April 28, 2016

BY HAND DELIVERY

Ms. Ingrid Ferrell
Executive Secretary
West Virginia Public Service Commission
201 Brooks Street
Charleston, WV 25301


Dear Ms. Ferrell:

Enclosed for filing in the above-captioned case, please find the original and twelve copies of the redacted version of the Comments of WV SUN and West Virginia Citizen Action Group on the 2015 Integrated Resource Plan of Monongahela Power Company and The Potomac Edison Company. A copy of these comments is being served on all parties of record.

Very Truly Yours,

Emmett Pepper
(W.Va. State Bar #12051)

Enclosures
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The IRP filed by the Companies is seriously deficient. As the Commission recognized in General Order 184.35, an IRP should be the product of “a planning and selection process for new energy resources that evaluates the full range of alternatives . . . in order to provide adequate and reliable service to [the electric utility’s] customers at the lowest system cost.” G.O. 184.35 at 1 (citing 16 U.S.C. §2602(19)). To achieve that purpose, the Commission established minimum standards for each utility’s IRP. Id. at 2-3. The Companies’ filing, however, falls far short of these standards.

As an initial matter, the Companies’ IRP presents an overinflated load forecast, estimating their capacity obligation using a methodology that is inconsistent with PJM rules. By doing so, the Companies significantly overestimate their customers’ future electricity needs, leading to the erroneous conclusion that they need to acquire 850 megawatts (“MW”) of new generation capacity. The IRP then presents a flawed “evaluation of resource options” that skews the analysis in favor of a single resource option: the acquisition of an existing coal-fired power plant. In reaching this result, the Companies fail to consider an array of resource options, including demand response, energy efficiency, renewables such as wind and solar, and market purchases. The Companies dismiss these options by either adopting unreasonable cost assumptions that make them appear less attractive than they really are, or by ignoring them entirely. And the IRP compounds these errors by underestimating the financial risks of acquiring another coal plant.
Indeed, given the IRP’s overestimation of future capacity needs, and its cursory dismissal of resources other than existing coal, this IRP appears to be a thinly disguised attempt to pave the way for a forthcoming proposal to purchase the Pleasants coal-fired power plant from Allegheny Energy Supply Company, LLC (“AE Supply”), one of the Companies’ non-regulated affiliates. As explained below in Section III.D, discovery responses provided in this case strongly suggest that this is exactly what FirstEnergy has in mind.

Regardless, the fact remains that the document filed by the Companies is not an IRP. It does not accurately forecast the Companies’ capacity obligations, it does not fairly evaluate demand-side and supply-side options, and its recommendations do not reflect the least-cost planning approach required by General Order 184.35. Because this IRP fails to meet minimum standards, the Commission should direct the Companies to file a revised integrated resource plan that addresses the errors identified below. These deficiencies should be corrected before the Commission considers any proposal from FirstEnergy to acquire or purchase additional resources.

I. IRP STANDARDS

The IRP process in West Virginia is governed by W. Va. Code § 24-2-19 and the Commission’s General Order 184.35, which directed every electric utility in West Virginia to submit an integrated resource plan by January 1, 2016. Section 24-2-19 directs the Commission to analyze and review the IRP, and empowers the Commission to request information from utilities as part of that process. W. Va. Code § 24-2-19(c).

Section 24-2-19 and General Order 184.35 also establish standards that an IRP must satisfy. These requirements include the following:

- The IRP must “compare projected peak demands with current and planned capacity resources in order to develop a portfolio of resources that represents a reasonable balance of cost and risk for the utility and its customers in meeting future demand . . . .” § 2-2-19(d).

- The IRP must contain “a narrative summary detailing the underlying assumptions reflected in the plan.” G.O. 184.35 at 2. This narrative summary must
  - include a description of the utility’s rationale for the selection of any particular supply-side or demand-side resource to fulfill its forecasted need, and the utility’s evaluation of alternatives considered for each resource option it has chosen”; and
  - “describe the internal planning processes of the utility and how the IRP considers or incorporates PJM planning and implementation requirements and how it will satisfy PJM capacity obligations.” Id.

- The IRP must include “a three-year historical record and a minimum ten-year forecast of the utility’s native load peak demand and energy requirements . . . .” Peak demand should be presented based on peak demand during the PJM peak
demand period and peak demand for the utility if that occurs at a different time.” *Id.* at 2-3.

- The IRP must also provide “a minimum ten-year forecast of the supply-side and demand-side resources expected to satisfy [the forecasted] loads.” *Id.* at 3.

- Finally, the IRP must include “descriptions, analyses and discussions of supply-side and demand-side resource options that were considered by the utility.” *Id.*

More generally, the Commission’s review of the IRP should be guided by the overarching goal of ensuring that the utility’s resource portfolio “represents a reasonable balance of cost and risk for the utility and its customers in meeting future demand for the provision of adequate and reliable service to its electric customers.” § 2-2-19(d). And that portfolio can only be identified by “evaluating the full range of alternatives,” including supply- and demand-side resources. G.O. 184.35 at 1 (quoting 16 U.S.C. §2602(19)).

Evaluation of the IRP should also be guided by the overall requirement that utility rates be “just and reasonable.” § 24-2-3; Affiliated Const. Trades Found. v. Pub. Serv. Comm’n of W. Va., 211 W. Va. 315, 322, 565 S.E.2d 778, 785 (2002) (noting that, *inter alia*, charges and services “shall not be contrary to law and . . . shall be just and fair, just and reasonable, and just and proper”) (citation omitted). A utility’s rates will almost certainly not be just and reasonable if they do not result from planning processes that seek to determine the resource portfolio that provides reliable service with the lowest cost and least amount of risk.¹

It is with these standards in mind that the Citizen Groups offer the following comments.

### II. THE COMPANIES’ LOAD FORECAST SIGNIFICANTLY OVERESTIMATES FUTURE DEMAND.

One of the core components of an IRP filing is the load, or demand, forecast. Load forecasts are used to identify projected capacity needs, which, in turn, must be addressed through demand-side and supply-side resources. In General Order 184.35, the Commission has established specific standards for such forecasts. This Order specifies that the IRP must include “a minimum ten-year forecast of the utility’s native load peak demand and energy requirements.” G.O. 184.35 at 2. The IRP must “detail[] the underlying assumptions” that the forecast relies upon. *Id.* Further, the IRP must describe how the plan “considers or incorporates PJM planning and implementation requirements,” and how the Companies will “satisfy PJM capacity obligations.” *Id.*

The Companies’ IRP falls far short of the requirements of the General Order. In the IRP, the Companies project that a capacity shortfall will begin this year, with the projected shortfall exceeding 700 MW by 2020, and 850 MW by 2027. *IRP* at 4. This purported 850 MW shortfall is used to justify the Companies’ recommendation that they acquire an existing coal plant. *Id.* at 5, 55, 57-58. But this recommendation is built on a faulty premise, because the IRP estimates the Companies’ capacity obligation by using a forecast of winter peak demand, a practice that is inconsistent with PJM requirements and which results in an overinflated estimate of capacity needs. Additionally, the IRP omits basic information regarding the data, assumptions, and

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¹ The Commission is also empowered to “investigate all rates, methods, and practices of public utilities,”
methods relied upon by FirstEnergy in generating its load forecasts. These omissions and errors call into question the IRP’s projected shortfall and recommended alternative.

A. The IRP Overestimates the Companies’ Capacity Obligation.

In the IRP, the Companies project that they will face a capacity shortfall throughout the ten-year forecast period. IRP at 14-19. But the load forecast that they use to estimate their capacity obligation is artificially inflated. This is evident from recent PJM auction results, as well as the methodology that the Companies used to estimate their capacity needs.

First, the results of PJM’s 2018/19 Base Residual Auction (“BRA”) demonstrate that FirstEnergy’s load forecast is artificially high. In the IRP, the Companies project a total peak load of 3651 MW in 2018, and 3818 MW in 2019. IRP at 19; Resp. to CAG-1, Att. A. These figures were derived using the Companies’ projected winter peaks, plus a reserve margin. But as the Companies implicitly admitted in discovery, these projected peaks are far higher than the capacity obligation established by PJM. As the Companies acknowledged, “[t]he most recent BRA conducted for the 2018/2019 delivery year resulted in an estimated capacity obligation of 3067 MW.” Resp. to CAD-1-3. This PJM capacity obligation – which should be used to drive resource planning – is far below FirstEnergy’s load forecast of 3651-3818 MW. Resp. to CAG-1-5. This striking discrepancy indicates that FirstEnergy likely overstated its capacity needs for each year of the planning period, with significant implications for the IRP’s projections of capacity shortfall.

Second, the IRP improperly inflates the Companies’ capacity obligation by calculating it as a function of winter peak load. This contravenes PJM rules, which establish that future capacity needs are a function of summer peak load coincident with the PJM peaks, not winter peak load. But instead of relying on summer peak load, which the PJM capacity obligation is based on, the IRP calculates the Companies’ capacity needs using winter peak load, a value which is typically greater than summer peak load within the Companies’ service territory. IRP at 16. By using these higher winter peaks, and departing from the PJM rules, the IRP presents an improperly inflated projection of the Companies’ capacity needs.

The IRP’s use of winter peak loads is also inconsistent with the Companies’ past practice before the Commission. During the Harrison plant transfer proceeding, Case No. 12-1571-E-PC, the Companies submitted a resource plan for the same service territory that relies upon summer peak load as the determinative factor for estimating capacity shortfall. See Case No. 11-1274-E-

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2 PJM Manual 19: Load Forecasting and Analysis, Revision 30, at 23 (Dec. 1, 2015), available at https://www.pjm.com/-/media/documents/manuals/m19.ashx. Specifically, PJM determines capacity obligation by, first, considering zonal weather-normalized summer peak loads and then calculating the contribution of each wholesale and retail customer to those peaks. Id. The resulting Peak Load Contribution serves as the basis for determining the capacity obligation of each customer, including the Companies. Id. This methodology makes sense, even for winter-peaking service territories such as the Companies’, because PJM’s determination of capacity obligation for an individual LSE takes into account capacity and demand across the entire grid. As the IRP itself acknowledges, “PJM determines what constitutes sufficient capacity to maintain overall reliability for each zone through its annual load forecast and reserve margin guidelines.” IRP at 18.
P, FirstEnergy 2012 Resource Plan at 33, 46-47, 58-59 (Aug. 31, 2012) (hereinafter, the “2012 resource plan”). The Companies’ approach also represents a departure from the standards of General Order 184.35, which require the IRP to describe how it accounts for “PJM planning and implementation requirements and how it will satisfy PJM capacity obligations.” G.O. 184.35 at 2. The IRP’s break with established methodology, and its evident disregard for the standards set forth in the PJM Manual and General Order 184.35, further undermines the validity of this forecast.

The IRP’s overestimate of the Companies’ future capacity needs can also be seen by considering the Companies’ likely future unforced capacity obligations. The Companies’ unforced capacity obligation for the 2015/16 delivery year is 3015 MW. Resp. to CAG-I-8. By using the Companies’ assumption that peak loads will increase by 2.2% through 2020, IRP at 15, the Companies’ future capacity obligation can be estimated. And the results of that calculation indicate that the IRP’s estimates of capacity obligation are significantly overstated. Assuming the rate of growth forecasted in the IRP, the Companies’ capacity obligation should rise to approximately 3289 MW by 2020. This is substantially smaller than FirstEnergy’s estimate of 3867 MW.5 Thus, FirstEnergy’s own numbers confirm that the IRP’s estimates of capacity obligation are inflated.

FirstEnergy exacerbates the errors in its load forecast by failing to provide adequate support for many of the underlying assumptions. For example, the Companies do not adequately support their claims of significant load growth due to natural gas development. The IRP projects a 300 MW growth in peak demand between 2016 and 2019, which the Companies attribute chiefly to “increased load in the natural gas sector.” IRP at 15, 17, 19; see also Resp. to CAG-I-5 Att. A; id. -12(a). Although the Companies provided some of the numbers used to generate their forecast, they failed to provide any underlying support for those numbers. When asked in discovery to identify and produce any studies or models regarding the future electricity needs of the natural gas sector within the Companies’ service territory, FirstEnergy failed to provide any such documentation. Resp. to CAG-I-9(b), (c); Resp. to CAG-I-12(b), (c). Because FirstEnergy has apparently not documented the basis for this projected increase in peak demand, there is no

3 The 2012 resource plan was re-submitted as Attachment A to the Companies’ application in Case No. 12-1571-E-PC.

4 In discovery, the Companies defended their use of winter peak loads for estimating their capacity obligations, suggesting that this was required by the Commission. Resp. to CAG-I-15(b). The Companies are mistaken. Just because the Commission asked utilities to identify their peak demand “if that occurs at a different time” than the PJM peak, G.O. 184.35 at 3, does not mean that the utility should disregard the PJM Manual in estimating their capacity obligation and future resource needs. PJM, which is responsible for maintaining reliability, has set forth the method by which it determines the capacity obligation of all utilities – both winter-peaking and summer peaking. There is no justification for FirstEnergy’s departure from those methods.

5 FirstEnergy estimates that by 2020 winter peak load and reserve margin, together, will reach 3867 MW. Resp. to CAG-I-5, Att. A. This figure, viewed in comparison with generation capacity, is the basis for the Companies’ estimate of capacity shortfall. Id.

6 The growth in peak demand is visually presented in Figures 5 and 6 of the IRP. The underlying numbers were included in an Excel file that was filed by CD on December 30, 2015, with the Companies’ IRP. These figures are also in Resp. to CAG-I-5 Att. A.
way to assess the validity of the Companies' claims, further undercutting the claimed capacity shortfall.  

III. THE IRP FAILS TO EVALUATE A REASONABLE RANGE OF RESOURCE OPTIONS.

One of the core aims of the IRP process is that a utility “develop a portfolio of resources that represents a reasonable balance of cost and risk for the utility and its customers in meeting future demand . . . .” W.Va. Code § 2-2-19(d). To achieve this goal, General Order 184.35 requires that the IRP “include a description of the utility’s rationale for the selection of any particular supply-side or demand-side resource to fulfill its forecasted need, and the utility’s evaluation of alternatives considered for each resource option it has chosen.” G.O. 184.35 at 2. Both supply-side and demand-side resources are to be considered in the planning process. Id. (IRP must provide “a minimum ten-year forecast of the supply-side and demand-side resources expected to satisfy [the forecasted] loads.”); id. at 3 (IRP shall include “descriptions, analyses and discussions of supply-side and demand-side resource options that were considered by the utility”). These requirements make clear that a utility cannot limit itself to a single resource option, but must instead “evaluate[] the full range of alternatives . . . in order to provide adequate and reliable service to [the electric utility’s] customers at the lowest system cost.” G.O. 184.35 at 1 (quoting 16 U.S.C. § 2602(19)).

FirstEnergy’s IRP fails to meet these standards. Far from providing a robust analysis of resource options and their alternatives, the IRP presents a skewed analysis that tilts the playing field in favor of a single resource alternative: the purchase of an existing coal plant. Of course, this is not surprising because the IRP is apparently being used by the Companies to lay the groundwork for a forthcoming proposal to acquire the Pleasants plant from AE Supply.

After erroneously concluding that the Companies are projected to face an 850 MW capacity shortfall in the next decade, and briefly discussing various “planning objectives,” the IRP lists different types of energy resources, IRP at 22-51, and then concludes with an “Evaluation of Resource Options.” Id. at 52-58. Although the IRP purports to consider different resource options, the document’s assumptions and discussions make clear that the Companies never seriously considered an array of resource options. The skewed assumptions in the IRP lead to the inevitable – and faulty – conclusion that the purchase of an existing coal-fired power plant would, together with co-firing retrofits at Mon Power’s currently-owned coal plants, best “meet[] the Companies [sic] resource needs in a cost-efficient manner . . . .” IRP at 4-5, 57-58.

As explained in detail below, the deficiencies with the IRP’s approach include the following:

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7 The IRP also fails to adequately explain FirstEnergy’s method for identifying weather-normalized peak loads. PJM prescribes standards for generating weather-normalized peak load values. See PJM Manual 19 at 22-23. But the IRP does not disclose the method that the Companies used in calculating their own weather-normalized peak loads, IRP at 14-15, and the Companies have not provided the underlying calculations for those adjustments.

8 Although the IRP does not explicitly state that the generating facility to be acquired is a coal plant, IRP at 5, 57, the only type of existing plants considered in the IRP are coal-fired, and the $57/MWh LCOE figure cited for the “existing plants option” is based on a figure for a coal plant. Id. at 53, 55. The Companies also admitted as much in a discovery response. Resp. to Staff 1.1(a).
The IRP fails to evaluate the potential for demand-side resources, such as energy efficiency and demand response, to meet customer needs;

- The IRP fails to consider renewable resources, such as wind and solar;

- The Companies adopted assumptions that skew the analysis in favor of existing generation sources; and

- The IRP fails to consider any existing resources other than coal-fired generation, and overestimates the cost of meeting customers’ electricity needs through market purchases.

A. The IRP Fails to Meaningfully Evaluate Demand-Side Resources.

In establishing the IRP filing requirement, the Commission explained that integrated resource planning, as defined in federal law, "evaluates the full range of alternatives" and "shall treat demand and supply resources on a consistent and integrated basis." G.O. 184.35 at 1-2 (quoting 16 U.S.C. §2602(19)). This description of IRPs is consistent with the underlying legislation that spurred the Commission’s IRP Order. The Legislature directed the Commission to require electric utilities to develop IRPs to provide a “future review of both supply side and demand side resources.” W. Va. Code § 24-2-19(a). Consideration of both supply- and demand-side resources is a defining characteristic of integrated resource planning, and is reflected in the Commission’s IRP filing requirements. G.O. 184.35 at 3 (At a minimum, IRPs must include, *inter alia*, “descriptions, analyses and discussions of supply-side and demand-side resource options that were considered by the utility”).

FirstEnergy failed to meet this basic requirement. Despite the forward-looking nature of resource planning, the Companies’ consideration of demand-side resources does not appear to stretch beyond 2018 and current levels leave much room for growth. The demand-side portion of the FirstEnergy’s inaugural IRP amounts to a summary of existing demand-side resources and a discussion as to why these resources purportedly cannot be relied upon to meet long-term needs. The Companies present no meaningful analysis examining how energy efficiency and demand response could factor in to their resource mix and address the purported 850 MW capacity shortfall during the 15-year forecast period. Instead, FirstEnergy writes off demand-side resources based on its view that they cannot meet an 850 MW capacity need.

But even if it demand-side resources could not meet all of this purported need, the IRP fails to explain why demand-side resources could not satisfy some of that need. This omission is especially unreasonable in light of the flexible nature of these resources and their ability to scale up at low cost. Moreover, FirstEnergy disregards the benefits that this flexibility could provide to renewable energy, facilitating greater integration of these resources.

The end result is an IRP whose recommendation consist entirely of supply-side components, while concluding that “demand side resources were not considered as a viable,

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9 While the Companies claimed that they evaluated demand-side resource options as a means to meet part of their load obligations, they also stated that “the amount required was too large to meet the capacity shortage.” Resp. to CAG-I-51(b). The Companies also failed to produce any documentation that they performed such an analysis.
long-term solution to meet” additional capacity needs. IRP at 5, 57. Combined with a flawed load forecast and supply-side analyses, the IRP’s inadequate treatment of demand-side resources leads to the unreasonable recommendation to acquire 850 MW of existing coal. The result is a huge missed opportunity for customer savings and the many other benefits that demand-side resources provide.10

1. The IRP does not evaluate energy efficiency as a resource option.

The IRP does not model efficiency in a way that allows it to compete on a level playing field with supply-side resources, nor does it even compare energy efficiency to other resource options it considers.11 Instead, the Companies’ “analysis” of energy efficiency resource options appears to be limited to defining energy efficiency, briefly describing its two current programs, and incorporating the Companies’ Phase I and II Energy Efficiency and Conservation (“EEC”) Plans as a fixed adjustment to the load forecast. IRP at 45-48.

The Companies account for energy efficiency resources by incorporating assumptions concerning the “impacts of energy efficiency” into the energy and load forecasts. IRP at 15; Resp. to CAG-I-10. It appears that these assumptions are meant to capture the Companies’ actual and projected savings from efficiency programs pursuant to the Companies’ Phase I and II EEC Plans, in addition to end-use efficiency not attributable to programs. Resp. to CAG-I-10 (discussing the Phase I Plan and describing the implicit and explicit “impacts of energy efficiency programs”); Resp. to CAG-I-41 (providing savings projections through May 2018 from EEC Plans).12 The Phase I EEC Plan includes a cumulative savings target of 0.5% energy and demand savings (from 2009 retail sales and demand levels) by 2016, and reported annual incremental savings range from 0.03-0.2 % (energy) and 0.02-0.15% (demand) through 2015. IRP at 46; Resp. to CAG-I-10, -40. The Phase II EEC Plan aims to achieve 1% cumulative energy savings by the delivery year ending May 31, 2018. IRP at 46-47; see also Resp. to CAG-I-41 (projecting cumulative energy savings of 1.09% and demand savings of 0.8%).13 Thus, the “impacts of energy efficiency” accounts for program savings amounting to roughly 1% of retail energy sales and 0.8% of demand by 2018.

Treating energy efficiency as a load modifier in this way relegates this resource option to a fixed amount that cannot increase based on need. The Companies’ approach prevents

10 Rachel Wilson and Bruce Biewald, Best Practices in Electricity Utility Integrated Resource Planning, Regulatory Assistance Project, at 4 (June 2013) (“In particular, the inclusion of demand-side options presents more possibilities for saving fuel and reducing negative environmental impacts than might be possible if only supply-side options were considered.”). This article is available at: www.raponline.org/document/download/id/6608.

11 The lack of efficiency modeling is unsurprising because the Companies failed to conduct dispatch modeling for any resource option. See infra Section III.C.1.

12 For residential and commercial savings, the Company relied on Itron’s SAE end-use modeling. Resp. to CAG-I-10. It is unclear whether this “implicit” modeling approach, id., accurately reflects the actual and projected residential and commercial savings of the Phase I and II EEC Plans.

13 However, it is unclear whether Phase II savings projections are included in the IRP. See Resp. to CAG-I-10 (referring only to the Phase I EEC Plan with regards to the “impacts of energy efficiency” input to the load forecast).
efficiency from being able to compete with supply-side alternatives in the IRP to meet electricity needs, frustrating the purpose of integrated resource planning – to treat demand and supply resources “on a consistent and integrated basis.” G.O. 184.35 at 2 (quoting 16 U.S.C. §2602(19)).

There is much room for FirstEnergy to increase the amount of efficiency it considers to address resource needs. The Companies project cumulative energy savings from 2012-2018 to be 1.09% as a percent of retail sales. Utilities across the country are exceeding this seven-year cumulative total on an annual basis. For example, 16 states achieved energy savings of more than 1% incremental savings in 2014 alone. And in neighboring Maryland, utilities must ramp up their energy savings by 0.2% per year to reach the goal of 2% annual incremental savings. By contrast, FirstEnergy does not appear to project any efficiency programs after 2018 in the IRP. The result is effectively zero projected incremental savings from 2019 through the end of the planning period.

The Companies’ failure to account for energy efficiency in the long term is not surprising given their lack of adequate analysis. In response to a request for workpapers and source documents used or developed in the evaluation of demand-side resources for the IRP, the Companies stated only that “[n]o such documents are available.” Resp. to CAG-I-3. In response to a request for information concerning the modeling of demand-side resources, the Companies referred to their prior response about the lack of documentation, as well as to sections of the IRP that address demand response and conclude that demand-side resources will not meet the need for additional capacity. Resp. to CAG-I-42 (referring to Resp. to CAG-I-3 and IRP sections 6.3.5.2 and 7.4). Finally, in response to a request for all modeling and/or studies to support the Companies’ ultimate conclusion that “demand side resource options will not meet Mon Power’s obligations,” FirstEnergy responded that “[n]o such studies were prepared.” Resp. to CAG-I-51(a). Though the Companies claim to have examined increasing their investment in demand-side resources, Resp. to CAG-I-53, no meaningful analysis is provided in the IRP or in discovery.

FirstEnergy’s lack of efficiency analysis is most clearly demonstrated in the Companies’ failure to include energy efficiency in the levelized cost of electricity (“LCOE”) analysis presented in Figure 16. IRP at 53. The Companies compared levelized cost estimates for various supply-side resource options, including existing coal, new fossil-fuel generation, new nuclear, and renewable technologies. Id. Energy efficiency is not considered, a decision which skews the analysis in favor of existing coal-fired generation and is inconsistent with best practice resource planning.

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14 See also Ron Binz et al., Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know, Ceres (2012), at 40 (explaining that to produce utility portfolios that are lower risk and lower cost, demand resources and supply resources must be considered on equal footing), http://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation.


Had efficiency been included, the analysis presented in Figure 16 of the IRP (p. 53) would have shown that energy efficiency has the lowest levelized cost of any resource option considered, likely ranging from roughly $25-35 per MWh in terms of utility costs. For example, a recent Lawrence Berkeley National Laboratory study found that across all sectors, energy efficiency programs cost program administrators about 2.3 cents per kWh saved over the lifetime of the energy efficiency measures installed and have an average total cost of 4.6 cents per kWh saved. Similarly, in a 20-state review of energy efficiency programs, the American Counsel for an Energy-Efficient Economy ("ACEEE") found an average levelized utility cost of about 2.8 cents per kWh saved. ACEEE also recently studied the cost of efficiency where energy savings are high (which is not the case in the Companies' service territory), and found that the average levelized cost to the program administrator is about 3.4 cents per kWh saved—well below the cost of supply-side generation. Taking the high end of these reported utility costs, energy efficiency is roughly 38% cheaper than the lowest cost resource in the Companies' analysis.

In addition to the money savings to accrue to all customers when utilities invest in the low-cost system resources, energy efficiency programs provide a wealth of related benefits. For example, efficiency helps customers exercise more control over their individual utility bills and can add value to their homes and businesses. Additionally, energy efficiency spurs economic activity by creating local job and driving investments, and helps meet emissions reductions targets for electric generation. FirstEnergy’s inadequate approach to efficiency in its IRP leaves these significant benefits on the table.

Energy efficiency programs are a key part of a cost-effective utility resource mix that can lower system costs and risk. FirstEnergy’s failure to adequately analyze efficiency alongside the supply side options is a critical error. The immediate result is an IRP that fails to “evaluate[] the full range of alternatives” and “treat demand and supply resources on a consistent and integrated basis.” G.O. 184.35 at 2 (quoting 16 U.S.C. §2602(19)). In the longer term, the Companies’ failure will result in a riskier, higher-cost resource mix, and higher energy bills for customers.

20 And even using a total cost of saved energy estimate of 4.6 cents per kWh, efficiency remains substantially cheaper than the Companies’ estimate for existing coal.
21 See 2015 State Energy Efficiency Scorecard at vi.
22 Binz Risk Aware Regulation report at 8 (findings that energy efficiency is the least-cost, least-risk resource).
2. The IRP does not evaluate demand response as a resource option.

Among its many benefits, demand response lowers costs and improves reliability during periods of peak demand. *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 781, 193 L. Ed. 2d 661 (2016), as revised (Jan. 28, 2016). As such, it is an important component of a lowest-cost, low-risk resource portfolio.

The Companies’ treatment of demand response as a resource options falls short. As presented in the IRP, the Companies’ analysis of demand response resource options consists of a description of demand response generally; a discussion of tariffs offered by FirstEnergy and programs offered by market providers; and a discussion of PJM market rules and the recent Supreme Court case concerning FERC Order 745, which was pending at the time of the IRP filing. IRP at 48-51. The Companies did not model future demand response investments or prepare any studies to support their ultimate conclusion that demand response resources will not meet FirstEnergy’s additional capacity needs. Resp. to CAG-I-51.

The Companies also “do not offer any DR programs in WV.” Resp. to CAG-I-43. The Companies offer interruptible tariffs and contracts to certain large retail customers, but such resources are “generally not used for reliability planning purposes.” IRP at 49. FirstEnergy customers can participate in market-based programs though a competitive third-party provider, *id.* at 49-50 (describing load curtailment, economic, and emergency demand response programs), but the Companies do not account for such resources in their forecasted load requirements. IRP at 51.

The Companies appear to justify their lack of demand response resources by pointing to “performance risks associated with DR resources.” IRP at 49. However, when asked in discovery about the Companies’ direct experience with DR resources failing to perform, FirstEnergy responded that “[t]he Companies do not offer any DR programs in WV.” Resp. to CAG-I-43(a). The Companies further stated that they are aware of “multiple breeches [sic] of DR obligations in MD and other states during the winter cold spells and bankruptcy/financial difficulties of DR suppliers,” but they are not familiar with the details of the performance of market-based economic and emergency DR programs within PJM and provided no documentary support of these perceived risks. *Id.*

While focusing on vague claims of performance risks, the Companies ignore the substantial reliability benefits that demand response resources provide. The Companies reference DR performance during “winter cold spells.” *Id.* During the Polar Vortex in January of 2014, demand response provided as much as 3000 MW to ensure the reliability when demand levels soared by roughly 25%.\(^{23}\) As PJM reported, “[a]lthough operational conditions were tight during the Polar Vortex, some variables exceeded PJM’s expectations in real-time: the availability and response of voluntary demand response, the response of the stakeholders to the

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public appeal for conservation, and the performance of wind-powered generation... This experience demonstrates the year-round value of demand response.\textsuperscript{24}

The Companies also observed that “[f]uture changes relative to participation of demand response in the RPM capacity market are currently under debate” in a Supreme Court case concerning FERC Order 745. IRP at 51; see also id. at 57 (“it is difficult and impractical for the Companies to rely on DR” due to the uncertainty created by the pending case). Order 745 set compensation levels for demand response in wholesale energy markets at the locational marginal price (LMP), in specified circumstances. The rule essentially placed demand response on a level playing field with power plants by requiring market operators to “pay the same price to demand response providers for conserving energy as to generators for making more of it.” \textit{Elec. Power Supply Ass’n}, 136 S. Ct. at 767. As the Companies noted, the U.S. Court of Appeals for the District of Columbia Circuit vacated Order 745 and the Supreme Court granted review to address two issues: whether FERC has authority under the Federal Power Act to regulate demand response in wholesale energy markets and whether FERC failed to justify adequately the LMP compensation level. \textit{Elec. Power Supply Ass’n}, 136 S. Ct at 767; IRP at 51.

The Supreme Court issued its decision less than one month after the Companies filed their IRP. The Court reversed the D.C. Circuit, holding that FERC has statutory authority to regulate wholesale market operators’ compensation of demand response bids and that Order 745 is adequately reasoned. \textit{Elec. Power Supply Ass’n}, 136 S. Ct at 773.

In their IRP, the Companies observed that the Supreme Court’s decision (which had not yet been issued) “affects many aspects of the market including investment decisions on whether to retire generating units, and where and how to invest in new reliability projects.” IRP at 51. This statement appears to recognize the importance and impact of demand response resources, including their ability to impact retirement decisions. However, when asked about the impact of the Supreme Court’s decision in discovery (after it issued), the Companies discounted the role of demand response, stating that “the demand response opportunities that would have been available to the Companies at the retail level had the Supreme Court decided otherwise, are not available now.” Resp. to CAG-I-44; see also id. at -52(a) (“The decision reduces the possibility that the Companies could utilize demand response since most, if not all, participants will be utilizing the existing PJM demand response programs that were upheld by the Supreme Court.”).

FirstEnergy’s reaction to the Supreme Court decision reveals its fundamental misunderstanding of demand response resources. Demand response is an important resource in both retail and wholesale markets. While the Supreme Court decision ensures that demand response will continue to be a key resource in wholesale electricity markets, the decision does not remove demand response from retail markets.

Wholesale-level demand response complements rather than threatens retail demand response. Indeed, there are important positive effects from wholesale demand response that are felt at the retail level (and vice-versa). Specifically, the technological and business innovations

\textsuperscript{24} PJM Analysis of January 2014 Cold Weather Events at 20-21 (emphasis added); see also id. at 38 (noting that demand response “exceeded PJM’s expectations” during winter storms following the Polar Vortex in January 2014).
developed through wholesale market participation benefit retail-level programs. As state public utilities commissioners explained to FERC, eliminating “demand response[’s ability] to participate in the wholesale energy market would... adversely affect the viability of retail price responsive demand programs.” Letter of New England Conf. Pub. Utilities Comm’rs, FERC Docket No. RM10-17, 2-3 (July 1, 2014) (emphasis added).

The Supreme Court decision presented FirstEnergy with an opportunity to reconsider its approach and meaningfully evaluate the role that demand response resources can play in meeting customer demand. Unfortunately, the Companies opted instead to double down on their flawed assumptions and concluded that demand response cannot help meet additional power needs.

As with energy efficiency, the Companies’ failure to meaningfully consider demand response in unsurprising given their lack of analysis. Demand response was not included in the Companies’ levelized cost analysis. When asked to provide workpapers and source documents used or developed in the evaluation of demand-side resources, the Companies stated only that “[n]o such documents are available.” Resp. to CAG-I-3; see also Resp. to CAG-I-42 (referring to Resp. to CAG-I-3 and IRP sections 6.3.5.2 and 7.4). Moreover, when asked to produce all modeling or studies supporting the Companies’ ultimate conclusion that “demand side resource options will not meet Mon Power’s obligations,” FirstEnergy responded that “[n]o such studies were prepared.” Resp. to CAG-I-51. Notwithstanding the Companies’ claim to have examined increasing their investment in demand-side resources, Resp. to CAG-I-53, no meaningful analysis is provided in the IRP or in discovery.

FirstEnergy’s position on demand response is especially troubling given that the Companies appear to be long on energy and their purported capacity shortfall is limited to a fairly small number of hours, particularly during the first four years of the forecast. IRP at 22; Resp. to CAG-I-14(a) (projecting that load will exceed capacity for 8 hours in 2016, 17 hours in 2017, 37 hours in 2018, and 121 hours in 2019). Demand response could be an especially useful resource to help meet demand during these hours.

As in the case of efficiency, the Companies’ failure to adequately analyze demand-side resources is a critical error and will result in a riskier, higher-cost resource mix.

B. The IRP Fails to Consider Renewable Resource Options.

Although General Order 184.35 makes clear that an integrated resource plan must thoroughly evaluate supply-side resource options, FirstEnergy’s IRP fails to meet that requirement. One of the IRP’s most serious deficiencies is its treatment of renewable resources, such as wind and solar. Rather than meaningfully considering these resources as options that could help meet the purported capacity shortfall, the Companies instead dismissed these options with a flawed, cursory analysis.

The IRP begins its discussion of renewables by expressing skepticism about them categorically:

[M]any sources, like solar, geothermal, new hydro and tidal, are not economic options for Mon Power within the Companies’
service territories based on the current state of development for those technologies or for meteorological or geographical reasons. The most viable renewable options for the Companies’ service territories, absent significant leaps in technology, are wind power plants or biomass co-firing in coal power plants.

IRP at 42. This language—which was directly lifted from the resource plan filed by the Companies in August 2012—signals the Companies’ unwillingness to consider wind and solar, purportedly for “economic” reasons and a supposed need for “significant leaps in technology.” The reality, however, is that the Companies dismissed these resources, particularly wind and solar, without seriously considering them. As explained below, the IRP devotes only two pages of the “Resource Options” section to these resources, IRP at 43-44, and evaluates the cost of these resources using unreasonable assumptions.

1. Wind

The discussion of wind in the “Resource Options” section was, yet again, lifted word-for-word from the 2012 resource plan. Perhaps because it relies on a discussion that is more three years old, the IRP fails to mention the significant strides in wind technology and deployment that have occurred in recent years. Instead, the IRP criticizes wind as an intermittent resource, a criticism it repeats in Section 7. There, too, the IRP relies on a cursory discussion of wind that was essentially cut and pasted from the 2012 plan. Citing to their LCOE analysis, the Companies also claim that new wind capacity would cost $124.20/MWh (with the federal production tax credit (“PTC”)) or $164.24/MWh (without the PTC). Resp. to Staff 1.10 (admitting computational error in the IRP, and providing revised figures); see also IRP at 53.

The IRP’s treatment of wind resources is flawed for multiple reasons. First and foremost, the Companies have rejected wind as a resource option without supporting analysis. As they admitted in discovery, the Companies have neither performed nor commissioned any studies regarding wind potential within their service territory. See Resp. to CAG-1-35. And, although the Companies were asked to produce any studies or other documents that were reviewed, created, or relied on in developing their levelized cost estimates for wind, they only produced an Excel spreadsheet with inputs and calculations of LCOE figures. This spreadsheet [Conf. Ex. 1.8] for many of the assumptions used to derive the LCOE figure. Resp. to Staff, Conf. Ex. 1.8.

The Companies’ failure to consider wind is particularly problematic given the important role that wind can play during periods of high customer demand. Wind generally has higher

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25 See 2012 resource plan at 38.
26 Compare 2012 resource plan at 39 with IRP at 43.
27 Compare 2012 resource plan at 52 with IRP at 55.
28 Specifically, in discovery the Citizen Groups asked the Companies to “produce any studies or other documents that were reviewed, created, or relied on in preparing Figure 16.” CAG-1-47(b). Figure 16 includes LCOE estimates for wind. IRP at 53.
capacity factors in the winter, when the Companies experience their peak loads.\textsuperscript{29} Wind’s importance during winter months was dramatically illustrated by the Polar Vortex of January 2014. While many coal and gas plants experienced forced outages, wind over-performed. As PJM noted, wind was one of the few resources that beat expectations, having “a positive impact on supply and contribut[ing] to PJM’s ability to maintain reliability.”\textsuperscript{30}

Second, the levelized cost figures that the Companies do provide are wildly inflated. As noted above, the Companies estimate that new wind resources would have an LCOE of $124.20/MWh (with the PTC) or $164.24/MW (without). These figures are significantly higher than the levelized cost estimates presented by independent analysts. For example, the Energy Information Administration’s (“EIA”) levelized cost analysis provides a total LCOE of $73/MWh (2013\$) for new onshore wind, with a range between $65.6-$81.6/MWh.\textsuperscript{31} Similarly, Lazard, which regularly analyzes the comparative LCOE of different generation technologies, estimates that onshore wind resources, without the benefit of a PTC, currently have a levelized cost of $32-$77/MWh.\textsuperscript{32} Even just taking the upper-bound numbers presented in these analyses, and accounting for potential regional variations in development costs, it is clear that the Companies’ LCOE figure is unreasonably high.\textsuperscript{33}

Moreover, the IRP completely ignores the decreasing cost of wind energy. Like other renewable resources, such as solar, wind generation costs have been steadily falling for decades, and these price decreases are projected to continue.\textsuperscript{34} And the IRP ignores the fact that West

\textsuperscript{29}EIA, Wind generation seasonal patterns vary across the United States (Feb. 25, 2015), http://www.eia.gov/todayinenergy/detail.cfm?id=20112# (showing that wind plant generation tends to be highest during winter months in the Midwest and Southeast).

\textsuperscript{30}PJM Analysis of January 2014 Cold Weather Events at 20, 21.


\textsuperscript{33}The IRP’s LCOE for wind is also significantly higher than the cost estimates provided in the 2012 resource plan. There, the Companies provided estimates of $58-88/MWh, and cited power purchase agreements with levelized costs of $63 and $66/MWh. See 2012 resource plan at 53. The fact that the Companies’ adoption of a 20-year timeframe underscores the unreasonableness of the Companies’ estimate.

\textsuperscript{34}As the Department of Energy recently noted, the “the average LCOE for U.S. land-based wind projects in good to excellent sites dropped more than 90% from 1980 to 2013,” and “[t]he LCOE of wind in good to excellent wind sites dropped by more than one-third over the five-year period from 2009 to 2013.” U.S. DOE, Wind Vision: A New Era for Wind Power in the United States, Chap. 2, at 10, 21 (April 2015), http://www.energy.gov/sites/prod/files/WindVision_Report_final.pdf. Similarly, Lazard estimates that the LCOE of wind dropped by 61% between 2009-2015. Lazard Analysis at 10.
Virginia, including the Companies’ service territory, has strong wind potential.35 Indeed, the West Virginia Department of Commerce has noted U.S. DOE’s determination “that West Virginia has significant wind development opportunities.”36 This is reflected in the multiple utility-scale wind projects that have been built or permitted within the Companies’ service territory.37

Third, even apart from the errors in the LCOE, and the complete lack of supporting analysis, the IRP’s treatment of wind is based on a flawed factual premise. The IRP suggests that the wind PTC is at imminent risk of expiring: “Wind projects are eligible for a substantial federal subsidy through a production tax credit . . . However, once this benefit lapses, the competitiveness of new wind generation projects will be reduced significantly.” IRP at 55. But the Companies’ discussion ignores the fact that, two weeks before this IRP was submitted, Congress extended the PTC by five more years, until 2019.38 The IRP fails to account for that development, just as it fails to acknowledge recent developments in wind technology, cost, and deployment. The Companies’ repetition of a superficial, three-year-old write-up, with virtually no supporting analysis, fails to satisfy the IRP standards set by the Commission and reflects poor planning. Cf. G.O. 184.35 at 2 (an IRP must include “the utility’s evaluation of alternatives considered for each resource option it has chosen”).

2. Solar

The IRP’s treatment of solar resources is equally flawed. Rather than perform a fair evaluation of this resource option, the Companies dismissed solar out of hand, claiming that their service area is “not particularly conducive to wide scale economical photovoltaic development.” IRP at 44. They further assert that solar is not “economic” within their “service territories based on the current state of development for those technologies or for meteorological or geographical reasons,” and suggest that “significant leaps in technology” would be needed before solar could be viable. Id. at 42. These sweeping claims are wholly unsupported.

In the IRP, the Companies attempt to justify their rejection of solar by pointing to a single map, prepared by the DOE’s National Renewable Energy Laboratory (“NREL”), of direct normal irradiance (“DNI”) – a measure of solar intensity – for the continental United States. IRP at 44. The Companies cite this map for their claim that “the Mon Power service area is still not
particularly conducive to wide scale economical photovoltaic development.” *Id.* But the Companies’ claims are highly misleading, and their rejection of solar as a resource option is unreasonable.

First, the IRP’s rejection of solar is unreasonable because the Companies did not actually perform any evaluation of solar resources. In discovery, the Citizen Groups asked multiple questions in an attempt to discover the source of the Companies’ claims. What they learned, however, was that the Companies simply did not study solar. Instead, all of the Companies’ claims about solar are premised on that single NREL map. See Resp. to CAG-I-36 (confirming no “studies conducted by or for [the Companies] regarding solar potential in the Companies’ service territories”); Resp. to CAG-I-37(a) (confirming that their conclusion, that “the Mon Power service area is still not particularly conductive to wide scale economical photovoltaic development,” is based entirely on the NREL graph). When asked to explain, and provide supporting documentation, for their skeptical view of the “current state of development” for solar, IRP at 42, the Companies simply pointed to the NREL map, claiming that the relatively lower DNI “renders solar less economical than many other areas of the nation.” Resp. to CAG-I-34(a); see also *id.* (b)-(d).

Moreover, the single source that the Companies do cite – the NREL map – says nothing about the potential value of including solar PV as part of the Companies’ resource portfolio. The fact that the Companies’ service territory may have a lower DNI than, say, Arizona is irrelevant. The reality is that solar PV is cost competitive, and can play an important role in a balanced resource portfolio. Indeed, looking at the NREL map, there are many states with similar DNIs that have substantial solar PV already installed. For example, as of January 2016, the New England states were estimated to have a combined 373 MW of net summer utility-scale PV capacity, with an additional 794 MW of distributed capacity.39

In short, the IRP dismisses the viability of solar without any supporting analysis. And in failing to do so, the Companies have fallen far short of the minimal requirements for an IRP. General Order 184.35 makes clear that an IRP must evaluate alternatives to the resource options ultimately chosen by the utility. G.O. 184.35 at 1-2. Here, however, the Companies have categorically rejected solar without actually studying its potential as a resource option.

The Companies compound these failures by using an unreasonable LCOE figure in Section 7. The Companies estimate that new solar PV resources would cost $209.63/MWh (with the federal investment tax credit (“ITC”)) or $291.35/MWh (without the ITC). Resp. to Staff 1.11(b). As with wind, these figures are much higher than the LCOE estimates presented by independent analysts. For example, the EIA estimates an unsubsidized levelized cost of solar PV

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of $125.30/MWh, with the ITC reducing that figure to $114.3/MWh.\textsuperscript{40} And Lazard estimates an unsubsidized LCOE for certain types of utility-scale solar installations in the northeast to be $82/MWh.\textsuperscript{41} Here again, the Companies generated their LCOE figure with an Excel spreadsheet, and \[\text{[...]}\] that support many of the underlying cost assumptions. Resp. to Staff, Conf. Ex. 1.8a. By assuming an unreasonably high, unsupported levelized cost for solar, the IRP effectively shuts the door on this resource option.\textsuperscript{42}

The IRP suffers from many other deficiencies with respect to solar. For example, the IRP wholly ignores the decreasing cost of solar—a key factor in the context of the long-term forecast required by General Order 184.35. Between 2009-2015, the LCOE of utility-scale solar PV dropped by 81%.\textsuperscript{43} And, like wind, these price decreases are projected to continue.\textsuperscript{44}

Moreover, the IRP entirely ignores the potential for distributed solar generation to reduce demand within the Companies’ service territory. The IRP does not mention, let alone study, distributed generation. The Companies defend this massive oversight by suggesting that they have no obligation to consider distributed generation, because such resources are “not within the control of MP/PE.” Resp. to CAG-I-56. This excuse strains credulity. The fact that the Companies are uninterested in promoting distributed generation does not mean it cannot or should not be pursued. Moreover, as Appalachian Power Company (“APCo”) noted in its IRP, even if a utility does not have control over the deployment of distribution generation, it must be recognized “that distributed rooftop solar will reduce [the utility’s] capacity and energy requirements.” See Case No. 15-2003-E-IRP, APCo IRP at ES-2 (Dec. 30, 2015). By ignoring the issue entirely, the Companies not only fail to recognize an important resource option, they exacerbate their overestimate of a future capacity shortfall. The Companies’ failure to

\textsuperscript{40} EIA Levelized Cost at 6.\textsuperscript{[...]}\textsuperscript{41} Lazard Analysis at 9. This cost figure for the Northeast is based on a crystalline utility-scale solar fixed-tilt design, \textit{id.}, and assumes a 30-year lifespan. \textit{Id.} at 16.

\textsuperscript{42} The IRP’s LCOE for solar is also significantly higher than the cost estimates provided in the 2012 resource plan. There, the Companies provided an estimate of $131/MWh (with ITC), and cited PPAs of $120 and $200/MWh. 2012 resource plan at 53. The fact that the Companies’ solar LCOE has escalated at a time when solar costs are actually decreasing further highlights the unreasonableness of the Companies’ estimate.

\textsuperscript{43} Lazard Analysis at 10.

\textsuperscript{44} The continued decline in solar costs can be seen from a Bloomberg New Energy Finance forecast for the states of West Virginia and Virginia. This forecast, which was reproduced in Appalachian Power’s IRP, shows that solar installation costs will continue to decline through 2030. See Case No. 15-2003-E-IRP, APCo IRP at 78 (Dec. 30, 2015) (citing BNEF H2 2015 US States Average Utility Forecast).
acknowledge distributed solar, as well as its broader dismissal of utility-scale solar without analysis, further demonstrates that the IRP fails the requirements of General Order 184.35.

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The Companies’ wholesale dismissal of wind and solar resources is particularly stark when compared to the evaluation of renewables in the integrated resource plan that APCo filed on the same day. In contrast to the cursory treatment of FirstEnergy’s IRP, APCo actually discussed the economic potential of wind, utility-scale solar, and distributed generation. APCo IRP at 38-41, 77-81. After modeling those resources using Plexos, a commercially-available dispatch model, APCo ultimately developed a resource portfolio that: (i) proposed adding 10 MW of solar by 2018, with subsequent additions for a total capacity of 260 MW by 2025; (ii) proposed adding 150 MW of wind energy by 2018, with subsequent additions for a total of 750 MW of wind capacity by 2025; and (iii) assumed that over 14 MW of distributed solar would be installed within APCo’s service territory by 2025. Id. at 104. Although the geography and economics may be somewhat different in the Companies’ service territory, the fact remains that wind, solar, and distributed generation are viable resource options in West Virginia. The Companies’ failure to assess these options violates the requirements of W.Va. Code § 24-2-19 and General Order 184.35.

C. The IRP Is Otherwise Skewed in Favor of the Companies’ Apparent Plan to Purchase Additional Existing Coal-Fired Generation.

As explained above, the Companies’ IRP wholly fails to address the potential for demand-side resources and renewable supply-side resources to address any capacity shortfall the Companies may face in future years. By dismissing these resource options without analysis, the Companies have violated the standards set by the Commission and the Legislature.

Yet even if those deficiencies are set aside, the IRP’s consideration of resource options would still be woefully inadequate. Throughout the IRP, the Companies used a series of assumptions that further skewed the analysis in favor of the Companies’ apparent plan to purchase additional existing coal-fired generation. In addition to the failures described above, some of the more serious deficiencies of the IRP’s evaluation of resource options are discussed below.

1. The IRP used a levelized cost approach that improperly favored existing generation.

As an initial matter, the overall approach taken in the IRP’s “Evaluation of Resource Options” is deeply flawed. First, the IRP’s evaluation is deficient because it relies on a rough levelized cost analysis, rather than identifying a least-cost resource portfolio through modeling. As the Companies concede, they performed no dispatch modeling in developing the IRP. Resp.

45 To be clear, the Citizen Groups are not claiming that APCo’s IRP necessarily satisfies the requirements of W.Va. Code §24-2-19 and General Order 184.35. Nor are we endorsing the resource portfolio that APCo recommended in its IRP. Rather, we cite these examples solely to underscore the degree to which FirstEnergy completely failed to consider resource options such as wind, solar, and distributed generation.
The main problem with relying on LCOE to develop a resource portfolio is that it's static: this approach assumes that capacity factors, and cost profiles, remain constant over time. LCOE also fails to capture the dynamics associated with the dispatch of different generating units into PJM, and fails to address sensitivities, such as higher-than-expected commodity prices or lower-than-expected load growth. Because FirstEnergy's LCOE fails to account for such variables, it presents an incomplete picture of the available resources, and prevents the Commission from identifying a resource portfolio that "provide[s] adequate and reliable service to [the Companies'] customers at the lowest system cost." G.O. 184.35 at 1 (quoting 16 U.S.C. § 2602(19)). Moreover, because it does not assess real world performance, this LCOE analysis certainly could not provide the basis for any future investment decisions, such as the acquisition of additional generating capacity.

By relying on a static LCOE approach, and by failing to model different resource portfolios and sensitivities, FirstEnergy also improperly tilts the playing field in favor of whichever resource option happens to have the lowest reported LCOE. And here, because the IRP failed to fairly evaluate other resource options, the Companies reached the flawed conclusion that acquiring additional existing coal generation is the preferred option. IRP at 5, 57-58.

Second, even if an LCOE approach were sufficient for integrated resource planning, the Companies' analysis would still be deficient because it lacks factual support. The LCOE evaluation is almost entirely premised on Figure 16, a graphic that purports to show the levelized cost of different power generation technologies. As explained supra in Section III.B, the graphic itself contains errors, improperly reporting the Companies' levelized cost figures for wind and solar. Moreover, these cost assumptions are largely unsupported. In discovery, FirstEnergy was specifically asked to "produce any workpaper, source document, and . . . input and output files" used to evaluate supply-side resources, and the only thing provided in response was an Excel spreadsheet used to create Figure 16. Resp. to CAG-I-2 (referring to Resp. to Staff, Conf. Ex. 1.8a). With one exception, this spreadsheet [Content removed]. Cf. IRP at 52 nn. 9-10. Moreover, when asked to identify the studies or other documents used in developing Figure 16, the Companies referred, again, back to the same spreadsheet. Resp. to CAG-I-47. Consequently, the majority of the assumptions used in developing the Companies' LCOE figures have no underlying support. This is not surprising, given the serious flaws in the Companies' levelized cost estimates for wind and solar. And the levelized cost analysis suffers from many additional flaws, as described below.

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46 When asked in discovery why they relied on LCOE for this long-term IRP, they claimed that LCOE is sufficient because "have relied on this type of analysis historically and relied on [sic] same methodology in Mon Power's 2012 IRP filed with the Commission." Resp. to CAG-I-48(a). In other words, the Companies justified their LCOE approach on grounds that that's the way they've done it before. Of course, that earlier plan preceded the Legislature's creation of an integrated resource planning requirement in 2014.

47 Here again, the contrast to APCo is telling. In its IRP, APCo developed its resource portfolio with Plexos, a commercially-available dispatch model, to model fifteen different scenarios. APCo IRP at 83, 87. Using a dispatch model, and analyzing different scenarios to assess the impact of different loads, commodity prices, and resource issues, is essential for robust integrated resource planning. The Companies took none of these steps in preparing their IRP.
2. The levelized cost analysis includes an unreasonably narrow scope of resource options.

Setting aside the lack of underlying factual support, one of the core problems with the Companies’ levelized cost analysis is its scope. Figure 16 presents a total of eight power generation technologies that were purportedly considered by the Companies: existing coal, new gas combined-cycle (CC), new supercritical coal, new nuclear, hydro, new combustion turbine (CT), new solar, and new wind. The range of resource options considered in the IRP is unreasonably narrow.

First, the Companies failed entirely to consider demand-side resources in their levelized cost analysis. In Section 7 of the IRP, the Companies assert that demand response cannot meet all of Mon Power’s purported need for an additional 850 MW of capacity. IRP at 56. Even if true, however, the Companies have provided no basis for concluding that demand-side resources could not play a role in meeting some of that capacity. Rather than carry out an integrated analysis to consider whether demand-side resources should be part of a least-cost portfolio, however, the Companies rejected those options out of hand, which was unreasonable, for the reasons explained above in Section III.A.

Second, as explained above in Section III.B, the IRP adopted unreasonably high cost estimates for wind and solar. Although these resources were included in Figure 16, the Companies’ use of those inflated cost figures gave them an excuse not to consider the potential for wind and solar to meet a portion of the purported capacity shortfall.

Third, the Companies further shrunk the scope of analysis by refusing to consider any existing resources other than coal. The only existing generation resource displayed in Figure 16, or otherwise discussed in the IRP, is an existing coal plant. IRP at 5, 53, 55, 57-58. In the Excel spreadsheet that was used to generate Figure 16, [Excel Group requested the Companies to state whether they had considered the acquisition of any existing CT plants, CC plants, or other non-coal resources, the Companies refused to provide a straight answer. Resp. to CAG-1-50. By narrowing the existing generation options to a single fuel type - coal - the Companies have yet again distorted the analysis.]

The Companies compound this error by assuming a short cost recovery period that artificially bolsters the cost-effectiveness of the one existing resource being considered. Although the IRP cites the EIA’s Annual Energy Outlook as a source, IRP at 52 n.9, the Companies used a much shorter cost recovery timeline than the EIA employs for its own analysis. Compare IRP at 53 (using 20-year timeline) with EIA Levelized Cost at 2 (using 30-year timeline). Because a shorter cost-recovery period makes new generation options appear to

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48 The figure includes solar estimates both with, and without, the ITC.
49 Notably, the spreadsheet that was used in developing Figure 16 [Excel Group asked the Companies to state whether they had considered the acquisition of any existing CT plants, CC plants, or other non-coal resources, the Companies refused to provide a straight answer. Resp. to CAG-1-50.]. See Resp. to Staff, Conf. Ex. 1.8a. In other words, there is essentially no support at all for several of the levelized cost figures that are in the heart of the Companies’ IRP.
be more costly, the Companies’ use of this timeframe further skews the analysis in favor of existing coal units.50

The Companies’ failure to consider other types of existing resources is especially problematic given that the purported capacity shortfall, especially over the next several years, is limited to a fairly small number of hours. As the IRP acknowledges, Mon Power is long on energy – its current facilities generate more energy than the Companies’ customers consume. IRP at 22. And, as the Companies admitted in discovery, their purported capacity shortfall – which, again, is based on an overinflated demand estimate, see supra Section II – is limited to a relatively small number of hours, particularly during the first four years of the forecast. See Resp. to CAG-I-14(a) (projecting that load will exceed capacity for 8 hours in 2016, 17 hours in 2017, 37 hours in 2018, and 121 hours in 2019). Given FirstEnergy’s long energy position, and the very few hours each year in which additional capacity is purportedly needed, the Companies likely could meet such a shortfall through demand response, the acquisition of a peaking plant such as CT, market purchases, or some combination of these options. But the Companies have apparently never studied such options.

Indeed, among the IRP’s many failings is its all-or-nothing approach to resource options, and its failure to consider the possibility that a least-cost generation portfolio may change over time. To take but one example, after discussing the purported limitations of demand response, the IRP baldly asserts “that demand side resources were not considered as a viable, long-term solution to meet Mon Power’s need for an additional 850 MW.” IRP at 57. Assuming, for the sake of argument, that there will be an 850 MW capacity shortfall, the Companies never explain why demand-side resources could not satisfy some of that capacity need. Apparently, in the Companies’ view, if a given resource cannot satisfy the entirety of the projected capacity shortfall, that resource should not be considered at all. Although helpful for a utility trying to lay the groundwork for the future purchase of an affiliate’s coal plant, such an approach forecloses feasible, low-cost options that would benefit the Companies’ customers.

Likewise, the Companies never consider the possibility that other, less expensive resource options could better serve customer needs during the early years of the IRP. Even if there were a need to acquire a baseload unit in later years, that does not necessarily mean that the Companies should do so right away. But, in the Companies’ telling, the 8-hour capacity shortfall in 2016 necessitates the immediate purchase of 850 MW of coal-fired generation. See IRP at 58 (“Because of significant capacity shortfall, Mon Power should acquire additional 850 MWs of capacity resources by the 2017/2018 delivery year when the shortfall begins to climb.”). The Companies fail to explain the need for such a massive purchase, particularly when capacity shortfalls in 2016-18 are projected to occur only 0.002% of the time.51

50 In discovery, the Citizen Groups asked the Companies to explain why they used a 20-year cost recovery assumption, unlike the 30-year assumption used by EIA. The Companies offered no explanation for their choice, other than the fact that that’s what they did previously. Resp. to CAG-I-46(b). The Companies also blithely noted that “[t]he Commission order required a 10 year forecast.” Id. The duration of the load forecast, however, does not explain why the Companies would use a 20-year rather than 30-year cost recovery period.

51 This percentage is calculated as follows: 62 hours / (8760 hours x 3 years).
3. The IRP relies on unreasonably high market price forecasts.

At the core of the Companies’ recommendation to purchase 850 MW of existing coal-fired generation is their conclusion that existing coal units are cheaper than any other alternative. Although the IRP hardly addresses it, one of those alternatives is to purchase energy and capacity from the PJM market to address some or all of the projected capacity shortfall. But here again, the IRP uses assumptions that make this option appear less favorable than it actually is.

The IRP presents a levelized cost figure of $57/MWh for existing coal generation, while citing a levelized cost of market purchases in the range of $72-76/MWh. IRP at 52-53, 55. Because the $57/MWh figure is below that range, the Companies apparently believe that market purchases do not need to be considered, and they do not discuss that option further.

But the Companies’ treatment of market purchases is flawed, because it relies on unreasonably high forecasts of energy and capacity. In discovery, the Companies produced a spreadsheet showing the calculations used to derive those levelized cost figures. Resp. to Staff, Conf. Ex. 1.8a, “Market Purchase” tab. The price forecasts are unreasonably high.

With respect to capacity prices, has already been proven wrong. The forecast 24 But , the PJM auction for the 2018/2019 delivery year has occurred. In contrast to the , the actual result for the 2018/2019 Capacity Performance product (i.e., the more expensive product in the auction) was $164.77/MW-day. Consequently, the Companies’ forecast a significant overestimate.

The Companies provide no basis for , which is much higher than independent estimates. For example, ICF, , recently issued a whitepaper noting that there is a “plausible scenario” in which the 2019/2020 capacity price would be lower than the

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52 The forecast shows a price of $[[6162]] for 2018, and a price of $[[6162]] for 2019. The $[[6162]] figure for the 2018/19 delivery year is calculated as follows: (($[6162] x 7 mos.) + ($[6162] x 5 mos.)) / 12 mos.
54 The $[[6162]] figure for the 2019/20 delivery year is calculated as follows: ($[6162] x 7 mos.) + ($[6162] x 5 mos.)) / 12 mos.
actual 2018/2019 price. The Companies’ forecasts, \( \text{[ ]} \).

The Companies’ energy forecasts are also unreasonably high. The fact that the \( \text{[ ]} \), which provided the basis for the upper-bound $76/MWh levelized figure, \( \text{[ ]} \). Compare Resp. to Staff, Conf. Ex. 1.8a, “Market Purchase” tab, column D with id., column N. Moreover, recent energy forwards demonstrate that \( \text{[ ]} \). As Judah Rose, an ICF consultant who served as a rebuttal witness for the Companies in the Harrison transfer case, noted at a 2015 evidentiary hearing before the Ohio PUC, energy forward prices for the 2016-19 timeframe “are pretty much steady at 35 or so dollars a megawatt-hour.” Since then, energy price forwards for the APS zone have fallen further. As the table below indicates, energy forwards for 2017-22 are consistently under $35/MWh.

<table>
<thead>
<tr>
<th>Year</th>
<th>Price ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>34.57</td>
</tr>
<tr>
<td>2018</td>
<td>32.93</td>
</tr>
<tr>
<td>2019</td>
<td>32.28</td>
</tr>
<tr>
<td>2020</td>
<td>31.81</td>
</tr>
<tr>
<td>2021</td>
<td>31.99</td>
</tr>
<tr>
<td>2022</td>
<td>32.63</td>
</tr>
</tbody>
</table>

Source: SNL Financial

These figures are \( \text{[ ]} \).

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57 The figure presented in the above table were derived using reported monthly averages of around-the-clock energy prices for the APS zone. The underlying forwards are from April 22, 2016. Those monthly figures were averaged for each year, thereby providing a proxy for the annual average forward prices for 2017-22. The monthly forward data were supplied by SNL Financial, but undersigned counsel performed the subsequent calculations.
In sum, the energy and capacity price forecasts that the Companies rely on for their levelized cost estimate of market purchases are unreasonably high. The IRP’s use of such figures further distorts the LCOE analysis in favor of existing coal.

4. The IRP Understates the Risks of Coal-Fired Power.

As explained above, in their IRP the Companies adopted a series of assumptions designed to make the acquisition of an existing coal plant appear to be the least-cost option. The IRP’s assumptions made some resources (wind, solar) appear less feasible than they are, made market purchases look more expensive than they really are, and excluded some types of resources (demand-side resources, existing CT and CC plants) entirely. But, in addition to skewing the analysis away from alternatives to an existing coal plant, the IRP also underestimates the financial risks of coal plants.

First, the IRP’s $57/MWh levelized cost figure for an existing coal-fired power plant appears to be based on unrealistically optimistic assumptions. For one thing, the assumed heat rate used for that figure is unreasonably low. Most existing coal units have a heat rate that is greater than 10,000 Btu/kWh, and [1]. See Conf. Resp. to CAG-1-19(b). Similarly, the Pleasants plant, which will apparently be the subject of a future proposal from the Companies, has consistently had a heat rate greater than 10,000 Btu/kWh.60 The IRP, [1]. Resp. to Staff, Conf. Ex. 1.8a, “Existing Coal COE” tab. By using a lower heat rate than a real-life coal unit might realistically achieve, the IRP further skews the analysis in favor of existing coal.60 Moreover, although the Companies produced a spreadsheet calculating the $57/MWh cost, [1]. See Resp. to CAG-1-47(b).

Second, even apart from the flaws of the LCOE analysis, the IRP otherwise downplays the financial risks of acquiring a coal plant. For example, although many coal plants will face significant environmental compliance costs due to the Effluent Limitation Guidelines (“ELGs”), the IRP devotes only a single paragraph to this issue, with no mention of the ELGs in the Companies’ “Evaluation of Resource Options.” See IRP at 23, 52-58. The IRP’s inattention to these regulations is mirrored by Mon Power’s lack of analysis concerning its currently owned plants. Although Fort Martin and Harrison will both likely require capital investments to convert their wet bottom ash handling systems to dry handling, Mon Power has not yet studied the issue.

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60 The variable O&M costs assumed for the LCOE also appears to be understated. The Companies’ analysis assumes that variable O&M costs [[1]]. Resp. to Staff, Conf. Ex. 1.8a, “Existing Coal COE” tab; EIA, Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants at 6 (Apr. 2013), http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf.
See Resp. to CAG-I-18 (noting that “the timeline and projected cost of any conversion at Harrison and Fort Martin is not known at this time,” and that “the Company is still in the early stages of evaluating its options and no studies are yet available”). The potential costs of the ELGs and other environmental regulations could produce compliance costs that the Companies’ LCOE analysis does not address.

Third, the Companies also underestimate the financial risk of owning far more generation than is generally needed to satisfy customer needs. As the IRP notes, Mon Power is already long on energy, generating more power than its customers use. IRP at 22. Because those plants are not strictly used to meet customer load, and are competing in the PJM wholesale markets, the plants’ costs and revenues affect the Companies’ finances and customer rates. This dynamic — where ratepayers must absorb the financial risks of Mon Power’s generating units — is projected to continue through at least 2030, even if the Companies do not acquire additional generating capacity. Id.; see also Resp. to CAG-I-24(b). Given that customer rates are already affected by Mon Power’s long energy position, acquiring another coal plant would expose customers to even greater market risks. Consequently, if market prices end up being lower than FirstEnergy anticipates, such that the plant earns less revenue than projected, the Companies’ customers could face future rate hikes.

The IRP argues the opposite, asserting that “energy prices may be more volatile” in the long term, such that adding generation capacity will benefit customers by “mitigating market price risk.” IRP at 22. But the Companies’ price volatility claims are not backed by any studies or documents. Resp. to CAG-I-26(b).

Moreover, this is not the first time that the Companies have sought to justify a coal plant acquisition based on claims of market price volatility. In the Harrison transfer proceeding, Case No. 12-1571-E-PC, FirstEnergy witness Michael Delmar asserted that acquisition of the Harrison plant “will minimize Mon Power’s market reliance on outside sources to make up for an ever-growing shortfall in capacity and energy - an approach that is expected to provide a hedge for customers from exposure to changes in market capacity and energy prices in future years and stabilize customer rates.” Direct Testimony of Michael B. Delmar, at 2 (Nov. 16, 2012). Mr. Delmar further claimed that having excess energy to sell into the market would benefit customers. See Delmar Rebuttal Testimony at 23-24 (May 17, 2013) (emphasizing “the substantial upside associated with owning baseload generation,” including the fact that “the availability of excess energy and capacity offers the potential for market sales in excess of the Companies’ load, serving as a direct offset to purchase power costs in the Companies ENEC proceedings. . . . To the extent the Companies are able to sell excess energy and capacity into PJM markets, any net revenues in excess of the marginal cost of production directly benefit

61 To the extent the plants are not used to meet customer needs, those plants effectively force customers to at least partially become merchant generators, because they are paying for the generation of energy that they do not need with the hope that this generation will earn enough revenue in the market to be profitable. But just because a plant is being dispatched (i.e., the variable cost of producing that energy is lower than the market price) does not mean that customers are benefiting from the plant’s operation. The variable costs are only a small slice of the picture: customers must also pay for the plant’s fixed O&M and capital costs for the extra capacity needed to generate such excess energy. In other words, a plant could be regularly dispatching into the PJM market, and yet still result in a net cost to customers.
customers."). These claims, which were made in 2013, did not pan out as FirstEnergy contended they would. Instead, the Harrison transaction increased Mon Power’s – and ratepayers’ – exposure to market price volatility. And as the most recent ENEC case has shown, not only was the Harrison transaction’s Temporary Transaction Surcharge more expensive than forecast, but ENEC rates also ended up being higher than projected due to lower-than-expected market prices, which resulted in lower revenues. See Case No. 15-1351-E-P, Direct Testimony of Billy Jack Gregg at 9-11, 14, 16, 25-26 (Nov. 2, 2015). In fact, less than two years after the Harrison acquisition was completed, the Companies were back at the Commission seeking a 12.5% rate increase, and later settled for an average increase of 7.3%. Case No. 15-1351-E-P, Commission Order at 2, 6-7 (Dec. 22, 2015) (approving stipulation).

D. The IRP appears to be a thinly disguised attempt to justify acquisition of the Pleasant plant.

As the Citizen Groups noted at the outset of these comments, and as the foregoing discussion demonstrates, the Companies’ IRP filing falls far short of the standards established by the Legislature and the Commission. This document does not reflect “a planning and selection process for new energy resources that evaluates the full range of alternatives . . . in order to provide adequate and reliable service to [the electric utility’s] customers at the lowest system cost.” G.O. 184.35 at 1 (quoting 16 U.S.C. §2602(19)). Simply put, the document filed by the Companies is not an integrated resource plan.

At bottom, this document appears to represent a surreptitious attempt by FirstEnergy to lay the groundwork for a future proposal: purchasing the Pleasants coal-fired power plant owned by AE Supply, the Companies’ deregulated affiliate. By presenting an overinflated load forecast, failing to consider many resource options, and using unreasonable cost assumptions for others, this IRP skews the analysis in favor of the purchase of an existing coal plant. And there is little doubt which plant is on the Companies’ radar: Because the Pleasants plant is currently deregulated, and therefore depends on market revenues for its profits, the acquisition of this plant would ensure a steady rate of return funded by captive ratepayers, and prove to be financially lucrative to FirstEnergy Corp., the parent company of AE Supply and the Companies.

Although the IRP itself does not identify which “existing facility[ies] within the region” is being considered for purchase, IRP at 55, the Companies tipped their hand twice in discovery responses. The first instance came in a response to a request seeking the files used to create the chart on page 6 of the IRP. CAG-I-5. In response to that request, the Companies produced a file that includes, inter alia, the spreadsheet listing Mon Power’s unforced capacity (“UCAP”) values. The spreadsheet includes each of the generating facilities that currently serve the Companies’ capacity needs. CAG-I-5 Att. A, “Generation” tab. But the spreadsheet also includes the Pleasants plant, showing the projected UCAP values for this plant starting in the 2018/19 delivery year. Id. The second instance where the Companies identified the Pleasants plant was in their response to CAG-I-15, which sought the files used to create Figure 6 of the IRP. That response also listed the UCAP values for Pleasant units 1-2. Resp. to CAG-I-15, Att. A. In that instance, however, those values are reflected in the spreadsheet starting in the 2017/18...
Given the Companies’ stated intention of acquiring “additional 850 MWs of capacity resources by the 2017/2018 delivery year,” IRP at 58, it certainly appears that the Companies have already identified which coal plant they wish to purchase.

FirstEnergy’s intentions became even more clear during a April 27, 2016 FirstEnergy Corp. quarterly earnings call. On the call, a participant noted the company’s effort to “transition more to a regulated utility” and then asked for the CEO’s “thoughts on maybe rate basing or getting some type of cost of severance return on Pleasants, on other power plants, particularly Pleasants . . . .” In his response, FirstEnergy’s CEO specifically cited this IRP, broadly hinting that Pleasants would be the subject of a future proposal:

We filed our integrated resource plan with West Virginia. I think later this year, they’ll start taking a look at it seriously and it’s up to the West Virginia Commission to decide would Pleasants be the appropriate solution. Obviously, we have a model in place already with Harrison and we think that is something they have to look at.” These statements further buttress the conclusion that this IRP is apparently being used to lay the groundwork for a future proposal to purchase Pleasants.

The Companies are, of course, free to propose the acquisition of a power plant. But that is not what they were instructed to do here. Rather, the Companies were directed to file an integrated resource plan that satisfies the standards of W.Va. Code § 24-2-19 and General Order 184.35. The Companies failed to do so, and instead filed a document that paves the way for a future proposal to buy Pleasants. The Commission should disapprove this cynical use of the IRP process, and direct the Companies to re-file their integrated resource plan.

IV. RECOMMENDATIONS

As explained in the discussion above, the IRP filing fails to satisfy the standards set forth by W.Va. Code § 24-2-19 and General Order 184.35. Given these deficiencies, the Companies should be directed to file a revised IRP that corrects the many errors identified above. And, to ensure compliance with the governing standards, the Companies should be directed to do the following in their revised filing:

- The IRP’s projection of capacity needs should be based on the methodology prescribed by PJM.
- The IRP should thoroughly evaluate all potential demand- and supply-side resources, including demand response, energy efficiency, renewable options (including wind and solar), and market purchases.
- To ensure that all resource options are thoroughly analyzed, the Companies should perform dispatch modeling that evaluates different portfolios, and includes sensitivities.
- The IRP should use cost assumptions for all supply-side and demand-side resource options that fairly reflect the cost of those options.


64 Id.
Finally, to better ensure that the revised IRP meets statutory and Commission standards, the Commission should notify FirstEnergy that the deficiencies in its IRP filing must be corrected before the Commission will consider any specific proposal to acquire or purchase additional resources.

April 28, 2016

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CERTIFICATE OF SERVICE

I hereby certify that on this date the foregoing Comments of WV SUN and West Virginia Citizen Action Group on the 2015 Integrated Resource Plan of Monongahela Power Company and The Potomac Edison Company were served upon each of the parties listed below via e-mail. (Counsel for Staff, Monongahela Power Company & The Potomac Edison Company, and CAD received a confidential version of the document; counsel for other parties received a redacted version.) A copy of the foregoing document was also served upon the following parties via U.S. Mail, first class, postage prepaid, with the exception of Staff, who were served a copy by hand delivery.

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