STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY ("IPL"), AN INDIANA CORPORATION, FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE GAS TURBINE GENERATION FACILITY ("CCGT"); (2) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO CONVERT COAL FIRED GENERATING FACILITIES TO GAS; (3) APPROVAL OF THE CONSTRUCTION OF TRANSMISSION, PIPELINE AND OTHER FACILITIES; (4) APPROVAL OF ASSOCIATED RATE MAKING AND CAUSE NO. 44339 ACCOUNTING TREATMENT; (5) AUTHORITY TO TIMELY RECOVER 80% OF THE COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE GAS REFUELING PROJECT THROUGH IPL'S ENVIRONMENTAL COMPLIANCE COST RECOVERY ADJUSTMENT; (6) AUTHORITY TO CREATE REGULATORY ASSETS TO RECORD (A) 20% OF THE REVENUE REQUIREMENT FOR COSTS, INCLUDING, CAPITAL, OPERATING, MAINTENANCE, DEPRECIATION TAX AND FINANCING COSTS ON THE REFUELING PROJECT WITH CARRYING COSTS AND (B) POST-IN-SERVICE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION, BOTH DEBT AND EQUITY, AND DEFERRED DEPRECIATION ASSOCIATED WITH THE PROJECTS UNTIL SUCH COSTS ARE REFLECTED IN RETAIL ELECTRIC RATES; AND (7) ISSUANCE OF A NECESSITY CERTIFICATE TO TRANSPORT NATURAL GAS IN INDIANA	)	CAUSE NO. 44339

Direct Testimony of Tyler Comings

Public Version

On Behalf of Citizens Action Coalition of Indiana

August 22, 2013

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1. <u>Introduction and Purpose of Testimony</u>

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

A My name is Tyler Comings. I am an Associate with Synapse Energy Economics, Inc. (Synapse), which is located at 485 Massachusetts Avenue, Suite 2, in Cambridge, Massachusetts.

Q Please describe Synapse Energy Economics.

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

Q Please summarize your work experience and educational background.

A I have eight years of experience in economic research and consulting. At Synapse, I have worked extensively on the energy planning sector including economic impact analyses for Vermont Energy Efficiency programs for the Vermont Department of Public Service, a proposed Renewable Portfolio and Efficiency Standard in Kentucky for Mountain Association for Community Economic Development (MACED), a "Beyond Business as Usual" energy future for the U.S. for Civil Society Institute (CSI) and a proposed carbon standard for Natural Resources Defense Council (NRDC). I have worked on several cases involving coal and gas plant economics. I have provided consulting services for various other clients including: Sierra Club, EarthJustice, Consumers Union, Energy Future Coalition, American Association of Retired Persons, and Massachusetts Energy Efficiency Advisory Council.

Prior to joining Synapse, I performed research in consumer finance for ideas42 and economic analysis of transportation and energy investments at Economic Development Research Group.

I hold a B.A. in Mathematics and Economics from Boston University and a M.A. in Economics from Tufts University.

My full resume is attached as Exhibit TFC-1.

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

A I am testifying on behalf of Citizens Action Coalition of Indiana.

Q **Have you testified in front of the Indiana Utility Regulatory Commission previously?**

A No, I have not.

Q **What is the purpose of your testimony?**

A Dr. Jeremy Fisher and I were hired by Citizens Action Coalition of Indiana to review Indianapolis Power and Light's (IPL or the Company) application for the issuance of a certificate of public convenience and necessity (CPCN) for a new natural gas combined cycle (CC) plant at Eagle Valley and re-fueling of Harding Street Units 5 and 6 to natural gas.

My testimony focuses on the assumptions for available capacity, capacity prices and peak load forecasts used in the Company's analysis supporting the CPCN for the Eagle Valley CC and testimony by Witness Herman Schkabla. I also briefly discuss the treatment of off-system sales profits and the Company's finances as raised by Witness Kelly Huntington. My colleague, Dr. Fisher, evaluates the assumptions and methodology of the Company's modeling and offers future recommendations.

Q **How much is the Company proposing to spend on the Eagle Valley CC for operation in 2018?**

A According to Witness Crawford, the plant is estimated to cost $631 million, excluding financing.[1]

[1] Crawford Direct Testimony, page 16 line 4

Q What are your findings regarding the Company's application?

A The Company's application provides insufficient justification for construction of the new Eagle Valley CC in 2018 for the following reasons:

1. The Company overestimates their capacity need in modeling future resource plans.
2. Using the Company's more up-to-date capacity price forecasts would favor delaying the new natural gas CC until 2020.
3. The more up-to-date capacity price forecasts are still likely too high given the supply conditions in MISO.
4. The Company's modeling treats off-systems sales profits from their resource plans as if they were passed on to ratepayers when, in reality, they all go to IP&L, or its parent company's (AES) shareholders.
5. The project represents an unnecessary financial risk for ratepayers at this time.

Q Did you perform any alternative analysis for the Company's results?

A Yes, I performed an alternative estimate of present value revenue requirements (PVRR) for the two resource plans involving the construction of a new 600 MW natural gas CC using the Company's more up-to-date capacity price forecasts.

Q Are capacity prices a key determinant of the PVRR for the resource plans in the Company's modeling?

A Yes. The Company assumes that if it is short on capacity relative to its reserve requirement, it will buy capacity from the market—either through a contract or on the MISO market. The cost of these purchases is determined by the Company's assumption for the capacity price, multiplied by the amount of capacity purchased.

Q What are the results of your analysis?

A Simply substituting the more up-to-date capacity price projection from the Company changes the outcome and the preferred alternative. Figure 1 shows the Company's original base case PVRR estimates for building a new natural gas CC in 2018 and 2020—Resource Plans 1 (in black) and 3 (in light blue), respectively. The use of older, higher capacity price forecasts leads to a higher PVRR ($23 million difference) for building the CC for operation in 2020 compared to 2018.[2]

Substituting more up-to-date capacity prices results in a reduction in PVRR--relative to the Company's original results--of $267 million for Plan 1 and $309 million for Plan 3 in the base case. The results show that delaying the build of the new CC until 2020 is now more favorable than the Company's chosen strategy of building it for operation in 2018 ($19 million lower than building in 2018). Further detail on this analysis is provided subsequently in my testimony.

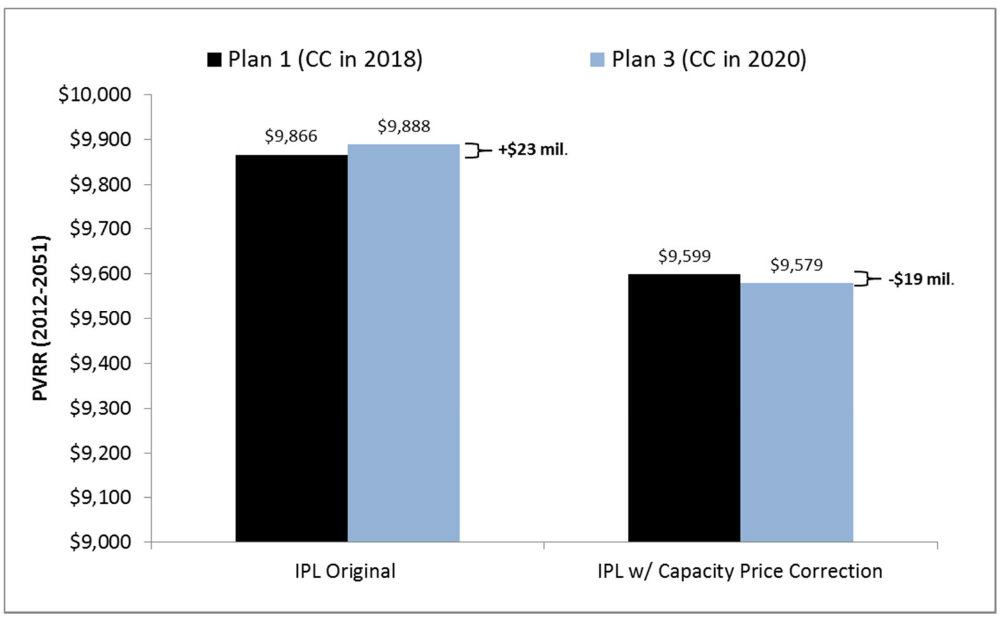

Figure 1: Base Case PVRR Results for Resource Plans 1 and 3 with Capacity Price Corrections[3]

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[2] IPL Public Workpapers, IRP11_CPCN_Plan_Results_40_Years.xlsx, Base tab

[3] Source: CAC DR 4-5, Confidential Attachment 1 (CPCN1 Annual Income Statement 20130709), calculations of updated results by Synapse

2. Overview of the Company's Economic Analysis

Q How did the Company choose the option to build a new natural gas plant at Eagle Valley?

A As discussed by Witness Schkabla, in the initial phase of modeling (Witness Fisher and I will refer to this as "CPCN Phase 1"), the Company modeled six resource plans for acquiring additional capacity with varying years for starting operations, including:[4]

1. 600 MW CCGT in 2018
2. 550 MW CT and 500 MW of Wind in 2018
3. 600 MW CCGT in 2020
4. 550 MW CT and 500 MW of Wind in 2020
5. 600 MW Supercritical pulverized coal in 2020
6. 600 MW Nuclear in 2020

These six plans all comprise 600 MW of capacity credit. (Due to its intermittent availability, wind receives a 10% capacity credit in MISO). The Company modeled these six resource plans using the Ventyx Midas model to estimate the plan with the lowest present value revenue requirement (PVRR). Resource Plan 1 (a new 600 MW CCGT in 2018) resulted in the lowest PVRR in their base case.[5]

The Company used this result to develop an RFP for a new natural gas CC to be built in 2018. They then performed a second phase of modeling congestion costs using the PROMOD IV model and combined that with Midas modeling, resulting in a PVRR comparison of the costs of bids that the Company received, along with the Eagle Valley CCGT or "self-build option" (Witness Fisher and I will refer to this as "CPCN Phase 2").[6]

[4] Direct Testimony of Herman Schkabla, page 5, line 6.
[5] Direct Testimony of Herman Schkabla, page 10, line 8.
[6] Direct Testimony of Herman Schkabla, page 13, line 5.

Q How did the Company choose to model the six resource scenarios listed above?

A These six resource plans modeled in this filing are identical to the "2011 IRP Scenario Resource Plans" from the Company's 2011 Integrated Resource Plan (IRP).[7]

Q Has the Company updated these six resource plans since the IRP from two years ago?

A No, they have not.

Q Has the Company updated the alternate future scenarios that were used in the IRP for purposes of modeling in this filing?

A To some extent. The Company has modeled sensitivities for low gas prices, high gas prices and a "moderate environmental" scenario as they did in their 2011 IRP. However, the IRP included other scenarios that were not modeled in this filing such as an "environmental scenario" which has a carbon cost that is both higher and starts earlier than the "moderate environmental scenario."

Q Has the Company used consistent modeling assumptions in CPCN Phase 1 and Phase 2?

A No. As I will explain in subsequent sections of my testimony, the Company used inconsistent assumptions for capacity prices and the amount of capacity available between the two phases of modeling. For instance, they included the 200 MW capacity from Harding Street Unit 5 and 6 in their CPCN Phase 2 modeling but not in CPCN Phase 1.[8]

Q Which phase of modeling used the most up-to-date assumptions?

A CPCN Phase 2 modeling--which evaluated different bids for natural gas CC construction--used more up-to-date assumptions for demand response, capacity price forecasts, and included the available capacity from the Harding Street re-

[7] Direct Testimony of Herman Schkabla, page 5, lines 3-7.
[8] Based on a comparison of CAC DR 2-1, Confidential Attachments 5 and 6, Monthly Thermal data.

fueling projects. However, CPCN Phase 1 modeling—which evaluated the type of resource plan to choose in the first place—used older, higher capacity price forecasts, lower demand response forecasts and did not include the Harding Street re-fueling capacity. Witness Fisher discusses other inconsistencies between the two modeling phases.

3. THE COMPANY OVERESTIMATES CAPACITY NEED WHEN CHOOSING A RESOURCE PLAN

Q Did the Company consistently model the impacts of demand response in this filing?

A No, the Company included additional demand response in their modeling of the CC build options ("CPCN Phase 2") but not in their resource plan modeling ("CPCN Phase 1"). Figure 2 shows this discrepancy which accounts for 103 MW of peak load that was unnecessarily included in their estimate of capacity need when estimating the PVRR of their six resource plans.[9]

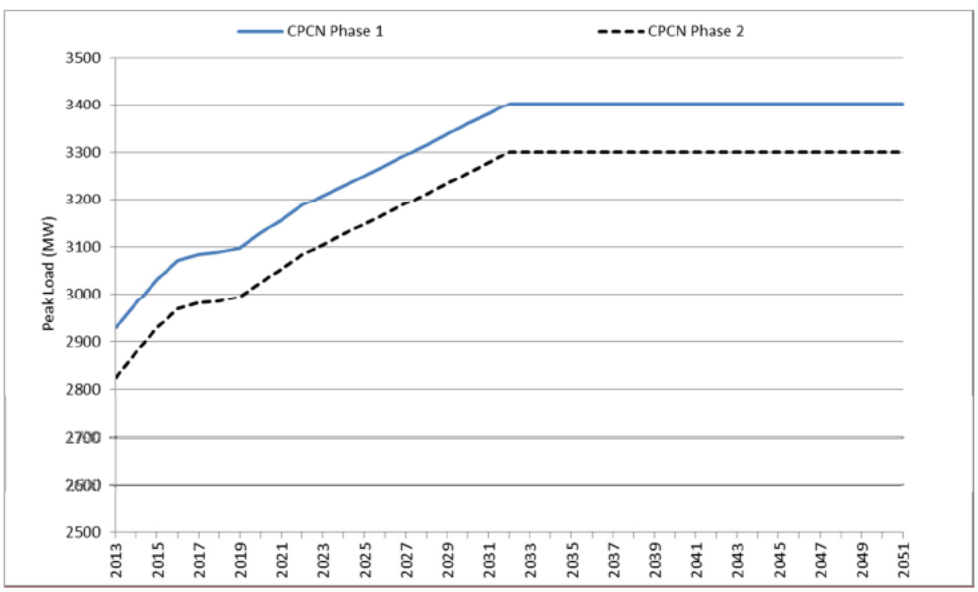

Figure 2: IPL Peak Load Forecasts (after DSM) used in CPCN1 and BCPCN modeling[10]

[9] Data Response CAC 4.4, Attachment 1
[10] Source: CAC DR 4-4, Attachment 1 (CPCN1 Transact C Monthly Summary 20130709)

Q Has the Company acknowledged this discrepancy in peak load assumptions between the two phases?

A Yes, the Company acknowledged this discrepancy:

> Although the omission of the Demand Response programs for the CPCN1 analysis will effectively increase the amount of capacity purchases and associated capacity expense for the six plans modeled, the additional capacity expense will be the same for each plan and will not change the relative PVRR results.[11]

Q Do you agree with the Company's statement above?

A I agree that, given the way the Company has modeled the six resource plans, changing the peak load would not change the ranking of the least cost plans. This is simply an artifact of the Company's capacity need being fixed at 600 MW. However, the point is that the exclusion of over 100 MW of demand response in resource planning means the Company is over-procuring capacity. Modeling a lower capacity need may indeed result in a different choice for the Company but there is no way to know this unless the analysis is consistent and up-to-date.

Q Did the Company consistently model the re-fueling projects at Harding Street Units 5 and 6?

A No, the Company included these projects in their modeling of the CC build options (Phase 2) but not in their resource plan modeling (Phase 1). This omission accounts for 200 MW of additional capacity that should have been available in the Phase 1 modeling.[12]

Q Are the missing demand response and re-fueling projects the only discrepancies in the capacity modeled in both phases?

A No. In Confidential Figure 3, I show the differences in capacity available in Phase 1 and Phase 2 modeling. The capacity available in both models varies for several other reasons, including: 1) the Petersburg coal units have different capacity ratings in Phase 1 and 2; 2) additional wind resources of 200 MW are not

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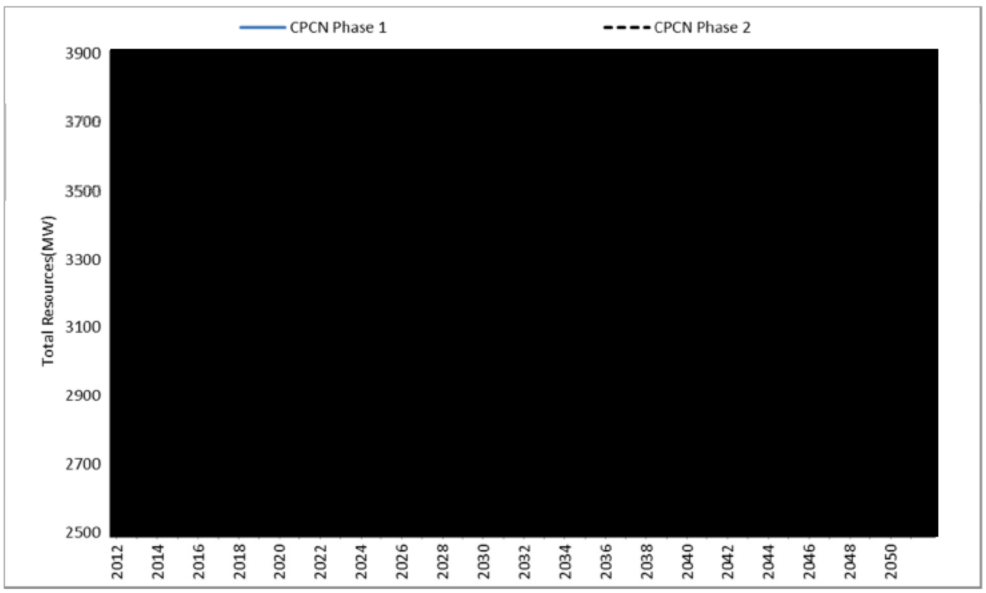
[11] Data Response CAC 4.4 (Exhibit TFC -2)

[12] Direct Testimony of Kevin Crawford, page 4, line 20 discusses mentions "200 – 210 MW after re-fueling" when discussing the Harding Street 5 and 6 projects.

available in Phase 1 but are in Phase 2; and 3) the gas CC comes on-line in different years (2018 in Phase 1 and 2017 in Phase 2).[13]

Phase 2 (the dashed line) modeling includes 292 MW more capacity than Phase 1 (the solid line) from 2018 through 2031 and 92 MW more capacity from 2032 through 2051. This drop in the difference in capacity (between the two phases) in 2032 occurs because the 200 MW from Harding Street re-fueling Units 5 and 6 go off-line in 2032.



Confidential Figure 3: Available Capacity in Phase 1 (CC in 2018) and Phase 2 (Chosen CC build) Modeling[14]

Q Does the inconsistency in available capacity overlap with the lack of 103 MW of demand response in the Company's Phase 1 modeling?

A No, the effects from these inconsistencies are additive. The additional demand response lowers the peak load requirement and resulting need for capacity by 103 MW. Confidential Figure 3 above shows 292 MW of available capacity included in Phase 2 that is not in Phase 1. This, along with the 103 MW of peak load reduction from demand response, means that Phase 1 underestimates available capacity by 395 MW. Originally, the Company was assuming a capacity need of

[13] Based on a comparison of CAC DR 2-1, Confidential Attachments 5 and 6, Monthly Thermal data.
[14] Source: CAC DR 2-1, Confidential Attachments 5 and 6, Monthly Thermal tab.

600 MW in their Phase 1 modeling but the proper accounting of available capacity resources would mean a capacity requirement of less than half of that.

Q Should the Company have assumed a capacity need of 600 MW in their Phase 1 modeling?

A No. The Company clearly omitted several key resources including demand response and the Harding Street re-fueling projects when modeling resource plans. The Company should properly re-evaluate its capacity need, perform modeling to meet this much lower requirement and ensure that its modeling is internally consistent.

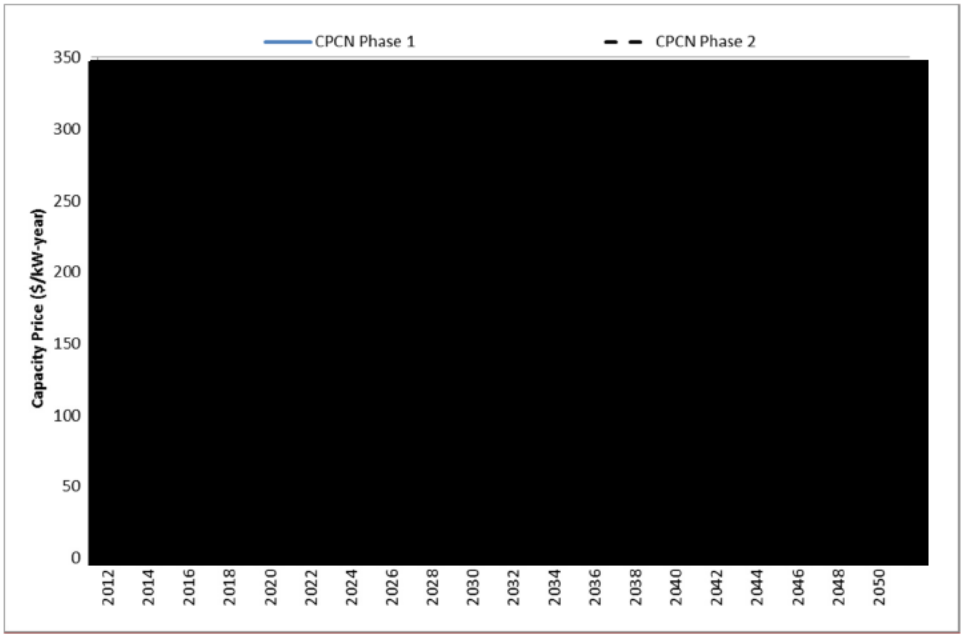
4. USING THE COMPANY'S MORE UP-TO-DATE CAPACITY PRICE FORECASTS WOULD RESULT IN DELAYING BUILDING A NEW NATURAL GAS CC UNTIL 2020.

Q Please explain the inconsistent capacity price forecasts used in the Company's modeling.

A In Phase 1 of the CPCN, when the Company was choosing the best resource plan, they used the same capacity prices from their 2011 IRP. However, in Phase 2, they used an updated capacity price forecast based on an adjustment to Ventyx's Spring 2012 Reference Case forecast assumptions.[15]

Confidential Figure 4shows the Company's most up-to-date capacity price forecast assumptions used in Phase 2 modeling compared to those used in Phase 1.

[15] CAC DR 4-5, Confidential Attachment 2 (Ventyx Documentation for Capacity Prices_Investment Component) (Exhibit TFC-3)



Confidential Figure 4: IPL Capacity Price Forecasts in CPCN Phases 1 and 2 ($/kW-year)[16]

Q Does using the more up-to-date capacity price forecast change the ranking of the resource plans in terms of lowest PVRR?

Yes. I performed an alternative estimate of present value revenue requirements for both of the Company's resource plans involving a new gas CC plant—shown in Figure 5, below. The Company concluded that building a CC in 2020 (in light blue) had a $23 million higher PVRR than building it in 2018 (in black). However, using the Company's more up-to-date capacity price forecasts, the updated results show that delaying the build until 2020 is more favorable than building it in 2018, now with a $19 million lower PVRR.

[16] Source: CAC DR 2-1, Confidential Attachments 5 and 6, Monthly Thermal tab.

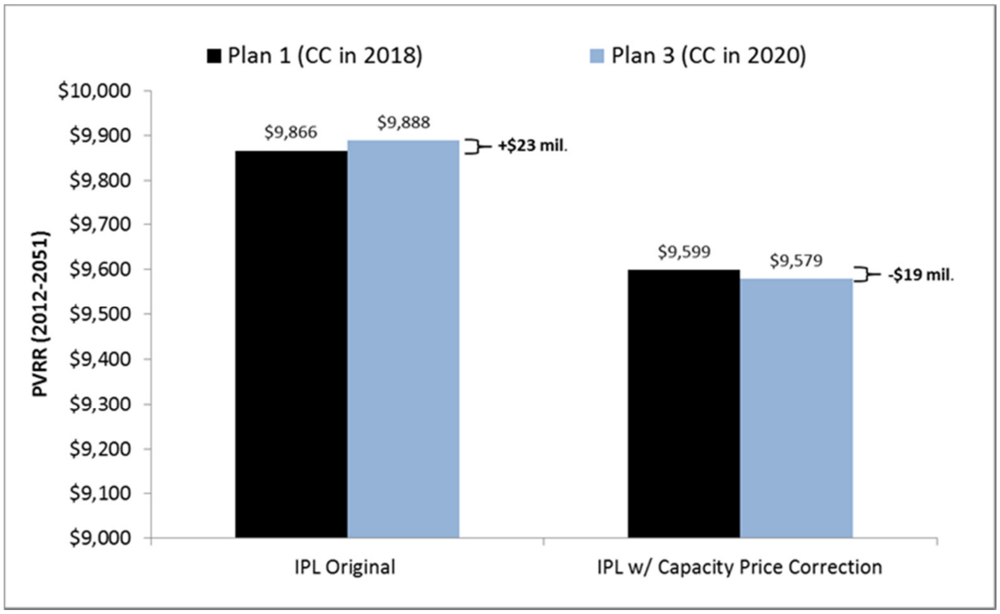


Figure 5: Base Case PVRR Results for Resource Plans 1 and 3 with Capacity Price Corrections[17]

Q Are you recommending that the Company plan on building a new natural gas CC in 2020?

A No. Correcting for the Company's use of inconsistent capacity price forecasts in the filing shows that delaying the build of the CC is the most economically viable scenario given the Company's current modeling structure. However, as I discussed earlier, and as discussed by my colleague Dr. Fisher, there are other issues of concern regarding the Company's analysis that suggest further flaws in their modeling and, by extension, choice of resource plan. Dr. Fisher presents more detailed recommendations for the Company going forward.

5. THE COMPANY'S MORE UP-TO-DATE CAPACITY PRICE FORECASTS ARE LIKELY TOO HIGH GIVEN THE SUPPLY CONDITIONS IN MISO.

Q Please summarize the Company's treatment of capacity prices.

A In Phase 2, the Company uses the Ventyx Spring 2012 Reference Case capacity price forecast with some adjustments by the Company including for "tightening

[17] Source: CAC DR 4-5, Confidential Attachment 1 (CPCN1 Annual Income Statement 20130709), calculations of updated results by Synapse

supply and demand due to retirement of coal units for EPA MATS [Mercury Air Toxics Standard] compliance."[18]

Q Has MISO evaluated the effect of coal retirements on capacity in the RTO?

A Yes, the 2012 MISO Transmission Expansion Planning (MTEP) resource adequacy analysis reported that MISO currently has over 112 GW of internal summer rated capacity. MTEP projects between 2241 MW and 9912 MW of coal retirement due to environmental regulations, and between 2710 MW and 7407 MW of new capacity to be built. This leads them to a range between 110 GW and 122 GW of total capacity that will be available in MISO in 2022,[19] assuming no unanticipated additions or retirements. The report concludes that with the maximum amount of coal retirements, projections of new capacity additions, and additional demand response that:

> Given the projections for both GIQ [Generator Interconnection Queue] projects and DR growth in MISO in this assessment, MISO expects that this will not be problematic, and that MISO's planning reserve margin requirement will be met during the 10th-year peak.[20]

Q Is it reasonable to assume that MISO capacity could be available at a price below the Company's forecast?

A Yes. The most recent clearing price for capacity in MISO was \$0.38 per kW-year (\$1.05 per MW-day).[21] If the capacity prices in MISO continue to be lower than the cost of building or procuring new capacity, then it may be advantageous for the Company to purchase a fraction of their capacity, in the short-term, if they are able to meet their energy requirements.

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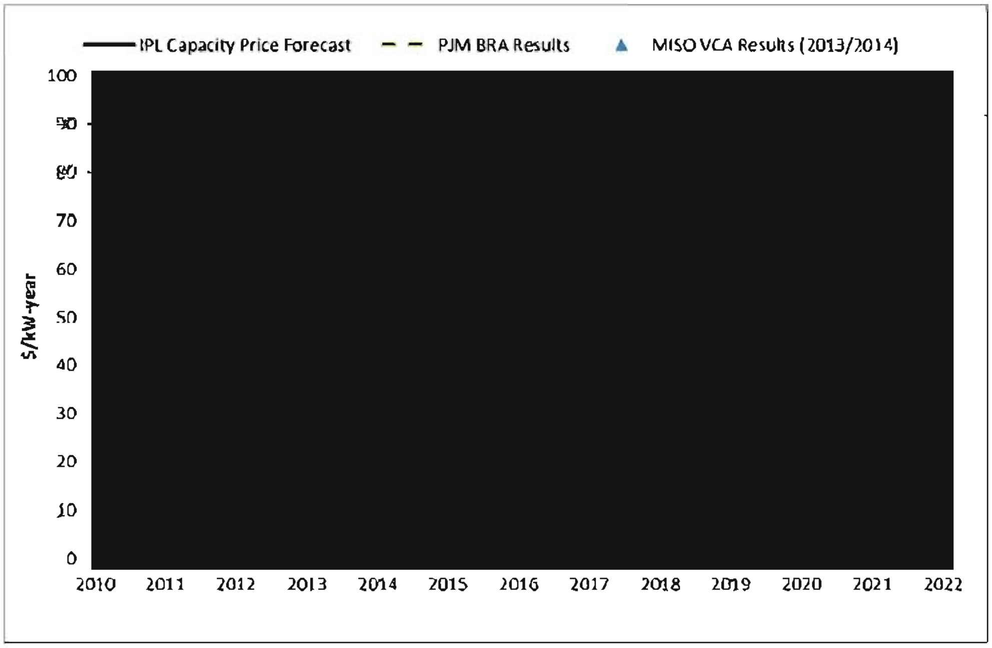
[18] CONFIDENTIAL Schkabla WP 5 (Update to Midwest_Spring 2012_Power_Reference_Case_-_Data_Supplement_IPL).xlsx
[19] MISO Transmission Expansion Planning 2012. Chapter Six, page 73 (Exhibit TFC-4)
[20] MISO Transmission Expansion Planning 2012. Chapter Six, page 69 (Exhibit TFC-4)
[21] CAC DR 1-35, Attachment 5 (2013-2014 MISO Planning Resource Auction Results) (Exhibit TFC-5)

Q How do the Company's up-to-date capacity price forecasts compare to capacity prices from past auctions in MISO and PJM?

A The capacity price increase forecasted by the Company is much higher than what has occurred historically in the both MISO and PJM regions. Confidential Figure 6 below shows the historical auction clearing prices for PJM RTO and MISO Voluntary Capacity Auction (VCA) which had its first annual capacity auction in 2013. This is a balance market whereby utilities are responsible for meeting their reserve requirement--and typically fulfill most of this requirement with their own generation--and can also purchase or sell on the VCA. The MISO VCA cleared at a price of $0.38 per kW-year ($1.05 per MW-day) in the 2013/2014 delivery year (blue triangle).[22]

PJM's Base Residual Auction (BRA) includes all capacity that will be available in the region (as opposed to the MISO market which is the balance of remaining reserves that are needed) and takes bids three years ahead of time. All capacity that clears the auction in the RTO for a given delivery year receives the same price (which can vary by sub-regions depending on delivery constraints). This market offers several years of historical data for comparison. Although the clearing price has been volatile in the past years (dashed line), the price has not exceeded $64 per kW-year (for delivery year 2010/2011). The most recent PJM BRA for 2016/2017 cleared at $21.67 per kW–year ($59.37 per MW-day using PJM's convention).[23] This most recent PJM auction period captures anticipated coal retirements in 2016 and 2017 yet showed a drop in capacity price. In contrast, the Company's MISO capacity price forecast predicts a sharp rise to $84 per kW-year in 2017.

[22] CAC DR 1-35, Attachment 5 (2013-2014 MISO Planning Resource Auction Results) (Exhibit TFC-5)
[23] PJM 2016/2017 Base Residual Auction Results, page 6 (Exhibit TFC-6)



Confidential Figure 6: Comparison of Capacity Prices from IPL, MISO[24] and PJM RTO Auction Clearing Prices ($/kW-year, Calendar Year)[25]

Q To what does PJM attribute the most recent drop in capacity prices in the 2016/2017 auction?

A According to PJM:

> The auction clearing prices are lower than the previous auction driven largely by a flat demand growth and an increase in supply from substantial amount of new entry offers, uprates associated with repowering existing resources to natural gas, increased imports, and withdrawn deactivations.[26]

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[24] Source: CONFIDENTIAL Schkabla WP 1 (CPCN Modeling Assumptions_Ventyx_04_12_13 Final Rev2).xlsx, PJM 2016/2017 Base Residual Auction Results (Exhibit ___), MISO 2013/2014 Auction Results (provided in DR CAC 1-35, Attachment 1).

[25] PJM BRA clearing prices are reported in terms of $/MW-day. I have converted these prices to $/kW-year (=$/MW-day*365 (days per year)/1000 (kW per MW)) to follow the IPL convention. The MISO clearing price was for the delivery year 2013/2014, so I have shown it as the 2013 calendar year price for simplicity; the MISO 2014 calendar year price will depend on the results from the 2014/2015 auction.

[26] PJM 2016/2017 Base Residual Auction Results, page 2 (Exhibit TFC-6)

Q Where were most of the imports of capacity located?

Imports from MISO represented 4723 MW of the total 7283 MW in imports that cleared the PJM 2016/2017 auction. [27]

Q How can capacity located in MISO place bids in the PJM auction?

MISO capacity that has "firm transmission service" to PJM can bid into PJM's forward capacity market. However, not all generators currently have this type of access.[28]

Q Why would MISO resources bid into the PJM market to provide capacity three years in the advance?

A If a generator in MISO bids into the PJM forward market for the 2016/2017 delivery year, they likely anticipate that PJM capacity prices are higher than what MISO's would be for the same delivery period since these generators have the option to bid into either market.

Q Would a generator have good reason to think that the most current PJM capacity clearing price will be higher than MISO's clearing price for delivery in 2016/2017?

A Yes, they would. The most recent MISO clearing price was $0.38 per kW-year for 2013/2014 while PJM's clearing price for that period was $10.22 per kW-year. Given that PJM's most recent clearing price in 2016/2017 was $21.67 per kW-year--and incorporates coal retirements from MATS--it would be reasonable to assume that the MISO price will remain lower than PJM's in 2016 and 2017.

Q How should the Company treat capacity prices in their modeling?

A The Company has assumed that capacity prices will rapidly increase in 2017 above what has occurred historically in the PJM market. However, evidence from the PJM forward capacity market shows that this rapid increase may not occur.

[27] PJM 2016/2017 Base Residual Auction Results, page 3 (Exhibit TFC-6)
[28] PJM 2016/2017 Base Residual Auction Results, page 3 (Exhibit TFC-6)

Therefore, the Company should at the very least perform a sensitivity analysis assuming that capacity prices in MISO do not rise sharply in 2017.

6. THE COMPANY'S MODELING TREATS OFF-SYSTEMS SALES PROFITS AS IF THEY WERE PASSED ON TO RATEPAYERS WHEN, IN REALITY, PROFITS ALL GO TO COMPANY SHAREHOLDERS

Q Is it reasonable that Company's modeling assumes that they are able to sell energy off-system?

A Yes.

Q Does the Company's modeling assume that the profits from off-system sales accrue to ratepayers?

A Yes, implicitly. The Company counts all sales from both retail and off-system sales as a benefit to ratepayers in their modeling.

Q Is it the Company's standard practice to share off-system sales profits with ratepayers?

A No. As confirmed by Kevin Crawford, Senior Vice President of IPL, in hearings for Cause 44242, the Company does not offer a sharing mechanism for these profits:[29]

> A. I apologize if I was inconsistent. My understanding is that off-system sales wholesale margins do not go to the ratepayer.
>
> Q. Do not?
>
> A. Yes, do not.
>
> Q. So they go to the shareholders?
>
> A. I think that's the only other place for them to go.

I assume that that the Company seeks, or should seek, a least cost solution for ratepayers, not an optimal solution for the Company's shareholders. Therefore, the Company's modeling and analysis should review costs and benefits that flow

[29] IURC Cause 44242, April 24, 2013, page 79 lines 6 to 12 of hearing transcript (Exhibit TFC-7).

to ratepayers, and exclude those that flow to the shareholders of IP&L or its parent Company, AES.

Q Would removing the off-system sales affect the rankings of lowest cost PVRR for the Company's six resource plans?

A Possibly. This correction would certainly change the PVRR estimates themselves and could change the order of lowest cost PVRR depending on the differences in amount of off-system sales profits between plans.

Q Given the model runs and outputs that have been made available by the Company, is it possible to disentangle the profits from off-system sales from revenue requirements?

A I do not believe so. Also, Witness Adkins, who oversaw the Ventyx Midas modeling in Cause 44242, was asked to remove off-system sales revenues and associated production costs and could not.[30] If the Company wanted to model appropriately, I believe they could restrict the model from offering off-system sales--thus providing only the costs to ratepayers.

Q Should off-system sales profits be modeled as benefitting ratepayers?

A No. Ratepayers currently do not receive profits from off-system sales; this money accrues to the Company's shareholders. Therefore, the Company modeling off-system sales profits as if they lowered revenue requirements is inconsistent with today's reality. This contradiction should be rectified in subsequent modeling.

7. THE EAGLE VALLEY CC PROJECT REPRESENTS AN UNNECESSARY FINANCIAL RISK FOR RATEPAYERS AT THIS TIME

Q Please explain why the filing for the CPCN for an Eagle Valley CC was premature.

A As I have shown, use of more up-to-date capacity prices leads to the conclusion that delaying the new natural gas CC plant by two years is less costly. In addition, the Company used inconsistent assumptions for peak load reduction from demand

[30] Cause 44242, Data Response CAC 7-4 (b) (Exhibit TFC-8)

response and available generating capacity, including Harding Street 5 and 6 re-fueling projects.

The Company's modeling also includes the operation of Harding Street Unit 7 and Petersburg Units 1 through 4 with environmental retrofits. Thus they were presuming to receive approval of the CPCN for environmental compliance projects for (IURC Cause 44242) at the time of the filing. Although the CPCN was approved for all units on August 14, 2013, the Company should have addressed the possibility that at least one their units would not be granted a CPCN (e.g. Harding Street Unit 7).

Q What key financial justification has the Company provided for the Commission to approve the CPCN for the Eagle Valley CC?

A Witness Huntington discusses the importance of the Company's credit rating and the potential risk if the CPCN for Harding Street and Eagle Valley projects are not approved, claiming that, "IPL will have lower credit metrics until it receives recovery of the costs through retail rates. Such lower metrics will increase the risk that IPL's investment grade credit rating is downgraded."[31]

Witness Huntington then discusses the harm that would befall ratepayers if the Company's credit rating fell to a "non-investment rating," claiming that:

> Customers would be adversely affected because higher capital costs lead to higher rates for electric service and strain resources that could otherwise be utilized to meet our customers' ongoing need for reliable electric service.[32]

Q Has the Company discussed the Eagle Valley CC project with credit rating agencies?

A Yes. When addressing Moody's, Standard and Poors (S&P), and Fitch Ratings , [redacted]

[31] Direct Testimony of Kelly Huntington, page 4 lines 8 through 11.
[32] Direct Testimony of Kelly Huntington, page 4 line 23 to page 5 line 2.

[redacted].[33]

Q How did the Company present the merits of the investments in Eagle Valley and Harding Street 5 and 6 compared to replacement with market purchases?

A The Company showed a chart of pre-tax income [redacted].”[34]

Q Do ratepayers or the Commission bear responsibility for maintaining the Company’s credit rating?

A No. The Company’s shareholders are responsible for upholding their credit rating.

Q What are the financial risks for the ratepayers if the Commission approves the CPCN for the Eagle Valley CC?

A If the Commission approves the CPCN for Eagle Valley, the investment will be recovered from ratepayers whether it is a sound investment or not. If the Company has underestimated the PVRR of their chosen scenario, then ratepayers will be paying more than the Company had originally planned—potentially more than they would have paid given one of the other resource plans or for plans that were not considered.

Also, the Company’s modeling of PVRR for the six resource options assumes that ratepayers will benefit from off-system sales profits, which is not the case in today’s reality.

Finally, as I have shown and Witness Fisher has discussed, the Company does not need to take on this investment at this time since they have overestimated their capacity need.

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[33] Data Response CAC 1-10, Attachments 34 through 36.

[34] As an example, see slide 33 in the presentation to Fitch Ratings: Data Response CAC 1-10, Attachment 36 (Confidential Exhibit TFC-9). This same slide was presented to Moody’s and Standard and Poors.

8. FINDINGS

Q What conclusions follow from your analysis?

A First, the Company should have modeled both Phase 1 and 2 with consistent demand response penetrations and available capacity. The most recent modeling (Phase 2) suggests less than half of the capacity need compared to what the Company modeled in Phase 1 (600 MW).

Second, my analysis shows that the Company has not performed sufficient modeling to justify the choice of building a new natural gas CC in 2018. Correcting for the use of outdated capacity prices in their modeling shows that delaying the investment of the Eagle Valley CC to 2020 is less costly than building it for operation in 2018. The PVRR results for building the CC in 2018 compared to building in 2020 differed by a small enough margin (0.2%, $23 million)[35] such that the inconsistency in capacity price forecasts was enough to make delaying the decision more economical.

Third, even the lower capacity price forecast used by the Company assumes a rapid increase in the MISO capacity clearing price that may not happen. Given that capacity prices are an important determinant of the PVRR results, the Company should have modeled a sensitivity assuming a more stable MISO capacity market.

Finally, if the CPCN for the Eagle Valley CC is approved, then ratepayers would be funding an investment that may or may not be financially advantageous for them. Since off-system sales profits are not shared with ratepayers while the fixed costs of the plant are shared, they would face all of the costs but none of the upside benefits. Conversely, assuming CPCN approval and rate recovery, the Company would stand to benefit from the additional profits from off-system sales while recovering the fixed costs regardless of whether or not the new plant was economically viable.

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[35] IPL Public Workpapers, IRP11_CPCN_Plan_Results_40_Years.xlsx, Base tab

Q **Does this conclude your testimony?**

A It does.