STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Rock Island Clean Line LLC	**)**	
	)	
Petition for an Order granting Rock Island	**)**	
Clean Line a Certificate of Public Convenience	**)**	
and Necessity pursuant to Section 8-406 of the	**)**	
Public Utilities Act as a Transmission Public	**)**	**Docket No. 12-____**
Utility and to Construct, Operate and Maintain	**)**	
an Electric Transmission Line and Authorizing	**)**	
and Directing Rock Island Clean Line pursuant	**)**	
to Section 8-503 of the Public Utilities Act to	**)**	
Construct an Electric Transmission Line.	**)**	

DIRECT TESTIMONY OF

KARL A. MCDERMOTT

ON BEHALF OF

ROCK ISLAND CLEAN LINE LLC

<u>ROCK ISLAND EXHIBIT 4.0</u>

OCTOBER 10, 2012

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Certain capitalized terms in this testimony have the meaning set forth in the Glossary included as Attachment A to the Direct Testimony of Michael Skelly, Rock Island Exhibit 1.0.

I. INTRODUCTION

Q. Please state your name, business address, and current position.

A. My name is Karl A. McDermott. My business address is 875 North Michigan Avenue, Suite 3650, Chicago, Illinois, 60611. I am currently the Ameren Distinguished Professor of Business and Government at the University of Illinois, Springfield ("UIS") and Acting Director of the Center for Business and Regulation housed in the College of Business and Management at UIS. I am also a Special Consultant to National Economic Research Associates, Inc. ("NERA").

Q. What are your qualifications to provide testimony in these dockets?

A. A detailed description of my background can be found in my curriculum vita attached to this testimony as Rock Island Exhibit 4.1. I have been working in the field of public utility regulation for over 30 years with experience in nearly every facet of the regulation of public utilities. I received a B.A. in Economics from Indiana University of Pennsylvania, an M.A. in Public Utility Economics from the University of Wyoming, and a Ph.D. in Economics from the University of Illinois at Urbana-Champaign.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of this direct testimony?

A. I have been asked by Rock Island Clean Line LLC ("Rock Island") to provide an opinion on its proposed high-voltage direct current ("HVDC") transmission line from Northwestern Iowa to Gundy County, Illinois ("Rock Island Project" or the "Project"). In particular, I was asked to review Rock Island's application for a certificate of public

convenience and necessity requested pursuant to §8-406 of the Illinois Public Utilities Act ("PUA" or "Act") and for an order pursuant to §8-503 of the PUA, and evaluate whether the proposed construction of the Rock Island Project will satisfy the statutory criterion in §8-406 that the Project will "promote the development of an effectively competitive electricity market that operates efficiently [and] is equitable to all customers…" (220 ILCS 5/8-406(b)) and the statutory criterion in §8-503 that the Project will "promote the development of an effectively competitive electricity market" (220 ILCS 5/8-503). My testimony pertains only to findings specified by the PUA concerning the Project's effect on competition in the electricity market, as quoted in the previous sentence, and not to other findings required by §8-406(b) or §8-503.

Q. Please summarize the results of your analysis and conclusions presented in this direct testimony.

A. My conclusion is that the Project will allow lower cost generation to enter the Illinois market, which will create competitive downward pressure on prices in the wholesale market. The additional transmission capacity promotes an effectively competitive electricity market by increasing the size of the supply side of the market competing to serve load in Illinois and opening the Illinois market to lower cost generation resources. Moreover, the projected downward pressure on prices is a strong indication of a market operating efficiently and it is expected to benefit customers directly through lower prices for electricity. Further, although not directly estimated in this testimony, consumers should benefit indirectly through lower input cost into production, which can help maintain lower prices for other goods and services.

My analysis indicates that the benefit of the line to Illinois consumers is between $667 million and $1,221 million (NPV in 2013 dollars), and that consumers in each electric utility service territory in Illinois will share this benefit, though the largest dollar benefits will accrue to customers in the Commonwealth Edison Company ("ComEd") and Ameren Illinois Companies' ("AIC") service territories. While I have not broken out the benefits to the other service territories in Illinois e.g., municipal utilities, co-ops, and the smaller investor-owned utilities, all of these entities are market participants in one or both of the regional transmission organizations ("RTOs") that serve Illinois, and to the extent that such utilities purchase energy in RTO markets or depend on contracts priced on RTO spot markets or access renewable power markets, customers in those service territories are expected to reap some benefit from the Project as well.

Further, the quantity of capacity competing to serve load in Illinois will increase as a result of the Project. My analysis indicates that the increase will be up to 2.9 % of total Economic Capacity (which I define below), depending on the specific future year and market development circumstances concerned.

Also, the stated purpose of the Project is to provide access to high value renewable (i.e., wind) generation resources that could be sited in northwestern Iowa and nearby areas. Renewable resources have added value through their ability to satisfy state level renewable portfolio standards ("RPS") currently in place as well as potentially provide cost-effective competition to traditional generation and even demand-side resources. As Rock Island witness Mr. Berry shows, the demand for renewable energy in both RPS markets and in wholesale and retail markets east of the Mississippi is forecast to grow over the next decade (Rock Island Exhibit 10.0.). The Project is projected to

provide access to new and currently untapped potential renewable resources that should have the effect of providing competitive pressure on prices in renewable energy credit ("REC") markets as well as competitive pressure on prices in markets for renewable energy.

On the basis of the evidence provided in this testimony, I conclude that the Illinois Commerce Commission ("ICC" or "Commission") should find that the Project satisfies that criterion set forth in §8-406(b) of the Act that the Project "will promote the development of an effectively competitive electricity market that operates efficiently, is equitable to all customers" and the provision of §8-503 that the Project will "promote the development of an effectively competitive electricity market."

III. DESCRIPTION OF THE PROJECT AND REVIEW OF THE PROPOSED ANALYSIS

Q. Would you please provide your understanding of the Project?

A. Rock Island is proposing to build a roughly 500-mile, ±600 kV HVDC line from Northwest Iowa (O'Brien County), crossing the Mississippi River near Princeton, Iowa (north of the Quad Cities), and extending approximately 120 miles through Illinois where, after DC-to-AC conversion, it will interconnect with the ComEd 765 kV transmission system near Morris, Illinois. I also understand that, when completed, the Project will have the capability of delivering 3,500 MW of power.

Q. How does the Project fit in the regulation of public utilities in Illinois?

A. Traditionally, public utilities build infrastructure to assure that consumers have access to service when they demand the service. For example, in Section 8-406 of the Act, the ICC may grant a certificate to a public utility if it finds that the construction of the infrastructure is "necessary to provide adequate, reliable, and efficient service to its

customers and is the least-cost means of satisfying the service needs of its customers." Under this criterion, the ICC must determine that the proposed construction will add to the reliability of the system. This makes perfect sense in a regulated monopoly marketplace. In 1997, however, the state of Illinois restructured its electric market to allow competitive forces more of a role in allocating electricity market resources. With that change, the legislature recognized that market forces will also play a role in dictating what and where infrastructure is built based on the economics of a particular project that may not necessarily increase the physical reliability of the system. The General Assembly added, in 2007, in both Sections 8-406 and 8-503 (and subsequently in new §8-406.1), language that recognized that because competition is important to protecting consumers interests, certain utility infrastructure may be necessary to support and promote competition, quite aside from, or perhaps in additional to, the traditional concern over reliable and safe service. The Project fits this second category of allowable utility construction.

Q. What is the purpose of the Project?

A. The Project is aimed at providing a pathway for high-value renewable generation resources sited in northwestern Iowa and nearby areas to reach load centers east of the Mississippi River.

Q. How does creating a new pathway for high-value renewable resources to reach Illinois translate to benefits for Illinois consumers?

A. There are several possible benefits from the proposed Project. First, renewable resources have very low marginal costs of production. As market prices are related to the marginal cost of production, additional renewable resources can have the effect of lowering overall

wholesale market prices. For example, the Illinois Power Agency ("IPA") reported in March 2012 that current renewable generation lowered the single year 2011 cost of wholesale generation in Illinois by roughly $176 million.[1] System modeling performed by GL Garrad Hassan on behalf of Rock Island, as summarized in this testimony and described in greater detail in the testimony of Rock Island witness Mr. Gary Moland, shows that by providing access to additional low cost renewable generation, the Project is expected to lower wholesale prices in Illinois in the future as well. Second, renewable energy, as it does not rely on fuel input markets, can provide a natural hedge against volatile electricity prices, which could benefit ratepayers who are risk averse.[2] Third, the Project should have positive competitive effects on the market for RECs in Illinois and surrounding regions. To the extent that those RECs will enter the Illinois energy portfolio, either via the IPA procurement process or through non-IPA procurement, competitive pressure should provide benefits to Illinois consumers in the long run. Further, the REC market in the Eastern Interconnection[3] is larger than in Illinois, and by providing access to tradable RECs or bundled RECs (i.e., with energy), the Project should have a positive effect on the entire regional REC market.

Q. How did you analyze the Project?

A. I started with Section 8-406 of the Illinois Public Utilities Act, which allows a public utility to request a certificate of public convenience and necessity for construction of new

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[1] Illinois Power Agency, "Annual Report: The Costs and Benefits of Renewable Resource Procurement in Illinois under the Illinois Power Agency and the Illinois Public Utilities Act," March 30, 2012.

[2] Refer, for example, to: Center for Renewable Energy, "Economic Impact: Wind Energy Development in Illinois," June 2011.

[3] The Eastern Interconnection is essentially the entire Alternating Current ("AC") transmission system east of the Rocky Mountains including parts of Canada and Texas.

plants, and Section 8-503, which allows a public utility to request an order authorizing and directing the construction of new plants. Section 8-406 of the Act requires, among other things, that the ICC find, in part (and as an alternative to the "necessary for reliable service" criterion), that the Project "will promote the development of an effectively competitive electricity market that operates efficiently and is equitable to all customers." Similarly, §8-503 of the Act requires the Commission to find (as an alternative to finding that the project is necessary for the security and convenience of the public) that the Project "will promote the development of an effectively competitive electricity market." Next, I developed an analytical technique to determine whether the Project meets this legislative test.

Q. Would you please describe the basis for your analytical technique?

A. I based the analytical technique on my interpretation of the requirement under the Act and the realities of the operation of a transmission system network. I expect if a transmission project is promoting competition in the PJM market, there would be downward pressure on prices in the Northern Illinois region and perhaps the rest of the state including the area where the Midwest Independent Transmission System Operator, Inc. ("MISO") operates. This will first show up as lower, on average, wholesale electricity prices (I discuss what I mean by "wholesale electricity prices" below). These future prices can be modeled using standard techniques. I call this the "Part 1" analysis. Further, we should also find that that the level of economic import capability should increase. Increasing economic import capability allows a greater level of lower cost generation resources to compete in the Illinois market allowing for greater competitive

pressure on prices. I call this the "Part 2" analysis. This analysis is sufficient to show that the Project is *promoting* competition in the Illinois wholesale electric market.

The additional language of §8-406(b) of the Act indicates that the competitive market should be equitable to all customers. The law must be referring to the market over which a transmission project has some influence. In this case, this is the wholesale electric market (including the REC market). A transmission asset cannot, except indirectly, have an influence on the competitiveness of the retail electricity market. Perhaps the most obvious way to apply this provision of the Act is to ask how wholesale electricity prices affect customers in Illinois. For the ComEd and Ameren retail customers who buy power through the real-time or close to real-time wholesale market, any reduction in wholesale prices will provide a direct and immediate benefit. For those customers that buy power from ComEd or Ameren through the procurement process under the Illinois Power Agency Act ("IPA Act"), the benefit will show up through the daily balancing process the utilities undertake and will subsequently reduce the purchased energy adjustment in the long term as more recent vintage contracts are added to the portfolio.[4] Likewise, for other customers in Illinois who buy power under contracts, the benefit will show up as new contracts are added to their portfolios.

Q. Would you please define what you mean by "wholesale electricity prices?"

A. For simplicity we can think of wholesale electricity markets as operating in two distinct realms—the short run and the long run. In the short run—a few minutes to a day—electricity is traded in a spot market and short term (day-ahead) futures markets operated

[4] A description of how ComEd and Ameren balance actual loads with pre-purchased contracts using the RTO-administered short-term markets can be found in the ICC's most recent order approving the IPA procurement plan. (Order, ICC Docket No. 11-0660, p. 25)

by the RTOs. (In Illinois, PJM operates in the northern part of the state and MISO operates in most of the rest of the state.) In the long run—days to years—electricity is traded in either formal futures markets, (e.g., NYMEX), or via bilateral trades among market participants (called forwards markets).[5] In this testimony I am reporting on modeling the short term, hourly prices or spot-market prices. These are the critical wholesale electricity prices, as spot markets underlie the pricing for all other markets. For example, consider a forwards contract purchased in September 2012 for delivery of energy in February 2013 in the NI-Hub trading hub. (NI-Hub is an electricity trading area in Northern Illinois.) One would expect that forwards price to represent the expected spot price in NI-Hub in February 2013 as of September 2012 (the date the contract is entered into). If the February 2013 forwards market price in September 2012 was much higher than what market participants, on average, expected, demand for the February 2013 forwards contract in September 2012 would fall because traders would wait and purchase at the lower spot prices at the delivery date. The opposite could occur as well. One expects, then, that there is a connection between forwards (or futures) prices and (expected) spot prices. In recognizing this connection, it is sufficient to understand how spot market prices change as a result of the Project in order to understand the influence of the Project on wholesale electricity prices in general, and in turn, retail electricity markets. For the purposes of this testimony, I am reporting modeling of the

[5] There is a distinction between "forwards" and "futures" markets. Forwards markets are bilateral trades for which terms and conditions including price, volume, and delivery points are agreed to between market participants. Futures markets are standardized contracts, including volume and delivery points, traded on a formal exchange, such as NYMEX, with only the price determined by trading.

hourly spot energy markets (as opposed to longer term capacity markets).[6]

These markets operate as buyers—the load-serving entities—reveal the level of demand, or load, needed to serve customers in each hour and sellers—producers as well as imports—bid to serve load in each hour. In principle the market-clearing price in an hour is the marginal cost, that is, the incremental production cost as offered, of the most expensive unit dispatched to serve load in that hour when the system is dispatched at the overall lowest-cost. In practice the market, and in turn the PROMOD modeling completed for this testimony, is somewhat more complex because some generation units may be physically prevented from delivering output to some parts of the network due to congestion or other factors. The impact of electrical losses on the transmission system can also impact the choice of least-cost generating units and the marginal cost of serving load. Accordingly, the RTOs run a program that determines which units to dispatch, taking into account the physical limitations of the system and the rate of transmission system losses (this program is called a security-constrained dispatch, and is simulated by PROMOD).

Prices are determined at different locations—called nodes—on the network, based on the marginal cost (or bids) of serving load at the node concerned. There are hundreds of nodes in Illinois alone. If there were no constraints on the transmission network and no transmission losses, then the price at each node would be identical and equal to the cost of the last unit dispatched in that hour to meet the entire load of the system. In practice, however, prices can vary from node to node due to transmission congestion and

[6] It is conceivable that due to non-market influences longer-term contracts might be priced significantly in excess of market determined prices. In this testimony I have focused on market-determined prices, as the finding required by the Act relates to the functioning of electricity markets.

the rate of transmission system losses. As the nodes represent physical locations on the network, the prices are called Locational Marginal Prices ("LMPs") reflecting the fact that the price at any location represents the (marginal) cost of serving load at that location. Often these prices differ by only fractions of a penny per kilowatt-hour in any sub-region of the system (e.g., NI-Hub or Illinois Hub, a trading area in Central Illinois). LMPs can differ more significantly between regions that are farther apart e.g., between the Illinois Hub and trading hubs in Wisconsin or Michigan, because transmission congestion and losses tend to increase in magnitude as the size of the region under review increases. The mix of generation (and its marginal cost) may differ more substantially as the size of the region under review increases.

Q. Do you believe it is equitable that customers that buy through the real-time market benefit immediately but customers that purchase power from the IPA process and other customers that purchase power under contracts must wait?

A. Yes, for two primary reasons. First, no matter the economics, the IPA process was created by the Illinois General Assembly, as was Section 8-406. I must assume that the General Assembly knew that Section 8-406, to the extent it would interact with the IPA process, would create a reasonable method of delivering whatever benefits might accrue as a result. Second, this issue is a short-term issue. The only contracts (IPA and otherwise) that do not include the effect of the Project are those contracts signed prior to the knowledge of the markets participants of the Project and its effect on wholesale electric prices (and transmission rights). Once bidders are confident that the Project will be built (and we can argue as to when that might occur, but it certainly will occur once the Project is in service), any contracted energy for sale after the Project is in service i.e.,

2016 or 2017, will include an expectation of the benefit from the Project. (And, as I noted above, there will be some immediate benefits even to customers buying from the IPA portfolio through the daily balancing activities of the utilities.)

Q. Does your analysis assume that the PJM wholesale market and the interchange between PJM and MISO are competitive?

A. Yes. There are two main reasons for this assumption.

First, the Federal Energy Regulatory Commission ("FERC") has jurisdiction over the PJM and MISO markets, and both PJM and MISO have independent market monitors that report on the state of the markets to FERC, state commissions, and other stakeholders. In the most recent market monitoring report, the PJM market monitor concluded that the energy and capacity markets in PJM are competitive.[7] Similarly, the most recent MISO market monitoring report found that energy markets were competitive and market participant behavior was broadly consistent with a workably competitive market.[8]

Second, in 2002, FERC conditionally accepted that certain utilities in the eastern portion of the US could join either MISO or PJM, but that pricing differentials and trade barriers between RTOs could frustrate the goals of FERC Order No. 2000 (the so-called "seams" issues). To address these concerns, FERC ordered PJM and MISO to begin exploring and designing a joint and common market that would attempt to remove trade barriers between the RTOs.[9] By 2007, FERC had determined that the RTOs were

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[7] Monitoring Analytics, LLC, *Q2 State of the Market Report for PJM*, August 16, 2012.

[8] Independent Market Monitor, *State of the Market Report for the MISO Electricity Markets*, June 2012.

[9] *Alliance Companies* 100 FERC ¶ 61,137 (July 31, 2002). The broad set of RTO functions can be found in: *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000).

making significant progress toward the goals of a joint and common market.[10] In 2009, FERC found that "the correlation between prices in the ComEd zone and the Midwest ISO is consistent with the existence of the Midwest ISO-PJM Interconnection Joint and Common Market."[11] The basis of the joint and common market is a Joint Operating Agreement ("JOA") between PJM and MISO, which enhances their combined operational reliability, reduces seams, and contains arrangements for joint administration of the joint and common market.[12] Seams were reduced by eliminating pancaking for transmission service charges across the combined territories and implementing less distortionary transmission cost recovery mechanisms instead. Indeed, when FERC approved the First Energy-Allegheny merger, it noted that the companies had considered a geographic market that included parts of PJM and MISO. While FERC did not need to rely on this analysis for its determination, it did note that the evidence was suggestive that competitive concerns were not raised by the merger if the PJM West market was included in the analysis, which implies that the PJM-MISO markets are sufficiently integrated as to consider them one market.[13]

Q. Would you please describe the scope of your analysis?

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[10] *Wisconsin Public Service Corp.. v. Midwest Independent Transmission System Operator, Inc.* 118 FERC ¶ 61,089 (February 8, 2007).

[11] *Exelon Corporation*, 127 FERC ¶ 61,161 (May 21, 2009), p. 30.

[12] *Midwest ISO, Second Revised Rate Schedule FERC No. 5, PJM Interconnection, L.L.C., Second Revised Rate Schedule, FERC No. 38; Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,251 order on reh'g, 108 FERC ¶ 61,143, reh'g denied, 109 FERC ¶ 61,166 (2004) *Also see Wisconsin Public Service Corp. . v. Midwest Independent Transmission System Operator, Inc.* 118 FERC ¶ 61,089 (2007) *order on reh'g* 120 FERC ¶ 61,269, p. 44 (September 24, 2007) ("Through the JOA the RTOs have achieved levels of coordination unequaled by other RTOs. Under the JOA, the RTOs have instituted a process to coordinate dispatch on their systems with the objective of managing loop flow and congestion in the most cost-effective manner.")

[13] *First Energy Corp. and Allegheny Energy Inc.* 133 FERC ¶ 61,222 (December 16, 2010) note 44.

A. In its simplest form, I was interested in determining the net benefit in terms of lower cost to serve load in Illinois as a result of building and operating the Project (Part 1 analysis) and the increase in the potential capability to serve the Illinois market (Part 2 analysis). I have investigated the market for electrical energy and the market for RECs. I have not investigated the markets for capacity or ancillary services, but I know of no reason why my findings with regards to the market for electrical energy would not be broadly transferable to the markets for capacity and ancillary services since changes in supply of generating capacity also impact the deliverability of supply to these markets. At a minimum, if I can show that the Project promotes a competitive market for energy, the Commission can conclude that it would do nothing to harm the competitiveness of these other markets.

Q. What marketplaces have you investigated?

A. Regarding energy, I have investigated the impact of the Project on the wholesale market for electrical energy in Illinois and separately for the PJM and MISO service territories within Illinois. I selected these geographic areas because they are the regions that are of import to the state of Illinois and to the ICC. As I noted above, in a competitive retail market such as Illinois, I expect the impact on the wholesale market to be transferred directly to the retail market and onto Illinois consumers.

Regarding RECs, I have investigated the potential impact of the Project as it relates to the REC market in Illinois and more broadly. REC markets are unique, and difficulty exists in defining REC relevant markets because of several factors. The main factor is that deliverability is defined in legal or regulatory terms, as opposed to physical terms. For example, in most instances, a REC buyer in State A can purchase from a REC

seller in State B and not be concerned about physical delivery between States A and B. The environmental benefit of a REC is a shared good and the legal and/or regulatory rules set out any commercial constraints on trading between states. A related factor is that deliverability can be different for buyers than it is for sellers. For example, currently a REC buyer in Colorado can buy from a REC seller with a facility in Illinois; however, a REC buyer in Illinois is only able to buy from a REC seller with a facility in Colorado – for purposes of meeting Illinois legal requirements – under restrictive conditions (namely that no cost-effective RECs are available from facilities in Illinois or adjoining states as noted below). Finally, many RECs are perfectly substitutable between certain states, sometimes up to predefined quantity limits or only once specific cost thresholds have been reached. The combined implication of these factors is that there is rarely, if ever, a one-to-one relationship between the geographic marketplace in which a REC can be sold and the geographic marketplace in which a REC must be purchased.

Under existing Illinois law, Illinois utilities buying RECs for RPS requirements for eligible retail customers must purchase from facilities in-state or from adjoining states, and these generation locations are treated equally, but if insufficient cost-effective resources are available, then RECs from outside that area may be used. (220 ILCS 3855/1-75(c)(3)) That is, resources from either Illinois or adjoining state resources receive equal preference before procurement from other states can be considered. I have investigated the market for RECs as defined by the geography of Illinois and adjoining states; however, I recognize this regional market definition is necessarily imperfect: on the supply side, REC facilities in these states are able to bypass the local regional market only if they wish, to sell directly to other states (e.g., Colorado); and on the demand side,

REC buyers in Illinois are able to purchase from outside this regional market if insufficient cost-effective resources are available in this regional market. Nevertheless this market definition is useful because it represents the available source of REC supply until such time as the regional market is no longer cost-effective as prescribed by Illinois law. From a purely economic perspective, however, a broader market defined by the entire Eastern Interconnection is also useful to investigate as decisions made in this broader market definition can, and likely would, have an effect on the Illinois market. For example this market definition might be more applicable for a situation where REC buyers in Illinois are able to purchase from outside the regional market because insufficient cost-effective resources are available in Illinois and adjoining states.

Q. Would you please describe your analytical technique?

A. For the Part 1 analysis for the energy market, I needed a model of the entire system with and without the Project to determine the impact of the Project on system costs and market prices. I supervised a team that worked with Rock Island witness Moland of GL Garrad Hassan who produced forecasts using the PROMOD modeling software. (Mr. Moland describes the PROMOD model and method and the underlying assumptions and data sources in his testimony.) PROMOD is one of the standard electric system modeling programs that I have relied on in the past for expert testimony. (*See e.g.*, McDermott Dir., in ICC Docket No.11-0661.) Mr. Moland provided me with results for the years 2016 and 2020, which included modeling of four alternative "futures."

While the Project will be in place for much longer than 2020, I deemed it reasonable to choose these two years as representative of the types of benefits that are likely to accrue to Illinois—and the broader region—as a result of the Project. While no

model can perfectly predict the future, given what we know today about factors that are likely to influence the value of the Project, this is a reasonable approach to estimate the benefits from the Project. I will describe the exact process of arriving at a net present value of the Project later in this testimony.

The four futures can be described as: Business as Usual, Slow Growth, Robust Economy and Green Economy. A summary of the different assumptions for each alternative future can be found in Mr. Moland's Direct Testimony, Rock Island Exhibit 3.0. These alternative futures represent a reasonable range of potential outcomes for the purposes of this type of modeling.

Mr. Moland produced two model runs for each future that result in predicted LMPs for all nodes in the model area.[14] For each future, a "with the Project" and "without the Project" run was completed, which allowed me to evaluate the Project's projected effect on the competitiveness of the energy markets in Illinois. I did so by deducing the potential energy market impact of the Project in each future by comparing the PROMOD "with the Project" case to the corresponding PROMOD "without the Project" case. I have focused solely on results as they relate to the state of Illinois, since this is the most relevant geography for this analysis.

For the Part 2 analysis for the energy market, I have investigated the extent to which the Project will potentially expand the set of generators that are able to compete to serve load in Illinois. In order to quantify this impact, I have applied the relevant calculations from the Delivered Price Test ("DPT"), as contained in Appendix A of

[14] The model area includes most of the Eastern Interconnection. This is important as Illinois is electrically connected to other regions and it is necessary to understand the interaction of Illinois in the broader region. While I report data solely for Illinois, these data include any resulting interactions with other regions of the Eastern Interconnection.

FERC's Merger Policy Statement, to determine the change in the quantity of capacity able to serve the destination market.[15] The DPT is relevant to the analysis of the Project because it includes a recognized standard for measuring the relevant size of electricity markets for competitive analysis. Suppliers to a destination market are the generators who can compete to supply load in that destination market and whose ability to do so contributes to competition in the destination market. The DPT measures the Economic Capacity of these generators, which is defined as the supply that can be delivered into the destination market at a delivered cost less than 105 percent of the destination market price.[16] (105 percent is a value specified by FERC and reflects the thinking that suppliers who can deliver up to this price are effectively competing in the same market.)

For the Part 1 analysis for the REC market, I did not attempt to forecast the cost of production or market prices of RECs for the reasons described above regarding the difficulty of determining the relevant REC market. Rather, I investigated whether the Project is capable of exerting downwards pressure on REC prices in Illinois. (I do not expect the Project to exert upwards pressure on REC prices in Illinois because with increased supply, I would expect, at worst, and with all other things remaining the same, that REC prices would remain unchanged.)

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[15] In 1996, FERC issued its "Merger Policy Statement" providing a detailed analytic framework for assessing the horizontal market power arising from electric utility mergers. Order No. 592, 77 FERC ¶ 61,265 (December 18, 1996). In 2000 FERC issued Revised Filing Requirements which affirmed the screening approach to mergers consistent with Appendix A in the Merger Policy Statement. Revised Filing Requirements Under Part 33 of FERC's Regulations, Order No. 642, III FERC Stats. & Regs. ¶ 31,111 (November 15, 2000)

[16] The DPT in Appendix A of the Merger Policy Statement also provides for an analysis of Available Economic Capacity, defined as energy over and above that required to meet native load and other long-term obligations that meets the delivered price test. I have not considered an analysis of Available Economic Capacity here because, as a result of retail unbundling, the concept of native load is no longer relevant in this context in Illinois.

For the Part 2 analysis for the REC market, I have investigated the extent to which the available supply of RECs increases as a result of the Project. I have conducted this analysis for a market defined by Illinois and adjoining states, as well as for a market defined by the Eastern Interconnection. The adjoining states area (plus Illinois) is the area in which renewable resources should reside for the purposes of meeting the Illinois renewable portfolio standard after June 2011. (20 ILCS 3855/1-56.) I have conducted this analysis separately on an energy (MWh) and on a capacity (MW) basis.

Q. Is it necessary to include a Herfindahl-Hirschman Index ("HHI") analysis as part of the Part 2 energy market analysis?

A. No. An evaluation of HHIs resulting from the DPT is relevant in the context of a merger application before FERC. An HHI analysis, however, is unnecessary in this case. As I have noted above, the competitiveness of the wholesale market is an assumption of the analysis, not something that must be proven (that determination is made by FERC). At this point, an HHI analysis is not possible to undertake because the owners of the generation that will use the Rock Island line are unknown. Moreover, even if the owners were known, this process would not yield any additional useful insight on the competitive dynamic in the state of Illinois as a result of the Project beyond the information provided by the DPT evaluation of the extent to which the set of generators, which are able to compete to serve load in Illinois has grown. Finally, the Act does not require a competitive analysis similar to FERC's Merger Policy Statement Appendix A. That is, the Act does not establish a threshold of a competitive market – rather it merely requires that the Project *promote* the development of an effectively competitive market for electricity and thereby promote a market that provides benefits to all consumers. It is

reasonable to conclude that a test such as the DPT is consistent with the intent of the Act to show the promotion of a competitive electricity market.

IV. THE PROJECT WILL REDUCE THE COST TO SERVE LOAD IN ILLINOIS, WHICH SHOWS THAT IT PROMOTES THE DEVELOPMENT OF A COMPETITIVE MARKET (PART 1 ANALYSIS)

Q. Would you please provide an overview of the methodology you used to calculate the net energy market benefit to Illinois of the Project?

A. I calculated the net present value ("NPV") of the benefits of the Project to Illinois load under each future as outlined above. I made the NPV calculation separately for the PJM and MISO service territories of Illinois and also for Illinois in total.

I assumed that all changes in LMP resulting from the Project would be passed through to customers and therefore reflected in the cost to load. As I noted above, given the structure of the Illinois market, this is a good approximation of the value to Illinois customers. The cost to load in a given year was calculated as the sum of the hourly LMP multiplied by hourly load, across all load nodes in Illinois, and across each hour in the year concerned.

I calculated the NPV for a period spanning and including the years of 2016 to 2020 inclusive.

Recall that I had Mr. Moland simulate the market to produce predicted prices for 2016 and 2020. For the between years – 2017, 2018 and 2019 – I interpolated cost to load based on the predicted 2016 and 2020 values for each future. For simplicity I have assumed the following:

1. The Project goes into service in 2016 and achieves the level of utilization predicted by the PROMOD model for that year;

2. There are no changes to investment decisions by other investors for projects coming online in the 2016-2020 period as a result of the Project, and likewise units that are close to closing do not accelerate their retirement plans in these years as a result of the Projects; and

3. In 2021 and after, I have assumed that other investors and "retirees" do modify their behavior as a result of the Project; no benefits are projected beyond 2020.

Q. Are your results invalidated if the in-service date of the Project is delayed to 2017?

A. No. Essentially that would mean that the net energy market benefit to Illinois I have calculated would be delayed by a year. It would reduce the NPV slightly since the benefits would be one year further in the future, but it would not change the overall conclusion of my analysis.

Q. Would you please describe the process you used to calculate the net present value or NPV of the Project in Illinois?

A. The NPV of the Project to Illinois load is the difference between the cost of market purchases to serve Illinois load in the "without" case and the cost to serve load in the "with" case in each year, discounted to a particular reference date. I have used a reference date of 2013 and have calculated the NPV for each of the four futures described above. NPV is a commonly-used financial tool that allows the analyst to compare cash flows over multiple periods for any project. If the NPV is greater than zero, then a project is beneficial. In essence, for each future I have calculated the cost of purchasing the predicted level of load in Illinois in the "with the Project" case at each node and compared that to the cost of purchasing the same level of load at each node under the

"without the Project" case and summed up the differences in each hour and each year and discounted those values to 2013.

Q. Why is the LMP cost-to-load metric appropriate for Illinois?

A. Both PJM and MISO are LMP markets, meaning that wholesale market prices are defined on a locational basis in each as I have described above. The LMP metric is therefore appropriate because it reflects the cost of purchasing electrical energy in both the PJM and MISO territories of Illinois.

Q. What discount rate did you use for your NPV calculation?

A. This is always a contention in using the NPV approach because a larger discount rate will show a smaller NPV than a smaller discount rate if benefits are relatively evenly spaced over time as is the case with the Project. Smaller discount rates are typically used for projects that have social costs and benefits, whereas larger discount rates are used for purely private transactions recognizing that individuals likely have higher discount rates than society. I have not formally derived a discount rate; rather, I used an 8% (real) discount rate for illustration purposes. I did perform a sensitivity analysis on the discount rate as I describe below.

Q. Would you please summarize the benefits you calculated using the above approach?

A. The predicted benefit of the Project to Illinois customers under each future is set out below. Table 1 shows that the NPV benefit through 2020 (in 2013 dollars) ranges from $667 million in the Slow Growth future to $1,221 million in the Robust Economy future. Table 2 provides the same data in cumulative NPV form and illustrates, for example, that in each future considered the benefits to Illinois consumers exceed $450 million (2013

dollars) by 2018 – i.e., within three years of the Project's in-service date. Figure 1 illustrates this graphically.

Table 1: Project Benefits to Illinois as a Result of Building the Project[17]

		Project Savings Illinois Total			
Year	NPV Factor	Business as Usual	Slow Growth	Robust Economy	Green Economy
2016	0.741	320	249	488	493
2017	0.671	301	232	438	393
2018	0.607	281	214	389	293
2019	0.549	262	196	339	193
2020	0.497	242	179	289	93
NPV ($2013million)		874	667	1,221	958

Table 2: Cumulative NPV Benefits to Illinois as a Result of Building the Project

	Project Savings (Cumulative, Discounted to $2013million) Illinois Total			
Year	Business as Usual	Slow Growth	Robust Economy	Green Economy
2016	238	185	362	365
2017	439	340	655	629
2018	610	470	891	806
2019	754	578	1,078	912
2020	874	667	1,221	958

[17] Note that the "NPV Factor" column in shows the NPV in 2013$ of a one-dollar benefit in the year of the row concerned, at the illustrative real discount rate of 8% and given an inflation rate assumption (used in the PROMOD analysis) of 2.5%. The sum-product of the "NPV Factor" column and each "future" column is used to derive the "Total NPV in $2013millions" row of NPVs for each future.

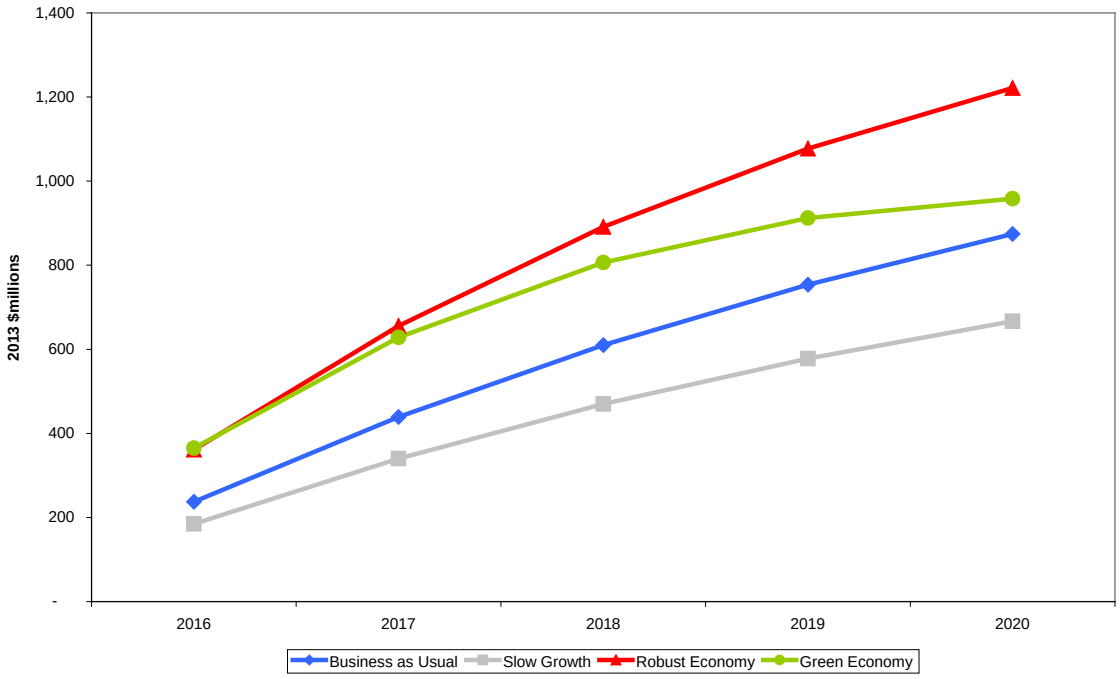

Figure 1: NPV Savings to Illinois Consumers from the Project (Source: Table 2)

Q. How do the forecast savings compare to the total cost to load?

A. Table 3 and Table 4 show total cost to load without and with the Project, respectively. Measured on a net present value basis, and for the state of Illinois in total, the forecast savings range from 2.4% of the total cost of load in the Green Economy future to 5.2% of the total cost to load in the Slow Growth future.

Table 3: Total Cost to Load in the Base Case (without Project)

	Total Cost to Load (nominal $ millions)			
	Illinois Total			
Year	Business as Usual	Slow Growth	Robust Economy	Green Economy
2016	6,923	5,252	8,656	16,113
2017	7,451	5,429	10,062	16,969
2018	7,979	5,607	11,468	17,826
2019	8,507	5,784	12,874	18,682
2020	9,034	5,961	14,280	19,538

Table 4: Total Cost to Load in the Project Case (with Project)

	Total Cost to Load (nominal $ millions)			
	Illinois Total			
Year	Business as Usual	Slow Growth	Robust Economy	Green Economy
2016	6,603	5,003	8,168	15,621
2017	7,150	5,198	9,624	16,577
2018	7,697	5,393	11,079	17,533
2019	8,245	5,587	12,535	18,489
2020	8,792	5,782	13,991	19,445

Q. How are the benefits distributed by service territory in Illinois?

A. Both RTO territories in Illinois receive benefits. The largest benefits are in the larger (in terms of total load served in Illinois) PJM service territory. These benefits range from $630 million (2013 dollars) in the Slow Growth future to $1,104 million in the Robust Economy future. In the case of the MISO territory these benefits range from $37 million in the Slow Growth future to $117 million in the Robust Economy future. Table 5 sets out the range of benefits for these two service territories.

Table 5: Benefits to Illinois by RTO Service Territory (PJM and MISO)

		Project Savings				Project Savings				Project Savings			
		Illinois Total ($2013million)				PJM Illinois ($2013million)				MISO Illinois ($2013million)			
Year	NPV Factor	Business as Usual	Slow Growth	Robust Economy	Green Economy	Business as Usual	Slow Growth	Robust Economy	Green Economy	Business as Usual	Slow Growth	Robust Economy	Green Economy
2016	0.741	320	249	488	493	301	236	452	446	19	13	36	46
2017	0.671	301	232	438	393	281	219	401	356	20	12	37	37
2018	0.607	281	214	389	293	260	202	350	265	21	12	38	28
2019	0.549	262	196	339	193	240	185	299	174	22	11	40	19
2020	0.497	242	179	289	93	219	168	249	83	23	11	41	10
NPV		874	667	1,221	958	810	630	1,104	867	64	37	117	92
NPV (%)		4.9%	5.2%	5.0%	2.4%	6.7%	7.2%	6.6%	3.4%	1.1%	0.9%	1.5%	0.6%

Q. Would you please summarize the cumulative NPV benefits by service territory and future, in graphical format?

A. These results are illustrated below in Figure 2, Figure 3, Figure 4, and Figure 5. These figures illustrate that:

- **The larger NPV benefits are in the PJM service territory** – since the Project will provide energy directly into the PJM system, we expect larger benefits in the PJM area of Illinois and smaller, though not insignificant, benefits to the rest of Illinois;
- **The largest NPV benefits occur in the Robust Economy future** – in the robust economy future, loads and input prices are increasing which increases production costs. As the Project will provide low marginal cost wind resources we expect that robust economic growth will produce larger savings; and
- **The smallest NPV benefits (although still considerable) occur in the Slow Growth future** – this occurs for the opposite reason we expect higher savings in the robust economy future.

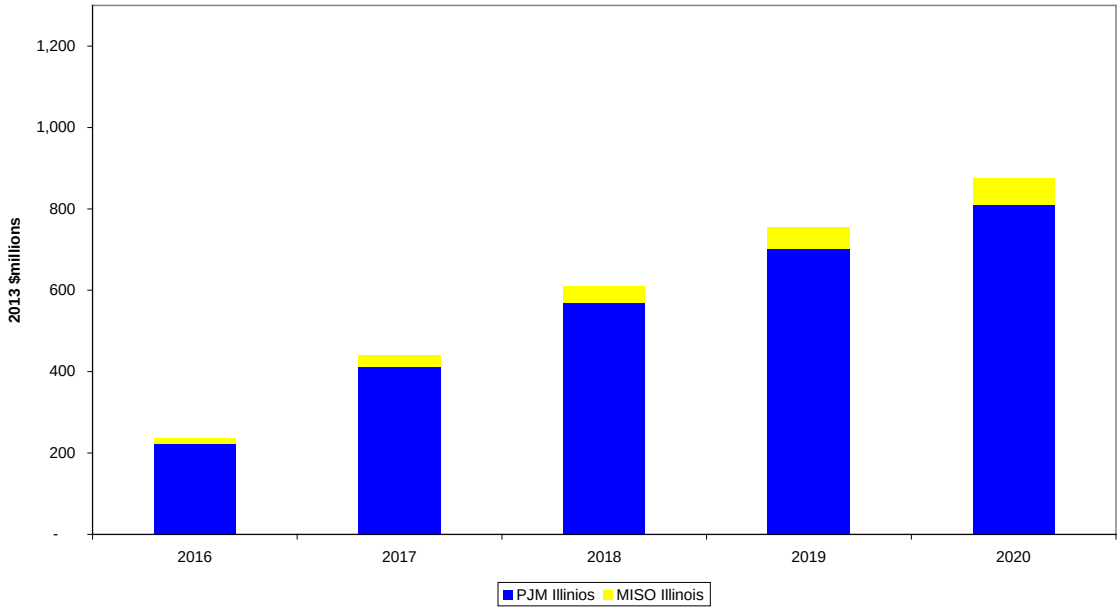

Figure 2: Business as Usual Future: Savings to Customers from Project by RTO Service Territory (cumulative in $millions, discounted to 2013 dollars)

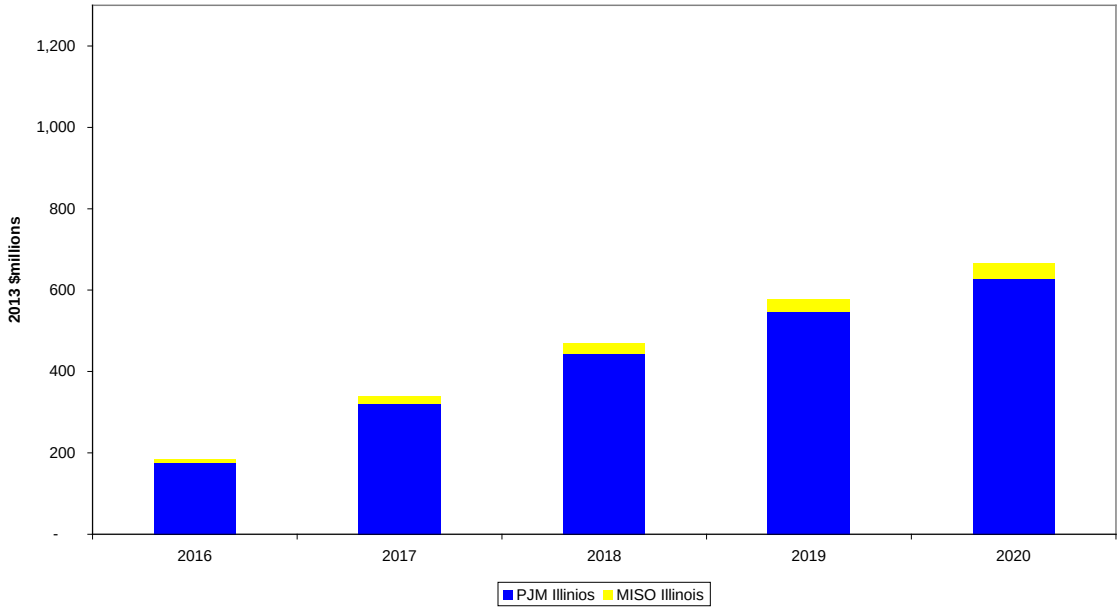

Figure 3: Slow Growth Future: Savings to Customers from Project by RTO Service Territory (cumulative in $millions, discounted to 2013 dollars)

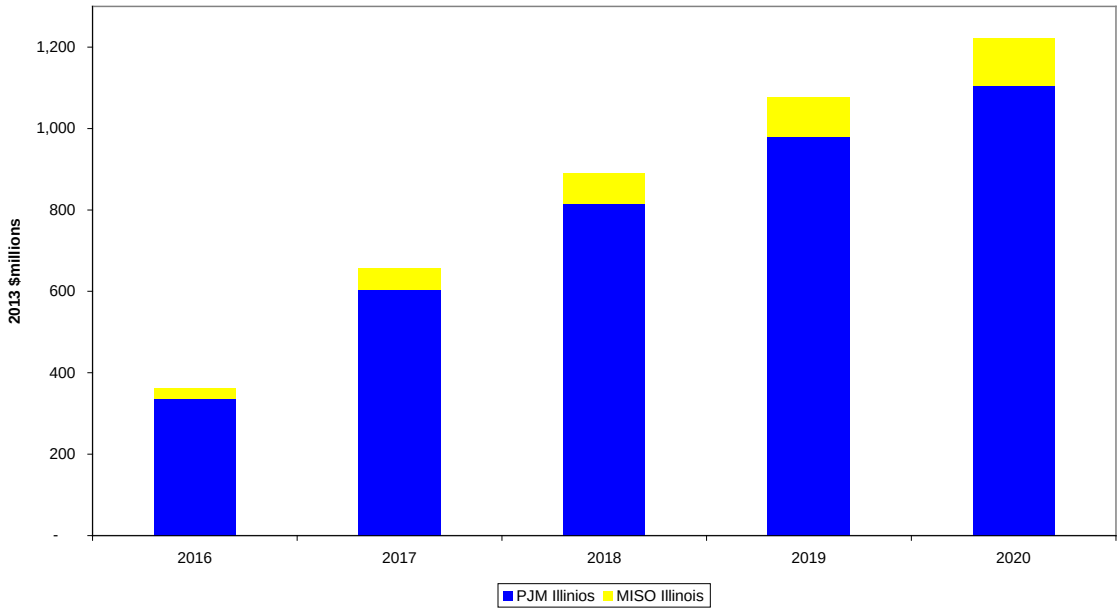

Figure 4: Robust Economy Future: Savings to Customers from Project by RTO Service Territory (cumulative in $millions, discounted to 2013 dollars)

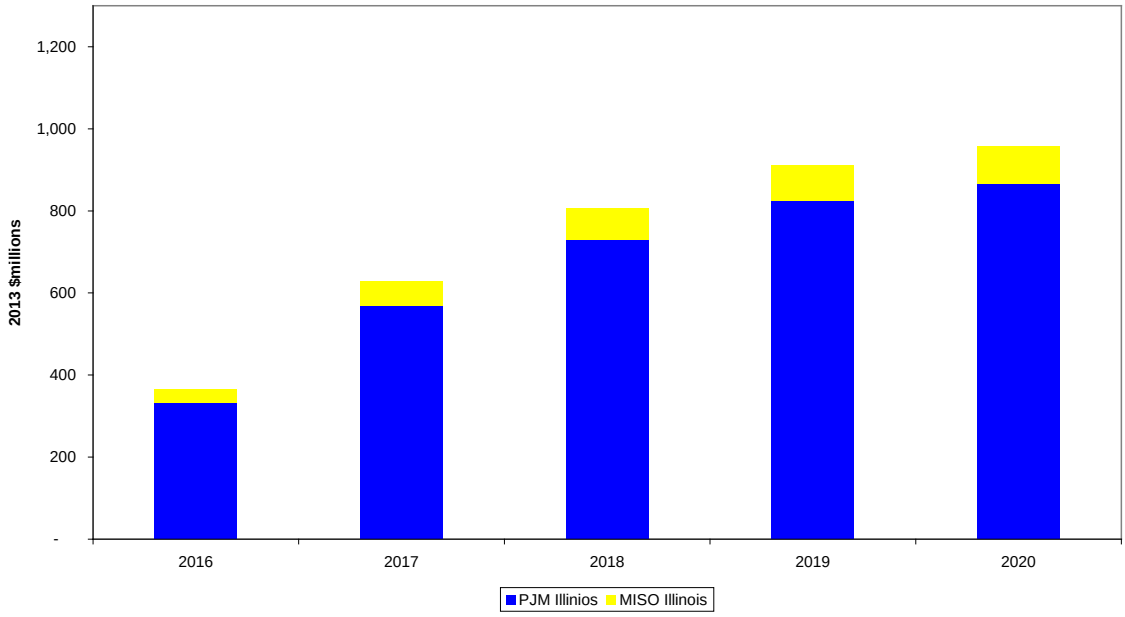

Figure 5: Green Economy Future: Savings to Customers from Project by RTO Service Territory (cumulative in $millions, discounted to 2013 dollars)

Q. Have you considered an alternative discount rate in your NPV calculations?

A. Yes. To investigate the sensitivity of the NPV of benefits to the assumed real discount rate I have repeated the NPV calculation described above for an illustrative range of real discount rates from 3% to 13%. The results are summarized in Table 6.

Table 6: Sensitivity of NPV Benefits to Illinois by Discount Rate ($2013millions)

Real Discount Rate	Business as Usual	Slow Growth	Robust Economy	Green Economy
3%	1,087	828	1,511	1,164
4%	1,040	792	1,447	1,119
5%	995	758	1,386	1,075
6%	952	726	1,328	1,034
7%	912	695	1,273	995
8%	874	667	1,221	958
9%	838	639	1,172	923
10%	804	614	1,126	889
11%	772	589	1,082	857
12%	741	566	1,040	827
13%	712	544	1,000	798

Q. What have you concluded from this sensitivity analysis?

A. The Project provides for benefits to Illinois in excess of $500 million over a range of alternative discount rates and a range of alternative market futures.

Q. Why did you not estimate future benefits past 2020?

A. One could argue that changes in generation supply as a result of the Project will perturb the electric market equilibrium until such time that other market participants begin to respond. For example, a higher cost unit that would have been built in the “without” case will be delayed in the “with” case causing the generation enabled by the Project to produce lower costs until such time as the delayed higher cost unit is built (and, in some sense, the “with” and “without” cases merge). Economists talk about this in terms of

market equilibrium. The Project will cause a movement from equilibrium, and subsequent cost savings, but eventually the market will move toward the original long-term equilibrium. If this new equilibrium date is later than 2021, then the benefits forecast as a result of the Project are higher; if it is earlier, then the benefits of the Project would be lower. It is important to note, however, that the forecast benefits will *always* be greater than zero as long as the Project results in *any* temporary increase in system capacity because the Project is forecast to provide benefits in every year for which it increases system capacity over that which otherwise would have been the case. In the worst case—if there were never an increase in system generating capacity due to the Project—the NPV of benefits is zero. This outcome is extremely unlikely as market players will need time to adjust to the new realities of the system due to several factors such as the lumpiness of capital investments in the electric market and the long lead time needed to site new generation and transmission. I used 2021 as the new equilibrium; however, it could be earlier or later than that date.

Q. Since you cannot accurately predict the equilibrium date, does this invalidate your conclusion that the Project will produce positive benefits?

A. No. As I noted above, in the worst case scenario, the Project creates a NPV of zero, which is not likely to happen. I have, however, considered a range of alternative equilibrium dates from 2018 to 202,1 and I find that the lowest NPV benefit from the Project occurs if the equilibrium date is assumed to be 2018 under the Slow Growth future. Yet even in that future the NPV benefits exceed $300 million. I conclude from this analysis that the choice of equilibrium dates affects only the amount of positive NPV benefits from the Project and not the existence of positive NPV benefits.

Q. How did you analyze the REC market benefit to Illinois of the Project?

A. I did not attempt to forecast the cost of production or market prices of RECs for the reasons described earlier in my testimony regarding the difficulty of determining the relevant REC market. There are, however, factors that suggest the Project is capable of exerting downwards pressure on REC prices in Illinois. For example, the differential wind speeds between Illinois and the area that will be served by the Project strongly suggests that potential wind resources served by the Project will have higher capacity factors than similar wind resources sited in Illinois. (See Direct Testimony of David Berry, Rock Island Exhibit 10.0.) I did not attempt to forecast the cost of production or market prices of RECs for the reasons described earlier in my testimony regarding the difficulty of determining the relevant REC market. The Project, however, seems capable of exerting downwards pressure on REC prices in Illinois. For example, the differential wind speeds between Illinois and the area that will be served by the Project strongly suggests that potential wind resources served by the Project will have higher capacity factors, and therefore lower per MWh cost, than wind resources in Illinois. (See Direct Testimony of David Berry, Rock Island Exhibit 10.0.) These two factors are highly suggestive of a REC market benefit from the Project.

Q. What do you conclude from your Part 1 analysis?

A. The Project is clearly cost-beneficial to Illinois consumers in terms of lowering the cost to serve energy load in Illinois and is capable of exerting downwards pressure on REC prices. I infer from this analysis that the Project promotes the development of an effectively competitive electricity market promoting efficient operations and to the extent that such benefits flow through to customers' bills from either direct market-based

purchases or purchases through a competitive process such as the IPA procurement process these efficiencies should flow to all customers in an equitable fashion. Further, it appears likely that the Project will also have positive benefits in the market for renewable energy credits as well.

V. THE PROJECT WILL CREATE A LARGER COMPETITIVE MARKET IN ILLINOIS (PART 2 ANALYSIS)

Q. You mentioned the DPT for analysis of the market for energy. Please explain how you performed that test for this Project?

A. I performed the DPT by comparing the Economic Capacity available to the destination market with the Project in place to that available without the Project in place. I considered a destination market consisting of the state of Illinois. I performed the DPT for each of 2016 and 2020, and for each future from the PROMOD analysis. For each year/future combination, I performed the DPT for three representative levels of load, which I have labeled "summer peak," "shoulder," and "light load." The result was 24 representative DPT cases. I calculated the Economic Capacity in each case as follows:

First, I reviewed PROMOD output data provided to me. Mr. Moland provided me with the PROMOD Available Capacity (in MW) and PROMOD Unit Dispatch Price (in $/MW) of each available generator in each of the 24 cases described above. This set of data provided for each case corresponded to a specific modeled hour, with "summer peak" being represented by the peak load hour, "shoulder" being represented by the hour having 70% of peak load, and "light load" being represented by the hour having 50% of peak load. The specific hours concerned are set out in Table 7.

Table 7: Project Classification of Representative Hours for DPT

2016			
100%:	02 August 2016	Hour 16	4:00 p.m.
70%:	06 June 2016	Hour 17	5:00 p.m.
50%:	29 January 2016	Hour 2	2:00 a.m.
2020			
100%:	04 August 2020	Hour 16	4:00 p.m.
70%:	04 September 2020	Hour 17	5:00 p.m.
50%:	04 March 2020	Hour 1	1:00 a.m.

The data for each specific hour included the impact of random generator outages, as represented by PROMOD. Mr. Moland also provided me with PROMOD market price forecast data for each year/ future.

Second, I established representative reference prices for each case as follows: for "summer peak" I used the maximum market price (rounded to the nearest $10/MWh) for the year/ future concerned; for "shoulder" I used the annual average market price (rounded to the nearest $10/MWh) for the year/future concerned; and for "light load" I used the reference price for "shoulder" divided by two. I selected these simple rules for establishing reference prices because I believe they produce a representative and reasonably broad cross-section of market outcomes to be analyzed by the DPT.

Third, I calculated the sum of Economic Capacity in each case. The Economic Capacity consists of two components: Economic Capacity located within the destination market; and Economic Capacity located outside the destination market. Economic Capacity within the destination market was calculated as the sum of Available Capacity in the destination market having a Unit Dispatch Price less than or equal to 105% of the reference price for the case concerned. Economic Capacity outside the destination market was calculated separately for the with-Project scenario and for the without-Project

scenario. Economic Capacity outside the destination market is the maximum capacity at a price less than 105% of the reference price that can feasibly be imported. I approximated this figure by evaluating the maximum hourly level of imports that occurred for each year/future concerned – i.e., I estimated the change in maximum import capacity resulting from the Project as being the change in maximum import flow resulting from the Project. I believe this is a reasonable approach. The resulting values are set out in Table 8. I assumed that all import capacity would be Economic Capacity at any of the reference prices considered, since throughout PJM and MISO there is considerable modeled capacity having a Unit Dispatch Price lower than the lowest reference price considered.

Fourth, I compared the total MW available to the market with the Project to that without the Project, and calculated the percentage change.

Table 8: Change in Import Capacity (MW) - Illinois

			With Project	Without Project	Change
2016					
	Business as Usual	1	858	600	258
	Green Economy	2	4,140	4,159	(19)
	Robust Economy	3	1,658	1,590	68
	Slow Growth	4	652	652	0
2020					
	Business as Usual	5	5,058	4,593	465
	Green Economy	6	5,322	4,881	441
	Robust Economy	7	3,143	2,549	594
	Slow Growth	8	3,687	3,512	175

Q. What are the results from the DPT?

A. Table 9 presents the results of the DPT. The Project is expected to increase the Economic Capacity able to supply the Illinois market by up to 2.9%, depending on the year and the

future considered. The maximum increase occurs in the Slow Growth future for 2020 in the light load hour, which is a case with a particularly low reference price in 2020 and – as a consequence – a relatively low level of Economic Capacity. More generally, the results of the DPT across the other cases shows the Project is expected to increase the Economic Capacity able to supply the Illinois market by between 0.4% and 2.4% in 2020. When measured on a percentage basis, the increase tends to be higher in low load cases and lower in high load cases because the MW size of the impact is fixed and the capacity concerned has very low marginal production cost - given that it is wind-powered. The Project is expected to increase the Economic Capacity able to supply the Illinois market by a lesser extent in 2016 than in 2020. In one case in 2016 (Green Economy, light load) the DPT shows a small (0.1%) reduction in the Economic Capacity able to supply the Illinois market. I do not consider this result to invalidate the value of the benefits of the Project in expanding supply to the Illinois market. First, this is an exceedingly small fraction of the overall 3,500 MW of the projects maximum delivery capacity. Second, this result is an artifact of the way the maximum hourly level of imports is calculated: the maximum occurs in a different hour when the Project is included, with different commitment/dispatch solutions and congestion patterns. On an averaged basis for the year, the Project nevertheless results in higher imports. (The 2016 Green Economy PROMOD results show that that there are more hours of the year (1,168) in the “with Project” case with energy imports relative to the “without Project” case (807), with average imports slightly higher in the “with Project” case – data provided to me by Mr. Moland.) Overall, the results of the DPT show that the Project is highly likely to increase the Economic Capacity able to supply the Illinois market.

Table 9: Increase in Economic Capacity Able to Supply Illinois Market (calculated using DPT)

	Reference Price ($/MWh)	MW without Project	MW with Project	Increase (%)
2016				
Summer Peak				
Business as Usual	270	38,772	39,030	0.7%
Green Economy	580	39,716	39,697	0.0%
Robust Economy	400	40,523	40,591	0.2%
Slow Growth	230	37,813	37,813	0.0%
Shoulder				
Business as Usual	40	30,999	31,257	0.8%
Green Economy	80	38,966	38,947	0.0%
Robust Economy	40	28,499	28,567	0.2%
Slow Growth	30	33,176	33,176	0.0%
Light Load				
Business as Usual	20	15,168	15,426	1.7%
Green Economy	40	22,859	22,840	-0.1%
Robust Economy	20	16,238	16,306	0.4%
Slow Growth	15	14,353	14,353	0.0%
2020				
Summer Peak				
Business as Usual	280	42,333	42,798	1.1%
Green Economy	570	42,669	43,110	1.0%
Robust Economy	500	43,734	44,328	1.4%
Slow Growth	100	40,086	40,261	0.4%
Shoulder				
Business as Usual	50	31,122	31,587	1.5%
Green Economy	90	33,409	33,850	1.3%
Robust Economy	70	32,499	33,093	1.8%
Slow Growth	30	29,521	29,696	0.6%
Light Load				
Business as Usual	25	19,094	19,559	2.4%
Green Economy	45	22,672	23,113	1.9%
Robust Economy	35	27,411	28,005	2.2%
Slow Growth	15	6,029	6,204	2.9%

Q. To what extent will the size of the REC market increase as a result of the Project?

A. I described earlier in my testimony the difficulty of defining the relevant REC market for a number of reasons. A practical implication of this is that it is not possible to apply the DPT to the REC market because it is not readily possible to model or identify price points within the REC price curve, or to develop a "REC merit order." I have, however, investigated the extent to which the supply of REC resources to the market will

potentially increase as a result of the Project. I have investigated a market for RECs as defined by REC facilities located within the geography of Illinois and adjoining states. I have also investigated the market for RECs as defined by REC facilities located within the entire Eastern Interconnection. I have investigated each on both a capacity (MW) and energy (MWh) basis. Table 10, Table 11, Table 12, and Table 13 set out the findings. In summary:

- In 2016 the Project provides for an increase of 18% to 28% of REC capacity in Illinois and adjoining states;
- In 2016 the Project provides for an increase of 18% to 30% of REC energy in Illinois and adjoining states;
- In 2016 the Project provides for an increase of 5% to 9% of REC capacity in the Eastern Interconnection;
- In 2016 the Project provides for an increase of 5% to 8% of REC energy in the Eastern Interconnection;
- In 2020 the Project provides for an increase of 10% to 27% of REC capacity in Illinois and adjoining states;
- In 2020 the Project provides for an increase of 10% to 28% of REC energy in Illinois and adjoining states;
- In 2020 the Project provides for an increase of 3% to 7% of REC capacity in the Eastern Interconnection; and
- In 2020 the Project provides for an increase of 3% to about 6% of REC energy in the Eastern Interconnection.

In each case listed above, the lower percentage corresponds to the Green Economy future. The percentage impact of the Project is lower in the Green Economy future because the total REC capacity from other sources in this future is expected to be higher. In each case listed above, the higher percentage corresponds to the Business as Usual, Robust Economy and Slow Growth futures.

Table 10: Change in REC Capacity (MW) – Illinois and Adjoining States*

			With Project	Without Project	Change
2016					
	Business as Usual	1	19,644	15,295	28%
	Green Economy	2	29,041	24,692	18%
	Robust Economy	3	19,644	15,295	28%
	Slow Growth	4	19,644	15,295	28%
2020					
	Business as Usual	5	20,714	16,365	27%
	Green Economy	6	47,407	43,058	10%
	Robust Economy	7	20,714	16,365	27%
	Slow Growth	8	20,714	16,365	27%

*Adjoining states include all states that share a formal state boundary with Illinois.

Table 11: Change in REC Capacity (MW) – Eastern Interconnection

			With Project	Without Project	Change
2016					
	Business as Usual	1	55,182	50,833	9%
	Green Economy	2	85,863	81,514	5%
	Robust Economy	3	55,182	50,833	9%
	Slow Growth	4	55,182	50,833	9%
2020					
	Business as Usual	5	68,845	64,496	7%
	Green Economy	6	137,077	132,728	3%
	Robust Economy	7	68,845	64,496	7%
	Slow Growth	8	68,845	64,496	7%

Table 12: Change in REC Energy (GWh) – Illinois and Adjoining States*

			With Project	Without Project	Change
2016					
	Business as Usual	1	62,217	47,928	30%
	Green Economy	2	93,811	79,487	18%
	Robust Economy	3	62,268	48,006	30%
	Slow Growth	4	61,918	47,647	30%
2020					
	Business as Usual	5	65,720	51,373	28%
	Green Economy	6	152,863	138,633	10%
	Robust Economy	7	65,823	51,476	28%
	Slow Growth	8	65,265	50,925	28%

*Adjoining states include all states that share a formal state boundary with Illinois.

Table 13: Change in REC Energy (GWh) – Eastern Interconnection

			With Project	Without Project	Change
2016					
	Business as Usual	1	194,663	180,377	8%
	Green Economy	2	292,407	278,098	5%
	Robust Economy	3	194,754	180,496	8%
	Slow Growth	4	193,127	178,856	8%
2020					
	Business as Usual	5	236,608	222,267	6%
	Green Economy	6	443,581	429,385	3%
	Robust Economy	7	236,871	222,532	6%
	Slow Growth	8	234,715	220,389	7%

Q. Does this complete your direct testimony?

A. Yes.

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SPECIAL CONSULTANT

Karl McDermott is the Ameren Distinguished Professor of Business and Government at the University of Illinois, Springfield and a Special Consultant to National Economic Research Associates, Inc. (NERA). Professor McDermott specializes in public utility regulation and public policies toward the regulation of business. Prior to taking the Ameren Professorship, Dr. McDermott was a Vice-President at NERA where he directed and participated in numerous projects in both the energy and telecommunications areas. His main focus has been the development of performance-based regulation mechanisms and advising clients on strategic regulatory options. Recent projects include evaluating and developing performance-based regulation plans and strategic regulatory options for Commonwealth Edison Company, Wisconsin Electric Power Company, Xcel Energy, Otter Tail Power, Peoples Energy, Louisville Gas and Electric, PowerGen, and Pacificorp. In addition, Dr. McDermott advises clients on competitive electric and gas markets including regulatory policy, generation location decisions, unbundling, tariff design, and corporate reorganization. Representative projects include an examination of essential facilities in the electric industry for the Edison Electric Institute, tariff design and competitive electric generation sitting for Southern California Gas Company, and unbundling of metering and billing, competitive declarations of tariffs and procurement options for Commonwealth Edison Company. He has testified before numerous state regulatory commissions and legislatures, as well as before the FCC and FERC and Missouri state court. Dr. McDermott lectures extensively on regulatory reform and restructuring and currently serves as an instructor for National Association of Regulatory Utility Commissioners summer seminars and advanced seminars.

Prior to joining NERA, Dr. McDermott served as Commissioner on the Illinois Commerce Commission during the negotiation of the Illinois restructuring law. He has also assisted the country of Poland since 1994 with their efforts to privatize and restructure their electric supply industry. As a Commissioner, Dr. McDermott also lectured extensively in Eastern Europe and South America on regulatory reform and restructuring.

Dr. McDermott received his Ph.D. in Economics from the University of Illinois at Urbana-Champaign, his M.A. in Public Utility Economics from the University of Wyoming, and his B.A. in Economics from Indiana University of Pennsylvania.

Education

University of Illinois at Urbana-Champaign
Ph.D., Economics, 1990
Major Fields: Monetary theory and Policy, Macroeconomic Theory, and History of Economic Thought

University of Wyoming
M.A., Public Utility Economics, 1978
Major Fields: Public Utility Economics and Industrial Organization Theory

Indiana University of Pennsylvania
B.A., Economics, 1976

Professional Experience

University of Illinois Springfield
2008- Ameren Distinguished Professor of Business and Government

Classes taught: Regulation and the American Economy, Economics of Public Utility Regulation, macro-economics

NERA Economic Consulting
2008- Special Consultant

1999-2008 Vice President
Directs projects in the energy and telecommunications fields. Conducts research in the design and review of performance-based regulation mechanisms. Provides strategic regulatory advice to international and domestic clients. Advises on competitive issues facing regulated firms, including regulatory policy, unbundling, corporate structure, and tariff design.

McDermott Associates
1998-1999 President
Directed projects in the energy and telecommunications fields focusing on performance-base regulation, electric industry restructuring, and competition policy issues.

Illinois Commerce Commission
1992-1998 Commissioner
Domestic: Served as Chairman of both the Telecommunications Policy Committee and Electricity Policy Committee. Served on the National Association of Regulatory Utility Commissioners (NARUC) Energy Resources and Environment Committee as the Chairman of its environmental subcommittee. Reviewed and voted on Illinois Bell Price-Cap plan, Peoples Gas PBR and

MidAmerican Electric PBR. While a commissioner, made over one-hundred presentations and speeches on telecommunications, electricity, and natural gas industry topics. Also served as NARUC representative on the President's Global Climate Change Task Force, the Federal Energy Regulatory Commission's Pipeline Competition Task Force, the National Coal Research council, and as a member of the Harvard Electric Policy Group.

International: In addition to regular Commission duties, served as part of the United States Energy Association and USAID educational effort in Eastern Europe. Lectured in Argentina, the Czech Republic, Latvia, Poland, Romania, Russia, and Slovakia and participated in two joint USEA/USAID and World Bank seminars in Vienna providing advanced regulatory training. While a commissioner, hosted visits with the above-listed countries, as well as Bulgaria, Lithuania, and Estonia.

Additional Professional Experience

Michigan State University, Institute for Public Utilities

2001- Faculty

Invited lecturer at Regulatory Studies Program ("Camp NARUC") held in East Lansing, Michigan. Lecture topics include performance-based regulation, rate-of-return regulation, infrastructure regulation for developing countries, and gas wholesale markets.

Center for Regulatory Studies, Inc.

1985-1998 Chairman of the Board

1985-1992 President

As a cofounder, involved in all aspects of operations, including fundraising, organization, and program development. Focused on the development of statewide energy planning options for the State of Illinois, the introduction of competition into the natural gas market, environmental issues in Illinois, and competition in the Illinois telecommunications market. Conducted research on the use of competitive bidding and avoided-cost pricing mechanisms to acquire electricity supplies, the role of demand-side management in electricity supply planning, and the use of incentive mechanisms and the role of incentive regulation in our current regulatory environment.

Argonne National Laboratory

1988-1992 Research Scientist

Served as an economic advisor to the office of Fossil Energy at DOE. Helped investigate possible ways to promote development of innovative emission control technologies and Clean Coal Technologies in the electric utility industry, as part of the Presidential Task Force on Regulatory Relief. Assignments also involved the writing of a chapter in the State of Science and Technology Report No. 25 of the National Acid Precipitation Assessment Program (NAPAP) concerning the use of tradable emission permits to control acid rain. In addition, worked on

incentive mechanisms to promote clean coal technology and the trading of greenhouse gas emissions. Also performed research on the nature of individual's risk perception regarding nuclear waste deposits on behalf of the office of Radioactive Civilian Waste Management at the Department of Energy.

NARUC Introductory Regulatory Training Program
1989-2006 Instructed new public utility commission employees from various state commissions on the basic economic issues confronting regulators.

Illinois State University, Department of Economics
1986-1992 Lecturer in Economics
Taught both graduate and undergraduate public utility courses, Money and Banking, as well as introductory courses.

Parkland Community College, Champaign, Illinois
1984-1991 Instructor in Economics
Taught both Principles of Economics I and II.

University of Illinois, Urbana-Champaign
1984-1986 Teaching Assistant
Taught both Principles of Economics and Introduction to Econometrics. Served as supervisory assistant in charge of coordinating Economics 101 assistants for Professor Fred Gotthiel.

Illinois Legislature, Select Joint Subcommittee on Regulatory Reform
1983-1985 Consultant
Investigated the effects of the AT&T divestiture and FCC decisions upon Illinois telephone utilities and assisted in identifying issues that require legislative action. Presented issue reports to the telecommunications subcommittee and served on the local exchange subgroup in developing recommendations for a new Illinois Public Utilities Act.

Department of Energy and Natural Resources, Governor's Sunset Task Force on Utility Regulatory Reform
1980-1982 Consultant
Delivered written and oral reports on the issues of power plant certification, monitoring of construction costs, and allocation of power plant cancellation costs.

Illinois Commerce Commission, Policy Analysis and Research Division
1980-1983 Economic Analyst III
Conducted research investigating the development and use of incentive mechanisms in utility regulation. Prepared and presented testimony on the use of incentive mechanisms in power plant construction. Conducted research and assisted in developing testimony on the cost of service for electric generation to meet PURPA requirements. Assisted in the development of proposals for PURPA innovative rates projects on productivity and time-of-use pricing; cost-benefit

analysis. Assisted in the management of consultants conducting the TOD cost-benefit study. Prepared and presented testimony on the time-of-day pricing standards to meet the PURPA requirements. Prepared and presented testimony regarding the use of q-ratios in determining rates-of-return for Illinois Bell Telephone Company and testimony regarding appropriate cost and pricing methodology and philosophy for Illinois Bell Telephone Company. Assisted in the investigation of capacity expansion, lifeline rates, efficiency measurement, and impact of deregulation in electric generation, water rate design, and investigated the impact of investment tax credit changes on utilities.

Ohio State University, National Regulatory Research Institute

1978-1979 Senior Research Associate

Conducted research in the areas of telecommunication licensee contract fees and cost of service, the effects of budget billing plans on utilities and consumers, as well as methods of monitoring fuel adjustment clauses. Assisted in research regarding marginal and average cost pricing, time-of-use pricing, power plant productivity, and the examination of cost and price differences of Ohio municipal gas rates. Assisted in the management of consultant subcontractors, as well as supervising the presentation of cost and load research seminars.

Ohio State University, Department of Economics

Fall 1979 Lecturer in Economics

Taught Macroeconomic Principles.

Action Computing, Laramie, Wyoming

1977-1978 Cost Analyst

Developed cost data for competitive pricing of bids for the provision of computer services provided by Action Computing.

University of Wyoming, Laramie

1976-1977 Graduate Research Assistant

Assisted professors in conducting research and teaching of Principles of Economics.

Honors and Professional Activities

Deans Award, The Institute of Public Utilities, Michigan State University 2002

Starfish Award, College of Business Administration University of Illinois Chicago 2001

Distinguished Alumni Award, Indiana University of Pennsylvania 2001

Alpha Lambda Delta Outstanding Freshman Teacher Award, University of Illinois, 1986

Thrift Prize, University of Illinois, for paper entitled “The Allocation of Savings: An Investigation of Portfolio Composition of Chicago Households,” 1983

President Elect and President, Illinois Economic Association, 1988-1990

Member, Alpha Lambda Delta Honorary Society

Member, American Economic Association

Member, Transportation Public Utilities Group of American Economic Association

Member, Illinois Economic Association

Representative Projects

Evaluation and design of performance based regulation for clients, including Detroit Edison Company (bundled electricity service), Michigan Consolidated Gas (gas distribution), Otter Tail Power (bundled electricity service), and Xcel Energy (bundled electricity service), among others.

Evaluation of damages from coal-fired power plant explosion for Kansas City Power and Light (Hawthorn 5 unit).

Evaluation of prudence of certain distribution investments and O&M costs for Commonwealth Edison Company.

Evaluation of POLR responsibility in state of Illinois for Commonwealth Edison.

Evaluation of market structure options and development of tariff model for Macedonian electric sector.

Evaluation of future options for the reform of the Albanian electric sector.

Evaluation of electric industry structure and proper public policy toward utilities building power plants.

Estimation of potential energy efficiency gains for Wisconsin Electric Power Company (WEPCO) and Wisconsin Public Service Corporation in support of power plant construction.

Evaluation of tariff options for Otter Tail Power Company.

Evaluation of options for unbundled distribution rates and policies toward small-use customer choice for Illinois Power.

Review of gas rate design for peaking service and evaluated electric generation site decisions in California for Southern California Gas Company.

Publications

"The Illinois Commerce Commission's Pro Forma Adjustment Rule: An Event Study of Regulatory Decision-Making," forthcoming in *Advances in Business Research.* (with C. Peterson)

"Innovation in Retail Electricity Markets: The Overlooked Benefit," White Paper published by COMPETE (2008)

"Rethinking the Implementation of the Prudent Cost Standard," in *The Line in the Sand: The Shifting Boundary Between Markets and Regulation in Network Industries,* S. Voll and M. King (eds), 2007. (with C. Peterson and R. Hemphill).

"Mergers and Acquisitions in the US Electric Industry: State Regulatory Policies for Reviewing Today's Deals," *The Electricity Journal*, 20(1), pp. 8-25, 2007 reprinted in *The Line in the Sand: The Shifting Boundary Between Markets and Regulation in Network Industries,* S. Voll and M. King (eds), 2007 (with C. Peterson).

"Critical Issues in the Regulation of Electric Utilities in Wisconsin," *Wisconsin Policy Research Institute Report*, 19(3), pp. 1-69, 2006 (with C. Peterson and R. Hemphill).

"The Anatomy of Institutional and Organizational Failure," in *Obtaining the Best from Regulation and Competition,* M. Crew and M. Spiegel (eds.), Kluwer Academic Publishers, London, UK, 2005, pp. 65-92 (with C. Peterson).

"Performance-Based-Rates Upward Trend to Continue," in *Natural Gas and Electricity,* 20(6), 2004 (with C. Peterson).

"Is There a Rational Path to Salvaging Competition?" *The Electricity Journal,* 15(2), 2002, pp. 15-30 (with C. Peterson).

"Further State Electric Deregulation can be Guided by Gas Experience," in *Natural Gas and Electric Power Industries Analysis*, R.E. Willett (ed.), Financial Communications Company, Houston, TX, 2002, pp. 343-372 (with C. Peterson).

"The Essential Role of Earnings Sharing in the Design of Successful Performance-base Regulation Programs," in *Electricity Pricing in Transition,* A. Faruqui and K. Eakin (eds.), Kluwer Academic Publishers, London, UK, 2002, pp. 315-328 (with C. Peterson).

"Critical Issues in Consumer States Include Unbundling and Performance-based Regulation," in *Natural Gas Industry Analysis*, R.E. Willett (ed.), Financial Communications Company, Houston, 2000, 321-343.

"Are Residential Local Exchange Rates Too Low? Drivers to Competition in the Local Exchange Market and the Impact of Inefficient Prices," in *Expanding Competition in Regulated Industries,* M. Crew (ed.), Kluwer Academic Publishers, Boston/Dordrecht/London, 2000, 149-168 (with A. Ros).

Essential Facilities, Economic Efficiency, and a Mandate to Share: A Policy Premier, Edison Electric Institute, January 2000 (with K. Gordon, W. Taylor, and A. Ros).

"Pipeline Regulation Must go to One Extreme or Another," in *Natural Gas*, 15(9), April, 1999.

"Is There a Rational Path to Implementing Competition?" in *The Electricity Journal*, 9(1), Jan-Feb 1996.

"Changing Regulatory Incentives," in *Reinventing Electric Utility Regulation*, G. Enholm and J. Robert Malko (Eds.), Public Utility Reports, Inc. Vienna, VA 1995.

"The Evolution of the "Investment Systems:" Keynes' Theory of Employment and Money Revisited," in *Review of Social Economy*, 51(1), Spring 1993.

Discussant. "The Urban Ozone Abatement Problem," in *Cost Effective Control of Urban Smog.* R. Kosobud, W. Testa, and D. Hansan (Eds.) Federal Reserve Bank of Chicago. November 1993.

"Strategic Use of Incentive Mechanisms as a Regulatory Policy Tool," in *The Electricity Journal.* 5(10), December 1992.

"Electric Utilities: Control Cost Reducing Methods," Chapter 7 in *Technologies and Other Measures for Controlling Emissions: Performance, Costs and Applicability*, David South (ed.). National Acid Precipitation Assessment Program, State-of-Science/Technology Report, 25 January 1990.

"The Quantity Theory of Money of J. M. Keynes: From the Indian Currency to the General Theory" in *Perspectives on the History of Economics Thought.* D., Walker (ed.), Edward Edgar Publishing Co., Brookfield, VT, 1989 (with C. Marme).

Computer Assisted Regulatory Analysis and Its Potential Application to the Colorado Public Utilities Commission. The National Regulatory Research Institute, 1979 (with M. S. Gerber).

Towards an Analysis of Telephone License Contracts and Measured Rates. The National Regulatory Research Institute, 1979 (with A. G. Buckalew, and D. Z. Czamanski).

Budget Billing Plans for Electric and Gas Utilities: An Analysis and Some Recommendations for Change. The National Regulatory Research Institute, 1979 (with J-M Guldman and C. Odle).

Conference Papers and Presentations

The Determinants of Electric Utility Capital Structure: Re-Examining the Turbulent 1980s, presented at Center for Research in Regulated Industries, Rutgers University, Annual Western Advanced Regulatory Conference, Monetary, CA, June 2011. (with C. Peterson)

The Determinants of Commission Total Revenue Decisions: A Case Study of Illinois Energy Utilities, presented at Center for Research in Regulated Industries, Rutgers University, Annual Western Advanced Regulatory Conference, Monetary, CA, June 2011. (with C. Peterson and A. Everette)

Tale of Two Policies: A Re-examination of State Telecommunications Policy on The Protection of Universal Service & the Advancement of Competition in the Post- Divestiture Period presented at Center for Research in Regulated Industries, Rutgers University, Annual Eastern Advanced Regulatory Conference, Sky Top, PA, May 2011. (with C. Peterson and A. Ros)

Regulatory Risk: A More Comprehensive Examination and Empirical Test (keynote) presented at Center for Research in Regulated Industries, Rutgers University, Annual Eastern Advanced Regulatory Conference, Sky Top, PA, May 2010. (with C. Peterson)

Regulatory Policy on Local Telephony Competition: The Effects of State Policies on Re-Balancing, presented at Center for Research in Regulated Industries, Rutgers University, Annual Western Advanced Regulatory Conference, Monetary, CA, June 2009. (with C. Peterson)

W(h)ither the Public Utility Concept: Obsolete, Passing or Timeless, presented at Center for Research in Regulated Industries, Rutgers University, Annual Eastern Advanced Regulatory Conference, Sky Top, PA, May 2009.

Balancing Effective Regulation and Utility Control- Is Managerial Discretion (Prerogative) a Myth?, (keynote), presented at Center for Research in Regulated Industries, Rutgers University, Annual Eastern Advanced Regulatory Conference, Sky Top, PA, May 2008

The Uncertain Role of Profit in Regulation-A Love-Hate Affair, presented at Center for Research in Regulated Industries, Rutgers University, Annual Western Advanced Regulatory Conference, Monetary, CA, June
2008

The Essential Facilities Doctrine-Core Concept or Mere Epitaph (Keynote), presented at Center for Research in Regulated Industries, Rutgers University, Annual Eastern Advanced Regulatory Conference, Sky Top, PA, May 2007.

The Role of market processes in the design of dynamic incentives, presented at Center for Research in Regulated Industries, Rutgers University, Annual Eastern Advanced Regulatory Conference, Sky Top, PA, May 2006. (with C. Peterson)

Competition as the Foundation of Regulation- An Exploration in the History of Ideas, (keynote), presented at Center for Research in Regulated Industries, Rutgers University, Annual Western Advanced Regulatory Conference, Monetary, CA, June 22, 2006

Prudence: The Regulators Strike Back: A Prequel to the Revenge of the Regulator, presented at Center for Research in Regulated Industries, Rutgers University, conference held in San Diego, CA, June 2005.

Mergers and Acquisitions in the Electric Industry: A Review of State Regulatory Policies, presented at Center for Research in Regulated Industries, Rutgers University, conference held in Sky Top, PA, May 2005 (with C. Peterson).

The Anatomy of Institutional and Organizational Failure: Economic Reform and the Search for Institutional Equilibrium in Regulated Network Industries, preliminary draft presented at Research Seminar on Public Utilities, Center for Research in Regulated Industries, Rutgers University, October 2003 (with C. Peterson).

The Efficiency of the Inefficient Firm Standard in Setting Network Access Charges, prepared for 20th Annual Advanced Workshop in Regulation and Competition, Rutgers University, May 25, 2001 (with C. Peterson).

Designing the New Regulatory Compact: The Role of Market Processes in the Design of Dynamic Incentives, presented at *Incentive Regulation: Making it Work*, Advanced Workshop in Regulation and Competition, Rutgers University, January 19, 2001 (with C. Peterson).

The Use of Nontraditional Universal Service Programs in a Competitive Local Exchange Market, presented at the National Association of Regulatory Commissioners Biennial Conference, 1996 (with C. Schieber).

Incentive Mechanisms as a Strategic Option for Acid Rain Compliance, presented to the Future of Incentive Regulation in the Electric Utility Industry, November 1991 (with D. W. South and K.A. Bailey).

Role of Emission Allowances in Utility Compliance Decisions, presented at the Eighth Annual International Pittsburgh Coal Conference, October 1991 (with D. W. South and K. A. Bailey).

Clean Coal Technology and Emissions Trading: Is There a Future for High Sulfur Coal Under the Clean Air Act Amendments of 1990? P. R. Dugan, D. R. Quigley, Y. A. Attia (eds.), Processing and Utilization of High Sulfur Coals IV, proceedings of the Fourth International Conference on Processing and Utilization of High Sulfur Coals, Idaho Falls, ID, sponsored by the U.S. Department of Energy, et al., Elseveir Science Publishing Co. Inc., New York, NY (with K. A. Bailey and D.W. South).

Incentive Mechanisms as a Strategic Option in the Design of Regulatory Policies, presented at National Association of Regulatory Utility Commissioners, Committee on Electricity, Subcommittee on Strategic Issues, San Francisco, July 1991 (with D. W. South).

Achieving Efficiency Through Emissions Trading: Paradoxes, Misconceptions and Market Performance, presented at National Association of Regulatory Utility Commissioners, Committee on Electricity, Subcommittee on Environment and Efficiency, San Francisco, July 1991 (with D. W. South).

To Mitigate or Not To Mitigate: Regulatory Treatment of Emissions Trading Decisions and Its Effect on Marketplace Incentives, presented at 84th Annual Meeting and Exhibition, Air and Waste Management Association, Vancouver, British Columbia, June 1991 (with D. W. South).

Regulatory Incentives: A Means to Accelerate Clean Coal Technology Adoption for Acid Rain Compliance, presented at Compliance and Emissions Trading Strategies: Facing Acid Rain Tradeoffs, Center for Regulatory Studies, Chicago, IL, June 1991 (with D. W. South).

Implementing Emissions Trading: Regulatory and Compliance Planning Issues, presented at the Workshop on Implementing the Electric Utility Provisions of the Clean Air Act Amendments of 1990: Midwestern State Public Utility Commission Issues, National Regulatory Research Institute, Chicago, IL, May 1991 (with D. W. South).

Clean Coal Technology and Acid Rain Compliance: An Examination of Alternative Incentive Proposals, presented at the American Power Conference, Chicago, IL, April 1991 (with D. W. South).

Emissions Trading: Implications for Regulatory Policy, presented at the 20th Annual Meeting of the Illinois Economic Association, Chicago, IL, October 1990 (with D. W. South).

The Future of Clean Coal Technology: An Evaluation of the Proposed CCT Incentives in S. 1630, presented at the 20th Annual Meeting of the Illinois Economic Association, Chicago, IL, October 1990 (with D. W. South).

The Future of Clean Coal Technology: An Evaluation of the Proposed Incentives in S. 1630, presented at the Seventh Annual International Pittsburgh Coal Conference, Pittsburgh, PA, September 1990 (with D. W. South).

The Future of Clean Coal Technology: An Evaluation of the Proposed Incentives in S. 1630, presented at the Seventh NARUC Biennial Regulatory Information Conference, Columbus, OH, September 1990 (with D. W. South).

Emissions Trading: Implications for Regulatory Policy, presented at the Seventh NARUC Biennial Regulatory Information Conference, Columbus, OH, September 1990 (with D. W. South).

Alternatives to Rate of Return Regulation in the Telephone Industry: A Survey of the New Incentive Mechanism Proposals. Illinois Economic Association, October 1988.

Market Structures in the Local Communication Market: Fact and Fiction, presented at the Intra-MSA Telecommunication Conference, September 1988.

The Quantity Theory of Money of J. M. Keynes: From the Tract to the General Theory. Proceedings of the 14th Annual Meeting of the History of Economics Society, June 1987 (with C. Marme).

Competitive Pricing and the Local Telephone Service Market: Some Problems of Balancing Equity and Efficiency. Illinois Economic Association, October 1986.

The Impact of Self-Selective Tariffs in Telecommunications Markets: The Design of an Experiment. Proceedings of the Fifth NARUC Biennial Regulatory Conference, September 1986 (with M. J. Morey and K. Costello).

An Incentive Plan to Control Power Plant Construction Costs. Third NARUC Biennial Information Conference, September 1982.

The Measurement of Efficiency and the Application of Incentives to Regulated Industries. Proceedings of the Second NARUC Biennial Regulatory Information Conference, September 1980 (with K. Costello).

Reports

Summary of Finding and User Guide: Tariff Model for the Macedonian Electric Sector, prepared for the Ministry of Economy, Republic of Macedonia, under contract with United States Agency for International Development, November 2003 (with C. Peterson and R. Zarumba; report is proprietary).

Distributed Resource Investment in Albania: Regulatory Options for Introducing Commercial Incentives and Promoting Solutions to Meeting Electricity Demand, white paper prepared for the law firm of Pierce Atwood under contract with United States Agency for International Development, January 2003 (with C. Peterson).

Restructuring Options for the Electric Sector in Macedonia, Report 1 and 2; prepared for the law firm of Pierce Atwood under contract with United States Agency for International Development, 2002 (with C. Peterson and R. Zarumba; report is proprietary).

Introducing Competition into the Albanian Electric Sector, white paper prepared for the law firm of Pierce Atwood under contract with United States Agency for International Development, 2001 (with C. Peterson).

Examination of Incentive Mechanisms for Innovative Technologies Applicable to Utility and Nonutility Power Generators, Environmental Assessment and Information Sciences Division, Argonne National Laboratory, publication ANL/EAIS/TM-2, August 1993.

Avoided Cost Pricing: Theoretical Issues and Problems in Estimation. Prepared for the Illinois Department of Energy and Natural Resources, June 1990.

Least-Cost Planning in the Natural Gas Industry: An Overview of the Issues. Prepared for the Illinois Department of Energy and Natural Resources, December 1989.

Equity Issues in a Least-Cost Planning Environment. Prepared for the Illinois Department of Energy and Natural Resources, October 1989.

An Analysis of Prudency Evaluation Within a Least-Cost Planning Framework: The Case of Natural Gas Planning. Prepared for the Illinois Department of Energy and Natural Resources, October 1989.

Consumer Choice Under Risk and Uncertainty: The Role of Risk Perceptions as a Causal Factor in Consumer Decisionmaking. Prepared for the Energy and Environmental Systems Division, Argonne National Laboratory for U.S. DOE Office of Civilian Radioactive Waste Management, April 1989.

The Effects of Alternative Definitions of the Obligation to Serve on the Least-Cost Plans of Local Gas Distribution Companies. A Report for the Northern Illinois Alliance to Support Least-Cost Utility Planning, February 1989.

A Complete and Economic Study on Proposed IPCB Regulation R89-9: Waste Prohibitions. Prepared for the Illinois Department of Energy and Natural Resources (with J. L. Carlson, M. J. Morey, R. C. Hemphill, and W. Mikucki).

The Role of Prices and the Pricing System Within the Regulatory Process. Prepared for the Illinois Department of Energy and Natural Resources, October 1986.

An Evaluation of the Minimization of Total Regional Requirements as an Objective in State-Wide Utility Planning Process. For the Illinois Department of Energy and Natural Resources, November 1986.

The Economic Incentives Provided by Section 9-215, Excess Capacity Rule of Proposed Illinois Public Utility Act. A Memorandum to the Joint Committee, June 1985.

An Analysis of the Issue of Cross-Subsidization in the Local Telephone Market. Prepared for the Joint Committee on Public Utility Regulation, May 1985.

A Survey of State Regulatory Actions and Legislative Developments Resulting from the Divestiture of AT&T. Prepared for the Joint Committee on Public Utility Regulations, Illinois State Legislature, March 1985.

A Memorandum to the Telecommunications Policy Working Group on the Concepts of Competing, Competition and Market Structure, September 1984.

The Evolution of Competition in the Telephone Industry and the Critical Issues Facing the Illinois Legislature on the Deregulation of Telephone Service. Prepared for the Select Joint Subcommittee on Regulatory Reform, July 1984.

The Review of Existing Power Plant Certificates, Monitoring of Power Plant Costs and the Allocation of Power Plant Cancellation Costs. Presented to the Sunset Task Force on Utility Regulatory Reform, January 1984.

Utility Efficiency Report Subtask IX - Final Report in Incentive Mechanisms. Prepared for the Illinois Commerce Commission, May 1981.

Utility Efficiency Report Subtask IV - Evaluation and Choice of Incentive Mechanisms. Illinois Commerce Commission for the U.S. Department of Energy, July 1980.

Utility Efficiency Report Subtask II - Review of Existing Incentive Mechanisms. Illinois Commerce Commission for the U.S. Department of Energy, March 1980.

Estimating Fuel Prices, a Memorandum to the Virginia State Corporation Commission with K. Kelly, National Regulatory Research Institute, 1979.

Summary of Regulatory Commission Activities on Power Plant Productivity. The National Regulatory Research Institute draft report for the U.S. Department of Energy, 1979.

Unpublished Papers

Electric Industry Evolution in Eastern Europe After 1990, Working Paper, NERA Economic Consulting, Chicago, IL, November 2002 (with C. Peterson).

Designing the New Regulatory Contract: Using the Market Process to Design Regulatory Mechanisms, Draft Paper, NERA Economic Consulting, Chicago, IL, November 2000.

Decentralization vs. Coordination: An Examination of the Options for Deregulating the Electric Supply Industry, June 1985.

Applied Fairness Theory: The Case of Allocating Canceled Power Plant Costs, October 1983.

Towards Developing a Framework for Evaluating Incentive Mechanisms, Performance Measures and Institutional Choice in Deregulation, August 1981.

An Overview of the Theories of Regulation and Pricing Policies for Regulated Industries. The National Regulatory Institute, 1979.

A Critique of the Averch-Johnson Bias and a Test of Some Alternative Hypotheses. Master Thesis submitted to the Graduate School of the University of Wyoming, July 1978.

Presentations

Performance-Based Regulation and the Stand-Alone Distribution System, Distribution System Planning, Maintenance and Reliability Conference, Denver, November 2000.

The Moral Obligation to Regulate Intelligently. Presented to the NARUC Telecommunications Staff Sub-Committee at the 112th Annual NARUC Convention, San Diego, November 2000.

Concepts of Utility Regulation for Developing Countries, 42nd Annual Regulatory Studies Program, Institute for Public Utilities, Michigan State University, August 2000.

The Essential Role of Earnings Sharing in the Design of Successful Performance-Based Regulation, Presented at EPRI's International Energy Pricing Conference, Washington, D.C. July 2000.

Transmission Pricing: Distance-sensitive, but not Pancaked. Presented at the EEI Transmission Pricing Conference, Washington, D.C., July 2000.

Telecommunications Rate Rebalancing. Presented to the NARUC Telecommunications Staff Sub-Committee at the NARUC Convention, Los Angeles, July 2000.

Coal, Energy and Clean Air: Challenges and Opportunities, facilitator, Illinois Department of Economic Development and Community Affairs and the Illinois Environmental Agency, Decatur, Illinois, July 2000.

PBR Strategy Seminar, Illinois Power Company, April 2000.

Strategic Application of Distributed Resources, Illinois Power Company, April 2000.

PBR Strategy Seminar, with Jeff Makholm, Georgia Power Company, April 2000.

Codes of Conduct for The Electric Industry, presented on behalf of the Edison Electric Institute at the Commissioner Liaison Committee meeting, NARUC Winter Meeting, Washington, D.C., March 2000.

Mergers and Acquisitions: Assessing the Trends in the Electric and Gas Industries, Presentation to the Midwest Energy Bar Association, Kansas City, March 2000.

Telecommunications Industry in the Aftermath of TA96: Creating a Consistent Regulatory Framework amidst the Complexities of the Contemporary Marketplace, Presented to the NARUC Telecommunications Staff Sub-Committee at the NARUC Annual Convention, San Antonio, November 1999.

Cost Allocation for Affiliate Transactions, presented on behalf of the Edison Electric Institute at the Joint Meeting of the Finance and Technology, Gas and Electric Committees, NARUC Summer Meeting, San Francisco, July 1999.

Avoided Cost Calculation Methodologies, presentation to Energy Sector Representatives of Romania and Bulgaria, Bucharest, Romania, Fall 1999.

RTO and ISOs: Restructuring Options, presentation to Energy Sector Representatives of Romania and Bulgaria, Sinaia, Romania, Summer 1999.

Convergence: The Utility of the Future, Presented to Wisconsin Electric Company and Wisconsin Gas merger transition team, 1999.

A Conflict of Paradigms: The Future Role of State Regulation of the Natural Gas Industry. Presented to the Midwest Gas Association, November 6, 1991.

Exit and Entry: Who Will Bear the Risk in a Competitive Natural Gas Industry. Presented at the conference "At the Crossroads: Restructuring the Natural Gas Industry," held by the Center for Regulatory Studies, October 1991.

"To Serve Man" - The Golden Rule or a Visit to the Twilight Zone: How to Reconcile the Obligation to Serve with Competitive Market Forces. Presented to the Gas Policy Committee of the Illinois Commerce Commission, April 16, 1991.

Regulatory Treatment of Emissions Trading Decisions and Their Effect on Marketplace Incentives with D. W. South Presented at the Notice of Inquiry Public Hearing, Illinois Commerce Commission, March 1991.

The National Energy Strategy: Impacts on the Farm Sector. Presented to the Illinois Farm Bureau Leadership Conference, February 1991.

Emissions Trading in the CAAA of 1990: Regulatory, Compliance Planning and Implementation Issues with D. W. South. Presented to the Illinois Commerce Commission, January 1991.

Obligations to Serve and Competition in the Natural Gas Industry. Luncheon presentation at the conference "Assessing the Competitiveness of the Natural Gas Industry," held by the Center for Regulatory Studies, October 1990.

Pricing in an Age of Opportunism: The Cost of Being a Provider of Last Resort. Presented at the conference "Natural Gas Supply Planning: The Implications for Planning Pricing and Competition," held by the Center for Regulatory Studies, March 1990.

Public Utility Issues: Long and Short-Term Impacts. Presented to the Illinois Farm Bureau Leadership Conference, February 1990.

Uncertainty in the Least-Cost Planning Process: The Case of Natural Gas. Presented at the conference "Issues in Least Cost Planning in the Natural Gas Industry," held by the Center for Regulatory Studies, December 21, 1989.

These are representative presentations. Dr. McDermott gave well over one-hundred presentations while at the Illinois Commerce Commission and continues to give many presentations on a variety of topics in the telecommunications, electricity and natural gas industries in a variety of contexts.

Testimony

Illinois Commerce Commission, American Transmission Company LLC Application for a Certificate of Public Convenience and Necessity, pursuant to Section 8-406.1 of the Illinois Public Utilities Act, to construct, operate, and maintain a new 345,000 volt electric transmission line in Lake County, Illinois, Docket No. 11-0661, expert testimony concerning the effect on electric competition of a proposed transmission line from Wisconsin to Illinois, Fall 2011.

Missouri Public Service Commission, *Proposed General Increase in Rates*, Missouri-American Water Company, Docket Nos. WR-2011-0337 and SR-201-0338, Testimony on standard tariff pricing of water services. June 2011.

Illinois Commerce Commission, *Proposed General Increase in Rates*, Commonwealth Edison Company, Docket No. 10-0527, Expert testimony on behalf of the National Resources Defense Council regarding electric decoupling. November 2010.

Utah Public Service Commission, *In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket No. 09-035-15, *Phase II*. Expert testimony on fuel adjustment mechanism, September 2010.

Illinois Commerce Commission, *Proposed General Increase in Rates*, Ameren Illinois Utilities, Docket Nos. 09-0306 through 09-0311 (Consol.), Summer 2010. Expert testimony on policy toward rulemaking.

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Wyoming Public Service Commission, *In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket No. 20000-368-EA-10, Expert testimony on public interest standard for fuel adjustment mechanism, 2010.

Regulatory Commission of Alaska, *In the Matter of the Petition filed by Chugach Electric Association, Inc. for Advance Determination of Prudence for Southcentral Power Project*, U-10-41, June 2010. Expert testimony regarding preapproval of generation investment by state public utility commissions in the United States.

Utah Public Service Commission, *In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket No. 09-035-15, *Phase I*. Expert testimony on public interest standard for fuel adjustment mechanism, 2009.

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North Dakota Public Service Commission, Case No. PU-06-525, Direct and Rebuttal Testimony on behalf of Northern States Power d/b/a Xcel Energy Inc. on reasonable cost of equity for North Dakota natural gas operations, 2006-7.

Oregon Public Utility Commission, UM 1121, Direct, Rebuttal and Surrebuttal Testimony on Behalf of Oregon Electric concerning public policy treatment of proposed purchase of Portland General Electric, 2004.

North Dakota Public Service Commission, Case No. PU-04-578, Testimony on behalf of Northern States Power d/b/a Xcel Energy Inc. on reasonable cost of equity for North Dakota natural gas operations, 2004.

Michigan Public Service Commission, Case No. U-13898, Direct Testimony on behalf of Michigan Consolidated Gas Company concerning the application of performance-based regulation, Fall 2003.

Michigan Public Service Commission, Case No. U-13808, Direct Testimony on behalf of Detroit Edison Company concerning the application of performance-based regulation. Fall 2003.

Circuit court of Jackson County Missouri, *Kansas City Power and Light Company v. Bibb Associates, et. al.* Case No. 01CV207987. Expert report and testimony on behalf of Kansas City Power and Light Company calculating the damages from the explosion of its Hawthorn 5 coal-fired generation unit, 2003-2004.

Public Service Commission of Wisconsin, Docket No. 05-CE-130, Direct, Rebuttal and Surrebuttal Testimony on behalf of Wisconsin Electric Power Company regarding energy efficiency and power plant construction, 2003.

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North Dakota Public Service Commission, Case No. PU-400-00-195, Direct and Rebuttal testimony on behalf of Otter Tail Power Company regarding application to operate under a performance-based regulation plan, Fall 2000.

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