DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF NorthWestern Energy's Application for Approval of Capacity Resource Acquisition	REGULATORY DIVISION Docket No. 2019.12.101

PREFILED DIRECT TESTIMONY
OF ANNA SOMMER
ON BEHALF OF MONTANA ENVIRONMENTAL INFORMATION CENTER
("MEIC")

Department of Public Service Regulation
Montana Public Service Commission
Docket No. 2019.12.101
MEIC

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I. Expert Witness Information

Q: PLEASE PROVIDE YOUR NAME, TITLE, AND EMPLOYER.

A: My name is Anna Sommer. I am a Principal at Energy Futures Group, a consulting firm that provides specialized expertise on energy efficiency and renewable energy markets, program design, power system planning, and energy policy. My business address is 30 Court Street, Canton, NY 13617.

Q: PLEASE PROVIDE A DESCRIPTION OF YOUR EXPERIENCE.

A: I have worked for over fifteen years in electric utility regulation and related fields. During that time, I have reviewed dozens of integrated resource plans and related planning exercises. I have reviewed planning modeling based on multiple models including Aurora, Capacity Expansion Model, EnCompass, PLEXOS, PowerSimm, PROSYM, PROMOD, SERVM, Strategist, and System Optimizer and have had formal training on the Aurora, EnCompass, PowerSimm, and Strategist models.

Prior to joining Energy Futures Group in 2019, I founded my own consulting firm, Sommer Energy, LLC, in 2010 to provide integrated resource planning, energy efficiency, renewable energy, and carbon capture and sequestration expertise to clients around the country. I was previously employed at Energy Solutions, where I helped implement energy efficiency programs on behalf of utilities like Pacific Gas & Electric. Prior to that, I was a Research Associate at Synapse Energy Economics, where I provided regulatory and expert witness support to clients on topics including integrated resource planning.

I am a member of the Expert Team for GridLab[1] and sit on the Board of the Public Utility Law Project of New York, which is a nonprofit advocate in New York State for residential low-income consumers of utility services. Finally, I hold a B.S. in Economics and Environmental Studies from Tufts University and an M.S. in Energy and Resources from University of California Berkeley. I have also taken coursework in data analytics at Clarkson University and in Civil Engineering and Applied Mechanics at McGill University and participated in the U.S. Department of Energy sponsored Research Experience in Carbon Sequestration.

My work experience is summarized in my resume, provided as Exhibit AS-1.

Q: **HAVE YOU PREVIOUSLY PROVIDED EXPERT WITNESS TESTIMONY?**

A: Yes, I have testified before utility commissions in Indiana, Michigan, Minnesota, New Mexico, North Carolina, Puerto Rico, South Carolina, and South Dakota.

II. Purpose and Summary of Testimony

Q: **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A: I was asked by the Montana Environmental Information Center ("MEIC") to provide testimony that may assist the Montana Public Service Commission ("Commission") with its evaluation of NorthWestern Energy's ("NorthWestern"

[1] GridLab's mission is to provide "technical grid expertise to enhance policy decision-making and to ensure a rapid transition to a reliable, cost effective, and low carbon future." For more information, see gridlab.org.

or “the Company”) application (and its supplement) for approval to acquire a portion of Colstrip Unit 4 (“CU4”).

Specifically, this testimony provides my assessment of the economics of acquiring additional CU4 capacity both during and after the period of the proposed power purchase agreement (“PPA”) with Puget Sound Energy (“Puget”). Additionally, I discuss the fundamental inadequacy of the 2019 Electricity Supply Resource Procurement Plan (“2019 Plan”) that much of the Company’s analysis in this proceeding relies on, and the risks inherent in acquiring additional CU4 capacity.

Q: PLEASE SUMMARIZE YOUR PRINCIPAL CONCLUSIONS AND FINDINGS REGARDING NORTHWESTERN ENERGY’S APPLICATION FOR APPROVAL OF CAPACITY RESOURCE ACQUISITION IN THIS DOCKET.

A: I conclude that the Commission ought to reject the proposed Colstrip Unit 4 acquisition on the basis that the Company has failed to demonstrate that additional Colstrip Unit 4 capacity would be reasonable and prudent. My principal findings upon which that recommendation is based are as follows:

1. The analyses described in the testimonies of Mr. LaFave and Mr. Markovich fail to demonstrate that acquiring additional CU4 capacity is in the public interest during the pendency of the PPA with Puget;

2. NorthWestern has failed to demonstrate that acquiring additional CU4 capacity is in the public interest during the post-2025 period;

3. The 2019 Electricity Supply Resource Procurement Plan suffers from numerous flaws that render it insufficient evidence that NorthWestern has properly evaluated alternatives to the Acquisition;

4. NorthWestern failed to evaluate sources of flexibility from load; and

5. NorthWestern has failed to demonstrate that there is an urgent need to approve this acquisition.

My silence in this testimony on any issue does not imply my agreement with NorthWestern; rather, it reflects a prioritization of issues that could be covered given the procedural schedule in this docket.

III. Background Information

Q: PLEASE DESCRIBE THE MATERIALS YOU REVIEWED IN PREPARATION FOR YOUR TESTIMONY.

A: I have reviewed NorthWestern's Application, its April 24, 2020 Supplemental Application, and its July 2 Corrected Testimony and Exhibits in this docket, the Company's responses to MEIC and certain other parties' discovery requests, the read-only PowerSimm "Dashboard Access," NorthWestern's 2019 Electricity Supply Resource Procurement Plan, the Staff Memorandum on the 2019 Plan as approved by the Commission on June 30, 2020, Synapse's comments to the Commission regarding the 2019 Plan, and the testimony of David Schlissel in Docket No.D2018.2.12.

IV. Mr. Markovich's Analysis Does Not Support Acquisition of Additional Colstrip Unit 4 Capacity

Q: **PLEASE EXPLAIN WHY WITNESS MARKOVICH'S TESTIMONY DOES NOT SUPPORT ACQUISITION OF ADDITIONAL COLSTRIP UNIT 4 CAPACITY.**

A: Witness Hines touts the "net benefits of the PPA [that] will also flow to the Reserve Fund, reducing future costs to customers."[2] Those claimed net benefits are predicated in part on the analysis presented by Mr. Markovich in Corrected Exhibit KJM-3. The exhibit purports to forecast the revenues and expenses of the 45-MW PPA with Puget that NorthWestern has included as part of its proposed acquisition of a 92.5-MW share of CU4.[3] That analysis, however, is based on multiple assumptions about CU4's cost and performance that are overly optimistic and inconsistent with NorthWestern's own PowerSimm modeling. These include:

1. The equivalent availability factor, 87 percent, assumed in Mr. Markovich's analysis, is based on the five-year average of CU4 equivalent availability factors from 2014 to 2018. But, rather than also using the average capacity factor of 77[4] percent during that same period, Mr. Markovich assumes that CU4 will operate whenever it is available and achieve an 87 percent capacity factor[5] except during 2024 when a

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[2] Testimony of John D. Hines at JDH-21.

[3] It is not clear to me whether Mr. Markovich has correctly characterized the PPA in his testimony, Corrected Exhibit KJM-3 or Corrected Exhibit KJM-4. Without the ability to clarify his characterization I take his analysis at face value.

[4] See Exhibit ALS-1.

[5] MEIC-155 (stating that in Mr. Markovich's analysis, "Equivalent Availability Factor and Capacity Factor are one and the same.")

planned eight-week outage is anticipated. CU4 has not come close to achieving an 87 percent capacity factor since 2015, and when it did in 2015, it was a year in which Colstrip Unit 4 also reportedly had a [redacted] availability factor.[6] Finally, in its PowerSimm modeling, NorthWestern projects a dramatically lower capacity factor for CU4, about 49%[7] for the period covered by Mr. Markovich's analysis. A lower capacity factor would mean that CU4 would generate less energy revenue than reflected in Mr. Markovich's analysis. And while a lower capacity factor also results in lower total variable operating costs, because there is less revenue over which to spread fixed costs, it also makes the acquisition less economic.

2. Mr. Markovich includes no CU4 budgeted capital expenditures in his analysis.

Q: HOW DOES CORRECTING THESE ASSUMPTIONS INFLUENCE THE CONCLUSION THAT RATEPAYERS WOULD HAVE A NET POSITIVE BENEFIT FROM THE PPA WITH PUGET?

A: Table 1 shows the net benefit under differing assumptions of capacity factors during the period 2021 to 2025 but holding all else equal.

[6] Protected MEIC-019(c).

[7] Copy of Expansion Studies Outputs – 92_W, which provides the same total net generation numbers given in Exhibit BJL-11a. The Company's response to MEIC-20(d) indicates this is the information needed to calculate CU4's capacity factor.

Table 1. Sum of Nominal Net Value Under Different Capacity Factor Assumptions

Source	**Capacity Factor Assumption**	**Sum of Nominal Net Benefits**
Markovich (Corrected KJM-3)	73% in 2024, 87% in remaining years	$ 3,615,767
Barnes (MJB-1)	66% in 2024, 80% in remaining years[8]	$ (781,774)
PowerSimm	43% in 2024, 51% in remaining years	$ (3,439,380)

Table 2 replicates Table 1 but is modified to include budgeted capital expenditures which are entirely missing from Mr. Markovich's analysis. These expenditures are outlined in the confidential Corrected Protected Exhibit MJB-12. I understand that the Company is not currently seeking to recover these expenses from ratepayers, but my understanding is that it will do so in future filings.

Table 2. Sum of Nominal Net Values from Table 1 Modified for Capex

Source	**Capacity Factor Assumption**	**Sum of Nominal Net Benefits**
Markovich (Corrected KJM-3)	73% in 2024, 87% in remaining years	[redacted]
Barnes (MJB-1)	66% in 2024, 80% in remaining years	[redacted]
PowerSimm	43% in 2024, 51% in remaining years	[redacted]

[8] The spreadsheet underlying Corrected KJM-3 automatically adjusts 2024 generation relative to the assumed capacity factor in non-outage years. Therefore, I use a non-2024 capacity factor that gives the same overall 77 percent average capacity factor experienced by Colstrip during the period 2014 to 2018.

The inclusion of capital expenditures simply worsens the picture for the economics of the PPA with Puget. Customers are likely to lose millions of dollars if this application is approved, and these numbers could well be even worse. These analyses are conservatively low for multiple reasons.

Q: WHY DO YOU CONSIDER THESE ANALYSES TO BE CONSERVATIVE?

A: The coal cost, which makes up the [redacted] of the variable cost of $16.47 per MWh is essentially based on a [redacted] percent loading level. If I had adjusted the coal cost using a heat rate closer to that exhibited in the PowerSimm outputs, then fuel costs and therefore variable O&M would be even higher.[9]

Finally, the non-fuel O&M numbers are all predicated on the presumption that Colstrip Unit 3 ("CU3") does not retire before 2025. There is a real risk that the CU3 owners will choose to retire the unit earlier than 2025, and if they did so, this would likely shift many of the shared costs onto the CU4 owners. Neither my nor Mr. Markovich's analyses account for this possibility.

Q: WHY DID YOU INCLUDE CAPITAL EXPENDITURES IN TABLE 2 WHEN MR. MARKOVICH CONTENDS THAT PROFIT AND LOSS STATEMENTS "NEVER" INCLUDE CAPITAL EXPENDITURES[10]?

A: Nowhere in his original, uncorrected testimony or in Corrected Exhibit KJM-3 does Mr. Markovich characterize his assessment of the PPA as a "profit & loss" statement. Even if he had, however, it remains the case that capital expenditures

[9] See, for example, Protected NWEC RN-032(d).

[10] See NorthWestern's response to MEIC-079.

are expenses that the Company intends to recoup from ratepayers[11] and so any assessment of the profitability of Colstrip Unit 4 from the ratepayers' perspective ought to include those expenditures. In sum, with very reasonable changes to his analysis, it becomes clear that Mr. Markovich's testimony cannot support the notion that the acquisition of this capacity and the PPA with Puget that it enables are in the public interest.

Q: MR. MARKOVICH'S BACKCAST ANALYSIS GIVEN IN CORRECTED EXHIBIT KJM-4 SHOWS AN EVEN BIGGER BENEFIT TO THE ACQUISITION THAN DOES CORRECTED EXHIBIT KJM-3. HOW DO YOU RESPOND?

A: Corrected Exhibit KJM-4 shows a comparison to cherry-picked prices and reflects a capacity factor that is twelve percentage points higher than Colstrip actually had in 2019. Furthermore, approving the acquisition now does not remedy the market exposure that customers faced in 2019. And as the Company's response to MCC-030(b) shows, those prices were, on average, much higher than in the prior four years. These prices are even more irrelevant because, as Mr. LaFave testifies:

> [The Company] assume[s] a significant drop in market prices and an increase in capital investment. The drop in market prices is due to NorthWestern's use of an implied declining heat rate in its 2019 Electricity Supply Resource Procurement Plan ("2019 Plan"). The Commission has rejected the use of the implied declining heat rate in recent cases involving Qualifying Facilities. Parties have argued that while there may be a drop in prices, it will not be as significant as NorthWestern suggests in the 2019 Plan. NorthWestern believes otherwise and stands by this planning decision.[12]

[11] See NorthWestern's response to MEIC-157(d).

[12] Testimony of Bleau LaFave at BJL-47.

In attempting to portray Corrected Exhibit KJM-4 as somehow indicative of the future benefits of the PPA, Mr. Markovich is trying to have it both ways.

V. Mr. LaFave's Analysis Does Not Support Acquisition of Additional Colstrip Unit 4 Capacity

Q: WHY DOES MR. LAFAVE'S POWERSIMM MODELING NOT SUPPORT THE ACQUISITION OF ADDITIONAL COLSTRIP UNIT 4 CAPACITY?

A: There are many issues of concern with the Company's PowerSimm modeling. I will start first by discussing the PowerSimm modeling performed in support of this Application and then discuss the Company's 2019 Electricity Supply Resource Procurement Plan modeling.

For purposes of evaluating this acquisition, the Company performed no additional capacity expansion runs, meaning that this acquisition has never been explicitly evaluated against other resource choices. Instead, NorthWestern took two scenarios, Current and Base, from its 2019 Plan filing and merely added the additional Colstrip Unit 4 capacity to those scenarios and then simulated their dispatch.[13]

[13] Testimony of Bleau LaFave at 18-19, 30-31. In addition, the PowerSimm "dashboard access" shows that the ARS optimization engine was not used when NorthWestern evaluated the capacity acquisition. NorthWestern only performed production cost modeling to evaluate the capacity acquisition. The only ARS studies included in the dashboard access are from the integrated resource plan.

Q: WHY SHOULD NORTHWESTERN HAVE EVALUATED THE ACQUISITION AGAINST OTHER RESOURCE CHOICES?

A: Quite simply, because there are other resource options that could provide capacity and flexibility. The 2019 Plan did not evaluate those alternatives sufficiently to warrant their exclusion from consideration as an alternative to this acquisition.

This is due to the fact that many of the criticisms of the Company's 2019 Plan articulated in the Commission's Comments on the 2019 Plan and the further flaws or areas of concern I discuss below so bias the modeling that it is impossible to derive a preferred plan of action from the 2019 Plan. In the words of the Commission, "the concerns and deficiencies addressed…are substantial enough that they call into question the adequacy, accuracy, and value of the 2019 Plan."[14] It therefore would not make sense to simply add additional Colstrip Unit 4 capacity on top of one of these flawed portfolios.

Q: WHAT OTHER FLAWS OR CONCERNS IN MR. LAFAVE'S POWERSIMM MODELING FOR THIS ACQUISITION DID YOU IDENTIFY?

A: In addition to the fact that it does not evaluate the acquisition against other resource choices, there are at least three areas of concern I have identified in my review of his modeling. These include:

1. His net present value ("NPV") calculations use a forecasted PPA revenue that cannot be replicated and is unreasonably high.

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[14] Montana Public Service Commission, Comments in Response to Northwestern Energy's 2019 Electricity Supply Procurement Plan, ¶ 120, Docket No. 2019.08.052 (July 1, 2020) ("Commission Comments").

2. Even if Mr. LaFave's NPV calculations could be relied upon, the least cost plan over the planning period does not include additional Colstrip Unit 4 capacity.

3. The PowerSimm runs provided to us call into question the future economic viability of Colstrip Unit 4.

Q: WHY DO YOU SAY THAT MR. LAFAVE'S NPV CALCULATIONS USE FORECASTED PPA REVENUE THAT CANNOT BE REPLICATED?

A: I believe the value of the PPA revenue is greatly overstated in Mr. LaFave's NPV calculation. Second Corrected Exhibit BJL-11 contains a tab called "PPA Revenue". That tab gives annual revenue values that are unconnected to any data source. The Company's response to MEIC-185(b) says, "[T]he PPA revenue shown was determined by multiplying the hourly generation output from the PPA item by the sales price or the PPA floor price, whatever was higher in each hour."

However, Exhibit C – Power Purchase Agreement to the Purchase and Sale Agreement defines the relevant portion of the Contract Price as "For each hour of the term of the contract, regardless of the Delivery Point, the higher of (i) the Mid C Day-Ahead Index Price for on-peak and off-peak periods, as applicable, minus O&M Costs (Base) Equilivant [sic] and (ii) the Floor Price applicable to such hour."[15] Furthermore, the contract states, "'O&M Costs (Base) Equilivant [sic]' means, O&M Cost (Base) divided by the annual net generation, as identified and

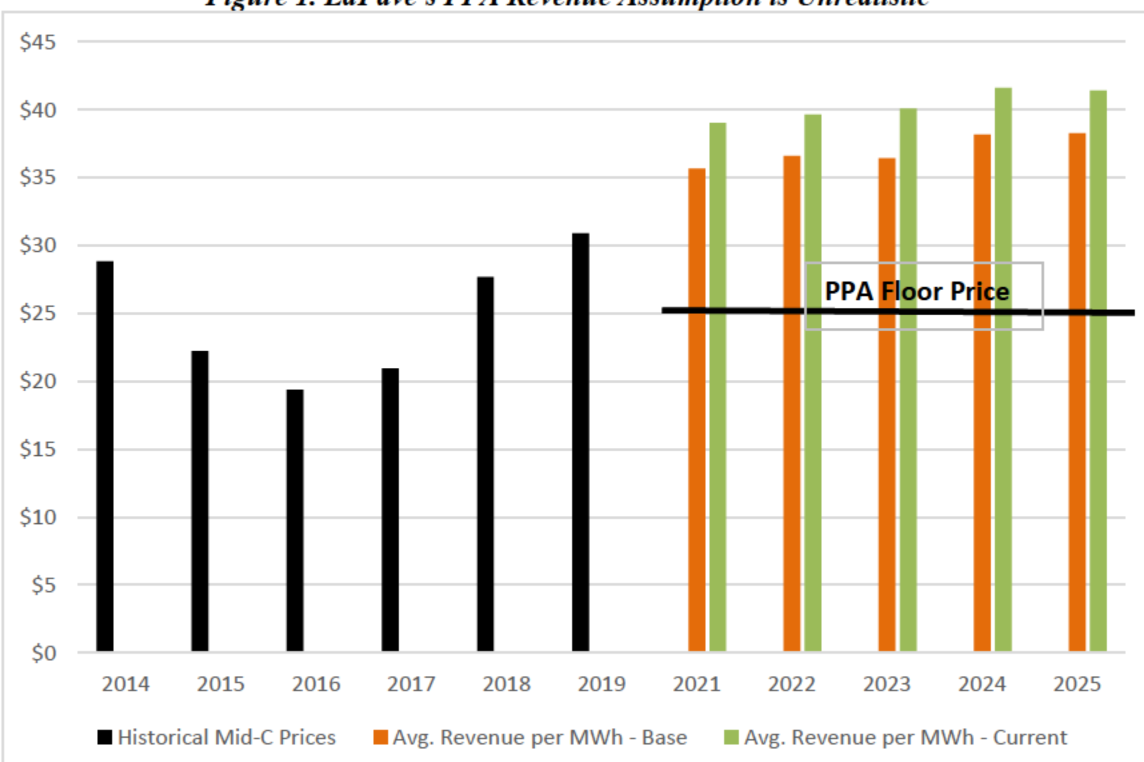
[15] Exhibit JDH-1 at 51.

approved annually for Colstrip Units 3 and 4 Budget."[16] The description of the Company's methodology for calculating PPA revenue in response to MEIC-185(b) does not account for the O&M related reduction in sales price when the Mid C price prevails.

Q: IS THIS THE ONLY REASON MR. LAFAVE'S PPA REVENUE ASSUMPTION IS UNREASONABLE?

A: No. His annual revenue assumption, when divided by the energy actually produced by the representation of the PPA in PowerSimm, yields an unrealistically high revenue per MWh generated as shown in Figure 1.

Figure 1. LaFave's PPA Revenue Assumption is Unrealistic[17]



[16] Id. at 52.

[17] Based on VS-014 in Docket No. 2019.09.059 and 2nd Corrected BJL Exhibit BJL-11.

To my knowledge, the Company has only provided its hourly price and generation for one year and one portfolio, the Base portfolio in 2024.[18] In that year, the Company predicts that [redacted] hours will fall below the $25.41 per MWh floor price used by Mr. Markovich in his Corrected Exhibit KJM-3. If all [redacted] hours are adjusted to a price of $25.41 per MWh and no reduction for O&M is made, then the weighted average market price in 2024 is [redacted] per MWh. This is substantially less than the average [redacted] per MWh revenue assumed in Mr. LaFave's NPV calculation in 2nd Corrected Exhibit BJL-11 and shown in Figure 1.[19]

Q: WHAT IMPACT DOES CHANGING MR. LAFAVE'S PPA REVENUE ASSUMPTION HAVE ON HIS NPV CALCULATIONS?

A: Because the data were not available to replicate Mr. LaFave's purported methodology, I used the PPA related revenue as calculated by Mr. Markovich in place of Mr. LaFave's calculations. As shown in Table 3, additional Colstrip Unit 4 capacity is more costly in all portfolios by at least 0.5 percent across the full planning period. And it is about the same cost as continuing to operate the Company's current portfolio of resources in the 2020 to 2025 time period.

[18] CORRECTED Exhibit BJL-13a 2024_BasePort with Expansion_Hourly Dispatch.

[19] 2nd Corrected Exhibit BJL-11, tab "PPA Rev."

Table 3. LaFave NPV Calculations Corrected for Capex and PPA Revenue

Portfolio	2020 to 2025		2020 to 2039	
	NPV	% Diff. from Current	NPV	% Diff. from Current
Current	$2,233,398,997	-	$4,964,917,736	-
Current w/ 92.5 MW Corrected	$2,232,200,471	-0.1%	$4,991,303,341	0.5%
Base	$2,337,500,816	4.7%	$5,813,963,624	17.1%
Base w/ 92.5 MW Corrected	$2,320,066,028	3.9%	$5,770,130,965	16.2%

Q: NORTHWESTERN CONTENDS THAT THE CURRENT PORTFOLIO IS NOT VIABLE "SINCE NORTHWESTERN REQUIRES ADDITIONAL CAPACITY."[20] HOW DO YOU RESPOND?

A: I would certainly agree that the Company's modeling to date does not support the idea that the Current portfolio is preferable over anything but the Base portfolio or the addition of Colstrip Unit 4 capacity. But that is because there were so many "thumbs on the scale" against nearly all the other resources that the Company could add to its system. While taking the time to properly evaluate those alternatives, the Company can certainly continue on the Current portfolio path.

And NorthWestern's need for additional capacity is really a product of a desire to avoid market exposure rather than the necessity to meet a reserve margin

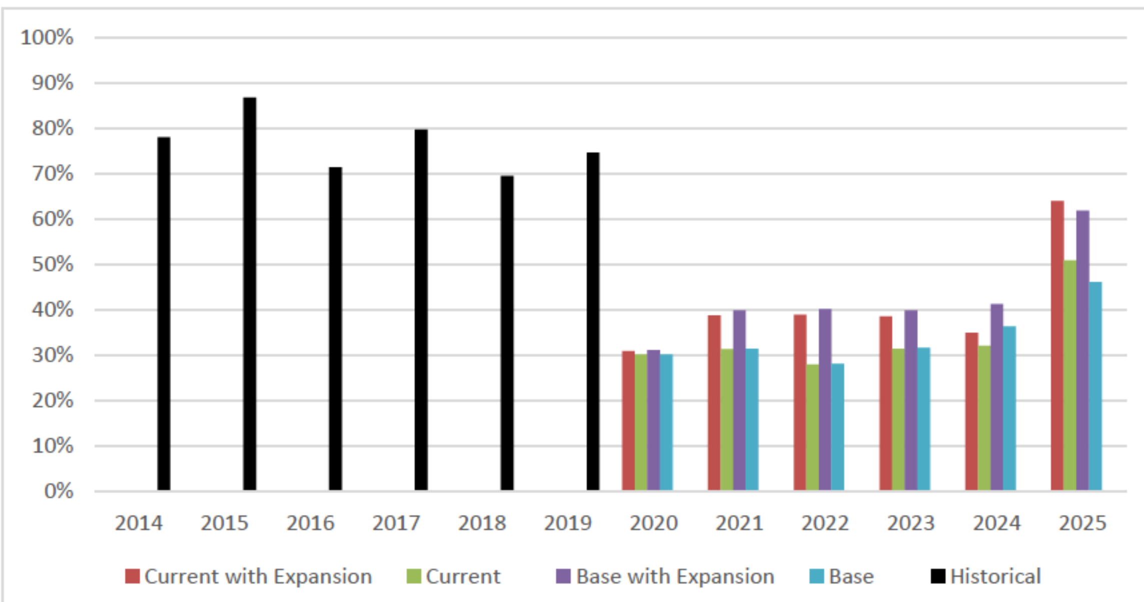
[20] Response to MEIC-068(b)

requirement. The risk of that market exposure is at least partially accounted for by performing 100 simulations in PowerSimm for each portfolio.

Q: WHY DO YOU SAY THE POWERSIMM RUNS YOU REVIEWED CALL INTO QUESTION THE FUTURE ECONOMIC VIABILITY OF COLSTRIP UNIT 4?

A: As I noted in Section IV, the PowerSimm runs show a much lower level of generation than what the plant has historically experienced. As shown in Figure 2, this is true across the Base and Current portfolios with and without additional CU4 capacity.

Figure 2. PowerSimm Projects that CU4 Capacity Factor will Drop Dramatically[21]



This is likely to be the case for one or more reasons:

[21] See VS-014 in Docket No. 2019.09.059 and Copy of Expansion Studies Outputs – 92_5W

1. The new coal supply agreement significantly worsens the economics of Colstrip.

2. Future market prices are expected to decline.[22]

3. Colstrip was already being operated “out of the money” in many hours.

Whether some or all of these are true, the PowerSimm modeling ought to give pause to the notion that *more* Colstrip Unit 4 capacity is prudent.

VI. The Company’s 2019 Electricity Supply Resource Procurement Plan Does Not Support the Acquisition

Q: WHY DO YOU SAY THAT THE COMPANY’S 2019 PLAN DOES NOT SUPPORT THE ACQUISITION OF ADDITIONAL COLSTRIP UNIT 4 CAPACITY?

A: It clearly cannot simply because the acquisition was not evaluated in the 2019 Plan. In addition, the modeling that provides the basis for the 2019 Plan was so flawed that it cannot be considered an accurate and prudent determination of the most reasonable supply and demand-side resources that NorthWestern should pursue. In addition to rendering the 2019 Plan inadequate to support the proposed CU4 acquisition, the flaws discussed herein should be corrected in any future resource planning analyses carried out by NorthWestern.

Because it is often my role to review utility resource planning, I would like to state first that transparency is key to thorough review of a utility’s modeling. The provision of dashboard access to PowerSimm and the ability to ask questions of

[22] Testimony of Bleau LaFave at BJL-47.

Brandon Mauch from Ascend Analytics were critical to the production of this testimony. As such, I would encourage the Company and the Commission to ensure that such access continues at a minimum.

Q: DID THE POWERSIMM MODELING THAT NORTHWESTERN CARRIED OUT FOR ITS 2019 PLAN FAIL TO FULLY ACCOUNT FOR CAPEX SPENDING, JUST AS THE ANALYSIS IN THIS PROCEEDING DID?

A: Yes. It is critical that resource planning analyses include capex for both new and existing resources. It would appear to me that the Company's PowerSimm modeling for the 2019 Plan also suffers from the same fatal flaw of including only partial amounts of these cost categories.

Q: DID THE POWERSIMM MODELING THAT NORTHWESTERN CARRIED OUT FOR ITS 2019 PLAN ACCOUNT FOR THE FULL CAPACITY VALUE OF WIND AND SOLAR RESOURCES?

A: No. I concur with the Commission[23] and with Synapse Energy Economics in its report on the 2019 Plan that the capacity credit given to wind and solar are unrealistically low and lead to those resources' not being selected in Automatic Resource Selection ("ARS"), the portfolio optimization engine of PowerSimm.[24] The testimony of MEIC Witness Dr. Michael Milligan explains why those capacity credit numbers are flawed and provides a better estimate for planning purposes. Using much more reasonable capacity credits for wind and solar

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[23] Commission Comments ¶106.

[24] Commission Comments ¶¶ 30-31.

resources would have reduced the capacity shortfall that NorthWestern claims needs to be filled and would have ensured a fairer assessment of the ability of new wind and solar resources to help address whatever capacity shortfall may exist.

Q: DID NORTHWESTERN PLACE UNREASONABLE CONSTRAINTS ON POWERSIMM MODELING FOR THE 2019 PLAN?

A: Yes, in at least three ways. First, as the Commission observed in its Order regarding the 2019 Plan, "In addition to being premature, the commitment to a 16% reserve margin in the 2019 Plan appears unnecessary, in that NorthWestern does not intend to achieve it, at least with long-term capacity resources, prior to filing its next plan."[25] This is merely a portion of the problematic constraint imposed by the Company. The aforementioned reserve margin constraint actually ramps up to the 16 percent level as shown in Table 4 and is eventually capped at no more than 20 percent of max load. Violations of this constraint are assessed at $10,000 per MW.[26]

Table 4. Reserve Margin Constraints in PowerSimm

	Reserve Margin May not Fall Below Max Load multiplied by	Reserve Margin May not Exceed Max Load multiplied by
2021	no capacity can be added	
2022	0.73	0.75
2023	0.88	0.9
2024	1.02	1.04
2025 and thereafter	1.16	1.2

[25] Commission Comments ¶102.

[26] Personal communication with Brandon Mauch.

The ramp up to the 16 percent reserve margin is arbitrary and would serve to dramatically narrow the resources added because (1) PowerSimm would be unlikely to return an optimal plan that meets the 16 percent reserve margin before 2025, (2) the narrow 2 percent band from 2022 to 2024 within which a plan can fluctuate without incurring a penalty would make the model prefer resources that keep the plan exactly within this window, and (3) the model will prefer resources that satisfy the annual step change in reserve margin requirement, which is also a very narrow window.

Second, the Company enforces an energy constraint that is set so that energy may not exceed load by more than 40 percent through the end of 2025 and, thereafter, it may not exceed load by more than 10 percent.[27] Intuitively, these constraints would serve to dissuade the model from picking resources that provide energy but not capacity because the model would prefer capacity resources to avoid the reserve margin penalty and would also be dissuaded from picking variable generation resources whose energy production might cause the plan to exceed load by more than 10 percent.

Third, the problematic nature of these constraints is magnified by the lack of an option to select a bilateral contract. The Commission found this to be "a critical deficiency because NorthWestern intends to use competitive solicitations to evaluate capacity resource offers with lives of three to as many as 25-30 years."[28]

[27] PowerSimm Dashboard Access.

[28] Commission Comments ¶103.

Q: MR. LAFAVE SAYS THAT HE REMOVED THE 10 PERCENT ENERGY CONSTRAINT AND RERAN ARS AND IT STILL SELECTED THE RICE UNITS. HOW DO YOU RESPOND?[29]

A: While Mr. LaFave says he did so, none of the PowerSimm runs available to us through "dashboard access" had this constraint removed. And removing the constraint will not in and of itself remove the other "thumbs on the scale" against other resources like the incorrect capacity credit for renewables.

Q: DID NORTHWESTERN'S POWERSIMM MODELING FAIL TO REASONABLY EVALUATE RENEWABLE RESOURCES AS PART OF THE 2019 PLAN?

A: Yes. I concur with the Commission[30] and with Synapse that NorthWestern should have modeled a wider range of resources including renewables plus battery storage. Solar and battery storage is a resource that is often picked as cost-effective in utility modeling that we review.

Further, the Company does not appear to have included the Investment Tax Credit ("ITC") for solar. The application of the production tax credit to wind is unclear because, like Synapse, I could not reconcile the PowerSimm capital costs with the capital cost forecast from HDR. While the production tax credit and ITC are ratcheting down, safe harbor provisions will allow renewables to capture those credits for several years to come. and the Company should certainly have included them in its analysis. In addition, the ITC is not set to expire. Even at its

[29] LaFave Direct Testimony at page BJL-21, lines 13 - 21.

[30] Commission Comments ¶114.

lowest level, a 10 percent ITC is expected to remain available and can be captured for both standalone solar and hybrid projects.

And battery costs in PowerSimm were not always modeled consistent with the costs given in the Company's response to MEIC-024(d). My review of the Company's PowerSimm runs identified several portfolios in which battery costs are [redacted] to [redacted] percent higher than HDR's forecast.

Q: DID NORTHWESTERN MODEL THE ECONOMIC RETIREMENT OF EXISTING COLSTRIP UNITS IN ITS 2019 PLAN?

A: No. I concur with Synapse that in future resource planning analyses, the Company should model the economic retirement of the Colstrip units. Indeed, it would be very wise to do so before acquiring *additional* Colstrip Unit 4 capacity. Evaluation of retirement of existing facilities, particularly coal plants, is frequently part of utility-sponsored resource planning analyses and ought to be adopted by NorthWestern as well. In doing so, it would be essential to have all costs of Colstrip including fixed O&M and capex accounted for within PowerSimm.

Q: DID NORTHWESTERN ADEQUATELY ACCOUNT FOR DEMAND-SIDE MANAGEMENT ("DSM") OPTIONS IN THE MODELING FOR ITS 2019 PLAN?

A: No. I agree with the Commission that the lack of DSM options in the PowerSimm modeling is concerning.[31] Energy efficiency and demand response (collectively, "DSM") have a real potential role to play in providing reliable

[31] Commission Comments ¶119.

service to NorthWestern ratepayers, and it would be a serious mistake to approve the acquisition of any large amount of capacity without giving appropriate consideration to these resources. The Commission endorsed Staff's recommendation that the potential study be completed, and I would add that, because of its importance to the discussion of the role of DSM, it needs to be completed promptly and by a reputable vendor. Furthermore, because market potential studies are inherently conservative[32] and easily biased, it is important that the representation of DSM in the modeling be informed by stakeholders and that stakeholders are involved in the development of the market potential studies from vendor selection to study completion.

Because PowerSimm lacks consideration of these resources, either explicitly or as a reduction to load, the Company cannot demonstrate that it has appropriately considered DSM.

Q: DO YOU HAVE ANY ADDITIONAL CONCERNS RELATED TO NORTHWESTERN'S POWERSIMM MODELING THAT YOU WOULD LIKE TO BRING TO THE COMMISSION'S ATTENTION?

A: Yes, on a more technical note, I am concerned about relying entirely on PowerSimm to perform all portfolio resource optimization instead of also using it to guide the creation of additional portfolios of interest. PowerSimm falls into a class of models known as mixed integer programming models. Ascend describes

[32] Kramer, Chris and Glenn Reed, Ten Pitfalls of Potential Studies (Nov. 1, 2012), https://www raponline.org/wp-content/uploads/2016/05/energyfutures-kramerreed-tenpitfallsesdraft2-2012-oct-24.pdf.

PowerSimm's optimization process as follows, "The optimization engine for ARS finds the optimal unconstrained solution, then goes through a solving routine until it finds a constrained solution within a given tolerance."[33] The "optimal unconstrained solution" means the optimal linear solution in each run. mixed integer programming models such as PowerSimm enforce integer constraints on variables like the number of new resources added, (e.g., only whole numbers of units can be added as opposed to, say, 1.5 units). The linear solution relaxes all integer constraints. Every mixed integer programming model has a tolerance setting which normally specifies the maximum gap in NPV between the linear solution and the incumbent solution (e.g. an optimized plan). Once it reaches this gap, the model can stop the optimization process. The tolerance setting for NorthWestern's ARS runs was 0.02 percent,[34] meaning that the optimization stopped when the "optimal" plan was within 0.02 percent of the linear solution. Energy Futures Group's experience with PowerSimm in another case is the basis for my concern about relying on ARS' optimization engine. Indianapolis Power & Light ("IPL") recently filed an integrated resource plan that was based on the use of PowerSimm. IPL's tolerance setting was 0.01 percent, i.e., narrower than NorthWestern's. Despite this, forcing in certain resource additions resulted in plans that were cheaper and, in several cases, significantly cheaper than the plan optimized by PowerSimm. It is not entirely clear why this was the case – the optimal plan should be lower cost than a plan with resources forced in because, if

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[33] Attachment AS-2 to Direct Testimony of Anna Sommer in Indiana Utility Regulatory Commission Cause No. 45370 (attached as Exhibit AS-2).

[34] Personal communication with Brandon Mauch on July 3, 2020.

those resources reduced the NPV, they should have been chosen by the model. However, even with dashboard access, one cannot see the Company's tolerance setting, nor the resulting gap in NPV between the optimal integer and linear relaxation results, nor even the NPV, as calculated by PowerSimm, of the optimal plan itself. This makes it nearly impossible to understand why a plan with forced-in resources would be cheaper, but because I have seen this happen in another case involving PowerSimm, it raises red flags about concluding that a plan optimized in ARS is indeed the optimal plan.[35]

VII. The Company has Failed to Properly Account for Flexibility and Capacity Resources on Both the Supply- and Demand-Side

Q: WHAT SOURCES OF FLEXIBILITY AND CAPACITY DID THE COMPANY IGNORE IN ITS MODELING?

A: Mr. LaFave paints a picture of a utility with frequent and long-duration outages in Table 1 of his testimony, reproduced below as Table 5. It is important to note that what Mr. LaFave is offering is not a resource adequacy analysis – that type of analysis is described in the testimony of Dr. Michael Milligan. And, therefore, it should not be relied upon to conclude that NorthWestern is meeting a 1 day in 10 years loss of load standard (or not).

[35] While IPL maintained that this was a result of differences in how PowerSimm and IPL calculate NPV, the categories of costs in PowerSimm's NPV formula (in its user guide) were substantially similar to IPL's categories of costs. And without the ability to audit, let alone view, the NPV in PowerSimm, there is no way to determine if there are valid differences between PowerSimm or, frankly, any utility's methodology for calculating NPV.

Table 5. Distribution of Duration of Deficits, 2009-2019
(Table 1 of LaFave Testimony)

Current Capacity (MW)	Additional Capacity (MW)	Total Capacity (MW)	Average Occurrences Annually	Length of Deficit Period (hours)				
				5th Percentile	50th Percentile (Mean)	95th Percentile	99.97th Percentile	Max
755	420	1175	1.3	1.0	2.1	4.4	5.0	5.0
755	370	1125	7.0	1.0	2.6	6.0	9.0	9.0
755	320	1075	22.0	1.0	3.5	7.0	9.9	10.0
755	270	1025	47.1	1.0	4.4	10.0	16.0	16.0
755	220	975	88.8	1.0	5.0	15.0	17.0	17.0
755	170	925	159.1	1.0	5.5	15.0	19.5	20.0
755	0	755	367	1.0	11.6	17.0	163.8	211.0

With that significant limitation in mind, it appears that his calculation of 755 MW of current capacity is based, in part, on the assumption that existing wind and solar provide nominally higher amounts than was modeled for new renewables in PowerSimm but still very low amounts of "dependable capacity". Using the effective load carrying capability approximation methodology described in Dr. Milligan's testimony, dependable capacity on the Company's system is actually closer to 977 MW, as shown in Table 6.

Table 6. Nameplate and Dependable Capacity on NorthWestern's System

Thermal		Nameplate Capacity (MW)	Capacity Value (MW)
Basin Creek	NG	52	51.42
Dave Gates	NG	150	145.5
Colstrip Unit	Coal	222	203.73
YELP	Coal	52	50.44
CELP	Coal	35	33.95
Renewables			
Judith Gap	Wind	135	46.71
Stillwater	Wind	80	27.68
South Peak	Wind	80	27.68
Spion Kop	Wind	40	13.84
Greenfield	Wind	25	8.65
Big Timber	Wind	25	8.65
Fairfield	Wind	10	3.46
Musselshell	Wind	10	3.46
Musselshell Two	Wind	10	3.46
Two Dot	Wind	11	3.81
Gordon Butte	Wind	10	3.46
71 Ranch	Wind	3	1.04
DA Wind Investors	Wind	3	1.04
Oversight Resources	Wind	3	1.04
Grizzly Wind	Wind	80	27.68
Black Bear	Wind	80	27.68
Small Wind	Wind	13	4.50
MTSun	Solar	80	26.64
Meadowlark	Solar	20	6.66
Green Meadow	Solar	3	1.00
South Mills	Solar	3	1.00
Black Eagle	Solar	3	1.00
Great Divide	Solar	3	1.00
Magpie	Solar	3	1.00
River Bend	Solar	2	0.666
Thompson Falls	Hydro	94	43
Madison	Hydro	8	6
Hauser	Hydro	17	14
Holter	Hydro	52	32
Black Eagle	Hydro	21	12
Rainbow	Hydro	64	33.7
Cochraine	Hydro	62	25
Ryan	Hydro	68	40
Morony	Hydro	49	24
Mystic	Hydro	12	5
Turnbull	Hydro	13	0
Tiber	Hydro	8	**
Small Hydro	Hydro	16	4.5
Total Supply			**977**
Summer Peak (Less DSM and PV)			**1186**
Winter Peak (Less DSM and PV)			**1210**
Summer Peak plus Reserve Margin			**1375**
Winter Peak plus Reserve Margin			**1403**
Summer Deficit			**(398)**
Winter Deficit			**(426)**

With 977 MW of dependable capacity, the number and duration of deficits is very close to that which corresponds to 975 MW of total capacity as shown in Table 5.

Taking Mr. LaFave's table at face value would then suggest that the mean length of deficits would be five hours and approximately 89 such deficits would occur in any given year. In other words, once NorthWestern's dependable capacity is properly measured, the potential deficits are only 23 percent as likely and less than half the duration as Mr. LaFave assumed.

Of course, with less capacity available (or more load) those deficits and their durations would go up, while with more capacity and/or less load, those deficits and their durations would decline even further. It makes no sense then that NorthWestern never explicitly evaluated load flexibility, i.e. demand response, in its PowerSimm modeling.

VIII. The Company has Failed to Justify the Urgency of Approving this Acquisition

Q: BUT AS TABLE 7 OF YOUR TESTIMONY SHOWS, THE COMPANY NEEDS SEVERAL HUNDRED MEGAWATTS OF ADDITIONAL CAPACITY IN ORDER TO MEET ITS RESERVE MARGIN REQUIREMENT. WHY SHOULDN'T THE COMMISSION MANDATE AN ALL-OF-THE-ABOVE STRATEGY THAT INCLUDES ADDITIONAL COLSTRIP UNIT 4 CAPACITY?

A: While Mr. LaFave has significantly overstated NorthWestern's current capacity shortfall and resulting likelihood of deficits, it is very clearly the case that the Company would need additional capacity and energy to meet its reserve margin requirement without relying on market purchases. But this has been true for over a decade now. It is not clear to me why the Company has failed to rectify this situation after so many years or why, after such years of inaction, there would be an urgent need to do so now. I do not believe that the Company has made the case for the urgency of approving this acquisition now without the benefit of a complete and unbiased analysis of alternatives. Inherent in the recommendation of an all-of-the-above strategy is the assumption that *all* resources are needed. But NorthWestern has not demonstrated this to be the case. Indeed, it cannot – simply by virtue of the exclusion of storage and larger amounts of renewables and any amount of additional demand-side management from its analysis.

Many of the Company's supplemental analyses, e.g. Mr. Markovich's assessment of the PPA or Mr. LaFave's analysis of historical deficits, which are intended to highlight the benefits of the Acquisition, simply cherry-pick facts that overstate both the need for and value of the proposed CU4 acquisition. The Company's PowerSimm analysis, despite its flaws, is a more thorough assessment of the costs and benefits of the Acquisition, and it shows that ratepayers would be better off without additional CU4 capacity. Indeed, as Mr. LaFave has testified, "PowerSimm models the risks associated with volatility in prices, renewable generation, hydroelectric generation, load, and forced outages."[36] Several of these risks are the very justification that the Company gives for approving the Acquisition. And as I demonstrated in Section V of my testimony, reasonable and

[36] LaFave Testimony at BJL-38, lines 5-6.

limited changes and corrections to Mr. LaFave's NPV analysis demonstrate that acquiring more CU4 capacity will raise customer cost relative to the Company's current portfolio. On top of that is the possibility that [redacted] of dollars of Colstrip Unit 3 costs would be transferred to Unit 4 owners if CU3 retires early.

Q: IN HIS CORRECTED TESTIMONY AT PAGE BJL-45, MR. LAFAVE SAYS THAT HE ALREADY INCLUDED ANALYSIS OF THE RISK THAT COLSTRIP UNIT 3 WOULD SHUT DOWN. HOW DO YOU RESPOND?

A: Mr. LaFave would seem to be making reference to the fact that Colstrip Unit 3 is assumed to shut down at the end of 2025 and, therefore, the capacity that the Company previously got from the reciprocal agreement would no longer be available to it. This causes the amount of CU3 capacity in PowerSimm to go to zero in 2026, and CU4 capacity increases by [redacted] MW. The only "risk" this captures is that of further reliance on a single unit – CU4. And there is no sensitivity that tests an even earlier retirement of CU3.

Q: WHAT KIND OF RISKS DID THE COMPANY FAIL TO CONTEMPLATE RELATED TO THE EARLY RETIREMENT OF CU3?

A: There are shared costs between CU3 and CU4 that could fall to the CU4 owners with the closure of CU3. For example, Protected Corrected Exhibit MJB-12 Budget Allocation of Capex contains a line item for "Equally Shared Unit 3 & 4 cost."[37] Over the period 2026 to 2029, the total capex is [redacted] million for the

[37] Protected Corrected Exhibit MJB-12, tab "MJB – 12 correct."

Company's share of CU4 alone. Notably and despite NorthWestern's assumed closure of CU3 in 2025, that assumption is not factored into this exhibit. Indeed, as NorthWestern acknowledged in its response to MEIC-119(c), "None of the costs in Exhibit MJB-12 include costs that would be incurred as a result of closure. The Operator is projecting costs assuming continued operation of the Project nor has NorthWestern projected the cost of closing Unit 3."

IX. Recommendations and Conclusions

Q: PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS TO THE COMMISSION.

A: I conclude that the Commission ought to reject the proposed Colstrip Unit 4 acquisition on the basis that the Company has failed to demonstrate that additional Colstrip Unit 4 capacity would be reasonable and prudent. My principal findings upon which that recommendation is based are as follows:

1. The analyses described in the testimonies of Mr. LaFave and Mr. Markovich fail to demonstrate that acquiring additional CU4 capacity is in the public interest during the pendency of the PPA with Puget;

2. NorthWestern has failed to demonstrate that acquiring additional CU4 capacity is in the public interest during the post-2025 period;

3. The 2019 Electricity Supply Resource Procurement Plan suffers from numerous flaws that render it insufficient evidence that NorthWestern has properly evaluated alternatives to the Acquisition;

4. NorthWestern failed to evaluate sources of flexibility from load; and

5. NorthWestern has failed to demonstrate that there is an urgent need to approve this acquisition.

Q: DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A: Yes.

Exhibits to Direct Testimony of Anna Sommer
on behalf of Montana Environmental Information Center

Exhibit AS-1

Docket No. 2019.12.101

Anna Sommer
Principal

Professional Summary

Anna Sommer is a principal of Energy Futures Group in Hinesburg, Vermont. She has more than 15 years' experience working on a wide variety of energy planning related issues. Her primary focus is on all aspects of integrated resource planning (IRP) including capacity expansion and production costing simulation, scenario and sensitivity construction, modeling of supply and demand side resources, and review and critique of forecast inputs such as fuel prices, wholesale market prices, load forecasts, etc. Additionally, she has experience with various aspects of DSM planning including construction of avoided costs and connecting IRPs to subsequent DSM plans. Anna has had formal training on the Aurora, EnCompass, PowerSimm, and Strategist models and has reviewed modeling performed using numerous models including Aurora, EnCompass, Capacity Expansion Model, PLEXOS, PowerSimm, PROSYM, PROMOD, RESOLVE, SERVM, Strategist, and System Optimizer. She has provided expert testimony in front of utility commissions in Indiana, Michigan, Minnesota, New Mexico, North Carolina, Puerto Rico, South Carolina, and South Dakota.

Experience

2019-present: Principal, Energy Futures Group, Hinesburg, VT
2010-2019: President, Sommer Energy, LLC, Canton, NY
2007-2008: Project Manager, Energy Solutions, Oakland, CA
2003-2007: Research Associate, Synapse Energy Economics, Cambridge, MA

Education

M.S. Energy and Resources, University of California Berkeley, 2010

Master's Project: *The Water and Energy Nexus: Estimating Consumptive Water Use from Carbon Capture at Pulverized Coal Plants with a Case Study of the Upper Colorado River Basin*

B.S., Economics and Environmental Studies, Tufts University, 2003

Additional training

Graduate coursework in Data Analytics – Clarkson University, 2015-2016.
Graduate coursework in Civil Engineering and Applied Mechanics – McGill University, 2010.
Research Experience in Carbon Sequestration (RECS), U.S. Department of Energy, 2009.

Selected Projects

- EfficiencyOne. Supporting EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process. (2019 to present)

- Minnesota Center for Environmental Advocacy. Evaluation of Xcel Energy's 2020 Integrated Resource Plan and Strategist modeling in support of that evaluation. (2019 to present) Evaluation of Minnesota Power Company's proposal to build a new natural gas combined cycle power plant and Strategist modeling of alternatives to the plant. Comments regarding Great River Energy's integrated resource plan to meet future energy and capacity needs. (2018) Comments regarding Otter Tail Power's integrated resource plan to meet future energy and capacity needs. Comments regarding Minnesota Power's integrated resource plan to meet future energy and capacity needs. (2016) Comments regarding Great River Energy's integrated resource plan to meet future energy and capacity needs. (2015) Comments regarding Otter Tail Power's integrated resource plan to meet future energy and capacity needs. (2014) Comments regarding Xcel Energy's Sherco 1 and 2 Life-Cycle Management Study. Comments regarding Minnesota Power's proposal to retrofit Boswell Unit 4. Comments regarding Minnesota Power's integrated resource plan to meet future energy and capacity needs. Comments regarding Xcel Energy's integrated resource plan to meet future energy and capacity needs. (2013) Evaluation of Otter Tail Power's plan to diversify its baseload resources. Comments regarding Minnesota Power's "Baseload Diversification Study" – a resource planning exercise examining the use of fuels other than coal to serve baseload needs. (2012) Comments regarding IPL's integrated resource plan to comply with pending EPA regulations and meet future capacity and energy needs. (2011) Evaluation of a proposal by seven utilities to build a new supercritical pulverized coal plant including alternatives to the plant and potential for greenhouse gas regulation. (2006)
- Coalition for Clean Affordable Energy. Evaluation of Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station. (2019 to 2020)
- Earthjustice. Evaluation of the Puerto Rico Electric Power Authority's 2019 Integrated Resource Plan. (2019 to 2020)
- Citizens Action Coalition of Indiana. Evaluation of Southern Indiana Gas and Electric's proposal to offer DSM programs to its customers. (2020 to present) Comments regarding Indianapolis Power & Light's integrated resource plan to meet future energy and capacity needs. (2020) Advising stakeholders on stakeholder workshops in preparation for Southern Indiana Gas and Electric's integrated resource plans to meet future energy and capacity needs. Evaluation of Indianapolis Power & Light's proposal to offer DSM programs to its customers. Evaluation of Duke Energy Indiana's proposal to offer DSM programs to its customers. Evaluation of Indiana Michigan Power's proposal to offer DSM programs to its customers. (2019 to 2020) Comments regarding Duke Energy Indiana's integrated resource plan to meet future energy and capacity needs. Comments regarding Indiana Michigan Power's integrated resource plan to meet future energy and capacity needs. (2019) Comments on Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (2019) Evaluation of Southern Indiana Gas and Electric's proposal to build a new natural gas combined cycle power plant. (2018) Evaluation of Duke Energy Indiana's proposal to offer DSM programs to its customers. Evaluation of Southern Indiana Gas and Electric's proposal to offer DSM programs to its customers. Comments regarding Southern Indiana Gas and

Electric Company's integrated resource plans to meet future energy and capacity needs. Comments regarding Indianapolis Power & Light's integrated resource plan to meet future energy and capacity needs. Comments regarding Northern Indiana Public Service Company's integrated resource plan to meet future energy and capacity needs. (2017) Comments regarding Duke Energy Indiana and Indiana Michigan Power's integrated resource plans to meet future energy and capacity needs. (2016)

- Environmental Law and Policy Center. Evaluation of DTE Energy's 2019 Integrated Resource Plan modeling and Strategist modeling in support of that evaluation. (2019)
- New Energy Economy. Evaluation of Public Service Company of New Mexico's Strategist modeling of coal plant retirement scenarios. (2017)
- Institute for Energy Economics and Financial Analysis. Evaluation of Puerto Rico Electric Power Authority's plan to build an offshore LNG port. (2017) Evaluation of Puerto Rico Electric Power Authority's proposal to meet future energy and capacity needs.

Selected Publications

The Husker Energy Plan: A New Energy Plan for Nebraska, prepared by Anna Sommer, Tyler Comings, and Elizabeth Stanton for the Nebraska Wildlife Federation. January 16, 2018.

Pennsylvania Long-Term Renewables Contracts Benefits and Costs, prepared by Elizabeth Stanton, Anna Sommer, Tyler Comings, and Rachel Wilson for the Mid-Atlantic Renewable Energy Coalition. October 27, 2017.

"Pursue Carbon Capture and Utilization of Storage," "Establish Energy Savings Targets for Utilities," and "Tax Carbon Dioxide Emissions," in Implementing EPA's Clean Power Plan: A Menu of Options, prepared by Anna Sommer for the National Association of Clean Air Agencies and the Regulatory Assistance Project. June 7, 2015.

Overpaying and Underperforming: The Edwardsport IGCC Project, prepared by Anna Sommer for Citizens' Action Coalition, Save the Valley, Valley Watch, and Sierra Club. February 3, 2015.

Public Utility Regulation Without the Public: The Alabama Public Service Commission and Alabama Power, prepared by David Schlissel and Anna Sommer for Arise Citizens' Policy Project. March 1, 2013.

A Texas Electric Capacity Market: The Wrong Tool for a Real Problem, prepared by Anna Sommer and David Schlissel for Public Citizen of Texas. February 12, 2013.

Independent Administration of Energy Efficiency Programs: A Model for North Carolina, prepared by David Nichols, Anna Sommer, and William Steinhurst for Clean Water for North Carolina, April 13, 2007.

Integrated Portfolio Management in a Restructured Supply Market, prepared by Paul Chernick, Jonathan Wallach, William Steinhurst, Tim Woolf, Anna Sommer, and Kenji Takahashi. June 30, 2006.

Ensuring Delaware's Energy Future: A Response to Executive Order No. 82, prepared by the Delaware Cabinet Committee on Energy with technical assistance at Synapse Energy Economics from William Steinhurst, Bruce Biewald, David White, Kenji Takahashi, Alice Napoleon, Amy Roschelle, Anna Sommer, and Ezra Hausman for the Delaware Public Service Commission staff. March 8, 2006.

"Assessment of Carbon Sequestration Feasibility and Markets," by Anna Sommer and William Steinhurst, in Mohave Alternatives and Complements Study, a Sargent & Lundy and Synapse Energy Economics, Inc., report prepared for Southern California Edison. February 2006.
Potential Cost Impacts of a Renewable Portfolio Standard in New Brunswick, prepared by Tim Woolf, David White, Cliff Chen, and Anna Sommer for the New Brunswick Department of Energy. October 2005.
Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value, prepared by Lucy Johnston, Amy Roschelle, Ezra Hausman, Anna Sommer, and Bruce Biewald as a Synapse Energy Economics, Inc. report. September 20, 2005.
Potential Cost Impacts of a Vermont Renewable Portfolio Standard, prepared by Tim Woolf, David E. White, Cliff Chen, and Anna Sommer as a Synapse Energy Economics, Inc. report for the Vermont Public Service Board. October 16, 2003.

Presentations and Articles

"Practical Strategies for the Electricity Transition." A presentation at Energy Finance 2019. June 18, 2019.
"Carbon Capture and Storage." A presentation at Energy Finance 2018. March 13, 2018.
"Puerto Rico's Electric System, Before and After Hurricane Maria." A webinar with Cathy Kunkel on behalf of the Institute for Energy Economics and Financial Analysis. October 24, 2017.
"Rebutting Myths About Energy Efficiency." A presentation at the Beyond Coal to Clean Energy Conference sponsored by Sierra Club and Energy Foundation. October 8, 2015.
"The Energy and Water Nexus: Carbon Capture and Water." A presentation at the Water and Energy Sustainability Symposium. September 28, 2010.
"Carbon Sequestration." A presentation to Vermont Energy Investment Corporation. August 17, 2009.
"Carbon Dioxide Emissions Costs and Electricity Resource Planning." A presentation before the New Mexico Public Regulation Commission with David Schlissel. March 28, 2007.
"Electricity Supply Prices in Deregulated Markets – The Problem and Potential Responses." A presentation at the NASUCA Mid-Year Meeting with Rick Hornby and Ezra Hausman. June 13, 2006.
"IGCC: A Public Interest Perspective." A presentation at the Electric Utilities Environmental Conference 2006. January 24, 2006.
Woolf, Tim, Anna Sommer, John Nielsen, David Barry and Ronald Lehr. "Managing Electric Industry Risk with Clean and Efficient Resources," The Electricity Journal, Volume 18, Issue 2, March 2005.
Woolf, Tim, and Anna Sommer. "Local Policy Measures to Improve Air Quality: A Case Study of Queens County, New York," Local Environment, Volume 9, Number 1, February 2004.

Professional Affiliations

Board Member, **Public Utility Law Project of New York,** 2018 – present
Board Member, **Community Development Program of St. Lawrence County,** 2017 – present

Exhibits to Direct Testimony of Anna Sommer
on behalf of Montana Environmental Information Center

Exhibit AS-2

Docket No. 2019.12.101

CAC Exhibit 2 (Redacted)

STATE OF INDIANA

BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT FOR APPROVAL OF DEMAND SIDE MANAGEMENT (DSM) PLAN, INCLUDING ENERGY EFFICIENCY (EE) PROGRAMS, AND ASSOCIATED ACCOUNTING AND RATEMAKING TREATMENT, INCLUDING TIMELY RECOVERY, THROUGH IPL'S EXISTING STANDARD CONTRACT RIDER NO. 22, OF ASSOCIATED COSTS INCLUDING PROGRAM OPERATING COSTS, NET LOST REVENUE, AND FINANCIAL INCENTIVES.	**)))))))))))**	**CAUSE NO. 45370**

DIRECT TESTIMONY OF ANNA SOMMER

ON BEHALF OF

CITIZENS ACTION COALITION OF INDIANA, INC.

JULY 29, 2020

PUBLIC VERSION

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Anna Sommer. I am a Principal at Energy Futures Group ("EFG"), a consulting firm that provides specialized expertise on energy efficiency and renewable energy markets, program design, power system planning, and energy policy. My business address is 30 Court Street, Canton, NY 13617.

Q. Please describe your professional background and experience.

A. I have worked for over 15 years in electric utility regulation and related fields. During that time, I have reviewed dozens of integrated resource plans ("IRPs") and related planning exercises. I have reviewed planning modeling based on multiple models including Aurora, Capacity Expansion Model, PLEXOS, PowerSimm, PROSYM, PROMOD, SERVM, and System Optimizer and have had formal training on the Aurora, EnCompass, PowerSimm, and Strategist planning models.

Prior to joining EFG, I founded my own consulting firm, Sommer Energy, LLC, in 2010 to provide integrated resource planning, energy efficiency, renewable energy, and carbon capture and sequestration expertise to clients around the country. I was previously employed at Energy Solutions where I helped implement energy efficiency programs on behalf of utilities like Pacific Gas & Electric. Prior to that, I was a Research Associate at Synapse Energy Economics where I provided regulatory and expert witness support to clients on topics including integrated resource planning.

I am a member of the Expert Team for GridLab[1] and sit on the Board of the Public Utility Law Project of New York ("PULP"), which is a nonprofit advocate in New York State for residential low-income consumers of utility services.

Finally, I hold a B.S. in Economics and Environmental Studies from Tufts University and an M.S. in Energy and Resources from University of California Berkeley. I have also taken coursework in data analytics at Clarkson University and in Civil Engineering and Applied Mechanics at McGill University and participated in the U.S. Department of Energy sponsored Research Experience in Carbon Sequestration ("RECS").

My work experience is summarized in my resume, provided as Attachment AS-1.

Q. Have you testified previously before the Indiana Utility Regulatory Commission ("Commission" or "IURC")?

A. Yes. I have filed testimony in Cause Nos. 43955 DSM 4, 43955 DSM 8, 44927, 45253, and 45285.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Citizens Action Coalition of Indiana ("CAC").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize the key components of the report that my team and I produced on Indianapolis Power and Light's ("IPL") 2019 Integrated Resource Plan ("IRP") as they relate to IPL's proposed demand side management

[1] GridLab's mission is to provide "technical grid expertise to enhance policy decision-making and to ensure a rapid transition to a reliable, cost effective, and low carbon future." For more information, see gridlab.org.

("DSM") plan in this Cause.[2] I will also provide my expert opinion on the manner in which IPL reconciled its 2019 IRP with its proposed DSM plan in this Cause and whether IPL's plan meets the definition of "energy efficiency goals" as prescribed by Senate Enrolled Act 412 in Section (c).

Q. Please summarize your conclusions and recommendations.

A. I conclude that while IPL's 2019 IRP was more thorough, more analytically rigorous, and based on the use of a model that is better suited to performing IRPs than IPL's prior model (though not without its drawbacks), IPL's evaluation of energy efficiency in its IRP was seriously flawed. Indeed, so much so that it is quite possible that a much higher level of savings would have been identified as "optimal" had those flaws been rectified. Specifically, I conclude that:

- The levelized cost of energy efficiency was calculated by incorrectly excluding the full lifetime of savings (*see* Section 5.1 in Attachment AS-2); and
- The modeling did not account for avoided transmission and distribution benefits (*see* Section 5.3 in Attachment AS-2).

[2] The updated Comments on IPL's 2019 IRP are included as Attachment AS-2 with the confidential pages as Attachment AS-2-Confidential. Attachment AS-5-Confidential is the spreadsheet referenced in the Comments as "Confidential - IPL 2019 IRP - Reserve Margin Base and Overbuild Constraint.xlsx" at footnote 28. Attachment AS-6-Confidential is the spreadsheet referenced in the Comments as "IPL 2019 IRP Stakeholder Process, IPL Response to CAC Data Request 3.17, Attachment 'CAC IRP DR 3.17ab Decrement Bundles with Measures'" at footnotes 43 and 45. Attachment AS-7-Confidential is the spreadsheet referenced in the Comments as "IPL 2019 IRP Stakeholder Process, IPL Workpaper Confidential Attachment 5.4 (Avoided Cost)" at footnotes 49-50. Attachment AS-8-Confidential is the spreadsheet referenced in the Comments as "IPL Response to CAC Data Request 3.12, Confidential Attachment CAC Data Request 3-12" at footnote 52.

II. IPL's Energy Efficiency Costs Are Incorrectly Modeled.

Q. Please describe how IPL modeled the cost of energy efficiency.

A. IPL input the energy efficiency ("EE") costs into PowerSimm as a levelized cost.[3] PowerSimm multiplies each bundle's levelized cost by the megawatt hours ("MWh") contained in that bundle. Therefore, the manner in which the bundles' levelized costs are calculated is very important to the selection of EE in IPL's IRP. As further described in Attachment AS-2, IPL's levelized costs used to characterize EE in PowerSimm are based on all costs of energy efficiency incurred through the last year of the planning period - 2039 - but include only the savings through 2039 despite the fact that at least some of the savings persist through 2068. Thus, <u>29 years</u>' worth of savings are eliminated from the calculation of levelized cost. To give an example, under IPL's methodology, the costs spent on EE in 2039 produce savings, some of which have lives that continue until 2068, but only the savings those expenditures produced in 2039 are included in the levelization calculation.

Q. Wouldn't this approach put EE on an equal footing with supply-side resources?

A. No, in fact, it would do the opposite. PowerSimm translates capital costs of supply-side resources into a levelized annual cost. Where the life of a resource would extend beyond the planning period, the levelized costs beyond the end of the planning period are not included in the net present value ("NPV") calculation. This means that the same years' worth of benefits *and* costs are included in the NPV

[3] A levelized cost is the present value of the total cost divided by the energy consumed or saved.

calculation for any given supply side resource. Yet, for energy efficiency, IPL is including *all* costs but excluding the benefits beyond the planning period.

Q. What impact would correcting this flaw have on the modeled levelized costs of energy efficiency in IPL's IRP?

A. Table 1 compares the bundles' levelized costs as modeled by IPL and the corrected levelized costs using the same methodology but appropriately including all savings.

Table 1. Levelized EE Bundle Costs without and with All Savings[4]

Bundle	Levelized Cost without All Savings (per MWh)	Levelized Cost with All Savings (per MWh)
Bundle 1	$12.33	$9.61
Bundle 2	$24.07	$20.34
Bundle 3	$41.44	$31.65
Bundle 4	$55.63	$41.11
Bundle 5	$70.07	$53.94
Bundle 6	$80.48	$68.41
Bundle 7	$140.28	$110.88
Bundle 8	$200.41	$132.09
All Bundles	$53.64	$42.25

Q. And what impact would using the correct levelized cost have on the economic selection of EE in IPL's 2019 IRP?

A. It is very possible that, with these corrected levelized costs, additional EE would have resulted in a lower NPV at higher levels of savings. There is no way to confirm that without being able to reformulate the capacity expansion runs in PowerSimm in order to derive a modified expansion plan with the higher levels of

[4] Based on IPL's Response to CAC Data Request 3-3, Attachment 1 (included as Attachment AS-3, Part 2). IPL's Response to CAC Data Request 3-3 is included as Attachment AS-3, Part 1.

savings, but there are several reasons to think a lower NPV at higher levels of savings would occur if the levelized cost calculation were corrected.

First, all the modeled measures were identified as cost-effective in IPL's Market Potential Study.

Second, IPL provided an average portfolio cost per MWh for each scenario and portfolio combination. This is the average of incremental costs of each run. Figure 1, below, shows the average portfolio incremental cost per MWh for Portfolio 3 with and without a price on carbon dioxide and with either the first 4 bundles or the first 5 bundles of energy efficiency.

[redacted]

Confidential Figure 1. The Levelized Cost of Additional EE is Often Less than Portfolio 3's Average Rates[5]

[5] Confidential – IPL 2019 IRP – PVRR and Rate Impact Summary (included as Attachment AS-4-Confidential); IPL Response to CAC Data Request 3-3, Attachment 1 (Attachment AS-3, Part 2).

In most years, across most bundles, the levelized cost of the combination of the first 6, the first 7, or all 8 bundles of energy efficiency[6] is less than the average incremental rate. Avoided costs do not decline linearly (and may not even decline at all) with additional EE because EE cannot defer a partial unit. Put another way and to give a hypothetical example, if EE contained in the bundles up to and including Bundle 5 was able to defer 19 MW of a 20 MW storage unit that was otherwise needed to meet the reserve margin constraint, the model would not be able to add just 1 MW of storage. Essentially, there are non-obvious inflection points in the effective avoided costs of EE that may trend downward or upward. So, the average incremental rates suggest that system costs would come down with EE in excess of that modeled by IPL, but one would have to perform those runs in order to confirm that it does or does not.

Q. Is calculating levelized cost using the full lifetime of savings the only change you would recommend to IPL's methodology of modeling energy efficiency?

A. No. I think the grouping of EE savings by cost is also problematic. As described in Attachment AS-2:

> *We expressed concern to IPL about using this approach since it does not reflect how IPL actually implements its DSM programs and that it would, therefore, distort the selection of EE. The first bundle of savings that IPL achieves would contain a mix of cost-effective measures, not merely the savings from the least expensive measures. IPL implements a diverse portfolio of measures, some of which would be included in Bundles 1-4, but also others that appear in higher cost bins. For example, there are numerous measures assigned to the Residential Multifamily Direct Install energy savings program. For this program, measures are assigned to Bundle 2 through Bundle 7.[] Since IPL's preferred plan includes only the savings up to and*

[6] Technically IPL modeled 9 bundles of EE but the ninth offered no savings until 2035, so like IPL frequently did in its IRP materials, I exclude it from this discussion.

> *including Bundle 4, will the measures that would otherwise be included in this program contained in Bundles 5 through Bundle 7 just be eliminated? And, if not, will program savings be increased to account for the additional, cost-effective potential that these measures bring? If measures from Bundles 5 through 7 are included in the portfolio without increasing the overall program savings, what happens to the savings from the least expensive measures in Bundles 1 through 4 that are displaced? The other question is how IPL will address programs included in previous DSM filings that were not selected in the IRP modeling. For instance, in the last DSM filing, IPL included a Residential Appliance Recycling program. However, the measures for this program were assigned to Bundles 5 and 7, which were not selected in the IRP modeling.* [internal citations omitted]

In fact, IPL is now proposing a Residential Appliance Recycling program as part of this plan. And this would likely lead to the result of program costs actually going up in the DSM plan relative to the modeled costs of those bundles because the bundles were cherry picked for the lowest cost measures rather than organized by portfolio, preferably, or by program, secondarily. Bundling measures by cost ignores the benefit side of the equation. It may be the case that a measure with a low levelized cost would have a high level of benefit. For example, refrigerator recycling has a cost-effectiveness score of 6.83[7] but the bundles in which it was modeled were not part of the "preferred plan." Furthermore, this is evidence that IPL should have modeled all EE bundles because the measures that provide the most net benefit may be spread out across the bundles.

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[7] IPL Response to CAC Data Request 1-6, Confidential Attachment 1 (included as CAC Exhibit 1, Attachment DM-5-Confidential). IPL's Response to CAC Data Request 1-6 is included as CAC Exhibit 1, Attachment DM-4.

Q. IPL contends that grouping measures by something other than cost "could result in inaccurate planning and future program delivery risk."[8] How do you respond?

A. We disagree on this point. Grouping measures by cost fundamentally relies on the pitfall that IPL cautions against, i.e. that "energy efficiency assumptions are rapidly changing (e.g., LED baselines) which is creating uncertainty and impacting near-term program offerings."[9] Grouping measures by cost is an all or nothing approach, whereas program planning identifies a balance of measures to offer. Under IPL's methodology, a measure is wholly forced into a cost-based bin. This introduces considerable risk and could definitely lead to a disconnect between modeled EE savings and program planning. Instead, modeling energy efficiency as a broad portfolio of measures targeting a wide variety of end-uses would lessen the dependence on being "right" about any given measure.

III. <u>The IRP Did Not Account for Avoided T&D Benefits</u>

Q. Why did IPL's IRP modeling of EE not account for avoided T&D benefits?

A. It is my understanding that PowerSimm cannot explicitly account for avoided transmission and distribution ("T&D"), but those benefits can be modeled as a decrement to the EE bundle costs. However, IPL did not do this. The IURC's IRP rules explicitly require, "An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system."[10]

[8] IPL Reply to Stakeholder Comments re: IPL's 2019 IRP, p. 7 (June 16, 2020).
[9] *Id*.
[10] 170 Ind. Admin. Code 4-7-8(c)(6).

Q. Would including the levelized avoided T&D benefit as a reduction to each EE bundle's avoided cost have solved this issue?

A. Yes, as long as the avoided T&D benefit was correctly derived, accounting for all avoided capacity and its benefits, as well as being based on a methodology that accurately assesses IPL's avoided T&D costs. As described in Section 5.3 of Attachment AS-2, IPL's avoided T&D costs are unreasonably low.

> *Second, the avoided T&D costs calculated by IPL are quite low, especially for the transmission portion. IPL estimated the avoided cost of transmission by taking [redacted]% of the long-term distribution capital costs. IPL did not provide any documentation supporting its selection of that percentage. IPL included a note with the calculation that, "No study was performed to estimate Transmission related avoided costs."[] The avoided cost of distribution is based on the percentage of IPL circuits that may need upgrades. It appears that IPL arrived at this avoided distribution cost by taking [redacted]% of the fixed charges for the distribution circuits. It appears that IPL is basing this on its reported number of circuits that are at or near capacity. It is also important to consider that IPL is projecting an increase in energy and demand for the planning period that is driven by growth in residential sales. We are unsure whether or not IPL factored this into the analysis for avoided T&D costs. The result is $[redacted] per kW-year for avoided distribution costs and $[redacted] per kW-year fo voided transmission costs for a total avoided T&D cost of $[redacted] per kW-year.[]*
>
> *The avoided distribution cost is at the [redacted] of the range identified by the Regulatory Assistance Project in a paper on this topic and the avoided transmission cost is at [redacted] too low:*
>
>> *The capital cost of augmenting transmission capacity is typically estimated at $200 to $1,000 per kilowatt, and the cost of augmenting distribution capacity ranges between $100 and $500 per kilowatt. Annualized values (the average rate of return multiplied by the investment over the life of the investment) are about 10% of these figures, or $20 to $100 per kilowatt-year for transmission and $10 to $50 per kilowatt-year for distribution.[]*
>
> *The total avoided T&D range identified by RAP is $30 per kW-year to $150 per kW-year. IPL's total avoided T&D costs are significantly [redacted] than this low range estimate from RAP.* [internal citations omitted].

IV. Conclusion

Q. What level of energy efficiency savings should this Commission approve?

A. It is unfortunate that not all bundles of savings (totaling 2% of sales) were modeled by IPL, leaving undone an important analysis and set of data that would have been useful to the Commission. That is a lesson learned for us in future IRPs so that a specific savings level can be recommended regardless of the level in the Company's preferred plan. Without that data, I would recommend the highest level modeled by the Company, i.e. the 5 bundles totaling 1.25% of sales. That would give incremental net savings at the generator of 146 GWh in 2021, 146 GWh in 2022, and 149 GWh in 2023. IPL's IRP Portfolio 3 with five, rather than four, EE bundles is no more than about 0.5% greater in cost across multiple scenarios, a difference that is well within the "noise." That gap narrows even more with the inclusion of avoided transmission and distribution benefits. Refining the line loss factor to the more appropriate marginal factor rather than an average one would narrow it even further (*see* Section 5.3 of Attachment AS-2). Furthermore, IPL has demonstrated that an even higher level of savings is achievable in its recent program delivery history. Establishing these levels as IPL's savings goal is eminently reasonable and achievable as described in the Direct Testimony of CAC Witness Dan Mellinger who provides several pathways to reach at least this level of savings.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

I, Anna Sommer, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Anna Sommer

July 29, 2020

Date

ATTACHMENT AS-1

Anna Sommer
Principal

ENERGY FUTURES GROUP

Professional Summary

Anna Sommer is a principal of Energy Futures Group in Hinesburg, Vermont. She has more than 15 years' experience working on a wide variety of energy planning related issues. Her primary focus is on all aspects of integrated resource planning (IRP) including capacity expansion and production costing simulation, scenario and sensitivity construction, modeling of supply and demand side resources, and review and critique of forecast inputs such as fuel prices, wholesale market prices, load forecasts, etc. Additionally, she has experience with various aspects of DSM planning including construction of avoided costs and connecting IRPs to subsequent DSM plans. Anna has had formal training on the Aurora, EnCompass, PowerSimm, and Strategist models and has reviewed modeling performed using numerous models including Aurora, EnCompass, Capacity Expansion Model, PLEXOS, PowerSimm, PROSYM, PROMOD, RESOLVE, SERVM, Strategist, and System Optimizer. She has provided expert testimony in front of utility commissions in Indiana, Michigan, Minnesota, New Mexico, North Carolina, Puerto Rico, South Carolina, and South Dakota.

Experience

2019-present: Principal, Energy Futures Group, Hinesburg, VT
2010-2019: President, Sommer Energy, LLC, Canton, NY
2007-2008: Project Manager, Energy Solutions, Oakland, CA
2003-2007: Research Associate, Synapse Energy Economics, Cambridge, MA

Education

M.S. Energy and Resources, University of California Berkeley, 2010

Master's Project: *The Water and Energy Nexus: Estimating Consumptive Water Use from Carbon Capture at Pulverized Coal Plants with a Case Study of the Upper Colorado River Basin*

B.S., Economics and Environmental Studies, Tufts University, 2003

Additional training

Graduate coursework in Data Analytics – Clarkson University, 2015-2016.
Graduate coursework in Civil Engineering and Applied Mechanics – McGill University, 2010.
Research Experience in Carbon Sequestration (RECS), U.S. Department of Energy, 2009.

Selected Projects

- EfficiencyOne. Supporting EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process. (2019 to present)

Energy Futures Group, Inc
PO Box 587, Hinesburg, VT 05461 – USA | 315-386-3834 | asommer@energyfuturesgroup.com

- Minnesota Center for Environmental Advocacy. Evaluation of Xcel Energy's 2020 Integrated Resource Plan and Strategist modeling in support of that evaluation. (2019 to present) Evaluation of Minnesota Power Company's proposal to build a new natural gas combined cycle power plant and Strategist modeling of alternatives to the plant. Comments regarding Great River Energy's integrated resource plan to meet future energy and capacity needs. (2018) Comments regarding Otter Tail Power's integrated resource plan to meet future energy and capacity needs. Comments regarding Minnesota Power's integrated resource plan to meet future energy and capacity needs. (2016) Comments regarding Great River Energy's integrated resource plan to meet future energy and capacity needs. (2015) Comments regarding Otter Tail Power's integrated resource plan to meet future energy and capacity needs. (2014) Comments regarding Xcel Energy's Sherco 1 and 2 Life-Cycle Management Study. Comments regarding Minnesota Power's proposal to retrofit Boswell Unit 4. Comments regarding Minnesota Power's integrated resource plan to meet future energy and capacity needs. Comments regarding Xcel Energy's integrated resource plan to meet future energy and capacity needs. (2013) Evaluation of Otter Tail Power's plan to diversify its baseload resources. Comments regarding Minnesota Power's "Baseload Diversification Study" – a resource planning exercise examining the use of fuels other than coal to serve baseload needs. (2012) Comments regarding IPL's integrated resource plan to comply with pending EPA regulations and meet future capacity and energy needs. (2011) Evaluation of a proposal by seven utilities to build a new supercritical pulverized coal plant including alternatives to the plant and potential for greenhouse gas regulation. (2006)
- Coalition for Clean Affordable Energy. Evaluation of Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station. (2019 to 2020)
- Earthjustice. Evaluation of the Puerto Rico Electric Power Authority's 2019 Integrated Resource Plan. (2019 to 2020)
- Citizens Action Coalition of Indiana. Evaluation of Southern Indiana Gas and Electric's proposal to offer DSM programs to its customers. (2020 to present) Comments regarding Indianapolis Power & Light's integrated resource plan to meet future energy and capacity needs. (2020) Advising stakeholders on stakeholder workshops in preparation for Southern Indiana Gas and Electric's integrated resource plans to meet future energy and capacity needs. Evaluation of Indianapolis Power & Light's proposal to offer DSM programs to its customers. Evaluation of Duke Energy Indiana's proposal to offer DSM programs to its customers. Evaluation of Indiana Michigan Power's proposal to offer DSM programs to its customers. (2019 to present) Comments regarding Duke Energy Indiana's integrated resource plan to meet future energy and capacity needs. Comments regarding Indiana Michigan Power's integrated resource plan to meet future energy and capacity needs. (2019) Comments on Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (2019) Evaluation of Southern Indiana Gas and Electric's proposal to build a new natural gas combined cycle power plant. (2018) Evaluation of Duke Energy Indiana's proposal to offer DSM programs to its customers. Evaluation of Southern Indiana Gas and Electric's proposal to offer DSM programs to its customers. Comments regarding Southern Indiana

Gas and Electric Company's integrated resource plans to meet future energy and capacity needs. Comments regarding Indianapolis Power & Light's integrated resource plan to meet future energy and capacity needs. Comments regarding Northern Indiana Public Service Company's integrated resource plan to meet future energy and capacity needs. (2017) Comments regarding Duke Energy Indiana and Indiana Michigan Power's integrated resource plans to meet future energy and capacity needs. (2016)

- Environmental Law and Policy Center. Evaluation of DTE Energy's 2019 Integrated Resource Plan modeling and Strategist modeling in support of that evaluation. (2019)
- New Energy Economy. Evaluation of Public Service Company of New Mexico's Strategist modeling of coal plant retirement scenarios. (2017)
- Institute for Energy Economics and Financial Analysis. Evaluation of Puerto Rico Electric Power Authority's plan to build an offshore LNG port. (2017) Evaluation of Puerto Rico Electric Power Authority's proposal to meet future energy and capacity needs.

Selected Publications

The Husker Energy Plan: A New Energy Plan for Nebraska, prepared by Anna Sommer, Tyler Comings, and Elizabeth Stanton for the Nebraska Wildlife Federation. January 16, 2018.
Pennsylvania Long-Term Renewables Contracts Benefits and Costs, prepared by Elizabeth Stanton, Anna Sommer, Tyler Comings, and Rachel Wilson for the Mid-Atlantic Renewable Energy Coalition. October 27, 2017.
"Pursue Carbon Capture and Utilization of Storage," "Establish Energy Savings Targets for Utilities," and "Tax Carbon Dioxide Emissions," in Implementing EPA's Clean Power Plan: A Menu of Options, prepared by Anna Sommer for the National Association of Clean Air Agencies and the Regulatory Assistance Project. June 7, 2015.
Overpaying and Underperforming: The Edwardsport IGCC Project, prepared by Anna Sommer for Citizens' Action Coalition, Save the Valley, Valley Watch, and Sierra Club. February 3, 2015.
Public Utility Regulation Without the Public: The Alabama Public Service Commission and Alabama Power, prepared by David Schlissel and Anna Sommer for Arise Citizens' Policy Project. March 1, 2013.
A Texas Electric Capacity Market: The Wrong Tool for a Real Problem, prepared by Anna Sommer and David Schlissel for Public Citizen of Texas. February 12, 2013.
Independent Administration of Energy Efficiency Programs: A Model for North Carolina, prepared by David Nichols, Anna Sommer, and William Steinhurst for Clean Water for North Carolina, April 13, 2007.
Integrated Portfolio Management in a Restructured Supply Market, prepared by Paul Chernick, Jonathan Wallach, William Steinhurst, Tim Woolf, Anna Sommer, and Kenji Takahashi. June 30, 2006.
Ensuring Delaware's Energy Future: A Response to Executive Order No. 82, prepared by the Delaware Cabinet Committee on Energy with technical assistance at Synapse Energy Economics from William Steinhurst, Bruce Biewald, David White, Kenji Takahashi, Alice Napoleon, Amy Roschelle, Anna Sommer, and Ezra Hausman for the Delaware Public Service Commission staff. March 8, 2006.

"Assessment of Carbon Sequestration Feasibility and Markets," by Anna Sommer and William Steinhurst, in Mohave Alternatives and Complements Study, a Sargent & Lundy and Synapse Energy Economics, Inc., report prepared for Southern California Edison. February 2006.

Potential Cost Impacts of a Renewable Portfolio Standard in New Brunswick, prepared by Tim Woolf, David White, Cliff Chen, and Anna Sommer for the New Brunswick Department of Energy. October 2005.

Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value, prepared by Lucy Johnston, Amy Roschelle, Ezra Hausman, Anna Sommer, and Bruce Biewald as a Synapse Energy Economics, Inc. report. September 20, 2005.

Potential Cost Impacts of a Vermont Renewable Portfolio Standard, prepared by Tim Woolf, David E. White, Cliff Chen, and Anna Sommer as a Synapse Energy Economics, Inc. report for the Vermont Public Service Board. October 16, 2003.

Presentations and Articles

"Practical Strategies for the Electricity Transition." A presentation at Energy Finance 2019. June 18, 2019.

"Carbon Capture and Storage." A presentation at Energy Finance 2018. March 13, 2018.

"Puerto Rico's Electric System, Before and After Hurricane Maria." A webinar with Cathy Kunkel on behalf of the Institute for Energy Economics and Financial Analysis. October 24, 2017.

"Rebutting Myths About Energy Efficiency." A presentation at the Beyond Coal to Clean Energy Conference sponsored by Sierra Club and Energy Foundation. October 8, 2015.

"The Energy and Water Nexus: Carbon Capture and Water." A presentation at the Water and Energy Sustainability Symposium. September 28, 2010.

"Carbon Sequestration." A presentation to Vermont Energy Investment Corporation. August 17, 2009.

"Carbon Dioxide Emissions Costs and Electricity Resource Planning." A presentation before the New Mexico Public Regulation Commission with David Schlissel. March 28, 2007.

"Electricity Supply Prices in Deregulated Markets – The Problem and Potential Responses." A presentation at the NASUCA Mid-Year Meeting with Rick Hornby and Ezra Hausman. June 13, 2006.

"IGCC: A Public Interest Perspective." A presentation at the Electric Utilities Environmental Conference 2006. January 24, 2006.

Woolf, Tim, Anna Sommer, John Nielsen, David Barry and Ronald Lehr. "Managing Electric Industry Risk with Clean and Efficient Resources," The Electricity Journal, Volume 18, Issue 2, March 2005.

Woolf, Tim, and Anna Sommer. "Local Policy Measures to Improve Air Quality: A Case Study of Queens County, New York," Local Environment, Volume 9, Number 1, February 2004.

Professional Affiliations

Board Member, **Public Utility Law Project of New York,** 2018 – present

Board Member, **Community Development Program of St. Lawrence County,** 2017 – present

ATTACHMENT AS-2

Redlined Pages

Report on
Indianapolis Power & Light Company's
2019 Integrated Resource Plan

Submitted to the IURC on April 16, 2020

Revised July 29, 2020

Authors:

Anna Sommer, Energy Futures Group
Chelsea Hotaling, Energy Futures Group
Dan Mellinger, Energy Futures Group

On behalf of Citizens Action Coalition and Earthjustice

3.2 POWERSIMM OPTIMIZATION

Following the release of the initial PowerSimm modeling files by IPL on October 28, 2019, CAC spoke with IPL about modeling additional EE bundles for the IRP. IPL provided updated modeling files showing the fourth and the fifth EE bundles[10] forced in – the bundles roughly equal to 1 percent of sales and 1.25 percent of sales incremental savings, respectively. Surprisingly, forcing in the fourth EE bundle resulted, in many instances, in a lower net present value ("NPV")[11] than in the optimized model runs, which did not pick beyond the first three EE bundles. This is surprising because, by definition, the optimal plan should produce the lowest cost plan.

Table 5 below compares the NPV results for Portfolio 3 across Bundles 3, 4, and 5. The addition of the fifth bundle also resulted in lower cost plans, compared to those with only three bundles, across all scenarios except for the reference scenario as indicated by the green highlight. Given these results, IPL revised its preferred plan to include Bundle 4, but did not commit to pursuing savings consistent with Bundle 5.

Table 5. NPV of Portfolio 3 with Bundles 3, 4, and 5 under Different Scenarios[12]

Scenario	Portfolio 3 with Bundle 3 (Portfolio 3A)	Portfolio 3 with Bundle 4 (Portfolio 3B)	Portfolio 3 with Bundle 5 (Portfolio 3C)
Ref	$7,016	$6,976	$7,034
A	$7,737	$7,661	$7,716
B	$8,211	$8,114	$8,165
C	$6,843	$6,786	$6,842
D	$7,798	$7,739	$7,794

We are very concerned that PowerSimm would develop an "optimal" plan with a lower level of EE and a higher NPV than the results from forcing additional bundles into the model. Indeed, the difference can be~~is~~ quite significant on a percentage basis as shown in Table 6.

Table 6. NPV Percentage Difference between Portfolio 3 with Bundles 3, 4, and 5

Scenario	NPV % Difference between Bundles 3 and 4	NPV % Difference between Bundles 3 and 5
Ref	-0.57%	0.26%
A	-0.99%	-0.28%
B	-1.20%	-0.56%
C	-0.84%	-0.01%
D	-0.76%	-0.05%

[10] IPL often uses the word "decrement" to describe its bundles, but its bundles are not decrements in the sense we mean when describing a decrement approach or as the term is defined in Merriam-Webster's Dictionary, i.e., "the amount of decrease." IPL's bundles are modeled on the supply-side with an assigned cost—they are not a reduction to load. Therefore, we use the term "bundle" throughout these comments.
[11] Throughout these comments, we use NPV and present value of revenue requirements ("PVRR") interchangeably.
[12] NPVs from workbook, 'Confidential – IPL 2019 IRP – PVRR and Rate Impact Summary'

It does not make sense that the optimized portfolios with Bundle 3 would have substantially higher NPVs than the portfolios with Bundles 4 and 5 forced in. Based on these results, PowerSimm should have returned an optimized result that included Bundle 4 since it results in the lowest cost plan.

We learned about this issue with the data provided in advance of IPL's last stakeholder meeting on December 9, 2019. We held a follow-up meeting with IPL the week of December 16, 2019 (which is when IPL filed the IRP), to discuss this issue and then received a follow-up email from Patrick Maguire on February 3, 2020. During our December meeting, we had hypothesized that there may have been something wrong with the tolerance setting used in the modeling. Mixed integer programming ("MIP") models like PowerSimm use this setting to specify when to stop the optimization process. Ascend describes the tolerance setting in the Automated Resource Selection ("ARS") module, the capacity expansion module of PowerSimm, as follows: [13]

> *The optimization engine for ARS finds the optimal unconstrained solution, then goes through a solving routine until it finds a constrained solution within a given tolerance. That tolerance is set to 0.0001 or 0.01%, meaning that we are requiring the solution to be within 0.01% of the unconstrained optimal solution.*

In this instance, the "optimal unconstrained solution" means the optimal linear solution in each modeling run. MIP models enforce integer constraints on variables like the number of new resources added, e.g., only whole numbers of units can be added as opposed to say 1.5 units. The linear solution relaxes all of those constraints, so it can solve more quickly. As shown in Table 6, there is a significant difference in NPV between the same portfolio but with higher numbers of EE bundles. Though this NPV difference is not relative to the "optimal unconstrained solution," it is significant enough that it raises questions about whether the optimization was appropriately set up to result in the "optimal" plan. Put another way, if under the Reference Case scenario, the tolerance setting was appropriately applied, then Portfolio 3 with Bundle 3 should be within 0.01 percent or less of the optimal unconstrained solution. However, since Portfolio 3 with Bundle 4 is 0.57 percent *less* expensive than Portfolio 3 with Bundle 3, then ~~the tolerance setting really needed to be specified in a much narrower band to arrive at what was truly the optimal plan.~~something must be amiss. Even with read-only access to PowerSimm, one cannot see: the Company's tolerance setting, the resulting gap in NPV between the optimal integer and linear relaxation results, or even the NPV as calculated by PowerSimm of the optimal plan itself. It is our understanding that IPL cannot see these either. This makes it nearly impossible to understand why a plan with forced in resources would be cheaper.

In a follow-up email on this topic, Mr. Maguire said the difference was due to other factors:[14]

> *Two other things to keep in mind. First is that we are calculating the PVRR outside of the model and the way PowerSimm calculates a levelized cost for each project, which is similar to how other models work, is slightly different than our financial revenue requirement model. Additionally, we made other changes post-ARS*

[13] Personal Communication with Patrick Maguire, December 10, 2019.
[14] Personal Communication with Patrick Maguire, February 3, 2020.

> *optimization, primarily for wind and the number of projects moved up to 2021. Both of these impact the PVRR calculation that are not picked up in the ARS optimization.*

Unfortunately, this explanation does not assuage our concerns. Because we do not have the NPVs as they would be calculated by PowerSimm, we cannot verify that the optimized NPVs are not actually higher than those with the forced-in additional energy efficiency from the standpoint of PowerSimm. More importantly, however, it does not make sense to us that these factors would result in not just different NPVs, but also in a reordered ranking of the modeling results. For example, if the unspecified changes in "wind and the number of projects moved up to 2021" results in a plan becoming cheaper by the degree shown in Table 6, then this is merely a different way of describing the same problem or is another flavor of the same problem – that forced-in changes could result in a much more optimal portfolio. The explanation also brings light to a new, potentially significant concern: that the Excel spreadsheets summarizing IPL's modeling runs do not show the actual optimization results from PowerSimm, a fact not communicated to stakeholders. Further, it seems unlikely that moving projects up, including wind, would influence the optimization in this way because resources are being dispatched against a market price, not against load. So the model is not actually weighing the tradeoff between advancing wind and choosing more EE to the extent that other, system-wide constraints such as the reserve margin constraints do not bind.[15] The model is choosing each resource based on its individual ability to reduce system cost compared to the market price that load would pay to otherwise procure that energy. Put another way, we do not see why moving wind around in time would enable *energy efficiency* to reduce system costs.

It also does not make sense to us that performing a second present value calculation outside of PowerSimm would result in this change. In a separate case involving PowerSimm, we were provided with PowerSimm's generic net present value formula and do not see any meaningful differences between that and IPL's NPV value methodology. Typically, out of model adjustments result in a different NPV, but not a wholesale change to the rank order of portfolios since the change in methodology does not change the underlying costs included in the modeling. One would be more likely to see a change in rank order with the addition of costs not considered by the model, but that does not appear to be the case here with two exceptions. First, Concentric, the company that developed IPL's out-of-model NPV calculations, added in a "bad debt expense," but that expense was calculated on the same percentage basis of [redacted]% across all portfolios so that should not change the relative rankings. PowerSimm adds a "risk premium" into its NPV calculations, which were not included in Concentric's model. However, as Figure 8.34 of the IRP shows, recreated below as Figure 3, adding in the risk premium does not make Portfolio 3 with Bundle 3 (i.e., Portfolio 3A) the lowest cost version of Portfolio 3 in any scenario except the Reference Case.

[15] We discuss the reserve margin constraints in Section 3.4 of these Comments.

3.4 MODELING CONSTRAINTS

3.4.1 RESERVE MARGIN CONSTRAINTS

IPL modeled a reserve margin penalty within PowerSimm. In the IRP, IPL states, "The PowerSimm model is designed to impose a 'penalty' to portfolios that exceed the reserve margin target or are short of the reserve margin target."[25] The penalty IPL modeled is $100,000/MW for every MW that is over the maximum build constraint specified by IPL.[26] In response to CAC Informal Discovery Set 3, IPL stated, "This penalty is applied to the objective function of minimizing portfolio costs, thus incentivizing the capacity expansion model to not overbuild. The penalty is not a real expense applied to the portfolio and does not show up in the PVRR; it is only used to influence resource selection."[27]

This penalty is significant enough that no "optimal" portfolio exceeded the reserve margin constraints. And because we cannot use PowerSimm ourselves, we cannot tell what plans the model would have produced in absence of this constraint. However, we did note, in a workbook[28] provided by IPL, that the maximum reserve margin constraint was highest for Portfolio 1 and lower for Portfolios 2 through 5 during the key years of the analysis, 2021 – 2032. IPL does not explain why each portfolio ought to be treated differently in this regard.

For Portfolios 3 through 5, the difference between the minimum reserve margin and the max Build Constraint, which were each specified annually, was just [redacted] MW in each year between 2023 and 2039. For Portfolios 1 and 2, it only became [redacted] MW in 2033 and 2031, respectively. IPL says that it set the MAX Build Constraint such that all DSM bundles could be selected,[29] but ~~we do not see how that could be the case. T~~the workbook provided to us that shows how the reserve margin constraints were developed uses a formula that accounts only for the capacity associated with the first 8 bundles; it does not include the ninth bundle nor the demand response bundles. ~~for "Annual Cumulative DSM Decrements." We assume this means the total cumulative MW impact of the EE bundles, but the numbers in that column are incorrect. For example, IPL's calculation assumes~~ [redacted] ~~MW of DSM in 2024, but IPL's "Confidential Attachment CAC DR 3-12.4_Decrement Levelized Cost" shows a cumulative total of~~ [redacted] ~~MW, and this does not include the demand response bundles.~~

~~Admittedly, we do not fully understand how these constraints impact the selection of all new resources, but t~~These constraints~~y~~ seem likely to have influenced the optimal portfolio, which raises a concern. We have pointed out in other IRPs that overbuilding capacity can be a risky proposition. This seems to be part of the justification for using this constraint and, in that sense, we are on the same page as IPL. However, we would rather see overbuilding manifest itself in the optimization and then have the modeler change the settings or the portfolio in some fashion to address the problem. IPL also imposes an energy constraint that it characterized as generally

[25] IPL 2019 IRP Submission, p. 122.
[26] IPL 2019 IRP Stakeholder Process, IPL Response to CAC Informal Data Request 4-5.
[27] IPL 2019 IRP Stakeholder Process, IPL Response to CAC Informal Data Request 3-19.
[28] Confidential - IPL 2019 IRP - Reserve Margin Base and Overbuild Constraint.xlsx
~~[29] IPL 2019 IRP Stakeholder Process, IPL Response to CAC Informal Data Request 4 – 5.~~

not binding,[30] but typically resources are overbuilt because the model thinks that significant off-system sales can be made at net positive profit so both the energy and the reserve margin constraint are imposed for the same reasons. The narrowness of the band between the minimum and maximum reserve margin constraints strikes us as overly restrictive on the optimization and likely to prevent the model from selecting what is truly the optimal plan.

3.4.2 ADDING COMBINED CYCLE AS FIXED RESOURCE

For this IRP, IPL included a fixed resource decision across all its portfolios to model a proxy resource for firm capacity once the Harding Street steam units retire. IPL chose a 1x1, 325 MW combined cycle ("CC") unit as the proxy resource to add to all portfolios in 2034. Since IPL has not performed a reliability study on what would be the best replacement resources for the Harding Street units, IPL decided to model a CC to present the firm capacity that is needed in place of the Harding Street units. IPL states, "The actual firm capacity need and solution will likely change through time and could be a different technology."[31] We acknowledge that IPL's intention is for the CC to be a proxy resource, but as we get closer to that date, we would like to see IPL model scenarios that include renewables, storage, energy efficiency, and demand response as replacement capacity for the Harding Street units.

[30] Personal communication with Will Vance, July 24, 2020.
[31] IPL 2019 IRP Submission, p. 156

3.5 EXPECTATIONS FOR FUTURE IMPROVEMENTS

One of the expectations for future improvements identified by IPL is the seasonal resource adequacy ("RA") construct currently under exploration by MISO. We appreciate that IPL did not include a seasonal resource adequacy construct as the base case assumption in its modeling in this IRP. MISO is exploring a number of rule changes to address MaxGen[32] events and ensure future reliability. ~~,~~ ~~but a~~ A seasonal RA construct is ~~by no means a foregone conclusion~~one of the potential options, but we think it is highly uncertain that such a construct, even if implemented, would simply require the application of the same reserve margin year-round. ~~The~~ A ~~most~~ recent~~ly~~ ~~available~~ MISO presentation on this topic says that stakeholders have told MISO that "MISO's current analysis [is] unconvincing as a basis for pursuing a seasonal resource adequacy construct" and MISO responded that its "analysis to date, coupled with historical events, has been intended to provide evidence that exploring a seasonal construct is warranted. MISO will continue to work with stakeholders on analysis to support any future changes."[33]

IPL includes the MISO seasonal resource adequacy in its discussion of expectations for future improvements. IPL states:

> *Resource capacity credit can vary by season, requiring careful consideration of a portfolio used to serve load reliably. MISO continues to evaluate the existing capacity construct that IPL participates in through a stakeholder process. Changes to the capacity construct that include seasonality as opposed to an annual consideration could have a significant impact on the capacity credit for renewables*[34].

CAC hopes that IPL's intention for future modeling of a seasonal resource adequacy will be dependent on a final decision by MISO and/or will explore a wide range of potential constructs because of the importance that this assumption has on the optimization of resources.

---

[32] Maximum Generation events occur when the economic supply of energy is not sufficient to meet fixed demand.
[33] *See* PDF page 8 of https://cdn.misoenergy.org/20190807%20RASC%20Item%2004b%20RAN%20Phase%203%20(RASC010)369675.pdf
[34] IPL 2019 IRP Submission, p. 205.

additional, cost-effective potential that these measures bring? If measures from Bundles 5 through 7 are included in the portfolio without increasing the overall program savings, what happens to the savings from the least expensive measures in Bundles 1 through 4 that are displaced? The other question is how IPL will address programs included in previous DSM filings that were not selected in the IRP modeling. For instance, in the last DSM filing, IPL included a Residential Appliance Recycling program.[44] However, the measures for this program were assigned to Bundles 5 and 7,[45] which were not selected in the IRP modeling.

It is not credible to argue that the bundles are merely proxies for overall program savings of similar costs. First, that assumes that the shape of all measures are substitutable for each other. Even more importantly, if Figure 8 was reworked to present the MPS savings by program type, then the supply curve of EE would look much more flat. This is because the less expensive measures would average out the costs of the more expensive measures, the result of which would almost certainly be the selection of additional EE as long as not all the bundles are "optimal".

Indeed, using IPL's levelization methodology, if all bundles were grouped into one bundle, then the overall levelized cost would be $[redacted] per MWh, much lower than the $[redacted] per MWh cost of the last bundle modeled by IPL. ~~The levelized cost of Bundle 3, the last bundle picked in the optimized PowerSimm runs, was $~~[redacted] ~~per MWh; and~~ In fact, this is even lower than the levelized cost of Bundle 4, $[redacted] per MWh, which is the bundle that was forced in but still reduced system NPV~~, was $~~[redacted] ~~per MWh~~.

There are several additional errors and conservatisms that likely impacted the selection of energy efficiency. For example, the levelized costs cited in the previous paragraph are based on the present value of all bundle costs through the end of the planning period in 2039, but that present value is divided by the present value of energy savings only through 2039 as well. ~~We suspect that~~ IPL, therefore, has an "end-effects" problem with respect to energy efficiency. And that end-effects problem begins almost immediately. For example, if the bundles available to the model in 2021 include measures with a 20-year life, because the planning period ends in 2039, then the model accounts for the full cost of that measure but only 19 years' worth of that measure's savings. And the problem grows with each year and each new measure added.

Taking the present value of bundle costs through 2039 and the present value of *all* savings those bundles produce, not a truncated amount, yields a bundle levelized cost of $[redacted] per MWh, which is significantly less than the modeled levelized cost of Bundle 4.

~~We do not know precisely how bundle costs were input into PowerSimm, although we suspect they were input as "as-spent dollars." But whether input in as as-spent dollars or some version of IPL's levelized costs were used, the same end-effects problem applies and would definitely bias the model against energy efficiency.~~

~~Further, the levelized costs were calculated using a nominal discount rate. However, IPL's MPS~~

[44] Appliance recycling program includes refrigerators, freezers, and AC units. *See* IURC Cause No. 44945, Direct Testimony of Zac Elliot.
[45] IPL 2019 IRP Stakeholder Process, IPL Response to CAC Data Request 3.17, Attachment "CAC IRP DR 3.17ab Decrement Bundles with Measures."

~~appears to use nominal dollars for incentive costs, but real dollars for non-incentive costs. Taking the present value of the real dollar costs using a nominal discount rate raises the levelized cost compared to what it actually would be.~~

Finally, the bundle savings ~~were~~ should have been converted to savings at the generator using a marginal loss factor ~~of~~ [redacted] ~~percent. This loss factor strikes us as improbably low even for an average line loss factor, and IPL should have used~~rather than an ~~marginal~~ average line loss factor because, by definition, energy efficiency reduces losses at the margin. Using ~~such~~ a marginal factor would further reduce IPL's levelized costs by as much as 14 percent.[46]

5.2 ENERGY EFFICIENCY SELECTED IN THE IRP FALLS SHORT OF HISTORICAL PERFORMANCE

The level of EE selected in this IRP falls short of the savings IPL has historically achieved. Table 12 shows the level of 2018 evaluated savings for IPL - 161,685,625 kWh.

[46] Based on the Regulatory Assistance Project's paper on accounting for avoided line losses: https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf

IPL is basing this on its reported number of circuits that are at or near capacity. It is also important to consider that IPL is projecting an increase in energy and demand for the planning period that is driven by growth in residential sales. We are unsure whether or not IPL factored this into the analysis for avoided T&D costs. The result is $[redacted] per kW-year for avoided distribution costs and $[redacted] per kW-year for avoided transmission costs for a total avoided T&D cost of $[redacted] per kW-year.[50]

The avoided distribution cost is at the [redacted] of the range identified by the Regulatory Assistance Project in a paper on this topic and the avoided transmission cost is at [redacted] too low:

> *The capital cost of augmenting transmission capacity is typically estimated at $200 to $1,000 per kilowatt, and the cost of augmenting distribution capacity ranges between $100 and $500 per kilowatt. Annualized values (the average rate of return multiplied by the investment over the life of the investment) are about 10% of these figures, or $20 to $100 per kilowatt-year for transmission and $10 to $50 per kilowatt-year for distribution.*[51]

The total avoided T&D range identified by RAP is $30 per kW-year to $150 per kW-year. IPL's total avoided T&D costs are significantly [redacted] than this low range estimate from RAP.

Confidential Table 13 shows the comparison between the levelized T&D benefit and the corrected cost of each EE bundle modeled by IPL. The T&D benefit is based on IPL's avoided T&D calculation contained in the 2019 IRP and escalated at the rate of inflation. This calculation is not precise because we lack the lifetime avoided peak capacity and therefore exclude both the avoided capacity benefits and the avoided savings after 2039.~~derived from the capacity provided by the bundles and the avoided T&D costs IPL used in their last DSM case.~~ ~~[52]~~

Confidential Table 13. Levelized T&D Benefit and IPL Levelized Cost of EE Bundles (per MWH)[53]

Bundle	T&D Benefit~~[54]~~	EE Cost
1	[redacted]	[redacted]
2		
3		
4		
5		

[50] IPL 2019 IRP Stakeholder Process, IPL Workpaper Confidential Attachment 5.4 (Avoided Cost).
[51] P. 6 of Lazar and Baldwin (2011). Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements. RAP. Retrieved from http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf
~~[52] Avoided T&D costs from DSM Cause 44945 provided in Informal Discovery CAC 3-20. Please note the avoided T&D costs start out at a value similar to the single point avoided T&D cost calculated by IPL for this IRP.~~
[53] Levelized DSM Costs provided in IPL 2019 IRP Stakeholder Process, IPL Response to CAC Data Request 3.12, Confidential Attachment CAC Data Request 3-12.4 corrected to include lifetime savings.
~~[54] Avoided T&D costs from DSM Cause 44945 provided in IPL 2019 IRP Stakeholder Process, IPL Response and Attachment to CAC Data Request 3-20. Please note the avoided T&D costs are similar to the avoided T&D costs calculated by IPL for this IRP.~~

6	[redacted]	[redacted]
7	[redacted]	[redacted]
8	[redacted]	[redacted]

If the avoided T&D cost is changed to $70 starting in 2021 and escalated at IPL's assumed inflation rate of 2 percent, the T&D benefit for each bundle significantly increased as shown in Confidential Table 14.

Confidential Table 14. Levelized T&D Benefit at $70 and Cost of EE Bundles ($/MWH)

Bundle	T&D Benefit[55]	EE Cost
1	[redacted]	[redacted]
2	[redacted]	[redacted]
3	[redacted]	[redacted]
4	[redacted]	[redacted]
5	[redacted]	[redacted]
6	[redacted]	[redacted]
7	[redacted]	[redacted]
8	[redacted]	[redacted]

A higher avoided T&D cost is more in line with the avoided T&D cost of other utilities. Confidential Figure 10 and Confidential Figure 11 show the avoided transmission and distribution costs for utilities included in a database of avoided T&D costs created by consulting company Synapse Energy Economics. The average avoided transmission cost across the utilities was $30 per kW-year and the average avoided distribution cost was $62 per kW-year for a total average T&D cost of $92 per kW-year in 2015$. ~~Using~~ Even if Confidential Table 14 had assumed $70 per kW-year~~r, even~~ in 2015$ that ~~,~~would still be [redacted] than the average avoided T&D in this database.

[55] Avoided T&D benefit starts at $70 in 2021 and escalates at a rate of 2%.

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Report on
Indianapolis Power & Light Company's
2019 Integrated Resource Plan

Submitted to the IURC on April 16, 2020

Revised July 29, 2020

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On behalf of Citizens Action Coalition and Earthjustice

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Overview

The following comments on the 2019 Integrated Resource Plan ("IRP") submitted by Indianapolis Power and Light Company ("IPL" or the "Company") were prepared by Anna Sommer, Chelsea Hotaling, and Dan Mellinger of Energy Futures Group. These comments were prepared for Citizens Action Coalition of Indiana ("CAC") and Earthjustice pursuant to the Indiana Utility Regulatory Commission's ("IURC" or "Commission") Integrated Resource Planning Rule, 170 IAC 4-7.

Our review of IPL's 2019 IRP is organized in response to guidance on IRP preparation in the IURC's IRP Rule. While CAC we has concerns about the categories mentioned above are concerned particularly with the optimization of energy efficiency in this IRP, IPL deserves significant credit for the marked improvement it exhibited throughout this IRP in contrast to its prior IRP. IPL's 2016 IRP stakeholder process was contentious, did not result in the resolution of issues raised by stakeholders, and did not encourage active participation on the part of stakeholders. IPL's process for this IRP was the virtual opposite in all these respects. We felt that IPL staff wanted to hear from stakeholders and incorporated their feedback in many, though not all, respects. Rather than reacting defensively to criticism and suggestions from stakeholders, IPL actively sought out feedback from stakeholders.

Finally, IPL's IRP is more thorough, more analytically rigorous, and based on the use of a model, though not without its drawbacks, that is better suited to performing IRPs. We greatly appreciated the collaborative thoughtfulness, attention to detail, and collaborative process and transparency that were core in this 2019 IRP process.

Table 1 gives the Indiana IRP rule sections and provides the section in which those requirements will be addressed in detail. Our review of IPL's 2019 IRP and our participation in its pre-IRP stakeholder workshops raised the following main categories of concern:

- IPL's post-modeling revenue requirement model revealed that, under most scenarios, Portfolio 3 with incremental energy efficiency ("EE") savings of 1 percent and 1.25 percent of sales was cheaper than Portfolio 3 with an "optimized" level of EE – or .75 percent savings. This fact raises questions about whether the optimal level of EE was actually identified. (Section 3.2);
- IPL appears to have incorrectly modeled the cost of EE in several ways that would bias the model against EE (Sections 5.1, 5.2, and 5.3,);
- Particularly for the portfolios in which additional Petersburg units were retired, the constraints placed on renewable resources likely limited the selection of otherwise cost-effective resources (Section 3.1);
- IPL's retirement analysis focused on a set of fixed decisions without exploring the results of optimized retirement (Section 3.3); and
- IPL imposed reserve margin constraints that seem likely to have prevented the model from picking an optimal plan (Section 3.4.1).

While we are concerned particularly with the optimization of energy efficiency in this IRP, IPL deserves significant credit for the marked improvement it exhibited throughout this IRP in contrast to its prior IRP. IPL's 2016 IRP stakeholder process was contentious, did not result in the resolution of issues raised by stakeholders, and did not encourage active participation on the part of stakeholders. IPL's process for this IRP was the virtual opposite in all these respects. We felt that IPL staff wanted to hear from stakeholders and incorporated their feedback in many, though not all, respects. Rather than reacting defensively to criticism and suggestions from stakeholders, IPL actively sought out feedback from stakeholders.

Finally, IPL's IRP is more thorough, more analytically rigorous, and based on the use of a model, though not without its drawbacks, that is better suited to performing IRPs. We greatly appreciated the thoughtfulness, attention to detail, and collaborative process that were core to this 2019 IRP process.

Table 1. Summary of IPL's Achievement of Indiana IRP Requirements

IRP Rule Section	Description	Findings	Citation
Integrated Resource Plan Submission	The IRP submission should include a non-technical appendix and an IRP summary that communicates core IRP concepts and results to a nontechnical audience.	**Partial**	See Section 1
Public Advisory Process	The IRP process should be developed and carried out to include stakeholder participation.	**Met**	See Section 2
Integrated Resource Plan Contents	The IRP should provide stakeholders with all of the information necessary to understand how the IRP modeling was performed.	**Partial**	See Section 3
Energy and Demand Forecasts	The IRP should clearly explain how energy and demand forecasts were developed and used for the IRP.	**Mostly**	See Section 4
Description of Available Resources	The IRP must include important characteristics for existing and new resources included in the IRP.	**Partial**	See Section 5
Selection of Resources	The IRP should describe the screening process used for evaluating future resources.	**Mostly**	See Section 6
Resource Portfolios	The IRP should discuss the preferred portfolio and discuss how alternative portfolios were developed to consider different scenarios.	**Mostly**	See Section 7
Short Term Action Plan	The IRP should discuss how the preferred portfolio will be implemented over the next five years.	**Mostly**	See Section 8

1 Integrated Resource Plan Submission

Section 1 describes our assessment of IPL's performance in meeting the requirements of 170 IAC 4-7-2 of the Indiana IRP Rule. Please see Table 2 below for our findings.

Table 2. Summary of IPL's Achievement of Indiana IRP Rule 170 IAC 4-7-2

IRP Rule	IRP Rule Description	Finding
4-7-2 (c)	Utility must submit electronically to the director or through an electronic filing system if requested by the director or through an electronic filing system if requested by the director, the following documents: (1) The IRP;	**Met**
4-7-2 (c)	(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP. The technical appendix shall include at least the following: (A) The utility's energy and demand forecasts and input data used to develop the forecasts; (B) The characteristics and costs per unit of resources examined in the IRP; (C) Input and output files from capacity planning models (in electronic format); (D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file;	**Partial**
4-7-2 (c)	(3) An IRP summary that communicates core IRP concepts and results to nontechnical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) public advisory process; and (vi) additional details requested by the director; and (B) A simplified discussion of the utility's resource types and load characteristics. The utility shall make the IRP summary readily accessible on its website.	**Met**

IPL used Ascend Analytics' PowerSimm model for capacity expansion and production cost modeling for this IRP. IPL was not able to provide the input and output files from the PowerSimm modeling. Our understanding is that this is because PowerSimm cannot export these files in a format that is readable without a model license. IPL did work with stakeholders to provide access to the model documentation online, used specified data release points to provide stakeholders with access to some key inputs and assumptions, and provided Excel files with significant model outputs and inputs. To provide full transparency, we would prefer to be able to have access to the input and output modeling files themselves, but Ascend charges $30,000 for a read-only PowerSimm license, and IPL did not pay this fee to have this available for the Commission or stakeholders. This leaves the technical appendix incomplete because we still lack access to all the input and output information that PowerSimm produces. Some information we know we do not have – for example, the PowerSimm documentation provided to us suggest that constraints are normally set on market sales/purchases, regulation requirements, spinning reserve, non-spinning reserve, and flex ramp requirements. All of these constraints can meaningfully impact resource optimization and, to our knowledge, there is no ramp requirement in MISO. We know there is other information that we lack, but do not even know exactly what is missing. All models have settings that are unique to that model, for example, Strategist has a "superfluous" unit setting which determines how much of any given resource can be added to reduce system cost even if the resource is not needed to meet reliability requirements. Unless one had previously examined Strategist files or the Strategist user guide, s/he would be unlikely to know this setting exists. While we were certainly provided access to documentation on

PowerSimm, it was not always clear what did and did not apply or whether we were missing certain pieces of information since the documentation was likely to be used while sitting in front the user interface.

PowerSimm is a vast improvement on the model IPL used in its last IRP, which could not even optimize to the correct reserve margin requirement. However, we cannot overstate the importance of transparency. It is the foundation of public participation in utility regulation, which, in turn, is foundational to the Commission's ability to render decisions based on a comprehensive record. Without a doubt, IPL deserves credit for the work it did on this IRP and for the significant improvements from the prior IRP, but the level of transparency must still be improved upon in future dockets and future IRPs.

2 Public Advisory Process

Section 2 describes our assessment of IPL's performance in meeting the requirements of 170 IAC 4-7-2.6 of the Indiana IRP Rule. Please see Table 3 below for our findings.

Table 3. Summary of IPL's Achievement of Indiana IRP Rule 170 IAC 4-7-2.6

IRP Rule	IRP Rule Description	Finding
4-7-2.6 (b)	The utility shall provide information requested by an interested party relating to the development of the utility's IRP within 15 business days of a written request or as otherwise agreed to by the utility and the interested party. If a utility is unable to provide the requested information within 15 business days or the agreed timeframe, it shall provide a statement to the director and the requestor as to the reason it is unable to provide the requested information.	**Met**
4-7-2.6 (c)	The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by: (1) the interested parties; (2) the OUCC; (3) the commission staff.	**Mostly**
4-7-2.6 (e)	The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following: (A) An introduction to the IRP and public advisory process; (B) The utility's load forecast; (C) Evaluation of existing resources; (D) Evaluation of supply-side and demand-side resource alternatives; (E) Modeling methods; (F) Modeling inputs; (G) Treatment of risk and uncertainty; (H) Discussion seeking input on its candidate resource portfolios; (I) The utility's scenarios and sensitivities; (J) Discussion of the utility's preferred resource portfolio and the utility's rationale for its selection.	**Met**
4-7-2.6 (e)	(2) The utility may hold additional meetings.	**Met**
4-7-2.6 (e)	(3) The schedule for meetings shall: (A) be determined by the utility; (B) be consistent with its internal IRP development schedule; and (C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.	**Met**
4-7-2.6 (e)	(4) The utility or its designee shall: (A) chair the participation process; (B) schedule meetings; (C) develop and publish to its website agendas and relevant material for those meetings at least seven (7) calendar days prior to the meeting; and (D) develop and publish to its website meeting minutes within fifteen (15) calendar days following the meeting	**Met**
4-7-2.6 (e)	(5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility.	**Met**
4-7-2.6 (e)	(6) The utility shall take reasonable steps to notify: (A) its customers; (B) the commission; (C) interested parties; and (D) the OUCC	**Met**

We appreciate the steps IPL took to ensure that this IRP process was improved upon from the 2016 IRP. IPL reached out to CAC on numerous occasions to schedule technical phone calls prior to the stakeholder meetings to provide CAC and its consultants with information and seek feedback. We also appreciate the time IPL took to schedule these meetings and to make this IRP process more collaborative.

Following IPL's initial release of its modeling results on October 28, 2019, we expressed concern about the level of energy efficiency selected by the model. Following discussion with IPL, IPL modeled additional plans that included the fourth and fifth bundles of energy efficiency. Conducting this additional modeling resulted in the discovery that there existed a lower cost plan with, at least, the fourth bundle of energy efficiency, which IPL then incorporated into its preferred plan.

IPL did a good job of managing its pre-IRP submission process. It had a specific timeline for when it would release data to stakeholders. IPL followed through on this commitment and provided stakeholders access to the data through its KiteWorks collaboration site. IPL also provided stakeholders with its version of output files prior to the filing of its IRP. The sharing of data with stakeholders was a major improvement from the last IRP process, where CAC had to wait up to four months after the 2016 IRP was already submitted to receive this same type of information. IPL was also very willing to have additional conversations with CAC and its consultants, as well as with other stakeholders interested in the technical details of the IRP. We particularly appreciate the willingness of Patrick Maguire, Erik Miller and their team to entertain most, if not all, of our substantive recommendations.

Among the stakeholder process best practices IPL adopted was to hire an outside facilitator, Stewart Ramsay, who was a helpful addition to the collaborative process. A competent facilitator without a stake in the outcome of the process really does improve the pre-IRP workshops. S/he keeps the process focused on outcomes rather than argument, makes sure that stakeholders are heard, and keeps the workshops on schedule.

Our main concern regarding this IRP has to do with whether DSM was properly optimized. While most of our communication with IPL throughout this IRP process has been fruitful, there was one instance where CAC provided IPL with feedback on its plan to model energy efficiency and that feedback did not result in a change to IPL's modeling assumptions. CAC, along with its consultants from EFG, had a phone call with IPL regarding the assumptions for modeling the EE bundles.[1] We cautioned IPL against grouping measures by cost insofar as this would not result in the optimal selection of energy efficiency since this approach does not provide a true representation of how IPL implements its energy efficiency programs. IPL's modeling approach for energy efficiency was identified as a deficiency in the 2016 IRP, and it continues to be a deficiency in this IRP.

[1] IPL 2019 IRP Stakeholder technical conference phone call with IPL on May 29, 2019.

3 Integrated Resource Plan Contents

Section 3 describes our assessment of IPL's performance in meeting the requirements of 170 IAC 4-7-4 of the Indiana IRP Rule. Please see Table 4 below for our findings.

Table 4. Summary of IPL's Achievement of Indiana IRP Rule 170 IAC 4-7-4

IRP Rule	IRP Rule Description	Finding
4-7-4 (1)	At least a twenty (20) year future period for predicted or forecasted analyses.	Met
4-7-4 (2)	An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.	Met
4-7-4 (3)	At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.	Met
4-7-4 (4)	A description of the utility's existing resources in compliance with section 6(a) of this rule.	Met
4-7-4 (5)	A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed.	Met
4-7-4 (6)	A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.	Met
4-7-4 (7)	The resource screening analysis and resource summary table required by section 7 of this rule.	Met
4-7-4 (8)	A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with section 8(a) and 8(b) of this rule.	Met
4-7-4 (9)	A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	Met
4-7-4 (10)	A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.	Met
4-7-4 (11)	A discussion of the: (A)inputs; (B)methods; and (C) definitions.	
4-7-4 (12)	Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this rule. If the IRP references a third-party data source, the IRP must include for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of adjustments made to the data. The data must be submitted within two (2) weeks of submitting the IRP in an editable format, such as a comma separated value or excel spreadsheet file.	Met
4-7-4 (13)	A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use.	Met
4-7-4 (14)	The database in subdivision(13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility; (B) Load research developed in conjunction with another utility; (C) Load research developed by another utility and modified to meet the characteristics of that utility; (D) Engineering estimates; and (E) Load data developed by a non-utility source.	Met
4-7-4 (15)	A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on: (A) end-use penetration; (B) end-use saturation rates; and (C) end-use electricity consumption patterns.	Not Met
4-7-4 (16)	A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	Met
4-7-4 (17)	A discussion of the designated contemporary issues designated, if required by section 2.7(e).	Met
4-7-4 (18)	A discussion of distributed generation within the service territory and the potential effects on: (A) generation planning; (B) transmission planning; (C) distribution planning; and (D) load forecasting.	Met
4-7-4 (19)	For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	Partial

4-7-4 (20)	A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development.	**Met**
4-7-4 (21)	A discussion of how the utility's emission allowance inventory and procurement practices for an air emission have been considered and influenced the IRP development.	**Met**
4-7-4 (22)	A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	**Met**
4-7-4 (23)	A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	**Met**
4-7-4 (24)	A discussion of how the utilities' resource planning objectives, such as: (A) cost effectiveness; (B) rate impacts; (C) risks; and (D) uncertainty; were balanced in selecting its preferred resource portfolio.	**Met**
4-7-4 (25)	A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include: (i) existing federal environmental laws; (ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and (iii) existing policies, such as tax incentives for renewable resources. (C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable. (D) Not include future resources, laws, or policies unless: (i) a utility subject to section 2.6 of this rule solicits stakeholder input regarding the inclusion and describes the input received; (ii) future resources have obtained the necessary regulatory approvals; and (iii) future laws and policies have a high probability of being enacted. A base case scenario need not align with the utility's preferred resource portfolio.	**Met**
4-7-4 (26)	A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	**Met**
4-7-4 (27)	A brief description of the models(s), focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies, and sensitivity analysis; (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC); and (C) Reliability criteria for transmission planning as well as the assessment practice used.	**Partial**
4-7-4 (28)	A list and description of the methods used by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use, and (B) The utility's effort to develop and improve the methodology and inputs.	**Partial**
4-7-4 (29)	An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement; (B) The avoided transmission capacity cost; (C) The avoided distribution capacity cost; and (D) The avoided operating cost.	**Met**
4-7-4 (30)	A summary of the utility's most recent public advisory process, including: (A) Key issues discussed and (B) How the utility responded to the issues.	**Met**
4-7-4 (31)	A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	**Mostly**

3.1 RENEWABLE ENERGY CONSTRAINTS

IPL placed annual and cumulative constraints on the amount of solar, wind, and energy storage that could be selected in the PowerSimm model as shown in Figure 1.

	Gas CC	Gas CT - Frame	Gas CT - Aero	Gas Recip	Wind	Utility Solar	4-Hour Battery Storage
First Year Available	2023	2023	2023	2023	2022 (2021 pricing)	2023	2023
Generic Project Size (ICAP MW)	325	100	126	108	50	25	20
Number of Projects Allowed Per Year	4	5	1	1	10 in 2022 4 in 2023+	20	20
MW Allowed Per Year	1,300	500	126	108	500 in 2022 200 in 2023+	500	400
Number of Total Projects Allowed	8	10	5	5	30	60	100
Total MW Allowed	2,600	1,000	630	540	1,500	1,500	2,000

Figure 1. IPL's Imposed Constraints on New Supply Side Resources[2]

IPL explains that the wind constraint is in place due to the expiration of the Production Tax Credit ("PTC")[3] which IPL expects to cause an anticipated drop in the amount of wind projects in the MISO generation queue.[4]

> *IPL allowed up to 500 MW of wind to be built in 2022 and 200 MW per year for every year after that. Wind pricing with 80% PTC eligibility provides a significant cost advantage, and because IPL is in [sic] net long position, the model was limited in capacity additions for 2022. Beyond 2022, IPL limited annual wind build to 200 MW due to concerns over the availability of wind projects after the phaseout of the [Production Tax Credit]. As shown in Figure 7.20, the amount of wind in Indiana in the MISO Generation Interconnection Queue decreases significantly after 2020 as many developers are shifting focus to meeting solar [Investment Tax Credit] safe harbor deadline.* [5]

[2] IPL 2019 IRP Submission, Figure 7.19, p. 140.
3 The PTC was extended for an additional year in December 2019 after IPL's IRP was filed.
[4] IPL 2019 IRP Submission, pp. 141 – 142.
[5] IPL 2019 IRP Submission, p. 141.

IPL does not include a justification for the constraint placed on solar resources. The cumulative limits on solar and wind over the entire 20-year planning period were 1,500 MW each.

IPL's 1,500 MW limit over the 20-year planning period is less than the 2,209 MW of wind NIPSCO received just in response to its 2018 all-source RFP to fill its 2023 capacity shortfall. NIPSCO also received bids for 2,580 MW of solar and 1,220 MW of solar + storage hybrid projects (Figure 2)—far more than IPL is even allowing PowerSimm to select over the entirety of the planning period.

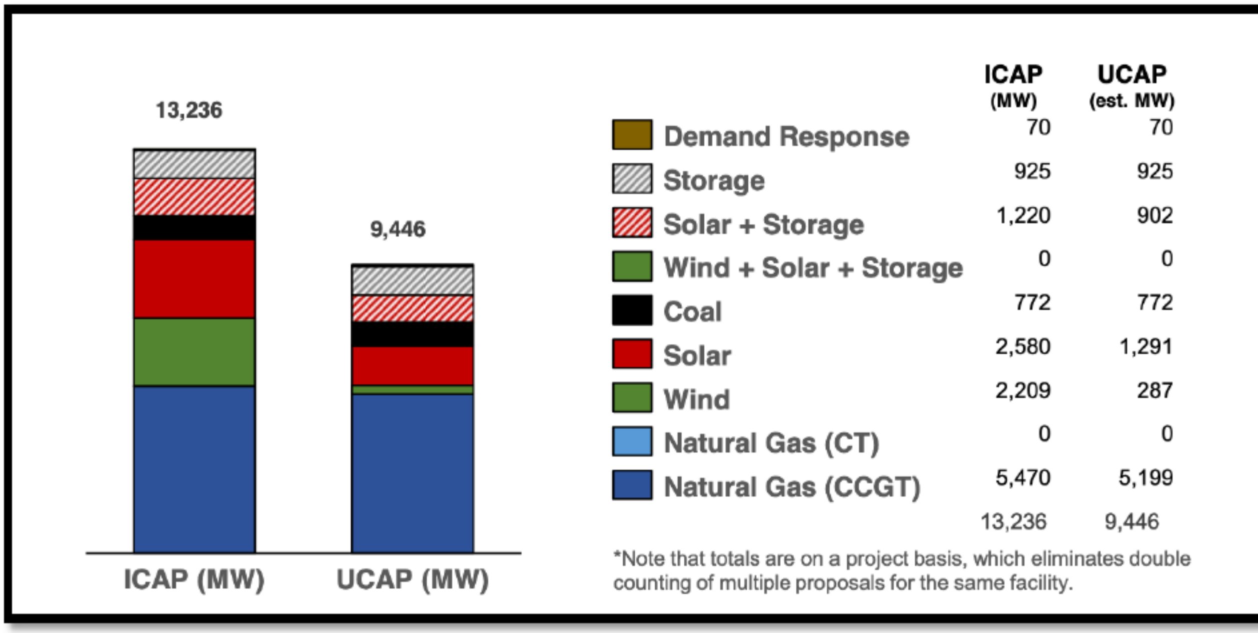

Figure 2. Summary of Bids Received. NIPSCO 2018 IRP, p. 55.

Even the response to NIPSCO's refresh RFP issued in 2019 received bids for 1,391 MW of wind, 6,404 MW of solar, and 4,743 MW of solar + storage bids.[6] Furthermore, in response to its own RFP, IPL received bids for [redacted] MW of wind,[7] [redacted] MW of solar, and [redacted] MW of solar + storage.[8]

IPL's limit of 1,500 MW for solar and 1,500 MW for wind resources over the 20-year planning period was even stricter than the limits used by I&M in its 2018-2019 IRP—I&M constrained portfolios to 1,700 MW of solar and 2,100 MW of wind.[9] IPL's solar constraint is binding for Portfolios 4 and 5, which retire Petersburg Units 3 and 4, respectively. The cumulative solar constraint is binding on Portfolios 3, 4b, 4c, 5b, and 5c and the cumulative wind constraint is

[6] NIPSCO 2019 RFP Results Presentation, February 18, 2020 at slide 12.
[7] We are not sure why IPL received [redacted] than did NIPSCO. But it is quite possible that potential respondents viewed IPL's deliverability requirements in its RFP as mandating physical rather than just contractual delivery to Zone 6.
[8] IPL 2019 RFP Results Presentation, March 20, 2020, at slide 7.
[9] I&M 2018-19 IRP Submission, p. 115.

binding on Portfolio 5c. The cumulative wind constraint was less likely to be binding, first, because of the effect of the expiration of the PTC on wind prices - IPL assumed that the PTC would completely sunset by the end of 2023. Second, wind was dispatched against a dramatically different market price due to the locational market price ("LMP") adjustment made to all resources, but which was much more significant for wind. That is, the LMP for wind was much lower than for other resources. In the absence of those factors, the cumulative constraint on wind could well have been binding.

Further, though the reason for the difference is unexplained, solar was first available to pick in 2023, and wind was first available in 2022. This equates to an average annual limit of 88 MW for solar and 83 MW for wind. It is not surprising, therefore, that the additional annual limits for solar of 500 MW per year and the additional annual limits for wind at 500 MW in 2022 and 200 MW from 2023 – 2039 were frequently not binding – the model would be unlikely to use its "budget" for these resources in just a handful of years by adding 500 MW of solar, for example.

With typical utility scale renewable projects in the hundreds of megawatts, these types of constraints are not likely to represent actual limits on capacity that can be acquired or built, but rather help to narrow the number of options that the model has to optimize. Therefore, they should be employed judiciously and only with the type of clear justification that IPL has not offered here.

Further, to the extent the justification for these types of constraints are related to a requirement for self-ownership, this is not a valid rationale. Utilities have a monopoly on providing customers with electric service—not on owning generation. Generation acquisition decisions should be made without consideration to ownership, but rather based on cost, counterparty risk, and other factors that tangibly impact cost of service.

3.2 POWERSIMM OPTIMIZATION

Following the release of the initial PowerSimm modeling files by IPL on October 28, 2019, CAC spoke with IPL about modeling additional EE bundles for the IRP. IPL provided updated modeling files showing the fourth and the fifth EE bundles[10] forced in – the bundles roughly equal to 1 percent of sales and 1.25 percent of sales incremental savings, respectively. Surprisingly, forcing in the fourth EE bundle resulted, in many instances, in a lower net present value ("NPV")[11] than in the optimized model runs, which did not pick beyond the first three EE bundles. This is surprising because, by definition, the optimal plan should produce the lowest cost plan.

Table 5 below compares the NPV results for Portfolio 3 across Bundles 3, 4, and 5. The addition of the fifth bundle also resulted in lower cost plans, compared to those with only three bundles, across all scenarios except for the reference scenario as indicated by the green highlight. Given these results, IPL revised its preferred plan to include Bundle 4, but did not commit to pursuing savings consistent with Bundle 5.

Table 5. NPV of Portfolio 3 with Bundles 3, 4, and 5 under Different Scenarios[12]

Scenario	Portfolio 3 with Bundle 3 (Portfolio 3A)	Portfolio 3 with Bundle 4 (Portfolio 3B)	Portfolio 3 with Bundle 5 (Portfolio 3C)
Ref	$7,016	$6,976	$7,034
A	$7,737	$7,661	$7,716
B	$8,211	$8,114	$8,165
C	$6,843	$6,786	$6,842
D	$7,798	$7,739	$7,794

We are very concerned that PowerSimm would develop an "optimal" plan with a lower level of EE and a higher NPV than the results from forcing additional bundles into the model. Indeed, the difference can be quite significant on a percentage basis as shown in Table 6.

Table 6. NPV Percentage Difference between Portfolio 3 with Bundles 3, 4, and 5

Scenario	NPV % Difference between Bundles 3 and 4	NPV % Difference between Bundles 3 and 5
Ref	-0.57%	0.26%
A	-0.99%	-0.28%
B	-1.20%	-0.56%
C	-0.84%	-0.01%
D	-0.76%	-0.05%

[10] IPL often uses the word "decrement" to describe its bundles, but its bundles are not decrements in the sense we mean when describing a decrement approach or as the term is defined in Merriam-Webster's Dictionary, i.e., "the amount of decrease." IPL's bundles are modeled on the supply-side with an assigned cost—they are not a reduction to load. Therefore, we use the term "bundle" throughout these comments.
[11] Throughout these comments, we use NPV and present value of revenue requirements ("PVRR") interchangeably.
[12] NPVs from workbook, 'Confidential – IPL 2019 IRP – PVRR and Rate Impact Summary'

It does not make sense that the optimized portfolios with Bundle 3 would have substantially higher NPVs than the portfolios with Bundles 4 and 5 forced in. Based on these results, PowerSimm should have returned an optimized result that included Bundle 4 since it results in the lowest cost plan.

We learned about this issue with the data provided in advance of IPL's last stakeholder meeting on December 9, 2019. We held a follow-up meeting with IPL the week of December 16, 2019 (which is when IPL filed the IRP), to discuss this issue and then received a follow-up email from Patrick Maguire on February 3, 2020. During our December meeting, we had hypothesized that there may have been something wrong with the tolerance setting used in the modeling. Mixed integer programming ("MIP") models like PowerSimm use this setting to specify when to stop the optimization process. Ascend describes the tolerance setting in the Automated Resource Selection ("ARS") module, the capacity expansion module of PowerSimm, as follows: [13]

> *The optimization engine for ARS finds the optimal unconstrained solution, then goes through a solving routine until it finds a constrained solution within a given tolerance. That tolerance is set to 0.0001 or 0.01%, meaning that we are requiring the solution to be within 0.01% of the unconstrained optimal solution.*

In this instance, the "optimal unconstrained solution" means the optimal linear solution in each modeling run. MIP models enforce integer constraints on variables like the number of new resources added, e.g., only whole numbers of units can be added as opposed to say 1.5 units. The linear solution relaxes all of those constraints, so it can solve more quickly. As shown in Table 6, there is a significant difference in NPV between the same portfolio but with higher numbers of EE bundles. Though this NPV difference is not relative to the "optimal unconstrained solution," it is significant enough that it raises questions about whether the optimization was appropriately set up to result in the "optimal" plan. Put another way, if under the Reference Case scenario, the tolerance setting was appropriately applied, then Portfolio 3 with Bundle 3 should be within 0.01 percent or less of the optimal unconstrained solution. However, since Portfolio 3 with Bundle 4 is 0.57 percent *less* expensive than Portfolio 3 with Bundle 3, then something must be amiss. Even with read-only access to PowerSimm, one cannot see: the Company's tolerance setting, the resulting gap in NPV between the optimal integer and linear relaxation results, or even the NPV as calculated by PowerSimm of the optimal plan itself. It is our understanding that IPL cannot see these either. This makes it nearly impossible to understand why a plan with forced in resources would be cheaper.

In a follow-up email on this topic, Mr. Maguire said the difference was due to other factors:[14]

> *Two other things to keep in mind. First is that we are calculating the PVRR outside of the model and the way PowerSimm calculates a levelized cost for each project, which is similar to how other models work, is slightly different than our financial revenue requirement model. Additionally, we made other changes post-ARS optimization, primarily for wind and the number of projects moved up to 2021.*

[13] Personal Communication with Patrick Maguire, December 10, 2019.
[14] Personal Communication with Patrick Maguire, February 3, 2020.

> *Both of these impact the PVRR calculation that are not picked up in the ARS optimization.*

Unfortunately, this explanation does not assuage our concerns. Because we do not have the NPVs as they would be calculated by PowerSimm, we cannot verify that the optimized NPVs are not actually higher than those with the forced-in additional energy efficiency from the standpoint of PowerSimm. More importantly, however, it does not make sense to us that these factors would result in not just different NPVs, but also in a reordered ranking of the modeling results. For example, if the unspecified changes in "wind and the number of projects moved up to 2021" results in a plan becoming cheaper by the degree shown in Table 6, then this is merely a different way of describing the same problem or is another flavor of the same problem – that forced-in changes could result in a much more optimal portfolio. The explanation also brings light to a new, potentially significant concern: that the Excel spreadsheets summarizing IPL's modeling runs do not show the actual optimization results from PowerSimm, a fact not communicated to stakeholders. Further, it seems unlikely that moving projects up, including wind, would influence the optimization in this way because resources are being dispatched against a market price, not against load. So the model is not actually weighing the tradeoff between advancing wind and choosing more EE to the extent that other, system-wide constraints such as the reserve margin constraints do not bind.[15] The model is choosing each resource based on its individual ability to reduce system cost compared to the market price that load would pay to otherwise procure that energy. Put another way, we do not see why moving wind around in time would enable *energy efficiency* to reduce system costs.

It also does not make sense to us that performing a second present value calculation outside of PowerSimm would result in this change. In a separate case involving PowerSimm, we were provided with PowerSimm's generic net present value formula and do not see any meaningful differences between that and IPL's NPV value methodology. Typically, out of model adjustments result in a different NPV, but not a wholesale change to the rank order of portfolios since the change in methodology does not change the underlying costs included in the modeling. One would be more likely to see a change in rank order with the addition of costs not considered by the model, but that does not appear to be the case here with two exceptions. First, Concentric, the company that developed IPL's out-of-model NPV calculations, added in a "bad debt expense," but that expense was calculated on the same percentage basis of [redacted]% across all portfolios so that should not change the relative rankings. PowerSimm adds a "risk premium" into its NPV calculations, which were not included in Concentric's model. However, as Figure 8.34 of the IRP shows, recreated below as Figure 3, adding in the risk premium does not make Portfolio 3 with Bundle 3 (i.e., Portfolio 3A) the lowest cost version of Portfolio 3 in any scenario except the Reference Case.

[15] We discuss the reserve margin constraints in Section 3.4 of these Comments.

	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
Portfolio 1A	$7,544	$8,401	$8,833	$7,489	$8,324
Portfolio 2A	$7,502	$8,356	$8,865	$7,401	$8,351
Portfolio 3A	$7,383	$8,156	$8,676	$7,213	$8,246
Portfolio 4A	$7,761	$8,278	$8,784	$7,388	$8,623
Portfolio 5A	$7,941	$8,317	$8,904	$7,379	$8,915
Portfolio 1B	$7,533	$8,370	$8,785	$7,472	$8,294
Portfolio 2B	$7,542	$8,363	$8,840	$7,425	$8,363
Portfolio 3B	$7,384	$8,129	$8,646	$7,201	$8,234
Portfolio 4B	$7,754	$8,277	$8,800	$7,374	$8,636
Portfolio 5B	$7,892	$8,268	$8,921	$7,250	$8,854
Portfolio 1C	$7,571	$8,387	$8,785	$7,502	$8,315
Portfolio 2C	$7,551	$8,335	$8,791	$7,418	$8,350
Portfolio 3C	$7,407	$8,139	$8,642	$7,221	$8,242
Portfolio 4C	$7,726	$8,281	$8,837	$7,347	$8,640
Portfolio 5C	$7,893	$8,223	$8,786	$7,305	$8,849

Figure 3. Replication of IRP Figure 8.34 | Risk-Adjusted PVRR: Expected Value (Mean) + Risk Premium ($MM)

Even if the difference were that PowerSimm uses one NPV methodology, e.g., carrying charges, and Concentric, who developed the post-modeling PVRRs, used another, e.g., revenue requirements, that should not drive this difference either.[16] The net present value of both economic carrying charges and revenue requirements is, by definition, the same, even if the value in any given year is different. Because the planning period does not capture the full lifetime of all resources, there would be some difference; but with a 20-year planning period, it would be highly unlikely to result in a reordering of the plans across so many different scenarios.

[16] Note that Concentric also used a levelized methodology, so we are not sure to what differences Mr. Maguire is referring.

3.3 RETIREMENT ANALYSIS

IPL's retirement analysis contained a set of fixed retirement decisions across all portfolios, in addition to the retirement of the Petersburg units, which varied across portfolios. The fixed retirements that were consistent across all portfolios involved the Harding Street units, as depicted in Table 7.

Table 7. IPL's Fixed Retirement Decisions[17]

Unit	Size (MW)	Retirement Date
Harding Street Oil 1-2	40	2024
Harding Street Gas ST5	100	2030
Harding Street Gas ST6	98	2030
Harding Street Gas ST7	420	2034

Figure 4 illustrates the different retirement portfolios IPL constructed for its Petersburg units.

Portfolio	Description
Portfolio 1	No Early Retirements
Portfolio 2	Pete Unit 1 Retire 2021 Pete Units 2-4 Operational
Portfolio 3	Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational
Portfolio 4	Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational
Portfolio 5	Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030

Figure 4. IPL's Retirement Portfolios[18]

As the IRP states, "IPL evaluated a set of fixed retirement dates on the Petersburg units based on age, existing technology, expected maintenance, and cost."[19] IPL attempts to defend its decision to model fixed retirements instead of allowing PowerSimm to co-optimize new resource and retirement decisions by contending that "optimization can be useful, but it introduces modeling complexities and forces the modeler to make up front decisions about constraints for retirements."[20] IPL attributes the modeling complexities to the assignment of fixed costs to

[17] IPL 2019 IRP Submission, p. 156.
[18] IPL 2019 IRP Submission, Figure 7.2, p. 123.
[19] IPL 2019 IRP Submission, p. 122.
[20] IPL 2019 IRP Submission, p. 122.

specific units and PowerSimm choosing to retire units prematurely to avoid going over the reserve margin target.[21, 22]

IPL states it used several factors to create the window on retirement dates, including the age of the units, renewable tax credits, and scale and timing of replacement capacity.[23] The expiry of the renewable tax credits would be reason to allow early retirement of coal units. Furthermore, NIPSCO's 2018 IRP announced its intent to retire Schahfer Units 14, 15, 17, and 18, which represent a total coal capacity of 1,625 MW[24] by 2023. While we acknowledges there is lead time to acquire new resources, we believe the Director's comments on NIPSCO's retirement analysis also apply here.

In the Director's Draft Report on NIPSCO's 2018 IRP, the Director stated at page 27,

> *Despite the reasonableness of the two-stage [retirement] analysis, both its rationale and the implementation, the Director would have liked to have seen a resource optimization with the timing of retirements and replacement options minimally constrained. We recognize that there are good reasons why the resulting portfolio might be unreasonable, but it still would have been a useful point of comparison.*

The same critique very clearly applies here. In no scenario were the retirements of Petersburg Units 1 – 4 optimized.

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[21] IPL 2019 IRP Submission, p. 122.
[22] We discuss the reserve margin target further in Section 3.4.1.
[23] IPL 2019 IRP Submission, pp. 122 – 123.
[24] NIPSCO 2018 IRP Submission, Table 4-9, p. 47. Schahfer 1 at 431 MW, Schahfer 2 at 472 MW, Schahfer 3 at 361 MW, and Schahfer 4 at 361 MW.

3.4 MODELING CONSTRAINTS

3.4.1 RESERVE MARGIN CONSTRAINTS

IPL modeled a reserve margin penalty within PowerSimm. In the IRP, IPL states, "The PowerSimm model is designed to impose a 'penalty' to portfolios that exceed the reserve margin target or are short of the reserve margin target."[25] The penalty IPL modeled is $100,000/MW for every MW that is over the maximum build constraint specified by IPL. [26] In response to CAC Informal Discovery Set 3, IPL stated, "This penalty is applied to the objective function of minimizing portfolio costs, thus incentivizing the capacity expansion model to not overbuild. The penalty is not a real expense applied to the portfolio and does not show up in the PVRR; it is only used to influence resource selection."[27]

This penalty is significant enough that no "optimal" portfolio exceeded the reserve margin constraints. And because we cannot use PowerSimm ourselves, we cannot tell what plans the model would have produced in absence of this constraint. However, we did note, in a workbook[28] provided by IPL, that the maximum reserve margin constraint was highest for Portfolio 1 and lower for Portfolios 2 through 5 during the key years of the analysis, 2021 – 2032. IPL does not explain why each portfolio ought to be treated differently in this regard.

For Portfolios 3 through 5, the difference between the minimum reserve margin and the max Build Constraint, which were each specified annually, was just [redacted] MW in each year between 2023 and 2039. For Portfolios 1 and 2, it only became [redacted] MW in 2033 and 2031, respectively. IPL says that it set the MAX Build Constraint such that all DSM bundles could be selected,[29] but the workbook provided to us that shows how the reserve margin constraints were developed uses a formula that accounts only for the capacity associated with the first 8 bundles; it does not include the ninth bundle nor the demand response bundles.

These constraints seem likely to have influenced the optimal portfolio, which raises a concern. We have pointed out in other IRPs that overbuilding capacity can be a risky proposition. This seems to be part of the justification for using this constraint and, in that sense, we are on the same page as IPL. However, we would rather see overbuilding manifest itself in the optimization and then have the modeler change the settings or the portfolio in some fashion to address the problem. IPL also imposes an energy constraint that it characterized as generally not binding,[30] but typically resources are overbuilt because the model thinks that significant off-system sales can be made at net positive profit so both the energy and the reserve margin constraint are imposed for the same reasons. The narrowness of the band between the minimum and maximum reserve margin constraints strikes us as overly restrictive on the optimization and likely to prevent the model from selecting what is truly the optimal plan.

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[25] IPL 2019 IRP Submission, p. 122.
[26] IPL 2019 IRP Stakeholder Process, IPL Response to CAC Informal Data Request 4-5.
[27] IPL 2019 IRP Stakeholder Process, IPL Response to CAC Informal Data Request 3-19.
[28] Confidential - IPL 2019 IRP - Reserve Margin Base and Overbuild Constraint.xlsx
[30] Personal communication with Will Vance, July 24, 2020.
[30] Personal communication with Will Vance, July 24, 2020.

3.4.2 ADDING COMBINED CYCLE AS FIXED RESOURCE

For this IRP, IPL included a fixed resource decision across all its portfolios to model a proxy resource for firm capacity once the Harding Street steam units retire. IPL chose a 1x1, 325 MW combined cycle ("CC") unit as the proxy resource to add to all portfolios in 2034. Since IPL has not performed a reliability study on what would be the best replacement resources for the Harding Street units, IPL decided to model a CC to present the firm capacity that is needed in place of the Harding Street units. IPL states, "The actual firm capacity need and solution will likely change through time and could be a different technology."[31] We acknowledge that IPL's intention is for the CC to be a proxy resource, but as we get closer to that date, we would like to see IPL model scenarios that include renewables, storage, energy efficiency, and demand response as replacement capacity for the Harding Street units.

[31] IPL 2019 IRP Submission, p. 156

3.5 EXPECTATIONS FOR FUTURE IMPROVEMENTS

One of the expectations for future improvements identified by IPL is the seasonal resource adequacy ("RA") construct currently under exploration by MISO. We appreciate that IPL did not include a seasonal resource adequacy construct as the base case assumption in its modeling in this IRP. MISO is exploring a number of rule changes to address MaxGen[32] events and ensure future reliability. A seasonal RA construct is one of the potential options, but we think it is highly uncertain that such a construct, even if implemented, would simply require the application of the same reserve margin year-round. A recent MISO presentation on this topic says that stakeholders have told MISO that "MISO's current analysis [is] unconvincing as a basis for pursuing a seasonal resource adequacy construct" and MISO responded that its "analysis to date, coupled with historical events, has been intended to provide evidence that exploring a seasonal construct is warranted. MISO will continue to work with stakeholders on analysis to support any future changes."[33]

IPL includes the MISO seasonal resource adequacy in its discussion of expectations for future improvements. IPL states:

> *Resource capacity credit can vary by season, requiring careful consideration of a portfolio used to serve load reliably. MISO continues to evaluate the existing capacity construct that IPL participates in through a stakeholder process. Changes to the capacity construct that include seasonality as opposed to an annual consideration could have a significant impact on the capacity credit for renewables[34].*

CAC hopes that IPL's intention for future modeling of a seasonal resource adequacy will be dependent on a final decision by MISO and/or will explore a wide range of potential constructs because of the importance that this assumption has on the optimization of resources.

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[32] Maximum Generation events occur when the economic supply of energy is not sufficient to meet fixed demand.
[33] *See* PDF page 8 of https://cdn.misoenergy.org/20190807%20RASC%20Item%2004b%20RAN%20Phase%203%20(RASC010)369675.pdf
[34] IPL 2019 IRP Submission, p. 205.

4 Energy and Demand Forecasts

Section 4 describes our assessment of IPL's performance in meeting the requirements of 170 IAC 4-7-5 of the Indiana IRP Rule. Please see Table 8 below for our findings.

Table 8. Summary of IPL's Achievement of Indiana IRP Rule 170 IAC 4-7-5

IRP Rule	IRP Rule Description	Findings
4-7-5 (a)	The analysis of historical and forecasted levels of peak demand and energy usage must include the following: (1) Historical load shapes, including the following: (A) Annual load shapes; (B) Seasonal load shapes; (C) Monthly load shapes; (D) Selected weekly load shapes; and (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	**Partial**
4-7-5 (a)	(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.	**Met**
4-7-5 (a)	(3) Actual and weather normalized energy and demand levels.	**Mostly**
4-7-5 (a)	(4) A discussion of methods and processes used to weather normalize.	**Met**
4-7-5 (a)	(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	**Met**
4-7-5 (a)	(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system; (B) Customer classes, rate classes, or both; and (C) Firm wholesale power sales.	**Met**
4-7-5 (a)	(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	**Mostly**
4-7-5 (a)	(8) Justification for the selected forecasting methodology.	**Met**
4-7-5 (a)	(9) A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools, and analysis.	**Met**
4-7-5 (a)	(10) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in subdivision 4(14) of this rule.	**Met**
4-7-5 (b)	To establish plausible risk boundaries, the utility shall provide at least three (3) alternative forecasts of peak demand and energy usage including: (1) high; (2) low; and (3) most probable peak demand and energy use forecasts.	**Met**
4-7-5 (c)	In determining the peak demand and energy usage forecast to establish plausible risk boundaries as well as a forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider likely based on alternative assumptions such as: (1) Rate of change in population; (2) Economic activity; (3) Fuel prices, including competition; (4) Price elasticity; (5) Penetration of new technology; (6) Demographic changes in population; (7) Customer usage; (8) Changes in technology; (9) Behavioral factors affecting customer consumption; (10) State and federal energy policies; and (11) State and federal environmental policies.	**Met**

4.1 SALES AND PEAK DEMAND FORECAST

As seen in Figure 5, the strongest sales growth for IPL's forecast is from the residential customer class.

Table 9 shows the 1.26% average annual growth for residential sales between 2020 and 2039.

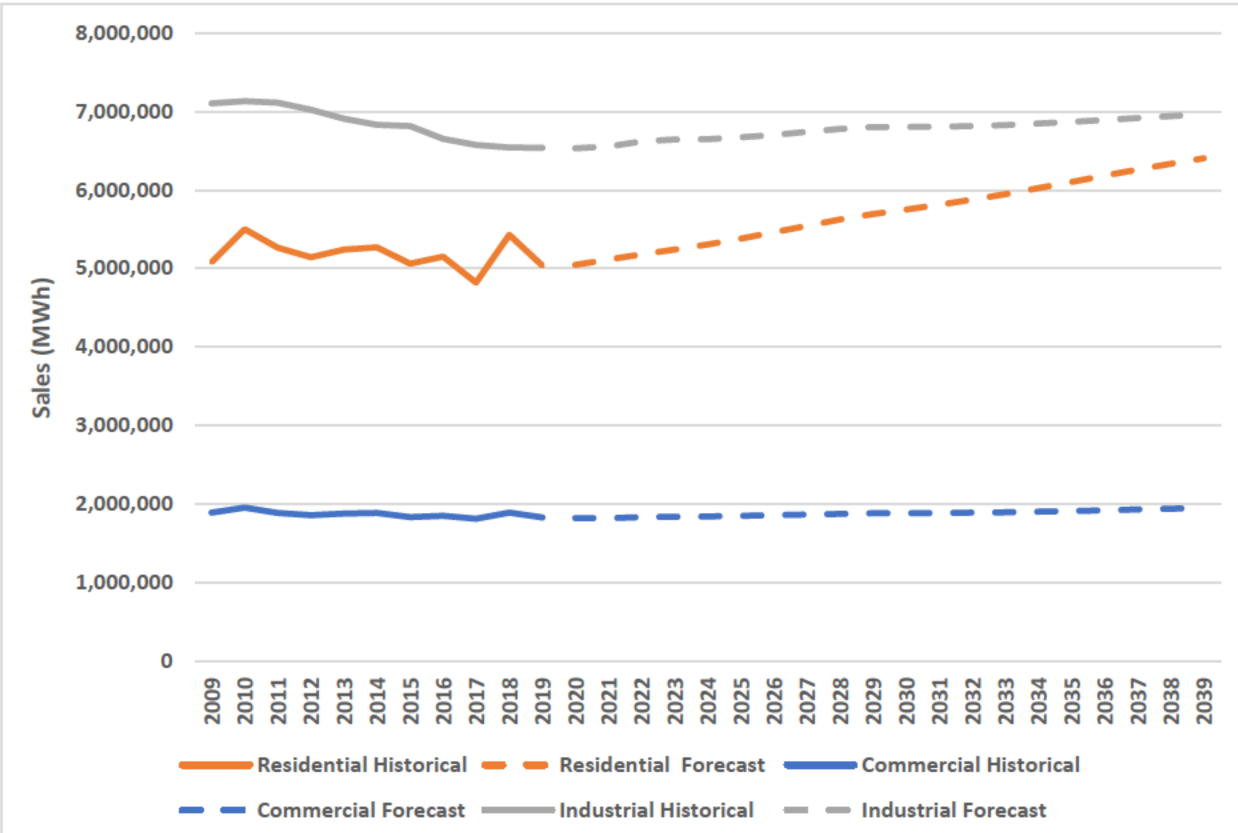

Figure 5. Historical and Forecasted Sales across Customer Classes

Table 9. Forecasted Average Annual Growth

	Historical	Forecast
Residential	0.09%	1.26%
Commercial	-0.28%	0.35%
Industrial	-0.83%	0.34%
Total	-0.45%	0.71%

IPL contends that the strong growth in residential sales that it is forecasting is due to additional multifamily apartments.[35] IPL cites figures from the Indianapolis Business Journal that apartments in downtown Indianapolis have grown by 250%.[36] However, the rate of growth in residential customers historically and the rate forecasted by IPL's economic data vendor are not all that different. The 2009 to 2019 rate is 0.70 percent, and the forecasted rate through 2039 is 0.80 percent as shown in Figure 6.

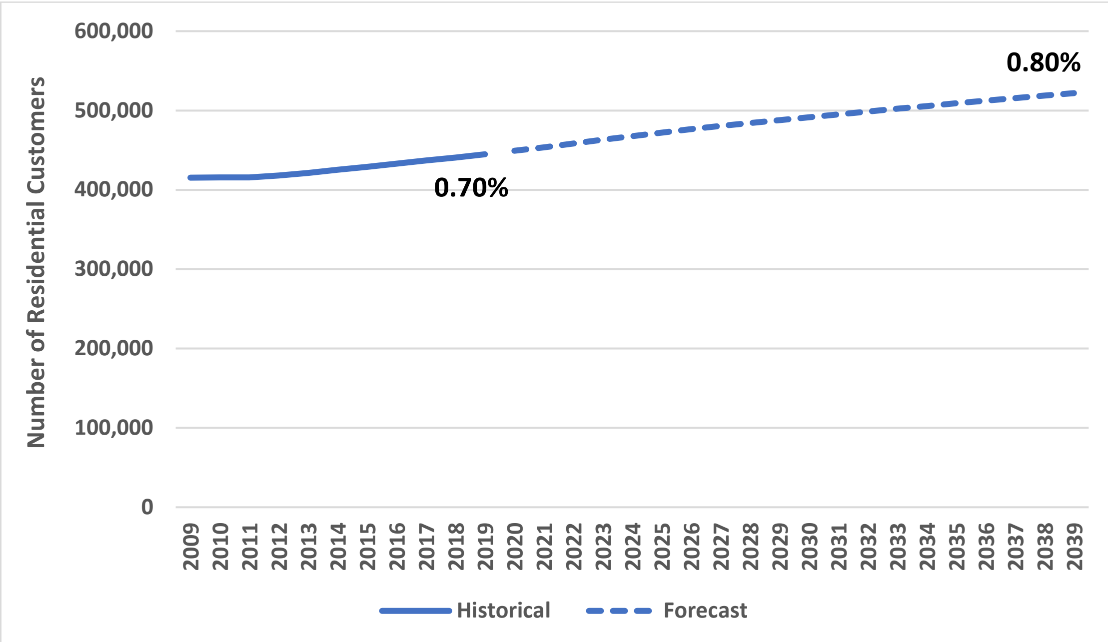

Figure 6. Historical and Forecasted Number of Residential Customers

Given that IPL has experienced essentially flat residential sales since 2009 even as its residential customers have increased by 0.70 percent per year, it seems very unlikely that a 0.80 percent annual increase in customers from 2020 through 2039 would lead to the 1.26 percent average annual growth in residential sales shown in Figure 5.

IPL is also projecting growth in its peak demand forecast throughout the planning period. Figure 7 shows the forecast for the base, low, and high cases compared to historical peak demand.

[35] IPL 2019 IRP Submission, p. 37.
[36] IPL 2019 IRP Submission, p. 37.

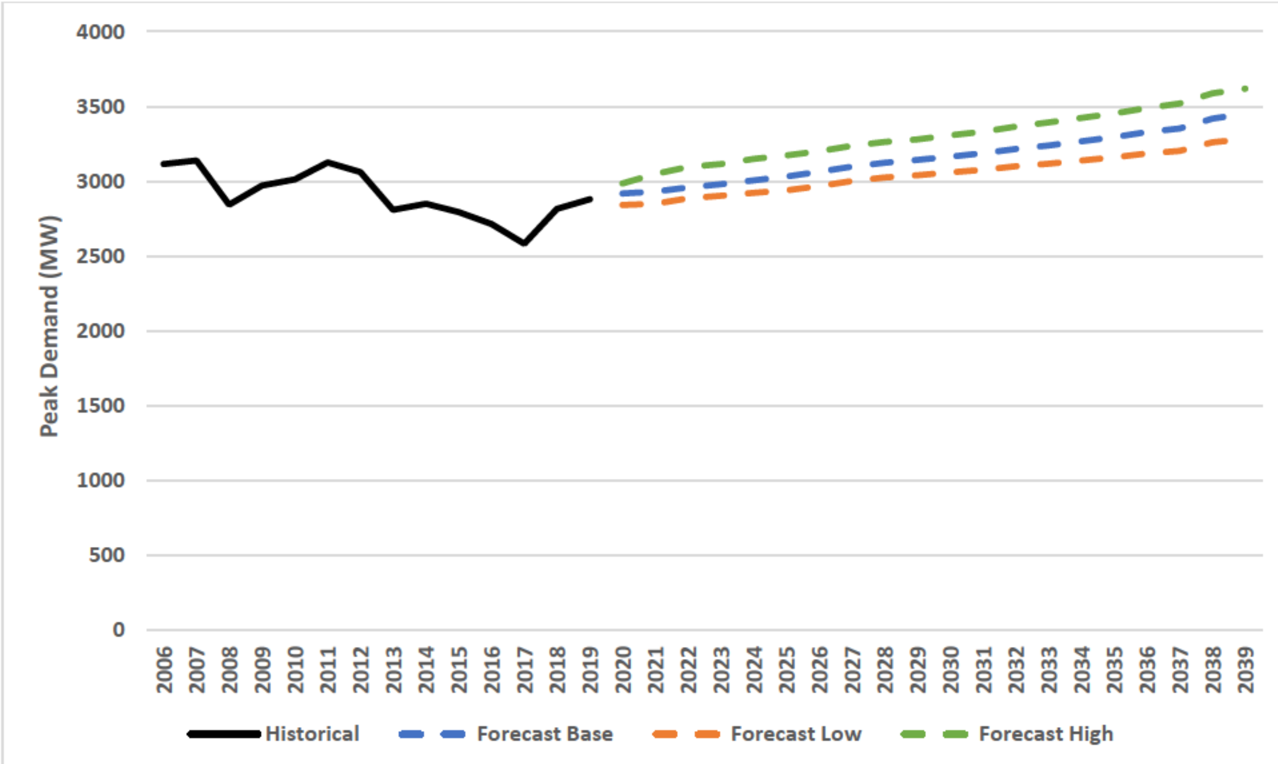

Figure 7. Comparison of Historical and Projected Peak Demand[37]

Driven, again, largely by an increase in residential consumption, IPL predicts it will reverse a multi-year trend of falling load. Note that the average percentage increases are given in Table 10, below.

Table 10. Average Annual Growth for Historical and Forecasted Peak Demand

	Historical	Base	Low	High
Average Growth	-0.48%	0.89%	0.76%	1.02%

[37] Forecasts for peak demand include impact of solar PV and EE.

4.2 ACCOUNTING FOR DSM IN THE LOAD FORECAST

IPL's approach for incorporating EE into its load forecast is to model historical EE as a variable included in Itron's Statistically Adjusted End-Use ("SAE") Model. While IPL's approach to modeling EE in its load forecast is briefly described in the IRP narrative, the detail behind the approach is limited. Following a technical call with IPL on March 19, 2020, we were better able to understand the steps IPL took to incorporate EE into its load forecast. These steps are necessary to ensure a "No DSM" load forecast, which we consider critical to accurately modeling DSM as an explicit resource in IRPs. For example, this load forecast meant that IPL did not have to make any distortionary adjustments to energy efficiency in the same way that I&M, for example, did in its 2018 IRP.

To develop a "No DSM" load forecast, IPL starts off with its historical EE,[38] which also includes planned EE under the existing DSM program. IPL includes an EE variable for each customer class. In order to allocate historical savings across the customer classes, IPL uses historical participation to distribute savings across each customer class. When IPL assigns the historical savings across each customer class, it uses a weighted average measure life. The only adjustment IPL makes to the historical savings is adjusting for the first and last year of savings. The first year of savings includes a ramp up period, whereas the last year of the measure life sees savings taper off as the measures reach the end of their lives.

Once the model is estimated and IPL has a coefficient for the EE model, an assessment is made based on the value of the coefficient. As IPL states in the IRP, "For example, if the model estimates a coefficient of 0.5, then the model is saying that 50% of the historic DSM is captured in the historic sales. IPL then adjusts out any planned DSM based on this approach."[39] In other words, it adjusts out the savings from already approved programs.

Itron's SAE model normally includes forecasted data, originally developed from an EIA dataset that accounts for a portion of future utility sponsored DSM savings. However, IPL uses a modified version of that dataset that scrubs out impacts from utility sponsored programs.

We consider this to be a best practice approach for treating existing and planned DSM in the load forecast and allowing future DSM to be evaluated independent of the load forecast.

[38] IPL includes data for EE dating back to the commencement of its EE programs in 2011.
[39] IPL 2019 IRP Submission, p. 35.

4.3 UTILIZATION OF AMI DATA

In Section 9.2 of the IRP, IPL identifies areas upon which it plans to improve on for subsequent IRP processes. One of the items identified by IPL is a plan to improve load research and load forecasting by using advanced metering infrastructure ("AMI") data. IPL states, "Additionally, IPL has plans to work with an external consultant to explore load forecasting at the customer meter level using the AMI data."[40] If IPL plans to utilize this methodology for its next IRP, we hope that IPL will also dedicate resources to exploring how AMI can help with targeting customers for participation in energy efficiency and demand response programs and other concomitant benefits of doing this data-driven work.

[40] IPL 2019 IRP Submission, p. 205.

5 Description of Available Resources

Section 5 describes our assessment of IPL's performance in meeting the requirements of 170 IAC 4-7-6 of the Indiana IRP Rule. Please see Table 11 below for our findings.

Table 11. Summary of IPL's Achievement of Indiana IRP Rule 170 IAC 4-7-6

IRP Rule	IRP Rule Description	Findings
4-7-6 (a)	In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the 20 year planning period being evaluated: (1) The net and gross dependable generating capacity of the system and each generating unit.	Met
4-7-6 (a)	(2) The expected changes to existing generating capacity, including the following: (A) Retirements; (B) Deratings; (C) Plant life extensions; (D) Repowering; and (E) Refurbishment.	Met
4-7-6 (a)	(3) A fuel price forecast by generating unit.	Met
4-7-6 (a)	(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; (D) subsequent disposal; and (E) water consumption and discharge at each existing fossil fueled generating unit.	Met
4-7-6 (a)	(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce: (i) transmission losses; (ii) congestion; and (iii) and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network.	Partial
4-7-6 (a)	(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy. The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.	Partial
4-7-6 (b)	In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Rate design as a resource in meeting future electric service requirements.	Met
4-7-6 (b)	(2) For potential demand-side resources, the utility shall include the following: (A) A description of the potential demand-side resource, including its costs, characteristics and parameters; (B) The method by which the costs, characteristics and other parameters of the demand-side resource are determined; (C) The customer class or end-use, or both, affected by the demand-side resource; (D) Estimated annual and lifetime energy (kWh) and demand (kW) savings; (E) The estimated impact of a demand side resource on the utility's load, generating capacity, and transmission and distribution requirements; (F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	Partial
4-7-6 (b)	(3) For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered; (B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost; (C) A description of significant environmental effects.	Met
4-7-6 (b)	(4) In analyzing transmission resources, the utility shall include the following: (A) The type of the transmission resource; (B) A description of the timing, types of expansion, and alternative options considered; (C) The approximate cost of expected expansion and alteration of the transmission network; (D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources; (E) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.	Mostly

5.1 DEVELOPING ENERGY EFFICIENCY BINS BASED ON COST

For this IRP, IPL models eight bins of energy efficiency that the model can select.[41] IPL translated the Realistic Achievable Potential results from its Market Potential Study ("MPS") into 8 bundles, with each bundle representing 0.25% of sales. IPL assigned measures to these eight bundles based on the measure levelized cost. Measures with the lowest levelized cost were wholly placed into Bundle 1 until they totaled roughly 0.25% of sales; the next group of least expensive measures were put into Bundle 2 until they approximately totaled another 0.25% of sales; and so on. Figure 8 below shows the costs of each bundle.

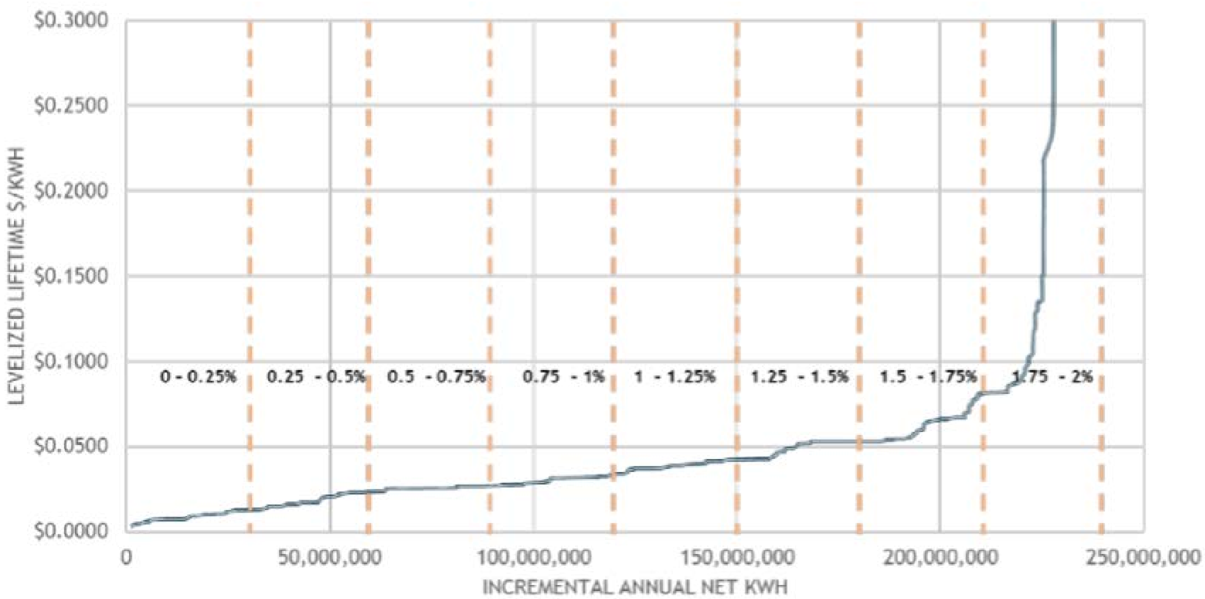

Figure 8. Realistic Achievable Potential Supply Curve[42]

We expressed concern to IPL about using this approach since it does not reflect how IPL actually implements its DSM programs and that it would, therefore, distort the selection of EE. The first bundle of savings that IPL achieves would contain a mix of cost-effective measures, not merely the savings from the least expensive measures. IPL implements a diverse portfolio of measures, some of which would be included in Bundles 1-4, but also others that appear in higher cost bins. For example, there are numerous measures assigned to the Residential Multifamily Direct Install energy savings program. For this program, measures are assigned to Bundle 2 through Bundle 7.[43] Since IPL's preferred plan includes only the savings up to and including Bundle 4, will the measures that would otherwise be included in this program contained in Bundles 5 through Bundle 7 just be eliminated? And, if not, will program savings be increased to account for the

[41] Note that IPL's IRP workpapers actually show nine bundles of energy efficiency, but its IRP refers to eight bundles and the ninth is not selectable until 2035, so we leave it off in our analysis as well.
[42] IPL 2019 IRP Submission, Figure 5.41, p. 100.
[43] IPL 2019 IRP Stakeholder Process, IPL Response to CAC Data Request 3.17, Attachment "CAC IRP DR 3.17ab Decrement Bundles with Measures."

additional, cost-effective potential that these measures bring? If measures from Bundles 5 through 7 are included in the portfolio without increasing the overall program savings, what happens to the savings from the least expensive measures in Bundles 1 through 4 that are displaced? The other question is how IPL will address programs included in previous DSM filings that were not selected in the IRP modeling. For instance, in the last DSM filing, IPL included a Residential Appliance Recycling program.[44] However, the measures for this program were assigned to Bundles 5 and 7,[45] which were not selected in the IRP modeling.

It is not credible to argue that the bundles are merely proxies for overall program savings of similar costs. First, that assumes that the shape of all measures are substitutable for each other. Even more importantly, if Figure 8 was reworked to present the MPS savings by program type, then the supply curve of EE would look much more flat. This is because the less expensive measures would average out the costs of the more expensive measures, the result of which would almost certainly be the selection of additional EE as long as not all the bundles are "optimal".

Indeed, using IPL's levelization methodology, if all bundles were grouped into one bundle, then the overall levelized cost would be $[redacted] per MWh, much lower than the $[redacted] per MWh cost of the last bundle modeled by IPL. In fact, this is even lower than the levelized cost of Bundle 4, $[redacted] per MWh, which is the bundle that was forced in but still reduced system NPV.

There are several additional errors and conservatisms that likely impacted the selection of energy efficiency. For example, the levelized costs cited in the previous paragraph are based on the present value of all bundle costs through the end of the planning period in 2039, but that present value is divided by the present value of energy savings only through 2039 as well. IPL, therefore, has an "end-effects" problem with respect to energy efficiency. And that end-effects problem begins almost immediately. For example, if the bundles available to the model in 2021 include measures with a 20-year life, because the planning period ends in 2039, then the model accounts for the full cost of that measure but only 19 years' worth of that measure's savings. And the problem grows with each year and each new measure added.

Taking the present value of bundle costs through 2039 and the present value of *all* savings those bundles produce, not a truncated amount, yields a bundle levelized cost of $[redacted] per MWh, which is significantly less than the modeled levelized cost of Bundle 4.

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[44] Appliance recycling program includes refrigerators, freezers, and AC units. *See* IURC Cause No. 44945, Direct Testimony of Zac Elliot.
[45] IPL 2019 IRP Stakeholder Process, IPL Response to CAC Data Request 3.17, Attachment "CAC IRP DR 3.17ab Decrement Bundles with Measures."

Finally, the bundle savings should have been converted to savings at the generator using a marginal loss factor rather than an average line loss factor because, by definition, energy efficiency reduces losses at the margin. Using a marginal factor would further reduce IPL's levelized costs by as much as 14 percent.[46]

5.2 ENERGY EFFICIENCY SELECTED IN THE IRP FALLS SHORT OF HISTORICAL PERFORMANCE

The level of EE selected in this IRP falls short of the savings IPL has historically achieved. Table 12 shows the level of 2018 evaluated savings for IPL - 161,685,625 kWh.

Table 12. IPL's 2018 DSM Program Energy Savings[47]

DSM Program	Evaluated 2018 Program Achievement (Ex Post Net kWh)*
Residential Programs	
Demand Response	68,609
Appliance Recycling	1,865,513
Community Based Lighting	8,014,916
Income Qualified Weatherization	2,256,228
Lighting & Appliances	20,125,603
Multifamily Direct Install	2,423,349
Peer Comparison	27,332,805
School Kits	4,003,124
Whole Home	4,027,393
Total Residential	**70,118,086**
Business Programs	-
Demand Response	-
Custom	14,639,238
Prescriptive	73,836,844
Small Business Direct Install	3,091,457
Total Business	**91,567,539**
Total All Programs	**161,685,625**

[46] Based on the Regulatory Assistance Project's paper on accounting for avoided line losses: https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf
[47] IPL 2019 IRP Submission, Figure 5.8, p. 64.

Figure 9 compares IPL's 2018 actual program achievement savings, 2019 savings reported in its scorecard, 2020 planned savings goal, the Realistic Achievable Potential ("RAP") identified in its MPS, the savings up to and including Bundle 3, and savings up to and including Bundle 4, separately. The savings from Bundles 3 and 4 are materially less than: IPL's historical savings in 2018 and 2019; IPL's planned savings goal for 2020; and the MPS RAP. We believe this is a direct result of the way the bundles were defined in the modeling as described above.

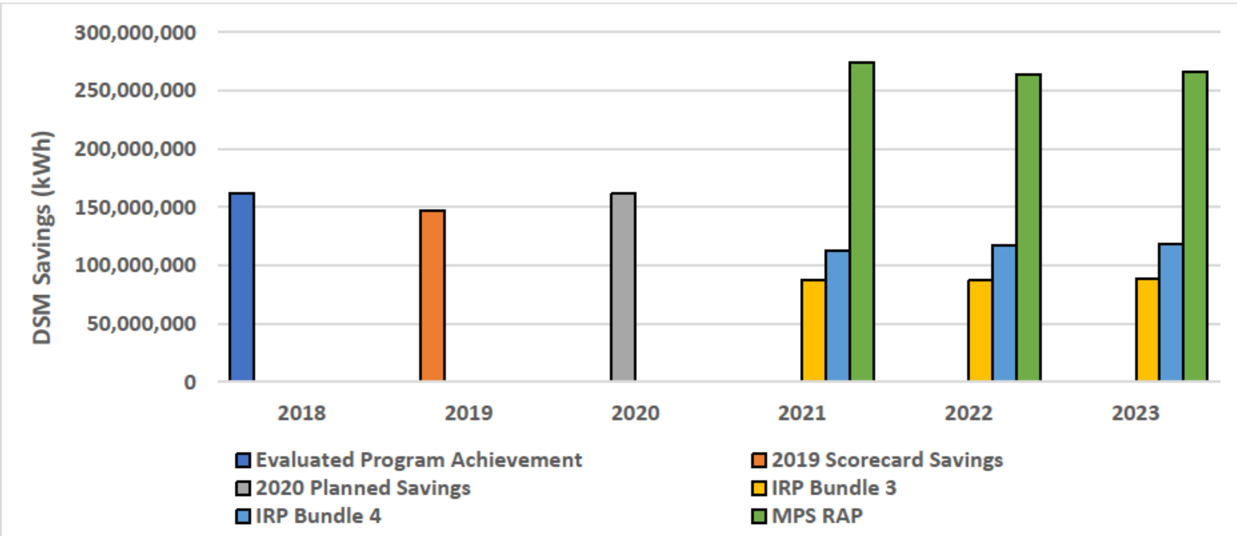


Figure 9. Comparison of Historical DSM Achievements and Savings from IRP [48]

5.3 AVOIDED TRANSMISSION AND DISTRIBUTION BENEFITS

Even if avoided transmission and distribution benefits cannot be modeled explicitly in PowerSimm, they can be accounted for as a reduction in DSM cost. IPL does not appear to have accounted for this benefit. This analysis is required by 170 IAC 4-7-8(c)(6), which says that the IRP must include, "An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system."

Second, the avoided T&D costs calculated by IPL are quite low, especially for the transmission portion. IPL estimated the avoided cost of transmission by taking [redacted]% of the long-term distribution capital costs. IPL did not provide any documentation supporting its selection of that percentage. IPL included a note with the calculation that, "No study was performed to estimate Transmission related avoided costs."[49] The avoided cost of distribution is based on the percentage of IPL circuits that may need upgrades. It appears that IPL arrived at this avoided distribution cost by taking [redacted]% of the fixed charges for the distribution circuits. It appears that

[48] 2019 savings from IPL's 2019 Scorecard. Planned 2020 savings based on projections from IPL's 2020 Scorecard.
[49] IPL 2019 IRP Stakeholder Process, IPL Workpaper Confidential Attachment 5.4 (Avoided Cost).

IPL is basing this on its reported number of circuits that are at or near capacity. It is also important to consider that IPL is projecting an increase in energy and demand for the planning period that is driven by growth in residential sales. We are unsure whether or not IPL factored this into the analysis for avoided T&D costs. The result is $[redacted] per kW-year for avoided distribution costs and $[redacted] per kW-year for avoided transmission costs for a total avoided T&D cost of $[redacted] per kW-year.[50]

The avoided distribution cost is at the [redacted] of the range identified by the Regulatory Assistance Project in a paper on this topic and the avoided transmission cost is at [redacted] too low:

> *The capital cost of augmenting transmission capacity is typically estimated at $200 to $1,000 per kilowatt, and the cost of augmenting distribution capacity ranges between $100 and $500 per kilowatt. Annualized values (the average rate of return multiplied by the investment over the life of the investment) are about 10% of these figures, or $20 to $100 per kilowatt-year for transmission and $10 to $50 per kilowatt-year for distribution.*[51]

The total avoided T&D range identified by RAP is $30 per kW-year to $150 per kW-year. IPL's total avoided T&D costs are significantly [redacted] than this low range estimate from RAP.

Confidential Table 13 shows the comparison between the levelized T&D benefit and the corrected cost of each EE bundle modeled by IPL. The T&D benefit is based on IPL's avoided T&D calculation contained in the 2019 IRP and escalated at the rate of inflation. This calculation is not precise because we lack the lifetime avoided peak capacity and therefore exclude both the avoided capacity benefits and the avoided savings after 2039.

Confidential Table 13. Levelized T&D Benefit and IPL Levelized Cost of EE Bundles (per MWH)[52]

Bundle	T&D Benefit	EE Cost
1	[redacted]	[redacted]
2	[redacted]	[redacted]
3	[redacted]	[redacted]
4	[redacted]	[redacted]
5	[redacted]	[redacted]
6	[redacted]	[redacted]
7	[redacted]	[redacted]
8	[redacted]	[redacted]

[50] IPL 2019 IRP Stakeholder Process, IPL Workpaper Confidential Attachment 5.4 (Avoided Cost).
[51] P. 6 of Lazar and Baldwin (2011). Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements. RAP. Retrieved from http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf
[52] Levelized DSM Costs provided in IPL 2019 IRP Stakeholder Process, IPL Response to CAC Data Request 3.12, Confidential Attachment CAC Data Request 3-12.4 corrected to include lifetime savings.

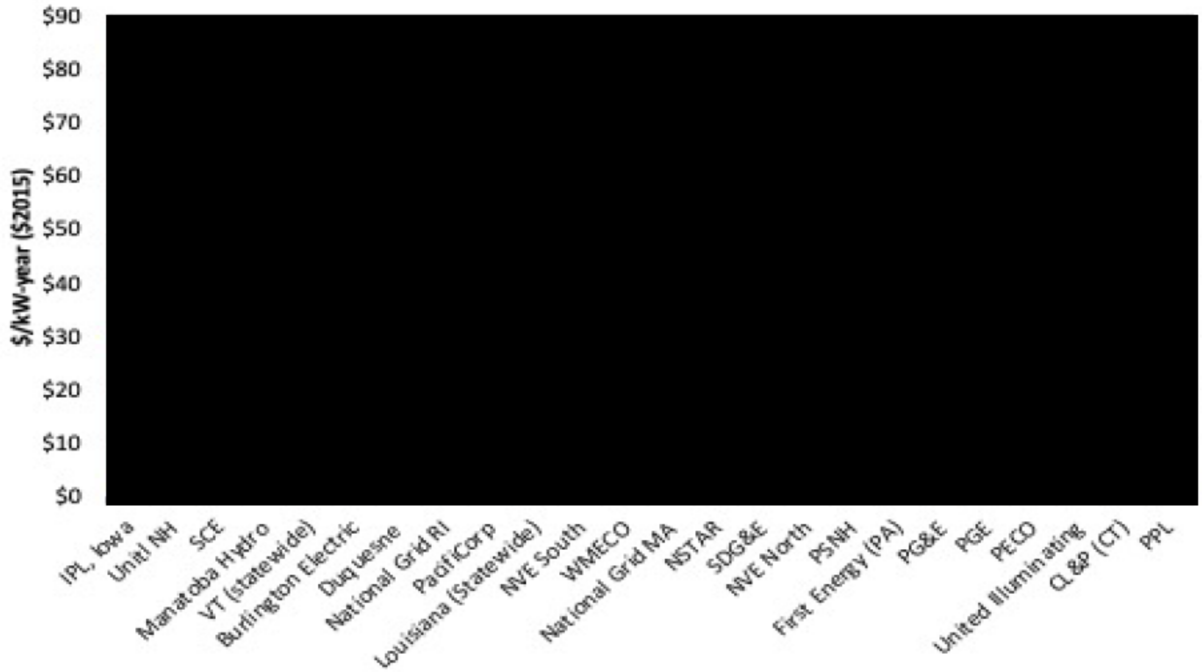
If the avoided T&D cost is changed to $70 starting in 2021 and escalated at IPL's assumed inflation rate of 2 percent, the T&D benefit for each bundle significantly increased as shown in Confidential Table 14.

Confidential Table 14. Levelized T&D Benefit at $70 and Cost of EE Bundles ($/MWH)

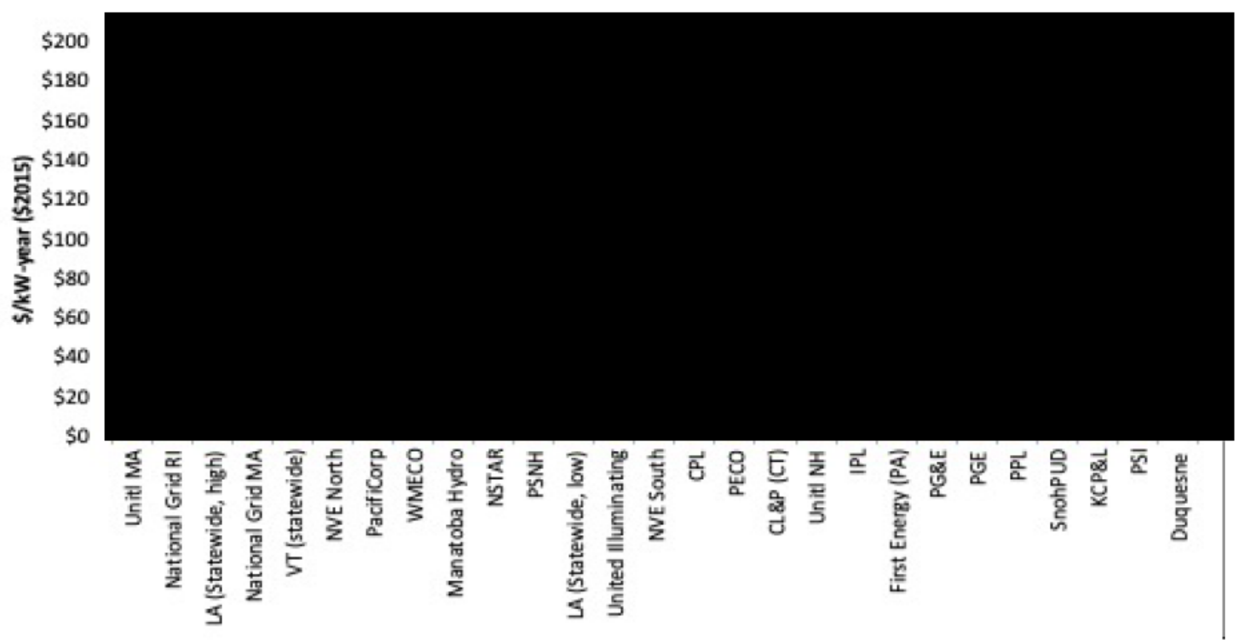
Bundle	T&D Benefit[53]	EE Cost
1	[redacted]	[redacted]
2	[redacted]	[redacted]
3	[redacted]	[redacted]
4	[redacted]	[redacted]
5	[redacted]	[redacted]
6	[redacted]	[redacted]
7	[redacted]	[redacted]
8	[redacted]	[redacted]

A higher avoided T&D cost is more in line with the avoided T&D cost of other utilities. Confidential Figure 10 and Confidential Figure 11 show the avoided transmission and distribution costs for utilities included in a database of avoided T&D costs created by consulting company Synapse Energy Economics. The average avoided transmission cost across the utilities was $30 per kW-year and the average avoided distribution cost was $62 per kW-year for a total average T&D cost of $92 per kW-year in 2015$. Even if Confidential Table 14 had assumed $70 per kW-year in 2015$ that would still be [redacted] than the average avoided T&D in this database.

[53] Avoided T&D benefit starts at $70 in 2021 and escalates at a rate of 2%.



Confidential Figure 10. Comparison of Avoided Transmission Costs across Utilities (2015$)[54]



Confidential Figure 11. Comparison of Avoided Distribution Costs across Utilities[55]

[54] Synapse Avoided Transmission and Distribution Value Database
[55] Ibid.

5.4 DECREMENT METHODOLOGY PROPOSED BY CAC

As part of the discussion with IPL about improvements for modeling DSM for the IRP, CAC presented its recommended decrement methodology during a conference call with IPL. The idea behind this methodology is to model DSM as discrete decrements (0.25% for example) to load, which results in a set of avoided costs for each level of potential. In the IRP, IPL expresses these concerns with this methodology:

> *1) if avoided costs are made available to bidders, then bidders would likely provide bids equal to the avoided cost in the RFP meaning the energy efficiency portfolio would breakeven and not maximize cost effectiveness to customers; DSM benefits = DSM costs 2) if through the RFP process bidders indicate the 2% savings level cannot be achieved, then the IRP and the plans for future generation that had been optimized at the 2% savings level would be need to be reevaluated at a lower savings level.*[56]

The first issue can be resolved by keeping the IRP derived avoided costs confidential but evaluating program implementation proposals based on those avoided costs. If in the unlikely case that bidders cannot propose programs that achieve a 2 percent incremental savings level or higher, then we do not see the near-term issue IPL fears. It takes time both to acquire new supply-side resources and to ramp up DSM programs to higher levels of achievement. The time it takes to go from issuance of an RFP for DSM services to hiring of a contractor is plenty of time to course correct, if such an action is needed.

[56] IPL 2019 IRP Submission, p. 99.

5.5 DEMAND RESPONSE

For this IRP, IPL created two demand response bundles to model as selectable resources within PowerSimm. One bundle represented commercial and residential air conditioner load management, while the second bundle represented residential and commercial water heater control measures. Despite modeling these bundles, neither of the bundles were selected by PowerSimm for the preferred plan. As a result, IPL's preferred plan only includes its existing demand response programs representing 55 MW.[57]

Given the Realistic Achievable Potential identified in the MPS, IPL's existing demand response falls short. Figure 12 compares IPL's existing demand response to the Achievable Potential identified in the MPS. Please note that the MPS identifies two different levels of Achievable Potential – one that considers residential programs plus "day of" curtailable programs for commercial customers and one that considers residential programs plus "day ahead" curtailable programs for commercial customers. The two blue bars represent the range of demand response potential, taking into consideration the different curtailment notification. The solid black line represents IPL's existing demand response programs. Based on the potential identified in the MPS, there are additional savings from demand response programs for IPL.

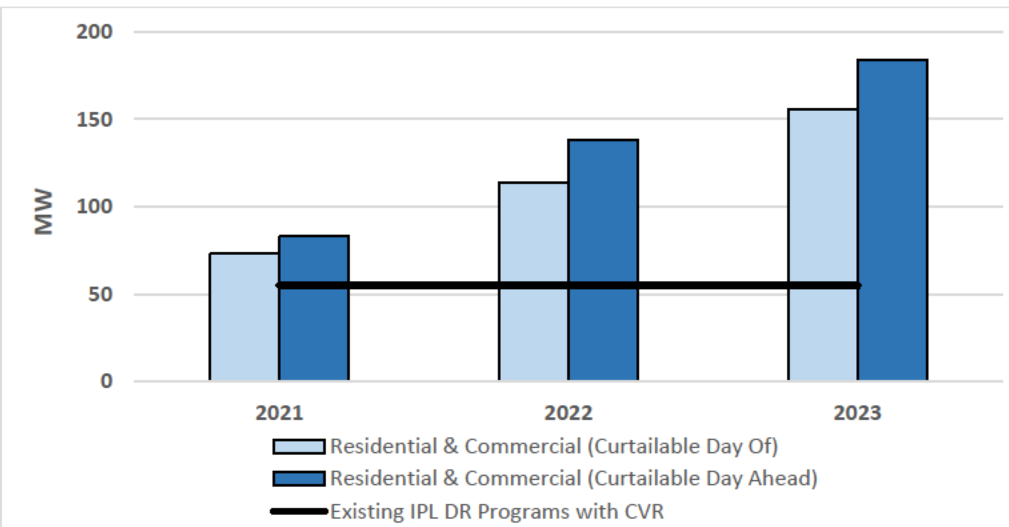


Figure 12. Comparison of IPL Existing Demand Response Resources to MPS Achievable Potential[58]

IPL's existing demand response program savings are dominated by its residential AC Load Management program. With just 1 MW representing commercial demand response savings, IPL does not compare well to what the other utilities in Indiana have been able to achieve with commercial demand response programs. Figure 13 shows IPL's commercial DR capability in comparison to the other Indiana utilities.

[57] IPL's existing DR program contributions are 38.6 MW from Air Conditioning Load Management; 1.1 MW from Rider 17; and 15.3 MW from Conservation Voltage Reduction. IPL 2019 IRP Submission, p. 65.

[58] Demand Response Achievable Potential from IPL's 2018 MPS, Table 8-2, p. 59.

Investor Owned Utility	C&I DR Total (MW)	2018 Peak Demand Forecast (MW)	C&I DR Capability (Percent of Peak)
Duke Energy Indiana	694	6,613	10.5%
NIPSCO	530	3,160	16.8%
I&M	298	4,434	6.7%
Vectren	35	1,104	3.2%
IPL	1	2,864	0.03%
IOU Total	**1,558**	**18,175**	**8.6%**

Figure 13. Existing Non-Residential Demand Response from AEE Study[59]

By focusing on programs that help to offset water heater and air conditioner use during periods of peak demand, IPL can utilize demand response programs as a resource to meet its capacity need. Furthermore, the MPS found a majority of the demand response programs evaluated to be cost-effective.[60] We are not clear why PowerSimm would view the cost-effectiveness of demand response differently. It could perhaps be a product of the same issue that results in the suboptimal selection of energy efficiency, but we do not know. Either way, we are skeptical that the optimal level of demand response has truly been derived in this IRP.

[59] *Potential for Peak Demand Reduction in Indiana*. Prepared for Indiana Advanced Energy Economy by Demand Side Analytics, LLC. February 2018. Table 7, p. 10.
[60] IPL's 2018 MPS, Table 8-6, p. 60. The AC – Switch and AC – Thermostat programs were both cost-effective for residential customers. Only the AC – Thermostat program was cost-effective for the non-residential customers. The water heating program was cost-effective for residential and non-residential customers.

6 Selection of Resources

Section 6 describes our assessment of IPL's performance in meeting the requirements of 170 IAC 4-7-7 of the Indiana IRP Rule. Please see Table 15 below for our findings.

Table 15. Summary of IPL's Achievement of Indiana IRP Rule 170 IAC 4-7-7

IRP Rule	IRP Rule Description	Finding
4-7-7	To eliminate nonviable alternatives, a utility shall perform an initial screening of the future resource alternatives listed in subsection 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	**Mostly**

Figure 5.35 of IPL's IRP includes the supply-side resources IPL evaluated for this IRP. One of the resources IPL should have considered for its modeling are hybrid resources, or renewables paired with battery storage. Hybrid resources allow utilities to realize the cost savings from the Investment Tax Credit as well as certain cost efficiencies, such as those from sharing an inverter. Many hybrid solar and battery systems are not a new or novel technology, but rather commercially available resources that many utilities are adopting. The alternatives considered by IPL should have included hybrid resources and in particular hybrid resources at utility scale.

Despite not modeling hybrid resources for its IRP, IPL anticipated that it would receive hybrid resource project bids in response to its all-source RFP.[61]

[61] IPL Request for Proposals. Appendix C Schedule B6. Retrieved from https://www.iplpower.com/About_IPL/Regulatory/Filings/IRP_2019/Request_for_Proposals/RFP_Documents/

7 Resource Portfolios

Section 7 describes our assessment of IPL's performance in meeting the requirements of 170 IAC 4-7-8 of the Indiana IRP Rule. Please see Table 16 below for our findings.

Table 16. Summary of IPL's Achievement of Indiana IRP Rule 170 IAC 4-7-8

IRP Rule	IRP Rule Description	Finding
4-7-8 (a)	The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider the following: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.	Met
4-7-8 (b)	With regard to candidate resource portfolios, the IRP must include: (1) An analysis of how each candidate resource portfolio performed across a wide range of potential future scenarios, including the alternative scenarios required under subsection 4(25) of this rule.	Met
4-7-8 (b)	(2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics.	Mostly
4-7-8 (b)	(3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	Met
4-7-8 (c)	Considering the analyses of its candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following information: (1) A description of the utility's preferred resource portfolio.	Met
4-7-8 (c)	(2) Identification of the standards of reliability.	Met
4-7-8 (c)	(3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	Met
4-7-8 (c)	(4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of the following: (A) safety; (B) reliability; (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	Partial
4-7-8 (c)	(5) An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, reliably, efficiently, and cost effectively meets the electric system demand taking cost, risk, and uncertainty into consideration.	Partial
4-7-8 (c)	(6) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system.	Not Met
4-7-8 (c)	(7) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio; (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule; (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio; and (D) The utility's ability to finance the preferred resource portfolio.	Mostly
4-7-8 (c)	(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties; and (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	Mostly
4-7-8 (c)	(9) Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	Met

4-7-8 (c)	(10) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including to the changes in the following: (A) Demand for electric service; (B) Cost of a new supply-side resources or demand-side resources; (C) Regulatory compliance requirements and costs; (D) Wholesale market conditions; (E) Changes in Fuel costs; (F) Changes in Environmental compliance costs; (G) Technology and associated costs and penetration; (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	**Partial**

7.1 RISK ASSESSMENT IN POWERSIMM

The PowerSimm model incorporates risk by modeling several variables stochastically. Multiple iterations are performed based on randomly selecting values, within a given distribution, for those variables. IPL varied natural gas prices, power prices, coal prices, load, and weather. We appreciate the fact that IPL did not perform stochastics on other variables like capital cost, which we believe would have been inappropriate. We feel quite strongly that stochastic analysis should be reserved for factors that are volatile rather than uncertain.

Unlike other models that perform stochastics on the portfolios after the fact of capacity expansion, PowerSimm incorporates stochastics into the resource selection itself. As IPL states, "Each scenario conducted stochastically with 100 iterations to widen the range of uncertainty considered."[62] However, using PowerSimm to model these variables stochastically comes with a trade off in the number of iterations. More iterations extend model run time. Relying on 100 iterations is not a particularly large sample size, especially given the number of variables that are modeled stochastically within PowerSimm. Although we are not privy to the run time of the modeling performed by IPL, our modeling experience suggests that running the number of iterations necessary for a large enough sample size would not be feasible. Apart from whether enough iterations were run to come up with a robust result, frankly there was very little to evaluate in the way of information about how the stochastic variables were modeled. The only probability distributions that were given to us were for market power prices but there was nothing in that spreadsheet to reveal the manner in which the distributions were derived.

PowerSimm also utilizes these probability distributions to identify the risk associated with each portfolio modeled. IPL refers to this as the risk premium, which it defines as "the probability-weighted average of costs above the median."[63] After calculating the risk premium, it can be added[64] to the PVRR, in order to create a risk-adjusted PVRR that puts all of the portfolios on equal footing. From the results of the risk premium, IPL notes that the risk premium trends higher as coal is retired. IPL's explanation for this is that:

[62] IPL 2019 IRP Submission, p. 120.
[63] IPL 2019 IRP Submission, p. 151.
[64] On p. 151 of the IRP, IPL states that, "Since different energy portfolios have different simulated cost distributions, the risk premium will be larger for wider cost distributions, or riskier portfolios, and smaller for narrower cost distributions, or less risky portfolios."

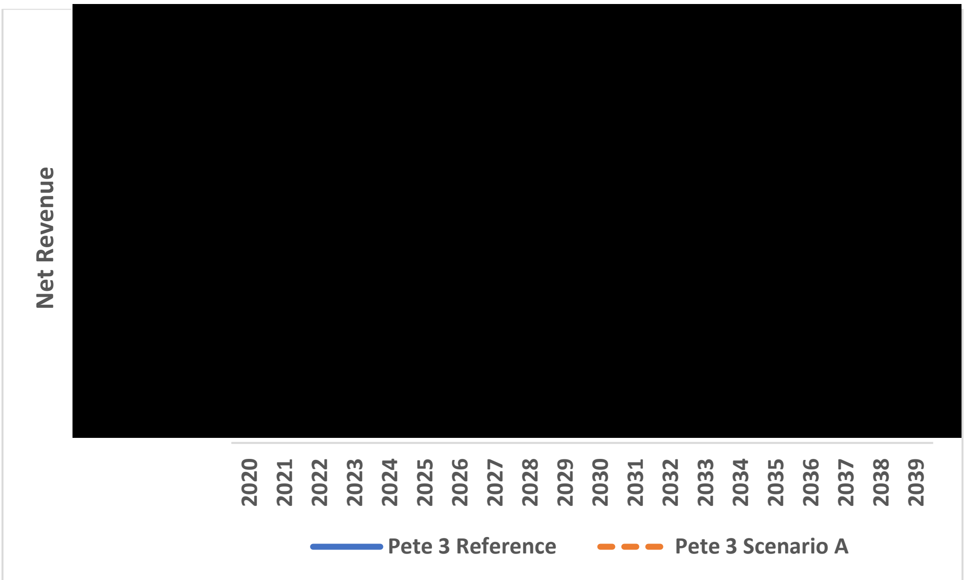
> *First, coal prices are relatively stable compared to power and natural gas prices, so coal can potentially reduce overall portfolio risk. Second, coal units are dispatchable units and will increase output during high price times and reduce output during low price hours.*[65]

IPL's explanation reveals exactly why stochastic analysis is limited in its ability to assess risk. The regulatory risks inherent in coal-fired generation were only captured in IPL's carbon price, which was not modeled as a variable in IPL's stochastic risk analysis. Nor did IPL model either stochastically or as a sensitivity the possibility of increased operating cost as IPL's coal units continue to age. Finally, the ability of IPL's coal units to turn down during times of low prices is finite and limited by the operating constraints of those units. Coal units typically have minimum up times of several hours and must run at a not insignificant minimum loading level when they are operating. In effect, IPL's argument assumes that its coal units will never have to face cost and price effects that would reverse the risk premium trends its modeling identified.

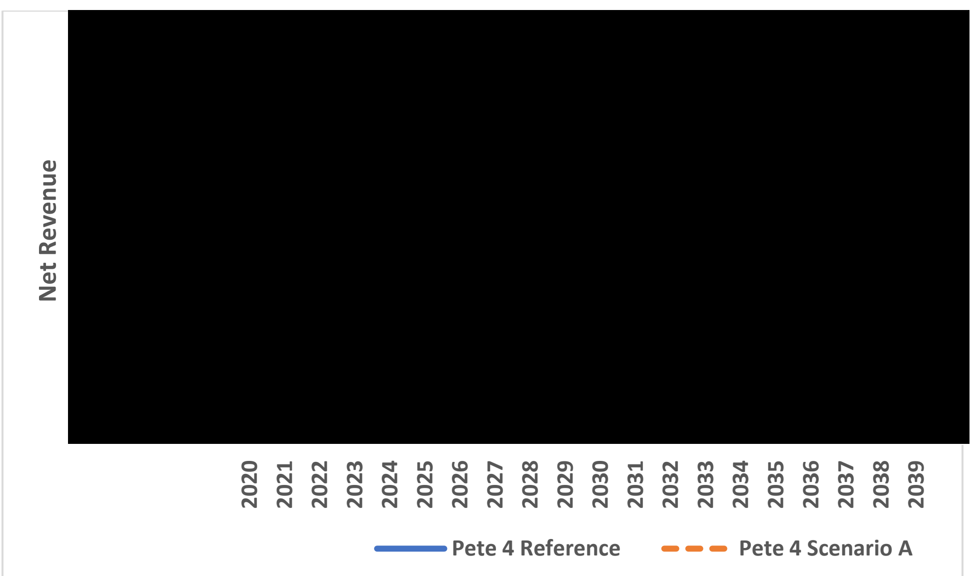
7.2 CARBON TAX IMPACT

IPL incorporated a Carbon Tax that starts at approximately $2/ton in 2028 and escalates to approximately $40/ton by 2039. IPL acknowledges that the Carbon Tax had the largest impact on the NPV of the portfolios modeled.[66] As Confidential Figure 14 and Confidential Figure 15 show, the introduction of a price on carbon dramatically reduces revenue to the Petersburg units. That is to be expected. What is surprising, however, is that, in the absence of the carbon tax, revenue would grow so much for these units starting around 2030. This suggests to us either that LMPs are growing at an unusually quick rate at the Petersburg units or that there has been an underestimation in the rate of growth in operating costs associated with these units. Put another way, we would expect the dotted orange line in each graph to be more consistent with a reference case that does not include a carbon tax because revenue is relatively unchanged from year to year.

[65] IPL 2019 IRP Submission, p. 181.
[66] IPL 2019 IRP Submission, p. 179.



Confidential Figure 14. Net Revenue Comparison for Petersburg Unit 3



Confidential Figure 15. Net Revenue Comparison for Petersburg Unit 4

7.3 CONSIDERATION OF ELECTRIFICATION AND DISTRIBUTED SOLAR

For this IRP, IPL used the same assumptions for modeling electric vehicles and distributed solar across all portfolios.[67,68] In the next IRP, we encourage IPL to explore scenarios or sensitivities around beneficial electrification and distributed generation adoption. We would like to see electrification resources and distributed solar drawn into the IRP as more explicitly considered resources because their presence can change the shape of load and may change the optimal resource selection.

We would also encourage IPL to start using adoption models for distributed solar and electric vehicles in order to better characterize their uptake. For example, professors from the Rochester Institute of Technology developed a model that looks at customer adoption of distributed solar based on a simple payback model.[69] IPL could use this model to develop blocks of distributed generation that could be modeled as a supply side resource with a cost connected to the incentive payment the utility pays out.

[67] IPL 2019 IRP Submission, p. 156.
[68] IPL 2019 IRP Submission, p. 156.
[69] Williams, et al. "Empirical development of parsimonious model for international diffusion of residential solar." *Renewable Energy*, December 27, 2019.

8 Short Term Action Plan

Section 8 describes our assessment of IPL's performance in meeting the requirements of 170 IAC 4-7-9 of the Indiana IRP Rule. Please see Table 17 below for our findings.

Table 17. Summary of IPL's Achievement of Indiana IRP Rule 170 IAC 4-7-9

IRP Rule	IRP Rule Description	Finding
4-7-9 (a)	A utility shall prepare a short term action plan as part of its IRP, and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule.	**Met**
4-7-9 (b)	The short term action plan is a summary of the utility's preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(c)(9) of this rule.	**Partial**
4-7-9 (c)	The short term action plan must include, but is not limited to, the following: (1) A description of resources in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio; and (B) The criteria for measuring progress toward the objective.	**Met**
4-7-9 (c)	(2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10, 170 IAC 4-8-1 et seq. and consistent with the utility's longer resource planning objectives.	**Partial**
4-7-9 (c)	(3) The implementation schedule for the preferred resource portfolio.	**Met**
4-7-9 (c)	(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.	**Not Met**
4-7-9 (c)	(5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually occurred.	**Not Met**

As Figure 19, Figure 20, and Figure 21 demonstrate, IPL is taking some steps to balance out its energy portfolio and reduce its reliance on coal in favor of renewable energy. However, investments in energy efficiency are still quite modest. Overall, we look forward to working with IPL on its next IRP to continue to advance the strides it has made in producing this IRP.

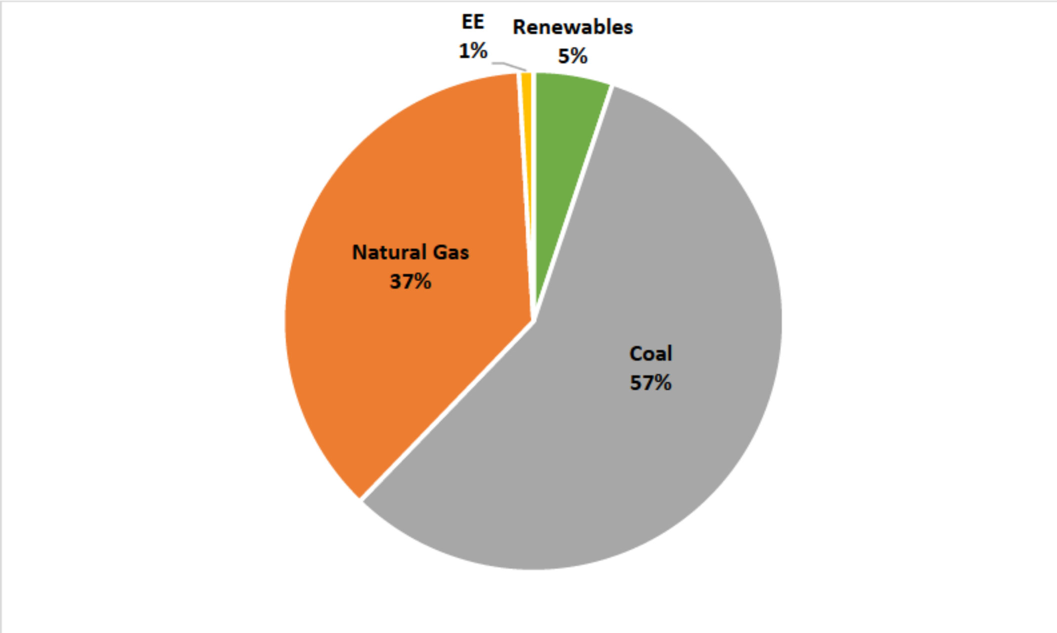


Figure 16. IPL's 2020 Energy Mix[70]

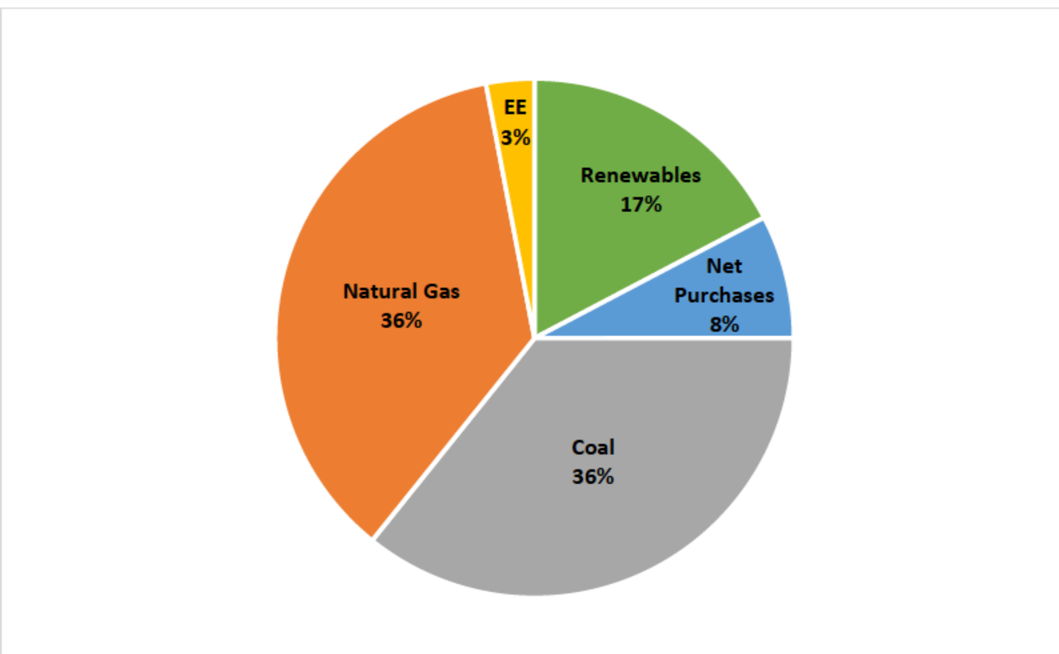


Figure 17. IPL's 2024 Energy Mix

[70] Energy Efficiency for 2020 represents projected net savings of 161,488 MWh from IPL's 2020 Scorecard.

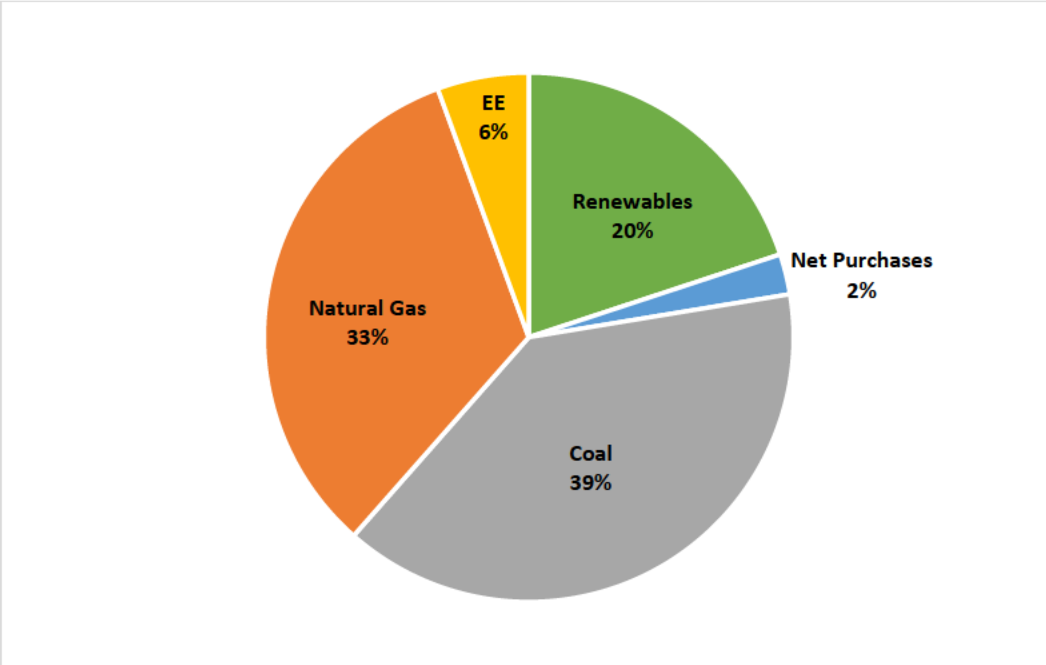


Figure 18. IPL's 2028 Energy Mix

ATTACHMENT AS-2- CONFIDENTIAL

ATTACHMENT AS-3-PART 1

Data Request CAC DR 3 - 3

Please provide all spreadsheets used in the development of the DSM bundle costs, capacity, and energy for input into PowerSimm if not contained in "Concept Test - Decrement Pricing v5--5-17-19".

Objection:

IPL objects to the request on the grounds and to the extent the request is overly broad and unduly burdensome, particularly to the extent the request seeks "all" spreadsheets. IPL further objects to the request on the grounds and to the extent the request seeks information previously provided to the CAC. Subject to and without waiver of the foregoing objections, IPL provides the following response.

Response:

Please see CAC DR 3-3 Attachment 1 for the calculation of the bundle levelized costs that were used in the IRP analysis.

Please refer to CAC DR 2-6 Attachments 1 – 23 for the capacity and energy calculation used in the IRP analysis.

Please refer to CAC DR 1-6 Attachments 1-3 for the calculations that support the bundle capacity and energy included in CAC DR 2-6 Attachments 1-23.

ATTACHMENT AS-3-PART 2

See separately filed Excel workbook

ATTACHMENT AS-4-
CONFIDENTIAL

ATTACHMENT AS-5-CONFIDENTIAL

ATTACHMENT AS-6-CONFIDENTIAL

ATTACHMENT AS-7-
CONFIDENTIAL

ATTACHMENT AS-8-
CONFIDENTIAL

CERTIFICATE OF SERVICE

I hereby certify that on the 25th day of September, 2020, I served the foregoing by electronic mail on the following:

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