**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**
**DOCKET NO. E-100, SUB 158**

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|---|---|---|
| **In the Matter of:** | ) | |
| **Biennial Determination of Avoided Cost** | ) | **NCSEA'S INITIAL** |
| **Rates for Electric Utility Purchases from** | ) | **COMMENTS** |
| **Qualifying Facilities – 2018** | ) | |
| | ) | |

**Attachment 2**
**[PUBLIC]**

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**
**DOCKET NO. E-100, SUB 158**

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|---|---|---|
| **In the Matter of:** | ) | |
| **Biennial Determination of Avoided Cost** | ) | **AFFIDAVIT OF** |
| **Rates for Electric Utility Purchases from** | ) | **R. THOMAS BEACH** |
| **Qualifying Facilities – 2018** | ) | |

I, R. THOMAS BEACH, being first duly sworn, do depose and say:

PURPOSE

1. My name is R. Thomas Beach. This affidavit was prepared at the request of the North Carolina Sustainable Energy Association ("NCSEA"), for use in Docket No. E-100, SUB 158.

2. This affidavit, and bits supporting materials contained in Exhibit Beach-1, respectfully provide certain factual evidence and expert opinion concerning the avoided cost rates proposed by Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP") and Virginia Electric and Power Company d/b/a Dominion Energy North Carolina ("DENC") (collectively, the "utilities"), as filed in this docket on November 1, 2018. In addition to preparing this affidavit and the accompanying materials, NCSEA has retained me to analyze specific issues in the utilities' initial statements, to assist with the preparation of discovery requests on those issues, to review the responses to that discovery, to respond to relevant material filed in this docket by the North Carolina Public Staff ("Staff") and other parties, and to recommend to the Commission for its consideration how to resolve the disputed issues in this proceeding.

QUALIFICATIONS

3. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

4. I earned my B.A. degree from Dartmouth College, graduating in 1977 with high honors in physics and honors in English. I received a Master of Engineering degree in mechanical engineering from the University of California at Berkeley in 1980. I am a registered professional engineer in the state of California.

5. I have more than 35 years of experience in utility analysis, resource planning, and rate design. I began my career on the staff at the California Public Utilities Commission (CPUC), working from 1981-1984 on the initial implementation in California of the Public Utilities Regulatory Policies Act (PURPA) of 1978. I also served for five years (1984-1989) as a policy advisor to three CPUC commissioners. Since entering private practice as a consultant in 1989, I have prepared expert testimony and served as a witness in a wide range of utility proceedings before many state utility commissions. This includes sponsoring testimony on a range of PURPA-related issues, including testimony on the calculation of avoided cost prices, in state regulatory proceedings in North Carolina, California, Idaho, Montana, Nevada, Oregon, Utah, and Vermont. In North Carolina I testified on behalf of NCSEA in the 2014 avoided cost docket, Docket No. E-100, SUB 140. I also have extensive experience on public policy issues related to the development and deployment of solar generation, both photovoltaic ("PV") and solar thermal. This includes assessing the costs and benefits of both small, distributed solar and large, utility-scale systems. My full CV is included as Exhibit Beach-2.

## PREPARATION

6. I have reviewed the Commission's December 31, 2014 Order Setting Avoided Cost Input Parameters (the "Sub 140 Order"); the October 11, 2017 Order Establishing

Standard Rates and Contract Terms for Qualifying Facilities (the "Sub 148 Order"); the utilities' Initial Filings in this proceeding; certain of the utilities' responses to discovery in this proceeding; the utilities' 2018 Integrated Resource Plans submitted in Docket No. E-100, Sub 157; and House Bill 589.

7. I have prepared a report on certain issues related to the utilities' avoided cost proposals in this docket. This report is attached as Exhibit Beach-1. This affidavit will provide a brief summary of the recommendations of that report.

## NATURAL GAS FORECAST

8. DENC and DEC/DEP have presented the Commission with disparate approaches to forecasting natural gas prices, as they have in prior avoided cost proceedings, with the result that DENC and DEC/DEP have significantly different forecasts for the next 10 years of gas prices in the benchmark Henry Hub market. DENC uses a forecast that is based on gas forward market prices for the initial 18 months, then transitions to a fundamentals forecast by 36 months. In contrast, DEC/DEP's gas forecast uses a full 10 years of forward market prices.

9. I support an approach similar to DENC's, using gas forward market prices as the forecast for no more than the first two years. 99% of the volumes transacted in the gas forward market are for contracts within the first two years; this is the period in which the market is deep and liquid, conveys the most accurate information, and is a reasonable forecast of future spot gas prices. After the first two years, the forecast should transition to the average of a set of fundamentals forecasts by year five. For the set of fundamentals forecasts, I recommend the use of the average of the private ICF forecast used by DENC and the just-released *2019 Annual Energy Outlook* Henry Hub forecast from the Energy

Information Administration. Using recent fundamentals forecasts from several sources avoids reliance on a single forecasting approach.

### Natural Gas Hedging Costs

10. Renewable QF generation provides a long-term physical hedge against volatile natural gas prices for the full 10-year term of the standard offer PPA. The natural gas hedging costs that have been included in avoided cost rates in the past are too low, because they represent the cost to fix gas prices for just 1 or 2 years, not the 10-year hedge provided by a renewable QF PPA. I recommend that the Commission use an approach to calculating long-term hedging costs developed for the Maine PUC. This approach determines the cost to fix upfront the cost of the natural gas displaced over 10 years by the output of the renewable QF. This method results in gas hedging costs of about $0.007 per kWh, using NCSEA's recommended gas price forecast.

### Firm Fuel Supplies for the Avoided CT

11. A significant share of the utilities' avoided capacity costs is now allocated to the winter months. The combustion turbine (CT) peaker that is the basis for QF avoided capacity costs requires a firm fuel supply to operate in peak winter periods. A firm winter fuel supply requires either firm pipeline capacity to assure delivery of natural gas at a time when pipelines often are constrained, or a capability to burn an alternate fuel (i.e. oil). Firm pipeline capacity appears to be the least-cost option, given today's oil prices. The additional costs needed to firm the CT's fuel supply should be added to the CT costs used as the basis for QF capacity rates in the winter months.

## Integration Costs: Critique of the DEC/DEP Modeling

12. I discuss the costs and benefits associated with integrating QF generation into the utilities' transmission and distribution (T&D) systems, critiquing the integration cost study prepare by Astrape Consulting on behalf of DEC and DEP. This study is fundamentally flawed in several respects. First, it assumes that DEC and DEP are an island, when in reality the interconnections of these utilities with neighboring power systems will reduce significantly the costs to integrate higher penetrations of solar resources. Real world experience with the new energy imbalance market in the western U.S. shows that regional cooperation can reduce substantially the costs of integrating high penetrations of renewable wind and solar generation. Second, the Astrape study assumes that future solar resources will not be able to supply ancillary services. This is not a reasonable assumption; utility-scale solar projects have already demonstrated this capability, and recent modeling of another utility in the U.S. Southeast shows that allowing solar resources to provide such services will be the least-cost way to integrate higher penetrations of solar. Finally, DEC/DEP assume that future solar will resemble today's solar installations, when in all likelihood, in response to changing price signals, a significant share of future solar projects will include storage. The storage that is paired with solar will be a firm source for a range of ancillary services, substantially reducing or eliminating integration costs. Solar projects that include significant storage should not be assessed integration costs, and all future solar projects should be allowed to provide ancillary services to the utility.

### <u>Integration Benefits: Avoided T&D Capacity Costs</u>

13. The utilities' proposed integration charges do not consider the benefits of integrating QF resources into the utilities' systems, despite the Commission's admonition in past avoided cost cases that both the costs and benefits of integrating QFs need to be considered.[1] In particular, the distributed output of appropriately-located small QFs will reduce peak loads on the utilities' transmission and distribution (T&D) systems, allowing the utilities to avoided capacity-related T&D costs. I present a calculation of these avoided costs for the North Carolina utilities at the system level, building off the avoided T&D capacity costs used for demand-side programs. I show how these avoided T&D costs can be allocated to the hours of the year, using peak capacity allocation factors (PCAFs) based on the hours when loads on the T&D system are highest. The PCAF-based allocation of avoided distribution costs uses a sample of loads at DEC's and DEP's distribution substations; I discuss how this data is a first step toward including more locational granularity in avoided cost rates. The rates for avoided T&D costs that I propose use the seasonal and time-of-day periods recommended by Dr. Ben Johnson's affidavit on behalf of NCSEA.

### <u>Other Integration Benefits</u>

14. It is well-known and widely observed that new renewable generation with zero variable costs reduces overall wholesale market prices. This provides a benefit for utility ratepayers broadly, by reducing the costs for market purchases; this "market price suppression" benefit has been quantified in several U.S. electric markets, at about 4% to 5% of avoided energy costs. I do not propose to include this impact in avoided energy

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[1] See December 31, 2014 Order in Docket No. E-100, Sub 140, at p. 39 and p. 61.

rates at this time but ask the Commission to acknowledge that this is a ratepayer benefit of integrating renewable QF generation.

NEED FOR HOSTING CAPACITY STUDIES

15. Finally, I propose that the Commission direct each of the utilities to undertake a comprehensive study of the ability of their T&D system to host distributed generation and storage resources. Such studies of a utility's "hosting capacity" for distributed resources have been completed in several other states, and similar studies make sense in North Carolina given the leadership position that the state has assumed in the deployment of distributed generation resources, particularly solar.

FURTHER THE AFFIANT SAYETH NOT.

This the 9th day of February, 2019.

R. Thomas Beach

R. Thomas Beach

Sworn to and subscribed before me
this the 09th day of February, 2019.

Notary Public Collin Becker

My commission expires: April 09, 2019

(Seal)

COLLIN BECKER
COMM. # 2106174
NOTARY PUBLIC - CALIFORNIA
ALAMEDA COUNTY
My Comm. Exp. 4-9-2019

# Exhibit Beach-1

## I. Introduction

On behalf of the North Carolina Sustainable Energy Association (NCSEA), this report addresses a set of specific issues in this avoided cost proceeding and supplements Dr. Ben Johnson's affidavit and reports on avoided cost rate design issues.

First, I address the natural gas issues raised by the avoided cost proposals of the North Carolina utilities. These include:

- the **10-year natural gas forecast,** a key input to the calculation of avoided energy costs:
- how to value **the long-term physical hedge** against natural gas price volatility that fixed-price renewable QF generation provides; and
- the **cost premium** that is required to provide firm fuel supplies for combustion turbine peakers during the winter months, a premium which should be included in the QF capacity price.

Second, I discuss the costs and benefits associated with integrating QF generation into the utilities' transmission and distribution (T&D) systems. I critique the integration cost study submitted by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP). This study is flawed by treating the Duke utilities as an island and by assuming that solar (or solar plus storage) resources cannot provide ancillary services. In addition, QFs reduce peak loads on the utilities' T&D systems, thus avoiding T&D capacity costs. I quantify these avoided T&D costs, which are a direct ratepayer benefit of integrating significant amounts of small, distributed QF generation. These benefits exceed the integration costs calculated in the DEC/DEP study. Next, I comment on the additional benefit for ratepayers from the fact that new renewable generation with zero variable costs reduces overall wholesale market prices. Finally, I propose that the Commission direct each of the utilities to undertake a comprehensive study of the ability of their T&D system to host distributed generation and storage resources. Such studies of a utility's "hosting capacity" for distributed resources have been completed in several other states, and similar studies make sense in North Carolina given the leadership position that the state has assumed in the deployment of distributed generation resources, particularly solar.

## II. Natural Gas Issues

### A. Natural gas forecast

The forecast of delivered natural gas prices is a key input into the calculation of avoided energy costs. On this issue, the utilities have taken the same positions in this docket that they took in the 2016 avoided cost case (E-100 Sub 148). Dominion Energy North Carolina (DENC) uses a forecast that is based on gas forward market prices for the initial 18 months, then transitions by 26 months to a fundamentals forecast from the consulting firm ICF. In contrast, DEC/DEP's gas forecast uses a full 10 years of forward market prices before moving to a fundamentals forecast. Practically, this means that the fundamentals forecast does not impact the avoided energy costs for a 10-year QF power purchase agreement (PPA).

The Commission's order in the 2016 case approved DENC's forecast and also adopted a compromise for DEC/DEP that uses 8 years of forward market prices, then 2 years of a fundamentals forecast. This was a compromise between the DEC/DEP proposal and the Public Staff's recommendation to use no more than 5 years of forward prices. The Commission thus 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 in this case.

The following **Figure 1** shows the DENC and DEC/DEP 10-year gas forecasts submitted in this case and also illustrates the forecasts that would result from the Public Staff's proposal in E-100 Sub 148 and from the use of eight years of forwards that the Commission adopted in that docket. The figure also shows two fundamentals forecasts – the ICF projection used by DENC and the recently-released *2019 Annual Energy Outlook* (*2019 AEO*) forecast from the Energy Information Administration (EIA) – as well as an updated set of Henry Hub forward market prices from the January 10, 2019 market.

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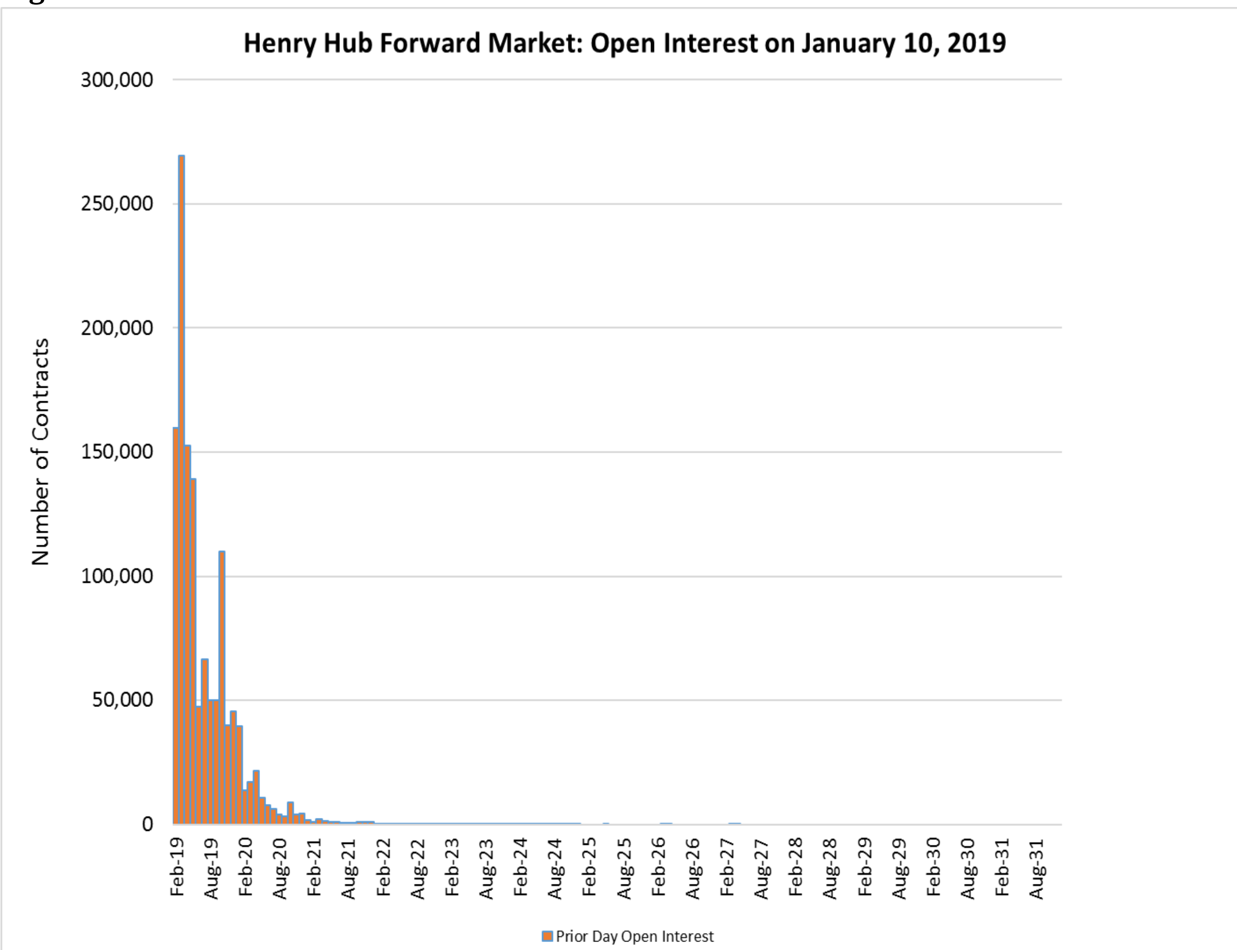
I have several issues with DEC/DEP's proposed gas forecast based on 10 years of forward market prices. First, the forward market for 10 years of natural gas at fixed prices is not transparent, broadly traded, or liquid. The open interest in the NYMEX gas forward market is almost entirely in the first two years. For example, **Figure 2** shows the open interest from the market on January 10, 2019. 99.0% of the open interest 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.

**Figure 2**




DEC/DEP's ability to purchase gas BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL for 10 years at close to the published 10-year forward prices is not dispositive. The DEC/DEP transactions are with financial institutions that may have a limited pool of counterparties for these transactions, but the utilities have not provided evidence of a deep and transparent market for 10-year gas transactions at fixed prices. As shown in **Table 1**, these fixed-price purchases represent BEGIN CONFIDENTIAL [redacted]

[redacted]

[redacted]

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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 I am not aware of substantial evidence that 10 years of

1 [redacted]

2 [redacted]

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/.

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 *2019 AEO* forecast considers the impacts of both the growing 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] EIA expects that increases in gas demand for electric generation will be driven by retirements of coal and nuclear capacity.[5] Fundamentals forecasts tend to be higher than forward market prices in falling markets (e.g. since 2010), but lag forward prices in rising markets (e.g. in the 2000s). 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.[6] 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.[7] 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.[8]

Having provided this context to staff at NCSEA, NCSEA supports a balanced forecast that uses forward market prices for the first two years, where the market is robust and deep, then transitions in the next three years to the average of a set of recent fundamentals forecasts. For the set of fundamentals forecasts, NCSEA will propose the use of (1) DENC's forecast from ICF and (2) the new *2019 AEO* forecast from EIA. As an alternative, NCSEA may also accept the

4 See *2019 AEO*, at pp. 73-76.

5 *Ibid*., at pp. 81-82.

6 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.

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

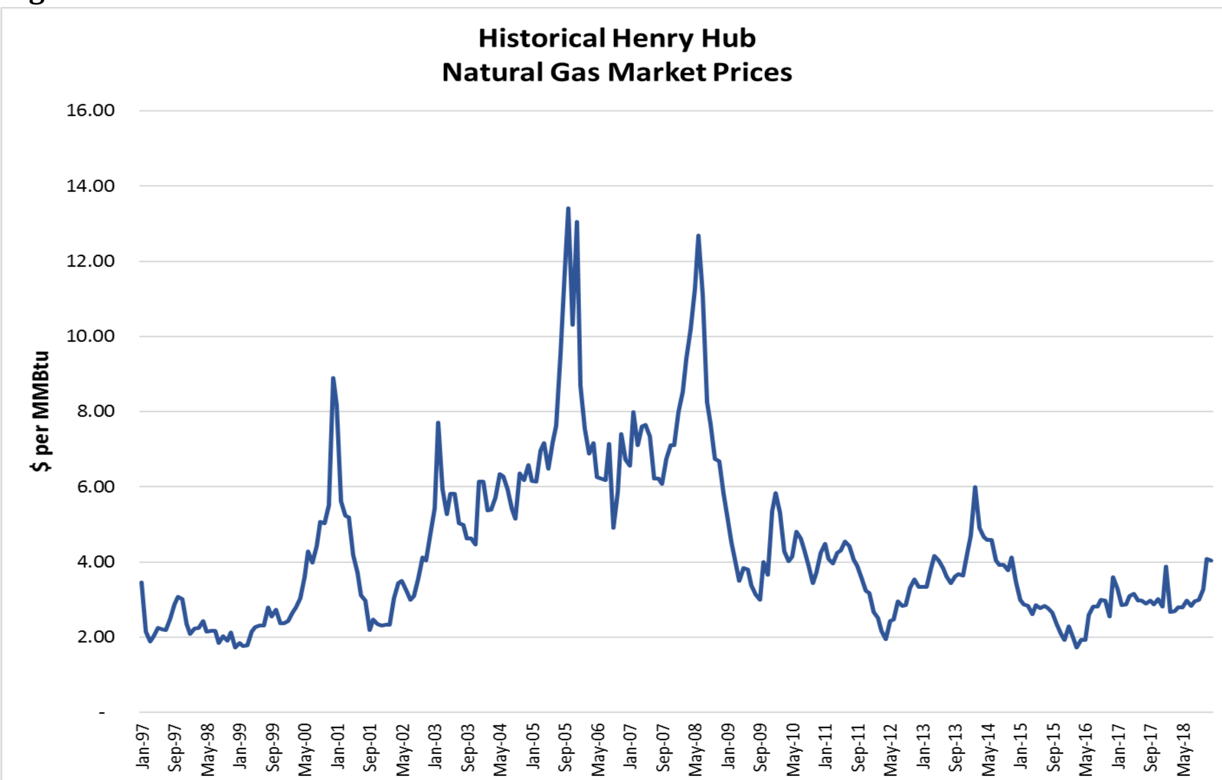
8 See *Joint Petition by Investor-Owned Utilities for Approval of Modifications to Risk Management Plans*, filed April 22, 2016 by Duke Energy Florida, Florida Power & Light, Gulf Power, and Tampa Electric in Florida Public Service Commission Docket No. 160096-EI, at ¶ 5.

use of DENC's similar forecast methodology (18 months of forwards, transitioning to a fundamentals forecast beginning at 36 months) for all of the North Carolina utilities.

### B. Fuel hedging benefits

Natural gas prices are volatile and uncertain, on multiple time scales. The history of Henry Hub spot price shows significant volatility over the last 20 years, as shown in **Figure 3**.[9]

**Figure 3**




There can also be significant price volatility on shorter time scales, as illustrated by the most recent year of Henry Hub prices shown in **Figure 4**.[10]

[9] Source for Figure 3: data compiled by EIA, at https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm.
[10] Source for Figure 4: https://markets.businessinsider.com/commodities/natural-gas-price.

**Figure 4**


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 above. 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 3,790 MW of solar that DEC and DEP anticipate to be on-line in the near future would displace about 143,000 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 a few years into the future.

In addition, renewable generation also hedges against market dislocations or generation scarcity such as was experienced throughout the West during the California energy crisis of 2000-2001 or as has occurred periodically during drought conditions in the U.S. that reduce hydroelectric output and curtail generation due to the lack of water for cooling.[11] 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

[11] For example, in 2014, the rapidly increasing output of solar projects in California made up for 83% of the reduction in hydroelectric output due to the multi-year drought in that state. This is based on Energy Information Administration data for 2014, as reported in Stephen Lacey, *As California Loses Hydro Resources to Drought, Large-Scale Solar Fills in the Gap: New solar generation made up for four-fifths of California's lost hydro production in 2014* (Greentech Media, March 31, 2015). Available at http://www.greentechmedia.com/articles/read/solar-becomes-the-second-biggest-renewable-energy-provider-in-california.

markets, and thus could replace a portion of their current budgets for risk management.[12] 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.[13]

In past avoided cost cases, the hedging benefit has been quantified using the Black-Scholes Model option pricing method. The hedging benefit calculated using this approach is too low and fails to fully value the long-term physical hedge that fixed-price renewable generation provides. The Black-Scholes method simply provides the cost of buying options to enable the purchase of 12- or 24-month gas at a fixed price.[14] When one such deal expires, one would have to renew it for the next 12 or 24 months at the then-prevailing market price for another one- or two-year 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 5 or 10 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.

I 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.[15] This study appears to have used the cost of call options in the over-the-counter gas futures market to calculate the hedging benefit.

More recently, the consultant Clean Power Research developed another approach to calculating the hedge value of renewables, as part of the Maine Public Utilities Commission's *Maine Distributed Solar Valuation Study*, released in 2015.[16] This method calculates the

[12] 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.

[13] 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."

[14] See Initial Statement of the Public Staff filed June 22, 2015 in E-100 Sub 140, at p. 36.

[15] 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.

[16] See Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (March 1, 2015); hereafter, "Maine Solar DG Valuation Study." Available at

additional costs to fix the fuel costs of a marginal gas-fired generator for a long-term period, compared to purchasing gas at prevailing short-term market prices on an "as you go" basis. The 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, removing the market risk that volatile gas prices could make gas-fired generation at times uneconomic.[17] I have used the Maine PUC method to calculate the 10-year hedging benefit of renewable PPAs in North Carolina, based on NCSEA's proposed gas forecast, current U.S. Treasury yields as the risk-free investments, the utilities' WACCs, and a marginal heat rate of 7,250 Btu per kWh. The hedging benefit calculated using the Maine PUC method with these assumptions is shown in Table 2 below, for NCSEA's gas forecast as well as the gas forecasts of DENC and DEC/DEP.

**Table 2**: *Avoided Fuel Hedging Costs ($ per kWh)*

| **Natural Gas Forecast** | **2019-2028 Average Henry Hub Gas Price** *($ per MMBtu)* | **2019-2028 Fuel Hedging Cost** *($ per kWh)* |
|---|---|---|
| NCSEA | 3.78 | 0.0073 |
| DENC | [redacted] | 0.0073 |
| DEC/DEP | [redacted] | 0.0052 |

### C. Adding firm pipeline capacity costs to the QF capacity price

In the "peaker method" used in North Carolina, the capacity price is based on the fixed costs of a combustion turbine (CT). The utilities allocate much of the capacity price to winter peak hours, corresponding to periods of cold weather when gas demand peaks and pipeline capacity can be constrained. In these circumstances, CTs need to be served with firm pipeline capacity, to be assured of receiving gas supplies, or to have a backup supply of an alternative fuel (oil). For this purpose, the North Carolina utilities both hold firm interstate pipeline

http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

[17] Another way to conceptualize the Maine PUC's method is to recognize that renewable generation has zero fuel costs, with upfront capital costs replacing fuel costs. To achieve a comparable outcome with gas-fired generation, one has to fix upfront the fuel costs for a long-term period. The funds required to do so is 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 marginal gas generation (or who purchases such power) 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 or more.

capacity and have duel-fuel capability at some of their CTs. There is, of course, a significant cost premium for either option. As a result, a reasonable premium should be added to the CT costs used to set the winter capacity price. BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL

## III. Integration Costs and Benefits

### A. Prior Commission orders

In its order in the 2014 avoided cost case, the Commission responded to a utility proposal to deduct from avoided cost rates certain costs of integrating renewable QF resources. The Commission declined to adopt those integration costs, and stated clearly that both integration costs and benefits needed to be quantified before either could be included in avoided cost rates.[19] In this case, DEC and DEP have produced a new integration cost study focusing on solar resources, prepared by Astrape Consulting.[20] Again, the utilities have asked that the resulting costs be subtracted from avoided cost rates. They present no analysis of any offsetting benefits from the growth of small, distributed solar resources in North Carolina. My analysis below will quantify several such integration benefits. These include the benefits for utilities and ratepayers that result from the ability of distributed solar to suppress market prices and to avoid costs for transmission and distribution capacity.

### B. Critique of the DEC/DEP integration cost study

I have reviewed and supports the critique of the Astrape Study prepared by Dr. Brendan Kirby on behalf of the Southern Environmental Law Center (SELC). Dr. Kirby's analysis concludes that the utilities' integration study is flawed in the following ways.

[18] See DEC/DEP response to NCSEA DR No. 5-7. The monthly gas price assumptions for DEC/DEP generating units are from the confidential PROSYM inputs; the CT heat rate is from the confidential PROSYM generating unit assumptions provided in response to NCSEA DR No. 1-8.

[19] See December 31, 2014 Order in Docket No. E-100, Sub 140, at p. 39 and p. 61: "The Commission finds that, while ultimately it may be appropriate for DEC, DEP and DENC to include the costs and benefits related to solar integration in their avoided cost calculations, such inclusion will be appropriate only when both the costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained."

[20] Astrape Consulting, *Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study* (November 2018), hereafter "Astrape Study."

- Modeled DEC and DEP as an isolated power system, without considering how they actually operate as part of the Eastern Interconnection.
- Developed an inappropriate one-day-in-ten-years loss-of-load reliability metric, instead of basing reserve requirements on the mandatory North American Electric Reliability Corporation (NERC) reliability standards under which Duke actually operates.
- Inappropriate accounting for the requirements for, and use of, contingency reserves.
- Improperly scaled solar plant intra-hour output variability data in a way that fails to accurately reflect geographic diversity benefits.
- Failed to identify under what specific operating conditions reliability was challenged or the specific added reserve requirements or changes in operating practices needed to cost effectively maintain reliability.

I concur with Dr. Kirby's critique of the Astrape Study and offer the following additional observations.

**Lack of a regional analysis.** I would like to expand upon the first flaw in the Astrape work that Dr. Kirby cites: the study's assumption that DEC/DEP are an island not connected to the rest of the Eastern Interconnection. Experience with the new Energy Imbalance Market (EIM) on the western U.S. grid is demonstrating that expanded regional cooperation among utilities is a key to reducing integration costs and renewable curtailment, as the penetration of renewable wind and solar generation grows. The EIM market in the West includes both utilities in LMP-based markets (the three California IOUs in the CAISO) and many traditional vertically-integrated utilities in the other western states (Arizona Public Service, NV Energy, PacifiCorp, Idaho Power, Portland General Electric, and Puget Sound Energy), with more utilities planning to join the EIM in the near future. The share of renewable generation is growing on the systems of all of these western utilities, but they are sufficiently diverse in loads, resources, and geography that the expanded and more efficient interchange of power facilitated by the EIM is providing significant integration cost savings and reduced renewable curtailments across the region.

It is important to note that the EIM is designed to fit within each balancing area's traditional hourly scheduling procedures, and focuses on finding more efficient and mutually beneficial transactions in sub-hourly time frames. For this reason, the EIM has been quickly and widely accepted by utilities with different market structures, different state regulators, and varying resource mixes whose service territories cover most of the western U.S. grid.

Since the EIM began operations in 2014 through the third quarter of 2018, the benefits to the participants have exceeded $500 million plus 734 GWh of avoided renewables curtailment.[21] The EIM also provides significant savings in ramping requirements, as balancing areas with excess ramping capacity in one direction can supply the excess to other areas that need such ramping. Exploiting this diversity has produced savings in ramping requirements of 40% to

[21] See *Western EIM Benefits Report: Third Quarter 2018*, at pp. 3, and 13-14.

50%.[22] This real-world result is particularly important given that the solar integration costs identified in the Astrape study consist primarily of additional load following resources.[23] **Attachment RTB-1** to this report provides additional details on the EIM.

The success to date of the EIM shows that it is essential to model renewable integration costs from a regional perspective. Through regional innovations such as an EIM that can fit within traditional market and regulatory structures, integrating a growing penetration of renewable resources does not necessarily result in higher costs, but instead can produce significant savings for the ratepayers of participating utilities.

**Assumption that solar generation is inflexible.** The Astrape study appears to be based on the assumption that future solar resources will be procured under must-take contracts that do not allow the utility any flexibility in dispatching future solar resources and that assume that solar projects will be unable to provide ancillary services such as load following. This is not necessarily a reasonable assumption. Utility-scale solar projects have demonstrated the technical capability to provide a broad range of ancillary services, including upward regulation and load following, provided the necessary control systems are in place to operate the plant to provide those services.[24] Recent modeling of a southeastern U.S. utility under scenarios with high penetrations of solar have demonstrated that solar's value is maximized if it is operated in the most flexible manner possible, including allowing the solar resources the headroom to provide upwardly flexible ancillary services.[25]

**Considering solar plus storage.** Solar will also be paired increasingly with storage. The pairing allows the storage to qualify for the solar investment tax credit, reducing the cost of storage significantly, and substantially increasing the value of the combined resource to the system compared to solar alone. Dr. Johnson's testimony discusses at length the implications of the pairing of solar plus storage for the design of avoided cost rates. The Astrape Study does not model the capabilities of solar plus storage projects. The use of storage will reduce substantially the variability of solar output, because storage either can be dispatched by the utility or can be pre-programmed to discharge at a specific rate in certain peak hours. The storage that is paired with solar can become a firm source for a variety of ancillary services, including load following, regulation, and fast frequency response. This will substantially reduce or eliminate integration costs, and may provide important ancillary services to the grid for which the solar plus storage project should be compensated.

For the foregoing reasons and those cited by Dr. Kirby, it is my recommendation that, if the Commission approves the proposed solar integration charge, then no integration charge shall

22 *Ibid*., at pp. 16-17.

23 See Astrape Study, at pp. 45-52.

24 CAISO / First Solar / NREL, *Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant* (March 2017). Available at https://www.nrel.gov/docs/fy17osti/67799.pdf.

25 Energy and Environmental Economics, *Investigating the Economic Value of Flexible Solar Power Plant Operation* (October 2018), at pp 4, 33-35. Available at https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf.

be assessed on solar projects unless their integration benefits have been fully evaluated by the serving utility in a transparent manner and found to be outweighed by integration costs. In no case should solar projects that include significant storage (for example, a four-hour discharge capacity equal to at least 50% of the AC solar nameplate) be assessed any integration costs.

### C. Calculation of avoided T&D capacity rates

There are direct ratepayer benefits from integrating the distributed output of small QFs interconnected to the utilities' distribution systems. QF generation can reduce peak loads on the utilities' upstream transmission and distribution systems, allowing the utilities to avoid load-related T&D capacity costs. Distributed resources that interconnect directly to the distribution system produce power that is often entirely consumed on the local distribution system by the solar project's neighbors, reducing loads on the upstream portions of the distribution system and the higher voltage transmission system.[26] Thus, much like energy-efficiency and demand response resources, distributed QFs displace traditional central station generation sources which must use the utility T&D system to be delivered to customers. This makes available T&D capacity that can serve load growth and provide transmission capacity for future wholesale generation, avoiding the need over time to expand the T&D system.

Solar resources have a useful life of 20-30 years. As a result, distributed solar can avoid future T&D upgrade or expansion costs that are not within the shorter time horizons that utilities use for transmission and distribution planning. Even within the shorter-term planning processes for T&D, utilities in several areas of the U.S. increasingly are incorporating solar and other types of distributed energy resources (DERs) as "non-wires alternatives" that can be less expensive than grid upgrades. This represents a natural extension of the well-accepted use of energy efficiency and demand response resources to "manage" the growth of the demands for electric energy and capacity, thus avoiding the need to build more generation and transmission infrastructure.

DEC/DEP have already quantified their avoided T&D capacity costs, based on the long-term relationship between T&D investments and peak demand. These avoided T&D costs are show in **Table 3** below.[27] These values already are used to assess the benefits of energy efficiency programs. DENC's avoided transmission costs are assumed to be the PJM Interconnection costs for network integration transmission service.[28]

[26] BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL

[27] See DEP/DEP confidential response to NCSEA DR Nos. 4-1 and 4-2.

[28] The calculation of an avoided distribution rate for DENC is complicated by DENC's limited service territory in North Carolina and the significant amount of solar interconnected to its system in the state, with solar output backflowing through a significant number of the area's distribution substations. Although the fact that backflow is occurring does not eliminate the possibility that solar is avoiding distribution costs that DENC would incur "but for" the solar generation, it also raises the potential for abundant solar generation in a limited area to trigger the need for distribution system upgrades. If the

BEGIN CONFIDENTIAL

[redacted]

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To develop generally-applicable avoided cost rates, these avoided T&D costs must be allocated to the hours of the year. To do this, I have developed a set of "peak capacity allocation factors" (PCAFs) based on hourly data on system net loads[29] (for transmission) or loads at a representative sample of distribution substations (for distribution).[30] PCAFs are hourly allocation factors that give a non-zero weight only to those system or substation loads that are within 20% of the annual peak load for the system or at each substation, using this formula:

$$PCAF_s(h) = \frac{Max\,[0, (Load_s(h) - Threshold_s)]}{\sum_{k=1}^{8760} Max[0, (Load_s(k) - Threshold_s)]}$$

where:

$PCAF_s(h)$ = peak capacity allocation factor for the system (or substation *s*) in hour *h*,
$Load_s(h)$ = the load for the system (or substation *s*) in hour *h*, and
$Threshold_s$ = 80% of the annual peak load for the system (or substation *s*).

All hours where the system or substation load is below 80% of the annual peak load have a PCAF of zero. The use of PCAFs is a more granular application of cost allocation methods such as the top 100 load hours or loads in the coincident peak hour. It is a deterministic variant of the loss-of-load-expectation (LOLE) methodology used for generation capacity, and uses the same conceptual framework of identifying hours of the year when high loads may result in a capacity constraint on the system. The threshold used to calculate PCAFs, such as 80% of the load in the system or substation peak hour, ties into planning for T&D capacity because utilities use such

costs of those upgrades were borne by ratepayers, they could offset avoided load-related avoided distribution costs.

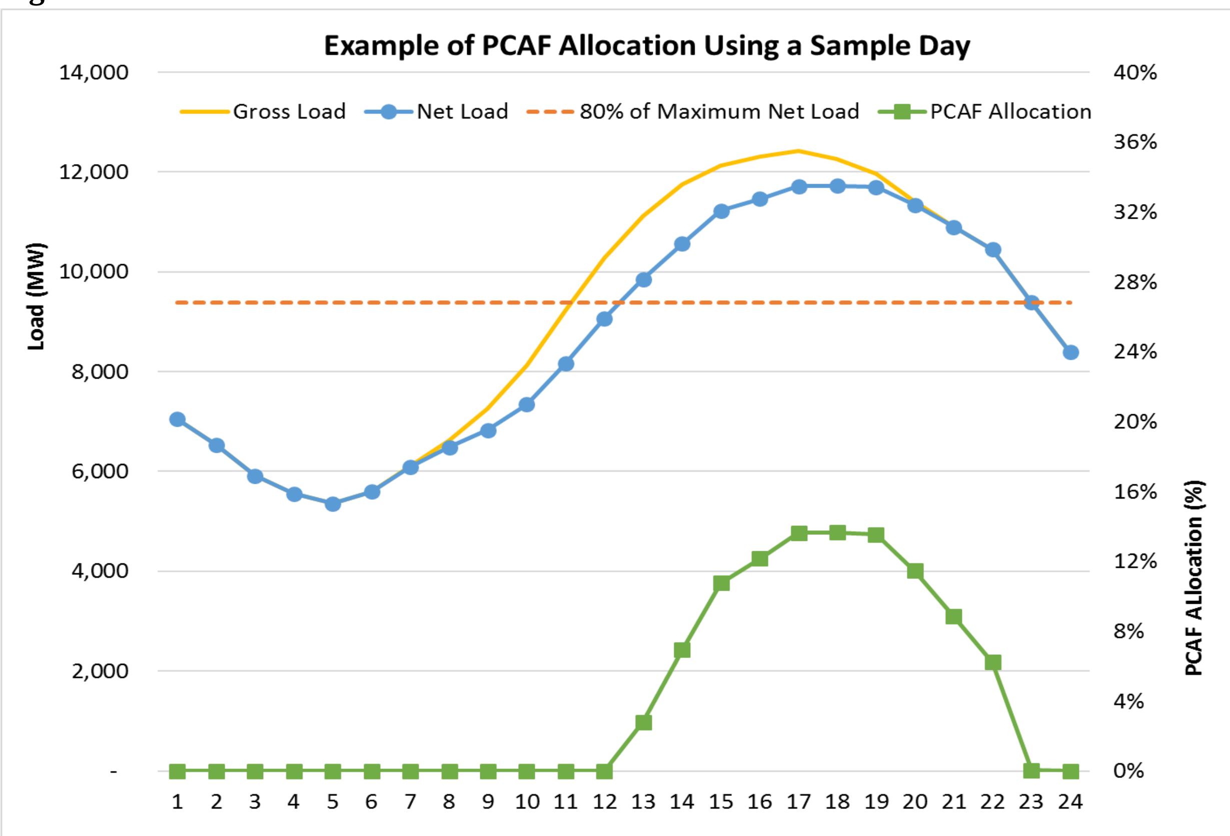
[29] The system net load is the load net of solar resources. This assumes that solar will serve loads on the distribution system, so the impact on the transmission system is the system load less the solar output.

[30] NCSEA requested substation load data for all of DEC's and DEP's distribution substations. Due to time constraints in assembling this data, the Duke utilities provided load data for what they believe to be a representative sample of 20 substations for each utility. See DEC/DEP response to NCSEA DR Nos. 4-3 and 4-4.

thresholds to identify when to plan for possible upgrades to circuits or substations whose loads exceed such thresholds.[31]

**Figure 5** shows a simple example of how a PCAF allocation is derived. This example calculates a PCAF distribution for just a single day with 24 hourly net loads (instead of the annual periods with 8,760 hourly net loads that I use to allocate avoided transmission costs). Only those hours with net loads that are above 80% of the peak hourly net load in hour ending (HE) 18 contribute to the PCAF allocation (the green line), and the hours with net loads closest to the peak are weighted more heavily than those that are just above the threshold.

**Figure 5**




[31] PCAF allocations are used by Pacific Gas and Electric and Southern California Edison to allocate marginal distribution costs across the hours of the year, in developing their time-dependent electric rates. See, for example, PG&E Testimony in California Public Utilities Commission (CPUC) Docket A. 16-06-013, Exhibit PG&E-9, Chapter 10, served December 2, 2016. The consulting firm Energy and Environmental Economics (E3) used PCAFs allocations for avoided subtransmission and distribution costs in developing the CPUC's Public Tool model for the cost-effectiveness of distributed solar systems in California. This model and the association documentation are available at http://www.cpuc.ca.gov/General.aspx?id=11285. The avoided subtransmission and distribution costs are shown in Lines 323-350 of the "Avoided Cost Calcs" tab; the PCAF allocation factors by TOU period are listed in Lines 352-371 of the same tab.

I have calculated hourly PCAF allocations for transmission from DEC's and DEP's system net loads for 2019. This is representative of the utilities' net loads for the amount of solar now online or under contract, i.e. "in the pipeline." In my opinion, this is the reasonable basis for calculating the avoided T&D rates to apply to the pricing of solar projects to be developed over the next several years.[32] **Figure 6** is a heat map showing the PCAF allocation for DEC's avoided transmission costs.

**Figure 6:** *Heat Map of DEC PCAFs for Avoided Transmission*

| | | Hour Ending | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | DEC | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
| Month | 1 | 0% | 0% | 0% | 0% | 0% | 0% | 2% | 4% | 4% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | 2 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | 3 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | 4 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | 5 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | 6 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 2% | 3% | 4% | 3% | 2% | 1% | 0% | 0% | 0% | 0% |
| | 7 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 3% | 4% | 5% | 6% | 6% | 5% | 3% | 1% | 0% | 0% | 0% |
| | 8 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 2% | 4% | 5% | 6% | 5% | 4% | 2% | 0% | 0% | 0% | 0% |
| | 9 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | 10 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | 11 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | 12 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

I developed hourly PCAF allocations for avoided distribution costs using the substation load data provided by DEC and DEP. I first computed a PCAF allocation at each substation. Then, to develop an overall system PCAF allocation for distribution, I computed a weighted average of the PCAF allocations for the substations, with the weights being the peak hour load at each substation.

The PCAF allocations for T and D are applied to the utilities' avoided transmission and distribution costs, to determine a set of hourly avoided T&D capacity costs. We have aggregated these hourly avoided T&D costs into the seasons and time periods recommended by Dr. Johnson. The result is the avoided transmission rates in **Table 4** and the avoided distribution rates in **Table 5**. I recommend that these avoided T&D rates should be paid to QFs which interconnect to the utilities' distribution systems.

[32] I did examine how PCAFs might be expected to change with the larger amounts of solar contemplated by HB 589 to be added over the next ten years, based on the net loads in the DEC and DEP workpapers. See DEC/DEP response to NCSEA DR Nos. 1-10 and 1-31. The changes to the PCAFs were not substantial. In addition, it is important to note that DEC's and DEPs projections of net loads assume that future solar additions will be standard solar projects without storage. This assumption is questionable given the major benefits of pairing solar with storage and the rapid decreases experienced recently in storage costs. Pairing solar and storage for a significant portion of future solar additions would have a significant impact on the future net load curve.

**Table 4:** *Avoided Transmission Rates ($ per kWh)*

| Season | Summer | | | Winter | | | Other/Shoulder | | |
|---|---|---|---|---|---|---|---|---|---|
| **Period** | **1** | **2** | **3** | **1** | **2** | **3** | **1** | **2** | **3** |
| **DEC** | 0.0167 | 0.0016 | -- | 0.0039 | 0.0006 | -- | -- | 0.0001 | -- |
| **DEP East** | 0.0133 | 0.0005 | -- | 0.0075 | -- | -- | -- | -- | -- |
| **DEP West** | -- | -- | -- | 0.0286 | 0.0068 | 0.0016 | -- | -- | -- |
| **DENC** | 0.0104 | 0.0141 | 0.0008 | 0.0344 | 0.0152 | 0.0085 | -- | -- | -- |

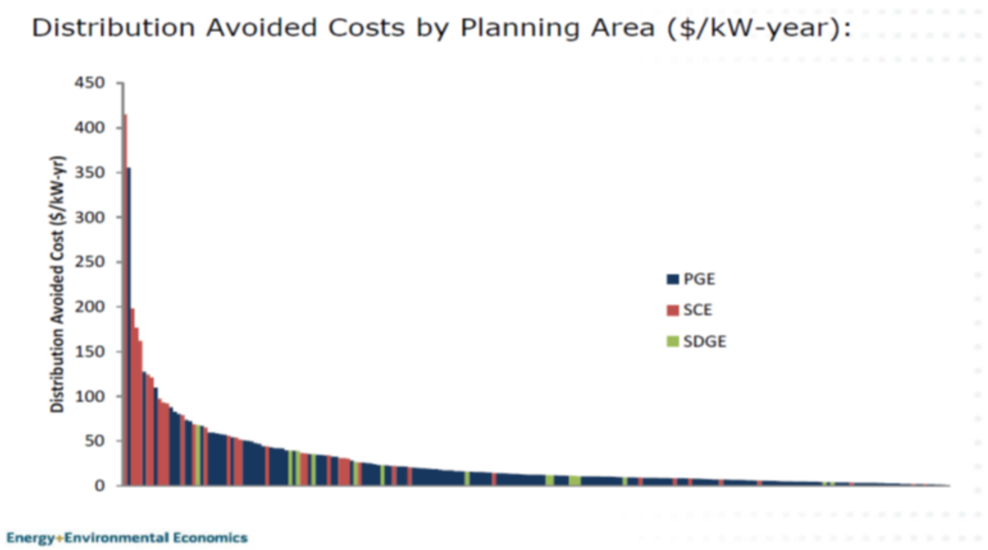
**Table 5:** *Avoided Distribution Rates ($ per kWh)*

| Season | Summer | | | Winter | | | Other/Shoulder | | |
|---|---|---|---|---|---|---|---|---|---|
| **Period** | **1** | **2** | **3** | **1** | **2** | **3** | **1** | **2** | **3** |
| **DEC** | 0.0115 | 0.0022 | 0.0004 | 0.0163 | 0.0124 | 0.0003 | 0.0002 | 0.0001 | 0.0003 |
| **DEP East** | 0.0048 | 0.0008 | 0.0001 | 0.0092 | 0.0042 | 0.0015 | 0.0004 | 0.0002 | 0.0002 |
| **DEP West** | -- | -- | -- | 0.0114 | 0.0081 | 0.0071 | -- | -- | -- |

The process used to develop the avoided distribution rates in Table 5 suggests how one could develop time-varying, locational values for avoided distribution costs. The substation data shows that some distribution substations are closer to capacity than others, and small, distributed solar resources (as well as other types of DERs) installed on those constrained parts of the distribution system will provide greater benefits than in other locations. In other words, there is significant variation in avoided distribution costs by location, and constrained parts of the distribution system will have avoided costs that are far higher than the system average. As an example, **Figure 7** shows the distribution avoided costs of the three large California electric utilities disaggregated by distribution planning area (DPA).[33] Some DPAs have distribution avoided costs that are significantly greater than other DPAs and much larger than the overall system average. Studies of other utilities in the U.S. also have demonstrated a wide range of marginal or avoided distribution costs.[34] Thus, if DERs – including distributed solar, storage, or energy efficiency programs – can be targeted to the parts of the system where they are most needed, i.e. where distribution avoided costs are the highest, they can produce significantly greater benefits than what are estimated using system-wide distribution avoided costs such as those presented in Table 5.

**Figure 7**

[33] E3, *Workshop Discussion: California Locational Net Benefits Analysis Update* (September 20, 2017 presentation in the New York REV process), at Slide 21.
[34] *Ibid*., at Slide 14.




In addition, the time profiles of distribution loads matter. Solar generation will be more effective at reducing peak loads and deferring upgrade costs at a substation that peaks in mid-afternoon in the summer than at a substation serving residential loads that peaks on summer evenings and winter mornings. At the substation which peaks in the evening, the more valuable resource would be solar with enough storage to shift significant output into the peak evening hours.

### D. Market price suppression

The zero-variable-cost output of wind and solar resources reduces market prices. New renewable generation will increase the electricity supplies available to the utilities, displacing the most expensive fossil-fired or market resources that the serving utility would otherwise have generated or purchased. The addition of this local generation will reduce the demand which the utility places on the regional markets for electricity and natural gas. With this reduction in demand, there is a corresponding reduction in the price in these markets, which benefits the utility when it does buy power or natural gas in these markets. This "market price response" benefit of renewable generation is widely acknowledged and has become highly visible in markets that now have high penetrations of wind and solar resources. The magnitude of these benefits will depend on the overall amounts of renewables on the grid in the southeastern U.S. This benefit reduces the ratepayer cost of market purchases, but does not necessarily depend on the utility being a net buyer in the wholesale power market, because a lower marginal cost of generation improves the competitiveness of market sales to others.

This benefit has been quantified. Beginning in 2010, the National Renewable Energy Laboratory (NREL) and GE Consulting undertook the Western Wind and Solar Integration Study (WWSIS), a major, multi-phase modeling effort to analyze much higher penetrations of wind and solar resources in the western U.S.[35] This modeling included analysis of the impact of

[35] The high penetration solar results from the WWSIS are reported in *Impact of High Solar Penetration in the Western Interconnection* (NREL and GE Consulting, December 2010), at p. 8 and

increasing solar penetration on market prices in the West; the results for spot prices in Arizona are shown in **Figure 8.** The high penetration solar cases (15% to 25% penetration) in the WECC resulted in 10% to 20% reductions in spot market prices.

**Figure 8:** *Impact of Solar Penetration on AZ Spot Prices, from WWSIS*

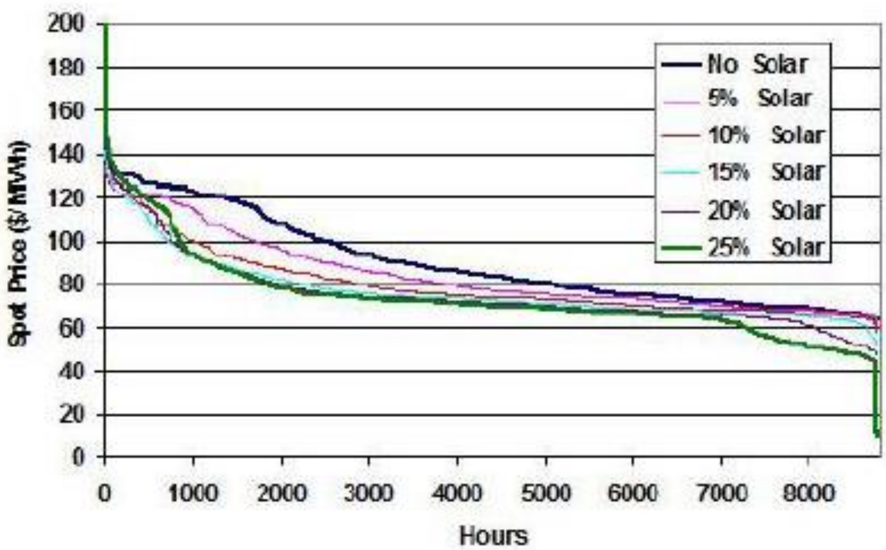



Figure 19 – Arizona Spot Price Duration Curves.

This benefit has been analyzed most extensively in the New England ISO market, where it is regularly included as part of the regional avoided costs used to evaluate the cost-effectiveness of distributed resources.[36] Based on this work, a market price suppression benefit of about 4% of avoided energy costs has been used for distributed solar in New England.[37]

Figure 19. This report, as well as all reports from the WWSIS, are available on the NREL website at https://www.nrel.gov/grid/wwsis.html.

[36] See Chapter 7 of the report on *Avoided Energy Supply Costs in New England*, March 27, 2015, at https://www9.nationalgridus.com/non_html/eer/ne/AESC2015%20merged%20report.pdf. Hereafter, "*AESC*" reports. MPR calculations are easier in regions with competitive energy markets based on transparent hourly locational marginal prices, such as New England.

[37] The New England states have done the most extensive work to calculate the MPR benefit, which they have labelled the Demand Reduction Induced Price Effect (DRIPE). DRIPE is included in the region's biennial *AESC* forecasts of avoided costs used for demand-side programs. I have reviewed the DRIPE calculations in the 2013 and 2015 AESC reports. See *2015 AESC*, at Appendix B, Tables One and Two, https://www9.nationalgridus.com/non_html/eer/ne/AESC2015%20merged%20report.pdf. There is a significant difference in the DRIPE impacts between the *2013* and *2015 AESC* reports, as a result of changes in the methodology for the DRIPE calculations in the *2015 AESC*. See *2015 AESC*, at pages 1-5 and 1-16 to 1-17. For example, the *2015 AESC* assumes a much shorter duration for energy DRIPE impacts (three years). The average of the energy DRIPE impacts between the two studies is a 4.1% to 4.5% reduction in 25-year levelized avoided energy costs. See *Direct Testimony of R. Thomas Beach on behalf of The Alliance for Solar Choice* in New Hampshire PUC Docket No. DE 16-576 (October 24, 2016), at Appendix D, p. D-5 (Table D-5).

I believe that the Commission should acknowledge that this is a ratepayer benefit of renewable QF generation in its order in this avoided cost docket.

### E. Integration capacity analysis

The key to "Building a Smarter Energy Future" is a robust interchange of information between the utility, its customers, and its suppliers. This includes the utility and its QF suppliers. The availability and exchange of more granular information on the utility's T&D system is a key to unlocking the smarter development of distributed resources in North Carolina.

As a first step, the Commission should adopt the systemwide distribution avoided costs presented above. The next step would be to develop distribution avoided costs on a more granular and locational basis (see Figure 7 above), as well as a complete set of substation-based PCAFs to enable a full understanding of the time profile of peak loads on the distribution system. This analysis would show on a granular basis where DG deployment would provide the greatest system benefits, and, as recommended by Dr. Johnson, could allow the development of location-specific distribution avoided costs that split the benefits between QFs and ratepayers from siting QFs in optimal locations.

More granular information on the distribution system also will streamline the interconnection process. QFs must pay the interconnection and upgrade costs necessary for the utility to be able to accept their power output into its system. QF developers have a strong interest in finding sites where the local grid has adequate capacity to accept their power, so they can move through the interconnection process quickly and at the lowest cost. Utilities in California, Hawaii, New York, and Minnesota have completed comprehensive analyses of the ability of their systems to host distributed resources, and then have made this "hosting capacity" data available to interested parties.[38] This information can guide developers to sites where there is adequate capacity to accept their power, thus simplifying and streamlining the interconnection process. In addition, a hosting capacity analysis also can be extended to other use cases, such as helping new business customers find sites where the grid has enough capacity to serve their new load. I recommend that the Commission encourage the North Carolina utilities to undertake systemwide hosting capacity analyses to provide detailed, granular information on the ability of their systems to host distributed generation projects.

[38] For a detailed explanation of states' experience to date with hosting capacity analyses, see Interstate Renewable Energy Council, *Optimizing the Grid: a Regulator's Guide to Hosting Capacity Analyses for Distributed Energy Resources* (December 2017).

# Attachment RTB-1

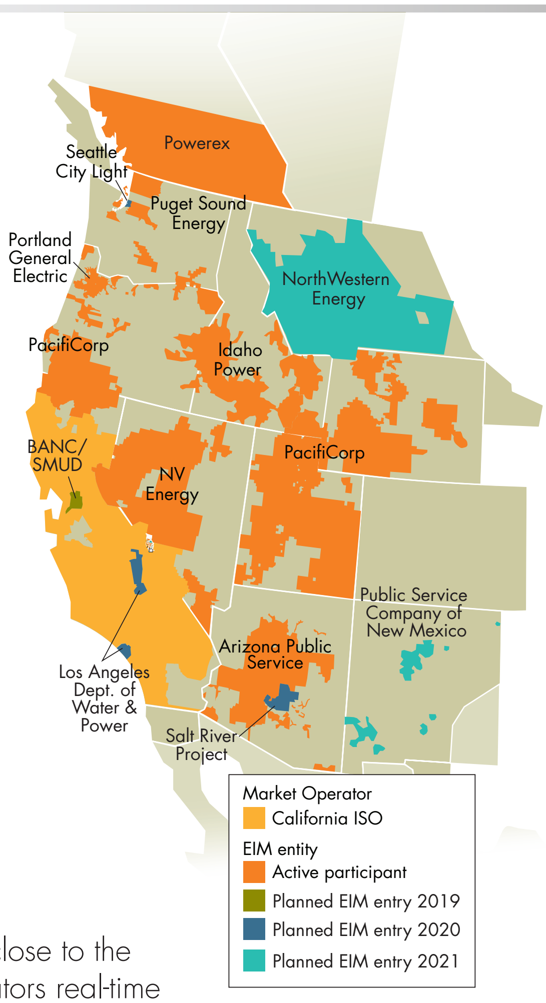
# Western Energy Imbalance Market FAQs

Source:
https://www.westerneim.com/Documents/EnergyImbalanceMarketFAQs.pdf

California ISO

# WESTERN EIM FAQ

## Expanding regional energy partnerships




### WHAT IS THE ENERGY IMBALANCE MARKET?

The ISO's Energy Imbalance Market (EIM) is a real-time energy market, the first of its kind in the western United States. EIM's advanced market systems automatically find low-cost energy to serve real-time consumer demand across a wide geographic area. Since launching in 2014, the western EIM has enhanced grid reliability and generated cost savings for its participants. Besides its economic advantages, the EIM improves the integration of renewable energy, which leads to a cleaner, greener grid.

### HOW DOES THE EIM WORK?

The EIM allows participants to buy and sell power close to the time electricity is consumed, and gives system operators real-time visibility across neighboring grids. The result improves balancing supply and demand at a lower cost. The EIM platform balances fluctuations in supply and demand by automatically finding lower-cost resources from across a larger region to meet real-time power needs. EIM also manages congestion on transmission lines to maintain grid reliability and supports integrating renewable resources. In addition, the market makes excess renewable energy available to participating utilities at low cost rather than turning the generating units off.

### WHO ARE THE CURRENT PARTICIPANTS IN EIM?

The ISO launched the western EIM on Nov. 1, 2014 with its first participant, Oregon-based PacifiCorp. Las Vegas-based NV Energy followed on Dec. 1, 2015, Puget Sound Energy of Bellevue, Washington, and Arizona Public Service of Phoenix, Arizona, on Oct. 1, 2016, Portland General Electric on Nov. 1, 2017, and Idaho Power and Powerex of Vancouver, British Columbia on Apr. 4, 2018. EIM is now serving consumers at lower cost in eight western states.

**WHAT ARE THE BENEFITS OF PARTICIPATING IN THE EIM?**

Increased regional coordination in generating and delivering energy produces significant benefits in three main areas:

- **Reduced costs for market participants by reducing the amount of** costly reserves utilities need to carry, and more efficient use of the regional transmission system.
- **Reduced carbon emissions and more efficient use and integration of renewable energy.** For instance, when one utility area has excess hydroelectric, solar, or wind power, the ISO can deliver it to customers in California or in one of the other seven western states served by EIM. Likewise, when the ISO has excess solar energy, it can help meet demand outside of California that otherwise would be met by more expensive — and less clean — coal or gas generation.
- **Enhanced reliability** by increasing operational visibility across electricity grids, and increasing the ability to manage transmission line congestion across the region's high-voltage transmission system.

**WHAT ARE THE BENEFITS TO THE ISO?**

Improved coordination and integration of renewable resources in the EIM provides a more cost-effective and accessible platform for California and other western states to gain real-time access to low-cost energy resources over the entire western region.

**WHAT ARE THE OTHER BENEFITS TO PARTICIPATION IN THE EIM?**

Easy and economical entry and exit.
Studies indicate that the benefits to all customers in the eight-state EIM footprint outweigh the costs of participating in the EIM. In addition, an EIM participant can choose to leave the market at any time with no exit fees.

Preserving autonomy
EIM participants maintain operational control over their generating resources, retain all their obligations as a balancing area, and must still comply with all regional and national reliability standards. For example, obligations to comply with standards, procuring ancillary services, physical scheduling rights and bilateral trades do not change with EIM.

**WHAT IS THE EIM GOVERNANCE STRUCTURE?**

The ISO Board of Governors appointed in May 2014 the EIM Transitional Committee to develop a long-term independent governance structure. Upon holding several open meetings throughout the West in 2015, the Committee completed a long-term governance proposal, which was approved by the Board on Dec. 18, 2015. The ISO Board seated a permanent EIM Governing Body in June 2016. Future members will be approved by the EIM Governing Body. Continued stakeholder involvement will be critical to the success of the EIM by offering valuable input and support to expand a market that can be leveraged to more effectively use resources in the West. See the EIM enhancements initiative page for the current status of activity.

**HOW CAN I LEARN MORE?**

The ISO has a website dedicated to EIM activities, with information on quarterly benefit studies, stakeholder meetings, Governing Body meetings and other important information. Please visit www.westerneim.com.

# Exhibit Beach-2

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.

## 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*

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.*

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.*

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.*

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.*

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.*

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.*

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.*

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.*

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.*

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.*

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*

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.*

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.*

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.*

**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).

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, 2104:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2

### 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).

### 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.