ENVIRONMENTAL LAW & POLICY CENTER
Protecting the Midwest's Environment and Natural Heritage

October 15, 2018

Ms. Kavita Kale
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-20165

Dear Ms. Kale:

The following is attached for paperless electronic filing:

Direct Testimony of Douglas B. Jester, Joseph M. Daniel, and James P. Gignac on behalf of the Environmental Law & Policy Center, the Ecology Center, the Union of Concerned Scientists, and Vote Solar.

Exhibits ELP-1 – ELP-8

Proof of Service

Sincerely,

Margrethe K. Kearney

Margrethe Kearney
Environmental Law & Policy Center
mkearney@elpc.org

cc: Service List, Case No. U-20165

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STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief	))))))	Case No. U-20165

DIRECT TESTIMONY OF DOUGLAS JESTER

ON BEHALF OF

THE ENVIRONMENTAL LAW & POLICY CENTER,

VOTE SOLAR, AND THE ECOLOGY CENTER

OCTOBER 15, 2018

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I. <u>INTRODUCTION & QUALIFICATIONS</u>

Q. Please state for the record your name, position, and business address.

A. My name is Douglas B. Jester. I am a Partner of 5 Lakes Energy LLC, a Michigan limited liability corporation, located at Suite 710, 115 W Allegan Street, Lansing, Michigan 48933.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Environmental Law and Policy Center (“ELPC”), Vote Solar (“VS”), and the Ecology Center (“EC”). I am also submitting separate testimony on behalf of Michigan Environmental Council (“MEC”), Natural Resources Defense Council (“NRDC”), and Sierra Club (“SC”).

Q. Please summarize your experience in the field of electric utility regulation.

A. I have worked for more than 20 years in electricity industry regulation and related fields. My work experience is summarized in my resume, provided as Exhibit ELP-1 (DJ-1).

Q. Have you testified before this Commission or as an expert in any other proceeding?

A. I have previously testified before the Michigan Public Service Commission ("Commission") in the following cases:

- Case U-17473 (Consumers Energy Company ("Consumers Energy" or "Company") Plant Retirement Securitization);
- Case U-17096-R (Indiana Michigan 2013 PSCR Reconciliation);
- Case U-17301 (Consumers Energy Renewable Energy Plan 2013 Biennial Review);

- Case U-17302 (DTE Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17317 (Consumers Energy 2014 PSCR Plan);
- Case U-17319 (DTE Electric 2014 PSCR Plan);
- Case U-17671-R (UPPCO 2015 PSCR Reconciliation);
- Case U-17674 (WEPCO 2015 PSCR Plan);
- Case U-17674-R (WEPCO 2015 PSCR Reconciliation);
- Case U-17679 (Indiana-Michigan 2015 PSCR Plan);
- Case U-17688 (Consumers Energy Cost of Service and Rate Design);
- Case U-17689 (DTE Electric Cost of Service and Rate Design);
- Case U-17698 (Indiana-Michigan Cost of Service and Rate Design);
- Case U-17735 (Consumers Energy General Rates);
- Case U-17752 (Consumers Energy Community Solar);
- Case U-17762 (DTE Electric Energy Optimization Plan);
- Case U-17767 (DTE General Rates);
- Case U-17792 (Consumers Energy Renewable Energy Plan Revision);
- Case U-17895 (UPPCO General Rates);
- Case U-17911 (UPPCO 2016 PSCR Plan);
- Case U-17911-R (UPPCO 2016 PSCR Reconciliation);
- Case U-17990 (Consumers Energy General Rates);
- Case U-18014 (DTE General Rates);
- Case U-18089 (Alpena Power PURPA Avoided Costs);
- Case U-18090 (Consumers Energy PURPA Avoided Costs);
- Case U-17911-R (UPPCO 2016 PSCR Reconciliation);

- Case U-18091 (DTE PURPA Avoided Costs);
- Case U-18092 (Indiana Michigan Power Company PURPA Avoided Costs);
- Case U-18093 (Northern States Power PURPA Avoided Costs);
- Case U-18094 (Upper Peninsula Power Company PURPA Avoided Costs);
- Case U-18095 (Wisconsin Public Service Company PURPA Avoided Costs);
- Case U-18096 (Wisconsin Electric Power Company PURPA Avoided Costs);
- Case U-18224 (UMERC Certificate of Necessity);
- Case U-18255 (DTE Electric General Rates);
- Case U-18322 (Consumers Energy General Rates);
- Case U-18406 (UPPCO 2018 PSCR Plan);
- Case U-18408 (UMERC 2018 PSCR Plan);
- Case U-18419 (DTE Certificate of Necessity);
- Case U-20111 (UPPCO Tax Cuts and Jobs Act of 2017 Adjustment);
- Case U-20134 (Consumers Energy 2018 General Rate Case);
- Case U-20150 (UPPCO Revenue Decoupling Mechanism Complaint).

Additionally, I have testified as an expert witness before the Public Utilities Commission of Nevada in Case No. 16-07001 concerning the 2017-2036 integrated resource plan of NV Energy; and before the Missouri Public Service Commission in Cases Nos. ER-2016-0179, ER-2016-0285, and ET-2016-0246 concerning residential rate design and electric vehicle ("EV") policy, revenue requirements, cost of service, and rate design. I testified before the Kentucky Public Service Commission in Case No. 2016-00370 concerning municipal street lighting rates and technologies. I testified before the Massachusetts Department of Public Utilities in Case Nos. DPU 17-05 and DPU 17-13 concerning EV charging infrastructure program design and cost recovery. Before the Rhode Island Public Utilities Commission, I testified concerning Advanced Metering Infrastructure and EV charging infrastructure in case 4780. Before the Delaware Public Service Commission, I testified regarding EV charging infrastructure in case 17-1094.

I have also testified as an expert witness on behalf of the State of Michigan before the Federal Energy Regulatory Commission ("FERC") in cases relating to the relicensing of hydro-electric generation and have participated in state and federal court cases on behalf of the State of Michigan, concerning electricity generation matters, which were settled before trial.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of ELPC regarding Consumers Energy’s proposals with respect to its obligations to contract with Qualifying Facilities (“QFs”) pursuant to the Public Utilities Regulatory Policies Act of 1978 (“PURPA”). For convenience of the reader, I duplicate related testimony concerning the Company’s proposal to competitively bid future generation resource needs which I submitted separately on behalf of MEC, NRDC, and SC and which ELPC endorses.

Q. Are you sponsoring any exhibits?

A. Yes. I have attached the following exhibits for review.

- Exhibit ELP-1 (DJ-1): Resume of Douglas Jester.

II. BACKGROUND AND CONTEXT

Q. Please summarize the major elements of this case from your perspective.

A. In this Integrated Resource Plan case, the Company proposes the following changes to its resource portfolio:

- Follow through on its previously announced termination of its Power Purchase Agreement for capacity and energy from the Palisades nuclear plant and the replacement of that capacity with a combination of energy waste reduction, demand response, and a PURPA Power Purchase Agreement contract with a Company affiliate for the capacity and energy from a gas cogeneration plant replacing the existing Filer City coal-fueled cogeneration plant;
- Retire its Karn 1 and 2 coal-fueled generating units in or around May 2023;
- Retire its Karn 3 and 4 peaking units in or around May 2031;
- Unilaterally extend its Midland Cogeneration Venture Power Purchase Agreement from 2025 through 2030 pursuant to the current contract and then terminate that Power Purchase Agreement in 2030;
- Retire its Campbell 1 and 2 coal-fueled generating units in or around May 2031;
- Retire its Campbell 3 coal-fueled generating unit in 2039 or 2040; and
- Replace these retired resources in advance of retirement through ramped implementation of a combination of Volt-VAR control with conservation voltage reduction, end-use energy waste reduction, demand response, 525 MW Michigan-based wind generation pursuant to its Renewable Energy Plan and an incremental 25 MW wind, and approximately 6,350 MW (nameplate) utility-scale solar. This includes 100 MW (nameplate) solar included in the Company's Renewable

Energy Plan pending approval in Case U-18231, 150 MW (nameplate) PURPA-contract solar ordered by the Commission in U-18090, and an additional 100 MW (nameplate) solar to be acquired before 2023.

In addition, the Company requests that the net book value and decommissioning costs of Karn 1 and 2 be rolled into a regulatory asset to be amortized through 2031, which would earn weighted average cost of capital on the regulatory asset's net value. The Company further proposes to competitively bid procurement of all generation resources going forward, conditional on a proposed Financial Compensation Mechanism allowing it to earn a return on Power Purchase Agreements. The Company also proposes a variety of changes in the standards for the Company's compliance with its obligation to purchase power from PURPA Qualified Facilities.

Consistent with 2016 PA 341, section 6t, the Company seeks cost approvals for those elements of its proposed course of action ("PCA") that are proposed to be implemented within three years of the final order in this case. These consist of

> (i) CVR deployment achieving a total peak load reduction of 44 MW (incremental 40 MW) by June 1, 2022 with a capital cost of $8,924,600 and a total Operations and Maintenance ("O&M") cost of $666,600; (ii) EWR increase from 1.5% to 2.0% per year achieving total EWR peak load reductions of 718 MW (incremental 52 MW from current EWR Plan) by June 1, 2022 with a capital cost of $0 and incremental O&M cost of $161,589,035; and (iii) DR expansion achieving total peak load reduction of 607 MW (an incremental 238 MW from 2019 levels proposed in the Company's pending electric rate case) by June 1, 2022 with a capital cost of $21,028,357 and a total O&M cost of $36,272,652.[1]

Q. Are you testifying as to the appropriateness of the Proposed Course of Action?

A. Only in a general sense. I find the Company's IRP to be generally persuasive as to an

[1] U-20165 Consumers Energy's Application, section 19, pages 10-11.

early 2020s retirement date for Karn 1 and 2 and the use of conservation voltage reduction ("CVR"), energy waste reduction ("EWR"), demand response ("DR"), wind generation, and solar generation to bring the Company into compliance with the renewable energy standard of 15% by 2021 and as replacement resources for the retirement of Karn 1 and 2. I have previously testified in various cases before this Commission that the Company should pursue additional CVR, EWR, DR, wind generation, and solar generation; the Company's proposals in this case are generally consistent with my prior testimony on these topics (though being implemented later than I previously advocated). However, I am not testifying to the specific quantities and costs of these resources that should be included in the PCA nor to the proposed cost approvals.

I am also persuaded that the Company's proposal to build up capacity through additional CVR, EWR, DR, and solar from 2022 onward in anticipation of future fossil resource retirements is sound. I am not persuaded by the Company's IRP that retirement of Campbell Units 1 and 2 should be delayed until 2031, nor that retirement of Campbell Unit 3 should be delayed until 2039 or 2040.

I am testifying on behalf of ELPC as to the appropriateness of the Company's proposals with respect to the Company's obligations to contract with Qualifying Facilities ("QFs") pursuant to the Public Utilities Regulatory Policies Act of 1978 ("PURPA").

Q. Are the Company's proposals with respect to its obligations to contract with Qualifying Facilities pursuant to the Public Utilities Regulatory Policies Act of 1978 ("PURPA") necessary for approval of the PCA?

A. No. Aside from the 150 MW (nameplate) PURPA contracts ordered by the Commission in U-18090, the Company does not propose to acquire resources through PURPA. However, it is possible that the Company's PURPA obligations would supersede the PCA by requiring the Company to acquire resources not included in the PCA and thereby either obviating some of the resource acquisition proposed by the Company or creating conditions for accelerated retirement of old resources such as Campbell 1 and 2.

III. COMPETITIVE BIDDING FOR FUTURE CAPACITY NEEDS (Filed On Behalf of MEC, NRDC, SC)

Q. Please explain in more detail the Company's proposal to use a competitive bidding process to address the Company's future capacity need.

A. The Company's proposal to use a competitive bidding process to address the Company's future capacity need is described in the testimony of Company Witness Troyer.[2] Mr. Troyer explains that the Company will issue a Request for Proposals ("RFP") prior to filing an IRP if the Company believes that it has a persistent need for capacity.[3] The RFP will be for a specific amount and type(s) of new generation capacity. Independent power producers may submit a proposal only for the specific type(s) of generation requested in the RFP. The RFP will be administered by a third party, which will allow Consumers Energy to submit proposals as well. The cost of any proposal subject to a FCM will be evaluated as including the FCM. "Proposals will be selected based on the criteria within the competitive solicitation and the attributes of the proposal including, but not limited to, performance standards, contract terms, technical competence, capability, reliability,

[2] U-20165. Direct Testimony of Keith G. Troyer, page 18, line 8 through page 20, line 9.
[3] In this testimony, I am not evaluating the Company's need for capacity, only the proposed method of procurement.

creditworthiness, past performance, and other applicable criteria."[4] According to Mr. Troyer, the solicitations will be tailored to the needs of the Company and may include "development asset acquisitions, build-transfer options, partnerships, joint ventures, and/or PPAs."[5]

Q. Do you recommend that the Commission approve this proposal?

A. The Commission should support using competitive bidding to address the Company's future capacity need. Reliance on a well-structured, fairly implemented competitive bidding process should lower the cost of acquiring needed resources and should not in any case increase costs (other than modest administrative costs for the competitive solicitation process). Further, the quantities of solar resources the Company contemplates acquiring in the period from 2022 through 2030 are large relative to the Company's existing project management capacity and likely cannot be developed as cost-effectively as can be done by soliciting help from the solar development industry.

However, the Company's proposal is flawed and incomplete, so the Commission should impose certain conditions on the proposal. Such conditions are especially important if the resulting contracts with independent producers are coupled with a Financial Compensation Mechanism or if the competitive bidding results are used to establish PURPA avoided costs.

Q. In what respects is the proposal flawed and incomplete?

A. Because it is incomplete, it is difficult to identify all flaws. Thus, my identification of

[4] Ibid, page 18, lines 19-22.
[5] Ibid, page 19, lines 6-8.

these is preliminary, but I discuss several below.

The Company does not specify the contract language that will be offered in its RFP. As the Commission well knows from its recent adjudication of the PURPA standard offer contract language in U-18090, contractual provisions can transfer risks and costs between the parties in ways that are material to the cost or viability of a project. These provisions can also effectively discriminate against an independent power producer vis-à-vis a proposal by the Company which will not have a specific contract. In order to rely on a competitive solicitation to determine the best option for resource acquisition, the Commission needs to ensure that the costs and risks to the Company's customers are commensurate when proposals are compared. In order to ensure that the request for proposals is not discriminatory, the Commission needs to ensure that the costs and risks that are compared between the Company's proposals and the proposals by independent power producers are reasonably equivalent.

In order to make a valid comparison between a Company-owned resource and a contract with an independent power producer, the contract duration must match the depreciation life that would apply to a comparable Company-owned resource. If contract duration is less than the Company's depreciation life, then the independent power producer will likely be in the position of having to recover its investment within the contract duration, increasing its required revenue rate during the contract as compared to the Company's proposal.

In this IRP, the Company primarily proposes to acquire utility-scale solar resources after implementation of its Renewable Energy Plan, which indicates that it will likely be acquiring solar generation through its competitive solicitation. The Company also indicates that it will solicit proposals prior to filing its next IRP and will use those proposals to fulfill up to three years of its perceived capacity needs.[6] The time lags between solicitation and commercial operation could be four to five years. The recent pace of change in costs of solar[7] suggests that this is simply too long a lead time for accurate costing and the Company should be acquiring resources in annual increments.

In its explanation of its proposed solicitation process, the Company posits that it will only ask for proposals if it perceives that it needs capacity. There is a very real possibility, particularly for wind generation in the near future, that a new resource would provide energy at a lower cost than generation from existing resources. Failure of the Company to solicit proposals because it does not "need capacity" could be more expensive for customers than acquiring new capacity based solely on its energy value or with minimal capacity value. The Company's predicate for soliciting proposals should be whether a new resource will be beneficial and not whether the Company "needs capacity."

In this IRP, the Company indicates that it will likely be acquiring solar generation through its competitive solicitation. In its current rate case, U-20134, the Company indicates intent to consider "non-wires alternatives" to distribution system investments.[8] Solar generation interconnected to the distribution system, either directly or behind a customer meter, is one option for "non-wires alternatives" but the Company has not described how it will incorporate this value of potential solar projects into its evaluation

[6] U-20165. Direct Testimony of Keith G. Troyer, page 18, lines 9-12

[7] Mark Bolinger, Joachim Seele. Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2018 Edition. Lawrence Berkeley National Laboratory.

[8] U-20134, Direct Testimony of Andrew J. Bordine, page 14, lines 9-12.

of generation resource proposals.

Finally, the Company's proposal is incomplete because it does not address the problems associated with the scope of an RFP. If the Company is quite specific in an RFP as to the technology it requires, then it is likely to forego beneficial proposals. On the other hand, if the Company is more general in the technology it will accept, the Company has not provided a clear and coherent method for evaluating proposals.

Q. Please explain your last point.

A. Suppose the Company solicits proposals for utility-scale solar projects through an RFP. The Company can do so by being very specific about the location(s) and configuration of the projects it wants. In that case, it is highly likely that some developers will have projects either in different locations or with different configurations that would provide greater value to Consumers Energy and its customers, but which would be excluded from consideration. On the other hand, if Consumers Energy solicits solar projects more generally and receives proposals for different locations or configurations, it has not adequately specified how selection will be made.

Optimum selection criteria are not obvious. For example, I used the National Renewable Energy Laboratory's System Advisor Model[9] to simulate the expected output from six different configurations of a 20 MW ground-mount solar array at the Grand Rapids airport weather station, using 2016 weather data. Those six configurations and the projected output are shown in the following table:

[9] Available from https://sam.nrel.gov/.

Scenario	Scenario Description			Array Type	Tilt[2] (degrees)	Azimuth (degrees)	Capacity Credit (ZRC)	Annual Energy (GWh)
A	Fixed panels	Tilted at latitude (approximately)	South	Fixed open rack	43	180	9.98	24.8
B	Fixed panels	Tilted at latitude (approximately)	Southwest	Fixed open rack	43	225	12.48	23.5
C	Fixed panels	Tilted at latitude (approximately)	West	Fixed open rack	43	270	12.56	19.8
D	Single axis-tracking	Horizontal		1 Axis Tracking	0	180	12.49	27.6
E	Single axis-tracking	Tilted at latitude (polar aligned)		1 Axis Tracking	43	180	12.10	29.3
F	Dual-axis tracking			2 Axis Tracking	43	180	13.05	32.3

Relative costs per unit nameplate capacity for these scenarios should be equal for scenarios A, B, and C and increase sequentially for scenarios D, E, and F. Thus, if Consumers Energy evaluates cost per nameplate capacity, it will choose one of scenarios A, B, or C even though scenarios D, E, and F may have more valuable output. If it wants to consider cost per unit output, it is unclear how it would do so. Scenario A has higher energy output but lower capacity credit than scenario B. Scenario E has higher energy output but lower capacity credit than scenario D. This analysis would be further complicated if the RFP allows integrated solar and storage to be proposed.

Q. How should Consumers Enegy choose amongst these kinds of options?

A. A bidding process requires a rank ordering of proposals in order to decide which ones to choose. With multiple outputs, it is necessary to construct a single metric by which to make this choice. There are two common methods that would make sense for Consumers Energy to use in this circumstance.

In the first method, Consumers would establish a nominal value for each output type, compute the total value of each proposal less the cost of the proposal and rank by the net value.

In the second method, Consumers would fix the value of one of the outputs and then rank proposals by the net cost of the other output after subtracting the value of the other output. So, for example, Consumers Energy could establish a value per unit capacity, calculate the cost of each proposal net of its capacity value, and then rank proposals on the net cost per unit of energy. Alternatively, Consumers Energy could establish a value per unit energy, calculate the cost of each proposal net of its energy value, and rank proposals on the net cost per unit of capacity.

Because capacity is a single value while energy is actually a measure of output at many different times (when that energy will have varying value), it is simpler to fix the value of capacity and rank proposals on the net cost of energy.

Q. In using either of these methods, how should the Company determine the value of one or more of the outputs?

A. The value of any output from one resource in its portfolio is just the avoided cost of obtaining that same output from the best alternative. This is fundamental economics and unrelated to PURPA.

Q. How do you recommend the Commission address the flaws and incompleteness that you have identified?

A. I recommend that the Commission require the Company to submit any proposed request for proposals to the Commission and that the Commission provide for stakeholder comment so that issues of this kind can be resolved in advance of issuance of the RFP. In that context, the Commission should assure that

(1) contract terms are reasonable for all parties and not unduly discriminatory as between independent power producers and Company-owned resources,

(2) contract duration and depreciation rates are comparable,

(3) RFP specifications are not too prescriptive, and

(4) selection criteria consider all significant benefits and costs including capacity, energy, avoided losses, and avoided or incurred transmission and distribution costs.

I further recommend that the Commission require the Company to conduct annual solicitations when the Company has anticipated resource needs.

IV. <u>CONSUMERS ENERGY'S PURPA PROPOSALS (On Behalf of ELPC)</u>

Q. Please explain in more detail the Company's proposals with respect to the Company's obligations to contract with Qualifying Facilities ("QFs") pursuant to the Public Utilities Regulatory Policies Act of 1978 ("PURPA").

A. The Company's position regarding its obligations to contract with QFs pursuant to

PURPA is primarily presented in the testimony of Company Witness Troyer.[10] He first correctly summarizes the Commission's considerations and decisions in U-18090 as of the time of the Company's filing in this case. He concludes his discussion of U-18090 by asserting that the avoided cost methodology determined by the Commission in U-18090 based on a natural gas combined cycle proxy plant is not reflective of the next generating unit the Company would acquire, as demonstrated by the PCA in this case, and should therefore be revised. He then compares the Company's avoided costs under U-18090 if applied to its current PPAs that likely qualify as QFs to recent costs for wind PPAs as a purported demonstration that the avoided cost established in U-18090 is excessive. He also discusses the strong response of the solar industry to the Commission's determination of avoided costs in U-18090 and again compares the potential costs per MWh from such solar facilities to the costs of recent wind PPAs. Mr. Troyer then proceeds to propose a number of changes from the Commission's decisions in U-18090 that the Company proposes to make in the present case.

Q. The Commission issued a final order in U-18090 on September 28, 2018 after the Company's Application and Mr. Troyer's testimony in the present case were filed. Did that order materially change the background assumptions presented by Mr. Troyer?

A. No.

[10] U-20165. Direct testimony of Keith G. Troyer, page 9, line 5 through page 41, line 11.

Q. Is Mr. Troyer correct in his claim that the Company's PCA in this case demonstrates that the Commission's determination of avoided costs in U-18090 should be revised?

A. Yes. The Commission's decisions about avoided costs in U-18090 were founded on an assumption shared by all parties that the Company's likely next resource would be a natural gas-fueled combined cycle plant. Changes in technology and fuel costs since that time have invalidated that assumption and it is appropriate to revise avoided costs to reflect the resources proposed in this IRP.

Q. Is Mr. Troyer's comparison of the implied avoided cost per MWh of its existing PPAs under the Commission's decisions in U-18090 to recent wind PPAs valid?

A. No. Those PPAs are for a variety of generation technologies, mostly not wind, that perform differently than wind with respect to capacity as measured by zonal resource credits, on-peak energy, and off-peak energy. They therefore have different avoided costs than does wind generation and this comparison is not valid.

Q. Is Mr. Troyer's comparison of the avoided cost per MWh for utility-scale solar in the Company's interconnection queue under the Commission's decisions in U-18090 to recent wind PPAs valid?

A. No. Solar generation provides a high amount of capacity relative to its energy output, while wind generation provides a high amount of energy relative to its capacity credit, so comparing the total avoided cost of a solar PPA on a per MWh basis to the total PPA cost of wind generation on a per MWh basis is not valid.

Q. What changes in PURPA policy as established in U-18090 does the Company propose?

A. The Company proposes to:

- Change the avoided cost calculation for new QFs so that when the Company has a capacity need avoided costs are based on the PCA in this case, specifically based on the results of competitive solicitations for PCA resources;
- Change the avoided cost calculation for new QFs so that when the Company does not have a capacity need avoided capacity costs are based on the annual MISO auction and the QF can choose either a 15-year contract based on actual locational marginal prices for energy in the MISO market or a 5-year contract based on forecast energy prices;
- Change the avoided cost calculation for new PURPA contracts for existing QFs so that avoided costs for capacity and energy are based on the PCA in this case, specifically based on the results of competitive solicitations for PCA resources;
- Reduce the period during which the Commission looks forward to determine that the Company has a capacity need from 10 years established in U-18090 to 3 years;
- If the Commission prefers to use a proxy plant rather than the results of competitive solicitation to determine avoided costs, the near-term avoided costs will be based on a blend of conservation voltage reduction, energy waste reduction, and demand response;
- If avoided costs are based on a renewable resource that conveys RECs to the Company and the QF does not convey RECs to the Company, then the market value of RECs are to be deducted from the energy price paid to QFs;
- Reduce the maximum system size that is eligible for a standard-offer tariff from 2

MW as established in U-18090 to 150 kW but to always compensate such QFs as though the Company has a capacity need; and

- Apply the Financial Compensation Mechanism ("FCM") proposed by the Company for PPAs to PURPA contracts.

Q. Do you support the Company's proposed changes to PURPA policy?

A. No. The net effect of the Company's proposals is grossly discriminatory against PURPA QFs. There are a few elements with which I can agree, but the fundamentals of their proposals do not comply with PURPA.

Q. Please summarize your assessment of the Company's proposals.

A. The Company's proposal to limit the determination of capacity need to consideration of three years forward will deny capacity compensation to all future PURPA contracts. The Company's proposals to deny capacity compensation to a QF that enters a PURPA contract when the Company does not have a current capacity need is unreasonable and inconsistent with the Company's own plans and practices. The Company's proposal to use competitive solicitation as the basis for determining avoided costs could be acceptable but the Company has failed to articulate an acceptable method to assign separate avoided costs to capacity, on-peak energy, and off-peak energy (or any other subcategorization of energy) that will properly reflect the different performance characteristics of the full range of technologies that can qualify as QFs. The Company's proposals concerning contract duration are discriminatory against QFs seeking PURPA contracts. The Company's proposal with respect to RECs is mostly reasonable but fails to give PURPA QFs the option to convey RECs to the Company in certain circumstances. Reducing the maximum system capacity that is eligible for a standard offer contract is functionally discriminatory against small generators. Under some circumstances, applying the FCM to PURPA contracts is inappropriate.

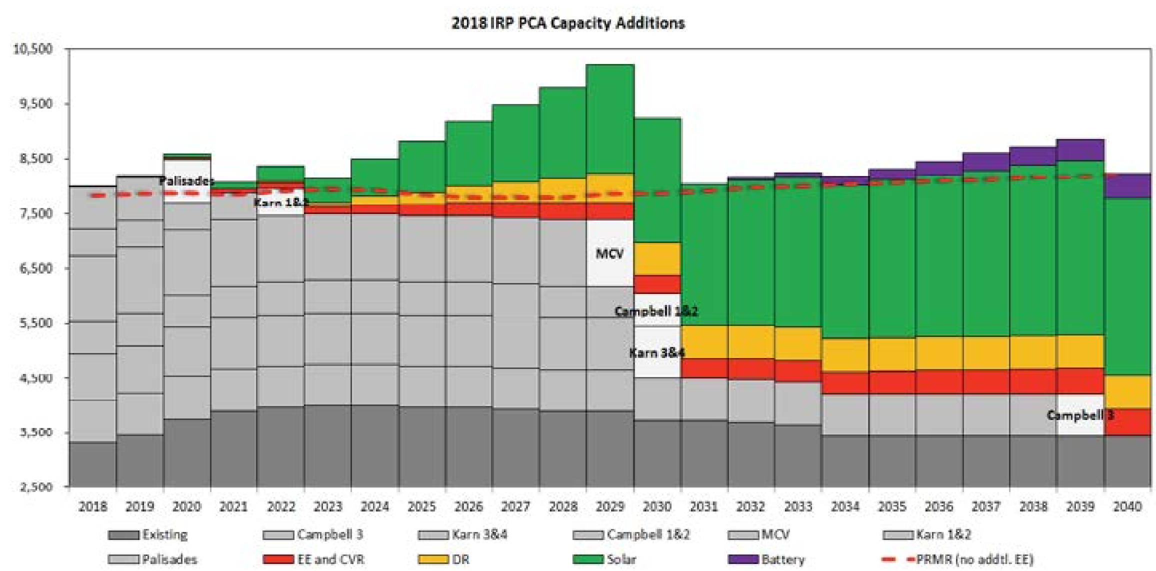
Q. Please explain why the Company's proposal to limit the determination of capacity need to consideration of three years forward will deny compensation to all future PURPA contracts.

A. Pursuant to the State Reliability Mechanism (MCL 460.6w), as implemented by the Commission in U-18197, all electric providers in the Company are obligated to demonstrate to the Commission that they have adequate resources to serve their customers 4 years forward. If the Company complies with this requirement and capacity need for PURPA purposes is determined by looking no more than 4 years forward, PURPA QFs will never be compensated for avoided capacity costs. This is an unreasonable result and likely violates PURPA.

Q. Please explain why the Company's proposal to deny capacity compensation to a QF that enters a PURPA contract when the Company does not have a current capacity need is unreasonable and inconsistent with the Company's own plans and practices.

A. Consumers Energy has an obligation to serve its customers reliably, which requires that it own or contract for sufficient capacity each year to meet its projected load plus a reserve margin. When Consumers Energy projects that it will fall short of sufficient capacity, it will then obtain another increment of capacity. However, new plants generally are built in capacity increments that are much larger than the forecasted annual increments and initiated several years in advance of need, due to decision and construction timelines. As a result Consumers Energy would expect to generally own or control capacity in excess of its needs. However, in the Commission's ratemaking cases, all of the costs of a new plant are subject to recovery whether or not the capacity is immediately needed and recovery of construction financing costs is generally allowed.

In this case, the Company does not propose to build in large capacity increments but proposes to ramp up capacity in anticipation of expected needs. The Company's IRP illustrates how this process works. Over the next couple of decades, expiration of large power purchase agreements and retirements will require the Company to add capacity to replace these agreements and retirements. The Company is proposing to add 6300 MW of solar generation and 550 MW of wind generation by 2040. The chart below, from the Company's IRP, illustrates how these capacity additions are built in advance to ensure reliability once power purchase agreements expire or generating resources retire:



Thus, the Company would be acquiring generation capacity through means other than PURPA contracts throughout the period from 2022 through 2040 but during this time would never "need capacity".

To the extent that the Company plans to ramp-up capacity in anticipation of subsequent resource retirements, the Company proposes to issue RFPs for that capacity in 3-year tranches in conjunction with IRP updates, so even if the Commission interprets "capacity need" as including the Company's proposed ramp-up of capacity in anticipation of retirements, PURPA contracts will rarely be eligible for avoided capacity costs. The Company will nearly always have surplus capacity and would therefore claim that it need not pay qualifying facilities the avoided cost of new capacity. When the Company acquires additional capacity, through either power supply agreements or building new generating facilities, its contracted capacity will typically be in excess of any immediate needs due to the lumpiness of their preferred procurement. The Company will then have a capacity surplus for a number of years, and could claim that they have no need for capacity from PURPA qualifying facilities. Then, when capacity is once again projected to be needed, the Company will again acquire excess capacity beyond immediate needs and the cycle will be repeated.

As a result, under the Company's proposed definition of "capacity need," it will never have a capacity need because it plans to acquire capacity additions far in advance of projected needs. Most importantly, these future plans to acquire capacity can be deferred or avoided by qualifying facilities, and that is one of the goals of PURPA.

The Company's proposal to not take into account its own plans to acquire future capacity additions when determining whether a capacity need exists will discriminate against qualifying facilities because they will never be able to obtain full avoided capacity costs even though they could defer or avoid the Company's future capacity additions.

Q. Do you support the Company's proposal to ramp-up replacement capacity in anticipation of future capacity retirements?

A. I do. The Company's analysis of the costs, benefits, and risks of this approach is persuasive to me. However, I acknowledge the Company's concerns that under the Commission's decisions in U-18090, the Company could be found to "need capacity" in the full amount of a future retirement 10 years before that retirement and that this could produce undesirable results. In general, it would be appropriate for the Commission to address such a circumstance by assuming a ramp-up of replacement capacity rather than that full replacement of the future retirement can occur 10 years in advance of the retirement. In this case, it would be reasonable to adopt the Company's ramp-up schedule or any modification of that schedule that results from the Commission's examination of the IRP.

Q. How would you determine whether the Company has a capacity need?

A. I would simply look to see if there are any future capacity additions that can be deferred or avoided, and I would also see if there is a projected shortfall between capacity supply and projected load plus reserve margin.

Q. Where would you draw the line between a future capacity addition that can be deferred or avoided and a future capacity addition that cannot be deferred or avoided?

A. I think a good dividing line is whether or not the Commission has approved cost recovery for future capacity additions. For example, the Company typically requires multiple years of time between initial Commission approval of a generating resource until that resource is constructed and begun operation. It would be unfair to customers and the Company to argue that a capacity addition with cost recovery approved is still "deferable." Conversely, a planned future capacity addition that is projected to begin operation in the future but has not yet been approved by the Commission can be deferred or avoided by incremental qualifying facility contracting. This approach would be more workable if, as I earlier recommended, the Company's competitive solicitation to meet its capacity needs is done in an annual rather than 3-year cycle.

Q. How should the Commission determine avoided capacity costs when there are future but not immediate capacity additions that can be deferred or avoided as a result of PURPA contracts?

A. It will be most useful for the Commission to think about avoided capacity costs in tranches based on the years and resource types that are planned. For example, based on the Company's IRP in the current case, there will be a quantity of solar capacity additions planned for each year from 2022 forward. Avoided capacity costs should be determined differently for PURPA contracts that replace capacity the Company would acquire in 2022 than for PURPA contracts that would replace capacity the Company would acquire in 2023, etc.. If two different types of resources are planned to be acquired in the same year, avoided costs might be separately determined for each of those resource types even though they are to be acquired in the same year. Thus, the Commission would not base avoided costs on whether the Company has a capacity need but rather on when it will have a capacity need.

The simplest way to do this consistent with the Commission's reasoning in U-18090 would be to compensate a new QF based on actual or projected market capacity value (in the MISO PRA) until the year in which the QF defers or replaces planned capacity and then compensate based on projected avoided capacity costs in that year and thereafter. Indeed, this is the only logical way to determine avoided costs for a resource whose capacity the Company currently does not need but whose capacity is needed during the life-cycle of the QF.

Q. Please explain how the Company has failed to articulate an acceptable method to assign separate avoided costs to capacity, on-peak energy, and off-peak energy (or any other subcategorization of energy) that will properly reflect the different performance characteristics of the full range of technologies that can qualify as QFs.

A. In his discussion of the Company's proposal to use the results of competitive solicitation to determine avoided costs for PURPA contracts,[11] Mr. Troyer says that

> The proposals selected will be used to establish a capacity clearing price and energy price based on the highest cost proposal selected as part of the solicitation. The Company will use the highest cost proposal selected as the basis for the proposed avoided costs in the next IRP filing.

He does not explain how the capacity clearing price and energy price will be determined from either the single highest-cost proposal or the body of proposals received in the solicitation. As I explained earlier, it may not even be possible to unambiguously compare and rank a variety of solar generation proposals in a competitive solicitation because of the variety of mixtures of capacity and energy that could be produced from a project of a given size. PURPA QFs seeking contracts cannot be limited to a single generation technology such as solar, so will have an even wider range of performance characteristics. It is thus critically important that the method used to establish the separate

[11] U-20165. Direct testimony of Keith G. Troyer, page 18, lines 4-7.

avoided costs for capacity and energy be carefully designed so as not to produce distorted results.

Q. How should the Commission establish avoided costs in a way that allows the determination of avoided costs for a variety of QF technologies?

A. Albeit the Commission's use of a combined cycle gas plant as a proxy in U-18090 has been overcome by events, the hybrid model adopted by the Commission to separate pure capacity costs from the total costs of a combined cycle plant and assign the remaining costs to energy was conceptually sound and can be applied in future. It will be necessary to identify the resource the Commission will use as a "pure capacity" resource and determine the annual avoided cost of that resource per zonal resource credit and then subtract that avoided cost from the total cost of the highest cost proposal selected in the competitive solicitation to determine the cost of energy for that proposal.

At the present time, it may still be appropriate to use the Cost of New Entry ("CONE") of a combustion turbine as the avoided cost of capacity, but it is likely that at some point in the future that cost will need to be based on another technology, such as solar. The need to make this change will become apparent when the net cost (after subtracting avoided capacity value based on CONE) of energy is very low or negative. The Commission should note that the value of CONE has changed since its decisions in U-18090 because of changes in technology costs and the change in corporate tax rates adopted in the Tax Cuts and Jobs Act of 2017. MISO determined that 2018/19 CONE for zone 7, in which Consumers Energy operates is $248.60/MW-day or $90,739/MW-yr. If we assume a forced outage rate of 8% for the reference combustion turbine, this establishes a CONE value of about $98,629/ZRC which is considerably less than the $140,505 per ZRC established in U-18090. Although this calculation shows that CONE can change significantly from time-to-time, historically it has been relatively stable aside from inflation. It would therefore be appropriate to use the current value of CONE to establish the avoided cost of capacity a few years hence for a QF that is placed in a tranche of capacity that is only needed in a few years.

Consistent use of CONE as a measure of avoided capacity cost, until such time as a combustion turbine ceases to be the least-cost "pure capacity" resource would also be an appropriate way to enable the comparison of proposals in a competitive solicitation where those proposals produce varying ratios of capacity and energy.

Q. Do you accept the Company's proposal to establish avoided energy costs when the Company does not need capacity?

A. No. First, as I have testified, I do not think that a bright line between "needs capacity" and "does not need capacity" is a sensible concept for establishing avoided costs in the current context. Instead, avoided costs should be based on when capacity is needed.

Second, there is no logical basis to value energy differently for a QF that meets a present capacity need from a QF that does not meet a present capacity need. Avoided energy costs should be the actual or projected marginal cost of energy without regard to how much the QF is paid for capacity. The Commission should apply exactly the same avoided energy cost method and values in either case.

Q. Please explain why the Company's proposals concerning contract duration are discriminatory against QFs seeking PURPA contracts.

A. If the Company builds or acquires a generation resource, it is placed on a depreciation schedule. The Company recovers its investment over the entire depreciation period. In order to be able to compete successfully against Company-ownership in a competitive solicitation, an independent power producer seeking a PPA will need contract duration approximating the Company's depreciation period for a competing and similar resource. I therefore earlier recommended just such parity in the competitive solicitation process proposed by the Company. Similarly, a PURPA QF will need to be able to recover its investment during the term of a PURPA contract. Thus, for the Company to impose contract duration on a PURPA contract that is significantly less than the contract duration or depreciation period of the resource used to establish avoided costs is discriminatory and unreasonable. Mr. Troyer argues that the contract duration should not exceed 15 years even for QFs that accept market rates, because the Company's customers are exposed to market changes.[12] Of course, those same market changes impinge on the value of resources owned by the Company, but the Company does not consequently propose to depreciate its assets over a period of 15 years or less.

The Company further proposes to limit to 5 years the duration of PURPA contracts established when the Company does not need capacity and where the QF chooses to use a fixed future schedule of energy prices. There is simply no basis for treating such contracts differently than PURPA contracts which fulfill a capacity need, as they are no more likely to be "out of market" and are subject to the same requirement that they not be

[12] U-20165. Direct testimony of Keith G. Troyer, page 35 lines 15-18

unduly discriminatory.

The "problem" the Company is trying to solve is that in later years of a PPA, costs may not align well with then current costs of new generation. That problem, however, does not result from contract duration but from the fact that the Company's recovery of costs is front-loaded in the life-cycle of a Company-owned resource while by the Company's choice PPAs are either levelized or back-loaded. If the Company wishes to address the risk that prices in later years of a PPA may not align well with then current costs of new generation, it can propose to front-load PPA payments.

Q. What do you recommend that the Commission decide with respect to PURPA contract duration?

A. The Commission made the right decision in U-18090 and the Company has not presented new arguments on this subject. The Commission should affirm its decision in U-18090 that the QF can choose contract duration of up to 20 years. The Commission could and should allow a longer duration if Company depreciation schedules or contract duration in competitive solicitation is significantly longer.

Q. Do you have an opinion on the Company's proposal with respect to RECs?

A. The Company's proposal with respect to RECs is mostly reasonable but fails to give PURPA QFs the option to convey RECs to the Company in certain circumstances. In U-18090, the Commission determined that avoided costs were based on a non-renewable resource and therefore that RECs should belong to the QF unless separately contracted for by the Company. The core of Mr. Troyer's discussion of RECs is as follows

> … if the full avoided costs are based on a competitive solicitation that requests proposals from a renewable resource, the Company's obligation to buy from

> renewable QFs hinders our ability to provide renewable energy to our customers by displacing resources that would have added to the Company's REC supply. Therefore, the energy avoided costs should be reduced by the market value of the RECs produced by the QF so that the Company can procure an equivalent number of unbundled RECs from the market.[13]

His analysis is correct, except that he fails to address the obvious solution, which is to give the QF a choice of whether to convey RECs or not and to make the appropriate adjustment in the avoided cost, depending on whether the avoided cost is based on a resource in which RECs are or are not bundled with energy.

Q. What do you recommend that the Commission decide regarding RECs?

A. I recommend that the Commission decide that if avoided costs of energy are based on a resource that bundles RECs with energy, then RECs are deemed to be included in the avoided cost and if the QF wants to retain them, the avoided cost will be reduced by the market value of the RECs. On the other hand, if the avoided cost for energy is based on a resource that does not bundle RECs with energy, the RECs are deemed not included in the avoided cost and if the Company wants to obtain the RECs, then it must purchase them at an additional cost agreed between the parties.

Q. Please explain why reducing the maximum system capacity that is eligible for a standard offer contract is functionally discriminatory against small generators.

A. Negotiating a contract with the Company will have a transaction cost, regardless of the size of the system for which a PURPA contract is sought. That transaction cost likely has a large fixed element that is not dependent on the size of the system. Spreading that cost over the output of a small system has a much more adverse effect on the economics of

[13] U-20165. Direct testimony of Keith G. Troyer, page 38, lines 15-21.

such a contract than when the cost is spread over the output of a larger system. This proposal is therefore functionally discriminatory.

In U-18090, the Commission decided that standard-offer contracts would be available up to 2 MW. Mr. Troyer makes the argument in this case that

> Standard Offer Tariff rates are most appropriate for small developers and customers that lack the experience and resources needed for larger forays into the electricity generation business. The current Standard Offer Tariff size extends to developers who have significant experience and resources that do not need to have their contracting facilitated through a Standard Offer Tariff.

He provides no justification for his predicate that the Standard Offer tariff is "most appropriate for small developers and customers that lack the experience and resources needed for larger forays into the electricity generation business." Nor does he make any argument against the proposition that standard offer contracts usefully reduce transaction costs for the QF, the Company, and the Commission.

Q. What do you recommend that the Commission decide with respect to the maximum system size for which a standard offer contract is available?

A. I recommend that the Commission increase the maximum size for a standard-offer contract to at least 3 MW. 2016 PA 341, paragraph 6v.(4)(e) provides that an order issued by the Commission establishing PURPA avoided cost rates shall do the following…

> (e) Require electric utilities to publish on their websites template contracts for power purchase agreements for qualifying facilities of less than 3 megawatts that need not include terms for either price or duration of the contract. The terms of a template contract published under this subsection are not binding on either an electric utility or a qualifying facility and may be negotiated and altered upon agreement between an electric utility and a qualifying facility.

Aside from not specifying the price or duration of the contract, this is tantamount to a standard-offer contract for systems up to 3 MW capacity.

With respect to avoided cost, I recommend that the Commission accept the Company's proposal that avoided costs for systems under 150 kW include avoided capacity costs regardless of when or if the Company might need capacity, for the reasons presented by Mr. Troyer. Avoided costs for standard-offer contracts between 150 kW and 3 MW should be determined in the same manner as avoided costs outside standard-offer contracts.

Q. Do you support the way in which the FCM will be considered and applied to PURPA contracts, as described by Mr. Troyer?

A. Under some circumstances the application of the FCM to PURPA contracts is problematic. Assume that the Commission determines that PURPA avoided costs in certain circumstances should be based on the costs determined through competitive solicitation for new resources. If the marginal resources that set the clearing price in the competitive solicitation are PPA resources and subject to the FCM, then applying the FCM to a PURPA contract and setting PURPA avoided costs base on the bid price of the marginal resource would be appropriate.

However, if the marginal resources that set the clearing price in the competitive solicitation are not PPA resources and are not subject to the FCM, then applying the FCM to a PURPA contract and reducing the payments to the PURPA QF by the amount of the FCM would result in the PURPA QF being paid less than the Company's full avoided cost. Paying the PURPA QF the full cost of the marginal resource in the competitive solicitation and also authorizing the Company to receive the FCM incentive would result in customers paying more as a result of the PURPA contract than without the PURPA contract. The only way to reconcile the FCM with PURPA in the case where the marginal resource used to set avoided costs is not a PPA that triggers the FCM is to pay full avoided cost to the PURPA QF and not authorize the Company to earn incentive compensation on that PURPA contract.

Since the Company is legally obligated to contract with QFs pursuant to PURPA, there is no rationale for PPA incentive compensation anyway.

V. <u>RECOMMENDATIONS AND CONCLUSION</u>

Q. Please summarize your recommendations to the Commission.

A. With respect to the Company's obligation under PURPA to contract with qualifying facilities for energy and capacity, I recommend that the Commission:

1. Deny the Company's proposals to determine that capacity is "needed" or "not needed" based on a 3-year forward look;
2. Identify capacity need in tranches based on when it is needed and compensate capacity at actual or projected MISO PRA rates until the time when the capacity is needed and at avoided capacity cost thereafter;
3. Determine capacity need for replacement of future resource retirements on a ramped basis, using the Company's proposed ramping plan in the current case or as adjusted by the Commission in its evaluation of the IRP;

4. Continue to use cost of new entry of a combustion turbine per ZRC as the avoided cost of capacity, until an alternative technology is demonstrated to be the lower cost capacity resource;
5. Base the avoided cost of energy for purposes of PURPA contracts on the cost of competitively determined resources net of avoided capacity costs, without regard to whether capacity is "needed" at the time the PURPA contract is established;
6. Continue to require that PURPA contract duration be determined by the QF up to the same duration as is offered in competitive solicitations, without regard to whether capacity is "needed" at the time the PURPA contract is established;
7. Accept the Company's proposal to adjust energy pricing for REC prices based on whether RECs are or are not bundled with energy in the resources used to determine avoided costs, but allow the PURPA QF to determine whether RECs will or will not be conveyed to the Company at the offered price;
8. Increase the maximum system capacity eligible for a standard offer contract to 3 MW; and
9. Allow the Company to earn PPA incentive on PURPA contracts if and only if the reference resource used to determine avoided costs provides the Company a PPA incentive, but do not allow the Company to earn PPA incentive if the reference resource is not eligible for the PPA incentive.

Finally, while it is appropriate for the Commission to establish PURPA policy in this and future IRP proceedings, because of the pace of change in generation technologies and costs, I recommend that the Commission follow its previous determination to review PURPA avoided costs every two years. I further recommend that the Commission include in that same proceeding the review of the Company's competitive solicitation RFP and contract language and the level of PPA incentives. These issues are closely linked and will generally be of interest to the same potential parties.

Q. Does that complete your testimony?

A. Yes.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief	)))))	Case No. U-20165

EXHIBIT OF DOUGLAS JESTER

ON BEHALF OF ENVIRONMENTAL LAW & POLICY CENTER,

VOTE SOLAR AND THE ECOLOGY CENTER

OCTOBER 15, 2018

Douglas B. Jester

Personal Information

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Professional experience

January 2011 – present 5 Lakes Energy
Partner

Co-owner of a consulting firm working to advance the clean energy economy in Michigan and beyond. Consulting engagements with foundations, startups, and large mature businesses have included work on public policy, business strategy, market development, technology collaboration, project finance, and export development concerning energy efficiency, smart grid, renewable generation, electric vehicle infrastructure, and utility regulation and rate design. Policy director for renewable energy ballot initiative and Michigan energy legislation advocacy. Supported startup of the Energy Innovation Business Council, a trade association of clean energy businesses. Expert witness in utility regulation cases. Developed integrated resource planning models for use in ten states' compliance with the Clean Power Plan.

February 2010 - December 2010 Michigan Department of Energy, Labor and Economic Growth
Senior Energy Policy Advisor

Advisor to the Chief Energy Officer of the State of Michigan with primary focus on institutionalizing energy efficiency and renewable energy strategies and policies and developing clean energy businesses in Michigan. Provided several policy analyses concerning utility regulation, grid-integrated storage, performance contracting, feed-in tariffs, and low-income energy efficiency and assistance. Participated in Pluggable Electric Vehicle Task Force, Smart Grid Collaborative, Michigan Prosperity Initiative, and Green Partnership Team. Managed development of social-media-based community for energy practitioners. Organized conference on Biomass Waste to Energy.

August 2008 - February 2010 Rose International
Business Development Consultant - Smart Grid

- Employed by Verizon Business' exclusive external staffing agency for the purpose of providing business and solution development consultation services to Verizon Business in the areas of Smart Grid services and transportation management services.

December 2007 - March 2010 Efficient Printers Inc

President/Co-Owner

- Co-founder and co-owner with Keith Carlson of a corporation formed for the purpose of acquiring J A Thomas Company, a sole proprietorship owned by Keith Carlson. Recognized as Sacramento County (California) 2008 Supplier of the Year and Washoe County (Nevada) Association for Retarded Citizens 2008 Employer of the Year. Business operations discontinued by asset sale to focus on associated printing software services of IT Services Corporation.

August 2007 - present IT Services Corporation

President/Owner

- Founder, co-owner, and President of a startup business intended to provide advanced IT consulting services and to acquire or develop managed services in selected niches, currently focused on developing e-commerce solutions for commercial printing with software-as-a-service.

2004 – August 2007 Automated License Systems

Chief Technology Officer

- Member of four-person executive team and member of board of directors of a privately-held corporation specializing in automated systems for the sale of hunting and fishing licenses, park campground reservations, and in automated background check systems. Executive responsible for project management, network and data center operations, software and product development. Brought company through mezzanine financing and sold it to Active Networks.

2000 - 2004 WorldCom/MCI

Director, Government Application Solutions

- Executive responsible in various combinations for line of business sales, state and local government product marketing, project management, network and data center operations, software and product development, and contact center operations for specialized government process outsourcing business. Principal lines of business were vehicle emissions testing, firearm background checks, automated hunting and fishing license systems, automated appointment scheduling, and managed application hosting services. Also responsible for managing order entry, tracking, and service support systems for numerous large federal telecommunications contracts such as the US Post Office, Federal Aviation Administration, and Navy-Marine Corps Intranet.
- Increased annual line-of-business revenue from $64 million to $93 million, improved EBITDA from approximately 2% to 27%, and retained all customers, in context of corporate scandal and bankruptcy.
- Repeatedly evaluated in top 10% of company executive management on annual performance evaluations.

1999-2000 Compuware Corporation

Senior Project Manager

- Senior project manager, on customer site with five project managers and team of approximately 80, to migrate a major dental insurer from a mainframe environment to internet-enabled client-server environment.

1995 - 1999 City of East Lansing, Michigan

Mayor and Councilmember

- Elected chief executive of the City of East Lansing, a sophisticated city of 52,000 residents with a council-manager government employing about 350 staff and with an annual budget of about $47 million. Major accomplishments included incorporation of public asset depreciation into budgets with consequent improvements in public facilities and services, complete rewrite and modernization of city charter, greatly intensified cooperation between the City of East Lansing and the East Lansing Public Schools, significant increases in recreational facilities and services, major revisions to housing code, initiation of revision of the City Master Plan, facilitation of the merger of the Capital Area Transportation Authority and Michigan State University bus systems, initiation of a major downtown redevelopment project, City government efficiency improvements, and numerous other policy initiatives. Member of Michigan Municipal League policy committee on Transportation and Environment and principal writer of league policy on these subjects (still substantially unchanged as of 2009).

1995-1999 Michigan Department of Natural Resources

Chief Information Officer

- Executive responsibility for end-user computing, data center operations, wide area network, local area network, telephony, public safety radio, videoconferencing, application development and support, Y2K readiness for Departments of Natural Resources and Environmental Quality. Directed staff of about 110. Member of MERIT Affiliates Board and of the Great Lakes Commission's Great Lakes Information Network (GLIN) Board.

1990-1995 Michigan Department of Natural Resources

Senior Fisheries Manager

- Responsible for coordinating management of Michigan's Great Lakes fisheries worth about $4 billion per year including fish stocking and sport and commercial fishing regulation decisions, fishery monitoring and research programs, information systems development, market and economic analyses, litigation, legislative analysis and negotiation. University relations. Extensive involvement in regulation of steam electric and hydroelectric power plants.
- Served as agency expert on natural resource damage assessment, for all resources and causes.
- Considerable involvement with Great Lakes Fishery Commission, including:
  - Co-chair of Strategic Great Lakes Fishery Management Plan working group

- o Member of Lake Erie and Lake St. Clair Committees
- o Chair, Council of Lake Committees
- o Member, Sea Lamprey Control Advisory Committee
- o St Clair and Detroit River Areas of Concern Planning Committees

1989-1990 American Fisheries Society

Editor, North American Journal of Fisheries Management

- Full responsibility for publication of one of the premier academic journals in natural resource management.

1984 - 1989 Michigan Department of Natural Resources

Fisheries Administrator

- Assistant to Chief of Fisheries, responsible for strategic planning, budgets, personnel management, public relations, market and economic analysis, and information systems. Department of Natural Resources representative to Governor's Cabinet Council on Economic Development. Extensive involvement in regulation of steam electric and hydroelectric power plants.

1983-present Michigan State University

Adjunct Instructor

- Irregular lecturer in various undergraduate and graduate fisheries and wildlife courses and informal graduate student research advisor in fisheries and wildlife and in parks and recreation marketing.

1977 – 1984 Michigan Department of Natural Resources

Fisheries Research Biologist

- Simulation modeling & policy analysis of Great Lakes ecosystems. Development of problem-oriented management records system and "epidemiological" approaches to managing inland fisheries.
- Modeling and valuation of impacts power plants on natural resources and recreation.

Education

1991-1995 Michigan State University
PhD Candidate, Environmental Economics
Coursework completed, dissertation not pursued due to decision to pursue different career direction.

1980-1981 University of British Columbia
Non-degree Program, Institute of Animal Resource Ecology

1974-1977 Virginia Polytechnic Institute & State University
MS Fisheries and Wildlife Sciences
MS Statistics and Operations Research

1971-1974 New Mexico State University
BIS Mathematics, Biology, and Fine Arts

Citizenship and Community Involvement	Youth Soccer Coach, East Lansing Soccer League, 1987-89
	Co-organizer, East Lansing Community Unity, 1992-1993
	Bailey Community Association Board, 1993-1995
	East Lansing Commission on the Environment, 1993-1995
	East Lansing Street Lighting Advisory Committee, 1994
	Councilmember, City of East Lansing, 1995-1999
	Mayor, City of East Lansing, 1995-1997
	East Lansing Downtown Development Authority Board Member, 1995-1999
	East Lansing Transportation Commission, 1999-2004
	East Lansing Non-Profit Housing and Neighborhood Services Corporation Board Member, 2001-2004
	Lansing – East Lansing Smart Zone Board of Directors, 2007-present
	Council on Labor and Economic Growth, State of Michigan, by appointment of the Governor, May 2009 – May 2012
	East Lansing Downtown Development Authority Board Member and Vice-Chair, 2010 – present.
	East Lansing Brownfield Authority Board Member and Vice-Chair, 2010 – present.
	East Lansing Downtown Management Board and Chair, 2010 – 2016
	East Lansing City Center Condominium Association Board Member, 2015 – present.

Douglas Jester
Specific Energy-Related Accomplishments

Unrelated to Employment

- Member of Michigan SAVES initial Advisory Board. Michigan SAVES is a financing program for building energy efficiency measures initiated by the State of Michigan Public Service Commission and administered under contract by Public Sector Consultants. Program launched in 2010.
- Member of Michigan Green Jobs Initiative, representing the Council for Labor and Economic Growth.
- Participated in Lansing Board of Water and Light Integrated Resource Planning, leading to their recent completion of a combined cycle natural gas power plant that also provides district heating to downtown Lansing.
- In graduate school, participated in development of database and algorithms for optimal routing of major transmission lines for Virginia Electric Power Company (now part of Dominion Resources).
- Commissioner of the Lansing Board of Water and Light, representing East Lansing. December 2017 – present.

For 5 Lakes Energy

- Participant by invitation in the Michigan Public Service Commission Smart Grid Collaborative, authoring recommendations on data access, application priorities, and electric vehicle integration to the grid.
- Participant by invitation in the Michigan Public Service Commission Energy Optimization Collaborative, a regular meeting and action collaborative of parties involved in the Energy Optimization programs required of utilities by Michigan law enacted in 2008.
- Participant by invitation in Michigan Public Service Commission Solar Work Group, including presentations and written comments on value of solar, including energy, capacity, avoided health and environmental damages, hedge value, and ancillary services.
- Participant by invitation in Michigan Senate Energy and Technology Committee stakeholder work group preliminary to introduction of a comprehensive legislative package.
- Participant by invitation in Michigan Public Service Commission PURPA Avoided Cost Technical Advisory Committee.
- Participant by invitation in Michigan Public Service Commission Standby Rate Working Group.
- Participant by invitation in Michigan Public Service Commission Street Lighting Collaborative.
- Participant by invitation in State of Michigan Agency for Energy Technical Advisory Committee on Clean Power Plan implementation.
- Conceived, obtained funding, and developed open access integrated resource planning tools (State Tool for Electricity Emissions Reduction aka STEER) for State compliance with the Clean Power Plan:
  - For Energy Foundation - Michigan and Iowa
  - For Advanced Energy Economy Institute – Arkansas, Florida, Illinois, Ohio, Pennsylvania, Virginia
  - For The Solar Foundation - Georgia and North Carolina
- Presentations to Michigan Agency for Energy and the Institute for Public Utilities Michigan Forum on Strategies for Michigan to Comply with the Clean Power Plan.
- Participant in Midcontinent Independent Systems Operator stakeholder processes on behalf of Michigan Citizens Against Rate Excess and the MISO Consumer Representatives Sector, including Resource Adequacy Committee, Loss of Load Expectation Working Group, Transmission Expansion Working Group, Demand Response Working Group, Independent Load Forecasting Working Group, and Clean Power Plan Working Group.
- Expert witness before the Michigan Public Service Commission in various cases, including:

- Case U-17473 (Consumers Energy Plant Retirement Securitization)
- Case U-17096-R (Indiana Michigan 2013 PSCR Reconciliation)
- Case U-17301 (Consumers Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17302 (DTE Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17317 (Consumers Energy 2014 PSCR Plan);
- Case U-17319 (DTE Electric 2014 PSCR Plan);
- Case U-17674 (WEPCO 2015 PSCR Plan);
- Case U-17679 (Indiana-Michigan 2015 PSCR Plan);
- Case U-17689 (DTE Electric Cost of Service and Rate Design);
- Case U-17688 (Consumers Energy Cost of Service and Rate Design);
- Case U-17698 (Indiana-Michigan Cost of Service and Rate Design);
- Case U-17762 (DTE Electric Energy Optimization Plan);
- Case U-17752 (Consumers Energy Community Solar);
- Case U-17735 (Consumers Energy General Rates);
- Case U-17767 (DTE General Rates);
- Case U-17792 (Consumers Energy Renewable Energy Plan Revision);
- Case U-17895 (UPPCO General Rates);
- Case U-17911 (UPPCO 2016 PSCR Plan);
- Case U-17990 (Consumers Energy General Rates); and
- Case U-18014 (DTE General Rates);
- Case U-17611-R (UPPCO 2015 PSCR Reconciliation);
- Case U-18089 (Alpena Power PURPA Avoided Costs);
- Case U-18090 (Consumers Energy PURPA Avoided Costs);
- Case U-18091 (DTE PURPA Avoided Costs);
- Case U-18092 (Indiana Michigan Electric Power PURPA Avoided Costs);
- Case U-18093 (Northern States Power PURPA Avoided Costs);
- Case U-18094 (Upper Peninsula Power Company PURPA Avoided Costs);
- Case U-18095 (UMERC PURPA Avoided Costs);
- Case U-18224 (UMERC Certificate of Necessity);
- Case U-18255 (DTE General Rate Case);
- Case U-18322 (Consumers Energy General Rate Case).

➢ Expert witness before the Public Utilities Commission of Nevada in
  - Case 16-07001 (NV Energy 2017-2036 Sierra Pacific Integrated Resource Plan)

➢ Expert witness before the Missouri Public Service Commission in
  - Case ER-2016-0179 (Ameren Missouri General Rate Case)
  - Case ER-2016-0285 (KCP&L General Rate Case)
  - Case ET-2016-0246 (Ameren Missouri EV Policy)

➢ Expert witness before the Kentucky Public Service Commission
  - Case 2016-00370 (Kentucky Utilities General Rate Case)

➢ Expert witness before the Massachusetts Department of Public Utilities in
  - Case 17-05 (Eversource General Rate Case)
  - Case 17-13 (National Grid General Rate Case)

➢ Coauthored “Charge without a Cause: Assessing Utility Demand Charges on Small Customers”

➢ Currently under contract to the Michigan Agency for Energy to develop a Roadmap for CHP Market Development in Michigan, including evaluation of various CHP technologies and applications using STEER Michigan as an integrated resource planning tool.

➢ Under contract to NextEnergy, authored “Alternative Energy and Distributed Generation” chapter of Smart Grid Economic Development Opportunities report to Michigan Economic Development Corporation and assisted authors of chapters on “Demand Response” and “Automated Energy Management Systems”.

➢ Developed presentation on “Whole System Perspective on Energy Optimization Strategy” for Michigan Energy Optimization Collaborative.

➢ Under contract to NextEnergy, assisted in development of industrial energy efficiency technology development strategy.

- Under contract to a multinational solar photovoltaics company, developed market strategy recommendations.
- For an automobile OEM, developed analyses of economic benefits of demand response in vehicle charging and vehicle-to-grid electricity storage solutions.
- Under contract to Pew Charitable Trusts, assisted in development of a report of best practices for electric vehicle charging infrastructure.
- Under contract to a national foundation, developed renewable energy business case for Michigan including estimates of rate impacts, employment and income effects, health effects, and greenhouse gas emissions effects.
- Assisted in Michigan market development for a solar panel manufacturer, clean energy finance company, and industrial energy management systems company.
- Under contract to Institute for Energy Innovation, organized legislative learning sessions covering a synopsis of Michigan's energy uses and supply, energy efficiency, and economic impacts of clean energy.

For Department of Energy Labor and Economic Growth

- Participant in the Michigan Public Service Commission Energy Optimization Collaborative, a regular meeting and action collaborative of parties involved in the Energy Optimization programs required of utilities by Michigan law enacted in 2008.
- Lead development of a social-media-based community for energy practitioners in Michigan at www.MichEEN.org.
- Drafted analysis and policy paper concerning customer and third-party access to utility meter data.
- Analyzed hourly electric utility load demonstrating relationship amongst time of day, daylight, and temperature on loads of residential, commercial, industrial, and public lighting customers. Analysis demonstrated the importance of heating for residential electrical loads and the effects of various energy efficiency measures on load-duration curves.
- Analyzed relationship of marginal locational prices to load, demonstrating that traditional assumptions of Integrated Resource Planning are invalid and that there are substantial current opportunities for cost-effective grid-integrated storage for the purpose of price arbitrage as opposed to traditionally considered load arbitrage.
- Developed analyses and recommendations concerning the use of feed-in tariffs in Michigan.
- Participated in Pluggable Electric Vehicle Task Force and initiated changes in State building code to accommodate installation of vehicle charging equipment.
- Organized December 2010 conference on Biomass Waste to Energy technologies and market opportunities.
- Participated in and provided support for teams working on developing Michigan businesses involved in renewable energy, storage, and smart grid supply chains.
- Developed analyses and recommendations concerning low-income energy assistance coordination with low-income energy efficiency programs and utility payment collection programs.
- Drafted State of Michigan response to a US Department of Energy request for information on offshore wind energy technology development opportunities.
- Assisted in development of draft performance contracting enabling legislation, since adopted by the State of Michigan.

For Verizon Business

- Analyzed several potential new lines of business for potential entry by Verizon's Global Services Systems Integration business unit and recommended entry to the "Smart Grid" market. This recommendation was adopted and became a major corporate initiative.
- Provided market analysis and participation in various conferences to aid in positioning Verizon in the "Smart Grid" market. Recommendations are proprietary to Verizon.

- Led a task force to identify potential converged solutions for the “Smart Grid” market by integrating Verizon’s current products and selected partners. Established five key partnerships that are the basis for Verizon’s current “Smart Grid” product offerings.
- Participated in the “Smart Grid” architecture team sponsored by the corporate Chief Technology Officer with sub-team lead responsibilities in the areas of Software and System Integration and Network and Systems Management. This team established a reference architecture for the company’s “Smart Grid” offerings, identified necessary changes in networks and product offerings, and recommended public policy positions concerning spectrum allocation by the FCC, security standards being developed by the North American Reliability Council, and interoperability standards being developed by the National Institute of Standards and Technology.
- Developed product proposals and requirements in the areas of residential energy management, commercial building energy management, advanced metering infrastructure, power distribution monitoring and control, power outage detection and restoration, energy market integration and trading platforms, utility customer portals and notification services, utility contact center voice application enablement, and critical infrastructure physical security.
- Lead solution architecture and proposal development for six utilities with solutions encompassing customer portal, advanced metering, outage management, security assessment, distribution automation, and comprehensive “Smart Grid” implementation.
- Presented Verizon’s “Smart Grid” capabilities to seventeen utilities.
- Presented “Role of Telecommunications Carriers in Smart Grid Implementation” to 2009 Mid-America Regulatory Conference.
- Presented “Smart Grid: Transforming the Electricity Supply Chain” to the 2009 World Energy Engineering Conference.
- Participant in NASPInet work groups of the North American Energy Reliability Corporation (NERC), developing specifications for a wide-area situational awareness network to facilitate the sharing and analysis of synchrophasor data amongst utilities in order to increase transmission reliability.
- Provided technical advice to account team concerning successful proposal to provide network services and information systems support for the California ISO, which coordinates power dispatch and intercompany power sales transactions for the California market.

For Michigan Department of Natural Resources

- Determined permit requirements under Section 316 of the Clean Water Act for all steam electric plants currently operating in the State of Michigan.
- Case manager and key witness for the State of Michigan in FERC, State court, and Federal court cases concerning economics and environmental impacts of the Ludington Pumped Storage Plant, which is the world’s largest pumped storage plant. A lead negotiator for the State in the ultimate settlement of this issue. The settlement was valued at $127 million in 1995 and included considerations of environmental mitigation, changes in power system dispatch rules, and damages compensation.
- Managed FERC license application reviews for the State of Michigan for all hydroelectric projects in Michigan as these came up for reissuance in 1970s and 1980s.
- Testified on behalf of the State of Michigan in contested cases before the Federal Energy Regulatory Commission concerning benefit-cost analyses and regulatory issues for four different hydroelectric dams in Michigan.
- Reviewed (as regulator) the environmental impacts and benefit-cost analyses of all major steam electric and most hydroelectric plants in the State of Michigan.
- Executive responsibility for development, maintenance, and operations of the State of Michigan’s information system for mineral (includes oil and gas) rights leasing, unitization and apportionment, and royalty collection.
- In cooperative project with Ontario Ministry of Natural Resources, participated in development of a simulation model of oil field development logistics and environmental impact on Canada’s Arctic slope for Tesoro Oil.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t and for related accounting and ratemaking relief	)))))	Case No. U-20165

DIRECT TESTIMONY OF JOSEPH M. DANIEL

ON BEHALF OF

THE ENVIRONMENTAL LAW & POLICY CENTER,

THE ECOLOGY CENTER,

THE UNION OF CONCERNED SCIENTISTS,

AND VOTE SOLAR

OCTOBER 15, 2018

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Joseph M. Daniel. My business address is 1825 K street NW, Suite 800, Washington DC, 20006.

Q. By whom are you employed and in what capacity?

A. I am employed by the Union of Concerned Scientists ("UCS") as a Senior Energy Analyst. As a Senior Energy Analyst, I conduct objective economic and technical analysis of energy policy and the electric sector. In my role, I lead research and advocacy efforts to shape electricity markets and state energy policies in order to develop a more flexible and modern electric grid that can accommodate high levels of renewable energy, demand-side resources, and electric vehicles.

Q. Please describe the Union of Concerned Scientists.

A. The Union of Concerned Scientists was founded in 1969 by scientists and students at the Massachusetts Institute of Technology. UCS employs scientists, analysts, and engineers to develop and implement innovative, practical solutions to some the most pressing problems that society faces today—from developing sustainable ways to feed, power, and transport ourselves, to reducing the threat of nuclear war. UCS's mission is to put rigorous, independent science to work by combining technical analysis and effective advocacy to create policy solutions for a healthy, safe, and sustainable future.[1]

Q. Please describe your educational background and professional affiliations.

A. I hold a Bachelor of Science in Chemical Engineering from the Florida Institute of Technology and a Masters of Public Administration in Environmental Science and Policy from Columbia University in the City of New York. I also hold a certificate in Petroleum Fundamentals from the University of Texas.

I am a member of the American Economic Association, the International Association for Energy Economists, and the US Association for Energy Economics. I also serve on the Earth Institute's Environmental Science and Policy Program Alumni Board.

Q. Please describe your professional background and work experience.

A. I have over 12 years of experience working on energy issues from engineering, regulatory, and economic perspectives. In my current work at UCS, I focus on energy system planning including integrated resource plans, energy procurement, avoided cost studies, power market rules and renewable energy integration. I have applied my technical expertise on these topics in regulatory proceedings at the state, regional, and national level.

I began my career as an engineer working for Baker Petrolite (now Baker Hughes, a GE Company) where I conducted engineering studies at power plants, co-generation facilities, and petroleum refineries.

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[1] For more information, including UCS's history and mission statement, visit: https://www.ucsusA:org/about-us.

Refineries and petrochemical plants were the focus of my work at first, where I conducted engineering performance analysis at dozens of facilities across the US including: Texas, Washington, Louisiana, California, Delaware, New Jersey, and Hawaii. I was eventually promoted to a permanent post in Hawaii. By the time I left in 2010, I was Baker Petrolite's lead engineer for all projects with clients and potential clients on the Islands, including: the AES coal plant on Oahu; Hawaiian Electric's fossil-fuel electric generating units on Oahu and Maui; and the larger of the two refineries in Hawaii, at that time owned by Tesoro.

In 2010, I was awarded a fellowship to work with the Deputy Mayor of Tel Aviv. There I worked with the Deputy Mayor, her staff, the office of the mayor and the city council to help quantify and monetize the social and economic benefits of existing and proposed policies.

After Tel Aviv, I went on to graduate school where I focused on energy and environmental economics while enrolled at Columbia's School of International and Public Affairs, Environmental Science and Policy Program.

After earning my MPA, I conducted economic and technical analysis of utility plans on behalf of public interest clients while employed at Synapse Energy Economics. While at Synapse, my clients included state and federal government agencies, state utility commissions, consumer advocates, rural affair advocates, and environmental advocates. At Synapse, I conducted detailed reviews of utility plans, authored expert reports, and assisted in writing expert testimony.

Prior to being hired by UCS, I was employed by the Sierra Club where I reviewed numerous utility filings related to PURPA, net metering, energy efficiency avoided costs, environmental compliance plans, and long-term resource plans.

My resume is attached to this testimony as Exhibit ELP-2 (JD-1).

Q. Please describe your experience working on integrated resource plans.

A. I have conducted technical reviews of dozens of utility long-term resource plans, most commonly referred to as Integrated Resource Plans (IRPs). This includes reviewing utility assumptions pertaining to the economic and technical elements of an IRP, specifically those related to renewables costs, fuel costs, market prices, regulations, and technical capabilities of resources. It also includes reviewing the structure and framework of the modeling process. I've conducted these types of technical review for the IRPs of Entergy Louisiana[2], Cleco Power[3], Big Rivers Electric Cooperative[4], Colorado Springs Utilities (CSU)[5], Kansas City Power & Light

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[2] Daniel, J. A: Napeoleon, T. Comings, S. Fields. 2015. Comments on Entergy Louisiana's 2015 Integrated Resource Plan. Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Entergy-2015-draft-IRP-review-15-033.pdf

[3] Daniel, J., T. Comings, J. Fisher. 2014. Comments on Preliminary Assumptions for Cleco's 2014/2015 Integrated Resource Plan. Synapse Energy Economics. Available Online: http://www.synapse-energy.com/sites/default/files/SynapseReport.2014-04.SC_.Cleco-IRP.14-045.pdf

[4] Daniel, J., F. Ackerman. 2014. Critical Gaps in the 2014 Big Rivers Integrated Resource Plan. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/Critical%20Gaps%20in%20the%202014%20Big%20Rivers%20Integrated%20Resource%20Plan%2014-080.pdf

[5] Vitolo, T., J. Daniel. 2013. Improving the Analysis of the Martin Drake Power Plant: How HDR's Study of Alternatives Related to Martin Drake's Future Can Be Improved. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-12.SC_.HDR-Drake-Analysis.13-121.pdf

Company (KCP&L),[6] KCP&L Greater Missouri Operations (GMO) Company[7], and over a dozen more utilities.

Q. Have you provided testimony or comment as an expert before this Commission?

A. No.

Q. Have you provided testimony or comment as an expert in other forums?

A. Yes. I presented public testimony to the EPA regarding that Agency's proposal to delay implementation of the Effluent Limitation Guidelines under the Clean Water Act, providing my expert opinion on the costs of delayed implementation.[8] I also provided a declaration to Federal Court of Appeals in *Sierra Club, et al., v. FERC*, 867 F.3d 1357 (D.C. Cir. 2017) testifying regarding the utilization of the Sabal Trail gas pipeline and the electric system's ability to meet electric demand.[9] I also presented a framework for calculating avoided costs of rooftop solar projects to Commission Staff at one of the Arkansas Net Metering Working Group meetings.[10]

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[6] Vitolo, T., P. Luckow, J. Daniel. 2013. Comments Regarding the Missouri 2013 IRP Updates of KCP&L and GMO. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-08.EJ_.KCP%26L-GMO-IRP-Updates.13-070.pdf

[7] Vitolo, T., P. Luckow, J. Daniel. 2013. Comments Regarding the Missouri 2013 IRP Updates of KCP&L and GMO. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-08.EJ_.KCP%26L-GMO-IRP-Updates.13-070.pdf

[8] Testimony on Proposal to Postpone Certain Compliance Dates for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category. Docket No. EPA-HQ-OW-2009-0819. Public Hearing in Washington, D.C. July 31, 2017.

[9] Declaration of Joseph Daniel. Sierra Club, et al., v. Federal Energy Regulatory Commission, Duke Energy Florida, et al.,. United States Court of Appeals Case #16-1329. October 31, 2017. Available online: http://blogs2.law.columbia.edu/climate-change-litigation/wp-content/uploads/sites/16/case-documents/2017/20171110_docket-16-1329_response.pdf

[10] Presentation to Arkansas Public Service Commission Staff on a Framework for Calculating Avoided Costs of Rooftop Solar. On behalf of Net Metering Working Group, Sub-Group 1. Docket No. 16-027-R, Implementation of Act 827 of 2015. Little Rock, AR. February 8, 2017

Q. Are you sponsoring any exhibits?

A, Yes.

Exhibit ELP-2 (JD-1): Resume; and,

Exhibit ELP-3 (JD-2): EM Magazine Article.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. Having reviewed Consumers Energy Company's ("Consumers" or the "Company") IRP Application, my testimony is intended to provide insights on IRP best practices and how the Company did or did not adhere to with those best practices. Recognizing that this is the first IRP conducted under Michigan's 2016 Energy Legislation, I also identify critical flaws that need to be improved as IRPs become a regular part of utility planning in Michigan. I go on to explain how some of these flaws can impact the results of an IRP, and should therefore be addressed by the Commission even if they would not materially change the Company's PCA.

Q. Can you summarize your testimony?

A. First, I detail flaws in the Company's treatment of wind resources in its IRP. Second, I explain why the Company should conduct more robust risk analysis via testing optimized portfolios in all scenarios. Third, I discuss how the Company failed to fully account for future environmental regulations. Finally, I provide recommendations to the Commission.

Q. Can you summarize any conclusions you reached?

A. Consumers Energy's IRP should have done a better job allowing the model to select resources on an economic basis without some of the unnecessary constraints the Company placed on the model. In reaching this conclusion, I mainly discuss constraints placed on wind. I also detail how the Company could have conducted a stronger and more quantitative risk assessment by "testing" the various optimized portfolios under the same range of scenarios the Company tested in its Proposed Course of Action ("PCA") and Alternative Plan. Lastly, I conclude that the Company should have more fully accounted for future environmental regulations by including the use of a national and/or regional carbon price in all scenarios.

Q. Can you summarize any recommendations you have for the Commission?

A. In my opinion, if the Commission approves the IRP, it should ensure IRP best practices in the future by ordering the Company to:

1. File an application for review of a new IRP within the next 3 years;
2. Issue a request for proposals or quotations (RFP or RFQ) for wind each year until the application for review of the next IRP is filed;
3. Allow the model to select wind as an economic option in all scenarios in all future IRPs;
4. Run all optimized portfolios in all scenarios for future IRPs;
5. Include a non-zero carbon price in all scenarios, or at the very least in the reference case; and,
6. Apply carbon prices system-wide.

III. TREATMENT OF WIND

Q. How does the Company treat wind in the IRP?

A. The Company modeled some wind, but treats wind differently depending on location and use. At several points during the IRP process, the Company made prejudicial decisions that disadvantaged wind and resulted in the model under-procuring wind and possibly under-procuring storage. For example, the company made an *a priori* decision to eliminate in-state wind as an option. The company does allow the model to select out-of-state wind but discredits the model's selection of wind for the Consumers system and creates overly stringent limits on the model to select off-system wind across the MISO system. Ultimately, these limitations resulted in the Company pursuing no wind in the PCA.

Q. How would you characterize decisions that limited wind?

A. The Company limited the model's selection of wind in two important, but distinct ways. My testimony addresses the Company's treatment of the following categories of wind resources in turn:

1) Wind that would be developed for or within the Consumers Energy System; and,
2) Wind that would be developed outside the Consumers Energy system but within MISO, or off-system wind.

Q. In what ways did the Company limit wind within the Consumers Energy system?

A. The Company limited realistic consideration of both in-state wind and out-of-state wind.

Q. How did the Company modeling structure limit in-state wind in the IRP?

A. The Company outright discredits in-state wind as a feasible option and did not include it as an option in the resource plan.[11] Witness Walz expands on this, stating that, "The Company assumes that any expansion of wind capacity would occur out of state."[12] And "that wind built in Michigan may not be cost-effective or a feasible option."[13]

Q. Does the Company offer any reports or analysis to back up their assumption that wind built in Michigan may not be cost-effective?

A. No. The Company appears to presume that wind is not cost-effective prior to the modeling process, thereby preventing the modeling from determining how much (if any) wind is cost effective. This *a priori* decision is based on the Company's qualitative assessment that siting of new wind resources would be problematic, not on the technical and economic considerations that should guide development of the IRP.

Q. Is the model capable of determining if wind is cost effective?

A. Yes. In fact, the job of the optimization modeling process is to calculate how much of the technical potential of various resources are economically achievable.

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[11] IRP at 137
[12] Walz at 32
[13] Walz at 32

Q. Is there technical potential for additional wind resource development in Michigan?

A. Yes. Even after accounting for land limitations and resource availability there are at least 81 gigawatts (GW) of technical potential for wind in Michigan.[14] With less than 2 GW of wind capacity currently installed, the Company is assuming that the state will only reach a small fraction of the state's potential.[15]

Q. Does the Company plan on pursing any in-state wind?

A. Yes, but no more than the 550 MW of wind that was already planned for purposes of complying with Act 342.[16] The Company discredits the possibility of further development of wind in the state due to challenges and opposition in siting.[17]

Q. Are there siting challenges in Michigan?

A. Yes. As noted in the Company's testimony there has been some recent opposition to construction of wind in parts of Michigan. However, while there are a few local moratoriums currently in place, I am not aware of any statewide bans to build new wind in Michigan.

[14] DOE. WINDExchange, Wind Energy in Michigan. Available online: https://windexchange.energy.gov/states/mi (retrieved 8/11/18).
[15] DOE. WINDExchange, Wind Energy in Michigan. Available online: https://windexchange.energy.gov/states/mi (retrieved 8/11/18).
[16] Walz at 28
[17] Walz at 32, IRP at 137

Q. Does the aforementioned opposition create risk and uncertainty to the viability of building wind?

A. Yes, but risk and uncertainty are things that should be analyzed and accounted for in an IRP; not held up as justification for eliminating options that could potentially provide benefits to ratepayers.

Q. Has the Company been unable to develop wind considering recent opposition?

A. No. The Company asserts that developers will avoid wind development projects in Michigan due to local opposition,[18] but that assertion goes unsupported and is somewhat contradicted by the results of recent request for proposals ("RFP's") issued by the Company. When the Company put out a RFP for wind they got 12 responses in 2016, 12 in 2017, and 13 in 2018.[19]

Q. Why is it important to model wind, even if there are perceived siting challenges in Michigan?

A. Even if the Company ultimately concluded after thorough analysis that wind is not a viable resource, stakeholders (including the Commission and elected officials) are entitled to understand the opportunity costs of not including new wind resources in Michigan's energy future. If the Company excludes wind as even being a viable option in long term plans like this IRP, their conclusion could become a self-fulfilling prophecy.

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[18] Walz at 32

[19] See Company Response to Discovery Request Question 20165-MEC-CE-10.

Q. How does this become a self-fulfilling prophecy?

A. If the Company's plan does not include wind, then the IRP will not yield results that suggest it would be economic to pursue wind. If there is no indication that pursing wind would be economic (or in the rate-payers best interest), then the Company would have no reason to issue a RFP for wind. A lack of RFPs reduces the ability to gauge the industry's appetite to build new wind in the state of Michigan.

Q. Could the Company ultimately rule out wind because of siting issues?

A. If the modeling indicated that building in-state wind was in the ratepayer interest, then the Company should pursue wind subject to adjustment of procurement plans using documented analysis on how much could be reasonably procured. This might include pursuing only a portion of the wind selected by the model.

Q. Are there other examples of the Company pursuing only a portion of a resource selected by the model?

A. Yes. The Company takes this approach with both out-of-state wind and solar. The Company allowed the model to select out-of-state wind, and the model selected 3.2 GW of out-of-state wind. However, the Company opted to not pursue any portion of that 3.2 GW in the PCA. The shortcomings of that decisions are discussed below. The Company took a similar approach to solar, but with a different result. The Company is including solar in the PCA, but the solar build-out plan in the PCA does not reflect a build-out chosen in a specific optimized plan. The solar build out is informed by – but not dictated by – modeling results. There is no reason this can't be done for in-state-wind as well.

The ability and willingness of the Company to allow the model to select resources and then evaluate the feasibility afterwards indicates the arbitrary way in which the Company treats in-state-wind.

Q. Are there ways to mitigate project risk associated with wind development?

A. Yes. Pursuing 500MW of wind doesn't necessarily mean one, 500 MW project. Projects can be spread out geographically, temporally, and across multiple developers. Other ways to mitigate risk include the structure of procurement contracts and procurement strategy.

Q. Does the company take this "small block" approach for other resources?

A. Yes, it does. The company's approach overall to resource procurement is described in the direct testimony of company witness Torrey:

> *Consumers Energy has identified an opportunity in this IRP to shift from large baseload generating resources to a cleaner, leaner, and more modular way of balancing supply and demand. This strategy will better meet our commitment to keep bills affordable, improve Michigan's competitive position, and limit risk to our customers and investors.*[20]

Specifically, the "small block" approach resembles how the company is going to procure solar, wherein the company plans to "fill any future capacity needs through adding solar generation on a yearly basis using a competitive bid process to select projects to fill capacity needs."[21]

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[20] Torrey at 4
[21] Torrey at 3 and 4.

Q. How does the Company evaluate options to develop wind out of state, but for the Consumers system?

A. The Company dismissed the potential for developing out-of-state wind as being "high risk."[22] Consequently, while the model selected 3.2 GW of out-of-state wind, the PCA includes no out-of-state wind.[23] The enumerated but unquantified risks associated with out-of-state wind include energy prices, energy cost spreads, transmission costs, capacity cost spreads, and the feasibility of building incremental wind in Iowa. [24]

Q. Did the Company consider including some portion of the 3.2 GW of out-of-state wind in the PCA?

A. The company acknowledges that it could have elected to include some portion of wind but opts not to pursue any wind because a lack of confidence.[25] However, the company prematurely eliminates the option to pursue wind. The model selected 3.2 GW of wind in 2023, the first year the model could select wind as a new build resource.[26] Rather than pursuing all 3.2 GW of wind in a single year, the Company could have chosen to pursue a portion of the 3.2 GW over the next five years. The company could have still pursued some potion of the wind by issuing RFPs for small blocks of wind (similar to how I recommend pursuing in-state-wind above or similar to how the company plans on procuring solar in the PCA).

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[22] Clark at 54
[23] Clark at 54
[24] Clark at 54
[25] Clark at 55
[26] Walz at 28

Q. **You have discussed the Company's treatment of in-state and out-of-state wind for the Consumers' system. Did the Company limit off-system wind?**

A. Yes. One way the Company limited off-system wind was by relying on the IHS Markit study, "How are North American Renewable Markets Evolving" (herein IHS Wind Study).[27] Company witness Walz notes that the model builds "in excess of 13 GW" of wind through 2023.[28] However, the Company capped the amount of wind built within MISO based on IHS Market study rather than allowing the model to select all economic off-system wind.[29]

Q. **Should the Company have relied on the IHS Wind Study?**

A. No. Placing a cap to the amount of wind a capacity expansion optimization model can select is allowable but should only be based on technical limits and never based on the economic projections of external forecasts, as is done with the IHS Wind Study. In fact, one of the benefits of conducting the modeling is to help determine what amount—and under what conditions—various resources like wind are economically viable. Relying on the IHS Wind Study is flawed for several reasons.

Q. **In what ways is relying on the IHS Wind Study flawed?**

A. One reason that placing a cap on wind based on exogenous projections of economic forecasts is flawed is that each forecast is based on its own set of assumptions of several variables. The IHS Wind Study is based on its own set of assumptions

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[27] Walz at 29
[28] Walz at 28
[29] Walz at 29

regarding coal retirements, gas prices, wind prices, change in load, and other variables; it is not internally consistent with Consumers' own projections of those variables. The Company even changes some of these variables in different scenarios/sensitivities (example: gas prices). However, the cap the Company uses for wind that the model can select within MISO is based on a single set of assumptions made by a third party that is not internally consistent with the modeling conducted by the Company.

It is worth adding that, at the national level, IHS Markit is consistently one of the lowest projections of how much wind will be built in the US.[30] Meaning that Consumers is basing the Company's cap to off-system wind based on a single study that is consistently low.

Q. Are there alternative studies the Company could have used?

A. Yes, other studies, including studies published by Bloomberg NEF ("BNEF") and MISO, could have been considered.

Q. Does the Company use BNEF studies for other market projections?

A. Yes, the Company used BNEF's projection for EVs.[31]

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[30] Wiser, R., M. Bolinger. 2017 Wind Technologies Market Report. US DOE Office of EERE. 2018. Page 73. Available online: https://www.energy.gov/sites/prod/files/2018/08/f54/2017_wind_technologies_market_report_8.15.18.v2.pdf

[31] IRP at 97

Q. How much wind does MISO project could be built within its footprint?

A. MISO recently conducted a study in which they found that over 15 GW of wind could be built by 2023 and as much as 40+ GW of wind could be built in MISO by 2033. The study further found that much of the new wind would be in Local Resource Zone ("LRZ") 7. According the MISO study, LRZ 7 is likely to host the 2nd most amount of new wind additions.[32]

Q. What is the impact of limiting off-system wind?

A. It is impossible to know for certain unless you conduct the modeling without these restrictions on off-system wind. It is reasonable to assume that there is a range of possibilities. Given that the model originally selected 13GW of wind in MISO prior to the cap being installed, it is at least reasonable to assume that some additional wind would have been selected.

Q. If additional off-system wind had been selected, what are some ways it could have impacted the results?

A. Wind is a zero marginal cost resource that reduces wholesale market clearing prices. If more off-system wind was selected, then wholesale market prices would be reduced. [33] Lower wholesale market prices make off system sales look less economically attractive and make market purchases look more economically viable.

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[32] MISO Planning Advisory Committee. MTEP19 Futures Resource Forecast and Sitting Review. MISO. 2018. Available online: https://cdn.misoenergy.org/20180926%20PAC%20Item%2004b%20MTEP19%20Futures%20Resource%20Forecast%20and%20Siting%20Results277726.pdf

[33] LBNL Study on RE in wholesale markets: http://eta-publications.lbl.gov/sites/default/files/report_pdf_0.pdf

Increased amounts of wind off-system may also increase the value of a storage resource for Consumers.

Q. Why would the model select additional storage in scenarios where there is more wind on the MISO system?

A. Wind is effective at creating pricing differentials in wholesale prices, which creates a price arbitrage opportunity for storage. As renewables increase market penetration, average wholesale market prices go down.[34] With wind, prices in both low-price hours and high-price hours go down but the low-price hours go down more. This means that there is likely to be lower prices overall and greater price differentials in a high renewable energy system. [35] This creates an opportunity for storage to charge up when wholesale prices are low and discharge when they peak. While models like Strategist tend to struggle in accounting for the value of storage, without strong signals that a price arbitrage opportunity exists, the model's deficiencies are exacerbated.

Q. In your opinion, how should Consumers have treated wind in its IRP?

A. Models like the one used by Consumers are designed to calculate the economics of resources, so limitations should be kept to a minimum. The Company should take an

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[34] Seel, J., A. Mills, R. Wiser. Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making. Lawrence Berkeley National Laboratory. 2018. Available online: http://eta-publications.lbl.gov/sites/default/files/report_pdf_0.pdf

[35] Seel, J., A. Mills, R. Wiser. Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making. Lawrence Berkeley National Laboratory. 2018. Available online: http://eta-publications.lbl.gov/sites/default/files/report_pdf_0.pdf

objective look at the technical limits of how much wind can be built in Michigan and how much wind can be built in any given year.

Q. Should limitations be based on historical data?

A. Limitations should not be based on historical data. The fact that only “X” MW of wind were built last year does not mean that “X” MW is the upper limit of the capabilities of the wind industry. To assume that the wind industry’s ability to install new capacity is somehow limited to past performance suggests the wind industry has peaked.

Q. What should the Commission do in response to these shortcomings?

A. I recommend that the Commission order the Company to do the following:

1. Issue an RFP or RFQ for wind each year until the Company files its next IRP,
2. Allow the model to select wind as an economic option in all scenarios in all future IRPs.

Q. Why should the Commission order the Company to issue an RFP or RFQ for wind each year until the next IRP is filed?

A. To mitigate the Company’s shortcomings in modeling wind, and to ensure that the Company and stakeholders stay up to date on the availability and cost of wind resources in state. Furthermore, renewable energy tax credits are being to phase out,[36] if the tax credits don’t get extended and if the company waits five years to file its next IRP it will have missed a window of opportunity to procure wind at a reduced cost.

[36] Smith at 5

Q. Why shouldn't they do an RFP for every resource?

A. The Company did a decent job modeling other resources, like solar, and that is why the Company's plan includes solar. Because the PCA includes solar, the Company presumably will be procuring solar through a process that will include an RFP. With no concrete plans to build additional wind, the Company may never issue an RFP for wind.

Q. Why should the Commission order the Company to allow the model to select wind as an economic option in all scenarios in all future IRPs?

A. To mitigate the shortcoming of how the Company handled wind in the current IRP and to ensure that the Company and stakeholders stay up to date on the availability and cost of wind resources in state.

IV. QUANTITATIVE RISK ANALYSIS OF THE PCA AND ALTERNATIVE PLAN

Q. How does the Company address risk in its IRP?

A. The Company addresses risk in several ways; including the qualitative enumeration of unknown factors that ultimately resulted in the Company eliminating courses of action due to perception of risk (see the above section on how the Company handles new wind).

Another way the Company assess risks is through quantitative means like conducting model runs of alternative scenarios and sensitivities to see how various "futures" impact the Present Value of Revenue Requirement ("PVRR") of the PCA. However, the Company's quantitative assessment is incomplete because the Company only assesses two courses of action: the proposed PCA and the Alternative Plan. The Company should conduct a more thorough and robust risk assessment.

Q. How did the Company quantitatively asses the risk of the PCA compared to alternatives?

A. The Company states that it:

> *[P]erformed a risk assessment on the different scenarios by evaluating its PCA through each of the six base scenarios, as well as many of the defined sensitivities. This allowed the Company to evaluate the economic performance of its PCA by seeing the range of NPVs generated. The smaller the range of NPVs indicates the PCA performed similarly in all worlds and therefore exposes the customers to less risk.*[37]

Q. How would you describe this type of risk assessment?

A. I would describe this type of risk assessment as "portfolio testing." Portfolio testing is the process of running a portfolio (or portfolios) through multiple scenarios and/or sensitivities in order to "test" how well they perform under a range of conditions.

Q. Is this common practice by utilities?

A. Yes, though the specific process and structure of portfolio testing can vary from utility to utility, it is common practice by utilities conducting IRPs. While different utilities refer to this practice in different ways, and some don't label it at all, it shows up in many of the IRPs I've reviewed.

[37] IRP at 162

Q. Does the Company test any other portfolio(s) of resources through the six base scenarios?

A. Yes, the Company ran both the PCA and the Alterative Plan through all six base scenarios. The company ran the PCA through another nine sensitivities for a total of 15 runs for the PCA. [38]

Q. Is this common practice by utilities?

A. Yes, conducting multiple runs on multiple portfolios is common practice by utilities conducting IRPs.

Q. Were there any other portfolios of resources that were constructed during the IRP process that could have been run through the six base scenarios?

A. Yes. In each of the scenarios the Strategist model assembled an optimized portfolio. In the IRP the Company labels these portfolios as “Strategist Selected” portfolios.

Q. Were any of the “Strategist Selected” portfolios tested in the way the PCA or the Alternative Plan was tested?

A. No. If “X portfolio” represents the optimized portfolio for “scenario X” then it was only run through the scenario X, the Y portfolio was only run through scenario Y. X portfolio was never tested under the conditions of the Y scenario or vice versa. The PCA and Alternative Plan, however, were tested in in both X and Y (and many other scenarios/sensitivities).

[38] Walz at 49

Q. Where either the PCA or the attentive plan an optimized portfolio?

A. No. Neither the PCA nor the Alternative Plan were selected by the model as an optimized portfolio in any scenario or sensitivity.[39]

Q. Why is testing portfolios important?

A. The Company notes that a small "range of NPVs indicates the PCA performed similarly in all worlds and therefore exposes the customers to less risk." This is true. However, we have no way of determining what constitutes a "small range." Only one other portfolio of resources (the Alternative Plan) was run through additional scenarios, and it is therefore the only portfolio we have to compare to. At best, the Company can only claim that the PCA is lower risk compared to the Alternative Plan. It is possible that the Company's plan is neither least cost nor least risk.

Q. How do you know the Company's plan isn't least cost?

A. The Company presents 15 possible futures in which it tested the PCA and in none of them is the PCA the least cost.

Q. How do you know the Company's plan isn't least risk?

A. I don't. Neither does the Company. Without testing portfolios under different scenarios, the Company does not provide the full range of information necessary to conclude that its PCA is low risk when compared to a variety of alternatives. Because the Company only compared the PCA to the Alternative Plan, the only information available is that the PCA is lower risk than the Alternative Plan.

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[39] See Company Response to Discovery Request Question 20165-ELPC-CONSUMERS-3.

Q. What is the value of testing portfolios?

A. Testing portfolios allows stakeholders to compare the relative risk of different portfolios. The Company tests the PCA and Alternative Plan for the right reasons: to help investigate risk. But the Company provides an incomplete picture, only presenting data that allows stakeholders to compare the Company's preferred and Alternative Plans.

Testing portfolios is about providing additional information and insights, providing the Company, Commission, Intervenors, IRP observers and any other stakeholder with more data with which the Company's plans can be judged. By not presenting this additional data, the Company has essentially unnecessarily hampered the Commission's ability to effectively evaluate the Company's plan.

Q. If the Company had done this, would the PCA be different?

A. I don't know. It may not have changed anything. It could reveal that there is a lower cost, lower risk option. It could also confirm the Company's assessment of the PCA.

Q. Are you aware of any IRPs in which optimized portfolios are tested in other scenarios?

A. Yes. Testing portfolios, including portfolios selected by a model as being optimal in a given scenario, in a range of alternative scenarios and sensitivities is a recognized best practice. Though different utilities conduct portfolio testing in different ways, all of the following utilities conduct some form of portfolio testing. The utility commission in Colorado mandates that utilities conduct portfolio testing for at least four plans (the equivalent of a PCA and three alternative plans).[40] Similarly, Arizona Public Service,[41] KCP&L and GMO in Missouri,[42] Xcel Energy's subsidiary Southwestern Public Service Company in New Mexico,[43] and PacifiCorp,[44] all conduct portfolio testing. Notably, Entergy Louisiana tests all optimized portfolios, and in doing so revealed underlying flaws in its IRP.

Q. How did testing optimized portfolios reveal underlying flaws in Entergy's IRP?

A. Entergy Louisiana's modeling in the 2015 IRP was deeply flawed and should not be held up as best practices in any way. Relevant to the Commission's review here is the fact that it was Entergy's scenario testing that helped illuminate critical flaws. As I noted in a report reviewing various elements of that IRP:

> *Entergy's IRP modeling produces results that are unintuitive. Each resource portfolio was presumably optimized under a given scenario. It would therefore be reasonable to assume that that resource portfolio would be the [lowest PVRR] choice for that scenario. That is curiously not the outcome that Entergy presents… For example, the Distributed Disruption portfolio, which was*

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[40] Wilson, R., B. Biewald. 2013. Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-06.RAP_.Best-Practices-in-IRP.13-038.pdf

[41] Wilson, R., B. Biewald. 2013. Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-06.RAP_.Best-Practices-in-IRP.13-038.pdf

[42] Vitolo, T., P. Luckow, J. Daniel. 2013. Comments Regarding the Missouri 2013 IRP Updates of KCP&L and GMO. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-08.EJ_.KCP%26L-GMO-IRP-Updates.13-070.pdf

[43] Southwestern Public Service Company. 2018 Integrated Resource Plan. 17.7.3 NMAC. 2018. Available online: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Resource%20Plans/2018-SPS-NM-Integrated-Resource-Plan.pdf

[44] Wilson, R., B. Biewald. 2013. Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-06.RAP_.Best-Practices-in-IRP.13-038.pdf

developed under the lowest load forecast and the reference natural gas price, would not be expected to outperform all other resource portfolios in the Business Boom (BB) scenario which has the highest load forecast and lowest natural gas price. These results strongly indicate that resources portfolios were not properly optimized and calls all of the model results into question.[45]

Table 6. Portfolios with the lowest revenue requirements under a range of scenarios, expected vs. actual

		IR Scenario	BB Scenario	DD Scenario	GS Scenario
Expected	IR Portfolio	1			
	BB Portfolio		1		
	DD Portfolio			1	
	GS Portfolio				1
Actual	IR Portfolio	1	3	1	4
	BB Portfolio	3	2	3	3
	DD Portfolio	1*	1	2	2
	GS Portfolio	4	4	4	1

Source: Entergy. 2015. 2015 Draft Integrated Resource Plan. LPSC Docket No. I-33014, January 30, 2015. Table 13. page 31.
**Entergy labels the DD portfolio as ranked 2nd in the IR Scenario, however, all of the data provided in the IRP indicates that the DD portfolio performed equally with, or better than, the IR portfolio.*

Figure 1: Table 6 from report on Energy Louisiana's scenario testing. Note: IR = Industrial Renaissance, BB = Business Boom, DD = Distributive Disruption, and GS = Generation Shift.[46]

Again, Entergy's 2015 IRP was deeply flawed and in no way should be used as guidance for how to conduct a proper IRP. The IRP modeling, portfolio selection, scenario development, price inputs, and assumptions across the board were either weakly supported or deeply flawed. However, scenario testing did reveal that the utility was selecting a plan that was neither lowest cost nor lowest risk.

[45] Daniel, J. A: Napeoleon, T. Comings, S. Fields. 2015. Comments on Entergy Louisiana's 2015 Integrated Resource Plan. Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Entergy-2015-draft-IRP-review-15-033.pdf

[46] Daniel, J. A: Napeoleon, T. Comings, S. Fields. 2015. Comments on Entergy Louisiana's 2015 Integrated Resource Plan. Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Entergy-2015-draft-IRP-review-15-033.pdf

Q. What should Consumers have done?

A. Consumers should have tested each optimized portfolio, along with the PCA and the Alternative Plan, against each of the six core scenarios. Ideally, Consumers should have tested each optimized portfolio against each sensitivity as well. This—on its own—would not fix other shortcomings of the IRP as described elsewhere in this testimony, but without this process the Company could easily justify a sub optimal course of action.

Q. What actions would you recommend to the Commission?

A. The Commission should order the Company to run all optimized portfolios in all scenarios for all future IRPs.

Q. Why should the Commission order the Company to run all optimized portfolios in all scenarios for future IRPs?

A. Doing so will provide all interested parties, including the Commission and the Company, with important information. It could even shed light on alternative courses the Company could take or confirm that the Company is pursuing the right resource portfolio.

V. ACCOUNTING FOR FUTURE ENVIRONMENTAL REGULATIONS

Q. Did you reach any conclusions about the Company's treatment of environmental regulations?

A. Consumers Energy failed to robustly model compliance with the full range and extent of likely environmental regulations. Specifically, it failed to fully analyze the regulatory risks associated with air emissions including carbon dioxide ("CO_2").

Q. How did the Company model compliance with future environmental regulations?

A. With respect to carbon emissions, the Company isolated the analysis of policy-driven carbon reductions to a single scenario and sensitivity. The Environmental Policy Scenario includes a 30 percent reduction in energy sector carbon emissions below 2005 levels by 2030 and a sensitivity to constrain carbon emissions to a 50% reduction below 2005 levels by 2030.[47] In both, the Company assumed a Michigan-specific cap without any constraints on the electric system beyond state borders (*i.e.*, the rest of MISO).[48]

The Company did not include a carbon price in any other scenario, nor in any other sensitivity of any other scenario.

Q. How did a state-specific cap on carbon affect the modeling results?

A. Application of a state-specific cap implicitly assumed that there will be no national or regional carbon or climate regulation. Setting a system-wide carbon price would impact the relative economic value of market purchases and market sales.

[47] IRP at 55 and 56
[48] See Company Response to Discovery Request Question 20165-ELPC-CE-403.

Q. How did failure to account for carbon emissions associated with imports affect the modeling results?

A. Had the Company included emissions associated with imports and those associated imported emissions counted towards emission reduction goals, then the Company would have either (a) imported less or (b) operated gas and coal power plants less.

Q. How did the lack of a carbon price in the modeling scenarios affect the results?

A. Because Consumers' coal plant retirement analysis was completed exogenously, and because the Company is not selecting to build any new gas generating resources, including a carbon price would likely have had little impact on the schedule of new resources expected to be procured in the PCA. At most, a carbon price would indicate the procurement of additional renewables on a faster pace. A carbon price could, in theory, tip the scales so that building a new gas plant in certain tested scenarios/sensitivities was no longer economic. Additionally, a carbon price would impact the dispatch amount of specific resources.

Q. What is the impact of isolating a carbon cap to a single scenario?

A. It presumes that there is no world in which there are, for example, both high gas prices and a carbon policy; or, high load growth and a carbon policy. This is because all other variables are held in isolation of any carbon policy. Essentially the Company is assuming that most futures won't include a carbon price or carbon cap, even out until 2040.

Q. Is assuming no carbon price until 2040 a commonly held view?

A. No, not in the space of utility planning. Including a carbon price in a reference case is both a smart practice, a common practice, and arguably a best practice. Utilities operating in at least 42 states include a carbon price in a reference case for modeling for their IRPs.[49] A literature review of IRPs that were released between 2012 and 2014 found that 38 out of 88 (43%) of IRPs reviewed included a non-zero carbon price in the reference case.[50]

Even Pace Global, the company hired by the Company during the IRP, noted that, "Pace Global anticipates an eventual, moderate national price on carbon for existing units beginning as early as the mid-2020s."[51] Consumer's projection of policy-driven carbon reductions is incongruent with Pace Global in that Consumers excluded any policy-driven carbon reductions outside of Michigan, whereas Pace projects a national carbon price that would affect Michigan and all other states in MISO. Pace Global also notes another limitation to the Company's approach on emissions reductions, stating that, "any potential for a future carbon tax or trading program that would place a price on all carbon emissions and [would therefore] impact dispatch

[49] Luckow, P., J. Daniel, S. Fields, E.A. Stanton, B. Biewald. CO2 Price Forecast, Planning for Future Environmental Regulations. 2014. EM (A publication of the Air & Waste Management Association). Exhibit ELP-3 (JD-2).

[50] Biewald, B.E., 2014. Written statement to U.S. Subcommittee on Energy and Power hearing: "Benefits of and Challenges to Energy Access in the 21st Century: Electricity" Available online: http://www.synapse-energy.com/sites/default/files/Benefits%20of%20and%20Challenges%20to%20Energy%20Access%20in%20the%2021st%20Century%20Electricity.14-019.pdf

[51] Exhibit A-36 (MH-2) at 26.

and overall costs."[52] Ultimately, PACE doesn't find Consumer's assumptions to be a "shortfall" to the IRP.

Q. Do you find it to be a shortfall?

A. Yes. Not sufficiently anticipating carbon regulations exposes the utility and the ratepayers to unnecessary risk. The limitation of policy-driven carbon reductions to Michigan only, the lack of accounting for emissions associated with imports, and the isolation of evaluating carbon risk to environmental scenarios are self-evident shortfalls of the Consumers IRP.

Q. How should uncertainty around the Clean Power Plan (CPP) and federal carbon policy impact the use of a carbon price?

A. When conducting modeling covering time periods of multiple decades, limiting input assumptions based on 2-year and 4-year political cycles is unnecessarily risky and myopic. Adjusting the severity or start date of a carbon price could be considered prudent based on current political situations—but excluding a carbon price altogether is imprudent.

As noted in the Company's Carbon Disclosure Project Climate Change 2017 report, the company uses an internal price on carbon and notes:

> *Consumers Energy cannot predict the outcome of [CPP] litigation or the Trump Administration's reconsideration, but will continue to monitor regulatory activity regarding greenhouse gas emissions standards that may affect [electric generating units]. Regardless of*

[52] Exhibit A-36 (MH-2) at 26.

> *the outcomes, Consumers Energy will continue to use updated carbon pricing models to evaluate potential carbon pricing scenarios to inform our future business decisions.*[53]

Consumers Energy IRP modeling should reflect the Company's view on the long-term likelihood of carbon regulations notwithstanding the policies of the current administration. They can do this by incorporating a carbon price into IRP model runs.

Q. What should Consumers Energy have done differently?

A. Consumers Energy should have included a carbon price, applied it system-wide.

Q. How should a carbon price have been utilized by Consumers Energy?

A. Carbon prices are commonly used tools that do not necessarily reflect any specific policy but can serve as a proxy for industry trends and the currently unknown, but likely to occur, policies around carbon emissions and climate change. Synapse Energy Economics, which is recognized as a leader in carbon price forecasting, notes that a carbon price can be used as a proxy for, or to model, carbon policies including: Carbon allowances (including cap-and-trade), a carbon tax, an effective price of carbon (also known as a shadow price, notional price, or voluntary price), marginal abatement cost of carbon, or social cost of carbon.[54]

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[53] CMS Energy Corporation. Carbon Disclosure Project Climate Change 2017 Report. Available online: https://www.cdp.net/en/formatted_responses/pages?locale=en&organization_name=CMS+Energy+Corporation&organization_number=3538&program=Investor&project_year=2017&redirect=https%3A%2F%2Fwww.cdp.net%2Fsites%2F2017%2F38%2F3538%2FClimate+Change+2017%2FPages%2FDisclosureView.aspx#ORSMENU_2 (sign-in required)

[54] Luckow, P., E.A. Stanton, S. Fields, W. Ong, B. Biewald, S. Jackson, J. Fisher. 2016. Spring 2016 National Carbon Dioxide Price Forecast. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008.pdf

So, even though forecasting a specific carbon policy could be considered complex, using a carbon price as a proxy for future environmental regulations is straightforward.

Q. Are there professionally assembled forecasts of carbon prices?

A. Yes. Several organizations release carbon price forecasts including Synapse Energy Economics, ICF International, Wood Mackenzie, and Energy Ventures.[55] The Strategist® model can place a value on pollutants, including carbon, and the model can incorporate that cost into both dispatch and capacity expansion optimization.

Q. How and why should the Company have applied the carbon price system-wide?

A. The carbon price can be placed as a price adder to dispatching costs of carbon emitting resources, which better reflects the nature of national and regional trends to decarbonize the electric sector.

Q. What is your recommendation to the Commission with respect to carbon prices?

A. The Commission should include in any order on this IRP instructions that IRPs should include:

1. A non-zero carbon price in all scenarios, or at the very least in the reference case; and.
2. Application of carbon prices system-wide.

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[55] Luckow, P., J. Daniel, S. Fields, E. A Stanton, B, Biewald. CO2 Price Forecast, Planning for Future Environmental Regulations. 2014. EM (A publication of the Air & Waste Management Association). Exhibit ELP-3 (JD-2).

Q. Why should the Commission require a non-zero carbon price in all scenarios, or at the very least in the reference case?

A. Inclusion of a non-zero carbon price is standard practice in utility long-term planning as a way of promoting robust economic analysis that accounts for regulatory risks associated with carbon emissions.[56] Including a CO_2 price is important in planning for uncertainty in environmental regulations—irrespective of when or how federal and state climate policies are adopted. State and regional policies, together with federal regulatory measures, place economic pressure on CO_2 emitting resources over the coming years and decades, such that it is relatively more expensive to operate a high-carbon-emitting power plant. Failure to account for environmental regulations related to carbon today will likely lead to more costly compliance requirements in the future.[57]

Q. Why should the Commission require application of carbon prices system-wide?

A. Application of a system-wide carbon price better reflects the likelihood of a national or regional carbon policy.

[56] Luckow, P., J. Daniel, S. Fields, E. A Stanton, B, Biewald. CO2 Price Forecast, Planning for Future Environmental Regulations. 2014. EM (A publication of the Air & Waste Management Association). Exhibit ELP-3 (JD-2).

[57] Luckow, P., J. Daniel, S. Fields, E. A Stanton, B, Biewald. CO2 Price Forecast, Planning for Future Environmental Regulations. 2014. EM (A publication of the Air & Waste Management Association). Exhibit ELP-3 (JD-2).

VI. RECOMMENDATIONS CONCERNING APPROVAL, MODIFICATIONS, AND FUTURE IRPS.

Q. Do you have any other recommendations for the commission?

A. Yes, if the Commission approves the IRP, the commission should order the company to file the next IRP within the next 3 years.

Q. Why shouldn't the Commission allow the company to wait 5 years?

A. Having the IRP done at least every 5 years is suitable as a backstop to ensure that companies come in on a regular schedule but if the Commission and Company wish to be better aligned with industry best practices they should conduct the IRP more frequently.[58]

Q. How often do utilities typically file IRPs with state Commissions?

A. According to "Best Practices in Electric Utility Integrated Resource Planning," it is far more common for IRPs to be filed every two years or every three years. According to the report, 25 of the 28 states identified in the report require IRPs to be filed every two years or every three years. [59]

[58] Wilson, R., B. Biewald. 2013. Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-06.RAP_.Best-Practices-in-IRP.13-038.pdf

[59] Wilson, R., B. Biewald. 2013. Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-06.RAP_.Best-Practices-in-IRP.13-038.pdf

Q. Are there other reasons why the Commission should order the company to file a new IRP in three years?

A. Yes, as detailed throughout my testimony, the Company made several decisions that could be improved in future IRPs. Conducting an IRP in three years, and correcting for those shortcomings, would mitigate the problems identified by my testimony including the problems pertaining to modeling wind. Conducting the IRP in three years would ensure that the Company and stakeholders stay up to date on the availability and cost of wind resources in state. Furthermore, due to the renewable energy tax credit phase out time table, the window for opportunity to buy renewables at a discount might be closed in 5 years and waiting 5 years to do the next IRP might deprive Michigan ratepayers of tangible benefits.

Q. Any other recommendations?

A. The commission should offer clear direction on the Company's next IRP to help strengthen this process and set good precedent. Such an order should include the following recommendations (all noted above):

1. File an application for review of a new IRP within the next 3 years;
2. Issue a request for proposals or quotations (RFP or RFQ) for wind each year until the application for review of the next IRP is filed;
3. Allow the model to select wind as an economic option in all scenarios in all future IRPs;
4. Run all optimized portfolios in all scenarios for future IRPs;
5. Include a non-zero carbon price in all scenarios, or at the very least in the reference case; and,

6. Apply carbon prices system-wide.

Q. Does this conclude your testimony?

A. Yes.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief	)))))	Case No. U-20165

EXHIBITS OF JOSEPH DANIEL

ON BEHALF OF ENVIRONMENTAL LAW & POLICY CENTER,

THE ECOLOGY CENTER,

THE UNION OF CONCERNED SCIENTISTS,

AND VOTE SOLAR

OCTOBER 15, 2018

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PROFESSIONAL EXPERIENCE

Union of Concerned Scientists, Washington, D.C. *Senior Energy Analyst*, 2018 – Present
- Conducts economic and technical analysis of industry forecasts including utility long term plans (Integrated Resource Plans) and energy market forecasts
- Works on efforts to modernize power grids and helps advance science-based public policy
- Leads research and advocacy efforts at state public utility commissions
- Conducts analysis that helps shape electricity markets and policies to develop a more flexible and modern electric grid that can accommodate high levels of renewable energy, demand-side resources, and electric vehicles while reducing carbon emissions and reliance on fossil fuels

Sierra Club, Washington, D.C. *Electric Sector Analyst*, 2016 – 2018
- Reviewed utility rate cases, integrated resource plans, and long-term planning
- Served as lead analyst on federal policy, natural gas, coal economics, and energy markets
- Built a deterministic model analyzing the economics of US coal-fired power plants
- Responsible for conducting economic analysis of federal regulations including: Clean Power Plan, Effluent Limitation Guidelines, Regional Haze, Cross-State Air Pollution Rule, and NAAQS
- Analyzed the impact future environmental regulations would impose on the US coal fleet

Synapse Energy Economics Inc., Cambridge, MA. *Associate*, 2013 –2015
- Reviewed and analyzed economic and technical assumptions of industry forecasts including utility long term plans (Integrated Resource Plans)
- Led researching efforts and conducted primary analysis on the electric industry including utility forecasting, regulatory compliance, and distributed energy resources
- Used optimization models to conduct long term utility analysis
- Modeled costs and benefits of utility programs including energy efficiency and rooftop solar

Independent Consultant, New York, NY. 2011 – 2013
- Analyzed technical and economic drivers for “Green Palm Oil Production” for ETG
- Designed and developed mathematical models for the STAR Community Index
- Assisted in building budget plans and developing fundraising strategies for the Coalition on the Environment and Jewish Life

Environmental Law & Policy Center, Madison, WI. *Policy and Science Intern*, 2011
- Investigated consequences of state policy changes related to wind turbine siting regulations
- Analyzed regional economic impacts of USDA grant data associated with renewable energy provisions of the 2008 Farm Bill

Tel Aviv – Yafo Municipality, Tel Aviv, Israel. *Research Assistant to Deputy Mayor*, 2010
- Helped quantify and monetize the social and economic benefits of existing and proposed policies
- Investigated US and European greenhouse gas emission reduction policies and programs

Baker Hughes - Baker Petrolite (Industrial Division), Honolulu, HI. *Engineer II*, 2006 – 2010
- Managed daily operation of the primary account on the island, worth over $1.8 million annually
- Monitored performance metrics, analyzed project performance, calculated energy and cost savings related to efficiency upgrades
- Consulted with customers on reducing environmental impacts of facilities

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EDUCATION

Columbia University – School of International Public Affairs, New York, NY
Master of Public Administration in Environmental Science and Policy, 2012

University of Texas, Austin, TX
PETEX Petroleum Fundamentals Program, 2007

Florida Institute of Technology – College of Engineering, Melbourne, FL
Bachelor of Science in Chemical Engineering, 2006

TESTIMONY AND PUBLIC COMMENT

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CO_2 Price Forecast

Planning for Future Environmental Regulations

by Patrick Luckow, Joseph Daniel, Spencer Fields, Elizabeth A. Stanton, and Bruce Biewald

This article explores the paths that the electricity sector has taken to appropriately account for the price of carbon dioxide (CO_2) in resource planning.

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U.S. electric utilities and other entities are increasingly incorporating CO_2 price projections into long-term electricity sector planning and investment decisions. Because power plants and other electric sector assets have long lifetimes—often 50 years or longer—prudent, long-term resource planning requires reasonable projections of future prices, both for fuel and for anticipated environmental policies and regulations. Incorporating a price for CO_2 in resource or investment planning benefits project developers, investors, customers, and society as a whole by promoting more economically robust and environmentally friendly power generation portfolios.

Mechanisms for Setting a CO_2 Price

A CO_2 price places a monetary value on the externalities associated with generation from fossil fuel combustion. Mechanisms include direct CO_2 taxes, the trading and sale of CO_2 allowances, a "social cost of carbon" used in federal rulemakings, and marginal CO_2 abatement cost curves used to estimate cost effectiveness of many CO_2 mitigation strategies. Some of these mechanisms, such as a carbon tax or allowance, internalize the external costs of climate change by making polluters pay; other CO_2 price-setting approaches inform regulatory standards in which non-market policies (e.g., unit-specific emissions limits or mandates for improved technology) may be represented by an "effective" price that—if instituted as an allowance or tax—would result in the identical emission reduction as the non-market policy.[1] Utilities can and do internalize an effective CO_2 price in resource planning processes as a way of including the potential costs of future regulations.

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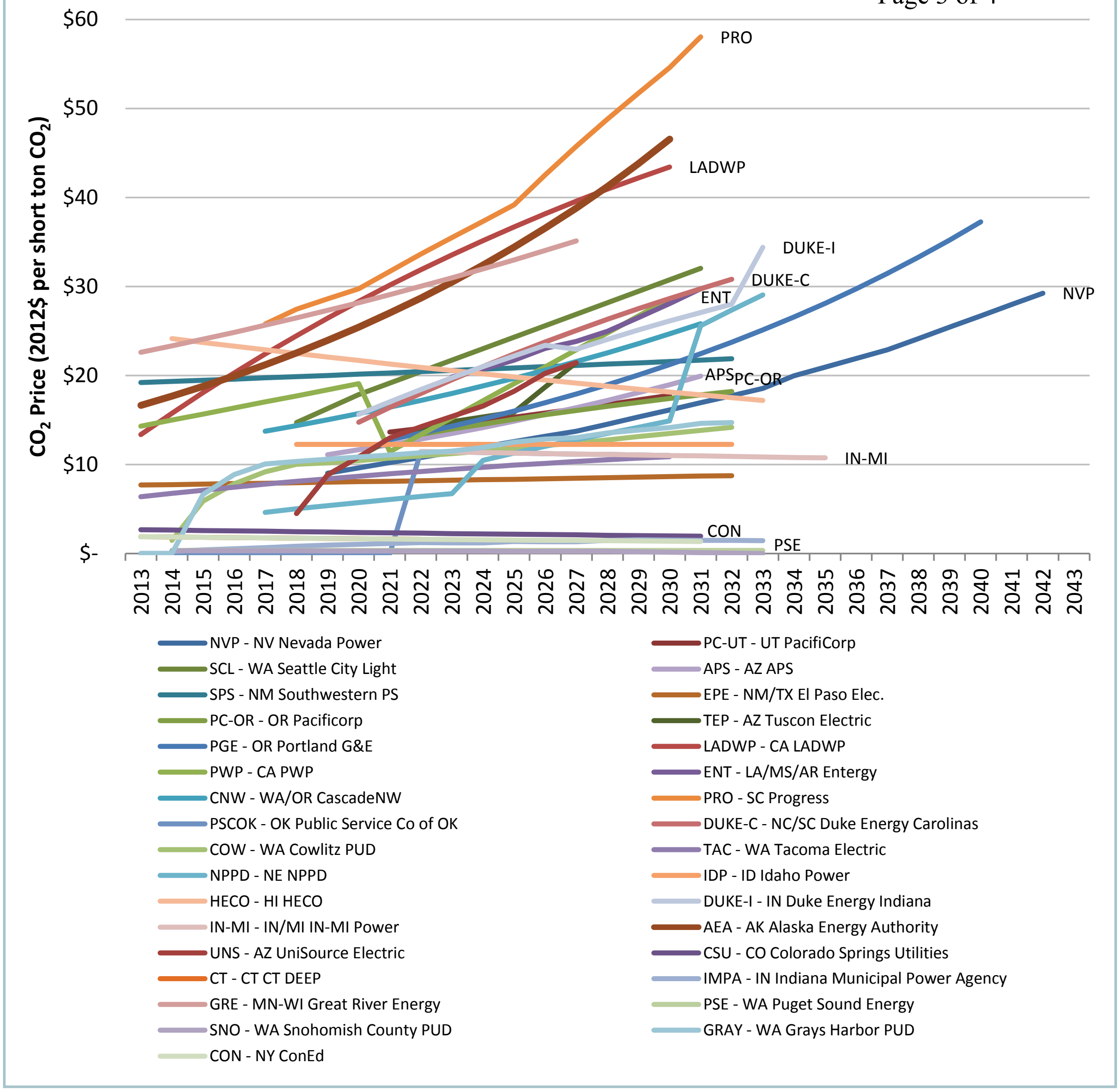
Figure 1. The wide range of CO_2 prices used by utilities in recent IRPs.



CO_2 Prices in Long-Term Utility Planning

The utility Integrated Resource Plans (IRPs) required by many states make it necessary to project future prices for fuel and electricity. The substantial uncertainties in these price forecasts are understood, and are accepted as part of the process of making the best possible predictions given current information. Forecasting a CO_2 price is a similar exercise. Given the current regulatory environment, many utilities have come to recognize that making the assumption that there will be no CO_2 price is unrealistic and may lead to significant unexpected future costs.

An ongoing review by Synapse of IRPs released by U.S. utilities in 2012 or later found that at least 44 IRPs from 39 utilities incorporated CO_2 prices in modeling used to aid in decision-making regarding generation and transmission investments.[2] (Note: These utilities operate in 42 states and represent a substantial fraction of total U.S. generation. States not included do not necessarily neglect CO_2 pricing. Such states may have utilities that do not make IRPs public, do not conduct integrated resource planning, have not produced a new IRP in the 2012–2013 window, or have simply not yet made it into our database.)

Many of these utilities use or incorporate the Synapse CO_2 forecast into their resource planning.[1] The Synapse CO_2 forecast, along with others, is developed through analysis and consideration of the latest information on federal and state policymaking and the cost of pollution abatement. (Note: Other forecasters of CO_2 prices include ICF International, Wood Mackenzie, and Energy Ventures Analysis; however, since the Synapse forecast is the only one that is made public, it is not possible to show comparisons between forecasts here.) Figure 1 presents the range of non-zero CO_2 price forecasts employed by utilities in the reference case (or "business as usual" case) of their 2012 and 2013 IRP planning processes. This figure demonstrates the wide range of CO_2 prices being used by utilities in recent IRPs.

The Writing on the Wall

Federal action is not the only route available to implement carbon prices in the United States. Historically, several states and regions have led the nation on climate and other environmental initiatives, and several states already have a mechanism in place to regulate CO_2 emissions. For example, Minnesota and Washington set baseline CO_2 price forecasts that utilities operating within the state must use in their planning;[3,4] Vermont requires an effective CO_2 price of $80 per ton for utility resource planning;[5] electricity generators in the Northeast states participating in the Regional Greenhouse Gas Initiative purchase allowances for each ton of CO_2 emitted; and California's statewide carbon cap-and-trade program, implemented under AB 32, represents the world's second-largest CO_2 market.

Given the broad scientific consensus on the need to reduce greenhouse gas emissions, it is likely that federal regulatory measures together with state and regional policies will lead to the existence of a cost associated with CO_2 in the near-term. Currently, there is a significant push for CO_2 regulation through Section 111(d) of the U.S. Clean Air Act, which would set caps on carbon emissions, inducing an effective price of carbon. Previous attempts by the U.S. Congress to pass climate legislation either (1) set a carbon price through a cap-and-trade system or carbon tax, or (2) encouraged low-carbon resources through portfolio standards mandating a set fraction of clean energy. These attempts, to date, have been unsuccessful.

Despite these challenges, it is clear that the U.S. federal government is already considering the cost of carbon. Since 2010 the federal government has included a carbon cost (the "social cost of carbon") in regulatory rulemakings to account for the climate damages resulting from each additional ton of greenhouse gas emissions, a value that was recently updated in 2013 to a central value of US$42/t$CO_2$.[6] While the adequacy of the chosen value is still being debated,[7] the federal government is already using this non-zero price in a range of rulemakings, including fuel economy standards, lighting efficiency standards, and air quality rules.

Prudent Planning Is Key

Including a CO_2 price is important in planning for uncertainty in environmental regulations—irrespective of when or how federal and state climate policies are adopted. State and regional policies, together with federal regulatory measures, place economic pressure on CO_2 emitting resources in the next several years, such that it is relatively more expensive to operate a high-carbon-emitting power plant. Delaying action to reduce CO_2 emissions makes emissions mitigation more costly.[8] If no action is taken today—but in 10 or 20 years a decision is made to act abruptly—changes which could have happened gradually over time will have to happen very quickly, and are likely to result in increased costs to utilities and their customers. Both effective CO_2 prices in investment planning and market CO_2 prices in the form of cap-and-trade policies are prudent planning actions that reduce emissions, assist in global efforts to avoid climate damages, and protect public interests. **em**

Utilities can and do internalize an effective CO_2 price in resource planning processes as a way of including the potential costs of future regulations.

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STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for approval of its integrated resource plan	)	Case No. U-20165
pursuant to MCL 460.6t and for related	)	
accounting and ratemaking relief	)	

DIRECT TESTIMONY OF JAMES P. GIGNAC

ON BEHALF OF

THE ENVIRONMENTAL LAW & POLICY CENTER,

THE ECOLOGY CENTER,

THE UNION OF CONCERNED SCIENTISTS,

AND VOTE SOLAR

OCTOBER 15, 2018

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is James P. Gignac. My business address is 1 N. LaSalle St., Suite 1904, Chicago, Illinois, 60602.

Q. By whom are you employed and in what capacity?

A. I am employed by the Union of Concerned Scientists ("UCS") as Lead Midwest Energy Analyst. In this role, I conduct research and analysis to advance understanding of renewable and other energy technologies, policies, and markets, and to evaluate energy resource and climate change mitigation options in the electricity sector.

Q. Please describe the Union of Concerned Scientists.

A. The Union of Concerned Scientists was founded in 1969 by scientists and students at the Massachusetts Institute of Technology. UCS employs scientists, analysts, and engineers to develop and implement innovative, practical solutions to some of the most pressing problems that society faces today—from developing sustainable ways to feed, power, and transport ourselves, to reducing the threat of nuclear war. UCS's mission is to put rigorous, independent science to work by combining technical analysis and effective advocacy to create policy solutions for a healthy, safe, and sustainable future.[1]

Q. Please describe your personal and educational background and professional affiliations.

A. I was born in Rochester Hills, Michigan, and graduated from Romeo Senior High School in Romeo, Michigan. I received a B.A. in History and Political Science from Albion

[1] For more information, including UCS's history and mission statement, visit: https://www.ucsusa.org/about-us.

College located in Albion, Michigan. I earned a Juris Doctorate from Harvard Law School located in Cambridge, Massachusetts. I have been licensed to practice law by the Supreme Court of the State of Illinois since 2005.

Q. Please describe your professional background.

A. I am an analyst and attorney with over thirteen years of experience in the environmental and energy fields. I support UCS's efforts to promote the understanding and adoption of clean energy alternatives in the Midwest and nationally. I joined UCS after serving as Environmental and Energy Counsel and an Assistant Attorney General to the Office of Illinois Attorney General Lisa Madigan. In this capacity I was responsible for representing the office and the state in environmental, energy, and utility regulatory matters including rulemakings and enforcement cases. I began my career as an environmental attorney representing private sector clients and then worked for a national environmental organization assisting efforts related to coal-fired power plants in Midwest states including Michigan. My resume is included as Exhibit ELP-4 (JG-1).

Q. Have you previously testified before this Commission as an expert?

A. No.

Q. Have you provided testimony or comment in other proceedings or venues?

A. With the Illinois Attorney General's Office, I submitted pre-filed testimony to the Illinois Pollution Control Board and appeared for cross-examination as a testifying witness in a rulemaking proceeding involving state air pollution standards for coal-fired power plants. *In the Matter of: Amendments to 35 Ill. Adm. Code 225.233 Multi-Pollutant Standards (MPS)*, R18-20. Also with the Illinois Attorney General's Office, I prepared comments and presentations to the Illinois Commerce Commission on renewable energy matters such as net metering and grid integration of wind and solar power; I assisted with petitions and comments to the Federal Energy Regulatory Commission ("FERC") regarding capacity markets and grid resiliency matters; I prepared comments to the Illinois Department of Natural Resources' rulemaking on high-volume hydraulic fracturing; and I appeared as a witness on behalf of the Illinois Attorney General's Office in state legislative hearings with respect to 2016 legislation on the Illinois Renewable Portfolio Standard.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

- Exhibit ELP-4 (JG-1) Resume of James P. Gignac
- Exhibit ELP-5 (JG-2) Consumers Energy Response to MCV-CE-28
- Exhibit ELP-6 (JG-3) Minnesota Public Utilities Commission Order dated January 11, 2017
- Exhibit ELP-7 (JG-4) Minnesota Public Utilities Commission Order dated April 26, 2017
- Exhibit ELP-8 (JG-5) Report entitled *Best Practices in Electric Utility Integrated Resource Planning*

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you appearing in this case?

A. I am testifying on behalf of the Environmental Law & Policy Center, Ecology Center, the Union of Concerned Scientists, and Vote Solar.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address Consumers Energy's presentation of the Proposed Course of Action ("PCA") in its Integrated Resource Plan ("IRP") as requiring approval in its entirety.

Q. Please summarize your testimony.

A. As my testimony will detail, the presentation of Consumers Energy's IRP as requiring approval of the PCA in its entirety is inconsistent with the Commission's ability to recommend modifications to the IRP, with Consumers Energy's own application, and with examples and best practices of IRPs in other states.

III. REVIEW AND MODIFICATION OF FILED INTEGRATED RESOURCE PLANS

Q. Have you reviewed Consumers Energy's IRP?

A. Yes.

Q. How does Consumers Energy present its Proposed Course of Action ("PCA")?

A. Consumers Energy states that its Proposed Course of Action ("PCA") "requires approval in its entirety." Application at 3.

Q. Can the Commission recommend modifications to a filed plan?

A. Yes. The Commission can recommend changes to the plan, and the electric utility then has an opportunity to file a revised plan that incorporates one or more of the changes. The process is set forth in Section (7) of MCL 460.6t. A possible change recommended by the Commission might, for example, be based on an "*alternative proposal*" provided by an intervening party "to any supply-side generation capacity resource included in the electric utility's integrated resource plan." Section 6t(6) (emphasis added). Moreover, the discovery process related to the integrated resource plan is intended to assist parties and interested persons to gather evidence on, among other things, "*alternatives to the plan* raised by intervening parties." Section 6t(7) (emphasis added). Modifications to the plan may be necessary for the Commission to ultimately determine that, pursuant to

Section 6t(8)(a), "[t]he proposed integrated resource plan represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs." *See also In re: DTE Electric Company*, Concurring Opinion of Commissioner Rachael A. Eubanks, Case No. U-18419 (April 27, 2018) at 5 (observing that Section 6t governing IRPs "allows for a more holistic and inclusive process for how major resource decisions will be made" and that Section 6t "will improve our process and will better incorporate a variety of perspectives instead of starting from a specific utility proposal"). In addition to its application, Consumers Energy also fails in discovery responses to acknowledge the Commission's ability under Section 6t to recommend modifications to the IRP. Instead the company refers to its options in the case of Commission *denial* of the plan under Subsections (9) and (10) of Section 6t. *See* Excerpt of Consumers Energy Response to MCV-CE-28, included as Exhibit ELP-5 (JG-2) (asking, in part, "Is it a standard condition of an IRP for a company to reserve the right to abandon or amend its chosen plan if the Commission rejects or modifies any of its proposals in the IRP?"):

> Subsections (9) and (1) of Section 6t of Public Act 341 detail the options afforded to the Company in the event the Commission denies a utility's IRP or any component thereof. If this Commission does not approve all requested items in the Company's IRP, the Company will utilize these options. Absent approval of all requested items, the Company will be required to consider the abandonment of the Proposed Course of Action and the submission of a different plan altogether.

Q. Is Consumers Energy consistent throughout its application that the PCA cannot be modified?

A. No. Consumers Energy recognizes that events and circumstances may prompt modification of its IRP including the PCA. The company states that "Consumers Energy expressly reserves the right to revise, amend, or otherwise change the relief it is requesting"—which includes approval of the PCA—"in any way appropriate depending upon the duration and progress of hearings in this proceeding, the issuance of Orders that have an impact upon this case, or the occurrence of other material events." Application at 14. Additionally, the Company states that "it is possible that other pending or to-be-filed proceedings or other events may have impacts upon the Company's requests in this proceeding." *Id*. at 14-15. And, further, that "[t]hese impacts will be evaluated for materiality and may need to be considered in the results of this proceeding." *Id.* at 15. While Consumers Energy claims for itself the ability to modify its IRP and the PCA, it should similarly acknowledge it may modify these in response to recommendations from the Commission pursuant to Section 6t.

Q. Have you reviewed IRP orders from other states?

A. Yes, I have reviewed IRP orders issued by the Minnesota Public Utilities Commission ("MPUC").

Q. Why are IRPs in Minnesota relevant to this proceeding?

A. Minnesota has benefited from a strong and robust integrated resource planning system for many years.[2] The IRP in this case is the first one under Section 6t that the Commission has reviewed. As discussed below, state procedures and requirements on IRPs do vary, but there are best practices to be gleaned from how other state commissions approach IRPs, including Minnesota.

[2] *See* https://www.mncee.org/blog/february-2018/minnesota%E2%80%99s-moonshot-decarbonizing-our-electric-s/.

Q. Are filed IRPs in Minnesota modified?

A. Yes, they can be and are modified. For example, in January 2017 the MPUC issued an order approving Xcel Energy's integrated resource plan with modifications. *See Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings,* In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan, Minnesota Public Utilities Commission Docket No. E-002/RP-15-21 (January 11, 2017).[3] In its order the MPUC emphasized the *collaborative* and *iterative* nature of integrated resource plan proceedings:

> Although the Commission must approve, reject, or modify the resource plans of investor-owned utilities, the resource-planning process is largely collaborative and iterative. The process is collaborative because there are a wide array of facts and considerations that may be relevant to resource choices or deployment timetables. The facts on which resource decisions depend—how quickly an area and its need for electricity will grow, how much electricity will cost over the lifetime of a generating facility or a purchased-power contract, how much conservation potential the service area holds and at what cost—*all require the kind of careful judgment that sharpens with exposure to the views of engaged and knowledgeable stakeholders*. The process is iterative because analyzing future energy needs and preparing to meet them is not a static process; strategies for meeting future needs are always evolving in response to changes in actual conditions in the service area. When demographics, economics, technologies, or environmental regulations change, so do a utility's resource needs and its strategies for meeting them.

Id. at 4 (emphasis added). Through the process outlined above, the MPUC modified Xcel Energy's plan to increase the amount of planned large-scale solar acquisition in 2016-2021 from 400 to 650 megawatts. *Id*. at 7. Likewise, in reviewing Otter Tail Power Company's most recent integrated resource plan, the MPUC also issued an order approving the plan with modifications. *See Order Approving Plan with Modifications and Setting Requirements for Next Resource Plan,* In the Matter of Otter Tail Power

[3] Included as Exhibit ELP-6 (JG-3).

Company's 2017-2031 Integrated Resource Plan, Minnesota Public Utility Commission Docket No. E-017/RP-16-386 (April 26, 2017).[4] There the MPUC modified Otter Tail Power Company's plan to include an additional 100 to 200 megawatts of wind power in the 2022-2023 timeframe. *Id*. at 8.

Q. Why is it relevant to this case that IRPs are modified in Minnesota?

A. While the MPUC can directly modify an integrated resource plan under the Minnesota approach to IRPs,[5] as discussed above, this Commission can recommend modifications to the IRP which can then result in a revised plan or proposed course of action reminiscent of what transpired in the Minnesota examples cited above. In those cases, the MPUC was able to ensure, as members of this Commission desire, that the IRP process be "holistic and inclusive" and "incorporate a variety of perspectives." *In re: DTE Electric Company*, Concurring Opinion of Commissioner Rachael A. Eubanks, Case No. U-18419 (April 27, 2018) at 5.

Q. Is it recommendable for an effective IRP process to not consider the possibility of modifying a proposed course of action?

A. No. Industry observers emphasize that effective IRP processes require an active and engaged state commission (referred to as "PUCs" below) to provide oversight and sometimes revision of the proposed plan. *See, e.g., Best Practices in Electric Utility Integrated Resource Planning*, Rachel Wilson and Bruce Biewald, Prepared by Synapse Energy Economics for the Regulatory Assistance Project (June 2013)[6] at 27 ("Active oversight and participation by the state PUC is critical to ensuring that comments and

[4] Included as Exhibit ELP-7 (JG-4).
[5] *See* Minnesota Statutes 216B.2422, Subd. 2(a).
[6] Included as Exhibit ELP-8 (JG-5).

proposals by interveners are reviewed, considered fully, and incorporated into utility resource plans when reasonable."). Like the Minnesota examples I highlight above, Wilson and Biewald note that, in Colorado the PUC "oversees the [IRP] process and may require that utilities revise resource plans in specific ways prior to receiving Commission approval." *Id*. at 21. Similarly, in Oregon, the PUC "acknowledges the plan or returns it to the utility with comments" and "may allow the utility to revise its resource plan before issuing an acknowledgement order." *Id*. at 15. As in the Minnesota examples, the Colorado and Oregon state commissions exercise oversight akin to this Commission's ability to recommend modifications to Consumers Energy's IRP. While state IRP laws and processes are different from one another, and the PUCs in various states have different options available to them, the best practice across all states is for commissions to be active and engaged and use the tools provided to them by the legislatures to ensure effective IRP results.

Q. How should the Commission proceed in this case?

A. The Commission should follow the process of allowing discovery and consideration of alternative proposals by intervening parties and the evaluation of comments and testimony from interested persons. Based upon the established record, the Commission should then determine whether any modifications should be recommended notwithstanding Consumers Energy's assertion in its application that its PCA requires approval in its entirety. At that point in the process (*i.e.*, following issuance of Commission recommendations), it would then be appropriate for Consumers Energy to decide whether to file a revised plan incorporating one or more of the recommendations. Consumers Energy should not at the outset dismiss consideration of recommended modifications from the Commission on the claimed basis that the PCA must be approved in its entirety.

Q. Does this conclude your testimony?

A. Yes.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief	)))))	Case No. U-20165

EXHIBITS OF JAMES P. GIGNAC

ON BEHALF OF

THE ENVIRONMENTAL LAW & POLICY CENTER,

THE ECOLOGY CENTER,

THE UNION OF CONCERNED SCIENTISTS,

AND VOTE SOLAR

OCTOBER 15, 2018

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EXPERIENCE

Lead Midwest Energy Analyst, Union of Concerned Scientists, Chicago, IL

(March 2018-Present). Conduct research and analysis to advance understanding of renewable and other energy technologies, policies, and markets, and to evaluate energy resource and climate change mitigation options in the electricity sector. Write and edit technical reports, fact sheets, and other materials to document and communicate research results; prepare regulatory and legislative comments and testimony; develop policy and legislative proposals; meet with policymakers, regulators, and stakeholders; represent UCS and its positions at public forums.

Environmental and Energy Counsel and Assistant Attorney General to the Office of Illinois Attorney General Lisa Madigan, Chicago, IL

(Nov. 2011-March 2018). Summary: Served as assistant attorney general in advanced special counsel role; handled select regulatory, legislative, and litigation matters with an emphasis on renewable energy, coal, nuclear, efficiency, and climate change issues; explored and evaluated new matters and cases; served as liaison to external stakeholders and groups; interacted with government officials and decision-makers; frequently appeared before state and regional gatherings to speak and present on energy and environmental issues.

Examples of specific roles/efforts:

- Provided expert advice to the Attorney General and senior staff on environmental and energy policy matters;
- Prepared comments, testimony, and draft language for legislative and state commissions and agencies;
- Spearheaded Illinois participation in multi-state attorneys general matters involving federal issues such as: Clean Power Plan litigation, methane regulation, DOE efficiency standards, and other Clean Air Act rules;
- Advised re: Volkswagen $3 billion environmental mitigation trust fund and zero emission vehicle program;
- Focused on implementation of new renewable energy programs in Illinois, especially low-income solar.

Midwest Director, Sierra Club's Beyond Coal Campaign, Chicago, IL

(June 2008-Oct. 2011). Coordinated legal, grassroots organizing, and communications activities to prevent new coal plant projects and to replace existing coal capacity with clean energy solutions; served as coal working group leader for regional network of foundations and advocacy organizations.

Associate, Mayer Brown LLP, Chicago, IL

(Sept. 2005-May 2008). Represented wide variety of private sector clients in environmental litigation, regulatory, and transactional matters, including chemical, railroad, real estate, manufacturing, mining, and wind energy industries.

Judicial Law Clerk, Alaska Supreme Court, Anchorage, AK

(Sept. 2004-Sept.2005). Assisted with all aspects of resolving appellate litigation.

EDUCATION

Harvard Law School, J.D. (2004) (Dean's Award, Community Leadership)

Albion College, B.A., History and Political Science (2001) (*summa cum laude*; Phi Beta Kappa)

TESTIMONY IN REGULATORY AND LEGISLATIVE PROCEEDINGS

- Pre-Filed Testimony on Behalf of the Illinois Attorney General's Office Before the Illinois Pollution Control Board in *In the Matter of: Amendments to 35 Ill. Adm. Code 225.233 Multi-Pollutant Standards (MPS)*, R18-20 (December 11, 2017)
    - Responses to Pre-Filed Questions (January 12, 2018)
    - Testifying Witness at Hearings (January 17-18, 2018)
    - Responses to Questions (February 16, 2018)
    - Testifying Witness at Hearing (March 7, 2018)
- Testimony Before the State of Illinois House of Representatives Renewable Energy & Sustainability Committee, Hearing on Consumer and Public Health Impacts of Utilizing Renewable Energy Sources and Increased Energy Efficiency Programs (April 29, 2015)

COMMENTS IN REGULATORY PROCEEDINGS

- Illinois Commerce Commission *NextGrid* Process, Multiple Written Comment Submissions and Participation in Working Groups on Behalf of Union of Concerned Scientists (June-September 2018)
- Comments on Behalf of Union of Concerned Scientists, et al. to the Illinois Commerce Commission's Distributed Generation Valuation and Compensation Workshop (July 27, 2018 and March 30, 2018)

- Comments on Behalf of the Illinois Attorney General's Office to the Illinois Commerce Commision Workshops Regarding Resource Adequacy in MISO Zone 4 (January 30, 2018 and November 30, 2017)
- Verified Reply to Responses to Objections to the Illinois Commerce Commission on the *Illinois Power Agency Petition for Approval of the Long-Term Renewable Resources Procurement Plan*, Docket No. 17-0838 (January 25, 2018); Response to Objections (January 11, 2018)
- Comments on Behalf of the Illinois Attorney General's Office to the Illinois Power Agency Regarding the Draft Long-Term Renewable Resources Procurement Plan (November 13, 2017)
- Comments on Behalf of the Illinois Attorney General, et al. to the Federal Energy Regulatory Commission in *Grid Reliability and Resiliency Pricing*, Docket No. RM18-1 (October 23, 2017)
- Comments on Behalf of the Illinois Attorney General's Office to the Illinois Power Agency Regarding Development of Long-Term Renewable Resources Procurement Plan (July 5, 2017)
- Comments on Behalf of the Illinois Attorney General's Office to the U.S. Department of Justice on the Proposed Partial Consent Decree in *In re: Volkswagen "Clean Diesel" Marketing, Sales Practices, and Products Liability Litigation*, Case No: MDL No. 2672 CRB (JSC) (August 5, 2016)
- Response Comments on Behalf of the People of the State of Illinois Before the Illinois Pollution Control Board in *In the Matter of Amendments to 35 Ill. Adm. Code Part 214, Sulfur Limitations, Part 217 Nitrogen Oxides Limitations, and Part 225, Control of Emissions From Large Combustion Sources*, R-15-21 (September 11, 2015); Initial Comments (August 28, 2015)
- Verified Initial Comments on Behalf of the People of the State of Illinois Before the Illinois Commerce Commission in *Amendment of 83 Ill. Adm. Code 465 [Net Metering]*, ICC Docket No. 15-0273 (June 24, 2015); Verified Reply Comments (July 27, 2015)
- Complaint to Federal Energy Regulatory Commission, *Challenging the MISO 2015-16 Planning Resource Auction Rate for Zone 4 as Unjust and Unreasonable*, Docket No. EL15-71 (May 28, 2015); Response to Motions to Dismiss and Answer (July 17, 2015); Answer (August 14, 2015)
- Post-Hearing Comments to the Illinois Pollution Control Board in *In the Matter of: Coal Combustion Waste (CCW) Surface Impoundments at Power Generating Facilities: Proposed New 35 Ill. Adm. Code 841*, R14-10 (October 20, 2014)

- Comments to the Illinois Department of Natural Resources on Proposed Administrative Rules for the Hydraulic Fracturing Regulatory Act (62 Ill. Adm. Code 245 and 240.796) (January 2, 2014)
- Comments to the Illinois Pollution Control Board in *Illinois Power Holdings, LLC v. Illinois Environmental Protection Agency*, PCB 14-10 (Variance-Air) (September 24, 2013)
- Comments to the Illinois Power Agency on the 2013 Draft Procurement Plan (September 14, 2012)
- Comments to the Illinois Pollution Control Board in *Ameren Energy Resources v. Illinois Environmental Protection Agency*, PCB 12-126 (Variance-Air) (July 23, 2012); Post-Hearing Comments (August 10, 2012)

PRESENTATIONS

- Illinois Climate and Energy Activities: Federal and State, Chicago Bar Association (Chicago, IL) (February 21, 2018)
- Illinois Commerce Commission Renewable Energy Policy Session (Chicago, IL) (July 12, 2017)
- The Changing Electricity Grid: Issues and Opportunities for State Attorney General Offices, National Association of Attorneys General (Charlotte, NC) (March 17, 2016)
- Clean Power Plan Litigation, Chicago Bar Association (Chicago, IL) (March 2016)
- Closing and Redeveloping Power Plant Sites: Lessons from the Chicago Area, American Bar Association (Chicago, IL) (October 29, 2015)
- Clean Power Plan Update, Illinois State Bar Association (Chicago, IL) (October 21, 2015)
- Clean Power Plan Implementation, Air & Waste Management National Conference (Rosemont, IL) (September 2015)
- Air Regulatory Update & Clean Power Plan Implementation, Midwest Environmental Enforcement Association (Madison, MI) (July 1, 2015)
- Nuclear Power Update, Midwest Environmental Enforcement Association (Madison, WI) (July 1, 2015)
- Petroleum Coke Regulation, Illinois State Bar Association (Chicago, IL) (April 2015)
- Climate Adaptation and Environmental Law, Chicago Bar Association (Chicago, IL) (February 24, 2015)

- Illinois Fracking Regulations, Illinois Institute for Continuing Legal Education (Chicago, IL) (January 2015)
- Illinois Air Update, Lake Michigan Association of Air & Waste Management (Oak Brook, IL) (November 12, 2014)
- Moderator to Illinois State Bar Association Panel on Illinois Renewable and Energy Efficiency Portfolio Standards Panel (Chicago, IL) (March 2014)
- Carbon Pollution and the Clean Air Act: Where We've Been and Where We're Going, Chicago Bar Association (Chicago, IL) (February 25, 2014)
- High-Volume Horizontal Fracturing Regulation in Illinois, Illinois State Bar Association (Chicago, IL) (March 2013)
- Update on Clean Air Act Regulatory Activity and Current Events in the Electricity Sector, Midwest Environmental Enforcement Association (Jefferson City, MO) (June 28, 2012)
- Update on Recent Clean Air Act Rulemakings and Litigation, Chicago Bar Association (Chicago, IL) (March 21, 2012)

20165-MCV-CE-145

Question:

MCV-CE-28: Refer to the direct testimony of Melissa Hauch. Is it a standard condition of an IRP for a company to reserve the right to abandon or amend its chosen plan if the Commission rejects or modifies any of its proposals in the IRP? If yes, please identify each IRP that contains such a provision.

Response:

The Integrated Resource Plan (IRP) filed by the Company on June 15, 2018 is the first IRP filed by any utility in Michigan pursuant to Section 6t of Public Act 341. As such, no precedent has been set, and there is no basis to establish a standard condition.

The Company's IRP requests several approvals that are critical for successful execution of the Company's Proposed Course of Action. Retirement of the Karn 1 and 2 generating units will only be realized if the Company receives approval to recover costs invested in those units. Execution of the Proposed Course of Action will only be realized if the Company receives approval for its proposed competitive bid and financial compensation mechanisms.

Subsections (9) and (10) of Section 6t of Public Act 341 detail the options afforded to the Company in the event the Commission denies a utility's IRP or any component thereof. If the Commission does not approve all requested items in the Company's IRP, the Company will utilize these options. Absent approval of all requested items, the Company will be required to consider the abandonment of the Proposed Course of Action and the submission of a different plan altogether.

Richard T. Blumenstock

Richard T. Blumenstock
September 11, 2018

Electric Supply

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John A. Tuma	Commissioner

In the Matter of Xcel Energy's 2016–2030 Integrated Resource Plan

ISSUE DATE: January 11, 2017

DOCKET NO. E-002/RP-15-21

ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS

PROCEDURAL HISTORY

On January 2, 2015, Northern States Power Company d/b/a Xcel Energy (Xcel) filed a resource plan under Minn. Stat. § 216B.2422 and Minn. R. 7843.0400, covering the period 2016–2030.

On January 16, 2015, the Commission issued a Notice of Comment Period and Procedures on Resource Plan, requiring Xcel to submit a revised preferred plan that incorporated resource decisions made in Docket E-002/CN-12-1240.[1] The Commission also established a public comment and reply-comment period for the resource plan.

On October 2, 2015, in response to stakeholder comment filings and information requests, Xcel filed reply comments proposing significant changes to its resource plan.

On January 6, 2016, the Commission issued an order requiring Xcel to supplement its resource plan no later than January 29, 2016, by filing updated plans and related additional analysis.[2] The order provided that the Commission would establish a procedural schedule after the Minnesota Department of Commerce (the Department) had an opportunity to initially review the filing and make procedural recommendations.

[1] In Docket E-002/CN-12-1240 the Commission approved certain power purchase agreements to meet identified resource needs arising before 2019. *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need*, Order Approving Power Purchase Agreement with Calpine, Approving Power Purchase Agreement with Geronimo, and Approving Price Terms With Xcel (February 5, 2015).

[2] Order Requiring Supplemental Filing (January 6, 2016).

On January 29, 2016, Xcel filed a supplement describing its "Current Preferred Plan." The supplemented resource plan proposed:

- Ceasing coal operations at Sherburne County Generating Station (Sherco) Units 1 and 2 in the 2020s;
- Adding 1,400 megawatts of large-scale solar (400 megawatts by 2020);
- Adding 1,800 megawatts of wind (800 megawatts by 2020);
- Adding natural gas generation in the 2020s, including a combustion turbine generator in North Dakota, and a combined cycle generator on the Sherco site by 2026.

On February 29, 2016, after conducting discovery and holding discussions with the Company, the Department filed its review of the plan and made procedural recommendations.

On March 3, 2016, the Commission requested comments on whether Xcel's Current Preferred Plan is in the public interest.

By July 8, 2016, the Commission received comments from:

- Becker City Council
- Fresh Energy, Minnesota Center for Environmental Advocacy, Sierra Club, and Wind on the Wires (the Clean Energy Organizations)
- EDF Renewable Energy
- Enel Green Power North America, Inc.
- Hennepin County
- Institute for Local Self-Reliance
- Invenergy LLC
- Minnesota Department of Commerce (the Department)
- Minnesota Pollution Control Agency
- Minnesota State Representative Jim Newberger
- NextEra Energy Resources, LLC
- Prairie Island Indian Community
- St. Paul Cogeneration, LLC
- Sherburne County Administration
- Flint Hills Resources, LP; Gerdau Ameristeel US Inc.; Unimin Corporation; and USG Interiors LLC (the Xcel Large Industrials)

By August 12, 2016, the Commission received reply comments from:

- City of Red Wing
- Center for Energy and Environment
- City of Minneapolis
- the Clean Energy Organizations

- Health Professionals for a Healthy Climate
- the Saint Paul Area Chamber of Commerce
- Sierra Club-organized individuals and organizations
- Xcel Energy
- Xcel Large Industrials
- 3 individuals via SpeakUp

On September 13, 2016, the Department submitted supplemental comments. The Department recommended approval of Xcel's revised resource plan, with further modifications and additional filing requirements.

On October 6 and 13, 2016, the Commission met to consider the matter.

FINDINGS AND CONCLUSIONS

I. Summary of Commission Action

In this order, the Commission will approve a modified version of Xcel's supplemented resource plan and set requirements for future resource plan filings. The Commission will:

- approve the acquisition of at least 1000 MW of wind generation by 2019 and at least 650 MW of solar generation by 2021;
- approve the retirement of Sherco 2 in 2023, and Sherco 1 in 2026;
- determine that there will likely be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco 1 in 2026.

The Commission will also approve resource acquisition processes to meet anticipated generation needs in a manner consistent with the public interest.

II. Legal Background

A public utility providing electricity to at least 10,000 customers and capable of generating 100 megawatts (MW) of electricity must file a resource plan or report for the Commission's approval, rejection, or modification. A resource plan or report generally details the projected need for electricity in its service territory for a forecasted planning period, and the utility's plans for meeting projected need, including the actions it will take in the next five years.[3] Resource plans are evaluated on their ability to:

> A. maintain or improve the adequacy and reliability of utility service;
>
> B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;

[3] Minn. Stat. § 216B.2422; Minn. R. Chap. 7843.

> C. minimize adverse socioeconomic effects and adverse effects upon the environment;
>
> D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
>
> E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.[4]

To reliably provide the electricity demanded by its customers, an electric utility considers both supply and demand. The utility can supply electricity through a combination of generation and power purchases, and by reducing the amount of electricity lost through transmission and distribution. The utility can manage customer demand by encouraging customers to conserve electricity or to shift activities requiring electricity to periods when there is less demand on the electric system. A resource plan contains a set of demand- and supply-side resource options that the utility could use to meet the forecasted needs of retail customers.[5]

By integrating the evaluation of supply- and demand-side resource options—treating each resource as a potential substitute for the others—a utility can find the least-cost plan that is consistent with legal requirements and policies.

Although the Commission must approve, reject, or modify the resource plans of investor-owned utilities, the resource-planning process is largely collaborative and iterative.

The process is collaborative because there are a wide array of facts and considerations that may be relevant to resource choices or deployment timetables. The facts on which resource decisions depend—how quickly an area and its need for electricity will grow, how much electricity will cost over the lifetime of a generating facility or a purchased-power contract, how much conservation potential the service area holds and at what cost—all require the kind of careful judgment that sharpens with exposure to the views of engaged and knowledgeable stakeholders.

The process is iterative because analyzing future energy needs and preparing to meet them is not a static process; strategies for meeting future needs are always evolving in response to changes in actual conditions in the service area. When demographics, economics, technologies, or environmental regulations change, so do a utility's resource needs and its strategies for meeting them.

III. Xcel's Resource Plan

Xcel projects that, under median forecast conditions, it will have sufficient generation capacity until the mid-2020s, but that three main factors will lead to a need for additional generating capacity in or around 2025. The Company expects the need for new generating capacity to be driven primarily by: (1) Xcel's proposal to retire Sherco units 1 and 2 (1,400 MW of generating capacity), (2) the retirement of roughly 850 MW of aging, Xcel-owned peaking plants, and (3) the expiration of power purchase agreements (PPAs) for more than 2,000 MW. The exact timing

[4] Minn. R. 7843.0500, subp. 3.

[5] Minn. Stat. § 216B.2422, subd. 1(d).

and amount of the anticipated need depends on the timing of plant retirements as well as the adoption of community solar gardens (CSGs) and other factors.

Xcel used an industry-standard modeling tool called Strategist to analyze its projected resource needs and propose its preferred plan for meeting the need. Based on its analysis, Xcel proposed to acquire 1,400 MW of large-scale solar, 1,800 MW of wind, and 2,856 MW of natural gas generation over the planning period.

To address a portion of the identified need, the Company specified that it preferred to use the Sherco site for an approximately 800 MW combined cycle natural gas plant. The Company acknowledged that its proposal goes beyond the Commission's historical approach to resource planning by specifying a location for a proposed plant. Xcel asserted that determining the proposed plant's size, type, timing, *and* location in this proceeding would be appropriate because the location is supported by reliability and socioeconomic factors and because a location determination now would provide certainty to employees and the community, which would likely be affected by retirement of Sherco units 1 and 2.

The Department replicated Xcel's modeling in Strategist, reviewed the Company's base assumptions, and ran additional scenarios under a variety of contingencies (or sensitivities). Based on its analysis and modeling, the Department made its own planning recommendations. Overall, the Department largely agreed with Xcel's planned resource additions and retirements, and recommended approval of the plan with modifications.

Concerns about Xcel's plan raised by the Department and other commenters fell into three broad categories: forecasts, modeling, and assumptions underlying the plan; details of proposed five-year and intermediate-term resource decisions; and information needed to evaluate future resource plans. These issues are addressed, with plan modifications and filing requirements where appropriate, in the sections below.

IV. Forecasting

Xcel forecasted energy requirements and peak demands from 2016 through 2030 using monthly data from 1998 to 2014. The Department raised concerns about the analyses Xcel used to reach its forecasting conclusions.

A. Positions of the Parties

The Department recommended approval of Xcel's base energy forecast and peak demand forecast for planning purposes only. In particular, the Department argued that the forecast results were subject to some uncertainty and, in light of the uncertainty, the use of the forecasts should be limited.

At the Commission meeting, Xcel agreed with the Department that its energy and peak demand forecasts should only be used for planning purposes.

B. Commission Action

The Commission agrees that Xcel's Strategist-modeled energy and demand forecast is acceptable for planning purposes but concludes it should not be used to support any resource acquisition proposal beyond the five-year action plan. Disagreement over Xcel's methodology for forecasting the long-term peak-demand growth rate and the long-run effects of Demand Side Management raise doubts about the forecasts' usefulness beyond the five-year action plan. The Commission is persuaded that the use of these forecasts should be limited as the Department has proposed. Resource acquisitions beyond the five-year plan should be subject to a more contemporaneous demonstration of need. The Commission will so order.

V. Five-Year Action Plan

Based on its forecasts, Xcel initially proposed adding 400 megawatts of large-scale solar by 2020, and 800 megawatts of wind. While generally supportive of Xcel's proposed resource additions, the Department recommended slightly different quantities and timing. Other commenting parties were also generally supportive of Xcel's proposals for wind and solar acquisitions through 2021.

The process or processes by which Xcel would pursue approved wind and solar resource acquisitions was subject to more disagreement. The process for acquiring generation resources can have a significant effect on the type, cost, and ownership structure of proposals submitted for consideration and ultimately chosen for acquisition. Xcel's proposal included 50% Company-owned wind resources.

A. Positions of the Parties

Xcel proposed to use what it characterized as a modified Track 1 Request for Proposals (RFP) process[6] to both acquire wind projects and demonstrate the competitiveness of its self-build proposal. Xcel's proposal contained features of both track 1 and track 2 acquisition processes—it contemplates both competitive bidding and a competing Company-owned resource proposal.

The Company proposed the following process:

1) Xcel issues an RFP for wind resources.[7]

[6] The Commission has approved a two-track resource acquisition process—which among other things provides that a competitive bidding process governs when Xcel does not submit a proposal in a competitive resource procurement process (Track 1), and that a Certificate-of-Need-like process governs procurement when Xcel does submit a proposal (Track 2). *In the Matter of Northern States Power Company d/b/a Xcel Energy's Application for Approval of its 2004 Resource Plan*, Docket No. E-002/RP-04-1752, Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, Subd. 5, and Requiring Compliance Filing (May 31, 2006). More detail on the lengthy history of the two-track bidding process can be found in the Department's Comments, pp. 44–50. (July 8, 2016).

[7] Xcel issued an RFP for wind resources on September 22, 2016, with a bid deadline of October 25, 2016. The Company states that it anticipates seeking Commission approval for agreements arising from the RFP in early 2017. Xcel Letter, this docket (September 22, 2016).

2) The day prior to receiving wind bids, Xcel will submit its own self-build proposal including estimates of final costs.
3) Xcel will evaluate the bids and select projects for negotiations based on a list of factors (factors which Xcel outlined in its reply comments).
4) Xcel will file with the Commission the results of the bidding process, project rankings, its analysis, and the results of a third party auditor's report of its bidding and review process. Additionally, Xcel will evaluate the criteria outlined in the Minn. Stat. § 216B.243, subd. 9 certificate of need exemption for renewable energy standard (RES) facilities.

Xcel argued that this modified or hybrid acquisition process was appropriate to ensure the timely and cost-effective acquisition of wind resources and to reduce the burden on wind developers. The Company also argued that Commission approval of the proposed process would exempt the chosen projects from a certificate of need requirement under Minn. Stat. § 216B.2422, subd. 5.

The Department, on the basis of its independent modeling and analysis, recommended that the Commission modify Xcel's action plan to acquire about 1,000 MW of wind by 2019 (instead of 800 MW in 2018) and to remove the large-scale solar from the action plan to allow for greater certainty from the CSG program. The Department also recommended that the Commission approve Xcel's proposed, modified acquisition process,[8] with the proper mix of purchased power and Company-owned resources determined by the facts established during the acquisition process regarding alternatives.

The Clean Energy Organizations advocated for a transparent acquisition process that would accommodate a variety of ownership structures and for regulatory oversight to protect ratepayer and public interests. The Institute for Local Self-Reliance objected to the Company's proposal to commit to Xcel's contemplated 50% Company ownership of proposed wind resources.

B. Commission Action

Despite slight variation in the exact timing and magnitude, the record clearly showed that acquisition of wind and possibly solar resources in the next five years represents the least-cost method of meeting Xcel's near-term resource needs. The Commission finds that the record shows that it is reasonable to acquire at least 1000 MW of wind by 2019. This acquisition is least-cost even though Xcel does not show a planning capacity deficit until the mid 2020s because it will provide incrementally lower-cost energy, thereby reducing system costs. Upon submission of evidence such as price, bidder qualifications, rate impact, transmission availability and location, additional acquisitions may be approved.

The Commission will modify Xcel's plan to acquire 400 MW of large-scale solar in 2016–2021. Instead, Xcel will be required to acquire approximately 650 MW of solar in this timeframe through a combination of the Company's community solar gardens program or other acquisitions (without limitation to "large-scale" solar). The Company may pursue additional, cost-effective

[8] Though initially the Department's recommendation was limited to approving a process for proposed wind acquisitions, at the Commission meeting the Department elaborated on its recommendation, agreeing with a proposal that the Commission "authorize use of the modified Track 2 bidding process and authorize the process as a Commission-authorized bidding process [under Minn. Stat. § 216B.2422, subd. 5(c)]" without expressing a requirement that the process be limited to wind acquisitions.

solar resources if it is in the best interests of its customers. Xcel shall report on its progress in its next resource plan.

Minn. Stat. § 216B.2422, subd. 5(a), provides that a utility may select resources to meet its projected energy demand through a bidding process approved or established by the Commission. The Commission established the existing two-track bidding process for Xcel just over a decade ago. Having reviewed the Company's proposed, modified acquisition process, the Commission agrees that it is a reasonable method of acquiring wind and solar resources in the 2016–2021 timeframe.

The Commission will therefore approve the bidding process described by Xcel for the limited purpose of acquiring wind and solar resources in the 2016–2021 timeframe. The Commission declines to approve the proposed acquisition process without limitation because the two-track process has provided needed certainty and transparency for participants and regulators. But in this case, given the scope and nature of the needed acquisitions, and the need for prompt action, the Commission agrees that the proposed modified process is reasonable and appropriate.

VI. Intermediate Term—Sherco Units 1 and 2

Xcel proposes to retire Sherco Units 1 and 2 before 2030. The two generating units produce approximately 1,400 MW of capacity and associated energy. Together with its proposal to retire the two units, Xcel proposes to construct a 780 MW combined-cycle generating unit on the Sherco site.

A. Positions of the Parties

There was no material disagreement among stakeholders over the proposed retirement of Sherco Units 1 and 2. Retirement of these units is supported by the Company's and Department's modeling showing that retirement is part of virtually every least-cost planning scenario, with some room to argue over the precise year in which to retire each unit.

While the need for some additional resources between 2025 and 2030 was relatively uncontroversial, details of Xcel's proposal drew some criticism, particularly the proposal to identify a specific generator fuel-type and location to meet the identified need. The Company asserted that socio-economic and technical factors justified identifying a fuel type and location as part of this proceeding.

Apart from the Sherco location's general suitability for new generating facilities because a generating facility is already sited there, Xcel argued that committing to the location would clearly mitigate the negative impact of the plant retirements for that community. It also argued that from a business planning perspective having those details decided well in advance would facilitate the Company's efforts to smoothly transition employees in the retiring plants. Finally, it contended that engineering studies showed that a combined cycle generator on the Sherco site would be uniquely well-suited to address grid reliability concerns that would need to be addressed in the same time frame.

Xcel's proposal received support from the City of Becker and Sherburne County Administration, and State Representative Jim Newberger. These commenters identified that retirement of the Sherco coal-fired plants would be detrimental to the local economy, and that building replacement generation on the site would mitigate the negative impact.

The Department, the Clean Energy Organizations, and the Xcel Large Industrials objected to a decision that would commit to specifics such as the exact location, fuel type, and generation capacity. They argued that the need for a decision on those details was not immediate, and would be better left for future consideration—which would allow more flexibility to consider alternatives in the meantime.

B. Commission Action

Historically, the Commission has used resource planning as a tool to assess and determine the appropriate size, type, and timing of generation resources. At issue is the level of planning detail the Commission should commit to as part of approving this resource plan.

At the Commission meeting, it became clear that the distance between the stakeholders' positions is small but nuanced. Xcel wishes for the Commission to approve an approximately 780 MW combined cycle facility at a particular location. The Department recommended that the Commission find a need for approximately 750 MW of "intermediate capacity."[9] And the Clean Energy Organizations recommended that the Commission find a need for approximately 750 MW of capacity.

The Commission is persuaded by the argument that, given the Sherco retirement dates of 2023 and 2026, it is premature at this time to determine with specificity the fuel type and location to address the identified 750 MW capacity need. The Commission is not persuaded that alternatives to the reliability concerns raised by Xcel have been fully considered, and believes there is adequate time to explore other resource options and consider the relevant socioeconomic factors without jeopardizing the feasibility of Xcel's preferred plan to build a combined cycle unit on the Sherco site.

Therefore, the Commission concludes that, more likely than not, there will be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco 1 in 2026. The Commission will authorize a certificate of need process to evaluate options for addressing this anticipated need. The process will allow consideration of resources or resource combination alternatives that meet the identified resource and reliability need without prejudging or foreclosing Xcel's preferred plan. Potential need-addressing alternatives between 2025 and 2030 could include renewal of some expiring PPAs, additional demand response, or some other new generation.

The certificate of need process will also be based on a more precise and contemporaneous forecast. Under Minn. Stat. § 216B.243, the Commission must consider the accuracy of the long-range energy demand forecasts offered to justify a certificate of need. As stated above, the forecasts in this resource plan may not be used to support acquisitions beyond Xcel's five-year action plan. At the Commission meeting, Xcel agreed that a certificate of need filing would incorporate an updated energy and demand forecast for Commission evaluation.

[9] The Department defined "intermediate" capacity facilities as having an overall capacity factor of 20–40%, as distinct from "baseload" (higher capacity factor), and "peaking" (a lower capacity factor). Capacity factor reflects the ratio of a facility's actual output over time relative to its nameplate capacity.

VII. Intermediate Term—Other Resources

The Commission will also require Xcel to evaluate and pursue other resource options between 2023 and 2030. In light of rapidly changing costs among potential energy and capacity sources, Xcel must maintain flexibility and consider a broad range of resource options. In addition to requiring evaluation of combinations of supply-side, demand-side, and transmission alternatives to address its 750 MW need identified above, Xcel's plan must include the acquisition of no less than 400 MW of additional demand response by 2023. This level of potential demand response capacity is supported by even the most conservative study of Xcel's system in the record.

For reasons similar to those stated above regarding the contemplated Sherco replacement, Xcel's planned additions of combustion turbine generation in 2025–2030 will also be modified to be less specific. Rather than approve a plan with a specific generation type or location for those resource additions, the Commission concludes that a plan that does not specify location or generation type in that time frame will be more consistent with the public and ratepayer interests.

VIII. Requirements for Future Resource Plans

Finally, the Commission will direct that Xcel investigate, evaluate, and discuss an array of resource and planning issues that arose during the course of this proceeding. Major plant retirements are coming over Xcel's planning horizon in upcoming resource planning cycles, and it is important that Xcel, the Commission, and stakeholders regard system needs holistically. As this proceeding demonstrated, individual plant retirements can give rise to complex locational and system concerns that, without sufficiently forward-looking planning, may constrain future decisions. Considering the future of Xcel's system as a whole as its generation fleet ages will help maximize planning flexibility.

ORDER

1. Xcel Energy's 2016–2030 Resource Plan is approved with the modifications required by this order.

2. Xcel's Strategist-modeled energy and demand forecast is acceptable for planning purposes but may not be used to support any resource acquisition proposal beyond the five-year action plan.

3. It is reasonable to acquire at least 1000 MW of wind by 2019. Acquisition of greater than 1000 MW may be approved upon submission of evidence such as price, bidder qualifications, rate impact, transmission availability, and location.

4. Xcel's resource plan is modified as follows:

    a. to remove 400 MW of large-scale solar in 2016–2021. Xcel shall acquire approximately 650 MW of solar in 2016–2021 through a combination of the Company's community solar gardens program or other acquisitions. The Company may pursue additional, cost-effective solar resources if it is in the best interests of its customers.

    b. to change Xcel's proposed Fargo combustion turbine to a generic combustion turbine.

c. to change Xcel's planned CT additions in the 2025–2030 time frame to provide instead for adding the most cost-effective combination of resources consistent with state energy policies, including but not limited to the following resource options: large hydropower, short-term life extensions of Xcel-owned peaking units, natural gas combustion turbines, demand response, utility-scale solar generation, energy storage, and combined heat and power.

5. Concerning wind and solar resource acquisitions, Xcel:

   a. may use the modified Track 2 process for the acquisition of wind resources included in the five-year action plan, and for any additional solar, if needed, through 2021;

   b. shall, if Xcel intends to provide a bid for wind generation, acquire wind resources through the modified Track 2 process.

   c. shall file a contingency plan early in the process (preferably with the filing of the Company's self-build proposal) to address the potential for the bidding process to fail; and

   d. shall, in wind acquisition proceedings, describe how revenues from wind generation sold into the MISO market will be returned to Minnesota ratepayers, and provide an estimate of these revenues.

   The proper mix of purchased power and Company-owned resources shall be determined during the resource acquisition process.

6. In any filing seeking approval of wind resources, Xcel shall discuss each project's wind curtailment risk.

7. Xcel's schedule to retire Sherco 2 in 2023, and Sherco 1 in 2026, is approved.

8. The Commission finds that more likely than not there will be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco 1 in 2026.

9. Xcel is authorized to file a petition for a certificate of need under Minn. Stat. § 216B.243 to select the resource or resource combination that best meets the system resource and reliability needs associated with the retirement of Sherco 1 in 2026. The Company's filing and the proceeding shall:

   - evaluate combinations of supply-side, demand-side, and transmission alternatives;
   - consider location-specific factors related to socioeconomic impacts on the local community and regional reliability;
   - allow for utility ownership of replacement resources if determined to be in the best interest of customers;
   - comply with all relevant state energy policies; and
   - ensure public participation.

10. Xcel shall acquire no less than 400 MW of additional demand response by 2023.

11. An average annual energy savings level of 444 GWh for all planning years is approved.

12. Xcel shall investigate the potential for an energy-efficiency competitive bidding process for customers that have opted out of the statewide Conservation Improvement Program (CIP) under Minn. Stat. § 216B.241, subd. 1a(b).

13. Xcel shall file its next resource plan on February 1, 2019.

14. In its next resource plan filing, Xcel shall:

    a. describe its plans and possible scenarios for cost-effective and orderly retirement of its aging baseload fleet, including Sherco, King, Monticello, and Prairie Island.

    b. evaluate combinations of supply-side (distributed and centralized), demand-side, and transmission solutions that could in the aggregate meet post-retirement energy and capacity needs as well as contribute to grid support.

    c. explore the role of cost-effective combined heat and power solutions.

    d. report on its solar acquisition progress.

    e. provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025.

    f. summarize its investigation and findings concerning the potential for an energy-efficiency competitive bidding process for customers that have opted out of CIP.

15. In future resource plan filings, analysis and inputs must, to the extent possible, be consistent with Xcel's distribution system planning.

16. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf
Executive Secretary

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

In the Matter of Otter Tail Power Company's 2017–2031 Integrated Resource Plan

ISSUE DATE: April 26, 2017

DOCKET NO. E-017/RP-16-386

ORDER APPROVING PLAN WITH MODIFICATIONS AND SETTING REQUIREMENTS FOR NEXT RESOURCE PLAN

PROCEDURAL HISTORY

On June 1, 2016, Otter Tail Power Company (Otter Tail or the Company) filed its 2017–2031 resource plan under Minn. Stat. § 216B.2422 and Minn. R. Ch. 7843.

On October 6, 2016, the Division of Energy Resources of the Department of Commerce (the Department), and the Clean Energy Organizations filed comments on Otter Tail's plan.[1]

The Department recommended approval with modifications and requested that Otter Tail file updated planning models and additional forecast data. The Clean Energy Organizations recommended delaying approval of Otter Tail's proposal to construct a 248 MW simple cycle natural gas combustion turbine to replace its retiring Hoot Lake Plant, and recommended requiring Otter Tail to acquire 200 additional megawatts (MW) of wind and to increase its energy efficiency goal.

On December 5, 2016, the Commission received reply comments from Otter Tail, the Midwest Large Energy Consumers, the Clean Energy Organizations, and the Department.

In its reply comments, Otter Tail included modifications to its proposed resource plan in response to the Department's comments and emphasized the need for a dispatchable unit to cost-effectively replace the capacity of the Hoot Lake Plant. The Clean Energy Organizations concurred with the Department's recommended energy efficiency goal of 46.8 gigawatt-hours. The Midwest Large Energy Consumers recommended approval of Otter Tail's proposed resource plan.

On March 16, 2017, the Commission met to consider the resource plan.

[1] The Clean Energy Organizations are Fresh Energy, Minnesota Center for Environmental Advocacy, Sierra Club, and Wind on the Wires.

FINDINGS AND CONCLUSIONS

I. Background

A. The Resource-Planning Process

The resource-planning statute and rules are detailed, but basically they require a utility to file biennial reports on (1) the projected energy needs of its service area over the next 15 years; (2) its plans for meeting projected need; (3) the analytical process it used to develop its plans for meeting projected need; and (4) its reasons for adopting the specific resource mix proposed to meet projected need.[2]

These requirements are designed to strengthen utilities' long-term planning processes by providing input from the public, other regulatory agencies, and the Commission. They are also designed to ensure that utilities give adequate consideration to factors whose public policy importance has grown in recent years, such as the environmental and socioeconomic impact of different resource mixes. For example, the statute requires utilities to develop plans for meeting 50% and 75% of new and refurbished capacity needs with conservation and renewable energy.[3] It also requires them to factor into resource decisions the environmental costs, or externalities, of different generation technologies.[4]

Although the Commission must approve, reject, or modify the resource plans of investor-owned utilities, the resource-planning process is largely collaborative and iterative.

The process is collaborative because there are a wide array wide of facts and considerations that may be relevant to resource choices or deployment timetables. The facts on which resource decisions depend — how quickly an area and its need for electricity will grow, how much electricity will cost over the lifetime of a generating facility or a purchased-power contract, how much conservation potential the service area holds and at what cost — all require the kind of careful judgment that sharpens with exposure to the views of engaged and knowledgeable stakeholders.

The process is iterative because analyzing future energy needs and preparing to meet them is not a static process; strategies for meeting future needs are always evolving in response to changes in actual conditions in the service area. When demographics, economics, technologies, or environmental regulations change, so do a utility's resource needs and its strategies for meeting them.

II. Otter Tail Power Company

Otter Tail is an investor-owned utility headquartered in Fergus Falls, Minnesota. The Company serves approximately 128,000 retail customers in a 70,000-square-mile rural service area in Minnesota, North Dakota, and South Dakota. About 47 percent of Otter Tail's retail customers are in Minnesota.

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[2] Minn. Stat. §216B.2422; Minn. R. Ch 7843.

[3] Minn. Stat. § 216B.2422, subd. 2.

[4] *Id.*, subd. 3.

Otter Tail's major generation resources include two jointly owned coal-fired power plants, one solely owned coal-fired power plant, three wind farms, long-term purchased power agreements with two more wind farms, a simple-cycle gas combustion turbine, oil-fired peakers and other purchased-power agreements.

The Company's service territory is within the footprint of the Midcontinent Independent System Operator (MISO), which operates the Midwestern transmission grid. As a MISO member, Otter Tail is able to purchase wholesale energy on MISO's day-ahead market when doing so is more cost-effective than using its own generation.

III. Otter Tail's Resource Plan – Five-Year Action Plan

Otter Tail projects a growing capacity deficit, beginning in 2017 and increasing over the next fifteen years. The near-term deficit coincides with the 2021 planned retirement of the Company's Hoot Lake Plant located in Fergus Falls — the Company's only coal-fired power plant in Minnesota.

To address future capacity deficits and to replace the capacity and energy components of the Hoot Lake Plant, as well as an expiring 50 MW bilateral capacity purchase, Otter Tail's resource plan included a five-year action plan to construct a 250 MW simple-cycle natural gas combustion turbine, procure 100 MW of wind in 2018, another 100 MW of wind in 2020, and 30 MW of solar by 2020 to comply with Minnesota's Solar Energy Standard.[5] The plan also included a proposal to meet the statutory energy-efficiency goal of 1.5 percent of gross annual retail energy sales.[6]

The Company's current resource plan filing closely coincides with, and furthers the implementation of, its prior resource plan, as approved by the Commission. That plan included retiring and replacing Hoot Lake in 2021, adding 200 MW of intermediate capacity and associated energy, and adding up to 300 MW of wind in the 2017–2021 timeframe, subject to need and cost-effectiveness.[7]

After its initial filing in this docket, the Company revised its load and forecasting data in response to the Department's request that the Company update its weather inputs (how it used sales to create weather station allocation factors), include yearly variables (affecting how sales are accounted for), add a trend line (to show trends in use over the planning period), and account for serial correlation (output patterns often caused by flaws in the model). According to the Company, the updates changed the forecast by less than one-half of one percent in each year of the study period and showed that the forecast remained within the high and low sensitivity bounds included in its original filing.

While the Clean Energy Organizations initially claimed that Otter Tail had overstated its need for additional resources, by the time the Commission met to consider the matter, no party objected to use of Otter Tail's demand and energy forecasts, and the Department recommended that the

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[5] Minn. Stat. § 216B.1692, subd. 2f.

[6] Minn. Stat. § 216B.241, subd. 1c(b).

[7] *In the Matter of Otter Tail Power Company's 2014-2028 Resource Plan*, Docket No. E-017/RP-13-961, Order Approving Plan with Modifications and Setting Requirements for Next Resource Plan (December 5, 2014).

Commission find the forecasts acceptable for planning purposes.[8] The Clean Energy Organizations did, however, challenge Otter Tail's inclusion of a 248 MW simple-cycle natural gas combustion turbine to address capacity needs in lieu of a renewable energy resource.

And the parties ultimately concurred that an annual energy savings goal of 46.8 gigawatt-hours (GWh), or approximately 1.6 percent, during the five-year action plan period was within the Company's reach.[9] The Department acknowledged that the goal is aggressive but explained that this amount of demand-side management reduced Otter Tail's system costs. Higher energy savings scenarios would increase system costs and were less likely to be achieved by the Company.

A. The Department

The Department recommended that the Commission approve a five-year action plan that includes 200 MW of wind in the 2018–2020 timeframe, 250 MW of peaking capacity, and 30 MW of solar in 2020, consistent with Otter Tail's proposal.

The Department evaluated Otter Tail's forecast models and results for reasonableness, explaining that Otter Tail developed both energy-sales and demand forecasts using regression analysis, a statistical technique used to forecast changes in variables. Specifically, the Company developed an energy sales model using data on historical monthly use per customer and a customer count, resulting in customer-class forecasts used to forecast total system energy sales. To forecast system peak demand, the Company used monthly demand proxy variables and weather variables, as well as estimates of pipeline and industrial peak demand, which showed growth in both summer and winter peak demand over the planning period.

Because the Company claimed that its winter peak demand is offset by its winter demand-response resources (load management and load shedding), the Department concurred with the Company's decision to focus on planning for the projected increase of 1.23 percent in summer peak demand.[10] That growth, along with the planned retirement of the Hoot Lake Plant and the Company's MISO reserve obligation, produces a net capacity deficit as shown in the table below.

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[8] The Clean Energy Organizations recommended that Otter Tail be required, in its next resource plan filing, to include a transparent methodology to reflect the load associated with pipelines to ensure that load forecasting based on pipeline sales is clearer.

[9] Minn. Stat. § 216B.241, the Conservation Improvement Program statute, sets an annual energy savings goal of 1.5 percent of gross annual retail sales for each utility.

[10] The Department noted that under MISO's reliability framework, the Company's peak demand is discounted, meaning that Otter Tail is allowed to have fewer resources that its own peak demand. But the Company chose to have enough resources to meet its forecasted load rather than the lower amount required by MISO, a reasonable decision considering the Company's explanation that the MISO numbers change every year and that the difference between the MISO peak and the Company's peak is covered by the forecast band.

Summer 2017-2031 Load and Capability Prior to Preferred Plan (MW)

	Obligation	Total	Net
2017	795.1	773.2	(21.9)
2018	801.8	772.8	(29.0)
2019	833.4	761.3	(72.1)
2020	840.7	761.3	(79.4)
2021	848.2	574.9	(273.3)
2022	855.0	575.9	(279.1)
2023	861.8	575.9	(285.9)
2024	878.5	575.9	(302.6)
2025	895.3	576.9	(318.4)
2026	902.4	577.9	(324.5)
2027	909.6	578.9	(330.7)
2028	916.7	578.9	(337.8)
2029	923.9	576.3	(347.6)
2030	931.0	577.3	(353.7)
2031	938.2	578.3	(359.9)

The Department stated that based on the Company's projections, the amount of capacity Otter Tail proposes to add is in line with its expected net capacity deficit, considering accredited capacity. The total nameplate capacity (480 MW) comes from 200 MW of wind, 250 MW of natural gas, and 30 MW of solar. But MISO counts *accredited* capacity for planning purposes. For wind, accredited capacity is approximately 16 percent of nameplate, and for solar, it is approximately 50 percent of nameplate. And while the numbers in the table do not account for demand-side management (DSM) programs that would be utilized to achieve energy savings, DSM was subsequently factored into the modeling the Company conducted to address its resource needs.

The Company used a capacity expansion modeling tool, Strategist, to model the least-cost mixture of supply-side and demand-side resources for meeting its resource needs. The Department scrutinized the results of the Strategist modeling by replicating the results, modifying the base case, assessing the results of possible scenarios, and running new scenarios to test the robustness of the preferred case. The Department then analyzed whether the Company's proposed plan is reliable, low-cost and low-impact, and whether modifications to the plan were warranted.

The Department studied the 30 scenarios evaluated by Otter Tail in its Strategist modeling and concurred with the Company that the results support Otter Tail's proposal to replace the capacity and energy components of the Hoot Lake Power Plant with a 248 MW combustion turbine unit and 200 MW of wind — creating a reliable and low-cost resource mix that would help the Company achieve Minnesota's greenhouse gas reduction goals.[11]

[11] Minn. Stat. § 216H.02.

According to the Department, Otter Tail experimented with differing levels of energy savings, wind, and solar, and demonstrated that a reasonable combination of these resources does not eliminate the need for a capacity resource, i.e., peaking capacity such as a combustion turbine, in the Company's five-year action plan. And the Department emphasized that the Company obtained approval of an additional resource to meet the capacity need arising from the retiring Hoot Lake Plant in its previous resource plan.

Additionally, the Department did not recommend use of bilateral purchased power agreements as a resource in lieu of the combustion turbine, noting the price risk involved for Otter Tail's customers. Long-term contracts could provide competitive pricing in the near term, but years into the contract market prices could drop, leaving the Company with comparatively higher fixed prices and no option for exiting the contract. The Department also reiterated, however, that the Company bears the burden to ultimately demonstrate, in a subsequent rate case, that its decision to add a combustion turbine was prudent and that cost recovery is warranted.

B. The Clean Energy Organizations

The Clean Energy Organizations recommended that the Commission reject Otter Tail's proposal to include a 250 MW natural gas combustion turbine as part of its resource plan. They emphasized the need to further explore the use of renewable energy alternatives, consistent with the policy preference for renewable energy unless a utility demonstrates that a renewable energy facility is not in the public interest.[12]

Specifically, the Clean Energy Organizations claimed that Otter Tail did not fully and quantitatively explore options other than a gas plant, such as combinations of wind, solar, energy efficiency, demand response, storage, distributed generation, and bilateral contracts. They also contended that at a minimum, the Company should have explained why bilateral contracts to meet capacity needs would be too expensive or not available, consistent with the Commission's directive in the Company's last resource plan to obtain 200 MW of intermediate capacity through construction of a facility, or through bilateral contracts, whichever is most cost-effective.

The Clean Energy Organizations recognized that bilateral contracts might include coal or gas, but maintained that contracts would be a more favorable outcome than adding new infrastructure such as a 40-year gas plant that would likely be retired before the end of its economic life. And they challenged Otter Tail's claim that short-term contracts could expose their customers to higher costs, stating that the market-exposure argument offered by Otter Tail was unconvincing and did not withstand scrutiny under the renewable energy preference statute.[13] As a result, they opposed Otter Tail's decision to include a natural gas plant, claiming that Otter Tail did not meet its burden to show why a renewable resource is not in the public interest as required by statute. At hearing, however, they acknowledged that the record had been supplemented sufficiently to support a Commission finding that the burden has been met.[14]

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[12] Minn. Stat. § 216B.2422, subd. 4.

[13] *Id.*

[14] *Id.*

C. Midwest Large Energy Consumers

The Midwest Large Energy Consumers recommended that the Commission approve Otter Tail's resource plan, including the Company's proposed five-year action plan.

They countered the claim by the Clean Energy Organizations that Otter Tail's modeling was flawed and that it does not support the addition of a natural gas plant. They stated that in lieu of a 250 MW gas plant, an additional 500 MW of solar and 1,000 MW of wind (assuming accredited capacity of 50 percent for solar and 25 percent for wind) would be needed. Considering that the Company's peak demand total is 800 MW, the Midwest Large Energy Consumers stated that such a plan is not cost-effective, would put reliability at risk, and would jeopardize the Company's ability to recover the costs of such a plan from its two other jurisdictions (North and South Dakota), which do not allow consideration of environmental externalities.

D. Commission Action

The Commission is persuaded that the Company's five-year action plan, accompanied by the Department's analysis of that plan, is a thorough consideration of the relevant factors governing the resource planning process and contains a reasonable set of resource options for meeting the Company's projected capacity deficits. And the Commission finds that the Company's demand and net energy forecasts are acceptable for planning purposes.

The Department noted that the Company included a mix of both renewable and non-renewable resources to replace the energy and capacity components of its retiring Hoot Lake Plant by proposing 200 MW of wind and 250 MW of natural gas. The Company analyzed the possibility of additional renewable resources and energy savings, but in the modeling replicated by the Department, the natural gas combustion turbine remained in the resource mix as the most cost-effective option relative to the Company's needs. Replacing its only coal-fired plant in Minnesota with a renewable energy component and a natural gas combustion turbine peaking plant reasonably balances renewable energy policy goals, reliability, and cost-effectiveness. In addition, the Company is adding 30 MW of solar (to meet the SES) prior to installation of the gas plant.

With the addition of 200 MW of wind, the Company will be on track to meet the Renewable Energy Standard, which requires a public utility – such as Otter Tail – to generate or procure, by 2025, 25 percent of its total retail electric sales using renewable energy technologies.[15]

And while the Clean Energy Organizations supported use of bilateral contracts in lieu of a new natural gas plant, contracts are likely to include coal or natural gas as the resource supply, not necessarily renewable energy resources. Whether to construct a natural gas plant or use bilateral contracts is relevant to the prudence of Otter Tail's decision and whether the Company can subsequently demonstrate in a future rate case that its decision to construct a natural gas plant was prudent and that cost recovery is warranted.

In this case, the Company explained that it considered the use of bilateral contracts, forecasted energy prices, and determined that bilateral contracts were not more cost-effective than building a power plant. Further, reliance on short-term contracts can subject the long-term planning

[15] Minn. Stat. § 216B.1691, subd. 2a.

process to shorter-term market volatility as contracts expire and market prices and resource availability change. And long-term contracts also carry price risks. Contract prices that are not competitive due to subsequent changes in market prices could result in higher long-term prices for Otter Tail's customers.

Finally, the parties concurred that an annual energy savings goal of 46.8 gigawatt-hours (GWh), or approximately 1.6 percent, during the five-year action plan period was within the Company's reach. The Department stated that 46.8 GWh is the most cost-effective amount in the Strategist analysis (higher energy savings would increase costs) and that Otter Tail has only surpassed the Department's proposed energy savings level of 46.8 GWh once, in 2015.

For all these reasons, the Commission will approve a five-year action plan that includes the addition of the following:

- 200 MW of wind in the 2018–2020 timeframe;
- 30 MW of solar in about 2020;
- Up to 250 MW of peaking capacity; and
- An average annual energy savings of 46.8 GWh (1.6 percent of retail sales).

IV. Additional Wind

In addition to the amount of wind included in the five-year action plan described above, the parties concurred that authorization for additional wind in the 2022 to 2023 time period is supported by the Company's Strategist modeling, which selected additional wind as a cost-effective tool for mitigating spot-market exposure. According to the Department, the modeling consistently selected an additional 100 MW of wind in 2022 and another 100 MW of wind in 2023. The Company concurred on adding additional wind in this timeframe, if needed and cost-effective.

The Commission concurs with the parties' analyses on this issue and will modify Otter Tail's plan to include an additional 100 MW to 200 MW of wind in the 2022 to 2023 timeframe, if needed and cost-effective.

V. Environmental Regulations

The Department evaluates utility resource plan filings for compliance with pending state and federal environmental legislation and concluded that Otter Tail is adequately tracking environmental regulations that might impact its operations. These include:

- an Acid Rain Program that aims to reduce emissions of sulfur dioxide and nitrogen oxides;
- National Ambient Air Quality Standards that are applicable to air quality surrounding the Company's facilities;
- Mercury and Air Toxics Standards that are aimed at reducing emissions of mercury and other hazardous air pollutants; and
- the Regional Haze Program that addresses visibility impairment in wilderness areas.

The Department stated that Otter Tail has, where necessary, installed emissions-control equipment and is in compliance with applicable requirements.

Additionally, the Department evaluated Otter Tail's filing to ensure that the Company is monitoring the impact of the Environmental Protection Agency's Clean Power Plan rule on its generation fleet and concluded that with the planned retirement of the Hoot Lake Plant, there are no compliance issues with the Clean Power Plan for the Minnesota portion of Otter Tail's three-state territory.

The Commission concurs with the Department and finds that the Company is adequately tracking environmental regulations that might impact its operations. Additionally, the Commission will direct the Company to address the status of the Clean Power Plan in the states included in Otter Tail's service territory in its next resource plan filing.

VI. Requirements for Next Filing

The Commission will direct Otter Tail to file its next integrated resource plan no later than June 3, 2019.

In its next filing, the Commission will require that the Company address the items described below.

- ***Clean Power Plan.*** The Commission will require Otter Tail to address the status of Clean Power Plan compliance plans in the states included in the Company's service territory.

- ***Forecast of Pipeline Load.*** The Clean Energy Organizations stated that load forecasting based on pipeline sales should be clearer. The Commission agrees and will therefore require Otter Tail to include a transparent methodology to reflect forecasted load associated with pipelines or pipeline replacements.

- ***New Wind.*** The Commission will require Otter Tail to include a discussion of how incremental levels of new wind could be reasonably procured and worked into the system while maintaining reliability of service.

- ***Capacity Savings.*** The Commission will direct Otter Tail to evaluate capacity savings the Company could achieve via demand-response programs, including additional savings from its existing direct load control programs, and will require Otter Tail to study reliability, price, and technology-based demand-response products.

- ***Direct Load Control Programs.*** The Commission will require Otter Tail to include a discussion of how the identified technical and economic potential for direct load control programs can be integrated into its supply-side and demand-side resource mix. The Commission will also require Otter Tail to provide its strategies to improve on its installed kilowatts as a percentage of technical potential and to include a discussion of any overall and specific program benchmarks.

- ***Oil Peaker Plants.*** The Commission will require Otter Tail to analyze the cost-effectiveness of its oil peaker plants at Jamestown, North Dakota, Units 1 and 2, and Lake Preston, South Dakota, relative to other supply-side and demand-side alternatives as it relates to transmission constraints.

VII. Conclusion

For all the reasons set forth above, the Commission will approve Otter Tail's resource plan, as amended in the ordering paragraphs below.

ORDER

1. The Commission hereby approves Otter Tail Power Company's 2017–2031 Integrated Resource Plan, as modified below.

2. The Commission finds that the Company's demand and net energy forecasts are acceptable for planning purposes.

3. Otter Tail shall file its next integrated resource plan no later than June 3, 2019.

4. The Commission hereby approves a five-year action plan that includes the addition of:

   a. 200 MW of wind in the 2018 to 2020 timeframe;
   b. 30 MW of solar in about 2020;
   c. Up to 250 MW of peaking capacity in 2021; and
   d. Average annual energy savings of 46.8 GWh (1.6 percent of retail sales).

5. The Commission hereby modifies Otter Tail's integrated resource plan to include 100 MW to 200 MW of wind in the 2022 to 2023 timeframe. This does not preclude additional wind during the five-year action plan period.

6. The Commission hereby finds that Otter Tail is adequately tracking environmental regulations that might impact its operations.

7. Otter Tail must include in its next resource plan filing:

   a. a transparent methodology to reflect forecasted load associated with pipelines or pipeline replacements.

   b. a discussion of how incremental levels of new wind could be reasonably procured and worked into the system while maintaining reliability of service.

   c. an evaluation of capacity savings the Company could achieve via demand- response programs, including more from its existing direct load control programs. The Company must also study reliability, price, and technology-based demand-response products.

d. a detailed discussion of how the identified technical and economic potential for direct load control programs can be integrated into its supply-side and demand-side resource mix. The Company must also provide its strategies to improve on its installed kilowatts as a percentage of technical potential and include any overall and specific program benchmarks.

e. an analysis of the cost-effectiveness of its oil peaker plants (at Jamestown, North Dakota, Units 1 and 2; and Lake Preston, South Dakota) relative to other supply and demand-side alternatives as it relates to transmission constraints.

f. the status of Clean Power Plan compliance plans in the states included in Otter Tail's service territory.

8. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf

Daniel P. Wolf
Executive Secretary

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Energy solutions
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Best Practices in Electric Utility Integrated Resource Planning

Examples of State Regulations and Recent Utility Plans

Authors
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Table of Contents

Executive Summary

An integrated resource plan is a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period. For utilities, integrated resource planning is often quite time- and resource-intensive. Its benefits are so great, however, particularly to consumers, that utilities are frequently required by state legislation or regulation to undertake planning efforts that are then reviewed by state public utilities commissions (PUCs). (In this document, the acronym IRP is used, depending on the context, to denote either an integrated resource plan or the process of integrated resource planning.)

IRP rules governing utilities have been created in a number of ways. Bills that mandate integrated resource planning have been passed into law by state legislatures; rules have been codified under state administrative code; and state utility commissions have adopted IRP regulations as part of their administrative rules, or have ordered it to be done as a result of docketed proceedings. Although some state IRP rules have remained unchanged since they were first implemented, other states have amended, repealed, and in some cases reinstated their IRP rules. Examples can be found in the rules of Arizona, Colorado, and Oregon. Rules that have been amended recently often reflect current concerns in the electric industry—e.g., fuel costs and volatility, the effects of power generation on air and water, issues of national security, electricity market conditions, and climate change, as well as individual state concerns.

There are, however, certain subject-matter areas that are essential to resource planning on which state regulations are silent. Utilities must use their discretion in determining how best to address these areas in their resource plans. This paper provides utilities, commissions, and legislatures with guidance on these subject-matter areas. Section III summarizes three recent utility IRPs from the states mentioned above, in an effort to determine both best practices in integrated resource planning and ways in which utilities can improve their planning processes and outcomes. Section IV then presents a series of recommendations, developed from these examples, for integrated resource planning and its resulting plans.

For an IRP process to be deemed successful, it should include both a meaningful stakeholder process and oversight from an engaged public utilities commission. A successful utility's resource plan should include consideration in detail of the following elements: a load forecast, reserves and reliability, demand-side management, supply options, fuel prices, environmental costs and constraints, evaluation of existing resources, integrated analysis, time frame, uncertainty, valuing and selecting plans, action plan, and documentation. Section IV describes in detail the elements of both the process and the plan.

Introduction

As energy demand across the United States rises and falls and the generation fleet ages, utilities must plan to add and retire resources in the most cost-effective manner while meeting regional reliability standards. Integrated resource planning began in the late 1980s, as states looked for a way to respond to the oil embargos and nuclear cost overruns of the previous decade—and ever since, it has been an accepted way in which utilities can create long-term resource plans. State requirements for resource plans vary in terms, among other things, of planning horizon, the frequency with which plans must be updated, the resources required to be considered, stakeholder involvement, and the actions that public utilities commissions should take in reference to the plan (review, acknowledge, and accept or reject the plan).

As the electric industry began to restructure in the mid-1990s, integrated resource planning rules in many states were repealed or ignored. Some states have since made an effort to update IRP rules to make them applicable to current industry conditions, while other states have continued to use rules that are now out of date. This report describes IRP requirements in three states that have recently updated their regulations governing the planning process, and it reviews the most recent resource plan from the largest utility in each of those states. Rules from Arizona, Colorado and Oregon are described in detail, in order to demonstrate ways in which states can require comprehensive planning processes and resource plan outcomes from the utilities under their jurisdictions.

These particular states were chosen not only because their rules have recently been updated, but also because the guidance they provide to electric utilities offers examples of best practices in integrated resource planning. The updated rules have been designed to give thoughtful consideration to specific resources that have traditionally been ignored, and to produce outcomes that are in the best interests of both ratepayers and society as a whole. Utility resource plans from Arizona Public Service, Public Service Company of Colorado, and PacifiCorp utilize progressive methodologies and contain modern elements that contribute to the production of high-quality plans that are useful examples of superior resource planning efforts.

This report is intended to be helpful to policymakers, public utility commissions and their staff, ratepayer advocates, and the general public as they each consider the ways in which utility resource planning can best serve the public interest.

I. The Purpose and Use of Integrated Resource Planning

An integrated resource plan, or IRP, is a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period. Steps taken in the creation of an IRP include:

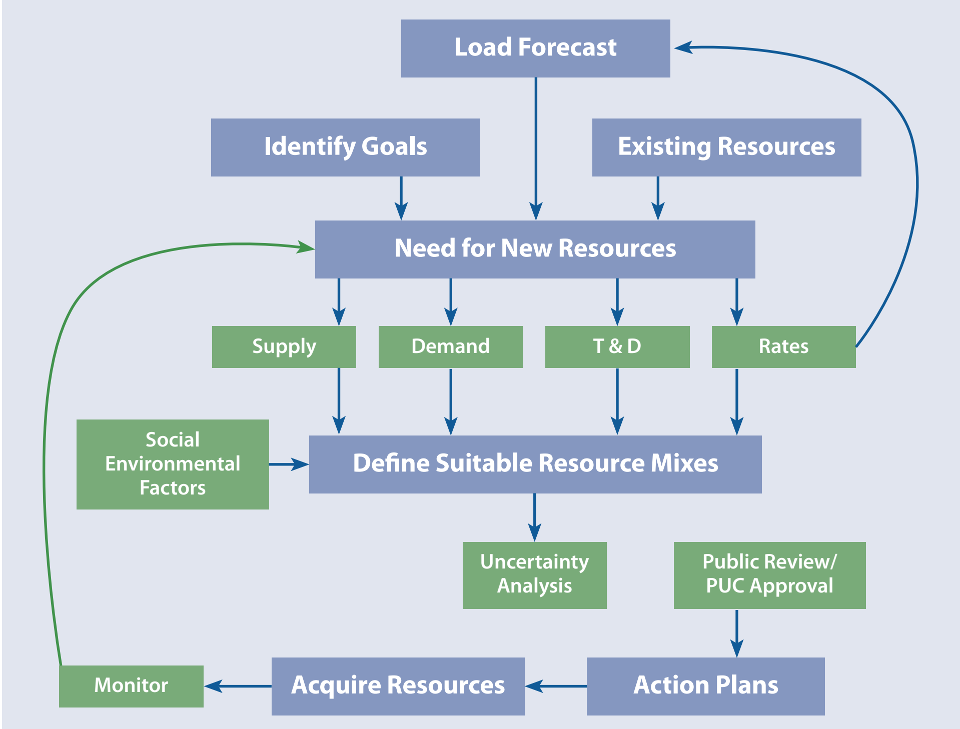
- forecasting future loads,
- identifying potential resource options to meet those future loads,
- determining the optimal mix of resources based on the goal of minimizing future electric system costs,
- receiving and responding to public participation (where applicable), and
- creating and implementing the resource plan.

Figure 1 shows these steps in a flow chart.

Integrated resource planning has many benefits to consumers, and other positive impacts on the environment. This is a planning process that, if correctly implemented, locates the lowest practical costs at which a utility can deliver reliable energy services to its customers. IRP differs from traditional planning in that it requires utilities to use analytical tools that are capable of fairly evaluating and comparing the costs and benefits of both demand- and supply-side resources.[2] The result is an opportunity to achieve lower overall costs than might result from considering only supply-side options. In particular, the inclusion of demand-side options presents more possibilities for saving fuel and reducing negative environmental impacts than might be possible if only supply-side options were considered.[3]

Figure 1

Flow Chart for Integrated Resource Planning[1]



1 Hirst, E. A Good Integrated Resource Plan: Guidelines for Electric Utilities and Regulators. Oak Ridge National Laboratory. December 1992. Page 5. As it appears in Harrington, C., Moskovitz, D., Austin, T., Weinberg, C., & Holt, E. Integrated Resource Planning for State Utility Regulators. The Regulatory Assistance Project. June 1994.

2 Integrated Resource Planning for State Utility Regulators. Available at: http://www.raponline.org/document/download/id/817

3 Kushler, M. & York, D. Utility Initiatives: Integrated Resource Planning. July 2010. American Council for an Energy-Efficient Economy. Available at: http://aceee.org/policy-brief/utility-initiatives-integrated-resource-planning

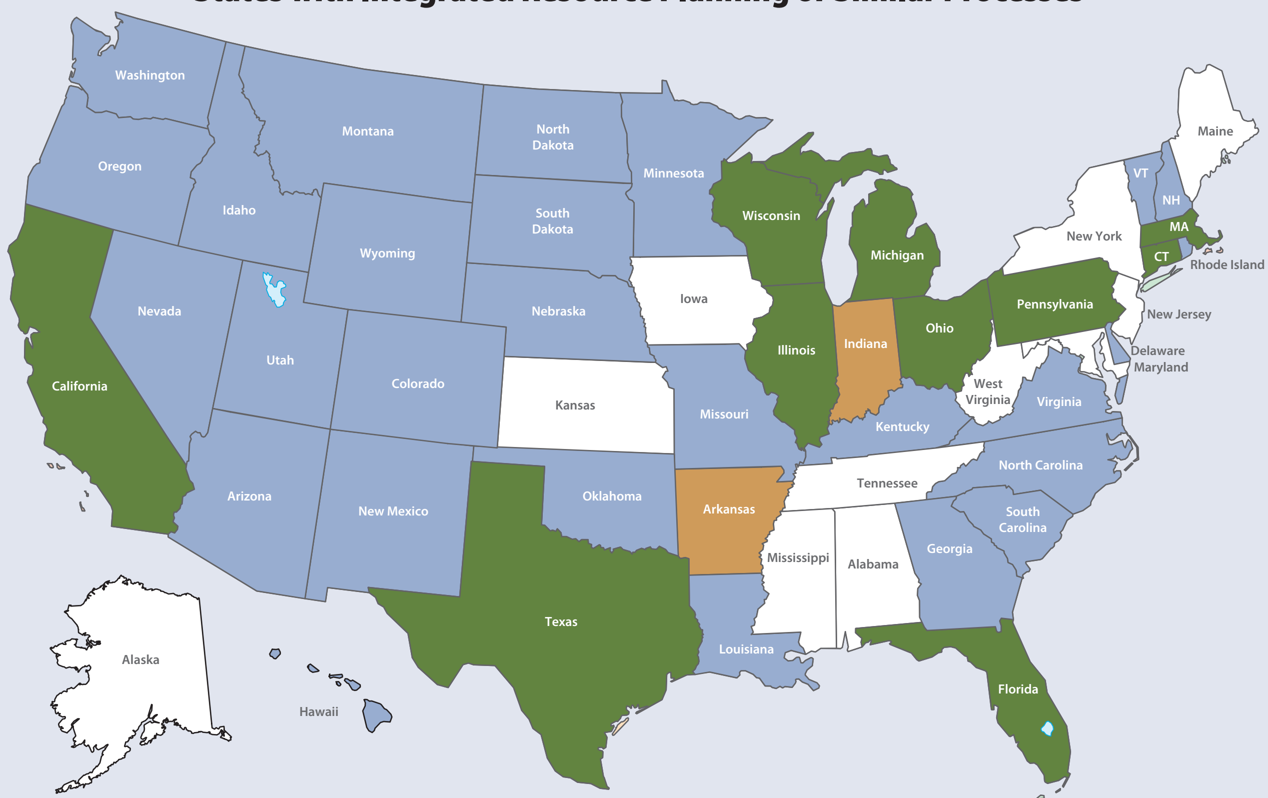
In general, IRP focuses on minimizing customers' bills rather than on rates—but an overall reduction in total resource cost achieved through the efficient use of energy will lower average energy bills. As a result, all customers benefit from the lower system costs that IRP achieves.[4]

Alternatives examined by system planners in an IRP setting include adding generating capacity (thermal, renewable, customer-owned, or combined heat and power), adding transmission and distribution lines, and implementing energy efficiency (EE) and demand response programs. Common risks that are addressed by scenario or sensitivity analyses in IRPs include fuel prices (coal, oil, and natural gas), load growth, electricity spot prices, variability of hydro resources, market structure, environmental regulations, and regulations on carbon dioxide (CO_2) and other emissions.[5]

Resource planning requirements exist in many states, but may differ significantly from state to state. Utilities that create more than one resource plan in the same state may have different processes for creating those plans and may arrive at significantly different conclusions, despite being governed by the same regulations. Figure 2 shows the states that have IRP or long-term planning requirements.[6]

Figure 2

States with Integrated Resource Planning or Similar Processes



State has an IRP rule and filing requirement

State is developing or revising an IRP rule and filing requirement

State has a filing requirement for long-term plans

State does not have filing requirements for long-term plans

4 Id footnote 2.

5 Hopper, C. & Goldman, N. Review of Utility Resource Plans in the West. Lawrence Berkeley National Laboratory. Presentation at the New Mexico PRC IRP Workshop, Santa Fe. June 8, 2006. Slide 17.

6 For a complete list of the rules and regulations associated with integrated resource planning in the states, see Appendix 1.

II. Examples of State Integrated Resource Planning Statutes and Regulations

State IRP rules have been established in a number of ways. In certain states, legislatures have passed bills into law mandating that utilities engage in resource planning; in others, IRP rules have been codified under state administrative code. Some state utility commissions have adopted integrated resource planning regulations as part of their administrative rules, or have ordered it through docketed proceedings. Rules can also be developed through a combination of these processes. Various state IRP rules and their individual requirements are discussed in the sections below.

A. IRP Planning Horizons

Integrated resource plans are long-term in nature, but these planning periods vary according to state regulations. Table 1 lists the length of planning horizons typically found in IRP rules, as well as the states that have implemented these various planning horizons as a part of their rules.

The most common planning horizon spans a 20 year period, with half of the IRP states mandating this planning period.

B. Frequency of Updates

Utility integrated resource plans must be updated periodically to reflect changing conditions with respect to load forecasts, fuel prices, capital costs, conditions in the electricity markets, environmental regulations, and other factors. IRP updates are typically required every two to three years, as shown in Table 2, below.

Montana appears twice in Table 2, as traditional utilities are required to file IRPs every two years, while restructured utilities are required to file updates every three years. There are some exceptions to the typical update requirements of

Table 1

Planning Horizons Found in IRP Rules

Planning Horizon	States with Specified Planning Horizon
10 years	Arkansas, Delaware, Oklahoma, South Dakota, Wyoming
15 years	Arizona, Kentucky, Minnesota, North Carolina, South Carolina, Virginia
20 years	Georgia, Hawaii, Idaho, Indiana, Louisiana, Missouri, Nebraska, Nevada, New Mexico, North Dakota, Oregon, Utah, Vermont, Washington
Multiple periods	Montana
Utility determined	Colorado
Not specified	New Hampshire

Table 2

Frequency of IRP Updates, as Determined by State Rules

Planning Horizon	States with Specified Planning Horizon
Every two years	Arizona, Delaware, Idaho, Indiana, Minnesota, Montana, New Hampshire, North Carolina, North Dakota, Oregon, South Dakota, Utah, Virginia, Washington
Every three years	Arkansas, Georgia, Hawaii, Kentucky, Louisiana, Montana, Missouri, Nevada, New Mexico, Oklahoma, South Carolina, Vermont
Every four years	Colorado
Every five years	Nebraska
Not specified	Wyoming

two to three years. Nebraska, for example, has a five year requirement for updates and is the only state to be made up entirely of public power utilities, many of which are customers of the Western Area Power Administration (WAPA). Pursuant to the Energy Policy Act of 1992, municipally-owned utilities are required to prepare resource plans every five years, but do not have to make those plans publicly available. Most Nebraska utilities must comply with both WAPA IRP requirements as well as state IRP requirements.

C. Resources Evaluated in Integrated Resource Planning

Generally, state rules mandate that utilities consider all feasible supply-side, demand-side, and transmission resources that are expected to be available within the specified planning period. Many state IRP requirements make no specifications for resources that must be evaluated beyond this. Other states have gone into further detail about the resources that should be investigated, including:

- **Delaware –** utilities shall identify and evaluate all resource options, including: generation and transmission service; supply contracts; short and long-term procurement from demand-side management (DSM), demand response (DR) and customer sited generation; resources that utilize new or innovative baseload technologies; resources that provide short or long-term environmental benefits; facilities that have existing fuel and transmission infrastructure; facilities that utilize existing brownfield or industrial sites; resources that promote fuel diversity; resources or facilities that support or improve reliability; and resources that encourage price stability.[7]
- **Indiana –** utilities shall examine: all existing supply and demand-side resources and existing transmission; all potential new utility electric plant options and transmission facilities; all technologies and designs expected to be available within the twenty-year planning period, either on a commercial scale or demonstration scale; and a comprehensive array of demand side measures, including innovative rate design.[8]
- **Kentucky –** utilities shall evaluate improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities.[9]

There are state IRP rules that specify not only the resources that must be evaluated, but also the amount of weight given to a particular resource by either the utilities or the Public Service/Utilities Commissions. Colorado is one such state, and is described in more detail in later sections.

In almost all cases, state integrated resource planning rules have specific requirements for the planning horizons that should be covered, the frequency with which utility plans must be updated, and the generating resources that should be considered. Some states require nothing more, while others might also require, for example: 1) a certain number or a certain type of scenario analysis; 2) that certain types of resource cost tests be used to evaluate demand-side management policies; or 3) that externalities be considered by utilities when creating resource plans. Requirements for generating unit retirements and associated decommissioning costs are another example of something that some states might include in integrated resource planning rules, while others might not. The next section describes the discussion of this type of requirement in state IRP regulations.

D. Retirements and Decommissioning

Integrated resource planning is generally understood to be primarily concerned with the addition of resources in order to meet growing demand for electricity, and very few IRP rules mandate that utilities address end-of-life issues for generating units in their resource plans. In a summary document on integrated resource planning, the Regulatory Assistance Project states that "as utilities compare the cost of each supply- and demand-side option, they need to capture the entire life-cycle cost. This life-cycle cost means the fixed and variable costs incurred over the life of the investments: construction, operation, maintenance, and fuel costs."[10] This description does not represent the full

7 HB 6, the Delaware Electric Utility Retail Customer Supply Act of 2006.

8 170 Indiana Administrative Code 4-7-1: Guidelines for Integrated Resource Planning by an Electric Utility.

9 Kentucky Administrative Regulation 807 KAR 5:058: Integrated resource planning by electric utilities.

10 Harrington, et al. Integrated Resource Planning for State Utility Regulators. The Regulatory Assistance Project. June 1994. Page 14.

life of the investment, however, as it does not specifically include the costs associated with the retirement and decommissioning of a resource.

State IRP rules and utility filings reflect this incomplete assessment of life-cycle costs. Twenty-seven states have IRP rules and 20 of them are silent with respect to unit retirements. Utah and Colorado require that utility filings include information about the life expectancies of the generating units in the resource plans. Three states – New Mexico, North Carolina, and South Dakota – are slightly more specific, and mandate that utilities provide expected retirement dates for generating facilities. Specifically, the utilities in each of the states are required to do the following:

- **Utah –** include the life expectancy of generating resources
- **Colorado –** provide the estimated remaining useful lives of existing generation facilities without significant new investment or maintenance expense
- **New Mexico –** give the expected retirement dates for existing generating units
- **North Carolina –** provide a list of units to be retired from service (applies to both existing and planned generating facilities), with the location, capacity and expected date of retirement
- **South Dakota –** include those facilities to be removed from service during the planning period, along with the projected date of removal from service and the reason for removal

There are only two state rules that make any mention of decommissioning costs:

- Arizona rules state that if the discontinuation, decommissioning, or mothballing of any power source or the permanent derating of any generating facility is expected, the utility must provide:
  "i. Identification of each power source or generating unit involved,
  ii. The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating, and
  iii. The reasons for each discontinuation, decommissioning, mothballing, or derating."[11]
- Georgia laws and rules state that "Total cost estimates for proposed projects must include construction and non-construction related costs incurred through commercial operation, including decommissioning/dismantlement costs."[12]

Rather than being addressed in utility integrated resource plans, generating unit retirements and associated decommissioning costs are largely left to be dealt with in other cases and proceedings that are brought before Public Utilities/Service Commissions.

E. Long-term Procurement Planning Requirements

As the electric industry began to restructure in the mid-1990s, many states that had integrated resource planning requirements either repealed them with restructuring laws, or simply began to ignore them. Some states eventually replaced integrated resource planning laws with rules for resource procurement plans. A document designed to inform California's 2010 Long-Term Procurement Plan (LTPP) requirement surveys the ways in which utilities in other states create their resource plans. The document states that "[w]hile California utilities have not undertaken a full integrated resource planning effort in many years, the 2010 LTPP proceeding is considering the appropriate role of utility resource planning in procuring the resources needed to meet state policy goals."[13]

Requirements for procurement plan filings differ from requirements for integrated resource plans. Planning periods are typically ten years, with some states requiring only a five year planning period. Procurement plans are usually required to be updated every year. Because utilities

11 Arizona Corporation Commission Decision No. 71722, in Docket No. RE-00000A-09-0249. June 3, 2010. Page 13. Amends Arizona Administrative Code Title 14, Chapter 2, Article 7, "Resource Planning." Available at: http://images.edocket.azcc.gov/docketpdf/0000112475.pdf

12 Integrated Resource Planning Act of 1991 (O.C.G.A. § 46-3A-1), Amended. See also: Georgia Public Service Commission, General Rules, Integrated Resource Planning 515-3-4. Available at: http://rules.sos.state.ga.us/cgi-bin/page.cgi?g=GEORGIA_PUBLIC_SERVICE_COMMISSION%2FGENERAL_RULES%2FINTEGRATED_RESOURCE_PLANNING%2Findex.html&d=1

13 Aspen Environmental Group and Energy and Environmental Economics, Inc. Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California - DRAFT. Prepared for the California Public Utilities Commission. September 2008. Page 1.

in these states operate in a deregulated market and do not own generation, procurement plans evaluate purchases for capacity and energy, as well as energy efficiency and other demand-side management programs.

Connecticut is one such state that used to have an integrated resource planning requirement, and now has a requirement for procurement plans. The state had IRP regulations in place by the late 1980s, but this requirement was repealed when the restructuring law (Public Act 98-28) was passed in 1998. A long-term procurement planning law then became effective in 2007 (Public Act 07-242). Plans submitted to the Connecticut Energy Advisory Board in compliance with the 2007 law have much in common with utility IRPs and have even been called "Integrated Resource Plans," though they are technically long-term procurement plans.

The following section describes the ways in which IRP rules have been made in Arizona, Colorado, and Oregon, and presents some of the specifics of each of those rules.

1. Arizona

The Arizona Corporation Commission (ACC) has been given both constitutional and statutory authority to oversee the operations of electric utilities, and to engage in rulemaking that includes the establishment of IRP regulations. Article 15 of the Arizona Constitution created the ACC, which oversees the operations of all public service corporations in the state, including investor-owned electric utilities. The Commission is given exclusive authority to establish rates, enact rules that are reasonably necessary in ratemaking, and determine what sort of regulation is reasonably necessary for effective ratemaking,[14] as established in Article 15, §3:

> *The Corporation Commission shall have full power to, and shall, prescribe just and reasonable classifications to be used and just and reasonable rates and charges to be made and collected, by public service corporations within the State for service rendered therein, and make reasonable rules, regulations, and orders, by which such corporations shall be governed in the transaction of business within the State…and make and enforce reasonable rules, regulations, and orders for the convenience, comfort, and safety, and the preservation of the health, of the employees and patrons of such corporations…*

Utility practices in Arizona are not governed by legislation or by statute, but rather through administrative code created by rulemaking proceedings of the Arizona Corporation Commission. Renewable energy requirements, distributed energy resource requirements, and integrated resource planning reporting requirements have all been established in this way.

The ACC has the authority to require that electric utilities provide reports concerning both past business activities and future plans. Integrated resource plans fall into this category. Article 15, §13 of the Arizona Constitution states that "[a]ll public service corporations… shall make such reports to the Corporation Commission, under oath, and provide such information concerning their acts and operations as may be required by law, or by the Corporation Commission." Arizona Revised Statute §40-204(A) expands on this requirement, stating that:

> *Every public service corporation shall furnish to the Commission, in the form and detail the Commission prescribes, tabulations, computations, annual reports, monthly or periodical reports of earnings and expenses, and all other information required by it to carry into effect the provisions of this title and shall make specific answers to all questions submitted by the Commission.*

Regulating and requesting information regarding the resource portfolios of electric utilities is one way in which the ACC meets its constitutional and statutory obligations to ensure that just and reasonable rates are being charged to consumers of electricity. In this pursuit, the ACC adopted the state's first Resource Planning and Procurement Rules in February 1989, requiring that utilities owning electric generation facilities file historical data every year, and 10-year resource plans every three years. The rules also provide for a Commission hearing to review these filings. In accordance with the rules, the first round of utility IRPs were filed in 1992 and hearings were held. In 1995, however, the Commission suspended the obligation of the electric utilities to file future resource plans until IRP rules could be modified to be consistent with impending electric industry competition and the passage of the retail electric competition rules.[15]

14 Arizona Corporation Comm'n v. Woods, 171 Ariz. 286, 294 ("Woods").

15 The Commission adopted retail electric competition rules in Decision No. 59943, dated December 26, 1996.

In revising the IRP rules, Commission staff were required to hold workshops, open to all stakeholders and to the public, on specific resource planning topics. These workshops:

> *Were to focus on developing needed infrastructure and a flexible, timely, and fair competitive procurement process; and were to consider whether and to what extent competitive procurement should include consideration of a diverse portfolio of purchased power, utility-owned generation, renewables, demand-side management, and distributed generation.*[16]

Following the workshops, a docket was opened for proposed rulemaking regarding resource planning, and on June 3, 2010 in Decision No. 71722, the Commission amended the Arizona Administrative Code Title 14, Chapter 2, Article 7, Resource Planning. In the most significant changes, compared to the original rules, the revised IRP rules:

- Extend the forecasting and planning horizon from 10 years to 15 years;
- Require submissions of utility IRPs every even-numbered year rather than every third year;
- Require load-serving entities to include, in their IRP, data regarding air emissions, water consumption, and tons of coal ash produced;
- Require that environmental impacts related to air emissions, solid waste, and other environmental factors and reduction of water consumption be analyzed and addressed in utility plans;
- Require that plans address costs for compliance with current and projected environmental regulations;
- Require that the resource plans include energy efficiency, to meet Commission-specified percentages;
- Require that the resource plans include renewable resources, to meet the specified percentages in Arizona Administrative Code R14-2-1804;
- Require that the resource plans include distributed energy resources, to meet the specified percentages in Arizona Administrative Code R14-2-1805;
- Require that utilities submit a work plan in every odd year that outlines the upcoming 15-year resource plan, and lays out: 1) the utility's method for assessing potential resources; 2) the sources of its current assumptions; and 3) a general outline of the procedures it will follow for public input, which includes an outline of the timing and extent of public participation and advisory group meetings that will be held before the resource plan is completed and filed.[17] Before they file the resource plan, utilities are required to provide an opportunity for public input. ACC practice also allows for public comment on the completed resource plan after it has been filed by the utility.

In the revised rulemaking proceedings emphasis was placed on diversifying the resource base in utilities' generation portfolios; on lowering costs through decreased reliance on volatile fossil-fuel based generation; and on considering and addressing environmental impacts, such as air emissions, coal ash, and water consumption.[18] Utilities must also submit a set of analyses to identify and assess the errors, risks, and uncertainties in: demand forecasts; the costs of DSM measures and power supply; the availability of sources of power; the costs of compliance with current and future environmental regulations; fuel prices and availability; construction costs, capital costs and operating costs; and any other factors the utility wishes to consider. This assessment should be done using sensitivity analysis and probabilistic modeling analysis.[19] The utility should provide a description of the ways in which these errors, risks, and uncertainties can be managed (e.g., by obtaining additional information, liming risk exposure, using incentives, creating additional options, incorporating flexibility, and participating in regional generation and transmission projects), along with a plan to do so.[20]

Following the review of the utility IRP, the Commission is required to file an order that either acknowledges the resource plan (with or without amendment) or states the reasons for not acknowledging it.

The first electric utility IRPs filed under the revised rules were submitted to the ACC in 2012. The filing from Arizona Public Service (APS) is discussed in later sections.

16 Arizona Corporation Commission. Decision No. 71722. Docket No. RE-00000A-09-0249. June 3, 2010.

17 Id.

18 Id. Page 12.

19 Arizona Corporation Commission. Decision No. 71722. Docket No. RE-00000A-09-0249. June 3, 2010. Exhibit A: Notice of Proposed Rulemaking. Page 42.

20 Id. Page 43.

2. Colorado

Title 40 of the Colorado Revised Statutes establishes the state Public Utilities Commission and gives it authority to regulate the public utilities located within the state, specifically with regard to "the adequacy, installation, and extension of the power services and the facilities necessary to supply, extend, and connect the same."[21] Title 40 also contains all of the legislative requirements with which Colorado's public utilities must comply, and prescribes the general methods by which the PUC should evaluate compliance.

The evaluation process is described in more detail in 4 Code of Colorado Regulations (CCR) 723-3: Rules Regulating Electric Utilities. This section of the code describes the rules promulgated by the Public Utilities Commission to establish the process for determining the need for additional electric resources by those electric utilities subject to the Commission's jurisdiction, and for developing cost-effective resource portfolios to meet such need reliably.[22] The rules, in their current form, were adopted in 2003 and were referred to as *least-cost planning* rules. Beginning in 2003, utilities were required to file resource plans every four years, and may file an interim plan if changed circumstances justify the filing.

Utilities may choose their own planning period, but that period must be at least 20 and no more than 40 years. Utilities may also specify the resource acquisition period they will follow, which will be between the first six and ten years of the planning period. The planning period is both the time frame for which the resource plan is developed, and the long-term period over which the net present value of revenue requirements is calculated. The resource acquisition period represents the near-term period in which the utility must actually acquire resources to meet system energy and demand requirements. For any resources they propose to acquire, utilities file needs assessments and draft requests for proposals (RFPs). The PUC may approve, deny, or order modifications to utility plans. Following PUC approval, utilities then begin the competitive bidding process to acquire the new resources needed to meet load and reserve requirements.

Over the past decade, the PUC has opened several docketed proceedings and issued emergency rules revising the least-cost planning rules to provide specific guidelines for utilities, and to ensure compliance with new legislation adopted by Colorado state government. In Decision No. C07-0829 of September 19, 2007, the PUC adopted emergency rules modifying LCP rules as required by bills enacted in the 2006 and 2007 sessions of the Colorado Legislature. In general, these bills required the PUC to consider not only the costs of new generation resources as prescribed in least-cost planning rules, but also various benefits, requiring more technical expertise and involvement from the PUC in the resource selection process.[23]

Specifically, the following bills required the associated changes:

- HB07-1037 establishes requirements for energy efficiency and demand-side management resources, and requires the PUC to shift from a least-cost planning standard to a more subjective consideration of multiple criteria "which will require substantially more Commission involvement in the resource selection process."[24] The criteria shift applies to the evaluation of all resources, not only demand-side management (DSM)[25] measures.
- HB07-1281 increases the renewable energy resources that electric utilities must acquire, necessitating greater integration between the resource planning rules and the new Renewable Energy Standards.
- SB07-100 is intended to improve the economic viability of rural renewable resources. The bill provides for the designation of energy resource zones, and for the construction of transmission infrastructure to bring energy from these zones to load centers.
- HB06-1281 requires the Commission "to give the fullest possible consideration to new clean and energy efficient technologies…(and) provides an

21 Colorado Revised Statutes 40-1-103.

22 4 Code of Colorado Regulations 723-3. Part 3: Rules Regulating Electric Utilities. Electric Resource Planning: 3601.

23 Colorado Public Utilities Commission. Decision No. C07-0829. Docket No. 07R-0368E. September 19, 2007.

24 Id. Page 7.

25 Demand-side management , or DSM, measures involve reducing electricity use through activities or programs that promote electric energy efficiency or conservation, or more efficient management of electric energy loads.

example of how the Commission can give such consideration to resources that may be in the public interest when accounting for the benefits of advancing the development of a particular resource, or when accounting for other benefits outside of a strict cost perspective."[26]

The statutory language describes some of those benefits:

The Commission shall give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases. The Commission shall consider utility investments in energy efficiency to be an acceptable use of ratepayer moneys.[27]

As a result of the various bills described above, the PUC chose to strike the term "least-cost" from the rules in all instances, changing their title to Resource Planning Rules. It also introduced the term cost-effective into the rules, defining it as "the reasonableness of costs and rate impacts in consideration of the benefits offered by new clean energy and energy-efficient technologies."[28] These and other emergency rules were adopted on a permanent basis in Decision No. C07-1101 in Docket No. 07R-419E.

Other significant changes to the Resource Planning Rules were adopted by the PUC in 2010 in response to the passage of HB10-1365, known as the Clean Air-Clean Jobs Act (CACJA). The legislative declaration of the Act states that:

The general assembly hereby finds, determines, and declares that the federal "Clean Air Act," 42 U.S.C. sec. 7401 et seq., will likely require reductions in emissions from coal-fired power plants operated by rate-regulated utilities in Colorado. A coordinated plan of emission reductions from these coal-fired power plants will enable Colorado rate-regulated utilities to meet the requirements of the federal act and protect public health and the environment at a lower cost than a piecemeal approach. A coordinated plan of reduction of emissions for Colorado's rate-regulated utilities will also result in reductions in many air pollutants and promote the use of natural gas and other low-emitting resources to meet Colorado's electricity needs, which will in turn promote development of Colorado's economy and industry.[29]

The Act required that all utilities owning or operating coal-fired generating units in Colorado file an emissions reductions plan, which may include the following elements: emission control equipment, retirement of coal-fired units, conversion of coal units to natural gas, long-term fuel agreements, new natural gas pipelines, increased utilization of existing natural gas resources, and new transmission infrastructure. The CO Department of Public Health and the Environment and the PUC were tasked with reviewing the utility filings.

Approval of the plans is contingent on several factors, including whether required emissions reductions would be achieved; whether the plan promotes economic development in the state; whether reliable electric service is preserved; and the degree to which the plan increases the utilization of natural gas or relies on energy efficiency or other low-emitting resources. Plans were to be filed by August 15, 2010, and full implementation is to occur by December 31, 2017.[30]

While required emissions reduction plans were separate from Electric Resource Plans, the PUC opted to revise and clarify Electric Resource Planning (ERP) rules to make them more consistent with the CACJA. The PUC adopted revised rules on July 29, 2010 in Decision No. C10-0958 as part of Docket No. 10R-214E. Significant changes to the rules include:

- Adoption as the policy of the state of Colorado that the PUC give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies.
- Inclusion in the resource plan of the annual water withdrawals and consumption for each new resource, and the water intensity of the generating system as a whole.
- Inclusion of the projected emissions of sulfur dioxide, nitrogen oxides, particulate matter, mercury, and

26 Id. Page 9.

27 Colorado Revised Statutes 40-2-123(1)(a).

28 Colorado Public Utilities Commission. Decision No. C07-0829. Docket No. 07R-0368E. September 19, 2007. Page 20.

29 Colorado Revised Statutes 40-3.2-203(1).

30 General Assembly of the State of Colorado. House Bill 10-1365.

carbon dioxide for new and existing generating resources.

- The Commission must consider the likelihood of new environmental regulations, and the risk of higher future costs associated with greenhouse gases, when it considers utility proposals.
- Descriptions of at least three alternate resources plans that meet the same resource need as the base plan but include proportionally more renewable energy or demand-side resources. For the purpose of risk analysis, a range of possible future scenarios and input sensitivities should be proposed for testing the robustness of the alternative plans.
- Permission for the utilities to implement cost-effective demand-side resources to reduce the need for additional resources that would otherwise need to be obtained through a competitive acquisition process.[31]

Colorado's IRP rules do not mandate public participation prior to the filing of the IRP. The rules are, however, unique in requiring that the utility, Commission staff, and the Office of Consumer Counsel agree upon an entity to act as an independent evaluator (paid for by the utility) and advisor to the Commission. The independent evaluator reviews all documents and data used by the utility in developing its resource plan, and submits a report to the Commission that contains its analysis of "whether the utility conducted a fair bid solicitation and bid evaluation process, with any deficiencies specifically reported."[32]

Following the filing of the utility's resource plan, the IRP rules state that parties in the proceeding have 45 days to file comments on the plan and on the independent evaluator's report. The utility has a chance to respond to comments, after which the Commission is required to issue a written decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan, "which decision shall establish the final cost-effective resource plan."[33] In 2011 the Colorado electric utilities filed the first electric resource plans that were consistent with these revised rules. The plan from Public Service Company of Colorado ("Public Service") is discussed in section III of this report.

3. Oregon

Oregon's IRP rules are the most straightforward of the three states examined here. The state first established resource planning rules in 1989, in Public Utility Commission Order 89-507. The order directs all energy utilities in Oregon to undertake least-cost planning, which the Commission defines in a somewhat unique way, stating that:

> *Least-cost planning differs from traditional planning in three major respects. It requires integration of supply and demand side options. It requires consideration of other than internal costs to the utility in determining what is least-cost. And it involves the Commission, the customers, and the public prior to the making of resource decisions rather than after the fact. …Least-cost planning as mandated by this order will allow the public as well as the Commission to participate in the planning process at its earliest stages.*[34]

The PUC thus identifies one of the key procedural elements of least-cost planning as allowance for significant involvement from the public and other utilities in the preparation of the resource plan, which includes opportunities for the public to contribute information and ideas as well as to receive information. The Commission's order states that "the open and collaborative character of least-cost planning may foster elevated confidence among those affected by the decisions and may make the process more responsive to demonstrated needs."[35] Substantive elements of least-cost planning are similar to those found in other states, with the PUC emphasizing the evaluation of conservation in a manner that is consistent and comparable to that of supply-side resources,[36] and with the analysis of economic, environmental, and social uncertainties.

The order also includes a concurring opinion from Commissioner Myron B. Katz, in which he discusses whether commissions, in the context of least-cost planning, should be interested in costs to utilities and ratepayers alone, or in overall costs to society. Katz suggests that utilities should seek to determine the costs for resources that include any externalities associated with those

31 Colorado Public Utilities Commission. Decision No. C10-0958. Docket No. 10R-214E. July 29, 2010.

32 4 Code of Colorado Regulations 723-3. Part 3: Rules Regulating Electric Utilities. Electric Resource Planning: 3613(b).

33 4 Code of Colorado Regulations 723-3. Part 3: Rules Regulating Electric Utilities. Electric Resource Planning: 3613(e).

34 Public Utility Commission of Oregon. Order No. 89-507. Docket No. UM 180. April 20, 1989.

35 Id. Page 3.

36 Id. Page 7.

resources, stating that "[a] resource should be deemed cost-effective and thus eligible for selection if its costs are lower than the costs of alternative resources assuming a market in which all costs, including environmental costs, are reflected in resource price tags."[37]

Subsequent PUC Orders 07-002, 08-339, and 09-041 (which became O.A.R. 860-027-0400) updated planning guidelines and requirements, and changed least-cost planning terminology to integrated resource planning, in recognition of the fact that there are many risks and uncertainties associated with any portfolio that must be weighed, and that least-cost is not the only criterion for selecting the best resource portfolio. This emphasis on the importance of risk in integrated resource planning is one way in which Oregon differs from some other states. The emphasis is placed in the forefront of the revised rules, with Guideline 1(b) stating that "(r)isk and uncertainty must be considered."[38] *Risk* is defined as a measure of the bad outcomes associated with a resource plan, while *uncertainty* is a measure of the quality of information about an event or outcome. Recognizing risks that are general to the electric industry and those that are specific to Oregon, the rules specify that, at a minimum, the following sources of risk must be considered in utility resource plans: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gases, as well as any additional sources of risk and uncertainty.[39]

In order to quantify these risks, utilities should calculate two different measures of the present value of revenue requirement risk (PVRR). The first should measure the variability of resulting PVRR costs under the different scenarios, and the second should measure the severity of any bad outcomes.[40] The primary goal of Oregon's IRP planning process is thus "the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[41] A portfolio of resources with the lowest expected cost before the inclusion of various risks may in fact have higher costs than other resource portfolios once those risks are considered.

The goal of the Oregon PUC in amending its rules was for utilities to identify the lowest-cost resource plan over the specified planning horizon by balancing both cost and risk. The Commission declines to mandate how the measures of PVRR risk be defined, instead leaving it up to the utilities and to "the interactive process of developing an IRP to make the best assessment of appropriate risk measures."[42] Unlike in Arizona, which requires that utilities create a plan to manage specific risks, Oregon requires that utilities take risks, their probabilities of occurrence, and the likelihood of bad outcomes into their choice of preferred resource plan.

These subsequent orders make few other substantive changes to the rules established in order 89-507, but instead add detail on the information and analysis that the PUC wanted in order to acknowledge utility resource plans. Notable changes include:

- The requirement that each utility ensure that a conservation potential study is done periodically for its entire service territory.
- The requirement that demand response and distributed generation be evaluated similarly to more traditional supply-side resources.
- The requirement that utilities include the expected regulatory compliance costs for various pollutants, that a range of potential CO_2 costs be analyzed,[43] and that sensitivity analyses be performed on a range of costs for nitrogen oxides, sulfur oxides, and mercury, if applicable.[44]

Order 07-002 also details the nature of public involvement in the IRP process, stating that the public and other utilities should be allowed significant involvement in the preparation of an IRP—that they should be allowed to contribute information and ideas, and to make relevant inquiries of the utility formulating the plan. The utility should also make a draft IRP available for public review

37 Id. Page 12.

38 Public Utility Commission of Oregon. Order No. 07-002. Docket No. UM 1056. January 8, 2007. Appendix A. Page 1.

39 Id.

40 Id. Appendix A. Page 2.

41 Id. Appendix A. Pages 1-2.

42 Id. Page 7.

43 From zero to $40 (1990$), as established in Order No. 93-695.

44 Public Utility Commission of Oregon. Order No. 07-002. Docket No. UM 1056. January 8, 2007.

45 Id. Page 8.

and comment before filing a final version with the PUC.[45]

Following submission of the integrated resource plan, intervening parties and Commission staff have six months to complete and file written comments on it. In advance of the deadline for written comments, the utility must also present the results of its resource plan to the Commission at a public meeting. The Commission then acknowledges the plan or returns it to the utility with comments. It may allow the utility to revise its resource plan before issuing an acknowledgement order.[46]

The IRP rules are careful to point out that acknowledgement of the IRP does not guarantee favorable ratemaking treatment later on, but that the acknowledgement simply means the plan seemed reasonable at the time it was reviewed by the Commission.[47] PacifiCorp, operating in Oregon as Pacific Power, is expected to file its 2013 IRP this year, but that plan was not available in time for inclusion in this paper. PacifiCorp's 2011 IRP is discussed in later sections.

46 Id. Page 9.

47 Id. Page 2.

III. Examples of Best Practices in Utility Integrated Resource Plans

A. Arizona Public Service

Arizona Public Service (APS) is the state's largest electric utility, and has been serving retail and wholesale consumers since 1886. In March 2012, APS filed the first formal resource plan in 17 years with the Arizona Corporation Commission. This IRP was also the first to be filed under the ACC's revised rules, as described in section II.A.

From the time when the Corporation Commission issued the final IRP rules to the date that APS filed its resource plan, the utility was "engaging key stakeholders to gain an understanding and appreciate of their areas of concern."[48] A series of workshops held during 2010 and 2011 sought to both inform and gather input from interested stakeholders on future resource decisions. The workshop topics included the resource fleet and transmission system; load forecasts; energy efficiency; smart grid; demand response; utility water consumption; fuel supplies and markets; technology options and costs; externalities; resource procurement; portfolios and sensitivities; and metrics and monetization costs for water, sulfur oxides, particulate matter, and nitrogen oxides. Approximately 35 to 50 stakeholders participated in each meeting, and several stakeholders were also invited to give presentations in some of the topic areas mentioned above.[49]

APS also contracted with the Morrison Institute at Arizona State University to conduct a series of four "Informed Perception Project" surveys on customer preferences and concerns regarding the energy resource options available to APS. Results showed that APS customers "favored an increase in the use of renewable energy resources, such as solar and wind, and were interested in both the environmental impacts and reliability of energy choices."[50]

Over the course of the 15-year planning period, with the assumption that migration to the state and individual electricity consumption will return to historic highs, APS has forecast 3% average annual growth in nominal electricity requirements through 2027. Energy efficiency and distributed generation, in the form of rooftop solar installations, will help offset some of this growth, but APS expects that it will need to add additional conventional supply-side resources, in the form of natural gas-fired generation, in 2019. APS created four resource portfolios to evaluate: a base case, a "four corners contingency," an "enhanced renewable" case, and a "coal retirement" case. Figure 3 shows the details of those plans.

Each of the resource plans created by APS were analyzed using a production simulation model, PROMOD IV, which dispatches the energy resources in each of the portfolios and generates system costs, or the likely future revenue requirements, associated with each. Calculation of system revenue requirements demonstrated that the APS base case portfolio was the most cost-effective of the resource plans evaluated. APS also monitors specific metrics to provide a context for comparing and evaluating the portfolios. In addition to revenue requirements, those metrics include fuel diversity, capital expenditures, natural gas burn, water use, and CO_2 emissions.

APS selected major cost inputs and evaluated several sensitivity scenarios, setting the assumptions for these variables higher and/or lower to test the impacts on the specific metrics being evaluated. These major cost inputs include natural gas prices, CO_2 prices, production and investment tax credits for renewable resources, energy efficiency costs, and monetization of SO_2, NO_x, PM, and water. APS also created low-cost and high-cost scenarios,

48 Arizona Public Service. 2012 Integrated Resource Plan. March 2012. Page 2.

49 Id. Page 25.

50 Id.

Figure 3:

Portfolios Considered in the APS 2012 IRP[51]

	Base Case (2012 Resource Plan)	Four Corners Contingency	Enhanced Renewable	Coal Retirement
Description	*Plan includes APS closing Four Corners units 1-3 and purchasing SCE's share of units 4-5; continues the current trajectory of EE and RE compliance*	*Contingency plan depicting the retirement of the Four Corners coal-fired plant; energy replaced by additional natural gas resources*	*Assumes 30% (after EE/DE) of energy needs met by renewable resources; include the consummation of the Four Corners transaction*	*Assumes APS retires all coal-fired generation; energy replaced with a combination of natural gas and renewable resources*
Resource Contributions *(2027 Peak Capacity Contribution/ % Energy Mix)*				
Nuclear	1,146 MW 18.7%MWh	1,146 MW 18.7% MWh	1,146 MW 18.7% MWh	1,146 MW 18.7% MWh
Coal	1,932 MW 26% MWh	962 MW 12.7% MWh	1,932 MW 26% MWh	0MW 0MWh
Natural Gas and Demand Response	7,424 MW 26.3% MWh	8,394 MW 39.6% MWh	7,138 MW 20.7%MWh	9,188 MW 46.3% MWh
Renewable Energy (RE) & Distributed Energy (DE)	1,141 MW 13.7% MWh	1,141 MW 13.7% MWh	1,427 MW 22.8% MWh	1,308 MW 19.7% MWh
Energy Efficiency (EE)	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh

which incorporate the low and high values for all of the variables mentioned above rather than testing them on an individual basis. The results of the sensitivity analysis showed that the four corners contingency and coal retirement portfolios have the most variability in terms of net present value of revenue requirements, which fluctuate 11-12% as compared to 6-7% for the base case and enhanced renewable portfolios. Natural gas price changes caused the largest impact on sensitivity results.

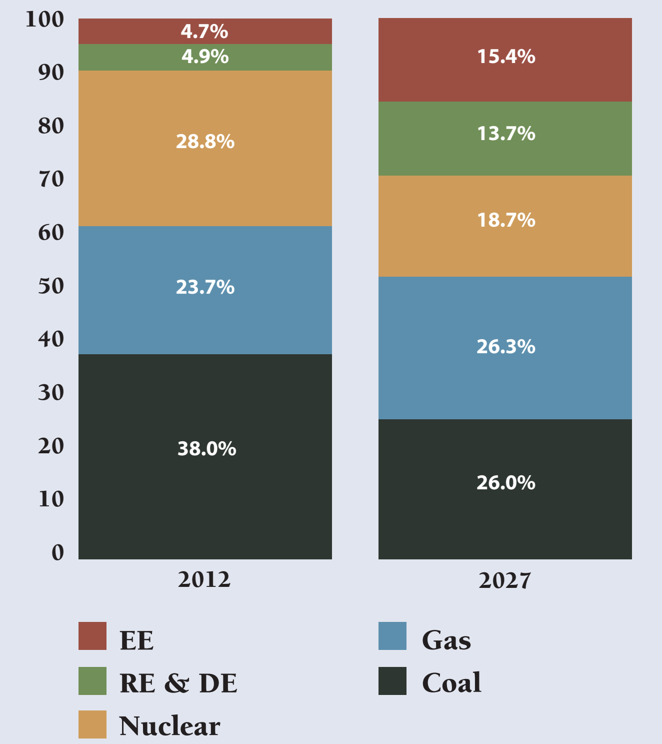
Under the base case plan, APS achieves compliance with energy efficiency requirements and slightly exceeds compliance levels for renewable energy. Consistent with the intent of the revised rules, APS's reliance on coal-fired generating resources drops by 12% between 2012 and 2027. Use of natural gas increases slightly over the course of the planning period under this scenario, but by 2027, no single fuel source makes up more than approximately 26% of the APS resource mix. Figure 4 shows the energy mix in 2027 compared to 2012 under the base case portfolio.

APS had approximately 600 MW of excess capacity in 2012, heading into the summer peak. In the short term—over the next three years—the company planned to continue to pursue energy efficiency and renewable energy resources. During the intermediate term, years four to 15 of the planning period, APS plans to add 3,700 MW of natural gas capacity and 749 MW of renewable capacity. However, "[i]n the event that solar, wind, geothermal, or other renewable resources change in value and become a

51 Id. Page 44. Arizona Public Service Company hired Black and Veatch Corporation to conduct a Solar Photovoltaic (PV) Integration Cost Study report that provides the company with an estimate for the incremental operating reserves necessary to integrate geographically diverse PV development in the APS service territory, and quantifies the anticipated incremental cost to provide the reserve capacity and energy services. "Solar Photovoltaic Integration Cost Study," B&V Project No. 174880 (November 2012).

Figure 4

Energy Mix Under The APS Base Case Portfolio[52]



more viable and cost-effect option than natural gas, future resource plans may reflect a balance more commensurate to the enhanced renewable portfolio."[53]

APS should be commended for several elements of its 2012 IRP. The first of those is the comprehensive stakeholder process, which included workshops covering most, if not all, of the topic areas that are vital to comprehensive integrated resource plans. Not only were stakeholders invited to listen and offer feedback, they were also invited to present their points of view on a subset of these important issues. In the IRP itself, APS provides all non-confidential input and output data for stakeholder review.

Second, APS continues to pursue energy efficiency, renewable energy, and distributed generation resources in each of the resource portfolios it analyzed, meeting or exceeding ACC-specified goals and consistent with the Commission finding that:

> *Continued reliance on fossil generation resources without the addition of renewable generation resources is inadequate and insufficient to promote and safeguard the security, convenience, health, and safety of electric utilities' customers and the Arizona public and is thus unjust, unreasonable, unsafe, and improper.*[54]

APS has also analyzed portfolios that meet the Commission goals of promoting fuel and technology diversity as the utility lowers its reliance on coal-fired generation and increases its use of energy efficiency and renewable energy resources.

Third, APS takes environmental costs into account when evaluating its resource plans. The company uses a CO_2 adder consistent with the assumption that federal regulation of CO_2 will occur within the 15-year planning period. In sensitivity scenarios, APS analyzes alternative prices for CO_2 emissions, and also includes adders for SO_2, NO_x, PM, and water. Emissions cost and water consumption are also two metrics by which APS evaluates its resource portfolios. Water in particular is a resource that has not been given much consideration in utility integrated resource planning in past decades, in this and in other jurisdictions—but it is especially important for Arizona and other states in the arid parts of the country, as it may at times act as a constraining resource on electric power generation.

While APS has indeed done an admirable job in its 2012 Integrated Resource Plan, there are several areas in which the utility can still improve. The first is with respect to its load forecast. APS assumes a return to very high levels of load growth, at 3% per year for a total of 55% growth in energy consumption over the planning period. Load growth is one variable that can be highly uncertain. APS even states that "weather, population growth, economic trends, and energy consumptions behaviors are among the key variables that impact the Company's view of future resource needs. Accurately forecasting any one of these variables over a 15-year period is a challenge. Accurately forecasting them all is impossible."[55]

52 Id. Page 45.

53 Id. Page 64.

54 Arizona Public Service. 2012 Integrated Resource Plan. Page 13.

55 Id. Page 18.

Changes in the forecast can lead to significant changes in the quantity and type of resources needed in a utility's portfolio. For this reason, utilities engaged in resource planning typically analyze sensitivity cases that use at least two (low and high) alternative load forecasts. APS admitted that "a challenge more specific to the APS service territory is load-growth uncertainty,"[56] and yet the company analyzed only a single load forecast—one that the company admits is more than triple the average growth of electricity demand in the United States.[57]

The second improvement that APS could make to its IRP process relates to the creation of the utility's resource portfolios. Often, in integrated resource planning, utilities will use resource optimization models—e.g., EGEAS, Strategist, or System Optimizer—to create resource portfolios. The user inputs data on peak and energy demand, reserve margins, fuel prices, emissions prices, capital and operating cost of both supply and demand resources, etc., and the optimization model will select the number and type of resources to be added over time to make up the least-cost plan. These models will also perform a simplified system dispatch in order to generate system revenue requirements over the planning period. Rather than using an optimization model to select the ideal resource portfolios, APS hand-selected the resource mix for each portfolio. Under this method, it is possible that a lower-cost resource plan exists that APS has not identified.

This is particularly true in the sensitivity analyses that the company conducted. As described above, natural gas prices led to the greatest variance in system revenue requirements in the sensitivity analyses. Had an optimization model been used to evaluate scenarios with high natural gas prices, one might see the model select fewer natural gas-fired resources in favor of increased renewable or energy efficiency. Similarly, in sensitivity scenarios that look at decreased costs for energy efficiency, an optimization model might select additional quantities of energy efficiency to be added to the resource mix. Some of the supply-side resources selected using base EE costs might then not be required, as additional EE would lower both peak and energy demand.

On page 104 of its IRP, APS presents a table of residential and non-residential EE programs that were rejected because program costs were higher than benefits. In sensitivity scenarios where lower EE costs were evaluated, some of these measures that were rejected may have met cost-effectiveness tests and been selected for inclusion in utility resource portfolios.

B. Public Service Company of Colorado

The October 2011 IRP filing from Public Service Company of Colorado ("Public Service") was filed shortly after the company's filing that addressed the Clean Air-Clean Jobs Act. In the CACJA plan ultimately approved by the Colorado PUC, Public Service will retire 600 MW of base-load coal generation, fuel switch from coal to natural gas at another 450 MW of coal generation, and install emission controls at three other coal units by the year 2017. Additionally, as part of two separate filings, the company planned for the installation of 900 MW of additional wind and 30 MW of new solar by the end of 2012. These additions, repowerings, and retirements, along with the current weak growth in Colorado's economy, led Public Service to project a resource need of only 292 MW of additional generation capacity by 2018.

Public Service developed a "least-cost baseline case" resource portfolio, designed to meet resource needs during the Resource Acquisition Period from 2012 to 2018 at the lowest measurement of present value of revenue requirements. The utility also developed eight alternative plans that evaluate increasing amounts of renewable and distributed generation resources. These resource portfolios were evaluated using the Strategist model from the period of 2011-2050, and are shown in Figure 5.

Public Service evaluated the baseline case and the eight alternative cases under several sensitivity scenarios, altering the price of CO_2 emissions, renewable tax incentives, natural gas prices, and level of sales. Figure 6 shows the results of the analysis for the first three variables.

Public Service concludes from its analysis that existing and planned resources would be sufficient to meet the forecasted energy requirements of its system, but that natural gas-fired combustion turbines (CTs) would be required to provide the capacity necessary to maintain reserve margins. The company also concludes that adding

56 Id. Page 20.

57 Id. Page 18.

Figure 5

Least-Cost Baseline Case and Alternative Plans During the Resource Acquisition Period (RAP) From Public Service Company of Colorado's 2011 IRP[58]

		Level A				Level B			
RAP Resource	**1 Baseline**	**A2 Wind**	**A3 PV**	**A4 Battery**	**A5 Solar Thermal**	**B2 Wind**	**B3 PV**	**B4 Battery**	**B5 Solar Thermal**
Thermal Resources	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	1 CT 173 MW	1 CT 173 MW	1 CT 173 MW
Wind		200 MW	200 MW	200 MW	200 MW	800 MW	800 MW	800 MW	800 MW
Solar			25 MW	25 MW	25 MW		100 MW	100 MW	100 MW
Battery				25 MW				100 MW	
Solar Thermal					50 MW				125 MW

Figure 6

Sensitivity Results for Co_2, Tax Incentives, and Gas Prices From Public Service Company of Colorado's 2011 IRP[59]

		Level A				Level B			
		A2 Wind	**A3 PV**	**A4 Battery**	**A5 Solar Thermal**	**B2 Wind**	**B3 PV**	**B4 Battery**	**B5 Solar Thermal**
Alternative Plan 2011-2050 PVRR Deltas from Baseline Case ($Millions)									
	Starting Assumptions	$98	$105	$160	$298	$427	$489	$672	$881
Sensitivities	**CO_2 3-Source Low Esc**	$9	$10	$65	$182	$75	$113	$297	$455
	CO_2 3-Source	$7	$8	$62	$178	$63	$101	$285	$441
	CO_2 Early ($20 in 2017)	($36)	($38)	$17	$124	$117	$92	$98	$223
	Low Gas	$164	$179	$238	$393	$671	$760	$979	$1,204
	High Gas	$21	$19	$72	$183	$151	$176	$369	$503
	PTC Wind	($97)	($90)	($35)	$103	$312	($251)	($67)	$142
	10% ITC Solar PV	$98	$119	$174	$312	$427	$546	$729	$938
	30% ITC Solar Thermal	$98	$105	$160	$235	$427	$489	$672	$741

58 Public Service Company of Colorado. 2011 Electric Resource Plan: Volume 1. October 31, 2011. Pp. 1-38.

59 Id. Pp. 1-41.

renewable generating resources would increase system costs under both baseline and sensitivity assumptions.[60] The results of the sensitivity analysis shown in Figure 6 seem to indicate, however, that if the production tax credit (PTC)[61] for wind were to be extended, there would be some benefit to adding additional wind generation, as shown by the decline in present value of revenue requirements in this scenario relative to the base case.

Given the results of the resource analysis, Public Service proposes to utilize a competitive All-Source Solicitation to acquire the resources needed to meet planning reserve margin targets. The solicitation would seek both short-term and long-term power supply proposals, with a preference for short-term contracts. Public Service lists several uncertainties that it will face over the coming years: future environmental regulations, changing technology costs, tax credits that impact the relative costs of generation alternatives, fuel prices, and economic growth in its service territory.[62] Given these uncertainties and the relatively small resource need, the shorter-term power urchase agreements would allow the utility to wait and see if and how uncertainties can be resolved before adding new generation facilities to its resource mix. The company will also offer enough self-build power supply proposals into the solicitation process to meet the needs over the resource acquisition period.

These proposals would ensure that at least one portfolio could be developed with company-owned facilities, and that generating capacity will be expanded at existing sites. Public Service requests that the PUC allow it to conduct periodic solicitations for additional renewable energy, if and when markets become most favorable to customers; but it reports no plans to add additional renewables over the acquisition period. The company states that, "[t]o the extent the Commission desires to see portfolios from the Phase 2 process that contain increasing levels of renewable or Section 123 Resources the Commission should direct the Company to do so in its Phase 1 order."[63]

Public Service's 2011 IRP is comprehensive, thorough, and a good example of effective resource planning. Resource planning in Colorado is driven by: 1) the state Legislature, as statutes dictate the content of state IRP rules; 2) by interveners, whose comments and suggestions during IRP processes can lead to changes in both rules and content of utility resource plans; and 3) by the PUC, which oversees the process and may require that utilities revise resource plans in specific ways prior to receiving Commission approval. The input and oversight from these three entities, combined with the utilities' expertise, leads to the inclusion of several notable elements in the resource plan that demonstrate additional issues of concern in Colorado.

First, recognizing that acquiring necessary resources does not always go according to plan, the utility creates and describes a series of the more common contingency events—e.g., bidders withdrawing proposals, transmission development delays, higher than anticipated electric demand, etc.—and develops plans to address them if they occur.[64]

Second, Public Service acknowledges that its planned volume of wind installations (2,100 MW by 2012) creates specific challenges and requirements that much lower volumes of renewables would not. Because wind output can be variable and uncertain, there may be additional flexibility requirements on an electric system—i.e., there must be a certain amount of generation that can be brought on-line within a 30-minute period in order to respond to changes in renewable output. Public Service conducts an assessment of the need for flexible resources in its IRP's general assessment of need.

Flexibility studies are not a part of traditional integrated resource planning, but Public Service is responding to unique circumstances in its service territory by incorporating this type of study in its resource planning. Utilities sometimes cite the variability and uncertainty of wind and other renewables as reasons *not* to pursue these types of resources in their portfolios; Public Service shows,

60 Id. Pp. 1-43.

61 The federal renewable energy production tax credit (PTC) provides a per-kilowatt-hour tax credit for electricity generating by various types of renewable energy resources and sold by the taxpayer to an unrelated person during the taxable year. The PTC was originally enacted in 1992 and has been extended several times, most recently in January 2013 as part of the American Taxpayer Relief Act of 2012 (H.R. 6, Sec 407). Currently, the PTC for wind resources for which construction began prior to December 31, 2013 is 2.3 cents/kWh.

62 Id. Pp. 1-5.

63 Id. Pp. 1-49.

64 Id. Pp. 1-59.

however, that these challenges can be planned for in a reasonable way and are not a reason to avoid renewable additions.

Finally, traditional integrated resource planning does not pursue short-term strategies, such as market purchases that may buy time in the hope that some uncertainties will be resolved."[65] The Public Service IRP does just that, however, by making shorter-term resource acquisition decisions and preserving "decisions involving new generation facilities to a point in the future when we see how these uncertainties are resolved."[66]

While Public Service should be applauded for its integration of renewables to date, it is unclear from the company's IRP whether it truly views renewable generating technologies as a system resource as opposed to an obligation established by the state legislature and the PUC. As mentioned above, Public Service has no plans to pursue additional renewable acquisitions during the next seven years, even though sensitivity analyses show that additional wind generation may be beneficial to ratepayers if the production tax credit were to be extended. The company does ask that it be granted permission to conduct solicitations for renewables outside of the resource planning process if it determines that market conditions are "favorable," but it gives no indication as to what favorable market conditions might look like. An evaluation of the market conditions favorable to renewables would be very helpful in the context of resource planning, and could be included in future IRPs or updates from Public Service.

C. PacifiCorp

Of the three utilities examined here, PacifiCorp is unique in that it operates across six states—Oregon, Washington, California, Idaho, Utah, and Wyoming, five of which have IRP or other long-term planning requirements.[67] This gives PacifiCorp the additional challenge of planning on a system-wide basis while meeting each of the resource-acquisition mandates and policies in the states where it operates. The company evaluates a 20-year study period, but focuses on the first ten years (2011-2020) in its assessment of resource need.

In that ten-year planning period, PacifiCorp forecasts that system peak load will grow at 2.1% per year (2.4% for

65 Chupka, M,, Murphy, D. & Newell, S. *Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches.* Brattle Group. 2008. Page 2.

66 Public Service Company of Colorado. *2011 Electric Resource Plan: Volume 1.* October 31, 2011. Pp. 1-5.

67 Wyoming does not have its own IRP obligation, but instead mandates that any utility serving in the state that is required to submit an IRP in another jurisdiction also file that IRP with the Wyoming PSC.

68 Id. Page 8.

Figure 7

Resource Additions in the Preferred Portfolio—PacifiCorp's 2011 IRP[68]

Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
CCCT F Class	-	-	-	625	-	597	-	-	-	-	1,222
CCCT H Class	-	-	-	-	-	-	-	-	475	-	475
Coal Plan Turbine Upgrades	12	19	6	-	-	18	-	8	-	-	63
Wind, Wyoming	-	-	-	-	-	-	-	300	300	200	800
CHP-Biomass	5	5	5	5	5	5	5	5	5	5	50
DSM, Class 1	6	70	57	20	97	-	-	-	-	-	250
DSM, Class 2	108	114	110	118	122	124	126	120	122	125	1,189
Oregon Solar Programs	4	4	4	3	3	-	-	-	-	-	18
Micro Solar – Water Heating	-	4	4	4	4	4	4	4	-	-	28
Firm Market Purchases	350	1,240	1,429	1,190	1,149	775	822	967	695	995	N/A

the eastern system peak and 1.4% for the western system peak), and that energy requirements will grow by 1.8% per year. Resource deficits will begin in the first year, with PacifiCorp being short 326 MW in 2011. This deficit grows to 3,852 MW by 2020. In the near-term, shortages will be met with DSM, renewables, and market purchases, but new baseload and intermediate generating units begin to be added to the resource mix in 2014.[69] Figure 7 shows the proposed resource additions.

If PacifiCorp were to proceed with these proposed resource additions, by 2020 its capacity mix would be as shown in Figure 8. In this scenario, traditional thermal resources still make up two-thirds of PacifiCorp's capacity mix; DSM makes up just over 13%, and renewables make up 2.6%.

As Figure 9 shows, PacifiCorp's energy mix looks slightly different under its preferred portfolio. The percentage of total energy generated from coal-fired resources drops by 26% between 2011 and 2020, while the amount of energy from gas-fired resources more than doubles. Even with the significant drop in generation from coal, energy from thermal resources makes up 61% of PacifiCorp's total energy. DSM makes up 11% of the energy mix, with another 11% coming from renewable resources. Hydroelectric power and energy purchases make up the bulk of the remaining energy.

Of the three utilities examined in this report, PacifiCorp's portfolio modeling process is the most comprehensive. It uses a model called System Optimizer, which has the capability to determine capacity expansion plans, to run a production cost simulation of each optimized portfolio, and to perform a risk assessment on these portfolios.

Figure 8

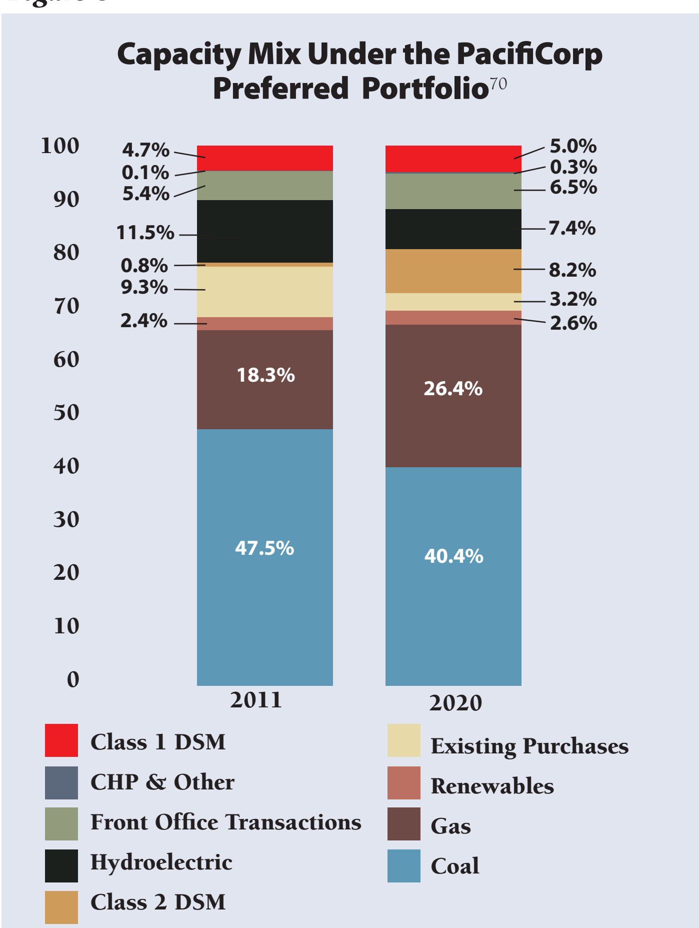
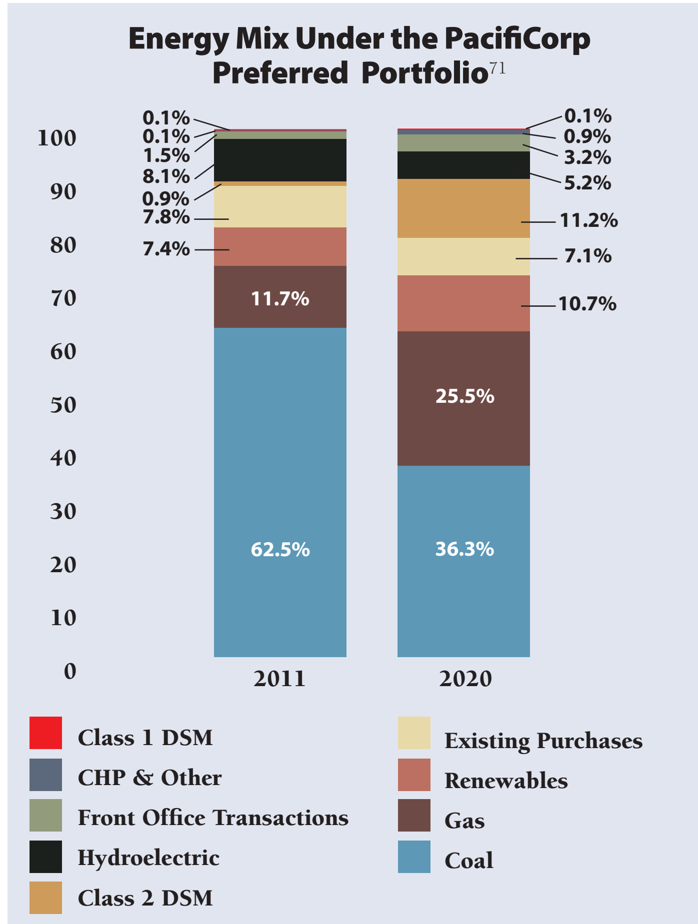


Figure 9



69 PacifiCorp. 2011 *Integrated Resource Plan: Volume 1*. March 31, 2011. Page 83.

70 Id. Page 10.

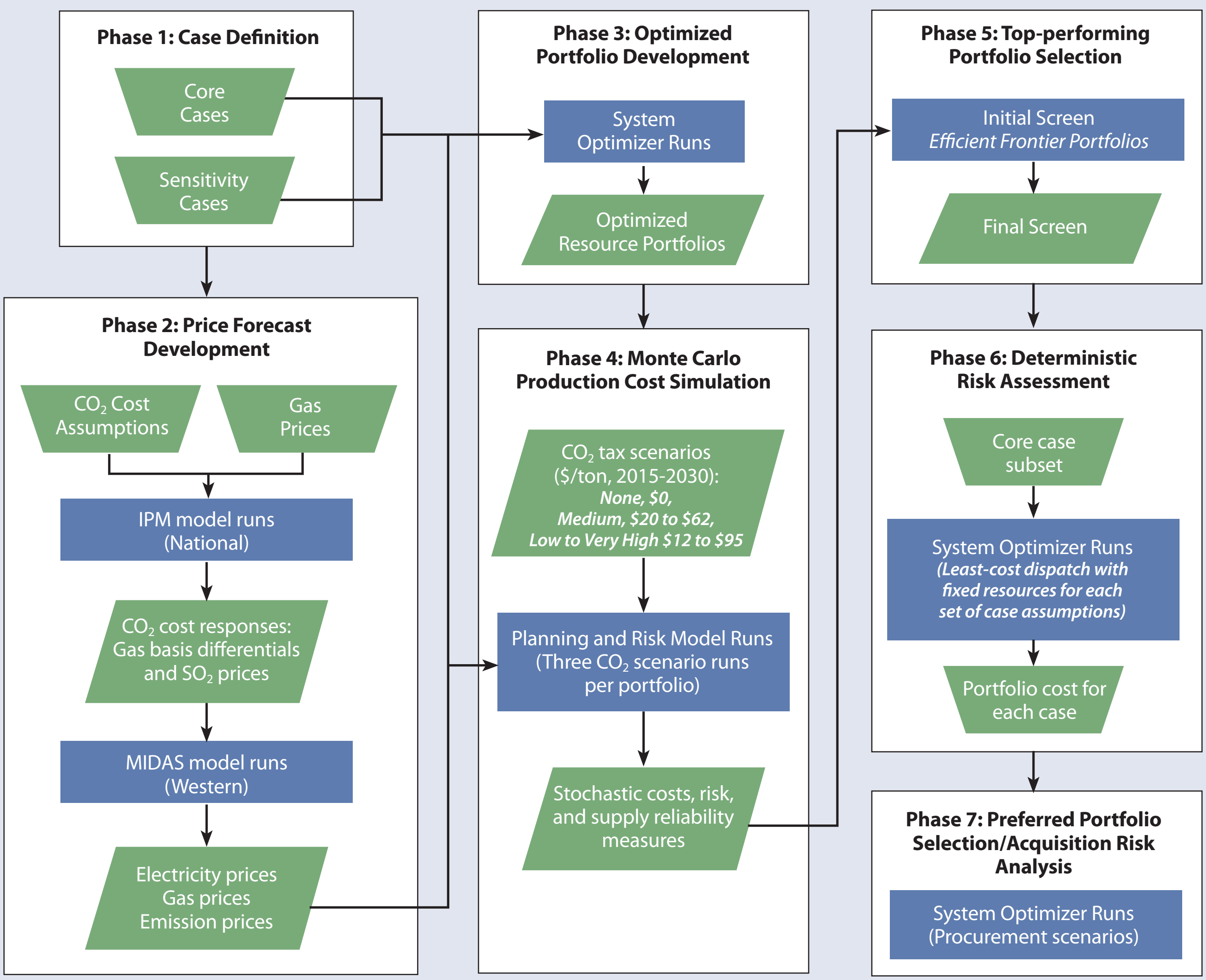
71 Id. Page 13.

Altogether, PacifiCorp defined 67 input scenarios for portfolio development. These looked at alternative transmission configurations, CO_2 price levels and regulation types, natural gas prices, and renewable resource policies. Sensitivity cases examined additional incremental costs for coal plants, alternative load forecasts, renewable generation costs and incentives, and DSM resource availability. Top resource portfolios were determined on the basis of the combination of lowest average portfolio cost and worst-case portfolio cost resulting from 100 simulation runs. Final portfolios were selected after considering such criteria as risk-adjusted portfolio cost, 10-year customer rate impact, CO_2 emissions, supply reliability, resource diversity, and uncertainty and risk surrounding greenhouse gas and RPS policies.[72]

Figure 10 shows PacifiCorp's schematic of its modeling process. PacifiCorp is one of the only utilities in the country that models energy efficiency resources as supply-side resources, rather than as load modifiers. The utility provides the model with specific quantities of energy efficiency at given costs, and allows those efficiency resources to compete against the other resources from

Figure 10

Pacificorp Modeling and Risk Analysis Process[73]



72 Id. Page 153.

73 Id. Page 155.

which the model is able to select. PacifiCorp's efficiency resource information in its 2011 IRP is based on a 2010 energy efficiency potential study that provided an estimate of the size, type, timing, location, and cost of the demand-side resources that are technically available in PacifiCorp's service territory. Data for more than 18,000 measures were available after the resources were separated by customer segment, facility type, and unique EE measures.

Energy efficiency measures are called Class 2 DSM, while capacity-based measures are separated into two categories: Class 1 DSM includes dispatchable demand-response programs, and Class 3 DSM includes pricing programs. Focusing on Class 2 DSM measures, PacifiCorp consolidated them into nine cost bundles grouped by levelized cost for inclusion in the modeling, and 1,400 supply curves were modeled for the IRP.[74]

Energy efficiency measures performed well in the modeling, representing the largest resource added through 2030 across all portfolios with cumulative capacity additions exceeding 2,500 MW in the preferred portfolio. The inclusion of such large quantities of energy efficiency creates huge cost savings to ratepayers. If energy efficiency were not included in PacifiCorp's resource portfolio, the utility would have to meet electric load by adding 2,500 MW of supply-side resources at much greater cost.

Although PacifiCorp's portfolio modeling process is comprehensive and well-executed, system resource modeling in general is only as good as the *input assumptions* used to generate the portfolios. The most significant area in need of improvement in the PacifiCorp IRP process relates to the input assumptions and analysis regarding the company's coal fleet—or, rather, the lack of analysis presented on this in the IRP. This lack of analysis began during the stakeholder process. In comments that it submitted, the Sierra Club states that it actively participated in the stakeholder input process, and raised many of the issues discussed in those comments. "The company did not respond to any requests for data related to the topics addressed in these comments, choosing instead to provide only a small amount of materials in the final draft, just days before the company submitted the final IRP."[75]

PacifiCorp's 26 coal-fired boilers make up almost two thirds of its generation. To keep these units running while meeting stricter federal air pollution standards, the company would have to spend $1.57 billion in environmental capital cost from 2011 to 2020, in addition to $1.2 billion that it invested before 2011. Operating costs would raise the total cost to customers to $4.2 billion, or $360 million on an annual basis by 2030.[76] PacifiCorp, however, makes no mention of these current compliance obligations or any future costs in the 2011 IRP or its appendices. The utility failed to disclose the costs that would be faced by its coal fleet in its 2011 IRP, and failed to do a comprehensive analysis of the economics of each of its coal-fired generating units. Absent this analysis, the resource portfolios analyzed by the company cannot be considered to be truly "optimized."

It is highly likely that PacifiCorp could add additional renewable resources to its portfolio. As discussed above, Public Service Company of Colorado had 2,100 MW of wind capacity alone on its system at the end of 2012, and they are a single utility operating in one state. PacifiCorp's territory covers portions of six states, many with large amounts of renewable potential. PacifiCorp's service territory also borders other states with large amounts of renewable potential, and the company could enter into long-term contracts for renewable energy. The company states in the IRP that it commissioned a study on geothermal potential, yet its resource portfolio does not include any anticipated geothermal energy or capacity during the study period.

74 Lamont, D. & Gerhard, J. The Treatment of Energy Efficiency in Integrated Resource Plans: A Review of Six State Practices. Regulatory Assistance Project. January 2013. Pp. 6-8.

75 Sierra Club's Preliminary Comments in the Matter of PacifiCorp 2011 Integrated Resource Plan before the Public Utility Commission of Oregon. LC 52. August 25, 2011.

76 Opening Comments of the Citizens' Utility Board of Oregon in the Matter of PacifiCorp 2011 Integrated Resource Plan before the Public Utility Commission of Oregon. LC 52.

IV. Recommendations for Prudent Integrated Resource Planning

Prudent integrated resource planning involves both the process of creating and sharing the resource plan with stakeholders, and the elements that are analyzed and included in the plan itself. This section provides recommendations, for both the IRP process and the resulting resource plan, that are designed to result in responsible and comprehensive utility integrated resource plans.

A. Integrated Resource Planning Process

Integrated resource planning processes differ from state to state. The ideal process begins with the determination of the IRP guidelines or rules. Integrated resource planning rules were first established in many states in the late 1980s or early 1990s; Oregon's first rules, for example, were established by PUC order in 1989. Significant changes have occurred since then. During the mid- to late 1990s, electric restructuring moved many utilities away from traditional resource planning in favor of market-based provision of electric supply; and today, climate change, national security, and volatility in fuel and commodity markets can make it difficult to determine the best way in which to supply electricity to consumers. Integrated resource planning rules should thus be reexamined periodically, to make sure they reflect the current conditions and challenges associated with providing reliable electric service at reasonable costs.

Arizona began the process of changing its rules after retail competition was instituted in the state by the Corporation Commission—and although the rules took over a decade to be revised and put into effect, the current regulations have been designed to address the issues that are of concern today. When IRP rules are reexamined, state commissions should open proceedings that are open to the public, and stakeholders should be allowed to offer input on the ways in which rules should be revised, as well as to review and comment on any draft documents that are issued. All three of the state IRP rules examined here have gone through this process, and in drafting revised rules, each of the state commissions carefully considered the feedback offered by interveners and adopted recommendations from both public interest groups and utilities.

1. Resource Plan Development

Stakeholder group involvement is equally important when it is time for a utility to develop its integrated resource plan. As was discussed in section III.A., APS detailed its stakeholder process in its 2012 IRP. During the two-year period that preceded the filing of the plan, the utility held various workshops where stakeholders received updates on the inputs to be used, and were able to offer feedback and even give presentations on these various inputs. Stakeholders were also surveyed to determine their preferences with regard to the energy resources selected by APS. Not only does this stakeholder process inform the content of the resource plan that is ultimately filed by the utility; it can also help to inform the review process once the filing has been made.

Other states have also recognized the benefits of stakeholder involvement in IRP and developed model processes. In its *Resource Planning Guidelines for Electric Utilities,* the Arkansas Public Service Commission suggests that utilities establish a Stakeholder Committee to assist in preparing resource plans that "should be broadly representative of retail and wholesale customers, independent power suppliers, marketers, and other interested entities in the service area."[77] The members of this committee would review utility objectives, assumptions, and estimated needs early in the planning cycle, and would submit a report along with the utility's resource plan. Committee members may also submit additional comments to the Commission, which may

77 Arkansas Public Service Commission. *Resource Planning Guidelines for Electric Utilities.* June 2007.

require the utility to re-evaluate its plan to address these comments.[78]

In Hawaii, IRP rules were designed to attempt to maximize public participation in the planning process. In each county within its service territory, the utility is required to organize advisory groups made up of representatives of public and private entities whose interests are affected by the utility's resource plan—including state and county agencies and environmental, cultural, business, and community interest groups. The rules specify that "(a)n advisory group should be representative of as broad a spectrum of interests as possible."[79]

Whether required by IRP rules or not, it is good practice for a utility to convene a stakeholder group, or to hold public meetings that are open to all interested parties, before creating and submitting its resource plan. These meetings are useful both to provide information and invite feedback on the input assumptions and the process that the utility is using in its resource planning, and to help ensure that the resulting plan is relevant and reflects the interests of ratepayers and the general public.

2. Resource Plan Review

Many state utility commissions are quasi-judicial boards that rely on the rules of civil procedure and allow for participation and intervention from different organizations and members of the public (provided they have standing in the proceeding, or an ability to assist the commission in making decisions). After a utility has filed its resource plan, the state PUC should open a proceeding that allows stakeholders to review and submit written comments on the filing. This feedback should be taken into account during the review by the PUC and its staff. Commissions should take an active role in assessing the validity of the inputs used by the utilities in their filings, the resulting outcomes, and whether these are consistent with both the IRP rules and the state's energy policies and goals.

In Kentucky, for example, the IRP rules specify that once a utility's IRP has been received, the Commission should develop a procedural schedule allowing for submission of written interrogatories to the utility by commission staff and any interveners, written comments by staff and interveners, and responses to these interrogatories and comments by the utility. The Commission may convene conferences to discuss the filed IRP if it wishes to do so. Following a review of the plan and intervener comments, Commission staff will issue a report summarizing its review and offering recommendations to the utility for subsequent IRP filings.[80]

Of the states examined in this report, the Colorado PUC has taken on a particularly active role in determining whether utility resource choices were in the public interest. The PUC did so, for example, in its review of Public Service Company of Colorado's 2010 DSM Plan, when it rejected the energy efficiency goals proposed by the company and instead asked that the utility adopt goals recommended by an intervener—the Southwest Energy Efficiency Project—that were approximately 130% of the goals in place at the time.[81] These EE goals were then incorporated into the 2011 IRP, in the calculation of resource need as one of the input modeling assumptions.[82]

Many states, though not all, require that utility plans be available to interveners and/or members of the public for review and participation in resource planning dockets. This signals to both stakeholders and utilities that the IRP process should be collaborative, and that stakeholders can and do offer valuable insights and opinions into resource planning that should be taken into account by utilities when developing their plans. Active oversight and participation by the state PUC is critical to ensuring that comments and proposals by interveners are reviewed, considered fully, and incorporated into utility resource plans when reasonable.

78 Id.

79 Public Utilities Commission, State of Hawaii. *A Framework for Integrated Resource Planning.* Revised May 22, 1992.

80 807 KAR 5:058. Integrated Resource Planning by Electric Utilities.

81 Colorado Public Utilities Commission. Decision No. C11-0442. Docket No. 10A-554EG. March 30, 2011.

82 *The Treatment of Energy Efficiency in Integrated Resource Plans*. Page 15.

B. Integrated Resource Plans

A good electric system IRP should include, at a minimum:

Load forecast

A company's load forecast (annual peak and energy) is one of the major determinants of the quantity and type of resources that must be added in a utility's service territory over a given time period, and has always been the starting point for resource planning. Projections of future load should be based on realistic assumptions about local population changes and local economic factors[83] and should be fully documented. Resource needs can rise or fall dramatically over a short period of time, and frequent, up-to-date load forecasts are necessary for utilities to be able to adequately assess the quantity and type of additional resources that might be needed in a specific planning period.

In Colorado, for example, at the time of Public Service's CACJA filing in mid-2010, the company was projecting a resource need of approximately 1,000 MW by 2018. At the time of its IRP filing in October 2011, the projection of resource need had dropped to 292 MW as a result of the economic recession and the success of DSM and solar programs.[84] In order to help plan for any future changes in load, utilities should model a range of possible load forecasts, not just a reference case.

Reserves and reliability

Reliability is typically defined as having capacity equal to the forecasted peak demand, plus a reserve margin during the hours in which that peak demand is expected to occur. Reserve requirements should provide for adequate capacity based on a rigorous analysis of system characteristics and proper treatment of intermittent resources. The system characteristics affecting reliability and reserve requirements include load shape, generating unit forced-outage rates, generating unit maintenance-outage requirements, number and size of the generating units in a region or service territory, transmission interties with neighboring utilities, and availability and effectiveness of intervention procedures.[85]

Demand-Side Management

Many state IRP statutes or regulations include in the definition of integrated resource planning an evaluation of energy conservation and efficiency. Even so, "[w]hile demand-side resources have always been a conceptual part of IRP, in practice they have not always been an important focus."[86, 87] As generation from traditional supply-side resources is growing more costly and energy efficiency measures are becoming less expensive, however, demand-side alternatives have gained a greater number of advocates across the United States.

Not only is energy efficiency often the lowest-cost resource available to system planners, it can also mitigate a variety of risks, such as that of impending carbon legislation and other environmental regulations affecting air and water quality. In addition to offsetting energy consumption, implementing EE measures can lead to a deferral in costly transmission and distribution investments.[88]

In the IRPs of most utilities, demand-side resources are included only up to the point that statutory goals are met, or mandatory levels of investment are included. Resource planners often incorporate the effects of those demand-side policies as adjustments ("decrements") to their forecasts of future load requirements. However,

83 State and Local Energy Efficiency Action Network. *Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures.* September 2011. Page 5.

84 Public Service Company of Colorado. *2011 Electric Resource Plan: Volume 1.* October 31, 2011. Pp. 1-5.

85 Biewald, B. & Bernow, S. *Electric Utility System Reliability Analysis: Determining the Need for Generating Capacity.* Boston: Energy Systems Research Group. 1988.

86 Chupka, M., Murphy D. & Newell, S. *Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches.* Brattle Group. 2008. Page 3.

87 Demand response, which is another type of demand-side resource, is considered in utility IRPs even less frequently than is efficiency. A full discussion of how demand response is included or excluded in IRPs is beyond the scope of this report.

88 *The Treatment of Energy Efficiency in Integrated Resource Plans.* Page 15.

> "The best IRPs create levelized cost curves for demand-side resources that are comparable to the levelized cost curves for supply-side resources. … By developing cost curves for demand-side options, planners allow the model to choose an optimum level of investment. So if demand-side resources can meet customer demand for less cost than supply-side resources, as is frequently the case, this approach may result in more than the minimum investment levels required under other policies."[89]

The three integrated resource plans discussed in this report each deal with energy efficiency in different ways. In Arizona, the Corporation Commission has set a demand-side management standard, and each of the portfolios analyzed in the IRP from Arizona Public Service assume full compliance with that standard.[90] Public utilities are required to achieve annual energy savings of at least 22% by 2020, and savings (measured as a percent of retail energy sales) should increase incrementally in each calendar year prior to 2020.[91] In its IRP, APS has calculated the number of MWh of energy savings needed to be compliant with Commission standards, and has imported these targets into the IRP as a load decrement over the planning horizon.

Colorado's Energy Efficiency Resource Standard (EERS) was established by Colorado House Bill 07-1037 and codified under the Code of Colorado Regulations §40-3.2-104. The law requires that the Colorado Commission set savings goals for energy and peak demand for the state's investor-owned utilities, but specifies minimum savings goals of at least 5% of both retail energy sales and peak demand from a 2006 baseline. Utilities are required to submit DSM plans, which are then reviewed and approved by the Commision, or approved with modifications. The plan that is ultimately approved may require levels of DSM that are higher than the minimum savings goals that have previously been established. Similar to APS, in its most recent IRP, Public Service took the most recent utility-specific DSM goals approved by the Commission and imported them into the IRP process as a load decrement, reducing the resource need over the planning period.

PacifiCorp is subject to EERS requirements in Washington and California. In 2006 in Washington, voters passed Initiative 937, which requires that electric utilities serving more than 25,000 customers undertake all cost-effective energy conservation. Beginning in 2010, utilities must do an assessment of all the achievable cost-effective conservation potential in even-numbered years.[92] Alternatively, efficiency targets may be based on a utility's most recent integrated resource plan, provided that plan is consistent with the resource plan for the Northwest Power and Conservation Council.[93]

California Assembly Bill 2021, enacted in 2006, called for a 10% reduction in electricity consumption within 10 years. It also required that the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and other interested parties develop a statewide estimate of all cost-effective electricity savings, develop efficiency and demand reduction targets for the next 10 years, and update the study every three years. Goals were developed by the CPUC in 2008 for years 2012 through 2020, and each of the three investor-owned utilities in the state has distinct requirements for electricity savings and demand reduction.[94]

89 State and Local Energy Efficiency Action Network. Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures. September 2011. Page 6.

90 Arizona Public Service. 2012 Integrated Resource Plan. March 2012. Page 36.

91 Arizona Corporation Commission. Decision No. 71819. Docket No. RE-00000C-09-0427. August 10, 2010.

92 Chapter 19.285 of the Revised Code of Washington (RCW): Energy Independence Act.

93 The Northwest Power and Conservation Council (NWPCC) is a regional entity that helps the states in the Pacific Northwest ensure an affordable and reliable energy system while maintaining fish and wildlife health in the Columbia River Basin. One responsibility of the NWPCC is to publish a 20-year electric plan that serves as a guide for Bonneville Power and its customer utilities in the region. The regional plan drives best practices in energy efficiency and is a reference against which utility plans may be measured. In the Sixth Power Plan, published in 2010, the NWPCC recommended that energy efficiency be deployed aggressively such that it meets 85% of new demand for electricity over the next 20 years.

94 California Public Utilities Commission. Decision 08-07-047. Rulemaking 06-04-010. July 31, 2008.

In California, PacifiCorp is also subject to a separate "loading order" requirement that requires utilities to first meet growth in energy demand through energy efficiency and demand response. Only after all cost-effective demand-side measures have been taken should the utilities consider adding conventional generation technologies.[95] PacifiCorp's 2011 IRP creates levelized cost curves for demand-side resources, as described above and in previous sections, and is a good example of this type of energy efficiency modeling effort. This type of modeling may be too costly to be feasible for some utilities, but it is important that consideration of various levels of DSM savings be given in integrated resource planning in order to give stakeholders confidence that all cost-effective DSM has been included in utility resource plans.

Supply options

A full range of supply alternatives should be considered in utility IRPs, with reasonable assumptions about the costs, performance, and availability of each resource. There can be uncertainties regarding the availability and costs of raw materials and skilled labor, construction schedules, and future regulations. Because these cost uncertainties can affect technologies in different ways, it is prudent to model a range of possible costs and construction lead times for supply alternatives. And because planning periods examined in IRPs are typically a decade or more, it is also prudent to evaluate supply technologies that are not currently feasible from a cost perspective, but may become so later in the planning period.

Fuel prices

Coal prices have been on the rise in recent years, and natural gas prices have historically been quite volatile. Fuel prices can shift as a result of demand growth, climate legislation, development of export infrastructure, and supply conditions.[96] It is thus extremely important to use reasonable, recent, and consistent projections of fuel prices in integrated resource planning.

Environmental costs and constraints

Utility IRPs should include a projection of environmental compliance costs—including recognition, and evaluation where possible—of all reasonably expected future regulations. At this time, the EPA has announced several upcoming environmental regulations. A final version of the Mercury and Air Toxics Standards (the "MATS" Rule) has been released, and rules are pending for Coal Combustion Residuals ("CCR"), cooling water intake structures under the Clean Water Act ("316(b)"), updates to the National Ambient Air Quality Standards ("NAAQS"), and new Effluent Limitation Guidelines.

Within the next three to five years, certain generating units may also become subject to new requirements under the Clean Air Act's Regional Haze Program, sometimes known as the BART rule because it requires installation of "best available retrofit technology." The Cross-State Air Pollution Rule, which would have required emissions reductions of SO_2 and NO_x in many states but was vacated by the US Court of Appeals for the DC Circuit in 2012, may return in a revised form at some point in the future.[97] Finally, greenhouse-gas emissions limits for electric generating units may come into effect in the next decade.[98]

These rules, both individually and in combination, have the potential to dramatically change the electric power industry. Utilities, in their IRP filings, need to acknowledge these rules and prepare for them as best they can through evaluations of emissions allowance costs, emission controls, and changes to resource portfolios. Few utilities now do this in a comprehensive manner. Of those discussed here, APS does the best job in its IRP by providing a discussion of each of the rules and its potential impacts on APS operations. The process could be improved through analysis of different compliance strategy scenarios.

Existing resources

Examination of existing resources in utility IRPs has become especially important as the mandated emission

95 See California Assembly Bills 1890 and 995. Similar loading order requirements exist in a few other states. See for example Connecticut Public Act No. 07-242, Section 51: An Act Concerning Electricity and Energy Efficiency.

96 *Reviving Integrated Resource Planning.* Page 6.

97 Colburn, K., et al. "Least-Risk Planning: The Homer City Decision Increases Uncertainty—but Rewards Forward Thinking." Public Utilities Fortnightly, November 2012.

98 EPA has proposed but not yet finalized greenhouse gas emission limits for newly constructed power plants. After those rules are finalized, EPA is required under the Clean Air Act to develop standards for existing power plants.

reductions associated with the MATS rule, discussed above, have led to utility decisions across the country to install pollution control retrofits, repower, or retire their coal units. PacifiCorp drew the ire of stakeholders and the Oregon PUC by not including this type of analysis for its coal-fired units in its 2011 IRP. All types of modifications to existing resources should be included in a utility's analysis of the optimum resource portfolio.

Integrated analysis

There are various reasonable ways to model plans, generally requiring the use of optimization or simulation models. Common models used throughout the industry include Strategist, EGEAS, System Optimizer, MIDAS, AURORA, PROMOD, and Market Analytics. These models are supplied to utilities by various third-party vendors.

It is important that the integrated model does not inadvertently exclude combinations of options that deserve consideration. This might occur in one of two ways. The first is in the instances that future resource portfolios are user-defined, rather than selected by an industry model. This is one of the criticisms of the Arizona Public Service IRP: the use of production cost modeling without an optimization component may have resulted in a less than optimal addition of supply- and demand-side resources over time.

The second way in which this may occur is if users constrain optimization models so that a model may not, given the cost, select the quantity of a specific resource that it may want. For example, a utility may constrain a model in such a way that it is only allowed to add 100 MW of wind generation over the resource planning period; but depending on the nature of the utility's electric system, the model may want to add additional wind resources. In this way, a combination of resources that deserves consideration may be excluded.

Time frame

The study period for IRP analysis should be sufficiently long to incorporate much of the operating lives of any new resource options that may be added to a utility's portfolio—typically at least 20 years—and should consider an "end effects" period to avoid a bias against adding generating units late in the planning period. Arizona rules require a 15-year planning period, Oregon a 20-year planning period, and Colorado a utility-specified planning period of between 20 and 40 years. Of the rules examined here, only Oregon explicitly states that an end effects period should be considered.

Uncertainty

At a minimum, important and uncertain input assumptions should be tested with high and low cases to assess the sensitivity of results to changes in input values. These assumptions include, but are not limited to, load forecasts, fuel prices, emissions allowance prices, environmental regulatory regimes, costs and availability of demand-side management measures, and capital and operating costs for new generating units.[99] The types of inputs listed are common to most utilities across the United States, but there are additional input assumptions that are regional or local in nature.

As discussed in the section on Oregon's IRP rules, its PUC requires utilities to model cases that vary the amount of hydroelectric output in the region. Utilities in states like Arizona, New Mexico, or Florida may want to examine

99 Decisions in the face of uncertainty come with degrees of risk. A recent study by CERES entitled, "Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know (How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility Resource Selection) concludes that it is "essential that regulators understand the risks involved in resource selection, correct for biases inherent in utility regulation, and keep in mind the long-term impact that their decisions will have on consumers and society. To do this, regulators must look outside the boundaries established by regulatory tradition." According to CERES, "risk arises when there is potential harm from an adverse event that can occur with some degree of probability." Risks for electric system resources have both time-related (i.e., the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers) and cost-related aspects (the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations). Practicing Risk-Aware Regulation (April 2012) at 20-21 http://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation

cases that vary the amount of solar output when doing long-term planning. Utilities located in arid regions, or those owning a significant number of generation assets that are dependent on the availability of a water source for power plant cooling, may want to analyze scenarios where water is scarce or is at too high a temperature to be useful for cooling. Individual utilities must determine those input assumptions that are subject to variability, and model sensitivity cases accordingly to properly account for risks and uncertainties that they face.

Performing single-factor sensitivities may not, however, be very informative. Many cases may warrant more sophisticated techniques, such as probabilistic techniques or those that combine uncertainties. "Testing candidate resource solutions against scenarios that address the range of plausible future trajectories of external factors, and their interrelationships, can more effectively support planning in an uncertain environment."[100]

Valuing and selecting plans

There are often multiple stages of running scenarios and screening in developing an IRP, and there are various reasonable ways to approach this. Traditionally, the present value of revenue requirements is the primary metric that is analyzed, and minimized, in utility IRPs. This metric alone may not, however, sufficiently address uncertainties. It may be useful also to evaluate plans along other dimensions like environmental cost or impact, fuel diversity, impact on reliability, rate or bill increases, or minimization of risk.

It is essential that the IRP process be executed in a manner that applies the selected metrics in a reasonably transparent and logical manner, without inappropriately screening out resources options or plans that deserve consideration at the next stage. Note also that it is highly unlikely that a single resource portfolio will be the best choice on every metric evaluated. A resource portfolio that performs well across several metrics, but perhaps is not the top performer on any single metric, may in fact be the best choice for utility planners.

Action plan

Even though IRPs should have a longer study period, a good plan will include a specific discussion of the implications of the analysis for near-term decisions and actions, and will also include specific plans for getting those near-term items accomplished. Demand-side measures take time to implement, and supply-side resources require months or years of lead time to permit and construct. Utilities must thus provide a thorough discussion of the steps they plan to take to implement, acquire, or construct resources that will meet energy and peak demand needs in their service territories in the three- to five-year period after the plan is filed. The availability of these near-term resources has a direct effect on the resources needed throughout the remainder of the planning period; so it is prudent for the utility to detail the ways in which it will go about acquiring the resources described in its IRP.

Documentation

A proper IRP will include discussion of the inputs and results, and appendices with full technical details. Only items that are truly sensitive business information should be treated as confidential, because such treatment can hinder important stakeholder input processes.

100 Reviving Integrated Resource Planning. Page 4.

V. Conclusion

Utility integrated resource planning has been in effect in various parts of the United States for more than 25 years. While some utilities are regulated by the original IRP rules developed more than a decade ago, many states have updated their IRP rules to reflect current conditions and concerns in regional and national electricity markets. In states where this has occurred, IRPs filed by utilities tend to be more comprehensive and to exhibit more of the "best practices" in utility resource planning that have been described in this report.

Nonetheless, there are still many ways in which utilities can improve both their resource planning processes and the plans that are generated as a result of these processes. Engaged stakeholders and state public utilities commissions can provide oversight to this process, helping to promote resource choices that lead to positive outcomes for society as a whole.

Appendix: State IRP Statutes and Rules

Arizona

Arizona Corporation Commission Decision No. 71722, in Docket No. RE-00000A-09-0249. June 3, 2010.[101]

Arkansas

Arkansas PSC. "Resource Planning Guidelines for Electric Utilities." Approved in Docket 06-028-R. January 4, 2007.[102] Rules are currently under review and updates have been proposed.

Colorado

Colorado PUC. 4 CCR 723-3, Part 3: Rules Regulating Electric Utilities. Decision No. C10-1111. Docket No. 10R-214E. November 22, 2010.[103]

Delaware

HB 6, the Delaware Electric Utility Retail Customer Supply Act of 2006.[104]

Georgia

Integrated Resource Planning Act of 1991 (O.C.G.A. § 46-3A-1), Amended.[105]

Georgia Public Service Commission. General Rules. Integrated Resource Planning 515-3-4.[106]

Hawaii

Public Utilities Commission, State of Hawaii, A Framework for Integrated Resource Planning, March 9, 1992.[107]

Idaho

Idaho Public Utilities Commission Order No. 22299, in Case No. U-1500-165.[108]

Indiana

170 Indiana Administrative Code 4-7-1: Guidelines for Integrated Resource Planning by an Electric Utility. New draft rules have been proposed in docket IURC RM 11-07.[109]

Kentucky

KY Administrative Regulation 807 KAR 5:058. Integrated Resource Planning by Electric Utilities. Relates to KRS Chapter 278.[110]

Louisiana

Louisiana Public Service Commission Corrected General Order. Docket No. R-30021. Decided at the Commission's March 21, 2012 Business and Executive Session.[111]

Minnesota

MN Statute §216B.2422.[112]

MN Rules Part 7843.[113]

Missouri

Rules of Dept. of Economic Development. Division 240 - PSC. Chapter 22—Electric Utility Resource Planning (4 CSR 240.22).[115]

Montana

Montana's Integrated Least-Cost Resource Planning and Acquisition Act (§§ 69-3-1201-1206, Montana Code Annotated).[116]

Administrative Rules of Montana 38.5.2001-2016, adopted by the Montana PSC, for traditional utilities.[117]

Administrative Rules of Montana 38.5.8201-8227, adopted by the Montana PSC, for restructured utilities.[118]

Nebraska

Nebraska Revised Statute 66-1060.[119]

Nevada

NRS 704.741.[120]

New Hampshire

Title XXXIV Public Utilities, Chapter 378: Rates and Charges, Section 38: Least Cost Energy Planning.[121]

New Mexico

Integrated Resource Plans for Electric Utilities, Title 17, Chapter 7, Part 3.[122]

North Carolina

North Carolina Utilities Commission Rule R8-60: Integrated Resource Planning and Filings.[123]

North Dakota

North Dakota PSC Order issued on January 27, 1987 in Case No. 10,799. Amended on March 11, 1992 in Case No. PU-399-91-689.[124]

Oklahoma

Title 165: Oklahoma Corporation Commission. Chapter 25: Electric Utility Rules, Subchapter 37: Integrated Resource Planning.[125]

Oregon

Oregon PUC Order No. 07-002, Entered January 8, 2007.[126]

South Carolina

Code of Laws of South Carolina, Chapter 37, Section 58 37 40. Integrated resource plans.[127]

Public Service Commission of South Carolina Order No. 91-885 in Docket No. 87-223-E. October 21, 1991.[128]

South Dakota

SL 1977, Ch. 390, § 23. Chapter 49-41B-3.[129]

Administrative Rule Chapter 20:10:21, Energy Facility Plans.[130]

Utah

Report and Order on Standards and Guidelines. Docket No. 90-2035-01. Issued June 18, 1992.[131]

Vermont

30VSA Sec 218c - Statute establishing least-cost integrated resource planning.[132]

Public Service Board Order of 4/16/1990 initiating the IRP progress (Docket No. 5270).[133]

Public Service Board Order of 7/16/2002 (Docket No. 6290).[134]

Virginia

Code of Virginia § 56-597 - § 56-599.[135]

Washington

Washington Administrative Code 480-100-238: Integrated Resource Planning.[136]

Wyoming

Wyoming Public Service Commission Rule 253 (submitted July 22, 2009), and associated Guidelines for Staff Review.[137]

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101 This Decision amends Arizona Administrative Code, Title 14, Chapter 2, Article 7: Resource Planning. It is available at: http://images.edocket.azcc.gov/docketpdf/0000112475.pdf

102 Arkansas guidelines available at: http://www.sosweb.state.ar.us/elections/elections_pdfs/register/june_07/126.03.07-003.pdf

103 Colorado PUC Decision available at: https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=10R-214E

104 Delaware legislation available at: http://legis.delaware.gov/LIS/lis143.nsf/vwLegislation/HB+6/$file/legis.html?open

105 Georgia annotated code available at: http://www.lexisnexis.com/hottopics/gacode/Default.asp

106 Georgia PSC rules available at: http://rules.sos.state.ga.us/cgi-bin/page.cgi?g=GEORGIA_PUBLIC_SERVICE_COMMISSION%2FGENERAL_RULES%2FINTEGRATED_RESOURCE_PLANNING%2Findex.html&d=1

107 Hawaii PUC Framework available at: http://www.heco.com/vcmcontent/Integrated%20Resource/IRP/PDF/IRP_Framework_052292.pdf

108 Idaho PUC Order available at: http://www.puc.state.id.us/search/orders/dtsearch.html

109 Indiana Administrative Code available at: http://www.in.gov/legislative/iac/title170.html

110 Indiana docket RM#11-07 available at: http://www.in.gov/iurc/2689.htm

111 Kentucky Administrative Regulation available at: http://www.lrc.ky.gov/kar/807/005/058.htm

112 Louisiana PUC Order available at: Rules from Arizona, Colorado and Oregon are described in detail in order to demonstrate ways in which states require comprehensive planning processes and resource plan outcomes from the utilities under their jurisdictions.

113 Minnesota Statute available at: https://www.revisor.mn.gov/statutes/?id=216B.2422

114 Minnesota rules available at: https://www.revisor.mn.gov/rules/?id=7843

115 Missouri rules available at: http://www.sos.mo.gov/adrules/csr/current/4csr/4c240-22.pdf, Final Order of Rulemaking was issued on March 3, 2011, as part of the Missouri Public Service Commission Rulemaking Case No. EX-2010-0254. That amendment is available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EX-2010-0254&attach_id=2011015905

116 Montana Annotated Code available at: http://data.opi.mt.gov/bills/mca_toc/69_3_12.htm

117 Montana Administrative Rules available at: http://www.mtrules.org/gateway/ChapterHome.asp?Chapter=38.5

118 Montana Administrative Rules available at: http://www.mtrules.org/gateway/ChapterHome.asp?Chapter=38.5

119 Nebraska Statute available at: http://nebraskalegislature.gov/laws/statutes.php?statute=66-1060

120 Nevada Statute available at: http://www.leg.state.nv.us/nrs/NRS-704.html#NRS704Sec741

121 New Hampshire Statute available at: http://www.gencourt.state.nh.us/rsa/html/NHTOC/NHTOC-XXXIV-378.htm

122 New Mexico PRC Rule available at: http://www.pnm.com/regulatory/pdf_electricity/irp_electricity.pdf

123 North Carolina PUC Rule available at: http://ncrules.state.nc.us/ncac/title%2004%20-%20commerce/chapter%2011%20-%20utilities%20commission/04%20ncac%2011%20r08-60.pdf

124 North Dakota PSC Order available at: http://www.raponline.org/docs/RAP_NDElectricResourceLongRangePlanningSurvey2005_09_17.pdf

125 Oklahoma Rule available at: http://www.occeweb.com/rules/2010Ch35ElectricpermanentMasterRuleseff7-11-10searchable.pdf

126 Oregon PUC Order available at: http://apps.puc.state.or.us/orders/2007ords/07-002.pdf

127 South Carolina Code available at: www.scstatehouse.gov/code/t58c037.docx

128 South Carolina PSC Order available at: http://dms.psc.sc.gov/pdf/orders/DF4FC4A9-EB41-2CB4-D44614AD02D02B8D.pdf

129 South Dakota Statute available at: http://legis.state.sd.us/statutes/DisplayStatute.aspx?Statute=49-41B-3&Type=Statute

130 South Dakota Rule available at: http://legis.state.sd.us/rules/DisplayRule.aspx?Rule=20:10:21

131 Utah Order available at: http://www.airquality.utah.gov/Public-Interest/Current-Issues/Regionalhazesip/RegionalHazeTSDdocs/Utah_PSC_Integrated_Planning_Rules.pdf

132 Vermont Statute available at: http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=005&Section=00218c

133 Public Service Board Orders issued prior to 1996 are not available online.

134 Vermont PSB Order available at: http://www.state.vt.us/psb/orders/2002/files/6290phaseIIextensionorder.pdf

135 Virginia Statute - content begins at: http://leg1.state.va.us/cgi-bin/legp504.exe?000+cod+56-597

136 Washington Administrative Code available at: http://apps.leg.wa.gov/wac/default.aspx?cite=480-100-238

137 Wyoming PSC Rule available at: http://legisweb.state.wy.us/ARULES/2009/AR09-043.htm; Guidelines for Staff Review available at: http://psc.state.wy.us/htdocs/electric/ElectricIRPGuidelines7-10.pdf

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STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the Application of **CONSUMERS ENERGY COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.	)))))	Case No. U-20165

PROOF OF SERVICE

I hereby certify that a true copy of the foregoing *Direct Testimony and Exhibits of Douglas B. Jester, Joseph M. Daniel, and James P. Gignac on Behalf of Environmental Law and Policy Center, the Ecology Center, the Union of Concerned Scientists, and Vote Solar* was served by electronic mail upon the following Parties of Record, this 15th of October, 2018.

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