
Comments on Duke Energy Indiana's 2013 Integrated Resource Plan

Prepared for

Mullett & Associates

Citizens Action Coalition of Indiana

Earthjustice

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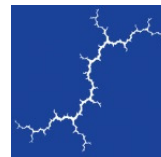
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1. INTRODUCTION

On November 1, 2013, Duke Energy Indiana (“DEI”) released its 2013 Integrated Resource Plan (“IRP”), the culmination of a new process involving periodic stakeholder feedback and review. Synapse Energy Economics, Inc. (“Synapse”), and Schlissel Technical Consulting were retained by Mullett & Associates and Citizens Action Coalition of Indiana, as well as others (“Citizens Groups”) to review IRP assumptions and provide comments and feedback to DEI throughout the stakeholder process, and review the final IRP.

The first section of our comments will address the Company’s coal capacity. DEI, as many other utilities, is facing the potential of significant transformation over the next few years. Steady or falling load, low gas prices, increasing public and regulatory urgency to reduce emissions of carbon dioxide, and existing and emerging environmental regulations all put pressure on coal-focused utilities such as DEI. In 2014, DEI estimates that it will have served over 90% of its energy from coal-fired generators, and while the utility expects that this fraction will drop moderately in the future, DEI expects it to stay well above 80% through the foreseeable future (2030). As a backdrop to this, the Energy Information Administration (“EIA”) indicates that the owners and operators of 27 GW, or 8.5%, of US coal-fired capacity are reporting expected retirements by 2016.¹ MISO estimates that 12.6 GW, or 21%, of the ISO’s coal generators will retire in the next few years.² It is widely acknowledged that this change will be transformative to utilities and their suppliers, as well as ratepayers. Effectively planning for retirements in a transparent and open fashion is critical to achieving a sustainable and cost effective resource portfolio that strikes an appropriate balance between cost-minimization and risk reduction, as the Commission’s proposed IRP rule requires.³ DEI’s resource portfolio is not immune from these changes, as can be seen in the planned retirement of Wabash River 2-5, and the conversion or retirement of Wabash River 6. However, other elements of DEI’s portfolio remain vulnerable. A bulk of the comments herein explore some of these vulnerabilities, and assess the extent to which DEI has appropriately disclosed and planned for needed changes to its portfolio.

The second section of our comments addresses DEI’s consideration of renewable energy resources. Duke Energy Indiana serves customers in some of the richest wind territory east of the Mississippi

¹ <http://www.eia.gov/todayinenergy/detail.cfm?id=7290>

² MISO Transmission Expansion Planning (MTEP) 2013, <https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP13/MTEP13%20Full%20Report.pdf>

³ 170 IAC 4-7-8(b)(7) (proposed rule). According to the official summary of the Commission’s 2012 Contemporary Issues Technical Conference, “[t]he revisions in the IRP rule are intended to stress that risk as well as cost should be considered when identifying future resources. The goal is to move from simply identifying the ‘least cost’ plan to a more robust plan that holds up to future risks and represents the best combination of cost and risk. . . . Commission staff hopes for discussion in the IRP regarding what went into decision-making process and how the utility weighed the uncertainties.” Summary of IRP Contemporary Issues Technical Conference, at 2-4 (Oct. 18, 2012), at http://www.in.gov/iurc/files/Summary_of_IRP_Contemporary_Issues_Technical_Conference_held_on_Oct_18_2012.pdf.

River,⁴ and yet the IRP envisions (in the base case) a slim 4% of load served by wind in 2025, barely growing to 6% by 2030.

The third section of our comments addresses the Company's consideration of energy efficiency resources, and the extent to which they are modeled as competitive resources within DEI's analysis structure.

The fourth section re-visits concerns raised by Synapse and Citizens Groups on DEI's modeling and analysis process in the prior CPCN docket as well as throughout this IRP. Duke Energy, as the largest electric power holding company in the nation, has the resources, capacity, and ability to perform cutting edge planning, modeling, and analysis, and offer appropriate resources to ensure that their planning is comprehensive and complete. Instead, the planning mechanism is poorly conceived and provides little actionable information.

2. COAL PLANT ECONOMICS

2.1. Price for carbon dioxide emissions

In Cause 44217 ("Phase 2 CPCN"), Synapse witnesses⁵ testified that DEI's base case prices for CO₂ emissions were too low – approximately equal to the "low case" CO₂ prices forecast by Synapse. That testimony was filed at the end of 2012, around the time that DEI began this IRP process. DEI's final IRP was submitted in November 2013, with no change to the CO₂ price used in 44217.

On June 25, 2013, the President announced a timeline for the completion of regulations of carbon emissions from new and existing fossil fuel fired electricity generators. Earlier, in May 2013, the Administration also released a new series of estimates for the "social cost of carbon" ("SCC"), a monetized estimate of the damage caused to society by global climate change.⁶ Together, these two announcements signal a strong intent by the current Administration to take significant actions aimed at reducing carbon emissions from new and existing coal-fired power plants. The EPA is actively developing a proposed regulation to control carbon from existing sources, soliciting state proposals and engaging in listening sessions. EPA is expected to publish a proposed rule in June 2014, and to finalize it in June 2015 with state implementation plans due the following year. Therefore, the idea that carbon regulations and restrictions are far off or of minor import is misplaced.

The EPA and other agencies use the social cost of carbon (and other externality estimates) to inform the cost-effectiveness of rulemakings; indeed, in recent years, EPA has successfully supported its rulemakings on the basis of their cost effectiveness relative to social benefits. In conjunction with the

⁴ See <http://www.nrel.gov/gis/wind.html>.

⁵ Direct Testimony of Dr. Frank Ackerman in Cause 44217.

⁶ See Exhibit JIF-15.

President’s highly public announcements on climate change directing EPA to regulate CO₂ under the existing source provision of the New Source Performance Standard (“NSPS”), these existing agency practices make it safe to assume that the SCC (or equivalent) will likely be used to justify the Administration’s expected stringent carbon reduction policies. As shown in Figure 1, below, the SCC has price impacts well above the “environmental focus” carbon price projected by the Company.

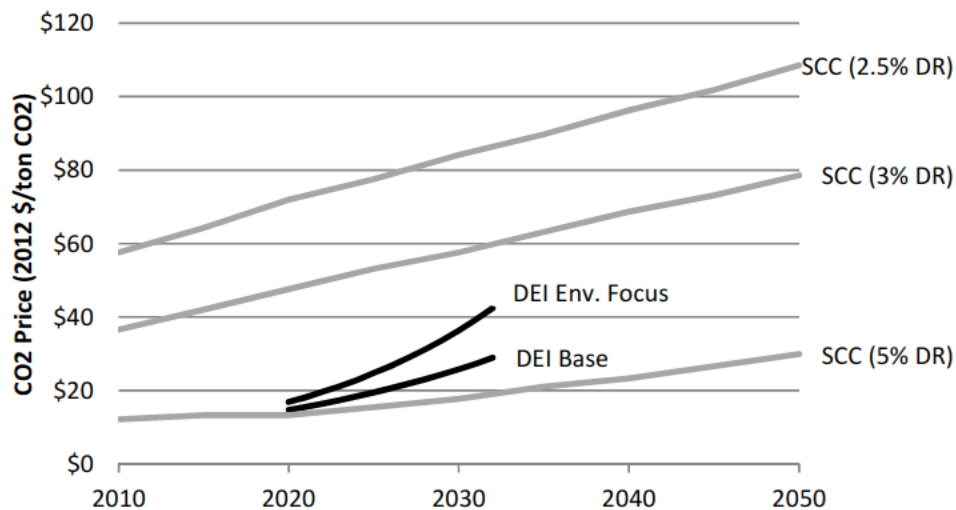


Figure 1. DEI Carbon Prices and Federal Social Cost of Carbon

We note that DEI does not now, and has not previously, provided an explanation or justification for the price of CO₂ considered in this IRP. The Company simply states that it “has considered a wide range of CO₂ cost assumptions in its group of scenarios,” and that it is “our belief that to be potentially politically acceptable, climate change policy would need to be moderate.”⁷ Synapse Energy Economics produces a publicly available CO₂ price forecast for the purposes of use in utility planning dockets,⁸ and in the Phase 2 CPCN (Cause 44217) witnesses from Synapse recommended that the Company evaluate their decisions in light of the then-current price forecast. The Company did not do so then, although it admitted that decisions regarding some of its units would be dramatically different if the Synapse mid-case were correct. Finally, DEI states that “if or when there is clarity around future U.S. legislative or regulatory climate change policy, Duke Energy Indiana will adjust its assumptions related to carbon emissions as needed to reflect that clarity.”⁹ Unfortunately, this view from Duke is only reasonable and appropriate if the ultimate CO₂ price or policy is less stringent than envisioned by the Company in their base case. With a low of zero and high case that only

⁷ DEI 2013 IRP, p10.

⁸ Luckow, P., E. Stanton, B. Biewald, J. Fisher, et al. 2013. 2013 Carbon Dioxide Price Forecast. <http://www.synapse-energy.com/Downloads/SynapseReport.2013-11.0.2013-Carbon-Forecast.13-098.pdf>.

⁹ DEI IRP, p10.

slightly exceeds the reference case, the Company has the low end of carbon risk well characterized – but has not disclosed the risks to their fleet at higher ranges.

We recommend that in order to capture the full range of risk, DEI should explore:

1. A higher carbon price in the base case comparable to that proposed by Synapse in Cause No. 44217, and
2. A much higher carbon price when reviewing more stringent environmental regulations.

2.2. Gallagher 2 & 4

In June 2012, DEI filed an application for a certificate of public convenience and necessity (“CPCN”) for its “second phase” of environmental retrofits at its coal-fired power plants to comply with the mercury and air toxics standard (“MATS”).¹⁰ In that analysis, DEI indicated that the Gallagher units would operate through the end of a 2030 analysis period if retrofitted, or would otherwise be retired expeditiously. On behalf of environmental interveners,¹¹ Synapse provided testimony highlighting analytical errors,¹² and reviewing additional risks to those units not considered by the utility, including higher CO₂ prices emerging from regulations or legislation. In response, the Company withdrew its request to retrofit the Gallagher units, choosing to defer that decision to a later date.¹³ In the current IRP, DEI estimates that Gallagher will need to be retired in 2019 to avoid “anticipated future regulations potentially requiring significant investments in 2019,”¹⁴ and indicates that “the NAAQS [National Ambient Air Quality Standards] assumptions mainly impacted future modeling of Gallagher, which was either required to install SNCR or assumed to retire due to a requirement to install SCR and/or FGD.”¹⁵

Reviewing data provided by the Company from this IRP, it is entirely unclear why Gallagher should not be retired as expeditiously as is technically and legally practicable in light of its very poor economics. In response to a data request, DEI provided unit-by-unit capacity, generation, fuel costs, variable and fixed O&M, start costs, and emissions costs.¹⁶ DEI also provided forecast hourly energy market prices, allowing us to estimate “optimal” dispatch of each unit relative to market prices,¹⁷ estimate a gross energy market margin, and after deducting fixed costs, net annual revenues.

¹⁰ IURC Cause 44217

¹¹ Environmental interveners included Citizens Action Coalition, Save the Valley, Valley Watch, and Sierra Club.

¹² Analytical errors in 44217 included counting the costs of continuing to operate the Gallagher units in the modeled scenario in which Gallagher was supposed to be retired. See Direct Testimony of Rachel Wilson in 44217, page 20.

¹³ See IURC Decision in 44217, page 14, “Duke’s Rebuttal Evidence.”

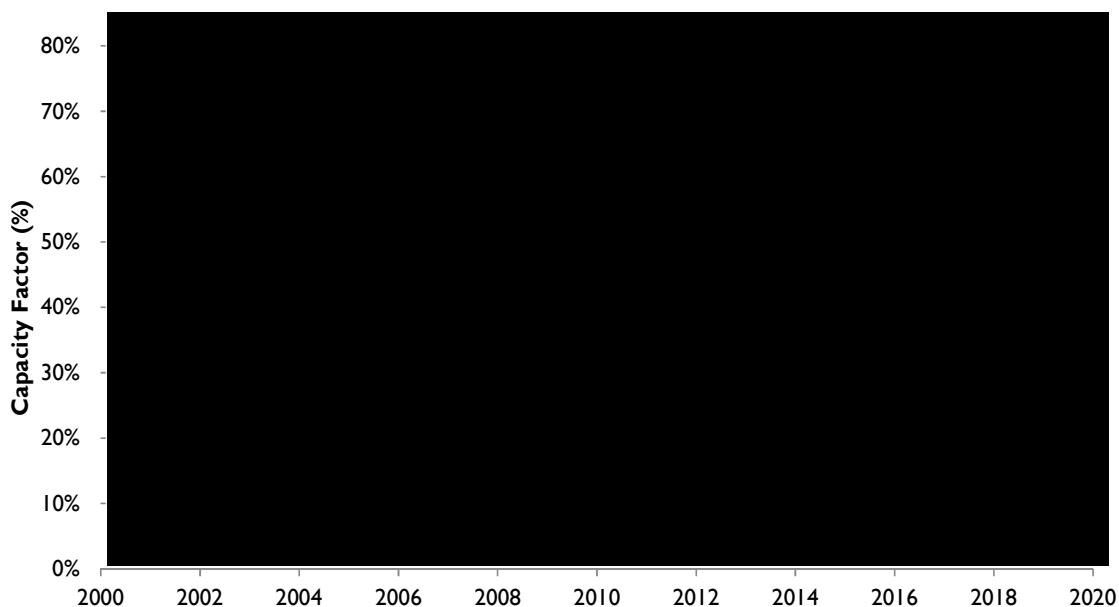
¹⁴ See IRP, p111.

¹⁵ See IRP, p94.

¹⁶ Confidential Attachment to JI DR 2.8-B.

¹⁷ This analysis performed simply, assuming that each unit would operate in full during hours where the market energy price exceeded the variable cost of production, and not at all otherwise.

Gallagher 2 & 4 perform dismally under the assumptions provided by the Company, and do not reflect the Company’s analysis results, as shown in Confidential Figure 2 below. Allowing Gallagher 4 to operate during any hour that it could net a positive energy margin (“optimal dispatch”), the unit’s capacity factor declines quickly from 2013 (a 30% capacity factor) towards its anticipated retirement date in 2019. In contrast, the Company had predicted that the unit would have performed nearly 30% better in 2013 than it actually did,¹⁸ and will maintain above a █% capacity factor through 2018. According to the Company’s supplied energy market prices, any hours in which the unit operates beyond those indicated by the “optimal” line cut further into the unit’s poor margins. Gallagher 2 shows a similar story.

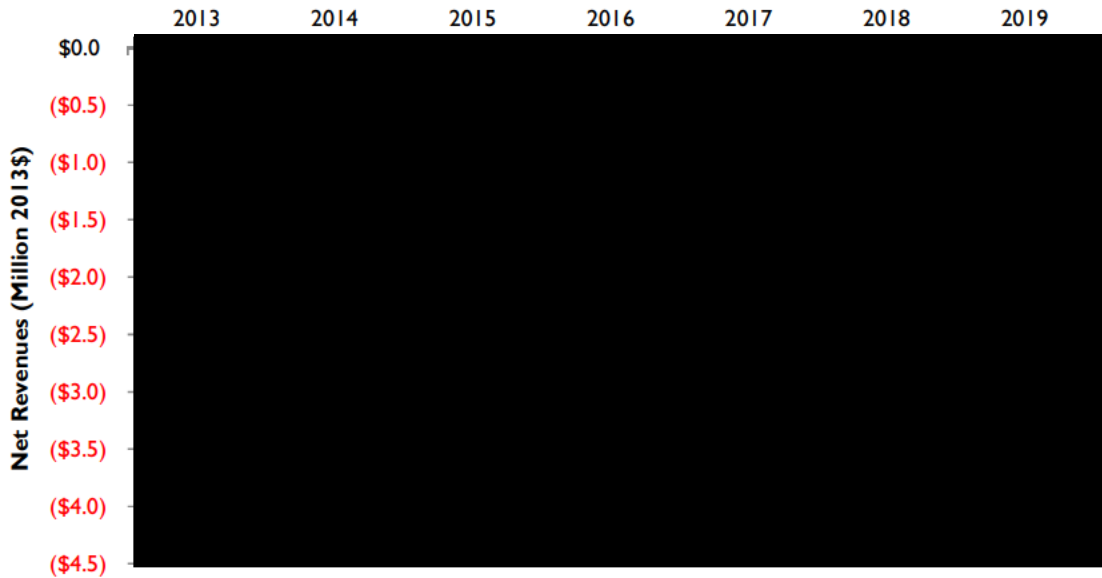


Confidential Figure 2. Gallagher 4 capacity factor, historical and projected. Projection from DEI model and “optimal” from Company hourly market prices.

Reviewing the margins that Gallagher 2 & 4 could make on the energy market, even if optimally dispatched, against the fixed O&M costs provided by the Company indicates that both Gallagher units are losing money today, and therefore do not appear to be “useful” assets for Duke’s ratepayers. The figure below shows the annual net revenues of Gallagher 2 & 4 from the present day through 2019. Together, these units are at least a █ liability between now and 2019 (net present value).¹⁹

¹⁸ Historical data derived from EPA Air Programs Market Data (“AMPD”).

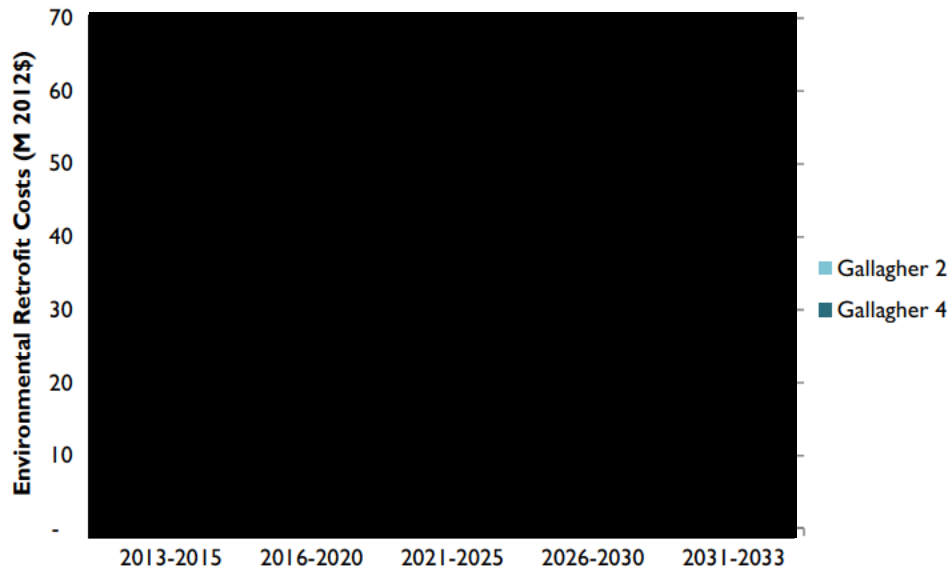
¹⁹ Exclusive of market capacity value.



Confidential Figure 3. Annual net revenues for Gallagher 2 & 4, according to Company data.

In addition, the net revenues above do not appear to take into account the incremental costs of additional environmental retrofits that may be required at Gallagher 2 & 4 simply to keep it operational through 2019. The Company indicates that these units are facing an estimated [REDACTED] (2012\$) of environmental costs between now and 2019 to meet Clean Air Act, Clean Water Act, and solid waste requirements.²⁰ But, it is not clear that DEI has considered the implications of these costs becoming avoidable through the retirement of the unit before 2019 (see Confidential Figure 4).

²⁰ Confidential Attachment to JI DR 2.6-A.



Confidential Figure 4. Environmental retrofit costs at Gallagher 2 & 4 (capital), CAC DR 2.6-A

According to information provided by the Company, Gallagher has a negative market value. Viewed from the perspective of an independent power producer (merchant generator), the resource is a liability. If offered for sale on the open market, Gallagher would be unlikely to produce offers for its purchase.

The Company indicates in the IRP that “the final decision to retire Gallagher 2 and 4 in 2019 will not be made until later. These units will continue to be evaluated in the future as regulatory rules become clearer.” The Company’s data would suggest that deferring such a decision would be imprudent. If the units are to remain in operation, the Company needs to justify their operations and show that they are decisively economic – or plan for the expeditious retirement of these units. Otherwise, the Company may well be converting significant retrofit costs from avoidable into sunk costs without the necessary economic justification for doing so. See Figure 4 above.

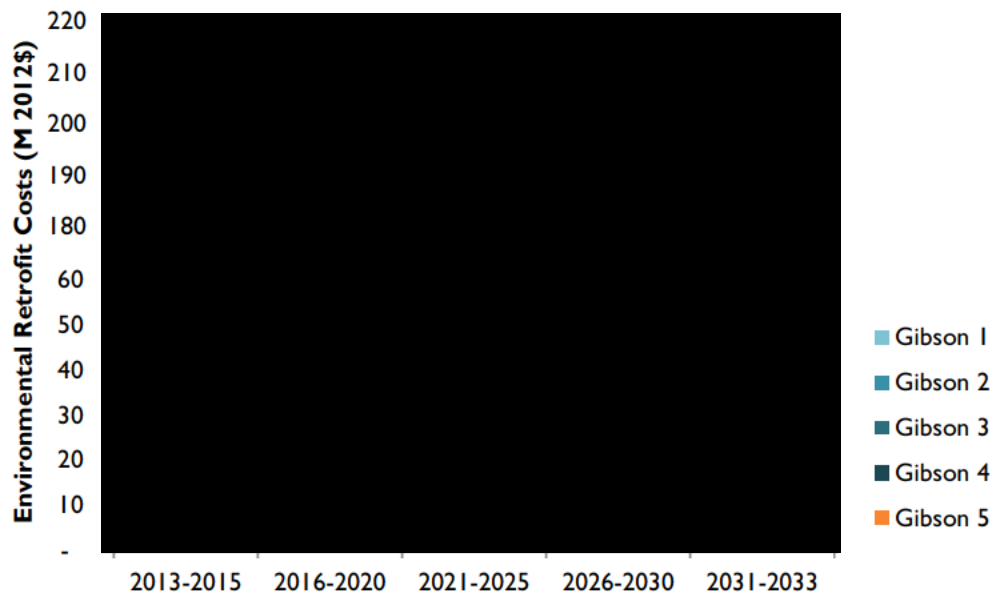
2.3. Gibson 5

The 2013 IRP flags Gibson 5 as a potential economic liability, showing that under the Environmental Focus scenario, Gibson 5 retires in 2024 prior to the requirement for a new flue gas desulfurization (“FGD”) system.²¹ Text within the IRP also indicates that Gibson 5 might be expected to retire prior to 2025: “At this time, it is cost prohibitive to install a new FGD under the Reference and Environmental Focus Scenarios. However, under a Low Regulation scenario, a new FGD on Gibson 5

²¹ See Table 8-A. and p113.

is economical.”²² Since the Company assumes that a new FGD would not be required before 2024, the retirement would be driven by such a decision.

A re-analysis similar to the Gallagher analysis shown above indicates that Gibson 5 does not suffer the same immediate concerns as Gallagher, but does raise areas requiring increased scrutiny. Relative to market energy, Gibson 5 appears to have a value of approximately [REDACTED] (again assuming optimal dispatch, which in this case is actually an improvement on the Company’s modeled dispatch). Reviewing the Company’s proxy costs for future environmental regulations in the base case (see Confidential Figure 5),²³ we see that the net present value of capital costs for environmental equipment exceeds [REDACTED], suggesting that over the long term, it does not make sense to retrofit this unit even using the Company’s base assumptions.



Confidential Figure 5. Environmental retrofit costs at Gibson units (capital and catalyst replacement), CAC DR 2.6-A

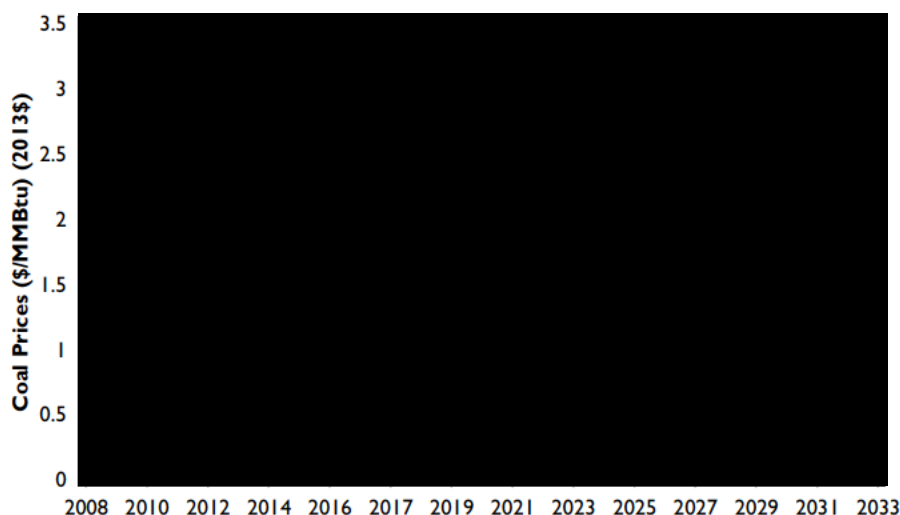
However, the Company makes an intriguing assumption regarding the cost of fuel at Gibson 5, which calls into question the value of the asset. The Company’s analysis suggests that the real cost of coal at Gibson 5 will [REDACTED] in real terms. This trend is in stark contrast to recent history, and expected trends for Illinois basin coal. From 2008 (the beginning of public record coal prices) through 2013, the delivered cost of coal at Gibson has risen by nearly 30% in real terms.²⁴ UBS, evaluating future coal demand, suggests that as more coal units install rigorous sulfur controls, the demand for historically inexpensive Illinois Basin Coal will increase, thus creating upward pressure on prices. Similarly, EIA projects that coal prices in the region will steadily increase from 2014, [REDACTED]

²² See p113.

²³ Confidential Attachment to JI DR 2.6-A.

²⁴ EIA Form 923 (2008-2013). Fuel Sources.

Gibson Coal Prices



Confidential Figure 6. Historic and projected fuel prices at Gibson 5.

Adjusting Gibson 5's coal prices such that they do not [REDACTED] [REDACTED] As a result of this adjustment, [REDACTED] [REDACTED] and the net revenues available to Gibson 5 decrease substantially. In aggregate, the net value of Gibson 5 falls [REDACTED] [REDACTED] Notably, with this fuel adjustment, the unit barely recovers the capital costs of environmental retrofits through 2020 (see Confidential Figure 5), much less the later FGD equipment anticipated by the Company after 2021. [REDACTED]

While not as clearly uneconomic as Gallagher 2 and 4, Gibson 5 should also be subject to more intensive scrutiny concerning its future costs and risks. In the most recent CPCN (Cause 44418), the Company begins this process in the testimony of Mr. Scott Park, reviewing the merits of retiring Gibson 5 in the near future, versus retrofitting the unit with mercury controls. While we have not yet reviewed this analysis in the CPCN, this more careful unit-by-unit analysis was lacking in the IRP.

Moreover, given that the Company acknowledges in this IRP that a requirement to install a new FGD at Gibson 5 would force its retirement under most scenarios, the Company should be required to more explicitly evaluate the risk that implementation of Clean Air Act rules, such as a reinstated Cross-State

²⁵ It should be noted that traditionally about 30% of Gibson's coal has been obtained from sources less than \$2.5/MMBtu (primarily from Black Beauty mine in Vincennes, Indiana). Unless DEI has special arrangements with this mine to increase output to meet 100% of Gibson's requirements, or unless other providers are able to compete at that same price point, there is currently no evidence that these prices are likely to drop.

Air Pollution Rule²⁶ or the 1-hour Sulfur Dioxide National Ambient Air Quality Standard,²⁷ may compel the Company to retire the unit.

2.4. Cayuga

The economic merits of retrofitting Cayuga with SCR were debated in the Phase 2 CPCN (Cause 44217). We have not re-performed the analysis of that unit here, but there are at least two notable points from that docket that are relevant to this IRP:

- **CO₂ price tipping point:** In response to a Docket Entry dated December 28th, 2012, DEI states that the CO₂ price considered in that CPCN (and in this IRP) would only need to be \$4/tCO₂ higher to make the decision to retrofit Cayuga a break-even decision with retirement. It is surprising, therefore, that the Environmental Focus scenario, which uses a higher CO₂ price, does not result in the retirement of Cayuga in the near term.
- **SCRs still under construction:** The analysis appears to consider the Cayuga SCRs a fully sunk cost, which is technically incorrect. If the Cayuga SCRs are still under construction, and the Company is not yet contractually committed to pay for the SCRs in full, then there may still be avoidable costs associated with retiring the units rather than continuing construction. As of July 22, 2013, in the midst of the IRP analysis, “Duke Energy ha[d] allocated \$125 million for...vendors and contractors” out of the total \$400 million project.²⁸ It would have been appropriate during the IRP development to examine the avoidable forward-looking costs of continuing the SCR construction (i.e. \$275 million). Under all circumstances, these avoidable costs should be examined in forward-looking analyses such as this IRP.

Even without the consideration of the SCRs, DEI indicates at least [REDACTED] in future environmental capital costs (see 7) that should be considered fully avoidable in the creation of optimal scenarios.

²⁶ Possible reinstatement of EPA’s Cross-State Air Pollution Rule (“CSAPR”) is now being considered by the U.S. Supreme Court. See SCOTUSblog, *Environmental Protection Agency v. EME Homer City Generation*, Docket No. 12-1182, at <http://www.scotusblog.com/case-files/cases/environmental-protection-agency-v-eme-homer-city-generation/>.

²⁷ In 2010, EPA promulgated stringent NAAQS requiring ambient SO₂ concentrations of less than 75 ppb over one-hour averaging periods; EPA found this limit necessary to protect public health because exposure to even small amounts of SO₂ over short periods of time can cause adverse health effects. See Primary National Ambient Air Quality Standard for Sulfur Dioxide, 75 Fed. Reg. 35,520 (June 22, 2010) (to be codified at 40 C.F.R. pt. 50); 326 IAC 1-3-4(b)(1).

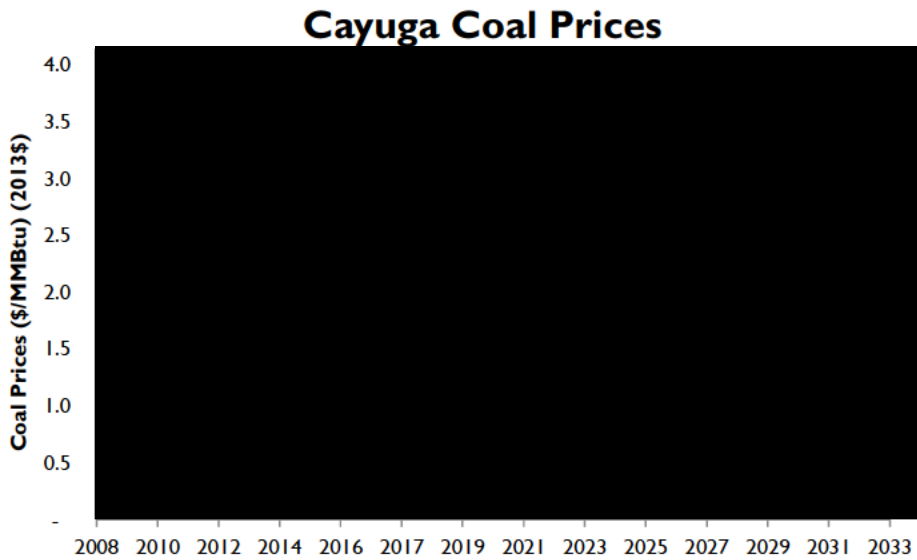
²⁸ <http://www.duke-energy.com/news/releases/2013072201.asp>.



Confidential Figure 7. Environmental retrofit costs at Cayuga units (capital and catalyst replacement), CAC DR 2.6-A

Similarly to Gibson, DEI’s projected coal prices at Cayuga appear optimistic relative to recent market trends at the plant, and other analysts’ forward looking estimates. See Confidential Figure 8 below. Delivered coal prices at Cayuga increased by 83% from 2008 to 2012 (in real terms), and while 2013 saw a downtick in prices by 3%, [REDACTED]

[REDACTED]



Confidential Figure 8. Historic and projected fuel prices at Gibson 5.

Similarly to the Gibson 5 analysis, an adjustment of Cayuga’s coal prices to maintain at mid-2013 prices (with few exceptions, the lowest in about 2 years) changes the outlook of the plant fairly dramatically. The market value of Cayuga 1 drops from \$200 million to \$95 million, and the value of Cayuga 2 drops from \$185 million to \$83 million. These values are significant because they are lower than the net present value of the environmental retrofits still believed to be required at Cayuga 1 & 2, even considering the SCRs to be a fully sunk cost. As shown in Confidential Figure 7 earlier, Cayuga has significant environmental expenses still remaining, amounting to \$106 and \$92 million NPV (2013\$) at Cayuga 1 & 2, respectively.

Similarly to Gibson, while the economics do not necessarily signal a need to immediately retire these units (unlike Gallagher), the information provided here suggests that these units are much closer to borderline than indicated by the Company. The Company did flesh out some of these issues in the Phase 2 CPCN, but this IRP (or even the 2011 IRP) would have been a reasonable venue to re-visit assumptions, examine a wider range of compliance alternatives, and review risks to the Company’s coal fleet – and examine these issues in light of still avoidable costs at Cayuga.

3. EDWARDSPORT²⁹

DEI’s assumptions regarding Edwardsport’s future operations are inconsistent with what we know today about other IGCC units, as well as Edwardsport’s first six months of operations. Duke has publicly stated that the IRP assumes the IGCC is expected to achieve a 75% capacity factor in its first year, and then maintain an 85% capacity factor through the analysis period. DEI has also stated that the unit is dispatched first as the most meritorious unit in the DEI system. These assumptions are unrealistic given

1. the actual operating performance of the Polk Station and Wabash River IGCC units and
2. the actual operating performance of the Edwardsport Plant since the Company declared the beginning of commercial operations in June 2013.

As show in Figure 9, below, the Polk Station’s annual availability as an IGCC plant ranged between 34 percent and 83 percent during its first ten years of operations – for an average 66.7% availability during the ten-year period. The unit’s availability as an IGCC unit averaged only 50.5% during its first two years of operations (1997 and 1998). Polk’s Stations overall availability with backup fuel was still just 75.9 percent during its first ten years of operations, or nearly ten percentage points below what Duke claims for Edwardsport.

²⁹ Comments prepared by David Schlissel.

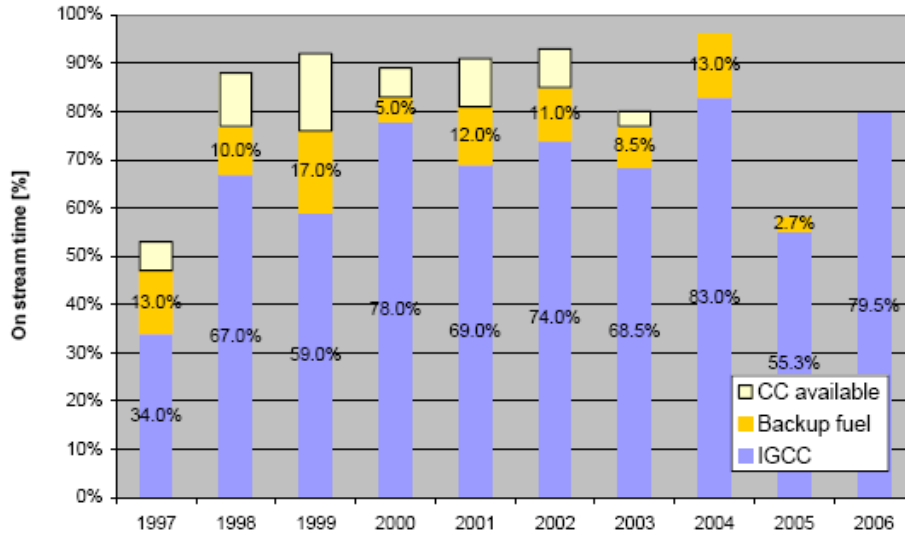


Figure 9. Annual availability of Polk Station IGCC.³⁰

As shown in Figure 10, below, the annual availability of Wabash River as an IGCC unit ranged between 18.6% and 78.7% during its first ten years of operations – for an average of only 49.5 percent. And Wabash River’s average annual availability was only 27% during its first two years of operations (1996 and 1997).

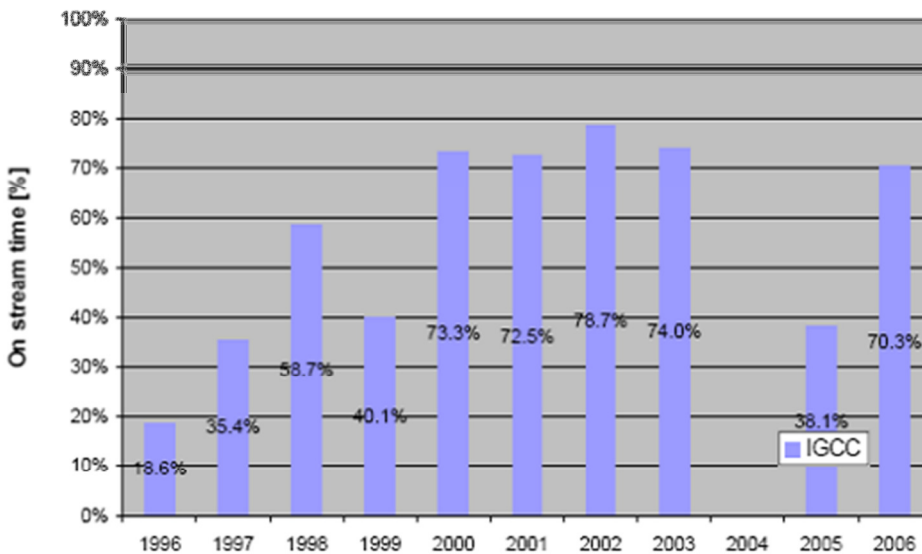


Figure 10. Annual availability of Wabash River as an IGCC.³¹

³⁰ EPRI, 2007. Integrated Gasification Combined Cycle (IGCC) Design Considerations for High Availability. Volume 1: Lessons from Existing Operations, Technical Update, March 2007. p3-12.

³¹ EPRI, 2007. Integrated Gasification Combined Cycle (IGCC) Design Considerations for High Availability. Volume 1: Lessons from Existing Operations, Technical Update, March 2007. p3-8

Edwardsport’s generation since the Company declared the start of commercial operations in June 2013 also shows that the plant has not achieved anywhere near a 75% or 85% availability as an IGCC unit using gasified coal. In fact, as shown in Figure 11, below, the plant’s average gross capacity factor using gasified coal was only 39% after the start of commercial operations was declared in June 2013.

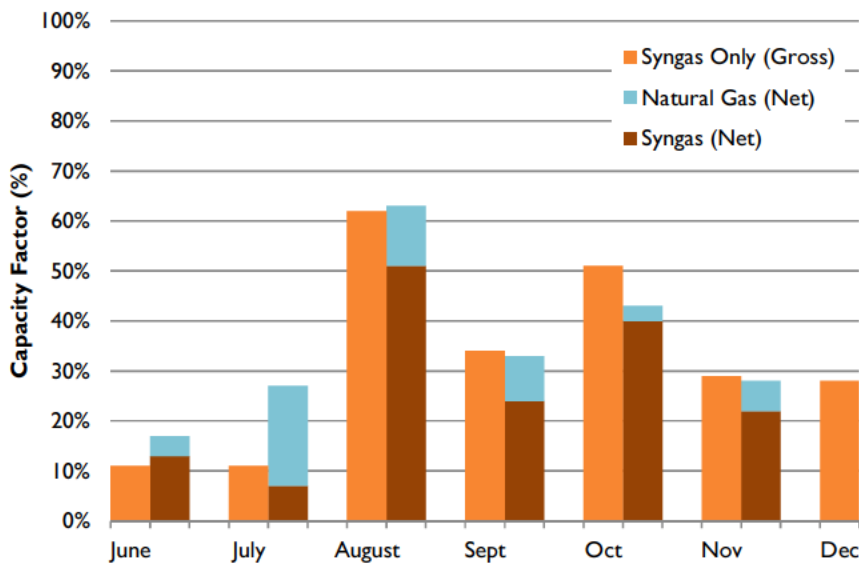


Figure 11. 2013 Gross monthly capacity factors on Syngas (left), net capacity factors on syngas and natural gas backup.

Edwardsport operating performance also has been significantly below what the Company had claimed when measured in net generation. This net generation reflects the very large (>100 MW) parasitic loads that the plant uses to operate on-site equipment. Net capacity factors on Syngas and natural gas (a backup fuel) are shown in Figure 11, above. These monthly net capacity factors certainly do not inspire any confidence that Edwardsport will achieve either a 75% capacity factor or availability during its first twelve months of operations or an 85% capacity factor or availability long-term.

Due to the uncertainty in Edwardsport’s future operating performance because of its first-of-a-kind design, its actual operating performance in 2013 and the actual operating performance of the Polk Station and Wabash River IGCC units, the Company should be required to examine the following model scenarios as part of its IRP analyses:

1. In the first scenario, assume that the Edwardsport IGCC plant achieves a 50% availability rate for the period 2013 through December 31, 2017 (roughly its first four and one-half years of operation) with an 85% availability rate in every year beginning in 2018.
2. In a second scenario, assume that the Edwardsport IGCC plant achieves a 50% availability rate for the period June 7, 2013 through December 31, 2017 (its first four and one-half years of operation) with a 75% availability rate in every year beginning in 2018.
3. Duke’s filing in Cause 43114 IGCC-11 showed that the O&M portion of Edwardsport’s annual revenue requirements had increased by \$27.487 million, or 65 percent, beyond

the estimated O&M at the time of the April 30, 2012 Settlement Agreement. However, the Company's IRP appears to use total O&M that is only some 15% or so higher than the IGCC-4S1 figure. Consequently, the Company should increase the annualized 2013 O&M used in the IRP to the IGCC-11 level and then escalate it by 2.5 percent per year to reflect overall inflation.

4. In addition, due to uncertainty, the Company also should look at scenarios where Edwardsport's annual O&M are 10% and 20% higher than the escalated IGCC-11 figure.

It should also be noted that the Polk and Wabash River plants improved their capacity factors and equivalent availability in recent years after changing their gasification feedstock from 100% coal – to 100% petcoke for Wabash River and 55% petcoke – 45% coal for Polk. The Company should thus also assess the implications of such changes for Edwardsport in its current IRP.

4. RENEWABLE ENERGY

The DEI 2013 IRP explains that minimum renewable energy builds are programmed into the three scenarios, rising to a small fraction of generation by the end of the analysis period.³² It is important to note that while the IRP indicates a minimum build, it does not suggest that the build out of wind (or solar) resources are optimized – i.e. the model does not examine if renewable resources can compete economically with either existing resource or against other new resource options, such as non-economic coal units, new gas options, the Wabash River 6 gas retrofit, or the nuclear unit envisioned at the tail end of the base case blended portfolio. As such, the IRP simply includes renewable resources as a “hard-wired” part of a lower risk portfolio, but does not actually examine them as competitive supply side options. This approach is directly contrary to the direction of the Commission's provisional IRP rule.

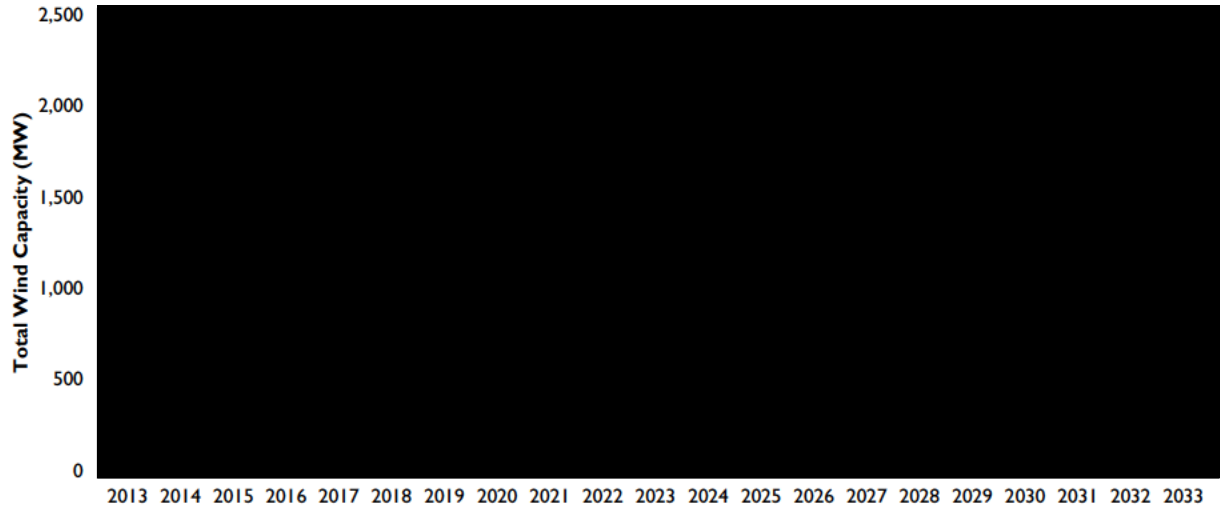
Wind

Confidential Figure 12 shows the build out of wind in each of the portfolios examined.³³ In each case, new wind only comes online in 2019, suggesting a model restriction, rather than a requirement.³⁴ The wind build out of the blended portfolio and the traditional portfolio closely mirror each other through 2025, at which point the blended portfolio rises to exactly [REDACTED] wind capacity and stays at that point through [REDACTED]. Curiously, wind build out in the blended portfolio rises rapidly after [REDACTED], exceeding even the “coal retires” scenario at the end of the analysis period.

³² “Each scenario begins with minimum renewables of 1% in 2018, rising to minimums of 4%, 5%, and 15% by 2032, in the Low Regulation, Reference, and Environmental Focus Scenarios, respectively.” DEI 2013 IRP, p9, p20.

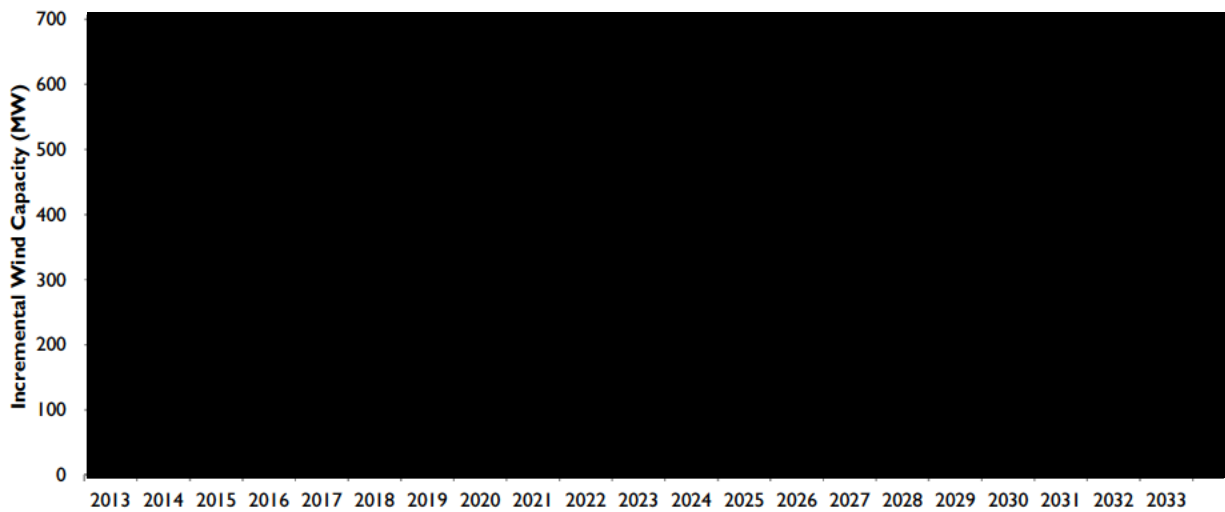
³³ From Confidential CAC DR 2.8-b, assumes 32.5% capacity factor.

³⁴ The new wind appears a year before the programmed carbon price, indicating that it is likely not a function of the carbon price. In addition, the traditional portfolio is crafted from a scenario without a carbon price, yet the wind still is built in the same year.



Confidential Figure 12. Total wind capacity (MW) in each DEI portfolio.

Wind resources appear to be built [REDACTED] with a capacity factor of approximately [REDACTED]³⁵. The annual incremental build is [REDACTED], or one block per year (generally) in the “blended” and “traditional” portfolios, and [REDACTED] in the “coal retires” scenario. These regular build patterns do not appear to represent an optimal build case (i.e. they do not replace retiring capacity or change as a function of market pressures such as carbon prices) – at least until [REDACTED]. The massive build of new wind in the blended portfolio [REDACTED] is even less explicable.



Confidential Figure 13. Incremental wind capacity (MW) in each DEI portfolio.

DEI’s model assumptions are inconsistent with real costs, and were not aligned with real costs at the time the IRP was prepared. DEI assumes very high costs for wind, above federal and industry cost assumptions. Every year, the EIA’s Annual Energy Outlook reviews potential costs for resources; in

³⁵ Derived from confidential data presented in CAC DR 2.8-b.

recent years, the Department of Energy and Lawrence Berkley Labs have also released the “Wind Technologies Market Report,”³⁶ which surveys recently built projects and power purchase agreements (“PPAs”). Against these sources, DEI’s estimates are high, as shown in the following table.

	DEI	EIA AEO 2013	DOE/LBL
Capital Cost, installed (\$/kw)	██████████	2,175 ³⁷	1,940 ³⁸
O&M (\$/kw-yr)	██████████	\$39	\$25

Overall, DEI’s assumptions result in wind that costs approximately \$████/MWh³⁹, which is difficult to justify economically. In contrast, recent wind farms have been built at costs that would have equated to \$70/MWh in DEI’s territory, before the production tax credit (“PTC”).⁴⁰

Wind built in prime locations in neighboring states has been offered into neighboring states for less than \$40/MWh (before the expiration of the PTC, worth about \$25/MWh).⁴¹ The DOE/LBL market report indicates an average wind PPA cost of \$50/MWh in the Great Lakes region, and about \$30/MWh in the Interior.⁴² Experience in other cases has shown that wind producers are able to ship and deliver that lower cost energy into service territories adjacent to DEI at less than half the cost assumed by DEI.

If DEI had modeled the PTC, reviewed recent PPA offers in its region, and reviewed the costs of competitive wind, it would have likely seen cost-effective wind offered into its territory at below-market prices. With the expiration of the PTC, low cost wind may still be available from independent producers willing to sell excess capacity. New wind farms are likely to be able to offer wind energy at a lower cost than DEI’s non-economic coal units (such as Gallagher) and the repowered Wabash River 6.

Rather than simply fix high-cost wind assumptions and force minimal wind into their model, DEI should have reviewed recent wind offers, both PPA and self-build options, and examined opportunities to build out renewable energy. In short, DEI should have comprehensively evaluated the wind resource in a comparable manner to other supply side resources as contemplated by the Commission’s provisional IRP rule.

³⁶ DOE/LBL. 2012 Wind Technologies Market Report, August 2013. <http://www.nrel.gov/docs/fy13osti/58784.pdf>

³⁷ EIA, 2013. Assumptions to Annual Energy Outlook. Table 8.2
<http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf>

³⁸ DOE/LBL. 2012 Wind Technologies Market Report, August 2013. Page 34.

“In 2012, the capacity-weighted average installed project cost stood at roughly \$1,940/kW, down almost \$200/kW from the reported average cost in 2011 and down almost \$300/kW from the apparent peak in average reported costs in 2009 and 2010. Anecdotal indications from a handful of projects currently under construction and anticipating completion in 2013 suggest that average installed costs may decline further in 2013.”

³⁹ Assumes Class 3 wind from NW Indiana, capital costs amortized with an █████ CRF from Cause 44217, DEI’s Phase 2 CPCN.

⁴⁰ The PTC was not modeled by DEI.

⁴¹ http://www.ucsusa.org/clean_energy/smart-energy-solutions/increase-renewables/production-tax-credit-for.html.

⁴² <http://www.nrel.gov/docs/fy13osti/58784.pdf>.

5. ENERGY EFFICIENCY

The Company’s load forecast assumptions are critical since they determine how much capacity is needed to serve demand on the system at peak times. Simply put, higher peak load means a more costly portfolio since more build-out is needed. Demand-side management (“DSM”) measures reduce peak load through Demand Response (“DR”) which is only called upon during peak hours and Energy Efficiency (“EE”) which is spread among all hours. Thus, DR directly reduces peak load but has little effect on energy sales while EE reduces sales and only reduces peak load if it happens to take effect during those hours. The Company’s load forecasts provided in the IRP are stated in terms of net and gross peak load, or with and without DSM, respectively.

The Company assumes compliance with the IURC Order from Cause No. 42693-S1, which requires a 2% reduction in energy sales (relative to the previous year) by 2019. DEI assumes that the annual energy savings ramp up to 2019 and then essentially stops after 2020 (see Figure 14). Unfortunately, while the Company is planning on meeting their obligation to the Commission, they are doing virtually nothing after that. As the figure below shows, their incremental savings from energy efficiency increases by 0.1% per year after 2020 (or about one sixteenth the rate it achieved in 2019).

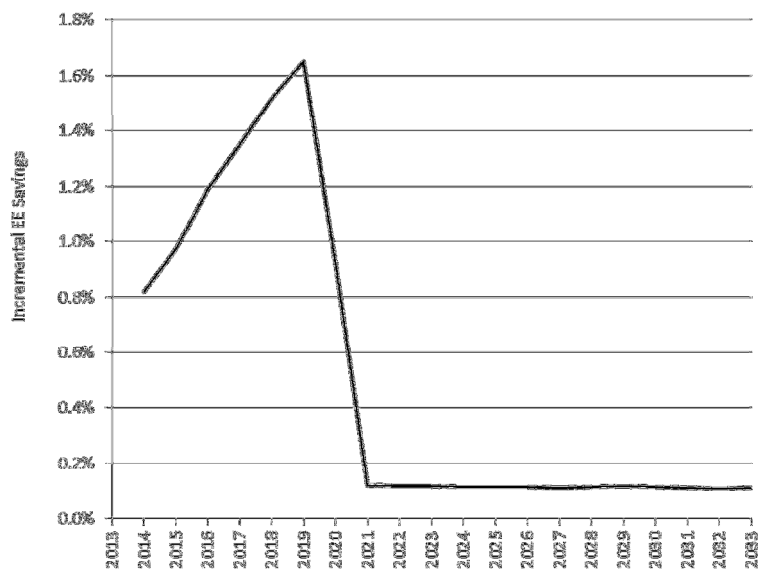


Figure 14. Incremental energy efficiency savings, by year.

Figure 15 shows the impact of these reductions on peak load. By 2019, there is a sizeable difference in the Company’s peak load forecasts with and without energy efficiency (grey and black solid lines); this is due to the cumulative effect of the accelerated installation of efficiency measures in previous years. However, the difference between the two forecasts remains virtually unchanged after 2020 because there are very little new measures being installed. Alternatively, if the Company chose to use a conservative assumption of 1% incremental savings after 2019 (dashed line), they would see significant

decreases in peak load persist through the modeling period.⁴³ By 2033, this would lead to further reduction of 733 MW—or approximately the size of a new natural gas combined-cycle plant.

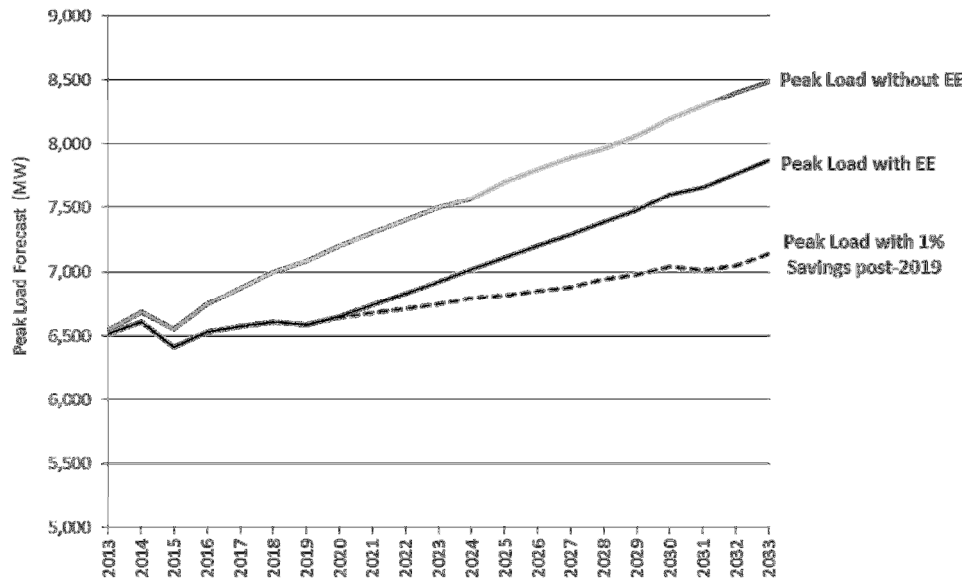


Figure 15. Peak load forecast for DEI, with DEI assumed EE, and peak load savings at 1% incremental past 2019.

The IURC’s order will spur Indiana utilities to build up infrastructure and create jobs through marketing programs, energy audits, installing new measures and other activities. Therefore, DEI will be required to build up such a network and infrastructure in order to achieve the 2019 savings goal. The Company should not then squander that learning and infrastructure by halting its efforts. Rather, the Company should continue to grow the efficiency resource by pursuing emerging technologies and different marketing approaches for existing measures. Other regions of the country with a long history of substantial efficiency savings (at levels beyond what DEI has achieved) continue to save energy at high levels through efficiency programs, and plan to do so long into the future. For example, the most recent power plan from the Northwest Power and Conservation Council projects that cost-effective, available energy efficiency will meet 85% of the region’s growing power needs through 2030.⁴⁴

Energy efficiency can lead to avoidance of building or retrofitting supply resources. For instance, the latest CPCN filing shows that Gibson 5 is uneconomic to retrofit under the “reference scenario” with the “low load” sensitivity. Energy efficiency is also being explored by the U.S. EPA as a mechanism for states

⁴³ A similar analysis is presented in Dr. Frank Ackerman’s Direct Testimony in Cause No. 44217.

⁴⁴ Sixth Northwest Conservation and Electric Power Plan, <http://www.nwcouncil.org/media/6284/SixthPowerPlan.pdf>.

to meet NAAQS obligations,⁴⁵ and may be a viable mechanism by which states can meet carbon reduction requirements under §111(d) of the Clean Air Act.⁴⁶

The Company's modeling does not optimize energy efficiency with its generation sources. Rather energy efficiency is "hard-wired" into the model each year. We also are not privy to the costs of energy efficiency that the Company is assuming so cannot compare it for ourselves. Further investments in efficiency could obviate the need for building new capacity and retrofitting existing capacity. Thus it could be an effective mechanism for compliance with pending environmental rules (including pending greenhouse gas regulation). For these reasons, and since it is typically the lowest cost resource, energy efficiency should be treated commensurately with generation in the Company's resource planning, as contemplated by the IURC provisional IRP rule.

6. SCENARIO PLANNING

6.1. Three scenarios are insufficient, and obfuscate important variables

The Duke Energy Indiana 2013 IRP evaluates its portfolio choice using nine permutations of three build-out portfolios ("traditional", "blended approach" and "coal retires") under three scenarios ("low regulation", "reference" and "environmental focus"). This analysis appears to perform exactly three optimizations associated with each scenario. No other optimizations are performed, and the analysis is thus limited to simply testing these three build-out portfolios against different commodity price variations.

Citizens Groups have expressed dissatisfaction with this mechanism through discussion with the Company, written comment, and testimony in a previous CPCN case (Cause 44217). By limiting the build-out to the review of exactly three worlds, the IRP loses the opportunity to review how different explicit variable changes impact the choices of portfolio and denies regulators and stakeholders the opportunity to assess how Company assumptions impact decisions. For example, by changing gas, coal, and carbon costs, as well as environmental regulations among the three scenarios, it is impossible to tell which factors contribute to the increased observed retirements. Is the choice to retire more units sensitive to coal prices, energy prices, or carbon prices? And to what degree?

⁴⁵ US EPA, 2012. Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans. <http://www.epa.gov/airquality/eere/pdfs/EEREmannual.pdf>.

⁴⁶ See, for example: US EPA, 2013. Considerations in the Design of a Program to Reduce Carbon Pollution from Existing Power Plants. <http://www2.epa.gov/sites/production/files/2013-09/documents/20130923statequestions.pdf>; AEP, 2013. Electric Sector CO2 Emissions Under 111(d). <http://bipartisanpolicy.org/sites/default/files/Braine%20Dec%206%20Workshop.pdf>; NRDC, 2013. Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters. <http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf>.

Similarly, while the subsequent CPCN (Phase 3, Cause 44418) does perform unit-by-unit valuation studies, the IRP fails to provide a mechanism by which regulators or stakeholders can review the economic viability of individual units without performing post-hoc analyses like those performed in these comments.

While we appreciate the steps the Company is taking towards the improvement of the structural framework for their analyses simply reserving this analysis for the docketed CPCN case rather than making it a part of the IRP missed valuable opportunities for stakeholder engagement and collaborative discussions.

6.2. Sensitivities are not illustrative

The Company also performed a sensitivity analysis of the nine portfolio-scenario permutations with varying carbon prices, natural gas prices, coal prices, load growth, capital cost, and amount of renewables. Again, the portfolios are locked-in and are not re-optimized given fluctuations in these key variables. Scott Park's Direct Testimony in Cause No. 44418 (CPCN Phase 3) presents a similar sensitivity analysis for individual units (Gibson 5, Edwardsport) and combinations of units (Gibson 1&2, Gibson 3&4, and Cayuga 1&2). In contrast to the IRP, the CPCN Phase 3 filing evaluates decisions to retire or retrofit at the plant or sub-plant level. Interestingly, the results for Gibson 5 under the "reference" scenario show that the unit is uneconomic with low load growth, low gas prices, or high coal price sensitivities.

The IRP takes a more "broad brush" approach by pre-selecting only three portfolios and subjecting them to variations in load, commodity prices and capital costs without changing the optimal build-out. The IRP also does not evaluate individual retirement decisions by unit or plant; these decisions are essentially fixed even though they should be influenced by sensitivities in load growth, capital costs and commodity prices. The CPCN filing shows an improved analysis by allowing the economic viability of units or plants to fluctuate with important variables, rather than holding them fixed. This type of unit-by-unit analysis should be a component of the Company's resource planning.

6.3. Gas-coal ratios

In the Phase 2 CPCN docket (Cause 44217), Dr. Frank Ackerman testified that the gas-coal ratios considered in the various sensitivities were biased against the selection of gas alternatives. In both sensitivity scenarios (environmental focus and low regulation), the ratio of gas to coal prices was higher than the reference case – in other words, coal was favored in both sensitivities.⁴⁷ He suggested that "the Company should consider scenarios with ratios of gas prices to coal prices that are less favorable to coal than its Base Case, rather than restricting its attention to scenarios where this price ratio is more favorable to coal." In this IRP, the Company has attended to this concern, but in an inverted way: in the environmental focus scenario, the gas-coal ratio is higher than the base case, while in the "low reg"

⁴⁷ See Direct Testimony of Dr. Frank Ackerman in Cause 44217, pages 29-31.

scenario, the gas-coal ratio is more favorable to gas than the base case. The Company's underlying assumption in the IRP is that fuel prices fall in the "environmental focus" case. However, coal prices fall almost 50% faster than gas prices in this scenario – leaving this scenario still more favorable to coal from a fuel price perspective.

Unfortunately, the mechanism employed by DEI to create three future scenarios results in systematic biases that only confuse reasonable decision-making, rather than elucidating particular risks. By modifying coal and gas prices, CO₂ prices, load, efficiency, and renewable energy requirements, we are unable to determine which of these factors – if any – pose the greatest risks for ratepayers or the Company.

7. CLOSING

The Commission should direct the Company to correct the significant deficiencies in the methodology which DEI adopted for its 2013 IRP as described in these Comments. These revisions are critical because they will result in changes in the Company's resource plans which will unquestionably improve both their cost and their risk profiles, thereby benefiting both DEI and its customers.