Dr. Brad Borum
Indiana Utility Regulatory Commission
101 West Washington Street, Suite 1500 East
Indianapolis, Indiana 46204-3419

May 10, 2022

Re: Duke Energy Indiana's 2021 Integrated Resource Plan

Dear Dr. Borum,

Indiana Advanced Energy Economy ("AEE") appreciates the opportunity to comment on the Integrated Resource Plan ("IRP") submitted to the Indiana Utility Regulatory Commission ("IURC") by Duke Energy Indiana ("DEI") on December 15, 2021.

Advanced Energy Economy ("AEE") is a national business association representing leaders in the advanced energy industry. AEE supports a broad portfolio of technologies, products and services that enhances U.S. competitiveness and economic growth through an efficient, high-performing energy system that is clean, secure, and affordable. AEE has been operating in the Hoosier state as Indiana AEE since 2016. In Indiana, AEE aims to drive the development of advanced energy by identifying growth opportunities, removing policy barriers, encouraging market-based policies, establishing partnerships, and serving as the voice of innovative companies in the advanced energy sector.

We participated in DEI's IRP stakeholder process and met one-on-one with DEI on two occasions. While we do not fully support their preferred portfolio, we appreciate that the process provided opportunity for stakeholders to contribute to the development of the IRP and that DEI willingly engaged with us and other stakeholders during their work on the IRP.

We have organized our comments as follows.

1. We offer some general observations on DEI's preferred course of action in this IRP, with the primary purpose of identifying those proposals in which significant investment will be made or should be made during the next few years and are therefore most salient in the IURC's current review.

2. We observe that DEI's fuel price forecasts, particularly for natural gas, are likely outdated and that as a result, IURC should be wary of new gas investments and instead emphasize renewable generation as a hedge against higher fuel prices.
3. We comment on the level of energy efficiency programming proposed by DEI and recommend that this should be ramped up to higher levels than those proposed by DEI.
4. We comment on opportunities to enable more effective use of demand response, which would then reduce the need for generation resources that supply capacity.
5. We comment that "must run" operation of Gibson, Cayuga, and Edwardsport is not best for customers and is not an appropriate assumption in this IRP.
6. We observe that energy storage resources are likely undervalued in DEI's IRP and we make recommendations for more appropriate levels of procurement and more thorough consideration of the value of energy storage in future IRPs and Request for Proposals.
7. We identify that federal policy that would affect DEI's best course of action is unsettled but that there are opportunities to adapt in upcoming resource procurements to take advantage of incentive programs that lower customer costs.
8. We comment that DEI's assessment of market price risks for electricity and natural gas may understate those risks and we identify that those risks could be reduced by accelerating in time DEI's proposed procurement of renewable generation resources while leaving open options to rebalance DEI's portfolio after their next IRP.
9. We discuss market interest in voluntary renewable energy purchases and recommend that DEI offer its customers options along those lines.
10. Finally, we sum up our comments with specific recommendations as to how the IURC and DEI should proceed.

General Observations on DEI 2021 Preferred Course of Action

As explained by DEI in their filed IRP, DEI selected a preferred course of action that they characterized as the *Renewables-CC-CT* portfolio. In this portfolio, they outlined the following resource decisions that would be either executed or substantially underway before DEI files their next IRP, or where the option to make earlier changes will be foreclosed until they are addressed in DEI's next IRP. These decisions would therefore be largely baked-in and could not be readily changed in their 2024 IRP:

- Gibson 5 retirement in 2025
- Edwardsport IGCC continuation after 2022
- Cayuga 1 and 2 retirements in 2027
- Continued operation of Gibson 3 and Gibson 4 through 2028

- Cumulative 119 MW through 2023 and 151 MW through 2024 avoided capacity need through energy efficiency programming
- Cumulative 512 MW through 2023 and 607 MW through 2024 cumulative enrollment of demand response resources
- Cumulative 197 MW solar resources through 2023 and 447 MW solar resources through 2024
- Cumulative 0 MW of hybrid solar with storage capacity and cumulative 0 MW stand-alone storage capacity through 2023/2024
- Cumulative 100 MW wind through 2023/2024

In addition, DEI's plans to acquire 1,221 MW of combined cycle capacity that would be available in 2027 could be timely revisited in their 2024 IRP but we would anticipate that DEI will have initiated planning and procurement for these resources and will have incurred some costs in doing so. Nonetheless, with an appropriate caution by the IURC against a firm commitment to these resources prior to the next IRP, DEI would be able to change these decisions, or proceed to implement them if their resource assumptions are validated by market bids collected from the next several Request for Proposals ("RFPs"), and by the modeling DEI conducts for its next IRP.

In 2025 and thereafter, DEI's preferred course of action as described in their 2021 IRP includes further annual acquisition of solar resources throughout the planning period until 2040 and of incremental wind resources beginning in 2030 and continuing through that decade. Acquisition of these resources can be timely revisited in their 2024 IRP, though procurement of solar resources for commercial operation in 2025 will need to be underway by that time.

We also observe that acquisition times for some resources are short enough that it remains possible to increase acquisition in the period from 2024 or 2025 through 2026 above the levels included in DEI's proposed course of action as described in this IRP. Resources that could be accelerated include energy efficiency, demand response, solar, solar plus storage, stand-alone storage, and wind.

DEI selected the hybrid Renewables-CC-CT portfolio from among several candidate portfolios. Based on our review of those portfolios and their projected performance on various criteria, we find that the IURC should focus its review of the Renewables-CC-CT portfolio by comparing it to the portfolio that DEI labeled as "Biden 90."

We also compare the Renewables-CC-CT portfolio with results from 5 Lakes Energy's STEP8760 IRP modeling tool, developed by researchers at the University of Michigan and 5 Lakes Energy for use in planning compliance with the Clean Power Plan. 5 Lakes Energy subsequently modified it as a general-purpose integrated resource planning tool. Appendix 1 more thoroughly describes the model and includes a summary table of its results compared to the Renewables-CC-CT portfolio.

First, we note the differences between DEI's two resource portfolios, Renewables-CC-CT and Biden 90, by comparing the tables on pages 102 and 105 of the filed IRP.

Resource	Renewables-CC-CT portfolio	Biden 90 portfolio
Cayuga 1 &2	Retires end of 2026	Retire one unit before 2024 and the other in 2027
Edwardsport IGCC	Retires in 2034	Retires in 2022
Gibson 1&2	Retires both in 2034	Retires one unit in 2030 and one unit in 2034
Gibson 3	Retires in 2028	Retires in 2027
Gibson 4	Retires in 2028	Retires in 2030
Gibson 5	Retires in 2024	Retires in 2026
Zero-Emissions Load-Following Resource	Not included	Ramped up to 1,756 MW from 2033 to 2035
New Combined Cycle	1,221 MW operable in 2027	815 MW operable in 2023
Capacity Power Purchases	450 MW in 2023	None
Energy Efficiency	Cumulative 207 MW by 2026 308 MW by 2030 338 MW by 2040	Cumulative 216 MW by 2026 324 MW by 2030 354 MW by 2040
Demand Response	Cumulative 613 MW by 2026 and thereafter	Cumulative 937 MW by 2026 and thereafter
Solar	Cumulative 847 MW by 2026 1,547 MW by 2030 3,025 MW by 2040	Cumulative 1,097 MW by 2026 2,997 MW by 2030 3,025 MW by 2040
Solar plus Storage	Begins with 75 MW in 2027 Cumulative 300 MW by 2030 600 MW by 2040	Begins with 75 MW in 2032 Cumulative 600 MW by 2040
Wind	Remains 100 MW until 2030 Cumulative 1,500 MW by 2040	Remains at 100 MW until 2024 Cumulative 400 MW by 2026 2,150 MW by 2030 2,850 MW by 2040
Stand-alone storage	none	200 MW in 2030 Cumulative 1,450 MW in 2040

Although there are a number of details in the evolution of these portfolios, we find the following summary to be helpful in comprehending the differences between these portfolios:

	2026		2030		2040	
Portfolio (all values in MW)	Ren-CC-CT	Biden 90	Ren-CC-CT	Biden 90	Ren-CC-CT	Biden 90
Existing Fossil Plants	4,465	3,660	2,198	2,207	586	0
New CC Gas Plants	0	815	1,221	815	1,221	815
New CT Gas Plants	0	0	0	0	1,160	1,160
DSM	820	1,153	921	1,261	951	1,291
Renewables & Adv Tech	947	1,497	2,047	5,347	7,325	9,681

Thus, the Biden 90 portfolio:

- Retires existing fossil plants more quickly than the Renewables-CC-CT portfolio
- Invests in new gas capacity earlier but to a smaller total amount than the Renewables-CC-CT portfolio
- Increases demand-side management resources earlier and to a higher level than the Renewables-CC-CT portfolio
- Acquires renewables and storage both earlier and to a higher level than the Renewables-CC-CT portfolio.

While we consider the 2040 portfolios to be interesting and indicative of future direction, they are also necessarily somewhat speculative regarding both available technology and costs. We observe, on the other hand, that the 2030 Renewables-CC-CT and Biden 90 portfolios maintain very similar amounts of existing plants and have important differences in the quantities of other resources that effectively represent different risks regarding future gas prices and GHG emissions restrictions or costs. Selection of the Renewables-CC-CT portfolio relies on moderate or low gas prices and GHG restrictions or costs. The Biden 90 portfolio modestly hedges against gas prices by developing more clean energy resources.

The differences between the Renewables-CC-CT and Biden 90 portfolios in 2026 warrant some further discussion. Effectively, the Biden 90 portfolio retires more existing fossil capacity before 2026 than the Renewables-CC-CT portfolio but replaces some of that capacity with new CC capacity, netting almost identical amounts of fossil generation. The Biden 90 portfolio, on the other hand, invests in significantly more demand-side management resources and renewables prior to 2026, which then enables more rapid reduction of fossil generation before and soon after 2030.

DEI's comparison of the various portfolios that they evaluated is summarized in their Table V.1 on page 109 of the IRP. We highlight here the comparison of the Renewables-CC-CT portfolio to the Biden 90 portfolio:

- The Biden 90 portfolio has somewhat higher (therefore better, all else equal) dispatchable resources as a percentage of load.
- Both portfolios have acceptable and very similar probabilities of serving load in all years of the planning period.
- Both portfolios have acceptable levels of annual market purchases of energy, with the Biden 90 portfolio having a modestly lower (therefore better, all else equal) share of market purchases than the Renewables-CC-CT portfolio.
- Both portfolios have the same value for the index of resource diversity.
- DEI rates the executability of the Biden 90 portfolio significantly below that of the Renewables-CC-CT portfolio.

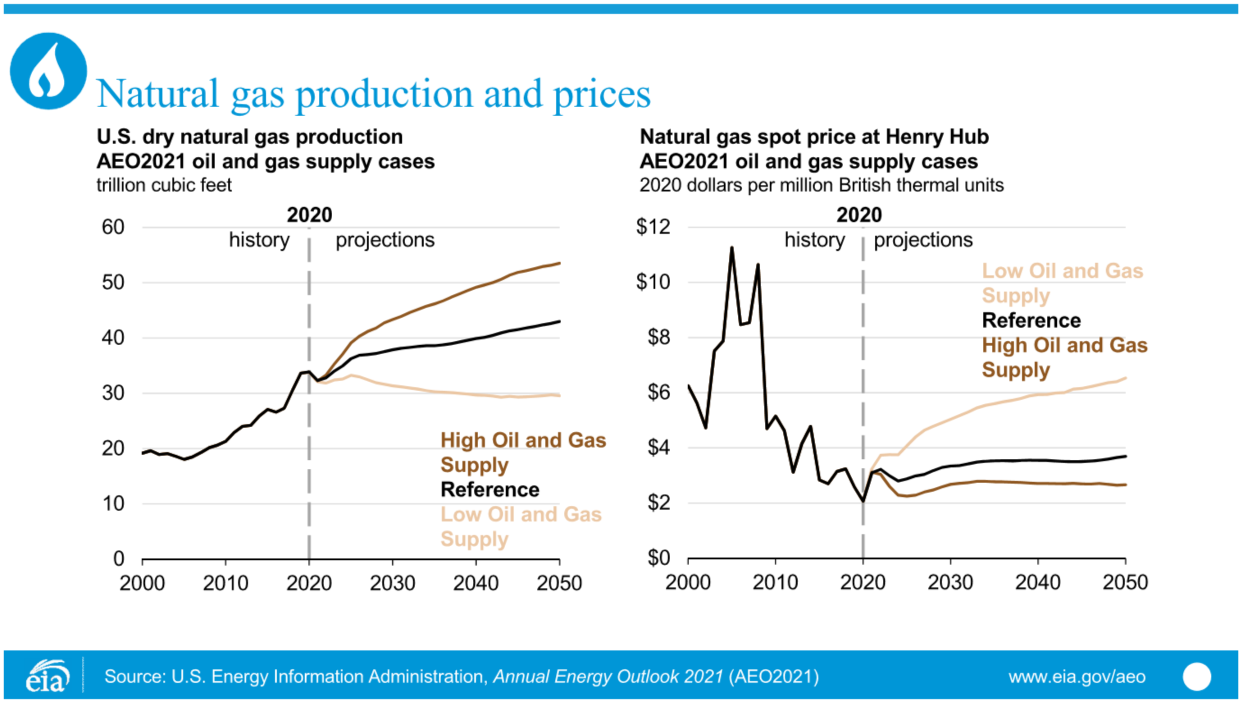
- DEI rates the Biden 90 portfolio in 2030 as having somewhat superior ability to service load in extreme weather conditions.
- The Biden 90 portfolio has a higher present value of required revenue over the full plan horizon, by approximately 10% but in a 5-year time horizon has growth in required revenue that is only 0.2% per year higher than that of the Renewables-CC-CT portfolio; however, the Biden 90 portfolio has significantly lower variability in present value of revenue requirements across various scenarios and sensitivities than does the Renewables-CC-CT portfolio.
- The Biden 90 portfolio reduces GHG emissions in 2040 by 90% while the Renewables-CC-CT portfolio only achieves a 78% reduction.
- The Biden 90 portfolio provides noticeably greater reduction of criteria pollutants under the Clean Air Act than does the Renewables-CC-CT portfolio.
- The Biden 90 portfolio has significantly lower variability in present value of revenue requirements across various scenarios and sensitivities than does the Renewables-CC-CT portfolio.

Thus, the two portfolios perform similarly in many respects, but DEI has evaluated the Biden 90 portfolio as harder to execute, providing better environmental performance and modestly more expensive through 2030. On this basis and other considerations we discuss later, we recommend that the IURC guide DEI toward a more aggressive acquisition of demand-side resources, renewables, and storage resources in the near term than are provided in the Renewables-CC-CT portfolio while retaining the ability to adjust resource changes in 2026 and thereafter based on the success of those efforts and evolving information about other considerations that will affect the post-2026 portfolio to be determined in DEI's next IRP.

Fuel Prices

In developing this IRP, DEI primarily relied on two fuel price forecasts as bookends in their analysis. For the low-end price forecast they used the US Energy Information Administration's 2021 Annual Energy Outlook (2021 AEO) High Oil and Gas Supply Case. For the high-end price forecast they used the 2021 AEO Low Oil and Gas Supply Case.

EIA's graphic representation of these 2021 AEO cases is shown below:



In mid-April, natural gas prices were approximately $4.90 per mmBTU at Henry Hub and current futures four months out are above $6.00 per mmBTU.[1] These higher gas prices are likely due to market responses to higher capital discipline amongst gas and oil producers, which has been widely reported in the financial press, and the global market effects of Russia's invasion of Ukraine. Although the outcome of the conflict between Russia and Ukraine is not something we venture to predict, announced policy responses seem likely to lead to increases in liquefied natural gas exports from North America and systematically higher prices. We therefore recommend that the IURC assume that natural gas prices will be as high as or higher than the high price scenario assumed by DEI in their preparation of this IRP.

We do not mean to suggest that DEI should have anticipated these world events that are affecting natural gas prices. However, these phenomena illustrate that fuel prices are inherently volatile and that reasonable prudence would argue for hedging those risks where possible and affordable.

On our behalf, 5 Lakes Energy used their STEP8760 IRP modeling tool to evaluate the significance of gas prices for DEI generation portfolios. While this is not the same software used by DEI, we consider that the results are similar to the results that would be produced using EnCompass. 5 Lakes Energy's assessment is that if projected gas prices exceed

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[1] Natural Gas Spot and Future Prices. Energy Information Administration. April 12, 2022. Available at: https://www.eia.gov/dnav/ng/ng_pri_fut_s1_d.htm

approximately $3.65 per mmBTU, new natural gas combined cycle plants are not included in the least-cost resource portfolio. This is consistent with DEI's findings.[2]

However, where DEI finds that high gas prices lead DEI's modeling to retain coal for now and build out renewables in the 2030s, we recommend proceeding to build additional renewables and storage much sooner. The primary reason that DEI's modeling of the high gas price scenario did not add more renewables sooner is that with delayed retirement of coal plants (as imposed as constraints within the modeling) there were not large capacity or energy needs to be met through development of any new resources. As we discuss below, DEI's storage modeling seriously undervalued storage and consequently likely chose much less storage and renewables than it should have.

Energy Efficiency

In developing this IRP, DEI followed a common practice of engaging a third party to develop an energy efficiency potential study, results of which were then used to define packages of energy efficiency resources that could be selected in IRP modeling. We understand that practice and respect its logical construct. However, we also observe that this approach delivers highly varying results when performed in different jurisdictions due to differences in policy and regulator expectations. We therefore discourage sole reliance on this approach in an IRP and recommend also considering a more direct empirical approach to identifying the supply of energy efficiency that might be available to a utility.

In the development of an energy efficiency potential study, it is common to begin with a profile of energy end uses by customer class, calculate the energy that would be saved from a range of technical options for each end use, analyze the economics of those technical options to identify a quantity called "economic potential", and then attempt to project the customer uptake of these end-use options under some assumed utility offer to its customers to produce an estimate of "achievable potential" with accompanying costs. Each of these steps involves a plethora of assumptions or parameters that can potentially affect the final estimate of energy efficiency potential. The estimate of "achievable potential" in particular is often empirically weak due to the absence of strong data and theory to project customer response in this "bottom-up" modeling approach.

Many utilities offer energy efficiency programs to their customers, with the intensity of those programs driven not only by the results of potential studies but also by mandates, incentives, and other policy or regulatory constructs. As a result, there are energy efficiency programs across a wide range of savings levels that can be compared in a "top-down" way. This comparison simply asks: what is the cost per unit of savings in real utility programs that achieve various levels of energy savings? Put another way, we think that DEI can accomplish energy efficiency at various levels with costs that are similar to the costs incurred by its peers that actually perform at those various levels of energy efficiency. Typical energy efficiency potential studies can then use the "bottom-up" approach to identify program designs that achieve these savings levels at costs

[2] 2021 Duke Energy Indiana Integrated Resource Plan, p. 96. December 2021.

similar to those achieved by other utilities. Below we compare DEI's energy efficiency performance with those of its peer utilities.

All regulated electric utilities and most other electric utilities are required to submit annual reports to the US Department of Energy's Energy Information Administration ("EIA") using Form 861. The EIA than compiles those data and makes them publicly accessible, with some time lags. Energy efficiency programs are amongst the reportable aspects of utility operations, including annual customer counts and sales by major customer class, annual incremental savings and life-cycle savings through utility energy efficiency programs by major customer class, and annual incremental and life-cycle costs of utility energy efficiency programs. We examined these data for all investor-owned utilities in the United States using 2019 Form 861 data.

We offer two important observations from that analysis.

First, in order to compare utilities of quite varying scale, we statistically examined the relationship within each customer class between incremental annual savings and cost per kWh sales. This fits with the common ways of discussing energy efficiency programs in which savings are typically characterized as first-year savings being a certain percentage of sales and costs are developed as a surcharge per kWh sales. We statistically tested this relationship using regression techniques and concluded that cost per kWh sales is proportional to the level of savings achieved as a percentage of sales and that across the range of savings levels achieved by various utilities there is no indication that costs per unit savings escalate at higher levels of savings.

Second, we compare DEI's energy efficiency programs to those of its peers as an indication of what should be possible. The following table shows that DEI's 2019 energy efficiency program for commercial customers operated at a level of savings well below that of many peer utilities. It also shows that the cost per unit savings of utilities with much higher savings are not systematically higher than the cost per unit savings for DEI.

Rank	Utility	State	Reporting Year Incremental Annual Savings (% of Sales)	Incremental Life Cycle Costs ($/kWh Life Cycle Savings)
1	Indianapolis Power & Light Co	IN	5.96%	$ 0.009
2	ALLETE, Inc.	MN	3.74%	$ 0.009
3	Commonwealth Edison Co	IL	3.44%	$ 0.015
4	Massachusetts Electric Co	MA	2.69%	$ 0.021
5	NSTAR Electric Company	MA	2.36%	$ 0.034
6	Indiana Michigan Power Co	MI	2.33%	$ 0.010
7	Public Service Co of Colorado	CO	2.32%	$ 0.009
8	Public Service Co of NH	NH	2.29%	$ 0.019
9	Unitil Energy Systems	NH	2.28%	$ 0.046
10	Oklahoma Gas & Electric Co	AR	2.12%	$ 0.015
11	Nevada Power Co	NV	2.08%	$ 0.008
12	DTE Electric Company	MI	2.03%	$ 0.014
13	Indiana Michigan Power Co	IN	2.00%	$ 0.006
14	Consumers Energy Co	MI	2.00%	$ 0.017
15	Potomac Electric Power Co	MD	1.97%	$ 0.022
16	Northern States Power Co	MI	1.96%	$ 0.010
17	Pennsylvania Electric Co	PA	1.96%	$ 0.004
18	The Narragansett Electric Co	RI	1.96%	$ 0.035
19	Pennsylvania Power Co	PA	1.88%	$ 0.005
20	San Diego Gas & Electric Co	CA	1.87%	$ 0.027
21	Pacific Gas & Electric Co.	CA	1.86%	$ 0.017
22	Connecticut Light & Power Co	CT	1.83%	$ 0.033
23	Northern Indiana Pub Serv Co	IN	1.82%	$ 0.009
24	Entergy Arkansas LLC	AR	1.74%	$ 0.011
25	Idaho Power Co	ID	1.72%	$ 0.000
…	…			
49	Duke Energy Indiana	IN	0.96%	$ 0.014

The next table similarly compares DEI's residential energy efficiency programs to those of peer utilities. Again, results of actual residential energy efficiency programs of other utilities illustrate that much higher levels of savings are achievable at unit costs that are similar to those of DEI.

We conclude that DEI should be able to substantially increase its level of energy and capacity savings through customer energy efficiency programs without materially increasing the unit cost of savings. Furthermore, when following the same resource retirement schedule as DEI's preferred portfolio, the STEP8760 model chooses more than double the amount of energy efficiency – up to 512 MW by 2030 and 834 MW by 2040.

Rank	Utility	State	Reporting Year Incremental Annual Savings (% of Sales)	Incremental Life Cycle Costs ($/kWh Life Cycle Savings)
1	Massachusetts Electric Co	MA	6.65%	$ 0.068
2	The Narragansett Electric Co	RI	6.17%	$ 0.056
3	NSTAR Electric Company	MA	4.75%	$ 0.090
4	Otter Tail Power Co	MN	3.91%	$ 0.011
5	Commonwealth Edison Co	IL	3.77%	$ 0.016
6	Public Service Co of Colorado	CO	2.55%	$ 0.016
7	Pacific Gas & Electric Co.	CA	2.52%	$ 0.028
8	The Potomac Edison Company	MD	2.40%	$ 0.027
9	Baltimore Gas & Electric Co	MD	2.32%	$ 0.032
10	Pennsylvania Electric Co	PA	2.22%	$ 0.021
11	Tucson Electric Power Co	AZ	2.16%	$ 0.007
12	Southwestern Public Service Co	NM	2.15%	$ 0.019
13	DTE Electric Company	MI	2.07%	$ 0.023
14	MidAmerican Energy Co	IL	1.98%	$ 0.025
15	Southern Indiana Gas & Elec Co	IN	1.92%	$ 0.016
16	Metropolitan Edison Co	PA	1.87%	$ 0.024
17	El Paso Electric Co	NM	1.86%	$ 0.019
18	Pennsylvania Power Co	PA	1.84%	$ 0.019
19	Northern Indiana Pub Serv Co	IN	1.78%	$ 0.017
20	UNS Electric, Inc	AZ	1.75%	$ 0.006
21	Potomac Electric Power Co	MD	1.71%	$ 0.060
22	San Diego Gas & Electric Co	CA	1.65%	$ 0.020
23	Indianapolis Power & Light Co	IN	1.65%	$ 0.024
24	Cleveland Electric Illum Co	OH	1.61%	$ 0.014
25	Niagara Mohawk Power Corp.	NY	1.59%	$ 0.029
…	…			
35	Duke Energy Indiana	IN	1.33%	$ 0.016

Demand Response

As we summarized earlier, DEI proposes in this IRP to ramp up its Demand Response resources from approximately 500 MW presently available to 613 MW by 2025 and then to continue at that level indefinitely. This stands in comparison to the STEP8760 modeling, which finds that DEI should increase its demand response capacity to 937 MW by 2026 and 1,300 MW by 2030.

If future federal requirements related to clean energy, high costs of natural gas, or greater declines in the cost of renewables drive utility portfolios to higher shares of renewables, the variability of renewable generation will require adaptation to provide greater non-generation reliability resources. These will undoubtedly include transmission to increase geographic diversity of generation, storage to shift power supply between times, and flexible demand to shift power demand between times. In the Biden 90 portfolio that was constructed by DEI in their IRP, flexible demand identified as demand response grows to 937 MW, almost 50% higher than in DEI's preferred portfolio; this is indicative of the increased role that flexible demand will play in a high-renewables portfolio.

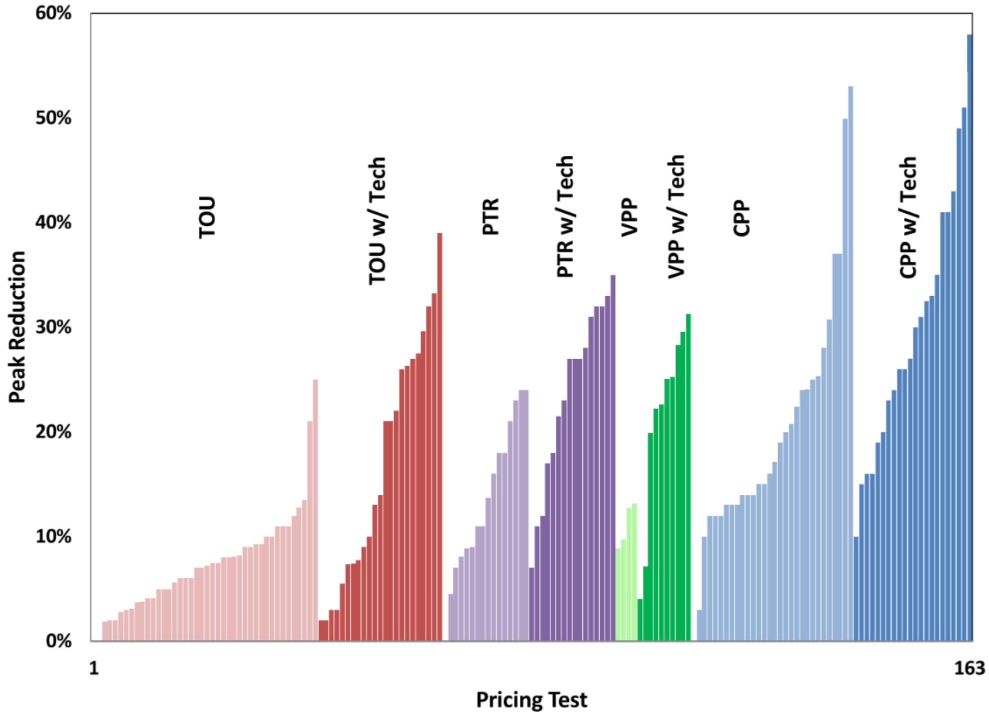
Additionally, we anticipate that new loads such as electric vehicles and hot water heaters will provide much greater load flexibility than current electricity loads and that evolving technology and utility business models will enable much more load flexibility even with existing loads.

Here, we offer recommendations of steps that should be taken during this immediate period to enable greater future use of flexible demand than is contemplated in DEI's preferred portfolio.

First, we note that demand response programs are more effective when customers can respond to time-varying rates that increase the savings a customer gains through participation in demand response and that time-varying rates are more effective in shifting load when customers are enabled by demand response technologies, such as energy management systems or smart thermostats. Although there is a significant body of literature on this topic that we do not present here, the following figure[3] serves to illustrate these essential points as well as the potential for far greater effectiveness than assumed in DEI IRP. In this Figure, time-of-use ("TOU") cases have fixed-schedule time of use rates, TOU w/Tech combines time of use rates with enabling technology – most commonly smart thermostats, peak time rebates ("PTR") cases provide peak time rebates to customers who reduce demand below their normal levels, variable peak pricing ("VPP") cases provide variable pricing at demand peaks to encourage load reduction, and critical peak pricing ("CPP") cases provide a fixed high price during announced critical load hours.

[3] Obtained from Ahmad Faruqui and Sanem Sergici (The Brattle Group), International Evidence on Dynamic Pricing. July 2013. Available at no cost from https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2288116.

Figure 4: Impacts from Pricing Tests by Rate Type and Use of Enabling Technologies



In this Figure, TOU refers to Time of Use Rates, PTR refers to Peak Time Rebates, VPP refers to Variable Peak Pricing, CPP refers to Critical Peak Pricing, and w/Tech refers to inclusion in the test of customer devices like in-home displays and smart thermostats.

Second, we note that Demand Response aggregators are particularly good at implementing Demand Response both because of their specialization and their platform investments. Much greater levels of Demand Response can be obtained if DEI contracts for Demand Response aggregation services with companies that specialize in this technology.

We therefore recommend that DEI should implement additional Demand Response by contracting with one or more Demand Response aggregators and should begin implementing rate designs that focus on time-of-use rates as well as dynamic peak pricing. These options should be offered to all customer classes, but due to their existing capacity to manage electricity demand, we particularly recommend that these practices be applied to industrial and commercial customers in the near term and deployed more gradually to residential customers.

We anticipate that engaging one or more Demand Response aggregators and beginning to implement rate designs that incent demand response will substantially increase the feasible Demand Response capacity that can be considered in DEI's next IRP.

Finally, we note that behavioral demand response programs that use an opt-out program design and leverage advanced metering infrastructure ("AMI") data can turn every residential household (including renters) into grid assets through behavioral nudges alone. Layering price signals on top of the behavioral nudges would have the effect of driving larger peak reductions and load shifting. Behavior-based solutions are delivering peak reduction and load shifting in some of the most constrained parts of the country,[4] and DEI should consider similar programs of this nature.

Coal/Edwardsport Scheduling

Our understanding is that DEI continues to self-commit the Gibson, Cayuga, and Edwardsport coal plants, generally by keeping them in a "must run" status, and has modeled them accordingly in this IRP. We continue to believe that this is inappropriate both operationally and as a basis for IRP modeling. "Must run" operations are costly to customers because there are significant periods when the operation of these plants is not economic, especially during the shoulder seasons when coal is generally not the marginal resource in the MISO market. This was true throughout Fall 2019, when the use of "must run" commitments resulted in losses estimated to be greater than $20 million.[5] While the Commission approved DEI's request to pass these loses through to customers through a fuel adjustment clause proceeding (Cause No. 38707 FAC 123 S1) because the Commission "does not engage in a hindsight analysis,"[6] we note that DEI can make different resource portfolio choices in this IRP to prevent similar situations whereby customers incur significant costs in the future. Not doing so runs contrary to DEI's obligation to serve customers at the lowest cost reasonably possible.

Modeling these resources as "must run" in the IRP has a distorting effect that affects portfolio decisions. Running these plants when they are not economic "crowds out" alternative generation that could have supplied power more cheaply at those times, making those alternative resources less beneficial to the portfolio. This raises customer in the long-term by preventing the selection of low-cost clean energy resources in not just DEI's resource plan – but also the plans of other utilities that participate in the MISO market because of artificially low market prices.

While commitment decisions are largely operational, the practice of allowing coal plants to operate at an economic loss and recovering those costs—even occasionally—from customers through the fuel adjustment clause ("FAC") raises electricity costs for Indiana ratepayers and impedes sound long-term resource planning. However, FAC proceedings are narrow in scope. In the review of DEI's unit commitment decisions from September to November 2019 in Cause 38707 FAC 123 S1, DEI Witness John D. Swez noted that unit "retirement decisions are contemplated in the IRP.[7]" DEI also contends that an analysis demonstrating the long-term commitment of the Edwardsport plant is the least-cost option for customers "is possible, but inappropriate for an FAC proceeding. The in-depth, long-term nature of the type of analysis … is ultimately concerning unit retirements. Such an analysis would be better suited for the

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[4] In 2019, CPS Energy expanded a pilot program that relied upon behavioral demand response, smart thermostats, and commercial and public customer engagement to 300,000 customers. They achieved 40 MW of additional demand response at peak periods. More information can be found here: https://www.prnewswire.com/news-releases/cps-energy-recognized-as-thought-leader-for-public-engagement-301098990.html, and a thorough evaluation of earlier iterations of the program can be found here: https://www.sanantonio.gov/Portals/0/Files/Sustainability/STEP/CPS-FY2020.pdf.

[5] Direct Testimony and Attachments of Robert B. Stoddard. Cause No. 38707 FAC 123 S1. July 2020.

[6] Order of the Commission. Cause No. 38707 FAC 123 S1. March 2021.

[7] Rebuttal Testimony of John D. Swez. Cause No. 38707 FAC 123 S1, p. 54. August 2020.

Company's IRP process."[8] As such, Indiana AEE anticipated a thorough analysis and discussion of, and analysis-bounded decision regarding, Edwardsport – a plant demonstrated to be losing customer money because of uneconomic self-commitment of its coal gasifiers.[9]

In its 2021 IRP, DEI reports that it did conduct a retirement analysis to consider multiple operating conditions for Edwardsport, which included operation on coal, operation on natural gas, and near-term retirement. They note that "optimized runs generally resulted in switching Edwardsport IGCC to only natural gas operations early in the 20-year period."[10] However, DEI has ignored such optimization in favor of continuing coal operations at Edwardsport through 2035 based on qualitative considerations that include a stated "trajectory of improving operations and lowering costs." This trajectory is not supported by Cause No. 38707 FAC 123 S1 (2019), which contains the most extensive record to date on Edwardsport losses. DEI also admits later in its discussion of the plant that a partial switch to natural gas operations during the shoulder months would "[provide] customers with lower fuel costs,"[11] but it has not committed to studying the possibility until its next IRP in 2024. This decision means that ratepayers will likely continue to pay foreseeable higher-than-necessary costs for the shoulder seasons for at least the next several years. We urge DEI to reconsider this decision and take corrective action for its customers before 2025.

Energy Storage

DEI included energy storage in the list of resources that could be selected in this 2021 IRP. In their preferred course of action, modest investments in storage in combination with solar begins in 2027 and ramps to cumulative deployment of 1,500 MW by 2038 and thereafter. In the Biden 90 portfolio, storage in combination with solar is not selected until 2032 then ramps to 600 MW in 2040 but standalone storage is deployed beginning with 200 MW in 2030 and ramps to cumulative 1,450 MW in 2040. These are both modest amounts of storage relative to recent IRPs of some other utilities.

While DEI's approach to modeling storage in the development of this IRP reflects historical practices, we believe that this approach undervalues the resource. Storage thrives on price variability that provides frequent opportunities to buy low and sell high. High peak vs. valley price spreads also increase net revenue. Many IRP models, including the one used by DEI, fail to recognize the full value of storage for at least three reasons:

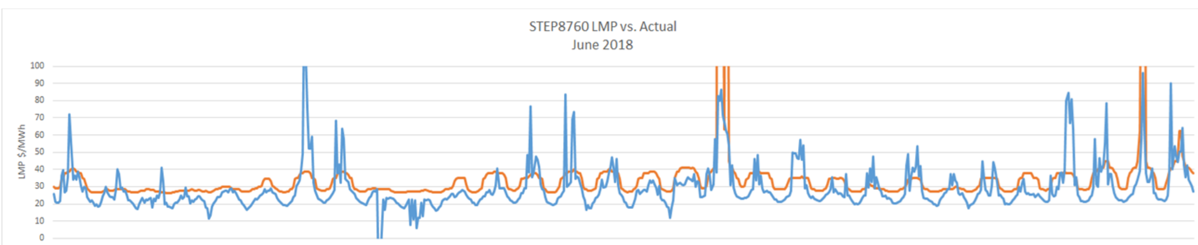
- They generally under-represent both the frequency and size of hourly price variation
- They ignore intra-hour price variation

[8] Reply to Intervenors' exceptions to Duke Energy Indiana's Proposed Order. Cause No. 38707 FAC 123 S1, p. 6. January, 2021.
[9] Direct Testimony and Attachments of Robert B. Stoddard. Cause No. 38707 FAC 123 S1. July 2020; the Direct Testimony of Devi Glick. Cause No. 38707 FAC 123 S1. July, 2020; and the Direct Testimony of Edward Burgess Cause No. 38707 FAC 123 S1. July, 2020.
[10] 2021 Duke Energy Indiana Integrated Resource Plan, p. 16. December, 2021.
[11] 2021 Duke Energy Indiana Integrated Resource Plan, p. 17. December, 2021.

- They typically use reserve margins instead of modelling all ancillary service values, which ignores the agility of storage, in that can provide responses to grid conditions without scheduling reserve generation.

Improvements to many models are still under development. Pacific Northwest National Laboratory and Lawrence Berkeley National Laboratory recently presented to the National Association of Regulatory Utility Commissioners ("NARUC")[12] on this topic, and the National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory are evaluating their Cambium model.[13] Our consultant, 5 Lakes Energy, recently completed a Storage Roadmap for the State of Michigan[14] and found similar issues in the application of their STEP8760 model.

The following graph illustrates the way in which inter-hour price variation is commonly underrepresented in traditional IRP models, including the one DEI used. The blue line is actual prices and the orange line is modeled prices; actual prices are simply much more variable than is typically predicted by production cost models because of the unexpected changes in demand, plant or transmission outages, and other random phenomena that affect actual prices and are not modeled in temporal detail in a production cost model.



Further, there is significant variation in prices within each hour in actual power markets that is simply ignored in an IRP model that calculates with only hourly granularity. Still further, although good IRP models attempt to account for limitations on ramp rates and other intertemporal constraints on actual power plants, they generally fall short of describing all of the operational limitations of real power plants; these phenomena are typically addressed by planning capacity reserves and scheduling generation reserves which serve to suppress short-term price variation in actual markets but if reflected directly in pricing could be exploited by storage due to its highly flexible operational capabilities.

As an indicator of the significance of this consideration, we compared the optimal operation of a representative small battery with 1 MW power rating and 4 MWh energy storage, using 5 Lakes Energy's STEP8760 model implementation of a model predictive controller for the battery.

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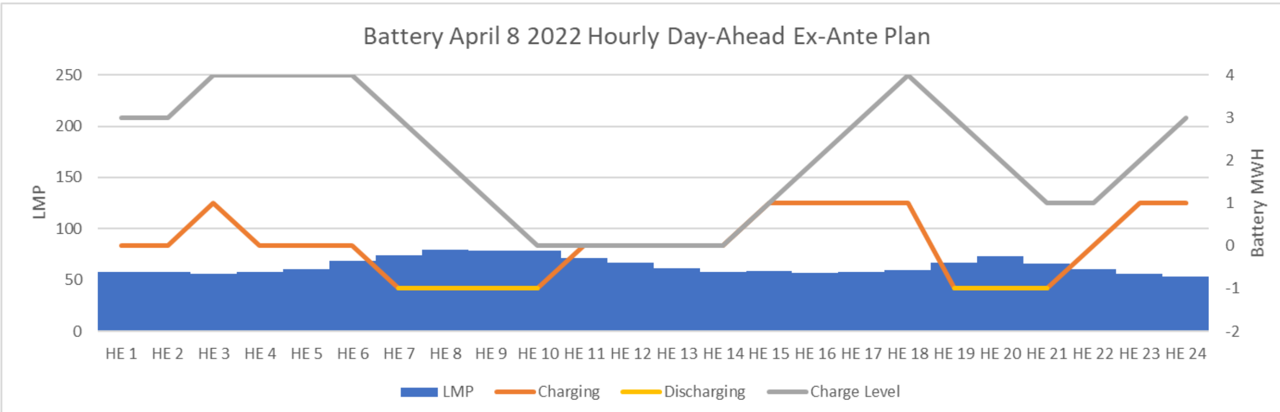
[12] Miller, C., Twitchell, J. and Schwartz, L. "State of the Art Practices for Modeling Storage in Integrated Resource Planning." Innovations in Electricity Modeling: Training for National Council on Electricity Policy. October 12, 2021. Available at: https://pubs.naruc.org/pub/CCBEFC58-1866-DAAC-99FB-3A405315FB9B.

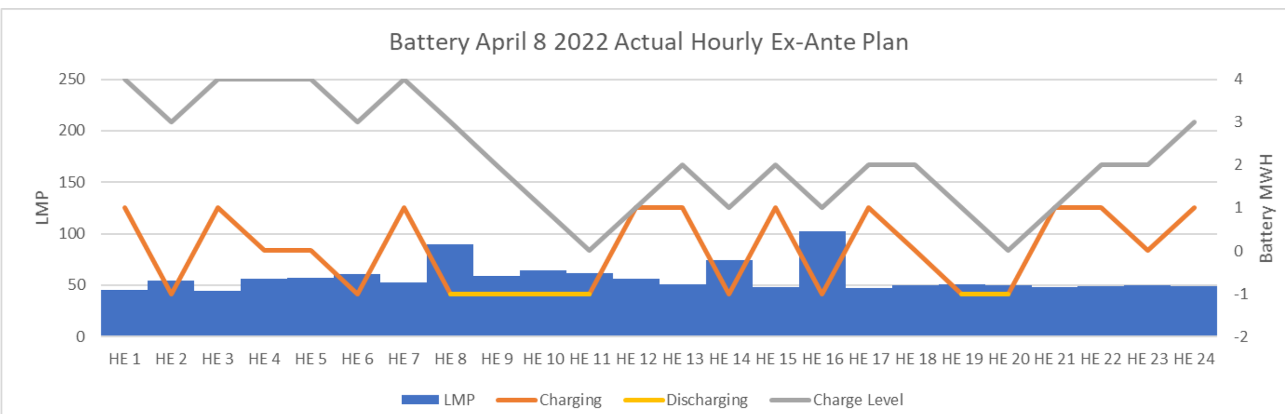
[13] Seel, Joachim and Mills, Andrew. "Integrating Cambium Marginal Costs into Electric-Sector Decisions." November, 2021. Available at: https://eta-publications.lbl.gov/sites/default/files/berkeley_lab_2021.11-_integrating_cambium_prices_into_electric-sector_decisions-_briefing.pdf

[14] Available here: https://mieibc.org/michigan-eibc-newsletter-energy-storage-roadmap-released%EF%BF%BC/

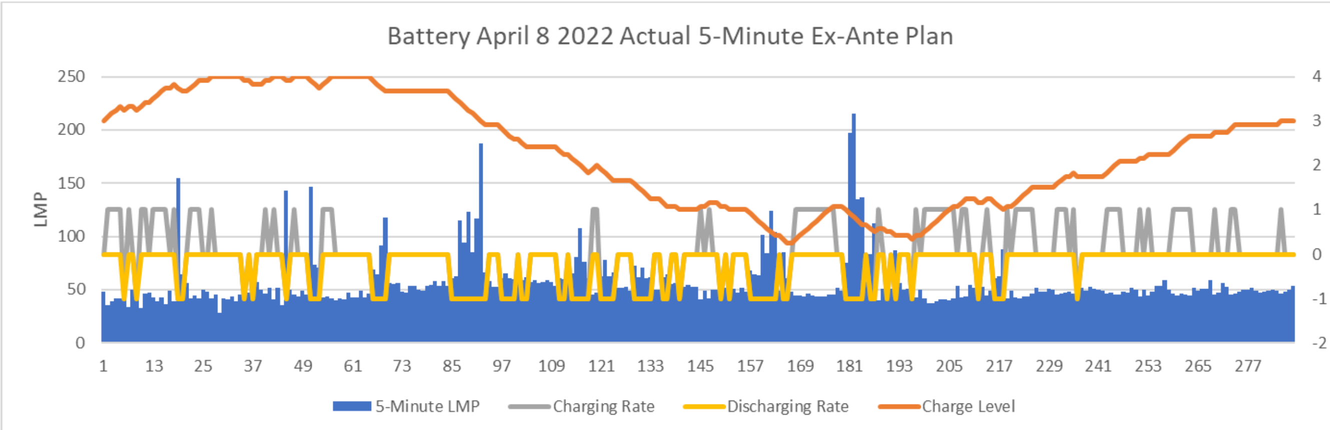
The following graph shows MISO's day-ahead hourly locational marginal prices ("LMPs") at a generation node on April 8, 2022. These LMPs are generated from the kind of merit order production scheduling as was used by DEI in its IRP modeling and the resulting optimal operation of a battery. Optimally operating this battery with these LMPs produces one-day net revenue of approximately $117.



The following graph shows MISO's actual average LMPs at the same node on the same day, and the corresponding optimal operation of the same hypothetical battery. It is notable that actual LMPs are significantly more volatile that modeled day-ahead hourly prices, reflecting the stochastic nature of the grid. Optimally operating this battery with the actual average hourly LMPs produces one-day revenue of approximately $177.



The following graph shows MISO's ex ante 5-minute LMPs at the same node on the same day, and the corresponding optimal operation of the same hypothetical battery. This graph illustrates that there is very considerable price variation within each hour that can be arbitraged by a battery. Optimally operating this battery with the ex-ante 5-minute LMPs produces one-day revenue of approximately $253.



These results for single day illustrate the economic significance of modeling storage with both realistic and fine-grained energy pricing.

Because of the limitations in how energy storage was modeled in the DEI IRP, we consider it a virtual certainty that storage has been under-valued and therefore under-selected in DEI's current IRP in favor of new gas peaking capacity. Even the STEP8760 model, which selected 1) 200 MW of stand-alone storage in 2026, a cumulative 600 MW by 2030 and 1,950 MW by 2040, and 2) 200 MW of solar plus storage in 2025 and a cumulative 500 MW by 2030, is likely to be under-selecting storage.

We therefore recommend that DEI's near-term procurements be structured so that storage and storage hybrid resources can respond and be properly valued (which includes energy, ancillary services, and capacity values), and that they seek out *at least* 400 MW of standalone and solar plus storage resources by 2026, consistent with STEP8760 model results and our understanding of model limitations.

We also recommend that in its next IRP, DEI adopt best practices used in other jurisdictions to better capture the full value of energy storage. There are a variety of ways to do this. In 2018, the National Association of Regulatory Utility Commissioners ("NARUC") passed a resolution on modeling energy storage. The resolution recommended a number of principles to guide NARUC member states in modeling energy storage and other flexible resources, including using tools to model the "full spectrum of services that energy storage and flexible resources are capable of providing, including subhourly services."[15] In 2017, the Washington Utility and Transportation Commission ("UTC") issued an Energy Storage Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition that provided guidance for "how utilities should model energy storage within the traditional construct of hourly

[15] National Association of Regulatory Utility Commissioners. EL-4/ERE-1 Resolution on Modeling Energy Storage and Other Flexible Resources. November 2018. Available at https://pubs.naruc.org/pub/2BC7B6ED-C11C-31C9-21FC-EAF8B38A6EBF

IRP models."[16] Other best practices for storage modeling in IRP processes have been identified by researchers at the Lawrence Berkeley National Laboratory ("LBNL") and Pacific Northwest National Laboratory ("PNNL"). A recent paper, "State of the Art Practices for Modeling Storage in Integrated Resource Planning," recognizes that the flexibility and scalability benefits of energy storage are continuously undervalued in the models that utilities currently use.[17] The authors argue that "more accurate inputs (e.g., up to date costs and forecasts) and improved modeling methods (e.g., assessing benefits for a wider range of grid services, incorporating behind-the-meter ("BTM") applications) are needed to better integrate storage into planning processes."[18]

If accurate modeling of energy storage resources is not possible given model limitations, storage benefits can also be incorporated into IRPs using a net-cost-of-capacity approach. Under this method, operational benefits of storage that are difficult to represent accurately within the IRP model (e.g., the value of real-time energy arbitrage or ancillary services) can be estimated using a separate analysis outside the IRP model and credited to storage within the IRP model as a reduction in the installed cost of storage.

Finally, we note that adding properly-valued storage in an IRP portfolio, especially in hybrid implementation with renewables, improves the economic benefits of high levels of renewables and leads to including higher levels of renewables in an optimal portfolio.

Federal Policy

At this time, relevant Federal policy remains unsettled and must, therefore, be considered a risk factor in an IRP. We track Federal policy closely. Our assessment is that it is likely that Federal policy will move in the direction of favoring clean energy resources, with the extent and timing of that movement remaining uncertain. In particular, it is expected that additional tax benefits for renewables and storage will be adopted or current benefits will be extended by the end of the year.

DEI did not explicitly model the possibility of material additional tax benefits for renewables and storage, but did consider a sensitivity that indicates the significance of such tax benefits. As one sensitivity, DEI used solar prices obtained through a Request for Information, which reduced capital costs of solar by approximately 15% below the costs assumed in the balance of DEI's modeling. Results in one scenario are presented on page 122 of the IRP and show an immediate increase in solar acquisition as a result of lower solar cost. This limited analysis does not demonstrate the optimal response to changes in Federal taxation but does show that the least-cost

[16] Washington State Utilities and Transportation Commission, Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition, Dockets UE-151069 and U-161024 (Consolidated). Available at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=237&year=2016&docketNumber=161024

[17] Miller, C., Twitchell, J. and Schwartz, L. "State of the Art Practices for Modeling Storage in Integrated Resource Planning." Innovations in Electricity Modeling: Training for National Council on Electricity Policy. October 12, 2021. Available at: https://pubs.naruc.org/pub/CCBEFC58-1866-DAAC-99FB-3A405315FB9B.

[18] Ibid.

portfolio is sensitive to the cost of solar and is likely also sensitive to the costs of wind and storage as these would likewise be affected by Federal tax policy.

It remains possible that Federal policy – now or within the coming years – will also move to restrict greenhouse gas ("GHG") emissions. Any commitment to reliance on fossil-fuel-based generation thus creates the possibility of stranded costs. It is therefore prudent to be cautious about investments in either new fossil-fueled-generation assets or in major life extensions of existing fossil-fueled-generation assets.

Natural Gas and Market Purchase Risks

Amongst the factors that DEI considered to evaluate alternative resource portfolios was the percentage of load purchased from the market. This factor provides an indication of market price risk. We observe that most of the time, the marginal generation in MISO is gas-fired. Thus, market price risk is strongly associated with gas price risk. Thus, a better risk metric would be the combined exposure of the portfolio to market purchases and to gas-fired generation. Although the IRP does not present the percentage of gas-fired generation in the various portfolios, it is clear that the Renewables-CC-CT scenario has greater exposure than does the Biden 90 scenario and that this difference emerges fairly early due to the accelerated build-out of renewables in Biden 90 as compared to Renewables-CC-CT.

Further, we note that DEI's course of action pursuant to the Renewables-CC-CT scenario includes the purchase of a new natural gas-fueled combined-cycle plant that is to be operational in 2027. Considering both the current high price of natural gas that is extreme in the gas price distribution considered by DEI in this IRP, as well as the continuing risk of high gas prices, our analysis suggests that the capacity requirements that motivated consideration of that combined cycle plant would be more economically met by obtaining capacity credits from a combination of solar and storage. We therefore recommend that IURC require DEI to prepare for accelerated purchases of solar and storage in the period from 2024 – 2027. The most appropriate method for doing so would be to solicit proposals for approximately 1,200 MW of zonal resource credits using solar and storage resources and select the most economical mix of resources that provides that quantity of capacity credits. This is consistent with the results of the STEP8760 model, which indicated that DEI should seek a cumulative 1,400 MW of solar by 2026, 2,700 MW by 2030, and 3,900 MW by 2040, and wind resources totaling a cumulative 400 MW by 2026, 2,150 MW by 2030, and 3,350 MW by 2040 (similar to the Biden 90 portfolio). Because these projects can have significant lead times, we suggest that DEI move quickly to accelerate its current procurement processes and schedules.

Voluntary Renewables Purchases

Finally, we note that DEI's IRP does not address the likely interest of some of its customers in voluntarily obtaining a larger share of their electricity supply from renewable sources than DEI proposes to provide overall in its portfolio. Across the country, green tariff programs are growing in popularity. As of December 2020, they have resulted in nearly 5,000 MW of new renewable energy.[19]

Allowing customers to participate in programs to bring renewable energy projects online, like DEI has done in its service territories in North Carolina, South Carolina, and Kentucky, gives those customers the ability to help absorb some of the costs of those additions. This may lower the modeled costs of the Biden 90 portfolio relative to the selected Renewable/CC/CT portfolio.

We attach two white papers previously developed by AEE, for your consideration. The first paper outlines "Renewable Energy Offerings That Work" and describes the needs of interested customers, particularly large industrial, data center, and other major consumers of electricity that have made commitments to renewable energy or sustainability. The second paper discusses "Essential Elements of Renewable Energy Tariffs" and goes to the specifics of economic terms that make sense to these customers.

We urge DEI, with support of the IURC, to offer such a voluntary renewables program to its customers. Any near-term uptake could be accommodated through incremental purchases of renewable generation in upcoming RFPs. Projected future participation in such programs should be incorporated into future IRPs.

Summary Recommendations

On the basis of our comments above, we recommend that IURC guidance and DEI resource decisions shift somewhat from the portfolio evolution described in DEI's Renewables-CC-CT scenario. In particular, we recommend that DEI:

- Place greater emphasis on customer programs
- Design RFP(s) to fully capture energy storage benefits and procure a minimum level of storage and storage hybrid resources
- Accelerate renewable energy procurements

By taking this approach, DEI can hedge against the natural gas and electricity market price risks associated with the Renewables-CC-CT scenario without committing to the execution risk that DEI claims is the main mark against the Biden 90 portfolio. We think that DEI has undervalued the price risks in the Renewables-CC-CT scenario (as is illustrated by current events).

Place Greater Emphasis on Customer Programs

As we discussed under the Energy Efficiency heading above, the available empirical evidence shows that DEI could achieve 2-3 times as much energy and capacity savings through customer energy efficiency programs as they have recently, at unit costs not much different than current unit costs. We recommend that DEI, with support from the IURC, develop its next energy efficiency plans with a material increase in targeted levels of savings. In lieu of continuing the

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[19] U.S. Electricity Markets: Utility Green Tariff Update. Clean Energy Buyers Association. Dec. 2020. Available at: https://cebuyers.org/us-electricity-markets-utility-green-tariff-update/.

current approach to energy efficiency potential studies, we recommend a focus on benchmarking studies to enable DEI to match the superior performance of some peer utilities.

As we discussed under the Demand Response heading above, we urge that DEI implement at least the level of Demand Response prescribed by the Renewables-CC-CT portfolio and hold open the possibility of acquiring additional Demand Response. Importantly, we encourage DEI and IURC to seek assistance from specialist Demand Response aggregators in implementing this incremental Demand Response, which will then enable greater use of flexible demand in the future. We also encourage DEI and IURC to make increasing use of rate designs that encourage flexible demand such as time of use and dynamic peak pricing.

As we discussed under the heading Voluntary Renewables Purchases, we urge DEI to offer its customers an option to use up to 100% renewably generated electricity from DEI.

Include Energy Storage in RFP(s) to Capture Energy Storage Benefits

As we discussed under the Energy Storage heading above, we urge DEI to issue RFPs that allow storage resources to be proposed either stand-alone or in hybrid configurations with solar and/or wind. The RFPs must ensure that the economic value used to evaluate bids include energy, capacity, and ancillary service values. Specifically, we urge that DEI's near-term Requests for Proposals for new resources seek out at least 400 MW of standalone and hybrid renewable plus storage resources by 2026 to account for storage being undervalued by IRP modeling.

Accelerate Renewable Energy Procurements

As DEI proceeds to implement its IRP, we recommend an approach that holds open the possibility of accelerated renewable energy procurement without incurring large execution risks. Our approach retains the potential to benefit from Federal tax incentives if those are extended. This approach also potentially reduces risks in the Renewables-CC-CT portfolio associated with fuel prices or future GHG restrictions.

Simply, we recommend that DEI issue RFPs that allow DEI to procure renewables up to quantities consistent with the Biden 90 portfolio or STEP8760 model. Proposals received can then be evaluated and selected to the extent that they are attractive. DEI would issue RFPs that would target the acquisition of at least 847 MW through 2026, as specified by the Renewables-CC-CT portfolio but allow for the acquisition of up to 1,097 MW through 2026, as specified by the Biden 90 portfolio. DEI would also issue RFPs for up to 300 MW incremental wind through 2026, as specified by the Biden 90 portfolio without committing to contract for wind since it is not included in the Renewables-CC-CT portfolio.

Proposals received in excess of the levels prescribed by the Renewables-CC-CT portfolio would be evaluated based on the costs they would avoid under the Renewables-CC-CT portfolio using updated projections of market prices for electricity and natural gas and in light of evolving Federal policy.

Any incremental renewables acquired under this strategy would be assumed in DEI's next IRP. If that IRP concludes that DEI should be on a path similar to Biden 90, it would be positioned for that. If that IRP concludes that DEI should be on a path similar to Renewables-CC-CT, DEI would simply defer additional renewables purchases that have been “pre-purchased” through this recommendation.

Given the cost and risks attached to new gas capacity, we recommend deferring the acquisition of new gas-fueled generation until at least after DEI’s next IRP. We further recommend that DEI prepare instead to purchase up to 1,200 MW capacity credits through a combination of solar and energy storage resources.

Appendix 1

STEP8760 is an Excel-based open-access electricity integrated resource planning tool. The first version was developed by researchers at the University of Michigan and 5 Lakes Energy for use in planning compliance with the Clean Power Plan. 5 Lakes Energy subsequently modified it as a general-purpose integrated resource planning tool.

STEP8760 optimizes production and capacity additions in a single year, using the criterion of either least utility revenue requirements or least social cost. Capacity additions can be based on the common practice of determining whether capacity is needed to achieve a planning reserve margin or on including the expected cost of lost load in addition to the cost of utility resources. Social cost includes utility required revenue and social costs attributed to lost load, emissions, and water use. STEP8760 assumes import and export constraints between the modeled entity and the rest of the world but assumes that there are no transmission constraints within the modeled entity that affect generator dispatch. STEP8760 simplifies unit commitment and ramping constraints. As a single-year model, STEP8760 does not fully solve the dynamic programming analysis of when resources should be retired and added. STEP8760 thus serves as an excellent screening tool in integrated resource planning, after which candidate strategies can be evaluated in a commercial integrated resource planning tool.

STEP8760 operates by numerical optimization of new resource additions, while calculating optimum ("merit order") dispatch given a set of resources. Resources in each hour are dispatched to serve load net of renewable generation plus an operating reserve margin that is calculated based on combined load and renewable generation uncertainty. Electricity storage operations are then optimized based on the initial dispatch schedule and generation is re-dispatched in light of storage operations.

Storage operations are based on a stochastic model predictive controller (sometimes called a receding horizon optimization) in which current state-of-charge and predicted marginal power costs plus expected value of lost load for one week (168 hours) are used to compute optimal storage operation in the current hour, then in the next hour a similar optimization is calculated.

For purposes of optimizing resource additions, the cost of a new resource is calculated as the levelized annual cost of capacity over the expected life of that resource. Sunk costs of existing resources are excluded from the analysis. Operating costs are based on assumed variable operations and maintenance costs, heat rate, and projected fuel costs in the modeled year. Potential resource additions include wind, solar, nuclear, combined cycle fueled by methane gas, and combustion turbine fueled by methane gas.

For purposes of these comments, we applied STEP8760 to minimize utility required revenue assuming continuation of current gas prices but otherwise generally assuming conditions and retirements similar to those assumed by DEI in their primary scenarios. Due to higher gas prices and our more appropriate assessment of energy efficiency potential, demand response, and valuation of storage, we recommend significantly more energy efficiency, demand response, wind, solar, and storage and no new natural gas plants. Notably, absent natural gas generation in winter, our analysis recommends significantly more wind and that energy storage be both more capacious and decoupled from solar in order to provide load-balancing services in winter.

Resource	Renewables-CC-CT portfolio	AEE STEP8760 Portfolio
Cayuga 1 &2	Retires end of 2026	Retires end of 2026
Edwardsport IGCC	Retires in 2034	Retires in 2034
Gibson 1&2	Retires both in 2034	Retires both units in 2034
Gibson 3	Retires in 2028	Retires in 2028
Gibson 4	Retires in 2028	Retires in 2028
Gibson 5	Retires in 2024	Retires in 2024
Zero-Emissions Load-Following Resource	Not included	Not included
New Combined Cycle	1,221 MW operable in 2027 1,160 MW in 2035	None
Capacity Power Purchases	450 MW in 2023	450 MW in 2023
Energy Efficiency	Cumulative 207 MW by 2026 308 MW by 2030 338 MW by 2040	Cumulative 272 MW by 2026 512 MW by 2030 834 MW by 2040
Demand Response	Cumulative 613 MW by 2026 and thereafter	Cumulative 937 MW by 2026 1,300 MW by 2030 and thereafter
Solar	Cumulative 847 MW by 2026 1,547 MW by 2030 3,025 MW by 2040	Cumulative 1,400 MW by 2026 2,700 MW by 2030 3,900 MW by 2040
Solar plus Storage	Begins with 75 MW in 2027 Cumulative 300 MW by 2030 1,500 MW by 2040	Begins with 200 MW in 2025 Cumulative 500 MW by 2030
Wind	Remains 100 MW until 2030 Cumulative 2,800 MW by 2040	Remains at 100 MW until 2024 Cumulative 400 MW by 2026 2,150 MW by 2030 3,350 MW by 2040
Stand-alone storage	none	200 MW in 2026 Cumulative 600 MW by 2030 Cumulative 1,950 MW in 2040

RENEWABLE ENERGY OFFERINGS THAT WORK FOR COMPANIES

A practical guide to meeting corporate renewable energy demand in vertically integrated markets

By the Advanced Energy Buyers Group

April 2019

ADVANCED
ENERGY
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the policy voice of advanced energy purchasers

ABOUT THE ADVANCED ENERGY BUYERS GROUP

The Advanced Energy Buyers Group is a business-led coalition of commercial, industrial, and institutional energy users engaging on policies to expand opportunities to procure energy that is secure, clean, and affordable.

Members of the Advanced Energy Buyers Group are leading companies and organizations spanning a range of market sectors. These businesses share a common interest in expanding their use of advanced energy, such as renewable energy like wind, solar, geothermal, and hydropower; demand-side resources like energy efficiency, demand response, and energy storage; and onsite generation from solar photovoltaics, advanced natural gas turbines, and fuel cells. Analyses and internal business planning have shown that expanding use of such technologies will help companies to be more competitive, resilient, and sustainable far into the future.

For more information, visit https://www.advancedenergybuyersgroup.org/.

TABLE OF CONTENTS

INTRODUCTION

Corporate demand for renewable energy is growing. The ability to control energy costs and sources has always been a critical business priority, particularly for energy-intensive industries. As renewable energy technologies such as wind and solar continue to drop in price, these sources are an increasingly attractive option for companies seeking to lower costs while protecting against fluctuating fuel prices.

At the same time, a growing number of companies have codified their commitment to renewable energy by setting a public target. In the United States, **71 of Fortune 100 companies and 215 of Fortune 500 companies** have set renewable energy or energy-related sustainability goals—and the number is rising.[1]

This demand has resulted in significant market activity; since 2013, voluntary renewable energy procurement by businesses has driven **over 15 gigawatts (GW)** of new, large-scale renewable energy projects—enough to meet the annual electricity needs of approximately three million households.[2]

States that help corporations with their renewable energy and sustainability goals stand to gain as they:

- Remove regulatory barriers to allow greater customer choice and competition;
- Meet changing customer needs to attract or retain a strong corporate presence;
- Promote economic growth through jobs and taxes;
- Add new clean power sources to the grid, including many not subject to fluctuating fuel costs; and
- Increase resource diversity, contributing to the reliability and resilience of the local grid.

However, much of the market activity—and therefore many of the benefits—to date has occurred in states that have competitive wholesale markets, and especially in states that have also introduced retail customer choice (at least for commercial and industrial customers). In such states, customers can source renewable energy

[1] Advanced Energy Economy. "2016 Corporate Advanced Energy Commitments," December 2016. http://info.aee.net/growth-in-corporate-advanced-energy-demand-market-benefits-report.

[2] Business Renewables Center. "BRC Deal Tracker," Updated December 2018. http://businessrenewables.org/corporate-transactions/.

through a power purchase agreement (PPA) or a virtual power purchase agreement (vPPA), two common transaction structures described in Table 1. In contrast, in traditionally regulated states (also called vertically integrated), where utilities control generation and retail sales, companies cannot typically go to the market and choose renewable energy.

Still, as this paper will explain, there are several ways for companies to meet their renewable energy goals in vertically integrated states. Specifically, state policymakers, regulators, and utilities can work with corporate customers to enact one or more of the following solutions:

- Transition to full retail choice for all customers (following the example of Texas and several states in New England and the mid-Atlantic);
- Allow or expand direct access, i.e., retail choice, for commercial and industrial (C&I) customers;
- Expand access to competitive wholesale markets to expand opportunities for vPPAs;
- Allow negotiated deals for individual customers through their local utility; and
- Introduce workable utility renewable energy offerings, also known as "green tariffs."

Each of these paths unlocks different renewable energy purchasing options, has different benefits and challenges, and involves varying levels of change and complexity. The first two—unlocking full or partial retail choice—provide C&I customers with the most flexibility and control in meeting their specific needs through customized solutions. Individual negotiated deals are an important tool for very large, often new load, customers who have the sophistication and resources to undergo a lengthy negotiation, but do not present scalable solutions for all customers. The last option—introducing workable utility renewable energy offerings—is less flexible than C&I retail choice, but more scalable than individualized utility negotiations. It is important to consider all of these options to determine which is the right fit for a given state and/or utility.

This guide provides practical advice to meet the renewable energy needs of C&I customers in vertically integrated states, based on lessons learned from states and utilities that have taken steps to introduce additional renewable energy options. Specifically, this guide recommends taking the following six steps:

1. Seek advice and input from customers, industry, and other states;
2. Determine which approaches align best with state and utility circumstances;
3. Account for the varying needs of different customers, including nonparticipants;
4. Adopt replicable best practices;

5. Guide customers through the decision and enrollment process;

6. Review, iterate, and improve.

7. These six steps take into account the specific circumstances of a given state or utility yet take advantage of universally applicable best practices and lessons learned. By following these recommendations, each state or utility will arrive at a slightly different answer—but whatever the final solution, these steps are intended to ensure that it will meet C&I customers' renewable energy needs and preferences while maximizing the benefits to all customers.

Table 1. Renewable energy purchasing options for corporate customers

Purchasing Option	Description
Renewable Energy Certificate (REC) Purchase	A REC is an electronic certificate that represents the environmental attributes of one megawatt-hour (MWh) of electricity from a renewable energy facility. It is distinct from the actual electricity production and can be marketed and sold separately. Customers can purchase RECs from REC suppliers, through a utility REC purchasing program, or via a long-term contract with a specific facility.
Power Purchase Agreement (PPA)	A PPA is a contract for the delivery of renewable energy, typically with a fixed or escalating price over 10 or more years. PPAs, and most of the solutions that follow, are typically "bundled" renewable energy offerings that include both power and RECs; many C&I customers have a strong preference for bundled offerings over RECs alone.
Virtual ("Financial") PPA (vPPA)	Under a virtual PPA, a customer signs a long-term fixed or escalating price contract (as under a standard PPA), but the electricity is sold on the wholesale market rather than contracted directly by the customer. If the selling price in the wholesale market is higher than the per-kWh rate of the virtual PPA, the customer receives the difference in credit; if the wholesale price received for the renewable energy is lower, the customer pays the difference.
Competitive Service Provider (CSP)	Some service providers in competitive (restructured) electricity markets offer products consisting of RECs bundled with electricity. Depending on the offering, RECs may come from a mix of renewable energy resources.
Utility Renewable Energy Program ("Green Tariff")	Some utilities in vertically integrated markets have introduced renewable energy programs, sometimes called "green tariffs," which allow customers to purchase bundled renewable energy through their utility at long-term, competitive prices.
Shared ("Community") Renewable Energy	Shared renewable energy, commonly "community solar," allows multiple customers to share the output of a single offsite project. Subscribers maintain their regular utility service, and the community renewable energy project feeds into the utility network. Depending on program design, residential, small business, and commercial energy users can all participate in a project. Note that not all community solar programs offer bundled renewable energy. In some cases, the utility retains the RECs.
Onsite distributed energy resources	Companies that have sufficient rooftop space or land at their facilities can install solar or other distributed energy resources. Depending on the policy landscape and customer preference, this can be done through direct ownership, an equipment lease, or a PPA.

SIX-STEP GUIDE TO MEETING RENEWABLE ENERGY NEEDS IN VERTICALLY INTEGRATED STATES

One: Seek Advice and Input from Customers, Industry, and Other States

For states with vertically integrated electricity markets seeking to increase corporate access to advanced energy, there are now many examples and significant expertise to draw on from across the country. **There is no reason to start from scratch, or work in a vacuum.**

There are several different pathways for states to choose from. They can be broadly categorized into retail choice and direct access (retail competition approaches) and utility renewable energy tariffs (utility program approaches). For each, there is a wealth of experience across a range of states with different geographic, economic, resource, and grid needs and challenges.

Since the first utility renewable energy offerings tailored to the needs of C&I customers were introduced in 2013, there have been many lessons learned that have resulted in new program designs that better meet the needs of a wider range of C&I customers. To date, **more than 1.9 GW of renewable energy has been purchased through utility offerings,** with another 950 MW in negotiation.[3] At the same time, there were nearly two dozen utility offerings across more than 15 states, with varying degrees of success and popularity. The utilities and regulators who worked on these programs are an important source of information on the challenges and opportunities such programs present.

Many states also have experience with transitioning to and managing retail choice and direct access programs. For example, Texas has successfully managed a restructured market for 20 years, with the state emerging as a national leader for renewable energy deployment while maintaining low electricity prices. Several states, including Arizona, California, Oregon, and Michigan, also have experience with direct access programs that give C&I customers some form of retail or wholesale choice in markets that are otherwise vertically integrated.

In addition, there are a number of coalitions and experts directly or indirectly focused on

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[3] World Resources Institute, Grid Transformation: Green Tariff Deals, available at https://www.wri.org/resources/charts-graphs/grid-transformation-green-tariff-deals.

the goal of expanding corporate access to renewable energy. First and foremost are the companies themselves; many C&I customers now have in-house energy teams with specific expertise in renewable energy purchasing, and many of these in-house experts have experience developing and/or participating in utility offerings and direct access programs. In addition, coalitions such as the Advanced Energy Buyers Group (AEBG) and the Renewable Energy Buyers Alliance (REBA) bring companies together to accelerate corporate procurement opportunities. Other groups with expertise for states to draw from on this topic include environmental nonprofits and clean energy trade associations.

Given the significant expertise and experience across multiple perspectives, states and utilities seeking to meet corporate renewable energy demand should start by looking to other states for potential models, talking to businesses and other large electricity users with operations in the state, and seeking advice from experts and coalitions focused on the goal of expanding corporate access to renewable energy.

Two: Determine Which Approaches Align Best with State and Utility Circumstances

When it comes to C&I renewable energy solutions in vertically integrated states, there are many common approaches and best practices that translate across states, as discussed in Step Four. However, there is not a simple copy-and-paste solution that will translate directly for each state or even each utility within a given state. Some issues that should be taken into account when considering C&I renewable energy options include:

- How existing utility rates are structured;
- Presence of an organized competitive wholesale market;
- Load growth and system resource needs;
- Cost-effectiveness of various renewable energy sources based on resource potential, land availability, and other factors; and
- Other energy policies that may interact with a new policy related to C&I renewable energy purchasing (e.g., a statewide carbon or renewable energy target).

None of these factors preclude introduction of workable C&I renewable energy options, but they will inform key strategic decisions about which path is the right one. For example, a vertically integrated utility that participates in an organized wholesale market will have straightforward options to offer direct access or to design a utility program that relies on the wholesale market to set pricing. At the same time, direct access programs can be developed without an organized wholesale market in place, as has been done in Oregon and, to a limited extent, Arizona. Similarly, there are a variety of ways to structure utility renewable energy programs, as discussed more in Step Four below, including options that would work with all types of underlying rate structures. And, in jurisdictions where load is not growing and new resources are not needed, there may be opportunities to save money for all consumers by replacing aging, inefficient generating resources with new renewable energy.

Three: Consider the Needs of Different Customers, Including Nonparticipants

Just as there is no one-size-fits-all solution for every utility, there is also not a singular solution that will work for all customers. Renewable energy buyers include manufacturers, technology firms (including electricity-heavy data center operators), retailers, hotels, consumer products companies, hospitals, universities, cities and municipalities, and more.

These customers differ in their load profiles, opportunities for onsite generation and load management, geographic spread, appetite for financial and technology risk, and renewable energy goals and preferences—and their operational differences translate into unique electricity needs and energy management strategies. Some companies prefer the flexibility of short-term contracts, while others want the cost savings and risk mitigation benefits offered by longer-term contracts; some have the sophistication and desire to source their own PPAs, while others prefer to lean on their utility or competitive service provider to do this for them; some have sufficient load to sign a PPA alone, while others prefer to offtake from a shared resource. Companies also have different underlying goals and priorities—some companies look to renewable energy to address price risk and hedge against future rate increases, while others are more concerned with simply avoiding upfront cost premiums.

In addition, different customers themselves bring varying strengths and challenges that must be accounted for. For example, a solution that can be made available for new customers may not be workable for existing load, and solutions that work for large customers or high load factor customers may be less appropriate for smaller customers.

One way to meet these different needs is to allow competitive service providers to work with C&I customers to deliver tailored offerings through direct access programs. For utility programs, a suite of different offerings, or significant flexibility within a single offering, is likely needed to meet different customer needs.

Finally, in addition to considering the different needs of participating customers, utilities and regulators must also protect non-participating ratepayers. For direct access programs, this necessitates a fair accounting of any supply costs that should be allocated to customers that transition to direct access to ensure that other customers are not unfairly burdened. California's "Power Charge Indifference Adjustment" is an example of such a charge. For utility renewable energy programs, this requires ensuring that the program is cost-based, and that participating customers are paying all the costs of the program. It also requires consideration of what happens to the renewable energy resource if the program is not fully subscribed or if customers subscribe for a term length shorter than the renewable energy contract that the utility has entered into to serve customers, because there is a risk that such customers will not re-enroll or have their allocation taken up by other customers.

Different utility programs have dealt with the necessity of protecting nonparticipating customers through different solutions. For example, Georgia Power required that the resources procured for C&I customers through its Renewable Energy Development Initiative (REDI) be priced below the utility's future avoided cost, such that nonparticipating customers would be unharmed if participating customers declined to re-enroll and the projects were folded into the rate base. In Oregon, Portland General Electric took a different approach, levying a "risk adjustment" fee for shorter contract terms to cover any stranded costs if customers do not re-enroll, or if new customers do not step in.

Four: Adopt Replicable Best Practices

Armed with information and advice from other states, utilities, renewable developers, and consumers, a good understanding of what makes sense given state- or utility-specific circumstances, and a thorough review of customer needs, the next step is to design the program. Here again, lessons learned from past experience can speed the process and improve outcomes.

Whether the path chosen is full retail choice, C&I direct access, a utility renewable energy offering, or something else, states and utilities have learned a lot through trial and error. Existing programs and approaches offer blueprints to guide development of new programs. While the sum of the parts of a new program or solution may be unique, most or all of the individual elements can be borrowed more or less directly from programs or solutions that have already been implemented elsewhere.

The next section of this report provides a detailed review of replicable elements that states should consider and adopt when designing new programs and solutions.

Five: Guide Customers Through the Decision and Enrollment Process

The decision to enter into a long-term utility renewable energy program or to select direct access service is not one customers take lightly. The underlying analysis to make an informed decision can be a significant undertaking, even for very sophisticated customers. Depending on the program structure or solution type, the customer may need to consider not only contract structure, environmental impact, and price, but also future pricing, technology risk, system and resource shape, etc. **Much of the information needed to make an informed decision lies with the utility and/or regulator.** In addition to robust outreach to potential customers, utilities introducing new renewable energy offerings should provide support and information during the decision process.

Six: Review, Iterate, and Improve

Just as important as reaching out to customers before developing or implementing a solution to expand customer access to renewable energy is the commitment to continue such outreach after a program or policy has passed, to ensure that customer needs are being met.

For a specific utility program, this means providing annual updates to regulators on enrollment, soliciting regular feedback from customers and making improvements as needed, and increasing the program cap as the program gets filled. For a direct access program, it means assessing the gap between customer enrollment requests and the overall program cap and assessing the need for expansion.

More broadly, iterating and improving also means assessing whether there are customers whose needs are not being met by existing policies and programs, and asking whether expansion or introduction of direct access options, development of new renewable energy offerings, or some other solution is needed to ensure all customers have at least one renewable energy option that works for them.

REPLICABLE BEST PRACTICES

The good news about designing solutions to meet C&I renewable energy demand in vertically integrated states is that there are a lot of pathways to do so—and plenty of examples to draw from. And while some elements will not translate directly across different states, many will. This section looks at key program design considerations that each state and utility will face and provides recommendations and examples of how to approach each decision (summarized in Table 2).

Table 2. Summary of replicable best practices

Pathway	Best Practices
Retail choice and/or direct access	States considering full retail choice should pay attention to the following best practices: 1. **Customer protection:** Ensure customers, especially residential customers, are protected from unfair marketing practices and other predatory practices. 2. **Customer control:** Allow C&I customers to directly contract with electric service providers to meet their needs (rather than bulk competitive purchases on behalf of blocks of customers); and States or utilities considering direct access should also consider: 1. **Size:** Programs should be sized so that all interested C&I customers are able to participate, to avoid creating an uneven playing field for businesses; 2. **Customer eligibility:** Allow all interested nonresidential customers to participate; 3. **Transition costs:** Fairly assess any stranded generation or supply costs resulting from DA customers no longer being served by the utility and assign costs equitably to DA customers; 4. **Duration:** Avoid time-limited programs to ensure customers are able to pursue long-term PPAs (10-30 years); 5. **Renewable energy requirements:** Where restrictions around resource type are contemplated, maintain full customer flexibility to pursue renewable or carbon-free resources through technologies and contracts that meet individual customer needs.
Utility renewable energy tariffs	States or utilities considering development of utility programs should consider the following: 1. **Rate Structure:** Select the most appropriate rate design from the several models available, taking into account existing rate structures and customer needs; 2. **Program Cap & Expansion:** Start with an initial offering large enough to enable C&I customers to make meaningful progress toward their renewable energy goals, while also including clear mechanisms for expansion; 3. **Customer eligibility:** Ensure that all C&I customers are eligible to participate in at least one renewable energy program that aligns with their needs; 4. **Resource Selection:** Rely on competitive procurement for resources to meet program needs, and give customers the option to source projects directly; 5. **Term Options:** Give customers a range of options, including mid-range (10-15 years); 6. **REC Treatment:** Transfer RECs to customers, or retire them on customers' behalf; 7. **Administrative Fees:** Adopt reasonable and cost-based administrative fees; 8. **Termination:** Include clear, fair, and flexible termination provisions that allow for transfer to a different account.

Because there are important differences between direct access solutions and utility solutions, we have separated these two approaches and identified key elements for each; where relevant, we provide examples of states and utilities whose solutions or programs have successfully met customer needs, as well as those that have fallen short. Table 2 provides a summary of the key best practices for retail choice and direct access approaches and for utility programs.

Note that positive and negative examples below do not indicate that an individual approach or program is either successful or unsuccessful overall, just that it does or does not meet customer needs for a specific design element.

Replicable Best Practices for Direct Access or Retail Choice

As noted in the introduction, direct access programs and full retail choice markets allow customers to meet their renewable energy needs through flexible, tailored solutions suited to their individual preferences. If full market restructuring is the chosen solution for a given state, the 13 states and the District of Columbia that have undergone restructuring, some as long as two decades ago, offer a wealth of replicable best practices, including some lessons learned the hard way.[4] While the details of this option is beyond the scope of this paper, the first two best practices below ("customer protections" and "customer control") are particularly relevant for states implementing full retail choice.

If development of a direct access or buy-through option is the chosen solution, there are examples to draw from across the country, including in California, Michigan, Oregon, Virginia, and Arizona. The remainder of the best practices described below, starting with "customer eligibility," are specifically focused on direct access programs. Altogether, we explore best practices around seven key design decisions:

1. Customer control;
2. Customer protection;
3. Size;
4. Customer eligibility;
5. Transition costs;
6. Duration; and
7. Renewable energy requirements.

CUSTOMER PROTECTION

Especially in states that are pursuing full retail choice, strong customer protection provisions are key to ensure fair and equitable outcomes. Residential customers, in particular, must be protected

[4] National Renewable Energy Laboratory, An Introduction to Retail Electricity Choice in the United States (August 2017), https://www.nrel.gov/docs/fy18osti/68993.pdf.

from unfair, misleading, and/or predatory marketing and sales practices. A few bad actors can damage the market and harm individual consumers.

CUSTOMER CONTROL

For the purpose of C&I renewable energy transactions, the primary benefit of both direct access and full retail choice is to give customers the option to pursue renewable energy in a way that suits their needs. Accordingly, it is key for such programs to allow C&I customers to directly control their electricity purchases. Programs or market structures that rely on bulk competitive market purchases on behalf of blocks of customers may be appropriate for residential or even small commercial customers who often lack the time, resources, sophistication, and scale to negotiate favorable or tailored arrangements. However, these bulk approaches are not appropriate for C&I renewable energy procurement.

Most direct access or retail choice structures enable customer choice and control, including full retail choice states like Texas, Pennsylvania, New York, and much of New England; and direct access programs in California, Virginia, Oregon, and elsewhere.

However, there are some places where C&I customers face restrictions. In particular, despite its beneficial applications, **Community Choice Aggregation** falls short of giving C&I customers their desired level of choice with respect to renewable energy procurement. Community Choice Aggregation—which is allowed in some form in several states, including California, Illinois, and Massachusetts—allows community-based organizations to provide power to all customers in a certain municipality or jurisdiction. This approach, if successfully executed, can lower costs for residential customers, and provides a pathway for introduction of flexible, customer-driven options, such as renewable energy offerings. However, the flexibility to make their own decisions and conduct their own negotiations is key for C&I customers to make progress on their renewable energy targets.

SIZE

Direct access programs are only useful to those customers who are able to participate, so these programs should be sized such that all interested nonresidential customers are eligible to participate. This is important to avoid creating an uneven playing field for businesses in the state. Note that this (along with subsequent sections in this section) is only relevant in direct access programs and not for full retail choice, where every customer is eligible.

No direct access program in the country has fully aligned with this best practice. However, some do include promising elements:

- **California.** After passage of Senate Bill 237 in 2018, the state Public Utilities Commission is studying full expansion of direct access to all nonresidential customers, with recommendations due to the legislature in June 2020.[5] As of the July 2018 lottery for participation, California's direct access allowance was oversubscribed by 8,000 GWh.

- **Virginia.** State code in Virginia limits customer eligibility for direct access service (as explained below), but among eligible customers there is no overall restriction on participation.[6]

- **Oregon.** All nonresidential customers of Pacific Power and Portland General Electric can elect some form of direct access service, with no overall cap.[7]

Some states and utilities have fallen well short of meeting C&I customer demand:

- **Arizona Public Service (AZ) – Rate Rider AG-X.** This buy-through program allows C&I customers to contract directly with competitive providers for wholesale power. However, the program is limited to just 200 MW.[8]

- **Michigan.** In Michigan, direct access is currently limited to 10% of retail sales for each investor-owned utility in the state. The program has been fully subscribed for years, preventing many customers from being able to take advantage of the program.[9]

CUSTOMER ELIGIBILITY

Similar to program size, broad customer eligibility provisions are key to ensure that interested nonresidential customers are able to participate in a direct access program.

Direct access programs that have broad or flexible customer eligibility requirements include:

- **Michigan.** Direct access service in Michigan is available to all residential and commercial customers.[10]

- **California.** While the overall program size in California is currently limited, all nonresidential customers are eligible to participate in the lottery regardless of the size of their load, their location in the state, or other characteristics.[11]

Direct access programs that have fallen short of allowing broad customer participation among C&I customers include:

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[5] SB 237, 2018 Regular Session (Calif. 2018).
[6] Virginia State Code §56-577.
[7] Public Utility Commission of Oregon, Restructuring Nonresidential Consumers, https://www.puc.state.or.us/Pages/electric_restruc/consumer/nonres.aspx.
[8] Arizona Public Service, Rate Rider AG-X, https://www.aps.com/library/rates/AG-X.pdf.
[9] Michigan Agency for Energy and Michigan Public Service Commission, Electric choice for residential and commercial customers (June 2017), https://www.michigan.gov/documents/mpsc/electric_choice_resandcomm_379617_7.pdf.
[10] Ibid.
[11] California Public Utilities Commission, California Direct Access Program, http://www.cpuc.ca.gov/General.aspx?id=7881.

- **Arizona Public Service (AZ) – Rate Rider AG-X.** This program is limited to customers with an aggregated peak load of 10 MW, and the first 100 MW of the 200 MW program is reserved for customers with single-site peak demands of at least 20 MW, and a monthly average load factor above 70%.[12]

- **Virginia.** Virginia state code restricts retail choice to customers with demand of at least 5 MW at a single site; customers also cannot exceed 1% of the utility's peak load. Customers with aggregated demand of 5 MW must petition to the State Corporation Commission to participate in retail choice, and all other customers are much more restricted in their access to retail choice, as described below (see "renewable energy requirements").[13]

- **Georgia.** In Georgia, only *new* customers with load of 900 kW or greater are eligible to participate in direct access.[14]

TRANSITION COSTS

In some states, the transition of some C&I customers to direct access could impact the remaining rate base. Where this is the case, any stranded generation or supply costs resulting from direct access customers no longer being served by the utility should be fairly assessed and equitably assigned to direct access customers. This should be done over a transition period such that direct access customers are not permanently paying for assets that are not needed to serve them, and should hold both direct access customers and cost-of-service customers neutral to the switch. Efforts should also be taken to minimize the total stranded cost.

Examples of states that have implemented a productive process and approach to assess and assign transition costs include:

- **California.** The Power Charge Indifference Adjustment (PCIA) is a charge assessed on customers that leave utility service to take service from a direct access provider or a community choice aggregator. In 2017 the Public Utilities Commission launched a process to revise the PCIA, including efforts to minimize the portfolio of stranded costs.[15]

- **Pacific Power (OR).** For customers that are eligible for and elect to take permanent direct access service via the "five-year fixed transition adjustment option," a five-year "Consumer Opt-Out Charge" applies. This charge is

[12] Arizona Public Service, Rate Rider AG-X, https://www.aps.com/library/rates/AG-X.pdf.
[13] Virginia State Code §56-577.
[14] Georgia Territorial Act of 1973.

[15] California Public Utilities Commission, Power Charge Indifference Adjustment (January 2017), http://www.cpuc.ca.gov/uploadedfiles/cpuc_public_website/content/news_room/fact_sheets/english/pciafactsheet010917.pdf.

based on the market value of energy across the utility's system, and customers no longer pay the charge after they have taken direct access service for five years.[16]

DURATION

To be used for renewable energy transactions, direct access programs must be available for sufficient duration to allow customers to pursue long-term PPAs (10-30 years). Direct access programs should therefore not be time-limited, or should at least allow multi-year opt-out options.

Direct access programs that allow permanent opt out, and therefore enable long-term renewable energy contracting, include **California, Virginia, and Michigan.**

However, not all programs allow long durations, including:

- **Pacific Power (OR) – Small nonresidential customer options.** Pacific Power does allow permanent direct access for large C&I customers, but smaller nonresidential customers can only opt out one year at a time.[17]

- **Arizona Public Service (AZ) – Schedule AG-1 (expired).** APS offered AG-1, a market buy-through program, on an experimental basis, and allowed the program to lapse in 2016. The short-term nature of the program prevented participants from pursuing long-term renewable energy options through the program.

RENEWABLE ENERGY REQUIREMENTS

States or utilities that are focused on C&I customer choice for the sole purpose of expanding corporate renewable energy options may consider limiting their direct access programs accordingly. While this is not itself a bad thing, any such limitations should be approached very carefully; even well-intentioned restrictions may impose unintended barriers to renewable energy access. As such, states or utilities that choose this approach should take care to maintain full customer flexibility to pursue renewable or carbon-free resources through technologies, vendors, and contract structures that meet individual customer needs.

The idea of limiting direct access programs to renewable energy purchases is mostly untested, but has had negative repercussions in **Virginia,** where state code allows all customers to purchase 100% renewable energy from competitive service providers *if their investor-owned utility does not already offer an approved 100% renewable energy tariff.*[18] This restriction has prevented competitive providers from

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[16] Pacific Power, "2019 Power Options for Oregon Customers," available at https://www.pacificpower.net/content/dam/pacific_power/doc/Business/17658-30_PP_DirectAccess_Booklet_5.5x8.5_webF.pdf.

[17] Ibid.

[18] Virginia State Code §56-577.

entering the market, resulting in this flexible customer option going unused.

Replicable Best Practices for Utility Programs

If a utility renewable energy offering is the chosen solution for a given state or utility, there are lessons learned from existing programs that can be applied to the new program—either through direct replication or with some adaptation or modification. **This section outlines key program design decisions for utility renewable energy programs, explaining best practices for each.** These decisions are split into eight primary categories:

1. Rate Structure;
2. Program cap & expansion;
3. Customer eligibility;
4. Resource selection;
5. Term options;
6. REC treatment;
7. Program fees; and
8. Termination provisions.

RATE STRUCTURE

The rate structure of a utility renewable energy program—how the renewable energy shows up on the customer's bill—is not something that can be directly replicated from one utility to another, for all the reasons outlined in Step Two, and different rate structures may be needed for different customer types, for all the reasons outlined in Step Three. However, there are a few priorities that are relevant across all states. Specifically, programs should avoid permanent cost premiums, and allow customers to address risk by either (a) directly passing the renewable energy cost to the customer, allowing the customer to take on and manage this risk, or (b) transferring the risk to the customer, and giving the customer a new renewable energy rate.

Keeping these goals in mind, there are a few key models to draw from that can be adapted for any new program:

- **Rate rider on top of the customer's bill.** Under this approach, customers stay on their underlying rate schedule, and the renewable energy charge (which may be positive or negative in any given month) is imposed on top of that. The renewable energy charge is based on the price of the renewable resource plus any administrative fees, minus a credit that accounts for the fact that the renewable resource has displaced the customer's existing supply.

  The credit can be calculated on a few different metrics, with the best approach varying according to the underlying rate structure:

  Energy and capacity value of the resource. In competitive wholesale markets, the resource can be compensated according to wholesale costs and capacity value (an approach taken by Dominion Energy's Schedule RG, Ameren's Renewable Choice Program, and Consumers Energy's LC-REP Option A, among others).[19] Other programs have developed alternate methods; for example, Georgia Power's REDI program utilizes real-time system pricing in Southern Co.'s service territory, while Pacific Gas & Electric's Green Future Impact program calculates upfront a fixed energy and capacity credit based on the value the resource brings to PGE's territory.

Utility avoided cost. The customer is charged (or credited) according to the difference between the cost of the renewable resource and the utility's avoided cost. This is the approach taken by Rocky Mountain Power's Schedule No. 34 in Utah and Xcel's Renewable*Connect program in Colorado, which uses an avoided energy and avoided capacity credit, updated annually.

Fuel swap, or unbundled services not used. Under this approach, customers are simply not charged for any services they are no longer using, i.e., generation and/or fuel costs that have been replaced by the customer's renewable energy purchase. Programs that have used this approach include Puget Sound Energy's Green Direct, which replaces the customer's energy-related charges with the renewable energy charge; Westar's DRPS program, which exempts customers from the utility's Retail Energy Cost Adjustment Surcharge; and Madison Gas & Electric's Renewable Energy Rider, which exempts customers from otherwise applicable fuel costs.

- **Tariff designed from ground up.** Under this approach, the customer is moved to an entirely new rate structure that charges the customer for delivered renewable energy, as well as system costs for any supplemental energy and capacity, and transmission and distribution services. Public Service New Mexico's Schedule No. 47 uses this approach.

- **REC purchase from a specified facility**. A REC purchase option charges the customer for the environmental attributes associated with a resource that is used to meet the needs of all utility customers; the corporate off-taker receives only the RECs, and does not purchase the energy or capacity output of the resource itself. For example,

[19] For an explanation of the rate structure of all the programs described in this section, see World Resources Institute, Priya Barua, and Celina Bonugli, Emerging Green Tariffs in U.S. Regulated Electricity Markets (October 2018), available at http://www.wri.org/publication/emerging-green-tariffs-us-regulated-electricity-markets.

Dominion's Schedule RF takes this approach. One downside of this program type is that it will always involve a price premium, which for some customers is unacceptable.

In addition to these renewable energy rates, another related solution is a **market-based rate.** This approach puts the customer on a new tariff for generation that mirrors wholesale market costs, so that a customer entering into a vPPA has alignment between that financial contract and their electricity costs. The customer's renewable energy vPPA may be executed separately from the market-based rate, and thus the market-based rate is not strictly a renewable energy offering. Some programs that utilize this approach include Dominion Energy's Schedule MBR, Omaha Public Power District's Schedule No. 261 M, and the Market Index Provision of Consumers Energy's LC-REP program.

There is still room for innovation, improvement, and new program design approaches, but the approaches above are a good starting point.

PROGRAM CAP & EXPANSION

Given the scale of corporate demand for renewable energy, and the ambitious timeline against which many companies are seeking to meet renewable energy targets, small programs offer frustratingly slow and incremental progress, especially given the time and resources needed to design and implement a program of any size. To better meet customer needs, renewable energy tariffs should start out sufficiently large to meet initial demand; experience suggests 300 MW as an appropriate starting size. Large companies may elect not to engage with green tariffs if they cannot make meaningful progress toward their purchasing targets; programs that spread available renewable energy for purchase among many potential customers present similar challenges for these buyers.

Recognizing that structuring project deals to secure capacity is complex and lengthy, successful programs are increasingly including a clear process through which the utility can expand its capacity without re-entering the regulatory approval process.

Programs that have successfully integrated program cap and expansion considerations include:

- **Rocky Mountain Power (UT) – Schedule 34.** In this program, there is no cap on customers or total program size; the maximum amount of renewable energy that can be purchased by a customer is based on projected annual energy use by that customer.[20] This allows a customer to meet up to their entire

[20] Rocky Mountain Power Renewable Energy Purchases for Qualified Customers, Schedule 34, Docket 16-035-T09.

electricity demand with renewable energy.

- **Ameren (MO) – Renewable Choice Program.** This program features a sizeable initial cap of 400 MW and will consider additional capacity if fully subscribed.[21]

- **Dominion Energy (VA) – Schedule RG.** This program is capped initially at 50 customers. Dominion proposes no caps on electricity purchased except that a customer may not purchase more than 100% of its annual electricity load.[22]

- **DTE Energy (MI) – Large Customer Voluntary Green Pricing Program.** This program is designed to raise its cap in phases as customer demand grows. When a phase is nearing full subscription, DTE will add new assets to ensure that the program meets customer needs. To ensure fairness and cost competitiveness, these additional assets will be approved through the program's existing approval process.[23]

- **Portland General Electric (OR) – Green Future.** This program is capped initially at 900 MW and has potential to add future tranches. In this tariff structure, subscribers can sign contracts for up to 100% of their electricity load.[24]

Programs that face cap and expansion challenges include:

- **Georgia Power (GA) – Commercial and Industrial Renewable Energy Development Initiative.** The cumulative capacity of this program was originally limited to 200 MW, and the current program is fully subscribed. Because the utility did not design the program with expansion in mind, it is undergoing expansion in 2019, several years after the tariff's inception. Having started at 400 MW initially or having included a provision for expansion would have significantly reduced delays and better met business needs.[25]

- **Dominion Energy (VA) – original Schedule RG.** This program's initial proposed cap was 240,000 MWh (equal to approximately 90 MW at 30% capacity factor) or 100 customers. Considering that the average PPA signed by corporate customers from 2014-16 exceeded 90 MW, this program cap was too small. In response, as highlighted in the earlier Dominion example, Dominion elected to cap the program

[21] Ameren Missouri Renewable Choice Program, Docket ET-2018-0063, Tariff Revision YE-2019-0005, Page 3.
[22] Dominion Energy Renewable Energy Supply Service, Schedule RG, Case PUR-2017-00163.
[23] DTE Electric Company's Application for Approval of its Large Customer Voluntary Green Pricing Program and Direct Testimony and Exhibit of Terri L. Schroeder, Document U-20343-0001, Page 16.
[24] Portland General Electric Green Future Program, Docket UM 1953, ORDER NO. 19-075, Pages 3-4.
[25] Georgia Public Service Commission, Docket No. 42310, 2019 Integrated Resource Plan, Filed Jan. 31, 2019.

only by number of participants, not megawatt-hours.[26]

- **Consumers Energy (MI) – LC-REP Option A.** This program enables customers to purchase between 20% to 100% of their load in 5% increments, but the overall program for the initial offering is capped at 155,000 MWh (approximately 60 MW).[27] This limited initial program was nearly fully subscribed by just two customers. As a result, Consumers Energy was required to expand its program by the Michigan Public Service Commission.

CUSTOMER ELIGIBILITY

In recent years, utility renewable energy tariff programs have attracted an increasingly wide range of customers. Whereas the first programs may have been designed to support one or two large customers with 25 MW or more of incremental load, demand for these programs now includes customers with smaller loads (in the range of a few megawatts) as well as larger customers with load distributed across multiple sites. One reason for this success is that modern programs are designed with enrollment requirements flexible enough to meet this diversity of demand.

There is still a role for programs tailored to very large customers, new load customers, and high load factor customers. These customers have specific needs and characteristics that may justify separate programs. However, where such programs exist, additional options should be made readily available to customers that do not meet these criteria, including existing customers and smaller or more distributed customers.

Some programs that have successfully allowed for broad customer participation include:

- **Consumers Energy (MI) – Large Customer Renewable Energy Pilot Program (LC-REP).** This Michigan program demonstrates multiple successful principles for customer eligibility in renewable energy tariff programs. First, all customers with at least 1 MW of annual maximum demand are eligible, allowing participation by many smaller C&I customers. In addition, customers are able to aggregate demand across multiple facilities to meet the 1 MW threshold, incorporating (for example) retailers, restaurants, hotels, or other business with multiple smaller locations.[28]

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[26] Application of Virginia Electric and Power Company, For approval to establish a companion tariff, designated Schedule RG, PUR-2017-00163, April 10, 2018, Page 8.

[27] Based on estimate of 30% capacity factor. Consumers Energy Voluntary Large Customer Renewable Energy Pilot Program, Case No. U-18393 and No. U-18351.

[28] Ibid.

- **Portland General Electric (OR) – Green Future Program.** Green Future is open to any nonresidential customer exceeding 30 kW in load, while also allowing customers to aggregate demand across facilities to reach this threshold.[29]

Other programs have not been as successful in this regard:

- **Dominion Energy (VA) – MBR Program.** The MBR program is open only to existing Dominion Energy customers with at least 5 MW peak demand and an average monthly load factor of at least 85%. Additionally, a customer must satisfy these standards on a single meter, as aggregate demand across facilities is not considered. These requirements are overly restrictive, and the high load factor (85%) unnecessarily limits eligibility to large, industrial users with a very stable load profile.[30] Dominion is requesting approval for changes to the program to slightly expand program eligibility.[31]

RESOURCE SELECTION

Customers generally prefer that utility renewable energy programs rely on new renewable energy procured through a competitive resource selection process. The best programs create new, customer-driven, competitive markets for renewable capacity and provide the customer with both transparency and an opportunity to provide input to the bidding process, if desired. Less successful programs are those that rely on existing projects, or only allow utility-built projects to satisfy customer demand.

Some examples of programs that have emphasized flexibility, transparency, and competition in the resource selection process include:

- **Dominion Energy (VA) – Schedule RG (RG).** In the RG program, Dominion provides the customer with the option of *either* requesting a specific renewable energy facility/resource *or* having Dominion execute a competitive bid process to fulfill customer demand. This optionality provides for the needs of both large and small energy buyers. Large buyers with enough scale to attract a third-party or Dominion-owned facility/resource can bring that project online through RG. Small buyers are included as well through the ability to enroll and see their needs aggregated by the utility with those of other customers and met through a competitive solicitation.[32]

- **Puget Sound Energy (WA) – Green Direct.** This program is a good example of transparency and coordination in the

[29] Oregon Public Utilities Commission, Docket No. UM 1953.
[30] Virginia State Corporation Commission, Docket No. PUE-2015-00108.
[31] Virginia State Corporation Commission, Docket No. PUR-2018-00192.
[32] Virginia State Corporation Commission, Docket No. PUR-2017-00163.

resource selection process. "Green Direct" program customers are able to work with PSE to identify a specific renewable energy resource that may be either PSE or third-party owned. Customers and PSE identify this resource through the contracting process and mutually agree that the project will provide long-term clean energy and support the local economy.[33]

- **Pacific Gas and Electric (OR) – Green Future Impact (Proposed).** This program allows customers to either subscribe to a project sourced by the utility or bring their own project. As proposed, the customer-sourced resource option would be limited to larger customers with at least 10 MW demand.[34]

On the other hand, some programs have not met the goal of developing new resources via a competitive bidding process. For example:

- **Appalachian Power Company (VA) – Rider REO.** The Rider REO program relies on renewable energy resources under existing PPAs, including one existing hydroelectric resource and three existing wind resources. Programs such as Rider REO utilizing existing resources merely shift the cost of existing resources from the rate base to program participants. Without bringing any new renewable energy resources online, the program fails to meet the demand for "additionality" that many customers require for their renewable energy purchases. Moving forward, Rider REO will contract with additional resources, but will do so independent of coordination with or input from program customers.[35]

- **Florida Power & Light (FL) – SolarTogether (Proposed).** FPL proposed the 1,450 MW SolarTogether program in March 2019 as a series of 74.5 MW projects, all FPL-owned. The lack of a competitive bidding process for project selection means that customers have no indication that the price they will be paying for the resources is the lowest possible cost.[36]

To best meet customer needs, utility renewable energy programs should be designed to take advantage of current market prices and stimulate new renewable energy development, which will also bolster the economy through private investment and local jobs.

TERM OPTIONS

Large companies procure renewable energy with different goals, time horizons,

[33] Docket No. UE-160977.
[34] Docket No. UM 1953.
[35] Petition of Appalachian Power Company for approval of an 100% renewable energy rider, April 28, 2016.
[36] Docket No. 20190061-EI, Petition by Florida Power & Light Company for Approval of FPL SolarTogether Program and Tariff, March 13, 2019.

and levels of commitment. A well-designed utility program will offer flexible term options including possibilities for short-term (1-3 year) and mid-range (10-15 year) options, not just longer-term options (20-30 years). Providing a range of term options enables companies to obtain internal approval as well as meet financial requirements. Indeed, these contracts must have a long enough term to achieve a reasonable project price, but not so long that companies encounter strategic issues. For instance, some companies have stated clearly and publicly that they do not sign contracts longer than 15 years for corporate governance reasons.[37]

When designing these tariffs, utilities must also consider the potential disconnect between PPA terms and customer terms—a disconnect that utilities are well suited to manage, adding significant value to customers seeking shorter term lengths.

Programs that provide a range of term options to meet customer needs include:

- **Georgia Power (GA) – C&I Renewable Energy Development Initiative.** This program allows customers to select time commitments of 10, 15, 20, 25, or 30 years for the same pricing regardless of contract length. Georgia Power's program is a proven success as companies like Google and Walmart have both signed deals with the utility.[38]

- **Xcel Energy Renewable*Connect.** This program offers contracts with three different lengths: month-to-month, five years, and 10 years. In this tariff, longer-term contracts have lower prices.[39]

- **Portland General Electric (PGE) Green Future Impact.** This program has contract time commitments of five, 10, 15, or 20 years. These five-year increments are exemplary of contract flexibility across the medium and long term. Shorter contract terms require higher "risk adjustment" payments to account for the disconnect between the utility's PPA term and the customer term.[40]

Programs that allow customers to source their own PPAs will meet the needs of at least some customers, even if they do not offer short-term options. For example, **Rocky Mountain Power's Schedule 34** requires that the customer's contract with RMP must, at a minimum, match the length of time in the renewable energy facility

[37] See Joel Makower, "How Google and Walmart work with utilities to procure clean power," Greentech Media (April 9, 2018), https://www.greenbiz.com/article/how-google-and-walmart-work-utilities-procure-clean-power.

[38] Docket No. 40161, Order Approving Renewable Energy Development Initiative Commercial and Industrial Program, Georgia Public Service Commission, August 9, 2017, Document Filing No. 169267.

[39] Xcel Energy Compliance Filing, Docket E002/M-15-985.

[40] Docket No. UM 1953.

contract.[41] As PPAs may range from 10 to 25 years in duration, customers looking for shorter-term contracts may find this term impractical and undesirable, but many customers will find it workable.

Examples of programs that lack term flexibility include:

- **Consumers Energy Co. LC-REP Option A.** In this program, customers must choose between two term options: three years or 20 years. Customers that select the shorter term may renew their subscriptions in three-year increments up to a maximum contract length of 20 years, but the subscription charge is increased by 2% with each enrollment after the first three years, limited to four re-enrollments. This rigid contract structure restricts term length options by offering only short- and long-term options that do not involve renewal. In this program, customers also face increased subscription costs unless they commit to a 20-year contract.[42]

- **Westar Energy (KS) Direct Renewable Participation Service.** This program requires a 20-year term, precluding participation by customers that require shorter term options and even those customers that are not able to commit beyond a medium-term contract of 10 or 15 years.[43]

REC TREATMENT

Unless the RECs associated with green tariff programs are retired on behalf of or transferred to the customer, the customer cannot make renewable energy claims. The ability to make verifiable statements about using clean power is a primary motivator for companies enrolling in these programs. As such, a program that does not provide RECs of bundled renewable energy has no value as a *renewable energy* product, even if it offers other attractive features.

Most current programs meet customer needs regarding REC treatment, including:

- **Xcel Energy (CO) – Renewable*Connect.** In this program, Xcel offers the subscribing customer two options: Xcel will (1) retire the RECs on their behalf or (2) transfer the RECs to a Western Renewable Energy Generation Information System (WREGIS) account.[44]

- **Puget Sound (WA) – Green Direct.** This program is the same as the above. Puget Sound will retire the RECs on behalf of the customer or transfer them to a WREGIS account (which the

[41] Rocky Mountain Power Electric Service Schedule 34, Docket 16-035-T09.

[42] Consumers Energy Voluntary Large Customer Renewable Energy Pilot Program, Case No. U-18393 and No. U-18351.

[43] Docket No. 18-WSEE-190-TAR

[44] Xcel Energy Filing, Docket 16A-0055E.

customer must join at their own expense).[45]

An example of a program which is problematic for its customers with respect to REC treatment:

- **NV Energy (NV) GreenRider 2.0 (proposed).** By NV Energy's own admission, this program "does not provide renewable energy and environmental attributes to participating customers." In this program, the RECs are used for compliance with the state Renewable Portfolio Standard, and customers must opt to purchase RECs at a premium over the program cost if they wish to claim the renewable energy.[46]

PROGRAM FEES

Program fees in utility renewable energy tariff programs — which include enrollment, administrative, and marketing fees — are often a make-or-break factor in enrollment, and poorly designed fee structures can overcharge and exclude potential customers. The best programs are cost-based, scale fairly for large load customers and customers with multiple facilities, and avoid excessive fees for any otherwise eligible customer profile.

For example, a customer should be able to enroll aggregate demand with multiple meters across facilities without being forced to pay a per-meter fee that does not reflect the marginal cost of adding additional meters to the program.

Some examples of programs that have fair administrative fees include:

- **Georgia Power (GA) C&I REDI.** The REDI program breaks administrative fees into two categories: (1) Initial administrative fees are paid at $0.00005/kWh for the first 10 years of the contract; and (2) Ongoing fees are paid over the entire life of the contract. Ongoing fees are $0.001/kWh for customers subscribing under 50 MW, and $0.0005/kWh for customers subscribing over 50 MW.[47] REDI is a good example of how fees should scale, so that larger customers are not unduly billed for what are diminishing marginal administrative costs to the utility.

- **Xcel Energy (CO) Renewable*Connect Program.** Customers pay a single, simple charge on a per kWh basis, starting at $0.00652/kWh in year one. The utility will track its actual administrative and other program costs each year. If profit to the utility (based on actual revenue and actual costs) exceeds 10% in a given year,

[45] Puget Sound Energy Filing, Docket UE-160977.
[46] Docket No. 18-11015.
[47] Georgia Power CIR-1, available at https://www.georgiapower.com/content/dam/georgia-power/pdfs/business-pdfs/rates-schedules/ci-redi-tariff.pdf.

participating customers are refunded in the following year.[48]

- **Consumers Energy (MI) – Voluntary Large Customer Renewable Energy Pilot.** Consumers Energy does not charge any administrative fees for customers enrolling in the Consumers Energy Sponsored Renewable Energy Program, one of two options offered by the utility. Under this program, customers pay an all-inclusive $0.045/kWh subscription fee and receive a credit for grid energy not used. This fee covers all the costs of developing, financing, constructing, and operating the utility-owned renewable energy project. However, the utility does not anticipate that administrative or marketing costs will make up a significant amount of the program costs given that the program is intended for large, sophisticated customers that are proactively seeking out renewable energy offerings.[49]

Other programs have been less successful in structuring administrative fees:

- **Dominion Energy (VA) – Schedule RG (original, retired).** This program in Virginia (since retired) was ineffective in that it charged a fee (greater of $500/month or $0.00025/kWh) for each meter receiving renewable energy.[50] The fee structure is unduly burdensome on those customers who enroll to serve a number of distributed loads, such as retailers, restaurants, or other businesses with multiple smaller locations. High per-meter administrative fees can price these potential customers out of the program and are not justified by the actual cost to serve distributed customers.

TERMINATION PROVISIONS

Utility customers often desire flexibility in entering, modifying, and transitioning out of program participation. For example, some customers have facilities leases that are shorter than the medium-term contracts required by some utility programs; such customers require utility contracts that allow for transfer to another account. Clearly written provisions that allow for transfer and are based on incremental costs are crucial for ensuring that all potential customers feel comfortable signing on, while still giving the utility and other customers the protection they require if customers leave. In the case that a customer chooses to terminate and fails to find another account to transfer the contract to, the customer should be charged only the incremental cost associated with the termination.

Several programs have developed flexible and fair termination provisions that protect

[48] Docket No. 16A-0055E, Direct Testimony of Kevin D. Schwain.
[49] Docket No. U-18351, Direct Testimony of Teri VanSumeren.
[50] Virginia State Corporation Commission, Docket No. PUE-2012-00142.

both participating and nonparticipating customers:

- **Georgia Power (GA) – C&I REDI.** This program features a clause in its user agreement that enables early termination without added cost if the customer gives Georgia Power at least 180 days written notice. If a customer terminates its agreement early, the customer may not re-subscribe to the program. Georgia Power and its other ratepayers are protected even in the case of customer unenrollment because the projects serving the REDI program are required to be priced below the utility's avoided cost.[51]

- **Consumers Energy (MI) – Large Customer Renewable Energy Pilot Program, Option A.** In this tariff program, if customers terminate their contracts early, they must take service under the existing rate schedule for the remainder of their contract. In addition, an early termination fee will be negotiated unless the contract is transferred to another eligible customer.[52]

- **Ameren (MO) – Renewable Choice Program.** In this program design, a customer that wishes to terminate its contract early may transfer the service to another customer without penalty or request for the utility to find another customer. If neither of options is possible, the customer is obligated to pay a monthly renewable energy adjustment until the end of the term. If the customer prefers not to pay a monthly adjustment, it may also pay a termination fee, which is the average monthly adjustment for the preceding 12 months multiplied by the remaining months in the term.[53]

Other programs have not been as successful in offering flexibility with regard to customer termination:

Duke Energy (NC) – Rider GS (original, expired). This program allows for early termination but levies a fee equal to the net present value of the entire remaining PPA cost.[54] Because this charge encompasses the full remaining life of the project, this structure assumes the asset would become stranded, which is unlikely even if another customer is not found. The program should instead rely on real costs incurred to the utility associated with the cancellation.

[51] Georgia Power CI REDI Tariff User Agreement, Docket 40161.
[52] Consumers Energy Voluntary Large Customer Renewable Energy Pilot Program, Case No. U-18393, Order, Page 10.
[53] Ameren Missouri Renewable Choice Program, Docket ET-2018-0063, Tariff Revision YE-2019-0005, Page 7.
[54] Docket No. E-7, Sub 1043.

CONCLUSION

Large customers with renewable energy goals are increasingly eager to source projects that are local and that connect in some way to their electric bill. In restructured states that allow full retail choice, achieving these goals is relatively simple, with multiple options to choose from. However, in vertically integrated states, customers rely on utility partners and state policy changes to meet their renewable energy goals through cost-effective, local projects that do not entail undue financial risk.

Given the growing interest in renewable energy among commercial and industrial customers, as well as among municipalities, universities, and other large customers, those states and utilities that unlock attractive renewable energy purchasing opportunities are better hosts for businesses looking to expand or move their operating footprint. And while states and utilities with vertically integrated market structures may be at an initial disadvantage when it comes to meeting customers' renewable energy needs and preferences, there are many solutions to pick from to close the gap.

States just starting on this journey can find that others have already uncovered many important best practices, and it's possible to copy or customize many elements of successful solutions and programs in use elsewhere.

From a process standpoint, this paper summarized six key steps for any state or utility to arrive at the best solution to meet its circumstances. These are: (1) conducting outreach and discussion with states, regulators, utilities, customers, and experts with experience implementing solutions and developing programs elsewhere; (2) determining which approaches or solutions align best with the specific circumstances of the state and/or utility; (3) listening to and accounting for the needs of different customers; (4) adopting replicable best practices from other states or utilities; (5) guiding customers and providing information through their decision-making and/or enrollment process; and (6) listening again to customers and other key stakeholders to review, iterate, and improve upon the final solution.

With respect to following best practices from other states, this paper provides examples from states across the country for direct access and retail choice solutions as well as for utility renewable energy tariff offerings. While each individual program or solution will be unique, many elements can be copied directly or adapted from a solution already in place.

Despite the best practices and lessons learned, there are still new opportunities for innovation and room for improvement, but progress will come more quickly and with less frustration if new programs rely on existing recipes rather than starting each time from scratch.

ESSENTIAL ELEMENTS OF NEXT-GENERATION RENEWABLE ENERGY TARIFFS

Voluntary utility programs can play a critical role in meeting the needs of Corporate America—with the right program design

Corporate demand for renewable energy is growing. The ability to control energy costs and sources has always been a critical business priority, particularly for energy-intensive industries. As renewable energy technologies such as wind and solar continue to drop in price, these sources are an increasingly attractive option for companies seeking to lower costs while protecting against fluctuating fuel prices.

At the same time, a growing number of companies have codified their commitment to renewable energy by setting a public target. In the U.S., 71 Fortune 100 companies and 215 Fortune 500 companies (43%) have set renewable energy or energy-related sustainability commitments as of 2016—and the number is rising.[1]

Renewable energy tariffs offer one approach for vertically integrated utilities to meet corporate needs. There are a number of approaches to purchasing renewable energy, ranging from onsite generation to virtual power purchase agreements (PPAs) to direct purchasing in competitive markets. Renewable energy tariffs give customers of vertically integrated utilities the option of purchasing renewable energy through their utility. Well-designed programs can give customers access to cost-competitive renewable energy without shifting costs to other customers or risking stranded assets for utilities. Such renewable energy tariffs can allow states with vertically integrated utilities to attract and retain top corporations by enabling companies to follow through on their clean energy targets.

Renewable energy tariffs can be win-wins for the corporate buyer and the utility. The first generation of renewable energy tariffs, developed starting in 2013, had mixed results: those that met corporate needs in whole or in part saw significant project development, totaling nearly 1 gigawatt of renewable energy across the country to date; those that failed to meet corporate needs went largely unused.[2] Moving forward, utilities have an opportunity to build upon the successes and learn lessons from the failures. Careful, creative, and collaborative program design can help develop the next generation of renewable energy tariffs that address the needs and preferences of corporate participants, nonparticipating customers, utilities, and regulators alike.

71 Fortune 100 companies have set renewable energy purchasing or energy-related sustainability goals, and 43% of the Fortune 500 have done the same.

Three categories of renewable energy tariffs

Sleeved PPA tariffs allow large customers to purchase energy from an offsite renewable project, with the terms of the PPA contract “sleeved” through that customer’s local utility and electricity delivered to the customer by the utility.

Subscription-based programs serve multiple customers from the output of one or more renewable energy facilities owned or contracted by the utility, and generally provide customers with flexibility in terms of subscription size and length.

Market-based rates replace the energy portion of a customer’s bill with a dynamic variable rate that moves up and down with wholesale market prices. The market-based rate does not itself supply renewable energy, but it can work in parallel with a virtual PPA between a customer and a renewable energy project or a renewable energy offering from the utility, providing a more direct correlation between the customer’s electricity rates (per kWh usage) and the variable market price of the renewable energy sold into the wholesale market.[3]

Six elements of successful utility renewable energy tariffs

While every program should be tailored to meet state-specific circumstances, the most successful next generation renewable energy tariffs will incorporate the following six design elements to meet the needs of renewable energy buyers, utilities, and other electricity customers:

1 **No impact on nonparticipating customers.** Corporate purchasers, utilities, ratepayer advocates, and other stakeholders unanimously agree that voluntary utility programs should not impact nonparticipating customers, and programs should be designed with this goal in mind; in particular, uncapped programs allowing participation by existing customers may require additional design parameters to ensure that nonparticipating customers are not impacted as large utility customers shift their electricity consumption away from existing utility resources and toward new renewable energy assets.[4]

2 **Program pricing that reflects actual market pricing and program costs.** Locked-in price premiums have made utility voluntary renewable energy purchasing programs unpopular among potential customers. To meet customer needs, programs should instead charge customers according to the actual cost of the resources, whether that results in a net premium or net savings for customers. Similarly, high administrative and system costs will make programs unattractive and dampen or prevent participation. Instead, utilities should accurately allocate both the costs and benefits to participating customers, and look for ways to lower costs, such as turning to third parties to pay for or find ways to lower administrative costs and program fees.

3 **Competitive project selection.** A competitive project solicitation process with participation open to both utilities and third-party suppliers will bring costs down for consumers. Depending on the program type, this may take the form of direct negotiation by participating customers or a transparent and competitive procurement process for a portfolio of utility-supplied resources.

4 **Development of new renewable energy, beyond business-as-usual.** Many corporate purchasers have public renewable energy or energy-related sustainability targets that include specific requirements to facilitate development of new renewable energy facilities and/or to demonstrate greenhouse gas reductions. To meet the needs of these customers, programs should specifically give customers the option of purchasing net new renewable energy, and allow them to retain the associated Renewable Energy Credits (RECs).

5 **Allowing a range of customers to participate.** Prospective participants in voluntary renewable energy programs span industry segments and have varied energy requirements. To enable participation by a full range of interested customers, programs should allow participation by both new and existing customers, and by customers with different load profiles, such as aggregated loads or a single, large load. Furthermore, many companies prefer to meet their entire renewable energy goal in a given state through a single solution. With the average PPA signed by individual corporate purchasers over each of the past three years exceeding 90 MW, programs should either set high program caps or, preferably, avoid such caps altogether.[5]

6 **Varied or flexible offerings to meet the needs of different customers.** There is no one-size-fits all offering that will meet the needs and preferences of all corporate purchasers. By providing a range of offerings and allowing for flexibility and special contracts within programs, utilities can meet the needs of the full range of corporate purchasers while still ensuring that the utility's needs and the needs of other customers are also met.

These six elements should be considered in parallel, not in isolation, as part of an inclusive program design process involving a broad range of stakeholders, from utilities and corporate purchasers to residential customer advocates and state economic development offices. By addressing corporate needs through consideration of these six essential elements, and through creative thinking and a spirit of compromise, all stakeholders ultimately stand to benefit from corporate renewable energy purchasing.

Endnotes: 1) http://info.aee.net/growth-in-corporate-advanced-energy-demand-market-benefits-report **2)** http://www.wri.org/resources/charts-graphs/grid-transformation-green-tariff-deals **3)** For more detail, see http://www.wri.org/publication/implementation-guide-green-tariffs **4)** A report from AEE Institute considers this issue in detail, see http://info.aee.net/making-corporate-renewable-energy-purchasing-work-for-all-utility-customers **5)** The average size of a PPA for a single company was 169 MW in 2014, 98 MW in 2015, and 97 MW in 2016. See http://www.businessrenewables.org/downloads/brc_nov_2016/State-of-the-market.pdf.

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