E-100 SUB 165

Analysis of the Duke Energy 2020 Integrated Resource Plans

Prepared by:

STRATEGEN

Prepared for:

DEPARTMENT OF JUSTICE N★C ATTORNEY GENERAL

Strategen Consulting, LLC | 2150 Allston Way, Suite 400 | Berkeley, CA 94704

+1 510 665 7811 | www.strategen.com

Introduction

This memorandum is prepared for the North Carolina Attorney General's Office (AGO) and summarizes Strategen Consulting, LLC's[1] review of the 2020 Integrated Resource Plans that were submitted by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) (referred to collectively as Duke). The memorandum provides analysis supporting Strategen's conclusions, along with recommendations to the North Carolina Utilities Commission (Commission) regarding three, core topics, which are summarized below:[2]

- **COAL UNIT RETIREMENTS**
    - *Conclusions:*
        - Some elements of Duke's coal retirement analysis do not appear to be based on reasonable assumptions.
        - The IRPs do not provide sufficient information to validate Duke's methods and assumptions for determining both the economically optimal and earliest practicable retirement dates for its coal plants.
        - Duke's approach unnecessarily siloes coal retirements from its overall resource planning processes.
    - *Recommendations:*
        - Duke should consider an alternative method for determining the most economic retirement dates for its coal assets.
        - Duke should utilize a commercial software model that can select coal asset retirement dates while simultaneously optimizing Duke's overall resource portfolio(s).
        - If warranted, Duke could then propose a later "earliest practicable" retirement date. However, a coal unit retirement should not be delayed solely because the company identified a preferred replacement resource prior to the model selecting that unit's retirement date and replacement resource(s) on its own.
- **RESOURCE ADEQUACY**
    - *Conclusions:*
        - Duke's analysis appears to suggest that there are significant reliability and economic benefits to increasing neighbor assistance.
        - Duke's analysis reveals that certain resources may have higher capacity values when considered in combination with each other.[3]

---

[1] Strategen Consulting, LLC (Strategen), a California firm, is comprised of a team of well-respected leaders with technical, regulatory, product, and organizational expertise in energy markets, who have decades of experience working closely with governments, utilities, research institutions, technology providers, project developers, and large energy users to evaluate, analyze, and implement strong regulatory and policy strategies.

[2] In addition to these core topics, this memorandum assesses recent developments following the release of the 2020 IRP reports, and, where applicable, provides recommendations on how Duke might address these issues in the future.

[3] For example, additional winter demand side management (DSM) appears to shift the outage risk from winter to summer months, and may therefore increase the capacity value of solar. *See* response to AGO DR 1-11.

- *Recommendations:*
    - Duke should conduct a more extensive analysis regarding the potential benefits of increased neighbor assistance. Specifically, Duke should run a sensitivity that relaxes import constraints, especially with regards to the PJM Interconnection.
    - If the import constraints sensitivity reveals that a lower reserve margin might be warranted, Duke should then identify steps to increase neighbor assistance.

- **NEW RESOURCE ASSUMPTIONS**

    - *Conclusions:*
        - Duke excluded 2-hour storage as an IRP resource option, despite the fact that its studies reveal 2-hour storage provides significant capacity value at moderate levels of penetration.
        - Duke's storage cost assumptions conflict with industry figures.
        - Duke's modeling unnecessarily constrains annual, renewable energy interconnections and fails to reflect recent developments.
        - Duke neglected to evaluate the potential synergies between different resources and assess whether these synergies might impact capacity value.
        - Duke does not provide sufficiently detailed information to demonstrate how it reduces its energy and demand forecasts to account for baseline improvements in the efficiency of lighting, heating, and other end uses after the savings from utility energy efficiency programs diminish or "roll off" over time.
        - Duke's planned energy efficiency portfolio does not appear to include enough long-lived energy efficiency measures.

    - *Recommendations:*
        - Duke should include 2-hour storage as an IRP resource option.
        - Duke should revisit its storage cost assumptions regarding operable life, depth of discharge, and integration.
        - Duke should consider increasing its wind and solar interconnection rate assumptions.
        - Duke should evaluate the impact that increased winter DSM might have on solar's capacity value.
        - Duke should provide more quantitative detail indicating how it accounts for more efficient end uses in its underlying demand or load forecasts. Specifically, it should show that it accounts for energy efficiency savings, even after savings for the implemented energy efficiency measures are "rolled off" at the end of each measure's life.
        - Duke should consider including more long-lived energy efficiency measures in its portfolio.

Coal Retirement

Overview of Duke's Proposed Plan for Continued Coal Operations

DEC and DEP's combined resource portfolio[4] includes a significant amount of coal-fired resources, with a total of 9,182 MW of capacity spanning 17 generation units at 6 plants. Many of these plants have been in service for decades.

Duke has selected future retirement dates for these units that reflect that (1) the economics of coal operations are much less favorable than they once were; (2) several of Duke's plants are approaching the end of their useful lives; (3) there is a high likelihood that future carbon legislation or policies would accelerate coal retirements; and (4) retirement will require careful planning. Nevertheless, Duke's Base Case Plan keeps a large portion of these units in operation into the 2030s and some into the 2040s.

Strategen's analysis indicates that several of Duke's proposed retirement dates would extend the operation of certain coal assets well beyond what may be in the financial best interest of Duke's customers. Furthermore, the process by which Duke selected these retirement dates is flawed and deviates from sound planning principles. Finally, continuing to operate these assets for an extended period of time is inconsistent with the spirit of Governor Cooper's Executive Order No. 80[5] and the North Carolina Clean Energy Plan.[6]

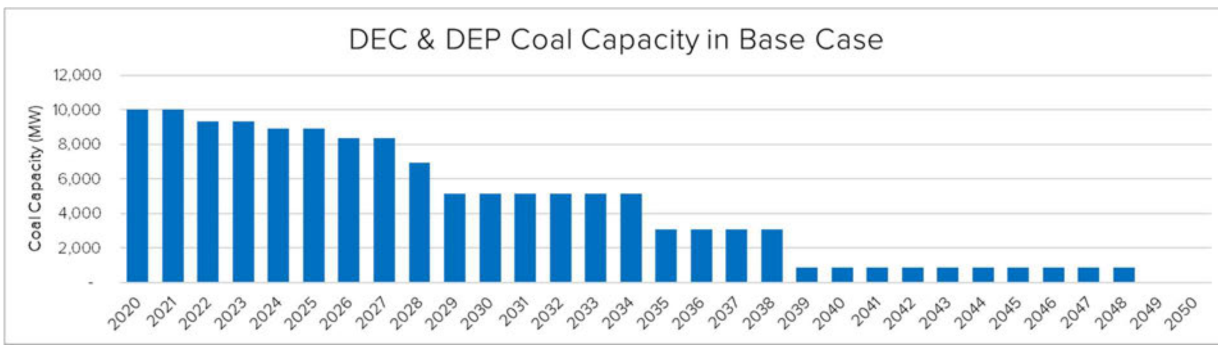

Figure 1. Chart derived from combined data found in Tables 11-A and A-11 in the 2020 IRPs.[7]

In a recent Commission order,[8] the Commission directed DEC and DEP respectively to prepare at least one resource portfolio that reflects the earliest practicable retirement dates for

[4] DEC and DEP operate their coal plants separately but are subject to a joint dispatch agreement and were analyzed accordingly in each IRP. *See* DUKE ENERGY CAROLINAS, NORTH CAROLINA INTEGRATED RESOURCE PLAN 2020 79 (2020) (DEC IRP Report) (noting that "the ranking of assets for retirement was evaluated across the [two] utilities"); DUKE ENERGY PROGRESS, NORTH CAROLINA INTEGRATED RESOURCE PLAN 2020 81 (2020) (DEP IRP Report) (noting the same).

[5] N.C. Exec. Order 80 § 1a. (Oct. 29, 2018) (establishing that North Carolina shall seek to reduce "statewide greenhouse gas emissions to 40% below 2005 levels" by 2025).

[6] NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY, STATE ENERGY OFFICE, NORTH CAROLINA CLEAN ENERGY PLAN 12 (2019), https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf (establishing that North Carolina shall reduce its "greenhouse gas emissions by 70% below 2005 levels by 2030"). The Clean Energy Plan also proposes carbon neutrality by 2050. *Id*.

[7] Duke projects that its 849 MW Cliffside 6 unit, which has a retirement date of 2049, will be converted to 100% natural gas by 2030. Given the uncertainty surrounding Duke's future plans for this unit, this conversion is not reflected in Figure 1.

[8] Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans In the Matter of 2019 Biennial Integrated Resource Plans and Related 2019 REPS Compliance Plans issued

their remaining coal assets. Among other things, retirement of these assets must reflect the rigor of the IRP process and be based on reasonable assumptions and the best available current knowledge regarding real world implementation considerations and challenges.[9]

Costs to Duke's Customers from Continued Operation of Uneconomic Coal Assets

The continued operation of Duke's coal plants imposes significant costs on customers. For DEC, Strategen projects that the present value of the revenue requirement (PVRR or revenue requirement) for continued coal plant operations will be approximately **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** through 2035, with **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** allocated to DEC's ongoing fixed coal costs[10] and **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** allocated to its ongoing variable costs.[11] This equates to about **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** of DEC customers' generation costs over the next 15 years.[12] Meanwhile, coal would only provide about BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL of the energy delivered to DEC customers over this same period.[13] These figures assume no new carbon policies. New carbon policies would likely increase coal costs quite significantly.

For DEP, the total revenue requirement for continued coal plant operations through 2035 will be approximately **BEGIN CONFIDENTIAL** [redacted] [redacted] [redacted] [redacted] [redacted] **END CONFIDENTIAL** allocated to ongoing fixed costs and **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** allocated to ongoing variable costs.[14] This in turn equates to about **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** of DEP customers' generation costs through 2035.[15] However, coal would only provide about **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** of the energy delivered to DEP customers during this 15-year period.[16]

Additionally, while Duke's coal plants provide capacity to meet peak demand, several units provide very little energy value. Duke's preliminary production cost modeling projects that *all* Duke's coal units will have capacity factors of less than 40% by 2025.[17] In fact, 13 of Duke's 17 coal units are projected to have capacity factors below *15%* after 2025. For context, between

---

6 April 2020 In Docket No. E-100, Sub 157.

[9] *See id.*

[10] Capital and fixed operation and maintenance (O&M).

[11] These figures were calculated based on the response to **BEGIN CONFIDENTIAL** [redacted], **END CONFIDENTIAL** using a discount rate of 6.26%.

[12] This figure was calculated by using the DEC IRP's "Base Planning Without Carbon Policy" scenario and comparing the PVRR of the coal costs set forth in **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

[13] Calculated from the capacity factors provided in **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** and the load forecast from DEC IRP REPORT at 240, Table C-11.

[14] These figures were calculated based on the response to **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** using a discount rate of 6.26%.

[15] This figure was calculated by using the DEP IRP's "Base Planning Without Carbon Policy" scenario and comparing the PVRR of the coal costs set forth in **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** with the PVRR through 2035 of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** which is set forth in **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**.

[16] Calculated from the capacity factors provided in **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** and the load forecast from DEP IRP REPORT AT 231, TABLE C-11.

[17] Based on Strategen's review of the underlying data for DEC IRP REPORT at 79, Table 11-A.

2015 and 2019, the average capacity factor for coal plants in the US ranged from 47.5% to 54.5%.[18]

The funds devoted to the continued operation of these coal units could instead be invested in cleaner, less expensive generation. These overarching concerns underscore the need for Duke to carefully and precisely identify when these coal units should be retired. Unfortunately, as discussed in the "Concerns with Duke's Methods for Selecting Retirement Dates" section of this memorandum, Duke's analysis to determine the optimal retirement dates of these units ultimately falls short. Additionally, as Duke's own modelling reveals, the "Earliest Practicable Coal Retirements" portfolio is actually the least cost portfolio under a wide range of fuel and carbon policy scenarios once carbon costs are included.[19] Even if carbon costs are *not* included, the cost of the "Earliest Practicable Coal Retirements" portfolio is close in cost to Duke's Base Case portfolio (i.e. a 3% increase in PVRR versus the Base Case). Moreover, as detailed in the "Concerns" section, Strategen also disputes Duke's "Earliest Practicable" retirement dates as they rest on a set of flawed assumptions.

Even though there are signs that Duke's coal plants are uneconomical for its customers, Duke nonetheless has a financial incentive to continue operating them as they make up a significant share of both the current and future rate base on which Duke can earn a rate of return. Based on estimates derived from discovery, DEC has an undepreciated coal plant balance of over **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** in incremental capital costs for its coal plants over the next **BEGIN CONFIDENTIAL** [redacted]0 **END CONFIDENTIAL** DEP on the other hand has an undepreciated coal plant balance of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** and expects to incur incremental capital costs of over **BEGIN CONFIDENTIAL** [redacted] [redacted] **END CONFIDENTIAL**

Concerns with Duke's Method for Selecting Retirement Dates

Duke has devised a novel and convoluted four-step process to select coal unit retirement dates. In contrast, the standard approach would involve a capacity expansion model capable of selecting coal retirements as part of the core resource optimization process. Moreover, Duke's approach relies on subjective factors that appear to extend the lives of these uneconomic coal units. These flaws include the following:

1. ***Coal retirement dates were selected separately from Duke's core resource portfolio optimization***: Instead of allowing coal retirement dates to be selected in its portfolio optimization (i.e. endogenously), Duke first ranked each coal unit for retirement and then compared each unit's costs and net production value with those of a generic peaker. Again, this was done prior to Duke proceeding to portfolio optimization. As a result, the "most economic" retirement date for each unit had already been determined by the time Duke began the core resource selection process. As

[18] Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels, U.S. ENERGY INFORMATION ADMINISTRATION, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a (last visited Feb. 21, 2021).

[19] *See* DEC IRP REPORT at 189, Table A-16.

[20] These figures are based upon Strategen's analysis of the response to **BEGIN CONFIDENTIAL** [redacted]. **END CONFIDENTIAL**

[21] These figures are based upon Strategen's analysis of the responses to **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

detailed below, there is no reason why this economic retirement analysis should have been conducted separately from portfolio optimization. Indeed, Duke acknowledged in its discovery responses that the System Optimizer model it used *can* select coal retirements.[22] To be sure, Duke suggests that the System Optimizer would be unsuitable for this purpose because its model cannot dynamically modify ongoing capital and fixed O&M expenses for each unit and retirement date.[23] However, Strategen believes this could be easily addressed in a post analysis, which would ultimately lead to a more optimal outcome. Furthermore, Duke did not have to use System Optimizer in the first place. There are other commercial tools that can determine capacity additions and endogenously select for coal retirements. These tools could also be supplemented by additional detailed production cost modeling, such as Prosym.

2. ***A subjective ranking method underpins all of Duke's subsequent retirement date analysis:*** Duke's initial ranking of its coal plants is the foundation of its retirement analysis; it influences *all* of its coal unit retirements. And, yet, some criteria in the initial ranking are not clearly linked to overall resource portfolio economics. [24] For example, larger coal unit groupings have been de-prioritized for early retirement. However, given their size, retiring larger unit groupings earlier might lead to greater cost savings for ratepayers. Ultimately, this de-prioritization appears to subjectively delay retirement of Duke's largest coal unit groupings and distorts the overall retirement analysis.

3. ***Duke's ranking method includes arbitrary unit groupings:*** Duke's initial ranking includes coal unit groupings that are not adequately explained. Moreover, the reasoning for grouping some of these units together appears to be arbitrary. For example, all four Marshall units are grouped together, despite having significantly different operating characteristics and projected capacity factors. Similarly, Belews Creek units 1 and 2 are grouped together. On the other hand, the four units at Roxboro are split into two groups: (i) Roxboro 1 and 2 and (ii) Roxboro 3 and 4. All the remaining units are evaluated and then ranked individually. These groupings have no apparent rationale and could distort the sequence of retirements.

4. ***A 2025 date was selected by Duke as the "earliest possible" retirement date for its coal assets***: When asked why 2025 was the earliest coal retirement date, Duke pointed to **BEGIN CONFIDENTIAL** [redacted]

[22] Based on response to AGO DR 1-2(b).
[23] Based on response to AGO DR 1-2(c).
[24] **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**
[25] *See* response to **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

as little as 1 to 2 years.[26] **END CONFIDENTIAL** Duke's own resource planning assumptions appear to confirm this.[27]

5. ***Duke's retirement analysis compares each coal unit to a peaker but provides few details about that peaker's characteristics or portfolio-level considerations***: In step 2 of Duke's retirement analysis, a peaker plant was selected as the default replacement resource for each coal unit. However, Duke has not provided sufficient information on how much this peaker costs, the full range of alternative resource costs, or the peaker's operating characteristics. Furthermore, it is not clear why evaluating a single replacement resource is preferable to conducting a more holistic, portfolio-level evaluation with a model that endogenously selects replacement resources.

6. ***Duke has included additional transmission costs as a requirement for retiring certain coal units, but provides inadequate justification for these requirements***: Duke has indicated that at least two of its coal plants provide "support to the transmission system"[28] and thus cannot be retired without additional transmission upgrades. Specifically, Duke has determined that **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** of assumed transmission upgrades respectively and factored these costs in as a constraint on retirement.[29] Duke's initial explanation was that these upgrades were needed because **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** However, this explanation appeared to lack support. **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

Duke provided additional information regarding these upgrades only three days before the comment deadline. Nevertheless, on first glance, there appear to be some issues that warrant further investigation.[32] Given that Strategen has had little time to analyze

---

[26] *See, e.g.*, Gavin Blade, *Inside construction of the world's largest lithium ion battery storage facility*, UTILITY DIVE (Dec. 6, 2016), https://www.utilitydive.com/news/inside-construction-of-the-worlds-largest-lithium-ion-battery-storage-faci/431765/ (concerning deployment of Lithium-ion battery storage that was scheduled to be constructed and installed in five months). *See also* response to **BEGIN CONFIDENTIAL** [redacted]. **END CONFIDENTIAL**

[27] *See* response to **BEGIN CONFIDENTIAL** [redacted]. **END CONFIDENTIAL**

[28] DEC IRP REPORT at 80.

[29] *See* response to **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

[30] *See* response to **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

[31] **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

[32] These concerns include, but are not limited to the following: **BEGIN CONFIDENTIAL** [redacted]

this information, Strategen and the AGO reserve the right to provide additional comments and analysis on these identified transmission upgrades. Additional analysis is critical given the potential impact these costs had on the selected retirement dates.[33]

7. ***BEGIN CONFIDENTIAL*** [redacted]

8. [redacted] **END CONFIDENTIAL**

Alternative Methods for Selecting Coal Retirement Dates

Instead of adopting this novel, four-step coal retirement analysis, Duke could have adopted a resource planning approach that economically retired resources as part of the IRP's core economic optimization (*i.e.* endogenous selection). Endogenous selection can be performed with readily accessible software applications. These tools would model coal resources (and coal resource retirements), along with other portfolio considerations. Indeed, other utilities are pursuing endogenous selection with these tools. For example, PacifiCorp – another vertically integrated

---

however, these costs do not appear to be specifically linked to Duke's analysis for either plant. **END CONFIDENTIAL**

[33] The fact that the upgrade costs could have a significant impact on the retirement dates is demonstrated by information Duke provided in discovery **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** according to Strategen's analysis.

[34] *See* response to **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

[35] Based on Strategen's analysis, it is unclear whether this **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** is the same one referred to in the public IRP reports.

utility – is endogenously selecting coal retirements in its IRP.[36] Duke has indicated that it could have endogenously selected coal retirement in its System Optimizer model.[37] Strategen believes this would be the superior approach and would address most of the concerns identified in the previous section.

Unnecessary Limitations on Earliest Practicable Dates

Lastly, Duke has placed additional, unnecessary limitations on the "earliest practicable" dates for its coal unit retirements. These limitations appear to prolong the use of the units[38] and conflict with public policy. Chief among these limitations is the assumption that certain coal assets like the Marshall and Belews Creek plants will be replaced with onsite natural gas capacity. Duke has estimated that it will need at least six years of construction lead time to replace the Marshall plant with natural gas generation and seven years to replace Belews Creek with similar resources.[39] However, this of course presumes that new natural gas resources are in fact required to retire these assets. Duke also asserts that an interstate gas pipeline will be required to retire Belews Creek in 2029.[40]

Given that these coal plants' projected capacity factors resemble peakers, Strategen recommends that alternatives be evaluated, including onsite battery storage. Furthermore, in some cases, Duke has assumed that combined cycle plants will replace coal plants.[41] In instances where plants will not be used solely for peaking, Strategen recommends evaluating a combination of portfolio resources that are less likely to present stranded cost risks than a combined cycle gas plant. These alternatives would be more in line with the state's climate goals. Indeed, even if the useful life of a new gas plant or pipeline were reduced to 25 years in accordance with Duke's recent proposals,[42] these assets would continue to be in service through 2054. This would be well past the Clean Energy Plan's 2050 carbon neutrality target[43] and President Biden's 2035 decarbonization target for the nation's power sector.[44] Thus, relying on natural gas as a replacement resource for coal poses significant stranded cost risk.

Resource Adequacy

---

36 PACIFICCORP, INTEGRATED RESOURCE PLAN, 2021 IRP PUBLIC INPUT MEETING, JULY 30-31, 2020 66 (2020), https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/07-30-31-2020_PacifiCorp_2021_IRP_PIM.pdf.

37 As discussed previously, Duke insists that the System Optimizer cannot "dynamically change . . . [ongoing capital and fixed O&M] expenses as it considers each possible retirement date." Response to AGO DR 1-2(c). Again, Strategen disagrees with Duke's implicit suggestion that this potential hindrance would then require the four-step approach Duke ultimately adopted. To the extent this was a problem, the System Optimizer should have been allowed to natively select coal retirement, with any ongoing costs addressed in post analysis.

38 This appears to be the case even under the "Earliest Practicable Retirements" scenario(s).

39 Response to AGO DR 1-8.

40 DEC IRP REPORT AT 175, Table A-11.

41 *See* DEC IRP REPORT AT 176; DEP IRP REPORT AT 175.

42 Josh Saul, *Duke Mulls New Gas Plants that Would Retire Early on Climate Goal*, BLOOMBERG (Feb. 11, 2021), https://www.bloomberg.com/news/articles/2021-02-11/duke-wants-to-build-gas-plants-but-close-them-early-for-climate.

43 *See* NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY, *supra* note 6.

44 *The Biden Plan to Build a Modern, Sustainable Infrastructure and an Equitable Clean Energy Future*, BIDEN HARRIS, https://joebiden.com/clean-energy/ (last visited Feb. 21, 2021).

Ratepayer Impact of Duke's Recommended Planning Reserve Margin

The reserve margin[45] identified in Duke's resource adequacy studies will have real consequences for North Carolina ratepayers in terms of the potential capacity costs required to comply with that target. To put matters into context, assume that DEP and DEC have a combined peak load or demand of around 32,000 MW. Under this scenario, every 1% of required reserve margin will equate to about 320 MW of additional generation capacity. If gas peakers[46] were to provide this excess capacity, then each additional 1% of reserve margin would translate to approximately $24 million in levelized costs for ratepayers each year, or $840 million over the life of the peakers.[47] Thus, it is critical for the Commission to (1) carefully analyze the validity of Duke's proposed 17% reserve margin and, if there is a sufficient basis upon which to conclude that Duke's reserve margin is too high, (2) assess the steps Duke is taking or could potentially take to reduce capital costs while maintaining the same level of reliability.

In addition to saving ratepayers money through avoided gas peaker capacity, a lower reserve margin could also save ratepayers by accelerating coal retirements. For example, Duke has represented that it could accelerate retirement of some of the Allen units without securing replacement supply because it currently has reserves well in excess of its current reserve margin.[48] However, for other coal units, Duke has determined that early retirement would result in Duke failing to meet its proposed reserve margin.[49] Thus, replacement generation would be required for those retirements. However, if the necessary reserve margin is lower than what Duke has proposed in its resource adequacy studies, additional coal units might be retired without the need for replacement generation. This could significantly alter the economic calculus for retiring these units and make accelerated retirement more viable.

Concerns with Duke's RA Study and its Implications for Duke Customers

Strategen and the AGO participated in Duke's resource adequacy stakeholder process and reviewed Duke's development and preparation of the studies. Duke accepted some of Strategen and the AGO's suggestions. Nevertheless, Strategen has some outstanding concerns with the resource adequacy studies, which are as follows:

1. Identifying benefits of interactions with neighboring systems

Duke's resource adequacy studies highlight how interconnection with neighboring systems can help reduce the need for an excessive reserve margin and lower capacity costs. Specifically, Duke tested an "Island Scenario" in which DEC and DEP were required to maintain resource adequacy without relying on each other or other neighbors. The results of this test showed that DEC would require a reserve margin of 22.5%, which is 6.25% higher than the margin it would need if it had moderate neighbor assistance.[50] Similarly, DEP would need a 25.5% reserve margin, which is 6.25% higher than the margin it would need if it had moderate neighbor

---

[45] Reserve margin is the amount of excess generation capacity (as expressed in percentage figures) that a utility or grid operator must self-build or procure to meet peak demand, ensure overall system reliability, and mitigate potential outage risks.

[46] Duke estimates a new gas peaker would cost approximately $75/kw-year. *See* DEC IRP REPORT at 333. This also assumes a 0% capacity factor.

[47] Assumes a 35-year life.

[48] DEC IRP REPORT at 81.

[49] *See id*; DEP IRP REPORT at 84.

[50] *See* KEVIN CARDEN ET AL., ASTRAPE CONSULTING, DUKE ENERGY CAROLINAS 2020 RESOURCE ADEQUACY STUDY 8 (2020).

assistance.[51] Assuming again that levelized capacity costs would decrease by about $24 million for each 1% reduction of reserve margin, the benefits of neighbor assistance appear to be about $156 million for DEC ratepayers each year and $150 million each year for DEP ratepayers. These figures do not take into account other energy-related benefits stemming from these neighbor interactions.

Duke should be applauded for evaluating and recognizing the potential benefits of neighbor assistance.[52] However, Strategen believes that even greater customer benefits could be achieved if either (1) Duke made concrete, future commitments to increase neighbor interactions, with these commitments reflected in Duke's resource need projections, or (2) Duke changed some of its current practices or made small, limited interventions to increase these exchanges. While Duke does provide a cursory, high-level estimate of what it might cost to increase its transmission import capabilities by 5 or 10 GW,[53] Duke neglects to assess the benefits of this course of action, let alone commit to increasing its import capabilities. Furthermore, Duke has not indicated how these upgrades were selected, or how this proposed import increase compares to existing import limits. It is a missed opportunity, given the significant, potential customer benefits and reliability benefits.[54]

While the testing results of the Island Scenario hint at the potential benefits of increased neighbor assistance, the experiences of other balancing authorities arguably help prove it. One particularly compelling example involves the Southwest Power Pool (SPP) regional market. Over the last decade, SPP has made strategic transmission investments which have enabled greater geographic diversity of resources and loads. This increased diversity and interconnectedness has enhanced the contribution of SPP's resources towards resource adequacy. As a result, in 2016, SPP determined that it could reduce its planning reserve margin from 13.6% to 12% without reducing reliability.[55] This reduction in planning reserve levels reduced SPP's capacity requirements by nearly 900 MW and should deliver cost savings on the order of $90 million annually, or $1.4 billion over the next 40 years.[56]

Given the potential benefits of increased neighbor assistance, Strategen recommends that Duke consider revising its resource adequacy studies to test relaxed import constraints as a sensitivity. Based on Strategen's review, the resource adequacy studies appear to impose

---

[51] *See* KEVIN CARDEN ET AL., ASTRAPE CONSULTING, DUKE ENERGY PROGRESS, 2020 RESOURCE ADEQUACY STUDY 8 (2020).

[52] On a similar note, Strategen supports Duke's decision to model an economics based approach to reliability planning.

[53] *See, e.g.*, DEC IRP REPORT at 58.

[54] *See infra*.

[55] Southwest Power Pool, *SPP Board Votes to Lower Planning Reserve Margins, Award First Competitively Bid Project, Approve $363M in Transmission Upgrades*, GLOBENEWSWIRE (Apr. 26, 2016), https://www.globenewswire.com/news-release/2016/04/26/1073420/0/en/SPP-Board-Votes-to-Lower-Planning-Reserve-Margins-Award-First-Competitively-Bid-Project-Approve-363M-in-Transmission-Upgrades.html.

[56] Strategen notes that SPP, which has more interconnections than Electric Reliability Council of Texas (ERCOT), was able to avoid many of the recent, rolling blackouts that impacted ERCOT. Camelia Juarez, *Power outages may continue, but Southwest Power Pool grid is stable- for now*, KCBD (Feb 16, 2021), https://www.kcbd.com/2021/02/17/power-outages-may-continue-southwest-power-pool-grid-is-stable-now/ (""West Texas is not experiencing long term black outs because we are not on the ERCOT electric grid. Instead we are on the Southwest Power Pool grid, which is shared with several other surrounding states."). Even more striking is that SPP has a lower reserve margin than Duke. In short, its response to the polar vortex lends further credence to the importance of increased neighbor assistance.

substantial limits on imports from neighboring balancing area **BEGIN CONFIDENTIAL** -- [redacted] **END CONFIDENTIAL**

2. Identifying Improvements that could improve neighbor interactions.

If a relaxed imports sensitivity reveals that a lower reserve margin might be appropriate, Duke should identify steps that would increase neighbor assistance. For example, Duke could explore new investments in transmission infrastructure for the purpose of increasing neighbor assistance and benefitting Duke customers. However, DEC and DEP do not have any planned transmission upgrade projects with neighboring systems, which concerns Strategen.[57]

Additionally, there may be import limit assumptions preventing Duke from increasing neighbor assistance. Strategen has reviewed the specific import limits identified in **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** and is concerned that some of these limits might be set too low. What is more, it is unclear if these limits are just Duke's rough approximations for modeling purposes or if they accurately represent actual constraints or current operating practices. If they are indeed rough approximations, then additional information is needed specifying the existing physical constraints or operating practices they are intended to approximate. Once these assumptions are sufficiently substantiated and linked to existing constraints, Duke should then identify what steps it could take to alleviate these constraints. For example, it is possible that a minor transformer upgrade could allow for significantly increased

[57] Response to NCPS DR 4-15(a).

[58] **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

imports of firm resources from PJM, thereby offsetting a much larger generation investment to meet Duke's reserve margin requirements. Alternatively, Duke could potentially increase its imports with its existing infrastructure by adopting dynamic line rating technologies (DLR). DLR would allow Duke to monitor real-time transmission conditions and increase power flows where possible. Duke could also pursue seasonal exchange of firm winter capacity with its summer-peaking neighbors. However, Duke has not yet provided sufficient information to evaluate these and other possibilities.

A Note on the California and Texas Blackouts

Recent rolling blackouts in the California Independent System Operator (CAISO) and ERCOT markets have resulted in the tragic loss of life, substantial costs to states, grid operators, utilities, localities, private businesses, and households, and significant physical damage to vital grid infrastructure.[60][61] For Texas in particular, the root causes of the recent blackouts are still being investigated, and it may be years until the public receives a thorough accounting of what went wrong, what lessons can be learned, and what steps are necessary to ensure that grid operators are prepared for the next crisis.

In light of these events, Strategen recognizes the tremendous importance of resource adequacy. However, whatever lessons can be taken from California and Texas, it is clear that increased inter-system exchanges will continue to be important.[62] With sufficient planning, renewable energy resources, storage, and demand side management can help utilities achieve resource adequacy. Moreover, it would be a mistake to cede ground on the clean energy transition due to fears of insufficient resource adequacy, especially when it is clear that both renewable and fossil fuel production were significantly strained during these recent blackouts.[63] Strategen will continue to monitor developments from Texas and explore how the lessons learned there may be applied in North Carolina.

New Resource Assumptions

Duke Discards Potentially High Value 2-Hour Storage Configurations

Strategen commends Duke for its pioneering work studying the effective load carrying capability (carrying capability or ELCC) value of energy storage resources. This is a critical input in the IRP process as it determines how much solar and storage can be relied upon to meet peak capacity needs. One notable finding from Duke's analysis is that a wide range of storage

---

[60] *See, e.g.*, Alex Gilbert & Morgan Bazilian, *California power outages underscore challenge of maintaining reliability during climate change, the energy transition* , UTILITY DIVE (Aug. 19, 2020), https://www.utilitydive.com/news/california-power-outages-underscore-challenge-of-maintaining-reliability-du/583727/.

[61] *See, e.g.*, Dionne Searcey, *No, Wind Farms Aren't the Main Cause of the Texas Blackouts*, ¸NY TIMES (Feb. 17, 2021) https://www.nytimes.com/2021/02/17/climate/texas-blackouts-disinformation.html.

[62] *See* Gilbert & Bazilian, *supra* note 60.

[63] *See id.* (noting that the "bulk of the power loss in Texas came from natural gas suppliers"). *See also* CAISO, FINAL ROOT CAUSE ANALYSIS, MID-AUGUST 2020 EXTREME HEAT WAVE 47-48 (2021), http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf (detailing the "1,000 MW difference between shown [natural gas] RA requirements and bid from [natural gas] RA resources" and concluding this difference was due to "forced outages and derates due, at least in part, to extreme heat").

durations provide capacity values comparable to a firm capacity resource. For example, DEP's carrying capability study determined that the first 800 MW of storage could provide at least 88%[64] of the capacity value of an equivalent firm resource, even at 2 hours of duration.[65] Meanwhile a 4- or 6-hour storage resource could provide upwards of 94%[66] of equivalent value.[67] Since the storage costs of modern batteries are largely driven by duration, the slight reduction in capacity value for 2-hour storage (relative to 4 or 6 hours) is more than likely offset by the significant reduction in costs for 2-hour storage (again, relative to the 4- and 6-hour options). Thus, the 2-hour storage configuration appears to provide significant, comparative value. While this value likely diminishes over time as more storage is added, this by no means detracts from 2-hour storage's *near-term* potential.

To optimize its system for least cost, Duke should include 2-hour battery storage as an IRP resource option. Unfortunately, only four-and six-hour storage options were considered in the optimization process. Yet short-term-duration storage is well suited to meet Duke's reliability needs, which are characterized by very acute winter peaking conditions during the 7 to 9 morning hours in the month of January.

Duke also excluded 2-hour storage as an option because Duke believes its value will likely diminish as winter DSM programs are expanded. While that may be true, that is no reason to completely remove shorter-duration storage from the IRP evaluation process. Expanded winter DSM was not evaluated as a resource option in the 2020 optimization process, which may have distorted other results. To optimize Duke's system for least cost, there is good reason to evaluate 2-hour storage as a resource option.

A Note on Capacity Value

It is worth noting that Duke does not appear to apply the same level of rigor when estimating the capacity value of its existing thermal resources. For example, some coal and gas plants have substantial outage rates, including during winter peaks,[68] which would reduce their value as capacity resources. The recent events in Texas are further evidence of this, as a large portion of the plants taken offline were natural gas.[69] Taking this into account, a 2-hour duration storage resource may actually be on par with or better than what Duke has assumed for some of its thermal resources. Strategen recommends that Duke consider adopting the Unforced Capacity (UCAP) framework to better evaluate resources and account for these considerations.

Duke's Artificial Constraints on Additional Renewables

Duke's base case in the IRP includes limits on the amount of solar and wind resources that can be interconnected in DEC and DEP each year. Specifically, Duke notes that "[c]onsistent with recent trends, total annual solar and solar coupled with storage interconnections were limited to 300 MW per year over the planning horizon in DEC."[70] Onshore wind in DEC is limited to 150

---

64 KEVIN CARDEN ET AL., ASTRAPE CONSULTING, DUKE ENERGY CAROLINAS AND DUKE ENERGY PROGRESS STORAGE EFFECTIVE LOAD CARRYING CAPABILITY (ELCC) STUDY 12, Table 5 (2020).

65 Assumes the recommended dispatch schedule.

66 CARDEN, *supra* note 64, at 12.

67 2-hour storage provides similarly high capacity

68 **BEGIN CONFIDENTIAL** [redacted]**.END CONFIDENTIAL**

69 Searcey, *supra* note 61.

70 DEC IRP REPORT at 287, Appendix E: Renewable energy strategy/forecast.

MW.[71] In DEP, solar deployment is limited to 200 MW per year, with wind limited in most cases to 150 MW per year.[72] These limits appear to track historical deployment rates, however, there is no reason why these rates should persist that far into the future – particularly given more recent developments[73] and Duke's growing experience interconnecting renewable resources. In addition, Strategen expects that Duke will proactively upgrade its grid to accommodate future resource additions. In light of these considerations, Duke's interconnection assumptions may unnecessarily limit the amount of low-cost renewable resources that can be added to Duke's system during planning. Accordingly, these assumptions should be revisited at a minimum.

Duke's Assumed Storage Costs Differ from Industry

The levelized cost values used to screen energy storage resources in Duke's IRP are partially driven by some overly conservative performance assumptions.[74] In particular, Duke assumes storage resources will have a relatively low depth of discharge limit (20%) and moderate project life (15 years), both of which might lead to higher levelized costs. Taking Lithium-ion batteries as just one example, one could reasonably justify an assumed depth of discharge limit of 10% and a 20 year lifespan if one assumes future, additional augmentation and maintenance.[75] These changes would have the impact of expanding this asset's financial benefits.

Another factor that might be increasing the relative costs of storage in Duke's IRP is the assumed cost of integration, which amounts to 15% of the cost of storage in the first year.[76] Duke attributes these costs to its limited operational experience with battery storage. While it is reasonable to expect that Duke would experience a learning curve as it brings battery resources online, these high costs are unlikely to persist over time. Additionally, since battery storage is a maturing technology, there are also turnkey solutions and procurement options available that could limit the amount of integration Duke would need to self-perform.[77]

Synergies Between Resources Should be Considered When Analyzing Capacity Value

While Duke's carrying capability analysis is an important first step in comparing the value of storage, Duke's analysis does not adequately consider potential synergies when certain resources are paired together. Detailed modeling results provided by Duke suggest that an increase in winter DSM might reduce the loss of load expectation or outage risk in the winter,[78] and could therefore increase the capacity value of solar and other summer peaking resources.[79]

---

[71] DEC IRP REPORT at 40.

[72] DEP IRP REPORT at 39-40.

[73] *See* AGO's Initial Comments at 25, n. 93 (discussing queue reform proposal and interconnection settlement).

[74] Duke storage assumptions are included in DEC IRP REPORT at 341-42, Appendix H: Energy storage.

[75] *See, e.g.*, LAZARD, LAZARD'S LEVELIZED COST OF STORAGE ANALYSIS-VERSION 6.0 4 (2020), https://www.lazard.com/media/451566/lazards-levelized-cost-of-storage-version-60-vf2.pdf (detailing six energy storage use cases with an assumed 10% depth of discharge limit and five use cases with an assumed twenty year lifespan).

[76] DEC IRP REPORT at 342, Table H-1; DEP IRP REPORT at 336, Table H-1.

[77] *See, e.g.*, David Pratt, *Siemens to deliver turnkey 1.4MWh battery storage unit to German public utility*, ENERGY STORAGE NEWS (Apr. 13, 2017), https://www.energy-storage.news/news/siemens-to-deliver-turnkey-1.4mwh-battery-storage-unit-to-german-public-uti.

[78] Response to AGO DR 1-11.

[79] Strategen would also note that there may be similar synergies between other pairs of resources.

Said another way, combining winter DSM and solar may increase solar's capacity value and contribution to resource adequacy. Accordingly, the capacity value for solar should be revisited to consider the interplay between winter DSM and solar.

Additional Effects of Energy Efficiency Measures Should be Considered

Strategen applauds Duke for pursuing utility energy efficiency (UEE) programs, as they are generally among the least-cost resources and can significantly reduce the need for more costly generation. However, Duke's level of planned energy efficiency, while above average for the Southeast, could still be improved given the savings other utilities have achieved nationwide.[80]

Additionally, the level of assumed energy savings from UEE in Duke's IRPs is significantly diminished by Duke's apparent assumption that there is a significant reduction in energy savings or "roll off" once utility implemented efficiency measures reach the ends of their lives. Indeed, "roll off" appears to erase approximately 67% of the incremental savings from DEP energy efficiency measures implemented by the final year of the forecast.[81]

Nevertheless, Duke states that, "the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from energy efficiency adoption,"[82] which would suggest that Duke is accounting for savings from more efficient appliances following roll off by adjusting its load forecast. In simple terms, Duke appears to be (1) assuming that savings from "rolled off" energy efficiency measures will persist due to market improvements and (2) accounting for these continued savings by reducing its energy demand forecasts. However, it is not readily apparent that Duke's forecast for gross retail sales actually reflects this. In fact, the year over year increase in gross retail sales appears to change very little in the latter part of the planning period.[83] Strategen recommends that Duke provide more quantitative detail on how naturally occurring end-use efficiency is incorporated into its load forecast model as energy efficiency program roll off occurs. Additionally, the steep roll off of energy efficiency measures later in Duke's forecasts suggests that Duke's energy efficiency portfolio is comprised of many short-lived measures. Strategen recommends that Duke identify steps it could take to incorporate more long-lived measures into its portfolio, such as new energy efficient construction, energy efficiency upgrades to building envelopes, and energy efficient HVAC equipment.

Recent Changes Affecting the IRPs

Federal Tax Credits Extended

---

80 *See generally* 2020 State Energy Efficiency Scorecard North Carolina, American Council for Energy-Efficient Economy, https://www.aceee.org/sites/default/files/pdfs/ACEEE_ScrSht20_NorthCarolina.pdf (last visited Feb. 25, 2021) (providing analysis on the general state of energy efficiency in North Carolina); Forster Bradley-Wright, *North Carolina and Duke Energy Hold Commanding Lead on Energy Efficiency in the Southeast*, SOUTHERN ALLIANCE FOR CLEAN ENERGY (Feb. 19, 2020), https://cleanenergy.org/blog/north-carolina-and-duke-energy-hold-commanding-lead-on-energy-efficiency-in-the-southeast/ (noting Duke's energy efficiency gains and highlighting other utilities that Duke can model to achieve even greater savings).

81 Based on Strategen's calculation from DEP IRP REPORT at 218, Table C-2.

82 *See page* DEC IRP REPORT at 217, Table C-10.

83 DEP IRP REPORT at 230.

As part of the federal stimulus package enacted in December 2020, the federal tax credits for wind and solar were both extended.[84] More specifically, the wind production tax credit was extended for one year at 60%, while the solar investment tax credit was extended for two years at 26%.[85] This is notable since solar and wind projects can claim these benefits through IRS-designated "commence-construction" or "safe-harboring" provisions, provided that they are completed within 4 years.[86] These extensions should be reflected in Duke's IRP planning assumptions as these credits could be applied to solar and wind projects completed between 2023 and 2025.

Gas Plant Lifetime and Potential Stranded Costs

Duke recently announced that it intends to shorten the lives of its new gas plants from 40 to 25 years.[87] A shorter book life would necessarily increase the annual revenue requirement during those years, as well as increase the overall portfolio costs for replacement resources when those plants are retired. This change was not reflected in the assumptions used to prepare the different IRP portfolios or the coal retirement analysis.

Even so, these gas plants and others present stranded asset risks due to the prospect of early forced retirements. Assuming a 40-year plant life, one recent analysis suggested that the stranded costs associated with Duke's natural gas fleet could translate to $4.8 billion in additional ratepayer costs.[88] But even a 25 year life presents risks. For example, some of the planned gas additions to Belews Creek would still be in use well past 2050, even with shorter lifespans. The North Carolina Clean Energy Plan[89] may complicate Duke's reliance on gas. Moreover, President Biden has called for power sector decarbonization by 2035.[90] Complying with these policies would likely require early gas plant retirements, which, as noted, would expose ratepayers to significant stranded costs.

Winter Demand Response Potential Study

During an IRP stakeholder meeting in September, Duke presented the results of its extensive winter demand response (DR) market potential study,[91] which identified a significant amount of available demand side resources. However, this market potential study was completed after the 2020 IRPs were released. Since Duke has a winter-peaking system, these demand response resources may help Duke address reliability more affordably. Therefore, the 2020 IRPs should be revised to reflect the full, identified potential of winter demand response.

---

[84] Catherine Morehouse, *Federal stimulus includes wind, solar tax credit extensions, adds first US offshore wind tax credit*, UTILITY DIVE (Dec. 22, 2020), https://www.utilitydive.com/news/federal-stimulus-includes-wind-solar-tax-credit-extensions-adds-first-us/592572/.

[85] *Id.*

[86] *Id.*

[87] *See* Saul, *supra* note 42.

[88] TYLER FITCH, ENERGY TRANSITION INSTITUTE, CARBON STRANDING: CLIMATE RISK AND STRANDED ASSETS IN DUKE'S INTEGRATED RESOURCE PLAN 48 (2021), https://energytransitions.org/carbon-stranding.

[89] *See* NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY, *supra* note 6.

[90] *See supra* note 44.

[91] NEXANT, DUKE ENERGY NORTH CAROLINA EE AND DSM MARKET POTENTIAL STUDY (2020).

About Strategen

Strategen is an internationally recognized, mission-driven, professional services firm focused on energy sector market transformation for a low carbon grid. Our multidisciplinary team specializes in work with policymakers and regulators, utilities, and unregulated market participants on issues related to zero carbon grid technologies such as energy storage, solar, wind, electric vehicles, demand response and energy efficiency. Our functional expertise includes technical analysis, economic analysis, regulatory thought leadership, and corporate strategy, as well as ability to leverage our thought leadership platform in ways that motivate and empower local leadership and change.

STRATEGEN

Edward Burgess

Senior Director

Ed leads the energy system decarbonization consulting practice at Strategen. Ed has served clients including consumer advocates, public interest organizations, Fortune 500 companies, energy project developers, trade associations, utilities, government agencies, universities, and foundations. His efforts, expert testimony and technical analysis have made impactful changes on energy system design across the United States, helping usher the closing of fossil plants with replacement of clean energy and energy storage in multiple states and creating actionable roadmaps for DER integration.

Contact

Location
Berkeley, CA

Email
eburgess@strategen.com

Phone
+1 (941) 266-0017

Education

PSM
Solar Energy Engineering and Commercialization
Arizona State University
2012

MS
Sustainability
Arizona State University
2011

MA
Chemistry
Princeton
2007

STRATEGEN.COM

Work Experience

Senior Director

Strategen / Berkeley, CA / 2015 - Present

+ Focuses on energy system decarbonization via economic analysis, technical regulatory support, resource planning and procurement, utility rates, and policy & program design.

Consultant

Kris Mayes Law Firm / Phoenix, AZ / 2012 - 2015

+ Consulted on policy and regulatory issues related to the electricity sector in the Western U.S.

Consultant

Schlegel & Associates / Phoenix, AZ / 2012 - 2015

+ Conducted analysis and helping draft legal testimony in support of energy efficiency for a utility rate case.

Project Manager & Researcher

Arizona State University / Tempe, AZ / 2012 - 2015

+ Conducted research and managing projects on energy policy, utilities and new regulatory models.

Research Fellow

Environmental Defense Fund / New York, NY / 2007 - 2009

+ Researched and analyzed policy in support of EDF's policy efforts at local, state, and national level.

Edward Burgess

Senior Director

STRATEGEN

Publications

+ New York BEST, 2020. *Long Island Fossil Peaker Replacement Study.*
+ Ceres, 2020. *Arizona Renewable Energy Standard and Tariff: 2020 Progress Report.*
+ Virginia Department of Mines and Minerals, 2020. "*Commonwealth of Virginia Energy Storage Study.*
+ Sierra Club, 2019. *Arizona Coal Plant Valuation Study.*
+ Strategen, 2018. *Evolving the RPS: Implementing a Clean Peak Standard."*
+ SunSpec Alliance for California Energy Commission.,2018. *Analysis Report of Wholesale Energy Market Participation by Distributed Energy Resources (DERs) in California.*

Domain Expertise

Avoided Cost Modeling

Rate Design

Energy Resource Planning

Benefit Cost Analysis

Stakeholder Engagement

Energy Policy & Regulatory Strategy

Energy Product Development & Market Strategy

STRATEGEN.COM

Relevant Project Experience

Arizona Residential Utility Consumer Office (RUCO)

IRP Analysis and Impact Assessment / 2015 - 2018

+ Supported drafting of expert witness testimony on multiple rate cases regarding utility rate design, distributed solar PV, and energy efficiency.
+ Performed analytical assessments to advance consumer-oriented policy including rate design, resource procurement/planning, and distributed generation consumer protection.
+ Ed was the lead author on the white paper published by RUCO introducing the concept of a Clean Peak Standard.

Western Resource Advocates

Nevada Energy IRP Analysis / 2018 - 2019

+ Conducted a thorough technical analysis and report on the NV Energy IRP (Docket No. 18-06003)
+ Investigated resource mixes that included higher levels of demand side management, renewable energy, battery storage, and decreased reliance on existing and/or planned fossil fuel plants.

Massachusetts Office of the Attorney General

SMART Program / 2016 - 2017

+ Appeared as an expert witness and supported drafting of testimony on the implementation of the MA SMART program (D.P.U. 17-140), which is expected to deploy 1600 MW of solar PV (and PV + storage) resources over the next several years. Ed served as an expert consultant on multiple rate cases regarding utility rate design and implications for ratepayers and distributed energy resource deployment.

New Hampshire Office of Consumer Advocate

NEM Successor Tariff Design / 2016

+ Worked with the state's consumer advocate to develop expert testimony on a case reforming the state's market for distributed energy resources, developing a new methodology for designing retail electricity rates that is intended to support greater deployment of energy storage.

Edward Burgess

Senior Director

STRATEGEN

Expert Testimony

Rocky Mountain Power (DKT: 20-035-04)
Embedded COS, Rate Design, and AMI rollout
Direct: https://pscdocs.utah.gov/electric/20docs/2003504/315452PhsIIDirTestRonNelsonOCS9-15-2020.pdf

Pacific Power (DKT UE 375)
Oregon 2021 Transition Adjustment Mechanism
Direct: https://edocs.puc.state.or.us/efdocs/HTB/ue375htb174343.pdf

PacifiCorp (DKT A.19-08-002)
California Energy Cost Adjustment Clause
Direct: https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1908002/2416/322232208.pdf

National Grid (DKT: 18-150)
Electric Vehicle Infrastructure Program
Direct: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/10505818

Dominion Energy South Carolina (DKT: 2019-184-E)
Dominion's Incorporated's Standard Offers, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitments to Sell Forms
Direct: https://dms.psc.sc.gov/Attachments/Matter/d84896b6-6a9f-47ee-9c26-d601396ca64d
Surrebuttal: https://dms.psc.sc.gov/Attachments/Matter/4f94de7d-3a82-4fce-bf66-da2e5feb83cc

Duke Energy South Carolina (DKT: 2019-185-E)
Duke's Incorporated's Standard Offers, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitments to Sell Forms
Direct: https://dms.psc.sc.gov/Attachments/Matter/53727849-78f0-47bf-b920-7cdbd0a18173
Surrebuttal: https://dms.psc.sc.gov/Attachments/Matter/de274f13-9bb7-4825-8ba9-73dfd0cd661c