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April 12, 2019

ELECTRONIC PORTAL

Mr. Adam Teitzman, Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: **Docket No. 20190017-EG - In re: Commission review of numeric conservation goals (Florida Public Utilities Company).**

Dear Mr. Teitzman:

Attached for electronic filing in the referenced docket, please find Florida Public Utilities Company's Petition for Approval of Numeric Conservation Goals. Also included for filing are the Direct Testimony and Exhibit RJC-1 through RJC-4 of Robert Camfield and the Direct Testimony of G. Scott Ranck on behalf of FPUC, submitted in support of the Petition.

As always, thank you for your assistance. Please do not hesitate to contact me if you have any questions whatsoever.

Sincerely,

Beth Keating

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Gunster, Yoakley & Stewart, P.A.
215 South Monroe St., Suite 601
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MEK

Enclosures

Cc: Service List

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission review of numeric conservation goals (Florida Public Utilities Company).	) Docket No. 20190017-EG)) Filed: April 12, 2019)

PETITION FOR APPROVAL OF NUMERIC CONSERVATION GOALS BY FLORIDA PUBLIC UTILITIES COMPANY

Pursuant to Sections 366.82, Florida Statutes, and Rules 25-17.001, 25-17.0021, Florida Administrative Code, Florida Public Utilities Company ("FPUC" or "the Company"), by and through its undersigned attorneys, files this petition addressing the Company's proposed numeric conservation goals and asks that the Florida Public Service Commission ("Commission") accept and approve FPUC's proposal for the period 2020 through 2029. In further support of this Petition, FPUC states:

1. The Company is a public utility, subject to jurisdiction of the Florida Public Service Commission ("Commission") in accordance with Chapter 366, Florida Statutes. The Company's principal offices are located at:

Florida Public Utilities Company
1750 S. 14th Street, Suite 200
Fernandina Beach, FL 32034

2. The name and mailing address of the persons authorized to receive notices and pleadings are:

Beth Keating
Gunster Law Firm
215 S. Monroe Street, Suite 601
Tallahassee, FL 32301-1804
(850) 521-1706
bkeating@gunster.com

Mike Cassel, Assistant Vice President
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3. The Commission is vested with jurisdiction in this matter in accordance with Section 366.82, Florida Statutes, part of the Florida Energy Efficiency and Conservation Act ("FEECA"), Section 366.80 *et seq*., Florida Statutes, pursuant to which the Commission is required to adopt appropriate goals designed to increase the efficiency of energy consumption and the development of demand-side renewable energy systems and resources, increase the conservation of expensive resources, such as petroleum fuels, reduce and control the growth rates of electric consumption, and reduce the growth rates of weather-sensitive peak demand.[1]

4. The Company is unaware of any material facts in dispute at this time, but the proceeding may involve disputed issues of material fact. The Company's request does not involve reversal or modification of a Commission decision or proposed agency action. This is instead a Petition representing an initial request to the Commission, which is the affected agency located at 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399.

5. The instant docket is one of seven dockets opened by the Commission to establish numeric conservation goals for the electric utilities subject to FEECA. These dockets have been consolidated for purposes of hearing as set forth in the Order Consolidating Dockets and Establishing Procedure, Order No. PSC-2019-0062-PHO-EG, ("OEP") issued February 18, 2019, in each of the respective utility dockets[2] This Petition, as well as the accompanying testimonies and exhibits of Robert J. Camfield and D. Scott Ranck on behalf of FPUC, are submitted in compliance with that OEP.

6. As result of FPUC's analysis and the studies performed by Nexant, the Company respectfully proposes that it would be appropriate for the Commission to establish no

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[1] s. 366.82(2), F.S.

conservation goals - or expressed another way, numeric goals equating to zero - for the 10-year period 2020 through the end of 2029, as set forth in Attachment A to this Petition. FPUC's proposal is consistent with the evaluation required by Section 366.82, Florida Statutes, and would result in the establishment of "appropriate goals" for the Company as contemplated by Section 366.82 (2), Florida Statutes.

7. Although FPUC proposes that no mandated conservation goals be set for it for this 10-year cycle, the Company proposes to update its existing conservation programs and, subject to Commission approval of cost recovery through the Conservation Cost Recovery Clause, continue to offer those programs to its customers.

8. As noted, FPUC is filing, contemporaneously with this Petition, the Direct Testimony and Exhibits of Robert J. Camfield, who describes the development of the avoided cost inputs utilized in the studies of technical, economic, and achievable potential for cost-effective energy efficiency measures conducted for FPUC. FPUC is also co-sponsoring the testimony and exhibits of Nexant, Inc. witness Jim Herndon. Witness Herndon introduces and summarizes the methodology and findings of the Market Potential Studies that Nexant conducted for each of the seven FEECA utilities. FPUC is also submitting the Testimony of G. Scott Ranck, who provides a historical perspective on FPUC's conservation and demand-side management (DSM) programs and describes FPUC's evaluation process and rationale behind FPUC's proposed DSM goals for the next 10-year cycle, as well as its proposed approach for the continuation of its conservation programs over that same period.

9. As reflected in the testimony and exhibits of Witnesses Camfield, Herndon, and Ranck, FPUC's proposal that the Commission establish no numeric conservation goals for FPUC for the

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[2] Dockets Nos. 20190015-EG (FPL); 20190016-EG (Gulf); 201900170-EG (FPUC); 20190018-EG (Duke);

10-year period 2020 through the end of 2029 is reasonable and consistent with the requirements of Section 366.82, Florida Statutes, and Rule 25-17.0021, Florida Administrative Code.

WHEREFORE, FPUC respectfully requests that the Commission enter an Order that sets the Company's numeric conservation goals at zero, as proposed herein, for the period 2020 through 2029 and allow the Company to continue to update and offer its current conservation programs to customers.

RESPECTFULLY SUBMITTED this 12th day of April, 2019.

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Attorneys for Florida Public Utilities Company

20190019-EG (Orlando Utilities); 20190020 –EG (JEA); and 20190021-EG (TECO).

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing Petition for Approval of Numeric Conservation Goals for Florida Public Utilities Company, filed in the referenced docket, have been served by Electronic Mail this 12th day of April, 2019, upon the following:

Margo DuVal/Charles Murphy/Andrew King Florida Public Service Commission 2540 Shumard Oak Boulevard Tallahassee, FL 32399-0850 mduval@psc.state.fl.us cmurphy@psc.state.fl.us aking@psc.state.fl.us	J.R. Kelly / Patricia Christensen/Tad David/Mireille Fall-Fry Office of Public Counsel c/o The Florida Legislature 111 W. Madison Street, Room 812 Tallahassee, FL 32399-1400 Kelly.jr@leg.state.fl.us Christensen.patty@leg.state.fl.us david.tad@leg.state.fl.us fall-fry.mireille@leg.state.fl.us
Erik L. Sayler/Joan T. Matthews/Allan J. Charles Florida Department of Agriculture and Consumer Services The Mayo Building 407 S. Calhoun Street, Suite 520 Tallahassee FL 32399 allan.charles@FreshFromFlorida.com erik.sayler@FreshFromFlorida.com joan.matthews@FreshFromFlorida.com	

By: Beth Keating

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Attachment A

FPUC: Residential Conservation Goals			
Year	Summer Demand (MW)	Winter Demand (MW)	Energy (GWh)
2020	0.000	0.000	0.000
2021	0.000	0.000	0.000
2022	0.000	0.000	0.000
2023	0.000	0.000	0.000
2024	0.000	0.000	0.000
2025	0.000	0.000	0.000
2026	0.000	0.000	0.000
2027	0.000	0.000	0.000
2028	0.000	0.000	0.000
2029	0.000	0.000	0.000

FPUC: Commercial/Industrial Conservation Goals			
Year	Summer Demand (MW)	Winter Demand (MW)	Energy (GWh)
2020	0.000	0.000	0.000
2021	0.000	0.000	0.000
2022	0.000	0.000	0.000
2023	0.000	0.000	0.000
2024	0.000	0.000	0.000
2025	0.000	0.000	0.000
2026	0.000	0.000	0.000
2027	0.000	0.000	0.000
2028	0.000	0.000	0.000
2029	0.000	0.000	0.000

FPUC: Total Conservation Goals			
Year	Summer Demand (MW)	Winter Demand (MW)	Energy (GWh)
2020	0.000	0.000	0.000
2021	0.000	0.000	0.000
2022	0.000	0.000	0.000
2023	0.000	0.000	0.000
2024	0.000	0.000	0.000
2025	0.000	0.000	0.000
2026	0.000	0.000	0.000
2027	0.000	0.000	0.000
2028	0.000	0.000	0.000
2029	0.000	0.000	0.000

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20190017-EG

IN RE: COMMISSION REVIEW OF NUMERIC CONSERVATION GOALS

(Florida Public Utilities Company)

DIRECT TESTIMONY OF G. SCOTT RANCK

ON BEHALF OF FLORIDA PUBLIC UTILITIES COMPANY

I. Introduction

Q. Please state your name and business address.

A. My name is G. Scott Ranck. My business address is 331 W. Central Avenue, Suite 200, Winter Haven, Florida 33880.

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

A. I am employed by Florida Public Utilities Company (FPUC) as Energy Conservation Manager.

Q. Please summarize your educational background and professional experience.

A. Upon receiving certification in residential construction from Williamsport Area Community College (n/k/a Pennsylvania College of Technology), I began my career in construction building houses in Pennsylvania and North Carolina. I then pursued my Bachelor's Degree in Theology (Summa Cum Laude) from Piedmont International University, Winston-Salem, NC. Upon graduation, I was a pastor for almost 20 years and have since become a published author. I then pursued a career change and in 2006, went back to my construction roots as an employee of FPUC in the natural gas conservation department. I became a Residential Energy Services

Network (RESNET) Home Energy Rating System (HERS) Rater in February of 2009. I was subsequently promoted to Senior Energy Conservation Specialist with FPUC in January of 2012. In this role, I was responsible for implementing the Company's natural gas energy conservation program and also assisted with the implementation of FPUC's Electric Demand-Side Management (DSM) Program. Furthering my pursuit of additional training in building science, energy and related topics, I received certification as a Certified Energy Auditor (CEA) on January 25, 2011, as well as certification as a Certified Energy Manager (CEM) in April 2013. Both credentials are through the Association of Energy Engineers. I was also appointed to the Energy Technical Advisory Committee for the Florida Building Commission in December of 2016. Recently, I was promoted to Energy Conservation Manager with FPUC in March of 2019. In this new role, I oversee both natural gas and electric energy conservation programs for the Company.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is (1) to discuss FPUC's historical and ongoing commitment to conservation and demand-side management (DSM), (2) to describe the overall process employed to evaluate FPUC's proposed DSM goals for the next 10-year cycle, and (3) to explain FPUC's proposed DSM goals, as well as its approach to conservation programs.

Q. Are you sponsoring any exhibits with your testimony?

A. No, I am not.

Q. Please describe FPUC's service territory and the customers that FPUC serves.

A. Florida Public Utilities Company is an electric utility regulated by the Florida Public Service Commission (Commission) pursuant to Chapter 366, Florida Statutes. FPUC provides electric distribution service to more than 28,000 customers in two, non-contiguous service territories, referred to as the Northeast Division and the Northwest Divisions. The Northeast Division serves retail consumers on Amelia Island, including the City of Fernandina Beach. The Northwest Division serves consumers in the City of Marianna and the surrounding areas including portions of Calhoun, Jackson, and Liberty counties, located in the northern tier of Florida's panhandle region. Across FPUC's electric divisions, the Company serves mostly residential customers, as well as some commercial and industrial customers.

II. FPUC's Historical DSM Program

Q. Does FPUC currently offer DSM programs to its customers?

A. Yes, Conservation goals were first established by the Commission for FPUC in 1996 focusing on conservation programs that were cost-effective under the Ratepayer Impact Measure (RIM) and Participants Tests.

In 2008, FPUC participated in a collaborative with the other Florida utilities subject to the requirements of the Florida Energy Efficiency and Conservation Act, Sections 366.80 et seq., Florida Statutes, (jointly, FEECA utilities) to engage a single contractor, Itron, to identify DSM measures and evaluate the technical, economic, and achievable potential for DSM for each of the utilities' service areas.

In 2015, FPUC proposed adjustments to its DSM Plan based on revised conservation goals established for the Company by way of a proxy methodology approved by the Commission in Order PSC-2013-0645-PAA-EU. The revised DSM Plan was approved by the Commission as reflected in Order No. PSC-2015-0326-PAA-EU, and Consummating Order No. PSC-2015-0360-CO-EU.

In 2018, FPUC again collaborated with the other FEECA utilities to jointly engage an experienced outside engineering consultant (Nexant) charged with evaluating the technical, economic and achievable potential for DSM tailored to each of the utilities' service areas.

Q. Please explain FPUC's approach to DSM programs.

A. As suggested by FPUC's size, the Company's limited resources impact its approach to conservation and DSM. As such, educating customers on the benefits of energy efficiency and energy conservation is a key element of FPUC's DSM plan. The Company puts a heavy emphasis on promoting zero-cost or low-cost energy efficiency and conservation measures through the Company's customer education initiatives.

Q. Does FPUC have a Demand Response (DR) program?

A. No. FPUC does not have a true Demand Response program, although it has implemented time-of-use rates in its Northwest Division on an experimental basis. To date, DR has not been included in FPUC's goals.

Q. Please provide additional detail regarding FPUC's current demand-side management programs.

A Certainly. As noted previously, FPUC's 2015 Demand-Side Management Plan was approved in August of 2015. Under its current DSM plan, FPUC implemented the following programs: Residential Energy Survey, Residential Heating and Cooling Upgrade, Commercial Heating and Cooling Upgrade, Commercial Chiller and Commercial Reflective Roof.

Since 2015, program participation totals for the Residential Energy Survey program were 962 participants, while the Residential Heating and Cooling Upgrade experienced 1015 program participants during this period. Commercial Heating and Cooling Upgrade has experienced 6 total participants since 2015. The Commercial Chiller program has experienced 1 participant and Commercial Reflective Roof has experienced 60 participants.

In 2018, FPUC significantly exceeded the residential winter peak demand goal, the summer peak demand goal, and energy reduction goals. The main reason for this level of exceedance was due to the high participation rate in the Residential Heating and Cooling Upgrade Program. While FPUC fell short of the commercial /industrial winter peak and energy reduction goals, FPUC exceeded the total winter peak demand goal (Total Achieved 0.205 MW), the total summer peak demand goal (Total Achieved 0.403), and the total energy reduction goal (Total Achieved 0.851 GWh).

<u>III.</u> **<u>Evaluation of New Goals</u>**

Q. What cost-effectiveness test or tests should the Commission use to set new DSM goals for FPUC, pursuant to Section 366.82, F.S.?

A The Commission should use the results of the RIM Test as the threshold for setting DSM goals. If the results of the RIM test indicate a DSM measure may be cost-effective, then it should also be required to pass both the TRC test and the Participants test.

Q. How were potential new DSM measures identified and evaluated for FPUC for purposes of this proceeding?

A. New DSM measures were identified and evaluated by the engineering consultant for the FEECA utilities, Nexant.

Q. How was FPUC's achievable potential for the 2020 through 2029 period determined?

A. The achievable potential estimates for FPUC were developed by Nexant, and addressed in the testimony and Exhibit JH-6 of Jim Herndon.

Q. What are FPUC's estimated residential and commercial/industrial energy efficiency achievable potentials based on the RIM test?

A Nexant's analysis indicates that there is no achievable potential for either residential or commercial/industrial energy efficiency for FPUC based on the RIM test, as reflected in Witness Herndon's Exhibit JH-6.

Q. What are FPUC's estimated achievable potentials for residential and Commercial/industrial demand response?

A Nexant's analyses indicates that there is no achievable potential for either residential or commercial/industrial demand response for FPUC based on the RIM test.

Q. Is the demand response achievable potential included in FPUC's proposed DSM goals?

A No.

Q. Have any residential and commercial/industrial demand-side renewable energy technologies been identified as meeting the achievable potential standard under the RIM test?

A No. Nexant's analysis indicates that there is no achievable potential for residential and commercial/industrial demand-side renewable technologies for FPUC based on the RIM test.

Q. Do applicable building codes and requirements for appliance efficiencies impact the assessment of DSM technologies for FPUC under the RIM test?

A. Yes. The impacts of the stringent building code provisions of *the Florida Building Code, Energy Conservation* on DSM are taken into consideration in the analyses conducted by Nexant, as noted in section 4.2 EE Technical Potential of Witness Herndon's Exhibit JH-6, which is the *Market Potential Study of Demand-Side Management in Florida Public Utilities' Service Territory*. The existing building code provisions, as well as increased federal requirements regarding lighting efficiencies, as well as appliance efficiencies such as those mandated for water heaters and HVAC equipment, serve to further reduce the likelihood that any available technologies will pass the technical potential requirements of the RIM test for FPUC. I further expect that the building codes for the next DSM period will only become more stringent.

Q. Does the analysis conducted by Nexant provide an adequate assessment of the full technical potential of demand-side and supply-side conservation and efficiency measures available to FPUC, including demand-side renewable energy systems?

A Yes. Drawing upon their recognized expertise, Nexant utilized its models to comprehensively analyze the full technical potential of energy efficiency, demand response, and demand-side renewable energy technologies for FPUC, as described in the testimony of Jim Herndon, resulting in a reasonable assessment of the full technical potential of available demand-side and supply-side conservation and efficiency measures.

Q. Does the analysis conducted by Nexant provide an adequate assessment of the achievable potential of demand-side and supply-side conservation and efficiency measures available to FPUC, including demand-side renewable energy systems?

A Yes. As a non-generating utility, supply-side conservation and efficiency measures are not applicable to FPUC. The achievable potential study performed by Nexant does however provide a reasonable assessment of the achievable potential of available demand-side and supply-side conservation and efficiency measures, including demand-side renewable energy systems.

IV. Conclusions

Q. Should the Commission establish separate goals for demand-side renewable energy systems for the period 2020 through 2029?

A No. The Commission should not establish separate goals for FPUC for demand-side renewable energy systems. All conservation goals for FPUC should be established to promote cost-effective DSM without any bias towards any particular technology or program. Furthermore, if demand-side renewable energy systems are cost-effective, FPUC should have the flexibility to include such systems as part of their renewable portfolio or as part of their DSM goals.

Q. Should the Commission establish separate goals for FPUC for residential and Commercial/industrial customer participation in utility energy audit programs for the period 2020 through 2029?

A No. The Commission should not establish separate goals for residential and Commercial/industrial customer participation in utility energy audit programs. Utility energy audits are performed by FPUC in response to customers expressing an interest in such audits. The utility does not require that customers participate in energy audits. FPUC should be allowed the flexibility to integrate energy audits into its conservation programs as appropriate.

Q. Please identify the 2020 through 2029 projected technical potential for FPUC.

A The projected technical potential for FPUC is presented in section 5.2 EE Technical Potential, page 35 of the Nexant report titled *Market Potential Study of Demand-Side Management in Florida Public Utilities' Service Territory*, which is Exhibit JH-6 to Witness Herndon's testimony. The report concludes that there are no technologies meeting the technical potential criteria of the RIM test for FPUC.

Q. **What overall DSM goals (peak demand and energy reductions) are appropriate and reasonably achievable for FPUC for the 2020 through 2029 period?**

A Based on Nexant's evaluations using the RIM test, no DSM measures were shown to be cost-effective. Therefore, FPUC is requesting that the Commission establish no mandated DSM goals for FPUC for the 2020 through 2029 period.

Q. **Should DSM goals nonetheless be set for FPUC to reflect the costs imposed by state and federal regulations on the emission of greenhouse gases, pursuant to Section 366.82(3)(d), F.S.?**

A No. Greenhouse gases are not currently regulated at either the State or Federal level, and there currently are no costs imposed on the emissions of greenhouse gases. It is therefore not appropriate to base DSM goals on speculation regarding yet-to-be defined regulations of emissions of greenhouse gases.

Q. **Does FPUC propose to continue its existing conservation programs even though FPUC is requesting that no goals be applied based on Nexant's evaluations?**

A Yes. Although FPUC does not think that conservation goals should be established for FPUC for the next implementation period, FPUC proposes to update its existing conservation programs and, subject to Commission approval of cost recovery through the Conservation Cost Recovery Clause, continue to offer those programs to its customers. FPUC has invested significant cost and effort in the development and implementation of its existing conservation programs, such that, when considered as a whole, maintaining the existing offerings is marginally cost effective. FPUC strongly believes that maintaining its existing programs is in the best interests of the Company and its customers, many of whom are lower income and live in areas hard-hit by recent hurricanes. The existing programs provide not only conservation benefits consistent with the intent of FEECA, but also cost-management and cost-saving options for our most vulnerable customers.

Q. **Does this conclude your testimony?**

Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20190017-EG

IN RE: COMMISSION REVIEW OF NUMERIC CONSERVATION GOALS

(Florida Public Utilities Company)

DIRECT TESTIMONY OF ROBERT J. CAMFIELD

ON BEHALF OF FLORIDA PUBLIC UTILITIES COMPANY

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert J. Camfield. My business address is 800 University Bay Drive, Suite 400 Madison, WI 53705.

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

A. I am employed by Christensen Associates Energy Consulting, LLC in the capacity of Senior Regulatory Consultant.

Q. Please describe your background and professional responsibilities.

A. My professional background is concentrated in electricity and gas utility services. This work has focused predominantly on the numerous issues associated with resource decisions and the process of determining prices for utility services, as set by regulatory authorities.

Q. Please describe Christensen Associates Energy Consulting, LLC.

A. Christensen Associates Energy Consulting is an integral part of Laurits R. Christensen Associates. Our consulting group is a full-service consulting firm focused on applied economics, with four practice areas including transportation, energy, litigation support, and analytical support for the U.S. Postal Service. We have served the electricity and natural gas industry since 1976, and our senior staff has decades of experience including testimony and official reports on a variety of topics, as filed before numerous state and federal regulatory authorities in the U.S. as well as regulatory authorities overseas including Canada.

Q. Have you provided testimony before the Florida Public Service Commission?

A. I have testified before Florida regulators regarding a variety of topics including power supply agreements, projections of electricity demand, cost allocation, escalation rates of resource inputs, and cost of capital.

Q. Please state your educational background and experience.

A. I have many years of experience in the energy industry and the economics of regulation including resource decisions, regulatory governance and incentive plans, market restructuring, cost allocation, energy contracts, cost of capital, and performance benchmarking. I have testified on a host of topics including cost of capital and rate of return, demand for electricity, resource planning, transmission congestion, rate of return incentives, wholesale power agreements, cost benchmarking and corporate performance, power procurement processes, electric and natural gas rate design, and regulatory phase-in plans. I have assisted electric utilities to determine Open Access Transmission Tariff (OATT) prices for regulatory filings and the commercial terms of power supply agreements. I have served in the capacities of System Economist for Southern Company and Chief Economist for the New Hampshire Public Utilities Commission. I have also published articles in *The Electricity Journal*, *CIGRE (International Council on Large Electric Systems)*, *IEEE*

Transactions on Power Systems, and contributed sections to *Pricing In Competitive Markets* and *Electricity Pricing In Transition*, Kluwer Academic Publishers. My management experience includes numerous projects involving retail and wholesale markets in the U.S. and abroad. I have served as the program director for Edison Electric Institute's (EEI) Transmission and Wholesale Markets summer program. I am a graduate of Interlochen Arts Academy and hold an M.A. in Economics from Western Michigan University. My resume is attached as Exhibit No. 4__(RCJ-4).

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss Florida Public Utility Company's (FPUC) avoided costs, as utilized by Nexant Consultants for purposes of economic and achievable conservation and demand-side evaluations. The testimony which follows summarizes FPUC's projections of avoided costs and discusses the underlying methodology.

Q. Please describe how the testimony content is organized.

A. The testimony which follows is organized into several sections including I. INTRODUCTION; II. CONTEXT: MARKETS SERVED BY FLORIDA PUBLIC UTILITIES COMPANY; III. AVOIDED COSTS: DEFINITION AND STRUCTURE; IV. SUMMARY OF FINDINGS AND AVOIDED COST RESULTS; V. DISCUSSION OF METHODOLOGY.

Three exhibits are sponsored with my testimony, including Exhibit No. 1 _ [RJC-1] in support of the Summary section, and Exhibit No. 2 _(RJC-2) in the Result Details section. A copy of my resume is presented in Exhibit No. 3 _[RJC-3].

II. CONTEXT: MARKETS SERVED BY FLORIDA PUBLIC UTILITIES COMPANY

Q. Please describe Florida Public Utilities Company and arrangements for power supply.

A. Florida Public Utilities Company is an electricity distributor. FPUC provides electric service to more than 28,000 customers in two non-contiguous service territories, referred to as the Northeast and Northwest Divisions. The Northeast Division serves retail consumers on Amelia Island, located in the far Northeast corner of Florida and including the City of Fernandina Beach. The Northwest Division serves consumers in the City of Marianna and the surrounding area including portions of Calhoun, Jackson, and Liberty counties, located in Florida's panhandle region. Combined, FPUC's two electricity divisions serve non-coincident peak loads of 170 MW and energy consumption of 706,300 MWh, stated annually for 2018.

Rather than producing generation services from resources internal to the Company, FPUC has in place power supply agreements with regional wholesale suppliers for generation services, and purchases transmission services under the Open Access Transmission Tariffs (OATT) of the respective transmission service providers. Under the power supply agreements—sometimes referred to as full requirements services—FPUC purchases wholesale power and accompanying transmission services from Florida Power & Light (FPL) and Gulf Power Company. For its Northeast Division, Florida Public Utilities Company also purchases power from the new Eight Flags Combined Heat and Power (CHP) facility. In addition, FPUC's Northeast Division obtains intermittent power supply from two large industrial consumers, Rayonier Advanced Materials and West Rock Paper and Packaging Products.

The estimates of avoided costs presented below are for Florida Public Utilities Company's Northeast Division. The avoided cost outlook for FPUC's Northwest Division has not been estimated, as FPUC's power supply agreement with the Southern Company, which currently serves the Northwest Division, is nearing end-of-term. New commercial terms for generation and transmission supply will soon be put into place, possibly calling for major revisions in supply costs, both as a matter of level and of configuration.

III. AVOIDED COSTS: DEFINITION AND STRUCTURE

Q. What is avoided cost and how are estimates of avoided costs used?

A. "Avoided cost" refers to the resource cost savings associated with changes in the services provided. Sometimes referred to as marginal costs, avoided costs are particularly important to infrastructure industries such as electricity and gas utility services. By definition, avoided costs reflect cost savings at the margin: the reduction in the total cost incurred by service providers with respect to a change (decrease) in the level of services provided. Avoided costs are typically measured as \$/MCF in the case of gas services, and \$/MWh in the case of electricity. The avoided cost estimates presented below are for electricity services.

Resource cost savings—i.e., avoided costs—are highly specific to the timeframe in which services are provided to consumers. For this immediate proceeding before the Florida Public Service Commission (Florida PSC), the relevant application of avoided costs is electricity demand side resource options including demand side management (DSM), distributed energy resources (DER), and tariff design in the form of static and dynamic pricing options, together referred to as demand response (DR). As an example, a large industrial customer selects a dynamic pricing option with hourly day-ahead prices. Off-peak prices based on avoided costs are typically $35/MWh (3.5 cents/kWh), whereas peak hour prices may reach well above $200/MWh (20.0 cents/kWh). Compared to the standard tariff, we can expect that electricity consumption will rise somewhat during off-peak hours increasing costs by $35/MWh, offset by consumption decreases during on-peak hours, thus reducing total costs by $200/MWh.

In brief, avoided costs serve as the cost benchmark by which supply - and demand - side resource options are gauged. The selection of demand-side options often involves long-term commitments, much like supply options. Accordingly, the process of resource assessment employs estimates of avoided costs over extended future years. To this end, FPUC's avoided cost estimates reach forward through 2038.

Q. What is the structure of forward-looking avoided costs and how are they estimated?

A. Avoided costs reflect the underlying resource technologies used in the production and transport of electricity from locations where it is produced to locations where it is consumed. Given technologies, avoided costs are determined by the costs of inputs including fuel, capital, and operating expenditures for labor, materials, and outside services. Until the recent appearance of battery storage at viable cost levels, electricity could not be readily stored at a sizable scale. Hence, electricity production must match demand exactly, in real time. Cost arbitrage across timeframes (off-peak, peak) is not readily possible; as a consequence, avoided costs can vary dramatically over the course of hours or from one day to another.

Electricity services are generally defined according to commonly recognized functional activities including generation, transmission, and distribution services. Avoided costs are organized in similar fashion: the costs of generation and power delivery are estimated for energy and capacity dimensions, where energy costs within power delivery account for the costs associated with physical losses in transmission and distribution circuits and transformers.

Q. What is the perspective of FPUC with respect to avoided costs?

A. For the immediate purposes, avoided costs reflect the input costs that are expected to be paid for the generation and transmission services received under FPUC's power purchase agreement with FPL, referred to as Native Load Firm All Requirements Power and Energy Agreement (power supply agreement). This presents a potential challenge for avoided cost estimates: the charges paid for power—that is, the private costs incurred by FPUC for power supply—may vary inordinately from the economic costs of producing and delivering electricity. While unlikely, it is possible for substantial differences to arise because of several contributing factors such as the exercise of market power, the use of financial costs as the basis to set contract prices, or major resource imbalances. For FPUC, these conditions do not appear to hold: that is, the underlying prices paid by FPUC for power supply appear to reasonably approximate the underlying incremental costs (marginal costs) used by FPL to provide generation and transmission services.

Estimates of avoided cost for FPUC are projected for off-peak and peak load hours for individual months. Estimates of avoided costs are developed for, and thus align with—the three major components specified within FPUC's power supply agreement with FPL. These cost components are covered two service categories, referred to as Intermediate Block Service (IBS) and Load Following Service (LFS). Avoided transmission services cover the transmission services provided by FPL, as well as the conventional suite of ancillary services covered within FPL's OATT. Estimates of avoided generation and transmission costs are adjusted for estimates of power delivery line and transformer losses, including losses for distribution services.

IV. SUMMARY OF FINDINGS AND AVOIDED COST RESULTS

Q. Please discuss Florida Public Utility Company's projections of avoided costs for use in the FEECA evaluation studies.

A. Exhibit RJC-1 summarizes FPUC's estimates of avoided costs over years 2019-2038. Reported in nominal dollars for selected years, avoided costs are presented for off-peak and peak timeframes according to season and cost component. The seasonal definitions include the winter season covering the months of November through March, the off-peak season including the months of April and October, and the summer season covering the months of May through September. As discussed above, cost components align with the structure of the commercial terms of FPUC's power supply agreement with FPL and include separate charges for energy and non-fuel operations and maintenance (O&M) and referred to as *Non-Fuel Energy Price*, under both Intermediate and Load Following service categories and charged on a $/MWh basis; and charges for generation capacity under Load Following Service and billed as $-kW-month demand charges. As described above, avoided transmission capacity and energy costs (losses) take account of the transmission services provided under FPL's OATT, where charges for services are billed as $/kW-month demand charges under several transmission schedules.

A close review of Exhibit 1 gives rise to several observations. First, the overall average avoided costs rise by 3.0% annually through 2028, though fuel costs are expected to rise only modestly, from $2.90/MMBTU in 2019 to $3.17/MMBTU in 2028, an annual rate of change of 1%. In other words, avoided costs are rising at approximately 3 times faster than fuel costs, even though fuel charges are the major cost element within avoided costs. This difference in escalation between avoided costs and fuel costs is a consequence of the expected ongoing increases in electricity usage by FPUC's customers which, by assumption, are expected to rise 1% annually. Essentially, the progressively higher load levels over time result in sizable increases in the number of hours where LFS fuel charges are on the margin, in lieu of IBS fuel charges. This matters in a significant way: Stated on a $/MWh basis, as the input energy content (BTU) underlying LFS fuel charges are nearly 50% above input energy content for IBS fuel charges.

Second, projected generation capacity costs remain unchanged for years 2019-2028, per the FPU-FPL power supply agreement for LFS. For years beyond 2028 through 2038, projected capacity costs are declining, from $11.09/MWh to $10.15/MWh—a decrease of approximately 0.9% annually. This path of declining costs reflects the expectation of utility-scale solar power assuming a prominent position in FPL's portfolio of generation supply which, with battery storage capability, assists in the provision of capacity under LFS. Should these years beyond 2028 not include steadily increasing solar energy in the provision of capacity, on the margin, the baseline avoided cost scenario, overall, rises somewhat more rapidly, as charges for LFS capacity are higher. This condition holds, providing that the costs for the solar/storage resource bundle is less than the costs of natural gas supply. Analysis suggests that if capacity is satisfied exclusively with natural gas resources (single cycle combustion turbine technologies) in isolation of the solar/battery resource bundle, capacity costs under LFS can be expected to rise at approximately 2.6% annually.

Expectations of transmission charges are set according to the recent historical experience of FPL with respect to investment and operations and maintenance expenditures in transmission, stated on a $/mile of facilities basis. This history suggests that transmission OATT charges will rise by 2.5% annually over the forward period through 2038.

Taken as a whole, FPUC anticipates that its overall avoided costs for generation and transmission (G&T) charges will rise from $46.61/MWh in 2020 to $73.03/MWh in 2038, an average annual rate of escalation of 1.6%, and somewhat less than the expected overall price inflation across the U.S. economy. Nonetheless, it goes without saying: the evolution of wholesale prices for generation and transmission services paid by FPUC can assume a different path. Indeed, the long-term history of electricity prices reveals noticeable variation in the trends in electricity prices paid by consumers.

V. DISCUSSION OF METHODOLOGY

Q. Please describe the notion of avoided costs.

A. As alluded to above, avoided costs are a variant of marginal supply costs. By definition, marginal costs—and thus avoided costs—refers to the change in total supply cost with respect to a change in the quantity of supply. The quantity of supply—or the quantity of output supplied—refers to the production and delivery of goods and services. With few exceptions, costs are a positive function of supply: total costs rise with increases in supply and decline as supply decreases.

Q. Are avoided costs different from marginal costs?

A. No. Avoided electricity costs are a specific application of marginal costs and, apparently, originate with the Public Utility Regulatory Policies Act (PURPA) of 1978 and incorporated in rules by the Federal Energy Regulatory Commission in 1980. Avoided costs are *internal costs not incurred* (or foregone) by service providers as a consequence of reductions in load *or* increases in alternative supply such as the purchase of power from qualifying facilities defined under PURPA or renewable resources. Marginal costs are similarly defined: the incremental (decremental) cost impact arising from an increase (decrease) in the services provided by electricity service providers (utilities).

More generally, avoided costs capture the decremental cost impact resulting from a decrease in services provided by conventional utilities resources (generation, transmission, possibly distribution). In the context of the immediate analysis, the decrease in utility services provided as a result of DSM, would be supplanted by demand side resources. If demand side resources are available at lower costs than the internal economic costs associated with the provision of services, as provided by utilities, total costs decline. Depending on the relative position of average prices set according to financial costs and avoided costs, average prices can rise as the employment of demand side resources increases. An exception to this general observation is the well-known two-part tariff application of time-varying pricing, which is often the structure for implementing dynamic pricing.

Q. Please discuss the features of electricity services and how electricity characteristics impact avoided costs?

A. The costs of producing goods and providing services is specific to the technologies and processes of supply. This is particularly the case of electricity services, where avoided and marginal costs are highly differentiated by timeframe—and also by location. This feature of electricity services is a direct consequence of power system supply technologies. Power systems constitute highly integrated systems for the production and transport of electricity from locations where it is produced to locations where it is consumed. Electricity services are provided as a continuous flow, with only occasional interruption to supply.

Power systems have unusual characteristics and features. First, demand and supply must be balanced in real time in order to avoid system collapse—a sudden, near-instantaneous loss of supply. Thus, the production of electricity is virtually identical to demand within each moment of time, as electricity cannot be stored on a sizable scale—notwithstanding battery storage technologies. Non-storability also means that inventories cannot readily serve as a means of cost arbitrage. Second, electricity flows within power delivery circuits follow, exactly, physical laws.

Together, these power supply features mean that operators of power systems, in addition to ensuring real-time balance of production and demand, carefully monitor flows within transport systems including high voltage transmission and distribution circuits. Indeed, power flows across circuits must remain strictly within pre-defined operational boundaries set by the North American Electric Reliability Corporation (NERC).

Features of electricity supply have major cost implications. Avoided and marginal costs are highly sensitive to near-term availability of supply. As electricity loads approach supply constraints, costs can vary dramatically: over the course of a single day—or between a high load-high cost day and a normal load day—costs can vary by a factor of 10 to 1 or greater. On occasion, hourly avoided costs can range from well over $1000/MWh to less than $30/MWh, though typical peak period avoided costs approximate $65/MWh, or 6.5 cents/kWh.

Q. Please describe how FPUC's estimates of avoided costs are developed, and identify the major inputs used in the estimation process.

A. Estimates of forward-looking avoided costs are developed using simulation methods. Avoided cost estimates, simulated for 2019-2038, are based on known parameters, observed market prices where relevant, observed electricity demand, historical cost data, and various cost studies, reports, and surveys, as follows:

- *Known parameters* reflect the commercial terms of the FPUC's ten-year power supply agreement with Florida Power and Light;

- *Observed market prices* refer to the records of daily spot natural gas prices at Florida Gas Transmission's Zone 3 hub, and Henry Hub futures contracts traded on the Chicago Mercantile Exchange;
- *Observed demand* refers to the measured hourly loads of FPUC's Northeast Division;
- *Historical cost data* refers to the detailed historical cost experience of FPL as reported within the public domain;
- *Cost studies and reports* refer to the Regional Load and Resource Plan of the Florida Reliability Coordinating Council and the long-term projections of energy supply costs based on simulation tools, as reported in the *Annual Energy Outlook* published by the Energy Information Administration; and,
- *Cost surveys* refer to surveys of observed or estimated costs of power technologies including single cycle combustion turbine (CT) and solar power generation (stated on a $/MWh basis); historical labor costs (wages and salaries) reported by the Bureau of Labor Statistics; and the costs of renewable resources reported by the National Renewable Energy Laboratory.

Q. Can you please describe the approach utilized to estimate Florida Public Utilities Company's avoided costs?

A. Estimates of FPUC's avoided costs draw upon *short-* and *long-run* marginal cost concepts. The most relevant definition for cost analysis and program evaluation—including efficient pricing of electricity services—is *short-run cost*, estimated for either near-term or longer-term forward periods, and including energy and reliability. As a practical matter, however, short-run reliability costs are not directly observable. Fortunately, estimates of *long-run costs* can often serve as viable proxies for forward-looking short-run marginal costs.

Avoided cost estimates follow directly from estimates of the service quantities (customer loads), and the underlying costs of the resources available to serve loads. Florida's assessment of demand-side resources under FEECA involves avoided cost estimates over an extended forward period—approaching 2040. Accordingly, avoided cost estimates were developed for this long-term forward timeframe. In the case of loads, FPUC's avoided cost estimates are based on the 2018 hourly loads of FPUC's Northeast Division, served by FPL.

Q. Can you please discuss the service quantities that support FPUC's estimates of avoided costs?

A. For our purposes, the relevant loads for estimation of avoided costs are the hourly purchases of energy and capacity (generation, transmission) by FPUC under the power supply agreement and FPL's OATT. This load definition is net load delivered at FPUC's 138 kV transmission substation, constituting the sum of the hourly consumption of electricity of customers served by the Northeast Division under its retail tariff, minus power supply produced by on-site cogeneration facilities and the Eight Flags generator (approximately 20 MW).

The Northeast Division's net hourly purchases of energy and capacity are projected to rise by a modest 0.2% annually through 2028. As a matter of assumption, the Northeast Division's load levels (net purchases) are held constant at the 2028 level over the remaining forecast period for avoided cost estimates, 2029-2038. Pages 1 and 2 of Exhibit RJC-2 present the net hourly loads of the Eastern Division, shown as average hourly load profiles for 2018 and previous years for the months of January and July.

Q. Please discuss the process for determining resource costs included in FPUC's avoided cost estimates.

A. As alluded to above, FPUC's estimates of forward-looking avoided costs are structured in a manner similar to the FPUC-FPL power supply agreement covering generation services and, separately, transmission services. As mentioned, the charges for generation services include energy costs and capacity costs, as defined in the commercial terms of the IBS and LFS. The starting point is hourly load level, which determines whether IBS or LFS charges are on the margin.

Avoided energy costs include fuel costs and non-fuel operations and maintenance (O&M) costs, which are specific to IBS and LFS. Avoided capacity costs reflect LFS capacity charges. In the case of fuel costs, charges are differentiated according to heat rates. If the hourly load is equal to or less than 10.0 MW, IBS-based fuel and O&M cost estimates determine avoided costs; if the hourly load is greater than 10.0 MW, LFS-based fuel and O&M cost estimates coupled with LFS capacity costs determine hourly avoided costs. (Note, however, that avoided capacity costs do not necessarily appear in all hours where LFS resource costs are on the margin.)

Q. How has FPUC estimated avoided fuel costs?

A. Avoided fuel costs are driven by estimates of the natural gas purchase costs FPL, including pipeline transportation charges and commodity charges. Currently, the charges paid by FPL for gas transportation, relevant for FPUC'S estimates of avoided costs, are approximately $0.95/MMBTU under the pipeline tariff of Florida Gas Transmission (FGT). Under IB and LFS terms, gas commodity prices are set according to FGT Zone 3 wholesale gas prices. Analysis of daily gas prices over recent months suggest that, often, Zone 3 gas prices closely follow Henry Hub gas prices. This is a convenient result for purposes of avoided cost estimation: Henry Hub prices serve as a proxy for Zone 3 prices. In short, owing to the close parallel between Zone 3 and Henry Hub prices, FPUC's estimates of avoided fuel costs are based on Henry Hub gas futures prices, as settled on the Chicago Mercantile Exchange for monthly deliveries through year 2028, plus observed transportation charges.

Projections of natural gas prices for years 2029-2038 are based on forecast natural gas prices, as reported within the 2019 Annual Energy Outlook (AEO) published by the Department of Energy (DOE). For purposes of avoided cost estimation, FPUC has attenuated the annual rates of natural gas price escalation reported by DOE. The concern is potential forecast bias within AEO's projections of natural gas prices over recent years—an issue which is being further discussed.

Q. **Please discuss the methodology for estimating the non-fuel O&M cost component of FPUC's avoided energy costs.**

A. For supply provided under both IBS and LFS, projections of non-fuel O&M cost components, stated on a $/MWh basis, are specified through 2028 under the power supply agreement. Beyond 2028, non-fuel O&M costs for IBS and LFS supply are based on projections of non-fuel O&M costs for FPL's fleet of natural gas generators. Rates of non-fuel cost escalation are based on expected inflation, according to the difference between observed interest rate yields on 10-year U.S. Treasury Constant Maturity and Inflation Protected securities of approximately 2.00% (2.48% − 0.54% = 1.94%). Avoided non-fuel energy costs are, as a matter of assumption, separated into two components: external contract service and internal costs. For years beyond 2028, external costs escalation is set at 2.00%. The internal cost component incorporates two adjustments: an upward adjustment of 1.06 percentage points to account for economy-wide differences between labor costs and inflation, as observed historically; and a downward adjustment of 0.50 percentage points for expected productivity gains within FPL's gas generation function.

Q. Please review FPUC's methodology for estimating avoided generation capacity costs.

A. Avoided generation capacity costs are LFS cost components and are specified as $/kW-month demand charges with the power supply agreement through 2028.

For years 2029-2038, avoided costs are determined by the weighted combination of natural gas and solar/storage resource costs. The weights are determined by the relative shares of natural gas and solar/storage resources within FPL non-nuclear generation supply. The relative shares reflect the baseline scenario of FPL's future generation mix, as estimated. In turn, FPL's baseline generation mix, projected for 2029-2038, are determined by the all-in projected costs of FPL's natural gas supply and solar/storage technology costs, stated in terms of $/MWh.

For solar/storage technology, the path of future costs assumes a declining logistic function. Under the baseline scenario of FPL's generation mix, projected solar/storage technology costs are $49/MWh in 2029, declining to $44/MWh in 2038. The projected all-in costs of the counterpart electricity supply technology, gas-fueled generation, are $62/MWh and $73/MWh for 2029 and 2038 respectively. Owing to its inherent cost advantage under the baseline scenario for FPL, solar/storage assumes a progressively rising share of FPL's generation mix. Under the scenario, levels of natural gas supply reach a maximum of 99 TWh in 2025, declining to 66 TWh in 2038. This result appears to be fully in accordance with other long-term projections of generation mix, including recent editions of the Annual Economic Outlook.

Once determined, avoided capacity costs are distributed to hours of each month according to the likelihood that individual hourly loads would be the maximum hourly load for determining monthly capacity costs, as billed. This approach is non-linear and tends to distribute $/kW-month capacity costs across peak hourly loads. The outstanding issue is whether capacity should be distributed narrowly or broadly across hours. FPUC's estimates of avoided costs takes the latter approach: capacity costs are distributed fairly broadly across peak load hours, based upon a parameterized non-linear max function.

Q. Please review FPUC's methodology for estimating avoided transmission capacity costs.

A. Avoided transmission capacity costs are based on projections of FPL's OATT prices for transmission services. The estimates of OATT prices reflect projections of FPL's all-in financial costs for transmission services for 2020-2038. Transmission cost projections are based on FPL's historical cost records for transmission, as reported in its FERC Form 1 reports for years 1994 through 2016. These historical costs serve as a basis to determine trends in transmission cost expenditures, both capital and operating. Once estimated, the trends in cost experience are extended over future years which, reflected in OATT prices for transmission services, are expected to rise at 2.49% annually.

Avoided transmission capacity costs, stated on $/kW-month basis, are distributed to hourly peak loads in a manner similar to that used for generation capacity costs. Transmission capacity costs are distributed somewhat more narrowly than generation capacity costs.

Also, FPL's charges for transmission services under its OATT cover the resource costs associated with the conventional suite of ancillary services including Scheduling (AS1), Reactive Power and Voltage Support (AS2), Regulation Services (AS3), Energy Imbalance Services (AS4), and Spinning and Supplemental Reserves (AS5, AS6).

Q. You have mentioned that avoided costs can vary substantially according to timeframe. Please elaborate?

A. As discussed, FPUC's avoided cost methodology takes account of time varying nature of resource costs, for electricity services. To this point, Exhibit RJC-3 presents the hourly profile of all-in avoided costs, estimated for the months of January and July for 2024. As shown, hourly avoided costs vary by approximately 2 to 1, *on average*. However, the hourly variation is dramatically higher—the hourly maximum avoided costs reaches over $600/MWh, for several hours. For this reason, properly designed dynamic pricing options provide the capability to provide major reductions in total resource costs.

Q. Is it your opinion that the appropriate avoided cost inputs were provided to Nexant for use in the Market Potential Study done for FPUC?

A. Yes.

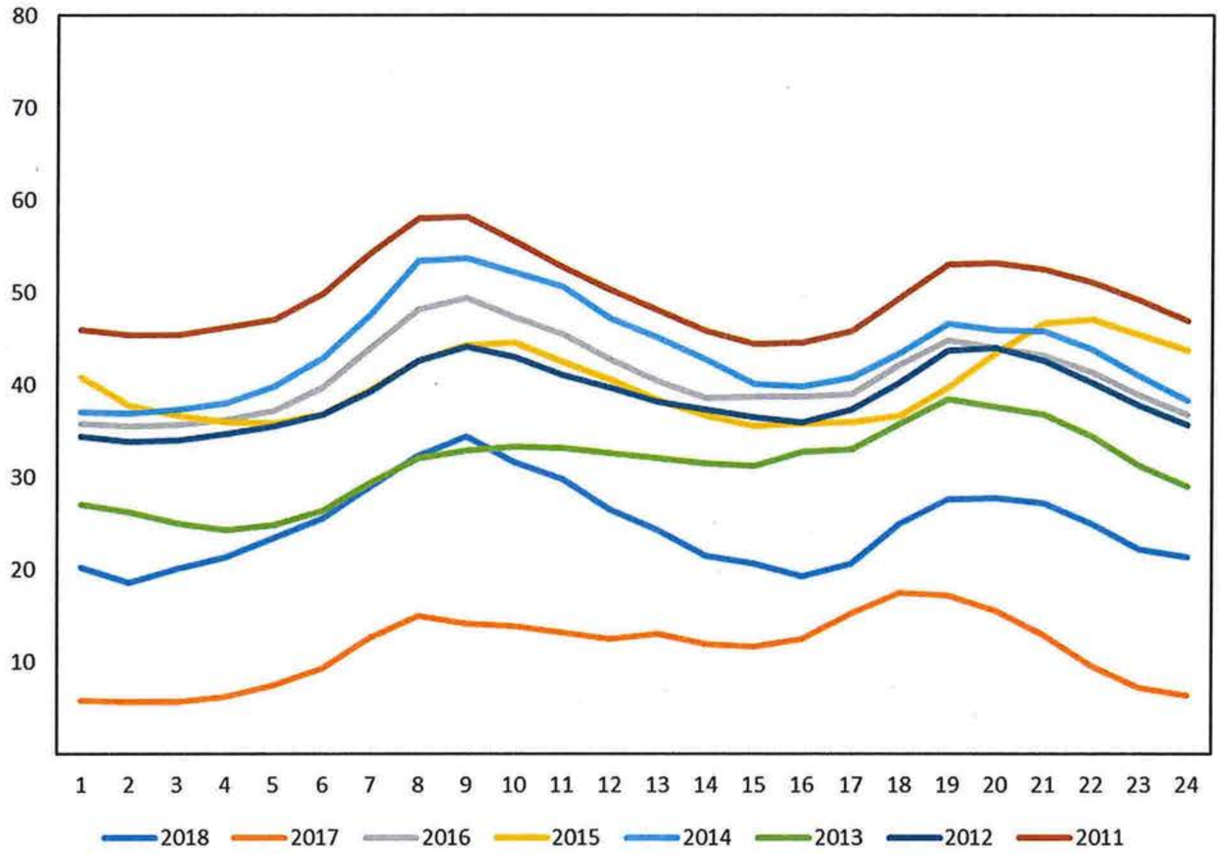
Q. Does this conclude your testimony?

A. Yes. It does.

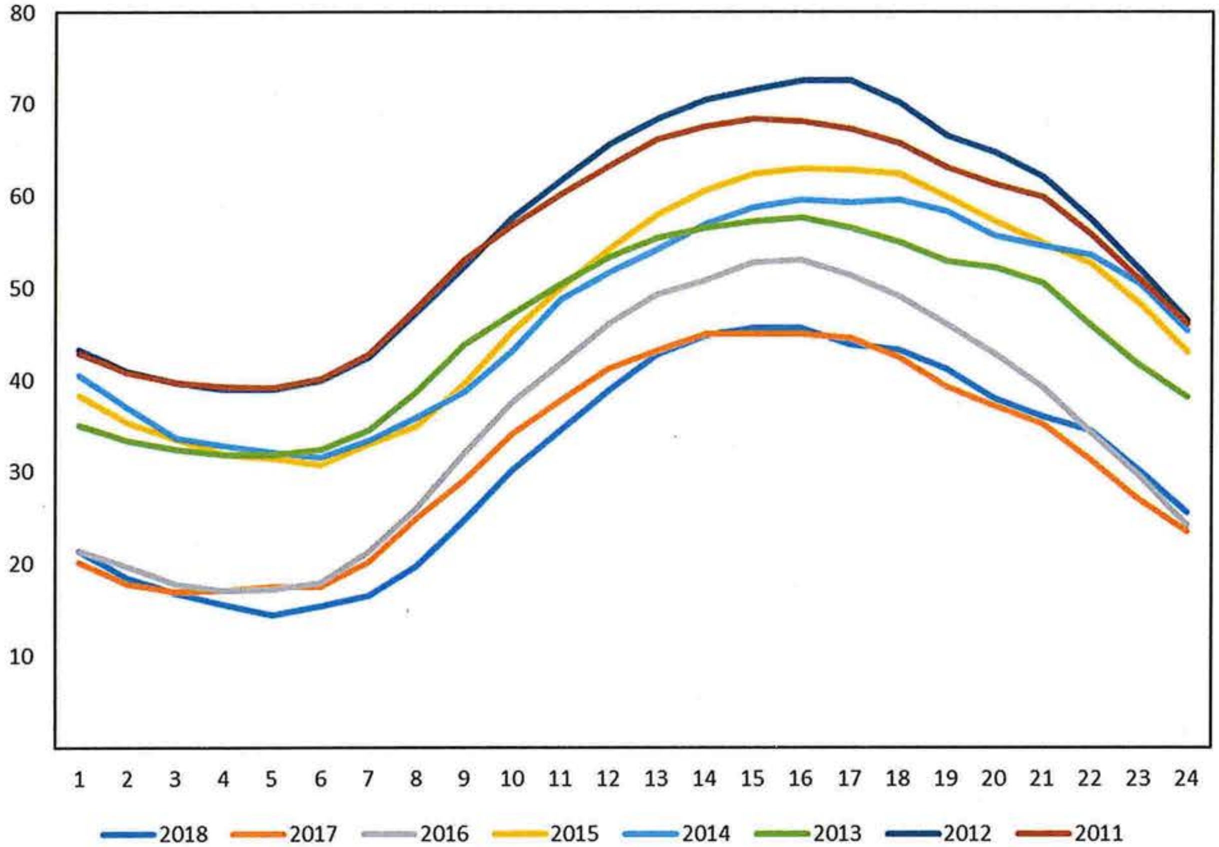
FLORIDA PUBLIC UTILITY COMPANY'S ESTIMATES OF AVOIDED COSTS, 2020-2038 ($/MWh)

YEAR	COST ELEMENT	WINTER (Nov-Mar)		APRIL, OCTOBER		SUMMER (May-Sep)		ANNUAL
		Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	
	Energy, Variable O&M	39.71	45.77	36.34	43.04	39.51	44.20	41.55
2020	Generation Capacity	3.89	15.91	5.34	16.49	2.90	26.22	11.09
	Transmission	1.52	5.18	1.95	5.36	0.93	9.27	3.82
	All-In G&T Avoided Cost	**45.14**	**66.96**	**43.87**	**65.27**	**43.62**	**80.20**	**56.70**
	Energy, Variable O&M	39.68	45.72	36.74	43.53	40.01	44.77	41.83
2022	Generation Capacity	3.89	15.91	5.34	16.49	2.90	26.22	11.09
	Transmission	1.59	5.44	2.05	5.63	0.98	9.73	4.01
	All-In G&T Avoided Cost	**45.18**	**67.18**	**44.37**	**66.05**	**44.17**	**81.25**	**57.17**
	Energy, Variable O&M	39.65	45.67	37.14	44.04	40.52	45.34	42.11
2024	Generation Capacity	3.89	15.91	5.34	16.49	2.90	26.22	11.09
	Transmission	1.67	5.72	2.15	5.91	1.03	10.23	4.22
	All-In G&T Avoided Cost	**46.27**	**68.64**	**45.73**	**67.79**	**45.55**	**83.20**	**58.63**
	Energy, Variable O&M	41.73	48.11	39.26	46.47	42.69	47.70	44.36
2026	Generation Capacity	3.89	15.91	5.34	16.49	2.90	26.22	11.09
	Transmission	1.76	6.01	2.26	6.21	1.08	10.74	4.43
	All-In G&T Avoided Cost	**52.99**	**76.90**	**50.06**	**73.04**	**50.07**	**89.18**	**64.66**
	Energy, Variable O&M	48.00	55.41	43.00	50.67	46.76	52.21	49.60
2030	Generation Capacity	3.88	15.87	5.33	16.46	2.90	26.17	11.07
	Transmission	1.94	6.63	2.50	6.85	1.19	11.85	4.88
	All-In G&T Avoided Cost	**56.62**	**81.12**	**53.34**	**76.89**	**53.49**	**93.30**	**68.42**
	Energy, Variable O&M	51.64	59.54	46.26	54.42	50.22	56.03	53.30
2034	Generation Capacity	3.72	15.23	5.11	15.80	2.78	25.11	10.62
	Transmission	2.14	7.31	2.75	7.56	1.32	13.08	5.39

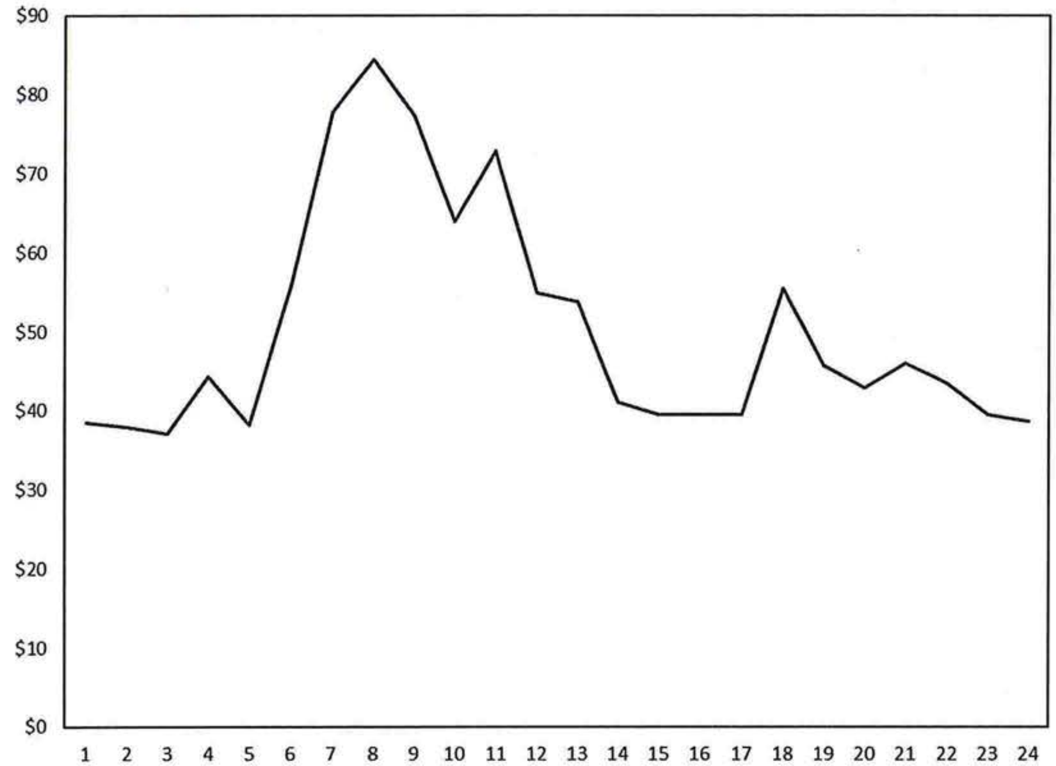
AVERAGE HOURLY LOAD BY YEAR (MW), JANUARY



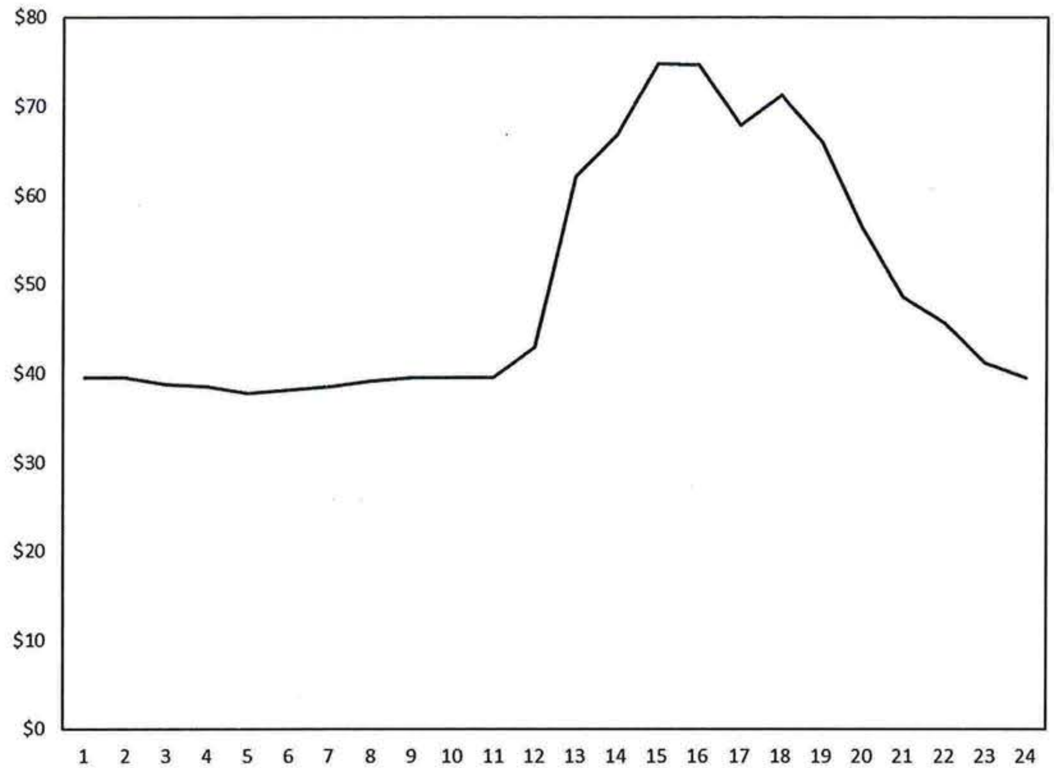
AVERAGE HOURLY LOAD BY YEAR (MW), JULY



ESTIMATED AVERAGE HOURLY ALL-IN AVOIDED COSTS, JANUARY 2024



ESTIMATED AVERAGE HOURLY ALL-IN AVOIDED COSTS, JULY 2024



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RESUME

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Academic Background:

M.A., Western Michigan University, 1975, Economics (High Pass, Comprehensive Exams)
B.S., Ferris State University, 1969, Management
Interlochen Arts Academy, 1964

Positions Held:

Senior Regulatory Consultant, Christensen Associates, LLC, 2016–present
Vice President, Christensen Associates Energy Consulting, LLC, 2002–2016
Senior Economist, Laurits R. Christensen Associates, Inc., 1994–2002
System Economist, Southern Company Services, 1993–1994
Economist, Southern Company Strategic Planning, 1992–1993
Strategic Planner, Southern Company Strategic Planning, 1990–1992
Project Manager, Georgia Power Company, 1983–1990
Chief Economist, Public Utilities Commission, State of New Hampshire, 1979–1983
Staff Economist, Michigan Public Service Commission, 1976–1979

Professional Experience:

I have served as the chief economist of a regulatory agency and the system economist for a major electricity service provider. My experience covers an array of retail and wholesale market issues including cost allocation, resource evaluation including renewables, rate of return and capital valuation, performance benchmarking, retail tariff design, rate base and financial projections, incentive regulation, transmission planning, energy contracts, regional analysis, cost measurement, marginal cost analysis, and electricity market forecasting. For electricity and gas clients, I have reviewed tariffs and cost allocation methods, conducted cost of capital studies, reviewed load forecast processes, assessed resource plans and electric generation technologies, negotiated power contracts, assessed energy procurement practices, helped finalize franchise licenses, and developed transfer pricing methods. I have managed power procurement processes and assisted with transmission contracts. I have developed and applied pricing and costing innovations including marginal cost-based cost-of-service, web-based self-designing retail electric tariffs, and efficient pricing of distribution services. I have represented and testified on behalf of integrated electricity utilities, gas distributors, cooperatives, regulatory agencies, utility associations, electric distribution companies, transmission companies, and generation companies in regulatory proceedings and public forums on a number of topics including tariff options, cost of capital, power supply contracts, load forecasts, cost of service allocation, phase-in plans, corporate performance and strategy, performance-based regulation, smart grid, transmission congestion, rate design, cost trackers, and integrated resource plans. I have participated in several large projects abroad, including the management of a market restructuring project in Central Europe. I have served on national committees and advised boards of trustees and major electric companies on corporate strategy. I served as program director for the Edison Electric Institute's Transmission and Wholesale Markets School from 1999 through 2008.

Testimony and Public Reports Filed Before Regulatory Agencies:

Marginal Cost Study Update, 2018, filed by newfoundland Labrador Hydro before the Public Utility Board, 2018.

Transmission Cost Allocation Methods to Account for Network Additions, filed with the Letter of Scope regarding Network Additions Policy of Newfoundland Labrador Hydro, 2018.

Transmission Cost Benchmark Study, submitted with the 2019 Capital Budget Application of Newfoundland Labrador Hydro, 2018.

Docket NG-0086: "Proposed Cost of Service Gas Hedge Agreement Between Black Hills Nebraska and Black Hills Utility Holdings, Inc.," an independent review with recommendations, filed before the Nebraska Public Service Commission, 2016.

Rate Base Methods for Determining Utility Rates: Consideration of Alternatives and Recommendations, a report focused approach options for estimation of rate base and the weighted average cost of capital, filed before the Public Utility Board in the General Rate Application of Newfoundland and Labrador Hydro, 2016.

Cash Working Capital: A Review of Newfoundland and Labrador Hydro's Methodology, filed before the Public Utility Board in the General Rate Application of Newfoundland and Labrador Hydro, 2017.

Cost-of-Service Methodology Review, a report filed before the Public Utility Board on behalf of Newfoundland and Labrador Hydro, 2016.

Estimation: Marginal Costs of Generation and Transmission Services for 2019, a regulatory report filed before the Public Utility Board on behalf of Newfoundland Labrador Hydro, 2016.

Methodology: Estimation of Marginal Costs of Generation and Transmission Services for 2019, a report filed on behalf of Newfoundland and Labrador Hydro, 2015.

Supplemental Review of Cost of Service Methods of Manitoba Hydro, filed before the Public Utilities Board of Manitoba, an independent review with respect contemporary cost allocation issues, co-authored with Michael O'Sheasy, 2015.

Docket 140025-EI: Direct testimony regarding load forecast and billing determinants before the Florida Public Service Commission, on behalf of Florida Public Utilities Company, 2014.

Docket UE 262: "PGE Decoupling Adjustment Evaluation," a report filed with the Oregon Public Utilities Commission on behalf of stakeholders including Portland General Electric, 2013 (co-authored with Dan Hansen and Marlies Hilbrink).

Docket 120001-EI: Direct testimony regarding the allocation of wholesale demand charges to classes, before the Florida Public Service Commission, on behalf of Florida Public Utilities Company, 2012.

Docket 566: "Analysis Update, Including Responses to Evidence filed By Interveners," filed before the Alberta Utilities Commission, on behalf of AtlaGas Utilities, co-authored with Philip Schoech, 2012.

General Rate Filing (2012/2013 and 2013/2014): "Review of Cost of Service Methods," filed before the Public Utilities Board of Manitoba, independent review with respect to the cost allocation methods employed by Manitoba Hydro and Centra Gas, co-authored with Bruce Chapman and Michael O'Sheasy, 2012.

Docket NG-0071: "Gas Purchasing Practices of Northwestern Energy for Retail Gas Services in Nebraska," filed before the Nebraska Public Service Commission, on behalf of the Nebraska Commission Staff, co-authored with Bruce Chapman and Mithuna Srinivasan, 2012.

"Inferred Class Contribution to Peak Loads for Allocation of Wholesale Demand-Related Costs Incorporated in Retail Fuel Charges," a report submitted before the Florida Public Service Commission on behalf of Florida Public Utilities Company/Chesapeake Utilities Corporation, co-authored with Mithuna Srinivasan and J. David Glyer, 2012.

Docket NG–0066: "Assessment of Gas Hedging Practices," filed before the Nebraska Public Service Commission, on behalf of the Nebraska Commission Staff, co-authored with Bruce Chapman, 2012.

Docket 100459-EI: Report: "Assessment of Impacts: Time-Of-Use Pilot Program for Customers of the Northwest Division," filed before the Florida Public Service Commission, on behalf of Florida Public Utilities Company, co-authored with Bruce Chapman, 2011.

Docket 110001–EI: "Electricity Demand: Northeast and Northwest Divisions," filed before the Florida Public Service Commission, on behalf of Florida Public Utilities Company, co-authored with David Glyer, 2011.

Docket 566: "Review and Evaluation of Incentive Regulation Plan," filed before the Alberta Utilities Commission, on behalf of AltaGas Utilities, co-authored with Philip Schoech, 2011.

Docket PUE–2011–0037: Direct testimony regarding class cost-of-service allocation, before the Virginia State Corporation Commission, on behalf of Steel Dynamics, Inc., July 2011.

Docket PUE–2011–0037: Supplemental Direct testimony regarding total financial costs for determination of retail rates, before the Virginia State Corporation Commission, on behalf of Steel Dynamics, Inc., August 2011.

Docket PUE–2011–00036: Direct testimony regarding the implementation provisions of a retail cost tracker for recovery of the costs associated with a new generating station, before the Virginia State Corporation Commission, on behalf of Steel Dynamics, Inc., July 2011.

Docket FTC–02/09: Affidavit regarding cost of capital and accompanying report, before the Fair Trading Commission, on behalf of Barbados Light & Power Company, Limited, June 2009.

Docket 2008–00408: Direct testimony regarding regulatory policy concerning employment of smart grid technologies in view of provisions of the Energy Independence and Security Act of 2007, before the Kentucky Public Service Commission on behalf of East Kentucky Power Cooperative, January 2009.

Docket 080366–GU: Direct testimony regarding cost of capital and rate of return recommendation for determining retail natural gas prices, before the Florida Public Service Commission, on behalf of Florida Public Utilities Company, December 2008.

Docket 080366–GU: Direct testimony regarding expected inflation and escalation factors for determining retail natural gas prices, before the Florida Public Service Commission, on behalf of Florida Public Utilities Company, December 2008.

Docket E015/GR–08–415: Direct and rebuttal testimony regarding the long-term energy and load forecast methodology, on behalf of Minnesota Power Company, before the Minnesota Public Utilities Commission, October 2008.

Docket PUE–2008–00046: Direct testimony regarding cost allocation and principles based on marginal costs, before the Virginia State Corporation Commission, on behalf of Steel Dynamics Corporation, September 2008.

Docket 070304–EI: Rebuttal Testimony before the Florida Public Service Commission regarding return on equity for the determination of retail rates, January 2008.

Docket 070304–EI: Direct Testimony before the Florida Public Service Commission regarding cost of capital and return on equity, on behalf of Florida Public Utilities Company, for the determination of retail rates, October 2007.

Docket 070108–EL: Testimony before the Florida Public Service Commission regarding a generation power supply agreement for long-term electricity service requirements, May 2007.

Docket 060001–EL: Testimony before the Florida Public Service Commission in support of a power procurement process and long-term full requirements contracts, November 2006.

Testimony and report before the Ontario Energy Board regarding the cost of capital for local distribution companies in Ontario, Canada, September 2006.

Docket ER–2006: Testimony before the Missouri Public Service Commission with regards to performance assessment, cost benchmarking, and capital risks attending electric utilities, on behalf of Kansas City Power and Light, January 2006.

Docket ER–2006: Rebuttal testimony before the Missouri Public Service Commission with regards the recognition of performance in the determination of retail prices, on behalf of Kansas City Power and Light, August 2006.

Docket 06–KCPE: Testimony before the Kansas Corporation Commission with regards to performance assessment, cost benchmarking, and capital risks attending electric utilities, January 2006.

Docket 050827–EI: Panel testimony before the Florida Public Service Commission regarding a regulatory phase in plan of the contract terms for generation services for the determination of retail rates, November 2005.

Docket 2006 EDR: Testimony before the Ontario Energy Board regarding the methodology and recommendations for electric distribution cost estimation and benchmarking of the local distribution companies of the Province of Ontario, January 2005.

Docket 040216–GU: Panel testimony regarding the cost of capital before the Florida Public Service Commission for the determination of retail rates, September 2004.

Docket 030438–EI: Panel Testimony before the Florida Public Utilities Commission regarding the cost of capital for determining retail electricity prices, economic costs of distribution services, and cost performance, February 2003.

Testimony and discussion on financial implications and risks under open access transmission, before the Energy Regulatory Office, Warsaw, Poland, September 1998.

Docket 9335-CE–100: Testimony regarding the implications of current and emerging competition on transmission reliability and planning, with particular focus on the Wisconsin western interface. The docket was a request before the Wisconsin Public Service Commission for Certificate for Public Convenience and Necessity (CPCN) to begin construction of a combined-cycle cogeneration plant in northeastern Wisconsin, July 1997.

Docket R–832331: Testimony regarding cost of capital for the determination of retail gas services of UGI Corporation, on behalf of the Consumer Advocate for the State of Pennsylvania, before the Pennsylvania Public Utilities Commission, August 1983.

Docket U–5724: Testimony regarding the cost of capital for Upper Peninsula Power Company in its application before the Michigan Public Service Commission for an increase in prices for retail telephone service, July 1978.

Docket 80–47: Testimony regarding projections of electricity demand, in the Commission's generic inquiry into the future demand for power, before the New Hampshire Public Utilities Commission, May 1981.

Docket 80–24: Testimony on the cost of capital in the application of Wilmington Suburban Water Corporation to determine prices for retail water service, before the Delaware Public Service Commission, November 1980.

Docket DR 80–23: Testimony on the cost of capital in the application of New England Telephone Company for an increase in retail rates, before the New Hampshire Public Utilities Commission, February 1980.

Docket DR 80–218: Testimony on the cost of capital in the application of Hudson Water Company before the New Hampshire Public Utilities Commission for an increase in prices for retail water service, February 1981.

Docket DR 81-86: Testimony on the cost of capital in the application of Granite State Electric Company before the New Hampshire Public Utilities Commission for an increase in prices for retail electricity service, July 1981.

Docket DR 79–187: Testimony on the cost of capital in the application of Public Service Company of New Hampshire before the New Hampshire Public Utilities Commission for an increase in retail electricity prices, February 1980.

Docket DR 80–104: Testimony on the cost of capital in the application of Northern Utilities before the New Hampshire Public Utilities Commission for an increase in prices for gas service, October 1980.

Docket DR 81–87: Testimony on the cost of capital in the application of Public Service Company of New Hampshire before the New Hampshire Public Utilities Commission for an increase in prices for retail electricity service, July 1981.

Docket U–5955: Testimony on the cost of capital in the application of Michigan Consolidated Gas Company before the Michigan Public Service Commission for an increase in prices for retail gas service, March 1979.

Docket U–6022: Testimony on the cost of capital in the application of Michigan Gas Utilities Company before the Michigan Public Service Commission for an increase in prices for retail gas service, June 1979.

Docket DE 81–312: Testimony on the topics of Demand Analysis (Technical Paper J) and Demand Elasticity (Technical Paper S) in the Commission's investigation of future supply and demand for electricity, New Hampshire Public Utilities Commission, October 1981.

ER 81–70, 71: Testimony on the cost of capital in the application of New England Power Company before the Federal Energy Regulatory Commission for an increase in prices for wholesale generation and transmission service, August 1981.

Docket U–5452: Testimony on Gas Rate Design in the application of Southeast Michigan Gas Company before the Michigan Public Service Commission for an increase in prices for retail gas service; June 1978.

Professional Papers and Key Reports:

"Cost Allocation and the Impact of Curtailable Service Options", a technical report with accompanying analytics prepared for a major wholesale service provider, 2018-19.

"Update: Long-Term Forward Looking Marginal Costs," prepared on behalf of a major G&T company, 2017.

"Pricing Policy and an Assessment of Regional Electric Rates," a report prepared for a major G&T company, 2017.

"Formula Rates for Wholesale Transmission Tariff," a white paper focused on the development, structure, and filing requirements for an open access transmission tariff (OATT). Provided for a major regulated G&T utility, the report includes the initial set of transmission access charges and prices for defined ancillary services, as calculated, 2017.

"Cost of Equity Capital," a report prepared on behalf of an integrated electric utility for a regulatory proceeding for a change in rates, 2017. (co-author with Nicholas Crowley).

"Cost Benchmarks," a comparative study of all-in electricity supply costs of major electric utilities, a report prepared for a major G&T service provider, 2017 (co-author with Mathew Morey).

"Methods for Determination of Rate Base and Weighted Average Cost of Capital," prepared for a major G&T company for use in a general rate application proceeding, 2017.

"Integrating Service Quality Standard into Regulation," a report focused on recently adopted service quality standards by regulatory authorities in the Eastern U.S., prepared for an integrated electric utility, 2016. (co-author with Rita Sweeney, Bruce Chapman, and Mathew Morey)

"Survey of Forecast Methods," a report summarizing the findings of survey of forecast methods used by retail electric utilities, prepared for a major electricity service provider, 2016.

"Assessment of Forecast Risks," a review of technical methods to estimate electricity forecast risks. Including examples, the report was prepared for a major electric utility, 2016.

"Cash Working Capital: A Review of Methodology," prepared on behalf of a major electricity service provider, 2016.

"Review of Load and Energy Forecast Methods," a technical review of long-term load and energy forecast models for electricity and natural gas markets served by a large integrated electric utility, 2015.

"Analysis and Findings: Contracts Package Associated with Restructuring and Resource Strategy," prepared on behalf of a major generation and transmission service provider, 2015.

"Load and Energy Forecast Review," a review of forecast issues, prepared for a large electricity service provider, 2015. (co-author with Dan Hansen and Steve Braithwait).

"Ensuring Adequate Power Supplies for Tomorrow's Electricity Needs," for the Electric Markets Research Foundation. A policy review of capacity markets within U.S. wholesale electricity markets, co-authored with Laurence Kirsch, Mathew Morey, and B. Kelly Eakin, 2014.

"Forecast Review," for a major integrated utility. A technical review of the methods and process of preparing the short- and long-term forecasts of electricity and water demand. The company's forecast serves as the basis for its financial projections and resource plans, 2012.

"Economic Impacts of Alternative Resources," for a major electric utility. A study of near- and long-term impacts of renewable energy resources, in lieu of conventional base load generation. Using general equilibrium methods, the study assessed local, regional and national impacts, including the incremental employment and household income effects resulting renewable resources, 2010.

"Study of the Costs of Service of the Puerto Rico Electric Power Authority," co-authored with Mathew Morey and Michael Welsh, 2010.

"Review and Recommendations: Forecast Methodology and Process," a report regarding the approach to load and energy forecasting, for a major integrated electric utility, 2008.

"Cost of Capital Report," for an integrated electric utility, 2008.

"Estimates of Marginal Costs of Electricity Supply," a report for an electric utility, and offered as testimony before a regulatory agency, 2008.

"Regulatory Policy Regarding Construction Work in Progress," a discussion paper prepared for an integrated electricity service provider, 2007.

"Asset Valuation: Original Cost and Fair Value Approaches," for an integrated electric service provider, 2007.

"Marginal Costs of Electricity Services," for an electric utility, 2007.

"Conservation Strategies and Resource Options," for a major electric utility, 2007.

"Rate of Return for Electric Distributors," for the Electricity Distributors Association, Ontario, Canada, 2006.

"Comments Regarding Staff Proposal for Rate of Return and Incentive Regulatory Mechanism," for the Electricity Distributors Association, Ontario, Canada, 2006.

"Economic Impacts of New Power Plants on Regional Economies," for a generation and transmission company, 2006.

"Other Factors Report," for American Transmission Company, 2005, co-authored with Laurence Kirsch, Mathew Morey, and Michael Welsh.

"Methodology and Study, Comparators and Cohorts Study for 2006 EDR," for the Ontario Energy Board, 2005, co-authored with David Glyer, Philip Schoech, and Michael Welsh.

"Power Procurement Options and Strategies," for an electric utility, 2005, co-authored with Mathew Morey.

"Approaches for Designing and Pricing Unbundled Transmission and Ancillary Services," for an integrated electric service provider, 2004, co-authored with Laurence Kirsch.

"Principles and Practices of Power Procurement," 2004, co-authored with Kelly Eakin, Mathew Morey, and Ross Hemphill.

"Findings and Recommendations: Comparators and Cohorts for Electric Distribution Rates," for the Ontario Energy Board, 2004.

"History, Status, Assessment: U.S. Electricity Markets," a discussion paper delivered before the annual national symposium on electric market restructuring, Poland, 2004.

"Methodology and Software for Evaluation of Transmission Development Options under Open Market Conditions," CIGRE, April 2004, co-authored with F. Buchta, D. Armstrong, and W. Lubicki.

"A Cost-Benefit Analysis of RTO Options," a report prepared for LGE Energy Corporation, September 2003, co-authored with Blagoy Borissov, Laurence Kirsch, and Mathew Morey.

"Methodology for Economic Assessment of Transmission Plans within Unbundled Power Markets," EPRI Report #54215, May 2002, co-authored with Rajesh Rajaraman.

"Determining the Marginal Costs of Transmission," a discussion paper prepared for a major electricity service provider, July 2003.

"Market Value Assessment of Hydro Units," for a major electric utility, 2003, co-authored with an engineering firm.

"Implications of SMD and RTOs for Retail Pricing," for a major retail service provider, July 2002.

"Self Designing Electricity Products," *Electricity Pricing In Transition*, Ahmad Faruqui and Kelly Eakin, eds., Kluwer Academic Publishers, 2000, co-authored with David Glyer and John Kalfayan.

"Exploring Transmission PBR and Power Market Reform," National PBR Conference, 2001, co-authored with Ross Hemphill.

"Incorporating Reserve Services and Scarcity Rents into Wholesale Price Forecasting," EPRI Pricing Forecasting Conference, 2001, co-authored with James Lamb, David Armstrong, and David Glyer.

"Self-Designing Tariffs," EPRI International Pricing Conference, 2000, co-authored with David Glyer and John Kalfayan.

"The New Pricing Organization," EPRI International Pricing Conference, 2000, co-authored with Michael O'Sheasy.

"Efficient Pricing of Transmission Services," *The Electricity Journal*, 2000, co-authored with Anthony Schuster.

"Developing and Pricing Distribution Services," *Pricing In Competitive Electricity Markets*, Ahmad Faruqui and Kelly Eakin, eds., Kluwer Academic Publishers, 2000, co-authored with Laurence Kirsch.

"Marginal and Average Power Losses," a technical discussion paper focused on the determination of line losses for power delivery systems, 1999, co-authored with David Glyer and Tom Gorski.

"Estimation of Marginal Costs for Real-Time Pricing," a technical report that reviews alternative approaches to determined short-run marginal costs, 1998.

"Marginal Costs of Distribution Wires Services," a technical discussion report that defines the theoretical basis and empirical methodology to determine the marginal costs of distribution services, 1999.

"Market Blueprint," for the transmission company of a Central European country. A report by an international team of experts for a transmission company facing market reform within a Central European country, 1999, co-authored with Charles Clark and Laurence Kirsch.

"Marginal Costs of Distribution Wires Services," a technical report of estimates of marginal distribution costs, 1998, co-authored with Boon-Siew Yeoh.

"Tariff Study," an EPRI report to the Polish Power Grid Company. The report provides recommendations for market reform and restructuring. Recommendations to unbundle electric service into competitive and regulated sectors are provided. The report also provides estimates of: 1) competitive generation prices with locational dimensionality and, 2) estimates of the net benefits from restructuring, 1999, co-authored with Charles Clark and Laurence Kirsch.

"Developing and Pricing Distribution Services," delivered before EPRI's Innovative Electricity Pricing Conference, 1998, and also in *Pricing in Competitive Electricity Markets*, Ahmad Faruqui and Kelly Eakin, eds., Academic Press, 2000, co-authored with Laurence Kirsch.

"Determination of Location and Amount of Series Compensation to Increase Power Transfer Capability," presented before the International Association of Electrical and Electronic Engineers, 1996, co-authored with Fernando Alvarado, Rajesh Rajaraman, Arthur Maniaci, and Sasan Jalali.

"Open Transmission Access: An Efficient, Minimal Role for the ISO," International Conference on System Sciences, 1996, co-authored with Fernando Alvarado and Rajesh Rajaraman.

"Transmission Comprehensive Marginal Costing," a report covering the conceptual design for software to determine locational prices, EPRI, 1996, co-authored with Keith R. Calhoun, David Glyer, Laurence Kirsch, Romkaew Broehm, and Michael Salve.

"Load Response Modeling Within Network Systems," a white paper that provides empirical estimates of the net benefits to consumers and service providers realized from incorporating spatially differentiated load response into system operations, EPRI, 1996, co-authored with Steve Braithwait, Pankaj Sahay, Arthur Maniaci, and Rajesh Rajaraman.

"Incorporating Optimal Power Flow Capability," a white paper that contrasts Optimal Power Flow methods and provides recommendations on incorporating Optimal Power Flow (OPF) into EPRI software, 1996, co-authored with Fernando Alvarado and Alfred Shultz.

"Transmission Pricing Strategies," a report that reviews transmission pricing methodologies and provides guidelines to a major integrated electric system to develop transmission tariffs, 1995, co-authored with Romkaew Broehm and Laurence Kirsch.

"Methodology to Estimate Regional Wholesale Power Prices," a technical white paper that presents, in substantial detail, a methodology to develop projections of power prices for regions of the U.S., 1995.

"Task II: Tariff Setting Mechanism" a report to the Turkish Electricity Authority. Task II was the second of two major scopes of service areas of the Operations and Management Improvement Program (OMIP), a World Bank funded project. Task II (Tariff Setting Mechanism) involved the determination of financial costs; estimation of long-run marginal costs including generation, transmission, and distribution services; allocation of financial costs; and retail tariff design, 1993–1994.

"Managing Risk in Restructured Power Markets," a technical white paper on risk management methodologies, 1997, co-authored with Kathleen King, Pankaj Sahay, and Fritz Schulz.

"Profitability of Retail Market Segments," a report of the expected long-run profits obtained from serving various retail markets for a major retail service provider, 1989.

"Profit Impact of Employment Multipliers," a report of the secondary profit impacts realized from the location of new business customers in the region served by an electric utility, 1988.

"Secular Distortions in Regulated Prices and Impacts on the Cost of Capital to Utilities," a discussion paper presented at the Eastern Economics Association that demonstrates the degree that investors discount internal cash returns from deferred taxes or non-cash returns associated with the allowance for funds used during construction (AFUDC), 1981, co-authored with Professor Peter Williamson.

"Long-Run Marginal Costs," a technical report of projections of marginal costs of generation, transmission, and distribution services provided by a major electric utility, 1985-1988.

"Impact of Electric Prices on the Regional Economy," a report that provides estimates of the impacts of regional electric prices on the costs of doing business within regions, 1985.

"Three Mile Island Two" a brief provided to the Legislature of the State of Michigan, 1979.

"Assessment of the FEA Long-Term Supply-Demand Model," a report to the Michigan Public Service Commission, 1978.

National Conferences, Engagements, and Technical Workshops:

Panel chair and presenter, "Beneficiary Pays," conference on *Regional Transmission Organizations* sponsored by the Wisconsin Public Utilities Institute, April 2018.

Speaker on the topic of "Recent Developments: Electricity Performance Standards," conference of the Large Public Power Council, July 2016.

Speaker on the topic of "Vertical Integration in Retail Gas Distribution," at the *Issues: Vertical Integration in Retail Gas Markets* workshop organized by the National Regulatory Research Institute, June 2016.

Speaker and panelist, "Developing an Outlook for Interest Rates," presented before the Society for Utility Regulatory Financial Analysts, April 2016.

Presenter, "Gas-Electric Coordination", before the Gas Committee of the National Association of Regulatory Utility Commissioners, 2015.

Participant and panelist at the *Stakeholder Workshop Series on Cost Allocation*, organized by Manitoba Hydro, 2014.

Workshop Speaker: "Regulatory Governance and Incentive Regulation"; "Developing Estimates of Marginal Cost", seminar for the *California Public Utilities Commission* organized by the Wisconsin Public Utilities Institute, 2014.

Speaker and Panelist at the session "Infrastructure: Challenges, Progress, Solutions", week-long workshop of the Bowhay Institute and Council of State Governments, La Follette School of Public Affairs, University of Wisconsin, 2014.

Moderator: "Transmission Cost Allocation" session, workshop on *Transmission Policy* sponsored by the Wisconsin Public Utilities Institute, 2012.

Speaker discussing "Roadmap for An Energy Secure Economy", *Annual Trustee Update* sponsored by Power South Energy Cooperative, 2012.

Speaker and Panelist, "U.S. – Canadian Energy Trade and Markets", *Bowhay Institute and Council of State Governments*, La Follette School of Public Affairs at the University of Wisconsin, 2012.

Speaker: *Setting a Strategic Direction*, Board of Trustees, Central Electric Power Cooperative, with David Glyer, 2011.

Speaker: *Electricity and the U.S. Economy*, G&T Manager's Fall Conference, 2011.

Speaker on the topic of "Alternative Financial and Market Arrangements for Transmission", *Transmission and Market Design School*, sponsored by the Edison Electric Institute, with co-author Bruce Chapman, August 2010.

Session Moderator on the topic of *The Problem of Cost Allocation, Status of Electric Transmission* conference sponsored by the Wisconsin Public Utilities Institute, May, 2010.

Lecturer: "Review of the U.S. Electric Power Industry," at a week-long symposium for power systems organized by the University of Wisconsin for a delegation representing the Republic of Georgia, April 2009.

Session Moderator at the *Feed-In Tariffs* workshop on renewable energy, sponsored by the Wisconsin Public Utilities Institute, July 2009.

Conference Chair, *Electricity: A Rising Cost Industry* conference, Chicago, September 2008.

Speaker at the conference "Managing Physical and Financial Uncertainty in the Power Industry," New York Mercantile Exchange, New York, June 2007.

Speaker and panelist, "Cost of Capital", *Annual Executive Symposium* of the Electricity Distributors Association, Ottawa, Canada, October 2006.

Speaker on the topic of "Reliability: What's It Worth", conference entitled *Transmission Reliability: Determining Appropriate Standards and Metrics*, Washington DC, September 2006 (co-speaker with Laurence D. Kirsch).

Speaker and workshop lecturer, "Transmission Planning: Gauging the Full Scope of Benefits and Costs", at the conference entitled *Transmission and System Reliability*, Cape Cod, September 2005.

Speaker at the conference entitled "Organization and Governance of the Market Agent," Washington DC, April 2005.

Chair and workshop lecturer "Market-based Criteria and Evaluation of Transmission Expansion Plans", at the national conference entitled *Assuring Reliability, System Operations, and Network Expansion*, San Francisco, October 2004.

Lecturer at the week-long course on Public Utility Regulation sponsored by the Wisconsin Public Utilities Institute, University of Wisconsin, Madison, October 2003.

Discussant on a panel of experts on the topic of market organization, conducted for a delegation of officials of the Korean electricity industry, sponsored by EPRI, Palo Alto, September 2003.

Chair and workshop lecturer on the topic of "Market-based Evaluation of Transmission Plans", *Markets for Power* conference, Denver, September 2003.

Discussant at the workshop on the topic of "Market-Based Evaluation of Network Expansion", organized for a delegation of officials of the Korean electricity industry, sponsored by EPRI, Madison, July 2003.

Week-long seminar on market organization issues, conducted for a delegation representing the Korean Power Exchange, sponsored by EPRI, Palo Alto, May 2003.

Conference chair and speaker at the national conference entitled *Linking Wholesale and Retail Markets*, Denver," April 2003.

Program Director and lecturer for the Edison Electric Institute's *Transmission and Wholesale Markets School*, University of Wisconsin, Madison, 1999-2008.

Lecturer on marginal costs at a three-day workshop organized for a large municipal utility.

Discussant at a workshop on ancillary services for a large integrated electric service provider, Denver, 2002 (co-presenter with Laurence Kirsch).

Lecturer at a three-day workshop on wholesale market design for a large integrated electric service provider, Birmingham, 2002 (co-presenter with Laurence Kirsch).

Lecturer at a three-day workshop entitled "Locational Pricing and Market Design," sponsored by WestConnect RTO, Phoenix 2002.

Session chair and speaker on the topic of performance-based regulation for transmission, at the national conference entitled *Performance-Based Ratemaking*, Denver, 2001.

Presenter at the "Review of U.S. Electric Markets" seminar for a delegation of officials of the power industry of China, Atlanta 2001.

Speaker and workshop lecturer at the workshop on distributed resources at the conference entitled *Unbundling and Pricing Wires Services*, Philadelphia, 1999 (co-presenter with Ross Hemphill).

Speaker on the topic of "Technical Methods for the Design of Unbundled Transmission and Distribution Tariffs" at the workshop entitled *Unbundling Electric Power*, sponsored by the Polish Power Grid Company, Warsaw, 1999.

Speaker on the topic of "Bottlenecks within Midwest Power Markets" at the conference entitled *Power Markets in the MAIN and MAPP Regions*, Chicago, 1999 (co-presenter with Rajesh Rajaraman).

Discussant on the topic of "Pricing Transmission Services" delivered before the economics committee of the Edison Electric Institute, San Diego, 1999.

Speaker on the topic of "The Key to Profits: Understanding Costs and Customer Behavior", the conference entitled *Measuring Customer Profitability for Utilities*, New Orleans, 1998 (co-presenter with Ahmad Faruqui).

Speaker on the topic of "Pricing Transmission Services", the conference entitled *Successful Transmission Pricing*, Houston, 1997.

Lecturer at the workshop on "Pricing Distribution Services", conference entitled *Achieving Success in Evolving Power Markets* sponsored by EPRI, Houston, 1997, (co-presenter with Charles Clark and Laurence Kirsch).

Speaker on the topic of "Incorporating Transmission Incentive Rates", conference entitled *Developing and Implementing ISO Rates and Structures*, Washington DC, 1997.

Speaker and panelist on the topic of "The ISO: Efficient Organization of Power Markets" *Rate Symposium*, sponsored by the University of Missouri, St. Louis, 1997.

Speaker on the topic of "Transmission Pricing Strategies," conference entitled *Pricing Strategies in Electric Power*, Chicago, 1996 (co-presenter with Keith R. Calhoun).

Lecturer on the topic of "Long and Short-Run Marginal Costs for Transmission and Distribution Services", *workshop on estimating economic costs* sponsored by EPRI, Denver, 1996.

Presenter on the topic of "Costing and Pricing Transmission", *workshop for the transmission pricing task force of the Southwest Power Pool* sponsored by EPRI, Kansas City, 1996.

Speaker on the topic of "Designing Rates and Services for Restructuring Electric Utilities", conference entitled *Performance-Based Pricing*, Washington DC, 1996 (co-presenter with Douglas Caves).

Speaker on the topic of "Projecting Wholesale Prices", conference entitled *Achieving Success in Evolving Electric Markets*, Indianapolis, 1996.

Chair of the session entitled "Market Coordination Functions", conference entitled *Achieving Success in Evolving Electric Markets* sponsored by EPRI, Atlanta, 1995.

Speaker on the topic of "Evolving Power Markets" conference entitled *Innovative Rate Design* sponsored by EPRI, 1994.

Speaker on the topic of "Evolving Power Markets Abroad" conference on *Real-time Pricing and C-VALU* sponsored by EPRI, Minneapolis, 1994.

Speaker on the topic of "Efficient Transfer Pricing of Generation and Transmission Services of Integrated Electric Systems", annual conference of the *Model Users Forum of Regional Economic Models*, Atlanta, 1993.

Speaker on the topic of "Changing Overseas Power Markets", conference entitled *Real-Time Pricing* sponsored by EPRI, New Orleans, 1993.

Speaker on the topic of "Secondary Impacts on Utility Profits, Impacts of New Business Locations", conference entitled *Model Users Forum of Regional Economic Models*, 1992.

Session Chair or Reviewer at the Annual Conference of the Advanced Seminar in Regulatory Economics, Rutgers University, Newark, 1986, 1990-1993.

Speaker on the topic of "Market Segmentation and Pricing Efficiency", conference entitled *Innovative Rate Design* sponsored by EPRI, 1988.

Special Assignments, Professional Associations, Awards:

Negotiation of a Purchase Power Agreement for generation services between the Power Delivery and Power Supply divisions, for a major investor owned electric company, 2001.

EPRI Advisory Committee on Market Management, 1992-1994.

Special Assignment to Southern Company's *Management Information Reporting System* (MIRS) project focused on the implementation of transfer pricing for generation and transmission services, 1993.

Evaluation Working Group, Southern Company: Initiation and coordination of a system-wide group focused on the evaluation of marketing plans. The group was charged with reaching a common conceptual design and methodology to estimate marginal costs and evaluate marketing programs and demand side options, 1990.

Economics Panel, Southern Company: Economics panel tasked with the development of business scenarios for use in long-term planning. The panel identified ranges of values for key exogenous economic drivers and assumptions, 1986-1987.

Load and Energy Forecast Review Committee, Alabama Power Company, 1991-1993.

National Association of Business Economists, 1987-1992.

Utility Planning Model Users Group, Southern Company, 1986-1987.

American Economic Association.

International Association of Energy Economists.

Board of Directors and Model Manager, New England Economic Project, 1981-1983.

Economics Committee, National Association of Regulatory Utility Commissioners, 1980-1983.

Policy Advisory Committee, Regional Energy Facility Siting Study, a project funded by the Nuclear Regulatory Commission, 1981-1982.

Go For the Gold Award, Southern Company Services, 1993.

Top Performer Award, Georgia Power Company, 1989.

Selected Assignments and Project Work:

Long-term projections of avoided costs, for use in the evaluation of DSM program options and distributed resources, 2019.

Update of TOU prices, based on generation and transmission costs, power supply contracts between an electric distributor and cogeneration facilities.

Technical review and formal report regarding cost allocation methodology and the determination of curtailable service options. Analysis findings were reviewed with senior managers and legal team of a major G&T cooperative.

Discussion of dynamic pricing tariff options, for consideration of a major distribution utility.

State energy policy, including discussion papers regarding the cost advantages of renewable resources, the technical elements of grid modernization, and the working mechanics and efficiency gains from dynamic pricing. Project work involved the preparation of state-wide quantitative impacts arising from market entry by renewable resources, accelerated grid modernization, and the implementation dynamic pricing. Scenarios of potential long-term impacts incorporated direct within-energy-sector effects, as well as secondary impacts within the regional economy. These region-wide impacts were assessed using the regional analysis tools of Regional Economic Models, Inc.

Tariff restructuring for large industrial customers with on-site cogeneration. The proposed tariff design was a two-part approach, with an option to for short-term power purchased settled again the service providers hourly marginal costs.

Update and amendments to power supply contracts.

Tariff strategy and general approach to remedy resource inefficiencies, resulting from underpricing of retail electricity services.

Discussion of criteria, evaluation methods, regional analysis, and procedures to manage economic development and load retention service through economic development rates and other service design options.

Technical memorandum on methods for capital measurement, for determination of utility rate base. The discussion includes a survey of methods used by electric utilities, prepared for a major G&T company.

Prices for inclusion in an OATT Transmission Tariff, for a major generation and transmission service provider.

Review of cost allocation methodology, for a major G&T cooperative.

Consultation with regulatory authorities regarding the commercial terms of supply contracts between gas production subsidiaries and their affiliates, local gas distributors.

Review of load and energy forecast methodology, for filing with an integrated resource plan of a large integrated electric utility.

Cost of capital review, prepared on behalf of a small integrated electric utility for presentation before its regulatory authority.

Review of the commercial terms of proposed power purchase and transmission agreements among affiliates, to ensure that contract provisions are incentive compatible.

Wholesale cost benchmarking, for a major generation and transmission company.

Benefit-cost analysis in support for a regulatory filing seeking approach for a long-term power purchase agreement with new cogenerator, situated at a large industrial site.

Economic evaluation of investment in a cogeneration facility.

Load and energy forecast review, for an integrated electric utility.

Discussion paper focused on the principles for determining the prices for services provided by affiliates to public utilities.

Review of an Integrated Resource Plan of an electric utility.

Capital valuation and assessment of generation investment strategies and options.

Electric power rate case, providing oversight for the overall filing preparation, forecast of load and energy (billing determinants), and estimates of cost escalation for a forward test year.

Policy discussion paper regarding cost trackers for gas distribution utilities.

Technical and advisory support to the Maine Public Utilities Commission regarding the electricity sales forecast of Central Maine Power, within CMP's current rate case proceeding.

Technical and policy support to a distribution utility regarding the negotiation of a power purchase agreement.

Technical comments regarding the features of a Green Energy Tariff, as proposed, of a major electricity service provider.

Advisory support to the Nebraska Public Service Commission regarding the technical and policy merits of the application of Source Gas Incorporated, a natural gas distributor, for authority to put in place a tariff rider for infrastructure cost recovery.

Technical support to an electric utility regarding a dispute over franchise rights.

Assessment of technical issues associated with a gas distribution rate case filing, in support of a regulatory agency and its staff.

Development and negotiation of the structure of the commercial terms of a cogeneration power supply agreement, for a distribution utility.

Assessment of the mechanics of a natural gas fixed bill-weather swap retail tariff option, for a generation and transmission cooperative.

Assessment of Joint Dispatch Agreement: Duke Energy—Progress Energy Merger, for a major distribution utility.

Review of the working mechanics of a weather normalization rate option, for a major distribution utility.

Assessment of incentive regulation options for the electric and gas distribution of a major utility services provider.

Transmission business strategy, for an integrated electric utility.

Cost benchmarking and projections of financial costs of peer group competitors, for an integrated electric utility.

Support of the renegotiation of a power supply contract, for an electric distribution utility.

Preparation of arguments regarding market dominance and regulatory policy, retail Standard Offer Service.

Support of technical staff of a regulatory agency, regarding natural gas rate case filings.

Open access wholesale tariffs including various supporting documents and reports, for a Caribbean utility.

Transmission evaluation model to assess interconnection redundancy, for a major electric service provider.

Assessment of the benefits and costs associated with joining an RTO, for an electric utility.

Assessment of regional economic impacts arising from renewable resources, for a major electric utility.

Economic assessment of IGCC technology and planned generator, for a major electric utility.

Qualitative assessment of the likely impacts of the Clean Energy Act of 2009, for a major electric utility.

Report on demand side participation in contingency reserves, for a major electric utility.

Development of a load and energy forecast and accompanying regulatory report, for a major electric utility.

Report reviewing alternative transmission business models, for a major electric utility.

Evaluation and critique of high voltage transmission network overlay, for an association of electric utilities.

Negotiation of terms for power supply contract, for a distribution utility.

Analysis of power procurement processes and outcomes for electricity service providers, and justification for incentive allowances, for a regulation agency.

Review of cost of service allocation methods, for an integrated electric and gas utility; report filed before regulatory authority.

Methodology dispute regarding load forecast methodology, on behalf of agency staff and a utility applicant, in an integrated resource planning docket before a regulatory agency.

Cost of service allocation study on behalf of an intervening party within a major utility rate case.

Manager of the support team preparing a natural gas rate case filing, on behalf of a combination electric-natural gas utility. Project work includes cost of service allocation, preparation of the Minimum Filing Requirements, design of retail tariffs, and cost of capital/rate of return recommendation and testimony.

Position paper on stranded costs resulting from off-system purchases by distributors, for a major generation and transmission cooperative (G&T).

Projections of escalators for determining commercial terms, for use in negotiation of new coal contracts.

Preparation of load and energy forecast for an electric utility.

Analysis and recommendations of regulatory issues underlying total costs (revenue requirements) for a utility's rate case filing. The issues, including fair value/original cost rate base, construction work in progress, normalization/flow through of income tax effects from accelerated depreciation/investment tax credits, working capital, and depreciation policy, were addressed in a series of discussion papers.

Report on integration of demand response into transmission and distribution planning.

Assessment of and recommendations for retail market strategies focused on conservation, efficient pricing, and renewable resources, for an electricity service provider.

Cost of capital/rate of return recommendation and testimony for a utility rate case filing.

Development of the draft commercial terms for a power supply contract for a renewable resource facility.

Negotiation of contracts for transmission services, for an electric distribution company.

Review of methodology and process for development of load and energy forecasts, for a major electric utility.

Development of cost allocation methodology for assignment of profits associated with off-system sales to jurisdictions, for a major electric utility.

Development of the structure of a proposed fuel adjustment clause for retail electric services, for a major electric utility.

Review of the commercial terms of a proposed power supply contract, for a major electricity service provider.

Review of a utility rate case filing, on behalf of a major electricity service provider.

Review and assessment of the efficiency of fuel procurement practices on behalf of a major electricity service provider.

Review of economic cost allocation methods and options, for an electric generation and transmission company.

Determination of strategy for transmission services, where options include exiting an RTO, the purchase of services from a private Transmission Services Coordinator, and the formation of a statewide or regional ISO with a consortium of electric utilities.

Analysis of the benefits and costs of electric transmission expansion plans, for an independent transmission company; report filed before regulatory authority.

Review of the design of market-based buy-through options for retail electricity curtailment contracts.

Support for the negotiation of long-term power supply contracts, including development of commercial terms.

Assessment of transmission costs and risks, in support of power supply contracts.

Management of a power procurement process including the determination of strategy and approach, development and issuance of a request for proposal, evaluation of offers, and the negotiation of power contracts.

Development of a regulatory phase-in plan of the costs associated with new wholesale power supply contracts.

Factor models for the determination of cost of capital, for a consortium of electric utilities.

Assessment of the secondary economic impacts (multiplier effects) on regional economies arising from the construction and commercial operation of new generating stations.

Comparative assessment of the economic viability of contemporary power generating technologies, for a major electric utility.

Definition of proposed RTO reporting requirements, for an association of electricity service providers.

Comparative assessment of the economic costs of electric distribution services.

Transfer pricing for generation and transmission services, for a major electric utility.

Evaluation of a proposed amendment and extension to a power supply contract, for an electric utility.

Interpretation and assessment of the Standard Market Design proposal developed by the Federal Energy Regulatory Commission, for a major electric utility.

Development of software for the evaluation of transmission expansion plans, for a major transmission company.

Development of methods to assess benefits and costs of transmission expansion plans.

Estimation of marginal cost for cost-of-service allocation, for a major electric utility.

Forecasts of regional electric wholesale prices and assessment of the reliability of power delivery, in support of the negotiation of a wholesale power supply contract for an electric power merchant.

Valuation and assessment of hydroelectric power plants, for a major electric utility.

Economic assessment of transmission expansion plans, for a major transmission company.

Assistance in the specification of the franchise licensing agreement underlying a utility privatization, for an international energy company.

Determination of the benefits of expanded network metering, for a large incumbent transmission service provider.

Specification of the terms associated with a purchased power contract, for a major electric utility undergoing corporate unbundling.

Estimation of regional wholesale prices for reserve services, for a major electric utility.

Evaluation of generation investment strategy, for a major electric utility.

Preparation of long-term projections of regional wholesale power prices, for a major electric utility.

Development of the blueprint and structure for wholesale electricity market design, for a major transmission company.

Estimation of consumer electricity outage costs (value of reliability), for a major electric utility.

Estimation of generator costs and network locational prices, for an electric distribution company in New Zealand.

Determination of principles and definition of the main elements for electricity market restructuring and tariff design, for a Central European country.

Analysis of retail tariff design and strategy, for a major electricity service provider.

Development of transmission and distribution marginal costs, for a large municipal electric utility.

Determination of economic costs and tariff prices, for the Turkish Electricity Authority.

Evaluation of transmission network costs and tariffs, for the national grid company of a Central European country.

Development of optimal power flow software for determining transmission spot prices, for a major electricity service provider.

Estimation of marginal costs for jurisdictional and class cost-of-service allocation.

Development of electric transmission spot pricing capability and software.

Estimation of wholesale electricity market prices in the Northwest region.

Determination of locational marginal costs and the implications for real time pricing.

Development of marginal costs and cost-of-service allocation study.

Development of pricing strategy for an electric distribution utility operating in an open retail access region.

Development of a cost-of-service study and retail pricing, for an electric distribution utility.

Preparation of a cost-of-service study utilized marginal costs.

Analysis of the impact of real-time pricing program options.

Development and implementation of generation and transmission transfer pricing for a major electric utility.

Economic analysis of retail electricity pricing options.

Economic analysis of time-of-use electricity retail service design options.

Development, evaluation, and feasibility assessment of the business case for the formation of a financing subsidiary.

Economic assessment of alternative cycles and schedules for nuclear plant refueling.

Assessment of retail electricity marketing strategies.

Estimates of marginal costs of power delivery services provided by U.S. electric utilities.

Operations and Management Improvement Program, a World Bank funded project for the Turkish Electricity Authority.