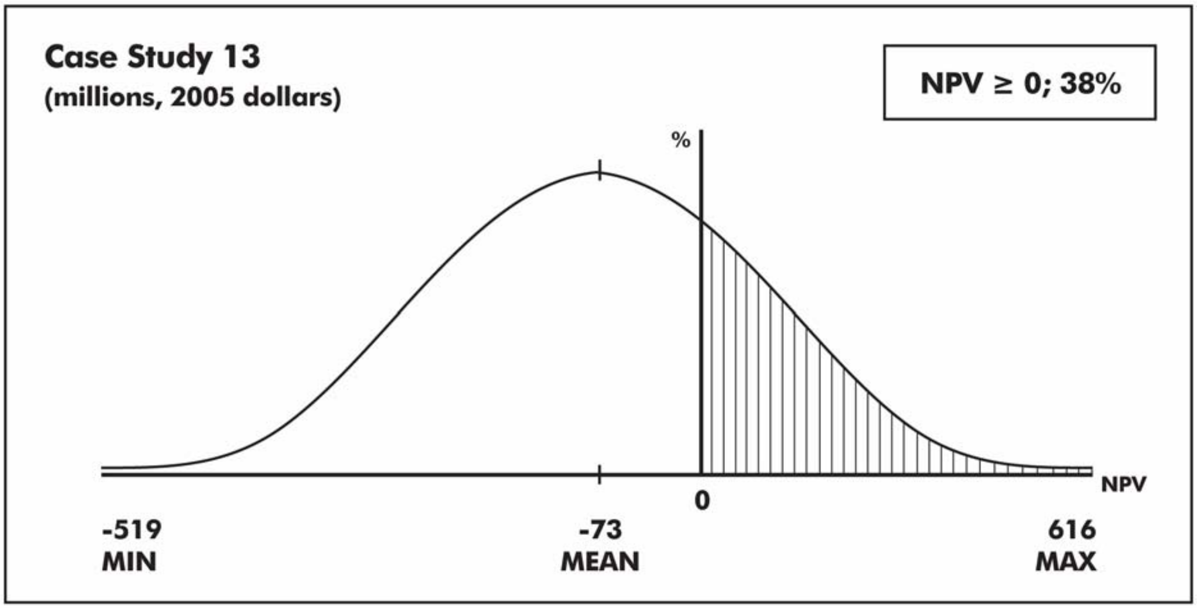
cost utility-types,[36] as do all of the middle-cost utility's forecast NPV results. The forecast difference in utility gas mixes also implies forecast differences in their average annual system lambdas. The average forecast lambda for the middle-cost utility is $32.74/MWh; for the high-, average-, and low-cost utilities, the average forecast lambdas are $37.98, $25.07, and $21.35, respectively. The assumed cost structure of the middle-cost utility resembles that of MWE and EDE. However, MWE's average annual lambda may be somewhat lower than the $32.74 amount; EDE's may be somewhat higher.

Because the results for the middle-cost utility all fall within those obtained for the high and low-cost utility-types, there is little need to present its employment implications. Similarly, there is little need to present comparisons among the Case Studies.

Case Study 13: Middle-cost Utility Enters PPAs, External Cost Savings Not Included

The NPV forecasts for this Case Study are generated using Equation (8) in Section 3.44. As with all other case studies, we consider 200,000 different forecast scenarios, and derive a forecast NPV for each scenario. Those NPV forecast results are offered in summary fashion by the probability distribution shown below in Graph 13.

[36] For middle-cost utility, the average forecast fuel mix is 5 percent. In comparison, the high, average, and low-cost utility-types have average forecast gas mixes of 20.0, 4.0, and 2.0 percent, respectively.



Graph 13: 736 MW, Middle-cost Utility-type, PPA Option, External Cost Not Savings Included

With 72 percent of the forecast NPVs coming in negative, meeting the Challenge in this case would not be cost effective for ratepayers. On average, meeting the Challenge would force the utility's internal costs up by $73 million in 2005 constant dollars.

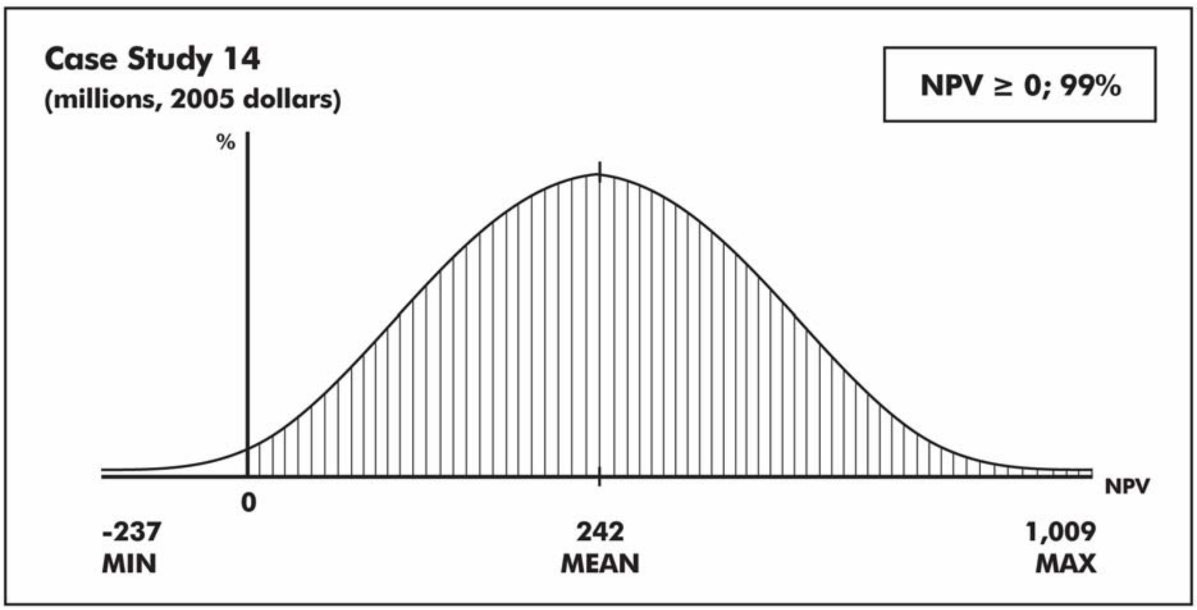
The forecast increase in the utility's revenue requirement implies higher rates. The average forecast rate increase in this case is $0.15/MWh. The maximal forecast rate increase in this case is $1.17/MWh; under the most optimistic forecast, the average rate would fall by $1.98/MWh. The average forecast annual bill increase for the typical residential customer is $1.65; this is a levelized bill increase, holding for each year of the investment horizon.

The wind premium in this case is ($32.66 + $4.60 - $32.74 =) $4.52/MWh. That is the average forecast difference between the utility total cost to acquire one MWh of wind energy under the PPA ($37.26) and its cost to acquire one MWh of electricity via conventional means.

The threshold level of external cost savings in this case is just $5.00/MWh. That amount is considerably lower than the comparable threshold level for the low-cost utility-type, at $16.25.

Case Study 14: Middle-cost Utility Enters PPAs, External Cost Savings Included

The NPV forecasts for this Case Study are generated using Equation (9) in Section 3.45. Again, we consider 200,000 different forecast scenarios, and, for each scenario, derive an NPV forecast. Those NPV forecast results are offered in summary fashion by the probability distribution shown below in Graph 14.



Graph 14: 736 MW, Middle-cost Utility-type, PPA Option, External Cost Savings Included

Inclusion of the estimated external cost savings makes all the difference in terms of economic efficiency. With that inclusion, over 99 percent of the forecast NPVs come in greater than zero. In this case, meeting the Challenge is cost effective from the societal

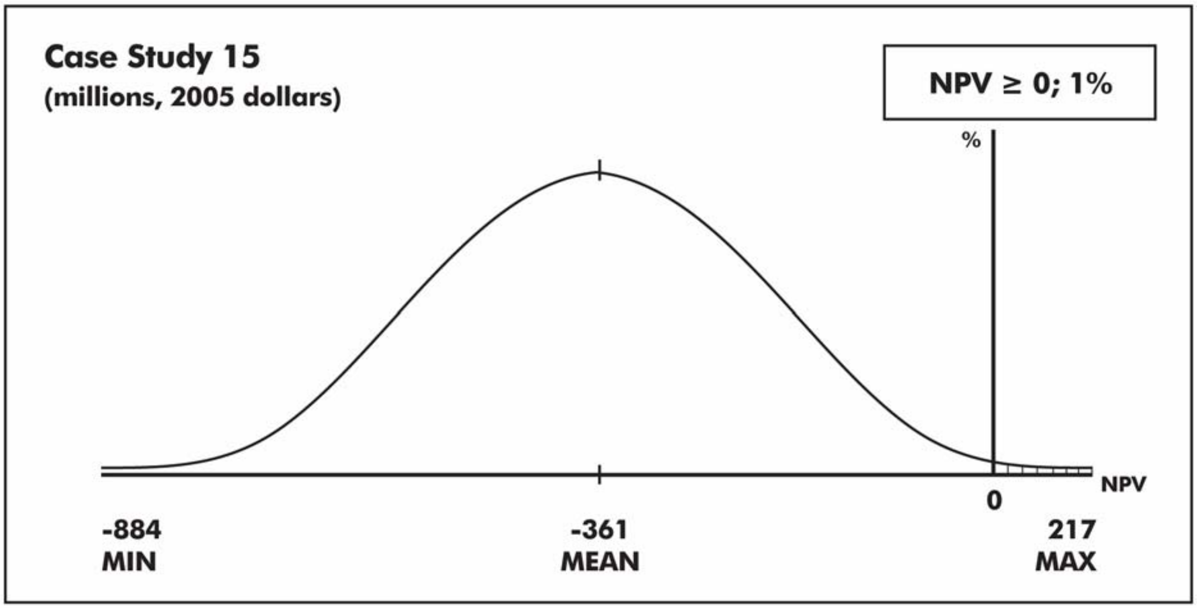
perspective. While the utility's internal costs, along with its rates would still increase as a result of meeting the Challenge, the estimated external cost saving would more than make up for that cost increase. Thus, when external cost savings are included in the analysis, the *total cost* of providing electricity to Kansans would actually decrease.

The inclusion of external cost savings does not alter the rate implications from the previous case. Rates would still increase by the forecast amount, which is $0.15/MWh. Obviously, the forecast billing implications and wind energy premium are unchanged from the previous Case Study as well.

Inclusion of the estimated external cost savings at $20/MWh clearly surpasses the threshold level, $5.00/MWh, that is needed for a cost-effective outcome. The inclusion of that forecast benefit in this case pushes pursuit of the Challenge into the cost effective category (again, not from the perspective from ratepayers, who would see their rates increase, but from the broader, societal perspective which extends beyond a concern strictly for the size of the utility bill).

Case Study 15: Middle-cost Utility Builds Own Wind Capacity, External Cost Savings Not Included

The NPV forecasts for this Case Study are generated using Equation (6) in Section 3.42. As with all other case studies, we consider 200,000 different forecast scenarios; for each scenario an NPV forecast was derived. Those NPV forecast results are offered in summary fashion by the probability distribution shown below in Graph 15.



Graph 15: 736 MW, Middle-cost Utility-type, Build Option, External Cost Not Savings Included

In this case, our forecast results show that less than 1 percent of the NPV outcomes are positive. The average forecast NPV is -$361 million in 2005 constant dollars. With these results, vis-à-vis our efficiency criterion, we would conclude that meeting the Challenge is not cost effective for Kansas ratepayers.

In this case, the retail rate would, as forecast, increase by $0.88/MWh, on average. Annual electric bills, for the average residential customer, would increase by $9.68. That amount also shows the average increase per year over the investment horizon. So for that 28-year horizon, the total increase in the cost of electricity, per household, is forecast to be $271 (in inflation-adjusted dollars).

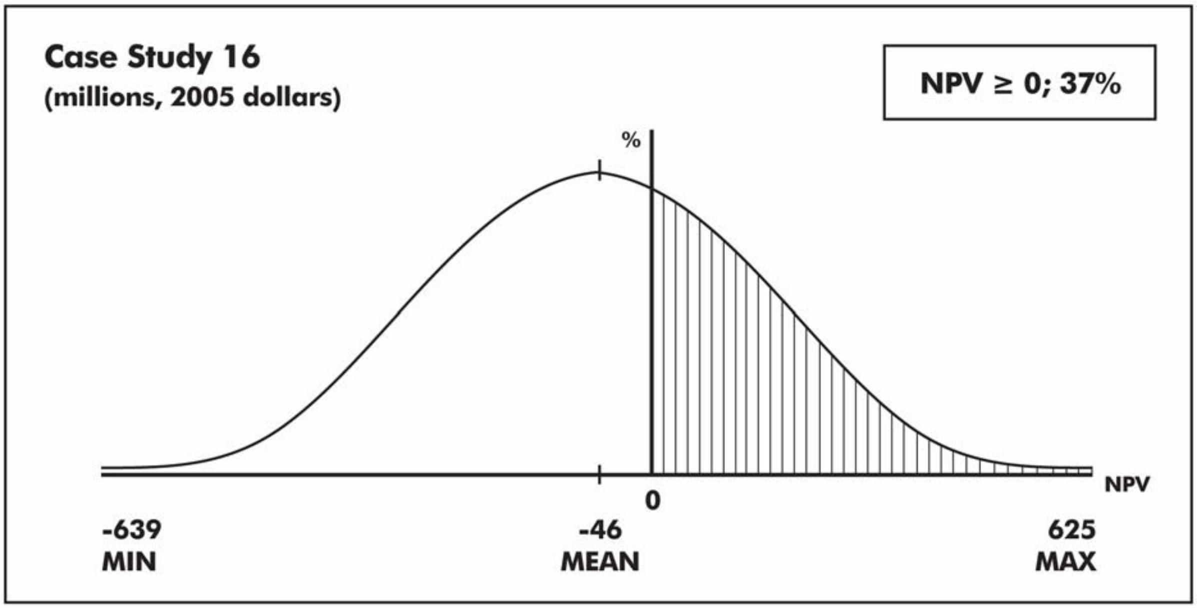
The forecast wind energy premium is $23.27/MWh. That amount shows the extra cost, on average, to the utility to acquire one MWh of wind energy from its own wind generators than one MWh of energy from its own conventional generators and fuels.

The threshold level of external cost savings is $23.51/MWh. Except in the case of the high-cost utility-type, the threshold level of external cost savings is high correlated with the wind energy premium. The extent to which wind energy is more costly than conventionally produced electricity, as measured by the wind energy premium, provides an indication of how much extra value or benefit wind energy must provide society in order for it to be cost effective. That extra benefit is the external cost savings. The more costly wind energy is compared to the existing alternatives, the more it needs to deliver in terms of avoided externalities in order to provide a positive net benefit.

Comparison of Case Studies 13 and 15: Cost—These two case studies are identical, except that in the former the utility enters a wind PPA, and in the latter it directly owns the wind capacity. As the results above show, this one difference means higher retail rates, a higher wind energy premium, and a higher level of threshold external cost savings. The retail rate would be higher by $0.73/MWh, on average, the wind energy premium is higher by $18.75/MWh, and the threshold level of external cost savings is higher by $18.51/MWh.

Case Study 16: Middle-cost Utility Builds Own Wind Capacity, External Cost Savings Included

The NPV forecasts for this Case Study are generated using Equation (7) in Section 3.43. As usual, we consider 200,000 different forecast scenarios, and for each scenario an NPV forecast was derived. Those NPV forecast results are offered in summary fashion by the probability distribution shown below in Graph 16.



Graph 16: 736 MW, Middle-cost Utility-type, Build Option, External Cost Savings Included

Adding in the forecast benefit of reduced external costs is unlikely to make the Challenge cost effective in this case. With less than 50 percent of the forecast NPVs greater than zero, we would conclude that the Challenge is not economically efficient in this case. Nonetheless, there remains a 37 percent chance that a positive outcome will prevail.

The rate, annual bill, and wind energy premium implications are unchanged from Case Study 15. Thus, higher rates and bills are likely in this case.

Since the estimated external cost savings ($20/MWh) included in the analysis fall just below the threshold level of savings, at $23.51/MWh, the Challenge is unlikely to yield sufficient savings (i.e., benefits) to end up with a positive net benefit. From neither the perspective of ratepayers, nor the broader, societal perspective, is the Challenge likely to be economically efficient in this case.

Summary Points for the Middle-cost Utility-type

- For the middle-cost utility, *meeting the Challenge using either wind option would likely be cost effective from the societal (or total cost) perspective, as long as estimated external cost savings are $23.51/MWh or more.* However, if the utility selects the PPA option, then the external cost savings only need to be as high as $5.00/MWh for the Challenge to be cost effective.

- In other words, if external cost savings are at least as large as our EPA-based estimate of $20/MWh, then the Challenge would be cost effective from the societal perspective, provided the utility selects the PPA option. On the other hand, if the utility selects the build option, even with external cost savings at $20/MWh it is unlikely that meeting the Challenge would be cost effective.

- *With either wind option, build or buy, ratepayers are likely to face higher rates and, consequently, higher annual bills due to the Challenge.* The respective, average forecast rate increases are $1.29/MWh and $0.57/MWh. Our analysis shows that the prospect for rates being higher is not certain, but nearly so.

- Our analysis shows that the purchase option is likely to be less costly for ratepayers than the build option. This forecast result is no different than the respective findings for the high- and average-cost utilities. As with the other utility-types, we find the build option costs the middle-cost utility about $18 more per MWh of wind energy, on average. The build option is the one that delivers allowed profits to utility shareholders.

- Not only is the build option more costly for ratepayers than the wind PPA option, it appears to be riskier as well. In terms of the forecast rate increase, with the build option there is the chance or risk that it could be as large as $2.09/MWh. With the purchase option the maximal forecast rate increase is $1.17/MWh.

- Pursuing the Challenge presents a trade-off for Kansans generally: they would face slightly higher electric bills, but receive a cleaner, healthier (and, therefore, less costly) environment to live in. Making that trade-off would be worthwhile—that is, *provide a*

positive net benefit—as long as (1) external cost savings attributable to wind energy are $5 or more per MWh and (2) the utility selects the less costly, wind PPA option.

- *It remains critical that the production of Kansas wind energy be used to actually reduce the level of energy and, thus, emissions, produced at Kansas' conventional power plants.* If Kansas wind energy is simply used to facilitate an increase in the utility's off-system, wholesale market sales—leaving the energy production levels at their conventional power plants unchanged—then Kansans may not capture the benefits of lower emissions because *Kansas emission levels will not have been reduced.*

- The net, statewide employment implications of the Challenge appear to be small, with some net gain in the utility sector accompanied by a nearly contemporaneous net reduction in the non-utility sectors. Reductions in externalities are likely to reduce employment in the healthcare sector, but could increase it in the non-healthcare sectors. *Again, overall, the Challenge's net influence on job creation is likely to be small.* However, to the extent wind facilities are located closer to rural communities, it seems likely the Challenge would boost employment in rural areas of the state but dampen employment in the urban job markets.

5.20 Background for Case Studies with 1,000-MW investment Base

5.21 Introduction: Going From the 736-MW investment Base to the 1,000-MW investment Base

To provide forecast NPV results for the full Challenge amount of 1,000 MW of installed wind capacity, we simply add in the NPV value of the state's existing facilities. That is, we add to the NPV forecasts presented above—all of which are based on the amount of new capacity needed to reach the Challenge as of January 1, 2006, 736 MW—the NPV forecasts for the 264 MW of wind capacity that was in operation just prior to January 2006. By combining those two sets of forecasts, we obtain the forecast NPV values for 1,000 MW of installed capacity.

5.22 Forecasting the NPVs for the Existing Wind Facilities

In this section we establish the forecast NPVs for the two wind facilities that were fully operational at the start of January 2006. Since these facilities are "historically given," there is no need to consider their use by difference possible utility-types. Nor is there any question about potential ownership; each is owned by a wind developer that offers the energy produced by the facility to the (local) utility through the terms of a PPA. Therfore, there is no need to examine the build option vis-à-vis the existing facilities. There is a need to forecast the net benefit of each facility with and without consideration of the possible external cost savings associated with the wind energy production.

In summary, for each existing wind facility we compute forecast NPVs with and without inclusion of external cost savings, under the terms (and mainly the price term) of the existing PPAs. We also compute forecast NPVs of the existing facilities on a *combined* basis, and those forecast results are aggregated with the NPV forecasts for Case Studies 1 through 16. The aggregated forecast NPVs yield the forecast results for Case Studies 17–32, all of which show the forecast net benefit of the Challenge based on 1,000 MW of installed wind capacity, the amount specified in the Challenge itself.

With one exception, all of the forecast methods and data sets used to develop the NPV forecasts for the new, not-yet-existing wind capacity are the same ones used to evaluate the historically given wind capacity. The one difference is our use of the actual, rather than forecast, purchase prices for wind energy. The actual prices are taken from the respective PPAs as filed with the Commission. Consistent with our usual forecasting method, for each existing facility we examine 200,000 different forecast scenarios. And for each scenario we develop an NPV forecast. By considering a large number of forecast scenarios that take on a

wide range of possibilities, we obtain the same of a set of NPV forecasts based on a wide range of possibilities. When estimated external cost savings are included in the analysis, that estimate is once again set equal to $20/MWh. Lastly, in addition to forecasting NPVs, we also determine the forecast rate and billing implications for each facility.

5.23 Forecast NPVs for the Gray County Facility

Aquila's Gray County wind facility consists of 112.5 MW of nameplate-rated generating capacity. Aquila receives electricity from this facility under the terms of a PCC with FPL Energy, LLC. It is our understanding that all energy generated at the Gray County facility is effectively "pooled" with that produced by Aquila's other generators. For that reason, it is difficult, if not impossible, to determine which retail customers ultimately consume the Gray County wind energy. It also our understanding that, for rate making purposes, Aquila divides the expense of the FPL Energy contract between its WestPlains and Missouri Public Service Company retail customers.[37] Nonetheless, for purposes of this study we simply attribute any NPV realized under the FPL Energy contract to the Challenge. Accordingly, we assume any net benefit from the facility accrues to Kansas, even though that approach is likely to overstate the actual net benefit to Kansans.

To forecast the NPV associated with the Gray County facility, we rely on the actual terms of Aquila's FPL Energy contract and the forecast avoided costs of the high-cost utility-type, which are specifically modeled on WestPlains. As previously stated, we develop 200,000 different forecast scenarios of the utility's avoided costs. For each scenario, we forecast the NPV of the Gray County PPA.

[37] An argument can be made that *about half* of the forecast net benefits of the Gray County facility should be allocated to Kansas customers and, thus, Kansas, with the other half allocated to Missouri. A small amount of the output from Gray County is acquired by MWE from Aquila under contract.

Case Study A: Aquila's Gray County PPA, Estimated External Cost Savings Not Included

We use Equation (8) in Section 3.44 to derive the forecasts for this case. The forecast results in this case are generally positive. The average forecast NPV is $24 million in 2005 constant dollars.[38] The maximal forecast NPV is $135 million; the minimal forecast NPV is -$7 million. The probability of having a positive forecast NPV in this case is 98 percent. By our criterion, the Gray County PPA is cost effective. These results imply that by acquiring the Gray County PPA, Aquila is likely to achieve fuel (and other) savings that exceed the cost of the PPA, thus, realizing a *net savings*. Those forecast net savings translate to a forecast reduction in Aquila's revenue requirement and, consequently, its retail rates.[39] The average forecast rate reduction in this case is $0.0326/MWh. However, rates could decrease by as much as $0.18/MWh; at worst they could increase by $0.01/MWh. With the expectation that the Challenge would reduce retail rates on average, it is clearly cost effective from the ratepayers' perspective. The forecast rate reductions are based on a *negative* forecast wind premium in this case.[40] With these forecast rate changes, the billing implications of the Challenge should be clear; slightly lower annual bills can be expected.[41] Finally, since meeting Challenge would be cost effective even when estimated external cost savings are not included in the analysis, there is no threshold level of external cost savings in this case.

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[38] Unless otherwise stated, the NPV results are stated in 2005 constant dollars.

[39] The rate changes shown here are not based on what would be Aquila's billing determinants. Rather they are based on statewide retail sales of electricity. On that basis we are able to directly add the forecast results of this Case Study with the forecast results of the other case studies. The actual rate implications for (only) WestPlain's retail customers are larger than our forecast rate changes.

[40] Aquila has deemed the terms of its Gray County PPA to be confidential. For that reason, we are not reporting the expected wind energy premium associated with that contract, except to say that it is negative and, therefore, likely to yield rate savings to Aquila's retail customers.

[41] The Gray County net benefits allocated on a statewide basis would result in the typical household's annual bill being lower by $0.34, on average, for each year of the investment horizon.

Case Study B: Aquila's Gray County PPA, Estimated External Cost Savings Included

Equation (9) in Section 3.45 is used to derive the NPV forecasts presented in this section. With the inclusion of estimated external cost savings, the average forecast NPV increases from the previous case. In this case, the average forecast NPV is $82 million. The maximal and minimal forecast NPVs are $194 million and $43 million, respectively. There is no chance for a negative NPV outcome. To say the obvious, meeting the Challenge is cost effective from the societal perspective. The rate and billing implications in this case are the same as in Case Study A.

5.24 Forecast NPVs for the Elk River Facility

EDE's Elk River wind facility consists of 150 MW of nameplate-rated generating capacity. EDE receives electricity from this facility under the terms of a PPA with PPM Energy. As with the Gray County facility, it is our understanding that all energy generated at the Elk River facility is effectively "pooled" with that produced by EDE's other generators. It is also our understanding that, for rate making purposes, EDE divides the expense of the PPM contract among all of its retail customers (who reside in four different states).[42] Nonetheless, for purposes of this study we simply attribute any NPV realized under the PPM Energy contract to the Challenge. Therefore, we assume any net benefit from the facility accrues to Kansas, though that approach is likely to overstate the actual net benefit to the state.

To forecast the NPV associated with the Elk River facility, we rely on the actual terms of EDE's PPM Energy contract and the forecast avoided costs of the middle-cost utility-type, which is specifically modeled after EDE (and MWE). As before, we develop

[42] An argument can be made that *between six and ten percent* of the forecast net benefits presented here should be allocated to Kansas customers and, thus, Kansas.

200,000 different forecast scenarios of the utility's avoided costs. And for each scenario, we forecast the NPV of the Elk River PPA.

Case Study C: EDE's Elk River PPA, Estimated External Cost Savings Not Included

We use Equation (8) in Section 3.44 to derive the NPV forecasts presented in this section. As with Gray County, the forecast results in this case are generally positive. The average forecast NPV is $12 million in 2005 constant dollars.[43] The maximal forecast NPV is $124 million; the minimal forecast NPV is -$5 million. The probability of having a positive forecast NPV in this case is 99 percent. Thus, although the forecast NPVs for Elk River are smaller than Gray County, the probability of a positive outcome is just slightly better. By our criterion, the Elk River PPA is cost effective. These results imply that by acquiring the Elk River PPA, EDE is likely to achieve fuel (and other) savings that exceed the cost of the PPA, thus realizing a *net savings*. Those forecast net savings translate to a forecast reduction in EDE's revenue requirement and, consequently, its retail rates.[44] The average forecast rate reduction in this case is $0.0277/MWh. However, rates could decrease by as much as $0.36/MWh; at worst they could increase by $0.01/MWh. With the expectation that the Challenge would reduce retail rates on average, it is clearly cost effective from the ratepayers' perspective. The forecast rate reductions are based on a *negative* forecast wind premium in this case.[45] With these forecast rate changes, the billing

[43] Unless otherwise stated, the NPV results are stated in 2005 constant dollars.
[44] The rate changes shown here are not based on what would be EDE's billing determinants. Rather they are based on statewide retail sales of electricity. On that basis we are able to directly add the forecast results of this Case Study with the forecast results of the other case studies. The actual rate implications for (only) EDE's retail customers are larger than our forecast rate changes.
[45] EDE has deemed the terms of its Elk River PPA to be confidential. For that reason, we are not reporting the expected wind energy premium associated with that contract, except to say that it is negative and, therefore, likely to yield rate savings to EDE's retail customers

implications of the Challenge should be clear; slightly lower annual bills can be expected.[46] Finally, since meeting Challenge would be cost effective even when estimated external cost savings are not included in the analysis, there is no threshold level of external cost savings in this case.

Case Study D: EDE's Elk River PPA, Estimated External Cost Savings Included

Equation (9) in Section 3.45 is used to develop the NPV and other forecasts presented in this section. With the inclusion of estimated external cost savings, the average forecast NPV increases from the previous case. In this case, the average forecast NPV is $106 million. The maximal and minimal forecast NPVs are $223 million and $78 million, respectively. There is no chance for a negative NPV outcome. To say the obvious, meeting the Challenge is cost effective from the societal perspective. The rate and billing implications in this case are no different than Case Study C.

5.25 The Combined Gray County and Elk River Forecasts

There are a couple of different ways to forecast the *combined* NPV of the Gray County and Elk River facilities. One approach treats each of the facilities as separate and distinct, doing an NPV analysis of each on a standalone basis. The other approach establishes the NPV of the two contracts on a combined basis. In this study we have taken both approaches. The forecast NPV results for the two facilities on a standalone basis are developed through our Case Studies A through D; those results are presented above. The forecast NPV results for

[46] The Elk River net benefits allocated on a statewide basis would result in the typical household's annual bill being lower by $0.30, on average, for each year of the investment horizon.

the two facilities on a combined basis are developed through Case Studies E and F, the results of which are presented below.

Case Study E: Gray County and Elk River PPAs Combined, External Cost Savings Not Included

In this case, the average forecast NPV is $37 million in 2005 constant dollars. The maximal forecast NPV is $202 million; the minimal forecast NPV is -$8 million. The probability of forecast NPVs being greater than zero is nearly 100 percent, at 99.9 percent. On a combined basis, the two PPAs are clearly cost effective. On a combined basis, the two contracts support a reduction in the average retail rate, on a statewide basis, of $0.0602/MWh.

Case Study F: Gray County and Elk River PPAs Combined, External cost Savings Included

In this case, the average forecast NPV is $188 million in 2005 constant dollars. The maximal forecast NPV is $361 million; the minimal forecast NPV is $127 million. The probability of forecast NPVs being greater than zero is 100 percent; there is no chance of a negative forecast NPV in this case. When external benefits are added in, on a combined basis, the two PPAs are obviously cost effective. The average retail rate implication in this case is the same as in Case Study E; combined, the two contracts support a reduction in the average retail rate, on a statewide basis, of $0.0602/MWh.

5.26 Combining Gray County and Elk River Forecasts: The 264-MW investment Base

. Obviously, on a combined basis, the Gray County and Elk River facilities represent an installation of approximately 264 MW of wind capacity within the state of Kansas. As of the

end of 2005, that was the state's historically given investment in wind capacity, which we characterize now as the "264-MW investment base."

In Section 5.25 we discussed the two methods for analyzing the combined value of the state's two existing PPAs. One approach establishes the NPV value of each PPA on a standalone basis. The combined value is found by simply summing the standalone results. The other approach establishes the NPV value of the PPAs on a combined basis. Since we have fully evaluated and performed both approaches, as presented through Case Studies A through F, depending on the performance measure of interest, we find there is no difference between the two approaches. More specifically, we find no difference between the two approaches in terms of the average forecast NPV results. The sum of the two average forecasts NPVs for the standalone PPAs equals the average forecast NPV of the combined PPAs. The same holds for influence of the PPAs on the average retail rate. In short, the sum of the value of the parts, *on average*, is no different than the value of the combined whole, *on average*. However, in terms of the maximal and minimal forecast NPVs and, of course, in terms of the percentage of forecast NPVs in excess of zero, the two approaches do not offer the same results.

Thus, in terms of the average forecast NPVs and the average retail rate implications, the combined Gray County and Elk River NPV average forecasts are the appropriate forecasts for the state's existing 264-MW investment base. We also find that it is reasonable to simply aggregate the average forecast results of those case studies having investment bases of 736 MW (Case Studies 1 through 16) with the average forecast results of those case studies having investment bases of 264 MW (Case Studies E and F) to obtain the desired forecast results: the average forecast NPVs for the 1,000-MW investment base (Case Studies

17 through 32). The same holds for the average retail rate implications and the average forecast threshold level of external cost savings.

5.27 Combining the 736 MW and 264-MW investment Base Forecasts: A Review

The numerical forecasts for Case Studies 1–16 are all based on the amount of *new* investment needed to meet the Challenge as of the start of January 2006. Accordingly, all of those forecasts are based on a *forecast installation* of 736 MW of wind capacity. Those forecasts represent the "736-MW investment base" forecasts.

The combined numerical forecasts for the Gray County and Elk River facilities are those based on the state's *existing* 264 MW installation of wind capacity. Those forecasts represent the "264-MW investment base" forecasts. And those forecast results are provided in Case Studies A through F.

In her letter to the Commission, the Governor seeks a benefit cost analysis of meeting the Challenge, which is tantamount to a benefit cost analysis of installing 1,000 MW of wind capacity in the state. Here we provide that analysis by combining the 736 MW and 264-MW investment base forecasts.[47] This is accomplished by simply adding together the average forecast values for the 264-MW investment base with the average forecast values from Case Studies 1–16.[48] Accordingly, Case Studies 17–32 are all based on the total 1,000-MW investment needed to meet the Challenge.

Because, as the reader shall see, expansion of the investment base from 736 MW to 1,000 MW does not yield significantly different forecasts, we present the forecast results for Case Studies 17–32 in table form. The reader shall also see that the economics of the

[47] Only mean value forecasts are combined.
[48] We do this irrespective of the inclusion of estimated external cost savings. That is, when external cost savings are included or excluded, it is for the entire 1,000-MW investment base.

Challenge *improve slightly* as a consequence of expanding the forecasts to cover the full investment base. However, that "improvement," because it is historically given, has no real economic implications for assessing wind economics for Kansas on a forward-going basis.

The employment implications of Case Studies 17–32 are not significantly different than their respective cases with the smaller, 736-MW investment base. Because the average forecast NPVs for the existing facilities are positive, we would expect a slightly expansive influence on net employment. Thus, the employment implications for Case Studies 17–32, arguably, are slightly more optimistic than those already presented for Case Studies 1–16. However, because the difference in employment implications for the two investment bases, 736 MW versus 1,000 MW, is expected to be slight, there is little need to further expand upon that analysis.

5.30 NPV Forecasts: Case Studies 17–32: 1,000-MW Investment Base

As the reader shall see, comparing the results of the case studies with the 736-MW with the results of those with the 1,000-MW investment bases, there is nothing categorically new to report. The comparison shows, in general terms, slightly higher average forecast NPVs and, accordingly, more favorable rate implications for ratepayers. More precisely, when external cost savings are not included in the analysis, adding the net benefit of the two existing wind facilities increases the average forecast NPV by $37 million and reduces the average retail rate by about $0.06/MWh. When external cost savings are included in the analysis, adding the net benefit of the two existing wind facilities increases the average forecast NPV by $188 million..

In comparing the first 16 case studies with the last 16 case studies, the following forecast results remain unchanged:

1. For every utility-type, the build option is more costly, *on average*, than the PPA option.
2. In most cases, estimated external cost savings must be included in the analysis for the Challenge to be cost effective (from the societal perspective).
3. In all cases except one, meeting the Challenge would lead to an increase in the average retail rate. Similarly, in all cases but one, the wind energy premium is positive.
4. The higher the utility's incremental cost of generation, the more valuable the wind options are likely to be to the utility.

Lastly, for Case Studies 17–32, we apply a slightly different criterion for establishing the cost effectiveness of the Challenge: the average forecast NPV must be positive. If the average forecast NPV is positive, we would conclude a cost-effective outcome is likely, whereas if it is negative, we would conclude the opposite.[49]

5.31 The High-Cost Utility-type

Case Study 17: High-cost Utility Enters PPAs, External Cost Savings Not Included

- Average forecast NPV: $24 million.
- Cost effective: yes, from ratepayers' perspective (because the Challenge delivers a positive net benefit to ratepayers that yields lower rates).
- Average retail rate change: decreases by $0.04/MWh.[50]
- Impact on levelized, annual bill, for average residential customer: lower by $0.44.
- Total cost of Challenge to average residential customer: -$12.32, in real dollars.[51]

[49] This change is made because, for the 1,000 MW investment base, we do not derive probability distributions for the forecast NPVs.
[50] That is the rate decrease when the average is represented by the mean. When the average is represented by the median, which may provide a better indication of the forecast rate change, the rate decrease is $0.07/MWh.

Case Study 18: High-cost Utility Enters PPAs, External Cost Savings Included

- Average forecast NPV: $489 million.
- Cost effective: yes, from both societal and ratepayers' perspective.[52]
- Average retail rate change: decreases by $0.04/MWh.
- Impact on levelized, annual bill, for average residential customer: lower by $0.44.
- Total cost of Challenge to average residential customer: -$12.32, in real dollars.

Case Study 19: High-cost Utility Builds Own Wind Capacity, External Cost Savings Not Included

- Average forecast NPV: -$262 million.
- Cost effective: no, from ratepayers' perspective (because the Challenge delivers a negative net benefit to ratepayers that forces them to pay higher rates).
- Average retail rate change: increases by $0.65/MWh.[53]
- Impact on levelized, annual bill, for average residential customer: higher by $7.15.
- Total cost of Challenge to average residential customer: +$200.20, in real dollars.

Case Study 20: High-cost Utility Builds Own Wind Capacity, External Cost Savings Included

- Average forecast NPV: $205 million.
- Cost effective: no, from ratepayers' perspective; yes, from societal perspective.[54]
- Average retail rate change: increases by $0.65/MWh.

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[51] This amount shows how the residential customer's total electric bill would differ between taking the Challenge and following the business-as-usual path. A negative amount shows the estimated total electric bill savings per the Challenge; a positive amount shows how much larger the estimated total electric bill would be per the Challenge. This calculation is made by multiplying the average annual billing implication, on a levelized-basis, by the number of years in the investment horizon.

[52] Both the state's total electric bill and total cost of providing electricity are lower. Thus, from the ratepayers' (collective) perspective and the broader, societal perspective, where the value of reduced external costs is recognized, meeting the Challenge is economically efficient.

[53] This is the rate decrease when the average is represented by the mean. When the average is represented by the median, which may provide a better indication of the forecast rate change, the rate decrease is $0.67/MWh.

[54] Ratepayers would face higher bills for electricity. But if external cost savings are $20/MWh of electricity, the resultant reduction in external costs would more than offset the higher electric bills.

- Impact on levelized, annual bill, for average residential customer: higher by $7.15.
- Total cost of Challenge to average residential customer: +$200.20, in real dollars.

5.32 The Average-cost Utility-type

Case Study 21: Average-cost Utility Enters PPAs, External Cost Savings Not Included

- Average forecast NPV: -$166 million.
- Cost effective: no, from ratepayers' perspective.
- Average retail rate change: increases by $0.40/MWh.
- Impact on levelized, annual bill, for average residential customer: higher by $4.40.
- Total cost of Challenge to average residential customer: +$123.20, in real dollars.

Case Study 22: Average-cost Utility Enters PPAs, External Cost Savings Included

- Average forecast NPV: $300 million.
- Cost effective: no, from ratepayers' perspective; yes, from societal perspective.
- Average retail rate change: increases by $0.40/MWh.
- Impact on levelized, annual bill, for average residential customer: higher by $4.40.
- Total cost of Challenge to average residential customer: +$123.20, in real dollars.

Case Study 23: Average-cost Utility Builds Own Wind Capacity, External Cost Savings Not Included

- Average forecast NPV: -$442 million.
- Cost effective: no, from ratepayers' perspective.
- Average retail rate change: increases by $1.10/MWh.
- Impact on levelized, annual bill, for average residential customer: higher by $12.10.
- Total cost of Challenge to average residential customer: +$338.80, in real dollars.

Case Study 24: Average-cost Utility Builds Own Wind Capacity, External Cost Savings Included

- Average forecast NPV: $24 million.
- Cost effective: no, from ratepayers' perspective; yes, from societal perspective.
- Average retail rate change: increases by $1.10/MWh.
- Impact on levelized, annual bill, for average residential customer: higher by $12.10.
- Total cost of Challenge to average residential customer: +$338.80, in real dollars.

5.33 The Low-Cost Utility-type

Case Study 25: Low-cost Utility Enters PPAs, External Cost Savings Not Included

- Average forecast NPV: -$213 million.
- Cost effective: no, from the ratepayers' perspective.
- Average retail rate change: increases by $0.51/MWh.
- Impact on levelized, annual bill, for average residential customer: higher by $5.61.
- Total cost of Challenge to average residential customer: +$157.08, in real dollars.

Case Study 26: low-cost Utility Enters PPAs, External Cost Savings Included

- Average forecast NPV: $253 million.
- Cost effective: no from ratepayers' perspective; yes, from the societal perspective.
- Average retail rate change: increases by $0.51/MWh.
- Impact on levelized, annual bill, for average residential customer: higher by $5.61.
- Total cost of Challenge to average residential customer: +$157.08, in real dollars.

Case Study 27: Low-cost Utility Builds Own Wind Capacity, External Cost Savings Not Included

- Average forecast NPV: -$498 million.
- Cost effective: no, from the ratepayers' perspective.
- Average retail rate change: increases by $1.23/MWh.
- Impact on levelized, annual bill, for average residential customer: higher by $13.53.
- Total cost of Challenge to average residential customer: +$378.84, in real dollars.

Case Study 28: Low-cost Utility Builds Own Wind Capacity, External Cost Savings Included

- Average forecast NPV: -$33 million.
- Cost effective: no, from both the ratepayers' and societal perspective.
- Average retail rate change: increases by $1.23/MWh.
- Impact on levelized, annual bill, for average residential customer: higher by $13.53.
- Total cost of Challenge to average residential customer: +$378.84, in real dollars.

5.34 The Middle-Cost Utility-type

Case Study 29: Middle-cost Utility Enters PPAs, External Cost Savings Not Included

- Average forecast NPV: -$36 million.
- Cost effective: no, from the ratepayers' perspective.
- Average retail rate change: increases by $0.09/MWh.
- Impact on levelized, annual bill, for average residential customer: higher by $0.99.
- Total cost of Challenge to average residential customer: +$27.72, in real dollars.

Case Study 30: Middle-cost Utility Enters PPAs, External Cost Savings Included

- Average forecast NPV: $430 million.
- Cost effective: no, from ratepayers' perspective; yes, from societal perspective.
- Average retail rate change: increases by $0.09/MWh.
- Impact on levelized, annual bill, for average residential customer: higher by $0.99.
- Total cost of Challenge to average residential customer: +$27.72, in real dollars.

Case Study 31: Middle-cost Utility Builds Own Wind Capacity, External Cost Savings Not Included

- Average forecast NPV: -$324 million.
- Cost effective: no, from the ratepayers' perspective.
- Average retail rate change: increases by $0.82/MWh.
- Impact on levelized, annual bill, for average residential customer: higher by $9.02.
- Total cost of Challenge to average residential customer: +$252.56, in real dollars.

Case Study 32: Middle-cost Utility Builds Own Wind Capacity, External Cost Savings Included

- Average forecast NPV: $142 million.
- Cost effective: no, from ratepayers' perspective, but, yes, from societal perspective.
- Average retail rate change: increase by $0.82/MWh.
- Impact on levelized, annual bill, for average residential: higher by $9.02.
- Total cost of Challenge to average residential: +$252.56, in real dollars.

5.35 Summary of Forecast Results for Case Studies 17–32: 1,000-MW Investment Base

Because the historically given wind PPAs are expected to be cost effective for ratepayers, adding them into the mix improves the case the for wind, but only slightly. By including the

existing 264 MW into the analysis, the utility's internal costs of providing service to retail customers are reduced by about $0.06/MWh. But in most cases, that small improvement is not enough to change the basic conclusions derived for the case studies based on the smaller, 736-MW investment base. For example, with the larger investment base case studies, and when the utility meets the Challenge with PPAs, the average forecast rate increase is $0.40/MWh, down from $0.46/MWh. And when the utility (going forward) meets the Challenge by building its own wind capacity, the average forecast rate increase is $1.10/MWh, down from $1.16/MWh.[55]

In addition, because the historically given wind PPAs are expected to reduce reliance on conventional fuels, they are expected to bring lower emissions and, consequently, offer reductions in external costs. On average forecast, total reduction is about $150 million in 2005 constant dollars, when the estimated external cost savings are put at $20/MWh. By adding that increase in net savings, the case for wind is improved from the societal perspective.

Some results are completely unchanged by the inclusion of the net value of the historically given wind PPAs. For one, the higher cost of the build option relative to the PPA option is unchanged, remaining in the $17 to $18 range per MWh of wind energy. For another, the inclusion of external cost savings is usually necessary to push the Challenge into the cost-effective category from the broader, societal perspective. However, inclusion of the historically given external cost savings reduces, for the average-cost utility, the threshold level of external cost saving per MWh of wind from about $13 to $11/MWh.

[55] These numerical examples hold for the average-cost utility-type and are presented as average forecast changes, on a levelized basis over the investment horizon.

Thus, utility rates and bills are likely to be higher as a result of the Challenge. Moreover, if external cost savings per MWh of wind are in excess of $11 to $13, then meeting the Challenge is likely to be a break-even proposition from the perspective of the average Kansan. If external cost savings are in the $20/MWh range, then it is likely the Challenge would deliver a positive NPV—that is, a positive net benefit—to Kansans.

5.40 Some Special Case Studies

5.41 Introduction

All of the special cases discussed below represent a specific modification of one of the 32 basic case studies. For each special case we describe which of the basic case studies is being modified, as well as the exact nature of the modification made.

5.42 Special Case Study 1: January 2008 Update of Case Study 5 (and 6)

As described above, Case Study 5 involves the average-cost utility-type meeting the Challenge by entering PPAs, with estimated external cost savings not included in the model. And it is those case studies involving the average-cost utility that we believe provide the best estimates of how the Challenge is likely to affect the average Kansan, served by the prototypical average Kansas electric utility.

In this special case, we update two of the input variable forecast models: (1) the wind-installation costs (per MW) and wind O&M (per MWh of wind energy) forecast models. The one modification to the installation cost forecast model is simply an increase of the average forecast value from $1.6 million/MW to $2.15 million/MW. That modification is based on current indications of what it would cost to install wind capacity in Kansas at this time

(October 2007). Those indications reveal actual installation costs are in the $2.0 million to $2.3 million/MW range. Hence, setting the new average forecast installation cost at $2.15 million/MW is reasonable at this time. In short, actual increases in installation cost over the last two years have been far in excess of our original forecast changes. Equivalently, recent increases in the installation cost of wind capacity have been far in excess of average annual rates of inflation. The appears to be the same case for recent changes in wind-installation cost estimates. In the basic case studies, we set the (year 1) wind O&M at $9.00/MWh.[56] In this special case we modify the forecast wind O&M expenses to reflect the latest information available. For a description of updated wind O&M expense forecasts, see the Direct Testimony of Dr. Robert Glass and Mr. Michael Elenbaas in Docket No. 08-WSEE-309-PRE. The natural gas price forecasts were also updated to reflect a slight increase shown by current (January 2008) forward gas prices. All other input variable forecast models are unchanged form those used previously.[57]

Special Case Study 1 Results

The average forecast NPV is -$454 million. The maximal forecast NPV is $116 million; the minimal forecast NPV is -$944 million. Thus, while our forecast results show there is some chance that the Challenge would yield a positive NPV, our forecast results show that chance is less than 1 percent. Therefore, we would conclude that meeting the Challenge in this case would not be cost effective (from the perspective of ratepayers). In this

[56] As we discussed previously, the wind O&M is expected to inflate over time at a rate in excess of the average annual rate of inflation. The amount of “excess” is assumed to be one percent per year, on average.
[57] In October 2007 we re-examined all of the input variable forecast models for their potential need for updating. Only the wind installation cost and O&M forecasts warranted updating. The forecast natural gas prices series (and, thus, FOM input variable forecast) in October 2007 differs from the originally forecast series, but not significantly. Therefore, the forecast FOMs were not updated. However, an updating of the natural gas prices may have resulted in slightly lower gas price forecasts being used.

case, the average forecast retail rate, on a levelized basis, would increase by $0.98/MWh. That means an annual average electric bill for the average Kansas household that is higher by $10.78. Over the investment horizon, that adds up to a total cost increase of about $302. The threshold level of external cost savings in this case is $27.79/MWh of wind energy. Therefore, for the Challenge to be cost effective in this case, external cost savings must be $27.79/MWh or more.[58]

What this updating shows is that *wind energy is less economic than it was two years ago.* Wind capacity installation costs have increased at an average annual rate of about 10 percent per year for the last two years; that rate is well in excess of the national rate of inflation. This recent evidence shows that our assumption—that the wind-installation cost increases at a rate that matches the national inflation rate—is very unlikely to hold.

With the updating, the average forecast rate increase (due to the Challenge) goes from $0.46/MWh to $0.98/MWh. Perhaps more importantly, the threshold level of external cost savings goes from $13.24 for each MWh of wind energy to $27.29/MWh. That means that even when the estimated external cost savings, at $20/MWh, are included in the updated analysis, the Challenge is no longer expected to be cost effective from the societal perspective. In other words, *with the updated forecasts, the Challenge changes from being cost effective to not, from the societal perspective.*

A Word of Caution—The growing general interest in wind energy resources, for a number of reasons, appears unlike to slow or diminish any time soon. And while that interest may be a favorable sign, it also suggests that the recent inflation of wind-installation costs is

[58] Even when estimated external cost savings (at $20/MWh) are included in these updated forecasts (which constitutes an updating of Case Study 6), the average forecast NPV is -$120 million. Moreover, in that case, only 20 percent of the forecast NPVs come in positive; therefore, even when external benefits are included meeting the Challenge would not be cost effective by our criterion for efficiency.

likely to continue. If wind-installation costs continue increasing relative to the generation fuel expenses and avoided costs generally, which seems likely, then investing in wind energy simply becomes less and less economic. And as long as the trend toward relatively higher installation costs continues, so will the trend of wind development being less economic, *all else equal*. Policy makers may be well advised to monitor this trend

5.43 Special Case Study 2: October 2007 Update of Basic Case Study 7 (and 8)

Case Study 7 involves the average-cost utility meeting the Challenge by directly investing in its own wind capacity, with estimated external cost savings not included in the model. Case Study 7 is identical to Case Study 5, except for the wind option selected by the utility.

In this special case, we apply the same input variable forecast updates as in the previous special case. Hence, Special Case Studies 1 and 2 are identical except for the wind option selected by the utility.

Special Case Study 2 Results

The average forecast NPV is -$834 million. The maximal forecast NPV is -$401 million; the minimal forecast NPV is -$1,316 million. In this case, none of the 200,000 forecast NPVs are positive. In this updated case, the average forecast retail rate is $1.90/MWh higher as a result of the Challenge; the average annual bill for the typical residential customer is higher by $20.90; and for that same customer the total cost of the Challenge comes in at about $585. In Case Study 7, with the original input variable forecasts, the average rate was higher by $1.16, the annual bill higher by $12.76, and the total cost higher by about $357. Not surprisingly, the updated higher forecast wind installation and

wind O&M costs translate to a higher cost for wind energy. As the results show, the effect of the forecast updating on the average retail rate alone is an increase of $0.74/MWh. Perhaps the most interesting effect of the forecast updating is that *the threshold level of external cost savings goes from $31.00/MWh of wind energy to $50.93*—that is, external cost savings must be $50.93 per MWh of wind energy for the Challenge to be cost effective in this special Case Study. Clearly, our EPA-based estimated external cost savings of $20/MWh are not large enough to yield outcomes likely to be cost effective.[59]

5.44 Special Case Study 3: ROR Adder to Utility Investment in Wind Capacity

Pursuant to K.S.A. 66-117(e), KCC-jurisdictional utilities can seek a higher rate of return (ROR), up to 200 basis points, on their allowed investment in wind capacity. Presumably, by allowing a higher ROR and, thus, providing shareholders with a greater incentive to invest in wind capacity, larger investment in wind capacity would be forthcoming. Whether it would have that effect, we do not investigate here, except to note that this statutory provision was in place for many years prior to KCPL's direct investment in the Spearville wind farm.[60] Our objective here is to evaluate the economic implications of the ROR adder for the utility's ratepayers.

To investigate the economic implications of the ROR adder, we again rely on Case Study 7, in which the average-cost utility meets the Challenge by direct investment in the requisite amount of wind capacity. In order to effectively isolate the economic implication of the ROR adder, we make one modification to the input variable forecasts used in Case Study

[59] In Special Case 2, when estimated external cost savings of $20/MWh are included in the analysis, the average forecast increases to -$501 million, and, instead of 100 percent of the forecast NPVs taking negative values, still over 99 percent of the NPV forecasts take negative values. (These result provide an update for Case Study 8.)
[60] It may also be worth noting that KCPL has not formally requested the ROR adder for its Spearville investment.

7: we add 200 basis points to the (post-tax) allowed forecast ROR. This addition changes the *average* forecast ROR, increasing it exactly 200 basis points. Otherwise, all else is held constant.

Special Case Study 3 Results

As one would expect, our results show the ROR adder simply increases the financial cost of wind capacity investments. As a consequence, *ratepayers would pay higher rates strictly as a result of the ROR adder*. Without the ROR adder, the average retail rate would increase by $1.16/MWh as a consequence of the Challenge. But with the ROR adder, the average retail rate would increase by $1.37/MWh as a consequence of the Challenge. Moreover, *the threshold level of external cost savings goes from $31.00 per MWh of wind energy to $37.45.* Thus, with the ROR adder, external cost savings have to be ever higher in order for the Challenge to be cost effective from the societal perspective. Our analysis also shows that the (non-discounted) net benefit of the Challenge is lower, on average, with the ROR adder. More specifically, our forecast results *show the ratepayers' net benefit is lower by $273 million, on average.* That is equivalent to saying the utility's net cost is higher with the ROR adder by $273 million, on average. Of course that higher financial cost must be recovered from the utility's customers. *That forecast cost increase, of $273 million, also reveals the extra profits shareholders would realize, on average, as a consequence of the ROR adder, all else equal.* Those extra profits would be realized over the term of the investment period.

5.45 Special Case Study 4: Implementation of a Kansas-based PTC (KPTC)

Besides the incentive of the ROR adder, Kansas policy makers could consider implementation of a Kansas-based wind energy production tax credit (KPTC). To examine that potential policy issue, we model a KPTC that is structured like the federal PTC, but is set at $10 per MWh of wind energy produced (compared to the roughly $19 per MWh of the federal PTC). Thus, the only difference between the federal PTC and the assumed KPTC is the size of the credit per unit of wind energy production.[61] We assume, of course, the KPTC would be available to wind developers and utilities alike.

In this special case, we examine how the KPTC would affect the forecast results for the average-cost utility when it meets the Challenge through entering wind PPAs. Using the (basic) Case Study 5 framework as the starting point, we modify that case by assuming that wind developers would have access to and would fully utilize the assumed KPTC. Naturally, we would expect if wind developers in Kansas were granted a KPTC, their cost of providing wind energy would be reduced, as would the wind energy prices embedded in PPAs.

Special Case Study 4 Results

We find that the inclusion of a $10 per MWh KPTC (starting in 2006) would reduce the forecast price of wind energy that is acquired by utilities through PPAs. Our analysis shows the average PPA price would decrease from $32.65/MWh to $23.16/MWh, on average. Accordingly, the NPV of meeting the Challenge goes from -$203 million, without the KPTC, to -$53 million, with the KPTC. The proportion of forecast NPVs greater than zero goes from 4 percent, without the KPTC, to 32 percent, with the KPTC. Thus, the assumed KPTC pushes the Challenge *toward* cost effectiveness from (strictly) the ratepayers'

[61] The KPTC is modeled so that the credit per unit would change over time based on changes in a specific inflation index. Moreover, the KPTC would apply for the first 10 years of an investment project.

perspective. In terms of the forecast change in the average retail rate, without the KPTC it is forecast to increase by \$0.46/MWh, while with the KPTC it is forecast to increase by \$0.11/MWh. Clearly, the assumed KPTC would make meeting the Challenge less costly to ratepayers. The KPTC would also reduce the threshold external cost savings from \$13.24 per MWh of wind energy to \$3.74. But, of course, this is not the whole story.

What Would the KPTC Cost?—Granting producers tax credits is not without cost. Our analysis shows that the forecast cost to the Kansas Treasury would be about \$250 million (in inflation-adjusted) dollars, on average, over the term of the investment horizon. It could be higher or lower, depending on the actual capacity factors of the wind facilities. In present value dollars (i.e., dollars that are adjusted for both inflation and the time value of money), the forecast cost to the Treasury is \$84 million in 2005 constant dollars.

PTCs Simply Shift the Cost of Wind Energy—The assumed KPTC, like the actual federal PTC, simply shifts the cost of wind from the customers' utility bill to their tax bill. So while it makes wind energy appear more attractive in terms of the monthly utility bill, it has the opposite effect on April 15th of each year.[62] Some could argue that shifting the cost burden from the utility bill to the tax bill may create a net gain for society. But it is not clear to us what that net gain might be. If anything, such a shift would possibly push the cost burden further into the future, which would be advantageous for the current generation.

5.46 Special Case Study 5: Implementation of a Carbon Tax: \$10/ton of CO_2

One of the policy tools available to fight CO_2 emissions is a direct tax on those emissions. Such a tax, if imposed, could take a number of different forms. Here we assume a direct tax

[62] We assume only that all government deficits remain the responsibility of taxpayers generally and that tax burdens, however they may be created, are evenly covered.

of \$10 per ton of CO_2. And for purposes of this special Case Study, we assume woul;d be imposed starting in 2006.

To evaluate the economic implications of this assumed carbon tax, we again use Case Study 5 as the basis for forecasting the changes that would result from the tax. That Case Study involves the average-cost utility meeting the Challenge strictly through wind PPAs. Because the average-cost utility-type provides a representation of the statewide average electric utility, a \$10 tax per ton of CO_2 translates to a tax of about \$7.50 per MWh of electricity, *on average*. That MWh tax amount represents a rough, weighted-average of the carbon tax across the state's existing portfolio of power plants and fuel contracts. For instance, if the state's entire electric load were met by coal-based generation, then a CO_2 tax of \$10/ton would translate to about \$11.13 tax per MWh of electricity. So in that case the translation is *roughly* one-to-one. But of course Kansas relies heavily on nuclear-fueled generation, on which no carbon tax would be imposed, and, to a far smaller extent, natural gas-fueled generation, which emits considerably less CO_2 than coal-based generation. Thus, using on the state's existing (and forecast) mix of generation technologies and fuels, the assumed \$10/ton carbon tax implies the average-cost utility's average generation cost would increase by approximately \$7.50/MWh.

Since we model wind energy production as a means to avoid conventional generation (as opposed to simply selling the wind energy off-system), if a carbon tax were imposed, then wind energy production would provide a means of avoiding that tax. Accordingly, imposition of a carbon tax would make wind energy relatively more valuable to ratepayers.

Special Case Study 5 Results

A expected, imposing the assumed carbon tax improves the case for wind. With the imposition of the carbon tax, the average forecast NPV of the Challenge goes from -$203 million to about -$85 million. The proportion of forecast NPVs less than zero goes from 4 percent to about 24 percent. And the average forecast rate increase goes from $0.46/MWh to $0.19/MWh. Thus, the assumed carbon tax is not large enough, from the ratepayers' view point, to push the Challenge into the cost-effective category; however, it does push the Challenge in that direction. The assumed carbon tax makes wind energy relatively more valuable and so reduces the relative cost disadvantage wind energy brings the utility. But a carbon tax would, *by itself*, also increase the retail price of electricity. In this example, the average retail price increase would be about $7.50/MWh simply as a consequence of the carbon tax. Again, it would increase yet again simply as a consequence of the utility meeting the Challenge. That rate increase would be $0.19/MWh.

Furthermore, the carbon tax would reduce the threshold level of external cost savings from $13.24/MWh to $5.74 per MWh of wind energy. Thus, with the assumed carbon tax, the external cost savings (based on the emissions of the more traditional pollutants, SO_2, NO_X, $PM_{2.5}$, and mercury) per MWh of wind energy need only be $5.74 or greater.

As an alternative, rather than assuming the carbon tax starts in 2006, we examined a 2015 start date. Although having a carbon tax makes wind relatively more cost effective, pushing back the start date of that tax diminishes this relative boost. With the later start date, the threshold level of external cost savings goes from $5.74 to about $8.74/MWh of wind energy. The later start date for a carbon tax, all else equal, means wind energy must deliver

greater external cost savings in order for the Challenge to be cost effective from the societal perspective.

Finally, we also examined the case in which the average-cost utility faces the assumed carbon tax when it meets the Challenge by investing in its own wind capacity.[63] In that case, the average forecast rate change due to the Challenge goes from $1.16/MWh to $0.89/MWh. The threshold level of external cost savings drops from $31.00 per MWh of wind energy to $23.49. Once again, we see that the imposition of a carbon tax improves the economic prospects for wind energy.

The Break-even Carbon Tax[64]

Our analysis shows that if the carbon tax was approximately $17.65/ton, then it would be cost effective for the average-cost utility that meets the Challenge through wind PPAs (from the ratepayers' perspective). In other words, depending on the size of a potential carbon tax, meeting the Challenge could be cost effective for ratepayers. If a carbon tax of $17.65 or more per ton of CO_2 were imposed in this case (average-cost utility meeting the Challenge via PPAs), and if external cost savings (per the traditional emissions) are simply greater than zero, then the Challenge is clearly cost effective from both the ratepayers' and societal perspective. Clearly, if there was a sufficiently high carbon tax, and if there were external cost savings related to the traditional emissions, then meeting the Challenge (in this case) would result in both (1) utility rates not being any higher, on average, and (2) a reduced

[63] This we did by modifying Case Study 9 by including the assumed carbon tax, all else the same.
[64] For case studies other than those dealing with the average-cost utility-type, by multiplying the threshold level of external cost savings (per MWh) by (10.0/7.50 =) 1.333 yields a *very rough* estimate of the (mean value) breakeven carbon tax (per ton of CO_2) is established.

total cost of providing electricity to Kansans. (Also see Table 0.1 for more information regarding the break-even carbon tax levels.)

5.47 Special Case Study 6: A Brief Assessment of Community Wind

This study focuses on larger-scale commercial-sized, modular wind farm development, in the 100 MW to 150 MW range. Thus, at any one location, the wind farm would consist of at least 100 MW of nameplate capacity. Modular additions of capacity may occur over time, so that, in time, a single wind farm could consist of between 200 and 600 MW of nameplate capacity.

What constitutes a community wind development is hardly established by any widely accepted definition. But surely community wind projects are smaller than the commercial projects, perhaps rarely exceeding, say, 50 or 75 MW of nameplate capacity. Yet even with the smaller relative size, the community projects may utilize basically the same wind equipment as the commercial projects.

To the extent that community wind projects use turbines and towers that are comparable to the larger projects, the smaller size of community projects suggests, all else constant, lower economies of scale relative to the commercial size projects. If there are economies of scale associated with procurement and transportation of equipment (which seems less likely) or with its installation (which seems more likely), that would be revealed through the installation cost per MW. If there are scale advantages, we would expect the community projects to have a relatively higher installation cost per MW. How much higher (in reality) we make no effort to assess. However, we would not be surprised if installation

cost at a community-sized project tends to be 10 to 15 percent higher compared with the commercial projects.

While installation costs may be relatively higher at the community level, it is possible that avoided fuels and/or purchase power expenses at the community level could be relatively higher. For instance, a municipal utility could have fuel costs/purchase power expenses that, on average, exceed that of the larger, KCC-jurisdictional utilities. In that case, the cost savings attributable to wind energy would be relatively higher for the community(s) served by the municipal utility. That would serve to offset some of the higher installation cost (per MW) faced by the smaller projects. *It also suggests that the economic value of wind energy could easily vary by the community,* which makes it difficult to infer conclusions about the relative cost of community wind. However, to the extent that municipal and rural cooperative utilities are supplied firm energy by jurisdictional utilities, then there may be little relative difference between the avoided generation costs of the smaller and larger utilities.

A Numerical Example of Community Wind

To gain some understanding of community wind economics, we rely on the same basic NPV model we use to evaluate commercial-scale wind economics. However, we make three modifications to that basic model: (1) 10-percent higher wind-installation costs , (2) a slightly larger capacity degradation factor, and (3) a reduced project size of 20 MW. The modification of the capacity degradation factor is based on the idea that there may be some economies of scale associated with maintaining the wind equipment. For instance, smaller projects may not be large enough to fully employee a maintenance team. If not, a single team would be required to serve several community wind projects. If those projects are

geographically dispersed, due largely to higher transaction costs, it may be more costly to keep equipment maintained. If so, then capacity factors over time may suffer as a consequence. With these two modifications, we model the costs of community wind identically to those of the average-cost utility-type.

Comparing two identically structured PPAs, one offered by a community wind developer and the other by a commercial developer, we find that the community-based wind energy is likely to cost more. When provided through a PPA, we estimate the price of community wind to be $37.54/MWh. However, we find, as described above, that a commercial developer is likely to provide wind energy through a PPA at a price of $32.65/MWh. Based strictly on those results, the price of community wind may run 15 percent higher than the price provided through larger scale projects. Of course, these results are driven by the assumed community wind modifications discussed above. Arguably, there are *many* alternative ways to modify the model that would reflect unique conditions faced by community developers. Even so, it seems likely that community wind energy would cost relatively more if it is less able to capture economies of scale, though how much higher is difficult to estimate.

5.48 Special Case Study 7: Discount Rate Variations—Lowering the Discount Rate

The choice of discount rate is frequently a critical component in project evaluation. Of course there are numerous considerations that can be made when selecting a discount rate. These include real rates of return (i.e., financial opportunities) available in the private marketplace, the highest rate of return among a portfolio of (as yet funded) public investment projects, intra- and inter-generational consideration of equity, and prospects for productivity gains and

income growth in the future. In this study, and mainly for simplicity, we set the discount rate equal to the utility's Commission-approved after-tax real rate of return. However, we recognize many other discount rates could reasonably be used. For purposes of simply examining the possible influence that different discount rates might have on the results, we modified Case Study 7 by changing only the discount rate.

As described above, the initial results for Case Study 7 use a real, inflation-adjusted discount rate of 8.6 percent. One of the strengths of that rate is that it is, within the context of this study, a Commission-approved rate and, therefore, one can argue it is consistent or reflective of the public interest, especially in terms of utilities investing in wind capacity on behalf of their customers. To explore alternatives to that discount rate, we re-run Case Study 7 with a discount rate of 5 percent and 3 percent, all else equal. [65]

The Main Results with a Five Percent Discount Rate

Changing the discount rate from 8.6 to 5.0 percent changes the average forecast NPV from -$203 million to -$743 million, both in 2005 constant dollars. Obviously, with a lower discount rate, the Challenge is less attractive in terms of net benefit analysis. The retail rate implications of the Challenge are unchanged because the forecast rate change is measured in inflation-adjusted dollars, not time-discounted dollars. Therefore, a change in the discount rate will not alter the utility rate change forecasts already presented. However, changing the discount rate does change the threshold level of external cost savings necessary for the Challenge to be cost effective from the societal perspective. Changing the discount rate from 8.6 to 5.0 percent changes the threshold level of external cost savings from $31.00/MWh to

[65] The utility's allowed rate of return is maintained at 8.6 percent.

$31.57/MWh. The reduction in the discount rate means external cost savings need to be higher, though just slightly, for the Challenge to be cost effective.

The Main Results with a Three Percent Discount Rate

Changing the discount rate from 8.6 to 3.0 percent changes the average forecast NPV from -$203 million to -$974 million, both in 2005 constant dollars. Again, reducing the discount rate makes the Challenge less attractive in terms of net benefit analysis, now even more so. For reasons stated in the previous paragraph, the retail rate implications of the Challenge are unchanged. Changing the discount rate from 8.6 to 3.0 percent changes the threshold level of external cost savings, increasing it from $31.00/MWh to $31.90/MWh, thus, raising the threshold level even more than before, but only slightly more.

5.49 Special Case Study 8: The Texas-type Utility Example

One of the main characteristics of Kansas electricity utilities generally is their relatively light dependence on natural gas as a generating fuel. *Currently, in a normal year, about four percent of the retail electric load in Kansas is served by natural gas generation.* In the very early 1990s that percent was about 10 percent. Moreover, as long as the price of natural gas increases relative to other generation fuels, this downward trend in the relative use of natural gas as a generating fuel in Kansas is likely to continue.

In contrast to Kansas are states like Texas and California, where the relative dependence on natural gas is far greater. Another comparison among states that is made is in the amount of installed wind capacity. Texas is sometimes cited as an example of leadership in that regard, while Kansas is sometimes described as “falling behind.” Whether either is

true is probably not of great interest, but what may be interesting is an examination of a state's relative reliance on natural gas and whether that has a significant influence on the incentives for wind development. For that examination, we use the same NPV analysis presented this report, but we modify the utility's gas mix.

In our modeling of the average-cost utility, we assume that its average annual gas mix is four percent. Again, that amount is representative of the current, statewide reliance on natural gas as a generation fuel in Kansas (see Table 5.1).

Table 5.1: Natural Gas Generation as Percent of Total

Year	Kansas	California	Texas	U.S. Total
1990	7.3%	44.7%	48.4%	12.3%
1991	10.0%	46.6%	47.7%	12.4%
1992	4.3%	50.1%	46.4%	13.1%
1993	5.3%	42.6%	49.1%	13.0%
1994	6.7%	50.7%	47.0%	14.2%
1995	6.2%	40.0%	46.3%	14.8%
1996	4.6%	36.8%	45.0%	13.2%
1997	5.6%	41.1%	45.0%	13.7%
1998	7.3%	39.6%	48.4%	14.7%
1999	7.0%	45.2%	47.9%	15.1%
2000	6.3%	49.6%	50.0%	15.8%
2001	4.4%	56.4%	51.0%	17.1%
2002	3.8%	48.7%	50.9%	17.9%
2003	2.6%	47.4%	48.8%	16.7%
2004	1.8%	51.6%	47.9%	17.9%
2005	2.5%	46.7%	49.4%	18.7%
Average	5.3%	46.1%	48.1%	15.0%

Source: Energy Information Administration, State Electricity Profiles, 2005 Edition, DOE/EIA-0348 (Date of Data: 2005; Data Release Date: March 2007).

To examine the incentives for wind development in a state like Texas, we increase the average annual forecast gas mix from 4 to 50 percent, as suggested by the data presented in

the above table. With this change in the forecast gas mix, we can examine how a significant increase in the utility's consumption of natural gas could influence the forecast net benefit of the Challenge. In essence then, with this increase in the utility's annual gas mix, all else equal, we arrive at a model for the Texas-type utility—one whose cost structure may resemble that of an average Texas electric utility.[66]

Results for Texas-type Utility: The PPA Purchase Option

When the Texas-type utility meets the Challenge by purchasing wind PPAs, the forecast NPV results are somewhat staggering. With external cost savings not included in the analysis, the average forecast NPV is $394 million, the maximal forecast NPV is $4,231 million, and the minimal forecast NPV is about -$242 million. Those forecasts show there is some chance for a negative NPV outcome, but our analysis shows the probability of a negative NPV forecast is only one percent. Equivalently, there is a 99 percent probability of a positive NPV outcome; clearly, in this case, the Challenge would be cost effective for ratepayers.

This result is also manifested in the forecast change to the average retail rate for electricity. By meeting the Challenge in this case, the average retail rate would decrease by $1.02/MWh, on average. Our forecast results show that it could decrease by as much as $14.25/MWh or increase by $0.57. Clearly, in this case, meeting the Challenge would have a good chance of decreasing retail rates. In terms of the annual billing implications, the average household would save about $11 per year, on average. Over the term of the investment

[66] To emphasize, the only difference between the modeling of the input variables for the average-cost utility-type and the Texas-type utility is the forecast modeling of the gas mix input variable. Thus, the data and modeling we use for Texas-type utility cases discussed in this section are identical to the data and modeling of Case Studies 5, 6, 7, and 8, except for the gas mix forecast model.

horizon, that same household would save about $308. In this case, the economic incentives for investing in wind are obvious.

When external cost savings, estimated at $20/MWh, are included in the analysis, the forecast results are, of course, better. The average forecast NPV is $709 million; the maximal and minimal forecast NPVs are $4,641 million and $19 million, respectively. When externalities are added in, there is no downside risk to pursuing the Challenge from the total cost, societal perspective.[67] Inclusion of external cost savings leaves the (previously discussed) rate and billing implication unchanged.

Results for Texas-type Utility: The Build Option

Since the build option tends to be more costly than the buy option, the results in this special case are not quite as impressive as those in the previous case. When external cost savings are not included, the average forecast NPV is $106 million. The maximal and minimal forecast NPVs are $3,195 million and -$638 million, respectively. In this case, the proportion of forecast NPVs that are positive is about 65 percent, which meets our criterion for (ratepayer) cost effectiveness. This result is further revealed by the forecast of retail rates falling by $0.29/MWh, on average.

When external cost savings are included, of course, the forecast results improve. The average forecast NPV is $421 million, and the maximal and minimal forecast NPVs are $3,585 million and -$396 million, respectively. The probability of a positive forecast NPV is 97 percent. From the societal perspective, taking the Challenge appears to be a good bet. From the same perspective, it appears to be cost effective. The rate and billing implications are the same as before.

[67] There remains the risk that ratepayers would face higher rates.

A Comment on the Texas-type Utility Results

The forecast results for this case suggest a rather natural, market-based outcome. In those locations where wind development is clearly cost effective for ratepayers and, thus, very likely to provide them with lower rates, policy makers, consumers, and utilities alike have sought the development of wind capacity. States like Texas and California may well have more installed wind capacity than a state like Kansas, but it hardly seems advisable for states like Kansas to keep up with those states simply for the sake of keeping up. It is probably the case that basic economic incentives underlie the relative differences in development. It should also be pointed out that, in 2005, the average retail rate in California was about $11.63/MWh; in Texas it was $9.14/MWh, in Kansas it was $6.55/MWh.[68] Needless to say, along with a relatively heavy reliance on natural gas as a generation fuel comes relatively higher retail rates. Places where retail rates are relatively high may be the best, natural candidates for wind development.

5.50 Sensitivity Analysis

The special cases, but particularly the Texas-type utility case, reveal the forecast NPV results to be sensitive to changing the input variable forecasts, and more precisely, their mean forecast value. Claims are sometimes made about the value of wind energy being greatly influenced by the price of natural gas—higher gas prices implying wind energy would be more valuable. In order to investigate such claims, we performed a standard sensitivity analysis.

With this sensitivity analysis, we examine the sensitivity of the forecast NPVs, which provide a summary indication of the value of wind energy to ratepayers and society, to the

[68] The EIA is our source.

following random variables: utility's gas mix, natural gas prices, capacity factor, capacity factor degradation, wind-installation costs, rate of return, and wind O&M expenses.[69] (As a group, we refer to those random variables as the *underlying random variables*, since they underlie the variation in NPV forecasts.) And for each of those random variables, we use the pdf specifications made in the case of the average-cost utility-type. The same holds for the forecast NPV results; we use the forecast NPV pdfs that come from Case Study 7 and Case Study 3. (Case Study 7 involves the average-cost utility pursuing the Challenge by directly investing in wind capacity; Case Study 3 involves the high-cost utility investing in wind capacity.)

We rely on the coefficient of variation as the basis for our sensitivity analysis results.[70] As a first step, we calculate the coefficient of variation for each of the random variables that are used to forecast the Challenge's NPVs. Next we determine the coefficients of variation for the resultant forecast NPV pdfs: one for the build option, the other for the PPA option. Those coefficients are based on holding all (input) random variables constant, except one.[71] Lastly, we determine the ratio of coefficients of variation, taking the coefficient of variation for the forecast NPV over that of that of the respective (input) random variables. For example, the coefficient of variation for the capacity factor is 0.092. Holding all of the underlying random variables constant, except the forecast capacity factor, we re-run the NPV analysis for all 200,000 forecast scenarios and derive a distribution of forecast NPVs. The coefficient of variation for that NPV is 0.072. Taking the third and final step, we calculate

[69] The probability distribution functions we use to model each of these random variables are fully described in Section 4 of this study.
[70] Consistent with its general definition, we define the coefficient of variation for a particular pdf as the ratio of its standard deviation and mean value.
[71] In that instance, the forecast NPVs are derived holding all the underlying random variables constant, but the price of natural gas. That variation would allow only the FOM input variable to vary, and that alone would be the basis for variance among the forecast NPVs.

the ratio of the two coefficients of variation, 0.072 over 0.092. That ratio, 0.789, provides a measure of the sensitivity of the forecast NPVs to the capacity factor forecasts. The greater that ratio, the more sensitive the net benefit of wind is to changing natural gas prices. Hereafter, we simply refer to that ratio as the sensitivity ratio.

5.51 Sensitivity Results for Case Study 7

Table 5.2 shows the sensitivity ratios derived from the basic Case Study 7 framework.

Table 5.2: Sensitivity Ratios for the Average-Cost Utility – Build Option

Underlying Random Variable	Sensitivity Ratio
Wind-installation costs	1.764
Capacity Factor	0.789
Wind O&M Expense/MWh	0.385
Gas Mix	0.136
Natural Gas Prices	0.095
Capacity Factor Degradation	0.049
Allowed, Post-tax Rate of Return	0.032

To construct the table above, obviously, we ranked the sensitivity ratios from largest to smallest. These results show that the net benefit (in terms of internal costs only) stemming from the Challenge is most sensitive to changes in the wind-installation costs s. In fact, the variables to which the NPV results are most sensitive are directly tied to the wind equipment itself. These variables are the cost of installing that equipment, the performance of that equipment as measured by annual capacity factor, and the cost to maintain and operate that equipment. Those variables to which the NPV results are less sensitive tie directly to the

(internal) costs avoided and, thus, benefits associated with the wind equipment. They are the gas mix variable and price of natural gas.

These results of the sensitivity analysis show that the net benefit of the Challenge is far more sensitive to changing costs than changing benefits. That is significant because of the significant increases in the cost of installing wind capacity during the last three years. If those cost increases continue over time, absent *even larger* increases in the benefits associated with wind energy, the sensitivity analysis alone shows that forecast NPVs are likely to decrease over time. In other words, absent natural gas usage by utilities and/or natural gas prices skyrocketing, the economics of wind energy in Kansas is unlikely to improve. Equivalently, in order for there to be some likelihood for the economics of wind energy in Kansas to improve, the wind equipment itself must get better: the costs to install and maintain it must decrease relatively and/or its productivity (i.e., capacity factor) must increase

5.51 Sensitivity Results for Case Study 3

For the high-cost utility, the one with the relatively higher reliance on natural gas as a generating fuel, the sensitivity results are slightly different, as shown in Table 5.3.

Table 5.3: Sensitivity Ratios for the High-Cost Utility – Build Option

Underlying Random Variable	**Sensitivity Ratio**
Wind-installation costs	2.917
Capacity Factor	1.961
Wind O&M Expense/MWh	0.635
Gas Mix	1.201
Natural Gas Prices	0.363
Capacity Factor Degradation	0.117
Allowed, Post-tax Rate of Return	0.600

The sensitivity results for the high- and average-cost utilities are similar, but there are a couple of interesting differences. First, all of the sensitivity ratios for the high-cost utility are higher than those for the average-cost utility. Regarding the utility's decision to invest in wind capacity, the ratepayers for the high-cost utility have more to either gain or lose with respect to changes in the underlying random variables. When the high-cost utility meets the Challenge, compared with other utility-types, its allowed rates are likely to change more with respect to changes in the underlying random variables. The other difference of interest is the high sensitivity ratio for the gas mix variable. As in Special Case 8, we see again the importance of the gas mix variable in terms of driving the NPV results. The above results show that for the high-cost utility, changes in its gas mix, as opposed to changes in the price of natural gas, will have a greater effect on the forecast NPVs.

5.60 The Realities on the Ground: Underlying Assumptions Matter

5.61 Summary of Basic Forecast Results: Case Studies 1 Through 16

Our forecast results (for the Case Studies 1–16) show the critical, and perhaps pivotal, role played by avoided external costs in establishing the economic value of wind energy to Kansans. In fact, it is only when potential external savings are included in the analysis that the Challenge would be cost effective. These facts are presented in Table 5.4.

Table 5.4: Critical Values: External Costs and Carbon Tax: Case Studies 1 - 16				
Utility-type	**Wind Option**	**Cost Effective without External Cost Savings**	**Cost Effective with $20/MWh External Cost Savings**	**Critical Carbon Tax level**
High	PPA	1. No	2. Yes ($1.22/MWh)	-
High	Build	3. No	4. Yes ($19.56/MWh)	-
Average	PPA	5. No	6. Yes ($13.24/MWh)	-
Average	Build	7. No	8. No ($31.00/MWh)	$14.66/ton
Low	PPA	9. No	10. Yes ($16.25/MWh)	-
Low	Build	11. No	12. No ($34.62/MWh)	$19.49/ton
Middle	PPA	13. No	14. Yes ($5.00/MWh)	-
Middle	Build	15. No	16. No ($23.51/MWh)	$4.68/ton

Notes: Numbers 1–16 indicate the specific Case Study number. The numbers in parenthesis are the threshold (i.e., critical) level of external cost savings. When the threshold level exceeds $20/MWh, then estimated external costs savings are not large enough to yield a positive NPV, on average.

As Table 5.4 shows, in no instance is meeting the Challenge cost effective unless external cost savings are included in the analysis. Obviously, that holds across all utility-types and for both wind options. However, when external cost savings of $20/MWh of wind energy (per the traditional emissions) are included in the analysis, then in most, but not all, cases the Challenge becomes cost effective. The fact that the cost effectiveness of the Challenge can change depending on the inclusion of estimated external cost savings shows the critical nature of that inclusion. It also shows the critical nature of the size of that estimate.

Table 5.4 also shows how large a carbon tax would need to be in those instances in which inclusion of the external cost savings at $20/MWh is not sufficient to push the Challenge into the cost-effective category. As shown, there are three such cases where inclusion of a carbon tax, in addition to the $20/MWh savings per traditional emissions, makes the critical difference. Thus, if there is a carbon tax of $20/ton or more (starting in 2006), and if external cost savings per the traditional emissions are estimated at $20/MWh of

wind energy, then in every case meeting the Challenge would be cost effective. And if all of the state's jurisdictional utilities jointly take up the Challenge based on their share of the state's total retail load, then the carbon tax only needs to be about $15/ton.

It is important to note that the results shown in Table 5.4 establish all conditions under which pursuit of the Challenge is likely to be cost effective. In every instance, some level of external cost and/or carbon tax savings must be attributable to wind energy production in order to push the Challenge into the cost effective category.

5.62 The Forecast Results Depend on Certain Assumptions Holding in Reality

Some of the key assumptions that underlie the analysis necessarily underlie the inferences and conclusions derived from that analysis. Therefore, it is critical to have some understanding of real conditions that may run counter to those assumed in the analysis. Below we highlight some of the key assumptions that, as a practical matter, may not be realized and indicate how the forecast results may be affected as a consequence.

Assumption A: Wind Energy Substitution

In this study we model wind energy production as negative load. That assumption implies that for each MWh of wind energy acquired by the utility there is a corresponding and equivalent one-MWh *reduction* in the amount of energy it produces via conventional means. In short, one MWh of wind energy produced in Kansas saves all costs associated with generating, in Kansas, one MWh of electricity via conventional means: this is our one-for-one substitution rule. This is a critical assumption because it helps to determine the dollar value of wind to Kansans. Based on this assumption, we know that wind energy would be at

least as valuable to Kansans as the avoided costs associated with them consuming that wind energy. However, there are several reasons why our assumed one-for-one substitution rule may not hold.

Kansas Wind Energy May be Traded or Exported to Other States—If Kansas wind energy is effectively sold off-system, the production of wind energy in Kansas may not alter the dispatch of conventional power plants in Kansas. If the dispatch of Kansas power plants is not altered as a consequence of meeting the Challenge, then there would be no change in emission levels from those power plants. More precisely, if Kansas power plant emissions are not *reduced* as a consequence of the Challenge, then it is not clear whether Kansans would realize lower external costs.

If Kansas wind energy is effectively sold off-system, and by that we mean out-of-state, it would, all else equal, alter the dispatch of power plants located outside of Kansas. Depending on where those plants are located, Kansans could still realize lower external costs as a result of the Challenge. However, the key point is this: to the extent Kansas wind energy production is not consumed by Kansans, the assumed one-to-one substitution of Kansas wind energy production for Kansas convention energy production will be diluted. In turn, the external cost savings Kansans realize as a consequence of the Challenge will be diluted. By how much is very difficult to say.

Alternatively, to the extent the Challenge alters the dispatch of power plant in states other than Kansas, then, arguably, some of the benefits of the Challenge would be realized in those states. Total regional or national benefits may not be altered, but the *allocation* of external cost savings could be influenced by effectively selling Kansas wind to other states.

Kansas Wind Energy May Reduce Out-of-State Purchases—It is also possible that Kansas wind energy may enable Kansas utilities to reduce their power purchases from utilities located outside the state. If this is the case—that is, if Kansas wind energy serves to simply reduce the power purchases Kansas utilities make with out-of-state utilities—then the dispatch of Kansas power plants may not be altered. Thus, whether it is effectively sold off-system or used to reduce out-of-state power purchases, Kansas wind energy production may not deliver to Kansans the reduced power plant emissions assumed in this study. To the extent real emissions are not reduced as assumed in this study, the actual external cost savings in Kansas will, on average, be lower than forecast in this study. The same would hold for this study's forecast NPVs: they may well overstate the net benefit that is realized in practice.

Assumption B: Kansas Emissions Affect Only Kansans

Once power plant emissions are dumped into the atmosphere, it is difficult to know if and where any related external costs may be experienced. We assume any Challenge-related emissions reductions in Kansas stand to benefit only Kansans. That is, we assume local reductions in the traditional emissions benefit only the local (i.e., Kansas) residents. If Kansas wind energy production reduces emissions and, thus, external costs in other states, that benefit could be attributed to the Challenge—which we have not done in this study. However, if external costs are reduced in other states as a consequence of the Challenge, it would be reasonable for consumers in other states to help pay Kansans for their pursuit of the Challenge. The point is that our analysis assumes a statewide focus, rather than a broader,

regional view. With respect to the externalities consideration, the actual, region-wide benefits associated with the Challenge could be larger than the benefits forecast in this study.

Assumption C: The Quality of Wind Energy and Wind Integration Costs

Given its intermittent nature, and given that it is neither dispatchable nor controllable, there is a question about whether installed wind capacity is a reliable source of firm energy.[72] More simply, there is a question about whether wind energy sources actually provide the quality of electric service consumers have grown accustomed to. It is generally recognized that investment in wind capacity provides little, if any, ratable generating *capacity*. But wind energy may also fail to provide sufficiently firm energy, the type of energy that Kansas ratepayers demand. If that is the case, if wind energy generally is not marketable as a firm energy source, then its value to Kansas ratepayers should be adjusted downward. In other words, it should be discounted to reflect any deficiency from the commercially accepted standard for quality.

In this study we assume that wind capacity sources do provide firm energy production over the course of an operating day. One of the reasons we make that assumption is that our analysis includes a wind-integration cost. Based on what we refer to as the Minnesota Study, we set the assumed wind-integration cost at $4.60 per MWh of wind energy. By incurring that cost, the utility can presumably firm-up wind energy sources over the operating day. However, it is not clear, as a practical matter, whether incurring the assumed integration cost actually accomplishes that objective. It may be that even when resources are spent to "integrate" wind assets with the conventional assets and fuels, wind remains a non-firm

[72] By controllable we mean the ability to follow marginal load via the usual application of standard generation control technologies.

energy source whose output should and would be discounted in commercial transactions.[73] If wind energy, even with wind-integration expenditures, is unable to sustain a price in the wholesale electricity market, then it may be reasonable to discount its value to ratepayers in order to reflect its real economic value.[74] (See Appendix F for a discussion of these and related issues.)

Another assumption that may not hold in reality is the size of the requisite wind-integration cost, which we assumed is $4.60/MWh of wind energy. In addition to questions about the size of the integration cost are questions about its composition. While they are difficult to estimate, the wind integration cost should also include the cost of "dispatch inefficiencies" that result from the utility's acquisition of wind resources. If that cost were include then for utilities that have a relatively heavy reliance on baseload units and fuels, as opposed to cycling and peaking units and fuels, the wind-integration cost may be significantly larger than what we have assumed. In fact, it is possible that the wind-integration cost for utilities like Westar and KCPL, with their relatively small reliance on natural gas generation, could be in the $10 to $20/MWh range. (See Direct and Rebuttal Testimony in Docket No. 08-WSEE-309-PRE for a more detailed discussion.) As a practical matter, the wind-integration cost in Kansas could be double what we have assumed. If it is, the forecast NPVs reported here are probably too large.

[73] Even with expenditures to integrate wind energy with existing, conventional portfolios, the question remains whether wind energy could be sold at a price that receives (or reflects) no cross-subsidization from those portfolios.

[74] It is possible that wind energy will be effectively discounted in terms of its value in the firm energy market. Similarly, it is possible that wind energy will effectively lean on the conventional portfolios, making it appear firmer than it really is.

Assumption D: Wind-installation Cost Inflation

We assume wind-installation costs will inflate no more or less than the average annual rate of inflation for the national economy. However, the last three to five years have provided ample evidence that this assumption is unlikely to hold. Our estimate is that the wind-installation costs have inflated at about 10 percent per year for the last three years—well in excess of the overall, aggregate rate of inflation. To assume that wind-installation costs will inflate at about the national rate is probably very optimistic. Moreover, if this assumption is wrong (as the results from Special Case 1 and 2 and our sensitivity analysis show), the forecast NPVs presented in this study will be quickly outdated and, therefore, offer a weak basis for guidance to policy makers. It will be critical to re-evaluate the wind-installation cost forecasts used in this study. Frequent updating of those forecasts may be desirable.

Assumption E: Federal PTC Subsidy is Certain

It is our view that once government subsidies are started, their existence is nearly guaranteed, at least over the near-term, which could stretch for decades. We assume that there is no risk of the federal PTC going away over the investment horizon, and, therefore, assume that investors can effectively bank upon its continued existence for their planning purposes. However, if the federal PTC were eliminated and not replaced with some type of substitute subsidy, the cost of wind energy in Kansas and elsewhere would increase dramatically. That is, if the federal PTC were eliminated, all of the forecast NPVs developed in this study would have a significant upward bias.

Assumption F: The EPA-based Estimate of External Costs per Traditional Emissions

In the next few years Kansas utilities will invest nearly a billion dollars on new pollution-control equipment to be installed at baseload coal facilities. That equipment is designed to reduce the emissions of several of the traditional pollutants. The $20 EPA-based estimate of the external costs associated with the emissions of traditional pollutants does not take account of the recently announced, and approved, pollution-control investments. It is possible that once that new equipment is in place and operational, the external costs associated with traditional generation in Kansas could be lower than the EPA estimates in its study of the Clear Skies initiative. Therefore, it is possible that over the next 5 to 10 years, the $20 estimate of external costs per MWh of conventional generation is upwardly biased. If it is, the forecast benefits of the Challenge will have the same upward bias, which implies that a potential carbon tax would need to be larger to offset that bias. In summary, in recognition of the new investments in pollution-control equipment in Kansas, the forecast NPVs in this study that include the EPA-based estimate of external cost savings may be upwardly biased.

Assumption G: No Network Transmission Costs

For a number of reasons, we do not include any estimates of the network upgrades costs that would be required to meet the Challenge. All of the NPV estimates of the Challenge are effectively at-the-busbar estimates, more precisely connected to the grid estimates. Inclusion of the necessary transmission network upgrade costs would alter the forecast NPVs presented here. It is difficult to know, but it appears likely that inclusion of transmission costs would tend to reduce the forecast NPVs.

Assumption H: Utility Capital Expansion Paths Remain Comparable to Their Historic Paths

As it turned out, one of the critical elements of the NPV analysis is the assumed or forecast capacity expansion path taken by the utility. By capacity expansion path we mean (1) the *timing* at which utilities add new power plants and fuel contracts to their generation asset and fuel portfolios, respectively, and (2) the *type* of plants and fuel contracts added. Depending on capacity expansion path forecasts, the composition of the utility's generation asset and fuel portfolios may change over time. As the composition of those portfolios change, so does the utility's generation cost structure (namely its gas mix). Depending on the utility-type, changes in the gas mix can significantly change the costs that the utility may avoid by taking up the Challenge. Thus, capacity expansion forecasts can certainly influence the NPV forecasts.

In this study, for each utility-type we assume their future capacity expansion paths will closely resemble their historic paths. Equivalently, for each utility-type we assume their cost structures remain fairly static over time. However, this assumption may not hold. For example, it is possible that a utility like Westar could follow an expansion path in which it adds relatively more natural-gas-fueled generation to its generation asset portfolio. That is, a low-cost utility could take a path that effectively transforms it into a high-cost utility. Similarly, our high-cost utility could, by adding relatively more natural-gas-fueled generation, begin to resemble a Texas utility.

While we assume cost structure transformations among Kansas utilities are unlikely over the roughly three decades, we fully recognize this assumption may not hold. Given concerns about global warming and the likelihood of more stringent and new emission

standards, there is some possibility that baseload coal plants will not be a part of any capacity expansion paths. In that event, utilities would have to increase their reliance on natural-gas-fueled capacity and perhaps nuclear-fueled generation.

If Kansas utilities end up following capacity expansion paths along which their relative reliance on natural gas increases (so that their gas mix amounts trend up over time), then the forecast NPV results for the Challenge will more closely resemble those for the high-cost utility-type than the average-cost utility-type. In fact, given the relative importance of the gas mix variable (as revealed through the sensitivity analysis), assumptions/forecasts regarding capacity expansion paths are critical.

The Implications of Relaxing the Assumptions

All of the forecast results presented in this study are conditioned by certain assumptions. If in reality those assumed conditions do not hold, then clearly the forecast NPVs offered through this study will be biased in one direction or another. From our perspective, we have been very conservative in the assumptions made to facilitate this research program. Not all, but the majority of assumptions favor the case for wind (Assumption H is a key exception.) As those assumptions are relaxed, or as conditions in reality prove different, the forecast NPVs presented in this study may be too optimistic. In fact, that is the likelihood; there is a greater risk that the NPV forecasts have an upward bias, and meeting the Challenge could deliver less net benefits than forecast here.

Chapter 6: Some Final Observations and Comments

6.00 Introduction

In this chapter we briefly summarize the key results. We also discuss a few ancillary issues related to meeting the Challenge. And finally, we outline a couple of issues that may require further research in the future.

6.10 Key Results

6.11 Key Result 1: In Terms of Internal Cost, Wind Energy Costs Relatively More

If potential external cost savings are ignored, on average wind energy is more costly than the conventional alternatives. In terms of a base case forecasts, and in terms of the non-updated data sets, wind energy acquired through a typical PPA is in the range of $12 to $13 per MWh more, on average, than the conventional alternatives. If the wind energy is acquired through utility investment, then wind energy costs, on average, about $31 more per MWh. Using the updated data sets and, thus, the NPV forecasts as of January 2008, the respective cost differentials are about $28/MWh and $51/MWh. Wind energy is clearly more expensive than the conventional alternatives, and it is becoming more so with time.

6.12 Key Result 2: In Terms of Total Generation Cost, Wind Energy May Cost Less

However, when potential external cost savings are included in the analysis, wind energy may cost less than business as usual. With the non-updated data sets, and under a PPA arrangement, if external cost savings per MWh of wind energy are approximately $13 or more, we find that wind energy is (likely to be) less costly than the alternatives and, therefore, cost effective. With the updated data sets, under the PPA arrangement, estimated

external cost savings must be greater—about $28 or more per MWh of wind energy. If the utility selects the build option, the respective external cost savings must surpass $31 and $51.

Depending on the level of external cost savings that result from wind energy production displacing conventional generation, taking the wind path may be less costly than the business-as-usual path. Other considerations also matter, such as the wind option selected by the utility and the utility-type in question.

The possible imposition of a carbon tax has nearly the same influence on the incentives for pursuing the Challenge as the inclusion of external cost savings. If a carbon tax comes to pass, that will improve the wind economics. In fact, implementing a carbon tax, in combination with explicit consideration of external cost savings (due to wind energy), may make the difference between Kansas wind energy being economic and not.

6.13 Key Result 3: It is Likely to Cost the Ratepayers Less When Utilities Choose PPAs

Under certain conditions, the wind PPA option costs the utility less than the build option. The opposite also holds: that is, under certain other conditions, the PPA option will be relatively more expensive. So the answer to the question of which wind option is more costly is not clear-cut. However, under those forecasts with the maximal likelihood of occurrence, the PPA option is less costly—by about $18/MWh. In other words, our analysis shows that it is likely that the PPA option will cost the utility (and ratepayers) less than the build option. Using the January 2008 updated input variable forecasts, the cost difference between the buy and build options increases to about $23/MWh. As the cost of wind installation increases, the PPA option is even more competitive and, thus, attractive.

6.14 Key Result 4: The Average Retail Rate is Likely to be Higher

Because wind energy is more costly than the conventional alternatives, if external benefits are ignored, when the utility pursues either wind option, its rates will be higher than if it had not added wind to its portfolio of assets. In other words, meeting the Challenge is likely to increase the average retail price of electricity in Kansas. The amount of increase depends on the utility-type, the wind options selected by the utility, and fuel price forecasts, etc. With the updated data sets, if the Challenge is met strictly with PPAs, the average rate increase is $0.98/MWh. But if it is met by utility investment, the average rate increase is $1.90/MWh.

6.20 Other Related Issues

6.21 Meeting the Challenge and Resource Sustainability

Might there be a link between the Challenge and some measure of sustainability? The answer depends on how the term *sustainability* is defined or interpreted. One interpretation of the concept is that of *sustainable development*, where the present society's needs would be satisfied without compromising the ability of future generations to meet their own needs.[1] Other interpretations abound, such as the ability to sustain resource usage over time. Depending on how sustainability is defined, there may be a link between policies that promote the development of renewable energy resources (like the Challenge and the Federal PTC) and sustainability. However, to analytically establish that link may be more difficult to achieve than many realize. Nonetheless, we offer the following hypothesis:

> *Absent the inclusion of the federal PTC, but with the inclusion of estimated external cost savings, pursuing the Challenge would be consistent with pursuing sustainability provided the average forecast NPV is positive.*

[1] See Arrow, et al., *Are We Consuming too Much?*

The basic idea is this: unequivocal pursuit of the Challenge or any one renewable energy policy may *not* be consistent with achieving sustainability. The fact that a project can be labeled a *renewable energy project* does not necessarily mean that it meets any criterion of sustainability. If the Challenge is to be consistent with the goal of achieving sustainability, it may be reasonable to pursue it only when the average forecast NPV is greater than zero. Equivalently, if sustainability matters to policy makers, then it may be reasonable for them to interpret negative average forecast NPVs as a clear stop sign and, thus, encourage a slower (or no further) pursuit of the Challenge in those cases.

Because the resources used in pursuit of the Challenge, once committed, cannot be reallocated to other purposeful objectives, it is critical to guard against their waste. The NPV analysis performed through this study and the resultant NPV forecasts provide policy makers with guidance for possibly avoiding waste and achieving sustainability objectives. Because of the inherent uncertainty of wind energy production, there can be no guarantees that the net benefit delivered by the Challenge will be positive, after the fact.

6.22 One of the Strengths of the Challenge is that it is Voluntary and Affords Flexibility

As we have stated repeatedly, if nothing else, our forecast results show there is a great deal of uncertainty about the net benefit the Challenge would deliver to Kansans. The net benefit could be positive and large; it could also be negative and just as large. Our sensitivity analysis also shows the degree to which NPV forecasts can change as underlying conditions change. For example, if wind installation costs continue on their present upward spiral, all else equal, the prospects of the Challenge delivering a negative net benefit quickly increase.

Because the Challenge is voluntary, utilities can respond to changing conditions and new information. As new information becomes available and new NPV forecasts can be generated, if the new forecasts are increasingly negative, then pursuit of the Challenge can be adjusted accordingly. Whether utilities should wait, or slow their pursuit of the Challenge should always be based on an examination of forecast NPVs. For example, arguments that stepping out of the order queue for wind equipment would result in higher installation costs in the future are not sufficient to determine whether continued pursuit of the Challenge is reasonable. Such arguments should be based on an examination of the forecast NPVs. If currently forecast NPVs are negative, stepping out of the order line may result in even less attractive NPV forecasts, but that should not be used as a basis to forge ahead anyway, at any cost. We summarize these points below:

> *Because the Challenge is voluntary, both the timing and target levels of installed wind capacity can be adjusted. Moreover, those adjustments could be quite valuable to Kansans. For example, if NPV forecasts improve over time as uncertainties are resolved, deadlines can be moved up and target levels of installed capacity increased—and to make those changes could be very valuable to Kansans. Conversely, pushing back deadlines and reducing target levels could also be valuable to Kansans. Hence, the flexibility built into the Challenge is a significant strength.*

6.23 Frequent Updating of the NPV Forecasts May be Advisable

Given the uncertainties surrounding the Challenge and the flexibility of it design, it may be advisable for policy makers to seek continual updates of the NPV forecasts. Wholesale changes to the Challenge can be evaluated using the framework we have developed and

presented through this report. Moreover, those changes can be evaluated against forecast NPVs, which probably provide policy makers with the best possible information on how to proceed over time in response to changing conditions and information.

The modular nature of wind farm development, in addition to the relatively short lead-time associated with that development, also calls for frequent updating of NPV forecasts as basis for continuing to pursue or modifying the Challenge. A commitment to pursue the Challenge should not be interpreted as a commitment to invest in a certain amount of resources by a certain date. Rather is should be seen as a commitment to pursue the Challenge with possible modifications being made to the Challenge along the way if those changes are likely to be cost effective. Again, those changes would need to be based on updated NPV forecasts.

6.24 The Federal PTC is Not Just a Subsidy, Rather it is a Life-line

One of the disconcerting elements of the PTC is its potential to distort economic decisions. Our analysis shows that without the federal PTC, the price of wind energy through a PPA would be about $55/MWh; and based on current information, that price would be closer to $68/MWh. The reason it is important to estimate the price of PPAs without inclusion of the PTC is that it reveals the actual, non-subsidized cost of wind energy. It also reveals how large the expected external cost savings need to be for investments in wind capacity to *actually* be cost effective. That information is critical if economically efficient resource allocation decisions are to be made—the kinds of decisions necessary if sustainability is to be accomplished as well.

Our analysis shows (using the non-updated NPV forecasts) that when the federal PTC is included, then the EPA-based estimate of external cost savings, at $20/MWh, puts the Challenge within the cost effectiveness ball park. That is, with the federal PTC in place, and with the EPA-based evidence regarding external cost savings, the Challenge is in the neighborhood of economic viability, and that viability is based on relatively well-founded, non-speculative evidence on externalities. Without the federal PTC, the current evidence suggests that meeting the Challenge would be hard to justify in terms of economics. That is, without the PTC, our analysis shows the real economic prospect of the Challenge is dim.

6.25 Markets for Renewable Energy Credits or Green Tags

Our analysis has not included a formal consideration of renewable energy credits (RECs) that may be available through some sort of market mechanism. If investors in (certifiable) wind capacity are granted RECs that possess positive value, and if that value is credited against the cost of meeting the Challenge, then the forecast NPVs associated with the Challenge would be higher than the forecasts presented in this study. Because is not clear to us whether REC markets will be long lived and sustainable or how much value RECs might hold, we have not included potential RECs as part of our analysis. Nonetheless, we recognize such value may exist and could be important at some future date. Another consideration is that implementation of a carbon tax could render an REC market largely redundant. If so, it is likely that the REC market would fail due to a lack of liquidity.

6.26 Kansans' Willingness to Pay Extra for Wind Energy: Conduct a Survey?

In terms of the utility's internal costs, our analysis shows that wind energy is more costly than conventionally generated electricity. That cost differential represents a premium payment for the acquisition of wind energy—a premium that many Kansas ratepayers may be willing and able to pay, but that would be forced upon ratepayers as a consequence of utilities' meeting the Challenge. (Our estimate of that premium payment has been presented previously for all of the basic and special case studies we examine in this study.)

To the extent ratepayers are both willing and able to pay the wind premium, then meeting the Challenge would be cost effective from the demand side (i.e., based strictly on consumers' willingness and ability to pay[2]). If cost-effectiveness of the Challenge matters to policy makers, it may be reasonable to conduct a survey of Kansas consumers as a basis for determining whether they may, in fact, be willing and able to pay extra for wind energy. However, in order to obtain meaningful survey result, those consumers responding to the survey need to understand or know approximately *how much* more costly wind energy is relative to the alternatives. This comparison of wind energy against the alternatives can be made in terms of both the internal and total cost of generating electricity.

6.27 Take a Regional Approach

Since meeting the Challenge is likely to increase the average retail rate of electricity in Kansas, some, perhaps all, electric rates in Kansas would increase relative to rates in other states (all else the same). Any action that makes the cost of doing business in Kansas more expensive relative to other states can dampen jobs and income growth in the state. How the

[2] Being cost effective on the demand side does not necessarily imply cost effectiveness on the supply side. To be cost effective on the demand side while not on the supply side means the consumer is willing and able to deviate from the least-cost, technical path.

costs of meeting the Challenge will be allocated among the customer classes and how much of those costs will be recovered through ECA-type mechanisms has yet to be determined by the Commission. Obviously, Commission decisions will influence how the costs of the Challenge will be allocated to the commercial and industrial classes; therefore, if the Challenge is met, then the Commission will have some influence on how the Challenge would influence the relative attractiveness of the business environment in Kansas.

One way to possibly limit the detrimental effects of the Challenge on the Kansas business environment would be to allocate more of its costs to the residential classes. But this approach may run counter to well-established cost allocation methods and certainly may call into question the fairness of placing a significant cost burden on residential customers.

Another way to limit the detrimental effects of the Challenge is to effectively expand its reach beyond the state's borders. For instance, if Kansas policy makers can encourage other states in the region to pursue comparably designed Challenges of their own, that would reduce the potential of the Challenge eroding the Kansas business climate. In short, a region-wide wind energy Challenge, where individual states pursue wind capacity targets, *may* serve to keep relative costs on par among states. A region-wide Challenge would be roughly equivalent with the implementation of a region-wide RPS.

Of course, one of the critical design features of a regional RPS would be whether it is voluntarily or mandatory. If the net cost of meeting a standard differs significantly among states in the region, then compliance (by state) may not be achieved unless it is somehow mandatory, which means taking a regional approach may not work well to keep relative cost differentials from appearing (as a consequence of meeting the Challenge). Therefore, if a

regional approach were to be pursued, it would be best to include states where the cost to develop wind energy is comparable to that in Kansas.[3]

Similar to implementing a regional RPS is the implementation of a regional CO_2 cap and trade program. Any time states' policy makers are confronted with issues that have implications beyond the state's boundaries, such as fighting carbon, protecting the state's relative business climate, a regional approach—and solution—is probably advisable. As a general proposition, whenever a state unilaterally takes on an issue that has implications beyond its borders, the state is at risk for harming its relative standing. In many instances, a regional, collective effort is superior to a unilateral effort—especially when externalities are involved. Lastly, policy makers should also consider the advantages a national approach provides relative to a regional approach. In many instances, a national approach may be superior to a regional. The same holds with respect to a global approach relative to all others.

6.28 Build Versus Buy: The Cost and Risk Differentials

Not only is the build option likely to be more costly than the wind PPA option, it is likely to expose ratepayers to greater risk (as measured by greater rate volatility). From the ratepayer's perspective, on a risk-adjusted basis, the cost difference between the build and buy options may be considerably larger than the $18/MWh amount presented in this study. If policy makers are interested in having the Challenge met in the least-cost way, it may be important for them to encourage greater reliance on the PPA option. That the least-cost wind options might also carry less risk for ratepayers simply adds to its relative attractiveness to ratepayers.

[3] Similarly, success at meeting Challenge while not losing relative attractiveness to other states is more likely to succeed if similarly situated states are included in the region-wide effort. States with both wind resources and utilities like those in Kansas would be good candidates for membership.

6.29 Economic Versus Energy Independence

It has been argued that Kansas policy makers should make an effort to attract wind equipment manufacturers to the state. As we understand it, the argument is that by doing so Kansas would be able to reap more of the benefits associated with the expanding effort to place greater reliability on renewable energy.

Clearly, the same argument could be made for a myriad of commodities and industries. For example, perhaps Kansas should attempt to attract farm equipment manufacturers to locate in the state so that Kansas wheat and corn farmers could stop purchasing combines, tractors, and implements manufactured in other states. And by doing so, Kansas would capture more of the benefits associated with farming in Kansas and may gain greater economic independence from other states. Similar arguments could be made with respect to automobiles, computers, dishwashers, cell phones, and the list goes on. Generally, such arguments are without economic merit. There is nothing inherently special about attracting wind equipment manufacturers to the state. Any expansion of employment opportunities and income growth for the state of Kansas is generally beneficial. And wherever Kansas has a comparative advantage in the business world, we would expect some capture of that advantage and an expansion of the state economy as a result.

Economic trade should be perceived as being of mutual benefit, and not a surrender of economic or any other form of “independence.” After all, if Kansas policy makers want Kansas to be an exporter of wind energy, it is necessary that other states be importers of that energy. And one way for other states to finance their imports of Kansas wind energy is by selling (i.e., exporting) things—like, perhaps, wind equipment—to Kansans. Policies

designed to increase exports and decrease imports are unlikely to be sustainable for a number of reasons.

6.29.1 Entry of New Wind Equipment Manufacturers Would be Beneficial

It is difficult to determine whether current manufacturers on wind equipment are exerting any form of market power. To the extent they are, the entry of new competitors to the industry would be a clear benefit to consumers of that equipment. The number of wind equipment manufacturers on a worldwide basis appears somewhat limited. Moreover, the significant increase in installation costs over the last three years, especially if unmatched by improvements in the quality of installed equipment, which seems likely, is a troubling trend. It is possible that as government support for wind energy increases (in the form of RPS implementation, increases in the federal PTC, and implementation of a carbon tax), wind equipment manufacturers will simply respond by increasing their prices. In that way, it would be the equipment manufacturers, and not end-use consumers, that would be benefiting from the increase in government support. If equipment manufacturers possess some market power, they, and not consumers, will be well positioned to capture the rent created by changing government energy policies.

6.29.2 Alternatives for Fighting Carbon (and Other) Emissions

If the Challenge is perceived more narrowly as a tool for reducing carbon and, perhaps, other emissions, it is possible there are more efficient ways to achieve that reduction. There is a large body of research comparing the relative economic performance of emission taxes, cap

and trade mechanisms, and command and control regimes.[4] Of course, there are many factors to consider; however, under fairly general conditions, taxing emissions tends to be the less costly way to reach a specific emissions target level. Equivalently, the cost of reducing the emissions level by one unit (say, one ton) is likely to be less with the imposition of a (revenue neutral) tax.

One of the things that complicate the analysis of the Challenge is that by meeting the Challenge multiple products will result. For example, through the Challenge electric energy output is increased while emissions are reduced. Nonetheless, even with the generation of electricity, the Challenge could be a very costly way to reduce carbon emissions. That cost would be moderated if the Challenge also reduces the level of externalities associated with other emissions.

One of the factors that complicate the analysis is the ultimate consumption of Kansas wind energy. To the extent it effectively flows to other states, the value of wind energy to Kansans is reduced. One of the advantages of a carbon tax is that it would not be dependent on the flow of electricity. In that sense, a carbon tax is a more direct way to affect carbon-emitting behavior. The Challenge does this, but only indirectly. It may be advisable for policy makers to remain focused on policy tools that will *most directly* affect carbon emissions.

6.29.3 Wind Energy Production is Random, and, thus, Not as Reliable

There are two characteristics of wind energy production that clearly distinguish it from conventionally generated electricity. First, it is free of emissions; it is not a source of external

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[4] See report by Trisha Shrum, *Greenhouse Gas Emissions: Policy and Economics*, prepared for the Kansas Energy Council, August 3, 2007.

costs. But its value *strictly* as a clean, emissions-free resource cannot exceed the avoided external costs.[5] That is, simply because wind energy is clean, it does not provide unlimited economic value to society. To be clean simply means society can *avoid the external costs*, whatever they may be, that come with energy sources that are not clean. Economically, to be clean implies no more than the potential of avoided external costs.

The other characteristic of wind energy production—perhaps its one truly unique characteristic—is that it is *random*. To say the obvious: it varies with the wind. Wind energy production is neither dispatchable nor controllable in the usual, operational sense.[6] Lacking those characteristics, wind energy does provide the utility with generating capacity that meets existing accreditation standards. Therefore, it does not provide the degree of reliability that is provided by generating facilities that do meet those standards. In short, as a stand-alone technology, wind energy production is not as reliable as conventionally produced electricity. More importantly, because wind energy production does not provide the reliability that Kansas consumers of electricity are accustomed to and actually demand, it fails to be sufficiently reliable from their perspective. That is, regardless of how wind energy is evaluated in terms of operational reliability, if it does not give consumers the reliability they demand, then it is not reliable; in other words, it fails the reliability test imposed by the ratepayers themselves. If having the lights come on becomes a random event for consumers, you can bet they will complain and demand service that is effectively certain. This is where wind energy faces a steep challenge of its own.

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[5] One could also consider the fact that there are no harmful byproducts associated with wind energy production. To the extent wind energy production enables avoidance of any externalities associated with harmful byproducts, that value can also be attributed to wind energy.

[6] For example, wind facilities can be shut down if and when certain performance limits are reached and are at risk for being surpassed.

6.29.4 The Problem With Wind is Not a Lack of Transmission Capacity

The old saying about building a better mouse trap has considerable merit in the evaluation of wind energy economics and the need for transmission facilities: if you can build (and offer) a better mouse trap, the world will beat a path to your door. The simple economic lesson is that if you can provide a commodity relatively better than the close alternatives, consumers will come to you, at their expense, and transport your commodity back to their homes. It is the relative attractiveness of a commodity at a specific location that provides the incentive to transport it away from that location. It is those incentives that provide a basis for expending resources on transport activities.

If we ignore consideration of externalities for the moment, because wind energy is likely to be more costly than the alternatives, there are not large incentives to ship it elsewhere.[7] Moreover, to simply build transport facilities does not imply it will get shipped. If and when wind energy is cheaper than the alternatives, then the need to invest in transport capacity will *naturally* arise. Efforts to build transport capacity to increase wind energy exports would be not only costly, but may meet with frustration unless Kansas wind energy becomes more attractive in its own right.

The key to making any wind energy resource relatively more attractive is to focus on its zero emissions characteristic. Efforts to tax carbon or internalize some of the costs associated with the more traditional pollutants (i.e., conventional generation) will make Kansas wind energy relatively more attractive in Kansas, and elsewhere. And when entities

[7] As Special Case 8 shows, there is an incentive to ship Kansas wind energy to Texas, and perhaps to California. But even then Kansas wind energy would have to compete with Texas wind energy. It is not clear whether Kansas wind energy has a significant cost advantage over Texas wind. If it does not, which seems likely, then the wind facility closer to the end-use location (in this example, a Texas location) will have the cost advantage. Therefore, if Kansas wind is competing with Texas wind for the purpose of supplying Texas customers, Texas wind is likely to win that contest.

outside the state see Kansas wind as relatively attractive, they will have an incentive to commit resources to take that energy out of state.

6.30 Topics for Further Research

6.31 Evaluation of External Cost Savings

The economic analysis of the Governor's 2015 Wind Challenge has proven to be sufficiently complex—one could say it has been a *challenge*. Because wind energy development becomes economically attractive depending on society's evaluation of the external costs associated with conventional generation, its economic value is conditional. In that case, and if development of wind energy *at any cost* is to be avoided (as a matter of policy), then the challenge simply becomes one of identifying and quantifying the benefits that come with reducing emissions and the associated external costs, whatever they may be.

6.32 The Last Word

Does this study somehow constitute the last word in Kansas wind energy economics? Of course it does not. One of the biggest lessons we learned while doing this study is how rapidly the relevant conditions change. That means there is a need to *continually update* the NPV forecasts presented in this study.

What this study provides is a framework (i.e., model) for evaluating the net benefit Kansas derive from consuming Kansas-produced wind energy. Certainly the model presented here can be improved and we look forward to suggestions in that regard. Indeed, we have in mind improvements of our own. Thus, over time, we expect both the model and forecast

results presented here to improve. The need for further examination of the role of wind energy is not likely to diminish in the near future.

Appendix A: Governor's Letter

AD ASTRA PER ASPERA
KANSAS

OFFICE OF THE GOVERNOR KATHLEEN SEBELIUS, GOVERNOR

January 21, 2005

Brian Moline, Chair
Kansas Corporation Commission
1500 Arrowhead Road
Topeka, Kansas 66604

CORPORATION COMMISSION
JAN 24 2005
BRIAN J. MOLINE

Dear Commissioner Moline:

I am requesting your assistance in assessing how the State of Kansas can better take advantage of the state's extensive renewable energy resources for electricity generation.

Producing renewable energy brings many benefits to Kansas: it is non-polluting, it produces no greenhouse gases, it adds value to Kansas resources, creates jobs, and brings substantial revenues to local governments. Additionally in some areas of the state, it may lower utility bills for consumers.

As part of my goals to promote wind energy development in appropriate areas of the state, I believe it is appropriate to establish a vision for Kansas. I am challenging our electric industry to have 1,000 megawatts (MW) of renewable energy capacity installed in Kansas by 2015. This would amount to about ten percent of the state's current total electric generation capacity and is more than nine times the current installed renewable generation capacity in the state. I realize this is an ambitious goal but one I am confident our energy developers and utilities can achieve if we all work together.

To help achieve this goal, I am-directing a number of state agencies and groups to find ways to facilitate renewable energy development. I am requesting the Kansas Energy Council, in cooperation with the appropriate state agencies, to prepare an impact analysis of requiring state an4. Regent's facilities to acquire 2.5 - 5% of their electricity on average statewide from renewable energy sources. This will help ensure a market for the utilities voluntary renewable energy portfolios. It is similar to our existing program to buy ethanol-based gasoline in state vehicles. I am also requesting that the Kansas Energy Council evaluate creation of voluntary "green tag" programs in Kansas. These programs allow consumers to voluntarily contract for renewable energy production.

I would like the Kansas Corporation Commission to look at-the full range of benefits that renewable energy brings to Kansas and how those relate to additional investment that may be needed to meet the goals I have outlined for our electric industry. Please draw on expertise in other state agencies as needed to carry out this task. I look forward to receiving your analysis and recommendations.

Sincerely,

Kathleen

Kathleen Sebelius
Governor of the State of Kansas

KS/TF/pl

Appendix B: Alternative Renewable Resources

B.1 Cost of Electricity of Renewable Generation

Wind generation of electricity is not the only possible renewable source of electricity. The three major categories of renewable resources that potentially could generate significant amounts of electricity are wind, solar, and biomass. Below is a table from a California Energy Commission study that provides 2005 estimates of the cost of electricity per kWh (in 2003 dollars) for different types of renewable generation. Although animal manure digestion and landfill gas are listed as cheaper than wind, fuel supply is not included in their case.

Estimated Costs of Renewable Electricity[1]

Resource	Scale (MW)	Cost of Electricity* (2003 $/kWh)
Animal Manure Digestion**	0.100	0.043
Landfill Gas	2.000	0.044
Wind	75.000	0.049
Geothermal	50.000	0.054
Biomass Direct Combustion	20.000	0.066
Solar Thermal	100.000	0.120
Solar PV	0.003	0.230

* In 2005. Excludes production tax credit and other incentives.
** Farmer or cooperative financed. For a developer, $0.069/kWh

This appendix will explain why we did not include solar and biomass generation in our analysis of the Governor's Renewable Resource Challenge for 2015.

B.2 Solar

B.2.1 Solar Thermal

Solar thermal electrical generation is used mostly for heating of swimming pools and houses. Large solar thermal electrical generating systems have not been installed since the 1980s. As the table above indicates, this technology is expensive which limits its usefulness. As of 2005, solar thermal electric technology provides only 350 MW to the grid, most of it from the Luz linear collector plant in southern California. For this solar technology to work, it must be located in places with a great solar resource, very clear air,

[1] California Energy Commission, ***Biomass in California: Challenges, Opportunities, and Potentials for Sustainable Management and Development***, June 2005, p. 42. Similar tables can be found in other publications with similar results, for example, ***Handbook on Renewable Energy Financing for Rural Colorado***, McNeil Technologies, Inc for the Colorado Governor's Office, p. 11.

and low land costs. Its primary usefulness is as a decentralized source of electricity. Solar thermal technology, when used to heat water, can store energy for awhile.

B.2.2 Solar Photovoltaic

The economic status of photovoltaic (PV) solar electricity generation was best summarized in a monograph about PV in California. The authors concluded:

> The primary constraint to future expansion [of photovoltaic power] is economics. Simply put, solar PV is not yet cost-competitive in most grid-connected applications, and substantial cost reductions will be required for PV to meaningfully contribute to worldwide electricity supply.
>
> Local, state, and federal government incentives are (and will continue to be) the principal drivers for the recent growth in grid-connected PV capacity.[2]

PV electrical generation in California has grown significantly to where it is now about 130 MW which makes California the third largest market in the world, but significantly behind Japan and Germany which both have about 1,000 MW of installed capacity.

B.2.3 Advantages and Disadvantages of Solar

Solar has some advantages over other renewable resources. One advantage is that solar generations peak generation is much closer matched to peak power needs. Another advantage is its application in remote areas and its ability to be modularized. It can be economical in situations where transmission and distribution assets are lacking.

However, solar is unlikely to support centralized, large scale electric production in Kansas. Where access to the grid is not an economic issue, it tends not to be economical against conventionally sourced electricity (see table above), nor is it as reliable.

B.3 Biomass

Biomass is any organic material that is not derived from a fossil fuel that can be used to create energy. More specifically, biomass is generally defined as plant material, including trees, vegetation, or agricultural waste used as a fuel or energy source.[3] Currently two types of uses of biomass for energy are particularly relevant for Kansas: the use of biomass to generate electricity and the creation of fuels from biomass. Other possibilities for the use of biomass, such as the capture and use of landfill gas could not generate

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[2] Ryan Wiser, Mark Bolinger, Peter Cappers, and Robert Margolis, ***Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California,*** Environmental Energy Technologies Division,Ernest Orlando Lawrence Berkeley National Laboratory, Report No. LBNL-59282, January 2006, p. 1.

[3] Melissa Pawlisch, Carl Nelson, and Lola Schoenrich, Designing a Clean Energy Future: A Resource Manual, The Minnesota Project, July 2003: 37.

enough electricity to provide much help in meeting the renewable resources 1000 MW challenge.

B.3.1 Switchgrass Co-Fired With Coal for Electrical Generation

Different modes of biomass have been suggested as the most efficient fuels for biomass generation of electricity. Wood and agricultural residues have a naïve appeal because they are waste from a production process and thus, “free.” Crops have also been grown for energy use such as corn for ethanol and wood for heating. Since Kansas is not the land of forests, a promising crop for energy production in Kansas is switchgrass. In a study done in part for the KCC, the authors used a model to investigate the economic viability of using switchgrass co-fired with coal to generate electricity.

> BIOPOWER, a computer program developed by the Electric Power Research Institute (EPRI), was used to evaluate inside the plant gate performance of switchgrass co-fired with coal at rates of 2% and 5% for Jeffrey Unit 1 and LaCygne Unit 1. Based on the costs of coal and biomass feedstocks, operational characteristics of a power plant, and capital requirements to handle and process biomass materials in a co-fire mode, BIOPOWER reports in a comparative manner the levelized cost of electricity generated and resulting atmospheric emissions for “coal-only” and “co-fired” cases.[4]

For Jeffrey Unit 1, the results from BIOPOWER indicate that “levelized cost of switchgrass-fired electricity ranges from \$0.050 to \$0.085/kWh, as opposed to a levelized cost of coal-fired electricity of \$0.025 to \$0.028 per kWh.”[5]

Unfortunately, biomass has several advantages which are not reflected in the differences in the cost of electricity. Biomass is “dispatchable” unlike wind or solar and biomass is CO_2 neutral. In addition, if the scope of the production tax credit were expanded to include co-firing biomass and coal at existing generating facilities, then using switchgrass for co-firing with coal would be more attractive.

B.3.2 Biofuels

Biofuels, especially when mixed with fossil fuels, have been used commercially for more than three decades. An older study of the feasibility of using biodiesel to generate electricity in Holton, Kansas found that the process was not economically feasiable.[6] Since that time, biofuels have become increasingly more competitive, especially ethanol. However, Michael Manella reports that, “At \$2.11/gallon, the spot price of ethanol (four-week national average, December 2005) is significantly higher than the spot price of

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[4] Pelletized Switchgrass for Space and Water Heating, U.S. Department of Energy, p. 14.
[5] Ibid.
[6] ***Economic Development Through Biomass Systems Integration in Northeast Kansas,*** draft report, prepared by The Kansas Electric Utilities Research Program, to the National Renewable Energy Laboratory, May 1995.

unleaded regular gasoline at $1.65."[7] More separation exists between biodiesel, $3.08/gallon and petroleum diesel at $1.79/gallon on January 6, 2006.

B.4 Conclusion

None of the alternative sources examined in this appendix is new. Solar and biomass have been available as an option to be considered for years. Market barriers have not been significant and, therefore, market access is not the issue. Solar and biomass, whether supported by various subsidies or not, have been or are being subjected to a market test – where the cost of electricity from conventional resources and wind, whether supported by subsidies or not, is taken as the relevant market standard/benchmark. Against that benchmark only wind has been a significant competitor.

[7] www.bioproducts-bioenergy.gov/ news/DisplayRecentArticle.asp?idarticle=227

Appendix C: Basic Employment Implications of the Wind Challenge

Brief Aside: The Relation between Net Savings and Net Employment (Gains) from Wind

The employment implications of wind development are complex. To forecast the employment implications of wind development in Kansas would require, at a minimum, modeling: 1) the regional electricity market, 2) employment in the Kansas electric utility sector, 3) Kansas' utility related net exports (based on a regional macro model) and 4) Kansas' aggregate labor market. Not only are these modeling requirements a challenge, the accompanying data requirements are not readily satisfied either.

Nonetheless, the *basic* employment implications of Kansas wind development can be framed by three questions, all interrelated: 1) whether selection of wind options would alter the cost effectiveness or economic efficiency of the utility sector, 2) whether selection of wind options would change the state's net export position, and 3) whether a reduction in external costs (due to utilities selecting wind) would largely constitute a wealth transfer (and, thus, have limited implications for state's overall economic efficiency and net trade position). For each question, we offer a *brief* discussion.

If wind is more costly to the utility than the next best (set of) conventional alternatives, by selecting wind the utility would be less efficient. The implications are higher utility bills and utility customers with less income available to spend in other sectors of the economy. Employment in the utility sector could actually increase; but employment in the non-utility sectors is likely to decrease.[1] The *net* change in statewide employment could be either positive or negative. However, reductions in efficiency

[1] Here we assume the price elasticity of demand for electricity is inelastic. However, assuming elastic price demand implies a similar result with respect to net employment in the economy except there would be less employment in the utility sector and more in the non-utility sectors.

generally imply either underemployment or unemployment of available resources and, therefore, net contractions in output. Selecting wind, if less efficient than available alternatives suggests a *net* reduction in employment.[2]

If wind reduces the state's net trade (or net export) position, Kansas employment could be reduced as a result of wind development. Obviously, wind would reduce Kansan's use of coal and natural gas, namely Wyoming-sourced coal and Mid-Continent-sourced natural gas; though much of the gas likely to be Kansas-sourced. Depending on which fuel use is reduced and where the reduced fuel is sourced, net fuel imports to the Kansas utility sector *could* fall which would boost Kansas employment. However, because (current) wind turbine/tower manufacturers are non-Kansas entities, as are the wind installation companies, to install wind capacity in the state, all else constant, implies an increase in imports. Thus, while Kansas wind development *could* reduce fuel imports, it would necessarily increase imports as a consequence purchasing and installing wind equipment. Depending on the *net* change in (utility) imports, there is likely to be a corresponding change in Kansas employment.

To the extent wind energy production would reduce power plant emissions and, thus, damages that may result from those emissions, wind development is likely to: 1) bolster economic efficiency due to a healthier workforce and 2) result in a transfer of spending/wealth (from the health-care sector of the economy to other sectors). If wind does contribute to a healthier and, hence, more productive labor force, a net gain in employment can be expected. The net employment effect of any wealth transfer is likely to be small; employment in the health-care industry would probably decline with

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[2] Equivalently, reductions in efficiency imply operating inside the production possibilities set and an overall reduction in output with less employment of resources.

employment increasing elsewhere and this wealth transfer is unlikely to have a significant influence on the states' net export position.

In summary, primarily through its possible influence on utility sector efficiency (in terms of possible departures from the least-cost path), Kansas' overall labor force efficiency, and the state's net export position, wind development is likely to have some influence on Kansas employment. These three employment factors working simultaneously may work in the same or opposite directions. If they go in opposite directions, definitive inferences about the influence of wind development on Kansas employment will not be possible without a more in depth analysis. However, under certain conditions, the net savings equation provides information on each of these three employment factors. If only internal costs are evaluated, the net savings equation offers an indication of how wind development would affect utility sector efficiency: negative net saving would indicate a loss in efficiency and, thus, a contraction in utility employment. If both internal and external costs are evaluated, the net savings equation offers an indication of how wind development would affect overall labor efficiency. And if the both the savings and costs associated with wind development are (largely) non-Kansas based, for example, Wyoming coal savings generated by installing turbines manufactured in Florida or California, then the net savings equation offers an indication of how wind development is likely to affect Kansas' net export position. For example, negative net savings would indicate a reduction in Kansas net exports and a probable contraction in Kansas employment. The key point is: the net savings equation can perform at least double duty providing a direct measure of wind savings and an indication of various employment factors that collectively offer an indirect measure of the net

employment implications of wind development. Later in this report, when actual net savings amounts/forecasts are presented, we offer our accompanying assessment of the actual employment implications for the state. Lastly, while the statewide net employment implications of wind development could be relatively small, we recognize geographical changes in employment are likely, e.g., employment may increase in rural areas at the expense of urban labor markets.

Appendix D: Forecasting the Price of Natural Gas

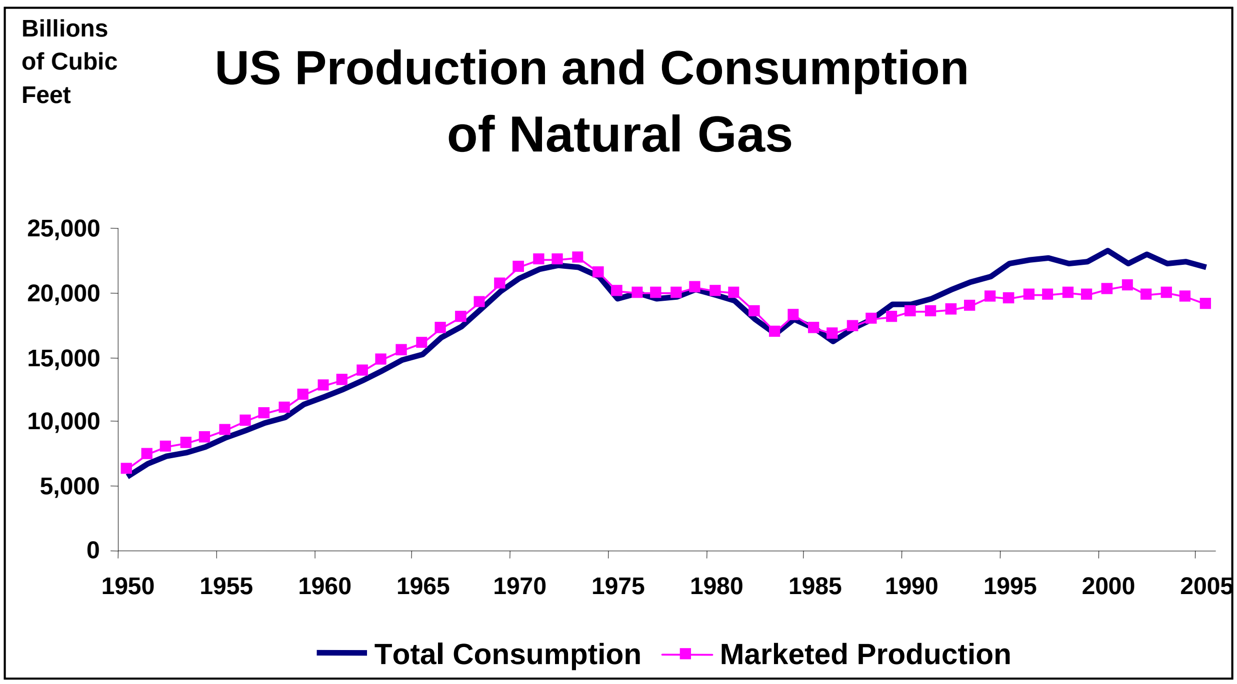
This appendix is relatively long and contains diverse material that ends with our forecast of natural gas prices. The idea behind the appendix is first to provide our view of the natural gas market (sections 1-4) and then to give our forecast and tie that forecast back to our view of the natural gas market (section 5). This material has excited the writers of this report but some or all of it may be of no interest to the reader. To spare the reader as much pain as possible, below is an outline of the appendix so the reader can pick and choose.

D.1 Production and Consumption of Natural Gas

D.1.1 Brief History of US Natural Gas Production and Consumption

The Chinese seem to be the first group to transport natural gas and then use it. About 500 B.C. they used simple bamboo pipelines to transfer natural gas from where it was seeping out of the ground to where it could be used to boil seawater to separate the salt from the water.[1] Around 1785 in Britain, natural gas extracted from coal was used to light houses and streets. In 1816 this process was brought to the United States to light the streets of Baltimore. Although interstate natural gas pipelines had existed in the US before World War II, the post-World War II era saw a boom in pipeline expansion due to increased demand for natural gas. Figure 1[2] shows how production and consumption of natural gas increased steadily from 1950 to the early 1970s. By 1972 and 1973 production and consumption temporarily peaked and then slowly declined. Consumption began rising again in the late 1980s and has plateau at about the same level as the peak in the early 1970s. Production also increased slightly in the late 1980s and continued to increase until 2001 when it started declining again.

Figure D.1



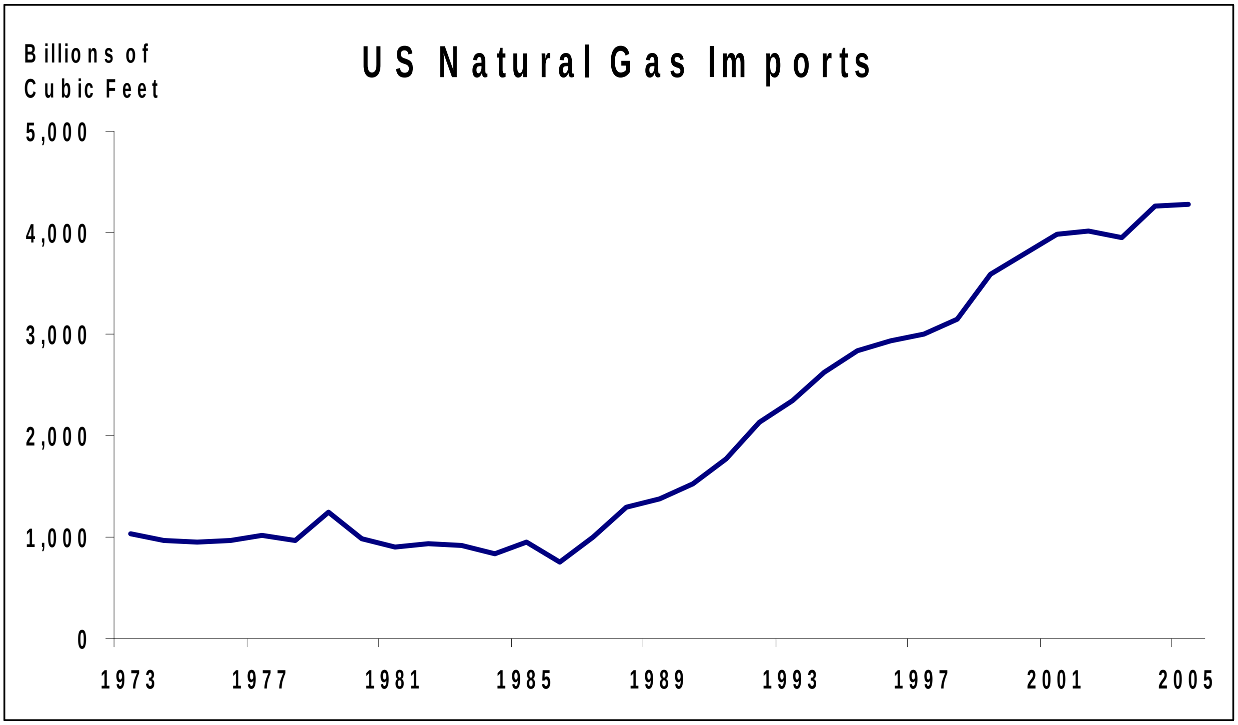
[1] For a brief history of natural gas see NaturalGas.org and Energy Information Administration.
http://www.naturalgas.org/overview/history.asp
http://www.eia.doe.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/ngmajorleg.html

[2] The data used for prices, consumption, production, and imports comes from the Energy Information Administration except for the Henry Hubb natural gas prices whieh come from the New York Mercantile Exchange.

D.1.2 United States Importing of Natural Gas

Natural gas is another resource that the US consumes more than it produces. Figure 1 shows the gap that has developed between U.S. production and consumption of natural gas since the mid 1980s. The response has been an increase in the quantity of natural gas imports as illustrated by Figure 2. Imports are four times what they were in 1985 and now they account for almost 20 percent of U.S. consumption of natural gas.

Figure D.2



D.1.3 Profile of United States Consumption of Natural Gas

D.1.3.1 Natural Gas Consumption by Consumer Class

A little deeper investigation into the trends in natural gas consumption reveals only aggregate consumption is nearly static. During the period 1997 through 2005, total consumption fell by 3.3%. At the same time, residential consumption fell 2.9%, commercial consumption fell 5.0%, and industrial consumption fell 21.9%. Of the four major consumer classes, only natural gas use for the generation of electrical power increased, but it increased 42.6%, nearly offsetting the decline in consumption in all other major consumer classes.

D.1.3.2 The Decline in Residential Consumption

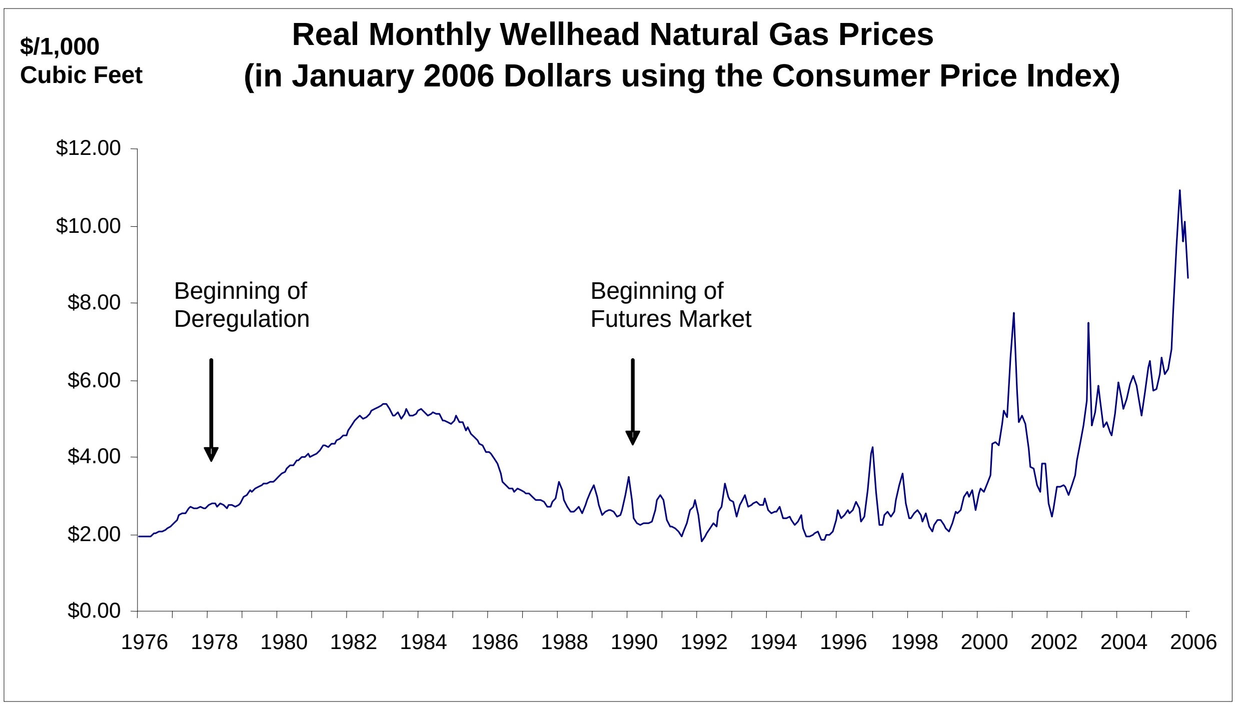
The decline in consumption by these major classes of consumers does not tell the whole story. As an example, we will further examine average residential consumption. Residential

consumption was highest in the 1970s – annual averaging of 4,926,596 MMcf, then dropped significantly in the 1980s – annual average of 4,534,078 MMcf, and then rose in the 1990s – annual average of 4,776,265 MMcf. For the first six years of the current decade, residential consumption has averaged 4,090,496 MMcf per year, about the same as the 1970s. However, from 1970 to 2004 U.S. population increased 43.2%. Thus, per capita residential consumption of natural gas has declined significantly over this time period. Even the 8.3% increase in residential use from the 1980s to the current decade pales by comparison to the nearly 30% increase in population from 1980 to 2005.

D.1.3.3 Price of Natural Gas and Consumption

The major reason for the decline in natural gas use by industrial, commercial and residential consumers has been the increase in natural gas prices since the since the late 1990s. (The increase in the use of natural gas for the generation of electricity will be discussed later.) Figure 3 illustrates the price path of natural gas since 1976 and shows how natural gas prices have increased dramatically over the past 8 years. The growing gap between U.S. production and consumption along with the relatively higher cost of imported natural gas explains the sustained increase in natural gas prices, but it does not explain the apparent increase in the natural gas price volatility. The increase in natural gas price volatility is a response to changes in the structure of the natural gas industry. The next section will explain the structural changes in the natural gas market and the different types of volatility.

Figure D.3



D.2 Structural Change in the Natural Gas Market and Volatility

D.2.1 Structural Changes: Deregulation and the Futures Market

In a response to the perceived excesses of public utility monopoly behavior in the 1920s, the federal government began regulating public utilities in the 1930s. The Natural Gas Act of 1938 was the first federal regulation of the natural gas industry The Natural Gas Policy Act of 1978 initial raised ceiling prices for natural gas and then eventually eliminated removed price caps. By the late 1980s wellhead natural gas prices were completely deregulated. In April 1990 of the NYMEX futures market for natural gas began. The relationship between deregulation, the opening of the futures market, and natural gas prices is illustrated in Figure 3. In addition, Figure 3 suggests that volatility has increased substantially in the past 10 years.

D.2.1.1 Deregulation

Deregulation of the natural gas market left production, transportation and storage, and distribution unbundled. As a result, natural gas distributors have two components to their demand for natural gas – a current use demand and a storage demand. To complicate matter more, the storage demand has two aspects: a seasonal cycle of summer purchases for storage and winter drawdown out of storage, and a speculative use of storage depending upon future expectations of supply and demand for natural gas.

D.2.1.2 Futures Market

The root of the natural gas financial structure is an extensive futures market with an associated derivatives market. This complexity means that although in the long-run, however lengthy that is, the natural gas price is determined by supply and demand, in any short-run period, the price of gas is determined by production, storage, futures prices, expectations, and speculation. If someone can forecast the short-run price of natural gas, there are piles of money out there to be made.

D.2.1.3 Structural Change, Speculation and Price Volatility

Two factors in the natural gas market contribute to price speculation:

- The possibility of storing natural gas, and
- The sophisticated financial structure which sits astride the natural gas spot market.

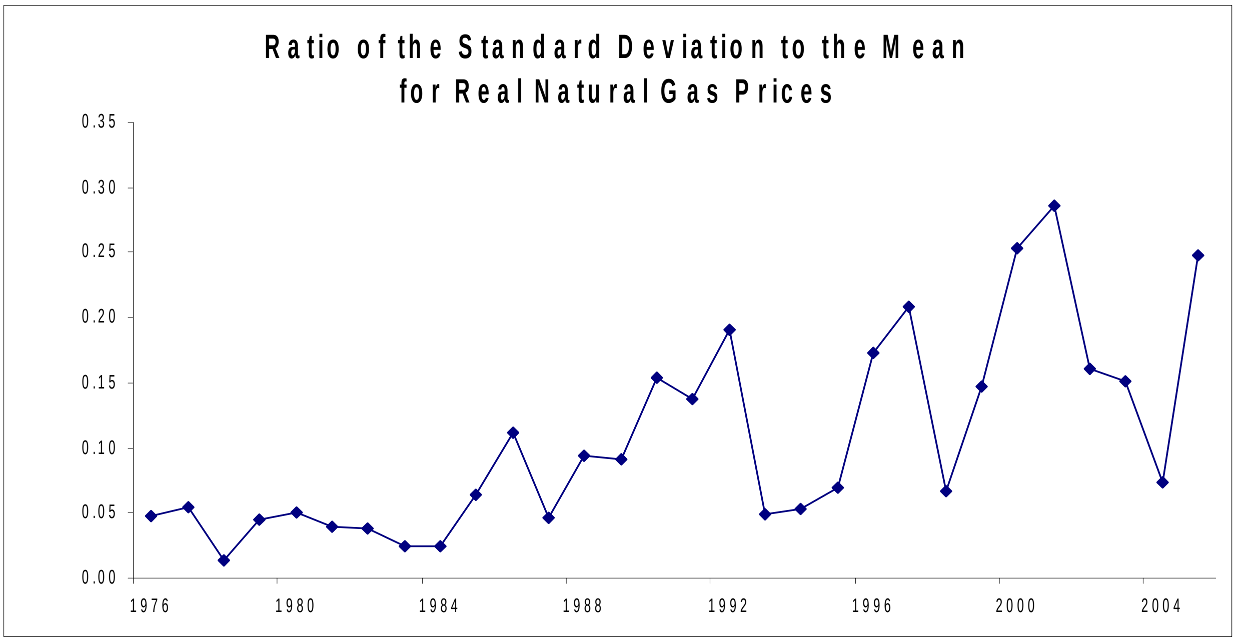
Speculation in a market can cut two ways. Speculation increases liquidity in a market allowing it to function more efficiently and speculation tends to make price more responsive to changes in information which is also an efficiency improvement. However, quick price responsiveness to information changes means quicker and more price changes – price volatility. Certainly when observing natural gas prices change on a daily or more frequent basis, one begins to wonder where investment ends and gambling begins. Price volatility is the price paid for the increased efficiency that speculation adds to the market.

D.2.2 Volatility

D.2.2.1 Price Volatility in the Natural Gas Market

Figure 4 below further quantifies the increase in natural gas price volatility. The metric for volatility used in Figure 4 is the ratio of the annual standard deviation to the annual mean. The annual mean and standard deviation were calculated using the monthly data. The result is a time series for both mean and standard deviation. Volatility has increased in two stages. The first increase in volatility coincides with the end of price regulation during the mid 1980s in the natural gas industry. The second stage corresponds with the introduction in 1990 of the natural gas futures market, and the volatility has increased as the futures market has grown. One additional side note: price volatility seems to be pretty volatile itself.

Figure D.4



D.2.2.2 Production Volatility

Production volatility over a period of more than a few months is almost non-existent in the natural gas industry. The industry seems to have nearly constant levels of production which gradually trend either downward or upward slowly. For example, in no five year period since 1976 does the standard deviation ever rise to 10% of the mean. Even events such as the 2005 hurricanes this summer dramatically affected production only temporarily. There are still some lasting production effects of the hurricanes but they are relatively small. The production side of the market is not a significant source of volatility.

D.2.2.3 Volatility in Residential Consumption and Price

On the consumption side, only residential consumption of natural gas stretches back far enough for meaningful analysis. From 1975 to 2005, for each five year period the standard deviation is between 60% and 70% of the mean suggesting residential consumption of natural gas is relatively volatile. Since residential consumption of natural gas is primarily used for heating, intuition suggests that a lot of this volatility might be seasonal and the data support this intuition. An example of the extreme difference in residential monthly consumption is that the average monthly mean for the December through March period is 721,761 MMcf while the June through September period's average mean is 139,919 MMcf.

The volatility in residential consumption affects the price of natural gas through the year. The average of the mean prices for November, December, and January from 1988 through 2004 is $3.44 while the average of the means for the remaining nine months is $3.05. The winter peak in residential natural gas consumption significantly increases the total price volatility of the natural gas market.

D.3 Historical Trends in the Price of Natural Gas

D.3.1 Random Walks and Mean Reverting Process

Although there are numerous different types of statistical trends, we will just look at two basic types of trends: a random walk with a drift and a mean-reverting process with a drift. If the drift is equal to zero, then the first process is just a random walk and the second process is just a mean-reverting process with a constant mean.[3]

The easiest way to differentiate these types of trends is to consider the effect of external shock to the price of natural gas; for example, Hurricane Katrina. Figure 5 below illustrates both processes's response to a one time price shock in year 3. In the case of a random walk, the price shock is permanent, and the random walk with a drift just resumes after the price shock at a higher level. With a mean-reverting process, a price shock like Katrina would temporarily push the price significantly higher, but then the mean-reversion would push the price back to the mean and in the case of Figure 5, below the linear tread. Economics does not promise a "soft landing." In the Figure 5 the mean reverting process is symmetrical: the process moves back toward its mean at about the same speed that the shock moved it up and away from its mean. Not all mean reverting processes are symmetrical. The classic example of a slow mean reverting process is the price of oil. The two different price shock to oil in the 1970s both rapidly pushed the price of oil to record levels. However, after peaking, the price slowly returned, in fits and starts, to its mean over a number of years.

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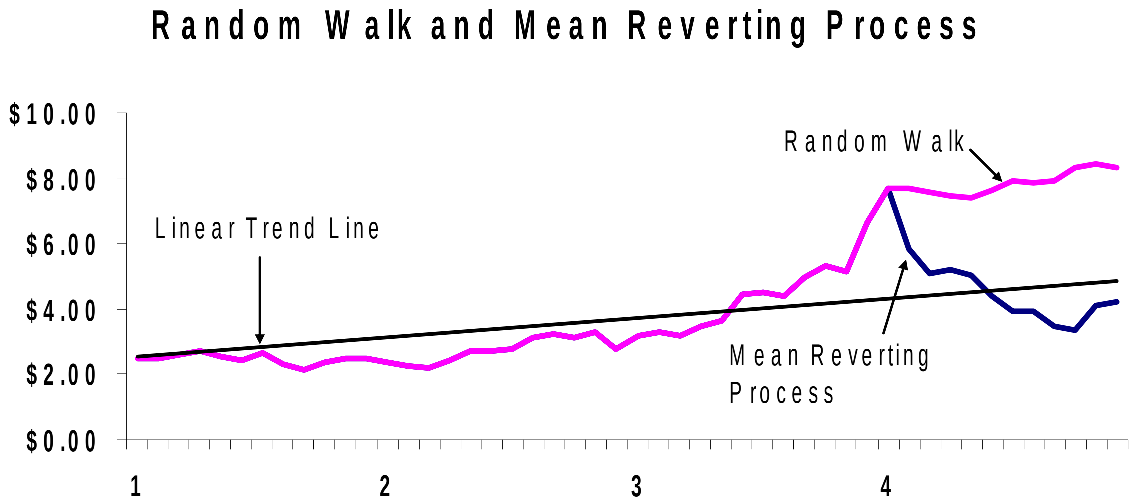
[3] For a good description of the problems in general of forecasting energy commodity prices and specifically of the problem of using some form of trend analysis see Robert Pindyck, "The Long-Run Evolution of Energy Prices." We used the MIT working paper version of this paper, December 1998, WP#4044-98-EFA. The paper was published under the same title in *The **Energy Journal*** 20 (2), 1999, 1-28. Also see Malcolm P. Baker, E. Scott Mayfield, and John E. Parsons, "Alternative Models of Uncertain Commodity Prices for Use with Modern Asset Pricing Methods," *The **Energy Journal** 19* (1), 1999, 115-148.

Figure D.5



D.3.2 Commodity Prices Tend to Be Mean Reverting Process

The two classic examples of random walks and mean reverting processes in finance are equity shares (stocks) and commodity prices.

- Equity Shares – equity shares have long been described as random walks. The basic argument is that a price shock to a stock tends to have a permanent effect till the next price shock. For example, when a pharmaceutical firm introduces a successful new product, the firm's stock tends to rise to a new level, and then continue on its basic path till a competitor develops a similar product or the patent expires.

- Commodity Prices – commodity prices usually do not follow a random walk because their price represents a dynamic market rather than the value of a firm. In a market, if the price rises unexpectedly, then consumers tend to use less of the commodity by either using a substitute or conserving, and if the price remains high long enough, producers will seek additional sources of the commodity.

An inspection of Figure 3 indicates that natural gas prices tend to follow a mean reverting process with a upper trend in the mean. The mean reverting process is explained the by sophisticated nature of the natural gas spot and future markets.

Why the upward trend in prices? Two answers are hinted at in our previous analysis.

- More of the U.S. demand of natural gas has been provided by imports which raise the price of the natural gas used; especially, imports of liquid natural gas.

- U.S. natural gas production peaked in 1973. World production has peaked or is expected to peak soon. Declining production introduces the possibility of a scarcity rent. Goods that have a high and constant or growing demand with fixed or declining production will have the gap between price and cost of production increase over time – this gap is the scarcity rent.

D.4 Fundamentals of the Natural Gas Market

The brief analysis of the natural gas market above was designed as a prelude to describing our forecasting natural gas prices. In particular, several notable features of the market were found which directly affect how and how well natural gas prices can be forecast.

D.4.1 Supply and Demand Features of the Natural Gas Market

- Aggregate consumption of natural gas peaked in the early 1970s, declined slightly till the mid 1980s, and has returned to a level slightly above the peak in the early 1970s. Over the past nine years, aggregate consumption has been nearly constant. Since population has continued to grow, this has meant that per capita consumption of natural gas has declined – the per capita demand curve for natural gas has shifted down.

- Of the four major consumer classes – residential, commercial, industrial, and electrical generation – only the use of natural gas for electrical generation increased from 1997 through 2005. Even with the use of natural gas for electrical generation increasing 42.6% during the time period, total consumption declined by 3.3%

- Production of natural gas has been remarkably stable over the past few decades. Domestic production peaked in the early 1970s and has since had down and up swings but has never returned to its peak level.

- With consumption increasing slightly and production declining, imports of natural gas have increased about four fold since the mid 1980s and now represent about 20% of U.S. consumption.

D.4.2 Natural Gas Price Volatility

- Natural gas price volatility has increased since the mid 1980s. Two institutional changes seem to have triggered the increased volatility: deregulation of the natural gas market and the introduction and development of the natural gas futures market.

- Temporary changes in the consumption of natural gas are seasonal and weather induced. Winter residential consumption of natural gas is on average about five times more than summer residential consumption.

- Short-run production of natural gas is limited by existing production capacity. A major disruption to short-run production would be some type of event causing temporary

elimination of some production; for example, a large natural catastrophe – Hurricane Katrina, or a disabling terrorist attack.

- Long-run production increases are limited by declining reserves and difficulty in finding and exploiting new natural gas sources.

D.4.3 Natural Gas Prices Follow a Mean Reverting Process with an Upward Drift

- Natural gas prices follow a mean reverting process because the price is reflective of a market value rather than an institutional value.

- The mean for natural gas prices has an upward trend since the mid 1980s. Two possible reasons for the upward drift are: increased use of imported natural gas which is more expensive, and the potential development of a scarcity rent for natural gas.

- There is no reason to expect the current growth rate in the mean of natural gas prices to remain stable. Some of the factors which could either raise or lower it are: increased expensive imports, reduced production, the use of substitutes for natural gas, or the development of new technology that replaces natural gas with another energy source.

D.5 Forecasting Natural Gas Prices

An old economics saw explains the problem: "A good economist can tell you what happened yesterday, a great economist can tell you what is happening today, but it takes a soothsayer to tell you the future." Most intelligent macroeconomic forecasts of more than a year into the future are presented with numerous caveats and much humility. We need a forecast of natural gas prices that runs to the year 2045. By 2045 we could be living in the world of the *Jetsons* or of *Mad Max*.

With a lot humility, a number of caveats, and the best information we have available, we will lay out our forecasts for the price of natural gas from now till 2045. Then we will provide our rational for the forecast. Finally, we will explain in some detail how we arrived at the forecast.

D.5.1 Forecast

Below in Table 1 is our forecast for natural gas prices from 2006 to 2045. These prices are:

- The prices are real – they do not include an inflation adjustment.

- The prices are based on Henry Hubb prices but are basis adjusted to represent Panhandle Eastern Pipeline prices.

Table D.1 Forecast of Real Natural Gas Prices: 2006 to 2045											
Year	Price	% Δ	Year	Price	% Δ	Year	Price	% Δ	Year	Price	% Δ
2006	$10.17	33.46%	2016	$6.92	-1.60%	2026	$8.26	1.48%	2036	$9.73	1.63%
2007	$8.24	-18.97%	2017	$6.90	-0.26%	2027	$8.41	1.78%	2037	$9.89	1.65%
2008	$7.16	-13.09%	2018	$7.11	2.92%	2028	$8.57	1.99%	2038	$10.05	1.64%
2009	$6.51	-9.12%	2019	$7.40	4.19%	2029	$8.74	1.90%	2039	$10.21	1.60%
2010	$6.12	-6.04%	2020	$7.68	3.71%	2030	$8.88	1.67%	2040	$10.37	1.57%
2011	$6.14	0.33%	2021	$7.85	2.26%	2031	$9.01	1.46%	2041	$10.53	1.56%
2012	$6.30	2.67%	2022	$7.90	0.56%	2032	$9.14	1.38%	2042	$10.70	1.57%
2013	$6.50	3.16%	2023	$7.90	0.06%	2033	$9.27	1.47%	2043	$10.87	1.59%
2014	$6.79	4.43%	2024	$8.01	1.38%	2034	$9.42	1.61%	2044	$11.04	1.60%
2015	$7.04	3.65%	2025	$8.14	1.60%	2035	$9.57	1.63%	2045	$11.22	1.60%

D.5.2 Rationale for Our Forecasts

Our forecast is based on a mixture of trend, technology and market assumptions about the natural gas industry. We assume that natural gas prices follow a slow mean reverting price path through 2010. This is captured by using the Henry Hubb futures market prices till 2010 and then adjusting the prices for expected inflation and basis adjustment to give Panhandle Eastern Pipeline prices.

By 2010 we expect the price of natural gas to be close to its long run trend. Seven years of natural gas prices in excess of its marginal cost should create incentives for more supply and less demand. These changes in supply and demand will result from:

1. Improved technology and infrastructure for the importation of liquid natural gas (LNG),
2. More investment in exploration and development of new natural gas fields,
3. Improved technology to make natural gas use more efficient, and
4. The further development of alternative types of energy to substitute for natural gas.

We expect natural gas prices to continue to follow a mean reverting path with an upward trend; however, we expect the growth rate of the mean to fall substantially as a result of the changes listed above. In particular, we expect the mean to reflect the marginal cost of natural gas from 2011 to 2045.

D.5.3 More Detailed Explanation of Our Forecast

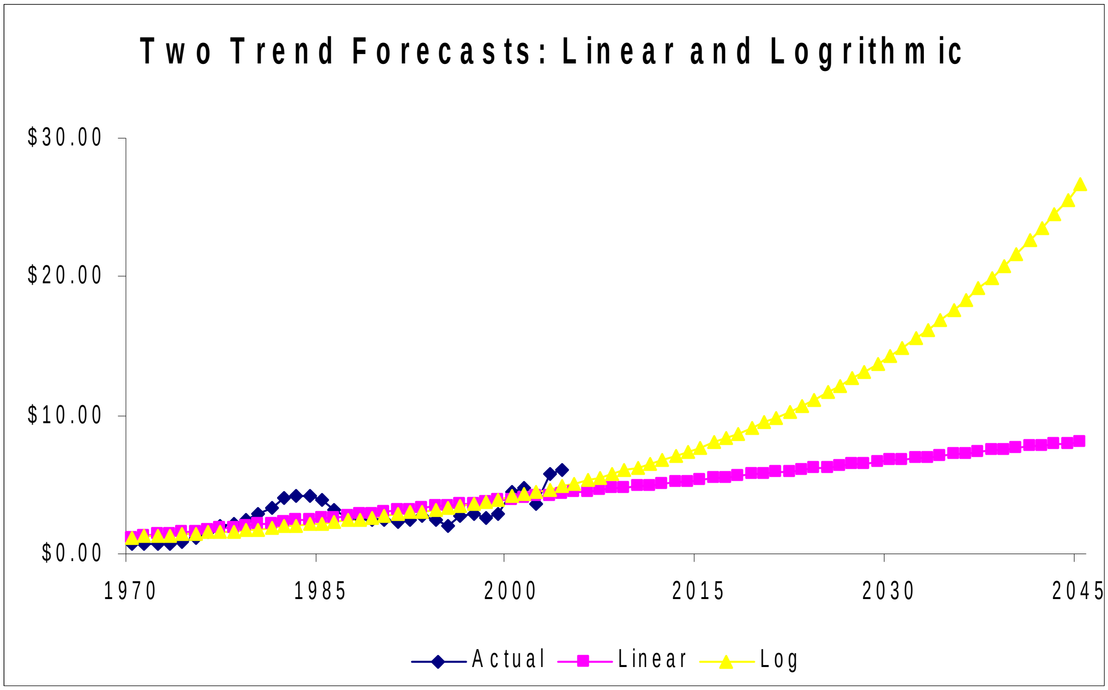
We developed an eclectic forecast of natural gas prices which mixes trend forecasting with a structural approach that assumes market signals are effectively responded to by producers and consumers. Trend forecasting is basically assuming what has happened in the past will continue in to the future. It is effective at short run forecasting but certainly has difficulty identifying turning points. Structural forecasting assumes that, for example, high prices will encourage producers to improve production and develop new technology and consumers to substitute alternative goods and reduce consumption. The rest of this section will explain in order: trend forecasting, structural forecasting and our eclectic approach.

D.5.3.1 Forecasting Natural Gas Prices with Historical Trends

When forecasting commodity prices using trends, the first step is to decide which type of trend is involved. We have already found that natural gas prices follow a mean-reverting process with a drift. Thus, our concern is with estimating the mean of the process. The next step is to specify the quantitative nature of that process – pick the model that best fits the data.

Figure 6 below shows the actual data for real annual natural gas prices from 1970 to 2004 and then two different mean-reverting forecasts of that data. The lower forecast is simply a linear trend of the data, and by 2045 its projected price of natural gas is $8.09. The higher forecast is a log-linear trend with a 2045 projected price of $26.65. As Figure 6 illustrates, both models fit the data about equally well. Which trend is to be chosen? For both trends, the slope parameter is accepted at the 99% level and the coefficient of determination (R^2) is about 50%.[4] As a final note, we did try shorting the time period we used to create the model from 1970-2004 to 1988-2004. Our assumption was that by eliminating the period where there was significant regulation of the market, we would get a better model. The results were a better fit for the model and more extreme forecasts: natural gas price in the log-linear model for 2045 was $43.74 while in the linear model it was $12.95. Our conclusion was to think of the short run in terms of trends and not the long run.

Figure D.6



[4] The coefficient of determination is a measurement of the variation in y explained by the right hand side, in this case, the variation in the price of natural gas explained by a time trend.

D.5.3.2 Forecasting Natural Gas Prices with Technology Assumptions

Economists feel more comfortable forecasting prices based on supply and demand fundaments. The long run supply curve should be a reflection of the long run marginal cost curve for the industry. Long run demand should reflect rational choice on the part of consumers, given the alternative possibilities and a budget constraint. In addition one would like to take into account economic growth and the changing structure of the economy – for example, a 30 year forecast in 1890 would need to know in advance that there would be a decline in blacksmiths and an increase in automotive workers. A structural model for long run forecasting natural gas prices would be superior. However, as we indicated earlier, the future fundaments of the natural gas market are difficult to anticipate and nearly impossible to time. If or when will new, large domestic natural gas fields be found? When will the technology for LNG become available enough to make importation from different continents cost effective? How will environmental laws change over the course of the next 30 years? Will a technological discovery make natural gas obsolete as an energy source?

These dilemmas have not stopped fools, or in this case a federal agency, from rushing in. Energy Information Administration (EIA) has developed The National Modeling System (NEMS) which,

> projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics.[5]

The EIA provides a reference case and two other forecasts of natural gas prices: a rapid and slow technology cases. However, these three forecasts are all extremely similar. From 2011 to 2025, the mean annual percentage change for the three cases is within 0.3%: reference, 1.87%; rapid technology, 1.77%; and slow technology, 2.07%. Growth rates this similar naturally result in similar price projections. The forecast for natural gas prices in 2025 varies from $4.35 in the rapid technology case to $5.18 per MMBtu in the slow technology case. Not only are the growth rates similar, but also none of the growth paths has much volatility as measured by the standard deviations: reference, 1.78; rapid technology, 1.41; and slow technology, 1.50.

D.5.3.2 Our Approach to Forecasting Natural Gas Prices

We took a three stage approach to dealing with the vast uncertainty of nearly 40 years into the future. For the period 2006 to 2010 we used the first of the month (FOM) prices for monthly futures contracts taken from the New York Mercantile Exchange. For the period 2011 to 2025 we used a forecast created by the EIA's energy model. For the period 2026 to 2045 we used a ten year moving average of the EIA forecast to project its trends into the future.

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[5] EIA, "The National Energy Modeling System: An Overview 2003," Report # DOE/EIA-0581, released March 4, 2003, p. 1.

D.5.3.2.1 2006 to 2010

The source for our 2005 to 2010 forecast, the monthly futures contracts taken from the New York Mercantile Exchange, have the advantage of being market generated forecasts – people are betting money on these forecasts. Presumably, the people in this market are going to find all the available information that is relevant in order to make the best possible bet. Thus, the prices for futures contracts have the advantage of being well informed, market driven prices. We used the prices taken at 9:31 a.m. on October 14, 2005 from the New York Mercantile Exchange. The monthly prices were averaged to give an annual expected price for natural gas.

As with most matters in economics, on the other hand, futures prices have the disadvantage of changing daily if not hourly. As an EIA report stated, "Futures prices vary substantially over time and apparently reflect current market conditions as well as future expectations." However, the EIA found no overall bias, "Although prices for futures contracts in any given heating season may exhibit a systematic bias (e.g., consistently underestimating prices for the 2002-2003 heating season), the patterns do not evolve in a predictable way between seasons." [6]

D.5.3.2.2 2011 to 2045

Building on the natural gas futures prices for the period 2006 through 2010, we used the EIS reference case as a basis for forecasting from 2011 to 2025. We took the forecasted percentage change in natural gas prices for each year from 2011 to 2025 and then used these percentage change figures to estimate the price level for natural gas. Then to project this forecast further into the future we used a ten year moving average of the percentage changes the EIA forecast to generate a forecast to the year 2045.

D.6 Natural Gas Forecast for January 2008 Update

One of the data updates for our January 2008 updated runs of the average-cost utility was an updated Natural Gas Price Forecast. We used the same basic methodology used for the original natural gas forecast. The updating was done by using more recent data. We used a January 2008 forward futures strip from NYMex for our futures prices out to December 2013. We used the base case December 2007 forecast for natural gas prices from the Energy Information

[6] EIA, Office of Oil and Gas, "An Assessment of Prices of Natural Gas Futures Contracts As Predictor of Realized Spot Prices at the Henry Hub," October 28, 2005, p. 1. http://tonto.eia.doe.gov/FTPROOT/features/futures.pdf. There is a large literature analyzing the relationship for storable commodities between spot prices and future prices. We will only mention an article by M. Chinn, M. LeBlanc, and O. Coibion, "The Predictive Characteristics of Energy Futures: Recent Evidence for Crude Oil, Natural Gas, Gasoline, and Heating Oil," UCSC Department Economics Working Paper 490, and the follow up article by the same authors "The Predictive Content of Energy Futures: An Update on Petroleum, Natural Gas, Heating Oil and Gasoline," NBER Working Paper 11033. In both papers, natural gas futures prices were found to be unbiased forecasts of spot market prices 12 months out, and in the second paper this was true for 6 month out. In both papers, futures prices for natural gas were biased at 3 months out. The authors found that futures prices predicted spot market prices better than either a random walk or simple time-series model.

Administration for the percentage change in prices from 2013 to 2030. Finally, we used a ten year moving average to complete the forecast out to 2036. The results are in Table I.2 below.

Table D.2

Forecast of Real Natural Gas Prices: 2008 to 2040

	Original Forecast			Updated Forecast: January 2008	
Year	Price	% Δ		Price	% Δ
2007	$8.24			$6.28	
2008	$7.16	-13.09%		$7.07	12.52%
2009	$6.51	-9.12%		$7.68	8.66%
2010	$6.12	-6.04%		$7.81	1.69%
2011	$6.14	0.33%		$7.91	1.23%
2012	$6.30	2.67%		$8.01	1.24%
2013	$6.50	3.16%		$7.91	-1.27%
2014	$6.79	4.43%		$7.73	-2.20%
2015	$7.04	3.65%		$7.55	-2.36%
2016	$6.92	-1.60%		$7.54	-0.14%
2017	$6.90	-0.26%		$7.53	-0.14%
2018	$7.11	2.92%		$7.55	0.27%
2019	$7.40	4.19%		$7.63	1.07%
2020	$7.68	3.71%		$7.54	-1.12%
2021	$7.85	2.26%		$7.46	-1.11%
2022	$7.90	0.56%		$7.68	2.94%
2023	$7.90	0.06%		$7.95	3.47%
2024	$8.01	1.38%		$8.19	3.12%
2025	$8.14	1.60%		$8.39	2.43%
2026	$8.26	1.48%		$8.49	1.14%
2027	$8.41	1.78%		$8.65	1.85%
2028	$8.57	1.99%		$8.78	1.54%
2029	$8.74	1.90%		$8.92	1.67%
2030	$8.88	1.67%		$9.16	2.60%
2031	$9.01	1.46%		$9.34	1.96%
2032	$9.14	1.38%		$9.55	2.27%
2033	$9.27	1.47%		$9.76	2.20%
2034	$9.42	1.61%		$9.96	2.08%
2035	$9.57	1.63%		$10.16	1.97%
2036	$9.73	1.63%		$10.35	1.93%
2037	$9.89	1.65%		$10.56	2.01%
2038	$10.05	1.64%		$10.78	2.02%
2039	$10.21	1.60%		$11.00	2.07%
2040	$10.37	1.57%		$11.23	2.11%

The forecasts are in real 2005 dollars and basis adjusted to account for the difference between Henry Hub indexed futures price and Panhandle index futures price.

Appendix E: EPA-based External Cost Savings per Wind Energy

E.1 Pollution as a Cost of Production

Electrical generation requires plant, equipment, resources, and labor. These are the usual categories of production costs and are reflected in the price of electricity. However, the cost of air pollution created by the generation of electricity is only partially included in the price of electricity. During the last third of the 20th century, some types of air pollution were reduced. Despite impressive successes, the generation of electricity still creates air pollution: specifically sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon dioxide (CO_2), and mercury (Hg).

An advantage of wind power is that it does not create air pollution. Wind turbines may create other types of non-market costs such as noise pollution and the destruction of the visual landscape, but any substitution of wind generated electricity for fossil fuel generated electricity reduces the relative amount of air pollution created. To complete the cost/benefit analysis, an estimate of the cost savings of pollution reduction by shifting to wind power is needed.[1]

E.1.1 Estimate of the Cost of Pollution: 2¢ per kWh

We estimate that at a minimum, electricity produced by fossil fuels generates an additional social cost of 2¢ per kilowatt hour (kWh), or $20 per megawatt hour (MWh), because of the pollution it creates. To fully estimate the benefits of wind power, either 2¢ per kWh needs to be added to the benefits or subtracted from the costs of wind generated electricity when wind energy is substituted for a fossil fuel.

This estimate of the cost of pollution is based on analysis by the Environmental Protection Agency (EPA) for the Clear Skies 2003 Proposal. EPA estimated that implementation of the Clear Skies Proposal would generate annually $940 million in health benefits ($180 million under an alternative estimate.) Kansas electrical utilities generate about 47,000,000 MWh of electricity each year. Divide $940 million by 47 million MWh, and on a per MWh basis, the cost of pollution in Kansas is about $20 or 2¢ per kWh.[2]

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[1] One of the standard complaints about Cost/Benefit Analysis is that it does not take account of intangible costs and benefits such as pollution. The most recent popular expression of this point of view is ***Priceless: On Knowing The Price Of Everything And The Value Of Nothing*** by Frank Ackerman and Lisa Heinzerling. W.W. Norton & Co Inc., 2004. An example of their argument is: “The basic problem with narrow economic analysis of health and environmental protection is that human life, health, and nature cannot be meaningfully described in monetary terms; they are priceless.” This is from an essay with the same name by the authors drawn from the book available at http://www.law.georgetown.edu/alumni/publications/2004/magazine/spring04/priceless.html.
Economists involved in trying to monetize of intangible costs and benefits have heaped scorn on this point of view. For example, V. Kip Viscusi states: “From an economic standpoint, for something to be ‘priceless’ means that it has an infinite value. Thus, if saving the snail darter is priceless, no amount of monetary cost should be spared in preserving these birds even if it depletes the entire GDP. Because no risk or environmental benefit warrants an infinite expenditure, the practical policy issue is what level of monetary cost is justified to obtain the benefit.” In “Monetizing the Benefits of Risk and Environmental Regulation,” Working Paper 06-09, April 2006, AEI-Brookings Joint Center for Regulatory Studies, p. 2.

[2] The Clear Skies Act of 2003 was proposed by President Bush and introduced as legislation in both the Senate and the House of Representatives in 2003 but never became law. It was reintroduced in 2005 and never got out of committee. It was designed to amend the Clean Air Act to reduce pollution, SO_2, NO_x, and mercury, through cap and trade programs. It was based on the successful SO_2 emissions cap and trade program in effect since 1995. EPA

We feel that the $940 million estimate is probably a low estimate of the cost of pollution in Kansas for a number of reasons we will list later. However, one reason we will give now: the $940 million is the difference between a baseline forecast with the already existing pollution regulations and the amount of pollution acceptable with the Clear Skies Proposal. The Clear Skies Proposal primarily affects NO_x and Hg emissions. The implementation of Clear Skies would not eliminate air pollution from electrical utilities. Thus, health costs of pollution would still exit with Clear Skies; the $940 million only represents the improvement due to Clear Skies. Unfortunately, EPA does not estimate the absolute level of health costs due to pollution, only the differences between two policy alternatives.

E.1.2 Alternative Method for Estimating of Pollution Costs

To provide more confidence in the estimate of 2¢ kWh for the cost of pollution, a second method was used to estimate pollution costs. EPA has estimated rules of thumb for the Western United States under the Best Available Retrofit Technology Rule (BART Rule): one ton of SO_2 emissions generate about $22,000 in health costs and one ton of NO_x emissions generate about $1,100 in health costs.[3]

In the base case, 1000 MW of wind power generates about 3.2 million MWh of electricity per year. This amount of generation would replace about 80% of the electricity produced by the first generator at the La Cygne power plant and about 70% of the electricity produced by a generator at the Jeffrey's Energy Center. Using the estimates above for the health costs of emissions, substituting wind power for the 80% of the La Cygne generator would reduce health costs of pollution about $60 million. Substituting wind power for 70% of a Jeffrey's generator would reduce health costs of pollution about $85 million. Using the $20 per MWh estimate for the cost of pollution, gives the reduced health costs of pollution due to 3.2 million MWh at $64 million.

The two methods of estimating pollution benefits from shifting to wind power give similar ballpark estimates: not little league ballpark estimates, but major league ballpark estimates.

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analyzed the impact of the program nationwide and for each state using its battery of models. Its results are available on their web page and are the basis for our analysis. The primary web page for the Clear Skies legislation is: http://www.epa.gov/air/clearskies/. For state information, go to http://www.epa.gov/air/clearskies/where.html and scroll down to the map of the United States and click on the state you want information for, or for Kansas information simply go to: http://www.epa.gov/air/clearskies/state/ks.html.

[3] This information was made available over the telephone in January 2006 by Ron Evans, Group Leader for the Air Benefit and Cost Group, U.S. Environmental Protection Agency. The same basic technique was used in the EPA's ***Methods for Projection Health Benefits for EPA's Multi-Pollutant Analyses of 2005,*** Technical Support Document for EPA's Multi-Pollutant Analysis, Office of Air and Radiation, U.S. Environmental Protection Agency, October 2005.

In October 2007, we again contacted Ron Evans to see if there were any updates of the rules of thumb he had given us earlier. Evans, through his benefits expert Neal Fann, gave us a wealth of new information including two documents with new, more discriminating rules of thumb. The new rules of thumb place a higher dollar value on the reduction of SO_2 and NO_x emissions. This suggests that our previous results underestimate the value of a ton of reduced SO_2 and NO_x emissions. Concerning the valuation of a reduction in mercury emissions, Neal Fann e-mailed that "I'm not aware of any benefit per ton estimates for this pollutant." Finally, I asked Neal Fann whether he thought there was a bias in estimating the health benefits of pollution reduction. His opinion, and we don't want to characterize it as anything other than the opinion of an expert, was "Given the rather large number of unquantified benefit categories (e.g. ecological benefits), I'd say that we're probably underestimating total benefits." We think this statement characterizes our own situation: we have "probably" understated the costs of pollution in our study but we recognized the existence of large uncertainties – we might have overestimated their value.

Estimating the cost of pollution is a formidable problem. We will describe some of the obstacles involved in estimating the cost of pollution in order to give the reader an appreciation of the nature and extent of the estimation problem. We think this informs the reader better than any caveats about viewing the estimate as an order of magnitude or the difficulty of putting a dollar value on something that does not have a market price attached to it.[4]

E.2 Assessing the Estimate of the Cost of Pollution

E.2.1 Model and Data Interaction

Assessing the cost of pollution is an interdisciplinary problem requiring multiple models to interact. Figure 1 below illustrates the interaction between models and data involved in estimating the cost of pollution. Because air pollution is nearly always at least a regional problem, the data requirements for the models are extensive.

E.2.2 Data

When dealing with economics or ecology, there is good data, adequate data, and bad data; but usually, there is just no data. What does a supply and demand model for white socks in Topeka look like? How does it change over time? What will the weather be in Manhattan, Kansas next week? Next month? Next year?

E.2.3 Emissions

Fossil fuel power plants are predictable. Because of monitoring, good data exists for the use of fuel, the amount of electricity generated and the amount of emissions created. Using a dispatch model, EPA has been able to run several scenarios of optimal power plant reaction to different pollution reduction regimes.

E.2.4 Emissions' Effect on Air Quality

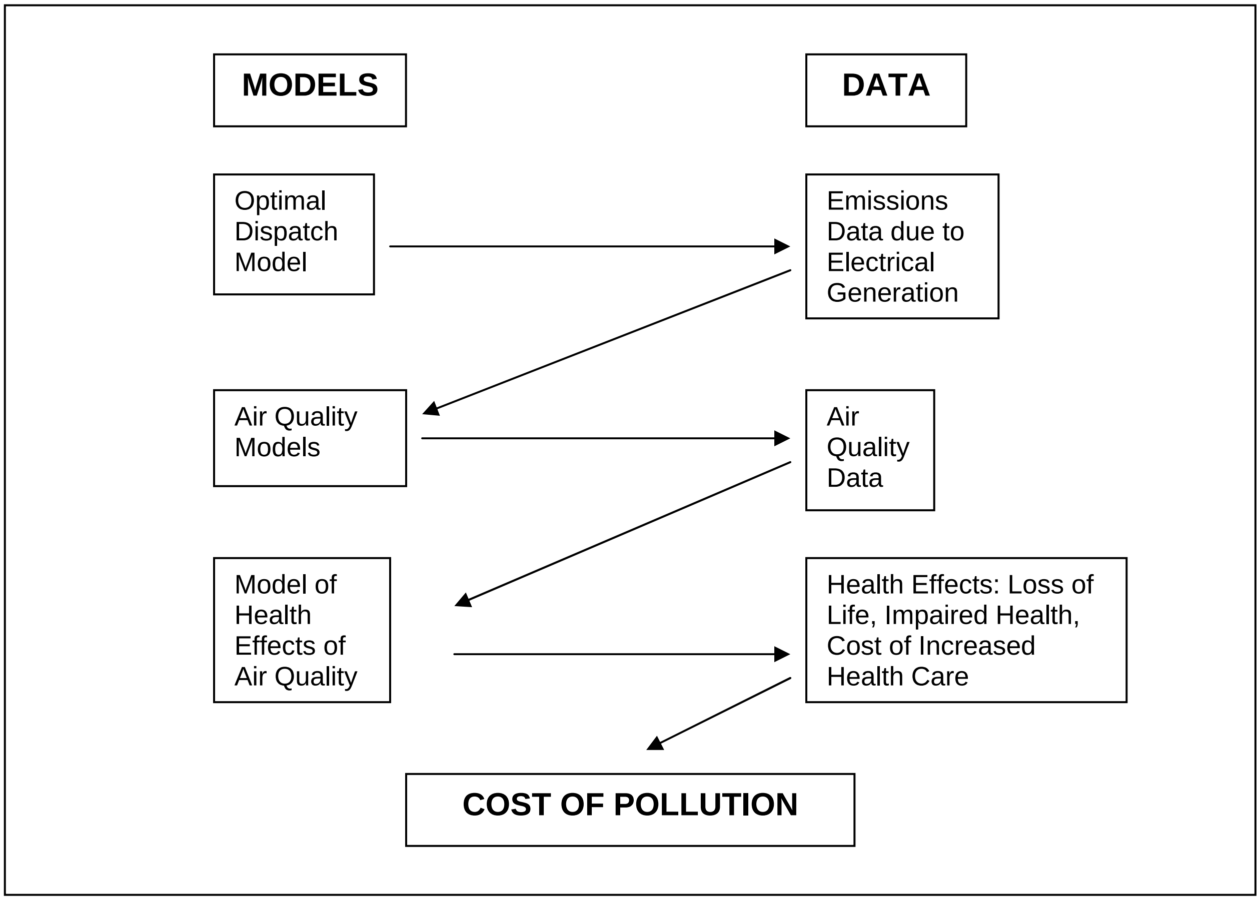
Unfortunately one cannot move directly from the quantity of emitted pollutants to the costs of pollution. Instead, the emissions must be run through an air quality model to determine how, how much and where the emissions change the air quality. The EPA uses several air quality models to estimate the effects of the emissions on air quality. These air quality models must have local, regional and continental scope because of the interaction between emissions and weather which implies immense data requirements simply to calibrate the air quality models. Add to this the complexity of local topography, regional weather patterns, and the chemical interactions in the atmosphere that the emissions cause, and one can see that just getting results is an accomplishment. The accomplishment of getting results should not be confused with the precision of the results. Air quality estimates are large order approximations.[5]

Figure E.1

[4] Bryan J. Hubbell has developed an alternative approach to estimating the effect of pollution. In the article, "Health Based Cost Effectiveness of Ambient $PM_{2.5}$ Reductions," ***Health Economics***, forthcoming he estimates what the value needed for the quality of adjusted life years (QALY) to exceed the estimated cost of pollution reduction. For $PM_{2.5}$ he finds that, taking into account $2.5 billion avoided medical costs, it needs to be at least $50,000 per QALY. For a description of QALY see Bryan J. Hubbell, "Implementing QALYs in the Analysis of Air Pollution Regulations," ***Environmental and Resource Economics***, Vol. 34, No. 3 (July 2006): pp. 365-384.

[5] ***Technical Addendum: Methodologies for the Benefit Analysis of the Clear Skies Act of 2003,*** U.S. EPA, September 2003, pp. 7-15. http://www.epa.gov/air/clearskies/technical.html

**Cost of Pollution Calculation:
Model and Data Interaction**



E.2.5 Air Quality Effect on Health

The air quality data is used to estimate the health effects of pollution. Concentration-response functions from epidemiological studies produce estimates of the changes in health outcomes as a result of the changes in air quality. One problem is that many of the epidemiological studies are done in one local area or a few local areas. Research money is not available to do nationwide canvasses. To compensate for the lack of general studies, the results of the studies that have been done have been generalized well beyond their initial scope. Another problem is that not all pollutants have been studied. Without the research, no mechanism exists for estimating the health costs of some pollutants. Consequently, the effects of these pollutants are ignored.

The concept of moving from air quality data to health effects is straight forward, but making the concept operational is data intensive and tedious. Each local area must have a defined air quality. The local air quality is combined with the population density and the age structure of the population to estimate the health effects at the local level. The local effects are summed to give regional and national health effects. For these estimates to be realistic, the local areas must be sufficiently finely divided. For example, anyone familiar with the Houston, Texas area knows

that the air quality in Pasadena (located near the refineries) and Katy (located in the western part of Houston area) is markedly different.

E.2.6 Health Effects to Pollution Costs

The last stage is transforming health effects, such as loss of life, increased hospital visits, etc., into dollar amounts. The value of the health effects are calculated by assigning a specific dollar value to each individual health effect. For example, EPA assigns $275 for a hospital visit. The assigned values that EPA uses come from studies of the value of a particular health effect. The health effects for the region under study are summed giving the cost of pollution for the area.

The most controversial assigned value and the most dominant health effect is the estimation of the value of premature mortality. EPA uses the concept of the value of a statistical life (VSL) and uses an estimate of $6.1 million for a VSL. The $6.1 million is the average mean of 26 studies approved by an independent advisory board established by EPA. The name is a misnomer: a more accurate description is the willingness to pay for greater safety to prevent one more fatality.[6] For a full description of the economic valuation of health endpoints see Table D-1 on the next page

E.3 Completeness of the Cost of Pollution Estimate

E.3.1 Pollution Effects Covered

The EPA health effects are based on estimates of the transformation of SO_2 and NO_x into fine particulate matter ($PM_{2.5}$) and ozone and then the effects of $PM_{2.5}$ and ozone on health outcomes. The costs of mortality are the major health effect for two reasons: the relatively strong concentration-response function for the effect of a change in $PM_{2.5}$ on premature deaths and the use of the value of a statistical life.

[6] The following example from Viscusi “Monetizing the Benefits” illustrates the fundamentals of VSL. “Suppose that you are in a group of 100,000 people, and that one of you will die with certainty. The risk of death is a random event that affects all people equally. How much would you be willing to pay to eliminate this risk? Suppose the answer is $70 for each person in the group. What this value implies is that collectively, the group of 100,000 people would be willing to spend $7 million to eliminate the risk of one statistical death to their group.” P. 7. In this case, the value of a statistical life is $7 million.

Table E-1
Unit Values for Economic Valuation of Health Endpoints
(1999$)

Health Endpoint	Description	Mean Estimate
Mortality	Base Estimate – VSL based on 26 studies	$6.1 million per statistical life
	Alternative Estimates - VSLY	Age / at 3% / at 7% Under 65 $172,000 $286,000 65 and Over $434,000 $527,000
Chronic Bronchitis	Base Estimate – WTP	$329,409 per case
	Alternative Estimate – Cost of Illness (COI)	Age / at 3% / at 7% 27-44 $144,654 $82,661 per case 45-64 $93,792 $69,435 per case 65+ $10,654 $8,677 per case
Non-Fatal Heart Attacks	COI	Age / at 3% / at 7% 18-24 $63,325 $62,739 per case 25-44 $71,755 $70,288 per case 45-54 $75,751 $73,865 per case 55-64 $135,148 $127,043 per case 65+ $63,325 $62,739 per case
Hospital Admissions	all respiratory, ages 65+	$17,635 per admission
	all respiratory, ages 0-2	$7,438 per admission
	pneumonia, ages 65+	$17,106 per admission
	COPD, ages 65+	$13,083 per admission
	COPD , ages 20-64	$11,333 per admission
	asthma, ages < 65	$7,467 per admission
	all cardiovascular ages 65+	$20,334 per admission
	all cardiovascular, ages 20-64	$21,864 per admission
	ischemic heart disease, ages 65+	$24,837 per admission
	dysrhythmias, ages 65+	$15,084 per admission
	congestive heart failure, ages 65+	$14,591 per admission
Emergency Room Visits	Asthma-related	$275 per visit
Minor Effects	Acute bronchitis	$344 per case
	Lower resp. Symptoms	$15.06 per symptom-day
	Upper resp. Symptoms	$23.84 per symptom-day
	Minor restricted activity day (MRAD)	$48.91 per day
	School loss days	$72.56 per day
	Work loss days	County-specific median daily wage
	Worker productivity	Change in daily wages adjusted by regional variations in income

Note: This is a reproduction of Table 8, p. 35 in ***Technical Addendum: methodologies for the Benefit Analysis of the Clear Skies Act of 2003***, September 2003, Environmental Protection Agency.

E.3.2 Limitations of the EPA Methodology

The EPA has underestimated the costs of non-mortality health effects. They did not have many willingness-to-pay studies available for estimating the costs of illness. Instead, they used approximations of willingness-to-pay such as the cost of health care for an illness. In other cases they combined willingness-to-pay for symptom clusters to approximate the willingness-to-pay for a more sever episode. Other reasons for EPA's underestimation of morbidity effects are:

- uses the lowest concentration-response functions from recent chronic exposure studies,
- focuses on first order end-point for mortality and hospital admissions when several end-points are significant risk factors for premature death,
- estimates in studies may already incorporate changed behavior that averts further effects – high ambient levels force those most affected inside, otherwise the concentration-response function might be stronger, and
- few concentration-response functions exit for air toxins; however, the reduction in these toxins prior to the discovery of their causing damage would reduce the risk of negative health effects – regulation as insurance.[7]

In addition, the EPA only monetarized one non-health effects cost of pollution, recreation visibility. Several other non-health effects exist:

- Ecosystem impacts
- Urban visibility
- Nitrogen deposition, and
- Materials damage such as the pollution damage to bridges and other infrastructure.[8]

The final pollution effects that EPA did not monetize were CO_2 emissions and its effect on global warming. This will be discussed in the next section. Table E-2 on the next page lists the major sources of uncertainty in the benefit analysis identified by EPA.

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[7] Bryan J. Hubbell, "Evaluating the Health Benefits of Air Pollution Reductions: Recent Developments at the U.S. EPA." Prepared for the Symposium on ***The Measurement and Economic Valuation of Health Effects of Air Pollution,*** Institute of Materials, London, February 19-20, 2001, pp. 3-5.

[8] ***Technical Addendum: Methodologies for the Benefit Analysis of the Clear Skies Act of 2003,*** U.S. EPA, September 2003, pp. 34-45. http://www.epa.gov/air/clearskies/technical.html

Table E-2
Primary Sources of Uncertainty in the Benefit Analysis

1. Uncertainties Associated With Concentration-Response Functions

- The value of the ozone- or PM-coefficient in each C-R function.
- Application of a single C-R function to pollutant changes and populations in all locations.
- Similarity of future year C-R relationships to current C-R relationships.
- Correct functional form of each C-R relationship.
- Extrapolation of C-R relationships beyond the range of ozone or PM concentrations observed in the study.
- Application of C-R relationships only to those subpopulations matching the original study population.

2. Uncertainties Associated With Ozone and Particulate Matter Concentrations

- Responsiveness of the models to changes in precursor emissions resulting from the control policy.
- Projections of future levels of precursor emissions, especially ammonia and crustal materials.
- Model chemistry for the formation of ambient nitrate concentrations.
- Lack of ozone monitors in rural areas requires extrapolation of observed ozone data from urban to rural areas.
- Use of separate air quality models for ozone and PM does not allow for a fully integrated analysis of pollutants and their interactions.
- Full ozone season air quality distributions are extrapolated from a limited number of simulation days.
- Comparison of model predictions of particulate nitrate with observed rural monitored nitrate levels indicates that REMSAD overpredicts nitrate in some parts of the Eastern US and underpredicts nitrate in parts of the Western US.

3. Uncertainties Associated with PM Mortality Risk

- No scientific literature supporting a direct biological mechanism for observed epidemiological evidence.
- Direct causal agents within the complex mixture of PM have not been identified.
- The extent to which adverse health effects are associated with low level exposures that occur many times in the year versus peak exposures.
- The extent to which effects reported in the long-term exposure studies are associated with historically higher levels of PM rather than the levels occurring during the period of study.
- Reliability of the limited ambient $PM_{2.5}$ monitoring data in reflecting actual $PM_{2.5}$ exposures.

4. Uncertainties Associated With Possible Lagged Effects

- The portion of the PM-related long-term exposure mortality effects associated with changes in annual PM levels would occur in a single year is uncertain as well as the portion that might occur in subsequent years.

5. Uncertainties Associated With Baseline Incidence Rates

- Some baseline incidence rates are not location-specific (e.g., those taken from studies) and may therefore not accurately represent the actual location-specific rates.
- Current baseline incidence rates may not approximate well baseline incidence rates in 2030.
- Projected population and demographics may not represent well future-year population and demographics.

6. Uncertainties Associated With Economic Valuation

- Unit dollar values associated with health and welfare endpoints are only estimates of mean WTP and therefore have uncertainty surrounding them.
- Mean WTP (in constant dollars) for each type of risk reduction may differ from current estimates due to differences in income or other factors.
- Future markets for agricultural products are uncertain.

7. Uncertainties Associated With Aggregation of Monetized Benefits

- Health and welfare benefits estimates are limited to the available C-R functions. Thus, unquantified or unmonetized benefits are not included.

Note: This is a reproduction of Table 13, p. 53 in ***Technical Addendum: Methodologies for the Benefit Analysis of the Clear Skies Act of 2003***, September 2003, Environmental Protection Agency.

E.4 Global Warming and CO_2 Emissions

So much about global warming and its relationship to CO_2 emissions is unknown that providing a reasonable estimate of the costs of CO_2 emissions is not possible. The sequence of models shown in Figure 1 is not sufficient to analyze global warming and estimate its costs. The inability to measure and estimate the impact CO_2 emissions on global climate does not mean that this impact does not exit.

The basic hierarchy of knowledge of CO_2 emissions and global warming begins with the nearly universal scientific agreement that climate change is taking place. A slightly smaller percentage of scientists think that CO_2 emissions are playing a role in climate change. The relative importance of the role of CO_2 emissions is further in dispute. The mechanism or mechanisms involved in causing the climate change are the source of both serious study and debate. How CO_2 emissions will affect the global climate can only be guessed at this point in time. The local impact of climate change, for example what will happen in Kansas, is well beyond the science of today. Without an estimate of climate change in Kansas it is impossible to give any estimate of the economic consequences of CO_2 emissions in Kansas.

Appendix F: Wind Generation in Organized Wholesale Markets

Regional wholesale power markets may provide opportunities for the sale of wind generation output. The Southwest Power Pool (SPP) Energy Imbalance Service (EIS), when implemented, will be a market for balancing energy, but more generally, the EIS will function as a real-time spot power market serving the SPP regional footprint. The market is currently scheduled for implementation on February 1st, 2007. Since the EIS will be an organized market, certain rules and requirements will apply to generation that bids to supply the market.

Generation will bid into the EIS, and when economic, SPP will dispatch generation to supply the market. Being dispatched by SPP, generators will be expected to follow the SPP dispatch signal. Generators will be required to achieve instructed ramp rates and maintain output at instructed set points. Section 8.5 of the SPP Market Protocols specifies that generation resources will be required to operate within a defined operating tolerance. Any difference between the SPP dispatch signal and the real-time operating level will be identified as Uninstructed Deviation. Resources that operate outside of their operating tolerance will be assessed Uninstructed Deviation Penalties.

Being an intermittent resource, wind generation is not dispatch-able; that is, wind generation cannot maintain specific ramp rates or output set points. This being the case, Uninstructed Deviation Penalties would make participation in the EIS market un-economic for intermittent resources. However, so as not to impede the development of the wind industry, the EIS market design includes an exemption from uninstructed penalties for intermittent resources. Wind generation will be allowed to bid into the market as an intermittent resource. Intermittent resources will be assigned minimum and

maximum operating limits and zero ramp rates, and the SPP dispatch signal will equal the operating level of the resource at the time calculations for the dispatch interval are performed. It is expected that intermittent resources will deviate from their dispatch signal, and therefore, they will not be subject to Uninstructed Deviation Penalties.

Opportunities to bid intermittent generation into the market will be limited to generation classified as designated resources. For example, a utility-owned wind facility could be designated as a resource and could be bid to supply the market. However, wind power obtained through purchase power agreements could not be designated as a resource and therefore could not be bid into the market. In general, opportunities to supply the EIS market will be limited to those resources that are owned or leased and are available for dispatch.

Appendix G: Cost Comparison of Wind Options: Build vs. Buy

G.1 Introduction

One of the most important results of our research is the establishment of the economic superiority, from a ratepayer's cost of service perspective, of a non-regulated developer owning and operating a wind farm rather than a regulated utility owning and operating a wind farm. This appendix focuses on how the developer and the regulated utility treat the identical costs of installation and equipment differently and how this difference affects the ratepayer.

Below is an outline of the rest of this appendix.

1) **Regulated Utility vs. Regulated Utility and Developer**

2) **Comparison of Regulated Utility and Developer Costs**

3) **Accelerated Depreciation**

    a) Regulated Utility Owning and Operating Investment
    b) Developer Owning and Operating Investment
    c) Variable Discount Rate Because of the Developer's Capital Structure

4) **Two Stage Solution to the Developer Owned Wind Farm Problem**

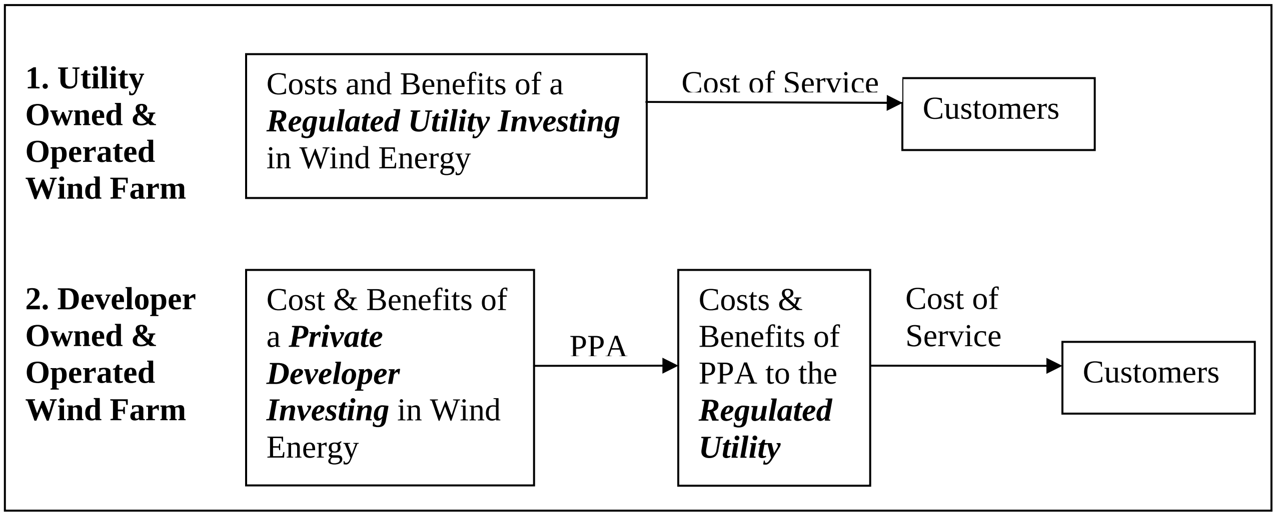
5) **Systematic Calculation of the Developer's Advantage**

    a) Capital Structure
    b) Regulatory Treatment of Investment
        i) Return on Rate Base and Depreciation
        ii) Accelerated Depreciation
        iii) Regulatory Lag

6) **Cost Advantage for the Developer**
    a) Total NPV Advantage for the Developer
    b) Per Unit of Electricity Advantage for the Developer

7) **Conclusions**

G.2 Regulated Utility vs. Regulated Utility and Developer
Because we modeled investment from the point of view of cost of service, the analysis flows through the utility to the utility's customers, with the customers' NPV determining the viability of the investment. The analysis flows through the utility to the customer even in the case of the developer owned and operated wind farm where the analysis starts with the private development of the wind farm and the sale of the wind energy generated through a purchase power agreement (PPA) to a regulated utility. The difference between a regulated utility and a developer owned and operated wind farm is illustrated below.



G.3 Comparison of Regulated Utility and Developer Costs
What is unique about investments with a regulated utility is the regulation. Regulators want utilities to:

1. Meet customer demand
2. With reliable service
3. At least cost while
4. Allowing utility investors a fair market return on their investment.

Regulators determine the appropriate return on plant and equipment investment through rate of return on ratebase regulation. The costs for a regulated utility and a developer are the same except that the utility internalizes the integration costs while the developer passes the integration costs on to the utility. The shaded cells in Table 1 below represent the difference between return on ratebase and standard private sector investment.

Inspection of Table 1 results in at least four observations.

- The two cost differences between a regulated utility and a developer owning and operating an investment are:
    1. Installation and equipment costs and
    2. Integration costs.

- Whether the regulated utility owns the wind farm or signs a PPA, the benefits are avoided costs while the benefits for the developer are the revenue generated by the PPA.

- Tax benefits are the same for the regulated utility and the developer; however, the needs to have a profitable partner or parent company that can effectively use the tax benefits are unique for the developer.

- The utility's decision becomes simpler when it allows the developer to own and operated the wind farm – costs are the PPA and integration costs and the tax benefits stay with the developer.

Table G.1
Costs and Benefits of a Wind Investment

Regulated Utility (Cost of Service)		**Developer (Profit)**
Utility Owning and Operating Wind Farm	**Utility Purchasing Wind Energy from Developer**	**Developer Owning and Operating Wind Farm**
Costs (Expenses)	***Costs (Expenses)***	***Costs***
Depreciation Return on Rate Base Land Lease In-lieu-of Property Tax Payment O&M Costs Integration Costs	Purchase Power Contract Integration Costs	Equity Payment (1^{st} year) Debt Payment (1^{st} 10 years) Land Lease In-lieu-of Property Tax Payment O&M Costs
Benefits (Avoided Costs)	***Benefits (Avoided Costs)***	***Benefits (Revenue)***
Avoided Fuel Costs Avoided Investment Costs Avoided Pollution Costs	Avoided Fuel Costs	Purchase Power Contract
Tax Benefits	***Tax Benefits***	***Tax Benefits – sent to parent company***
Production Tax Credit Accelerated Depreciation		Production Tax Credit Accelerated Depreciation

G.4 Accelerated Depreciation

Accelerated depreciation is available to both regulated utilities and non-regulated developers of wind generation.[1] Because of the regulated treatment of investment, utility customers benefit more from the developer's use of accelerated depreciation. To see the developers' advantage, we will examine $10,000 wind investment as treated by a regulated utility and as treated by a non-regulated developer.

G.4.1 Regulated Utility Owning and Operating Investment

The example of a regulated utility owning and operating a $10,000 investment is illustrated in Table 2 below. Columns 2 and 4 of Table 2 have the annual book value and annual straight-line depreciation based on a 20 year life expectancy of the wind generation.

(1) $$\text{Book value}_{t+1} = \text{Book value}_t - \text{Depreciation}_t$$

Column 3 is book value with regulatory lag taken into account which becomes the rate base. Regulatory lag is the result of the time difference between rate cases. At each rate case the book value is set based upon depreciation from the previous rate case. We have assumed a four year lag between rate cases. Between rate cases, the rate base is unchanged and depreciation expense for the firm is the same every year. The depreciation the firm is allowed to expense every year as a revenue requirement is different than the accelerated depreciation the firm is allowed to take for tax purposes. Table 3 below has the annual depreciation amounts allowed for U.S. corporate income tax purposes. Returning to Table 2, column 5 is column 3 of Table 3 minus column 4 of Table 2. Column 6 of Table 3 is column 5 times the tax rate, or:

(2) $$\begin{pmatrix} \text{Tax value of} \\ \text{depreciation} \end{pmatrix} = \left[\begin{pmatrix} \text{Accelerated} \\ \text{depreciation} \end{pmatrix} - \begin{pmatrix} \text{Straight} - \text{line} \\ \text{depreciation} \end{pmatrix} \right] * \begin{pmatrix} \text{Tax} \\ \text{rate} \end{pmatrix}$$

The tax value of depreciation (column 6) is positive for the first six years while accelerated depreciation is taking place and then turns negative after all of the value of the investment has been depreciated. Column 6 sums to $0 although the listed numbers in the column to not add to zero due to rounding. The additional tax value of depreciation due to the accelerated depreciation must then be taken out of rate base or when it become negative it must be added back into the rate base. Because of regulatory lag, the tax value of depreciation is summed for the four years since the last rate case (column 7) and then subtracted from the rate base (column 3).

(3) $$\begin{matrix} \text{Tax adjustment} \\ \text{for rate base} \end{matrix} = \sum_{\substack{\text{year after last} \\ \text{rate case}}}^{\text{year rate case}} \begin{pmatrix} \text{Tax value of} \\ \text{depreciation} \end{pmatrix}_t$$

The rate base, column 3, is then used to calculate column 8: the return on rate base that the utility is allowed to earn. Two different rates of return are used. During the period the utility is paying taxes prior to depreciating all of the investment; the utility gets a tax adjusted rate of return to

[1]Economic Recovery Tax Act of 1982 (ERTA, P.L. 97-34); see Internal Revenue Code, subtitle A, Chapter 1, Subchapter B, Part VI, Section 168 (e)(3)(vi)(1994) – accelerated cost recovery.

reflect the tax benefit of interest payment. After the investment has been depreciated, the utility get the unadjusted rate of return post tax rate of return.

Table G.2
Regulatory Treatment of a $10,000 Investment

Year	Book Value	Rate Base	Regulated Depreciation	Accelerated Depreciation minus Regulated Depreciation	Tax Value of Depreciation	Adjustment for Rate Base	Return on Rate Base	
1	2	3	4	5	6	7	8	
1	$10,000	$10,000	$500	$1,500	$597		$863	
2	$9,500	$10,000	$500	$2,700	$1,074		$863	
3	$9,000	$10,000	$500	$1,420	$565		$863	
4	$8,500	$10,000	$500	$652	$259	$2,495	$863	Tax Adjusted RoR = 8.63%
5	$8,000	$5,505	$500	$652	$259		$475	
6	$7,500	$5,505	$500	$76	$30		$475	
7	$7,000	$5,505	$500	-$500	-$199		$475	
8	$6,500	$5,505	$500	-$500	-$199	-$108	$475	
9	$6,000	$6,108	$500	-$500	-$199		$371	
10	$5,500	$6,108	$500	-$500	-$199		$371	
11	$5,000	$6,108	$500	-$500	-$199		$371	
12	$4,500	$6,108	$500	-$500	-$199	-$796	$371	
13	$4,000	$4,796	$500	-$500	-$199		$291	
14	$3,500	$4,796	$500	-$500	-$199		$291	
15	$3,000	$4,796	$500	-$500	-$199		$291	Not Tax Adjusted RoR = 6.07%
16	$2,500	$4,796	$500	-$500	-$199	-$796	$291	
17	$2,000	$2,796	$500	-$500	-$199		$170	
18	$1,500	$2,796	$500	-$500	-$199		$170	
19	$1,000	$2,796	$500	-$500	-$199		$170	
20	$500	$2,796	$500	-$500	-$199		$170	

Table G.3
Accelerated Depreciation for a $10,000 Investment

Year	Depreciation Rate	Amount Depreciated Each Year
1	20.00%	$2,000
2	32.00%	$3,200
3	19.20%	$1,920
4	11.52%	$1,152
5	11.52%	$1,152
6	5.76%	$576
TOTAL	100.00%	$10,000

G.4.2 Developer Owning and Operating Investment

A developer owned and operated investment, illustrated in Table 4 below, is a standard capital budgeting problem explained in most mid-level finance textbooks. The developer pays $3,000 in period 0 and repays the debt in 10 years, the same time period as the production tax credit. The tax value of the accelerated depreciation is sent to a parent corporation where it offsets tax payments. The wind investment itself would probably not make enough money to be able to use this tax advantage during the first 10 years when it is still making debt payments. This is the reason that many wind farms are partially or completely owned by large, profitable companies that can put the two large tax breaks – accelerated depreciation and the production tax credit – to tax avoidance use.

Table G.4
Developer Accounting for a $10,000 Investment

	Debt Payments	Accelerated Depreciation	
Year	5.00%	Depreciation	Tax Value
1	-$907	$2,000	$796
2	-$907	$3,200	$1,273
3	-$907	$1,920	$764
4	-$907	$1,152	$458
5	-$907	$1,152	$458
6	-$907	$576	$229
7	-$907		
8	-$907		
9	-$907		
10	-$907		

G.4.3 Variable Discount Rate Because of the Developer's Capital Structure

Because the developer pays off its debt in 10 years, it has a changing capital structure which leads to a variable discount rate. Starting with a 5% interest rate and a 20% return on equity and a 70% debt and 30% equity capital structure, the initial discount rate is 9.5%. The formula is:

*Discount rate = percentage debt * interest rate + percentage equity * return on equity*

As the debt is paid off, the percentage of debt decreases and the percentage of equity increases which raises the discount rate. In 10 years, after all the debt is paid off, the discount rate is 20%.

G.5 Two Stage Solution to the Developer Owned Wind Farm Problem

Analyzing a developer owned and operated wind farm that sells its wind generated electricity to a regulated utility requires a change in our utility cost/benefit model. The addition of the developer makes the utility's problem simpler: the relevant variables are the purchased power price, the integration costs of the purchased power, and the utility's cost of conventional generation of electricity. The decision problem for the utility boils down to:

$$\begin{pmatrix} \text{Price of wind} \\ \text{Generated Electricity} \end{pmatrix} + \begin{pmatrix} \text{Integration} \\ \text{Costs} \end{pmatrix} < \begin{pmatrix} \text{Average Marginal Cost of} \\ \text{Conventional Generation} \end{pmatrix} \Rightarrow \begin{pmatrix} \text{Buy Wind} \\ \text{Generation} \end{pmatrix}$$

$$\begin{pmatrix} \text{Price of wind} \\ \text{Generated Electricity} \end{pmatrix} + \begin{pmatrix} \text{Integration} \\ \text{Costs} \end{pmatrix} > \begin{pmatrix} \text{Average Marginal Cost of} \\ \text{Conventional Generation} \end{pmatrix} \Rightarrow \begin{pmatrix} \text{Do Not Buy} \\ \text{Wind Generation} \end{pmatrix}$$

If wind generated electricity, including integration costs, is the same price as the marginal cost of generation, then the utility is indifferent between the buy and not buy choices. The important unknown for the utility is the price of the wind generated electricity.

To estimate price of wind energy, we created a model of an unregulated wind developer. Our assumptions were:

- The wind developer forms a Limited Liability Corporation (LLC) and has a partner with sufficient profits to use all of the tax subsidies involved in the building and operating of the wind farm,

- The LLC negotiates a Purchase Power Agreement (PPA) with a regulated utility where that utility agrees to purchase all wind power generated over the life of the wind farm at an agreed upon price that increases at the rate of inflation and the utility agrees to absorb the integration costs which are the same as in the utility model: $4.6 MWh,

- The LLC is able to borrow enough money for the construction of the wind farm at a 5% real interest rate that the LLC's capital structure is 70% debt and 30% equity,

- The LLC plans on receiving a 20% pre tax return on equity, and

- The LLC operates in a competitive environment – it is a price taker.

Given these assumptions, the wind investment problem becomes a two stage decision problem. The developer chooses the smallest PPA which makes its NPV = 0. Then the utility determines if the PPA plus the integration costs are greater than, less than or equal to the average marginal cost of conventional generation.

G.6 Systematic Calculation of the Developer's Advantage

G.6.1 Capital Structure

Regulated Kansas electrical utilities are constrained by a capital structure rule of thumb: about 50% equity and 50% debt. In our utility model, we have assumed 47.8% equity and 52.2% debt. The unregulated developers are not constrained by this rule of thumb. As a result we have assumed the developer uses 30% equity and 70% debt to pay for the investment.[2]

The higher debt to equity ratio (more leverage) increases the NPV for the developer and decreases the breakeven PPC as long as the developer is at least breaking even. The problem with leverage is that it works both ways, as, for example, the 1929 crash demonstrated. So as long as the developer is at least breaking even, leverage helps, but if the developer should loose money, then the losses also become leveraged.

The developer is assumed to have to pay a higher real interest rate than the regulated utility on money borrowed: 5.00% rather than 4.21%. The developer is also assumed to expect a higher pre-tax, real return on equity: 20.00% rather than 13.47%. The quantitative effect of the difference in capital structure is illustrated below in Table 5.

The Table 5 shows the effect of a two stage adjustment for the developer from the developer's capital structure to the regulated utility's capital structure.

1. The reduction in leverage raises the PPA and reduces the NPV.

2. The introduction of the utility's lower interest rate and lower return on capital reduce the rate of return which reduces the PPA and increases the NPV.

The net effect of the developer's capital structure is to reduce the PPA and the utility's NPV.

[2] The capital structure of wind farm investment varies, but the 70% debt/30% equity split seems reasonable. Mark Eilers from GE Wind in a September 13, 2005 presentation in Madison, South Dakota suggested that if the PTC can be monetized, then 70/30 is typical. The slides for the presentation can be found at the web site http://www.state.sd.us/puc/pucevents/RegWindConf05/Eilers.pdf. Another example is a presentation by Bill Sutherland, Vice President – Project Finance, April 20, 2006 at the AWEA's "Wind Project Finance & Investment Workshop" – describes equity/debt ratios from 50/50 to 17/83. However, in the two examples he uses the ratios are 23/77 and 24/76.

Table G.5

The Effect of Capital Structure on Purchase Power Agreement and Net Present Value			
	Base Case[1]	Change Leverage Ratio[2]	Change Leverage Ratio and Rate of Return[3]
Purchase Power Agreement $/MWh	$32.04	$37.52	$34.52
NPV in millions of $	-$181	-$267	-$220

[1]Base Case is 70% debt, 30% equity, 5% interest rate, and 20% return on equity for the Developer selling wind energy to the State Average Utility
[2]52.2% debt and 47.8% equity
[3]4.21% interest rate and 13.47% return on equity

G.6.2 Regulatory Treatment of Investment

G.6.2.1 Rate of Return Regulation: Return on Rate Base and Depreciation

For the utility consumer, putting a wind farm in rate base is more costly than having the developer sell the energy to the regulated utility through a PPA. The reason putting the wind farm in rate base is costly is because rate of return regulation allows the utility to earn a return on rate base and to depreciate the investment over the expected lifetime of the investment. If the wind farm is developer owned and operated with a PPA, then the utility only recovers the cost of the PPA – it does not get a rate of return on the PPA.

If the rest of the investment problem is the same for the utility and the developer – no regulatory lag, same capital structure, straight-line depreciation, etc., and if a utility capital structure is used, 50% debt, 50% equity, and 8.6% rate of return, then the NPV cost advantage for a developer for a 150 MW wind farm is $18 million. If the developer's capital structure is used, 70% debt, 30% equity, and 9.5% rate of return, then the cost advantage increases to $50 million in NPV.

G.6.2.2 Accelerated Depreciation

Regulated treatment of accelerated depreciation shares the benefits between the utility and its customers in a convoluted way that only accountants could love. For the developer, the accelerated depreciation is much simpler – it is a reduction in cost, and because we assume that the PPA is determined by cost, the cost reduction is fully passed on to consumers.

To give an indication of the effect of the difference, we compare developer and utility NPVs with straight-line depreciation and with accelerated depreciation. When the State Average Utility changes from straight-line depreciation to accelerated depreciation the NPV drops from -$494 million to -$466 million. If the developer selling to the State Average Utility makes the same change, then utility's NPV drops from -$312 million to -$181 million. The difference to the consumer is the difference between a reduction in NPV of -$28 million for the utility and a reduction in NPV of -$131 million for the utility when it just buys the energy from a developer.

Another indication of the impact of accelerated depreciation on the developer is that the PPA drops from $40.36 to $32.04 per MWh – for the consumer this is 0.832¢ per kWh.

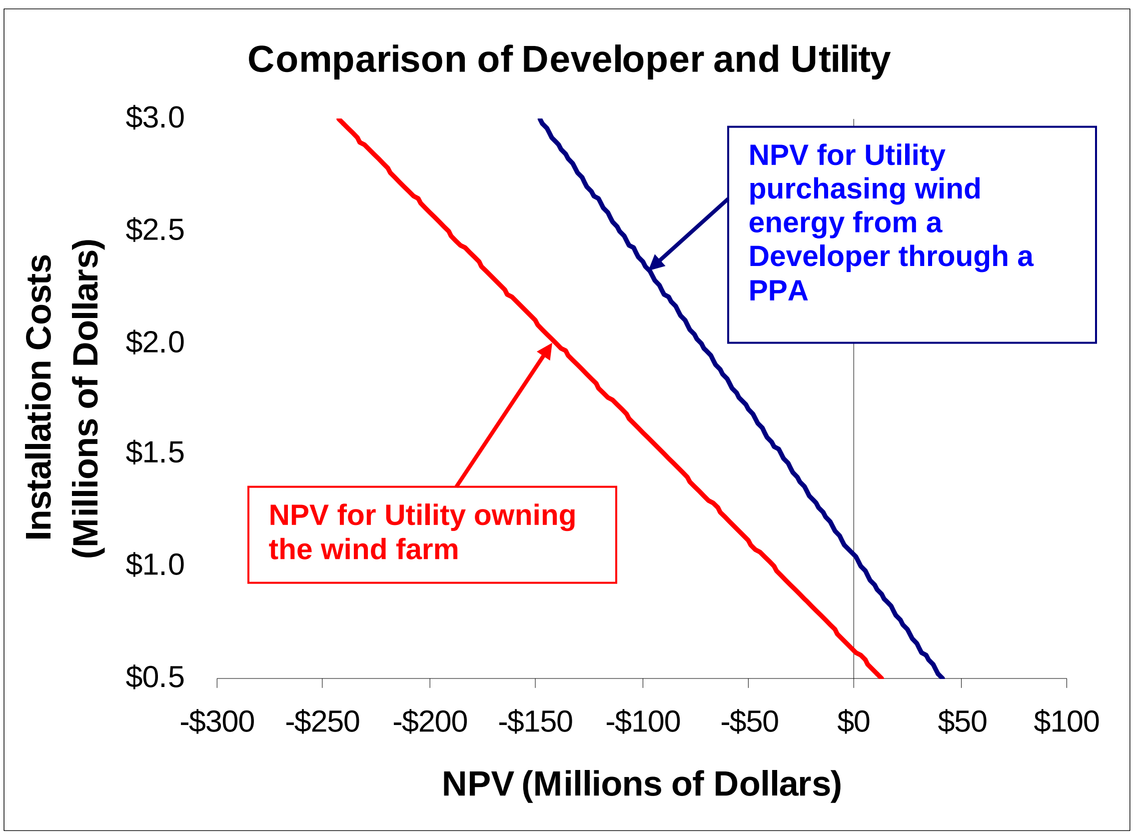
G.6.2.3 Regulatory Lag

Regulatory lag is created by the interim between rate cases. In our models we have assumed a regulatory lag of four years, but in real life these lags can shorter or extend much longer. In 2006, Kansas City Power and Light had their first full rate case since 1987. To give some quantitative illustration of the effect of regulatory lag, consider that our State Average Utility's NPV without regulatory lag but with accelerated depreciation was -$439, and with regulatory lag and with accelerated depreciation NPV declined to -$466.

G.7 Cost Advantage for the Developer

The graph below (Figure G.1) illustrates the cost advantage for the ratepayer of having the utility purchase the wind energy from a developer rather own the wind farm. The NPV paths for both the utility owning the wind farm and for the utility purchasing the wind energy from a developer were generated by incrementally increasing the wind turbine installation costs and calculating the NPVs for both business structures.

Figure G.1



G.7.1 Total NPV Advantage for the Developer

The graph above illustrates two aspects of the comparison between utility ownership of wind farms and utility purchase of energy from a developer through a PPA.

1. The purchase of the wind energy from a developer through a PPA is always cheaper for the ratepayer, and

2. The difference between the NPVs for the different business structures increases as installation costs increase.

The wind farm model used to generate Figure G.1 is the update (as of January 2008) Average Utility with a capacity of 100 MW. The difference between the two NPVs is $28.2 million with installation costs at $0.5 million per MW and increases to $94.4 million when installation costs increase to $3.0 million per MW. The best measure of the cost difference between the two business structures is the comparison of NPVs, but it is also difficult to translate this difference meaningfully into the effect on rates.

G.7.2 Per Unit of Electricity Cost Advantage for the Developer

A per unit comparison of electricity can be done by manipulating the cost of pollution concept which we will call the Cost of Pollution metric. The internal avoided costs are the same for the utility whether it buys the wind energy from a developer or whether it owns the wind farm. In the models of both business structures we solve for the level of pollution costs necessary to cause the NPV to go to zero. These pollution costs are the additional per unit net benefits necessary to make the NPV = 0.

Subtracting the pollution costs which drive the NPVs in their respective business structure models to zero gives the Cost of Pollution metric. The Cost of Pollution metric calculates the per unit benefit difference between the two business structures. In addition, since the NPV is set equal to zero, benefits must equal costs, so the difference in per unit benefits between the business structures must also be the difference in per unit costs between the business structures. Thus, the Cost of Pollution metric is both a measure of the difference in per unit benefits and costs.

The Cost of Pollution metric, like the NPV, increases as costs increase. When installation costs are $500,000 per MW, the difference is only $8.53 per MWh. Installation costs of $1,500,000 per MW drive the difference in pollution costs to $17.89 per MWh. Installation costs of $2,000,000, a little below the current level, result in pollution cost differences of $22.56 per MWh. Finally, installation costs of $3,000,000 cause the difference in pollution costs to expand to $31.91 MWh.

G.8 Conclusions

Comparing the utility-owned and operated wind farm with the developer-owned and operated wind farm selling the wind energy to the utility through a purchase power agreement leads to the following conclusions:

- **From a utility customer point of view, the wind developer can sell the electricity significantly cheaper than the utility can generate it on its own.**
- **This conclusion holds true for all four types of utilities that we have analyzed.**
- **The developer's cost advantage is substantial and increases as the cost of the wind farm increases.**

These three conclusions stem from the institutional setting that the investments are assumed to take place. The developer has advantages in potential capital structure and in the investment accounting that is used. These conclusions can be summarized simply as:

- **Because of the institutional setting, the developer business structure is better for utility customers than the utility owning and operating a wind farm.**

Appendix H: NPV Sensitivity Analysis: Coefficient of Variation

H.1 Introduction

The Monte Carlo Analysis provides a broad sensitivity analysis of the wind models. This analysis recognizes the difficulty of providing a particular numerical forecast (a point forecast) for a variable input. In this study, the difficulty is magnified because up to seven input variables are involved and the forecast horizon stretches out to the year 2034. The Monte Carlo Analysis provides a probabilistic forecast of NPV given probabilistic forecasts of the variable inputs.

A second type of traditional sensitivity analysis estimates the impact of a change in one particular variable, holding all other variables fixed, on the model output. For example, suppose that installation costs increase 10%, what is the impact of this change alone on NPV? This example is based on the standard point forecast: a single numerical estimate of the variable and a single numerical estimate of the NPV. Because we think the Monte Carlo Analysis is superior to point forecasts, we have emphasized the Monte Carlo Analysis. However, this decision precludes the use of the second type of traditional sensitivity analysis. In order to estimate the influence of individual variable inputs on model outputs, we needed a method of summarizing probability distributions. Our choice has been to use the Coefficient of Variation.[1]

H.2 Coefficient of Variation (CoV)

Outline of the rest of this appendix.

1. Definition and Explanation
2. Ratio of Coefficients of Variation
3. The Relevant Models for Analysis
4. Results
5. Guide to Interpretation
6. Conclusions and Explanations

    - *The most influential input variables are installation costs and capacity factor.*
    - *Operations and maintenance and capacity factor degradation, in relative terms, have about the same secondary effect in all five models.*
    - *The impact of changes in fuel mix and natural gas prices depends heavily upon the mean or median fuel mix of the utility under analysis.*
    - *The rate of return has a complex and ambiguous impact on NPV.*

[1] The Coefficient of Variation is sometimes referred to as the unitized risk measure.

H.2.1 Definition and Explanation

The CoV is a measure of the dispersion a probability distribution. It is calculated by taking the absolute value of the ratio of the standard deviation to the mean:

$$Coefficient\ of\ Variation = \left|\frac{\sigma}{\mu}\right|.$$

Dividing the standard deviation by the mean of the same distribution standardizes the standard deviation and creates a dimensionless number[2] that allows comparison of the dispersion of different distributions. For example suppose that a researcher wanted to compare distribution with a mean of 500 and standard deviation of 25 and another distribution with a mean 5 and a standard deviation of 1. Although the distribution with the standard deviation of 25 looks like it has more dispersion, in fact in relative terms, the distribution with the standard deviation of 1 has more relative dispersion: 0.20 to 0.05.

$$Coefficient\ of\ Variation\ = \frac{25}{500} = 0.05 < \frac{1}{5} = 0.20$$

H.2.2 Ratio of Coefficients of Variation

Our purpose in this appendix is to mimic as much as possible the tradition sensitivity analysis of changing the value of a variable input and calculating change on the model output. The CoV allows us to collapse the information in a probability distribution down to a single number.

Specifically what we have done is to:

1. Hold all variables except one as fixed at a point value (the mean of their distribution),
2. For the remaining variable, the input variable probability distribution is used,
3. The Monte Carlo technique is used to produces a distribution for the model output,
4. The CoVs for both the input variable and the model output are calculated, and
5. The ratio of the CoV for the output over the CoV of the input variable is calculated.

$$Ratio\ of\ Coefficients\ of\ Variation = \frac{\frac{\sigma_{Output}}{\mu_{Output}}}{\frac{\sigma_{input}}{\mu_{input}}}$$

The ratio of CoVs was used to estimate the influence of the input distribution on the NPV distribution. Since the CoVs are a measure of dispersion, we are equating the dispersion of the model output caused by the variable input divided by the dispersion of the variable input as a measure of influence of the input on the output. An advantage of the ratio of CoVs is that it allows for comparison when different units are used. For example, capacity factor is in percentage between 30% and 50% while installation costs varied by hundreds of thousands of dollars.

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[2] Dimensionless means that there are no units attached to the CoV such as meters, dollars, or years. To make the CoV a percentage all that needs to be done is multiply by 100 and add a percentage sign.

H.2.3 Relevant Models for Analysis

We have used 32 basic models in our analysis of wind energy. We started with the four basic utility models – State Average Utility, Westar/KCPL, Intermediate Utility, and WestPlains, and assumed each was a statewide utility that would build the necessary wind capacity to move the state from its 2005 level of wind capacity (263.5 MW) to the Governor's Challenge of 1000 MW of capacity by 2015. First we calculated the NPV of the 736.5 MW of additional capacity necessary to meet the challenge. Next we added a model of the existing wind farms in Kansas – Gray County Wind Farm and Elk River Wind Farm – to the 736.5 MW models to provide the NPV of the full challenge. Then we changed the ownership structure of the wind farms and assumed that they were owned by developers who sold the electricity generated by the wind farms to the four different types of statewide utilities through a Purchased Power Agreement (PPA). This gives a total of 16 models. We added a cost of pollution estimate to each of these models to estimate the Net Social Benefit (NSB) of wind energy. That gives 32 models.

Because of the policy question asked, the parallel structure among some models, and the linear relationship among other models, we only needed to calculate the CoV ratios for five models to cover all the policy variations. We do not need to investigate the existing wind farms because in terms of future investment they are irrelevant. The Developer Owned Model is the same for each of the utilities, and thus needs only be examined once. The NSB models are simply linear extensions of the NPV models and do not change the relative effect of the inputs on output. This leaves five basic models for the ratio of CoV analysis: the four statewide basic utility models and the Developer Owned Wind Farm Model.

H.2.4 Results

The ratios of the CoVs are summarized in Table H.1 below.

For the four models of utility types, the model output is NPV and there are seven variable inputs: fuel mix, natural gas prices, capacity factor, capacity factor degradation, installation costs, rate of return, and O&M costs.

For the developer model, the output is the price of the Purchase Power Agreement and only four variable inputs are relevant: capacity factor, capacity factor degradation, installation costs, and O&M costs.

Table H.1

Ratio of Coefficients of Variation[1] for Input Variables in the Models

Wind Model	Fuel Mix	Natural Gas Prices	Capacity Factor	Capacity Factor Degradation	Installation Costs	Rate of Return	Operations and Maintenance
State Average	0.136	0.095	0.789	0.049	1.764	0.032	0.385
Intermediate Utility	0.258	0.186	1.293	0.077	2.263	0.231	0.493
Westar	0.087	0.050	0.536	0.034	1.515	0.162	0.331
WestPlains	1.201	0.363	1.961	0.117	2.917	0.600	0.635
Developer Owned Wind Farm	None	None	1.268	0.031	1.187	None	0.321

[1]

$$\textit{Ratio of Coefficients of Variation} = \frac{\dfrac{\sigma_{NPV}}{\mu_{NPV}}}{\dfrac{\sigma_{input}}{\mu_{input}}} \quad \textit{or for the Developer} = \frac{\dfrac{\sigma_{PPA}}{\mu_{PPA}}}{\dfrac{\sigma_{Input}}{\mu_{Input}}}$$

H.2.5 Guide to Interpretation

There are three aspects of the ratio of CoVs that help interpretation:

- The higher the ratio of CoVs, the more influence a change in the particular input has on the model output.
- The absolute size of the CoV is not as important as its relative value for its utility type.
- A comparison absolute size of ratio values between utility types has little usefulness.

H.2.6 Conclusions and Explanations

The seven input variables in the models will be discussed in pairs except for the rate of return. First we give a basic statement about the relative importance of input variable and then explain why it has the effect it does. We begin with the most influential input variables – installation costs and capacity factor – and end with the most ambiguous input variable – rate of return.

The most influential input variables are installation costs and capacity factor.—The input variables in the four utility models that have the greatest effect on NPV are first the installation costs and second the capacity factor. A small change in installation costs – an increase from $1.6 million to 1.7 million per MW of capacity – has a major impact: decreasing NPV from -$468 million to -$520 million. A change from $1.2 million per MW of capacity as was assumed a few years back to $2.0 million which may soon be the case in Texas causes NPV to decline from -$262 million to -$675 million. Capacity factor has a smaller but still significant effect on NPV. A change from a 35% to a 45% capacity factor leads to an increase in NPV from -$515 million to -$422 million. These two inputs should be important because installation costs dominate a wind farm's cost and capacity factor measures a wind farm's productivity.

With the developer owning the wind farm, capacity factor and installation costs remain the most influential inputs; however, capacity factor is slightly more influential than installation costs. This stems from accounting differences between a private developer and a regulated utility. Since a developer has no return on rate base, the installation costs have less influence.

Operations and maintenance (O&M) and capacity factor degradation, in relative terms, have a secondary effect in all five models.—In the case O&M and capacity factor degradation, our models look at the impact of small changes in variable values on NPV and find relatively small changes as Table H.1 indicates. On the other hand, if a relatively large change in these variables took place, the result would be a relatively large change in NPV. Changing from a 1% decline in capacity factor to a 3% decline results in a reduction in NPV from -$468 million to -$509 million – a $41 million reduction in NPV. An increase in O&M costs from $9.00 per MWh to $12.00 per MWh results in a decline in NPV from -$468 million to -$528 million – a $60 million reduction in NPV.[3]

The impact of changes in fuel mix and natural gas prices depends heavily upon the mean or median fuel mix of the utility under analysis.—For utilities that use more natural gas, changes in both fuel mix and changes in natural gas prices have more effect.[4] We illustrate this by

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[3] In our models, capacity factor degradation is limited to the last 17 years of operation with the median decline only 1% per year – over 20 years the capacity factor is reduced from 40% to 33.7%. However, we have found several examples of capacity factors falling far more than this amount in a few years: the decline in the capacity factor using Energy Information Administration data for the Gray County Wind Farm has been more of the order of 4% to 5% per year. Our models have O&M costs increasing at a rate of 2.5% a year from about $9.00 per MWh the first year. However, in a presentation before the Kansas Senate Utilities Committee, Westar used an estimate of $12.13 per MWh for combined fixed and variable O&M. John Olsen, "Long-Term Power Supply," Presentation to the Kansas Senate Utilities Committee, Executive Director, Power Marketing, February 1, 2005, slide 11.

[4] Fuel mix is the percentage of electricity generated by natural gas or petroleum and was calculated based on 2000-2005 FERC 1 forms for the three utility types and by EIA fuel use data for 2000-2004 for the State Average Utility. Natural gas price is the forecasted price of natural gas in our model and serves as a proxy for both natural gas prices and petroleum prices. Although in the short-run natural gas prices and petroleum prices might move in opposite directions, in the long-run the prices move together. "We find a cointegrating relationship relating Henry Hub prices to the WTI and trend capturing the relative demand and supply effects over the 1989-through-2005 period. The dynamics of the relationship suggest a 1-month temporary shock to the WTI of 20 percent has a 5-percent contemporaneous impact on natural gas prices, but is dissipated to 2 percent in 2 months. A permanent shock of 20 percent in the WTI leads to a 16 percent increase in the Henry Hub price 1 year out all else equal." Jose A. Villar and Fredrick L. Joutz, "The Relationship Between Crude Oil and Natural Gas Prices," Energy Information Administration, Office of Oil and Gas, (October 2006): from the abstract.

comparing fuel mix values provided in Table H.2 with normalized ratios of CoVs provided in Table H.3. The ratios of CoVs are normalized by adding the row for each type of utility and then dividing by that total. The normalization shows the relative influence of each input on NPV. Inspection of Tables H.2 and H.3 indicate a close similarity between a utility's fuel mix and its ratios of CoVs for both fuel mix and natural gas price. This is demonstrated in Table H.4 where the relative ranks of each utility type for mean fuel mix and ratios of coefficients of variation for fuel mix and natural gas price are compared. This is because a change in either fuel mix or natural gas price directly affects the avoided average fuel cost which directly affects the average marginal cost which is the major avoid cost of using wind generation. Changes in either fuel mix or natural gas prices have a direct, proportional effect on NPV; thus, the larger the fuel mix; the greater the impact on NPV.

However, fuel mix is still not of primary importance. Even in the case of WestPlains which has a fuel mix four times higher than the next highest utility and five times higher than the State Average Utility, fuel mix is still a distant third in influence compared to installation costs and capacity factor. Further down the list of influence is natural gas price change because for natural gas prices to influence NPV they must first go through the fuel mix.

Table H.2

Fuel Mix Values by Utility Type[1]

Wind Model	Mean	Median	Standard Deviation
State Average	4.23%	4.00%	1.24
Intermediate Utility	5.16%	5.00%	1.11
Westar	2.52%	2.42%	0.93
WestPlains	22.77%	22.18%	6.84

[1] The fuel mix values for mean and median represent the percentage of electricity generated by natural gas or petroleum. These values were calculated based on FERC 1 forms for 2000-2005 for the three utility types and by EIA fuel use data for 2000-2004 for the State Average Utility. The reason the means are always greater than the medians is because all fuel mix probability distribution functions are skewed toward higher fuel mixes.

Table H.3

Normalized Ratio of Coefficients of Variation[1]

Wind Model	Fuel Mix	Natural Gas Prices	Capacity Factor	Capacity Factor Degradation	Installation Costs	Rate of Return	Operations and Maintenance
State Average	0.042	0.029	0.243	0.015	0.543	0.010	0.119
Intermediate Utility	0.054	0.039	0.269	0.016	0.471	0.048	0.103
Westar	0.032	0.019	0.197	0.013	0.558	0.060	0.122
WestPlains	0.154	0.047	0.252	0.015	0.374	0.077	0.081

[1] The ratios of coefficients of variation are normalized by adding the row for each type of utility and then dividing by that total. The result is that each row of ratio of coefficients of variation adds to 1.00. The normalization helps to show the relative influence of each input on NPV.

Table H.4

Rank of Coefficients of Variation Relative to Fuel Mix Mean[1]

Wind Model	Relative Rank of Fuel Mix Mean	Relative Rank of the Ratio of Coefficients of Variation	
		Fuel Mix	Natural Gas Price
State Average	**3rd**	**3rd**	**3rd**
Intermediate Utility	**2nd**	**2nd**	**2nd**
Westar	**4th**	**4th**	**4th**
WestPlains	**1st**	**1st**	**1st**

[1] Ranks are based on Tables H.2 and H.3.

The rate of return has a complex and ambiguous impact on NPV.—The impact of rate of return is more complex than the other input variables because it plays two non-linear roles for utilities – rate of return for rate base and discount rate for NPV – which have opposite effects. The matter is further complicated by the fact that the relative size of these impacts is dependent upon the negative size of the NPV. The ambiguity created by the two clashing roles of the rate in return is illustrated in Table H.5 below.

Table H.5

The Ambiguous Effect of Changes in the Rate of Return on NPV

	Net Present Value	
Deterministic Wind Model	Rate of Return = 7.6%	Rate of Return = 9.6%
Westar	-$553.7	-$533.6
State Average	-$466.9	-$464.1
Intermediate Utility	-$351.0	-$371.2
WestPlains	-$258.0	$298.0
Neutral Utility[1]	$452.5	$452.5

[1] The influence of rate of return on return on rate base is countered by the influence of rate of return as the discount rate for NPV.

The effect of increasing the rate of return from 7.6% to 9.6 increases Westar's NPV by $20.1 million while decreasing the Intermediate Utility's NPV by $20.2 million. Since the rate base is the same in both cases, changing the rate of return only changes the discount rate. Because Westar starts with a larger negative NPV than the Intermediate Utility, the discount rate has more effect. Using this logic suggest that WestPlains should have an even greater decline in NPV that the Intermediate Utility and Table H.5 confirms this logic. This also explains why WestPlains has the highest normalized ratio of CoV for rate of return in Table H.3.

Intuition suggests that between Westar and the Intermediate Utility there is a case where a change in the rate of return has no effect. The last line in Table H.5, labeled Neutral Utility is that case. This explains why in the table of normalized ratios of CoVs (Table H.3) the value for the State Average is so much lower than the other utilities.

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