**DIRECT TESTIMONY OF
WILLIAM K. CASTLE
ON BEHALF OF KINGSPORT POWER COMPANY
D/B/A AEP APPALACHIAN POWER
BEFORE THE TENNESSEE REGULATORY AUTHORITY
DOCKET NO. 15-** 00093

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is William K. Castle. My business address is 1051 E. Cary St, Suite 1100, Richmond, VA. I am the Director of Regulatory Services VA/TN for Kingsport Power Company d/b/a AEP Appalachian Power (Kingsport, KgPCo or the Company).

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science degree in Mechanical Engineering from Tulane University in 1988, and a Masters of Business Administration degree from the University of Texas – Austin in 1998. I hold the Chartered Financial Analyst (CFA) designation. I have worked in the utility industry since 1998, beginning with the Columbia Energy Group, Herndon, Virginia, where I held positions in financial planning and corporate finance. Subsequent to the acquisition of Columbia Energy Group by Merrillville, Indiana based NiSource in 2000, I performed financial planning and analysis functions. Since 2004, and prior to my current position, I was employed by AEP Service Corporation in the Corporate Planning and Budgeting department. Assignments included resource planning and demand-side management analysis, which encompasses Energy Efficiency and Demand Response. I have been in my current position since July, 2014.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY AS A WITNESS BEFORE ANY REGULATORY COMMISSION?

A. Yes. I presented testimony on behalf of APCo before the Virginia State Corporation Commission in Case Nos. PUE-2009-00023, PUE-2014-00026, and PUE-2014-00039. I have also presented testimony in the states of Ohio, Oklahoma, Indiana, West Virginia, and Arkansas

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I will provide the rationale for the Company's allocation of the requested increase among customer classes; sponsor a rate realignment plan; support the proposed amortization period for rate case expense and demand response regulatory asset; and propose a recovery mechanism for previously deferred DSM costs. I will explain the alternative rate mechanism: the Variable Cost Rider (VCR), which will be the subject of a future filing, in order to allow the Tennessee Regulatory Authority (TRA or Authority) an adequate opportunity to evaluate that mechanism, given its inter-relationship with elements of this case. I discuss proposed changes to Tariff N.M.S. and propose Tariff N.M.S.-2. Last, I will recommend the expansion of the Company's Demand Side Management (DSM) program and sponsor the accompanying economic analysis.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. I am sponsoring the following four exhibits:

- Exhibit No. 1(WKC) Tariff N.M.S. (Revised)
- Exhibit No. 2(WKC) DSM Program Descriptions
- Exhibit No. 3(WKC) DSM Cost-Benefit Test Results
- Exhibit No. 4(WKC) Optional Rider R.P.R.P.

Q. DESCRIBE KINGSPORT POWER COMPANY'S CURRENT COST RECOVERY.

A. Kingsport Power Company has not sought a base rate increase since 1992. Since then, changes in revenues and costs have occurred such that current rates are no longer adequate to allow the Company to fully recover its costs. To some degree, a portion of the Company's incremental costs are recovered through mechanisms other than base rates, primarily the Fuel Adjustment Clause (FAC) and the Purchased Power Adjustment Rider (PPAR). Kingsport's current base rates include partial recovery of fuel, transmission costs, and purchased power costs.

Q. DESCRIBE HOW THE FUEL, TRANSMISSION, AND PURCHASED POWER COSTS NOT RECOVERED IN BASE RATES ARE CURRENTLY RECOVERED.

A. Under the current mechanisms, a recovery rate is determined in advance and applied to future usage. The FAC rate is adjusted monthly while the PPAR rate is adjusted annually. There is never a reconciliation of the actual revenues (recovery rate times actual usage) to actual costs. Any difference between what was estimated, and what is ultimately recovered from customers, results in a permanent over- or under-recovery of costs.. These differences result from variances in consumption and/or costs and can be off-setting or compounding.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED ALTERNATIVE RATE MECHANISM.

A. The Company will be requesting the TRA's approval to utilize deferral accounting for specific costs and the subsequent recovery of such deferred costs through a single consolidated "rider" which will true up "variable" costs not fully recovered in base rates and which will adjust annually. The Company will seek specific approval for this alternative rate mechanism as discussed below. Most of the costs proposed for recovery in this way are currently included in existing riders that adjust periodically. In this case, the Company proposes to eliminate the current PPAR and FAC riders and include the Company's current level of costs in base rates. In a future filing, KgPCo will propose to establish a new rider, the Variable Cost Rider or "VCR". The VCR, while initially set at zero (dollars), will be designed to recover from, or credit to, customers the expense for specific items that differs from what is actually recovered through the base rates established in this proceeding.

Q. WHAT ARE THE ADVANTAGES OF THE VCR AND ASSOCIATED DEFERRAL ACCOUNTING?

A. Deferral accounting, commonly referred to as "over/under-recovery" accounting, allows the Company to recover from customers the exact amount of cost incurred -- no more or no less. This protects both the Company and customers from unavoidable differences between forecasted rates and consumption, and actual rates and consumption. As Company witness Allen explains in his testimony, actual costs and revenues for the items included in the VCR will be subject to "true-up" periodically. The Company will propose an annual true-up with exceptions made for extraordinary circumstances, should they arise. A further advantage of resetting the rider cost recovery factor annually is the certainty around rates for customers. Instead of monthly changes to rates, customers can expect, in usual circumstances, to have their rates change only annually. In extraordinary cases, the Company will propose to petition the TRA, outside of the usual annual timeframe, to adjust the recovery factor to avoid large over- or under-recovery balances from accruing.

Q. WHAT COSTS WILL THE COMPANY PROPOSE TO BE SUBJECT TO DEFERRAL ACCOUNTING AND INCLUSION IN THE VCR?

A. Consistent with Tennessee Code § 65-5-103 (d), the Company will propose that the following costs be subject to deferral accounting and recoverable primarily in base rates but with a component in the VCR designed to credit to customers, or collect from customers, over- or under-recovered balances respectively.

1. Fuel (currently in base rates and the FAC)
2. Purchased Power costs (currently in base rates and PPAR)
3. Transmission costs (currently in base rates and PPAR)
4. Demand-side Management Costs
5. Distribution Tennessee Reliability Strategy (TRS) Costs
6. Major Storm Recovery Costs
7. Emerging Costs

Q. WHAT ARE "EMERGING COSTS" AND HOW WILL THEY BE RECOVERED?

A. The utility landscape has changed considerably since the Company's last rate proceeding. One emerging cost is that of cyber and physical security. Requirements to enhance or otherwise improve the security of the distribution system may emanate from numerous federal agencies. Other costs may emerge as a result of Federal or State environmental requirements as well as membership in the PJM Regional Transmission Organization (RTO). The Company does not have a projection for these costs at this time, but will request that as these costs emerge and are incurred, they be deferred for future recovery, subject to regulatory review, through the VCR factor. No emerging cost item would be recovered from customers without regulatory review.

Q. DESCRIBE CURRENT STORM COST RECOVERY AND THE COMPANY'S PROPOSAL.

A. The Company currently petitions the TRA for authority to defer costs incurred to restore service following major weather events, and subsequently has been allowed to recover approved costs through a rider. The Company proposes including a normalized level of major storm recovery costs in base rates, subject to over/under-recovery accounting, to be reconciled in annual VCR filings. Company witness Wright discusses the normalized level of major storm expense that the Company proposes to reflect in base rates in his testimony. For example, if actual major storm costs for a year are less than the normalized level established in base rates, customers would receive a credit for the amount of the difference for that component of the VCR after the next annual VCR filing.

Q. DESCRIBE THE TENNESSEE RELIABILITY STRATEGY AND COST RECOVERY PLAN.

A. The Tennessee Reliability Strategy (TRS) is a multi-year approach to enhancing distribution reliability. It is explained in detail in Company witness Wright's testimony. Pursuant to the plan, Kingsport proposes to include, in base rates, a level of vegetation management spending consistent with a four-year trim cycle. The test year level of vegetation management expense has been increased to a going-level of such expense through Adjustment OM-08. The TRS also requires spending over and above the expected going level of expense during the first four years of the program to get the Company to the point where it is on a four-year trim cycle. The Company proposes not to include this incremental level of expense in base rates, as it is expected to be incurred only over a four year period; rather, Kingsport will propose to recover such actual expenses above the level in base rates through the VCR mechanism that it will be filing in the near future.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER CAPITAL COSTS ASSOCIATED WITH THE TRS?

A. The return of (through depreciation) and on (at the pre-tax weighted-average cost of capital approved in this proceeding) capital associated with vegetation management and other distribution reliability investments not in base rates are proposed to be included in the VCR.

Q. HOW WILL THE VCR FACTOR ACCOUNT FOR UNDER- OR OVER-RECOVERY OF THE COSTS SUBJECT TO THE VCR?

A. The Company will propose an annual filing that details all actual costs and revenues for the types of costs associated with the VCR. Further, the Company will propose periodic reporting of deferral balances for each cost item. The VCR factor will be calculated based on the actual over- or under-recovered balances for the individual items in aggregate. All costs would be subject to established regulatory oversight processes, or as the Authority further directs.

Q. WHEN DOES THE COMPANY EXPECT TO IMPLEMENT THE VCR?

A. In its future filing requesting approval of the VCR, the Company will ask the Authority to allow deferral accounting upon implementation of new base rates, and to set the VCR factor at zero. In the future, the Company expects to petition the Authority to set the VCR factor at a rate that recovers or returns under- or over-collected costs associated with the components subject to deferral accounting, to be effective approximately twelve months after the implementation of new base rates, and annually thereafter.

Q. DESCRIBE THE REQUESTED TIMING FOR THE RECOVERY ELEMENTS IN THIS CASE.

A. Tennessee Code Section 65-5-103 requires that the Authority rule within nine months of the filing of a base rate increase petition. The same Section also requires the Authority to act within 120 days of a filing of an alternative regulatory method. In order to meet the timing requirements of a base case rate filing and a filing under Section 65-5-103(d) of the Tennessee Code, the Company plans to file for approval of the VCR, an alternative regulatory method whose purpose and manner of implementation are described in this case, 120 days prior to the expected completion date of this base rate case. In this way, both the TRA and all parties will have adequate time and information to fully understand the interrelationship of the Company's proposals in this case and its upcoming filing for approval of the VCR. Thus, while not seeking explicit approval of this alternative regulatory method in this case, the Company will, in parallel and at the appropriate time, file for approval of the alternative regulatory method, the VCR, as also described in this case.

Q. WHAT LEVEL OF GENERATION, TRANSMISSION, AND FUEL COSTS IS THE COMPANY PROPOSING TO REFLECT IN BASE RATES TO BE APPROVED IN THIS PROCEDING?

A. The Company is proposing to reflect the going level of those costs in base rates, and will propose that they be subject to true-up in the annual VCR filings. Currently, these costs reside partially in base rates, with significant portions recovered through riders, which, while subject to periodic adjustment, are not subject to true-up.

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED REVENUE INCREASE ALLOCATION AMONG CLASSES AND RATE REALIGNMENT PLAN.

A. As Company witness Buck describes, the Company's current rates result in disparate rates of return among the rate classes. If, in addition to allocating the requested increased revenue requirement, class rates of return were immediately equalized, the impact on certain classes, primarily the residential and public school classes, would be overly burdensome. To gradually equalize the class rates of return, the Company proposes to realign the base rates over a six year period. The initial allocation of the revenue increase maintains the current level of subsidy for the residential and public school classes, and institutes an equal percentage increase for other customer classes, thus keeping the increases for each class within a reasonable range in the first year. For the following five years the residential and public school base rates will be increased no more than 2.33% annually, with concomitant reductions to the other classes annually so as to produce no additional base rate revenues for the Company, until the class rates of return have been equalized based upon the cost-of-service data filed in this case. Company witness Buck's testimony shows the annual rate reductions and increases by class over the realignment period.

Q. WHAT OTHER ITEMS DO YOU SPONSOR?

A. I sponsor the Company's proposal to amortize rate case expenses over a 5-year period (Adjustment OM-10). Additionally, I sponsor Kingsport's proposal to recover deferred expenses associated with the Company's Tariff RTODR, approved in Cases Nos. TRA

2012-00012 and TRA 2012-00026, over the same 5-year period (OM-27). The period of five years is consistent with the statutory time allowed between base rate cases to opt into an annual review (§65-5-103). I also sponsor revisions to the Company's Tariff N.M.S. or Net Metering Service Rider, included as Exhibit No. 1(WKC) Tariff N.M.S. (Revised).

Q: PLEASE DESCRIBE THE CHANGES THE COMPANY IS PROPOSING TO ITS NET METERING SERVICE RIDER.

A: The current rider has some provisions that are confusing to current customers and has the potential to compensate them unequally based simply on the month they installed their generator. The proposed changes to the rider address these shortcomings and are consistent with the provisions contained in APCo Virginia's Optional Rider N.M.S. (Net Metering Service Rider). The changes are threefold. First, when determining the customer's billed consumption for purposes of determining the net energy, accumulated billing credits that are carried forward and applied from the previous net metering period are currently excluded from the calculation. Second, it is clarified that a $50 inspection will only be charged to customers whose generators require inspections, as not all generators are necessarily inspected. Last, the proposed tariff clarifies that insurance requirements are specific to losses that arise from the use of the generator. The Company proposes to close this rider to new customers December 31, 2016. Customers wishing to interconnect renewable generators and engage in "net metering, on or after January 1, 2017 would be required to take service under proposed Rider N.M.S.2.

Q: PLEASE DESCRIBE THE RIDER N.M.S.-2.

A: The Company proposes to close its current Rider N.M.S. to new customers at the end of 2016 and introduce a new Rider N.M.S.-2. Participation in Rider N.M.S.-2 will require customers to take service under a demand-metered tariff. Customers on those tariffs will be required to pay, in addition to their basic service charge, a charge based on their highest peak demand realized during the month, as measured by the demand meter. Further, the energy component of the customer's bill will be charged, or credited, at the Company's variable cost of production as described in the tariff.

Q: WHAT IS THE BASIS FOR CLOSING THE RIDER N.M.S. TO NEW CUSTOMERS AND ADDING A NET METERING SCHEDULE THAT REQUIRES DEMAND METERS?

A: The proposed rider reduces or eliminates the cross-subsidization that occurs with the current net metering construct. Currently, a customer on Rider N.M.S. that is served on a tariff that does not have a demand charge can effectively avoid paying a large portion of fixed charges by having his or her excess generation valued at the fully delivered cost, or retail rate. Those avoided fixed costs must be recovered from other customers. With the incorporation of demand meters, participating customers will be charged for the fixed infrastructure they utilize and their excess generation will effectively be valued at the Company's cost to purchase that generation from other sources.

<u>DEMAND SIDE MANAGEMENT</u>

Q. WHY IS KINGSPORT PROPOSING TO EXPAND ITS DSM PROGRAMS?

A. The Company is proposing to expand the DSM Programs beyond Tariff RTODR to provide an opportunity for participating residential customers to lower their monthly electric bills. A well-implemented DSM program will provide benefits to both the Company and its customers and is proposing two programs.

Q. PLEASE DESCRIBE THE RESIDENTIAL DSM PROGRAMS THAT KINGSPORT POWER PROPOSES TO IMPLEMENT.

A. KgPCo is proposing to implement two programs that reduce energy and demand requirements for its residential customers. The programs included in this portfolio, as well as a short description, are listed below. A more detailed description of each program can be found in Exhibit No. 2 (WKC).

- **Residential Direct Load Control Program:** This program is designed to reduce residential summer peak demand by cycling off air conditioners and electric heat pumps through the use of separately installed control devices. KgPCo will operate this equipment during times such as utility system peak, high loading on distribution circuits, and/or emergency conditions. The instances that KgPCo will be allowed to operate the equipment will be predefined and customers will be provided a financial incentive should they elect to participate. Participants will be subject to the provisions in Optional Rider R.P.R.P. (Residential Peak Reduction Program).
- **Residential Low Income Program:** This program aims to generate savings for high usage low income residential customers through the evaluation of energy improvement opportunities, installation of cost-effective weatherization upgrades, and other energy savings for dwellings. To administer the program, KgPCo will partner with existing Weatherization Assistance Program providers. The program is also designed to reduce residential energy use by partnering with local food banks to distribute compact fluorescent light ("CFL") bulbs to food bank recipients.

Q. WHAT ARE THE EXPECTED ENERGY AND DEMAND SAVINGS OF THE DSM PROGRAMS?

A. Figure 1 below displays the expected energy and summer peak demand savings of each program in the proposed Portfolio. The savings for the Residential Direct Load Control program reflect the expected impacts for each year. The savings for the Residential Low Income program are the incremental savings in each year; the cumulative or on-going effect after Year 3 is also shown.

Figure 1 – DSM Programs – Energy and Summer Demand Savings

Residential Direct Load Control		Year 1	Year 2	Year 3
Participants	Annual	300	600	900
Demand Savings (kW)	Summer	270	540	810
Energy Savings (kWh)	Annual	12,000	24,000	36,000

Residential Low Income		Year 1	Year 2	Year 3	Cumulative
Energy Savings (kWh)	Annual	505,000	170,000	170,000	845,000
Demand Savings (kW)	Annual	45	14	14	73

Q. WHAT IS THE ESTIMATED COST FOR THE PORTFOLIO?

A. KgPCo estimates that it will spend approximately $300,000 annually on the Portfolio, which is detailed in the table below.

Figure 2 – Total KgPCo Projected Program Costs

Projected Program Cost	Year 1	Year 2	Year 3
Residential Direct Load Control	$150,000	$162,000	$162,000

Residential Low Income	$150,000	$138,000	$138,000
Total	**$300,000**	**$300,000**	**$300,000**

A more detailed breakdown of the estimated costs of these programs is provided in Exhibit No. 2 (WKC).

Q. IS THE DSM PORTFOLIO COST EFFECTIVE?

A. Yes, the Portfolio is cost-effective from several perspectives as measured by industry-standard benefit-to-cost tests. The Company evaluated the cost-effectiveness of the Portfolio using several tests because each test quantifies the benefits and costs of the programs from different perspectives. This ensures that the Portfolio strikes the appropriate balance between the impact on ratepayers and the overall public interest.

Q. HOW DOES THE COMPANY PLAN TO RECOVER THE COSTS OF ITS DSM PROGRAMS?

A. KgPCo is proposing to recover the costs of the Programs primarily through base rates. In particular, the costs associated with the design, implementation and operation of the Programs have been added to KgPCo's test year Administrative and General (AG) expenses as Adjustment OM-14. Additionally, KgPCo will propose to reflect differences between actual DSM costs incurred, and DSM revenues collected through base rates, as a component of its upcoming VCR filing.

Q. IF THE AUTHORITY APPROVES KGPCO'S REQUEST, WHEN DOES KGPCO PLAN TO IMPLEMENT THE RESIDENTIAL DSM PROGRAMS?

A. Approximately 120 days after the TRA's approval, KgPCo plans to implement the Residential Low Income Program, with the program continuing for three years. In addition, both programs will be evaluated during the three-year portfolio period and, if deemed successful, could become ongoing elements of the Company's DSM portfolio. By making the DSM costs an element of the VCR, and thus subject to true up, customers will only pay for programs that are implemented. If the programs are discontinued or reduced, the VCR would reflect the reduced expense.

Q. HOW DOES KGPCO PLAN TO IMPLEMENT ITS RESIDENTIAL DSM PROGRAMS?

A. The Residential Low Income Program is expected to be implemented by Community Housing Partners. Appalachian Power Company, an affiliate of Kingsport, selected a third-party program contractor through a competitive bidding process to implement the Residential Direct Load Control Program in its Virginia service territory. KgPCo will be able to "bolt on" to this capability, effectively reducing the cost to implement the program in its service territory. In this initial three-year Program plan, third-party program implementation contractors can provide a number of benefits. These contractors have successfully operated similar programs in various parts of the United States and have the ability to develop forms, processes, tracking databases, payment procedures, as well as the systems, materials, and market understanding to quickly and effectively launch customer programs.

During the three-year program period, KgPCo intends to review the performance of selected implementation contractors, determine best practices, and refine operational plans as deemed necessary. All costs for the KgPCo programs will be charged to work orders set up to capture only those costs related to the KgPCo programs. Further detail regarding the implementation of these programs is provided in Exhibit No. 2 (WKC).

Q. HOW WILL THE COMPANY MEASURE PROGRAM SAVINGS?

A. Program Evaluation, Measurement, and Verification (EM&V) activities are an important component of the Portfolio and will be used to verify program savings and monitor program performance in Tennessee. Effective EM&V ensures that expected results are measurable, achieved results are robust and defensible, and program delivery is effective in maximizing participation. KgPCo will use the EM&V results to monitor and further develop its DSM Programs.

EM&V will be conducted throughout the program through activities such as review of program-specific data, surveys, and periodic field visits to randomly selected participant sites, where appropriate. Process evaluations may be conducted in an early stage of program implementation to assure program delivery mechanisms are effective. Impact evaluations will be periodically conducted and may include, as appropriate for each program, compilation and review of all costs, installed measures, demand and energy impacts, review of the measurement and verification field visit results, surveys of samples of participating and non-participating customers, analyses of participant's billed energy and available interval usage, and cost/benefit analyses based upon actual program costs and achieved savings.

Q. PLEASE DISCUSS THE FOUR COST/BENEFIT TESTS USED IN THE ECONOMIC EVALUATION.

A. The four tests used to evaluate the proposed programs are commonly referred to as the "California Tests," as they have their origin in that state in the 1980s. The tests have been updated over the years and are industry standard tests and are defined in the California Standard Practice Manual: Economic Analysis of Demand-side Programs and Projects, October 2001. The tests seek to quantify the benefits and costs associated with demand-side investments from different perspectives. The results are often expressed, as they are here, in terms of a ratio, where a ratio of the benefits to costs that exceeds 1.0 is "cost-effective."

1. The Total Resource Cost (TRC) test is also known as the "all ratepayers" test and it evaluates costs and benefits from that perspective. In the plainest sense, it compares the value of all the resources saved to the cost of installing and operating the energy efficiency or demand response measure, regardless of who pays.

2. The Program Administrator, or Utility Cost (UCT) test, quantifies cost-effectiveness from the perspective of the utility (or program administrator) that is implementing the program. It compares utility benefits (avoided costs) to the costs of the program. This test is also referred to as the "revenue requirement" test as it provides an indication of the effect on revenue requirements the programs will have on the utility.

3. The Participant Cost test evaluates cost-effectiveness from the perspective of the utility customer that participates in the program.

4. The Ratepayer Impact Measure (RIM) test is also called the "non-participant" test as it takes the perspective of a utility customer that does not participate in the program. It compares the utility benefits (avoided costs) to the costs of the program and utility net lost revenues. It is indicative of the direction of rates as a result of the program implementation.

Q. PLEASE PROVIDE AN OVERVIEW OF THE ELEMENTS OF THE TESTS.

A. **Discount Rate** - Because the savings from an energy efficiency investment accrue over the useful life of the measure, the benefits are discounted back to the period when the investment was made using an appropriate discount rate. For all but the Participant test, the utility's weighted average cost of capital is typically used. For participants, the discount rate is arguably higher as efficiency investments often need payback periods of five years[1] to be viable.

Avoided Costs - Energy efficiency and demand response investments are said to "avoid costs." All things being equal, less energy needs to be produced and transmitted as a result of the investment: thus, the marginal, variable costs of production (largely fuel) are not incurred; and/or less capacity is necessary during peaks to produce and transport energy, thereby avoiding the marginal cost of capacity. This analysis uses forecasted market prices of energy and capacity within the PJM market, and the most recent NITS rate for transmission for the avoided costs.

Retail Rates – The retail rates are those rates and tariffs that will be in effect in 2016, escalated at 2% for the lives of the measures.

Cost and Impact Data – The estimates for costs and multi-year demand and energy impacts were developed by AEPSC Consumer Programs using information from programs in effect in other AEP companies.

Q. ON WHAT BASES WERE THE PROGRAMS EVALUATED?

A. Capacity impacts were evaluated at the time of PJM's system peak (summer). Generation capacity values used consist of PJM market auction results, actual and forecasted. Similarly, energy costs are a forecast of the marginal energy costs at the AEP

[1] Commercial and Institutional Building Energy Use Survey 2000, December 2003, Office of Energy Efficiency, Natural Resources Canada.

Hub within PJM. Avoided transmission costs are reflective of the rate included in the most recent PPAR.

Q. DESCRIBE THE RESULTS OF THE COST BENEFIT TESTS.

A. The test results tabulated in Exhibit 3 (WKC) show that the proposed Residential Direct Load Control (DLC) Program is solidly cost-effective (benefit-to-cost ratios greater than 1) from all perspectives, while the Residential Low Income Program is cost-effective from all but the non-participant's perspective, which is typical across the industry for these types of programs. The Portfolio is cost-effective from all perspectives, with the exception of the RIM test, where it is "break-even."

Q. DID YOU EMPLOY SENSITIVITY ANALYSIS?

A. Yes. The absolute value of these programs over their useful lives can only be estimated. Thus, it is instructive to vary the estimates of avoided costs to understand how robust the determination of cost-effectiveness is. The tests were calculated under "Base," "Low," and "High" commodity price scenarios which varied energy and capacity costs +/- 15%. The results are shown in Exhibit 3 (WKC).

Q. DO YOU CONSIDER THE PORTFOLIO TO BE COST-EFFECTIVE AND REASONABLE TO IMPLEMENT?

A. Yes. Even under scenarios of substantial reductions in future avoided costs, the Portfolio remains cost-effective from the perspective of all rate payers, the utility, and program participants. The impact on rates, as described by the RIM score, is nearly neutral when evaluating the Portfolio in the context of the forecast of PJM market prices for energy and capacity. Additionally, other system benefits will result from the implementation of the Portfolio, including reduced rate volatility associated with fuel and emissions costs.

Q. HAS THE COMPANY SUBMITTED A PROPOSED TARIFF FOR PARTICIPATION IN THE RESIDENTIAL PEAK LOAD CONTROL PROGRAM?

A. Yes. Exhibit 4 (WKC) is the Company's proposed Optional Rider R.P.R.P.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.