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March 23, 2010

VIA ELECTRONIC FILING

The Honorable Joel H. Peck
Office of the Clerk, State Corporation Commission
c/o Document Control Center
P.O. Box 2118
Richmond, Virginia 23218-2118

RE: Case No. PUE-2009-00097; Ex Parte; Appalachian Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.

Dear Mr. Peck:

Enclosed for filing in the above-captioned matter is the pre-filed direct testimony of William Steinhurst, PhD, on behalf of Southern Environmental Law Center, Appalachian Voices, the Chesapeake Climate Action Network, and the Virginia Chapter of the Sierra Club (collectively, "Environmental Respondents"). This filing is being completed electronically, pursuant to the Commission's Electronic Document Filing system.

Sincerely,

Frank Rambo

cc: Parties on Service List
Commission Staff

CERTIFICATE OF SERVICE

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DATED: March 23, 2010

Frank Rambo, Southern Environmental Law Center

TESTIMONY
OF
WILLIAM STEINHURST, Ph.D.

ON BEHALF OF
THE SOUTHERN ENVIRONMENTAL LAW CENTER, CHESAPEAKE CLIMATE ACTION NETWORK, APPALACHIAN VOICES, AND THE VIRGINIA CHAPTER OF THE SIERRA CLUB

Virginia State Corporation Commission
Case number PUE-2009-00097

March 23, 2010

I. PRELIMINARIES

Q. PLEASE STATE YOUR NAME, EMPLOYER, AND PRESENT POSITION.

A. My name is William Steinhurst, and I am a Senior Consultant with Synapse Energy Economics ("Synapse"), which is headquartered in Cambridge, Massachusetts. My business address is 45 State Street, #394, Montpelier, Vermont 05602.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of a coalition (the "Environmental Respondents") consisting of the Southern Environmental Law Center, the Chesapeake Climate Action Network, Appalachian Voices, and the Virginia Chapter of the Sierra Club.

Q. PLEASE DESCRIBE SYNAPSE ENERGY ECONOMICS.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have over twenty-five years of experience in utility regulation and energy policy, including work on renewable portfolio standards and portfolio management practices for default service providers and regulated utilities, green marketing, distributed resource issues, economic impact studies, and rate design. Prior to joining Synapse, I served as Planning Econometrician and Director for Regulated Utility Planning at the Vermont Department of Public Service, the State's Public Advocate and energy policy agency. I have provided consulting services for various clients, including state public advocates, other government agencies, and various non-governmental organizations. A list of my clients and publications was included in my prefiled testimony in SCC Docket # PUE-2009-00081.

I hold a B.A. in Physics from Wesleyan University and an M.S. in Statistics and Ph.D. in Mechanical Engineering from the University of Vermont.

I have testified as an expert witness in approximately 30 cases on a wide range of topics in utility policy and regulation, and have been a frequent witness in legislative hearings and participant or leader in collaborative settlement processes.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE VIRGINIA STATE CORPORATION COMMISSION ("THE COMMISSION" OR "SCC")?

A. Yes, I have. I testified in 2009 in SCC Docket # PUE-2009-00023 and in 2010 in SCC Docket # PUE-2009-00081. I also prepared written testimony which has been prefiled in SCC Docket # PUE-2009-00096. A copy of my resume is attached to this testimony as Exhibit WS-1.

Q. ARE YOU PRESENTING ANY OTHER EXHIBITS TO SUPPORT YOUR TESTIMONY?

A. Yes. Exhibit WS-2 is a chart prepared by the World Resources Institute titled “Net Emission Reductions Under Cap-and-Trade Proposals in the 111th Congress, 2005-2050.”

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to consider the question of whether the Company’s proposed integrated resource plan (“IRP”), originally filed on September 1, 2009, should be approved as reasonable and in the public interest.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In Part III, below, I provide an overview of the IRP process, based on more than a quarter century of nationwide experience with IRPs. In Part IV, I address the Commission's role in evaluating the IRP under Virginia law. Part V identifies strengths in Dominion's currently proposed IRP, while Part VI identifies the weaknesses.

III. OVERVIEW OF IRP

Q. WHAT IS IRP? WHAT ARE ITS BENEFITS?

A. From its inception, a cornerstone of IRP policy and practice has been that IRPs must abide by two broad principles.

First, all resources must be considered—and considered on a "level playing field." That means that energy efficiency and demand response (together, demand-side management ("DSM")) resources, transmission and distribution resources (including improvements to transmission and distribution efficiency), and all types of generation resources must be considered on an equal footing.

Second, the IRP process must deliver an integrated portfolio of resources with the mix of resources that will provide adequate and reliable service at the lowest life cycle cost, with the life cycle cost comparisons (between resources or portfolios) and with an acceptable level of risk to ratepayers.

An IRP that fails to follow these two principles will not provide efficient and economical service or serve the public interest.

Q. WHAT IS MEANT BY THE TERM LIFE CYCLE COST?

A. Life cycle cost in an IRP context means the cumulative cost of meeting customers' needs for energy services over the planning period using a given resource plan. The planning period is typically 20 years, but sometimes other lengths, such as the 15 years specified in Virginia statute (Va. Code § 56-597). The costs included are typically the total resource cost as it is used in the TRC test, possibly with adjustments for external costs, such as environmental externalities. When a single figure is needed for comparison between two resource plans the life cycle cost is often expressed as a discounted net present value or "NPV." (Here, "net" refers to the total cost of service under a given resource plan net of off system revenues.)

Q. PLEASE EXPLAIN THE POLICY SIGNIFICANCE OF IRP PRACTICES AND GUIDELINES ADOPTED IN OTHER JURISDICTIONS.

A. Under a new IRP statute, Va. Code §§ 56-597 *et seq.*, Virginia's investor-owned utilities are now required to submit, and the Commission is required to analyze, IRPs. As the Commission undertakes this inaugural round of IRP proceedings, it would, in my opinion, be appropriate for the Commission to recognize the more than twenty-five years of IRP experience nationally in the field of power planning. As a matter of policy, the Commission may wish to interpret and implement its new statutory mandate in a manner that is consistent with the standards that are widely recognized in the field of electric utility planning and are the standards to which IRPs are held in many jurisdictions. Those standards ought to form the cornerstone of IRP review.

Q. DO IRP PRACTICES AND GUIDELINES CALL FOR SUCH PLANNING TO BE DONE IN SPECIFIC WAYS?

A. Yes. As already mentioned, the broad principles that are central to IRP practice are that all resources are considered on a "level playing field," and that the planning process results in an integrated portfolio of resources with the mix of resources that will provide adequate and reliable service at the lowest life cycle cost.

Q. WHAT HAPPENS IF AN IRP DOES NOT FOLLOW THE TWO FUNDAMENTAL PRECEPTS YOU DISCUSS ABOVE? THAT IS, WHY SHOULD THE PUBLIC OR THE COMMISSION CARE WHETHER THE COMPANY'S IRP STAYS TRUE TO THOSE BASICS?

A. There are several important reasons why the public and the Commission should care deeply about such a failure. Among the most important are (1) a substandard IRP cannot deliver least cost service to ratepayers, leading to excessive utility bills over the long term, and (2) there will be no way for regulators or the public to determine whether the utility has planned properly to meet their needs reliably and in an economical and efficient manner. A sound IRP is widely recognized as a vital tool for good utility management and oversight. Also, without a sound IRP, it is impossible to accurately gauge the riskiness of a utility's resource plans or the degree of risk being imposed on present and future ratepayers.

Q. ARE THERE OTHER IMPORTANT POINTS THE UTILITIES AND THE COMMISSION SHOULD HAVE IN MIND WHEN PREPARING, REVIEWING, OR IMPLEMENTING A PLAN?

A. Yes. The two most important are (1) assessment of uncertainties and risk and (2) consideration of environmental impacts.

Q. PLEASE PROVIDE SOME EXAMPLES OF THE UNCERTAINTIES AND RISKS THAT THE COMMISSION SHOULD CONSIDER.

A. The resource portfolio that is projected to have the lowest life cycle cost under one set of assumptions about the future, might not be the best under another set of assumptions due to the many uncertainties and risks inherent in utility planning. Assumptions that can make a material difference to the performance of resource portfolios include, but are not limited to:

- load growth, weather and other factors affecting the size and timing of resource needs over time, such as trends in customer types, end use make up and load shape;

- cost, availability and deliverability of fuels, equipment, construction materials and expertise, labor, land, transmission service and other goods and services that determine the cost of the various resources in the portfolio;
- financial factors, such as inflation rates, utility bond ratings and changes in the rating criteria, cost and availability of various types of insurance, cost and availability of various types of capital;
- factors relating to implementation schedules and “lumpiness” of various resource options, such as construction or installation times or delays in those times, risk of project failure or cost increase;
- environmental and regulatory risks, such changes in emission standards (including the likelihood of CO_2 regulations and other new regulations), new emission standards or fees, permitting risk; and
- planning risk, for example, the risk that a resource will become obsolete or unnecessary while under construction.

Q. PLEASE EXPLAIN THE ASSESSMENT OF UNCERTAINTIES AND RISK IN THE CONTEXT OF UTILITY RESOURCE PLANNING.

A. I will discuss several of these risks below. However, while the technicalities can be somewhat abstract, the essence of risk and uncertainty assessment in this context is to measure the variability of a resource portfolio’s results due to uncertainties in factors or assumptions such as those listed in the preceding answer. The Commission should look for (1) a thorough inventory and description of the relevant risks, together with an assessment of their probabilities, (2) an objective analysis of how those risks impact the performance of various resource plans individually and in combination, (3) development of a plan relying on a portfolio of resources that manages risk and uncertainty to a reasonable level while delivering the lowest life-cycle cost over the fullest possible range of plausible future scenarios.

Q. THE PRACTICES AND GUIDELINES YOU RECOMMEND SEEM TO INCLUDE SUBSTANTIAL ANALYSIS AND DATA GATHERING. TO WHAT STANDARDS SHOULD THE COMMISSION HOLD THOSE ACTIONS?

A. In order to facilitate review by the Commission and parties, and to promote accuracy, I recommend that these assessment and data gathering activities should be transparent (clear and understandable to the Commission, the parties and the public), fully documented and supported by work papers and methodologies that allow the Commission and the parties to determine their validity, quantitative whenever possible, and treat all resources on a level playing field.

Q. PLEASE EXPLAIN HOW ENVIRONMENTAL IMPACTS SHOULD BE CONSIDERED IN THE CONTEXT OF UTILITY RESOURCE PLANNING.

A. Any resource choice will entail some environmental effects. Those effects are of two general types. One is the considerable and highly uncertain cost of compliance with environmental regulations, present and future. The second is environmental and public health effects of pollution and land or water use that are not eliminated by compliance with regulations.

Much of the discussion of risks and uncertainties for the IRP has to do with the former—current and future regulatory requirements and their costs. Those costs can be in the form capital additions, increased operation and maintenance, reduced output due to parasitic loads of control equipment, outages for installation of control equipment, switching to cleaner fuels, or constraints on plant operation on high pollution days, to name just a few. Clearly, an IRP that deals inadequately with those costs and risks can be neither reasonable nor in the public interest.

As for the second group of environmental effects—those due to pollution that is not completely eliminated by compliance with regulations—the most straightforward way to reflect their consequences for the public interest is through adjustments to the TRC test, such as those I recommended to the Commission in prior proceedings. I reiterate that recommendation here. To the extent that the Commission had ordered use of the TRC Test, it should adopt for IRP purposes monetary proxies for those environmental costs that are likely to impact resource costs in the future.

Q. WHY IS IT NECESSARY TO CONSIDER COST-BENEFIT TESTS AND THEIR DEFINITIONS IN THIS, AN IRP PROCEEDING?

A. The fundamental exercise in an IRP is to compare resources and portfolios of resources against each other. It is the industry norm to use some form of the TRC test (or, in some states, the Utility Cost test or the Societal Test) to perform this basic function. However, as I have previously testified in SCC Docket # PUE-2009-00081, in which the Commission has not yet entered an order, I read the cost-benefit provisions of the Commission's December 2009 Report in SCC Docket # PUE-2009-00023 (the "Report") to require the use of a multi-test approach (RIM, closely followed by TRC, rounded out by the remaining tests) for the screening and development of the Company's proposed DSM programs. As far as I am aware, this multi-test approach is foreign to integrated resource planning as it is practiced by utilities around the nation.

Thus, depending on how the Commission resolves the question of the proper cost-benefit test in PUE-2009-00081, this IRP proceeding potentially raises a new and important issue: there may be a dissonance between the Commission's DSM screening approach and the norm for IRP analysis. As I have mentioned elsewhere, I still support the use of the TRC test as the sole tool for determining if a DSM measure or program is cost-effective, reserving the other tests listed in the Commission's Report (PUE-2009-00023) for other purposes. However, given the Commission's

Report, it may be appropriate to conduct IRP cost studies using the TRC test (with or without the adjustments I recommended, as the Commission determines) equally for all resources in the IRP analysis, but then further review the DSM measures and programs selected by the IRP process considered against the test as set out in the Commission's Report (or as the Commission further orders).

This approach would have the benefit of resolving the practical planning issue of having two different testing standards, one for resource planning in general and a different one for DSM program screening. It would also, unfortunately, violate the principal of the "level playing field" discussed above. I recommend this approach to the Commission, but with the gravest of reservations and only as a distant second best to doing all screening with the TRC test alone. However, as a practical matter, if the Commission adopts my recommendation from Docket # PUE-2009-00081 (a weighted combination of the four tests listed in the Report), the practical difference from a level playing field may be reduced or minimized.

Q. PLEASE EXPLAIN IN MORE DETAIL WHAT TOPICS FORM A NECESSARY PART OF IRP DEVELOPMENT.

A. While there are many details that may vary from situation to situation, in general, the following aspects of IRP development need careful consideration:

- establish objectives;
- survey energy use patterns and develop demand forecasts;
- investigate electricity supply options;
- investigate demand-side management measures;
- prepare and evaluate supply plans;
- prepare and evaluate demand-side management plans;
- integrate supply- and demand-side plans into candidate integrated resource plans;

- select the preferred plan based on the selected benefit-cost test, uncertainty and risk analysis, and other factors; and
- during implementation of the plan, monitor, evaluate, and iterate (plan revision and modification).

Q WHAT OTHER ISSUES SHOULD THE COMMISSION EVALUATE IN ITS REVIEW OF THE IRP PROVIDED BY A UTILITY?

A. There are several other questions that should be evaluated by the Commission in the IRP process. These include, but are not limited to:

- What is the potential for and what are the utilities' assumptions concerning energy efficiency, combined heat and power applications, and renewable generating technologies within each utility's service territory? Are these assumptions reasonable and are they properly integrated into their forecasts or considered as a separate resource option?
- What is the potential for and what are the utilities' assumptions concerning demand response within each utility's service territory? Are these assumptions reasonable and are they properly integrated into their forecasts or considered as a separate resource option?
- Have the utilities made reasonable assumptions regarding future generating resource capital and operating costs and performed realistic sensitivity analyses in this area?
- What are likely future emissions costs for CO_2 and other pollutants, and how have these costs been incorporated in utility planning?
- How have the utilities treated the requirements for individual utility and statewide reserve margins?
- How do the utilities accommodate sharing of reserves, demand response and transmission enhancements to improve reserve sharing vs. generation in peaking resources?
- Have the utilities considered transmission and demand management on a comparable economic basis with new generation?
- How are capital costs and operating costs and their respective uncertainties treated?

- How have the utilities accommodated likely future technological advances, such as the potential for carbon capture and sequestration?

Q. IS THERE SUPPORT IN VIRGINIA LAW FOR THE IRP PRINCIPLES YOU HAVE SET OUT ABOVE?

A. Yes, there is. The Virginia Code § 56-597 defines an IRP as a document that "provides a forecast of its [the utility's] load obligations and a plan to meet those obligations by supply side and demand side resources over the ensuing 15 years to promote reasonable prices, reliable service, energy independence, and environmental responsibility." Additionally, Virginia Code § 56-598 provides, "An IRP should . . . [r]eflect a diversity of electric generation supply and cost-effective demand reduction contracts and services so as to reduce the risks associated with an over-reliance on any particular fuel or type of generation demand and supply resources." Sections 56-598 and 56-599 are replete with several other directives to include demand side management and energy efficiency programs as resources for meeting forecasted demand.

To summarize the above testimony about IRP standards and how they apply specifically to Virginia and the Commission's IRP mandate, and without offering a legal opinion, I am aware as a practitioner that a "reasonable" IRP and one that is in "the public interest" is widely understood in the practice of electric utility planning and management to mean one that ensures provision service at the lowest life-cycle cost. In addition, based on my knowledge of and experience in electric utility regulation, I believe that practitioners of utility resource planning would implement the IRP process in Virginia by considering (and incorporating) in utility resource plans energy efficiency and demand response (together, demand-side management) resources, transmission and distribution resources (including improvements to transmission and distribution efficiency), and all types of generation resources, including renewable generation, in utility resource plans. Such consideration must be on an equal basis (i.e., the “level playing field”) across all types of resources if it is to result in efficient and economical service and to serve the public interest. Therefore, I conclude that the cited statutes mean that the Commission should follow the practices and guidelines of least-cost integrated resource planning.

Q. DID THE COMPANY TAKE A DIFFERENT POSITION IN ITS REPLY COMMENTS?

A. In general, it does not. For example, on page x (page ten) of the IRP’s Executive Summary, the Company states, “The recommended capacity resource plan provides the ‘lowest reasonable cost’ solution through a combination of traditional supply, renewable and demand side investments.” However, there are certain particulars of the Company’s IRP methodology and assumptions that need further examination to be sure that this premise is followed throughout. Some of those issues are discussed in Section V of this testimony.

Q. HAVE YOU CONCLUDED THAT THE COMPANY’S FILED IRP IS WITHOUT ANY FLAW? IF NOT, DOES THAT MEAN THAT THE IRP PROCESS AND THE COMMONWEALTH’S IRP REQUIREMENT CANNOT SERVE THE PUBLIC INTEREST?

A. I do find a number of shortcomings in the Company’s filed IRP, some of them quite significant. However, that is not surprising, especially at this stage in the development of integrated resource planning in Virginia. The Commission should understand that fully establishing a comprehensive and transparent IRP process serving the public interest takes time.

Q. SO, WHAT SPECIFICALLY ARE YOU ASKING COMMISSION TO DO?

A. I recommend that the Commission do the following in this proceeding:

1. Identify the most important shortcomings of the filed IRP,
2. Prescribe the required remedies for those shortcomings,

3. Conditionally approve the IRP subject to submission of a revised version addressing certain of the most important shortcomings be remedied promptly in a compliance filing by a date certain, such as September 1, 2010.

4. Require the remaining shortcomings to be remedied in the Company's next Virginia IRP due in September 2011.

I will identify my recommendations as those key shortcomings and their remedies as part of my overall review of the IRP in my testimony below.

IV. COMMISSION EVALUATION OF THE IRP

Q. SHOULD THE COMMISSION EXPECT ITS REVIEW OF THE IRP TO BE STRAIGHTFORWARD?

A. Commission evaluation of IRPs is complex and often contentious, at least the first few times around, but the Commission should not be dissuaded from doing a thorough review as that is of vital importance. Beyond the obvious issues, such as forecasting, comprehensive and level playing field consideration of supply and DSM resource choices, the Commission should be sure to satisfy itself concerning thorough consideration of strategic challenges and opportunities, methods for risk assessment and mitigation, residual (unmitigated) environmental effects of generation, transmission and distribution construction and operation, and other relevant public policies.

Q. BY WHAT STANDARD SHOULD THE COMMISSION REVIEW THE IRP?

A. The Va. Code simply states:

> 56-599. E. The Commission shall analyze and review an integrated resource plan and, after giving notice and opportunity to be heard, the Commission shall make a determination as to whether an IRP is reasonable and is in the public interest.

The Commission is to "analyze and review" the IRP. To me that means checking not only the accuracy of assumptions and calculations, but also consistency with the best practices outlined above.

Second, the statute calls for both a reasonableness inquiry and for a public interest inquiry. A practitioner would apply these separately, by which I mean that the IRP must clear both hurdles. Neither term, however, is defined in the IRP Code.

In the public utility context, based on my experience of over 29 years in many jurisdictions, for an IRP, "reasonable" means, at a minimum, focusing on factors such as current best practices, good utility practice, and cost of service. In general, a public utility must furnish reasonably adequate service and facilities at reasonable and just rates. Reasonable and just rates are those required by a utility operating under efficient and economical management. This concept is now commonly referred to as "least cost planning." The "public interest" analysis considers whether the total benefits of a proposal outweigh the potential adverse impacts. Thus, for an IRP to be in the "public interest," it must be the plan that will meet public utility service needs most appropriately, considering not only cost of service, but also impacts to public health and the environment, economic development, risk and uncertainties, and other factors affecting the public interest. This general approach is echoed in relevant provisions of Virginia statutes and guidelines, such as the definition of IRP, which singles out promotion of "reasonable prices, reliable service, energy independence, and environmental responsibility." Va. Code § 56-597[1] and the order establishing the guidelines for the IRPs. *See* Order Establishing Guidelines for Developing Integrated Resource Plans, PUE-2009-00099 (Dec. 23, 2008) ("[T]he exclusion from the guidelines herein of any comments or recommendations

[1] Likewise, this point finds support in Va. Code § 56-585.1.A.5.c (standard of review in energy efficiency proceedings).

received in this matter does not represent a rejection of such request for purposes of any particular, subsequent IRP case. Rather, such issues may be raised – and addressed by all participants and the Commission—as part of the specific IRP case filed by the utility.”).

Applying these factors under the two pronged inquiry in conjunction with the two broad principles I discussed earlier in this testimony should help guide the Commission in its task of ensuring that the IRP lays out the framework for providing efficient and economical services and serving the public interest. First, all resources must be considered on a “level playing field.” That is, the development of the IRP considers all resources that may contribute to meeting need. It also means that DSM resources, transmission and distribution resources, and all types of generation resources must be considered on an equal basis. Second, the planning process should result in an integrated portfolio of resources with the mix of resources that will provide adequate and reliable service at the lowest life cycle cost. As discussed at length earlier in this testimony, an IRP that fails to follow these two principles cannot hope to lay out the framework for providing efficient and economical services and serving the public interest.

Q. ARE YOUR RECOMMENDATIONS CONCERNING IRP PRACTICES CONSISTENT WITH BEST PRACTICES FOR INTEGRATED RESOURCE PLANNING?

A. Yes, they are. There is a broad consensus on the basic purposes of IRP and the best approach to executing integrated resource planning. The principles and practices laid out in this testimony are consistent in scope, process and objectives with widely accepted models.[2]

[2] See, for example, Tellus Institute, *Best Practices Guide: Integrated Resource Planning for Electricity*, prepared for U.S. AID, n.d., (ca. 1996); Montana PSC, *Least Cost Planning - Electric Utilities* 38.5.2001-2012, available at http://www.mtrules.org/gateway/ChapterHome.asp?Chapter=38.5; R. Hornby, *Integrated Resource Planning (IRP) and Portfolio Management (PM): What are the Key Issues for Regulators?*, 2009 Advanced Regulatory Studies Program, Institute of Public Utilities.;

Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATION REGARDING COST-BENEFIT TESTING IN IRP?

A. Yes, today more than ever, the public interest demands consideration of the full range of environmental regulatory risks in a reasonable manner.

As discussed previously in SCC Docket # PUE-2009-00023 and SCC Docket # PUE-2009-00081 life cycle cost comparisons (between resources or portfolios) should be made using certain well-defined cost-benefit tests. I have testified elsewhere about both my beliefs about the most appropriate use for each test and my recommended interpretation of the Commission's directive regarding such tests.

V. STRENGTHS OF THE COMPANY'S IRP

Q. CAN YOU IDENTIFY ANY AREAS OF STRENGTH IN THE COMPANY'S FILED IRP?

A. Yes, there are several. For example, the Company's filed IRP incorporates results from certain potentially useful modeling approaches, adopts reasonable base case values for carbon costs, considers demand side management ("DSM") resources as part of resource plans, and conducts extensive risk analysis, albeit on an incomplete set of risks as I discuss below.

Q. PLEASE EXPLAIN THE POTENTIALLY USEFUL MODELING AND RISK ANALYSIS RESULTS INCORPORATED IN THE COMPANY'S FILED IRP.

A. One such type of modeling result is the IRP's analysis of resource plans and sensitivity cases by means of comparing life cycle present value (TRC) costs developed with the Strategist model. The results of this modeling are perhaps discussed in the greatest detail in Section 11 of the

National Action Plan for Energy Efficiency, *Guide to Resource Planning with Energy Efficiency*, 2007, available at www.epa.gov/eeactionplan

IRP. Another is the risk analysis methodology set out in Section 12 of the IRP.

The development of resource plans based on comparisons of life cycle present value costs is a fundamental feature of sound integrated resource planning. In addition, the filed IRP includes consideration of multiple resource strategies that vary from the base plan, as well as consideration of several important sensitivities off of the base case and how they affect results of each resource strategy. (Concerns about the range of resource strategies are discussed below.) For example, Exhibit 11-3 on pages 95-96 in the IRP shows in a compact manner how comparison life cycle present value costs (expressed as net present values or “NPVs”) for various resource plans and sensitivities can show the relative merits of resource plans, both in terms of their *expected* NPV and the *robustness* of that NPV to sensitivities. That Exhibit also allows an assessment of whether any resource strategies are unaffected by sensitivities when they should be, which provides an indication of whether the strategies themselves are sufficiently diverse.

The risk analysis methods discussed in Section 12 of the IRP are well established techniques and develop indicators such as Revenue Requirement at Risk (“RRaR”) that can be quite useful in assessing the robustness of a given portfolio. While I cannot speak to the specific modeling software or inputs used, the Monte Carlo simulation approach used to do that analysis is a state of the art choice in this field. However, the *way* in which the modeling tools are used is, of course, where “the rubber meets the road.”

As an example, consider page 101 of the IRP. The text indicates that the “risk factors” considered were: Eastern and Western coal prices, natural gas prices, power prices, S02, C02, and NOx emissions allowance prices, full requirements loads, forced outages of AEP's units. While we are not given the *degree* of uncertainty that the Company permitted in each of these risk factors, those are all relevant factors. However, Exhibit 12-4, a table of showing the assumed variability of capital costs for power plants gives us a peek at one set of inputs. It shows that the risk analysis assumes that the 95th percentile for a natural gas plant's installed cost was 120% of the budget amount on which the plan is based. I believe that is consistent with recent experience. However, it also shows that the risk analysis assumes that the 95th percentile for coal *or* nuclear plant's installed cost was only 130% of the budget amount on which the plan is based. I find that implausible. The experience with nuclear plant construction costs is more consistent with a 95th percentile cost of 200% than 130%, and it is also worth considering the potential for construction delays which have often been many years, leading to great cost and many cancellations of plant after construction had begun. Arguments to the contrary based proposed improvements in licensing, cost management, standardization, and simplification are not convincing enough to permit that history to be ignored. While perhaps not to the same degree, the experience for coal plants in this regard is also a concern.

It is possible to ask other, similar questions about the risk analysis. For example, in the list of risk factors on page 101, consider forced outage rates. There is no indication that this input is differentiated between old, recent and future technologies. Perhaps it is, but we cannot tell. In particular, we do not know if the Mountaineer project is assumed to have the same outage rate post-CCS installation as prior to installation. (This also applies to several other possible retrofit units.)

In summary, the risk analysis, while methodologically praiseworthy, does not inspire confidence in its results, given what we have in the IRP. This is a good first step towards sound integrated resource planning and should help the Commission in its analysis of the IRP.

Q. PLEASE EXPLAIN THE COMPANY'S APPROACH TO CARBON COST ISSUESS AND YOUR VIEW OF THAT APPROACH.

A. One of the most notable features of the Company's IRP is its extensive discussion and analysis of the effect of carbon emission costs on the resource plan and the cost of service. While I have reservations about the particulars, such as input for carbon prices, and the strategies considered, the Company has started down the right path with this IRP. For example, page 97 of the IRP discusses recent adjustments the Company made to its strategic thinking:

> • During the course of the IRP analysis in the Spring of 2009, it became apparent that reducing the size of AEP's significant carbon footprint would be necessary over the long term due to the emerging likelihood of some level Of CO_2 emission limits in the future. Based on the analysis performed within the "CO_2 Limited" sensitivity view, CCS retrofits were introduced into the AEP-East plan so as to accelerate this further migration to a reduced CO_2 position.
>
> • Further, the Renewable Energy Plan that was used in all of the resource optimization runs was revised to reflect an acceleration of wind resource additions. This acceleration was likewise envisioned due to the growing prospect of a Federal Renewable Portfolio Standard either within comprehensive Climate Change/C02 legislation or that would be stand-alone. This revised Renewable Energy Plan was used in the development of the Hybrid Plan.

Without in any way endorsing either the Company's interpretation of those issues or the Hybrid Plan the Company offers in response to them, and not at all intending to gloss over various IRP concerns discussed below, I will say that this is an example the type of responsiveness that helps make IRP valuable to the Commission and ratepayers. However, as seen in IRP Summary Exhibits 5 and 6 on pages viii and ix of the IRP, as well as Exhibit 13-8 on pages 114-115 of the IRP, the Company responds by making assumptions about the availability of offsets (including international offsets) and the availability of tradeable CO_2 emission permits in vast quantities.

Q. GIVEN THE UNCERTAIN FUTURE OF CONGRESSIONAL CAP-AND-TRADE BILLS, WHY IS IT REASONABLE TO INCORPORATE THOSE COSTS INTO THE IRP'S BASE CASE?

A. One might wonder about this since the Company's IRP states that it used two pieces of legislation, the "Low Carbon Economy Act of 2007" and the "Climate Security Act of 2008" to develop CO2 price forecasts[3] and a third, the Waxman-Markey Bill, to assess the potential CO2 mitigation shortfall of the Company's preferred Hybrid Plan.[4] However, as the Company says, despite "considerable uncertainty . . . . current political and economic realities" make it clear that an IRP must reflect future carbon regulation.[5] I agree. There are inherent uncertainties in all aspects of planning, including the pricing of carbon. For the professional planner, the correct view on carbon costs does not rise or fall with the fate of one bill. Additionally, I do think it likely that some form of CO_2 regulation will happen in the U.S. in the next few years and that the longer it is delayed, the more stringent such regulation will likely have to be to achieve the necessary public policy result of mitigating the effects of global climate change.

Current disputes about the best form for CO_2 regulation and public relations fallout from controversies surrounding a relatively very small portion of the documentation of the multitude of compelling indicators of global climate change will not outweigh the urgent need of the energy industries, insurers, and other energy policy stakeholders for clarity about their future and assurance that regulation that credibly addresses climate change can be relied on for their planning. The general trend toward carbon regulation is clear; and it would be a mistake to ignore it in long-term decisions concerning electric resources. Over time, since the introduction of the first prominent federal bill calling for mandatory greenhouse gas reductions, the 2003 McCain-Lieberman

3 IRP at 83
4 IRP at 113-115.
5 IRP at 83.

Climate Stewardship Act, the proposals are becoming more stringent as evidence of climate change accumulates and as the political support for serious governmental action grows. The emissions levels that would be mandated by some recent bills are shown in Exhibit WS-2, which is a chart prepared by the World Resources Institute on "Net Emission Reductions Under Cap-and-Trade Proposals in the 111th Congress, 2009."

Federal legislation is not the only potential pathway for regulation of GHG emissions from power plants. The U.S. Environmental Protection Agency ("EPA") is poised to issue regulations establishing permitting requirements for GHG emissions under the New Source Review program under the Clean Air Act. It is also considering setting GHG emission limitations under another section of the Clean Air Act, the New Source Performance Standards provision.[6]

Q. HOW DOES THE COMPANY HANDLE CO_2 COSTS?

It is helpful that the Company's IRP incorporates in its base case an initial value per ton in year 2015 that rises gradually to a significantly higher value per ton in year 2030. It is also helpful that the Company displays a significant range of high and low cases around that trend.[7] On the other hand, the IRP discloses only the relative growth of those costs, not their absolute dollar values, so it is impossible to express an opinion on their suitability for use in the IRP.[8] Those absolute dollar values should be compared in a litigated forum with base case values estimated elsewhere before the Commission considers accepting those values as a useful starting point for resource planning.[9]

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[6] Larry Parker and James E. McCarthy, U.S. Congressional Research Service, *Climate Change: Potential Regulation of Stationary Greenhouse Gas Sources Under the Clean Air Act*, May 14, 2009, available at www.crs.gov; Lisa P. Jackson, U.S. EPA, letter to Sen. Jay D. Rockefeller IV, February 22, 2010.
[7] *See*, for example, IRP Exhibit 2-10.
[8] *See*, for example, IRP Exh. 2-2 at 7 and discussion (without specific dollar values) on at 83.
[9] R. Hornby, et al., *Avoided Energy Supply Costs in New England: 2009 Report*, Revised: October 23, 2009, available at http://www.synapse-

From the graphs in the Company's IRP Exhibits, it appears that the first date of use for carbon costs in modeling is either 2015 or 2016, except for the low carbon cost case, where the start date is either 2016 or 2017.[10] While it might be *possible* for those to be the start dates, they could also be earlier.

The Company did not factor into the IRP potential EPA regulations[11] even though that regulatory risk is distinct from the risk presented by the prospects of federal legislation. It was unreasonable for the Company to have entirely ignored the prospect of EPA regulation. While this failure does not change my opinion that the Company could arrive at reasonable forecats of CO_2 prices, in future IRPs it should fully explain how it addresses that risk and how it affects its CO_2 cost assumptions.

Q. WHY DO YOU SINGLE OUT INCLUSION OF DSM RESOURCES AS A STRENGTH OF THE IRP?

A. The answer to this is quite simple. As I have explained in several recent cases before the Commission (cited above), inclusion of robust DSM programs in the Company's resource portfolio is critical to the public interest. Although the Company's current, proposed slate of DSM programs is in serious need of improvement, it is encouraging that the Company is committed to including DSM resources in the planning process for this IRP.

VI. Weaknesses of the Company's IRP

Q. WHAT ARE SOME OF THE SHORTCOMINGS IN THE COMPANY'S FILED IRP?

A. I have identified a number of significant shortcomings in the following areas of the IRP: documentation of modeling, power supply

energy.com/Downloads/SynapseReport.2009-10.AESC.AESC-Study-2009.09-020-Appendices.pdf

[10] IRP Exhibit 2-10.

[11] Response to Environmental respondents First Set of Discovery, Question 4.

planning, investment in DSM, and treatment of risk and uncertainty, especially uncertainties regarding environmental regulation risks.

Q. PLEASE EXPLAIN THE NATURE AND IMPORTANCE OF THE COMPANY'S LACK OF NUMERICAL DETAIL AND DOCUMENTATION OF ASSUMPTIONS IN ITS FILED IRP.

A. The Company did a good job of *explaining* in words and a few flow charts what it did to develop the IRP, but failed to include the certain important underlying numerical values and formulae or key modeling inputs that were relied in its analysis and modeling. Where such information is not fully provided, some of it was presented in the form of graphs rather than numerical values that can be critiqued, but even there, some of the graphs still did not give numerical values, but only index numbers. An example of this problem is the reporting of various commodity and emission costs in IRP Exhibits 2-6 through 2-10. (SELC intends to request further detail through the discovery process and perhaps more will be forthcoming before the scheduled hearing in this proceeding.) The importance of this shortcoming is that it prevents a critical assessment of specifics by either the Parties or the Commission.

For another, more subtle example we can look again to IRP Exhibit 11-3. As discussed above, this table presents in a compact form the net present value ("NPV") planning period cost of service for each of the resource plans and sensitivity cases run by the Company. While this is a helpful first step, that type of presentation obscures certain features of the cost streams that are important to proper assessment of cases by the Commission. Each cell in the table presents the cumulative NPV cost of the case as of the *end of the planning period*. What a given cell entry does not show is the time pattern of those costs relative to the other cases.

Suppose, for the sake of argument, that two resource plans need to be compared: Plan A with construction of one large base load generator in year 1 of the plan, and Plan B with a mix of smaller DSM and generating resources added at intervals over the planning period. Further suppose that Plan A shows an NPV cost that is 1% lower than that of Plan B. It is typical of very large generators that their costs are heavily front-loaded and it is only in the “out years” that they justify themselves economically. In my experience with such comparisons, Plan A would typically be considerably more expensive than Plan B for many years, with Plan A gradually pulling ahead (if ever) in the “out years,” and then *only* if the planning assumptions turn out to be completely accurate, an unlikely outcome. For example, if load growth is slower than the base case assumption or if its large generator has cost overruns or construction delays, Plan A may never catch up with Plan B. Thus it is vital to consider how much cost exposure is incurred year by year in Plan A compared to Plan B. If the (base case) crossover point when Plan A finally becomes cheaper than Plan B is in year 14 out of 15 in the planning period, the Commission would do well to be aware of that and take it into account in weighing both reasonableness and the public interest. By the way, Plan B does not necessarily suffer in the opposite case. If, for example, load growth is faster than expected in the base case, Plan B, made up of many modular additions can be accelerated or be augmented with additional generators as and when needed.

I recommend that the Commission require full and transparent documentation of modeling inputs, assumptions and methodological choices for the IRP in the compliance filing recommended earlier and in future IRP filings. I also recommend that the Commission require specific year-by-year comparisons of costs for different resources, resource plans, and sensitivity cases as part of IRP filings.

Q. PLEASE EXPLAIN THE NATURE AND IMPORTANCE OF CONCERNS WITH THE COMPANY’S POWER SUPPLY PLANNING.

A. There are a number of such concerns worthy of further examination. Those concerns mainly have to do with apparently arbitrary assumptions about what will or will not be done with certain power plants. For instance, the IRP adopts a 10% "internal target" for renewable generation, states that it will be met, and leaves it at that.[12] Further, the IRP asserts that the Mountaineer plant technology for carbon capture and sequestration will perform as intended, technically and economically and relies on that assumption in its analysis of the CO_2 Limited sensitivity.[13] Also in various places, the IRP references "R/R/R" flexibility. That flexibility has option value and is a benefit to the Company. However it is not a blank check for the Company to do whatever it chooses. Those options have cost implications and the IRP is the place to address those implications. Further, the IRP states on page 30 that it should "Recognize that the retirement date represents the year that the unit is projected to no longer provide firm capacity value in PJM, however it still may provide energy value and therefore operate well beyond the planned capacity retirement date." This statement is puzzling. Obsolescent plants tend to have relatively high running costs and are usually kept in service for their capacity value, not their energy value.

The Commission's IRP Guidelines state that "Major capital improvements such as the addition of scrubbers, shall be evaluated through the IRP analysis to assess whether such improvements are cost justified when compared to other alternatives, including retirement and replacement of such resources." The various presumed limits, plant retirements, retrofits or other changes discussed in this answer may have material effects on the screening of renewable generation or energy efficiency, as well as other matters the Commission is required to consider in its IRP review. For example, I would expect that addition of CCS technology would qualify as a major capital improvement.

Q. PLEASE EXPLAIN THE NATURE AND IMPORTANCE OF CONCERNS WITH THE COMPANY'S DEMAND SIDE MANAGEMENT PLANNING.

[12] IRP at 64.
[13] IRP at 93-94, for example.

A. One concern is that the overall level of demand side management ("DSM") resource acquisition proposed in the IRP is that the "Optimized Plan Results" for the favored Hybrid Plan, supposedly prepared in response to heightened concerns about carbon costs and constraints, contains exactly the same amount of DSM as did the No CO_2 Price Optimal Plan.[14] This is not a plausible outcome and is an indication of a basic shortcoming in either DSM planning or power supply modeling. In addition, the Hybrid Plan shows zero additional DSM resources acquired during the eleven years 2020 through 2030.[15] Again, it does not seem plausible to assume there will be no cost-effective new DSM available in that period, given the significant power cost increases, presumed carbon constraints, and time available for technological improvements in the cost-effectiveness and consumer acceptability of energy efficiency measures. For example, as of today there are lighting products about to enter commercial production that use considerably less energy than even the current best compact fluorescent ("CFL") bulbs, last several times longer than CFLs, and produce a light comparable to and perhaps more acceptable to consumers than CFLs.

The IRP mentions the potential for transmission and distribution line loss reduction as a resource but does not list it among its energy efficiency programs.[16]

These are serious matters. The IRP's DSM portfolio is especially problematic given the Company's lack of clarity in exactly what DSM programs will or will not be implemented in Virginia. Unfortunately, we have not had the benefit of a thorough DSM filing subjected to scrutiny in a litigated proceeding. The Company's concerns in SCC Docket # 2009-00023 over implementing programs in Virginia that might differ from those in neighboring states do not give me confidence that DSM planning

[14] IRP Exhibit 11-3. A number of similar examples can be found in this Exhibit.
[15] IRP Exhibit 11-4.
[16] *See*, for example, IRP Exhibit 9-5. *Compare to* IRP at 68.

and implementation by the Company will ultimately be all it should be. The IRP mentions that this EPRI study indicated a potential of 3.3% savings over *twelve* years of program implementation.[17] As was shown by SELC's testimony in SCC Docket # 2009-00023, that is the potential that can be and has been achieved in a cost-effective manner is two or three years by committed utilities. The Company's sophisticated modeling and risk assessment tools deserve to be used in a better manner.

Q. WHY IS IT SO VITAL TO CONSIDER DSM RESOURCES ON AN EQUAL FOOTING WITH OTHER RESOURCES?

A. To put it bluntly, if DSM is shortchanged in the IRP, ratepayers are shortchanged, now and for many years to come. Leaving cost-effective DSM options on the table costs ratepayers money they should not have to pay because the alternatives are not least-cost, and ratepayers typically have to pay for those more expensive supply-side resources for decades. Those extra, unnecessary costs will be a dead weight on the Commonwealth's economy for as long as they persist.

The merits of DSM have been discussed at length in several recent cases before the Commission, including SCC Docket # PUE-2009-00023 and in 2010 in SCC Docket # PUE-2009-00081. Therefore, I will only summarize those benefits briefly in this testimony.

The main point to keep in mind is that many energy efficiency measures cost significantly less than generating, transmitting and distributing electricity. Thus, energy efficiency programs offer a huge potential for lowering system-wide electricity costs and reducing customers' electricity bills. This is the logical proceeding for the Commission to follow through on the progress it made in its DSM goals docket (PUE-2009-00023).

[17] IRP at 72-72.

In addition to lowering electricity costs and customers' bills, energy efficiency offers a variety of benefits to utilities, their customers, and society in general:

- Energy efficiency can reduce the risks associated with fossil fuels and their inherently unstable price and supply characteristics and avoid the costs of unanticipated increases in future fuel prices.
- Energy efficiency can reduce the risks associated with environmental impacts. By reducing a utility's environmental impacts, energy efficiency programs can help utilities and their ratepayers avoid the hard to predict costs of complying with potential future environmental regulations, such as CO_2 regulation. It is important to note that reducing these risks associated with environmental compliance costs (i.e., regulation) is different from and in addition to reducing the costs (discussed below) associated with pollution impacts and environmental degradation.
- Energy efficiency can improve the overall reliability of the electricity system by substantially reducing peak demand, during those times when reliability is most at risk.[18] Second, by slowing the rate of growth of electricity peak and energy demands, energy efficiency can provide utilities and generation companies more time and flexibility to respond to changing market conditions such as unexpected demand growth (or slumping sales), while moderating the "boom-and-bust" effect of competitive market forces on generation supply.[19]

[18] ACEEE 2000. Using Targeted Energy Efficiency Programs to Reduce Peak Electrical Demand and Address Electric System Reliability Problems, Steven Nadel, Fred Gordon and Chris Neme, 2000, http://www.aceee.org/pubs/u008.htm.
[19] Regulatory Assistance Project 2001. *Efficient Reliability: The Critical Role of Demand-Side Resources in Power Systems and Markets*, prepared for the National Association of Regulatory Utility Commissioners, funded by the Energy Foundation, June.

- Since efficiency programs have a substantial impact on peak demand, they help reduce the stress on local transmission and distribution systems, potentially deferring expensive T&D upgrades or mitigating local transmission congestion problems.

- Energy efficiency can result in significant benefits to the environment.[20] Every kWh saved through efficiency results in less electricity generation and, thus, less pollution. Energy efficiency can delay or avoid the need for new power plants or transmission lines, thereby reducing the environmental impacts associated with power plant or transmission line siting.

- Energy efficiency can also promote local economic development and job creation by increasing the disposable income of citizens and making businesses and industries more competitive compared to importation of power plant equipment, fuel, or purchased power from outside the utility service territory.

- Energy efficiency can help a utility, state and region increase its energy independence, by reducing the amount of fuels and electricity that are imported from other regions or even from other countries.

- Energy efficiency offers a variety of societal benefits for low-income electricity customers and the charitable, state, county and local budgets that they depend on for services and funding.

Q. IS DSM REALLY AVAILABLE IN LARGE AMOUNTS IN VIRGINIA? IF SO, WOULD IT BE REASONABLE AND IN THE PUBLIC INTEREST TO RELY ON MUCH MORE DSM IN THE COMPANY'S IRP?

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[20] Unlike other pollution control measures—such as scrubbers or selective catalytic reduction—energy efficiency measures can reduce air emissions with a *net reduction* in costs. Thus, energy efficiency programs should be considered as one of the top priorities when investigating options for reducing air emissions and other environmental impacts from power plants.

A. Certainly. SELC witness Jeff Loiter testified in SCC Docket # PUE-2009-00023 that huge potential of cost-effective efficiency savings exist in Virginia, likely on the order of 20% of forecast load in a 15 to 20 year time-frame with conservative studies showing comparable potential in nearby states of North Carolina and Georgia. As he explained there:

> Virginia residents consume on average 14,000 kWh annually, which is 25% more than the national average. Commercial customers now consume 50% more than they did in 1990. These facts alone indicate to me that there is a massive untapped reservoir of readily accessible and inexpensive energy that could be acquired by Virginia's electric distribution utilities. Unless Virginia's utilities presume that their customers are somehow less capable of participating in well designed efficiency programs than other US citizens, the only real difference that sets Virginia apart from the leading states is the level (or lack) of market intervention in which Virginia chooses to engage. Consequently, Virginians are just as likely to invest wisely and curb their electric consumption if provided with appropriate, well-designed, and attractive programs like those provided by other leading states.[21]

Q. PLEASE EXPLAIN THE NATURE AND IMPORTANCE OF CONCERNS WITH THE COMPANY'S TREATMENT OF RISK AND UNCERTAINTY IN ITS IRP RESOURCE PLANNING.

A. Despite inclusion of certain interesting sensitivity runs in the IRP (as discussed above), the Company failed to consider reasonable range of or intensity of risks and uncertainties, especially environmental regulation risks. It also failed to analyze and quantify those risks in a reasonable manner that reflects the public interest. These regulatory uncertainties are most significant for the Company's existing coal-fired power plants, however the same concerns apply to new facilities as well.

Q. WHAT ARE SOME OF THOSE RISKS?

A. They include carbon costs mercury regulation, coal combustion waste risks ("CCW"), and a lengthy list of pending regulatory issues.

[21] *See* Testimony of Jeffrey Loiter on behalf of Southern Environmental Law Center, Case No. PUE-2009-00023, at 16 (filed July 31, 2009).

Q. PLEASE EXPLAIN HOW THE IRP CONSIDERS THE RISKS AND UNCERTAINTIES WITH REGARD TO CARBON COSTS.

A. It is soemhat diffuclt to tell. Exhbit 2-10 shows forectsed prices in rlative terms for a reference case, a low CO2 cost case and a high CO2 case. At least in reletive terms, then, the exhbit suggests that the Copmany considered a ressoabel range of possible prices.

Q. PLEASE EXPLAIN HOW THE IRP FAILS TO PROPERLY CONSIDER THE RISKS AND UNCERTAINTIES WITH REGARD TO MERCURY EMISSIONS.

A. The Company recognizes that mercury emissions from its existing coal-fired generating units carry with them the risk of the costs of complying with future regulations and notes that "[o]peration of these units becomes increasingly uneconomical with stricter limits on [mercury emissions]." It also expresses the belief that there is "a strong possibility that a plant-by-plant [mercury] standard" that could come into effect in 2014 that would require installation of pollution control technology devices such as activated carbon injection (ACI), baghouses (also known as fabric filters), or a combination of a flue gas desulphurization (FGD) and selective catalytic reduction (SCR) system. In addition, the IRP states that the costs associated with these installation could affect the retirement dates of older, noncontrolled units.

Yet the Company does not incorporate the risks associated with mercury regulation into its IRP. As it stated in response to a discovery request from Environmental Respondents, the IRP "did not specifically account for the potential cost of complying with [mercury] regulation." The Company should have gone the crucial extra step of translating the awareness of those potential costs into the IRP. I note that one utility has deemed the risk of mercury regulation sufficiently certain enough to have cited it as one of the reasons for filing plan with its utility commission to retire 550 MWs of coal-fired generation that is not equipped with scrubbers.[22]

Q. WHY SHOULD THE COMMISSION BE CONCERNED WITH MERCURY EMISSIONS?

A. Coal-fired utility boilers account for roughly 40% of U.S. anthropogenic emissions. Exposure to mercury has severe and widely documented effects on human health and environment, including neurological and developmental impairment to both humans and other animals. EPA has referred to mercury as the Hazardous Air Pollutant (HAP) with the greatest concern for public health from coal-fired power plants.[23] Public awareness has been high due to state and local advisories about contaminated water bodies and fish populations unsafe for consumption.

Q. HOW LIKELY IS REGULATION OF MERCURY EMISSIONS BY POWER PLANTS?

A. Although the standards for mercury emissions by existing coal-fired electric utility steam generating units (EGUs) have not yet been established, it is almost certain that regulation of these emissions will go into effect during the period of the Company's IRP. On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated EPA's Clean Air Mercury Rule (CAMR). CAMR would have established a cap-and-trade program for mercury emissions from existing (and new) coal-fired power plants. Consistent with the D.C. Circuit's opinion, EPA is currently developing traditional "command and control" mercury emission rate standards for coal-fired EGUs consistent with Clean Air Act section 112(d). This section compels EPA to set standards requiring the

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[22] Progress Energy, Plan to Retire 550 MWs of Coal Units Without SO2Controls, pp. 2-3.

[23] I do not address here the potential costs associated with emissions of other HAPS emitted by coal burning units, which are due to be regulated in the same rulemaking as mercury. These other HAPs include arsenic, lead, chromium, hydrogen fluoride, and hydrogen chloride. U.S. EPA, Study of Hazardous Air Pollutant Emissions for Electric Steam Generating Units," Final Report to Congress (1998) ("1998 HAP Report to Congress"), at ES-2, Table ES-1. Neither do I address the regulation of HAPs from oil-fired units, which EPA must also address at the same time.

maximum degree of emission reduction that the EPA determines to be achievable (referred to as “maximum achievable control technology” or MACT) by each particular source category. The MACT rulemaking for EGUs is commonly called the Utility MACT.

Associated activity indicates that EPA will issue a proposed rulemaking expeditiously. In October 2009, EPA lodged a consent decree with the federal district court in Washington, D.C., setting deadlines for the development of the Utility MACT pursuant to Clean Air Act section 112(d).[24] The deadline calls for EPA to propose a rule by March 16, 2011, and to make a final rulemaking no later than November 16, 2011.[25] Under that schedule, existing coal-fired units would have to meet the MACT emission rate for mercury around the beginning of 2015.

Q. WHAT MIGHT THE COMPANY BE REQUIRED TO DO TO CONTROL OF MERCURY EMISSIONS AT ITS POWER PLANTS?

A. The emission reduction strategy, and its cost, will likely depend on the specific plant and its emission limitation requirements. As the Company says in the IRP, it will likely require cutting emissions through control technologies such as FGD, SCR, fabric filters, sorbent injection (e.g., ACI), or some combination of these strategies. Electrostatic precipitators (ESPs) may also help control emissions. Another strategy would be fuel-switching or, simply, retirement, especially for older, noncontrolled units.

EPA estimated the costs of emissions allowances under the proposed CAMR to be on the order of $12,000 to $26,000 per pound.[26]

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[24] As of this writing, the consent decree has not been entered by the court.

[25] In December 2009, EPA issued an Information Collection Request (ICR) requiring all US power plants with coal-fired EGUs to submit emissions information for use in developing the proposed emissions rule for air toxics.

[26] These dollar values are projections for allowance prices in 2010, and in are in 1999 dollars. U.S. EPA, Regulatory Impact Analysis of the Clean Air Mercury Rule: Final Report. March 2005. EPA-452/R-05-003. Table 7-8. They are an approximation of the cost of controls.

But this is an overly conservative estimate of the potential costs. First, these dollar values are projections for allowance prices in 2010, and in are in 1999 dollars. Second, because CAMR allowed emissions trading, which would have allowed the units with the lowest cost of reducing mercury emissions to sell allowances to units with higher cost of compliance, the Company is almost certain to face much higher costs for control of mercury emissions under the upcoming MACT rule, which will prohibit trading to comply with the D.C. Circuit's ruling.

It is more realistic to think in terms of the cost of installation additional control technologies. A recent report by the U.S. Government Accountability Office (GAO) focused on the "relatively inexpensive" strategy of sorbent injection. The GAO pegged the average cost of installation at $3.6M per boiler, with an average annual operating cost of $675,000 per boiler, all in 2008 dollars. Costs for other control technologies that could be required to achive compliance with the merucrry emission rate limits or could be desired to control other pollutants simultaneously would dramatically increase overll costs. Installing a sorbent injection system with a fabric filter would boost the installation cost to almost $15.8M per boiler.[27] Of course these costs are dwarfed by the costs of installing an FGD (average $86.4M) or an SCR (average $66.1M) on a per boiler basis.[28]

Q. WHAT IS THE COMPANY'S EXPOSURE TO THIS RISK?

A. The Company has not provided an analysis in the IRP. However, the age of its fleet of coal-fired generators and its existing or already-planned pollution control devices suggest that exposure may be significant. Figure 1 in Appendix A to the IRP shows that of the 13 coal-fired units owned by the Company (five in Virginia, seven in West Virginia) the newest went in service 30 years ago, in 1980. Three others have in-service dates from the early 1970s. One came on-line in 1961.

[27] GAO rpt, Appendix V, p. 41 , and unnumbered summary page preceding Table of Contents.
[28] Ibid., p. 14 (citing 2006 EPA cost estimates).

Seven others started operation in the 1950s. The oldest dates from 1944, approaching 70 years of age. Only the four units that are 40 years or younger, all located in West Virginia, have FGDs and SCRs installed or planned for installation.

One way to get a conservative estimate of the costs that could be facing the Company under the Utility MACT is to assume that suffinet emission reduction could be achived though the use of the “relatively inexpensive” sorbent injection system. Using the average number from the GAO report, the installation costs for nine units would total $32.4M ($18M on the five units at Glen Lyn and Clinch River). Annual operating costs would come to almost $6.1M (almost $3.4M on the Virginia units).

Also, in response to discovery (SELC Interrogatories, 1st Set, Question 3) the Company provided projections of emissions of mercury (Hg) (as well as nitrogen oxides, sulfur dioxide and carbon dioxide) from 2009 to 2024. In 2024, Hg emissions across the entire AEP-East system would be almost 2000 pounds per year under the Base Plan. (As noted elsewhere, a shortcoming in the Company’s presentation of modeling results prevents examination of how variable a given plan’s outputs are across the sensitivity cases.)

Even using EPA's projected CAMR allowance costs in 2010 (which are certain to be low), the AEP-East’s economic exposure would be roughly $24M to $52M per year for the Company's Base Plan in 2024, not counting the possibility of costly disruption of or constraints of plant operation.

Q. DOES THE COMPANY ACCOUNT FOR THE RISK OF COST INCREASES DUE TO CONTINUING OPERATION OF EXISTING COAL PLANTS IN THE FACE OF REGULATION OF MERCURY EMISSIONS?

A. It does not appear so. At one point the IRP does refer to a discussion in the Technical Addendum to the IRP concerning its strategy for complying with CAMR or its replacement that considers “additional power plant emission reduction requirements," but the Company specifically states that its IRP "did not specifically account for the potential cost of complying with regulation of Hg emissions under MACT emissions standards for HAPs." So it seems that the Company did not factor in potential costs of compliance with mercury regulations when developing the Alternative Plans. In addition, the Company did not include these potential costs in its modeling, which would distort the Alternative Plans' performance relative to each other (to the extent that there are any differences in how coal resources are dispatched in the modeling). Moreover, it appears that human and environmental costs of Hg emissions are not considered in the Plan development, as should be considered consistent with the "public interest" part of the IRP statute.

Q. HOW SHOULD THE COMPANY HAVE ACCOUNTED FOR THE RISK OF MERCURY REGULATIONS IN ITS IRP?

A. At a minimum the Company should have

1. assumed a likely emissions standard for mercury, providing some justification for that standard (i.e., with reference to the evidentiary record on the health effects of mercury),
2. identified the plants that would be subject to the rule and would fail to meet the assumed emissions standard, and
3. identified options for fuel switching, retrofitting, or other means of compliance for each affected plant, and identified the relevant capital and operating cost increases, as well as any necessary plant outages for implementation, reduced availability or reliability, and potential retirements triggered by the requirements.

All of this information should have been considered when developing the base plan and Alternative Plans, used in avoided cost calculations for screening DSM and renewables, and also incorporated into the IRP modeling. Additional sensitivity scenarios would also likely have been needed to address the potential for more stringent rules.

Q. WHAT DO YOU RECOMMEND THE COMMISSION DO FOR THE PURPOSES OF THE CURRENT PROPOSED IRP?

A. The Commission should require the Company to submit as part of its IRP in this docket a detailed and accurate discussion of the expected new pollution control standards. The modeling underlying the IRP should be rerun to reflect the additional cost of continuing to run existing coal plants, and of constructing and operating supply-side resources in future.

Q. PLEASE EXPLAIN HOW THE IRP FAILS TO PROPERLY CONSIDER THE RISKS AND UNCERTAINTIES WITH REGARD TO COAL COMBUSTION WASTES.

A. The IRP fails to account for the uncertainty in the potential costs of continuing to operate existing coal plants in the face of likely regulation of coal combustion waste.

Q. WHY SHOULD THE COMMISSION BE CONCERNED WITH COAL COMBUSTION WASTE ("CCW")?

A. The toxic elements in CCW include arsenic, chromium, lead, cadmium, selenium, and mercury. These substances are known to be toxic to humans and aquatic life.

The U.S. EPA has stated that "if not properly managed, . . . [Coal Combustion Residues] may cause a risk to human health and the environment and, in fact, EPA has documented cases of environmental damage."[29]

Q. ARE CCWS CURRENTLY REGULATED?

A. Some regulations exist for the use of CCW for mine reclamation, although these regulations vary by state.[30] State wastewater permitting also varies widely in terms of structural requirements.[31]

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[29] U.S. EPA. *Fact Sheet: Coal Combustion Residues (CCR) - Surface Impoundments with High Hazard Potential Ratings*. EPA530-F-09-006. June 2009 (updated August 2009). http://www.epa.gov/epawaste/nonhaz/industrial/special/fossil/ccrs-fs/index.htm, accessed March 17, 2010.

[30] U.S. EPA. *Regulation and Policy Concerning Mine Placement of Coal Combustion Waste in Selected States: Final Draft*. Dec 2002.

Q. WHAT FORMS OF REGULATION MIGHT BE IMPLEMENTED FOR DISPOSAL OF CCW?

A. There are developments on several regulatory fronts that may have a considerable impact on how and at what cost CWW must be handled and disposed of. Perhaps the one that looms largest is EPA's current consideration of whether to propose to classify CCW as a hazardous waste under Subtitle C of the Resource Conservation and Recovery Act (RCRA) or retain its current non-hazardous classification but impose more stringent requirements under Subtitle D of RCRA. Consideration of the uncertainties surrounding this regulation – like all other uncertainties – are something that are fundamental to completion of a reasonable IRP that would be in the public interest.

Q. HOW LIKELY IS REGULATION OF CCW DISPOSAL?

A. In the wake of the release of more than 5 million cubic yards of waste from a coal ash storage pond at TVA's Kingston Fossil Plant into the Emory River in December 2008, public and regulatory pressure to address the disposal of CCW is high. This public pressure stems from not only the concerns that the ash ponds which are sometimes used to store CCW, as was the case at the Kingston Plant, are inadequate to physically contain the CCW, but from knowledge of the toxic content of the CCW. In the aftermath of the Kingston spill, elevated levels of arsenic and mercury have been found in the river water and sediment near the site.

It is now commonly appreciated that the toxicity problem may worsen as emissions controls such as FGDs become more common. Currently, 25% of CCW is from FGD material. An escalation in the production of CCW will put additional pressure on EPA to address the issue. In fact, EPA has indicated that, apart from new regulation under

[31] U.S. GAO. *Letter to the Chairman of the Senate Committee on Environment and Public Works and Chairman of the House of Representatives Committee on Oversight and Government Reform RE: Coal Combustion Residue: Status of EPA's Efforts to Regulate Disposal*. October 30, 2009.

RCRA, current effluent guidelines for electric generating plants under the Clean Water Act should be revised.[32]

Q. WHAT IS THE COMPANY'S EXPOSURE TO RISK OF INCREASED COST DUE TO CCW DISPOSAL REGULATIONS?

A. The Company has not provided an analysis of that risk exposure. However, the size of its fleet of coal-fired generators (having a capacity rating of roughly 5,093 MW, 1040 MW of that in Virginia) suggests that the exposure may be significant.[33] Based on a 2009 EPA survey, the Company has four ash ponds in Virginia – two at Clinch River and two at Glen Lyn.[34] Among its nine ash ponds in West Virginia, in November 2009, EPA issued an information request letter requiring the company to conduct several studies to assure the safety of two impoundments at the Sporn Plant because an EPA report done as part of the ongoing comprehensive review of dam integrity of coal ash impoundment sites found factors at the facility that are similar to the TVA Kingston facility that failed in December 2008. [35] Retiring some or all of these coal-fired units could avoid the need for new investments in more expensive, RCRA-compliant disposal facilities. This is the type of information that should have been, but was not included, in the IRP.

Virginia's Department of Environmental Quality has formed an advisory committee to look at strengthening the regulations for structural fills using CCW. New requirements could limit the permeability of fills and prohibit the construction of fill sites in the 100-year floodplain.[36]

Q. WHAT ARE THE EXPECTED COSTS OF REGULATION OF CCW DISPOSAL?

A. A 2009 report by EOP Group, Inc., estimates that, industry-wide, the net present value costs of phasing out ash ponds are on the order of

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[32] *Ibid*.
[33] VA Supplemental information, Schedule 7a; IRP, Appendix A, Figure 1. AEP-East has 21,655 MW of coal-fired capacity. VA Supplemental Information, Schedule 7b.
[34] http://www.epa.gov/waste/nonhaz/industrial/special/fossil/surveys/survey2.pdf
[35] http://www.epa.gov/waste/nonhaz/industrial/special/fossil/surveys2/statement.htm
[36] Manuel, *op. cit.*

$39 billion, or $2.5 billion per year over a 20-year period, assuming a 3% discount rate. According to the report, many smaller or older units may become uneconomic to run under a scenario in which CCW disposal in surface impoundments is no longer permitted

> For some smaller units and/or units with limited remaining useful life, the fixed costs associated with the conversion to dry management of CCBs may, depending on a range of factors, be too high to allow the facility to recover the conversion costs given the limited capacity of these units. The most cost-effective compliance solution for generators with such units may be to terminate operations and purchase replacement power from elsewhere. Based on discussions with utilities, the Report concludes that units with below 230 MW of generating capacity have the greatest potential risk of ceasing operations if required to undertake the mandatory closure of CCB surface impoundments. This does not mean that such units will close, but rather that units below this MW generating capacity cutoff are at greater risk of no longer being economically viable. [37]

Q. DOES THE COMPANY ACCOUNT FOR THE RISK OF COSTS OF CONTINUING TO OPERATE EXISTING COAL PLANTS IN THE FACE OF REGULATION OF CCW DISPOSAL IN ITS IRP?

A. No. The Company states that it did not account for any potential future regulation of CCW in its 2009 Plan, [38] nor has it done an assessment of the impact of the retirement of the coal units at Glen Lyn or Clinch River Stations on its production of CCW within the 2009 Plan. [39] From the Company's response, it is not clear whether such assessments have been conducted outside of the IRP. In any event, inclusion of these data in the IRP is necessary for considering all resources on a level playing field.

Q. HOW SHOULD THE COMPANY HAVE ACCOUNTED FOR THE RISK OF CCW DISPOSAL REGULATIONS IN ITS IRP?

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[37] EOP Group, Inc., 2009, *Cost Estimates for the Mandatory Closure of Surface Impoundments Used for the Management of Coal Combustion Byproducts at Coal-Fired Electric Utilities*.
[38] Response to Environmental Respondents First Set Question No. 9.
[39] Response to Environmental Respondents First Set Question No. 10.

A. At a minimum, the Company should have:

1. projected the incremental costs, with justification, for future CCW disposal under two CCW regulation scenarios (RCRA Subtitle C and RCRA Subtitle D), and
2. identified alternative options for mitigating the generation of CCW, such as fuel switching, retrofitting, or other means of compliance, and identified the incremental costs for such options.

This information should have been considered when developing Alternative Plans and incorporated into the cost of running existing coal plants in the IRP modeling, if not in the base case then in a scenario.

Q. WHAT DO YOU RECOMMEND THE COMMISSION DO FOR THE PURPOSES OF THE CURRENT PROPOSED IRP?

A. The Commission should require the Company to submit a compliance filing to form part of its IRP, which would provide a detailed and accurate discussion of the expected CCW disposal regulation(s). The modeling underlying the IRP should be rerun to reflect any projected additional costs due to these potential regulations as a cost of continuing to run existing coal plants.

Q. PLEASE EXPLAIN HOW THE IRP FAILS TO PROPERLY CONSIDER THE RISKS AND UNCERTAINTIES WITH REGARD TO POTENTIAL FUTURE ENVIRONMENTAL REGULATIONS.

A. As with carbon regulation, coal combustion waste issues, and the pending mercury emission rules discussed above, other environmental regulations are under review or being proposed. New or potentially more stringent requirements on existing coal-fired power plants include tougher ozone, fine particulate matter, sulfur dioxide and nitrogen oxide national ambient air quality standards, a new regulations on the transboundary air pollution for these pollutants (that is, a new Clean Air Interstate Rule, or CAIR), the forthcoming Haze Federal Implementation Plan, and EGU effluent limitation guidelines under the Clean Water Act.

While I am not offering an opinion at this time as to the likelihood of these regulations nor on the effects they would have of coal plant costs or operations, the sheer length and breadth of the list should make clear the need for careful examination of the risks and uncertainties associated with envirotal compliance requirements for coal-fured generation..

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, at this time.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA.
Senior Consultant, July 2003 to Present
Consulting services to state public advocates, consumer advocates, environmental organizations, and utility regulators on regulatory policy, power supply procurement, electric industry restructuring, portfolio management, rate setting and rate design, economic impacts of efficiency and renewable generation programs, and other utility and energy topics. Expert witness services and litigation advice. Co-authored reports, journal articles and conference presentations on portfolio management, energy efficiency programs, and electric reliability.

Vermont Department of Public Service, Montpelier, VT.
Director for Regulated Utility Planning, 1986-2003
Preparation of long range policy plans in the areas of electric utilities, energy and telecommunications, including oversight of research, modeling, public input processes, policy analysis and writing. Development of policy positions and drafting of legislation and rules concerning utility resource planning, power supply acquisition, generation and transmission permitting, environmental costing, energy efficiency and alternative generation, utility restructuring and retail choice, distributed utility planning, rate setting and rate design, mergers, financing and acquisitions, decision analysis, power contract restructuring, Qualifying Facility contracts and permits, net metering, and other critical regulatory issues. Extensive expert testimony on those matters, as well as utility bankruptcy, prudence reviews, and critical utility policy matters. Extensive legislative testimony.

Planning Econometrician, 1981-1986
Energy demand forecasting, economic and demographic projections, economic and policy impact analysis, avoided cost estimates, and other quantitative analysis for utility and energy policy making. Development of State's basic policies regarding least cost planning and resource selection, including methods for evaluation of and program design for generation, transmission and demand-side options. Implementation of utility energy efficiency program requirements.

Vermont Agency of Human Services, Montpelier, VT.
Director of Planning, 1979-1981

Vermont Department of Social and Rehabilitation Services, Waterbury, VT.
Director of Planning and Evaluation, 1977-1979
Acting Deputy Commissioner, 1977

Vermont Department of Corrections, Montpelier, VT.
Director of Planning and Research, 1974-1977
Chief of Research and Statistics, 1973-1974

Pre-2004 Energy Consulting

Illinois Energy Office, 1986.
Massachusetts Executive Office of Energy Resources, 1986.

Northern Technology, Inc., Gorham, NH, 1983-1985.
James River Corporation, Green Bay, WI, 1985.
Newfoundland Department of Natural Resources, 1995

Teaching

University of Vermont, Burlington, Vt., 1977 to 1989
Adelphi University, Garden City, N.Y., 1980 to 1988
University of N. H., Complex Systems Ctr., Grad. Studies Comm., 1992-1994
Institute of International Education, Least Cost Planning Seminar, 1999
Community College of Vermont, 2002-2004

Miscellaneous

National Science Foundation Undergraduate Research Grant, 1965.
Wesleyan University Astronomy Prize, 1967.
Association for Criminal Justice Research (Northeast/Canada), Director, 1973 to 1981,
Secretary/Treas., 1973 to 1980.
University of Vermont Graduate Award in Statistics, May, 1980.
Contributing Editor, Current Index to Statistics, 1976-1985.
Chair, Session on Energy Economics, New England Business and Economics Association
Annual Meeting, 1983.
Member, Intl. System Dynamics Soc., Tau Beta Pi.
Northeast International Committee on Energy, New England Governors' Conference/Eastern Canadian Premieres,
various periods, 1986 to 2003
Director, Vermont Girl Scout Council, 1989-1991, 2000-2008; Secy., 1991-1997
3rd Vice President, Girl Scouts of the Green and White Mountains, 2009 to date
Editor, Intl. System Dynamics Soc. Bibliography, 1990-
Advisory Group Member, New England Project, MIT Analysis Group for Regional
Electricity Alternatives, 1991-1995.
Chair, Steering Committee & Modeling Subcommittee, New England Governors Conf.
Regional Energy Planning Project, 1991-1995.
Member, Montpelier School System Technology Steering Committee and Montpelier
High School Technology Committee, 1992-1993.
Reviewer, Vermont Experimental Program to Stimulate Competitive Research, 1993-
Invited Speaker, 3rd Intl. Conf. on Externality Costs, Ladenburg, FDR, 1995.
Member, Steering Committee, New England Governors Conference, Restructuring/
Environmentally Sustainable Technologies Project, 1996-1997
U. S. DOE Distributed Generation Collaborative, 2000-2003
Justice of the Peace, Montpelier, Vermont, 2007–

EDUCATION

Degrees

B.A., Physics, Wesleyan University, Middletown, CT, 1970
M.S., Statistics, University of Vermont, Burlington, VT, 1980
Ph.D., Mechanical Engineering , University of Vermont, Burlington, VT, 1988

Continuing Education

Seminar in Electricity and Telecommunications Demand, 1981
Advanced Workshop in Regulation and Public Utility Economics, June, 1982 and
June, 1983, Rutgers University
Transmission Reliability Assessment, Power Technologies, Inc., 1986
Regional Forecasting and Simulation Modeling, January, 1991, U. Massachusetts-Amherst

TESTIMONY and AFFIDAVITS

Vermont Public Service Board

On behalf of the Vermont Department of Public Service:

Docket 4661 - Green Mountain Power Rate Increase

Dockets 5009/5112 - Vt. Electric Coop. Rate Increase

Dockets 5108/5109 - Vt. Marble Co. Small Power Rate

Docket 5133 - Moretown Hydro Energy Co. Small Power Rate

Docket 5202 - VPPSA Refinancing

Docket 5248 - DPS Ontario Hydro Power Purchase

Docket 5270 - Least Cost Planning and Demand-Side Management

Docket 5270-GMP-1 - Highgate Apartments Fuel Switching

Docket 5270-CV-1&3 - Demand-Side Management Preapproval and Ratemaking Principles

Docket 5270-CV-4 - IRP

Docket 5270-VGS-1 - Demand-Side Management Preapproval

Docket 5270-WEC-1 - Demand-Side Management Preapproval

Dockets 5270-BRTN-1, 5270-CUC-3, 5270-HDPK-1, 5270-JHNS-1, 5270-JKSN-1, 5270-LDLW-1, 5270-LYND-1, 5270-MRSV-1, 5270-ORLN-1, 5270-RDSB-1, 5270-ROCH-1, 5270-STOW-1, 5270-SWNT-1, 5270-VMC-1 - IRP's

Docket 5270-VGS-2 - Demand-Side Management Preapproval

Docket 5277 - DPS Ontario Hydro Transactions Agreement

Docket 5330A - Hydro Quebec Power Purchase

Docket 5330E - Hydro Quebec Power Purchase, Waiver and Amendment

Docket 5372 - CVPSC Rate Increase

Docket 5491 - CVPSC Rate Increase

Docket 5630/32 - VEC Debt Restructuring & Rate Increase

Docket 5634 - NET Toll Dialing Plan

Docket 5638 - CVPSC Mack Molding*

Docket 5664 - EPACT Standards

Docket 5810/11/12 - VEC Debt Restructuring & Rate Increase

Docket 5825 - Ludlow IRP - externalities

Docket 5826 - Vermont Marble Electric Division - IRP - externalities

Docket 5832 - Lyndonville IRP - externalities

Docket 5841/5859 - Citizens Utilities Prudence Review & Revocation Petition

Docket 5854 - Electric Restructuring*

Docket 5857 - GMP Rate Increase*

Docket 5971 - VEC Bankruptcy Reorganization*

Docket 5980 - Proposal for Statewide Efficiency Utility

Docket 5983 - GMP Rate Increase (HQ Issues)

Docket 6018 - CVPSC Rate Increase (HQ Issues)

Docket 6107 - GMP Rate Increase (HQ Issues)

Docket 6140 - Electric Industry Restructuring (various presentations)*

Docket 6033/6053/6110/6142/6158/6326/6327/6371/6462/6464 - various municipal electric rate increases*

Docket 6270 - Qualifying facility contract reform

Docket 6290 - Distributed Generation*

Docket 6300 - Sale of Vermont Yankee

Docket 6330 - Petition of CVPSC and GMP on Restructuring (various presentations)*

Docket 6149/6315 - WEC electric rate increases* (HQ and Settlement Issues)

Docket 6460 - CVPSC Rate Increase (HQ Issues)

Docket 6495 - Vermont Gas Systems Rate Increase (Deferral Account and Hedging)

Docket 6565 - Various station service contracts

Docket 6596 - CUC rate Increase (HQ Issues)

Docket 6758 - Fourteen Utilities - Violations of Statutes on Special Contracts and Special Rates—Phases I & II

For consulting clients:

Docket 6958 - Green Mountain Power Rate Design - for AARP

Docket 6958 - Green Mountain Power Rate Design - for Conservation Law Foundation

Docket 6958 - Green Mountain Power Rate Design - for Conservation Law Foundation

Docket 7085 – CVPS Street Lighting Tariff – for Village of Woodstock

Docket 7175 - Green Mountain Power Rate Design – for Conservation Law Foundation and AARP

Docket 7176 - Green Mountain Power Alternative Regulation Plan—for Conservation Law Foundation and AARP

Docket 7336 – CVPS Alternative Regulation Plan – for Conservation Law Foundation*

Docket 7466—Efficiency Utility Structure—for Conservation Law Foundation

Vermont State Environmental Board

Docket 5W0584-EB - Developers Diversified Land Use Permit

Federal Energy Regulatory Commission

Docket Nos. ER95-1586-000 and EL96-17-000 - Citizens Utilities Company **

California Public Utilities Commission

Multi-Stakeholder Study of Alternatives to the Mohave Generating Plant Pursuant to CPUC Decision 04-12-016 - for Southern California Edison (February 2006) *

R.06-02-013 – Long Term Procurement Plans of PG&E, SCE and SDG&E&E – for the Division of Ratepayer Advocates (March 2007)

Connecticut Department of Public Utility Control

Docket No. 03-07-16 - Alternative Transitional Standard Offer (live testimony Dec. 2004, prefiled comments Jan. 2003) *

Delaware Public Service Commission

Docket No. 04-391 – Standard Offer Service – for the Commission Staff (live testimony October 2006)

District of Columbia Public Service Commission

Formal Case 1047 – Investigation into the Structure of the Procurement Process for Standard Offer Service – for the District Office of People's Counsel (June 2006 to date) **

Florida Public Service Commission

Dockets 080407 through 080413-EG – Commission Review of Numeric Conservation Goals – for the Southern Alliance for Clean Energy and the Natural Resources Defense Council (August 2009)

Illinois Commerce Commission

Docket No. 05-0159 - Commonwealth Edison Basic Utility Service Procurement

Docket No. 05-0160, 0161 and 0162 - Ameren CILCO, AmerenCIPS, and AmerenIP - Basic Utility Service Procurement

Indiana Utility Regulatory Commission

CAUSE NO. 42598 - Vecrtren North - Gas cost rate making mechanism and demand side management programs (Sept. 2004)

CAUSE NO. 42612 - Public Service of Indiana - demand side management programs (Sept. 2004)

Massachusetts Department of Public Utilities

Docket 07-050 – Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources – for The Energy Consortium (June 2007) *

Mississippi Public Service Commission

Docket 2008-AD-158 – Proceeding to Review Statewide Electric Generation Needs – for The Sierra Club (June 2008)

Docket 2008-AD-477— Docket to Consider Standards Established by the Energy Independence and Security Act of 2007, Section 111(d) of Public Utility Regulatory Policy Act (16 U.S.C. § 2621)—for The Sierra Club (November 2009) *

New Hampshire Public Utilities Commission

Docket DE 07-064 – Revenue Decoupling Investigation – for Conservation Law Foundation (May 2007 to date) *

Ohio Public Utilities Commission

Restructuring Roundtable – System Benefit Charges - Commission workshop presenter *

Case No. 09-906-EL-SSO—Competitive Bidding Process—for Ohio Consumers' Counsel (December 2009)

Oklahoma Corporation Commission

Cause No. RM 2007-007 – Demand Side Management Rulemaking – for The Sierra Club and the Oklahoma Sustainability Network (May 2008) *

South Carolina Public Service Commission

DOCKET NO. 2009-261-E—SCE&G DSM filing—for Southern Environmental Law Center and the South Carolina Coastal Conservation League (January 2010) (testimony filed)

U.S. District Court for the District of Vermont

Civ. No. 2:03-cv-279 – Circumferential Highway Impact Analysis – for Vermont Public Interest Research Group, Inc., Friends of the Earth, Inc., Conservation Law Foundation, and The Sierra Club (January 2004) **

Virginia State Corporation Commission

Docket # PUE-2009-00023 – Conservation and demand response targets – the Southern Environmental Law Center, Appalachian Voices, Chesapeake Climate Action Network and the Virginia Chapter of the Sierra Club (September 2009)

Docket # PUE-2009-00081 – Demand Side Management Program Approvals – the Southern Environmental Law Center, Appalachian Voices, Chesapeake Climate Action Network and the Virginia Chapter of the Sierra Club (December 2009)

Docket # PUE-2009-00096 – Dominion IRP – the Southern Environmental Law Center, Appalachian Voices, Chesapeake Climate Action Network and the Virginia Chapter of the Sierra Club (February 2010) (testimony filed pending hearing)

Docket # PUE-2009-00097 – APC0 IRP – the Southern Environmental Law Center, Appalachian Voices, Chesapeake Climate Action Network and the Virginia Chapter of the Sierra Club (March 2010) (testimony filed pending hearing)

* No prefiled testimony
** Affidavit only

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Bartels, C., R. Squires, and W. Steinhurst. *Electric Power Supply in Vermont*. Vt. DPS, 1983.

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Wilson, D., J. O'Rourke, W. Steinhurst, et al. *Welfare Reform: A Vermont Perspective*. Vt. AHS, 1980.

von Turkovich, B., and W. Steinhurst. "Plastic Flow Localization and Instability in Metal Processing." *Proc. 14th N. Amer. Manuf. Res. Conf.*, Minneapolis, May, 1986, pp. 340-347.

ARTICLES AND PRESENTATIONS

Andersen, D., G. Richardson, J. Rohrbaugh, S. Ratanawijitrasin, W. Steinhurst. "Group Model Building. *Proceedings of the International System Dynamics Conference*. Intl. System Dynamics Soc., 1992.

Biewald, B., Chernick, P., and W. Steinhurst. *Environmental Externalities: Highways and Byways*. Proc. NARUC IRP Conf., Kalispell, MT, 1994.

Hamilton, B., L. Milford, S. Parker and W. Steinhurst, "Fuel Switching in Vermont: Issues and Experiences." *Proc. of ACEEE 1992 Summer Study on Energy Efficiency in Buildings*, 12 pp.

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------- "Don't Throw Out the Baby: Some Design Requirements for Federalism Reform." *New England Journal of Human Services*, 1, 41 - 45 (1981).

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------- and G. Backus. "Application of System Dynamics to an Integrated Economic and Environmental Policy Assessment." In D. F. Andersen, et al., *System Dynamics '90, Proc. of the 1990 International System Dynamics Conf.*, Boston, MA., pp. 1060-1074.

------- and W. Merten. "Statistical Analysis of Thermal Shock Tests." *Statistics in Manufacturing*, S. G. Kapoor and M. R. Martinez, eds., ASME Proc., PED-9 (83), 51-56.

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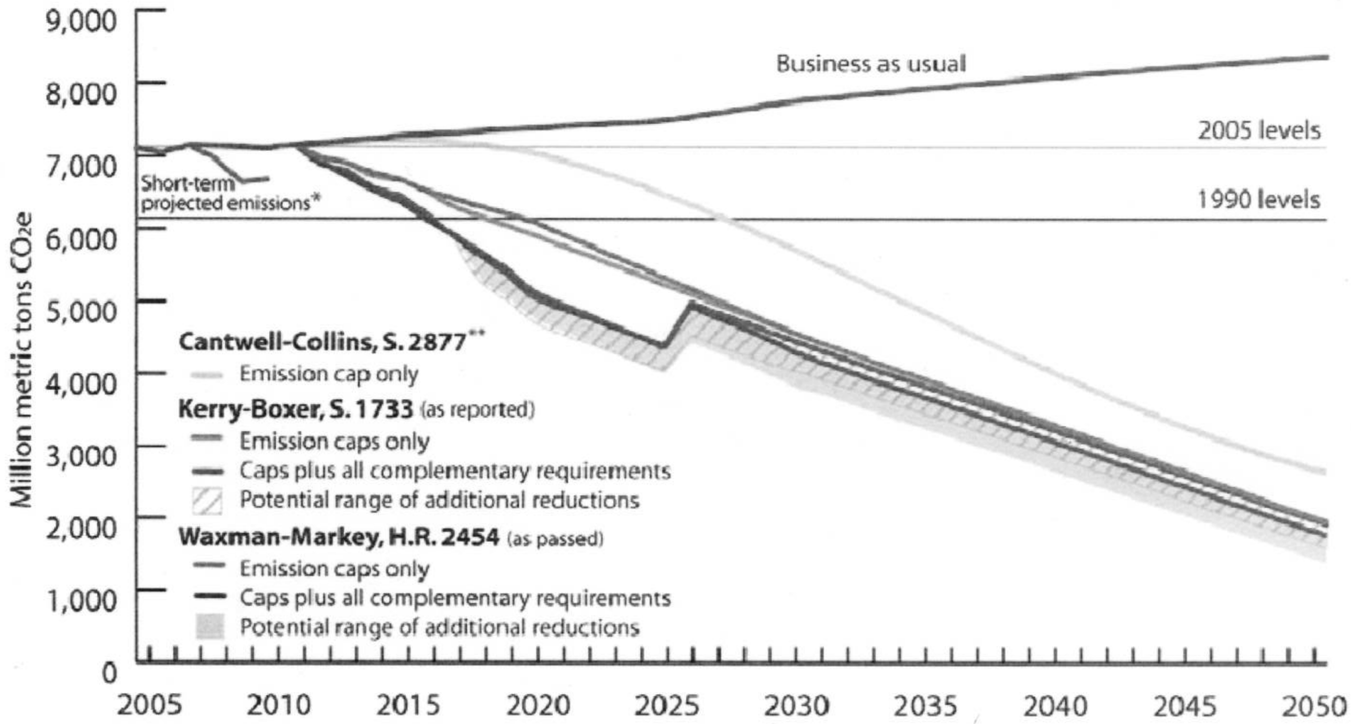
Resume dated March 2010.

Net Emission Reductions Under Cap-and-Trade Proposals in the 111th Congress, 2005-2050

December 17, 2009



WORLD RESOURCES INSTITUTE

For a full discussion of underlying methodology, assumptions and references, please see http://www.wri.org/usclimatetargets.

* "Business as usual" emission projections are from EPA's reference case for its analysis of the Waxman-Markey bill. "Short-term projected emissions" represent EIA's most recent estimates of emissions for 2008-2010.

** Cantwell-Collins sets economy-wide reduction targets beginning with a 20 percent reduction from 2005 levels by 2020. However, additional action by Congress would be required before these targets could be met. Reduction estimates do not include emissions above the cap that could occur due to the safety-valve.