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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish A Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan	)	Case No. 11-346-EL-SSO Case No. 11-348-EL-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority	)	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM

DIRECT TESTIMONY OF
THOMAS LYLE
ON BEHALF OF THE
NATURAL RESOURCES DEFENSE COUNCIL

Q. Please state your name and business address.

A. Thomas Lyle, Optimal Energy, Incorporated, 14 School Street, Bristol, VT 05443.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Natural Resource Defense Council.

Q. Mr. Lyle, by whom are you employed and in what capacity?

A. I am employed as a Managing Consultant by Optimal Energy, Inc, a consultancy specializing in energy efficiency, integrated resources planning and utility planning. In this capacity, I direct and perform analyses of energy efficiency and renewable energy programs, author reports and presentations, and interact with clients to address their energy consulting needs.

Q. Please summarize your qualifications.

A. I have 17 years of experience working in the electric and telecommunications industries. I have conducted and participated in several studies and/or reviews of efficiency and renewable energy potential studies and best practices, including but not limited to studies in British Columbia, New York, South Carolina, Florida, Pennsylvania, Illinois, Manitoba, Iowa, Texas, and Vermont. These studies have ranged from macro-level assessments of potential to detailed, bottom-up assessments evaluating hundreds of measures among numerous market segments. A recent example of the latter is an analysis of the electric efficiency potential for the Long Island Power Authority in New York State. Additionally, I critique and analyze long-range integrated resource plans of utilities on behalf of clients in Tennessee, Missouri and Vermont.

Prior to joining Optimal Energy in 2008, I was a Hearing Officer with the Vermont Public Service Board (VPSB), where I presided over litigated proceedings and was responsible for writing Board Orders in accordance with State law. During my tenure at the VPSB, I was primarily engaged in efforts to diplomatically resolve disputes over public policy issues related to utility revenue requirements, rate design, transmission siting, alternative resource configurations, Gas and Electric DSM programs and Performance-Based Regulation. I have a *B.A.* in Political Science and Economics from the University of New Hampshire and an *MBA* with a concentration in Finance from Southern University of New Hampshire. My resume is provided as Exhibit NRDC-TSL-1.

Q. Have you previously testified before the Public Utilities Commission of Ohio ("PUCO")?

A. No.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to address the following issues:

- Fuel Adjustment Clause (FAC)
- Alternative Resource Rider (AER)
- Environmental Investment Carrying Costs (EICCR)
- Generation Resource Rider (GRR)
- Facilities Closure Cost Rider (FCCR)
- Carbon Capture and Sequestration Rider (CCSR)

Additionally, I discuss American Electric Power's (AEP) proposed renewable energy projects: the Timber Road Wind project and Turning Point Solar project.

Introduction

Q. Please provide a summary of your recommendations.

A. Except for the CCSR, American Electric Power's (AEP or Company) request for approval of the above-noted rate riders is in the public interest provided that a number of important modifications are implemented prior to approval. In the table below, I provide comparisons of AEP's requests and my recommended modifications.

	AEP Proposal		NRDC's recommendation	
Rider	By pass/ Non Bypass	Request	By Pass/ Non Bypass	Recommendation
FAC	Bypass	Remove RECs	Bypass	Approve
AER	Bypass	Account for value of RECs	Bypass	Approve
EICCR	Non-Bypass	Recover capital carrying charges on environmental controls and retrofits, eliminate regulatory lag	Non-Bypass	Approve, with modifications. Subject to prudency review and least-cost analysis
GRR	Non-Bypass	Recover RE investments, and other traditional supply side resources	Non - Bypass	Approve – subject to removing language pertaining to "traditional" supply
FCCR	Non-Bypass	Recover cost of early facility closure	Non-Bypass	Approve, with modifications. Subject to prudency review and least-cost analysis
CCSR	Non-Bypass	Recover cost of FEED study	N/A	Decline – no clear ratepayer benefits at this time
Timber Road	Bypass	Recover cost of REPA	Bypass	Approve - support long term development of eligible renewable energy purchase agreements.
Turning Pt.	Non-Bypass	Recover cost of phase 1 of project	Non- Bypass	Approve, subject to the development of REC tracking as described below. Support long term cost recovery of eligible renewable projects.

Implementing the above-noted recommendations will further support AEP's efforts to develop an Electric Security Plan (ESP) that stabilizes customer rates over the long term. A modified ESP would provide the Company with a roadmap to follow for reducing its exposure to significant environmental compliance risks and increase the likelihood that additional renewable energy projects would be built in Ohio. These recommendations should also help the PUCO's efforts to strike a reasonable balance between the competing interests of AEP, Competitive Retail Electric Service providers (CRES) and retail customers.

Q. Does the current regulatory framework provide for a robust analysis of alternative resource options?

A. No. Over the next several years, the company will be facing a number of challenging financial decisions. It will need to proactively address environmental compliance risks, acquire escalating amounts of renewable energy, increase in-state renewable energy generation and close coal-fired electric generating plants that are no longer worth additional investment of rate payer funds. Ideally, all of these financial decisions would be addressed in a holistic, integrated fashion so that stakeholders could assess the full ramifications of the collective impact these costs would have on retail rates. Unfortunately, the regulatory framework appears to encourage individual rate rider filings.

Despite the incentive to file individual rate riders, the Company should nevertheless be required to file comprehensive least-cost present value analyses when they propose to recover actual costs Comprehensive least-cost present value analyses will help the PUCO safeguard the interest of rate payers. It would demonstrate to the PUCO that the Company's preferred course of action results in the lowest possible impact on long term utility costs. Requiring the Company to file least-cost analyses would establish an appropriate framework for assessing AEP's approach and methodology to resolving the myriad issues it faces. In addition, a comprehensive least-cost analysis would allow for ample opportunities to weigh the risks and benefits of the options AEP has identified. Finally, it would ensure the PUCO that it has all the facts necessary to render an opinion.

Q. Please describe the hallmarks of a least-cost present value analysis.

A. Without getting into too much detail, least-cost present value analyses compare the benefits and costs of alternative resource options on an equal basis with traditional supply side resources. Least cost alternative analysis considers, for example, the benefits and costs of shuttering plants rather than retrofitting coal-fired plants. Such analysis would quantify the full range of reasonably foreseeable capital, operating, maintenance, and fuel costs for coal plants and compares them to alternative low cost, low risk resources like energy efficiency, utility-scale renewable power, customer-sited renewable power programs, and combined heat & power solutions. It weighs the benefits and costs of coal plant retrofits, including eventual environmental remediation and decommissioning costs, against the benefits and costs of best practice energy efficiency programs and cleaner energy alternatives on an equal basis.

Q. Would least cost analysis help to lower AEP's risk profile?

A. If done correctly, yes. Many utilities throughout the U.S. and even Wall Street investment bank analysts have embraced comparative least-cost present value analysis for several years now. Wall Street's analyses confirm that declining economic competitiveness of coal facilities vis-à-vis alternative resource solutions is leading to many more coal plant retirements. In fact, Credit Suisse's analysts reported the following:[1]

"…. a large chunk of the U.S. coal fleet is vulnerable to closure simply due to crummy economics…"

Credit Suisse's analyst goes on to state that due to poor economics, utilities should be re-evaluating the operating costs of their coal fleets before taking on the burden of capital expenditures for environmental control equipment. In fact, closing coal plants would likely have a positive economic effect on many power producers.[2]

Q. Would best practice energy efficiency programs result in energy savings in excess of the goals established in ORC 4928.66(A)(1)(a).

A. ORC 4928.66(A)(1)(a) states:

> *Beginning in 2009, an electric distribution utility shall implement energy efficiency programs that achieve energy savings equivalent to at least three-tenths of one per cent of the total, annual average, and normalized kilowatt-hour sales of the electric distribution utility during the preceding three calendar years to customers in this state. The savings requirement, using such a three-year average, shall increase to an additional five-tenths of one per cent in 2010, seven-tenths of one per cent in 2011, eight-tenths of one*

[1] Freese, B, et al, *A Risky Proposition, the financial hazards of New Investments in Coal Plants*, Union of Concerned Scientists, March , 2011, pgs 5-6.
[2] *Id.*

> *per cent in 2012, nine-tenths of one per cent in 2013, one per cent from 2014 to 2018, and two per cent each year thereafter, achieving a cumulative, annual energy savings in excess of twenty-two per cent by the end of 2025.*

If AEP were to develop aggressive energy efficiency programs that acquired all cost effective efficiency resources, the company could certainly achieve, and probably exceed, the state's goals under ORC 4928.66(A)(1)(a). And, more importantly, investments in best practice energy efficiency would lower the Company's overall risk profile and postpone new supply additions.

<u>Fuel Adjustment Clause</u>

Q. AEP is proposing to modify the existing FAC. In your opinion, are these proposed modifications fair and reasonable?

A. Yes, they are. AEP is proposing to split expenses related to renewable energy projects currently recorded to account 555, purchased power, into two categories: Renewable energy credits (RECs) and non-REC costs.[3] Going forward, REC related expenses (or benefits) will be recoverable under the proposed Alternative Energy Rider (AER). Non REC related expenses will continue to be recoverable under the FAC. I discuss further the AER below.

In many restructured states, such as Ohio, fuel adjustment clauses take into account a broad array of supply related costs, including the cost of energy, capacity and expenses associated with administration or inventory finance charges. The value of RECs may also

[3] AEP Witness Nelson Dir. at 4-10.

flow through a utility's FAC. But, the exact composition of FAC-related costs as shown on customers' bills depends on the degree of transparency the PUCO wants to include. In many states, customers only see a single FAC-related charge on their bill and have no idea about the value of RECs purchased on their behalf. By separating out REC and Non-REC costs, AEP would be providing important and useful additional information about RECs. In my opinion, customers should know and understand what these costs (and benefits) amount to over time. This level of transparency would demonstrate for customers that a policy of continuing to rely heavily on dirty coal plants as a source of energy has real costs. Without such a transparent rate mechanism, it would be difficult for consumers to compare the costs of purchasing traditional dirty coal power and the value of renewable energy sources. Since AEP's proposal will separately identify REC expenses and non-REC expenses, the company's proposal will help to make transparent the value of the environmental attributes associated with renewable energy. Accordingly, the Company's proposal is in the public interest.

Alternative Energy Rider

Q. Please comment on AEP's proposed AER.

A. As noted above, AEP proposes to begin recovering REC related expenses and benefits associated with Renewable Energy Purchase Agreement (REPA) or purchased directly in the market through a by-passable AER. The intent of the AER is to separate REC charges from other charges on the customer's bill, making the monitoring, tracking and collection of REC benefits and expenses relatively easier compared to the existing practice of including RECs in the FAC. Going forward, REC expenses will no longer be recoverable through the FAC.

Q. How will AEP account for the value of RECs purchased in accordance with the terms of a REPA?

A. AEP's method for recording RECs purchased in accordance with the terms of a REPA will be determined through the residual method, as discussed by AEP witness Nelson.[4] Under the residual method, the value of RECs will be unbundled from the wholesale value of energy and capacity. Energy will be determined by the monthly average PJM energy market price. Capacity will be valued using the capacity prices relevant to AEP's fixed resource requirement (FRRs) designation. Any difference between the energy market price and capacity price and the agreed upon REPA price will therefore be assigned to the value of RECs. The net result of the residual method is that AEP's accounting entries (and banked revenues) associated with RECs will fluctuate over time.

Q. Can AEP mitigate the risks associated with fluctuating REC costs?

A. Yes, they can. Because RECs are unbundled from the underlying renewable power and sold to utilities (or other buyers) with renewable energy obligations, they are commodities subject to a variety of market forces that affect their value. Fortunately, AEP and the State can mitigate the effects of potentially wide fluctuations in REC values by implementing energy efficiency best practice programs.

[4] AEP Witness Nelson Dir. at 12-13.

RPSs are typically set to equal a pre-determined percent of energy sales. In Ohio, AEP and other energy service providers are required to generate 12.5% of their load from renewable energy sources by 2025. Thus, AEP's obligation to acquire RECs can be lowered by reducing overall load. Moreover, the value of RECs, especially banked RECs used for subsequent sale, may increase as the market value of energy and capacity fall with lower demand. Insofar as AEP is able to reduce load by implementing comprehensive best practice energy efficiency programs, the company can potentially reduce its forward-looking RPS obligations in terms of total MWHs delivered.

<u>Environmental Investment Carrying Cost Rider</u>

Q. Are AEP's proposed modifications to the EICCR in the public interest?

A. Yes, assuming additional modifications to the proposed EICCR are implemented and the PUCO conducts a thorough review of AEP's future filings seeking recovery of investments in environmental controls and power plant retrofits (environmental investments), and ensures that the least-cost present value approach described above has been satisfied.

Q. Please explain your additional modifications and concerns regarding what needs to be scrutinized before a new EICCR is approved.

A. AEP proposes two significant modifications to the existing EICCR. First, AEP is seeking permission to reduce the regulatory lag time associated with the current EICCR rider. The second is to change the EICCR from a bypassable rider into a non-bypassable rider.

Reducing Regulatory Lag

Under current rules, the carrying costs[5] of prudently incurred environmental investments are recoverable through the EICCR *after* such eligible investments are put into service. As explained by AEP witness Nelson, EICCR rates for the 2009 – 2011 Electric Security Plan (ESP) went into effect in August, 2010, eight months after most environmental investments were made. Going forward, AEP seeks approval to establish a new EICCR rider, effective beginning January 1, 2012, that would be based on a combination of actual and estimated environmental investments made from 2009 through 2012.[6]

Line No.	Description	In Thousands CSP	OPCo	AEP Ohio
1	2009 Actual	$ 73,838	$ 148,928	$ 222,766
2	2010 Estimate	$ 76,620	$ 67,463	$ 144,083
3	2011 Estimate	$ 20,614	$ 49,443	$ 70,057
4	2012 Estimate	$ 18,841	$ 30,115	$ 24,478
5	Total Capital Expenditures	$ 189,913	$ 295,949	$ 461,384

Because the proposed rider would include the carrying costs on actual and estimated future capital expenditures, subject to true-up, the regulatory time lag between the date when environmental investments were completed and when rates were effective would be nearly eliminated, according to AEP witness Nelson.

[5] Carrying costs represent financial returns on actual investments used and useful in the provision of electric services. For further explanation of the individual carrying costs components see AEP witness Nelson at 16 -18.
[6] AEP Ex. AEM – 1.

I am not opposed to the company seeking to recover the carrying costs on used and useful environmental investments that have been prudently incurred. But, I do not believe it is in the public interest to subject ratepayers to costs that may not actually be incurred or prudent. Before approving the proposed EICCR, AEP should instead demonstrate to the PUCO that:

a) power from a generating plant is needed to serve local load and is not being sold off-system,
b) environmental investments have actually been incurred rather than estimated, and;
c) such investments are the least-cost alternative in light of all of the reasonably foreseeable costs facing the particular facility at issue and the cost of serving energy needs through energy efficiency and cleaner energy alternatives.

Such analysis must include the full range of additional environmental investments as well as incorporate all direct operating and maintenance expenses associated with running the plant reliably.

Q. Should the proposed EICCR include actual 2009 expenditures?

A. For the purposes of establishing the new EICCR, I assume actual 2009 investments included in the table above reflect the unamortized environmental expenditures that are still on AEP's books and that these expenditures have been determined to be prudently incurred by the PUCO.[7] If so, the carrying costs on the unamortized balance should be included in the next generation of EICCR. If the above-noted 2009 expenditures have not been approved by the PUCO, then AEP's request should be denied until a prudency review has been conducted.

[7] AEP Witness Nelson states, however, that the EICCR that went into effect in August 2010, included 2009 expenditures. So it is not clear whether AEP is over-recovering the carrying costs associated with actual 2009 expenditures.

Q. How should 2010, 2011 and 2012 expenditures be treated?

A. Before AEP is allowed to put the next EICCR into effect, the company should present *actual* investments for 2010 and 2011 and demonstrate that such expenditures were prudent. Further, the 2012 EICCR should not include carrying costs for estimated expenditures in 2012. Only known and measureable carrying costs based on prudently incurred least-cost investments should be included in the next EICCR.

Q. Is AEP also requesting to recover estimated O&M expenses associated with environmental controls as part of its EICCR?

A. Yes. According to AEP Witness Nelson, the proposed EICCR includes $28 million[8] to reflect estimated annual O&M expenses. For the same reasons noted above, AEP needs to demonstrate that its expenses are known and measurable before the proposed EICCR is approved. At this point, AEP has not made such a demonstration. Therefore, I recommend that the PUCO disallow the inclusion of forecasted O&M expenses from the rider.

Q. Please explain why it is necessary for AEP to make a showing that its environmental capital expenditures are prudent and least cost.

A. Before the new EICCR is established, AEP should demonstrate that its investment of ratepayer funds in generation is needed to serve local load, prudent, and the least-cost present value alternative. At this stage, the company has simply provided a wish list of expenditures that it seeks to recover from customers. Although retrofitting coal plants

[8] See AEP Ex. AEM – 1.

with environmental controls may appear to be beneficial in some cases, installing environmental controls may not result in the least cost investment in all scenarios. For example, AEP witness Thomas states that some generation facilities may be closed due to age.[9] If plants need additional investments and environmental controls just to keep operating reliably, then the PUCO should determine whether such investments are prudent and least cost. As noted above, making such a determination requires the Company to conduct an open and transparent assessment of least cost present value costs and benefits of alternative resource configurations. If the cost of retrofitting a coal-fired facility is not a least cost option, then the investment would not be prudent or necessary.

Bypass or Non-bypass designation

Q. Do you believe the change from a bypassable to non-bypassable rider is appropriate?

A. AEP's proposal is not inappropriate, provided that costs reflected in the rider were the result of competitive bidding processes, generation serves local load, and AEP sufficiently addresses the issues noted directly above (e.g. the riders reflects carrying charges on actual expenditures that have been prudently incurred and are least cost). After AEP satisfies these fundamental conditions, then I contend it would be appropriate to make the EICCR non-bypassable. Just like any regulated utility, AEP's should be afforded the opportunity to earn a return on (as well as a return of) capital investments that have been providing a service to the general body of ratepayers.

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[9] AEP witness Thomas Dir. at 23.

Generation Resource Rider

Q. Is AEP's proposed GRR a sufficient funding mechanism to support the development of renewable energy resources?

A. The proposed GRR can serve as a reliable and sufficient funding source for renewable energy projects, with a few modifications. A modified GRR could, if structured properly, balance the competing interests of AEP, Competitive Retail Electric Service providers (CRES), and ratepayers while also stabilizing sources of revenue for renewable energy projects. However, three important issues need to be resolved before the GRR should be approved.

Q. What are the unresolved issues associated with AEP's proposed GRR that need to be resolved?

A. There are three main issues that need to be resolved before a GRR funding mechanism should be approved. The first issue pertains to the types of costs that may be included in the GRR. The second pertains to whether the three year ESP hinders the development of renewable projects. The third pertains to AEP's processes for tracking RECs.

Q. Please identify the types of costs that could be included in the proposed GRR.

A. The proposed GRR is designed to recover renewable and alternative capacity additions, as well as more *traditional* capacity constructed or financed by the Company and approved by the Commission. The rider will also recover O&M and capital carrying costs and lease payments associated with the Company's investment in facilities dedicated to

Ohio retail customers.[10] AEP's description of GRR-related costs is vague and subject to too much interpretation.

Q. Please explain why AEP needs to clarify which costs could be included in the GRR.

Neither AEP's application nor Company witnesses define the meaning of "traditional" capacity in the proposed GRR. It is my understanding, however, that investments and expenses associated with "traditional" facilities essentially mean fossil fuel generation. These types of costs are recoverable via the Standard Service Offer (SSO) and are by-passable under the current regulatory framework. Shopping customers can avoid paying AEP for these types of "traditional" and "dedicated" charges if they opt to purchase power from a CRES. Given that such costs are bypassable, it is unclear what purpose this type of language serves in the proposed GRR. Consequently, the PUCO should direct AEP to eliminate references to "traditional" capacity from the proposed GRR.

Q. In your opinion, does the three-year ESP term hinder the development of AEP-owned renewable projects?

A. Yes. Because the proposed ESP is valid for three years, it is my understanding that AEP faces a number of challenges obtaining low-cost, long term financing for renewable energy projects that would provide benefits to Ohioans for 20 or more years. At the same time, AEP is obligated to comply with the state's RPS. This is an unfortunate situation for AEP.

[10] Application at 10, AEP witness Nelson Dir. at 21-23.

At this point in time, it appears that AEP's only alternatives are to purchase power under long-term agreements with third party project owners or to propose a non-bypassable but potentially anti-competitive rider (if a REC tracking system is not developed). AEP has pursued both alternatives in this ESP. The former alternative is viable but removes much of the control from AEP. Rather than aggressively develop good renewable projects, the company instead must rely on the market to develop projects. Additionally, the company can only pass through the costs associated with power purchase agreements. As a result, there is little or no opportunity to earn a return on investment. The latter alternative, however, is equally problematic but for different reasons. By making the GRR a non-bypassable rider, many CRESs may conclude that it is anticompetitive. This may dissuade competitors from entering the Ohio market and building viable renewable projects.

Q. Are there any solutions to this regulatory dilemma?

A. There are many possible solutions. One potential solution is to amend the ESP rules and extend the terms of a GRR that is strictly limited to renewable projects that have been deemed by the PUCO to be needed, prudent and competitively bid.

Under this scenario, the Company would still need to demonstrate need and prudency in accordance with the current rules. Demonstrating whether a specific renewable project was competitive would include a showing by AEP that its renewable energy projects were competitive compared to independently-owned renewable energy projects. Such a showing would include but not be limited to a comparison of generation rates, timing of when projects would come on line, capacity factors and O&M expenses.

Q. How will RECs associated with shopping customers be tracked and recorded?

A. The third issue related to the proposed GRR is how to track RECs. The record to date is not entirely clear with respect to how RECs associated with shopping customers will be tracked and monitored. Without a system for tracking and monitoring RECs, there will be a risk that shopping customers may be charged twice for RECs. To resolve this issue, I recommend that the PUCO require AEP to develop a REC tracking system in collaboration with interested stakeholders. During this collaborative, stakeholders could assist AEP to develop an accounting system that allows for the transfer of RECs from AEP and CRES's (and vice versa) as customers migrate between multiple energy providers.

<u>Facilities Closure Cost Rider</u>

Q. Is retiring dirty coal plants that are facing significant upgrade costs in the public interest?

A. I agree with the comments of AEP witness Laura Thomas on pages 23 and 24 of her direct testimony. Because current and future environmental requirements are becoming more stringent, and aging coal units face increasing capital, operating, maintenance, and fuel costs, retiring coal plants in need of mechanical upgrades, in addition to environmental retrofits, could be an especially prudent course of action for AEP. So, yes, retiring dirty coal plants will be in the public interest, especially when it's the least cost option.

Q. Is a separate non-bypassable rider an appropriate funding mechanism to pay for the cost of early retirement?

A. Assuming AEP has demonstrated that actual facility closure costs have been prudently incurred, then a separate non bypassable rider is an appropriate funding mechanism. AEP's plants have been used and useful for several decades, therefore the general body of customers should pay for the cost of decommissioning.

As with other investments, however, AEP will need to demonstrate the prudency of closure related costs. According to the Company, closure costs may include the following types of cost categories:[11]

1. Un-depreciated plant balances, net of salvage value,
2. Material and supplies unique to the facility being closed,
3. Environmental liabilities requiring action upon facility closure,
4. Mitigation costs required by applicable existing and future environmental regulations; and,
5. Legacy pension and benefit requirements.

Q. Should AEP's proposed FCCR be subjected to the same type of least cost analysis discussed above.

[11] AEP witness Laura Thomas Dir. at 24.

A. Yes. Similar to my arguments about the EICCR, any demonstration by AEP of need must include a least cost analysis of alternative investment choices. As such, all the costs (including capital carrying costs) associated with complying with current and anticipated environmental regulations, along with other reasonably foreseeable capital needs, and projected operating, maintenance, and fuel costs need to be weighed against the cost of closing the facility. All such costs need to be objectively forecasted and equally considered. Under such an analysis, AEP will likely discover that continuing to run dirty coal plants in the face of increasingly stringent regulations poses significant risks to the Company. As Credit Suisse concluded (referenced above), retiring coal plants are projected to have a positive economic impact on the company's financial condition.

Q. Does a by-passable FCCR provide sufficient incentives to close coal-fired electric generating facilities?

A. No. If the rider is rejected or made bypassable, then AEP would most likely continue operating aging plants. This would result in additional rate increases in the future and increase the Company's risk profile.

Q. Should the Company's FCCR request be extended to plants that have generated off-system sales?

A. Yes. Irrespective of whether plants have generated off-system sales, the FCCR should be non-bypassable, provided AEP has demonstrated that closing plants is prudent and the least cost option. A non-bypassable rider would provide for, but not guarantee, a relatively stable cost recovery mechanism to pay for the cost of closing plants that have been used and useful for several decades. If the PUCO were to deny the Company an opportunity to recover facility closure costs, it would send the wrong signal to utilities as it would encourage them to continue operating and investing in aging coal units even when retiring such units is the least cost option. Denial would jeopardize the intent of the regulatory compact that investor owned utilities operate under. And, it would make future investment decisions much more difficult to analyze. Going forward, AEP's operating decisions could be impaired by overly cautious concerns about cost recovery rather than making decisions that reduce long term utility costs.

Carbon Capture and Sequestration rider

Q. What is the purpose of the new CCSR?

A. This proposed non-bypassable CCSR is designed to recover the cost associated with AEP's share of developing Carbon Capture and Sequestration (CCS) technology. In the short term, AEP is seeking recovery of the Phase 1 Front-End Engineering and Design Study (FEED). AEP's share of the FEED study approximates $10.9 million and would increase its annual revenue requirement by $1.6 million, inclusive of carrying costs.[12] If the FEED study supports additional investment in CCS technology, then the Company will submit a separate filing requesting cost recovery in an amended CCSR.

[12] AEP witness Nelson Dir. at 20.

AEP claims the FEED study would result in clear benefits to AEP and the electric utility industry.[13] Surprisingly, AEP does not specify any ratepayer benefits that would result from the study.

Q. Do you agree that the FEED study results in clear benefits to AEP and the electric utility industry?

A. No, I do not. AEP asserts that the FEED study is essential because[14]:

> a) coal is an essential part of the current and future generation of electricity because of its abundance and versatility;
> b) the coal industry plays a significant role in the economy by the creation of jobs, and;
> c) it provides a promising way of addressing current and future greenhouse gas regulation/legislation.

Coal may be a significant part of the current generation mix, but it certainly cannot continue to be a significant contributor over time, even with CCS technologies. As AEP witnesses have stated, the cost of complying with environmental regulation and operating and maintaining coal plants is increasing the cost of coal-fired electricity compared to alternative resources and energy efficiency. At this point, CCS will only add to the costs of coal-fired electricity. Thus, continuing to rely on coal as a source of electricity will increase retail electric rates.

Any assessment of whether the coal industry plays a significant role in the economy needs to be weighed against the cost of sustaining such jobs and the benefits of job

[13] AEP witness Nelson Dir. at 19.
[14] AEP witness Nelson Dir. at 19.

created by alternative resource programs. AEP has not presented any such assessment. Irrespective of AEP's inability to make a case for coal as an economic driver, it is certainly safe to assume that sustaining jobs in the coal industry is a costly proposition. Costs include but are not limited to the oversight of dangerous mining operations, coal miner's health costs, cost of maintaining infrastructure to transport coal from the mine to the generating plant, and environmental penalties for electric generating plant emissions and mining. Funds spent on these types of costs could be invested in new schools, commercial development zones for high tech companies, and R&D facilities at local universities. These types of alternative investments also create jobs. Investments in energy efficiency also create jobs in the local community as skilled workers are employed weatherizing homes and businesses and installing efficiency measures. AEP's filing has not considered any of these alternative job impacts.

Q. Would you agree that retiring coal-fired electric plants would have economic impacts on local communities?

A. Yes, in the absence of robust transition plans, retiring coal plants could have a negative economic impact on local communities. Accordingly, there should be a concerted effort to mitigate such impacts by providing workers at the generating plant with a reasonably acceptable severance plan, new job placement, and/or retraining, if requested, so that workers could gain the necessary skills to seek employment in other fields. Additionally, measures ought to be undertaken to alleviate the loss of property tax revenues to municipalities

Renewable Energy Strategy for the 2012 -2014 Electric Security Plan (ESP)

Q. Please comment on AEP's renewable energy strategy for this ESP.

A. Given the current regulatory framework, AEP's renewable energy options are fairly limited. The Company needs to comply with escalating annual benchmarks from solar and non – solar resources while simultaneously ensuring that half of the company's renewable energy is sourced in Ohio.[15] At the same time, the three year term limit on the ESP undermines AEP's ability to lock in long-term financing for AEP-owned renewable generation. Despite the challenging regulatory framework, AEP's approach to acquiring renewable energy resources via long term Renewable Energy Purchase Agreements (REPAs) and AEP-owned renewable projects is sensible.

With the exceptions noted above regarding the GRR, I agree in principal with AEP's renewable energy strategy. Additionally, I agree with AEP Witness Godfey's statement regarding cost recovery.[16] New renewable generation resources are unlikely to be built in Ohio unless there are assurances that prudently incurred costs are recoverable over the life the of the renewable generation asset. Without cost recovery assurances, project owners (including AEP) will face challenges obtaining favorable financing terms.

[15] ORC §4928.64 (2)(B) (3).
[16] AEP Witness Godfrey Dir. at 9.

<u>Timber Road Wind Project</u>

Q. Have you had the opportunity to review the RFP issued by AEP that resulted in the Timber Road Wind REPA?

A. Yes, I have. The RFP appears to reflect a competitively bid process. The terms and conditions of the REPA also reflect common terms and conditions accepted by many PUC's throughout the United States.

Q. Please comment on the terms and conditions of the Timber Road REPA.

A. Generally speaking, REPAs (alternatively, Power Purchase Agreements or PPAs) are an excellent tool for capturing low cost energy resources. A wide variety of pricing mechanisms can be used to create PPAs such as the Timber Road contract to foster further development of renewable energy projects so long as there are assurances of cost recovery. A key advantage of power purchase agreements is the predictable cost of electricity over the life of a 15- to 20-year contract, which is typical of many PPAs. Long-term pricing contracts mitigate the unpredictable nature of energy price fluctuations that can negatively impact utility retail rates. In a renewable energy PPA, wholesale electricity rates are predetermined between seller and buyer, explicitly spelled out in the contract, and legally binding with little or no dependency on fossil fuel or climate change legislation, both of which can increase utility retail rates.

It is important to emphasize that all PPAs are unique. Nevertheless, there are many common pricing terms included in PPAs across the industry. Common terms include but are not limited to "all-in" fixed pricing per MWh, a fixed escalator, and unit contingent clauses. All-in pricing terms reflect all costs incurred to operate the facility without regard to seasonality or peak demand. Fixed escalation factors are also common and typically range from 1.0% to 3%, similar to the 2.25% escalation factor included in the Timber Road PPA. Unit contingencies specify that project owners are paid for what they produce.

Q. Are you aware of any alternative PPA structures?

A. An emerging PPA structure that the PUCO may want to consider has consumers (or AEP in lieu of consumers) either 1) prepaying for a portion of the power to be generated by a renewable energy project or 2) making certain investments at the site to lower the installed cost of the system. Either method can reduce the cost of electricity agreed to in the PPA itself. Prepayments can improve economics for both parties and provide greater price stability over the life of the contract. Boulder County, for example, exercised this option by making upfront investments to lower project costs. The investments resulted in a 20-year PPA with a fixed-price term of $0.065/kWH for the first seven years. Thereafter, Boulder has the option to re-negotiate terms or buy-out the contract.[17] Irrespective of which method AEP implements – either the traditional PPA or the emerging 'buy-down' path, the Company will need to demonstrate need, prudency and that its selection processes were competitively bid.

Q. Please comment on AEP's solicitation process.

[17] See; *Energy Analysis: Power Purchase Agreements Checklist for State and local governments*, NREL, 2009. http://www.nrel.gov/docs/fy10osti/46668.pdf , accessed 5/12/2011.

A. Based on AEP's representations, the RFP appears to have been sufficiently detailed and relatively transparent as to what AEP's interests were for this solicitation. AEP adequately described for potential bidders their project requirements and desired contract structures. That AEP made the RFP universally available is another indication that AEP's bidding process was a competitive solicitation. Also, AEP adequately explained how timely submitted proposals would be evaluated. This was another positive indication of a competitive solicitation. Further, webinars and pre-bid meetings were indicative of the open and transparent process that AEP conducted.

Despite all of its representations, however, it is impossible to conclusively determine whether the Company's processes were actually competitive and negotiated at "arms-length". To conclusively determine if negotiations were at "arms-length" and fair to all bidders, I would need to know more about how bidders received the RFP and who was on the bid list. From the list of bidders, I could then look into whether AEP had any formal or informal business relationships with bidders or their subsidiaries.

Q. Do you have any general comments about the Timber Road PPA?

A. Yes, I do. Although AEP's representations certainly suggest that a competitive solicitation was conducted, two important facets of the Timber Road bidding process could be improved. The first pertains to the timing of the solicitation; the second pertains to the minimum size requirements. Both of these limitations were probably a byproduct of the company's need to comply with current regulatory requirements.

With respect to the timing of the solicitation, the RFP was issued on June 1, 2009 with a commercial operation date set for December 31, 2011. This two and half year time constraint suggests that AEP was interested in projects that were already well under way and had already been through much of the planning/pre-development phase. Furthermore, the tight time frame most likely limited proposals to wind projects. New biomass and hydro projects would typically be unable to respond within 30 months. Even new wind projects, which are able to navigate through the planning phase at a quicker pace than most other non-solar renewable projects, would find the tight turnaround time a challenge. Another similar constraint is that AEP appears to have signaled its preference for projects that were already in the PJM interconnection queue.

As for the minimum size limitation, the Company's policy to limit projects to 20MW or larger precluded small wind developers from aggregating projects to achieve greater economies of scale.[18] Had AEP not imposed this size limitation on wind projects, additional projects may have been proposed.

Consequences of AEP's constraints are extremely difficult to quantify but the effects of their process may have limited the range of new renewable energy projects that could have been brought on line. AEP essentially issued a RFP with the hope that projects were already in process and sufficiently developed so that the Company could step into the benefits of an existing project. Additionally, these limitations most likely limited the full

[18] The Company did allow bidders to propose smaller (5MW) solar, hydro and landfill projects.

competitiveness of projects that could have been built; either in-state or somewhere else within the PJM footprint.

Turning Point Solar Project

Q. Is AEP's proposed solar project structured in a manner that would generate rate payer benefits?

A. Aside from the issues noted above with respect to the GRR, there is nothing in AEP's representations that suggest to me that the ownership structure of the Turning Point project would be economically harmful to ratepayers. As noted above, self-building renewable generation through an equity position in a joint venture such as Turning Point, LLC, is a sensible approach to acquiring low-cost renewable resources and achieving the state's renewable goals. Consequently, I agree with the concept that renewable energy projects should be recoverable through a rider like the proposed GRR, as amended per my recommendations. As mentioned above, however, the short term nature of the ESP makes financing this type of project challenging for AEP. To remove this barrier, the PUCO may want to consider extending the length of renewable energy specific riders.

Q. Has AEP requested cost recovery of the Turning Point project?

A. The company recently filed a preliminary rate to recover the first phase of the Turning point project through the GRR. As the company has noted, the GRR is designed to recover actual expenses and will therefore be trued-up on a regular basis. The proposed impact for a residential customer using approximately 1,000 kWh per month is $0.25 when the project is implemented.[19]

Q. In your opinion, does the Turning point project satisfy the requirements of ORC 4928.143(B)(2)(c)

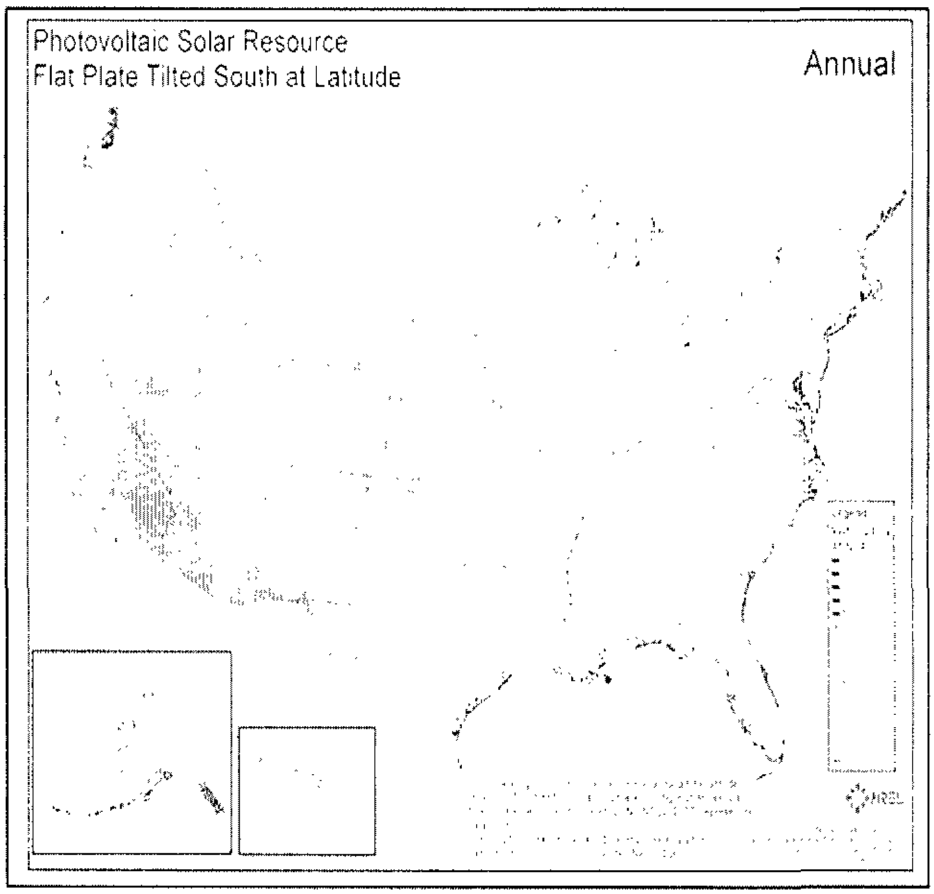
A. Yes, it does. While I am not an attorney, it is my understanding that under ORC 4928.143(B)(2)(c) AEP needs to demonstrate that a project satisfies two important criteria before the PUCO can approve recovery of project costs through a non-bypassable rider. The criteria are:

- The project was sourced through a competitive bid process subject to any such rules as the commission adopts under division (B)(2)(b) of this section, and;
- There is a need for the facility in question based on resource planning projections.

With respect to AEP's competitive-bidding process, the Turning point project is a joint venture with an unaffiliated developer.[20] Because AEP will be a partial owner, it is obligated to develop a project at the lowest possible costs subject to such considerations as risks, reliability and statutory requirements. On the other hand, AEP's partner will seek to maximize profits. This tension, however, appears to have resulted in a relatively competitively-priced agreement.

[19] Roush Supp. at 4.
[20] Godfrey Supp. at 3.

According to AEP Witness Nelson, the levelized cost of the project is estimated to be $257 per MWh based on a number of assumptions such as energy output and inflation.[21] The reported levelized cost is within the range of reasonableness considering Ohio's available solar resources.



As the NREL map shows above, Ohio is not necessarily rich in solar resources.[22] There is sufficient global insolation to produce roughly 3.0 – 4.0 kwh/m2/day, a little less than 1/2 the amount that can be produced in sunnier locals like California. In Vermont, an area

[21] AEP Witness Nelson Supp. at 7.
[22] http://www.nrel.gov/gis/solar.html, accessed on July 7, 2011.

that is similar with respect global insolation, the feed–in tariff for PV systems was originally established at $0.30 per kWh (or $300 per MWh). In other reports, the levelized cost of large solar facilities has ranged from a low of $100/MWh to as much as $340/mWh.[23] Accordingly, the levelized cost of Turning Point power can be assumed to reflect a competitively bid arrangement.

With regard to need, AEP has filed a long term resource plan with the PUCO for approval. While I have not fully analyzed the plan, it is my understanding that AEP has adequately demonstrated that the Turning Point project is needed to satisfy its obligations under SB 221.

Q: Does this conclude your testimony?

A: Yes.

[23] Freese, B, et al, *A Risky Proposition, the financial hazards of New Investments in Coal Plants,* Union of Concerned Scientists, March , 2011, pg. xiv.

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the Direct Testimony of Thomas Lyle has been filed with the Commission and has been served on the following parties by U. S. Postal Service or by e-mail on this 25th day of July, 2011.

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Optimal ENERGY *Integrated Energy Resources*

Thomas S. Lyle
Managing Consultant

Mr. Lyle has over 17 years of professional experience in the utility sector. The primary focus of Mr. Lyle's practice is to work collaboratively with clients to develop and implement climate-friendly public policies that result in positive economic benefits. Specifically, Mr. Lyle has been assisting clients and stakeholder advisory committees with program planning, budgeting and implementation, best practice reviews, integrated resource planning, program and portfolio evaluation, and risk management. Currently, Mr. Lyle is managing a variety of program planning, evaluation and IRP projects for clients in New York, Ohio, South Carolina, Tennessee, Iowa, Vermont, Missouri and Illinois. Mr. Lyle has also been a key advisor to renewable energy program managers on Long Island, New York. With Mr. Lyle's assistance, his client's solar program was able to exceed its annual goals. Prior to joining Optimal, Mr. Lyle was a Hearing Officer for the Vermont Public Service Board ("VPSB"). As a Hearing Officer, he was responsible for conducting technical hearings, case-load management and writing Board Orders in accordance with State law. During Mr. Lyle's tenure at the VPSB, he diplomatically resolved disputes over a diverse set of public policy issues related to utility revenue requirements, rate design, transmission siting, alternative resource configurations, Gas and Electric DSM programs and Performance-Based Regulation.

Professional Experience

Optimal Energy, Inc. — ***Bristol, VT***
Managing Consultant – 2008 to present

Mr. Lyle works with clients to develop sound public policies and program plans to cost effectively achieve organizational goals. Specifically, he is responsible for providing clients with the following services:

- Pre-filed testimony on a range of DSM issues such as program designs, implementation tactics and evaluation plans.
- Developing Portfolio and Program Evaluations and plans
- Providing written reports and presentations on State energy and regulatory policies regarding financing programs, integrated least cost resource planning, efficiency program best practices, program designs and implementation strategies.
- Managing renewable energy initiatives. Responsibilities include developing program objectives, goals and budgets, monitoring and tracking performance for cost effectiveness and reporting.
- Assessing the effectiveness of efficiency program administration models in the United States and Canada—Best Practice reviews.

- In consultation with clients, developing energy and demand Savings goals and budgets, design appropriate financial performance incentives for Efficiency program administrators and plan for program evaluations
- Develop Scopes of Work for Efficiency Program and Renewable Contractors to perform.
- Develop and Design operational workflows and processes to ensure effective program administration and data capture.
- Perform analysis of viable non-transmission alternatives to ensure electric grid reliability and stability.
- Writing reports, client memoranda, and testimony before U.S. Public Utility Commissions on a range of DSM issues such as financing programs, program evaluations and implementation.

Hearing Officer/Utility Analyst ***Vermont Public Service Board***
Feb. 2003–Dec. 2007

Responsible for evaluating the public policy impact of utility and stakeholder petitions filed with the Board, and determining whether such petitions were consistent with the general good of the state of Vermont. Charged with the responsibility of advancing and protecting the State's interests at FERC and US Department of Energy. Determined the appropriate revenue requirements of utilities by balancing the competing interests of utility shareholders and consumers. Conducted analysis of alternative regulation policies, energy efficiency programs and the adequacy of the state's energy resources. Responsible for project and case management

International Telecommunications Consultant
Independent Consultant May 2001- Jan. 2003

Provided technical assistance to U.S. Public Utility Commissions and government officials of several Southern African Countries. Other tasks included:

- Conducting workshops on regulatory methods and procedures, financial and economic analysis techniques
- Project/Program Design and Management
- Capacity-building and Leadership/management training, empowering clients
- Reviewing federal, state and international policies, and writing testimony

Government Affairs Manager
Vitts Networks, Inc., 1999-April 2001

Hands-on manager responsible for advancing and protecting the business interests of a small Telecommunications Start-up Company at all Government, Industry and Community levels. Assisted executive management to obtain venture capital and expand operations in 14 states.

Utility Analyst
Public Utility Commission (NH), 1993-1999

As a Staff and Consumer Advocate, I presented expert testimony on:

- Utility Revenue requirements
- Risk adjusted cost of capital
- Cost allocations and rate design

Other specific responsibilities included:

- Stakeholder outreach and collaboration
- Policy development and implementation

Education

Masters in Business Administration, Finance	So. University of New Hampshire
Bachelor of Arts	Univ. of New Hampshire

Highlights of Project Experience

Program planning, evaluation and assessment

- Lead C&I contributor to a Best Practice Report to Manitoba Hydro (MH's). In this project, Mr. Lyle compared MH's programs, including cost effectiveness, to best practices throughout North America. The report evaluated the cost of energy saved, delivery strategies and MH's capabilities to overcome market barriers. (2009)
- Lead author of the U.S. Department of Energy's new financing webpage. This project includes a step-by-step guide for municipal, state and NGO officials who want to establish public-private financing programs to accelerate clean energy program participation. The guide showcases innovative, cost effective financing programs currently in operation that are successfully transforming the marketplace for clean energy financing. The guide includes instructions for conducting market assessments, developing program objectives, designing and implementing programs, evaluating program outcomes and redesigning programs based on evaluation results. (*in progress*)
- Lead witness for the Southern Environmental Law Center (SELC) before the South Carolina Public Utilities Commission. Provided prefiled testimony on South Carolina Gas & Electric Company's (SG&E) 3-year energy efficiency program plan and budget. Mr. Lyle's testimony focused on SG&E's potential studies, cost of saved energy, program designs and implementations strategies. Compared SG&E program plans to best practices in the United States and determined that SG&E underestimated its savings goals relative to maximum achievable potential resources. Provided SELC with litigation support and assisted with negotiations. (2009-2010)
- Provide on-going technical support to Southern Environmental Law Center (SELC) in South Carolina. Technical support thus far has focused primarily on

reviewing program evaluation plans and budgets, monitoring program performance and reviewing program revisions. *(in progress)*

- Co-authored prefiled testimony for the Iowa Office of Consumer Advocate before the Iowa Utilities Board. Testimony focused on energy efficiency administrative models, best practices, program designs and implementation. (2008-2009)
- C&I team leader to the Iowa Office of Consumer Advocate. Regularly participate in stakeholder committee meetings to ensure energy efficiency programs administered by Investor owned utilities are cost effective and achieving a high rate of energy savings. *(in progress)*.
- Lead author of New York Power Authority's (NYPA) evaluation planning guidebook. This guidebook provides NYPA's staff with the resources needed to prepare for an evaluation of its large C&I projects. The guidebook also includes a step-by-step process for determining project baseline energy consumption based on market driven opportunities or early retirement, discretionary retrofit projects. (2009 – 2010).
- Team lead of Efficiency Vermont's (EVT) Commercial Real Estate initiative. EVT is in the process of assessing market barriers to the Commercial Real Estate market, including first costs, split incentives and lack of knowledge. Under Mr. Lyle's research and direction, EVT is developing innovative program tools and tactics to address market barriers in this market space. *(in progress)*.

Resource Planning

- Lead technical advisor to the Southern Alliance for Clean Energy (SACE) in its review of the Tennessee Valley Authority's (TVA) Integrated resource plan. Based on Mr. Lyle's assessment of TVA's potential studies, program plans and implementation strategies, TVA substantially increased the role of energy efficiency in TVA's 20 year integrated resource plan. Mr. Lyle's work focused on gaps in TVA's planning processes such as omitting commercially available technologies and retrofit opportunities, underestimating penetration rates and severely restricting the role of cost effective energy efficiency compared to risky supply side resources. (2010-2011).
- Technical advisor to the Natural Resource Defense Council in its review of Ameren Missouri's 20 year Integrated Resource Plan before the Missouri Public Utilities Commission. The focus of Mr. Lyle's work is to ensure the Company's alternative resource plans can reliably serve customer demand at the lowest present value life cycle costs. His primary responsibility is to work with the Company and stakeholders to analyze demand side management resources on an equal basis with supply side resources. *(in progress)*

Program management

- Management advisor to American Municipal Power Association (AMP) in Ohio. Optimal has provided financial and management operations support to AMP as it begins the operation of "Efficiency Smart" in 2011. Efficiency Smart provides a wide range of energy efficiency and implementation services for AMP's municipal member utilities. As part of AMP's ramp-up, Mr. Lyle developed a management operations manual tailored to the needs of AMP managers who are charged with overseeing the day-to-day operations of "Efficiency Smart". The operations manual provides AMP managers with a checklist tool to systematically review proposed energy efficiency programs for comprehensiveness, fairness and adherence to best practices.

- Technical advisor to Long Island Power Authority's Renewable energy program manager. Provided technical support in developing program goals, budgets and implementation strategies. Responsibilities included monitoring program progress, cost of installed systems and generation, and reporting. (2009).