STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC., FOR APPROVAL OF (1) A PHASE 2 COMPLIANCE PLAN REGARDING EMISSIONS REDUCTION REQUIREMENTS; (2) THE USE OF CERTAIN QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECTS; (3) CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR CLEAN COAL TECHNOLOGY; (4) THE USE OF CONSTRUCTION WORK IN PROGRESS RATEMAKING TREATMENT; (5) CERTAIN FINANCIAL INCENTIVES IN CONNECTION WITH PETITIONER'S COMPLIANCE PLAN, INCLUDING THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CLEAN COAL TECHNOLOGY PROJECTS VIA DUKE ENERGY INDIANA'S RIDER NOS. 62 AND 71, AND THE USE OF ACCELERATED DEPRECIATION; (6) THE AUTHORITY TO DEFER POST-IN-SERVICE CARRYING COSTS, DEPRECIATION COSTS, AND OPERATION AND MAINTENANCE COSTS ON AN INTERIM BASIS UNTIL THE APPLICABLE COSTS ARE REFLECTED IN PETITIONER'S RATES; (7) CONDUCTING ONGOING REVIEWS OF THE IMPLEMENTATION OF PETITIONER'S COMPLIANCE PLAN; (8) THE TIMELY RECOVERY OF EMISSION ALLOWANCE COSTS IN DUKE ENERGY'S RIDER NO. 63; AND (9) DEFERRAL AND RECOVER THE PHASE 3 PLAN DEVELOPMENT, ENGINEERING AND PRE-CONSTRUCTION COSTS	**)**	**CAUSE NO. 44217**

Direct Testimony of
Rachel S. Wilson

PUBLIC VERSION

On Behalf of
Citizens Action Coalition, Sierra Club, Save the Valley, and Valley Watch

November 29, 2012

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1. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Rachel Wilson and I am an Associate with Synapse Energy Economics, Incorporated (Synapse). My business address is 485 Massachusetts Avenue, Suite 2, Cambridge, Massachusetts 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse 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. Please summarize your work experience and educational background.

A. At Synapse, I conduct research and write testimony and publications that focus on a variety of issues relating to electric utilities, including: integrated resource planning; federal and state clean air policies; emissions from electricity generation; environmental compliance technologies, strategies, and costs; electrical system dispatch; and valuation of environmental externalities from power plants.

I also perform modeling analyses of electric power systems. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electricity dispatch models to conduct analyses of utility service territories and regional energy markets. I have direct experience running the Strategist, PROMOD, PROSYM/Market Analytics, and PLEXOS models, and have reviewed input and output data for a number of other industry models.

Prior to joining Synapse in 2008, I worked for the Analysis Group, Inc., an economic and business consulting firm, where I provided litigation support in the form of research and quantitative analyses on a variety of issues relating to the electric industry.

I hold a Master of Environmental Management from Yale University and a Bachelor of Arts in Environment, Economics, and Politics from Claremont McKenna College in Claremont, California.

A copy of my current resume is attached as Exhibit RW-1.

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

A. I am testifying on behalf of the Citizens Action Coalition of Indiana, Sierra Club, Save the Valley, and Valley Watch (the Joint Intervenors).

Q. Have you testified previously before the Indiana Utility Regulatory Commission?

A. No.

Q. What is the purpose of your testimony?

A. My testimony details and evaluates specific components of Duke Energy Indiana's ("the Company" or "Duke") analysis supporting this certificate of public convenience and necessity ("CPCN") application. I evaluate the Market Analytics/PROSYM ("PROSYM") modeling performed by the Company, as well as certain inputs to the PROSYM model. I also describe my own PROSYM modeling efforts using the Company's input data and present the results of that analysis.

Finally, I discuss some of the current and likely upcoming federal environmental regulations that are likely to affect the operations and economics of the fleet of Indiana coal plants owned by the Company and identify shortcomings in the Company's assumptions about those regulations.

Q. Please identify the documents and filings on which you base your opinion regarding the Company's analysis of the environmental compliance costs affecting its fleet of coal plants.

A. In addition to the application, testimony from Company witnesses, and discovery responses in this case, I have reviewed the Company's Market Analytics/PROSYM modeling input and output files.

2. OVERVIEW OF TESTIMONY AND CONCLUSIONS

Q. In your opinion, do the modeling assumptions and the Market Analytics/PROSYM modeling performed by Duke support the decision to install the proposed pollution control retrofits on its coal fleet?

A. The modeling performed by Duke and the underlying assumptions do not appear to support the installation of pollution controls on Gallagher Units 2 and 4 and Cayuga Units 1 and 2.

The Company committed a critical modeling error in its analysis of the benefits of the installation of pollution controls at its Gallagher units by failing to actually retire Gallagher Units 2 and 4 in the retirement scenarios, thereby charging those scenarios with both the cost of operating those units and the cost of replacing them. Duke also makes several assumptions that are incorrect, including: 1) inconsistency with respect to the retirement dates of Gallagher 2 and 4; 2) the assumption that energy efficiency savings will decline sharply after 2019; and 3) the use of a CO_2 allowance price projection at the low end of the range of utility forecasts. I was able to use PROSYM to correct the modeling error and update the results with more reasonable assumptions about extended energy efficiency and CO_2 price (the "Synapse Base Case"). Those results are shown in Table 1.

Table 1. Net Benefit of Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4	Cayuga 1	Cayuga 2
Duke Base Case	[redacted]	[redacted]	[redacted]	[redacted]
Duke Base Case (Corrected)	[redacted]	[redacted]	[redacted]	[redacted]
Synapse Base Case (Extended EE + Mid CO_2)	[redacted]	[redacted]	[redacted]	[redacted]

There were two additional errors regarding the analysis of the Gallagher units that can be corrected outside of PROSYM. The first is the retirement of Gallagher 2 on [redacted] and Gallagher 4 on [redacted]. These units are retired in PROSYM after being controlled in the Company's Base Case retrofit scenario. However, no additional capacity is added to maintain the Company's reserve margin when these retirements occur. A calculation done outside the modeling shows that correction of this error would lead to an additional capital cost of [redacted] for Gallagher 2 and [redacted] for Gallagher 4 in the retrofit scenario. This adjustment would lower the net benefit of control retrofits by the same dollar amounts. Additional production costs associated with the operation of replacement capacity would lower the net benefits by even more. [redacted] Corrections for these errors are shown in Table 2.

Table 2. Net Benefit of Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4
2032-2033 Replacement Cost Adjustment	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
With Adjustments Shown Above:		
Duke Base Case (Corrected)	[redacted]	[redacted]
Synapse Base Case (Extended EE + Mid CO_2)	[redacted]	[redacted]

I have additional concerns about: 1) the transparency of the modeling performed by Duke in this analysis; 2) the exclusion of any capacity and energy associated with the potential Wabash River Unit 6 natural gas conversion or replacement RFP; 3) the failure to consider additional demand response in the analysis period, 4) the difference in the dispatch methodology between the Company's Engineering Screening Model and the PROSYM model; and 5) the energy market price forecast.

The next sections of my testimony describe in more detail the errors and flawed assumptions that are included in Duke's modeling analysis, as well as the scenarios that were modeled by Synapse in our Market Analytics/PROSYM analysis.

3. DESCRIPTION OF COMPANY MODELING

Q. Please describe the modeling methods used by Duke in this docket.

A. It is my understanding that four different modeling methodologies were used by Duke in this docket. First, Wood Mackenzie used the Aurora XMP model to determine an hourly energy price forecast using its forecasts for coal and natural gas prices, a carbon dioxide ("CO_2") pricing regime, and coal retirements associated with national environmental regulations. These environmental regulations include the Cross States Air Pollution Rule ("CSAPR"); the Mercury and Air Toxics Standards ("MATS"); Coal Combustion Residuals ("CCR"); Clean Water Act 316(b) ("316(b)"); and the National Ambient Air Quality Standards ("NAAQS") for 8 hour ozone, $PM_{2.5}$, and sulfur dioxide ("SO_2"). This hourly energy price forecast is referred to as the Duke Fundamental Forecast.

Price forecasts for coal and natural gas, as well as the hourly energy price forecast, were then transferred to Duke for use in the Company's proprietary Engineering Screening Model. The Engineering Screening model evaluates various pollution control retrofit installations at each of the Duke units. Using unit specific information about such factors as capacity, emissions rate, heat rate, fixed costs, variable costs, etc., the Duke units are dispatched individually against an energy market price curve (in this case, the energy price curve provided by Wood Mackenzie in the Duke Fundamental Forecast). Model outputs are based on this unit dispatch, and include unit generation, capacity factor, fuel cost, operations and maintenance ("O&M") cost, emissions allowance cost, etc. These operating costs are combined with the capital costs associated with the particular pollution control retrofit technologies installed at a unit to arrive at a cash flow stream for each unit, and the net present value ("NPV") of this stream is calculated. Retrofit options are then selected based on a combination of NPV and whether or not required emission reductions are likely to be achieved by a given suite of controls.

Results from the Engineering Screening Model are then used in the Company's proprietary Integrated Resource Planning Model. This model analyzes the economics of installing pollution controls at each of the units compared to retirement scenarios that replace the retired units with natural gas combustion turbine or combined cycle options. A build-out schedule is generated for each scenario, showing the new capacity added (both type and size) in a given year for the simulation period.

These build-out schedules, as well as individual unit data from both of the Duke proprietary models are passed to the PROSYM model. PROSYM dispatches the Duke units in each scenario against the Company's load forecast in order to arrive at total production costs for the system on an annual basis.

For each scenario, production costs from PROSYM are combined with the stream of capital costs for the pollution controls and new capacity. These streams are discounted to calculate the total present value of revenue requirements ("PVRR") for each control option. Those PVRRs are presented in the exhibits of Company Witness Robert A. McMurry.

4. Description of Synapse Modeling

Q. Did you utilize any of the models used by Wood Mackenzie or Duke when conducting your review of the Company's analysis?

A. Only one – the PROSYM model. I was not given access to the Wood Mackenzie input and output files used in its Aurora XMP analysis, nor to the Company's proprietary Engineering Screening Model and Integrated Resource Planning Model. I did, however, receive the PROSYM input and output files from the Company and was able to use this model to review the Duke analysis.

Q. Please describe the modeling you performed in this docket.

A. First, I took the Company's PROSYM input files and re-ran the retrofit and retire scenarios for the Gallagher and Cayuga units (together the "Base Case") in order to confirm that the output results from my modeling were the same as the Company's results. For those scenarios that I ran, the output results were indeed the same. I then proceeded to conduct my own modeling analysis in order to correct a subset of the errors and erroneous assumptions that I believe are contained in the Company's analysis. There are additional erroneous assumptions that I did not correct for, which I will describe in Section 5.

Q. What are the errors and mistaken assumptions that you believe exist in the Duke analysis that you have corrected?

A. There is one error, and two flawed assumptions that I believe exist in the Duke analysis that I was able to correct in the PROSYM model:

A. A failure to actually retire Gallagher Units 2 and 4 in the Duke Base Case, resulting in a double counting of the production of both the replacement CT unit and the existing Gallagher Unit.
B. The assumption that the Company's efforts at energy efficiency and the resulting peak and energy savings will decline steeply at the end of 2019.
C. The use of a CO_2 emissions allowance price forecast that is at the low-end of the range of utility price projections.

The failure to actually retire the Gallagher units represents the error, and the points about energy efficiency and CO_2 are Duke's flawed assumptions. I will describe each of these in turn.

A. Duke's Failure to Actually Retire Gallagher Units 2 and 4 in Duke Base Case

Q. What do you mean when you say that the Company failed to retire Gallagher Units 2 and 4 in the Company Base Case?

In running the Base Case scenarios for the Gallagher units, I discovered an error in the Company modeling. The Base Case for each unit compares two scenarios: installing environmental controls at that unit (retrofit) to retiring the unit and replacing it (retire) with either a combustion turbine (in the case of Gallagher and Wabash) or a combined cycle unit (in the case of Cayuga and Gibson). However, in the Base Case scenario that retires Gallagher Unit 2, the replacement combustion turbine (CT) is added to the production cost simulation in PROSYM **without** actually retiring Gallagher 2. This is clear by reviewing the PROSYM output files in which Gallagher 2, with installed pollution controls, continues to operate throughout the planning period. Production costs are thus much higher than they should be with an extraneous unit in the analysis. The same error is made for the Gallagher Unit 4 retirement scenario.

When I corrected this error, the benefit of controlling the Gallagher units decreases substantially. Those results are shown in Table 3, below.

Table 3. Net Benefit of Gallagher Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4
Duke Base Case	[redacted]	[redacted]
Synapse Corrected Case	[redacted]	[redacted]

[redacted]

[redacted]

Table 4. Net Benefit of Gallagher Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4
Synapse Corrected Case	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Note that all of the Synapse modeling results that follow include the retirement of Gallagher 2 and 4, as well as the [redacted]

Q. Did the sensitivity scenarios modeled by Duke for Gallagher Units 2 and 4 contain the same error?

A. Yes, the PROSYM output files for the sensitivity scenarios show that the same error was made for Gallagher Units 2 and 4.

Q. Did you run the PROSYM model to correct these errors?

A. No. Time constraints did not allow for me to run PROSYM to correct this error in each of the Gallagher sensitivities.

B. New Energy Efficiency Savings Drop Significantly after 2019

Q. What do you mean when you say that new energy efficiency savings drop significantly after 2019 in the Company's analysis?

A. In its analysis, Duke assumes no new energy efficiency (EE) savings after 2019. Beginning in 2012, the Company's incremental energy efficiency rises from about 1.0% per year to approximately 1.4% in 2019. After 2020, however, the energy efficiency savings drop to 0.1% per year, as no new EE measures are introduced. My colleague, Dr. Frank Ackerman, describes in more detail the ways in which this assumption is erroneous.

In order to correct for this in the PROSYM modeling runs, we modified the Company's load forecast. We also had to modify the new capacity build-out, as smaller amounts of capacity were needed to maintain the Company's reserve margin. I call this case the "Extended EE Case." Note that this case corrects the Company's error of continuing to run the Gallagher units in the scenarios that should retire them.

Q. How did you adjust the Company's peak load in the Extended EE Case?

A. Duke's load forecasts were provided as part of Data Response 1.79A. In order to arrive at a case with the possibility for slower peak load growth, Synapse assumed half of the annual growth of the Company's peak load (0.6% compared to 1.2% annual growth), which is a conservative assumption. The net peak load matches the Company's net peak load through 2019, but we reasonably assume that peak load growth can be mitigated or grow more slowly after that period. The projections of peak load used in the Extended EE Case are shown in Figure 1, below.

[redacted]

We also adjusted annual energy requirement (MWh) to grow at 0.6 percent per year as a result of new efficiency measures. The forecast of the resulting native load used in the Extended EE Case is shown in Figure 2, below.

[redacted]

Q. How did you revise the Company's capacity build-out for the Synapse Extended EE Case?

A. Confidential Attachment CAC 1.89A contain the assumptions regarding the new capacity that Duke would need to replace retiring units and also to meet future load requirements. We incorporated the load forecast from the Synapse Extended EE Case (shown above) into this analysis and recalculated the capacity that would be necessary under this forecast to maintain the Company's planning reserve margin; the Synapse Extended EE Case maintains the Company's 15% minimum reserve margin in all planning years. These reconstructions of the Company's build-out were done for both the retrofit and retire scenarios for the Gallagher and Cayuga units.

The Extended EE Case resulted in a reduction of between [redacted] and [redacted]MW of new capacity compared to the Company's base case for all scenarios of retrofitting or retiring the Gallagher and Cayuga units. Thus the Company would not need as many new gas CC's and CT's to maintain reserves. The summary of these results is shown below in Table 5.

Table 5. New Capacity (MW) for Duke and Extended EE Cases.

Company scenario	Duke Base	Synapse Base	New Capacity Saved
Control Cayuga 1&2	[redacted]	[redacted]	[redacted]
Retire Cayuga 1	[redacted]	[redacted]	[redacted]
Retire Cayuga 2	[redacted]	[redacted]	[redacted]
Control Gallagher 2&4	[redacted]	[redacted]	[redacted]
Retire Gallagher 2	[redacted]	[redacted]	[redacted]
Retire Gallagher 4	[redacted]	[redacted]	[redacted]

Source: Data Response 1.89A, Synapse

In the Extended EE Case as modeled, the benefits of installing the retrofits at Gallagher 2 drop by [redacted]. The benefits of controlling Gallagher 4 drop by a little less than one-third. The benefits of controlling Cayuga 1 are cut in half, while the benefits of controlling Cayuga 2 decline by about 25 percent. These results are shown in Table 6.

Table 6. Net Benefit of Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4	Cayuga 1	Cayuga 2
Duke Base Case	[redacted]	[redacted]	[redacted]	[redacted]
Corrected Case	[redacted]	[redacted]	[redacted]	[redacted]
Extended EE Case	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

C. Use of a CO_2 Price Forecast on the Low-End of the Utility Range

Q. What do you mean when you say that the Company uses a CO_2 price forecast that is on the low-end of the utility range?

A. Many utilities include forecasts of future CO_2 allowance prices in their forward planning analyses. Synapse has collected utility forecasts from the last two years, and when compared to these other forecasts, the Duke forecast falls into the lower part of the range. Dr. Ackerman provides a more in-depth discussion of Duke's CO_2 allowance price forecast, and provides a graph of the other, publicly available utility price forecasts.

In order to correct for this in the PROSYM modeling runs, we modified the Company's CO_2 price forecast input to use the Synapse Mid CO_2 Forecast. When incorporating this new CO_2 forecast, we also had to modify the market price forecast to reflect the additional CO_2 costs. I call this case the "Mid CO_2 Case."

Q. How did you incorporate higher carbon prices into the market price in the Mid CO_2 Case?

A. Data Response 1.79A contained the market price forecast used by Duke in both its Base Case and its No Carbon Case. We were able to compare the market prices in these two cases, and impute the effect of the Company's carbon prices on its energy market. We then applied the hourly marginal emission rate (in tons of CO_2 per MWh) to the Synapse Mid CO_2 price ($/ton) in a given year in order to arrive at the new energy market prices for the Mid CO_2 Case ($/MWh).

The resulting average annual energy market prices are shown below in Figure 3 (nominal $/MWh). The prices are identical from 2012 through 2019 because there was no assumed carbon price for these years in either case. Market prices are higher in the Synapse Mid CO_2 Case as a result of the increased price of CO_2 allowances in each year.

[redacted]

[redacted]

[redacted]

In the Mid CO_2 Case as modeled, the benefits of installing the retrofits at Gallagher 2 drop by [redacted]. The benefits of controlling Gallagher 4 drop by a little less than one-third. These results are shown in Table 5.

In the Mid CO_2 Case as modeled, the benefits of installing the retrofits at Gallagher 2 drop by [redacted] from the Synapse Corrected Case. The benefits of controlling Gallagher 4 also drop by [redacted] from the Corrected Case. The benefits of controlling Cayuga 1 and 2 turn negative, meaning that it would be a liability to control these units, and that a combined cycle replacement would be more economic. These results are shown in Table 7.

Table 7. Net Benefit of Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4	Cayuga 1	Cayuga 2
Duke Base Case	[redacted]	[redacted]	[redacted]	[redacted]
Synapse Corrected Case	[redacted]	[redacted]	[redacted]	[redacted]
Extended EE Case	[redacted]	[redacted]	[redacted]	[redacted]
Mid CO_2 Case	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Q. Did you do any additional model runs?

A. Yes. For each of the retrofit and retire scenarios for Gallagher 2 and 4 and Cayuga 1 and 2, I executed model runs using a combination of the Extended EE Case and the Mid CO_2 Case. We believe this combination is a more likely future than the Duke Base Case, and call it the "Synapse Base Case." Those results are shown in Table 8.

Table 8. Net Benefit of Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4	Cayuga 1	Cayuga 2
Duke Base Case	[redacted]	[redacted]	[redacted]	[redacted]
Synapse Corrected Case	[redacted]	[redacted]	[redacted]	[redacted]
Extended EE Case	[redacted]	[redacted]	[redacted]	[redacted]
Mid CO_2 Case	[redacted]	[redacted]	[redacted]	[redacted]
Synapse Base Case (Extended EE + Mid CO_2)	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

5. Concerns with the Duke Modeling Input Assumptions

Q. Did you identify anything in the Company's analysis that you were concerned with but did not correct?

A. Yes, I have several areas of concern with regard to Duke's modeling that I was unable to or did not correct, including:

A. Lack of transparency in the first three pieces of the Duke modeling analysis: the Wood Mackenzie hourly energy price forecast, the proprietary Engineering Screening Model, and the proprietary Integrated Resource Planning Model.
B. A failure to include the capacity associated with the Wabash River Unit 6 natural gas conversion and/or the replacement capacity associated with the RFP for purchased power issued by Duke in February 2012.[1]
C. The retirement dates for Gallagher 2 and 4 in PROSYM for the Base Case retrofit scenario are [redacted] and [redacted], respectively. However, the Company does not include these retirements in its build-out plan.[2] As a result, the necessary replacement capacity does not get added to the calculations of PVRR, nor do the production costs associated with that replacement capacity.
D. The failure to incorporate any additional demand response in the Duke peak load forecast.
E. Difference in dispatch methodology between the Engineering Screening Model and the PROSYM model.
F. The use of an energy price forecast that appears to be too high.

A. Lack of Transparency in Duke Modeling Analysis

Q. Please describe what you mean when you say there was a "lack of transparency in the first three pieces of the Duke modeling analysis."

[1] Page 11, lines 1-11 of the Direct Testimony of Robert A. McMurry.
[2] "Prosym Portfolios.xlsx," provided as Confidential Attachment CAC 1.89-A.

A. Company Witness Douglas F. Esamann states that Duke's Phase 2 compliance plan is estimated to require a capital investment of $450 million, plus AFUDC estimated at $19 million.[3] The Company is also forecasting future investments of $945 million without AFUDC. Though not seeking recovery for it at this time, this additional $945 million is taken into account in the Company's assessment of the economics of the retrofit of its units compared to their retirement. With almost $1.5 billion in investment capital going into the continued operation of the Duke units, it is critical that any analysis of the economics of this decision be executed thoughtfully and carefully, and that it is subject to check by intervenors and the Commission.

There were four pieces to the Duke modeling analysis, which I have described above. We were given access to only one of the four pieces – the PROSYM modeling – and found one crucial error, several important omissions, and a number of flawed assumptions. Without access to the remaining three pieces of the analysis, neither the Commission nor any intervenors can be confident that there are no other errors that would significantly impact the results of this analysis.

B. Wabash River Replacement

Q. How did the Duke modeling runs fail to include possible capacity from the Wabash River 6 natural gas conversion, and/or from the replacement capacity associated with the RFP?

A. The Company's analysis of the economics of the Wabash River units led to a decision to retire Units 2-5, and the possibility of converting the 318 MW Wabash River Unit 6 to natural gas. Though Duke has not yet made a decision about Wabash River 6, the Duke analysis indicates that the economics of the natural gas conversion are positive. However, in the PROSYM model runs, Wabash Units 2-6

[3] Page 19, lines17-19 of the Direct Testimony of Douglas F. Esamann.

are all retired at the end of 2014, totaling 668 MW of retired capacity. No replacement capacity is added to the Company's generation mix as a result of these retirements, nor is the gas conversion included in any of the modeling scenarios or sensitivities. Consequently the reserve margin drops from 26.1% in 2014 to 15.2% in 2015. Any retirement that occurs in 2015, then, Duke would need to offset with the addition of new capacity in order to maintain the reserve margin. An analysis of the retirement of the Gallagher or Cayuga units will thus have to include replacement capacity on a MW-for-MW basis. Inclusion of any replacement capacity for Wabash 2-5, or with the natural gas conversion of Wabash Unit 6, Duke could retire both Gallagher 2 and 4 or a portion of the Cayuga unit without the addition of new capacity. Also, because of their low capacity ratings, it might be better for Duke to evaluate the Wabash and Gallagher units in tandem, with their retirement considered together against a larger replacement combined cycle unit, rather than comparing each unit to a combustion turbine on a stand-alone basis.

Similarly, the Company issued an RFP for purchased power for a period of one to three years, largely as a result of the decision to retire Wabash 2-6.[4] According to Mr. McMurry, five bids were received and three are being evaluated further. None of the capacity and energy associated with any of these bids was included in any base or sensitivity analysis evaluating coal unit retrofits/retirements done by the Company.

Had any replacement capacity been included, it very likely would have changed both the capital and production cost components of the Company's analysis, changing the PVRRs for both the retrofit and retire scenarios for the Gallagher and Cayuga units.

[4] Page 11, lines 1-11 of the Direct Testimony of Robert A. McMurry.

C. Gallagher Retirement Dates in the Retrofit Scenario

Q. Please explain what you mean when you say that Duke does not include the retirements of Gallagher 2 and 4 on January 1, 2033 and January 1, 2032, respectively, in its retrofit scenario.

A. The retirement dates for Gallagher 2 and 4 in PROSYM for the Base Case retrofit scenario are [redacted] and [redacted], respectively. This is the case in which both units receive the recommended pollution controls, and is compared against each of the retirement scenarios for the standalone units. However, the Company does not include these retirements in its build-out plan.[5] In order to maintain the appropriate reserve margin, capacity would need to be added as the Gallagher units retire. However, because the retirements are not included in the build-out, the necessary replacement capacity does not get added to the calculations of PVRR, nor do the production costs associated with that replacement capacity.

A natural gas combustion turbine added in 2032 to replace Gallagher 4 would have a net present value of approximately [redacted]. A natural gas combustion turbine added in 2033 to replace Gallagher 2 would have a NPV of approximately [redacted]. Both of these retirements occur in the Duke Base Case retrofit scenario, and should be added to the total capital cost associated with that scenario. Doing so would lead to a decrease in the benefits associated with controlling the Gallagher units. Those results are shown in Table 9.

[5] "Prosym Portfolios.xlsx," provided as Confidential Attachment CAC 1.89-A.

Table 9. Net Benefit of Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4	Cayuga 1	Cayuga 2
Duke Base Case	[redacted]	[redacted]	[redacted]	[redacted]
Synapse Corrected Case	[redacted]	[redacted]	[redacted]	[redacted]
Extended EE Case	[redacted]	[redacted]	[redacted]	[redacted]
Mid CO_2 Case	[redacted]	[redacted]	[redacted]	[redacted]
Synapse Base Case (Extended EE + Mid CO_2)	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

The Company's PROSYM model runs simulate the period from 2012 to 2032. The study period for the analysis, however, is 2012 to 2034. In the final two years, Duke applies an inflation rate to grow the production costs. This may not accurately represent what the production costs would have been if the PROSYM period had been extended by two years. This is especially true when changes are being made to Duke's capacity mix. Adding in the production costs associated with the new CT replacement capacity would likely lead to an even greater decline in the benefits associated with controlling the Gallagher units.

D. Failure to Include Additional Demand Response

Q. How does the Duke analysis fail to consider additional demand response?

A. As discussed by Dr. Ackerman in his testimony, the estimated potential for demand response is much greater than what is assumed in the Duke analysis. This is important due to the fact that the utility is capacity short but energy long. In any given year in the retirement scenarios, Duke maintains thousands of GWh of market sales and seems to have no issues meeting its native load. Duke does have excess capacity in 2014, with a reserve margin greater than 26%. However, after the retirement of the Wabash units, that excess capacity disappears, and the Company must add additional combined cycle units over the planning period in order to meet peak load. Additional demand response would serve to lower that peak load, and could perhaps offset some of those capacity additions in later years, lowering the total cost to the utility and to consumers.

E. Difference in Dispatch Methodology between Models

Q. How is there a difference in dispatch methodology between the models used by the Company?

A. As described above, Duke's proprietary Engineering Screening Model dispatches the Company's units against the set of market energy prices created by Wood Mackenzie. PROSYM, however, has been set to dispatch the Duke units against the utility's load. The PROSYM simulation is thus just the Duke system, and represents neighboring utilities in an oversimplified way.

Thermal stations are dispatched against load based on their fuel prices and heat rates. This may cause an unrealistic increase in the generation from some of the Duke units, specifically Gallagher 2 and 4. When thermal stations are dispatched against the market, they do not generate electricity in hours when their running costs are higher than the market price, subject to ramping constraints, minimum up and down times, etc. When thermal stations are dispatched against load, they are stacked according to their running costs from low-to-high, and the least-cost generators are dispatched first. Generators in the stack are dispatched, subject to the same operating constraints mentioned above, until the load in a given hour is met. While certainly not the lowest-cost generator in the Duke fleet, the Gallagher units are less expensive to operate than older peaking units in Duke's fleet. When dispatched against load, they would likely generate more than when dispatched against market prices, especially when more efficient units in neighboring utility service territories are bidding in their generation.

Figure 4, below, shows historic capacity factors for the Gallagher units, as well as those capacity factors projected by the PROSYM model.

[redacted]

Gallagher capacity factors are expected to rise slightly in 2013, and then to continue to grow through 2019, when they begin to decline again. These units are aging, and will experience greater operating costs with the installation of pollution control equipment. It seems highly unusual that, absent a spike in natural gas prices, the capacity factors of these units should rise from 5 percent or less in 2012 to 30-35 percent between 2017 and 2019.

Market purchases and sales in PROSYM are assigned a maximum capacity value, designated as "must run," and dispatched against load using the input market energy price forecast provided by Wood Mackenzie to calculate their running cost. When market sales are compared across the retrofit and retirement scenarios for both Cayuga 1 and 2, and Gallagher 2 and 4, we see that volume of sales (in GWh) stays relatively constant across scenarios. These outputs can be seen in Figures 5 and 6, below.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

In the energy market, one might expect that energy sales would adjust as the mix of capacity and fuel in a region changes. It seems possible that in each of these sets of scenarios, as units retire, the more expensive replacement capacity has to generate more than it otherwise would in order to maintain the same sales volume. This would lead to a higher total production cost in the retirement scenarios than would otherwise occur, and bias the output results in favor of the retrofit scenarios. In the real-world energy market, I believe that volume of sales would adjust downward as more expensive gas peaking capacity is added to the generation mix.

F. Wood Mackenzie Market Price Forecast

Q. How was the market energy price forecast developed for the purposes of the Duke analysis?

A. Wood Mackenzie used the Aurora XMP model in a deterministic manner to derive its market energy price forecast, as confirmed in Data Response CAC 2.23. That is, Wood Mackenzie developed base forecasts for a variety of input assumptions, including (but not limited to) fuel prices, potential carbon prices, environmental regulations, load growth, capacity additions and retirements, and economic growth. Wood Mackenzie then estimated a single set of future market prices based on these static assumptions. Deterministic models thus allow for no amount of randomness in their output when using a given set of input values.

Q. Do you agree with this methodology?

A. No. All of the input assumptions listed above are drivers of future energy market prices, and each one is subject to some amount of uncertainty and risk. To use a single forecast for each of these variables to generate a single market price forecast is erroneous.

Q. How would you recommend that energy market prices be determined?

A. The Aurora XMP model has the capability to operate stochastically, meaning that it can incorporate a range of uncertainties and risks and produce a range of potential outcomes. It is, in fact, my understanding that entities obtain and use the Aurora model specifically because it has this capability. Duke should develop reference cases for important input variables like natural gas or CO_2 allowance prices, but the Company should also develop some number of iterations of these forecasts (e.g. 200 iterations). Duke should then run the same number of model iterations in order to determine the energy market price forecast. The Company can then develop a reference case for energy market prices by taking the mean outcome of the distribution of the model iterations.

Q. What is your impression of the Company's market price forecast?

A. The Duke market price forecast seems high when compared to historic market prices and MISO market forward energy prices.

Q. How do recent MISO market prices compare to the cost of running the Company's fleet?

A. In recent years, the MISO market prices have been lower than the running costs for the Gallagher units for a majority of hours, and have been lower than the operating and fuel costs of the Cayuga units in many hours. Figure 7 below shows the operating and fuel costs for the Gallagher and Cayuga units compared to the most recent MISO market prices for the Cinergy Hub. Note that O&M data provided by the Company were not broken out into fixed and variable components. In order to include solely variable O&M, I applied a fixed to variable cost ratio of 80/20, which I have seen in industry literature. Note also that the 2011 increase in the running costs of the Gallagher units is due to the use of low sulfur coal. The units are expected to continue burning low sulfur coal during the study period in the Company's analysis.

[redacted]

[redacted]

Figure 7. Cinergy Hub Forwards Compared to Gallagher and Cayuga Operating and Fuel Costs
(MISO, Confidential Attachment CAC 1.77A)

Because the decision to generate or not is based largely on whether or not the market price (and thus the revenue that can be earned) is higher than a unit's running cost, this indicates that the Gallagher units would not generate for the majority of the year. The Cayuga units would generate more often, but not as much as one might expected from a baseload coal plant. The costs above do not account for capital expenditures (including costs of environmental controls) which would impact the forward-going economics of the units.

Q. What are the expectations for MISO market prices in the near future?

A. The NYMEX forward energy prices for the MISO region have the prices remaining low through 2015. Figure 8 below shows recent NYMEX futures for the Cinergy Hub as compared to the Wood Mackenzie market price projection.

[redacted]

[redacted]

Q. Do you have an opinion about the possible drivers of an inflated Wood Mackenzie energy market price forecast?

A. Yes. Projections of the rate of coal capacity retirements in the near term as a result of EPA regulations are greater in the Wood Mackenzie forecast than might actually be expected. Mr. Robert W. Fleck states that the Wood Mackenzie expectation in the Duke Fundamental Forecast is that 49.3 gigawatts (GW) of coal-fired capacity will retire in the United States by 2016, and 57.9 GW will retire by 2030.[6] A comparison of these projections to those from Ventyx, the PROSYM model vendor, shows that the Wood Mackenzie projected retirements are higher by approximately [redacted] in [redacted], as shown in Figure 9, below. While the Wood Mackenzie forecast shows a dramatic spike in number of GW of coal

[6] Page 20, lines 8-10 of the Direct Testimony of Robert W. Fleck.

retired in 2015, and then a very gradual rise through 2030, [redacted]. These forecasts converge around [redacted]. In contrast to the Wood Mackenzie forecast of coal retirements, the Ventyx schedule would likely have a more favorable effect on the upward trajectory of market prices. [redacted]

[redacted]

As mentioned above, Mr. Fleck states that the projected retirements in the Wood Mackenzie price forecast are determined by taking into consideration the CSAPR, MATS, CCR, and 316(b) rules, as well as revisions to the NAAQS.[7] On August 21, 2012, U.S. District of Columbia Circuit Court vacated CSAPR. It is reasonable to assume that a portion of coal capacity retirements were being driven

[7] Page 14, lines 1-23 of the Direct Testimony of Robert W. Fleck.

by CSAPR and the need to install emission control retrofits to lower emissions of SO_2 and NO_x. Because these controls are no longer required due to the vacatur of CSAPR, it is reasonable to assume that a portion of the retirements projected by Wood Mackenzie may not occur.

Assumptions about replacement capacity for retired coal units are significant to an hourly energy market price forecast. Renewable resources operating at variable costs of zero, or close to zero, would lower energy market prices in the hours in which they are operating. Assuming more renewable capacity could displace certain peaking and intermediate units, and thus lead to lower market prices. The assumption that all or most coal-fired generation that retires is replaced with natural gas would not lead to a similar decline in market prices.

6. EVALUATION OF DUKE ENVIRONMENTAL COMPLIANCE ASSUMPTIONS

Q. Were you able to review the Company's assumptions about environmental compliance?

A. Yes.

Q. Do you believe that the Company's proposed retrofits for which it is seeking recovery will bring its units into compliance with current pending EPA regulations?

A. Not necessarily. The revised NAAQS for the 8-hour ozone standard are still in flux. In March 2008, EPA strengthened the 8-hour ozone standard from 84 ppb to 75 ppb. On September 16, 2009, EPA announced that because the 2008 standard was not as protective as recommended by EPA's panel of science advisors, it would reconsider the 75 ppb standard. In 2010, EPA proposed lowering the 8-hour ozone standard from 75 ppb to between 60 and 70 ppb. As acknowledged by Company witness Geers, this range is significantly more stringent than the 2008 standard and "would likely drive additional NOx emission reductions."[8] However,

[8] Page 16, lines 17-22 of the Direct Testimony of Michael Geers.

on September 2, 2011, the Administration announced that EPA would not finalize its proposed reconsideration of the 75 ppb standard ahead of the regular 5-year NAAQS review cycle. The next 5-year review for 8-hour ozone is expected in 2013. Compliance with the upcoming standard would likely be required in the 2019-2020 timeframe.

Mr. Geers states that "The vast majority of Indiana…is in attainment with the [current] 75 ppb standard. The potential for EPA to issue a lower standard, possibly in the 60 to 70 ppb range, is still a risk…"[9] If the EPA does in fact issue a standard in the 60 to 70 ppb range, or an even lower standard (in its 2010 proposal, EPA also evaluated a 55 ppb standard[10]), many Indiana counties may be out of attainment with the 8-hour ozone standard, including Floyd County, where the Gallagher Plant is located. If this were to occur, the proposed SNCR retrofits at Gallagher might be insufficient to meet the standard. Some other form of control technology could be required at the units, and would most likely be more expensive from a capital cost perspective than the SNCR. This would negatively affect the economics of controlling Gallagher 2 and 4. The magnitude of that effect would be dependent on the control technology, but it would likely push the analysis in favor of retirement.

The Company also used the Engineering Screening Model to evaluate a "Strict Scenario" that assumes the most stringent combination of potential outcomes of the various EPA regulations.[11] No additional analysis of this scenario was performed. Nonetheless, Mr. Miller states that the retrofit economics would be highly stressed for Cayuga 1 and 2, Gallagher 2 and 4, and Gibson 5. The retrofit economics would be marginal for Gibson 1-4.[12] I believe this Strict Scenario

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[9] Page 17, lines 9-11 of the Direct Testimony of Michael Geers.
[10] 75 Fed. Reg. 2938 (January 19, 2010)
[11] Page 22, lines 16-21 of the Direct Testimony of Joseph. A. Miller, Jr.
[12] Page 23, lines 1-3 of the Direct Testimony of Joseph. A. Miller, Jr.

should have been run through all of the steps in the Company's modeling process to properly evaluate, and present, the risks associated with this scenario.

Q. Do you believe that costs of all necessary environmental compliance technologies were included in the Company's analysis, based on the Company's understanding of the current and pending EPA regulations?

A. No, I do not. Two pieces of cost information are missing from the Company's economic analysis – capital and operating costs associated with upgrades of electrostatic precipitators, and capital and operating costs associated with the entrainment provision of the 316(b) cooling water rule. While the Company admits that these control retrofits will likely be necessary, it has left the capital and operating costs out of its analysis.

Installation of activated carbon injection ("ACI") and/or dry sorbent injection ("DSI") for compliance with the MATS rule can lead to additional loading of particulate matter and may necessitate upgrades to existing electrostatic precipitators ("ESPs") at the Duke units. Under the Company's Phase 2 Compliance Plan, the Gallagher and Gibson units will be retrofit with ACI technologies, while the Cayuga units will receive both ACI and DSI systems. Mr. Joseph A. Miller states that current precipitators installed at the units were not designed for the addition of carbon for mercury removal, and "increased particulate loading will most likely require some precipitator enhancement to prevent too much particulate breakthrough to the FGDs."[13] Mr. Miller also states that Duke has not yet had the proper time to fully develop and evaluate the potential ESP improvement alternatives. Thus, any capital and operating costs associated with ESP upgrades that might be needed at any of the units are not included in the Company's economic analysis. Had they been included, it would most likely increase the total PVRR associated with Duke's Base Case retrofit scenarios for each of the units requiring the upgrades.

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[13] Page 38, lines 8-10 of the Direct Testimony of Joseph A. Miller, Jr.

EPA's proposed 316(b) cooling water rule has provisions to mitigate the impingement and entrainment of aquatic organisms. In its economic analysis, the Company has included costs associated with the impingement provisions of the rule. These include capital costs for upgrades of fine mesh screens and the installation of fish return systems, as well as O&M for impingement mortality monitoring. According to Mr. Miller, however, Duke has "not included in our analysis any costs for implementing the entrainment provisions of the rule."[14] Mr. Miller states that the "primary risk associated with compliance would be the installation of closed cycle cooling towers." [15] Closed cycle cooling towers are one method of achieving compliance with the entrainment portion of the rule, however, many utilities are claiming that compliance can be achieved through the use of traveling screens and other lower cost, less effective technologies. Duke makes no mention of having evaluated any of these technologies for compliance with the entrainment provision, nor has any capital or operating cost for entrainment compliance been included in the economic analysis. Had these costs been included, it would most likely lead to an increase in the total PVRR associated with Duke's Base Case retrofit scenarios for each of the units requiring the technologies.

Q. Are there any other issues with the Company's environmental compliance that you would like to raise at this time?

A. Yes. Under EPA's Final Tailoring Rule, the largest sources of greenhouse gas emissions are subject to permitting requirements. A "large source" is a new facility with GHG emissions of at least 100,000 tons per year of carbon dioxide equivalent (CO_2e) or an existing facility with at least 100,000 tons per year CO_2e making changes that would increase GHG emissions by at least 75,000 tons per year CO_2e. These sources are required to obtain permits under the New Source

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[14] Page 11, lines 1-2 of the Direct Testimony of Joseph A. Miller, Jr.
[15] Page 11, lines 4-5 of the Direct Testimony of Joseph A. Miller, Jr.

Review Prevention of Significant Deterioration and title V Operating Permit programs.

In response to discovery request CAC 2.10, the Company provided Attachment CAC 2.10A, which is the approval of a significant source modification to the Part 70 Operating Permit Renewal for Cayuga Generating Station dated September 5, 2012. This permit authorizes the construction of the Company's Phase 2 SCR, DSI, and ACI projects at the Cayuga Generating Station. The Company indicates that the past actual emissions of CO_2e at the facility are 6,280,278 tons per year.[16] The future projected actual emissions of CO_2e after the installation of the Phase 2 projects at the Cayuga plant will be 7,662,250 tons per year. The Company indicates that this is a net increase in CO2e of 1,582,414 tons per year, or, a 25 percent increase. This significant increase in CO_2e is attributed entirely to "demand growth," with none of the increase attributed to the projects, and so the Company determined that the modification would not trigger PSD compliance. "Demand growth" is not defined in Attachment CAC 2.10 and IDEM did not review this determination.

A nearly 1.6 million ton per year increase in CO_2e is considered significant under the Tailoring Rule and should trigger PSD permitting. The Company's determination that the 25 percent increase in CO_2e emissions is due entirely to demand growth is difficult to understand, especially in light of Duke Energy Indiana's very weak growth forecast. In his testimony, Witness Merino explains that:

> The latest forecast for Duke Energy Indiana points to negative growth between 2012 and 2017 for MWH sales and no growth for MW peaks. The weak outlook in sales is attributable to a slow economic recovery, low levels of new customer additions, the impact of energy efficiency programs, and the

[16] Attachment CAC 2.10, page 090004112-004284 (page 196 of the .pdf file).

expiration of wholesale backstand contracts associated with the Gibson 5 ownership.[17]

PROSYM results for the Company's Base Case retrofit scenario for the Cayuga units do not indicate a sustained increase in the capacity factors of the units subsequent to the retrofit projects. The projected capacity factors of the units are shown in Figure 10, below.

[redacted]

[redacted]

[redacted]

The Cayuga capacity factors do increase early in the planning period, but begin to decline beginning 2017. It does not appear as though load growth is in fact leading to a sustained increase in the energy output of the Cayuga units, nor to the increase in CO_2e emissions that is projected in the Operating Permit.

The use of Trona as a sorbent in DSI systems, on the other hand, can lead to significant increases in CO_2 emissions. The additional energy requirements of the

[17] Page 7, lines 5-9 of the Direct Testimony of Jose I. Merino.

new controls can also lead to increased CO_2e emissions, though on a smaller scale.

I believe that the Company should provide justification for the decision not to obtain a PSD permit for GHGs as required by the Tailoring Rule. The increase in CO_2e emissions that is projected in the Operating Permit is not reflected in the PROSYM output associated with the retrofit of the units. If these increases are truly expected to occur, they will cause a significant rise in the production cost between 2020 and 2034, when the CO_2 emissions allowance pricing regime is expected to be in effect.

7. CONCLUSIONS

Q. Please summarize your conclusions.

A. Based on my review, I conclude that the errors and flawed assumptions present in the Duke modeling analysis causes the Company to overstate the benefits associated with the continued operations of Cayuga 1 and 2 and Gallagher 2 and 4. After correcting for the modeling errors and updating the input assumptions, we see that the net benefits of installing emission controls at these units decline dramatically, and disappear entirely under many scenarios. Thus, I conclude that the modeling performed by Duke and the underlying assumptions, when corrected, do not appear to support the installation of pollution controls on Gallagher Units 2 and 4 and Cayuga Units 1 and 2.

Q. Does this conclude your direct testimony?

A. Yes.