

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 167**

In the Matter of:)	JOINT INITIAL COMMENTS
Biennial Determination of)	OF THE SOUTHERN
Avoided Cost)	ALLIANCE FOR CLEAN
Rates for Electric Utility)	ENERGY, NORTH CAROLINA
Purchases from)	CLEAN ENERGY BUSINESS
Qualifying Facilities – 2020)	ALLIANCE, AND THE NORTH
)	CAROLINA SUSTAINABLE
)	ENERGY ASSOCIATION

**JOINT INITIAL COMMENTS OF THE SOUTHERN ALLIANCE FOR
CLEAN ENERGY, NORTH CAROLINA CLEAN ENERGY BUSINESS
ALLIANCE, AND THE NORTH CAROLINA SUSTAINABLE ENERGY
ASSOCIATION**

I. INTRODUCTION

The 2020 Avoided Cost proceeding, as set forth in the Procedural Background below, was limited at the request of Duke Energy Carolinas, LLC (“DEC”), Duke Energy Progress, LLC (“DEP”) (DEC and DEP, collectively, “Duke”), and Virginia Electric and Power Company d/b/a Dominion Energy North Carolina (“Dominion,” or “DENC”) (DEC, DEP, and DENC, collectively, the “Utilities”) and as ordered by the North Carolina Utilities Commission (“Commission”). Typically, an even-year avoided cost proceeding would involve a full review of the utilities’ avoided cost calculations and methodologies relied upon therein. However, in this proceeding the Utilities sought to limit the present proceeding and requested a continuance in order to address certain of the requirements established by the Commission in its April 15, 2020 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* (the “Sub 158 Order”).

The Southern Alliance for Clean Energy (“SACE”), the North Carolina Clean Energy Business Alliance (“NCCEBA”)¹, and the North Carolina Sustainable Energy Association (“NCSEA”) (SACE, NCCEBA, and NCSEA, collectively, “Joint Commenters”) were not opposed to the Utilities’ streamlining request so long as certain conditions were met. The Joint Commenters provide the comments below in response to Duke’s November 2, 2020 Joint Initial Statement and Exhibits (the “Duke 2020 Filing”) and Dominion’s November 2, 2020 Initial Statement and Exhibits (the “Dominion 2020 Filing”).

The Joint Commenters retained Crossborder Energy’s Tom Beach (“Mr. Beach”) to conduct an analysis of the Utilities’ avoided cost initial statements and related work papers, attached hereto as **Exhibit A** (the “Crossborder Energy Report”). Consistent with the streamlined nature of this proceeding, the Crossborder Energy Report identifies and describes instances in which the Utilities have failed to update their avoided cost calculations as required by the methodologies established in the Sub 158 Order.² Certain issues addressed in the Crossborder Energy Report also involve inputs that the Utilities have used or choices the Utilities have made within the constructs of the Sub 158 Order’s prescribed methodologies that fall into a “gray area” between compliance with, and revisions to, the existing methodologies. The Joint Commenters accordingly respond to

¹ NCCEBA recently assumed the prior functions of the South Carolina Solar Business Alliance and is now named the Carolinas Clean Energy Business Association (“CCEBA”). CCEBA has not yet updated its entity name in each of its Commission dockets and was advised by Clerk of the Commission to wait until after these Initial Comments were filed to request a name change within the docket.

² See generally Crossborder Energy Report.

certain substantive comments and contentions made by the Utilities in their respective 2020 Filings in that area.³

In summary, as set forth more fully below, the Joint Commenters' conclusions and recommendations regarding the Utilities' 2020 Filings are the following:

1. Duke used Henry Hub basis differentials beginning in 2026 based on the existence of a new natural gas pipeline that does not currently exist and is not currently planned. Duke should be required to continue using its existing Henry Hub differentials.
2. Duke arrived at inappropriately low winter on-peak energy prices, in what appears to be a modeling error. Duke should be required to correct its modeling to address this issue.
3. Duke used two private fundamentals forecasts for the calculation of its avoided energy rates and did not include a publicly available forecast. Duke should be required to use at least one publicly available Henry Hub forecast.
4. Duke undervalued the long-term physical hedge against natural gas price volatility provided by renewable QFs. Duke should be required to develop a more accurate value.
5. Duke's choice of combustion turbine for capacity prices is outdated. Duke should be required to use the more accurate assumption of an advanced turbine model.

II. PROCEDURAL BACKGROUND

On August 13, 2020, the Commission issued its *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* ("Order Establishing Biennial Proceeding") pursuant to the provisions of Section 210 of PURPA and the regulations of the Federal Energy Regulatory Commission ("FERC"), initiating the 2020 biennial proceeding to set avoided cost rates. The Order Establishing Biennial Proceeding

³ Duke, for instance, made assertions in support of the peaker methodology and argued in support of its preferred 10-year forward natural gas market price data methodology. Both of these topics appear to be outside the realm of model inputs. However, the Joint Commenters do not seek to strike the Utilities' comments regarding issues that appear to fall outside of the streamlined focus on inputs at this time, the Joint Commenters merely point this out because both we and our expert likewise found it somewhat challenging to determine which issues qualify strictly as a model inputs versus methodological issues.

made DEC, DEP, Dominion, Western Carolina University (“WCU”), and Appalachian State University, d/b/a, New River Light and Power Company (“New River”) parties to the proceedings.

In the Order Establishing Biennial Proceeding, the Commission reminded the Utilities of the requirements coming out of the prior avoided cost proceeding⁴ and other pertinent orders. Namely:

- Real-time pricing tariffs;
- Cost increments and decrements to the publicly available combustion turbine cost estimates;
- The use of other reliability indices, specifically the Equivalent Unplanned Outage Rate (“EUOR”) metric, to support development of the performance adjustment factor (“PAF”);
- The extent of backflow at substations;
- the potential for qualifying facilities to provide ancillary services and appropriate compensation;
- The results of an independent technical review of the Astrapé Study solar integration services charge (SISC) methodology.⁵

The Commission also directed Duke to conduct a virtual stakeholder process to address issues related to the addition of energy storage at existing QFs and to report to the Commission in the Sub 158 Proceeding on the results of the stakeholder process by September 1, 2020.⁶

In the Commission’s July 21, 2020 *Order Denying Motion for Reconsideration* in the Sub 158 Proceeding, the Commission ordered Duke to file its resource adequacy studies, together with any additional detail and support for the study inputs and outputs,

⁴ Commission Docket No. E-100, Sub 158 (herein the “Sub 158 Proceeding”).

⁵ Order Establishing Biennial Proceeding, p. 1.

⁶ *Id.* at pp. 1-2.

and the Nexant energy efficiency, and demand-side management market potential studies in the instant proceeding. The Commission noted in the Order Establishing Biennial Proceeding that the FERC issued Order No. 872 on July 16, 2020, in its Docket Nos. RM19-15-000 and AD16-16-000 potentially driving additional changes to PURPA implementation and the determination of avoided cost rates in North Carolina.⁷ Lastly, unlike prior avoided cost proceedings, the Commission stated that it intended to limit the docket to filings and a public hearing, so no evidentiary hearing would be held.⁸

On October 20, 2020, the Utilities filed the *Notification of Intended Compliance with N.C. Gen. Stat. § 62-156(b), Request for Continuance of Compliance with Certain 2020 Filing Requirements and Request to Prospectively Modify Timing of Biennial Proceedings* (“Notice of Intended Compliance”). In the Notice of Intended Compliance, the Utilities acknowledged the requirements it had for the 2020 Avoided Cost proceeding, both by prior Commission orders and also by statute, and requested the Commission change its 2020 avoided cost proceeding requirements to alleviate a number of issues. Specifically, the Utilities sought to:

- (i) Notify the Commission of their intended compliance with the provisions of N.C. Gen. Stat. § 62-156(b) on November 2, 2020, as directed in the Commission’s Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearings, issued on August 13, 2020, in the above captioned docket (“Scheduling Order”);
- (ii) Request that the Commission continue until November 2021 certain of the collaborative discussions with the Public Staff and filing requirements primarily applicable to the Duke Companies, as directed by the Commission’s Order Establishing Standard Rates and Contract Terms For Qualifying Facilities, issued April 15, 2020 in Docket No. E-100, Sub 158 (“Sub 158 Order”) and the Scheduling Order to be met in their standard offer contract and avoided cost rates filing on November 2, 2020; and

⁷ *Id.*

⁸ Order Establishing Biennial Proceeding, p. 2.

- (iii) Request that starting November 1, 2021, comprehensive biennial avoided cost proceedings be scheduled to commence in odd-numbered years after biennial integrated resource plan (“IRP”) proceedings are held in even-numbered years.⁹

The Utilities went on to state that their request for the 2020 avoided cost docket included the following limitations for Duke specifically:

[T]he Duke Companies propose to update their avoided energy rates and avoided capacity rates to be offered in the standard offer contracts required to be biennially reviewed and approved by the Commission under North Carolina’s implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978 (“PURPA”) pursuant to N.C. Gen. Stat. § 62-156(b). Specifically, the Duke Companies plan to update their avoided costs rates applying the methodologies approved in the Sub 158 Order, but do not contemplate making updates to the currently-approved solar integration services charges (“SISC”) and the provisions in the standard power purchase agreement or the standard terms and conditions, other than those required by the passage of time, such as effective dates.¹⁰

The Utilities also requested “the Commission to grant a continuance of the additional technical assessments and collaborative requirements directed in the Sub 158 Order to analyze numerous inputs to the Utilities’ avoided cost rates for a period of 12 months through and including November 1, 2021.”¹¹ The Utilities also requested to move “the future biennial avoided cost proceedings to an ‘odd year’ filing schedule to commence November 2021.”¹²

The Commission granted the Utilities’ request, with some caveats. On October 30, 2020, the Commission issued the *Order Granting Continuance and Establishing Reporting Requirements* (“Order Granting Continuance”). The Order Granting Continuance ordered:

1. That the Commission acknowledges the intention of DEC, DEP, and DENC to comply with N.C. Gen. Stat § 62-156(b) by filing “streamlined” 2020

⁹ Notice of Intended Compliance, pp. 1-2.

¹⁰ Notice of Intended Compliance, p. 2.

¹¹ *Id.* at 3.

¹² *Id.*

avoided cost filings that will update the inputs in their avoided cost energy rates and avoided capacity rates based on the methodological guidelines and requirements approved in the Sub 158 Order, as outlined in their October 20, 2020 filing;

2. That DEC, DEP, and DENC shall address the Sub 158 Additional Issues by November 1, 2021;
3. That on or before December 7, 2020, DEC, DEP, and DENC shall file a list of the Sub 158 Additional Issues, and a timeline for how they intend to address the issues by November 1, 2021;
4. That DEC, DEP, and DENC shall file updates on their progress on the Sub 158 Additional Issues at least every 45 days after the December 15, 2020 filing until the issues are fully addressed; and
5. That considering the expedited nature of this proceeding the parties to the docket are encouraged to strictly adhere to the schedule set forth in the Scheduling Order.

Thereafter, on November 2, 2020, the Utilities filed their respective avoided cost applications: DENC filed its *Initial Statement and Exhibits of Dominion Energy North Carolina* (“Dominion Initial Statement”) and Duke filed the *Joint Initial Statement and Proposed Standard Avoided Cost Rate Tariffs of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC* (“Duke Initial Statement”).

On December 29, 2020, the Public Staff filed a Motion for Extension of Time for filing initial and reply comments in this docket, which was granted by order of the Commission on December 30, 2020.

III. INITIAL COMMENTS

A. Duke Failed to Comply with the Commission’s Sub 158 Order in at Least Two Instances.

As noted above, the streamlined nature of this proceeding simply requires that the Utilities update their avoided cost calculations as required by the methodologies established in the Sub 158 Order. However, Duke failed to comply with this mandate in at

least two instances. **BEGIN CONFIDENTIAL** [REDACTED]

[REDACTED]

[REDACTED] **END CONFIDENTIAL**

Second, Duke’s avoided energy winter on-peak rates appear to reflect a modeling error that results in lower prices during the on-peak period than during the adjacent non-peak periods.

1. Pipeline Assumption and Henry Hub Basis Differentials

As part of Duke’s natural gas forecast, Duke applies the basis differentials between the Henry Hub Zones 4 and 5 on the Transco pipeline, where Duke’s gas-fired power plants are located.¹³ The “basis differential” is simply the difference between (1) market prices in a reference market (for natural gas, this is the Henry Hub in Louisiana where the major gas forward market is located) and (2) market prices at a different location on the gas system (e.g. market prices in the Transco Zones 4 and 5 in North Carolina). Note that the basis can be positive or negative relative to the Henry Hub. Generally, the basis is (2) minus (1), so for example, if Transco Zone 5 prices are higher than the Henry Hub, the basis for Transco Zone 5 is positive.

BEGIN CONFIDENTIAL [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

¹³ Crossborder Energy Report 4-6.

¹⁴ Crossborder Energy Report, Figure 3, *Comparison of NCSEA and DEC/DEP market area forecasts*.

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

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[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

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[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] **END CONFIDENTIAL**

2. Winter Peak Energy Prices

In the near term, Duke’s proposed avoided energy costs for the winter morning peak period are unreasonably low—much lower, in fact, than the avoided energy prices for surrounding off-peak hours.¹⁶ DEC/DEP’s proposed avoided energy costs for the winter morning peak period are very low in near-term years, which does not make sense for a peak

¹⁵ See Crossborder Energy Report 4-5.

¹⁶ See Crossborder Energy Report 10.

period. This is apparently due to old production cost modeling techniques.¹⁷ The Commission should not rely on these quite clearly erroneous results. As Mr. Beach recommends, the Joint Commenters agree that the avoided energy costs for this period should be averaged, for at least the first few years, with the avoided energy costs in the other winter peak and premium peak periods, so that accurate price signals are sent to QFs.

B. Duke's Compliance with the Commission's Sub 158 Order is Unclear on Certain Issues and, Given the Uncertainty, These Topics Warrant Discussion.

It is not entirely clear whether Duke complied with the Commission's Sub 158 Order in Duke's treatment of three issues. First, Duke has relied exclusively on fundamentals forecasts developed by private firms, omitting public data. Second, Duke has undervalued the fuel hedge provided by long-term renewable PPAs. Third, Duke's avoided capacity pricing incorporates an outdated combustion turbine model.

1. Source for Fundamentals Forecast

Duke currently uses fundamentals forecasts for Henry Hub prices from the private consultancies IHS and ICF.¹⁸ The Joint Commenters recommend that these private forecasts should be supplemented with a public Henry Hub forecast, such as the Energy Information Administration's *2020 Annual Energy Outlook* forecast of Henry Hub prices. The Commission in the Sub 158 Order cited transparency as an important element of combustion turbine price estimates for an avoided cost filing, and the Joint Commenters similarly think such transparency is necessary here.¹⁹ The addition of a public Henry Hub

¹⁷ See DEC/DEP response to Public Staff DR 7-5.

¹⁸ Crossborder Energy Report 2.

¹⁹ See, Sub 158 Order at p. 33 ["...the Commission agrees that there may be some circumstances where it is appropriate for the CT costs derived from generic publicly available estimates to be tailored based on internal data and actual construction experience. However, the Commission stresses that these adjustments must be clearly delineated and justified to ensure the Commission's effort in recent proceedings to increase the

forecast would serve as an appropriate check, would add transparency, and would provide the useful additional perspective and data of another prominent forecaster. Therefore, the Joint Commenters request that Duke be required to supplement its IHS and ICF fundamentals forecasts with a public Henry Hub forecast.

2. Fuel Hedging Valuation

The Commission’s determination of the avoided cost of energy to the utility must include “the expected costs of the additional or existing generating capacity which could be displaced, the expected cost of fuel and other operating expenses of electric energy production which a utility would otherwise incur in generating or purchasing power from another source, and the expected security of the supply of fuel for the utilities’ alternative power sources.”²⁰ Citing this requirement, the Commission directed Duke to “include an appropriate fuel hedging value utilizing the Black-Scholes Model *or a similar model* to determine the hedging value of renewable generation, and that the fuel hedge value should be included for each year of the entire term of the QF PPA.”²¹ It specified that the method used must value “the added fuel price stability gained through each year of the entire term of the QF power purchase agreement.”²²

While use of the Black-Scholes Model to determine the fuel hedging value provided by qualifying facilities that use renewable energy meets the minimum requirements of the Commission’s order and has been litigated in prior Commission proceedings, a more

transparency in these CT cost inputs to the avoided capacity rate calculations is not lost. Further, when the Utilities use generic publicly available estimates, whether adjusted or not, the burden is on the utility to demonstrate that the estimates approximate the utility’s actual costs, and procedures should be made available that allow not only parties but other interested persons to obtain access to the estimates and any adjustments made to the estimates, if applicable.”

²⁰ N.C. Gen. Stat. § 62-156(b)(2).

²¹ Sub 158 Order, p. 62 (emphasis added).

²² *Id.* at 11.

accurate methodology would better comply with the Sub 158 Order’s requirement for an appropriate fuel hedging value and with the underlying statute. The statute requires the avoided cost of energy to include both “the expected cost of fuel and other operating expenses” for alternative sources and, separately, “the expected security of the supply of fuel for the utilities’ alternative power sources.”²³ The Commission properly implemented this directive when it required Duke to account for the “added fuel price stability gained through each year” as a result of purchases from a renewable QF under a long-term PPA.

As discussed in the Crossborder Energy Report, the Black-Scholes Model undervalues the long-term physical hedge against natural gas price volatility provided by a long-term fixed-price PPA with a renewable QF.²⁴ This type of PPA provides added fuel price stability over the full term of the contract, or 10 years. By contrast, the Black-Scholes Model simulates buying sequential options to purchase an 8-month supply of natural gas at a fixed price, over a 10-year period.²⁵ Because the price of each successive option depends on the then-prevailing market price, the Black-Scholes Model updates the price of natural gas fuel 15 times over the course of the 10-year period.

Accordingly, the Black-Scholes Model does not accurately represent the added fuel price stability gained through each year in a long-term fixed-price PPA with a renewable QF, and the Commission should direct Duke to investigate and apply a more accurate model that better conforms to the Commission’s prior order. In the alternative, if the Commission views this as a methodological issue rather than a compliance issue then it would be appropriate to revisit the issue in the full proceeding beginning in November.

²³ N.C. Gen. Stat. § 62-156(b)(2).

²⁴ See Crossborder Energy Report 6-9.

²⁵ See *id.* at 8.

3. Assumptions Used for Combustion Turbine (CT) Costs

Capacity prices should be based on up-to-date assumptions about the model of combustion turbine that would be used as a peaking resource. Duke assumes that it would be an F-class turbine. However, DEC is currently constructing a combustion turbine and chose an advanced H-class model. Furthermore, advanced turbines have lower heat rates, i.e., are more fuel-efficient, and efficiency will become increasingly important over time as combustion turbines compete with clean-energy resources that have very low variable costs. Accordingly, the Commission should direct Duke to make the more accurate assumption that a combustion turbine added as a peaking resource would be an advanced H-class model.

C. The Joint Commenters Provide the Following Additional Comments

In addition to the compliance issues discussed above, the Joint Commenters provide additional comment regarding two issues. First, the Joint Commenters respond to Duke's arguments regarding the natural gas forecast methodology regarding the transition from forward market prices to fundamentals forecasts. Second, the Joint Commenters discuss the application of carbon pricing in the existing avoided cost methodology and recommend that Duke should include a price on carbon in its calculations.

1. Transition from Forward Prices to Fundamentals Forecast

In the Sub 158 Order the Commission determined that Duke should calculate their avoided energy costs using forward natural gas prices for no more than eight years before using the fundamental forecast data for the remainder of the planning period.²⁶ The Commission reached this conclusion after weighing the evidence presented by multiple

²⁶ Sub 158 Order, p. 11.

intervenors. The Public Staff presented comments recommending that Duke use no more than five years of forward market data before transitioning to Duke’s fundamental forecast, noting that the Public Staff had not identified any utilities other than Duke that rely wholly on forward prices for terms greater than six years, that Duke did not purchase ten-year forwards as a standard part of its fuel procurement practices, and Duke’s ability to purchase ten-years forwards on five occasions in the past three years should not be determinative as to whether the use of ten-year forwards is appropriate.²⁷ The Public Staff also noted that Duke Energy Florida, Duke Energy Kentucky, and Duke Energy Indiana all rely wholly on market prices for the first five years, blend market and fundamental prices for the next five years, and switch to the fundamental forecast for the remainder of the planning period.²⁸

In the Sub 158 Proceeding, SACE recommended that Duke use no more than two to three years before transitioning to a blended price forecast and then a fundamental price forecast, and NCSEA recommended that Duke use forward market prices for two years before transitioning over the next three years to an average of a set of recent fundamental forecasts.²⁹

The Commission ultimately ruled that it was “not persuaded that a change in the fuel forecasting methodology approved in the 2016 Sub 148 Order is appropriate, at this time.”³⁰

In its 2020 Filing, Duke states that they have “developed their respective avoided energy rates by relying upon the methodology directed to be used in the *2018 Sub 158*

²⁷ *Id.* at 56-57.

²⁸ *Id.*

²⁹ *Id.* at 57.

³⁰ *Id.* at 59.

Order,”³¹ specifically, “relying upon forward market price data out eight years (2021-2028) as an indicator of the near-term future commodity costs of natural gas.”³² However, Duke also goes on to state that “the Companies continue to believe that the methodology that they have utilized since 2014 and included in their 2020 IRPs relying upon ten years of forward natural gas market price data before transitioning to commodity price estimates derived from fundamental forecasts after year ten is accurate and appropriate both for integrated resource planning and calculating avoided costs.”³³ Duke spends nearly three pages arguing in support of its preferred forecast methodology and repeating arguments it made during the E-100 Sub 158 avoided cost proceeding.

In response to Duke’s arguments in its 2020 Filing, the Joint Commenters believe that Duke should rely on fewer than eight years of forward natural gas market price data before transitioning to a fundamentals forecast in both the avoided cost proceeding and the IRP proceeding. As described in the Crossborder Energy Report, the use of eight years of forward market prices raises concerns about the transparency, practical applicability, and liquidity of such price data. Additionally, the use of a transition period between the forwards-only forecast and the fundamental forecast, rather than an immediate switch from one method to the other, would allow for a smoother transition between forecast methodologies. This method would be consistent with DENC’s approach of using a transition period of blended rates between use of the forward market prices and the fundamentals forecast, and consistent with the methodologies of other Duke utilities as noted by the Public Staff in the E-100 Sub 158 proceeding.³⁴

³¹ Duke 2020 Filing at 19.

³² *Id.* at 21.

³³ *Id.* at 19.

³⁴ Crossborder Energy Report at 2-4.

2. Exclusion of carbon emission costs from the emission costs used in the utilities' modeling of their avoided energy costs.

Duke's input assumptions for the production cost modeling used to determine avoided energy costs include the emission costs for certain air pollutants. These include criteria air pollutants such as NO_x and SO₂. The DENC avoided cost modeling also includes as an input the forecasted costs for carbon dioxide (CO₂) emissions for the Regional Greenhouse Gas Initiative, which Virginia is assumed to join in 2021. This is consistent with the DENC IRP.

The inputs for the production cost runs used by DEC/DEP do not include CO₂ emissions *costs* over the 10-year forecast period. However, Duke has included a line item for carbon emissions allowance in its work papers. Specifically, in Duke's Response to Public Staff Data Request 2-3, Duke provided an excel document including "Per ton costs of emission allowances for NO_x, SO₂, mercury, and CO₂" and also a tab for "Emissions Allowance" with a zero cost allowance for CO₂ in Duke's "Emissions Allowance Forecasts".³⁵ This cost allowance forecast includes assumed costs for NO_x and SO₂ through year 2044, but no such cost allowance assumptions are made for carbon.

Further, Duke has announced a corporate commitment to achieve a 50% reduction in carbon emissions by 2030 and to be carbon-neutral by 2050.³⁶ The Duke 2020 IRPs reflect this carbon goal and include carbon prices in most of their modeling scenarios. The DEC and DEP 2020 IRPs include a base forecast for carbon emission costs that starts at \$5

³⁵ Duke Excel Spreadsheet Tab responsive to Public Staff Data Request 2-3 attached hereto as **Exhibit B**. Note that while the broad excel spreadsheet responsive to Public Staff Data Request 2-3 is marked confidential, the sheet attached here as **Exhibit B** is specifically marked "non-confidential" by Duke.

³⁶ See DEC 2020 IRP, at p. 8: "In 2019, Duke Energy announced a corporate commitment to reduce CO₂ emissions by at least 50% from 2005 levels by 2030, and to achieve net-zero by 2050. This is a shared goal important to the Company's customers and communities, many of whom have also developed their own clean energy initiatives."

per ton in 2025 and escalates at \$5 per ton per year thereafter; this forecast of carbon emission costs is used in many IRP scenarios.³⁷ The IRP scenarios that would place DEC and DEP on trajectories to meet their long-term commitment to be carbon-neutral by 2050 include a non-zero price for carbon.³⁸ The IRP notes that “[t]his CO₂ price trajectory incentivizes the continued adoption of renewables, storage, accelerated coal retirements which supports a path to net-zero by 2050.”³⁹ The IRP recognizes that placing such an economic weight on carbon emissions is important to stimulate development of new zero-emitting load-following resources.⁴⁰ The Duke utilities have not explained how they could meet their long-term commitment to reduce carbon emissions without an assumption of increasing carbon emission costs over time.

Given Duke IRPs’ extensive use of this forecast of increasing CO₂ emission costs, and Duke’s own recognition that an assumption of non-zero carbon emission costs is necessary to meet its long-term corporate commitment, the avoided energy cost modeling in this case should use the DEC/DEP IRPs’ Base scenario for carbon emission costs starting in 2025. Alternatively, the Joint Commenters believe this point should not be lost as the Commission considers the 2020 IRPs and the subsequent 2021 avoided cost proceeding where methodological changes will be at issue and carbon pricing can be addressed more fully.

³⁷ *Id.*, at pp. 152-154.

³⁸ *Id.*, at pp. 192-195.

³⁹ *Id.*, at p. 153.

⁴⁰ *Id.*, at p. 152-153.

IV. CONCLUSION

The Joint Commenters request that the Commission order Duke to correct and adjust their avoided cost calculations consistent with the recommendations herein. The Joint Commenters do not have any recommendations for the Dominion proposal but will provide further analysis in reply comments, if necessary, upon review of other intervenors' initial comments.

Respectfully submitted this the 25th day of January 2021.

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CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing Petition to Intervene by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 25th day of January 2021.

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2020) **BUSINESS ALLIANCE, AND THE**
) **NORTH CAROLINA**
) **SUSTAINABLE ENERGY**
) **ASSOCIATION**

EXHIBIT A

Crossborder Energy Report

2021 Avoided Cost Proceeding – E-100 Sub 167

Authors: R. Thomas Beach and Patrick G. McGuire

I. Introduction

On behalf of the North Carolina Sustainable Energy Association (NCSEA), Southern Alliance for Clean Energy (SACE), and the North Carolina Clean Energy Business Alliance (NCCEBA), this report reviews the 2021 avoided cost filings of Duke Energy Carolinas (DEC), Duke Energy Progress (DEP), and Dominion Energy North Carolina (DENC). The North Carolina Utilities Commission (Commission) has set a limited scope for this “streamlined” proceeding, to focus on updating the input assumptions used in the avoided cost methodology adopted in the Commission’s 2018 Avoided Cost Order in Docket E-100 Sub 158.¹ That order also directed the utilities to address specific issues with and possible changes to the avoided cost methodology; those issues will be addressed in subsequent proceedings in 2021.

First, I review and address the key assumptions used to produce the 10-year natural gas forecasts that are a central input into the avoided energy costs of the North Carolina utilities. The issues with this forecast include:

- the source(s) for a **fundamentals-based forecast** of long-term natural gas prices in the benchmark Henry Hub market;
- the **transition** in the forecast of Henry Hub prices from the use of forward market prices to the use of fundamentals forecasts;
- the source and assumptions for the **basis differential** from the Henry Hub to the North Carolina market area; and
- how to value **the long-term physical hedge** against natural gas price volatility that fixed-price renewable QF generation provides.

Second, I comment on the exclusion of **carbon emission costs** from the emission costs used in the Duke utilities’ modeling of their avoided energy costs.

Third, I review DEC’s and DEP’s assumption for the choice of the **combustion turbine** (CT) used in the Commission’s “peaker methodology.” The costs of the CT are the source for the avoided capacity costs in the peaker methodology. The report closes with observations about the choice of the year of first capacity need.

¹ See the October 30, 2020 *Order Granting Continuance and Establishing Reporting Requirements* in this docket.

II. Avoided Energy Costs

A. Natural Gas Issues

The forecast of delivered natural gas prices is a key input into the calculation of avoided energy costs. DENC uses a forecast that is based on gas forward market prices for the initial 18 months, then transitions by month 37 (i.e. after three years) to a fundamentals forecast from the consulting firm ICF. In contrast, DEC/DEP's gas forecast for a 2020-2029 forecast period uses an 8 years of forward market prices for 2020-2028 before moving to a fundamentals forecast from the consultant IHS in the final year.

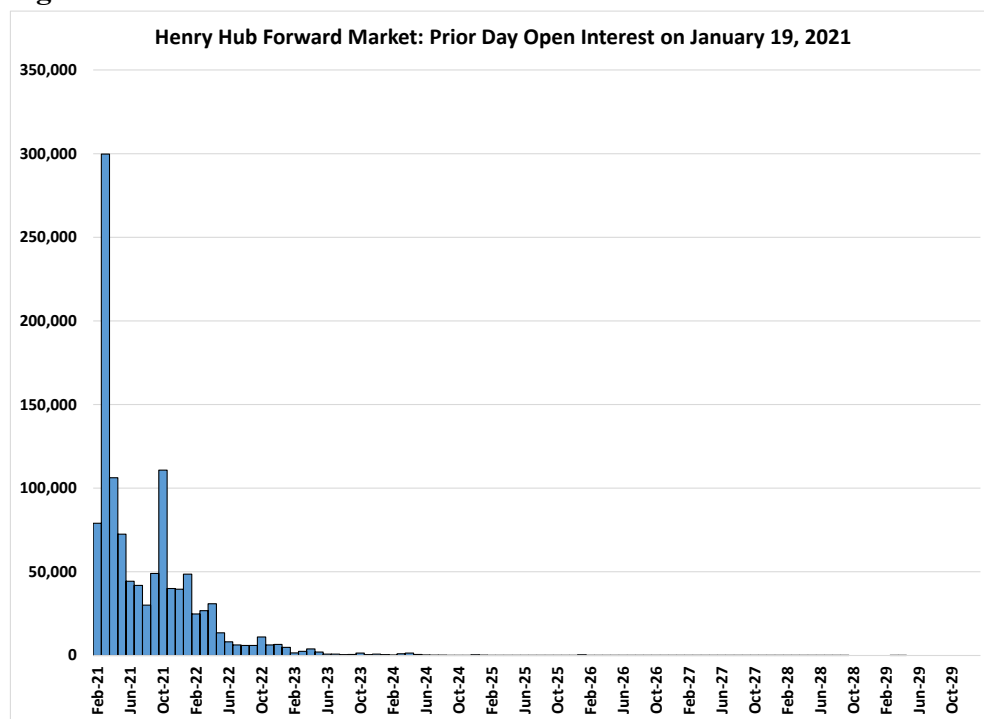
The Commission's order in the 2018 avoided cost case approved DENC's forecast and adopted a forecast for DEC/DEP that uses 8 years of forward market prices, then 2 years of a fundamentals forecast.² The resolution for DEC/DEP was a compromise, first adopted in the 2016 avoided cost case, between the DEC/DEP proposal to use 10 years of forward prices and the Public Staff's recommendation to use no more than 5 years of forward prices. The Commission thus has adopted two significantly different approaches to forecasting future gas prices, one for DENC and another for DEC/DEP. The same discrepancy again is apparent in the proposals filed in this case. We comment further on this below.

Fundamentals forecast. The utilities use fundamentals forecasts for Henry Hub prices from the private consultancies IHS and ICF. We do not question these private forecasts, but recommend that they should be supplemented with a public Henry Hub forecast, as a check, to add transparency, and to provide the additional perspective and data of another prominent forecaster. We recommend that the IHS and ICF Henry Hub forecasts should be averaged with the Energy Information Administration's (EIA) *2020 Annual Energy Outlook (2020 AEO)* forecast of Henry Hub prices. Thus, the average of the EIA and IHS forecasts should be the fundamentals forecast for DEC/DEP; the average of the EIA and ICF forecasts should be used as the fundamentals forecast for DENC.

Transition. We recognize that, in the 2016 and 2018 avoided cost orders, the Commission has not been troubled by the differences between the DENC and DEC/DEP gas forecasts, even though the two utilities place substantially different reliance on gas forward market prices. We continue to have questions about the reasonableness of using as much as 8 years of forward market prices. First, the forward market for 8 years of natural gas at fixed prices is not transparent, broadly traded, or liquid. The open interest in the NYMEX gas forward market is almost entirely in the first two years, as illustrated in **Figure 1**. For example, typically 99% of the open interest in the Henry Hub natural gas forward market is in the first two years. Given the small and sporadic volumes traded in the out years, the reported prices after two years are less certain and convey far less information than the initial two years that are heavily traded.

² 2018 Avoided Cost Order, at Finding 27 and pp. 58-59.

Figure 1



Forward prices and fundamentals forecasts both have roles to play in a reasonable gas price forecast. Forward prices provide market-based information on short-term price trends influenced strongly by current demand, by near-term expected demand, and by the current status of gas in physical storage. It is important to remember that forward prices represent the price at which parties are willing to contract for future supplies today, but not necessarily what the price for those future supplies will be tomorrow or when the future date is reached. Forward prices often track current prices, and it is a common observation that the magnitude of the forward price curve shifts up or down largely in parallel to changes in the current spot price.³ There is some evidence that short-term forward prices provide a reasonable forecast of short-term spot prices, in part because the two markets are clearly linked by the physical and economic ability to store gas from one season to the next. But we are not aware of substantial evidence that as much as 8 years of forward price data is superior to forecasts that examine the fundamentals of natural gas supply and demand.

Fundamentals forecasts look at longer-term trends in the gas supply and demand balance in North America and the world market for liquified natural gas (LNG). For example, the *2020 AEO* forecast considers the impacts of both the demand for U.S.-produced natural gas in domestic and export markets as well as the growth in production from shale gas and gas associated with tight oil production.⁴ Fundamentals forecasts tend to be higher than forward

³ For a graphic illustration of this using forward oil price curves, see Timera Energy, *The dangers of mixing forecasts and forward curves*, Chart 1, available at <https://timera-energy.com/the-dangers-of-mixing-forecasts-and-forward-curves/>.

⁴ See *2020 AEO*, Slides 45-46, 49-50, and 55-60. Available at <https://www.eia.gov/outlooks/aeo/>.

market prices in falling markets (e.g. since 2010), but lag forward prices in rising markets (e.g. in the 2000s).⁵ Obviously, that trend has changed since 2010. These changing trends over time also are apparent in the EIA's own analysis of the accuracy of its past AEO forecasts.⁶ I concur with the observations of a group of utilities (including a Duke affiliate), who commented on the importance of the fundamental factors that influence future gas prices in seeking to extend a gas hedging program in Florida:

[The] increased dependence on natural gas means customers will have significant exposure to the uncertainties of natural gas prices if hedging were completely discontinued. While natural gas prices have trended downward in recent years, neither future gas prices nor the level of price volatility can be predicted with any certainty. Additionally, the recent downward trend in natural gas market prices cannot continue indefinitely. Factors such as production costs, weather, environmental regulations and exportation impact natural gas supply and demand, as well as natural gas price volatility.⁷

We continue to support the DENC methodology of using 18 months of forward market prices, then transitioning over the next 18 months to the fundamentals forecasts. However, recognizing the limited scope of this case, the Commission may continue to allow DEC/DEP's longer use of forward market prices over 8 years. Assuming the use of 8 years of forward prices continues, we recommend that the DEC/DEP forecast should transition to the fundamentals forecasts over a longer four-year period (i.e. in years 5-8), instead of immediately moving from forwards to fundamentals in moving from year 7 to year 8. Thus, the mix of forward and fundamentals prices for DEC/DEP would be 80% forwards / 20% fundamentals in year 5, 60% forwards / 40% fundamentals in year 6, 40% forwards / 60% fundamentals in year 7, and 20% forwards / 80% fundamentals in year 8, before moving to 100% fundamentals in year 9. This would parallel the DENC approach of transitioning to the fundamentals forecast over the same length of time that would be used for the forwards-only forecast. This compromise approach would continue to use 8 years of forward market data, but would add gradually the important information from the fundamentals forecasts in years 5-8.

Basis differentials. The DEC/DEP forecast uses the basis differentials between the Henry Hub and Zones 4 and 5 on the Transco pipeline, where DEC/DEP's gas-fired power plants are located. **BEGIN CONFIDENTIAL** [REDACTED]

⁵ For example, in 2009 researchers at the Lawrence Berkeley National noted that EIA's yearly AEO gas forecast had fallen below contemporaneous forward prices for nine years in a row. See Mark Bolinger and Ryan Wiser, *Comparison of AEO 2010 Natural Gas Price Forecast to NYMEX Futures Prices* (LBNL, January 2010), available at <https://emp.lbl.gov/sites/all/files/update-memo-lbnl-53587.pdf>.

⁶ See https://www.eia.gov/outlooks/aeo/retrospective/pdf/table_8a.pdf.

⁷ See *Joint Petition by Investor-Owned Utilities for Approval of Modifications to Risk Management Plans*, filed April 22, 2016 by Duke Energy Florida, Florida Power & Light, Gulf Power, and Tampa Electric in Florida Public Service Commission Docket No. 160096-EI, at ¶ 5.

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Comparison of NCSEA and DEC/DEP gas forecasts. Figure 2 compares the NCSEA and DEC/DEP gas forecasts for the Henry Hub; the NCSEA proposal uses four years of forwards, then transitions to the average of the EIA and IHS fundamentals forecasts in years 5-8. We also show the EIA, IHS, and ICF Henry Hub forecasts.

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⁸ See DEC/DEP response to Public Staff DR 9-2.

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Table 1 presents NCSEA’s recommended gas cost forecast for the Henry Hub and Transco Zone 5.

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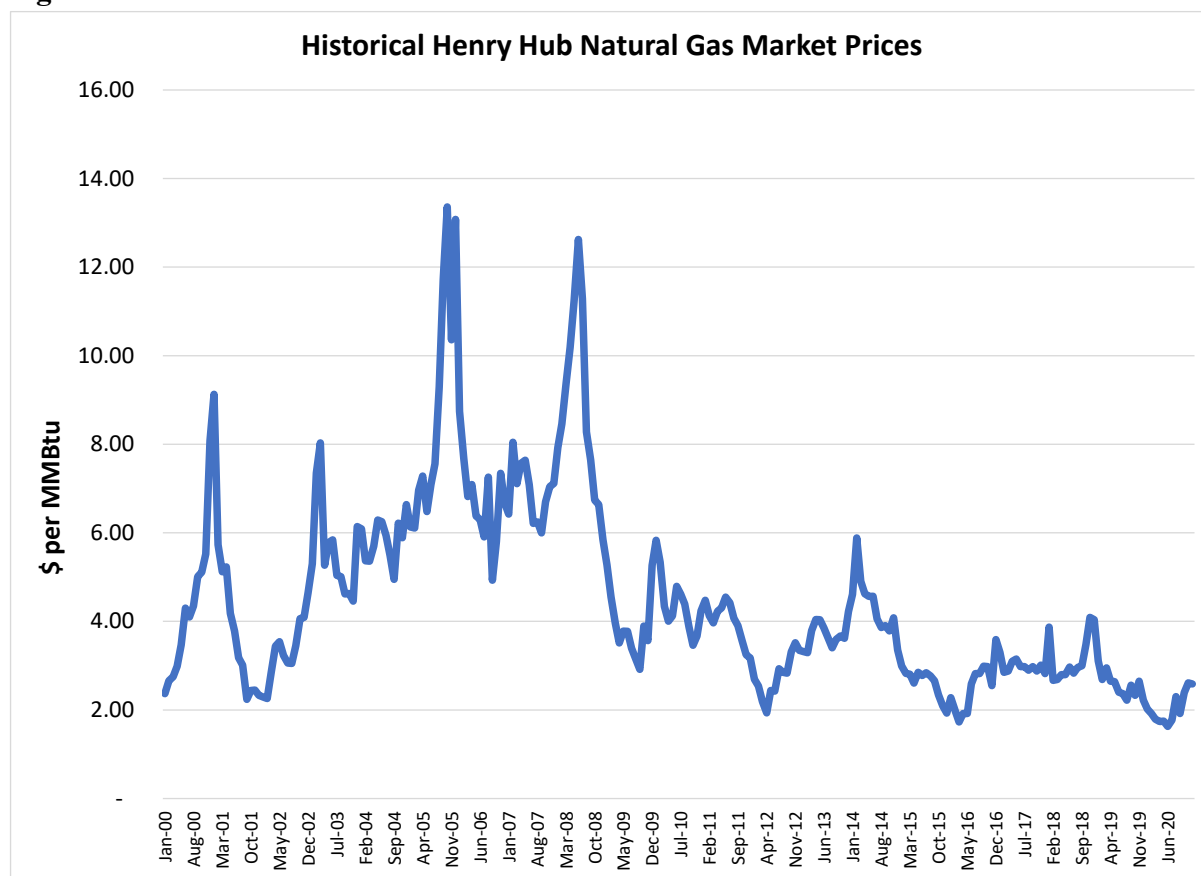
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Fuel hedging. The Commission has found repeatedly that there are fuel hedging benefits associated with renewable generation. In the 2018 Avoided Cost Order, the Commission found, at page 62, “that DEC and DEP should be required to recalculate their avoided energy rates to include an appropriate fuel hedging value utilizing the Black-Scholes Model or a similar model to determine the hedging value of renewable generation, and that the fuel hedge value should be

included for each year of the entire term of the QF PPA” (emphasis added). In their filings in this case, all of the utilities have used a Black-Scholes calculation performed by DENC. We recommend a different hedging model for use in the 2020 avoided costs that better represents the long-term physical hedge that renewable generation provides.

Renewable QFs largely displace natural gas-fired generation, thus reducing the purchasing utility’s use of natural gas and decreasing the exposure of ratepayers to the volatility in natural gas prices, as exemplified by the periodic spikes in natural gas prices shown by the history of Henry Hub prices in **Figure 4** below.⁹ If the avoided cost prices paid to a renewable QF are fixed for the term of a PPA (i.e. for 10 years), the renewable QF provides a long-term physical hedge for the 10-year term of the PPA, by displacing market-priced gas with fixed-price renewable power. The 4,492 MW of solar that DEC and DEP anticipate to be on-line in the near future would displace about 195,000 Dth per day of natural gas use, assuming a system heat rate of 7,250 Btu/kWh. This hedge extends far longer than current utility hedging programs, which typically are limited to hedging no more than one or two years into the future.

Figure 4



⁹ Source for Figure 4: data compiled by EIA, at <https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm>.

In addition, observers have noted that long-term, fixed-price contracts for renewable generation provide utilities with a means not available in the financial markets to hedge their long-term exposure to gas and power markets, and thus could replace a portion of their current budgets for risk management.¹⁰ Again, however, the hedge provided by long-term, fixed-price renewable PPAs extends in time far beyond the limited hedging programs now undertaken by utilities. The long-term price hedge provided by renewable generation also is a significant factor driving the demand from large corporate customers to be served directly from new renewable projects.¹¹

In past avoided cost cases, the hedging benefit has been quantified using the Black-Scholes Model option pricing method. This method fails to fully value the long-term physical hedge that fixed-price renewable generation provides. As proposed by the utilities in this case, the Black-Scholes method simply provides the cost of buying options to enable the purchase of an 8-month supply of gas at a fixed price.¹² When one such deal expires, one would have to renew it for the next 8 months at the then-prevailing market price for another 8-month supply of gas. Such a process would not fix the gas price or the resulting power price upfront for a 10-year period, as does a renewable PPA. Essentially, the Black-Scholes approach assumes that the displaced gas is re-priced at the prevailing market price 15 times over a 10-year period, which is a far less effective hedge than provided by a renewable PPA that provides 10 years of prices fixed from the start of the contract's term. This is the difference between a 30-year mortgage with a fixed interest rate for the entire 30-year term versus a mortgage whose interest rate is re-priced to market every other year of the 30-year term. The second mortgage provides a far less valuable hedge against interest rate fluctuations than the first.

We would like to bring to the Commission's attention several studies that have quantified the long-term hedge value of renewable generation. These values are significantly higher than those that the Commission has adopted using the Black-Scholes method. In 2013, Xcel Energy's Public Service of Colorado unit estimated the long-term (20-year) hedging benefits of distributed solar resources on its system to be \$6.60 per MWh.¹³ This study appears to have used the cost of call options in the over-the-counter gas futures market to calculate the hedging benefit.

¹⁰ See Lisa Huber, *Utility-scale Wind and Natural Gas Volatility: Unlocking the Hedge Value of Wind for Utilities and Their Customers* (Rocky Mountain Institute [RMI], July 2012), at pg. 15, available at http://www.rmi.org/Knowledge-Center/Library/2012-07_WindNaturalGasVolatility.

¹¹ See <https://www.greentechmedia.com/articles/read/large-corporations-are-driving-americas-renewable-energy-boom#gs.bDKjHRoo>. Also, Center for the New Energy Economy, *Private Procurement, Public Benefit: Integrating Corporate Renewable Energy Purchases with Utility Resource Planning* (December 2016), available at http://info.aee.net/hubfs/PDF/CNEE_Corporate%20Procurement.pdf, at p. 2: "For these large corporations, investing in a long-term resource that gives them stable rather than fluctuating energy costs can be an attractive financial risk mitigation strategy as well as a corporate responsibility commitment."

¹² See DENC response to Public Staff Data Request 2-1, showing the price for a 252-day option.

¹³ Xcel Energy Services, *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System: Study Report in Response to Colorado Public Utilities Commission Decision No. C09-1223* (May 2013), at pp. 6 and 43, and Table 1.

The consultant Clean Power Research developed another method for calculating the hedge value of renewables, as part of the Maine Public Utilities Commission's *Maine Distributed Solar Valuation Study*, released in 2015.¹⁴ The Maine PUC's method recognizes that renewable generation has zero fuel costs, with capital costs replacing fuel costs. These upfront capital costs are known and fixed in year 0. To achieve a comparable outcome with gas-fired generation, one has to fix upfront the fuel costs for a long-term period, and set aside the money to do so in year 0. The funds required to do this are the amount of money which, when invested in "risk free" U.S. Treasury securities, yields the future funds required to fulfill gas futures contracts in each year of the long-term period. This results in higher costs because this money could otherwise be deployed to earn a higher return (assumed to be the utility's weighted average cost of capital) if it was available to be used for alternative investments. These incremental costs are what the utility who owns or buys marginal gas generation would have to spend to obtain the same hedging benefit that it can obtain from an identical renewable resource whose fuel costs are zero, thus eliminating the uncertainty and volatility in future fuel costs for the life of the fixed-price renewable generation. These additional costs are substantial when one considers the alternative uses to which one can put the money that must be set aside upfront to fix the cost of natural gas for 10 years.

Thus, the Maine PUC method compares the long-term cost of the displaced gas generation at a risk-free discount rate (U.S. Treasuries) versus the same cost discounted at the utility's weighted average cost of capital (WACC). The difference represents the hedging benefit of fixing the cost of gas upfront. We have used the Maine PUC method to calculate the 10-year hedging benefit of renewable PPAs in North Carolina, based on the gas forecasts proposed by NCSEA, DENC, and DEC/DEP, current U.S. Treasury yields as the risk-free investments, the utilities' WACCs, and a marginal heat rate of 7,250 Btu per kWh. These hedging benefits are shown in **Table 1**. The detailed calculations are included in confidential **Attachment A**, which shows the hedging calculations for the NCSEA, DENC, and DEC/DEP Henry Hub gas forecasts.

¹⁴ See Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (March 1, 2015); hereafter, "Maine Solar DG Valuation Study." Available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

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B. Carbon Emission Costs

The input assumptions for the production cost modeling used to determine avoided energy costs include the emission costs for certain air pollutants. These include criteria air pollutants such as NO_x and SO₂. The DENC avoided cost modeling also includes as an input the forecasted costs for carbon dioxide (CO₂) emissions for the Regional Greenhouse Gas Initiative, which Virginia is assumed to join in 2021. This is consistent with the DENC IRP.

The inputs for the production cost runs used by DEC/DEP do not include CO₂ emissions costs over the 10-year forecast period. However, the Duke utilities have announced a corporate commitment to achieve a 50% reduction in carbon emissions by 2030 and to be carbon-neutral by 2050.¹⁵ The DEC and DEP 2020 IRPs include a base forecast for carbon emission costs that starts at \$5 per ton in 2025 and escalates at \$5 per ton per year thereafter; this forecast of carbon emission costs is used in many IRP scenarios.¹⁶ The IRP scenarios that would place DEC and DEP on trajectories to meet its long-term commitment to be carbon-neutral by 2050 include a non-zero price for carbon.¹⁷ The IRP notes that “[t]his CO₂ price trajectory incentivizes the continued adoption of renewables, storage, accelerated coal retirements which supports a path to net-zero by 2050.”¹⁸ The IRP recognizes that placing such an economic weight on carbon emissions is important to stimulate development of new zero-emitting load-following resources.¹⁹ The Duke utilities have not explained how they could meet their long-term commitment to reduce carbon emissions without an assumption of increasing carbon emission costs over time. Given the Duke IRPs’ extensive use of this forecast of increasing CO₂ emission

¹⁵ See DEC 2020 IRP, at p. 8: “In 2019, Duke Energy announced a corporate commitment to reduce CO₂ emissions by at least 50% from 2005 levels by 2030, and to achieve net-zero by 2050. This is a shared goal important to the Company’s customers and communities, many of whom have also developed their own clean energy initiatives.”

¹⁶ *Ibid.*, at pp. 152-154.

¹⁷ *Ibid.*, at pp. 192-195.

¹⁸ *Ibid.*, at p. 153.

¹⁹ *Ibid.*, at p. 152-153.

costs, and Duke’s own recognition that an assumption of non-zero carbon emission costs is necessary to meet its long-term corporate commitment, the avoided energy cost modeling in this case should use the DEC/DEP IRPs’ Base scenario for carbon emission costs starting in 2025.

C. Winter Peak Energy Prices

DEC/DEP’s proposed avoided energy costs for the winter morning peak period are very low in near-term years. This does not make sense for a peak period. In discovery, DEC/DEP appear to say that this is due to artifacts of its production cost modeling in how start-up costs are assigned to hours.²⁰ Start-up costs are assigned to specific hours, rather than spread over a unit’s entire operating period. This can produce such anomalous results for TOU periods with relatively few hours such as the winter peak period. Rather than retain this nonsensical result of a very low energy price during a peak period, we recommend that the avoided energy costs for this period should be averaged with the avoided energy costs in the other winter peak and premium peak periods, so that accurate price signals are sent to QFs. This adjustment appears necessary only for the first two years of the forecast period (2021-2022).

III. Avoided Capacity Costs

A. Choice of Combustion Turbine

The DEC/DEP avoided cost filings assume an F-class frame CT as the modeled gas-fired peaking resource. The screening study of generation resources in the DEC IRP shows that F-class CTs and more advanced CTs have virtually identical overall costs for both energy and capacity.²¹ DEC/DEP use public data on F-class turbines from EIA;²² there is also public data on advanced H-class CTs from the Brattle Group’s 2018 Cost-of-New-Entry study for PJM.²³ DENC uses the CT costs for the advanced CTs from its Greenville plant.²⁴ There are several reasons why DEC and DEP should use the costs of an H-class turbine as the CT cost assumption for its avoided capacity costs. First, the new CT that DEC is actually building – the Lincoln CT Unit 17 – is an advanced CT using a Siemens H-class turbine.²⁵ As a result, the lower heat rate for this CT is included in the modeling of avoided energy costs. Accordingly, it is inconsistent with and undervalues DEC’s avoided capacity costs for the capital costs of the CT to use a lower cost turbine with a higher, less efficient heat rate than the type of CT that DEC is building. Second, the H-class turbines have important operational improvements (a lower heat rate, faster

²⁰ See DEC/DEP response to Public Staff DR 7-5.

²¹ See DEC 2020 IRP, at Appendix G, p. 333.

²² EIA also has cost data on H-class turbines, but only in a combined-cycle configuration.

²³ Brattle Group and Sargent & Lundy for PJM, *PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date* (April 19, 2018), hereafter “PJM Net CONE Study,” available at <https://www.pjm.com/~media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx>.

²⁴ Initial Statement and Exhibits of Dominion Energy North Carolina, at p. 14.

²⁵ See <https://www.duke-energy.com/our-company/about-us/new-generation/natural-gas/lincoln-ct-expansion>.

start-ups and higher ramp rate) which will be important and beneficial to ratepayers in a world with intermittent renewable resources with low variable costs. The Commission recognized the importance of these operating characteristics in approving the Lincoln CT.²⁶ The Duke utilities clearly are headed into a world with an increasing penetration of renewables, given the companies' commitment to reduce their carbon emissions and the substantial growth of solar resources on the Duke system in North Carolina. As a result, the choice of the CT unit should be one that is most consistent with the utilities' system needs when they add such a unit of capacity.

The H-class capital cost from the PJM CONE Study is \$835 per kW for a 2022 on-line date in nominal 2022 dollars (annualized to \$98.20 per kW-year), which should be the basis for DEC's and DEP's avoided capacity costs.²⁷

Mr. Beach, the lead author of this Report, has included his Curriculum Vitae as **Exhibit B** to this Report.

²⁶ The Commission's order approving the Lincoln Advanced CT project found:
The technology selected by the Company for the Lincoln CT Project will provide enhanced reliability, low turn down, fast ramp, and efficient dispatch capability for the Duke Energy Carolinas system. The load following capability of the Lincoln CT Project will provide additional system flexibility and generation ancillary service benefits to help accommodate the impacts resulting from the increasing amounts of intermittent renewable resources being added to the Duke Energy Carolinas system. The advanced-class simple cycle CT technology proposed by Duke Energy Carolinas for the Lincoln CT Project is a practical technological option to provide peaking generation capacity by 2024, when it is needed.

See *Order Issuing Certificate of Public Convenience and Necessity with Conditions* (Docket No. 7, Sub 1134, issued December 7, 2017), at Finding of Fact 6.

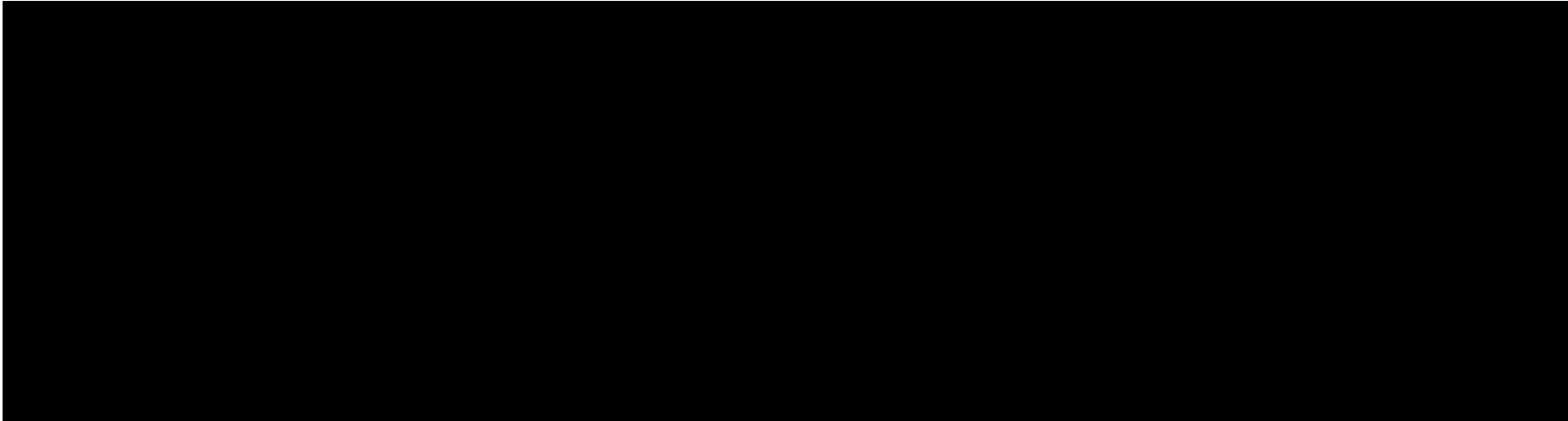
²⁷ See PJM Net CONE Study, at pp. 22 (Table 9) and 51 (Table 19). The "Rest of RTO" costs are used, as those are the ones most applicable to the North Carolina utilities.

1. Calculation of Fuel Hedging Value - NCSEA Forecast



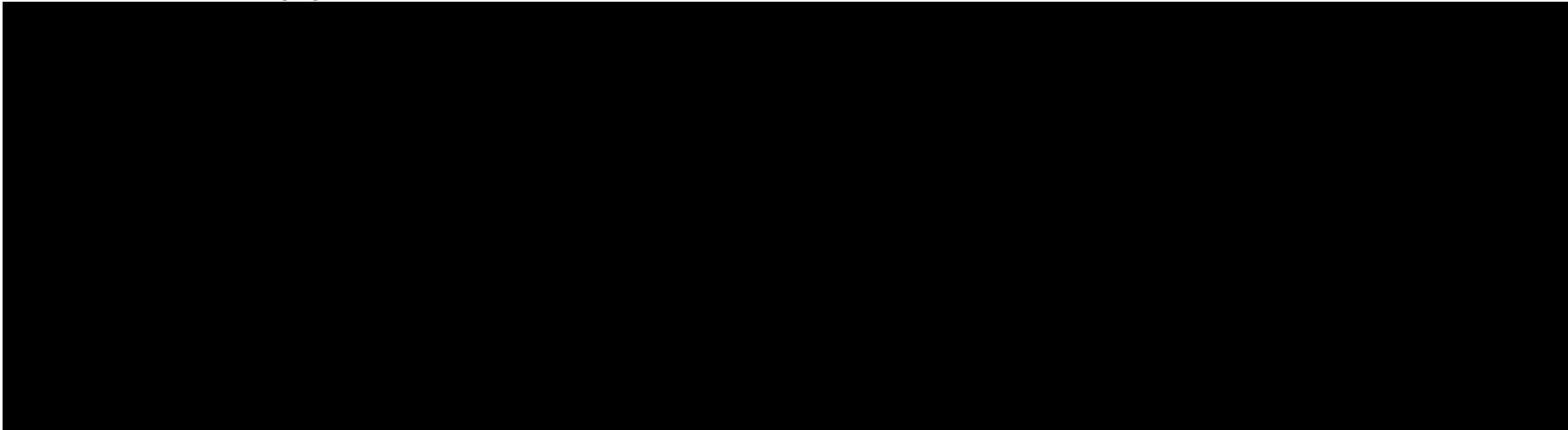
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2. Calculation of Fuel Hedging Value - DEC/DEP Forecast



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3. Calculation of Fuel Hedging Value - DENC Forecast



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R. THOMAS BEACH
Principal Consultant

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the U.S., and Canada.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.
- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.
- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.
- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.
- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

R. THOMAS BEACH
Principal Consultant

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)
 - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*
2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)
 - *Natural gas procurement policy; gas cost forecasting.*
3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)
 - *Brokering of interstate pipeline capacity.*
4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)
 - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*
5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)
 - *Firm and interruptible rates for noncore natural gas users*

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6.
 - a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
 - b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)
 - *Brokering of interstate pipeline capacity; intrastate transportation policies.*
7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)
 - *Natural gas brokerage and transport fees.*
8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)
 - *Natural gas parity rates for cogenerators and solar thermal power plants.*
9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)
 - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*
10.
 - a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
 - b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26, 1991)
 - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*
11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)
 - *Natural gas procurement policy; prudence of past gas purchases.*
12.
 - a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
 - b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)
 - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*
13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)
 - *Performance-based ratemaking for electric utilities.*

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14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)
 - *Natural gas transportation service for wholesale customers.*
 15. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)
 - *Natural gas pipeline rate design issues.*
 16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)
 - *Utility overcharges for natural gas service; cogeneration parity issues.*
 17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)
 - *Natural gas rate design for wholesale customers; retail competition issues.*
 18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)
 - *Natural gas rate design issues; rate parity for solar thermal power plants.*
 19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)
 - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*
 20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)
 - *Recovery of above-market nuclear plant costs under electric restructuring.*
 21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)
 - *Natural gas rate design; unbundled mainline transportation rates.*

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22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)
 - *Incremental Energy Rates; air quality compliance costs.*
 23.
 - a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
 - b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)
 - *Natural gas market dynamics; gas pipeline rate design.*
 24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)
 - *Natural gas rate design: parity rates for cogenerators.*
 25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)
 - *Impacts of a major utility merger on competition in natural gas and electric markets.*
 26.
 - a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
 - b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)
 - *Natural gas rate design for gas-fired electric generators.*
 27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)
 - *Natural gas service to Baja, California, Mexico.*
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28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
- b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
- c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).
- *Natural gas cost allocation and rate design for gas-fired electric generators.*
29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
- b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
- c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
- d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
- e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).
- *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*
30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
- b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).
- *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*
31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
- b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).
- *Natural gas cost allocation and rate design for gas-fired electric generators.*

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32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
 b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).
- *Rate design for a natural gas “peaking service.”*
33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
 b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).
- *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*
34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
 b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).
- *Avoided cost pricing for alternative energy producers in California.*
35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
 b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)
- *Consumer benefits from expanded natural gas storage capacity in California.*
36. Prepared Direct Testimony on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)
- *Reasonableness review of a natural gas utility’s procurement practices and storage operations.*
37. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
 b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
- *Electric procurement policies for California’s electric utilities in the aftermath of the California energy crisis.*

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38. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)
- *“Exit fees” for direct access customers in California.*
39. Prepared Direct Testimony on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)
- *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility’s procurement practices.*
40. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)
- *Recovery of past utility procurement costs from direct access customers.*
41. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
- b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)
- *Rate design issues for Pacific Gas & Electric’s gas transmission system (Gas Accord II).*
42. a. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
- b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)
- *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*
43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)
- *Design and implementation of a Renewable Portfolio Standard in California.*

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44. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
- b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)
- *Power procurement policies for electric utilities in California.*
45. Prepared Direct Testimony on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)
- *Electric revenue allocation and rate design for commercial customers in southern California.*
46. a. Prepared Direct Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
- b. Prepared Rebuttal Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)
- *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*
47. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)
- *Policy and contract issues concerning cogeneration QFs in California.*
48. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
- b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)
- *Natural gas cost allocation and rate design for large transportation customers in northern California.*
49. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
- b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)
- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

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50. Prepared Direct Testimony on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)
- *Cost-effectiveness of the Million Solar Roofs Program.*
51. Prepared Direct Testimony on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)
- *Natural gas rate design policy; integration of gas utility systems.*
52. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)
- *Avoided cost rates and contracting policies for QFs in California*
53. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)
- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*
54. a. Prepared Direct Testimony on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
b. Prepared Rebuttal Testimony on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)
- *Transportation and balancing issues concerning California gas production.*
55. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)
- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*
56. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)
- *Review and approval of a new contract with a gas-fired cogeneration project.*

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57. a. Prepared Direct Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
- b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)
- *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*
58. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)
- *Utility procurement policies concerning gas-fired cogeneration facilities.*
59. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
- b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)
- *Electric rate design issues that impact customers installing solar photovoltaic systems.*
60. a. Prepared Direct Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
- b. Prepared Rebuttal Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)
- *Utility subscription to new natural gas pipeline capacity serving California.*
61. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
- b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)
- *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

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62. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)
- *Electric rate design issues that impact customers installing solar photovoltaic systems.*
63. a. Phase II Direct Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
- b. Phase II Rebuttal Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)
- *Natural gas cost allocation and rate design issues for large customers.*
64. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)
- *Natural gas cost allocation and rate design issues for large customers.*
65. a. Prepared Direct Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
- b. Prepared Rebuttal Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)
- *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*
66. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)
- *Electric rate design issues that impact customers installing solar photovoltaic systems.*
67. Prepared Rebuttal Testimony on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)
- *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

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68. a. Supplemental Prepared Direct Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
- b. Supplemental Prepared Rebuttal Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
- c. Supplemental Prepared Reply Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)
- *Local reliability benefits of a new natural gas storage facility.*
69. Prepared Direct Testimony on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)
- *Distributed generation policies; utility distribution planning.*
70. Prepared Reply Testimony on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)
- *Electric rate design for commercial & industrial solar customers.*
71. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)
- *Electric rate design for solar customers; marginal costs.*
72. a. Prepared Direct Testimony on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
- b. Prepared Rebuttal Testimony on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)
- *Natural gas pipeline safety policies and costs*
73. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)
- *Electric rate design for solar customers; marginal costs.*
74. Prepared Direct Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)
- *Natural gas pipeline safety policies and costs*

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75. a. Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
- b. Reply Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)
- *Ability of combined heat and power resources to serve local reliability needs in southern California.*
76. a. Prepared Testimony on behalf of the **Southern California Indicated Producers and Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
- b. Prepared Rebuttal Testimony on behalf of the **Southern California Indicated Producers and Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)
- *Allocation and recovery of natural gas pipeline safety costs.*
77. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)
- *Electric rate design for commercial & industrial solar customers; marginal costs.*
78. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)
- *Electric rate design for commercial & industrial solar customers; marginal costs.*
79. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)
- *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

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80. a. Prepared Direct Testimony on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
- b. Prepared Direct Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest, and the City of Palo Alto** (A. 13-12-012—August 11, 2014)
- c. Prepared Rebuttal Testimony on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
- d. Prepared Rebuttal Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest, and the City of Palo Alto** (A. 13-12-012—September 15, 2014)
- *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*
81. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)
- *Comprehensive review of policies for rate design for residential electric customers in California.*
82. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)
- *Electric rate design for commercial & industrial solar customers; marginal costs.*
83. a. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
- b. Prepared Rebuttal Testimony on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)
- *Time-of-use periods for residential TOU rates.*
84. Prepared Rebuttal Testimony on behalf of the **Joint Solar Parties** (R. 14-07-002 — September 30, 2015)
- *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*
85. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 15-04-012—July 5, 2016)
- *Selection of Time-of-Use periods, and rate design issues for solar customers.*

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86. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 16-09-003 — April 28, 2017)
- *Selection of Time-of-Use periods, and rate design issues for solar customers.*
87. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 17-06-030 — March 23, 2018)
- *Selection of Time-of-Use periods, and rate design issues for solar customers.*
88. Prepared Direct and Rebuttal Testimony on behalf of **Calpine Corporation** (A. 17-11-009 – July 20 and August 20, 2018)
- *Gas transportation rates for electric generators, gas storage and balancing issues*
89. Prepared Direct Testimony on behalf of **Gas Transmission Northwest LLC** and the **City of Palo Alto** (A. 17-11-009 – July 20, 2018)
- *Rate design for intrastate backbone gas transportation rates*
90. Prepared Direct Testimony on behalf of **EVgo** (A. 18-11-003 – April 5, 2019)
- *Electric rate design for commercial electric vehicle charging*
91. Prepared Direct and Rebuttal Testimony on behalf of **Vote Solar** and the **Solar Energy Industries Association** (R. 14-10-003 — October 7 and 21, 2019)
- *Avoided cost issues for distributed energy resources*
92. Prepared Direct and Rebuttal Testimony on behalf of **EVgo** (A. 19-07-006 – January 13 and February 20, 2020)
- *Electric rate design for commercial electric vehicle charging*
93. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 19-03-002 — March 17, 2020)
- *Electric rate design issues for solar and storage customers*

EXPERT WITNESS TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION

1. Prepared Direct, Rebuttal, and Supplemental Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. E-00000J-14-0023, February 27, April 7, and June 22, 2016).
 - *Development of a benefit-cost methodology for distributed, net metered solar resources in Arizona.*
2. Prepared Surrebuttal and Responsive Testimony on behalf of the **Energy Freedom Coalition of America** (Docket No. E-01933A-15-0239 – March 10 and September 15, 2016).
 - *Critique of a utility-owned solar program; comments on a fixed rate credit to replace net energy metering.*
3. Direct Testimony on behalf of the **Solar Energy Industries Association** (Docket No. E-01345A-16-0036, February 3, 2017).
4. Direct and Surrebuttal Testimony on behalf of **The Alliance for Solar Choice and the Energy Freedom Coalition of America** (Docket Nos. E-01933A-15-0239 (TEP), E-01933A-15-0322 (TEP), and E-04204A-15-0142 (UNSE) – May 17 and September 29, 2017).

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits on behalf of the **Colorado Solar Energy Industries Association** and the **Solar Alliance**, (Docket No. 09AL-299E – October 2, 2009).
https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y
 - *Electric rate design policies to encourage the use of distributed solar generation.*
2. Direct Testimony and Exhibits on behalf of the **Vote Solar Initiative** and the **Interstate Renewable Energy Council**, (Docket No. 11A-418E – September 21, 2011).
 - *Development of a community solar program for Xcel Energy.*
3. Answer Testimony and Exhibits, plus Opening Testimony on Settlement, on behalf of the **Solar Energy Industries Association**, (Docket No. 16AL-0048E [Phase II] – June 6 and September 2, 2016).
 - *Rate design issues related to residential customers and solar distributed generation in a Public Service of Colorado general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

1. Direct Testimony on behalf of **Georgia Interfaith Power & Light and Southface Energy Institute, Inc.** (Docket No. 40161 – May 3, 2016).
 - *Development of a cost-effectiveness methodology for solar resources in Georgia.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)
 - *Costs and benefits of net energy metering in Idaho.*
2. a. Direct Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
b. Rebuttal Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)
 - *Issues concerning the term of PURPA contracts in Idaho.*
2. a. Direct Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — December 22, 2017)
b. Rebuttal Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — January 26, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

1. Direct and Rebuttal Testimony on behalf of **Northeast Clean Energy Council, Inc.** (Docket D.P.U. 15-155, March 18 and April 28, 2016)
 - *Residential rate design and access fee proposals related to distributed generation in a National Grid general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

1. Prepared Direct Testimony on behalf of **Vote Solar** (Case No. U-18419—January 12, 2018)
2. Prepared Rebuttal Testimony on behalf of the **Environmental Law and Policy Center, the Ecology Center, the Solar energy Industries Association, Vote Solar, and the Union of Concerned Scientists** (Case No. U-18419 — February 2, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony on Behalf of **Geronimo Energy, LLC**. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])
 - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

1. Pre-filed Direct and Supplemental Testimony on Behalf of **Vote Solar and the Montana Environmental Information Center** (Docket No. D2016.5.39, October 14 and November 9, 2016).
 - *Avoided cost pricing issues for solar QFs in Montana.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)
 - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*
2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)
 - *QF pricing issues in Nevada.*
3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)
 - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*
4.
 - a. Prepared Direct Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket Nos. 15-07041 and 15-07042 –October 27, 2015).
 - b. Prepared Direct Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 1, 2016).

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- c. Prepared Rebuttal Testimony on Grandfathering Issues on behalf of TASC, (Docket Nos. 15-07041 and 15-07042 –February 5, 2016).
- *Net energy metering and rate design issues in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

1. Prepared Direct and Rebuttal Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. DE 16-576, October 24 and December 21, 2016).
- *Net energy metering and rate design issues in New Hampshire.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)
<http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF>
 - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*
2. Direct Testimony and Exhibits on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)
 - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)
 - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

April 25, 2014: <http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1>

May 30, 2014: <http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443>

June 20, 2014: <http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2>

R. THOMAS BEACH
Principal Consultant

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2. Direct Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018; Docket E-100 Sub 158; June 21, 2019)
 - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)
2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)
 - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*
3. Direct Testimony on Behalf of the **Oregon Solar Energy Industries Association** (UM 1910,01911, and 1912 — March 16, 2018).
 - *Resource value of solar resources in Oregon*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)
<https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85>
 - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF TEXAS

1. Direct Testimony on behalf of the **Solar Energy Industries Association (SEIA)** (Docket No. 44941 – December 11, 2015)
 - *Rate design issues concerning net metering and renewable distributed generation in an El Paso Electric general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)
 - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)
 - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

Direct Testimony and Exhibits on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011)
<http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF>

- *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 167**

In the Matter of:) **JOINT INITIAL COMMENTS OF**
Biennial Determination of Avoided) **THE SOUTHERN ALLIANCE FOR**
Cost Rates for Electric Utility) **CLEAN ENERGY, NORTH**
Purchases from Qualifying Facilities –) **CAROLINA CLEAN ENERGY**
2020) **BUSINESS ALLIANCE, AND THE**
) **NORTH CAROLINA**
) **SUSTAINABLE ENERGY**
) **ASSOCIATION**

EXHIBIT B

2020 Emission Allowance Prices

NON-CONFIDENTIAL

Allowance Price Forecasts - Nominal\$/Ton

Year	Nox: Oct - Apr	Nox: May - Sep	SO2 - NC	SO2 - SC	CO2
2020	2.00	74.50	2.00	3.00	0.00
2021	2.00	74.50	2.00	3.00	0.00
2022	2.00	74.50	2.00	3.00	0.00
2023	2.00	74.50	2.00	3.00	0.00
2024	2.00	74.50	2.00	3.00	0.00
2025	2.00	74.50	2.00	3.00	0.00
2026	2.00	74.50	2.00	3.00	0.00
2027	2.00	74.50	2.00	3.00	0.00
2028	2.00	74.50	2.00	3.00	0.00
2029	2.00	74.50	2.00	3.00	0.00
2030	2.00	74.50	2.00	3.00	0.00
2031	2.04	75.99	2.04	3.06	0.00
2032	2.08	77.51	2.08	3.12	0.00
2033	2.12	79.06	2.12	3.18	0.00
2034	2.16	80.64	2.16	3.25	0.00
2035	2.21	82.25	2.21	3.31	0.00
2036	2.25	83.90	2.25	3.38	0.00
2037	2.30	85.58	2.30	3.45	0.00
2038	2.34	87.29	2.34	3.51	0.00
2039	2.39	89.03	2.39	3.59	0.00
2040	2.44	90.82	2.44	3.66	0.00
2041	2.49	92.63	2.49	3.73	0.00
2042	2.54	94.48	2.54	3.80	0.00

ITIAL