–BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN UTAH AND FOR APPROVAL OF ITS PROPOSED ELECTRIC SERVICE SCHEDULES AND ELECTRIC SERVICE REGULATIONS	))))))))))))	**DOCKET NO. UT 20-035-04** **Exhibit No. DPU 12.0 DIR**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

Direct Testimony of

Robert J. Camfield

September 15, 2020

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. FOR 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 natural gas markets. This body of work has focused predominantly on numerous issues associated with resource choice, cost analysis, and the determination of prices for utility services set by regulatory authorities.

Q. PLEASE DESCRIBE CHRISTENSEN ASSOCIATES ENERGY CONSULTING.

A. Christensen Associates Energy Consulting is a wholly owned subsidiary of Laurits R. Christensen Associates. Our consulting group is a full-service consulting firm focused on applied economics, with four practice areas consisting of 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 regulatory authorities in the U.S. and Canada, including the Federal Energy Regulatory Commission.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE UTAH PUBLIC SERVICE COMMISSION?

A. No.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have many years of experience in the energy industry and the economics of regulation. This work covers resource decisions, regulatory governance and incentive plans, market restructuring, cost allocation, energy contracts, cost of capital, and performance benchmarking. I have testified on many topics including rate of return, demand for electricity, cost of service issues, wholesale power agreements, avoided costs, cost benchmarking and corporate performance, electric and natural gas rate design, and regulatory phase-in plans. I have assisted electric utilities to determine prices for Open Access Transmission Tariffs (OATTs) 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 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 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 in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses three areas: expected price inflation across the U.S. economy; marginal electricity costs and their application to the determination of tariff and rate design, and Rocky Mountain Power's marginal cost study; and Rocky Mountain Power's proposed tariff and rate design changes advanced for consideration by Witness Meredith.

SUMMARY OF TESTIMONY: FINDINGS AND RECOMMENDATIONS

Q. WOULD YOU PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY, HIGHLIGHTING YOUR FINDINGS AND RECOMMENDATIONS WITH RESPECT TO THE TOPICS IDENTIFIED ABOVE?

A. My findings and recommendations for the defined topics are as follows:

Expectations of Overall Price Inflation: As discussed below, current expectations of inflation have declined somewhat compared to late 2019 – early 2020, and also with respect to the outlook for overall price inflation over recent years. (Reference the testimony of Mr. Steven McDougal on behalf of Rocky Mountain Power, lines 175-177 and 545-559.) I have reached this conclusion from an assessment of 1) yield differences on U.S. Treasury securities and 2) surveys of households, economists, and forecasters. This change in the general outlook for overall price inflation is a result of the unanticipated circumstances of the current year and the impacts on macroeconomies over the succeeding 2-4 years. RMP's cost estimates for the forecast test year were prepared prior to these current-year developments. The recent decline in expected overall price levels suggests that the escalation rates used to determine RMP's input costs should be reviewed with respect to the contemporary outlook. RMP should ensure that input price escalation conforms with the consensus view for the U.S. economy.

<u>Marginal Cost Study</u>: Marginal costs reflect the economic cost and worth of resources employed in the provision of electricity services, and thus serves as important guidance in determining retail tariff prices. To this end, RMP's marginal cost study appears to be constructed with substantial care and diligence. Nonetheless, my review of RMP's study identified several areas where RMP ought to give consideration to several revisions and changes, as follows:

Supply-Demand Balance: RMP estimates generation reliability costs using a capacity proxy methodology, an approach with which I generally concur. RMP marginal generating capacity costs utilize the full cost of RMP's proxy generator on the margin, a large combined cycle generator. For the contemporary timeframe, generation capacity costs should reflect expected near-term supply-demand conditions, where current supply may be somewhat capacity-short or capacity-long. For guidance in determining electricity prices, RMP should consider adjusting marginal capacity costs, should either condition characterize its current supply-demand balance.

Inclusion of the Costs of Operating Reserves: The organization of wholesale generation services has revealed a suite of standard unbundled generation services including energy and operating reserves comprised of regulation, spin, non-spin, and supplemental reserve categories, as well as voltage support and black start. I recommend that RMP consider the inclusion of the operating reserve services in marginal cost, noting that the impact of operating reserve costs/prices is typically small, once scaled to the retail load level.

Inclusion of Ancillary Support Costs: Bundled electricity services include generation, power delivery—transmission and distribution—and customer services. These services draw on support services and resources, reflected as ancillary cost elements, including administrative and general expenses, general plant facilities and equipment, working capital, and materials and supplies. Where relevant, the marginal dimension of these ancillary cost elements should be incorporated in RMP's marginal cost study.

Measuring Administrative and General Expenses, On the Margin: RMP's marginal cost appears to estimate administrative and general expenses (A&G) with reference to net plant—essentially, net book value of plant-in-service. I suggest that, for purposes of marginal cost estimation, A&G expenses should be measured on the basis of the real capital stock, net of economic depreciation. The real capital stock can be greater or less than net book value, depending on the age of RMP's capital facilities.

Determining Load and Non-Load Related Distribution Costs: Using property records and observed loads across substations, RMP has prepared a highly granular study of distribution marginal costs. My concern is a matter of attribution of the costs of wires services (poles, conductors): RMP does not appear to have an analytical foundation for determining the shares of these transport facility costs attributed to peak loads—and thus demand-related—and non-load services. Moreover, I would not anticipate a strong causal relationship between distribution costs and energy flows on conductors.

<u>Tariff Design</u>: RMP's proposed cost allocation and tariff design, as advanced by Mr. Robert Meredith, calls for the implementation of numerous changes to RMP's retail tariff package. Viewed as a whole, the proposed tariff changes assume two overarching themes. First, they assume a more complete accounting for economic resource costs in tariff prices including curtailable services, time-of-use rates, and a real-time pricing option. Included in this use of economic resource costs is RMP's proposes utilization of the seasonal patterns of loads and costs as the basis to seasonalize customer charges. Second, the proposed retail tariff consolidates the residential and commercial tariffs, including the collapse of tariff block tiers for RMP's residential tariff, and the closure of selected tariff schedules which involves the assignment of customers to other tariff schedules. My concerns with respect to the proposed changes are as follows.

<u>Compression of Residential Tariff Block Tiers from Three to Two</u>: Absent evidence of significant, systematic differences in the economic costs of serving customers with marginal loads on the three blocks, I concur with RMP's proposed reduction in tariff blocks. The challenge is getting the two-tier block prices right.

There are two issues: First, in the presence of a fixed customer charge and changing energy costs (net power costs), the reduction in blocks can give rise to sizable windfalls and losses for selected customers. Second, the net margin on sales (revenues minus marginal cost to serve) may have substantial variation across customers. As a consequence, changing tariff blocks will change net revenues realized by RMP. It is not likely that the proposed change is revenue neutral, as changes in marginal prices cause customers to alter usage patterns—essentially, the effects of own price elasticity of demand. However, it is an empirical issue; the impacts may be of modest scale.

<u>Customer Charges Schedule 23</u>: RMP proposes to differentiate charges according to seasons. It is not likely, however, that the underlying costs associated with customer services or interconnection (including meters) are differentiated according to load-related seasonal cost patterns. On the other hand, RMP and stakeholders may wish to seasonally vary customer charges for other reasons, possibly including perceptions of improved fairness and equity.

<u>Time-of-Use Periods, Schedules 8 and 9</u>: RMP proposes to put in place time-of-use (TOU) pricing, including peak and off-peak pricing periods. My concerns focus on the methodology used to determine the peak and off-peak periods. Generally speaking, TOU periods can be determined through analysis of variance or statistical clustering methods, as applied to hourly marginal costs for selected months.

<u>TOU Rates for 1MW GS Customers Schedule 6A</u>: RMP proposes to progressively lower the energy charges with lower load factor customers. I concur, providing that the marginal cost to serve systematically declines as load factor increases.

<u>Electric Furnace Tariff, Schedule 31</u>: RMP proposes to close Schedule 21 and move the two customers served on Schedule 21 and Schedule 6A respectively. These two GS customers are apparently sizable and face, respectively, significant windfalls and losses as a consequence of the proposed move. I recommend that RMP give serious consideration to phasing in the rate changes in order mitigate unanticipated gains and losses, as experienced by customers under Schedule 6A.

<u>Transmission Voltage Customers Schedule 9A</u>: RMP proposes to close Schedule 9 and assign the customers taking service thereunder to Schedule 9A. This tariff reassignment involves major changes in customer bills, with an accompanying phase-in of the change in bills. I generally concur with RMP's proposed change, providing RMP can demonstrate that the cost to serve Schedule 9 customers does not vary much from the economic costs of serving Schedule 9A customers.

<u>Partial Requirements/Back Up Power Schedule 31</u>: RMP's proposal calls for two changes to the Schedule 31 tariff. Proposed prices rise by 4.9%, in keeping with RMP's overall system-wide change in tariff rates. Second, partial requirements charges would be aligned with the timeframes and seasonal differences to that of Schedules 8 and 9. My concern is that partial requirements customers may not use

resources in a manner similar to full requirements customers served on Schedule 8 and 9.

Renewable Facilities Schedule 32: For customers with renewable facilities, RMP proposes to set delivery charges (non-energy charges) according to the fixed demand-related T&D costs of full requirements customers, determined daily. The daily power charges are set at levels that, in combination with demand-related charges, cover all-in costs of such facilities. This approach is generally correct. The issue is whether avoided power costs should be determined according to all-in costs of generation or according to opportunity cost-based energy costs determined within the EIM

Pilot Program Options Schedule 35: Curtailable Services and Real-Time Pricing. I concur with RMP's initiative to offer dynamic tariff options to its retail customers. Dynamic pricing takes account of the high frequency variation of economic supply costs. Large gains in resource efficiency can be realized by pricing electricity according to the highly varying cost patterns inherent to electricity.

In the case of curtailable services, I recommend that RMP give consideration to the expansion of the curtailment options available to customers through a menu of service approach, which provides customers with an array of alternatives, differentiated according to notice, duration, and total hours of interruption. For real time pricing, RMP should consider the implementation of a two-part tariff approach, sometimes referred to as a contract for differences. Under a two-part approach, the customer's observed baseline load pattern is priced according to standard tariff; load differences from baseline loads are priced according to day-ahead hourly prices, set according to EIM prices. The two-part approach obtains greater resource efficiency than RMP's proposed one-part RTP approach and also obtains a steady flow of revenue under the customer's standard tariff.

EXPECTATIONS OF OVERALL PRICE INFLATION

Q. HOW DOES PRICE INFLATION IMPACT ELECTRICITY PRICES?

A. The starting point for setting electricity prices is a test period, an annual timeframe for assessment of normalized sales quantities and costs. Contemporary regulatory procedures often utilize a forward test period, which involves estimates of costs and sales quantities for the defined near-term forward period. In turn, assessment of costs over forward timeframes involves projections of future input price levels, likely including some degree of overall price inflation and corresponding escalation rates.

This constitutes the approach in Utah: RMP's projections of financial cost-based revenue requirements—and marginal costs—involve baseline estimates of resources including fixed inputs such as professional labor and capital facilities, and variable inputs such as fuel costs. Projections of inputs costs draw on overall assumptions with respect to input price inflation to yield financial projections. As mentioned above, projections of input price escalation underlying RMP's projections revenue requirements are outlined in the testimony of Mr. Steven McDougal. RMP uses cost escalators prepared by IHS Markit, a major macroeconomic forecasting service (Testimony of Mr. Steven McDougal, lines 176-177).

As a consequence of unanticipated developments beginning late in the first quarter this year, expectations of price inflation have abruptly changed, and it is useful to gauge current expectations of overall price inflation. Measurable changes in expected inflation may result in similar changes in selected elements of RMP's revenue requirements.

My approach to assessing current expected inflation draws upon observed market yields on financial securities of equivalent risk, U.S. Treasury securities, as well as three surveys of expected price inflation. This broad-based approach captures the expectations of investors, forecasters, consumers, and business and academic economists—in other words, a broad cross section of participants in the economy. These methods are as follows:

<ins>Treasury Security Yield Differentials</ins>: Interest rate/yield differentials between two types of Treasury securities: Nominal and Treasury Inflation-Protected Securities (TIPS). The Interest Rate Differentials approach provides estimates of the inflation expectations of investors.

<ins>Survey Methods</ins> include:

Expectations of Inflation by Economists: Inflation expectations held by academic and business economists, as reported in the *Livingston Survey*, as conducted by the Philadelphia Federal Reserve Bank.

Survey of Households: Expectations of future inflation as reported by sampled households included in the *Survey of Consumers* conducted monthly by the Survey Research Center, University of Michigan/Thomson Reuters.

Projections of Inflation by Forecasters: The consensus view of professional forecasters, as reported in the Philadelphia Federal Reserve Bank's *Survey of Professional Forecasters* (SPF).

Treasury Security Yield Differentials: this approach focuses on the inflation expectations of investors, where the term "investors" is interpreted broadly to mean any party that holds—and thus purchases and sells—financial assets, including equities and debt obligations. Transacting parties can thus include individual households, retirement funds, and investment banks trading on behalf of their own accounts.

The market value of financial assets can rise or fall with respect to changes in expected inflation. Some types of assets, such as equities, are less sensitive to expected inflation than others. In the case of debt securities, yield to maturity refers to the expected rate of return on the outstanding principal (the securities themselves). Precisely because the face yields of debt securities such as corporate or Treasury bonds are generally held constant at the time of origination, the market value—and thus the realized net yield—of outstanding debt obligations either declines as expected inflation increases or rises as expected inflation decreases. Changes in market yield account for changes in expected inflation for the investment community as a whole. As a consequence, the expected real return on outstanding debt—realized net return after accounting for expected inflation—at a point in time is predominantly, though not exclusively, a function of perceived risks.

This is a natural result of efficient capital market processes, where expected inflation is capitalized within market yields. Debt securities with equivalent risks and terms can be expected to trade at nearly equivalent yields, given expected inflation. This result also means that, for debt obligations of common risk attributes, obligations that fully compensate for (i.e., are protected from) inflation should trade at market yields below the yields for obligations with nominal yields, where the difference is approximately equal to expected inflation.

This is the case for selected bond issues of the U.S. Treasury. The U.S. Treasury issues debt securities with nominal yields, and other debt securities that include provision for inflation compensation. As mentioned, this latter type of Treasury bond, Treasury Inflation-Protected Securities (TIPS), insulates investors from inflation risk.

Accordingly, this metric for expected inflation, the Interest Rate Differentials method, reveals investor expectations by examining the yield differences between nominal and TIPS obligations of equivalent maturity. For these analyses, nominal and TIPS yield differentials for 5-year, 10-year, and 20-year U.S. Treasury obligations are calculated monthly for each month, 2018 – August 2020.

<u>*Survey-Based Methods*</u> include three surveys of expected inflation including the *Livingston Survey*, the *Survey of Consumers*, and the *Survey of Professional Forecasters* (SPF).

Expectations of inflation of economists are based on the survey results gathered and reported semi-annually by the *Livingston Survey*, as mentioned above. The survey is compiled from the results provided by some fifty respondents, and covers eighteen survey items such as economic output (real and nominal GDP, corporate profits, business fixed investment, industrial production, retail sales, and auto sales), price inflation (CPI and the PPI), labor markets (unemployment rate, average earnings of wage earners), and capital markets (prime interest rate, 10-year U.S. Treasury bond rate, and the S&P 500 Index).

Consumer expectations of inflation are captured by the *Survey of Consumers* which, as mentioned, is conducted by the Survey Research Center at the University of Michigan in collaboration with the Thomson Reuters News Service. This survey consists of approximately 500 telephone interviews with randomly selected households, where the question categories include personal finances, business conditions, and purchasing plans. The Survey of Consumers was initiated during the late 1940s.

The SPF-based projections of inflation are predominantly model-based forecasts of overall price changes. The SPF dates to 1968 and is carried out quarterly. Survey results present the consensus view of forecasters, covering the usual macroeconomic metrics of interest but with considerable density—a selection of twenty-three variables altogether. Of potential interest, I note that the SPF reports the dispersion and range of expectations of survey respondents for selected data series.

Our estimates of the expected rate of inflation during the 2020/22 timeframe are based on these several measures of expected inflation (*Treasury Yield Differentials*, *Survey of Professional Forecasters, Survey of Consumers*, and the *Livingston Survey*). Analysis results are presented in the following tables.

Estimates of Overall Price Inflation
Based on Yield Differences (%)

Implied Expectations of Inflation, Inferred from Financial Markets (%)

Time of Sample of Market Yields	U.S. Treasury Yield Differences: Constant Maturity minus TIPS* 5-year	7-year	10-year	*Expected Inflation: Years 5 - 10* Expectations, year 5 through year 10	Difference between 2nd and 1st 5-year periods
2018	2.14	2.20	2.25	2.36	0.22
2019	1.78	1.85	1.92	2.06	0.28
Mar--Aug '20	1.19	1.35	1.44	1.70	0.51
August '20	1.73	1.81	1.84	1.95	0.22

* Adjusted for inflation and liquidity risk premia

Estimates of Overall Price Inflation
Based on National Surveys (%)

Forward Period	Time of Survey of Projections of Price Inflation	*Surveys of Markets and Forecasters* Livingston Survey CPI	Livingston Survey PPI	SRC Survey of Consumer Expectations	Survey of Professional Forecasters CPI	Survey of Professional Forecasters PCE
2019	2017	2.20	2.10		2.20	2.00
	2018	2.30	2.50	2.70	2.35	2.10
	2019	1.80	0.80			
2020	2018	2.20	2.10		2.40	2.10
	2019	2.10	1.70	2.30	2.23	2.00
	Latest, '20*	0.80	-2.10	3.00	1.50	1.30
2019-2023	2019				2.20	1.90
2020-2024	2020				1.90	1.70

* for Late 2020

Based on the above assessment of expectations, I project overall price inflation for the U.S. to likely reside in the range of 1.75-2.00% over years 2021-2023 and rising toward the end of the period. In summary, expectations of overall price inflation have declined somewhat compared to late-year 2019.

Reduced inflation generally attenuates price escalation associated with RMP's resource inputs. As a result, there may be reason to adjust downward selected inflation factors used by RMP to determine projected revenue requirements. However, this general result does not necessarily imply that test period escalation rates applicable to specific types of power system equipment and related facilities decline by equivalent magnitudes to that overall inflation. First, price escalation of specific equipment or sector reflects overall levels of demand and supply for the underlying resources, which can cause sector prices to vary from overall inflation, often significantly for short duration periods. Second, RMP may have contracts in place with suppliers and vendors for specific equipment, agreements with its skilled labor force, and for outside services also. The commercial terms of the contracts and agreements may not mirror overall price inflation. In addition, labor compensation for electricity services nationwide rise somewhat more rapidly than overall price inflation, which reflects a comparatively large share of highly skilled employees within the electricity services sector.

RMP's MARGINAL COST STUDY

Q. HAVE YOU REVIEWED ROCKY MOUNTAIN POWER'S (RMP) ESTIMATES OF MARGINAL COSTS, AS FILED IN THE IMMEDIATE PROCEEDING? PLEASE DISCUSS.

A. Yes, I have reviewed RMP's marginal cost methodology and cost estimates (marginal cost study contained in Mr. Robert Meredith's workpapers). Generally speaking, RMP's marginal cost methodology and the cost estimates thus obtained are in keeping with longstanding marginal cost principles and methods, as first codified within the Electric Utility Rate Design Study carried out by the Electric Power Research Institute in collaboration with the Edison Electric Institute and the National Association of Regulatory Utility Commissioners. Electricity markets have evolved in significant ways and, at a detailed level, changes in methodology have come about as a consequence of better understanding and improvements in models and data.

Q. PLEASE DESCRIBE MARGINAL AND ELECTRICITY SUPPLY CHARACTERISTICS.

A. Marginal cost is the change in total supply cost with respect to change in the quantity of output. Total supply cost refers to all costs associated with the resource inputs contributing to the production of output. Supply costs are specific to output content and quantity, what is being produced, resource inputs including supplying technologies. This is particularly the case for electricity where resources are highly specialized with long service lives. Average cost is total supply costs normalized by the level of output/sales (MWh) and typically reported in financial cost terms. In the context of utility regulation, total supply costs are commonly referred to as revenue requirements, with average cost equivalent to average prices. Marginal supply costs are often referred to as economic costs and avoided costs.

Electricity services are provided as a continuous flow with only occasional interruption of supply. Power systems constitute highly integrated technologies used in electricity production, and its transport from locations where it is produced to locations where it is consumed. 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 real-time production of electricity is virtually identical to demand within each moment of time, as electricity cannot be readily stored on a sizable scale, at least until very recently. 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. This means that operators of power systems must, in real time, ensure the balance of production and demand while monitoring flows and operating parameters within transport systems including high voltage transmission and distribution circuits. Indeed, the characteristics of power flows across circuits must remain strictly within pre-defined operational boundaries. Third, production involves highly specific, large-scale technologies and processes that involve real-time control of numerous generators, meshed transmission networks, and distribution systems. Electricity production and transport are capital-intensive with unusually long capital lives. Advances in electricity supply technologies have progressed steadily over decades punctuated by major innovations including, most notably, renewable facilities which are available at scale at increasingly favorable costs.

Power systems, moreover, are characterized by substantial scale economies. This means that, at normal levels of output and under normal supply-demand conditions, marginal costs are generally below average costs. Average costs reflected in retail electricity prices are measured in terms of financial cost metrics, where capital is valued according to original accounting cost principles. Also, in the case of conventional generation technologies, capital-fuel substitution opportunities have been present historically where, in the interest of minimizing total costs, more intensive use of capital may provide the means to substitute away from fuel costs.

Estimates of marginal costs are often carried out and reported separately for the well-recognized functions of bundled electricity services: generation, power delivery (transmission, distribution), and customer-related activities. In the case of generation, marginal costs may be measured in terms of opportunity costs and reflected in regional wholesale electricity market prices, or as internal generation costs of electricity service providers.

Conditions which contribute to differences between average and marginal costs are many, and several notable events can be cited: contemporary fuel costs may deviate significantly from long-term fuel cost trends used for purposes of supply planning; demand may be unusually high or low with respect to available capacity; and capacity may be attenuated because of unexpected outages. Accordingly, marginal costs, which reflect near-term supply-demand conditions, can vary substantially in the short term. Examples are readily at hand, and wholesale market price changes of over twofold within a few days are not unusual. On the supply side, marginal costs are highly sensitive to the performance of generating units, transmission line availability, and the costs of primary fuels. On the demand side, near-term changes in weather patterns can cause demand for electricity service to rise and fall significantly, often with corresponding impacts on marginal costs. Meanwhile, average financial costs remain comparatively unchanged across months.

Q. ARE ESTIMATES OF MARGINAL COSTS RELEVANT TO SETTING THE RETAIL PRICES OF ELECTRICITY SERVICES?

A. Yes. To the degree practicable, marginal electricity prices should reflect marginal supply costs, including energy and reliability cost elements. The relevant measure of marginal cost, forward-looking estimates of short-run marginal costs, is determined in high frequency and has substantial cost variation, thus reflecting the unique features of electricity supply. Depending upon public policy, marginal costs used to guide the determination of electricity prices can take account of and include environmental externalities including the damage costs of carbon and air toxins, and other societal costs where relevant.

The major reasons for incorporating marginal costs within the process of setting electricity prices are twofold. First, marginal cost-based prices obtain efficiency gains in the form of improved resource allocation which yield net gains in social value. At a conceptual level, for power systems with optimal least-cost supply of diverse technology and varying loads, marginal cost-based prices cover total costs and are also efficient. At a practical level, marginal cost-based prices provide a means to ration supply: high marginal cost-based prices during tight supply-demand balance conditions reflect the comparative scarcity of supply whereas low prices reflect a condition of plentiful supply.

Second, marginal costs provide necessary guidance to the process of cost allocation. In this respect, marginal costs can inform regulatory decisions regarding issues and concerns of equity and fairness in rate levels paid by retail consumers.

In summary, there is reason to claim that marginal costs should be an integral part of the tariff design process.

Q. PLEASE SUMMARIZE RMP'S METHODOLOGY FOR ESTIMATING MARGINAL COST.

A. RMP's marginal cost methodology aligns with the general principles outlined above, obtaining marginal cost estimates specific to each of the generally accepted activities and functions which constitute bundled electricity services and include generation services; transmission services; distribution services; and customer-related activities. Marginal costs specific to function are adjusted for ancillary costs including administrative and general expenses. In the case of generation services used for time-of-use tariff design, RMP has differentiated market-based marginal energy costs according to timeframes based on observed hourly price patterns of the EIM of the WECC region. These prices are obtained under workably competitive markets and are the relevant measure of marginal costs for use in determining retail prices.

Q. PLEASE DISCUSS FURTHER RMP'S MARGINAL COST METHODOLOGY.

A. RMP's methodology includes the following features:

Marginal costs of generation services include energy and reliability. Marginal energy costs are estimated using an opportunity cost approach; reliability costs are determined according to a capacity cost proxy, which serves as the shadow price of reliability costs incurred by retail consumers. An opportunity cost basis of marginal energy costs is appropriate under the condition where service providers are actively engaged in workably competitive regional wholesale electricity markets. In this case, marginal energy costs are equal to electricity wholesale prices, adjusted for marginal losses and congestion. This result is relevant to RMP, which is actively involved in the Energy Imbalance Market (EIM) organized under the auspices of the California Independent System Operator (CAISO), and operating within the territorial footprint of the Western Electricity Coordinating Council (WECC). As briefly discussed in the testimony of Witness Webb, RMP purchases power from the EIM on a day-ahead basis when EIM wholesale prices are below RMP's internal marginal cost of supplying power and sells power into the EIM when RMP's internal costs are below EIM prices (RMP Data Response to UDPU). Carried out properly, the result is net power cost (NPC) which approximates least total costs of short-term energy supply.

RMP's marginal generation capacity is based on RMP's estimates of the all-in installed investment expenditures of a combined cycle generating unit, multiplied by the appropriate economic carrying charge rate and ancillary cost elements. All-in costs can include several ancillary cost elements including property taxes, property insurance, materials and supplies, working capital, general plant, fixed operations and maintenance expenses, and administrative costs, to the extent that such cost elements are on the margin. Marginal generation capacity costs are typically stated on a kW-year basis and, under optimal least-cost supply-balance, should approximate the sum of consumer outage costs stated on a kWh basis for an annual period.

Estimates of load-related marginal costs of transmission and distribution (T&D) services are approached similarly—reliability-driven costs measured in terms of capacity cost proxies which, ideally, should not stray too far from the shadow price value of reliability costs of consumers. However, there are important distinctions between generation and T&D capacity costs. First, generation capacity costs reflect power systems in their entirety and often reflect capacity costs for broadly defined areas or footprint. In contrast, the true underlying T&D capacity costs, on the margin, are highly specific to locale and circuit. Second, T&D facilities provide a form of joint services, including transport and reliability. Transport services refer to the physical capability to deliver a continuous flow of electricity services from locations where it is produced to locations where it is used by electricity consumers. Reliability services, on the other hand, are load-related, based on the capability to satisfy peak loads.

The starting point for RMP's estimates of transmission and distribution capacity costs is planned investment expenditures for transmission facilities over near-term years, including high voltage bulk power and local facilities; observed incremental expenditures for distribution substations where such expenditures reflect the costs of increased load-carrying capability; and wires services including poles, conductors and related equipment.

In the case of wires services (including poles and conductors) marginal costs are developed for a set of hypothetical circuits which appear to be matched up to RMPs distribution facilities currently in the field. Each of the several stylized facilities, referred to as hypothetical circuits, are assigned percentage shares of RMP's retail customers, where shares appear to correspond to field experience. The incremental costs of distribution circuits are based on equipment and installation costs, stated on a pole-mile basis, and reflect observed circuit distances in the field. Incremental circuit cost estimates are demarcated into commitment and demand cost elements. Commitment costs account for the direct expenditures associated with primary 3-phase circuits; demand costs reflect secondary branch circuits. Expenditures for distribution poles are divided into commitment- and demand-related cost elements according to the relative costs of commitment-related facilities (primary circuits) and demand-related facilities (secondary circuits). Demand-related costs are assigned to months according to observed peak loads of RMP's numerous distribution substations covering the Utah service territory during 2019.

Q. ARE THERE REASONS FOR POSSIBLE CHANGES TO RMP'S MARGINAL COST METHODOLOGY?

A. Yes. I suggest that RMP give consideration to incorporating several changes within its general approach for determining marginal costs: generation capacity costs can be adjusted for planning reserve margins; ancillary costs can be expanded to cover several types of support services and resources on the margin; marginal energy costs can be expanded to include generation operating reserves; and the level of administrative and general expenses should be measured with reference to estimates of the real capital stock rather than net plant-in-service balances. In addition, RMP should explore an alternative methodology for estimating the shares of distribution circuit and wires costs (on the margin) attributed to demand and transport services. Each is briefly discussed below.

<u>Adjustment of Generation Capacity Costs to Reflect Contemporary Levels of Planning Reserves</u>: As general rule, generation adequacy is measured by planning reserves, stated as percent of peak loads. Planning reserve requirements are specific to individual power systems and regional markets. To the extent that increases in peak loads cause increases in capacity requirements, planning reserves also rise, other factors constant. Generally speaking, reserve requirements (%) are lower for large power systems, for systems with strong regional interties, and for systems where total capacity is comprised of small units which tend to diversify reliability risks, providing that the unforced outages of individual units are predominantly uncorrelated.

Because of inherent intermittency, the presence of significant amounts of energy and renewable supply within regional generation portfolios can markedly alter planning reserve requirements and the timeframes and duration of reserve service calls. Going forward, strategically situated storage facilities across power systems will mitigate concerns regarding the sufficiency of reserves. Along this line, the Federal Energy Regulatory Commission (FERC) Order 841 has recently set forth necessary features of market protocols for the inclusion of storage facilities within RTO wholesale markets, referred to as the Participation Model.

Accordingly, RMP should adjust marginal generation capacity costs to reflect contemporary supply-demand balance conditions when appropriate: generation capacity costs used to guide the development of tariff prices and demand-side options including curtailable service options should reflect the balance conditions over the timeframe in which rates will be in effect. A capacity-long condition suggests that, on the margin, curtailable services are worth less than during tight supply-demand conditions. Assessment of the contemporary worth of operating reserves and value of capacity is straightforward though requires sufficiently articulate power system models. Example analyses describing the sensitivity of the value of capacity to changes in supply-demand conditions instructive and useful, as a matter of demonstration.

A related issue is whether a capacity cost proxy should be incorporated in marginal generation costs, in view of RMP's opportunity cost approach to generation services. Where wholesale energy prices adhere to marginal running costs, it is generally appropriate to include a capacity cost proxy, at least in lieu of explicit estimates of reliability costs. If, however, the wholesale energy prices also contain substantial scarcity rent content under tight supply-demand conditions, such prices implicitly reflect reliability, thus covering capacity costs on the margin. This concern remains an outstanding issue: what share of capacity costs are reflected in scarcity rent? Going forward, RMP should consider adjusting generation capacity costs to account for scarcity rent content implicit within EIM prices.

<u>Inclusion of the Costs of Operating Reserves in Marginal Costs</u>: I suggest that RMP give consideration to incorporating the operating reserves along with energy within its estimates of variable costs, on the margin. Regional unbundled wholesale electricity markets typically cover both energy and operating reserve services. Inclusion of operating reserves more fully represents economic costs on the margin, thus providing a more accurate cost basis for determining retail prices. On the other hand, the inclusion of operating reserve costs may not matter much: with the exception of selected hours, the economic costs of operating reserves are comparatively small, particularly when factored down to account for the load level and perspective of retail services.

<u>Ancillary Support Costs</u>: Generally speaking, I anticipate that, on the margin, incremental increases in physical facilities which constitute the main functions of bundled electricity services and their operation and use precipitates increases in the demand for supporting resources, including materials and supplies, equipment and facilities which constitute general plant, and possibly additional working capital. In addition, some elements of administrative and general expenses are related to the operating cost-based resources of functions (fixed operations and maintenance expenses), not exclusively to capital. I suggest that RMP consider

the inclusion of this larger bundle of support services within estimates of marginal costs.

Determining Demand-Related Costs, Distribution Lines: As mentioned above, RMP’s distribution wires costs, including poles and circuits, are obtained by simulating the costs of several hypothetical circuits, an approach which can be referred to as a design-basis of distribution cost estimation. Cost estimates cover both dimensions of power delivery services including the reliable satisfaction of serving peak loads, and the provision for transport services. RMP’s approach, however, does not appear to have an analytical foundation for determining the share of incremental distribution wires costs attributable to demand.

An alternative approach calls for an empirical assessment of the relationship between incremental distribution wires costs and relevant explanatory factors including expected peak loads, transport distances, customer density and numbers of customers served, and variables describing the characteristics of physical facilities and service territories. Datasets used in cost estimation can be organized as panel data, obtained from RMP’s distribution system databases, or a cross-section of electric utilities. Statistical procedures can then be used to assess cost differences—in particular, determining the relationships between peak loads and distribution wires costs. This approach provides an analytical basis to estimate demand-related costs within wires services. Analyses often suggest that a fairly large proportion of distribution wires costs are customer-related.

A second alternative methodology is the so-called minimum distribution system (MDS) approach. MDS methodology provides a means to estimate load- and customer-related cost shares of distribution wires services. MDS is a build-up construct, executed through deterministic cost simulation; results are highly specific to analysis parameters and inputs. A concern with respect to MDS methods is that it does not reflect power distribution currently in place and how, on the margin, the costs of power distribution changes with respect to ongoing increases in the number of customers served and peak loads. In this respect, the MDS is somewhat akin to RMP's approach and, arguably, is better suited to cost allocation than to estimating marginal costs of distribution services.

I do not suggest that the results of RMP's methodology for determining demand- and energy-related cost shares are inappropriate, nor do I imply that the Utah Public Service Commission and stakeholders cannot rely on RMP assessment of the costs of wires services. While RMP's methodology lacks analytical foundation, the estimates of demand-related costs for wires services appear credible, both in terms of magnitude and the respective demand and energy shares of total costs. At this point, we simply cannot say, with confidence, where the underlying distribution cost shares reside. Accordingly, I recommend that, going forward, the analytical approach described above—statistical analysis applied to panel data—serve to supplement RMP's current methodology, possibly affirming RMP's demand costs.

RMP describes non-demand related wires costs as an energy-related services. As a matter of cost causality, non-demand distribution wires costs are related to the presence of customers taking electricity services from distribution systems, where the number of customers served and transportation distances are the main causal drivers. I doubt that energy quantities have much impact on distribution wires costs. Notwithstanding other criteria for tariff design, the implication of the causal relationship between distribution wires costs and customers is sharply higher customer charges.

PROPOSED TARIFF DESIGN

Q. PLEASE TURN TO YOUR TARIFF DESIGN ISSUES, FIRST HIGHLIGHTING RELEVANT CONCERNS.

A. Mr. Robert Meredith advances several major tariff design changes on behalf of Rocky Mountain Power. RMP's proposed tariff design includes several changes and additions, as follows:

- *2-Tier Residential Rates in Lieu of 3-Tier Rates;*
- *Changes to Time-of-Use Periods;*
- *Increases In Customer Charges;*
- *Seasonally Differentiated Tariff Rates;*
- *Differentiated TOU Periods, Schedules 8 and 9*;
- *Seasonally Differentiated Customer Charges, Schedule 23*;
- *Transmission Voltage Customers, Schedule 9A*;
- *Schedule 6A, TOU for >1MW GS Customers*;
- *Schedule 21, Electric Furnace Tariff*;
- *Schedule 9A, Transmission Voltage Customers*;

- *Schedule 31, Partial Requirements/Back Up Power*;
- *Schedule 32, Service for Customers with Renewable Energy Facilities*; and
- *Schedule, 35, Pilot Programs for Large Customers*

Each of the proposed changes is discussed below along with the relevant line numbers of Mr. Meredith's testimony.

Proposed 2-tier Rates in Lieu of 3-tier Rates (lines 566-613): It is likely appropriate to compress the three-tiered residential tariff to two tiers, as RMP recommends. Load-related costs to provide service are not likely to be significantly different between low-use customers and high-use customers. However, compressing tariff rate tiers is complicated; the proposed tariff rates can result in major windfalls and losses to customers while, because of load changes, also alter the net margins to underwrite fixed costs, as realized by RMP on residential class sales.

It is important to sample customer bills and explore rate impacts on customers, while also understanding the effects that the proposed tariff changes have on net margin. The analytical basis to determine net impacts is the coincidence of loads and marginal costs. To the extent that 1) consumer load patterns underlying the third tier tariff rate are different from second tier load patterns, and 2) load-related marginal costs are differentiated according to loads, the proposed changes can give rise to significant shifts in the realization of net margins by Rocky Mountain Power. Depending on the above, net margins may increase or decrease and impacts may be sizable or be insignificant. Further, where tariff prices are set equal to cover total costs associated with retail electricity services, changes in net margins have an impact on the prices paid by other customers.

Mr. Meredith’s testimony presents an analysis of bill impacts as a consequence of the proposed 2-Tier rate design. Going further, an assessment of net impacts requires a load research sample of residential customers, for customers selected from RMP’s customer billing records. Sample load shapes are assigned to sample customers and bills. Net margins, measured as the difference between billed revenue and load-related marginal cost to serve, is estimated under RMP’s current rates and compared to the proposed 2-Tier rate.

The analysis outlined above is straightforward, though carrying out the procedures requires a commitment of resources focused on sample selection and assembling and organizing load and hourly cost data. To discover the appropriate block threshold and set prices, it is likely that RMP will need to carry out several iterations of this—or similar—analytical procedure in order to obtain adequate balance, where the end result satisfies fairness criteria among RMP’s retail customers while also preserving net margins. The proposed tariff rates can cause major windfalls and losses on customers. It’s important to sample customer bills and explore rate impacts across customers inclusive of the proposed changes in customer charges.

<u>Proposed Changes in Customer Charges (lines 476-483)</u>: RMP’s proposed increase in customer charges is in keeping with the trend over recent years of increased customer charges across retail electricity service, and is partially a consequence of improved cost analysis. The cost structures of customer services and interconnection (meters, line drops,

and customer transformers) are not strongly related to the energy sales and peak loads of individual customers.

I concur with RMP's proposed changes: bringing customer charges to levels that more closely approximate the all-in customer-related costs of providing service. Further, because customer-related costs are separable, I suggest that RMP consider setting the all-in energy charges of the proposed two-tier tariff design according to load-related costs, providing that standards of fairness and continuity in rates are also satisfied. To this end, it may be appropriate to phase in needed changes. The concern is that an abrupt change in customer charge levels can imply a breach in standards of fairness in rates, particularly when implemented along with changes in usage prices. The proposed changes can yield sizable changes in bills for selected customers, creating substantial windfalls and losses. A comparative bills analysis is appropriate.

<u>Schedule 23, Seasonally Differentiated Customer Charges (lines 770-775)</u>. RMP proposes to differentiate summer and winter customer charges according to seasonal differences in power and energy charges. Unlike load-related economic costs of generation and power delivery services, customer service costs do not generally have seasonal variation. There are two conditions regarding metering and customer site transformer costs where this generalization may not hold. First, transformer and metering equipment are sized according to customer peak loads and peak loads take place during summer months, and vary with respect to load factor where loads are comparative high during summer months. Second, where RMP experiences larger call volume in customer

service centers during high load periods, thus reflecting seasonal variation in load and energy sales. Further, the frequency of on-site customer calls may assume a seasonal pattern similar to loads. For these reasons, I suggest that RMP and stakeholders give consideration to leaving customer charges unchanged across seasons. Nonetheless, RMP and stakeholders may prefer seasonally differentiated customer costs for reasons of equity and fairness in rates.

In addition, RMP should compare the proposed Schedule 23 rates with reference to 1) the all-in costs serving small commercial customers based on RMP's COS methodology and, 2) marginal costs of service using load research sample data. In particular, experience suggests that commercial customers can have widely varying loads, implying substantial differences in the economic cost to serve.

In summary, detailed cost analysis may find cause to set Schedule 23 prices which depart from the proposed uniform percentage change proposed by Mr. Meredith. Generally speaking, the starting point for determining tariff prices is the underlying cost basis, including COS and estimates of the marginal cost to provide services. These dimensions of costs coupled with the current tariff prices in place provide the foundation for identifying how best to evolve prices over time.

<u>Schedule 6A TOU for <1MW GS Customers (lines 776-847)</u>. RMP proposes to differentiate energy charges per unit of demand (kWh-per-kW), with lower kWh prices as load factor declines. As stated, the result is to lower the average prices from the counterfactual, though low load factor customers will face higher average prices

compared to high load factor customers on Schedule 6A. I agree with the proposed change to the extent that demand charges serve as the basis to cover capacity-related costs, providing that the end result approximates the hourly pattern of marginal costs of generation and power delivery services. A concern is a matter of how broadly the peak period is defined. Under narrowly defined peak periods, a significant number of customers may record maximum demands during off-peak hours.

RMP's analyses accounts for bill savings as customers migrate to Schedule 6A from Schedule 6. Of note, RMP does not appear to provide analytical support for the anticipated migration of Schedule 6 customers to Schedule 6A. Analytical methods for assessment of customer selection of tariff options are available, where parameters for status quo bias, perceptions of risk, and estimates of net benefits provide the means to develop projections of tariff selection options. However, such models have high levels of prediction error particularly where the underlying parameters are not empirical based; at the end of day, may be little better than the ad hoc assumptions used by RMP.

Electricity customers self-select: customers that opt for the TOU tariff are likely to be those customers that expect to realize net benefits in the form of reduced electric bills through load shifting. To the extent that decreased revenue under the TOU tariff is more than offset by decreased cost to serve—that is, increased net margin—RMP and Utah customers as a whole realize net gains.

<u>Schedule 21 Electric Furnace Tariff (lines 877-903)</u>. RMP proposes to close Schedule 21 and assign the two customers served on Schedule 21 to Schedules 6 and 9, respectively.

These two GS customers are sizable and, apparently, will realize significant windfalls and losses as a consequence of the proposed move. I suggest that RMP give consideration to phasing in the change in rates (bills paid) in order to avoid major changes in the prices paid under Schedule 21 compared to 6A. Because of the large change in bills, electricity consumption level and peak loads may change accordingly.

<u>Schedule 9A Transmission Voltage Customers (lines 905-923)</u>: RMP proposes to close Schedule 9A and assign the customers to Schedule 9. The change yields very large bill changes for some customers. Accordingly, RMP proposes a 3-period phase-in of the change, where each phase is an equal proportionate change of 33%, as applied to the 9A tariff price. RMP's approach appears appropriate, providing that the marginal cost to serve customers currently under Schedule 9A is similar to serving customers on Schedule 9.

Mr. Meredith indicates, at line 917: "Similarly situated customers should pay the same price…" I concur, provided that "Similarly situated…" refers to the underlying cost incurred by RMP to provide service, on the margin. If so, RMP has a strong case to close Schedule 9A.

<u>Schedule 31 Partial Requirements/Backup Power (lines 924-945)</u>. As proposed, Schedule 31 prices rise by 4.9%, equivalent to the proposed overall system-wide change in tariff rates. Second, partial requirements charges would be aligned with the timeframes and seasonal differences to those of Schedules 8 and 9. My concern is that the underlying load patterns of the partial requirements customers may be highly dissimilar compared to

the resources—and thus the underlying costs—employed by RMP in service of full requirements customers under Schedule 8 and 9. Additionally, some Schedule 31 customers may be served at transmission voltages, which would affect cost to serve.

Experience suggests that consumption patterns of customers with on-site power supply capability are sensitive to backup service charges: reduced (increased) charges for backup services precipitate increased (decreased) use of backup power. RMP should consider pricing backup power service according to the pattern of load-related marginal costs plus fixed charges associated with RMP's interconnection facilities for serving customer sites, which are likely to be specific to individual customers.

One approach to pricing backup power services is a two-part tariff, where Schedule 31 tariff prices are set according to cost to serve a predefined or historical consumption pattern and also satisfy all-in costs, determined according to COS. Hourly departure of actual consumption pattern from historical cost patterns are then priced according to RMP's marginal cost of providing service. This approach ensures that choice of supply, by RMP's customers with on-site resources, is consistent least cost principles. The challenge is determining historical consumption patterns in the use of backup services, which is likely to reveal substantial, and inconsistent, variation.

<u>Schedule 32 Service from Renewable Energy Facilities (lines 946-957)</u>. Delivery charges (non-energy charges) are set according to the fixed demand-related T&D costs of full requirements customers and determined daily. The daily power charges are set at levels

which, in combination with demand-related charges, cover all-in costs of such facilities. RMP's proposed approach is correct.

For two reasons, the presence of renewable resource facilities has virtually no near-term impact on the all-in costs of providing power delivery services. First, power delivery facilities—particularly distribution facilities—are highly cost indivisible. At the time of installation, distribution facilities are sized in order to serve prospective loads and customers over the long term, where facilities consist of long-lived equipment. Across the numerous distribution systems in a place, many systems will have significant levels of redundancy, in the form of unused capacity. This approach, sizing facilities to cover expected loads and customers over the long-term is appropriate, as a significant share of installed costs are installation; a degree of oversizing with respect to current load levels avoids the costs of periodic facility changeout.

Second, once installed, retail service providers realize virtually no power delivery cost savings from reduced loads other line losses. Accordingly, retail consumers with renewable resource facilities should pay normal charges for power delivery services, usually in the form of demand charges. Nonetheless, the presence of renewable facilities may, on occasion, yield load-related capacity cost savings of voltage transformation (distribution transformers). Going forward, these situations are likely to be few.

My concern with respect to RMP's general approach is in the application: should facility charges associated with the provision of distribution services, covered in demand charges, are accounted for in common charge which reflects full-service customers as a whole? I anticipate that RMP will incur major differences in the all-in power delivery costs, as revealed in the details underlying RMP's estimates of marginal costs for distributions services. The policy question is whether a demand charge applicable to customers with renewable facilities should take account of power delivery cost differences among customers. If so, is it practical to implement cost differences in the tariff charges?

Schedule 35 Pilot Programs for Large Customers. RMP proposes two "dynamic" tariff design options: *Interruptible Service* (IS) and *Real-Time Pricing* (RTP). For this discussion, dynamic pricing is defined as electricity prices that reflect near-term marginal costs of electricity services, have high levels of frequency, and are conveyed to retail consumers on short notice. Dynamic pricing can assume the form of short notice of pending curtailment periods, or hourly energy prices applicable to near-term consumption, such as hourly usage during the following day.

RMP's plans bring the utility in line with use of dynamic pricing initiatives at many other utilities. Real-time pricing, arguably the most comprehensive dynamic pricing program due to its applicability in all hours of the year, dates to the 1980s in California and New York. In the early 1990s Georgia Power Company introduced both day-ahead and hour-ahead RTP options for its large customers (discussion by Steven Braithwait, Transmission and Wholesale Markets School, Edison Electric Institute, 2003). Properly executed, dynamic pricing is generally viewed as the most cost-effective means to mitigate the costs of energy and capacity costs by delivering demand response by customers at times of system need. Essentially, near-real-time economic costs of electricity supply are conveyed to electricity consumers, who can elect to respond by reducing usage. It is common for the generation expansion plans of electric utilities to take account of the expected peak load reductions associated with IS and RTP programs in capacity requirements over future plan years. Similarly, capacity auctions of the RTOs of the Eastern Interconnection have significant demand-side participation in the provision of capacity (results of PJM capacity auction, referred to as the Reliability Pricing Model),

Interruptible Service Pilot Program: RMP's initial proposal offers demand and energy credits to participating customers. The credits are applicable quantity nominations (MWs) and appear to be set according to avoided capacity and energy costs (marginal costs). I concur with RMP's general approach but wish to offer a few comments. First, curtailment quantities during curtailment calls should be measured with respect to the counterfactual reference load levels—what loads would have been in the absence of calls. Generally speaking, reference loads can be set according to the historical load patterns, or hourly load levels during hours and days near the time of curtailment.

Second, RMP and stakeholders may wish to explore a "menu of service" approach, where potential participants face a set of curtailment service options, differentiated according to notice, duration of calls, and annual curtailment hours. Load curtailments are costly to electricity consumers. A menu-based approach to interruptible services provides for broader participation by RMP's larger retail customers. Some customers can reduce loads on short notice with only modest disruption, while others may require considerable advance notice of a pending curtailment call because the costs of disruption—say, a sudden abrupt closure of a highly automated production line—are expensive. In the case of duration, customers with fairly tight commitment schedules may find it highly costly to reschedule foregone production to later timeframes. On the other hand, short notice is likely to provide greater value to electricity service providers compared to longer notice.

It is perhaps useful to mention that deploying curtailable services (curtailment calls) in a manner that maximizing the value of limited curtailment contracts to the RMP system is a challenging optimization problem, requiring dynamic programming.

Real-time Pricing Pilot Program: RMP's proposed approach is "one-part" RTP, where day-ahead hourly prices, posted by the CAISO for the EIM, are conveyed to participating RTP customers of RMP (lines 638-642). The monthly bill of participating customers is equal to the sum across the hours of the billing period of the product of hourly day-head prices and loads. Prices are scaled to achieve revenue neutrality with the baseline tariff, which reflects financial costs (revenue requirements). This approach preserves the differences in hourly prices, which encourages participating customers to shift load from high-cost hours to low-cost hours. RTP customers shift loads locally, within hours of the day and among near-term days (e.g., from, say, Wednesday to the following Thursday and Friday).

The primary concern with the one-part approach to dynamic pricing is the end-of-period reconciliation of marginal cost-based bills to financial cost levels. Such approach tends to blunt the incentive to shift loads, resulting in a loss of resource efficiency: normalization of hourly prices to the baseline tariff negates long-run price impacts, foregoing benefits to customers and to RMP. Second, day-ahead hourly prices can vary considerably from real-time marginal costs; this is a particular consideration in the Western System. Third, load responses resulting from day-ahead hourly prices will likely change revenues, as realized following reconciliation.

As an alternative, I suggest that RMP and stakeholders give consideration to a two-part pricing approach, where a baseline consumption level—usually the observed hourly load pattern--is set beforehand and priced out under the standard baseline tariff. Differences between metered actual hourly loads and baseline loads are priced according to avoided costs/marginal costs (EIM prices at the relevant locations for RMP). Expected impacts of two-part RTP including within day, across days, and long-run load responses to price changes can be easily simulated.

The advantages of two-part RTP are several: marginal prices reflect short-run marginal costs and are thus efficient; long-run price response based on short-run marginal costs is facilitated; revenue flows to underwrite RMP’s financial costs are sustained at normal levels and are stable; and there is relative ease of facilitation and ongoing program management. When hourly day-ahead RTP prices reach exceptional levels reflecting, say, tight supply-demand balance conditions, participating customers have strong incentives to reduce loads below baseline loads levels. For these hours, RTP customers realize bill credits equal to avoided costs. Conversely, low hourly day-head prices signal plentiful resource supply, thus encouraging participating customers to increase usage above baseline levels. For these hours, customers pay day-ahead RTP prices for the incremental electricity above baseline levels. This two-part approach has a counterpart in financial markets referred to as a "contract for differences". Since 1992, Georgia Power Company has served a major share of its industrial customers under two-part day-ahead real-time pricing. Customers also have available a hedge option priced at forward-looking marginal costs/avoided costs in order to help customers manage the inherent risk from the exposure of a significant share of load to short-run marginal cost-based prices.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A

Robert J. Camfield

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, Fine Arts Diploma

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, New Hampshire Public Utilities Commission, 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 assignments regarding wholesale and retail markets including cost allocation, resource evaluation including renewables, energy contracts, regional analysis, cost measurement, marginal cost analysis, electricity market forecasting, rate of return and capital valuation, performance benchmarking, retail tariff design, rate base and financial projections, incentive regulation, and transmission planning. For electricity and gas clients, I have reviewed tariffs and cost allocation methods, conducted cost of capital studies, helped negotiate power contracts, reviewed load forecast processes, assessed resource plans and electric generation technologies, 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 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:

Docket 20190017-EG: Testimony regarding Long-Term Projections of Avoided Costs, filed on behalf of Florida Public Utilities Company before the Florida Public Service Commission, 2019.

The Cost of Power Outages to Electricity Consumers, filed by Newfoundland Labrador Hydro before the Board of Commissioners of Public Utilities, 2019.

Marginal Cost Study Update, 2018, filed by Newfoundland Labrador Hydro before the Board of Commissioners of Public Utilities, 2018.

Review of Load and Energy Forecast Methods, a report filed by Manitoba Hydro in the General Rate Application before the Public Utility Board, 2017.

Transmission Cost Allocation Methods to Account for Network Additions, filed with the proposed Network Additions Policy of Newfoundland Labrador Hydro before the Board of Commissioners of Public Utilities, 2018.

Docket NG-0086: "Proposed Cost of Service Gas Hedge Agreement Between Black Hills Nebraska and Black Hills Utility Holdings, Inc.," 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 Board of Commissioners of Public Utilities 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 Board of Commissioners of Public Utilities in the General Rate Application of Newfoundland and Labrador Hydro, 2017.

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

Estimation: Marginal Costs of Generation and Transmission Services for 2019, a regulatory report filed before the Board of Commissioners of Public Utilities 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 before the Board of Commissioners of Public Utilities, 2016.

Transmission Cost Benchmark Study, submitted with the 2019 Capital Budget Application of Newfoundland Labrador Hydro before the Board of Commissioners of Public Utilities, 2018.

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, 2015, co-authored with Michael O'Sheasy.

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, 2012, co-authored with Philip Schoech.

General Rate Filing (2012/2013 and 2013/2014): "Review of Cost of Service Methods," filed before the Public Utilities Board of Manitoba by Manitoba Hydro, 2012, co-authored with Bruce Chapman and Michael O'Sheasy.

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, 2012, co-authored with Bruce Chapman and Mithuna Srinivasan.

“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, 2012, co-authored with Mithuna Srinivasan and David Glyer.

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

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, 2011, co-authored with Bruce Chapman.

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

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

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

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

Docket FTC–02/09: “Estimates of Marginal Costs of Electricity Supply In 2010” report filed before the Fair Trading Commission, on behalf of Barbados Light & Power Company, Limited, 2009, co-authored with Bruce Chapman and David Armstrong.

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, 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, 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, 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, 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, 2008.

Docket 070304–EI: Rebuttal Testimony before the Florida Public Service Commission regarding return on equity for the determination of retail rates, 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, 2007.

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

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

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

Docket 06–KCPE: Testimony before the Kansas Corporation Commission with regards to performance assessment, cost benchmarking, and capital risks attending electric utilities, 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, 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, 2005.

Docket 040216–GU: Panel testimony regarding the cost of capital before the Florida Public Service Commission for the determination of retail rates, 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, 2003.

Testimony and discussion on financial implications and risks under open access transmission, before the Energy Regulatory Office, Warsaw, Poland, 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, 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, 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, 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, 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, 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, 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, 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, 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, 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, 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, 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, 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, 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, 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, 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, 1978.

Professional Papers and Key Reports:

"Cost of Capital Report," prepared for a small gas distribution utility, 2019, co-authored with Nicholas Crowley.

"Cost Allocation and the Impact of Curtailable Service Options," a technical report with accompanying analytics prepared for a major wholesale service provider, 2019.

For Determination of Rate Base, supporting Study of Working Capital and Calculation of Accumulated Deferred Income Taxes, prepared for small gas distribution utility, 2019.

"Update: Forward Looking Marginal Costs," prepared on behalf of a major G&T company, 2017, co-authored with Nicholas Crowley.

"Pricing Policy and an Assessment of Regional Electric Rates," a report prepared for a major G&T company, 2017, co-authored with Bruce Chapman.

"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, 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-authored 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-authored with Mathew Morey.

"Methods for Determination of Rate Base and Weighted Average Cost of Capital," prepared Newfoundland Labrador Hydro 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-authored with Rita Sweeney, Bruce Chapman, and Mathew Morey.

"Review of Forecast Methods Underlying the 2015 Energy Forecast," prepared for Manitoba Hydro and filed in the 2017 general rate application before the Public Utilities Board of Manitoba, 2015, co-authored with Steven Braithwait and Daniel Hansen.

"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.

"A Competitive Benchmark Study, A Comparison of Wholesale Rates and Costs", 2015, co-authored with Mathew Morey, Laurence Kirsch, and Eric Peterson.

"2015 Load and Energy Forecast Review," prepared for a major G&T power supplier, 2015.

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

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

"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, 2014, co-authored with Laurence Kirsch, Mathew Morey, and Kelly Eakin.

"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, 2012.

"Assessment Criteria for Development of Renewable Resources," for a major electric utility, 2011, co-authored with Laurence Kirsch and Philip Schoech.

"Financial Cost Benchmark Projections," projections of all-in revenue requirements of a regional peer group of competing utilities, prepared for a major municipal electric and water utility, 2010.

"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 regional models, the study assessed local, regional, and national impacts including the incremental employment and household income effects resulting renewable resources, 2010, co-authored with Bruce Chapman and Michael Welsh.

"Contingency Reserve Pricing Methods," a report to a major electric utility regarding the incorporation of demand side participation in the provision of operating reserves, 2009, co-authored with Dave Armstrong and Laurence Kirsch.

"Documentation and Analysis, 2009 Annual Forecast Review" for the general rate case and Integrated Resource Plan filing of a major electric utility before its regulatory authority, 2009.

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

"Demand Side Participation in Contingency Reserves," conducted on behalf of a major electric utility, a survey of the markets for ancillary services of ISO/RTOs where loads actively participate in the auctions for operating reserves, 2009, co-authored with Bruce Chapman and Michael O'Sheasy.

"Review and Recommendations: Forecast Methodology and Process," a report prepared for a major integrated electric utility, 2008.

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

"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, 2004, co-authored with F. Buchta, D. Armstrong, and W. Lubicki.

"Long-Term Outlook for Regional Electricity Prices," prepared for a G&T cooperative, co-authored with Michael Welsh, 2003.

"A Cost-Benefit Analysis of RTO Options," a report prepared for a major electric utility, 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, 2002, co-authored with Rajesh Rajaraman.

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

"Market Value Assessment of Hydro Units," for a major electric utility, 2003, co-authored with David Armstrong.

"Cost Effectively Improving the Network Metering," a report on observability: clarifying the technical methodology for determining the least-cost placement of CT and PT meters within power transmission networks, 2001, co-authored with Fernando Alvarado, John Kalfayan, Laurence Kirsch, Wei Liu.

"An Assessment of Retail Pricing Portfolio," prepared for a major electric utility, 2002, co-authored with Bruce Chapman, David Glyer, and Michael O'Sheasy.

"Value of Reliability to Customers" a survey-based assessment of consumer outage costs prepared for a major G&T cooperative, 2000, co-authored with Michael Welsh.

"Unbundled Marginal Cost-Based Cost of Service Allocation," a marginal cost basis of allocation of financial costs prepared for a major electric utility, 2001, co-authored with David Armstrong and David Glyer.

"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 editors, 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 editors, 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 Tomas 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, co-authored with Kathleen King.

"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 editors, 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.

"Analysis of Power Wheeling Transactions: Network and Price Impacts," 1996, co-authored by Arthur Maniaci and Rajesh Rajaraman.

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

"Marginal Cost-Based Allocation of Financial Costs," a marginal cost-basis of cost of service allocation prepared for a major electric utility, 1996, co-authored with Arthur Maniaci and Alfred Schulz.

"Transmission Comprehensive Marginal Costing," a report covering the conceptual design for software to determine locational prices, EPRI, 1996, co-authored with Keith 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, 1994, co-authored with Romkaew Broehm, Laurence Kirsch, Harry Singh, and Peter Shatrawka.

"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 involved several assignments including the determination of financial costs, estimation of long-run marginal costs of generation, transmission, and distribution services, allocation of financial costs, and tariff design, 1994.

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

"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:

Presenter, "Estimating Regional Wholesale Electricity Prices", seminar sponsored by EUCI, July 2020.

Presenter, "Marginal Costs of Electricity Services", seminar sponsored by EUCI, June 2020.

Presenter and panel participant, "Electric and Gas Coordination", conference on recent developments in natural gas markets sponsored by the Wisconsin Public Utilities Institute, March 2020.

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 Arizona 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:

Estimates of avoided costs for estimation of the benefits associates with demand side options.

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

Evaluation Criteria for Electrification and Conservation Policy Options, discussion paper prepared for a major G&T power system and distribution service provider.

Discussion of dynamic pricing tariff options, for the 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.

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

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

Economic evaluation of investment in a cogeneration facility.

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.

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

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 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.

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.

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.

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.

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.