COMMENTS OF CITIZENS ACTION COALITION OF INDIANA, INC., EARTHJUSTICE AND SIERRA CLUB

Pursuant to the Indiana Utility Regulatory Commission's ("IURC" or "Commission") Electric Utility Integrated Resource Planning Rule, 170 IAC 4-7,[1] Citizens Action Coalition of Indiana, Inc., Earthjustice and Sierra Club (collectively, "Commenters") hereby submit the following comments on Indiana Michigan Power's ("I&M" or "the Company") 2013 Integrated Resource Plan ("IRP").

I&M's 2013 IRP reflects certain positive developments with respect to stakeholder engagement and the Company's resource mix. For the first time, I&M's 2013 IRP process included stakeholder participation through workshops. While the process would benefit from several improvements, the initial stakeholder engagement is a step in the right direction. As a result of the retirement of Tanners Creek in 2015, the Preferred Portfolio reduces I&M's reliance on coal-fired generation, which carries significant costs and risks. Specifically, I&M projects that its percentage of coal-based capacity will fall from roughly 58% to 43% during the twenty-year planning period. IRP at ES-7.[2] Similarly, the percentage of I&M's energy mix that comes from coal-fired generation is projected to decline from roughly 49% to 41% during the planning period. *Id.* While the economic and risk profiles of coal suggest that I&M should pursue further reductions, the shift reflected in the IRP is directionally correct. The Preferred Portfolio also reflects an increase in solar, wind, and energy efficiency, which constitute the chief resource additions (excluding rerates) during the planning period. *Id.* at ES-7, ES-10. This increase is

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[1] Unless otherwise noted, all references to the Commission's IRP Rule, 170 IAC 4-7, refer to the revised draft of the Proposed IRP Rule, which the Commission circulated on October 4, 2012 in the IRP rulemaking, RM# 11-07. Cross references to the current IRP rule are provided, where applicable.
[2] All citations to I&M's 2013 IRP refer to Volume I, unless otherwise noted, and are provided in the following format: "IRP at __".

directionally correct, though the Company fails to sufficiently evaluate clean energy resources and, as a result, undervalues them.

As discussed in detail below, I&M's IRP contains several significant shortcomings that raise concerns about the Company's planning practices and render the plan inconsistent with the IRP Rule, including:

- The Company fails to adequately evaluate energy efficiency by fixing efficiency impacts in the near term; limiting the availability of additional resources in the long term; and failing to model compliance with Indiana's energy saving goal;

- The Company's analysis of distributed solar generation appears to undervalue the benefits provided by this important resource, and I&M fails to explain the underlying inputs and assumptions;

- The Company fails to evaluate cogeneration and distributed wind resource options, and constrains its consideration of utility-scale renewable resources; and

- The Company fails to identify, and quantify where possible, a number of additional costs and risks facing its Preferred Portfolio, in particular with regard to a number of environmental regulatory requirements facing the Rockport, Kyger Creek, and Clifty Creek coal-fired generating units.

Until these shortcomings in I&M's IRP are remedied, the IRP cannot be found to be consistent with the IRP Rules. As such, the reasonableness of I&M's future actions relying on this resource planning may be in question. Commenters respectfully request that the Director of the Electricity Division's report on the IRP, *see* 170 IAC 4-7-2(h), (k), reflect the informational, procedural and methodological deficiencies, as detailed below. The Company should address each of these shortcomings in its response to the Director's draft report, and should remedy them in future resource planning and decision making.

I. IRP Standards

The IRP process in Indiana is governed by 170 IAC 4-7, which requires I&M and other utilities to submit, on a biennial basis, plans for meeting customers' electricity needs over a twenty-year planning period. IRPs must adhere to informational, procedural and methodological requirements prescribed by the Commission's rules. An IRP helps the Commission develop a plan for meeting future electric needs, as required by IC 8-1-8.5, and can serve as evidence, or inform Staff reports, in formally docketed proceedings before the Commission. 170 IAC 4-7-2(r). Core elements of the IRP and IRP process include:

- Transparent public advisory process in which the utility provides information to, and solicits and considers relevant inputs from, interested parties regarding IRP development and related resource acquisition issues (170 IAC 4-7-2.1);
- Discussion of inputs, methods and definitions used in the IRP, and inclusion of data sets and sources (170 IAC 4-7-4(b)(1), (2));
- Discussion of distributed generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting (170 IAC 4-7-4(b)(5));
- Demonstration that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis (170 IAC 4-7-8(b)(3));
- Demonstration that the utility's preferred resource portfolio utilizes, to the extent practical, all economical load management, demand side management, nonconventional technology relying on renewable resources, cogeneration, distributed generation, energy storage, transmission, and energy efficiency improvements as sources of new supply (170 IAC 4-7-8(b)(4)); and
- Demonstration of how the preferred resource portfolio balances cost minimization with cost-effective risk and uncertainty reduction (170 IAC 4-7-8(b)(7)).

With these standards in mind, the undersigned offer the following comments.

II. I&M's Stakeholder Process is a Good First Step, but Substantial Improvements are Needed.

Pursuant to 170 IAC 4-7-2.1, I&M established a stakeholder engagement process beginning in March 2013. IRP at ES-3. The undersigned commenters commend the Company for conducting this process in this inaugural year of stakeholder participation in IRP development. However, ample opportunity exists for improvement in the process. The Commission and I&M should consider the following suggestions to improve the stakeholder advisory process going forward.

First, while I&M is not required to hold more than two meetings, an effective process with substantial stakeholder participation requires at least four to five meetings to allow time for stakeholders to digest the information presented and revise their recommended portfolios. During the 2013 process, the meetings were often too short to delve deeper into discussions of the Company's IRP model, assumptions and the various scenarios. Additionally, remote participation using software, such as GoToMeeting®, and teleconferencing would enable participants to review materials and remain engaged in the event they could not attend all meetings in person.

Second, a majority of the meetings should be held in the service territory so that stakeholders in the area are able to attend. In the past round of meetings, several important stakeholders were unable attend because two of three of the meetings were held in Indianapolis. In the future, two meetings in each major area would improve the quality of participation by allowing many stakeholders to attend on a consistent basis. The Company should distribute meeting materials at least one or two weeks before the meeting so that participants have sufficient time to review, research and consult with others in advance of the meeting. A stakeholder listserv would also facilitate more effective participation.

Finally, in this past round, the Company's IRP scenarios were devised at the first meeting, and stakeholders did not have an opportunity to meaningfully review and further develop them before the Company ran them in the model. Stakeholders' suggestions concerning pricing information and the treatment of energy efficiency, for example, were rejected, as reflected in these comments. Going forward, stakeholders should be afforded more time to review and provide feedback on these and other IRP modeling issues.

We urge the Commission and the Company to incorporate these suggestions in an effort to improve the stakeholder process going forward.

III. I&M Fails to Adequately Evaluate Energy Efficiency And Underestimates the Potential for Increased Savings.

Energy efficiency is the least-cost, least-risk system resource. With an average levelized cost of roughly 2-5 cents per KWh,[3] no emissions, and the ability to defer or avoid the need for generation and related infrastructure, energy efficiency programs are a critical part of a cost-effective utility resource mix that can lower system costs and customer bills. Therefore, as this Commission has recognized, "an important component of long-term planning for Indiana's generation needs is the effective utilization of DSM programs by jurisdictional utilities that have a duty to serve their ratepayers in a cost effective manner."[4] The IRP rule ensures such utilization by requiring Indiana's utilities to demonstrate that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis, and that their preferred resource portfolios utilize, to the extent practical, all economical load management,

[3] *See, e.g.*, Ethan A. Rogers, Energy Efficiency as a Resource in Integrated Resource Planning, American Council for an Energy-Efficient Economy ("ACEEE"), presentation at IURC Contemporary Issues Technical Conference, slide 8 (Oct. 17, 2013) ("Rogers IURC Presentation"), *available at* http://www.in.gov/iurc/files/Ethan_A._Rogers__ACEEE_Contemporary_Issues_Presentation.pdf; Katherine Friedrich *et al.*, Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs, ACEEE, p. 4 (2009), *available at* http://aceee.org/research-report/u092.

[4] Phase II Order, p. 30, IURC Cause No. 42693 (Dec. 9, 2009).

demand side management ("DSM")[5] and energy efficiency improvements as sources of new supply. 170 IAC 4-7-8(b)(3),(4).

I&M's IRP does not reflect adequate consideration (or utilization) of the energy efficiency resource and, as such, fails to meet the requirements set out in 170 IAC 4-7-8(b)(3), (4). The Company projects noncompliance with Indiana's energy savings goal, and fails to properly evaluate higher levels of savings. I&M modeled the impacts of energy efficiency in the near term by adjusting its load forecast by a fixed amount of energy and demand savings that is insufficient to meet the savings goal. Done this way, efficiency is not allowed to compete with supply-side resources on equal footing. In the long term, the Company modeled efficiency using cost estimates that are not sufficiently explained or justified. I&M fails to model a higher efficiency and does not sufficiently justify the selected amount in its Preferred Portfolio. Finally, the Company incorrectly assumes that federal lighting standards eliminate future cost effective savings opportunities.

A. I&M Projects Non-Compliance with Indiana's Energy Efficiency Savings Standard.

Although I&M concludes that it "needs to make continued investment in demand-side management," IRP at ES-2, the Preferred Portfolio appears to fall significantly short of the 2% annual energy savings goal established by the Commission in 2009 in Cause No. 42693.[6] After a thorough investigation into DSM programs in Indiana and best practices in other states, the Commission set annual savings goals for jurisdictional electric utilities starting at 0.3% in 2010 and ramping up gradually to 2% by 2019.[7] The annual goals add up to roughly 11.9% (on a

[5] DSM, or demand-side management, is the planning, implementation, and monitoring of a utility activity that is designed to influence customer use of electricity and produces a desired change in a utility's load, and includes energy efficiency and demand response programs. 170 IAC 4-7-1(j); IRP at 8, note 3.
[6] Phase II Order, p. 30-31, IURC Cause No. 42693.
[7] *Id.*

cumulative basis) by 2019, and represent a savings *floor* in Indiana.[8] By contrast, the Company's Preferred Portfolio includes energy efficiency programs that are projected to meet 9.5% of projected energy needs (2,586 GWh) by 2033. IRP at ES-6. That is, I&M has selected a portfolio that fails to comply with the minimum energy savings requirements. IRP at 30 (stating that noncompliance with regulatory mandates "has become I&M's view of a 'base' or expected outcome").[9] Moreover, the IRP does not even consider, in its optimizing model, a level of energy efficiency that would meet or exceed the goal. As a result, I&M failed to demonstrate that its preferred portfolio utilizes, to the extent practical, "all economical ... demand side management ... and energy efficiency improvements as sources of new supply." 170 IAC 4-7-8(b)(4).

"Saving energy is the most cost effective way of meeting future energy supply needs and has the corresponding benefit of reducing the need to build additional generation capacity."[10] Yet, in failing to select a portfolio that meets the minimum savings goal, I&M contends that it is not practical for it to achieve 2% savings by 2019. *See* IRP at 8 ("This IRP includes energy efficiency programs designed to comply with [the Phase II Order and Michigan's Energy Optimization Standard], to the extent practicable."). I&M further characterizes the energy savings floor as "aggressive." IRP at 30.

I&M's flawed characterization of the savings goal stands in stark contrast to the experience of utilities across the country, including in neighboring states. At least 15 states have set cumulative energy efficiency savings goals for 2020 in excess of 10%. Moreover, ten states

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[8] *Id.* at 32 ("These savings goals are established as statewide objectives and represent a savings *floor* to be achieved in Indiana.") (emphasis added).

[9] *See also* IRP at 80 (stating that the plan reflects efficiency levels required for compliance with Michigan's targets (10.55% of installed energy savings by 2020) and forecasted expected performance in Indiana).

[10] Phase II Order, p. 30.

achieved energy savings of more than 1.2% in 2011.[11] Similar to Indiana, the neighboring state of Ohio passed legislation in 2008 requiring 22% energy savings by 2025, starting at 0.3% annual savings in 2009, ramping up to 1% annual savings by 2014, and 2% in 2019.[12] A comprehensive analysis by ACEEE, ICF International, Synapse Energy Economics, and Summit Blue Consulting found that such savings levels could be "easily" satisfied cost effectively with "innovative policies and proven utility programs."[13] Indeed, Ohio's investor-owned utilities collectively exceeded the savings goals during each of the first three years of implementation at a cost of 1.1 cents per kwh saved (levelized cost of saved energy, $0.011/kwh).[14] AEP Ohio's efficiency programs have resulted in $1 billion in net savings to customers since 2009, at an average levelized cost of 1.1 cents per KWh.[15] Another example is the neighboring state of Michigan, where utilities have ramped up their savings from 0.3% in 2009 to roughly 1.25% in 2012.[16] Electric IOUs achieved 128% of their savings target of one percent of retail sales in 2012.[17] As the Michigan PSC noted, with a statewide levelized cost of 2 cents per KWh ($20/MWh), energy efficiency is "significantly cheaper than supply side options such as new natural gas combined cycle generation at $67/MWh or more," and has a simple payback period of 2.3 years.[18]

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[11] Annie Downs *et al*., The 2013 State Energy Efficiency Scorecard, p. 31, ACEEE (2013), *available at* http://www.aceee.org/research-report/e13k.
[12] Ohio Revised Code 4928.66.
[13] ACEEE, Shaping Ohio's Energy Future: Energy Efficiency Works, at iv (March 2009), *available at* http://aceee.org/research-report/e092.
[14] Rogers IURC Presentation, slide 27; Max Neubauer *et al.*, Ohio's Energy Efficiency Resource Standard: Impacts on the Ohio Wholesale Electricity Market and Benefits to the State, p. 4, ACEEE, p. 4 (2013), *available at* http://www.aceee.org/sites/default/files/publications/researchreports/e138.pdf.
[15] *Id.*
[16] Hon. John D. Quackenbush, *et al.*, 2013 Report on the Implementation of P.A. 295 Utility Energy Optimization Programs, Michigan Public Service Commission, p. 4 (Nov. 26, 2013), *available at* http://www.michigan.gov/documents/mpsc/eo_report_441092_7.pdf.
[17] *Id.*
[18] *Id.* at 6-7.

Far from being impractical or aggressive, Indiana's energy savings standard, as outlined in the Commission's Phase II Order, is a reasonable *floor* for efficiency savings. I&M's failure to sufficiently evaluate higher levels of efficiency, and its adoption of a base case and preferred mix that achieves a level of savings that is below this established floor, is unreasonable and should be remedied.

B. I&M Fails to Adequately Model Energy Efficiency Resource Alternatives

I&M projects a low energy savings level due to its inadequate evaluation of energy efficiency. I&M states that it used an optimization model, Plexos® Linear Program, to develop a "least cost" resource plan that includes "the appropriate level" of additional demand-side resources. IRP at ES-5, 172. However, the Company does not make any additional energy efficiency resource options available in its optimization modeling until 2020, the year after the total statewide savings goal is to be met (2% annual savings by 2019). IRP at 90,182. This is especially troubling in light of I&M's baseline assumption of noncompliance with the goal.

I&M incorporates efficiency into its IRP through 2019 by adjusting its load forecast to account for the impacts associated with its programs (past, current and future implementation) as well as federal standards. IRP at 9, 76. Treating energy efficiency as a load modifier in this way relegates efficiency to a fixed amount that cannot increase based on need. Simply put, it does not allow efficiency to compete with supply-side alternatives in the IRP to meet electricity needs during the next five years. This approach contravenes the purpose of the IRP Rule, which requires that a utility "[d]emonstrate that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis." 170 IAC 4-7-8 (b)(3). As discussed during the 2012 IRP Contemporary Issues Technical Conference, "[t]he intent of the revised IRP Rule is to have demand-side resources compete with supply-side resources in the IRP, *not simply* *subtracting a value from the forecast*."[19] Yet, in its plan, I&M does precisely what the revised proposed rule seeks to guard against – it subtracts its projected value of efficiency savings through 2019 from its load forecast. The result is projected savings well below the energy savings goal. Further, I&M fails to explain why it did not consider higher levels of efficiency in the near term (either in the form of new or expanded programs) to help it meet or exceed Indiana's energy savings goal.

Beginning in 2020, I&M allowed its optimization model to select additional energy efficiency resources incremental to those in the load forecast. IRP at 176. The two optimized cases that I&M constructed contain the same amount of DSM (249 MW). Thus, it does not appear that I&M evaluated any variation in energy efficiency levels in the long term either. The Company does not explain how it arrived at the selected amount of DSM other than noting that it modeled "[e]nergy efficiency resources incremental to those included in the load forecast." IRP at 176. What is clear is that by fixing the amount of efficiency in the short-term and limiting its role in the optimization model in long term, I&M fails to adequately consider energy efficiency as resource alternative on a comparable basis to supply-side alternatives.

C. I&M's Energy Efficiency Cost Assumptions Are Unexplained and Raise Concerns.

I&M modeled additional energy efficiency resources starting in 2020 based on cost assumptions that appear substantially out of step with the cost of efficiency across the country, including in the Midwest and from the third party data source upon which I&M relies in its IRP. In Table 4E-1 of the IRP (p. 91), I&M presents the costs of the additional efficiency resource options it considered after 2019, which is broken down into two tiers. I&M does not explains the

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[19] Summary of IRP Contemporary Issues Technical Conference, p. 4 (held Oct. 18, 2012), *available at* http://www.in.gov/iurc/files/Summary_of_IRP_Contemporary_Issues_Technical_Conference_held_on_Oct_18_2012.pdf (emphasis added).

tiered system, but several of the selected measures have a higher cost in Tier 2. The costs of the efficiency measures, which I&M presents in "$/first year MWh" terms, range from $158 - $2,074/MWh, with an average cost of $578/MWh and $899/MWh in tiers 1 and 2, respectively. IRP at 91.

At the outset, it is important to note that the "$/first year MWh" cost metric represents the entire measure cost divided by only the first year of savings that the installed measures produce. However, the savings for a given installed measure will continue to accrue throughout the life of the measure. Thus, the $/first year MWh is not comparable to the cost of generating electricity ($/MWh). Rather, the levelized cost of energy efficiency (or electricity saved) over the measure life of savings provides a comparison to supply-side generation. For example, efficiency has a levelized cost of 2-5 cents per KWh energy efficiency as compared to 6.5-14.5 cents per KWh for coal and 6-9 cents per KWh for natural gas.[20]

I&M states that in developing its cost assumptions it used data from Efficiency Vermont, adjusting the data "to account for the difference in climate." IRP at 90. However, I&M does not provide the underlying Efficiency Vermont data or the Company's underlying workpapers, nor is I&M's general reference to this third-party data source sufficient to allow the Commission or the public to analyze or even verify the data. I&M merely provides a hyperlink to a page on Efficiency Vermont's website that contains more than thirty documents, including annual reports and plans spanning back to 2003 through the present. IRP at 90. The IRP does not contain a specific reference to a page or even a document, thus failing to provide specific information

[20] Lazard's Levelized Cost of Energy Analysis – Version 7.0 (2013).

required by 170 IAC 4-7-4(b)(2).[21] Critically, I&M's method for making adjustments to the data set that it used is not explained anywhere in the IRP.

Based on what is presented in the IRP, I&M's measure costs appear high in comparison to estimates from other states. In 2011, for example, Efficiency Vermont (the source of the data I&M uses) delivered energy efficiency at an average cost of $318/first year MWh,[22] or 4.3 cents/KWh.[23] In 2012, Efficiency Vermont delivered energy efficiency at an even lower cost of 3.4 cents/KWh.[24] I&M's estimates are also substantially higher than cost estimates in other states in the Midwest and across the country. For example, in 2009 and 2010, efficiency programs in Ohio, Michigan, Illinois, Iowa and Arkansas had average costs of $120 per first-year MWh.[25] A 2009 study across 14 states found that on average, efficiency programs costs roughly $0.025/KWh levelized, which is equal to roughly $230 per first-year MWh net (or $180/MWh in gross savings).[26]

Thus, numerous utilities across the country and in the Midwest are saving energy at significantly lower cost than what I&M assumes in its IRP. As required by 170 IAC 4-7-4(b)(2),

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[21] 170 IAC 4-7-4(b)(2) provides that a reference to a third party data source "must include the source title, author, publishing address, date, and page number of relevant data."

[22] Utility Facts, Vermont Public Service Department, pp. EFF.4-5 (2013), *available at* http://publicservice.vermont.gov/sites/psd/files/Pubs_Plans_Reports/Utility_Facts/Utility%20Facts%202013.pdf (costs include utility initiatives & acquisitions expenditures).

[23] Year 2010 Savings Claim, Efficiency Vermont, p. 2 (2012), *available at* http://www.efficiencyvermont.com/docs/about_efficiency_vermont/annual_reports/2010_Savings_Claim.pdf; Savings Claim Summary 2011, Efficiency Vermont, p. 4 (2012), *available at* http://www.efficiencyvermont.com/docs/about_efficiency_vermont/annual_reports/2011_Savings_Claim_Summary_EfficiencyVermont.pdf.

[24] Savings Claim Summary 2012, Efficiency Vermont, p 4 (2013), *available at* http://www.efficiencyvermont.com/docs/about_efficiency_vermont/annual_reports/Efficiency-Vermont-2012-Savings-Claim-Summary.pdf.

[25] *See* ACEEE, An Assessment of Utility Program Portfolios, Prepared for the U.S. Department of Energy, Energy Efficiency and Renewable Energy, Technical Assistance Program (2011), *available at* http://energy.ky.gov/Programs/SEE%20KY/March%202012%20Meeting/ACEEE%20Utiilty-Program%20Analysis%20Report.pdf (providing levelized cost estimates).

[26] Katherine Friedrich *et al.*, Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs, p. 4, ACEEE (2009), *available at* http://aceee.org/research-report/u092.

and in light of the significant difference between what I&M assumes in its model and these lower cost estimates, I&M should provide the third party data set it used, specifically cite to any sources relied upon, and explain the adjustments made to arrive at the estimates presented in the IRP.

D. I&M Must Continue to Pursue Cost-Effective Savings Opportunities.

I&M's position that it cannot reach the savings goals is based on the phasing in of federal lighting standards under the Energy Independence and Security Act of 2007 (EISA), which began in 2012. IRP at 76-78. As I&M notes, a substantial amount of utility efficiency savings comes from lighting-focused programs (*e.g.* residential and commercial lighting programs) or programs with lighting measures (*e.g.* home energy audits, low-income direct install). Increasing lighting baselines will reduce energy savings attributable to utility programs and the cost of programs may increase modestly. However, a significant amount of cost effective savings potential remains for lighting technologies, including CFLs, even after accounting for federal efficiency standards.[27] Inefficient light bulbs still occupy more than 70% of the lighting sockets in the U.S. and federal standards alone will not eliminate inefficient lighting.[28] Thus, a substantial amount of energy savings from lighting has not yet been realized.

As baselines increase in lighting and other technologies, I&M should continue to explore emerging technologies and different marketing approaches for existing measures. For example,

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[27] *See e.g.,* Dan York *et al.*, Frontiers of Energy Efficiency: Next Generation Programs Reach for High Energy Savings, ACEEE (2013) p.5, http://www.aceee.org/sites/default/files/publications/researchreports/u131.pdf ("Frontiers of Energy Efficiency"); Seth Craigo-Snell, Is it Still Cost Effective to Promote Light Bulbs? Should We?, Applied Proactive Technologies, Inc., Presented at the International Energy Program Evaluation Conference (2013); Bonn, The Once and Future CFL Efficiency Vermont, (2013), http://efficiencyvermont.com/docs/about_efficiency_vermont/whitepapers/White_Paper_Bonn.pdf.

[28] Frontiers of Energy Efficiency at 30; U.S. EPA, Next Generation Lighting Programs: Opportunities to Advance Efficient Lighting for a Cleaner Environment (2011), pp 1,11 http://www.energystar.gov/ia/partners/manuf_res/downloads/lighting/EPA_Report_on_NGL_Programs_for_508.pdf

in response to increasing baselines and other challenges in the CFL market, Efficiency Vermont developed new approaches to increase consumer participation in the residential CFL market.[29] Efficiency Vermont launched a specialty CFL campaign and new collaboration with food banks targeting low-income customers, which resulted in a combined 15% increase in socket saturation of CFLs.

Other regions of the country with a long history of substantial efficiency savings continue to save energy at high levels through efficiency programs – and plan to do so long into the future – despite the phase out of the least efficient light bulbs. The most recent power plan from the Northwest Power and Conservation Council, for example, projects that cost-effective, available energy efficiency will meet 85% of the region's growing power needs through 2030.[30] Although I&M and other utilities will need to adapt to changing baselines, vast amounts of cost-effective savings opportunities remain.

E. Conclusion

In sum, I&M's evaluation of energy efficiency in its IRP is inadequate and falls short of complying with 170 IAC 4-7-8 (b)(3), (4). The Company fixed the efficiency impacts in the load forecast in the short term, which results in projected noncompliance with the Indiana's achievable efficiency standard. In the out years of the planning period, I&M modeled additional efficiency based on adjustments to third party cost estimates that are not sufficiently explained. The Company did not model any variation in efficiency levels, including levels beyond the projected 9.5% cumulative savings by 2033, and incorrectly assumed that federal lighting standards eliminate additional cost effective efficiency opportunities. I&M's treatment of

[29] Lara Bonn, A Tale of Two CFL Markets: An Untapped Channel and the Revitalization of an Existing One, Efficiency Vermont, (2012), *available at* http://www.aceee.org/files/proceedings/2012/data/papers/0193-000197.pdf.
[30] Sixth Northwest Conservation and Electric Power Plan, http://www.nwcouncil.org/media/6284/SixthPowerPlan.pdf.

energy efficiency is especially troubling in light of the results of the Company's generation risk analysis, which showed that additional energy efficiency, along with solar generation, reduced the risk or revenue requirement volatility. IRP at 188-89.

The result is a Preferred Portfolio that falls short on efficiency, depriving customers of significant energy savings. Such energy savings would save ratepayers money not only by reducing the amount of electricity they need to purchase, but also by enabling I&M to reduce the amount of retrofitted power generation capacity that it pursues. In the absence of evaluation and implementation of increased levels of efficiency, the prudency of investments in new or retrofitting generation capacity is called into question. I&M should evaluate and implement a much more robust DSM program that would save ratepayer money and reduce system-wide cost and risk by achieving significantly higher energy and peak demand reductions.

IV. I&M's Distributed Solar Generation Analysis Undervalues this Important Resource and is Insufficient.

IRPs must include a discussion of distributed generation and the potential effects on generation, transmission, and distribution planning and load forecasting. Rule 170 IAC 4-7-4(b)(5). In its IRP, I&M recognizes the emergence of "a potentially significant amount of behind-the-meter distributed generation," primarily solar PV, on its system. IRP at 8. With "rapidly declining installed solar costs," IRP at 30, solar distributed resources are increasingly viable and cost competitive. Further, as the Company notes, solar produces the majority of its energy at times when power prices in PJM are at their highest. IRP at 92. I&M's Preferred Portfolio accounts for net metering customers (who own on-site distributed generation) beginning with 10 MW (nameplate) of distributed solar in 2016 and increasing to 153 MW by 2033. IRP at 192.

There has been a steady increase in the net metering capacity and customers in Indiana since 2005, growing from 16 customers and 23 KW in 2005 to 388 customers and 5297 KW in 2012.[31] As of early September 2013, I&M has 83 net metering customers with a total of 566 KW of distributed generation. IRP at 58-59. In light of this increase in Indiana and the significant market penetration of distributed solar across the country, a comprehensive analysis concerning the full value of the resource – including costs and benefits – is critical to resource planning.[32]

Unfortunately, the Company's analysis raises more questions than it answers and appears to undervalue distributed solar generation, thus falling short of the requirements of Rule 170 IAC 4-7-4(b)(5). The Company presents Figure 4E-3 (IRP at 93)[33] to illustrate the value of distributed generation (represented by solar PV) to I&M as compared to the costs of providing net metering payments to customers.[34] I&M concludes that customer-sited solar distributed generation is uneconomic from I&M's perspective, *i.e.*, it costs I&M more than the PJM value it provides, and that it did not optimize it in its modeling. However, I&M fails to provide any underlying data, inputs or assumptions in the IRP or appendix. This information is critical to assessing the breakeven figure presented in the IRP.

I&M appears to undervalue distributed solar generation. Based solely on the Figure 4E-3, the "PJM value of solar," which is represented by the blue line, likely represents energy and

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[31] IURC, 2012 Annual Summary Report, (March 2012), *available at* http://www.in.gov/iurc/files/2012_Net_Metering_Required_Reporting_Summary.pdf.

[32] Jason B. Keyes and Karl R. Rábago, A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, Interstate Renewable Energy Council, Inc. ("IREC Regulator's Guidebook") (Oct. 2013), http://www.irecusa.org/wp-content/uploads/2013/10/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG.pdf.
(citing Andrew Mills & Ryan Wiser, An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes, Lawrence Berkeley National Laboratory, LBNL-5933E (December 2012), http://emp.lbl.gov/sites/all/files/lbnl-5933e_0.pdf)).

[33] The same figure is presented on page 184 of the IRP (Figure 8-C).

[34] While net metering facilitates distributed generation, it should be noted that the Company is using a net metering analysis to assess the economics of distributed generation more broadly.

generation capacity prices. IRP at 93. Limiting the value of solar to the energy and generation capacity that is avoided, however, overlooks several other critical benefits distributed solar generation provides and, as a result, undervalues this resource. Moreover, without evaluating the underlying data, it is unclear whether the energy and generating capacity values presented are reasonable.

While not comprehensive, what follows are a list of some of the categories of benefits that should be considered when assessing the value of distributed solar generation:[35]

- Energy - The energy generated by distributed solar systems displace energy generated by remote centralized power plants, and reduce line losses;
- Capacity – Distributed solar systems avoid capital costs in generation plants as well as transmission and distribution infrastructure (including new lines and upgrades);[36]
- Grid Support – By reducing load, solar distributed generation avoids ancillary service costs. VAR support should also be considered;
- Fuel Prices – Distributed solar generation reduces reliance on fuel sources and therefore serves as a hedge against the risk of fuel shortages and price volatility; and
- Environmental – As an emissions-free resource, distributed solar generation reduces reliance on fossil-fuel generation, and results in fewer emissions and reduced compliance costs.

Without knowing whether and how these benefits were incorporated in I&M's evaluation of distributed solar generation, the results as presented in Figure 4E-3 cannot be relied upon.

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[35] I&M appears to have included the primary utility cost, the retail credits provided to net metering customers, in its analysis. For a more complete discussion of evaluating the benefits and costs of distributed solar generation, *see* IREC Regulator's Guidebook, pp. 20-42.

[36] I&M asserts that the transmission and distribution benefits that distributed solar resources provide are "largely absent" due to the Company's flat-to-declining load growth and its summer peaking pattern (late in the day, trailing off slowly). IRP at 93-94. However, most, if not all, of the electricity generated by solar distributed generation systems are either consumed on site or by nearby customers on the distribution system. This results in a reduction in the use of the transmission and distribution system and associated costs.

The Company's analysis and modeling of distributed solar generation raises a couple of additional concerns. First, the Company modeled distributed generation as a solar PV resource in 10 MW blocks per year. IRP at 176. I&M does not explain why it used a 10 MW increment. Such an explanation is warranted, particularly in light of the fact that I&M's total distributed solar nameplate capacity is 137 kw (or 0.137 MW), as of 2012. Second, I&M states that the solar PV is modeled at a cost equal to the full retail net metering rate. *Id.* However, it is unclear whether the Company is using residential rates or a mix of customer sector rates (e.g. residential, commercial, school) in the model. Given the difference in rates across customer sectors, it is important to know what constitutes "the full retail net metering rate" in the model.

In light of I&M's apparent failure to include several categories of benefits of distributed solar generation and the complete absence of data underlying its Figure 4E-3, I&M's evaluation of distributed generation appears to significantly undervalue distributed solar resources.

V. I&M's IRP Fails to Evaluate Cogeneration and Distributed Wind Resources, and Limits its Evaluation of Utility-Scale Resources.

I&M must consider cogeneration and non-utility generation in meeting future electric service requirements, and must demonstrate that its preferred portfolio utilizes, to the extent practical, all economical renewable resources, cogeneration, and distributed generation, among other resources. I&M's cursory discussion and dismissal of cogeneration and distributed wind resources does not meet this IRP requirement and should be remedied.

Although I&M identified combined heat and power ("CHP"), also known as cogeneration, as an "increasingly viable" distributed resource, the Company did not evaluate this resource in its IRP.[37] IRP at 30, 88. CHP is the simultaneous production of electricity and heat

[37] Cogeneration more generally is also not discussed in the IRP.

from a single fuel source.[38] Because the heat produced would typically otherwise be wasted, CHP provides a great opportunity to save money and conserve resources while also generating electricity.

Indiana has 37 CHP sites, totaling nearly 2500 MW of installed capacity.[39] A recent study found that Indiana has a technical potential of 3,553 MW in additional CHP capacity and an economic potential of about 611 MW additional, with supportive policies.[40] To close the gap between the economic potential for CHP (additional 611 MW) and currently economically viable CHP opportunities (additional 56 MW) will require the removal of market barriers and adoption of supportive state policies, including financing assistance and incentives.[41] However, I&M and other utilities must also play a role in helping identify, develop, and finance CHP opportunities in their service territories.[42] And the resource planning stage is where such effort to increase CHP should be documented and planned for the future. By not evaluating this resource, I&M's IRP has fallen short in this regard.

The Company also failed to evaluate small distributed wind generation facilities (residential and commercial), IRP at 88, despite the fact that the majority of the net metering capacity in Indiana (3509MW out of 5297 MW total) is comprised of wind generation facilities, including 251 kw in I&M's service territory.[43] While the penetration rates may be low,

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[38] EPA CHP Partnership, Basic Information, *available at* http://www.epa.gov/chp/basic/index.html; *see also* 170 IAC 4-7-1(e) (proposed rule); 170 IAC 4-7-1(d) (current rule).
[39] Pew Environment Group, Combined Heat and Power: Energy Efficiency to Repower U.S. Manufacturing, p.1 (May 2011), *available at* http://www.pewenvironment.org/uploadedFiles/PEG/Publications/Fact_Sheet/CHP_INDIANA_HI-RES_5.10.11.pdf.
[40] Anna Chittum and Terry Sullivan, Coal Retirements and CHP Investment Opportunity, ACEEE Research Report IE 123, p. 29 (2012), http://www.aceee.org/sites/default/files/publications/researchreports/ie123.pdf.
[41] *Id.* at 29-30.
[42] ACEEE, Why Utilities Are an Essential Partner for a Strong CHP Future (Oct. 18, 2012), *available at* http://www.aceee.org/blog/2012/10/why-utilities-are-essential-partner-s.
[43] IURC, 2012 Annual Summary Report, (March 2012), *available at* http://www.in.gov/iurc/files/2012_Net_Metering_Required_Reporting_Summary.pdf.

distributed wind is a low-cost, clean technology that currently is being utilized by Indiana customers and will continue to grow. As such, its role in meet demand over the twenty-year planning period must be evaluated.

I&M projects an increase in utility-scale solar and wind resources over the planning period. The Preferred Portfolio includes a total of 300 MW of wind and 700 MW utility solar (nameplate) during the planning period. IRP at ES-10. Although these planned additions recognize the value of these cost-competitive renewable resources, the Company limited the amount of resources that the model could select. Specifically, utility solar and wind resources were available in annual increments of no more than 50 MW and 100 MW, respectively. IRP at 176. The Company should explain why it imposed this annual cap in its modeling, which constrained the level of solar and wind resources that could be selected.

VI. The Company Fails to Identify, and Quantify Where Possible, A Number of Additional Costs and Risks Facing Coal-Fired Generating Units in its Preferred Resource Portfolio.

A core requirement of the Commission's proposed IRP rule is that Indiana's utilities should attempt to quantify the risks and uncertainties facing different alternative resource plans and, in selecting a preferred resource portfolio, "balance[] cost minimization with cost-effective risk and uncertainty reduction." 170 IAC 4-7-8(b)(7). According to the official summary of the Commission's 2012 Contemporary Issues Technical Conference, "[t]he revisions in the IRP rule are intended to stress that risk as well as cost should be considered when identifying future resources. The goal is to move from simply identifying the 'least cost' plan to a more robust plan that holds up to future risks and represents the best combination of cost and risk. . . .

Commission staff hopes for discussion in the IRP regarding what went into decision-making process and how the utility weighed the uncertainties."[44]

I&M's 2013 IRP filing fails to live up to this requirement. Although the IRP includes a Monte Carlo analysis of the Revenue Requirement at Risk ("RRaR") in the alternative resource plans that it considers, this analysis of risk fails to fully quantify numerous risks and uncertainties engendered by the Company's continued heavy reliance on coal-fired generation – both from the Company's own two units at the Rockport plant, and from purchases of power from Ohio Valley Electric Corporation ("OVEC") plants that the Company partly owns – throughout the planning period. Even assuming that the Company's Monte Carlo analysis is valid, that analysis concludes that the Company's preferred resource portfolio and other resource portfolios in which the Company continues to rely on generation from its two coal-fired units at the Rockport plant have the highest RRaR. IRP at 189. Conversely, the Company's Monte Carlo analysis also concludes that alternative resource portfolios that add greater energy efficiency and renewable capacity have less RRaR than the Company's preferred approach. *Id.* at 188-89. Nevertheless, the Company asserts in the IRP that the higher RRaR of its preferred plan is acceptable given that the Company finds that its preferred plan has a lower cost and that it represents a "reasonable combination of expected costs and risk relative to the cost-risk profiles of the other portfolios." *Id.* at 190.

The Company's comparison of the relative cost-risk profiles of different portfolios is not valid, however, because the Company fails to account for a number of additional future costs and risks facing coal-fired generating units and/or it is impossible to determine whether the Company

[44] Summary of IRP Contemporary Issues Technical Conference, at 2-4 (Oct. 18, 2012), *available at* http://www.in.gov/iurc/files/Summary_of_IRP_Contemporary_Issues_Technical_Conference_held_on_Oct_18_2012.pdf.

accounts for those costs and risks because it fails to explain key assumptions. First, as noted in the preceding sections, the Company fails to evaluate the risk that by failing to evaluate and implement increased levels of DSM and renewable energy, the prudency of its planned investments in coal-fired generation can be called into question. Second, with respect to the Company's Rockport Power Plant, I&M has failed to fully identify and reasonably quantify and account for the risks that the Rockport units will face greater costs, or face costs earlier in the planning period, from regulations of greenhouse gases, air quality, wastewater, and coal ash, as well as the risks to the Rockport units from natural gas prices and capacity prices will be lower than the high projections that the Company is assuming in its modeling. Third, I&M's preferred portfolio continues to rely on purchases of power from two other coal-fired power plants, the Ohio Valley Electric Corporation's Clifty Creek and Kyger Creek plants (of which I&M is a partial owner), but the Company's IRP filing contains absolutely no discussion of the future costs or risks facing those plants, and in particular no discussion of any future environmental compliance costs at those plants.

For all of these reasons, the IRP's analysis of the costs and risks of its preferred resource portfolio and its comparison of its preferred portfolio with alternatives fails to live up to the requirements of the Commission's proposed IRP rule, in particular 170 IAC 4-7-8(b)(7). The undersigned commenters respectfully urge Commission staff to note these deficiencies in its report on the Company's IRP.

A. Carbon Prices

By evaluating only a narrow range of potential carbon prices, the IRP underestimates the economic risks posed by greenhouse gas ("GHG") regulation and the effect of those risks on the desirability of various resource portfolios. I&M itself acknowledges it "will be significantly affected by any GHG regulation." IRP at 9. Yet, on this issue, I&M does not analyze "how candidate resource portfolios performed *across a wide range* of potential futures." 170 IAC 4-7-8(b)(7) (emphasis added). Nor does I&M adequately discuss "how the preferred resource portfolio balances cost minimization with cost-effective risk and uncertainty reduction," given the Company's refusal to consider the possibility that the cost of emitting CO2 will be high enough to render Rockport uneconomic. *Id.* (proposed rule); *see also* 170 IAC 4-7-8(5) (current rule) (requires utilities to "[d]iscuss how the utility's resource plan takes into account the utility's judgment of risks and uncertainties associated with potential environmental and other regulations").

First, all three of the commodity pricing scenarios I&M uses for "capacity planning sensitivity analyses" of alternative resource portfolios in the 2013 IRP assume the same carbon price of $15/metric ton.[45] IRP at 50, 190. While other commodity prices were varied according to high, low, and base case scenarios, the portfolios have not been compared using any other carbon price for the planning period. I&M simply did not test their sensitivity to carbon price changes. The Company explained its reasoning as follows:

> The underlying reason for this assumption is that a CO2 cost cannot be so onerous that it "shuts in" a significant portion of the nation's generation fleet. Scenarios with untenably high CO2 prices simply mean higher power prices, not universal coal retirements. Very efficient coal plants, such as Rockport, will continue to dispatch as base load.

IRP Stakeholder Workshop 3 presentation, slide 5. In other words, a key assumption I&M used in developing the IRP is that coal-fired generation will not become uneconomic as a result of GHG regulations. I&M further assumed that Rockport's units in particular will not become

[45] I&M does not specify, but this price appears to be given in nominal dollars; the commodity price graphs at IRP Figure 8B-1 and the chart at IRP Exhibit 8-5 show the prices I&M assumed for CO2 in 2011 dollars. *See* IRP at 179; 198. The CO2 price in 2011 dollars starts at $11.57/metric ton in the year 2022 and gradually *drops* to $10.55/metric ton by 2033. IRP at 179, 198.

uneconomic as a result of GHG regulations because it deems them "relatively efficient." IRP at 190. These assumptions severely limit the robustness of I&M's analysis by failing to evaluate the alternative resource portfolios considered by I&M (and the risks and uncertainties inherent in each) against a range of potential futures. I&M's result-driven approach to analyzing the possible future costs and risks of GHG regulation disregards predictions by the federal government, the research community, public utility commissions, and other utilities engaged in recent IRP processes that contemplate a range of possible future carbon prices, some of which would be significantly greater than the single $15/metric ton carbon price that I&M used to evaluate alternative resource portfolios.

Furthermore, all three of I&M's pricing scenarios for the 2013 IRP assume that the earliest year any carbon price would take effect is 2022. IRP at 190. I&M does not explain how it takes into account the possibility that EPA regulations on greenhouse gas emissions at existing power plants could be finalized as early as 2015.

1. <u>Carbon price assumptions</u>.

The IRP contains no serious evaluation of the sensitivity of alternative resource portfolios to potential carbon prices. Despite recent developments in federal greenhouse gas policies, I&M assumes that the cost of CO2 will "stay within the $15-20/metric ton range over the long-term analysis period." IRP at ES-4. As noted above, all three of I&M's commodity pricing scenarios for evaluating alternative resource portfolios in its 2013 IRP assume the same nominal carbon price of $15/metric ton. *Id.* at 190. In terms of real dollars, I&M assumes that a carbon price, once established in 2022, will decrease over the remaining eleven years in the planning period. *Id.* at 190, 179. Although in selecting a preferred resource portfolio, the Company did run two sensitivities to evaluate it using "a suite of commodity prices associated with a zero carbon cost as well as a $25/metric ton cost," there is no way for the Commission or interested parties to compare how alternative resource portfolios would perform under the same assumptions. *Id.* at 190. Moreover, I&M has not provided any detailed information about the assumptions underlying this "suite of commodity prices" used to create these two sensitivities, nor does it clarify in which of the 20 planning-period years the $25/metric ton cost was assumed to take effect. "The underlying reason" I&M failed to consider carbon price sensitivity analyses for alternative resource portfolios is that it believes that "a CO2 cost cannot be so onerous that it 'shuts in' a significant portion of the nation's generation fleet." IRP Stakeholder Workshop 3 presentation, slide 5. The conclusion that carbon prices will necessarily remain so low as to have no significant impact on the economics of coal-fired generation is both speculative and at odds with forecasts used by the federal government, the research community, public utility commissions, and other utilities engaged in recent IRP processes.

In November 2013, Synapse Energy Economics published updated CO2 price forecasts based on its evaluation of regulatory developments, the carbon price used to assess the climate benefit of federal rulemakings, carbon forecasts in IRPs from 28 utilities, and the results of a multi-year Energy Modeling Forum (EMF) research effort on the costs of U.S. emissions abatement.[46] Synapse published low, mid, and high cases for the years 2020-2040.[47]

Synapse's low case is based on the type of scenario I&M believes is most likely: one in which federal policies to limit greenhouse gases exist, but are not stringent.[48] Yet, Synapse's low case forecasts a price of $10/ton beginning in 2020, increasing to $13/ton in 2022 and

[46] Synapse Energy Economics, *2013 Carbon Dioxide Price Forecast* (Nov. 1, 2013) [hereinafter Synapse 2013 Carbon Price Forecast], *available at* http://www.synapse-energy.com/Downloads/SynapseReport.2013-11.0.2013-Carbon-Forecast.13-098.pdf.
[47] *See id.* at 20, Table 1.
[48] *Id.*; IRP Stakeholder Workshop 3 presentation, slide 5.

$29.50/ton in 2033 (2012 dollars), expressed in American tons.[49] By contrast, I&M's assumed $15/metric ton (nominal dollars) carbon price assumption, expressed in the same units, would yield a price of just $10.71/ton that would take effect in 2022, decreasing to $9.77/ton in 2033 in its three pricing scenarios (2012 dollars). IRP at 198. Synapse's low price forecast begins two years earlier than I&M's, is more than $2 higher in 2022, rises during the planning period and finishes at more than triple what I&M considers likely. Over I&M's planning period, Synapse's low case forecast represents between 121% and 302% of the prices I&M used.

Synapse's mid case represents a future in which federal policies implement more ambitious but "reasonably achievable" goals.[50] In this forecast, CO2 costs $15/ton in 2020 and increases steadily to reach $19.50/ton by 2022 and $44.25/ton in 2033.[51] Again, these prices begin two years earlier. They range from 182 – 453% higher than I&M's $10.71-$9.77/ton during the planning period.

Synapse's high case assumes that "somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technological alternatives such as nuclear, biomass, and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions" will influence the CO2 price.[52] Synapse's high case forecast begins at $25/ton in 2020, reaches $31.50 by 2022, and finishes the I&M planning period at $67.25.[53] The Synapse high case forecasts 294 – 688% higher prices than I&M's $10.71-$9.77/ton.

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[49] *See* Synapse 2013 Carbon Price Forecast, at 20, Table 1.
[50] *Id.* at 3.
[51] *Id.* at 20, Table 1.
[52] *Id.* at 3.
[53] *Id.* at 20, Table. 1.

I&M's carbon price assumptions ignore more than Synapse's forecast. Other utilities have recognized that carbon prices pose serious risks that their IRP processes should take into account. Of the 29 high case forecasts from utility planning processes in 2012-2013 that Synapse reviewed, all but three modeled prices higher than $20/ton (American tons, 2012 dollars) after 2022.[54] The list includes Duke Energy Indiana, which has a carbon price in its reference case that begins at $17/ton in 2020 and rises to $50/ton by 2033.[55]

There is also a growing consensus among states that utilities must address climate change risk now rather than later, as evidenced by requirements that electric utilities include carbon emissions costs in their resource planning analyses or otherwise evaluate risks associated with future carbon regulation. In 2008, the Public Service Commission of Wisconsin denied an application for a certificate of public convenience and necessity for a new coal-fired power plant where the applicant utility failed to consider the costs of compliance with future carbon regulation.[56] A recent order by the Arkansas Public Service Commission called for consideration of the cost of compliance with future carbon regulation.[57] In Minnesota, utilities are required by statute to factor into all electricity generation resource acquisition proceedings "an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation" that is determined by the Minnesota Public Utilities Commission.[58] And in 2003, the California Public Utilities Commission ("PUC") adopted an energy resource "loading order" that requires

[54] *Id.* at 25, Fig. 8.
[55] *Id.*
[56] Application of Wisconsin Power and Light Company, Docket No. 6680-CE-170, at 8–10 (Wis. Pub. Serv. Comm'n Dec. 12, 2008) ("This large increase in greenhouse gas emissions takes this utility and this state in the wrong direction at a time when carbon constraints are imminent.").
[57] *In the Matter of the Continuation, Expansion, and Enhancement of Public Utility Energy Efficiency Programs in Arkansas*, Docket No. 13-002-U, at 19 (Ark. Pub. Serv. Comm'n Jan. 4, 2013) ("The Commission proposes that, while reasonable minds can differ regarding the exact magnitude of the cost of compliance with greenhouse gas regulation at existing power plants, it is prudent to forecast that the effect of greenhouse gas regulation on energy costs, and thus the associated economic risk, is not zero.").
[58] Minn. Stat. Ann. § 216H.06.

investor-owned utilities to account for the financial risk associated with CO_2 emissions when making long-term power plant investments and in developing long-term resource plans.[59] Recognizing that "[g]reenhouse gas emissions pose a real and substantial financial risk to customers and the utilities," the California PUC concluded that utilities must take into account the cost of future carbon regulation when evaluating resource investment decisions in order to protect ratepayers from such risk.[60] I&M's ratepayers face a similar financial risk, but the Company has failed to follow a prudent approach to evaluating that risk in this IRP process.

I&M's carbon price assumptions also fall far short of the collective societal cost of climate change harms, as quantified by a working group of federal agencies and assigned a dollar value.[61] These "social cost of carbon" estimates allow federal agencies and others to incorporate the benefits of greenhouse gas reduction in their cost-benefit analyses for regulatory actions, thus enabling a more complete understanding of their consequences. To this end, the working group quantified agricultural productivity loss, adverse human health effects, property damages from sea level rise and flooding, and depletion of ecosystem services expected to be caused by climate change.[62] Implicit in this undertaking is a recognition of the need to make some calculation of the marginal benefit of reducing CO_2 emissions, despite the limitations inherent in evaluating benefits across a multi-decade time horizon and the uncertainty in extrapolating damages from

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[59] *See* California Energy Comm'n, Energy Action Plan (May 8, 2003), *available at* http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF.
[60] California Pub. Utils. Comm'n, Decision 04-12-048 (Dec. 20, 2004), *available at* http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/43224.htm.
[61] Interagency Working Grp. on Social Cost of Carbon, U.S. Gov't, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (February 2010), *available at* http://www.epa.gov/otaq/climate/regulations/scc-tsd.pdf [hereinafter "2010 SCC Support Document"]; Interagency Working Grp. on Social Cost of Carbon, U.S. Gov't, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013), *available at* http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf [hereinafter "2013 SCC Update"]; *see also* U.S. EPA, The Social Cost of Carbon, http://www.epa.gov/climatechange/EPAactivities/economics/scc.html (last visited Jan. 30, 2014).
[62] 2010 SCC Support Document at 2.

temperature rises. The working group's recent update of its social cost of carbon estimates range from $11-221/metric ton (2007 dollars) depending on discount rate and year of emissions avoidance.[63] For the sake of comparison, the IRP assumes a price per metric ton, in 2007 dollars, of less than $10.66-$9.72 between 2022 and 2033.

2. <u>Regulatory timing assumption.</u>

I&M's assumption that any carbon price that results from EPA greenhouse gas regulations will not go into effect until 2022 may no longer be reasonable in light of recent developments that confirm the Obama Administration's intention to finalize new Clean Air Act New Source Performance Standards for greenhouse gases in the next two years. On June 25, 2013 (more than four months before the Company was required to submit its IRP), President Obama announced a comprehensive plan to cut the carbon pollution that causes climate change and endangers public health. Noting that nearly 40 percent of this pollution is produced by the power sector, the President directed the EPA to revise its proposal for carbon pollution standards for new power plants by September 20, 2013, to issue proposed standards, regulations, or guidelines addressing carbon pollution from existing power plants by June 1, 2014, and to finalize those limits within a year.

The President's announcement only confirmed and publicized a regulatory process that has been underway for years. In 2007, the Supreme Court held that carbon dioxide and other greenhouse gases are covered by the Clean Air Act's broad definition of "air pollutant" and that the EPA must decide whether greenhouse gases endanger public health.[64] After analyzing the available climate science, the EPA issued a formal finding that current and projected emissions of six greenhouse gases, including CO2, threaten the public health and welfare of current and

[63] 2013 SCC Update, Table A1.
[64] *Massachusetts v. Envtl. Prot. Agency*, 127 S. Ct. 1438, 1462–63 (2007).

future generations. This finding has since been upheld by the U.S. Court of Appeals for the District of Columbia Circuit.[65] That court also confirmed that the Clean Air Act requires the EPA to address greenhouse gas emissions under its stationary source permitting programs.[66] As confirmed by these decisions, Section 111 of the Clean Air Act requires the EPA to issue performance standards for air pollutants from both new and existing electric generating units.[67] While the precise details of these rules are still uncertain, it is clear that utilities will need to meet new regulatory requirements (and their associated costs) in the near future.

Given the risk that ratepayers will bear the costs of future carbon regulation, any prudent utility must mitigate its CO2 emissions to protect against such risks. Instead, I&M's 2013 IRP unreasonably discounts the possibility of future regulations placed on carbon dioxide emissions. If greenhouse gas regulations apply to Rockport prior to its projected retrofits in 2015, 2017 and 2019, or if they are more burdensome than I&M is willing to consider during this IRP process, it would have a significant negative impact on the economic viability of the Company's preferred resource plan as compared to alternative plans that do not include continued investments in Rockport. These possibilities also cast doubt on continued purchases of coal-fired power from the Ohio Valley Electric Corporation's ("OVEC") Clifty Creek and Kyger plants, although (as discussed in more detail below) I&M fails *entirely* in this IRP to address the future costs and risk facing these plants.

B. SO2 NAAQS

By delaying the installation of modern SO2 control technology at Rockport for more than a decade, the Company's preferred resource portfolio exposes ratepayers to the risk of costly

[65] *See Coal. for Responsible Regulation v. Envtl. Prot. Agency*, 684 F.3d 102, 120–22 (D.C. Cir. 2012).
[66] *Id*. at 134–36.
[67] *See* 42 U.S.C. § 7411(b) & (d).

enforcement actions and unplanned retrofits necessary to comply with health-based National Ambient Air Quality Standards ("NAAQS") for SO2. For the same reason, the preferred portfolio entails prolonging Rockport's contribution to ambient SO2 levels that EPA has found dangerous to public health. Although I&M acknowledges that compliance with the one-hour SO2 NAAQS will be required at the Rockport plant during the planning period, the Company fails to address at all in this IRP the possible future costs and risks to its preferred resource portfolio from implementation of the new standard.

In 2010, EPA promulgated stringent NAAQS requiring ambient SO2 concentrations of less than 75 ppb over one-hour averaging periods; EPA found this limit necessary to protect public health because exposure to even small amounts of SO2 over short periods of time can cause adverse health effects.[68]

While NAAQS are not emission limitations on individual sources, they impact emission limitations because states are required to develop plans to implement the NAAQS in areas that exceed the required concentrations ("nonattainment areas").[69] EPA's most recent SO2 NAAQS implementation strategy would require states to complete all SO2 NAAQS implementation plans by 2019 or 2022, with corresponding deadlines for bringing any non-attainment areas back into attainment (through measures such as more stringent emissions limits on individual sources) by 2022 or 2025, respectively. The earlier schedule applies to areas designated nonattainment through modeling, while the later schedule applies to areas designated through monitoring.[70] Even before non-attainment designations are completed and state implementation plans

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[68] *See* Primary National Ambient Air Quality Standard for Sulfur Dioxide, 75 Fed. Reg. 35,520 (June 22, 2010) (to be codified at 40 C.F.R. pt. 50); 326 IAC 1-3-4(b)(1).
[69] *See* 42 U.S.C. § 7410(a).
[70] *See* U.S. EPA, Next Steps for Area Designations and Implementation of the Sulfur Dioxide National Ambient Air Quality Standard at 5 (Feb. 6, 2013), *available at* http://www.epa.gov/airquality/sulfurdioxide/pdfs/20130207SO2StrategyPaper.pdf..

approved, major sources of SO2 emissions such as the Rockport plant may also be subject to emission limits ensuring compliance with the one-hour SO2 NAAQS if they are found to contribute significantly to violations of NAAQS in other states,[71] or in connection with seeking approval for any physical modifications at the facility that would cause a significant emissions increase.[72] In short, there are multiple legal mechanisms, and potential timeframes, under which emission limits to ensure that the SO2 NAAQS is not violated may be implemented at a major source of SO2 emissions such as the Rockport plant.

I&M itself acknowledges that the NAAQS could lead to more stringent SO2 limits at Rockport. *See* IRP at 150. Yet despite acknowledging this risk, I&M's preferred resource portfolio does not ensure compliance with the one-hour SO2 NAAQS until at least 2025, if not 2028. Those are the years in which I&M under its preferred approach would add modern flue gas desulfurization ("FGD") to control SO2 emissions at Rockport units 1 and 2, respectively. *See* IRP at ES-6. In 2015, the preferred plan would add cheaper, less effective dry sorbent injection ("DSI") SO2 controls to both Rockport units as a stopgap attempt to comply with EPA's distinct Mercury and Air Toxics Standards ("MATS"). *See* IRP at ES-5, 111, 146, & 152. Whether or not DSI would enable Rockport to comply with the MATS rule, it does not ensure that Rockport will not cause violations of the one-hour SO2 NAAQS.[73]

In fact, modeling has shown that Rockport will likely cause violations of the one-hour SO2 NAAQS in surrounding parts of Indiana and Kentucky after the proposed DSI controls are

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[71] 42 U.S.C. §§ 7410(a)(2)(D)(ii), 7426(b)-(c).

[72] 40 C.F.R. § 52.21(k); 326 IAC 2-2-5(a).

[73] I&M is also installing the DSI in order to comply with a recently-modified Consent Decree that I&M's parent company, American Electric Power, entered with the U.S. Department of Justice, eight state attorneys general, and thirteen citizen groups to settle alleged violations of the Clean Air Act's New Source Review ("NSR") provisions. *See* Order Entering Third Modification of Consent Decree, *United States of America v. Am. Elec. Power Serv. Corp.*, Civil Action No. C2-99-1182 (S.D. Ohio May 14, 2013). Nothing in that Consent Decree addresses what types of controls or levels of emission reductions I&M would need to achieve to ensure that Rockport complies with the 1-hour SO2 NAAQS. *See id.*

installed and until Rockport uses FGD, a period of more than 10 years. In a report dated December 10, 2012, expert air quality modeler Camille Sears concluded, using EPA's AERMOD air dispersion model, that Rockport's SO2 emissions will violate the one-hour NAAQS and may result in EPA's designation of the surrounding area as nonattainment even if I&M installs DSI controls with 50% SO2 control efficiency.[74] The affected area extends several miles into Kentucky, exposing I&M and its ratepayers to potential action by a political subdivision of that state under 42 U.S.C. § 7426.[75] Even after DSI controls are added, Sears' report projects peak ambient SO2 concentrations of up to 145% of the one-hour NAAQS.[76] Furthermore, Sears' modeling showed that Rockport would need to install SO2 controls with an efficiency rate of at least 82% to ensure compliance with the NAAQS.[77] Consistent with this finding, modeling showed no violations of the one-hour SO2 NAAQS at Rockport with 95% efficient FGD on both units.[78] I&M was made aware of Sears' modeling results during litigation in 2012 but subsequent developments in the case mooted the issue.[79]

The undersigned commenters are unaware of any evidence, from I&M or otherwise, that contradicts Sears' conclusion that Rockport will still cause SO2 NAAQS violations even if the plant achieves 50% SO2 reductions through the use of DSI. I&M makes no effort to refute this in its IRP materials, asserting instead that "the scope and timing of potential [NAAQS-related] requirements is uncertain." IRP at 150. Put another way, the Company is gambling that the one-hour SO2 NAAQS will not be enforced at the Rockport plant until at least 2025, if not 2028.

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[74] *See* Camille Sears, Air Dispersion Modeling Analysis for Verifying Compliance with the One-Hour SO2 NAAQS: AEP – Rockport Power Plant at 12, attached as Attachment 1.
[75] *See id.*, Fig. 3.
[76] *Id.* at 12.
[77] *Id.* at 11.
[78] *Id.*
[79] *See* Order Entering Third Joint Modification of Consent Decree at 2Reply, Case No. 2:99-CV-1182 (S.D. Ohio filed Dec. 7, 2012).

This approach imprudently dismisses both the economic and health risks associated with the Company's preferred portfolio. By delaying the large projected investment in FGD controls for Rockport for more than a decade, I&M lowers the portfolio's projected present value of revenue requirement ("PVRR") only at the expense of environmental compliance. This puts the preferred portfolio at an unrealistic advantage as compared with each of the stakeholder portfolios, which would either accelerate compliance with the NAAQS through earlier FGD installation or retirement of Rockport in favor of cleaner alternatives. *See* IRP, Table 2F-1, at 29.

Furthermore, it is not at all clear from the IRP documents why I&M expects enforcement to be so delayed. I&M is obligated to "[d]emonstrate how the preferred resource portfolio balances cost minimization with cost-effective risk and uncertainty reduction, including . . . [i]dentification and explanation of assumptions." 170 IAC 4-7-8(b)(7)(A) (proposed rule); *see also* 170 IAC 4-7-8(9) (current rule) (requiring utilities to "[i]dentify and explain assumptions concerning existing and proposed regulations, laws, practices, and policies made concerning decisions used in formulating the IRP."). The Company might be assuming that its area will not be designated nonattainment, that it will not be designated by modeling, that DSI will ensure that Rockport complies with the NAAQS, or that one FGD-controlled unit will be sufficient until 2028. Each of these assumptions entails different types and magnitudes of risk. Without knowing which assumptions I&M has made, the Commission has no way to evaluate those assumptions or the crucial resource decisions premised on them.

C. ELG and CCR Rules

I&M does not disclose its assumed capital expenditures at the Rockport plant that will be necessitated by EPA's proposed effluent limitation guidelines for wastewater discharges from steam electric sources (ELG rule) and EPA's proposed rule for handling coal combustion residuals (CCR rule).[80] The amount of and basis for I&M's assumed capital expenditures should have been included in the IRP under both the Commission's current and draft proposed IRP regulations. Indiana's current administrative code requires I&M to "[d]iscuss the financial impact . . . of acquiring future resources identified in the utility's resource plan [including t]he operating and capital costs of the integrated resource plan." 170 IAC 4-7-8(8). The latest draft proposed IRP rule requires "[q]uantification, where possible, of assumed risks and uncertainties, which may include . . . regulatory compliance [and] construction costs." 170 IAC 4-7-8(b)(7).

I&M states in the IRP that it assumes that the ELG and CCR rules will require capital expenditures for projects at the Rockport plant. As a result of the upcoming ELG rule, for example, "I&M anticipates that wastewater treatment projects will be necessary at the Rockport units and these have been considered as part of the respective long-term unit evaluations." IRP at 149. Similarly, "I&M anticipates that the CCR Rule —based on the preliminary assumption that these residual materials may be categorized as 'Subtitle D,' or non-hazardous materials — would require plant modifications and capital expenditures (which are factored into this IRP) to address these requirements by, approximately, the 2018 timeframe." *Id.* However, I&M does not identify, let alone quantify, its assumptions concerning these expenditures in the IRP, some of which may be significant. As a result, the Commission and interested parties have no way to determine whether the Company's estimates are reasonable, or whether they have been appropriately "factored into" the IRP.

For example, EPA's proposed ELG includes some regulatory options that would require the Company to retrofit its bottom ash handling at Rockport to a dry handling or closed loop

[80] *See* Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Source Category, 78 Fed. Reg. 34,432 (June 7, 2013); Disposal of Coal Combustion Residuals from Electric Utilities, 75 Fed. Reg. 35,127 (June 21, 2010).

system that would result in zero discharge of bottom ash sluice water.[81] EPA estimates that, on average, each plant undertaking such a retrofit would incur $17 million in capital costs and $2 million in annual O&M costs.[82] Moreover, these costs may be larger for a 2,600 MW power plant such as Rockport than the average plant costs estimated by EPA. I&M's IRP filing, however, contains no discussion at all of whether the Company factored into its IRP modeling the risk that it will have to meet these significant additional compliance costs at Rockport or took any steps to evaluate what the costs of a bottom ash retrofit would be for the plant.

D. CSAPR

The IRP also fails to address the impact on the Company's preferred resource plan from the possible reinstatement of EPA's Cross-State Air Pollution Rule ("CSAPR"), which is now being considered by the U.S. Supreme Court.[83] Although the Company acknowledges that a decision in the case is expected in 2014, the Company does not attempt to analyze the impact that a reinstated CSAPR might have on the Rockport plant's future costs and whether a reinstated CSAPR would force the Company to accelerate its projected timeline for installing air pollution controls at Rockport (DSI in 2015; SCR in 2018/2020; FGD in 2025/2028). By contrast, in 2011, before CSAPR was stayed by a federal appeals court, I&M found that CSAPR could have very significant impacts on the Rockport plant, applying to the Commission in 2011 for a Certificate of Public Convenience and Necessity to install both FGD and SCR on one

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[81] 78 Fed. Reg. at 34,458.

[82] EPA, Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category at 9-40 (Apr. 2013), Docket No. EPA-HQ-LW-2008-0819-2257, *available at* http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/Steam-Electric_TDD_Proposed-rule_2013.pdf.

[83] *See* SCOTUSblog, *Environmental Protection Agency v. EME Homer City Generation*, Docket No. 12-1182, *available at* http://www.scotusblog.com/case-files/cases/environmental-protection-agency-v-eme-homer-city-generation/.

Rockport unit to comply with CSAPR and MATS.[84] The Company does not address at all in its IRP whether the DSI systems that it is planning to install in 2015 to comply with MATS will also allow it to comply with CSAPR's SO2 requirements at Rockport if CSAPR is reinstated, or if (as the Company found in 2011) compliance with CSAPR at Rockport would require installing a SCR system on at least one Rockport unit in the near future. Moreover, even if CSAPR's reinstatement would not impact the timing of environmental retrofits, at a minimum the imposition of a more stringent rule governing interstate transport of air pollution would likely increase the cost to I&M of any purchases of SO2 or NOx emission allowances need to comply with CSAPR. The Company does not evaluate these possible future costs and risks at all in the IRP.

E. Natural Gas Price Projections

I&M relies on two different sets of long-term natural gas price projections in this IRP filing. In its long-term load forecasting models, I&M based its projections of future natural gas prices in its service area on national price projections published by the U.S. Department of Energy's Energy Information Administration ("EIA") in its *Annual Energy Outlook* ("AEO") for 2013. IRP at 42. In modeling different alternative resource portfolios in the *Plexos* model, however, I&M used a different set of long-term natural gas price projections developed internally by AEP. *Id.* at 176. The AEP internal long-term natural gas price projections were provided to stakeholders as a handout at the third IRP stakeholder meeting.[85] As compared to the EIA AEO numbers that I&M incorporated into its load forecast, the AEP internal numbers are significantly higher. The chart below compares the EIA AEO 2013 and AEP internal natural

[84] *See* Direct Testimony of Paul Chodak III & Scott C. Weaver, Cause No. 44033 (Aug. 1, 2011).
[85] *See* I&M Cost Assumptions, *available at* https://www.indianamichiganpower.com/global/utilities/lib/docs/info/projects/IntegratedResourcePlan/IM_2013_IRP_Stakeholder_Mtg_3_Cost_Assumptions.pdf.

gas price projections throughout the planning period. Also included for reference is the recently released EIA AEO 2014 Early Release projections, which are somewhat higher than the EIA AEO 2013 numbers but still significantly lower than the AEP internal numbers until the final years of the planning period.

Natural Gas Price Projections at Henry Hub, in nominal dollars per mmBtu[86]

	EIA 2013	EIA 2014 ER	AEP
2013	3.36	3.66	4.04
2014	3.28	3.86	5.05
2015	3.32	3.93	5.47
2016	3.86	4.41	5.83
2017	4.06	4.76	6.01
2018	4.42	5.27	6.12
2019	4.59	5.19	6.19
2020	4.77	4.96	6.43
2021	5.00	5.37	6.75
2022	5.35	5.64	7.18
2023	5.68	5.90	7.30
2024	5.93	6.20	7.51
2025	6.14	6.45	7.75
2026	6.44	6.72	7.85
2027	6.65	7.00	8.04
2028	6.94	7.26	8.22
2029	7.18	7.63	8.41
2030	7.45	8.12	8.52
2031	7.78	8.47	8.73
2032	8.06	8.91	8.94
2033	8.41	9.41	9.16

The Commission's proposed IRP rule directs I&M to provide "[a]n explanation of . . . [t]he utility's effort to develop and improve the methodology and inputs for its forecast." 170 IAC 4-7-4(b)(11). In order to comply with this provision of the rule, I&M must explain on what

[86] The EIA's *Annual Energy Outlook* natural gas price projections can be viewed on the EIA's web site at http://www.eia.gov/oiaf/aeo/tablebrowser/.

basis it has chosen to use two different sets of natural gas price projections in its load forecast and its resource modeling and why the AEP internal numbers used in its resource modeling are significantly higher than the publicly available EIA AEO projections. I&M's use of high natural gas price projections in its resource modeling biases its modeling of future electricity prices in favor of finding that the coal-fired generation in I&M's preferred resource portfolio will be cost-competitive with alternative resource portfolios. I&M should be required to provide a clear and transparent explanation for this bias in its modeling.

F. Capacity price projections

I&M should also provide under 170 IAC 4-7-4(b)(11) "[a]n explanation of . . . [its] effort to develop and improve the methodology and inputs" for PJM capacity prices in its resource modeling. I&M fails to discuss the basis for its assumptions concerning capacity prices at all in its IRP filing, and the Company's capacity price projections (*see* IRP at 181) appear to be unreasonably high relative to recent experience with capacity prices in PJM. Specifically, the Company's capacity price projections appear to assume that capacity prices in PJM will escalate during the planning period to reach a level approaching the cost of new entry ("CONE"), i.e. the cost of constructing new capacity, and remain at that level through the remainder of the planning period.

In theory, CONE should represent an upper limit on capacity market prices, as CONE represents the cost of constructing a new resource solely to bid it into the capacity market. CONE values are typically defined based on the cost per MW of a new combustion turbine, which is the cheapest form of capacity to build. In practice, however, prices in PJM's capacity market have remained far below CONE in recent years, clearing at a price below 40 percent of

CONE for every year from 2012 through 2016.[87] This result is likely due to the fact that, in a broad and diverse market such as PJM, a range of resources contribute to the capacity market but do not need to recover their entire cost of entry through the capacity market alone. These resources include additional demand response, energy efficiency, imports of power from other regions, and uprates of existing resources, all of which may bid into the PJM capacity market even as they earn revenue through energy sales and other means.[88]

However, for reasons that are not explained at all in I&M's IRP filing, I&M appears to assume that PJM's capacity market will function very differently in coming years – i.e., that there will no longer be non-combustion turbine resources available for procurement that will continue to drive down the prevailing price in PJM's capacity market well below CONE. Moreover, like the Company's high natural gas price projections, assuming an unreasonably high capacity price would introduce a bias into the Company's modeling, as it would have the effect of inflating the projected competitiveness of the Company's existing resources versus procuring alternative resources on the wholesale market. Accordingly, the Company should be required to provide a clear and transparent explanation of its methodology and inputs for developing capacity price projections.

G. OVEC plants not analyzed.

I&M's IRP filing contains absolutely no discussion of the future costs or risks facing the OVEC Clifty Creek and Kyger Creek power plants, despite the fact that I&M owns

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[87] *See* Direct Testimony of Frank Ackerman, pages 13-14, *In re: Application of Big Rivers Electric Corp. for a General Adjustment of Rates*, Case No. 2013-0199 (Kentucky P.S.C. filed Oct. 28, 2013), attached as Attachment 2.

[88] Moreover, although I&M has in recent years opted out of PJM's Reliability Pricing Model ("RPM") capacity auction, if capacity prices really do rise to the levels the Company is projecting, I&M has the option to opt in to future RPM capacity auctions in order to bid its own energy efficiency and demand response resources into the auction. *See* IRP at 25 (noting that the Company has the option to opt in to future RPM capacity auctions). Bidding energy efficiency and demand response resources into the PJM auction, as other utilities are also likely to do, could potentially both benefit I&M ratepayers and contribute to keeping capacity prices well below CONE.

approximately 18% of those plants' capacity, IRP at 109, and intends to rely on purchases of power from the plants to serve its customers throughout the planning period, *id*. at 199, totaling 174 MW in the winter and 166 MW in the summer, *id.* at 133.

Even if nothing in the Commission's IRP rules (proposed or current) explicitly requires I&M to provide detailed information concerning future costs and risks facing the OVEC plants, including those related to environmental compliance, such information is undeniably relevant to "the balance of costs and risks" facing I&M's preferred resource portfolio, of which the OVEC plants are an integral part. The requirements in 170 IAC 4-7-8(b)(7) that I&M both identify and explain its assumptions concerning risks and uncertainties with its preferred resource portfolio, and also quantify those risks and uncertainties where possible, applies equally to all "resources" in the Company's portfolio – which includes the Clifty Creek and Kyger Creek plants. *See* 170 IAC 4-7-1(oo) ("'Resource' means a facility, project, contract, or other mechanism used by a utility to provide electric energy service to the customer."); *id.* (current) (same definition). I&M's failure to include in this IRP any evaluation of the future environmental requirements or any other future costs or risks facing the OVEC plants throughout the planning period violates this requirement of the Commission's IRP rules.

Moreover, not only does I&M fail to identify, let alone attempt to quantify, the costs and risks facing this resource, I&M also does not appear to have considered in this IRP process any alternative resource portfolios that do not include purchases of power from the two OVEC plants. Although I&M provided stakeholders with a spreadsheet tool to facilitate their proposals for alternative resource plans, I&M's spreadsheet tool fails to mention the OVEC plants or suggest that discontinuing purchases of power from the plants is an option that stakeholders might consider.[89] Perhaps not surprisingly, since I&M did not suggest that it was an option, none of the stakeholder-proposed alternative resource portfolios that I&M considered in the IRP stakeholder process mention the OVEC plants either. *See id.* at 29 (stakeholder portfolios summary). Rather, I&M appears to assume in this IRP, without explanation, that purchases of power from the OVEC plants are "off the table" for the purposes of this planning process, and thus that it will continue purchasing power from the OVEC plants under all possible futures. This also violates the Commission's proposed IRP rule, which requires I&M to "consider continued use of an existing resource as a resource alternative in meeting future electric service requirements" rather than assuming that any of its existing resources will continue to be utilized in the future. 170 IAC 4-7-6(a).

VII. Conclusion

The undersigned Commenters respectfully request that the Director of the Electricity Division's report on the IRP, as provided by 170 IAC 4-7-2(k), reflect the numerous informational, procedural, and methodological deficiencies in I&M's IRP that are detailed above. The cumulative effect of these deficiencies is an IRP that (1) significantly underestimates the potential for DSM and renewable energy to serve as valuable resources for ratepayers by placing artificial constraints on the Company's modeling of those resources; and (2) fails to identify and quantify where possible all of the costs, risks, and uncertainties facing coal-fired generating units, unduly biasing the Company's modeling in favor of investments in coal-fired generation

[89] *See* I&M Shareholder Portfolio Tool, *available at* https://www.indianamichiganpower.com/global/utilities/lib/docs/info/projects/IntegratedResourcePlan/ResourceGapForIM_shareholderPortfolioTool.xls; *see also* I&M March 7 Presentation: 2013 Integrated Resource Plan Stakeholder Workshop #1, slide 43 (defining "resource gap" for which stakeholders should propose alternative resource plans with assumption that purchases from Clifty Creek and Kyger Creek plans would continue in all scenarios), *available at* https://www.indianamichiganpower.com/global/utilities/lib/docs/info/projects/IntegratedResourcePlan/IM_IRP%20Stakeholder%20Presentation1.pdf.

that may not be prudent. Commission Staff should call on the Company to correct the informational, methodological, and procedural deficiencies identified herein, both in response to the Director's draft report and in all future resource planning. If these deficiencies are corrected, the Company would then be evaluating DSM and renewable resources on a more level economic playing field with other supply-side resource alternatives, which would inevitably result in a further acceleration of the Company's shift – already beginning to take place in this IRP – away from coal-fired generation toward clean energy resources.

Respectfully submitted,

Jennifer A. Washburn

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IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	)	Consolidated Cases: Civil Action No. C2-99-1182 Civil Action No. C2-99-1250 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Terence P. Kemp
OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	)	
) UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	)	JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King Civil Action No C2-05-360

AFFIDAVIT OF CAMILLE SEARS

State of California)
)
County of Ventura)

Before the undersigned, a notary public, duly qualified and acting in and for this county and state, personally appeared Camille Sears, satisfactorily proven to me to be the affiant herein, who stated the following under oath and acknowledged that she executed the same for the purposes herein stated:

1. I, Camille Sears, am over the age of twenty-one years old. I have personal knowledge of each and every fact set forth herein and am competent to testify about the matters set forth herein.
2. I make this affidavit in order to support Citizen Plaintiffs' Supplemental Opposition to Defendants' Application for Judicial Interpretation of Consent Decree filed on November 30, 2012 in these cases.
3. I am an individual residing at 502 W. Lomita Avenue, Ojai, Ventura County, California, 93023.
4. I received my Bachelor of Science in Atmospheric Science from the University of California, Davis in 1978 and I received my Master of Science degree in Atmospheric Science from the University of California, Davis in 1980.
5. I have over 30 years of professional experience performing air quality and toxics exposure analyses. I was a senior air quality modeler and air toxics program coordinator for the Santa Barbara County Air Pollution Control District, where I worked for approximately eight years. For the past 20 years, I have been a private consultant, specializing in regulatory agency and litigation support. My clients

include the California Attorney General's Office, the Los Angeles County District Attorney's Office, the California Office of Environmental Health Hazard Assessment, various air pollution control agencies, the California Air Pollution Control Officer's Association, and many private firms. I have prepared over 300 complete air toxics health risk assessments and over 1,000 air dispersion modeling analyses. I have successfully provided expert testimony in numerous Federal and State Court cases. My *curriculum vitae* is included in my modeling report (Attachment 1).

6. I was contacted and hired by Ms. Kristin Henry to perform modeling on behalf of the Citizen Plaintiffs[1] in C2-99-1182 and C2-99-1250 (*"AEP I")* and *United States, et al. v. American Electric Power Service Corp., et al.,* Civil Action Nos. C2-04- 1098 and C2-05-360 (*"AEP II"*).

7. Ms. Henry asked me to model sulfur dioxide (SO_2) emissions from the Rockport coal-fired power plant in Indiana to determine if such emissions, in conjunction with background concentrations, would lead to a violation of the one-hour SO_2 NAAQS that EPA established on June 2, 2010. *See* 75 Fed. Reg. 35,520 (June 22, 2010).

8. Ms. Henry asked me to do three iterations of this modeling: to model the SO_2 emissions that the Rockport Unit is currently allowed to emit under its Clean Air Act permit; to model 50% of those allowable SO_2 emissions, to represent emissions we would expect if this facility was equipped with dry sorbent injection

[1] The Citizen Co-Plaintiffs are: Ohio Citizen Action, Citizens Action Coalition of Indiana, Hoosier Environmental Council, Ohio Valley Environmental Coalition, West Virginia Environmental Council, Clean Air Council, Izaak Walton League of America, United States Public Interest Research Group, National Wildlife Federation, Indiana Wildlife Federation, League of Ohio Sportsmen, Sierra Club, and Natural Resources Defense Council, Inc.

technology; and to model a 95% reduction of those SO_2 emissions, to represent emissions we would expect if this facility was equipped with flue gas desulfurization technology.

9. I summarized the modeling results in a report entitled "*Air Dispersion Modeling Analysis For Verifying Compliance with the One-Hour SO_2 NAAQS: AEP – Rockport Power Plant*, *September 17, 2012*" which Ms. Henry provided to the court as an attachment to her declaration on November 30, 2012.

10. On December 7, 2012, Ms. Henry contacted me regarding this report. Ms. Henry subsequently provided me with American Electric Power Service Corporation's ("AEP") Reply Brief and the Affidavit of David J. Long and asked me if I wanted to revise my report in any way.

11. I have revised my report in two ways. First, there was a typographical mistake on page 5, footnote 8. I had inadvertently stated that I received the modeling files from USEPA's Montana Regional Haze Federal Implementation Plan modeling report. This footnote has been corrected to state "[t]he modeling files were sent via email by Brian Callahan, IDEM. The email from IDEM, and a description of the modeling files prepared by David Long, are included in Attachment 2." Second, I have included Attachment 2 to my report, which includes an email from Brian Callahan of the Indiana Department of Environmental Management. The email states "I recently modeled the AEP Rockport facility (for SO_2 only). Take a look at the attached zip file. <u>This file came directly from AEP Rockport</u> and contains data that should help you in your modeling analysis." (Emphasis added). The zip file attached to Mr. Callahan's email includes AEP's AERMOD modeling

files and a text file from David Long dated 3/21/2011 describing the air modeling files that AEP provided directly to the Indiana Department of Environmental Management. I used these files provided by AEP to the state of Indiana as the basis for the modeling preformed and summarized in my report. Mr. Long's modeling description file is also included in Attachment 2 to my report.

12. My revised report entitled "*Air Dispersion Modeling Analysis For Verifying Compliance with the One-Hour SO_2 NAAQS: AEP – Rockport Power Plant, December 10, 2012*" is attached hereto as Attachment 1.

13. In addition, I want to clarify inconsistent statements in Mr. Long's December 7, 2012 Affidavit regarding the Honey Creek air quality monitor. Mr. Long states in ¶ 18 of his Affidavit that "Attachment 5 [sic] further demonstrates that the actual monitored air quality data from the Honey Creek Site, in the immediate vicinity of the Rockport Plant, has been below the one-hour SO_2 standard since 2005." But, as Mr. Long acknowledges, use of that monitor was discontinued in 2008. *See* David J. Long Affidavit at ¶ 16 & Attachment 4. As such, the Honey Creek monitor data show only that ambient SO_2 concentrations were below the one-hour SO_2 NAAQS level at that site in 2005 through 2007 – there are no data since 2007 to verify whether or not there is a violation of the standard.

14. Furthermore, I note that due to the very tall stacks at the Rockport Plant, modeled SO_2 air concentrations are relatively low in the immediate vicinity of the Plant, which, as Mr. Long states, is where the Honey Creek monitor was located. Long Affidavit at ¶¶16, 18. In essence, the elevated Rockport stack plumes pass over the areas closest to the Plant. This effect can be seen in Figures 2 and 3 of

Attachment 1 to this Affidavit. Thus, even when the Honey Creek SO_2 monitor was operating, it was not likely measuring peak impacts from the Rockport Plant.

I, Camille Sears, do hereby certify that I have read the foregoing statements set forth above and swear, affirm, and verify that the statements contained therein are true and correct to the best of my knowledge and belief.

Executed this 13th day of December, 2012, at Ojai, California.

Camille Sears
Camille Sears

State of California)
)
County of Ventura)

Subscribed and sworn before me this 13TH day of December, 2012.

Notary Public: John C Higbie

In and for the State of: California

My Commission Expires: 06/03/2013

JOHN C. HIGBIE
COMM. # 1847783
NOTARY PUBLIC-CALIFORNIA
VENTURA COUNTY
MY COMM. EXP. JUN. 3, 2013

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC	**)**	**Case No.**
CORPORATION FOR A GENERAL	**)**	**2013-00199**
ADJUSTMENT IN RATES	**)**	

DIRECT TESTIMONY
OF

FRANK ACKERMAN
SENIOR ECONOMIST
SYNAPSE ENERGY ECONOMICS

ON BEHALF OF

SIERRA CLUB

Date
October 28, 2013

Table of Contents

1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and position.

A. My name is Frank Ackerman. I am a senior economist at Synapse Energy Economics, Inc., 485 Massachusetts Avenue, Cambridge Massachusetts 02139.

Q. Please summarize your work experience and educational background.

A. I received a BA in mathematics and economics from Swarthmore College, and a PhD in economics from Harvard University. I have over 25 years of experience in economic analysis of energy, climate change, environmental policy, and related issues. Before joining Synapse Energy Economics, I held senior research positions at Tellus Institute in Boston; at Tufts University's Global Development and Environment Institute; and at the Stockholm Environment Institute's U.S. Center, located at Tufts University in Massachusetts. Beginning in the spring semester of 2014, I will lecture at the Massachusetts Institute of Technology.

I have published more than 40 articles in professional journals, written or edited more than a dozen books, and directed numerous studies for state and federal government agencies, non-governmental organizations, and international bodies such as the United Nations. More detail on my experience and publications is provided in my resume, which is attached as Exhibit FA-1.

Q. Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government, and utilities.

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

A. I am testifying on behalf of the Sierra Club.

Q. Have you submitted testimony in other recent regulatory proceedings?

A. Yes. I submitted testimony in Duke Energy Indiana's Certificate of Public Convenience and Necessity Application before the Indiana Utility Regulatory Commission (Cause No. 44217) and in the Joint Application for Proposed Merger of NV Energy with MidAmerican Energy Holdings Company before the Nevada Public Service Commission (Docket No. 13-07021).

Q. Have you testified previously in Kentucky?

A. Yes, in the previous Big Rivers rate case – the "Century" rate case (Case No. 2012-00535).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the request by Big Rivers Electric Corporation ("BREC," or "the Company") for a rate increase, and to discuss alternative approaches to the underlying problem that has led to this request.

Q. Are you sponsoring any exhibits?

A. Yes. I have prepared the following exhibits to my prepared testimony:

1. Exhibit Ackerman-1	Professional CV for Frank Ackerman
2. Exhibit Ackerman-2	TVA Board Meeting Presentation
3. Exhibit Ackerman-3	U.S. DOE/Lawrence Berkeley National Laboratory - Benefits of Demand Response
4. Exhibit Ackerman-4	24/7 Hourly Response to Electricity Real-Time Pricing Study
5. Exhibit Ackerman-5	Using Real-Time Electricity Data to Estimate Response to Time-of-use and Flat Rates
6. Exhibit Ackerman-6	Synapse CO2 Price Forecast

Q. How is your testimony organized?

A. After the introduction and summary, my testimony presents four areas in which Big Rivers' analysis omits or misrepresents important facts and trends, in Sections 3 through 6, then addresses the likely implications for future rates in Section 7, and recommends alternative treatment of the Wilson and Coleman plants in Section 8.

In outline form, my testimony is organized as follows:

1. Introduction and qualifications.
2. Summary of conclusions and recommendations.
3. Projections of load growth and off-system sales are unrealistic.
4. Revised price forecasts now include implausible capacity prices.
5. Price elasticity impacts are underestimated.
6. Future transmission revenues from smelters are omitted.
7. Need for additional rate increases to support the existing plants.
8. Selling or closing Wilson and Coleman will reduce revenue requirements.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATION

Q. Please summarize your conclusions.

A. In Section 3, I review BREC's projections that within a few years, it will somehow gain access to enough new load and off-system sales to almost completely replace the demand from the two smelters. This is an enormous level of sales: in 2012 the two smelters consumed about 7,400 GWh of electricity, or 8 percent of total industrial electricity sales in Kentucky and Indiana.[1] (Or, since industrial sales were almost equal in the two states, the smelters amounted to about 16 percent of either state's industrial electricity use.) There are many competitors for the region's industrial customers, including utilities that are building large new gas plants. The meager new load acquired in BREC's first year

[1] Retail sales of electricity to industrial customers in 2012 amounted to 47,898 GWh in Indiana and 44,753 GWh in Kentucky (downloaded from http://www.eia.gov/electricity/data/browser).

of post-smelter planning does not suggest any real chance of replacing the entire smelter load.

In Section 4, I evaluate BREC's price forecasts, which changed dramatically in the few months between the two rate cases. Since this case was filed, the Company's price forecaster has made another radical change in projections. [redacted] in contrast, recent experience in the more established PJM capacity market shows that capacity prices are typically no more than 40 percent of CONE.

In Section 5, I examine the treatment of price elasticities in BREC's current forecast. The elasticities adopted for rural customers are at the low end of published estimates, and may represent short-run rather than (more appropriate and larger) long-run elasticities. The Company's omission of all price elasticity effects for industrial customers is illogical; both common sense and economic research confirm that energy use by industrial customers declines in response to price increases. Larger price elasticities for rural customers and nonzero elasticities for industrials would imply that the more than doubling of rates that would occur from 2012 to 2016 under BREC's plan will cause significant reductions in BREC's existing load – reductions that the Company has failed to account for in its financial forecasting.

In Section 6, I turn to one area in which BREC has underestimated its expected future revenues. The Company should have included in the financial forecast the transmission revenues that it will receive from the smelters' future operations, roughly $7 million from the Hawesville smelter and $5 million from the Sebree smelter.

In Section 7, I discuss BREC's long-term financial forecast and the likely need for additional rate increases for the Company to have even the chance of achieving financial stability. Even under the Company's overly optimistic forecast, BREC would only barely achieve the 1.40 TIER that the Company's own witness argues is the minimum that BREC needs to reach soon for financial stability once in the next 15 years. If their expert is to be believed, then BREC will need additional increases in rates – particularly since, as I have shown in earlier sections, its current planning greatly overstates its prospective revenue.

Finally, in Section 8, I explore the obvious remedy for BREC's financial woes: either selling at greatly reduced prices or closing the Coleman and Wilson plants. To date, BREC has only offered to sell these plants at unrealistically high prices. Selling or shutting down these plants would save money via the avoided costs of planned environmental upgrades, and the avoided fixed costs of plant ownership such as insurance and property taxes. Idling but keeping the plants, as BREC proposes, is more expensive; it imposes the fixed costs of ownership of unused capacity on ratepayers, and it will require the substantial expenses of environmental upgrades before the plants can be brought back into service. In the worst case, if BREC cannot sell the plants, the Company could reduce revenue requirements by closing them rather than idling them.

Q. Please summarize your recommendation.

A. I recommend that the Commission grant BREC only short-term rate increases, sufficient to allow the Company to recalculate the costs and benefits of selling or closing Wilson and Coleman, and to modify its plans accordingly. The full, permanent rate increase requested by the Company should not be granted; it would impose substantial burdens on BREC's remaining customers, yet it would be far from enough to solve the underlying problem that BREC has approximately three times as much capacity as it needs.

As I will explain, BREC's analysis and forecasts appear deficient in several respects, perhaps strained by the attempt to prove the impossible case for keeping Wilson and Coleman. The Commission should direct them to develop revised and improved analyses, as a basis for more careful resource planning.

BREC can reduce revenue requirements and the burden on its customers can be eased by selling or closing the Coleman and Wilson plants. The Commission should direct BREC to immediately drop the asking prices, at least down to book value net of the avoided costs of planned environmental upgrades; arguably BREC could lower the prices could even further to reflect the avoided fixed costs of plant ownership. If no one offers to buy the plants at these greatly reduced prices, then BREC's plan to idle but preserve the plants is not adequate; to minimize revenue requirements and rate impacts, it is time to plan the shutdown of Wilson and Coleman. The Commission should design BREC's recovery of the stranded assets to provide the minimum necessary to pay its outstanding debts, without increasing burdens on its ratepayers.

3. PROJECTIONS OF LOAD GROWTH AND OFF-SYSTEM SALES ARE UNREALISTIC.

Q. Please describe the projections of load growth used by BREC in this case.

A. Big Rivers now projects that after idling the Wilson and Coleman plants for approximately five years, it will have sufficient sales to bring them back on line, at relatively high capacity factors, in May 2018 and July 2019, respectively. The resulting picture of load by customer class is shown in Figure 1.[2] The graph begins in 2012, the last full year of BREC sales to both smelters; it continues through the 2014-2017 trough, reflecting the loss of the smelter load, and then [redacted]

[2] Based on sales data from the spreadsheet "Financial Forecast (2014-2027) 5-16-2013", tab "Stmts RUS."

[redacted]

More precisely, total BREC sales are forecast to [redacted] While market sales are projected to [redacted] which BREC expects to [redacted]

Q. Are there any grounds for expecting the projected level of new market and replacement load sales to materialize after 2017?

A. No. The smelters represented a huge level of sales; there is no plausible path that leads to replacing their load. In 2012, the last full year in which both smelters were Big Rivers customers, they bought 7.4 TWH of electricity. This can be compared to statewide total electricity sales to industrial customers in 2012 of 44.8 TWH in Kentucky, and 47.9 TWH in Indiana. In other words, the two smelters represent 8 percent of the two-state total of industrial electricity use, or roughly 16 percent of either state's total. To sell that much to other customers, Big Rivers would have to capture one-sixth of all Kentucky or Indiana industrial electricity sales, or one-twelfth of the two-state total (or, of course, equivalent amounts of residential or commercial load). Other utilities, which currently sell to other customers in the region, are likely to compete vigorously to maintain their markets.

Q. Has BREC developed any new sales since learning of the loss of the smelters?

A. After a year of vigorous marketing, in which Big Rivers has [redacted] (response to PSC 2-16), BREC has been [redacted] and has reported the announcement or siting of 25 MW of new load through several small economic development opportunities in its service territory (response to SC 1-10). This is about 3 percent of the 850 MW of smelter demand it is attempting to replace. If the Company continues to acquire 25 MW of new load per year, it will take until 2046 to replace the smelters' 850MW.

Q. Will BREC have new market opportunities as other area utilities close their coal plants?

A. Not necessarily. While utilities are closing a number of coal plants, some are replacing their retired units with large new natural gas plants. AEP is planning to repower unit 1 of its Big Sandy plant as a gas-burning facility, and is replacing Big Sandy Unit 2 with a 50% share of the Mitchell plant in West Virginia. Louisville Gas & Electric and Kentucky Utilities are already proceeding with a 640MW natural gas combined cycle ("NGCC") plant at Cane Run, and recently proposed a second NGCC 700MW in size. Indianapolis Power & Light is also planning to build a 650 MW NGCC plant to replace retiring coal capacity.

In addition, increasing pursuit of demand response, energy efficiency, and renewable resources in the region will satisfy at least some of the capacity and energy lost due to the retirement of uneconomic coal units. While coal capacity is declining, this does not necessarily imply an impending scarcity of total generating capacity in the region.

Q. Is the regional economy likely to grow fast enough to create substantial increases in electricity demand?

A. As I noted in my testimony for the Century rate case, recent Kentucky state projections for economic growth ("Kentucky's Unbridled Future") do not focus on electricity-intensive sectors. The projections imply encouraging growth of incomes, technological capacity, and skilled jobs, but not substantial growth of demand for electricity.

A similar impression is created by a more detailed 2011 study, "Kentucky's Target Industry Sectors," done for a group of agencies and organizations including the Kentucky Department of Workforce Investment.[3] It selects and analyzes five areas of strength in which the Kentucky economy is likely to have a competitive advantage. Two relatively energy-intensive sectors, automobile and aircraft manufacturing, and energy production and transmission, are projected to have constant or slightly declining employment from now through 2018. Three other sectors that are projected to grow rapidly are much less energy-intensive: transportation, distribution, and logistics; business services and R&D; and health care and social assistance. Again, the expected direction of growth of the state economy is moving away from the older pattern of energy-intensive industry.

Meanwhile, one of Kentucky's largest energy-intensive industries has recently closed: the USEC uranium enrichment facility at Paducah shut down permanently in May 2013. At a recent board meeting, the Tennessee Valley Authority (TVA), USEC's former supplier, reported that the USEC closure is leading to a decline in energy sales of 8,200 GWH from fiscal year (FY) 2013 to FY 2014; in recent years, USEC had used more than 10,000 GWH of energy per year from TVA.[4] Thus TVA may have at least as much suddenly-excess capacity as BREC – greatly increasing competition for new load in the region, and making it very unlikely that TVA will want to buy or lease any of BREC's plants. [redacted]

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[3] http://workforce ky.gov/KYTargetIndustrySectors.pdf.

[4] *TVA Board Meeting – Fiscal Year 2014 Financial Plan, Finance, Rates, and Portfolio Committee*, August 22, 2013, http://www.tva.gov/abouttva/board/pdf/aug-22-2013_public_board.pdf, pp.50, 48, attached as Exhibit Ackerman – 2.

[redacted] TVA itself is putting a priority on incentives to win new and expanded manufacturing load, including offers to match other utilities' rates.[5]

4. REVISED, STILL-FLAWED PRICE FORECASTS NOW INCLUDE IMPLAUSIBLE CAPACITY PRICES.

Q. In the Century rate case, you criticized BREC's electricity price forecasts for their unexplained upward surge starting in 2019. Is the Company using the same price forecasts in this case?

A. No. In the current case, the ACES consulting firm, the source of Big Rivers' price forecasts, has provided a [redacted]. Since this case was filed, [redacted]

Q. What is the basis for these changing ACES forecasts?

A. In responses to SC 2-9 and PSC 2-14, BREC witness Robert Berry explained that ACES uses regularly updated broker values for the first 7 years of its forecasts, and Wood Mackenzie projections for year 10 and later. Between years 7 and 10, the two forecasts are "blended."

Based on these responses, I have graphed the three ACES forecasts provided in the (confidential) attachment to PSC 2-14. [redacted]

[redacted]

[5] *TVA Board Meeting*, August 22, 2013 (see note 4), pp.81-86.

[redacted] **Does this mean that the Company's price forecasts are more reasonable in this case?**

[redacted] I would say that the underlying error in the ACES/BREC methodology, [redacted] has a less extreme, but still pronounced effect in this case. As Figure 2 shows, [redacted]

This unreasonable methodology produces results, in this case, [redacted]

[redacted]

[redacted]

Moreover, Big Rivers' forecasts of revenues now include projections of capacity revenues as well as the ACES-based energy forecasts. MISO capacity prices, near zero today, [redacted]

Q. Why would capacity prices be expected to increase in 2016?

A. MISO currently has a surplus of capacity, so it is not surprising that the price paid in the initial MISO capacity auction was close to zero. That capacity surplus may shrink or disappear in 2016, when some coal plants will retire to avoid the costs of MATS compliance.

Q. Has MISO addressed the risk of a capacity shortfall in 2016?

A. Yes. The 2013 MISO Transmission Expansion Plan (MTEP 2013) projected the retirement of about 10 GW of existing capacity by 2016; together with other minor capacity changes, this implies a potential shortfall of 3 - 7 GW for the MISO Midwest Region by 2016.[6] MISO projects that this could be mitigated by increased energy efficiency and DSM (much of it in response to existing state mandates), additional power imports from the MISO Southern Region (roughly speaking, Arkansas, Louisiana, and Mississippi), and transmission upgrades to

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[6] *MISO Transmission Expansion Plan 2013*, section 6.2 ("Long-Term Resource Assessment"), https://www misoenergy.org/Library/Repository/Study/MTEP/MTEP13/MTEP13%20Report.pdf.

increase access to resources that are currently transmission-limited or lacking in firm transmission. MISO's conclusion is that the midrange estimate of a 5 GW capacity shortfall before these mitigation measures could be converted to a 1 GW surplus after mitigation.

Q. What determines capacity prices when there is no surplus of existing capacity?

A. In theory, the cost of new entry ("CONE"), i.e. the cost of constructing new capacity, should limit capacity prices. This is typically defined as the cost per MW of a new combustion turbine, the cheapest form of capacity to build. In practice, in PJM's capacity market, prices have remained far below CONE in recent years, despite capacity being tighter than in MISO.

Q. How do BREC's capacity price projections compare to CONE and to PJM market prices?

A. Figure 3 compares actual and projected capacity prices to CONE, both for PJM and for Midcontinent Independent System Operator ("MISO") zone 6 (the relevant region of MISO). The red triangles represent PJM; the upper, dashed red line is the PJM calculation of CONE, while the lower, solid red line is the actual market price in the PJM capacity market.[7] It is routinely calculated a few years ahead, and is now available through the 2016/2017 power year. (For comparability with BREC data, I have interpolated PJM power year prices to obtain calendar year data, as shown in Figure 3.

[7] PJM market (clearing) prices are available at https://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx; PJM CONE values are available at https://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx. Values used in Figure 3 are unweighted averages across all zones of PJM, interpolated to a calendar year basis for comparability with MISO prices and BREC forecasts. Because PJM prices are reported for a June-May year, the interpolation uses, e.g., 7/12 of the 2011/2012 value plus 5/12 of the 2012/2013 year for the 2012 calendar year value.

[redacted]

The blue circles represent MISO zone 6. The upper, dashed line shows MISO calculations of CONE for zone 6 for 2013 and 2014,[8] followed by an assumed 2 percent annual increase after 2014; the assumed values are shown with open circles. (Since the graph is in nominal dollars, a 2 percent annual increase is equivalent to a roughly constant real value.) The lower, solid line shows the BREC projection of MISO capacity prices, [redacted]

For PJM, Figure 3 shows that the capacity market has cleared at a price below 40 percent of CONE for every year from 2012 through 2016. [redacted]

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[8] MISO Zone 6 CONE values are available for 2014 at https://www misoenergy.org/Library/Repository/Tariff/FERC%20Filings/LRZ%20CONE%20Filing_3%20Sept%202013.pdf and for 2013 at https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/LOLEWG/2013/20130508/20130508%20LOLEWG%20Item%2002%20RA%20Update.pdf. Annual values in $/MW-year were divided by 365 to obtain $/MW-day.

Q. Does BREC provide any justification for its projections that MISO capacity prices will [redacted]?

A. No, it does not. In response to SC 2-10, which asked about [redacted] capacity prices, Robert Berry said that:

> Big Rivers relies on industry experts to provide [capacity] price forecasts. As such, Big Rivers does not have the detailed drivers of the specific increases. However, Big Rivers believes the increase is driven by MATS compliance. … Big Rivers relied on the May 2013 capacity price forecast prepared by Wood Mackenzie for MISO Zone 6.

Note that in projecting the price of capacity, as well as energy, Wood Mackenzie appears to be the source of [redacted] forecasts. A re-examination of the basis for Wood Mackenzie forecasts, and an exploration of alternatives, should be a priority for future BREC planning efforts.

Q. What is the effect on BREC's financial projections of [redacted]?

A. The [redacted] in capacity prices, together with the [redacted] energy prices [redacted], serves to [redacted] the economic benefits of keeping the Wilson and Coleman units as opposed to selling or retiring such units.

5. PRICE ELASTICITY IMPACTS ARE UNDERESTIMATED.

Q. What is price elasticity and why is it important in this case?

A. Price elasticity, more precisely speaking the price elasticity of demand, is the percentage change in the demand for a good (in this case, electricity) associated with a one percent change in the price. Price elasticity provides a quantitative yardstick to measure the common-sense notion that higher prices lead consumers to buy less, while lower prices lead them to buy more.

Price elasticity is important in this proceeding because BREC is requesting large rate increases, both in the Century rate case and in the current one. Projections of future sales should therefore include the effects of price elasticity, which will tend to reduce the consumption of electricity by the Company's customers.

Q. How has BREC addressed price elasticity in this case?

A. For the rural customer class, separate price elasticity estimates have been developed for each of the three member coops, -0.21 for Kenergy and -0.16 for Jackson Purchase and Meade County (Barron testimony, p.12). The average residential elasticity is -.174 (response to SC 2-15). For the industrial customer class, no elasticity has been estimated and no elasticity-based reductions in demand have been included in the forecasts (response to PSC 2-20).

Q. What is your evaluation of the rural price elasticities used in this case?

A. Elasticities of -.16 to -.21 are at the low end of the range of published estimates.[9] In response to a data request on the subject, Ms. Barron stated that Big Rivers' consultant who developed the elasticities compared their estimates to two national studies, from EIA and NREL (SC 1-20c, attachments). Both of those studies distinguish between short-run and long-run price elasticities: short-run elasticity is the effect of a price change in the current year, while long-run elasticity is the effect of a price change that persists over many years. Big Rivers' estimates are similar to some of the short-run estimates in both sources, but distinctly smaller than the long-run estimates.

The NREL study, which provides more easily summarized estimates, concludes that an analysis of national data from 1977 through 2004 implies a short-run residential price elasticity of -.20 and a long-run elasticity of -.32. The EIA study presents 14 separate estimates for residential price elasticity, from differing models; the unweighted average is -.10 for short-run and -.33 for long-run elasticity. Thus both studies recommend values for long-run elasticity that are almost twice as great as the Big Rivers estimates.

Q. Is long-run or short-run elasticity more relevant in this case?

A. In the year of a rate increase, a utility should use the short-run estimate. The projections presented in this case, however, extend for more than a decade beyond

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[9] Price elasticities are negative, since an increase in price is associated with a decrease in demand. I follow the common convention of referring to elasticities closer to zero as "smaller," regardless of whether they are positive or negative.

the proposed rate increases. Therefore, the Company should use the long-run price elasticity for most of the years in this analysis.

Q. What is your evaluation of the failure to include any price elasticity effect in the industrial class?

A. I find it simply implausible to assume that industrial customers are unaffected by price increases. Yet that is the implicit assumption BREC made by excluding industrial price elasticity effects.

Q. Does BREC *explicitly* assume that industrial customers are not interested in electricity prices?

A. No. In response to SC 2-20, BREC witness Lindsay Barron said that the large industrial customers

> …have a strong profit motive and incentive to minimize costs in order to maximize margins. … Big Rivers expects that these customers have already taken steps to minimize their consumption and energy bills.

This statement, however, indirectly assumes that, since steps to minimize energy costs have already been taken, rate increases would have no further effect on consumption – effectively (and inaccurately) assuming a price elasticity of zero. Contrary to this assumption, the industrial customers' "strong profit motive" would be expected to lead to even more reduction in energy use at higher prices.

Q. Is there any published research on industrial customers' price elasticity?

A. There are fewer studies of industrial than of residential price elasticity for electricity demand, but the research literature is not completely silent on this question. A 2006 study performed for the U.S. Department of Energy by Lawrence Berkeley National Laboratory reviewed the state of knowledge on the subject.[10] A common finding is that industrial customers are quite diverse in their responses to electricity prices. In three studies of medium and large customers summarized in the 2006 U.S. DOE/Lawrence Berkeley National Laboratory

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[10] LBNL, "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them." See the estimates of "own-price elasticity" (the relevant measure for this discussion) in Table C-1, p.88. http://energy.gov/oe/downloads/benefits-demand-response-electricity-markets-and-recommendations-achieving-them-report, attached as Exhibit Ackerman-3.

study, different companies had different price elasticities, ranging from close to zero, up to a maximum of -.27, -.28, or -.37, depending on the study.[11]

One of these studies is an examination of large customers of Duke Energy, done by Duke employees in collaboration with an academic researcher. A 2005 article estimated price elasticities separately by hour of the day, finding all-customer average elasticities as large as -.26 in mid-afternoon, and -.155 for peak hours in general (2 – 9 PM).[12] A 2012 update from the same researchers, re-examining Duke's large customers who were on real-time electricity rates, found that hourly elasticities for the group of customers could be as large as -0.7, well above the 2005 estimate.[13]

In short, I conclude that it is not reasonable to exclude industrial price elasticity effects from Big Rivers' financial projects.

Q. How has BREC modeled the effects of price elasticity in this case?

A. Relatively little is said about this important topic in the Company documents. Barron's testimony on the load forecast does little more than mention the estimated elasticities for the rural class (p.12). Other statements seem to minimize the effective price increase, as well as the elasticity impact. For example, Mark Bailey's testimony, providing an introduction and overview to the Company's application, says that the average rural customer will experience a 44 percent increase over current rates (p.10). The response to KIUC 1-33 suggests that the elasticity effect will reduce the average rural user's energy consumption by 5.5 percent by 2016.

Q. What is your response to these estimates?

A. The actual decline in energy usage by BREC's customers due to rate increases is likely to be considerably higher than 5.5 percent both because rates are projected

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[11] One of the three studies was Thomas N. Taylor, Peter M. Schwarz, and James E. Cochell, "24/7 Hourly Response to Electricity Real-Time Pricing with up to Eight Summers of Experience," *Journal of Regulatory Economics* 27:3 (2005), pp.235-262, which is attached as Exhibit Ackerman-4

[12] Taylor et al. (see previous note).

[13] Cochell, Schwarz, and Taylor, "Using Real-Time Electricity Data to Estimate Response to Time-of-use and Flat Rates: An Application to Emissions," *Journal of Regulatory Economics* 42:2 (2012), pp.135-158, attached as Exhibit Ackerman-5.

to increase far more than 44% and because the elasticity values that BREC used are understated.

Regarding rate increases, the effective rate for rural customers [redacted][14] In short, rates are projected to [redacted] within the next few years, for all remaining customers of Big Rivers.

Regarding the reported elasticity-driven reduction of only 5.5 percent in a rural customer's energy use by 2016, that is the reduction that would result from a 32 percent rate increase, if using the Company's average rural elasticity of .174. I see no way to derive a 2016 rate increase as small as 32 percent from the projections filed in this case. Even from 2014 to 2016, the effective rural rate is projected to [redacted]

Q. Can you estimate the magnitude of the elasticity effects that would result from the proposed rate increases?

A. Broadly speaking, the expected elasticity effects will be large: at an elasticity of .174, a doubling of rates reduces demand by 17.4 percent. In this case, rates are projected to [redacted] Using that elasticity, the increase in effective rates from 2012 to 2017-2018 would reduce rural sales by [redacted]; it appears that the Company has included only a small fraction of that reduction in its projections.

If the same elasticity applied to large industrial customers, sales to that customer class would decline by [redacted] in the peak years. The reduction in 2017 or 2018, from these elasticity effects on the rural and large industrial classes combined, would be [redacted], more than [redacted] of the Company's projected total sales in 2017.

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[14] Calculated from the "Effective Rate ($/MWH)" lines in the spreadsheet "Financial Forecast (2014-2027) 5-16-2013", tab "Stmts RUS."

As I mentioned above, the Company's elasticity is near the low end of published estimates, and appears comparable to short-run elasticities in other studies; long-run elasticities for residential customers can be higher, perhaps .32 - .33. To reflect a "blended" average of short-run and long-run effects, suppose that the average elasticity throughout the forecast period is actually .25. Under that assumption, rural sales would fall [redacted] below 2012 levels by 2017-2018, while large industrial sales would fall [redacted] The combined effect would be a loss of [redacted] of the Company's total projected sales in 2017.

If everything goes as BREC is currently projecting, the Company says that it may be able to mildly reduce rural and industrial rates starting in 2019. But even if these projections end up being accurate, the elasticity effects would taper off only slowly as the projected rates begin to come down after 2018. By 2027, the end of the forecast period, elasticity-induced reductions, relative to the 2012 base year, would still be more than half the peak level.

Q. What effect would larger elasticity-induced sales losses have BREC planning and projections?

A. In the words of the Company's response to PSC 2-20 (a question about the absence of elasticity estimates for the Large Industrial class), "Lowering Big Rivers' projection of Large Industrial consumption would result in an increase in the revenue requirement for this case." Indeed, if a more accurate calculation of elasticity losses were included, Big Rivers' sales would be lowered throughout the forecast period, with the greatest reduction in 2017-2018, on the eve of the planned reactivation of the Wilson and Coleman plants. Additional revenue requirements, resulting from the decline in sales and the increase in fixed costs per MWH, would drive the need for even greater rate increases which, in turn, could lead to even further declines in rural and industrial demand and, in turn, even larger rate increases.

6. FUTURE TRANSMISSION REVENUES FROM SMELTERS ARE OMITTED.

Q. Please describe the smelter transmission revenues that BREC can expect to receive.

A. BREC has agreed to provide transmission service to the Hawesville (Century) smelter, and is likely to make a similar agreement with the Sebree (Alcan) smelter. Although the smelters are no longer customers of Big Rivers, they are dependent on Big Rivers to transmit the power purchased from other suppliers on the market. The agreements call for payments to Big Rivers for such transmission services.

Q. How are these payments treated in Big Rivers' financial projections?

A. The transmission payments are simply omitted, apparently because BREC had not finalized and signed the agreements with the smelters when it filed this case (see Berry testimony, p. 17, and the response to SC 2-17).

Q. How large are the smelter transmission payments?

A. Assuming that both smelters continue to operate at full capacity, the Hawesville smelter agreement will result in $7.5 million per year in transmission payments to Big Rivers (response to SC 1-12). A comparable agreement with the Sebree smelter, assuming that there are no offsets for system reliability (SSR) costs, would result in $5.7 million per year (response to SC 2-19). Once the SSR issue is resolved, BREC will receive approximately $13.2 million per year in transmission revenues, assuming both smelters continue to operate at full capacity.

These revenues, omitted from all current projections, will make an important contribution to Big Rivers' financial stability. It is worth noting that these revenues are independent of the continued operation of the Wilson and Coleman plants; they depend only on the continued operation of the smelters.

7. BREC WILL NEED ADDITIONAL RATE INCREASES TO SUPPORT THE EXISTING PLANTS.

Q. Will the rate increase requested in this case be sufficient to put BREC on a sound financial basis?

A. No, it will not. Fiscal soundness for cooperatives such as BREC is often measured in terms of TIER (Times Interest Earned Ratio), the ratio of earnings to interest obligations. According to the Company's own finance consultant, Daniel Walker,

> In order to attract capital in the capital markets and retain an investment grade rating, I believe a [cooperative such as Big Rivers] should set rates to earn, on a consistent basis, a TIER in the range of 1.40x to 1.60x. (Walker testimony, pp.12-13)

Walker clarified that Big Rivers was in a "transition period" toward the time when it could reach a TIER of 1.40 or more (testimony, p.13). When asked to "identify the duration of the transition period that would be acceptable" (SC 1-23a), he said, "It is expected that the transition period will take 1 to 3 years." (response to SC 1-23a). Yet BREC's own long term financial forecast, which incorporates the numerous implausibly favorable assumptions discussed above, leads to a TIER exceeding 1.40 only once in the next 15 years. (BREC Resp. to SC 1-23e).

In a related question, when asked whether BREC could reach a TIER of 1.40 to 1.60 without an additional rate increase, Company witness Christopher Warren simply answered, "Yes" (complete text of response to SC 1-23c). Billie Richert echoed this view in response to SC 2-6, asserting that the load-building measures described in the Load Concentration Analysis and Mitigation Plan would allow BREC to achieve a TIER between 1.40 and 1.60 without additional rate increases. Yet projections of TIER for 2016 and beyond (attachment to response to SC 1-23e) remain in the range of 1.10 to 1.13 from 2016 through 2020, only climbing above 1.20 in 2021, when the implausibly high price forecasts, discussed above, begin to boost BREC's projected fiscal health. Even then, the projected TIER dips back down to 1.11 in 2024 and 1.14 in 2026.

Moreover, the errors and omissions I discussed earlier will, on balance, make BREC's financial results even worse. The vast projected increase in energy sales and the imagined 2016 surge in capacity prices are not likely to occur; and price elasticities (and therefore sales reductions) will turn out to be much larger than the Company has assumed. These factors will more than outweigh the overlooked $13 million of transmission revenues.

Q. What consequences would you anticipate from the failure of this rate case to stabilize the Company's finances?

A. At that point, BREC's only recourse would be to request yet another rate increase. Coming on top of the increase from the Century case and this one, that could pose an intolerable burden on the ratepayers, and could prompt discussion of utility "death spiral" effects. Industrial and even rural customers would begin to explore self-generation or other options, including moving out of Big Rivers' service territory.

Q. What alternative would you suggest to avoid this bleak outcome?

A. The only viable alternative is to reduce the Company's revenue requirements, by shedding excess capacity and resizing to meet the existing, post-smelter load.

8. SELLING OR CLOSING WILSON AND COLEMAN WILL REDUCE REVENUE REQUIREMENTS.

Q. [redacted] What more can they do to reduce excess capacity?

A. To sell Wilson and Coleman, [redacted] As of July 31, 2013, net book values were roughly $187 million for Coleman and $454 million for Wilson (response to SC 1-22). This amounts to about $420 per kw for Coleman and $1,090 per kw for Wilson. Yet as I testified in the Century rate case, recent market transactions involving sale of coal plants (excluding transfers between divisions of the same corporate parent) have occurred at prices of roughly $160 per kw or less.

Q. Please summarize your description of recent coal plant sales, from your earlier testimony.

A. In August 2012 Exelon sold three Maryland power plants with a total capacity of 2,648 MW, of which more than 2,000 MW is coal, for $400 million, or an average price of $151/kw.[15]

In March 2013 Dominion Resources sold three power plants, the Brayton Point and Kincaid coal-fired plants (totaling 2,686 MW) and a 50% interest in the 1,424 MW Elwood gas-fired plant, to Energy Capital Partners. Although Dominion said its after-tax proceeds will be $650 million,[16] the *Platts* financial newsletter estimated the true purchase price at about $450 million, or $132/kw of capacity,[17] and the *Wall Street Journal* commented that "after stripping out tax benefits, the implied underlying price paid per kilowatt of capacity was just over $100."[18]

Also in March 2013, Ameren agreed to divest an Illinois-based subsidiary to Dynegy, involving five coal-fired plants totaling 4,100 MW, 80% of another 1,186 MW coal- and gas-fired plant, and other energy businesses. In payment, Dynegy assumed $825 million of Ameren's debt associated with the coal plants – equivalent to $163/kw for the 5,050 MW of capacity that Dynegy acquired.[19]

Q. Based on this evidence, what conclusions do you draw about the appropriate treatment of the Coleman and Wilson plants?

A. A serious attempt at selling these plants requires asking prices that recognize current market conditions. If they cannot be sold at these low rates, BREC's plan

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[15] See Exelon's press release, August 9, 2012, at http://www.exeloncorp.com/newsroom/PR_20120809_EXC_Mdcoalplantsale.aspx (accessed May 15, 2013).
[16] See Dominion's press release, March 11, 2013, at http://dom.mediaroom.com/2013-03-11-Dominion-To-Sell-Three-Merchant-Power-Stations-To-Energy-Capital-Partners (accessed May 15, 2013).
[17] "Recent plant sales establish new floor for coal assets," *Platts*, March 14, 2013, http://www.platts.com/RSSFeedDetailedNews/RSSFeed/ElectricPower/6260790 (accessed May 15, 2013).
[18] Liam Denning, "There is Life After Death for Coal Power," *Wall Street Journal*, March 31, 2013, http://online.wsj.com/article/SB10001424127887323361804578390561956760382 html (accessed May 15, 2013).
[19] See Dynegy's press release, March 14, 2013, http://phx.corporate-ir.net/phoenix.zhtml?c=147906&p=irol-newsArticle_Print&ID=1796097&highlight= (accessed May 15, 2013).

to idle the plants is not sufficient to protect the ratepayers; instead, the Company should move to retire the plants.

Q. The Company's loans are tied to the value of its plants, and debt covenants restrict the ability to sell the plants for less than their book value. Doesn't this make your proposal infeasible?

A. No. If the Commission makes it clear that it will approve rates that allow repayment of the Company's debts after sale or closure of the plants, I believe that it will be possible to renegotiate the debt covenants. In particular, the Company's creditors may be interested to learn that this could be the only way they can hope to be repaid in full. If they insist on the letter of their agreements, forbidding sale for less than book value, they are likely to drive Big Rivers into a new bankruptcy, resulting in much less than full repayment. For the reasons I have described above, the Company's projections are out of touch with reality in several respects; BREC has essentially no chance of earning the future revenues that justify keeping Wilson and Coleman on the books.

Q. If the Commission approves rates that allow repayment of the Company's debts, why is it better for ratepayers to sell or retire Wilson and Coleman?

A. Because selling or retiring those plants would enable BREC's ratepayers to avoid having to pay for significant fixed costs each year. Consider the difference between two scenarios. I will call them the Status Quo scenario, as proposed by BREC in this case, and the Right-Sized scenario, in which BREC achieves the right size of capacity for its existing load by promptly selling Wilson and Coleman at whatever price the market will bear, or else retiring them.

In both scenarios, I assume that the Commission wants to ensure the continued, non-bankrupted existence of BREC, and therefore will grant rates sufficient to pay BREC's current debts. Revenue requirements in both scenarios include meeting all scheduled debt payments, so interest obligations are not a difference between the two options.

Q. Why is the Status Quo scenario the more expensive option for ratepayers?

A. Under the Status Quo scenario, revenue requirements include the fixed costs of maintaining Wilson and Coleman through several years when they are idled.

These costs include about $6 million per year of depreciation and $1 million of property tax and insurance at Coleman, and $19 million of depreciation and $2 million of property tax and insurance at Wilson (response to SC 2-12).[20] When the plants are brought back into service, they will incur one-time restart costs of [redacted] at each plant (attachment to response to AG 2-9). Before the plants can be restarted, they will also need a number of environmental upgrades.

Q. What environmental upgrade costs would be required in order to restart the Wilson and Coleman plants in 2018-2019?

According to the Sargent & Lundy study, commissioned by the Company its 2012 CPCN case, the remaining requirements for regulatory compliance at these plants could be substantial: $154 million (in 2011 dollars) at Wilson for MATS and other regulatory compliance (including the need for ACI, a new SCR, and DSI), and $96 million at Coleman for a series of regulatory requirements including CCR compliance (dry ash handling), MATS (ACI, ESP upgrade, lime DSI), 316(b) compliance (rotating circular intake screens), and CSAPR or its successor (low-NOx burners). Only a fraction of these costs are included in the projections for this case; BREC projects no additional environmental capital expenditures after June 2014 (financial forecast spreadsheet, tab “Capex & Depr”). Yet many or all of these costs would have to be incurred before the restart of Coleman and Wilson. None of them, of course, are required in the Right-Sized scenario.

An additional category of environmental costs could be required within the next few years. The Environmental Protection Agency (EPA) has announced its intention to develop CO_2 emission standards for existing power plants. While there are many steps between that announcement and the enactment of a binding standard, prudent planning at this point requires some consideration of possible carbon taxes or fees. Such policies would accelerate the movement away from

[20] The response to SC 2-12 also cites interest savings of $10 million and $18.5 million that would result from sale of Coleman and Wilson, respectively. Since this response refers to BREC’s response to SC 1-16, which assumed the plants were sold at net book value, it seems possible that these interest savings would result from using the sale proceeds to pay down BREC’s debts. Since both scenarios assume equal responsibility for BREC’s debts, I have omitted the potential interest savings from the costs of the Status Quo scenario.

coal, by increasing the competitive advantage of natural gas, renewables, and energy efficiency. With a fee on carbon emissions, BREC's coal plants would be less profitable, and alternatives involving less coal capacity would be even more attractive for the Company's ratepayers.

Synapse Energy Economics has surveyed carbon price assumptions made by utilities, government agencies, and other parties, and has developed recommended low, mid, and high case assumptions for future carbon prices, seeking to define a reasonable range of price estimates for use in utility planning. Our 2012 forecast, the latest currently available, assumes that carbon prices will begin in 2020. The low case starts at $15 per ton of CO2, rising to $22 in 2027 (the last year of BREC's financial forecasts in this case), and $35 in 2040. The mid case begins at $20 in 2020, reaches almost $36 in 2027, and $65 in 2040. The high case begins at $30, reaches $58 in 2027, and $90 in 2040.[21]

Q. What costs and risks would ratepayers face under the Right-Sized scenario?

A. This scenario would involve the transaction costs of selling or closing Wilson and Coleman. If no buyer can be found and it becomes necessary to retire the plants, some costs would be incurred for closing the plants. These costs are not enormous; a recent study by Navigant Research reportedly produced an estimated median cost of $18.9 million for decommissioning a coal plant with capacity between 350 and 500 MW.[22] Broadly similar estimates are provided for three case studies in EPRI's 2004 *Decommissioning Handbook for Coal-Fired Power*.[23]

Finally, the Right-Sized scenario means that ratepayers would lose the option to keep on gambling that a huge upturn in the market is right around the corner, making old coal plants profitable. If absolutely everything goes right – if BREC

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[21] Rachel Wilson, Patrick Luckow, Bruce Biewald, Frank Ackerman, and Ezra Hausman, "2012 Carbon Dioxide Price Forecast" (Synapse Energy Economics, 2012), available from http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf, attached as Exhibit Ackerman-6.
[22] Saqib Rahim, "Billions stand to be made in coal plant decommissioning," August 7, 2013, http://www.eenews.net/stories/1059985699, accessed October 28, 2013.
[23] *Decommissioning Handbook for Coal-Fired Power Plants*, EPRI, Palo Alto, CA: 2004. 1011220, available from www.epri.com.

and its consultants are right to imagine that MISO capacity prices will go through the roof in 2016, followed by energy prices in 2021-2023; if the load forecast is correct in showing that BREC will somehow acquire massive new load, on the same scale as the smelters, around 2019-2021; if BREC's requested more than doubling of rates has only a minor impact on rural demand and no impact on industrial demand; if no new regulations make coal plants even more expensive to operate in the future; if other utilities retire their coal plants, but stop building gas plants in order to continue serving their existing load – then keeping Wilson and Coleman available to restart in the future could turn out to be a bargain.

This is the future BREC is gambling on, when it refers to sales of Wilson and Coleman below book value as tantamount to throwing away a valuable asset (responses to SC 2-25, 2-26). They could, of course, win the gamble someday. But experience has shown, over and over, that they are far more likely to continue to lose. They have presented no persuasive evidence or arguments that their luck is about to turn.

Q. How would you summarize the costs of the two scenarios?

A. The Status Quo scenario includes several million dollars of annual fixed costs to keep the plants on standby, and likely more than $200 million of environmental upgrades before they can be restarted, in order to gamble on a very unlikely future. The Right-Sized scenario incurs only modest transaction costs and perhaps plant shutdown costs, and loses nothing except the opportunity to gamble on a future in which every one of BREC's hopes and forecasts comes true. Meanwhile, it leaves BREC and its ratepayers with an appropriately sized utility, without the risks of carrying the additional capacity that once served two enormous smelters.

Q. What is your recommendation to the Commission?

A. I recommend that the Commission grant BREC only very short-term rate increases, sufficient to keep the Company afloat while it recalculates the costs and benefits of selling or closing Wilson and Coleman, and adjusts its plans accordingly. The recalculation should include more sober estimates of future capacity and energy prices, more realistic load forecasts for a regional economy that is turning rapidly toward less energy-intensive technology and service sectors, accurate calculation of price elasticity effects, more realistic assessments of likely future environmental compliance costs facing those plants, and other corrections to the projections presented in this case.

The Commission should also make clear its willingness to allow rates that cover scheduled debt payments after the departure of Wilson and Coleman, but nothing more: there should be no additional markup, adders, or rate of return allowed on such payments. It will be challenging to produce a revised forecast of Big Rivers' prospects in this right-sized scenario – but it is the only solution that offers fair, just, and reasonable rates to the Company's ratepayers.

Q. Does this conclude your testimony?

A. Yes, it does.