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Issue(s):	IRP Rule Compliance
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Case No.:	EO-2011-0271

REBUTTAL TESTIMONY

OF

TIM WOOLF

Submitted on Behalf of
the Office of the Public Counsel

UNION ELECTRIC COMPANY D/B/A AMEREN MISSOURI

Case No. EO-2011-0271

October 28, 2011

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title and employer.

A. My name is Tim Woolf. I am a Vice-President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning and analysis. Our work covers a range of issues including integrated resource planning; economic and technical assessments of energy resources; electricity market modeling and assessment; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a variety of clients, with an emphasis on consumer advocates, regulatory commissions, and environmental advocates.

Q. Please summarize your professional and educational experience.

A. Before joining Synapse Energy Economics, I was a commissioner at the Massachusetts Department of Public Utilities (DPU). In that capacity I was responsible for overseeing a significant expansion of clean energy policies, including an aggressive increase in ratepayer-funded energy efficiency programs; the implementation of decoupled rates for electric and gas companies; an update of the DPU energy efficiency guidelines; the promulgation of net metering regulations; review of smart grid pilot programs; and review of long-term contracts for renewable power.

Prior to being a commissioner at the Massachusetts DPU, I was employed as the Vice President at Synapse Energy Economics; a Manager at Tellus Institute; the Research Director of the Association for the Conservation of Energy; a Staff Economist at the Massachusetts Department of Public Utilities; and a Policy Analyst at the Massachusetts Executive Office of Energy Resources.

I hold a Masters in Business Administration from Boston University, a Diploma in Economics from the London School of Economics, a BS in Mechanical Engineering and a BA in English from Tufts University.

Q. Please describe your professional experience as it relates to energy efficiency policies and programs.

A. Energy efficiency policies and programs have been at the core of my professional career. While at the Massachusetts DPU I played a leading role in updating the Department's energy efficiency guidelines, in reviewing and approving the recent three-year energy efficiency plans, in reviewing and approving energy efficiency annual reports, in leading a working group on rate and bill impacts, and advocating for allowing energy efficiency to participate in the New England wholesale electricity market. I served as a co-chair of the Working Group on Utility Motivation as part of the State Energy Efficiency Action Network sponsored by the US Department of Energy and the US Environmental Protection Agency.

As a consultant I have reviewed and critiqued utility energy efficiency policies and programs throughout the US, and I have testified on these issues in British Columbia, Colorado, Delaware, Massachusetts, Minnesota, Nevada, Nova Scotia, Québec, and Rhode Island. My work has encompassed all aspects of energy efficiency program design and implementation, including efficiency measure assessment, program delivery options, program budgeting, cost-benefit analyses, avoided costs, utility performance incentives and other relevant regulatory policies. I have represented clients on several energy efficiency collaboratives, where policies and programs were discussed among a variety of stakeholders. Additional information is provided in my resume, attached to this testimony.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Office of Public Counsel (OPC).

Q. Is the Office of the Public Counsel sponsoring other witnesses in this docket?

A. Yes, my colleague at Synapse Energy Economics, Dr. Vitolo, is sponsoring testimony on behalf of the OPC. In addition, Ryan Kind is sponsoring testimony

on behalf of the OPC. Mr. Kind, Dr. Vitolo and I have collaborated closely in preparing our testimonies.

Q. What is the purpose of your testimony?

A. On June 23, 2011 the OPC filed a *Review of Union Electric Company's Electric Resource Planning Compliance Filing*, Case No. EO-2011-0271 (OPC Review). That review identified several significant deficiencies with the Union Electric (UE or the Company) Integrated Resource Plan (IRP), and recommended that the Company correct for these deficiencies and conduct its analysis again to select a more appropriate Preferred Resource Plan and Resource Acquisition Strategy. That OPC review was accompanied by a technical report entitled, *Review of the Union Electric Company Integrated Resource Plan* (OPC Technical Report), authored by Mr. Kind, Dr. Vitolo and myself. On August 22, 2011 UE filed a *Response to Comments of Parties* (Response), including responses to the issues raised by the OPC.

The purpose of my testimony is to rebut the UE Response. In my testimony I focus on those topics that I was primarily responsible for addressing in the OPC Technical Report, including: analysis of demand-side resources, analysis of existing coal facilities, assumptions regarding new nuclear generation options, and assumptions regarding new wind resources.

Q. How is your testimony organized?

A. My testimony is organized as follows:

1. Introduction and Qualifications.
2. Summary of Conclusions and Recommendations.
3. Analysis of Demand-Side Resources.
4. Analysis of Existing Coal Facilities.
5. Assumptions Regarding New Nuclear Facilities.
6. Assumptions Regarding New Wind Resources.

2. SUMMARY OF CONCLUSIONS

Q. Please summarize your primary conclusions.

A. In sum, I find that the UE Response does not sufficiently address the deficiencies identified in the OPC Review and the OPC Technical Report. I confirm the OPC's original finding that the UE IRP is fundamentally flawed, does not meet the requirements of the MO IRP rule (4 CSR 240-22), and does not provide the Company or the Commission with sufficient analysis and information to identify an appropriate Preferred Resource Plan or a reasonable Resource Acquisition Strategy.

In particular:

- The UE Response does not provide sufficient justification for its approach to modeling demand-side resources, where it essentially limits the analysis to the Low-Risk DSM scenario on the grounds that this is the only scenario consistent with its financial objectives.
- The UE response does not provide sufficient justification for its assertion that it has analyzed a broad range of demand-side management portfolios.
- The UE response does not provide sufficient justification for how it modeled the future costs of operating its existing coal facilities in light of new EPA environmental regulations.
- The UE response does not provide sufficient justification for its overly optimistic assumptions regarding the construction costs of new nuclear generation facilities.
- The UE response does not provide sufficient justification for its methodology and assumptions for modeling new wind resources.

Q. Please summarize you primary recommendations.

A. I recommend that the Commission find that the UE IRP does not comply with the MO IRP rule. In addition, I recommend that the Commission find that the UE IRP contains so many significant flaws that it cannot be relied upon by the

Company for short-term or long-term resource planning purposes, nor can it be relied upon by the Commission for regulatory review of resource plans.

I recommend that the Commission require the Company to conduct its IRP analysis again with the following significant modifications:

- The Company should properly analyze a wide range of DSM portfolios for the purpose of identifying the Preferred Resource Plan, including a complete assessment of the so-called Maximum Achievable Potential (MAP) scenario, as well as a scenario with savings in between the Reasonably Achievable Potential (RAP) portfolio and the MAP portfolio.
- The Company should design future environmental scenarios that properly reflect the expected level of EPA regulations affecting its coal-fired plants. The Company should also expand its analysis to properly consider the economics of retiring existing coal plants in light of those more realistic scenarios.
- The Company should adopt more reasonable estimates of new nuclear plant construction costs. The Company should also adopt more realistic assumptions regarding the probability of nuclear plant construction cost over-runs.
- The Company should model wind resources in a way that better reflects how such resources might be developed on the UE system, including modeling the wind resources in smaller blocks, and modeling the wind resources without including associated peaking resources.

3. ANALYSIS OF DEMAND-SIDE RESOURCES

Q. Please summarize the OPC's concerns about the Company's analysis of demand-side resources.

A. In the OPC Review and the OPC Technical Report, we find that UE failed to develop alternative resource plans that capture the full range of demand-side resources. We note that the final candidate resource plans in the IRP include only two levels of demand-side resources: the Low-Risk Portfolio and the Reasonably

Achievable Portfolio (RAP). The former includes less energy efficiency savings than in the Company's 2008 IRP, and the latter significantly understates the amount of energy efficiency that is reasonably achievable. The Company's methodology essentially precludes the selection of all demand-side resource portfolios except for the Low-Risk Portfolio, by placing too much emphasis on the financial rewards to the Company and too little emphasis on minimizing the Present Value of Revenue Requirement (PVRR). (OPC Review, pages 4-5 and OPC Technical Report, pages 10-13.)

Q. Please summarize the Company's response to OPC's concerns.

A. The Company argues that it has evaluated a broad range of DSM portfolios and that it has evaluated DSM resources on an equivalent basis with supply-side resources. UE points to its analysis of five DSM resource portfolios as evidence that it has evaluated a "broad range" of DSM options. (UE Response, pages 29-30.)

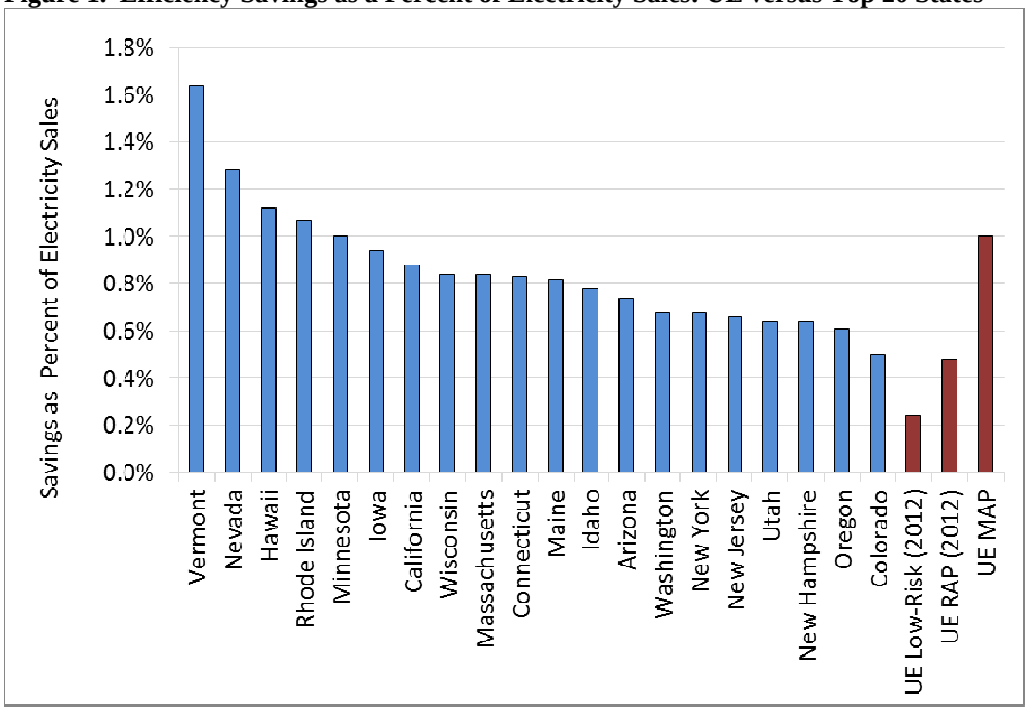
Q. Do you agree with the Company's response on these issues?

A. No, I do not agree. While it is true that the IRP analysis began with five DSM resource portfolios with varying levels of demand-side resources, the Company did not apply a *meaningful* analysis to these different portfolios. The Company's methodology did not properly account for the benefits offered by the different DSM resource portfolios, and the Company's decision-making process was so limited that it could only lead to one outcome: the selection of the Low-Risk Portfolio.

First, the Company uses relatively conservative assumptions to develop the RAP and Maximum Achievable Potential (MAP) scenarios. The RAP savings are limited by the Company's assumptions regarding customer incentives and customer awareness rates. (OPC Technical Report, pages 11 and 12.) The MAP savings are described as essentially the upper limit on what the Company could possibly save through energy efficiency programs. This portfolio assumes that the Company is able to achieve incrementally roughly one percent of annual

energy savings each year after 2015.[1] However, by 2009 five states have already achieved efficiency savings equal to roughly one percent of annual sales per year, and another 15 states have achieved efficiency savings of between 0.5 and 1.0 percent of annual energy savings per year. This is indicated in Figure 1 below. The experience of other states suggests that the MAP scenario is not the maximum that could potentially be achieved by the Company. It also suggests that there is a lot more energy efficiency that could be reasonably achieved by the Company beyond the amounts included in the RAP resource plan.

Figure 1. Efficiency Savings as a Percent of Electricity Sales: UE versus Top 20 States[2]



Second, the Company significantly downplays the economic benefits of the demand-side resources. As described in the testimonies of my colleagues Dr. Vitolo and Mr. Kind, the Company does not give sufficient weight to minimizing PVRR in its resource plan selection process. Reducing costs and minimizing PVRR is one of DSM's greatest advantages. The Company's own analysis indicates that the RAP scenario can reduce PVRR by roughly $1.5 to $2.5 billion

[1] Union Electric, *2011 Integrated Resource Plan*, Chapter 7, page 2.

[2] Information for the other states is from: American Council for and Energy-Efficient Economy, *The 2011 State Energy Efficiency Scorecard*, October 2011.

present value dollars relative to the Low-Risk DSM scenario. (OPC Technical Report, pages 26-27 and UE IRP Chapter 9, page 24, Figures 9.16 – 9.18.) The Company's analysis clearly indicates that the RAP scenario significantly reduces PVRR relative to the Low-Risk scenario, under all future scenarios and relative to all alternative resource plans. (OPC Technical Report, pages 26-27 and UE IRP Chapter 9, page 24, Figures 9.16 – 9.18.)

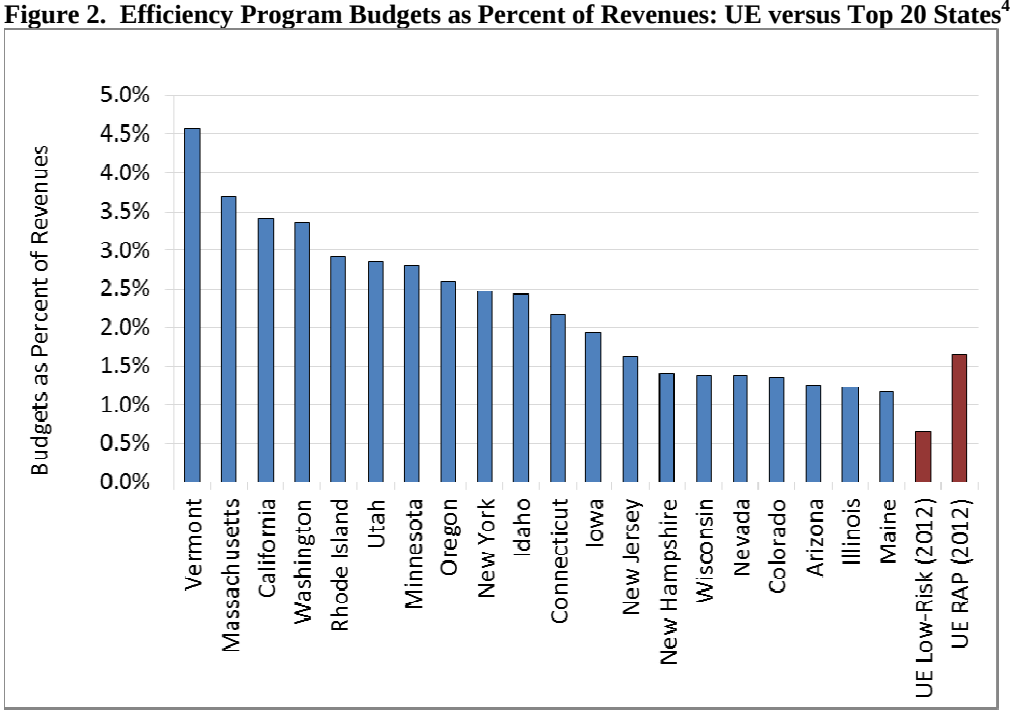
Third, the Company has made it abundantly clear in its IRP and in its response to comments that that it is unwilling to implement energy efficiency resources that create financial risk to the Company as a result of lost revenues. (For example, UE Response, pages 12-15) Throughout its IRP the Company finds that the RAP scenario offers significant benefits relative to the Low-Risk DSM Portfolio, and yet in choosing its Preferred Resource Plan the Company is clear that RAP is "less attractive given the constraints of current state policies and regulations" (UE IRP, Chapter 10, page 14.) The Company's description indicates that it is unwilling to implement any energy efficiency that is more aggressive than the Low-Risk DSM Portfolio, regardless of the key results of its IRP analysis. This is clearly not a *meaningful* analysis of a wide range of demand-side resources.[3]

Fourth, the Company eliminates the MAP scenario too early in the IRP analysis. The Company explains that it was "unnecessary to continue to analyze both plans since the analysis was clear that both were performing similarly and both were lower cost than supply-side options." (UE Response, page 13.) However, as indicated in Figure 1 above, both plans do not perform similarly – the MAP scenario has considerably more efficiency savings. Also, while it is true that both scenarios reduce PVRR relative to supply-side options, the Company's own DSM potential study that found that the MAP scenario could reduce costs by $500 million, relative to the RAP scenario. (UE DSM Market Potential Study, Volume 1: Executive Summary, page ES-8.) This is a significant amount of potential electricity cost savings that is quickly dismissed by the Company as if it were

[3] In addition, my colleague Mr. Kind addresses how inappropriate this approach is, in light of the IRP rule requirements and the DSM cost recovery framework currently available.

irrelevant. The Company's approach unnecessarily and dramatically limits the full range of cost-effective energy efficiency resources, and cannot be described as a *meaningful* analysis.

Figure 2. Efficiency Program Budgets as Percent of Revenues: UE versus Top 20 States[4]



It is instructive to compare the Company's proposed Low-Risk DSM budgets to the energy efficiency budgets that are currently being implemented by other electric utilities in the US. Figure 2 presents the 2010 annual electric energy efficiency budgets for the top 20 states, as a percentage of 2010 annual electric revenues. For comparison purposes it also presents the UE 2012 budgets for the Low-Risk and RAP scenarios, also as a percent of 2010 annual electric revenues. As indicated in the figure, the Low-Risk budgets are well below many of those of other states, and the RAP budget is also well below the budgets of some states as well.

[4] The information for the other states is from: American Council for and Energy-Efficient Economy, *The 2011 State Energy Efficiency Scorecard*, October 2011.

Q. Are you presenting the data in figures 1 and 2 to imply that Ue should be one of the top states in the us with regard to energy efficiency implementation?

A. Not necessarily. I present the information on other states' efficiency activities to put the Company's planning assumptions in context. As indicated in Figure 1, the MAP scenario does not necessarily represent the upper bound of the efficiency savings that are achievable during the course of the UE IRP study period, given that many utilities have already achieved this level of savings, in 2009. Similarly, the data in Figures 1 and 2 demonstrate that in its analysis to select the Preferred Resource Plan, the Company did not assess a broad range of DSM portfolios, as it claims to have done.

4. ANALYSIS OF EXISTING COAL FACILITIES

Q. Please summarize the OPC's concerns about the Company's analysis of existing coal facilities.

A. In the OPC Review and the OPC Technical Report, we find that UE failed to properly assess how future environmental scenarios for new EPA regulations affecting existing coal plants will influence the candidate resource plans. In particular, the Company did not properly account for increased environmental regulations as a critical uncertain factor. The Company creates resource plans according to two sets of environmental scenarios – the moderate scenario and the aggressive scenario. However, the Company's methodology for scoring and ranking the moderate and aggressive environmental scenarios contains a fundamental flaw in that it compares costs and benefits of plans across the two different scenarios, even though the costs of the aggressive environmental scenario will be higher *by definition*. (OPC Technical Report, pages 15-16.)

Furthermore, the Company did not investigate the economics of retirement versus continued operation of its other three coal fired power plants: Labadie, Rush Island, and Sioux. Given the potentially significant increase in costs of these plants associated with complying with anticipated environmental regulations, as acknowledged by the Company, this represents a significant omission in the Company's IRP. (OPC Technical Report, pages 6-7.)

Q. Please summarize the Company's response to OPC's concerns.

A. The Company claims that its approach to modeling environmental regulations using the moderate scenario and the aggressive scenario is appropriate, and that it would not be appropriate to use the probability tree approach. UE argues that consideration of different environmental regulation scenarios would "involve decisions that potentially alter the existing resource mix and thus the future need for resources within alternative resource plans." The Company claims their approach to modeling a moderate and an aggressive environmental regulations scenario is equivalent to including these two scenarios in its probability tree. (UE Response, pages 55-56.)

The Company does not respond to the OPC's finding that the Company's methodology for scoring and ranking resource plans across the two different environmental regulations scenarios is fundamentally flawed by definition.

The Company claims that it is not appropriate to evaluate the retirement of the Labadie, Rush Island and Sioux plants at this time. UE claims that the Meramec plant is the most obvious candidate for retirement, and that its IRP analyses do not provide a definitive indication of the economics of retiring Meramec. The Company concludes that "it is prudent to continue to analyze the Meramec decision and to only evaluate the other coal plants as a result of changed circumstances in the Meramec analysis." (UE Response, page 41-42.)

Q. Do you agree with the Company's response regarding its approach to modeling the moderate and aggressive environmental scenarios?

A. No, I do not. First and foremost the Company does not provide a response to our finding that the scorecard methodology for selecting the Preferred Resource Plan contains a fundamental flaw by definition. The Company uses the scorecard to compare 14 different resource plans, five of which are based in the moderate environmental scenario and nine of which are based on the aggressive environmental scenario. The moderate and the aggressive environmental scenarios are mutually exclusive and based on two significantly different futures. The nine resource plans under the aggressive environmental scenario will most likely require higher costs than the five resource plans under the moderate

environmental scenario, leading to higher PVRR results. The Company then uses a scoring system, including PVRR as one of the scoring criteria, to compare and rank all the different resource plans. The Company assigns each resource plan a score ranging from one to five, based on how it compares with all of the other resource plans.[5]

The problem with this approach is that skews the ranking in favor of the resource plans under the moderate environmental scenarios. These resource plans are likely to have lower PVRRs by definition because they will have lower environmental compliance costs. It is not appropriate to score and rank resource plans that are based on mutually exclusive and significantly different futures in this way, because the resource plans are not comparable by definition. (OPC Technical Report, pages 15-16.) The Company has provided no response to our findings on this critical point, and no explanation for why its methodology is not flawed.

Q. Is the Company's approach to modeling the moderate and aggressive environmental scenarios consistent with the IRP rule?

A. No, it is not. First, the IRP rule is clear in the opening section that utilities shall consider risks associated with "critical uncertain factors that will affect the actual costs associated with alternative resource plans." (4 CSR 240-22.010(2)(C).1.) Among all the potential critical uncertain factors that utilities could consider, the IRP rule lists one in particular that must be considered: "[r]isks associated with new or more stringent environmental laws or regulations that may be imposed at some point within the planning horizon." (4 CSR 240-22.010(2)(C).2.) The Company developed a list of 22 uncertain factors that might be critical to resource performance, but none of them included the EPA environmental regulations that the Company considers through its moderate and aggressive environmental scenarios. (UE IRP, Chapter 9, page 13, Table 9.6.) The Company did include carbon policy as an uncertain factor, and decided that carbon policy should be

[5] Note that there are additional flaws with the Company's scorecard methodology for selecting the preferred resource plan, as described in the testimony of my colleague Dr. Vitolo.

modeled in the decision tree analysis as one of the few critical uncertain factors. (UE IRP, Chapter 2, pages 2-3.) The Company should have considered the EPA environmental regulations in a similar fashion.

Q. Is there another reason why the Company's approach to modeling the moderate and aggressive environmental scenarios is not consistent with the IRP rule?

A. Yes. The IRP rule is also clear that the utility shall "explicitly state and document the subjective probabilities that utility decision-makers assign to each of these uncertain factors." (4 CSR 240-22.070(1).) By modeling the moderate and aggressive environmental scenarios as they have, the Company has essentially acknowledged that the EPA environmental regulations are a critical uncertain factor, but they have declined to state and document the subjective probabilities associated with this uncertain factor, as they would have to do if they included this uncertain factor in their probability tree approach. As a result, the IRP does not provide an indication of the subjective probability that the Company might assign to this uncertain factor, and readers of the IRP cannot gauge the extent to which this issue is likely to affect the resource plans or their costs.

Q. Is there a better option available for modeling the moderate and aggressive environmental scenarios?

A. Yes. The Company should have included these two scenarios as branches in the probability tree analysis. Given the likely magnitude of the impact of anticipated future environmental regulations on the Company's coal plants, this should clearly have been considered by the Company as a critical uncertain factor to model in its probability tree analysis.

Q. But the Company claims in its Response that it would not be appropriate to model these two scenarios in its probability tree analysis because the two scenarios would require different mitigation options and different resource plans. (UE Response, pages 55-56.) Do you agree?

A. I do agree that the Company should create different resource plans that are expected to perform well under the moderate and aggressive environmental scenarios. Resource plans should always be designed to meet the particular constraints and definitions of the relevant scenario.

However, I disagree that probability tree analysis cannot be used for this purpose. In fact, probability tree analyses are designed to address a variety of different resource plans. Every branch of the probability tree may need to have its own unique resource plan in order to best meet the particular constraints or assumptions associated with that branch. Probability tree analysis would be meaningless if it were applied to a single resource plan for every branch, which is what is implied by the Company's response.

Furthermore, the branches of the probability tree should be designed so that they are mutually exclusive. This is important because the combined probabilities of all the branches must add up to 100 percent by definition. The moderate and aggressive environmental scenarios are mutually exclusive, and therefore are well-suited for probability tree analysis.

Q. Do you agree with the Company's response regarding the need to analyze the economics of retiring the Labadie, Rush Island or Sioux power plants?

A. No. I do not agree with the Company's argument that it is not appropriate to analyze these other coal plants in light of the IRP not reaching a definitive result on the retirement of Meramec. First, the OPC has identified several significant deficiencies with the IRP that make it difficult to rely upon the results with regard to Meramec retirement. These deficiencies include the following:

- The Company has not properly modeled the implications of the moderate and aggressive environmental scenarios, as described above in this section.
- The Company has not properly modeled the potential for energy efficiency and demand response, which represent an alternative to the Meramec plant, as described above in Section 3.
- The Company has not properly modeled the potential for wind resources, which represent an alternative to Meramec plant, as described in Section 6.
- The Company has not used PVRR as the primary criterion for scoring its alternative resource plans, as described in the testimony of Mr. Kind.

- The Company has not applied its scorecard properly in selecting among its alternative resource plans, as described in the testimony of Dr. Vitolo.

With so many significant deficiencies in the IRP, it cannot be used to justify the lack of analysis of retiring the Company's coal plants. A properly performed IRP might indicate that it would be economic to retire the Meramec plant, and might indicate that it would also be economic to retire an additional coal plant.

Q. Is there another reason why you do not agree with the Company's response regarding the need to analyze the economics of retiring the Labadie, Rush Island or Sioux power plants?

A. Yes. EPA environmental regulations are expected to impose substantial requirements on many coal-fired power plants, leading to significantly increased capital, operation and maintenance costs. The Company has acknowledged the potential costs associated with compliance with environmental regulations, in its annual report to the Security and Exchange Commission, and in the Generation Initiative established by Ameren, UE's parent company. (OPC Technical Report, pages 6 and 7.) The lack of analysis of the economics of retiring additional coal units in light of these expected environmental requirements and costs represents a glaring omission in the Company's IRP analysis. While it may be true that Meramec is the most likely candidate for retirement, the Company has not performed the analysis to assess the economics of retiring any of the other coal plants.

5. ASSUMPTIONS REGARDING NEW NUCLEAR FACILITIES

Q. Please summarize the OPC's concerns about the Company's assumptions regarding new nuclear facilities.

A. In the OPC Review and the OPC Technical Report, we find that UE failed to properly identify the full range of likely construction costs for its new nuclear units, and has not adequately addressed the tremendous financial and economic risks associated with new nuclear units. (OPC Review, page 6 and OPC Technical Report, pages 4-6.)

Q. Please summarize the Company's response to OPC's concerns.

A. The Company argues that its assumptions for nuclear resources are reasonable, and that it has performed the appropriate sensitivity analyses. In particular, the Company notes that its low, base and high assumptions on capital costs are roughly equivalent to the assumptions in the 2011 US Department of Energy Annual Energy Outlook, as well as three nuclear plants being constructed in other countries (Olkiluoto in Finland, Flamanville 3 in France, and Taishan 1 in China). (UE Response, page 73.)

Q. Do you agree with the Company's response with regard to its assumptions regarding nuclear plant construction costs?

A. No, I do not agree. While the Company has cited some evidence of nuclear cost estimates that are close to its estimates, it does not account for a great deal of evidence suggesting that (a) its costs are too low, and (b) there is a very significant risk of nuclear construction cost estimates increasing over time.

First, it is widely recognized that the US nuclear industry has a history of significant construction cost overruns. A report prepared by Synapse Energy Economics calculated that for all of the nuclear plants installed in the US, with construction starting in the years 1966 through 1977, the average construction cost overrun was 207 percent.[6] In other words, the final costs turned out to be more than three times the original estimate.

Another report presents the range of cost estimates that has been used for new nuclear power projects, which could be part of what the authors describe as the "nuclear renaissance."[7] Some of the early (2001-2005) vendors, government and academic construction cost estimates have been quite low, on the order of $1,500 to $2,500/kW. More recently (2007-2009), the utility construction cost estimates have been in the range of $3,000 to $5,500/kW, roughly in line with UE's estimates. However, Wall Street analysts and independent analysts have recently

[6] Synapse Energy Economics, *Nuclear Plant Construction Costs*, July 2008. www.synapse-energy.com.
[7] Mark Cooper, *The Economics of Nuclear Reactors: Renaissance or Relapse?*, June 2009. See in particular page 3, Figure ES-1.

presented estimates of nuclear plant construction costs of $5,000 to $10,000/kW, significantly higher than UE's high nuclear cost estimate.

Furthermore, there is information from new nuclear plants proposed in the US that should be considered in evaluating nuclear plant costs and risks. A recent report from Synapse Energy Economics evaluates the cost estimates associated with new power plants that are currently being planned by utilities in the US.[8] The experience of Progress Energy Florida in planning their Levy 1 and 2 nuclear units is instructive here. In 2006 Progress Energy proposed to build one 1,100 MW unit for a cost of $2.5 to $3.5 billion.[9] In 2008 the project was expanded to include two 1,100 MW units, for a total cost of approximately $17 billion. In 2010, Progress Energy announced another increase in the expected cost of the project, to $22.5 billion. As indicated in Table 1 below, the current estimate from Progress Energy represents a 221 percent (i.e., more than three-fold) increase over its initial high case estimate, in $/kW terms. Levy 1 is scheduled to be completed in 2021, and Levy 2 is scheduled to be completed in 2023. It is quite possible that the final construction costs turn out to be even higher than the current estimates.

Table 1. Construction Cost Estimates at the Proposed Levy 1 and 2 Nuclear Units[10]

Year of Estimate	Capacity (MW)	Cost (bil.$)	Cost ($/kW)	Increase Relative to 2006 - High
2006 - Low	1,100	2.5	$2,273	---
2006 - High	1,100	3.5	$3,182	---
2008	2,200	17.0	$7,727	143%
2010	2,200	22.5	$10,227	221%

[8] Synapse Energy Economics, *Big Risks, Better Alternatives: An Examination of Two Nuclear Projects in the US*, October 6, 2011. www.synapse-energy.com.

[9] Note that the costs presented here for the Levy units include "all-in" construction costs. The other costs presented in this discussion include "overnight" construction costs, and thus cannot be directly compared. The main point here with regard to the Levy experience is in the *increase* in construction cost estimates over time.

[10] Synapse Energy Economics, *Big Risks, Better Alternatives: An Examination of Two Nuclear Projects in the US*, October 6, 2011, pages 9-11.

In determining its base case construction cost estimate for new nuclear units, the Company should acknowledge the history of nuclear construction costs in the US, and adjust its base case estimate accordingly.

Q. Has the OPC raised other concerns regarding the Company's analysis of new nuclear units?

A. Yes, the OPC found that the Company has not adequately recognized the potential for cost overruns in its sensitivity analyses (OPC Technical Report, pages 4-5).

Q. What was the Company's response to these concerns?

A. The Company did not respond to these concerns raised by OPC. However, the Company did respond to essentially the same concerns raised by the Natural Resources Defense Council (NRDC). The Company claims that its approach to developing the uncertain range of nuclear costs estimates, as described in Chapter 9, is appropriate. (Company Response, page 74.)

Q. Do you agree with the Company's response?

A. No, I do not agree. The Company has assumed low, base and high values of nuclear construction costs of $3,563/kW, $4,222/kW, and $5,000/kW. (Company Response, page 73.) The high value is roughly 18 percent higher than the base value. This is a remarkably narrow range, especially given that US nuclear power plant construction costs have historically been over 200 percent higher than the original budget on average, as described above.

In addition, the Company apparently used a standardized methodology for determining the probability of occurrence of low and high values for uncertain factors. In particular, the Company standardized the meaning of low to be the value at the 10th percentile of a probability distribution, the meaning of the base value to be the value at the 50^{th} percentile, and the meaning of the high value to be the value at the 90^{th} percentile. (UE IRP, Chapter 9, page 15.) In the case of nuclear construction costs, these assumptions combined means that UE assumes that there is only a ten percent chance that the new nuclear facility will be 18 percent or more over the current budget. This range is clearly not

representative of the types of cost over-runs that can occur when constructing new nuclear power plants.

Furthermore, the probability distribution used by the Company implies that a nuclear plant construction cost over-run of 50 percent would occur at the 99.9th probability percentile. (Company response to OPC Data Request, OPC 2052.) In other words, under the Company's probability distribution, there is less than a 0.1 percent chance that the project would over-run its original budget by 50 percent or more. Again, this is a remarkably narrow range of potential cost over-runs given the history of nuclear plant construction costs. The final cost of a new nuclear unit for UE could easily be 100 percent higher than this original estimate, but the probability distribution used by the Company essentially does not include this possibility.

6. ASSMPTIONS REGARDING NEW WIND RESOURCES

Q. Please summarize the OPC's concerns about the Company's assumptions regarding new wind resources.

A. In the OPC Review and the OPC Technical Report, we conclude that UE failed to properly characterize and model renewable resources, particularly wind resources. First, UE overstates the cost of new wind resources by combining 346 MW of simple cycle combustion gas turbines (CTs) with every 800 MW (nameplate capacity) of wind facilities. Second, UE applies 205 MW (accredited capacity) of "build thresholds" to wind resources, which ignores the potential benefits of adding smaller wind resources to the system. Third, UE uses average capital cost and capacity factor assumptions for all of its wind resources, which ignores the potential for some resources to have lower costs or better capacity factors. (OPC Technical Report, pages 8-9.)

Q. Please summarize the Company's response to OPC's concerns.

A. UE claims that it is appropriate to include 346 MW of peaking capacity with every 800 MW of wind capacity, on the grounds that wind resources currently receive a capacity credit of eight percent of the installed nameplate capacity and that each 800 MW of nameplate wind capacity is equal to 64 MW of accredited

wind capacity that can be available to meet reserve margin requirements. The 64 MW of wind resources is combined with the 346 MW of peaking capacity to provide total accredited capacity of 410 MW to meet reliability needs. (UE Response, pages 62-63.)

In addition, UE claims that its approach to using build thresholds is appropriate, that "there is no evidence that modeling wind in large amounts biases the results against wind," and the IRP would be largely the same if wind resources are modeled in large amounts or if they are spread out over a period of time. (UE Response, page 61.)

Finally, UE claims that its approach to modeling average wind construction costs and capacity factors is consistent with the IRP rule 22.040(1), which requires that it model generic wind resources. (UE Response, pages 60-61.)

Q. Do you agree with the Company's response with regard to combining wind resources with peaking capacity?

A. No. I do not agree. It is not appropriate to combine every MW of wind capacity with peaking capacity. The Company's methodology is based on two premises: (1) that it is only appropriate to add wind resources to the system when there is a capacity need, and (2) that resources must be added to the system in such a way that results in little or no excess UE capacity and little or no shortfall of UE capacity. Both of these premises are flawed, as indicated by the Company's own IRP analysis.

The first premise implies that capacity is the only benefit that wind resources provide to UE and its customers, and that it is not appropriate to add wind resources unless there is a capacity need. Of course, all resource plans must have sufficient capacity to meet reliability requirements. However, capacity need is not the only reason that resources are added to the Company's system. Wind resources offer significant benefits in terms of reducing energy costs. It may be possible to reduce PVRR by adding wind resources to the system in years when capacity is not needed for reliability purposes. This is comparable to adding energy efficiency to a resource mix even though there may not be an immediate

capacity need – the energy benefits of the resource are sufficient to reduce net costs.[11] Furthermore, as indicated by the Company's scorecard used to select the Preferred Resource Plan, minimizing PVRR is not the only criterion that is used to evaluate resource plans. It is quite possible that adding wind resources to the system in the absence of a capacity need would lead to benefits with regard to the other scoring criteria, especially the environmental/diversity criteria.

The second premise underlying the Company's methodology is that resources must be added to the system in a way that results in little or no excess UE capacity and little or no shortfall of UE capacity. However, this is not how the Company has developed its resource plans in the IRP. Instead, UE relies upon capacity purchases and sales to make up for any shortfall or excess capacity in any one year. This is made clear in the UE IRP in Chapter 9, Appendix A, Table 9.A.1. Note that for every resource plan the Company uses capacity purchases and sales to make up for any shortfall or excess of capacity. This is indicated in the last line of the table for each resource plan. In some cases, the capacity sales are as much as 400, 500 and even 600 MW. In some cases, the capacity purchases are as much as 200 or 300 MW. It is clear that the Company's planning methodology allows for excesses and shortfalls of UE capacity. Thus, the Company could easily model new wind resources without any associated peaking capacity in some years when there is no need for capacity, and in some years when the capacity need is greater than the amount of wind capacity available. UE's insistence on combining 346 MW of peaking capacity with every 800 MW of wind capacity is based on overly simplistic premises about resource planning and will result in significant additional costs associated with the wind resource plans.

[11] Note that the RAP DSM resource plans reduces PVRR by roughly $1.5 – 2.5 billion dollars, relative to the Low-Risk DSM resource plans, even though there is "excess" UE capacity associated with the RAP DSM plans. (OPC Technical Report, page 26.) This is because of the energy benefits from avoiding fuel costs and/or off-system sales margins.

Q. Do you agree with the Company's response regarding the build thresholds for wind resources?

A. No, I do not agree. The Company did not provide a substantive response to the OPC critique on this point. UE provides no evidence to support its claim that the IRP would be largely the same if wind resources are modeled in large amounts or if they are spread out over a period of time. Under the Company's approach there may be a considerable delay in the introduction of wind resources to the system. During those years when wind resources might have been added to the system but were not due to the build threshold, they might be able to reduce PVRR, especially as a result of the energy benefits of wind.

The problem with the Company's approach to applying build thresholds to wind resources becomes even worse when combined with its methodology of combining CT capacity with wind capacity. The build threshold for each new supply-side resource is derived by taking one half of the "full" capacity of the resource. (UE IRP, Chapter 9, page 4.) While this may make sense for most thermal power plants that are typically built in large amounts of MW, it does not make sense for wind resources that can be built in much smaller MW increments.

The 205 MW build threshold for wind resources is based on one-half of the 410 MW of new wind resources. As described above, this 410 MW of new "wind" resources is actually composed of 800 MW of nameplate wind capacity (64 MW accredited capacity) and 346 MW of new CT capacity. Therefore, the wind resource build threshold applied by the Company means that no wind is added to the system until there is a need for 205 MW of capacity. Once this point is reached, the model includes 346 MW of new CT capacity and 800 MW of nameplate wind capacity. This approach defies common sense and will clearly understate the potential and overstate the cost for new wind resources.

Note that the one scenario that includes wind and makes it to the final selection stage, Plan H3, does not include any wind until the year 2024. The wind resources are added in 2024 because this is the first year where the UE capacity "shortfall" would reach 205 MW. (UE IRP, Chapter 9, Appendix A, Table 9.A.1, Plan H3.) The Company's build threshold methodology limits the ability of wind

to play a role on its system for over 12 years. Clearly there may be opportunities for wind resources to provide cost benefits, energy benefits and environmental/diversity benefits between now and 2024. The Company has not conducted its modeling in a way that would identify these benefits.

Q. Do you agree with the Company's claim that its approach to modeling average wind construction costs and capacity factors is consistent with modeling generic wind resources?

A. No, I do not agree. In this context, the term "generic" suggests that the Company is not obligated to model site-specific renewable resource projects. This would clearly be burdensome and limit the ability of the Company to evaluate the full range of potential resources over the study period.

However, using a generic assumption for wind resources costs and capacity factors does not mean the company must use a single, average estimate. If a certain resource type is likely to have a range of construction costs or a range of capacity factors, then it may be appropriate to model several estimates within the range. The Company has not done so. When this simplified approach to modeling wind is combined with the Company's build threshold and the Company's method of combining wind capacity with peaking capacity, the result is an extremely limited analysis of the wind resource potential and does not come close to optimizing the wind resource potential.

Q. Is there a better approach available for modeling the potential for wind resources in the IRP?

A. Yes. A better approach would be for the Company to model a range of wind resource types, and to investigate a schedule for installing wind resources that minimizes PVRR and results in other important benefits to the Company and its customers. For example, UE could add wind projects in different increments of 50 MW, 100 MW and 200 MW, and could add different quantities in different years to identify the best combination of wind resources in each year. Each resource plan would be designed to have sufficient capacity to meet reliability needs, after accounting for the opportunities for off-system sales and purchases. If the Company feels that it is necessary to incorporate wind resource build

thresholds for ease of computation, then the build thresholds should be half of the wind resources' nameplate capacity (e.g., 25 MW, 50 MW 100 MW), not some inflated value based on an unnecessary CT facility. In the absence of this type of analysis, UE has not been able to identify the best mix of wind resources to include in the IRP.

Q. Does this conclude your pre-filed testimony?

A. Yes, it does.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. Vice President, 2011 to present. Provides expert consulting on the economic, regulatory, consumer, environmental, and public policy implications of the electricity and gas industries. The primary focus of work includes technical and economic analyses, electric power system planning, climate change strategies, energy efficiency programs and policies, renewable resources and related policies, power plant performance and economics, air quality, and many related aspects of consumer and environmental protection.

Massachusetts Department of Public Utilities, Boston, MA. Commissioner, 2007- 2011. Oversaw a significant expansion of clean energy policies as a consequence of the Massachusetts Green Communities Act, including an aggressive expansion of ratepayer-funded energy efficiency programs; the implementation of decoupled rates for electric and gas companies; an update of the DPU energy efficiency guidelines; the promulgation of net metering regulations; review of smart grid pilot programs; and review of long-term contracts for renewable power. Oversaw six rate case proceedings for Massachusetts electric and gas companies. Played an influential role in the development of price responsive demand proposals for the New England wholesale energy market. Served as President of the New England Conference of Public Utility Commissioners from 2009-2010. Served as board member on the Energy Facilities Siting Board from 2007-2010. Served as co-chair of the State Energy Efficiency Action Working Group on Utility Motivation. Served as co-chair of the Steering Committee for the Northeast Energy Efficiency Partnership's Regional Evaluation, Measurement and Verification Forum.

Synapse Energy Economics Inc., Cambridge, MA. Vice President, 1997-2007.

Tellus Institute, Boston, MA. Senior Scientist, Manager of Electricity Program, 1992-1997.

Association for the Conservation of Energy, London, England. Research Director, 1991-1992.

Massachusetts Department of Public Utilities, Boston, MA. Staff Economist, 1989-1990.

Massachusetts Office of Energy Resources, Boston, MA. Policy Analyst, 1987-1989.

Energy Systems Research Group, Boston, MA. Research Associate, 1983-1987.

Union of Concerned Scientists, Cambridge, MA. Energy Analyst, 1982-1983.

EDUCATION

Masters, Business Administration. Boston University, Boston, MA, 1993.
Diploma, Economics. London School of Economics, London, England, 1991.
B.S., Mechanical Engineering. Tufts University, Medford, MA, 1982.
B.A., English. Tufts University, Medford, MA, 1982.

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