AEP Ohio Exhibit ___

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company.	**))))**	**Case No. 10-2929-EL-UNC**

PRE-FILED REBUTTAL

TESTIMONY OF

EUGENE T. MEEHAN

IN SUPPORT OF AEP OHIO'S

MODIFIED ELECTRIC SECURITY PLAN

Filed May 11, 2012

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

Columbus Southern Ohio Power Company and Ohio Power Company d/b/a AEP Ohio

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On Behalf of AEP Ohio

I. Qualifications and Purpose of Testimony

1. Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Eugene T. Meehan. I am a Senior Vice President at NERA Economic Consulting ("NERA"). My business address is 1255 23rd Street, N.W., Washington, D.C. 20037.

2. Q. PLEASE BRIEFLY DESCRIBE THE NATURE OF NERA'S BUSINESS.

A. NERA is a firm of over 450 professional economists located in offices throughout the United States, Europe, Australia, and Asia. NERA provides consulting advice in litigation and regulatory settings, as well as strategic and planning advice to clients in the energy, telecommunications, television and broadcasting, securities, transportation, health, and banking industries.

3. Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I have over thirty years of experience consulting with electric and gas utilities. That work has involved examination and advice on many issues related to power markets, power contract design, competitive bidding, and contract evaluation. For the past fifteen years, I have been extensively involved in advising clients on restructuring-related issues, including risk analysis, risk management, power plant and power contract valuation, and post-transition regulatory issues. I have testified as an expert on electric industry issues before numerous state regulatory commissions (including the Public Utilities Commission of Ohio), before the Federal Energy Regulatory Commission, the Atomic Safety and Licensing Board, federal courts, and arbitration panels. I have also submitted expert affidavits or declarations to the same authorities and in state court and presented the results of regional production simulations to utility Boards of Directors. Rebuttal Exhibit ETM-R1 contains a more detailed statement of my qualifications.

4. Q. DO YOU HAVE EXPERIENCE CONDUCTING ANALYSES AND TESTIFYING WITH RESPECT TO LARGE SCALE PRODUCTION SIMULATION MODELS AND POWER MARKET INFORMATION?

A. Yes. From 1980 through 1994, I was employed by Energy Management Associates, Inc. ("EMA"), the company that developed the PROMOD production simulation model. I had a large role in developing the multi-area version of that model, which incorporated the modeling of transmission constraints and was designed to model regional and power pool systems. As a Vice President at EMA, I concentrated on providing consulting service to clients, many using the multi-area version of the PROMOD model. I testified on model validation, development of model inputs, and analysis of model outputs. The applications of the model I helped to implement included projections of marginal and avoided costs, fuel budgets, power sale and margin forecasts, merger related production cost savings, transmission line economics, generating plant retirement impacts, generation expansion analyses, and power pool restructuring analyses. Prior to joining EMA, I worked from 1973 to 1980 at NERA, also using production costs models. After rejoining NERA in 1996, I continued to work on projects that involved regional production cost modeling including analyses of stranded costs, forecasts of market prices, and development of integrated resource plans. I also have worked extensively with market data in particular with forward power and gas prices and have examined locational marginal prices ("LMP") basis differentials in several Regional Transmission Organizations ("RTOs"). I worked on a confidential assignment with a large distribution company examining Auction Revenue Right valuation which involved analyses of generation hub to load zone price differentials. I have directed NERA's work for the past two triennial resets of the New York ISO Installed Capacity Market Demand Curve. That work has included estimating peaking unit net energy revenues at various levels of installed reserve, a task performed primarily using historical market data and statistical methods.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have reviewed the testimonies of Staff Witness Harter and Staff Witness Medine. The purpose of my testimony is to evaluate the suitability of their analysis estimating the gross energy margins of AEP Ohio's generating units for use in the development of a cost-based capacity rate for AEP Ohio during the remainder of the Fixed Resource Requirement ("FRR") period. In addition, I have conducted an independent analysis of the gross margins that AEP could realistically have the potential to achieve during the remainder of the FRR period, namely from June 1, 2012 to May 31, 2015. I present the results of that analysis to show the magnitude of the deficiencies in Mr. Harter's and Ms. Medine's results ("EVA results"). My analysis, which is more reliable, realistic, and transparent, provides information that could be used to develop a reasonable energy credit if the Public Utilities Commission of Ohio ("PUCO" or "Commission") implements an energy credit as part of a cost-based capacity rate. Given the paucity of information provided by EVA with respect to the Aurora input data and modeling choices, an independent analysis is an appropriate way to evaluate, and illustrate the deficiencies of, the EVA analysis. It is also an appropriate way to demonstrate the magnitude of the errors in the results of EVA's analysis.

6. Q. YOU REFER JOINTLY TO MR. HARTER'S AND MS. MEDINE'S RESULTS AND EQUATE THE TWO. ARE THEIR RESULTS THE SAME?

A. Yes. It appears that Mr. Harter performed an Aurora model run and testified to that run. Ms. Medine acknowledges errors, but seemingly only errors in aggregating results, accounting for correct ownership shares, or modeling retirement dates. A second run appears to have been performed for the purpose of correcting these "inadvertent" errors. Ms. Medine's testimony is limited to clarifying the description of model inputs used by Mr. Harter and to correcting inadvertent errors made in estimating the energy credit. She uses the second run made by Mr. Harter. Given the relationship of the two testimonies, I will address aspects that are common as "EVA testimony" or "EVA analysis". Ms. Medine relies on Mr. Harter's model runs so I believe it is fair to attribute the underlying analysis to both witnesses. I will also address Ms. Medine's testimony specifically and focus on whether her clarification of inputs in any way solves the shortcomings of EVA's initial testimony, which was sponsored by Mr. Harter, or the second run of the model, which was performed by Mr. Harter but sponsored by Ms. Medine.

7. Q. CAN YOU CLARIFY THE SCOPE OF YOUR TESTIMONY?

A. Yes. My testimony addresses the analyses used by Mr. Harter and Ms. Medine to estimate the gross energy margins that AEP Ohio units could potentially earn when dispatched in their entirety against the PJM market. I did not examine how the AEP pool operating agreement would impact the realization of these margins by AEP Ohio, the potential impact of excess capacity and sales of capacity to other AEP companies, or whether and how a portion of any energy margin should be applied to sales to non-shopping customers. Additionally, I do not address potential ancillary service margins or report the energy credit in any measure except total dollars. In conducting my analysis, I have relied upon AEP to provide detailed information with respect to its generating fleet that Mr. Nelson provided to me. I believe that it is appropriate to rely on this information as AEP has the best knowledge of these costs.

II. Summary of Conclusions

8. Q. PLEASE PROVIDE A SUMMARY OF THE CONCLUSIONS YOU HAVE REACHED.

A. The conclusions I have reached are as follows:

- The approach used by EVA develops zonal LMPs based on modeling the Eastern interconnection using a production costs model (Aurora), which requires thousands of unverified inputs. Accordingly, it is not suitable for the task at hand, which requires a very realistic three-year projection of the power prices that the AEP Ohio units will face in order to provide accurate results.
- EVA has failed to perform a basic step, which is to effectively calibrate the results of the model it is using to actual market outcomes and to utilize the results of that calibration.
- The approach used by EVA is impossible to verify as it is produced by a "black box approach" that cannot be examined for errors.
- Demonstrated errors with respect to the costs of the AEP Ohio units indicate that the modeling performed by EVA has not been done with the care required for this application.

- EVA's testimony implying that correcting errors in the operating costs of AEP Ohio units could lead to a less accurate result as opposed to a more accurate result is implausible.
- There are other ways to forecast energy margins that are much less subject to the potential for error. Additionally, these other methods can be fully examined and validated as they do not rely on proprietary data and calculation methods and thus are verifiable objectively.

9. Q. HAVE YOU IMPLEMENTED A MORE RELIABLE, REALISTIC, AND TRANSPARENT METHOD FOR QUANTIFYING GROSS ENERGY MARGINS FOR AEP OHIO UNITS FOR THE NEXT THREE YEARS IN ORDER TO EXAMINE THE MAGNITUDE OF DEFICIENCIES IN EVA'S MODEL RESULT?

A. Yes. I have implemented a methodology that can more realistically and transparently develop estimates of forecasted net energy margins in order to assess the reasonableness of EVA's results. These estimates demonstrate conclusively that EVA's analysis grossly exaggerates energy margins. Additionally, I have provided the results of this analysis to AEP so that it can develop estimates of forecast energy credits using an analysis of gross margins that is more realistic and transparent than that of EVA. My analysis, for which I provide all inputs and all calculations and describe in detail all calculations, shows conclusively that EVA overstates the gross margins for the units it studies by roughly two and one-half times.

III. Deficiencies in EVA's Analysis

10. Q. YOU HAVE CONCLUDED THAT EVA'S APPROACH IS NOT SUITED TO THE TASK. PLEASE ELABORATE ON HOW YOU REACH THIS CONCLUSION.

A. As I understand the situation, the PUCO may set an FRR capacity rate that is generally based on subtracting a projection of energy margins from fixed costs. To the extent that projections of energy margins are used in that application, it is very important to develop the most realistic projections. This is the case as margins that are too high would lead to an under recovery of cost and margins that are too low would lead to an over recovery of cost. While a "true-up" would mitigate the effects of over or under statement, there is no reason not to start with the most realistic projection possible. If the objective is to develop the most realistic view of projected energy margins, this requires extreme care because accuracy with respect to a difference (the energy margin is the difference between the market price and the operating cost) is very sensitive to misstatements in either the operating cost or the market price. For example if market price is $35 and the unit cost is $30, the margin is $5. An error of a 5 percent overstatement of the market price would mean that the market price would be $33.75 a 5% difference, a seemingly small delta. However, the resulting margin would not be $5 but would be $3.75. This is a difference of 33% from the actual margin. A difference of 33% is not a small delta. To reiterate, in the example, the margin overstatement from a 5% error in the overstated market price would be a 33% overstatement of the actual margin. The approach used by EVA is inappropriate, as there is significant room for deviations from reality in the methodology that EVA has used. According to the website of EPIS (the Aurora developer), "The North American Zonal Market Database includes 115 Market Areas with over 13,600 Generating Units, Fuel Prices, Area, Zone and Pool Demand, Hydro Energy and Constraints, Emissions Rates and Prices, Spinning & Operating Reserves, Area and Zonal Transmission, Flexible System Consolidations, and a Comprehensive Set of Resource Groups." There are different control areas with varying commitment and dispatch practices, different environmental regimes in different geographic areas, potentially unique fuel delivery or contract situations at each plant and transmission system average and marginal losses that are changing all the time. In PJM these marginal losses directly affect the revenues that the plants would realize. A large amount of this data is not publicly available at the required level of detail. In RTOs like PJM, power prices are determined at nodes, representing the bus to which each unit or plant is attached. Detailed unit characteristics such as input/output curves, operating constraints and start-up costs are not public information. Each control area has its own set of Demand Response programs and assembling and modeling how each of these programs would impact the market is difficult. Aurora or any similar model requires and is sensitive to such information, yet it is impossible to develop a sufficiently expansive set of input data to a model without making hundreds of assumptions that cannot be validated. Even a high level validation effort would take many person months, require significant judgment, and at most would produce a finding that the data appeared not to be obviously unreasonable. The quality of information coming from such a model may be used for planning purposes, and could also be used for some decision making as long as the decision maker can consider the possible inaccuracies when applying the information to results developed knowing that all input information has not been validated. However, as shown above, a small error in price can produce a large error in margin. In an application this sensitive, where accuracy is important and the absolute value of the model result will be directly used, the methodology used by EVA, which is to model the entire interconnected electric system using a production costs model where all material inputs cannot be validated is not well suited for the task. This becomes even more evident when one realizes that there is available another method that is more accurate, realistic, timely and transparent.

11. Q. PLEASE ELABORATE ON EVA'S FAILURE TO EFFECTIVELY CALIBRATE THE RESULTS OF ITS AURORA MODELING.

A. The most basic step in any large scale production costs model analysis is to calibrate the results of the model that will be used to a known measure. That does not appear to have been done by EVA. For example, one would compare the forecast of market prices that the model and data set are producing on and off peak to available forward market data at the AEP/Dayton hub (recognizing that prices at the AEP Dayton hub have been roughly 3% above prices at the AEP generation hub). If one could determine that the model and data were consistently overstating prices by say 5%, the model results could be reduced by that amount. If one could determine that the model and data were consistently understating prices by say 5%, the model results could be increased by that amount. This is a rough adjustment, but at least represents an effort to asses any model and/or data bias and adjust. Alternatively, one could do a backcast with the model and see how well the model reproduces prices at the AEP generation hub. This is called a benchmark and is extremely time consuming. Mr. Harter has not discussed these and to my understanding has testified that he has only made two runs of the model for this case (*see* Tr. X at 2163:13-2164:8 (Medine); Tr. IX at 1845:25-1846:4(Harter)), which tends to confirm that he did not develop a calibration or benchmark in the context of the analysis being performed in this case. Ms. Medine also does not mention the results of any such effort in her written testimony. (*See, generally,* Medine Test. at 4-20.) She in fact rejected a benchmark exercise under cross examination. (Tr. X at 2164:18-2165:1.) Under cross examination, she did claim that EVA had been calibrating the model and that she was "comfortable" with the result. But that is not an effective calibration. We have no information as to how each zone's prices came out relative to a calibration marker. We do know that no calibration factor was applied. That could mean that the model and data base were so closely simulating prices for the AEP zone that the calibration factor was exactly one. That is highly unlikely. Or it could mean that EVA looked at some general measures and simply concluded the model and data were "close enough" and it would not implement a calibration adjustment. That is not an effective calibration. An effective calibration is an essential step when applying a large scale complex model like EVA has used to a detailed calculation like the energy credit. To demonstrate that a calibration has been done the values compared must be identified and the results presented and used. EVA provides no evidence of an effective calibration. A calibration is not always sufficient to render the methodology suited for an application but is always desirable if the model results are being used directly. For example, if a calibration was done that showed the model was overstating zonal prices by 5%, the model could be used and its output prices reduced by 5%. Zonal prices could then have been further adjusted to nodal prices. The result could in theory possibly be a forecast with enough accuracy to use in this type of application. Without calibrating the results and knowing whether they accurately reflect reality, it is inappropriate to use model results. The failure to perform and describe the results of any type of calibration exercise reinforces the unsuitability of the methodology used by EVA.

12. Q. IF EVA HAD PERFORMED A CALIBRATION TO CURRENT FORWARD PRICES WHAT WOULD IT HAVE FOUND?

A. The average AEP Zone LMPs from EVA's final Aurora run are in final work paper 4. I compared these to current forwards. The prices developed by this Aurora run, which was used by Ms. Medine, are on average 8% higher than current forward prices at the AD hub. As the example illustrates, this could lead to an error much greater than 8% in the margin forecast. If work papers had been provided that showed gross revenues and costs used to calculate the gross margins, I could have quantified the impact. However, Ms. Medine has not provided even this basic information in her final work papers. I would, however, be confident to estimate that the resulting impact on gross margin is well over 20%. This means that even if EVA were to have all AEP Ohio unit operating costs correct, it would be overstating margins by at least 20%. As I will discuss below EVA does not have all such costs correct, which leads to an even greater overstatement of energy margins. The overriding point with respect to methodology is that a calibration effort, if properly done and extended to consider zonal and nodal price differences, could have possibly substituted in part for the inability to validate all input assumptions. However, no such evidence of any such effort has been provided and no calibration factor has been used.

13. Q ARE YOU TESTIFYING THAT THE WORK PAPERS PROVIDED ARE INCOMPLETE AND INADEQUATE?

A. Yes. This is the case on many levels. First, no data has been provided on the Aurora model inputs. What units are in and are out, what zones are they in, what is the load by zone, what is the load shape by zone, what units are must run, how is unit commitment done in each zone, what transmission links are modeled, what are the heat rates for all modeled units, what are the fuel costs, what are the emission characteristics and many more data items are critical inputs and choices. These are all necessary inputs that EVA would have had to review and decide on and no information is provided in the EVA work papers regarding them. Second, the way in which Aurora takes market price data and AEP unit data is neither described nor shown. Complete data would be appropriate, but not even an example for an hour or a month is provided. Third, a limited set of data is provided for AEP Ohio units. But it is missing important detail. Monthly gross revenues and cost are not provided and variable O&M assumptions are not provided. The work papers are completely unsuitable to assess the analysis and only useful in that even this limited set shows errors that demonstrate that EVA has grossly overstated gross margins for AEP Ohio units.

14. Q. IN PLACE OF A MODEL FORECAST WOULD IT BE APPROPRIATE TO USE CURRENT FORWARD PRICES TO FORECAST PRICES USED TO CALCULATE THE ENERGY CREDIT?

A. Yes. Forward energy prices are the market's collective view of the most likely price outcome as they represent real money committed to actual market transactions by actual buyers and sellers. While any one entity may have a different view, the forward energy price reflects the consensus that the market has reached. Forward prices also represent at any given time the price at which any commitment can be hedged. If a model analysis is inconsistent with forward energy prices, it is simply one of many possible divergent views. There likely are numerous market views at any one time. The only view that represents a price that is current and can be transacted at is the market view or forward price. A cost-based rate established using a forecast that is inconsistent with market prices does not have this property. In my experience parties that face the market look to the current market price as established in forward markets to make pricing decisions and do not look to models when forward prices are available. Enron popularized the "mark to model" concept and we all know where that led. The forward market price is the most realistic and current forecast of the market prices that will prevail in the future. The forward price is not subject to the whim of potential errors or inconsistencies in thousands of input data items or limitations in model capabilities. The forward price can be observed and represents the consensus view of many market participants. Using a forward price eliminates the need to construct a forecast from thousands of unverifiable inputs and to calibrate for things which a model cannot measure. These items are all embedded in the forward market price.

15. Q. CAN THE MODEL AND DATA USED BY EVA BE REASONABLY VERIFIED?

A. No, the model and data are essentially a black box approach. EVA has not supplied a complete set of model inputs or a description of its workings and there is no testimony offered as to the logical structure of the model. Models like Aurora are general and provide the user with many modeling options. My experience and expectation as a witness who on numerous occasions has testified to production costs model applications has been that I would describe and be available for cross examination on how the model worked and what options I had selected, would provide a complete data set and be available for cross examination on the data, provide a model User's Manual, and describe and be available for cross examination on calibration efforts. While certain information may require a confidentiality agreement, it would be made available so that the model and data were not a black box. EVA has only provided some of the data it has used for AEP Ohio units. It has described but not provided the data from the firm's FUELCAST data set or any detail regarding the Aurora data customized by EVA. There is simply no way to examine the reasonableness of the analysis or assumptions used to develop the market prices other than to conduct a parallel analysis. There may well be numerous errors or inappropriate uses of the model, but that cannot be seen or tested with the information provided.

IV. The Limited Information That Has Been Provided Shows Significant Errors By EVA.

16. Q. FROM THE LIMITED INFORMATION YOU HAVE SEEN ARE THERE OBVIOUS AND SIGNIFICANT ERRORS IN EVA'S ANALYSIS?

A. Yes. I have observed the following errors:

- EVA has performed a zonal analysis, presumably for the AEP load zone, although without the model documentation and inputs the exact zone definition is unknown. Units receive revenue at the nodal level and most often at a several percent discount to the zonal LMP. Consequently, use of the zonal analysis results in an overstatement of market prices. Prices are not the same at all points within PJM zones.
- EVA has understated operating costs for many AEP Ohio generating units. One obvious example is the Gavin plant where EVA uses approximately $14/MWH for fuel costs while the actual fuel cost calculated by data supplied by AEP for the June 2012 to May 2105 period is expected to be approximately $24/MWH. As EVA projects Gavin to generate over 60 TWH (terawatt-hours), the impact on margin of this single fuel costs error, all else equal, is an overstatement of gross margins by at least $600 million. This is just from the fuel cost error for one plant.

17. Q. HAVE YOU OBSERVED DEFICIENCIES IN THE QUALITY CONTROL MEASURES USED BY EVA?

A. The errors noted above, observed from a very limited set of information indicate significant quality control problems. However, I cannot comment on quality control measures specifically as none were described in Mr. Harter's testimony. They are either non-existent or undocumented. To the best of my knowledge EVA made only two Aurora runs for this case. (Tr. IX at 1845:25-1846:4.) This means Mr. Harter would have to have obtained the model and basic data base, replaced some unidentified subset of data with unidentified FUELCAST data, run the Aurora model and accepted the results and then done a second run to correct only what Ms. Medine characterizes as inadvertent errors. And all this would be done so exactly that no calibration was required. Essentially, the first run nailed it except for a few inadvertent errors which the second run cleaned up. In well over a hundred production costs studies that I have done, I have never had the first model run be the final. The odds that the first run done is an acceptable run are in my opinion akin to the odds of winning the lottery or being struck by lightning. Ms. Medine clarifies this and notes that EVA has been running the model since six months prior to licensing the model in November 2011 and in that time compiled and fine-tuned the dataset. (Medine Test. at 5:2-3.) That said she provides no description or evidence of any benchmark or calibration exercise, provides no data for any non AEP unit and no indication of the various options available in the model and which ones EVA elected to use with respect to unit commitment except to imply in her heat rate discussion that EVA had the units operate at zero or full output.

18. Q. IN SUM, WHAT DO YOU CONCLUDE FROM REVIEWING THE LIMITED AMOUNT OF INFORMATION THAT HAS BEEN MADE AVAILABLE AND MR. HARTER'S AND MS. MEDINE'S TESTIMONIES?

A. I conclude that even if one were inclined to think that the methodology was acceptable, which I do not, the execution of the analyses contains significant errors and has not been performed with requisite care. Important information concerning model inputs remains a black box approach. Consequently it cannot be tested or validated by the parties and the Commission.

V. It Is Implausible that Results Would Not Be Improved by Updating to Correct Just the Costs of the AEP OHIO Units.

19. Q. EVA HAS TESTIFIED THAT CORRECTING THE OPERATING COSTS FOR AEP OHIO UNITS FROM THAT OBTAINED FROM THE FUELCAST DATA SET WOULD DECREASE RATHER THAN INCREASE THE ACCURACY OF THE ENERGY MARGIN ANALYSIS. DO YOU AGREE?

A. No. The claim is implausible.

20. Q. WHY IS THIS CLAIM IMPLAUSIBLE?

A. It is implausible because significant errors in AEP Ohio operating costs, which are present in EVA's analysis, have a direct impact on energy credits. Failing to correct an error of this type renders the results unreliable. The energy margin is the difference between the market price and unit operating cost. For example, EVA has an approximate fuel cost for Gavin of about $ 14/MWH. (*See* AEP Ex. 124; Tr. IX at 1889:3-19.) The correct level of fuel cost is about $24/MWH based on data provided by AEP. This understatement of fuel costs contributes an error that overstates Gavin's gross energy margin between June 2012 and May 2015 by at least $600 million, all else equal given EVA's generation estimates. There may well be many other errors in the EVA Aurora database – but there is no reason to believe that these other errors offset the impact of the error in Gavin fuel cost. EVA, by defending and not correcting the very substantial Gavin fuel cost error, is asking us to believe that its gross margins are correct because if it corrected all errors in the model, the market price would change by the exact same amount that it has understated Gavin fuel costs -- $10/MWH. This is preposterous. There are no indications that there is any, let alone a significant, understatement of market prices in EVA's Aurora model. In fact relative to current forwards the model seems to be overstating market prices. The current market price at the AD hub over these 36 months is $35.23/MWH. EVA models the average price at $37.88/MWH. For the offsetting error theory to be correct it would have to be the case that with correct data the average price over these 36 months in EVA's model would be $47.88/MWH but that through some magical error mix the EVA model produces an average price of $37.88/MWH, and hence the correct margin is determined using a fuel cost for Gavin that is $10/MWH below the correct fuel cost. That is obviously ridiculous. Hence, it is implausible, illogical and unreasonable to believe that energy margin results are made more accurate by ignoring the error in the assumptions regarding the cost of AEP Ohio units, in particular in Gavin's fuel costs, than by fixing it. The correct thing to do is to fix known errors not ignore them. By implying that correcting the error in AEP Ohio units would reduce accuracy, EVA is acknowledging other unknown errors in the base Aurora model and inputs and FUELCAST data and saying that all errors are exactly offsetting in direction and magnitude of the impact upon market price estimates. There is no justification for ignoring a known error with a direct impact and broadly assuming without basis that unknown errors will affect market price in the same direction and magnitude, especially when we know the EVA forecast already exceeds forward prices. Also note that the Gavin error is not the only fuel costs error. It is just the fuel cost error with the most impact.

VI. MS. MEDINE'S CLARIFICATIONS PROVIDE VERY LITTLE NEW INFORMATION.

21. Q. MS. MEDINE EXPANDS UPON THE INFORMATION INPUT TO AURORA. DOES THIS EXPANDED INFORMATION PROVIDE ANY USEFUL INFORMATION?

A. No. Ms. Medine notes several things. First, she states that EVA has been fine tuning the model for 6 months. Second she states that EVA has populated the model with every U.S. electric power generating unit. Third she states that EVA incorporated its view of plant additions and retirements. Fourth she states that EVA applied proper load characteristics for each energy market. Fifth she states that EVA incorporated its own delivered fuel price forecast by plant and its own emission allowance forecasts. Virtually no detail is supplied as to any of these items. The most detailed description concerns fuel costs where she testifies that "EVA utilizes data from the EIA-923 dataset, publicly-available filings, government macroeconomic models, and industry press releases to develop its own estimates of commodity prices and transportation rates in building a delivered coal price forecast for each coal-fired plant in the U.S." No data for any non-AEP Ohio plant is provided, no description of how the various sources are combined is included, and no description of any quality control procedures is given. Despite this attempt to add clarity, no useful information to review or judge what is EVA's individual view of coal price forecasts is available. It is still a black box. She concludes that, "Many of the individual pieces of information are used for model input validation and/or aggregated to levels that are congruent with the modeling structure." Yet she provides not a single example of validating one piece of fuel cost data for any non-AEP Ohio unit nor any description of the "modeling structure". She then testifies that she uses "EVA's quarterly natural gas price forecast derived from analyzing detailed gas well production data for each U.S. natural gas play in combination with EVA's assessment of future natural gas demand." But no data are provided. All we have is a single proprietary natural gas forecast that can't be examined or tested. Despite her alleged clarifications the inputs remain a black box.

22. Q. IS THERE ANY DATA AREA WHERE MS. MEDINE PROVIDES A MORE DETAILED DESCRIPTION?

A. Ms. Medine provides more information on heat rates. She states that EVA uses the default heat rate which she says is the most efficient heat rate at which the plant can operate and is also known as the full load heat rate. She explains that the Aurora developer states that "this is the appropriate heat rate in most circumstances because [the unit] will operate at full output or zero output." (Medine Test. at 10:11-13.) She does not explain how the developer obtained this data. She does, however, compare these data for AEP Ohio units to FERC Form 1 reported heat rates and concludes the comparison is reasonably good for plants that operate at high capacity factors. (*Id.* at 11:3-5.) She supplies this comparison in her work papers. This is the only item in EVA's analysis that we can see evidence that assumptions have been compared to actual data. Whether the comparison is close enough is a matter for debate and I understand from reviewing the transcript of her cross examination that the heat rate she uses for the Darby CTs is clearly much too low. (Tr. X at 2254:21-2255:1 (acknowledging that "it's certainly possible that Darby was an aggressive number.") However, these are minor issues compared to the error resulting from just using the full load heat rate. The point is that the model developer's claim that it is appropriate to use full load heat rates and have units be at full capacity or off is wrong and has been offered without any context concerning the specific application of the model. Large steam units simply cannot run that way. Many of AEP's large steam units are supercritical units, such as Gavin and Amos 3, that have minimum up and down times of 72 hours. If the unit is economic over this cycle it will run and it will be profitable during the day, but to achieve these profits it will have to run at minimum load over the night period and sustain losses that will offset its daytime profits. The failure to model with correct minimum up and down times, to model a heat rate at minimum load, and to only reflect the full load heat rate and turn AEP's coal units on and off with no regard for minimum up and down times, is a fatal flaw in modeling unit profits. While it may well be a simpler way to model it is inadequate for estimating unit margins as it does not recognize the losses that will be incurred to run the generating units at minimum load overnight as opposed to unrealistically assuming the units can be turned off and on at the flip of a switch. The heat rate description shows that EVA has misused the Aurora model for this application. EVA has not provided any data on unit minimum up and down times, unit start-up costs or unit commitment parameters nor any data on heat rate curves and its approach simply does not reflect reality.

VII. Description, Implementation and Results of a More Reliable, Accurate, and Transparent Quantification of Gross Margins That Demonstrates the Substantial Error of EVA's Margin Estimates.

23. Q. PLEASE DESCRIBE THE APPROACH THAT YOU USED TO DEVELOP ESTIMATES OF PROJECTED GROSS MARGINS TO REBUT EVA'S APPROACH?

A. The approach that I used is as follows:

- Develop a monthly on- and off-peak market price for each month of the remainder of 2012, 2013, 2014 and the first five months of 2015 using monthly price quotes or, if monthly quotes are not available, calendar quotes shaped to monthly values based on historic month to calendar-year quote ratios for the AEP-Dayton ("AD") trading hub.

- Calculate the basis differential between the AD hub and the AEP generation hub using historical day-ahead LMP data. The basis differential is the percentage by which the price at the AD hub differs from the price at the AEP generation hub.

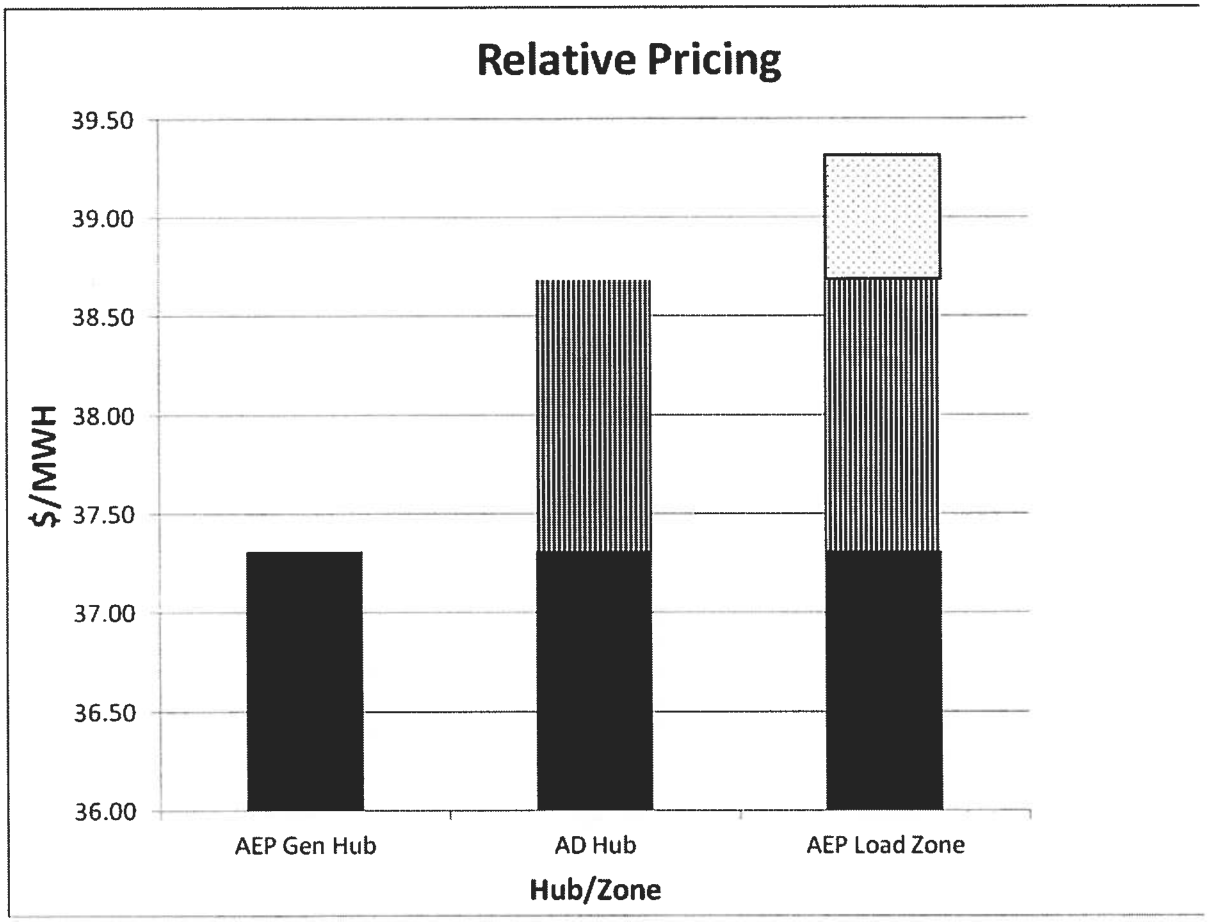
- Develop an 8760-hour shape for day-ahead LMPs at the AEP generation hub.
- From historical data develop an on-peak and off-peak basis differential between the AEP generation hub and the individual node at which each AEP Ohio generating unit is connected.
- Develop a profile for each hour of the June 1, 2012 to May 31, 2015 FRR period using the monthly forward price data, the AD to AEP generation hub basis, the hourly AEP generation hub shape, and the AEP generation hub to generating unit node basis.

At this stage in my analysis, I have developed a forward looking price profile that is completely calibrated to the actual market outcomes. This is the base against which unit gross margins can be calculated on a nodal basis. The complete development of these hourly nodal prices is shown in my work papers.

24. Q. CAN YOU BRIEFLY REVIEW HOW PRICES MAY DIFFER AT THE VARIOUS POINTS – BY POINTS I MEAN HUBS, ZONES OR NODES?

A. Yes. While forward market price data is available at the AD Hub, such data is not typically available at either the AEP Gen Hub (the price which AEP on average receives for its generation sold into PJM) or at the AEP Load Zone (the price at which energy for the AEP Ohio load is purchased from PJM). AD Hub prices were 3.69% above prices at the AEP Gen Hub in 2011. Prices at the AEP Load Zone were 1.63% above prices at the AD Hub over the same period. These pricing relationships are illustrated by the following chart.

Figure 1. Relative Pricing (2011).



Pricing at the individual AEP generation nodes, while on average equal to the hub price across all of AEP, will differ by plant. The nodal hub to AEP generation hub adjustment, which may increase or decrease the price at a particular node, is a necessary additional adjustment. A significant advantage of the methodology that I use is that these differences can be accounted for. While it is true that the differences are only on the order of several percent and could be dismissed as fine tuning for some purposes, as I have shown previously, when translated from price to margin, a difference of several percent in price becomes a much larger difference in margin. The EVA analysis is a zonal analysis. As we can see above the LMP or the AEP load zone is higher than the LMP for the generation hub. This is not only a function of intra-zonal congestion but is also attributable to the fact that marginal losses are included in LMPs. As described above, the analysis I perform accounts for the nodal price differences by adjusting prices to account for the basis relationship on a nodal level. I understand that Ms. Medine testified that there is no intra-zonal congestion. (Tr. X at 2282:7-17.) That is simply wrong. Prices differ at nodes within a zone.

At this point in my analysis I have two significant differences with the EVA analysis. First, the prices I use are calibrated to the actual market outcomes because they are derived from current market quotes. Second, the prices that I use are adjusted to nodal prices and the nodal price level is where generating unit revenues are determined. Both of these features are significant analytical advantages for developing realistic and accurate price profiles that can be used to estimate net revenues.

25. Q. WOULD A MODEL DEVELOPED USING A NODAL VERSION OF AURORA OR A SIMILAR MODEL BE SUPERIOR TO THE PRICES THAT YOU HAVE DEVELOPED USING MARKET DATA?

A. No. A model-based forecast of a value that can be observed in the market from actual transactions is generally inferior to the information coming from actual transactions and should only be relied upon if carefully calibrated. To claim otherwise is the height of arrogance. If EVA had forecasting skills that were reliably superior to the market, it would be irrational for the firm to provide client services as they do. The rational thing to do would be to take proprietary market positions and trade using their superior insight. A model would be useful for estimating items such as fuel burns, as described in Ms. Medine's testimony, since market data does not provide this level of information, but a model is not needed and should not be used to estimate market prices when actual market data is available. As I testified earlier, mark-to-model was an Enron practice, and it was discredited.

26. Q. ONCE YOU HAVE DEVELOPED CALIBRATED HOURLY NODAL PRICES FOR THE PERIOD JUNE 1, 2012 TO MAY 31, 2015 BASED ON ACTUAL MARKET DATA, HOW DO YOU ESTIMATE GROSS MARGINS?

A. This is a very detailed modeling exercise. It consists of the following steps:

- Assemble detailed costs data for each generation unit including fuel costs, variable O&M costs, and emission allowance costs. AEP Ohio witness Nelson provides these data.

- Assemble detailed unit output curves. For coal units these are quadratic equations. For gas-fired units these are average and incremental heat rates at several discrete operating levels. AEP Ohio witness Nelson provides this data.

- Assemble detailed unit operating characteristics. These include unit minimum up and down times, unit start-up costs, unit forced outage rates, maintenance and retirement dates and units that must run for area security. AEP witness Nelson provides this data.

At this point, I have assembled all the data required to examine the commitment and dispatch of AEP Ohio units against the calibrated nodal prices.

27. Q. WHAT IS THE NEXT STEP IN THE ANALYSIS?

A. The next step is to analyze commitment and dispatch which is done as follows for the coal units that are not must-run for area security.

- Calculate for each generating unit the point at which the incremental cost of operation equals the market price for the hour. The most fundamental aspect of economic dispatch is that dispatch is done based on unit incremental cost to equalize marginal costs over all units. This is textbook economic dispatch theory. Economic dispatch is not performed on full-load average cost. Absent any constraint a unit should operate at the point at which the incremental cost equals the nodal market price. If this point is above the maximum, the unit should operate the maximum. If it is below the minimum, the unit should be offline or if constrained to be on, which is the case for must-run units, should operate at its minimum.

- Determine the margin in each hour resulting from operating at the point where the unit's incremental cost equals the market price.

- Look ahead over the unit minimum run time (usually 36 or 72 hours for coal plants) to determine anticipated market margins over the cycle. Note that this recognizes that the unit may operate at minimum, maximum or another point at each hour during the cycle. If the unit is not operating in the hour, add the start-up cost to the anticipated margin for the minimum run period.

- If the minimum run period margin look ahead is positive and the margin in the hour is positive, start up the unit that hour. At the end of the minimum run time period look, for each subsequent hour, at the forward looking margin for the minimum downtime period (again usually 36 or 72 hours) and shut down the unit when both the profit for the hour and the look ahead profit over the minimum downtime period adjusted for start-up costs for a future start would be negative. In performing these steps account for scheduled maintenance dates.

- For each hour in which the unit is dispatched calculate the revenues at the nodal prices and dispatch level, the costs at the nodal prices and dispatch level and the gross margin.

- Sum the gross margin over all hours, add in start-up costs and adjust margins to account for the forced outage rate.

The end result is an estimate of gross margins based on calibrated nodal market prices that fully account for unit operating characteristics. Each step of this dispatch is fully shown in my work papers and the hourly dispatch and hourly margin look ahead over the minimum down and up time periods are clearly shown. This detailed analysis is critical as there are many hours in which AEP Ohio units are either operated at minimum load or at a point between minimum and maximum.

28. Q. DOES THE AURORA ANALYSIS OF GROSS MARGINS ALSO CONSIDER THE DETAILED OPERATIONAL CONSTRAINTS ON AEP OHIO PLANTS?

A. No. While no information has been provided on how Aurora performs profitability calculations, it cannot do the detailed analysis that I performed as it does not have the information to do so. It only has full load heat rates as Ms. Medine testifies. (Tr. X at 2237:14-2239:4.) This is a very significant flaw. For the subset of AEP Ohio plants that are coal plants and are not must run, I estimate that gross margins properly calculated using minimum up and down time constraints are $430 million over the June 2012 to May 2015 period. Ignoring those constraints, I would estimate gross margins at $686 million. Hence, the proper modeling of operating constraints and detailed unit heat rates, which EVA failed to do, results in an overstatement of gross margins by $256 million, all else equal.

29. Q. IS THERE A BETTER WAY THAT EVA COULD HAVE USED AURORA THAN THE WAY IT DID?

A. Yes. Even if EVA only found a zonal Aurora analysis feasible, it could have used Aurora to develop hourly zonal prices, calibrated those prices, adjusted those to a nodal basis and then performed a detailed dispatch using a spreadsheet as I did. This is not a trivial matter as a failure to recognize operational constraints alone overstates gross margins by $256 million. This is in addition to the $600 million overstatement error resulting from Gavin fuel costs.

30. Q. HOW DID YOU DEVELOP GROSS MARGINS FOR COAL UNITS THAT WERE MUST RUN?

A. I required these units to operate all available hours at their minimum operating level. Then, in each hour, I increased operation to the optimal level where incremental operating costs equaled market price. On a daily basis I calculated gross margins and, if the gross margin was negative for the day, I set the margin in each hour of the day to zero. This is the case because PJM will compensate generation owners for daily losses associated with units that must run for area security. I then summed gross margins over all hours of all positive margin days and adjusted for forced outage.

31. Q. HOW DID YOU DETERMINE GROSS MARGINS FOR GAS-FIRED UNITS?

A. For gas fired units, I dispatched each gas fired unit at its optimal level when comparing its incremental operating cost to the market price. I summed hourly profits over all hours and adjusted for forced outage. I did not account for minimum up and down times nor did I add start-up costs. I carefully reviewed gas unit operating patterns. While there are some instances where a unit may operate for only a few hours or be turned off for only for a few hours, generally it did not appear that more detailed modeling would have a large impact. Given more time I would have accounted for minimum up and down times and start-up costs. I emphasize that this approach is conservative as not accounting for these factors unambiguously increases estimates of gross margins.

32. Q. ARE THERE ANY OTHER UNIT TYPES THAT YOU MODEL?

A. Yes. I model the Racine hydro plant and the OVEC purchase. For these plants I divide the estimated monthly generation provided by AEP into on and off peak generation and multiply the generation by the forward price for the monthly on and off peak period adjusted to the plant node less the variable energy cost. EVA does not include the OVEC purchase in its analysis nor does it include the Mone plant combustion turbines. In my analysis OVEC contributes over $60 million in gross margin over the June 2012 to May 2015 period.

33. Q. HAVE YOU PREPARED AN EXHIBIT TO SUMMARIZE YOUR RESULTS?

A. Yes. My results are summarized in Exhibit ETM-R2. I show aggregate gross margins by year and summed over the period for three unit groupings. These are all AEP Ohio units and the OVEC purchase, all AEP Ohio units excluding Amos and Mitchell and the OVEC purchase and all AEP Ohio units considered in EVA's analysis presented by Ms. Medine. The latter includes all AEP Ohio units excluding Amos and Mitchell and excludes OVEC. Exhibit ETM-R3 shows for each resource the annual generation, annual revenue, annual variable cost and annual gross margin. These data were provided to AEP witnesses to calculate the energy credit. A very noticeable result is that when gross margins are examined over the June 2012 to May 2015 period for the units included by EVA I estimate gross margins of under $700 million while EVA estimates gross margins of over $1.6 billion. The EVA analysis grossly overstates the gross margin. My work papers show hourly and monthly details and all formulas.

34.Q. YOU TESTIFY THAT THE EVA ANALYSIS GROSSLY OVERSTATES THE GROSS MARGIN. HOW CAN YOU BE SURE THAT YOUR ANALYSIS DOESN'T GROSSLY UNDERSTATE THE GROSS MARGIN?

A. That is a good question, but easy to answer. There is simply no room for material misstatement in the type of analysis I have conducted. The forward prices are what they are. Different analysts may use slightly different methods to shape annual forwards to months, but the impact on the results will not be significant compared to the difference with EVA. Adjustments from the AD hub which is the traded product to the AEP generation hub and then to each generation node could also be done slightly differently by different analysts – for example using a 7x24 as opposed to on and off peak basis differentials or using individual months as opposed to annual average bases, but again the impact will not be material relative to the difference with EVA. Similarly I have developed a logical set of commitment rules and different analysts may use somewhat different rules, but again the impact will not be material relative to the aggregate difference with EVA's analysis. I have supplied in my work papers every assumption and calculation that validates the results. In contrast the EVA analysis is a black box with known errors. There is no question that in comparing the two analyses it is the EVA results which are overstated.

35. Q. ARE THERE ADDITIONAL FACTORS WHICH DEMONSTRATE THAT THE EVA GROSS MARGINS ARE OVERSTATED?

A. Yes. Several major sources of overstatement are easily identifiable and quantifiable. For example the overstatement of Gavin fuel costs by $10 per MWH alone erroneously adds at least $600 million in operating profits to EVA's margin estimates. The use of full load heat rates and failure to model operation at minimum load adds $256 million as I have shown above. These two factors alone would cut the EVA estimates in half. A variety of other factors such as the failure to calibrate and consider nodal prices contribute smaller but non-trivial amounts to the overstatement of gross margins by EVA. As important as many of the detailed data and modeling issues are and as numerous as EVA's errors are, I want to emphasize that the vast majority of the overstatement in EVA's gross margins have nothing at all to do with the details of the underlying forecast or the use of forecast versus forward prices or even the use of zonal versus nodal prices. That is all a distraction in the bigger picture when fuel costs errors and the failure to model operating constraints for AEP Ohio units alone causes EVA to overstate gross margins by at least 100%.

36. Q. IS YOUR ANALYSIS SO ACCURATE THAT THERE WOULD BE NO NEED TO TRUE-UP?

A. I have not considered the issue of a true-up from the overall policy perspective and offer no opinion on the desirability of a true-up. I do believe that the analysis that I have performed is the most realistic that can be done at this time and reflects current market conditions. If gas prices move lower relative to coal prices, gross margins would fall. If gas prices move higher relative to coal prices, gross margins would rise. This is true of any forecast. Note, however, that the most significant differences between the EVA estimate of gross margin and the estimates that I develop are totally unrelated to the basic forecast with most of the discrepancy arising from the error in the Gavin fuel price and the failure to model operational constraints. Also note that the methodology I present and document could very easily be updated at any time by substituting new forward prices.

VII. Conclusions

37. Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I conclude as follows:

- The EVA analysis grossly overstates energy margins. For the units that EVA considers EVA overstates energy margins by a factor of about two and one half times over a realistic estimate.

- Most of this overstatement comes from two simple errors. These are the error in Gavin fuel costs and the error in not recognizing operating constraints and the full area of the heat rate curve. Correcting these two errors alone would cut EVA's estimate in half.

- A variety of other errors including the failure to recognized intra-zonal congestion and marginal losses exacerbates the errors and accounts for the remaining overstatements.

- EVA's analysis is a "black box approach" that cannot be verified.

- The transparent and realistic analysis that I present is far more realistic than EVA's estimates.

38. Q. DOES THIS CONCLUDE YOUR PREPARED TESTIMONY?

A. Yes.

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EUGENE T. MEEHAN
SENIOR VICE PRESIDENT

Mr. Meehan is a Senior Vice President at NERA. He has over thirty years of experience consulting with electric and gas utilities and has testified as an expert witness before numerous state and federal regulatory agencies, as well as appeared in federal court and arbitration proceedings.

At NERA, Mr. Meehan's practice concentrates on serving energy industry clients, with a focus on helping clients manage the transition from regulatory to more competitive environments. He has performed consulting assignments for over fifty large electric, gas, and combination utilities in the areas of retail access, regulatory strategy, strategic planning, financial and economic analysis, merger and acquisition advisory services, power contract analysis, market power and market definition, stranded cost analysis, power pooling, power markets and risk management, ISO and PX development, and costing and pricing. In addition, he has advised numerous utilities on power procurement issues and administered power procurements on behalf of utilities and regulators.

Mr. Meehan has experience leading NERA's advisory work on several major restructuring and unbundling assignments. These assignments were multi-year projects that involved integration of regulatory and business strategy, as well as development of regulatory filings associated with the recovery of stranded cost and rate unbundling.

Education

Boston College, BA, Economics, *cum laude*
New York University (NYU), Graduate School of Business, completed core courses for the doctoral program.

Professional Experience

	NERA Economic Consulting
1999-	Senior Vice President
1996-1999	Vice President
1973-1980	Senior Economic Analyst; Research Assistant
	Deloitte & Touche Consulting Group
1994-1996	Principal
	Energy Management Associates, Inc.
1980-1994	Vice President

Areas of Expertise

Restructuring/Stranded Cost Recovery

Mr. Meehan has directed several multi-year projects associated with restructuring and stranded cost recovery. These projects involved facilitating the development of an integrated regulatory and business strategy and formulating regulatory filings to accomplish strategy. As part of these assignments, Mr. Meehan facilitated sessions with senior management to set and track filing strategy. Clients include Public Service Gas & Electric and Baltimore Gas and Electric.

Unbundling/Generation Pricing

Mr. Meehan has formulated unbundling strategies, with a specialization in generation pricing. He has advised several utilities in standard offer pricing and has testified on shopping credits on behalf of First Energy and Baltimore Gas and Electric.

Power Procurement

Mr. Meehan has been involved in power procurement activities for a variety of utilities and regulatory agencies. He has advised utilities in developing and implementing evaluation processes for new generation, with the objective of achieving the best portfolio evaluation. He has helped regulators in Ireland and Canada design and implement portfolio evaluation processes. He has testified before FERC and state regulatory agencies on competitive power procurement. In addition, Mr. Meehan helped to design and implement the New Jersey BGS auction process.

Power Contracts

Mr. Meehan has extensive experience with power contracts and power contract issues. He has reviewed and testified on the three principal types of power contracts: integrated utility to integrated utility contracts, IPP to utility contract, and integrated or wholesale utility to distribution utility contracts. He has testified in power contracts disputes on behalf of Carolina Power and Light, Duke Power Company, Southern Company, Orange and Rockland Utilities, and Tucson Electric Power. He has also advised Oglethorpe Power Corporation in the reform of its wholesale contracts with its distributor cooperative members.

Retail and Wholesale Settlements

In addition to his expertise on power pooling issues, Mr. Meehan has significant experience with assignments related to the settlement process. He has focused on the issues of credit management as new entrants appear in retail and wholesale markets and has designed efficient specifications for retail settlement systems, including the use of load profiling, and examined the risk and cost allocation issues of alternative settlement systems.

Risk Management

Mr. Meehan has advised several large utilities on price risk management. These assignments have included evaluation of price management service offers solicited from power marketers in association with management of assets and entitlements, as well as provision of price managed service for various terms.

Marginal Costs

Mr. Meehan has provided comprehensive marginal cost analyses for over 25 North American Utilities. These assignments required detailed knowledge of utility operations and planning.

Power Supply and Transmission Planning

Mr. Meehan has advised electric utilities on economic evaluations of generation and transmission expansion. He has testified on the economics of particular investments, the prudence of planning processes, and the prudence of particular investment decisions.

Generation Strategy

Mr. Meehan has led NERA efforts on a client task force charged with developing an integrated generation asset/power marketing strategy.

Power Pooling

Mr. Meehan has in-depth working knowledge of the operating, accounting, and settlement processes of all United States power pools and representative international power pools. He has provided consulting services for New York Power Pool members on a continuous basis since

1980, advising the Pool and its members on production cost modeling, transmission expansion, competitive bidding and reliability, and marginal generating capacity cost quantification. In NEPOOL, he has quantified the benefits of continued utility membership in the Pool and the impact of the Pool settlement process on marginal cost. He has worked with a major PJM utility to explore the impact of PJM restructuring proposals upon generating asset valuation and examine the implications of alternative restructuring proposals. He has consulted for Central and Southwest Corporation, Entergy, and Southern Company on issues that involved the internal pooling arrangements of the utility operating companies of those holding companies, as well as for various utilities on the impact of pooling arrangements on strategic alternatives.

Representative Assignments

Worked with Public Service Electric & Gas Company (PSE&G) to direct a three year NERA advisory effort on restructuring. Facilitated a two-day senior management meeting to set regulatory strategy in 1997. Throughout 1997 and 1998, worked over half time at PSE&G to help implement that strategy and advised on testimony preparation, cross-examination, and briefing. Also advised PSE&G on business issues related to securitization, energy settlement and credit requirements for third party suppliers. During 1999, advised PSE&G during settlement negotiations and litigation of the settlement. PSE&G achieved a restructuring outcome that involved continued ownership of generation by an affiliate and the securitization of $2.5 billion in stranded costs.

Worked on separate assignments for a large utility in the Northeast and a large utility in the Southeast, advising on the evaluation of risk management offers from power marketers. The assignments included reviewing proposals, attending interviews with marketers and providing advice on these, and the developing analytical software to evaluate offers.

Worked with government of Ontario beginning in 2004 to help design the RFP and economic evaluation process for the solicitation of 2500 Mw of new generating capacity. Supervising NERA's portfolio-based economic evaluation on behalf of the Ontario Ministry of Energy.

Testified on behalf of Pacific Gas & Electric Company before the FERC in a case benchmarking the PSA between the distribution utility and a soon-to-be-created generating company. This effort involved developing detailed expertise in applying the Edgar standard and a detailed review of DWR procurement during the western power crisis. In addition, this effort involved the review of more than 100 power contracts in the WECC.

Directed NERA's efforts, on behalf of the electricity regulator in Ireland, to design an RFP and implementation process for the purchase of 500 Mw of new generating capacity in 2003. NERA advised on the RFP, the portfolio evaluation method, and the power contract and also conducted the economic evaluation.

Reviewed the economic evaluation conducted by Southern Company Service for affiliated operating companies in connection with an RFP for over 2000 Mw of new generating capacity. Submitted testimony before FERC on behalf of Southern Company Service.

Worked with Baltimore Gas and Electric (BG&E) to conduct a one and one-half year consulting assignment that involved providing restructuring advice. The project began in March/April 1998 with senior management discussions and workshops on plan development and filing strategy. Advised BG&E in the development of testimony, rebuttal testimony, and public information dissemination. Worked to review and coordinate testimony from all witnesses and offered testimony on shopping credits and in defense of the case settlement. BG&E achieved a restructuring outcome enabling it to retain generation ownership. As part of this assignment, advised BG&E on generation valuation and unregulated generation business strategy.

Directed the efforts of a large Southeastern utility to develop a short-term power contract portfolio and to evaluate the relative value of power options, forwards, and unit contracts to determine the optimal mix of instruments to manage price risk.

Testified for XCEL Energy on the use of competitive bids for new generation needs. Examined whether XCEL was prudent not to explore a self-build plan and the reasonableness of relying on ten-year or shorter contracts as opposed to life-of-facility contracts, in order to meet needs and facilitate a possible future transition to competition. This project addressed the comparability of fixed bids to rate base plant additions.

Advised and testified on behalf of First Energy in the Ohio restructuring proceeding on the issues of generation unbundling and stranded cost. Defended the First Energy shopping credit proposal.

Advised Consolidated Edison and Northeast Utilities on merger issues and testified in Connecticut and New Hampshire merger proceedings. Testimony focused on retail competition in gas and electric commodity markets.

Directed NERA's effort to train selected representatives of a major European power company in American power marketing and risk management practices. The project involved numerous meetings and interviews with power marketing firms.

Led NERA's effort to advise the New England ISO on the development of an RTO filing. Examined performance-based ratemaking for transmission and market operator functions.

Examined ERCOT power market conditions during the period of time from 1997 to 1999 and testified on behalf of Texas New Mexico Power Company for the prudence of its power purchase activity.

Advised a Midwestern utility on restructuring of a wholesale contract with an affiliate. Involved forecasting of the unbundled wholesale cost-of-service and market prices, as well as development of a regulatory strategy for gaining approval of contract restructuring and the transfer of generation from regulated to EWG states.

Performed market price forecasts for numerous utility clients. These forecasts have employed both traditional modeling and newly developed statistical approaches.

Examined the credit issues associated with the entry of new entities into retail and wholesale settlement market. These assignments involved a review of current Pool credit procedures, examination of commodity and security trading credit requirements, coordination with financial institutions, and recommendations concerning credit exposure monitoring, credit evaluation processes, and credit requirements.

Oversight of EMA's consulting and software team in designing and implementing the LOLP capacity payment, a portion of the UK wholesale settlement system.

Advised Oglethorpe Power Corporation in the reform of its contracts with its distribution cooperative members and the evolution of full requirement power wholesale power contracts into contracts that preserve Oglethorpe's financial integrity and are suitable for a competitive environment.

Developed long run marginal and avoided costs of natural gas service, as well as avoided cost methods and procedures. These costs have been used primarily for the analysis of gas DSM opportunities. Clients include Consolidated Edison Company, Southern California Edison Company, Niagara Mohawk Power Corporation, and Elizabethtown Gas Company.

Review of power contracts and testimony in numerous power contract disputes.

Development of long run avoided costs of electricity service and avoided cost methods and procedures. These costs have been used to assess DSM and cogeneration, as well as to develop integrated resource plans. Clients include Public Service Company of Oklahoma, Central Maine Power Company, Duquesne Light Company, and the New York investor-owned utilities.

Advised Central Maine Power Company (CMP) on the development of a competitive bidding framework. This framework was implemented in 1984 and was the first of its kind in the nation. CMP adopted the framework outlined in EMA's report and won prompt regulatory approval.

Advised a utility in the development of an incentive ratemaking plan for a new nuclear facility. This assignment involved strategic analysis of alternate proposals and quantification of the financial impact of various ratemaking alternatives. Presented strategic and financial results in order to convince senior management to initiate negotiations for the incentive plan.

Advised and testified on behalf of the New York Power Pool utilities on the methodology for measuring pool marginal capacity costs. This work included development of the methodology and implementation of the system for quantifying LOLP-based marginal capacity costs.

Provided testimony on behalf of the investor-owned electric utilities in New York State, concerning the proper methodology to use when analyzing the cost-effectiveness of conservation programs. This methodology was adopted by the Commission and used as the basis for DSM evaluation in New York from 1982 through 1988.

Developed the functional design of a retail access settlement system and business processes for a major PJM combination utility. This design is being used to construct a software system and develop business procedures that will be used for retail settlements beginning January 1999.

Reviewed the power pool operating and interchange accounting procedure of the New York Power Pool, the Pennsylvania, New Jersey, Maryland Interconnection, Allegheny Power System, Southern Company, and the New England Power Pool as part of various consulting assignments and in connection with the development of production simulation software.

Summarized and analyzed the operational NEPOOL to examine the feasibility of incorporating NEPOOL interchange impacts with Central Maine and accounting procedure of the New England Power Pool Power Company's buy-back tariffs.

Developed and presented a two-day seminar delivered to electric industry participants in the UK (prior to privatization), outlining the structure and operation of power pools and bulk power market transactions in North America.

Benchmark analysis and FERC testimony of PGE's proposed twelve-year contract between PG&E and Electric Gen LLC (contract value in excess of $15 billion).

Responsible for NERA's overall efforts in advising New Jersey's Electric Distribution Companies on the structuring and conduct of the Basic Generation Service auctions (the 2002 auction involved $3.5 billion, and the 2003 and 2004 auctions involved over $4.0 billion).

Publications, Speeches, Presentations, and Reports

Capacity Adequacy in New Zealand's Electricity Market, published in *Asian Power*, September 18, 2003

Central Resource Adequacy Markets For PJM, NY-ISO AND NE-ISO, a report written February 2004

Ex Ante or *Ex Post*? Risk, Hedging and Prudence in the Restructured Power Business, The Electricity Journal, April 2006

Distributed Resources: Incentives, a white paper prepared for Edison Electric Institute, May 2006

Restructuring Expectations and Outcomes, a presentation presented at the Saul Ewing Annual Utility Conference: The Post Rate Cap and 2007 State Regulatory Environment, Philadelphia, PA, May 21, 2007

Making a Business of Energy Efficiency: Sustainable Business Models for Utilities, prepared for Edison Electric Institute, August 2007

Restructuring at a Crossroads, presented at Empowering Consumers Through Competitive Markets: The Choice Is Yours, Sponsored by COMPETE and the Electric Power Supply Association, Washington, DC, November 5, 2007

Competitive Electricity Markets: The Benefits for Customers and the Environment, a white paper prepared for COMPETE Collation, February 2008

The Continuing Rationale for Full and Timely Recovery of Fuel Price Levels in Fuel Adjustment Clauses, The Electricity Journal, July 2008

Impact of EU Electricity Competition Directives on Nuclear Financing presented to: SMI – Financing Nuclear Power Conference, London, UK, May 20, 2009

Testimony

Forums

Arkansas Public Service Commission

Federal Energy Regulatory Commission

Florida Public Service Commission

Maine Public Utilities Commission

Minnesota Public Service Commission

Nevada Public Service Commission

New York Public Service Commission

Nuclear Regulatory Commission – Atomic Safety and Licensing Board

Oklahoma Public Service Commission

Public Service Commission of Indiana

Public Utilities Commission of Ohio

Public Utilities Commission of Nevada

Public Utilities Commission of Texas

Public Utilities Commission of New Hampshire

United States District Court

United States Senate Committee on Energy and Natural Resources

Various arbitration proceedings

Clients

Arkansas Power & Light Company

Baltimore Gas & Electric

Carolina Power & Light Company

Central Maine Power

Consolidated Edison Company of New York, Inc.

Dayton Power and Light Company

Florida Coordinating Group

Houston Lighting & Power Company

Minnesota Power and Light Company

Nevada Power Company

Niagara Mohawk Power Corporation

Northern Indiana Public Service Company

Oglethorpe Power Corporation

Pacific Gas and Electric Company

Power Authority of the State of New York

Public Service and Electric Company

Public Service Company of Oklahoma

Sierra Pacific Power Company

Southern Company Services, Inc.

Tucson Electric Power Company

Texas-New Mexico Power Company

Recent Expert Testimony and Expert Reports

Supplemental Testimony on behalf of Texas-New Mexico Power Company, Docket No. 15660, September 5, 1996.

Direct Testimony on behalf of Long Island Lighting Company before the Federal Energy Regulatory Commission, September 29, 1997.

Rebuttal Testimony on behalf of Texas-New Mexico Power Company, SOAH Docket No. 473-97-1561, PUC Docket No. 17751, March 2, 1998.

Prepared Testimony and deposition testimony on behalf of Central Maine Power Company, United Stated District Court Southern District of New York, 98-civ-8162 (JSM), March 5, 1999.

Prepared Direct Testimony Before the Public Service Commission of Maryland on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, June 1999.

Rebuttal Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, March 22, 1999.

NORCON Power Partners LP v. Niagara Mohawk Energy Marketing, before the United States District Court, Southern District of New York, June 1999.

Prepared Supplemental Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, July 23, 1999.

Prepared Supplemental Reply Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, August 3, 1999.

Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0681, September 3, 1999.

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Exhibit ETM-2
Generation and Gross Margin[1] for All AEP Ohio Resources
June 1, 2012 to May 31, 2012

All AEP Ohio Resources

	Year	Generation (GWh)	Gross Margin ($'000)
Jun-Dec	2012	17,033	126,564
Jan-Dec	2013	38,012	256,451
Jan-Dec	2014	36,449	250,994
Jan-May	2015	17,972	92,630
	Total	**109,467**	**726,639**

All AEP Ohio Resources Excluding Amos and Mitchell

	Year	Generation (GWh)	Gross Margin ($'000)
Jun-Dec	2012	15,529	113,469
Jan-Dec	2013	32,064	220,280
Jan-Dec	2014	31,347	219,277
Jan-May	2015	15,469	83,735
	Total	**94,409**	**636,761**

All AEP Ohio Resources Included in EVA Final Analysis

	Year	Generation (GWh)	Gross Margin ($'000)
Jun-Dec	2012	14,331	106,100
Jan-Dec	2013	29,446	201,440
Jan-Dec	2014	28,436	195,723
Jan-May	2015	14,019	73,292
	Total	**86,231**	**576,555**

1. Generation and Gross Margin are adjusted by the Equivalent Unplanned Outage Rate.

Exhibit ETM-3

Generation, Revenue, Variable Cost, and Gross Margin[1] by Unit for All AEP Ohio Resources - June 1, 2012 to May 31, 2012

Unit	2012				2013				2014				2015			
	Generation (GWh)	Revenue ($'000)	Variable Cost ($'000)	Gross Margin ($'000)	Generation (GWh)	Revenue ($'000)	Variable Cost ($'000)	Gross Margin ($'000)	Generation (GWh)	Revenue ($'000)	Variable Cost ($'000)	Gross Margin ($'000)	Generation (GWh)	Revenue ($'000)	Variable Cost ($'000)	Gross Margin ($'000)
Amos 3	447	19,080	14,127	4,132	1,904	75,276	61,400	11,217	1,314	57,982	46,644	8,321	908	36,898	33,228	2,592
Mitchell 1	408	17,696	13,139	3,995	1,505	62,174	50,353	10,070	1,681	73,517	61,347	10,121	762	31,563	28,303	2,654
Mitchell 2	649	25,866	20,114	4,968	2,541	97,556	80,694	14,884	2,107	88,864	73,327	13,276	833	33,379	29,496	3,648
Beckjord 6	88	3,247	2,592	599	132	5,425	4,492	821	10	700	547	133	2	105	100	0
Cardinal 1	2,221	68,794	54,089	14,322	4,096	138,445	102,174	36,118	3,223	121,052	97,226	23,173	1,809	68,161	56,201	11,877
Conesville 3	177	6,290	7,784	401	0	0	0	0	0	0	0	0	0	0	0	0
Conesville 4	51	2,704	2,073	543	133	7,277	5,616	1,486	149	8,632	6,618	1,796	29	1,400	1,290	22
Conesville 5	419	17,035	13,165	3,368	1,261	49,543	40,102	8,565	952	42,493	35,041	6,355	623	25,882	22,657	2,754
Conesville 6	413	16,883	12,901	3,414	1,088	44,372	35,785	7,652	1,055	46,358	37,803	7,286	718	29,502	25,495	3,431
Darby 1	53	2,624	1,953	671	46	2,816	2,179	637	39	2,650	2,014	636	7	394	339	55
Darby 2	53	2,608	1,941	667	46	2,827	2,186	641	39	2,654	2,015	639	4	247	220	26
Darby 3	52	2,586	1,925	661	44	2,713	2,096	617	40	2,692	2,043	650	10	600	522	78
Darby 4	53	2,635	1,961	674	44	2,738	2,111	627	40	2,683	2,035	648	10	581	505	77
Darby 5	53	2,616	1,948	668	43	2,687	2,081	606	40	2,697	2,046	651	10	600	522	78
Darby 6	53	2,608	1,940	668	43	2,687	2,081	607	41	2,734	2,071	663	10	595	518	77
Gavin 1	1,431	52,293	41,001	9,253	5,457	196,165	162,142	30,216	5,290	202,510	167,623	31,859	3,483	130,030	112,312	16,480
Gavin 2	1,335	49,203	38,445	8,690	4,486	164,430	134,290	26,885	5,979	226,717	185,376	37,743	2,213	83,245	69,795	12,161
Kammer 1	433	15,655	16,725	1,049	611	24,693	26,058	1,565	560	24,460	27,387	1,179	192	8,643	9,227	189
Kammer 2	423	15,319	16,722	962	761	30,715	32,929	1,580	542	23,374	27,085	1,070	187	8,406	9,141	149
Kammer 3	0	0	0	0	179	7,177	7,356	249	156	6,664	7,322	90	0	0	0	0
Lawrenceburg 1	1,984	63,812	47,275	16,537	2,609	99,672	78,748	20,924	2,537	104,724	83,923	20,801	1,116	45,738	38,603	7,135
Lawrenceburg 2	2,006	64,338	47,601	16,737	2,775	105,587	83,565	22,022	2,372	98,267	78,348	19,919	1,127	45,925	38,885	7,040
Muskingum 1	0	0	0	0	80	2,845	2,691	211	36	1,340	2,162	0	0	0	0	0
Muskingum 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Muskingum 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Muskingum 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Muskingum 5	149	6,665	4,943	1,259	0	0	0	0	0	0	0	0	0	0	0	0
Picway 5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Robert Mone 1	57	2,722	1,970	752	57	3,276	2,561	715	46	2,938	2,279	659	14	819	720	99
Robert Mone 2	57	2,722	1,970	752	54	3,153	2,450	703	46	2,946	2,285	661	14	819	720	99
Robert Mone 3	54	2,617	1,876	741	56	3,240	2,529	711	46	2,941	2,280	661	14	819	720	99
Sporn 2	326	10,930	12,228	730	471	17,866	18,974	1,124	513	20,324	24,483	838	138	5,651	6,711	35
Sporn 4	32	1,573	1,122	419	36	1,990	1,407	550	27	1,722	1,253	425	0	0	0	0
Stuart 1	62	2,671	2,090	527	384	14,845	12,505	2,083	507	20,060	17,079	2,671	281	10,880	9,518	1,247
Stuart 2	61	2,647	2,092	501	374	14,513	12,299	1,948	463	18,386	15,736	2,357	290	11,229	9,935	1,136
Stuart 3	42	1,791	1,423	-912	333	13,075	10,919	29	507	20,064	16,919	874	315	12,118	10,627	217
Stuart 4	62	2,699	2,123	519	364	14,138	11,982	1,884	388	15,765	13,329	2,184	287	11,130	9,847	1,125
Waterford 1	2,132	72,233	51,244	20,989	3,004	120,257	93,938	26,319	2,565	112,081	86,851	25,229	796	35,253	29,764	5,488
Zimmer	65	3,406	2,578	677	387	17,199	14,006	2,519	181	9,721	7,425	1,990	284	11,942	10,894	643
Racine	100	3,001	1,497	1,504	159	5,324	2,371	2,952	184	6,610	2,747	3,864	78	2,942	1,171	1,771
OVEC	1,032	35,290	30,167	5,123	2,451	87,934	71,223	16,711	2,774	103,462	81,889	21,572	1,408	52,594	42,447	10,147

1. Generation, Revenue, Variable Cost, and Gross Margin are adjusted by the Equivalent Unplanned Outage Rate.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of Ohio Power Company's Pre-filed Rebuttal Testimony of Eugene T. Meehan have been served upon the below-named counsel and Attorney Examiners by electronic mail to all Parties this 11th day of May, 2012.

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